

CANADIAN CRUDE OIL AND NATURAL GAS PRODUCTION, SUPPLY COSTS, ECONOMIC IMPACTS AND EMISSIONS OUTLOOK (2019-2039)



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 Canadian Energy Research Institute

**CANADIAN CRUDE OIL AND NATURAL GAS PRODUCTION, SUPPLY COSTS,
ECONOMIC IMPACTS AND EMISSIONS OUTLOOK (2019-2039)**

Canadian Crude Oil and Natural Gas Production, Supply Costs,
Economic Impacts and Emissions Outlook (2019-2039)

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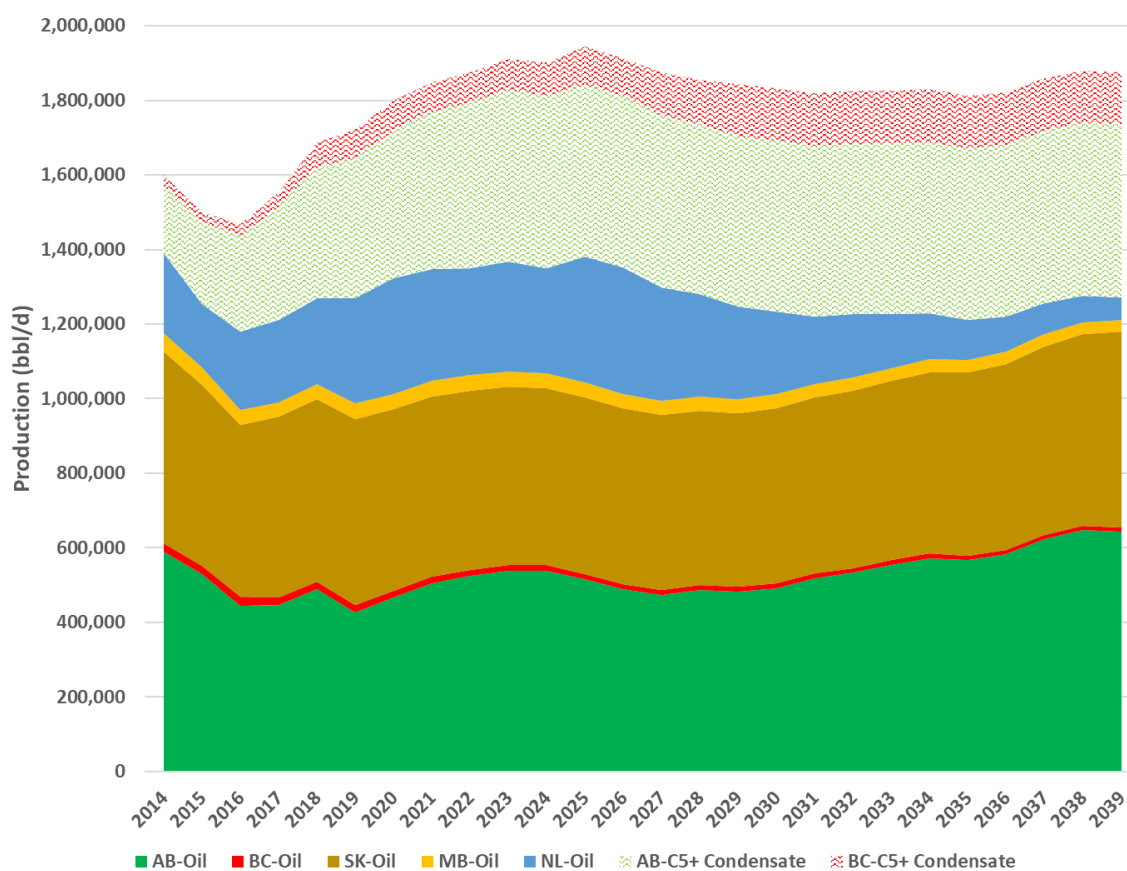
Executive Summary

This study examines Canada's conventional crude oil and natural gas industries, including production forecasts and supply costs, over the next 20 years. The study covers onshore and offshore conventional oil, including shale and tight oil activity, conventional natural gas, coalbed methane, tight and shale gas, and the associated natural gas liquids (pentanes plus and condensate only). It does not include oil sands.

In this study, the overall oil outlook is shaped based on several factors: the dynamics of the US crude imports (declining before 2030 and growing afterwards), relatively stable demand from domestic refineries, the pentanes plus and condensate's growth underpinned by the demand from oil sands, the additional pipeline exports to Central Canada to displace foreign oil, and additional exports via the Trans Mountain Pipeline. The outlook for gas is formed based on the expectations of additional domestic natural gas consumption, declining net exports to the US, and the additional demand for gas from LNG developments.

Figure E.1 shows historical and forecasted oil production between 2014 and 2039.

Figure E.1: Canada Crude Oil Production Forecast



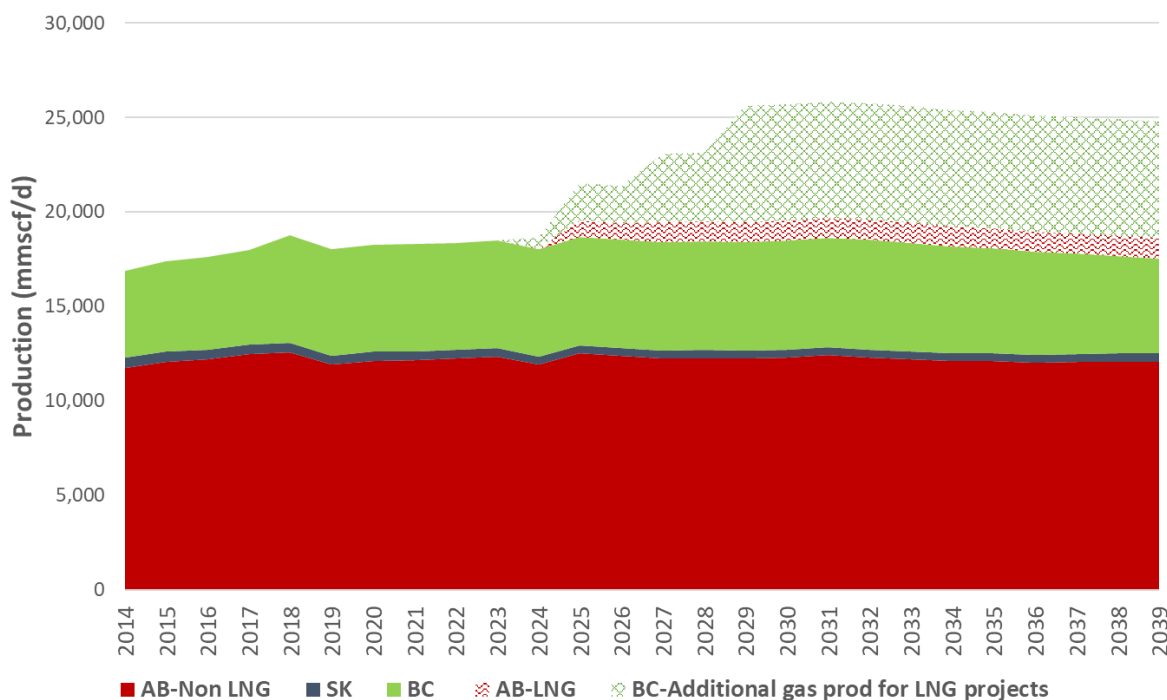
Source: CERI, BCOGC, AER, Government of SK, Government of MB, CNLOPB, PSAC, CAPP

For crude oil, the pricing environment over 2014-2018 had an impact on the industry and led to a sharp reduction in production. More than 200 Mbpd of oil production was lost from 2014 to 2016. However, from 2016 the trend reversed and is expected to do so until 2025 reaching approximately 1.4 million bpd (without pentanes plus and condensate). This is followed by a decline to 1.3 MMbpd due to falling production in Newfoundland and Labrador (Figure E.1) by the end of 2039. Growth in crude oil production will be led by Alberta followed by Saskatchewan (Figure E.1). Together with Saskatchewan, Alberta is affected most by the dwindling US imports in the coming years. After 2030 exports to the US grow due to the decline in production from their maturing shale fields.

Total pentanes plus and condensate will keep growing for the forecasted period from 418 Mbpd in 2019 to 604 Mbpd in 2039 underpinned by demand from oil sands and driven by liquids-rich natural gas drilling.

For natural gas, an incremental trend in production in recent years was caused by two factors: addition to the net exports to the US by 0.4 billion cubic feet per day (bcf/d) and an increase in domestic gas consumption. However, the net exports to the US started to decline in 2017 and are expected to continue for the foreseeable future. Growth in domestic demand by 2.5 bcf/d in the next 20 years will largely, but not completely, counterbalance this decline of net exports. The domestic incremental demand is expected to come from the electricity sector which explains 47 percent of growth, followed by industry which drives 35 percent of gas demand additions including by the oil sands sector (NEB, Energy Futures 2019).

Figure E.2: Total Canadian Natural Gas Production



Source: CERl, Government of SK, BCOGC, AER, PSAC, CAPP

LNG plants provide an opportunity to develop production capacity in western Canada and attract more growth-oriented investments into the upstream gas industry. Such a scenario will lead to a consistent increase in production until 2029 to levels slightly over 25 bcf/d. Post-2029, production will stabilize through the remainder of the study period. The gas for LNG will constitute approximately 30 percent of total Canadian production by 2039 and is expected to be supplied by British Columbia and Alberta.

This study also examines the economic impacts of the Canadian conventional oil and natural gas industry on the Canadian economy (Table E.1) as well as on the US economy. The impacts analysis is done for the period 2019-2029.

Table E.1: Total Economic Impacts from Oil and Natural Gas Development, 2019-2029*

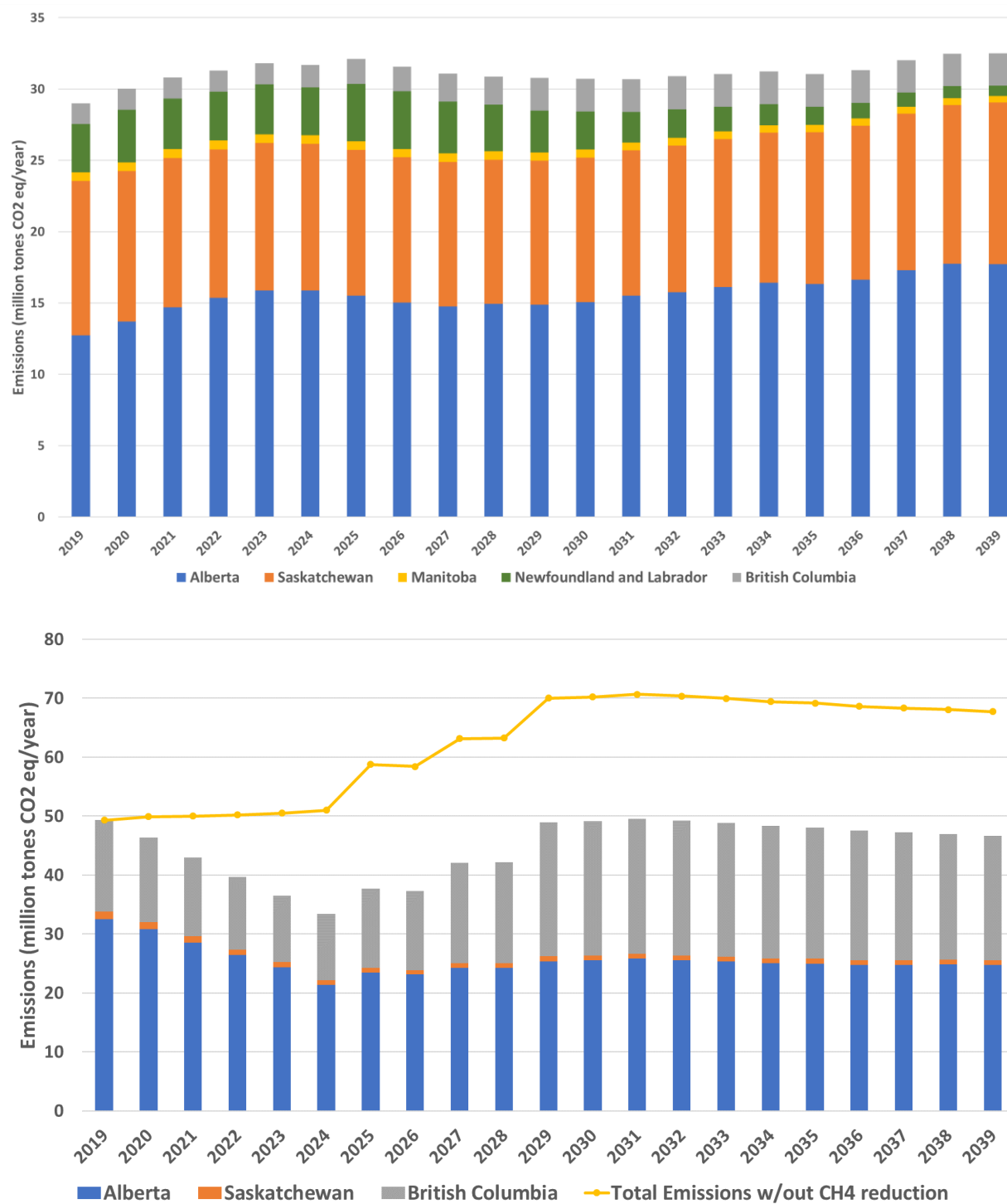
Province	GDP (\$CAD million)	Employment (Direct and Indirect) (person-years)	Tax Revenue (including royalties) (\$CAD million)
Alberta	\$368,188	1,927,236	\$15,248
British Columbia	\$122,102	670,345	\$5,054
Manitoba	\$13,606	33,532	\$569
Newfoundland and Labrador	\$91,443	191,472	\$587
Saskatchewan	\$137,203	275,150	\$4,223
Canada	\$853,893	4,163,385	\$31,436

*The effects in each province show both direct and indirect effects of crude oil developments within that province, while the effects for Canada represents direct and indirect effects of crude oil developments in all Canadian provinces.

For the forecast period of 2019-2029, it is estimated that the total US gross state product impact (direct and indirect) will amount to almost US\$19.6 billion or CAD\$26.2 billion. The total employment impact (direct and indirect) is measured in creating or preserving 153.2 thousand full-time equivalent jobs in the 11-year period.

Another component in the study is carbon dioxide equivalent emissions from the oil and gas upstream activities. More specifically, upstream emissions encompass emissions from the following activities: drilling, production and extraction, processing in the field, and venting, flaring, and fugitive emissions.

On average, annual emissions from oil production will be 31.1 million tonnes/year during the study period or less than 1 percent below the 2017 level. Alberta and Saskatchewan will generate the highest emissions at 48 and 35 percent, respectively (Figure E.3). For the natural gas production, on the other hand, the average annual emissions will be 44.7 million tonnes/year over the 2019-2039 period, or 10 percent decrease compared to 2017 levels due to methane reduction regulation implementation. Alberta and British Columbia will generate the highest emissions at 57 and 15 percent, respectively.

Figure E.3: Emissions for Crude Oil Production (top) and Natural Gas Production (bottom)

Chapter 1: Introduction

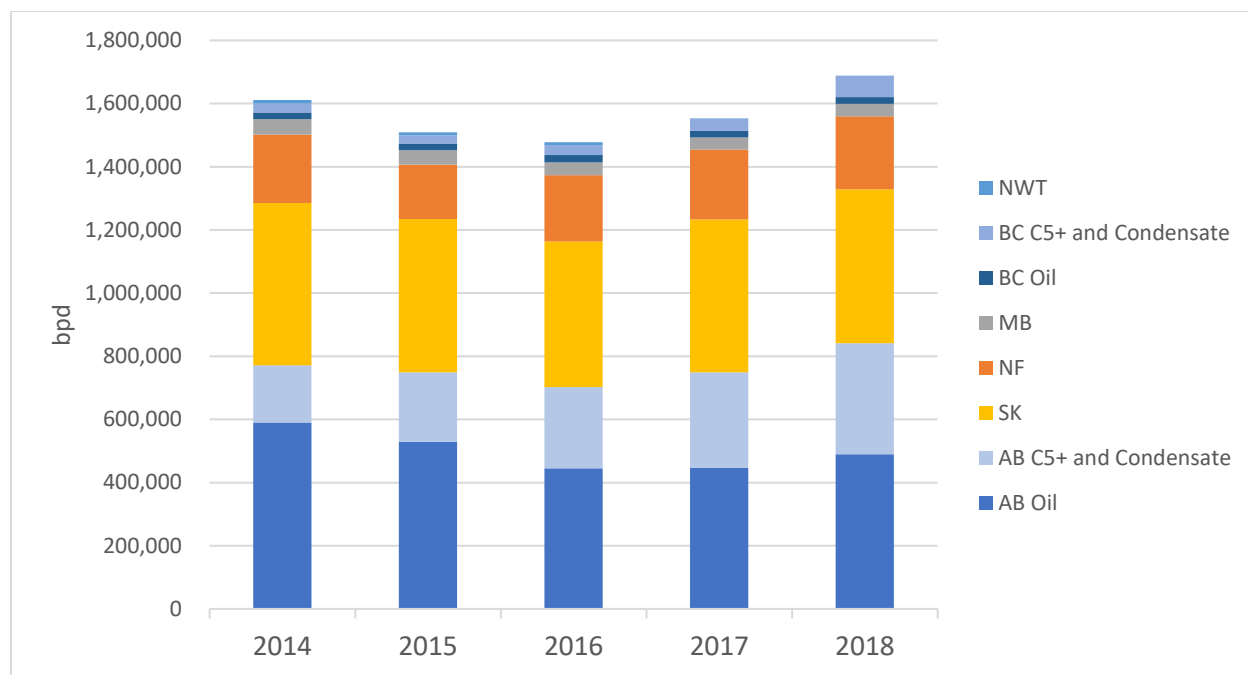
Crude Oil

The last two years in the Canadian oil industry were dominated by continuing themes of market access, oil price differential, and changes in the regulatory processes, specifically those introduced by Bill C-69. These themes impacted the level of investment and production in the country. A booming US oil industry also raised questions about the competitiveness of the Canadian industry and measures that should be taken to attract new investment into Canadian plays.

Despite the fact that its role in total Canadian oil production has been diminishing, conventional oil¹ still commanded slightly over one-third of all domestic oil production (including pentanes plus and condensates). The conventional oil production has seen 9 percent year-over-year (YOY) growth in 2018 ending with 1.67 MMbpd. This growth was driven by pentanes plus and condensate production in Alberta and British Columbia as well as by light oil in Alberta and heavy in Newfoundland and Labrador from the new Hebron asset.

Conventional oil (including pentanes plus and condensate) has been growing by 1.3 percent annually (compound average growth rate) since 2014 (Figure 1.1), falling significantly short of oil sands annual growth of 7.4 percent. Pentanes plus and condensate added the most in relative terms for the same period growing by 19 percent annually driven by demand from the oil sands industry. If pentanes plus and condensate are excluded, the conventional volumes would show a 2.4 percent annual decrease since 2014.

¹ The study covers onshore and offshore conventional oil, including shale and tight oil activity.

Figure 1.1: Conventional Oil and Condensate Production, Canada

Source: CERl, CAPP, AER

Light oil continues to dominate the conventional oil production (64 percent) followed by heavy oil (28 percent) and pentanes plus and condensate (24 percent). However, the share of light oil in the total conventional production will keep decreasing as it did recently because of the boost of heavy oil from the Hebron project and additions of heavy oil in Alberta and Saskatchewan.

In terms of provincial supply, Alberta keeps its dominance with a 48 percent share of conventional oil supply, followed by Saskatchewan with 29 percent, Newfoundland and Labrador with 14 percent and British Columbia with 6 percent. Alberta also added the most in 2018 – 92 Mbpd, followed by British Columbia with 30 Mbpd and Newfoundland and Labrador with 10 Mbpd. Newfoundland and Labrador could have added 50 Mbpd more if not for two reasons. First, the drop in production of Hibernia caused by the planned shutdown and declining production. Second, the temporary shut-in of White Rose production caused by the oil spill. Both Saskatchewan and Manitoba have been showing declining production since 2014 – modest for Saskatchewan at 1.4 percent annually and more significant for the latter at 5.2 percent.

Overall, conventional oil (excluding C5+ and condensates) reversed its production decline in 2016 and grew since then but is still short by 132 Mbpd from 2014 levels. The lack of additional egress does not provide growth opportunities beyond what the domestic refining sector can offer, which has been stable in its demand recently (Statistics Canada). Canadian oil has been able to displace 30 Mbpd of foreign oil in the Eastern refineries since 2015 but faces stiff competition from US light Bakken oil which added 105 Mbpd into Sarnia since 2015 via Enbridge Mainline (Statistics Canada, NEB) and rail. Overall, the refining sector has not provided a base for Canadian

oil supply as it added only 1.4 percent of demand growth since 2015 (Statistics Canada), leaving growth opportunities to expanded market access pursuits.

On this front, no additional physical capacity has been added in the last two years. The one million one hundred thousand barrels per day Energy East pipeline was cancelled in October 2017.

The Line 3 replacement and expansion pipeline project connecting Hardisty, Alberta and Superior, Wisconsin has also seen multiple challenges in recent years. When built, it should add 370 Mbpd of additional egress to its original capacity of 760 Mbpd. The current Enbridge schedule aims at putting the Canadian part of the pipeline into service in the latter half of 2019 with the American side to be finished in the latter half of 2020. The Wisconsin part has been constructed, and Minnesota and North Dakota's parts will be constructed concurrently. At the time of writing, Line 3 faces another challenge by the Minnesota court, which has ruled that the project's environmental impact assessment was inadequate.

The Trans Mountain Expansion project, which will add 590 Mbpd to existing capacity, has seen its challenges on the way to construction. In August 2018, the Federal Court of Appeal cancelled the certificate of Public Convenience and Necessity (CPCN) for the Expansion Project. In February 2019, the NEB provided its Reconsideration report to the Government of Canada, "with an overall recommendation that the Trans Mountain Expansion Project is in the Canadian public interest and should be approved. The Project will be subject to 156 conditions enforceable by the NEB".² The federal government has taken a positive decision on TMX on June 18th, 2019; however, the Government of British Columbia remains in opposition to the construction.

The third major undertaking – Keystone XL, an 830 Mbpd pipeline – planned to start construction in 2019, but TC Energy (formerly TransCanada Corp.), the owner of the pipeline, suggested they already missed this year's construction period due to the November 2018 US Federal Court ruling on the need of additional environmental review.³ Irrespective of the challenges, the project has the US Federal Administration support who just issued a new permit for the pipeline in April 2019.⁴

When built, three pipelines would add 1.8 MMbpd of egress capacity in Western Canada which is currently running at full capacity. As of March 2019, Mainline pipeline (ex-Gretna in Manitoba leading to the US) was 97 percent full, Trans Mountain Pipeline and Keystone Pipeline both at 100 percent to available capacity (NEB). In the meantime, crude-by-rail was expected to alleviate the volume and, to some extent, the price differential problem. Since August 2017, rail volumes (see Figure 1.2) have been on the rise, reaching 353 Mbpd in December 2018 (NEB).

² Transmountain project website, <https://www.transmountain.com/project-overview>

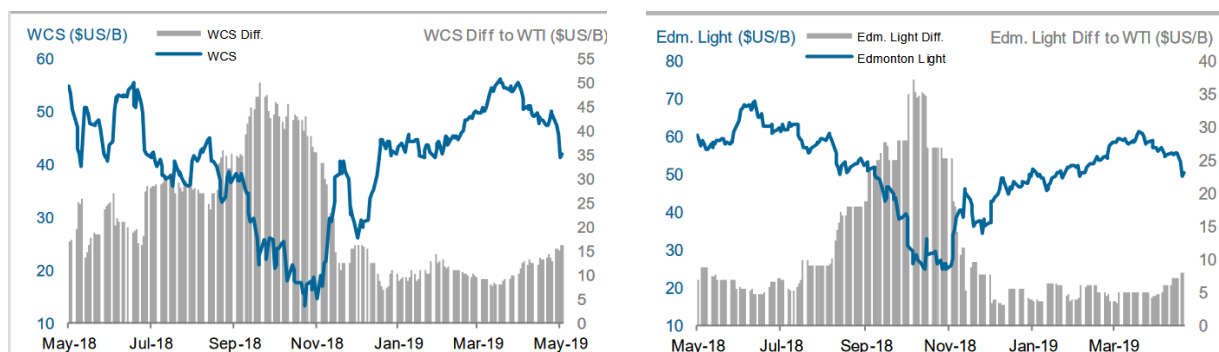
³ CBC, Court delays block Keystone XL pipeline construction in 2019
<https://www.cbc.ca/news/canada/calgary/keystone-delays-1.5123603>

⁴ *ibid*

Figure 1.2: Canadian Crude-by-Rail

Source: NEB, CERl

This growth was supported by over US\$20 differential between WCS and WTI which peaked at over US\$50 in October 2018 (Figure 1.3). The differential for light oil was less dramatic getting slightly over US\$35 in the same period. Both differentials made transportation by rail more economic putting oil exports over 300 Mbpd levels. The oil production curtailment for all types of oil announced by the Alberta government in December 2018 allowed for the differential to get to \$10-15 per barrel even before the physical curtailment materialized (initial cut level was set at 325 Mbpd volume starting January 2019). Consequently, the economics of rail shipments became unfavourable and plummeted crude-by-rail shipments to early 2018 levels.

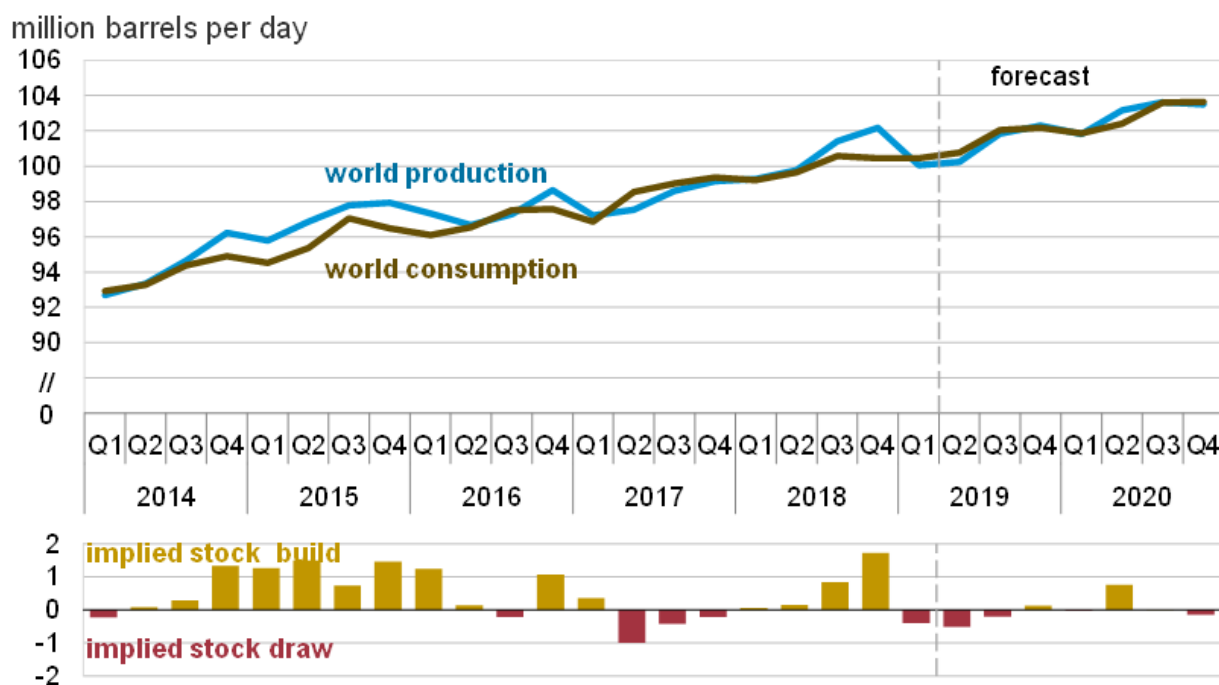
Figure 1.3: Canadian Heavy and Light Oil Differential to WTI

Source: ARC Energy Institute

The WTI price has been over US\$60 (CA\$78) during most of 2018, sliding to \$45 at the end of 2018 but has recovered to over US\$55 (CA\$72) for most of 2019, providing some level of stability (Bloomberg). OPEC and other 10-member states continued to play a role in the price stability in 2018-2019. The current production cut target of 1.2 MMbpd has been largely met, however, the individual performance of countries was different. For four months into the current deal, OPEC has been able to cut 150 percent of its commitment, while Russia just reached 80 percent of its target.⁵ The next cut is to be discussed later in June or July of 2019.

OPEC cuts, declining production in Mexico, Venezuela as well as in the North Sea, Azerbaijan, Argentina, Colombia, and Qatar, led the market to rebalance in 2017 and the first half of 2018 (Figure 1.4); the second part of 2018 saw a spike of global production largely driven by the US which added 1.6 MMbpd year-over-year and Saudi Arabia which increased output in anticipation of a drop in Iranian supply which did not materialize in the volumes expected.

Figure 1.4: World Liquid Fuels Production and Consumption



Source: EIA Short-Term Energy Outlook, May 2019

In 2019, the largest supply decline could be expected from Iran due to the US sanctions, while the largest growth is expected to continue in the US.⁶ However, this does not provide opportunities for Canadian oil as Iran is not an exporter to the United States.

⁵ Bloomberg, Face it, OPEC. Russia Is No Longer Your Friend

<https://www.bloomberg.com/opinion/articles/2019-06-02/face-it-opec-russia-is-no-longer-your-friend>

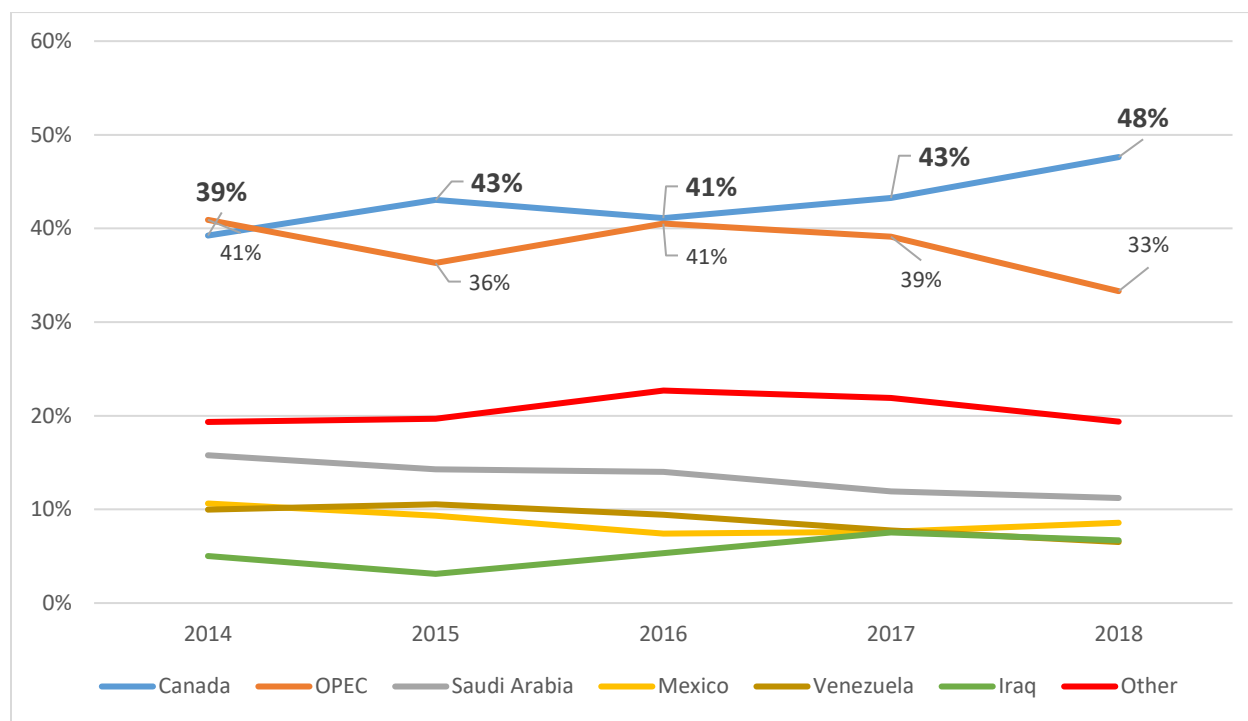
⁶ EIA, Short term energy outlook, July 2019, https://www.eia.gov/outlooks/steo/report/global_oil.php

Irrespective of surging US oil developments, Canadian oil is still in demand in the US as many mid-continent and Gulf Coast refiners are suited to the processing of heavy Canadian crude. Because the US has allowed oil exports effective 2015, it can now monetize its light shale oil at the premium price in export markets, while refining cheaper, heavier oil domestically. This model allows for sustaining and even increasing Canada's oil exports to the US in parallel to US shale oil developments, especially on the heavy oil side.

The US market continues to be the only market for Canadian conventional oil exports if we do not include under 50 Mbpd which are exported to European countries from Newfoundland offshore assets.

In recent years, Canada has been able to solidify its position in this market by growing its market share from 39 percent to 48 percent from 2014 to 2018 (Figure 1.5). The growth, however, came due to oil sands rather than conventional oil. The imports of Canadian light and medium oil has fallen by 110 Mbpd since 2014, while heavy sour and heavy sour rose by 930 Mbpd (CERI, EIA) and the output of conventional heavy oil in Canada for the same period was relatively flat.

Figure 1.5: Shares of Oil Importers in the US Market



Source: EIA, CERI

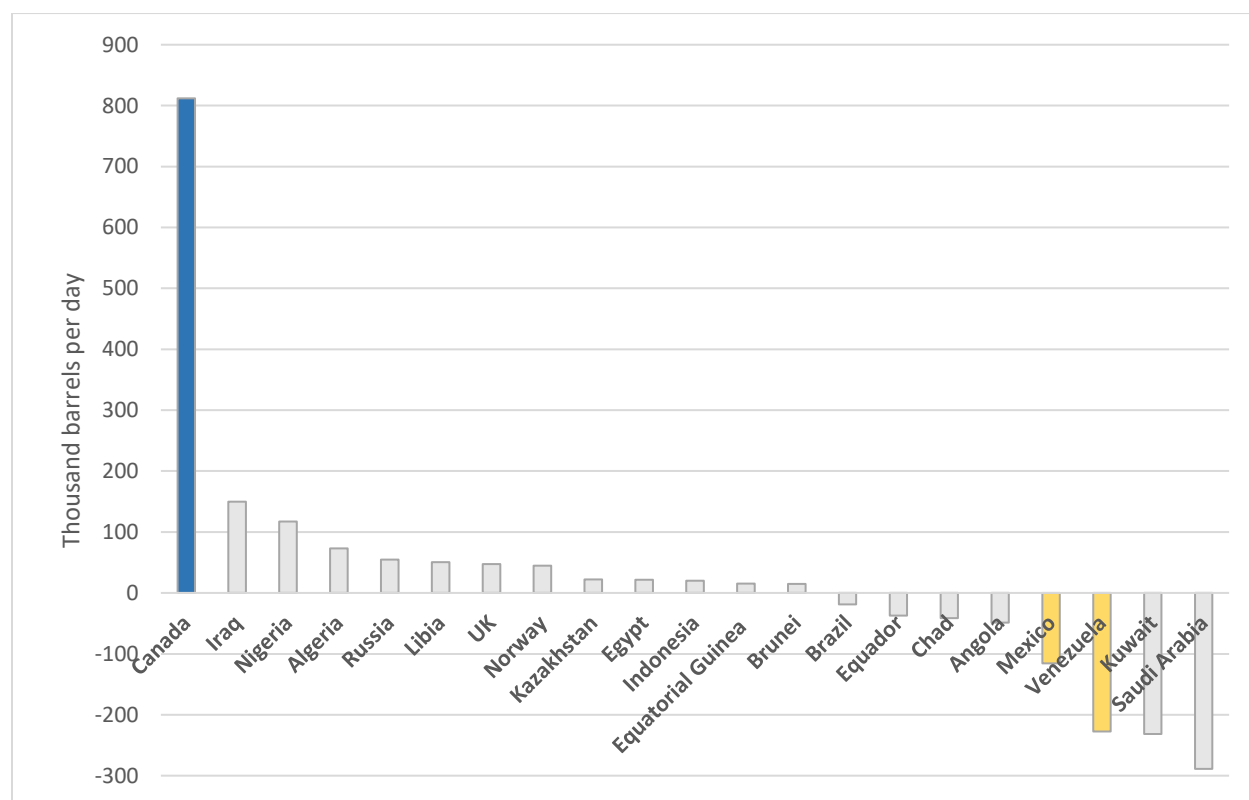
The growth of Canadian exports by 812 Mbpd was achieved due to additions of total imports by the US by 412 Mbpd and “displacing”⁷ oil from Saudi Arabia (-289 Mbpd), Kuwait (231 Mbpd),

⁷ Canada did not literally displace oil from these countries as there were other producers which increased their exports to the US.

Venezuela (-227 Mbpd), Mexico (-116 Mbpd), Angola (-49 Mbpd), Chad (-41 Mbpd) and others (Figure 1.6). All other major producers have fallen to under 15 percent of market share: Saudi Arabia (11 percent), Mexico (9 percent), Venezuela (7 percent), Iraq (7 percent), and Colombia (4 percent).

Canada has been able to add 2.4 times more crude between 2014 and 2018 to the US market than all imports that disappeared from Mexico and Venezuela combined (343 Mbpd) (Figure 1.6). However, further market share expansion in the US is constrained by the limited egress and rail economics, which is not favourable under low differentials.

Figure 1.6: Key Changes in Oil Importers Volumes in the US Market, 2014-2018



Source: EIA, CERl

On the regulatory side, the largest items that have dominated discussion remain as Bill C-69 and Bill C-48. The former is comprehensive legislation which would reform the National Energy Board and introduce a more comprehensive impact assessment which includes not only economic and environmental impacts but also social and health aspects. Cumulative impacts will also be considered in project evaluation. It also consolidates the impact assessment of all major projects – not just oil and gas – in the hands of one agency. The agency is to be accountable to the Environment Ministry of the federal government.

The second piece of legislation – Bill C-48 – bans tanker's shipping in the northern parts of British Columbia Coast if carrying oil exceeding the allowable tonnage limit. The industry sees this as a

possible limitation to the expansion of oil exports via the west coast. In the recent developments, the government agreed to a “review of its proposed tanker ban bill five years after it comes into law”. As of the time of writing, the Senate passed the bill into law.

Natural Gas

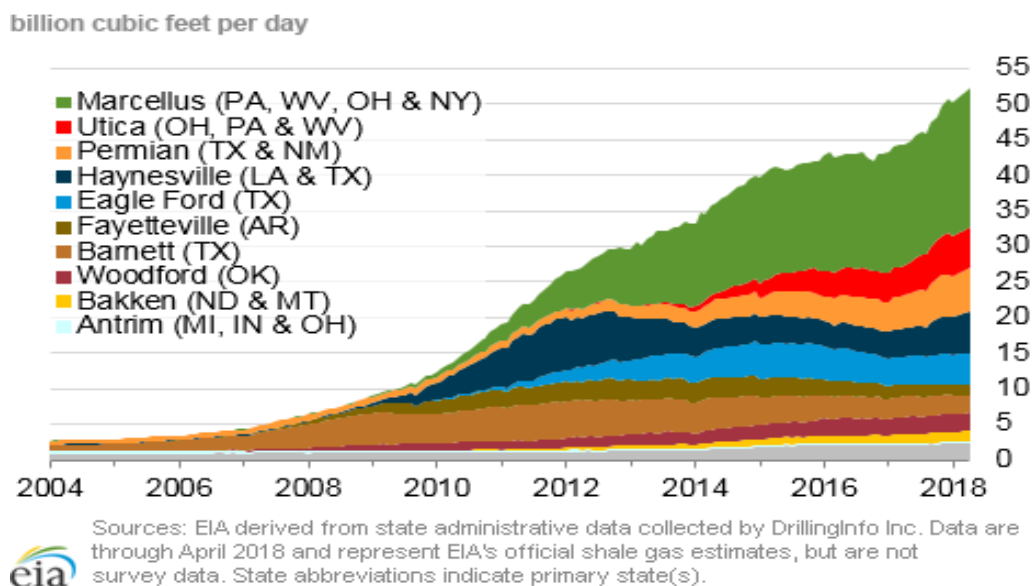
The natural gas sector has been addressing its own set of challenges. The main challenge is lower demand for Canadian natural gas from the US, which ultimately impacts gas prices in Western Canada due to overproduction.

2018 continued the trend of low AECO-C gas prices which hovered near CAD\$2/GJ since 2016. Prices were under \$2/GJ at AECO-C market for all of 2018, falling to as low as \$0.75/GJ in June 2018, putting stress on the economics of gas producers and government coffers (Alberta Government⁸).

Net exports were growing up until 2016 but the trend reversed in 2017. There are some egress issues and bottlenecks, but they are not as severe as for the oil sector. The fundamental strategic change is the available volume of natural gas in the US lower 48. Specifically, the Marcellus/Utica gas in the east threatening Canadian gas in Ontario and Quebec, and Bakken, Biobara-Codell gas in the US Rockies area near Montana, Idaho, North Dakota, and Minnesota where 75 percent of Canadian exports enter the US.

The US became a net gas exporter in 2017 because of major production increases in several natural gas basins in the country including the prolific Marcellus Play (see Figure 1.7). While both shale oil and shale gas have soared in the US, the impact on the natural gas market has been more significant.

Figure 1.7: US Shale Natural Gas Production, 2004-2018



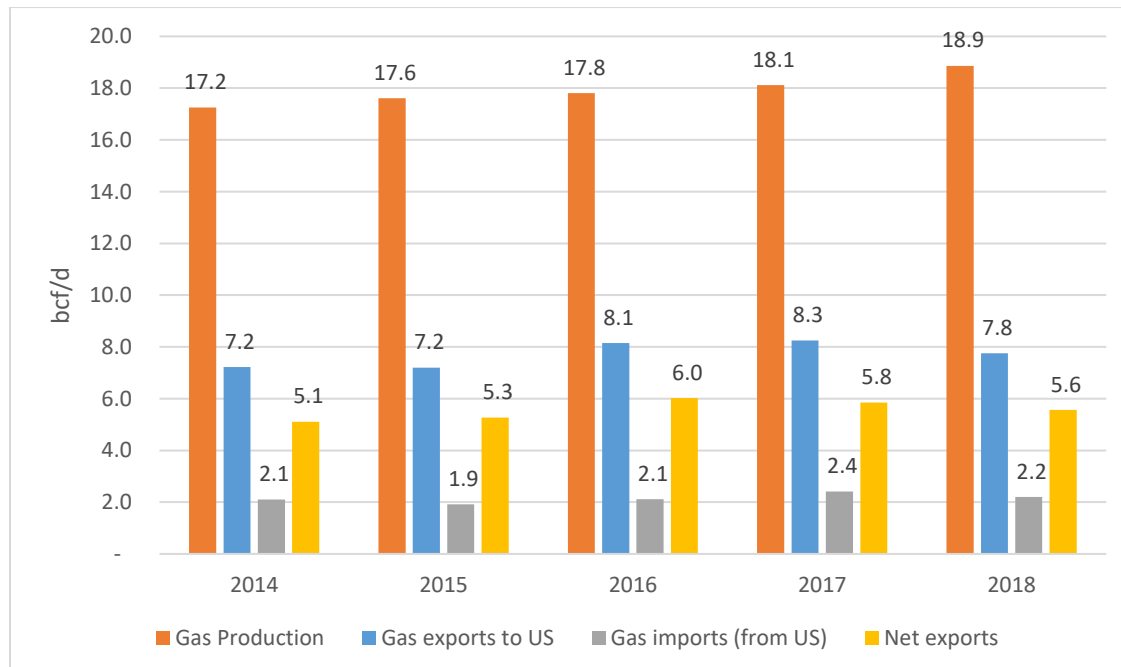
⁸ Alberta Government, <https://www.alberta.ca/natural-gas-prices.aspx>

Until 2016, the US did not have an opportunity to export its natural gas in the form of LNG. Thus, surging production from shale gas, especially from the Marcellus and Utica plays in Pennsylvania, West Virginia and Ohio, and Eagle Ford and Haynesville in Texas has been competing with and displacing Canadian gas and US LNG imports. The shale natural gas supply in the US soared from around 5 bcf/d ten years ago to over 50 bcf/d in 2018, totalling almost three times that of Canadian production.

With Canada historically being the main natural gas exporter to the US, it is no surprise that in the long-term there are negative consequences for Canadian gas producers. In recent years (2014-2018), there have not been significant changes in trade, however, the trend of diminishing net exports⁹ is materializing.

Overall, Canada's gas production kept growing, supported by domestic demand. As shown in Figure 1.8, net exports reached the 6.0 bcf/d level in 2016 only to decrease to 5.6 bcf/d in 2018. Lower sales to the US were a larger factor than increased imports from the US in Central Canada to the declining trend as imports were relatively stable over the last five years. In the first quarter of 2019, we see a further decrease in pipeline flows outside of Western Canada while US total natural gas demand has grown by 5 percent for the same period.¹⁰ Despite current stable exports, recall that today's export volumes have already dropped by 20 percent from its peak in 2007 of 10.4 bcf/d.

Figure 1.8: Canada's Gas Exports and Raw Production



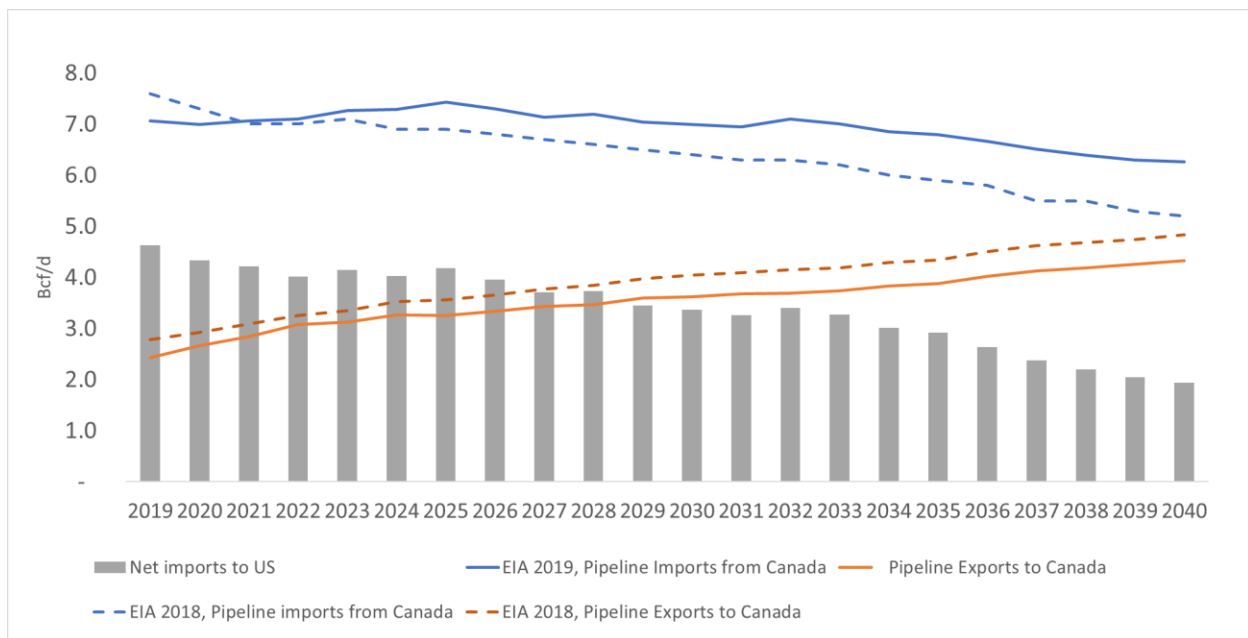
Source: CERI based on CAPP, Statistics Canada, NEB

⁹ Net exports = Exports – Imports.

¹⁰ EIA Natural Gas Consumption, ARC Energy Institute (May 27 Charts).

Going forward, the US EIA Energy Outlook 2019 forecasts that net imports from Canada will fall from existing levels to 2 bcf/d by 2040 (Figure 1.9). Note that the EIA has changed their perspective on their natural gas trade with Canada for both imports and exports; last year the EIA suggested net imports from Canada will fall under 0.5 bcf/d by 2040. The new perspective could come from the existing dynamics in factual flows from and into Canada compared to recent EIA forecasts which were bullish on exports to Canada and bearish on imports from Canada. The other reason is that the US EIA Energy Outlook 2019 suggests faster growth of consumption (approximately by 1.1 bcf/d) than for domestic production, and Canadian gas is relied upon to make up this difference.

Figure 1.9: Canada-US Natural Gas Trade Volumes (bcf/d)



Source: CERl, based on EIA Outlook 2019, 2018

Even if the EIA Outlook does not fully materialize, it is likely to occur to some significant extent.

The growth of imports from the United States into Ontario and Quebec is expected to continue. Existing import pipeline capacity of 5.4 bcf/d (5.2 bcf/d to Ontario and 0.2 bcf/d to Quebec) (EIA 2018) is already enough to push the volumes of US gas that the EIA forecasts out to 2040. Ontario and Quebec have historically been large customers of western Canadian gas. However, because of the Marcellus Play in the US close to Ontario and Quebec, the eastward throughput of the TC Energy Mainline fell from 6 bcf/d in 2006 to 2.7 bcf/d in 2017 (NEB 2017).

To increase western Canadian producers' cost-competitiveness in central and eastern Canada, TC Energy introduced in 2017 a discounted toll of \$0.77/GJ substituting its existing rate of \$1.86/GJ. It was reported that 23 companies signed for 1.5 million gigajoules per day (1.4 bcf/d) under this rate (MCINTOSH 2017). This measure gives Canadian gas a chance to be cost-

competitive in eastern gas markets. Indeed, the shipment of volumes from WCSB to the East stabilized and reached 3.13 bcf/d in 2018.

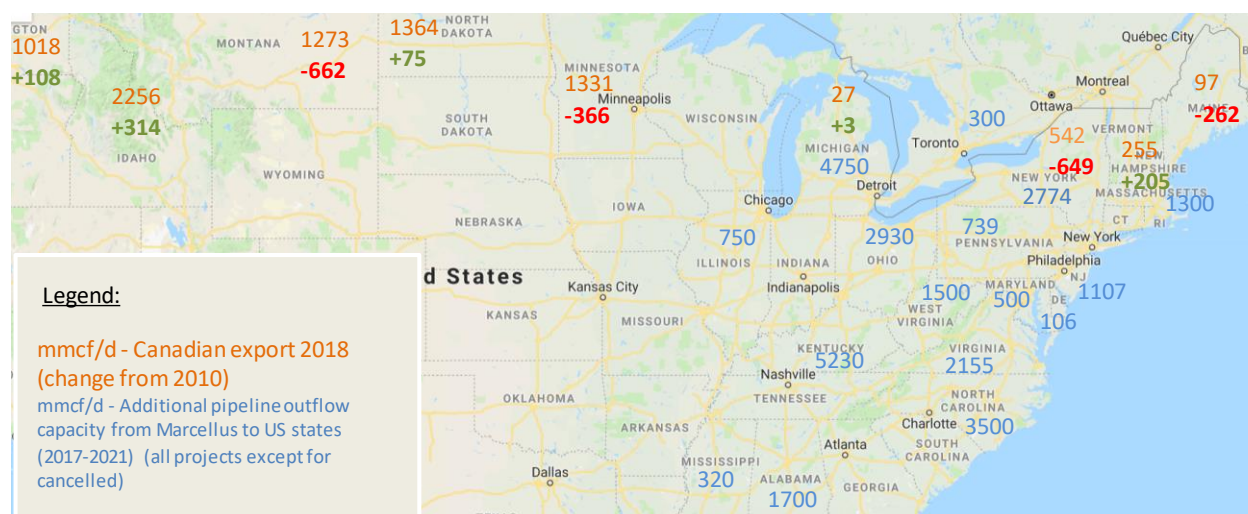
With respect to exports, Canada has mainly been exporting to ten states. In most of them, the demand for Canadian gas has diminished in the last ten years, except for Idaho, New Hampshire, and marginally North Dakota and Washington (Figure 1.10).

In the East, changes were related to a number of events: Maine started to consume less natural gas and New York was awash with Marcellus gas from Pennsylvania.

In the West, large supplies from North Dakota, Colorado, and Wyoming influence the presence of Canadian gas in the market. Montana's drop in imports is related to North Dakota's growing local production where Montana had previously exported. North Dakota, in turn, increasingly preferred Canadian gas over Montana's while keeping its interstate exports to South Dakota and Minnesota on similar levels. Canada also lost its market share in Minnesota to supplies from North and South Dakota. Idaho has been steadily growing its import volumes from Canada largely to transit them to Washington, which in turn sends them to Oregon (EIA, CERI).

Over the last two years, the import levels in all states that have seen a declining trend – Maine, Minnesota, New York – have stabilized, except for Montana which continues to drop.

Figure 1.10: Pipeline Capacity Additions for Marcellus Natural Gas Outflows



The LNG sector in Canada got a significant boost in 2018 with the final investment decision obtained by the LNG Canada project sponsored by Shell, Petronas, KOGAS, Mitsubishi and CNPC. Several projects have advanced in their stages to get to the FID including BearHead and Goldboro on the east coast, Kitimat LNG (sponsored by Chevron and Australian Woodside) and Woodfibre on the west coast. Kitimat LNG has also applied recently to the NEB to expand its capacity to 18 mtpa (2.3 bcf/d). Several projects were cancelled or delayed in the last two years as well, including the WCC project by ExxonMobil (cancelled) and Steelhead LNG (project ceased). Both projects are on the west coast.

In total, 15 LNG projects on both coasts are at different stages of activity and regulatory processes. CERI estimates that four of them (besides LNG Canada) are active and have chances of getting to FID (a more detailed picture of Canadian LNG projects and competitiveness is available in CERI Study 172, “Competitive Analysis of Canadian LNG”, July 2018). CERI assumes that first shipments of LNG can start as early as 2024 in the following order:

- 2024: Woodfibre LNG with 0.3 bcf/d (sourced from British Columbia)
- 2025: LNG Canada with 1.85 bcf/d (10 percent sourced from Alberta, 90 percent from British Columbia)
- 2025: East coast project with 0.7 bcf/d (100 percent sourced from Alberta)
- 2027: LNG Canada expansion to 3.7 bcf/d (+1.85 bcf/d) (the same as above)
- 2029: Kitimat LNG with 2.5 bcf/d (sourced from British Columbia)

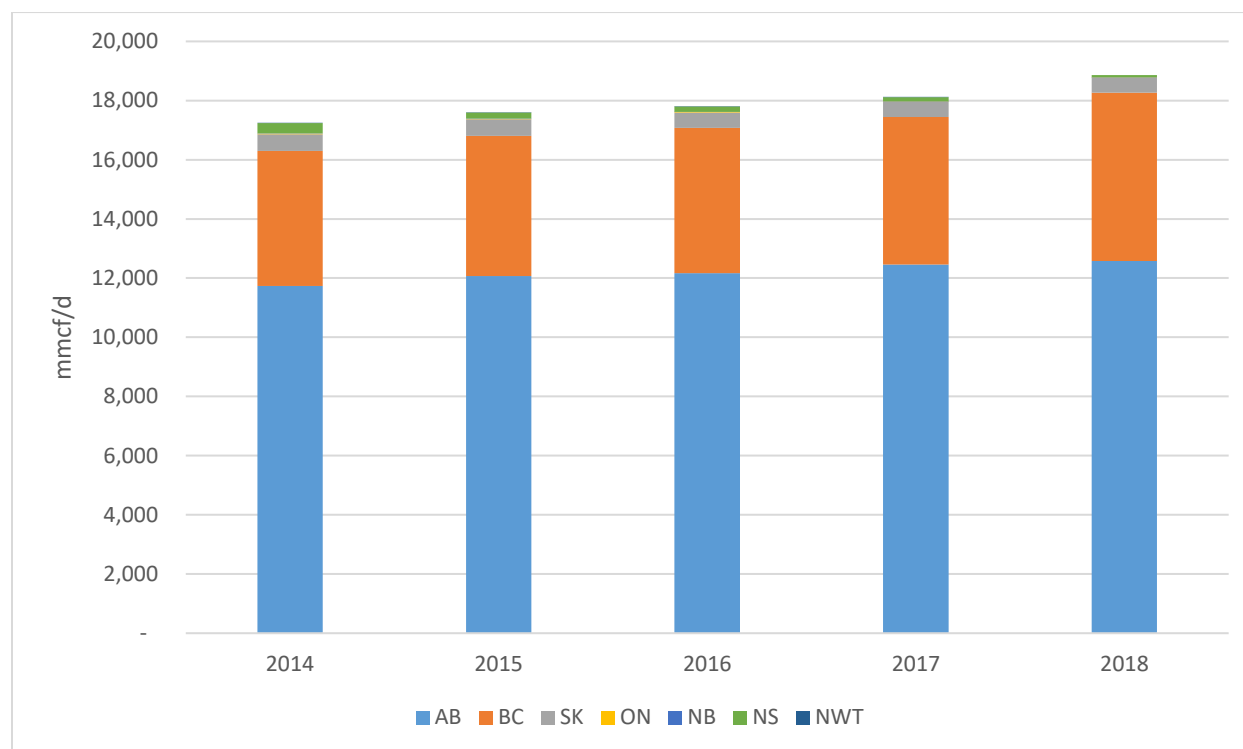
In total, this year’s forecast includes a peak of 7.1 bcf/d of additional gas production for LNG purposes reached in 2029.

Another driver for natural gas growth has been a high demand for natural gas liquids, specifically pentanes plus and propane. Pentanes plus is used as a diluent for bitumen exports and are in high demand due to further growth of the oil sands industry and as a solution to existing US imports of condensate. Propane demand is to increase due to the development of two export terminals on the British Columbia coast and two PDH/PDP facilities in Alberta (for more details please refer to CERI Study 176, Market Review of Natural Gas Liquids in Western Canada). The Canadian NGLs are of interest to Asian petrochemical producers, but the challenge going further will be the egress of methane. If methane cannot be exported in the needed volumes, it can serve as a limit to NGLs production with the existing level of fractionation and recovery. For more details, please refer to CERI Study 176.

As mentioned, even with ongoing challenges of sustaining net exports to the US in 2017-2018, the industry kept adding production volumes (Figure 1.11). At the provincial level, the picture of natural gas supplies has been relatively stable. Alberta represents a 67 percent share of total Canadian production. Since 2014, this share has been growing by 2 percent annually. British Columbia’s share has increased from 26 percent to 30 percent, growing by 6 percent annually. Saskatchewan’s share has been dropping by 3 percent annually, holding an approximate 3 percent share in production in 2018. Nova Scotia’s share has diminished from 2 percent to under

0.4 percent, decreasing by 32 percent annually due to production declines of the Deep Panuke project; the asset was abandoned by Encana Corp. on May 7, 2018.

Figure 1.11: Canadian Natural Gas Production



Source: CAPP, CERI

Nova Scotia and Quebec continue their bans on shale fracking. These regulations do not allow for the local natural gas production developments which could compete with the US and western Canadian gas. New Brunswick announced a partial lifting of the fracking ban as a “responsible” path toward facilitating a transition to a greener economy”.¹¹ The passed regulatory changes should allow shale gas development to resume in the Sussex area. More detailed information about the gas potential in these provinces can be found in CERI’s reports published in 2017 (CERI 2017) and 2015 (CERI 2015). The study showed a potential of 13 trillion cubic feet (TCF) of recoverable gas resources in New Brunswick, which can sustain local demand and support gas exports to the US or worldwide as LNG.

Competitiveness

Another recurring theme in the Canadian oil and gas industry is competitiveness. This theme is voiced by the industry itself, oil and gas producing provinces, industry associations, consulting firms, political parties, research institutes as well as by legislature, e.g., by the Senate in its 2018 report “Canada: Still Open for Business?”.

¹¹ CBC, Energy minister says 'responsible' fracking will help transition to green economy, <https://www.cbc.ca/news/canada/new-brunswick/political-panel-shale-gas-moratorium-1.5173656>

Competitiveness is a complex issue and it takes a separate study to look into it. In this section, we take a look at how to best view the issue for the oil and gas sector in Canada. We then compare Canada's oil and gas industry relative to global and US performance in terms of activity, output, investments, and equity value as measures of the attractiveness of Canadian products and jurisdictions.

Competitiveness as a term in a most general sense implies that one option is preferred over the other by a decision-maker because that option proves a better value for that decision-maker. The value can be measured as the ratio of benefits and costs. In the oil and gas industry context, the decision-makers are investors who make two choices:

1. **Business/Product:** which business to invest in, e.g., upstream oil, gas, NGL, LNG, refined petroleum products, pipeline transport, storage, services, EPC, etc.
2. **Jurisdiction:** where to do the business – in which country and province/state.

Both businesses/products and jurisdictions compete for investments. For the investment to happen, firstly, both of these choices should work simultaneously for a particular jurisdiction. Secondly, for a particular jurisdiction to win, the overall value – economic and strategic – should be the highest among jurisdictions. The value of diversification across types of products and geography for investors should not be discounted as well, meaning that investors, especially global, will balance their business portfolio, rather than focusing on just one jurisdiction/business which yields the best rate of return. All investors have their own portfolio strategies, but economic attractiveness – the rate of return on investments and equity value of a company in a particular jurisdiction – plays an important role. This means that investors will not continuously keep investing just for diversification reasons in geography which underperforms on the important metrics.

A more detailed picture of the decision factors for investors which feed into business/product and jurisdictions competitiveness is presented in Figure 1.12.

Figure 1.12: Investment Decision Factors for Investors

Business (Product) Competitiveness	Jurisdiction Competitiveness
• demand (global, regional) • availability of capital • proximity to customers • costs • prices • competition • expectations of growth • risks specific to business • power of customers and suppliers • substitutes • carbon intensity	• institutions • infrastructure including market access • macroeconomic environment • resource base • fiscal (taxes, royalty, incentives) • regulatory • government support • uncertainty of regulations and their enforcement • ease of doing business • labour/supplier availability

A prevailing claim of those who suggest that Canadian oil and gas competitiveness has been diminishing was around the jurisdiction competitiveness, not the business/product one. The argument is that the products that Canada is producing – oil, natural gas, NGLs, refined products, petrochemicals – are in demand and this global demand is growing. Indeed, the outlook for oil, natural gas, natural gas liquids, LNG, refined petroleum products all grow in the IEA Energy Outlook (Figure 1.13), even for the New Policies Scenario where countries meet their Paris agreement targets. The argument goes that incremental supply will have to be met by the oil and gas industry and Canada is well-positioned from a resource and location standpoint on both coasts to fill part of that growing need. The recent Asia Pacific Energy Research Centre (APERC) Demand and Supply Outlook for the Asia Pacific region also include continued demand for oil and natural gas in its base case and alternative scenarios.¹²

¹² APERC 7th Edition APEC Demand and Supply Outlook. <https://aperc.iecej.or.jp/publications/reports/outlook.php>

Figure 1.13: Primary Energy Demand Outlook (mtoe)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Coal	2 308	3 750	3 768	3 809	3 998	4 769	3 045	1 597
Oil	3 665	4 435	4 754	4 894	4 902	5 570	4 334	3 156
Gas	2 071	3 107	3 539	4 436	3 616	4 804	3 454	3 433
Nuclear	675	688	805	971	803	951	861	1 293
Renewables	662	1 334	1 855	3 014	1 798	2 642	2 056	4 159
Hydro	225	353	415	531	413	514	431	601
Modern bioenergy	377	727	924	1 260	906	1 181	976	1 427
Other	60	254	516	1 223	479	948	648	2 132
Solid biomass	646	658	666	591	666	591	396	77
Total	10 027	13 972	15 388	17 715	15 782	19 328	14 146	13 715
<i>Fossil fuel share</i>	<i>80%</i>	<i>81%</i>	<i>78%</i>	<i>74%</i>	<i>79%</i>	<i>78%</i>	<i>77%</i>	<i>60%</i>

Source: IEA Energy Outlook 2018

Canadian products attractiveness has indeed diminished in the US market, specifically for gas and NGLs, due to their domestic growth. But internationally, especially in Asia, the Canadian products are in demand which supported LNG Canada final investment decision and AltaGas propane export terminal in British Columbia, and the federal government support of the Trans Mountain pipeline.

The argument further goes that Canadian oil and gas business competitiveness has diminished in recent years because the business cannot deliver similar value to investors. This, in turn, is caused by low commodity prices and netbacks and, consequently, difficulty in attracting capital for new developments. Prices, in turn, have fallen due to market access issues: lack of new pipeline capacity on the oil side and lack of LNG projects on the gas side. The expectations of growth also feed into competitiveness as they are essential components of equity valuation. With all things being equal, the investment will be attracted where growth is likely, rather than to companies in jurisdictions which simply sustain their level of production. The value of equity and lower returns could also be impacted by the current level and future expectations of fiscal burden and regulatory complexity and uncertainty relative to other jurisdictions.

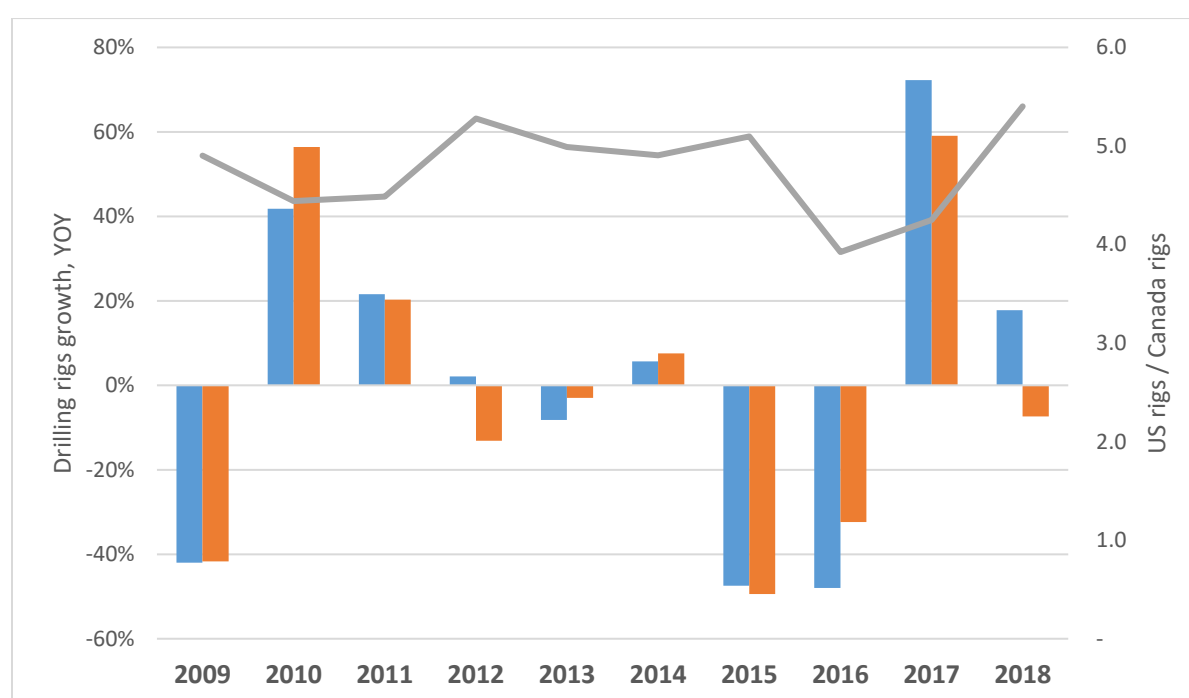
The signals that investors send about their preferences may come in many forms, but the indicators which combine the majority of competitiveness factors are:

1. the level of activity (we used drilling rigs in the US and Canada)
2. production growth (we used global oil and gas production and Canadian share)
3. investment growth (we used global investments and Canadian share)
4. valuations of equity (we used US and Canadian oil and gas equities)

We further review these four factors. To make a fair comparison and understand if investors favour Canada more or less, these indicators should be measured *relative to* global levels or levels in similar geographies rather than to their change over time in one jurisdiction.

For drilling activity, the ratio of the US number of rigs over Canadian rigs has been 4.5-5 times between 2009-2016, except for 2016 when it fell to 4 (Figure 1.14). The growth of Canadian and US rigs year-over-year was fairly close. However, since 2017, the US has been picking up activity reaching 5.4 times more rigs than in Canada. In the first 6 months of 2019, the trend continued: Canada had 26 percent fewer rigs than in the same period of 2018, while the US has added 1.6 percent for the same period (Baker Hughes). This signifies increasing investment flows to the US relative to Canada in the last two years and the first half of 2019.

Figure 1.14: Drilling Rigs (Canada, US)



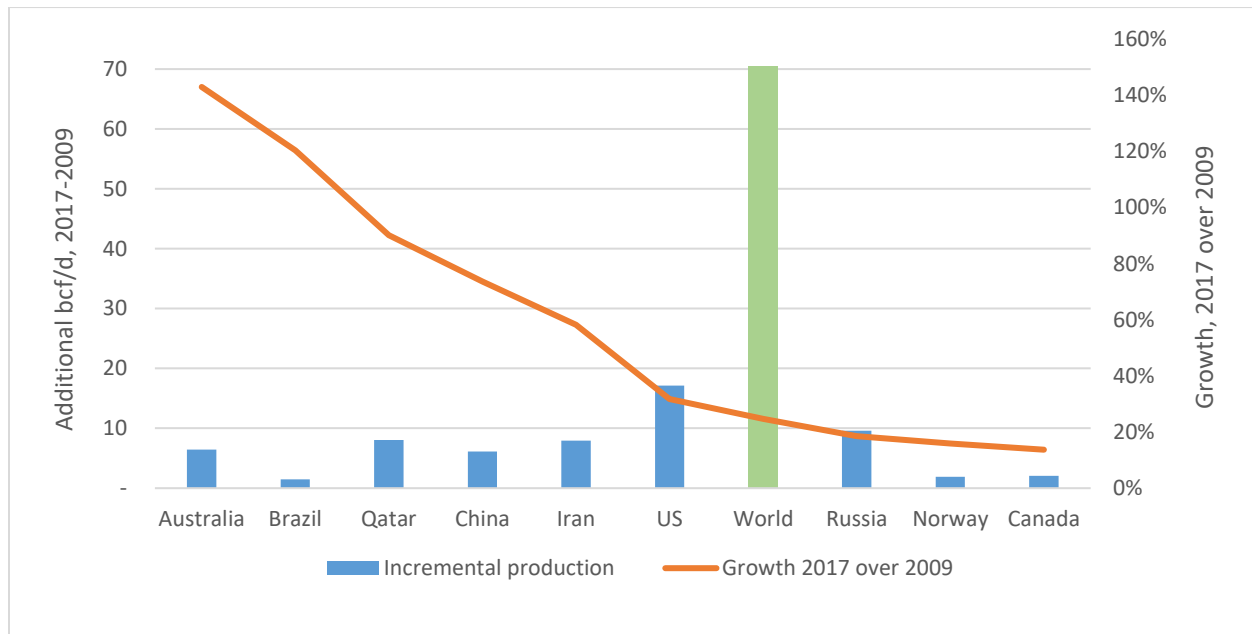
Source: Baker Hughes, CERI

For natural gas production, Canada has been lagging behind in terms of growth rate compared to the worlds and other large producers. This means that investors have been relatively more active in other jurisdictions than in Canada (Figure 1.15).

The world has added 70 bcf/d for nine years (24.6 percent growth), while Canada grew its production by 13.7 percent for the same period – the lowest number of the selected producers which together account for 80 percent of world growth for the period. Additional pipeline and LNG export capacities supported growth in Australia, Qatar, the US, and Russia. This result is impacted by Canadian geographical specifics translated into gas trade only with one nation, the US shale revolution, and the relatively lower population growth in Canada. However, the most significant factor is due to Canada's inability to bring about LNG projects. The latter was

successfully done by export-oriented Australia – a country, arguably, similar in quality of institutions and political stability.

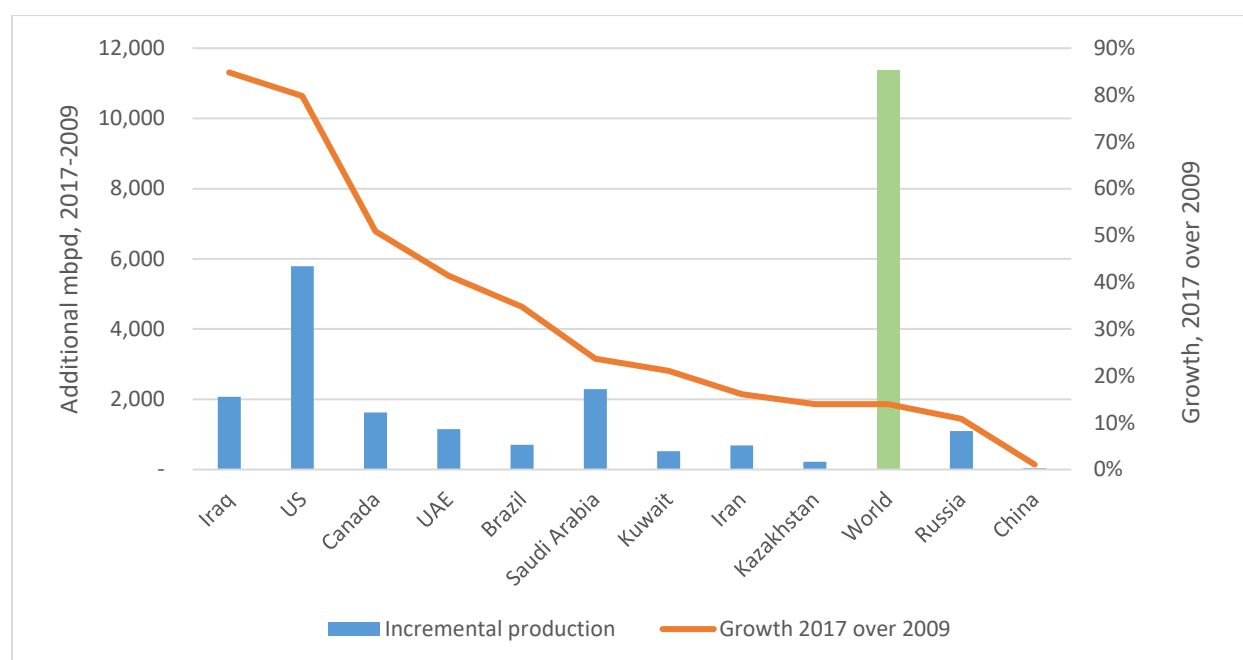
Figure 1.15: Global Natural Gas Production Growth, 2009-2017



Source: CERI based on BP Statistical Report 2019

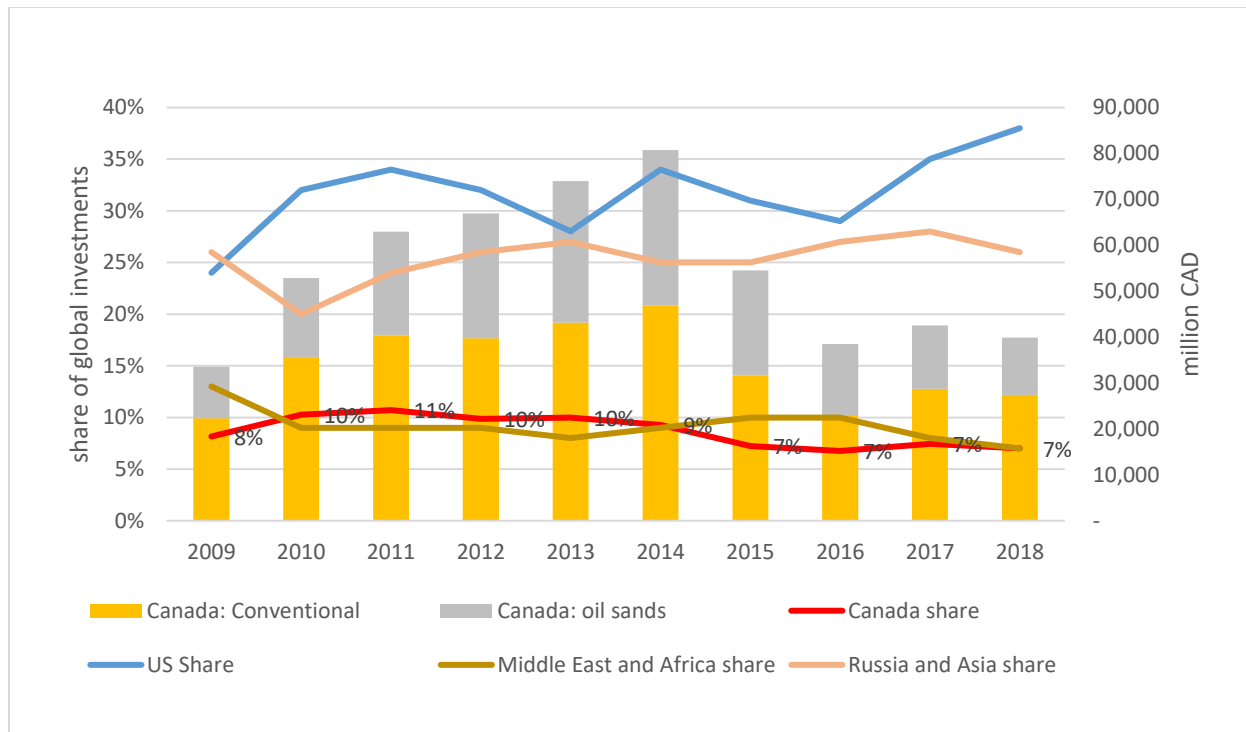
Canada has performed better in terms of oil production. It is in the top three countries in terms of growth for the 2009-2017 period, after Iraq and the US (Figure 1.16). The world grew by 14 percent for the period, while Canada added 50 percent. In terms of physical volume, Canada was in the top four. Note, over 80 percent of the growth came from the oil sands sector. This growth was possible largely due to demand from the US for heavy Canadian oil, falling supplies of OPEC, Mexico and Venezuela to the US, and availability of export pipeline capacities.

Figure 1.16: Global Oil Production Growth, 2009-2017



Source: CERI based on BP Statistical Report 2019

For upstream investments, Canada has been losing its share in the global investment portfolio since 2013 falling from 10 percent to 7 percent (Figure 1.17). Latin America and Europe were the other two regions which have seen fewer investments, and Russia, Central Asia and Asia Pacific countries have been balancing between 25-27 percent of global investments. The United States has attracted the attention of investors in recent years growing to 38 percent of global investment.

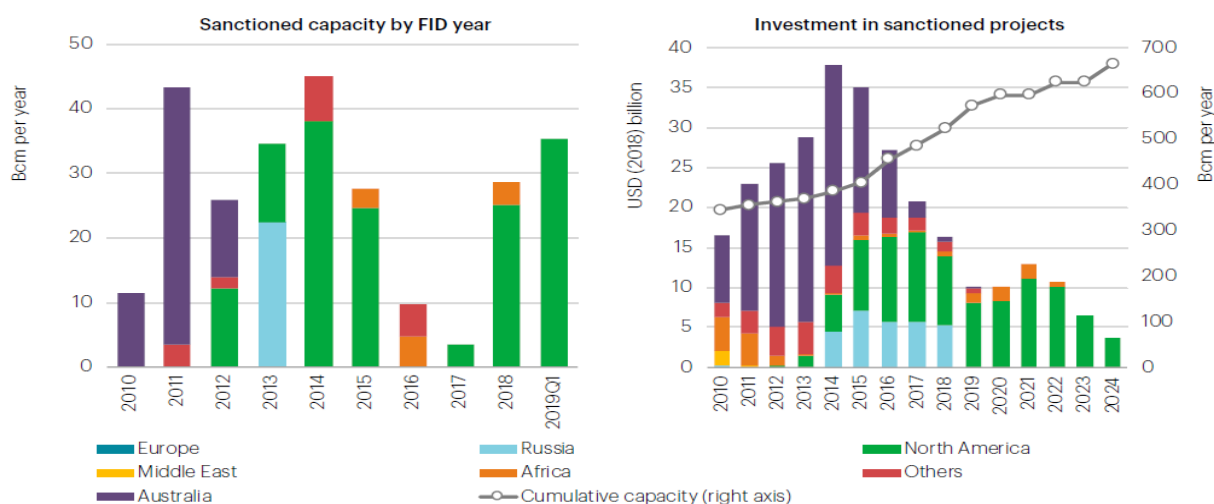
Figure 1.17: Global Upstream Oil and Gas Investments, 2009-2017

Source: EIA, IEA, ARC Energy Institute, CERI

With regard to natural gas liquefaction, Canada has been pursuing this sector for almost a decade. Despite the availability of cost-efficient and abundant Alberta and British Columbia natural gas resources, the country has seen only one FID from the LNG Canada project for 13 metric tonnes per annum (MTPA) of LNG (17.6 bcm, or 1.7 bcf/d). Canada's share in North America (in Figure 1.18) is an approximate US\$15 billion spread over 2019-2024 for two LNG Canada trains.

The plant should commence shipments in 2025. To put into perspective, the world's total liquefaction capacity is 392 MTPA as of early 2019, and 101 MTPA is under construction; this equates to sanctioned LNG capacity in Canada to only 2.5 percent of existing and under construction global capacity. Similar jurisdictions from political, macroeconomic, institutions and infrastructure perspective have attracted most of the investments: Australia and the United States (Figure 1.18).

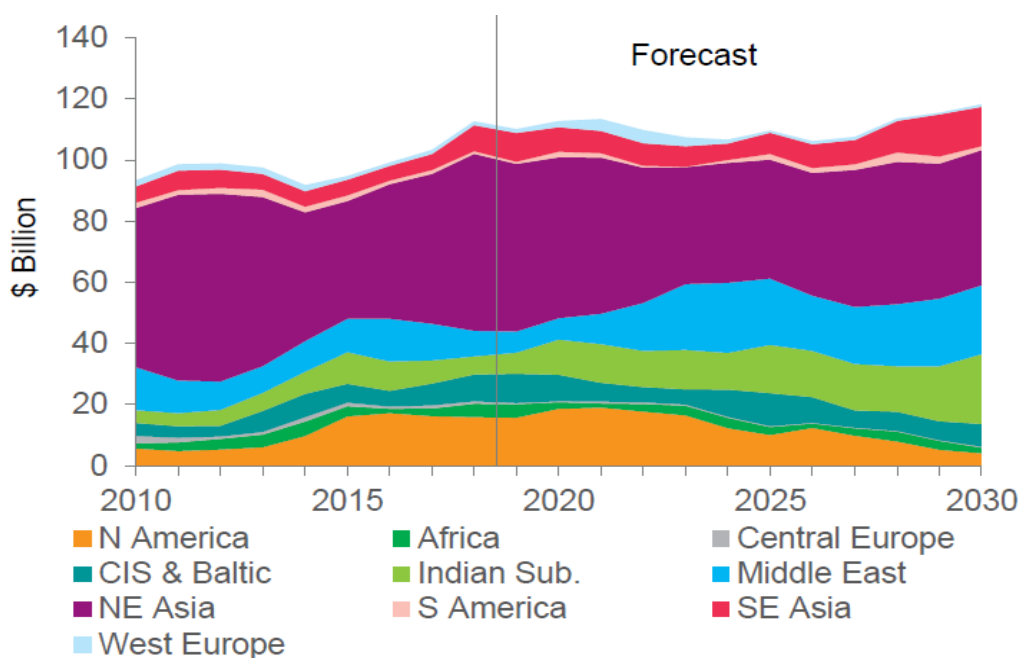
Figure 1.18: Global LNG FID and Investments, 2010-2024



Source: IEA Energy Outlook 2018

Petrochemical sector investments have been growing in northeast Asia, the Middle East, and the US since 2010 (Figure 1.19) while Canada has received under \$500 million or approximately 0.45 percent of global investments a year from 2010-2018 (\$500 million is a CERI estimate of CERI). As of 2019, Interpipeline's PDH/PDP \$3.5 billion facilities are under construction and the \$4.5 billion joint-venture of Pembina and Kuwait's Petrochemical Industries Co. has received FID.

Figure 1.19: Petrochemical Investments, 2010-2024

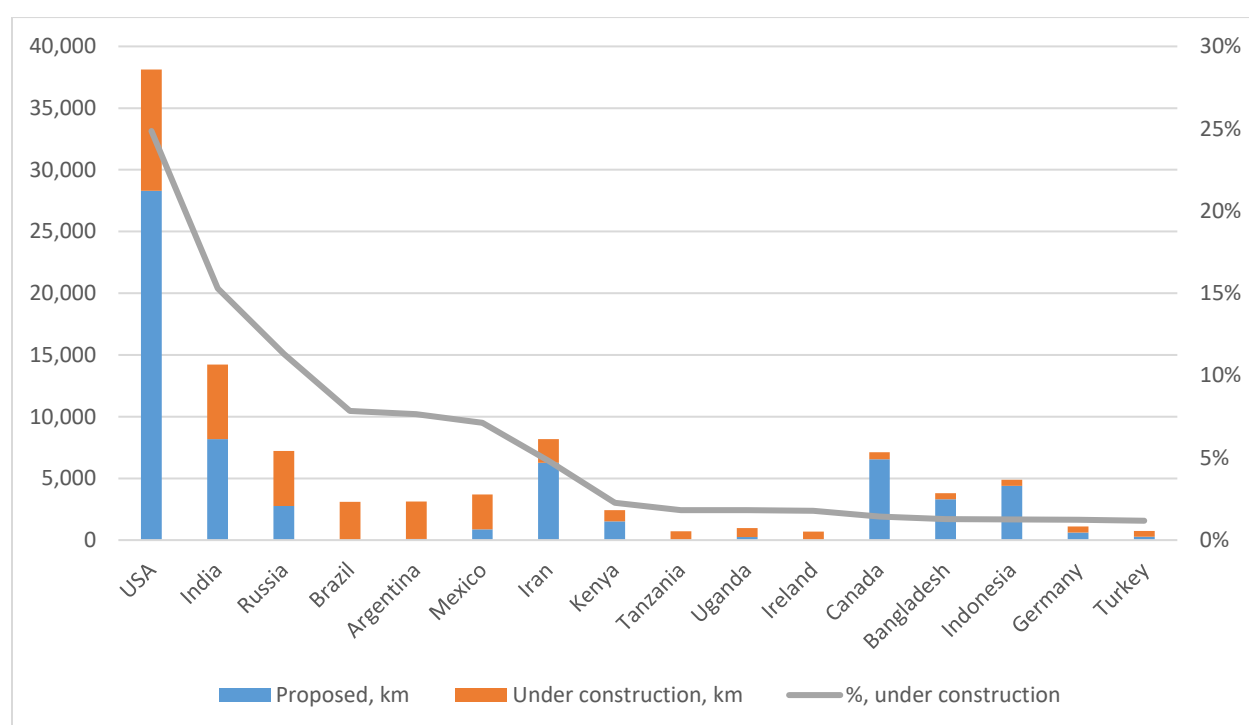


Source: IHS Markit

In the pipeline sector, Canada's share in total projects under construction (by km) is 1.4 percent and 5 percent of the globally proposed and under-construction projects (Figure 1.20). The latter includes NGTL expansion, Keystone XL, Trans Mountain Pipeline, Coastal Gas Link Pipeline, Pacific Trail Gas Pipeline, Prince Rupert Gas Transmission, and Eagle Spirit Pipeline.

The United States is holding leadership with 25 percent and 26 percent, respectively, in total under construction and proposed and under construction volumes. India, Russia, Brazil, and Argentina follow Canada as a leader in pipelines under construction. Canada is also in the top 2 for cancelled and shelved projects having 12 percent of the global share, followed by the US with 22 percent.

Figure 1.20: Global Pipeline Projects and Construction, 2019



Source: Global Fossil Infrastructure Tracker, CERl

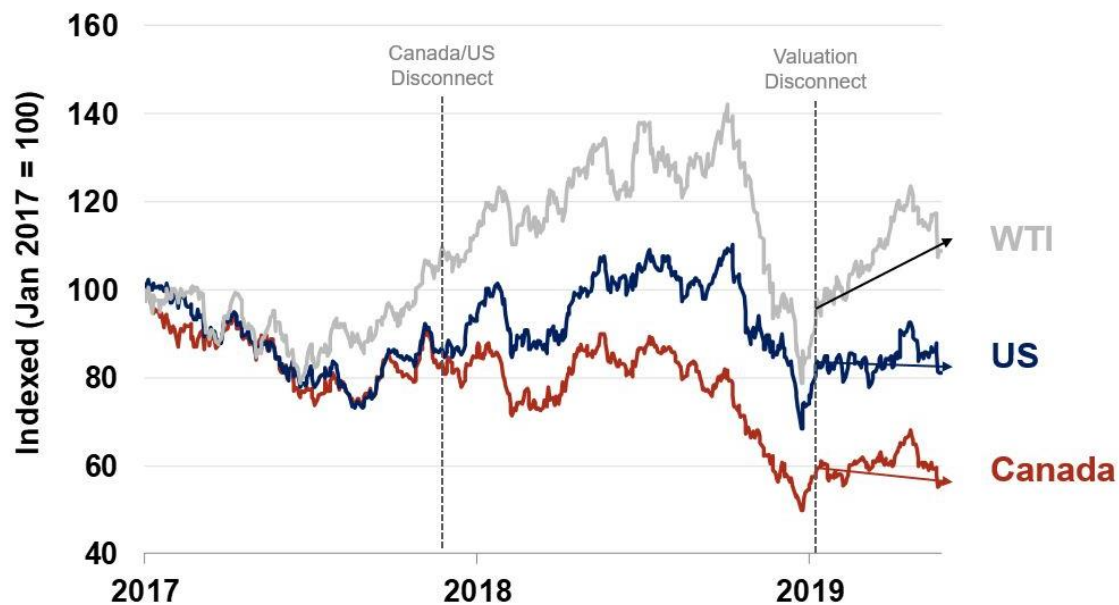
To summarize, there is a disparity between Canadian resource endowment and its recent performance in terms of investment attraction and activity. Canada lagged behind world growth except for oil and has seen lower investment in many subsectors of the oil and gas industry:

- The global share of Canada in upstream oil and gas – Declining, from 10 percent in 2013 to 7 percent in 2017
- Oil production – Faster than the world's growth rate: 50 percent versus 14 percent for 2009-2017
- Gas production – Slower than the world's growth rate: 13 percent versus 24 percent for 2009-2017

- Sanctioned LNG investments – 2.5 percent by capacity out of global sanctioned plus existing projects
- Petrochemical investments – Approximately 0.45 percent of global investments (2010-2018)
- Pipelines under construction (by km) – 1.4 percent of total global projects under construction in 2019

This shows that while products that Canada can produce are of global interest, investors were relatively more active in other jurisdictions. On the upstream side, market access challenges translate into low oil and gas prices but that might not be the full explanation for the investment behaviour. Figure 1.21 shows that Canadian oil and gas equities have disconnected from WTI prices, and more importantly from US oil and gas stocks in 2017 and into 2018. Canadian stocks are down by 40 percent compared to January 2017, while US stocks are down by 20 percent.

Figure 1.21: Canadian and US Oil and Gas Equities, 2017-2019



Source: Bloomberg, ¹S&P 500 Oil and Gas E&P Index, ²S&P/TSX Oil and Gas E&P Index

May 30, 2019
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Source: ARC Energy Institute

According to the ARC Energy Institute, the timing of disconnecting with US stocks “corresponds to when the price discounts for Canadian oil started to widen because of growing oil sands supply and a lack of pipeline and crude-by-rail takeaway capacity.”¹³ The large price differentials have since disappeared,¹⁴ however, the Canadian equity index did not return to the US one or at least did not move much closer. This shows that attractive commodity prices returned by the non-market mechanism of curtailment are not enough to mask the current comparative disadvantage of Canadian business/products and jurisdiction to the US.

Another factor that pushed equity down irrespective of higher oil prices is low natural gas prices. The curtailment itself is not the mechanism that investors appreciate as it is a signal of inability to provide enough egress at the right time.

What else can be behind this disconnect with the US and lower attractiveness in general to other subsectors? It includes market access issues and the resultant low expectations of growth. It also could be differences in fiscal regime (taxes, royalty), incentives, regulatory, and overall ease in doing business.¹⁵ All other required elements appear to be in place – resource base, demand, cost-efficiency, global prices, institutions, infrastructure, macroeconomic environment, labour, and suppliers’ availability.

Report Structure

This study provides an outlook of production for crude oil (excluding oil sands) and natural gas, production supply costs for new development, the economic impacts as well as emissions due to oil and gas production.

This study is divided into four chapters. Chapter 1 provides 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 production forecasts and supply costs. It is subsequently divided into two parts: oil and natural gas. Both sections are further sub-divided by province. Chapter 3 reviews methodology and assumptions used in modelling of the economic impacts, and the capital and operations investment forecasts, for two commodities (crude oil and natural gas). It further presents the impacts of the Canadian oil and gas industry in Canada during the 11-year period (2018-2028) and the United States. Economic impacts include economy-wide impacts such as value-added gross domestic product (GDP), job creation, and government revenues (the latter except for the US). The chapter concludes with details of GHG emissions due to oil and gas production during the study period.

¹³ <https://www.arcenergyinstitute.com/the-underperformance-of-upstream-oil-and-gas-equities-in-the-united-states-and-canada/>

¹⁴ As of time of writing, it was approximately US\$20 (from over US\$50 in October 2018)

¹⁵ On the ease of doing business, Canada fell from 8th in the world in 2009 to 22nd in 2019 according to the World Bank, behind oil and gas producers – Denmark (3rd), United States (8th), United Kingdom (9th), UAE (11th), and Australia (18th).

Appendices A and B present more detailed information on the models. Appendices C and D include detailed tables of oil and natural gas production forecasts by region and provincial maps 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 (WCSB) by province (British Columbia, Alberta, Saskatchewan, and Manitoba) as well as for the province of Newfoundland and Labrador, for the period 2019-2039. This analysis is for both onshore and offshore conventional oil, including shale and tight oil activity, conventional natural gas, coalbed methane, tight and shale gas, and the natural gas liquids (pentanes plus and condensate only). Oil production out of Alberta's oil sands is not included and can be found separately in CERI's forthcoming 2019 Annual Oil Sands Update.

In producing this forecast of drilling and production, CERI relied on and accounted for a variety of data which included historical well-licensing data, historical drilling activity in activity areas, supply costs, the ratio of horizontal and vertical wells, and industry's interests in a resource play.

CERI has also accounted for the forecast of domestic demand for conventional crude oil and natural gas, exports, and imports of these products. For the latter, the US EIA Outlook 2019 forecast was used for natural gas (US imports and exports to Canada) as a basis. Thus, the forecast reflects the changes in expected trade volumes of natural gas and oil between the US and Canada due to US growth of shale oil and gas volumes. For domestic consumption, the NEB Energy Futures forecast was used. At the same time, CERI did not constrain the production outlook for any potential bottlenecks in export pipelines or current recoverable reserves estimates. It is worthwhile mentioning that the additions that CERI forecasts to oil production could be well handled by existing rail infrastructure in the short term as well as new pipelines in the medium and long term.

More details about factors which impacted the oil and gas forecast are provided below.

The overall oil outlook is shaped by the following key factors:

1. Dynamics of US crude imports. According to the EIA Energy Outlook 2019, US imports will decline until 2027, remain flat until 2034, and then start to grow onwards. The change in dynamic after 2034 is related to the maturity of US shale oil reserves.
2. Relatively stable demand from domestic refineries and increasing share of Canadian crude in Central Canadian refineries by 150 Mbpd in the course of seven years (note, Canadian oil has added 52.6 Mbpd in refinery intake slate in the last four years).
3. Pentanes plus and condensate growth underpinned by the demand from oil sands and increased natural gas production due to LNG developments.
4. Additional pipeline exports to countries except for the US. A 40 Mbpd of light oil addition egress via TMX pipeline is assumed starting from 2022.

The natural gas outlook, in turn, is shaped by the following key factors:

1. Domestic natural gas consumption adds 2.5 bcf/d in the forecasted period (NEB, Energy Futures 2019).
2. Declining net exports with the United States due to domestic production growth. Net exports to the US are assumed to fall by 50 percent from 5.6 bcf/d in 2018 to 2.5 bcf/d in 2039 (EIA Energy Outlook 2019).
3. Additional demand for gas from LNG developments. In total, this year's forecast includes a peak of 7.1 bcf/d of gas production for LNG purposes which is reached by 2029 and remains until the end of the forecasted period.

CERI assumes that first shipments of LNG can start as early as 2024 in the following order:

- 2024: Woodfibre LNG with 0.3 bcf/d (sourced from British Columbia)
- 2025: LNG Canada with 1.85 bcf/d (10 percent sourced from Alberta, 90 percent from British Columbia; the breakdown is driven by the location of upstream assets of the shareholders)
- 2025: East coast project with 0.7 bcf/d (100 percent sourced from Alberta)
- 2027: LNG Canada expansion to 3.7 bcf/d (+1.85 bcf/d) (sourced same as above)
- 2029: Kitimat LNG with 2.5 bcf/d (sourced from British Columbia)

In total, this year's forecast includes a peak of 7.1 bcf/d of additional gas production for LNG purposes reached at 2029.

All supply costs are provided for both vertical and horizontal wells and labelled by Pipeline Influence Areas (PIA areas). All provinces (except for Newfoundland and Labrador) are divided into PIA areas (the map and locations are available in Appendix D). The revenues for gas wells do not include sales from NGLs, while revenues from oil wells do not include sales from associated gas.

To produce our oil production supply costs, CERI used the information contained in the 2017 Well Cost Study from the Petroleum Services Association of Canada (PSAC). The 2018 well cost estimate is based on 2017 well cost data with a weighted average -8 percent factor applied. The factor was calculated by CERI and based on the number of wells drilled and drilling capital investments from the annual reports of a number of Canadian oil and gas producers in total representing 830 barrels of oil equivalent per day of conventional oil and gas. The changes in drilling costs were weighed by the company's production.

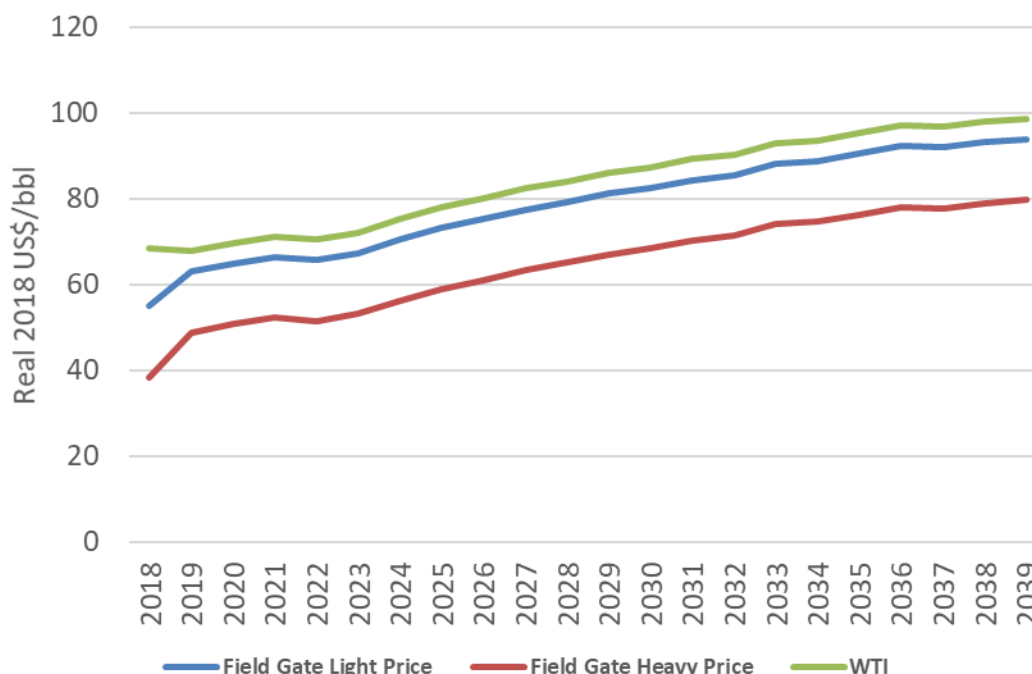
The Canadian Association of Petroleum Producers (CAPP) Statistical Handbook (2018) was used to obtain operating costs. Field equipment, land, tie-in, geological and geophysical costs, and enhanced oil recovery costs are added to the well capital cost.

Reference wells are assigned to each activity area and formation under study, and the well capital cost is calibrated to the average historical drill depth (for the last 7 years) in that area.

The EIA's Reference Case forecast for WTI crude oil used in this report is shown in Figure 2.1. The EIA's Annual Energy Outlook 2019 predicts that the WTI price will rise to US\$98.7/bbl by 2039 (in 2018 USD) from the 2018 price of US\$68/bbl.

Canadian Field Gate Light and Heavy oil prices are estimated by applying differentials to the WTI forecast; these prices are used for revenue estimates for economic impacts analyzing and royalty calculations for supply costs.

Figure 2.1: WTI Crude Oil Price Forecast



Source: EIA (EIA 2019)

Note that the supply costs figure only shows results for those regions with the cost lower than CAD\$80/bbl for oil and with costs lower than CAD\$3/mscf for natural gas.

Canadian Crude Oil, Pentanes Plus and Condensate

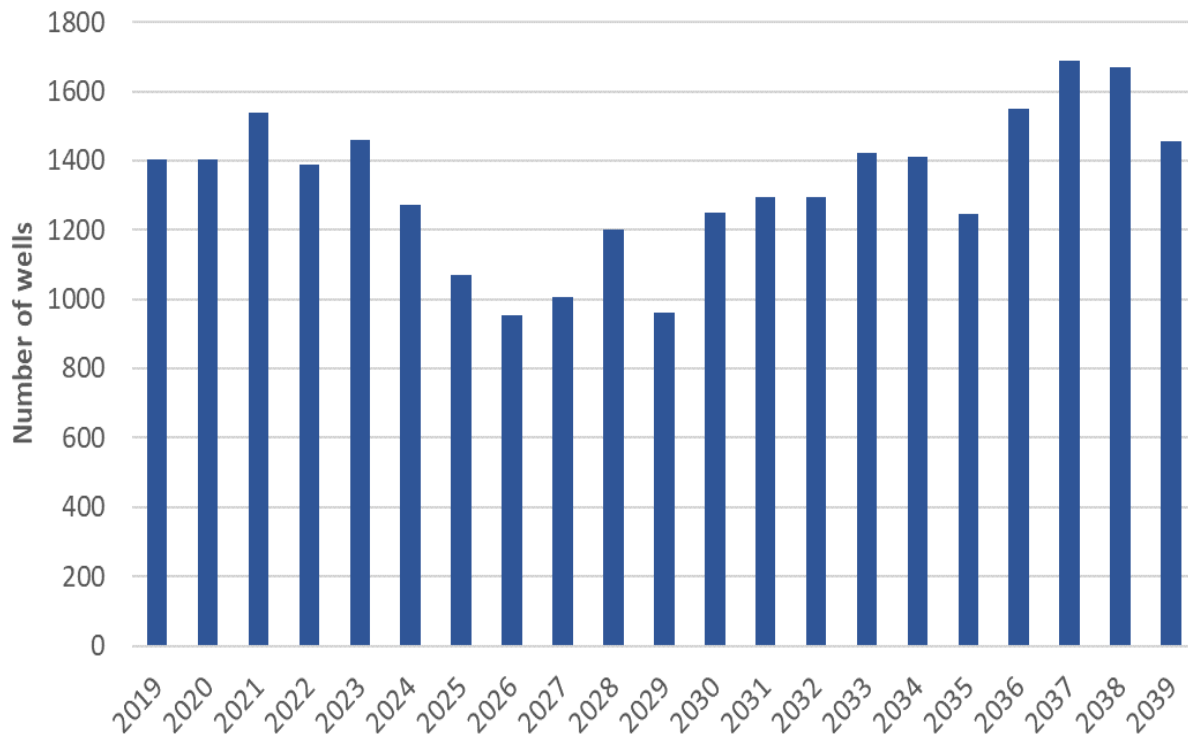
Alberta

Alberta's conventional oil production has been in decline since 2014 (-4.5 percent CAGR). Overall production for oil (not including pentanes plus and condensate) fell from 590 Mbpd in 2014 to 490 Mbpd in 2018. However, the declining trend ceased in 2017. Pentanes plus and condensate output has been on the rise (17.9 percent CAGR over the same period) reaching 351 Mbpd in 2018, adding 170 Mbpd since 2014 (CAPP 2018).

Going forward, CERI estimates 1,400 horizontal and vertical oil wells will be put into production in 2019, not including cold bitumen production (CBP) or in-situ thermal (Steam Assisted Gravity

Drainage) producing wells. In the longer term, CERI estimates oil wells put in service to fluctuate within a range of 950 to 1,650 wells per year until 2039, which is reflected in Figure 2.2.

Figure 2.2: Alberta New Oil Well Forecast

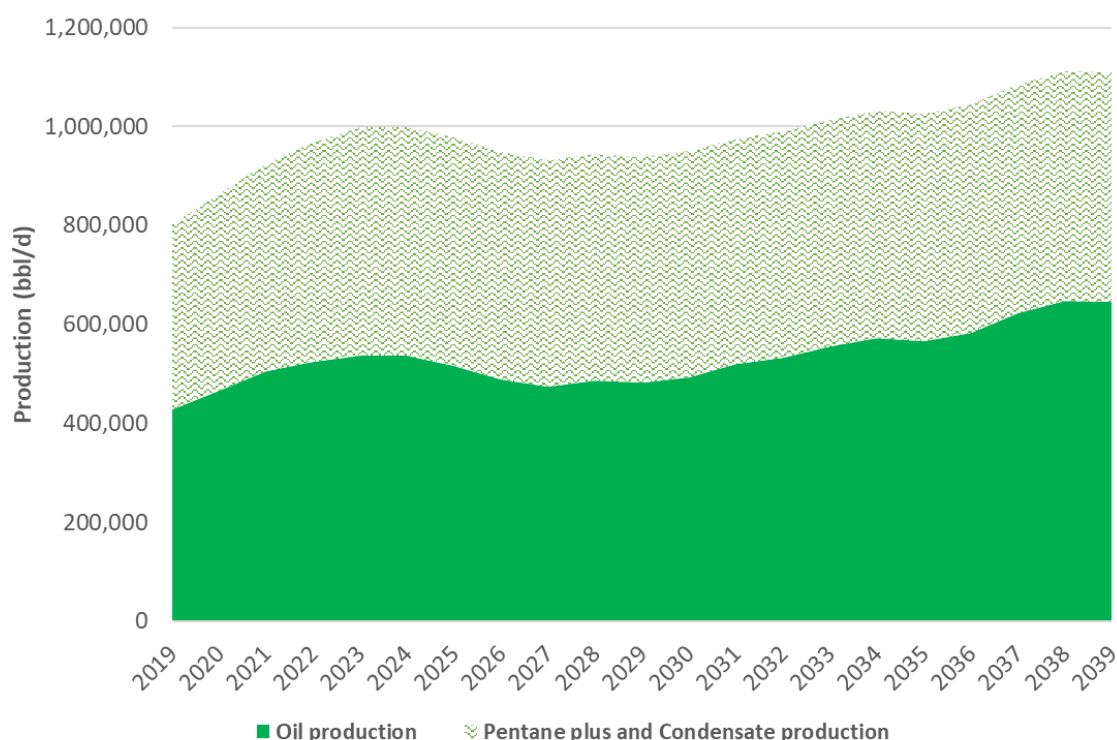


Source: CERI

The changing nature of drilling and, consequently, production in Alberta is explained by fluctuating needs for imported oil from the US. Together with Saskatchewan, Alberta takes the biggest hit from dwindling US imports as well as experiences growth after 2030 to satisfy growing imports to the US caused by a decline in production from their maturing shale fields.

Given drilling expectations, forecasted production declines and IP 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 2.3.

Figure 2.3: Alberta Crude Oil Production Forecast



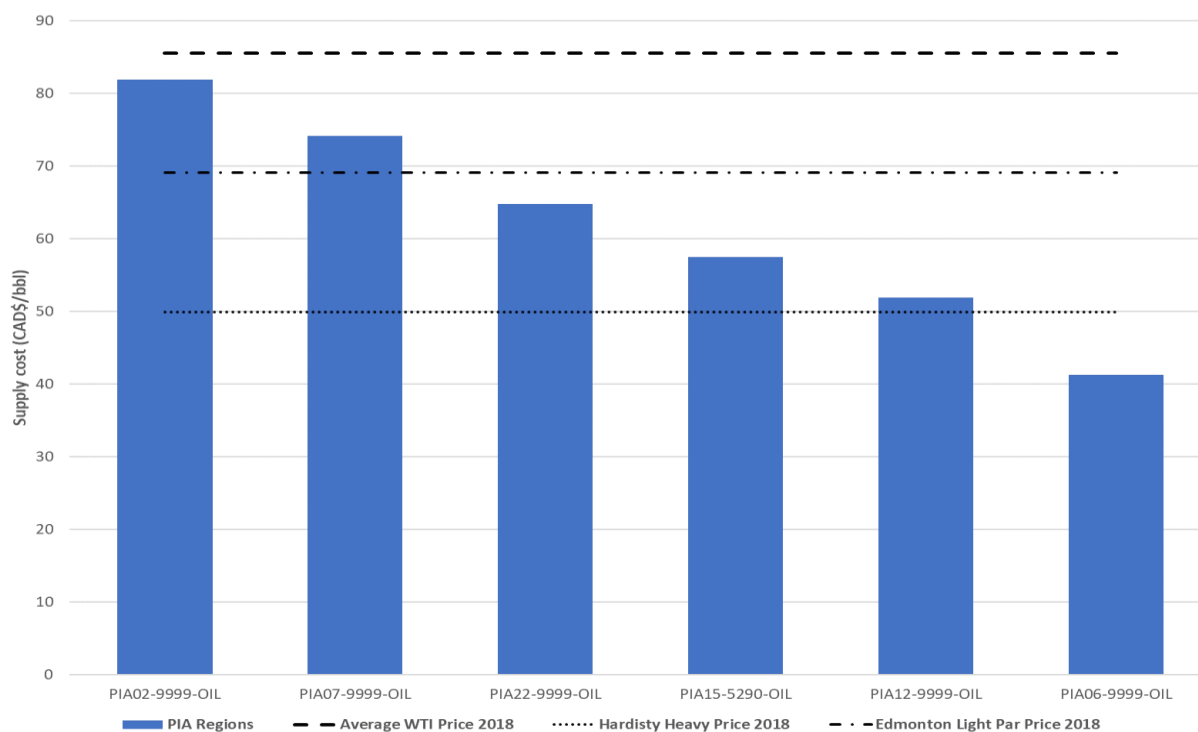
Source: CERI, AER, PSAC, CAPP

The production forecast displays similar behaviour as the drilling rates. Overall, oil production grows from 427 Mbpd in 2019 to 645 Mbpd by the end of 2039 (51 percent increase). Note that 2019 production considers an estimated average of 60,000 barrels per day production curtailment policy by the Government of Alberta.

For condensate and pentanes plus, the production is expected to increase from 375 Mbpd in 2019 to 466 Mbpd in 2039.

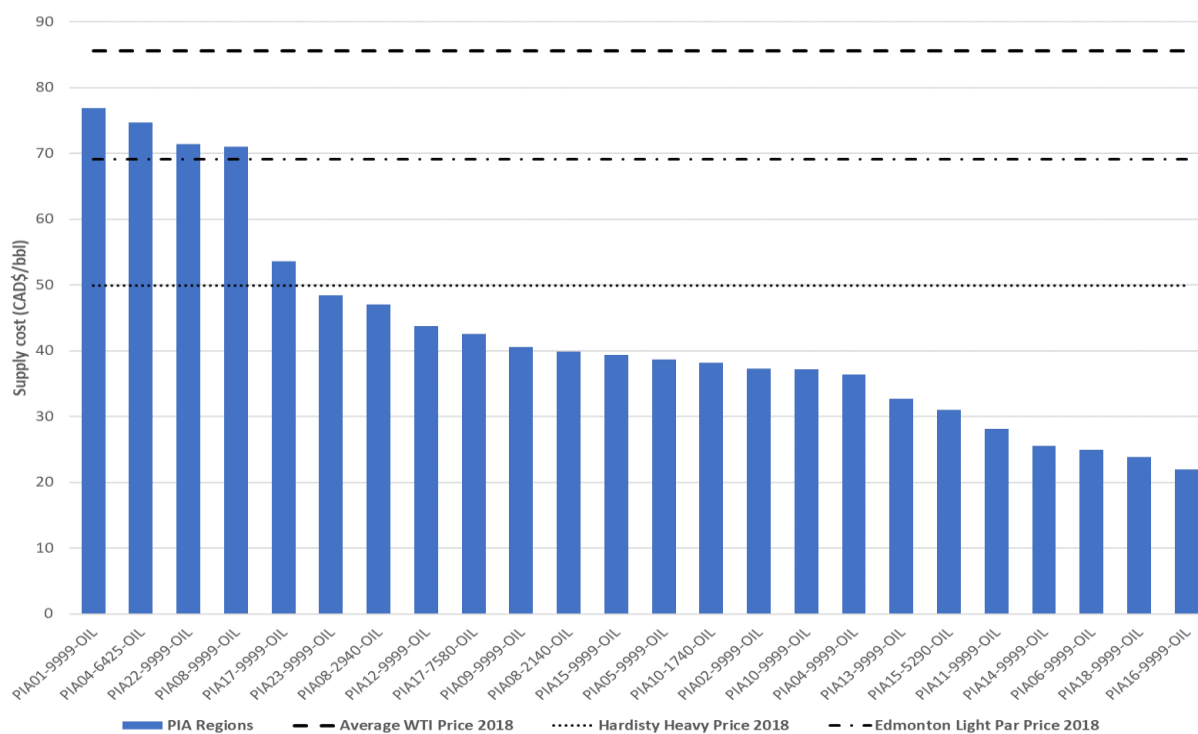
The supply costs for specific areas are shown in Figures 2.4 and 2.5 with the average WTI price, Hardisty Heavy, and Mixed Sweet Blend Edmonton overlaid for reference. Note that 75 percent of wells put into production in 2018 in Alberta were horizontal wells.

Figure 2.4: Alberta Vertical Oil Well Supply Costs



Source: CERi, AER, PSAC, CAPP

Figure 2.5: Alberta Horizontal Oil Well Supply Costs



Source: CERi, AER, PSAC, CAPP

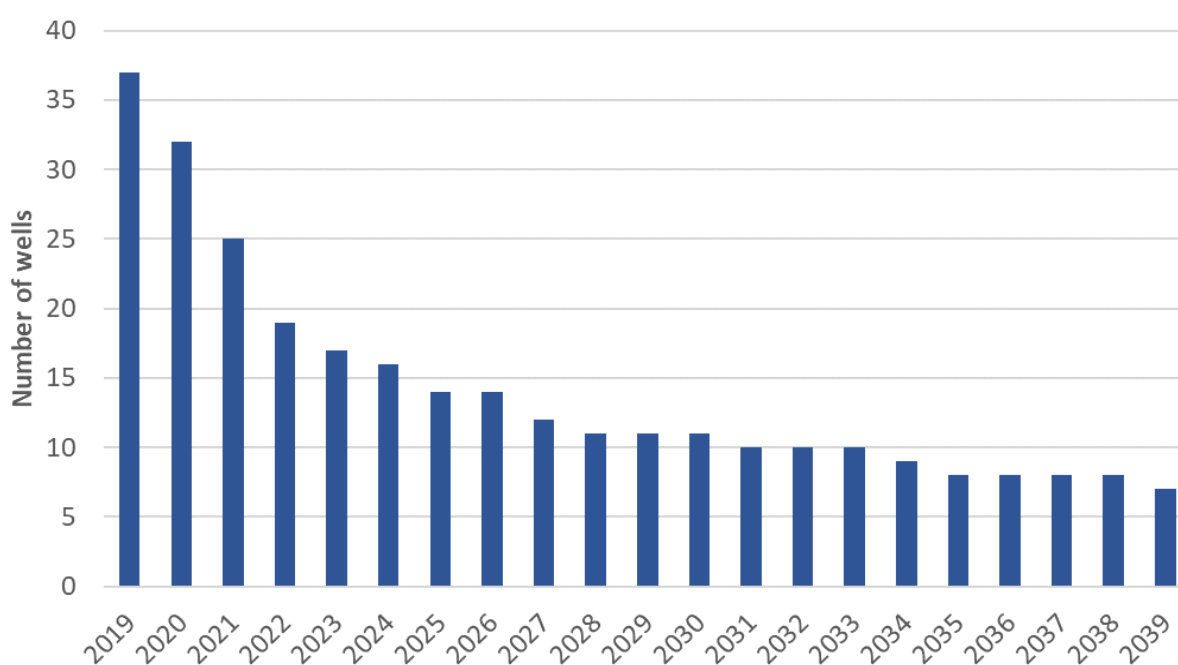
In Alberta, the lowest supply cost estimates belong to the western, central, south-western regions of the province, which contain many of the PIAs, including PIA 13, 14, 11, 06, 15, 16, 14, 09, 10, 02, 12 and 17 in both the horizontal and vertical supply cost curves. The Montney, Duvernay, Spirit River, and Cardium formations are represented at the lower end of the supply cost curve. Going forward, it is expected that most of the drilling will occur in these areas.

British Columbia

Historically, British Columbia has been a marginal oil producer in Canada. Over the last four years (2014 to 2018), British Columbia produced less than two percent of Canada's total crude. Oil production has been stable at around 21 Mbpd for the period (CAPP 2018).

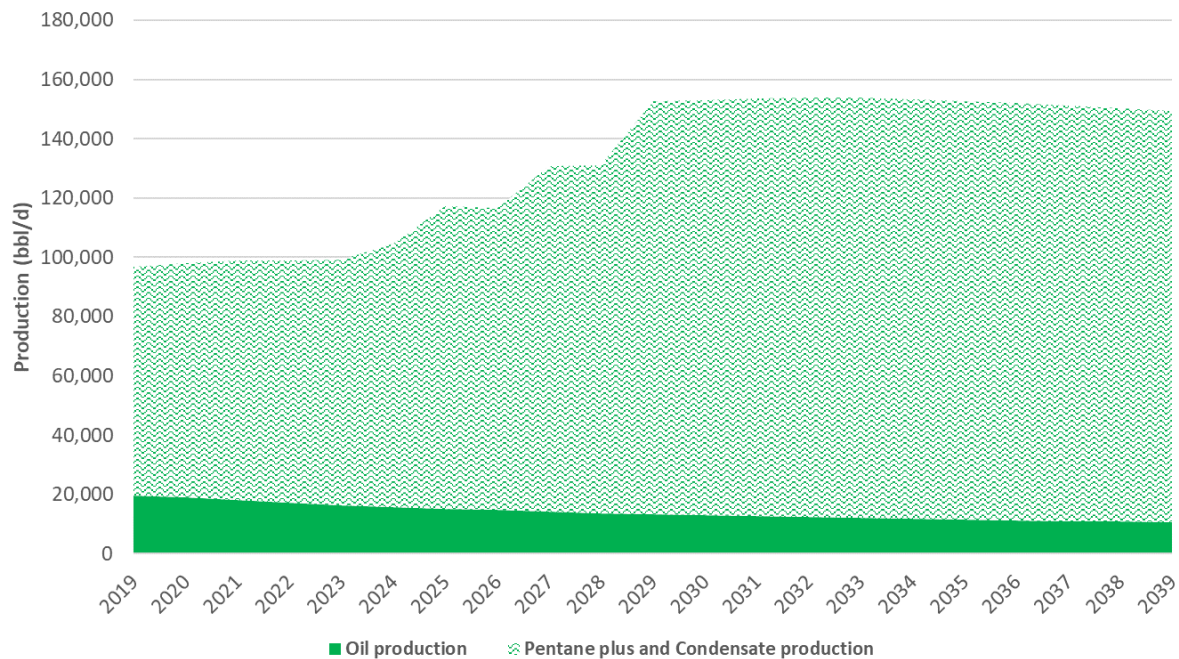
CERI does not predict a significant drilling program targeting crude oil in the province. The province will drill over 35 wells at the beginning of the forecast and under 10 wells closer to the end of the forecast (Figure 2.6).

Figure 2.6: British Columbia New Oil Well Forecast



Source: CERI, BCOGC

Given drilling expectations, forecasted production declines and IP rates in the drilling areas, CERI developed a 20-year production forecast for oil in British Columbia as shown in Figure 2.7.

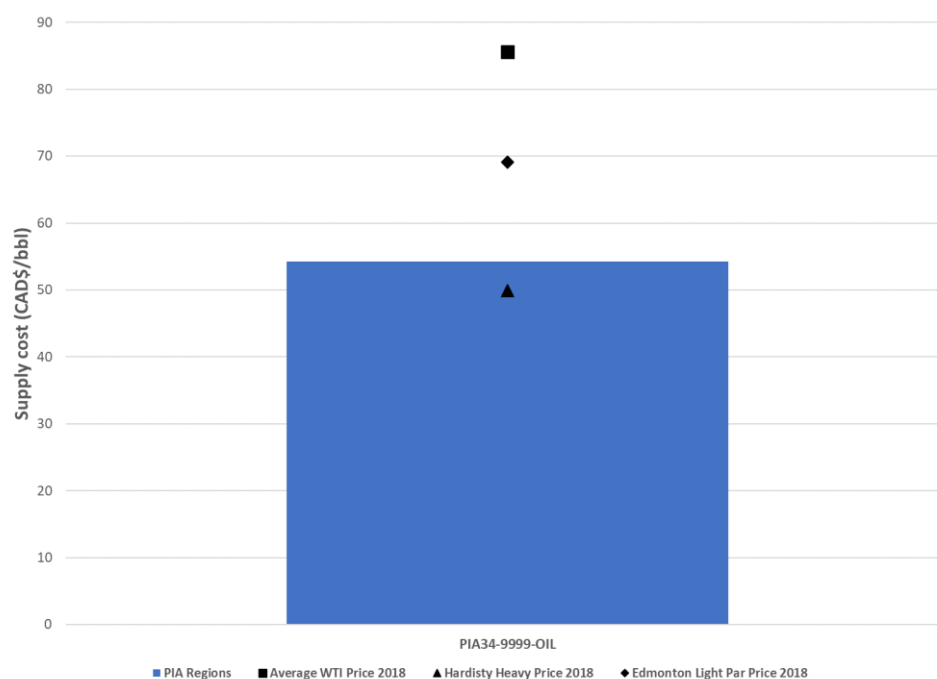
Figure 2.7: British Columbia Crude Oil Production Forecast

Source: CERI, BCOGC, PSAC, CAPP

CERI predicts continuous declining levels of crude production out of British Columbia owing to a preference for targeting NGLs-rich natural gas rather than crude oil. With regard to the production of condensate and pentanes plus, new LNG plants are driving additional natural gas production, and hence, condensate and pentanes plus. CERI assumed new LNG plants are coming online in 2024, 2025, 2027, and 2029 which result in the growth of these products from 77 Mbpd to 139 Mbpd in 2039. Further details are provided in the natural gas section, British Columbia.

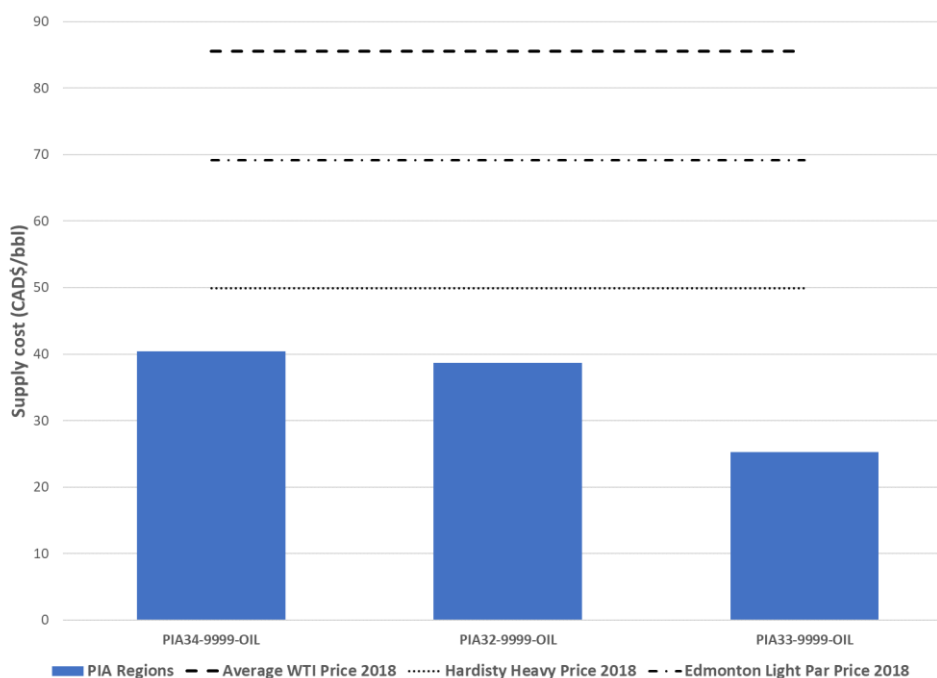
The supply costs for specific activity areas are shown in Figures 2.8 and 2.9, with the average WTI price, Hardisty Heavy price and Edmonton Heavy par price overlaid for reference. Note that 100 percent of wells put into production in 2018 in the province were horizontal wells.

Figure 2.8: British Columbia Vertical Oil Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

Figure 2.9: British Columbia Horizontal Oil Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

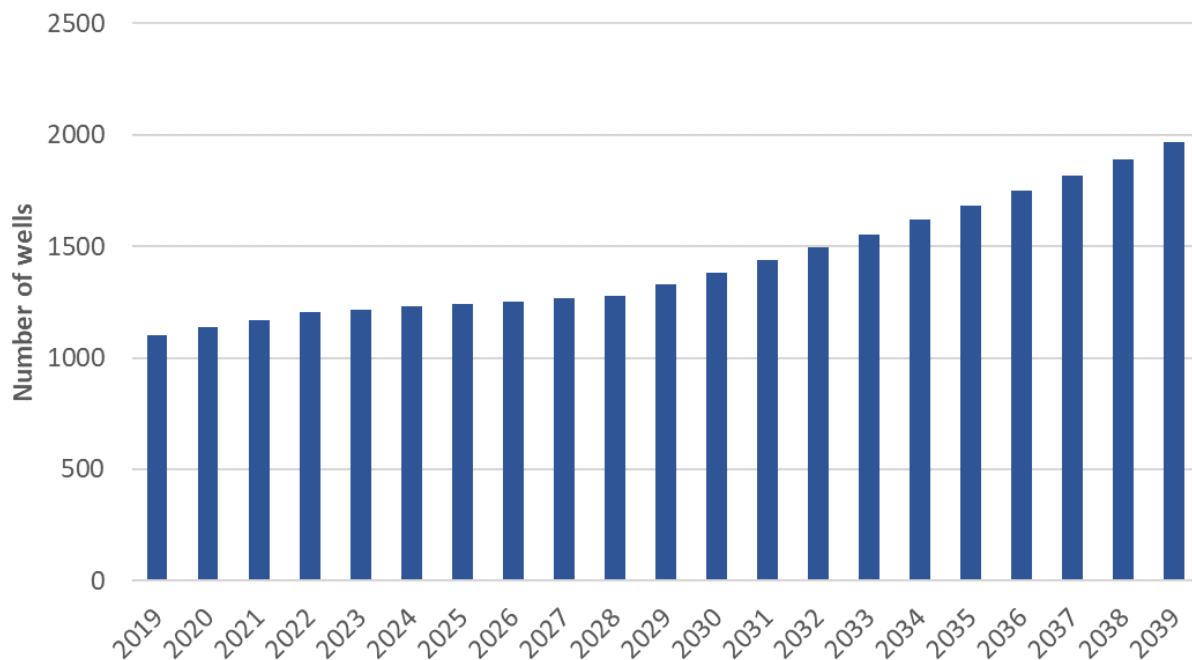
The supply costs of horizontal wells are less expensive than those of vertical wells. The three areas shown in Figure 2.9 all have favourable average supply costs for horizontal drilling and are all part of British Columbia's Montney formation. Future oil well drilling is expected to continue to be in this formation, concentrated in the three regions identified above (in 2018, more than 90 percent of drilling in British Columbia was in the Montney area). Appendix A includes other areas that are not depicted in Figures 2.8 and 2.9, i.e., PIA 31 and 35 to 45, due to their high supply costs.

Saskatchewan

Unlike Alberta, Saskatchewan's production has not seen such a deep decline over 2014-2018. Overall oil production decreased by 1.3 percent CAGR for the period, or from 514 to 488 MMbpd.

Drilling is expected to increase consistently through the study period to maintain production with the expectation of decreasing IPs over time, with 2039 having approximately 80 percent more drilling than 2019 to sustain production. Most of the activities will fall within the tight oil formations within the WCSB, in Saskatchewan's portion of the Bakken. CERI's forecast for conventional oil wells in Saskatchewan is shown in Figure 2.10.

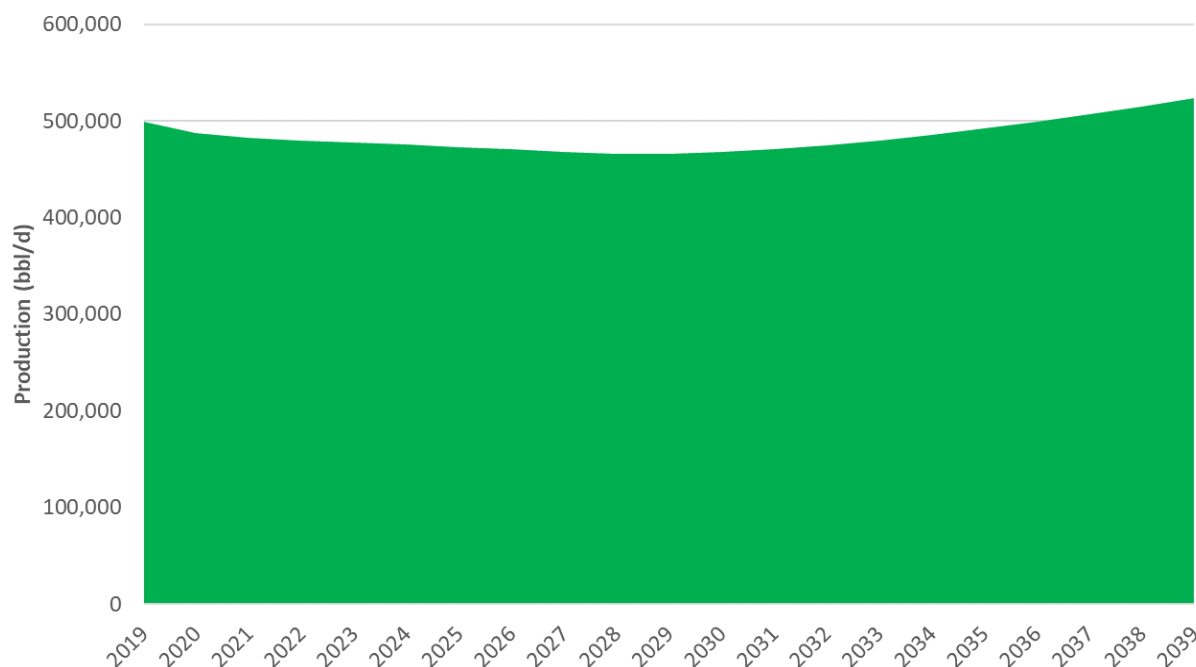
Figure 2.10: Saskatchewan New Oil Well Forecast



Source: CERI, Government of SK, PSAC, CAPP

Given drilling expectations, forecasted production declines and IP rates in the drilling areas, CERI developed a 20-year production forecast for oil in Saskatchewan as shown in Figure 2.11.

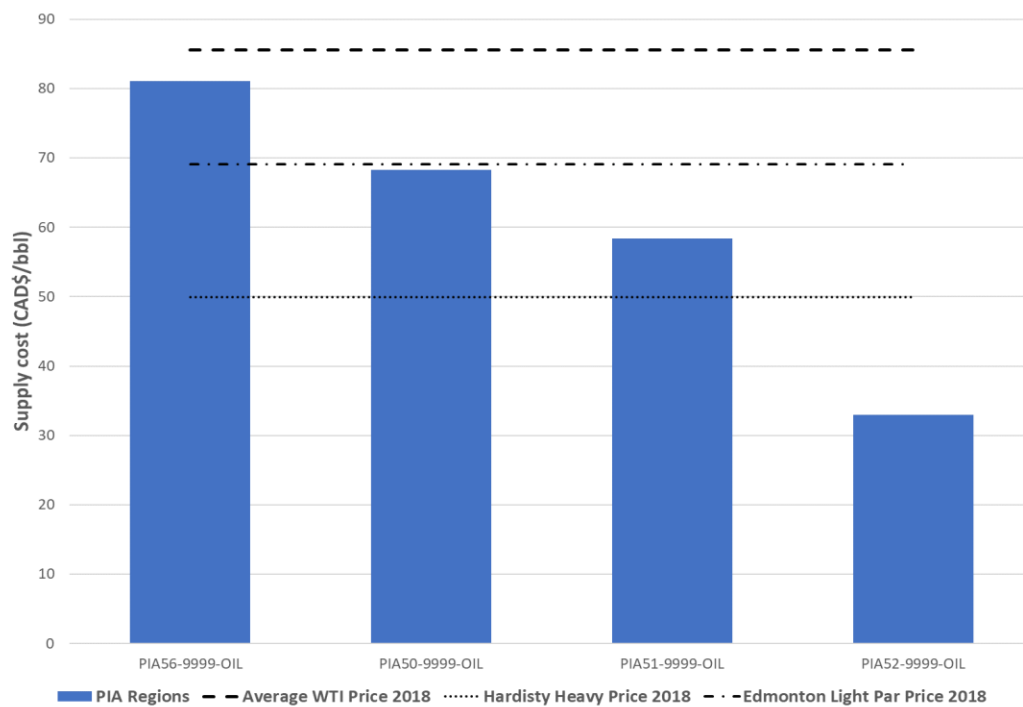
Figure 2.11: Saskatchewan Crude Oil Production Forecast



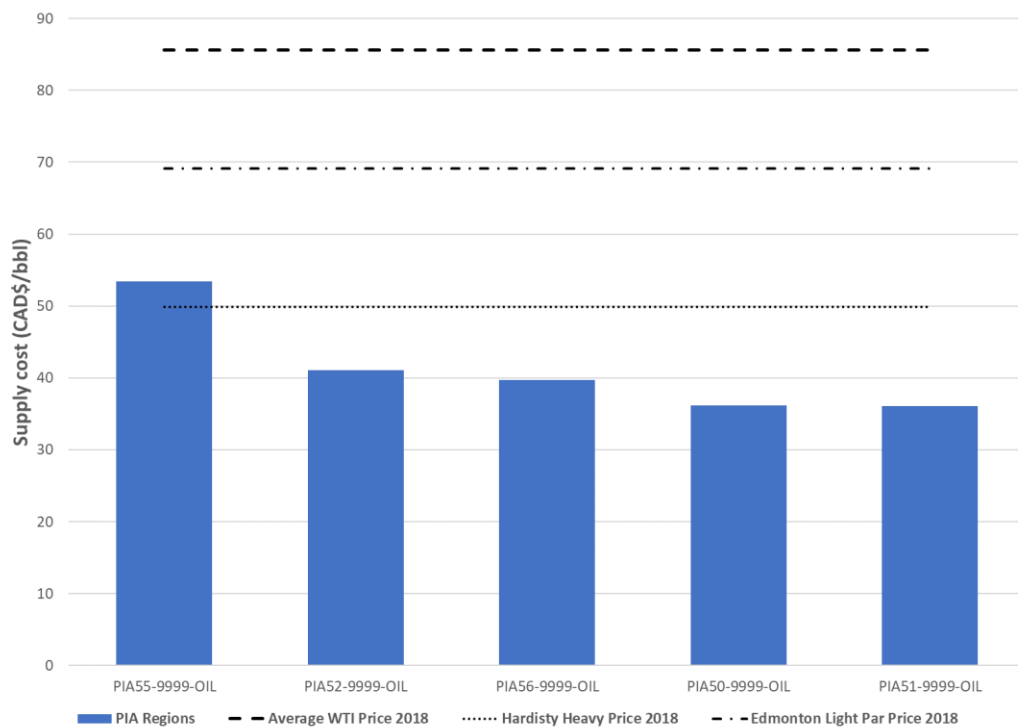
Source: CERI, Government of SK, PSAC, CAPP

Overall, Saskatchewan's crude oil production is also impacted by the changing exports to the US – both negatively until 2030 and positively afterwards. The province now exports slightly over 100 Mbpd to the United States. CERI predicts that oil production will decrease slightly until 2029 followed by a continuous incremental trend throughout the rest of the study period. In 2039, production is expected to reach approximately 524 Mbpd from the 2019 level of 500 Mbpd (5 percent increase).

The average calculated well costs for specific pipeline areas are shown in Figures 2.12 and 2.13, with the average WTI price, Hardisty Heavy price and Edmonton Light par price overlaid for reference. Note that 94 percent of wells put into production in 2018 in the province were horizontal wells.

Figure 2.12: Saskatchewan Vertical Oil Well Supply Costs

Source: CERI, Government of SK, PSAC, CAPP

Figure 2.13: Saskatchewan Horizontal Oil Well Supply Costs

Source: CERI, Government of SK, PSAC, CAPP

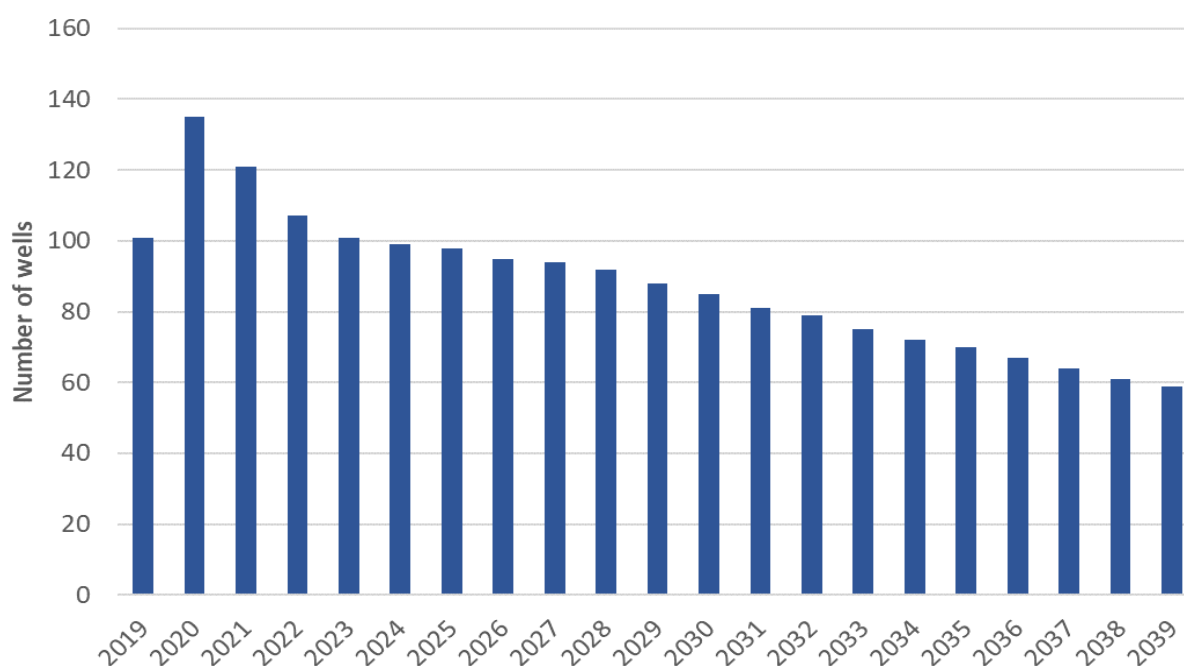
While vertical wells in PIA 52 can deliver oil at supply costs below benchmark prices, the supply costs for horizontal wells in Saskatchewan, like Alberta and British Columbia, are generally lower than those for vertical wells, and well below the benchmark prices making them economically attractive.

Manitoba

Manitoba saw its production of crude oil decline by 4.8 percent annually from 2014 to 2018, or from 49 Mbpd to 40 Mbpd (CAPP 2018).

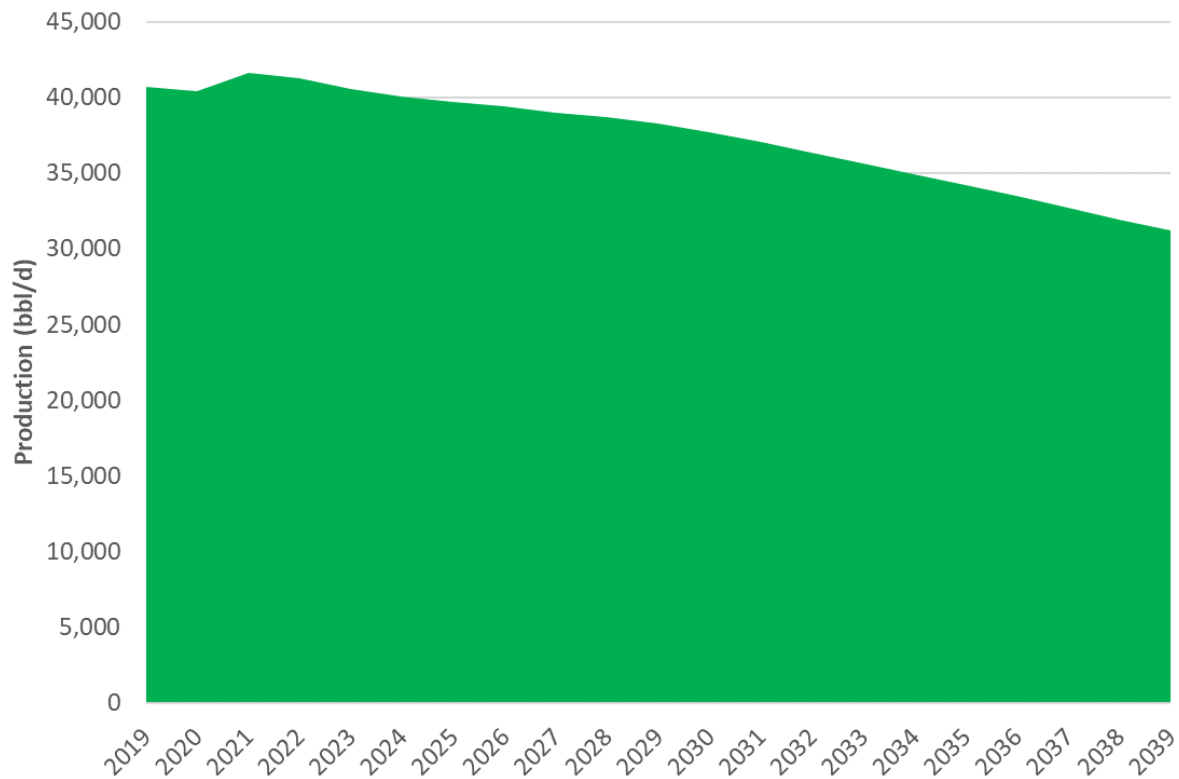
During the forecast, CERl expects an overall declining drilling trend during the study period (Figure 2.14).

Figure 2.14: Manitoba New Oil Well Forecast



Source: CERl

Given drilling expectations, forecasted production declines and IP rates in the drilling areas, CERl developed a 20-year production forecast for oil in Manitoba as shown in Figure 2.15.

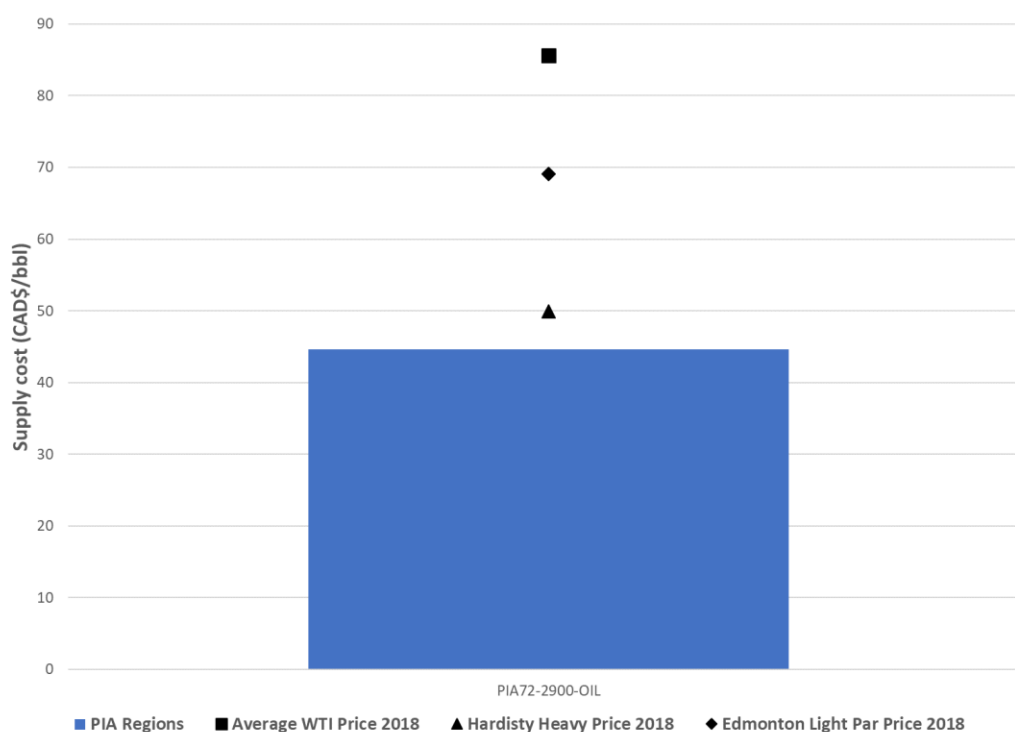
Figure 2.15: Manitoba Crude Oil Production Forecast

Source: CERI, Government of MB, PSAC, CAPP

The production is forecasted to fall from 41 Mbpd to almost 31 Mbpd by the end of the study period (23 percent less than in 2019) largely due to less favourable economics than in other jurisdictions.

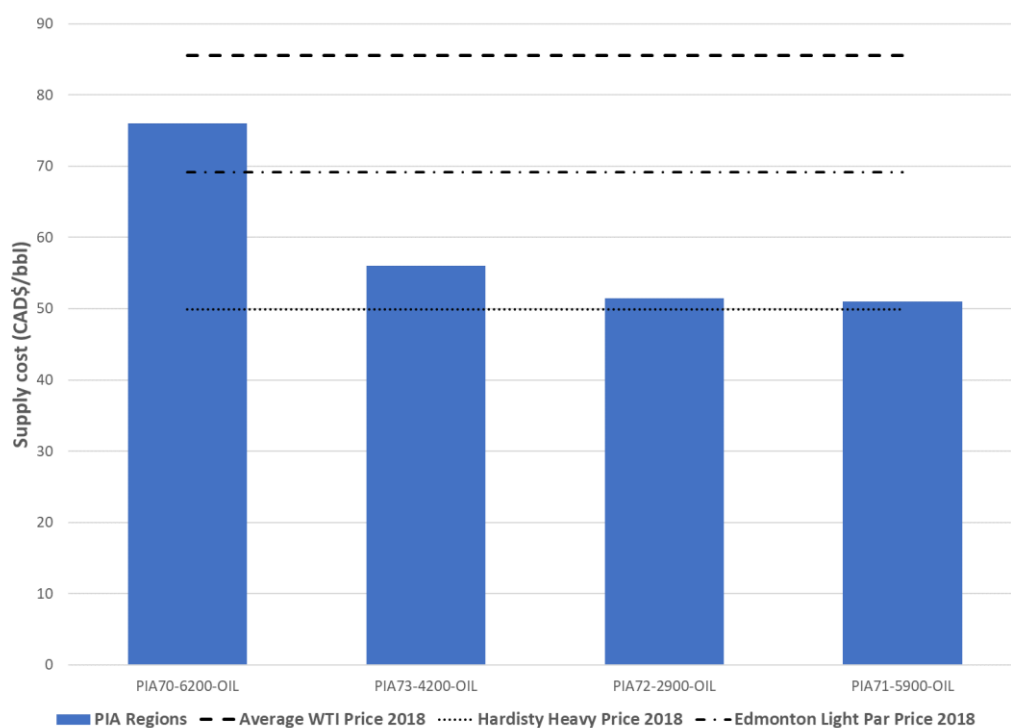
The calculated supply costs for specific areas are shown in Figures 2.16 and 2.17, with the average WTI price, Hardisty Heavy price and Edmonton Light par price overlaid for reference.

Figure 2.16: Manitoba Vertical Oil Well Supply Costs



Source: CERI, Government of MB, PSAC, CAPP

Figure 2.17: Manitoba Horizontal Oil Well Supply Costs



Source: CERI, Government of MB, PSAC, CAPP

The supply costs for horizontal wells are lower than those for vertical wells, except in PIA 72, where the supply cost for vertical wells is cheaper than horizontal wells. With forecasted production rates, the supply costs are less favourable than in other jurisdictions, specifically in Alberta and Saskatchewan where many areas are under \$40 supply cost.

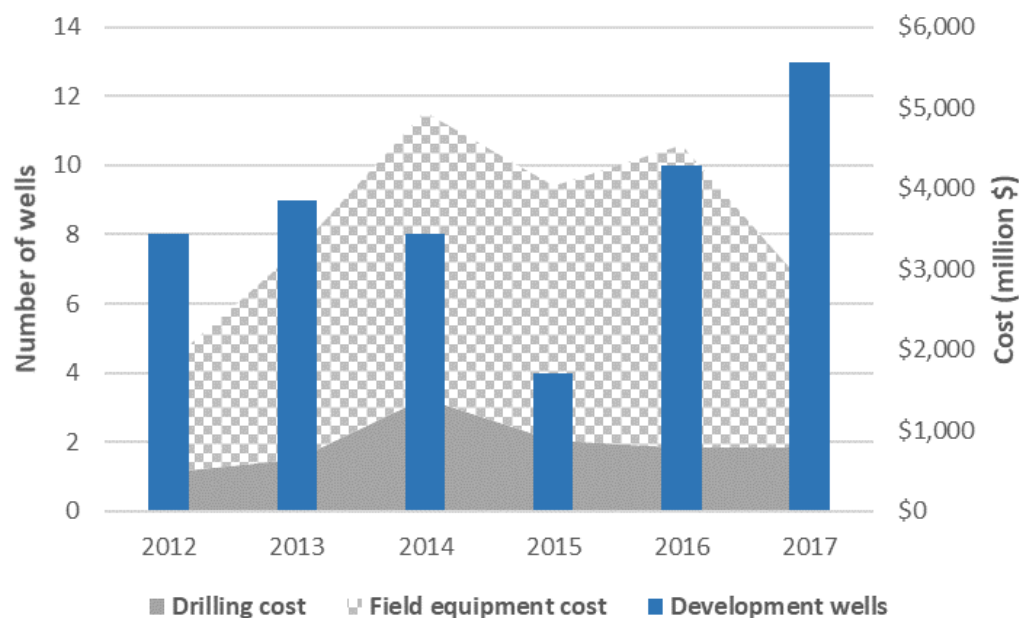
Newfoundland and Labrador

Over the past three years (2016 to 2018), Newfoundland and Labrador accounted for approximately 14 percent of Canada's total conventional crude oil per year. In 2018, Newfoundland and Labrador's offshore projects produced 230 Mbpd (CNLOPB).

The offshore assets that have been included in the production forecast are only producing projects – Hibernia, Terra Nova, White Rose, North Amethyst, and Hebron and approved project development extensions (White Rose South Extension). Unlike the western Canadian provinces, CERI has assessed offshore Newfoundland and Labrador on a per asset basis rather than per well.

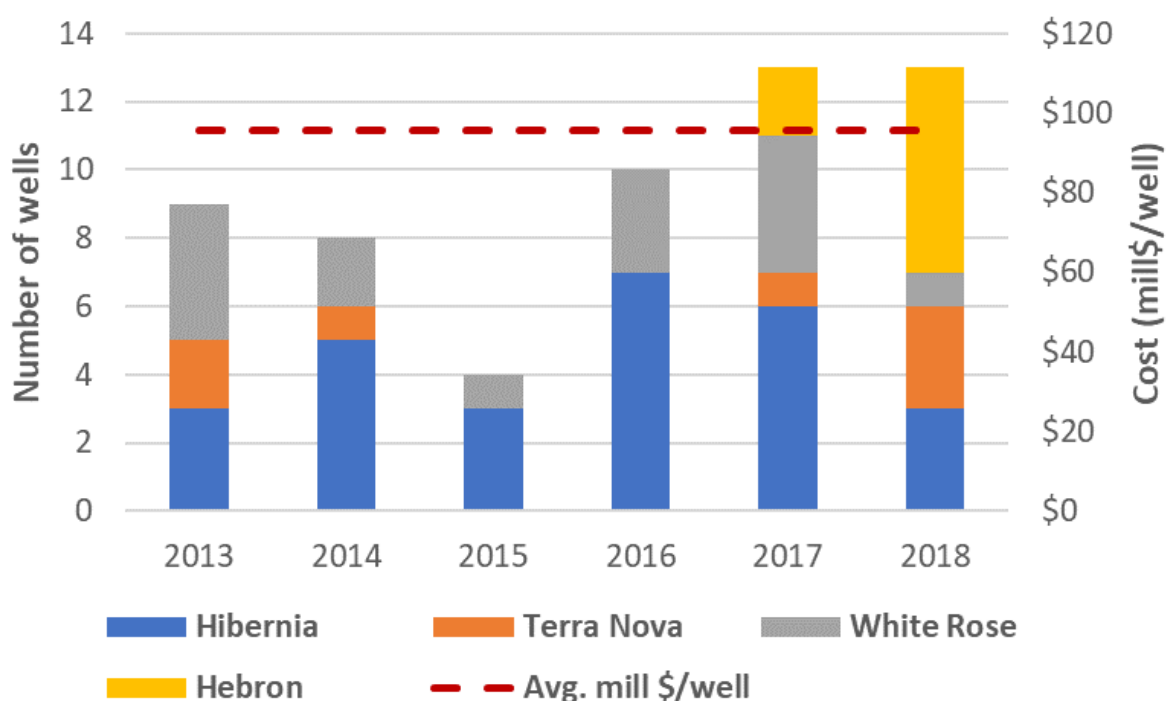
CERI used the following information available from the provincial regulator (CNLOPB) to model future forecasts for the study period: historical planned and actual production information, drilling, and production forecasts from approved project development plans, initial and updated recoverable reserves per asset, project life-spans, and asset extension plans. Figure 2.18 shows the actual data for the number of wells and drilling and equipment costs from 2013 to 2018 for different fields in Newfoundland and Labrador including Hibernia, Terra Nova, White Rose, and Hebron. The distribution of the wells among the offshore fields with the average well cost per well is depicted in Figure 2.19.

Figure 2.18: Number of Wells with Drilling and Equipment Costs, 2012-2016



Source: CERI, CAPP, and CNLOPB

Figure 2.19: Development Wells Distribution among Fields in Newfoundland and Labrador

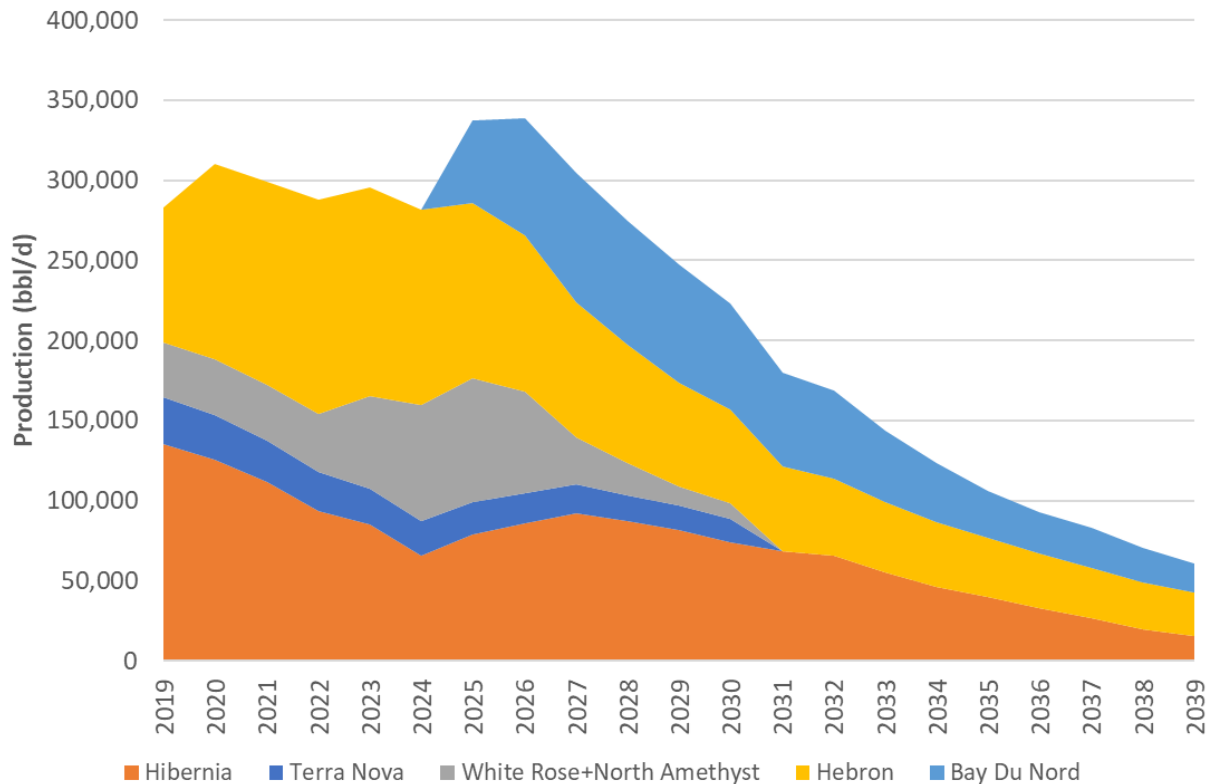


Source: CERI, CAPP, and CNLOPB

Over the period 2013-2018, the number of development wells declined until 2015 to as low as four, and increased to 13 wells in 2017-2018, driven by the Hebron project, Hibernia, and Terra Nova. The average cost per well for the period was about \$95.7 million as shown in Figure 2.19.

The highest number of development wells put in service between 2013-2018 belong to the Hibernia field with an average of 5 wells per year, followed by White Rose. Total drilling and field equipment costs in Newfoundland and Labrador between 2013 and 2018 are \$4.4 and \$14.9 billion, peaking at \$1.4 billion and \$3.5 billion in 2014. A recent decline in field equipment is linked to the passing of the investment phase for Hebron; the next large investment will come from two new developments: a) between 2019-2022 in the amount of \$2.4 billion from the White Rose South Extension project and b) between 2019-2025 in the amount of \$3.4 billion from the Bay Du Nord project.

CERI's forecast for offshore Newfoundland and Labrador crude oil production is shown in Figure 2.20.

Figure 2.20: Offshore Newfoundland and Labrador Crude Oil Production Forecast

Source: CERI, CNLOPB, Various individual operators

Total crude oil production will increase until 2020 as the Hebron asset helps to ramp up its output. After 2022, Hebron's annual production is set to decline steadily throughout the study period. The White Rose South Extension will boost provincial production in 2022-2025, returning to declining mode after that.

In 2018, Equinor and Husky announced that they were intending to develop a 300-million-barrel Bay Du Nord project located 450 km offshore east-northeast of St. John's. The project will cover fields located in the Flemish Pass Basin of the Atlantic Ocean offshore Canada, a first Canadian deep offshore venture with a depth of 1,100 metres. This Bay Du Nord development, coming onstream in 2025, will push the provincial peak oil production to the 340 thousand barrel per day level in 2026, after which the province will see the production decline unless other fields come onstream.

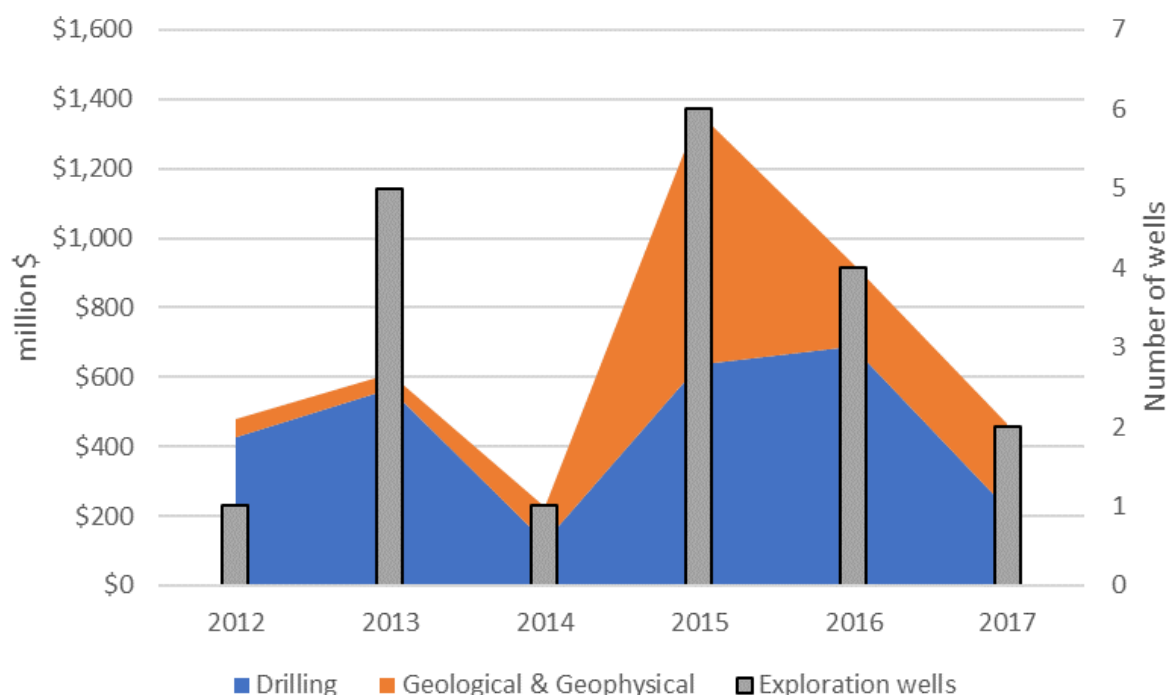
Terra Nova is set to continue its production decline of approximately 0.5 million barrels per year from 11.4 million barrels per year in 2018 (31.2 Mbpd). Hibernia is predicted to recover from last year's drop in production and reach 49.5 million barrels per year in 2019 (135.6 Mbpd). As the project keeps drilling producing wells (six in 2017 and three in 2018), this will help maintain the archived level of production until the decline mode resumes in 2020. White Rose and North Amethyst are predicted to gradually decline until 2022, and then ramp up to 77 Mbpd in 2025

due to an extension project. Hebron, which produced first oil in 2017, is going to increase production up to 134 Mbpd in 2022, after which the gradual decline will follow.

From 2013 to 2017, the exploration activity in the region was dominated by Equinor in the Flemish Pass basin but gradually faded away as the company finished its exploratory and delineation work needed to move on with Bay Du Nord development. The geophysics spending grew accordingly in that period. In 2018, only one exploration well was drilled. So far, it is not quite what the government set for itself – the ambitious goal of 100 new exploration wells in the next 12 years (Financial Post 2018). To put into perspective, 20 exploration wells have been drilled over the last 7 years.

However, there is a promise for an upswing in the exploration activity as the 2018 licensing round has seen \$1.4 billion of commitments from five companies including the largest single bid by BHP Billiton Petroleum (621 million).¹ Other companies include Equinor, Husky, and Suncor. Another 2.7 million hectares has been announced by C-NLOPB in April 2019 in addition to over 4 million hectares that were bid in 2018.

Figure 2.21: Exploration Activity in Newfoundland and Labrador



Source: CERI, CNLOPB, CAPP

While offshore Newfoundland and Labrador see 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

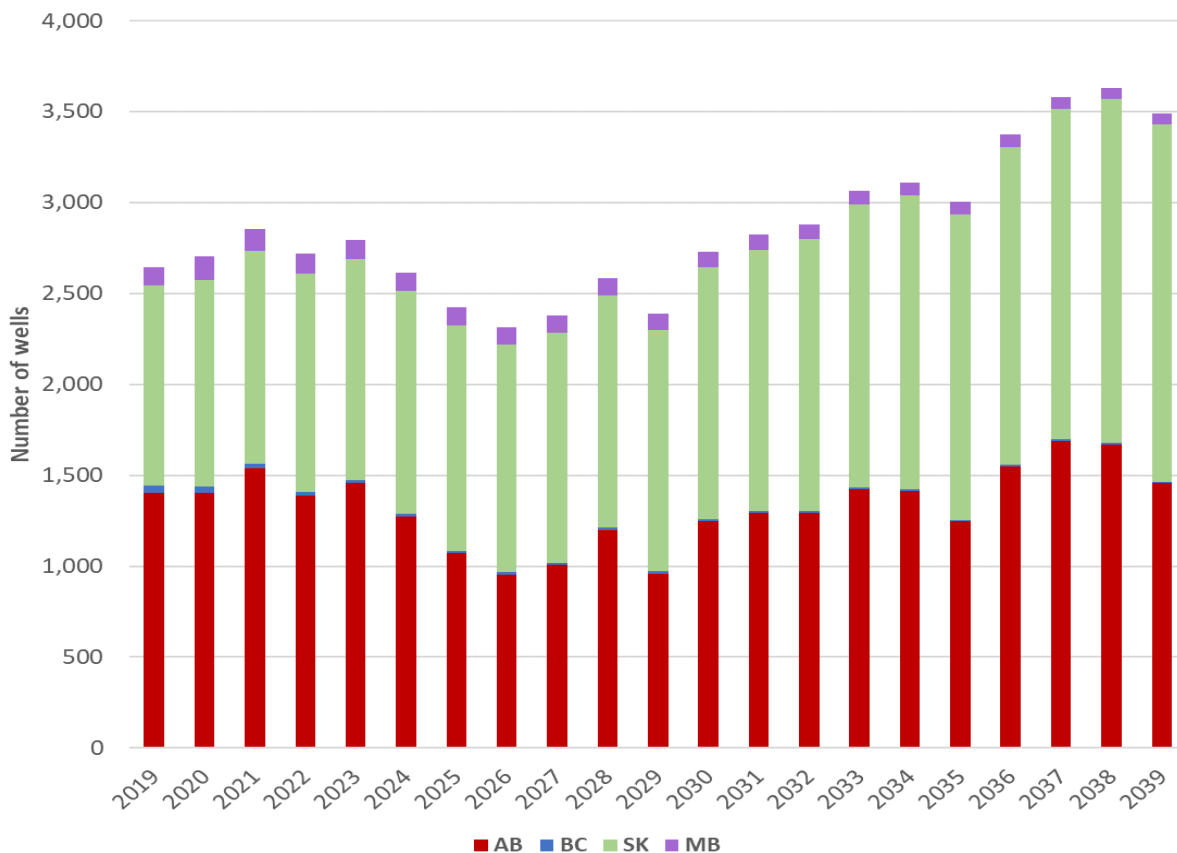
¹ CNLOPB, C-NLOPB Releases Results for 2018 Calls for Bids, <https://www.cnlopb.ca/news/nr20181107/>

stored for potential future commercial use. One consideration is its use as a feedstock for East Coast LNG plants delivered as CNG.

Canada

Overall in Canada, the number of wells put into production will increase throughout the study period, with approximately 30 percent more producing wells in 2039 (3,488 wells) than in 2019 (2,644 well). The increase predominantly comes from Alberta and Saskatchewan (Figure 2.22).

Figure 2.22: Canada New Oil Well Forecast



Source: CERi, BCOGC, AER, Government of SK, Government of MB, CNLOPB, PSAC, CAPP

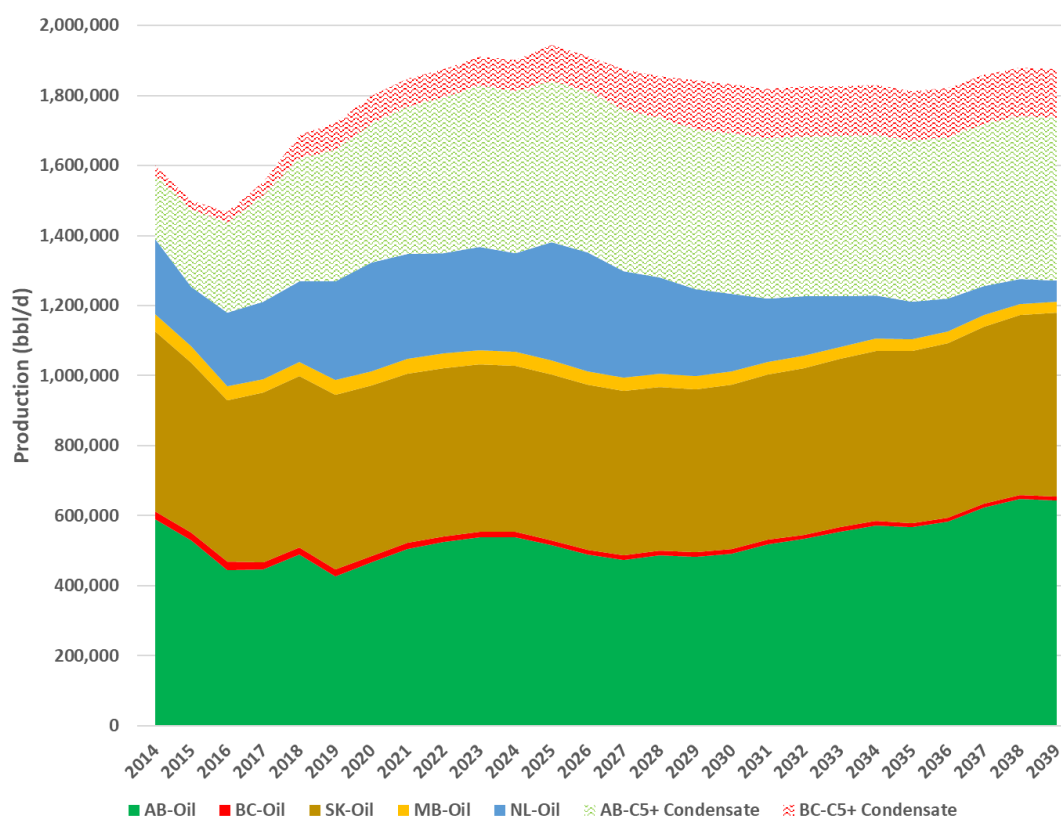
Similarly, Figure 2.23 illustrates the total production forecast for all provinces in Canada both for 2014 to 2018 (actual data) and for the forecast period (2019 to 2039). This assists in interpreting production fluctuations during the period of low oil prices.

The pricing environment over 2014-2018 had an impact on the industry and led to a sharp reduction in production. More than 200 Mbpd of oil production was lost from 2014 to 2016. However, from 2016 the trend reversed and is expected to do so until 2025 reaching approximately 1.4 MMbpd (without pentanes plus and condensate). This is followed by a decline to 1.2-1.3 MMbpd levels due to falling production in Newfoundland and Labrador. The increase

in US imports predominantly drives the upward trend in oil production in Alberta and Saskatchewan after 2030.

By the end of 2039, total production of conventional oil is forecasted to be around 1.3 MMbpd. Total pentanes plus and condensate will keep growing for the forecasted period from 450 Mbpd in 2019 to 604 Mbpd in 2039 driven primarily by natural gas from the wells for LNG purposes.

Figure 2.23: Canada Crude Oil Production Forecast



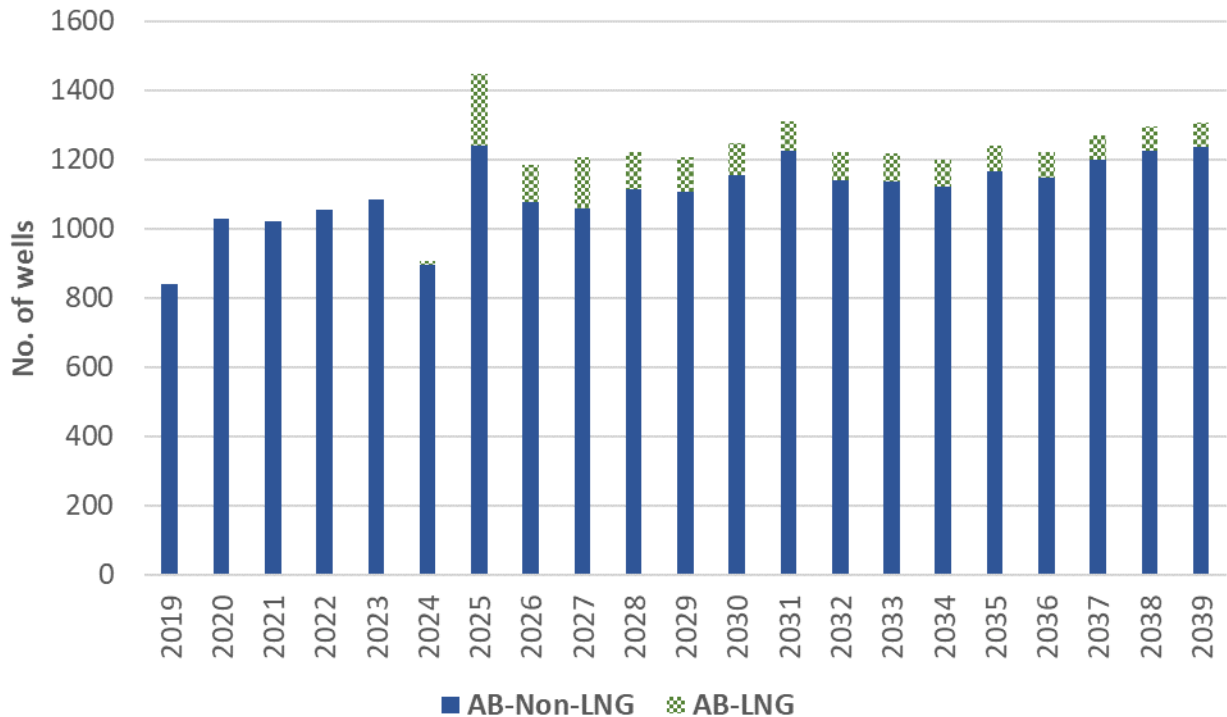
Source: CERI, BCOGC, AER, Government of SK, Government of MB, CNLOPB, PSAC, CAPP

Natural Gas

Alberta

Alberta is a major natural gas producer in Canada. It accounted for 67 percent of total natural gas production in 2018. From 2014 to 2018, the production increased by 7.2 percent and reached 12.6 Bcf/d.

Natural gas drilling in Alberta is expected to increase from 839 tied-in wells in 2019 to 1,236 wells by 2039 (not including wells drilled for LNG projects in BC) (Figure 2.24).

Figure 2.24: Alberta New Gas Well Additions

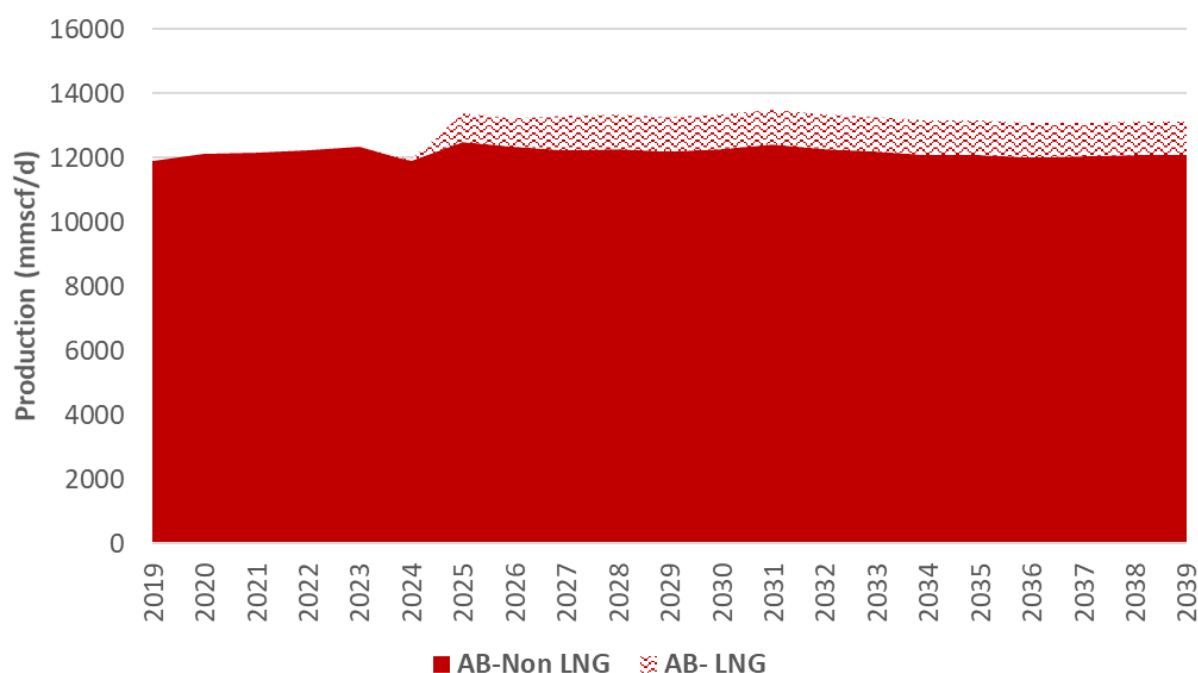
Source: CERI

LNG projects located on Canada's west coast may source natural gas from British Columbia and Alberta. Both provinces have an attractive resource base, while Alberta has a more developed midstream infrastructure. It is yet to be seen where exactly LNG proponents will source their gas, however, their current asset base suggests that the majority of natural gas is likely to come from British Columbia.² CERI estimates that 10 percent of LNG Canada's supply and 100 percent of the Eastern project will be sourced from Alberta and the rest from British Columbia.

Given drilling expectations, forecasted production declines and IP rates in the drilling areas, CERI developed a 20-year production forecast for natural gas in Alberta as shown in Figure 2.25.

² CERI reviewed public information provided by LNG proponents and location of assets of Shell, Mitsubishi, KOGAS, Petronas, PetroChina, Chevron, and Pieridae.

Figure 2.25: Alberta Wellhead Natural Gas Production Forecast

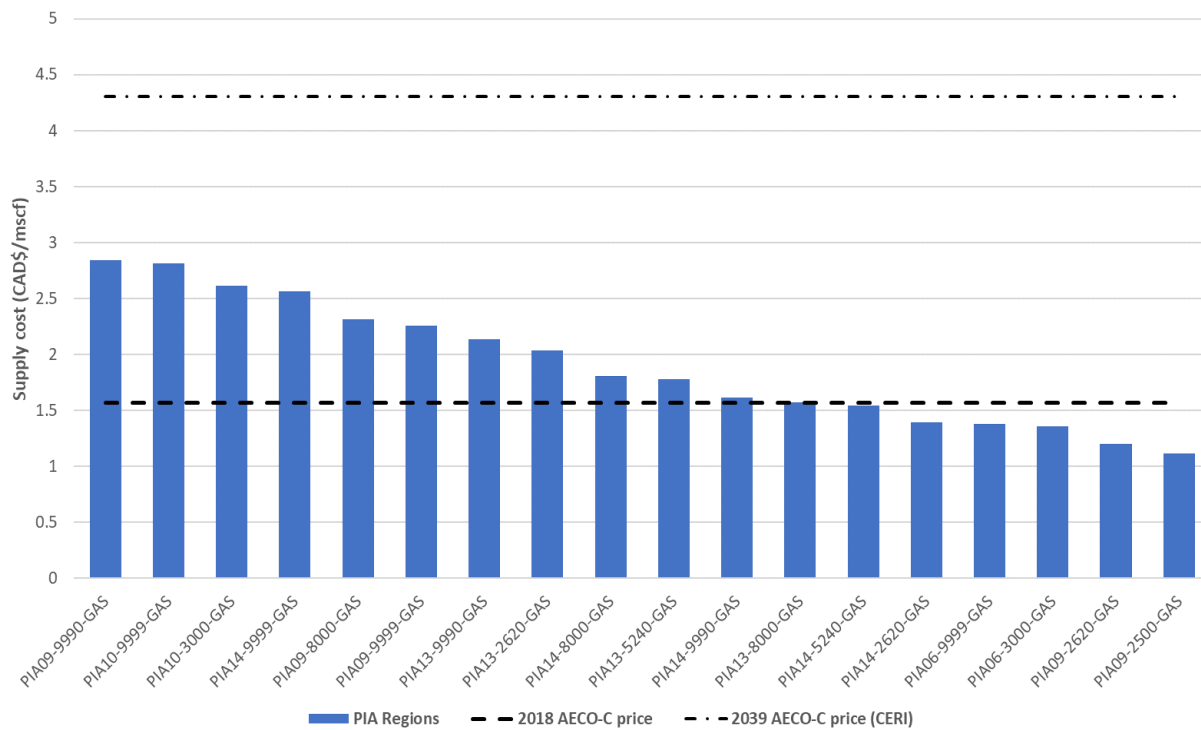


Source: CERl, AER

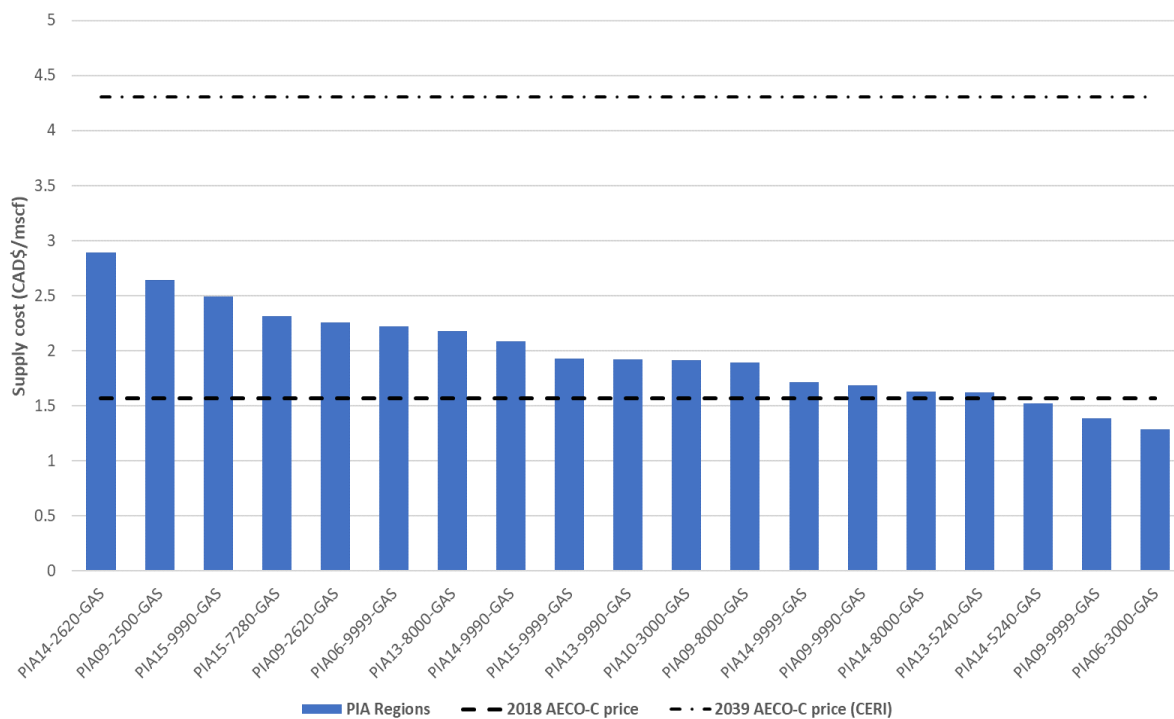
The supply of natural gas from Alberta will follow the drilling trend and is expected to be rather flat (it will have a 0.2 bcf/d increase from 11.9 Bcf/d in 2019) without LNG. The decline in exports to the US is compensated by expected domestic demand. With LNG plants built as assumed, Alberta will add approximately 1 bcf/d to its production by the end of 2025.

The supply costs for vertical and horizontal natural gas wells in Alberta are shown in Figures 2.26 and 2.27 against the average AECO-C price for 2018 and CERl's AECO-C price forecast to 2039.³ Note that 85 percent of wells put into production in 2018 in Alberta were horizontal wells.

³ CERl assumes a gradual diminishing differential for AECO-C with Henry-Hub which will reach CAD\$0.88/mscf by 2025 and remain the same afterwards. EIA Energy Outlook 2019 Henry-Hub forecast is taken as a base

Figure 2.26: Alberta Vertical Natural Gas Well Supply Costs

Source: CERI, PSAC, CAPP, NEB

Figure 2.27: Alberta Horizontal Natural Gas Well Supply Costs

Source: CERI, PSAC, CAPP, NEB

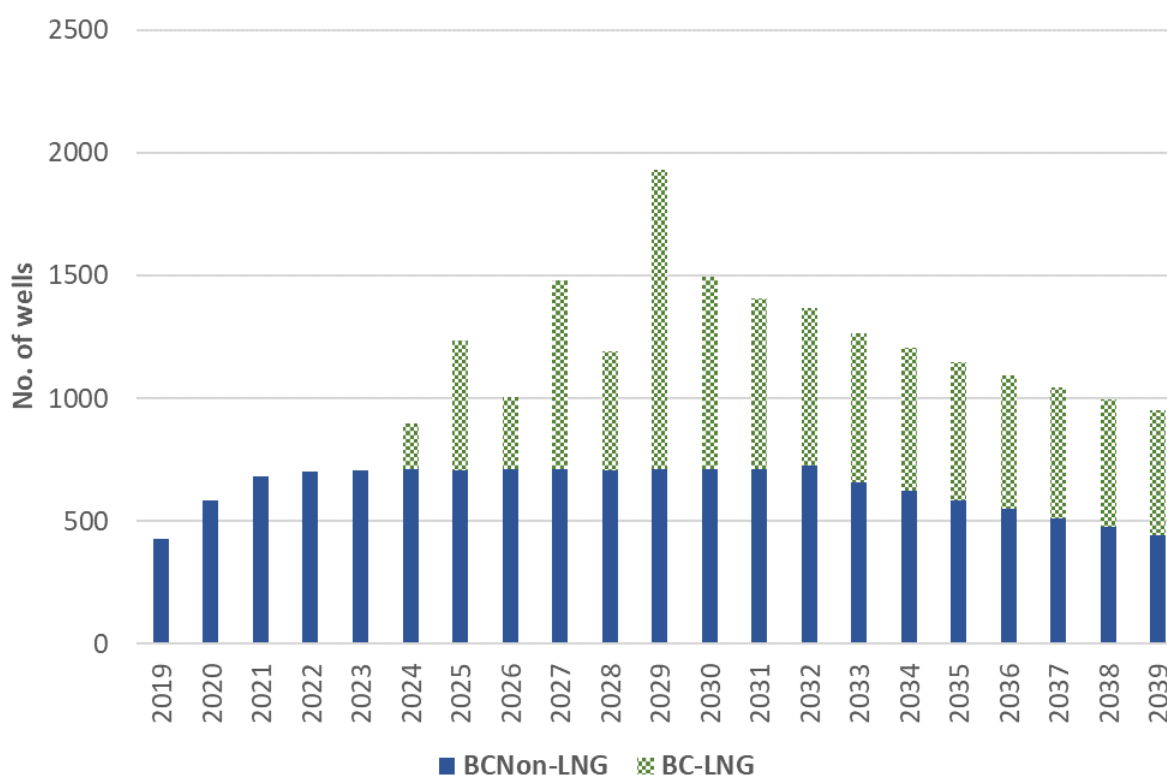
When considering recent drilling intensities, the corridor to the east of the Rocky Mountains has collectively the highest concentration of activity. These formations include Alberta's Montney, Cardium, Duvernay, and Spirit River. The weighted average supply cost of these Alberta areas for horizontal wells is \$1.8/mscf.

British Columbia

British Columbia has had a more significant focus on the production of natural gas compared to crude oil. During 2014-2018, British Columbia has been able to increase its share in total Canadian gas production from 26 percent to 30 percent, growing by 25 percent for the period reaching 5.7 Bcf/d.

British Columbia natural gas well additions are driven to sustain its production for local demand and exporting to the US. However, the fall of exports to the US is expected to somewhat outpace domestic demand and inter-provincial exports resulting in declining production and drilling after 2030. The wells drilled for LNG purposes help to offset this decline (Figure 2.28).

Figure 2.28: British Columbia New Gas Well Forecast



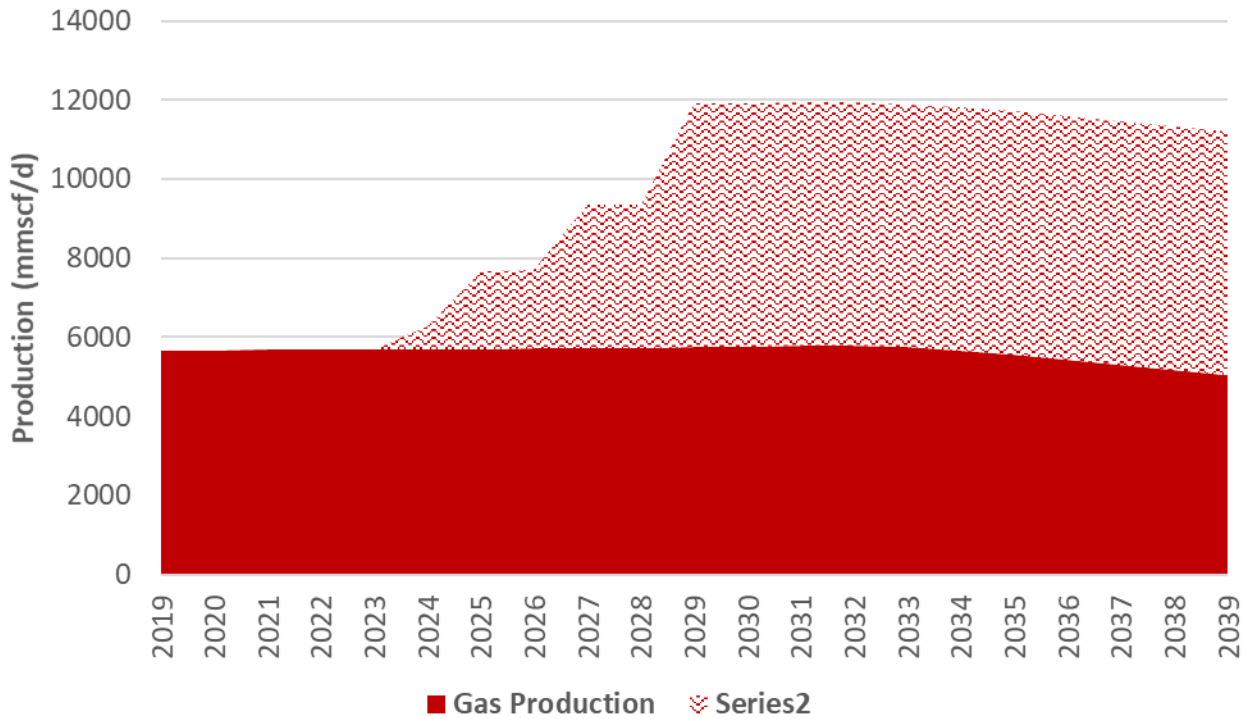
Source: CERI

As mentioned above, CERI assumed four LNG developments that come to service during the forecast period. The number of new wells increases from 2024 to meet the plant's capacities. The pre-drilling was modelled to start two years prior to each plant's commissioning. After 2030,

new well additions due to LNG are expected to drop off, and the province will see a small but consistent decline of drilling through the remainder of the study period.

CERI's production forecast for natural gas in British Columbia is shown in Figure 2.29.

Figure 2.29: British Columbia Field Gate Natural Gas Production Forecast

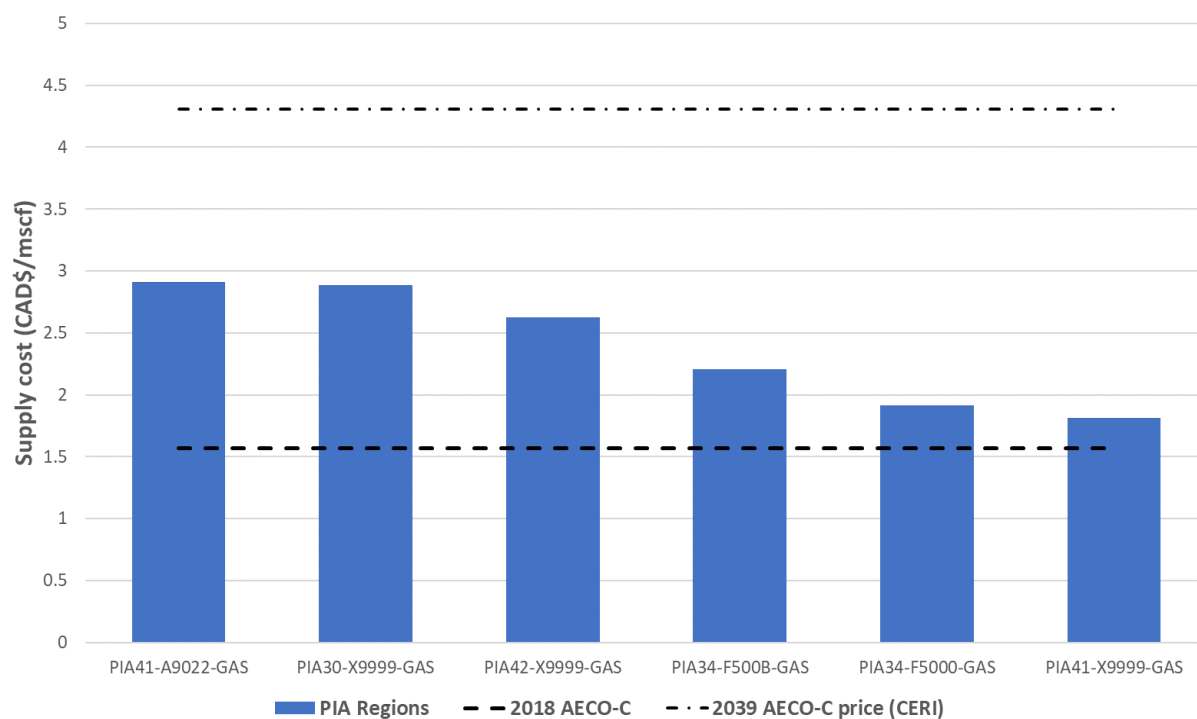


Source: CERI, BCOGC, PSAC, CAPP

The Montney formation, with sound economics and a prolific resource base, leads British Columbia gas developments. The supply cost of horizontal wells in British Columbia's Montney formation (PIA-34) is \$0.9-\$2.6/mscf with a weighted average of \$1.8/mscf. For vertical wells, the supply costs are between \$1.9-\$3.9/mscf with a weighted average of \$2.3/mscf.

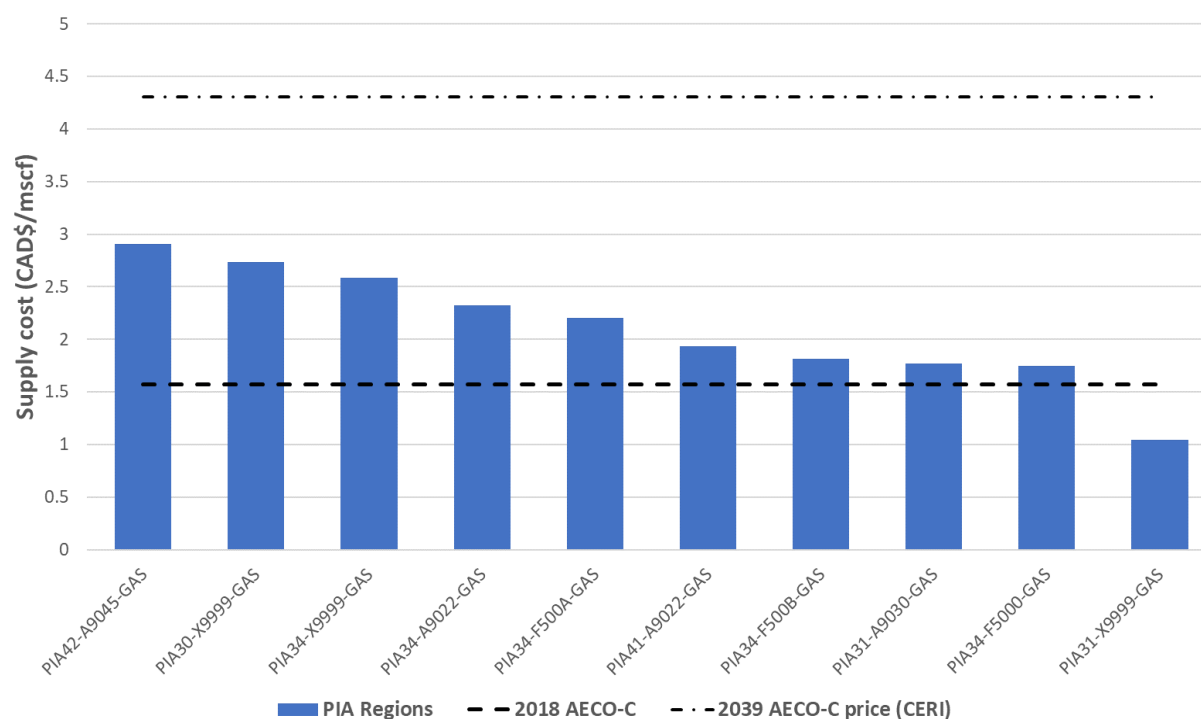
The supply costs for natural gas wells, vertical and horizontal, are shown in Figures 2.30 and 2.31, respectively. Note that 95 percent of wells put into production in 2018 in the province were horizontal wells.

Figure 2.30: British Columbia Vertical Natural Gas Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

Figure 2.31: British Columbia Horizontal Natural Gas Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

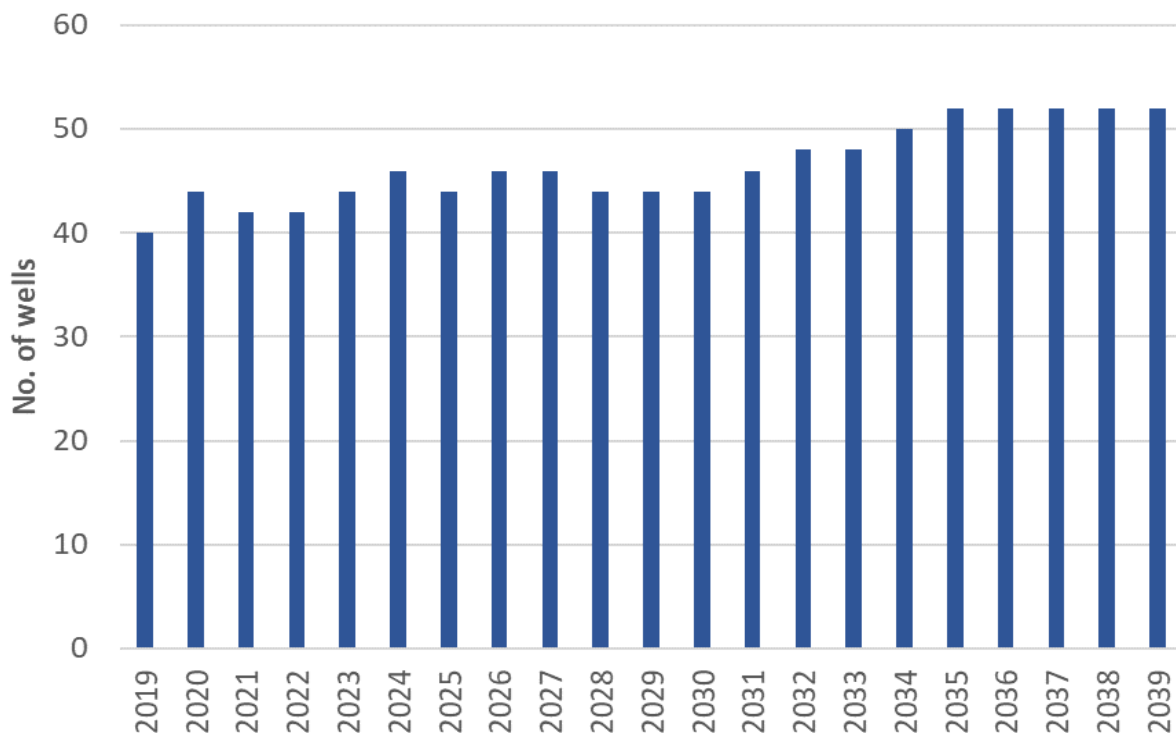
In 2018, the ratio of the producing wells in British Columbia in the Montney formation to total wells has grown to 97 percent. It is expected that this will remain the case throughout the study period due to its favourable well economics.

Saskatchewan

Unlike Alberta and British Columbia, Saskatchewan's natural gas production for 2014-2018 dropped by almost 11 percent and represented 0.5 Bcf/d, or 2.7 percent, of Canada's total production in 2018 (CAPP 2018).

Drilling of gas wells put into production in Saskatchewan is expected to rise slightly from current levels of above 40 wells per year to 52 wells per year in 2035 and remain constant through the end of the study period (Figure 2.32).

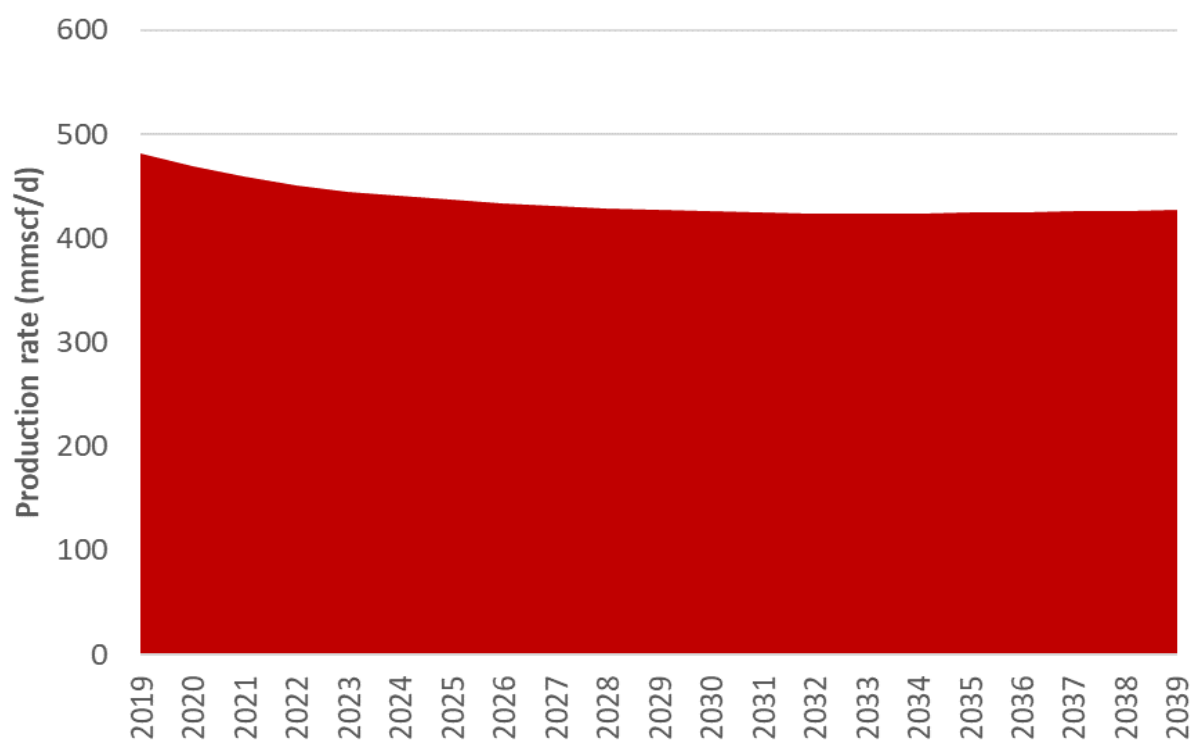
Figure 2.32: Saskatchewan New Gas Well Forecast



Source: CERI

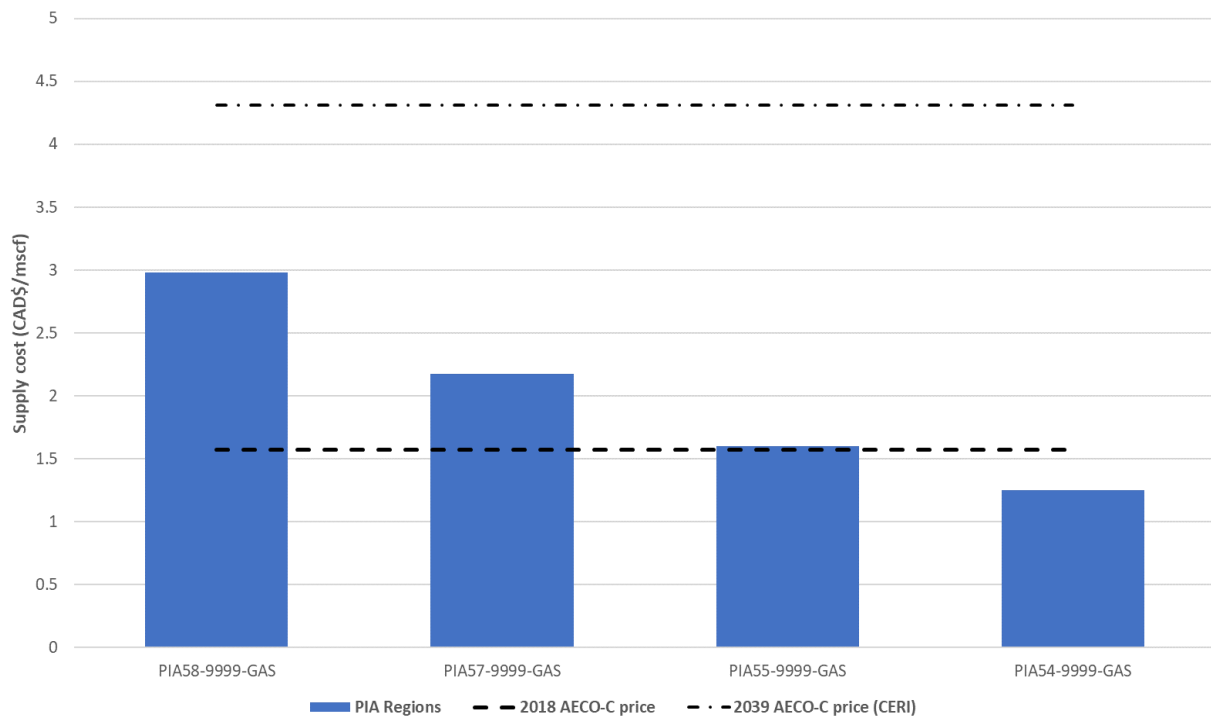
CERI's 20-year production forecast for natural gas in Saskatchewan is shown in Figure 2.33. Natural gas production in Saskatchewan is expected to slightly decline throughout the study period due in part to the higher interest of drillers in Canada for other plays. The consistent addition of more than 40 new wells per year during the forecast period is also enough to sustain a consistent decline rate as shown in Figure 2.33.

Figure 2.33: Saskatchewan Natural Gas Production Forecast

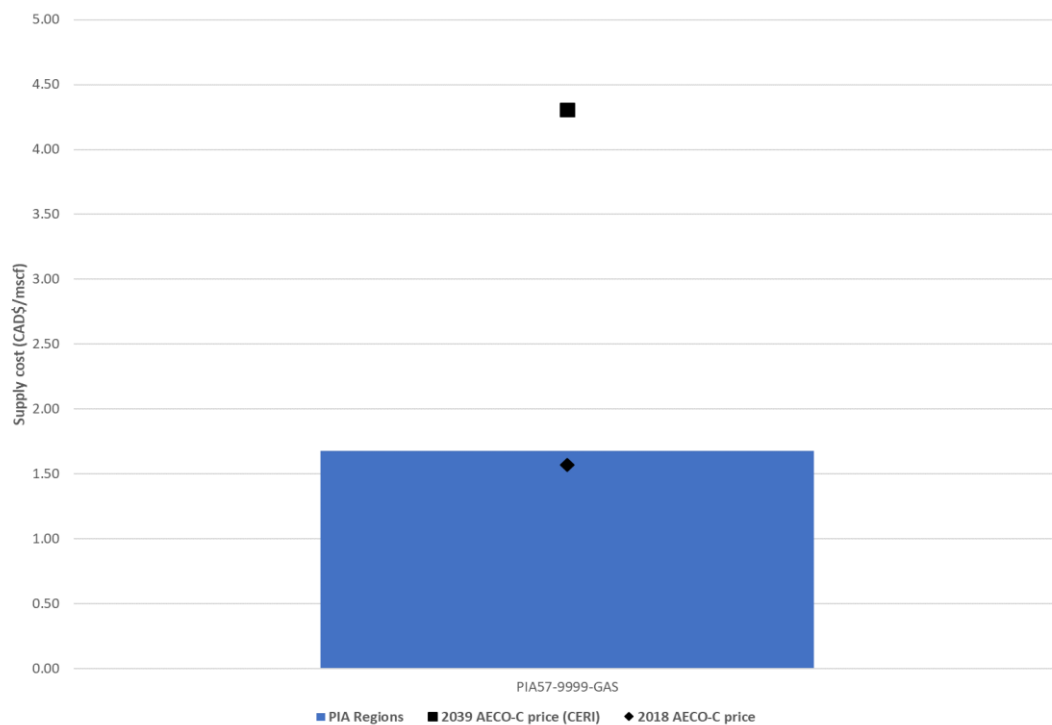


Source: CERI, Government of SK, PSAC, CAPP

Supply costs for natural gas wells in Saskatchewan are calculated in the same manner as Alberta and British Columbia. The supply costs for vertical and horizontal wells are shown in Figures 2.34 and 2.35.

Figure 2.34: Saskatchewan Vertical Natural Gas Well Supply Costs

Source: CERI

Figure 2.35: Saskatchewan Horizontal Natural Gas Well Supply Costs

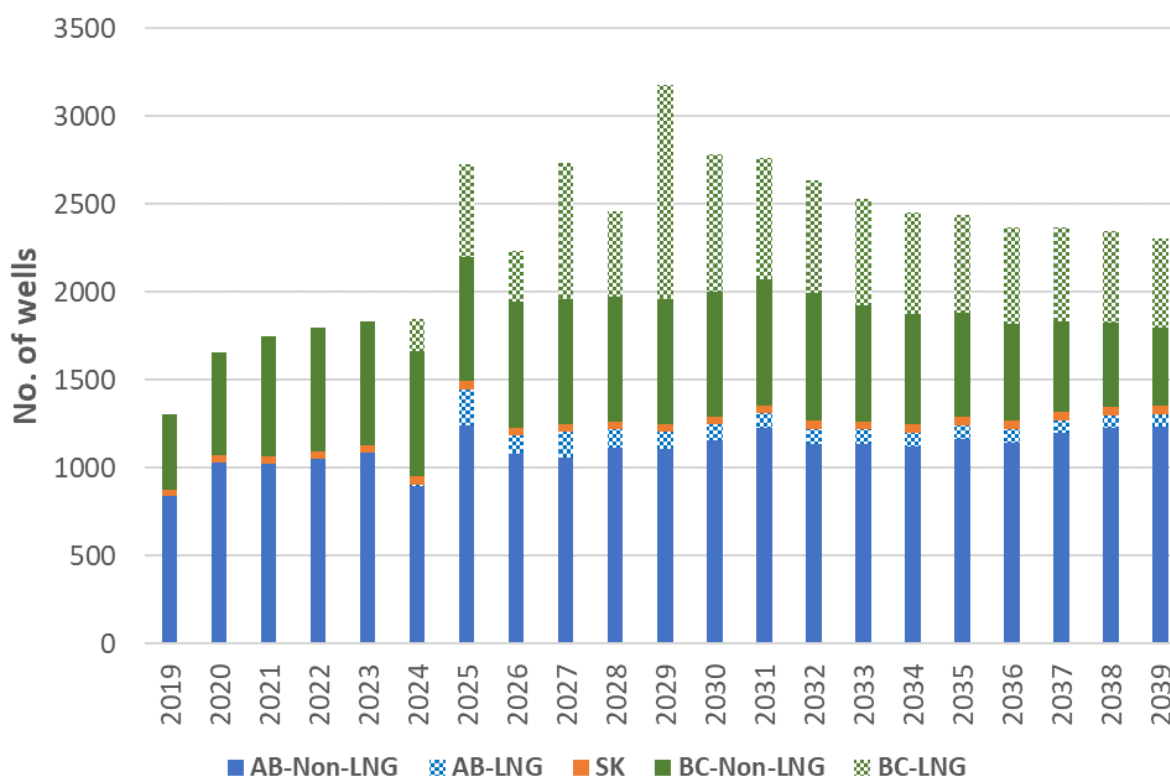
Source: CERI

Notwithstanding other provinces in the WCSB, the supply costs of horizontal wells in Saskatchewan are higher than the vertical well supply costs in some areas (PIAs 54 and 55) due to relatively higher decline curves and lower IP rates.

Canada

Overall in Canada, Alberta, and British Columbia account for almost all drilling over the next 20 years (Figure 2.36), with British Columbia's numbers growing and Alberta's being relatively stable; in 2039, British Columbia's share in total new wells will account for 41 percent.

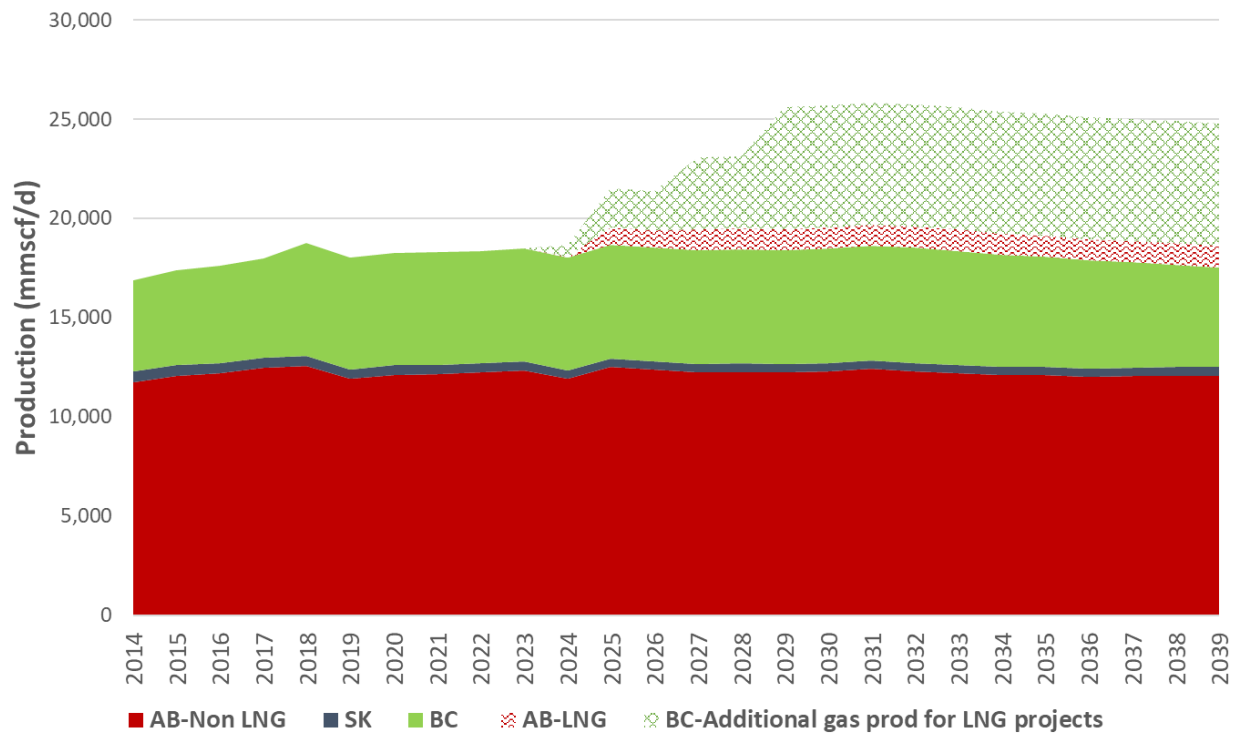
Figure 2.36: Canada New Natural Gas Well Forecast



Source: CERI, Government of SK, PSAC, CAPP

Figure 2.37 shows the actual production from 2014 to 2018 and the production for the forecast period from 2019 to 2039. An incremental trend in gas production in recent years was caused by two factors: an addition to the net exports to the US by 0.4 bcf/d and an increase in domestic gas consumption.

As mentioned earlier, the net exports started to decline in 2017 and are expected to do so in the foreseeable future. Growth in demand by 2.5 bcf/d in the next 20 years will largely counterbalance this decline of net exports. The domestic incremental demand is expected to come from the electricity sector which explains 47 percent of growth, followed by industry which drives 35 percent of gas demand additions (NEB, Energy Futures 2019).

Figure 2.37: Canada Natural Gas Production Forecast

Source: CERI, Government of SK, BCOGC, AER, PSAC, CAPP

LNG plants provide an opportunity to develop production capacity in western Canada and attract more growth-oriented investments into the gas upstream industry. Such a scenario will lead to a consistent increase in production until 2029 to the levels slightly over 25 bcf/d. Post-2029, production will stabilize through the remainder of the study period. The gas for LNG will constitute approximately 30 percent of total Canadian production by 2039.

Chapter 3: Canadian Oil and Gas Economic Impacts and Emissions

Economic Impacts

Input/Output (I/O) analysis in general addresses the way economic circumstances in one part of an economy can ripple through the rest. It deals with inter-industry relationships, notably the use of the output from one industrial process as an input into another. CERI's model is used to determine an approximate impact on the macroeconomic variables with the introduction of investments (or 'shocks'). In the case of resource or infrastructure developments, the expenditures include those for the investment and operation phases of a project. Any activity that leads to increased production capacity in an economy has two components: a) the construction or development of the capacity, and b) the operation of the capacity to generate outputs. Generally, the operations (revenues) drive most of the economic impacts; for this reason, even with stable or falling investments and rising operations, the economic impacts may rise. The operations are in their turn driven by production and prices; the latter is expected to grow within the study period both for natural gas and oil. This explains the growth of operations with stable production, and hence the economic impacts.

The first component is referred to as the investment phase, while the second is the operation phase. Both activities affect the economy through purchases of goods, services, and labour. The construction phase represents short-term activity and hence leads to short-term temporary impacts; whereas, operations and management of a facility are typically continuous. The first step is to estimate and forecast the value of the investment (i.e., construction or development expenditure) and operations. CERI has done this for the various activities. The second step is to estimate and forecast the value of total operations from those processes.

The forecasted values of investment and operations are then used to estimate the demand for the various goods and services and labour used in both phases. These demands are met through two sources: domestic goods production and goods imports. Domestic contents of the goods and services are calculated using Statistics Canada data. Impacts are calculated for Canada, broken down by province. They are presented as Gross Domestic Product (GDP) and employment. For employment, jobs are direct or indirect. Direct jobs are those tied directly to the activity. Indirect jobs would be those where economic sectors play a support role in the activity such as financial or legal services. Induced jobs are a third category that CERI has determined that, as an indicator of economic impact, these effects are too diverse to meaningfully be attributed to any one activity. As such, going forward we will focus on direct and indirect jobs only.

There are two main assumptions underpinning the construction of an I/O model. The first assumption is that the economy is in equilibrium. Equilibrium means that the existing relationship between economic activities is constant and there are no surplus or deficits of production or need

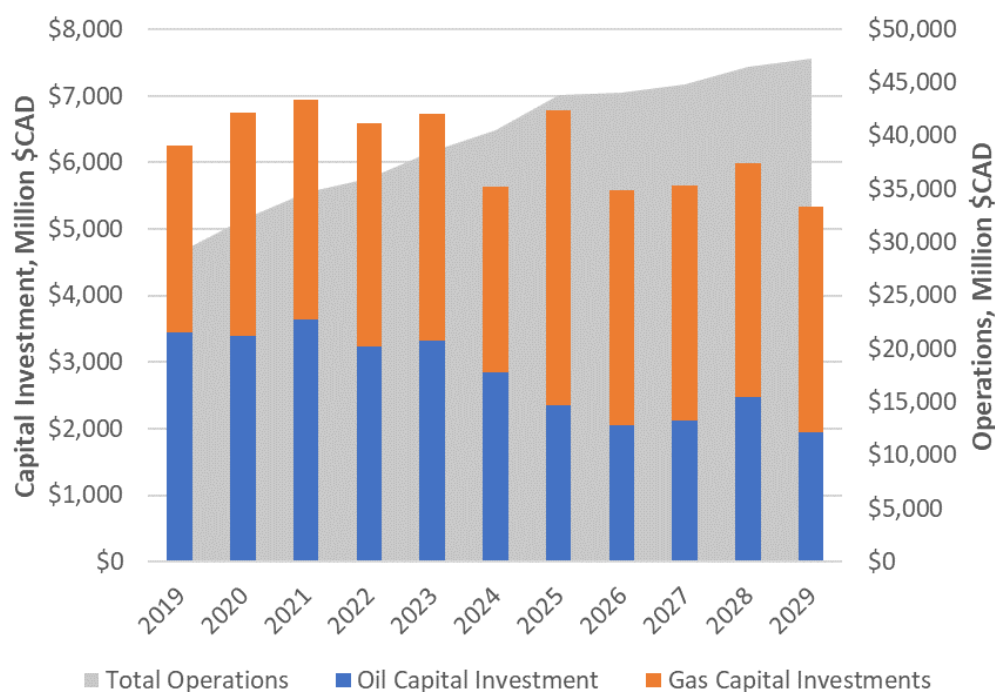
between sectors. This is a realistic assumption in the long run, as economies move to use up surplus or create additional production to meet a need. A second important assumption in the I/O analysis is the linear relationship between inputs and outputs in the economy. Each sector uses a variety of inputs linearly to produce various final products under the assumption of fixed proportions. A very interesting aspect of this assumption is the constant return to scale. Though the linearity of the production relationship function gives a constant average and marginal products, these are justified if the analysis focuses on the medium term. Long-run changes in the economy (beyond 20 years) may affect the fixed relationship between sectors. CERI employs a 10-year horizon to limit the challenges of changing economic relationships between sectors.

Assumptions for Economic Impact Modelling

This section reviews the capital investments and producer's gross revenues (operations), which are used as inputs, or injections, into CERI's I/O model. The model, in turn, calculates the various economic impacts associated with the level of activity stemming from the outlook models over the 2019-2029 period.

The capital investment and operations forecasts are discussed by province: Alberta, British Columbia, Saskatchewan, Manitoba, and Newfoundland and Labrador. The capital investments are further illustrated by commodity (i.e., crude oil and natural gas), whereas the operations are aggregated. All monetary values are in **real 2018 Canadian dollars** unless stated otherwise. Capital investments do not include oil sands-related expenditures and exploratory wells; they include only production wells (including all costs associated with production from a well such as land, tie-in, batteries, EOR, etc.; all costs that are included are provided in Appendix A). Economic impacts do not include those coming from the production of natural gas liquids. Figure 3.1 illustrates operations and capital investments in Alberta. Total capital investments are divided by type of commodity, whether crude oil or natural gas.

Figure 3.1: Alberta Operations and Capital Investment



Source: CERI, PSAC, CAPP

Natural gas and crude oil capital investments in Alberta peak at \$6.9 billion in 2021. Annual capital costs for drilling and the connection of new natural gas and crude oil wells – including infrastructure costs plus geological and geophysical costs, land, and enhanced oil recovery – make up the capital expenditures for natural gas and crude oil. Annual capital costs come from the multiplication of drilling forecast in an activity area by the total well cost in that area, while total annual capital cost per province is the summation of total capital costs of all areas.

Operations (representing producer revenues) are, on the other hand, driven by the amount of oil and gas produced and the pricing for each producing asset. The shaded area in Figure 3.1 illustrates the operations from all crude oil and natural gas production (existing wells plus future new well additions). These are based on the prices of:

- Canadian oil prices for heavy and light/medium oil estimated by CERI using the EIA Annual Energy Outlook 2019 as a basis by applying differentials between WTI and Canadian oil
- Natural gas price at AECO-C using the EIA Annual Energy Outlook 2019 as the basis by applying differentials between Henry Hub and AECO-C

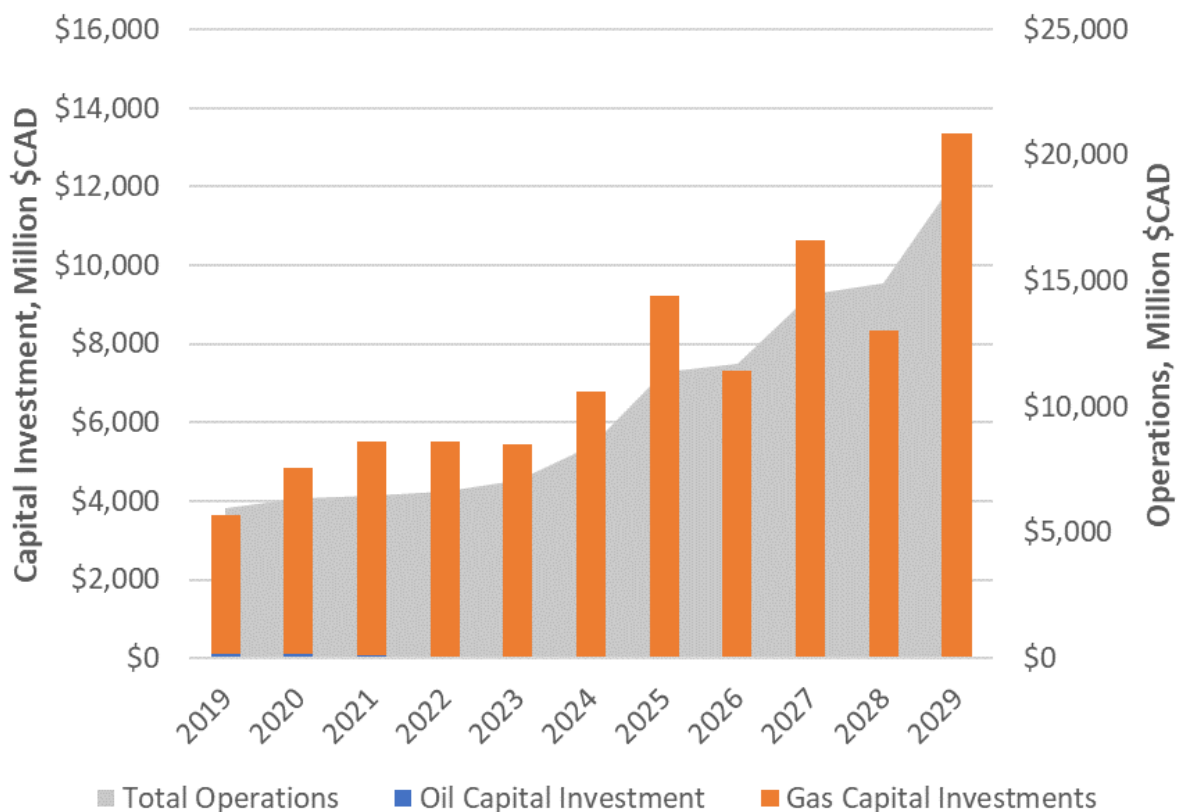
All prices were converted to real 2018 Canadian dollars.

Total operations in Alberta between 2019 and 2029 is \$437.4 billion (\$111.3 billion and \$326.1 billion for natural gas and crude oil, respectively) growing from \$29.1 billion in 2019 and peaking at \$47.3 billion in 2029. Such an increase in revenues against the fall in production of natural gas

in Alberta is explained by two factors: a) growth of oil and condensate production, and b) the increase of WTI price in real dollars from US\$67.8 in 2019 to US\$85.96 in 2029.

Figure 3.2 illustrates operations and capital investments in British Columbia for both crude oil and natural gas. Over the study period (2019-2029), natural gas and crude oil capital investments in British Columbia total \$79.9 billion and \$642 million, respectively. Most of the capital investments in British Columbia are in the natural gas sector. Natural gas capital investments peak at \$13.3 billion in 2029, while for crude oil, they peak at only \$115 million in 2019. Total operations in British Columbia between 2019 and 2029 is \$112.4 billion, peaking at \$19.1 billion in 2029. Between 2019 and 2029, total operations related to natural gas is \$71.5 billion, followed by \$40.9 billion in crude oil. Overall growth in operations is explained by the growth of natural gas demand due to the new LNG plants in the province.

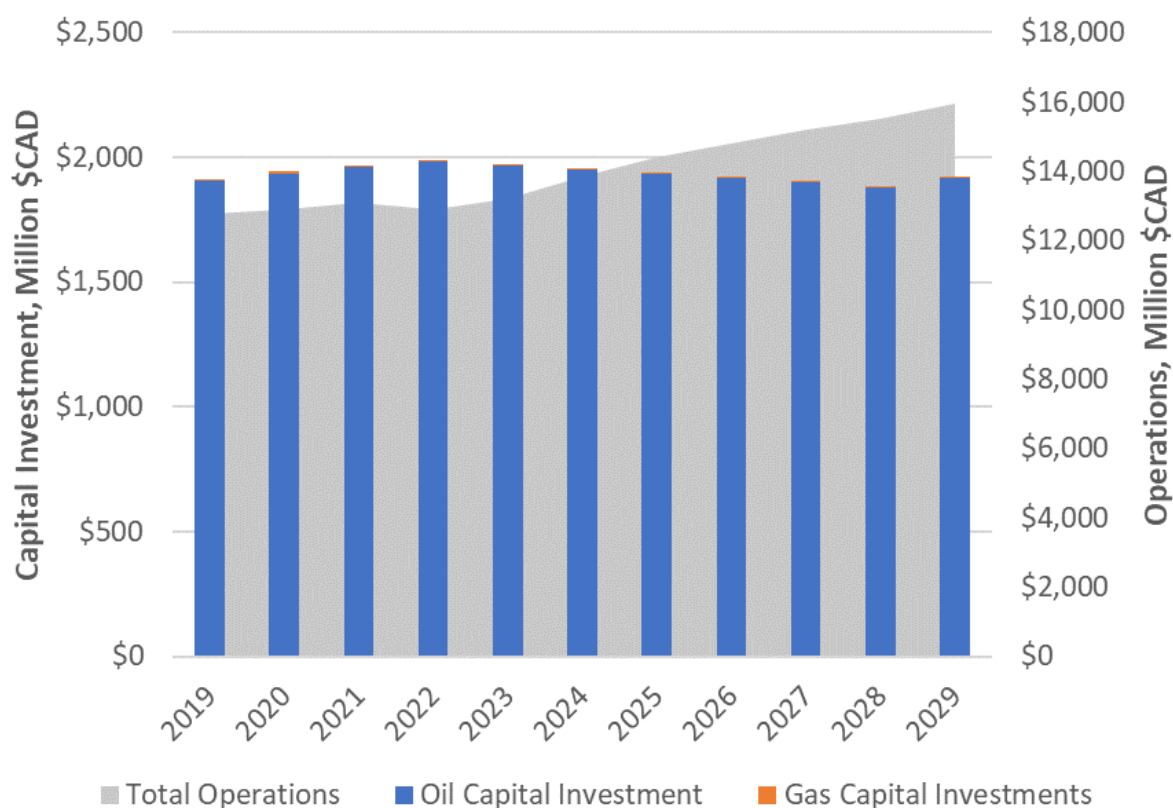
Figure 3.2: British Columbia Operations and Capital Investment



Source: CERI, PSAC, CAPP

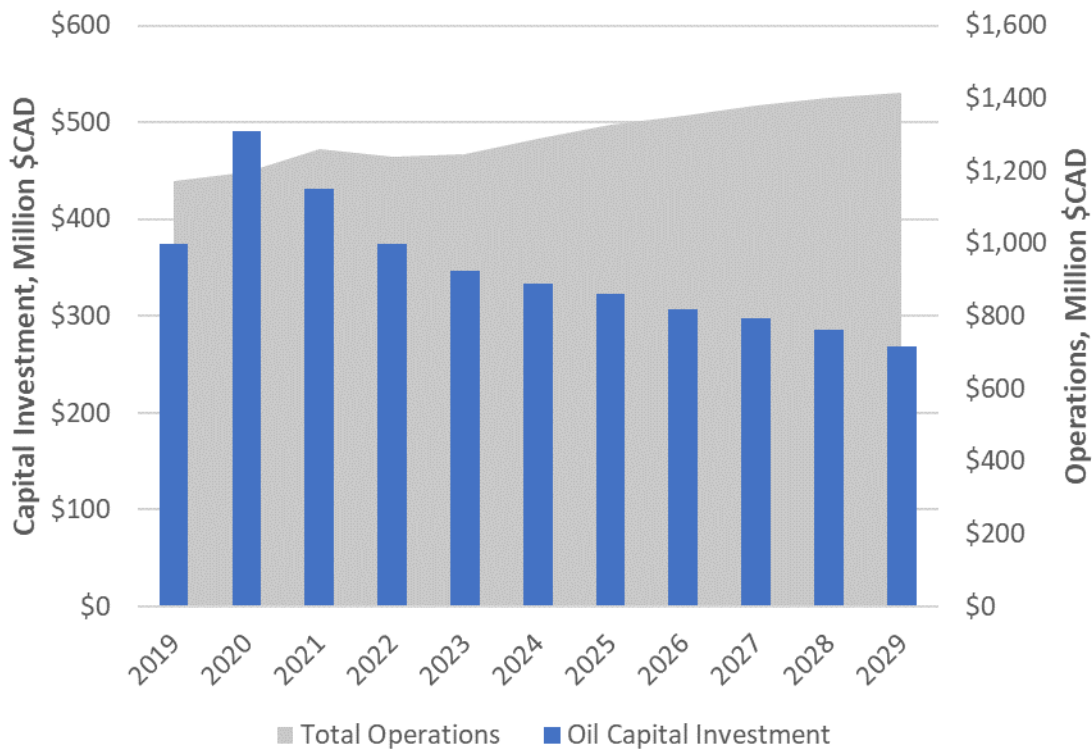
Figure 3.3 illustrates operations and capital investments in Saskatchewan. Over the study period, crude oil and natural gas capital investments in Saskatchewan total \$21.3 billion, which peaks at \$1.9 billion in 2022. Total operations in Saskatchewan between 2019 and 2029 is \$154.5 billion, peaking at \$15.9 billion in 2029 from \$12.7 billion in 2019. Between 2019 and 2029, total operations related to crude oil is \$150.7 billion, followed by only \$3.8 billion in natural gas.

Figure 3.3: Saskatchewan Operations and Capital Investment



Source: CERI, Government of SK, PSAC, CAPP

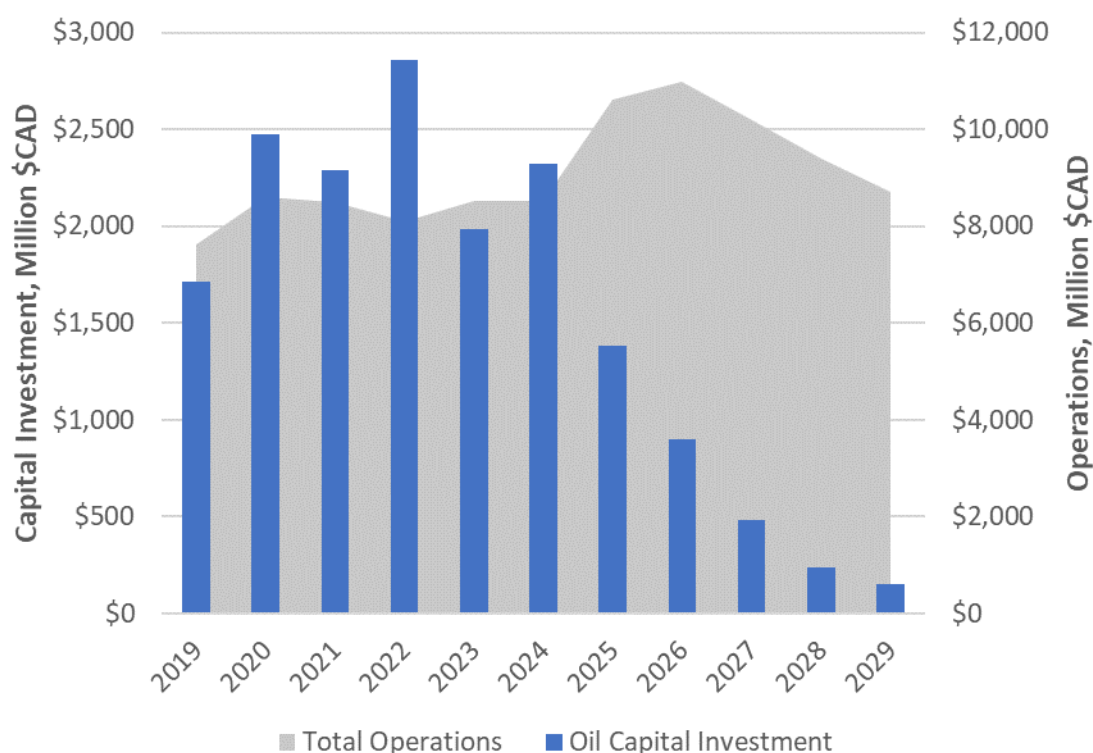
Figure 3.4 illustrates operations and capital investments in Manitoba. In the case of Manitoba, only crude oil is included, with the province not producing any natural gas. Over the study period (2019-2029), crude oil capital investments in Manitoba are \$3.8 billion. Crude oil capital investments peak at \$491 million in 2020, declining to \$268 million in 2029. Total operations in Manitoba between 2019 and 2029 is \$14.3 billion, peaking at \$1.4 billion in 2029 from \$1.1 billion in 2019.

Figure 3.4: Manitoba Operations and Capital Investment

Source: CERI, PSAC, CAPP

Figure 3.5 illustrates operations and capital investments in Newfoundland and Labrador. In the case of Newfoundland and Labrador, only crude oil is included, with the province not producing any natural gas. Associated natural gas is assumed to be reinjected to maintain reservoir pressure. Over the study period, crude oil capital investments in Newfoundland and Labrador total \$16.8 billion (this includes \$2.1 billion of investments for White Rose Extension and \$3.4 billion for the Bay Du Nord project). Crude oil capital investments peak at \$2.8 billion in 2022, declining to \$154 million in 2029. Total operations in Newfoundland and Labrador between 2019 and 2029 is \$99.7 billion, peaking at \$11 billion in 2026.

Figure 3.5: Newfoundland and Labrador Operations and Capital Investment



Source: CERI, PSAC, CAPP

Economic Impacts of Conventional Crude Oil Development

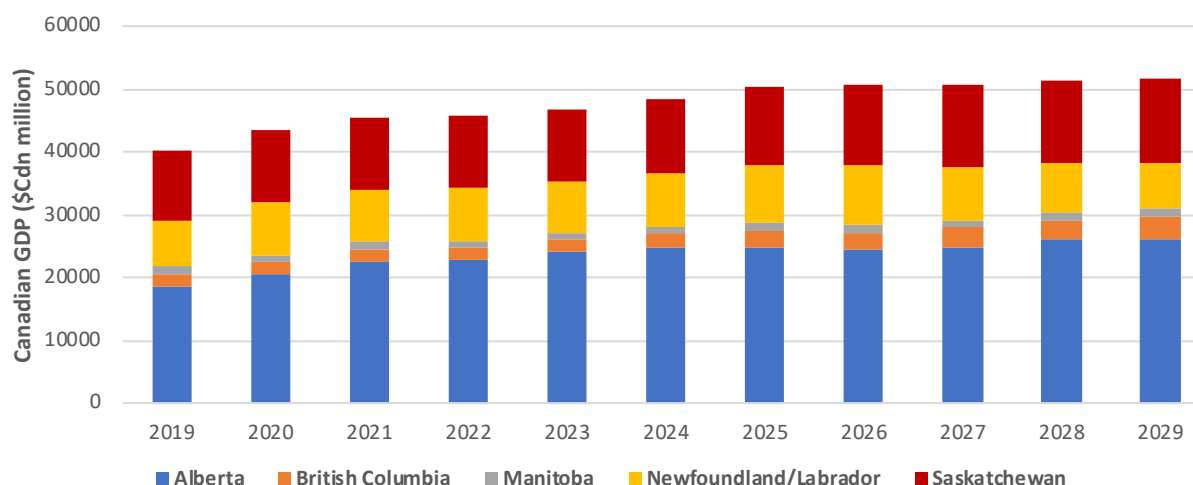
This section presents the economic impacts of conventional crude oil development including both existing and future drilling activity within the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and offshore Newfoundland and Labrador over the period 2019 to 2029. The analysis covers conventional crude, tight oil, and offshore.

Table 3.1 presents the total impacts associated with both investment and operation of crude oil projects (excluding oil sands) in British Columbia, Alberta, Saskatchewan, Manitoba, and Newfoundland and Labrador for the period 2019 to 2029. Total Canadian GDP impact is estimated to be CAD\$604.7 billion (2018 Canadian dollars), with 43 percent of impacts contributed by Alberta, 22 percent by Saskatchewan, 15 percent by Newfoundland and Labrador, and the rest by other provinces and territories. Annual GDP impact will average approximately CAD\$54.9 billion; CAD\$46.3 billion in 2019, increasing to almost CAD\$59.6 billion in 2029. Figure 3.6 shows GDP effects within Alberta, British Columbia, Manitoba, Newfoundland and Labrador, and Saskatchewan.

Table 3.1: Total GDP and Employment Impacts of Crude Oil Development, 2019-2029

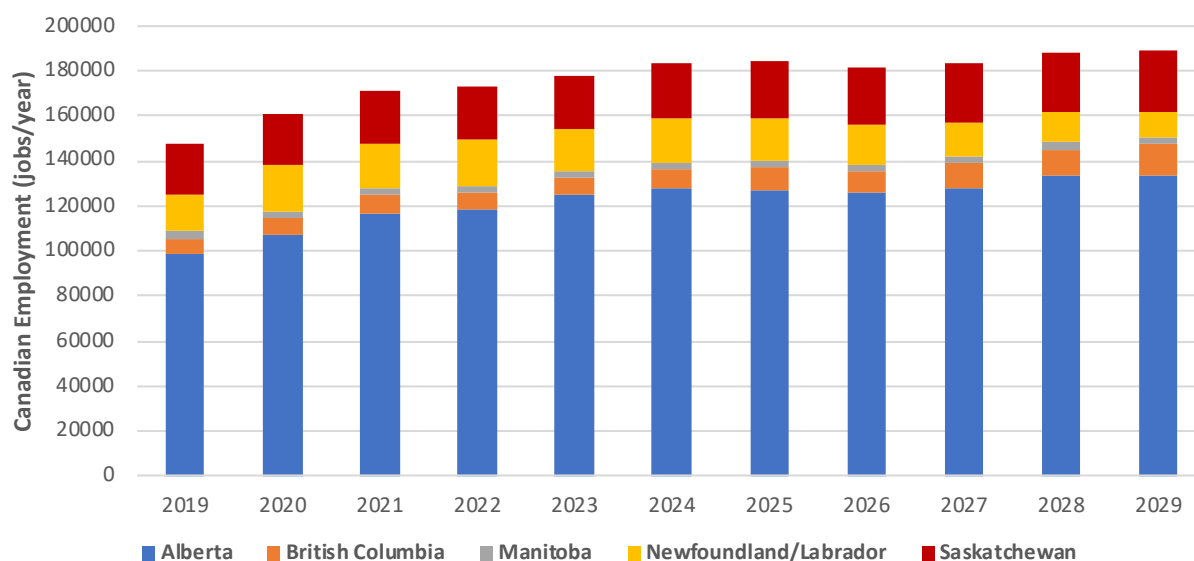
Province	GDP (\$CAD million)	Employment (person-years)
Alberta	260,098	1,339,793
British Columbia	26,890	102,584
Manitoba	13,606	33,532
Newfoundland and Labrador	91,443	191,472
Saskatchewan	134,065	269,777
Canada	604,707	2,643,936

Note: The effects in each province shows both direct and indirect effects of crude oil developments within that province, while the effects for Canada represent direct and indirect effects of crude oil developments in all Canadian provinces.

Figure 3.6: Annual GDP Impacts of Crude Oil Development, 2019-2029

Total employment (direct and indirect) in Canada will amount to 2,643 thousand-person years, translating to growth from 201 thousand jobs in 2019 to 258 thousand jobs in 2029. Figure 3.7 shows employment effects within Alberta, British Columbia, Manitoba, Newfoundland and Labrador, and Saskatchewan.

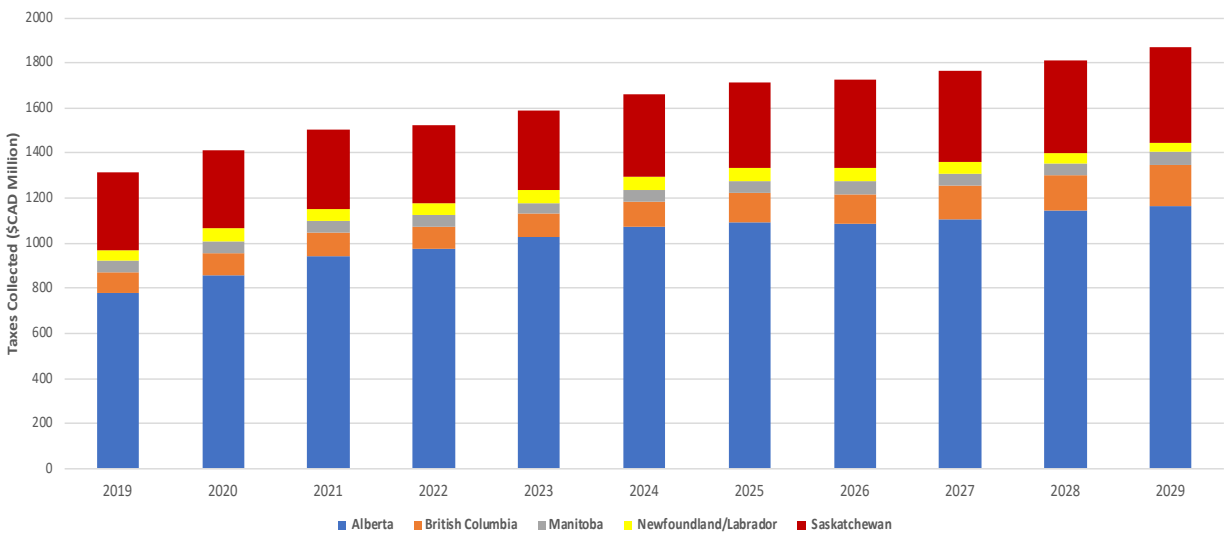
Figure 3.7: Employment Impacts of Crude Oil Development, 2019-2029



Total (federal, provincial, and municipal) government tax revenue will be CAD\$20.9 billion over the 2019-2029 period (Table 3.2). On average, annual tax revenue will be CAD\$1.9 billion. The provinces of Alberta and Saskatchewan will generate the highest shares of tax revenues.

Table 3.2: Total Tax Receipts from Crude Oil Development, 2019-2029

Province	Tax Revenue (\$CAD million)
Alberta	11,248
British Columbia	1,364
Manitoba	569
Newfoundland and Labrador	587
Saskatchewan	4,126
Canada	20,914

Figure 3.8: Annual Tax Receipts from Crude Oil Development, 2019-2029

Economic Impacts of Natural Gas Development

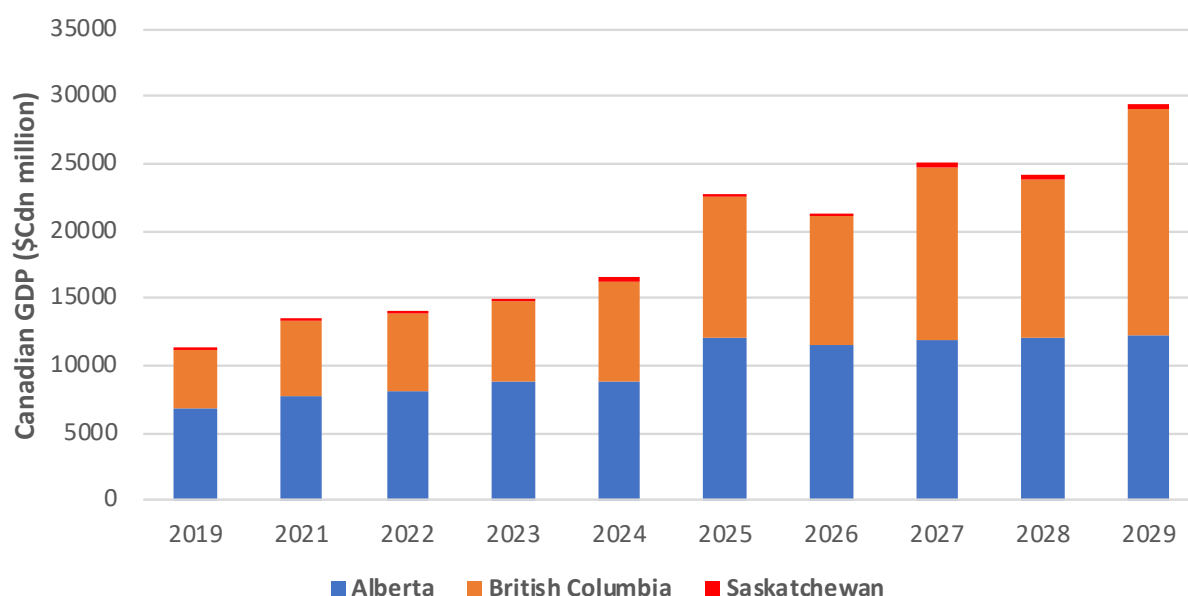
This section presents the economic impacts of natural gas development, including both existing and future drilling activity within the provinces of British Columbia, Alberta, and Saskatchewan over the period 2019 to 2029. The analysis covers conventional, tight, shale gas, and coalbed methane, but not offshore natural gas production.

Table 3.3 presents the total impacts associated with both investment and operation of natural gas projects in British Columbia, Alberta, and Saskatchewan. Total Canadian GDP impact is estimated to be CAD\$249.1 billion (2018 Canadian dollars) with 43 percent of impacts felt in Alberta, 38 percent in British Columbia, and the rest across other provinces and territories. Annual GDP impact will average approximately CAD\$22.6 billion, starting at CAD\$13.5 billion in 2019, increasing to CAD\$35.8 billion in 2029. Figure 3.9 shows GDP effects within Alberta, British Columbia, and Saskatchewan.

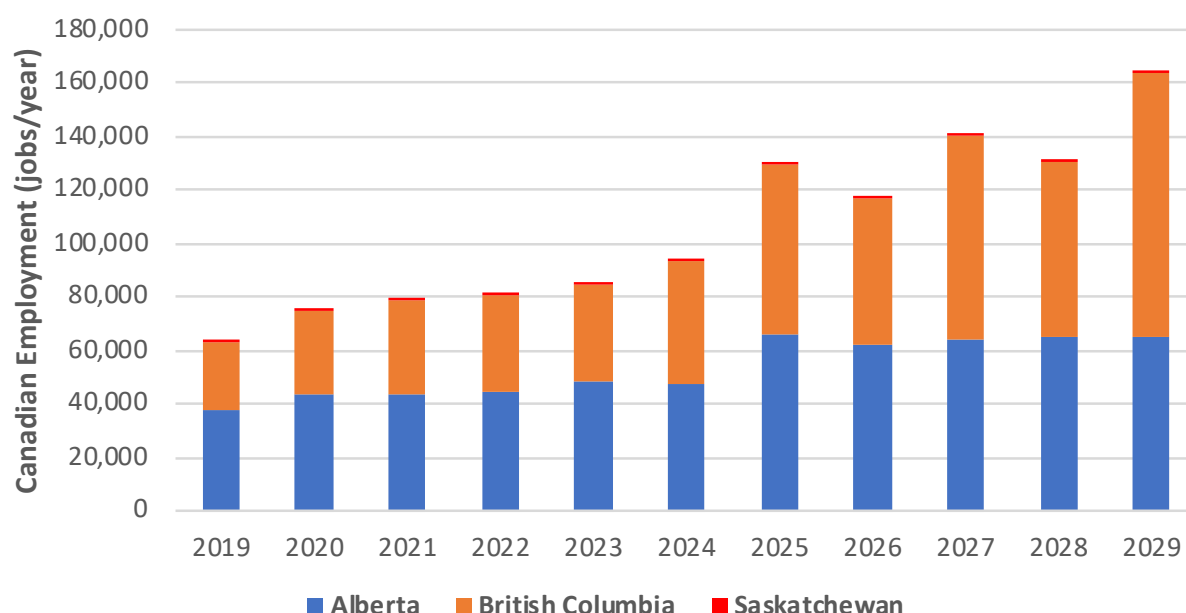
Table 3.3: Total GDP and Employment Impacts of Natural Gas Development, 2019-2029

Province	GDP (\$CAD million)	Employment (person-years)
Alberta	108,089	587,443
British Columbia	95,211	567,761
Saskatchewan	3,137	5,373
Canada	249,187	1,519,448

Figure 3.9: Annual GDP Impacts of Natural Gas Development, 2019-2029



Total employment (direct and indirect) in Canada will amount to 1,519 thousand-person years, translating to growth from 82 thousand jobs in 2019 to 217 thousand jobs in 2029. Figure 3.10 shows employment effects within Alberta, British Columbia, and Saskatchewan.

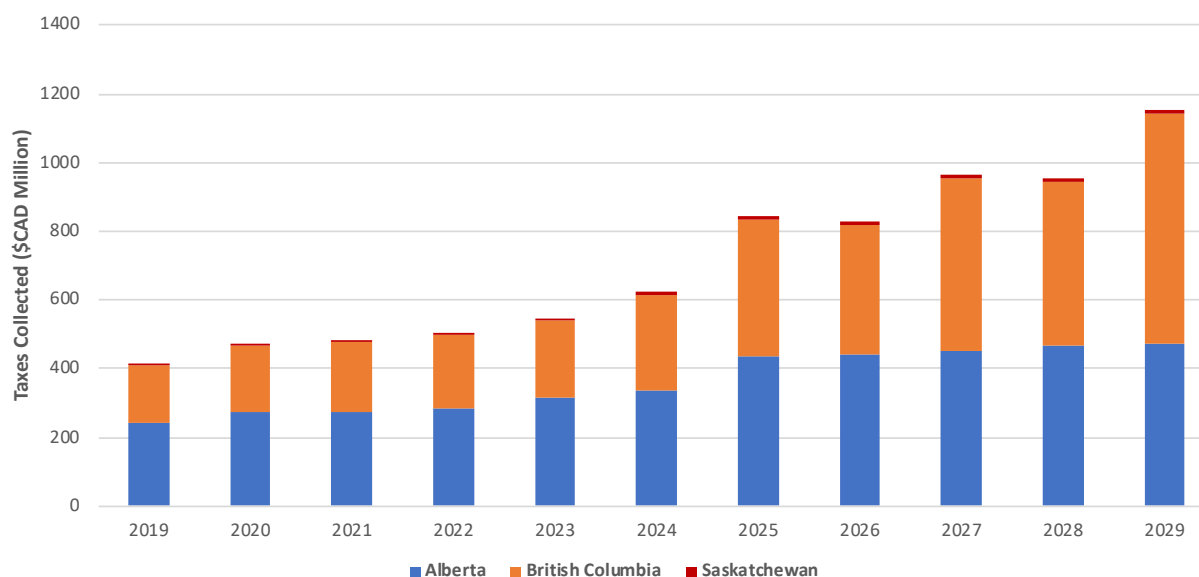
Figure 3.10: Employment Impacts of Natural Gas Development, 2019-2029

The tax impact on a corporation includes taxes generated by economic activity within a province payable to federal, provincial, and municipal governments. Total tax revenue generated from natural gas development in Canada will amount to CAD\$10.5 billion over the 2019-2029 period (Table 3.4). On average, annual tax revenues will be CAD\$0.9 billion per year. The provinces of British Columbia and Alberta will generate the highest shares of tax revenues.

Table 3.4: Total Tax Receipts from Natural Gas Development, 2019-2029

Province	Tax Revenue (\$CAD million)
Alberta	4,000
British Columbia	3,691
Saskatchewan	97
Canada	10,521

Figure 3.11: Annual Tax Receipts from Natural Gas Development, 2019-2029



US Economic Impacts of Canadian Conventional Oil and Gas

Investments and operations of Canadian oil and gas projects make important contributions to the United States economy. While the benefits of the Canadian oil and gas industry across Canadian provinces is relatively straightforward and well documented, the benefits of the Canadian oil and gas industry across *both* Canadian provinces and US states are lesser reported. The US benefits from not only importing oil and gas from Canada but also from supplying goods and services used by the Canadian oil and gas industry.

The Canadian oil and gas production sector imports billions worth of products and services from the US. Supply of those products and services spur economic activity and create or preserve jobs in respective US states. In 2017, CERI published a comprehensive study on US economic impacts from Canadian conventional oil and gas and oil sands production (Economic Impacts of Canadian Oil and Gas Supply in Canada and the US 2017-2027).

This section presents the update of the results initially provided in 2017, specifically, the economic impacts of the upstream Canadian oil and gas supply chain of goods and services purchased in the US. The update change is driven by the difference of revenues and investments of the current forecast with the revenues and investments used for the 2017 study.

There are significant economic impacts associated with the Canadian oil and gas sector's development, not just in Canada but in the US as well. Through highly integrated economies of two countries, the impacts generated by purchases of goods (like machinery, equipment, valves, etc.) and services (legal, environmental, engineering, etc.) by the Canadian companies in the US reverberate throughout the US economy. Conventional oil and gas firms purchase goods and services in the US in order to develop their projects and hence contribute to the US economy in generating a positive gross state product growth and creating or sustaining US employment.

For the forecast period of 2019-2029, it is estimated that the total of all US gross state products (direct and indirect)¹ will amount to almost US\$19.6 billion or CAD\$26.2 billion in 2016 dollars (using the current exchange rate of US \$0.75 per CAD \$1). The total employment impact (direct and indirect) is measured in creating or preserving 153.2 thousand full-time equivalent jobs in the 11-year period (Table 3.5).

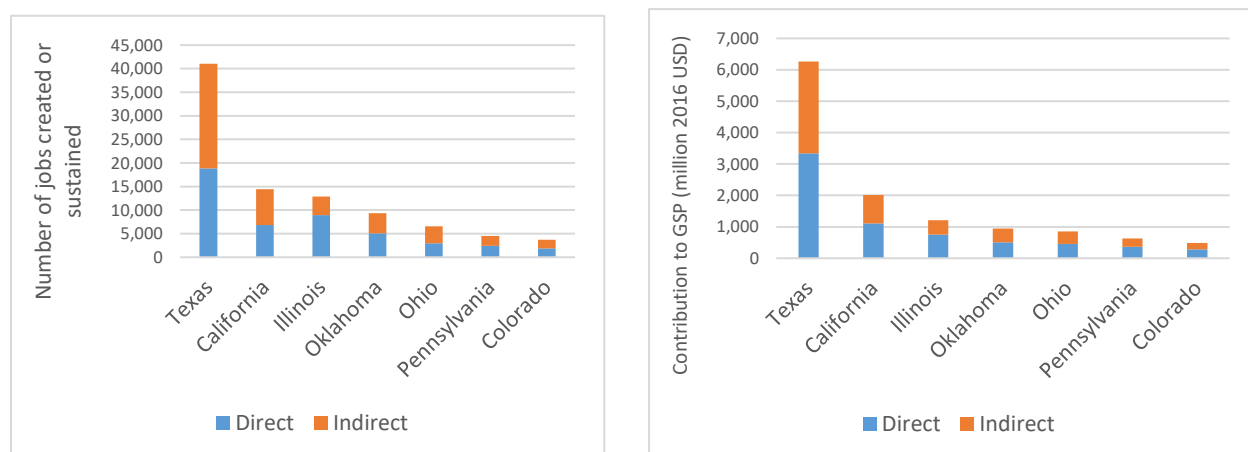
Table 3.5: Oil and Gas Economic Impacts in the US by State and by Type of Impact, 2019-2029

	Employment Impact (# of jobs created or sustained)			Contribution to Gross State Product (2016 USD, millions)		
	Direct	Indirect	Total	Direct	Indirect	Total
Texas	18864	22205	41069	\$3,340	\$2,927	\$6,266
California	6857	7605	14461	\$1,106	\$905	\$2,011
Illinois	8931	3968	12900	\$754	\$460	\$1,214
Oklahoma	5044	4272	9316	\$511	\$437	\$948
Ohio	2931	3625	6556	\$459	\$391	\$850
Pennsylvania	2413	2106	4519	\$360	\$269	\$628
Colorado	1890	1851	3741	\$282	\$208	\$490
Wisconsin	2751	1803	4554	\$322	\$169	\$491
Wyoming	602	656	1258	\$469	\$68	\$537
Florida	1554	2036	3589	\$178	\$199	\$378
Arizona	1224	2008	3231	\$215	\$135	\$350
Indiana	1318	1232	2550	\$279	\$105	\$384
Minnesota	1387	1036	2423	\$225	\$109	\$334
Utah	1687	1714	3401	\$164	\$162	\$325
Montana	1608	1365	2973	\$217	\$119	\$336
Michigan	3671	1515	5187	\$107	\$144	\$251
Oregon	1048	1267	2315	\$141	\$124	\$266
Iowa	1025	950	1975	\$150	\$92	\$242
Georgia	955	854	1809	\$143	\$89	\$232
Virginia	795	603	1398	\$170	\$68	\$239
New York	890	649	1538	\$125	\$89	\$215
Kansas	1142	1076	2218	\$104	\$103	\$207
Washington	1119	901	2019	\$98	\$105	\$203
New Jersey	622	724	1346	\$99	\$95	\$193
North Carolina	658	646	1304	\$122	\$58	\$179
Missouri	568	521	1089	\$116	\$45	\$162
Louisiana	781	664	1446	\$107	\$64	\$171

¹ In the US, the definition of gross state product (GSP) is similar to the provincial gross domestic product (GDP) in Canada.

	Employment Impact (# of jobs created or sustained)			Contribution to Gross State Product (2016 USD, millions)		
	Direct	Indirect	Total	Direct	Indirect	Total
Mississippi	801	819	1619	\$105	\$73	\$178
Alabama	587	746	1332	\$96	\$74	\$170
North Dakota	254	436	690	\$103	\$50	\$153
Tennessee	519	473	992	\$69	\$45	\$114
Nevada	636	530	1167	\$66	\$48	\$114
Kentucky	542	420	962	\$72	\$40	\$112
Connecticut	446	245	691	\$65	\$35	\$100
Nebraska	446	405	851	\$60	\$41	\$101
South Carolina	514	333	846	\$65	\$27	\$92
Idaho	638	482	1120	\$60	\$35	\$95
Arkansas	394	389	784	\$57	\$38	\$95
Massachusetts	302	232	535	\$54	\$28	\$82
New Hampshire	265	157	422	\$27	\$15	\$42
Maryland	156	124	279	\$20	\$14	\$34
New Mexico	166	142	308	\$16	\$13	\$29
West Virginia	74	54	128	\$10	\$5	\$14
South Dakota	53	37	90	\$9	\$3	\$13
Delaware	20	8	29	\$3	\$1	\$4
Maine	48	20	68	\$2	\$2	\$4
Rhode Island	22	11	33	\$2	\$1	\$4
Alaska	10	4	14	\$1	\$0	\$1
Vermont	5	3	7	\$0	\$0	\$1
Total	79,234	73,918	153,152	\$11,323	\$8,329	\$19,652

The top ten states that benefit the most from Canadian conventional oil and gas development are, in descending order: Texas, California, Illinois, Oklahoma, Ohio, Pennsylvania, Colorado, Wisconsin, Wyoming, and Florida (Figure 3.12). Together, the top ten states make up 70 percent of the total GDP impact and 68 percent of total employment impact. Again, Texas is the largest beneficiary in terms of gross state product (GSP) and employment (Figure 3.12).

Figure 3.12: Oil and Gas Economic Impacts in the US in the Top-7 States, 2019-2029

Emissions

This section presents emission forecasts from the upstream production of conventional oil and conventional and unconventional gas in Canada. Upstream emissions in this study are defined as emissions related to the upstream extraction of these hydrocarbons. Hence, emissions related to oil sands, midstream/downstream processing, and pipeline transportation are excluded. More specifically, upstream emissions encompass emissions from the following activities: drilling, production and extraction, processing in the field, and venting, flaring, and fugitive emissions.

For natural gas, methane releases (or fugitive emissions) are closely associated with well completion, equipment selection and operations. The quality of the cement and the cementing process are key to leak management before, during and after production. Valve and seal leaks are the principal sources of these emissions during the production phase of the well (during operational offsets, gas can be vented to maintain desired operational conditions, like pressure). While there have been numerous studies on methane leaks and flaring and energy requirements to support developmental and operational phases of the gas supply chain, there is no scientific consensus.

For our analysis, CERI is using the emissions intensity of the natural gas industry derived from data published by Environment and Climate Change Canada (Government of Canada 2019). According to the publication, as of June 2019, total emissions from the natural gas industry were 48.6 megatonnes of carbon dioxide equivalent in 2017. Using 18.11 Bcf/d as raw natural gas production for 2017 (CAPP), the resulting intensity is 7.49 tonnes CO₂ eq/mmscf. In its emissions forecast, CERI accounted for the federal methane emissions reduction regulation as follows:

- The program targets to reduce methane emissions by 45 percent from 2012 levels over the period 2019 to 2025
- Natural gas emissions level in 2012 was 54.3 MTCO₂eq (Government of Canada 2019)
- Methane part of these emissions is assumed proportionally to the methane percentage in the total amount of methane, ethane and CO₂ in the average cubic foot of natural gas

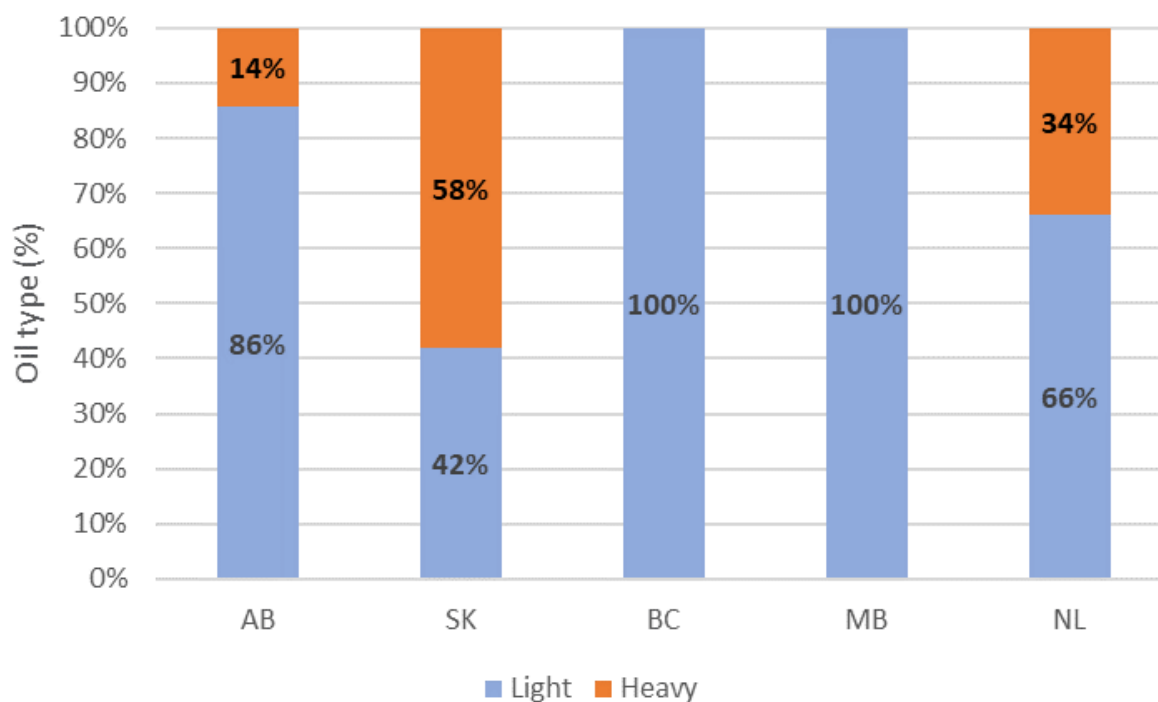
in Alberta and British Columbia, that is 92.8 percent. Methane emissions in CO₂eq in 2012 are thus estimated at 50.4 MtCO₂eq.

- Upstream share of all methane emissions is assumed to be 93 percent for all provinces (CERI Study 177, Economic and Environmental Impacts of Methane Emissions Reduction in the Natural Gas Supply Chain). Methane emissions from upstream in CO₂eq in 2012 is estimated at 46.9 MtCO₂eq.
- The targeted reduction is thus 21 MtCO₂eq. (45 percent of 46.9 MtCO₂eq.) which is going to be gradually accumulated within 6 years (2019-2025) and subtracted from the no-policy forecast which assumes the constant intensity (7.49 tonnes CO₂ eq/mmscf).
- The calculation assumes that all provinces comply in full, decreasing their methane emissions by 45 percent.

For conventional crude oil, we used data from CERI Study 167, “An Economic and Environmental Assessment of Eastern Canada Crude Oil Imports.” In particular, emissions intensity for light crude volumes for this study is calculated as a weighted average of two emission intensity figures – mixed sweet blend and mixed sour blend. The estimated intensity is 12.2 kg CO₂ eq/bbl for Newfoundland and Labrador and 41.12 kg CO₂ eq/bbl for the rest, which is used to calculate total upstream emissions for light, medium and condensate production. For heavy oil production, an intensity of 72.4 CO₂ kg eq/bbl is used for calculating upstream emissions.

CERI assumes that oil carbon intensity will remain constant over the forecast period. The global focus on reduction of emissions, Canada’s international commitments and new regulations as well as leadership taken by the industry itself is translating into actions which help to lower these intensities. The Canadian oil and gas industry has shown its ability to decrease emissions per unit of production over time as conventional oil emissions intensity has been falling by 0.9 percent annually from 2000-2017 (or by 14 percent in total). Thus, the constant intensity for oil likely represents a conservative view of the future.

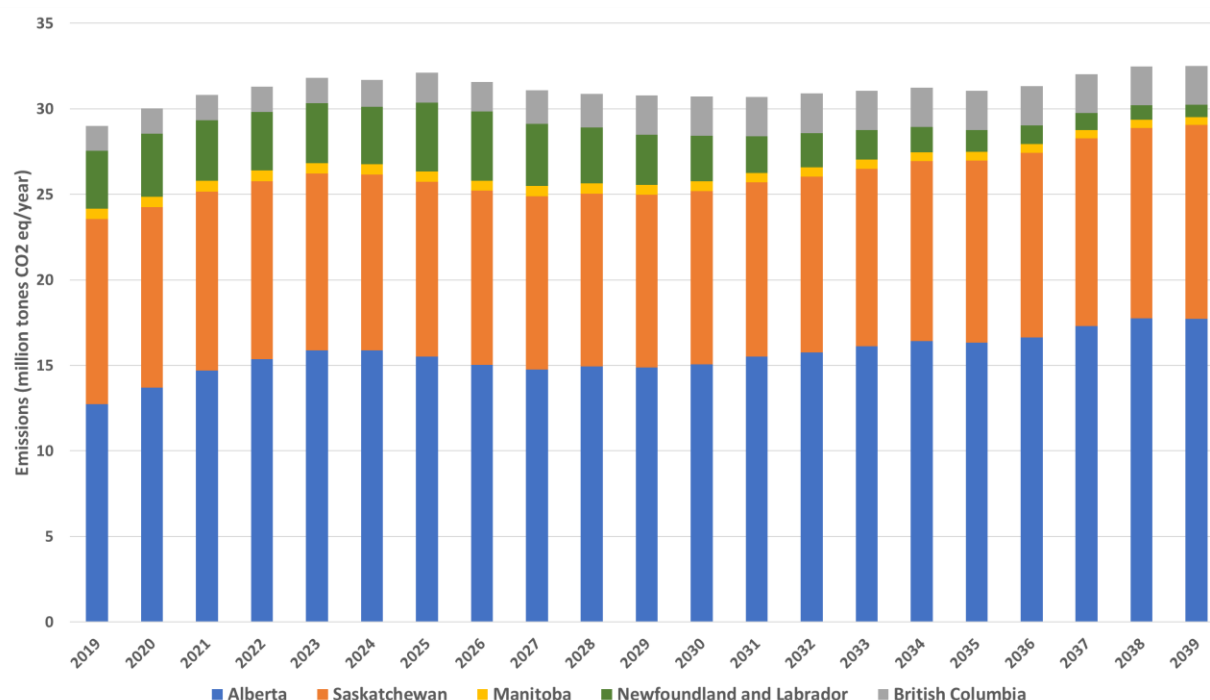
Lastly, CERI also assumes the same ratios between heavy and light oil for all provinces according to 2018 actual production data (NEB 2019) (Figure 3.13). For Newfoundland and Labrador, a forecast of production was used to arrive at the average shares of light and heavy oil for 2019-2039. This was required as Hebron asset is adding heavy oil into the province’s historically light crude slate.

Figure 3.13: Assumed Percentage of Oil Type by Province, 2019-2039

Source: CERI, NEB

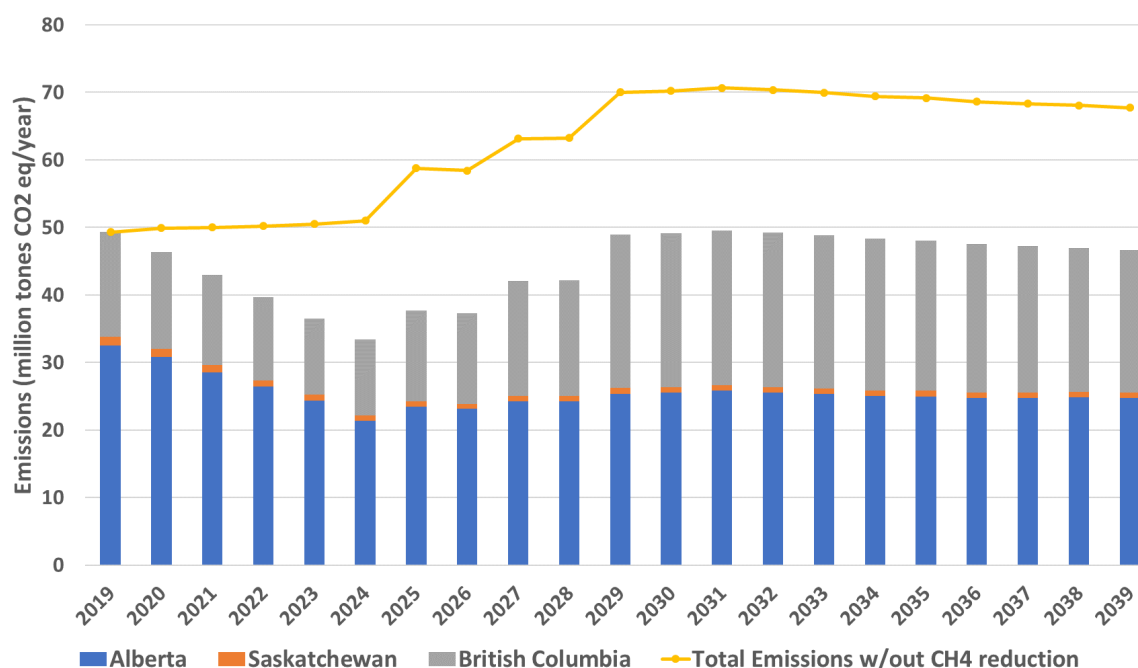
On average, annual emissions from oil production will be 31.1 million tonnes/year during the study period, or less than 1 percent below 2017 levels (31.3 million tonnes/year). Alberta and Saskatchewan will generate the highest emissions at 50 and 34 percent, respectively (Figure 3.14).

Figure 3.14: Emissions from Crude Oil Production, 2019-2039



On average, annual emissions from natural gas production will be 44.7 million tonnes/year during the study period, or a 10 percent decrease compared to 2017 levels (49.5 million tonnes/year) due to the methane reduction policy. Alberta and British Columbia will generate the highest emissions at 57 and 41 percent, respectively (Figure 3.15).

Figure 3.15: Emissions from Natural Gas Production, 2019-2039



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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 CERI Study 173, “Canadian Crude Oil and Natural Gas Production and Supply Costs Outlook (2018-2038)”. CERI completed supply cost calculations, explained below, which populated the production forecast.

In producing this forecast of drilling and production, CERI relied on and accounted for a variety of data which included historical well-licensing data, historical drilling activity in activity areas, supply costs, the ratio of horizontal and vertical wells, and industry’s interests in a resource play.

CERI has also accounted for the forecast of domestic demand for conventional crude oil and natural gas, exports, and imports of these products. For the latter, the US EIA Outlook 2019 forecast was used for natural gas (US imports and exports to Canada) as a basis. Thus, the forecast reflects the changes in expected trade volumes of natural gas and oil between the US and Canada due to US growth of shale oil and gas volumes. For domestic consumption, the NEB Energy Futures forecast was used. At the same time, CERI did not constrain the production outlook for any potential bottlenecks in export pipelines or current recoverable reserves estimates. More details about factors which impacted the oil and gas forecast are provided below.

The WCSB supply costs represent the natural gas price (in real 2018 dollars) required by producer project to receive each year 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 revenues for gas wells do not include sales from NGLs, while revenues from oil wells do not include sales from associated gas.

The net cash flow is discounted back over the lifetime of the well (on average 25 years) to the first time period (2018) using a specified discount rate of 10 percent, 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.

Each well is considered operational when the gross revenue is greater than the operating costs and royalties. If revenue falls below these costs, the well is shut off and the economic evaluation is conducted for that time period only.

Historical trends in the number of wells per pad are incorporated into the supply costs to account for economies of scale.

Production Inputs

Historical well data were used to calculate the 2018 production inputs. Information was collected from the Alberta Energy Regulator (AER), the Government of Saskatchewan and the BC 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). Drilling and completion costs per metre drilled were estimated for each area and then applied to each area given the assumed well depth driven by a recent average of depth per PIA area.
- Geological, geophysical, tie-in costs (infrastructure), and land costs were all derived from data sourced from the Canadian Association of Petroleum Producers (CAPP) (CAPP 2018) and assigned to new build wells.
- Operating costs were estimated from CAPP at the provincial level.
- Royalties were derived for all wells consistent with the regulations for natural gas royalties across the three provinces (Government of Alberta 2018; Government of British Columbia 2018; Government of Saskatchewan 2018).
- Within the supply cost model, federal corporate income tax rates were assumed constant at 15 percent. Alberta, British Columbia, and Saskatchewan income tax rates were assumed to be constant at 12 percent.

Other Economic Assumptions

- The inflation rate applied to operating costs 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 **real 2018 Canadian dollars**. The Canadian dollar was assumed to be 80 cents/USD over the next 20 years.
- **Supply costs are calculated as field-gate costs**, that is, they do not include transportation or processing costs.
- Gas supply costs are presented as Canadian dollars per thousand cubic feet of natural gas (\$/mcf).
- The natural gas price is assumed to increase at 2 percent per annum.

Crude Oil Production: Western Canada Forecast and Supply Cost Methodology

The production forecast in this study is an update from CERI Study 173, "Canadian Crude Oil and Natural Gas Production and Supply Costs Outlook (2018-2038)". The methodology for supply forecast and supply cost calculations have not changed; the assumptions used have been updated to reflect their changes over time.

The supply cost represents the oil price (in real 2018 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 22 years) to the first time period (2018) 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/d or greater and the gross revenue is greater than the sum of operating costs and royalties. Otherwise, the well is 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.

The analysis has been undertaken for all PIA areas, and the results represent the supply cost for a “typical well” located in each area.

Historical trends in the number of wells per pad are incorporated into the supply costs to account for economies of scale.

Production Inputs

Historical well data were used to calculate the production inputs. Information was collected from the AER, the Government of Saskatchewan, the BC 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 new wells considered the IP rates of wells that were drilled in the past seven years. A curve was derived for each area and is used to establish the different IPs for the forecasted years.
- Production **decline** parameters were derived from historical monthly production rates from wells drilled in the past seven years. A “type” curve was derived for each area and is used to establish the production decline profile for all new wells.
- 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). 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. These were derived at the provincial level, so they do not vary between areas or wells (CAPP 2018).
- **EOR costs and land costs** were estimated by CAPP at the provincial level and are assumed to be constant per barrel of oil produced (CAPP 2018).
- **Operating costs** were estimated by CAPP at the provincial level and are assumed to be constant per barrel of oil produced (CAPP 2018).
- **Royalties** were derived for all wells consistent with the regulations for oil royalties across the four provinces (Government of Alberta 2018; Government of British Columbia 2018; Government of Saskatchewan 2018; Government of Manitoba 2018).
- Within the supply cost model, federal corporate income tax rates were assumed constant at 15 percent. Alberta, British Columbia, and Saskatchewan 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 2.35 percent per annum (EIA 2019).

Crude Oil Production: Offshore Newfoundland and Labrador Forecast and Supply Cost Methodology

The production profile for the Newfoundland and Labrador offshore assets comprises aggregated profiles of producing assets: Hibernia, Terra Nova, White Rose, North Amethyst, and Hebron producing assets as well as all officially approved for development extensions of these projects.

Production Profile Inputs

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

- a) Recoverable reserves. For most assets, the C-NLOPB latest reserves estimation (May 2018) was used. For the Hebron project, Operator estimation of reserves was used from the Development Plan of 2011. For the perspective asset, an assumption of recoverable reserves had to be made based on the best available information issued by Operators in the public domain.
- b) Produced up to date reserves. Historical production published by C-NLOPB was used.
- c) Project Life. Due to the maturity of all producing assets and the 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 level, used in Development plans or Amendments per project, was also taken into consideration while modelling a production profile.

- d) Production profile per asset from 2018 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 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 Operators 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 of Hebron, the latest Operator's production forecast was used. For a 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.
- e) Historical production per well. Historical production per well per asset for the last 3 years and drilling of new wells in 2016-2018 to better estimate production in 2019-2020.

Production Profile Assumptions

- No gas production is modelled irrespective of the 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.

Appendix B: Input-Output Model

To calculate GDP, employment and tax impacts of oil and gas developments, this study used the most recent provincial detailed-level input-output multipliers (2015) published by Statistics-Canada. Input-output multipliers show how a certain target variable – such as provincial GDP – would respond to changes in a certain control variable – such as additional spending on products of an industry. These effects can be direct (i.e., direct demand for a specific industry) or indirect. The indirect effects of the initial spending begin when businesses receiving the initial order purchase additional materials and supplies from other businesses who, having received their own new orders, similarly expand their productive activities. Considering the geographical aspect of the effects, this study included the following impacts:

1. the direct impact on the province where new spending occurs,
2. the direct impact plus the sum of all other indirect impacts of the new spending on the province in question (simple multiplier – within province) and
3. the direct and indirect impact on the province in question plus all indirect impacts on all other provinces (simple multiplier – all provinces).

The GDP, employment, and tax effects for each province shown in this study are calculated by multiplying capital investment and operational revenues in each industry by the corresponding simple “within-province” multipliers. The effects for the whole of Canada are derived similarly but using the simple “all-provinces” multipliers.

Before using the multipliers, capital cost and operational revenues from products should be translated into corresponding shocks for industries. Based on input-output tables, in this study, it is assumed that the capital investment in conventional oil increases demand in three industries with the following shares: 39 percent in conventional oil and gas extraction, 58 percent in oil and gas engineering construction, and 3 percent in the finance, insurance, real estate and rental and leasing industry. It is also assumed that 97 percent of the operating revenues in conventional oil stimulates the conventional oil and gas extraction industry and 3 percent increases demand for the finance, insurance, real estate and rental and leasing industry.

Appendix C: Forecasts

Table C.1: Oil and Condensate Production Forecast (bpd)

Year	AB-Oil	AB-Pentanes plus and Condensate	SK-Oil	BC-Oil	BC-Pentanes plus and Condensate	MB-Oil	NL-Oil	Total-Oil	Total - Pentanes plus and Condensate	Total
2014	589,640	181,517	514,074	21,474	27,926	49,188	216,135	1,390,511	209,443	1,599,953
2015	529,684	219,253	485,763	21,242	24,762	46,191	171,790	1,254,670	244,015	1,498,685
2016	445,372	257,528	460,282	23,306	31,531	40,236	210,361	1,179,557	289,060	1,468,616
2017	446,127	302,507	484,844	21,267	38,234	38,750	220,846	1,211,833	340,741	1,552,574
2018	489,546	351,260	488,115	20,754	67,663	40,077	230,270	1,268,761	418,923	1,687,684
2019	427,139	375,282	499,619	19,586	77,223	40,712	283,363	1,270,420	452,505	1,722,925
2020	466,018	396,642	487,106	19,022	79,050	40,408	309,933	1,322,487	475,692	1,798,179
2021	505,555	419,735	482,602	18,269	80,483	41,626	299,025	1,347,077	500,218	1,847,295
2022	523,940	443,504	480,160	17,304	81,656	41,291	287,987	1,350,682	525,159	1,875,841
2023	537,799	460,966	477,938	16,426	82,691	40,565	295,351	1,368,079	543,657	1,911,736

Year	AB-Oil	AB-Pentanes plus and Condensate	SK-Oil	BC-Oil	BC-Pentanes plus and Condensate	MB-Oil	NL-Oil	Total-Oil	Total - Pentanes plus and Condensate	Total
2024	537,535	461,451	475,412	15,764	88,776	40,049	281,811	1,350,570	550,227	1,900,797
2025	515,146	462,394	472,881	15,158	102,180	39,737	337,111	1,380,033	564,574	1,944,607
2026	488,463	459,309	470,530	14,701	101,839	39,415	338,968	1,352,077	561,147	1,913,224
2027	473,544	458,620	468,228	14,175	116,575	39,006	304,501	1,299,453	575,195	1,874,649
2028	486,615	456,823	466,349	13,626	117,280	38,705	274,549	1,279,844	574,103	1,853,947
2029	481,755	457,059	466,188	13,216	139,333	38,243	247,474	1,246,876	596,392	1,843,268
2030	492,598	457,675	468,011	12,941	140,051	37,683	223,090	1,234,323	597,726	1,832,050
2031	519,142	457,603	471,053	12,603	140,805	37,036	180,064	1,219,897	598,408	1,818,306
2032	533,448	457,433	475,139	12,295	141,638	36,376	169,049	1,226,306	599,072	1,825,378
2033	554,812	458,247	480,053	12,087	141,650	35,665	143,461	1,226,078	599,897	1,825,975
2034	572,707	459,234	485,765	11,845	141,463	34,911	123,467	1,228,695	600,697	1,829,392
2035	566,446	460,174	492,192	11,494	141,213	34,191	106,416	1,210,739	601,387	1,812,126

Year	AB-Oil	AB- Pentanes plus and Condensate	SK-Oil	BC-Oil	BC- Pentanes plus and Condensate	MB-Oil	NL-Oil	Total-Oil	Total - Pentanes plus and Condensate	Total
2036	582,977	461,492	499,232	11,197	140,715	33,473	92,838	1,219,717	602,207	1,821,924
2037	622,542	462,792	506,907	11,004	140,151	32,727	83,433	1,256,613	602,943	1,859,556
2038	647,365	464,244	515,173	10,860	139,520	31,937	70,754	1,276,089	603,763	1,879,853
2039	644,543	465,668	523,990	10,571	138,883	31,184	60,918	1,271,207	604,551	1,875,758

Table C.2: Natural Gas Production Forecast (mmscf/d)

Year	AB	SK	BC	Total
2014	11,733	563	4,568	16,864
2015	12,069	561	4,737	17,367
2016	12,173	518	4,907	17,598
2017	12,463	513	4,987	17,963
2018	12,575	501	5,693	18,770
2019	11,901	482	5,660	18,042
2020	12,125	469	5,664	18,258
2021	12,148	459	5,678	18,285
2022	12,228	451	5,686	18,365
2023	12,344	445	5,694	18,483
2024	11,929	441	6,289	18,658
2025	13,391	437	7,671	21,499
2026	13,243	434	7,688	21,365
2027	13,306	431	9,360	23,097
2028	13,333	429	9,365	23,128
2029	13,292	427	11,900	25,619
2030	13,352	426	11,912	25,691
2031	13,491	425	11,931	25,847
2032	13,355	424	11,960	25,739
2033	13,271	424	11,895	25,590
2034	13,162	424	11,808	25,395
2035	13,156	425	11,716	25,296
2036	13,081	425	11,591	25,097
2037	13,109	426	11,463	24,997
2038	13,145	426	11,329	24,900
2039	13,147	427	11,194	24,768

Table C.3: Input Data for I/O Oil (Mln CDN\$)

Provinces	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital investment											
AB	\$3,446	\$3,393	\$3,639	\$3,231	\$3,319	\$2,847	\$2,349	\$2,057	\$2,118	\$2,484	\$1,944
BC	\$115	\$100	\$78	\$59	\$53	\$50	\$43	\$43	\$36	\$33	\$32
SK	\$1,909	\$1,937	\$1,959	\$1,983	\$1,970	\$1,953	\$1,934	\$1,917	\$1,899	\$1,881	\$1,918
MB	\$375	\$491	\$432	\$374	\$347	\$333	\$323	\$307	\$298	\$286	\$268
NFLD	\$1,715	\$2,475	\$2,291	\$2,856	\$1,983	\$2,320	\$1,379	\$898	\$480	\$236	\$154
Revenues											
AB	\$22,364	\$24,766	\$27,202	\$28,126	\$29,756	\$31,180	\$31,718	\$31,670	\$32,127	\$33,253	\$33,907
SK	\$12,502	\$12,597	\$12,813	\$12,592	\$12,878	\$13,484	\$13,997	\$14,383	\$14,804	\$15,109	\$15,510
BC	\$2,786	\$2,904	\$2,993	\$2,967	\$3,043	\$3,358	\$3,914	\$4,000	\$4,625	\$4,733	\$5,648
MB	\$1,172	\$1,197	\$1,261	\$1,238	\$1,245	\$1,286	\$1,325	\$1,353	\$1,380	\$1,399	\$1,416
NFL	\$7,618	\$8,593	\$8,496	\$8,089	\$8,509	\$8,518	\$10,606	\$10,993	\$10,195	\$9,407	\$8,694

Table C.4: Input Data for I/O Gas (Mln CDN\$)

Provinces	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital investment											
AB	\$2,805	\$3,352	\$3,300	\$3,350	\$3,411	\$2,787	\$4,434	\$3,530	\$3,530	\$3,502	\$3,387
BC	\$3,544	\$4,760	\$5,422	\$5,456	\$5,397	\$6,743	\$9,181	\$7,264	\$10,600	\$8,291	\$13,320
SK	\$6	\$6	\$6	\$6	\$6	\$6	\$5	\$6	\$6	\$5	\$5
Revenues											
AB	\$6,690	\$7,413	\$7,423	\$7,852	\$8,731	\$9,384	\$12,127	\$12,417	\$12,720	\$13,205	\$13,395
BC	\$3,181	\$3,463	\$3,470	\$3,651	\$4,028	\$5,091	\$7,439	\$7,702	\$9,833	\$10,166	\$13,443
SK	\$271	\$287	\$280	\$290	\$315	\$347	\$396	\$407	\$412	\$425	\$430

Table C.5: Annual GDP, Employment and Tax Impacts of Oil Development, 2019-2029

GDP (\$CAD million)					
Province	Alberta	British Columbia	Manitoba	Newfoundland/Labrador	Saskatchewan
2019	\$18,794	\$1,872	\$1,152	\$7,264	\$11,213
2020	\$20,510	\$1,940	\$1,240	\$8,541	\$11,307
2021	\$22,464	\$1,983	\$1,257	\$8,344	\$11,494
2022	\$22,845	\$1,955	\$1,204	\$8,378	\$11,331
2023	\$24,099	\$2,000	\$1,194	\$8,157	\$11,553
2024	\$24,799	\$2,202	\$1,219	\$8,381	\$12,029
2025	\$24,835	\$2,557	\$1,244	\$9,465	\$12,429
2026	\$24,590	\$2,613	\$1,257	\$9,469	\$12,729
2027	\$24,968	\$3,013	\$1,273	\$8,554	\$13,056
2028	\$26,052	\$3,081	\$1,281	\$7,759	\$13,290
2029	\$26,142	\$3,673	\$1,284	\$7,131	\$13,634
Employment (person-years)					
Province	Alberta	British Columbia	Manitoba	Newfoundland/Labrador	Saskatchewan
2019	98,329	7,327	2,948	16,176	22,846
2020	106,848	7,541	3,361	20,183	23,062
2021	116,931	7,648	3,264	19,396	23,424
2022	118,330	7,492	3,044	20,884	23,203
2023	124,714	7,645	2,965	18,311	23,543
2024	127,628	8,392	2,981	19,530	24,303
2025	127,187	9,709	3,008	18,909	24,931
2026	125,597	9,917	2,996	17,697	25,397
2027	127,562	11,401	3,006	15,149	25,903
2028	133,445	11,646	2,997	13,233	26,256
2029	133,223	13,865	2,964	12,003	26,910

Tax (\$CAD million)					
Province	Alberta	British Columbia	Manitoba	Newfoundland/Labrador	Saskatchewan
2019	\$779	\$94	\$48	\$47	\$345
2020	\$861	\$98	\$51	\$56	\$348
2021	\$945	\$100	\$52	\$54	\$354
2022	\$974	\$99	\$50	\$55	\$348
2023	\$1,029	\$101	\$50	\$53	\$355
2024	\$1,075	\$112	\$51	\$55	\$370
2025	\$1,090	\$130	\$52	\$60	\$383
2026	\$1,087	\$133	\$53	\$60	\$392
2027	\$1,103	\$153	\$53	\$54	\$402
2028	\$1,143	\$157	\$54	\$49	\$409
2029	\$1,162	\$187	\$54	\$45	\$420

Table C.6: Annual GDP, Employment and Tax Impacts of Natural Gas Development, 2019-2029

GDP (\$CAD million)			
Province	Alberta	British Columbia	Saskatchewan
2019	\$6,894	\$4,229	\$221
2020	\$7,814	\$5,156	\$234
2021	\$7,785	\$5,565	\$229
2022	\$8,134	\$5,704	\$236
2023	\$8,819	\$5,911	\$256
2024	\$8,848	\$7,423	\$282
2025	\$12,031	\$10,435	\$321
2026	\$11,594	\$9,431	\$330
2027	\$11,816	\$12,852	\$334
2028	\$12,149	\$11,654	\$344
2029	\$12,206	\$16,853	\$349

Employment (person-years)			
Province	Alberta	British Columbia	Saskatchewan
2019	37,993	25,197	381
2020	43,280	31,874	404
2021	43,066	35,151	394
2022	44,875	35,763	406
2023	48,377	36,384	440
2024	47,744	45,601	484
2025	65,723	63,318	548
2026	62,412	54,505	564
2027	63,523	76,123	570
2028	65,156	65,552	586
2029	65,295	98,296	593
Tax (\$CAD million)			
Province	Alberta	British Columbia	Saskatchewan
2019	\$244	\$164	\$7
2020	\$271	\$194	\$7
2021	\$271	\$205	\$7
2022	\$286	\$211	\$7
2023	\$316	\$223	\$8
2024	\$335	\$280	\$9
2025	\$438	\$398	\$10
2026	\$442	\$375	\$10
2027	\$453	\$501	\$10
2028	\$469	\$474	\$11
2029	\$475	\$666	\$11

Table C.7: Emissions from Crude Oil Production, 2019-2039 (mill ton/yr)

Emissions	Alberta	Saskatchewan	Manitoba	Newfoundland and Labrador	British Columbia	Total Emissions
2019	12.74	10.81	0.61	3.37	1.45	28.99
2020	13.71	10.54	0.61	3.69	1.47	30.02
2021	14.71	10.44	0.62	3.56	1.48	30.82
2022	15.38	10.39	0.62	3.43	1.49	31.30
2023	15.87	10.34	0.61	3.52	1.49	31.82
2024	15.87	10.29	0.60	3.35	1.57	31.68
2025	15.51	10.23	0.60	4.01	1.76	32.12
2026	15.02	10.18	0.59	4.03	1.75	31.58
2027	14.76	10.13	0.59	3.62	1.96	31.07
2028	14.95	10.09	0.58	3.27	1.96	30.86
2029	14.88	10.09	0.57	2.95	2.29	30.77
2030	15.07	10.13	0.57	2.66	2.30	30.71
2031	15.51	10.19	0.56	2.14	2.30	30.70
2032	15.74	10.28	0.55	2.01	2.31	30.89
2033	16.11	10.39	0.54	1.71	2.31	31.05
2034	16.42	10.51	0.52	1.47	2.30	31.23
2035	16.33	10.65	0.51	1.27	2.29	31.06
2036	16.63	10.80	0.50	1.11	2.28	31.32
2037	17.31	10.97	0.49	0.99	2.27	32.03
2038	17.74	11.15	0.48	0.84	2.26	32.47
2039	17.72	11.34	0.47	0.73	2.24	32.49

Table C.8: Emissions from Natural Gas Production, 2019-2039 (mill ton/yr)

Emissions	Alberta	Saskatchewan	British Columbia	Total Emissions	Total Emissions w/out CH₄ Reduction
2019	32.54	1.32	15.47	49.33	49.33
2020	30.81	1.19	14.40	46.40	49.92
2021	28.54	1.08	13.34	42.96	49.99
2022	26.41	0.97	12.28	39.66	50.21
2023	24.36	0.88	11.24	36.47	50.53
2024	21.37	0.79	11.27	33.43	51.01
2025	23.47	0.77	13.45	37.68	58.78
2026	23.13	0.76	13.43	37.32	58.41
2027	24.23	0.79	17.04	42.05	63.14
2028	24.29	0.78	17.06	42.14	63.23
2029	25.40	0.82	22.74	48.95	70.04
2030	25.54	0.81	22.79	49.14	70.23
2031	25.87	0.81	22.88	49.57	70.66
2032	25.57	0.81	22.90	49.27	70.37
2033	25.34	0.81	22.71	48.87	69.96
2034	25.05	0.81	22.48	48.33	69.43
2035	25.00	0.81	22.26	48.07	69.16
2036	24.77	0.81	21.95	47.52	68.61
2037	24.78	0.80	21.67	47.25	68.34
2038	24.80	0.80	21.37	46.98	68.07
2039	24.75	0.80	21.07	46.62	67.71

Appendix D: Study Supply Areas

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

Table D.1: Supply Study Areas

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

Area ID	Province	Area Description
PIA18	AB	Darling Creek to Slave Lake Compressor
PIA19	AB	Fort McMurray Area
PIA20	AB	Owl Lake Area
PIA21	AB	Thunder Creek to Tanghe Creek
PIA22	AB	Zama Lake to Meikle Compressor
PIA23	AB	Princess to Empress Mainline
PIA30	BC	Pine River Lateral
PIA31	BC	Tupper Creek/Noel Area
PIA32	BC	Groundbirch Area
PIA33	BC	Dawson Creek
PIA34	BC	Fort St. John Area
PIA35	BC	Chinchauga River
PIA36	BC	Ring Area
PIA37	BC	Kahntah Area
PIA38	BC	Shekilie Area
PIA39	BC	Peggo-Pesh Area
PIA40	BC	Helmut North Area
PIA41	BC	Fort Nelson to CS2
PIA42	BC	Fort Nelson to NWT Border
PIA45	BC	CS2 to Summit Lake Area
PIA50	SK	Southwest
PIA51	SK	Central West
PIA52	SK	Northwest
PIA54	SK	Northeast

Area ID	Province	Area Description
PIA55	SK	Central East
PIA56	SK	Southeast
PIA70	MB	Bakken - Tourquay, Bakken
PIA71	MB	Lodgepole
PIA72	MB	Amaranth
PIA73	MB	Mission Canyon
PIA79	MB	Others

Source: CERI

Figure D.1: Map of British Columbia Study Areas

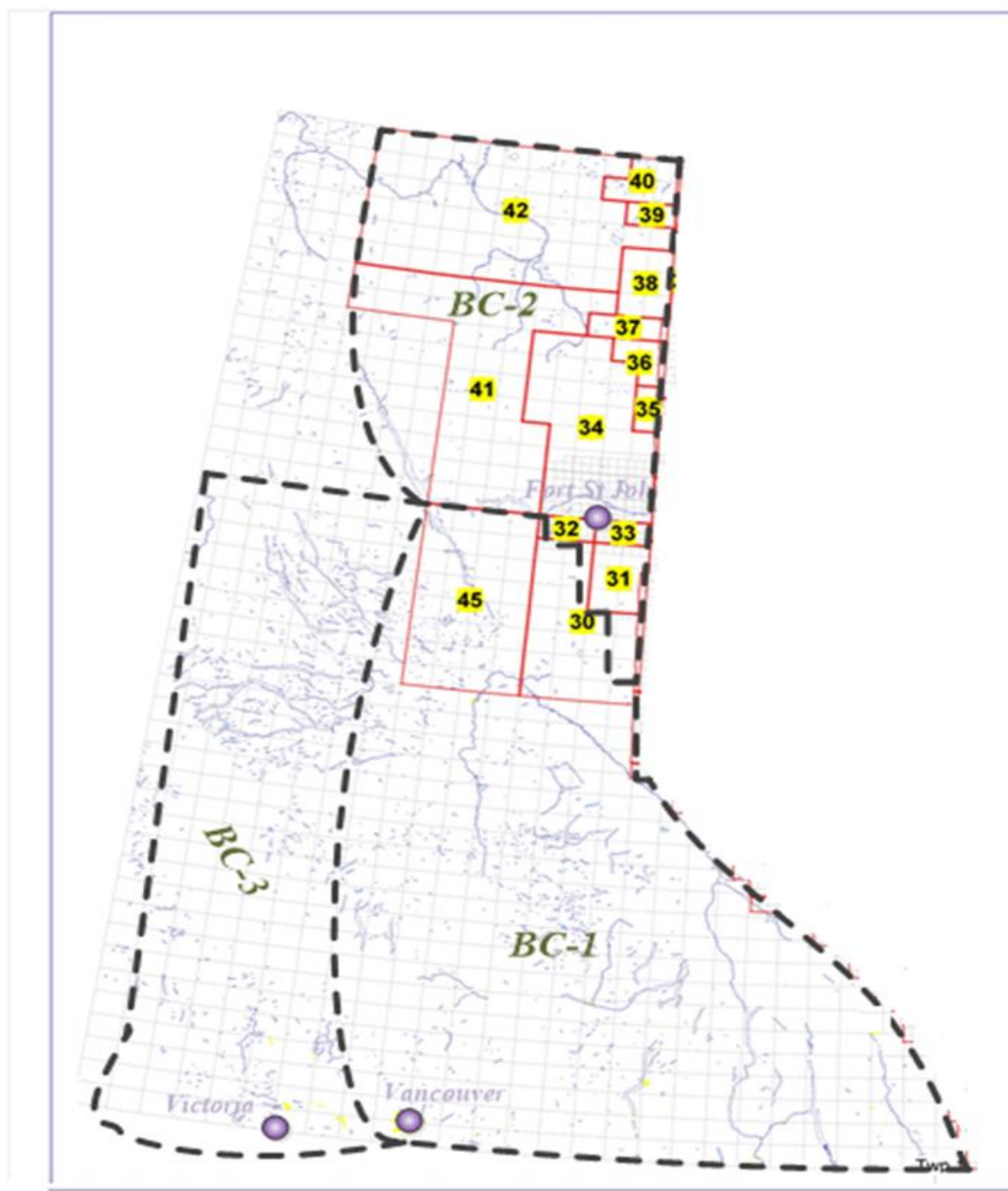


Figure D.2: Map of Alberta Study Areas

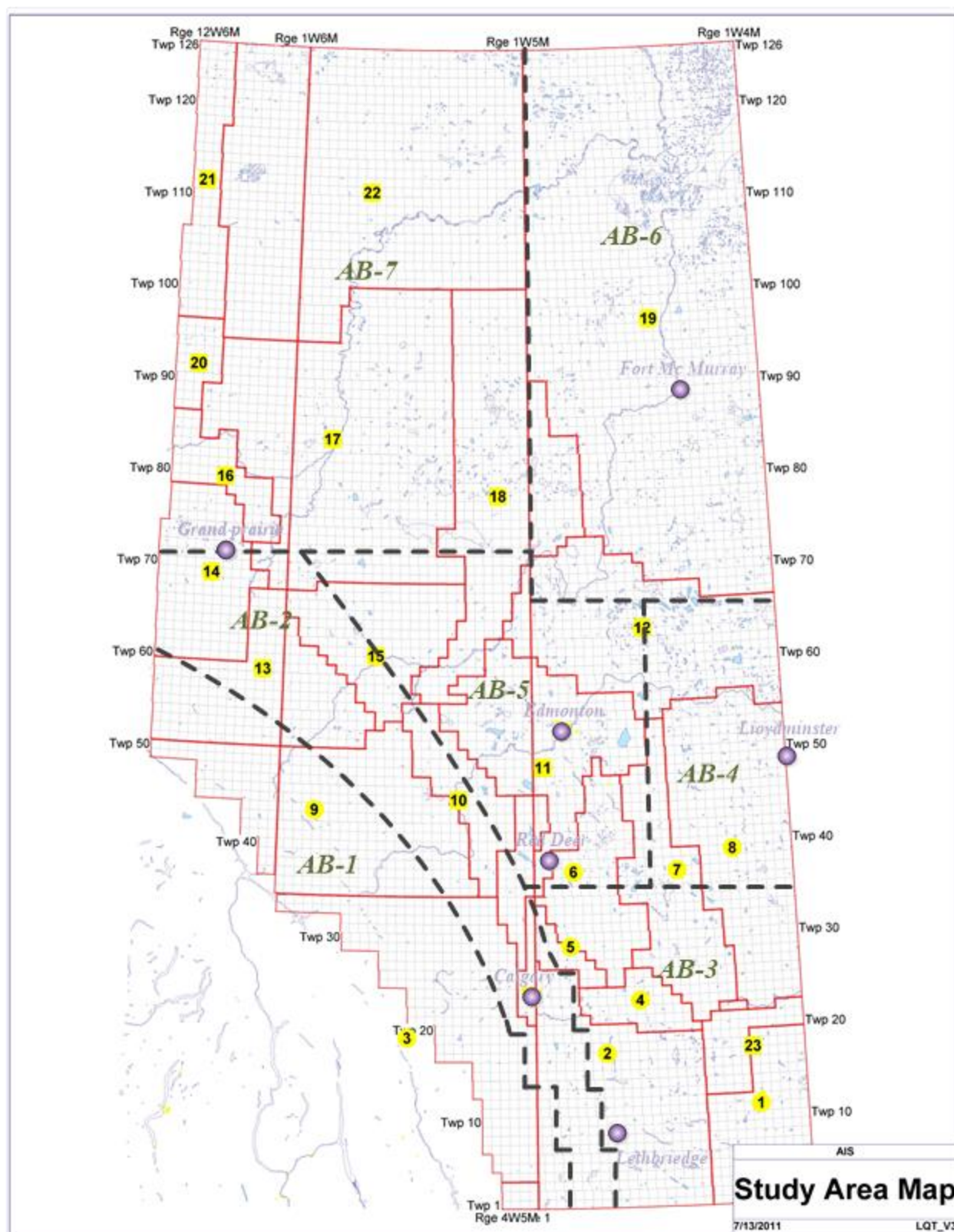


Figure D.3: Map of Saskatchewan Study Areas

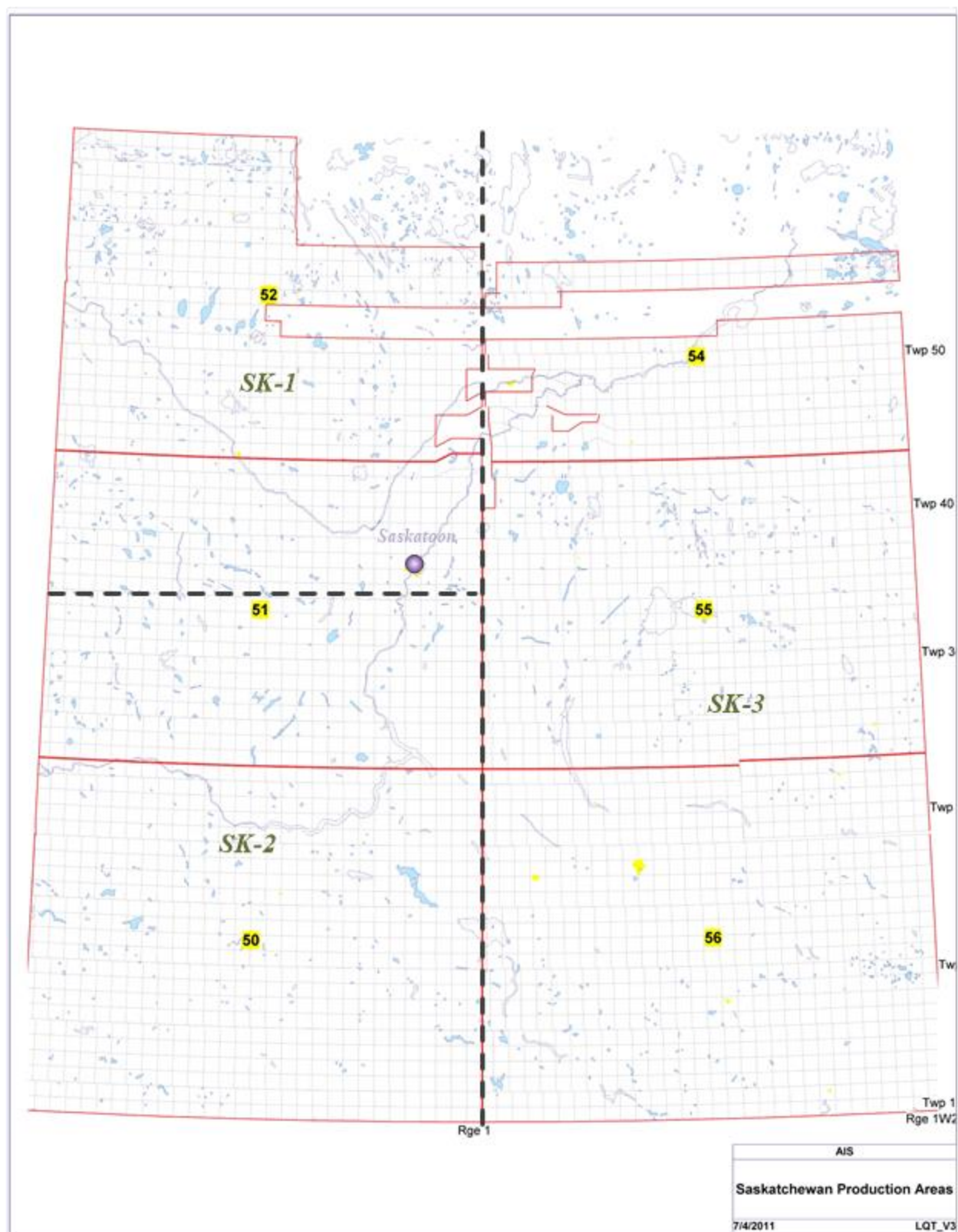


Figure D.4: Map of Manitoba Study Areas

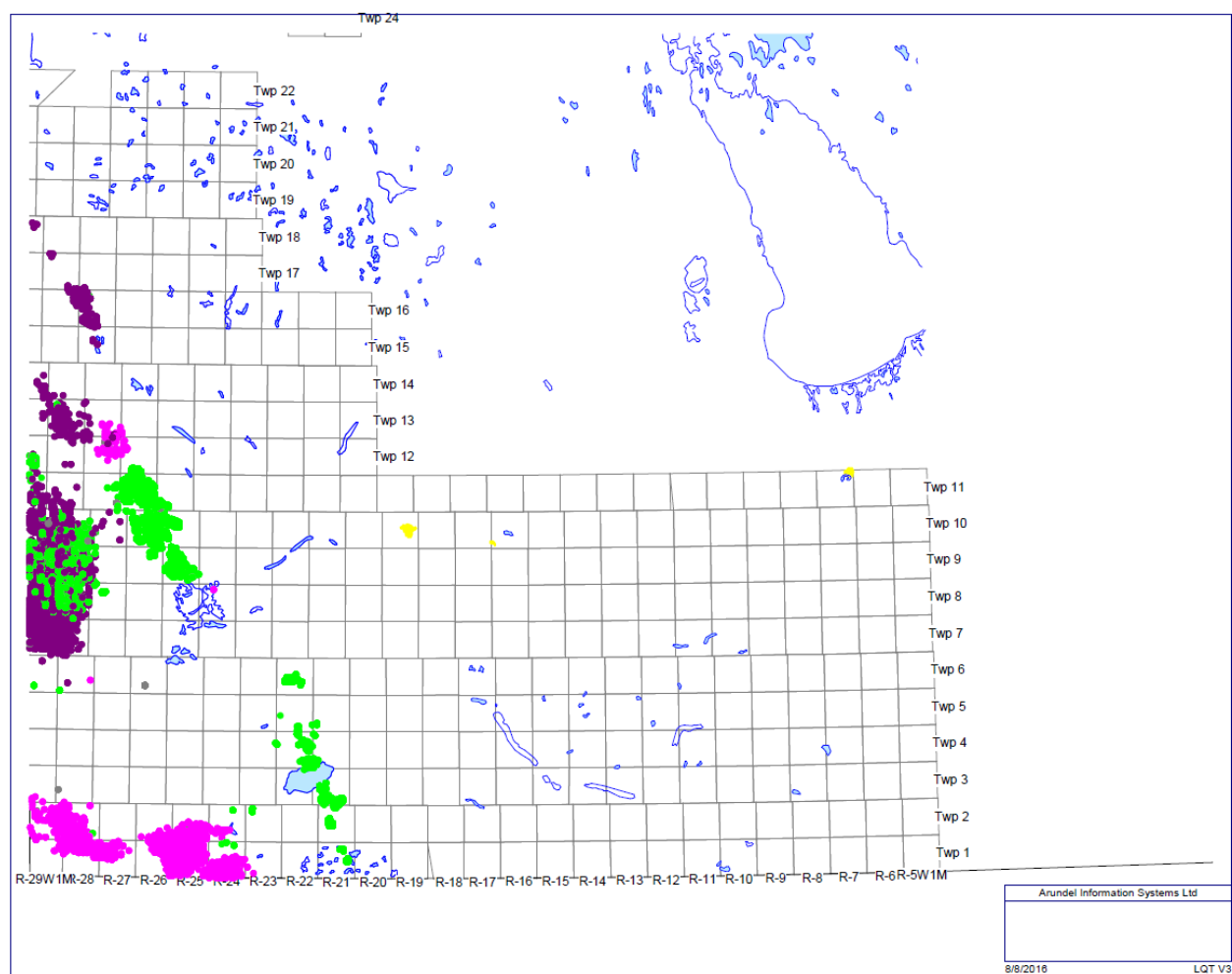
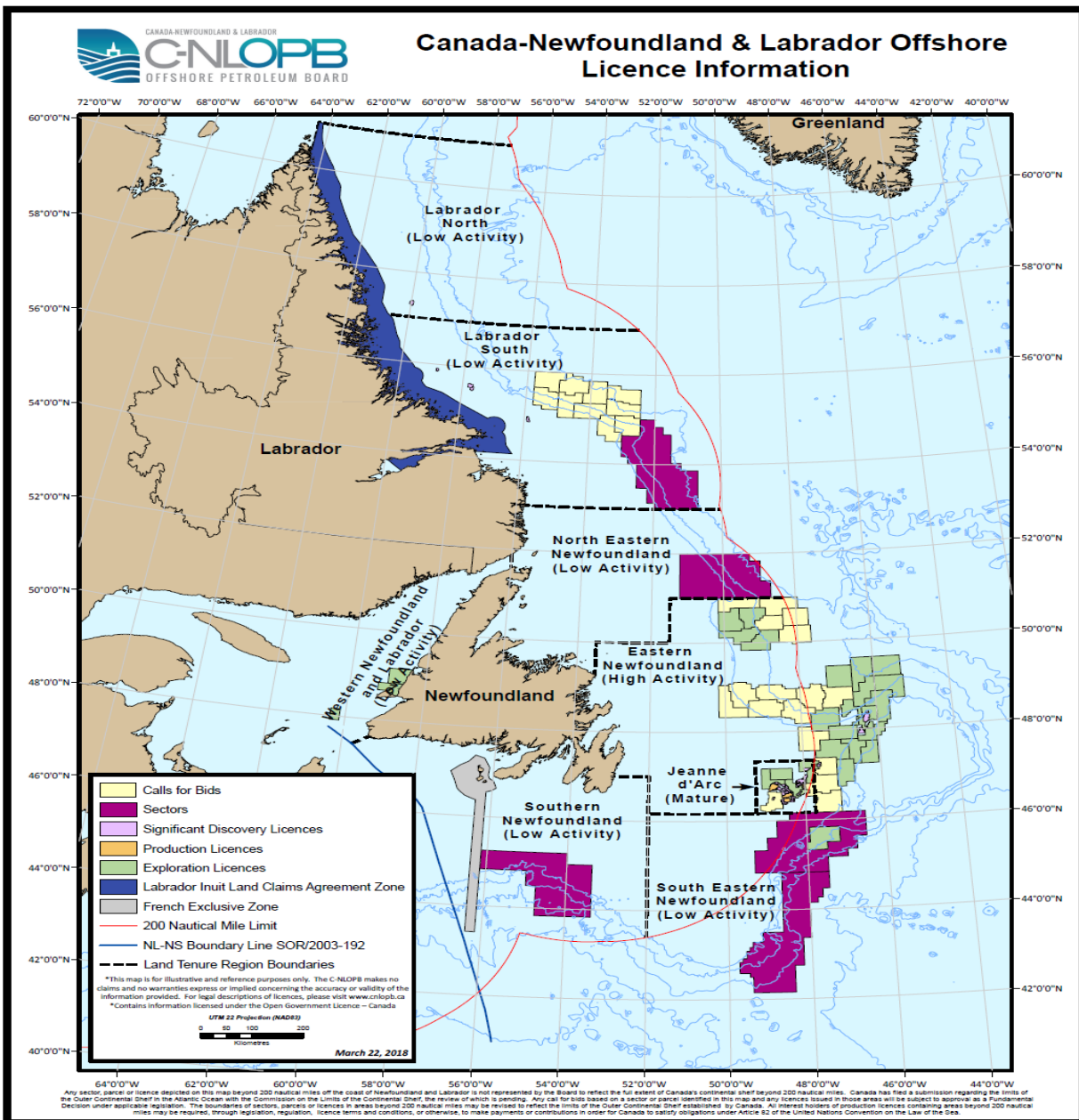


Figure D.5: Map of Newfoundland and Labrador Study Areas*



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

Source: CNLOPB

Core Funders:



Donors:



In-kind:

