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WESTERN CANADA NATURAL GAS FORECASTS AND IMPACTS (2015-2035)

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Western Canada Natural Gas Forecasts and Impacts (2015-2035)

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Table of Contents

List of Figures

List of Tables

Executive Summary

In 2008, the oil and gas industry in Western Canada brought 10,153 new gas wells on stream. This included conventional gas wells in Alberta (7,513), British Columbia (737) and Saskatchewan (1,152). In addition, 751 coalbed methane wells were brought on stream in Alberta. With respect to these wells, less than 10 percent of the Alberta wells drilled were considered a horizontal well, in Saskatchewan it was less than 2 percent, while in British Columbia the number was closer to 35 percent. The annual average market price for natural gas at Alberta's market hub (AECO-C) was CDN$7.50/mmbtu.

Since that time, the natural gas industry has been challenged, first by the global recession in 2009, then by the weak recovery in the gas market following the recession and finally by the extraordinary ramp-up in production from the Marcellus shale in the US. Shale plays, with the Marcellus being the largest, have been made economic as a result of the innovations in horizontal drilling and multi-stage hydraulic fracking. Growing from a volume of less than 1,000 mmcf/day in 2008, the Marcellus surpassed the 14,000 mmcf/day level in 2014 and the current trend suggests it will surpass 30,000 mmcf/day within the next 10 years.

The road forward for the Canadian gas industry is partially linked to the success or failure of LNG liquefaction developments in North America and this linkage has two views. First, from a Canadian perspective looking at the US, the hope that building the LNG liquefaction projects in the Gulf of Mexico or the eastern seaboard or even the east coast of Canada will pull some of the Marcellus gas supply away from the mid-continent and west coast markets, thus allowing Canadian natural gas to continue delivering to those markets. Second, from a Western Canadian perspective looking inward, the wish to build the British Columbia LNG liquefaction projects as a means of sending Canadian gas (as LNG) to the global markets.

In addition, the reality that the Marcellus gas supply will continue to enter the Ontario and Quebec markets thus backing out western Canada gas from those markets. The reality is that the long history of the TransCanada mainline and the Great Lakes Gas Transmission pipelines delivering gas to the Eastern Canadian and US eastern seaboard markets (New York) has been declining in recent years and it appears that that will continue to do so in the future.

The purpose of this report is to update the work done for the 2013 CERI report ("North American Natural Gas Pathways") [1] including an update to the North American natural gas supply/demand base case and update to the LNG assumptions for the United States and Canada. This will be the basis for forecasting the future for the Western Canadian gas industry and in determining the

[1] CERI Study 138, North American Natural Gas Pathways, http://ceri.ca/index.php?option=com_content&view=article&id=55&Itemid=59, August 2013

economic impacts that this industry conveys to the provinces and to the Canadian national economy.

The US supply/demand forecast as presented in Figure 1.1, as part of the North American gas market, includes the following LNG assumptions:

- 13 bcf/day of LNG exports from the Gulf of Mexico
- 4.8 bcf/day of LNG exports from British Columbia, Canada
- 1 bcf/day of LNG exports from Cove Point, Maryland
- 2 bcf/day of LNG exports from Atlantic Canada

This analysis forecasts annual volumes over 2015-2035 and the requirement for the export pipelines emanating from western Canada (Gas Transmission Northwest, Northern Border, Alliance, Spectra BC, and TransCanada mainline) as part of the North American supply/demand balance. These export volumes were then added to the western Canada domestic demand (including field processing recoveries, transmission fuel, straddle plant recoveries and LNG exports from British Columbia) to determine the western Canada total demand.

The analysis is based on determining the number of annual new gas wells that would be required to balance western Canada supply and demand. A cost estimate for these new gas wells along with the expected future revenues from total production, including natural gas liquids was injected into CERI's economic input/output model to determine the economic impacts of these natural gas developments. If the BC LNG projects are not constructed then the export volumes from British Columbia to Alberta will increase after 2017 resulting in a decline in Alberta new well connections for several years.

Table E.1 illustrates some of the economic impacts as a result of new natural gas developments in Western Canada. These economic impacts are upstream gas developments and do not include the economic impacts of constructing and operating the proposed LNG facilities on the west coast of British Columbia. Although the capital investment for Alberta and British Columbia is very similar, the disparity in GDP impacts is a direct result of the existing infrastructure (wells) that exist in the two provinces for the base year. In 2014, Alberta had 102,670 operating gas wells producing 10 bcf/day while British Columbia had 8,701 operating gas wells producing 4 bcf/day. Saskatchewan at the same time had 18,260 operating gas wells producing 0.15 bcf/day. The revenues from these operating gas wells pays for the fixed and variable operating costs, royalties, taxes, head office expenses and other expenses, all of which contributes to the GDP per province, and for gas developments more so in Alberta.

Table E.1: Summary of Economic Impacts from Natural Gas Developments in Western Canada, 2015-2035 (Billion CDN$)

	AB	BC	SK	Total
Capital investment in the drilling, completing and connection of new gas wells	225.8	228.1	0.5	454.4
Revenues from natural gas domestic sales, export sales and natural gas liquids sales	1,032.00	391.1	5.9	1,429.0
Total Canadian GDP impacts	1,630.0	643.0	4.0	2,277.0
Federal Government tax revenues	186.2	63.8	0.37	250.4
Provincial Government tax revenues	114.1	40.1	0.21	154.4

Source: CERI

Chapter 1: Introduction

In 2013, the Canadian Energy Research Institute (CERI) undertook a study to detail the future of the North American gas market as played out in four equally plausible narratives. The four narratives depicted the influence of high/low natural gas usage for power generation, and high/low liquefied natural gas (LNG) export scenarios for both the United States (US) and Canada. These four scenarios were the subject matter for the CERI report titled "North American Natural Gas Pathways" published in August 2013.[2] The names assigned to these four distinctive and equally plausible narratives were "Power Wave" (high power generation, low LNG exports), "Full Speed Ahead" (high power generation, high LNG exports), "Nowhere Fast" (low power generation, low LNG exports), and "LNG Tsunami" (low power generation, high LNG exports).

The purpose of this report is to update the North American supply/demand base case and to restate the LNG assumptions for forecasting natural gas developments in Western Canada to meet Canadian domestic demand, export volumes to the United States and export volumes to Canadian LNG terminals. In addition, this report will estimate the economic impacts associated with natural gas developments in Western Canada. Natural gas developments will be detailed as capital requirements for new natural gas wells coupled with production revenues from all production,(including natural gas and natural gas liquids from existing and new gas wells) and the economic impacts associated with this industry in terms of GDP growth, employment and industry taxes (excluding royalties) for the period 2015 to 2035.

For the North American analysis, CERI collaborated with ICF International to update the 2013 Natural Gas Pathways base case and generate three LNG scenarios utilizing ICF's Gas Market Model. ICF International's Gas Market Model (GMM®) is a general equilibrium model representation of gas markets throughout the US and Canada, with Mexican gas production and consumption currently modeled at four border crossing points. The model simulates North American gas markets on a monthly basis, solving for gas demand, production, LNG exports and imports, storage activity, and prices within 119 market areas, or "nodes", and pipeline flows on 350 pipeline corridors. The model sequentially solves one month after the next, optimizing each month's solution but does not inter-temporally optimize across months or years; this approach avoids "over-optimizing" gas storage and production response. GMM® is calibrated by "back casting" recent historical market activity. GMM® is used to evaluate the marginal value of natural gas prices at different market centers under base case and alternative scenarios developed by ICF or in collaboration with clients; inter-regional flow volumes and the future value of pipeline capacity; and storage activity and value at different market centers.

For Western Canadian well developments, the CERI gas forecasting model was utilized. The linkage between these two models is the GMM calculated annual flow volume requirements on the Canadian export pipelines including Gas Transmission Northwest, Northern Border, Alliance,

[2] CERI Study 138, North American Natural Gas Pathways, http://ceri.ca/index.php?option=com_content&view=article&id=55&Itemid=59, August 2013

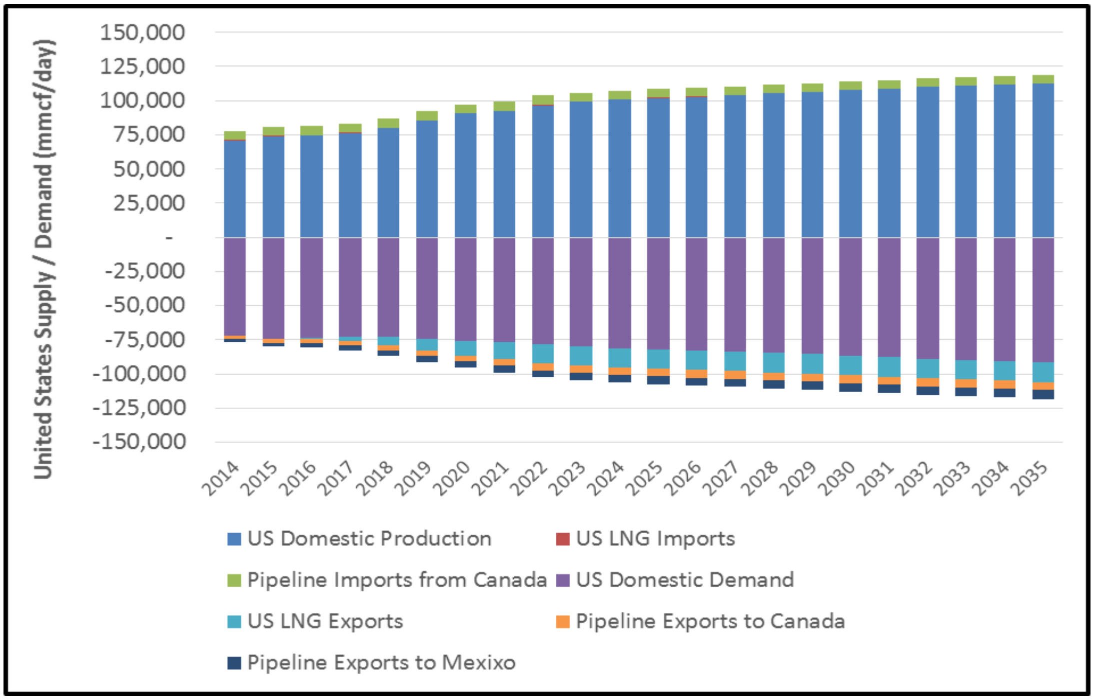
Spectra BC, Iroquois Pipeline, Great Lakes Gas Transmission and others. These export requirements are added to the western Canada domestic demand, eastern Canada net domestic demand (minus imports from the US) and BC LNG exports to equal the annual demand requirements. CERI's gas forecast model determines the number of wells required to balance supply and demand and estimates the region within the three western provinces where these wells could be drilled and determines the initial production rates and decline curve that could be anticipated from these wells in the future. Revenues to producers for natural gas production, liquids recovered and Sulphur recovered are also estimated. Capital costs, operating costs, operating revenues and other elements are used to ascertain the economic impacts of the natural gas industry for the period 2015 to 2035.

Figure 1.1 details the United States supply/demand balance, as part of the North American gas market forecast, based on the ICF GMM® base model (Q4 2014) including the following LNG assumptions:

- 13 bcf/day of LNG exports from the Gulf of Mexico
- 4.8 bcf/day of LNG exports from British Columbia, Canada
- 1 bcf/day of LNG exports from Cove Point, Maryland
- 2 bcf/day of LNG exports from Atlantic Canada

The inclusion of these LNG assumptions and the ICF base case (Q4-2014) determined the CERI LNG January 2015 North American case. Based on this view, the US domestic production is forecasted to grow from the current level of 71 bcf/day (25.9 tcf/year) to 112 bcf/day (41.2 tcf/year) by 2035. Led by the Marcellus developments, this growth equates to 43 percent growth in domestic supply over the next 12 years. The total US supply is augmented by pipeline imports from Canada that will continue to decline from the current 7.2 bcf/day to 6.2 bcf/day by 2025 and remain at that level to the end of the forecast. Pipeline imports of US natural gas into eastern Canada will grow from the current level of 2.6 bcf/day to 6.0 bcf/day by the end of the forecast. Canada will remain a "net" pipeline exporter (exports to US minus imports from the US into Canada) for the duration of the forecast albeit by less than 0.5 bcf/day by the end of the forecast. Ontario, Quebec and Atlantic Canada imports of natural gas from the US will expand from 2.6 bcf/day to 6.1 bcf/day over the next 12 years, which effectively backs western Canada gas out of these markets. Part of this increase in demand is the assumption that 2 bcf/day of LNG exports will be developed in Atlantic Canada. While US domestic demand displays minimal growth, from 71.7 bcf/day to 81.6 bcf/day, exports to Mexico, exports of LNG to global markets and pipeline exports to Canada, in total, show a growth from 4.5 bcf/day to 25.7 bcf/day over 12 years.

Figure 1.1: United States Supply/Demand Balance (2014-2035)

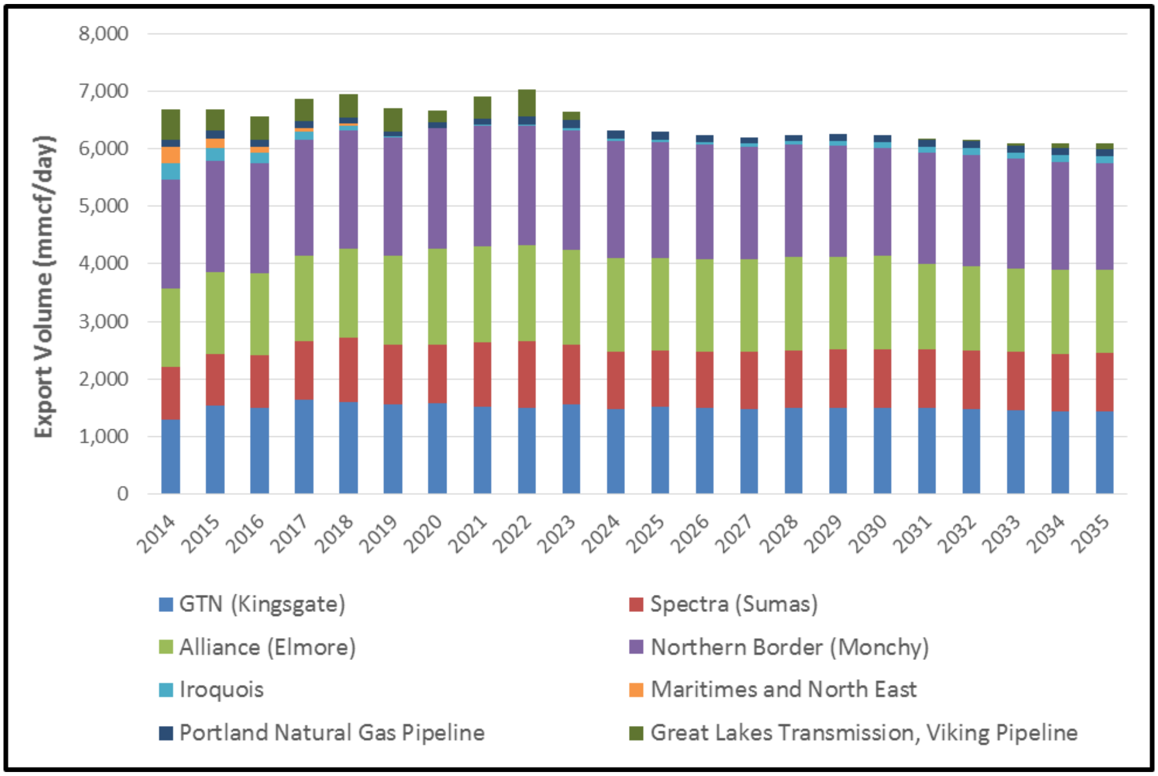


Source: ICF International, CERI

Examining the Canadian export pipelines to the US (see Figure 1.2), by 2025 the export flows on three pipelines will have effectively declined to zero. Included are the Iroquois Pipeline, the Maritimes and Northeast pipeline and Great Lakes Gas Transmission Pipeline. The Maritimes and Northeast pipeline will be reversed to bring US gas into Atlantic Canada for domestic use and LNG exports while the Iroquois pipeline will be reversed to bring US gas into the Ontario and Quebec markets. Flows on the Great Lakes Gas Transmission will be reduced to supplying local demand in Wisconsin and upper Michigan peninsula.

This study assumes that pipelines will be constructed or pipeline connections will be developed to bring Marcellus gas to the Dracut, Massachusetts area in order to connect with the Maritimes and North East pipeline for deliveries to New Brunswick and Nova Scotia.

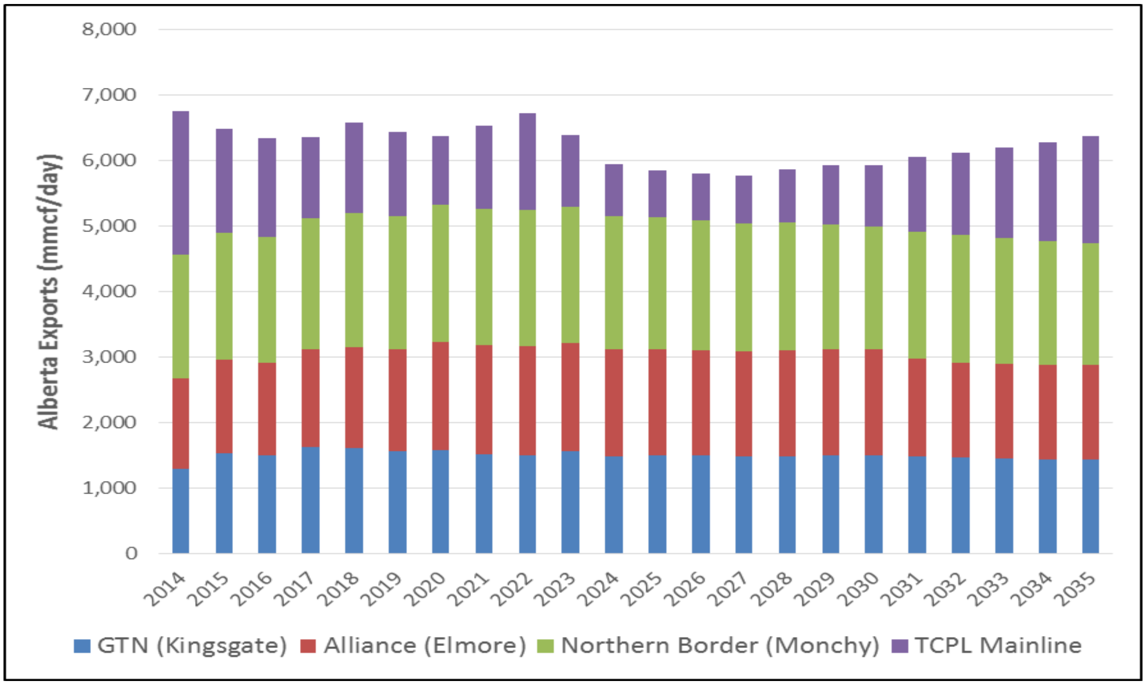
Figure 1.2: Export Pipelines to the United States (2014-2035)



Source: ICF International, CERI

Flows on the major export pipelines between Alberta and the US will display a slight increase, over the period 2014 to 2025, of 0.6 bcf/day for the 3 pipelines before declining by the same amount by the end of the forecast in 2035 (see Figure 1.3). This is a reflection of Marcellus supply volumes being channeled away from the mid-continent markets (Illinois) in favour of the exports to Ontario/Quebec and LNG projects in the Gulf of Mexico, US east coast and Atlantic Canada. Marcellus natural gas entering Ontario and Quebec in increasing quantities coupled with a decline on volumes on the TCPL mainline and Great Lakes Gas Transmission contribute to a reduction in Western Canada drilling activity.

Figure 1.3: Alberta Export Pipelines (2014-2035)

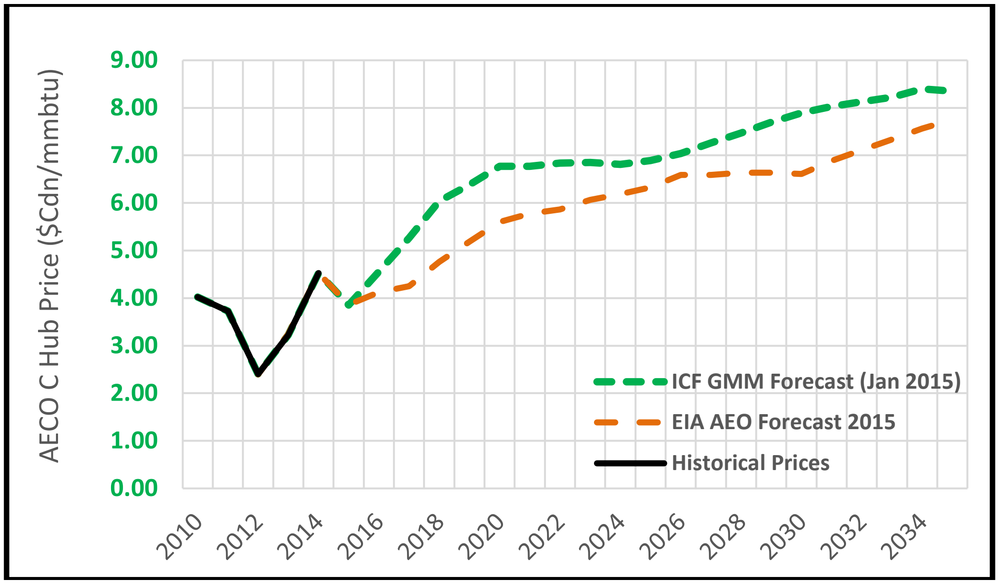


Source: ICF International, CERI

Figure 1.4 illustrates the AECO-C/NIT market price used as a starting point for determining the producer revenue streams from natural gas production, and associated natural gas liquids, in western Canada. This price forecast is an output from the ICF International GMM® model (previously described) which was utilized in this study to determine the supply/demand balance for North America in general and the US in particular. The ICF model performs a monthly supply/demand and associated market hub price balance calculation, utilizing input basin supply costs, pipeline transportation tolls and regional market demand estimates. Figure 1.4, details the gas price forecast for the AECO "C" pricing hub. The natural gas price forecast from the Annual Energy Outlook (2015) report from the Energy Information Administration of the US Government is also detailed on Figure 1.4 for comparative reasons. Both curves have been converted to Canadian dollars per million BTU ($CDN/mmbtu).

The following chapters detail the drilling profile, capital requirements, revenues and economic impacts for Alberta, British Columbia and Saskatchewan. Each province depicts a different story; Alberta facing reduced exports and increasing oil sands domestic demand, British Columbia eyeing the potential for LNG exports coupled with upstream developments, and Saskatchewan facing declining activity because of a depleting resource basin and uneconomic developments at current gas prices.

Figure 1.4: Alberta AECO-C/NIT Market Price Forecast (2014-2035)



Source: ICF International, CERI, EIA

Chapter 2: Economic Impacts of Natural Gas Developments – Alberta

This chapter examines the natural gas forecast and associated economic impacts of natural gas developments, including both existing and future drilling activity within the province of Alberta over the period 2015 to 2035. This analysis covers conventional, shale and tight gas activity, with or without natural gas liquids present and using vertical and horizontal wells.

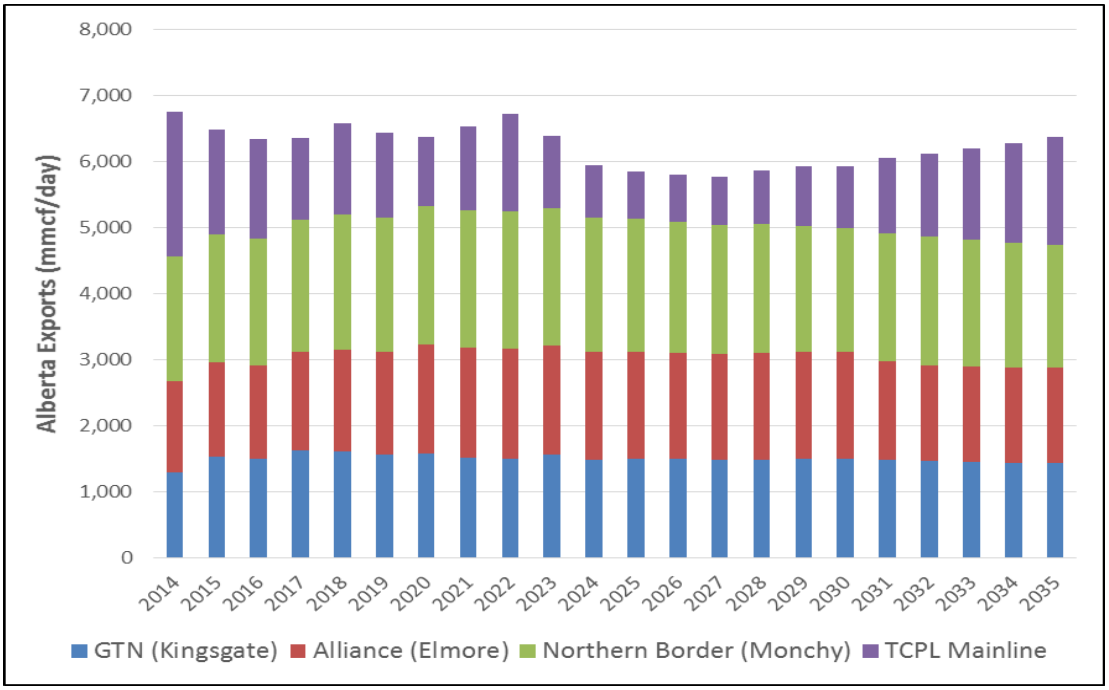
As was described in the introduction, the linkage between Alberta and the larger North American market is the export pipelines that connect Alberta to California, Alberta to Illinois, Alberta to the US eastern seaboard and Alberta to eastern Canada. These linkages and the calculated annual flow volumes on each export pipeline, as determined by ICF's GMM®, is added to the domestic demand for natural gas from within Alberta and the import volumes from British Columbia which together determine the annual supply/demand balance for Alberta.

Figure 2.1 illustrates the forecast of export volumes for the four major export pipelines leaving Alberta: the Gas Transmission Northwest Pipeline (GTN) to California, the Alliance Pipeline (Alliance) to Illinois, the Northern Border Pipeline (NBPL) to Illinois, and the TransCanada Mainline (TCPL Mainline) connecting Alberta to eastern Canada and the US eastern seaboard. The results from the GMM January 2015 forecast for North American Supply/Demand Update[1], would suggest that for the length of the forecast, the annual average flows for the GTN pipeline will stabilize at the 1,500 mmcf/day level, NBPL will experience flow levels varying between 1,900 and 2,100 mmcf/day, and Alliance will grow slightly from 1,400 to 1,650 mmcf/day. However, the real story surrounds the TCPL Mainline, which is forecasted to continue its decline that started in 2010 and averaging 1,600 mmcf/day in 2015, heading to 600 mmcf/day by 2025 before experiencing a recovery back to the 1,500 level by the end of the forecast.

Figure 2.2 illustrates that the future demand for natural gas will change from a 50:50 split between export volumes and internal use volumes (residential, commercial, industrial, pipeline fuel and losses and straddle plant shrinkage) to a 60:40 split because of declining exports and increasing internal demand. Figure 2.3 details the breakdown of the elements that define the annual Alberta supply/demand relationship. As it relates to this figure, imports from British Columbia (discussed in Chapter 3) are added to the Alberta-sourced supply and Alberta supplies are considered as wellhead volumes from which liquids are extracted in the field and at the straddle plant locations (shrinkage). Transmission fuel and losses is considered field processing, gas plant fuels and transmission fuels.

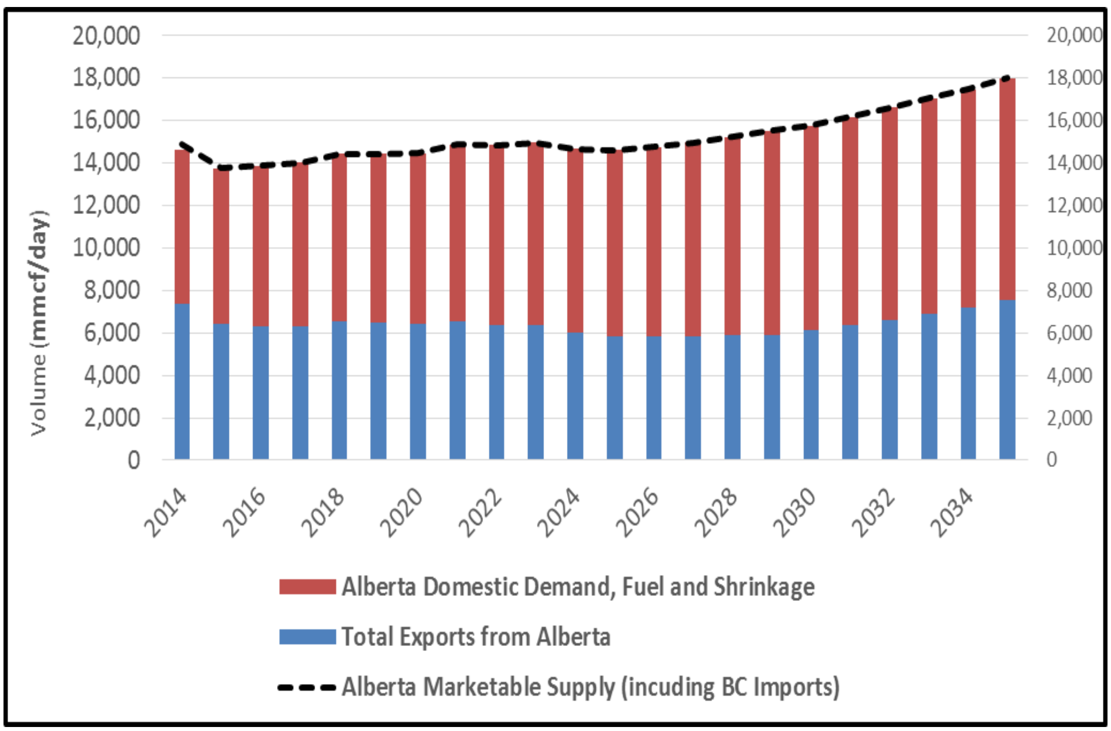
[1] CERI/ICF North American Supply/Demand Update, January 2015

Figure 2.1: Alberta Exports to the United States and Eastern Canada (2014-2035)



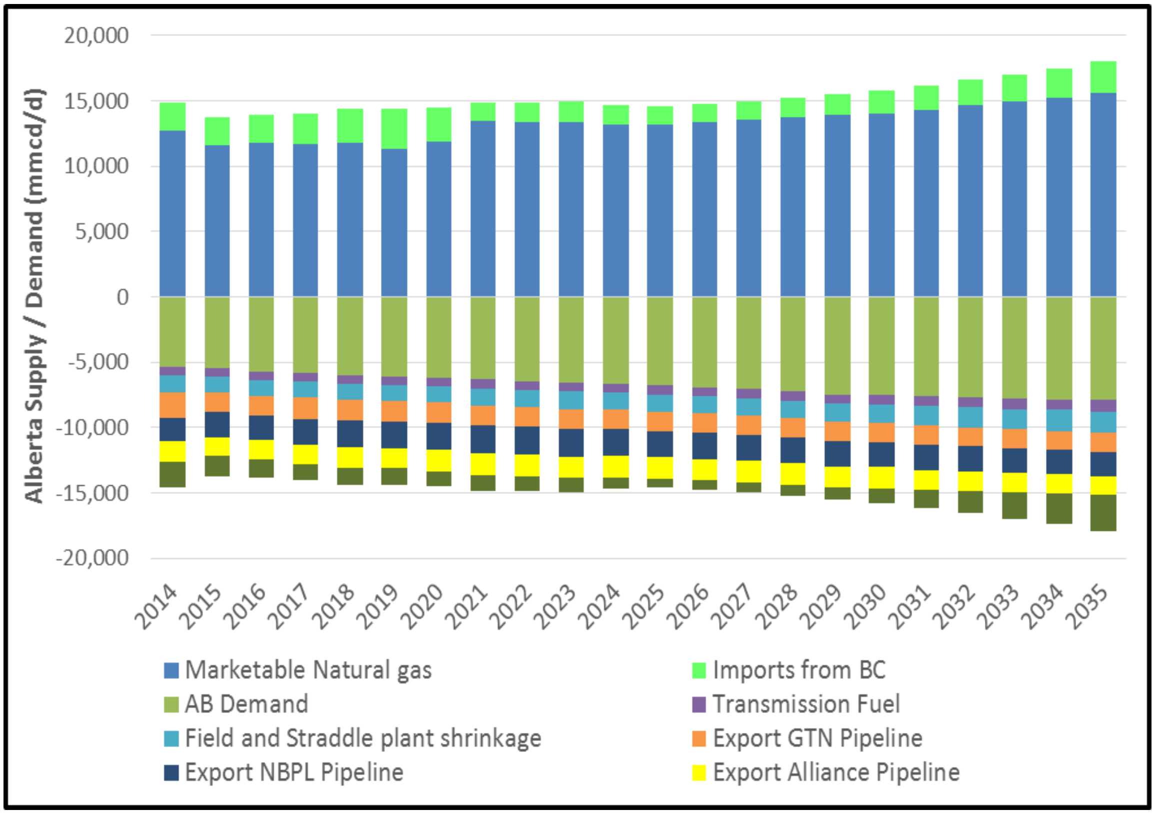
Source: ICF International, CERI

Figure 2.2: Alberta Natural Gas Exports and Internal Requirements (2014-2035)



Source: AER, NEB, CERI

Figure 2.3: Alberta Supply/Demand (2014-2035)

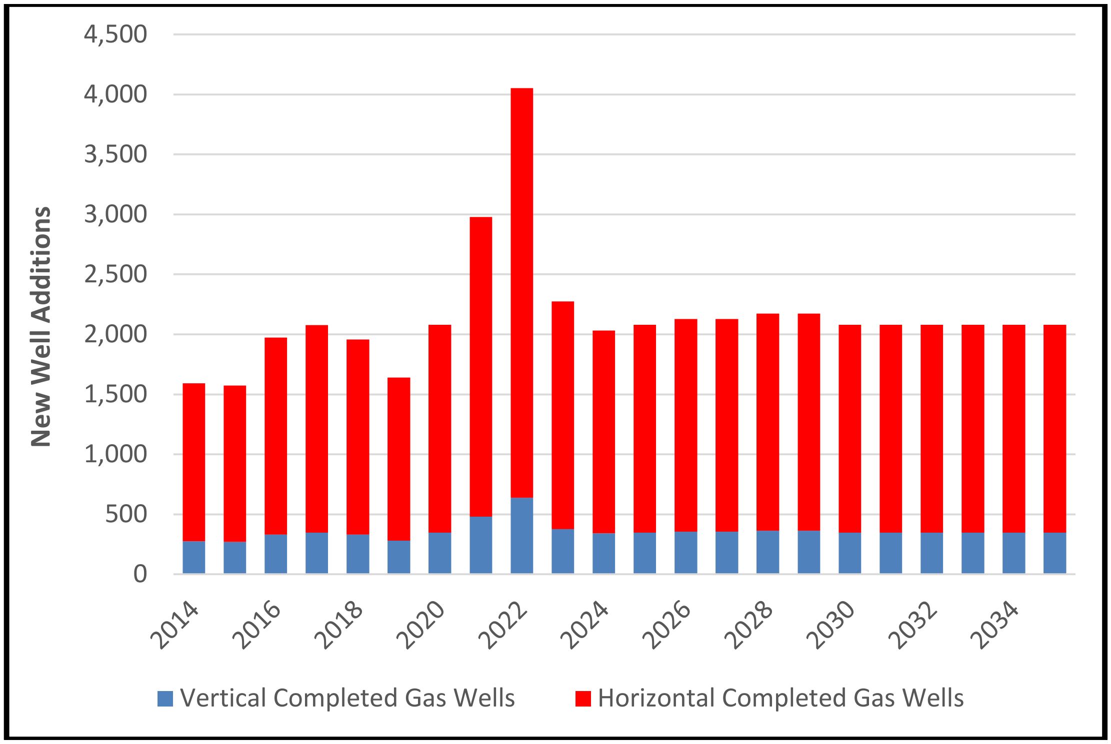


Source: AER, NEB, CERI

In order to meet this increase in demand, the CERI natural gas forecast model (described in Appendix A) is used to determine the number of wells required to be drilled and connected each year and the area of the province where these wells will be drilled.

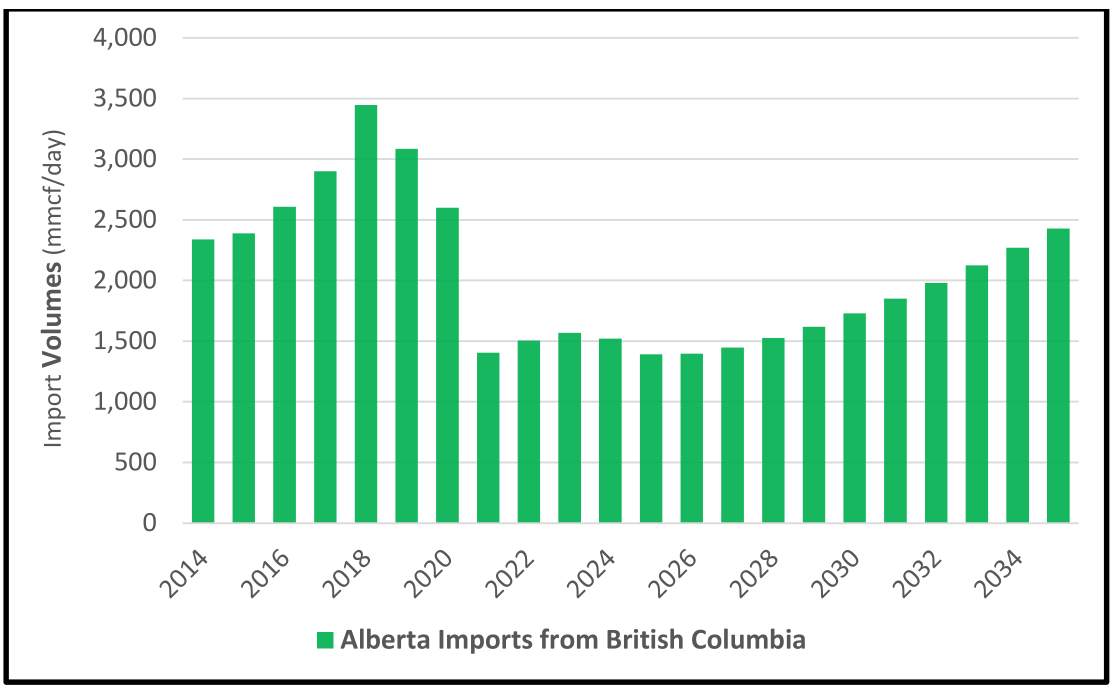
The forecast of annual new well requirements is demonstrated in Figure 2.4. The rise in new wells between 2020 and 2022 is a response to the assumed staggered startup of LNG liquefaction operations at Kitimat and Prince Rupert, British Columbia. Gas from northeastern British Columbia will be used as feedstock to the LNG plants, which temporarily reduces the imports of gas into Alberta until the BC well activity catches up resulting in Alberta new well activity returning to the trend line in 2023/24. The assumption used in the model reflects a new LNG plant coming online in each of the years 2019, 2020 and 2021. The model also accounts for a two year build up to full capacity for each plant. Figure 2.5 illustrates the effect on Alberta import volumes because of the ramp-up in LNG facilities. Two of the LNG plants will be directly connected by pipeline from northeastern British Columbia field operations to Kitimat and Prince Rupert. The third LNG plant is assumed to buy feedstock supply directly from the BC transmission system for delivery to the coast. The CERI model assumes that a number of BC wells will send natural gas into Alberta prior to the startup of the LNG plants but will be redirected to the BC coast after startup of the LNG facilities. These are the reasons for the drop in import volumes from British Columbia, which must be made up by Alberta drilling efforts.

Figure 2.4: Alberta New Well Additions (2014-2035)



Source: AER, CERI

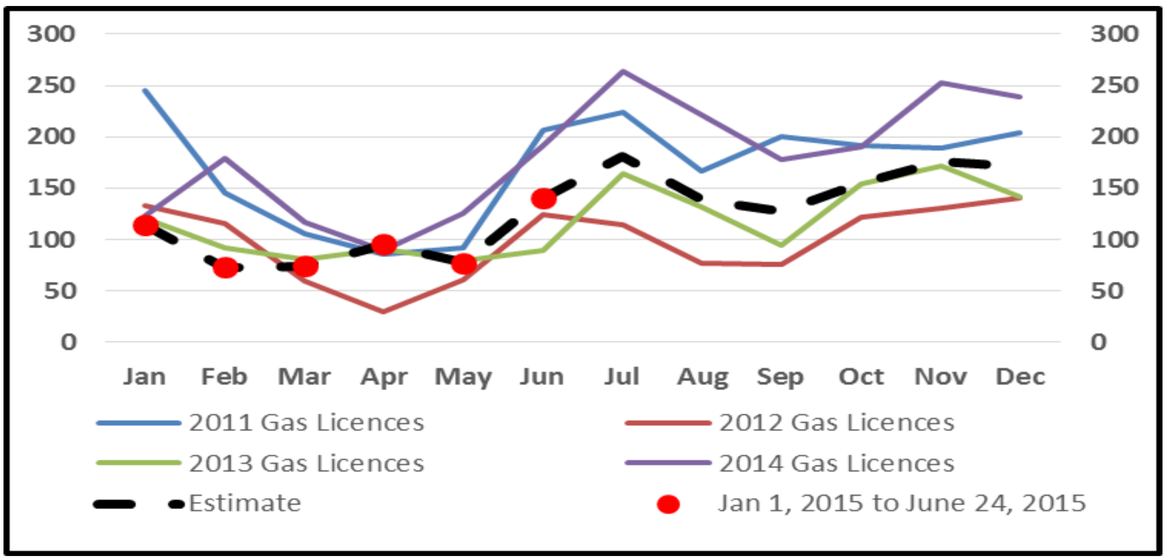
Figure 2.5: Alberta Import Volumes (2014-2035)



Source: CERI

Figure 2.6 details the historical monthly new gas well licenses issued by the Alberta Energy Regulator (AER) for the years 2011 to 2014 along with the first 6 months of 2015 gas licenses (shown as red dots). The dashed line is a curve fit representation of the first 6 months of 2015 and an extrapolation to the end of the year using an average historical trend. This extrapolation suggests that the oil and gas industry will license 1,575 Alberta wells for 2015. By comparison, the CERI gas forecast model, which utilizes newly connected wells, determined that, for Alberta, 1,500 wells would be required to balance western Canada supply and demand for 2015. This demonstrates the calibration of the CERI gas forecast model as, in reality, not all licensed wells are brought on line in the year of licensing. Year-end timing of infrastructure (pipeline connection) or failure of the company to actually drill a well accounts for a reduction of approximately 5 percent of annual well licenses.

Figure 2.6: Alberta New Well Licenses (2011-2014)

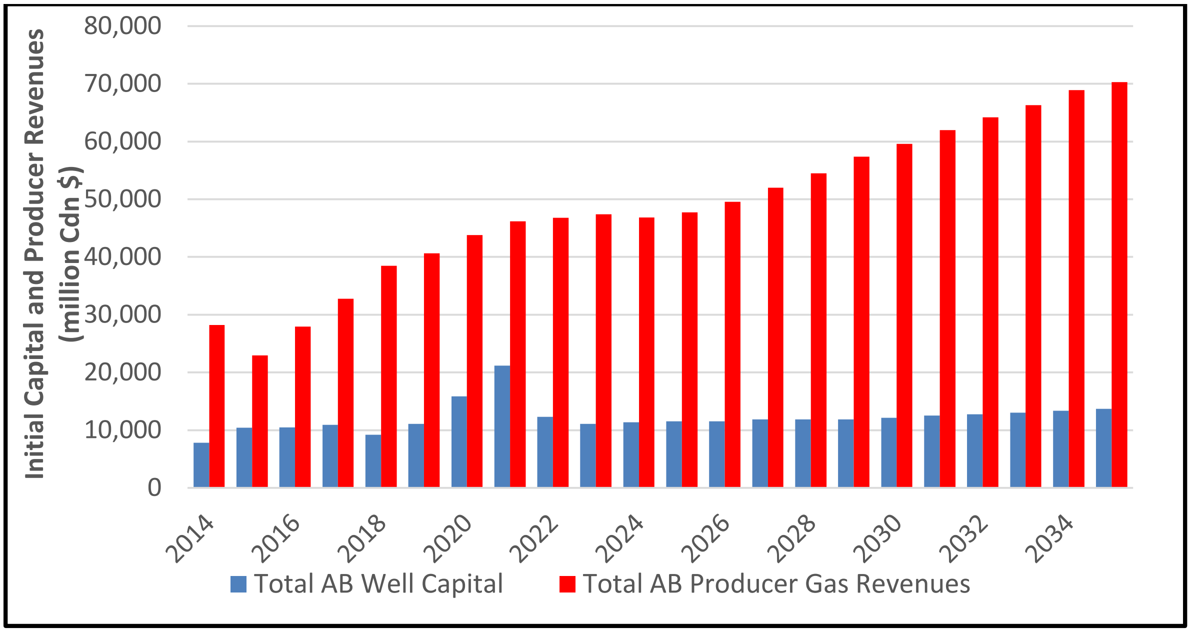


Source: AER, CERI

In order to determine the cost of the drilling activity outlined in Figure 2.7 (blue bars), CERI makes use of the information contained in the 2015 Well Cost Study (winter 2015 costs) from the Petroleum Services Association of Canada. Reference wells are assigned to each area and formation under study and the well cost is calibrated to the average drill depth using true vertical depth for a vertical well and total drill depth for a horizontal well. A provision for connection infrastructure costs plus geological and geophysical costs are added to the well capital cost as represented by the blue bars in Figure 2.7.

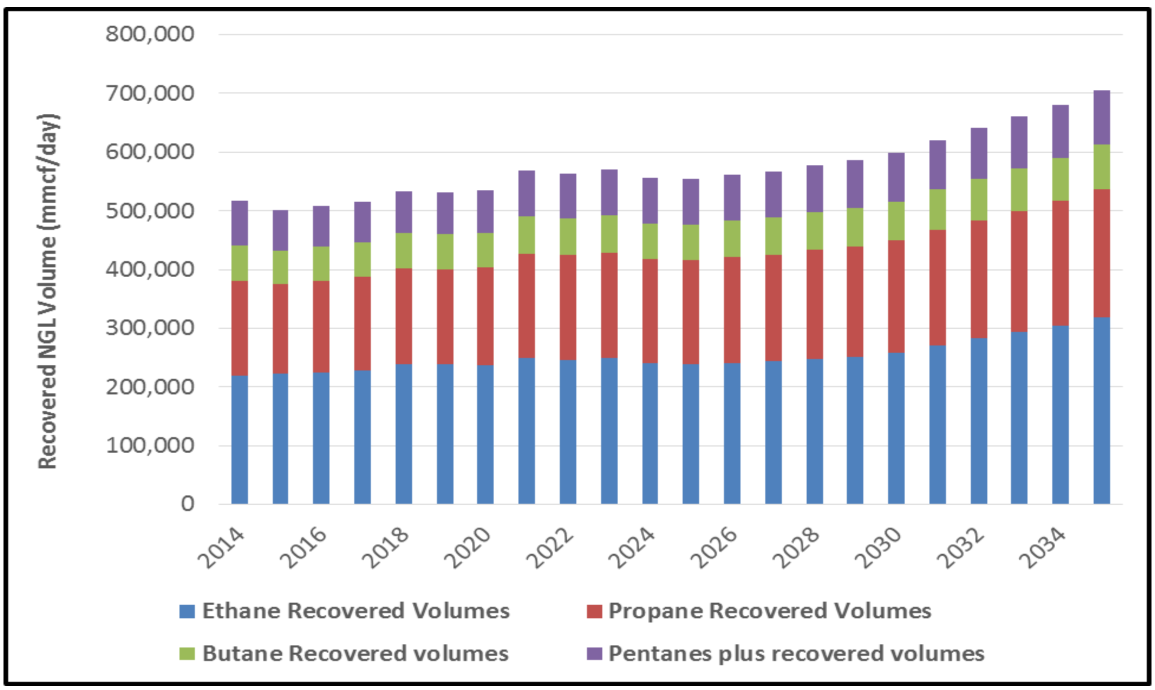
Each producing area and formation is connected to a reserves weighted average component structure and modeled as to the type of field plant operation (shallow or deep cut). The marketable gas (exit of the area plant) is connected to a nodal representation of the NOVA/ATCO transmission systems so that straddle plant recoveries can be determined. The total of field plant recovered NGLs (spec product or mix steam) and the straddle plant recoveries are represented in Figure 2.8. These NGL components along with the natural gas streams are used to calculate the gross producer revenue (wellhead) and are represented as the red bars in Figure 2.7. A complete description of this process is detailed in Appendix A.

Figure 2.7: New Well Capital Cost and Annual Producer Revenues (2014-2035)



Source: ICF International, CERI

Figure 2.8: NGL Recoveries by Field Plants and Straddle Plants (2014-2035)



Source: ICF International, CERI

Figure 2.7 illustrates that the capital investment in new gas wells will grow from CDN$10 billion in 2015, peaking at CDN$21 billion in 2021 and ending at CDN$14 billion in 2035. In contrast, the producer revenues as a result of production from new and existing gas wells, is expected to grow from CDN$18 billion in 2015 to CDN$70 billion in 2035. Part of this growth can be attributed to the increasing gas price (real) and part is a result of producers developing liquids rich resources resulting in an uptick in NGL revenues in the future.

Tables 2.1 and 2.2 and Figures 2.9 and 2.10 demonstrate the economic impacts derived from natural gas developments.

- Capital investments in the development of new gas wells in Alberta will total CDN$225.8 billion or average CDN$10.7 billion per year.
- Revenues from natural gas domestic sales, export sales and natural gas liquids recovery will total CDN$1,032 billion or average CDN$49.1 billion per year.
- Total Canadian GDP impacts are estimated at CDN$1,630 billion, 89 percent within the province of Alberta and 11 percent across the other provinces and territories (Table 2.1).
- Taxes directed to the Federal government will total CDN$186.2 billion and CDN$114.1 billion to the Provincial governments (Table 2.2).
- Employment (direct, indirect and induced) will grow from 195,000 jobs in 2015 to 491,000 by 2035 (Figures 2.9 and 2.10).

Table 2.1: Economic Impacts of Conventional and Unconventional Gas Developments in Alberta (2015-2035)

Investment and Operations	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	1,453,687	613,267	6,189
British Columbia	40,244	24,721	364
Manitoba	6,836	3,924	68
New Brunswick	2,061	1,156	21
Newfoundland/Labrador	946	433	7
Nova Scotia	1,624	1,006	17
Nunavut	146	104	2
Northwest Territories	326	202	3
Ontario	85,942	51,984	636
Prince Edward Island	140	81	2
Quebec	26,982	15,265	254
Saskatchewan	10,975	4,853	80
Yukon Territory	148	92	1
Total Canada	**1,630,056**	**717,089**	**7,643**

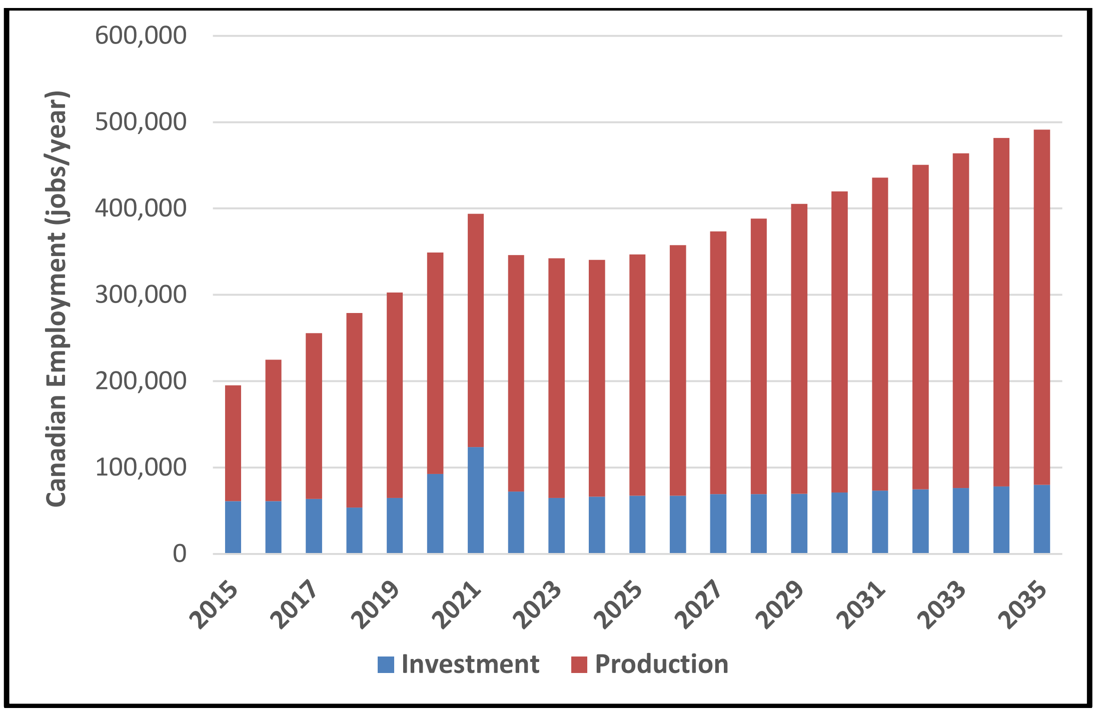
Source: CERI

Table 2.2: Tax Receipts Derived from Conventional and Unconventional Gas Developments in Alberta (2015-2035)

Investment and Operations	Federal Corporate $CAD Million	Federal Indirect $CAD Million	Federal Personal $CAD Million	Provincial Corporate $CAD Million	Provincial Indirect $CAD Million	Provincial Personal $CAD Million
Alberta	51,587	17,182	99,184	26,127	18,780	53,508
British Columbia	794	694	2,709	292	1,465	1,175
Manitoba	107	119	401	37	279	321
New Brunswick	31	29	122	14	69	93
Newfoundland/Labrador	19	11	48	26	24	34
Nova Scotia	28	27	105	15	51	88
Nunavut	2	2	8	0	1	3
Northwest Territories	7	7	14	4	8	6
Ontario	1,567	1,601	6,092	824	3,139	3,650
Prince Edward Island	2	3	8	1	7	7
Quebec	491	478	1,771	344	1,259	1,642
Saskatchewan	245	158	540	166	384	326
Yukon Territory	2	3	7	0	3	3
Total Canada	54,881	20,315	111,009	27,851	25,469	60,856

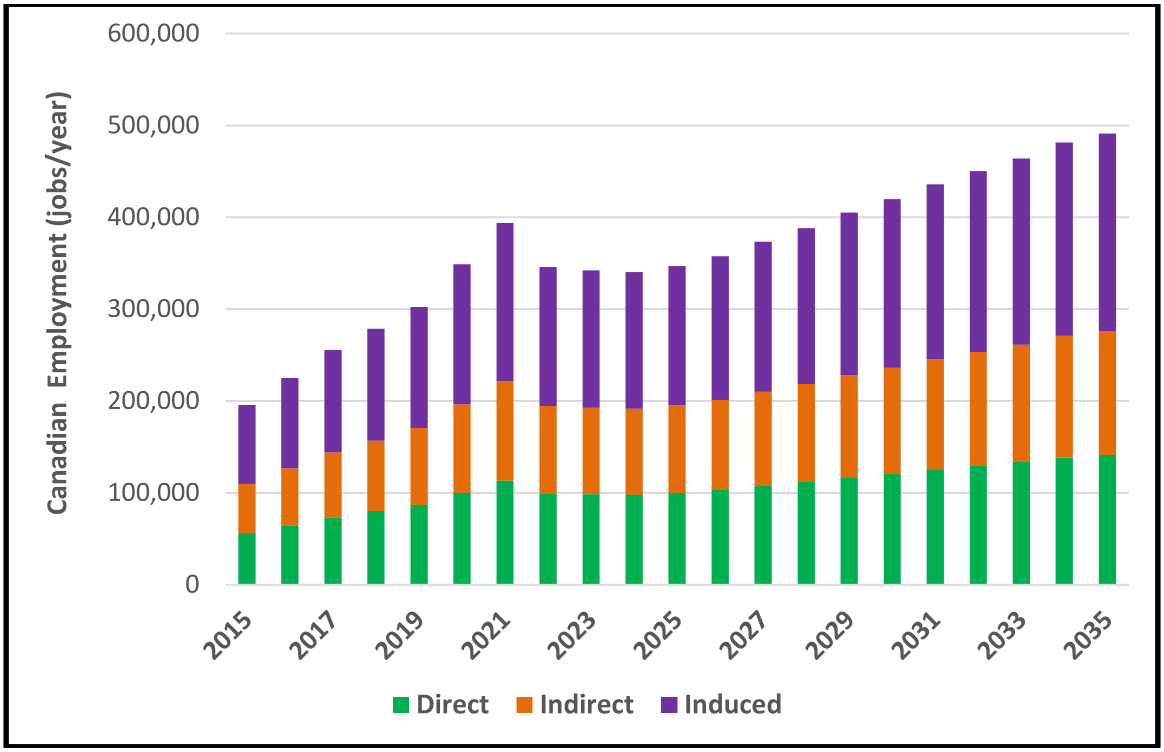
Source: CERI

Figure 2.9: Alberta Employment Impacts: Investment and Production (2015-2035)



Source: CERI

Figure 2.10: Alberta Employment Impacts: Direct, Indirect and Induced (2015-2035)



Source: CERI

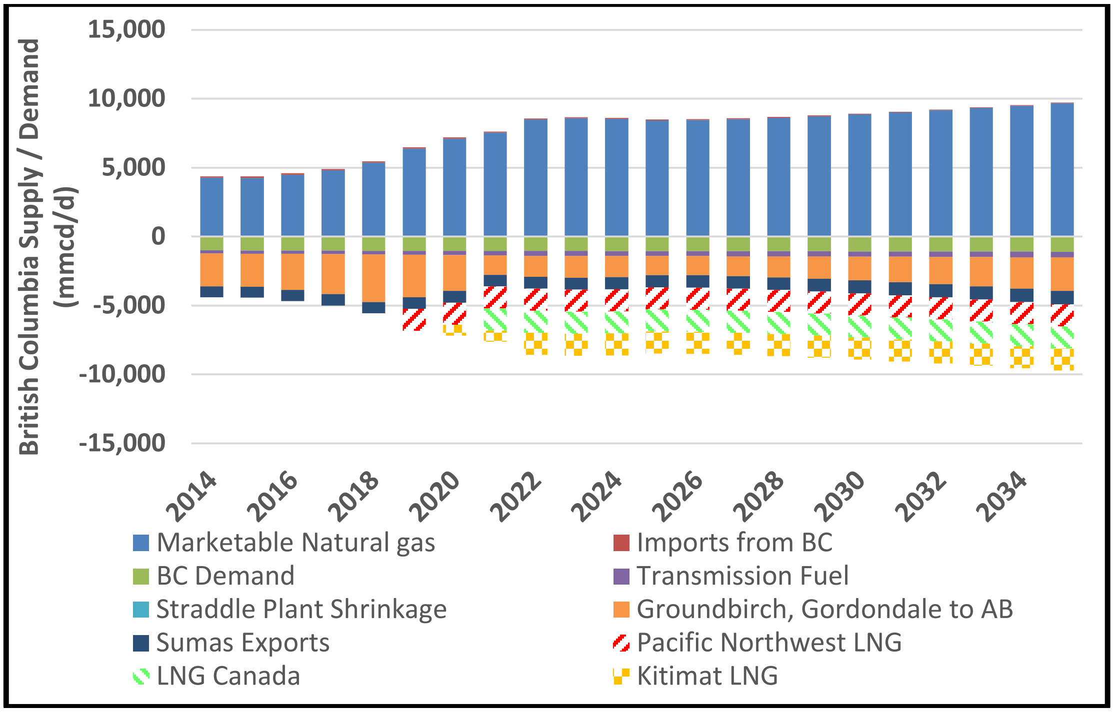
Chapter 3: Economic Impacts of Natural Gas Developments – British Columbia

This chapter details the natural gas forecast and associated economic impacts of natural gas developments, including both existing and future drilling activity within the province of British Columbia over the period 2015 to 2035. This analysis covers conventional, shale and tight gas reservoirs, with or without natural gas liquids present and using vertical and horizontal wells.

For the past three years, the Montney formation has been the focus of upstream developments for British Columbia. In fact, in excess of 84 percent of the newly licensed gas wells in British Columbia the period January 2012 to December 2013 have been to explore the Montney formation. CERI has determined that, on a supply cost basis, the Montney is ranked among the top shale gas deposits in North America from a productivity, NGL content and economic point of view. However, the industry fascination with the Montney formation is as much about its proximity to the proposed LNG terminals as it is to the resource potential metrics. As in the case of Alberta competing against the Marcellus for market share, northeastern British Columbia must compete against Alberta, and flow through Alberta, in order to access the larger US markets. Currently, natural gas from northeastern British Columbia has three demand points, the lower mainland (Vancouver), the I5 corridor in Washington State and connection to the TCPL/NOVA system via the Groundbirch/Gordondale laterals. Figure 3.1 suggests that the British Columbia domestic demand and the export to the US at Sumas (I5 corridor) will expand at the rate of about 15 mmcf/day/year. This is relatively small when compared to the proposed LNG projects that could see incremental growth of between 3,000 to 5,000 mmcf/day. With respect to this report, it has been assumed that three terminals will be constructed totaling 5,400 mmcf/day capacity operating at an annual average volume of 4,800 mmcf/day. The three terminals are indicated on Figure 3.1 as the red, green and yellow hatched bars.

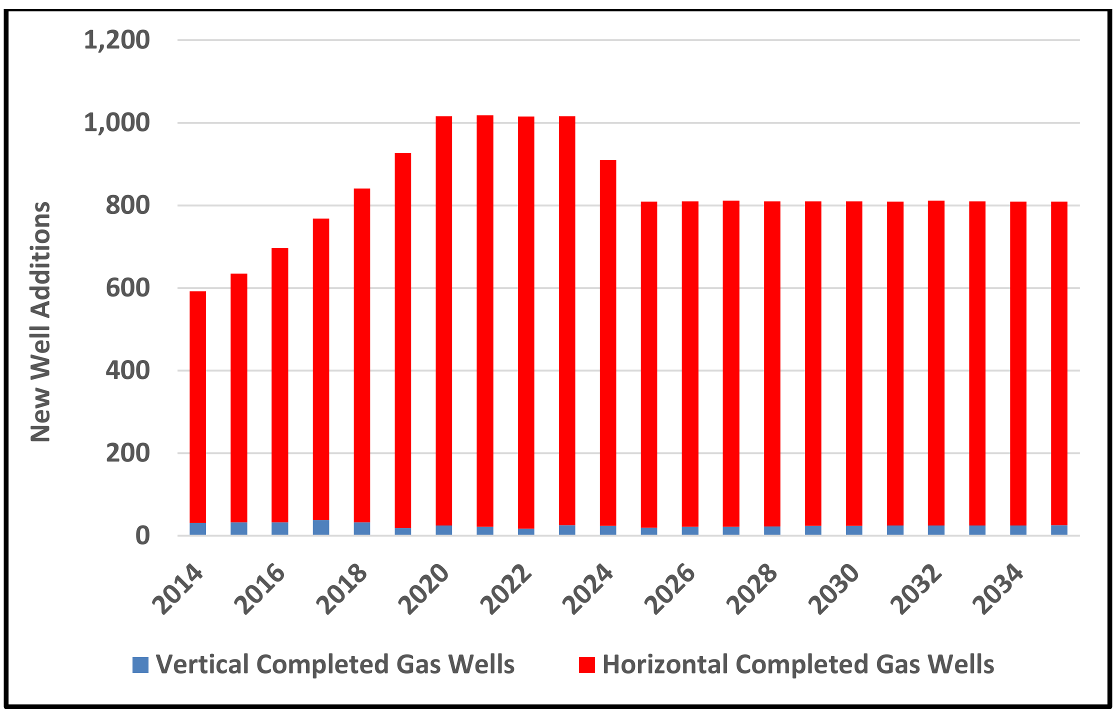
The forecast of annual new well requirements is demonstrated in Figure 3.2. The continuing rise in new wells between 2014 and 2020 is a function of the LNG proponents proving up reserves and test well performances in preparation for the startup of LNG liquefaction operations at Kitimat and Prince Rupert, British Columbia. The CERI gas forecast model determined that 650 wells would be required in 2015. Figure 3.3 shows the historical monthly new gas well licenses issued by the British Columbia Oil and Gas Commission for the years 2011 to 2014. The first 6 months of 2015 gas licenses are shown as red dots and the dashed line is a curve fit and extrapolation to the end of the year using an average historical trend. This extrapolation suggests that the oil and gas industry will license 1,000 wells for 2015. This suggests that the industry has, for several years now, licensed wells to be drilled and not completed until such time as the pipelines to connect northeastern British Columbia with the LNG projects comes online.

Figure 3.1: British Columbia Supply/Demand (2014-2035)



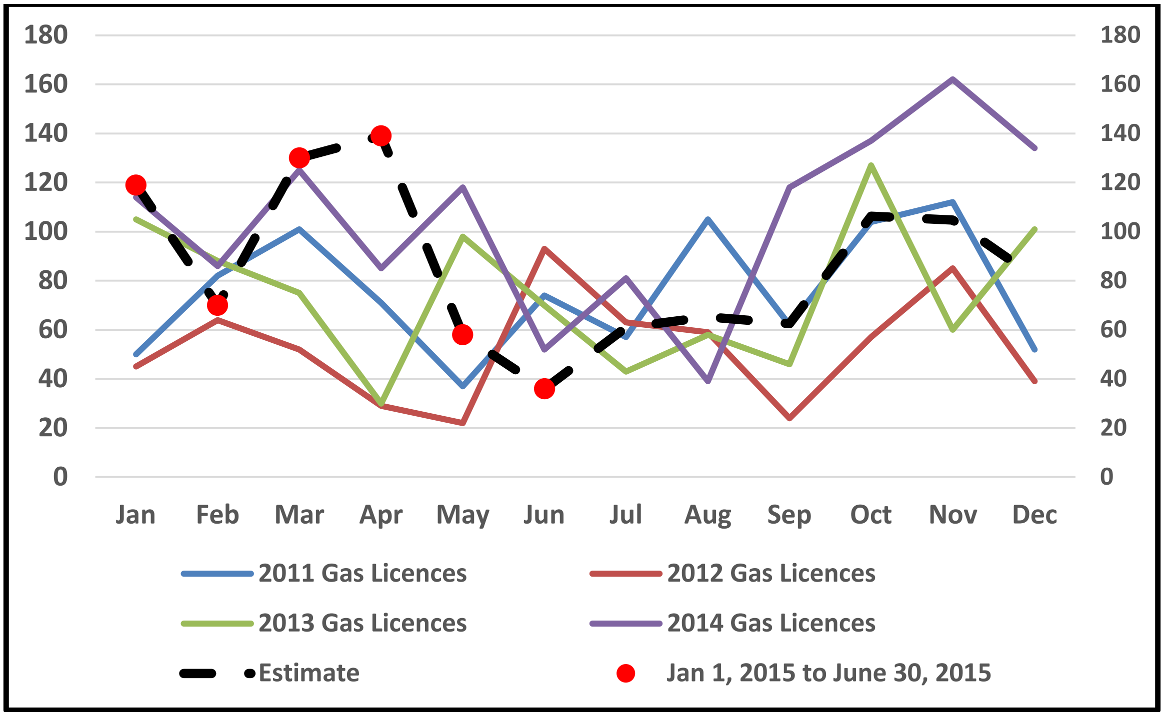
Source: CERI

Figure 3.2: British Columbia New Well Additions (2014-2035)



Source: ICF International, CERI

Figure 3.3: British Columbia New Well Licenses (2011-2014)

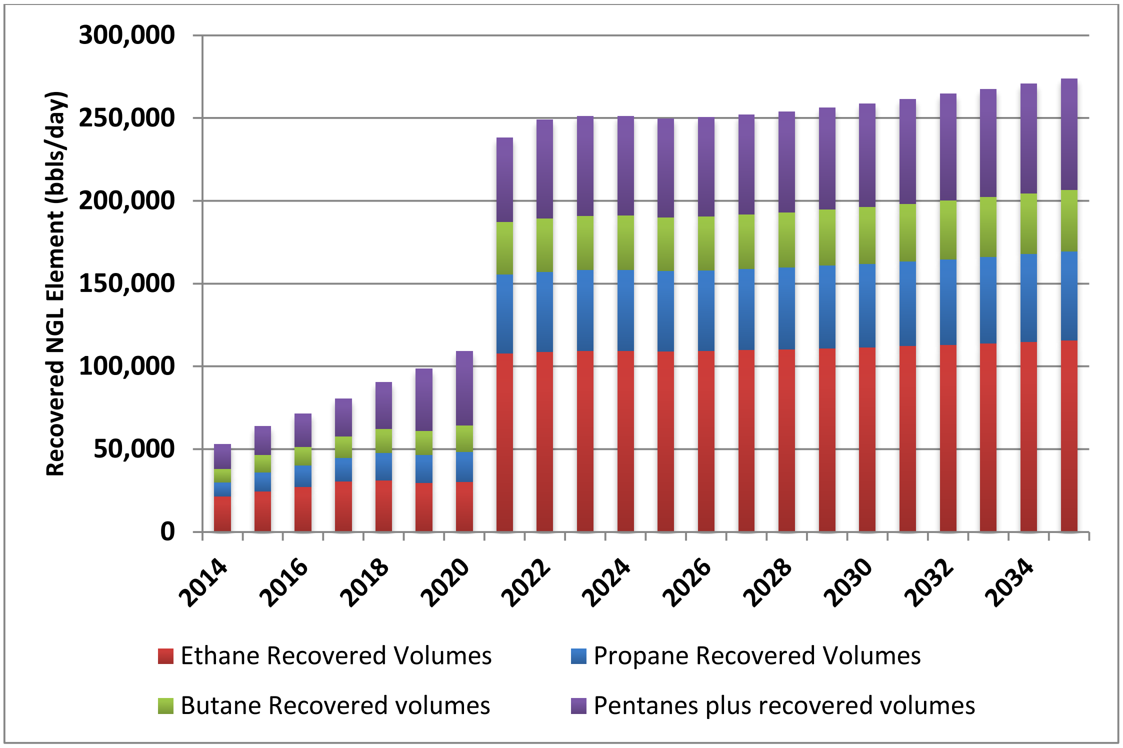


Source: ICF International, CERI

In order to determine the cost of the drilling activity outlined in Figure 3.5 (blue bars), CERI makes use of the information contained in the 2015 Well Cost Study (winter 2015 costs) from the Petroleum Services Association of Canada. Reference wells are assigned to each area and formation under study and the well cost is calibrated to the average drill depth using true vertical depth for a vertical well and total drill depth for a horizontal well. A provision for connection infrastructure costs plus geological and geophysical costs are added to the well capital cost as represented by the blue bars in Figure 3.5.

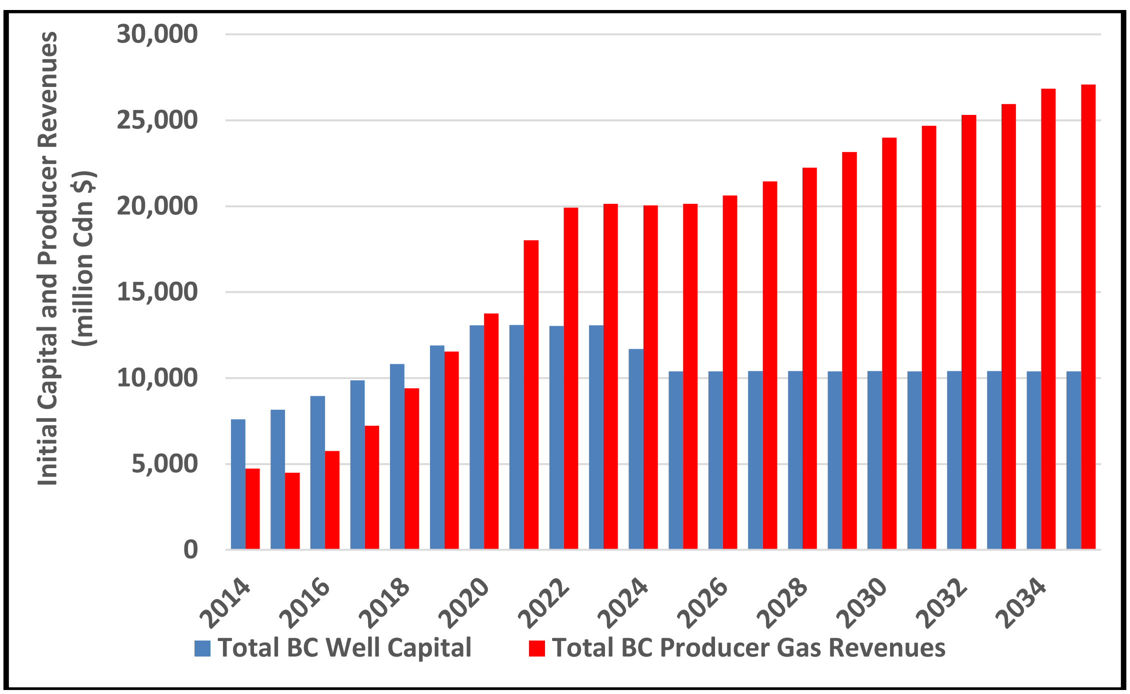
Each producing area and formation is connected to a reserves weighted average component structure and modeled as to the type of field plant operation (shallow or deep cut). The marketable gas (exit of the area plant) is connected to a nodal representation of the Spectra Transmission systems so that area plant recoveries can be determined. The total of field plant recovered NGLs (spec product or mix steam) and the straddle plant recoveries are represented in Figure 3.4. These NGL components along with the natural gas streams are used to calculate the gross producer revenue (wellhead) and are represented as the red bars in Figure 3.5. A complete description of this process is detailed in Appendix A.

Figure 3.4: British Columbia NGL Recoveries by Field Plants (2014-2035)



Source: CERI

Figure 3.5: New Well Capital Cost and Annual Producer Revenues (2014-2035)



Source: CERI

Tables 3.1 and 3.2 and Figures 3.6 and 3.7 demonstrate the economic impacts derived from natural gas developments.

- Capital investments in the development of new gas wells in British Columbia will total CDN$228.1 billion or average CDN$10.8 billion per year.
- Revenues from natural gas domestic sales, export sales and natural gas liquids recovery will total CDN$391.7 billion or average CDN$18.6 billion per year.
- Total Canadian GDP impacts are estimated at CDN$643 billion, 90 percent within the province of British Columbia and 10 percent across the other provinces and territories (Table 3.1).
- Taxes directed to the Federal government will total CDN$63.8 billion and CDN$40.1 billion to the Provincial governments (Table 3.2).
- Employment (direct, indirect and induced) will grow from 52,720 jobs in 2015 to 156,000 by 2035 (Figures 3.6 and 3.7).

Table 3.1: Economic Impacts of Conventional and Unconventional Gas Developments in British Columbia (2015-2035)

Investment and Operations	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	19,980	10,589	123
British Columbia	582,991	205,787	2,128
Manitoba	2,119	1,220	20
New Brunswick	466	264	5
Newfoundland/Labrador	206	100	2
Nova Scotia	511	315	5
Nunavut	17	13	0
Northwest Territories	209	94	1
Ontario	26,645	16,229	201
Prince Edward Island	40	23	0
Quebec	8,763	5,012	86
Saskatchewan	1,643	746	12
Yukon Territory	401	146	2
Total Canada	**643,989**	**240,538**	**2,585**

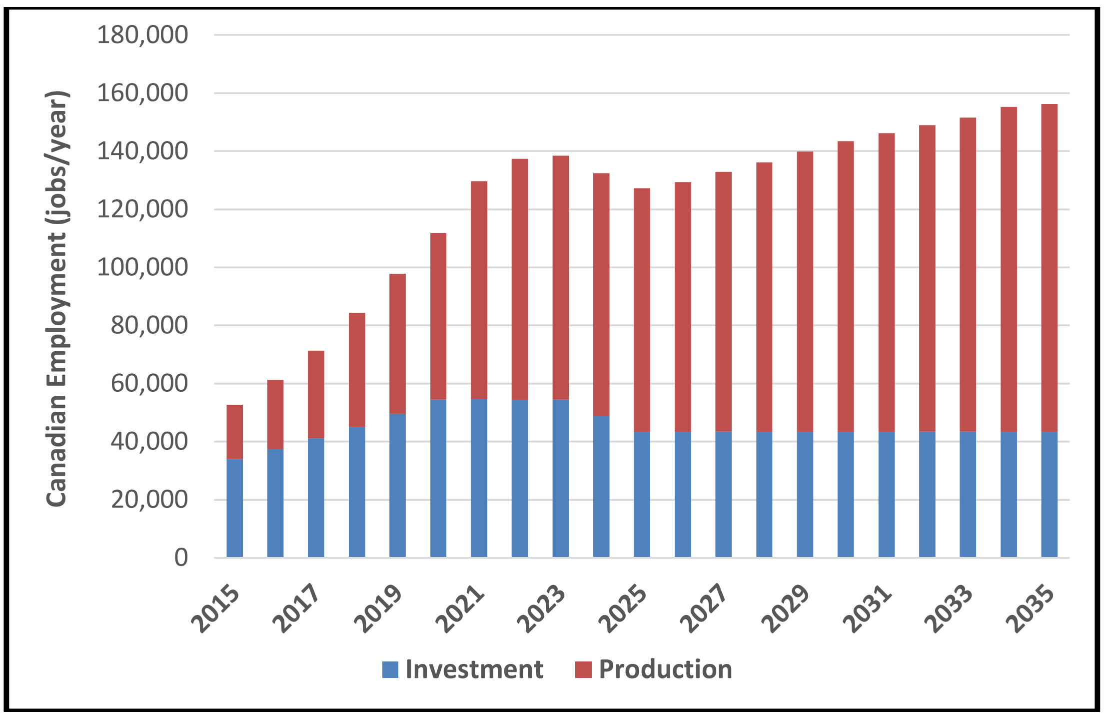
Source: ICF, CERI

Table 3.2: Tax Receipts Derived from Conventional and Unconventional Gas Developments in British Columbia (2015-2035)

Investment and Operations	Federal Corporate $CAD Million	Federal Indirect $CAD Million	Federal Personal $CAD Million	Provincial Corporate $CAD Million	Provincial Indirect $CAD Million	Provincial Personal $CAD Million
Alberta	709	297	1,363	359	325	735
British Columbia	11,500	6,486	39,242	4,228	13,693	17,021
Manitoba	33	36	124	11	84	99
New Brunswick	7	6	27	3	15	21
Newfoundland/Labrador	4	3	10	6	5	7
Nova Scotia	9	8	33	5	16	28
Nunavut	0	0	1	0	0	0
Northwest Territories	5	3	9	3	4	4
Ontario	486	482	1,889	255	946	1,132
Prince Edward Island	1	1	2	0	2	2
Quebec	159	140	575	112	369	533
Saskatchewan	37	24	81	25	59	49
Yukon Territory	4	4	20	1	3	9
Total Canada	12,954	7,491	43,377	5,008	15,521	19,641

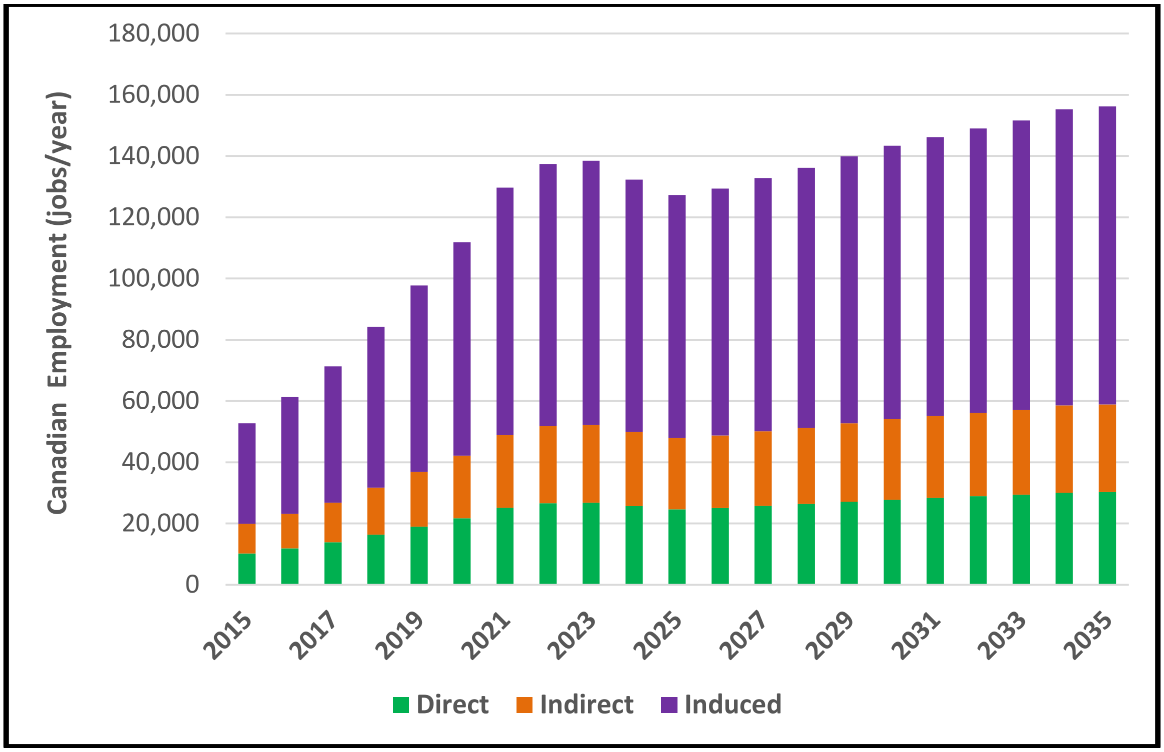
Source: CERI

Figure 3.6: British Columbia Employment Impacts: Investment and Production (2015-2035)



Source: CERI

Figure 3.7: British Columbia Employment Impacts: Direct, Indirect and Induced (2015-2035)



Source: CERI

Chapter 4: Economic Impacts of Natural Gas Developments – Saskatchewan

This chapter details the natural gas forecast and associated economic impacts of natural gas developments, including both existing and future drilling activity within the province of Saskatchewan over the period 2014 to 2035. This analysis covers conventional, shale and tight gas reservoirs, with or without natural gas liquids present and using vertical and horizontal wells.

Tables 4.1 and 4.2 and Figure 4.1 demonstrate the economic impacts derived from natural gas developments.

- Capital investments in the development of new gas wells in Saskatchewan will total CDN$0.5 billion.
- Revenues from natural gas domestic sales, export sales and natural gas liquids recovery will total CDN$5.9 billion.
- Total Canadian GDP impacts are estimated at CDN$4 billion, 89 percent within the province of Saskatchewan and 11 percent across the other provinces and territories (Table 4.1).
- Taxes directed to the Federal government will total CDN$0.37 billion and CDN$0.21 billion to the Provincial governments (Table 4.2).
- Employment (direct, indirect and induced) will decline from 650 jobs in 2015 to 510 by 2035 (Figure 4.1).

Table 4.1: Economic Impacts of Conventional and Unconventional Gas Developments in Saskatchewan (2015-2035)

Investment and Operations	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	220	109	1
British Columbia	35	22	0
Manitoba	21	13	0
New Brunswick	2	1	0
Newfoundland/Labrador	1	1	0
Nova Scotia	3	2	0
Nunavut	0	0	0
Northwest Territories	0	0	0
Ontario	129	76	1
Prince Edward Island	0	0	0
Quebec	37	20	0
Saskatchewan	3,828	759	9
Yukon Territory	0	0	0
Total Canada	**4,276**	**1,003**	**12**

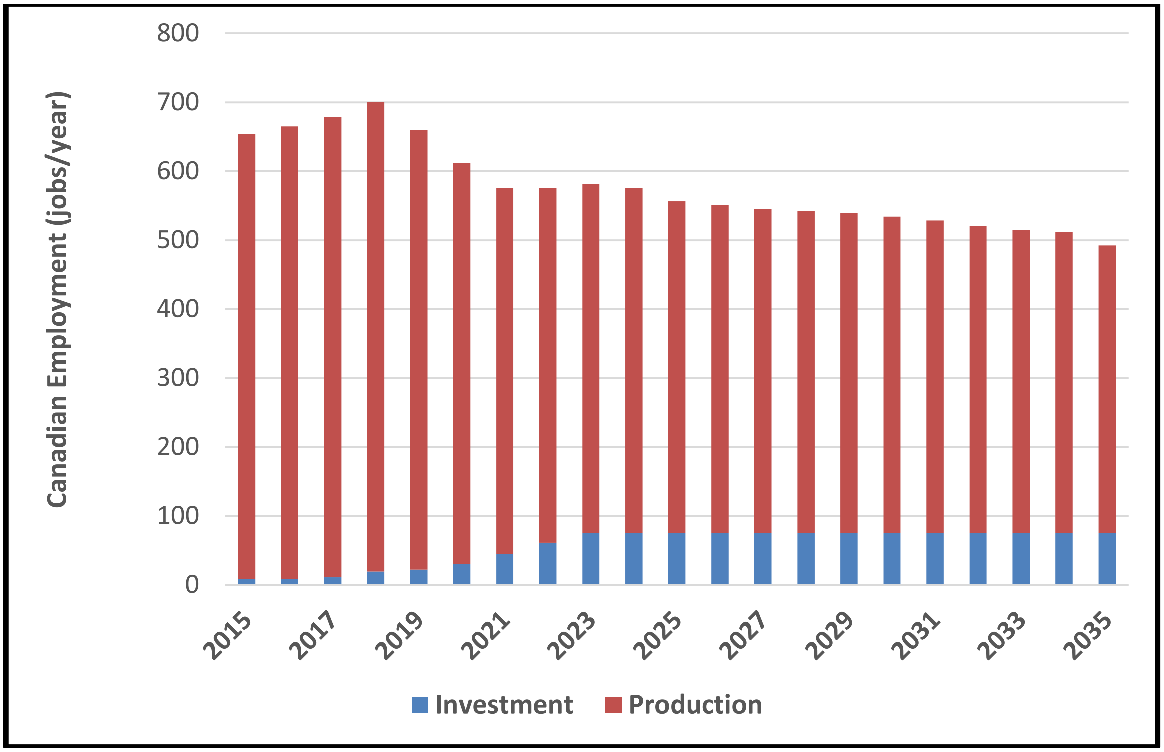
Source: CERI

Table 4.2: Tax Receipts Derived from Conventional and Unconventional Gas Developments in Saskatchewan (2015-2035)

Investment and Operations	Federal Corporate $CAD Million	Federal Indirect $CAD Million	Federal Personal $CAD Million	Provincial Corporate $CAD Million	Provincial Indirect $CAD Million	Provincial Personal $CAD Million
Alberta	8	3	15	4	3	8
British Columbia	1	1	2	0	1	1
Manitoba	0	0	1	0	1	1
New Brunswick	0	0	0	0	0	0
Newfoundland/Labrador	0	0	0	0	0	0
Nova Scotia	0	0	0	0	0	0
Nunavut	0	0	0	0	0	0
Northwest Territories	0	0	0	0	0	0
Ontario	2	2	9	1	5	5
Prince Edward Island	0	0	0	0	0	0
Quebec	1	1	2	0	2	2
Saskatchewan	86	49	188	58	118	114
Yukon Territory	0	0	0	0	0	0
Total Canada	97	56	219	64	130	132

Source: CERI

Figure 4.1: Saskatchewan Employment Impacts: Investment and Production (2015-2035)



Source: CERI

Appendix A: WCSB Gas Production Forecast

Methodology

The CERI gas forecast model is designed to convert a provincial well activity forecast to a natural gas and natural gas liquids forecast. This process involves utilizing historical data to determine base line production parameters (initial production rates, decline rate, compositional makeup, and gas plant design) linked to a nodal representation of the physical gas transmission system to link supply to demand. Between supply and demand, the model accounts for liquids recovered at field gas plants and straddle plants along with deliveries to domestic meter stations (major cities and grouped rural locations), fuel used in the transport system and volumes delivered to export locations. This model utilizes the physical description of the gas transmission systems (NOVA Alberta pipeline system, TransCanada pipeline system, Spectra pipeline system) and subdivides these pipelines into PIA areas (Pipeline Influence Areas). PIA's are a group of receipt points between compressor station locations, divergent or convergent pipeline locations, major off-take locations (cities) or export point. This is done to facilitate the volume recovery at the straddle point locations or the compositional makeup (energy content) of streams delivered for domestic consumption. In addition to PIA areas, special attention is paid to geological formations (PIA-Formation) that have or are about to attract industry attention. Examples of this include the Montney (British Columbia and Alberta), Duvernay (Alberta), Wilrich (Alberta), and Bakken (Saskatchewan). Data for these special elements are identified by a reference to the formation code and the closest PIA area.

The version used for this report takes input the annual volumes to be received at the export points connecting provinces (British Columbia to Alberta, Alberta to Saskatchewan, etc.) and connecting the Western Canada Sedimentary Basin (WCSB) to eastern Canada and the US. The ICF International GMM® is utilized to investigate the North American market and determine the annual flow levels at these major export pipelines linking Canada to the US.

The model then utilizes an iterative procedure to determine the provincial well drilling (on a year by year basis) that will deliver sufficient natural gas to the domestic market, export market and all uses and losses on the transmission system. Output from the model is in the form of upstream wellhead supply, gas plant recoveries and losses (fuel and volume shrinkage) component makeup of the gas stream at various locations on the pipeline, recoveries at the straddle plants and energy delivered to markets.

The model relies heavily on public information from various sources to determine the basic parameters used in establishing the initial model framework. Sources for this information include:

1. The Alberta Energy Regulator (AER; formally the Energy Resources Conservation Board)

2. Saskatchewan Energy and Mines (SEAM)
3. The British Columbia Oil and Gas Commission (BCOGC)
4. The National Energy Board of Canada (NEB)
5. Canadian Association of Petroleum Producers (CAPP)
6. Petroleum Services Association of Canada (PSAC)

The three provincial regulators provide detailed well information coupled with the complete historical (month by month) list of produced fluids (natural gas, crude oil, bitumen, coalbed methane, condensate and water) on a well-by-well basis. In addition, data pertaining to the individual well configuration as to its finish drilling date, initial production date, major production fluid (oil, gas, coalbed methane, bitumen, etc.), original status, current status, total depth, true vertical depth and physical locations. A National Topographic System (NTS) location is available for wells drilled in British Columbia outside the Peace River block. These individual well records are linked to the individual well raw gas compositional analysis (methane, ethane, propane, butane, pentanes, hydrogen sulphide, carbon dioxide and others) or if that is unavailable, an average pool analysis. Relying on the most recent month and year the model can be calibrated as to natural gas liquids recovered, composition and heating value and points on the pipeline system, recoveries at straddle plants and deliveries to domestic off-take points and export border points.

This information is utilized to determine: the average Initial Production rate (peak month of production in the first 3 months of production), annual production by year, first production date, and last production date (if abandoned). Monthly production is used to determine the historic decline curve for all wells within a given study area that commenced production in a given year. A series of harmonic and exponential curves are investigated to establish a representative “Type” decline curve for a given study area. This process is replicated for vertical and horizontal wells separately.

The “Type” curve is used to establish the decline path for wells that are currently on stream (as of the base year 2014), based on the average number of months the existing operating wells have been operating. The average on stream months defines the starting point on the “Type” curve where the production rate will be for the forecast months. This same curve starting at time zero is used to define the production path for new wells drilled and connected in the future.

At the completion of the iterative procedure, the model generates information which describes the number of wells drilled by PIA or PIA-Form group, the annual wellhead production, the component stream, the recovered components by plant, deliveries (volume and composition) to domestic points and export points and the composition of the flow stream at several points on the transmission system. This information is processed to determine capital requirements for the drilling program, gross and net gas flows, natural gas liquids recovered, Sulphur recoveries, condensate recoveries and pentanes (C5, C6, C7, etc.) recoveries that together determine the producer revenue.

Figure A.1 is a graphical representation of the Pipeline Influence Area adopted for the Province of Alberta. Table A.1 is a list of the Pipeline Influence Area and Pipeline Influence Area Formations and the historical new well completions for the years 2008 to 2014.

Figure A.2 is a graphical representation of the Pipeline Influence Area adopted for the Province of British Columbia. Table A.2 is a list of the Pipeline Influence Area and Pipeline Influence Area Formations and the historical new well completions for the years 2008 to 2014.

Figure A.3 is a graphical representation of the Pipeline Influence Area adopted for the Province of Saskatchewan. Table A.3 is a list of the Pipeline Influence Area and Pipeline Influence Area Formations and the historical new well completions for the years 2008 to 2014.

Figure A.1: Pipeline Influence Area: Alberta

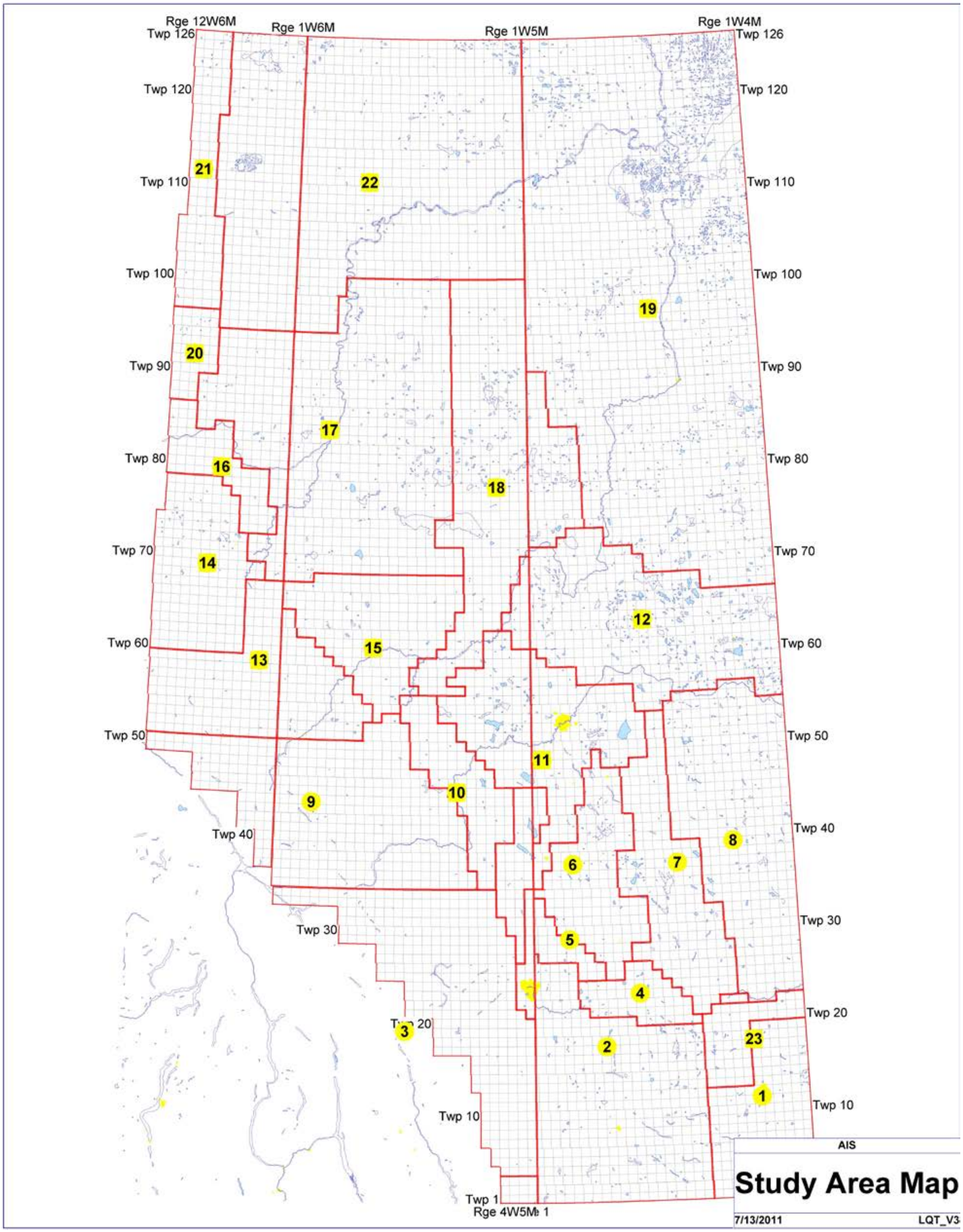


Table A.1: Pipeline Influence Area, PIA-Formation Areas for Alberta

	NEW PRODUCING WELLS BY YEAR BY PIA/FORM COUNT						
	2008	2009	2010	2011	2012	2013	2014
PIA01-3000-GAS	0	0	0	0	0	0	0
PIA01-8000-GAS	795	613	335	253	18	6	4
PIA01-9999-GAS	33	16	1	2	1	0	0
PIA02-2500-GAS	32	9	8	4	2	0	2
PIA02-3000-GAS	6	2	6	0	2	0	0
PIA02-8000-GAS	544	292	206	40	23	3	1
PIA02-9990-GAS	4	2	4	10	10	1	2
PIA02-9999-GAS	121	52	36	13	9	8	8
PIA03-1760-GAS	6	1	1	1	0	0	0
PIA03-8000-GAS	22	10	9	7	4	1	1
PIA03-9999-GAS	15	12	11	8	5	10	6
PIA04-3000-GAS	3	2	1	2	2	3	2
PIA04-8000-GAS	565	300	206	152	56	67	24
PIA04-9990-GAS	0	6	2	2	4	9	141
PIA04-9999-GAS	22	18	15	21	2	3	2
PIA05-8000-GAS	22	40	24	17	11	16	0
PIA05-9990-GAS	2	1	2	7	9	0	77
PIA05-9999-GAS	18	16	10	10	5	3	3
PIA06-1760-GAS	1	0	0	0	0	0	0
PIA06-2180-GAS	18	17	12	10	3	4	10
PIA06-2500-GAS	13	6	5	4	0	1	4
PIA06-3000-GAS	17	8	8	8	2	5	9
PIA06-8000-GAS	513	222	166	90	64	92	23
PIA06-9990-GAS	18	12	13	7	8	5	46
PIA06-9999-GAS	147	62	41	30	9	13	19
PIA07-2180-GAS	9	17	7	2	1	0	0
PIA07-2500-GAS	27	7	8	2	1	0	1
PIA07-3000-GAS	14	9	14	10	1	2	1
PIA07-8000-GAS	414	70	72	42	4	3	2
PIA07-9990-GAS	2	0	0	1	0	0	0
PIA07-9999-GAS	96	55	23	13	2	3	6
PIA08-2180-GAS	27	16	16	4	1	1	0
PIA08-2500-GAS	30	23	12	1	0	1	0
PIA08-2620-GAS	17	2	3	3	0	1	0
PIA08-2760-GAS	33	9	9	7	1	1	5
PIA08-2940-GAS	10	3	2	2	0	2	0
PIA08-3000-GAS	7	5	3	0	0	0	0
PIA08-8000-GAS	167	47	50	26	6	3	9
PIA08-9990-GAS	2	3	1	1	0	0	2
PIA08-9999-GAS	149	71	42	28	4	3	5
PIA09-1760-GAS	8	5	4	6	14	7	44
PIA09-2180-GAS	0	1	1	1	0	1	0
PIA09-2500-GAS	4	6	4	6	8	24	17
PIA09-2620-GAS	1	0	1	1	0	9	24
PIA09-8000-GAS	140	49	113	93	79	39	21
PIA09-9990-GAS	0	0	2	25	15	18	75
PIA09-9999-GAS	38	19	21	15	10	17	51
PIA10-1760-GAS	2	2	1	2	1	0	7
PIA10-2180-GAS	0	1	0	0	0	0	2
PIA10-2500-GAS	18	13	8	8	3	4	8
PIA10-2620-GAS	4	1	2	3	4	4	4
PIA10-3000-GAS	3	2	3	11	4	9	22
PIA10-7280-GAS	0	0	0	0	0	1	2

Table A.1: Pipeline Influence Area, PIA-Formation Areas for Alberta (continued)

	NEW PRODUCING WELLS BY YEAR BY PIA/FORM COUNT						
	2008	2009	2010	2011	2012	2013	2014
PIA10-8000-GAS	225	132	153	146	95	89	83
PIA10-9990-GAS	0	1	5	2	2	0	18
PIA10-9999-GAS	101	44	34	20	6	14	34
PIA11-1760-GAS	1	0	0	0	0	0	0
PIA11-2180-GAS	7	3	5	1	0	0	1
PIA11-2500-GAS	47	11	10	5	3	4	2
PIA11-3000-GAS	10	6	8	8	3	4	1
PIA11-8000-GAS	39	20	22	5	1	1	0
PIA11-9990-GAS	1	4	4	2	0	0	2
PIA11-9999-GAS	99	49	32	12	11	6	8
PIA12-2180-GAS	23	9	6	5	1	1	3
PIA12-2500-GAS	37	13	16	3	0	0	2
PIA12-2620-GAS	50	28	17	3	3	3	0
PIA12-2760-GAS	11	6	3	1	0	2	1
PIA12-2800-GAS	5	2	1	0	0	0	0
PIA12-3050-GAS	4	1	0	0	0	0	0
PIA12-8000-GAS	95	36	18	10	1	0	0
PIA12-9990-GAS	1	1	0	2	0	0	2
PIA12-9999-GAS	110	54	26	19	2	2	3
PIA13-1760-GAS	7	9	8	8	7	10	3
PIA13-2500-GAS	2	0	0	0	1	14	1
PIA13-2620-GAS	0	2	3	11	12	17	64
PIA13-5240-GAS	1	2	4	16	24	33	41
PIA13-8000-GAS	470	250	311	235	215	134	46
PIA13-9990-GAS	0	0	6	19	21	29	135
PIA13-9999-GAS	31	24	16	18	6	6	13
PIA14-1760-GAS	8	4	17	11	7	2	3
PIA14-2620-GAS	7	4	5	4	8	3	19
PIA14-5000-GAS	9	1	8	1	2	1	0
PIA14-5240-GAS	16	21	29	42	46	68	95
PIA14-8000-GAS	331	226	315	210	101	58	46
PIA14-9990-GAS	0	1	0	6	7	9	72
PIA14-9999-GAS	60	33	49	19	17	9	13
PIA15-1760-GAS	1	0	3	1	0	0	0
PIA15-2500-GAS	6	3	6	6	1	0	1
PIA15-2620-GAS	10	4	4	9	1	0	0
PIA15-5000-GAS	0	3	1	2	2	0	0
PIA15-5240-GAS	2	8	7	5	12	9	2
PIA15-7280-GAS	0	0	0	1	0	2	10
PIA15-7440-GAS	5	5	25	13	5	0	0
PIA15-8000-GAS	172	99	92	72	47	39	46
PIA15-9990-GAS	0	0	1	3	1	1	14
PIA15-9999-GAS	43	17	14	11	3	3	7

Table A.1: Pipeline Influence Area, PIA-Formation Areas for Alberta (continued)

	NEW PRODUCING WELLS BY YEAR BY PIA/FORM						
				COUNT			
	2008	2009	2010	2011	2012	2013	2014
PIA16-5000-GAS	7	4	2	1	0	0	0
PIA16-5240-GAS	10	4	4	4	0	2	5
PIA16-8000-GAS	19	9	8	7	2	3	2
PIA16-9990-GAS	1	0	0	0	0	0	1
PIA16-9999-GAS	46	23	20	3	3	4	3
PIA17-3050-GAS	0	0	0	0	0	0	0
PIA17-5000-GAS	4	2	4	3	0	0	0
PIA17-5240-GAS	32	19	17	12	0	1	1
PIA17-7440-GAS	0	0	0	0	0	0	0
PIA17-8000-GAS	33	7	18	6	2	1	3
PIA17-9990-GAS	0	0	0	0	0	0	0
PIA17-9999-GAS	58	27	39	8	3	6	1
PIA18-3050-GAS	5	2	2	0	0	0	1
PIA18-8000-GAS	25	13	6	1	0	0	0
PIA18-9999-GAS	75	32	24	2	0	2	1
PIA19-3050-GAS	3	5	4	0	0	0	0
PIA19-9999-GAS	89	64	23	10	1	0	5
PIA22-9990-GAS	0	0	0	0	0	0	0
PIA22-9999-GAS	90	22	14	2	3	2	0
PIA23-2500-GAS	2	2	1	0	0	0	0
PIA23-3000-GAS	0	0	0	0	0	0	0
PIA23-8000-GAS	790	349	156	169	10	8	2
PIA23-9999-GAS	18	8	5	4	0	10	2

Figure A.2: Pipeline Influence Area: British Columbia

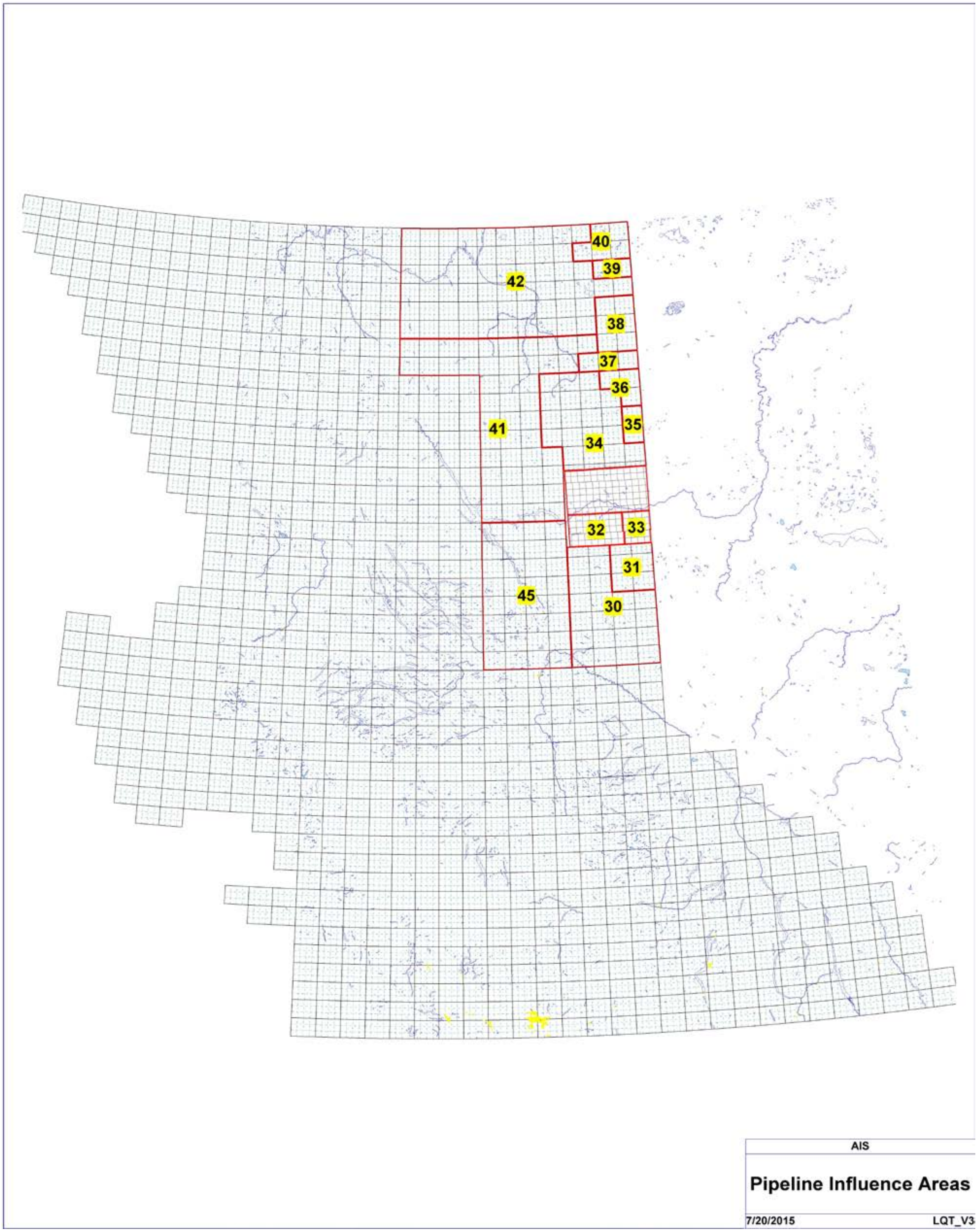


Table A.2: Pipeline Influence Area, PIA-Formation Areas for British Columbia

	NEW PRODUCING WELLS BY YEAR BY PIA/FORM						
	COUNT						
	2008	2009	2010	2011	2012	2013	2014
PIA30-X9999-GAS	52	32	14	15	2	0	0
PIA31-A9030-GAS	37	14	21	13	3	9	2
PIA31-X9999-GAS	20	10	15	9	6	4	3
PIA32-X9999-GAS	12	4	2	2	3	0	0
PIA33-X9999-GAS	19	8	6	1	2	0	0
PIA34-A6200-GAS	0	0	0	0	0	0	0
PIA34-A9022-GAS	0	0	0	5	28	24	18
PIA34-F5000-GAS	3	6	25	47	37	114	169
PIA34-X9999-GAS	235	90	52	19	7	9	6
PIA35-X9999-GAS	11	18	1	1	0	0	0
PIA36-X9999-GAS	6	8	0	0	0	0	0
PIA37-X9999-GAS	0	0	0	0	0	0	0
PIA38-X9999-GAS	16	7	4	5	0	1	0
PIA39-X9999-GAS	7	2	3	0	0	3	0
PIA40-X9999-GAS	2	1	1	6	13	0	0
PIA41-A9022-GAS	1	10	32	46	30	31	21
PIA41-X9999-GAS	72	23	14	4	0	0	4
PIA42-A9045-GAS	18	31	58	38	53	18	17
PIA42-L9045-GAS	0	0	0	0	0	0	0
PIA42-X9999-GAS	121	35	37	29	3	1	8
PIA45-X9999-GAS	0	2	0	0	0	0	0
PIA88-X9999-GAS	0	0	0	0	0	0	0
PIA34-F500A-GAS	3	0	2	3	8	8	11
PIA34-F500B-GAS	102	165	208	262	174	181	237
Kitimat LNG:New Wells	0	0	0	0	0	0	0
Kitimat LNG Groundbirch:New Wells	0	0	0	0	0	10	10
LNG Canada:New Wells	0	0	0	0	0	25	25
Pacific North-West LNG:New Wells	0	0	0	0	0	50	50

Figure A.3: Pipeline Influence Area: Saskatchewan

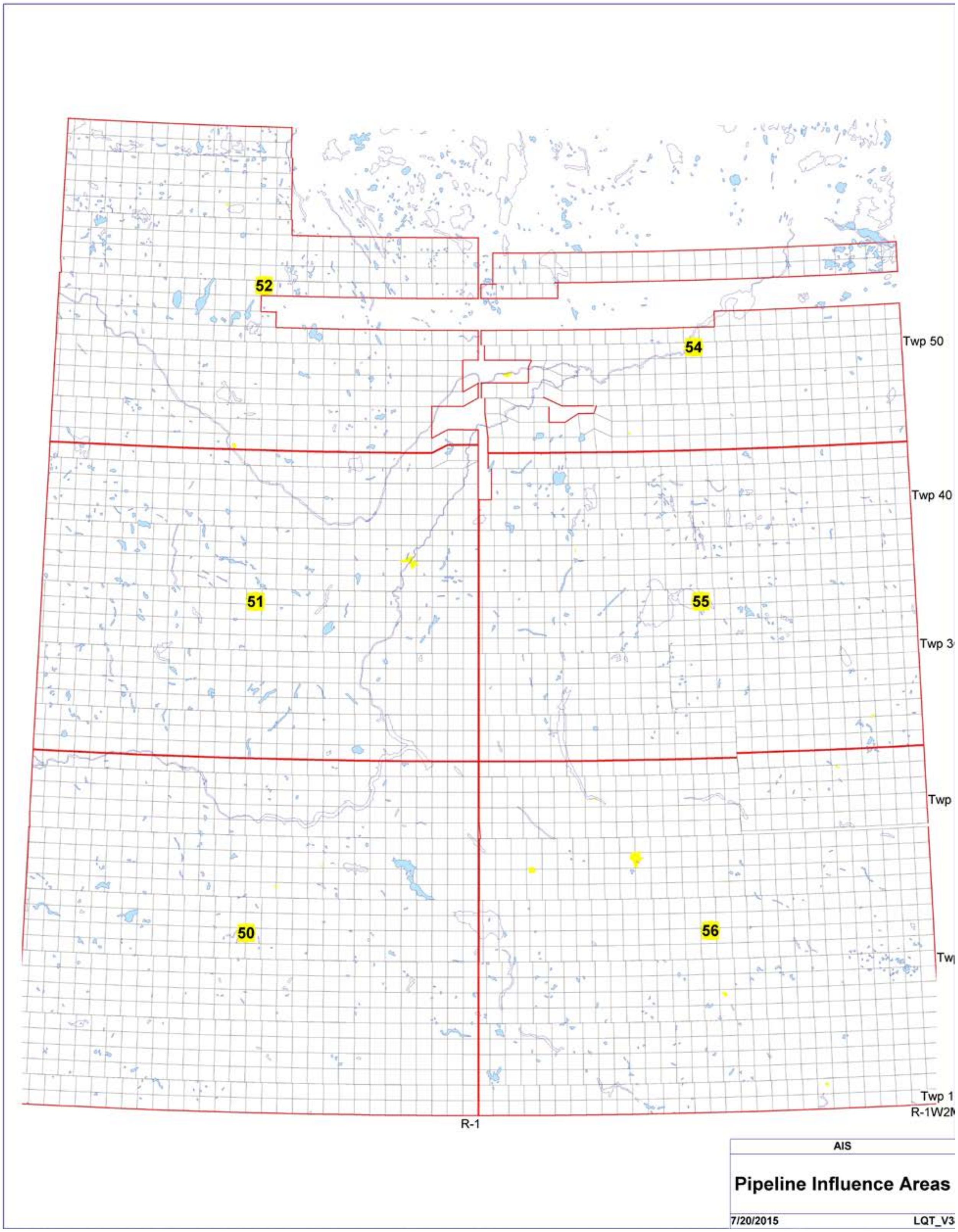


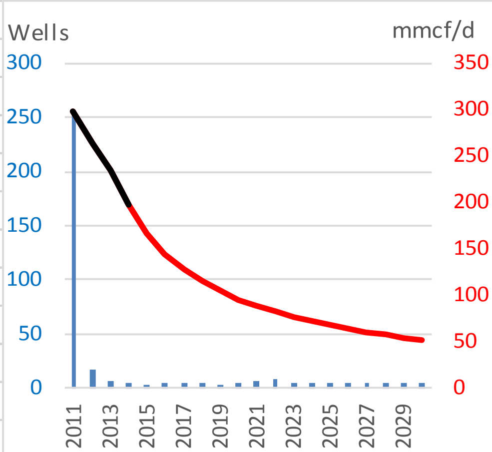
Table A.3: Pipeline Influence Area, PIA-Formation Areas for Saskatchewan

	NEW PRODUCING WELLS BY YEAR BY PIA/FORM						
	COUNT						
	2008	2009	2010	2011	2012	2013	2014
1							
PIA51-9999-GAS	1	0	0	0	0	0	0
PIA52-9999-GAS	0	0	0	0	1	0	0
PIA53-9999-GAS	5	0	0	0	0	0	0
PIA54-9999-GAS	2	1	0	0	0	1	0
PIA55-9999-GAS	833	238	100	32	10	14	4
PIA56-9999-GAS	177	80	34	2	0	0	0
PIA57-9999-GAS	111	100	9	4	9	42	2
PIA58-9999-GAS	17	7	9	0	0	1	2
PIA59-9999-GAS	6	2	2	0	0	0	0

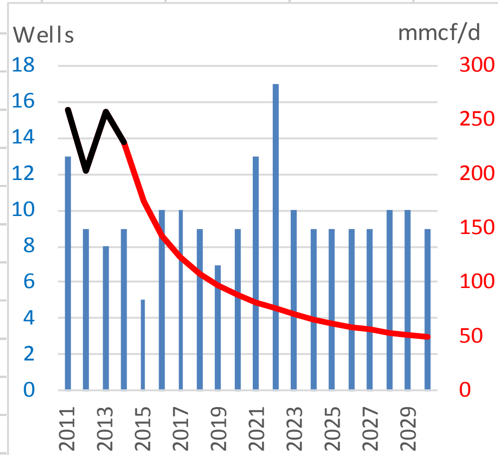
Appendix B: Selected PIA Charts for Alberta

The following charts are example PIA Area and PIA-Formation forecasts indicating, on an annual basis, the number of new well connections along with the total average day production.

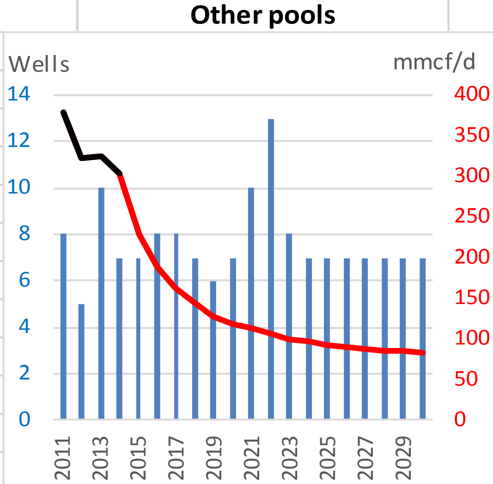
PIA01-8000-GAS
Commingled pools



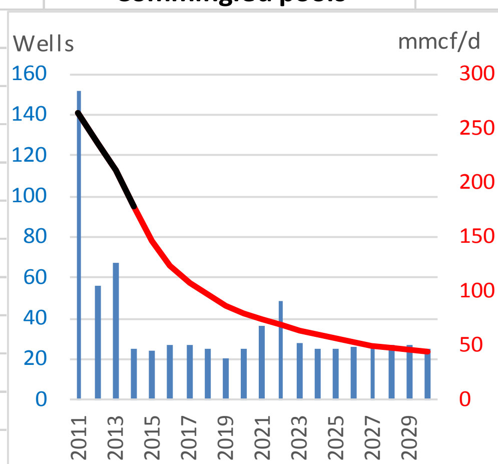
PIA02-9999-GAS
Other pools



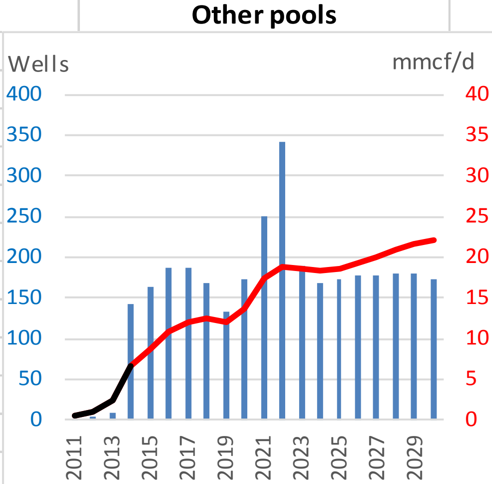
PIA03-9999-GAS
Other pools



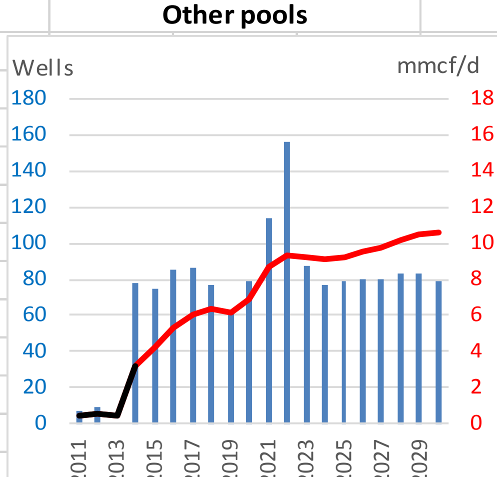
PIA04-8000-GAS
Commingled pools



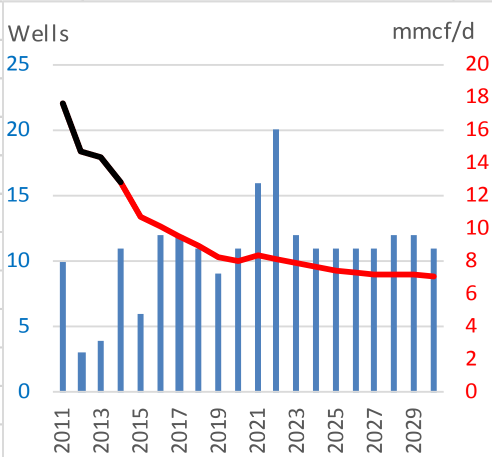
PIA04-9990-GAS
Other pools



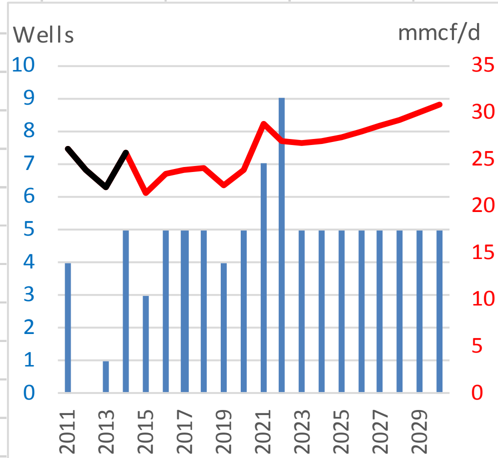
PIA05-9990-GAS
Other pools



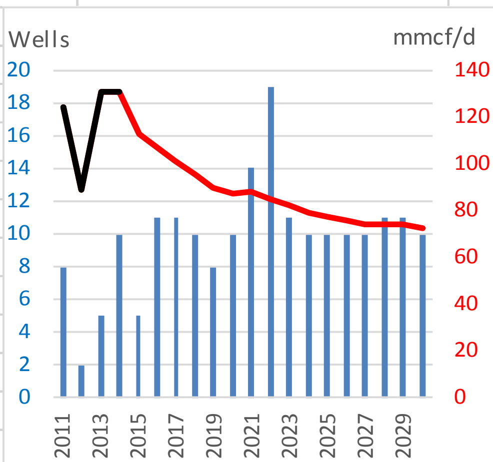
PIA06-2180-GAS
Viking Gas



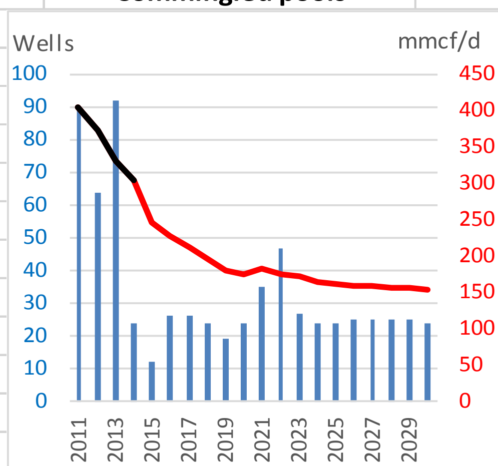
PIA06-2500-GAS
Upper Mannville



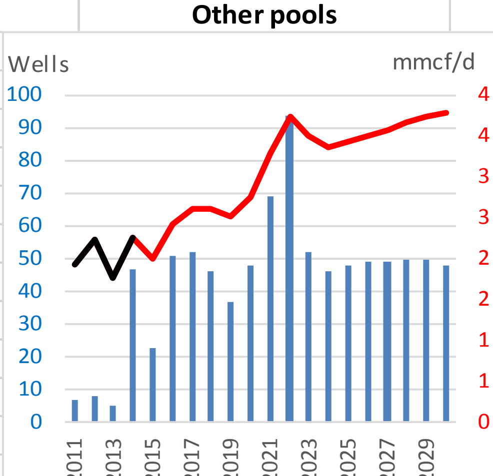
PIA06-3000-GAS
Glauconitic



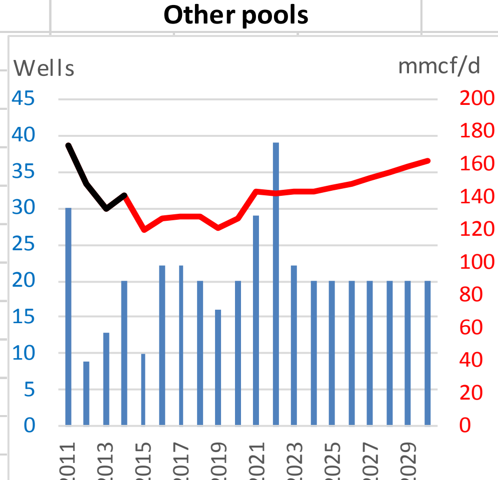
PIA06-8000-GAS
Commingled pools



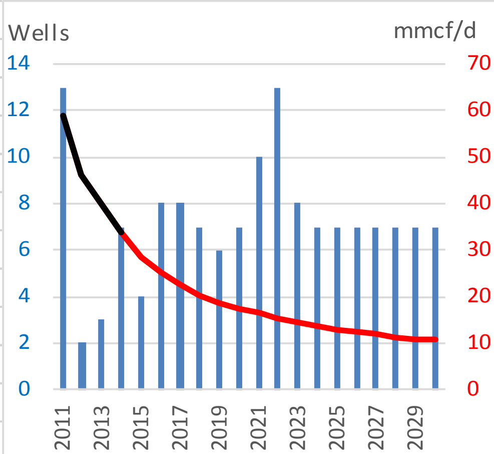
PIA06-9990-GAS
Other pools



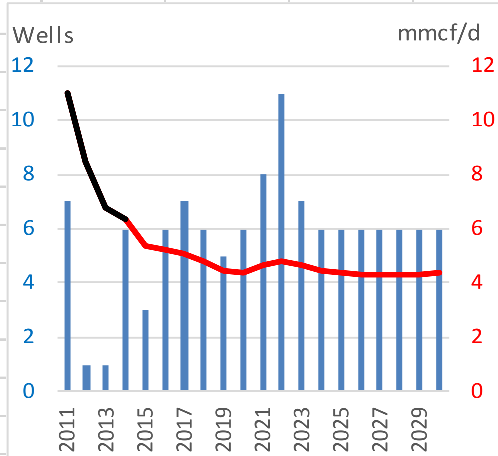
PIA06-9999-GAS
Other pools



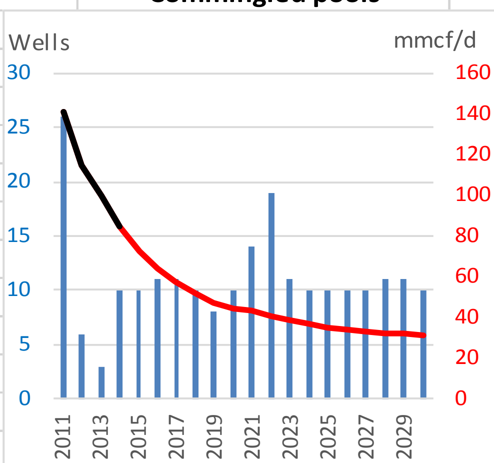
PIA07-9999-GAS
Other pools



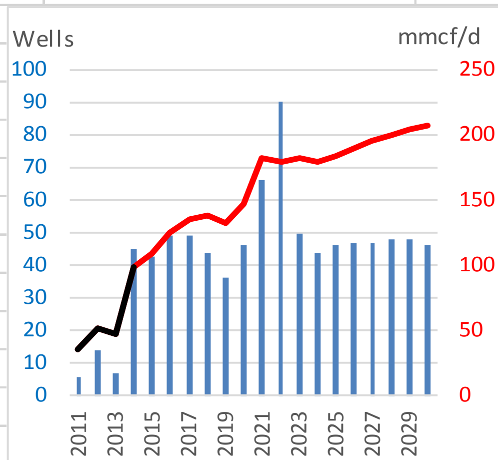
PIA08-2760-GAS
Falher



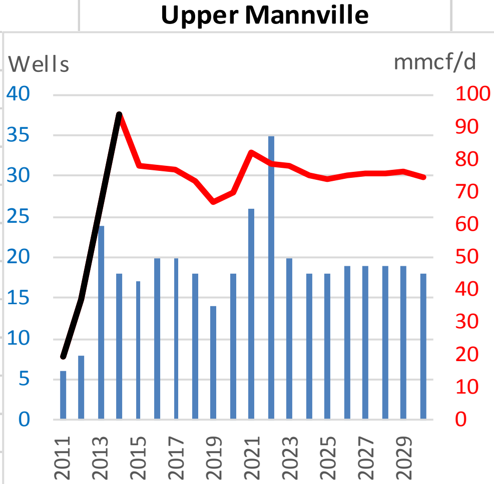
PIA08-8000-GAS
Commingled pools



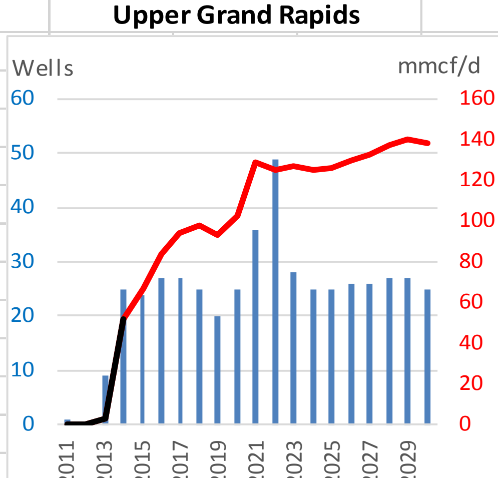
PIA09-1760-GAS
Cardium Gas



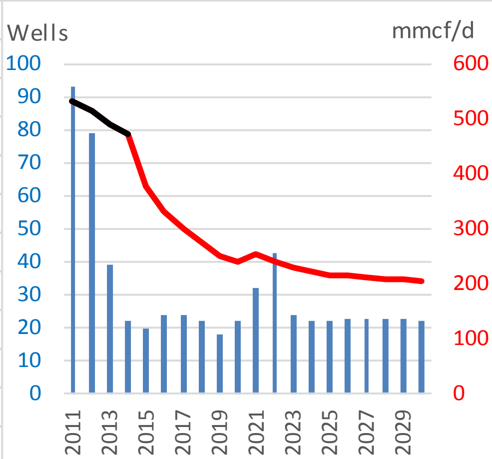
PIA09-2500-GAS
Upper Mannville



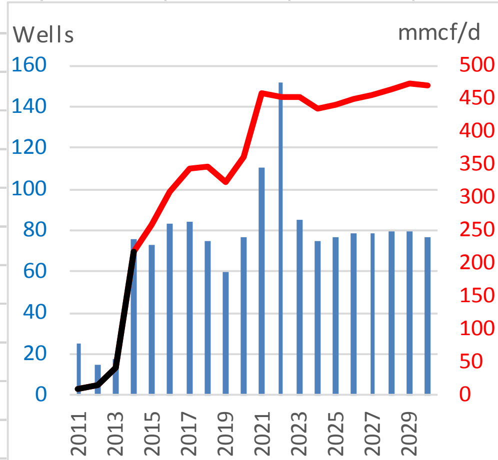
PIA09-2620-GAS
Upper Grand Rapids



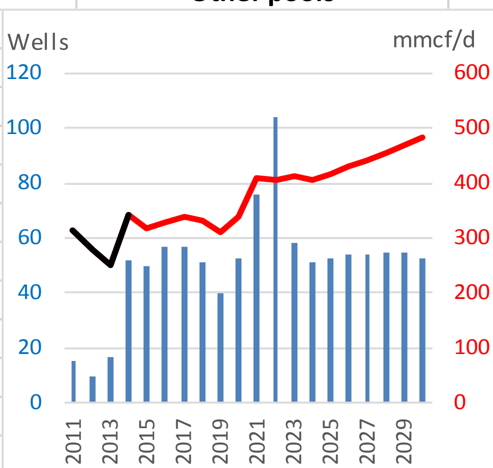
PIA09-8000-GAS
Commingled pools



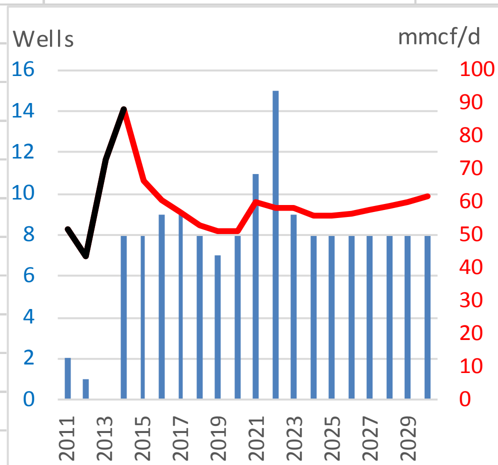
PIA09-9990-GAS
Other pools



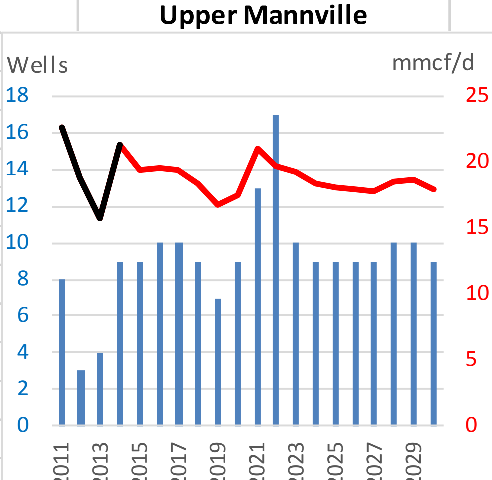
PIA09-9999-GAS
Other pools



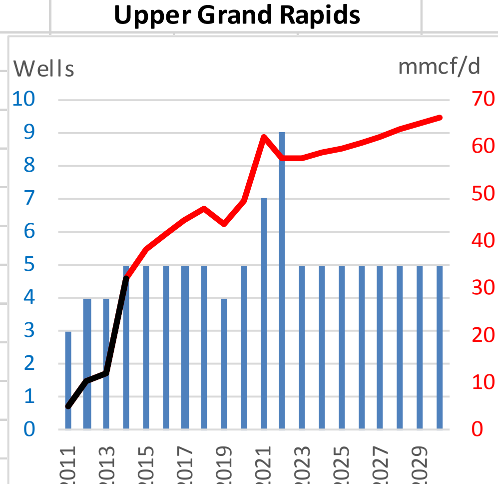
PIA10-1760-GAS
Cardium Gas



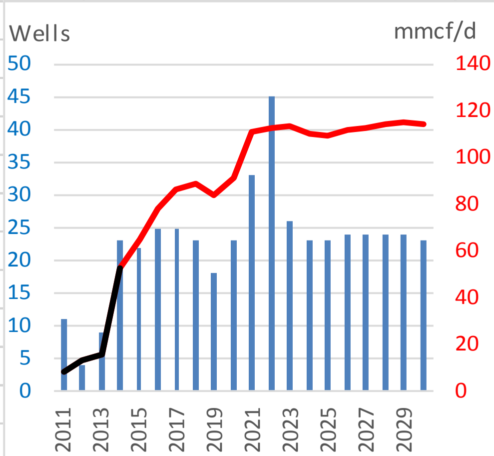
PIA10-2500-GAS
Upper Mannville



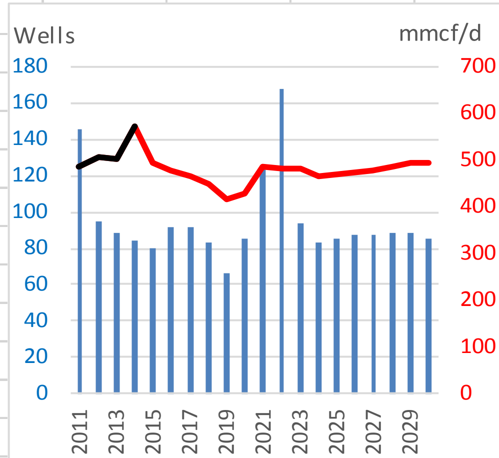
PIA10-2620-GAS
Upper Grand Rapids



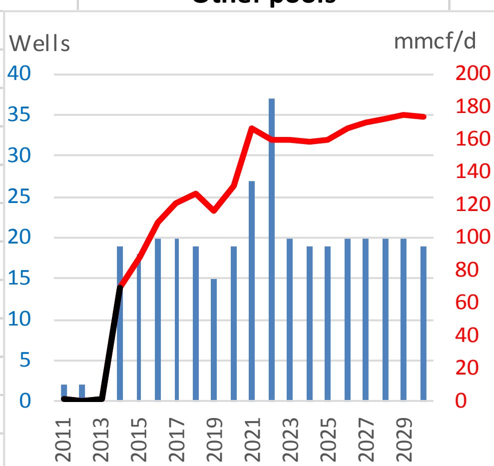
PIA10-3000-GAS
Glauconitic



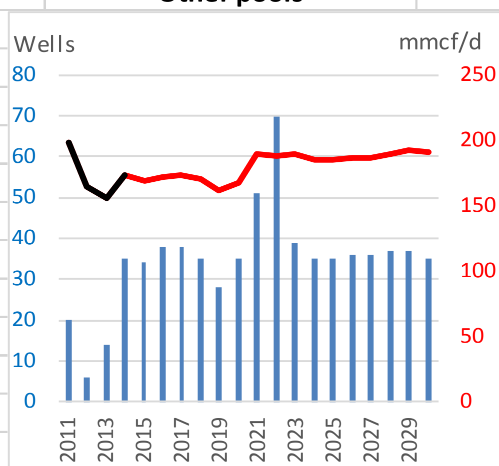
PIA10-8000-GAS
Commingled pools



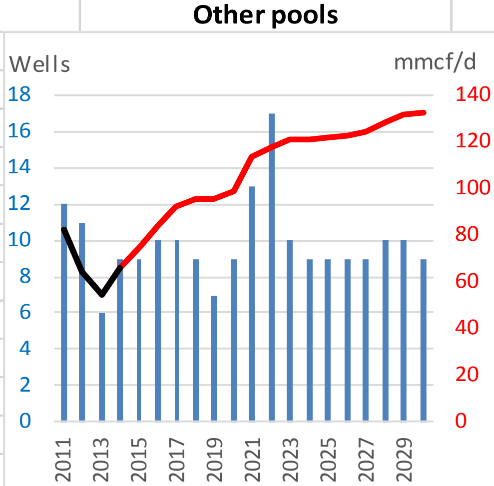
PIA10-9990-GAS
Other pools



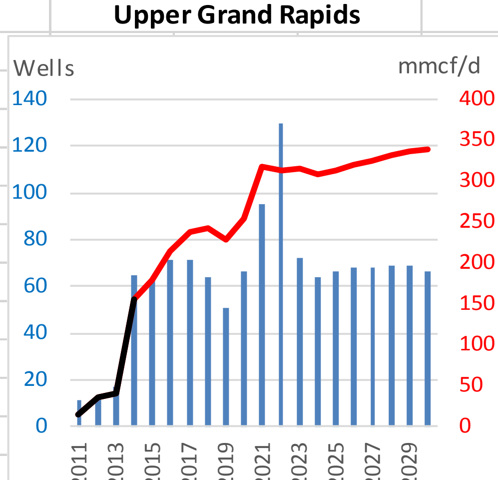
PIA10-9999-GAS
Other pools



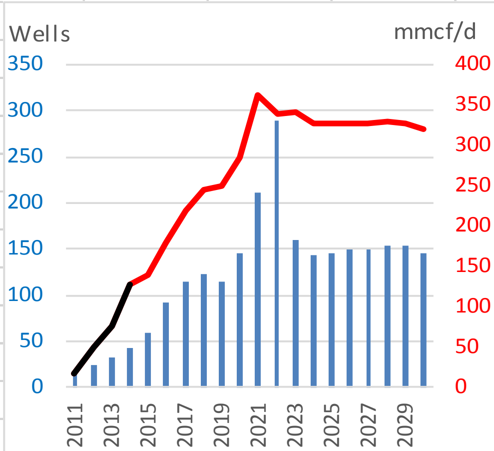
PIA11-9999-GAS
Other pools



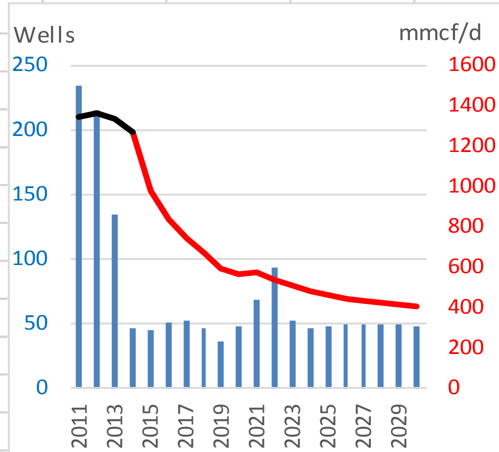
PIA13-2620-GAS
Upper Grand Rapids



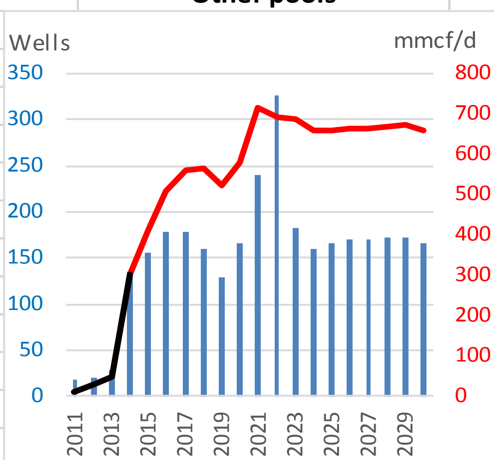
PIA13-5240-GAS
Montney



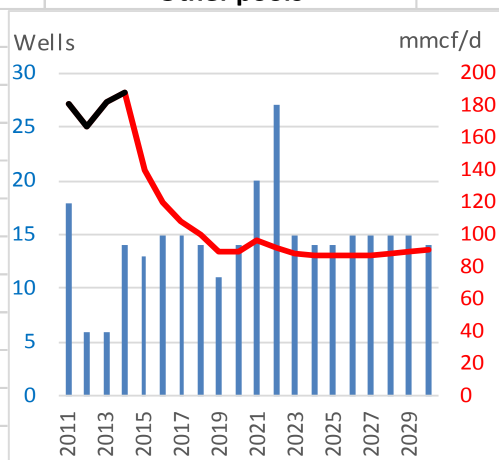
PIA13-8000-GAS
Commingled pools



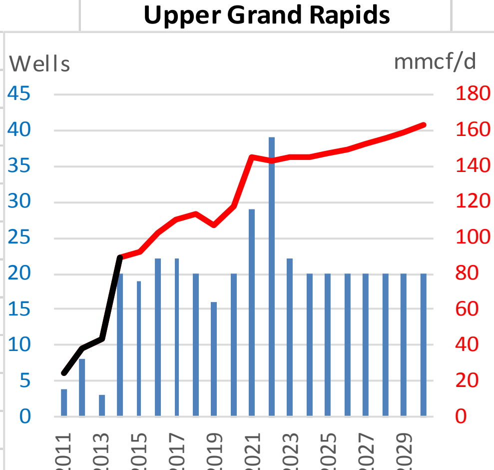
PIA13-9990-GAS
Other pools



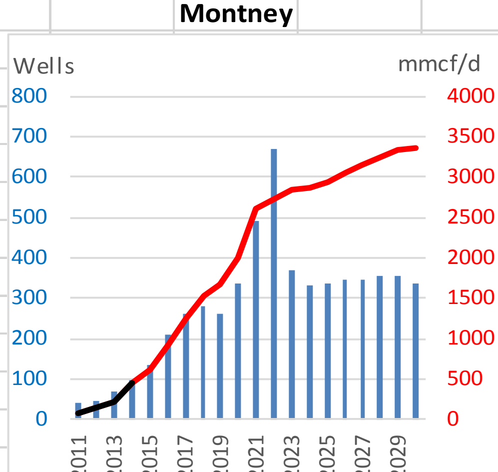
PIA13-9999-GAS
Other pools



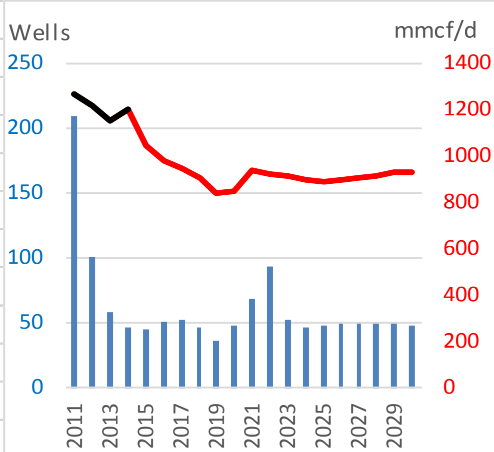
PIA14-2620-GAS
Upper Grand Rapids



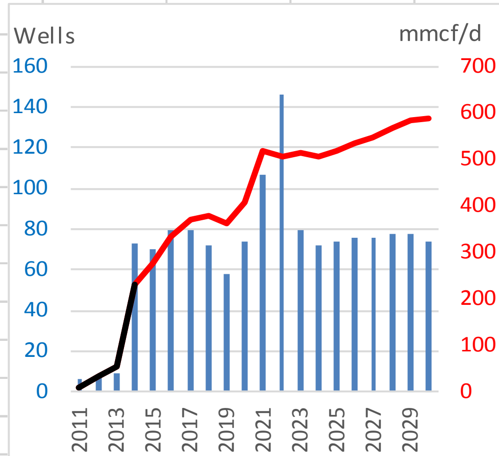
PIA14-5240-GAS
Montney



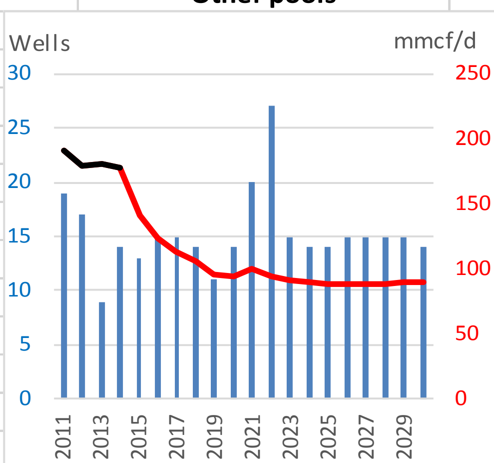
PIA14-8000-GAS
Commingled pools



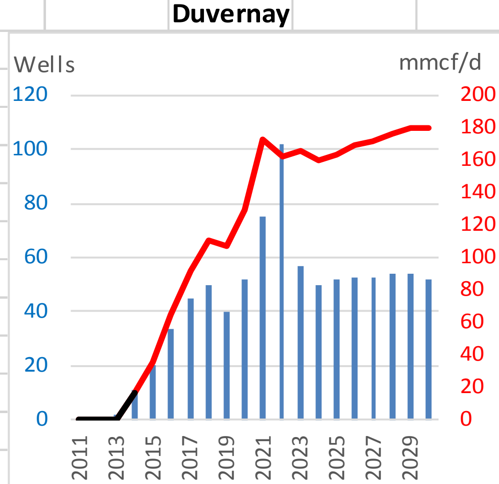
PIA14-9990-GAS
Other pools



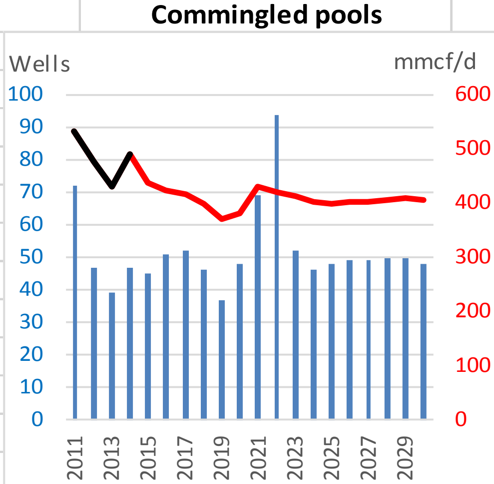
PIA14-9999-GAS
Other pools



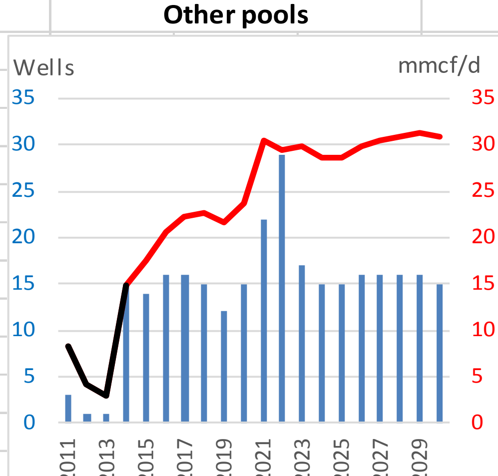
PIA15-7280-GAS
Duvernay



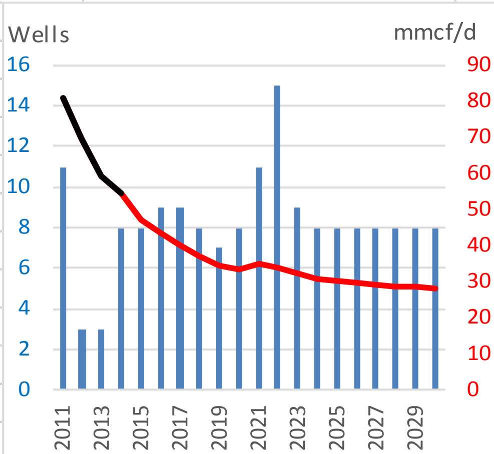
PIA15-8000-GAS
Commingled pools



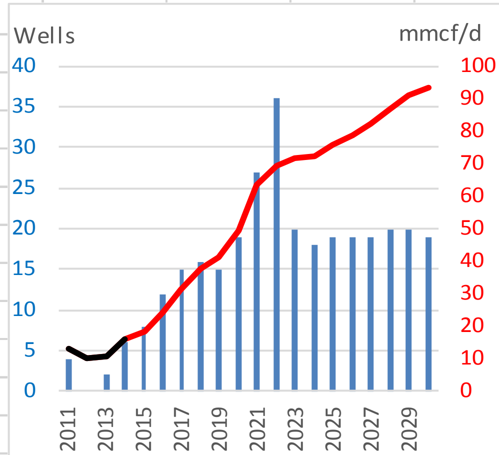
PIA15-9990-GAS
Other pools



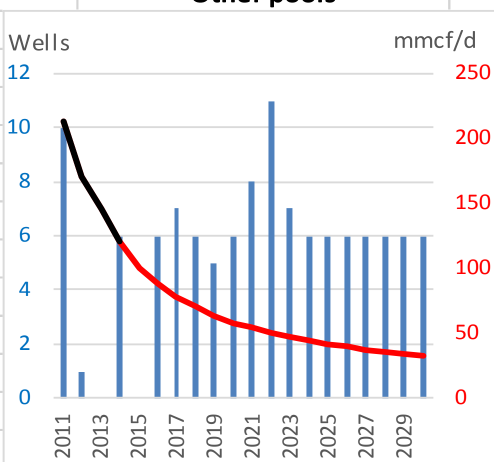
PIA15-9999-GAS
Other pools



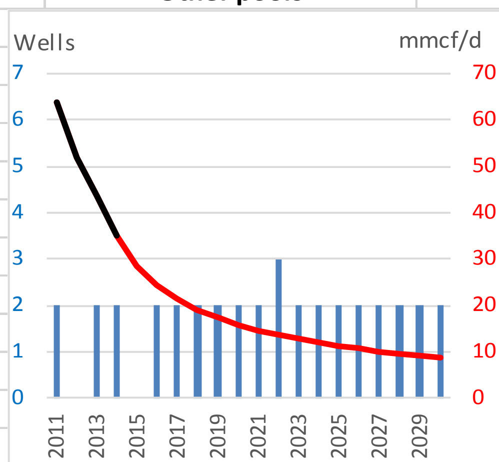
PIA16-5240-GAS
Montney



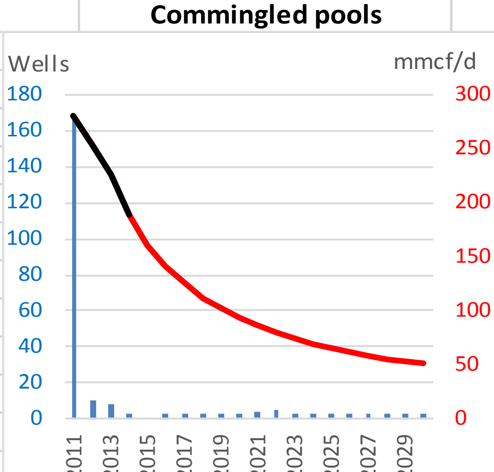
PIA19-9999-GAS
Other pools



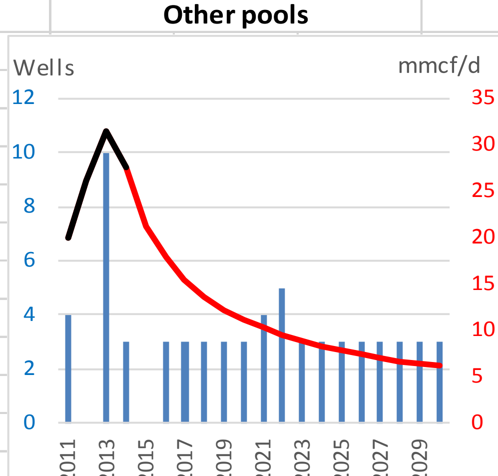
PIA18-9999-GAS
Other pools



PIA23-8000-GAS
Commingled pools



PIA23-9999-GAS
Other pools

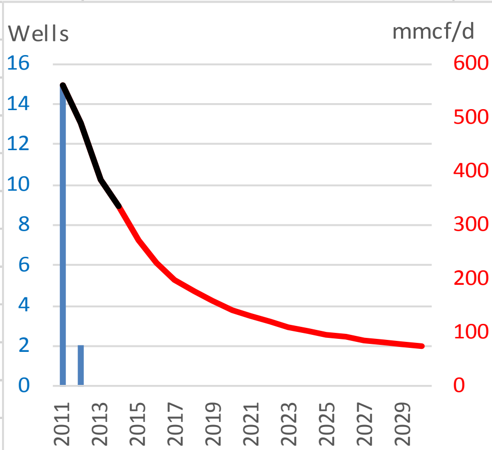


Appendix C: Selected PIA Charts for British Columbia

The following charts are example PIA Area and PIA-Formation forecasts indicating, on an annual basis, the number of new well connections along with the total average day production.

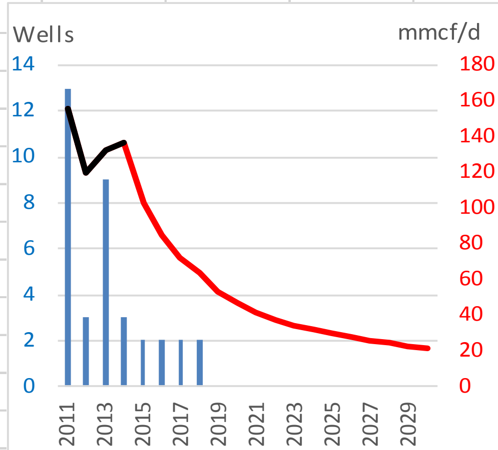
PIA30-X9999-GAS

Other pools



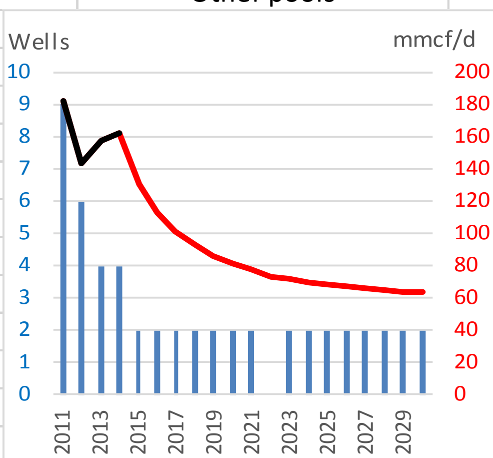
PIA31-A9030-GAS

Deep Basin Area



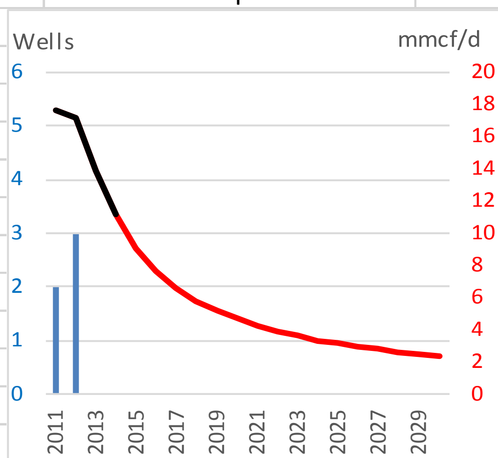
PIA31-X9999-GAS

Other pools



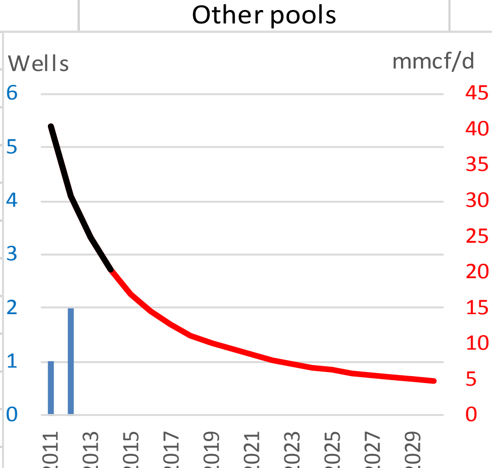
PIA32-X9999-GAS

Other pools



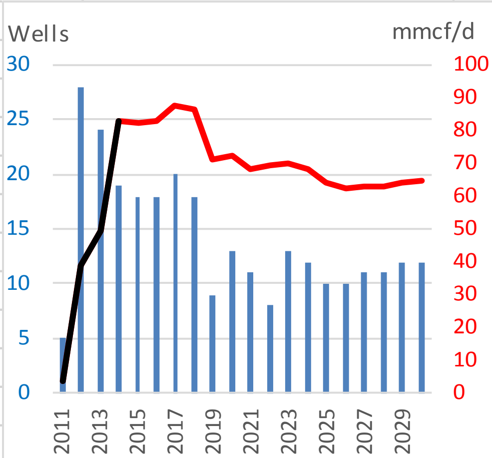
PIA33-X9999-GAS

Other pools



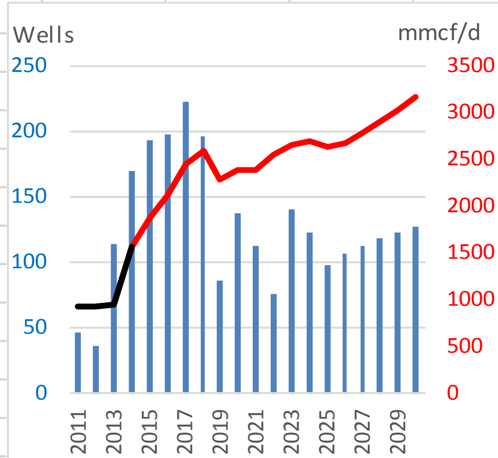
PIA34-A9022-GAS

North Montney Area



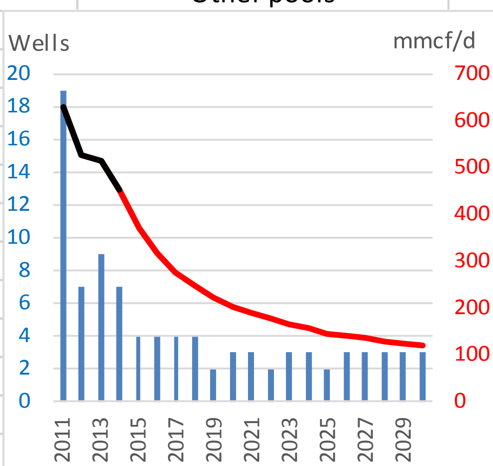
PIA34-F5000-GAS

Montney Area



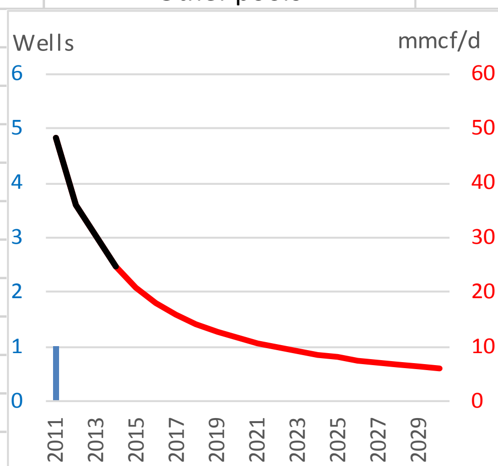
PIA34-X9999-GAS

Other pools



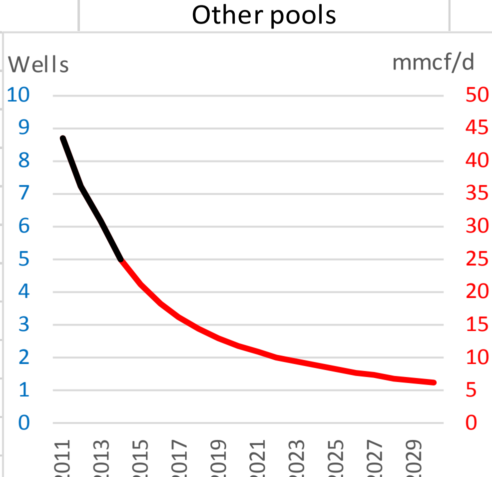
PIA35-X9999-GAS

Other pools



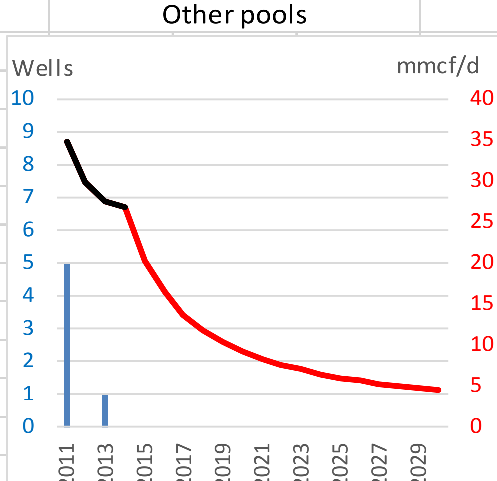
PIA36-X9999-GAS

Other pools

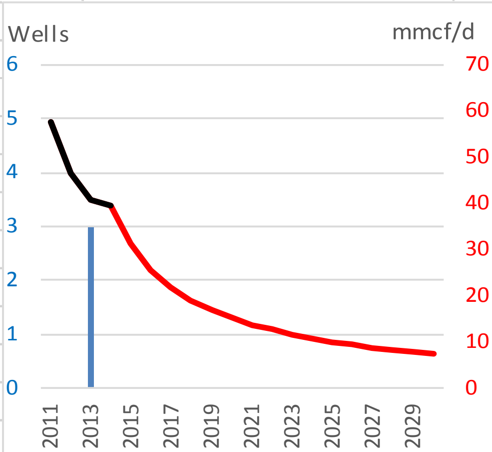


PIA38-X9999-GAS

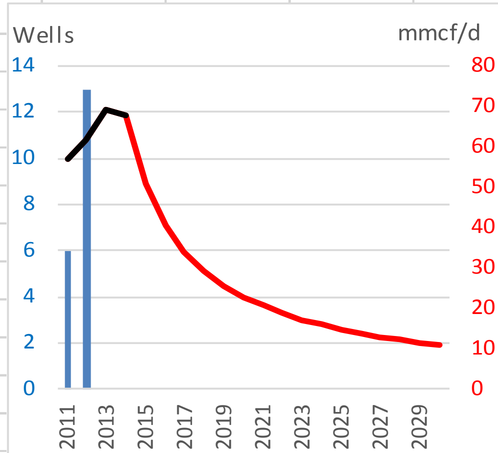
Other pools



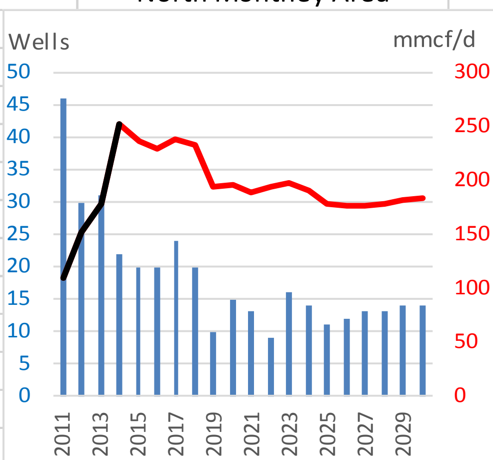
PIA39-X9999-GAS
Other pools



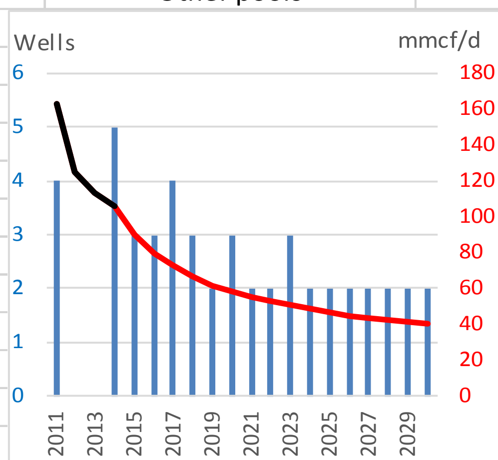
PIA40-X9999-GAS
Other pools



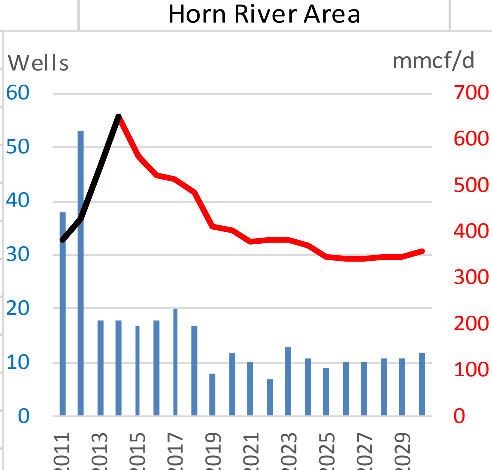
PIA41-A9022-GAS
North Montney Area



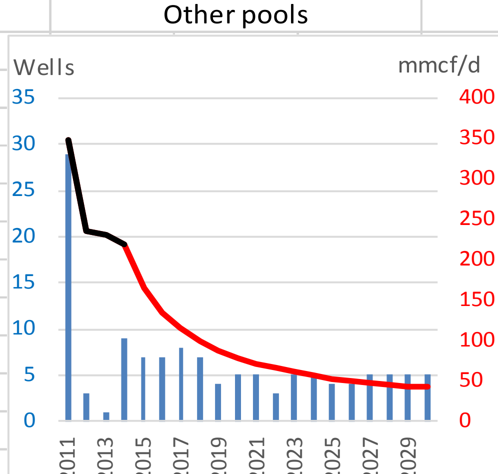
PIA41-X9999-GAS
Other pools



PIA42-A9045-GAS
Horn River Area

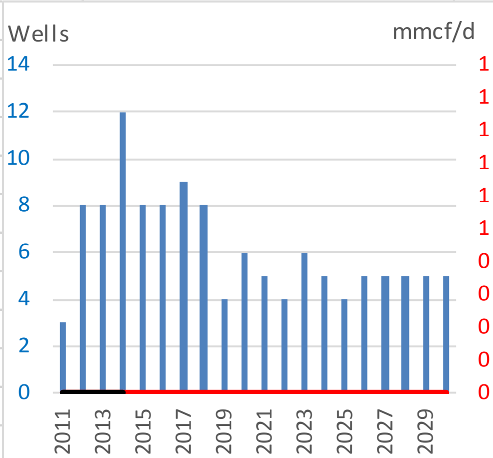


PIA42-X9999-GAS
Other pools



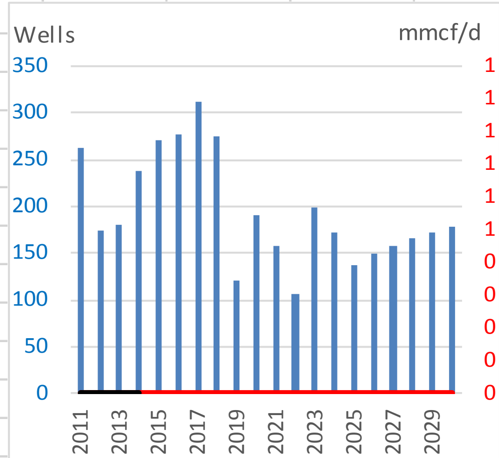
PIA34-F500A-GAS

North Montney Area



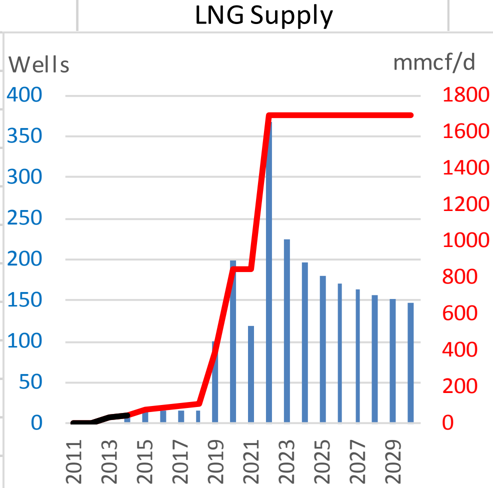
PIA34-F500B-GAS

South Montney Area



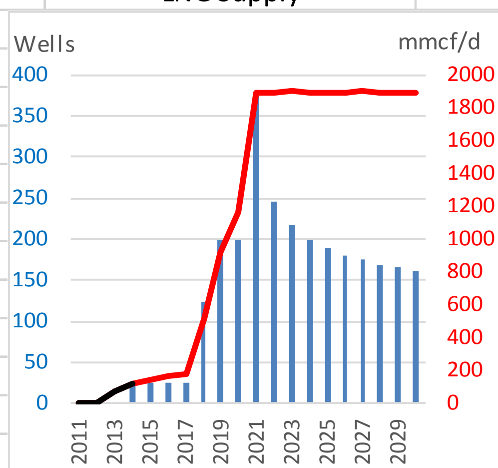
Kitimat LNG Groundbirch

LNG Supply



LNG Canada

LNG Supply



Pacific North-West LNG

LNG Supply