Canada's Energy Outlook

CURRENT REALITIES AND IMPLICATIONS FOR A CARBON-CONSTRAINED FUTURE

CHAPTER 2: NON-RENEWABLE ENERGY SUPPLY, RESOURCES AND REVENUE
Full report available at energyoutlook.ca

By J. David Hughes

MAY 2018

CCPA
CANADIAN CENTRE for POLICY ALTERNATIVES
BC Office

PARKLAND INSTITUTE

CORPORATE MAPPING PROJECT

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Contents

Introduction to Part 2

The previous section outlined the big picture of where Canada stands in terms of energy consumption and emissions with respect to the rest of the world. Canadians enjoy a high standard of living compared to much of the world, but this is fuelled by high levels of energy consumption, a major portion of which is from fossil fuels. Canada has been touted as an "energy superpower" by the former Harper government, and the Alberta government clamours for expanded oil and gas production and new pipelines to "tidewater" for more oil and gas exports to boost the economy. The Trudeau government has subscribed to this rhetoric with its approval of new pipelines and liquefied natural gas export terminals. Fossil fuels, however, are finite, non-renewable resources, and despite the urgent need to reduce emissions, they will likely be needed in the long term at some level. The following section examines Canada's energy supply from non-renewable resources, from both a historical and future sustainability perspective.

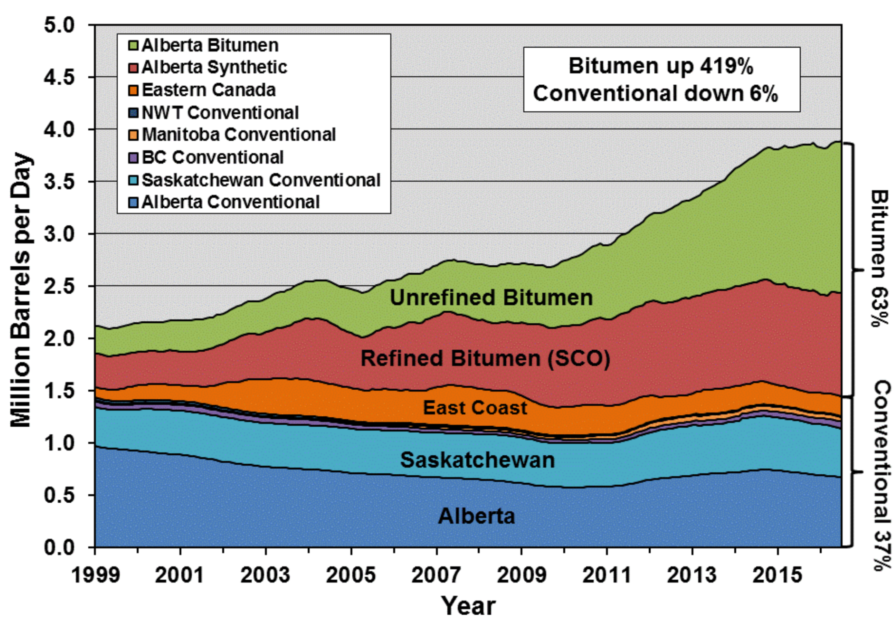
2.1 Oil and gas

Canada is a mature oil and gas exploration region with the exception of the Far North and parts of the East and West coasts offshore. The four western provinces comprise the majority of production, along with some declining offshore production from Newfoundland in Eastern Canada. There has been a moratorium on exploration off the West Coast for several decades and exploration in the Arctic has been minimal since the 1970s.

Figure 50 illustrates Canadian oil production over the past 17 years. Conventional oil production has declined overall, but strong growth in "unconventional" bitumen production has resulted in overall production of nearly four million barrels per day, 63% of which was bitumen in mid-2016.

Figure 50: Marketable oil production in Canada by province and oil type from 1999 to 2016.

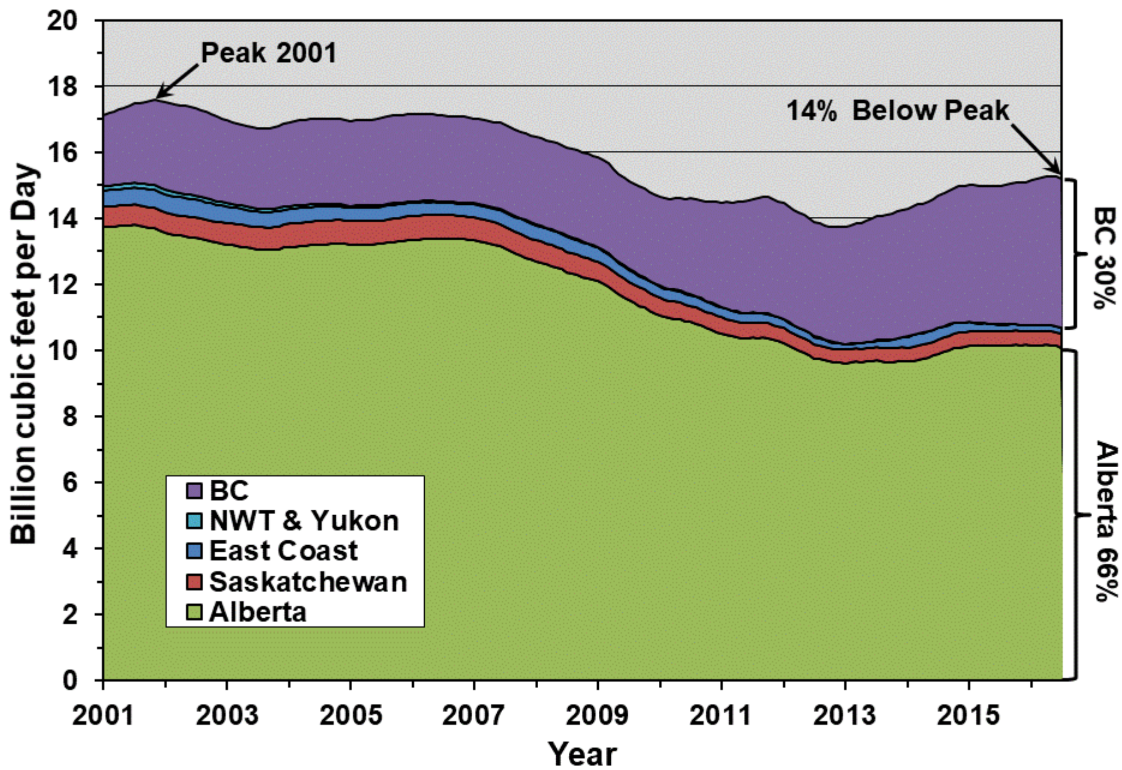
The majority of bitumen production is in Alberta.[1]



[1] Data from National Energy Board, 1988–2016, crude oil, C5+ and condensate; 12 month centred moving average

Figure 51 illustrates Canadian natural gas production over the past 15 years. Natural gas production peaked in 2001 and is now down 14% from peak. Alberta comprised two-thirds of Canadian gas production in 2016. Recent growth in gas production has been mainly confined to British Columbia, which is also the major hope for future growth. Exports to the US, which once comprised more than half of Canadian production, have been declining as US shale gas production increases.

Figure 51: Marketable natural gas production by province from 2001 to 2016. [2]



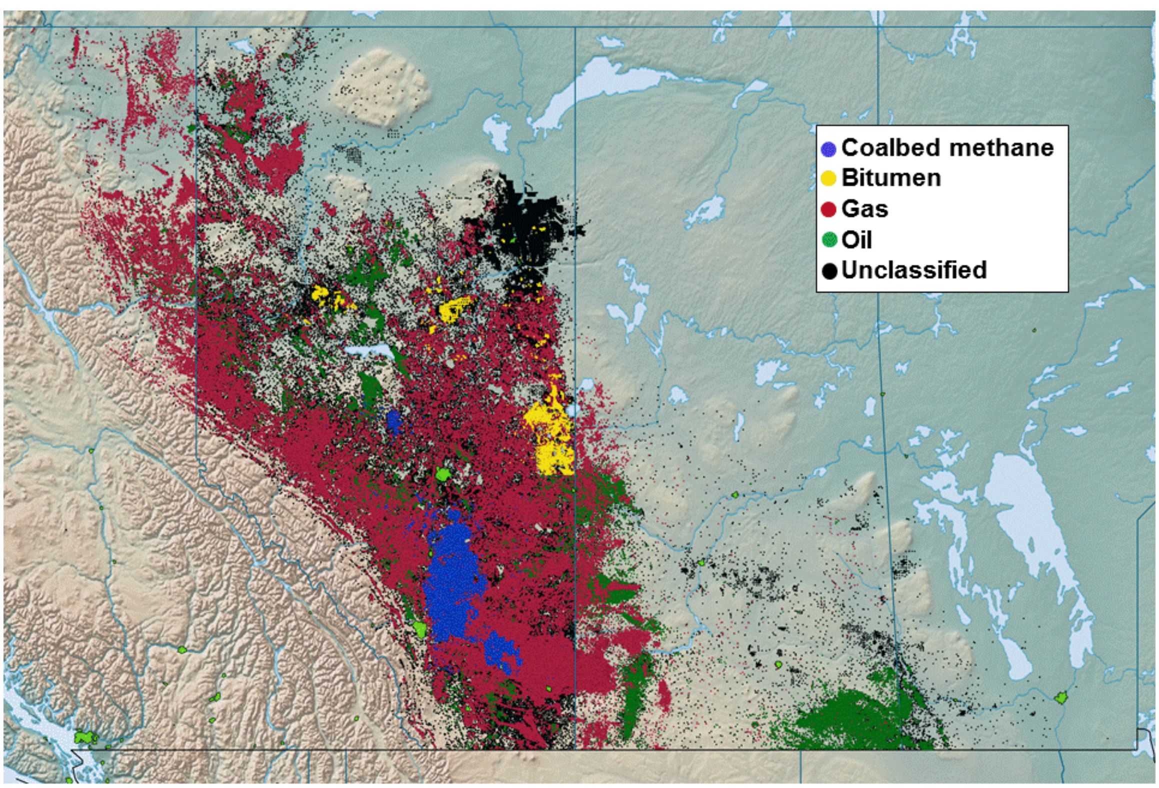
Western Canada is a mature petroleum exploration region, with more than 800,000 wells drilled since the discovery of oil in the early part of the last century. Table 2 (next page) provides the distribution of wells by type and province, and Figure 52 illustrates well distribution in Western Canada. Of the total, some 491,000 wells are producing or have produced bitumen, oil or gas. Other wells produce water used in secondary and/or tertiary oil recovery operations and hydraulic fracturing, or are used for injection of fluids (mainly water but also solvents, carbon dioxide, acid gas and waste), and a great many wells (labelled N/A in Table 2 and unclassified in Figure 52) are stratigraphic tests delimiting the extent of resources in the oil sands and elsewhere. The distribution of well types mimics the fundamental nature of the geology: BC is gas prone, due to the higher thermal maturity of its reservoir rocks; Alberta is both oil and gas prone; Saskatchewan is primarily oil prone, as thermal maturity decreases eastward; and Manitoba is almost exclusively oil prone. Some 77% of all wells have been drilled in Alberta, 18% in Saskatchewan, 3.2% in BC and 1.3% in Manitoba.

[2] Data from National Energy Board, 1988–2016, 12 month centred moving average

Table 2: Distribution of wells by type and province associated with the oil and gas industry as of late 2015.

Well type	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Gas	17,301	186,201	35,501	1	**239,004**	29.1%
Oil	3,323	91,718	90,104	7,758	**192,903**	23.4%
Bitumen	0	23,243	0	0	**23,243**	2.8%
Cyclic-steam	0	9,063	990	0	**10,053**	1.2%
SAGD	0	3,422	0	0	**3,422**	0.4%
CBM	0	22,295	0	0	**22,295**	2.7%
Water	1,011	1,624	834	18	**3,487**	0.4%
Injection	8	15,758	7,941	588	**24,295**	3.0%
Other	0	1,387	12,523	1,906	**15,816**	1.9%
N/A	4,951	282,751	49	431	**288,182**	35.0%
Total	**26,594**	**637,462**	**147,942**	**10,702**	**822,700**	**100.0%**

Figure 52: Distribution of wells associated with the oil and gas industry in Western Canada by well type as of late 2015.[3]



[3] Data from Drillinginfo, December 2015

Wells are categorized by current status in Table 3. Of the more than 800,000 wells drilled, just 235,876 (28.7%) are currently active. The remainder have been plugged and abandoned, are inactive or suspended, or were never used for oil and gas production (e.g., injection wells and stratigraphic tests).

Table 3: Western Canadian wells associated with oil and gas production by well status and province.

Well status	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Active	9,716	168,496	52,700	4,964	**235,876**	28.7%
Inactive	3,926	294,603	15,594	1,649	**315,772**	38.4%
Suspended	5,972	64,766	21,164	6	**91,908**	11.2%
Abandoned	4,797	74,564	42,307	1,898	**123,566**	15.0%
Other	2,183	35,033	16,177	2,185	**55,578**	6.8%
Total	**26,594**	**637,462**	**147,942**	**10,702**	**822,700**	**100.0%**

The advent of horizontal drilling in conjunction with high-volume hydraulic fracturing (fracking) has opened up previously inaccessible shale and tight reservoirs, resulting in a turnaround in US oil and gas production. Fracking has also been widely applied in Canada. Although they are more costly, fracked wells are generally more productive, requiring fewer wells to maintain production. Horizontal drilling has proved very effective in draining the last of the oil and gas from old reservoirs developed mainly with vertical drilling, and in accessing previously uneconomic reservoirs. Table 4 provides the distribution of wells by drill type and province. Although horizontal wells make up only 11% of the total, they are now responsible for the majority of production. Figure 53, for example, illustrates the takeover of horizontal drilling for natural gas production in Western Canada—from nothing in the early 1990s to 59% of production in 2014. In BC, where new production is coming from shale and tight reservoirs, 82% of production comes from horizontal wells. In terms of oil production, the takeover by horizontal drilling is even more remarkable. Figure 54 illustrates oil production by drill type. In 2015, 74% of production came from horizontal wells.

Table 4: Western Canadian wells associated with oil and gas production by drill type and province.
The "undifferentiated" wells in Alberta are primarily vertical.

Drill type	BC	Alberta	Saskatchewan	Manitoba	Total	Per cent
Vertical	15,592	n/a	109,593	6,858	**132,043**	16.0%
Horizontal	7,805	49,311	27,481	3,736	**88,333**	10.7%
Directional	3,197	n/a	10,868	108	**14,173**	1.7%
Undifferentiated	0	588,151	0	0	**588,151**	71.5%
Total	**26,594**	**637,462**	**147,942**	**10,702**	**822,700**	**100.0%**

Figure 53: Raw gas production in Western Canada by drill type from 1965 to 2015.
Horizontal drilling now accounts for 59% of production. Note that raw gas production is higher than marketable gas production due to losses in processing, etc. [4]

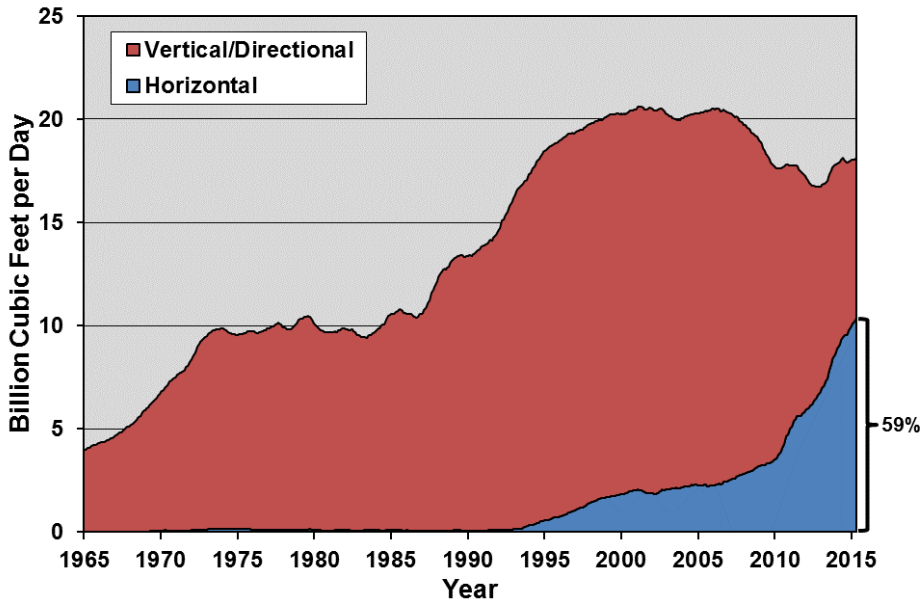
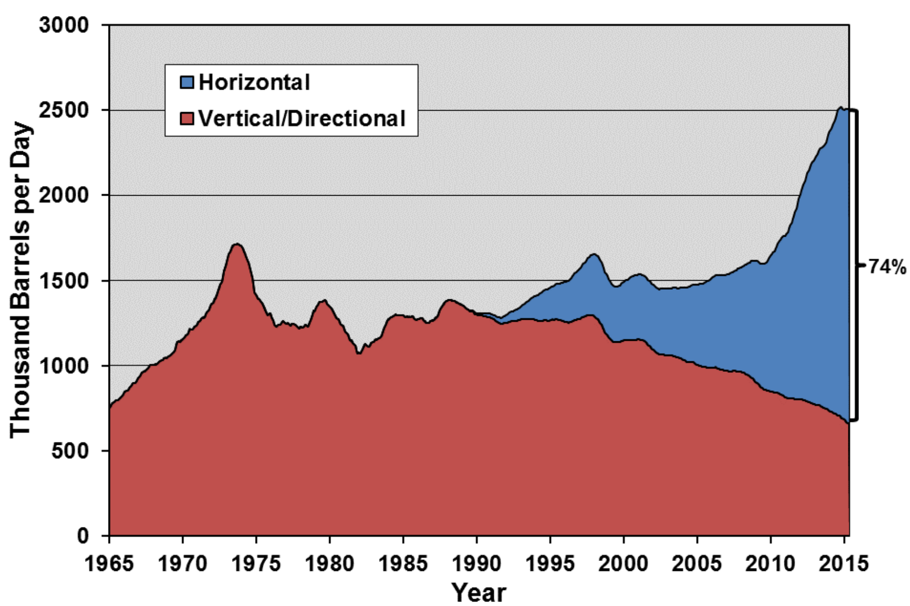


Figure 54: Oil production by drill type in Western Canada from 1965 to 2015.
Horizontal drilling now accounts for 74% of production. [5]



Horizontal wells require variable levels of fracking, depending on the nature of the reservoir. In the Horn River basin of northeast BC, for example, more than 25 million gallons of water have been used to frack individual wells, whereas in BC's Montney tight gas play an average well uses about 4 million gallons. The environmental ramifications of this include sourcing the water for the fracking operation, potential

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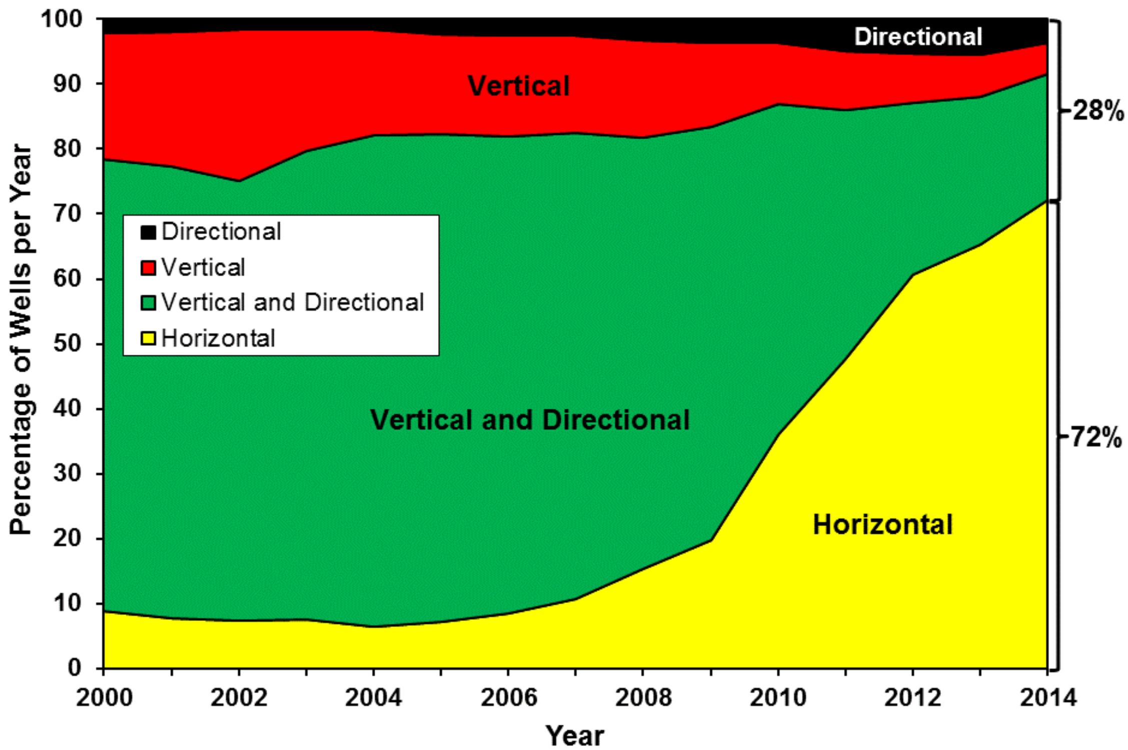
4 Data from Drillinginfo, December 2015; 12 month centred moving average
5 Data from Drillinginfo, December 2015; 12 month centred moving average

contamination of aquifers through casing failure and from produced frack water, and induced seismicity from both the fracking operation and the disposal of frack water in injection wells.

Notwithstanding the potential environmental impacts, Figure 55 illustrates drilling activity trends by drill type. Horizontal wells made up 72% of all wells drilled in 2014, up from 10% as recently as 2006, and are likely to increase further.

Figure 55: Drilling in Western Canada by well type from 2000 to 2014.

Horizontal drilling made up 72% of the total in 2014. Data are wells with first production in each year.[6]



[6] Data from Drillinginfo, December 2015;

The importance of horizontal drilling and hydraulic fracturing (fracking) to oil and gas production in Western Canada is summarized in Table 5. Even though horizontal wells make up only 20% of producing wells and 11% of all wells, they produced 75% of the oil and 58% of the gas in Canada as of August 2015. In British Columbia horizontal wells produced 83% of the gas and in Alberta they produced 76% of the oil. New oil developments in Saskatchewan and Manitoba are highly dependent on horizontal drilling and fracking.

Table 5: Oil and gas production from wells by province and well type as of August 2015.
Also shown are the number of producing wells and total well count by type. Horizontal drilling now accounts for the majority of Canada's oil and gas production.

PRODUCTION						
	Total		Vertical/directional		Horizontal	
Province	Oil (kbd)	Gas (bcf/d)	Oil	Gas	Oil	Gas
BC	**30.9**	**4.6**	34.6%	16.7%	65.3%	83.4%
Alberta	**1,952.4**	**11.9**	23.7%	51.0%	76.3%	49.0%
Saskatchewan	**482.3**	**0.6**	30.4%	55.5%	69.6%	44.5%
Manitoba	**41.5**	**0.0**	23.7%	25.5%	76.3%	74.5%
Total	**2,507.0**	**17.1**	**25.1%**	**42.0%**	**74.9%**	**58.1%**

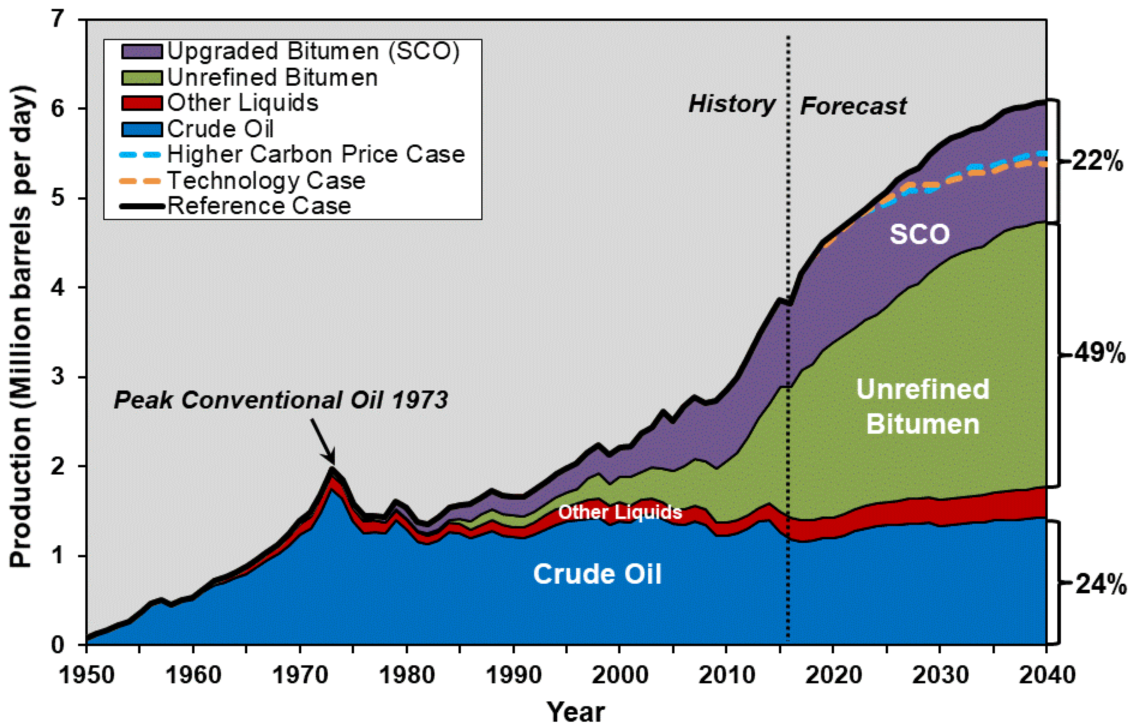
	Producing wells			All wells		
Province	Total	Vertical/ directional	Horizontal	Total	Vertical/ directional	Horizontal
BC	**9,047**	49.3%	50.7%	**26,594**	70.7%	29.3%
Alberta	**163,014**	86.3%	13.7%	**637,462**	92.3%	7.7%
Saskatchewan	**46,001**	66.4%	33.6%	**147,942**	81.4%	18.6%
Manitoba	**4,167**	44.3%	55.7%	**10,702**	65.1%	34.9%
Total	**222,229**	**79.9%**	**20.1%**	**822,700**	**89.3%**	**10.7%**

The trend of increasing application of horizontal drilling will continue, given that the bulk of remaining oil is contained in tight reservoirs requiring fracking, and in bitumen deposits accessible only by in situ methods such as steam-assisted gravity drainage (SAGD). Similarly, the bulk of remaining gas is contained in shale and tight reservoirs in western Alberta and northeast BC. Notwithstanding pushback from environmental groups against fracking, this technology will be needed to access most of the remaining oil and gas resources in Western Canada.

2.1.1 Conventional oil

Conventional oil production peaked in Canada in 1973 and production has remained flat since the mid-1990s. Figure 56 illustrates Canadian oil production by type since 1950, including the latest National Energy Board projections through 2040. Given the mature state of exploration, there is little prospect for major new discoveries of conventional light and heavy oil in Western Canada. Although conventional oil production will continue with some new discoveries along with production from known fields through primary, secondary and tertiary recovery methods, the only prospect for a significant ramp-up in Canadian oil production is from the oil sands.

Figure 56: Canadian oil production by type since 1950 with the latest National Energy Board projections (higher carbon price case, technology case and reference case) through 2040.[7]

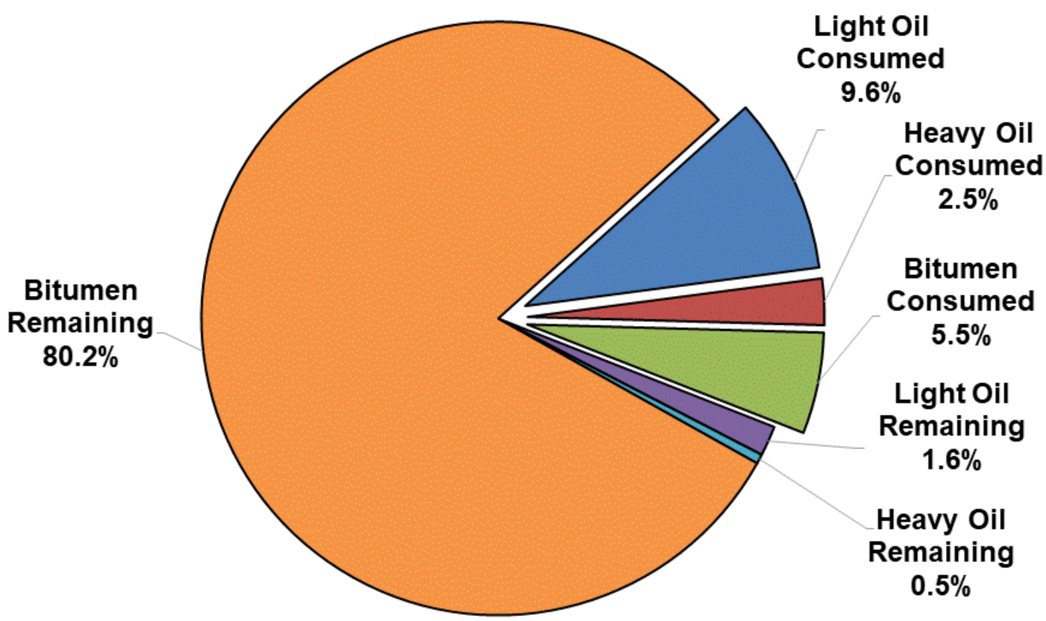


[7] 1950-2004 data are from the Canadian Association of Petroleum Producers Statistical Handbook retrieved December 3 2016. 2005-2040 data are from the National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA. ("Other liquids" include condensate and C5+.) The NEB's "reference" case projection is illustrated along with totals for its "higher carbon price" and "technology" cases. The reference case is based on the current economic outlook, a moderate view of energy prices, and climate and energy policies that have been announced at the time of analysis. The higher carbon price case assumes the Canadian price for carbon increases steadily by $5 per tonne per year after reaching $50 per tonne in 2022, to $90/tonne in 2030 and $140/tonne in 2040. The technology case considers, in addition to higher carbon prices, the impact on the Canadian energy system of greater adoption of select emerging production and consumption energy technologies.

Figure 57 illustrates Canadian oil reserves at the end of 2015, according to the National Energy Board. Of an original reserve endowment of 206.1 billion barrels, 86% is bitumen and 14% is conventional oil. Some 85% of conventional oil reserves have been consumed, which means that 97.4% of Canada's remaining reserves of 169.8 billion barrels are bitumen. Bitumen from the oil sands represents a large potential resource, but compared to conventional oil its production requires large energy inputs with associated emissions, and imported diluents to move it through pipelines (a 30% blend of diluent with the bitumen is needed). Bitumen also commands a lower price than conventional oil due to its inferior quality. Under Alberta's recently announced cap, oil sands emissions will rise to 19.3% of all Canadian emissions by 2030 if commitments under the Paris Agreement signed at COP21 are kept (oil sands emissions were 10.9% of Canadian emissions in 2015). The sections that follow examine conventional oil and bitumen in more detail.

Figure 57: Canadian oil reserves at the end of 2016 according to the National Energy Board.[8]

Of the original endowment of 206 billion barrels, 17.6% has been consumed, including 85% of conventional oil reserves. Oil sands constitute 97.4% of remaining reserves.

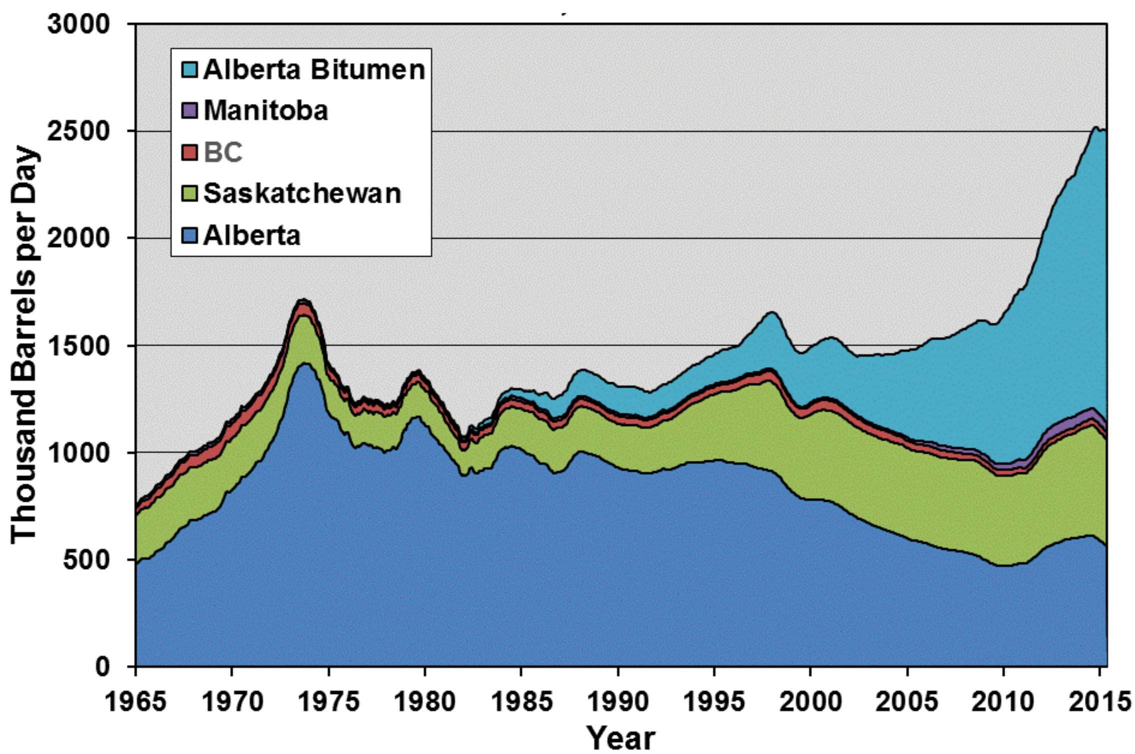


[8] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA (these were received via email from NEB November 2, 2017 as corrections to data originally posted in the report).

Conventional oil production in Western Canada peaked in 1973, as illustrated in Figure 58. Although Alberta has produced the majority of Canada's oil, Saskatchewan has been increasing in part due to the development of the northern extension of the Bakken field of North Dakota through the application of horizontal fracturing technology, and now accounts for nearly half of conventional oil production in Western Canada.

Figure 58: Conventional oil and bitumen production from wells (i.e., does not include mined bitumen) by province in Western Canada from 1965 to 2015.

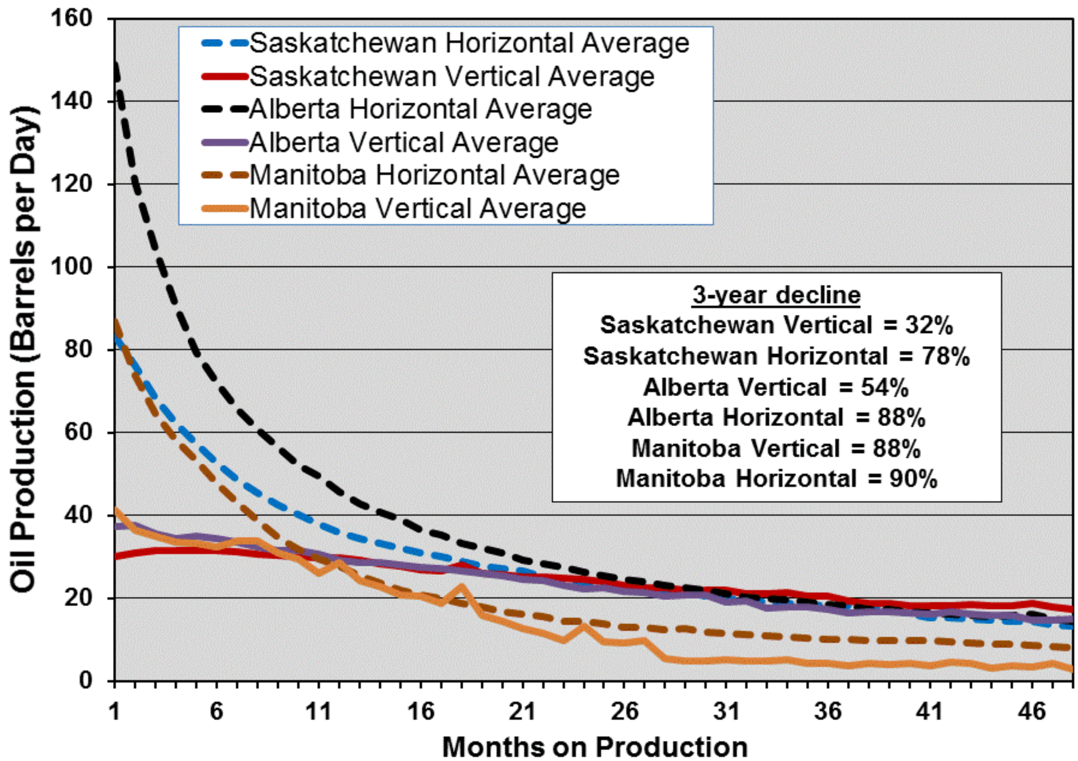
Peak conventional production occurred in 1973.[9]



[9] Data from Drillinginfo, December 2015; 12 month centred moving average

Oil wells, especially horizontal ones, decline in production rapidly over their first few years, necessitating more drilling to maintain production. Figure 59 illustrates the average production rates over time of conventional oil wells (not including bitumen wells or liquids production from gas or other wells). Production decline in the first three years averages between 78% and 90% for horizontal wells and between 32% and 88% for vertical wells. As decline is hyperbolic, with the steepest decline in the first few years, overall field declines from a mix of old and new wells typically ranges between 25% and 35% per year, meaning that this much production must be replaced each year through more drilling to keep production flat. On average, Manitoba oil wells are less productive that those in Alberta and Saskatchewan (BC's oil production is relatively minor—see Figure 58). Production from oil wells in even the best shale plays, such as the Bakken in southeast Saskatchewan and southwest Manitoba, is typically far less than that from wells in the "sweet spots" of US tight oil plays like the Bakken or Eagle Ford.

Figure 59: Average production decline profiles for oil wells in Alberta, Saskatchewan and Manitoba.[10]

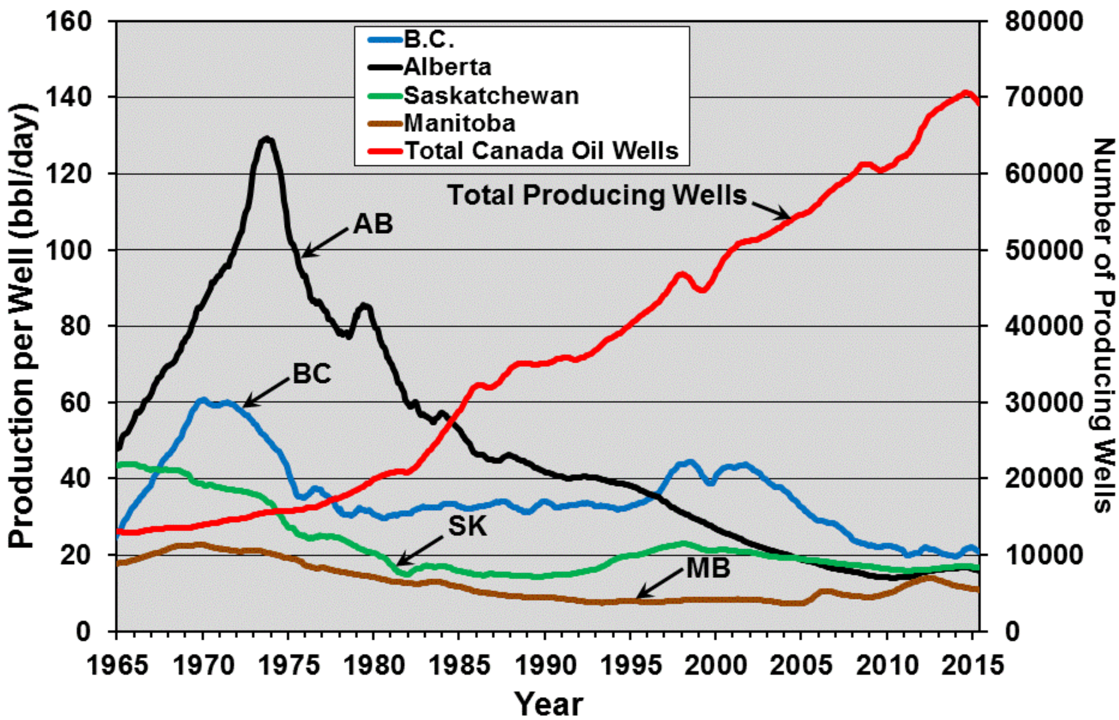


[10] Data from Drillinginfo, December 2015

Given the steep drop in production of the average oil well in the first few years after it is drilled, and the rapidly escalating number of wells, the average productivity of wells has declined over time. Figure 60 illustrates average oil well productivity since 1965. Peak production per well occurred in the late 1960s and 1970s for all provinces. More and more wells and infrastructure are required to maintain production as fields are exhausted. This trend of declining productivity will continue.

Figure 60: Average production per conventional oil well by province from 1965 to 2015, and total number of producing oil wells.

Does not include bitumen production from bitumen, cyclic-steam and SAGD wells or liquids from gas wells.[11]



Oil reserves are defined as discovered resources that are technically and economically recoverable. They are usually expressed in probabilistic terms: "proven", "probable" and "possible".[12] The National Energy Board (NEB) provides no such subdivisions, however, providing instead only "reserve" and "resource" breakdowns. In the NEB's parlance, "resources" include both "discovered resources" (which include "reserves") and "undiscovered resources" that may be proven to exist in the future with more exploration. Since the NEB does not provide the backup information required under regulations such as National Instrument 51-101, under which Canadian reserve and resource reporting is regulated, its estimates of reserves and resources should be viewed as approximate and likely subject to downward revisions if measured under current regulatory requirements.

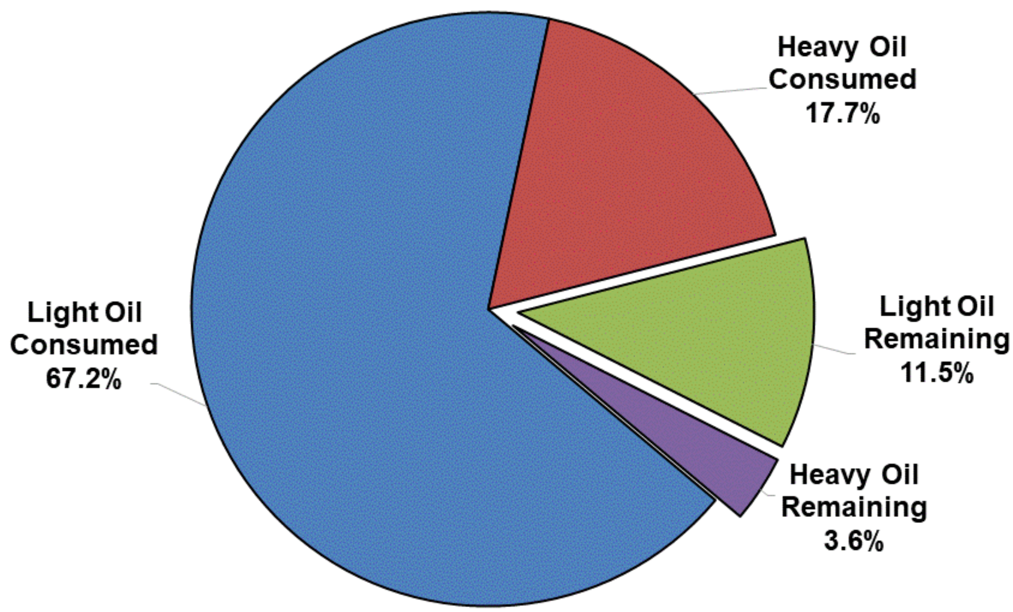
[11] Data from Drillinginfo, December 2015; 12 month centred moving average

[12] Society of Petroleum Engineers, 2011, Guidelines for Application of the Petroleum Resources Management System http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf . In Canada reserve and resource reporting is regulated under National Instrument 51-101 which is guided by technical standards in the Canadian Oil and Gas Evaluation Handbook updated periodically by the Canadian branch of the Society of Petroleum Engineers.

Figure 61 illustrates Canada's conventional reserves at the beginning of 2015 according to the NEB. Of the 29.4-billion barrel endowment, 85% has been consumed, leaving just 4.5 billion barrels remaining (Canada consumed .55 billion barrels of conventional oil in 2015, so conventional oil reserves represent 8.2 years of current consumption).

Figure 61: Canadian conventional oil reserves at the end of 2016 according to the NEB.

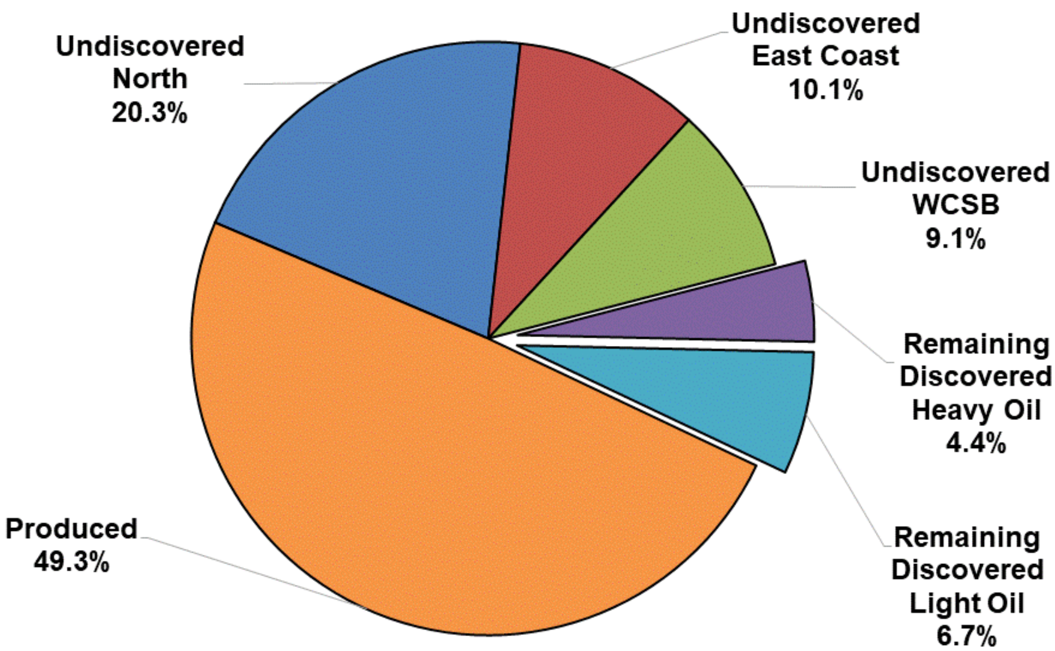
Of the original endowment of 29.4 billion barrels, 85% has been consumed.[13] *Remaining light oil reserves are 3.4 billion barrels and remaining heavy oil reserves are 1.1 billion barrels.*



[13] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Figure 62 illustrates Canada's conventional oil "resources", including undiscovered resources thought to exist off the East Coast and the Arctic Coast, according to the NEB. Undiscovered resources have a low certainty of existence compared to reserves and include no assurance that they are technically and economically feasible to develop. Furthermore, there are additional environmental concerns with developing oil resources in the Arctic given its remoteness and susceptibility to spills. Of the 50.6-billion barrel original endowment of conventional oil resources, 49.3% have been consumed, 39.5% have yet to be discovered and 11.1% are discovered resources that have not yet been produced.

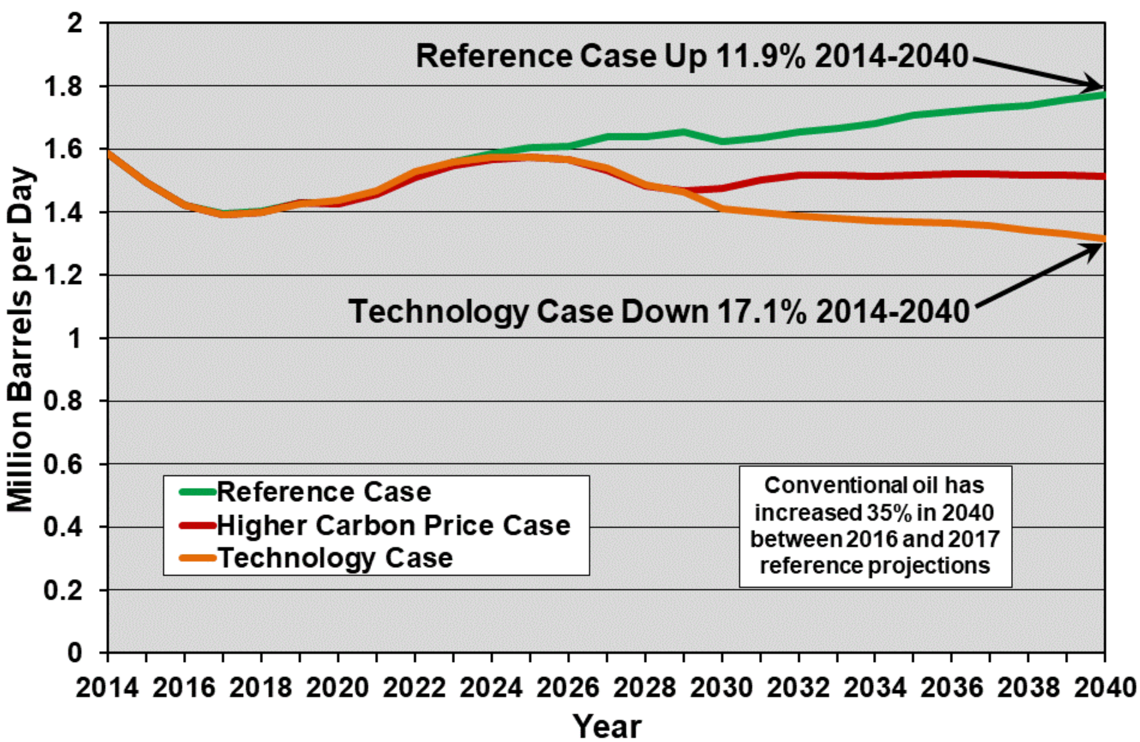
Figure 62: Canadian conventional oil resources at the end of 2016 according to the National Energy Board.
Of the hoped for 50.6-billion barrel endowment, 49.3% has been consumed, 39.5% has yet to be discovered and 11.1% are discovered resources that have not yet been produced.[14]



14 Data from NEB Energy Future, October 2017

Although there is hope that relatively new plays made possible by horizontal drilling and fracking technology (like the Montney and Duvernay in Alberta and BC and the Bakken in Saskatchewan and Manitoba) will replace declining production in older plays, their collective production amounted to less than 12% of Canadian conventional production as of late 2015. The NEB's projections range from a 12% growth to a 17% decline in conventional oil production from 2014 levels by 2040, as illustrated in Figure 63.[15] Clearly there is no bonanza ahead for conventional oil production in Canada. The only hope for substantially increased production, as previously stated, lies in the oil sands.

Figure 63: National Energy Board projections of conventional oil production by scenario over the 2014–2040 period, from its latest outlook.[16]



The NEB's reference case estimate in Figure 63 would see 14.1 billion barrels of conventional oil recovered between 2017 and 2040. This would require the recovery of 100% of Canada's remaining discovered resources, 100% of the undiscovered resources in Western Canada, and 25% of the undiscovered resources off the East Coast and in the Arctic. This seems a highly optimistic assessment of what is possible, and would leave Canada with very little remaining conventional oil by 2040 (and located in vulnerable Arctic and offshore locations).

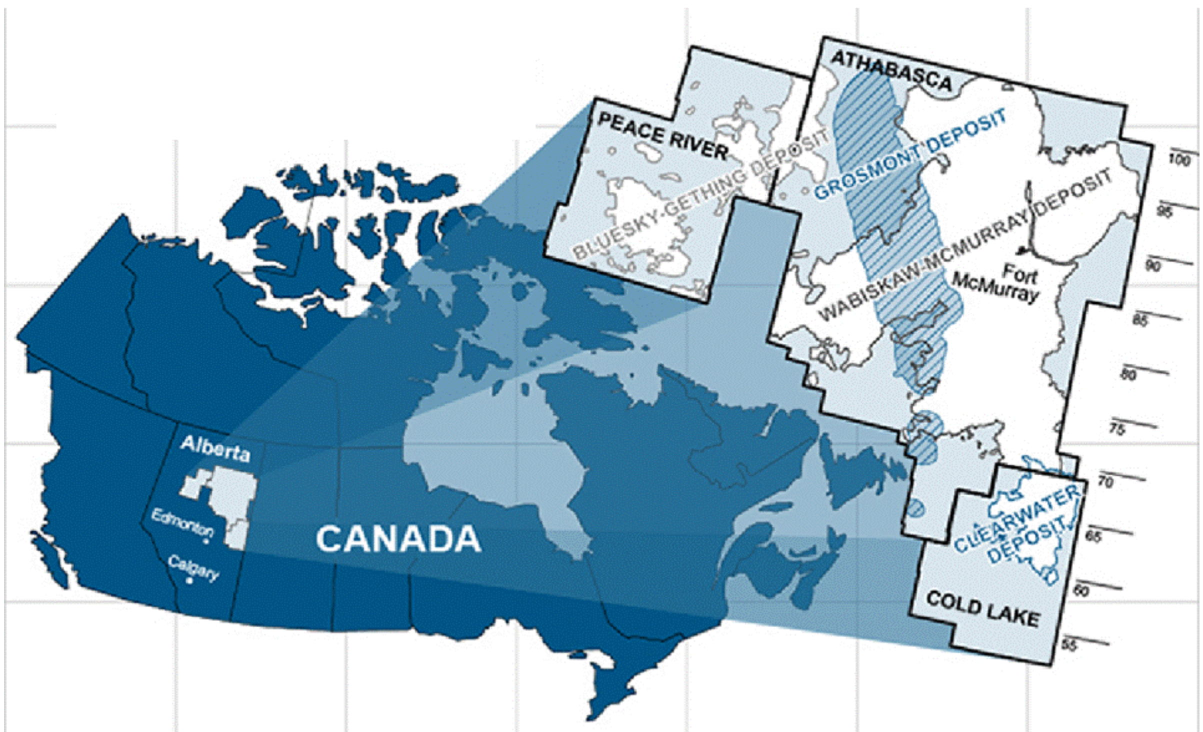
[15] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

[16] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA (conventional includes NGLs)

2.1.2 Bitumen production

Bitumen represents by far the largest remaining portion of Canada's oil resources. It is recovered by surface mining as well as drilling where deposits are too deep to be mined. Oil sands deposits are widespread in northern Alberta, as illustrated in Figure 64. However, the mineable portion is exclusively within the Athabasca region and largely confined to the Wabiskaw-McMurray deposit. Elsewhere bitumen is recovered from greater depths by in situ methods using conventional wells and thermally heated cyclic-steam and steam-assisted gravity drainage (SAGD) wells.

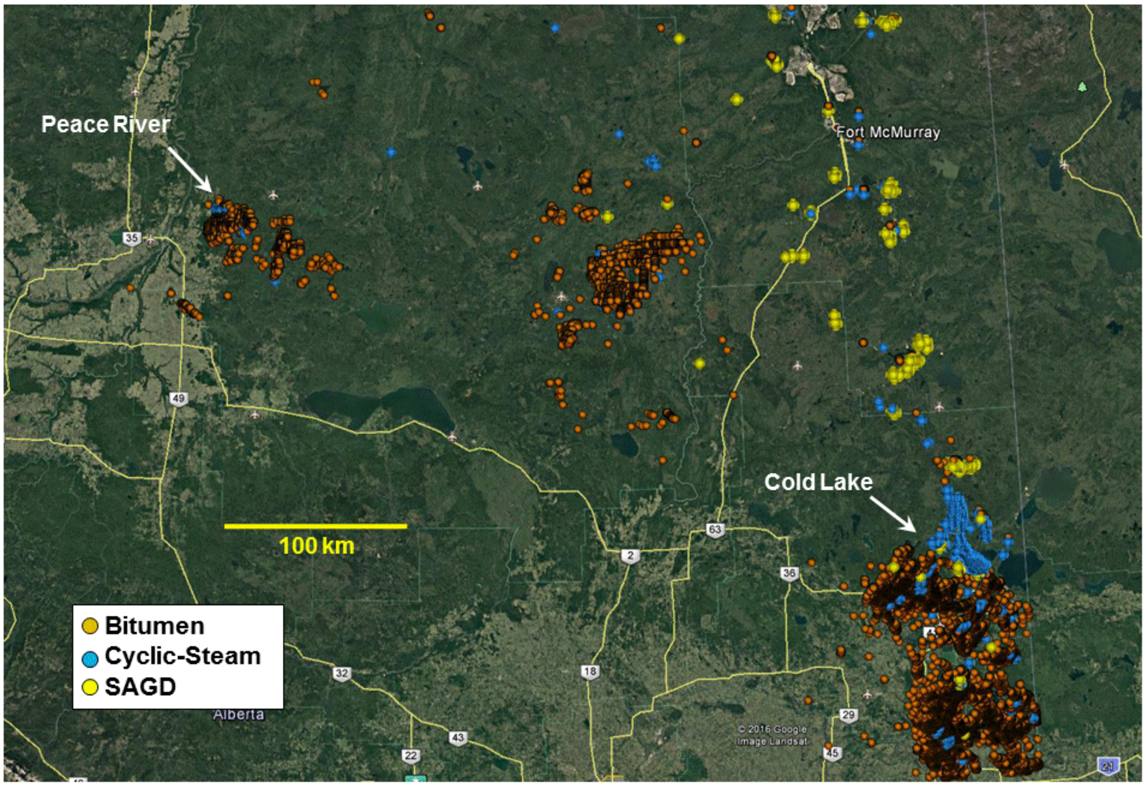
Figure 64: Distribution of oil sands regions in northern Alberta.[17]



[17] Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report. https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_1Albertasoilsandsareasandselectdeposits/FigureR3_1Albertasoilsandsareasandselectdeposits?:embed=y&:showShareOptions=true&:display_count=no

Figure 65 illustrates the geographical distribution of wells recovering bitumen in northern Alberta. Bitumen in the Cold Lake and Peace River regions is mainly recovered by cyclic-steam wells as well as by bitumen wells without thermal stimulation. In the Athabasca region production is mainly from SAGD wells as well as surface mining.

Figure 65: Distribution of bitumen wells by type in northern Alberta.
Non-thermal bitumen wells are in orange, cyclic-steam wells are in blue and steam-assisted gravity drainage (SAGD) wells are in yellow. Note that most of these are multi-well pads.[18]

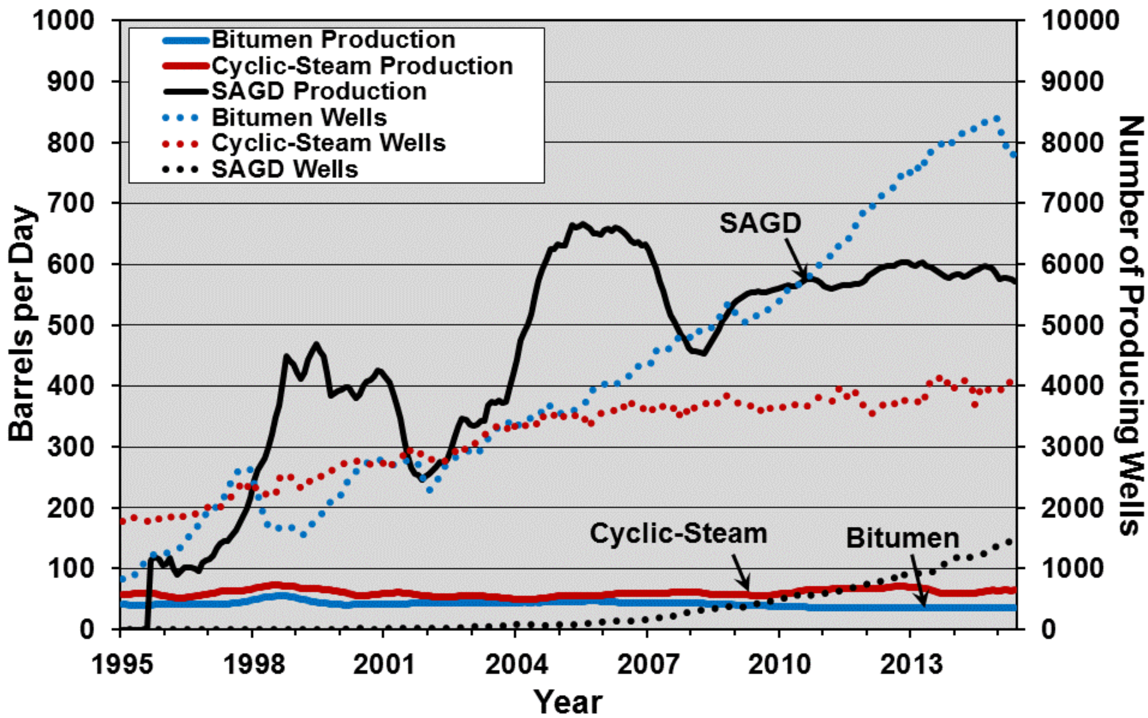


The development of SAGD technology in the 1990s marked a major improvement in the ability to recover in situ bitumen. SAGD uses horizontal well pairs, one well for steam injection to heat the reservoir and a second for bitumen recovery. Cyclic-steam wells, on the other hand, alternate periods of steam injection with production, while bitumen wells use no thermal heating to produce bitumen (bitumen and cyclic-steam wells may be vertical or horizontal).

[18] Data from Drillinginfo, December 2015

The difference in average well productivity for these different technologies is striking, as illustrated in Figure 66. SAGD wells averaged 572 barrels per day in 2015 compared to 64 barrels per day for cyclic-steam wells and 35 barrels per day for bitumen wells. The per-well upfront cost of a SAGD project is higher, however, given the need for a steam generation plant, pipelines to distribute the steam and collect the bitumen, and the drilling of horizontal well pairs.

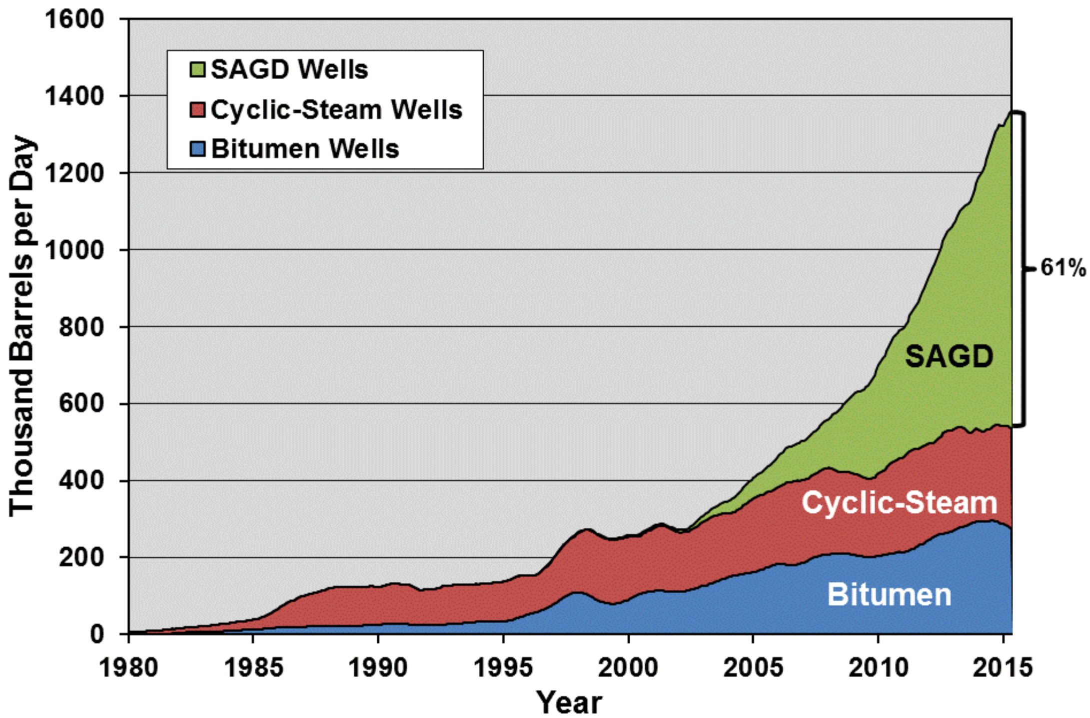
Figure 66: Average bitumen production per well for different technologies and number of producing bitumen wells in Alberta.[19]



[19] Data from Drillinginfo, December 2015; production is 12 month centred moving average

Given the superior productivity of SAGD wells, it is no surprise that SAGD produced 61% of in situ bitumen in 2015 with just 1,450 producing wells, compared to 19% from 4,200 cyclic-steam wells and 20% from 7,800 bitumen wells, as illustrated in Figure 67. Cenovus has a good field tour guide for its Foster Creek project, the first application of SAGD on a commercial scale, which illustrates that the life of a SAGD well at full production is five to 10 years, with a wind-down phase of an additional six or more years before the well must be abandoned.[20]

Figure 67: Bitumen production by well type from 1980 to 2015.[21]



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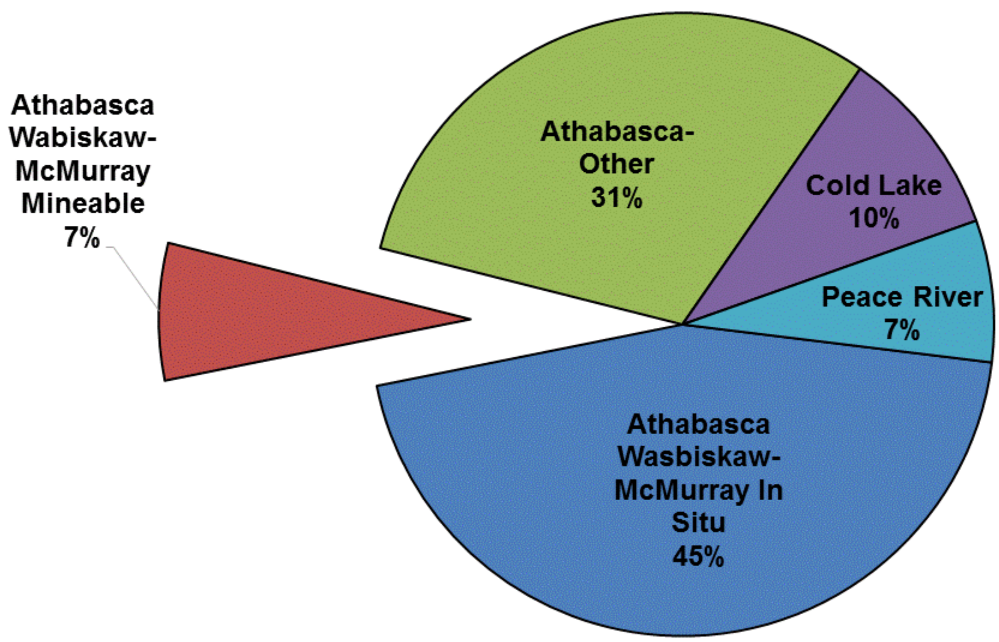
[20] Cenovus Field Tour Guide, accessed September 2016, https://www.cenovus.com/invest/docs/FC-Field-Tour-Handout.pdf
[21] Data from Drillinginfo, December 2015; 12 month centred moving average

2.1.2.1 BITUMEN RESERVES

The Alberta Energy Regulator (AER) produces an in-depth review of bitumen resources and production each year. In its 2016 edition, the AER reports an "initial in-place" bitumen resource of 1,845 billion barrels, of which 83% is in the Athabasca region and 93% is too deep to be mined. The distribution by region is illustrated in Figure 68. In 2015, 82% of bitumen was recovered from the Athabasca region, 16% from the Cold Lake region and 2% from the Peace River region.

Figure 68: Initial in-place bitumen resources by region according to the Alberta Energy Regulator.[22]
Athabasca area contains 83% and the Wabiskaw-McMurray Formation in the Athabasca area contains 52%. Just 7% is potentially surface mineable.



The AER's resource assessments are accepted by the NEB and are used here, but like the NEB's estimates they don't conform to Canadian regulatory standards under National Instrument 51-101. The AER reports that 11.4 billion barrels of bitumen have been recovered as of the end of 2015, with a further 23.9 billion barrels of "reserves under active development." These "reserves" are not categorized by probability, as required, but otherwise qualify as "reserves" under NI 51-101. The AER reports an additional bitumen resource of 141.5 billion barrels to make up its total "remaining established reserves" of 165.4 billion barrels. The latter are more correctly termed "contingent resources" under NI 51-101, as they are not under development as is required to be termed "reserves," nor have they been definitively proven to be commercially extractable based on the information provided by the AER.

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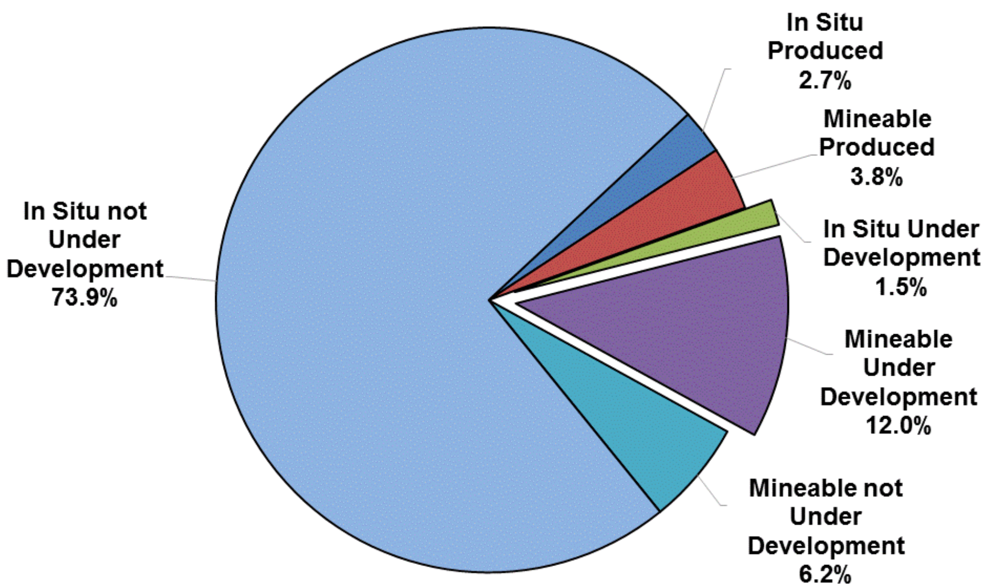
22 Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report. http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_6.html

Figure 69 illustrates the AER's "initial established reserves" of bitumen in 2015. Although 81% of the remaining portion of these reserves is too deep for surface mining, the subset "reserves under active development" is predominantly surface mineable. One of the reasons for this is the amount of energy required for in situ development, which increases operating costs even though initial start-up costs are lower for in situ extraction compared to mining.

Figure 69: Initial established reserves of bitumen by recovery method and development in 2015 according to the Alberta Energy Regulator.[23]

Under development (Billion barrels): Mineable = 21.2; In situ = 2.7; Total = 23.9.
Not under development: Mineable = 10.9; In situ = 130.6; Total = 141.5.



2.1.2.2 LIMITATIONS ON LONG-TERM BITUMEN PRODUCTION

Given that bitumen represents Canada's main hope for growing and even maintaining crude oil production in the long term, it is useful to consider constraints to its development. These include the following:

- Oil sands have higher emissions per unit of production than conventional oil, and Canada has committed to emissions reductions of 30% below 2005 levels by 2030. Alberta has imposed a cap on oil sands emissions of 100 megatonnes per year, some 47% above 2014 levels, which will cap production at some point. More stringent emissions reductions through the periodic reviews required under the Paris Agreement will add further pressure to reduce oil sands production, given that it is one of the largest sources of Canadian emissions.
- Oil sands have a lower energy return on energy investment (EROI) than most other oil sources owing to the large inputs of energy required, which accounts for their higher emissions.[24] The highest EROI is from mining, but the majority of the reserve is only recoverable using in situ methods, hence the average EROI will decline overtime as mineable reserves are exhausted. When EROI approaches a breakeven point it makes no energetic sense to pursue further extraction.

[23] Alberta Energy Regulator, 2016, Report data for ST-98 2016 reserves report. http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_1.html

[24] Energy return on energy investment, or EROI, is the ratio of all energy inputs required for production compared to the amount of energy contained in the produced oil.

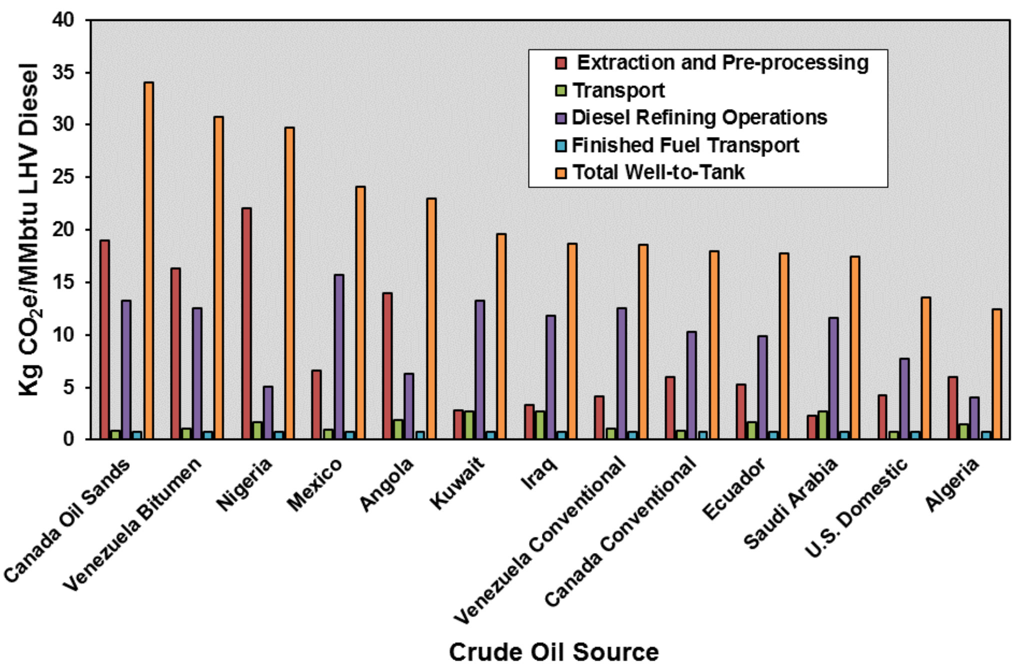
- Companies, when given the choice, develop the highest-quality, cheapest resources first, to maximize return on investment. These are the thickest, highest-quality parts of the deposits with the highest EROI and lowest emissions per unit of production. Notwithstanding the large "established reserves" purported by the AER, the questions remain: What portion of these resources are recoverable at a net energy (and financial) profit, and what are the emissions consequences of recovering lower and lower quality portions of the resource in the future?

Each of these is dealt with in more detail below.

2.1.2.2.1 Life cycle assessment of emissions

There are many life-cycle assessments of greenhouse gas emissions for various crude oil sources. Virtually all of these show that oil sands emissions are considerably higher than most other conventional crude oil sources. For example, according to a 2009 study done by the U.S. Department of Energy's National Energy Technology Laboratory, oil sands emissions are roughly twice that of conventional Canadian oil on a well-to-tank basis,[25] as illustrated in Figure 70.

Figure 70: Well-to-tank emissions for various crude oil sources to produce diesel fuel (Kg CO_2e/MMBtu = kilograms of carbon dioxide per million British Thermal Units).[26]



A more comprehensive life-cycle assessment that also includes emissions from the combustion of refined products is presented in Table 6. Well-to-wheels emissions for oil sands synthetic crude oil range from 36% to 56% higher than the best-performing crude oil, and from 19% to 37% higher than conventional Canadian oil from Saskatchewan. Given that the tank-to-wheels portion of emissions is quite similar for most oils, the bulk of the variation is in the well-to-tank portion of the supply chain. Oil sands synthetic

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[25] "Well-to-tank" emissions include extraction and preprocessing, transport to refinery, refining, and transport to point of use. "Tank-to-wheels" emissions include the combustion of the refined product as motor fuel or other end uses. "Well-to-wheels" emissions include the full lifecycle from extraction to final end use.

[26] NETL 2009, An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions. http://ethanolrfa.org/wp-content/uploads/2015/09/An-Evaluation-of-the-Extraction-Transport-and-Refining-of-Imported-Crude-Oils-and-the-Impact-on-Life-Cycle-Greenhouse-Gas-Emissions-.pdf

crude oil emissions on a well-to-tank basis are 179% to 297% higher than the best-performing crude oil, and from 93% to 161% higher than conventional Canadian oil from Saskatchewan.

Table 6: Carbon dioxide emissions for representative crude oils on a well-to-tank and tank-to-wheels basis (kgCO2e/barrel = kilograms of carbon dioxide equivalent per barrel of oil).

Well-to-tank emissions of oil sands such as Suncor Synthetic H are 297% higher than the best-performing oil (Kazakhstan Conventional–Tengiz) and 161% higher than Canadian conventional oil from Midale, Saskatchewan.[27]

Crude Oil Source (kgCO2e/barrel)	Well to tank	Tank to wheels	Well to wheels	Well to tank %	Tank to wheels %
China Conventional Heavy Oil (Bozhong)	342.7	390.4	733.1	46.7%	53.2%
Nigeria High Flaring (Obagi)	262.7	442.5	705.2	37.3%	62.7%
Canada Oil Sands Mining and Upgrading (Suncor Synthetic H)	**254.6**	**441.2**	**695.8**	**36.6%**	**63.4%**
US California Heavy Oil with Steam (Midway-Sunset)	289.8	404.2	694	41.8%	58.2%
Canada Oil Sands Mining and Upgrading (Syncrude Synthetic)	**251.8**	**428.9**	**680.7**	**37.0%**	**63.0%**
Indonesia Heavy Oil with Steam (Duri)	279.2	375.8	655	42.6%	57.4%
Nigeria High Flaring (Bonny)	194.2	442.5	636.7	30.5%	69.5%
Venezuela Orinoco Heavy Oil (Hamaca)	199.8	433.4	633.2	31.6%	68.4%
US California Heavy Oil with Steam (South Belridge)	214.1	409.2	623.3	34.3%	65.6%
Canada Oil Sands Mining and Upgrading (Suncor Synthetic A)	**179.1**	**427.4**	**606.5**	**29.5%**	**70.5%**
US California Conventional Heavy Oil (Wilmington-Duffy)	147.5	410.1	557.6	26.5%	73.6%
Canada Oil Sands In situ (Cold Lake Dilbit)	**189.1**	**355.5**	**544.6**	**34.7%**	**65.3%**
UK Offshore (Brent)	135.1	408.6	543.7	24.9%	75.2%
US Conventional with High Gas (Alaska North Slope)	119.7	421.6	541.3	22.1%	77.9%
Brazil Deep Offshore (Lula)	97.4	431	528.4	18.4%	81.6%
Iraq Conventional (Zubair)	106.8	418.6	525.4	20.3%	79.7%
Brazil Conventional Heavy Oil (Frade)	121.8	394	515.8	23.6%	76.4%
Russia Deep Offshore (Chayvo)	96.3	417.8	514.1	18.7%	81.3%
Canada Conventional High Water (Midale)	**97.6**	**411.8**	**509.4**	**19.2%**	**80.8%**
Angola Conventional (Girassol)	73.4	430.5	503.9	14.6%	85.4%
US Average Crude Oil Refined (2005)	91.2	409.9	501.1	18.2%	81.8%
Angola Conventional Heavy Oil (Kuito)	69.6	425.7	495.3	14.0%	85.9%
UK Offshore (Forties)	84.4	406.5	490.9	17.2%	82.8%
US GOM Deep Offshore (Mars)	67	422.6	489.6	13.7%	86.3%
US Tight Oil (Bakken)	79.9	408.6	488.5	16.4%	83.6%
Canada Offshore (Hibernia)	**55.1**	**421.9**	**477**	**11.6%**	**88.4%**
Kuwait Conventional (Ratawi)	60.8	414	474.8	12.8%	87.2%
US GOM Deep Offshore (Thunder Horse)	58.7	413.6	472.3	12.4%	87.6%
Azerbaijan Conventional (Azeri)	50.2	419.5	469.7	10.7%	89.3%
Nigeria Conventional (Agbami)	68.9	388.7	457.6	15.1%	84.9%
US Tight Oil (Eagle Ford)	49	408.6	457.6	10.7%	89.3%
Norway Offshore (Ekofisk)	39.5	411.8	451.3	8.8%	91.3%
Kazakhstan Conventional (Tengiz)	64.1	382.1	446.2	14.4%	85.6%

[27] ARC Financial, 2016, Crude Oil Investing in a Carbon Constrained World - see Table 3, based on data from the Oil-Climate Index by the Carnegie Endowment for International Peace, NETL (for US average - see previous footnote), and IHS (for Eagle Ford tight oil), http://www.arcfinancial.com/assets/693/Crude_Oil_Investing_in_a_Carbon_Constrained_World.pdf

Oil sands operators have made considerable improvements in emissions per barrel of bitumen over recent years. They have also added cogeneration plants, which use some process gas (but mainly increasing amounts of purchased gas, according to the AER) to generate electricity needed for production as well as to feed some electricity into the Alberta grid, displacing coal generation and hence improving emissions performance. These improvements are likely reaching the law of diminishing returns, however, and emissions performance can be expected to worsen as lower-quality portions of the bitumen resource are accessed.

2.1.2.2.2 Energy return on energy investment

Energy return on energy investment (EROI) is reported to be about 17:1 for global oil and 11:1 for US oil, on average.[28] Oil sands EROIs for the bulk of the recoverable resource are considerably below this given the large inputs of energy required, mainly in the form of natural gas. In situ oil sands EROIs average about 4:1 (81% of remaining recoverable bitumen), whereas mining operations with upgrading average about 8:1 (see Table 7). This only considers the purchased gas from external sources required to fuel the process. It does not consider the energy needed to build the facilities, power the mining equipment and pumps, produce and transport the diluent needed to move bitumen through pipelines, etc., and therefore must be considered an upper limit of actual EROI if all energy inputs were accounted for. Brandt et al (2013) have produced a thorough analysis of net energy returns for oil sands that came up with similar values.[29] They point out, however, that if the energy inputs used in the calculation include transport and refining to the point of use (well-to-tank), the EROI of bitumen produced by in situ methods is closer to 2:1.

Table 7: Energy return on energy investment (EROI) of oil sands given extraction method and upgrading based on inputs of purchased gas only.

(Considerable amounts of produced and process gas are also used, but these sources amount to "self-fuelling" and are therefore not considered in the calculations.) Estimates of purchased gas used per barrel are from the Alberta Energy Regulator (mcf/bbl = thousand cubic feet of gas per barrel of oil).[30]

	Purchased gas consumption (mcf/bbl)			EROI		
Extraction method	Min	Max	Mean	Max	Min	Mean
Mining bitumen only	0.4	0.6	0.5	14.50	9.66	11.60
Mining with upgrading	0.6	0.8	0.7	9.66	7.25	8.28
In situ bitumen only	1	2	1.5	5.80	2.90	3.87
In situ with upgrading	1.2	2.2	1.7	4.83	2.64	3.41

Thus, oil sands are a low-quality source of oil, both energetically and in terms of emissions, compared to conventional crude. New greenfield oil sands SAGD projects without upgrading will not be built unless oil prices reach $US85 per barrel, according to a recent analysis by the Petroleum Technology Alliance of Canada (PTAC).[31] Prices needed for new greenfield standalone mining projects are even higher, at

[28] Murphy DJ. 2014 The implications of the declining energy return on investment of oil production. *Phil. Trans. R. Soc. A* 372: 20130126. http://dx.doi.org/10.1098/rsta.2013.0126

[29] Brandt et al., 2013, The energy efficiency of oil sands extraction: Energy return ratios from 1970 to 2010, Energy Volume 55, 15 June 2013, Pages 693–702.

[30] Alberta Energy Regulator, 2016, ST-98, In situ and standalone mine purchased gas requirements http://www1.aer.ca/ST98/tables/supply_cost/table_1_4.html . The estimate of upgrading purchased gas requirement (.2 mcf/bbl) is from Alberta Energy Regulator, 2011, ST-98, Table 3-10.

[31] Petroleum Technology Alliance of Canada, March 31, 2015, Needs Assessment for Partial and Field Upgrading, 15p; the $US85/barrel price estimate for SAGD and the $US105.50 estimate for standalone mining includes the cost of diluent and

$US105.50 per barrel. PTAC points out that greenfield mining projects with upgrading require prices that are only marginally higher than mining projects without upgrading ($US109.50 per barrel). This is due in part to the fact that upgraded bitumen (synthetic crude oil) does not require a 30% blend of diluent to move it through pipelines, which is a considerable cost savings. Nonetheless, new bitumen projects are unlikely unless the price of oil goes higher (WTI oil price was $US60 per barrel as of this writing[32]). Existing projects will continue to operate, however, as upfront capital expenditures have already been made and operating costs vary between $C19.31 and $C32.75 per barrel, depending on extraction method and degree of upgrading.[33]

2.1.2.2.3 High-grading the bitumen resource

As pointed out previously, the term "reserves" has a specific meaning under Canadian security regulations in that they must be technically and economically recoverable. It is by no means assured that what the Alberta Energy Regulator terms "initial established reserves" meets this test. In fact, up until 1999, prominent compilers of global oil reserve statistics, such as BP and the *Oil & Gas Journal*, carried much smaller numbers on their books for the oil sands. In 1999, with a stroke of the pen, reported oil sands reserves went from 43.1 billion barrels in the previous year to 175.2 billion barrels, as BP accepted the AER's number.[34] The *BP Statistical Review of World Energy* is a widely used handbook on global energy reserves, however, the company is careful to include a disclaimer:

> The data series for proved oil and gas reserves in *BP Statistical Review of World Energy June 2016* does not necessarily meet the definitions, guidelines and practices used for determining proved reserves at company level, for instance, as published by the US Securities and Exchange Commission, nor does it necessarily represent BP's view of proved reserves by country.

Given that companies target the highest-quality portion of oil sands deposits first, and there has been abundant exploration to identify these areas, it remains to be seen how much of the AER's "initial established reserves" can actually be recovered at a financial and a net-energy profit.

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transportation to move the bitumen to market in the US. The supply cost of in situ SAGD bitumen at the well is estimated at $CA50.90/barrel, and the supply cost of standalone mining at the mine mouth is estimated at $CA71.10/barrel by PTAC.

32 West Texas Intermediate (WTI) is a North American benchmark oil price.

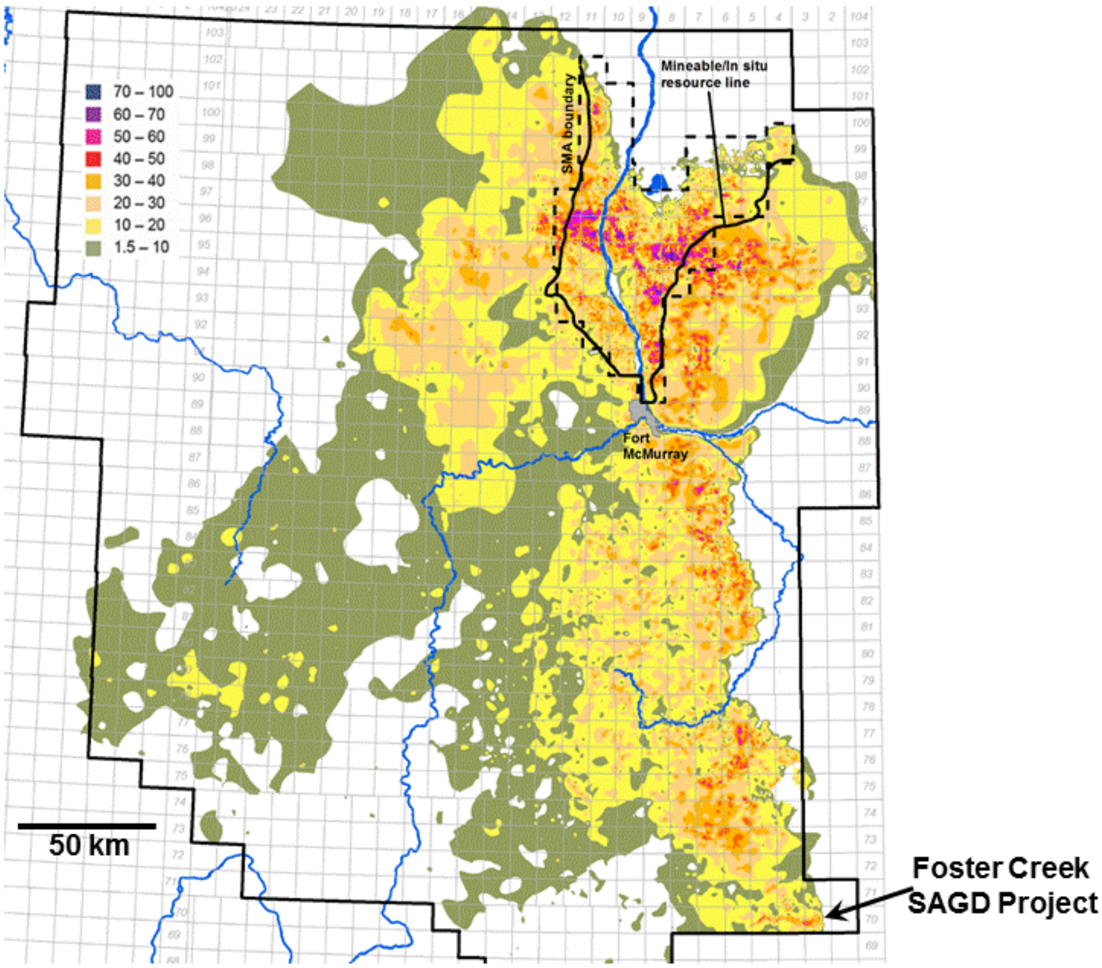
33 PTAC op. cit.

34 BP Statistical Review of World Energy data workbook, 2016, http://www.bp.com/content/dam/bp/excel/energy-economics/statistical-review-2016/bp-statistical-review-of-world-energy-2016-workbook.xlsx

Figure 71 illustrates the distribution of the oil sands resource in the Athabasca Wabiskaw-McMurray deposit, which contains 52% of the "initial established reserves" and all of the mineable oil sands. As can be seen, pay thickness is highly variable, with the thickest parts falling into the surface mineable area. Although pay thickness as depicted in this figure is a primary indicator of economic viability, the actual economics depend on the nature of the distribution of this pay, as several pay intervals have been aggregated in some areas to make this map. Other oil sands deposits show similar variability.

Figure 71: Pay thickness in the Athabasca Wabiskaw-McMurray deposit, which contains 52% of the oil sand's "initial established reserves."[35]

"SMA" indicates the general boundaries of the surface mineable area, with the solid black line indicating a more accurate delineation of the mineable/in situ boundary.

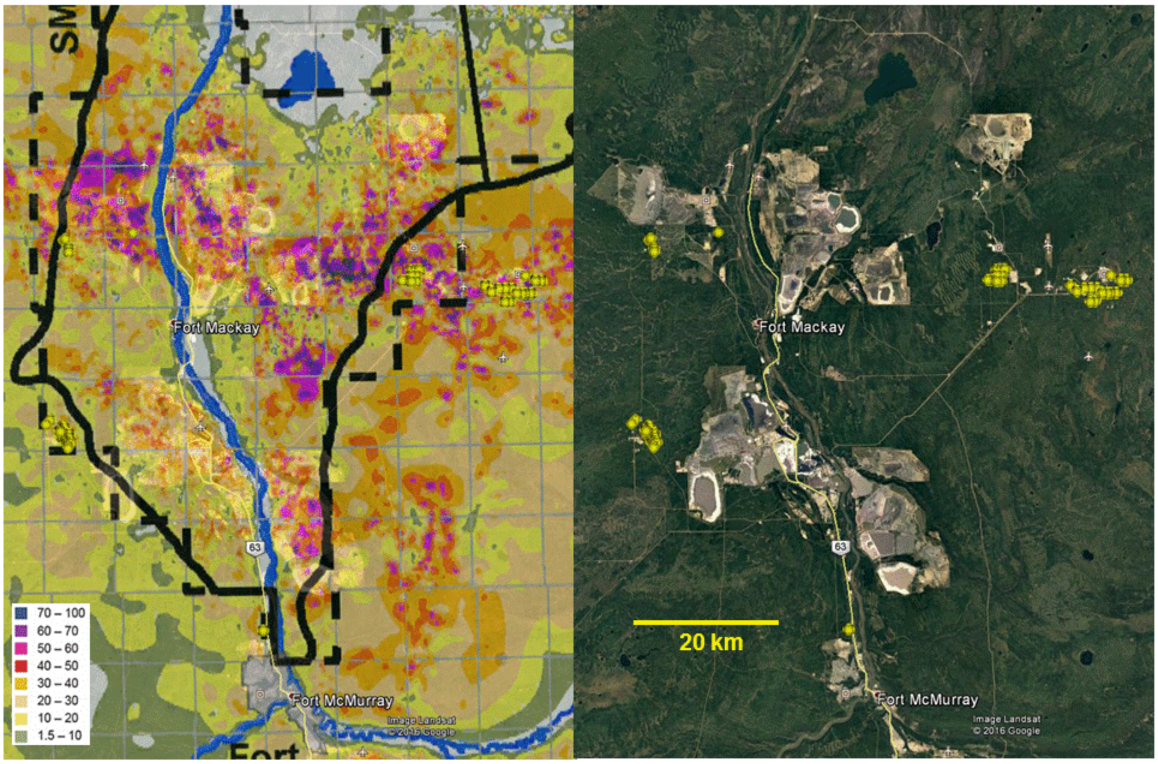


[35] Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?:embed=y&:showShareOptions=true&:display_count=no

Figure 72 illustrates surface mineable development with an overlay of bitumen pay thickness, showing that the thickest, most attractive portions of the resource are already being developed. Although there are still some attractive areas yet to be developed, more than half of the thickest surface mineable pay is under development.

Figure 72: Overlay of the Athabasca Wabiskaw-McMurray deposit pay thickness on a satellite image of surface mining development in the surface mineable area north of Fort McMurray.[36]

The left- and right-hand images cover exactly the same area. The solid line marks the approximate boundary of mineable and in situ resources. See Figure 71 for location. SAGD wells are indicated in yellow (these are multi-well pads).



[36] Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?:embed=y&:showShareOptions=true&:display_count=no, Satellite image from Google Earth. Data from Drillinginfo, December 2015.

Figure 73 illustrates a similar overlay for Cenovus Energy's Foster Creek in situ SAGD project. As with surface mineable resources, Foster Creek is understandably focused on the thickest parts of the deposit, which is restricted to a relatively small part of the total area underlain by bitumen in this area.

Figure 73: Overlay of Athabasca Wabiskaw-McMurray deposit pay thickness on satellite image of the Cenovus Foster Creek project, which is the first commercial SAGD operation.[37]

The upper and lower images cover exactly the same area and contours of pay thickness are shown on both images. See Figure 71 for location. SAGD wells are indicated in yellow (these are multi-well pads). The economic pay thickness is relatively restricted in this area and is being fully exploited.

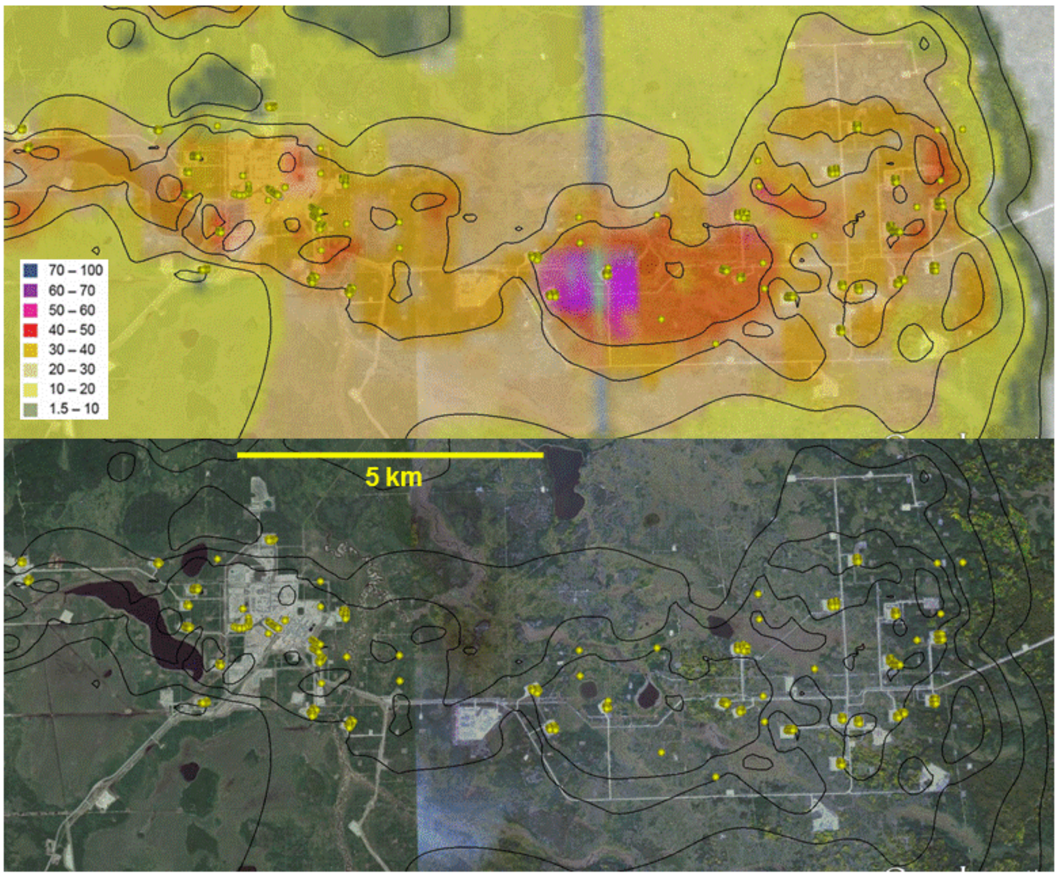


Figure 74 (next page) illustrates the distribution of the initial in-place resources by pay thickness (the in-place resource distribution by deposit is illustrated in Figure 68).[38] Some 90% of the overall resource area and 79% of the in-place resource has a pay thickness of less than 15 metres. Although resources shallow enough for surface mining average about 26 metres thick, existing mines have focused on only the thickest subset of this, in the 30–70 metre range (see Figure 72). In situ projects such as Foster Creek have focused on portions of the deposit with pay in the 20–50 metre range on the AER's map (see Figure 73).

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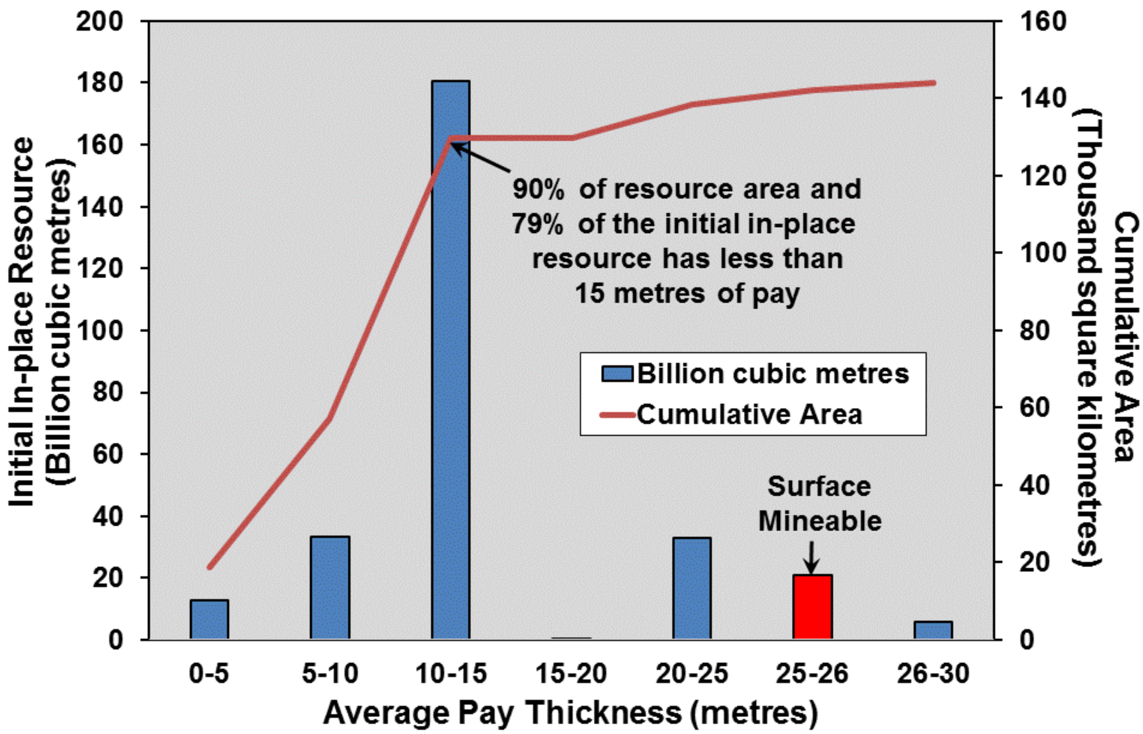
37 Alberta Energy Regulator, 2016, ST-98, Figure R-3.6, https://www2.aer.ca/t/Production/views/CrudeBitumenFigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit/FigureR3_6BitumenpaythicknessofAthabascaWabiscaw-McMurraydeposit?:embed=y&:showShareOptions=true&:display_count=no, Satellite image from Google Earth. Data from Drillinginfo, December 2015.

38 Note that the Alberta Energy Regulator states "the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval.", hence the thicknesses on the AER pay thickness map in Figures 70-72 could include zones not considered for extraction based on a full economic evaluation and hence may overstate the actual economic pay thickness. See AER ST-98-2016 "Pay thickness discussion", http://www1.aer.ca/st98/data/crude_bitumen/BitumenPayThicknessDiscussion.pdf

Figure 74: Initial in-place oil sands resources by pay thickness.[39]

Also shown is the cumulative area underlain by bitumen in each pay thickness class. Some 90% of the resource area and 79% of the in-place resources have a pay thickness of less than 15 metres, but most extraction is currently from areas with pay thicknesses of greater than 20 metres.



Although oil sands resources are reported to be vast, the thickest and highest-quality portion of them are being developed now and are being sold off mostly for export at low prices that bring in little benefit in terms of royalties and taxes compared to earlier years. Oil sands reserves that are recoverable at a financial and net-energy profit are likely considerably smaller than the AER's "initial established reserve" estimates (which do not conform to the regulatory protocols of National Instrument 51-101). Furthermore, emissions are growing as production rises, making Canada's greenhouse gas commitments ever more difficult to achieve. What will be left when the highest-quality resources are gone will be the thinner, higher-cost, more energy- and emissions-intensive resources, which will require ever higher prices to break even and make Canada's climate commitments even more difficult to meet.

2.1.2.2.4 Bitumen production outlook

The National Energy Board's *Energy Futures* report makes three projections of bitumen production through 2040 with different assumptions of price and market accessibility.[40] In addition, the Alberta government has announced a Climate Leadership Plan that will cap emissions from the oil sands at 100 megatonnes (Mt) per year.[41]

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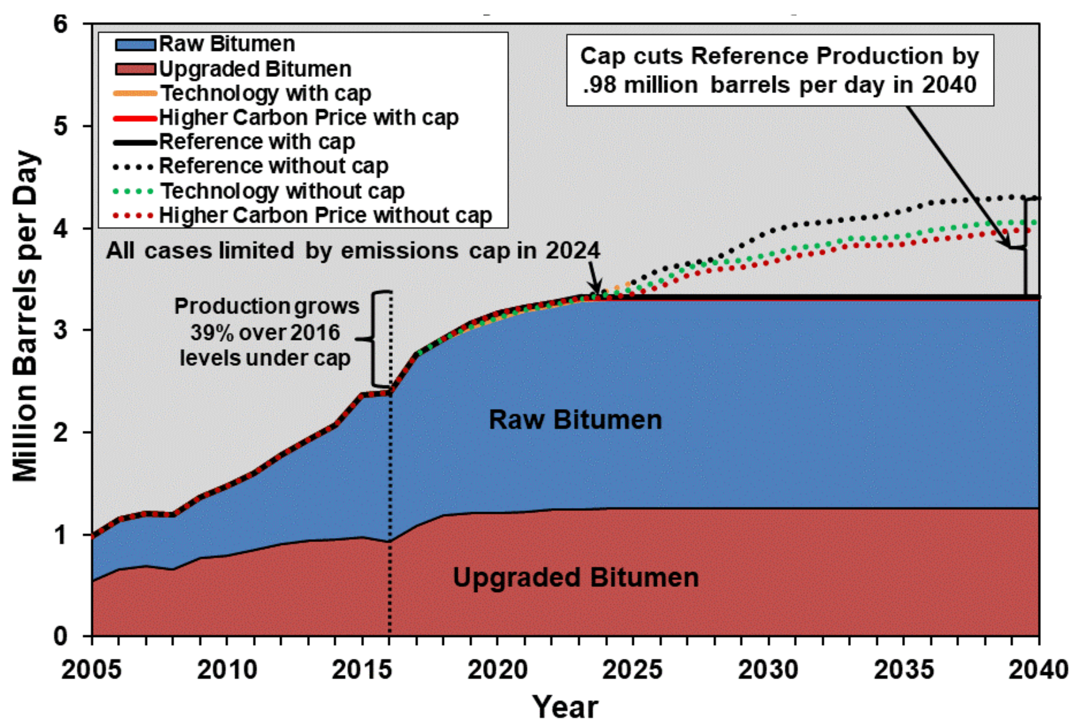
[39] Alberta Energy Regulator, 2016, ST-98, Table R-3.7, http://www1.aer.ca/st98/tables/crude_bitumen/table_R3_7.html
[40] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[41] Alberta Government, November 2015, Climate Leadership Report to Minister, http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf .

Environment and Climate Change Canada's latest report to the United Nations on Canada's greenhouse gas emissions contains estimates for the oil sands.[42] These are subdivided into extraction by "mining" and "in situ" methods, as well as "upgrading" to synthetic oil. Collectively these summed to 71 Mt in 2015, the most recent year for which data are available. This means that a 100-Mt cap will allow a 41% growth in emissions above the 2015 level. To evaluate the impact of the emissions cap on the NEB's bitumen production projections, the average emissions per unit of production from the most recent four years were used to calculate future emissions for the NEB projections. Figure 75 illustrates the production implications.[43]

Bitumen production in all three NEB production cases is constrained by the cap, beginning in 2024, at a production rate of between 3.3 and 3.4 million barrels per day (mbd), or 39% above 2016 levels. Bitumen production would be constrained by .98 mbd in 2040 in the NEB reference case with the cap. Given the current low oil price environment, and the previously discussed thresholds needed for new projects, new greenfield oil sands projects are unlikely unless prices move higher, hence even increasing oil sands production to the cap remains uncertain. This could change relatively quickly, however, given changes in the global supply/demand balance and remembering that the price was over $US100 per barrel as recently as 2014.

Figure 75: Marketable bitumen production in the National Energy Board's production scenarios through 2040.

Raw bitumen is converted into upgraded bitumen with a volume loss of 14%, so the volumes here reflect delivered quantities. Production in the reference case can grow 39% over 2016 levels before being limited by the emissions cap.[44]



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[42] Environment Canada, April 2017, National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/hrv-2017-nir-26may17.zip

[43] For more detail on the assumptions used in determining production under the Alberta oil sands emissions cap see: David Hughes, 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives. https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf

[44] Data from NEB Energy Futures 2017; emissions from ECCC NIR report 2017

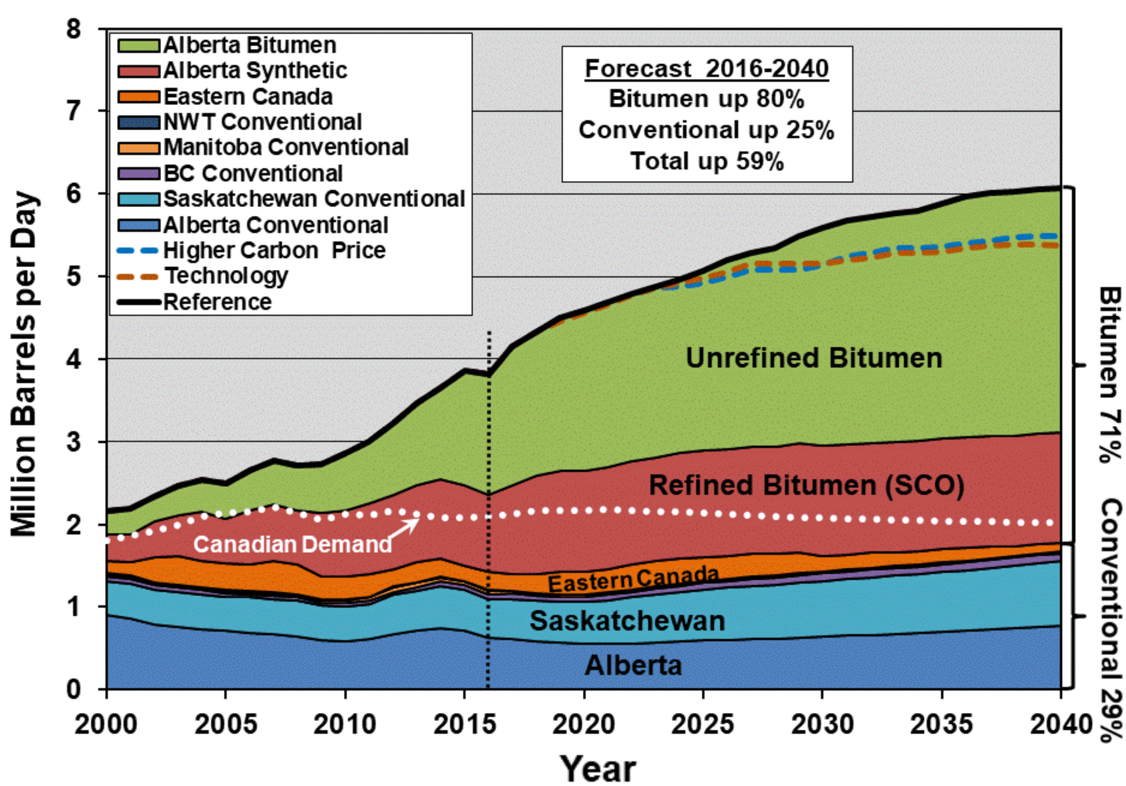
Under the emissions cap, the NEB reference case production scenario would see the extraction of 46% of remaining mineable bitumen reserves, and 15% of remaining in situ reserves, from 2016 to 2040. Given the uncertainties of the NEB's estimates, and the fact that the highest-quality and most economic resources are extracted first, this is a significant inroad on the best part of the bitumen resource—particularly the mineable portion, which has the lowest emissions and highest EROI. The cap allows for aggressive growth in production, which will make meeting Canada's emissions-reduction commitments under the Paris Agreement extremely difficult to achieve given that oil sands emissions will grow from 9.8% of Canada's emissions in 2015 to 19.3% in 2030 if the Paris Agreement commitment is met.[45]

2.1.3 Overall oil production outlook

Figure 76 illustrates the NEB's reference case forecast for Canadian oil production through 2040, not including Alberta's oil sands emissions cap. Bitumen production nearly doubles whereas conventional production increases by 25% from 2016 levels. According to this forecast, 71% of Canadian oil production will be bitumen by 2040.

Figure 76: The National Energy Board's "reference" case projection of Canadian oil production through 2040 by province and oil type.[46]

Also shown are the overall "higher carbon price" and "technology" production cases as well as Canadian demand, which is projected to peak in 2021 and decline by 7% through 2040.



[45] The Paris Agreement commits Canada to a 30% reduction of greenhouse gas emissions below 2005 levels by 2030. This amounts to a reduction to 517 Mt/year in 2030. See Environment Canada, 2016, Canada's Emission Projections in 2020 and 2030 (Mt CO_2 eq), https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8BAAFCC5-1

[46] Data from National Energy Board 2000–2005; National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA (data and reference case demand); Emissions from Environment Canada, National Inventory Report, released April, 2016. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2016-nir-14apr16.zip (conventional includes NGLs).

The implications of this forecast for conventional oil, along with two other NEB projection variants, are summarized in Table 8. By 2040 conventional oil production will consume more than triple the currently known reserves, and consume between 55% and 60% of all discovered and undiscovered resources, a significant proportion of which has not been demonstrated to be economically or technically recoverable, and would require extraction of undiscovered resources in the Arctic and on the East Coast. Table 8 also shows cumulative carbon dioxide emissions from upstream emissions in producing this oil, assuming average 2011–2015 emission levels in the future. Under the Paris Agreement commitments, conventional oil production would comprise between 5.5% and 6.3% of all Canadian emissions in 2030.

Table 8: Conventional oil production and emissions according to the National Energy Board's scenarios, from 2016 to 2040 (Gbbls = billion barrels).[47]

The emissions production rate in 2030 would constitute 5.5% to 6.3% of allowable emissions under the Paris Agreement in 2030.

	Reference	Higher carbon price	Technology
Total conventional oil production (Gbbls)	14.10	13.14	12.58
% of conventional reserves produced	316%	294%	282%
% of discovered and undiscovered conventional resources produced	55.0%	51.3%	49.1%
Emissions of conventional oil 2017–2040 ($MtCO_2$)	789	734	703
% of 2030 emissions under Canada's Paris Agreement target	6.4%	5.8%	5.6%

[47] Production forecasts from: National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA . Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip .

Bitumen production, according to these production projections, would consume 14.3% to 15.4% of in situ bitumen reserves and 46% of mineable bitumen reserves by 2040 (Table 9). Doing so would see upstream oil sands emissions rise to between 21.4% and 22.8% of all Canadian emissions in 2030, up from 9.8% in 2015, if the Paris Agreement target is met. Coupled with upstream emissions from the production of conventional oil, oil production would constitute between 27.2% and 29.2% of allowable 2030 Canadian emissions under the Paris Agreement.

Table 9: Production and emissions for three National Energy Board production projections from 2016 to 2040 (Gbbls = billion barrels).[48]

The emissions production rate in 2030 would constitute 18.8% to 24.3% of allowable emissions under the Paris Agreement in 2030.

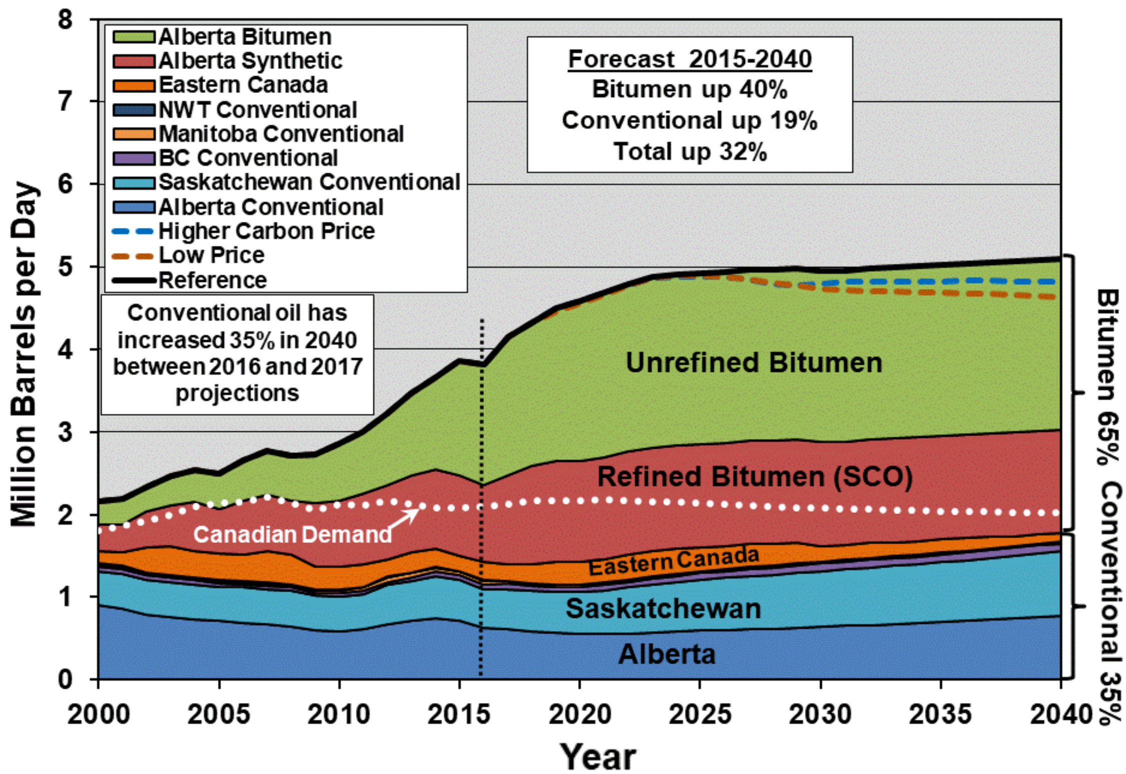
Bitumen production and emissions without emissions cap, 2016–2040			
	Reference	Higher carbon price	Technology
Mined bitumen production (Gbbls)	14.74	14.74	14.74
% of mineable reserves produced	46.0%	46.0%	46.0%
In situ bitumen production (Gbbls)	20.58	19.02	19.43
% of in situ reserves produced	15.4%	14.3%	14.6%
Upgraded bitumen (Gbbls)	11.26	11.26	11.26
Total diluent required (Gbbls)	6.39	5.92	6.05
Imported diluent required (Gbbls)	3.91	3.64	3.75
Total bitumen shipped including imported diluent (Gbbls)	50.58	47.79	47.74
Emissions of oil sands ($MtCO_2$)	2,729.52	2,623.85	2,651.34
% of 2030 emissions under Canada's Paris Agreement target	22.8%	21.4%	21.7%

[48] Production forecasts from: National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017. Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip .

Total Canadian oil production under Alberta's emissions cap in the NEB's reference case is illustrated in Figure 77. In this case, oil production would rise until the cap constrained oil sands production in 2024, and then grow gradually through 2040 to just over five mbd, mainly through the growth in conventional oil production. In the NEB's higher carbon price and technology cases, however, Canadian oil production would peak in 2025 at 4.9 mbd. Production in 2040 would be 65% bitumen in the reference case, and total oil production would be roughly double Canadian domestic demand, meaning Canada would remain a significant net oil exporter over the 2016–2040 period.

Figure 77: The National Energy Board's reference case projection of Canadian oil production through 2040 under Alberta's 100-megatonne per year emissions cap by province and oil type.[49]

Also shown are the overall higher carbon price and technology production cases, and Canadian demand under the reference case, which is projected to decline slightly from 2021 through 2040.



Under Alberta's oil sands emissions cap, bitumen production, given the NEB's forecasts, would consume 12–13% of in situ reserves and 45–46% of mineable reserves over the 2016–2040 period (Table 8). Doing so would see the oil sands rise to 19.3% of all Canadian emissions in 2030, up from 9.8% in 2015, under the Paris Agreement. Coupled with upstream emissions from conventional oil production, total oil production under the cap would constitute 27–29% of all Canadian emissions in 2030 if the Paris Agreement target is met.

[49] Data from National Energy Board, 2000–2005; National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017 (for 2005–2040 data and reference case demand). Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip (conventional includes NGLs).

As indicated in Table 10, in response to the cap, overall bitumen production would be reduced by between 2.6 and 4 billion barrels over the 2016–2040 period in the NEB's reference and higher carbon price cases, respectively. This amounts to a cutback in the production of bitumen over this period of 8–12%, depending on the scenario, and a reduction in cumulative emissions of 7.4–10.9%. Under the NEB's reference case, the cap would result in a reduction of 12% in bitumen production and an emissions reduction of 10.9% over the 2016–2040 period.

Table 10: Production and emissions for three National Energy Board production cases from 2016 to 2040 under the 100-megatonne per year Alberta emissions cap (Gbbls = billion barrels; $MtCO_2eq$ = megatonnes of carbon dioxide equivalent).

The production and emissions implications of the cap compared to no cap are also illustrated.[50]

	Reference	Higher carbon price	Technology
Mined bitumen (Gbbls)	14.55	14.72	14.63
% of mineable reserves	45.36%	45.89%	45.60%
In situ bitumen (Gbbls)	16.68	16.45	16.52
% of in situ reserves	12.51%	12.34%	12.39%
Upgraded bitumen (Gbbls)	11.17	11.30	11.23
Total diluent required (Gbbls)	5.47	5.41	5.43
Imported diluent required (Gbbls)	2.91	3.05	3.04
Total bitumen shipped including imported diluent (Gbbls)	32.33	32.38	32.37
Emissions of oil sands ($MtCO_2eq$)	2,431.11	2,430.83	2,427.11
Bitumen production difference due to cap (Gbbls)	4.02	2.55	2.96
% production difference due to cap	12.03%	7.98%	9.18%
Emissions difference due to cap ($MtCO_2eq$)	298.40	193.02	224.23
% oil sands emissions difference due to cap	10.93%	7.36%	8.46%
% of 2030 emissions under Canada's Paris Agreement target	19.30%	19.30%	19.30%

2.1.4 Pipeline requirements under the cap

The issue of building more export pipelines to move increasing production of western Canadian oil has been a major point of contention between environmental groups and citizens, the oil and gas industry, and governments. Industry and the Alberta and Saskatchewan governments claim that new capacity is needed to get oil to "tidewater" in order to capture a significant "price premium," given that exports now are largely to a "single customer," the US Other studies have shown that there is sufficient export capacity under Alberta's emissions cap if rail is considered, that there will be little or no price premium for tidewater access, and that increasing oil sands emissions by 41% over 2015 levels, as allowed under the cap, will make meeting the 2030 target Canada committed to under the Paris Agreement virtually impossible.[51,52] The issue of pipeline capacity is briefly reviewed below for the three National Energy Board production cases.

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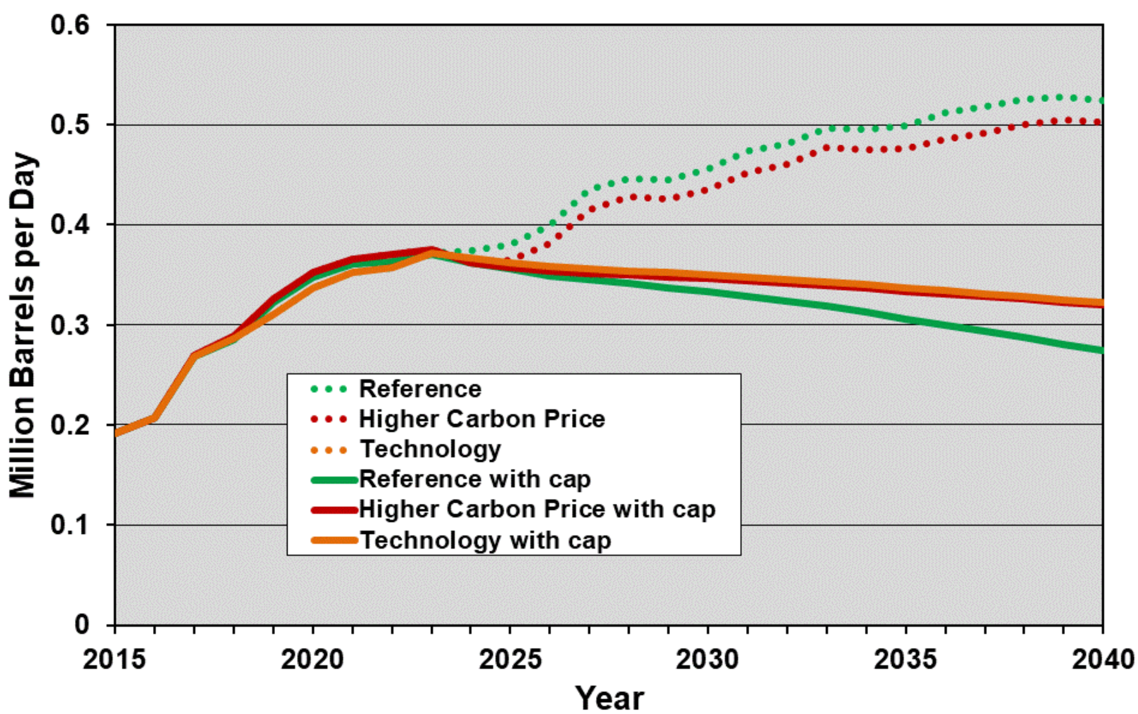
[50] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017. Emissions are from Environment Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip .

[51] Hughes, J.D., 2016, Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?, Canadian Centre for Policy Alternatives, 38p,

One of the issues with exported raw bitumen, as opposed to upgraded synthetic oil, is that it must be diluted with lighter hydrocarbons to lower the viscosity enough for it to flow through pipelines. The preferred diluent is condensate and other light natural gas liquids, which are needed at a blending rate of 30% by volume to create "dilbit" (synthetic crude oil can also be used as a diluent but at a higher blending ratio—typically 50%). As the NEB has pointed out, the need for diluent to blend with bitumen production for export has already exceeded Canada's domestic production capacity, hence increased bitumen production will require diluents to be purchased on international markets and imported. The volumes of imported diluent needed are substantial, ranging from 2.9 to 3.1 billion barrels over the 2016–2040 period with the emissions cap in the NEB's projections (Table 10). The need to purchase diluent and ship it in and out of Alberta further impacts the economics of bitumen. The need for diluent also means that pipelines have to be sized 30% larger to transport a given volume of product than if they carried synthetic or conventional oil alone, to accommodate the diluent. Figure 78 illustrates the imported diluent required for the three NEB production cases with and without the Alberta oil sands emissions cap. Under the cap, between 371 and 376 thousand barrels per day (kbd) of imported diluent will be needed at peak requirements in 2023.

Figure 78: Rates of imported diluent required in three National Energy Board production cases with and without the 100-megatonne per year Alberta oil sands emissions cap.[53]

This assumes that domestically produced diluents will be used first before importing.



Although some of Western Canada's oil production will be consumed by domestic refineries, most will be exported to the US and Eastern Canada. The Canadian Association of Petroleum Producers (CAPP) expects refinery consumption to rise from 602 kbd in 2016 to 671 kbd in 2020, with the completion of the

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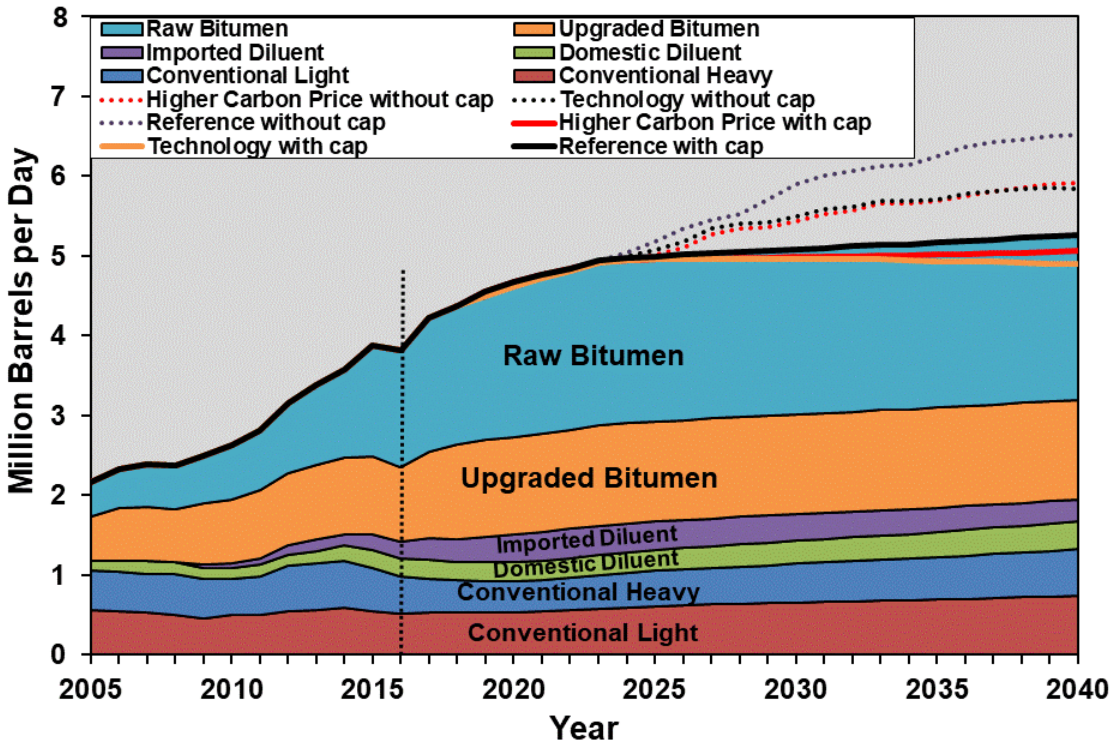
https://www.policyalternatives.ca/sites/default/files/uploads/publications/National%20Office%2C%20BC%20Office/2016/06/Can_Canada_Expand_Oil_and_Gas_Production.pdf

52 Hughes, J.D., 2017, Will the Trans Mountain Pipeline and Tidewater Access Boost Prices and Save Canada's Oil Industry?, Canadian Centre for Policy Alternatives, 42p, https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf

53 Data from National Energy Board, Canada's Energy Future 2017, and author calculations

Sturgeon refinery in Alberta and other increases.[54] Figure 79 illustrates western Canadian supply for refinery consumption and export under the emissions cap, including bitumen, conventional oil production and imported diluent.

Figure 79: Western Canadian oil supply with and without the Alberta emissions cap in three National Energy Board scenarios.[55]



Existing export pipeline and rail capacities from Western Canada are given in Table 11, along with three proposed pipelines: Line 3 restoration, Keystone XL and Trans Mountain expansion. Nameplate export capacity from existing pipelines is 4,236 kbd, however, effective capacity is usually less, owing to outages for maintenance and other logistical issues. Assuming a 95% availability yields an existing effective pipeline capacity of 3,974 kbd. Refinery consumption adds a further 671 kbd of supply handling capability. Rail loading capacity of 754 kbd is also available and is typically used for incremental volumes not shipped by pipelines. Although rail is flexible, given that railways exist to most North American refineries and offshore export points, it is significantly more expensive than pipelines for shipping dilbit. If bitumen is shipped in undiluted form, however, rail can ship 42% more product per unit volume than pipelines, eliminating the need for imported diluent and increasing safety in the event of an accident, given that undiluted bitumen doesn't flow like dilbit. This confers significant cost savings and makes rail more competitive with pipelines, while reducing risk at the same time. Rail capacity is also cheaper to build than pipelines, and can be used for other purposes in the event that it is not needed for oil transport. Adding rail capacity to export pipelines and refinery consumption yields an effective ability to handle western Canadian supply of 5,399 kbd, which is more than sufficient to meet the export needs of any of the NEB's production scenarios under the Alberta emissions cap.

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[54] CAPP, 2016, Crude Oil Forecast, Markets and Transportation, http://www.capp.ca/~/media/capp/customer-portal/publications/284950.pdf

[55] Author calculations from National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Table 11: Pipeline and rail export capacity and refinery consumption in Western Canada. Net capacity discounts nameplate capacity by 5%, allowing for maintenance and outages.

All capacities come from the Canadian Association of Petroleum Producers[56] except for the Rangeland-Milk River pipeline, which is from Alberta Energy.[57]

Pipeline	Nameplate capacity	Net capacity at 95%	Source
	Existing pipelines		
Enbridge Mainline	2,851	2,708	CAPP 2016
Kinder Morgan Trans Mountain*	300	235	CAPP 2016
Spectra Express	280	266	CAPP 2016
TransCanada Keystone	591	561	CAPP 2016
Rangeland–Milk River	214	203	AE 2009
Total existing capacity	**4,236**	**3,974**	
	Western refinery receipts and rail capacity		
Refinery consumption[58]	671	671	CAPP 2016
Rail export capacity	754	754	CAPP 2016
Grand total	**5,661**	**5,399**	
	Proposed pipelines likely to be built under the Trump administration		
Line 3 replacement	370	352	CAPP 2016
TransCanada Keystone XL	830	789	CAPP 2016
Existing plus likely capacity	**6,861**	**6,539**	
	Proposed Canadian "tidewater" pipelines[59]		
KM Trans Mountain expansion	590	561	CAPP 2016
Total	**7,451**	**7,100**	

* Parkland's Burnaby refinery needs subtracted from Trans Mountain export capacity (50 kbd)

56 CAPP, 2016, Crude Oil Forecast, Markets and Transportation, http://www.capp.ca/~/media/capp/customer-portal/publications/284950.pdf

57 Alberta Energy, 2009, BRIK Infrastructure and Bitumen Supply Availability, http://www.energy.alberta.ca/oilsands/pdfs/brik_availability_infrastructure_to_industry.pdf

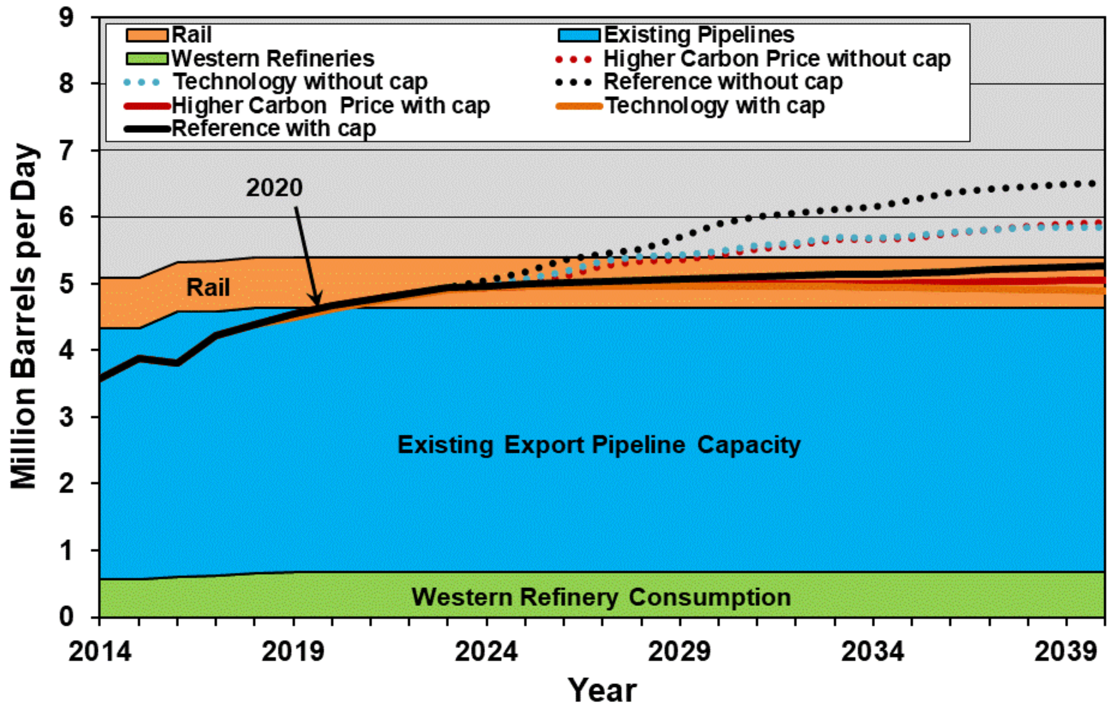
58 Refinery consumption as of 2019 according to Canadian Association of Petroleum Producers, *2016 CAPP Crude Oil Forecast, Markets & Transportation* (Calgary: CAPP, 2016). If built, TMEP would be completed by this date.

59 "Tidewater" refers to ocean access and the capability to transport oil to overseas markets via tankers.

Figure 80 illustrates existing capacity compared to production, assuming pipelines can only operate at 95% of rated capacity. Existing pipeline capacity would be full by 2020 in all of the NEB's scenarios. Oil moved by rail amounted to 93 kbd in July 2017, or about 2% of western Canadian supply.[60]

Figure 80: Western Canadian supply with and without the Alberta emissions cap compared to existing export pipeline, rail and refining capacity.

The National Energy Board's reference, higher carbon price and technology supply forecasts are shown. Pipelines are assumed to run at 95% of nameplate capacity. Pipeline capacity in all cases would be full by 2020, but if rail is included, existing capacity can handle all cases under the oil sands emissions cap.[61]



The election of Donald Trump in the US has changed the political landscape for pipelines. The Obama administration cancelled the Keystone XL pipeline in November 2015, which would have added 830 kbd of export capacity. The Trump administration has reversed this decision and approved the Keystone XL pipeline. Furthermore, the Trudeau government approved the Line 3 restoration project in November 2016, which will add an additional 370 kbd of capacity, for a total of 1,200 kbd over and above existing capacity. Given the political support on both sides of the border, it seems likely that these pipelines will be built.

In addition, two tidewater pipelines have been proposed, the Trans Mountain expansion to the West Coast and Energy East to the East Coast (the Energy East pipeline has since been cancelled). The rationale for these pipelines was that a price premium would be obtained by selling oil on international markets. In fact, although a price differential did exist between the international price of oil (the Brent benchmark) and the North American price (the West Texas Intermediate or WTI benchmark) in the 2011–2014 timeframe when these pipelines were proposed, this differential has since been largely eliminated. The differential was caused by insufficient pipeline capacity from Cushing, Oklahoma, where the WTI benchmark is set, to the US Gulf Coast, where international prices can be accessed. This bottleneck was eliminated with the

[60] National Energy Board, 2017, retrieved November 14, 2017, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html

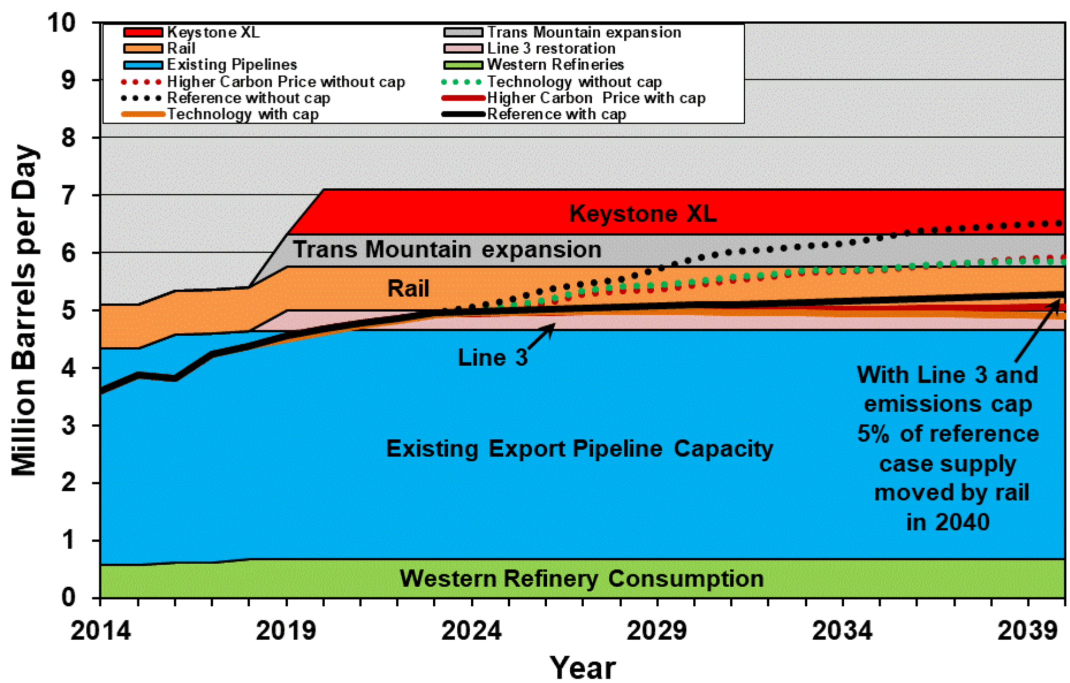
[61] Data from CAPP Oil Forecast 2016; National Energy Board, Canada's Energy Future 2017

construction of new pipelines and the differential averaged just 82 cents per barrel in 2016.[62] Although this differential increased to $3.49 per barrel in 2017, it is still far below the $18 differential that existed in 2013 when these tidewater pipelines were proposed.

Figure 81 illustrates export pipeline capacity, refinery consumption and rail capacity compared to the western Canadian oil supply assuming the Line 3 restoration project, currently under construction, is completed, and the full capacity of the Keystone pipeline is restored (the capacity of the existing Keystone pipeline was reduced by 20% following a spill in November 2017). Under the emissions cap, pipeline capacity would be sufficient until 2025 and about 5% of 2040 production would have to be shipped by rail in 2040 in the NEB's reference scenario.[63] In the NEB's technology scenario, no rail would be needed. Also shown is the additional surplus capacity the Trans Mountain expansion and Keystone XL pipelines would represent. The Trans Mountain expansion project is facing legal challenges as of this writing; the Keystone XL project, however, has received approval from the Trudeau government, the Trump administration and the State of Nebraska, and appears likely to go ahead.

Figure 81: Western Canadian supply with and without the Alberta emissions cap compared to existing export pipeline, rail and refining capacity if the Line 3 restoration project is completed.

With the emissions cap, pipeline capacity would be sufficient until 2025 and about 5% of 2040 production would have to be shipped by rail in 2040. The completion of either Keystone XL or the Trans Mountain expansion would provide sufficient pipeline capacity without rail in all three of the National Energy Board's scenarios under the emissions cap.[64]



[62] Hughes, J.D., 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives. https://www.policyalternatives.ca/sites/default/files/uploads/publications/2017/05/Trans%20Mountain%20Pipeline%20and%20Tidewater%20Access%20FINAL.pdf

[63] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017. Emissions are from Environment and Climate Change Canada, National Inventory Report, released April, 2017. See Table A10-2 for emissions by economic sector, http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2017-nir-13apr17.zip .

[64] Data from CAPP Oil Forecast 2016; National Energy Board, Canada's Energy Future 2017; and author's calculations.

Table 12 summarizes export capacity in the three NEB scenarios for western Canadian supply with the oil sands emissions cap, assuming various combinations of pipeline and rail. Existing pipeline capacity with the Line 3 restoration project would be sufficient for peak western Canadian supply only in the NEB's technology scenario. If rail is included, however, there would be a surplus capacity of between 8% and 14% at peak supply, with 5.4% carried by rail in 2040 in the NEB's reference scenario. If the Keystone XL and Trans Mountain expansion projects are also built, there would be a surplus of pipeline-only capacity of between 17% and 22% at peak supply. If rail is added to this latter case, surplus export capacity at peak supply would be between 26% and 30%.

Table 12: Pipeline and rail export capacity (including refinery consumption) compared to western Canadian supply at peak rates in three National Energy Board production cases, with various combinations of existing and proposed pipelines and rail (through 2040).

With rail, existing pipeline capacity and the completion of the Line 3 restoration project there would be between 8.4% and 13.8% surplus capacity at peak supply. Pipelines are assumed to run at 95% of nameplate capacity. (mbd = million barrels per day)

Maximum WCSB supply with 100-Mt cap (mbd)		Year of maximum WCSB supply	Surplus capacity with existing pipelines and Line 3 (%)	Surplus capacity with existing pipelines, and Line 3 plus rail (%)	Surplus capacity with existing pipelines, Line 3, Trans Mountain expansion and Keystone XL (%)	Surplus capacity with existing pipelines, Line 3, Trans Mountain expansion and Keystone XL, plus rail (%)
NEB reference scenario	5.27	2040	-5.46%	8.36%	16.97%	25.79%
NEB higher carbon price scenario	5.06	2040	-1.26%	12.02%	20.28%	28.74%
NEB technology scenario	4.96	2027	0.74%	13.75%	21.85%	30.15%

The Trans Mountain expansion project from Edmonton to Burnaby has been vigorously opposed by environmental groups, First Nations and municipal governments. The principal argument the federal government has used for approving this project, that new pipeline access to tidewater will confer a significant price premium for western Canadian oil, has been shown to be false.[65,66,67] If the Alberta oil sands emissions cap is observed, new pipelines would not be needed if small amounts of rail transport are included. Even with the emissions cap, oil production emissions alone will grow to 25% of Canada's allowable commitments under the Paris Agreement in 2030, which will make meeting these commitments very difficult or impossible.[68] Without the cap, additional export pipelines would be needed, but would render Canada's commitments under the Paris Agreement even less achievable.

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[65] Oil Change International, March 2016, TAR SANDS: THE MYTH OF TIDEWATER ACCESS, http://priceofoil.org/content/uploads/2016/05/Tidewater-2016-v2.pdf

[66] Jeff Rubin, Globe and Mail, November 1, 2016, New pipelines? The oil sands may have trouble filling the ones it has, http://www.theglobeandmail.com/report-on-business/rob-commentary/new-pipelines-the-oil-sands-mayhave-trouble-filling-the-ones-it-has/article32601876/

[67] Hughes, J.D., 2017, Will the Trans Mountain pipeline and Tidewater Access raise Prices and Save Canada's oil industry?, Canadian Centre for Policy Alternatives

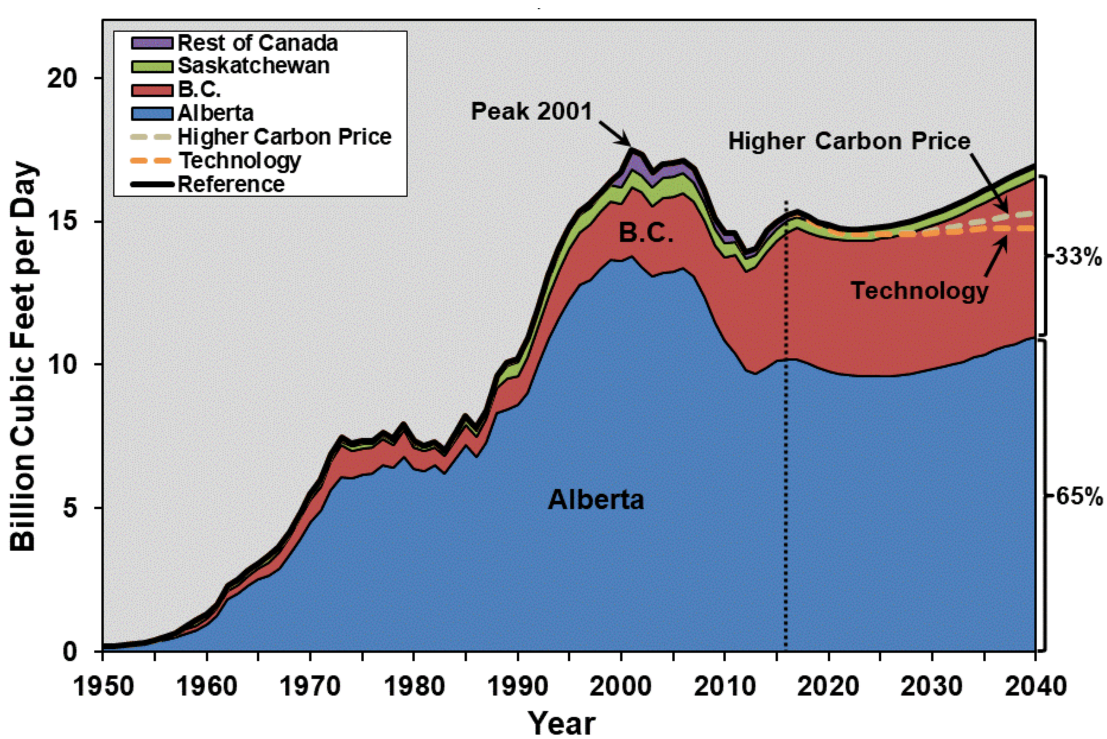
[68] Hughes, J.D., 2016, Can Canada Expand Oil and Gas Production, Build Pipelines and Keep Its Climate Change Commitments?, Canadian Centre for Policy Alternatives, 38p, https://www.policyalternatives.ca/sites/default/files/uploads/publications/National%20Office%2C%20BC%20Office/2016/06/Can_Canada_Expand_Oil_and_Gas_Production.pdf

2.1.5 Natural gas

Natural gas production in Canada peaked in 2001 and is now down 14% from its peak (see Figure 51), despite record drilling rates in 2006 and record high prices in 2008. Although Alberta has been by far the most important contributor to the Canadian gas supply, BC has become a major supply source and is forecast to provide one-third of the Canadian supply in 2040, mainly through the development of extensive shale and tight gas resources made accessible with horizontal drilling and hydraulic fracturing technology (fracking). Figure 82 illustrates historical production and the NEB's reference case forecast by province. Under the reference scenario, Canadian production in 2040 is projected to be roughly what it was in 2001.

Figure 82: Historical natural gas production by province from 1950 to 2016, and the National Energy Board's reference case forecast to 2040.

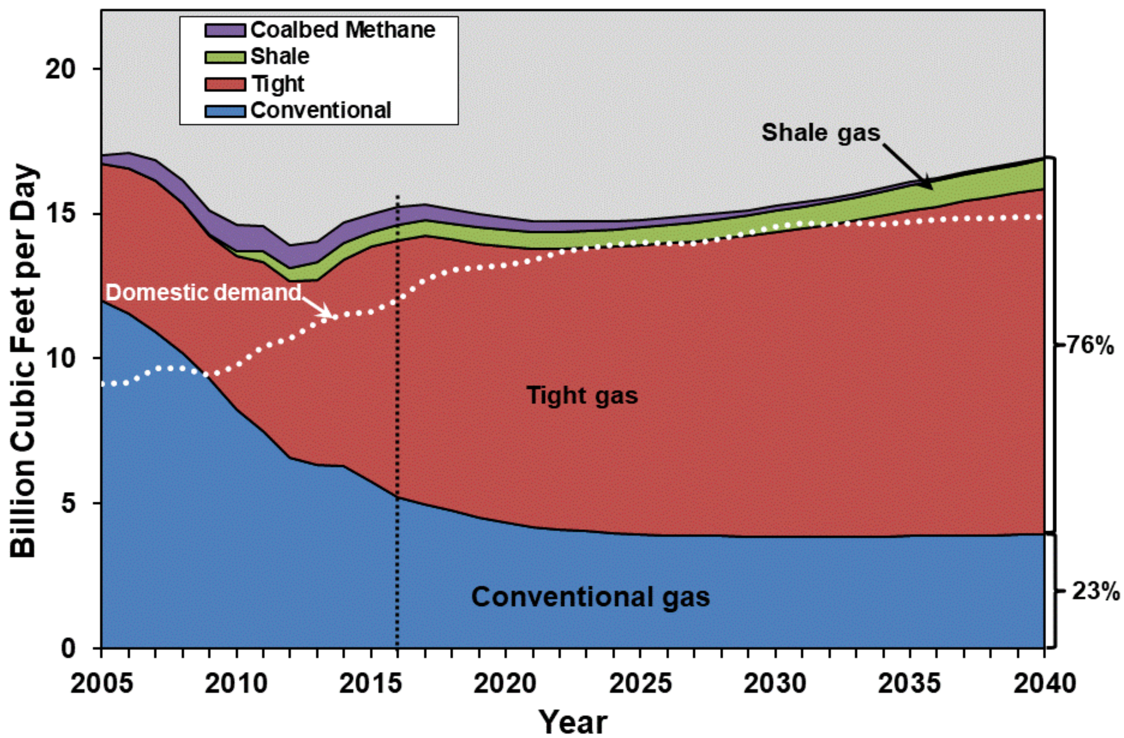
Peak production occurred in 2001 and is currently down 14% below peak (see Figure 51). Also shown are the NEB's higher carbon price and technology production scenarios.[69]



[69] 1950–1999 data from CAPP; 2000–2004 data from National Energy Board, Energy Future 2016; 2005–2040 data from National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017.

Figure 83 illustrates current and future production by play type as well as projected gas consumption in the NEB's reference scenario. Although conventional gas dominated Canadian production in the past, future production will predominantly come from unconventional tight and shale gas sources. Canada has historically been a major exporter of natural gas, however, future NEB projections suggest that the production surplus compared to domestic demand will narrow to less than 10% beginning in 2021.

Figure 83: Natural gas production by play type from 2005 to 2040 in the National Energy Board's reference case scenario, and domestic demand. [70]

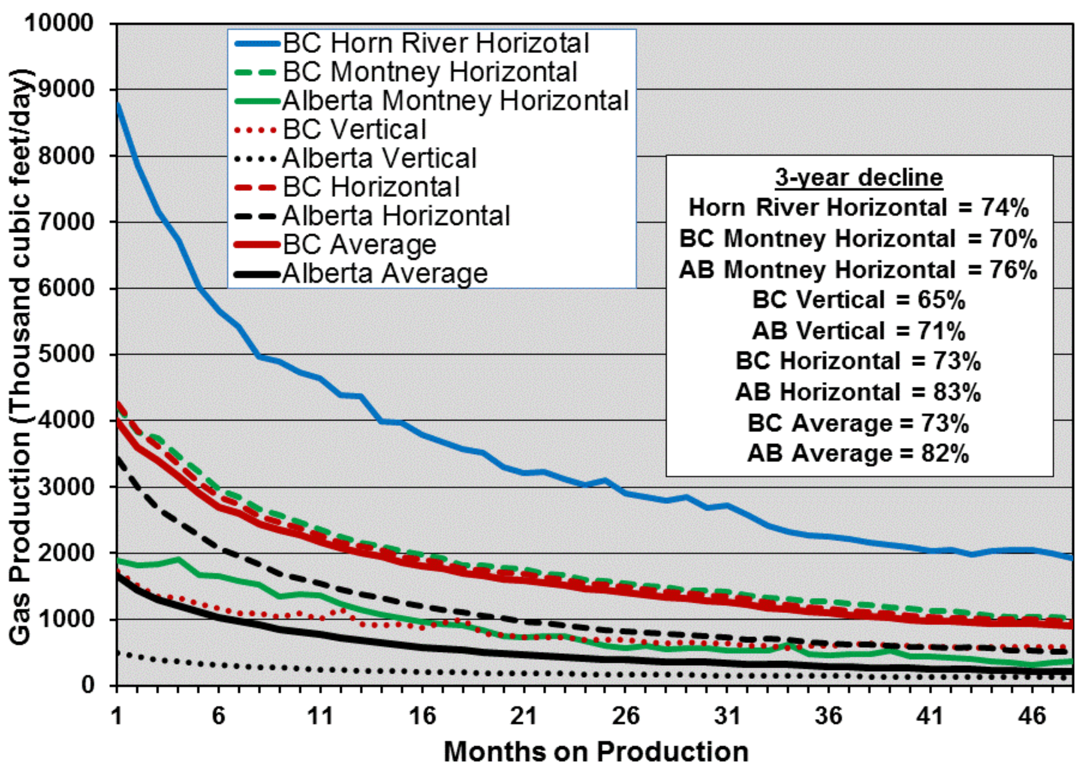


[70] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA retrieved Oct 29, 2017.

As with oil, gas wells decline in production rapidly over the first few years, necessitating more drilling to maintain production. The decline in natural gas prices since 2008 has resulted in a decline in drilling rates, which is responsible for much of the decline in Canadian production. This decline was offset in part by increasing numbers of horizontal fracked wells, which opened up new resources in the Montney and Horn River plays of western Alberta and northeast BC. Figure 84 illustrates the average production rates over time of gas wells (it does not include gas production that may come from oil or bitumen wells). As can be seen, horizontal wells are much more productive than vertical wells. The Horn River shale wells in northeast BC are very productive—equivalent to the best US shale gas plays—but they are also very expensive. Horn River wells average 25 million gallons of injected fracking fluid, compared to four million for the Montney.[71] Production declines in the first three years average between 70% and 83% for horizontal wells and between 65% and 71% for vertical wells. As decline is hyperbolic, with the steepest decline in the first few years, overall field decline from a mix of old and new wells typically ranges between 25% and 40% per year, requiring replacement each year through more drilling to keep production flat.

Figure 84: Average production decline profiles for horizontal and vertical wells in Alberta and BC

Includes gas wells only—not oil or bitumen wells, which also may produce some gas.[72]



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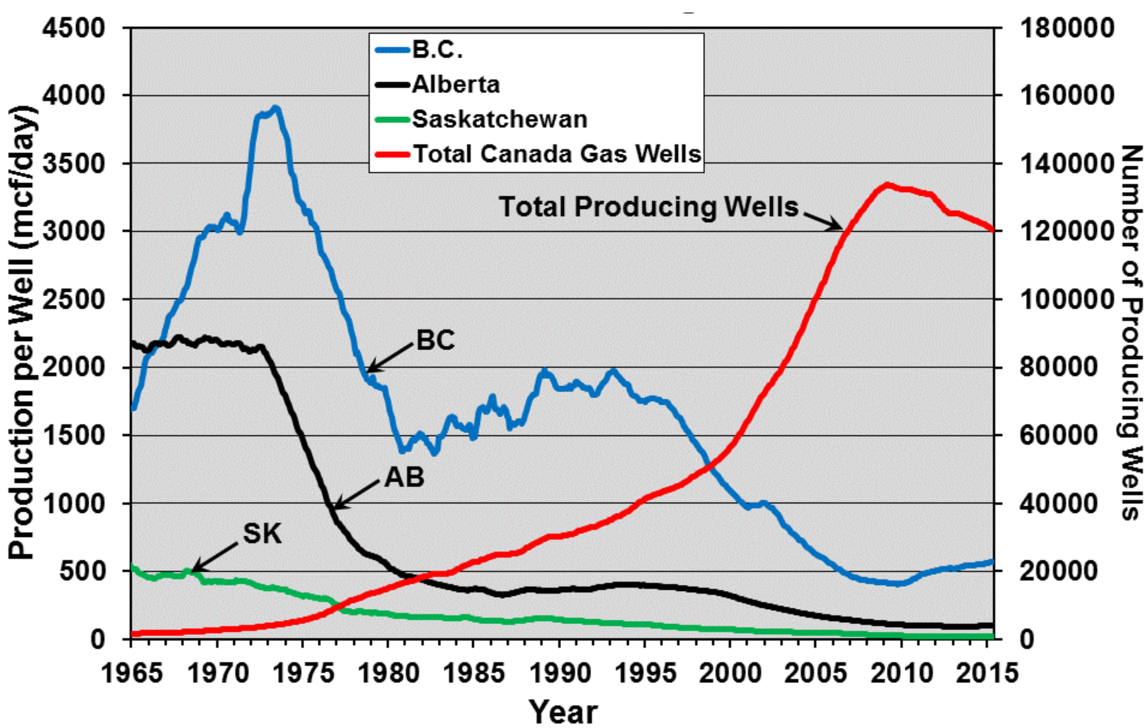
[71] Hughes, J.D., 2015, A Clear Look at BC LNG, https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/05/CCPA-BC-Clear-Look-LNG-final_0_0.pdf

[72] Data from Drillinginfo, December 2015

Given the steep drop in production of the average natural gas well in the first years after it is drilled and the rapidly escalating number of wells, the average productivity of wells has declined over time. Figure 85 illustrates average natural gas production per well by province since 1965. Peak production per well occurred in the late 1960s and early1970s in all provinces. More and more wells and infrastructure are required to maintain production as wells decline and fields are exhausted. This trend of declining average production will continue despite the generally higher productivity of new horizontal wells, given the large number of lower-producing legacy wells that are responsible for the bulk of production. The total number of producing wells peaked at just over 133,000 in late 2009 and has declined since as older wells become uneconomic and are shut in.

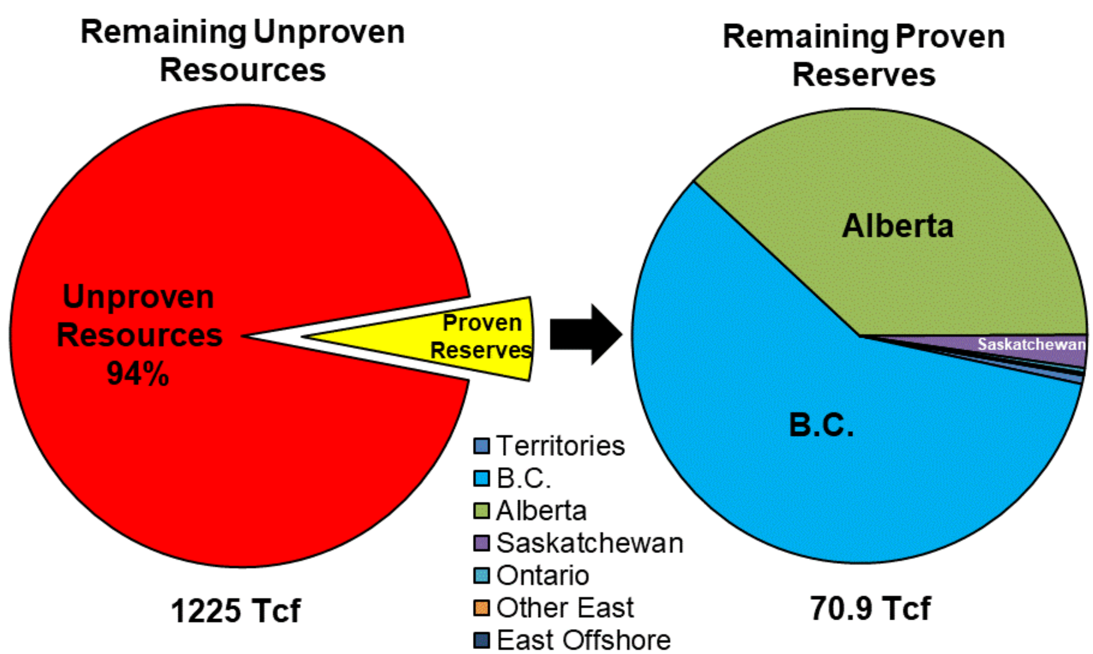
Figure 85: Average production (mcf = thousand cubic feet) per natural gas well by province from 1965 to 2015, and total number of producing natural gas wells (includes gas wells only—not oil or bitumen wells, which also may produce some gas).[73]



[73] Data from Drillinginfo, December 2015; 12 month centred moving average

Natural gas reserves are defined as discovered resources that are technically and economically recoverable. They are usually expressed in probabilistic terms: "proven," "probable" and "possible."[74] The NEB does not provide estimates of natural gas reserves in its *Energy Futures* reports as it does for oil. Instead, it provides only estimates of "marketable resources" calculated by methodology that does not conform to the requirements of regulations such as National Instrument 51-101, under which Canadian reserve and resource reporting is regulated. Given the assumptions and limited data used as a basis for its estimates, the NEB's reported marketable resources should be viewed as approximate and likely highly optimistic. However, the provinces do apply stringent criteria to estimate natural gas "reserves." These are compared to the NEB's resource estimates in Figure 86.

Figure 86: Marketable natural gas resources as of year-end 2015 estimated by the National Energy Board[75] compared to reserves estimated by the provinces and compiled by the Canadian Association of Petroleum Producers[76] (tcf = trillion cubic feet).



Reserves are typically replaced over time with more drilling, but this cannot continue indefinitely as natural gas is a non-renewable resource. The NEB's reference case forecast calls for the production of 135 trillion cubic feet (tcf) over the 2017–2040 period, which is nearly double Canada's currently known reserves of 70.9 tcf.

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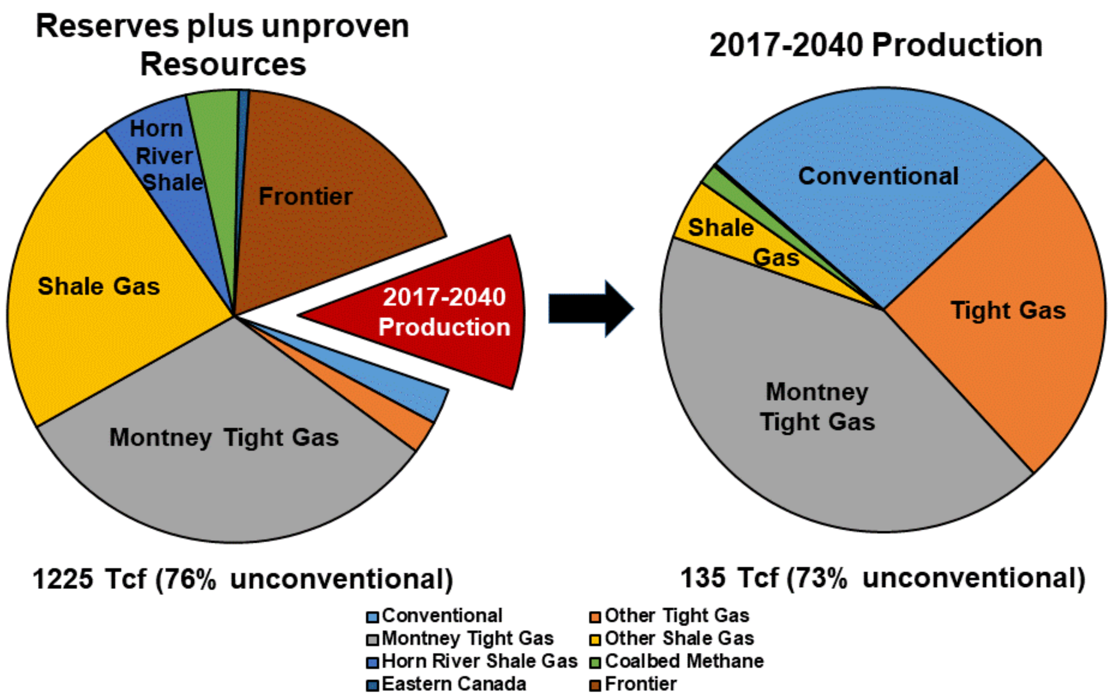
[74] Society of Petroleum Engineers, 2011, Guidelines for Application of the Petroleum Resources Management System http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf . In Canada reserve and resource reporting is regulated under National Instrument 51-101 which is guided by technical standards in the Canadian Oil and Gas Evaluation Handbook updated periodically by the Canadian branch of the Society of Petroleum Engineers.

[75] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

[76] Canadian Association of Petroleum Producers Statistical Handbook, retrieved November 5, 2017, http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook

The NEB's estimates of marketable resources by source in its reference case are illustrated in Figure 87, along with forecast production under this scenario. Unconventional resources made possible by the application of horizontal drilling and fracking constitute 76% of remaining resources, and 73% of 2017–2040 production.

Figure 87: Remaining Canadian marketable natural gas resources by type after 2017–2040 production is removed (tcf = trillion cubic feet), according to the National Energy Board (left), along with cumulative production over the same period (right).[77]

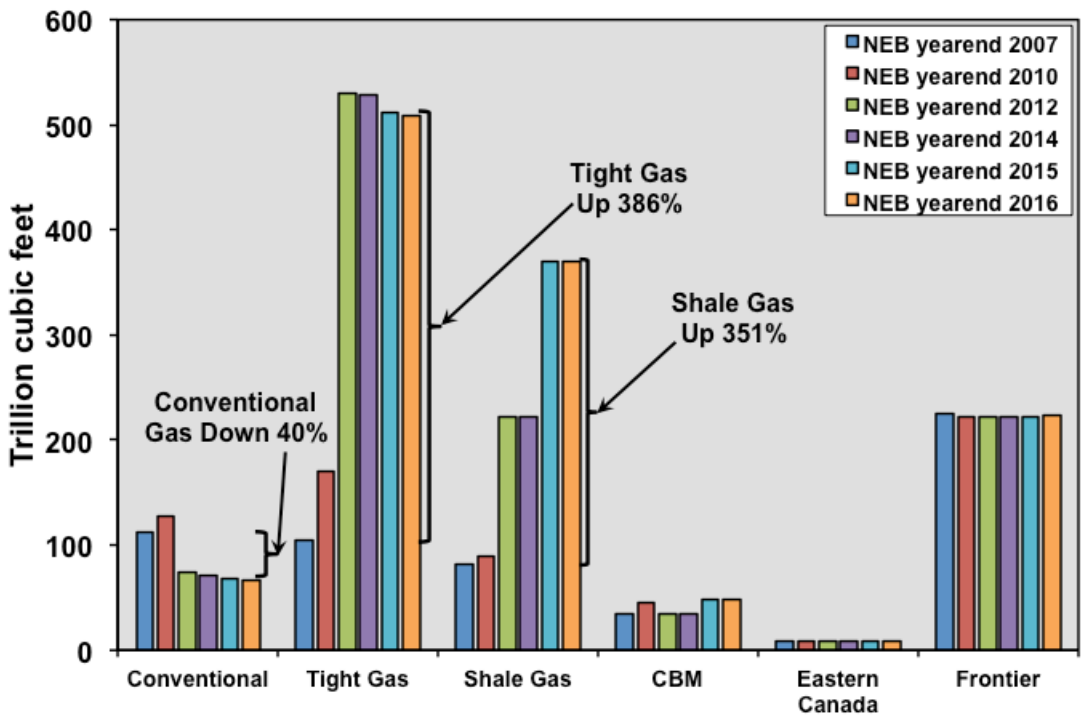


[77] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

As Canada is now mainly dependent on unconventional sources of natural gas for future supply, and the recovery of that gas depends on hydraulic fracturing technology, which has been found to have serious environmental impacts in some jurisdictions,[78] it is prudent to assess the uncertainty of the NEB's estimates, given their importance for future energy security. Figure 88 illustrates the growth of NEB estimates of marketable resources by source from 2007 to 2017. Virtually all of the increases have been in unconventional tight gas and shale gas—conventional gas resources have declined by nearly half since 2010 and frontier resources have remained constant. Coalbed methane, which in 1999 the NEB believed would be able to provide up to 80% of Canadian production by 2025, has increased little and is projected to be a very minor portion of supply through 2040.[79]

Figure 88: NEB estimates of "marketable" natural gas resources from year-end 2007 through to year-end 2016.

Virtually all growth stems from vast increases in estimates of unconventional tight gas and shale gas resources.[80]



[78] U.S. Environmental Protection Agency, 2016, EPA's Study of Hydraulic Fracturing for Oil and Gas and Its Potential Impact on Drinking Water Resources, https://www.epa.gov/hfstudy

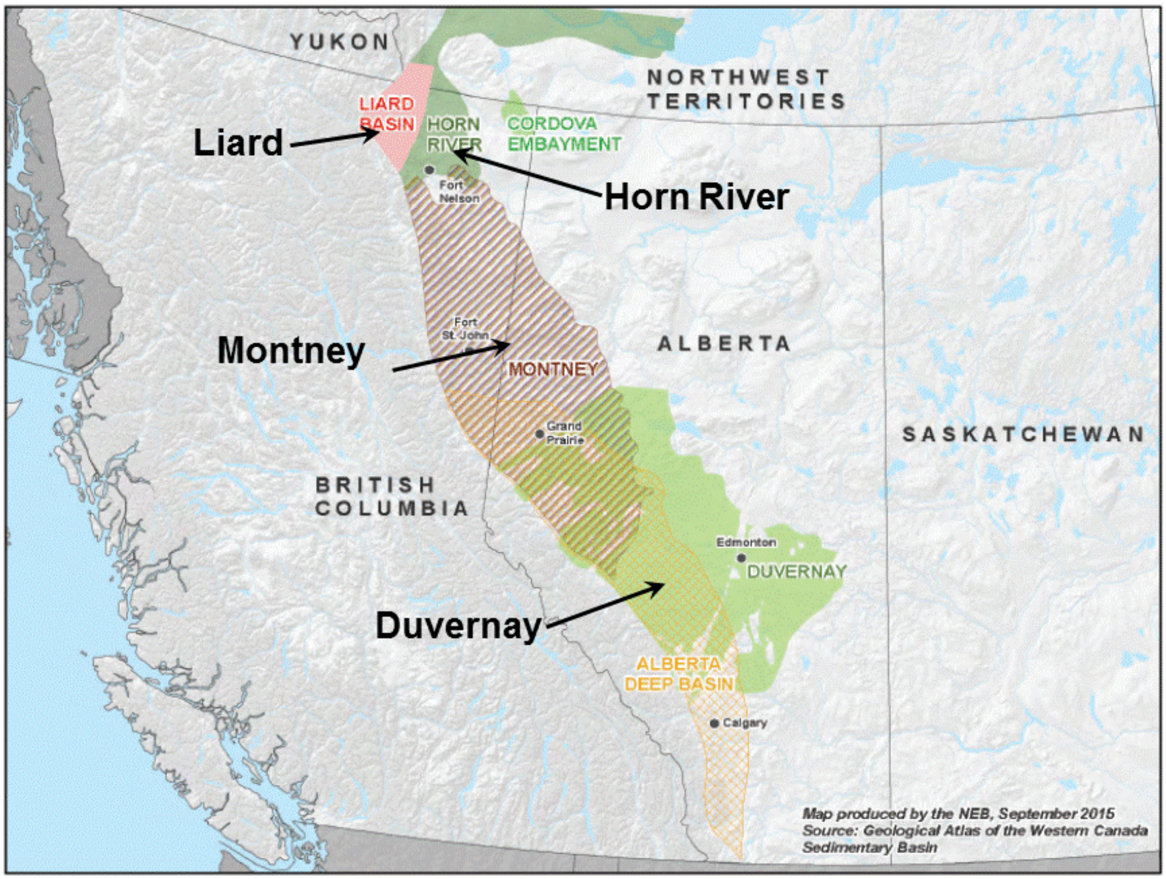
[79] National Energy Board, 1999, Canadian Energy - Supply and Demand to 2025 (released in 1999), see Figure 5.6 on page 49.

[80] Data from National Energy Board, 2009, 2011, 2013, 2016, 2017

The NEB has more than quadrupled its estimates of tight gas and shale gas since 2007, based primarily on three studies of resources in northwest Alberta and northeast BC: the Horn River shale play,[81] the Montney tight gas play[82] and the Liard Basin shale play.[83] Together, these plays made up 74% of the NEB's remaining marketable resource estimates for Western Canada at year-end 2015 (see Figure 89). A fourth study, of the unconventional Duvernay play, has recently been released but has not yet increased the NEB's marketable gas estimates.[84]

Figure 89: Location of Montney, Horn River and Liard plays, which constitute 74% of the National Energy Board's estimate of remaining "marketable" natural gas resources.[85]

The Duvernay is an emerging play that produces both gas and oil.



[81] National Energy Board, 2011, Ultimate Potential for Unconventional Natural Gas in Northeast British Columbia's Horn River Basin, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ncnvntnlntrlgshrnrvrbsnhrnrvr2011/ncnvntnlntrlgshrnrvrbsnhrnrvr2011-eng.pdf

[82] National Energy Board, 2013, The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note, http://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

[83] National Energy Board, 2016, The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon - Energy Briefing Note, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/index-eng.html

[84] National Energy Board, Duvernay Resource Assessment Energy Briefing Note September 2017, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2017dvrn/2017dvrn-eng.pdf

[85] National Energy Board, January 2016, Canada's Energy Future 2016 - Energy Supply and Demand Projections to 2040, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf

Table 13 illustrates the well count, cumulative production and year-end 2015 NEB marketable resource estimates for the Montney, Horn River and Liard tight gas and shale gas plays. Of these, the Montney has the most drilling, with 6,800 wells drilled, of which 4,200 are still producing. It has produced nearly seven tcf to date, or less than 2% of the NEB's recoverable estimate of 445 tcf. The NEB estimate is based on a probabilistic assessment of variables such as thickness, depth, organic content, pressure, temperature, porosity and recovery factors over very broad areas, and hence yields a very large number—larger than the Marcellus, the largest shale gas play in the US, which has had considerably more exploration and production effort. The Montney study has a high level of uncertainty as to how much of this resource will ever be recovered. Its authors note that "no study has been undertaken to determine the economics for marketable resources."[86]

Table 13: Well count, cumulative production and the National Energy Board's year-end 2015 "marketable" resource estimates for the Montney, Horn River and Liard tight gas and shale gas plays, which account for 74% of its estimates of Western Canada's remaining gas resources.[87]
Also shown are the uncertainty ratings for the NEB's estimates (tcf = trillion cubic feet).

Play	Province	Well type	Total wells	Producing wells	Total producing wells	Cumulative production (tcf)	Total cumulative production (tcf)	NEB estimate gas (tcf)	Uncertainty
Montney (tight gas)	Alberta	Vertical	1,646	618	4,181	1.67	6.86	177	High
		Horizontal	1,587	1,141		0.89			
	BC	Vertical	1,231	499		0.73		268	
		Horizontal	2,325	1,923		3.57			
Horn River (shale gas)	BC	All	313	186	186	0.88	0.88	77	Very high
Liard (shale gas)	BC	All	4	3	3	0.01	0.01	167	Extremely high
	Yukon	All	-	-		0.00		8	
	NWT	All	-	-		0.00		44	
Total		**All**	**7,106**	**4,370**	**4,370**	**7.76**	**7.76**	**741**	**Very high**

The Horn River shale gas play was the first unconventional play assessed by the NEB, in a 2011 report. This play has had relatively little exploration, with 313 wells drilled, of which 186 are still producing. The Horn River play is more remote and wells are more expensive than in the Montney, as they are deeper and use much larger volumes of injected water, proppants and chemicals. The Horn River wells are, however, much more productive on average than the Montney wells (see Figure 83), and are among the most prolific shale gas wells in Canada and the US The NEB's assessment of Horn River marketable resources used the same probabilistic methods outlined above for the Montney, however, given the fact that the there is much less drilling information for the play, the uncertainty as to how much of this resource will ever be recovered

[86] National Energy Board, 2013, The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note, http://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

[87] Total and producing well counts and well type are from Drillinginfo and are current to August 2015. "Marketable" resource estimates are current to year-end 2015 and are from the NEB October 2016 Energy Future update.

must be rated as very high. For example, the Horn River study used recovery factors of 15% to 25%[88] of in-place resources, compared with estimates from more mature shale plays in the US of 1.7% to 11.2%.[89] Using an average recovery factor of 6% instead of 18% (the average used in the NEB's "medium" estimate) would alone reduce the marketable resource estimate by two-thirds (from 77 tcf to 25.4 tcf). As with the Montney study, the Horn River study adds the disclaimer that "no study has been undertaken to determine the economics for marketable resources,"[90] hence the marketable resource assessment should be viewed as highly optimistic.

The Liard shale play study is the most recent NEB assessment of an unconventional natural gas resource.[91] The Liard Basin is located in northern BC and parts of the southern Yukon and Northwest Territories, as shown in Figure 88. There are four modern shale gas wells located in the BC portion of the basin, of which three are producing. Estimates of in-place resources used a probabilistic methodology comparable to the earlier Horn River and Montney studies, however, the marketable estimate used the estimated ultimate recovery (EUR) of an "index" well. Presumably it was assumed that all wells drilled within the play area would be successful (with modest reductions in deformed portions), and would have EURs comparable to the index well after adjustments for variables like depth and pressure.

The production data for the four available wells are given in Table 14 (next page). The EURs are estimated at between 2.2 and 10.3 billion cubic feet (bcf), with a mean EUR of 6.25 bcf (an EUR of 6.25 bcf is a very good well by comparison to most shale plays). The NEB chose the best well, C-45-K, for its "index" well and assumed it would have an EUR of 15.8 bcf, or nearly three times the average of the four available wells and 53% higher than actual production data for C-45-K suggest, and hence its estimate is extremely optimistic.

The NEB estimates recovery factors of 19.7% of in-place resources in its "expected" case for the BC portion of the basin, compared to estimates of 1.7% to 11.2%[92] in mature US shale plays. Using the average EUR of the four available wells (rather than an overestimate of the best one) would reduce the recovery factor to 7.8% and the estimated marketable resource by 60%. This, coupled with the relatively small amount of data available for the probabilistic part of the assessment, means that the NEB's marketable resource estimate for the Liard Basin should be viewed as extremely optimistic. As with the Montney and Horn River studies, the NEB adds the disclaimer that "no study has been undertaken to determine the economics for marketable resources."[93]

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[88] National Energy Board, 2011, Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin, see page 6-7, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ncnvntnlntrlgshrnrvrbsnhrnrvr2011/ncnvntnlntrlgshrnrvrbsnhrnrvr2011-eng.pdf

[89] Oil and Gas Journal, November 3, 2014, New well-productivity data provide US shale potential insights, http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html

[90] Supra note 88

[91] National Energy Board, 2016, The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon - Energy Briefing Note, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/index-eng.html

[92] Oil and Gas Journal, November 3, 2014, New well-productivity data provide US shale potential insights, http://www.ogj.com/articles/print/volume-112/issue-11/drilling-production/new-well-productivity-data-provide-us-shale-potential-insights.html

[93] Supra note 91

Table 14: Producing shale gas wells in the Liard Basin using the National Energy Board's assessment.

Estimated ultimate recoverable gas (EUR) is shown for each well along with the NEB's assumed EUR for its "index" well used to estimate marketable resources.

Well	C-45-K	C-86-F	D-28-B	B-20-I
First production	2/1/2011	12/1/2011	9/1/2009	11/1/2013
Months of production	55	44	52	15
Total depth (feet)	15,567	14,514	12,963	15,414
Status	active	active	suspended	active
Drill type	H	V	V	H
Cumulative gas (bcf)	6.8	3.8	1.4	0.6
Peak gas (mcf/d)	18,818	6,178	3,508	3,843
Latest gas (mcf/d)	1,263	1,945	724	587
EUR 50 years (bcf)	10.3	9.1	3.4	2.2
BC C-45-K well EUR assumption (bcf)	15.8 (.85 km lateral)			
BC index well EUR assumption (bcf)	32.5 (1.75 km lateral)			

With its three unconventional gas resource studies, the NEB increased Canada's remaining marketable gas resources by 60% (741 tcf). This compares to just 68 tcf of remaining conventional resources, which Canada has relied on for the past 70 years. Other resources are mainly offshore, on the East Coast and in the Arctic. Given the highly to extremely optimistic nature of the three NEB studies outlined above, it is a mistake to weight these unconventional resources too heavily when planning future Canadian supply.

2.2 Coal

Coal has been a major source of electricity generation in Alberta, Saskatchewan, Ontario and Nova Scotia for many decades. Metallurgical coal for steel-making also supports a large export industry from mines in the foothills and front ranges of Alberta and BC. Emphasis on reducing the carbon emissions from coal-fired power generation has resulted in a coal phase-out in Ontario, which was completed in 2014, and a pledge by Alberta to shutter the last of its coal plants by 2030. Saskatchewan, which has employed carbon capture and storage (CCS) technology to reduce emissions,[94] and Nova Scotia are likely to continue to use coal at some level beyond 2030.

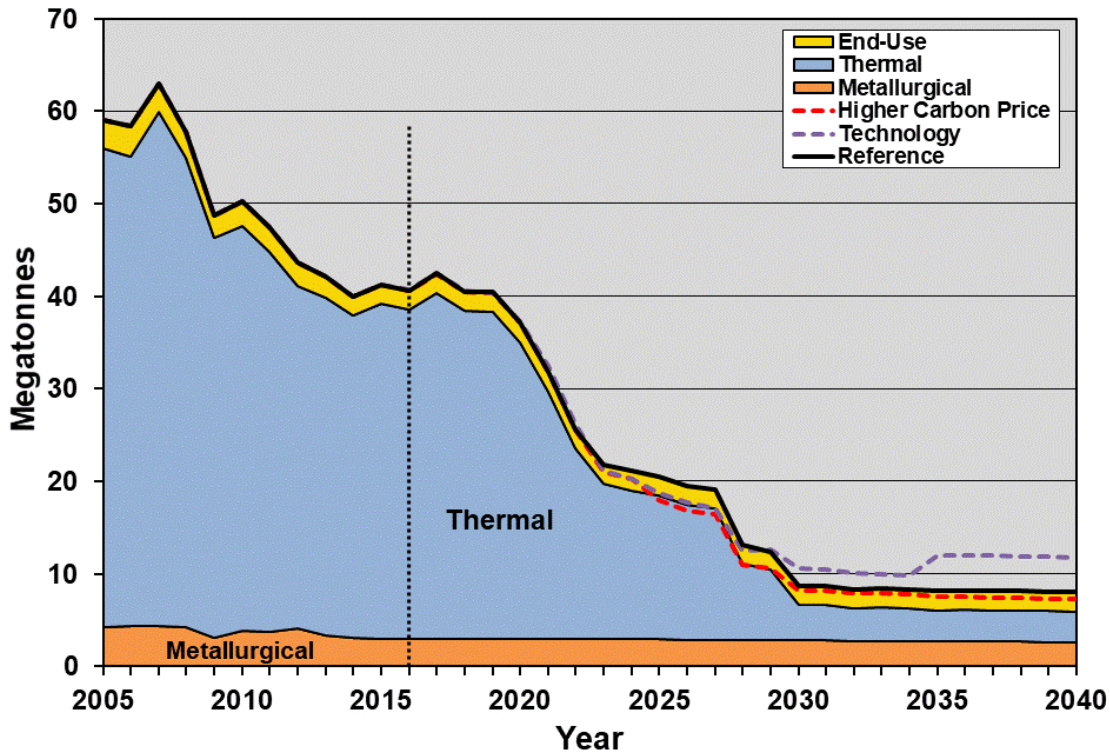
Although a large proportion of coal burned in the world is used for electricity generation, metallurgical (or "coking") coal is essential in the steel-making industry and has few economical substitutes. Coal is classified by rank or thermal maturity, which is a function of the temperature and time it has been exposed to over its geological history. Lower-rank subbituminous and lignite coals, along with non-coking bituminous coals, are used exclusively for thermal applications. They are widespread in the plains and foothills of Alberta and BC, in southern Saskatchewan and in Nova Scotia, with smaller deposits in the

[94] Global CCS Institute, Boundary Dam Carbon Capture and Storage Project, retrieved 21 February 2017, https://www.globalccsinstitute.com/projects/boundary-dam-carbon-capture-and-storage-project

interior of BC, on Vancouver Island and in the James Bay region of Ontario. Higher-rank metallurgical coal is limited to the foothills and front ranges of BC and Alberta.[95]

Figure 90 illustrates coal consumption in Canada and the NEB's projections through 2040. The shutdown of coal-fired electricity generation in Ontario has resulted in a major drop from 2005 levels, and the planned coal phase-out in Alberta by 2030 will result in a further major drop by 2030. Metallurgical coal for steel plants in Eastern Canada, which is mainly imported from the US, will continue to be used, along with some thermal coal for power generation and non-power end-use applications.

Figure 90: Coal consumption in Canada by type from 2005 to 2040, the National Energy Board's reference case is illustrated, along with its higher carbon price and technology case projection through 2040.[96]



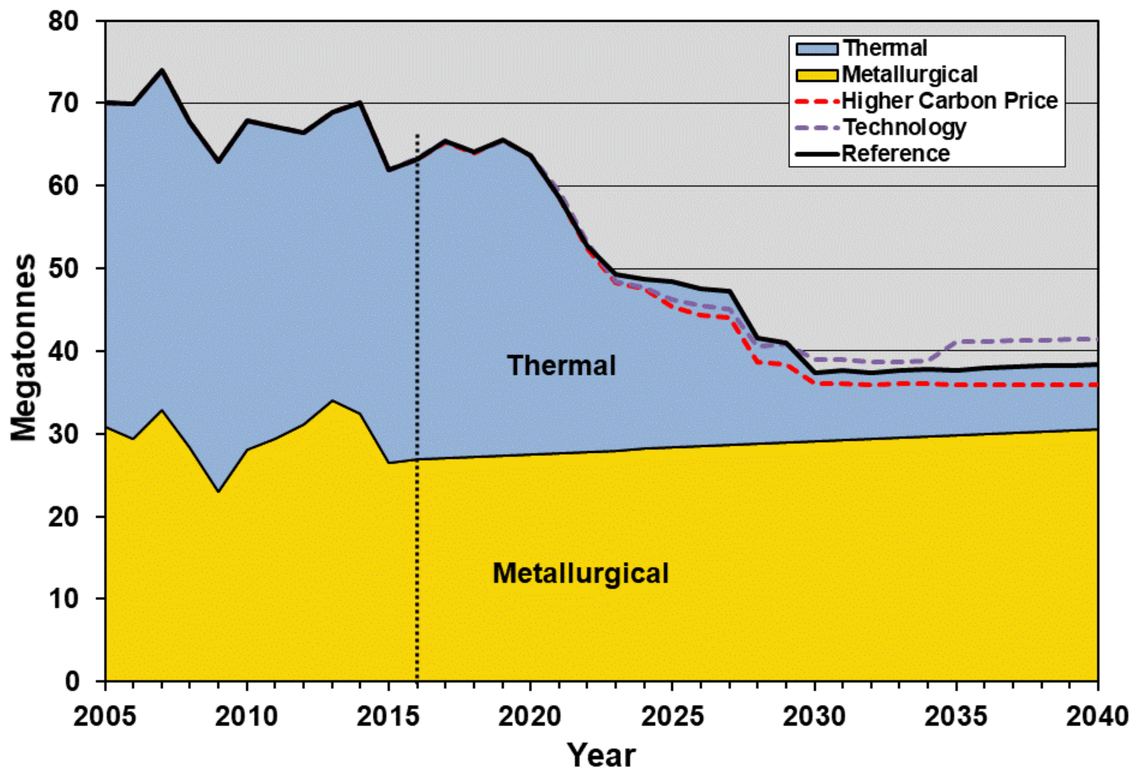
[95] For a detailed look at the distribution and characteristics of coal in Canada, see Smith, G.G., 1989, Coal Resources of Canada, Geological Survey of Canada Paper 89-4.

[96] National Energy Board Energy Future, October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Canadian coal production, along with the NEB's projections, is illustrated in Figure 91. Metallurgical coal production in Western Canada for export is expected to continue at slightly increasing levels through 2040, whereas thermal coal production is expected to fall by 77% (from 2016 levels) by 2030, due to the closure of coal-fired power plants in Alberta.

Figure 91: Canadian coal production by type from 2005 to 2040.

The National Energy Board's reference case is illustrated along with its higher carbon price and technology case projections through 2040.[97]



[97] Data from NEB Energy Future 2017

Figure 92 illustrates the NEB's projections of coal imports and exports through 2040. Canada will continue to export some thermal coal through 2040, and will export gradually increasing amounts of metallurgical coal from Western Canada. Thermal coal imports have been radically reduced with the closure of coal-fired power plants in Ontario but will continue to supply plants in New Brunswick and Nova Scotia. Metallurgical coal imports will also continue to supply steel mills in Eastern Canada.

Figure 92: Canadian coal imports and exports by type from 2005 to 2040.
The National Energy Board's reference case projection is illustrated through 2040. The NEB's higher carbon price and technology projections are not shown here, as they are not significantly different from the reference case. [98]

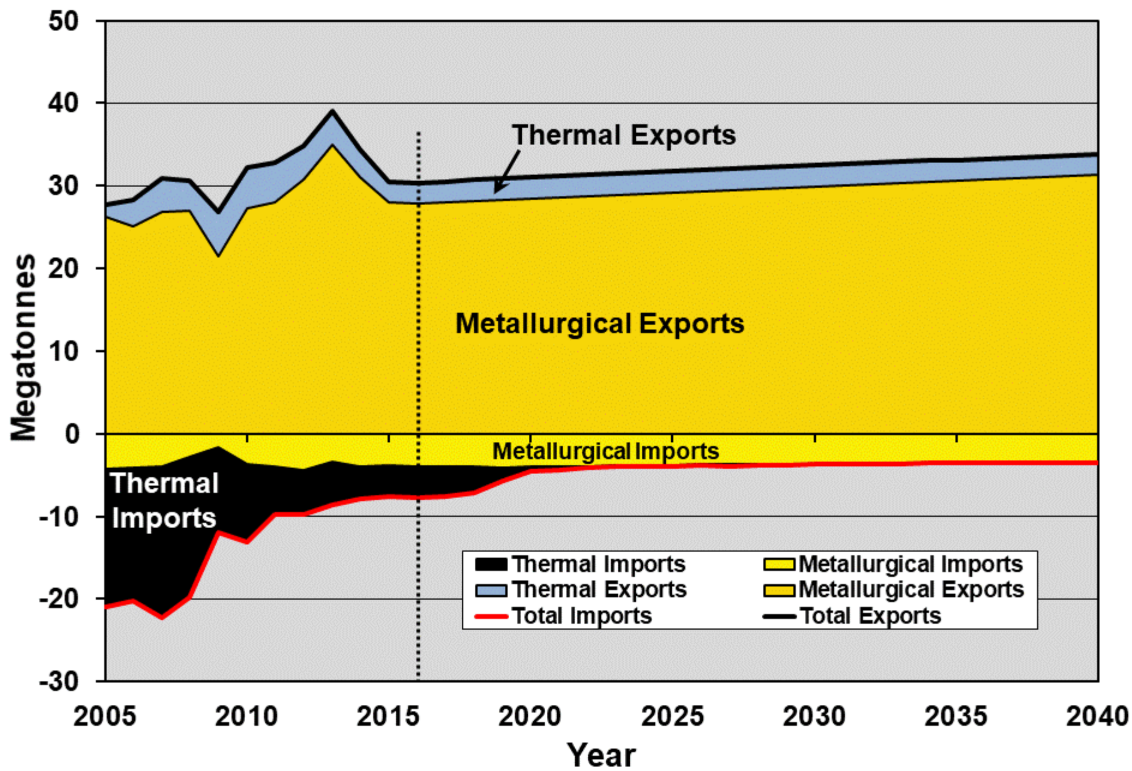


Table 15 illustrates remaining Canadian coal reserves and resources as of 2014. At 2015 production levels, reserves would last for 155 years for metallurgical coal and 70 years for thermal coal. At 2030 production levels metallurgical and thermal coal reserves would last for 142 and 675 years, respectively. The resources in Table 15 should be viewed as highly speculative.

Table 15: Canadian coal reserves and resources as of 2014 according to the World Energy Council. [99]
Hard coal roughly equates to metallurgical coal, and subbituminous/lignite to thermal coal.

2014 reserves (billion tonnes)			2014 resources (billion tonnes)		
Hard coal	Subbituminous/ lignite	**Total**	Hard coal	Subbituminous/ lignite	**Total**
4.35	2.24	**6.58**	183.26	118.27	**301.53**

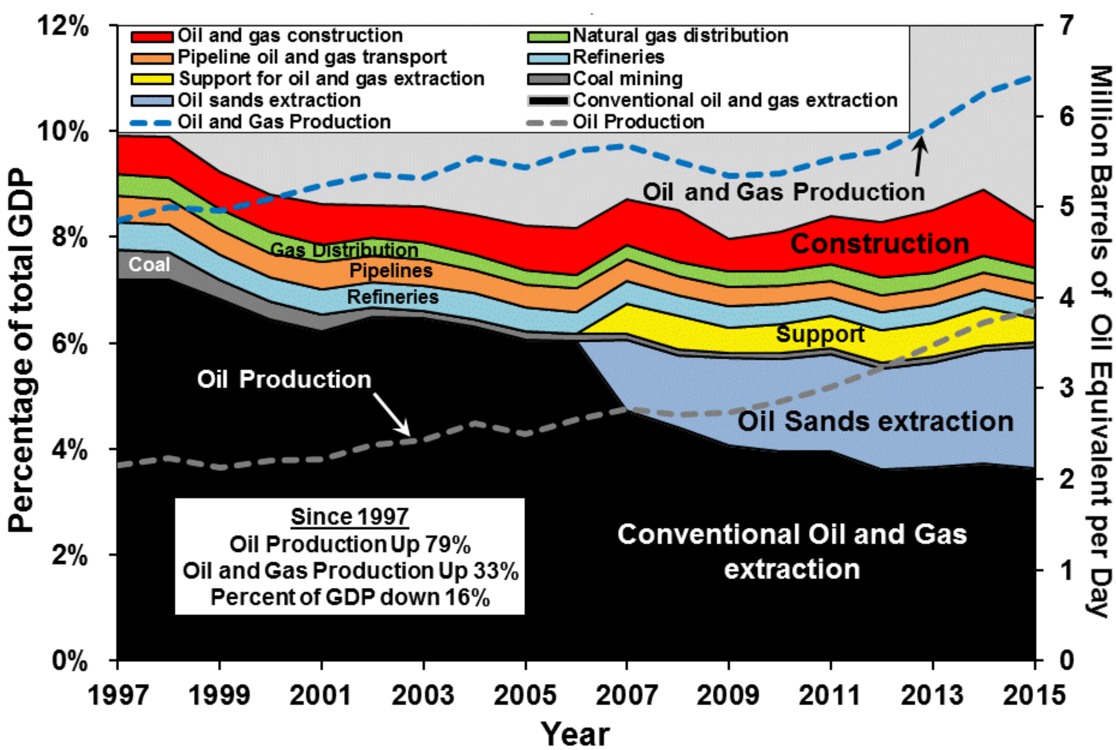
[98] Data from NEB Energy Future 2017 Reference Case
[99] World Energy Council, 2016, World Energy Resources 2016, https://www.worldenergy.org/wp-content/uploads/2016/10/World-Energy-Resources_Report_2016.pdf

2.3 Government revenue from oil, gas and coal production

Canada is touted as a "petrostate"[100] by some, although in fact the percentage of Canada's GDP generated by fossil fuel extraction, processing and related construction has declined from 10% to 8.3% over the past two decades—despite the fact that oil production has gone up by 79% and combined oil and gas production by 33% over this period. Figure 93 illustrates the percentage of Canada's GDP generated by fossil fuel production, distribution and construction.

Figure 93: Gross domestic product (GDP) generated by the fossil fuel industry in Canada as a percentage of total GDP from 1997 to 2015.[101]

Oil and gas production during this period is also shown.[102] GDP from fossil fuels as a percentage of total GDP has fallen by 16% while production has grown substantially.



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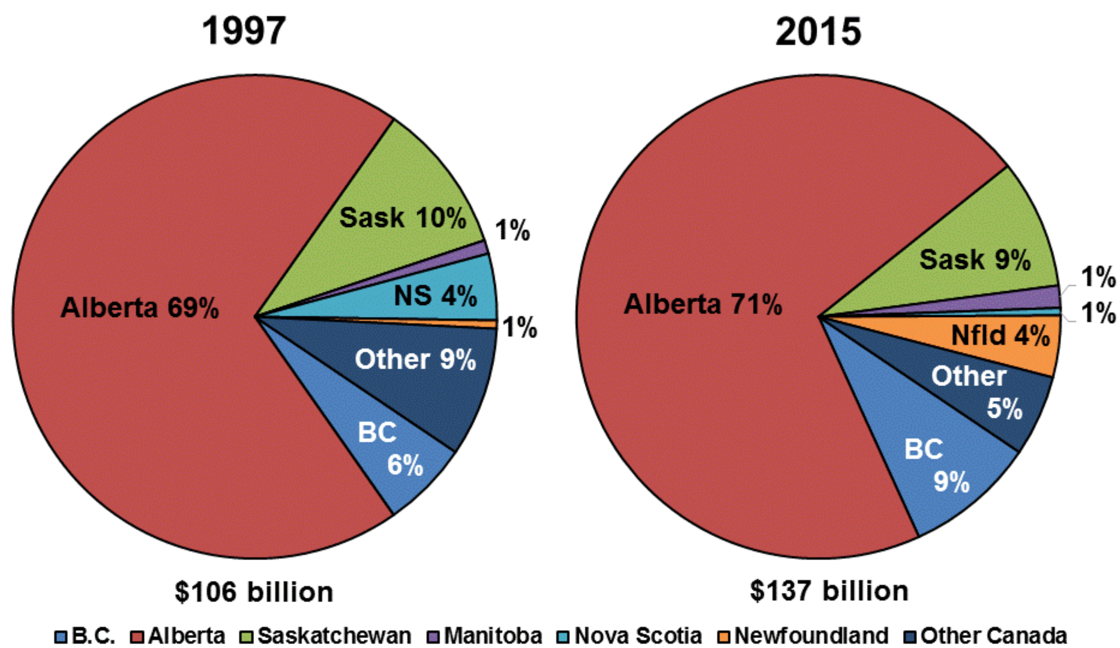
[100] Bloomberg, June 17, 2016, Canada Flirts With the Petrostate Trap, https://www.bloomberg.com/view/articles/2016-06-17/canada-flirts-with-the-petrostate-trap

[101] Statistics Canada CANSIM Table 379-0030, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790030&&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid

[102] National Energy Board Energy Future October 2017, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2017/2017nrgftr-eng.pdf appendices https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

More than two-thirds of GDP from fossil fuel production, distribution and construction is generated in Alberta, as illustrated in Figure 94. BC has increased its share since 1997, Nova Scotia has reduced its share, and Newfoundland has increased its share markedly.

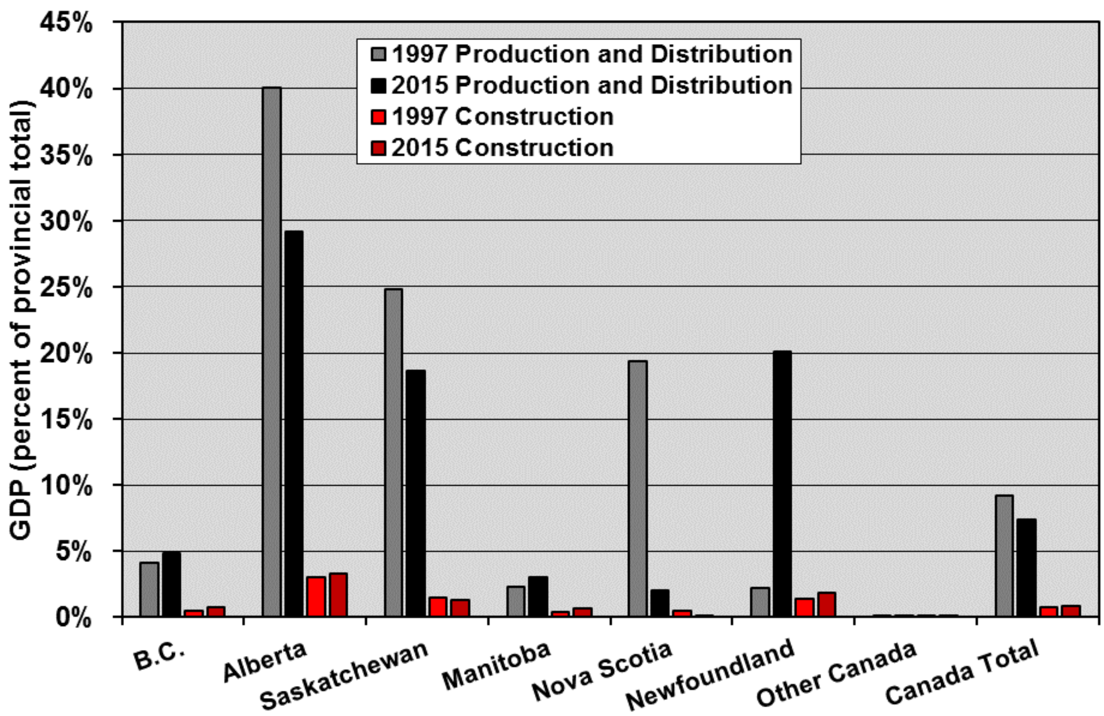
Figure 94: Canadian gross domestic product (GDP) from fossil fuel production, distribution and construction by province in 1997 and 2015.[103]



[103] Data from Statistics Canada CANSIM Table 379-0030, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790030&&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid= (totals are in chained 2007 dollars)

On a provincial basis, the percentage of GDP attributable to the production and distribution portion of the fossil fuel industry has declined since 1997 in Alberta, Saskatchewan and Nova Scotia, and in Canada overall (see Figure 95). GDP from production and distribution has increased slightly in BC and Manitoba and markedly in Newfoundland, where offshore oil production was just beginning in 1997. Construction of oil and gas production infrastructure has increased GDP in BC, Alberta and Newfoundland as well as in Canada overall, although construction is only about a tenth of the GDP generated by production and distribution.

Figure 95: Gross domestic product (GDP) as a percentage of provincial totals for production and distribution and for construction.[104]

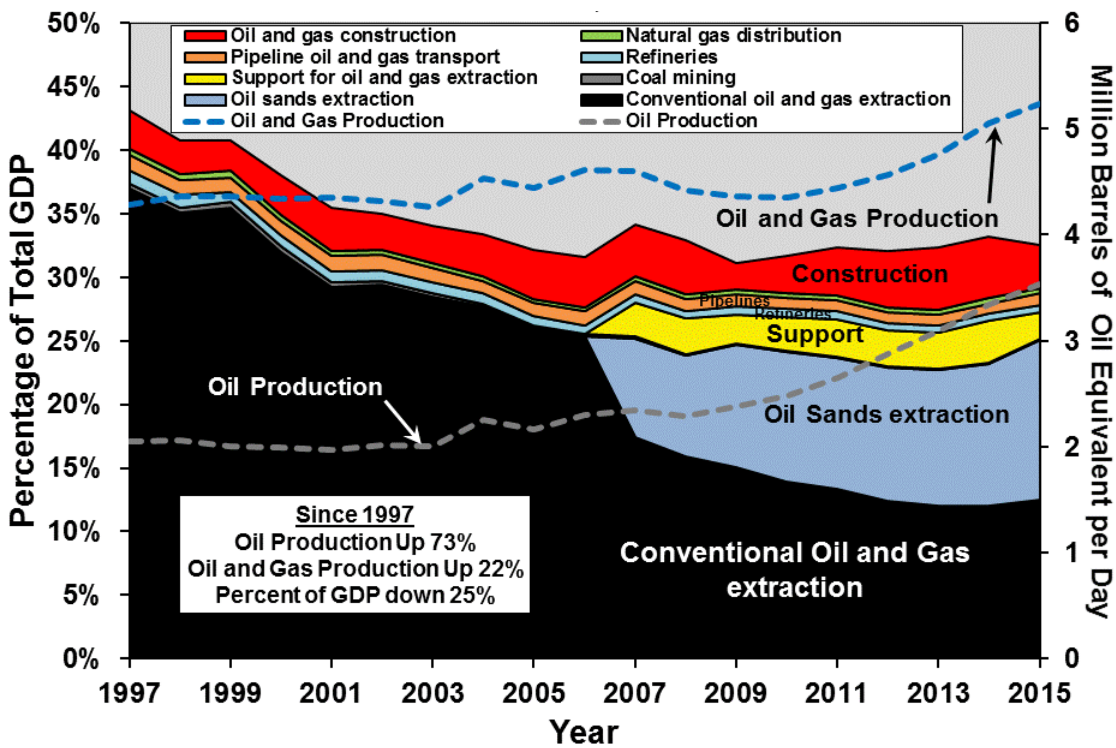


[104] Op. cit.

Figure 96 illustrates the GDP share of components of the fossil fuel supply chain in Alberta, which accounts for 70% of Canadian fossil fuel GDP. Although oil production has gone up 75% in Alberta since 1997, and combined oil and gas production has gone up 22%, the proportion of provincial GDP generated by fossil fuel has declined by 25%.

Figure 96: Alberta gross domestic product (GDP) generated from fossil fuel production, distribution and construction as a percentage of total provincial GDP.[105]

Although this portion of GDP has grown slightly in real terms, GDP from the rest of the economy has grown faster, resulting in a declining share from fossil fuel despite increasing fossil fuel production. (Note that the oil sands were not distinguished separately until 2007.)



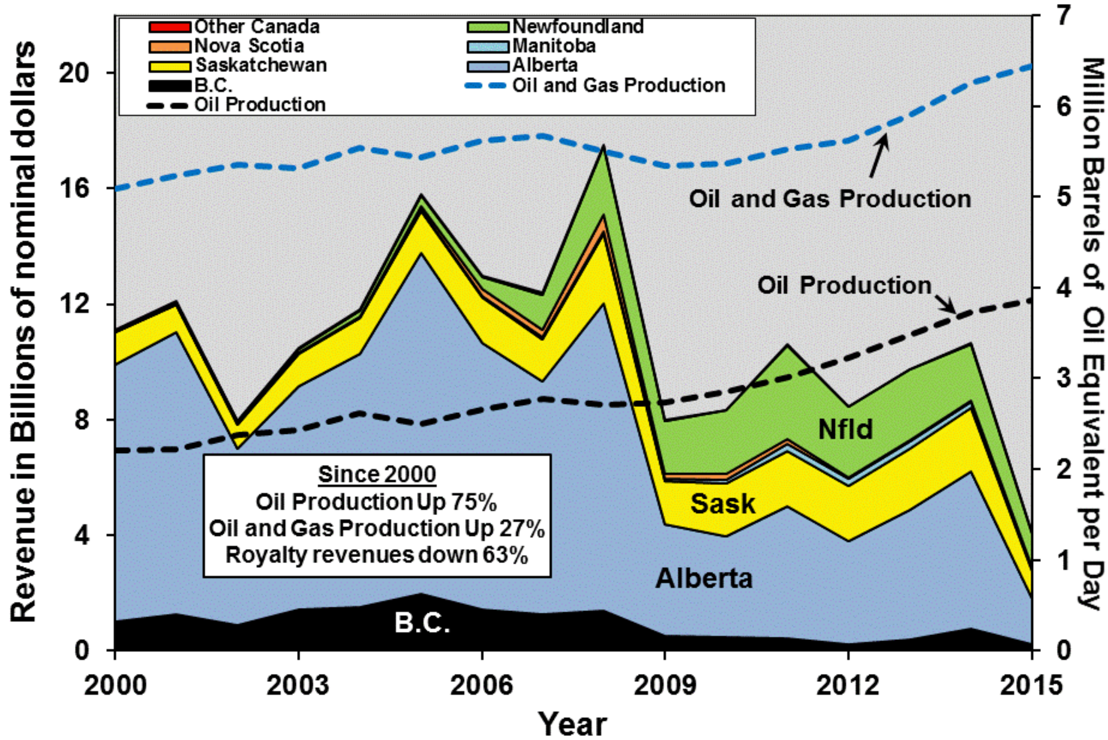
GDP, which is a broad measure of economic activity, includes much more than the actual monetary return to Canada from the sale of its non-renewable energy assets, which is primarily represented by royalties. Royalties are ongoing payments per unit of production to governments representing the owners of the resources—the Canadian public. Royalty take is a function of commodity prices and the policies of governments, which may vary the way in which royalties are calculated and offer incentives and rebates that reduce the amount of revenues received. More ephemeral income comes from land sales and bonus bids when Crown land is first leased or sold to energy companies. Ongoing lease rentals and corporate income taxes paid by companies developing the resources provide some additional revenue, however, royalties provide the lion's share of benefit to the public owners of the resource.

[105] Op. Cit.

Figure 97 illustrates royalty revenue received in Canada by province from 2000 to 2015. Royalty revenue peaked in 2008 with the spike in oil and gas prices and has collapsed since then. Royalty revenue has declined by 63% since 2000, despite oil production growth of 75% and combined oil and gas production growth of 27%. Canada's non-renewable energy resources are clearly being sold off for ever-decreasing benefit.

Figure 97: Royalties paid by province from 2000 to 2015.[106]

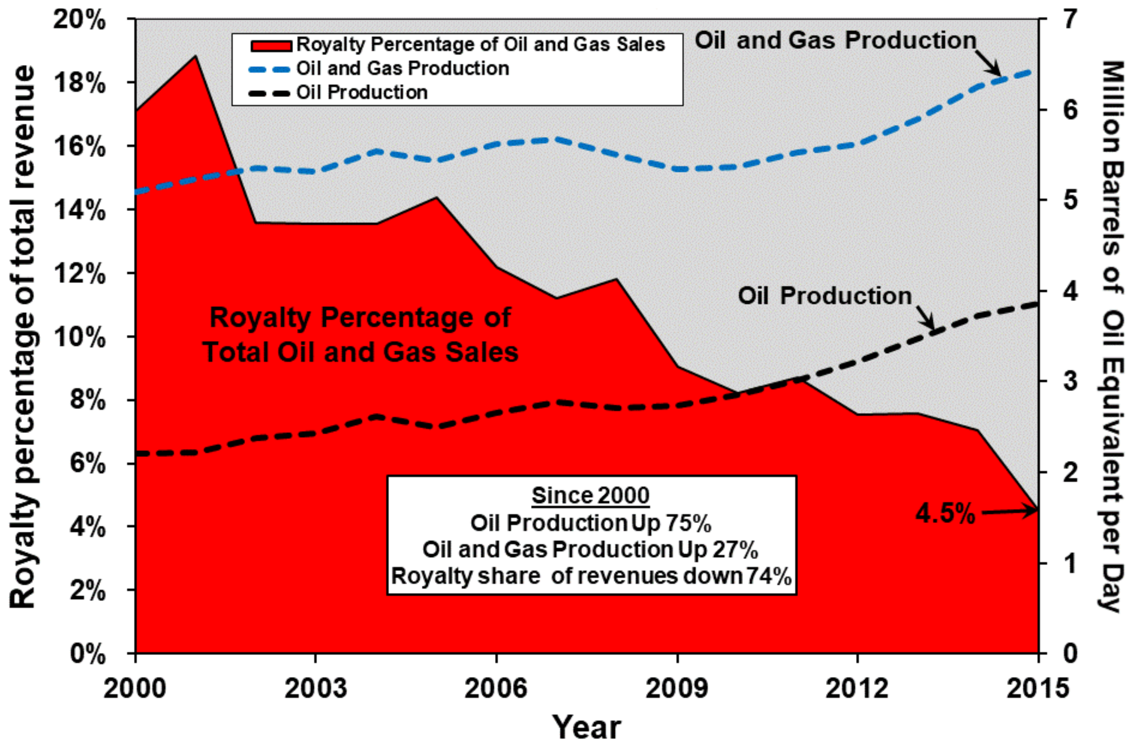
Royalties are down 63% since 2000, despite a 75% growth in oil production and a 27% growth in combined oil and gas production.



[106] CAPP Statistical Handbook, retrieved February 24, 2017, Tables 04-03B through 04-16B; Production data from NEB 2016

A clearer view on the ever-decreasing royalty take from Canada's non-renewable energy assets is illustrated in Figure 98, using data from the Canadian Association of Petroleum Producers (CAPP).[107] Royalties ranged between 13% and 17% of the sales revenue from oil and gas between 1990 and 2000. Since 2000, they have declined to 4.5% of sales revenue, a decrease of 74%, while at the same time oil and gas production grew by 27%. This decline continued through the oil and gas price spike in 2008, indicating that this trend is independent of price.

Figure 98: Revenue from royalties in Canada as a percentage of total revenue from oil and gas sales from 2000 to 2015.[108]



[107] CAPP Statistical Handbook, retrieved February 24, 2017, Tables 04-02B and 04-25B.
[108] Data from CAPP Statistical Handbook, Tables 04-25B and 04-02B; Production data from NEB 2016

In Alberta, home to 70% of Canada's fossil fuel–generated GDP, government resource revenue has declined 90% from 1980 levels, despite a doubling in oil and gas production, as illustrated in Figure 99. In 1980, 80% of Alberta government revenue came from fossil fuel production compared to just 3.3% in 2016 (see Figure 100).

Figure 99: Revenue from oil, gas and coal in Alberta from 1970 to 2016.[109]

Oil and gas production has doubled from 1980, however, revenues are down 90% as of 2016.

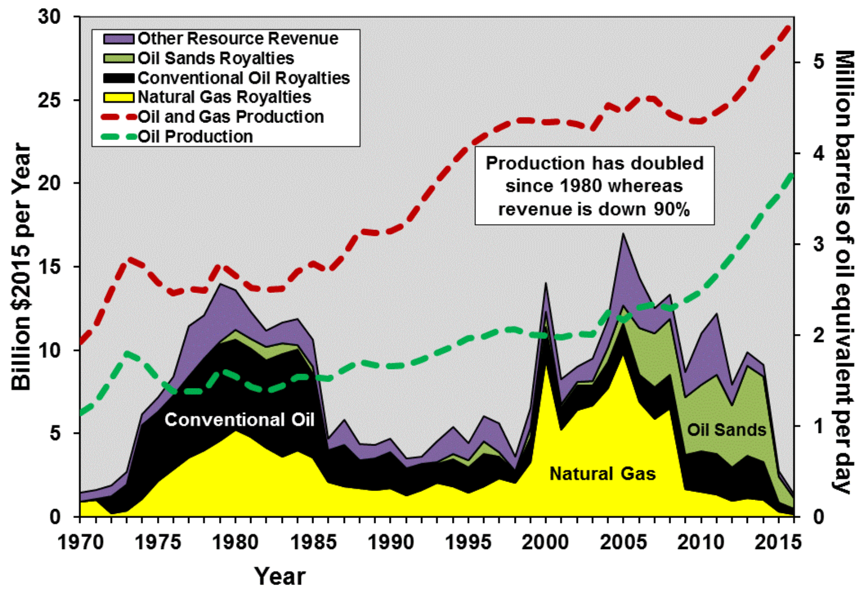
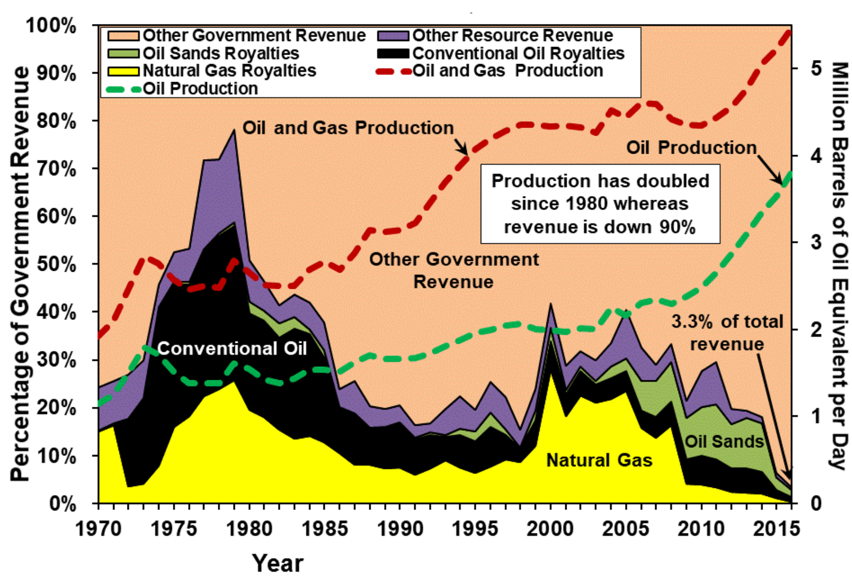


Figure 100: Non-renewable energy resource revenue in Alberta as a percentage of total government revenue from 1970 to 2016.[110]



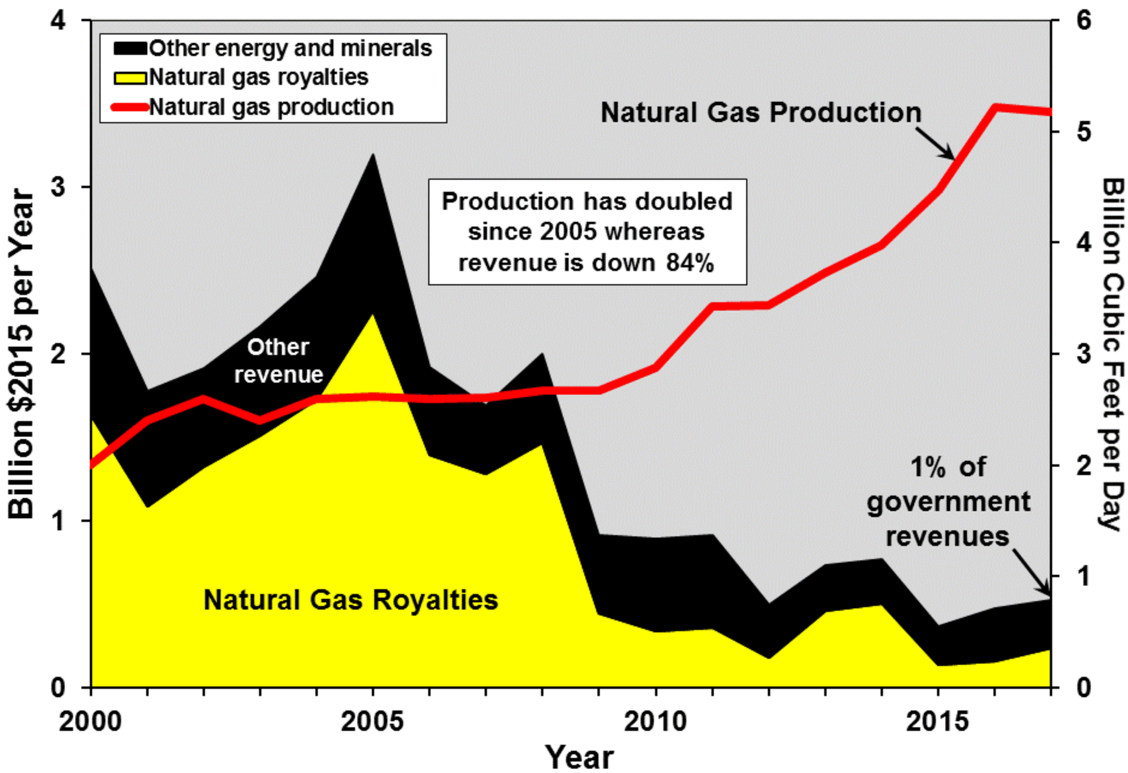
[109] Alberta Energy revenue workbook, August 2016, accessed February 15, 2017, http://www.energy.alberta.ca/Org/docs/Revenueworkbook.xls; Oil and gas production from NEB Energy Futures update 2016 and from CAPP; Other resource revenue includes rental feels, lease sales and coal royalties

[110] Data from Alberta Energy, July 2017, and Alberta 2017 budget estimates; Production fata from CAPP and NEB; Other resource revenue includes rental feels, lease sales and coal royalties

BC energy resource revenues to government have followed a similar pattern. Revenues generated from oil, gas and coal have declined by 84% since 2005, while over the same period natural gas production has doubled (see Figure 101). Non-renewable resource revenues made up just 1% of total government revenue in BC in 2017.

Figure 101: BC government revenues from fossil fuels from 2000 to 2017.[111]

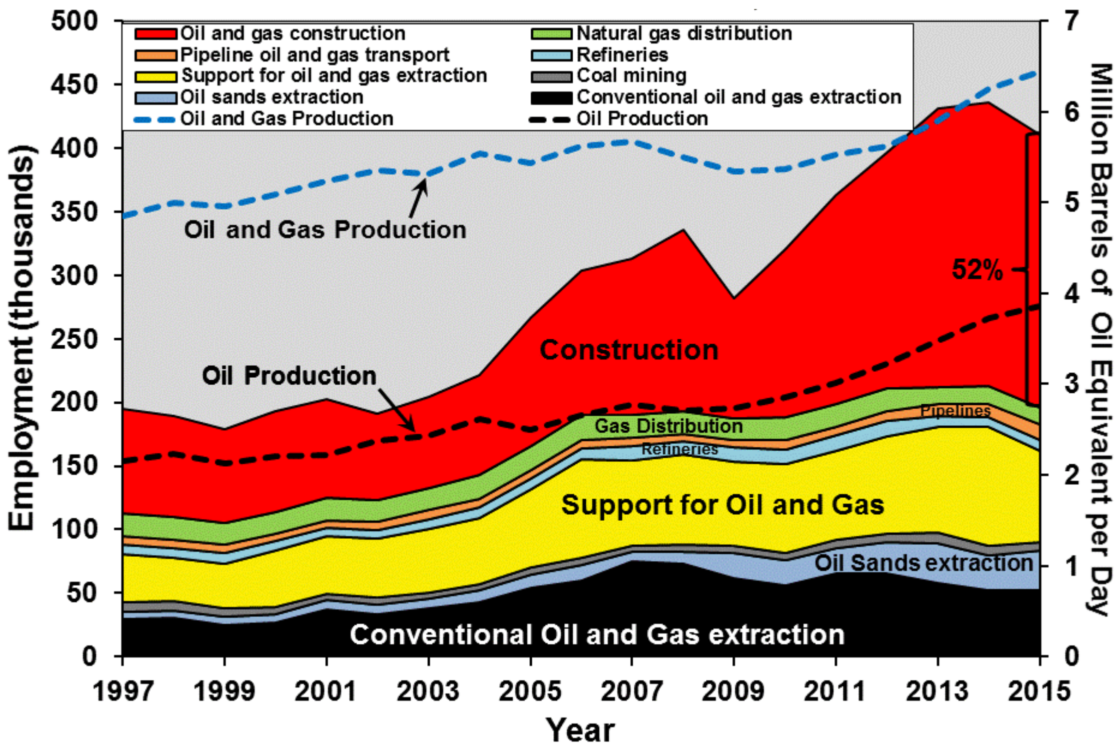
Crown lease revenue, which was estimated to be $353 million in 2017, has been excluded as it includes revenue from forestry and mining.



[111] BC Budget documents from 2000 through 2017, retrieved February 10-March 1, 2017, http://www.bcbudget.gov.bc.ca/default.htm (note: 2016 and 2017 are estimates); Production data from NEB update, 2016; Crown lease revenue data excluded as it includes mining and forestry

Employment is often touted as a reason for continuing to ramp up oil and gas production. Figure 102 illustrates employment in the production, distribution and construction segments of the fossil fuel industry since 1997. Despite growing production, jobs in the extraction and distribution portions of the industry have been relatively flat since 2006 and declined in 2015 with the downturn in oil price. The exception is construction, mainly in the oil sands, which in 2015 comprised 52% of all jobs. Construction jobs are short-term, however, unlike jobs in the production and distribution parts of the industry. With the completion of projects currently under construction, many of these jobs will disappear.

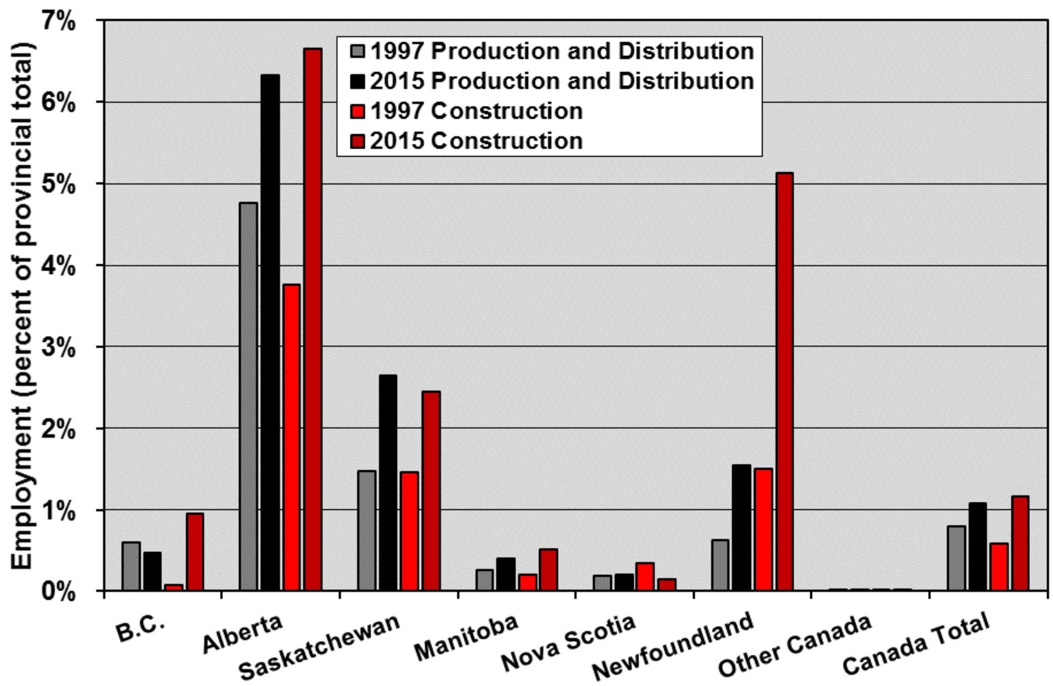
Figure 102: Employment in fossil fuel production, distribution and construction in Canada from 1997 to 2015.[112]



[112] Statistics Canada CANSIM Table 383-0031, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3830031&&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid= ; production data from NEB.

Jobs in the industry as a proportion of total employment by province are illustrated in Figure 103. Overall in Canada, production and distribution amounted to just over 1% of total employment in 2015, and construction accounted for an additional 1.17%. Jobs in production and distribution increased in most provinces except BC, compared to 1997, and construction provided even more jobs than production and distribution in BC, Alberta and Newfoundland. At some point construction will be largely completed and jobs provided by the industry will contract to the basic production and distribution functions.

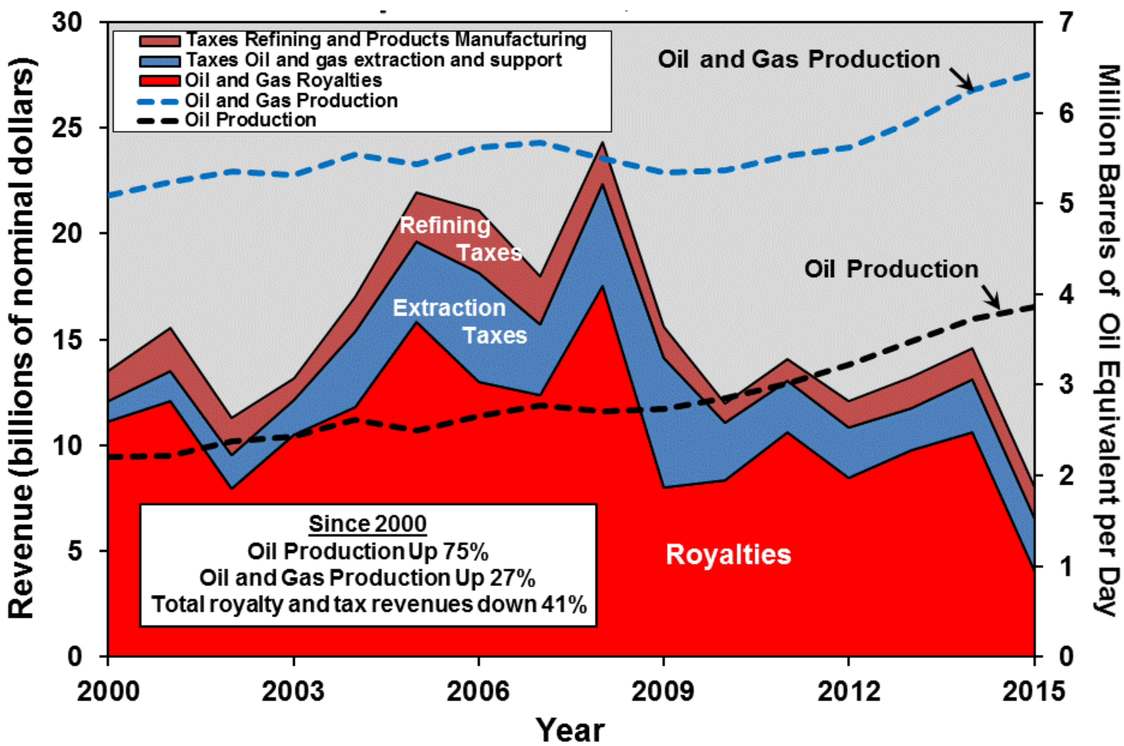
Figure 103: Employment in fossil fuel production, distribution and construction by province in 1997 and in 2015.[113]



[113] Statistics Canada CANSIM Table 383-0031, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3830031&&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid=

A final source of government revenue from fossil fuel extraction is corporate income tax paid by the corporations extracting the resources. Corporate tax revenue comprised an average of 30% of total government revenues from fossil fuel production between 1997 and 2015, with royalties providing the balance, as illustrated in Figure 104. Corporate income tax revenue peaked in 2006 and has declined by 51% since then, along with a 69% decline in royalty revenues. These declines occurred despite a 45% growth in oil production and a 15% growth in combined oil and gas production since 2006. The oft-cited claim that growing oil and gas production is vital to Canada's economic well-being and its ability to protect the environment has become progressively less true over the past decade.

Figure 104: Corporate income tax and royalties received by governments from 2000 to 2015.[114]
Also shown is oil and gas production.



An argument can be made that the personal income taxes paid by employees in the sector should also be included as government revenue attributable to fossil fuel production. However, personal income taxes would be paid whether employees worked in the sector or not (i.e., they would not be unemployed). Natural Resources Canada suggests that such "indirect taxes" amount to about 45% of corporate taxes paid.[115]

Further reading

To find other sections of this report, download the full report or access related resources, please visit energyoutlook.ca.

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[114] Data from CAPP Statistical Handbook, retrieved February 24, 2017, Tables 04-02B; Statcan Table 180-0003; Production data from NEB, 2016

[115] NRCan, 2016, Energy Fact Book 2016–2017, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/EnergyFactBook_2016_17_En.pdf

CORPORATE MAPPING PROJECT

This paper is part of the Corporate Mapping Project (CMP), a research and public engagement initiative investigating the power of the fossil fuel industry. The CMP is jointly led by the University of Victoria, the Canadian Centre for Policy Alternatives and the Parkland Institute. This research was supported by the Social Science and Humanities Research Council of Canada (SSHRC).

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