

ALBERTA ENERGY OUTLOOK

ST98 | Executive Summary | **2019**



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EXECUTIVE SUMMARY

The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. As part of this mandate, we provide our stakeholders with credible information about Alberta's energy resources that can be used for decision making. A key part of this is ST98: Alberta Energy Outlook (formerly ST98: Alberta's Energy Reserves and Supply/Demand Outlook), a report we issue annually with independent and comprehensive information on the state of reserves and the supply and demand outlook for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids,¹ coal, and sulphur. This year's report also includes a new section on new reserve estimates for three formations in low permeability and shale areas.

REPORT OVERVIEW

In 2018, the oil and gas industry in Alberta faced a mix of positive developments and persistent challenges.

The price for both the North American benchmark for light sweet crude oil (West Texas Intermediate [WTI]) and natural gas (Henry Hub) increased last year, but Alberta producers were unable to capture the full value for their oil and gas. The Canadian Light Sweet (CLS) price also increased last year, while the price for Western Canadian Select (WCS) and Alberta's natural gas at AECO-C decreased.

Inadequate market access was a major factor affecting oil producers in 2018. Limited export capacity and outages for maintenance at key refineries caused price differentials between Alberta and the United States to widen beyond transportation costs and quality adjustments. Pipeline project delays, pipeline maintenance, and constrained rail service also contributed to the difference between Alberta's pricing and the North American benchmark.

Oil production in Alberta increased in 2018, which contributed to large oil inventories and lowered the province's average prices even further. All of these factors contributed to below-average capital spending in Alberta's oil and gas industry. The Government of Alberta responded with energy diversification programs, investments in processing and takeaway capacity, and crude oil curtailment rules.

Alberta's crude oil producers started the year facing tight takeaway constraints. Not only was the Keystone pipeline operating under pressure restrictions² imposed by U.S. regulators, which reduced capacity, but rail was unable to keep pace with production, causing an oil inventory backlog in

Alberta. However, producers that were able to move crude oil to the United States experienced some relief because the global oil cuts led by the Organization of the Petroleum Exporting Countries (OPEC) worked to decrease global oil volumes, and increase global oil prices. In the first quarter of 2018, the prices of CLS and WCS averaged Cdn\$70.15 per barrel (bbl) and US\$38.59 /bbl, respectively.



¹ Natural gas liquids refers to ethane, propane, butanes, and pentanes plus—on their own or combined—obtained from processing raw gas or condensate.



Prices improved as infrastructure came back online. In the second quarter of 2018, the price of CLS averaged Cdn\$79.72/bbl and the price of WCS averaged US\$48.67/bbl, up 14 and 26 per cent from the first quarter, respectively. However, prices began to decline entering the third quarter as refinery outages in key markets reduced demand. Inventory increased once again as a result. Alberta's crude oil and crude bitumen production was higher by 240 103 barrels per day (bbl/d)—up 7.7 per cent from the third quarter of 2017. This added additional supply to an already oversupplied market and Alberta's prices for crude oil dropped. The price of WCS fell to unprecedented levels, averaging US\$5.97/bbl in December and the price differential between WCS and WTI was over US\$40/bbl.

In response, the Government of Alberta announced new rules in December 2018 mandating that Alberta producers reduce their production by 325 10³ bbl/d (set to begin in January 2019). The rules aimed to help lower storage inventories and, therefore, improve Alberta's oil prices. Following the announcement, the differential between WCS and WTI narrowed

to under US\$16.00/bbl by the end of December 2018—the narrowest level recorded since June 2018. The narrowing price differential was also supported by refineries coming back online from maintenance and demanding more of Alberta's heavy oil, while there was a global shortage of heavy oil.

The narrow differential negatively affects rail transportation economics because it is more expensive to move oil by rail than by pipeline. With pipeline capacity limited, an estimated price differential between US\$15.00/bbl and US\$20.00/bbl is required for rail to be economic and used for exporting oil.

The past year was also challenging for the natural gas industry in Alberta because natural gas prices continued to be weak and volatile. AECO-C, the benchmark price for natural gas in Alberta, started the year at an average of Cdn\$1.94 per gigajoule (GJ) and remained under Cdn\$2.00/GJ for the rest of the year. Gas prices reached historical lows, even entering negative territory at times, as production from western Canada outstripped market demand. Prices were



further affected by scheduled pipeline maintenance during the summer, resulting in export pipelines reaching capacity.

Marketable production of natural gas in Alberta decreased in 2018 while production increases from the Foothills Front region and from oil wells failed to offset production declines in rest of the province. The growth in production was driven almost entirely by drilling for higher value natural gas liquids.

In spite of these challenges, 2018 saw positive developments, such as the Government of Alberta's petrochemical energy diversification programs, company's plans to phase-out coal-fired electricity, and recent investment decisions and announcements on liquefied natural gas (LNG) projects in Canada. All of these developments have the potential to increase demand for Alberta's natural gas.

Globally, capital spending in the oil and gas sector increased in 2018, but total capital expenditures in Alberta decreased by an estimated 6 per cent to Cdn\$28.9 billion. This primarily

resulted from low crude oil and natural gas prices and market access constraints. These factors negatively affected investment decisions, drilling programs, and project development. Going forward, capital expenditures in Alberta are anticipated to focus on developments with lower costs and shorter investment cycles.

Figures 1-4 highlight the prices, capital expenditures, and supply and demand outlook for 2019 to 2028 (the forecast period) for Alberta's hydrocarbons and a snapshot of the province's reserves as of December 2018.

² *Pressure restrictions were imposed on the Keystone pipeline by the U.S. Pipeline and Hazardous Materials Safety Administration following a spill in South Dakota in November 2017. The restrictions were lifted in May 2018.*



REPORT HIGHLIGHTS

Oil And Gas Production

- Alberta remains the largest producer of natural gas and oil in Canada. In 2018, Alberta produced 66 per cent of Canada's natural gas and 82 per cent of Canada's oil and equivalent.³ Almost 65 per cent of Canada's total oil and equivalent production was marketable bitumen.
- Alberta's raw crude bitumen production in 2018 exceeded 3 million barrels per day (10⁶ bbl/d) for the first time.
- Although Alberta is the largest producer of natural gas in Canada, growing production in British Columbia has resulted in a slight decrease in Alberta's share of Canadian production.

Oil And Gas Prices

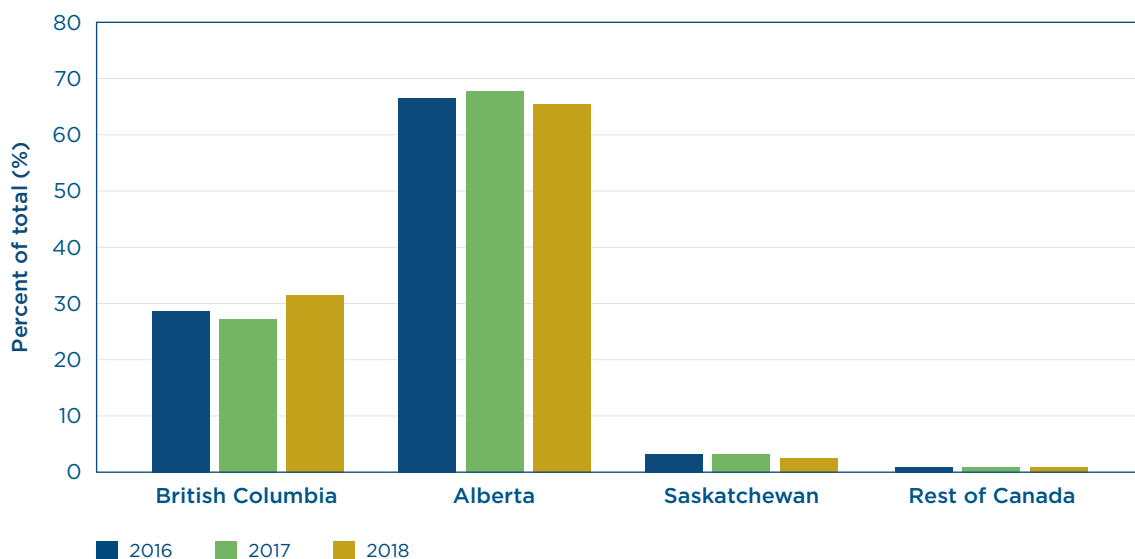
- For the second consecutive year, the price of WTI increased, averaging US\$64.74/bbl compared with US\$50.80/bbl in 2017.
- The price of CLS also increased by 4 per cent from 2017, averaging Cdn\$65.66/bbl.
- The price of WCS decreased by 1 per cent from 2017, averaging US\$38.46/bbl. The WTI price in the base price

scenario is projected to be slightly lower in 2019 at US\$60/bbl because of both increasing supply reaching markets with the construction of new pipelines in the U.S. and weak global oil demand from a predicted slowdown in the global economy.

- The low price scenario of US\$49.20/bbl in 2019 assumes noncompliance with OPEC's decision to restrict production, stronger than anticipated production growth, primarily in the U.S., and weakened global oil demand.
- The high price scenario of US\$70.80/bbl assumes high compliance with OPEC's decision, an increase in geopolitical tensions in the Middle East and Latin America, and a stronger-than-anticipated world economy.

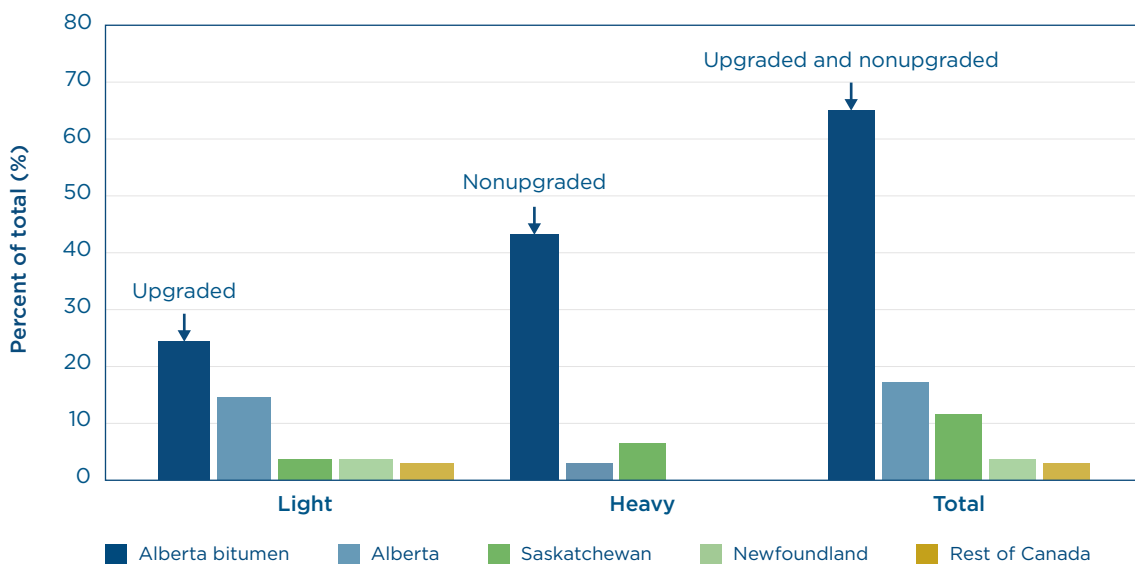
³ *Oil and equivalent includes light, medium, heavy, and ultra-heavy crude oil; condensate (pentanes plus); and upgraded and nonupgraded bitumen (referred to as marketable bitumen).*

Figure 1 Marketable natural gas percentage of production—Canada



Source: National Energy Board.

Figure 2 Oil and equivalent percentage of production—Canada

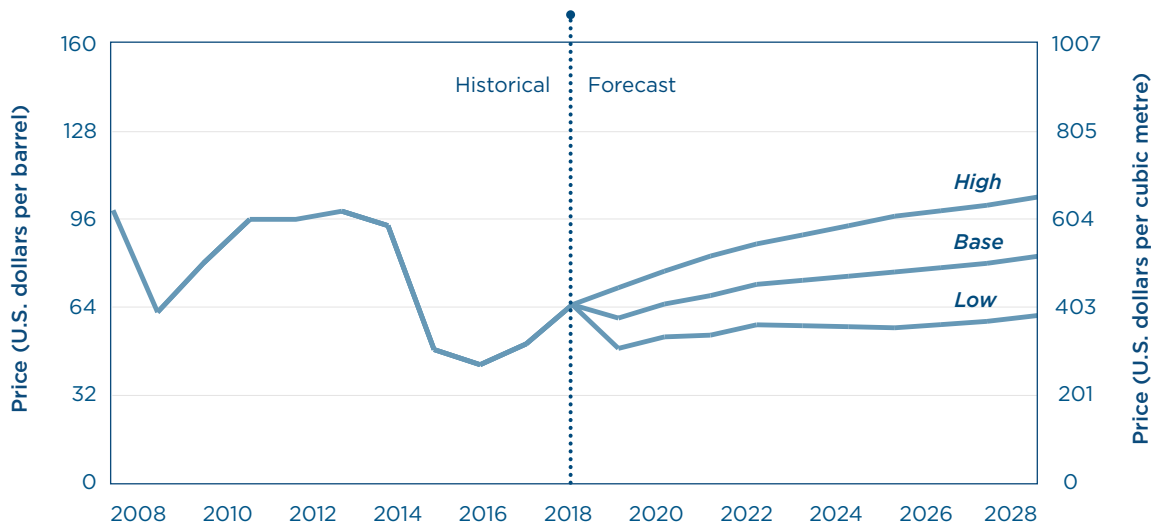


Source: National Energy Board.



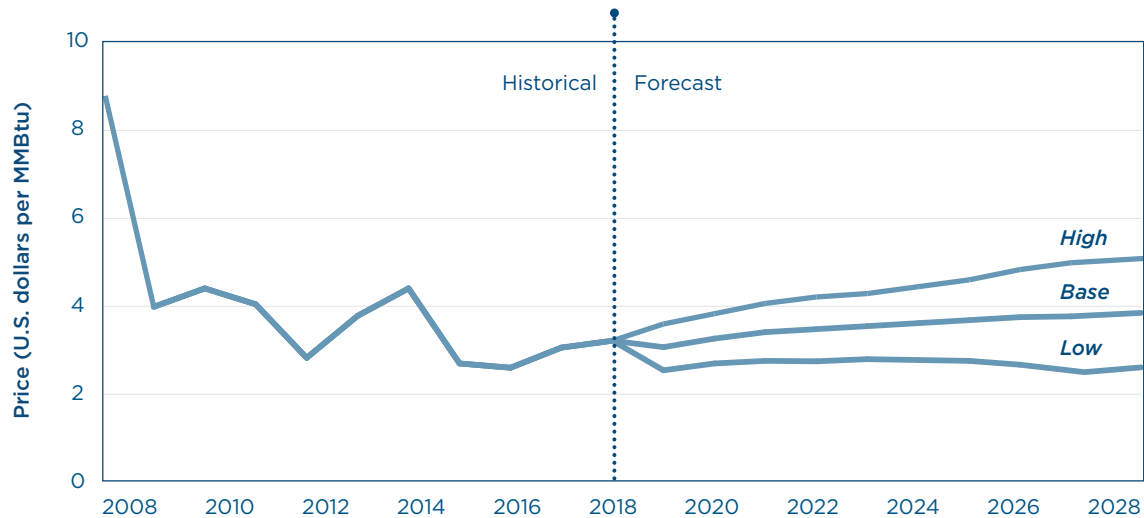
- The resilience of U.S. shale oil production to low prices and the significant number of drilled but uncompleted wells are expected to cap any significant price rallies in both the base and low price scenarios over the short term. With both Russian and U.S. production having grown to rival Saudi Arabia's production, volatility in oil prices is expected.
- The WTI crude oil price is forecast to gradually strengthen to US\$81.08/bbl by 2028 in the base price scenario, with prices in the low and high price scenarios reaching US\$60.00/bbl and US\$102.17/bbl, respectively.
- Although other global heavy oil benchmarks saw some strengthening because of supply shortages, the differential between WTI and WCS remained wide, as Alberta producers were unable to capture the increase in the North American benchmark prices due to takeaway constraints and refinery outages. As a result, the differential fluctuated between US\$15.22/bbl and US\$45.57/bbl.
- The Henry Hub natural gas price increased to an estimated US\$3.15 per million British thermal units (MMBtu) in 2018, an increase of 5 per cent. Stronger demand and below average storage levels offered moderate relief to an oversupplied North American market.
- In 2019, the price is forecast to decrease slightly to US\$3.00/MMBtu. U.S. production is anticipated to increase and outpace the growth in demand.
- In the low price scenario, the price is forecast to average US\$2.46/MMBtu because of increased production and delayed development of LNG export facilities.
- In the high price scenario, the price is forecast to average US\$3.54/MMBtu as growth in demand and exports of U.S. LNG are expected to outpace growth in supply.
- The Henry Hub natural gas price is forecast to gradually strengthen to US\$3.85/MMBtu by 2028 in the base price scenario, reflecting balanced supply and demand while the U.S. LNG exports and U.S. exports to Mexico are anticipated to increase. By 2028, the prices are expected to reach US\$2.58/MMBtu and US\$5.12/MMBtu, in the low and high price scenarios, respectively.

Figure 3 Price of West Texas Intermediate



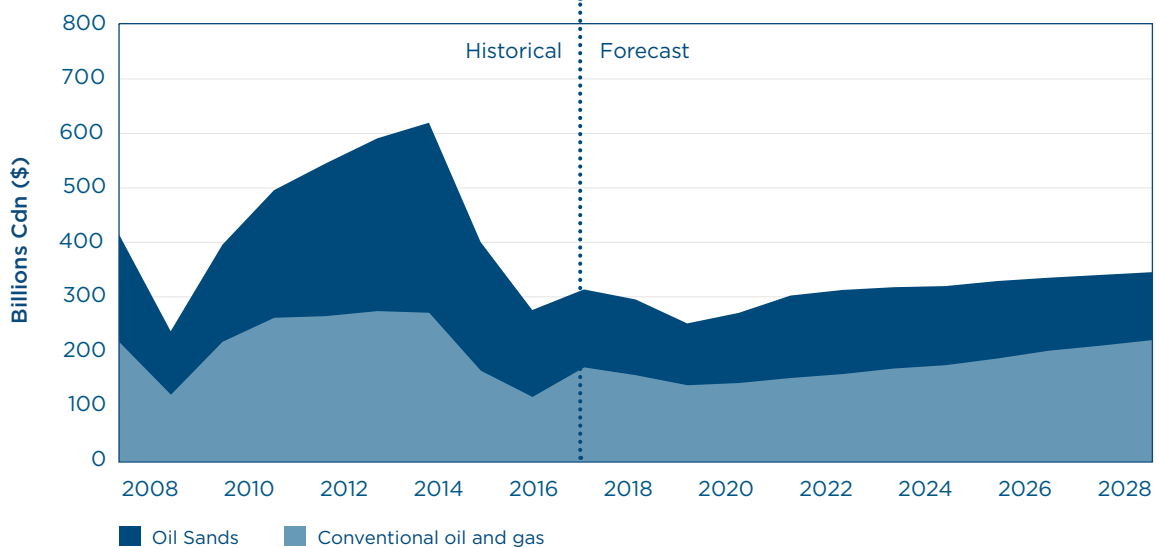
Historical values sourced from U.S. Energy Information Administration.

Figure 4 Henry Hub natural gas price



Historical values sourced from U.S. Energy Information Administration.

Figure 5 Alberta conventional oil and gas and oil sands capital expenditure



Historical values sourced from the Canadian Association of Petroleum Producers. 2017 values are estimated.

CAPITAL EXPENDITURES

- Total capital expenditures in the conventional oil and gas and oil sands sectors decreased by 6 per cent in 2018, reaching Cdn\$28.9 billion.⁴ This was primarily driven by a deeply discounted WCS price, a weak natural gas market, and operating efficiencies that lowered the need for investment.
- Capital expenditures in conventional oil and gas decreased to an estimated Cdn\$15.5 billion in 2018, which is 8 per cent lower than it was in 2017. This is primarily because of low levels of investment in natural gas, which more than offset higher spending in conventional oil.
- Exploration and production companies continue to adapt to the low price environment, saving costs with innovation and technology, so that they can either maintain or grow production at lower levels of capital expenditures.
- Oil sands capital expenditures continued to decrease from an estimated Cdn\$13.8 billion in 2017 to an estimated Cdn\$13.4 billion in 2018, a level of spending not seen since 2005. Continued deferral of some projects and the recent completion of multibillion dollar mining and upgrading projects lowered the need for capital spending.

Capital expenditures in the oil sands are projected to be primarily focused on sustaining capital, debottlenecking, and expanding existing projects.

- Capital expenditures are forecast to continue to decline in 2019. After 2019, they are projected to moderately increase for the rest of the forecast period, with a larger share of investment directed toward the conventional oil and gas sector.

⁴ Historical statistics obtained from the Canadian Association of Petroleum Producers' Statistical Handbook (2017 data). Capital expenditures for 2017 are estimates.

Table 1 Resources, reserves, and production summary, 2018

	Crude bitumen		Crude oil		Natural gas ^a		Raw coal	
	(million m ³)	(billion barrels)	(million m ³)	(billion barrels)	(billion m ³)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	13 906	87.5	10 135	360	93.7	103.3
Initial established reserves ^b	28 092	177	3 103	19.5	5 841	207.3	34.8	38.4
Cumulative production	2 112	13.3	2 830	17.8	5 025	178.4	1.7	1.8
Remaining established reserves	25 980	164	270.7	1.7	816^c	29.0^c	33.1	36.6
Annual production	176.8	1.113	28.3	0.178	109.6 ^d	3.9 ^d	0.025 ^e	0.028 ^e
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276 ^f	223 ^f	620	683

Note: Columns may not add up due to rounding.

^a Expressed as “as is” gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.

^b Initial established reserves have not been updated at this time; the remaining established reserves have been calculated to reflect 2018 annual production.

^c Measured at field gate.

^d Includes unconventional natural gas.

^e Annual production is marketable.

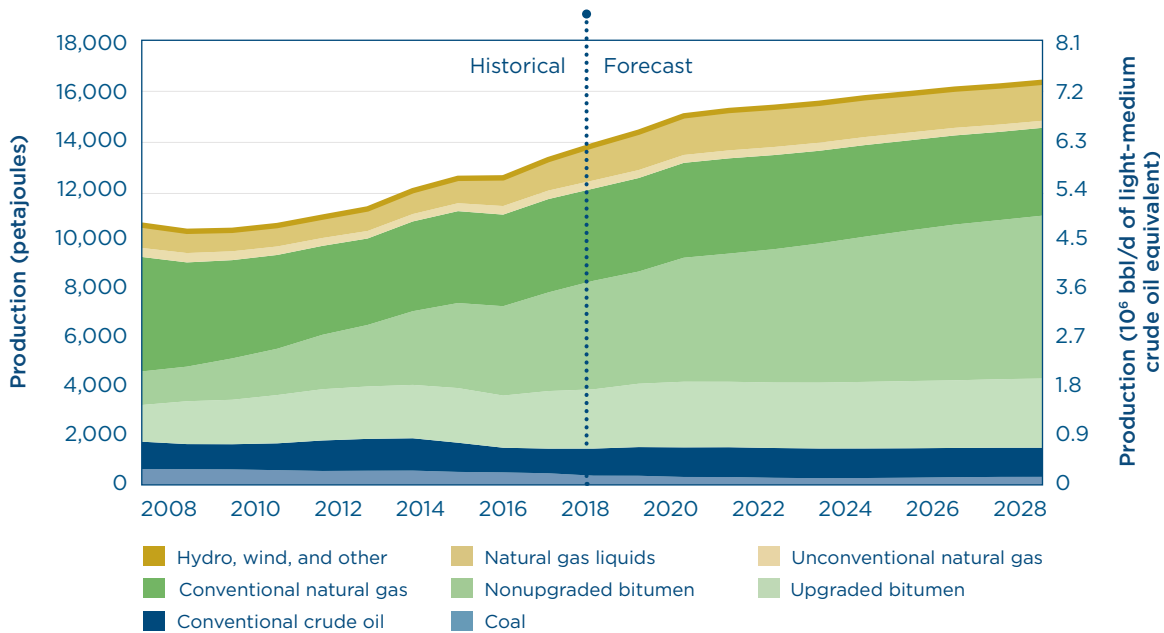
^f Does not include unconventional natural gas.

RESERVES

- The AER has been providing an independent appraisal of Alberta’s energy resources since 1961. The AER studies hydrocarbon extraction and ensures that energy resources are being extracted in an efficient and environmentally responsible manner.
- The information is used by the Government of Alberta to develop policies and regional land-use plans and by the energy industry to evaluate investment opportunities in Alberta.
- The AER has incorporated new methodologies to determine low permeability and shale reserves and resources. Information on the reserves estimates for low permeability and shale resources for the Montney, Duvernay, and Cardium Formations can be found in the reserves section. These new reserve numbers are not included in Table 1, as the methodologies for low permeability and shale reserves differ.
- Table 1 shows the reserves determined for crude bitumen, crude oil, natural gas, natural gas liquids, and coal. According to Table 1, Alberta has reserves sufficient for many years of production.



Figure 6 Total primary energy production in Alberta

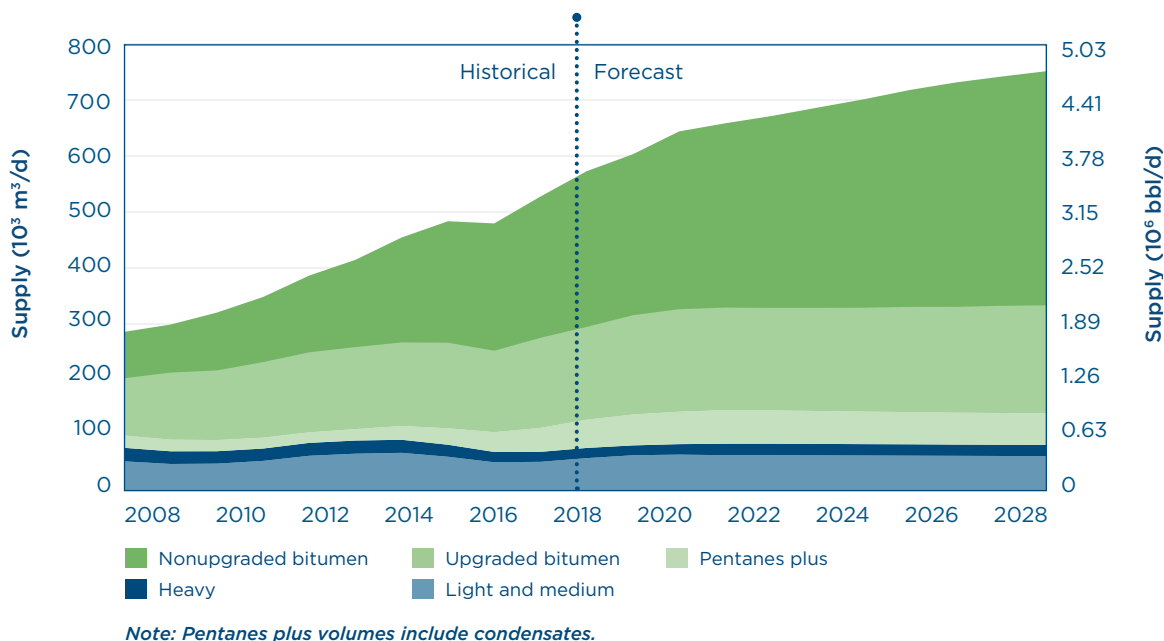


PRODUCTION AND DEMAND

- Total primary energy⁵ produced in Alberta grew by 4.4 per cent in 2018, largely due to growth in the oil sands sector; particularly where new phases were added to existing projects and where new mined bitumen operations began.
- Marketable bitumen production increased by 7.4 per cent in 2018. As a result of the increased oil prices for CLS in 2018, conventional crude oil production increased by 9.8 per cent from 2017. Companies continued to streamline operations and reduce costs (to generate cash flow with shorter investment cycles) while targeting higher value, light density crude oil. Marketable natural gas production decreased by 1.4 per cent compared with 2017 due to low natural gas prices caused by abundant supply from U.S. shale gas resources.
- In 2018, Alberta produced an estimated 13 845 petajoules (PJ) of energy from all sources or 6.20 million barrels per day of conventional light-medium quality crude oil equivalent (10⁶ BOE/d).
- In 2028, Alberta is projected to produce 16 461 PJ (7.35 10⁶ BOE/d) of energy from all sources.
- Upgraded and nonupgraded bitumen production accounted for almost half of total primary energy production in 2018. This percentage is expected to grow over the forecast period, reaching about 60 per cent by 2028.
- In 2018, on the basis of energy content, natural gas liquids production was about 24 per cent higher than conventional crude oil production. Production of natural gas liquids is expected to continue to be greater than production of conventional crude oil over the forecast period.

⁵ The trends and growth rates may differ slightly when standard units of measure, such as cubic metres or tonnes, are compared. Various grades of energy commodities have different heating values, and any changes to their composition may yield slightly different numerical trends and growth rates.

Figure 7 Alberta supply of crude oil and equivalent



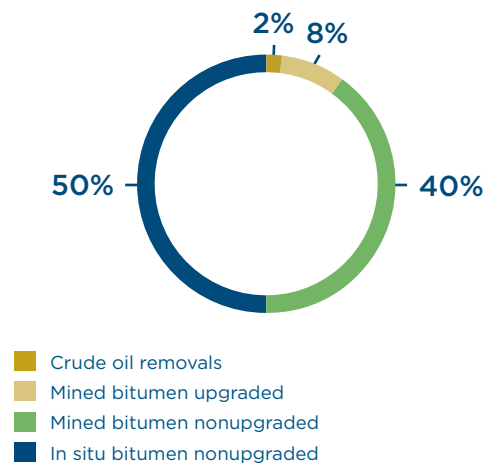
- Total natural gas liquids production increased by an estimated 14 per cent in 2018 as companies focused on liquids-rich natural gas development.
- Alberta’s production of crude oil and equivalent increased by about 9 per cent in 2018, reaching 3.7 10⁶bbl/d. The increase is largely attributed to growth in the supply of upgraded and nonupgraded bitumen and pentanes plus.
- The Alberta supply of crude oil and equivalent is expected to continue to grow throughout the forecast period, reaching 4.8 10⁶ bbl/d by 2028, driven primarily by growth in upgraded and nonupgraded bitumen production.
- Conventional crude oil production increased in 2018 to 0.49 10⁶ bbl/d. Production is forecast to grow moderately over the forecast period, reaching 0.52 10⁶ bbl/d by 2028.
- Pentanes plus production is forecast to grow from 0.32 10⁶ bbl/d in 2018, reaching 0.36 10⁶ bbl/d by 2028.





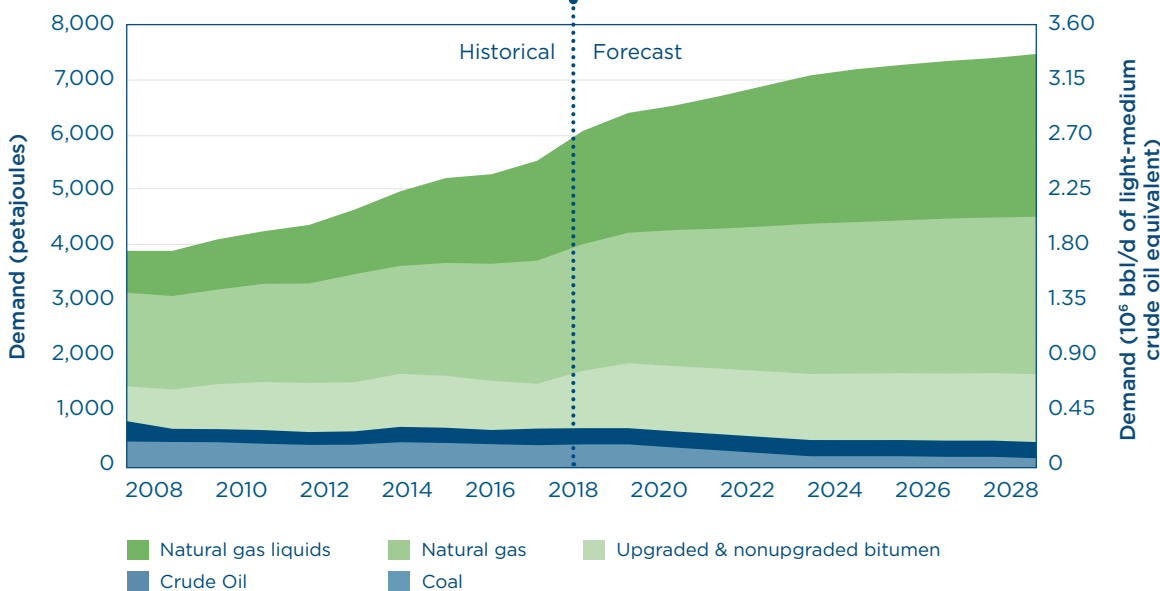
- In 2018, an estimated 41 per cent of produced raw bitumen was sent for upgrading in Alberta. This figure decreased slightly from 2017, mainly due to reduced in situ bitumen upgrading. Despite diversification programs to support partial upgrading, growth in in situ and mining production is expected to outpace additions to any upgrading capacity at new or existing facilities. The sustained increases in raw production are anticipated to result in the percentage of raw bitumen sent for upgrading shrinking to 35 per cent by 2028.
- Upgraded bitumen output for 2018 was up 3 per cent, largely due to growth in production at Canadian Natural Resources Limited's (CNRL's) Horizon upgrader. This growth offsets the decreases at Suncor's and Syncrude's upgraders, which both experienced operational challenges.
- Total primary energy demand within the province increased by 9.1 per cent to 5 898 PJ (2.63 10⁶ BOE/d) of crude oil in 2018. Alberta demand is projected to increase to about 7 252 PJ (3.24 10⁶ BOE/d) by 2028, largely because of both strengthening demand for pentanes plus as a diluent in bitumen blending and an increasing demand for natural gas because of the

Figure 8 Percentage of mined and in situ bitumen sent for upgrading in Alberta



*Total mined: 234.1 thousand cubic metres per day.
Total in situ: 250.4 thousand cubic metres per day.*

Figure 9 Primary energy demand in Alberta



transition from coal to natural gas in power generation. Alberta demand for bitumen and crude oil is also forecast to increase with the projected provincial economic growth.

- Demand for coal from power generation is anticipated to decrease by 61 per cent over the forecast period as a result of federal and provincial policies targeting a reduction in carbon dioxide emissions.
- Primary energy removals from Alberta increased in 2018 by 5.8 per cent, largely because of an increase in bitumen production and the resulting need for pentanes plus as a diluent, which limits takeaway capacity for crude oil.
- Total primary energy removals from the province in 2018 were estimated at 10 434 PJ (4.67 10⁶ BOE/d), with bitumen and natural gas liquids representing about three-quarters of primary energy removals for the year.
- Removals from the province are projected to reach 12 716 PJ by 2028 (5.68 10⁶ BOE/d), with upgraded and nonupgraded bitumen representing a growing share of primary energy removals.
- Natural gas removals from Alberta are projected to decrease over the forecast period due to declining provincial production and increasing Alberta demand.
- Despite the small share, removals of marketable bituminous coal from Alberta increased by 32 per cent in 2018, reflecting continued marketing of higher value bituminous coal to outside of Canada.
- In 2018, removals of conventional crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were an estimated 566.1 thousand cubic metres per day (10³ m³/d) or 3.56 10⁶ bbl/d.
- By 2028, 786.0 10³ m³/d (4.95 10⁶ bbl/d) of conventional crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen are forecast to be removed from the province. This projection assumes that most of these removals will go to the U.S. and that there will be sufficient transportation capacity (by pipeline and by rail) to ship these volumes.

Figure 10 Primary energy removals from Alberta

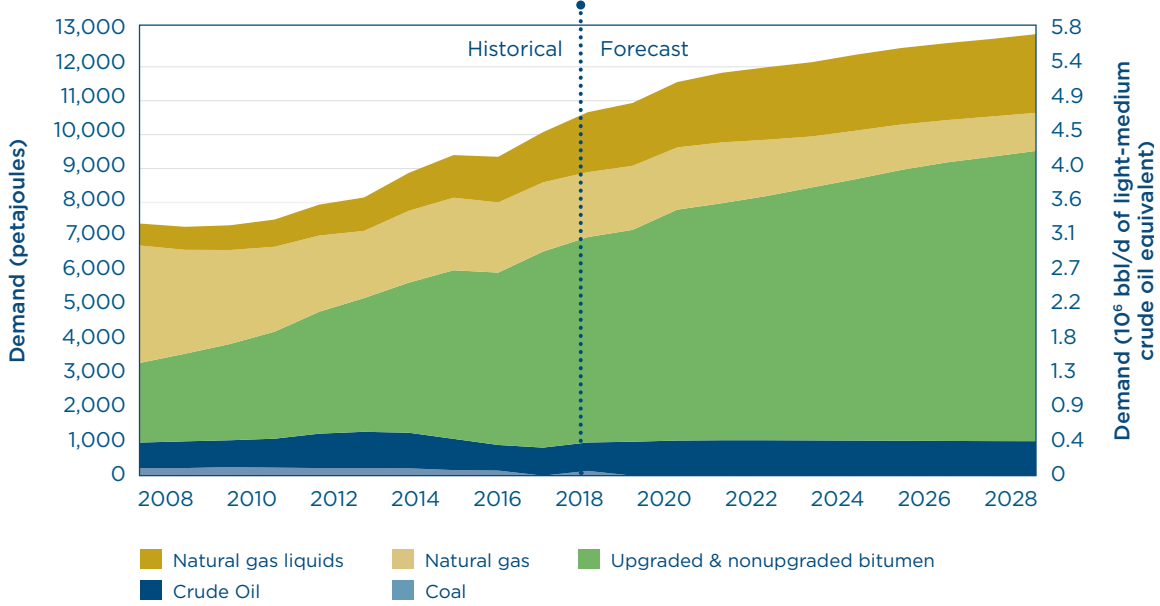
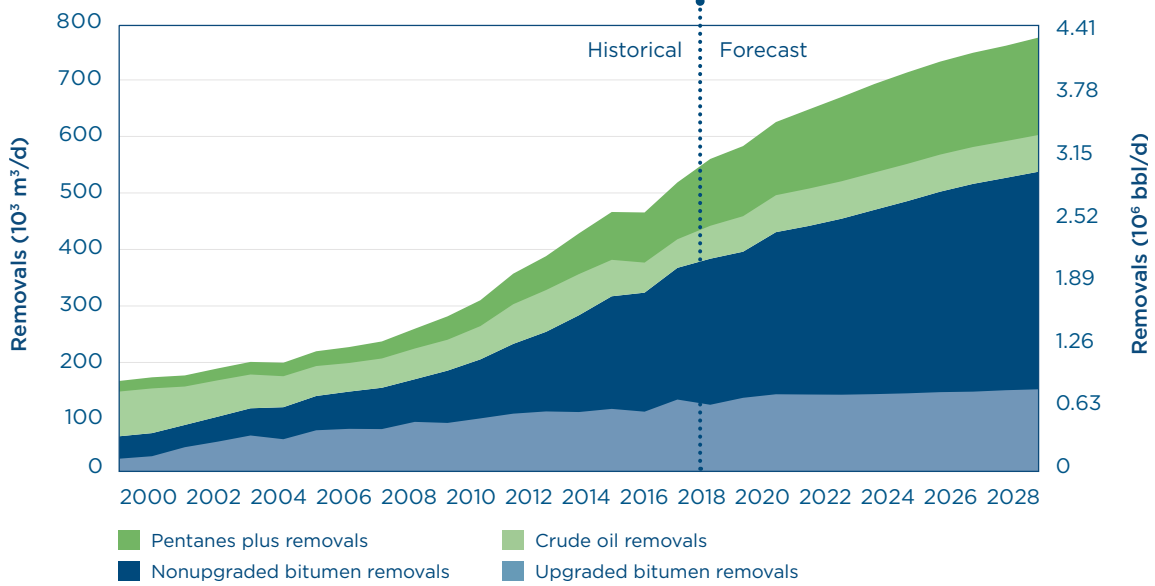
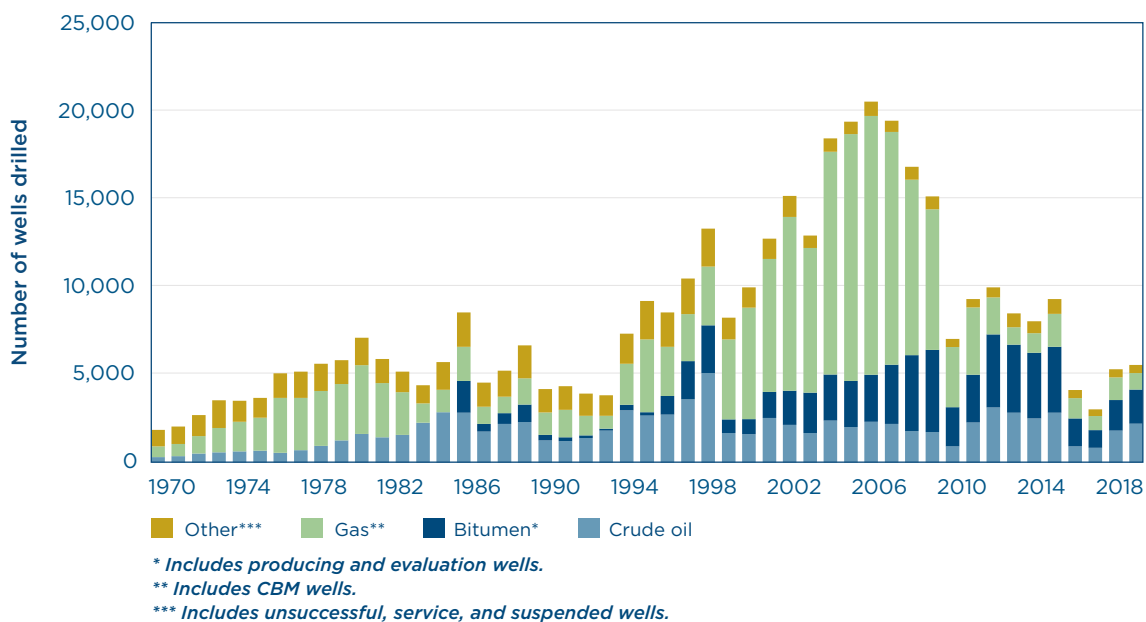


Figure 11 Total oil removals from Alberta



Note: Pentanes plus volumes include condensates.

Figure 12 Historical drilling activity in Alberta



DRILLING ACTIVITY

- Total drilling increased by 4.7 per cent in 2018. A 27 per cent decrease in natural gas drilling activity was more than offset by an increase in crude oil and bitumen drilling. The increase in crude oil drilling is attributed to the increase in CLS price.



ECONOMIC ASSUMPTIONS

The forecasts are based on various assumptions about economic indicators.

Table 2 Major Alberta economic indicators, 2018–2028

	2018 ^a	2019	2020	2021–2028 ^b
Real gross domestic product (GDP) growth (%)	2.30	1.50	2.00	3.00
Inflation rate (%)	2.40	1.80	2.00	2.00
Exchange rate (US\$/Cdn\$)	0.77	0.76	0.78	0.82

^a 2018 values are estimated.

^b Average over 2021–2028.





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