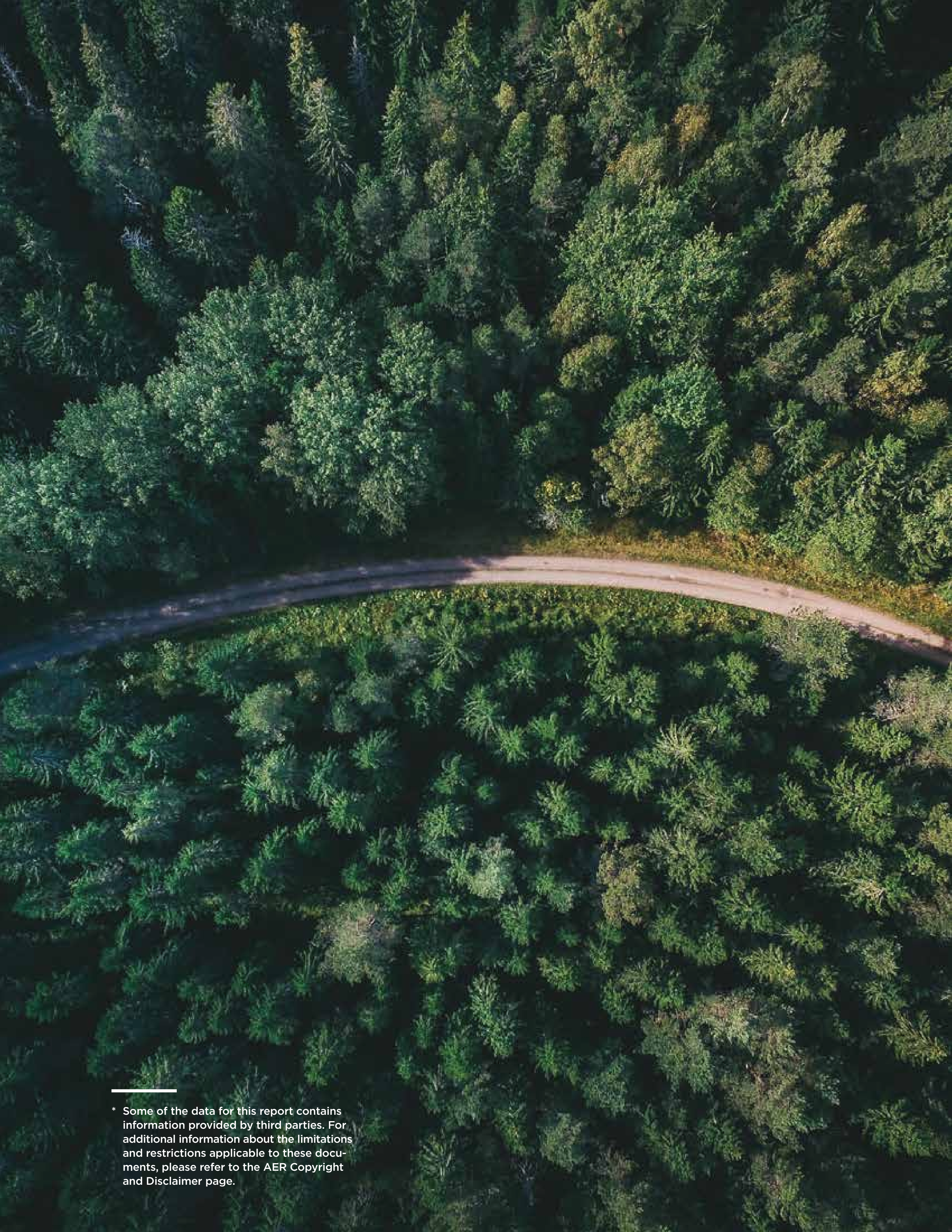
Alberta Energy Regulator

ALBERTA ENERGY OUTLOOK

ST98 I Executive Summary I 2024



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EXECUTIVE SUMMARY

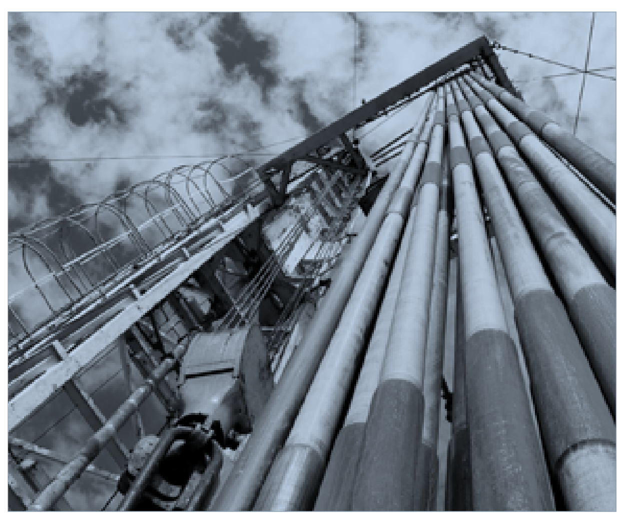
The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon, geothermal, and mineral resources over their entire life cycle. As part of our mandate, we provide our stakeholders with credible information about Alberta's energy resources that can be used for decision making. A key information resource is the *Alberta Energy Outlook (ST98)*, an annual report with independent and comprehensive information on the state of hydrocarbon 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 emerging resources). Additionally, this report discusses prices and capital expenditures in the oil and gas sector and pipelines and other infrastructure related to Alberta's resources. This year's report includes a new section on carbon capture, utilization and storage (CCUS).

REPORT OVERVIEW

With expected pipeline capacity improvements and reasonably elevated oil prices, Alberta's oil and gas industry continued to grow in 2023. Despite a dip from the record levels observed in 2022, oil prices in 2023 remained notably higher than prepandemic levels, which supported oil and liquids-rich natural gas production. In addition, the anticipated rise in oil and gas demand from international markets, facilitated by the Trans Mountain Pipeline Expansion and Coastal GasLink Pipeline, contributed to the production growth. In the near term, the central banks in many developed countries are poised to cut interest rates this year, lifting global economic growth and energy demand; however, oil and gas companies in Alberta are expected to maintain disciplined investment strategies. Meanwhile, energy affordability and security remain a top priority for many nations while transitioning to a low-carbon economy.

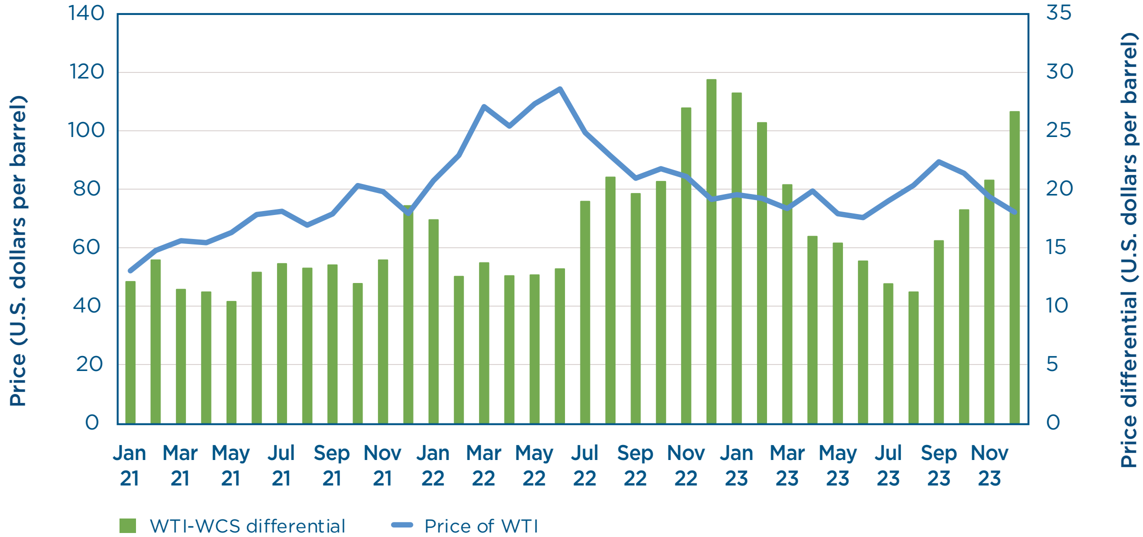
Oil prices experienced smaller percentage declines compared with natural gas prices in 2023. The North American light oil benchmark price (West Texas Intermediate [WTI]) retreated by 18%, and Alberta's heavy oil benchmark price (Western Canadian Select [WCS]) retreated by 22%. In comparison, the North American natural gas price (Henry Hub) declined by 59%, and Alberta's local price (AECO-C) declined by 46%.

In 2023, the price of WTI averaged US$77.62 per barrel (/bbl), an 18% drop from the previous year. The WTI price trended down from a multiyear high reached in June 2022 to about US$70.00/bbl in June 2023, primarily because of softening economic growth and the relatively stable situation of the war in Ukraine. In the third quarter of 2023, the oil price bounced back to just below US$90.00/bbl in September due to the tighter supply from the voluntary cut by the Organization of the Petroleum Exporting Countries and its allies (OPEC+). However, it swiftly dropped back to around US$72.00/bbl by the end of the year as the worries about the weaker economy re-emerged. We expect the economic growth, OPEC+ supply controls, and geopolitical conflicts will influence the short-term market and forecast a WTI price of US$76.00/bbl in 2024.



[1] *Natural gas liquids include ethane, propane, butane, and pentanes plus—on their own or combined—obtained from processing raw gas or condensate.*

Figure 1 Canadian oil price differential



Historical values from the Government of Alberta and U.S. Energy Information Administration.

The price differential between WTI and WCS prices was US$18.65/bbl in 2023, slightly higher than in 2022. Figure 1 shows the oil price history and price differential.

After reaching a multiyear high in 2022, the Henry Hub price for natural gas retreated to an average of US$2.67 per million British thermal units (MMBtu) in 2023, a 59% decrease from the previous year. Heating demand for natural gas was down because of the mild winter in 2023, and U.S. production continued to rise due to associated gas production from shale oil fields. Both factors drove the natural gas storage to high levels and depressed the Henry Hub price below US$3.00/MMBtu for most of 2023 and early 2024. With relatively high natural gas inventories, the Henry Hub price is forecast to average US$2.60/MMBtu in 2024.

The average price of AECO-C natural gas was Cdn$2.74 per gigajoule (GJ) in 2023, representing a decrease of 46% from 2022. The natural gas price differential between Henry Hub and AECO-C shrank in 2023 with sufficient pipeline capacity.

Total oil production (including crude oil, oil sands, and pentanes plus) continued to climb as companies ramped up production, preparing for the start-up of the Trans Mountain Pipeline Expansion in May 2024. The production increase mainly came from nonupgraded bitumen, followed by upgraded bitumen and crude oil.

Although the rate of the production increase slowed relative to 2022, marketable natural gas production in 2023 rose by 2% due to sustained drilling activity. This increase resulted from higher natural gas production in the liquids-rich regions and rising associated gas production from oil wells.

In 2023, total capital expenditures for crude oil, natural gas, oil sands, and emerging resources continued to grow to Cdn$29.5 billion, a six-year high. Oil sands investment increased by 11% with optimization projects. Crude oil and natural gas investment declined by 6% as companies exerted capital discipline.

Market access remained sufficient for oil exports during the spring and summer of 2023, while a rising apportionment on the Enbridge Mainline by the year's end indicated higher crude-by-rail volumes. The Trans Mountain Pipeline Expansion start-up in May 2024 has enhanced oil takeaway capacity. For natural gas transportation, capacity met the export demand in 2023, and transportation capability improved further after the completion of the Coastal GasLink pipeline in British Columbia, connecting to future LNG Canada facilities.

For emerging resources, Alberta presents growth opportunities for hydrogen, geothermal energy, helium, and lithium. Hydrogen production is estimated to increase from 2.5 million tonnes in 2023 to 3.9 million tonnes in 2033 (an average annual growth rate of 4%). Despite small production, geothermal production will grow at an average rate of 21% annually and helium at 21% annually over the forecast period. Although there is no commercial lithium production in Alberta, the production of lithium chemical compounds is forecast to reach 13.4 thousand tonnes per year by 2033.

This year's report features a new chapter on CCUS, highlighting its pivotal role in reducing carbon emissions. In 2023, notable achievements were reached in Alberta's CCUS initiatives. The Shell Quest project permanently sequestered 1.0 million tonnes of carbon dioxide and Enhance Energy's Clive Field project, part of the Alberta Carbon Trunk Line, permanently sequestered 1.6 million tonnes of carbon dioxide.

REPORT HIGHLIGHTS

This section provides highlights of oil and gas production, prices, capital expenditures, demand, and drilling activity for 2023 and their outlook for 2024 to 2033 (the forecast period). A snapshot of the province's reserves as of December 2023 is also provided.

Oil and Gas Production in Canada

Alberta remains the largest natural gas and oil producer in Canada (see Figure 2 and Figure 3). In 2023, Alberta produced 61% of Canada's natural gas, although British Columbia's share of marketable gas production has trended up from 27% in 2013 to 37% in 2023. Alberta accounted for 84% of Canada's oil and equivalent[2], and 66% was marketable bitumen in 2023.

In 2023, raw crude bitumen production in Alberta was close to 3.4 million barrels per day (10^6 bbl/d), a 3% increase from 2022.

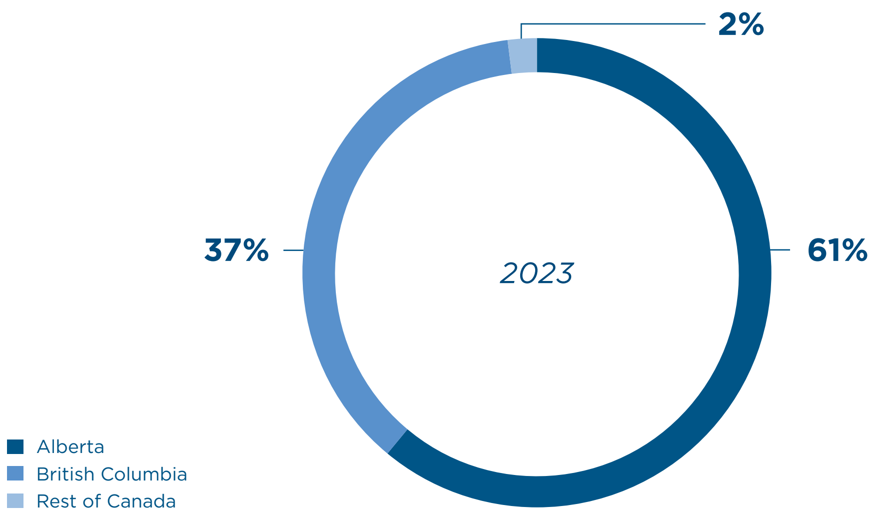
Oil and Gas Prices

Figure 4 shows the WTI price history and forecast price ranges.

- The price of WTI decreased by 18% in 2023, averaging US$77.62/bbl.
- The price of WCS decreased by 22% in 2023, averaging US$58.97/bbl.
- The WTI base-price case is projected to be lower in 2024 at US$76.00/bbl. Growth for global liquid fuel demand is expected to slow in 2024, with global economic activity weighed down by high interest rates. Meanwhile, commitments by OPEC+ to restrict supply are expected to support the WTI price.
- The low-price case of US$46.47/bbl in 2024 considers global oil demand to fall more than expected due to global economic recession, OPEC+ production exceeding their target output level, and strong U.S. shale production growth.
- The high-price case of US$124.29/bbl in 2024 considers both Chinese oil demand and overall global economic activity will accelerate faster than projected, OPEC+ cuts more than expected to oil supply, and deteriorating geopolitical conditions will further disrupt regional oil supply.

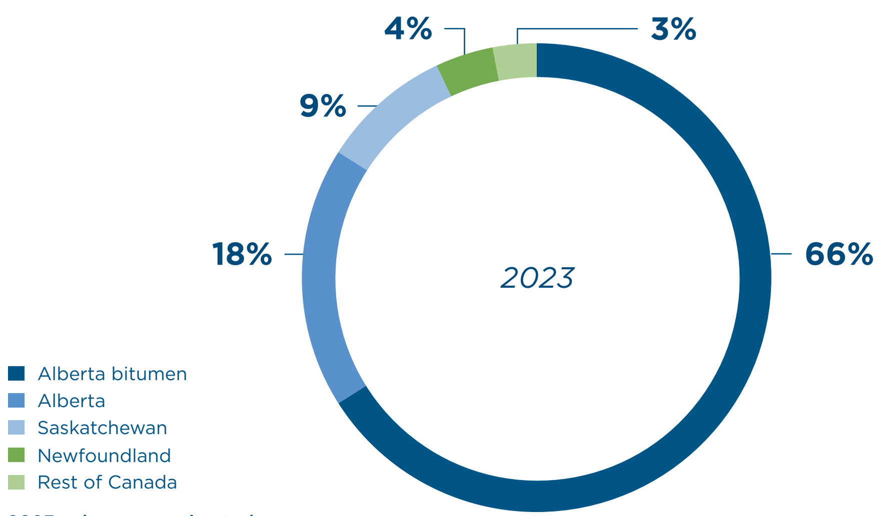
[2] Oil and equivalent comprises light, medium, heavy, and ultra-heavy crude oil; upgraded and nonupgraded bitumen (referred to as marketable bitumen); and condensate (pentanes plus).

Figure 2 Marketable natural gas percentage of production in 2023—Canada



2023 values are estimated.
Source: Canada Energy Regulator.

Figure 3 Total oil and equivalent percentage production in 2023—Canada



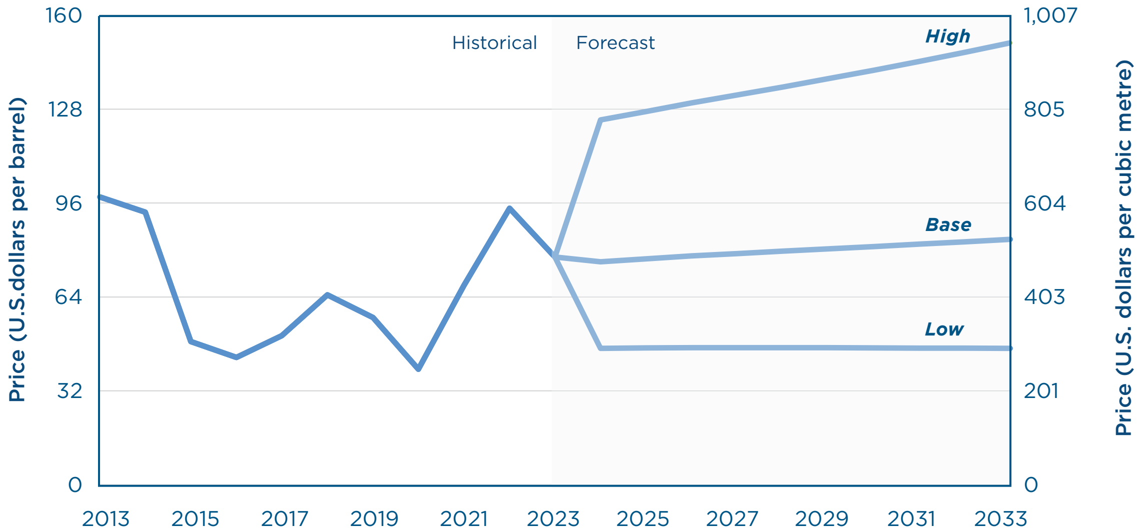
2023 values are estimated.
Source: Canada Energy Regulator.
Alberta bitumen includes synthetic crude oil.

- The WTI crude oil price is forecast to rise to US$77.00/bbl in 2025 as oil demand growth is expected to rebound as global economic growth resumes. The price is projected to increase moderately from 2026 onwards, reaching US$83.63 by 2033 (base-price case).
- The differential between WTI and WCS widened slightly in 2023 to an average of US$18.65/bbl compared with the 2022 average of US$18.22/bbl; the growing oil sands supply leading to some congestion on export pipelines and U.S. refinery turnarounds caused the differential to widen.

Figure 5 shows the Henry Hub price history and forecast price ranges.

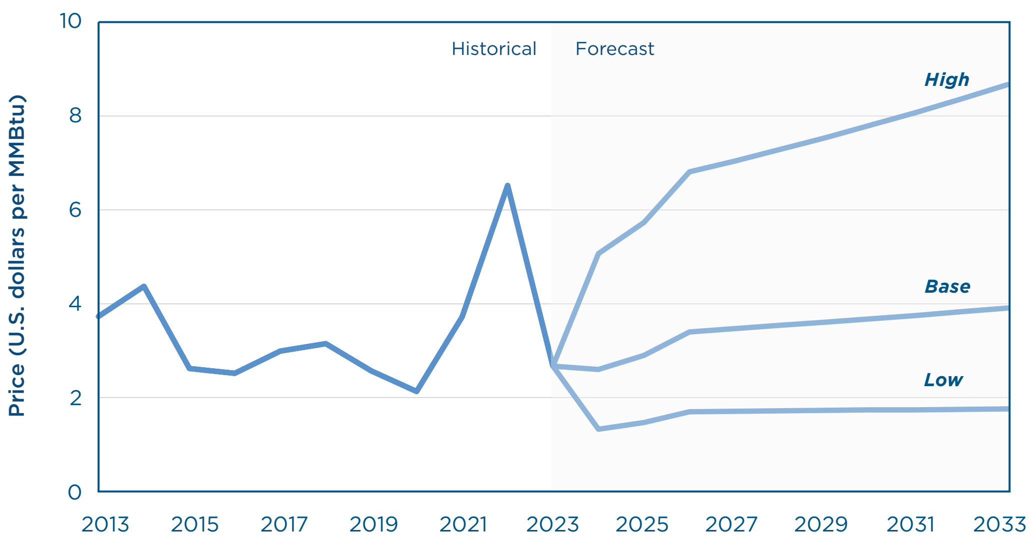
- The Henry Hub price decreased by 59%, averaging US$2.67 per MMBtu in 2023, driven by elevated North American inventories and weak heating demand from mild winter weather.
- The Henry Hub base-price case is expected to dip to an average of US$2.60/MMBtu in 2024 amid mild winter weather and ample supply. Natural gas export capacity is limited, and natural gas prices in North America are only partially dependent on international prices. North American regional factors are the primary drivers of the price forecast.
- In the low-price case, the price is forecast to average US$1.33/MMBtu in 2024 because North American demand is less than expected due to an economic slowdown and strong U.S. natural gas production growth.
- In the high-price case, the price is forecast to average US$5.07/MMBtu in 2024 because of a colder winter and a stronger-than-expected economic activity supporting North American demand.
- The Henry Hub price is forecast to rise to US$2.90/MMBtu in 2025 as U.S. demand growth rebounds; however, solid production growth will limit price gains. The price is forecast to increase from 2026 onwards, reaching US$3.91/MMBtu by 2033 (base-price case).

Figure 4 Price of West Texas Intermediate



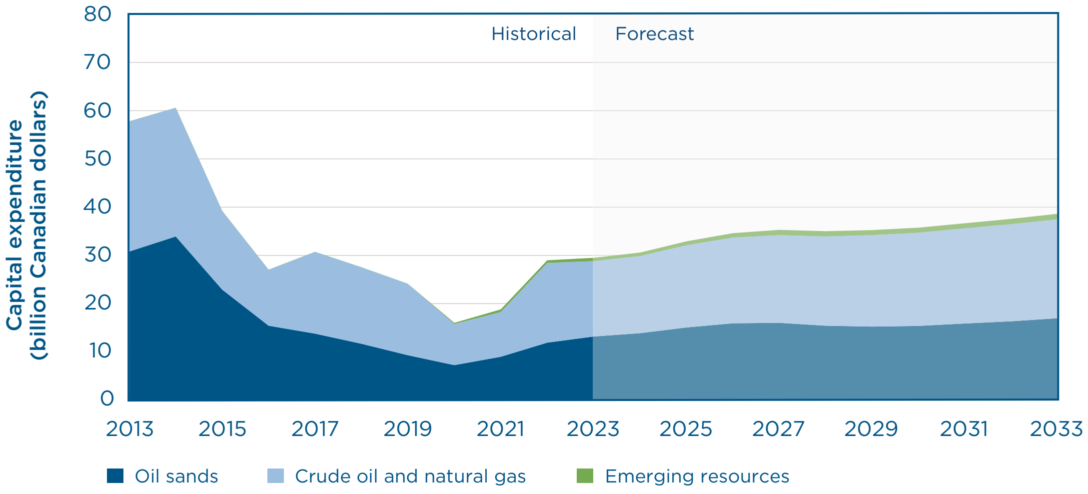
Historical values from U.S. Energy Information Administration.

Figure 5 Henry Hub natural gas price



Historical values from U.S. Energy Information Administration.

Figure 6 Alberta oil and gas, oil sands, and emerging resources capital expenditure



Oil sands, crude oil, and natural gas historical values are from CAPP. 2023 values are estimated. Emerging resources include geothermal, hydrogen, helium, and lithium. Historical figures are estimated.

CAPITAL EXPENDITURES

Figure 6 shows the capital expenditure history and forecast for hydrocarbons and emerging resources.

- Total capital expenditures in the crude oil, natural gas, oil sands, and emerging resources sectors increased by 2% in 2023, rising to Cdn$29.5 billion.[3] A decline in oil and gas prices hindered total capital expenditures in 2023.
- Estimated crude oil and natural gas capital expenditures fell to Cdn$15.6 billion in 2023, a 6% decrease from 2022, driven by lower prices and less drilling activity.
- With the expected improvement of market access, estimated oil sands capital expenditures increased from Cdn$11.9 billion in 2022 to Cdn$13.2 billion in 2023, an 11% increase from 2022. Debottlenecking and efficiency enhancements on various projects contributed to the increased expenditure.
- Total oil sands, crude oil, and natural gas capital expenditures are estimated to be Cdn$28.8 billion in 2023. Investment is projected to grow steadily over the forecast period. By the end of the forecast period, the total capital expenditures are expected to remain relatively low compared with the 2014 peak level.
- Capital spending for emerging resources was an estimated Cdn$0.70 billion in 2023 and is projected to increase to Cdn$1.1 billion by 2033, with some uncertainty. This spending is projected based on public announcements for hydrogen, helium, lithium, and geothermal projects and estimated capacity additions.

[3] *Historical data on oil sands, crude oil, and natural gas investments are from the* Canadian Association of Petroleum Producers (CAPP) Statistical Handbook *(2023 data). Capital expenditures for 2023 are estimates from CAPP. 2024–2033 forecasts are produced by AER.*

Table 1 Resources, reserves, and production summary, 2023

	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	15,628	98.3	10,749	381.5	93.7	103.3
Initial established reserves	28,092	177	3,254	20.5	6,216	220.6	34.8	38.4
Cumulative production	3,044	19.2	2,966	18.7	5,499	195.2	1.7	1.9
Remaining established reserves	**25,048**	**157.6**	**288.0**	**1.8**	**718[b]**	**24.3[b]**	**33.1**	**36.4**
Annual production	197.9	1.245	29.7	0.187	115.0[c]	4.1[c]	0.011[d]	0.012[d]
Ultimate potential (recoverable)	50,000	315	3,130[e]	19.7[e]	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] Measured at field gate.
[c] Includes coalbed methane and shale gas.
[d] Annual production is marketable.
[e] Does not include oil from tight oil or shale oil plays.
[f] Does not include coalbed methane and shale gas.

RESERVES

The AER has been providing an independent appraisal of Alberta's energy resources since 1961. The AER studies hydrocarbon extraction and ensures energy resources are being extracted in an efficient and environmentally responsible manner.

The Government of Alberta uses the information to develop policies and regional land use plans, and the energy industry uses it to evaluate investment opportunities in Alberta.

Table 1 shows the reserves determined for crude bitumen, crude oil, natural gas, and coal. The data suggests Alberta has sufficient reserves for many years of production.

PRODUCTION AND DEMAND

Figure 7 shows the primary energy production in Alberta by type.

- Total primary energy produced in Alberta increased by 3% in 2023[4] as crude oil and oil sands producers ramped up production in anticipation of the Trans Mountain Pipeline Expansion start-up and the relatively elevated prices in 2024. Natural gas producers continued to focus on drilling in liquid-rich areas with reasonably high prices for liquids.
- Marketable bitumen production, which includes nonupgraded and upgraded bitumen, increased by 4% in 2023 with the anticipated takeaway capacity improvement and relatively elevated oil prices.
- Crude oil production increased by 5% in 2023 as producers took advantage of relatively high oil prices despite inflation driving up capital and operating costs of production.
- Total marketable natural gas production increased by 2% in 2023 as producers focused on conventional gas, tight gas, and gas from oil wells production. The higher production was driven by increases in conventional gas (including tight gas) production concentrated in Foothills Front and Northwestern Alberta.
- In 2023, Alberta produced an estimated 15 029 petajoules (PJ) of energy from all sources or 6.7 million barrels per day of light-medium quality crude oil equivalent (10^6 BOE/d).
- In 2033, Alberta is projected to produce 16 862 PJ (7.6 10^6 BOE/d) of energy from all sources.
- Upgraded and nonupgraded bitumen production accounted for 51% of total primary energy production in 2023.
- In 2023, based on energy content, natural gas liquids production was about 32% higher than crude oil production. This trend is expected to grow over the forecast period.
- Total natural gas liquids production increased by 1% in 2023, driven mainly by increased pentanes plus and ethane production.

[4] *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 Total primary energy production in Alberta

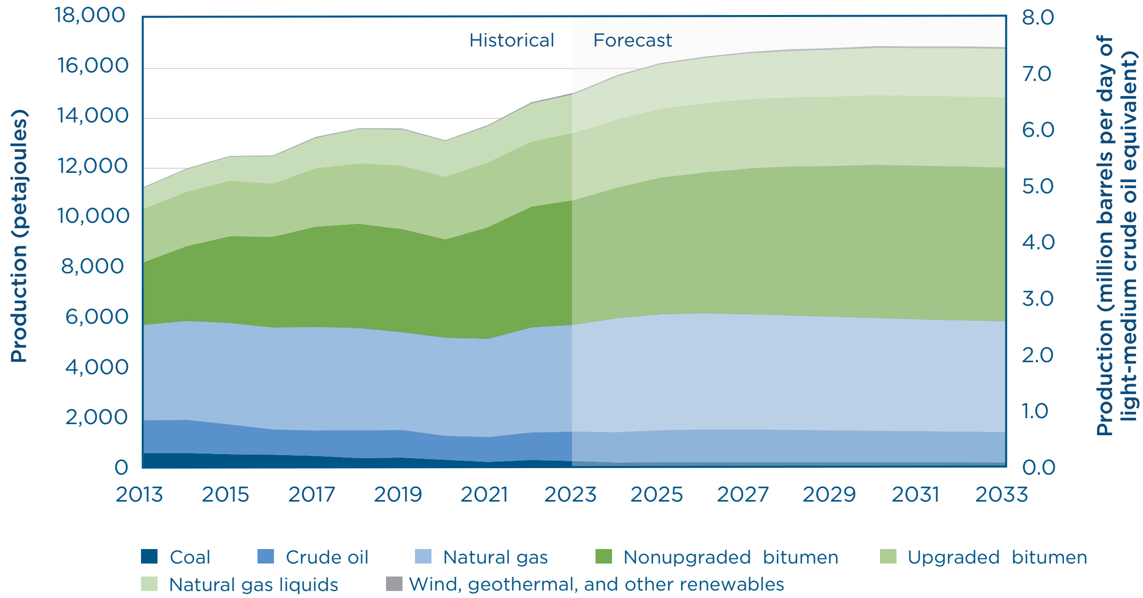


Figure 8 Alberta supply of crude oil and equivalent

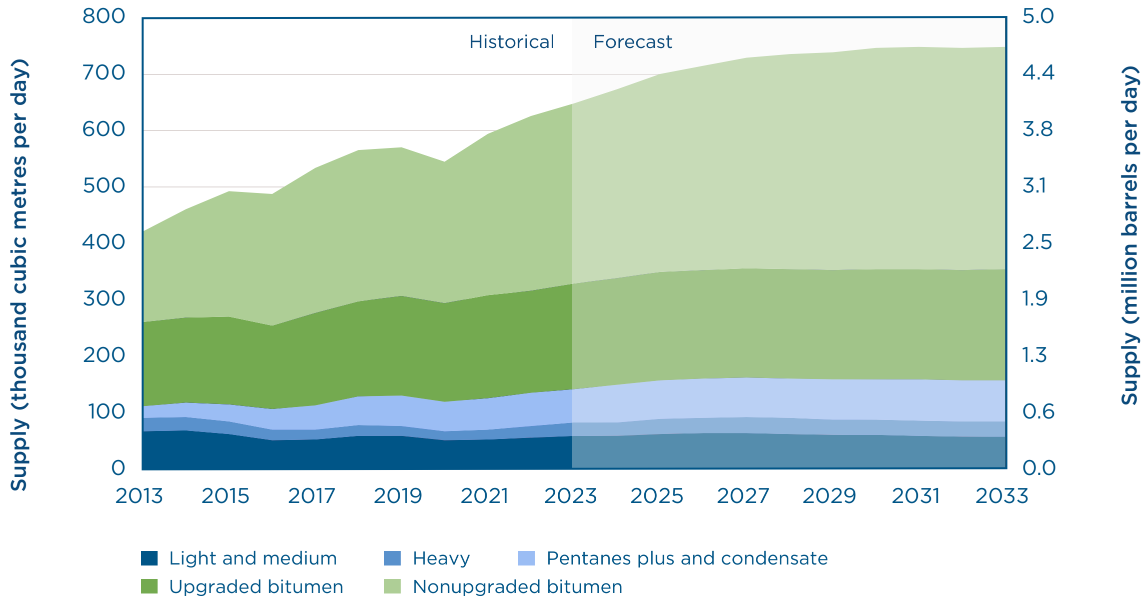


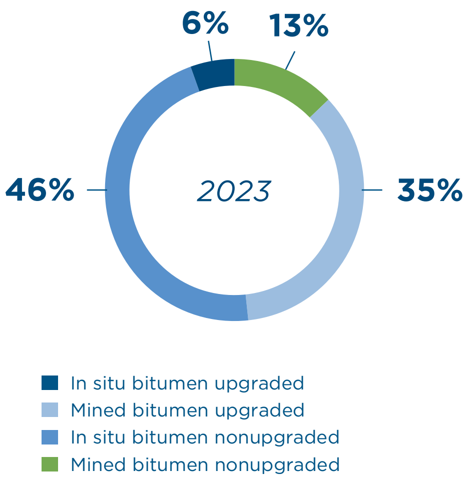
Figure 8 shows the Alberta supply of crude oil and equivalent.

- Alberta's production of crude oil and equivalent increased by 4% in 2023, reaching 4.1 10^6 bbl/d. The increase is primarily driven by nonupgraded bitumen, upgraded bitumen, and crude oil.
- Crude oil and equivalent production is expected to grow throughout the forecast period, reaching 4.7 10^6 bbl/d by 2033, primarily driven by increased upgraded and nonupgraded bitumen production.
- Crude oil production increased in 2023 to 0.5 10^6 bbl/d and is projected to continue growing until 2026. However, from 2027 to 2033, it will gradually decline as new wells placed on production may be insufficient to offset the decline in existing production.
- Production of pentanes plus is forecast to grow from 0.4 10^6 bbl/d in 2023 to 0.5 10^6 bbl/d by 2033.

Figure 9 shows the percentage of bitumen upgraded in Alberta.

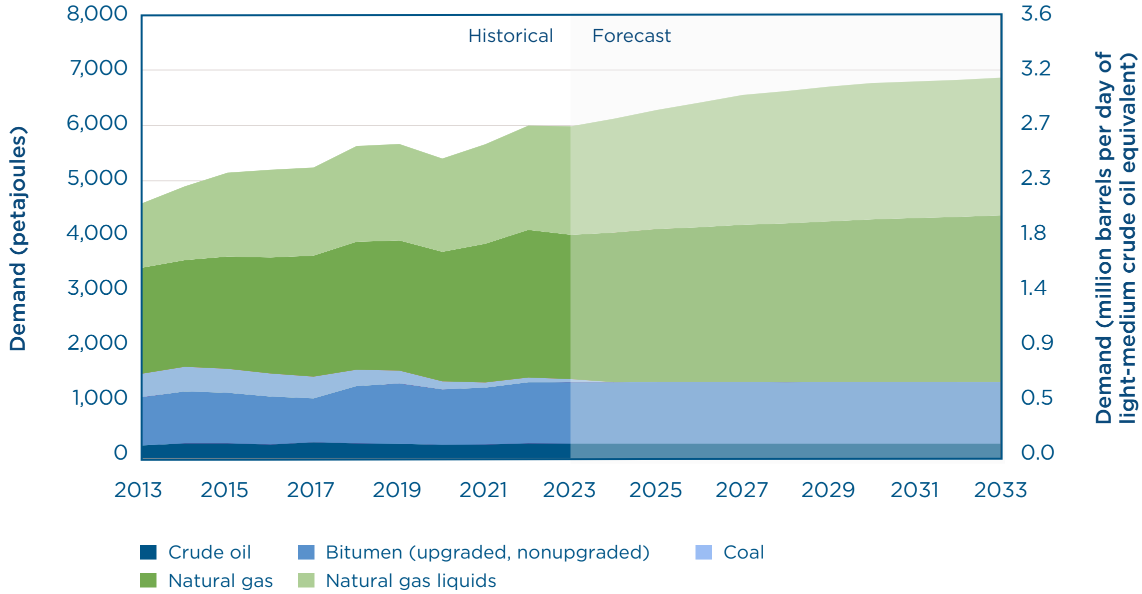
- In 2023, an estimated 41% of produced raw bitumen was upgraded in Alberta. By 2033, only about 37% of raw bitumen is projected to be upgraded in Alberta as the growth in raw bitumen production is expected to outpace upgrading capacity additions.

Figure 9 Percentage of mined and in situ bitumen sent for upgrading in Alberta



Total mined: 261.9 10^3 m^3/d.
Total in situ: 280.2 10^3 m^3/d.

Figure 10 Primary energy demand in Alberta



- Upgraded bitumen output increased by 4% in 2023, as all upgraders recorded production increases, in line with higher overall bitumen production levels.

Figure 10 shows the primary energy demand in Alberta by type.

- Alberta's total primary energy demand in 2023 was 5987 PJ (2.7 10^6 BOE/d). Alberta demand is projected to increase to about 6860 PJ (3.1 10^6 BOE/d) by 2033. This increase is attributed to strengthening demand for pentanes plus as a diluent in bitumen blending. Increasing demand for natural gas was driven by power generation and oil sands in situ operations.
- Federal and provincial government policies targeting the reduction of carbon dioxide emissions will drive the demand for coal in Alberta to zero, as the remaining coal-fired power plant will be phased out in 2024.

Figure 11 shows the primary energy removal of energy types from Alberta.

- Primary energy removals from Alberta increased by 3% in 2023. Higher production output due to relatively high commodity prices enabled increased energy removals.
- Total primary energy removals from the province in 2023 were estimated at 11 105 PJ (5.0 10^6 BOE/d), with oil (bitumen and crude oil) and natural gas liquids representing 83% of the primary energy removals for the year.
- Removals from the province are projected to reach 12 557 PJ (5.6 10^6 BOE/d) by 2033, with bitumen representing a growing share of primary energy removals.
- Natural gas removals from Alberta are projected to grow in the short term and decline starting in 2026 and to the end of the forecast period. This decline in removals will occur as demand growth is forecast to outpace production increases.
- Removals of marketable bituminous coal from Alberta decreased slightly by 2% in 2023 as production decreased at the Coal Valley and Vista coal mines.

Figure 12 shows the removal of oil from Alberta by type.

- In 2023, removals of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were estimated at 613.8 thousand cubic metres per day (10^3 m^3/d) or 3.9 10^6 bbl/d—about 4% higher than in 2022.
- By 2033, about 726.8 10^3 m^3/d (4.6 10^6 bbl/d) of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen are forecast for removal from the province. This projection assumes sufficient removal capacity because of pipeline expansion, optimization, and crude-by-rail transportation.

Figure 11 Primary energy removals from Alberta

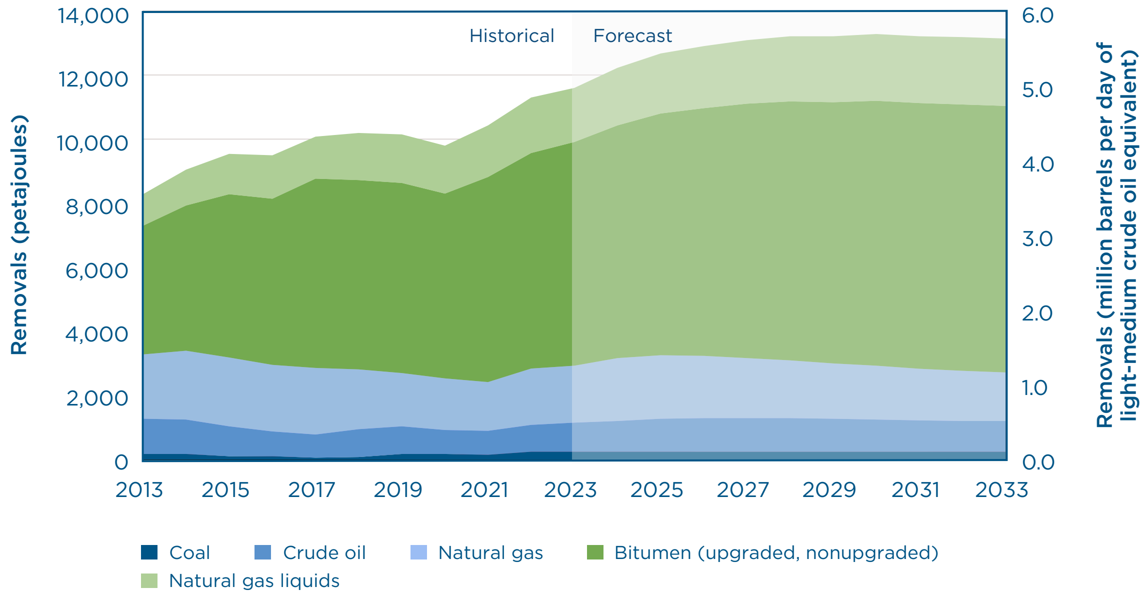


Figure 12 Total oil removals from Alberta

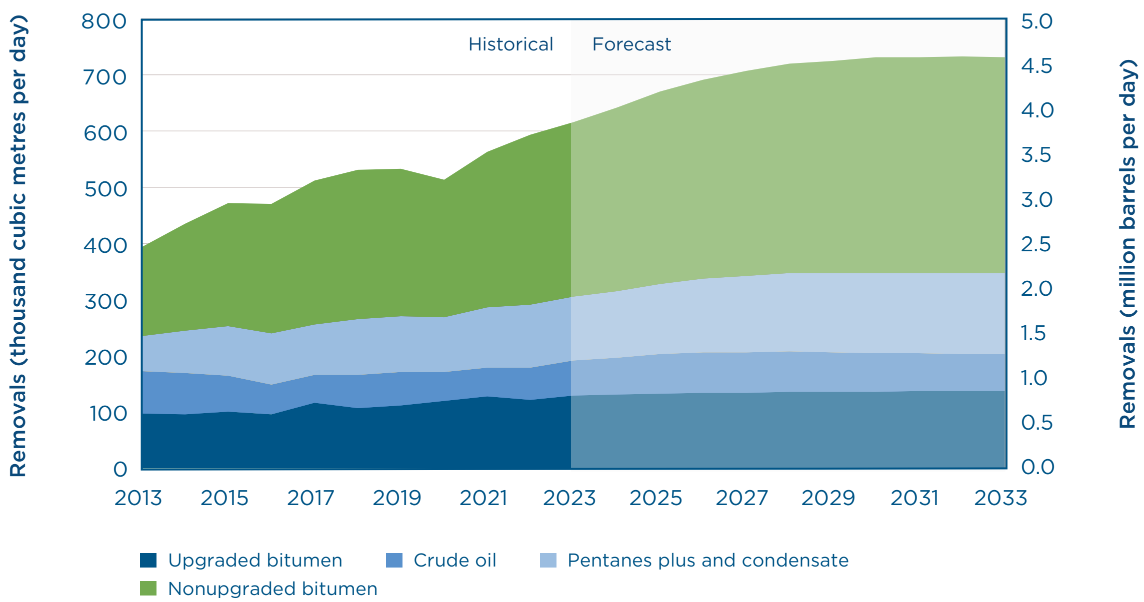
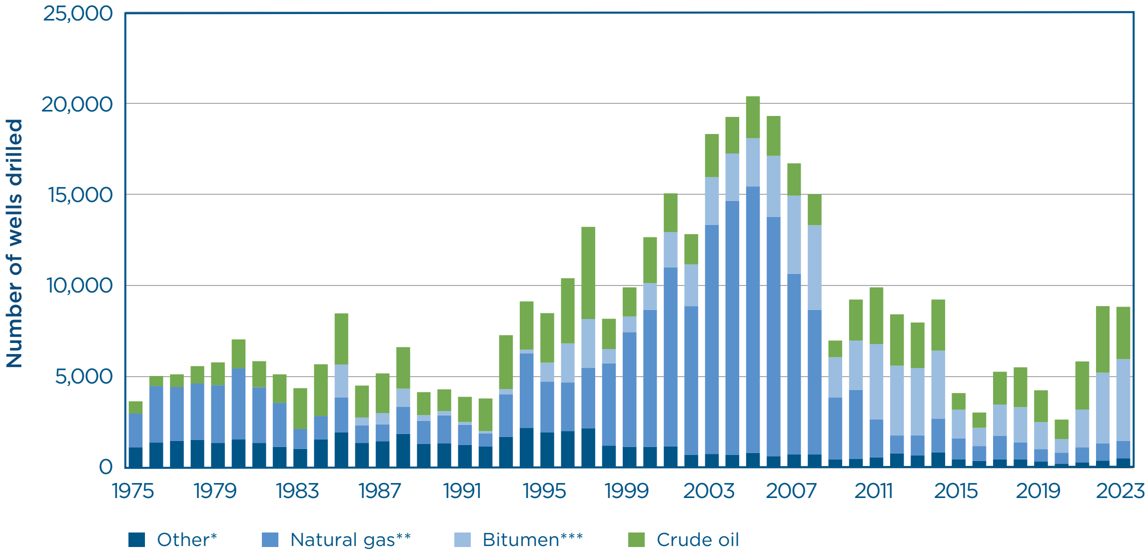


Figure 13 Historical drilling activity in Alberta



Includes unsuccessful, service, and suspended wells.
*** Includes coalbed methane wells.*
**** Includes producing and evaluation wells.*

DRILLING ACTIVITY

Figure 13 shows that total drilling decreased very slightly by 0.5% in 2023 (natural gas drilling increased by 1%, crude oil drilling decreased by 22%, and oil sands drilling increased by 16%).

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