# ALBERTA ENERGY OUTLOOK

## ST98 I Executive Summary I 2022

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# EXECUTIVE SUMMARY

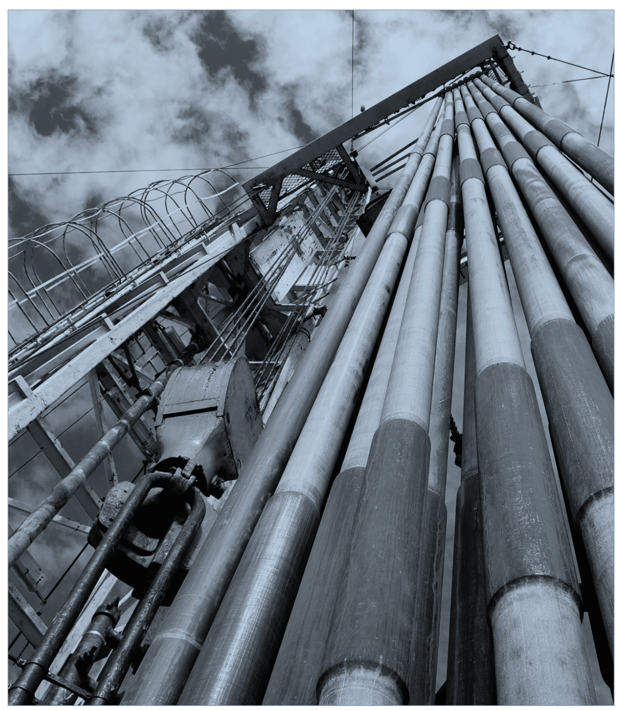
The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. As part of this mandate, we provide credible information about Alberta's energy resources that can be used for decision making. A key information resource is *ST98: Alberta Energy Outlook*, 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 sulphur. This year's report includes a new section on emerging resources, including geothermal, hydrogen, and helium.

## REPORT OVERVIEW

After encountering significant challenges due to the global COVID-19 pandemic in 2020, the oil and gas industry in Alberta rebounded in 2021. With the vaccination rollout and the removal of pandemic restrictions, the world economy started to recover in 2021. The rising demand for energy and a lagged supply response pushed oil and gas prices to higher than pre-pandemic levels and contributed to higher inflation. In early 2022, shrinking global oil storage and a geopolitical conflict in Eastern Europe raised energy prices even further to the highest levels seen since 2014. This is partly due to bans on importing Russian oil and natural gas by some western countries, including the U.S. and Canada. Meanwhile, the recent turmoil in energy markets because of the conflict in Eastern Europe has renewed the importance of energy security for many nations including members of the Organisation for Economic Co-operation and Development.

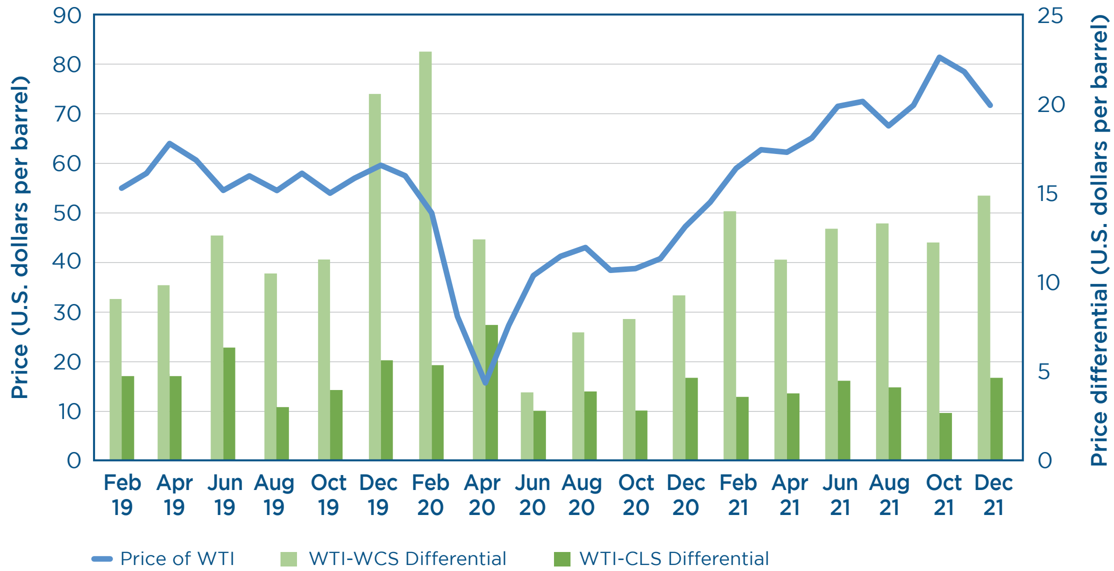
The North American benchmark prices for light sweet crude oil (WTI) and natural gas (Henry Hub), and Alberta benchmark oil and gas prices (Canadian Light Sweet [CLS], Western Canadian Select [WCS] and AECO-C) all increased by at least 60 per cent in 2021.

Economic growth and continued crude oil supply management by the Organization of the Petroleum Exporting Countries and its allies (OPEC+) supported the return of the WTI price to pre-pandemic levels in spring 2021. The WTI price continued to advance during summer and fall but slowed by the end of the year due to pandemic-related effects on demand (i.e., more transmissible COVID-19 variants). In late February 2022, WTI exceeded US$100 per barrel (bbl) and recorded a multiyear high as the tension started to unfold in Eastern Europe. The higher price reflected the risks of potential supply disruptions due to banning Russian oil imports in an already tight oil market.



*[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 differentials**




Like the WTI price, Alberta's price for CLS in December 2021 reached US$67.00/bbl and WCS US$54.90/bbl. In 2021, with improved market access, the price differential between WTI and CLS averaged US$3.89/bbl and for WTI and WCS US$12.78/bbl. The average differential between WTI and CLS in 2021 was narrower than 2020, while the average differential between WTI and WCS was slightly wider. Figure 1 shows the price history and price differential.

The natural gas price at Henry Hub averaged US$3.72 per million British thermal units (MMBtu) in 2021, a 75 per cent increase from the 2020 level. The price steadily increased through most of 2021 because of tighter supply, growing U.S. liquified natural gas exports, and low inventories. Prices peaked in October at US$5.58/MMbtu and declined by the end of year to US$3.86/MMbtu.

AECO-C started the year at an average of Cdn$2.55 per gigajoule (GJ) and gradually increased to Cdn$4.28/GJ by the end of 2021. The natural gas price differential between Henry Hub and AECO-C was wider in 2021 than in 2020 but narrower than in 2019.

After a drop in 2020, production of oil and equivalent rebounded across the board surpassing the pre-pandemic levels. Nonupgraded bitumen contributed the biggest production increase, reflecting higher energy prices and improved market access.

Marketable production of natural gas in Alberta declined slightly in 2021 as production from new natural gas wells took time to ramp up. Lower natural gas production from conventional sources (including tight gas) was the main driver for the overall decline. Production from unconventional resources also declined. Producers remained focused on drilling for higher-value natural gas liquids in the most productive areas of the province.

Total capital expenditures for crude oil, gas, and oil sands increased by an estimated 24 per cent in 2021 to Cdn$19.6 billion. Investments in crude oil and gas drilling and oil sands development reacted positively to higher energy prices. However, capital discipline, more stringent environmental, social, and governance standards, and decarbonization capped spending.

Market access improved in 2021 with the start of long-waited Enbridge Line 3 replacement, which became operational in October. This is the first successful major expansion of a Canadian crude oil pipeline in six years. The new pipeline added 370 thousand barrels per day ($10^3$ bbl/d) of export capacity to the U.S. Midwest and substantially alleviated pipeline takeaway constraints for Alberta's crude oil. With the reversal of the Capline pipeline in early 2022, more Alberta oil is expected to ship from the U.S. Midwest to the Gulf Coast.

With the proclamation of the *Geothermal Resource Development Act*, the AER's mandate expanded to include geothermal development. Once proclaimed, the *Mineral Resource Development Act* will establish the AER as the life cycle regulator for Alberta's mineral resources. Higher energy prices provided an opportunity for the development of emerging resources.

Alberta has a relatively significant hydrogen production to meet industrial demand from upgrading, refining, petrochemical processing, and fertilizer plants. Hydrogen production was estimated to be 2.5 million tonnes per year in 2021. Several hydrogen projects have been announced with notable investments. The Government of Alberta published the hydrogen roadmap in November 2021 to guide the industry development. The development of helium and geothermal industries in Alberta is in its early stages, but the growth potential is high.


# **REPORT** HIGHLIGHTS

This section provides highlights of oil and gas production, prices, capital expenditures, demand, and drilling activity in 2021, and their outlook for 2022 to 2031 (the forecast period). A snapshot of the province's reserves as of December 2021 is also provided.

## Oil and Gas Production in Canada

Alberta remains Canada's largest natural gas and oil producer (see Figure 2). In 2021, Alberta produced 62 per cent of Canada's natural gas and 85 per cent of Canada's oil and equivalent[2]. Almost 68 per cent of Canada's total oil and equivalent production was marketable bitumen.

Alberta's raw crude bitumen production in 2021 was close to 3.3 million barrels per day ($10^6$ bbl/d), a 9 per cent increase from 2020 (see Figure 3).

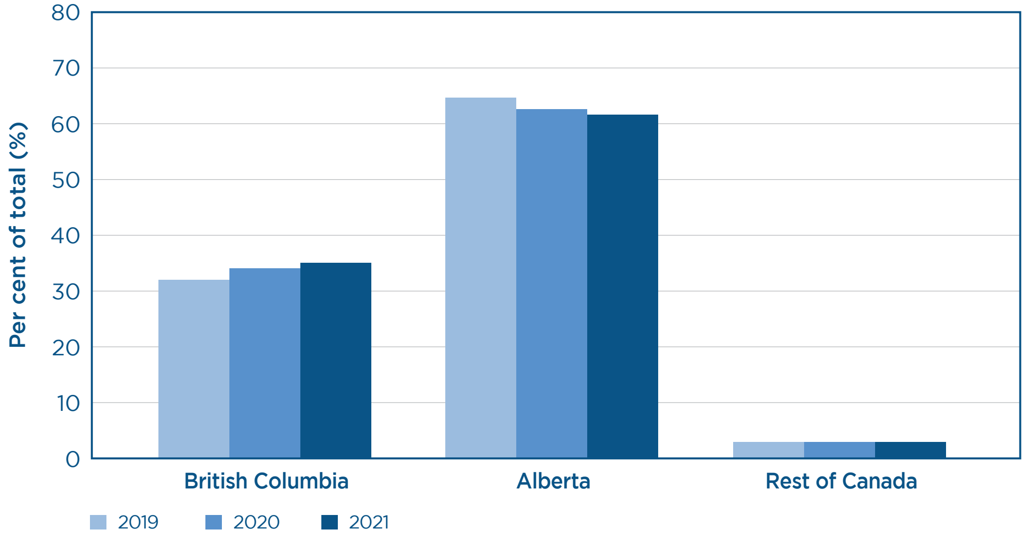
## Oil and Gas Prices

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

- The price of WTI increased by 73 per cent in 2021, averaging US$67.68/bbl.
- The price of CLS increased by 76 per cent in 2021, averaging Cdn$80.28/bbl.
- The price of WCS increased by 105 per cent in 2021, averaging US$54.90/bbl.
- The WTI base-price case is projected to be significantly higher in 2022 at US$95.00/bbl. Global demand for liquid fuels is expected to increase in 2022, while major supply disruptions are expected to persist due to the conflict in Eastern Europe. Both supply-side and demand-side factors are putting upwards pressure on the price of WTI.
- The low-price case of US$57.71/bbl in 2022 primarily considers reductions in global oil demand due to resurgence of new COVID-19 variants, larger than expected production hikes by OPEC, and a quick resolution to the conflict in Eastern Europe.
- The high-price case of US$156.38/bbl in 2022 considers stronger than expected growth of the world economy,

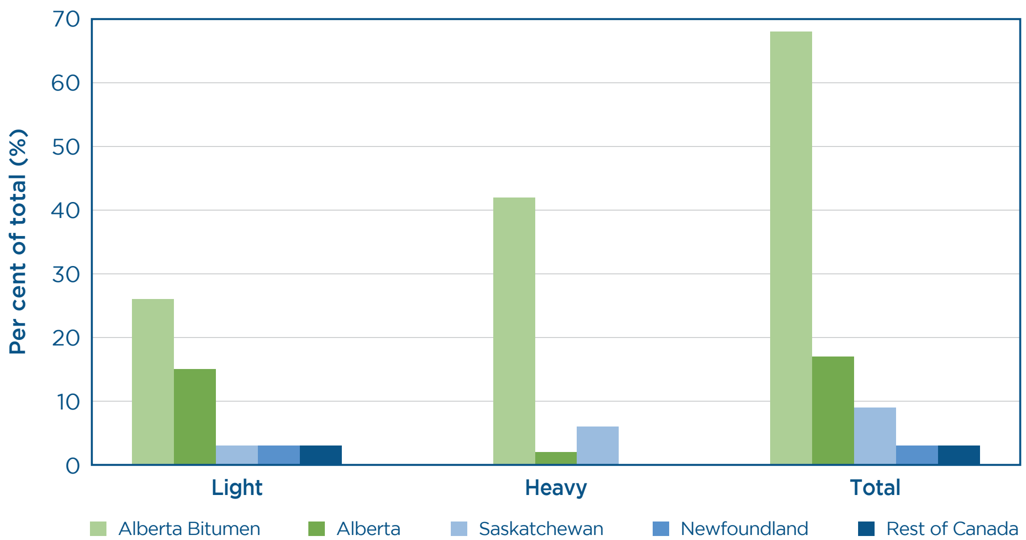
*[2] Oil and equivalent include light, medium, heavy, and ultra-heavy crude oil; condensate (pentanes plus); and upgraded and nonupgraded bitumen (referred to as marketable bitumen).*

## Figure 2 Marketable natural gas percentage of production—Canada




*Source: Canada Energy Regulator.*

## Figure 3 Oil and equivalent percentage of production—Canada




*Source: Canada Energy Regulator.*

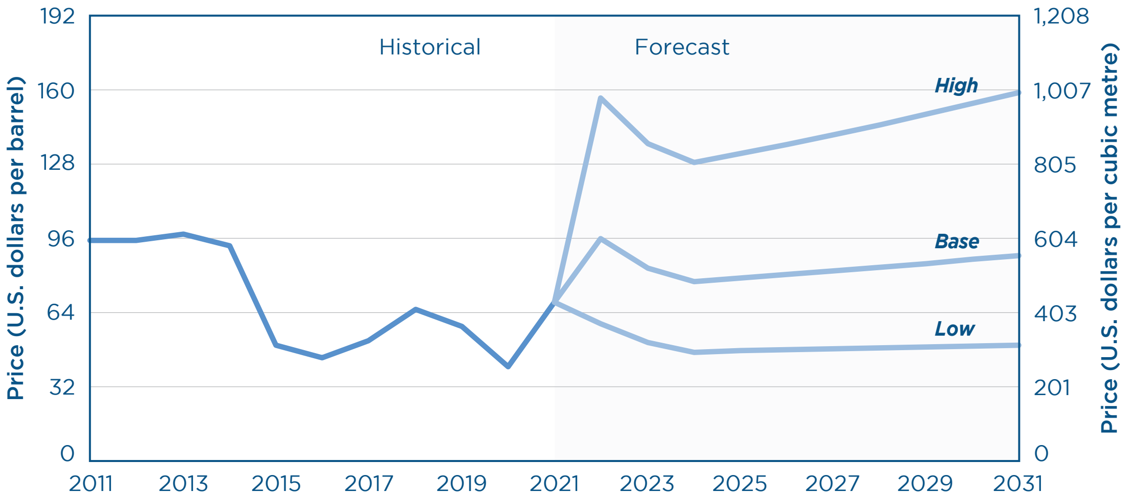

faster global COVID-19 vaccination rollouts, and deteriorating conditions in Eastern Europe leading to further supply disruptions.

- The WTI crude oil price is forecast to fall to US$83.00/bbl in 2023 and to US$77.00/bbl in 2024 as global oil production responds, supply chains are reorganized, and geopolitical tensions simmer. The price is projected to increase in 2025 onwards reaching US$88.45 by 2031 (base-price case).
- The differential between WTI and WCS increased slightly in 2021 to an average of US$12.78/bbl compared with the US$12.43/bbl average in 2020. The differential remained relatively stable supported by adequate pipeline capacity compared with previous years.

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

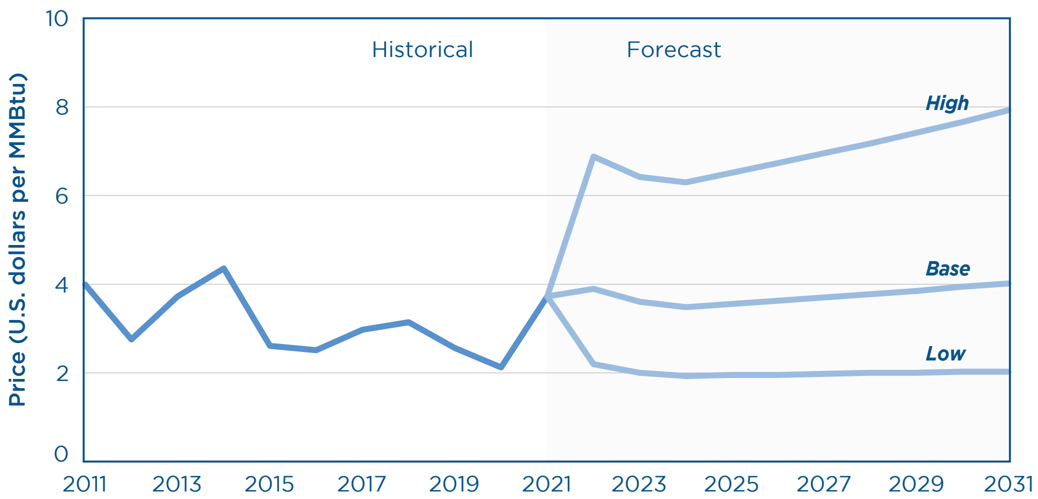
- The Henry Hub price increased by 75 per cent, averaging US$3.72 per MMBtu in 2021. U.S. natural gas exports grew by 26 per cent in 2021 (both natural gas via pipeline and LNG by ship increased).
- The base-price case of Henry Hub is expected to increase to an average US$3.90/MMBtu in 2022 with the expectation that demand will also increase. The forecast expects relatively little volatility in North American natural gas markets compared with oil markets as export capacity is limited and natural gas prices in North America are only partially dependent on international prices. To the extent that spillover effects from Europe affect demand in North America, regional factors are the primary drivers of the price forecast.
- In the low-price case, the price is forecast to average US$2.21/MMBtu in 2022 because of slower than expected economic recovery and demand.
- In the high-price case, the price is forecast to average US$6.88/MMBtu because of faster than expected economic recovery and demand.
- The Henry Hub natural gas price is forecast to slide to US$3.60/MMBtu in 2023 and US$3.50/MMBtu in 2024 as drilling activity increases. Growth in associated gas production will further contribute to the supply response in which production is expected to outpace demand. The price is forecast from 2025 onwards, reaching US$4.02/MMBtu by 2031 (base-price case).

Figure 4    Price of West Texas Intermediate



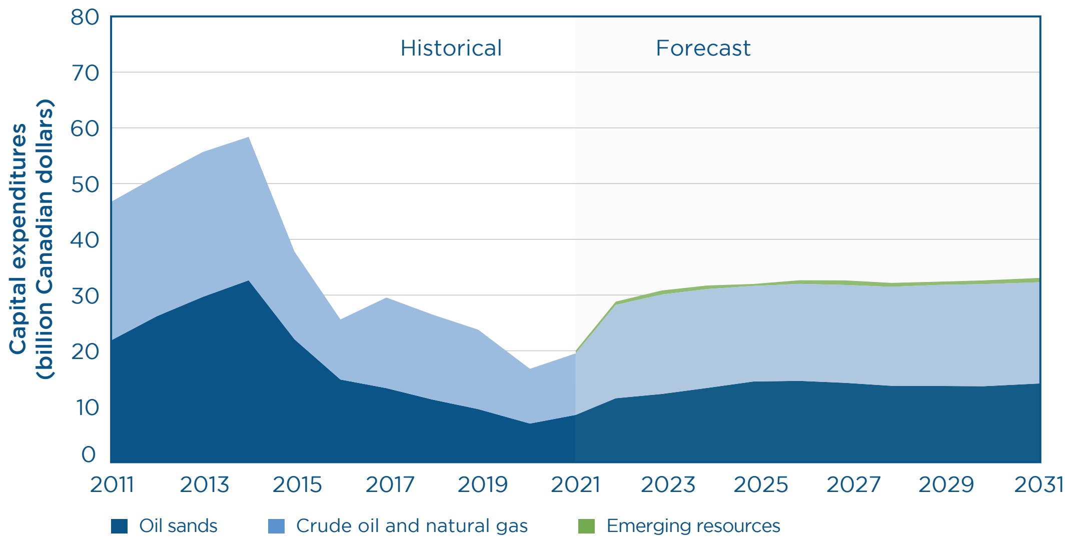

*Historical values from U.S. Energy Information Administration.*

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**




***2021 values are estimated.***
***Oil sands, and oil and gas historical values from CAPP.***
***Emerging resources includes hydrogen, geothermal, and helium.***
***Carbon capture, utilization, and storage costs are not included in the capital expenditure numbers.***

## CAPITAL EXPENDITURES

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

- Total capital expenditures in the crude oil, gas, and oil sands sectors increased by 24 per cent in 2021, rising to Cdn$19.6 billion.[3] The increase in oil and gas prices in 2021 led to a more favourable investment environment.
- Capital expenditures in crude oil and natural gas increased to an estimated Cdn$10.9 billion in 2021, an increase of 28 per cent from 2020. This was primarily driven by the recovery in drilling activity.
- Estimated oil sands capital expenditures increased from Cdn$7.3 billion in 2020 to Cdn$8.7 billion in 2021. With 2021 being the exception, capital expenditures have slid since the peak in 2014 as oil sands producers have focused less on new projects and more on expansions and efficiency enhancements.
- Total oil sands and crude oil and gas capital expenditures are forecast to increase to Cdn$28.6 billion in 2022, reflecting market uncertainties and the AER's price forecast. Investment is projected to grow modestly over the forecast period, in line with economic recovery and corresponding price forecasts. By end of the forecast period, the total capital expenditures remain relatively low compared with the last decade.
- Capital spending for emerging resources was Cdn$0.6 billion in 2021 and is projected to increase to Cdn$0.8 billion by 2031, with a high degree of uncertainty. This spending is projected based on public announcements for hydrogen, helium, and geothermal projects and estimated capacity additions.

*[3] Oil sands and oil and gas historical statistics from the Canadian Association of Petroleum Producers (CAPP) Statistical Handbook (2021 data). Capital expenditures for 2021 are estimates from CAPP.*

### Table 1 Resources, reserves, and production summary, 2021

| | 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 | 14,749 | 92.8 | 10,374 | 368.2 | 93.7 | 103.3 |
| Initial established reserves | 28,092 | 177 | 3,170 | 20.0 | 5,986 | 212.5 | 34.8 | 38.4 |
| Cumulative production | 2,654 | 16.7 | 2,908 | 18.3 | 5,277 | 187.3 | 1.7 | 1.9 |
| **Remaining established reserves** | **25,438** | **160.1** | **262.0** | **1.6** | **709[b]** | **25.2[b]** | **33.1** | **36.5** |
| Annual production | 189.0 | 1.189 | 23.9 | 0.150 | 101.0[c] | 3.6[c] | 0.010[d] | 0.015[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 information is used by the Government of Alberta 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 per cent in 2021[4], largely due to increased demand for energy in the Canadian and U.S. economies after easing the COVID-19 restrictions.
- Marketable bitumen production, which includes nonupgraded and upgraded bitumen, increased by 10 per cent in 2021 as producers responded to improving demand and higher prices.
- Crude oil production increased by 3 per cent in 2021 because of the same reasons stated for bitumen production, which was due to an increase in drilling activity.
- Total marketable natural gas production decreased in 2021. The lower production was largely driven by declines in conventional (including tight) gas production due to the lagged production response from new wells.
- In 2021, Alberta produced an estimated 13 564 petajoules (PJ) of energy from all sources or 6.1 million barrels per day of light-medium quality crude oil equivalent ($10^6$ BOE/d).
- In 2031, Alberta is projected to produce 16 024 PJ (7.2 $10^6$ BOE/d) of energy from all sources.
- Upgraded and nonupgraded bitumen production accounted for 52 per cent of total primary energy production in 2021. This percentage is expected to grow over the forecast period, reaching about 56 per cent by 2031.
- In 2021, based on energy content, natural gas liquids production was about 46 per cent higher than crude oil production. Production of natural gas liquids is expected to continue to be greater than production of crude oil over the forecast period.
- As ethane production decreased by 6 per cent, total natural gas liquids production increased by 2 per cent in 2021, driven by an increase in propane, butane, and pentanes plus 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**

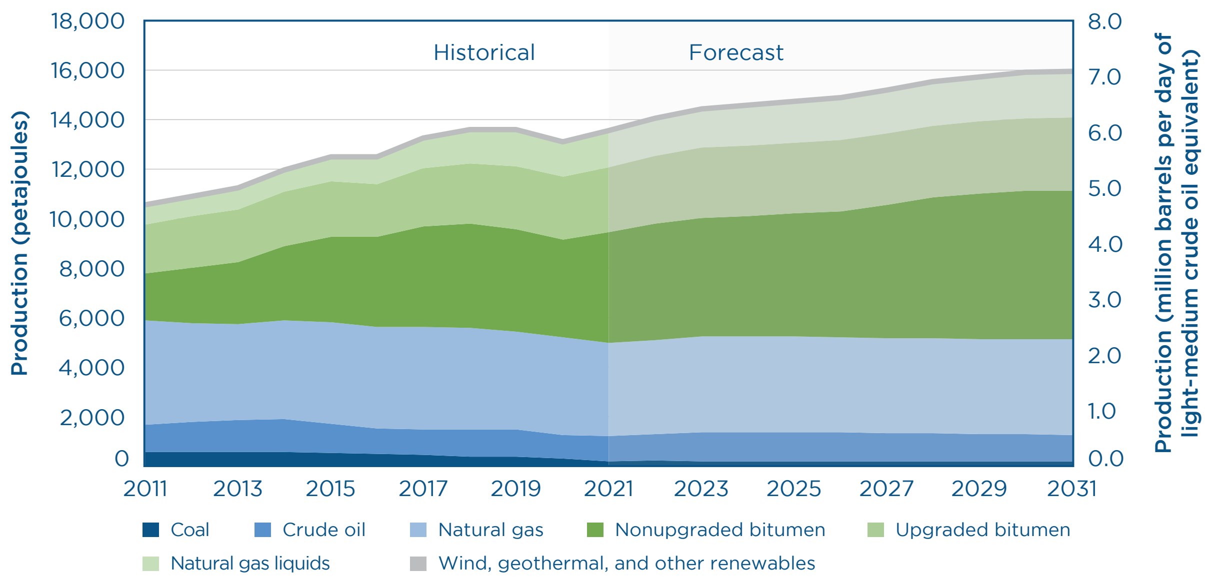



**Figure 8 Alberta supply of crude oil and equivalent**

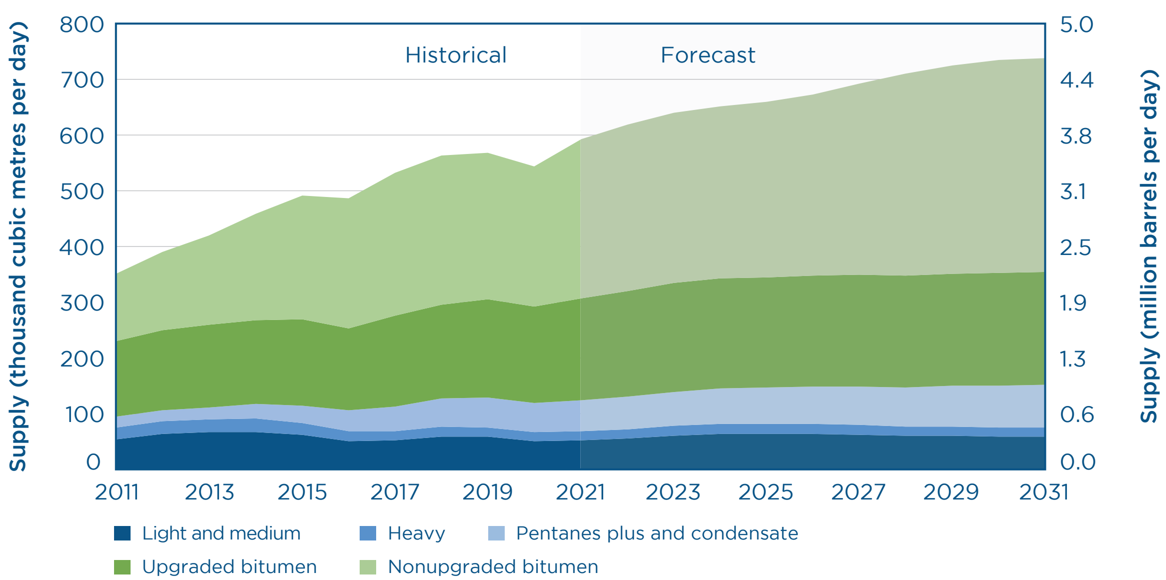


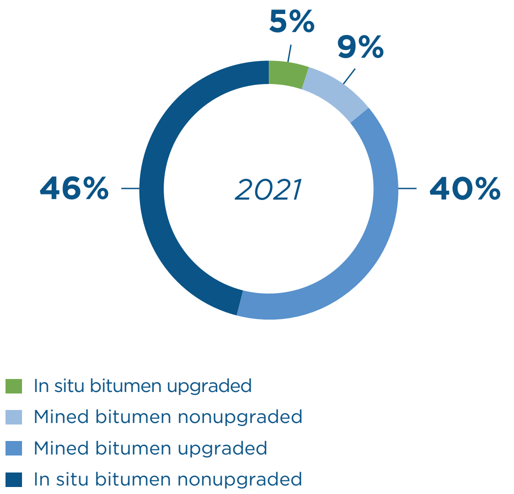
Figure 8 shows the Alberta supply of crude oil and equivalent.

- Alberta's production of crude oil and equivalent increased by 8 per cent in 2021, reaching 3.7 $10^6$ bbl/d. The increase is largely attributed to the increase in the supply of upgraded and nonupgraded bitumen and crude oil.
- Production of crude oil and equivalent is expected to grow throughout the forecast period, reaching 4.7 $10^6$ bbl/d by 2031, driven primarily by growth in upgraded and nonupgraded bitumen production.
- Crude oil production increased in 2021 to 0.4 $10^6$ bbl/d. As prices gradually improve throughout the forecast, production is projected to grow by 2025 and then gradually decline by 2031 as the number of new wells placed on production do not offset the decline in existing production.
- Pentanes plus production is forecast to grow from 0.4 $10^6$ bbl/d in 2021 to 0.5 106 bbl/d by 2031.

Figure 9 shows the percentage of bitumen upgraded in Alberta.

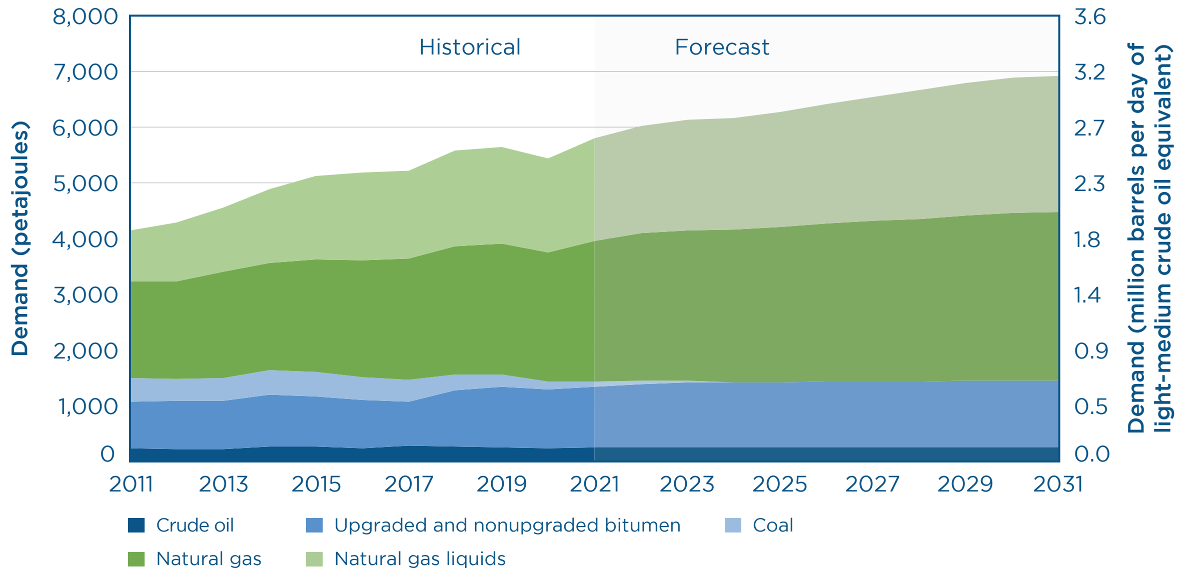
- In 2021, an estimated 45 per cent of produced raw bitumen was sent for upgrading in Alberta. By 2031, only about 35 per cent of raw bitumen is projected

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




***Total mined: 253.0 $10^3$ $m^3$/d.***
***Total in situ: 264.6 $10^3$ $m^3$/d.***

**Figure 10 Primary energy demand in Alberta**




to be upgraded in Alberta as the growth in raw bitumen production is expected to outpace upgrading capacity additions.

- Upgraded bitumen output for 2021 was up 4 per cent. Production was up across most upgrading facilities, except at the CNRL Horizon mine site.

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

- Total primary energy demand within the province increased by 7 per cent to 5828 PJ (2.6 $10^6$ BOE/d) in 2021. Alberta demand is projected to increase to about 6950 PJ (3.1 $10^6$ BOE/d) by 2031. The largest increase is attributed to strengthening demand for pentanes plus as a diluent in bitumen blending. Increasing demand for natural gas will come from power generation (including coal-to-gas switching and cogeneration) and increasing production of bitumen. Alberta demand for bitumen is also forecast to increase with a recovery in overall energy demand and increased intake at the Sturgeon refinery.
- Federal and provincial government policies targeting a reduction in carbon dioxide emissions will drive the demand for coal in Alberta to zero as existing coal-fired power plants are phased out by 2023.

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

- Primary energy removals from Alberta increased by 4 per cent in 2021. Higher production output brought on by high oil prices resulted in the increase of crude oil and bitumen removals.
- Total primary energy removals from the province in 2021 were estimated at 9784 PJ (4.4 $10^6$ BOE/d), with oil (bitumen and crude oil) and natural gas liquids representing about 86 per cent of primary energy removals for the year.
- Removals from the province are projected to reach 11 772 PJ (5.3 $10^6$ BOE/d) by 2031, with bitumen representing a growing share of primary energy removals.
- Natural gas removals from Alberta are projected to decrease over the forecast period as domestic demand is expected to grow over the same period while production remains relatively flat.
- Removals of marketable bituminous coal from Alberta decreased by 22 per cent in 2021. Several mines suspended operations partway through 2020 and into 2021 due to operational constraints related to the pandemic combined with weakened global demand for coal. However, these mines came back online in the latter half of 2021 as demand rebounded and prices rose.

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

- In 2021, removals of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were an estimated 559.2 thousand cubic metres per day ($10^3$ $m^3$/d) or 3.5 $10^6$ bbl/d. This is about 10 per cent higher than in 2020.
- By 2031, about 718.5 $10^3$ $m^3$/d (4.5 $10^6$ bbl/d) of 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 (pipeline and rail) to ship these volumes.

**Figure 11 Primary energy removals from Alberta**

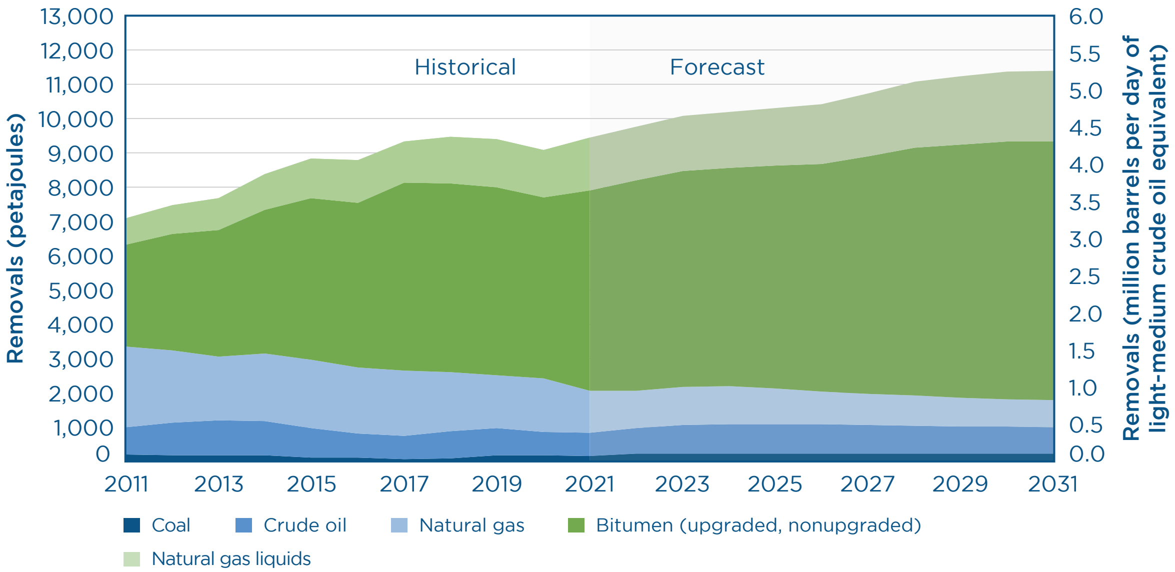



**Figure 12 Total oil removals from Alberta**

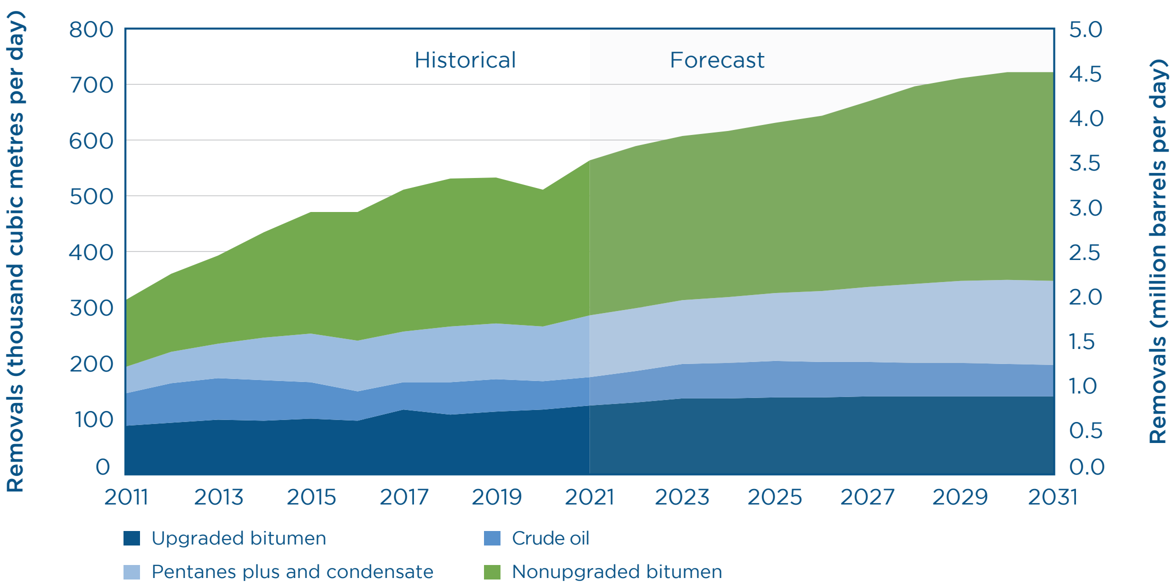
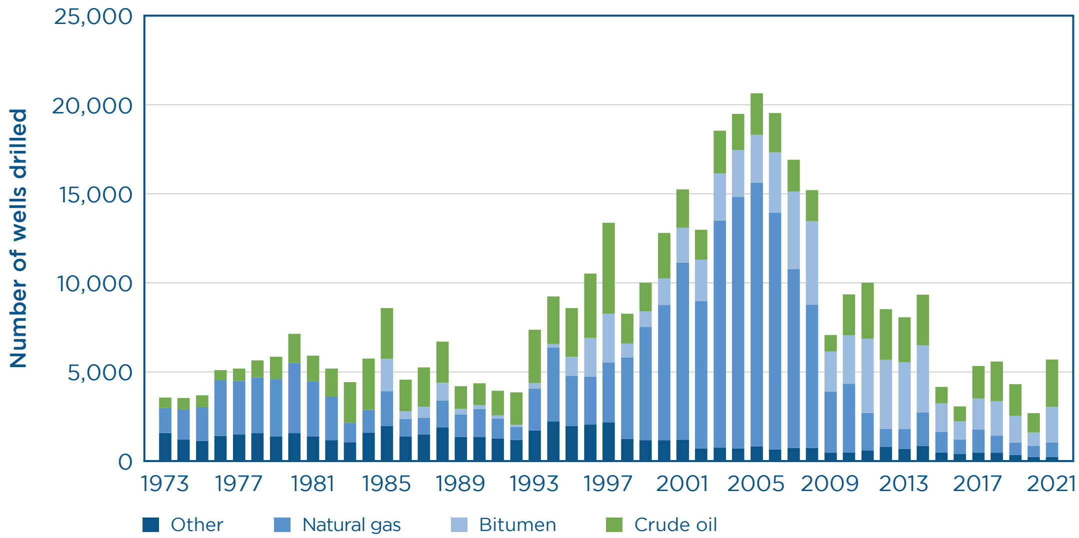


Figure 13 Historical drilling activity in Alberta




## DRILLING ACTIVITY

Figure 13 shows that total drilling increased by 121 per cent in 2021 (natural gas drilling increased by 36 per cent, crude oil drilling increased by 147 per cent, and oil sands drilling increased by 179 per cent). This increase is attributed to the rise in energy prices; as COVID-19 restrictions were lifted, economic activity surged and increased the demand for refined products. Last year's drilling activity was the highest over the past six years.

**ALBERTA ENERGY REGULATOR**

Head Office
Suite 1000, 250 – 5 Street SW
Calgary, Alberta T2P 0R4

inquiries
1-855-297-8311
inquiries@aer.ca

24-hour emergency
1-800-222-6514

www.aer.ca

@aer_news

resource.aer.ca

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