ST98-2016

ALBERTA'S ENERGY RESERVES 2015 & SUPPLY/DEMAND OUTLOOK 2016–2025

Executive Summary

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, one of the AER's key services is to provide credible information about Alberta's energy resources that can be used for good decision making. To this end, the AER issues a report every year that gives stakeholders independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal.

This year, the AER is publishing this information and analysis in a new way. Content is now more interactive, appearing in a user-friendly web-based format to improve accessibility and to allow for a quicker release of the report information. The information will still be accessed in the same location on the AER website as previous reports. Although this year's report will look and feel different, all the key information and analysis remains, including estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left after production), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). The 10-year supply and demand forecasts for Alberta's energy resources from 2016 to 2025 and the historical trends on energy commodities are also available. This executive summary covers the highlights and key commodities, while the remaining commodities and additional details can be accessed on the AER website.

[1] 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).

Report Highlights

- Alberta has been and remains the largest producer of natural gas and oil in Canada. In 2015, Alberta produced 68 per cent of Canada's natural gas and 80 per cent of Canada's oil and equivalent. More than 60 per cent of Canada's total oil and equivalent production[1] was marketable bitumen.
- The dramatic collapse of crude oil prices in 2015 was a result of significant global production growth and slowing global demand for crude oil. West Texas Intermediate (WTI) light sweet crude oil—the benchmark for North American crude oil price—decreased by almost 50 per cent from US$92.91 per barrel (bbl) in 2014 to US$48.79/bbl in 2015.
- Despite the significant weakness in crude oil prices, marketable bitumen production in Alberta rose in 2015 and is projected to continue to increase over the next 10 years, reaching 3.8 million barrels of marketable bitumen per day by 2025.
- Natural gas prices throughout North America remain low, as the market remains oversupplied due to growing shale gas production in the United States. Alberta natural gas prices are particularly vulnerable due to the loss of traditional export markets, particularly in central Canada.

- Conventional natural gas production in Alberta increased slightly in 2015 despite low prices, and all of the additional gas produced was consumed in Alberta. Production increased due to the increased drilling levels in 2014, which was driven by drilling using hydraulic multistage fracturing completion technology targeting liquids-rich plays.
- The production outlook calls for a decline in natural gas production over the forecast period, because production from new drilling is not forecast to offset production declines. Meaningful development of Alberta's shale gas resources is not anticipated until significant natural gas demand materializes and raises natural gas prices.
- Capital expenditures in conventional oil and natural gas development, as well as in oil sands development, dropped from Cdn$60.5 billion in 2014 to Cdn$37.3 billion in 2015, down 38 per cent.[2]
- Capital expenditures are forecast to remain weak until 2018, based on the commodity price projections. After 2018, capital expenditures are forecast to recover, while becoming balanced between the conventional oil and gas and the oil sands subsectors.

Report Overview

Alberta's upstream oil and gas industry relies heavily on export markets, primarily the United States, because commodity production from the province far exceeds domestic demand requirements. Commodity prices are set in markets outside of Alberta, primarily in the United States, and with the low price environment for commodities in 2015, operators were focused on cost-cutting measures, such as project deferrals or cancellations, service cost reductions, employee layoffs, dividend reductions, and consolidations. The same is anticipated for 2016. Over time, though, technology improvements to successfully reduce costs will result in an even more efficient sector capable of competing with lower-cost basins. In the oil sands sector, projects that had committed capital before the price collapse continue to move forward, resulting in an increase in production from this subsector in 2015. Bitumen production is projected to increase over the forecast period, albeit at a slower pace than previously forecast due to project deferrals and cancellations. Conventional crude oil and natural gas production is projected to continue to decline due to the maturity of the basin. Alberta's shale oil and natural gas resources are not projected to be developed in a meaningful way until new sources of demand and resultant stronger prices are realized.

In 2015, the Government of Alberta (GoA) and the Government of Canada announced new policies that aim to reduce the carbon intensity of the energy industry. The GoA also introduced changes to Alberta's hydrocarbon royalties and is focused on enhancing economic diversification. Where information is available, the forecasts incorporate these policy changes. As the policies proceed and further information becomes available, more details will be added to the forecast.

[2] Historical statistics obtained from Canadian Association of Petroleum Producers' Statistical Handbook (2015 data). Capital expenditures for 2015 are estimates.

Reserves

Table 1 Resources, reserves, and production summary, 2015[a]

	Crude bitumen		Crude oil		Natural gas[b]		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	13 171	82.9	9 880	351	94	103
Initial established reserves	28 092	177	3 032.9	19.1	5 654	201	34.8	38.4
Cumulative production	1 808	11.4	2 752.1	17.3	4 772	169	1.63	1.8
Remaining established reserves	**26 284**	**165**	**280.7**	**1.8**	**882**[c]	**31.3**[c]	**33.2**	**36.6**
Annual production	146.6	0.923	30.6	0.193	109.0[d]	3.9[d]	0.027[e]	0.030[e]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[f]	223[f]	620	683

[a] Columns may not add up to rounding.

[b] Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.

[c] Measured at field gate.

[d] Includes unconventional natural gas.

[e] Annual production is marketable.

[f] Does not include unconventional natural gas.

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 under development are being optimized. The information is used to develop policies, for regional land use planning, and by the energy industry to help evaluate investment opportunities in Alberta.

Reserves are determined for crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal, as illustrated in Table 1. Until now, the AER used a reserves reporting system called IPACE (Inter-Provincial Advisory Committee on Energy) for uniform terminology and definitions in estimating and publishing hy-drocarbon reserves information in Canada. IPACE was adopted in Canada in 1978 to provide consistency between provincial regulators, and the system is still in use for this report. However, IPACE focuses on conventional reservoirs and does not fully account for the complexities of unconventional plays. Unconventional plays are more complex and uncertain, and probabilistic methods that produce a range of values within a reasonable level of certainty are more appropriate.

In 2015, the AER created a differentiated resource classification system to capture the increased production from low-permeability and shale resources. The resource classification system accounts for both conventional and unconventional resources. The system categorizes unique resource types by trapping mechanism, giving the AER the flexibility to tailor its reserves evaluation, classification, and reporting procedures according to the unique properties of individual resource types. Six different resource categories are identified within the system: conventional, low-permeability, shale, coalbed methane, bitumen, and coal. Each resource category has a unique set of properties and requirements for characterizing the resource and evaluating its reserves.

The system's criteria are also being used to assign a resource type to the geological plays defined in Alberta. The AER is using probabilistic methods to help capture the uncertainty of unconventional reserves. For the past few years, the AER has been delineating subsurface plays based on geological attributes; there are currently over 160 plays identified. The delineations are flexible and evolving, and they might change as more information becomes available

Oil & Gas Prices

Figure 1 Price of WTI

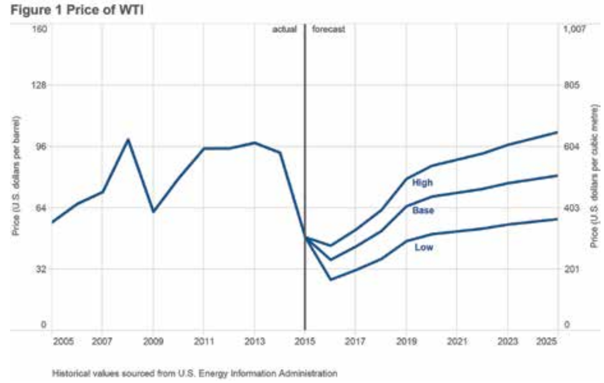
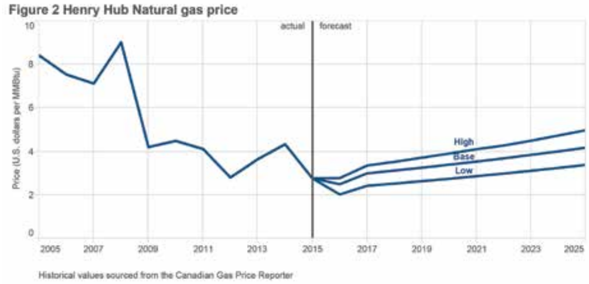


Figure 2 Henry Hub Natural gas price



.Crude Oil Prices

- The price for WTI averaged US$48.79/bbl in 2015, down 47.5 per cent from 2014.[3]

[3] This report uses New York Mercantile Exchange (NYMEX) WTI near-month futures prices. WCS prices are averaged from the Natural Gas Exchange (NGX) index, Argus, NYMEX, and Flint.

- The price for Western Canadian Select (WCS)—Alberta's heavy crude oil and bitumen index—averaged US$35.27/bbl in 2015, down 50.9 per cent from 2014. In 2015, WCS traded at US$13.52/bbl below the price of WTI.
- The AER Base forecast of WTI is US$37.00/bbl in 2016.
- In 2025, WTI and WCS prices are projected to reach US$81.00/bbl and US$60.75/bbl respectively.

WTI prices were stronger in the first half of 2015, when there was optimism that the Organization of Petroleum Exporting Countries (OPEC) would cut production to manage the market and that non-OPEC producers would respond more quickly and strongly to the low prices by curtailing their production. However, neither of these events occurred. As the oil oversupply compounded and the U.S. dollar gained value in the second half of 2015, oil prices fell to levels not seen since 2003.

The AER assumes that WTI prices will continue to be volatile in the short term. This is due to an oversupplied global market, historically high storage levels of crude oil, weak global oil demand, and OPEC's strategy for defending its market share by not cutting production. In addition, U.S. production, thought to be more sensitive to lower prices, seems less responsive than expected. The price of WTI is projected to recover after 2016 because the reduction in capital investment over the past two years will lessen supply. Global oil production, in addition to satisfying the growing demand, requires new production to offset declines in existing legacy wells. Global demand is projected to increase by 1.2 million barrels per day in 2016, and when combined with lower capital investment, the global crude oil market is projected to move toward a more balanced supply and demand situation after 2016.

[4] This report uses the NYMEX Henry Hub average close (spot month) price and the NGX Alberta Market Price.

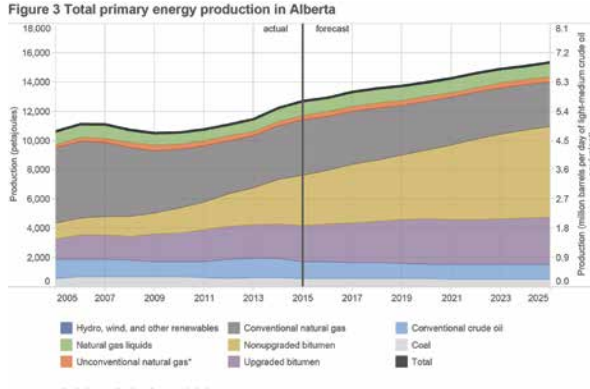
Natural Gas Prices

- The U.S. natural gas price at Henry Hub[4] averaged US$2.77/million British thermal units (MMBtu) in 2015, down 36.2 per cent from 2014.
- The Natural Gas Exchange (NGX) Alberta Market Price (AMP) in 2015 was Cdn$2.66 per gigajoule (GJ), compared with Cdn$4.23/GJ in 2014—a 37.1 per cent decrease. AMP traded at Cdn$0.71/GJ below the price of Henry Hub in 2015.
- The AER base case projects the Henry Hub price to average US$2.50/MMBtu in 2016 and the AMP price to average Cdn$2.64/GJ.
- In the near term, prices are projected to remain weak due to increasing gas supply in North America. Longer term, a combination of liquefied natural gas exports and increased domestic demand is expected to strengthen natural gas prices, with AMP and Henry Hub prices forecast at Cdn$4.29/GJ and US$4.18/MMBtu respectively in 2025.

Production & Demand

Energy Production

Figure 3 Total primary energy production in Alberta



- In 2015, Alberta produced more total primary energy than ever before, despite low energy prices.
- Alberta produced 12 710 petajoules of energy from all sources, including renewable sources, in 2015.

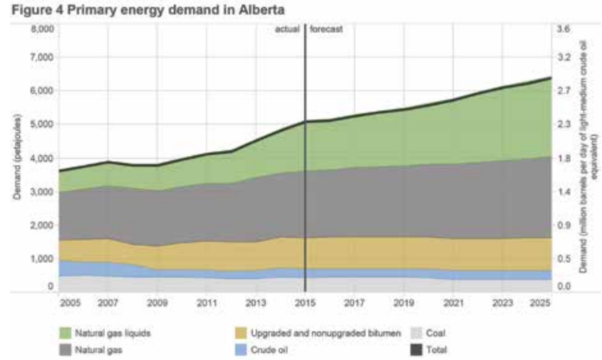
This is equivalent to about 5.69 million barrels per day of conventional light-medium quality crude oil, a 3.9 per cent increase over 2014.
- In 2025, Alberta is projected to produce 15 356 petajoules of energy from all sources, which is equivalent to over 6.88 million barrels per day of conventional light-medium crude oil.

Bitumen production accounted for 83 per cent of Alberta's total oil production in 2015. As projects were completed and started producing in 2015, production increased by 11.9 per cent at mining projects and by 7.8 per cent at in situ projects. This resulted in an overall raw bitumen production increase of 9.6 per cent over 2014. In 2015, on the basis of energy content (petajoules)[5], conventional crude oil production was impacted by low prices, and decreased by about 10.6 per cent. Total marketable natural gas production in Alberta increased by 2.2 per cent, as a result of the lag effect of increased drilling in 2014. Total natural gas liquids (NGLs)[6] production increased by 7.0 per cent because production focused on liquids-rich development. Total coal production decreased by 9.8 per cent, due to suspended operations in several coal mines. While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

Energy Demand—Alberta

- In 2015, Alberta demand for all fossil-based energy commodities increased by 5.4 per cent relative to 2014.
- Total primary energy consumption within the province in 2015 was 5111 petajoules, equivalent to 2.29 million barrels per day of crude oil. This amount is projected to increase to about 6425 petajoules, or 2.88 million barrels per day, by 2025.
- Demand for natural gas and pentanes plus is anticipated to increase throughout the forecast period in conjunction with the projected increase in crude bitumen production.
- Natural gas demand is also expected to increase throughout the forecast period, supported by the switch from coal to natural gas as a fuel for the province's electricity generation sector as a result of the GoA's Climate Leadership Plan and pre-existing federal regulations.

Figure 4 Primary energy demand in Alberta



Energy Demand—Removals

- In 2015, primary energy removals were at a historical high, despite low energy prices and a lack of diversified markets.
- Total primary energy removals from the province are projected to reach 10 390 petajoules in 2025, equivalent to 4.65 million barrels per day of crude oil, up from 8328 petajoules, or 3.73 million barrels per day, in 2015, with upgraded and nonupgraded bitumen contributing to the majority of removals. This projection assumes that the majority of upgraded

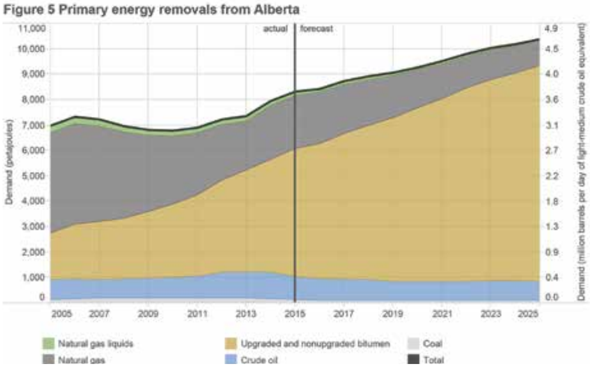
[5] The trends and growth rates may differ slightly when standard units of measure, such as cubic metres or tonnes, are compared. Various grades of energy commodities have different heating values and any changes to their composition may yield slightly different numerical trends and growth rates..

[6] Natural gas liquids refers to ethane, propane, butanes, and pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

and nonupgraded bitumen removals will go to the United States and that the transportation options (pipeline and rail) will be sufficient to ship these volumes.

- Natural gas removals from Alberta are projected to decrease over the forecast period, assuming that production will decline and Alberta will continue to lose market share to U.S. shale gas production in the eastern United States and central Canada.

Figure 5 Primary energy removals from Alberta

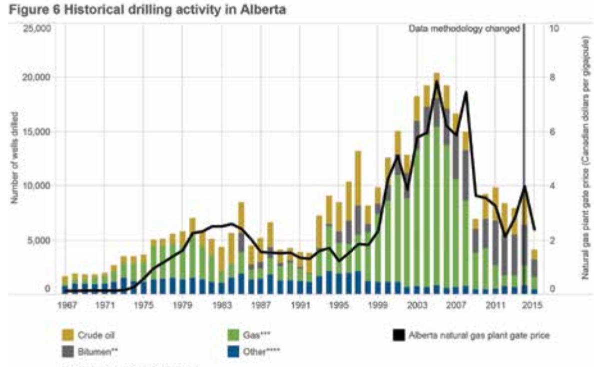


Drilling Activity

- Weak oil and natural gas prices in 2015 resulted in total drilling dropping by 55.6 per cent. More than 60 per cent of the drilling activity was related to crude oil and bitumen operations.
- Conventional oil and gas drilling activity is sensitive to oil and gas price fluctuations. Bitumen projects, though, are long-term investments, which makes well activity in the oil sands less vulnerable to near-term price fluctuations.

Over the forecast period, conventional oil and gas drilling levels are not forecast to return to the peak levels observed from 2004 to 2006, primarily because of the changing nature of drilling. Historically, drilling was focused on vertical wells producing from conventional reservoirs, which are characterized by lower initial productivity rates which need more wells to maintain and grow production. Horizontal drilling using multistage hydraulic fracturing completion technology has become the predominant method of extraction in Alberta, and this type of drilling is characterized by much higher initial productivity rates, with fewer wells needed to achieve similar production levels.

Figure 6 Historical drilling activity in Alberta



Capital Expenditures

- As capital spending cuts and project delays were announced, capital expenditures in the conventional

Economic Assumptions

The forecasts are based on various assumptions about economic indicators. The key assumptions are listed here:

Table 2 Major Alberta economic indicators, 2015-2025

	2015[a]	2016	2017	2018-2025[b]
Real gross domestic product (GDP) growth (%)	-1.60	-0.30	1.50	3.00
Inflation rate (%)	1.20	1.50	1.60	2.00
Exchange rate (US$/Cdn$)	0.78	0.70	0.72	0.79

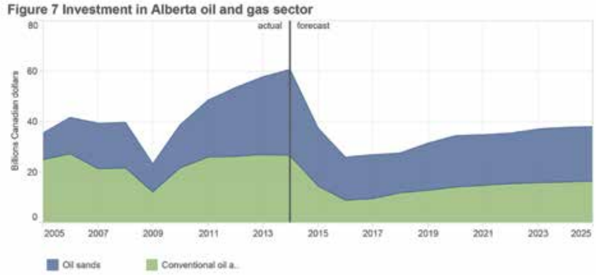
[a] Values from the Bank of Canada and Statistics Canada.

[b] Average over 2018-2025.

oil and gas and oil sands subsectors plummeted 38.4 per cent between 2014 and 2015, corresponding to the commodity price decline over the same period.

- Capital expenditures in both subsectors are projected to be impacted by the continued weak price forecast for 2016. A 30.3 per cent decline in investment between 2015 and 2016 is projected, with total capital expenditures reaching Cdn$26 billion in 2016.
- Oil sands capital expenditures are forecast to decrease from Cdn$23 billion in 2015 to Cdn$17 billion in 2016.

Figure 7 Investment in Alberta oil and gas sector



Historical values sourced from the Canadian Association of Petroleum Producers.

- Capital expenditures in conventional oil and gas are projected to decrease from Cdn$14.3 billion in 2015 to Cdn$9 billion in 2016.
- Investment is forecast to recover slowly after 2018 in conjunction with the projected strengthening of commodity prices. There is a positive correlation between capital expenditure investment decisions and commodity prices, although the recovery of capital expenditures lags behind price changes.

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

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