ERCB Energy Resources Conservation Board

ST98-2012

Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021

ACKNOWLEDGEMENTS

The following ERCB staff contributed to this report:

Principal Authors:

Reserves—Michael Teare, Andy Burrowes, Cathy Baturin-Pollock, Dean Rokosh, Curtis Evans, Patricia Gigantelli, and Rick Marsh;

Supply/Demand and Economics—Banafsheh Ashrafi, Charles Tamblyn, Shimpei Ito, Andrea Willwerth, Mussie Yemane, Joseph Fong, Marie-Anne Kirsch, and Carol Crowfoot;

Editors: Carol Crowfoot, Rick Marsh, Kevin Parks, and Fran Hein;

Data: Debbie Giles, Judy Van Horne, Glen Tsui, and Afshan Mahmood;

Production: Jennifer Wagner, Nicole Dunn, Aaron Dalton, Sarah Hamza, Karen Logan, Robert de Grace, and Jessica Riches;

Communications Advisor: Darin Barter

Coordinator: Rick Marsh

For inquiries regarding reserves, contact Rick Marsh at 403-297-8218 or Andy Burrowes at 403-297-8566.
For inquiries regarding supply/demand, contact Marie-Anne Kirsch at 403-297-8476.

ENERGY RESOURCES CONSERVATION BOARD
ST98-2012: Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021

ISSN 1910-4235

June 2012

The following related documents are also available from ERCB Information Services
(telephone: 403-297-8311; when connected, press 2):

- CD with detailed data tables for crude oil and natural gas, as well as map of Designated Fields, Oil Sands Areas, and Development Entities, $546
- CD with Gas Reserves Code Conversion File, $459
- CD with Gas Pool Reserve File (ASCII format), $3095
- CD with Oil Pool Reserves File (ASCII format), $1834
- Map of Designated Fields, Oil Sands Areas, and Development Entities: 60 x 101 cm, $61; 33 x 54 cm, $29

Published by
Energy Resources Conservation Board
Suite 1000, 250 – 5 Street SW
Calgary, Alberta
T2P 0R4

Toll-free: 1-855-297-8311
Fax: 403-297-7040
Website: www.ercb.ca

Contents

Table of Tables

OVERVIEW

ECONOMICS

CRUDE BITUMEN

CRUDE OIL

NATURAL GAS

NATURAL GAS LIQUIDS

SULPHUR

COAL

ELECTRICITY

APPENDIX B

APPENDIX D

Table of Figures

OVERVIEW

ECONOMICS

RESOURCE ENDOWMENT

CRUDE BITUMEN

CRUDE OIL

NATURAL GAS

NATURAL GAS LIQUIDS

SULPHUR

COAL

ELECTRICITY

APPENDIX E

HIGHLIGHTS

In 2011, conventional crude oil remaining established reserves increased by 4 per cent and production increased by 7 per cent.

OVERVIEW

The Energy Resources Conservation Board (ERCB) is a quasi-judicial regulatory agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources take place in a manner that is fair, responsible, and in the public interest. As part of its legislated mandate, the ERCB provides for the appraisal of the reserves and their productive capacity and the requirements for energy resources and energy in Alberta. The ERCB continues to offer a perspective on supply and demand for Alberta's electricity sector in conjunction with the Alberta Utilities Commission, which regulates this sector.

Providing information to support good decision-making is a key service of the ERCB. Making energy resource data available to everyone involved—the ERCB, landowners, communities, industry, government, and interested groups—results in better decisions that affect the development of Alberta's resources.

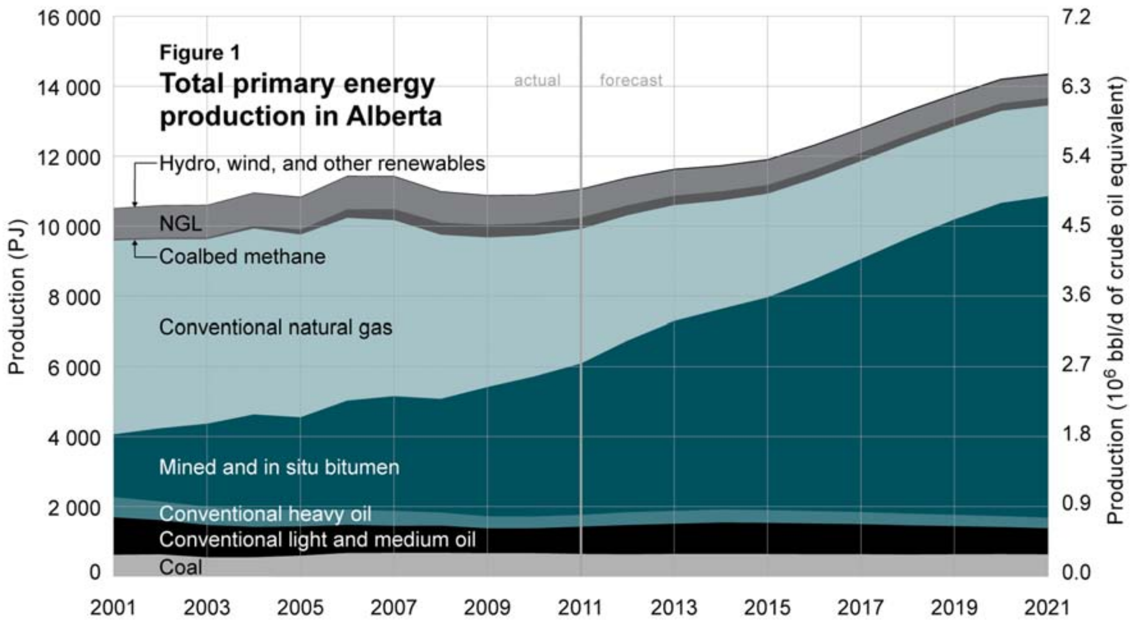
Every year the ERCB issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources—crude bitumen, crude oil, natural gas, natural gas liquids, coal, and sulphur. This year's *Alberta Energy Reserves 2011 and Supply/Demand Outlook 2012–2021* includes 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), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources, and it provides some historical trends on selected commodities for better understanding of supply and price relationships.

In 2011, Alberta produced 11 064 petajoules of energy from all sources, including renewable sources. This is equivalent to more than 4.9 million barrels per day of conventional light- and medium-quality crude oil. In 2021, Alberta is projected to have produced 14 329 petajoules of energy from all sources, which is equivalent to over 6.4 million barrels per day of conventional light- medium-quality crude oil. A breakdown of production by these energy sources is illustrated in **Figure 1**.

Summary of Energy Reserves, Production, and Demand in Alberta

Reserves

Reserves are the recoverable quantities of energy resource commodities that are known with reasonable certainty. In-place resources are the larger quantities existing in the ground from which a portion has been, or may be, recovered as reserves. The ERCB



also estimates a quantity (the ultimate potential) from discovered and undiscovered in-place resources that may be ultimately recovered when all future resource extraction activities have ceased within Alberta. The ERCB's current reserves and resource classification system is discussed in **Section 2.3**.

The following table summarizes Alberta's energy reserves, resources, and production at the end of 2011.

Reserves, resources, and production summary, 2011

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 844	11 357	71.5	9 504	337	94	103
Initial established reserves	28 092	177	2 863	18.0	5 384	191	35	38
Cumulative production	1 294	8.1	2 617	16.5	4 377	155	1.49	1.64
Remaining established reserves	**26 798**	**169**	**246**	**1.5**	**1 007**[b]	**35.7**[b]	**33**	**37**
Annual production	101	0.637	28.4	0.179	111	3.9	0.030[d]	0.033[d]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Expressed as "as is" gas, except for annual production, which is at 37.4 megajoules per cubic metre; includes coalbed methane natural gas.
[b] Measured at field gate (or 34.7 trillion cubic feet downstream of straddle plant).
[c] Does not include unconventional natural gas.
[d] Annual production is marketable.

Production

Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to produce bitumen. Bitumen production accounted for 78 per cent of Alberta's total crude oil and raw bitumen production in 2011. Bitumen production increased by 4 per cent at mining projects and by

13 per cent at in situ projects in 2011, resulting in an overall raw bitumen production increase of 8 per cent relative to 2010.

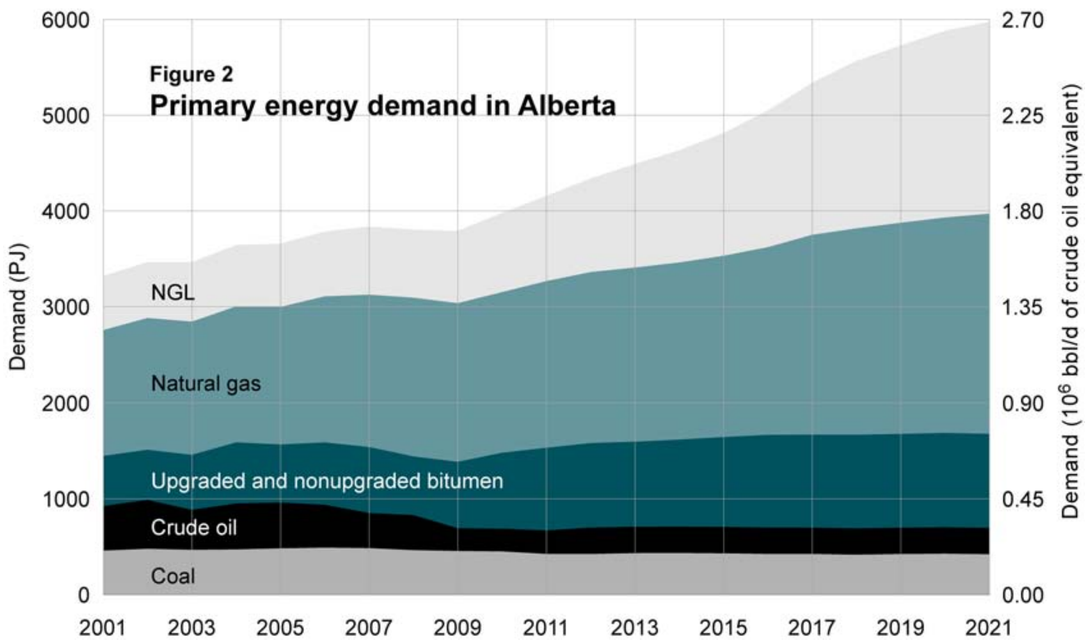
In 2011, crude oil production increased by 7 per cent, total marketable natural gas production in Alberta declined by 4.6 per cent, total natural gas liquids (NGLs) production remained flat, and sulphur production declined by 5 per cent. Coal production declined by 5 per cent.

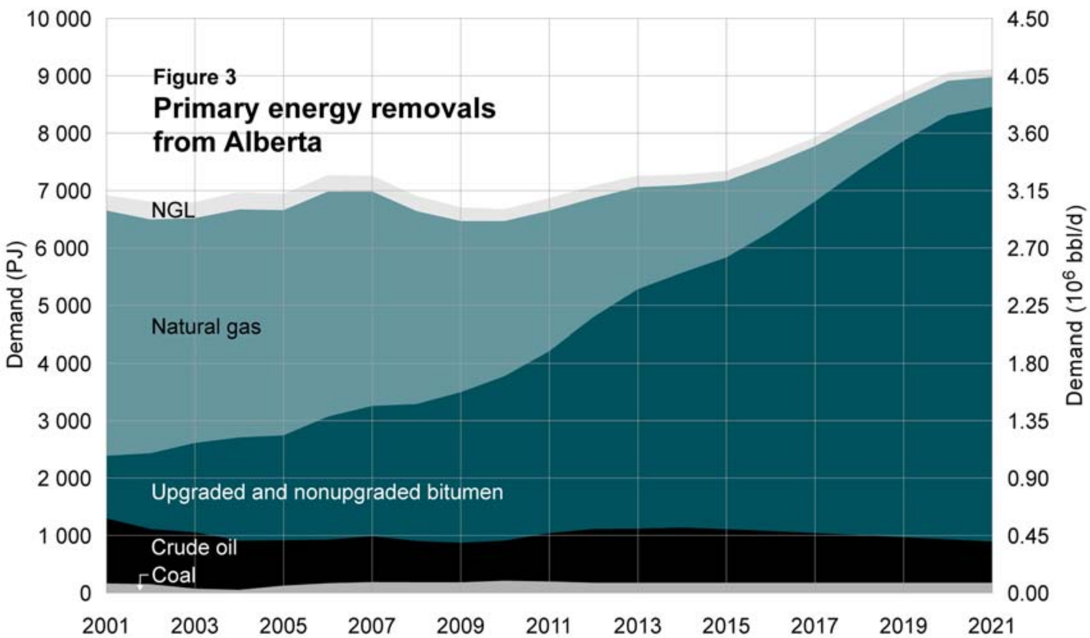
While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 2**. In 2011, demand for coal was lower relative to 2010 demand, while 2011 demand for conventional crude oil, natural gas, and upgraded and nonupgraded bitumen increased relative to 2010 demand. Total primary energy consumption in 2011 was 4 160 petajoules, equivalent to about 1.9 million barrels per day of crude oil. This amount is projected to increase to 5 977 petajoules, or 2.7 million barrels per day, by 2021.

The primary energy removals from Alberta are shown in **Figure 3**. Most shipments are to the United States. Total primary energy removals from the province are expected to reach 9 115 petajoules in 2021, equivalent to 4.0 million barrels per day of crude oil, up from 6 864 petajoules, or 3.1 million barrels per day, in 2011.





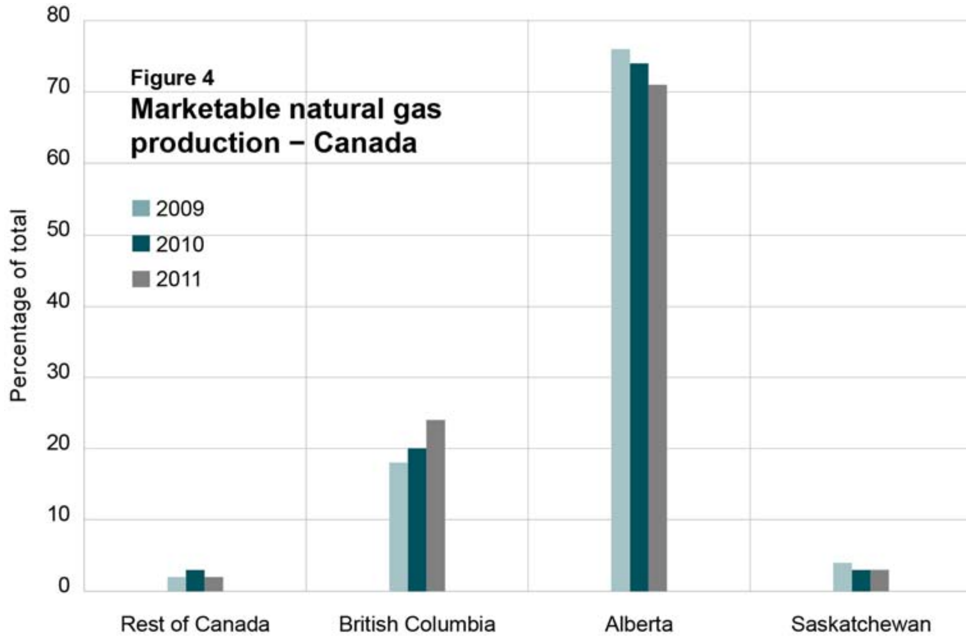
Alberta Hydrocarbon Production in the Canadian Perspective

Alberta is Canada's largest producer of marketable natural gas. In 2011, Alberta produced 71 per cent of Canada's total production, down from 74 per cent in 2010. Over the same period, Canada's second largest contributor, British Columbia (B.C.), increased its share from 20 per cent to 24 per cent. **Figure 4** shows the contribution percentage breakdown by region in Canada for 2009, 2010, and 2011.

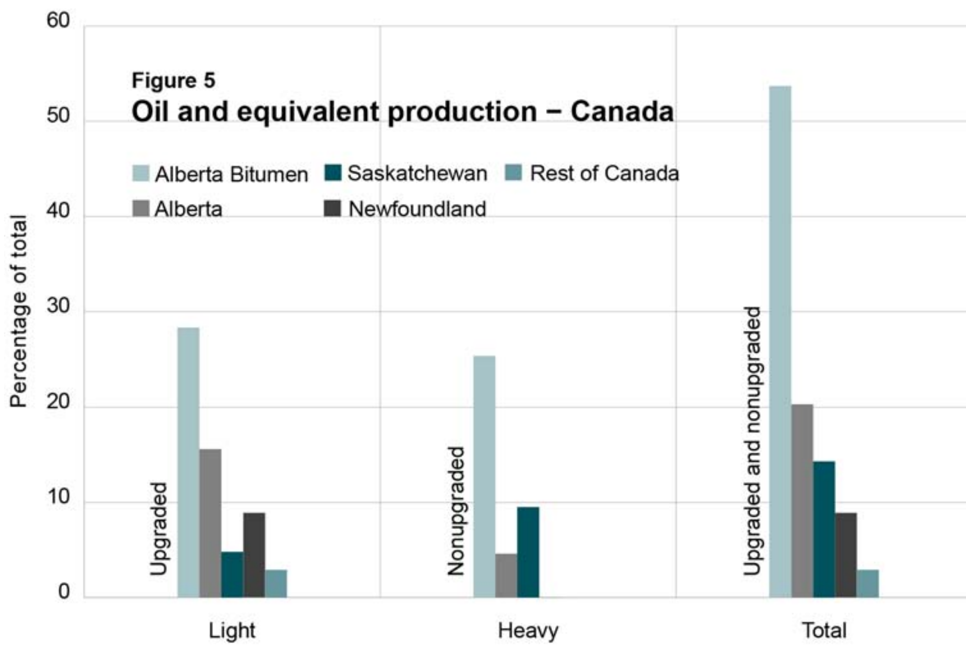
Alberta is also the largest contributor to Canadian oil and equivalent production and is the only contributor of upgraded[1] and nonupgraded bitumen, which are the marketed components of raw bitumen production. **Figure 5** illustrates the contribution percentage breakdown by category and region in Canada for 2011.

Only two provinces, Alberta and Saskatchewan, contribute to conventional heavy crude oil production in Canada. In 2011, Alberta accounted for nearly three-quarters of Canada's oil and equivalent production, with marketed bitumen being more than 50 per cent of the total.

[1] Beginning with this report, the ERCB is replacing the term "synthetic crude oil" with the term "upgraded bitumen." The ERCB believes that upgraded bitumen more fully denotes the different types of products generated in the various kinds of upgrading facilities within Alberta.



Source: National Energy Board.



Source: National Energy Board.

Oil and Gas Prices and Alberta's Economy

Crude Oil Prices—2011

Crude oil prices strengthened at the beginning of the year in response to political unrest in the Middle East and North Africa starting in late 2010. In February 2011, civil war in Libya resulted in a loss of 1.5 million barrel per day of exports. Supplies were constrained as a result of these events, and prices continued to increase. Prices remained elevated into 2012 as a result of several supply interruptions and production declines in Libya, South Sudan, Syria, Yemen, and the North Sea. Unusually cold weather in Europe in early 2012 increased demand for heating oil. The United States and Europe also tightened sanctions against Iran, and Iran threatened to close the Strait of Hormuz, an important export route for Middle Eastern crude. Although shipping continues, the market has placed a risk premium on crude oil prices due to the threat and uncertainty regarding supply from this region.

The monthly Organization of Petroleum Exporting Countries (OPEC) reference price averaged US$92.83 per barrel in January 2011, reached a high of US$118.09 per barrel in April 2011, and then moderated to range between US$111.62 per barrel and US$106.29 per barrel between May and December 2011, with a yearly average of US$107.43 per barrel. The West Texas Intermediate (WTI) price averaged US$95.11 per barrel in 2011 and reached a yearly high of US$110.04 per barrel in April and a low of US$85.61 per barrel in September. Prices are expected to remain high through 2012.

In 2011, differentials between the OPEC basket and WTI ranged from US$3.25 per barrel to US$22.00 per barrel and averaged US$12.31 per barrel. This discount reflects the land-locked nature of WTI, significant increases in North American supplies, and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast. Other methods of transportation used to transport crude are generally more costly and include rail, truck, and barge.

Crude Oil Prices—Forecast

The ERCB bases its analysis on the expectation that the crude oil price in North America, measured by WTI crude oil, will continue to be volatile. The ERCB projects WTI to average US$102.00 per barrel in 2012 with a range from US$92.00 per barrel to US$112.00 per barrel. The forecast price of WTI is expected to increase throughout the forecast period as increasing crude oil demand exerts upward pressure on supplies and price. By 2021, WTI prices are projected to be US$113.00 per barrel with a range from US$105.00 per barrel to US$121.00 per barrel.

Natural Gas Prices—2011

While North American crude oil prices historically have closely tracked international prices, natural gas prices in North America are reflective of domestic supply and demand with little global gas market influence aside from the impact of liquefied natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price. The most significant recent change in the market has been the increase in U.S. natural gas supply from shale gas, which has become economic due to horizontal drilling and multistage fracturing technology. Natural gas producers in North America have been, and are expected to continue to be, challenged by a weak price environment.

The average Alberta reference price of natural gas price in 2011 was Cdn$3.28 per gigajoule, compared with Cdn$3.57 per gigajoule in 2010—an 8.1 per cent decrease. The monthly Alberta reference price for natural gas was highest in June at Cdn$3.51 per gigajoule and lowest in December at Cdn$2.92 per gigajoule. In 2011, U.S. natural gas prices at Henry Hub also decreased by 8.1 per cent over 2010.

Natural Gas Prices—Forecast

The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$1.50 per gigajoule and Cdn$2.50 per gigajoule in 2012, with a base price of Cdn$2.00 per gigajoule. The Alberta natural gas wellhead average price from January to May 2012 is estimated at Cdn$1.85 per gigajoule. In the near term, prices are projected to remain weak due to surplus gas supply in North America. In early 2012, natural gas production was reported to be shut in due to low natural gas prices. A decrease in production could alleviate continued downward pressure on prices in the short term. Longer term, a combination of LNG exports and increased domestic demand is projected to contribute to a slow strengthening of natural gas prices. Over the forecast period, the price of natural gas is projected to increase slowly to reach an average of Cdn$6.00 per gigajoule by 2021.

Alberta's Economy—2011

Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003–2007 timeframe. Average Alberta GDP growth from 2002 to 2011 was 2.8 per cent, compared with a Canadian average of 1.9 per cent. Similarly, the unemployment rate in Alberta averaged 4.8 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

In 2011, the total value of production increased by 19.7 per cent relative to 2010. The value of upgraded and nonupgraded bitumen production significantly exceeded the value of natural gas production for the third year, the continuation of a trend that is expected to continue throughout the forecast period. In 2011, combined upgraded and nonupgraded bitumen revenues are greater than the combined revenues from conventional gas, conventional crude oil, and natural gas liquids.

Alberta's Economy—Forecast

Economic growth is projected to continue to increase in 2012 as oil and gas activity continues to strengthen. Real GDP is forecast to increase by 3.5 per cent in 2012 and to continue growth at a 3.3 per cent trend from 2013 to 2021.

The ERCB estimates that oil sands capital expenditures increased to $19.9 billion in 2011 compared with $17.2 billion in 2010 and $11.2 billion in 2009. Investment is predicted to increase to $21.5 billion in 2012 and peak in 2015 at $24.7 billion. Construction activity for the Imperial Oil Kearl Lake project continues, and first production is planned to begin in late 2012. Many in situ projects have been announced and are proceeding through the application process, and projects that are further along are commencing or continuing construction. Conventional oil and gas expenditures rebounded to $21.5 billion in 2010, significantly higher than the 2009 level of $12 billion as activity in the basin has shifted to the application of horizontal wells and multi-fracturing to tight oil and liquids-rich gas. This trend is expected to continue throughout the forecast period.

Production from upgraded and nonupgraded bitumen derived from the oil sands will more than offset the decline in conventional resource production, increasing from 58.4 per cent of total revenues in 2011 to an average of 69 per cent of total revenues from 2014 to 2021.

Continued investment in oil sands mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. Alberta's economic growth will continue to be a strong contributor to Canadian economic growth.

Commodity Discussion

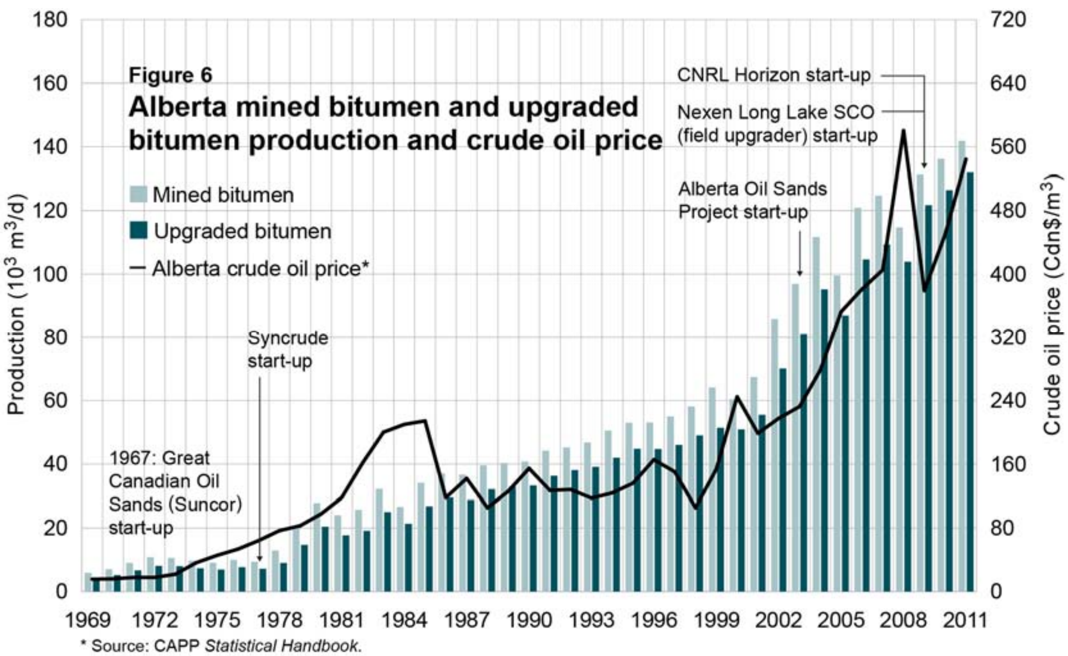
Crude Bitumen and Crude Oil

Crude Bitumen Reserves

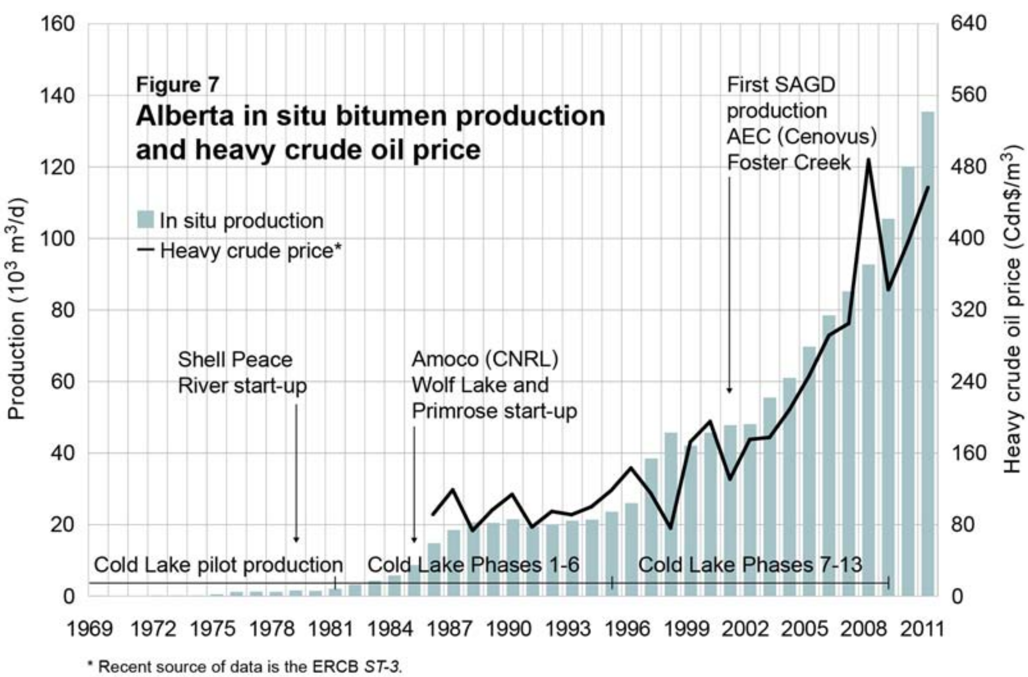
The total remaining established reserves of in situ and mineable crude bitumen is 26.8 billion cubic metres (m^3) (168.7 billion barrels), slightly less than in 2010 due to production. Only 4.6 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

Figure 6 shows the historical mined bitumen and upgraded bitumen production, beginning with the start-up of Great Canadian Oil Sands (Suncor) in 1967. This was followed by Syncrude in 1978 and the Alberta Oil Sands Project (Shell Muskeg River Mine and Shell Scotford Upgrader) in 2003. The Horizon Project (CNRL) commenced mining operations in late 2008 and produced upgraded bitumen in 2009. The figure also shows the price of Alberta average wellhead crude oil.



Historical in situ production and the price of heavy crude oil are shown in **Figure 7**. Regionally, in situ production growth in 2011, as in recent years, was strongest in Athabasca (15 per cent increase), followed by Cold Lake (12 per cent increase), and Peace River (2 per cent increase).



In 2011, Alberta produced 51.8 million m^3 (326 million barrels) from the mineable area and 49.4 million m^3 (311 million barrels) from the in situ area, totalling 101.2 million m^3 (637 million barrels). This is equivalent to 277.2 thousand m^3 (1.7 million barrels) per day. Total raw bitumen production is projected to reach 587.3 thousand m^3 (3.7 million barrels) per day by 2021. Production from in situ bitumen projects is projected to surpass that of bitumen from mining projects by 2015.

Upgraded Bitumen Production

In 2011, all crude bitumen produced from mining, as well as a small portion of in situ production (about 9 per cent), was upgraded in Alberta, yielding 50.0 million m^3 (315 million barrels) of upgraded bitumen. About 56 per cent of total crude bitumen produced in Alberta was upgraded in the province in 2011. By 2021, upgraded bitumen production is forecast to increase to 81.6 million m^3 (513 million barrels).

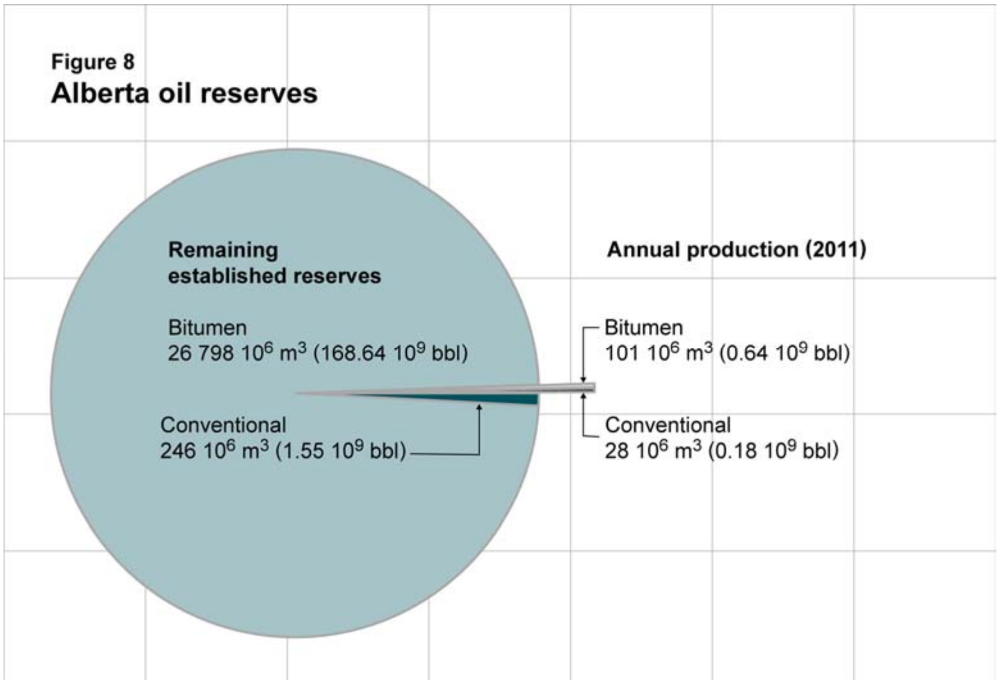
Over the next 10 years, mined bitumen is projected to continue to be the primary source of the crude bitumen to be upgraded in Alberta. However, the portion of in situ production upgraded in the province will increase from 9 per cent in 2011 to 14 per cent by the end of the forecast period. As in situ production is forecast to exceed mining production after 2015, and in situ production growth is forecast to outpace currently approved upgrading capacity, only 44 per cent of total crude bitumen produced in Alberta will be upgraded in the province under this projection by the end of the forecast period.

Crude Oil Reserves

The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 245.9 million m^3 (1.5 billion barrels), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 9.0 million m^3, or 3.8 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2011.

In 1994, based on the geological prospects at that time, the ERCB estimated the ultimate potential of conventional crude oil to be 3130 million m^3 (19.7 billion barrels). Given recent reserve growth in low permeability oil plays, the ERCB believes that this estimate may be low.

Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 8**.



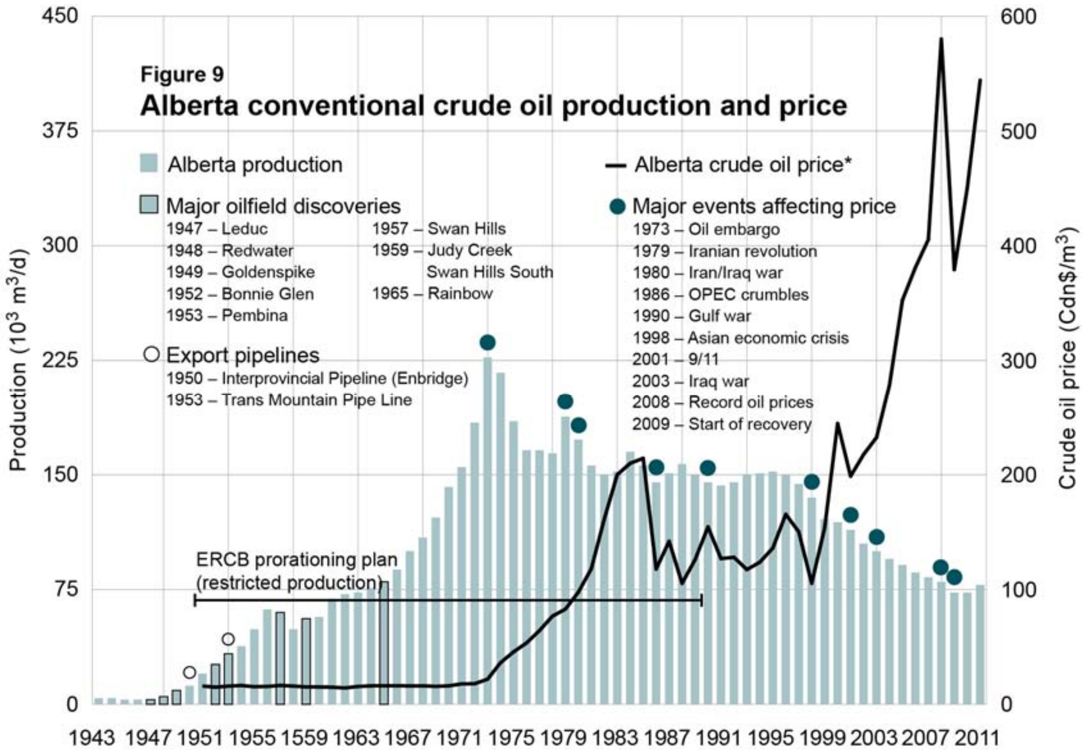
Crude Oil Production

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 9**. Production from the Turner Valley field, which was discovered in 1914, accounted for 99 per cent of oil production in 1938 and 89 per cent of production in 1946. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with peak production of 227.4 thousand m^3 per day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure.

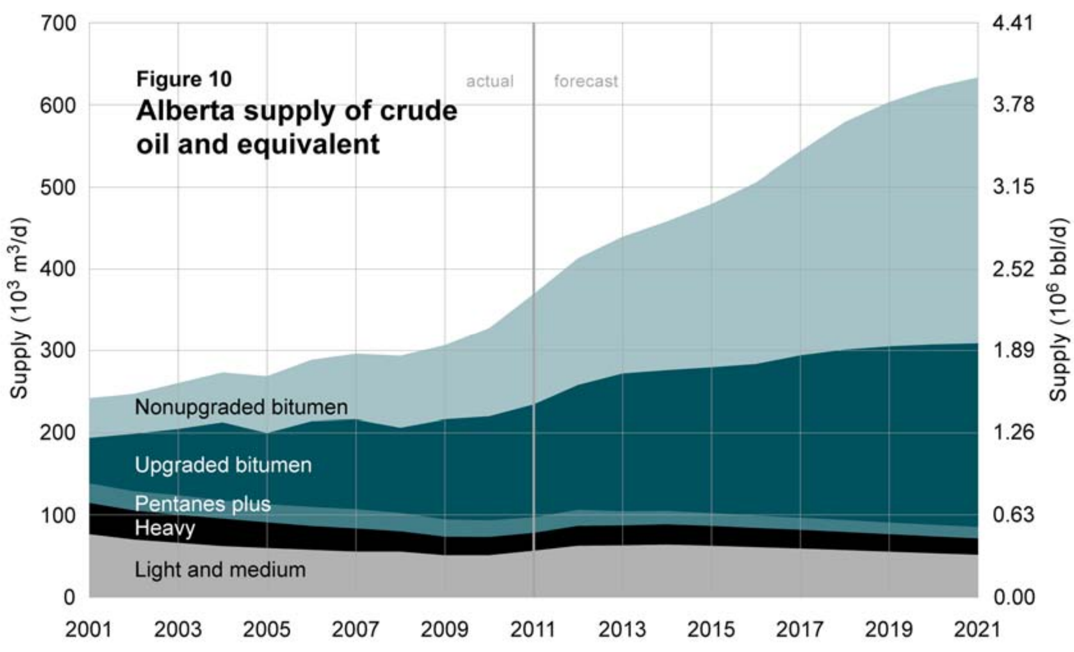
Starting in 2010, total crude oil production in Alberta reversed the downward trend that was the norm since the early 1970s. In 2010 and 2011, light-medium crude oil production began to increase as a result of increased, mainly horizontal, drilling activity with the introduction of multistage hydraulic fracturing technology. The successful application of this technology and increased drilling resulted in total crude oil production increasing by 7 per cent in 2011. Alberta's production of conventional crude oil totalled 28.4 million m^3 (179 million barrels) in 2011.

Total Oil Supply and Demand

Figure 10 shows crude oil and equivalent supply. Alberta's 2011 supply of crude oil and equivalent reached 355.8 thousand m^3 (2.2 million barrels) per day, a 9 per cent increase compared with 2010. Production is forecast to reach 633.3 thousand m^3 (4.0 million barrels) per day by 2021.

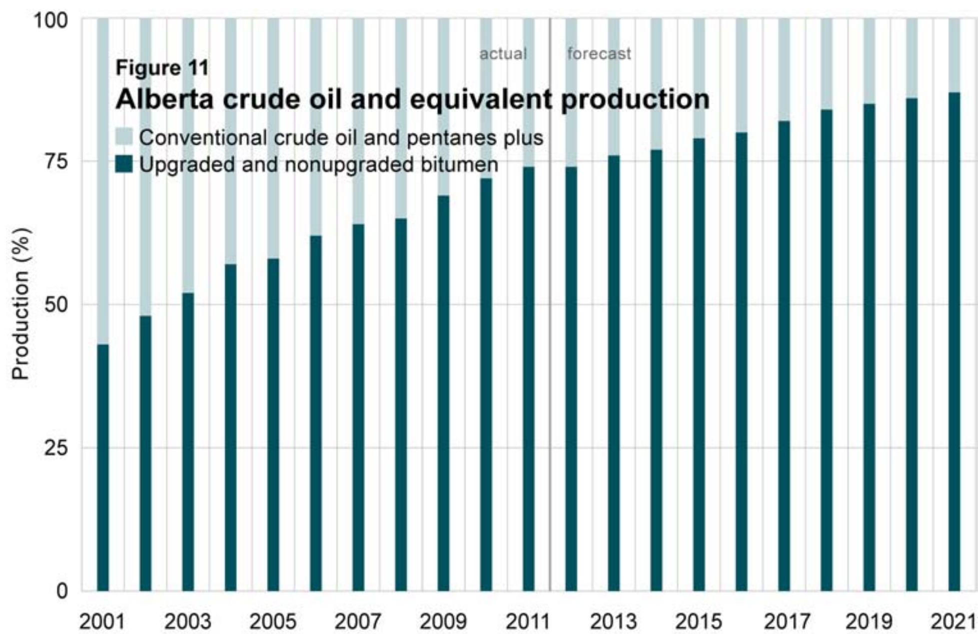


* Source: CAPP *Statistical Handbook*.



A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 11**, clearly shows the increasing contribution of bitumen to Alberta's oil production.

The ERCB estimates that bitumen production will more than double by 2021. Over the forecast period, as illustrated in **Figure 11**, the growth in production of upgraded and nonupgraded bitumen is expected to more than offset the projected long-term decline in conventional crude oil. The share of upgraded and nonupgraded bitumen will account for close to 90 per cent of total production by 2021, compared with about 73 per cent in 2011. Since 2003, upgraded and nonupgraded bitumen has accounted for more than 50 per cent of total production.

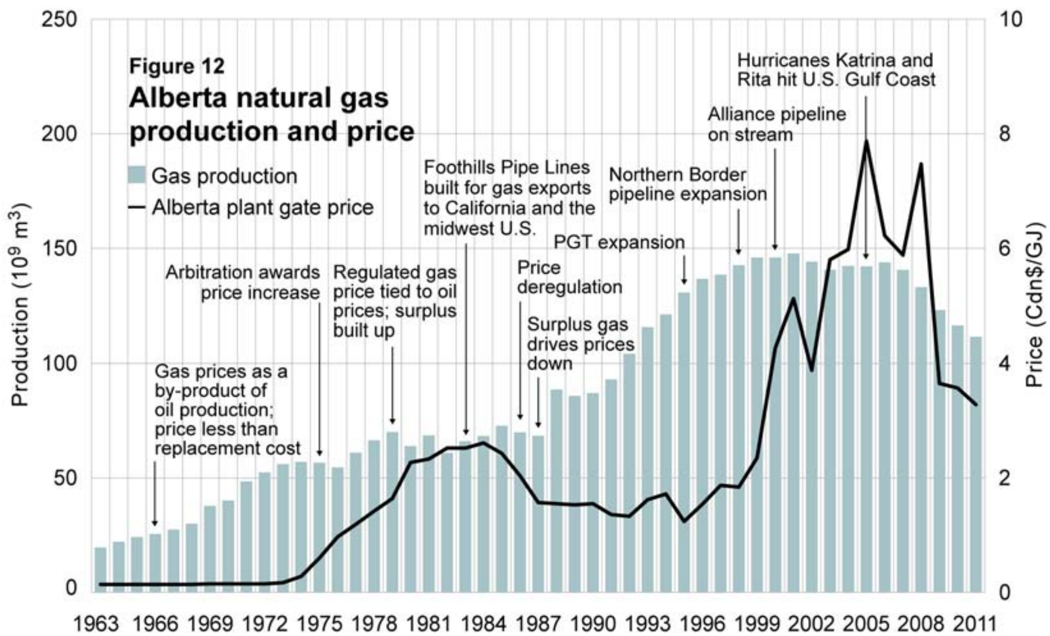


Natural Gas

Historical gas production and price are shown in **Figure 12**. In the 1950s and 1960s, it was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when OPEC increased crude oil prices, natural gas prices started to increase.

In 1980, through the National Energy Program, the federal government imposed regulated gas prices tied to crude oil prices based on their relative calorific values. High gas prices in the 1980s spurred drilling, which resulted in a significant oversupply of reserves.

In 1985, natural gas prices were deregulated in Canada. The removal of set prices, the oversupply of reserves, and the drop in demand because of recession resulted in the decline of natural gas prices for the rest of the decade.



In the early 1990s, natural gas prices became more market responsive. Development of trading points in Chicago, New York, and the Henry Hub (near Erath, Louisiana) in the United States in the late 1980s, and AECO “C” (near Suffield, Alberta) in the early 1990s facilitated natural gas being traded as a true commodity. More recently, shale gas production in the United States has significantly contributed to the growth in natural gas production, reversing the trend of annual U.S. production declines. The influence of increased supply and lagging demand has resulted in low gas prices in North America and contributed to the reduction in natural gas activity in Alberta.

Natural gas is produced from conventional and unconventional reserves in Alberta. Most natural gas is produced from conventional sources.

Conventional Natural Gas Reserves

As of December 31, 2011, the ERCB estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 945 billion m^3, with a total energy content of about 37 exajoules. This decrease of 80.0 billion m^3 since December 31, 2010, is the cumulative result of all reserves additions less production during 2011. These reserves include 29.4 billion m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value from 39.1 megajoules per m^3 to 37.3 megajoules per m^3 for gas downstream of straddle plants. Reserves added through drilling (new plus development) totalled 44.8 billion m^3, replacing 43 per cent of Alberta’s 2011 production.

In March 2005, the ERCB (then known as the Alberta Energy and Utilities Board) and the National Energy Board jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas*, an updated estimate of the ultimate potential for conventional natural gas. The Boards adopted the medium case, representing an ultimate potential of 6276 billion m^3, or 223 Tcf (6528 billion m^3, or 232 Tcf, at 37.4 megajoules per m^3).

Unconventional Natural Gas Reserves

The ERCB estimates the initial established reserves of CBM to be 100.9 billion m^3 as of December 31, 2011, relatively unchanged from 2010. Remaining established reserves in 2011 are 62.0 billion m^3, down from 67.6 billion m^3 in 2010 due to production.

Total Natural Gas Production

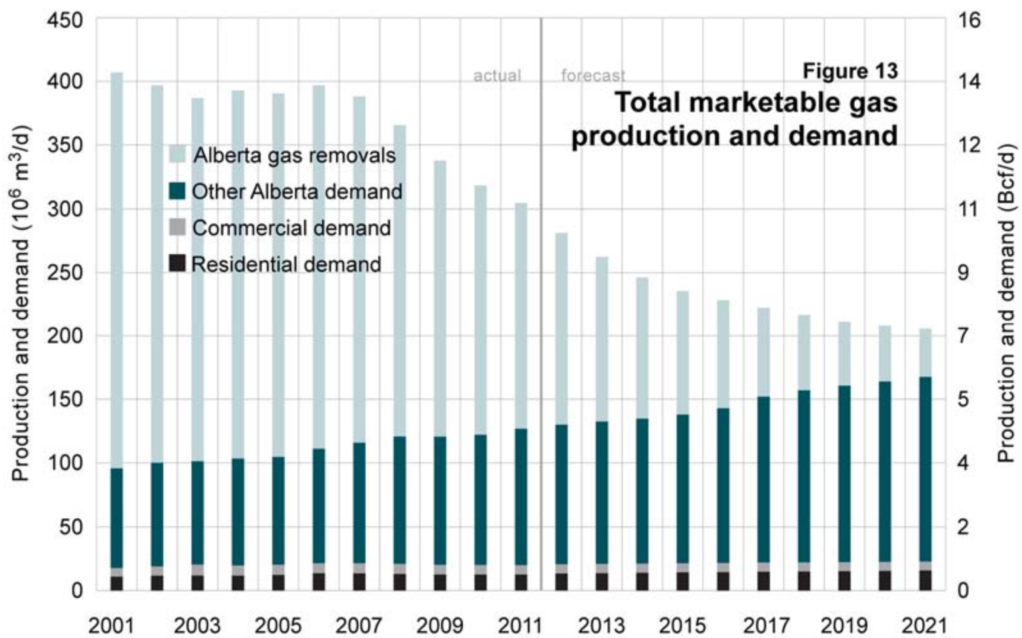
Several major factors affect natural gas production, including natural gas prices, drilling and connection activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. In 2011, total marketable natural gas production in Alberta, including unconventional production, declined by 4.6 per cent to 304.8 million m^3 per day from 319.5 million m^3 per day. Total production from identified CBM and CBM hybrid connections decreased 5.2 per cent in 2011 to 23.9 million m^3 per day from the revised 2010 volume of 25.2 million m^3 per day. In 2011, natural gas from conventional gas and oil connections, at 280.6 million m^3 per day (standardized to 37.4 megajoules per m^3), represented 92 per cent of production. The remaining 8 per cent of gas supply came from CBM (and minor shale gas) connections at 23.9 million m^3 per day and 0.3 million m^3 per day, respectively.

Total Natural Gas Supply and Demand

Although the decline in production was moderated in 2011 relative to 2010, the ERCB believes that new connections will not be able to sustain production levels over the forecast period. CBM production is forecast to supplement the declining supply of conventional gas in the province but only to a limited extent.

Although natural gas supply from conventional sources is declining, sufficient supply exists to meet Alberta's demand. In 2011, about 42 per cent of Alberta production was consumed within Alberta. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand in Alberta is forecast to represent 81 per cent of total Alberta natural gas production, not including potential shale gas production or natural gas supply from British Columbia that connects to the pipeline network in Alberta.

Therefore, as Alberta requirements continue to increase and production continues to decline, less gas is forecast to be available for removal from the province. Alberta's historical and forecast marketable gas production (at 37.4 megajoules per m^3) and demand are shown in **Figure 13**.



Ethane and Other Natural Gas Liquids

Ethane Reserves

As of December 31, 2011, the ERCB estimates remaining established reserves of extractable ethane to be 108.8 million m^3 in liquefied form. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

Ethane Production

In 2011, ethane volumes extracted at Alberta processing facilities increased marginally to 35.2 thousand m^3 per day from 34.2 thousand m^3 per day in 2010. About 68 per cent of total ethane in the gas stream was extracted in 2011, while the remainder was left in the gas stream and sold for its heating value. Although the forecast ethane supply from conventional gas crosses over the demand curve before the end of the forecast, incremental ethane supply from oil sands off-gas and imports are assumed to meet demand over the forecast period.

Propane, Butane, and Pentanes Plus Reserves

As of December 31, 2011, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 64.2 million m^3, 35.0 million m^3, and 46.5 million m^3, respectively. Cumulatively, these NGLs reserves equate to 82 per cent of Alberta's remaining light-medium crude oil reserves.

Propane, Butane, and Pentanes Plus Production

The supply of propane and butanes is expected to meet demand over the forecast period. The production decline of propane, butanes, and pentanes plus in Alberta is slowing down as a result of the increased focus by industry on developing liquids-rich gas pools because the prices of these NGLs track the price of crude oil. Propane, butanes, and pentanes plus production declined by 0.5 per cent, 0.3 per cent, and 3.2 per cent, respectively, in 2011 over 2010. This compares to the decline rates in 2010 of 5.6 per cent, 3.1 per cent, and 3.5 per cent, respectively.

Due to the tightness of the supply of pentanes plus, alternative sources of diluent are being used by industry to dilute heavier crudes to meet pipeline quality.

Sulphur

Sulphur Reserves

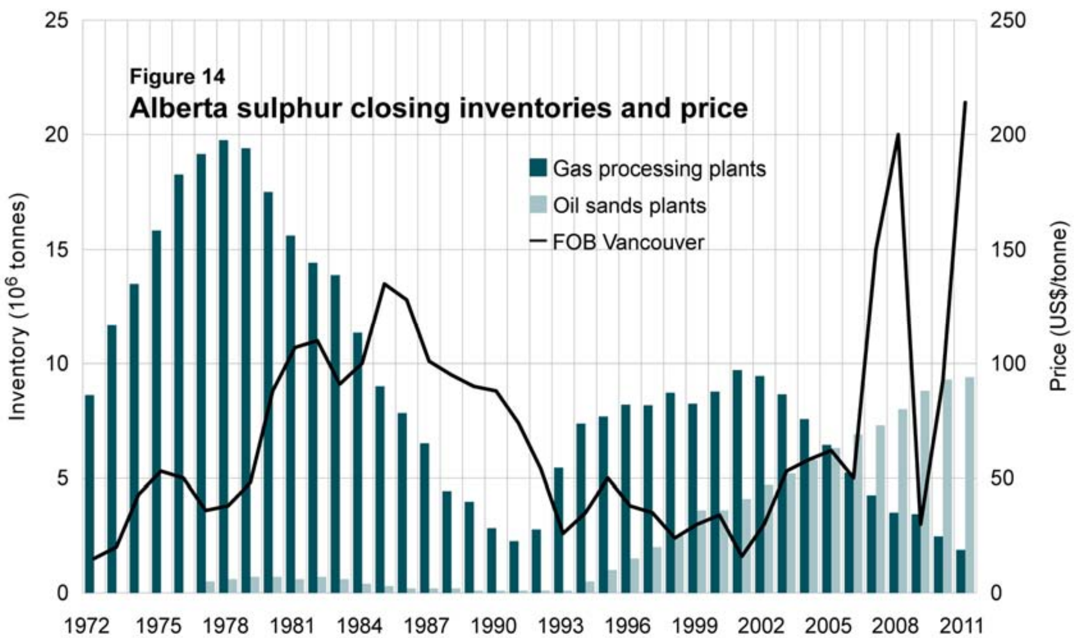
The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2011, to be 173.1 million tonnes, down 1.9 per cent from 2010. Sulphur is recovered from the processing of natural gas and the upgrading of bitumen.

Sulphur Production

There are three sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading, and crude oil refinement into petroleum products. In 2011, Alberta produced 4.73 million tonnes of sulphur, of which 2.95 million tonnes were derived from sour gas, 1.77 million tonnes from upgrading of bitumen, and just 11 thousand tonnes from oil refining. The total sulphur production in 2011 represents a decrease of 4.6 per cent from 2010 levels due to a decline in natural gas production. Most of Canada's sulphur is produced in Alberta.

Figure 14 illustrates historical sulphur closing inventories at processing plants and oil sands operations and sulphur prices. When international demand is high, Alberta sulphur blocks are used as an additional source to increase the supply.

About 60 per cent of the sulphur marketed by Alberta producers in 2011 was shipped outside the province, compared with about 89 per cent in 2010. Exports offshore and to the United States represented 48 and 14 per cent of the total sulphur deliveries, respectively, with the remainder being delivered to the rest of Canada. Exports out of Vancouver, B.C., in 2011 declined because sulphur output from the Shell Caroline gas plant and associated sulphur facilities was disrupted from late 2010 until April 2011 as a result of a series of mechanical problems. Thirty-one per cent of offshore export activities were from Shell. The increase in prices for sulphur in offshore markets also helped curtail demand. In 2011, sulphur prices averaged at US$214 per tonne, an increase of 131 per cent over last year's prices of US$92.50 per tonne.



Coal

Coal Reserves

The ERCB estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2011, to be 33.3 billion tonnes (36.7 billion tons). Of this amount, 22.7 billion tonnes (or about 68 per cent) is considered recoverable by underground mining methods, and 10.5 billion tonnes is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2011. Alberta's coal reserves represent more than a thousand years of supply at current production levels. This massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 55 per cent of the province's electricity generation in 2011.

Coal Production

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 15**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and cost-of-service contracts with the mining companies generally determine the price of subbituminous coal.

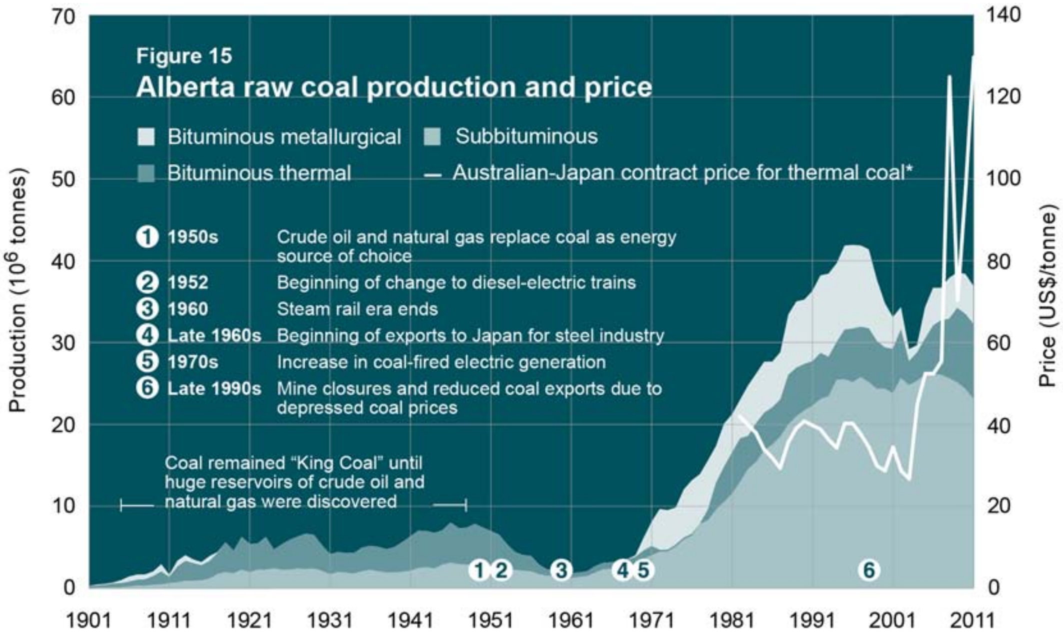


Figure 15
Alberta raw coal production and price

*Source: Australian Bureau of Agricultural and Resource Economics (ABARE).

In 2011, eleven mine sites produced coal in Alberta. These mines produced 30.1 million tonnes of marketable coal. Subbituminous coal accounted for 77 per cent of the total, metallurgical bituminous 9 per cent, and thermal bituminous coal the remaining 14 per cent.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan being the country that imports the most metallurgical and thermal coal. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export coal producers. Throughout 2011, the demand of the metallurgical coal export market was weak, mainly due to a decrease in demand for coal for steelmaking in Japan after the March 2011 earthquake and tsunami. In addition to the relatively weak demand, the oversupply in global coal markets is not expected to improve in the near future. The strong growth in exports from a number of countries will increase global competition in coal markets, which will affect price negotiations for Alberta exporters, and therefore price decreases are expected in the near term.

Electricity

At year-end 2011, Alberta's available power generation capacity was 13 111 megawatts (MW), slightly higher than the 2010 capacity due to the addition of a coal-fired plant and a wind power facility, as well as small additions to biomass capacity. The ERCB anticipates electricity generating capacity in Alberta to be close to 17 000 MW by the end of the forecast period, which is 7 per cent higher than last year's forecast of 15 900 MW in 2020. This increase is mainly due to the inclusion of new natural gas generation facilities.

In 2011, total electricity generation reached 70 685 gigawatt hours (GWh), similar to the 2010 level of 70 586 GWh. Alberta was a net importer of electricity in 2011, importing 3596 GWh, which is about 7 per cent of total Alberta demand. By 2021, total electricity generation is forecast to be close to 96 300 GWh, higher than last year's forecast of over 94 000 GWh by 2020.

Alberta's total electricity demand amounted to 74 281 GWh in 2011. This represents a 2.5 per cent increase over the 2010 total of 72 488 GWh. This increase was led by a 7.5 per cent growth in electricity demand from the oil sands sector. By 2021, Alberta electricity demand is forecast to be 97 960 GWh. Growth in oil sands electricity demand is projected to grow by 6.8 per cent per year.

Oil and Gas Activity

Crude Oil

In 2011, 3170 successful oil wells were drilled, an increase of 37 per cent from 2010. The last time Alberta experienced this high level of oil drilling was in 2005. From this total, 1818 new horizontal oil wells (including those using multistage fracturing technology) were brought on production in 2011, an increase of 78 per cent from 2010 levels of 1023 horizontal wells. This raises the total number of horizontal wells to 6643.

The number of new vertical oil wells placed on production is projected to be 1440 in 2012 and is expected to decline to 1040 wells in 2021. Although this well count is relatively low and reflects the view that many new wells will be horizontal wells using multistage fracturing technology, the 2012 forecast for the number of vertical wells has increased relative to last year based on 2011 industry levels. The number of new horizontal oil wells forecast to be placed on production in 2012 and beyond is projected to increase from 1818 in 2011 to 2160 in 2012 and 2013, and to decline gradually to 1560 in 2021. The forecast number of horizontal oil wells has been significantly increased relative to our forecast last year and reflects 2011 actual activity and anticipated continued strong crude oil prices.

Natural Gas

For conventional natural gas, in 2011, 2310 new conventional gas connections were placed on production in the province, a decrease of 24 per cent from 2010. This is the fifth straight year of reductions in conventional gas connections. The number of horizontal gas wells drilled and connected in the province is increasing as a percentage of the total. In 2011, about 25 per cent of new gas connections were horizontal wells compared with 14 per cent in 2010 based on the revised well connection counts.

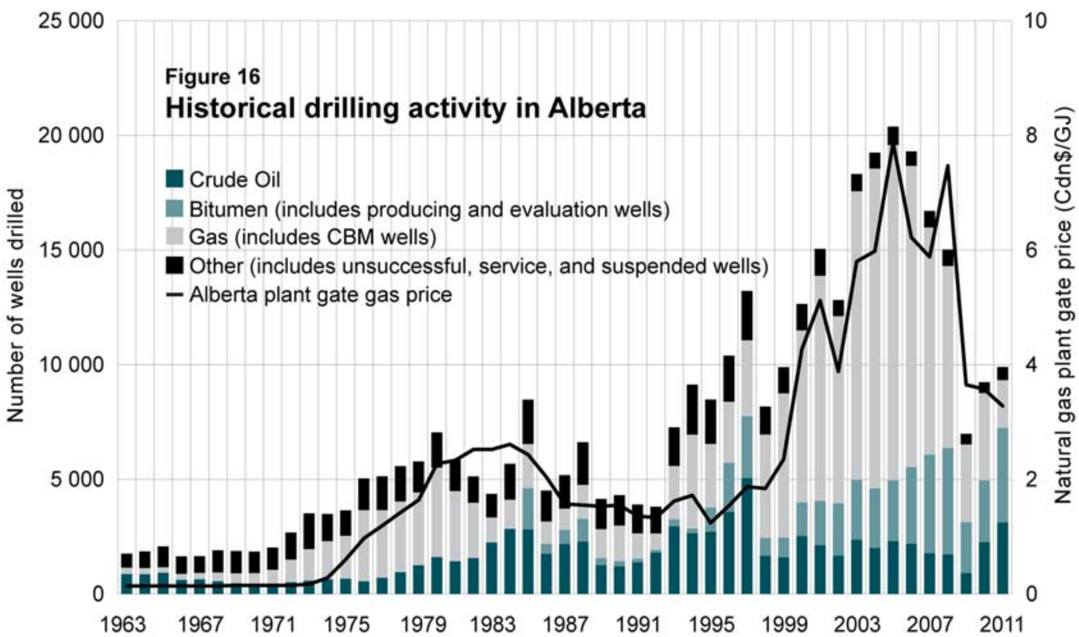
The numbers of new conventional gas connections over the forecast period are projected to be 1620 in 2012 and gradually increasing to 3800 by 2021. The number of forecast connections is significantly lower relative to last year's forecast due to the low activity levels in 2011 and the lower natural gas price forecast relative to last year's forecast.

In 2011, there were 1023 new connections for CBM and CBM hybrid production: 1015 in the Horseshoe Canyon Formation and 8 in the Mannville Group. New connections in the Horseshoe Canyon increased in 2011 by 4 per cent, and new connections in the Mannville decreased by 20 per cent from the revised number of connections in 2010. Overall, new CBM and CBM hybrid connections increased slightly by 3 per cent in 2011 over 2010.

The ERCB currently recognizes 149 producing shale and commingled shale gas connections in 2011.

Over the forecast period, almost all new CBM production will be from the Horseshoe Canyon. The number of new CBM and CBM hybrid connections in the Horseshoe Canyon play area is forecast to be 500 in 2012, gradually increasing to 800 in 2021. This forecast is significantly lower than last year's expectation and is due to the very low level of activity reported in 2011 and the expectation that activity levels will only slowly improve over the forecast period.

Figure 16 illustrates the province's drilling history over the past six decades, together with the price of natural gas. Historically, most drilling in Alberta is related to successful gas wells relative to crude oil, although this trend reversed in 2011.



HIGHLIGHTS

WTI crude oil prices averaged US$95.11 per barrel (bbl) in 2011, compared with US$79.61/bbl in 2010, an increase of 19 per cent.

Alberta wellhead natural gas prices averaged $3.28 per gigajoule (GJ) in 2011, compared with $3.57/GJ in 2010, a decrease of 8 per cent.

There were 9894 wells drilled in Alberta in 2011, compared with 9233 in 2010, a 7.2 per cent increase.

1 // ECONOMICS

Energy production is determined by energy prices, technology, costs, demand, and remaining reserves. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. This section introduces some of the main variables affecting Alberta's energy sector and sets the stage for later discussions in this report.

1.1 Energy Prices

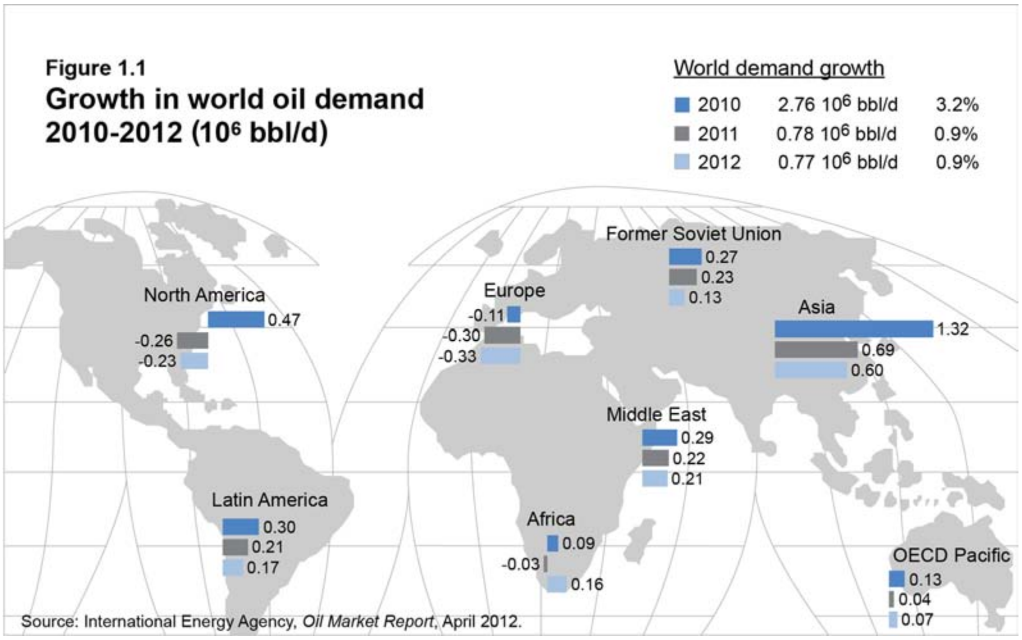
1.1.1 World Oil Market[1]

World oil demand in 2011 rose modestly by 0.8 million (10^6) barrels per day (bbl/d) to 89.1 10^6 bbl/d, a 0.9 per cent change from 2010. Throughout the year, European and North American demand slowed as a result of weak economic growth and high prices. In 2011, International Energy Agency (IEA) data reports that net oil consumption in the Organization for Economic Co-operation and Development (OECD) dropped by 0.6 10^6 bbl/d to 45.6 10^6 bbl/d. This decline was offset by an increase from non-OECD countries, specifically the Asian-Pacific region, where demand rose by 1.3 10^6 bbl/d to 43.5 10^6 bbl/d.

Figure 1.1 illustrates changes in oil demand across the globe in 2010 and 2011, along with the most recent forecast for 2012 by the IEA. The IEA projects global crude oil demand to increase by 0.80 10^6 bbl/d in 2012, or 0.9 per cent, to reach 89.9 10^6 bbl/d. Developing economies' growth will continue to offset declining growth in OECD countries in 2012. Demand in OECD countries is projected to decline by 0.5 10^6 bbl/d in 2012, while non-OECD demand will increase by 1.3 10^6 bbl/d.

In 2011, the Organization of Petroleum Exporting Countries (OPEC) produced 29.9 10^6 bbl/d, compared with 29.4 10^6 bbl/d in 2010. OPEC production in 2011 satisfied approximately 34 per cent of total world oil demand. Including OPEC natural gas liquids, OPEC produced 35.7 10^6 bbl/d, equal to 40 per cent, of total oil demand. Non-OPEC oil production increased slightly from 52.6 10^6 bbl/d in 2010 to 52.7 10^6 bbl/d. In 2011, the world's top three oil producing countries (Russia, Saudi Arabia, and the United States) produced 31 per cent of total oil supply. Russia produced 10.6 10^6 bbl/d, Saudi Arabia produced 9.0 10^6 bbl/d, and the United States produced 8.1 10^6 bbl/d in 2011.

[1] Statistics obtained from the International Energy Agency's *Oil Market Report* (April 2012).



1.1.2 International Oil Prices

Monthly average world oil prices for 2011, represented by the OPEC reference basket price[2] and the price of West Texas Intermediate (WTI),[3] are shown in **Figure 1.2.** The monthly OPEC basket price averaged US$92.83/bbl in January 2011, reached a high of US$118.09/bbl in April 2011, and then moderated to range between US$111.62/bbl and US$106.29/bbl between May and December 2011, with a yearly average of US$107.43/bbl. The WTI price averaged US$95.11/bbl in 2011 and reached a yearly high of US$110.04/bbl in April and a low of US$85.61/bbl in September.

Crude oil prices strengthened at the beginning of the year in response to political demonstrations and protests occurring in the Middle East and North Africa, which started in late 2010. In February 2011, civil war in Libya resulted in a loss of 1.5 10^6 bbl/d of exports. Supplies were constrained as a result of these events and prices continued to increase.

Prices remain elevated into 2012 as a result of continued supply interruptions and production declines in Libya, South Sudan, Syria, Yemen, and the North Sea. As a result of concerns regarding Iran's nuclear program, the United States and Europe tightened sanctions against Iran, and in response, Iran threatened to close the Strait of Hormuz, an important canal route to export Middle Eastern crude. Although shipping continues, the threat has placed a risk premium on crude oil prices. At the same time as these

[2] OPEC calculates a production-weighted crude oil, known as the reference basket, to reflect the average quality of crude oil in OPEC member countries. The price of this reference crude is referred to as the OPEC reference basket price (also know as the basket price).

[3] WTI is a light sweet grade of crude oil that is typically referenced for pricing purposes at Cushing, Oklahoma.

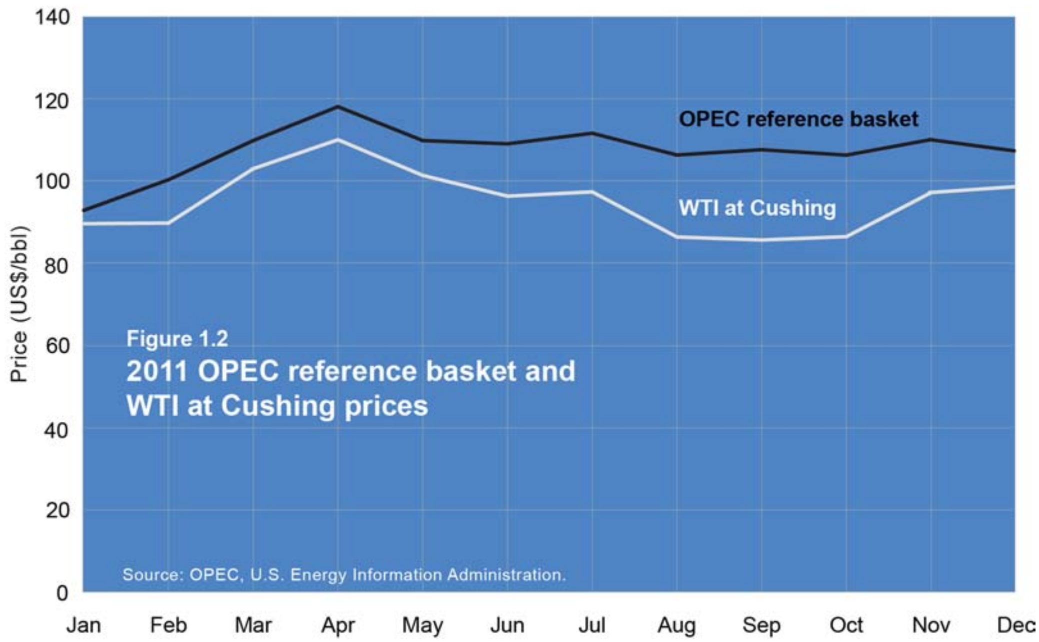
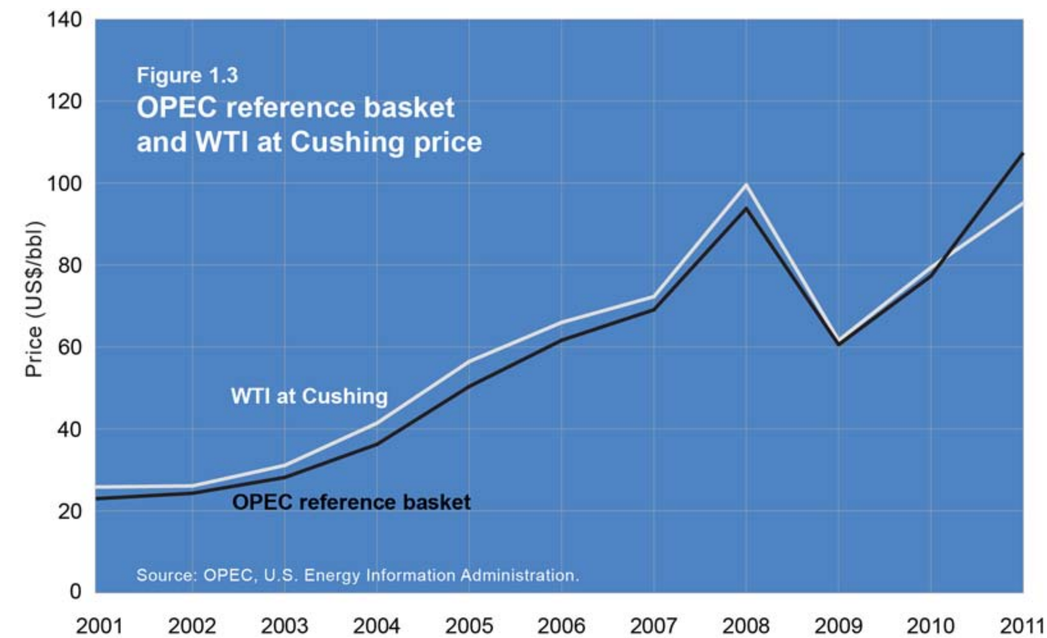


Figure 1.2
2011 OPEC reference basket and WTI at Cushing prices

supply constraints, unusually cold weather in Europe in early 2012 increased demand for heating oil. Supply concerns due to these political risks are expected to continue in 2012, and therefore prices are expected to remain high throughout 2012.

The other significant market condition, highlighted on **Figure 1.2**, is the disconnect between WTI and international crude oil prices. WTI began 2011 trading at a US$3.25/bbl discount to the OPEC basket. However, by September, the discount had widened to US$22.00/bbl, resulting in an average 2011 discount of US$12.31/bbl. This discount reflects the land-locked nature of WTI, significant increases in North American supplies, and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast. Other methods of transportation are generally more costly and include rail, truck, or barge.

Figure 1.3 depicts the yearly average OPEC basket price and the yearly average WTI price from 2002 to 2011, showing the continued upward trajectory in crude oil prices, interrupted only by the global recession which began in late 2008. The discount seen in 2011 is not only significantly wider, but the relationship between the two benchmark prices has reversed from the historical relationship. For instance, from 2002 to 2008, WTI averaged US$2.00/bbl to $6.00/bbl higher than the OPEC basket price annually, reflecting quality differences, the cost of shipping, and localized market conditions. In 2009, the premium of WTI relative to the OPEC basket narrowed, averaging approximately US$1.00/bbl, as WTI prices were affected by high North American crude oil storage levels and depressed market conditions. In 2010, WTI moved back to a US$2.00/bbl average annual premium relative to the OPEC basket, which is in stark contrast to the 2011 discount of US$12.31/bbl.



1.1.3 North American Gas and Oil Prices

Unconventional oil and gas production from tight oil and shale gas resources have been major contributors to U.S. supply growth over the last 5 years. Horizontal drilling with multistage hydraulic fracturing techniques is securing new supplies from geologic formations where the accumulated hydrocarbons were previously considered unrecoverable or uneconomic.

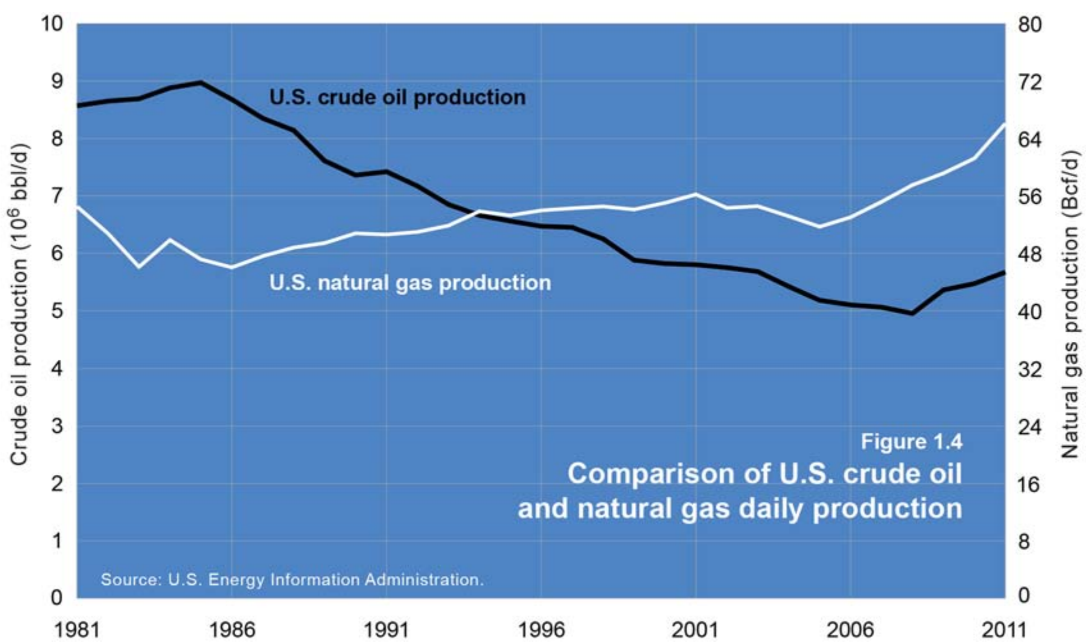


Figure 1.4 shows historical total U.S. oil production and total U.S. natural gas production. The long-term outlook for U.S. gas supply has changed with the recent growth in supply from shale gas. U.S. conventional gas supplies had a stable rate of increase from 1986 to 2001 and then began to decline from 2001 to 2005. Natural gas production in the United States has significantly increased after 2005. Multistage hydraulic fracturing technology has allowed for the economic development of shale gas plays that are responsible for the increase in production. When combined with horizontal drilling, this new completion technique results in high initial production rates from previously uneconomic shale gas reserves. U.S. production has increased significantly as a result of the development of shale gas plays using this technology. Total U.S. marketed gas production was 66.2 billion cubic feet per day (bcf/d) (1.87 billion cubic metres per day [10^9 m^3/d]) in 2011, a 19.8 per cent increase from 2005 levels.

Increased U.S. natural gas production has resulted in low natural gas prices, as shale gas production has more than offset production declines from conventional resources and has exceeded demand growth in the U.S. Projects to convert some of the Liquefied Natural Gas (LNG) regasification terminals to liquifaction terminals are occurring to allow for exports of domestic natural gas supplies to markets offering higher prices. In addition, new LNG export terminals have been proposed in both the United States and Canada. In Canada, the National Energy Board has approved two export licenses to export LNG from Kitimat, B.C., to Asia-Pacific markets with shipments planned to occur within the next few years.

With the abundance of natural gas in North America, producers are also exploring non-traditional uses. According to Natural Gas Vehicles for America, 11 000 transit buses, 4000 refuse trucks, 3000 school buses, 17 000 medium-duty vehicles, and 30 000 light-duty vehicles in the United States are using natural gas as fuel. Most natural gas vehicles use compressed natural gas; however, LNG is becoming more common as a replacement for diesel in heavy trucks and bus fleets.

The U.S. Energy Information Agency recently identified 44 LNG vehicle fueling stations in the United States In 2012, the first LNG fuelling station was opened in Louisiana. The station will serve heavy duty truck fleets and is open for public use. Other plans by industry include opening 150 LNG stations in the United States, with 70 stations in operation by the end of 2012. In Alberta, three LNG stations for heavy duty truck fleets are scheduled to open in 2012.

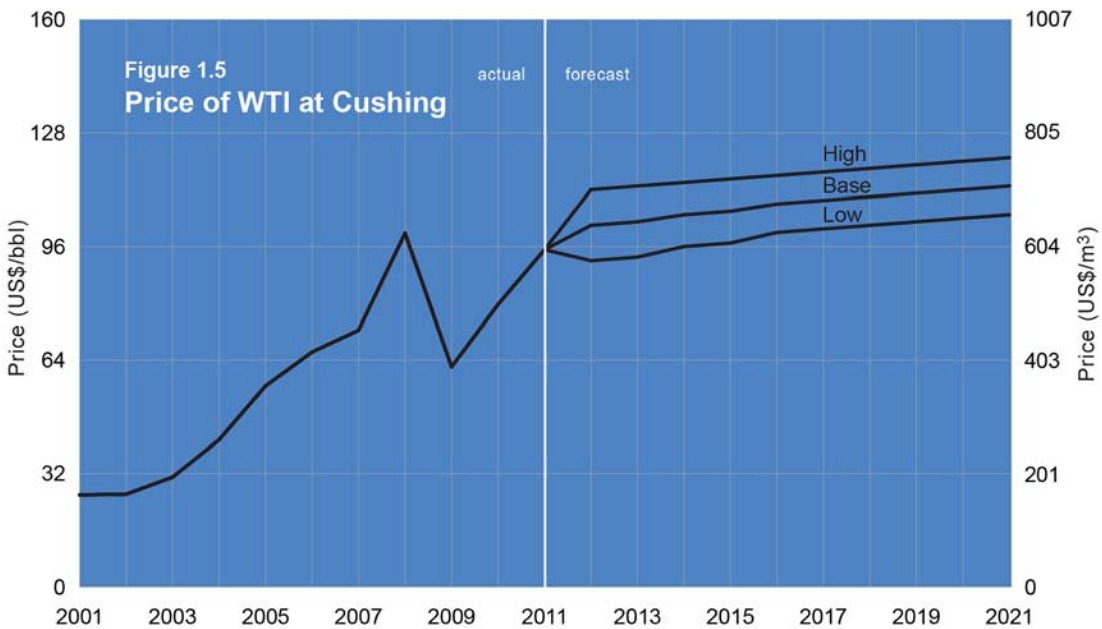
Natural gas is not the only hydrocarbon development successfully employing multistage fracturing completion technology. This technology is being used to access crude oil in reservoirs previously considered uneconomic. As illustrated in **Figure 1.4**, since 2009 the declining trend in crude oil production in the United States has reversed, and production has increased from 4.95 10^6 bbl/d (0.79 10^6 m^3/d) in 2008 to 5.7 10^6 bbl/d (0.91 10^6 m^3/d) in 2011, a 14.6 per cent increase. As discussed earlier, the increase in crude oil production has been a contributing factor for the WTI discount relative to the OPEC basket price.

New plays, like the North Dakota section of the Bakken Formation and the Eagle Ford Formation in Texas, are drilled using horizontal wells and multistage hydraulic fracturing techniques. In North Dakota, crude oil production averaged 419 10^3 bbl/d in 2011, an increase of 241 per cent from 2007 levels. In Texas, onshore production of crude oil averaged 1.4 10^6 bbl/d in 2011, an increase of 31 per cent from 2007 levels. U.S. crude oil production is further discussed in **Section 4.2.1.2**.

1.1.2.1 North American Crude Oil Prices

North American crude oil prices are based on the WTI crude oil price at Cushing, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) for light crude oil contracts. WTI crude oil has an API of 40 degrees and a sulphur content of less than 0.5 per cent. **Figure 1.5** shows historical and forecast WTI prices at Cushing.

In 2011, the WTI price averaged US$95.11/bbl, up US$15.50/bbl from 2010. The ERCB projects WTI to average US$102.00/bbl in 2012, with a range from US$92.00/bbl to US$112.00/bbl.



As illustrated in **Figure 1.5**, the forecast price of WTI is expected to increase throughout the forecast period, reflecting the long-term historical trend of nominally increasing prices, continued concern regarding the political stability and sustainability of OPEC production, and increasing crude oil demand. By 2021, WTI prices are projected to be US$113.00/bbl, with a range from US$105.00/bbl to US$121.00/bbl.

The ERCB calculates light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI Cushing price is adjusted for transportation and other charges between Edmonton and

Cushing, for the exchange rate, and for crude oil quality. The Edmonton price is adjusted for WTI quality. **Figure 1.6** shows historical and the ERCB's forecast prices for Alberta light-medium crude oil in Canadian dollars.

Table 1.1 Alberta wellhead annual average crude oil prices[a]

Average annual price (Cdn$/bbl)	2011	2010
Alberta light-medium crude oil price	91.00	74.74
Alberta heavy crude oil price	72.59	62.96

[a] Prices from ERCB's report *ST3: Alberta Energy Resource Industries Monthly Statistics*.

Table 1.1 compares 2010 and 2011 Alberta light-medium and heavy crude oil prices. In 2011, the average price of light-medium crude oil averaged Cdn$91.00/bbl, up Cdn$16.26/bbl from 2010. The ERCB projects the price of light-medium crude oil to average Cdn$91.67/bbl in 2012, with a range of Cdn$81.57/bbl to Cdn$101.78/bbl. As illustrated in **Figure 1.6**, the forecast price of light-medium crude oil is expected to increase moderately throughout the forecast period from 2012 to reach an average of Cdn$105.43/bbl in 2021, with a range from Cdn$97.19/bbl to Cdn$113.68/bbl. Differentials are projected to narrow as transportation constraints are alleviated.

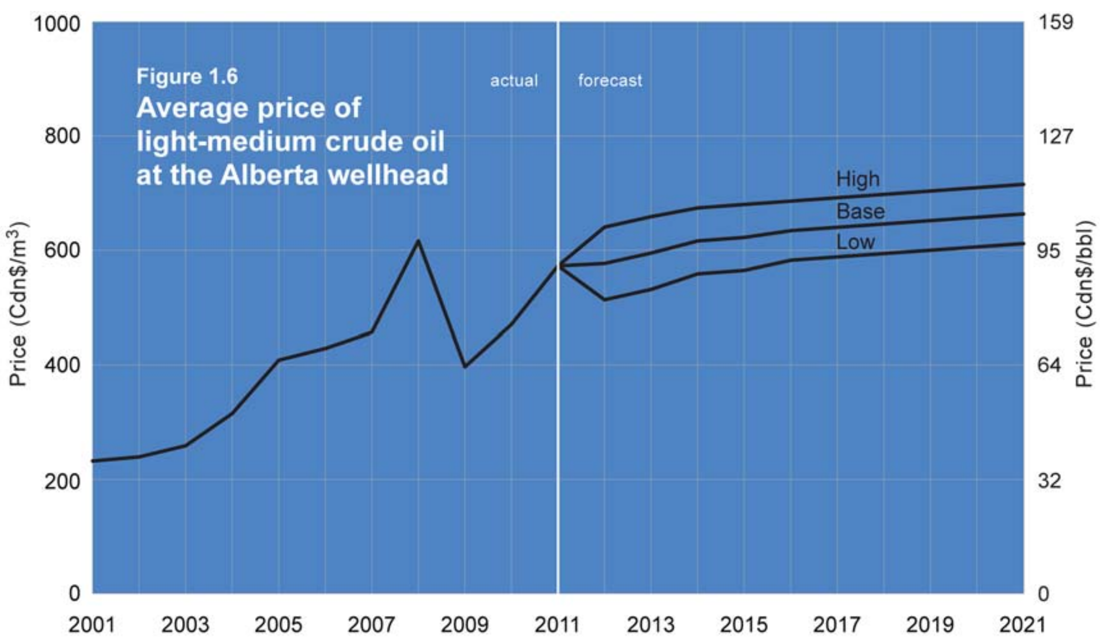
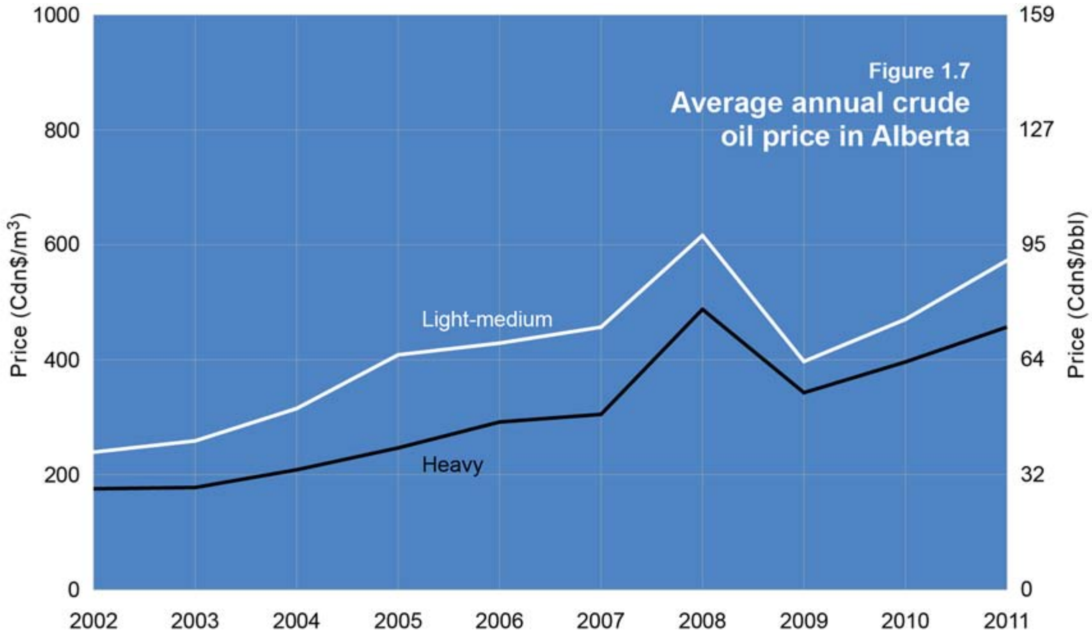


Figure 1.7 illustrates the average annual price of Alberta light-medium and heavy crude. The differential between Alberta heavy and light-medium crudes averaged Cdn$17.10/bbl, or 27.1 per cent, from 2002 to 2011. The heavy/light-medium differential in 2011 averaged Cdn$18.40/bbl, or 20.3 per cent, compared with $11.79/bbl, or 15.9 per cent, in 2010. The heavy/light-medium differential is expected to average 18.9 per cent over the forecast period, slightly narrower than the most recent five-year average of 21.2 per cent due to continuing increases to light sweet crude oil production.



With increased production from the oil sands, Canada has become the United States' leading crude oil supplier. Total crude oil production in Alberta exceeds volumes required by Alberta and ex-Alberta domestic refinery demand, and the excess production is exported to the United States. The Petroleum Administration for Defense Districts (PADDs) 2 and 4 in the United States are the largest importers of Alberta heavy crude oil and upgraded bitumen, with a combined total refinery capacity of 690 10^3 cubic metres per day (m^3/d) (4345 10^3 bbl/d). Increased heavy oil upgrading capabilities at the recently completed Wood River refinery conversion project in Illinois and at the BP refinery modernization project at Whiting, Indiana (due on-stream mid-2013), will allow PADD 2 and PADD 4 to take on increasing amounts of Alberta's heavier crudes.

Total refinery capacity in the United States increased marginally during the 1990s and 2000s with the de-bottlenecking of existing refineries. No new refineries have been built since the 1970s. Before the global economic recession in 2008 and 2009, product demand had increased significantly, resulting in U.S. refineries operating at high utilization rates since about 1993. More recently, depressed refinery margins have resulted in some U.S. refiners operating at lower utilization rates, temporarily idling or shutting down.

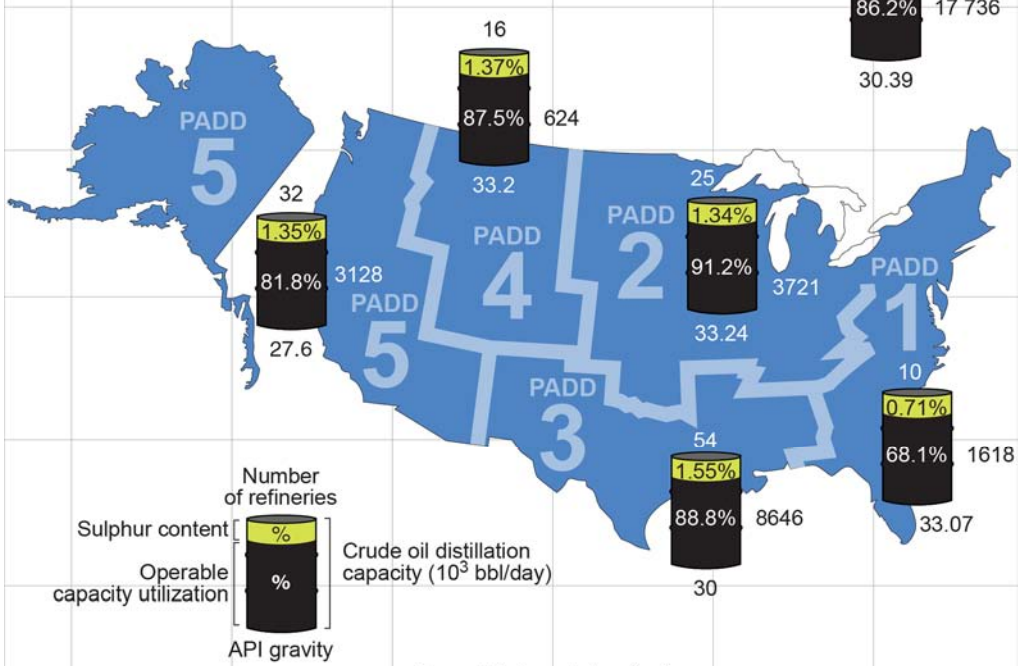
With expected increases in both nonupgraded and upgraded crude oil bitumen supply over the forecast period, incremental pipeline capacity will be required in order to transport growing volumes to market. Consequently many pipeline companies are moving ahead with planning and construction of new projects.

In November 2011, Enbridge Inc. announced the reversal of the Seaway pipeline. Crude oil in the pipeline will now move from Cushing, Oklahoma, to the Gulf Coast. Initial capacity on the pipeline is

150 10^3 bbl/d, and the line is expected to be operational by mid-May 2012. The company plans to increase capacity by an additional 400 10^3 bbl/d by mid-2013 and has plans to twin the pipeline by 2014, which will increase capacity by an additional 450 10^3 bbl/d.

In January 2012, TransCanada Corporation's proposed 700 10^3 bbl/d capacity Keystone XL project was denied a U.S. regulatory permit. TransCanada has since announced it will re-apply for regulatory approval for the project and expects the application will be expedited to allow for an in-service date of late 2014. In February, the company announced they will be building the southern section: the Cushing MarketLink phase. If approved, the Keystone XL project in its entirety will deliver Canadian crude oil to Gulf Coast refineries in PADD 3, the largest refining region in the United States, as illustrated in **Figure 1.8**. Additional pipeline projects are discussed in **Section 3.2.4**.

Figure 1.8
U.S. operating refineries by PADD, 2011



Source: U.S. Energy Information Agency.
Number of operating refineries as of January 1, 2012. Data for the year 2011.
Sulphur content and API gravity are weighted averages.

Figure 1.8 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the United States, with 54 operating refineries and a net crude oil distillation capacity of 8.6 10^6 bbl/d (1370 10^3 m^3/d). PADD 3 was not previously viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude oil production. However, traditional crude oil inputs to PADD 3 have been on the decline, suggesting a significant market opportunity for Alberta heavy crude oil producers. As a result, projects such as the discussed TransCanada Keystone XL project are under way to increase pipeline capacity to the area.

There have been a number of refinery closures on the U.S. East Coast, and more closures have been announced for 2012. The lost capacity in PADD 1 cannot be immediately replaced by refiners in other parts of the United States due to transportation logistics and constraints.

1.1.2.2 North American Natural Gas Prices

While North American crude oil prices have historically tracked international prices, natural gas prices in North America basically reflect the North American supply and demand situation, with little global gas market influence aside from the impact of liquid natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price. As discussed earlier, the most significant change in the market continues to be the growth in U.S. natural gas supply from shale gas**.**

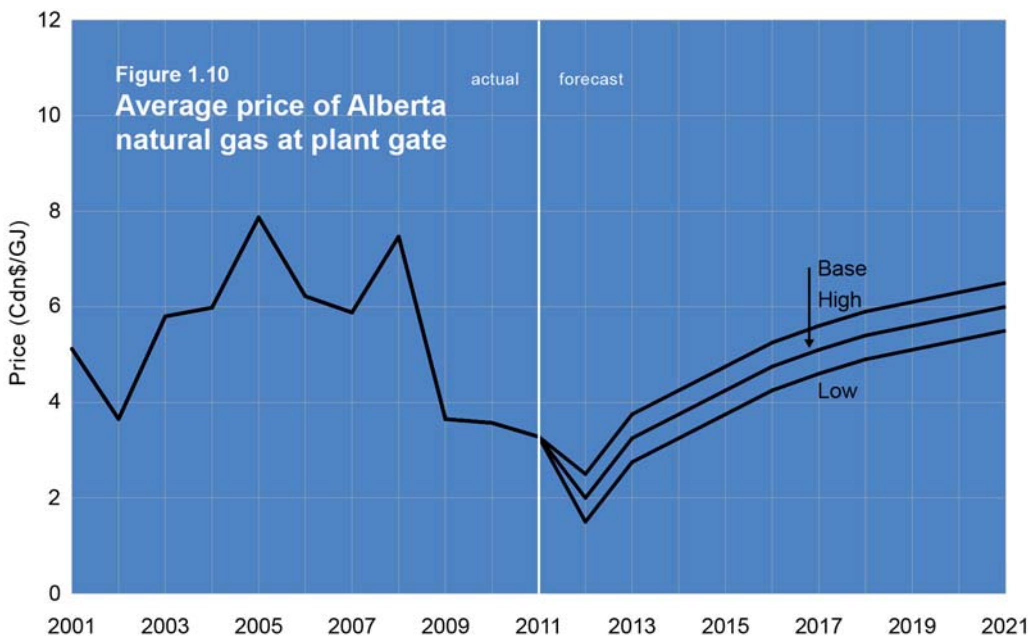
Figure 1.9 shows the monthly Alberta reference price for natural gas in 2011. Gas prices have been relatively stable throughout 2011, exhibiting little volatility. Prices were highest in June at Cdn$3.51/gigajoule[4] (GJ) and lowest in December at Cdn$2.92/GJ. The average Alberta reference price of natural gas in 2011 was Cdn$3.28/GJ, compared with Cdn$3.57/GJ in 2010, an 8.1 per cent decrease. In 2011, U.S. natural gas prices at Henry Hub also decreased by 8.1 per cent over 2010.

Figure 1.9
2011 Average monthly price of Alberta natural gas at plant gate

[4] Giga = 10^9.

Figure 1.10 shows the historical and forecast average price of Alberta natural gas at the plant gate. The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$1.50/GJ and Cdn$2.50/GJ in 2012, with a base price of Cdn$2.00/GJ. The Alberta natural gas wellhead average price from January to May 2012 is estimated at Cdn$1.85/GJ. In the near term, prices are projected to remain weak due to surplus gas supply in North America. In early 2012, natural gas producers in the United States and Canada announced that natural gas production will be shut in due to low natural gas prices. The shut-in may result in a floor for natural gas prices, as a decrease in production could alleviate downward pressure on prices in the short term. Over the forecast period, the price of natural gas is projected to increase slowly to reach an average of Cdn$6.00/GJ by 2021.

The Alberta gas-to-light-medium-oil price parity ratio on an energy content basis averaged 0.59 from 2001–2010. The Alberta gas-to-light-medium-oil price parity averaged 0.29 in 2010 and 0.22 in 2011. The gas-to-oil price parity is projected to average 0.28 over the forecast period, as North American gas prices are projected to increase slowly relative to crude oil prices.



1.1.2.3 Electricity Pool Prices in Alberta

Since deregulation, the wholesale, or pool, price of electricity in Alberta has been determined by the equilibrium between electricity supply and demand. **Table 1.2** shows the average monthly pool price and electricity load, also referred to as demand, in 2011. The 2010 average is included for comparison. The 2011 pool price averaged $76.22 per megawatt-hour (MWh), compared with the 2010 average of $50.88/MWh. The annual average pool price in 2011 was 49.8 per cent higher than in 2010, reflecting the impact of coal-fired power plant outages and planned and unplanned transmission maintenance, as well as strong demand. In 2011, monthly pool prices averaged $122.45/MWh in February, 126.36/MWh in August, and 108.24/MWh in November and ranged between $32.27/MWh and $96.57/MWh in the remaining months.

The forecast for electricity supply and demand in Alberta is discussed in **Section 9**. In 2011, Alberta's electricity demand increased by 2.5 per cent. This followed a five-year period where growth averaged only 1.6 per cent per year. Growth was led by an increase in oil sands demand of 7.5 per cent in northeastern Alberta, which was driven by an 8.2 per cent increase in mined and in situ bitumen output.

The outlook for electricity supply in the forecast period has considered the effects of two factors. First, the federal government released proposed regulations in 2011 for coal-fired electricity generation units. The regulations will limit each unit's emissions to 375 tonnes of carbon dioxide for each gigawatt-hour of electricity produced from all fossil fuel sources in a calendar year. The regulations would apply to new coal-fired units commissioned after July 1, 2015, and to old units that have been producing for at least 45 years.

Table 1.2 Monthly pool prices and electricity load

	Price ($/MWh)	Load (MW)		
2011	**Average**	**Average**	**Min**	**Max**
Jan	79.05	8 940	7 682	10 226
Feb	122.45	8 893	7 642	9 978
Mar	48.52	8 719	7 493	9 990
Apr	52.23	8 100	7 138	8 796
May	32.27	7 606	6 459	8 567
Jun	71.85	7 873	6 575	9 063
Jul	61.21	8 276	7 020	9 552
Aug	126.36	8 354	7 186	9 455
Sep	96.57	8 195	7 120	9 376
Oct	69.75	8 202	7 137	9 112
Nov	108.24	8 772	7 564	10 064
Dec	51.26	8 926	7 679	10 186
2011	**76.21**	**8 405**	**6 459**	**10 226**
2010	**50.88**	**8 188**	**6 641**	**10 196**

Source: Statistics obtained from Alberta Electric System Operator (AESO).

As part of the federal government's long-term strategy to reduce emissions from the electricity sector, the government has announced that they will also be releasing gas-fired electricity generation regulations within the next few years. Final regulations for coal-fired electricity generation units are expected in 2012. The other factor affecting the Alberta electricity supply forecast is the stoppage of two coal-fired plants. In December 2010, Sundance 1 and 2 went out of service, and TransAlta subsequently declared that they would be demolished because of the cost of repairs. The current forecast does not assume that output from Sundance 1 and 2 will resume.

Electricity supply growth in the forecast period will largely come from growth in gas-fired cogeneration facilities associated with oil sands projects and from other new gas-fired generation. Wind power projects are projected to be added at a pace similar to the past decade.

Although average daily electricity prices in Alberta will continue to be affected by seasonal temperature influences and unplanned generating plant outages, over the long term the average annual electricity pool price will reflect Alberta natural gas prices and the cost of adding new capacity.

Figure 1.11 illustrates the historical and the ERCB forecast of average annual pool prices in Alberta. Electricity prices are projected to remain in the range of prices reported from 2002 to 2008, and the forecast prices reflect the natural gas price forecast. In 2008, pool prices spiked and rose to $89.95/MWh as a result of high natural gas prices and transmission and generation outages. Prices fell to average $47.81/MWh in 2009, as the outages from 2008 did not carry over, and pool prices declined in response to low natural gas prices. The loss of electricity from the Sundance units increases the risk for higher prices if further unplanned outages occur.

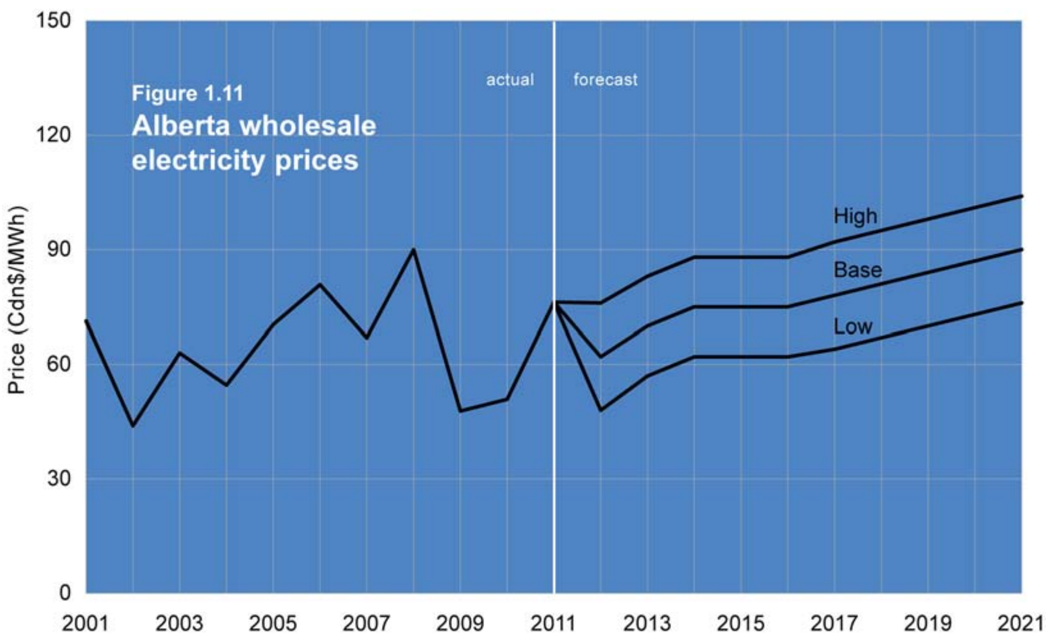


Figure 1.11
Alberta wholesale electricity prices

1.2 Oil and Gas Production Costs in Alberta

For over 30 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical oil and gas wells for the upcoming drilling season. PSAC defines a typical oil and gas well as a well that reflects the most common well type drilled in 2012 in western Canada. The cost estimates in **Figure 1.12** were obtained from the 2011 and 2012 PSAC Well Cost Studies. **Table 1.3** outlines the median well depth for each area, a major factor contributing to drilling costs. Many other factors influence well costs, including the economic environment, the type of commodity produced, whether it is a development or an exploratory well, surface conditions, sweet versus sour production, drilling programs, well location, nearby infrastructure, and completion method.

Table 1.3 Alberta median well depths by PSAC area, 2011 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3 841	3 178	1 067	555	934	555	2 060
Oil wells	n/a	3 002	1 167	788	1 639	458	2 065

As illustrated in **Figure 1.12**, the estimated cost to drill and complete a typical oil well slightly increased from the previous year. The estimated cost of drilling and completing a typical oil well in the winter of 2011–2012 ranged from as low as $794 578 in east-central Alberta (Area 4) to as high as $3 062 644 in central Alberta (Area 5). On average, across the PSAC areas, estimates for oil well costs increased by 5.3 per cent.

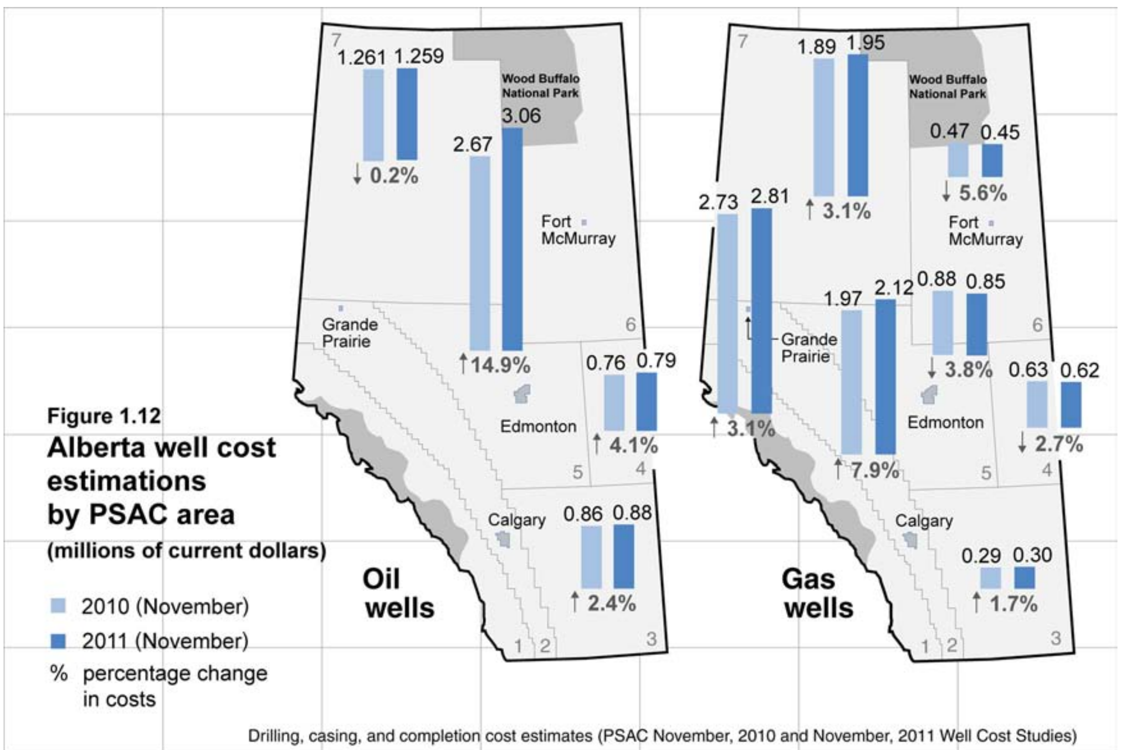


Figure 1.12 Alberta well cost estimations by PSAC area (millions of current dollars)

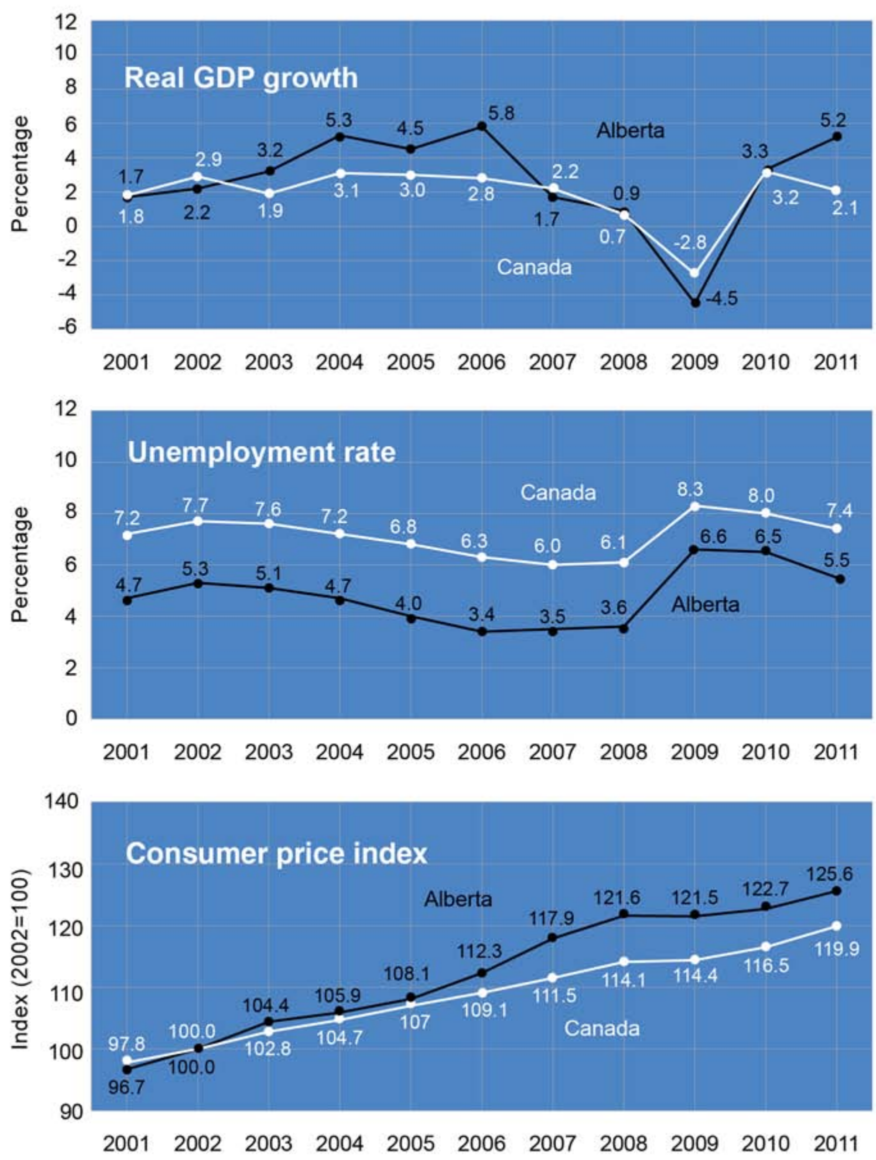
Gas well drilling and completion costs are also projected to increase. Estimated costs to drill and complete a typical gas well in the winter of 2011–2012 were highest in the Foothills (Area 1) at over $2.8 million. In Southeastern Alberta (Area 3), a typical gas well was estimated to cost about $291 000 to drill and complete. The average estimated cost to drill and complete a typical gas well across the PSAC areas increased by 0.5 per cent from the previous year.

1.3 Economic Performance

1.3.1 Alberta and Canada

The historical performance of major economic indicators for Alberta and Canada are depicted in **Figure 1.13**. Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003–2007 timeframe. Average Alberta GDP

Figure 1.13
Alberta and Canada economic indicators

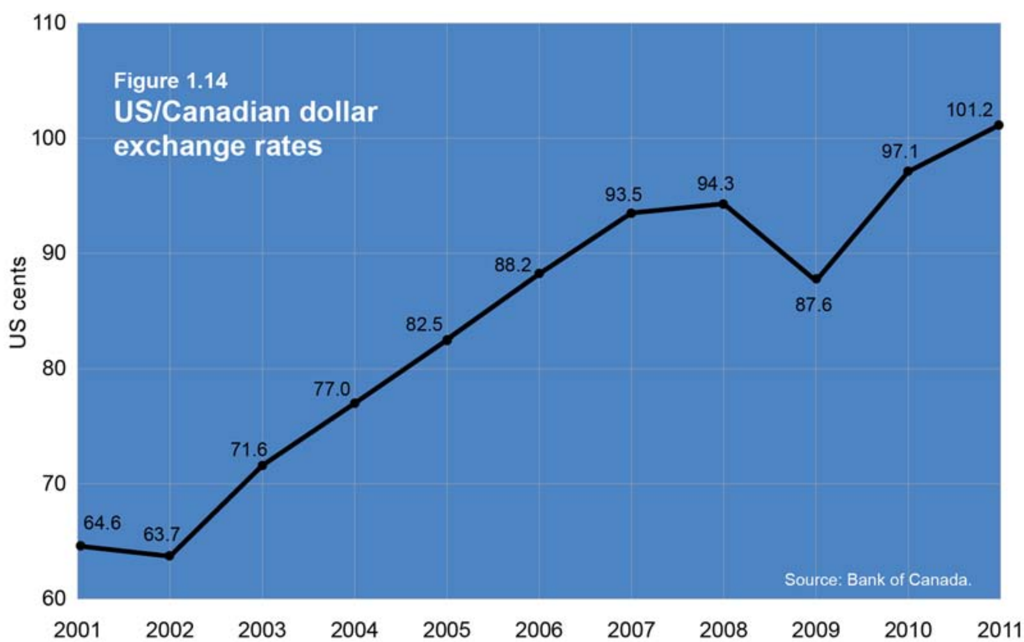


Source: Statistics Canada.

growth from 2002 to 2011 was 2.8 per cent, compared with a Canadian average of 1.9 per cent. Similarly, the unemployment rate in Alberta averaged 4.8 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2002, inflation in Alberta has averaged 2.9 per cent per year, while Canadian inflation has averaged 2.1 per cent. Inflation averaged 4.0 per cent in Alberta during the 2006–2008 peak.

Figure 1.14 illustrates the historical performance of the US/Canadian dollar exchange rate between 2000 and 2011. The exchange rate is an economic parameter that affects both the Canadian and Alberta economies.



The US/Canadian dollar exchange rate averaged US$1.01 in 2011, compared with US$0.971 in 2010. The exchange rate began the year averaging US$1.01 in January 2011 and averaged US$0.98 in December 2011, exhibiting relative stability as the global economy and financial system continued to recover from the financial crisis of 2008. The US/Canadian dollar exchange rate is projected to average US$0.99 for the remainder of the forecast period as crude oil prices are forecasted to remain strong.

1.3.2 The Alberta Economy in 2011 and the Economic Outlook

The ERCB forecast of Alberta real GDP and other economic indicators is shown in **Table 1.4**. Alberta real GDP is estimated to have increased by 5.2 per cent in 2011, compared with 3.3 per cent in 2010.

Real GDP is forecast to again increase by 3.5 per cent in 2012 and to continue to grow at a 3.3 per cent trend from 2013 to 2021 based on expectation of strong hydrocarbon development and exports. Alberta's inflation rate was 2.4 per cent in 2011, compared with the national inflation rate of 2.9 per cent.

Table 1.4 Major Alberta economic indicators, 2011–2021 (%)

	2011	2012	2013–2021[a]
Real GDP growth	5.2	3.5	3.3
Population growth	1.6	1.7	1.8
Inflation rate	2.4	2.4	2.4
Unemployment rate	5.5	4.7	4.1

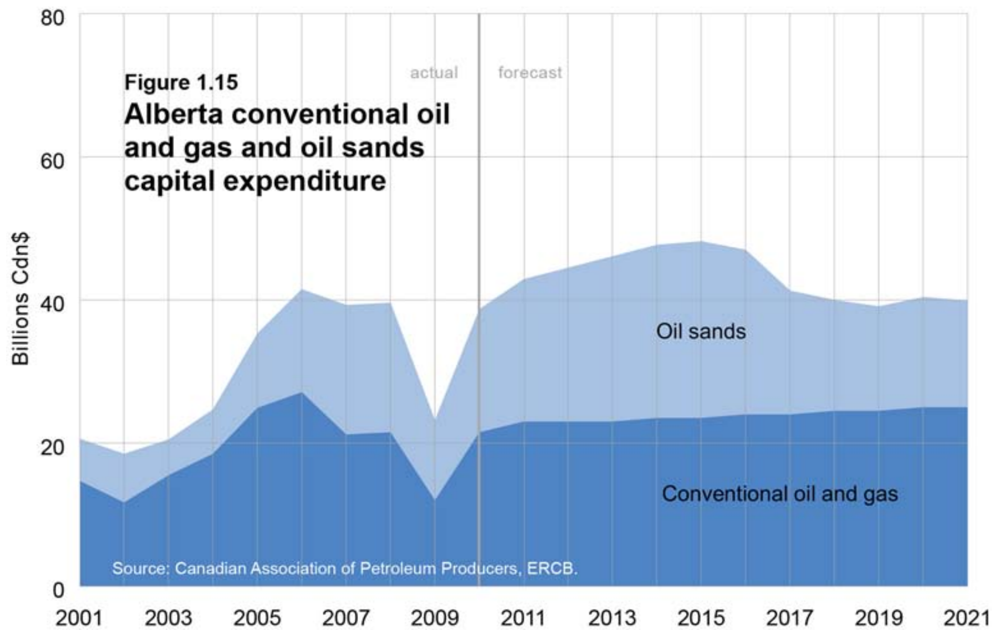
[a] Averaged over 2013–2021.

Economic growth is projected to increase in 2012 as oil and gas activity continues to recover from the depressed levels of 2009. There were 9894 wells drilled in Alberta in 2011, compared with 9233 in 2010, an increase of 661wells, or 7.2 per cent.

The ERCB estimates that oil sands capital expenditures increased to $19.9 billion in 2011, compared with $17.2 billion in 2010 and $11.2 billion in 2009. Investment is predicted to increase to $21.5 billion in 2012 and peak in 2015 at $24.7 billion. Construction activity for the Imperial Oil Kearl Lake project continues, and production is planned to begin in late 2012. Many in situ projects have been announced and are proceeding through the application process, and projects that are further along are commencing or continuing construction. Conventional oil and gas expenditures have rebounded significantly since the 2009 level of $12 billion and reached $21.5 billion in 2010 as activity in the basin has shifted to the application of horizontal wells and multistage fracturing to tight oil and liquids-rich gas. This trend is expected to continue throughout the forecast period.

Figure 1.15 illustrates the historical and projected profile of investment in Alberta's conventional oil and gas industry and in the oil sands industry.[5] The estimated actual for 2010 has been revised to be substantially higher based on the actual figure published in November 2011 by the Canadian Association of Petroleum Producers (CAPP). A significant part of the higher forecast capital profile comes from higher conventional oil and gas spending due to the rapid implementation of horizontal wells combined with multistage fracturing technology. The sharp decline in 2009 was followed by an immediate rebound in 2010. This rebound in conventional oil and gas spending occurred in a relatively mature oil and gas basin in an environment of depressed gas prices. The continued application of horizontal wells combined with multistage fracturing technology is expected to maintain conventional oil and gas investment throughout the forecast period close to current levels. Due to the higher forecast for conventional oil and gas spending, the current forecast has higher capital cost inflation than was projected in last year's forecast. This results in total oil and gas sector spending exceeding the peak of the previous decade in nominal dollar terms.

[5] Historical statistics obtained from CAPP *Statistical Handbook* (2010 data).



The forecast of capital spending for oil sands is consistent with the ERCB's forecast of upgraded and nonupgraded bitumen production. The oil sands capital cost forecast has been revised upwards to reflect the higher inflation rate and greater project certainty as projects move closer to production.

As shown in **Figure 1.15**, oil sands related expenditures are projected to increase significantly by the middle of the decade to meet the anticipated increases in upgraded and nonupgraded bitumen production. Combined with the recovery in conventional oil and gas expenditures, total oil and gas investment exceeds levels of capital spending experienced during the 2006–2008 peak.

During the forecast period, nonupgraded bitumen production is forecast to increase at an average annual rate of 7.2 per cent. Upgraded bitumen production is projected to increase at an average annual rate of 5.1 per cent. Virtually all of this production increase will be exported, providing export-led economic growth for the province.

The value of Alberta's energy resource production in 2010 and 2011 is depicted in **Figure 1.16**. In 2011, the total value of production increased by 19.7 per cent relative to 2010. The value of upgraded and nonupgraded bitumen production significantly exceeded the value of natural gas production for the third year, the continuation of a trend that is expected to continue throughout the forecast period. In 2011, combined upgraded and nonupgraded bitumen revenues are greater than the combined revenues from conventional gas, conventional crude oil, and natural gas liquids.

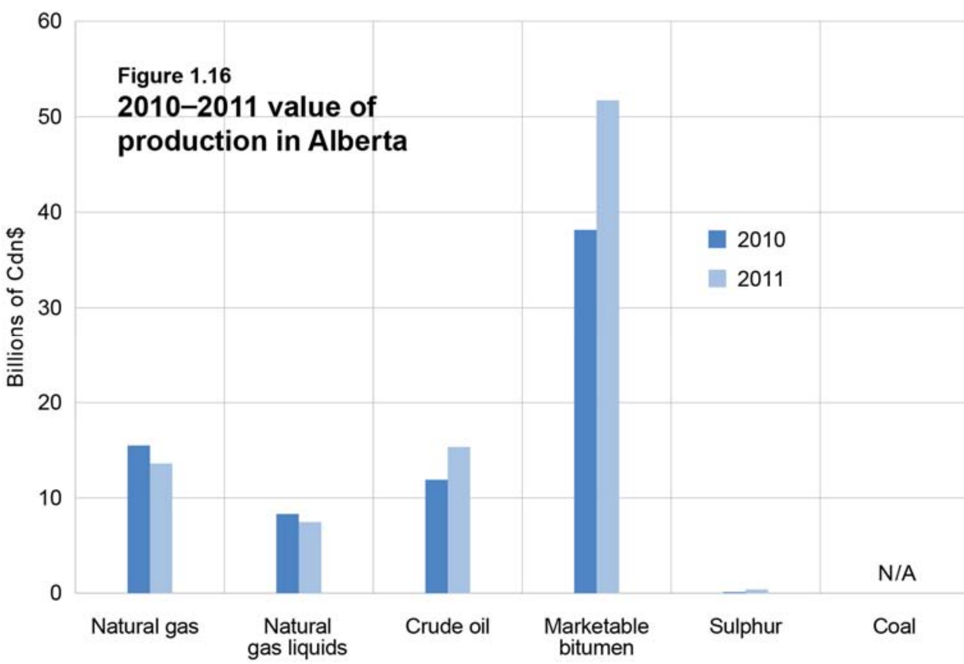
The total economic value of Alberta's energy resource production for 2011 to 2021 is shown in **Table 1.5**. Production from upgraded and nonupgraded bitumen derived from the oil sands will more than offset the decline in conventional resource production, increasing from 58.4 per cent of total revenues in 2011 to an average of 69.0 per cent of total revenues from 2014 to 2021.

Continued investment in mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy, based on the projected price and production forecasts. Alberta's economic growth will continue to be a strong contributor to Canada's economic growth.

Table 1.5 Value of annual Alberta energy resource production (millions of current dollars)

	2011	2012[a]	2013[a]	2014–2021[a,b]
Conventional crude oil	15 352	17 395	18 010	17 763
Nonupgraded bitumen	18 348	20 662	23 678	41 019
Upgraded bitumen	33 361	35 232	40 020	51 522
Marketable gas	13 644	7 712	11 652	15 272
Natural gas liquids	7 490	8 826	8 693	8 477
Sulphur	375	140	140	142
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	**88 569**	**89 967**	**102 192**	**134 195**

[a] Values calculated from the ERCB's annual average price and production forecasts—columns may not add due to rounding.
[b] Annual average over 2014–2021.



HIGHLIGHTS

A discussion of the geological framework of the Western Canada Sedimentary Basin is included.

A discussion of Alberta's petroleum systems is included.

The methods the ERCB uses to estimate resources and determine reserves are given.

The reserves framework employed in the report is detailed.

2 // RESOURCE ENDOWMENT

Of Alberta's many natural resources, this report focuses on energy resources—namely, petroleum hydrocarbons and coal. Resource appraisal is performed by the Energy Resources Conservation Board (ERCB) in the fulfillment of its legislated mandate. The *Energy Resources Conservation Act* defines the activities of the ERCB. Its purposes, in Section 2, include

(a) providing for the appraisal of the reserves and productive capacity of energy resources and energy in Alberta, and

(b) providing for the recording and timely and useful dissemination of information regarding the energy resources of Alberta.

The resource appraisal function includes geological survey, resource estimation, and reserve determination activities at the ERCB. These activities are done in a framework that provides consistent year-to-year comparisons of energy development in Alberta. Some elements of this framework are under review to ensure that the ERCB's reserve reporting remains timely and useful, as discussed at the end of this section.

2.1 Geological Framework of Alberta[1]

2.1.1 Western Canada Sedimentary Basin

The overall stratigraphic sequence of Alberta consists of a northeast thinning wedge of sedimentary rocks. This wedge comprises three thick packages of rock most simply described as a carbonate succession sandwiched between two clastic successions. These sedimentary strata lie overtop a crystalline basement of igneous and metamorphic rock of Precambrian age that forms the foundation of the modern North American continent. The thickness of the sedimentary wedge tapers to zero in northeastern Alberta where the crystalline basement is exposed as part of the Canadian Shield.

The lower clastic succession is restricted to the Rocky Mountains. It is composed of thick metamorphic quartzite and slate rocks of Precambrian age and overlying sedimentary strata of Cambrian to Ordovician age. The middle carbonate succession is composed mainly of limestones, dolostones, and evaporites of Devonian to Mississippian age. The upper clastic succession is Triassic to Tertiary in age.

[1] The *Geological Atlas of the Western Canada Sedimentary Basin* contains a full description of Alberta's geological history and forms the basis for the summary in this section. The atlas is available through the ERCB's Alberta Geological Survey, a co-sponsor of the atlas.

Both the middle carbonate and the upper clastic successions cover most of Alberta. Just beneath the modern land surface is a major unconformity that separates the youngest bedrock from gravels, thick glacial deposits, and modern alluvium.

The continental margin and structural trough that received sediments that comprise these three thick packages are collectively known as the Western Canada Sedimentary Basin (WCSB). The WCSB is often divided into regional basinal and sub-basinal elements including the Alberta Basin, the Williston Basin, and the Liard/Horn River Basin, as shown on **Figure 2.1**. The eastern edge of the basin is defined by the erosional edge of the sediments, while the north and southern boundaries are arbitrary and correspond to the Tathlina structural high in the Northwest Territories and the Canada-U.S. border respectively. The western edge is variously described as the edge of the disturbed belt in front of the Rocky Mountains, the Rocky Mountain trench, or the westernmost extent of sediments that occur within the western part of the Omineca belt of British Columbia. **Figure 2.1** illustrates the western edge at the Rocky Mountain Trench.

Figure 2.1
Basinal elements of the Western Canada Sedimentary Basin

The geological origin and structure of Alberta's strata ultimately determine the type and extent of Alberta's energy resources. The overall geologic history of Alberta falls into two main phases:

- Phase I lasted from 1.5 billion years ago to 170 million years ago. It was characterized first by deposition in a shallow sea lying along the passive continental margin of the proto-Pacific ocean. This was followed by deposition within a shallow, interior continental seaway. This seaway marked the formation of an intracratonic basin, formed indirectly in association with uplift and mountain building far to the southwest of Alberta. The lower clastic and middle carbonate successions were deposited during Phase I.
- Phase II lasted from 170 million years ago to present. It was characterized by uplift and structural deformation, which formed the Rocky Mountains and mountain ranges farther west. Loading of the mountains onto the crust caused the shallow seaway of Phase I to deepen into a depositional trough called a foreland basin. Sediments from the rising mountains were shed eastward into the basin, gradually filling it in and causing the seas to retreat. Uplift abated about 55 million years ago, and the Alberta basin has undergone erosion ever since, with the exception of deposition related to glacial advances and retreats over the last two million years. The upper clastic succession was deposited during Phase II.

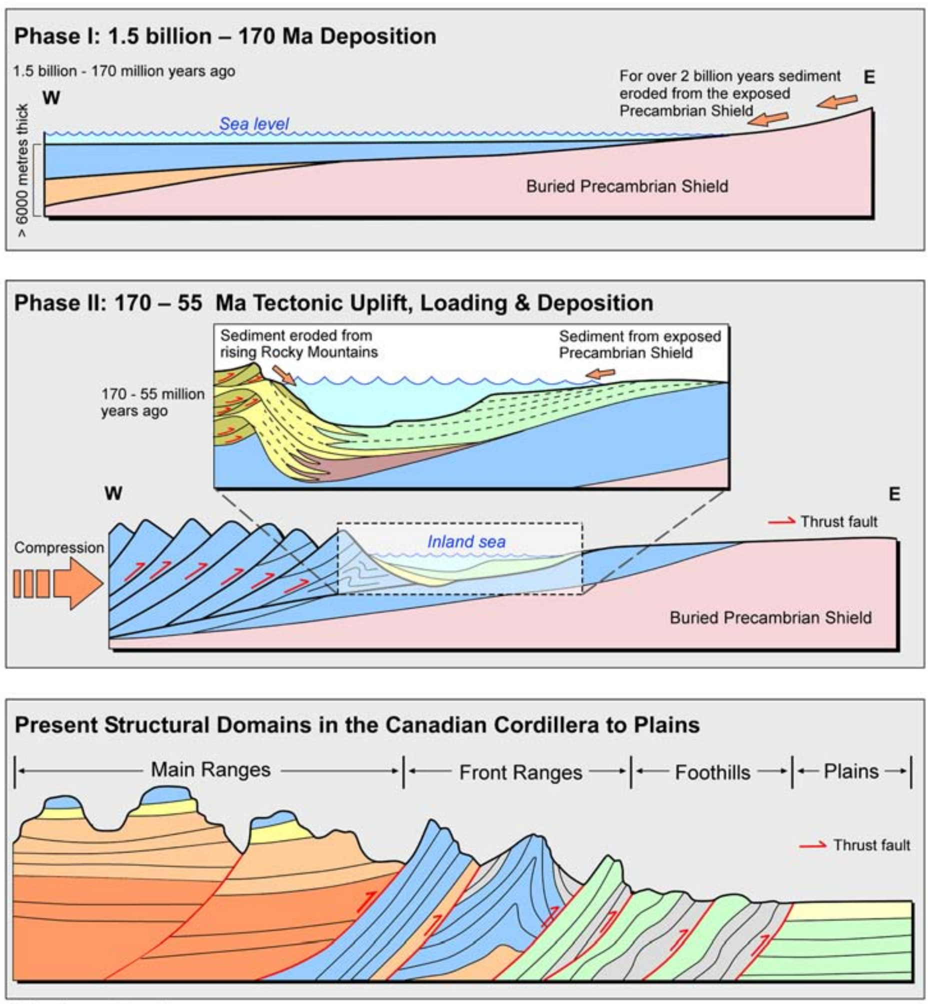
These events are shown in **Figure 2.2**.

The geological record of events in Phases I and II is preserved in the strata of the WCSB. A simplified version of Alberta's strata is shown in **Figure 2.3**. The stratigraphy is formalized in ERCB's Table of Formations. The Alberta Geological Survey of the ERCB has begun a multi-year major review of the Table of Formations to ensure that it is fully aligned with the most recent North American Stratigraphic Code, released in 2005.

2.1.2 Alberta's Petroleum Systems

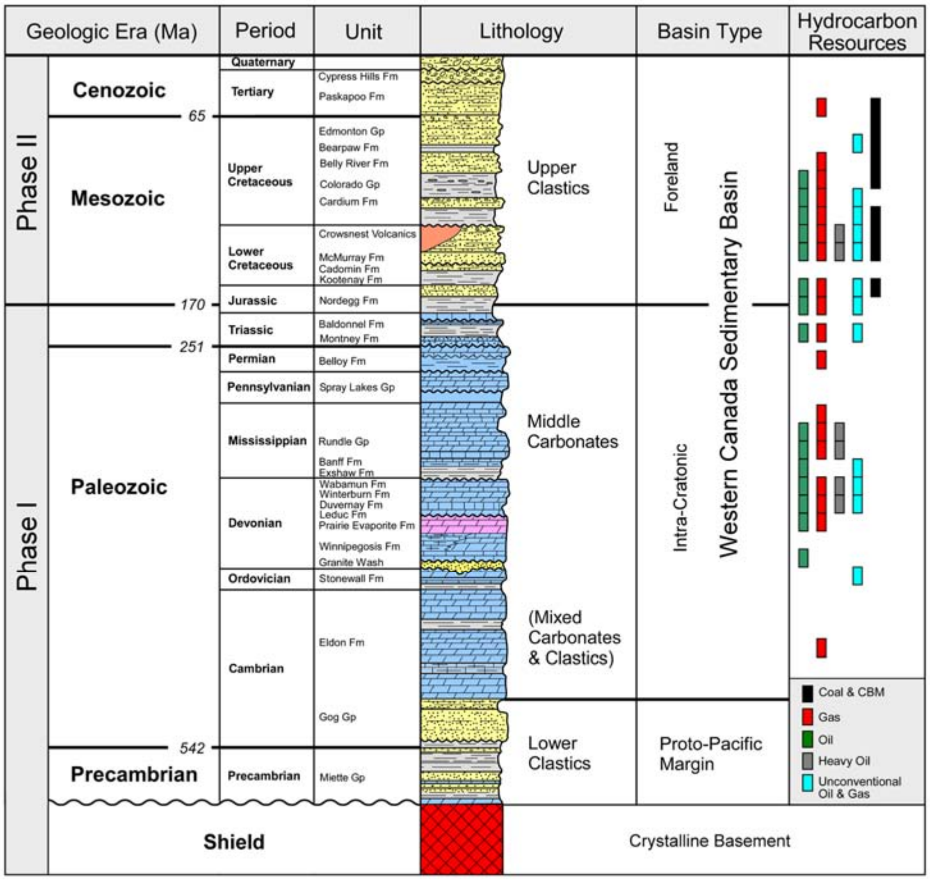
Petroleum is a naturally occurring organic mixture consisting predominantly of chain and ring molecules of carbon and hydrogen with varying amounts of sulphur, nitrogen, and oxygen as impurities. Petroleum forms underground by the action of heat and pressure over millions of years on buried organic matter that originated as dead algal, plankton, and plant remains. Rock units sufficiently rich in organic matter to generate petroleum during burial are called source rocks. After petroleum generation begins, the petroleum is driven from the source rock and migrates along permeable strata and fractures until it is trapped by favourable geological configurations of low-permeability rock or escapes to the surface. Not all of the petroleum generated in source rocks will migrate; much is left within the source beds themselves. Coal beds are a special type of source rock in which the organic material content is well over 50 per cent of total rock mass. Coal beds can produce substantial amounts of methane.

Figure 2.2
Geologic evolution of Alberta



* Drawings not to scale

Figure 2.3
Generalized stratigraphic column of Alberta



The linked assemblage of source rock, migration routes, and ultimate traps is called a petroleum system. The Alberta Basin component of the WCSB contains at least eight petroleum systems associated with the following major source rocks:

- Middle Devonian System—sourced by basinal marine laminites of the Keg River/Winnipegosis formations
- Upper Devonian System—sourced by basinal marine laminites of the Leduc-equivalent Duvernay and Cooking Lake–equivalent Majeau Lake formations
- Upper Devonian System—sourced by basinal laminites of the Cynthia Member of the Nisku Group
- Uppermost Devonian and lowermost Mississippian System—sourced by the basin-wide marine mudstones of the Exshaw Formation

- Middle Triassic System—sourced by the marine phosphatic siltstones at the base of the Doig Formation
- Lower Jurassic System—sourced by the marine lime muds of the Nordegg (Gordondale) Member of the Fernie Group
- Lower Cretaceous System—sourced by the continental coals and carbonaceous shales of the Mannville Group
- Upper Cretaceous System—sourced by the marine mudstones of the Colorado Group, principally the First and Second White Speckled Shales and the Fish Scales Zone

The Exshaw, Nordegg, and Duvernay source rocks are thought to have supplied most of the hydrocarbons in the Alberta Basin, and hydrocarbon accumulations within upper systems can be sourced from lower systems. For example, a likely source for the Lower Cretaceous crude bitumen deposits is the Lower Mississippian Exshaw Formation.

Conventional oil and gas pools are found throughout the middle carbonate and upper clastic successions. Little oil and gas is known to occur in the lower clastic succession, and the crystalline basement has none. Coals and coalbed methane (CBM) are found within the Jurassic, Cretaceous, and Tertiary-age portions of the upper clastic succession. Heavy oil pools and crude bitumen[2] deposits occur mostly in Cretaceous-age strata at the shallow, updip edge of the Alberta Basin, near the contact of the sedimentary successions with the underlying crystalline rocks of the Precambrian basement. There is also bitumen in the middle carbonate succession directly underneath.

In addition to these accumulations, there is widespread biogenic generation of methane in the shallow subsurface, mostly found in unconsolidated glacial deposits and shallow, coal-bearing bedrock units. This gas is pervasive but does not occur in commercial quantities and sometimes is a geological hazard in shallow water wells in Alberta.

2.1.3 Energy Resource Occurrences—Plays, Deposits, and Pools

Estimates of potential volumes of hydrocarbon generation and migration can be quantified for petroleum systems through detailed basin analysis. Petroleum-system analyses are not generally performed at scales applicable to issues of resource conservation and industry regulation. Instead, each petroleum system can be subdivided into geological plays.

[2] Crude bitumen is extra heavy oil that in its natural state will not flow to a well. Most bitumen in Alberta has been formed by the biodegradation of lighter crude oils.

A geological play can be defined as a set of known or postulated oil and/or gas accumulations (pools and deposits[3]) within a petroleum system sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play represents the limits of the geologic elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour gas play.

It is common practice for industry to categorize exploration and development opportunities in terms of geological plays. The ERCB does not currently designate or otherwise formally declare geological plays. The ERCB does designate oil sands areas, coal fields, oil and gas pools and fields, and strike areas. These constructs were originally congruous with geological plays, but some have devolved into administrative entities as more geological plays became recognized within and across their boundaries. The ERCB is considering designating play areas where unconventional resource development is expected to take place.

The ERCB has begun assembling a catalogue of geological plays in Alberta from various past studies and summarizing Alberta's energy resources and reserves in a geological-play context.

2.2 Resource Appraisal Methodologies

The ERCB uses the term "resource appraisal" to encompass all aspects of quantifying Alberta's in-place resources and recoverable reserves. To add clarity to the major components of resource appraisal, this report uses the phrase "resource estimation" to describe activities related to quantifying the amount of energy resources in the ground, and the phrase "reserves determination" to describe activities related to quantifying the recoverable portion of these in-place resources (i.e., the established reserves).

2.2.1 Resource Estimation

The ERCB generates its own resource estimates. The in-place resources estimation process starts with the receipt by the ERCB of raw data submitted by energy resource industries, either as required by legislation or through regulatory applications or submissions, the vast majority of which is well or borehole data. ERCB geological staff use pertinent data such as geophysical well logs, cores and drill cuttings, core analysis, and well test data (such as pressure) together with industry or academic information such as reports, seismic data, or regional studies to estimate petrophysical information and various geological surfaces and zones. These geological and petrophysical evaluations are used for both regulatory and resource appraisal purposes. Several techniques, including geostatistics, are used in generating a volumetric estimate of in-place resources for the various energy resources. As the ERCB's play catalogue is compiled, resource estimates for each play will be reported.

---

[3] In general, pools are discrete accumulations of hydrocarbons, whereas deposits are wide spread continuous accumulations of hydrocarbons and coal. Pools also can be commingled into larger administrative units.

2.2.2 Reserves Determination

The ERCB determines two types of estimates of the recoverable portion of Alberta's in-place resources. The portion determined recoverable from known accumulations or deposits using today's technology is classified as "established reserves." The portion determined from known and unknown resources using reasonably foreseeable technology is classified as the "ultimate potential." Established reserves are determined on an ongoing basis, whereas ultimate potentials usually result from major studies conducted periodically. These terms are defined in a following section.

In determining the established reserves of an energy resource, consideration is given to geology, pressures, production, technology, and economics. Geological factors are mainly considered when estimating in-place quantities. However, additional considerations are usually required to reduce the in-place quantity to a more likely developable quantity and to assure the existence and extent of the recoverable portion.

Alberta's production of oil and gas has predominantly come from conventional pools in which hydrocarbons have accumulated in concentrated quantities in porous and permeable reservoirs drainable by vertical wells. The ERCB determines reserves of conventional pools through accepted practice of geology-based volumetric estimation, production decline-analysis, and material balance methodology.

Initially there is a higher level of uncertainty in the reserves estimates, but this level decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. Analysis of production decline data is a primary method of determining recoverable reserves. It also provides a realistic estimation of the pool's recovery efficiency when it is combined with a volumetric or a material balance estimate of the in-place resource.

The determination of reserves in deposits is similar to the methods used to determine pool reserves. One or more factors are applied against an in-place volume or tonnage to determine the recoverable portion of the resource. These reserves are often estimated by three-dimensional geological models that routinely involve the data from hundreds or thousands of wells and drillholes.

2.2.3 Ultimate Potential

Ultimate potential estimates represent recoverable quantities. They are determined for each energy resource commodity over the entire province on the basis of a future end-of-the-day timescale. These estimates are the result of considering all development of an energy resource up to the time of the estimate and looking forward to cessation of exploration activity and the type of technology that might reasonably be expected to be used in the future. Future-based economic circumstances are also considered. These estimates form a reasonable and credible basis for longer term production forecasts and government policy decisions regarding energy resources.

2.3 Resources and Reserves Classification System

The ERCB reports the reserves of Alberta by commodity (crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal) based on the Inter-Provincial Advisory Committee on Energy (IPACE) system for uniform terminology and definitions in the estimating and publishing of hydrocarbon reserves information in Canada. The IPACE system was adopted by most government and national bodies for the use of reserves reporting in Canada in 1978 and has been in use since that time. The IPACE system was designed as a simple categorization of reserves to facilitate understanding and transparency in reporting to the public. The key reserves definitions in the IPACE system are

- Initial volume in-place—the gross volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced;
- Established reserves—those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgment portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty;
- Initial established reserves—established reserves prior to the deduction of any production;
- Remaining established reserves—initial established reserves less cumulative production;
- Ultimate potential—an estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools.

The IPACE system was designed, and is most appropriate, for use with conventional oil and gas resources. Consequently, the ERCB has introduced alterations to the IPACE system to make it compatible for all energy resources, including coal. More recently, alterations have also been applied to unconventional resources, such as crude bitumen, to more fully report the resource endowment of Alberta.

Unlike conventional resources, for which the lead time between successful exploration and development is relatively short, resources developed by mines (coal and mineable oil sands) often require long lead times. As a result, much exploration information can become available without the requisite increase in the number of mines. Such a condition existed in the late 1970s and early 1980s in Alberta. One of the ERCB's first IPACE alterations was the publication of separate estimates for those coal and mineable oil sands resources that were determined to be recoverable on a province-wide basis and those determined only from areas being actively mined ("established reserves under active development"). For the estimates on a provincial basis, a recoverable portion was determined (i.e., established reserves) only from areas with sufficient data and assuming proven mining technology, generalized industry economic scenarios, and the existence of adequate markets when required.

The ERCB adopted a similar approach for in situ crude bitumen reserves. In this case, however, because new technologies were being used, the ERCB began publishing provincial established reserves estimates based on active development areas only. As confidence in the technologies grew, the ERCB decided to produce, for year-end 1999, a much larger provincial estimate in addition to the active development estimate. This approach helped reflect the true size of the in situ bitumen resource that could be developed using existing technologies.

The ERCB's approach to determining CBM reserves also follows the approach taken for in situ crude bitumen. CBM reserves are generally restricted to areas of active development. The ERCB believes that moving to a province-wide determination is not yet appropriate, but it may be in the future.

For unconventional hydrocarbon resources and coal, another significant change from IPACE is the differentiation between the total amount of in-place resource and the more developable portion that recovery operations might reasonably be expected to target. An example of the determination of this developable in-place quantity is detailed in **Section 3.1.3**, where it is classified as the "initial mineable volume in place" of crude bitumen.

Since 1978, and particularly since 1997, the mineral and petroleum industries have strived for tighter definitions of reserves to better suit the financial markets. These efforts include the promulgation of National Instrument (NI) 51-101, in 2003, for petroleum reserve reporting to Canadian securities regulators, the creation of and updates to the Canadian Oil and Gas Evaluation Handbook (COGEH),[4] the Petroleum Resources Management System (PRMS),[5] the United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009 (UNFC-2009), and NI 43-101[6] for Canadian minerals (including coal) securities reporting. These efforts are under review by the ERCB, and a decision to either maintain or modify the IPACE system, or to adopt one or more of these newer frameworks, will be considered in the future.

---

[4] The COGEH was prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the then Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (now part of the Society of Petroleum Engineers). COGEH forms the technical basis of NI 51-101.

[5] The PRMS was prepared by the Society of Petroleum Engineers and reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

[6] The technical basis of NI 43-101 is the CIM Definition Standards on Mineral Resources and Mineral Reserves, prepared by the Canadian Institute of Mining, Metallurgy and Petroleum, known as CIM. This standard is itself based other international standards that have now been coalesced as the International Template for Reporting of Exploration Results, Mineral Resources and Mineral Reserves, prepared by the Committee for Mineral Reserves International Reporting Standards, know as CRIRSCO.

HIGHLIGHTS

Athabasca Nisku deposit was updated with initial in-place resources increasing 57 per cent to 16.2 billion cubic metres.

Athabasca Upper, Middle, and Lower Grand Rapids deposits were updated with total initial in-place resources increasing 7 per cent to 9.3 billion cubic metres.

Total bitumen production increased by 8 per cent, mineable production increased by 4 per cent, and in situ production increased by 13 per cent.

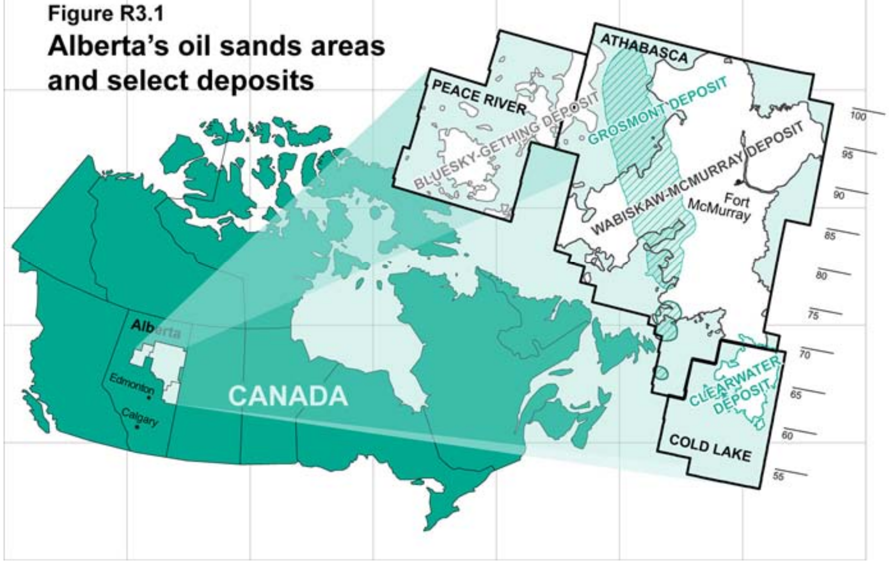
Upgraded bitumen production increased by 9 per cent.

3 // CRUDE BITUMEN

Crude bitumen is extra heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern Alberta. The crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes, the geologic formations and the geographic areas containing the bitumen are designated as oil sands areas (OSAs). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated OSAs in Alberta are shown in **Figure R3.1**. Combined, they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Contained within the OSAs are 15 oil sands deposits designated according to the specific geologic zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

Figure R3.1
Alberta's oil sands areas and select deposits



Depending on the depth of the deposit, one of two methods is used for the recovery of bitumen. North of Fort McMurray, crude bitumen occurs near the surface and can be recovered economically by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted from the mined material in large facilities using hot water. At greater depths where it is not economical to recover the bitumen through mining, in situ methods are employed. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development. Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are the two main methods of enhanced development whereby the reservoir is heated to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore.

3.1 Reserves of Crude Bitumen

3.1.1 Provincial Summary

The ERCB continually updates Alberta's crude bitumen resources and reserves on both a project and deposit basis. For this year's report, the initial volume in-place resource estimates for the Athabasca Grand Rapids and Nisku deposits were updated. The remaining established reserves at December 31, 2011, are 26.80 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.10 10^9 m^3. Of the total 26.80 10^9 m^3 remaining established reserves, 21.46 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods, while the remaining 5.34 10^9 m^3 is recoverable by surface mining methods. Of the in situ and mineable totals, 4.06 10^9 m^3 is the remaining established reserve within active development areas. **Table 3.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

Table 3.1 In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.82	5.34	3.59
In situ	272.3	21.94	0.47	21.46	0.48
Total	**293.1**	**28.09** [a]	**1.29**	**26.80**[a]	**4.06**
	(1 844)[b]	(176.8)[b]	(8.1)[b]	(168.7)[b]	(25.6)[b]

[a] Any discrepancies are due to rounding.
[b] Imperial equivalent in billions of barrels.

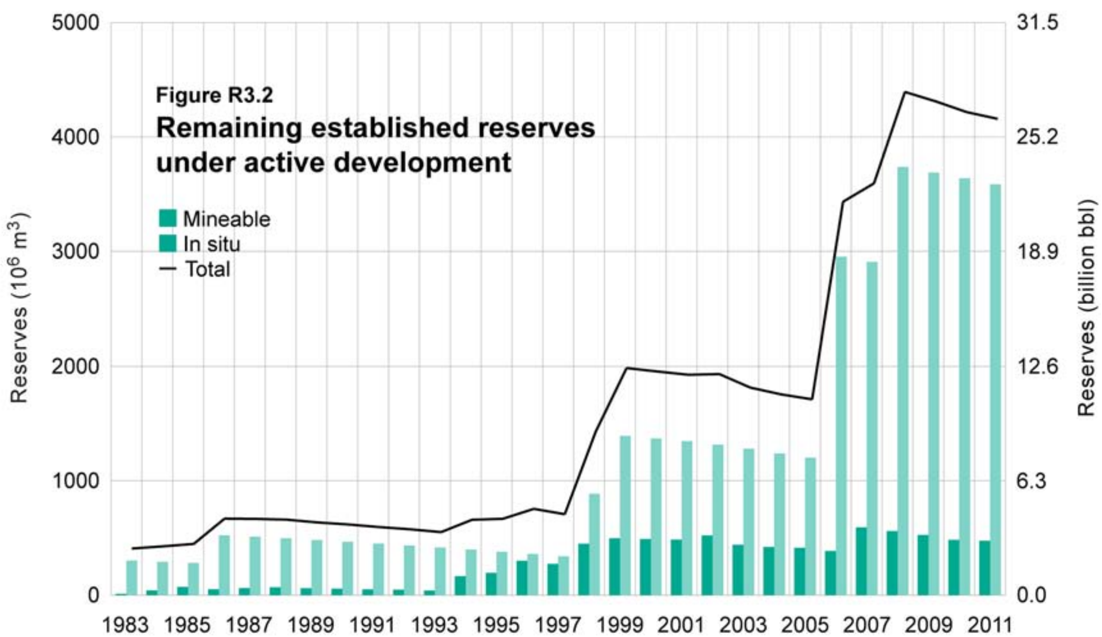
The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative and annual production for 2011 are shown in **Table 3.2.** Crude bitumen production in 2011 totalled 101 10^6 m^3, with in situ operations contributing 49 10^6 m^3.

The remaining established reserves in active development areas are presented in **Figure R3.2**. These project reserves have a stair-step configuration representing start-up of new large mining projects. The intervening years between additions are characterized by a slow decline due to annual production.

Table 3.2 Reserve and production change highlights (10^6 m^3)

	2011	2010	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total[a]	**28 092**	**28 092**	**0**
	(176 780)[b]	(176 780)[b]	
Cumulative production			
Mineable	820	768	+52[c]
In situ	474	426	+49[c]
Total[a]	**1 294**	**1 194**	**+101[c]**
Remaining established reserves			
Mineable	5 337	5 389	-52
In situ	21 461	21 509	-49
Total[a]	**26 798**	**26 898**	**-101**
	(168 637)[b]	(169 267)[b]	
Annual production			
Mineable	52	50	+2
In situ	49	44	+5
Total[a]	**101**	**94**	**+7**

[a] Any discrepancies are due to rounding.
[b] Imperial equivalent in millions of barrels.
[c] Change in cumulative production is a combination of annual production and all adjustments to previous production records.



3.1.2 Initial In-Place Volumes of Crude Bitumen

3.1.2.1 Year-end 2011 Updates

Efforts to update the province's crude bitumen resources and reserves began in 2003, and since then 11 of the 15 deposits have been updated. The Athabasca Wabiskaw-McMurray deposit, with the largest cumulative and annual production, was updated for year-end 2004 and subsequently revised in 2009 to take new drilling into account. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005, as was the northern portion of the Cold Lake Wabiskaw-McMurray deposit. The Peace River Bluesky-Gething deposit was updated for year-end 2006.

In 2009, the ERCB completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit. Bitumen pay thickness maps for these deposits are presented in **Appendix E**. Also included in **Appendix E** are two structure contour maps for the sub-Cretaceous unconformity. One is a regional map covering all the oil sands areas, the other is a map detailing the Cold Lake OSA.

The Athabasca Upper, Middle, and Lower Grand Rapids deposits and the Athabasca Nisku deposit were reassessed for year-end 2011. Bitumen pay thickness maps for these deposits are presented in **Figures R3.3, R3.4, R3.5,** and **R3.6**.

The year-end review for the three Athabasca Grand Rapids deposits (Upper, Middle, and Lower) included an evaluation of 3575 wells for stratigraphic tops and 1887 for reservoir parameters. The study area covered Townships 73 to 87 within Range 17, West of the 4th Meridian, to Range 1, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 8 678 10^6 m^3 to 9 274 10^6 m^3 for the Grand Rapids deposits. This represents a 7 per cent increase, which is attributed to an increased number of wells drilled in the area.

The Grand Rapids Formation is interpreted to be prograding sequences of shoreface sands and shales. The formation has informally been divided into Upper, Middle, and Lower sequences, with the boundaries often defined by laterally extensive marine shales (maximum flooding surfaces). The Athabasca Upper Grand Rapids accounts for the majority (approximately 60 per cent) of the bitumen-bearing sand within this formation (**Table 3.3**). The Grand Rapids Formation is bounded above and below by the marine shales of the Joli Fou and Clearwater formations, respectively.

The year-end review of the Athabasca Nisku Formation included an evaluation of 560 wells for stratigraphic tops and 130 wells for reservoir parameters. The study area covered Townships 75 to 96 within Range 18, West of the 4th Meridian, to Range 4, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 10 330 10^6 m^3 to 16 232 10^6 m^3. This represents a 57 per cent increase, which is attributed to an increase in well data and expansion of the delineated resource area.

The Nisku Formation is a late-Devonian shelf carbonate. Early dolomitization and subsequent leaching of meteoric waters led to karsting and the creation of vugs and caves. The Nisku is a naturally fractured reservoir. Similar to the Grosmont Formation, the bitumen in the Nisku is contained in a triple porosity system within the vugs, the fractures, and the rock matrix. Hydrocarbons were probably trapped structurally along the updip erosional edge before degradation to bitumen.

Recently, industry has been actively exploring the Leduc Formation for potential bitumen resources west of Fort McMurray. Preliminary results indicate bitumen pay thickness may exceed 100 m.

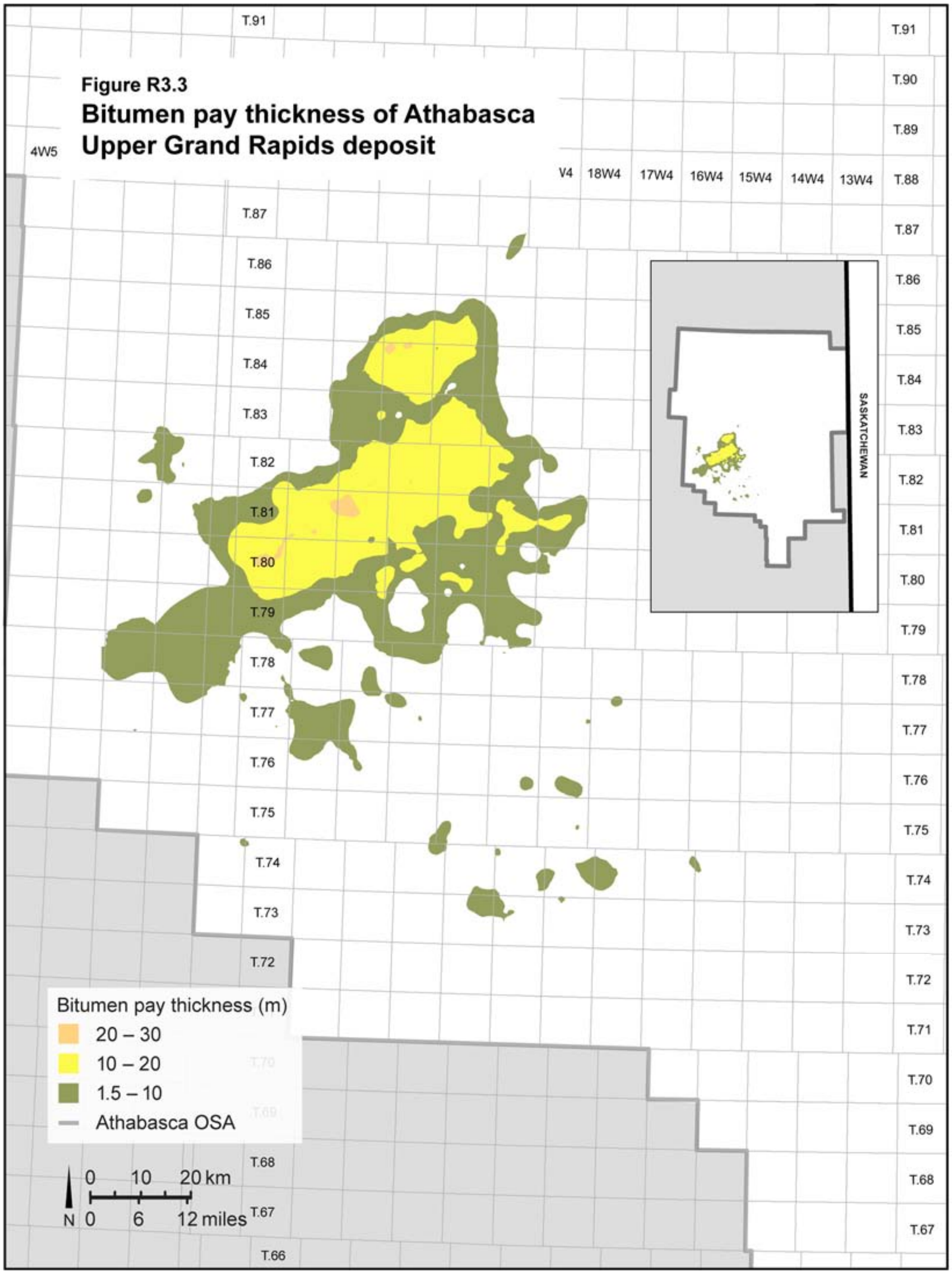


Figure R3.3
Bitumen pay thickness of Athabasca Upper Grand Rapids deposit
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
4W5
V4 18W4 17W4 16W4 15W4 14W4 13W4
T.91 T.90 T.89 T.88 T.87 T.86 T.85 T.84 T.83 T.82 T.81 T.80 T.79 T.78 T.77 T.76 T.75 T.74 T.73 T.72 T.71 T.70 T.69 T.68 T.67 T.66

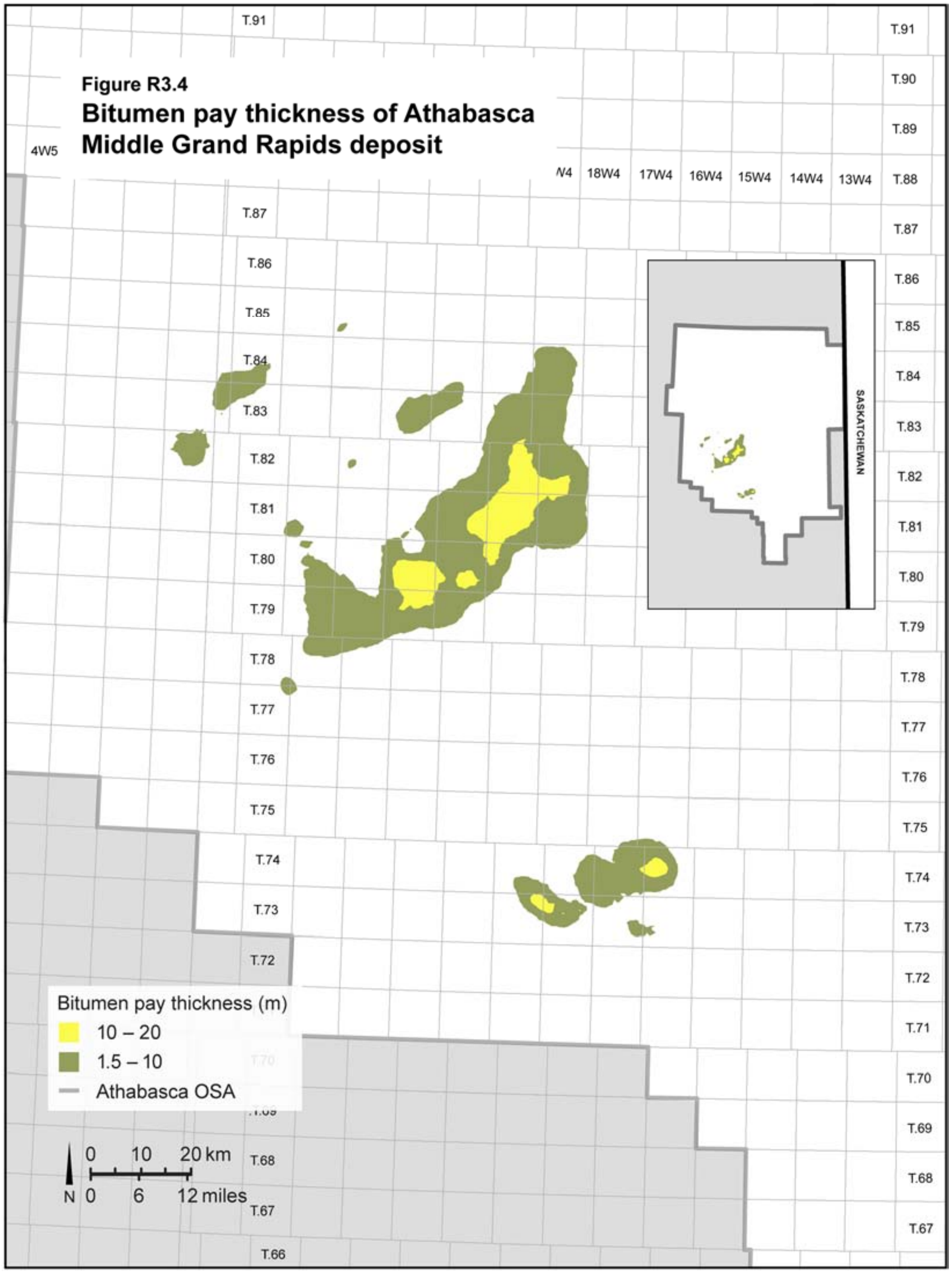


Figure R3.4
Bitumen pay thickness of Athabasca Middle Grand Rapids deposit
Bitumen pay thickness (m)
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
18W4 17W4 16W4 15W4 14W4 13W4
4W5
T.91 T.90 T.89 T.88 T.87 T.86 T.85 T.84 T.83 T.82 T.81 T.80 T.79 T.78 T.77 T.76 T.75 T.74 T.73 T.72 T.71 T.70 T.69 T.68 T.67 T.66

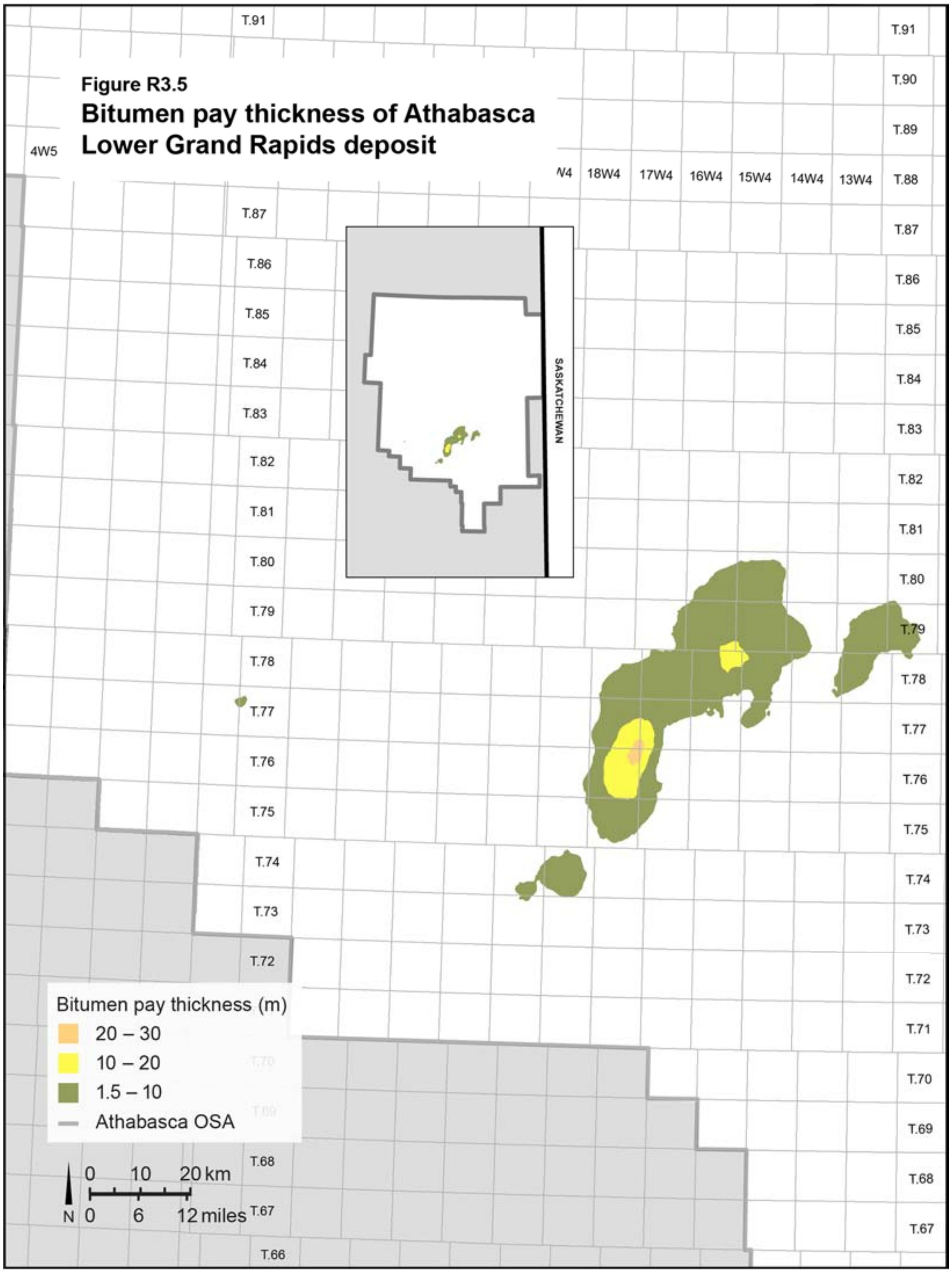


Figure R3.5
Bitumen pay thickness of Athabasca Lower Grand Rapids deposit
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66
4W5
18W4
17W4
16W4
15W4
14W4
13W4
SASKATCHEWAN
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
N 0 6 12 miles

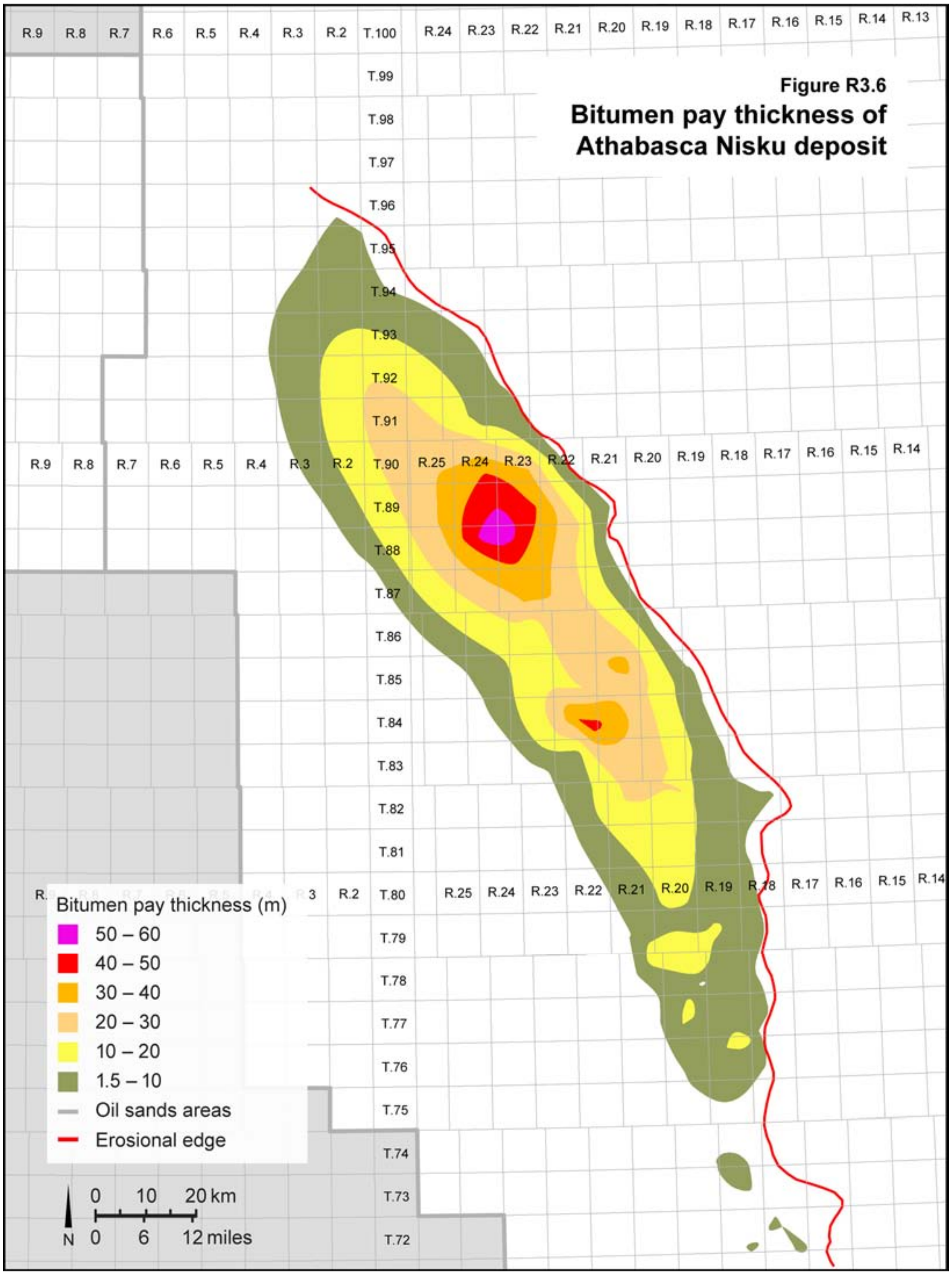


Figure R3.6
Bitumen pay thickness of Athabasca Nisku deposit
Bitumen pay thickness (m)
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Oil sands areas
Erosional edge
0 10 20 km
0 6 12 miles
N
R.9 R.8 R.7 R.6 R.5 R.4 R.3 R.2 T.100 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14 R.13
T.99
T.98
T.97
T.96
T.95
T.94
T.93
T.92
T.91
R.9 R.8 R.7 R.6 R.5 R.4 R.3 R.2 T.90 R.25 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
R.3 R.2 T.80 R.25 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72

3.1.2.2 Discussion

The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation decreases as the shale or clay content within the reservoir increases or as the porosity decreases. The relative amount of bitumen is expressed as mass per cent in clastics (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water). In carbonates, the relative amount of bitumen is expressed as bitumen saturation (the percentage of the volume of pore space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. The Athabasca Wabiskaw-McMurray; Athabasca Upper, Middle, and Lower Grand Rapids; Cold Lake Clearwater; Cold Lake Upper and Lower Grand Rapids; and the Peace River Bluesky-Gething deposits, as well as a portion of the Cold Lake Wabiskaw-McMurray deposit, were estimated using a 6 mass per cent saturation cutoff.

The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. In the revision of the Athabasca Grosmont and Nisku deposits, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values.

The ERCB believes that in measuring the quality of an oil sands area, cutoffs of 6 mass per cent for clastic bitumen deposits, and a pore volume of 50 per cent and porosity of 8 per cent for carbonate bitumen deposits, more accurately reflect the volumes from which bitumen can reasonably be expected to be recovered.

Within the Athabasca OSA is the ERCB-defined surface mineable area (SMA). It encompasses an area of 51½ townships north of Fort McMurray, covering the part of the Athabasca Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. As a result of the lower overburden thickness, it is presumed that the main recovery method will be surface mining. Outside of the SMA, in the rest of Alberta's crude bitumen area, in situ technology is the only viable recovery mechanism to date.

The defined boundaries of the SMA are simply for resource administration purposes and carry no regulatory authority. While the ERCB has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment purposes, surface mining may not actually take place, possibly reducing the estimate of mineable reserves. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resource occurs at a depth of less than 25 m of overburden. Since the boundaries of the SMA are defined using the boundaries of townships, a few areas of deeper bitumen resources more amenable to in situ recovery are included. As a result, while the extent of the SMA covers both mineable and in situ resources, estimates of mineable bitumen exclude those volumes within the SMA that are beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA and those deeper areas, generally greater than 65 m, within the SMA.

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Appendix B** (**Tables B.1** and **B.2)** and are summarized by formation in **Table 3.3**.

The in-place resource values in **Table 3.3** represent the total crude bitumen accumulated throughout the deposit where the cumulative thickness is equal to or greater than 1.5 m; however, current and anticipated recovery operations often only develop the better-quality portion of this total. This developable portion (also known as mineable and exploitable) varies depending on the type of recovery technology employed. Recovery factors are normally applied against this developable portion to determine the established reserves. The parameters used to reduce the total in-place volumes to a developable subset are given in **Section 3.1.3**.

Table 3.3 Initial in-place volumes of crude bitumen as of December 31, 2011

Oil sands area Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha*)	Average pay thickness (m)	Average Reservoir Parameters Mass (%)	Pore volume oil (%)	Average porosity (%)
Athabasca						
Upper Grand Rapids	5 817	359	8.5	9.2	58	33
Middle Grand Rapids	2 171	183	6.8	8.4	55	32
Lower Grand Rapids	1 286	134	5.6	8.3	52	33
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	16 232	819	14.4	5.7	68	20
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	**242 475**					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	**29 090**					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**293 125**					

* ha = hectare.

3.1.3 Established Reserves

There are two types of established reserves of crude bitumen: mineable reserves that are anticipated to be recovered by surface mining operations, and in situ reserves that are anticipated to be recovered through wells by one of several in situ recovery methods.

3.1.3.1 Surface-Mineable Crude Bitumen Reserves

With the 2008 expansion of the SMA and the subsequent updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the ERCB now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resource at depths most suitable to mineable technologies, generally less than 65 m. For year-end 2008, economic criteria were applied to potentially mineable areas in the total in-place portion of the SMA. Economic strip ratio (ESR) criteria, along with a minimum saturation cutoff of 7 mass per cent bitumen and a minimum saturated interval thickness cutoff of 3.0 m, were applied. The ESR criteria are fully explained in Appendix III of *ERCB Report 79-H: Alsands Fort McMurray Project*. This method reduced the total initial bitumen in-place resource of 20.8 10^9 m^3 to an initial mineable bitumen in-place resource of 10.3 10^9 m^3 as of December 31, 2008.

Factors were then applied to the initial mineable volume in place to determine the established reserves. A series of reduction factors were applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume; therefore, each factor is set at 90 per cent. A combined mining and extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserves of crude bitumen is 6.16 10^9 m^3. As of December 31, 2011, the remaining established mineable crude bitumen reserves has decreased from 5.39 10^9 m^3 year-end 2010 to 5.34 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2011, are presented in **Table 3.4**. At the end of 2011, almost three quarters of the initial established reserves were under active development. Currently, Canadian Natural Resources Limited (CNRL Horizon), Shell Canada Energy Limited (Shell Muskeg River and Shell Jackpine), Suncor Energy Inc. (Suncor), and Syncrude Canada Ltd. (Syncrude), are the only producers in the SMA, with a combined cumulative bitumen production of 820 10^6 m^3. The Fort Hills mine project (owned by Suncor, TOTAL E&P Canada Ltd., and Teck Resources Ltd.) and the Imperial Oil/ExxonMobil Kearl project are not yet producing bitumen but are considered to be under active development and are included in **Table 3.4**. In 2011, Total E&P Canada Ltd. received approval for the Joslyn North mine. It has not been added to **Table 3.4** as it was neither producing nor under construction at the end of 2011.

Table 3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2011

Development	Project area[a] (ha)	Initial mineable volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
CNRL Horizon	28 482	834	537	13	524
Fort Hills	18 976	699	364	0	364
Imperial/Exxon Kearl	19 674	1 324	872	0	872
Shell Muskeg River	13 581	672	419	70	349
Shell Jackpine	7 958	361	222	7	215
Suncor	19 155	990	687	300	387
Syncrude	44 037	2 071	1 306	430	876
Total	**151 863**	**6 951**	**4 407**	**820**	**3 587**

[a] The project areas correspond to the areas defined in the project approval.

Production from the five current surface mining operations amounted to 51.7 10^6 m^3 in 2011, with 20.1 10^6 m^3 from the Syncrude project, 16.7 10^6 m^3 from the Suncor project, 7.4 10^6 m^3 from the Shell Muskeg River project, 4.7 10^6 m^6 from the Shell Jackpine project, and 2.8 10^6 m^3 from the CNRL Horizon project.

3.1.3.2 In Situ Crude Bitumen Reserves

The ERCB has determined an in situ initial established reserve for those areas considered suitable for in situ recovery methods. Reserves are estimated using cutoffs appropriate to the type of development and differences in reservoir characteristics. Areas amenable to thermal development were determined using a minimum zone thickness of 10.0 m in all deposits with commercial development. For deposits with primary development, a minimum zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. While some reserves estimates have been updated using a minimum saturation cutoff of 6 mass per cent bitumen, much of the current data is still based on the 3 mass per cent bitumen cutoff for most deposits. Future reserves estimates will be based on values higher than 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to areas that met the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the active project recovery factors to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer-quality resource areas.

The volume of the in-place crude bitumen was reassessed in the Athabasca Grosmont deposit in 2009 and the Athabasca Nisku and Upper, Middle, and Lower Grand Rapids deposits in 2011. No reserves were estimated as there are no commercial projects currently operating within these deposits. Exploration has occurred and different recovery methods have been experimented with, but commercial operations have yet to be established. The ERCB estimates reserves only in deposits where commercial operations are in place.

In 2011, the in situ bitumen produced was 49.2 10^6 m^3, an increase from 43.8 10^6 m^3 in 2010. Cumulative production within in situ areas now totals 474.3 10^6 m^3, of which 319.8 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.51 10^9 m^3 in 2010 to 21.46 10^9 m^3 in 2011 due to production of 0.05 10^9 m^3.

The ERCB's 2011 estimate of the established in situ crude bitumen reserves under active development is shown in **Table 3.5**. Information on experimental schemes has been removed from the table due to the limited number of experimental schemes and the confidential nature of the associated production data.

The ERCB has assigned initial volumes in place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. The initial established reserves under primary development are based on a 5 per cent average recovery factor, with 10 per cent being used in Peace River based on production results. An additional 10 per cent recovery is applied to those primary schemes in Athabasca undergoing enhanced recovery by polymer injection or waterflooding. The recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake areas, respectively, reflect the application of various steaming strategies and project designs.

Table 3.5 In situ crude bitumen reserves[a] in areas under active development as of December 31, 2011

Development	Initial volume in place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	63.7	40	25.5	11.1	14.4
Primary recovery schemes	160.8	10	16.1	12.3	3.8
Subtotal[c]	**224.5**		**41.6**	**23.4**	**18.2**
Athabasca Oil Sands Area					
Thermal commercial projects	391.8	50	195.9	89.1	106.8
Primary recovery schemes	1 026.2	5	51.3	23.1	28.2
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	18.9	10.0
Subtotal[c]	**1 418.0**		**276.1**	**131.1**	**145.0**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	226.6	76.6
Thermal commercial (SAGD)[g]	33.8	50	16.9	2.6	14.3
Primary recovery schemes	6 257.5	5	312.9	90.6	222.3
Subtotal[c]	**7 504.1**		**633.0**	**319.8**	**313.2**
Total[c]	**9 146.6**		**950.7**	**474.3**	**476.4**

[a] Thermal reserves reported in this table are assigned only for lands on which thermal recovery is approved and drilling development has occurred.
[b] Includes amendments to production reports.
[c] Any discrepancies are due to rounding.
[d] Schemes currently on polymer or waterflood in the Brintnell-Pelican area. Previous primary production is included under primary schemes.
[e] The in-place number is that part of the initial volume in place for primary recovery schemes that will see incremental production due to polymer or waterflooding.
[f] Cyclic steam simulation projects.
[g] Steam-assisted gravity drainage projects.

That part of the total remaining established reserves of crude bitumen from within active in situ project areas is estimated to be 476.4 10^6 m^3. This is a net decrease from 2010's 483.5 10^6 m^3, as 2011 production exceeded the volume added due to a comprehensive review of pad volumetrics for the major commercial and primary recovery schemes in Athabasca, as well as thermal schemes in Peace River.

3.1.4 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ recovery methods is estimated to be 33 10^9 m^3 from Cretaceous clastic sediments and 6 10^9 m^3 from Paleozoic carbonate sediments. Prior to the expansion of the SMA, nearly 11 10^9 m^3 of bitumen was expected to be recovered. The ultimate potential from within the area of expansion has yet to be estimated, leaving the total ultimate potential crude bitumen unchanged at 50 10^9 m^3.

3.2 Supply of and Demand for Crude Bitumen

This section includes crude bitumen production, upgrading, and disposition of both upgraded and nonupgraded bitumen. Nonupgraded bitumen refers to crude bitumen that is blended with a lighter-viscosity product (referred to as a diluent) in order to meet specifications for transport through pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to synthetic crude oil or other petroleum products. Most upgraded bitumen is used by refineries as feedstock.

Upgraders chemically alter the bitumen by adding hydrogen, subtracting carbon, or both. In upgrading, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. The bitumen upgrading process produces off-gas that is high in natural gas liquids (NGLs) and olefins. The off-gas is used primarily as fuel in oil sands operations. There are increasing volumes of off-gas being processed to remove the NGLs and olefins, which are used as feedstock in the petrochemical industry. Most oil sands coke recovered as a by-product of the upgrading process is stockpiled, and a small amount is burned to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Pentanes plus and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to allow bitumen to meet pipeline specifications. Heated and insulated pipelines can decrease the amount of diluent needed to move bitumen through them. Pentanes plus is lighter than upgraded bitumen as a diluent, which means a smaller volume of pentanes plus is required to move bitumen through a pipeline. On average, a blend of bitumen and pentanes plus will contain 30 per cent pentanes plus, whereas a blend using upgraded bitumen will contain up to 50 per cent upgraded bitumen to meet pipeline specifications.

If pentanes plus is used as a diluent to transport bitumen to destinations within Alberta, it is usually recycled. However, if it is used to transport bitumen to markets outside Alberta, it is generally not returned to the province. Instead, it is used as part of the feedstock for upgraders and refineries downstream. In July 2010, Southern Lights Pipeline began delivering additional imported diluent from the U.S. Petroleum Administration Defense District (PADD) 2 to Alberta.

The forecast of crude bitumen and upgraded bitumen production relies heavily on information provided by project proponents. This includes data on production capacity submitted during a project's application process, in addition to other publicly available materials such as quarterly reports, presentations, and press releases, which provide information on schedules for bringing the resource on stream. A project's viability depends largely on the cost-price relationship between production, operating and transportation costs (supply), and the market price for bitumen and upgraded bitumen (demand). Other factors include the refining capacity to handle bitumen or upgraded bitumen and competition with other sources of supply in U.S. and Canadian markets. The forecasts for crude bitumen and upgraded bitumen include production from existing projects, expansions of existing projects, and new projects that have been granted approval. Demand for upgraded bitumen and nonupgraded bitumen in Alberta is based on refinery demand and transportation needs. Alberta upgraded and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

Project sponsors' projections of existing and future bitumen production can change over time for various reasons. Large oil sands production projects are complex and capital intensive. They require long lead and construction times, making the projects vulnerable to material and labour cost increases throughout the planning, construction, and production phases.

3.2.1 Crude Bitumen Production—2011

Surface mining and in situ production for 2011 are shown graphically by oil sands areas (OSA) in **Figure S3.1**. In 2011, Alberta produced 277.2 thousand (10^3) m^3/d of crude bitumen from all three areas, compared with 256.3 10^3 m^3/d in 2010. Of this additional 20.9 10^3 m^3/d increase in production, 15.3 10^3 m^3/d is from in situ schemes and 5.6 10^3 m^3/d is from mining. Regionally, in situ production growth appears strongest in Athabasca (14.6 per cent increase) followed by Cold Lake (12.1 per cent increase) and Peace River (1.6 per cent increase). Combined, production for all three in situ areas grew by 12.7 per cent, compared with 4.1 per cent growth for mined bitumen production.

Overall this incremental increase in production of 20.9 10^3 m^3/d represents an annual increase of 8.2 per cent, very similar to the production increase of 8.3 per cent between 2010 and 2011. In situ production continues to account for an increasing share of the total production and is poised to overtake production from mining by 2015. In 2011, total in situ production accounted for 49 per cent of total bitumen production, compared with 47 per cent in 2010. **Figure S3.2** shows combined upgraded bitumen and nonupgraded bitumen production as a percentage of Alberta's total crude oil and equivalent production. Combined upgraded bitumen and nonupgraded bitumen production volumes have increased from 40 per cent of the province's total crude oil production in 2000 to 73 per cent in 2011.

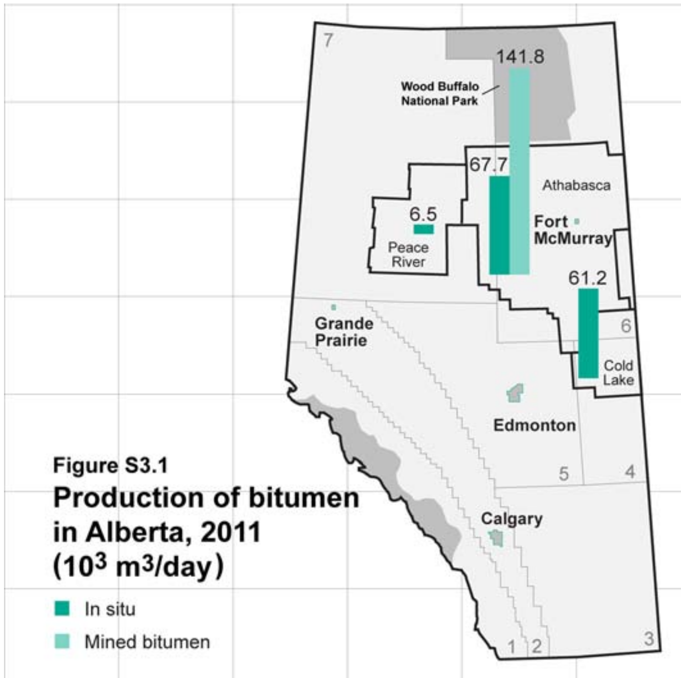


Figure S3.1
Production of bitumen in Alberta, 2011 (10^3 m^3/day)

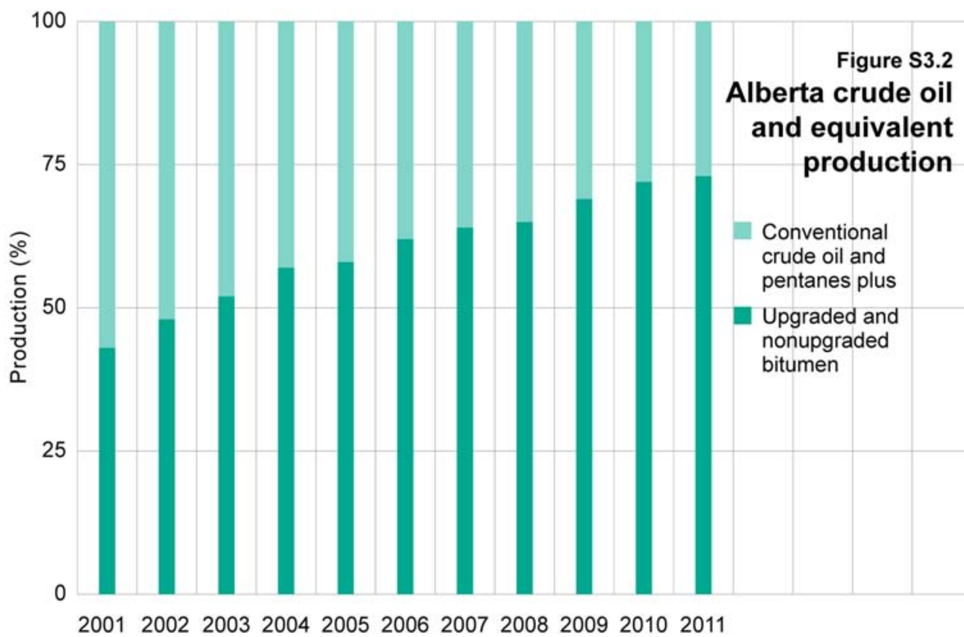


Figure S3.2
Alberta crude oil and equivalent production

3.2.1.1 Mined Crude Bitumen

Annual mined production growth was 5.6 10^3 m^3/d in 2011 as daily volumes grew to 141.8 10^3 m^3/d, up from 136.2 10^3 m^3/d in 2010. Production growth in 2011 at 4.1 percent was very similar to growth in 2010 at 3.8 per cent. Production gains at Shell and Suncor of 12.3 10^3 m^3/d and 3.5 10^3 m^3/d, respectively, were sufficient to offset CNRL production declines of 9.7 10^3 m^3/d. Syncrude increased its production at its Aurora mine by 0.3 10^3 m^3/d, while production at its Mildred Lake mine declined by 0.7 10^3 m^3/d. At present, all mined bitumen in Alberta serves as feedstock for upgraders.

Syncrude (Mildred and Aurora), Suncor, Shell (Muskeg River and Jackpine), and CNRL's Horizon account for 39, 32, 24, and 5 per cent of total mined bitumen, respectively.

Syncrude's mined bitumen production in 2011 remained largely unchanged from 2010 levels. Production in 2011 averaged 55.1 10^3 m^3/d, a decrease of 0.4 10^3 m^3/d from 55.5 10^3 m^3/d in 2010.

Mined bitumen production at Suncor increased 8.2 per cent in 2011 following reduced production in 2010 due to unplanned plant shutdowns caused by two fires at one of their two upgraders in December 2009 and February 2010. Production in 2011 increased to 45.8 10^3 m^3/d, up from 42.3 10^3 m^3/d in 2010.

Shell's Muskeg River and Jackpine mining projects produced 33.4 10^3 m^3/d in 2011, compared with 21.0 10^3 m^3/d in 2010 (a 72 per cent increase). The increase is largely attributable to full-year production from the Jackpine mine.

CNRL's Horizon project produced 7.6 10^3 m^3/d, down from 17.3 10^3 m^3/d in 2010, following a coker fire in early 2011 that halted production for six months. Production resumed in August and was at pre-fire levels by September of 2011.

3.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production for 2011 increased to 135.4 10^3 m^3/d from 120.1 10^3 m^3/d in 2010. This represents a 12.7 per cent annual increase, slightly lower than the increase of 13.8 per cent from 2009 to 2010. Since 2002, in situ crude production has grown an average of 11.1 per cent per year.

Annual total in situ bitumen production, along with the number of bitumen wells on production for each year, is shown in **Figure S3.3**. The number of producing bitumen wells has increased along with in situ crude bitumen production from 2300 in 1992 to about 10 960 in 2011. The average annual productivity of in situ bitumen wells remained relatively flat between 1992 and 2004 at a level of 8.0 m^3/d but began to climb in 2005 to average 8.7 m^3/d, reaching 11.9 m^3/d by 2010 and 12.3 m^3/d in 2011. This change is due to the increase in steam-assisted gravity drainage (SAGD) wells, which have higher average productivity rates than cyclic steam stimulation (CSS) wells.

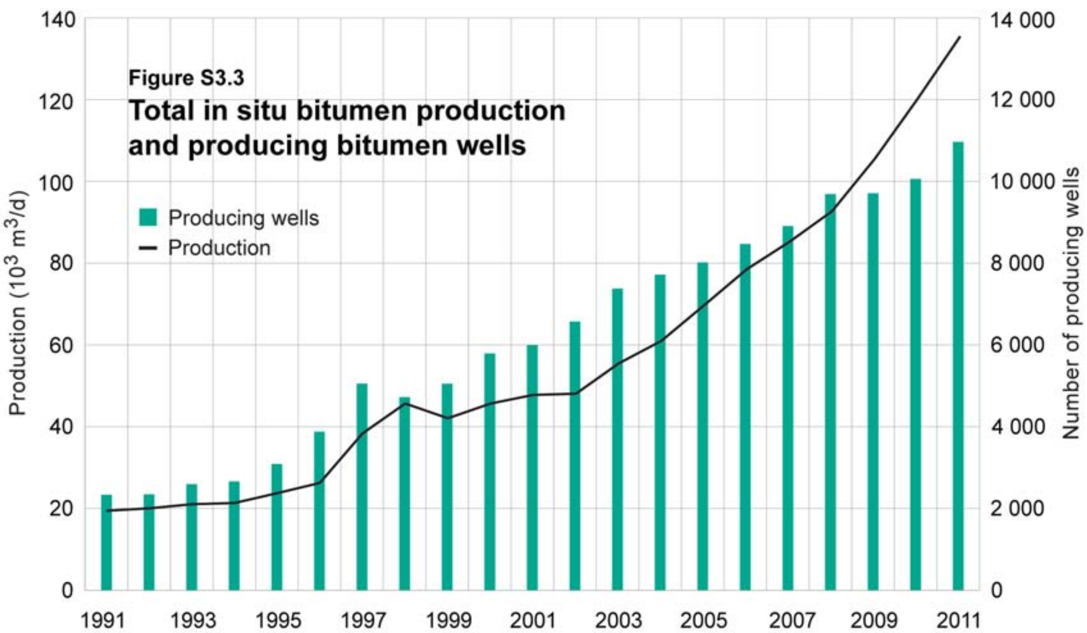


Figure S3.4 shows historical in situ production by OSA. For the second year, production from the Athabasca OSA has been higher than that from the Cold Lake OSA, with Athabasca OSA and Cold Lake OSA accounting for 50 per cent and 45 per cent of total in situ production, respectively. In 2011, the Athabasca, Cold Lake, and Peace River OSAs each produced 67.7 10^3 m^3/d, 61.2 10^3 m^3/d, and 6.5 10^3 m^3/d, respectively. In 2011, annual production growth rates for the Athabasca and Cold Lake OSAs were 15 per cent and 12 per cent, respectively. Following a decline in production in 2010, production from the Peace River OSA increased by 2 per cent in 2011. Significant increases in production within the Athabasca OSA since 2002 are due to SAGD development, while increases in the Peace River OSA are largely the result of increased primary production of bitumen in the Seal area located southeast of Shell's Peace River thermal in situ bitumen production project.

Currently, there are three main methods for producing in situ bitumen: primary production, CSS, and SAGD. In situ bitumen production by recovery method per year is shown in **Figure S3.5**. Primary production includes those schemes that use water and polymer injection (considered as enhanced recovery) as a recovery method. In 2011, 31 per cent of in situ production was recovered by CSS, 44 per cent by SAGD, and 25 per cent by primary schemes. SAGD production was responsible for 59 per cent of the total increase in production between 2010 and 2011. CSS experienced positive growth for the second year, adding 3.4 10^3 m^3/d in production, a 9 per cent increase over 2010 production levels.

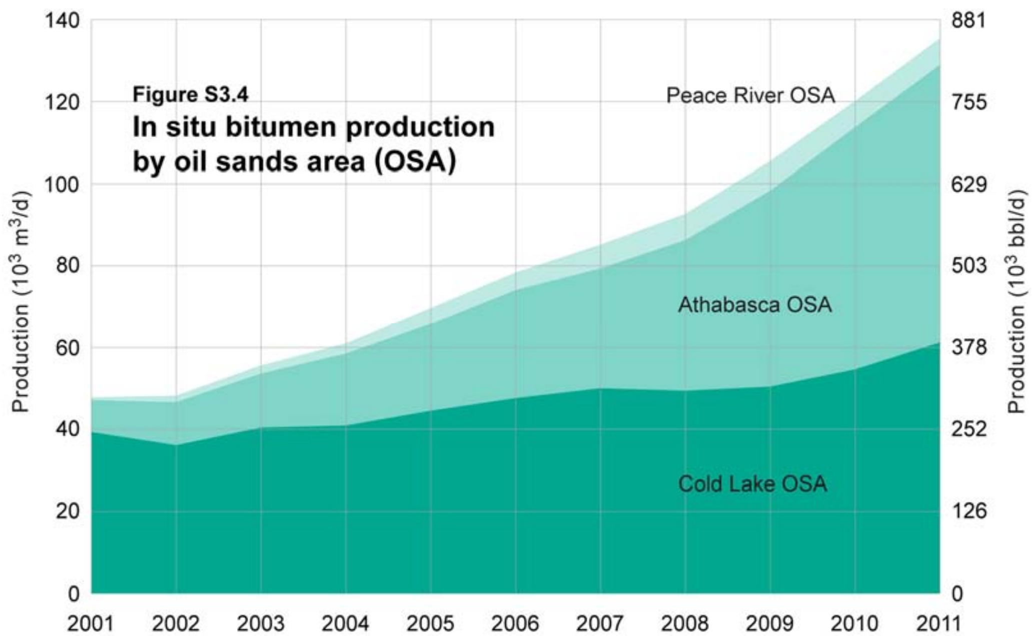


Figure S3.4
In situ bitumen production by oil sands area (OSA)
Peace River OSA
Athabasca OSA
Cold Lake OSA
Production (10^3 m^3/d)
Production (10^3 bbl/d)
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011

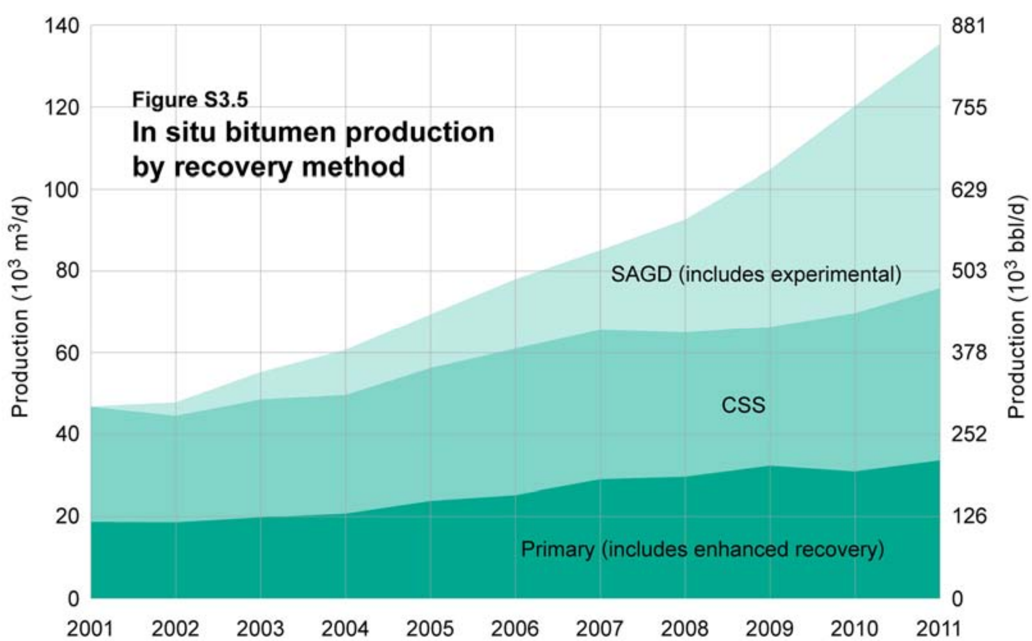
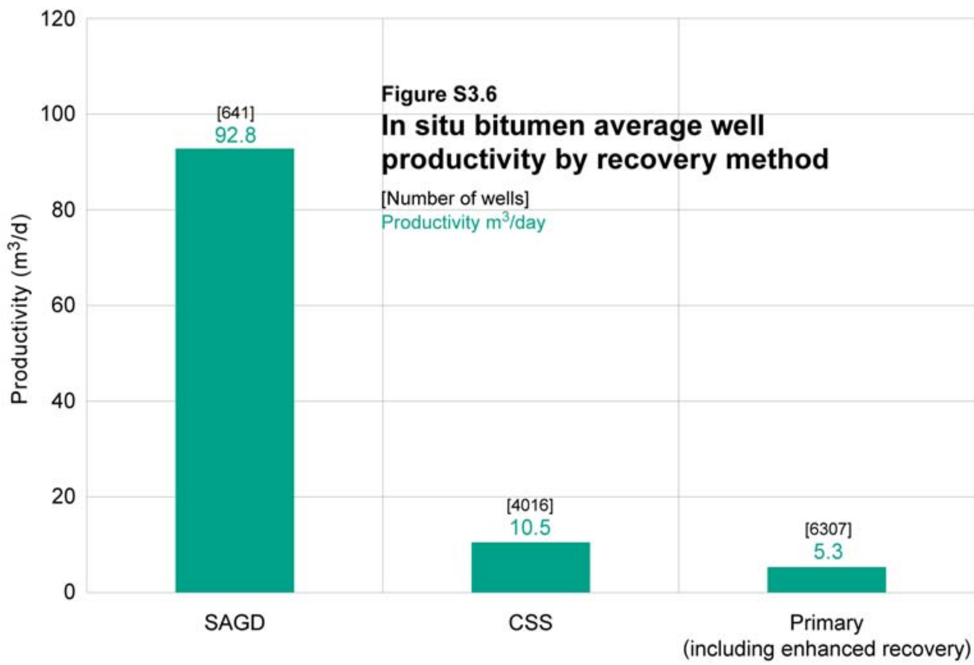


Figure S3.5
In situ bitumen production by recovery method
SAGD (includes experimental)
CSS
Primary (includes enhanced recovery)
Production (10^3 m^3/d)
Production (10^3 bbl/d)
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011

SAGD technology has been in use since 2001 and is the preferred method of recovery for most new projects in the Athabasca OSA. As discussed earlier, the total productivity of in situ wells has been increasing, largely due to an increase in the use of SAGD as a method of recovery. **Figure S3.6** shows the average well productivity in 2011 by recovery method for SAGD, CSS, and primary (including enhanced recovery).



3.2.1.3 Upgraded Bitumen (formerly Synthetic Crude Oil)

Currently, all Alberta mined bitumen and a portion of in situ production (9 per cent) are upgraded. Upgraded bitumen production in 2011 was 137.1 10^3 m^3/d, compared with 126.3 10^3 m^3/d in 2010. **Table 3.6** shows upgraded bitumen production in 2011 by individual operator.

Table 3.6 Upgraded bitumen production in 2011[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	46.4
Suncor	45.8
Shell Canada Scotford	33.7
CNRL Horizon	6.4
Nexen/OPTI Long Lake	4.8

[a] Any discrepancies are due to rounding.

Alberta's five upgraders produce a variety of upgraded products: Suncor produces light sweet and medium sour crudes, including diesel; Syncrude, CNRL Horizon, and Nexen Inc. (Nexen) Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell

Scotford Refinery as well as sweet and heavy synthetic crude oil. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use delayed coking as their primary upgrading technology and achieve volumetric liquid yields (upgraded bitumen produced/bitumen processed) of 80 to 90 per cent, whereas projects employing hydroconversion can achieve volumetric liquid yields of 100 per cent or more. The Nexen Long Lake project uses OrCrude™, a carbon rejection upgrading process using conventional thermal cracking, distillation, and solvent deasphalting equipment. A key aspect of this process is the removal of coke precursors (asphaltenes) prior to thermal cracking of the upgrader feed.

3.2.1.4 Gasification

Gasification allows companies to convert materials that would otherwise be low-value products into energy sources and reduces the reliance on external energy sources. Gasification can be used to convert asphaltenes, petroleum coke, and vacuum distillation bottoms into a synthetic gas (syn gas) fuel.

The Nexen Long Lake project integrates the gasification of asphaltenes to produce a syn gas that is used in the SAGD and the upgrading operations, significantly reducing the amount of natural gas that is required.

Gasification of low-value products is also being planned for the proposed North West Upgrader. The gasifier will produce syn gas and hydrogen from refinery bottoms.

3.2.1.5 Petroleum Coke

Petroleum coke is a by-product of the oil sands upgrading process that is currently being stockpiled in Alberta and is considered a potential source of energy. It is high in sulphur but has a lower ash content than conventional fuel coke. Petroleum coke has the potential to become a future energy resource through gasification and is discussed in more detail in the **Coal** section.

Suncor Energy Inc. and Syncrude Canada Ltd. operate Alberta’s two largest oil sands mines near Fort McMurray. Built with the capacity for both on-site extraction and upgrading, Syncrude and Suncor both produce coke. The CNRL Horizon project that commenced operations in 2009 has an oil sands mine, on-site extraction and upgrading capabilities that use delayed coking technology, and it also produces coke.

Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke used as site fuel. In 2011, Suncor used approximately 19 per cent of its annual coke production as site fuel and sold approximately 4 per cent through its Energy Marketing Group. Syncrude began using coke as a site fuel in 1995 and by 2011 used 21 per cent of its annual coke production as site fuel. At CNRL’s Horizon project, all coke produced is stockpiled, accounting for approximately 3 per cent of total inventories.

Suncor and Syncrude are exploring new ways to use their coke surplus, including using it as a reclamation material. In August 2009, Suncor applied to the ERCB for permission to use coke inventories for capping two tailings ponds. Suncor estimated that it could use about 40 million tonnes of the coke stockpiled for non-energy use for reclamation purposes. In July 2011, Suncor received partial approval to begin a full-scale operational test on one of the ponds.

Statistics of coke inventories reported in *ST43: Mineable Oil Sands Annual Statistics* show general increases in the total closing inventories per year, as illustrated in **Figure S3.7**. In 2011, coke inventories reached 72 million tonnes, up 4 million tonnes from 2010. This represents a change of approximately 6 per cent, which is consistent with the 2010 rate of growth. Coke inventories are expected to continue their growth with the recent addition of CNRL's Horizon project, unless significant alternative uses are found. Inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders.

3.2.2 Crude Bitumen Production—Forecast

3.2.2.1 Mined Crude Bitumen

In projecting the future supply of bitumen from mining, the ERCB considered potential production from existing facilities and supply from future projects. Projects that have been approved are considered for inclusion in our forecast. Announced projects are generally not included in our forecasts. The projects actually considered for the forecast are shown in **Table 3.7**.

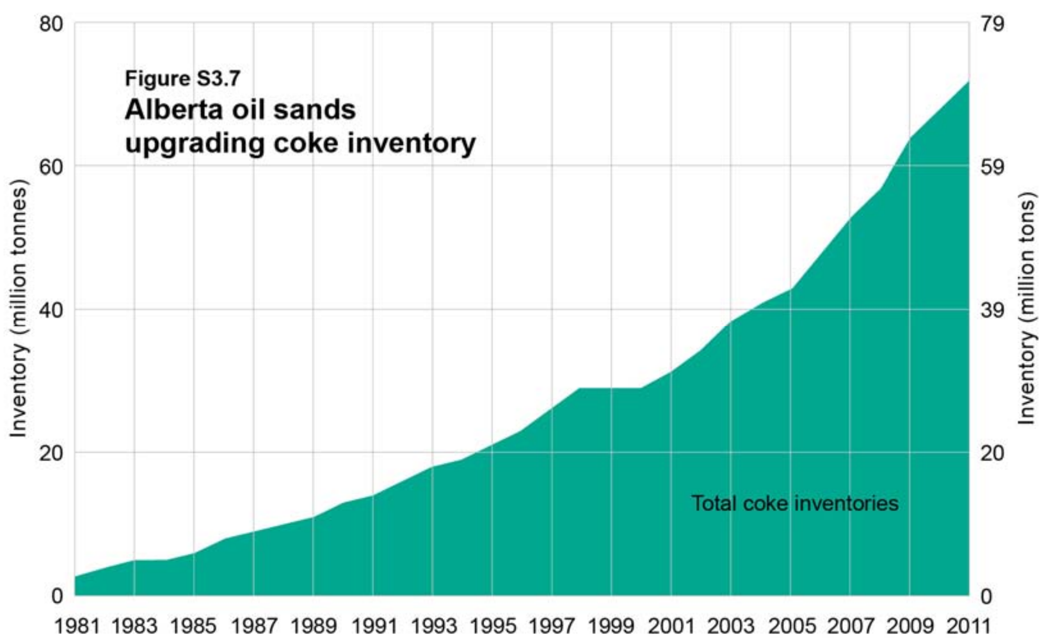


Table 3.7 Surface mined bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Suncor/Total E&P Canada			
Voyageur South Phase 1	TBD*	19.1	Application
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD	18.3	Approved
Jackpine Phase 1B	TBD	15.9	Approved
Jackpine Phase 2	TBD	15.9	Application
Pierre River Phase 1	TBD	15.9	Application
Pierre River Phase 2	TBD	15.9	Application
CNRL			
Horizon Phase 2/3	TBD	21.5	Approved
Suncor/Total E&P Canada			
Fort Hills Phase 1	TBD	26.2	Approved
Fort Hills debottleneck	TBD	4.0	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	2012	17.5	Under construction
Kearl Phase 2	TBD	17.5	Approved
Kearl Phase 1 debottleneck 1	TBD	4.5	Approved
Kearl Phase 1 debottleneck 2		5	Approved
Kearl Phase 2 debottleneck 1		4.5	Approved
Kearl Phase 2 debottleneck 2		5	Approved
Total E&P Canada/Suncor			Approved
Joslyn (North)	TBD	15.9	Approved
Silverbirch/Teck Resources Limited			
Frontier Phase 1	TBD	11.9	Application

Source: ERCB, company releases, and Strategy West.
* To be determined.

Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. Due to uncertainties regarding timing and project scope, some projects, including Silver Birch's Equinox project, have not been considered in the ten-year forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the ERCB considered factors such as the strong crude oil price environment and the availability of foreign investment. These factors are expected to be tempered by the current wide light/bitumen differential, escalating construction costs, anticipated construction delays, and availability of both suitable and timely refinery capacity, all of which can delay the production schedule for these projects.

By 2021, mined bitumen is expected to reach 262.7 10^3 m^3/d. This represents an upward revision of 5 per cent compared with the end of the forecast period in last year's report. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure S3.8**, which shows that the percentage of mined bitumen to total production is expected to decrease from 51 per cent in 2011 to 45 per cent in 2021.

3.2.2.2 In Situ Bitumen

Similar to surface mining, the future supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects. In forecasting production from existing and future schemes, the ERCB considered all approved projects, projects currently before the ERCB for approval, and applications it expects to receive for projects over the next 12 to 18 months. The forecast assumes that existing projects will continue producing at their current or projected production levels over the forecast period. To this projection the ERCB has added crude bitumen production from new and expanded schemes. The production forecasts from future crude bitumen projects takes into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, pipeline availability, and the ability of North American markets to absorb the increased volumes.

The current forecast has increased over last year primarily due to the addition of new proposed projects and the accelerated development schedules for existing and approved projects. The increase in forecasted production is a result of relatively high oil prices and the availability of foreign capital investment.
In addition, factors which may affect the pace of development have been considered, such as the availability of labour and equipment. As illustrated in **Figure S3.8**, the ERCB expects in situ crude bitumen production to increase to 324.6 10^3 m^3/d by 2021. This represents an increase of 3 per cent when compared to the end of the forecast period in last year's report. Based on this projection, in situ bitumen production will exceed mined bitumen production by 2015 and will account for 55 per cent of total bitumen produced by 2021.

Projects that have been approved are considered for inclusion in this forecast. Announced projects are generally not included in the forecast. Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. The projects considered for the forecast are shown in **Table 3.8.**

Table 3.8 In situ crude bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Athabasca Region			
Alberta Oil Sands			
Clearwater West	TBD	1.6	Application
Hangingstone	TBD	1.9	Application
Athabasca Oil Sands			
Dover Phase 1–5	TBD	40.0	Application
Cenovus			
Christina Lake Phase D	2013	6.4	Under Construction
Christina Lake Phase E-G	TBD	19.2	Application
Foster Creek Phase F	2014	5.6	Under Construction
Foster Creek Phase G-H	TBD	11.2	Approved

(continued)

Table 3.8 In situ crude bitumen projects (continued)

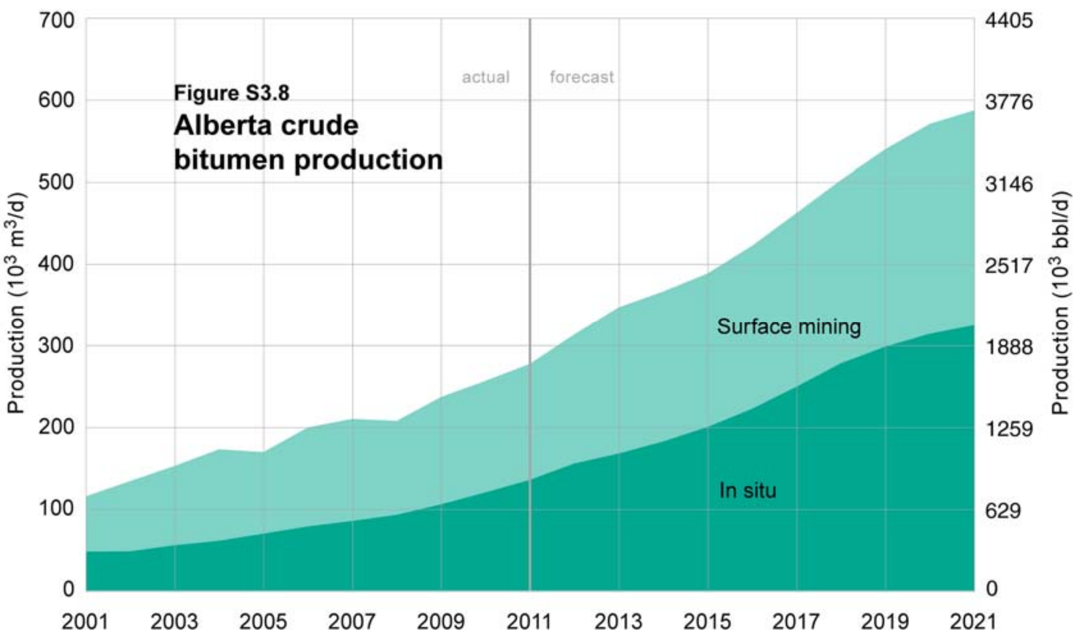
Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Narrows Lake Phase 1A–1B	TBD	10.3	Application
Pelican Lake Grand Rapids Phase A–C	TBD	9.5	Application
Telephone Lake Phase A–B	TBD	7.2	Application
CNRL			
Grouse Stage 1	TBD	7.9	Announced
Kirby South Phase 1	2013	7.2	Under Construction
Kirby North and South Phase 2	TBD	15.2	Application
Connacher			
Great Divide Expansion Phase 1–2	TBD	3.8	Application
ConocoPhillips			
Surmont Phase 2	2014	17.3	Under Construction
Devon			
Jackfish 3	2014	5.6	Under Construction
E-T Energy			
Poplar Creek Commercial	TBD	1.6	Application
Grizzly Oil Sands			
Algar Phase 1–2	TBD	0.9	Approved
Harvest			
BlackGold Phase 1	2013	1.6	Under Construction
BlackGold Phase 2	TBD	3.2	Application
Husky			
Sunrise Phase 1	2014	9.5	Under Construction
Sunrise Phase 2–3	TBD	22.2	Approved
Ivanhoe			
Tamarack Phase 1–2	TBD	3.2	Application
JACOS			
Hangingstone Expansion	TBD	5.6	Application
Laricina			
Germain Phase 2–4	TBD	23.8	Application
Saleski Phase 1	TBD	2.0	Application
MacKay Operating Corp.			
MacKay River Phase 1–4	TBD	24.0	Approved
MEG			
Christina Lake Phase 3A–3C	TBD	23.7	Application
Nexen			
Kinosis Phase 1–2	2013	3.2	Approved
Petrobank			
May River Phase 1	2013	1.6	Approved
Southern Pacific			
McKay Phase 1	TBD	1.9	Approved
Statoil			
Kai Kos Dehseh Leismer Commercial	TBD	1.6	Approved
Kai Kos Dehseh Leismer Expansion	TBD	3.2	Approved
Kai Kos Dehseh Corner	TBD	6.4	Approved
Suncor			
Firebag Phase 4	2013	9.9	Under construction
Firebag Phase 5–6	TBD	19.8	Approved
MacKay Phase 2	TBD	6.4	Approved

(continued)

Table 3.8 In situ crude bitumen projects (continued)

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Sunshine Oilsands			
Legend Lake	TBD	1.6	Application
Thickwood	TBD	1.6	Application
West Ells Phase 1-2	TBD	1.6	Approved
Value Creation			
Terre de Grace Phase 1	TBD	1.6	Application
Cold Lake Region			
Husky			
Caribou Lake Phase 1	TBD	1.6	Approved
Imperial			
Cold Lake Phases 14-16	TBD	4.8	Approved
Koch Exploration			
Gemini Phase 2 (inc. Pilot)	TBD	1.8	Application
Osum			
Taiga Phase 1-2	TBD	7.2	Application
Shell			
Orion (Hilda Lake) Phase 2	TBD	1.6	Approved
Peace River Region			
Shell Peace River			
Carmon Creek Phase 1-2	TBD	10.6	Application

Source: ERCB, company releases, and Strategy West.



In 2011, approximately 9 per cent of in situ production in Alberta was upgraded. It is expected that by the end of the forecast period, about 14 per cent of in situ bitumen production will be used as feedstock for upgrading within the province, which is consistent with the projection in the 2010 forecast.

3.2.2.3 Upgraded Bitumen (formerly Synthetic Crude Oil)

To forecast upgraded bitumen production, the ERCB includes existing production from Suncor, Syncrude, Shell, CNRL, and Nexen projects plus their planned expansions and the new production expected from projects listed in **Table 3.9**. Production from future upgrading projects considers the high cost of engineering and materials and the substantial amount of skilled labour required for expansions to existing and new projects. The ERCB also recognizes that other key factors, such as the forecast of oil prices, the narrow light/bitumen differential, the length of the construction period, and the market penetration of new upgraded volumes, will affect project timing.

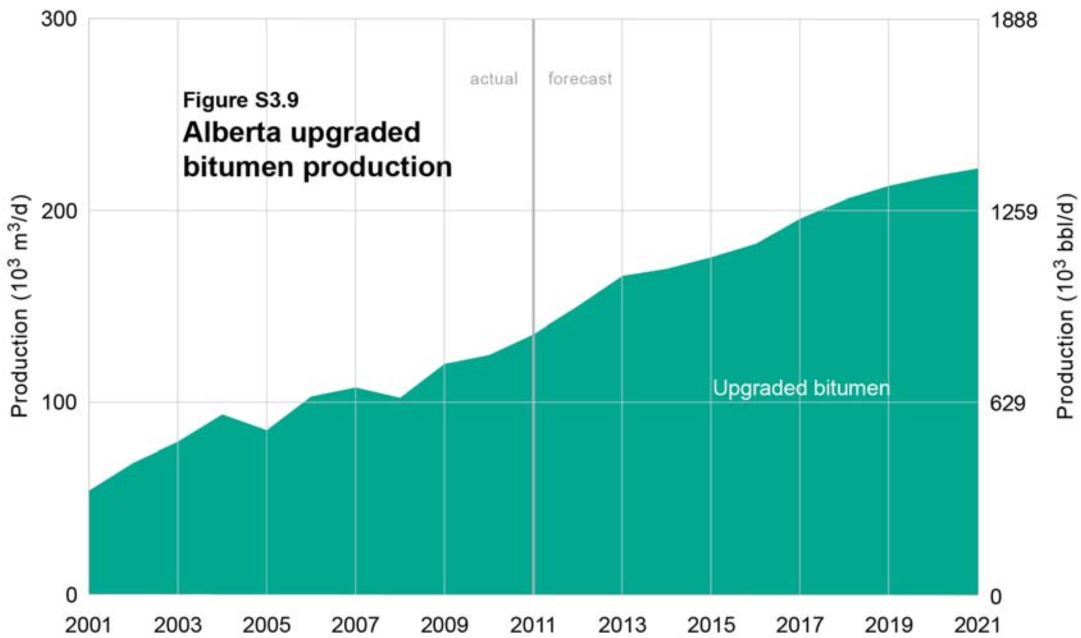
Over the forecast period, the percentage of crude bitumen upgraded is expected to decline from 56 per cent of total crude bitumen in 2011 to 44 per cent in 2021. This is a result of the in situ production growth outpacing the growth in upgrading capacity.

Table 3.9 Upgraded bitumen projects

Company/project name	Start-up	Upgrading capacity (10^3 m^3/d)	Status
Athabasca Region			
Suncor/Total			
Voyageur Phase 1	2016	20.2	Under Construction
Voyageur Phase 2	TBD	10.0	Approved
CNRL			
Horizon Phase 2A	2014	1.6	Approved
Horizon Phase 2B/3	TBD	19.9	Approved
Nexen/OPTI			
Long Lake Phase 2	TBD	9.3	Approved
Value Creation Inc.			
Terre de Grace Pilot	TBD	1.3	Application
Industrial Heartland Region			
Shell			
Upgrader 2 Phase 1-4	TBD	47.7	Withdrawn
North West Upgrading			
NW Upgrader Phase 1	2014	7.4	Approved
NW Upgrader Phase 2-3	TBD	14.8	Approved
Total E&P Canada			
Strathcona Upgrader Phase	TBD	43	Approved

Source: ERCB, company releases, and Strategy West.

Figure S3.9 shows the ERCB's projection of upgraded bitumen production, which is expected to increase from 137.1 10^3 m^3/d in 2011 to 151.7 10^3 m^3/d 2012. This increase reflects resumption of operations at CNRL following the fire in 2011 as well as the expected increase in production from Shell's Scotford upgrader expansion as it continues to ramp up. The 2012 upgraded bitumen production forecast assumes that Suncor, Syncrude, and CNRL are able to return to production targets following disruptions at their respective facilities in early 2012. The forecast production increases to 223.5 10^3 m^3/d by 2021. This is similar to last year's end-of-forecast-period production of 223.3 10^3 m^3/d.



3.2.3 Supply Costs

The supply cost for a resource or project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as earn a specified return on investment. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used for comparative project economics.

The supply cost calculation typically determines a value received per unit of production. For SAGD and standalone mining, this entails solving for a bitumen price at plant gate. In order to provide a more meaningful comparison, the results of the supply cost analysis have been converted to a West Texas Intermediate (WTI) price, which is directly comparable to current market prices.

3.2.3.1 Assumptions

The significant cost inflation experienced by projects in the previous economic boom resulted in some operators delaying and deferring new projects. It also meant that capital cost information submitted in applications were no longer applicable in the new economic environment. Although each project is unique in its location and the quality of its reserves, this supply cost analysis relies on more generic project specifications and capital and operating cost estimates. Data selected for the analysis are provided in **Table 3.10** in both metric and imperial units since North American price data are based on a US$WTI. The input cost data, and the resultant supply cost outputs, are in 2012 dollars.

The generic projects represent proposed project types, including in situ SAGD (with and without cogeneration) and standalone mining with cogeneration. An integrated mine was not considered for this analysis as there are currently no proposed integrated bitumen projects in Alberta. Although significant production currently comes from CSS projects, few new CSS projects have been proposed, and therefore supply costs have not been determined for this recovery method. The wide range in SAGD capital costs represents the current economic environment in which producers are pursuing additional phases as well as green field development, with the lower range of the capital cost being applicable to phased additions where portions of the infrastructure are already in place.

Table 3.10 Supply cost project data

Project type	Production (10^3 m^3/d)	Production (bbl/d)	Capital cost range (millions of dollars)	Estimated supply cost $US WTI equivalent per barrel	Purchased natural gas requirement (10^3 m^3 gas/ m^3 oil)	Purchased natural gas requirement (mcf/bbl)
In situ SAGD	4.8	30 000	750 to 1,500	50 to 78	0.177 to 0.265	1 to 1.5
Standalone mine	15.9	100 000	5,500 to 7,500	70 to 91	0.071 to 0.106	0.4 to 0.6

A major component of operating costs is purchased natural gas for fuel and feedstock. This analysis assumes an average value of Cdn$5.78 per gigajoule real price at AECO-NIT over the project's 30- to 40-year life. The analysis assumes a real discount rate of 10 per cent.

3.2.3.2 Results

The results of the supply cost analysis show a marked increase over the results from last year. This increase is largely attributable to the forecast light/heavy differential and higher sustaining capital expenditures. As illustrated in **Table 3.10**, after accounting for the higher costs of the current pricing environment, the ongoing development of in situ and mining projects is still supported.

A major risk to the capital cost assumptions in this analysis would be the re-emergence of cost escalation that occurred in the last decade. When too many projects proceed, resources such as labour quickly become scarce, which results in an escalation in capital and supply costs.

3.2.4 Pipelines

Sufficient physical capacity currently exists to satisfy existing and expected exports through to 2014. However, a significant portion of the export market, namely Cushing, Oklahoma, is currently oversupplied with crude (see **Economics** section). Resolution of the supply glut at Cushing is essential to ensure producers receive the highest price for their products and that there is available capacity for Alberta exports. Proposed projects such as the northern leg of the Keystone XL and Northern Gateway are currently in the regulatory review process and will not be in service until late 2014 at the earliest. It is projected that capacity additions along the Enbridge system may provide additional capacity as discussed below.

At present, a supply glut at Cushing and a bottleneck at Superior, Illinois, are affecting the ability of Enbridge to take advantage of unused capacity existing on the mainline system (including Alberta Clipper) entering Superior. Export capacity additions leaving Superior would serve only to add to the oversupply that currently exists in Cushing. It is expected that export capacity additions leaving Superior will only occur following resolution of the oversupply at Cushing.

The push to resolve the oversupply situation at Cushing has drawn considerable attention, and companies have announced and applied for projects that would see the movement of crude oil from Cushing to the U.S. Gulf Coast. In late 2011, Enbridge announced the purchase and reversal of the Seaway Pipeline, which prior to the oversupply carried crude oil brought into the U.S. Gulf Coast by tanker to Cushing. The Seaway reversal would have an initial capacity of 150 10^3 bbl/day by mid-2012, before expanding to 400 10^3 bbl/day by early 2013. Following the reversal, Enbridge has announced plans to twin the Seaway Pipeline, which would add an additional 450 10^3 bbl/day of capacity in 2014. Following the denial of a U.S. regulatory permit for its Keystone XL pipeline in early 2012, TransCanada Corporation has announced plans to go ahead with the southern leg of the Keystone project. The southern leg (the Cushing MarketLink), with a planned in-service date of 2014, includes the development of a 150 10^3 bbl/d pipeline between Cushing and Port Arthur, Texas. Other projects currently being discussed include the 800 10^3 bbl/day Enbridge Wrangler project that would connect the Cushing storage hub to the U.S. Gulf Coast. Should all or some of these pipelines go ahead, it is expected they will ease the oversupply currently occurring in Cushing.

The development of incremental pipeline capacity exiting Cushing in sufficient volume to clear the oversupply is expected to spur additional capacity to ship increasing production volumes through Cushing to other U.S. markets, such as PADDs 1 and 3 (see **Demand** section). One such option would be the elimination of the bottleneck existing on Enbridge's system exiting Superior, such as the Southern Access pipeline, which is capable of expanding to 1200 10^3 bbl/day from 400 10^3 bbl/day with the additional pumping stations. Supporting the expansion of the Southern Access pipeline is the proposed Flanagan South project, which would mirror the Spearhead pipeline. Flanagan South is being proposed with an initial design capacity of 585 10^3 bbl/d that is expandable to 800 10^3 bbl/d. Pending regulatory approval, Enbridge plans to have the Flanagan South pipeline in service by mid-2014.

Among the factors affecting the availability of pipeline capacity for Alberta crude oil production is competition from U.S. Bakken light oil production from the Williston Basin. This competition for capacity is expected to increase due to production growth in the Bakken (and equivalents) light oil of both the Williston and Alberta basins. As of May 2011, Enbridge completed the Portal link, which has the capacity to deliver 25 10^3 bbl/d of U.S. Bakken production into Enbridge's Steelman Terminal in Saskatchewan. Currently, Enbridge has plans to expand the Portal Link to 145 10^3 bbl/d by early 2013. In addition to the projects put forward by Enbridge, Plains All American Pipeline has plans to reverse its Wascana pipeline, which would see U.S. Bakken production flow into Enbridge's system in Regina, Saskatchewan. Currently, rail plays a significant role in moving crude oil from the U.S. Midwest to market, with movements of 100 10^3 bbl/d being reported in early 2011. With continued growth in production and new terminals in planning or under construction, rail movements are expected to continue growing into the foreseeable future.

Regarding capacity additions later in the forecast, Kinder Morgan has been gauging interest in expanding its Trans Mountain pipeline, which has recently been experiencing apportionment. The Trans Mountain pipeline moves crude oil from Edmonton, Alberta, to marketing terminals and refineries in the central British Columbia region, the Greater Vancouver area, and international destinations, including the western United States In early 2012, Kinder Morgan announced that it would proceed with plans to increase capacity from 47.7 10^3 m^3/d to 135.1 10^3 m^3/d by 2017. Although put on hold in 2009 due to lack of commercial support, Enbridge's former Trailbreaker project, which would see Line 9 between Sarnia Ontario and Montreal Quebec reversed, still draws considerable attention for its potential to access the eastern seaboard. Enbridge is currently proposing to reverse a section of the line between Sarnia and Westover, Ontario, at the request of a customer but otherwise has no further plans to pursue the Trailbreaker project at this time. Further analysis of export pipeline capacity can be found below under **Section 3.2.4.4**.

Within Alberta, the current pipeline system's ability to expand, in addition to proposed projects, should provide adequate transportation capacity for the expected increases in upgraded and nonupgraded bitumen production over the forecast period. The current pipeline systems in the Cold Lake and Athabasca areas are shown in **Table 3.11**. **Figure S3.10** shows the current pipelines and proposed crude oil pipeline projects within the Athabasca and Cold Lake areas. Numerals within parentheses in the following sections on existing and proposed pipelines in Alberta refer to the legend on the map in **Figure S3.10**.

Table 3.11 Alberta upgraded and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty	73.0
	Edmonton	
Husky Oil Pipeline	Hardisty	78.0
	Lloydminster	
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	62.0
Corridor Pipeline	Edmonton	73.9
Syncrude Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0
Access Pipeline	Edmonton	23.8
Waupisoo Pipeline	Edmonton	55.6
Horizon Pipeline	Edmonton	39.7

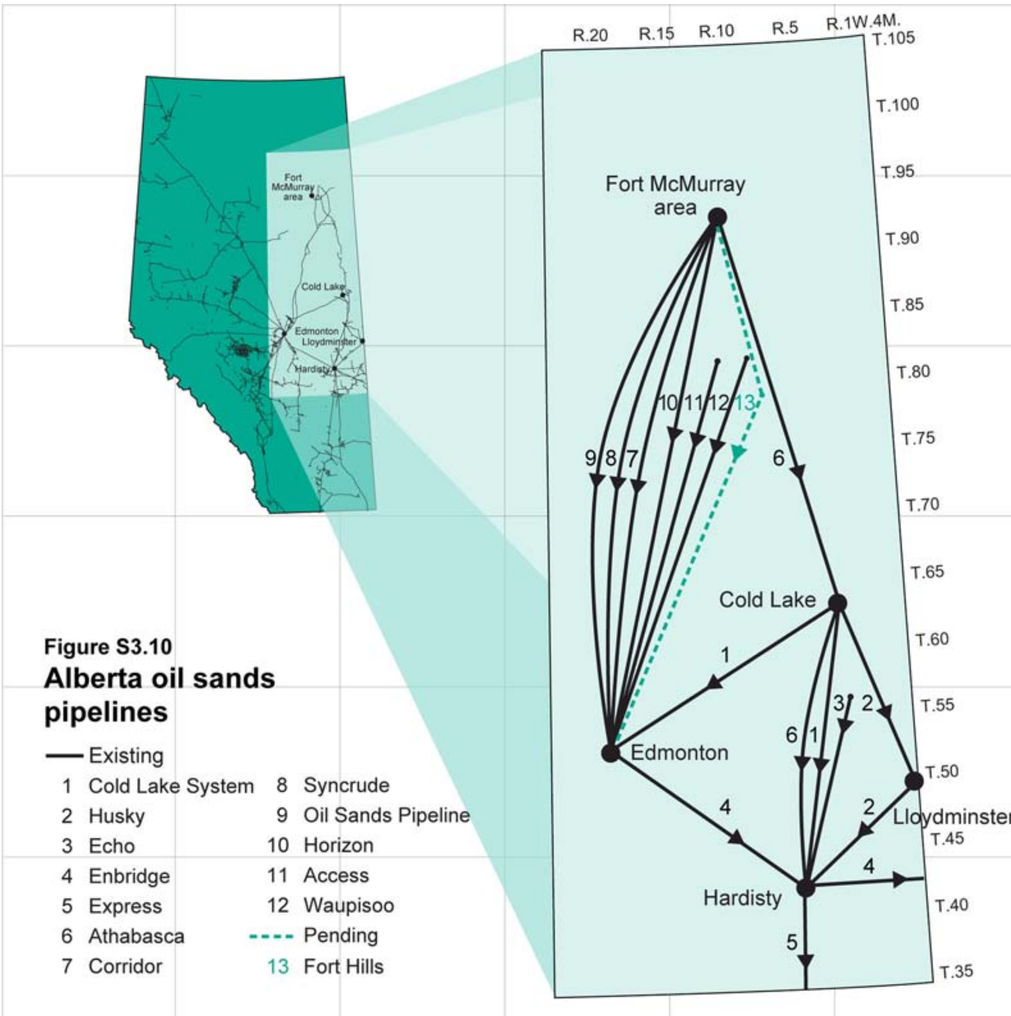


Figure S3.10
Alberta oil sands pipelines

3.2.4.1 Existing Alberta Pipelines

- The Cold Lake pipeline system (1) is capable of delivering heavy crude from the Cold Lake area to Hardisty and Edmonton.
- The Husky pipeline (2) moves Cold Lake crude oil to Husky's heavy oil operations in Lloydminster. Heavy crude oil and upgraded bitumen are then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge (4) or the Kinder Morgan Express pipeline (5) systems.
- The Echo pipeline system (3) is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending. This pipeline delivers Cold Lake crude to Hardisty.
- The Enbridge Pipeline (4), described below, is an existing export pipeline.
- The Kinder Morgan Express Pipeline (5), described below, is an existing export pipeline.

- The Athabasca Pipeline (6) delivers upgraded product and bitumen blends to Hardisty. Its current capacity is 62 10^3 m^3/d but it has the potential to carry 90.6 10^3 m^3/d.
- The Inter Pipeline Fund Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford Upgrader near Edmonton. As of 2011, the pipeline has been expanded from 30.2 10^3 m^3/d to 73.9 10^3 m^3/d through the construction of a 1.1 metre diluted bitumen line and conversion of the existing 0.61 metre line to transport diluent.
- The Syncrude Pipeline (formerly Alberta Oil Sands Pipeline) (8) is the exclusive transporter for Syncrude. It runs from the Syncrude mine site north of Fort McMurray to the Edmonton area.
- The Oil Sands Pipeline (9) transports Suncor upgraded bitumen to the Edmonton area.
- Pembina Pipeline's Horizon Pipeline (10) is the exclusive transporter for CNRL's Horizon oil sands development. With an initial capacity of 39.7 10^3 m^3/d, it transports upgraded bitumen to the Edmonton area.
- The Access Pipeline (11) transports diluted bitumen from the Christina Lake area to facilities in the Edmonton area. The capacity of the pipeline is 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d.
- The Enbridge Waupisoo Pipeline (12) moves blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline has a current capacity of 55.6 10^3 m^3/d and is expandable to 95.3 10^3 m^3/d.
- The Rainbow Pipeline System (not shown on **Figure S3.10**) is owned by Plains Midstream and transports Peace River oil sands crude oil and condensate from Rainbow Lake to Edmonton, with a capacity of 31.7 10^3 m^3/d.

3.2.4.2 Proposed Alberta Pipeline Projects

- From the Cheecham terminal, Enbridge is proposing to expand its existing Waupisoo (12) line to the Edmonton Terminal. The second expansion will increase the line's capacity for transporting oil sands crude oil from 38.1 10^3 m^3/d to 87.4 10^3 m^3/d by 2013.
- Enbridge also intends to expand its capacity to move bitumen from the Christina Lake region by expanding the capacity of its Athabasca system (6), which moves product into the Hardisty Terminal.
- Enbridge has announced that the Fort Hills Pipeline system (13) has been commercially secured and is currently pending, based on customer timing.

3.2.4.3 Existing Export Pipelines

Table 3.12 lists the existing export pipelines with their corresponding destinations and capacities, and **Figure S3.11** shows the existing export pipelines leaving Alberta.

- The Enbridge Pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the U.S. Midwest.
- The Kinder Morgan Express Pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends east into Wood River, Illinois.
- The Kinder Morgan Trans Mountain pipeline system transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State. Trans Mountain's current capacity is 47.7 10^3 m^3/d, assuming heavy oil represents some 20 per cent (historical average) of the total throughput.
- The Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake blended bitumen to Montana refineries.
- The Milk River Pipeline delivers Bow River heavy crude oil to Montana refineries.
- TransCanada's Keystone pipeline commenced commercial operations in June 2011, shipping crude oil to markets in the U.S. Midwest.
- Enbridge's Alberta Clipper pipeline was also completed in 2011, shipping crude oil from Hardisty, Alberta, to Superior, Wisconsin.

Table 3.12 Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Enbridge Pipeline	Eastern Canada U.S. east coast U.S. midwest	301.9
Alberta Clipper Pipeline	U.S. midwest	71.5
Kinder Morgan Express Pipeline	U.S. Rocky Mountains U.S. midwest	44.9
Trans Mountain Pipeline	British Columbia U.S. west coast Offshore	47.7
Plains Midstream Canada		
Milk River Pipeline	U.S. Rocky Mountains	18.8
Pacific Energy Partners, L.P.		
Rangeland Pipeline	U.S. Rocky Mountains	13.5
TransCanada Pipelines		
Keystone Pipeline	U.S. midwest	93.8

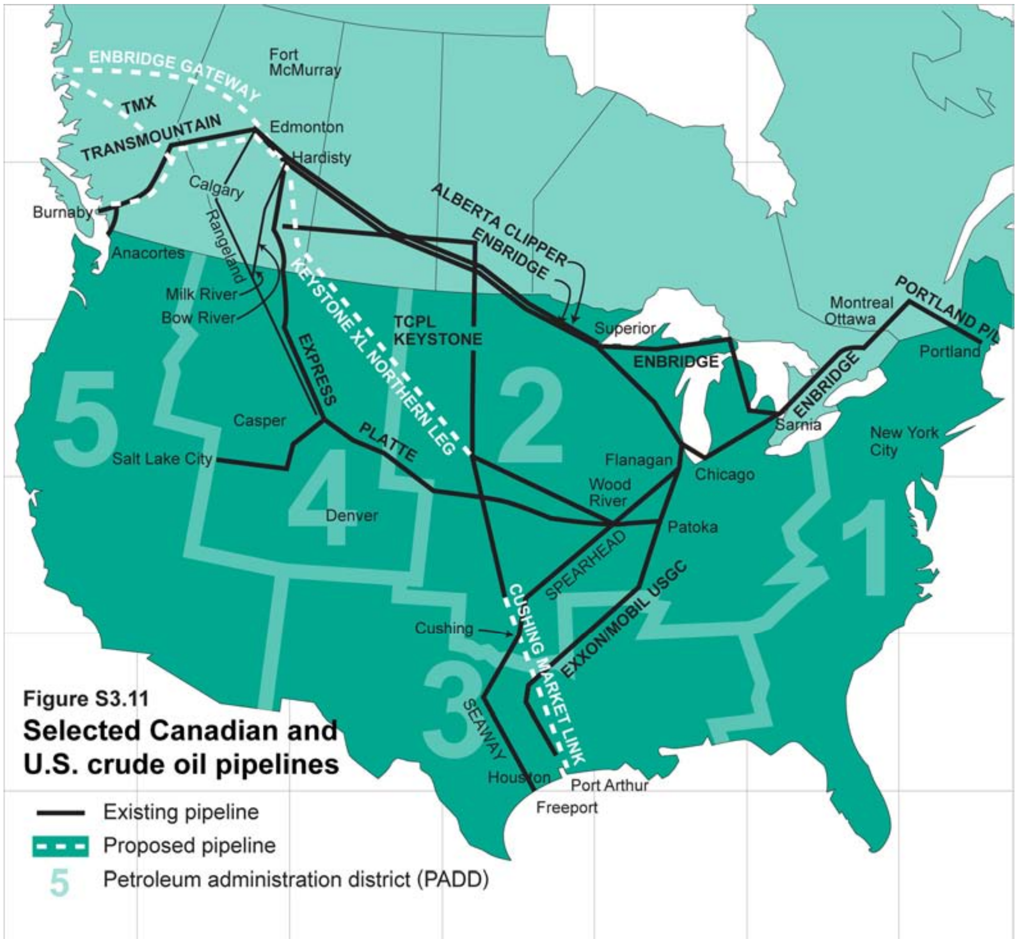


Figure S3.11
Selected Canadian and U.S. crude oil pipelines

3.2.4.4 Proposed Export Pipeline Projects

Table 3.13 provides a summary of the pipeline expansions and new pipeline projects that are proposed to move upgraded and nonupgraded bitumen to existing and new markets. **Figure S3.11** shows the proposed export pipeline expansions and new pipeline export projects.

Table 3.13 Proposed export pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. west coast Offshore	83.3	2017
Kinder Morgan			
Trans Mountain Expansion	British Columbia U.S. west coast Offshore	87.4	TBD
TransCanada Pipeline			
Keystone XL Pipeline	U.S. Gulf Coast	111.3	TBD

3.2.4.5 Rail Transportation

Rail shipments still represent a small portion of total volumes of crude bitumen moved. Currently rail is being used to service projects with limited pipeline capacity or to export volumes to areas not serviced by pipeline. This may change in the future. Rail transportation is being promoted as an economic alternative to pipelining oil and provides an option for producers to send oil to markets other than Cushing, where oversupply is occurring.

Rail continues to play an important role in supplying the diluent needed to transport bitumen through pipelines. Currently, Canada's two main rail providers handle diluent at the Alberta Diluent Terminal in Edmonton in addition to shipping crude oil from the Bakken play in Saskatchewan.

In the short term, it is anticipated that rail will serve as a complementary niche used by industry, depending on economic factors unique to each producer and refiner. Rail could allow producers to bypass short-term pipeline bottlenecks to take advantage of higher prices in PADD areas with refineries capable of handling heavier crudes.

Longer term, however, growth in shipments of bitumen by rail will depend on several factors, such as the availability and supply of diluent, the prices offered by other commodity producers already using rail, and the development of crude oil handling facilities to fill cars with bitumen.

3.2.5 Demand for Upgraded Bitumen and Nonupgraded Bitumen

Alberta oil refineries use bitumen (both upgraded and nonupgraded) and other feedstocks to produce a wide variety of refined petroleum products. Overall, total Alberta demand for upgraded and nonupgraded bitumen was 54.2 10^3 m^3/d in 2011, which is 7 per cent above the 2010 level of 50.8 10^3 m^3/d. This increase was primarily due to higher capacity utilization rates of refineries.

In 2011, the five refineries in Alberta, with a total capacity of 74.6 10^3 m^3/d, used 46.0 10^3 m^3/d of upgraded bitumen and 2.3 10^3 m^3/d of nonupgraded bitumen. Additional demand for upgraded bitumen as diesel fuel and plant fuel accounted for 5.9 10^3 m^3/d in 2011, compared with 5.4 10^3 m^3/d in 2010, an increase of 9 per cent. The Alberta refinery demand consumed 33 per cent of Alberta upgraded bitumen production and 2 per cent of nonupgraded bitumen production in 2011, compared to the 34 per cent of Alberta upgraded bitumen production and 2 per cent of nonupgraded bitumen production consumed in 2010.

Light sweet upgraded bitumen has two principal advantages over light crude oil as a refinery feedstock: it is very low in sulphur and produces very little heavy fuel oil. The latter is particularly desirable in Alberta, where there is virtually no local market for heavy fuel oil. Among the disadvantages of using upgraded bitumen in conventional refineries are the low quality output of distillate and the high level of aromatics (benzene) that must be recovered.

Overall demand for Alberta upgraded bitumen and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, the expansion of refineries currently processing upgraded bitumen and blended bitumen, the altering of current light crude oil refineries to process upgraded bitumen and blended bitumen, and the availability and price of diluent for shipping blended bitumen.

Upgraded bitumen is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor also operates a Suncor Energy-branded "cardlock" station where it sells diesel fuel supplied from its oil sands operation in the Fort McMurray area. In 2011, the sale of refined upgraded bitumen as diesel fuel oil accounted for about 8 per cent of Alberta upgraded bitumen demand, compared to 7 per cent in 2010.

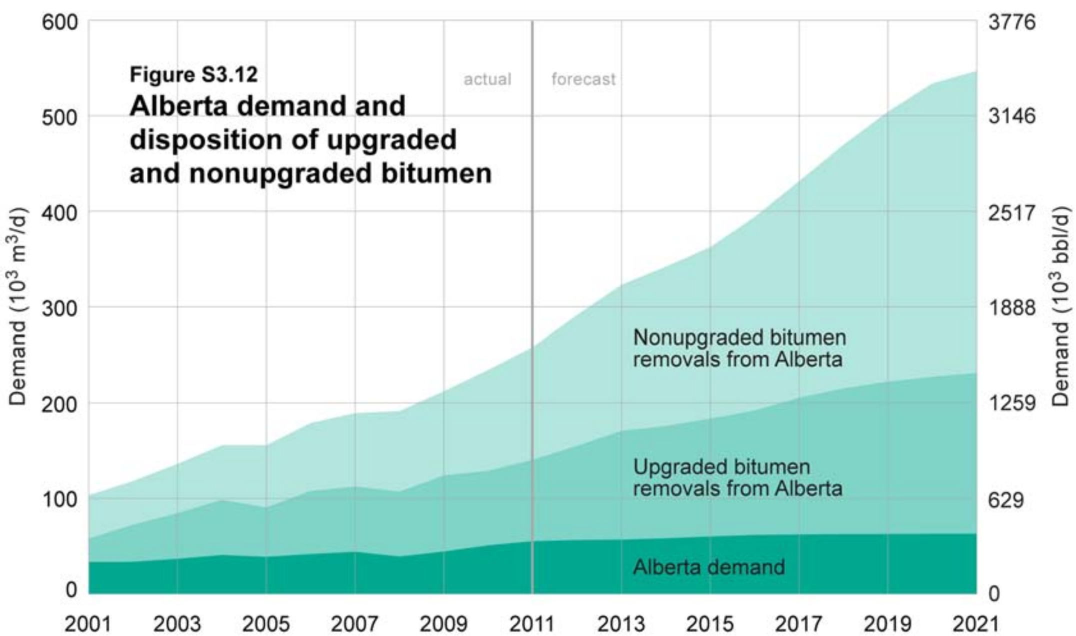


Figure S3.12 shows that in 2021, Alberta demand for upgraded and nonupgraded bitumen will increase to about 62.9 10^3 m^3/d. It is projected that, on average, upgraded bitumen will account for approximately 90 per cent of total Alberta demand, and nonupgraded bitumen will account for approximately 10 per cent throughout the forecast period.

As illustrated in **Figure S3.12**, removals of upgraded bitumen from Alberta will increase from 85.2 10^3 m^3/d in 2011 to 168.4 10^3 m^3/d in 2021, with removals of nonupgraded bitumen increasing from 117.8 10^3 m^3/d to 315.6 10^3 m^3/d over the same period.

Given the current quality of upgraded bitumen, western Canada's eight refineries, with a total capacity of 99.8 10^3 m^3/d, are able to blend up to 34 per cent upgraded bitumen and a further 2 per cent of blended bitumen with crude oil. These refineries receive upgraded bitumen from both Alberta and Saskatchewan. The four refineries in the Sarnia area of eastern Canada, with a combined total capacity of 56.6 10^3 m^3/d, are currently the sole ex-Alberta Canadian market for Alberta upgraded bitumen.

With resurgent light oil supplies in western Canada and the U.S. Midwest, and an oversupplied U.S. Midwest market, discounting of upgraded bitumen and western Canada light oil is expected to continue in the short term. The largest export markets for Alberta upgraded and nonupgraded bitumen have traditionally been the U.S. Midwest, with a refining capacity of 591 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 99 10^3 m^3/d. However, these markets are now currently oversupplied due to the increase in light oil production and limited pipeline capacity to other markets. As such, there is increasing interest in accessing other market regions going forward. Among the other regions is the U.S. Gulf Coast, with a refining capacity of 1374 10^3 m^3/d. Access to this region is of particular importance for nonupgraded bitumen, as this region has traditionally been served by heavy oil and maintains refineries capable of handling the nonupgraded bitumen.

HIGHLIGHTS

For the second year in a row, remaining established reserves increased almost 4 per cent.

Reserves additions from drilling replaced 86 per cent of production in 2011, compared with an average of 69 per cent per year over the 2005–2009 period.

Production increased by 7 per cent in 2011, compared to a slight decrease in 2010 and a 9 per cent decline in 2009.

There were 3170 successful oil wells drilled in 2011, an increase of 37 percent compared to the number of wells drilled in 2010.

4 // CRUDE OIL

In Alberta, crude oil (also known as conventional oil) is deemed to be oil produced outside the oil sands areas, or if within the oil sands areas, from formations other than the Mannville or Woodbend. Crude oil is classified as light-medium if its density is less than 900 kilograms per cubic metre (kg/m^3) or as heavy if its density is 900 kg/m^3 or greater.

4.1 Reserves of Crude Oil

4.1.1 Provincial Summary

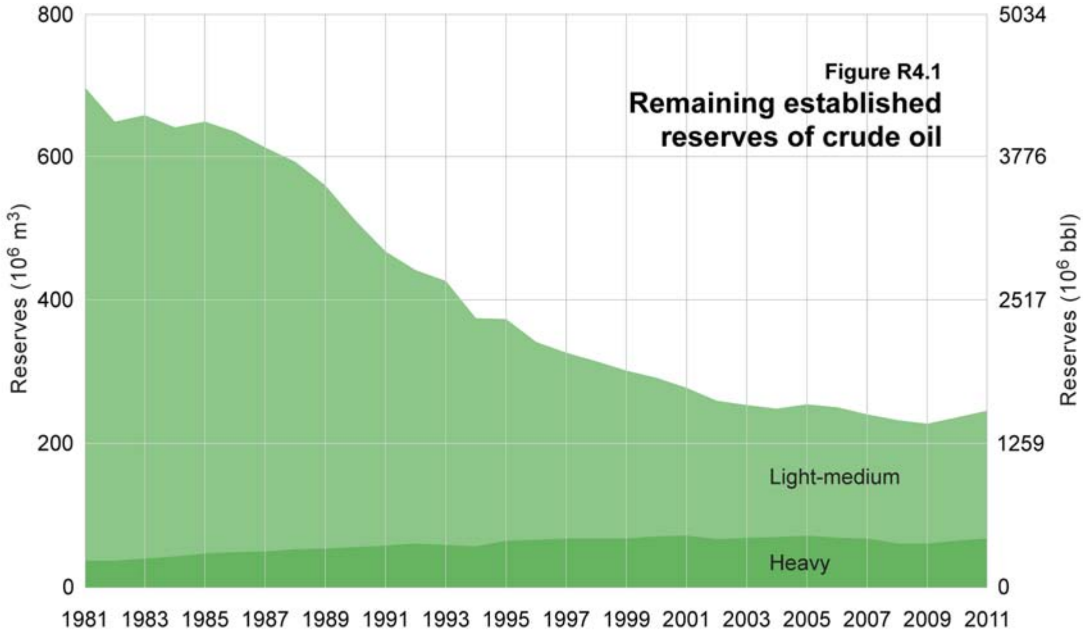
The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 245.9 million cubic metres (10^6 m^3), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 9.0 10^6 m^3, or 3.8 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2011.

Table 4.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2011, while **Figure R4.1** shows the province's remaining conventional oil reserves over time. Remaining reserves have decreased to 20 per cent of the peak reserves of 1223 10^6 m^3 in 1969.

Table 4.1 Reserves and production change highlights (10^6 m^3)

	2011	2010	Change
Initial established reserves[a]			
Light-medium	2 474.7	2 450.3	+24.4
Heavy	388.5	379.4	+9.1
Total	**2 863.2**	**2 829.7**	**+33.5**
Cumulative production[a]			
Light-medium	2 296.7	2 278.1	+18.5
Heavy	320.6	314.7	+5.9
Total	**2 617.3**	**2 592.8**	**+24.4**[b]
Remaining established reserves[b]			
Light-medium	178.0	172.2	+5.8
Heavy	67.9	64.7	+3.2
Total	**245.9**	**236.9**	**+9.0**
	(1 547 10^6 bbl)		
Annual production			
Light-medium	20.3	18.5	+1.8
Heavy	8.1	8.1	0.0
Total	**28.4**	**26.6**	**+1.8**

[a] Any discrepancies are due to rounding.
[b] May differ from annual production due to amendments to reported production and other reasons.



4.1.2 In-Place Resources

The total initial in-place and remaining in-place resources for conventional oil in Alberta stand at 11 357 10^6 m^3 and 8740 10^6 m^3, respectively. Sixty-five per cent of remaining in-place resources (5403 10^6 m^3) are in the largest 2 per cent of pools (260 pools), from which about 27 per cent of oil in place is expected to be recovered with today's technology. This remaining in-place resource represents a substantial potential for enhanced oil recovery (EOR) or for new drilling and completion techniques, such as high-density drilling and multistage fracturing technology.

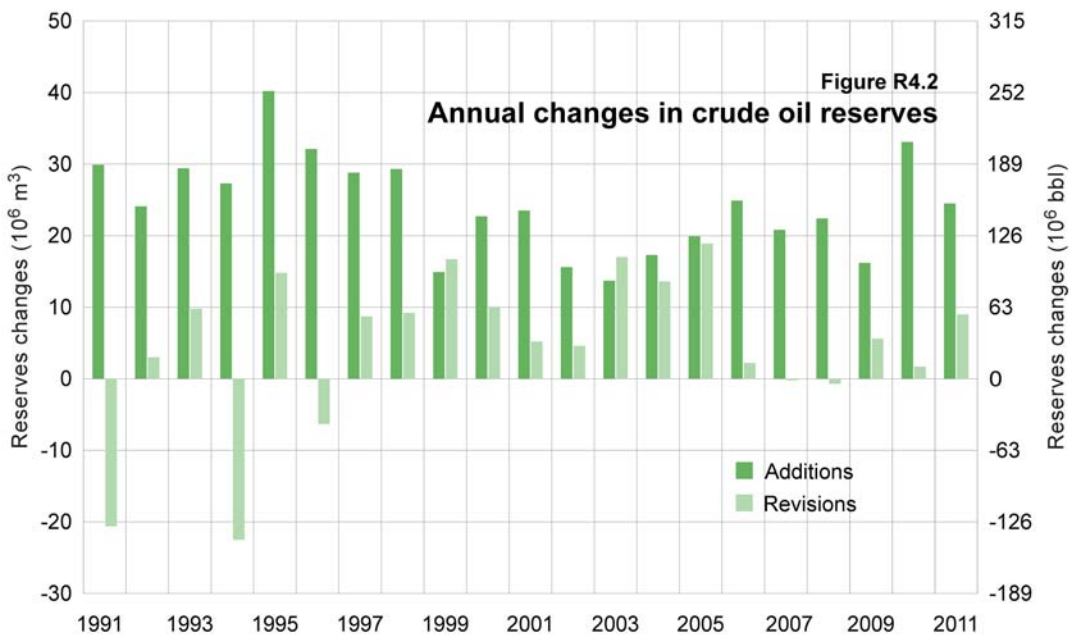
4.1.3 Established Reserves

The initial established reserves attributed to the 285 new oil pools defined in 2011 totalled 2.9 10^6 m^3 (an average of 10 thousand [10^3] m^3 per pool), similar to previous years. **Table 4.2** breaks down this year's changes to initial established reserves into the following categories: new discoveries, development of existing pools, new and expansions to EOR schemes, and revisions to existing reserves. **Figure R4.2** shows the history of additions and net revisions to reserves. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

Table 4.2 Breakdown of changes in crude oil initial established reserves (10^6 m^3)

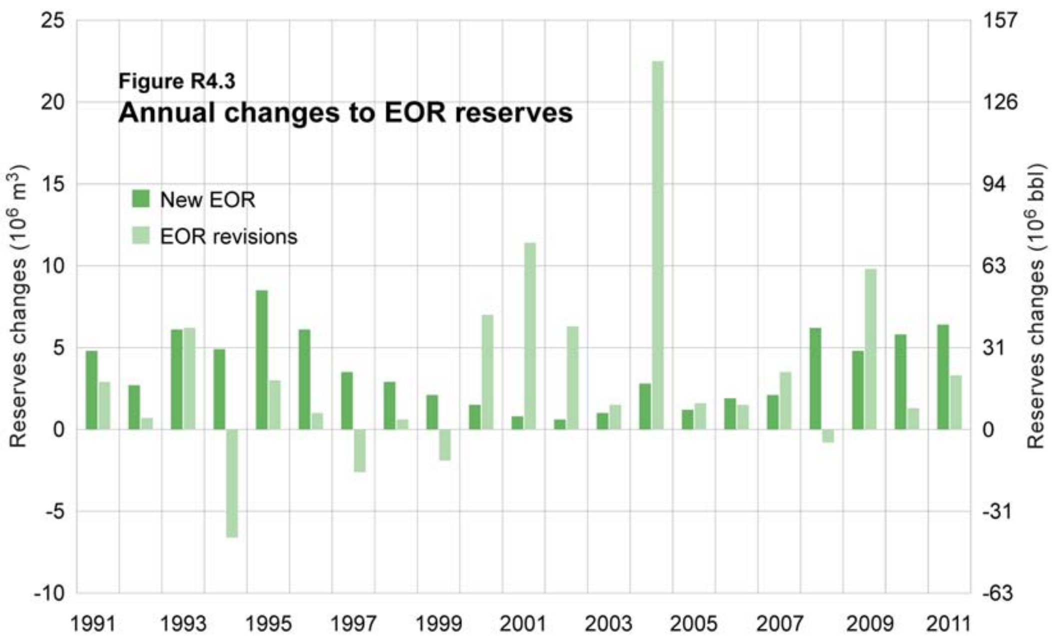
	Light-medium	Heavy	Total[a]
New discoveries	3.3	0.7	**4.0**
Development of existing pools	8.7	5.3	**14.0**
Enhanced recovery (new/expansion)	5.3	1.1	**6.4**
Revisions	+7.1	+2.0	**+9.0**
Total[a]	**+24.4**	**+9.1**	**+33.5**

[a] Any discrepancies are due to rounding.



The ERCB processed 130 applications for new EOR schemes or expansions to existing schemes, resulting in reserves additions totalling 6.4 10^6 m^3, compared with 5.8 10^6 m^3 in 2010 (**Figure R4.3**). Development of existing pools resulted in an increase in initial established reserves of 14.0 10^6 m^3, compared with 23.5 10^6 m^3 in 2010. Overall, total reserves growth from new drilling plus new and expanded EOR schemes (excluding revisions) amounted to 24.4 10^6 m^3, replacing 86 per cent of the 28.4 10^6 m^3 total conventional crude oil production in Alberta. This compares with a previous five-year average replacement ratio of about 80 per cent. Revisions to existing reserves resulted in an overall net change of +9.0 10^6 m^3. The total increase in initial established reserves for 2011 amounted to 33.5 10^6 m^3, similar to the previous year's 34.8 10^6 m^3. **Table B.3** in **Appendix B** provides a history of conventional oil reserves growth and cumulative production from 1968 to 2011. **Section 4.1.3.1** contains further details on the largest reserves changes.

As of December 31, 2011, oil reserves were assigned to 10 454 light-medium and 2752 heavy crude oil pools in the province. While some of these pools contain thousands of wells, most consist of a single well. About 70 per cent of the province's remaining oil reserves are in the largest 3 per cent of pools, most of which were discovered before 1980. The largest of these pools in terms of remaining reserves are Pembina Cardium, Swan Hills Commingled Pool 001, Ferrier Commingled Pool 001, and Chauvin South Commingled Pool 001. In contrast, the smallest 75 per cent of pools contain only 6 per cent of remaining reserves.



While the median pool size has consistently been less than 10 10^3 m^3 since the mid-1970s, the average size has declined from 155 10^3 m^3 in 1970 to about 15 10^3 m^3 recently. The Valhalla Commingled Pool 002 (previously the Doe Creek I and Dunvegan B pools), discovered in 1977, is the last major oil discovery (over 10 10^6 m^3) in Alberta. Initial established reserves for the pool are estimated at 12 630 10^3 m^3. The largest oil pools discovered since the beginning of 2000 include the Dixonville Montney C, Killam North Upper Mannville F2F, Kleskun Beaverhill Lake A, and Chinchaga Slave Point GG pools, with remaining established reserves currently estimated at 1763 10^3 m^3, 936 10^3 m^3, 710 10^3 m^3, and 507 10^3 m^3, respectively.

A detailed pool-by-pool list of reservoir parameters and reserves data for all of Alberta's 13 000 pools is available on CD from the ERCB's Information Services (see **Appendix C**).

4.1.3.1 Largest Reserves Changes

Revisions to existing pools over the past year resulted in a net total reserves change of +9.0 10^6 m^3. **Table 4.3** lists pools with the largest reserves changes in 2011. The most significant change was to the Swan Hills Commingled Pool 001, which saw initial established reserves increase by 2 655 10^3 m^3 to 157 400 10^3 m^3 as a result of waterflood expansion. Reserves were increased in the Dixonville Montney C Pool by 1 059 10^3 m^3 to 2 704 10^3 m^3 as waterflood reserves responded to positive results from infill horizontal drilling. There continues to be potential for significant reserves growth from new horizontal wells in the Cardium Formation at Pembina, Willesden Green, and other fields. Horizontal, multistage fractured wells are being drilled on the periphery of the main pools where permeability declines to less than 1 millidarcy (mD) as a result of a change to a shalier facies. This technique is also being used in many other formations, including Montney, Beaverhill Lake, Slave Point, Glauconitic, Pekisko, Duvernay, and Viking. With respect to negative revisions, reassessment of reserves in the Goose River Beaverhill Lake A Pool resulted in a 467 10^3 m^3 decrease.

Table 4.3 Major oil reserves changes, 2011

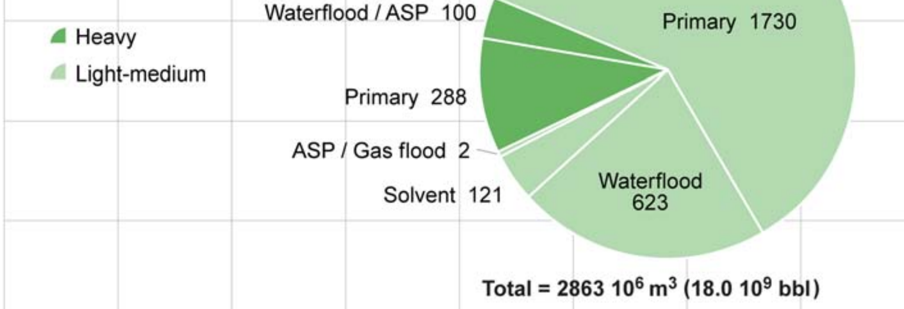
Pool	Initial established reserves (10^3 m^3) 2011	Change	Main reason for change
Chigwell Viking E	1 054	+384	Development of solvent flood reserves
Dixonville Montney C	2 704	+1 059	Reassessment of waterflood reserves
Excelsior D-2	4 888	+264	Pool development
Goose River Beaverhill Lake A	10 610	-467	Reassessment of waterflood reserves
Halkirk East Viking A	663	+305	Pool development
Judy Creek Beaverhill Lake B	19 880	+980	New primary and reassessment of solvent flood reserves
Kaybob Beaverhill Lake A	21 010	-226	Reassessment of waterflood reserves
Lloydminster Commingled Pool 012	6 927	+1 918	Pool development
Lloydminster Sparky G	2 902	+386	New waterflood reserves and reassessment of primary reserves
Loon Granite Wash P	1 105	-133	Reassessment of reserves
Marwayne Sparky D	1 144	-202	Reassessment of reserves
Medicine Hat Glauconitic C	5 747	+1 096	Reassessment of waterflood reserves
Medicine River Commingled Pool 007	3 894	-196	Reassessment of reserves
Mooney Bluesky A	1 417	+331	Development of chemical flood reserves
Pembina Cardium	235 800	+593	Pool development and new chemical flood scheme
Rainbow Muskeg O	559	-249	Reassessment of primary reserves
Suffield Upper Mannville YYY	881	+297	Pool development and reassessment of chemical flood reserves
Swan Hills Commingled Pool 001	157 400	+2 655	Development of waterflood
Swimming McLaren D	813	+276	Pool development and new waterflood scheme
Turner Valley Rundle	29 470	+260	Reassessment of reserves
Valhalla Commingled Pool 009	1 838	+394	Reassessment of reserves
Vauxhall Upper Mannville G	412	-118	Reassessment of reserves
Viking-Kinsella Sparky E	2 001	+335	Reassessment of reserves
Wembley MFP8524	5 318	+254	Development of waterflood reserves
Willesden Green Commingled Pool 007	26 840	+431	Pool development

4.1.3.2 Distribution by Recovery Mechanism

Alberta's total initial volume in place and initial established reserves of conventional crude oil currently stand at 11 357 10^6 m^3 and 2863 10^6 m^3, respectively, yielding an overall recovery efficiency of 25 per cent. **Figure R4.4** and **Table 4.4** show the distribution of in-place volumes and reserves by recovery mechanism and crude oil density.

In light-medium pools under waterflood, recovery increased from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Pools under solvent flood, on average, recovered 12 per cent more than projected theoretical waterflood recovery. Primary recovery in heavy crude pools has increased from an average 8 per cent in 1990 to 12 per cent in 2011 as a result of improved water handling, increased drilling density, and the use of horizontal wells with multistage fracturing. Incremental recovery from all waterflood projects represents about 25 per cent of the province's initial established reserves, while solvent floods are projected to add 4 per cent to the province's recoverable reserves. Alkali surfactant polymer (ASP) floods are becoming more popular, typically adding 3 to 10 per cent recovery over waterflood.

Figure R4.4
Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)

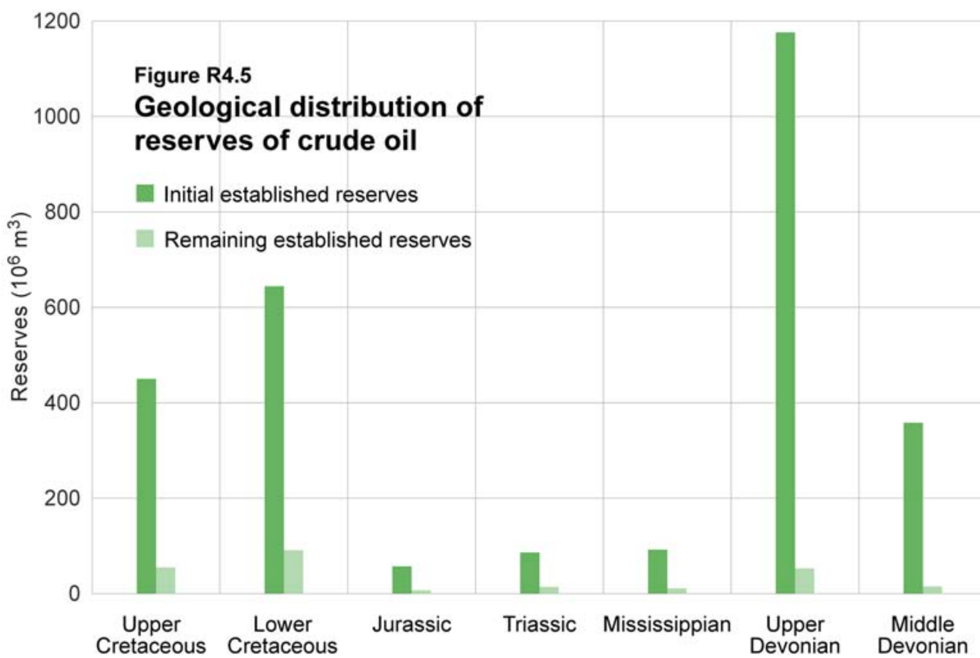


4.1.3.3 Distribution by Geological Formation and Area

The distribution of reserves by geological period and Petroleum Services Association of Canada (PSAC) geographical area is depicted in **Figure R4.5** and **Figure R4.6**, respectively. The Lower Cretaceous is the major source of conventional oil as evidenced by the increase in initial established reserves from 284 10^6 m^3 to 644 10^6 m^3 over the period from 1990 to 2011.

Table 4.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2011

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Waterflood/ gas flood	Solvent flood	Total	Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	4 387	904	0	0	**904**	21	-	-	**21**
Waterflood	3 450	521	440	0	**960**	15	13	-	**28**
Polymer/ASP	20	3	6	2	**11**	15	28	10	**53**
Solvent flood	986	266	167	121	**554**	27	17	12	**56**
Gas flood	124	36	10	0	**46**	29	8	-	**37**
Heavy									
Primary depletion	1 654	196	0	0	**196**	12	-	-	**12**
Polymer/ASP	47	4	5	5	**14**	9	11	11	**30**
Waterflood	689	88	90	0	**178**	13	13	-	**26**
Total	**11 357**	**2 018**	**717**	**128**	**2 863**	**18**	**6**	**1**	**25**
Percentage of total initial established reserves		71%	25%	4%	**100%**				



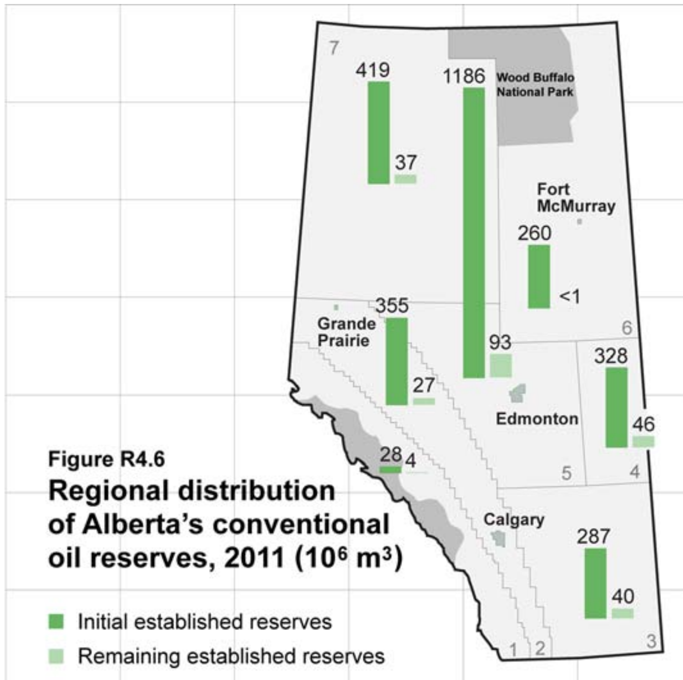


Figure R4.6
Regional distribution of Alberta's conventional oil reserves, 2011 (10^6 m^3)

4.1.3.4 Oil Reserves Methodology

The process of quantifying reserves is governed by many geological, engineering, and economic considerations. Initially there is higher uncertainty in the reserves estimates, but this uncertainty decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. The earliest reserves estimates are usually based on volumetric estimation. An estimate of bulk rock volume is based on net pay isopach maps derived primarily from geological evaluation of well log data. This is combined with data gathered on rock properties, such as porosity and water saturation, to determine oil in place at reservoir conditions. Areal assignments for new single-well oil pools range from 64 hectares (ha) for light-medium oil producing from regionally correlatable geologic units to 32 ha or less for heavy oil pools and small reef structures.

Converting volume in place to standard conditions at the surface requires applying oil shrinkage data obtained from pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir-drive mechanism. Recoveries range from 5 per cent for heavy oils to over 50 per cent for light-medium oils producing from highly permeable reefs with full pressure support from an active underlying aquifer. Provincially, 25 per cent of the in-place resource is expected to be recovered.

Once there are sufficient pressure and production data, material balance or production decline methods can be used as an alternative to volumetric estimation to determine in-place resources. Analysis by material balance is seldom used as it requires good pressure and PVT data. Production decline analysis, therefore, is the primary method for determining recoverable reserves. When combined with a volumetric estimate of the in-place resource, it also provides a realistic estimate of the pool's recovery efficiency.

Secondary recovery techniques using artificial means of adding energy to a reservoir by water or gas injection can considerably increase oil recoveries. Less common tertiary recovery techniques may be applied by injecting fluids that are miscible with the reservoir oil at high pressures. This improves recovery efficiency by reducing the residual oil saturation at abandonment. However, irregularities in rock quality can lead to channelling, which causes low sweep efficiency and bypass of oil in some areas in the pool.

Incremental recovery over primary depletion is estimated for pools approved for waterflood and is displayed separately in the ERCB's oil reserves database. To accommodate the Alberta government's royalty incentive programs, incremental recovery over an estimated base-case waterflood recovery is determined for tertiary schemes. Typically a base-case waterflood recovery is estimated even in cases where no waterflood was implemented before the solvent flood.

Reserves numbers published by the ERCB represent estimates for in-place, recoverable reserves, and recovery factors based on the most reasonable interpretation of available information from volumetric, production decline, and material balance methods.

4.1.4 Ultimate Potential

In 1994, based on the geological prospects at that time, the ERCB estimated the ultimate potential of conventional crude oil to be 3130 10^6 m^3. This estimate does not include potential oil from very low permeability reservoirs, referred to by industry as "tight oil," which is now starting to be exploited using horizontal multistage fracturing technology. **Figure R4.7** illustrates the historical decline in remaining established reserves relative to cumulative oil production. Extrapolation of the decline suggests that the ERCB's estimate of ultimate potential may be low, especially given that after decades of decline, remaining reserves have increased in each of the last two years.

Figure R4.8 shows Alberta's historical and forecast growth of initial established reserves. As of December 31, 2011, approximately 83 per cent of the estimated ultimate potential for conventional crude oil has been produced. To date, industry has discovered 91 per cent of the estimated ultimate potential, leaving 9 per cent yet to be discovered, which when added to the remaining established reserves leaves 513 10^6 m^3 (3.2 billion barrels) of conventional crude oil available for future production.

The ERCB estimates that there are 267 10^6 m^3 of reserves yet to be discovered. The discovery of new pools and the development of existing pools will also continue to add new reserves and associated production each year.

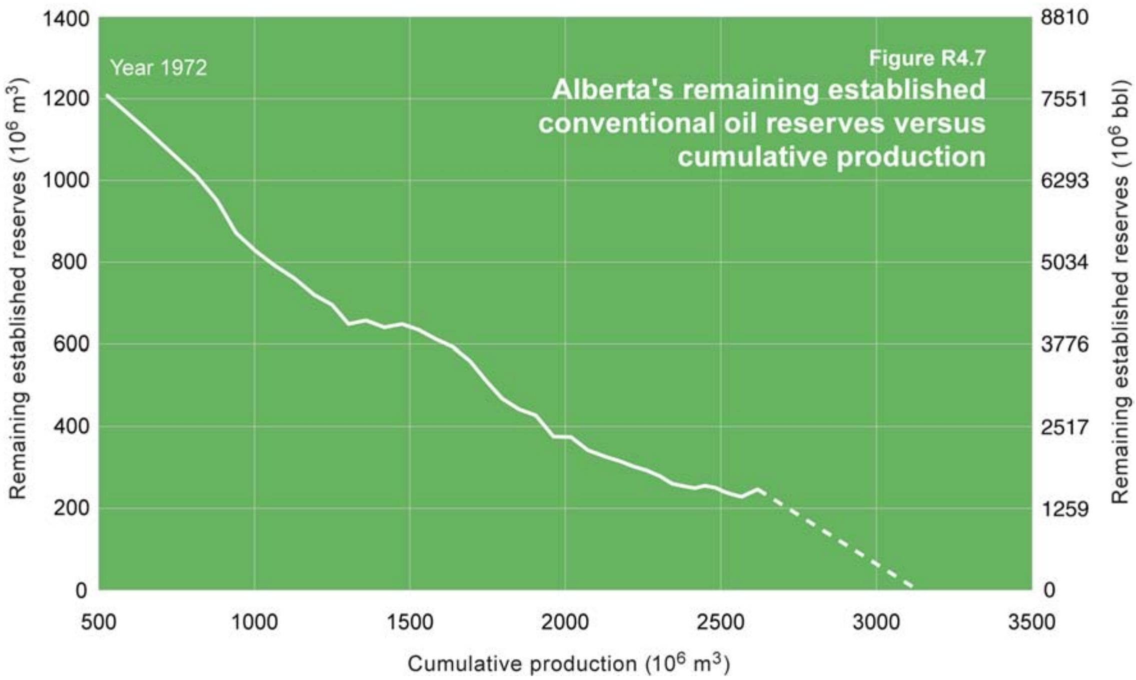


Figure R4.7
Alberta's remaining established conventional oil reserves versus cumulative production
Year 1972
Remaining established reserves (10⁶ m³)
Remaining established reserves (10⁶ bbl)
Cumulative production (10⁶ m³)
0
200
400
600
800
1000
1200
1400
0
1259
2517
3776
5034
6293
7551
8810
500
1000
1500
2000
2500
3000
3500

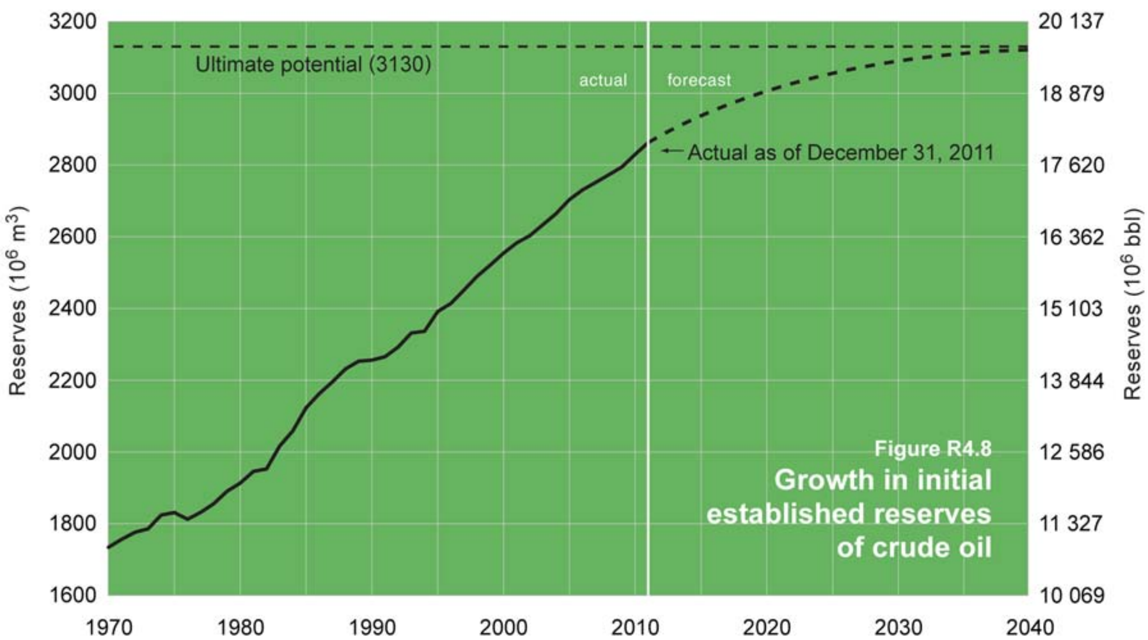


Figure R4.8
Growth in initial established reserves of crude oil
Ultimate potential (3130)
actual
forecast
Actual as of December 31, 2011
Reserves (10⁶ m³)
Reserves (10⁶ bbl)
1600
1800
2000
2200
2400
2600
2800
3000
3200
10 069
11 327
12 586
13 844
15 103
16 362
17 620
18 879
20 137
1970
1980
1990
2000
2010
2020
2030
2040

4.2 Supply of and Demand for Crude Oil

In projecting crude oil production, the ERCB considers two components: expected crude oil production from existing wells at year-end and expected production from new wells. Total forecast production of crude oil is the sum of these two components. Demand for crude oil in Alberta is based on provincial refinery capacity and use. Alberta crude oil supply in excess of Alberta demand is marketed outside the province.

4.2.1 Crude Oil Production—2011

Starting in 2010, total crude oil production in Alberta reversed the downward trend that was the norm since the early 1970s. In 2010 and 2011, light-medium crude oil production began to increase as a result of increased, mainly horizontal, drilling activity with the introduction of multistage hydraulic fracturing technology. This new technology creates permeability in low-permeability units, which, until artificial fracturing, were largely considered to be source rocks and not reservoir rocks. The successful application of this technology and increased drilling resulted in total crude oil production increasing by 7 per cent in 2011 to 77.9 10^3 m^3/d from 73.0 10^3 m^3/d.[1] Light-medium crude oil production increased in 2011 to 55.7 10^3 m^3/d, an increase of 10 per cent from its 2010 levels. By contrast, heavy crude oil production declined by 0.5 per cent to 22.2 10^3 m^3/d.

4.2.1.1 Drilling Activity

In 2011, 3170 successful oil wells were drilled, an increase of 37 per cent from 2010.[2] The last time Alberta experienced this high a level of drilling was in 2005. **Figure S4.1** shows the number of successful oil wells drilled in Alberta in 2010 and 2011 by PSAC geographical area. Most oil drilling (88%) in 2011 was development drilling. As shown in the figure, all areas of the province in which drilling activity occurred, in particular PSAC Areas 2 and 7, experienced substantial increases over last year's levels, except for PSAC 1, where fewer wells were drilled.

[1] Unrounded production numbers were used to calculate per cent change in this section. Per cent change may be slightly different using rounded production numbers.

[2] Although the success ratio for conventional crude oil wells cannot be determined separately from all other drilling activity (excluding oil sands evaluation wells), 1 per cent of all development wells and 4 per cent of all exploratory wells drilled in 2011 were abandoned at the time of drilling. Overall, less than 2 per cent of all wells drilled in 2011 were abandoned at the time of drilling.

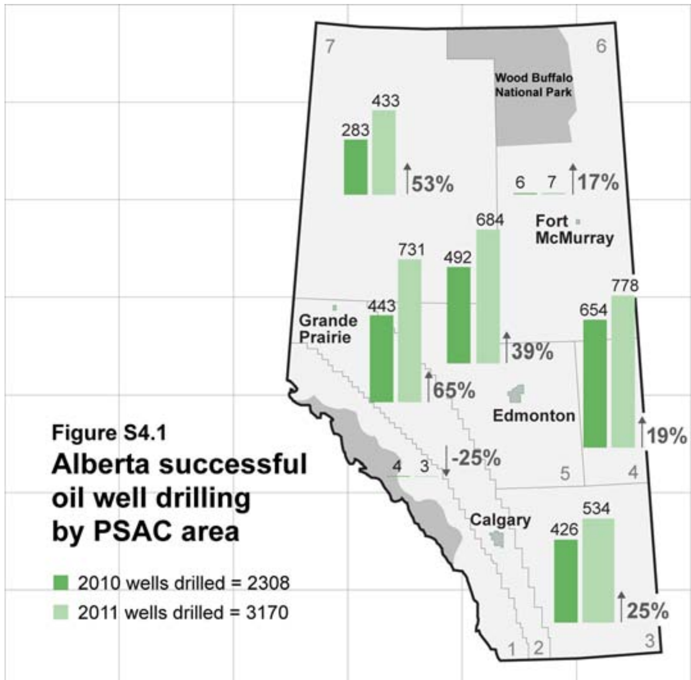


Figure S4.1
Alberta successful oil well drilling by PSAC area

Figure S4.2 depicts the distribution of new crude oil wells placed on production, and **Figure S4.3** shows the initial operating day rates of new wells in 2011. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are put on production shortly after being drilled. In 2011, wells placed on production increased by 46 per cent, from 2148 in 2010 to 3138. This increase corresponds to the increase seen in the number of successful oil wells drilled.

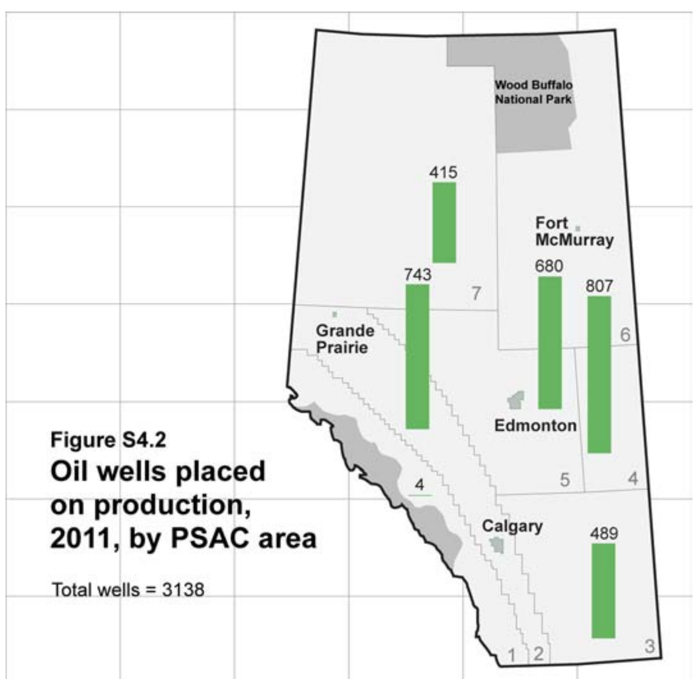


Figure S4.2
Oil wells placed on production, 2011, by PSAC area

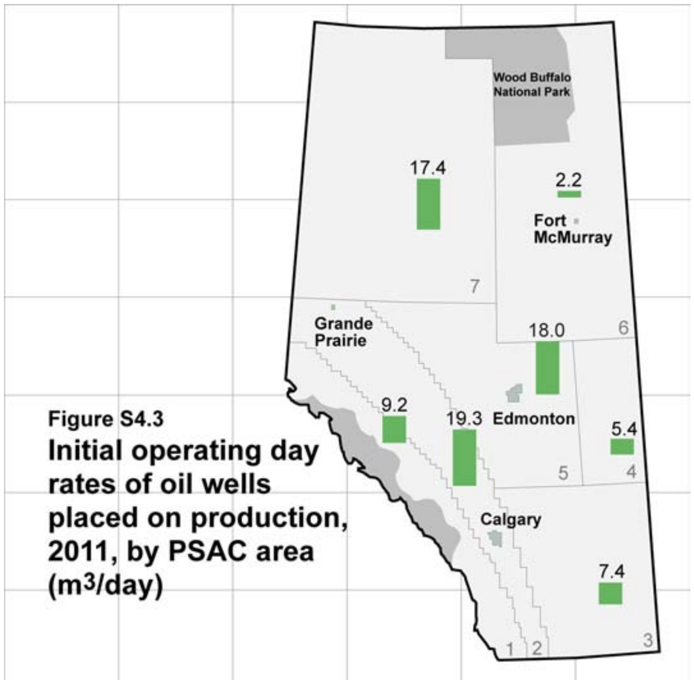


Figure S4.3
Initial operating day rates of oil wells placed on production, 2011, by PSAC area (m3/day)

4.2.1.2 Production Characteristics

Historical oil production by PSAC area is illustrated in **Figure S4.4**. In 2011, PSAC Areas 2, 4, and 5 experienced increases in production when compared with 2010, ranging from a 2 per cent increase in PSAC Area 4 to a 26 per cent increase in PSAC Area 2.

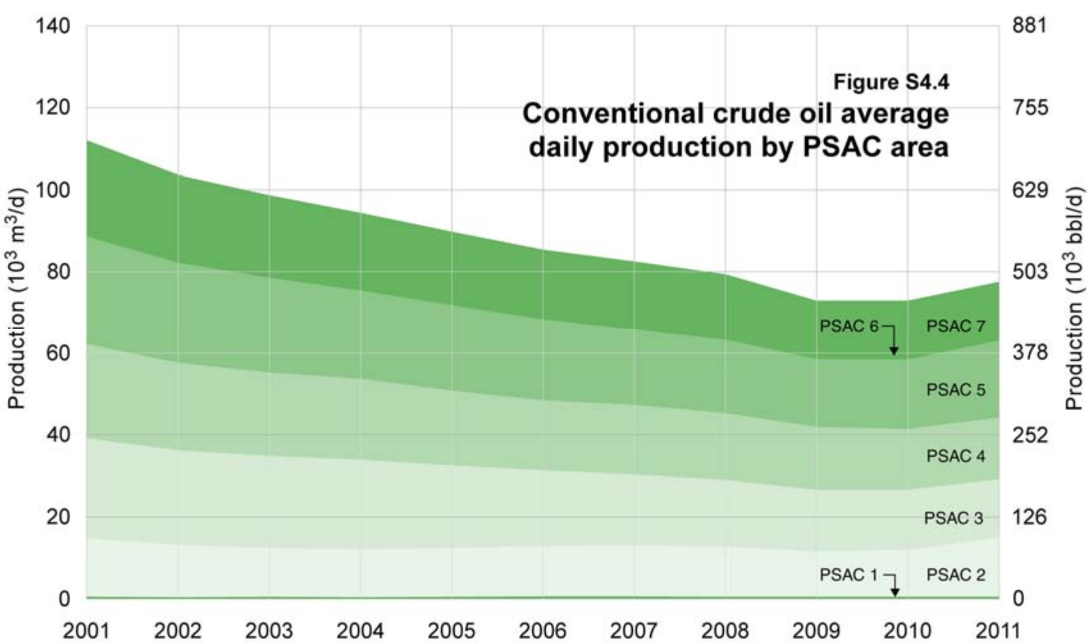
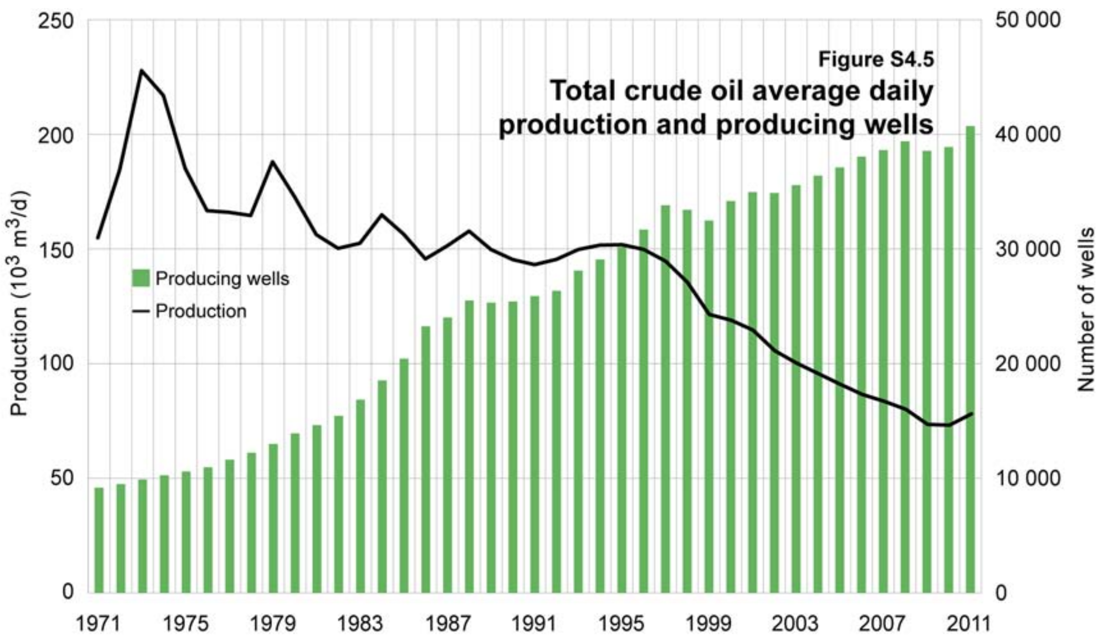


Figure S4.4
Conventional crude oil average daily production by PSAC area

Figure S4.5 shows the total average daily production rate and the number of wells producing crude oil. The number of wells producing oil has increased over time from 9100 in 1970 to 40 707 in 2011. The average annual production rate of oil producing wells, however, has been on the decline since 1973. The average daily production rate per well in 1973 for all producing oil wells was 23 m^3/d. This average declined to 5.5 m^3/d by 1991 and reached the lowest level of 1.9 m^3/d by 2009 but has remained constant since then as a result of increased drilling activity and, in particular, the increased use of multistage fracturing technology in horizontal wells.



Of the 40 707 wells producing oil in 2011, about 3010 were classified as gas wells. Although these gas wells represented 7.5 per cent of wells that produced oil, they produced at a very low average rate of 0.3 m^3/d and accounted for less than 1 per cent of total production. Also included were about 6643 producing horizontal oil wells that accounted for 16 per cent of producing oil wells but contributed about 33 per cent to the total crude oil production because of the higher average production rate per well.

Figure S4.6 depicts producing oil wells and the average daily production rates of those wells by region in 2011. The average well productivity of crude oil producing wells in 2011 was 2.0 m^3/d. Roughly 45 per cent of producing crude oil wells produce at rates less than 1 m^3/d per well, a characteristic typical of mature basins. In 2011, the 16 600 oil wells in this category produced at an average rate of 0.5 m^3/d and accounted for only 11 per cent of the total crude oil produced. **Figure S4.7** shows the distribution of crude oil producing wells (including horizontal oil wells) based on their average production rates in 2011.

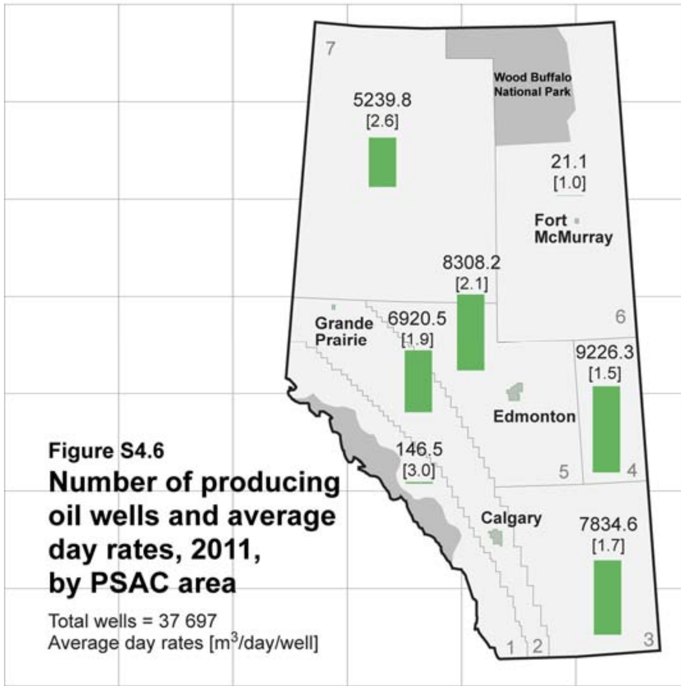


Figure S4.6
Number of producing oil wells and average day rates, 2011, by PSAC area

Total wells = 37 697
Average day rates [m^3/day/well]

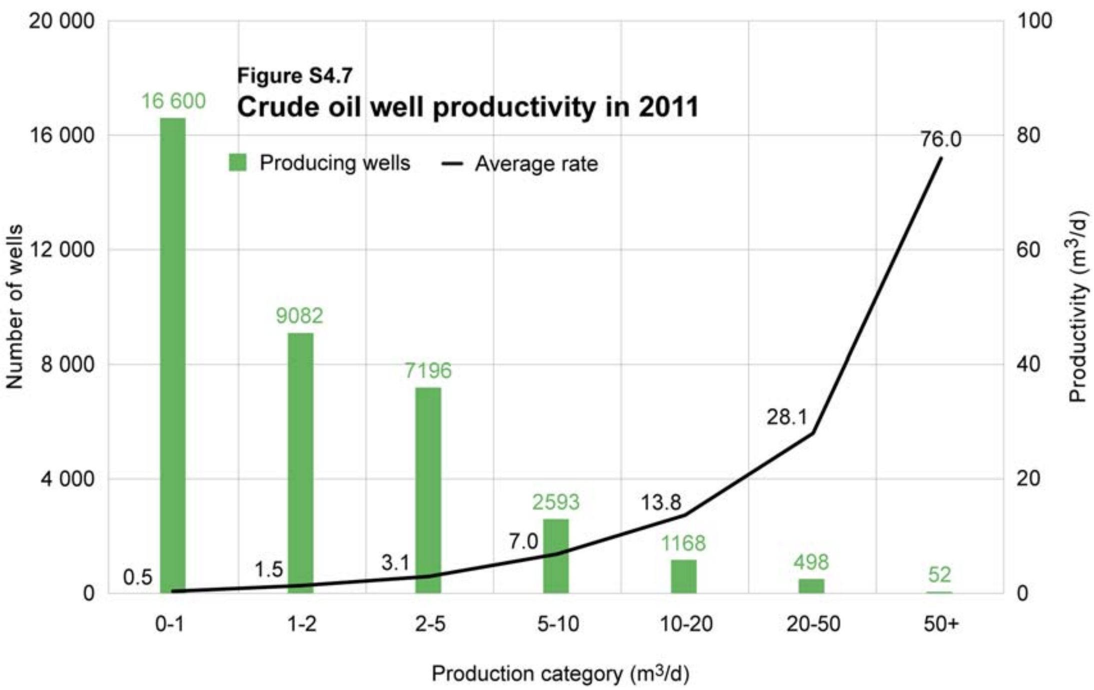


Figure S4.7
Crude oil well productivity in 2011

In 2011, 1818 new horizontal oil wells (including those using multistage fracturing technology) were brought on production, an increase of 78 per cent from 2010 levels of 1023 horizontal wells. This raises the total number of horizontal wells to 6643.

Initial average daily production rates were calculated for new wells, using the first full calendar year of production. Initial production rates for new horizontal wells are 6.2 m^3/d, compared with 3.2 m^3/d for vertical wells.

Crude oil production from existing wells placed on production from 2001 to 2011 is depicted in **Figure S4.8**. This figure illustrates that 41 per cent of crude oil production in 2011 represents wells placed on production in the last five years.

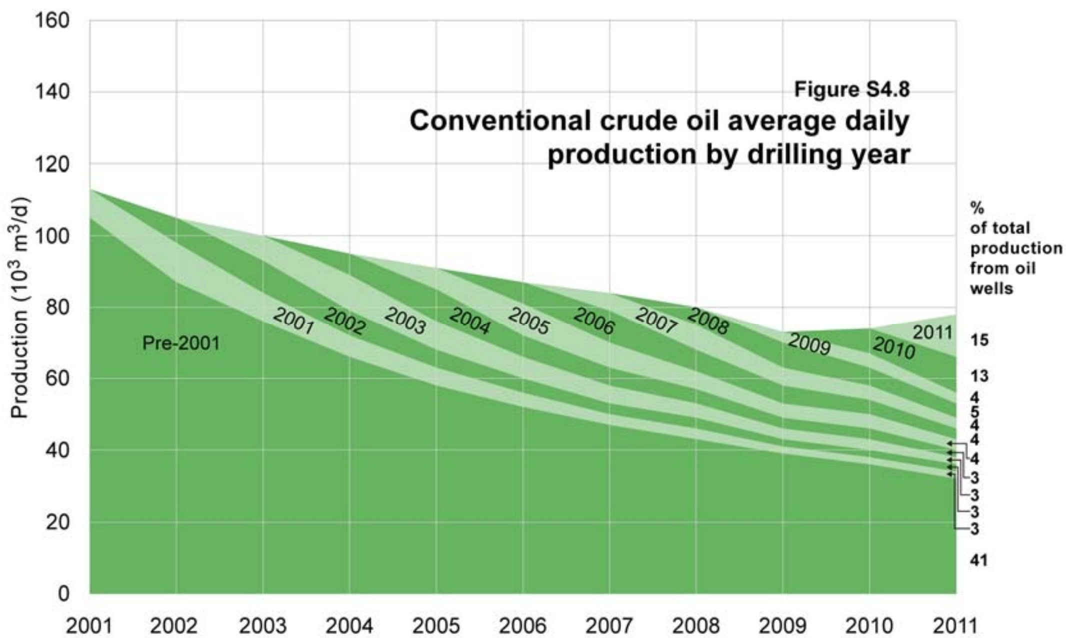


Figure S4.9 compares historical Alberta crude oil production with crude oil production from Texas onshore and North Dakota. North Dakota production has been relatively flat since 1981; however, since around 2007, production has taken off, and 2011 production levels are more than triple 2002 production levels due to the successful application of horizontal multistage fracturing technology that has resulted in the economic production of new plays. In 2011, Texas onshore and Alberta production have also reversed the downward production trend, with Texas onshore in particular exhibiting significant growth in 2011. The figure shows that Alberta has not experienced the same steep decline rates that Texas has, although the flattening of production, as opposed to a continued decline, is indicative of the strong price environment encouraging additional drilling and the successful deployment of horizontal multistage fracturing technology in Alberta's conventional plays.

Total production from new wells is a function of the number of new wells that are anticipated to be drilled successfully, initial production rate, and the expected average decline rate for these new wells.

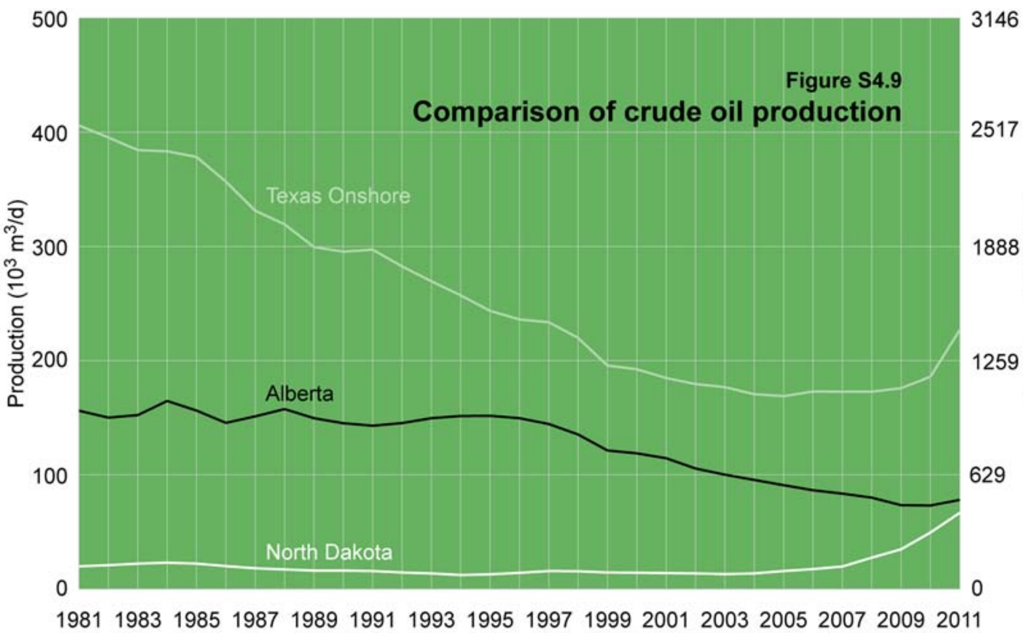
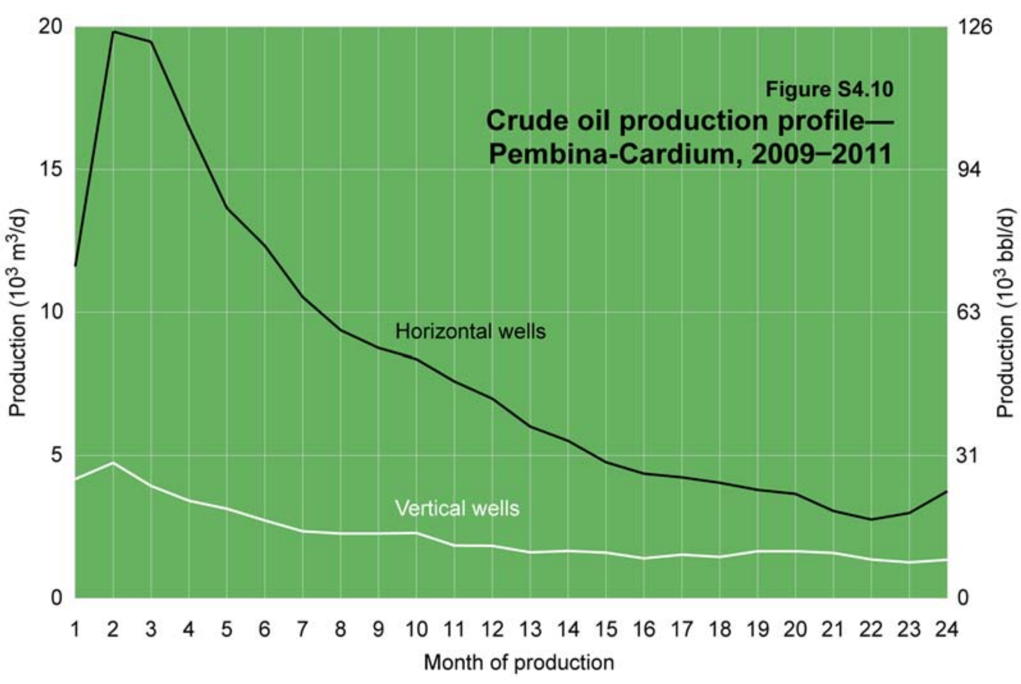


Figure S4.10 shows the production profiles of oil produced from a representative sample set of vertical and horizontal multistage fractured and vertical oil wells in the Pembina field that are producing crude oil from the Cardium formation. Oil wells that were placed on production within the 2009 to 2011 period were used to illustrate the difference in production profiles by well types. As shown in the **Figure S4.10**, multistage fracturing technology has significantly improved well productivity, as these horizontal multistage fractured oil wells have much higher initial well productivities than do vertical wells.



4.2.2 Crude Oil Production—Forecast

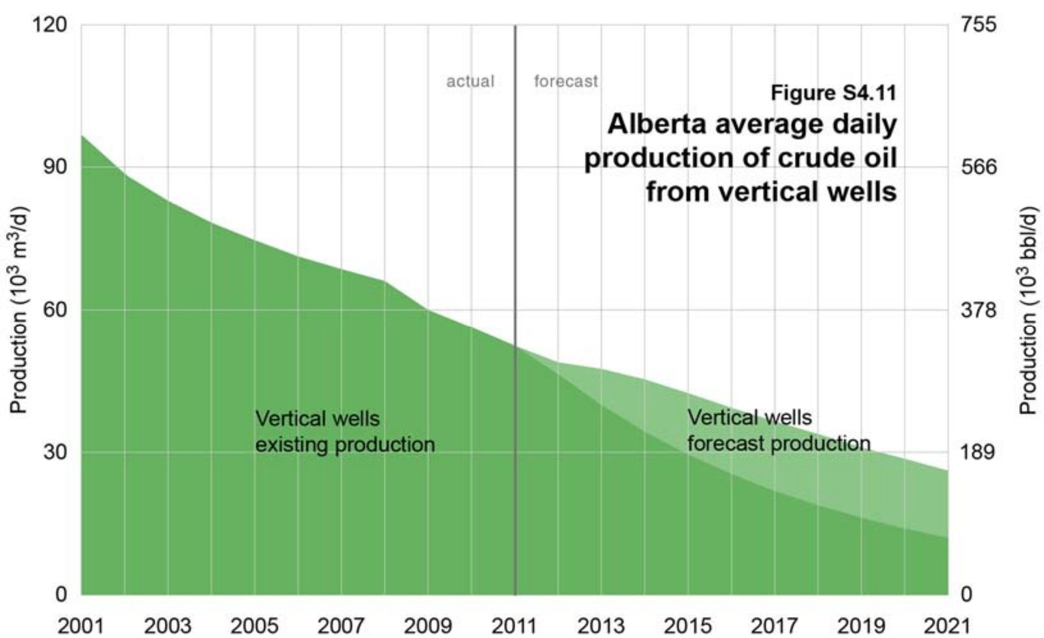
To project crude oil production over the forecast period, the ERCB has forecast production from vertical wells separate from horizontal wells. The forecast for production from new vertical wells acknowledges industry's continued interest in drilling for oil using conventional technology. The horizontal category of wells includes multistage fractured horizontal wells.

To forecast production from each category, production from existing and new wells drilled each year has been analyzed. The number of wells drilled and the average productivity of the wells in each category are the main factors used to project oil production over the forecast period.

4.2.2.1 Vertical Wells

Figure S4.11 illustrates the projected crude oil production from vertical wells. The ERCB based its projection on the following assumptions:

- Production from existing vertical wells will decline by 14.0 per cent per year.
- The number of new vertical oil wells placed on production is projected to be 1440 in 2012 and expected to decline to 1040 wells in 2021. Although this well count is relatively low and reflects the view that many new wells will be horizontal wells using multistage fracturing technology, this forecast has increased relative to last year due to 2011 industry levels.
- The average initial production rate for new vertical wells is projected to be 3.5 m^3/d/well and is expected to decrease to 2.0 m^3/d/well by the end of the forecast period.



- Production from new wells will decline at a rate of 26 per cent the first year, 22 per cent the second year, 21 per cent the third year, 19 per cent the fourth year, and 16 per cent over the rest of the forecast period.

4.2.2.2 Horizontal Wells

Since 2008, multistage fracturing techniques have been used in targeting the Cardium tight oil and other emerging plays and reserves that have so far been unrecovered in major pools in Alberta. Multistage fractured horizontal wells have been used successfully to unlock the Bakken tight oil play in North Dakota and southeastern Saskatchewan for a number of years, as discussed earlier.

A methodology similar to that used for vertical wells is used to project crude oil production from horizontal wells. Potential crude oil production from existing and new wells is combined to project total production in this category of wells over the forecast period.

Figure S4.12 illustrates the projected crude oil production from horizontal wells. The ERCB based its projection on the following assumptions:

- Production from existing wells will decline at a rate of 18.0 per cent per year.
- The number of new horizontal oil wells is projected to increase from 1818 in 2011 to 2160 in 2012 and 2013 and to decline gradually to 1560 in 2021. The forecast number of horizontal oil wells has significantly increased relative to our forecast last year and reflects 2011 actual activity and anticipated continued strong crude oil prices.
- The average initial production rate for new conventional horizontal wells is projected to be 6.0 m^3/d/well in 2012 and remain constant for the remainder of the forecast period, as opposed to the projection last year that average initial production rates would decrease.
- Production from new wells will decline at a rate of 40 per cent the first year, 26 per cent the second year, 19 per cent the third year, and 19 per cent over the remaining forecast period.

The projected total crude oil production, which comprises production from both existing wells and new vertical and horizontal wells, is illustrated in **Figure S4.13**. The production forecast is higher than what was forecast last year, with production forecast in 2021 at 71.1 10^3 m^3/d compared with last year's forecast of 65.0 10^3 m^3/d in 2020.

Figure S4.14 illustrates the split for light-medium and heavy crude oil. Light-medium crude oil production is expected to decline from 55.7 10^3 m^3/d in 2011 to 51.2 10^3 m^3/d in 2021. Over the forecast period, heavy crude production is also expected to decrease from 22.2 10^3 m^3/d in 2011 to 19.9 10^3 m^3/d. **Figure S4.14** also illustrates that by 2021, heavy crude oil production will continue to hold the same proportion of total conventional crude oil production in Alberta (28 per cent) for the remainder of the forecast period.

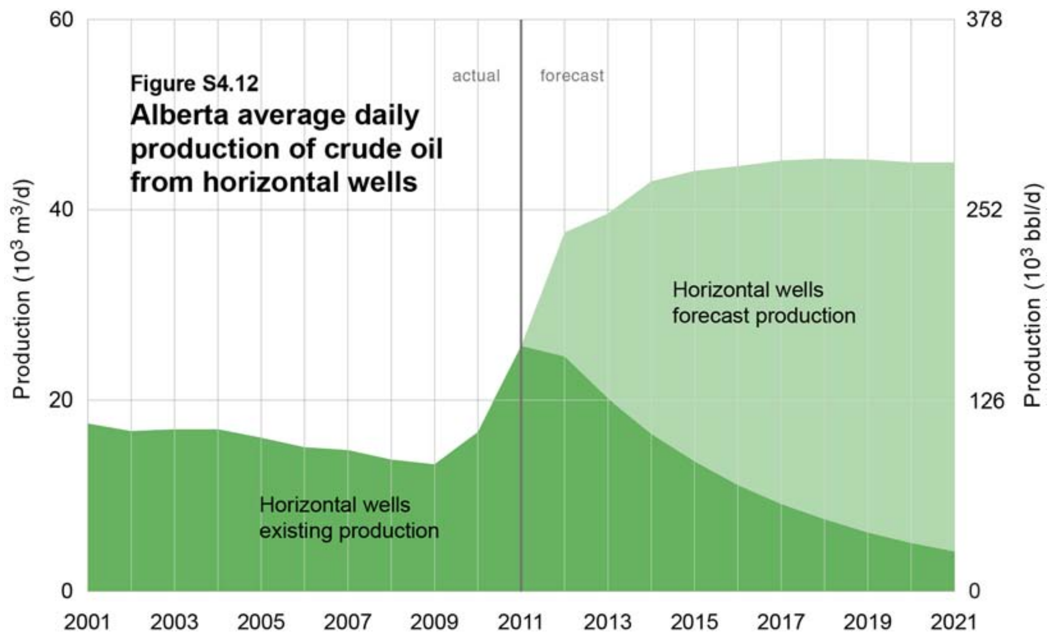


Figure S4.12
Alberta average daily production of crude oil from horizontal wells
actual
forecast
Horizontal wells forecast production
Horizontal wells existing production
Production (10^3 m^3/d)
Production (10^3 bbl/d)
60
40
20
0
378
252
126
0
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021

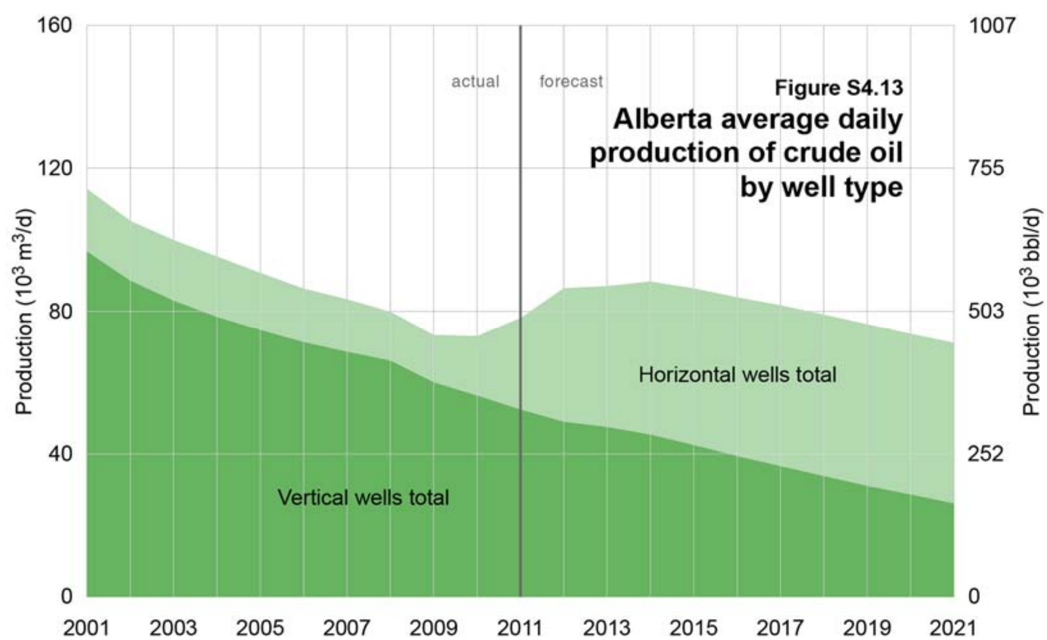
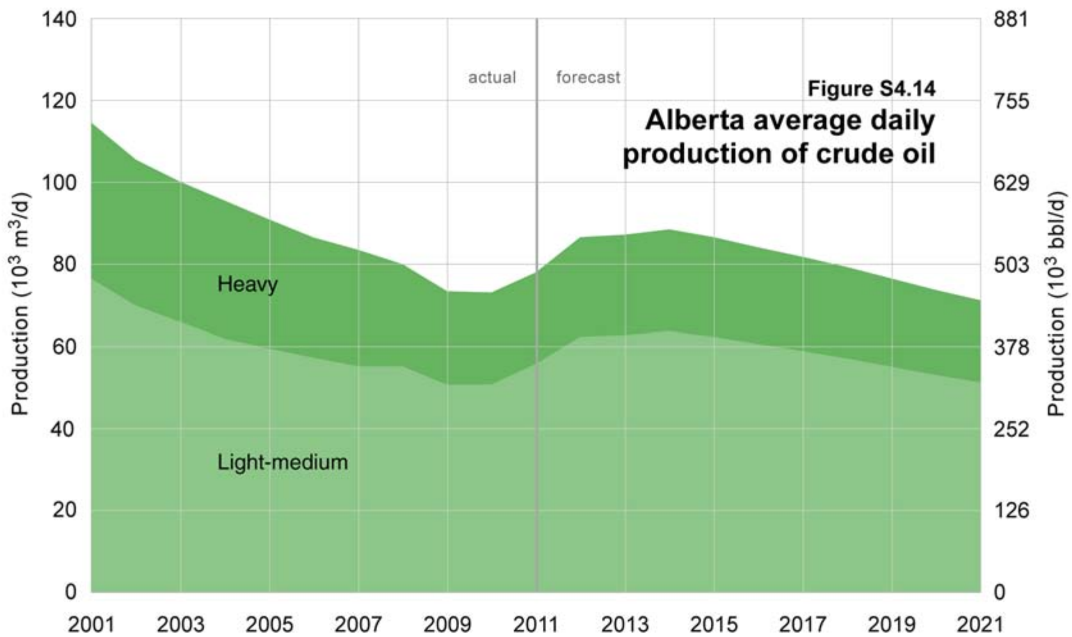


Figure S4.13
Alberta average daily production of crude oil by well type
actual
forecast
Horizontal wells total
Vertical wells total
Production (10^3 m^3/d)
Production (10^3 bbl/d)
160
120
80
40
0
1007
755
503
252
0
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021

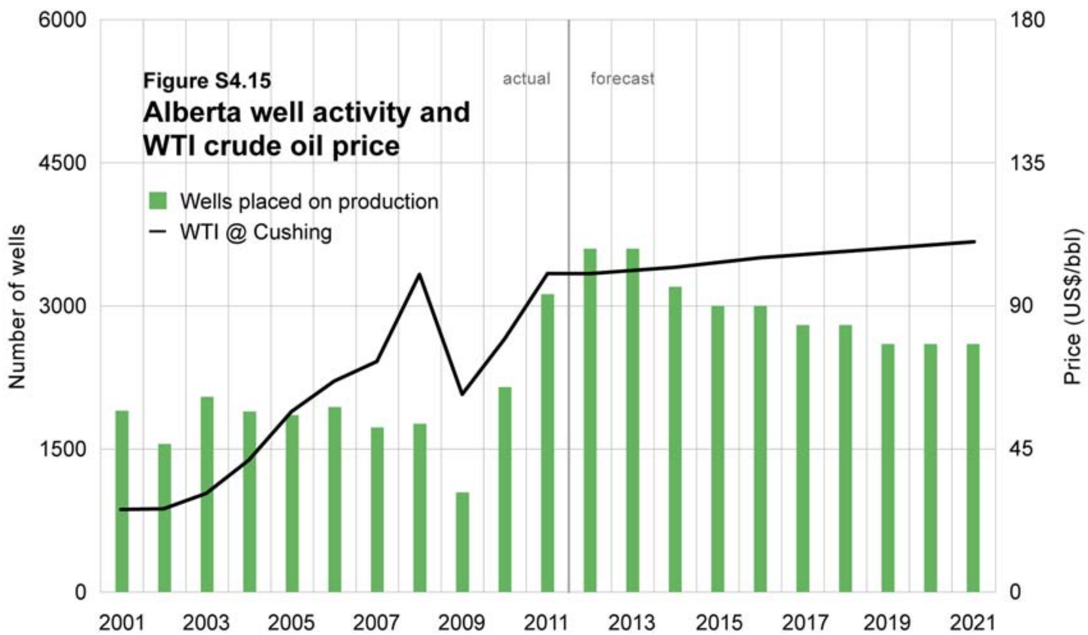


This production forecast assumes that crude oil production will increase by 11 per cent in 2012, up from the increase of 7 per cent in 2011, primarily due to the continued increase in drilling activity and use of multistage fracturing technology on horizontal wells. Crude oil production is expected to peak in 2014 and begin declining at an average rate of between 2 to 3 per cent over the remainder of the forecast period. This is a reflection of the lower levels of drilling activity expected in the basin over time. The combined forecasts for existing and future wells indicate that total crude oil production will increase from 77.9 10^3 m^3/d in 2011 to 88.4 in 2014, before declining to 71.1 10^3 m^3/d in 2021. Based on this projection, Alberta will have produced about 92 per cent of the estimated ultimate potential of 3130 10^6 m^3 by 2021. However, the ultimate potential is a 1994 estimate of conventional crude oil only. Any new estimate that included reservoirs currently being exploited by multistage fracturing would likely be higher.

Figure S4.15 illustrates the annual number of new wells expected to be placed on production from 2012 to 2021 and includes the forecast for WTI crude oil price. In spite of a strong crude oil price forecast, the oil drilling activity is expected to moderate to pre-2010 levels. Over the longer term, investment dollars are expected to be more evenly distributed between gas and oil drilling.

4.2.3 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta refineries are domestic Albertan demand for RPPs, shipments to other western Canadian provinces, exports to the United States,

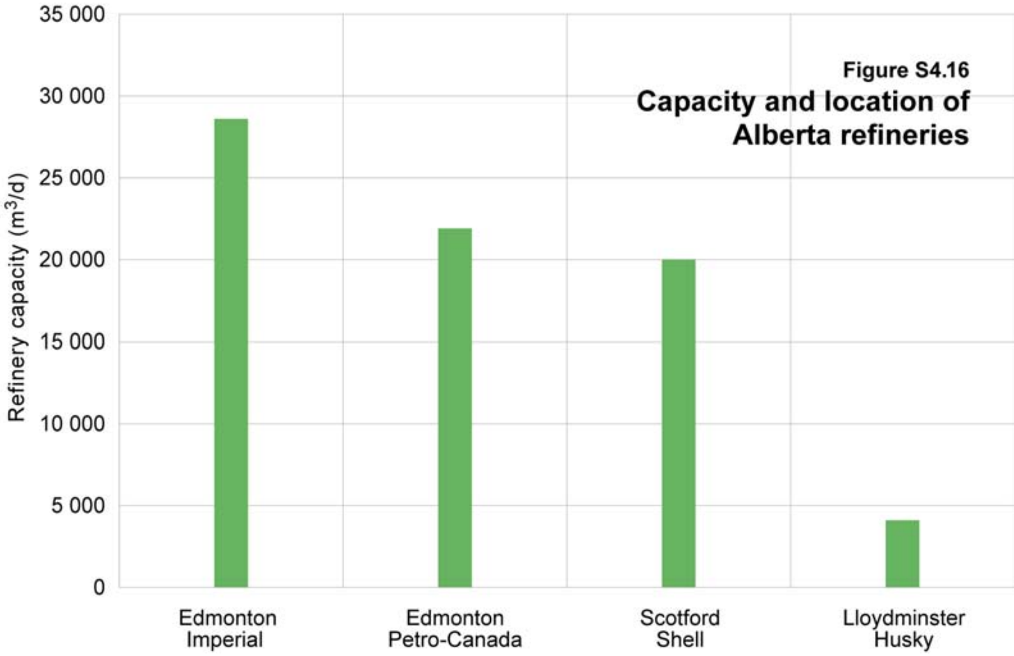


and competition from other feedstocks. Since Alberta is a "swing" supplier of RPPs in western Canada, a refinery closure or expansion in this market may have a significant impact on the demand for Alberta RPPs and on Alberta crude oil feedstock requirements.

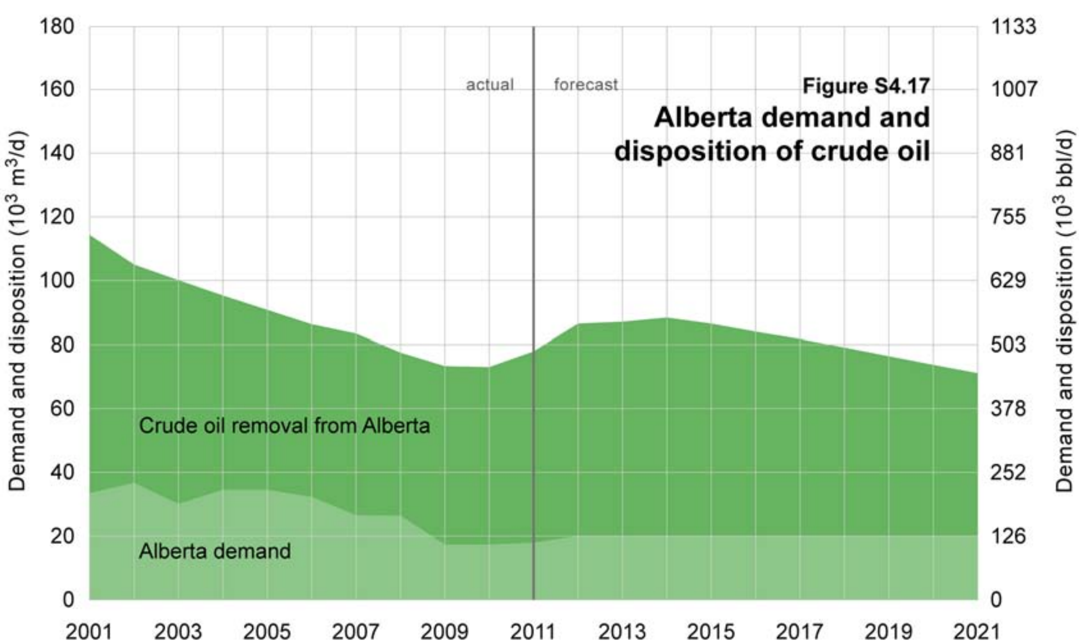
In 2011, Alberta operating refineries, with a total inlet capacity of 74.6 10^3 m^3/d of crude oil and equivalent, processed 18 10^3 m^3/d of conventional crude oil. This is a 4 per cent increase in crude oil processed in 2010. Refinery demand for conventional crude oil in Alberta declined substantially between 2008 and 2009 as a result of Suncor's (formerly Petro-Canada's) Edmonton refinery fully replacing light-medium crude oil with upgraded and nonupgraded bitumen in 2009.

Both upgraded and nonupgraded bitumen, together with pentanes plus, constitute the remaining feedstock processed through Alberta refineries. **Figure S4.16** illustrates the current capacity and location of refineries in Alberta. Additions to crude oil refining capacity are not expected over the forecast period.

In 2011, the refinery utilization capacity was about 88 per cent, up from 84 per cent in 2010. Refinery operations in 2009 were severely affected by planned maintenance turnarounds at all three Edmonton refineries in addition to unplanned operation outages. In 2010, refinery operations in the Edmonton area were affected by planned maintenance at Imperial's Strathcona refinery in May and Suncor's Edmonton refinery in October. The forecast assumes that total crude oil use in Alberta's refineries will increase to 20 10^3 m^3/d in 2012, based on an increased utilization rate of 90 per cent, and will remain at this level for the remainder of the forecast period.



Shipments of crude oil outside of Alberta, depicted in **Figure S4.17**, amounted to 77 per cent of total production in 2011. The ERCB expects that by 2021 about 72 per cent of production will be removed from the province due to the decline expected in Alberta light-medium and heavy crude oil production by 2021.



HIGHLIGHTS

Alberta's remaining established conventional natural gas reserves decreased by 7.8 per cent in 2011 to 945 billion cubic metres.

Reserves additions as a result of new drilling replaced 43 per cent of conventional gas production.

Marketable gas production declined by 4.6 per cent in 2011, compared with a 5.6 per cent decline in 2010.

There were 2310 new conventional gas well connections and 1023 CBM and CBM hybrid connections in 2011, down 24 per cent and up 3 per cent, respectively, from 2010.

5 // NATURAL GAS

Raw natural gas consists mostly of methane and other hydrocarbon gases, but it also contains other non-hydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide (H_2S). These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Hydrocarbon components that exist in gaseous form in the reservoir, but which condense and are recovered as a liquid at the surface, may be reported as gas equivalent or condensate. Such liquids, as well as ethane, which is primarily produced as a gas, are referred to as natural gas liquids (NGLs) and are reported in **Section 6**. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume, as described in **Section 5.1.3.6**.

In this section, natural gas volumes are referred to as either the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated to be 39.1 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for coalbed methane (CBM), which consists mostly of methane.

This section discusses conventional and unconventional natural gas, where unconventional gas is defined in this section as CBM and shale gas.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

As of December 31, 2011, the ERCB estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 945 billion (10^9) m^3, with a total energy content of about 37 exajoules. This decrease of 80.0 10^9 m^3 since December 31, 2010, is a result of all reserves additions less production during 2011. These reserves include 29.4 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value from 39.1 MJ/m^3 to 37.3 MJ/m^3 for gas downstream of straddle plants. Details of the changes in marketable reserves during 2011 are shown in **Table 5.1**. Total provincial initial gas in place and raw producible gas reserves for 2011 are 9203.9 and 6108.9 10^9 m^3, respectively, which translates into an average provincial recovery factor of 66 per cent. Total initial established marketable reserves are estimated to be 5283.0 10^9 m^3, representing an average surface loss of 14 per cent. In 2011 the ERCB reduced the surface loss calculated for all solution gas reserves. A flared gas volume was estimated as part of the surface loss, and upon review of this calculation it was determined that this estimate is outdated. With the limited flaring allowed by the ERCB and being practiced by industry, it was determined that both past flaring volumes and predicted future volumes have been overestimated. As a result of this change, initial and remaining marketable reserves were increased by 70.0 10^9 m^3 and 25.7 10^9 m^3, respectively. In addition, cumulative production in these pools was increased by 47.0 10^9 m^3.

Table 5.1 Reserve and production changes in marketable conventional gas (10^9 m^3)

	Gross heating value (MJ/m^3)	2011 volume	2010 volume	Change
Initial established reserves		5 283.1	5 213.5	+69.5
Cumulative production		4 338.0	4 188.4	+149.6[a]
Remaining established reserves downstream of field plants				
"as is"	39.1	945.1	1 025.1	-80.0
at standard gross heating value	*37.4*	*987.0*	*1 065.7*	
Minus liquids removed at straddle plants		29.4	30.2	-0.8[b]
Remaining established reserves				
"as is"	37.3	915.6[b] (32.5 Tcf)[c]	994.9[b] (35.3 Tcf)[c]	-79.2[b]
at standard gross heating value	*37.4*	*913.8*	*991.4*	
Annual production	37.4	102.4[d]	107.3	-4.9

[a] Differs from annual production due to a change in surface loss calculation for solution gas reserves.
[b] Any discrepancies are due to rounding.
[c] Tcf = trillion cubic feet.
[d] Does not include conventional gas from ERCB-defined unconventional wells.

Annual historical reserves additions and natural gas production are depicted in **Figure R5.1**. It shows that since 1983, reserves additions have generally not kept pace with production. As illustrated in **Figure R5.2**, Alberta's remaining established reserves of marketable conventional gas have decreased by about 49 per cent since 1982.

The ERCB estimates the initial established reserves of CBM to be 100.9 10^9 m^3 as of December 31, 2011, relatively unchanged from 2010. Remaining established reserves in 2011 are 62.0 10^9 m^3, down from 67.6 10^9 m^3 in 2010 due to production.

A summary of CBM reserves and production is shown in **Table 5.2**. In 2011, the annual production from all wells listed as CBM was 8.7 10^9 m^3. This volume represents the total contribution from CBM wells, including wells commingled with conventional gas.[1] The portion of production estimated to be attributed to only CBM is 6.0 10^9 m^3, as listed in **Table 5.2**.

[1] Wells commingled with conventional gas are defined as CBM hybrid wells.

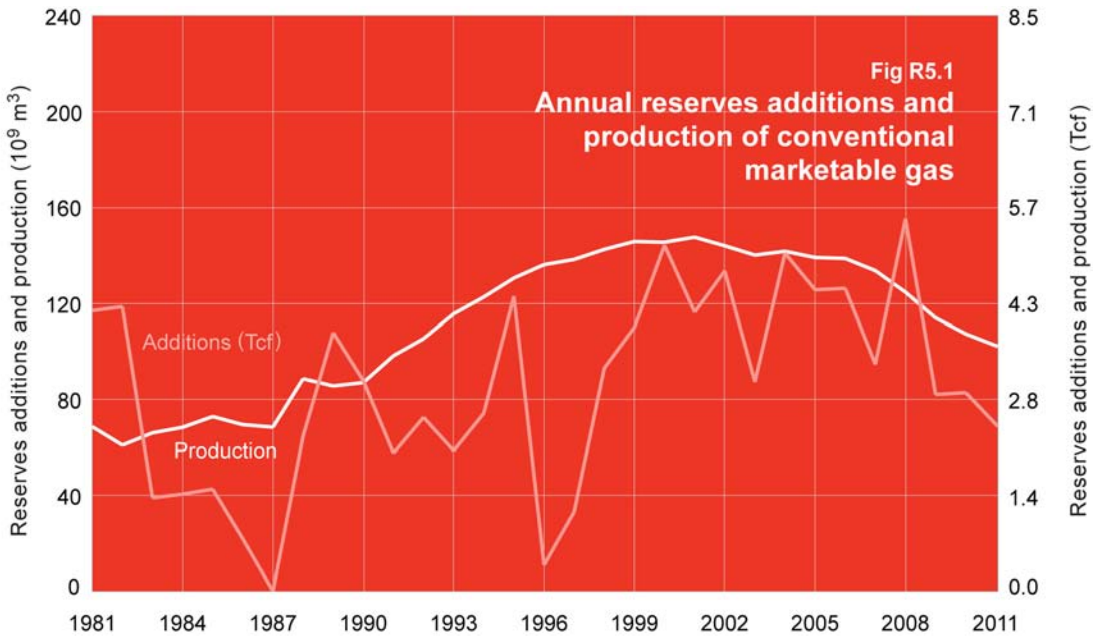


Fig R5.1
Annual reserves additions and production of conventional marketable gas
Reserves additions and production (10^9 m^3)
Reserves additions and production (Tcf)
Additions (Tcf)
Production
240
200
160
120
80
40
0
8.5
7.1
5.7
4.3
2.8
1.4
0.0
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011

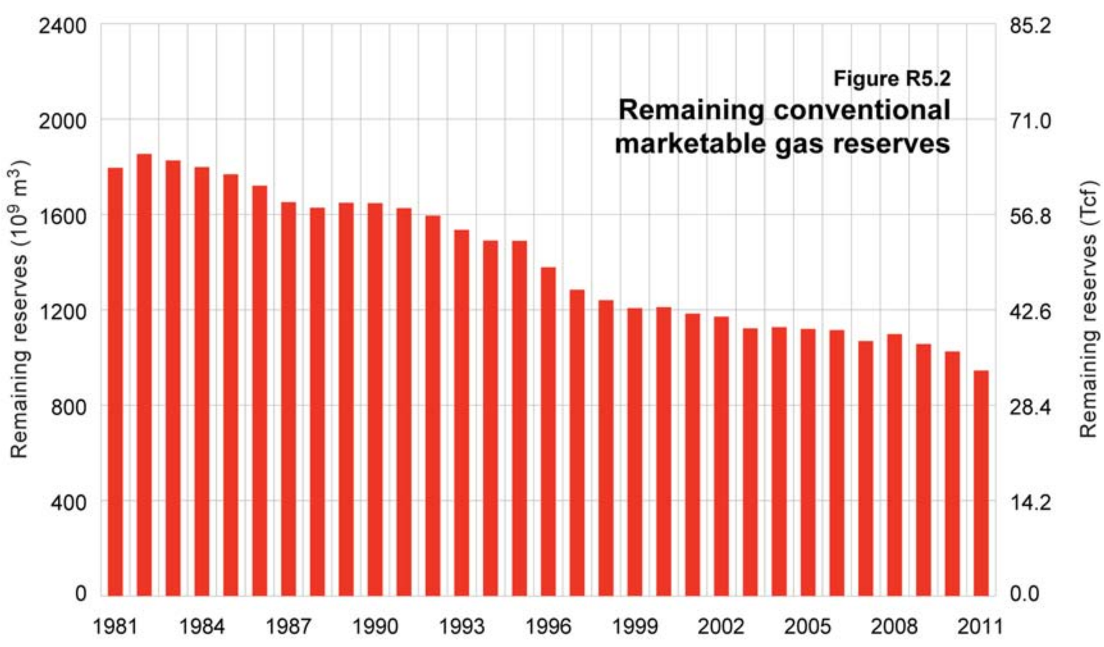


Figure R5.2
Remaining conventional marketable gas reserves
Remaining reserves (10^9 m^3)
Remaining reserves (Tcf)
2400
2000
1600
1200
800
400
0
85.2
71.0
56.8
42.6
28.4
14.2
0.0
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011

Table 5.2 CBM reserve and production change highlights (10^9 m^3)

	2011	2010	Change
Initial established reserves	100.9	100.5	+0.4
Cumulative production	38.9	32.9	+6.0[a]
Remaining established reserves	62.0	67.6	-5.6
	(2.2 Tcf)[b]	(2.4 Tcf)[b]	
Annual production	6.0	7.4	-1.4

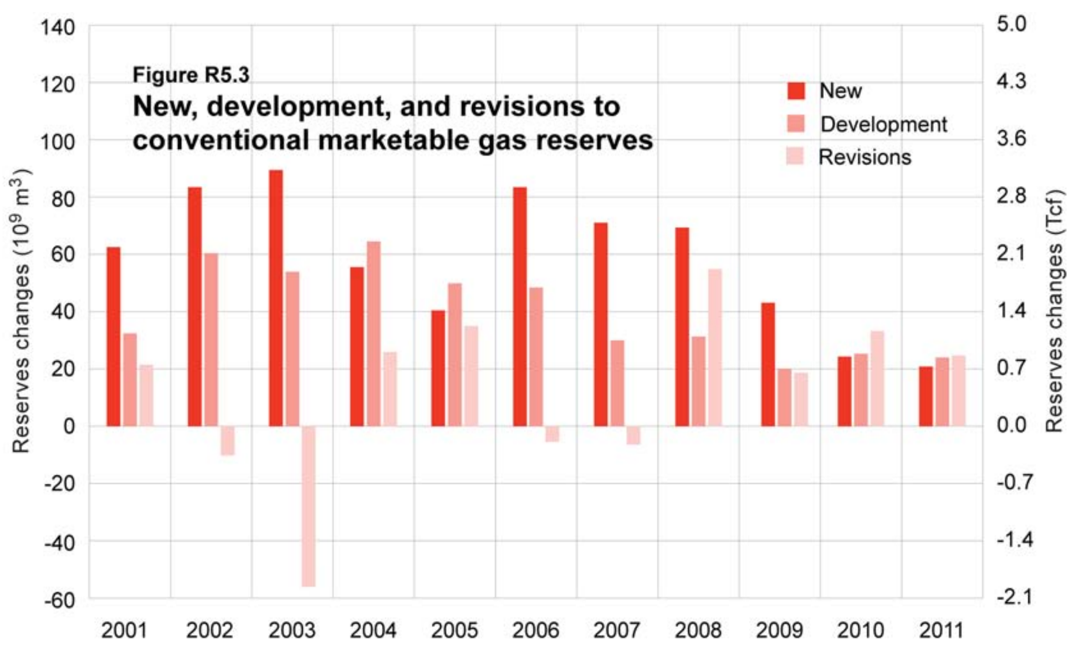
[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.
[b] Tcf = trillion cubic feet.

5.1.2 In-Place Resource of Natural Gas

The ERCB estimates the initial in-place resource of conventional and CBM natural gas in Alberta to be 9504 10^9 m^3, consisting of 9203 10^9 m^3 of conventional natural gas and 301 10^9 m^3 of CBM. With conventional cumulative raw production of 5063 10^9 m^3, 4140 10^9 m^3 of this gas remains in the ground. CBM cumulative raw production is 39 10^9 m^3, and 262 10^9 m^3 remains in the ground. As of December 31, 2011, 4402 10^9 m^3 of natural gas remains unproduced in Alberta. With current technologies, 1107 10^9 m^3 is still expected to be produced.

5.1.3 Established Reserves of Conventional Natural Gas

Figure R5.3 shows the breakdown of historical annual reserves changes into new pools, development of existing pools, and reassessment of reserves of existing pools. The 69.5 10^9 m^3 increase in initial reserves for 2011 includes the addition of 20.8 10^9 m^3 attributed to new pools booked in 2011, 24.0 10^9 m^3 from the development of existing pools, and a net reassessment of 24.7 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 44.8 10^9 m^3, replacing 43 per cent of Alberta's



2011 production. Historical reserves growth and production data since 1966 are shown in **Appendix B**, **Table B.4**.

During 2011, a review was done of pools that appeared to have reserves under- or overbooked based on their reserves-to-production ratios; another review was done of large pools that had not been evaluated for several years. Positive revisions to existing pools totalled 221 10^9 m^3, while negative revisions totalled 196 10^9 m^3. The major reserves changes are summarized below.

- The 20 pools with the largest changes listed in **Table 5.3** resulted in a net addition of 23.1 10^9 m^3. This increase in reserves was largely a result of infill drilling and completion of previously undeveloped zones.
- The review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in a reserves decrease of 3.4 10^9 m^3.
- Approximately 8000 pools were evaluated with low or high reserves life indices, resulting in an overall reserves decrease of 11.5 10^9 m^3.

Figure R5.4 illustrates initial marketable gas reserves growth between 2010 and 2011 by area as defined by the Petroleum Services Association of Canada (PSAC). The most significant growth was in PSAC Area 2 (Foothills Front), which accounted for 51 per cent of the total annual increase for 2011. Some pools in PSAC Area 2 that contributed to this increase in reserves are the Elmworth Commingled MFP9513, Kakwa Commingled Pool 005, Kaybob South Commingled MFP9529, Pine Creek Commingled MFP9531, and Resthaven Commingled MFP9525, for a total reserves increase of 22.8 10^9 m^3.

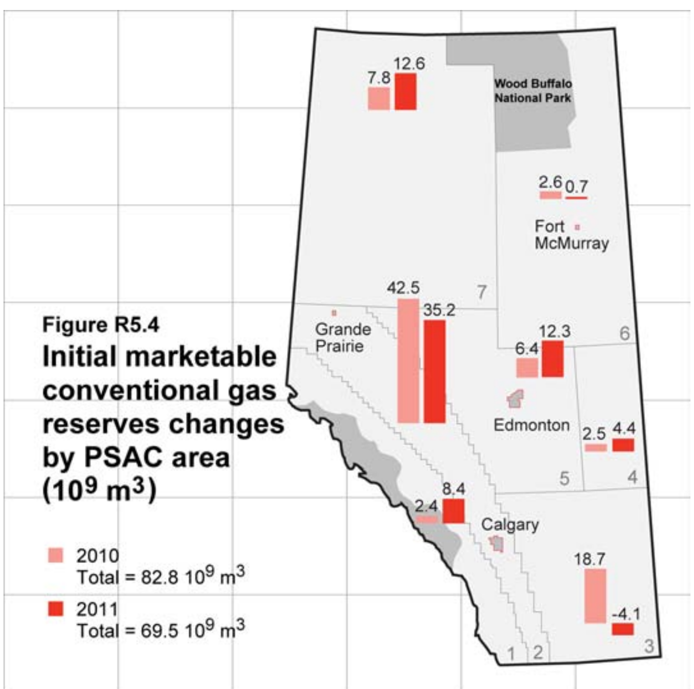


Figure R5.4
Initial marketable conventional gas reserves changes by PSAC area (10^9 m^3)

Table 5.3 Major natural gas reserve changes, 2011

Pool name	Initial established reserves (10^6 m^3) 2011	Change	Main reasons for change
Atlee-Buffalo Southeastern Alberta Gas System	7 571	-1470	Re-evaluation of recovery factor
Bruce Commingled MFP9509	5 532	+1 361	Re-evaluation of initial volume in place and recovery factor
Chickadee Commingled MFP9510	4 462	+868	Re-evaluation of initial volume in place
Countess Southeastern Alberta Gas System	72 583	+1 128	Development and re-evaluation of initial volume in place
Edson Commingled Pool 017	1 805	+1 174	Re-evaluation of initial volume in place
Elmworth Commingled MFP9513	66 023	+7 432	Re-evaluation of initial volume in place
Eyremore Southeastern Alberta Gas System	2 375	-1 425	Re-evaluation of initial volume in place and recovery factor
Ferrier Commingled Pool 002	7 038	+1 450	Re-evaluation of initial volume in place
Kakwa Commingled Pool 005	19 338	+5 364	Re-evaluation of initial volume in place
Kaybob South Commingled MFP 9529	17 551	+6 091	Re-evaluation of initial volume in place and recovery factor
Leo Commingled Pool 001	3 693	-1 219	Re-evaluation of initial volume in place and recovery factor
Newell Southeastern Alberta Gas System	3 543	+895	Development and re-evaluation of initial volume in place
Pine Creek Commingled MFP9531	4 132	+1 916	Re-evaluation of initial volume in place
Pouce Coupe South Commingled Pool 012	13 648	+1 723	Re-evaluation of initial volume in place
Resthaven Commingled MFP9525	4 692	+1 978	Re-evaluation of initial volume in place
Sundance Commingled MFP9502	16 334	-2 501	Re-evaluation of initial volume in place
Verger Southeastern Alberta Gas System	18 760	-1 230	Re-evaluation of initial volume in place
Wild River Commingled MFP9529	37 138	-4 302	Re-evaluation of initial volume in place and recovery factor
Willesden Green Commingled MFP9537	1 685	+1 677	Development
Wilson Creek Commingled Pool 005	7 843	+2 179	Re-evaluation of initial volume in place

[a] MFP (multifield pool) is defined in Section 5.1.3.7.

5.1.3.1 Distribution of Conventional Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table 5.4**. Commingled pools are considered as one pool, whereas each pool in a multifield pool is counted as a separate pool. The data show that pools with reserves of less than 30 million (10^6) m^3, while representing 75 per cent of all pools, contain only 11 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 1500 10^6 m^3, while representing only 0.5 per cent of all pools, contain 52 per cent of the remaining reserves.

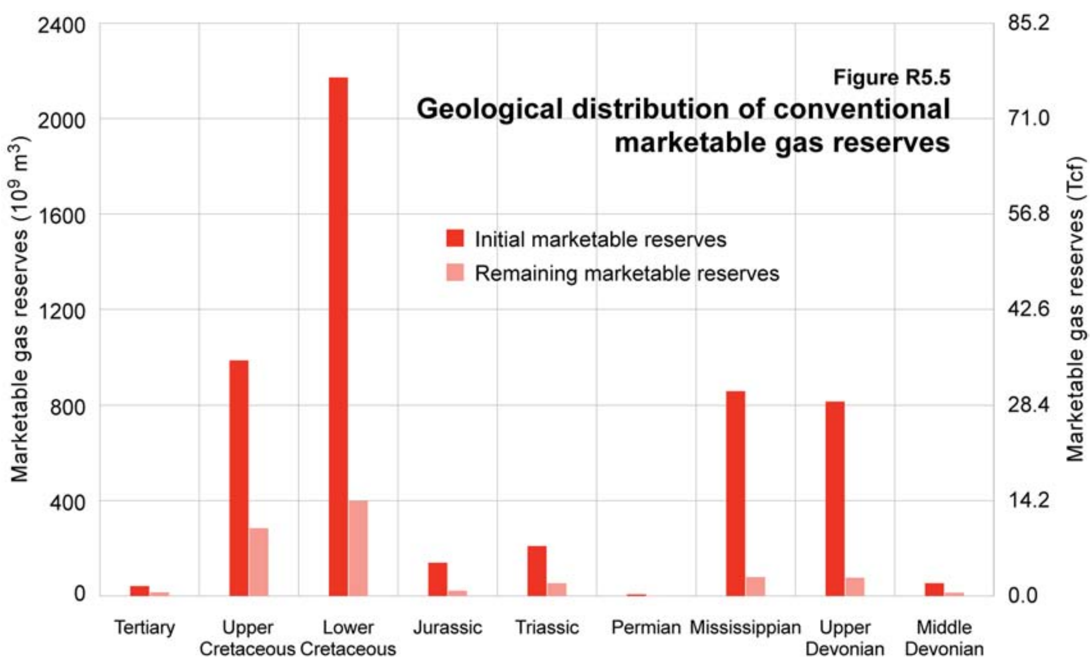
Table 5.4 Distribution of natural gas reserves by pool size, 2011

Reserve range (10^6 m^3)	Pools #	%	Initial established marketable reserves 10^9 m^3	%	Remaining established marketable reserves 10^9 m^3	%
3000+	222	0.5	2 931	56	488	52
1501-3000	175	0.4	374	7	67	7
1001-1500	187	0.4	229	4	37	4
501-1000	522	1.1	361	7	48	5
101-500	3 372	7.1	702	13	113	12
30-100	7 309	15.5	389	7	87	9
Less than 30	35 393	75.0	298	6	104	11
Total	**47 180**	**100.0**	**5 283**	**100**	**945**	**100**

5.1.3.2 Geological Distribution of Conventional Natural Gas Reserves

The distribution of reserves by geological period is shown in **Figure R5.5**. The Upper and Lower Cretaceous period accounts for about 73 per cent of the province's remaining established reserves of marketable gas and is important as a future source of natural gas.

The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 37 per cent; the Upper Cretaceous Belly River, Milk River, and Medicine Hat, with 18 per cent; and the Mississippian Rundle, with 7 per cent. Together, these strata contain 62 per cent of the province's remaining established marketable gas reserves.



5.1.3.3 Gas Commingling

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. As shown in **Table 5.5**, 26 per cent (15 336) of all gas pools in Alberta are commingled. This represents 587 10^9 m^3, about 62 per cent of remaining established reserves. In comparison, in 2001, commingled pools represented only 33 per cent of remaining reserves.

Table 5.5 Pool reserves as of December 31, 2011 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
Commingled pools	4 123	15 336	2 837	2 250	587
Noncommingled pools		43 663	2 446	2 088	358
Total			**5 283**	**4 338**	**945**

In 2006, the ERCB issued orders establishing two development entities (DE No. 1 and 2)[2] that allow for commingling of gas without application of certain formations within these areas. Subsequently, the ERCB amended the area described as DE 2 in August 2010. The commingling of gas of certain formations within these areas has enabled operators to produce reserves from zones that would otherwise have been uneconomic to produce on their own.

Table 5.6 shows that DE No. 1 and 2 have remaining established reserves of 64 10^9 m^3 and 215 10^9 m^3, respectively. The commingled gas reserves of DE No. 1 and 2 account for about 30 per cent of Alberta's remaining established reserves.

Table 5.6 Commingled pool reserves within development entities as of December 31, 2011 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
DE No. 1	687	2 057	380	315	64
DE No. 2	783	3 690	811	596	215
Total	**1 470**	**5 747**	**1 191**	**911**	**279**

5.1.3.4 Reserves of Conventional Natural Gas Containing Hydrogen Sulphide

Hydrogen sulphide (H_2S) is a naturally occurring substance present in many oil and gas reservoirs worldwide. Natural gas that contains more than 0.01 per cent H_2S is referred to as sour in this report.

In oil and gas reservoirs, H_2S is primarily generated through thermal and biological processes, both of which involve a reaction between dissolved sulfates and hydrocarbons. Thermally generated H_2S produces the highest concentrations of H_2S and occurs in reservoirs that have undergone diagenesis due

[2] A DE is a specific area consisting of multiple formations from which gas may be produced without segregation in the wellbore. These areas are described in an order of the ERCB and are subject to certain criteria in Section 3.051 of the *Oil and Gas Conservation Regulations*.

to deep burial. Biologically generated H_2S is commonly found in shallower, lower-temperature reservoirs but can also occur in sewers, swamps, composts, and manure piles.

In Alberta, sour gas is found in several regions and formations across the province. The maps in **Figure R5.6** and **Figure R5.7** show the distribution of both 2011 and historical development of H_2S-bearing hydrocarbons within the clastic and carbonate successions of the WCSB. The division of these two maps reflects Alberta's basin architecture, which consists of a Tertiary to Permian aged clastic wedge overlying a primarily Mississippian- and Devonian-aged carbonate succession (as discussed previously in **Section 2.1**, *Geological Framework of Alberta*).

The highlighted wells on the maps in **Figure R5.6** and **Figure 5.7** showcase areas of new sour gas development contrasted against historical production. As shown by these maps, in 2011, much of the H_2S-bearing hydrocarbon development in the province was focused on the production of oil containing a percentage of H_2S in solution.

Prominent areas of sour gas production for 2011 include the Triassic-focused activity in the northwest, development of Lower Cretaceous- and Jurassic-aged strata east of the foothills, and Cretaceous-aged enhanced oil recovery near the Saskatchewan border (**Figure R5.6**). Sour development within the carbonate-dominated strata (**Figure R5.7**) was focused on the oil-rich Devonian and Mississippian strata of the central and eastern plains.

As of December 31, 2011, sour gas accounts for about 21 per cent (197 10^9 m^3) of the province's total remaining established gas reserves and about 20 per cent of raw natural gas production in 2011. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2011 is 8.4 per cent.

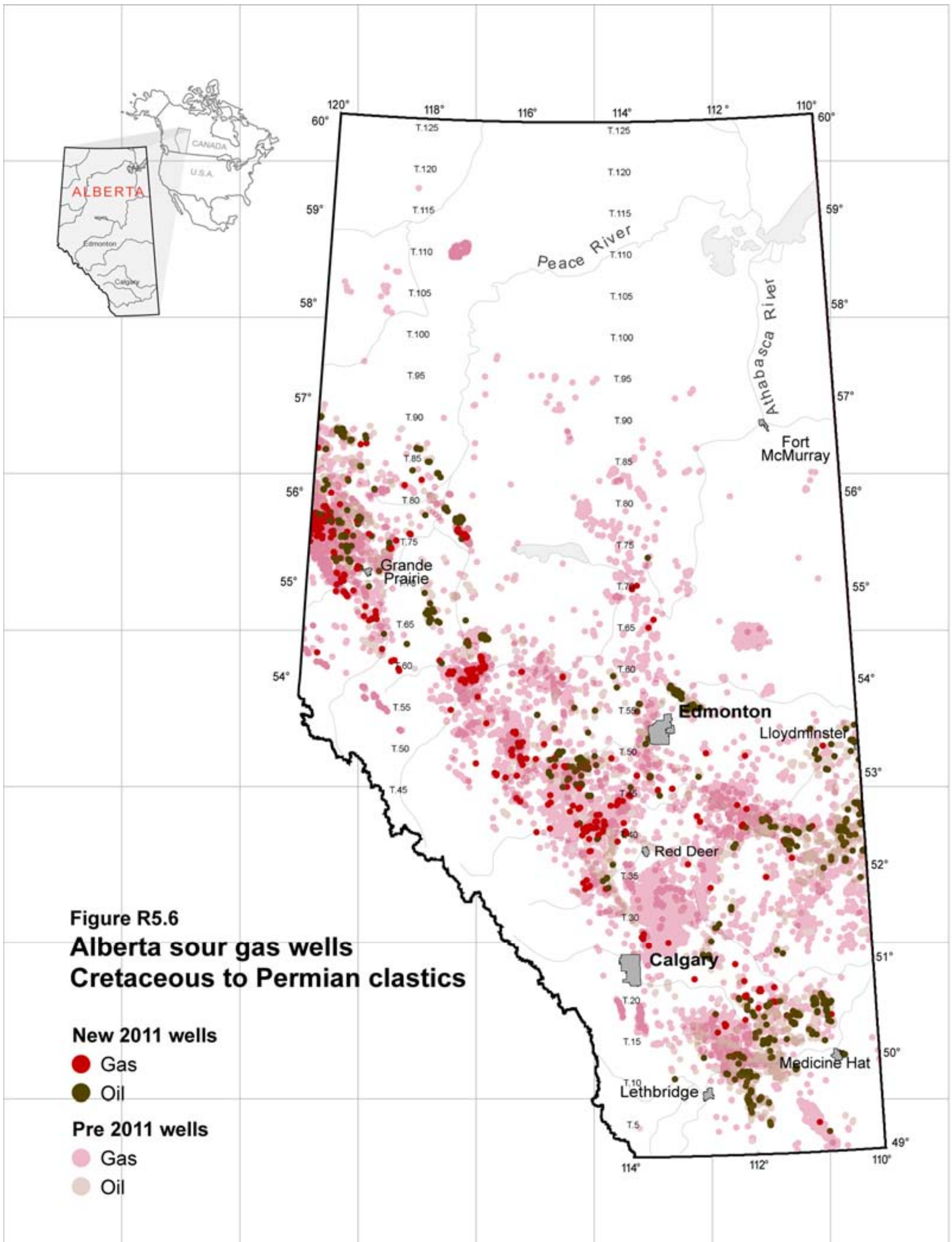


Figure R5.6
Alberta sour gas wells
Cretaceous to Permian clastics

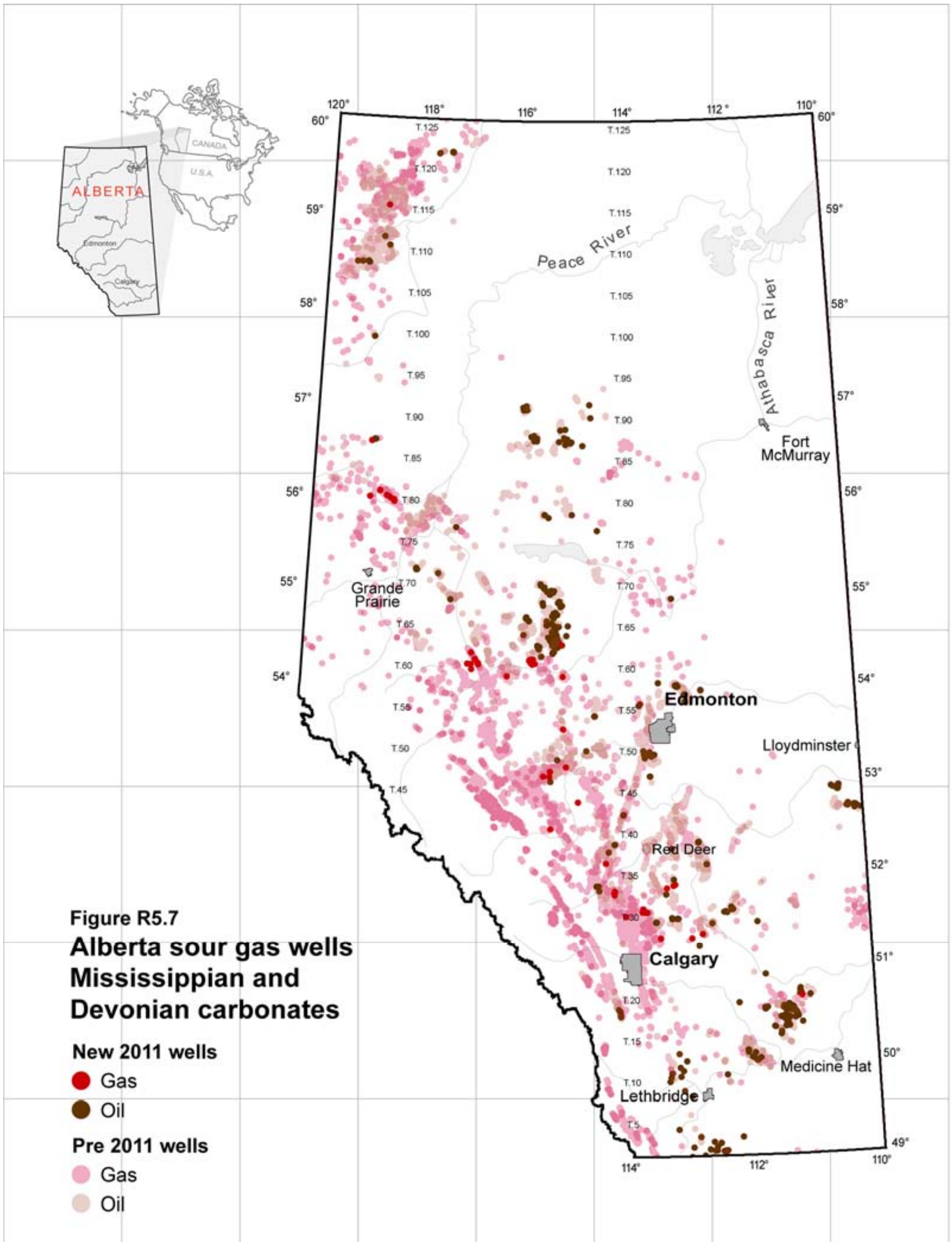


Figure R5.7
Alberta sour gas wells Mississippian and Devonian carbonates

The distribution of reserves of sweet and sour gas provided in **Table 5.7** shows that 127 10^9 m^3, or about 64 per cent, of remaining sour gas reserves are in nonassociated pools. Since 2002, sour gas has consistently accounted for about 20 per cent of the total remaining marketable reserves. The distribution of sour gas reserves by H_2S content, shown in **Table 5.8**, indicates that 16 per cent (30 10^9 m^3) of remaining sour gas contains H_2S concentrations greater than 10 per cent, while 56 per cent (110 10^9 m^3) contains concentrations less than 2 per cent.

Table 5.7 Distribution of sweet and sour gas reserves, 2011

Type of gas	Marketable gas (10^9 m^3) Initial established reserves	Cumulative production	Remaining established reserves	Percentage Initial established reserves	Remaining established reserves
Sweet					
Associated and solution	796	633	163	15	17
Nonassociated	2 757	2 171	586	52	62
Subtotal	**3 553**	**2 804**	**749**	**67**	**79**
Sour					
Associated and solution	517	448	69	10	7
Nonassociated	1 214	1 087	127	23	14
Subtotal	**1 731**	**1 535**	**196**	**33**	**21**
Total	**5 284 (187)[b]**	**4 339 (154)[b]**	**945[a] (33.5)[b]**	**100**	**100**

[a] Reserves estimated at field plants.
[b] Imperial equivalent in Tcf at 14.65 pounds per square inch absolute and 60˚F.

Table 5.8 Distribution of sour gas reserves by H_2S content, 2011

H_2S content in raw gas (%)	Initial established reserves (10^9 m^3) Associated and solution	Nonassociated	Remaining established reserves (10^9 m^3) Associated and solution	Nonassociated	Total	%
Less than 2	382	445	54	57	**110**	56
2.00-9.99	92	405	10	45	**56**	29
10.00-19.99	32	210	4	13	**17**	9
20.00-29.99	11	49	1	5	**6**	3
Over 30	0	105	0	7	**7**	4
Total	**517**	**1 214**	**69**	**127**	**196**	**100**
Percentage	30	70	35	65		

5.1.3.5 Reserves of Gas Cycling Pools

Gas cycling pools are gas pools rich in liquids into which dry gas is re-injected to maintain reservoir pressure and maximize liquid recovery. These pools contain 11.2 10^9 m^3 (1.2 per cent) of remaining gas reserves. The four largest pools are Harmattan East Commingled Pool 001, Valhalla MFP8524 Halfway, Waterton Rundle-Wabamun A, and Wembley MFP8524 Halfway, which together account for over 70 per cent of all remaining reserves of gas cycling pools. Surface loss and recovery factor are calculated on an energy basis in cycling pools. Reserves of major gas cycling pools are tabulated on both an energy-content and a volumetric basis in **Appendix B**, **Table B.5**. The table also lists raw and marketable gas heating values used to convert from a volumetric to an energy basis. The detailed reservoir parameters of these pools are included in the Gas Reserves and Basic Data table, which is on the companion CD to this report (see **Appendix C**).

5.1.3.6 Reserves Methodology for Conventional Natural Gas

A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools is on CD (see **Appendix C**) and is available from ERCB Information Services.

The process of determining reserves takes into consideration geological, engineering, and economic factors. Though initial estimates contain a level of uncertainty, this level of uncertainty decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculation, which uses bulk rock volume (based on isopach maps derived from geological interpretation of well log data) and initial reservoir parameters to estimate gas in place at reservoir conditions. Drainage areas for single-well pools range from 200 hectares (ha), for gas wells producing from regional sands with good permeability, to 32 ha or less. The smaller areas are assigned to wells producing from low-permeability formations (less than 1 millidarcy) or from geological structures limited in areal extent.

Converting gas volume in place to specified standard conditions at the surface requires knowledge of reservoir pressure and temperature and the analysis of reservoir gas. A recovery factor is applied to the in-place volume to yield recoverable reserves, the volume that will actually be produced to the surface. Given their low viscosity and high mobility, gas recoveries typically range from 70 to 90 per cent. However, low-permeability gas reservoirs and reservoirs with underlying water may only recover 50 per cent or less of the in-place volume.

Once a pool has been on production for some time, material balance analysis involving the decline in pool pressure can be used as an alternative to volumetric estimation to determine in-place resources. Material balance is most accurate when applied to high-permeability, nonassociated, and noncommingled gas pools. Analysis of production decline data is a primary method for determining recoverable reserves, given that most of the larger pools in the province have been in decline for many years. When combined with an estimate of the in-place resource, it also provides a practical, realistic estimate of the pool's recovery factor.

The procedures described above generate an estimate of initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants. Typically, 5 per cent is added to account for loss due to lease fuel (estimated at 4 per cent) and flaring. Surface losses range from 3 per cent for pools containing sweet dry gas to over 30 per cent for pools with raw gas that contains high concentrations of H_2S and gas liquids. Therefore, marketable gas reserves of individual pools on the ERCB's gas reserves database reflect expected marketable reserves after processing at field plants. The pool reserves numbers published by the ERCB represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric estimates, production decline analysis, and material balance analysis.

Additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago on the Alliance Pipeline and some of the dry southeastern Alberta gas. As removal of these liquids cannot be traced back to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These provincial reserves therefore represent the volume and average heat content of gas after removal of liquids from both field and straddle plants.

It is expected that about 29.4 10^9 m^3 of liquids-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 945.1 10^9 m^3 to 915.6 10^9 m^3 and the total thermal energy content from 36.9 to 34.2 exajoules (10^9 joules).

Figure R5.8 shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants. Therefore, the ERCB estimates reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in **Section 6**.

5.1.3.7 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in **Appendix B**, **Table B.6**. Each multifield pool shows the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool.

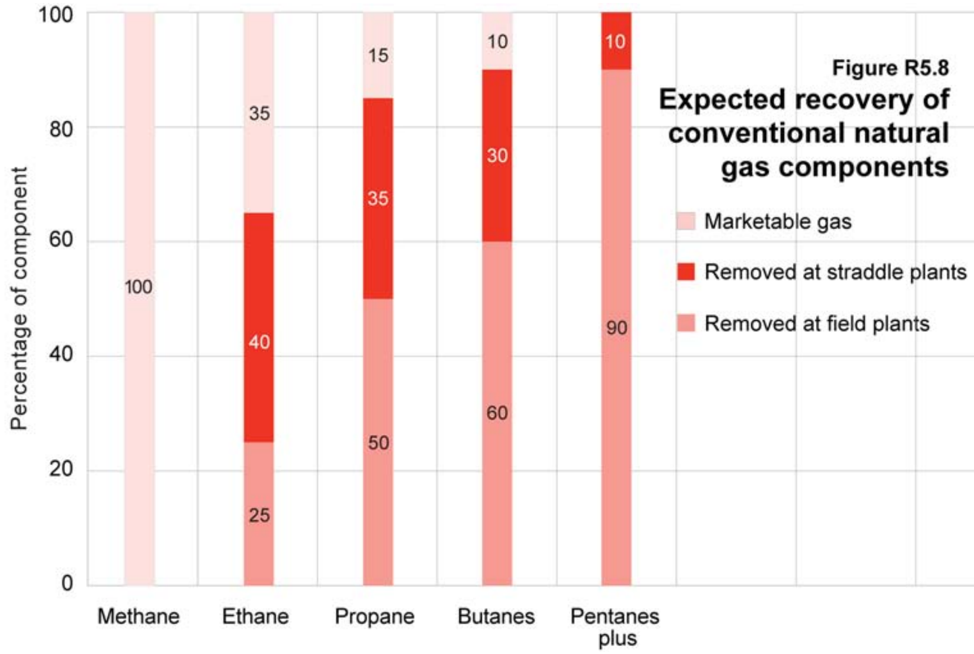


Figure R5.8
Expected recovery of conventional natural gas components

5.1.4 Established Reserves of CBM

CBM is the methane gas found in coal, both as adsorbed gas and as free gas. Unlike conventional gas, which occurs as discrete accumulations, or pools, CBM most often occurs in interconnected coal seams within defined stratigraphic zones as laterally continuous accumulations or deposits.

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). H_2S is not normally associated with CBM production as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 megajoules per cubic metre.

5.1.4.1 CBM Potential by Geologic Strata

Based on thousands of coal holes and oil and gas wells, coal is known to underlie most of central and southern Alberta, one of the largest geographical extents of continuous coal in North America. Coal seams occur as layers or beds within several Cretaceous coal zones. While individual coal seams can be laterally discontinuous, coal zones can be correlated very well over regional distances. All coal seams contain CBM to some extent, and each seam is potentially capable of producing a quantity of CBM.

The ERCB recognizes CBM reserves in the following horizons in Alberta:

- **Coals of the Horseshoe Canyon Formation and Belly River Group**—Horseshoe Canyon coals generally have low gas content and low water volume, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, and they constitute the majority of CBM reserves booked. Reserves from the Taber or MacKay coal zones of the Belly River Group have not yet been established.

- **Coals of the Mannville Group**—Mannville coals generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. The initial reserves for areas other than the Corbett area within the Mannville Group have been set at cumulative production.

The Ardley coals of the Scollard Formation and the Kootenay coals of the Mist Mountain Formation also show potential for production, but at this time no CBM reserves have been calculated for these coals.

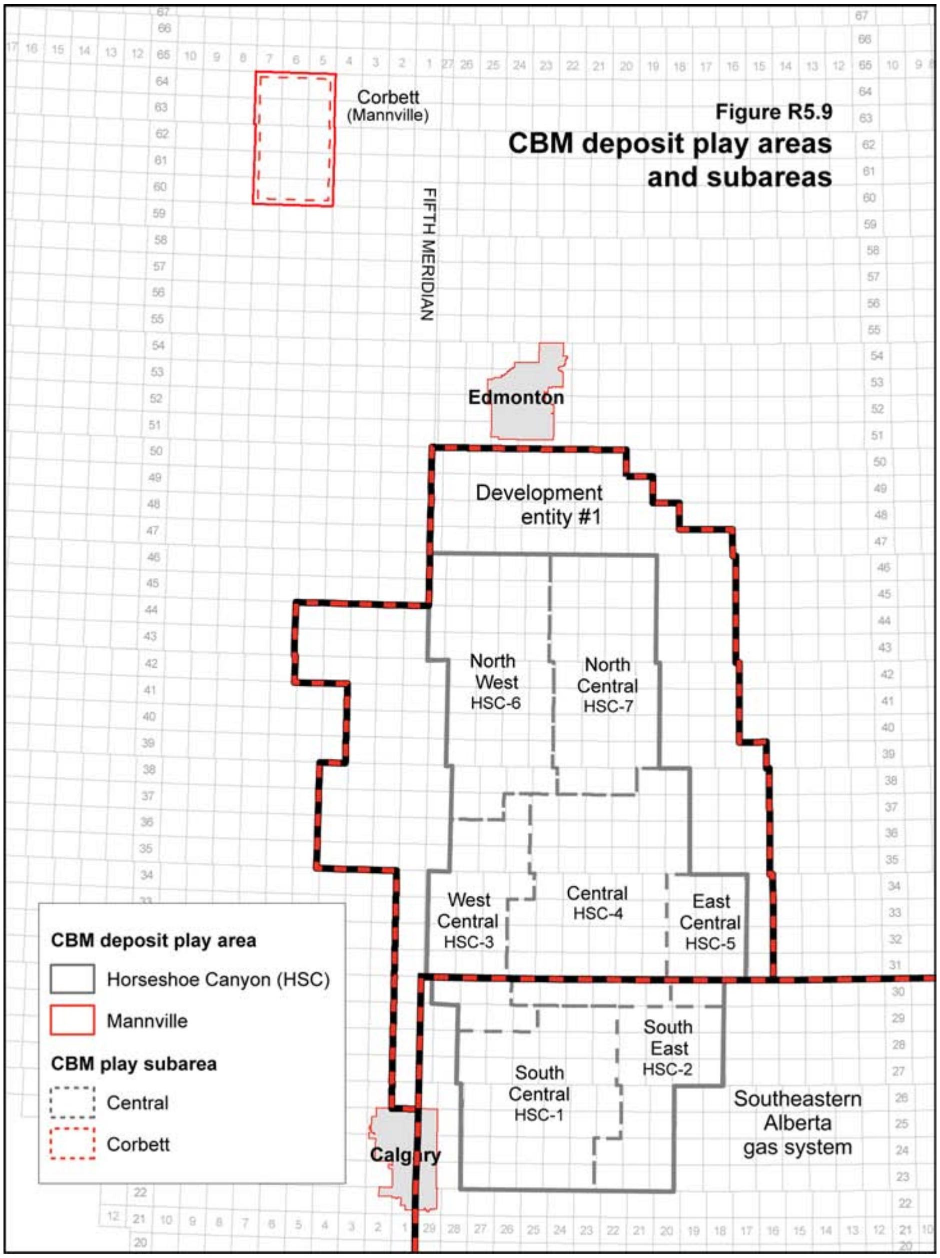
An individual CBM zone is defined as all coal seams within a formation separated by less than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries have been converted to multifield CBM pools. However, as multifield pools are still problematic in grouping CBM resource and reserves estimates, the ERCB groups CBM volumes into deposit-based play areas.

5.1.4.2 CBM Deposits, Play Areas, and Play Subareas

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The ERCB assesses CBM deposits for reserve determination in a manner similar to the way it assesses oil sands deposits. CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the ERCB has yet to formally define CBM deposits (e.g., through Board orders) because it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities have until now been concentrated mainly in a single smaller play area.

While Mannville activity is clustered almost exclusively in the Corbett area, the more widespread Horseshoe Canyon play occurs over a large area between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is within the ERCB-designated DE No. 1 and the Southeastern Alberta Gas System. The current play areas for the Horseshoe Canyon and Mannville deposits are shown in **Figure R5.9**.

Although coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by control well data within the deposit. The location of the Horseshoe Canyon play subareas is also shown on **Figure R5.9**.



5.1.4.3 CBM Reserves Determination Method

The ERCB uses three-dimensional block models to estimate in-place CBM resources for each play area or subarea. Desorption data are used on a zonal basis by applying gas content trends from core to all coals in each zone to estimate in-place CBM resources. Desorption values from drill cuttings are used to validate the continuity of the zonal trends from core.

Current reserves estimates are determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table 5.9**.

The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero, which becomes the recovery factor. Future analysis is expected to improve estimates of recovery factors. CBM data are available on two systems from the ERCB: summarized net pay data on the Integrated Geological database and individual coal seam thickness picks on the Coal Hole database.

5.1.4.4 Detail of CBM Reserves and Well Performance

CBM reserve values remain unchanged from 2010. The ERCB is currently reviewing the reserves determination process for CBM in Alberta.

Horseshoe Canyon coals, which are mainly gas-charged with little or no pumping of water required, remain the main focus of industry and currently have the highest established reserves (see **Table 5.9**). New data have supported the inclusion of additional areas within many of the Horseshoe Canyon CBM play subareas. In subarea 1, coals are deeper and have higher gas content, which results in this area having the largest initial established reserves of CBM in the Horseshoe Canyon play.

The undefined portion of **Table 5.9** includes noncommercial production from these areas, but reserves have not been booked pending commercial production.

Table 5.9 CBM gas in place and reserves by deposit play area, 2011

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas/m^3 coal)	Initial gas in place (10^9 m^3)	Average recovery factor (%)	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
HSC-1	10.1	35.37	2.95	104.38	27	28.56	5.95	22.61
HSC-2	4.3	9.04	1.06	9.61	25	2.37	0.44	1.93
HSC-3	5.8	13.91	2.41	33.56	30	10.19	3.93	6.26
HSC-4	6.4	28.39	1.72	48.84	34	16.47	11.20	5.27
HSC-5	3.0	3.93	1.11	4.37	26	1.13	0.67	0.46
HSC-6	3.5	8.67	1.57	13.58	30	4.14	3.09	1.05
HSC-7	4.4	14.74	1.30	19.19	32	8.31	6.82	1.49
Undefined[b]	-	-	-	-	-	0.95	0.95	0.00
Subtotal	**5.4**[c]	**114.05**	**2.05**[c]	**233.53**	**31**[c]	**72.12**	**33.05**	**39.07**
Mannville								
Corbett	4.9	6.97	9.73	67.86	42	28.18	5.27	22.91
Undefined[b]	-	-	-	-	-	0.57	0.57	0.00
Total		**121.02**		**301.39**	**33**[c]	**100.87**	**38.89**	**61.98**

[a] Includes Upper Belly River CBM.
[b] Most of the undefined areas are for tests in the Mannville coals but include a few Horseshoe Canyon, Ardley, and Kootenay wells with minor production and many Belly River recent recompletions with incomplete reporting.
[c] Weighted average.

5.1.4.5 Commingling of CBM with Conventional Natural Gas

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the ERCB until 1995. Significant development with commercial production commenced in 2002. The actual CBM production to date continues to be uncertain because of the difficulty differentiating CBM from conventional gas production where commingled production occurs.

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. For CBM, this includes commingling of two or more CBM zones, as well as the commingling of one or more CBM zones with one or more conventional gas pools.

As the Horseshoe Canyon and Belly River formations generally contain "dry CBM" with little or no pumping of water required, the commingling of CBM and other conventional gas pools is common. Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

CBM hybrid wells lack segregated reservoir data from commingled zones, making reserve estimation more difficult. Many hybrid wells report only CBM production, even though analysis of the well indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints, the following was completed on wells with commingled production:

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from more than 1300 CBM control wells and numerous other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. There is an administrative process in place to correct for the CBM production in these cases.

5.1.5 Shale Gas Resources

Shales are the traditional source rocks for conventional hydrocarbon accumulations as well as a seal for conventional reservoirs. More recently, organic-rich shales have become a target for production of gas, natural gas liquids, and oil. Shale gas, for example, refers to natural gas that is found in shale and other related rock types, existing mostly as free gas in the matrix and fractures and as adsorbed gas on organic matter and clays.

Typically, these fine-grained rocks have extremely low matrix permeability, and stimulation is required to produce fluids from the rock. Shale gas or shale oil is not restricted to shale, since claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential shale gas strata.

Based on an evaluation of geophysical logs from oil and gas wells, shale is known to underlie most of the province, existing in various formations both shallow and deep. Not all shale, however, is organic-rich, and at the present time, industry is concentrating exploration on relatively organic-rich shale. Furthermore, not all organic-rich shale has the potential to contain economic quantities of shale gas or oil.

More than 15 shale formations exhibit potential for shale gas, natural gas liquids, or oil. The generalized stratigraphic chart of formations shown in **Figure R5.10** details the formations (indicated with red shading) that have organic matter that could have potential to produce gas or oil. Not all of these formations are source rocks (i.e., are organic rich); some contain small amounts of organic matter and may be more like low-permeability strata or aquitards than organic-rich shale.

The presence of organic-rich or relatively organic-rich shale throughout the province does not mean that there will be pools of shale gas or oil, or wells drilled throughout all parts of the province. Shale is still a seal for conventional and nonconventional hydrocarbon reservoirs, and much of the shale encountered will not yield economic quantities of hydrocarbons.

The geographic distribution of significant shale gas horizons is shown in **Figure R5.11** and includes shales of the Colorado Group and equivalents, the Fernie Group, Banff and Exshaw formations, and the Woodbend Group and Muskwa Formation.

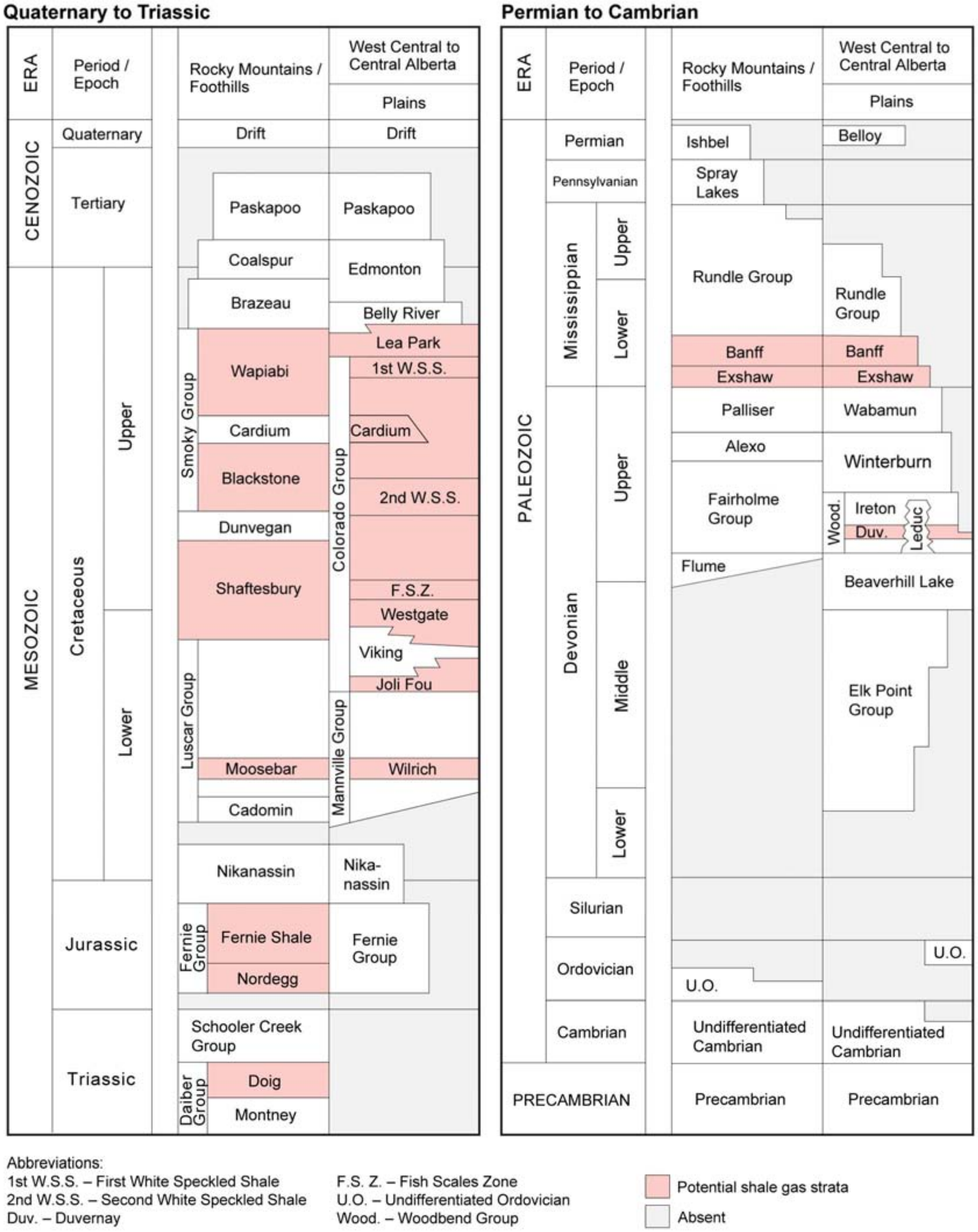
Exploration for shale gas, natural gas liquids, and oil is taking place in many of the formations highlighted in **Figure R5.10**. Receiving most of the attention is the Duvernay (Woodbend Group), Banff/Exshaw, and Nordegg (Fernie Group) as these strata are rich in natural gas liquids and oil. The depth from the surface to the shale formations increases westward in Alberta. Typically, the deeper formations have a higher formation pressure, which is a favourable aspect for shale gas exploration. With the drop in the price of natural gas, development activity for shallow natural gas has dropped dramatically.

5.1.6 Ultimate Potential of Conventional Natural Gas

The Alberta Energy and Utilities Board (EUB) and the National Energy Board (NEB) jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas* (EUB/NEB 2005 Report), an updated estimate of the ultimate potential for conventional natural gas. The ERCB, the successor organization to the EUB, has adopted the medium case, representing an ultimate potential of 6276 10^9 m^3 "as is" volume (223 trillion cubic feet [Tcf]) or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3. This estimate does not include unconventional gas, such as CBM.

Figure R5.10

Potential shale gas strata



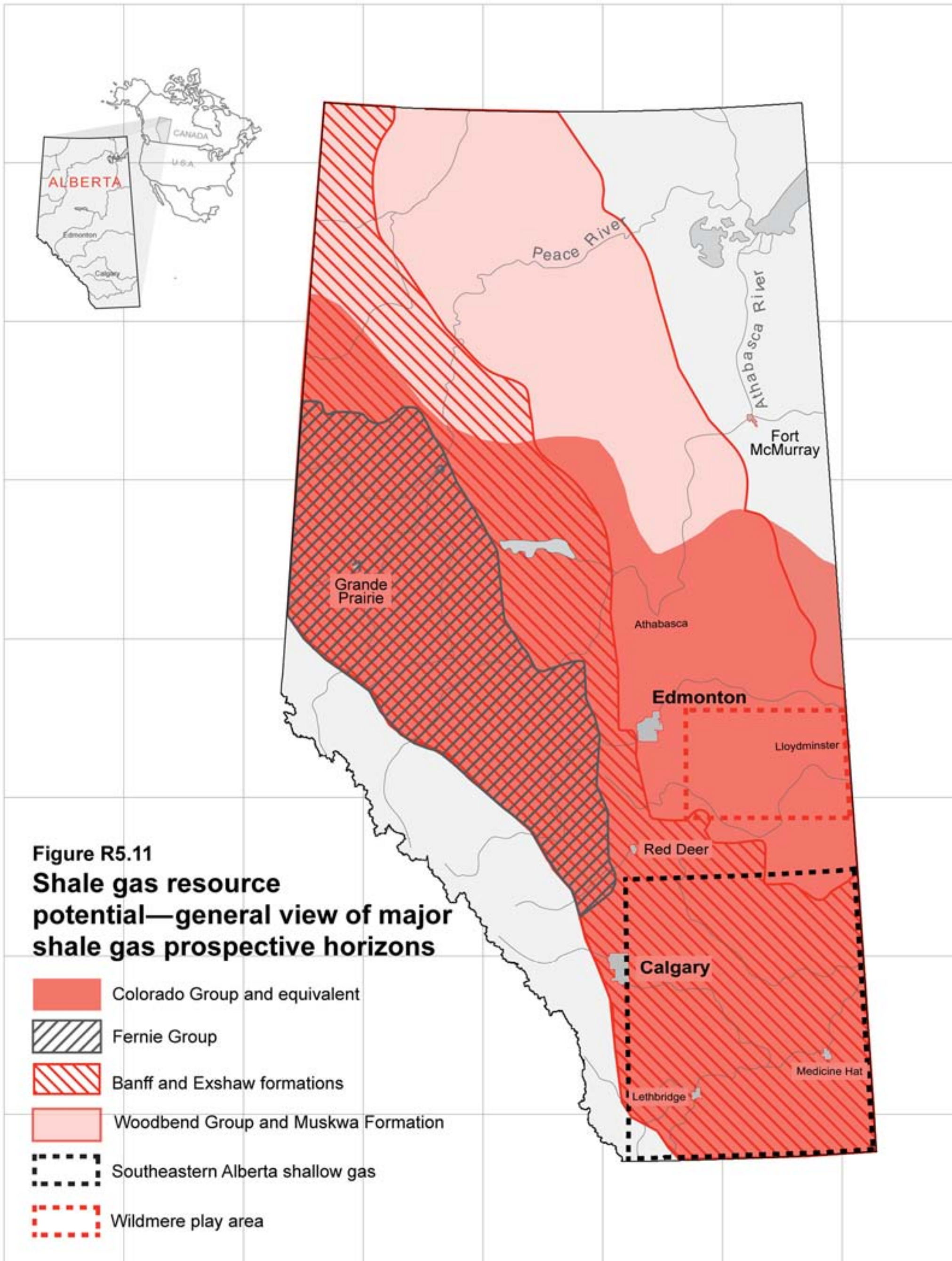


Figure R5.11
Shale gas resource potential—general view of major shale gas prospective horizons

Figure R5.12 shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth up to 2011 equalled 5517 10^9 m^3. **Figure R5.13** plots production and remaining established reserves of marketable gas compared with the estimate of ultimate potential.

Table 5.10 provides details about the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 5283 10^9 m^3, or 84 per cent of the ultimate potential of 6276 10^9 m^3 ("as is" volumes), have been discovered as of year-end 2011. This leaves 993 10^9 m^3, or 16 per cent, as yet-to-be-discovered reserves. Cumulative production of 4338 10^9 m^3 at year-end 2011 represents 69 per cent of the ultimate potential, leaving 1938 10^9 m^3, or 31 per cent, available for future use.

Table 5.10 Remaining ultimate potential of marketable conventional gas, 2011 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	**at 37.4 MJ/m^3**
Ultimate potential	6 276	6 528
Minus initial established reserves	-5 283	-5 517
Yet-to-be-established reserves	**993**	**1 011**
Initial established reserves	5 283	5 517
Minus cumulative production	-4 338	-4 530
Remaining established reserves	**945**	**987**
Yet-to-be-established reserves	993	1 011
Plus remaining established reserves	+945	+987
Remaining ultimate potential	**1 938**	**1 998**

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure R5.14**. It shows that the PSAC Area 2 (Foothills Front) contains 36 per cent of the remaining established reserves and 16 per cent of the yet-to-be-established reserves. Although most gas wells are being drilled in the southern plains (PSAC Areas 3, 4, and 5), **Figure R5.14** shows that, based on the EUB/NEB 2005 Report, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in PSAC Areas 1, 2, and 7.

Figure R5.15 shows by geological period the discovered and ultimate potential gas in place for year-end 2005. It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous. Discovered gas in place represents the known value as of December 2011. Current methods of evaluating gas in place have changed from discrete pooling of wells in 2005 to more of a block-type model in areas such as the development entities and southeastern Alberta. This has resulted in the current discovered gas in place being greater than the 2005 forecasted ultimate gas in place for the Upper Cretaceous.

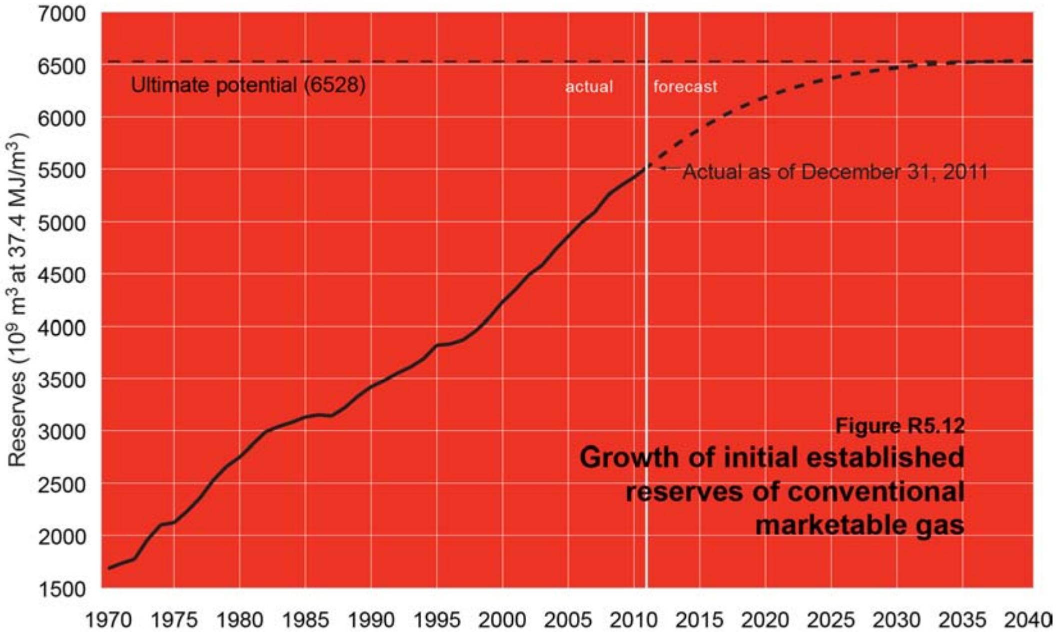


Figure R5.12
Growth of initial established reserves of conventional marketable gas

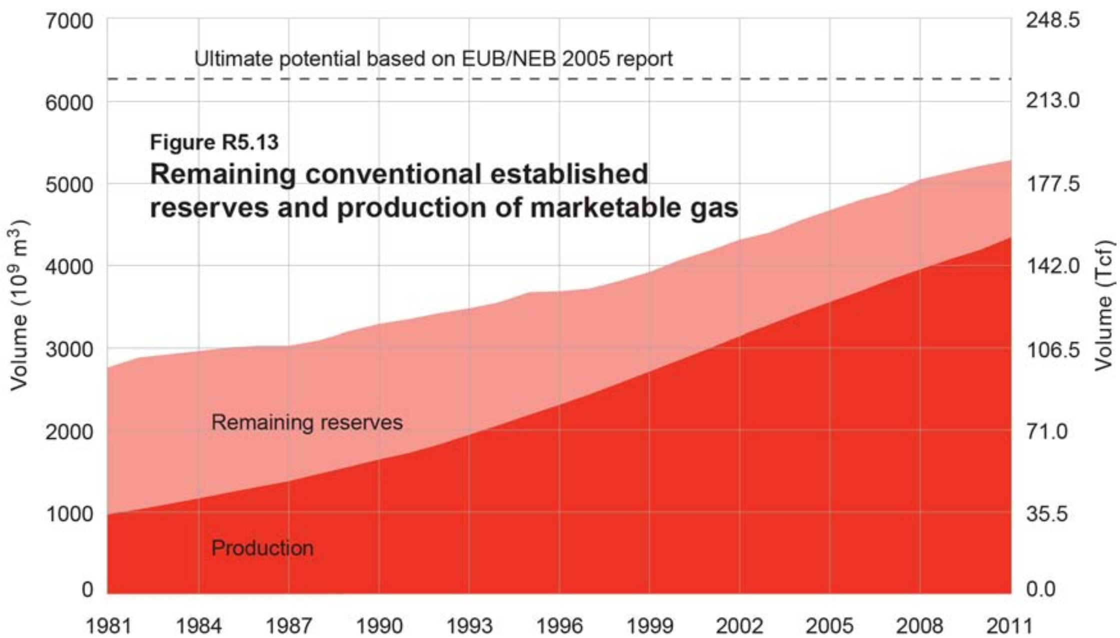


Figure R5.13
Remaining conventional established reserves and production of marketable gas

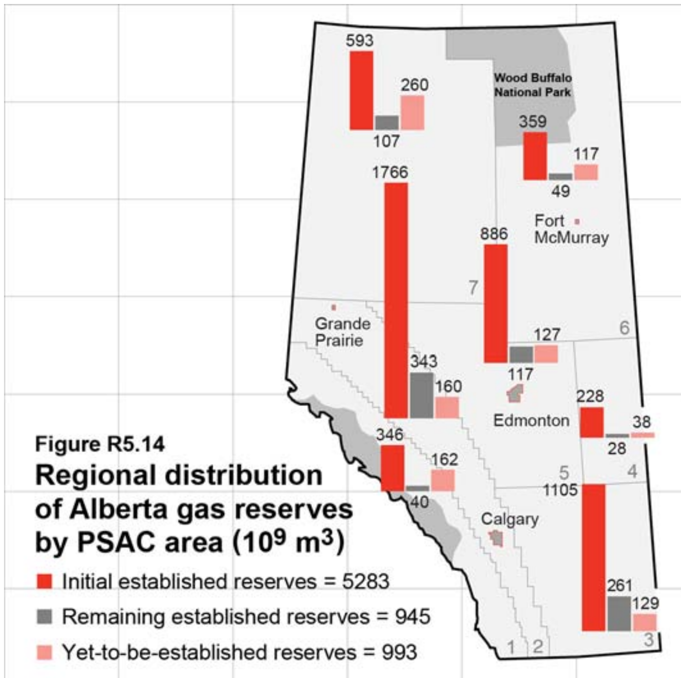


Figure R5.14
Regional distribution of Alberta gas reserves by PSAC area (10^9 m^3)

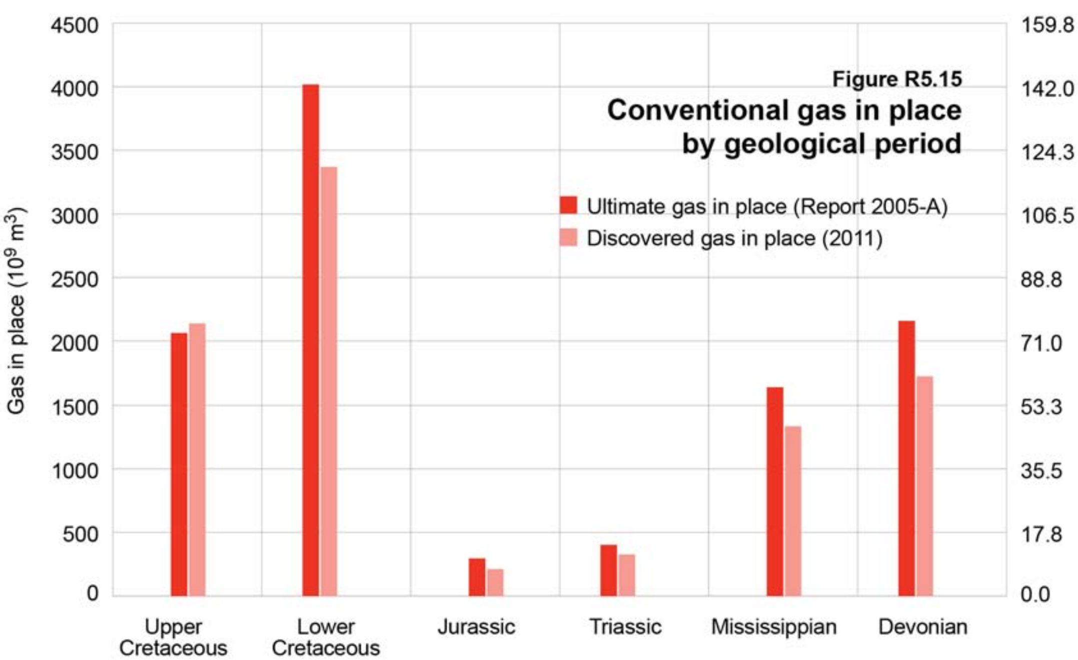


Figure R5.15
Conventional gas in place by geological period

5.1.7 Ultimate CBM Gas in Place

The Alberta Geological Survey (AGS), in *Earth Sciences Bulletin 2003-03*, estimated that there are 14 trillion (10^{12}) m^3 (500 Tcf) of gas in place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta's ultimate CBM gas in place (see **Table 5.11)**. However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion of these large values—the ultimate potential—has yet to be determined.

Table 5.11 Ultimate CBM gas in place[a]

Area	10^{12} m^3	Tcf[b]
Upper Cretaceous/Tertiary—Plains	4.16	148
Mannville coals—Plains	9.06	321
Foothills/Mountains	0.88	31
Total	**14.10**	**500**

[a] EUB/AGS *Earth Sciences Report 2003-03: Production Potential of Coalbed Methane Resources in Alberta.*
[b] Tcf = trillion cubic feet.

Although not a type of natural gas, there is potential in Alberta for the production of synthetic gas from coal and other sources. Synthetic gas from coal is discussed in **Section 8**.

5.2 Supply of and Demand for Natural Gas

In projecting marketable natural gas production, the ERCB considers three components: expected production from existing connections, expected production from new connections, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be established reserves of natural gas in the province. The ERCB projects conventional gas production from oil wells and gas connections separately from CBM connections. The forecasts are combined and referred to as total gas production in Alberta.

The ERCB annually reviews the projected demand for Alberta natural gas. The focus of these reviews is on intra-Alberta natural gas use, and a detailed analysis is undertaken of many factors, such as population growth, industrial activity, alternative energy sources, and other factors, that influence gas consumption in the province.

5.2.1 Marketable Natural Gas Production—2011

With weak drilling activity for natural gas the third year in a row, Alberta's production continued to slide, although the drop was less severe than in the previous two years. In 2011, total marketable natural gas production in Alberta, including unconventional production, declined by 4.6 per cent to 304.8 10^6 m^3/d from 319.5 10^6 m^3/d. The decline in production is less than the 5.6 per cent production decrease reported from 2009 to 2010. In 2011, natural gas from conventional gas and oil connections, at 280.6 10^6 m^3/d (standardized to 37.4 MJ/m^3), represented 92.1 per cent of production. The remaining

7.9 per cent of gas supply came from CBM and shale gas connections at 23.9 10^6 m^3/d and 0.3 10^6 m^3/d, respectively.

Total production from identified CBM and CBM hybrid connections decreased 5.2 per cent in 2011 to 23.9 10^6 m^3/d from the revised 2010 volume of 25.2 10^6 m^3/d. Gas production from connections completed in the Horseshoe Canyon play area was 21.3 10^6 m^3/d, representing 89 per cent of total CBM production. Gas production from the Mannville Group was 2.6 10^6 m^3/d. Total production volume includes production from connections outside the defined CBM subareas as outlined later in this section.

Marketable natural gas production volumes for conventional gas are calculated based on production data from the "Supply and Disposition of Marketable Gas" section of *ST3: Alberta Energy Resource Industries Monthly Statistics*, as shown in **Table 5.12**. Gas production from CBM and shale gas connections is determined separately.

Table 5.12 Conventional marketable natural gas volumes (10^6 m^3)

Conventional marketable gas production	**2011**
Total raw gas production including storage withdrawals	133 434
Minus production from CBM and hybrid connections	-8 707
Minus production from shale gas connections	-103
Total conventional raw gas production	124 624
Minus storage withdrawals	-5 642
Net raw gas production	118 981
Minus total injection	-10 381
Net raw gas production	108.600
Minus processing shrinkage–raw	-7 116
Minus flared—raw	-671
Minus vented—raw	-384
Minus fuel—raw	-10 293
Plus storage injections	8 330
Conventional marketable gas production at "as-is" conditions	98 467
Conventional marketable gas production at 37.4 MJ/m^3	102 406
Daily rate of conventional marketable gas at 37.4 MJ/m^3	(280.6 10^6 m^3/d)

Major factors affecting Alberta natural gas production are basin maturity, drilling and connection activity, the location of Alberta's reserves, well production characteristics, gas liquids content, market demand, and natural gas prices and their volatility.

Three related themes were instrumental in shaping Alberta's natural gas industry and activity levels over the past year. First, North American gas production has been increasing as a result of shale gas production. New multistage completion technology is being used to fracture rock at intervals along a horizontal well to release gas trapped in shale gas deposits. In 2011, U.S. marketed gas production from the lower 48 states reached 1837 10^6 m^3/d up from 1700 10^6 m^3/d in 2010. This increase in U.S. marketed gas production represents approximately half of Alberta's marketable conventional gas production in 2011. In 2011, natural gas prices in Alberta averaged \$3.28/GJ, down 8.2 per cent from the 2010 average natural gas price of \$3.57/GJ. Alberta's relatively high drilling and development costs did lead to reduced investment in Alberta's conventional gas development, which resulted in a year-over-year reduction in both gas drilling activity and production.

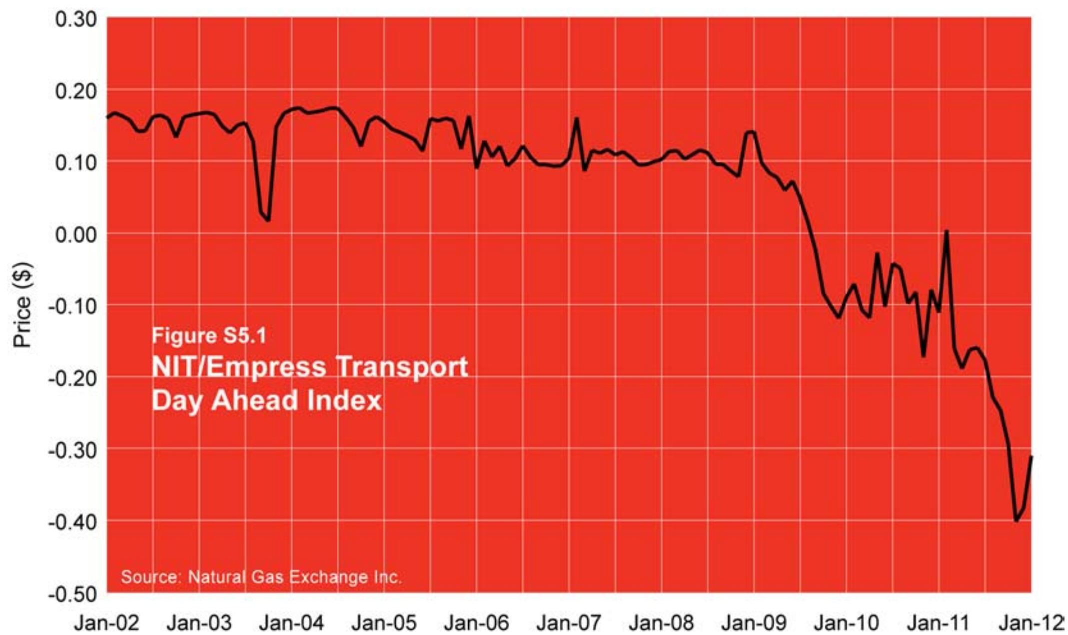
The second factor shaping Alberta's natural gas industry in 2011 was the lessening of the production decline for natural gas. Since 2001, natural gas production in Alberta has been declining, but in 2011 the decline has been somewhat softened due to the use of technology. To combat the low price of natural gas, producers in Alberta are drilling more horizontal gas wells, instead of vertical wells, and using multistage completion technology, which substantially improves well productivity when used in combination with horizontal wells.

The third factor affecting natural gas activity in Alberta is the competition for investment dollars between commodities, and in the current price environment, investment has been flowing to the crude oil and oil sands industry, or has focused on liquids-rich gas. The resurgence in crude oil drilling activity is a result of high crude oil prices and the application of multistage fracturing technology in horizontal wells.

Natural gas producers in Alberta and elsewhere are developing liquids-rich gas plays as a way to offset the low natural gas prices. Propane, butanes, and pentanes plus are by-products of natural gas and are priced relative to crude oil. Historically, the "rule of thumb" was that crude oil and natural gas prices generally maintained a 6:1 ratio, which is close to thermal parity. Now the relationship can be as high as 45:1, an indication that natural gas is very inexpensive compared with crude oil. Natural gas producers with a steady stream of liquids-rich output can therefore continue to drill new wells economically.

The spread between the natural gas price and the liquids price, typically referred to as a "frac spread," can be seen in the Alberta market gas prices as well. **Figure S5.1** shows the historical data for the Nova Inventory Transfer (NIT)/Empress Transport Day Ahead Index. This index is based on the price differential between NIT and Empress gas prices. Historically this instrument was traded at about $0.15 $0.17/GJ, indicating that the Empress gas prices were at premium over NIT by the same amount. Generally this spread approximated export transportation costs. The high frac spread in recent years has reversed this trend, resulting in NIT prices trading at a premium over Empress.

While Alberta gas production declined in 2011 from 2010 levels, gas production in British Columbia (B.C.) continues to increase. If this gas moves through Alberta straddle plants, the value of natural gas liquids remaining in the gas stream will also be captured.



5.2.2 Natural Gas Connections—2011

Gas-well connections include newly drilled wells placed on production and recompletions into new zones of existing wells. This section identifies recompletions as those connections that went on production at least one year after the finished drilling date.

5.2.2.1 Conventional Natural Gas Connections

The number of gas well connections in 2011 has not been this low since 1992. **Figure S5.2** shows the number of new conventional gas connections in Alberta in the last two years by PSAC area. In 2011, 2310 new conventional gas connections were placed on production in the province, a decrease of 24.2 per cent from 2010. This is the fifth straight year of reductions in conventional gas connections.

New conventional gas connection activity for 2011 and 2010 is shown in **Table 5.13**. The table provides information on the number of vertical or direction wells versus horizontal wells drilled in the province. The table also breaks down the number of new gas connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2011, roughly 22 per cent of gas connections were recompletions into existing wellbores.

The number of horizontal gas wells drilled and connected in the province is increasing as a percentage of the total. In 2011, about 25 per cent of new gas connections were horizontal wells, compared with 14 per cent in 2010 based on the revised well-connection counts.

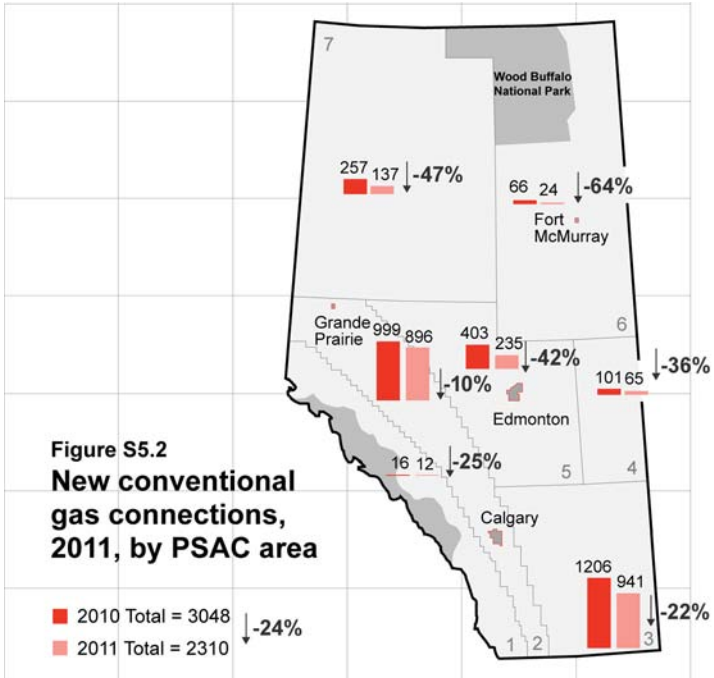


Figure S5.2 New conventional gas connections, 2011, by PSAC area

Table 5.13 Conventional gas connections by well type

Well Type	New connections 2011	New connections 2010	Recompletions 2011	Recompletions 2010	Total 2011	Total 2010
Vertical/Directional wells	1 229	1 866	504	758	1 733	2 624
Horizontal wells	564	415	13	9	577	424
Total	**1 793**	**2 281**	**517**	**767**	**2 310**	**3 048**

Traditionally, conventional gas activity had been focused on the shallow gas plays in southeastern Alberta, accounting for 50 per cent of activity because of the lower cost of drilling, existing infrastructure, and short tie-in times, despite the low production rates from wells in this area. However, with very low natural gas prices, the trend is changing. In 2011, the share of new connections in southeastern Alberta (an area containing mostly dry gas) dropped to about 41 per cent, after peaking in 2004 at 56 per cent. Meanwhile, the share in PSAC Area 2 (an area of more liquids-rich gas) increased from about 12 per cent in 2004 to about 39 per cent in 2011.

Figure S5.3 illustrates the number of producing conventional gas connections and the average daily connection productivity by PSAC area in 2011. These rates are calculated using the annual gas production volume and the number of producing gas connections for each PSAC area.

5.2.2.2 Coalbed Methane Connections

The ERCB identifies CBM and CBM hybrid connections using licensing data, production reporting, and detailed geological evaluations. These designations are re-evaluated annually and adjusted if required based on new information. Historical numbers are also updated annually as a result. All connections and volumes in this section are based on CBM connection designations as of December 31, 2011.

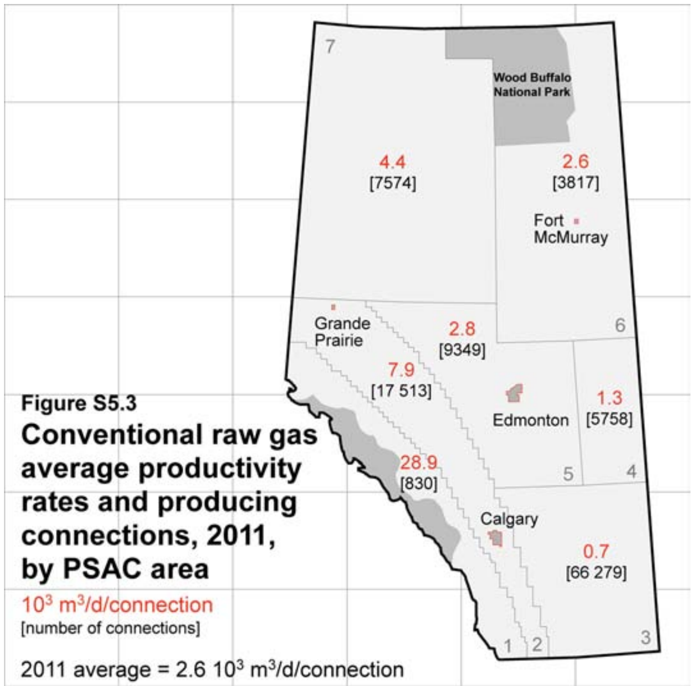


Figure S5.3
Conventional raw gas average productivity rates and producing connections, 2011, by PSAC area

In 2011, there were 1023 new connections for CBM and CBM hybrid production: 1015 in the Horseshoe Canyon Formation and 8 in the Mannville Group. New connections in the Horseshoe Canyon increased in 2011 by 4 per cent, and new connections in the Mannville decreased by 20 per cent from the revised number of connections in 2010. Overall, new CBM and CBM hybrid connections slightly increased by 3 per cent in 2011 over 2010.

New CBM and CBM hybrid connection activity for 2011 and 2010 is shown in **Table 5.14**. The table shows the number of CBM and CBM hybrid connections in vertical, or directional, wells and horizontal wells within the ERCB-defined CBM play areas. Most CBM and CBM hybrid connections in the Horseshoe Canyon Formation are in vertically drilled wells, whereas most connections into the Mannville Group are in horizontal wells.

The table also breaks down the number of new CBM and CBM hybrid connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2011, about 28 per cent of the new connections were recompletions into existing vertical wells in the Horseshoe Canyon Formation.

Table 5.14 CBM and CBM hybrid connections by well type and CBM play area

CBM play subarea	New connections 2011	New connections 2010	Recompletions 2011	Recompletions 2010	Total 2011	Total 2010
Vertical/directional wells						
Horseshoe Canyon	716	503	237	336	**953**	**839**
Mannville Corbett	4	0	0	0	**4**	**0**
Undefined[a]	10	77	48	62	**58**	**139**
Subtotal	**730**	**580**	**285**	**398**	**1 015**	**978**
Horizontal wells						
Horseshoe Canyon	3	0	1	1	**4**	**1**
Mannville Corbett	4	10	0	0	**4**	**10**
Undefined[a]	0	0	0	0	**0**	**0**
Subtotal	**7**	**10**	**1**	**1**	**8**	**11**
Total	**737**	**590**	**286**	**399**	**1 023**	**989**

[a] Includes connections outside defined play subarea boundaries.

Figure S5.4 shows the 2011 average productivity rates for CBM and CBM hybrid production connections by CBM play and subareas. In 2011, the 2314 CBM and CBM hybrid connections located outside of the ERCB-defined CBM play subareas had a total production of 2.0 10^6 m^3/d (0.88 10^3 m^3/d/connection) and are grouped as undefined.

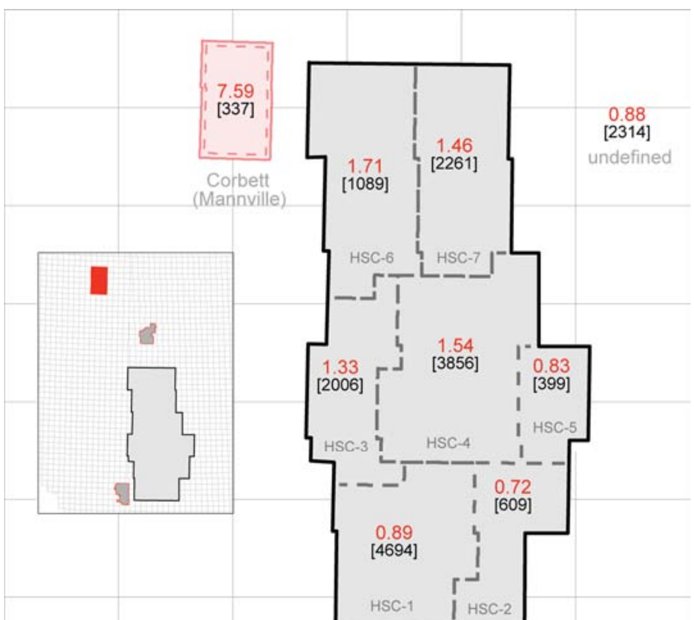


Figure S5.4
2011 CBM and CBM hybrid average productivity rates and producing connections by CBM plays and subareas
10^3 m^3/d/connection
[number of connections]

2011 average = 1.31 10^3 m^3/d/connection
18 263 connections

5.2.2.3 Shale Gas Connections

The ERCB identifies shale gas connections using the designation submitted by the operator to the Petroleum Registry of Alberta. These designations are evaluated and adjusted if required based on new information, resulting in revisions to historical annual numbers. All shale gas connections and volumes in this section are based on current connection designations as of December 31, 2011.

The ERCB currently recognizes 149 producing shale and commingled shale gas connections in 2011. Horizontal gas wells drilled in low permeability gas-bearing formations in northwest Alberta are reported as conventional gas, and reserves associated with this development are included in the conventional gas category in this report; however, the extension of the play into B.C. becomes generally shalier and is defined as shale gas.

Most producing shale gas connections in Alberta are shallow vertical wells, although the trend may have started to change in 2011. **Table 5.15** identifies the type of shale connection in 2011 and 2010. About 89 per cent of the designated shale gas connections have been made in the last 5 years, with most in 2008. With the exception of 2011, recompletions into shale gas producing zones from existing wells has been common in this current low natural gas price environment; the gas is commingled in the wellbore with conventional gas and/or CBM production from other formations.

Table 5.15 Shale gas connections by well type

	New Connections		Recompletions		Total	
Well type	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Vertical wells	4	12	3	10	7	22
Horizontal wells	19	3	0	0	19	3
Total	**23**	**15**	**3**	**10**	**26**	**25**

The 2011 average daily productivity rate for all producing shale gas connections was 1.9 10^3 m^3/d and the three-year average initial daily productivity rate was 2.1 10^3 m^3/d. The average initial daily rate is calculated using the average of the first full calendar year of production for the most recent three years.

5.2.3 Production Trends

5.2.3.1 Conventional Gas

Figure S5.5 illustrates historical conventional marketable gas production, including gas from oil wells, by PSAC area. Production in all areas of the province decreased from 2010 to 2011. The top three producing areas in the province—PSAC Area 2 (Foothills Front), PSAC Area 3 (southeastern Alberta) and PSAC Area 7 (northwestern Alberta)—are responsible for 40 per cent, 16 per cent, and 11 per cent of gas production in 2011, respectively.

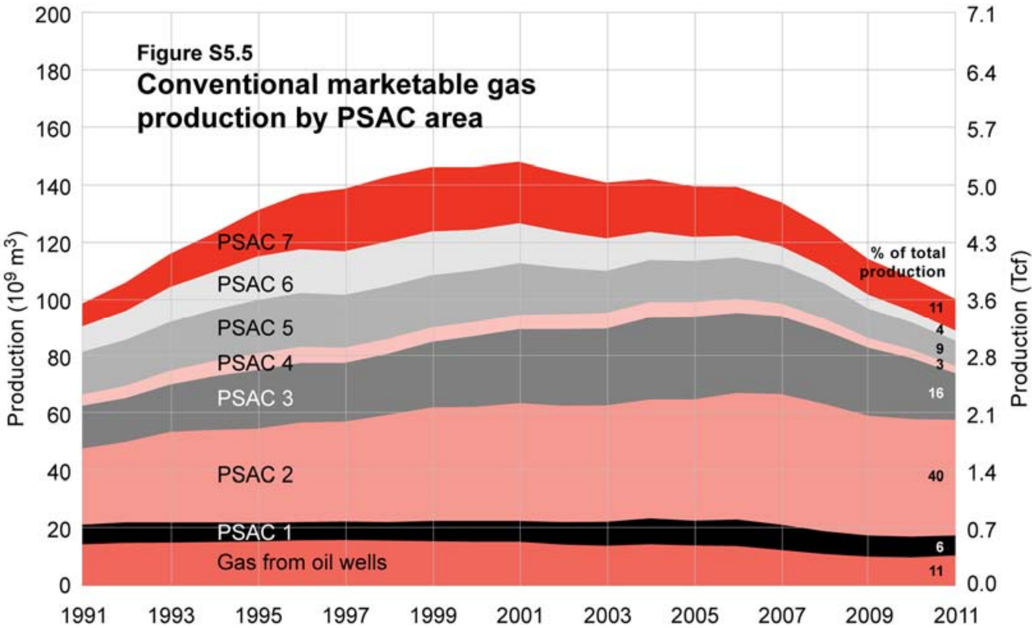
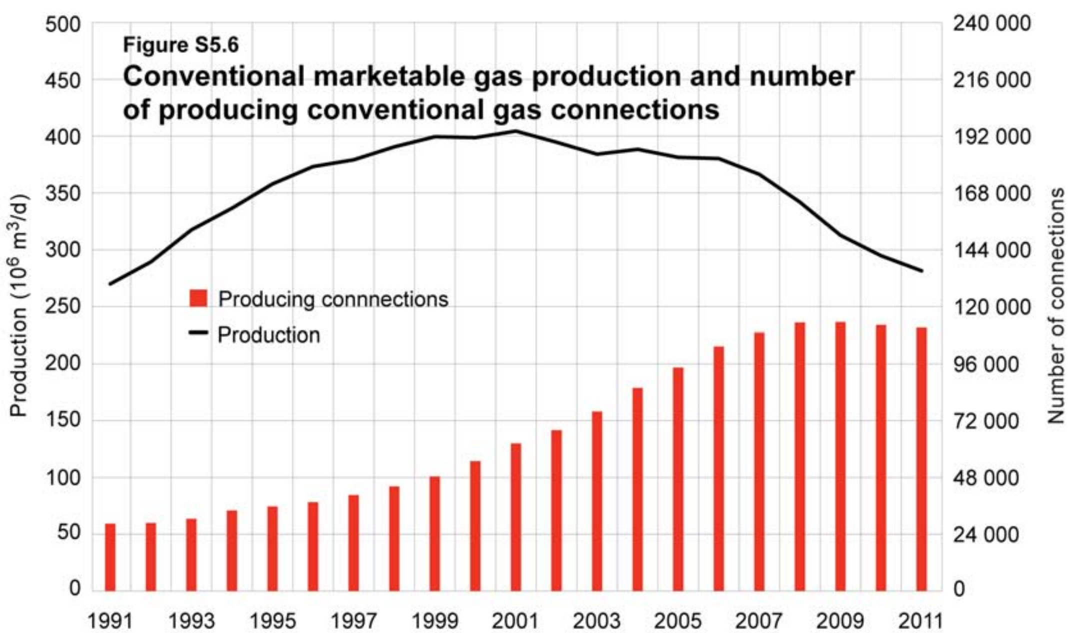


Figure S5.6 shows that from 1992 to 2009, the total number of producing conventional gas connections has increased, while gas production has decreased since reaching its peak in 2001. The numbers of new conventional gas connections each year had not been adequate to offset production declines in existing connections. 2010 was the first year in recent history in which the number of conventional gas well connections dropped over the previous year, and the same trend continued in 2011. In 2011, conventional gas well connections continued to decline to 111 120 after reaching a high of 113 450 connections in 2009.



Historical conventional raw gas production by connection year is presented in **Figure S5.7**. Natural gas production from oil wells has remained relatively stable, as shown by the band on the bottom of the chart. Each band above the gas production from oil wells represents production from new conventional gas connections by year. The percentages on the right-hand side of the figure represent the area's shares of total production from conventional gas connections in 2011. About 9 per cent of conventional gas production in 2011 came from the connections in 2011. Connections before 2001 contributed 30 per cent of gas production in 2011.

The percentage of sour gas relative to total gas production decreased from 31 per cent in 2000 to 20 per cent in 2011 because of the decline in production from the large sour gas pools in the province.

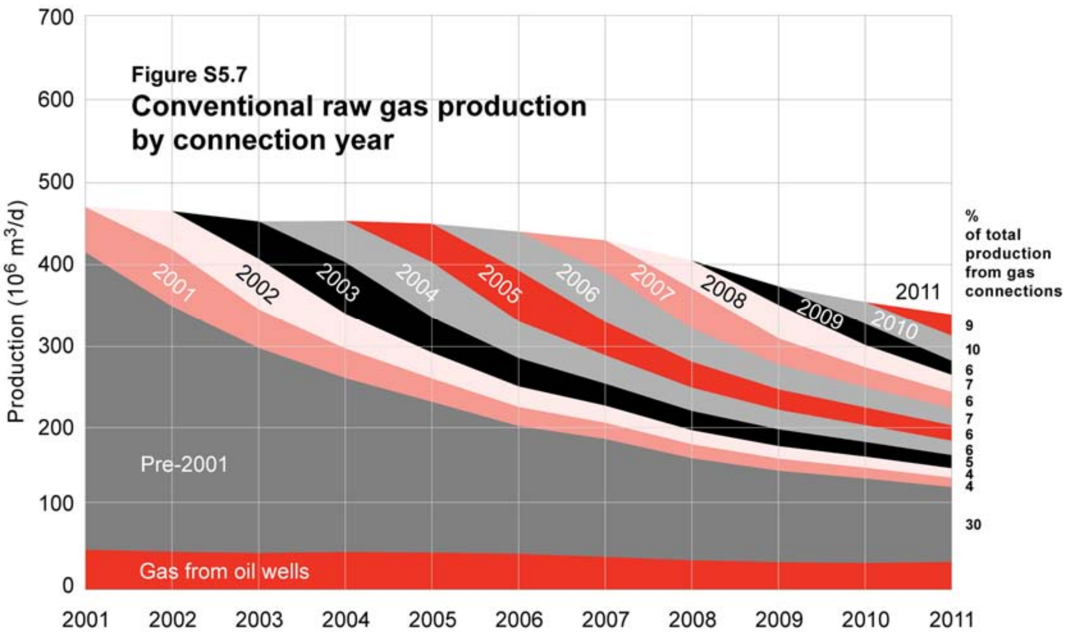
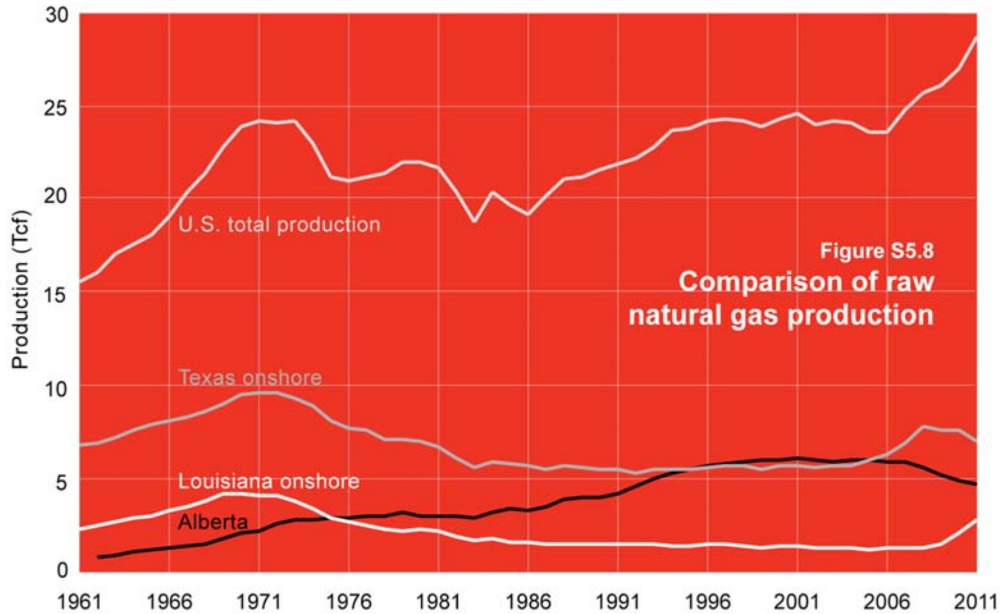


Figure S5.7
Conventional raw gas production by connection year

Figure S5.8 compares total raw natural gas production in Alberta with both Texas and Louisiana onshore production and total U.S. gas production over the past 50 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production has a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates stabilized. Only recently has Texas seen an increase again in gas production because of growth in shale gas production from the Barnett, Haynesville, and Eagle Ford shale plays.

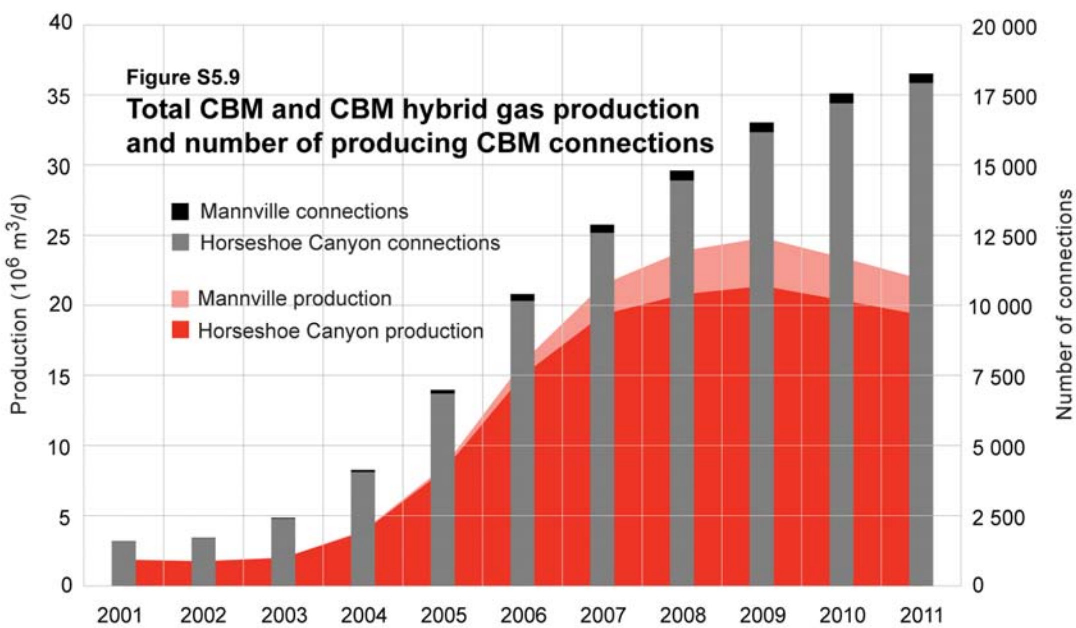
The long-term outlook for North American gas supply has changed with the recent growth in supply from shale gas production. With the success of the Barnett and Eagle Ford shales in Texas, and the expected potential of other shale gas plays in the United States—particularly the Marcellus, Woodford, and Fayetteville shales, as well as the Horn River and Montney shale plays in northeastern B.C.—shale



gas production continues to grow and has become a significant source of natural gas production in North America. The U.S. Energy Information Administration expects that shale gas production in the United States will increase from 5.0 trillion cubic feet (Tcf) in 2010 (23 per cent of total U.S. dry gas production) to 13.6 Tcf in 2035 (49 per cent of total U.S. dry gas production).

5.2.3.2 Coalbed Methane

Total CBM and CBM hybrid production and numbers of producing connections are shown in **Figure S5.9**. This figure shows that the production contribution from the Mannville CBM connections

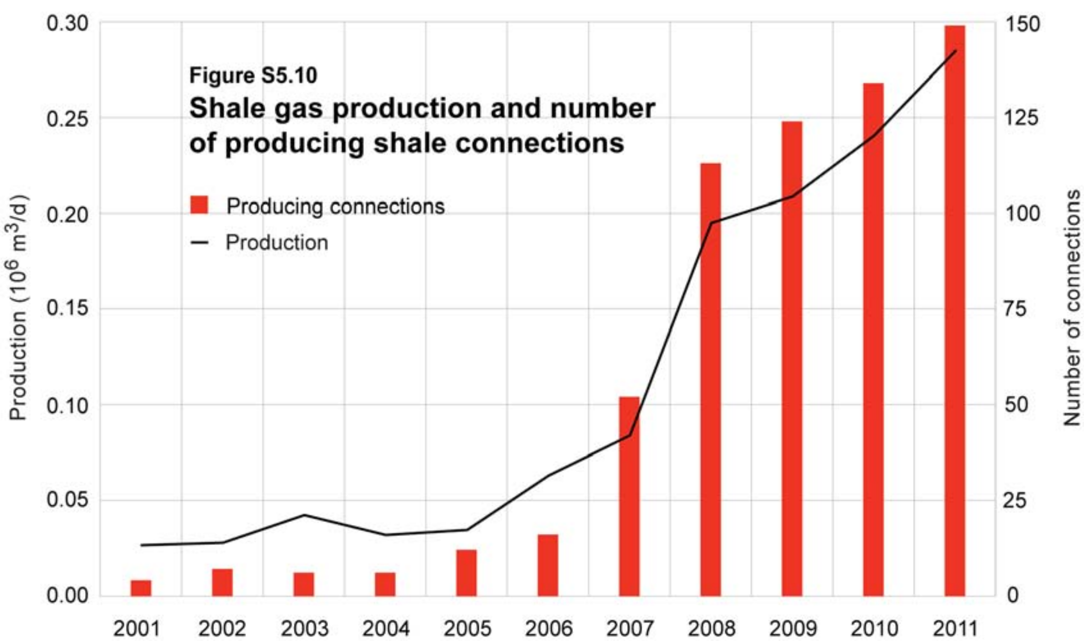


accounts for 11.7 per cent of the total CBM produced but from only 1.8 per cent of the total producing CBM connections. The chart illustrates the much higher productivity rates of the horizontal Mannville CBM connections compared with the vertical CBM and CBM hybrid Horseshoe Canyon connections.

Although these high productivity rates would normally indicate resource development, there have been low activity levels in the Mannville CBM play due to the limited number of industry participants in the area, the high cost of development and maintenance, and the low gas price environment.

5.2.3.3 Shale Gas

Shale gas production in Alberta is shown in **Figure S5.10** along with the number of producing shale gas connections in each year.

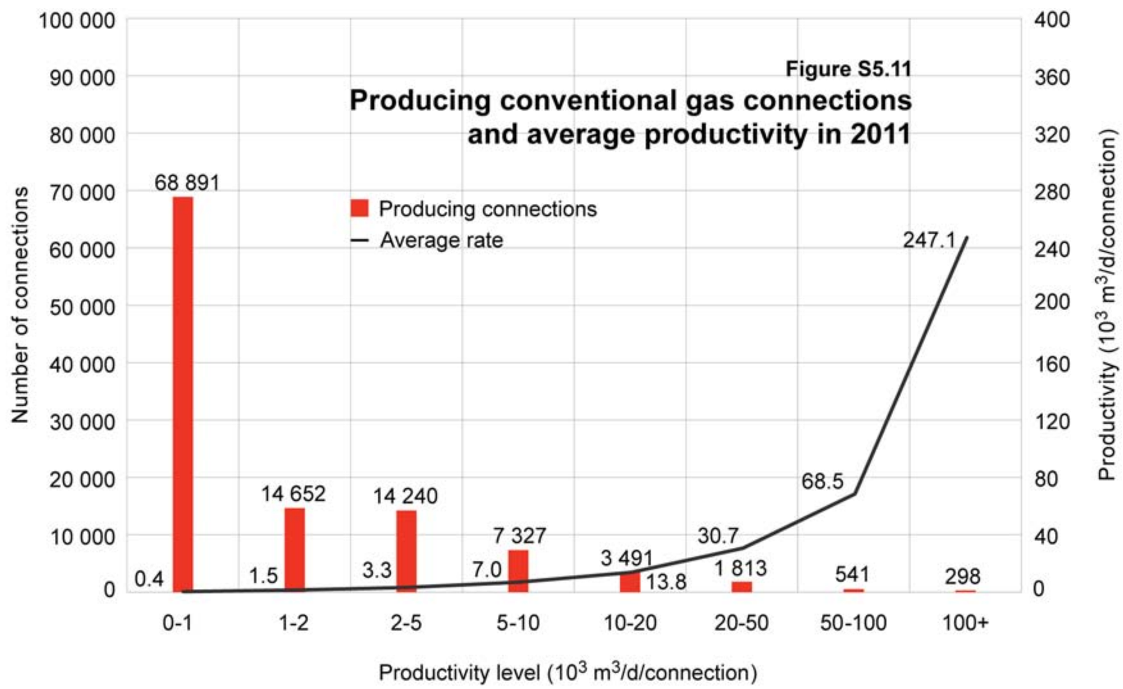


5.2.4 Production Characteristics of New Connections

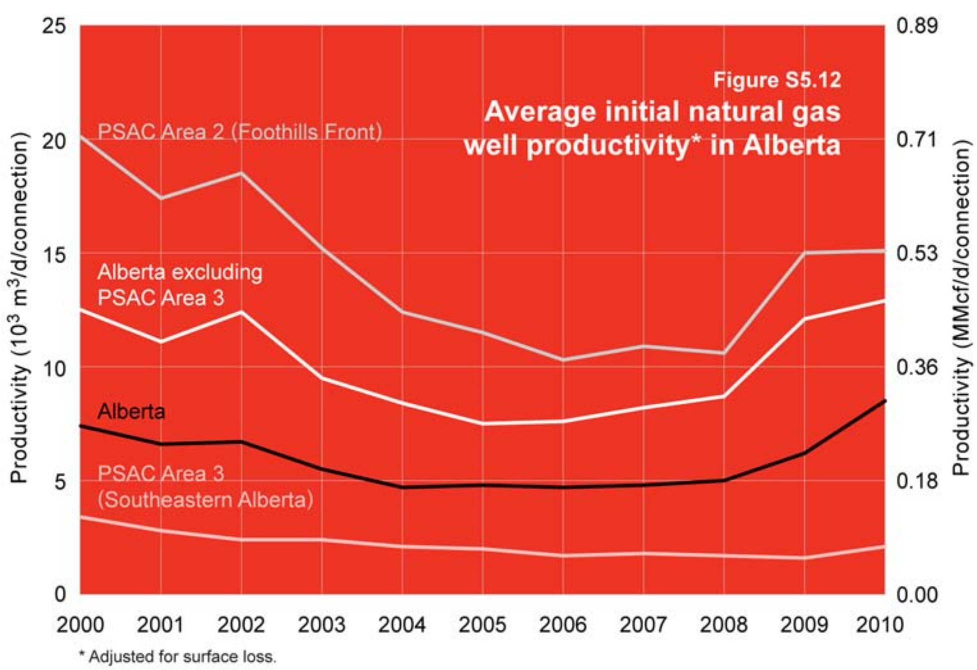
5.2.4.1 Conventional Gas

As shown in **Figure S5.11**, 68 891 producing gas connections, or about 62 per cent, produce less than 1.0 10^3 m^3/d of raw gas. In 2011, these gas connections produced at an average rate of 0.4 10^3 m^3/d and contributed less than 10 per cent of the total natural gas production.

Less than 1 per cent of the conventional gas connections produced at rates over 50 10^3 m^3/d, but they contributed 31 per cent of total production. New horizontal gas wells with high gas productivity rates are responsible for increasing the share of total gas production from wells in this category of well productivity to 31 per cent, up from 26 per cent in 2010.



Average initial productivities of new conventional gas connections in some areas of the province are higher than in past years. **Figure S5.12** shows the average initial productivity of new connections by connection year for the province and for wells in PSAC Area 3 (southeastern Alberta) and in PSAC Area 2 (Foothills Front). The productivities have been adjusted for surface losses to reflect sales gas rates as opposed to raw gas rates shown in the previous chart. Initial average daily production rates are

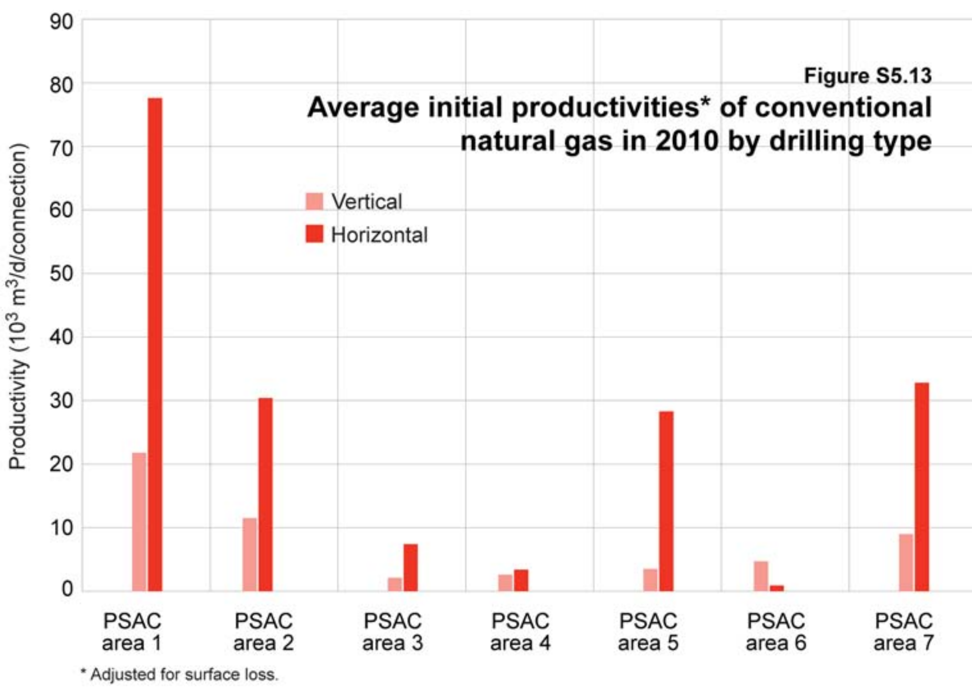


calculated using the first full calendar year of production for gas connections. Average initial productivities for new connections, excluding southeastern Alberta, are shown in the figure.

This chart illustrates the improvement in average initial productivities of recent connections. This is a result of horizontal drilling and new completion techniques. Average initial well productivities increased in all areas of the province with the exception of PSAC Area 1 (Foothills) and PSAC Area 4 (east-central Alberta).

Figure S5.13 shows average initial productivities for wells by well type for wells connected in 2010 in selected PSAC areas. PSAC Areas 2, 5, and 7 are where most horizontal wells have been brought on production.

Figure S5.14 shows typical gas production profiles for vertical and horizontal wells in the Kaybob South field that are producing commingled gas from the Bluesky, Gething, Nordegg, and Montney formations. Wells that were placed on production within the 2009 to 2011 time period were used to illustrate the difference in production profiles by well type. Initial well productivities of horizontal wells that are completed using multistage fracturing technology are significantly higher than initial well productivities of vertical wells. New horizontal wells have much higher initial well productivities than vertical wells, as illustrated earlier in **Figure S5.13**, and they continue to produce at much higher rates over the first 30 months of production.



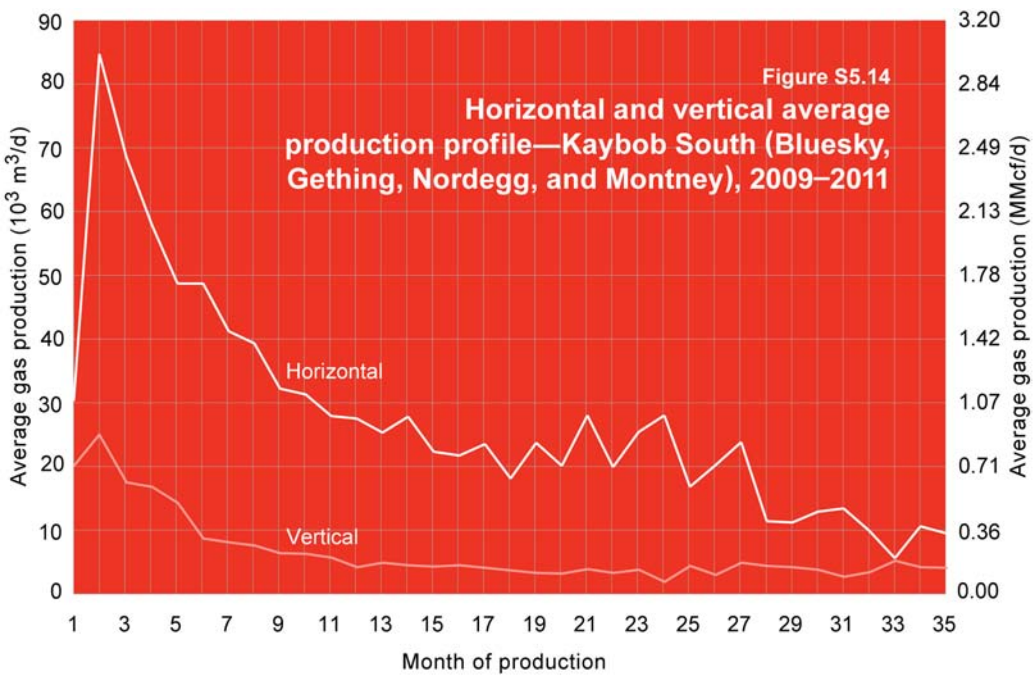
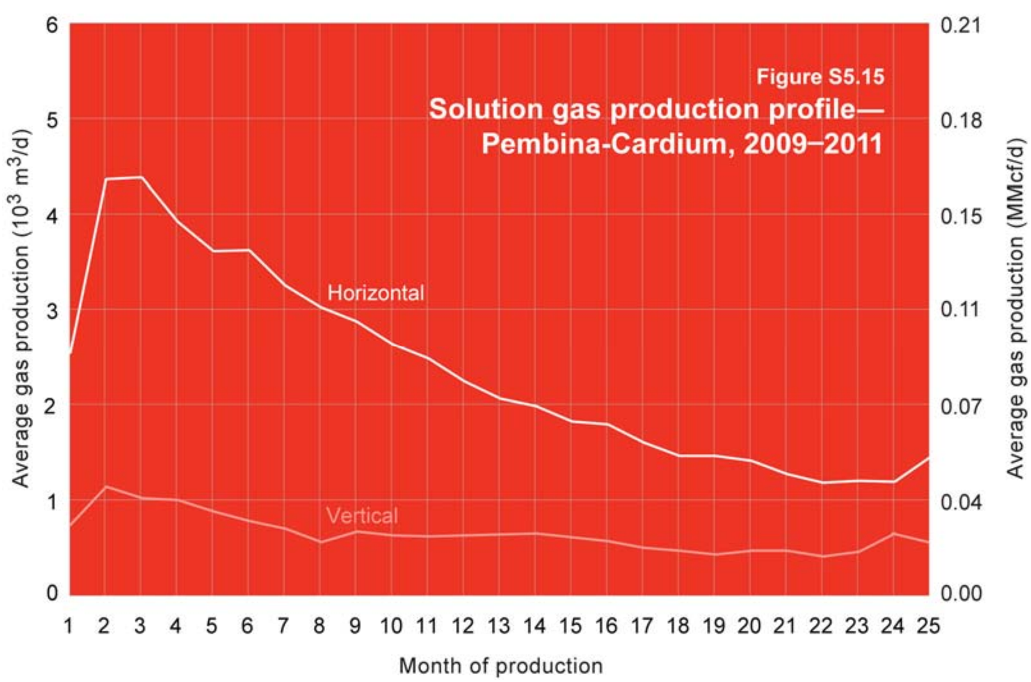
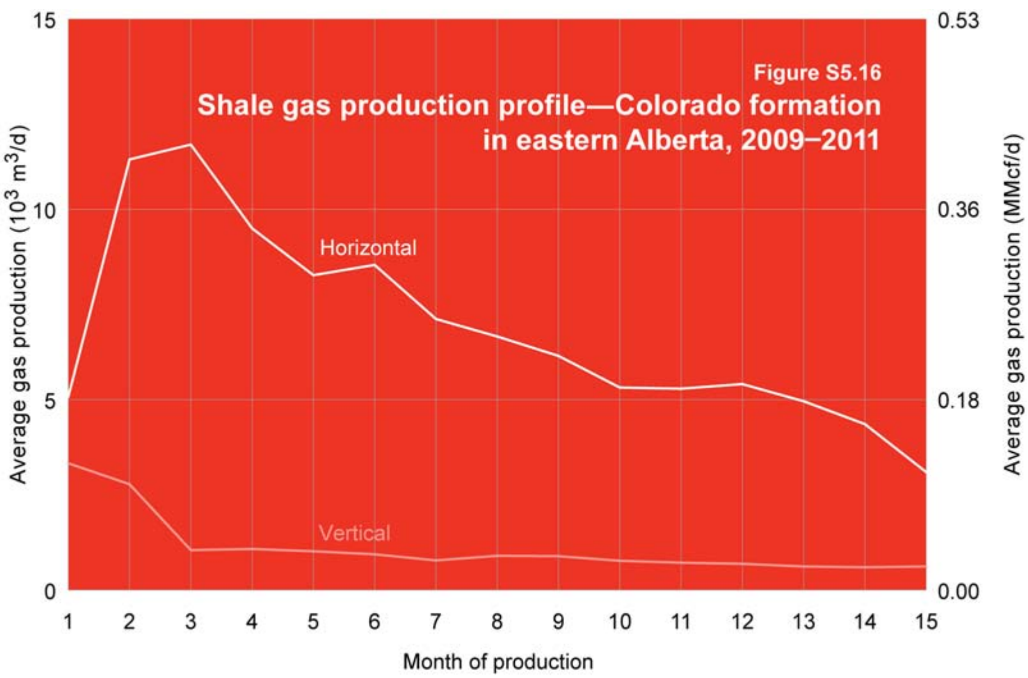


Figure S5.15 shows production profiles of gas produced from vertical and horizontal oil wells in the Pembina field that are producing crude oil and gas from the Cardium Formation. Gas connections that were placed on production within the 2009 to 2011 period were used to illustrate the difference in production profiles by well type. Horizontal drilling combined with multistage fracturing technology has significantly improved well productivity. New horizontal oil wells have much higher initial well productivities for crude oil and for solution gas than do vertical wells, as illustrated in the chart.



5.2.4.2 Shale Gas

The Colorado shale in east-central Alberta, particularly in the Wildmere area, is where most shale development has occurred in the province to date. **Figure S5.16** shows the profiles of gas produced from vertical and horizontal wells from this area. Gas connections that were placed on production within the 2009 to 2011 period were used to illustrate the difference in production profiles by well type. In 2011, 88 per cent of the new shale gas connections were horizontal wells, although most of the shale gas production was from vertical wells until 2010. The trend may have switched from vertical wells to focusing on horizontal wells as they have much higher initial well productivities and are therefore more economic to produce.



5.2.5 Marketable Natural Gas Production—Forecast

In projecting conventional gas and CBM supply, the ERCB considers three components: expected production from existing conventional gas and CBM connections, expected production from new conventional gas and CBM connections in new and existing wells, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. Since shale gas development is in its early stages in Alberta, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time.

To forecast gas production, production from existing wells and new wells drilled and connected each year has been analyzed. The number of new connections and the average productivity for the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.5.1 Conventional Gas

To project natural gas production from conventional gas connections prior to 2011, the ERCB assumes the following:

- Gas production from existing conventional gas connections at year-end 2011, based on observed performance, is assumed to decline by 16 per cent per year over the forecast period.
- Production from existing conventional gas connections will be 213.2 10^6 m^3/d in 2012.
- Over the forecast period, production of conventional gas from existing wells is expected to decline from 213.2 10^6 m^3/d to 44.4 10^6 m^3/d.

To project natural gas production from new conventional gas connections, the ERCB made the following assumptions:

- The numbers of new conventional gas connections over the forecast period are projected to start at 1620 in 2012 and to gradually increase to 3800 by 2021. The number of forecast connections is significantly lower relative to last year's forecast due to the low activity levels in 2011, and the natural gas price forecast is also lower relative to last year's forecast.
- Conventional gas connections in southeastern Alberta will represent 40 per cent of all new conventional gas connections in 2012 and 2013. This will decline to 35 per cent of new connections in each year from 2014 to 2019 and will rise to 40 per cent in 2020 and 2021, based on the expectation of improving natural gas price.
- The average initial productivity of a new conventional gas connection in southeastern Alberta will be 2.0 10^3 m^3/d.
- The average initial productivity of a new conventional gas connection in the rest of the province will be 13.5 10^3 m^3/d in 2012, increasing to 14.5 in 2013, 15.0 in 2014 and 2015, and gradually decreasing to 13.0 10^3 m^3/d by 2021. This forecast is significantly higher than the previous forecast due to the expectation that new conventional gas connections will increasingly utilize horizontal wells. In later years, the average initial productivity is projected to decrease because the recovery in natural gas price will allow the producers to expand their activities into less prolific reservoirs, potentially switching to less capital-intensive drilling such as vertical and directional wells.

- Production from new gas wells will decline by 33 per cent in the first year, 23 per cent in the second year, 19 per cent in the third year, and 16 per cent in the fourth year and every year thereafter over the forecast period.

- Gas production from oil wells, based on observed performance, will slightly increase to peak at 35.5 10^3 m^3/d in 2016 and 2017. It will start to decline in 2018 by 7 per cent per year for the rest of the forecast period. This forecast reflects recent actual performance and differs from last year's forecast which assumed a steady decline of 3 per cent.

Based on the remaining established and yet-to-be-established reserves, and the assumptions described above, the ERCB forecasts conventional marketable gas production to 2021. The production of marketable gas from conventional reserves is expected to decrease from 280.6 10^6 m^3/d in 2011 to 189.9 10^6 m^3/d by 2021.

If conventional natural gas production rates follow the projection, Alberta will have recovered 81 per cent of the 6528 10^9 m^3 ultimate potential by 2021.

5.2.5.2 Coalbed Methane

In projecting CBM supply, the ERCB considers expected production from existing CBM connections and expected production from new CBM connections. These new CBM connections include CBM connections into new wells drilled and recompletions into existing wells. Continual reclassification of CBM connections results in revisions to historical data and, therefore, changes to annual forecasts.

To forecast production from CBM and CBM hybrid connections before 2012, the ERCB assumed the following:

- All gas production from identified CBM and hybrid connections is included.

- All existing CBM and hybrid producing connections are expected to decline annually based on historical trends.

- Over the forecast period, production of existing CBM and CBM hybrid wells is expected to decline from 20.0 10^6 m^3/d to 10.0 10^6 m^3/d.

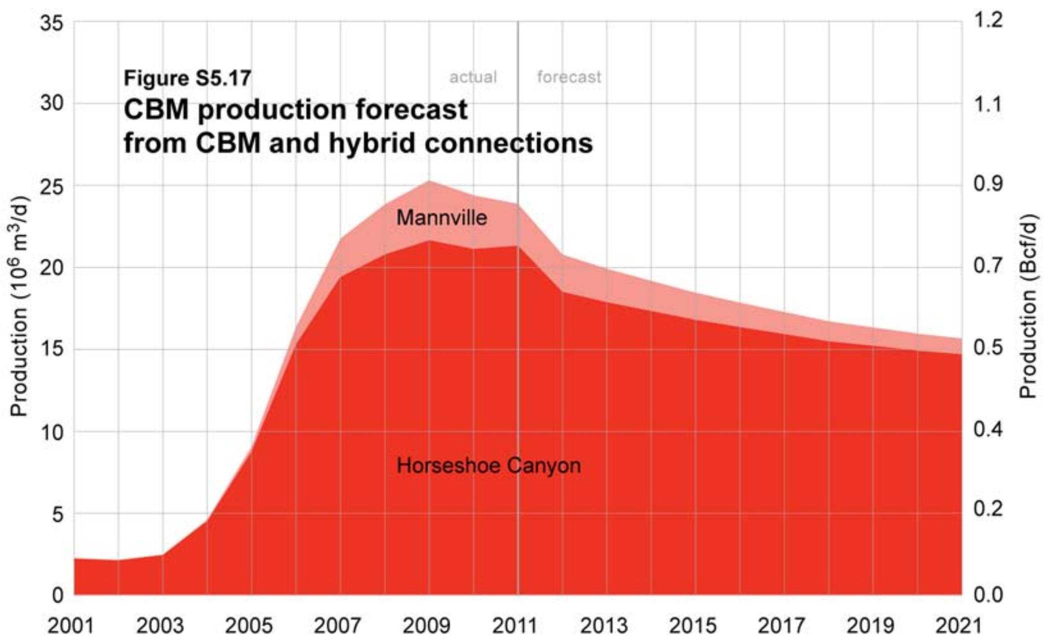
To project production from new CBM and CBM hybrid connections, the ERCB assumed the following:

- Over the forecast period, the majority of new CBM and CBM hybrid production will be from the Horseshoe Canyon.

- The number of new CBM and CBM hybrid connections in the Horseshoe Canyon play area will be 500 in 2012 and gradually increase to 800 in 2021. This forecast is significantly lower than last year's expectation and is due to the very low level of activity reported in 2011 and the expectation that activity levels will only slowly improve over the forecast period.

- The average initial productivity of a new gas connection in the Horseshoe Canyon Formation will be 1.4 10^3 m^3/d from 2012 to 2016, and 1.3 10^3 m^3/d from 2017 to 2021.
- The percentage of recompletions in existing wells versus new connections within the Horseshoe Canyon play will remain at 2011 levels over the forecast period.

Figure S5.17 illustrates the ERCB forecast of CBM production to 2021. Production from CBM connections, which includes commingled production from conventional gas formations, is expected to decrease from 23.9 10^6 m^3/d in 2011 to 15.6 10^6 m^3/d in 2021, significantly lower than last year's forecast. In 2011, CBM production contributed 7.8 per cent of the total Alberta marketable gas production, similar to last year, and it is projected to contribute 7.6 per cent of the total Alberta marketable gas production in 2021, compared to last year's expectation of a 13 per cent contribution in 2020.



5.2.5.3 Shale Gas

As mentioned earlier, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time. The economic viability of shale development in Alberta is currently unclear; however, it has the potential to become a significant supply source. Commercial shale gas production is in its infancy, and it will take time to establish the producibility of the resource. The pace of shale gas development will be affected by the natural gas price environment, supply costs, and technology.

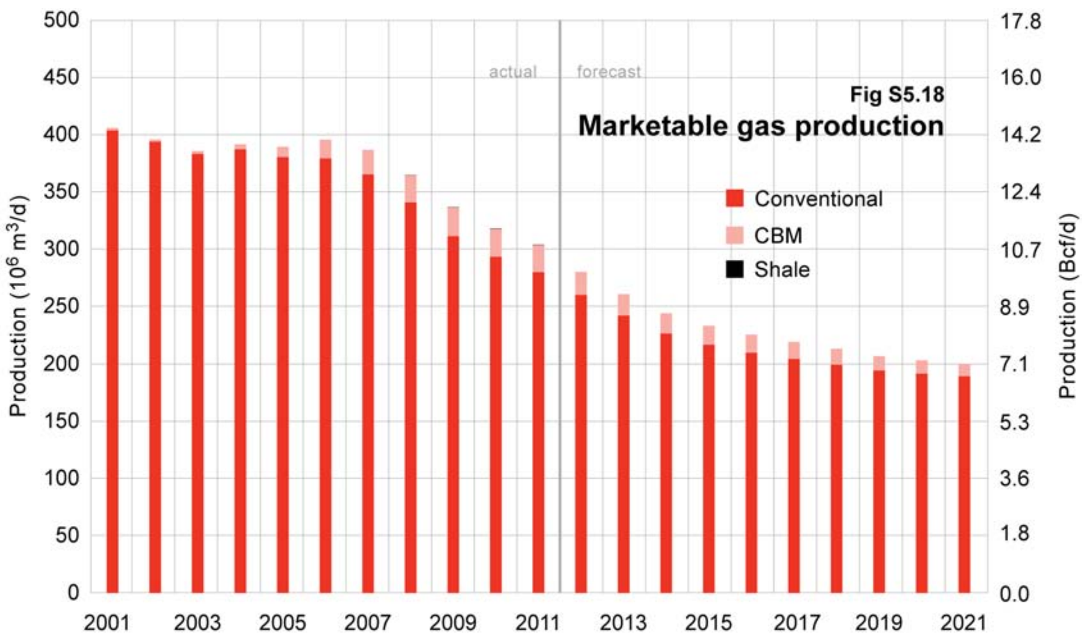
5.2.5.4 Total Gas Production

The ERCB's forecast of conventional gas and CBM production to 2021 is shown in **Figure S5.18**.

Figure S5.19 illustrates historical and forecast new connections from conventional gas and coalbed methane wells along with plant gate gas prices (see **Section 1** for discussion on price forecasts).

Figure S5.20 shows process gas production (rich in liquids) from bitumen upgrading operations and raw natural gas from bitumen wells. Gas from these sources is used primarily as fuel in oil sands development.

In 2011, about 16.5 10^6 m^3/d of process gas was generated at oil sands upgrading facilities, compared to a revised volume of 15.4 10^6 m^3/d in 2010, and is primarily used as fuel. This number is expected to reach 22.9 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells increased by 0.6 10^6 m^3/d in 2011 to 4.9 10^6 m^3/d and is forecast to increase to 7.6 10^6 m^3/d by 2021. This gas is used mainly as fuel to create steam for on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.



2011 volumes for shale gas production is included in the chart; shale gas production has not been forecast.

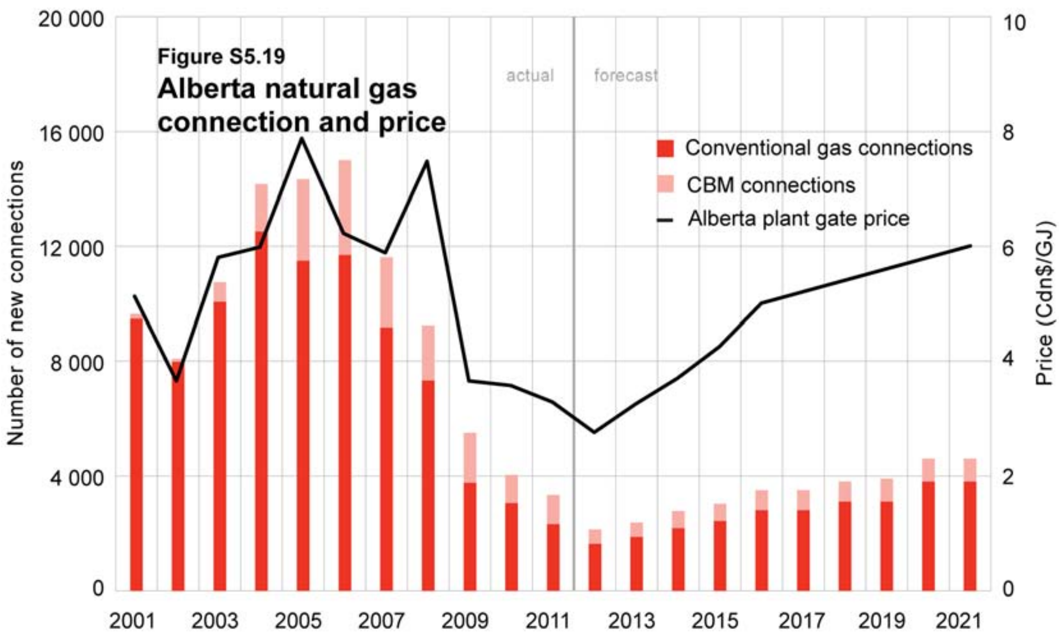


Figure S5.19
Alberta natural gas connection and price

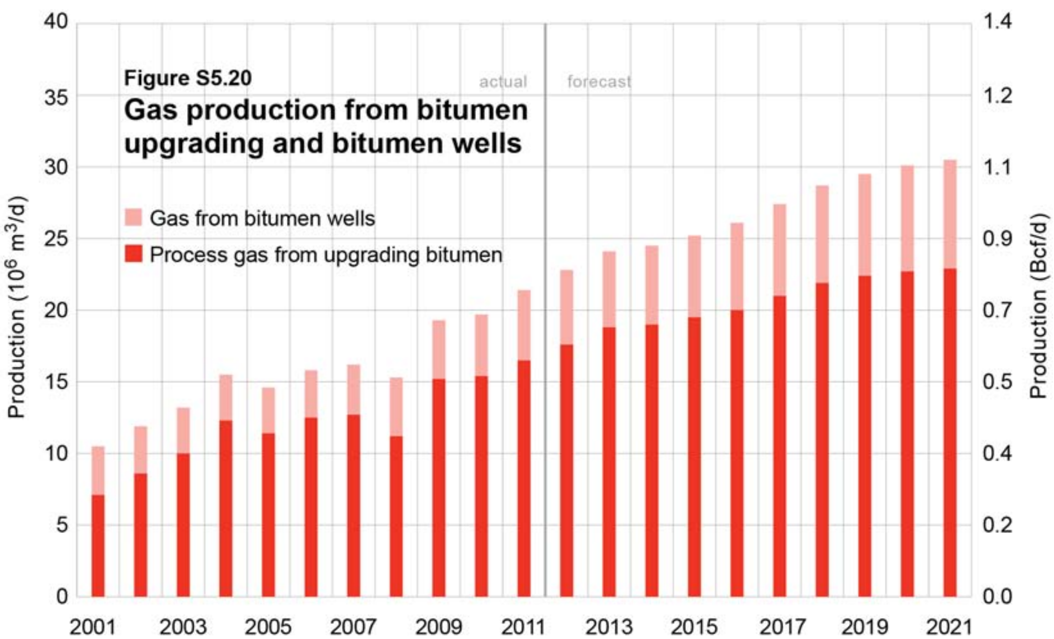


Figure S5.20
Gas production from bitumen upgrading and bitumen wells

5.2.6 Supply Costs

While the supply costs listed below have not been updated from last year, the ERCB believes that they remain representative of actual costs. The supply cost for a resource or project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, and earn a 10 per cent specified return on investment.

The following table summarizes estimated costs of conventional gas supplies from selected areas in Alberta based on 2009 drilling and operating costs and production rates. Supply costs for different geological plays within the province can vary significantly because of differing discovered reserves and resulting production rates and drilling and operating costs. Some selected results for Alberta are displayed below in **Table 5.16**.

Table 5.16 Supply costs for gas wells in Alberta

Area of Alberta	Resource type	Resource group	Supply cost ($C/GJ)
Central	Tight	Mannville	3.23
West Central	Conventional	Upper Cretaceous; Upper Colorado	3.68
Southwest	Conventional	Middle and Lower Manville	4.45
Kaybob	Conventional	Triassic	4.76
Southern	Conventional	Mannville	5.44
Deep Basin	Tight	Mannville; Jurassic	5.62
CBM deposit play area	Coalbed methane	Mannville	6.31
Southern Foothills	Conventional	Mississipian; Upper Devonian	7.14
Northeast Alberta	Conventional	Manville; Upper Devonian	8.54
Central Foothills	Conventional	Mississippi	9.04
Eastern	Conventional	Colorado; Manville	9.83

Source: National Energy Board (NEB), November 2010, *Supply Costs in Western Canada in 2009*.

5.2.7 Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the ERCB does not use these volumes in the long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; traditionally it allows marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Natural gas from many sources may be stored at these facilities under fee-for-service, buy-sell, or other contractual arrangements.

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas supply rises, injection slows or ends, and storage withdrawals generally begin at high withdrawal rates. Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table 5.17**.

In 2011, natural gas injections for all storage schemes exceeded withdrawals by 2687 10^6 m^3. This compares to 277 10^6 m^3 net withdrawal in 2010. The increase in the U.S.-marketed gas production discussed earlier in this section has reduced the volume of Alberta export gas entering Canadian and U.S. markets. Even though the intra-Alberta demand has been steadily increasing, as mentioned later in this section, the decrease in the export demand contributed to the large amount of net injection in 2011.

Marketable gas production volumes determined for 2011 were adjusted to account for the imbalance between volumes injected and volumes withdrawn from these storage pools. For the purpose of projecting future natural gas production, the ERCB assumes that injections and withdrawals are balanced for each year during the forecast period.

Table 5.17 Commercial natural gas storage pools as of December 31, 2011

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2011 (10^6 m^3)	Withdrawal volumes, 2011 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	1 050	820
Carrot Creek CCC	Iberdrola Canada Energy Services Ltd.	986	16 900	409	344
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	35 217	1 691	1 092
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	795	557
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	963	599
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	248	217
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	419	225
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	50 713	2 182	1 411
Warwick Glauconitic-Nisku A	Warwick Gas Storage Inc. (WGSI)	881	3 300	572	377
Total		**10 477**	**172 025**	**8 329**	**5 642**
Difference					**2 687**

Figure S5.21 shows the location of existing gas storage facilities at the Alberta pipeline systems.

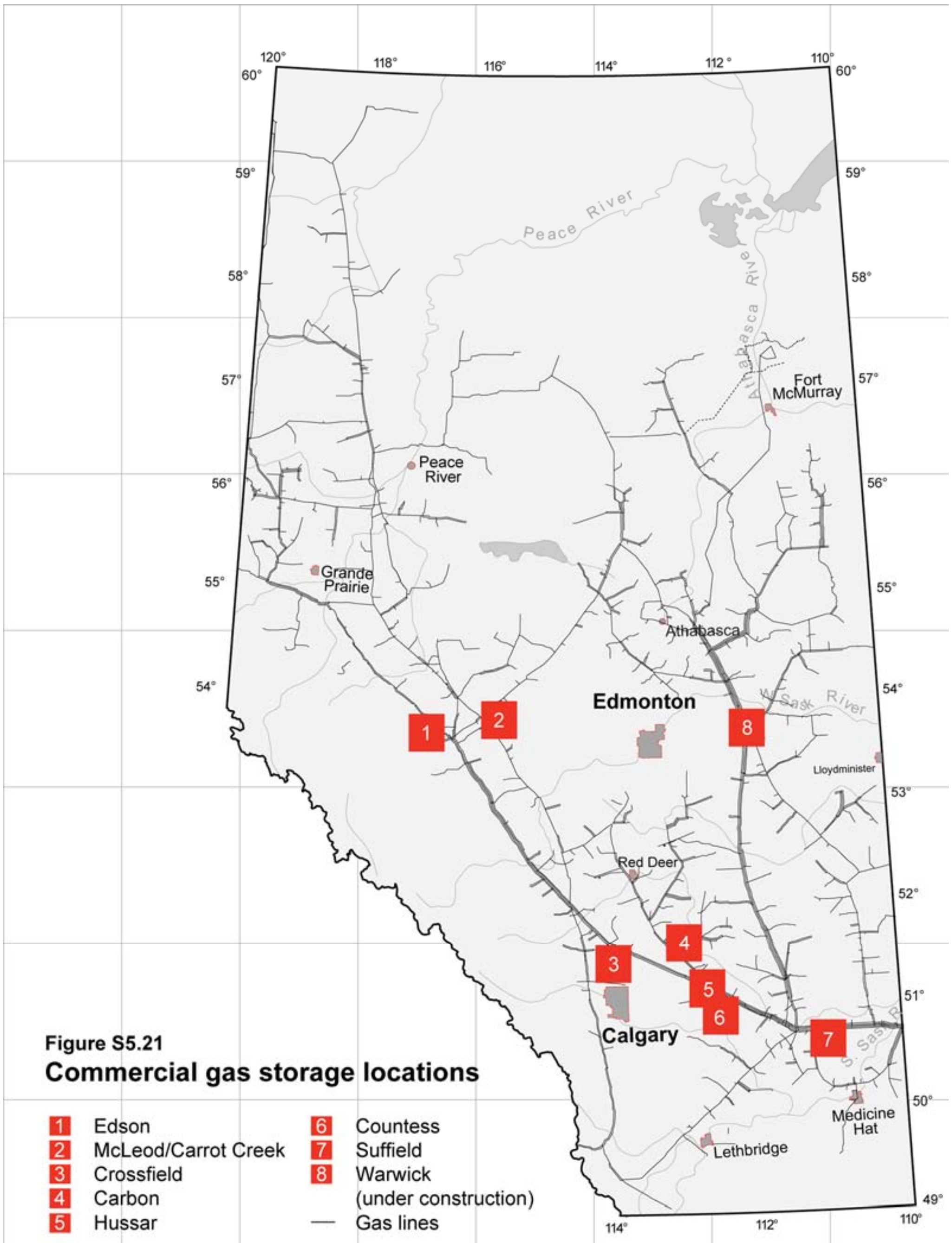


Figure S5.21
Commercial gas storage locations

5.2.8 Alberta Natural Gas Demand

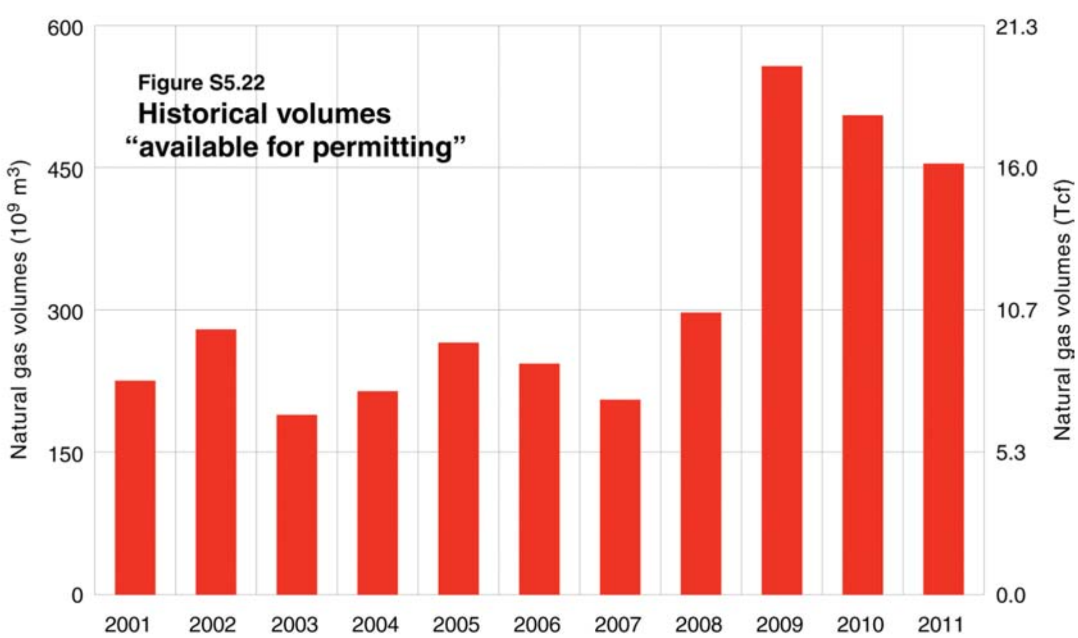
The *Alberta Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the ERCB for a permit authorizing the removal. Removal of gas from Alberta is only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.

The calculation in **Table 5.18** is done annually to determine what volume of gas is available for removals from Alberta after accounting for Alberta's future requirements. Using the 2011 remaining established reserves number, surplus natural gas is currently calculated to be 454 10^9 m^3. **Figure S5.22** illustrates historical "available for permitting" volumes.

Table 5.18 Estimate of gas reserves available for inclusion in removal permits as of December 31, 2011

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2010)	
1. Total remaining established reserves	987
Alberta requirements	
2. Core market requirements	119
3. Contracted for non-core markets[a]	141
4. Permit-related fuel and shrinkage	25
Permit requirements	
5. Remaining permit commitments[b]	248
6. Total requirements	533
Available	
7. Available for removal permits	454

[a] For these estimates, 15 years of core market requirements and 5 years of noncore requirements were used.
[b] The remaining permit commitments are split approximately 95 per cent under short-term permits and 5 per cent under long-term permits.



Gas removals from Alberta have declined since 2001, from 311.5 10^6 m^3/d in 2001 to 178.1 10^6 m^3/d in 2011. Based on the ERCB's projection of gas production, this rate is forecast to drop to 38.1 10^6 m^3/d by 2021.

The ERCB annually reviews the projected demand for Alberta natural gas. It focuses these reviews on intra-Alberta natural gas use and provides a detailed analysis of many factors, such as population growth, industrial activity, alternative energy sources, and other factors that influence natural gas consumption in the province.

Forecasting demand for Alberta natural gas in markets outside the province is done less rigorously. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets and on the recent historical trends in meeting that demand. Excess pipeline capacity to the United States allows gas to move to areas of the United States that provide for the highest netback to the producer. The major natural gas pipelines in Canada that move Alberta gas to market are illustrated in **Figure S5.23**, with export points identified.

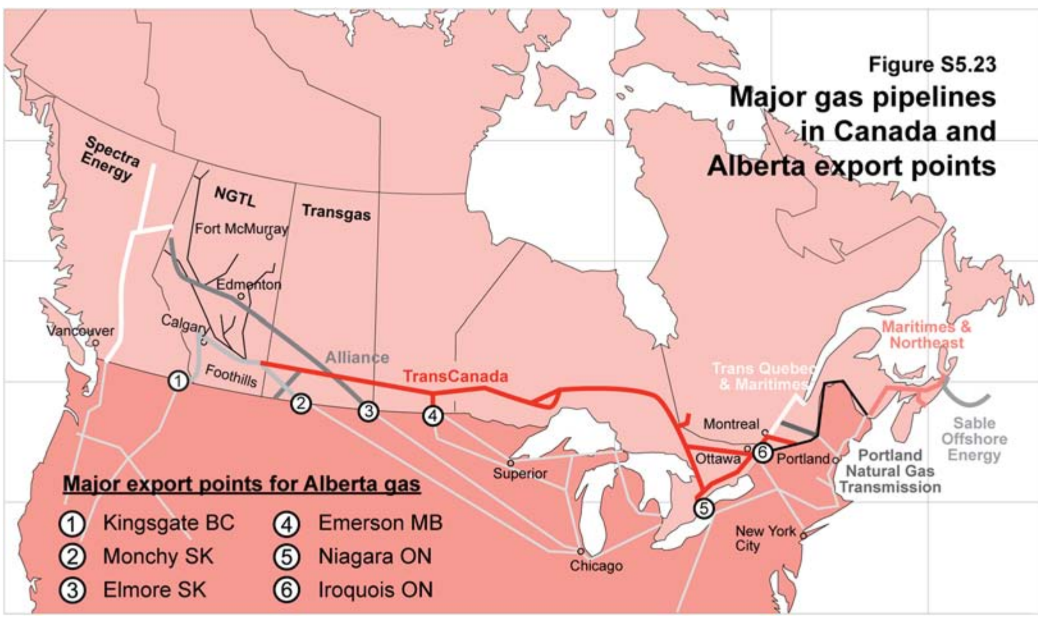


Figure S5.24 illustrates the breakdown of marketable natural gas demand[3] in Alberta by sector. In 2011, demand within Alberta was 126.6 10^6 m^3/d, which represented 42 per cent of the total Alberta natural gas production. By the end of the forecast period, demand will reach 167.5 10^6 m^3/d, or 81 per cent of total Alberta production.

[3] The Imperial System units shown in Figure S5.24 are in billion cubic feet per day (Bcf/d).

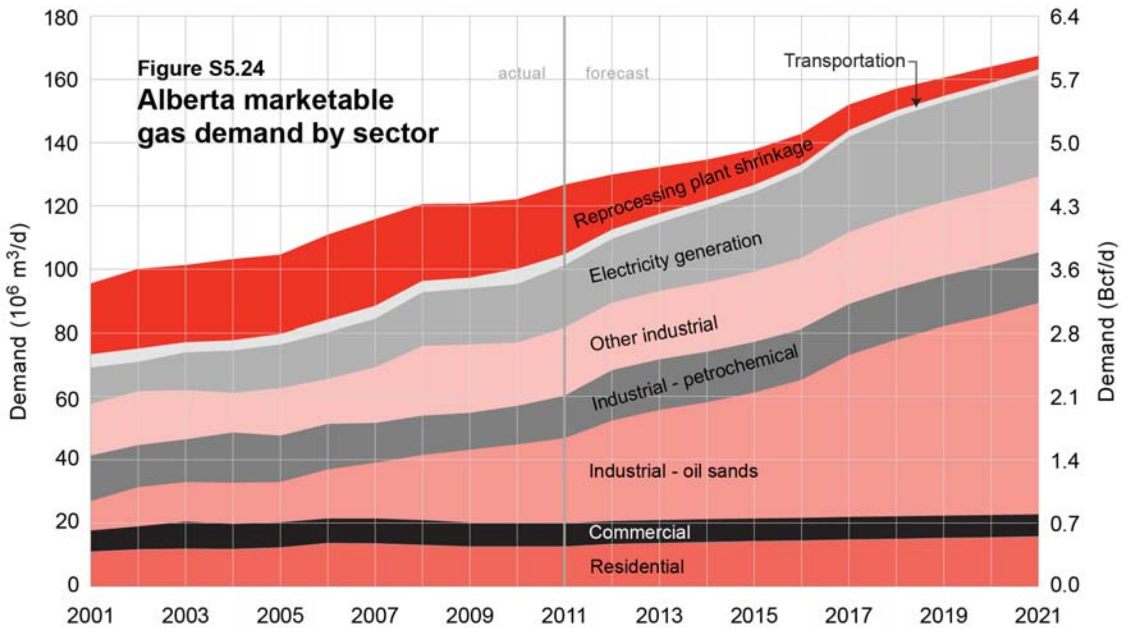


Figure S5.24
Alberta marketable gas demand by sector

Residential gas requirements are expected to grow moderately at an average annual rate of 2 per cent over the forecast period. The key variables that affect residential gas demand are natural gas prices, population, the number of households, energy efficiencies, and the weather. Energy efficiency improvements prevent household energy use from rising significantly.

Commercial gas demand in Alberta has declined gradually since 2003 and is expected to continue to decline at an average annual rate of 0.5 per cent per year over the forecast period. This is largely due to gains in energy efficiencies and a shift towards electricity.

The electricity-generating industry will require increased volumes of natural gas to fuel the new industrial on-site and peaking plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 19.6 10^6 m^3/d in 2011 to 32.0 10^6 m^3/d by 2021. The projected increase in gas demand in this sector is due to the assumption that gas will be the preferred feedstock for new power plants. See **Section 9** for details on the new gas-fired plants projected to come on stream over the forecast period.

Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations will increase from 26.9 10^6 m^3/d in 2011 to 66.6 10^6 m^3/d in 2021. The purchased natural gas requirements for bitumen recovery and upgrading, including gas used by the electricity cogeneration units on site at the oil sands operations, shown in **Figure S5.25**, are expected to increase from 34.1 10^6 m^3/d in 2011 to 77.5 10^6 m^3/d by 2021. All purchased gas use for upgrading operations, including the gas used by Nexen/OPTI to upgrade in situ bitumen, is included in the mining and upgrading category shown in the figure. **Table 5.19** outlines the average purchased gas use rates for oil sands operations. Gas production from and demand for the oil sands operations are sourced from the Petroleum Registry of Alberta.

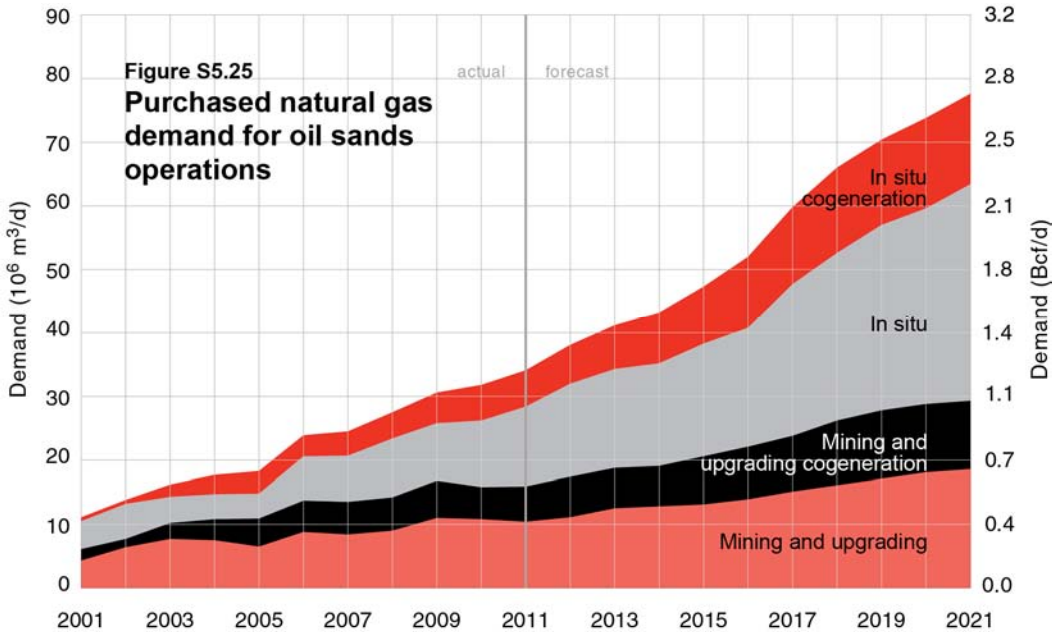


Figure S5.25
Purchased natural gas demand for oil sands operations

Table 5.19 Oil sands average purchased gas use rates, 2011[a]

Extraction method	Excluding purchased gas for cogeneration (m^3/m^3)	(mcf/bbl)	Including purchased gas for cogeneration (m^3/m^3)	(mcf/bbl)
In situ				
SAGD	175	0.98	241	1.35
CSS	167	0.94	210	1.18
Mining with upgrading	76	0.43	116	0.65

[a] Expressed as cubic metres of natural gas per cubic metre of upgraded/nonupgraded bitumen production. Rates are an average of typical schemes with sustained production.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.26** illustrates the sector’s total gas demand, which is the sum of purchased gas, process gas, and solution gas produced at bitumen wells. This demand is expected to nearly double from 41.0 10^6 m^3/d in 2011 to 79.6 10^6 m^3/d by 2021.

Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, as shown in **Figure S5.27**, was 55.4 10^6 m^3/d in 2011 and is forecast to increase to 108.0 10^6 m^3/d by 2021.

Figure S5.28 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading (**Figure S5.20**) is considered to be used on site and is not included as marketable production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional and CBM only (and not including imports from B.C.), minus Alberta demand.

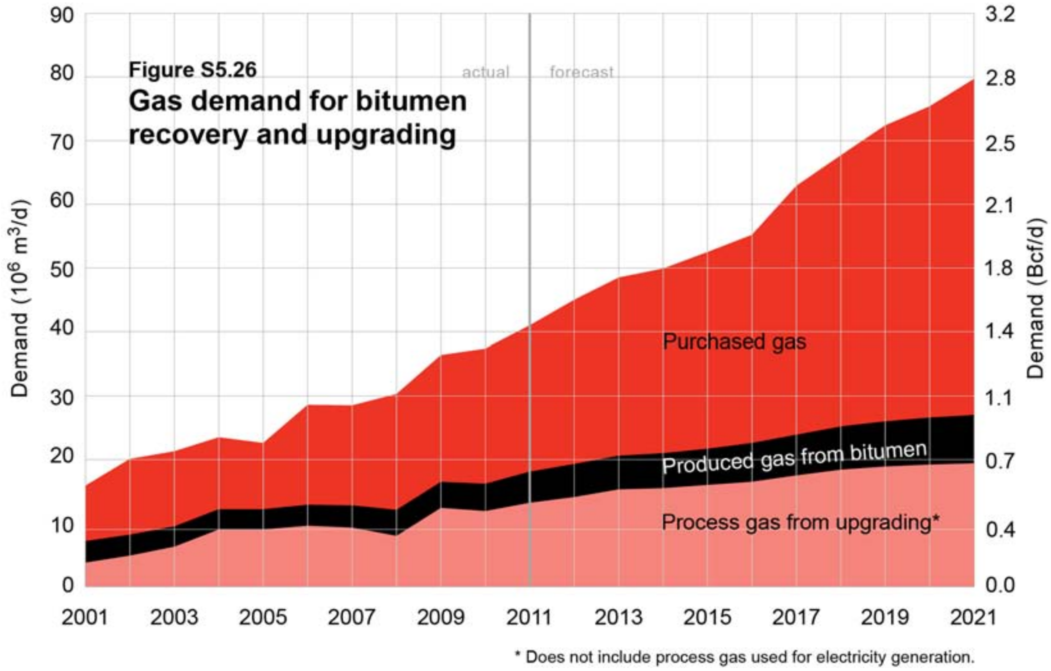


Figure S5.26
Gas demand for bitumen recovery and upgrading
actual
forecast
Demand (10^6 m^3/d)
Demand (Bcf/d)
Purchased gas
Produced gas from bitumen
Process gas from upgrading*
* Does not include process gas used for electricity generation.

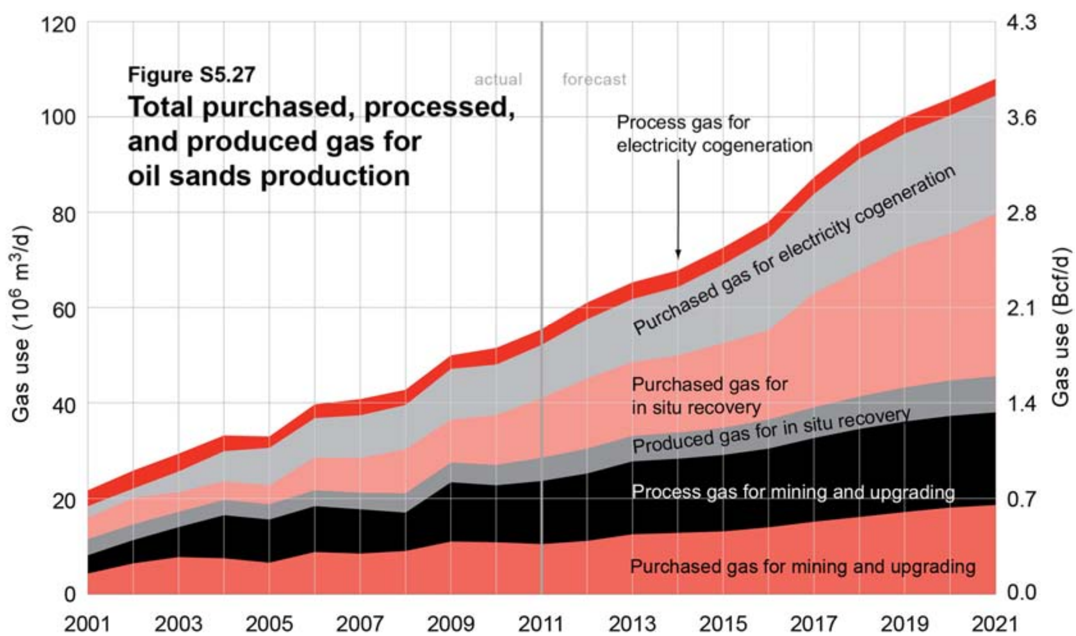
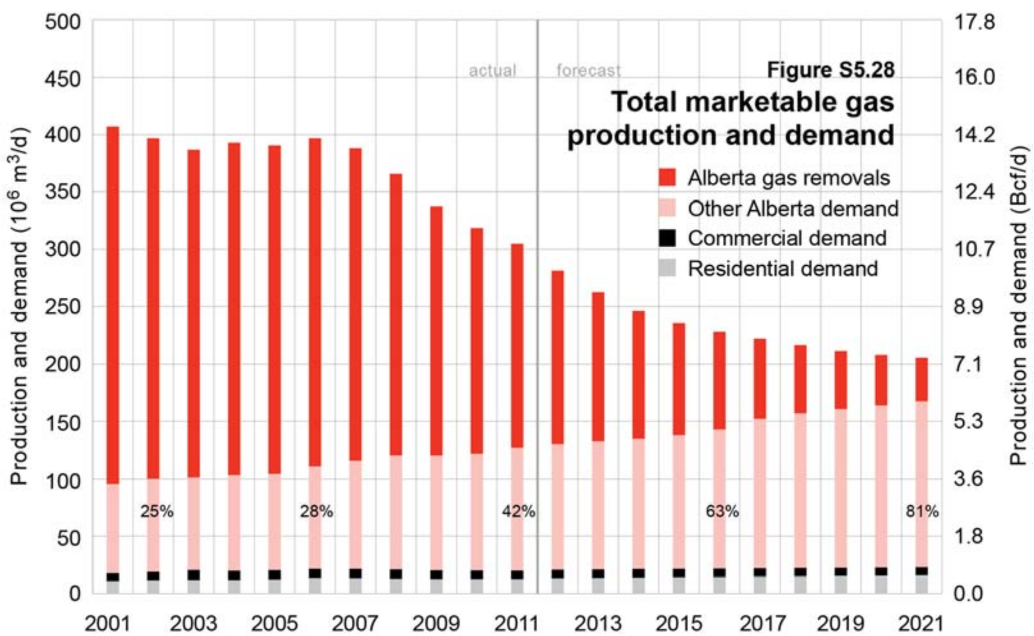


Figure S5.27
Total purchased, processed, and produced gas for oil sands production
actual
forecast
Gas use (10^6 m^3/d)
Gas use (Bcf/d)
Process gas for electricity cogeneration
Purchased gas for electricity cogeneration
Purchased gas for in situ recovery
Produced gas for in situ recovery
Process gas for mining and upgrading
Purchased gas for mining and upgrading

In 2011, about 42 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand will represent 81 per cent of total Alberta natural gas production. However, the forecast does not include any potential shale gas production that may occur in Alberta. Additionally, natural gas supply from B.C. that moves through Alberta to market is also not included in this analysis. The B.C. supply is expected to increase over the forecast period and provides Alberta with the availability of natural gas if needed.



6 // NATURAL GAS LIQUIDS

HIGHLIGHTS

Total remaining extractable NGL reserves have decreased by 3 per cent from 2010 as a result of decreasing natural gas reserves.

Approximately 68 per cent of total ethane in the gas stream was extracted in 2011, compared with 63 per cent in 2010 and 56 per cent in 2009.

Produced natural gas is primarily methane, but it also contains heavier hydrocarbons consisting of ethane (C_2), propane (C_3), butanes (C_4), and pentanes and heavier hydrocarbons (typically referred to as pentanes plus or C_5+), all of which are referred to as natural gas liquids (NGLs). Natural gas also contains water and contaminants such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S). In Alberta, the production of all ethane, pentanes plus, and most propane and butanes are from the raw natural gas stream. Most of the NGL supply is recovered from the processing of natural gas at gas plants, although some pentanes plus is recovered as condensate at the field level and sold as product. Other sources of NGLs are crude oil refineries, where small volumes of propane and butanes are recovered, and from gases produced as by-products of bitumen upgrading called off-gas. Off-gases are a mixture of hydrogen and light gases, including ethane, propane, and butanes. Most of the off-gases produced from oil sands upgraders are currently being used as fuel for oil sands operations. Unconventional gas is generally lean, with fewer hydrocarbon liquids, so it is not expected to contribute to future NGL reserves.

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in **Section 6.2.1**. Initial reserves for NGLs are not calculated, since historically only a fraction of the liquid volume that could have been extracted was recovered, and much was flared for lack of market demand. The ERCB's projections for the overall recovery of each NGL component are explained in **Section 5.1.3.6**. As shown graphically in **Figure R5.7**, the estimate of the reserves of liquid ethane is based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the ERCB's calculations assume that the composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict, and the volume is not expected to be significant. The NGL reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in **Section 5.1**.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2011 are summarized in **Tables 6.1** and **6.2**. **Figure R6.1** shows remaining established reserves of extractable NGLs compared with 2011 production.

Total remaining reserves of extractable NGLs have decreased by 2.6 per cent compared with 2010 because of the decline in natural gas reserves. Fields that have contributed significantly to this decrease are Ansell, Caroline, Kaybob South, Sundance, and Wild River. These fields and others containing large NGL volumes are listed in **Appendix B**, **Tables B.7** and **B.8**.

Table 6.1 Established reserves and production change highlights of extractable NGLs (10^6 m^3 liquid)

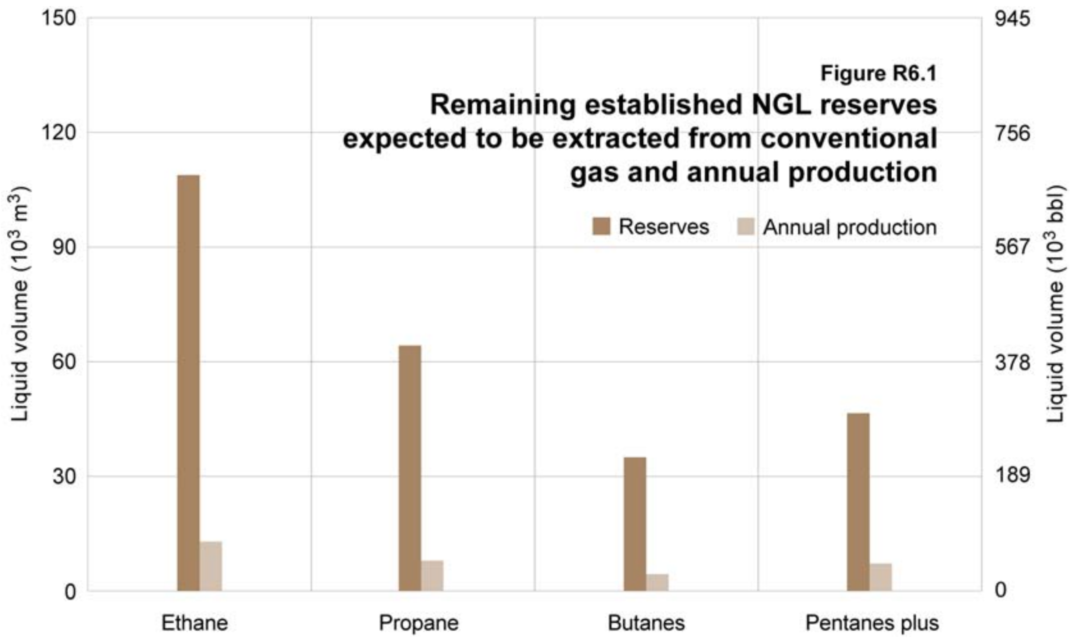
	2011	2010	Change
Cumulative net production			
Ethane	305.5	292.6	+12.9
Propane	295.1	287.2	+7.9
Butanes	168.4	164.0	+4.4
Pentanes plus	359.6	352.4	+7.2
Total	**1 128.6**	**1 096.2**	**+32.4**
Remaining (expected to be extracted)			
Ethane	108.8	113.2	-4.3
Propane	64.2	64.0	0.2
Butanes	35.0	35.4	-0.4
Pentanes plus	46.5	48.7	-2.2
Total	**254.5**	**261.3**	**-6.8**
Annual production	**32.4**	**32.2**	**0.2**

6.1.2 Ethane

As of December 31, 2011, the ERCB estimates remaining established reserves of extractable ethane to be 108.8 million cubic metres (10^6 m^3) in liquefied form. Of that, 42.6 10^6 m^3 is expected to be recovered from field plants and 66.2 10^6 m^3 from straddle plants that deliver gas outside the province, as shown in **Table 6.2.** It is estimated that 3.1 10^6 m^3 is recoverable from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. At the end of 2011, only four pools were still actively injecting solvent, the largest being the Rainbow Keg River B and Rainbow Keg River F pools.

Table 6.2 Reserves of NGLs as of December 31, 2011 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total NGLs in remaining raw gas	166.8	75.5	38.9	46.5	327.7
Liquids expected to remain in dry marketable gas	58.0	11.3	3.9	0	73.2
Remaining established reserves recoverable from					
Field plants	42.6	37.8	23.4	41.8	145.5
Straddle plants	66.2	26.4	11.7	4.6	109.0
Total	**108.8**	**64.2**	**35.0**	**46.5**	**254.5**

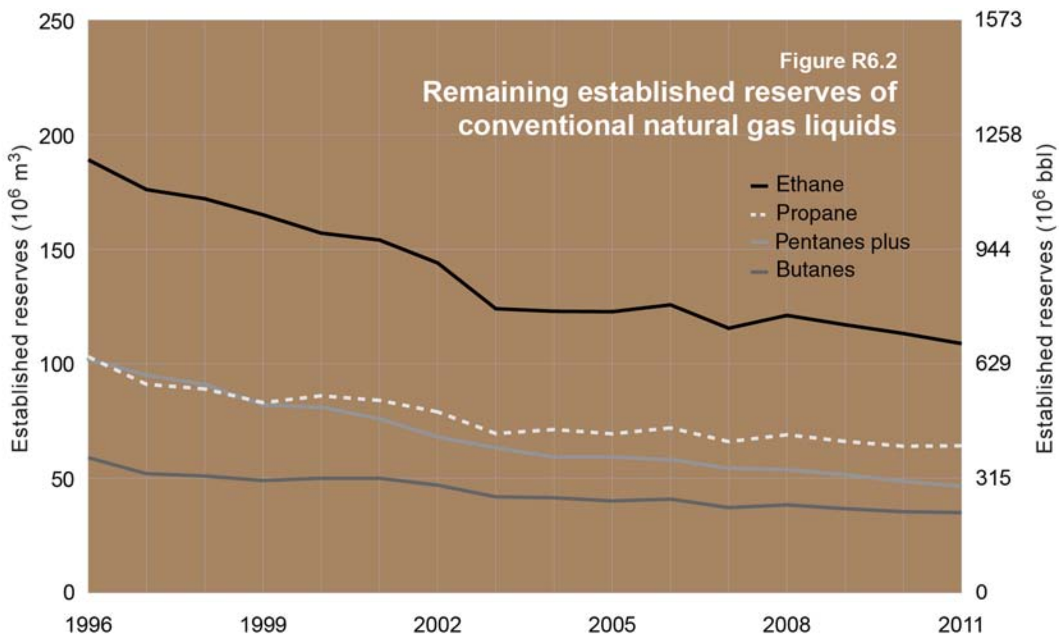


Thirty-five per cent of the total raw ethane, or 58.0 10^6 m^3 (liquid), is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure R6.2** shows the remaining established reserves of ethane declining rapidly from 1996 to 2003, then levelling off thereafter as more ethane is extracted from raw gas. In 2011, the extraction of specification ethane was 12.9 10^6 m^3, compared with 12.5 10^6 m^3 in 2010.

For individual gas pools, the ethane content of gas in Alberta varies considerably, falling within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in **Appendix B**, **Table B.7**, the volume-weighted average ethane content of all remaining raw gas is 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves. Of these fields, the eight largest—Ansell, Elmworth, Kakwa, Pembina, Rainbow, Wapiti, Wild River, and Willesden Green—account for 26 per cent of total ethane reserves but only 15 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2011, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 64.2 10^6 m^3, 35.0 10^6 m^3, and 46.5 10^6 m^3, respectively. The breakdown in the liquids reserves at year-end 2011 is shown in **Table 6.2**. **Table B.8** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The largest of these fields—Ansell, Brazeau River, Elmworth, Kaybob South, Pembina, Rainbow, Wild River, and Willesden Green—account for about 25 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.



6.1.4 Ultimate Potential

The remaining ultimate potential of liquid ethane is determined based on projected market demand and the volumes that could be recovered as liquid from the remaining ultimate potential of natural gas using existing cryogenic technology. The percentage of ethane volumes that have been extracted have been generally increasing over time. In 2011, there was a substantial increase for the second year in a row as the percentage recovered was 68 per cent, up from 63 per cent in 2010 and 56 per cent in 2009. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on a remaining ultimate potential of ethane gas of 117 billion (10^9) m^3, the ERCB estimates the remaining ultimate potential of liquid ethane to be 290 10^6 m^3. The other 30 per cent, or 35 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus combined, the remaining ultimate potential is 330 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas—about 31 per cent.

6.2 Supply of and Demand for Natural Gas Liquids

For the purpose of forecasting ethane and other NGLs, the NGL content, gas plant recovery efficiencies, NGL prices, and gas production volumes from remaining established reserves and future gas reserves additions affect future production. For ethane, demand also plays a major role in future extraction. The NGL content from new gas reserves is expected to be more liquids rich than existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will supplement supplies from conventional gas production and will be needed to meet the forecast ethane demand.

Ethane and other NGLs are recovered mainly from the processing of natural gas. Field gas processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which may require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Removal of other gas contaminants, such as H_2S and CO_2, is also required. The field plants generally recover additional volumes of NGLs—more than what is required to meet pipeline specifications, depending on the plant's extraction capability—to obtain full value for the NGL components. Generally, the heavier hydrocarbon constitutes (butanes and pentanes plus) are removed at field plants. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products.

Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure S6.1** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Figure S6.2 shows the pipeline systems that move ethane and C_2+ mix NGLs from the processing plants to the markets. Gas processing plants capable of extracting C_2+ mix are typically tied to C_2+ mix gathering systems that move liquids to NGL fractionators in Fort Saskatchewan area. Ethane recovered at field processing plants, NGL fractionators, and the straddle plants is shipped on the Alberta Ethane Gathering System to the Alberta ethane market.

6.2.1 Ethane and Other Natural Gas Liquids Production—2011

In Alberta, there are about 520 active gas processing plants that recover NGL mix or specification products, 8 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants. The Harmattan-Elkton gas plant was approved by the ERCB in December 2010 as a co-streaming operation that allows the plant to reprocess marketable gas. It is also a field plant for the processing of raw gas from nearby pools. The approval allows the Harmattan-Elkton plant to divert up to 13.89 10^6 cubic meters per day (m^3/d) to the plant for reprocessing and recovery of ethane and other NGLs. Harmattan-Elkton co-streaming is projected to start in 2012.

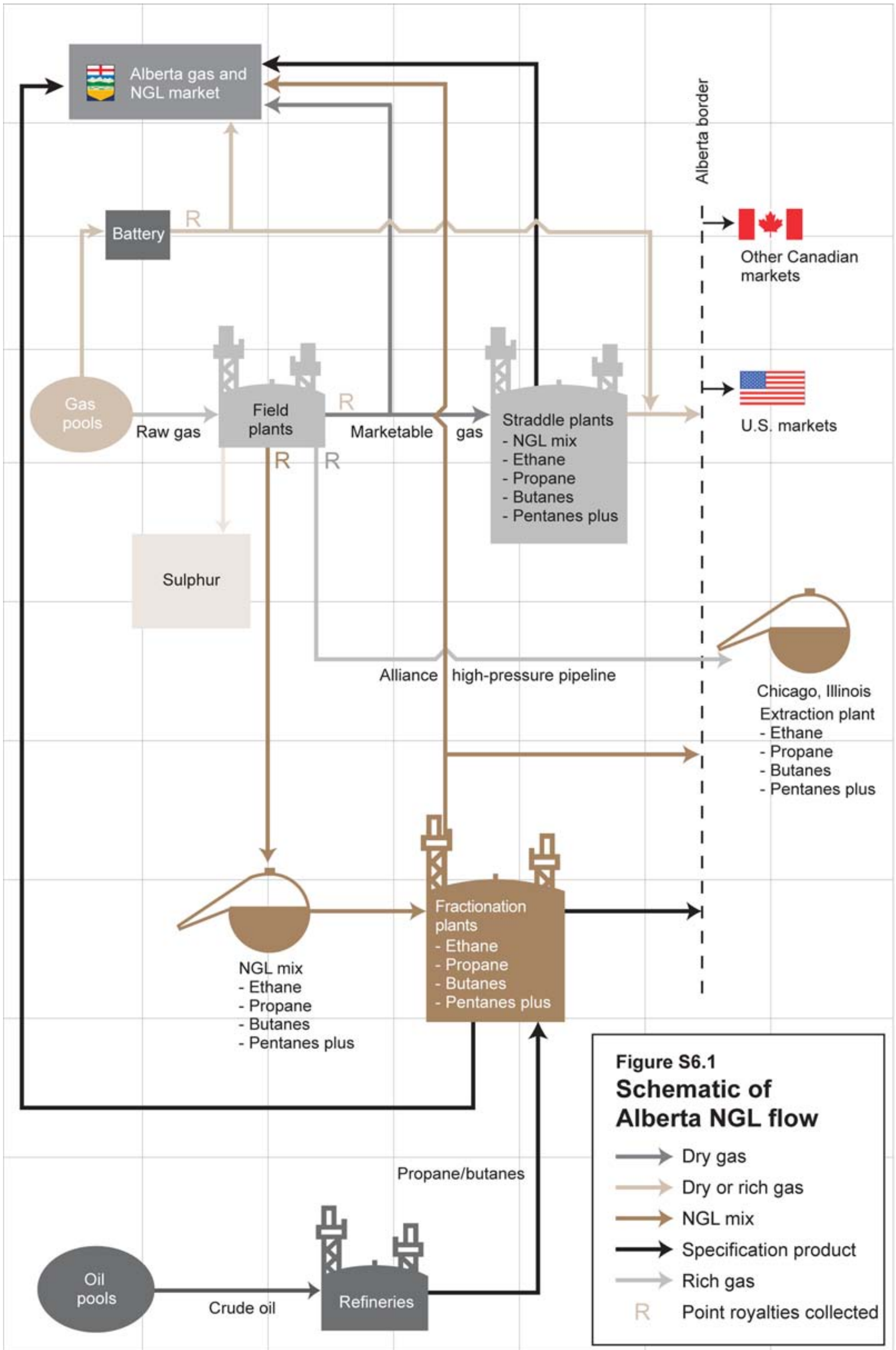
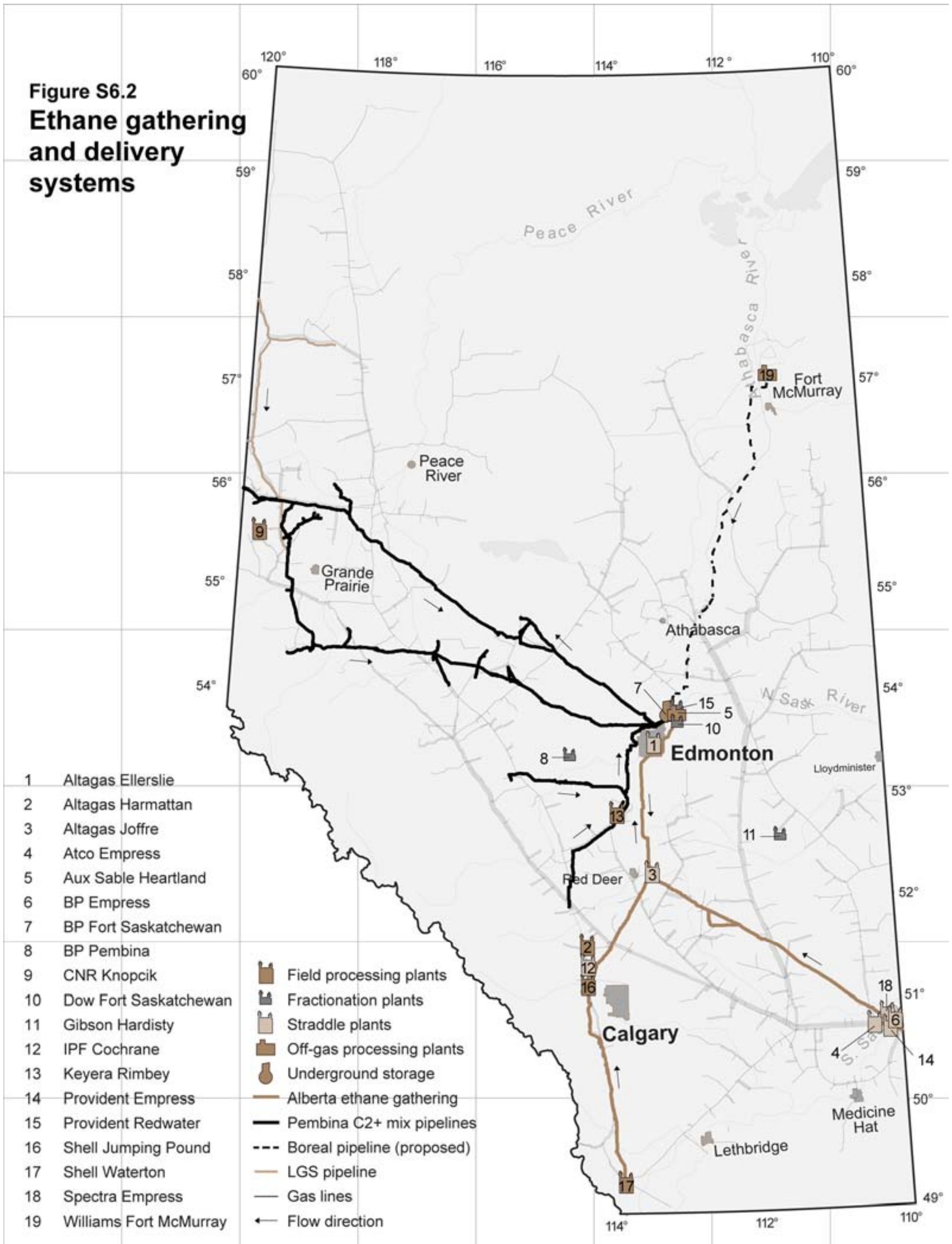


Figure S6.1
Schematic of Alberta NGL flow



Recovery efficiencies of NGL specification products at field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A few field plants are also capable of extracting ethane as a specification product or as an ethane plus mix (C_2+) and are referred to as deep cut facilities.

Ethane recovery at straddle plants varies from 40 to 90 per cent and averages 65 per cent. The average percentages of propane, butanes, and pentanes plus recovered at Alberta straddle plants are 98.5, 99.5, and 99.8, respectively. **Table 6.3** outlines information about the straddle plants operating in Alberta in 2011, including the plant location, operator name, approved natural gas throughput volumes, 2011 natural gas receipts (actual throughput volumes), and the volume of specification ethane recovered in 2011.

Table 6.3 Straddle plants in Alberta, 2011

Area of straddle plant	Location	Operator	2011 gas approved volumes (10^3 m^3/d)	2011 gas receipts (10^3 m^3/d)	2011 ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	46 551	4 379
Empress	04-12-020-01W4M	BP Canada Energy Company	176 750	45 980	6 063
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	46 356	8 013
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 762	1 703
Empress	01-10-020-01W4M	ATCO Midstream Ltd.	31 000	13 748	906
Fort Saskatchewan*	01-03-055-22W4M	ATCO Midstream Ltd.	1 051	816	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	32 273	4 323
Joffre (JEEP)	03-29-038-25W4M	Taylor Management Company Inc.	7 066	307	792
Atim* (Villeneuve)	08-05-054-26W4M	ATCO Midstream Ltd.	1 133	974	0
Total			**400 219**	**195 767**	**26 178**

* These plants are approved to recover a C_2+ mix and not specification ethane.

In 2011, ethane volumes extracted at Alberta processing facilities increased marginally to 35.2 thousand (10^3) m^3/d from 34.2 10^3 m^3/d in 2010. About 68 per cent of total ethane in the gas stream was extracted in 2011, while the remainder was left in the gas stream and sold for its heating value. **Table 6.4** shows the volumes of specification ethane extracted at the three types of processing facilities during 2011.

The C_2+ mix of NGLs shipped from the Younger gas plant in British Columbia to the Redwater fractionation plant for fractionation into specification products are included in Alberta production volumes.

Table 6.4 Ethane extraction volumes at gas plants in Alberta, 2011

Gas plants	Volume (10^3 m^3/d)	Percentage of total
Field plants	2.4	7
Fractionation plants	6.6	19
Straddle plants	26.2	74
Total	**35.2**	**100**

Table 6.5 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2011. Despite weak levels of natural gas drilling and new well connections, Alberta ethane production increased by 2.9 percent in 2011 over 2010. The decline in the production of propane,

butanes, and pentanes plus in Alberta is slowing down as a result of the increased focus by industry on developing liquids-rich gas pools because the prices of these NGLs track the price of crude oil. Propane, butanes, and pentanes plus production declined by 0.5 per cent, 0.3 per cent, and 3.2 per cent, respectively, in 2011 over 2010. This compares to the decline rates in 2010 of 5.6 per cent, 3.1 per cent, and 3.5 per cent, respectively.

Ratios of the liquid production to marketable conventional gas for 2011 and 2021 are shown in **Table 6.5**. In 2011, propane and butane volumes recovered at crude oil refineries were 0.7 10^3 m^3/d and 1.9 10^3 m^3/d, respectively.

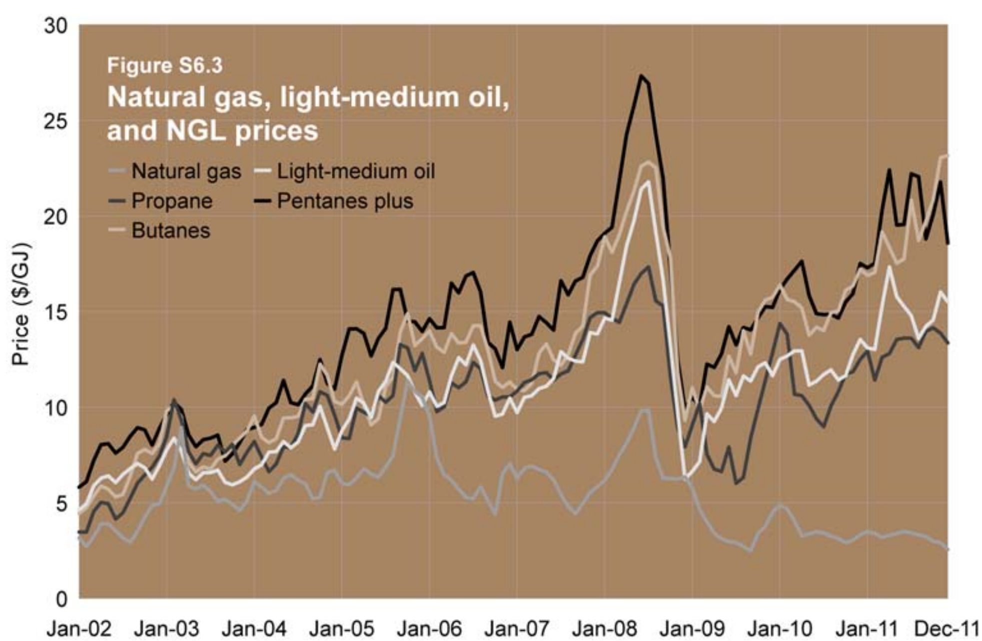
Table 6.5 Liquid production at ethane extraction plants in Alberta, 2011 and 2021[ab]

	2011		2021	
Gas liquid	Daily production (10^3 m^3/d)	Liquid/gas ratio ($m^3/10^6$ m^3)	Daily production (10^3 m^3/d)	Liquid/gas ratio ($m^3/10^6$ m^3)
Ethane	35.2	125	37.9	200
Propane	21.6	77	15.4	81
Butanes	12.0	43	8.9	47
Pentanes plus	19.6	70	14.1	74

[a] Ratios of liquid production are in m^3 liquid per 10^6 m^3 marketable conventional gas production.
[b] Liquid production volumes include small volumes of NGL mix shipped from outside Alberta.

Figure S6.3 shows the historical natural gas and liquids prices in Canadian dollars per gigajoule (GJ). The figure shows that propane, butanes, and pentanes plus prices follow the light/medium crude oil price.

In 2011, gas production from PSAC Area 2 (Foothills Front) held steady, whereas the gas production decreased in all the other PSAC areas. This area has the largest remaining extractable liquids reserves in



the province. Production from PSAC Area 3 (Southern Alberta), known for its dry gas production, experienced a 10 per cent decrease in production. Overall, gas production in the province decreased by 4.6 per cent. The shift by industry to develop pools with gas liquids is expected to continue over the forecast period.

6.2.2 Ethane and Other Natural Gas Liquids—Recent Developments

As conventional gas production declines, less ethane will be available for use by the petrochemical sector. To address the tight supply of ethane in Alberta, the provincial government implemented the Incremental Ethane Extraction Policy (IEEP) in September 2006 and amended and extended the program in March 2011. The program, initially designed to encourage extraction of ethane from natural gas, has been revised to also encourage ethane extraction from off-gases that result from bitumen upgrading or refining. Alberta's petrochemical industry is the largest in Canada and depends on the availability of competitively priced ethane to remain viable. The capture of ethane from oil sands off-gases are part of the additional sources of ethane feedstock. Most off-gas is currently consumed as fuel in oil sands operations.

IEEP is in effect until December 31, 2016. Fractionation credits are provided to petrochemical companies that consume incremental ethane for value-added upgrading, in Alberta, to ethylene and derivatives. The credit value for ethane or ethylene from natural gas remains unchanged at $1.80 per barrel (/bbl). The government program recognizes that off-gas capture from bitumen upgrading or refining, including ethane or ethylene, is considerably more capital intensive than conventional-sourced ethane and, as a result, provides a credit value for off-gas ethane of $5.00/bbl. The credit is owned by the company that consumes the ethane or ethylene and can be sold to either a natural gas or bitumen royalty payer to be applied against its royalty obligation.

Seven IEEP projects have been approved to date, and one project is under review by the provincial government. These eight projects are described in **Table 6.6.**

Table 6.6 IEEP Projects as of December 31, 2011

Feedstock Type	Date Approved	Project Name	Company	Submission Year
Conventional	April 14, 2008	*Empress V Deepcut - IPF/Dow	Dow	2008
Conventional	April 14, 2008	*Rimbey Plant - Keyera/Dow	Dow	2008
Conventional	Sept 14, 2010	**Hidden Lake Streaming - TCPL/NOVA	Nova	2010
Off-Gas	Sept 14, 2010	**Redwater De-ethanizer - Williams/Nova	Nova	2010
Conventional	Under review	Harmattan Co-Stream Project	Nova	2011
Conventional	Dec 7, 2011	Musreau Deep Cut Project	Dow	2011
Conventional	July 26, 2011	Waterton NGL Plant	Shell	2011
Off-Gas	July 26, 2011	Scotford Off-Gas Capture (Refinery)	Shell	2011

Source: Alberta Department of Energy.

Williams Companies Inc. (Williams) currently extracts a C_3+ and olefins mix from a small portion of the off-gas produced at Suncor's upgrading facility in the Fort McMurray area and sends the liquid mix to the Redwater fractionation plant near Edmonton for further processing into products. The off-gas is currently transported to the Williams extraction plant by the Suncor Oil Sands Pipeline. Production from the Williams facility was 1853 m^3/d in 2011, up from 1718 m^3/d in 2010.

Williams received approval in June 2010 to build a new pipeline to transport 6795 m^3/d of off-gas liquids from its extractions facility to its fractionation plant for the removal of ethane and other NGLs and olefins. This 12-inch proposed Williams Boreal Pipeline will provide additional capacity for Suncor liquids as well as for liquids from the other oil sands producers' off-gas. The pipeline is expected to be in service in 2012 and will have the potential to transport up to 19 750 m^3/d with the construction of additional pump stations.

The Aux Sable Heartland off-gas processing plant started operating in September 2011. This processing plant receives off-gas from the Shell Scotford upgrader and refinery and extracts ethane, a C_3+ mix, and hydrogen. The ethane is shipped on the Alberta Ethane Gathering System to meet petrochemical demand. The C_3+ mix and hydrogen is shipped back to Shell's facilities for their refining operations.

Nova Chemicals signed a deal with Hess Corporation to purchase and transport ethane produced at the Tioga gas plant in North Dakota via a new pipeline to Alberta. The Vantage Pipeline, approved by the NEB in January 2012, is expected to start up in the forth quarter of 2012. The pipeline will have the capacity of 6300 m^3/d and is expandable to 9500 m^3/d with the addition of two additional pump stations.

As more producers are focusing on the liquids-rich natural gas plays, midstream companies are either building new liquids extraction facilities or expanding the existing extraction capacities. Altagas Ltd. is building a new deep-cut natural gas processing facility in the Gordondale area. This processing plant will process the Montney liquids-rich gas and recover 477 m^3/d of C_2+ mix.

Pembina Pipeline Corporation (Pembina) has completed the construction of a deep-cut facility at its existing Musreau gas processing facility and a 10 km pipeline connecting Musreau gas plant to its Peace Pipeline. Pembina will also expand its shallow-cut capacity at this site, which will bring the aggregate processing capacity up to 11 603 10^3 m^3/d of natural gas and 2066 m^3/d of C_2+ mix.

Pembina also announced two new projects in October 2011. The Resthaven project is to develop a combined shallow-cut and deep-cut facility at an existing gas processing plant. Pembina expects these facilities to be in service in late 2013, and once operational, the total plant capacity will be 2066 m^3/d with the potential of up to 2861 m^3/d of C_2+ mix.

In response to the anticipated increase in liquids-rich natural gas production, Pembina is currently undertaking a detailed review and assessment of a two-phase expansion of its Peace Pipeline capacity. The plan is to expand the pipeline capacity by total of 8741 m^3/d, or up to 27 018 m^3/d, by the end of 2013.

Keyera Corp. is evaluating the addition of a de-ethanization capacity to accept ethane-rich NGL streams at its Fort Saskatchewan fractionation plant.

6.2.3 Ethane and Other Natural Gas Liquids Production—Forecast

The ERCB expects that the Alberta ethane supply will gradually increase over the next few years. New ethane supplies are expected to come from liquids rich natural gas supplies and from oil sands off-gas. As discussed, gas producers are focusing on the liquids rich gas stream with higher ethane content, and the midstream companies have announced a number of projects to maximize liquids recovery. **Figure S6.4** shows the ethane supply and demand forecast in Alberta.

The ERCB expects that all ethane recovered in Alberta will be used in Alberta. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities; this is expected to continue through the forecast period. Small volumes of ethane may start being imported from the United States at the end of 2012 or in 2013 to supplement domestic supplies.

Figure S6.4 also refers to the potential ethane supply from conventional natural gas and the ethane volumes that could be recovered from oil sands off-gas production. The ethane supply volumes from conventional natural gas are calculated based on the volume-weighted average ethane content of conventional gas in Alberta of 0.052 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is about 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast. Potential ethane supply from oil sands off-gas is calculated assuming an average ethane content of 16.2 per cent in the off-gas production volumes and an 80 per cent recovery rate of ethane. The assumed ethane content increased by 35 per cent based on a recent gas analysis from an oil sands off-gas stream.

The forecast ethane supply from conventional natural gas crosses over the demand curve around 2014. This forecast assumes that incremental ethane volumes required to meet demand will be available from off-gas over the forecast period.

Over the forecast period, the ratios of propane, butanes, and pentanes plus liquid to marketable conventional gas are expected to increase as shown in **Table 6.5**. **Figures S6.4** to **S6.7** show forecast production volumes to 2021 for ethane, propane, butanes, and pentanes plus.

6.2.4 Demand for Ethane and Other Natural Gas Liquids

The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline transports a range of feedstock from Fort Saskatchewan to Joffre. The feedstock supplements the ethane supplies now used at the petrochemical plants at Joffre, where three of the four plants are located. The fourth is in Fort Saskatchewan. The plants in the province that use ethane as a feedstock operated collectively at 75 per cent of their capacity in 2011. The industry adds value to NGLs by upgrading them to be used in the manufacture of products such as plastic, rope, and building materials.

The petrochemical industry in Alberta continues to benefit from the low gas price environment, since the price of ethane, the primary feedstock for ethylene production, is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost advantage compared with a typical propane or naphtha cracking plant in the U.S. Gulf Coast. Prices of propane and other heavier gas liquids are linked to crude oil, which averaged US$95.11/bbl West Texas Intermediate in 2011. Historically, crude oil traded at six to seven times the price of natural gas. Now the difference can be as high as 45 times, an indication that natural gas and ethane are inexpensive as a feedstock to the petrochemical industry.

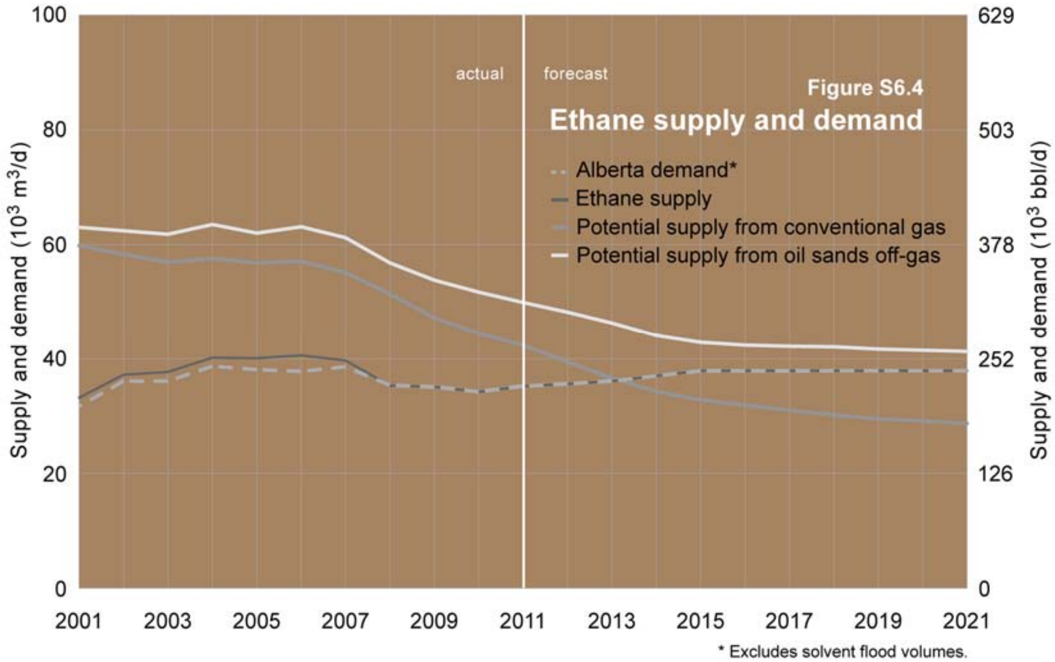
The recent development of liquids-rich shale gas plays in North America is providing opportunities for the petrochemical industry outside of Alberta to change their feedstock slate. Ethylene producers across the continent are shifting their feedstock from propane, butanes, pentanes plus, and naphtha to ethane as more supplies become available. Ethane as feedstock provides a price advantage and yields higher ethylene volumes than other heavier feedstocks.

The ERCB expects that ethane demand by the ethylene producers in the province will increase for the next few years, judging by the continued investment in Alberta infrastructure such as extraction facilities and pipelines, and that the increasing supplies of ethane will meet demand. As shown in **Figure S6.4**, Alberta demand for ethane is projected to increase from the 2011 level of 35.2 to 37.9 10^3 m^3/d in 2015 and remain flat for the remainder of the forecast period.

For the purpose of this forecast, it is assumed that the existing ethylene plants will increase their throughput from 75 per cent to 80 per cent of capacity in 2015, and that no new ethylene plants requiring ethane as feedstock will be built in Alberta over the forecast period.

Historically, small volumes of ethane were exported from the province, primarily for use as a buffer for pipeline ethylene shipments to eastern Canada. Since 2008 and the end of ethylene deliveries to Ontario in the Cochin pipeline, however, there have been no ethane removals from the province, and this is expected to remain the case over the forecast period.

Demand for NGL mix streams in the form of C_2+ mix and C_3+ mix exists in Alberta as solvent for injection into enhanced oil recovery schemes (EOR). Most of the NGL mix solvent is extracted at deep-cut facilities located adjacent to the injection facilities. Historically, small volumes of specification ethane were also delivered from Fort Saskatchewan to be used for injection at EOR schemes. In 2011, the ethane volumes in the solvent used for this purpose were equivalent to 2 per cent of total ethane demand in Alberta. Propane and butanes injected as solvent were equivalent to 17 per cent and 5 per cent of the provincial total demand for the products, respectively. Small volumes of pentanes plus were injected as solvent in 2011. The ERCB expects that the demand for NGL mix volumes for injection will



remain unchanged over the forecast period. The supply and demand figures in this section exclude solvent flood volumes.

Figure S6.5 shows Alberta's demand for propane compared with the total available supply from gas processing and straddle plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Alberta propane demand is forecast to grow moderately by 1.8 per cent throughout the forecast period. As mentioned earlier, small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue throughout the forecast period.

Figure S6.6 shows Alberta demand for butanes compared with the total available supply from gas processing plants. As with propane, the difference between Alberta butane requirements and total supply represents volumes used by markets outside of Alberta. Butanes are used as refinery feedstock as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

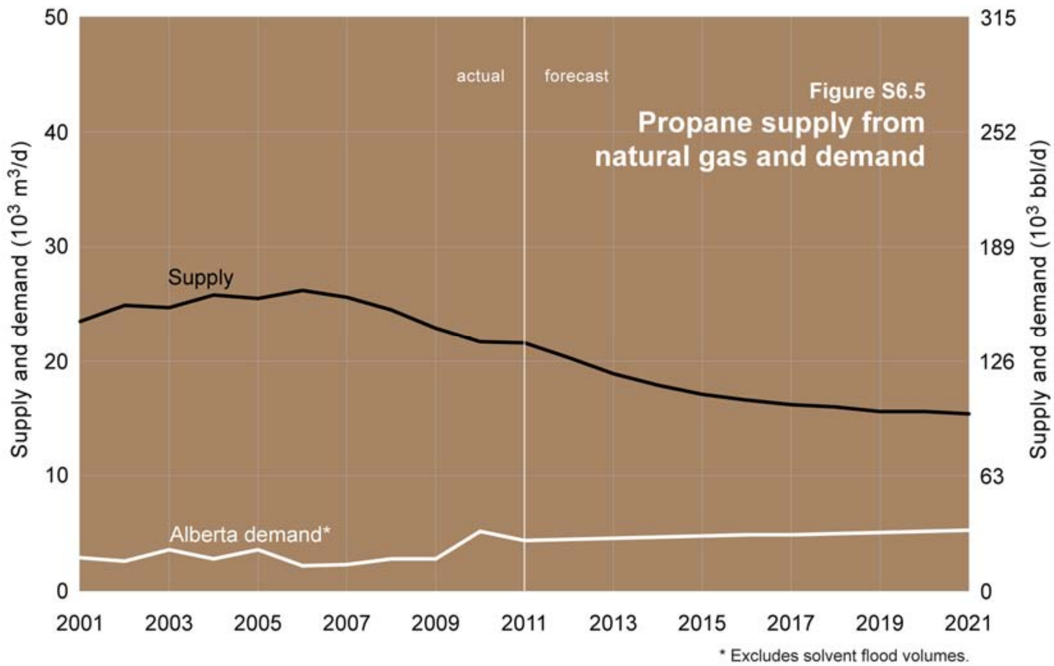


Figure S6.5
Propane supply from natural gas and demand
actual
forecast
Supply
Alberta demand*
Supply and demand (10^3 m^3/d)
Supply and demand (10^3 bbl/d)
0
10
20
30
40
50
0
63
126
189
252
315
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
* Excludes solvent flood volumes.

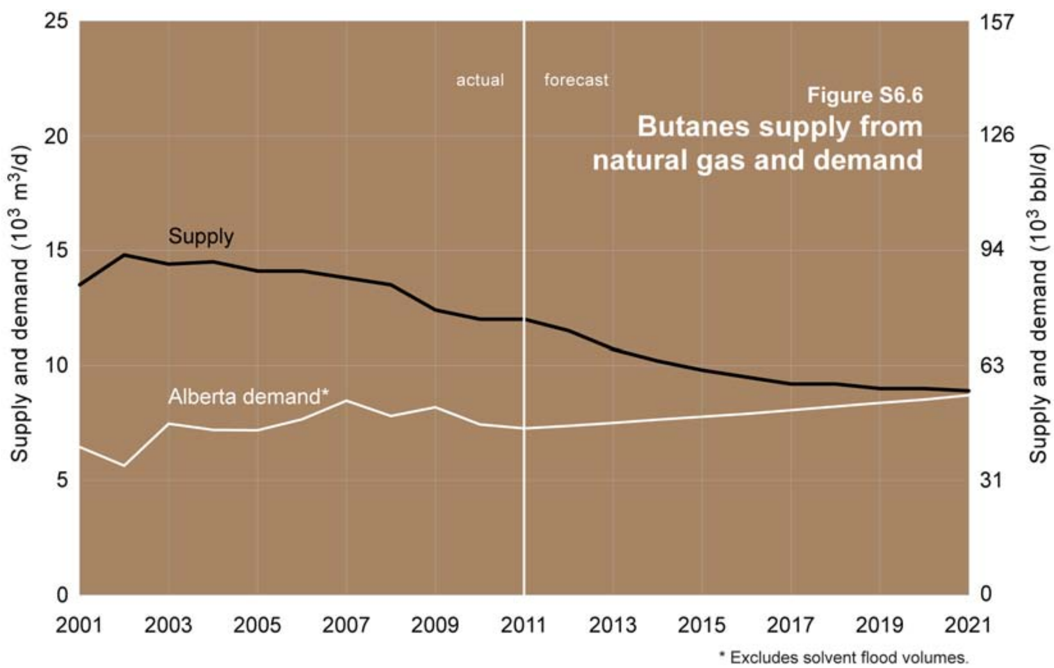


Figure S6.6
Butanes supply from natural gas and demand
actual
forecast
Supply
Alberta demand*
Supply and demand (10^3 m^3/d)
Supply and demand (10^3 bbl/d)
0
5
10
15
20
25
0
31
63
94
126
157
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
* Excludes solvent flood volumes.

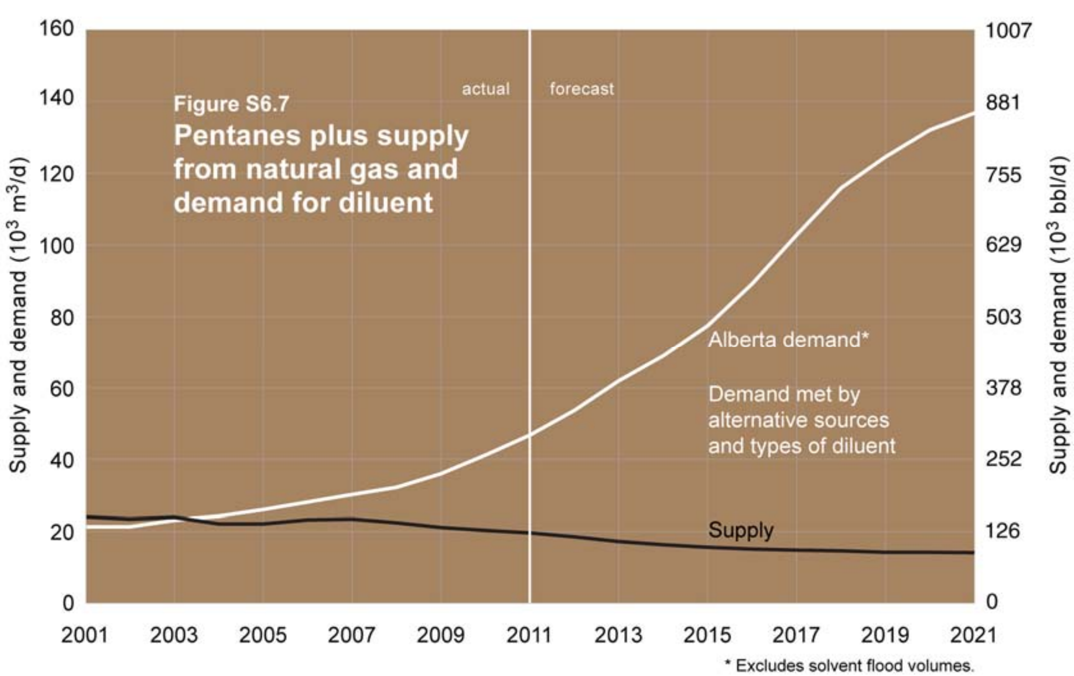
In recent years, butanes have been blended with conventional light/medium crude oil to benefit from the higher price of crude oil. Alberta producers and shippers are also blending butanes with crude oil to reduce the viscosity of the crude oil to minimize the penalties on the pipeline equalization process.

Butanes are also used as diluent (to reduce viscosity) and blended with heavy crude oil and bitumen to facilitate the pipeline transportation of the product to market. In 2011, Alberta demand, excluding solvent flood demand, was 7.2 10^3 m^3/d, down from a revised 7.4 10^3 m^3/d for 2010. The revised 2010 figure is markedly higher than the previous value of 4.6 10^3 m^3/d and is attributed to diluent demand. Alberta demand for butanes over the forecast period is expected to increase to help meet diluent demand as bitumen production increases.

The largest use of Alberta pentanes plus is as diluent in the blending of heavy crude oil and bitumen. **Figure S6.7** shows the ERCB estimate of Alberta demand for pentanes plus used for diluent compared with the total available supply. Pentanes plus are also used as feedstock for the refinery in Lloydminster; these small volumes (0.8 10^3 m^3/d in 2011) are not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production.

Demand for pentanes plus is expected to remain strong due to continued high diluent requirements. As a result, pentanes plus demand as diluent is forecast to increase from 46.8 10^3 m^3/d in 2011 to 136.8 10^3 m^3/d in 2021; this is significantly higher than last year's forecast and reflects the higher bitumen production forecast.

As illustrated in **Figure S6.7**, the diluent demand is estimated to have exceeded Alberta supply around 2004. The current estimated demand reflects the inadequate Alberta supply of pentanes plus since 2004,



which has resulted in the use and assessment of alternative sources (imports) and types of diluent. Alberta currently imports offshore condensate by rail from Kitimat, B.C.

Alberta imports of pentanes plus are expected to increase over the next 10 years with growing oil sands demand. The following list outlines current and future sources of diluent from outside Alberta that will be needed to facilitate transportation of nonupgraded bitumen to markets.

- In 2011, Alberta pentanes plus supply was augmented by 6.8 10^3 m^3/d of pentanes plus from outside of Alberta.
- Enbridge Inc.'s Southern Lights Pipeline transports diluent from Chicago to Edmonton with a capacity to deliver 28.6 10^3 m^3/d.
- Enbridge is proposing to build a condensate pipeline capable of initially transporting 23.8 10^3 m^3/d of offshore condensate from Kitimat to Edmonton.
- Kinder Morgan Energy Partners, L.P., is proposing to reverse the western leg of Cochin Pipeline to supply condensate from Kankakee County, Illinois, to Fort Saskatchewan, with a capacity of 11.9 10^3 m^3/d.

HIGHLIGHTS

Remaining established sulphur reserves decreased 1.9 per cent because of a decrease in remaining natural gas and crude bitumen reserves.

Sulphur production from gas processing declined 8 per cent from 2010 to 2011 to 2.9 million tonnes, while sulphur production from crude bitumen increased marginally.

Total sulphur production fell from 5.0 million tonnes in 2010 to 4.7 million tonnes in 2011.

7 // SULPHUR

Sulphur is a chemical element found in conventional natural gas, crude bitumen, and crude oil. The sulphur is extracted and sold primarily for use in making fertilizer. Currently, most produced sulphur is derived from the hydrogen sulphide (H_2S) contained in about 20 per cent of the remaining established reserves of conventional natural gas.

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2011, to be 173.1 million tonnes (10^6 t), down 1.9 per cent from 2010. **Table 7.1** shows the changes in sulphur reserves over the past year. The ERCB does not estimate sulphur reserves from sour crude oil, as only a very small portion of Alberta's sour crude oil is refined in the province.

Table 7.1 Reserve and production change highlights (10^6 tonnes)

	2011	2010	Change[a]
Initial established reserves from			
Natural gas	270.5	269.1	+1.4
Crude bitumen[b]	178.5	178.5	0.0
Total	**449.0**	**447.6**	**+1.4**
Cumulative production from			
Natural gas	249.6	246.6	+3.0
Crude bitumen	26.3	24.5	+1.8
Total	**275.9**	**271.1**	**+4.8**
Remaining established reserves from			
Natural gas	20.9	22.5	-1.6
Crude bitumen[b]	152.2	154.0	-1.8
Total	**173.1**	**176.5**	**-3.4**
Annual production	4.8	5.0	-0.2

[a] Any discrepancies are due to rounding.
[b] Reserves of elemental sulphur from bitumen mines under active development as of December 31, 2011. Reserves from the entire surface mineable area are larger.

7.1.2 Sulphur from Natural Gas

The ERCB estimates that there are 20.9 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2011, a decrease of 7 per cent from 2010. Remaining established sulphur reserves have been calculated using a provincial recovery factor of 97 per cent, which was determined taking into account plant efficiency, acid-gas flaring at plants, acid-gas injection, and solution-gas flaring.

The ERCB's sulphur reserve estimates from natural gas are shown in **Table 7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2011 are Caroline, Crossfield East, and Waterton. Together, these account for 4.9 10^6 t, or 23 per cent, of the remaining established reserves of sulphur from natural gas.

The ERCB estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from ultrahigh H_2S pools currently not on production. Based on initial established reserves of 270.5 10^6 t, this leaves 124.3 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current bitumen upgrading operations, an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in by-products of upgrading bitumen, such as coke.

It is currently estimated that 216.3 10^6 t of sulphur will be recoverable from the 5.34 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by using a factor of 40.5 tonnes of sulphur per 10^3 m^3 of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology recovers more sulphur than does alternative carbon-rejection technology. With the latter technology, more of the sulphur in the bitumen remains in upgrading residues and less is converted to H_2S.

If less of the mineable crude bitumen reserves are upgraded with the hydrogen-addition technology than is currently estimated, or if less of the mineable reserves are upgraded in Alberta, the total sulphur reserves will be less.

In 2011, the Nexen/OPTI Long Lake Upgrader continued its operations of upgrading in situ bitumen, resulting in the production of small quantities of sulphur, most of which was not marketed. The ERCB will include in situ upgrading projects in future reports as they come on-stream. At the same time, however, those mining projects that do not upgrade bitumen will have their sulphur reserves removed from the provincial total.

Table 7.2 Remaining established reserves of sulphur from natural gas as of December 31, 2011[a]

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[b] (%)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Bighorn	3 562	6.7	290	394
Blackstone	1 256	10.3	170	231
Brazeau River	8 174	4.0	391	530
Burnt Timber	1 257	17.9	329	446
Caroline	5 906	13.2	1 059	1 436
Coleman	801	26.6	318	431
Crossfield	2 703	16.3	660	895
Crossfield East	2 124	28.8	1 070	1 451
Elmworth	22 746	1.5	371	503
Garrington	3 657	3.6	158	214
Hanlan	6 789	8.8	791	1 073
Jumping Pound West	3 808	6.5	307	417
La Glace	3 014	6.9	243	329
Limestone	2 872	12.4	487	660
Lone Pine Creek	1 978	7.3	176	239
Marsh	1 141	13.3	196	266
Moose	3 015	12.7	496	672
Okotoks	796	25.3	322	437
Panther River	2 872	5.2	182	247
Pembina	22 182	0.9	284	385
Pine Creek	8 720	3.6	356	483
Quirk Creek	1 283	9.4	162	219
Rainbow	9 605	2.0	255	346
Rainbow South	2 849	6.1	253	344
Ricinus	4 310	3.5	179	243
Ricinus West	1 306	32.4	732	993
Waterton	4 289	21.8	1 470	1 994
Wimborne	1 832	8.4	183	248
Windfall	1 830	12.1	308	418
Subtotal	**139 196**	**9.0**	**12 534**	**16 997**
All other fields	805 862	0.3	2 826	3 849
Total	**945 058**	**1.4**	**15 359**	**20 846**

[a] Any discrepancies are due to rounding.
[b] Volume-weighted average.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only some of the production from established surface-mineable crude bitumen reserves will be upgraded by the Suncor, Syncrude, Shell Muskeg River, Shell Jackpine, CNRL Horizon, Suncor/Total/Teck Fort Hills, and Imperial Kearl projects. The ERCB's estimate of the initial established sulphur reserves from these active projects is 178.5 10^6 t, representing 82 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. A total of 26.3 10^6 t of sulphur has been produced from these projects, leaving 152.2 10^6 t of remaining established reserves, a decrease of 1.2 per cent due to production. During 2011, 1.8 10^6 t of sulphur were produced from the currently producing projects.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Production—2011

There are three sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading, and crude oil refinement into petroleum products. In 2011, Alberta produced 4.73 10^6 t of sulphur, of which 2.95 10^6 t were derived from sour gas, 1.77 10^6 t from upgrading of bitumen, and just 11 thousand (10^3) t from oil refining. The total sulphur production in 2011 represents a decrease of 4.6 per cent from 2010 levels due to a decline in natural gas production. Most of Canada's sulphur is produced in Alberta.

7.2.1.1 Sulphur Production from Natural Gas

Figure S7.1 shows historical sulphur production from gas processing plants. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional sour gas production declines, less sulphur will be recovered from gas processing plants. This trend is evident in the steep decline in sulphur production from gas processing plants since 2000, as shown in **Figure S7.1**.

Table 7.3 shows the changes in sulphur production from major gas processing plants over the past year. Production at the Shell Caroline plant was down significantly as a result of extended downtime. In early 2010, declining gas reserves led to the planned closure of the Nexen Balzac gas plant. The plant and sour gas wells tied in to the facility were shut down at the end of April 2011.

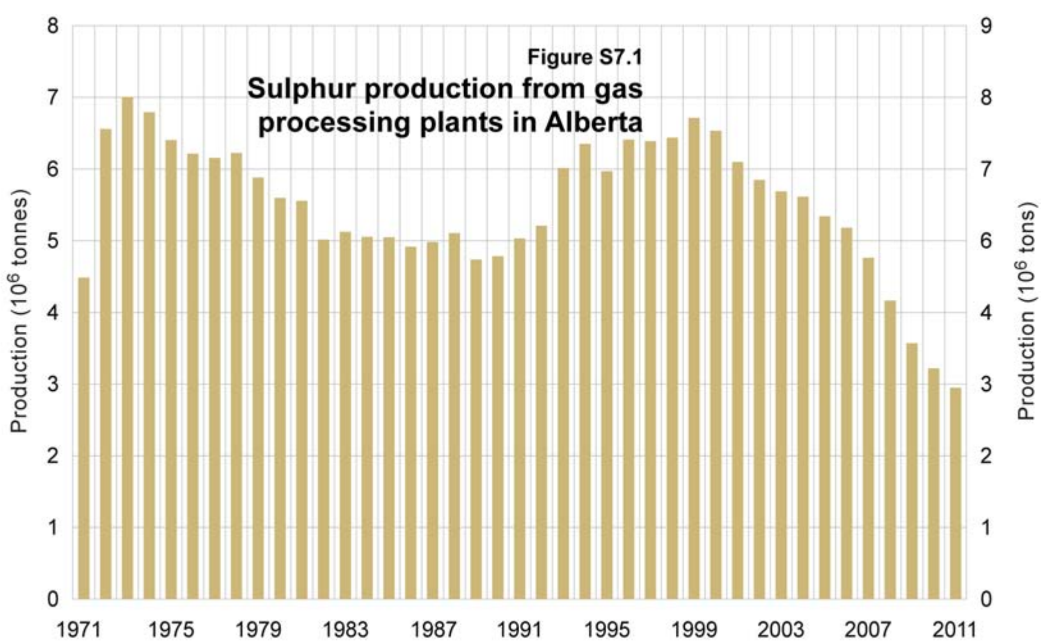


Table 7.3 Sulphur production from gas processing plants (10^3 tonnes)

Major Plants	2011	2010	Change	Per Cent Change
Shell Caroline	583	685	-102	-15%
Shell Waterton	416	374	42	11%
Husky Strachan	303	256	47	18%
Shell Jumping Pound	180	205	-25	-12%
Semcams Kaybob South	153	202	-49	-24%
Keyera Strachan	185	182	2	1%
Suncor Hanlan	138	153	-14	-10%
Shell Burnt Timber	138	124	14	11%
Nexen Balzac	25	85	-60	-71
Total	**2121**	**2266**	**-145**	**-6%**

Sulphur stockpiles stored as solid blocks at gas processing plants have been drawn down significantly in recent years as the result of an increase in global sulphur demand. **Figure 15** in the Overview section illustrates historical sulphur closing inventories at gas processing plants and oil sands operations, as well as sulphur prices. Inventory blocks of sulphur at gas processing plants in Alberta were 1.88 10^6 t at year-end 2011, down from 2.47 10^6 t at year-end 2010.

7.2.1.2 Sulphur Production from Bitumen Upgrading

Historical sulphur production from the five oil sands upgrader operations is shown in **Figure S7.2**. Total production in 2011 was 1.77 10^6 t, up 3 per cent from 2010 production of 1.72 10^6 t. Production increases at Shell Scotford and Suncor offset decreases at CNRL Horizon that were due to the suspension of production as a result of a fire in 2011.

7.2.2 Sulphur Production—Forecast

Total Alberta sulphur production from sour gas, crude oil, and bitumen upgrading and refining is depicted in **Figure S7.3**. Sulphur production from sour gas is expected to decrease from 2.95 10^6 t to 2.01 10^6 t—about 32 per cent—by the end of the forecast period; however, sulphur recovery from bitumen upgrading and refining is expected to increase from 1.78 10^6 t to 2.77 10^6 t (about 56 per cent). The large increase in sulphur from bitumen upgrading in 2012 reflects resumption of operations at CNRL following the fire in 2011 and the expected increase in production from Shell's Scotford upgrader expansion as it continues to ramp up. The sulphur production forecast assumes that Suncor, Syncrude, and CNRL are able to return to upgraded bitumen production targets following disruptions at their respective facilities in early 2012.

Sulphur recovery from Alberta refineries is forecast to increase from 11 10^3 t in 2011 to 17 10^3 t by 2021. The forecast is based on the assumption that Alberta refineries will continue to recover volumes of sulphur similar to what they have recovered historically.

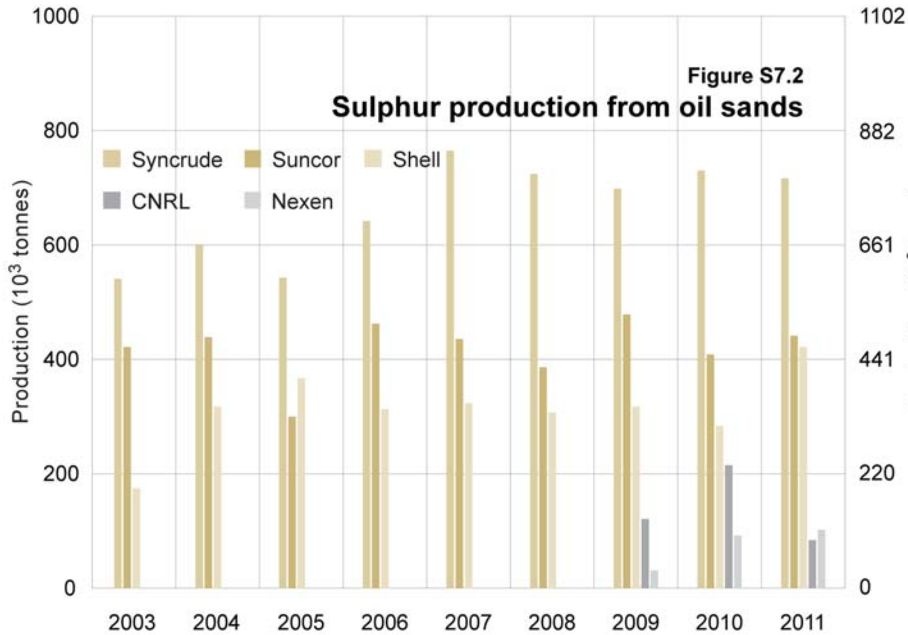


Figure S7.2
Sulphur production from oil sands
Syncrude
Suncor
Shell
CNRL
Nexen
Production (10^3 tonnes)
Production (10^3 tons)
1000
800
600
400
200
0
1102
882
661
441
220
0
2003
2004
2005
2006
2007
2008
2009
2010
2011

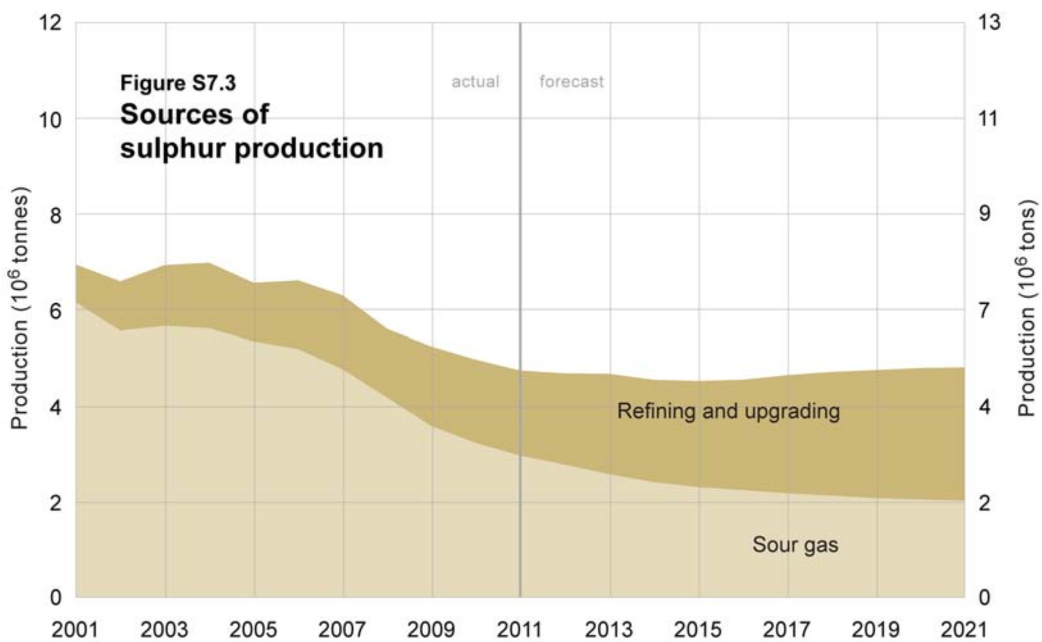


Figure S7.3
Sources of sulphur production
actual
forecast
Refining and upgrading
Sour gas
Production (10^6 tonnes)
Production (10^6 tons)
12
10
8
6
4
2
0
13
11
9
7
4
2
0
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021

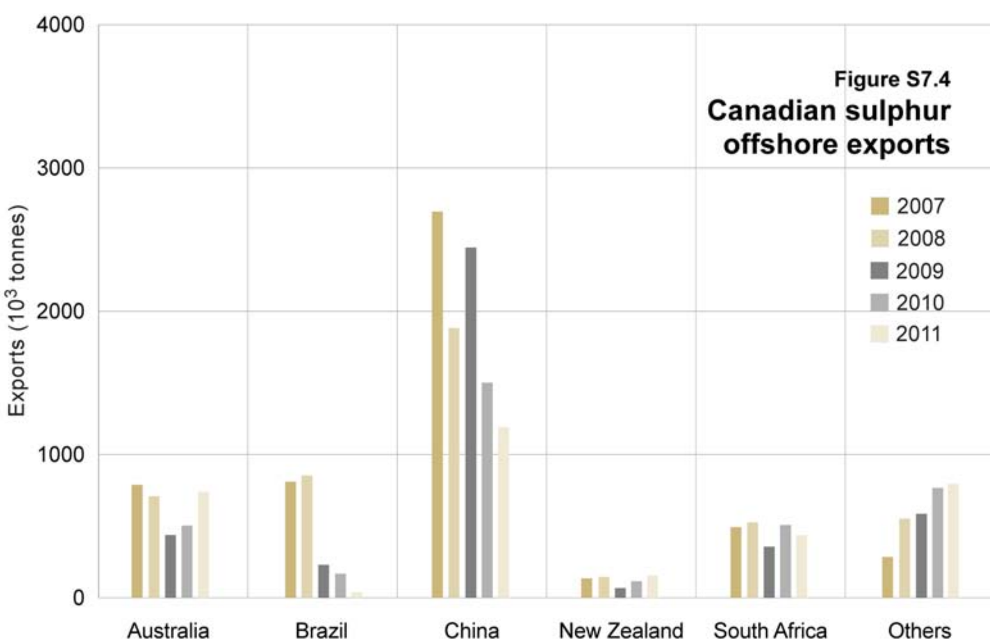
7.2.3 Sulphur Demand

Disposition of sulphur within Alberta in 2011 was 2 063 10^3 t, up from 584 10^3 t in 2010. The volume in 2011 may include Alberta plant-to-plant transfers that could cause disposition of sulphur in the province to be higher than actual volumes consumed; therefore, forecast volumes are kept constant at 2010 levels.

Sulphur is used in the production of phosphate fertilizer and kraft pulp and in other chemical operations. About 60 per cent of the sulphur marketed by Alberta producers in 2011 was shipped outside the province, compared to about 89 percent in 2010. Exports offshore and to the United States represented 48 and 14 per cent of the total sulphur deliveries, respectively, with the remainder being delivered to the rest of Canada. Exports out of Vancouver, B.C., in 2011 declined when compared to the levels in 2010. Sulphur output from the Shell Caroline gas plant and associated sulphur facilities was disrupted from late 2010 until April 2011 as a result of a series of mechanical problems. Thirty-one per cent of offshore export activities were from Shell. The increase in prices for sulphur in offshore markets also helped curtail demand. In 2011, sulphur prices averaged at US$214 per tonne, an increase of 131 per cent over last year's prices of US$92.50 per tonne. **Figure S7.4** shows the historical Canadian export volumes sent to markets outside of North America.

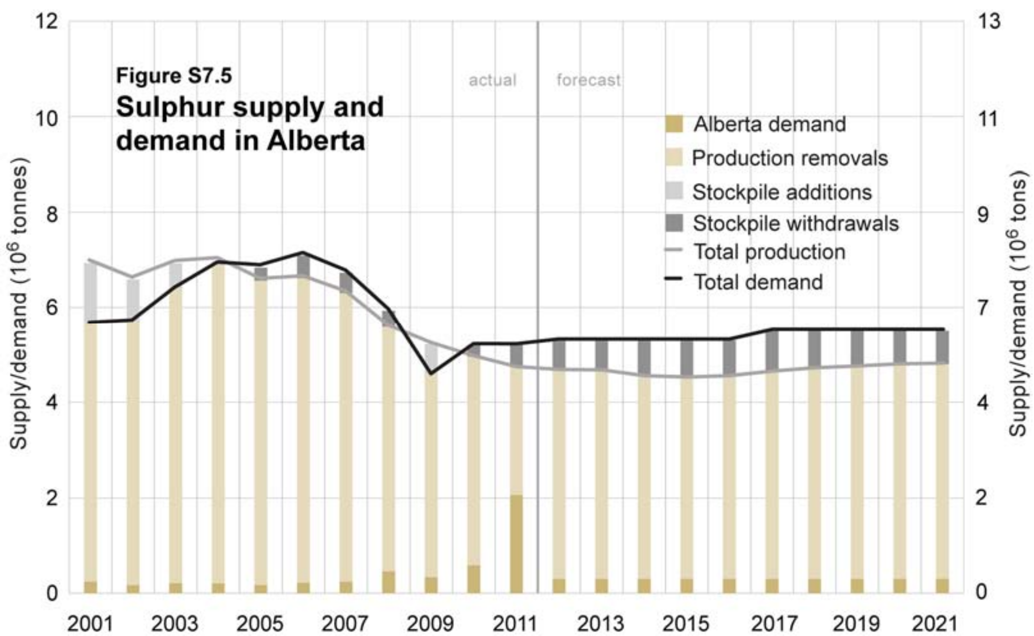
China is the world's largest importer of sulphur, which is used primarily for making sulphuric acid to produce phosphate fertilizer. China imported 9.53 10^6 tonnes of sulphur in 2011, with Canada accounting for 12.5 per cent of imports. Canada is the second-largest supplier of sulphur to China (Saudi Arabia being the largest).

Because sulphur is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds



supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles. **Figure S7.5** shows the historical and forecast total supply and demand of sulphur, including inventory additions and withdrawals.

In the early part of the previous decade, weak global sulphur demand resulted in less demand for Alberta exports, and as a result, Alberta built a significant stockpile of sulphur. Since 2004, supply and demand have generally been in balance, with small withdrawals from inventory stockpiles. The forecast assumes that, on average, this situation will continue as declining production from natural gas processing plants is replaced by increasing sulphur recovery from the bitumen upgrading industry. The forecast also assumes that demand will remain approximately constant in the first half of the forecast period and rise slightly in the second half.



HIGHLIGHTS

Remaining established reserves under active development decreased slightly in 2011 due to production but still represent decades of supply.

Overall coal production was 5 per cent lower in 2011. While thermal bituminous coal production remained flat, metallurgical bituminous coal and subbituminous coal decreased 11 per cent and 6 per cent, respectively, mainly as a result of weaker demand.

8 // COAL

Coal is a combustible sedimentary rock with greater than 50 per cent organic matter. Coal occurs in many formations across central and southern Alberta, with lower-energy-content coals in the plains region, shifting to higher-energy-content coals in the foothills and mountain regions.

Production of coal from mines is called raw coal. Some coal, particularly that from the mountain and foothills regions of Alberta, needs to be processed prior to marketing; this processed coal is referred to as clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are termed marketable coal. In this report, "reserves" refers to raw coal unless otherwise noted.

The possible commercial production of synthetic gas from coal (synthetic coal gas) in Alberta is still being investigated, and new legislation is in place for regulating in situ coal gasification (ISCG) development. A discussion of ISCG is found in **Section 8.1.2.3**.

The following coal reserves and production information summarizes and marginally updates the material found in the ERCB serial publication *ST31: Reserves of Coal, Province of Alberta* (2000 edition). See that publication for more detailed information and a greater understanding of the parameters and procedures used to calculate established coal reserves.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2011, to be 33.3 gigatonnes[1] (Gt) (36.7 billion tons). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods and 10.5 Gt is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2011. **Table 8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

---

[1] Giga = 10^9.

Minor changes in remaining established reserves from December 31, 2010, to December 31, 2011, resulted from additions to cumulative production. During 2011, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.005 Gt, 0.009 Gt, and 0.023 Gt respectively.

Table 8.1 Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2011[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.245	0.566
Underground	5.06	0.738	0.111	0.627
Subtotal	**6.83[c]**	**1.56[c]**	**0.356**	**1.20[c]**
High-volatile bituminous				
Surface	2.56	1.89	0.195	1.695
Underground	3.30	0.962	0.047	0.915
Subtotal	**5.90[c]**	**2.88[c]**	**0.242**	**2.64[c]**
Subbituminous[d]				
Surface	13.6	8.99	0.826	8.16
Underground	67.0	21.2	0.068	21.1
Subtotal	**80.7[c]**	**30.3[c]**	**0.894**	**29.4**
Total	**93.7[c]**	**34.8[c]**	**1.49[e]**	**33.3[c]**

[a] Tonnages have been rounded to three significant figures.
[b] Includes minor amounts of semi-anthracite.
[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.
[d] Includes minor lignite.
[e] Any discrepancies are due to rounding.

8.1.2 In-Place Resources

There was no change to the in-place resource estimate over the previous year.

8.1.2.1 Geology and Coal Occurrence

Coal occurs extensively in Alberta through the non-marine units of the sequence of Jurassic- to Paleocene-aged formations. The coal-bearing formations underlie about 300 000 square kilometres—almost half of Alberta. **Figure R8.1** shows the subcrops of most of the coal-bearing formations, and their equivalents, in Alberta.

Coal, with or without thin clastic layers called partings, occurs in vertical accumulations called seams. Coal maturity, or rank, is measured on the basis of calorific value for lower-ranked coals and carbon content for higher-ranked coals. Coals of all rank groups, from lignite to semi-anthracite, occur in Alberta.

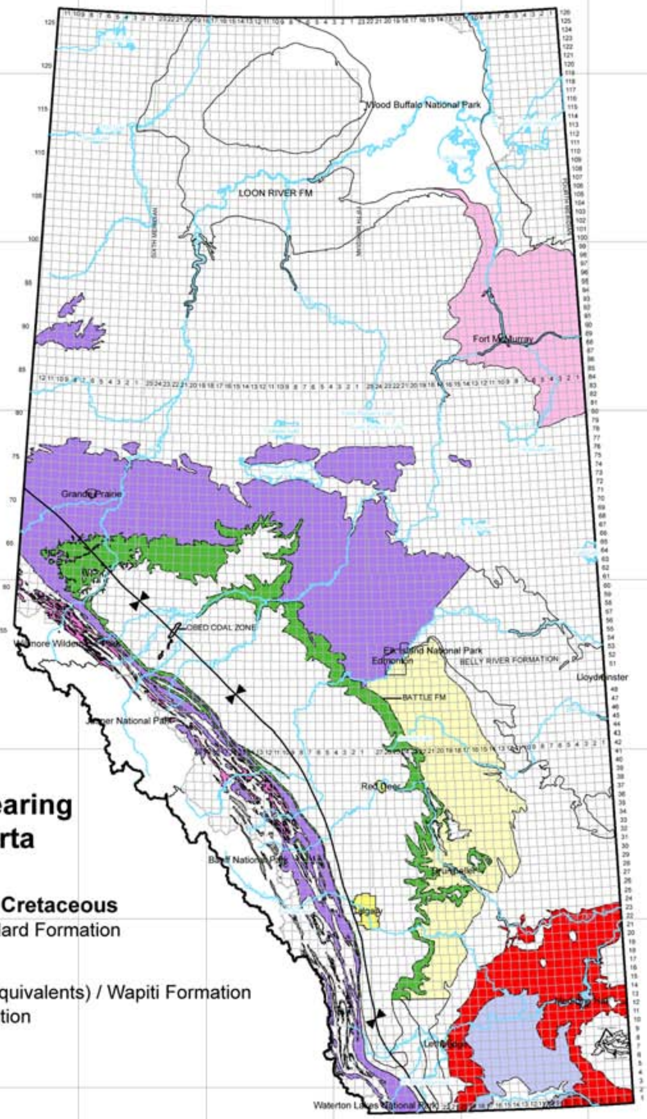


Figure R8.1
Significant coal-bearing formations in Alberta

Paleocene and Upper Cretaceous
- Coalspur Formation / Scollard Formation

Upper Cretaceous
- Brazeau Formation (and equivalents) / Wapiti Formation
- Horseshoe Canyon Formation
- Oldman Formation
- Foremost Formation

Lower Cretaceous
- Luscar Group
- Mannville Group

Lower Cretaceous and Upper Jurassic
- Kootenay Group

The ERCB has subdivided Alberta’s coal-bearing regions into three designated regions (broadly shown in **Figure S8.1** in **Section 8.2.1**) based on rank, geology, and topography, so as to group coals by method of recovery and market. The mountain region exhibits complex geologic structures and steep topography with higher-ranked coal amenable to export for metallurgical purposes. The foothills region exhibits moderately complex structures and hilly topography with moderate-ranked coals amenable to export for thermal purposes. The plains region is the largest and exhibits generally flat lying seams and flat or incised plateau topography with lower-ranked coals amenable for domestic thermal purposes. The plains region contains about 88 per cent of Alberta’s coal, most of which is of subbituminous rank.

Figure R8.2 shows periods of exploration for coal in Alberta. The figure shows that recent coal exploration has been predominately within areas defined by ERCB mine permits. While very significant coal resources were identified from holes drilled in the 1970s and 1980s, very few areas, other than currently producing areas, have seen follow-up drilling.

8.1.2.2 Coal Mineability

In general, shallow coal is mined more economically by surface than by underground methods and is classified as surface mineable. At some stage of increasing depth and strip ratio,[2] the economic advantage passes to underground mining; this coal is considered underground mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio and is designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

These classifications are used to categorize total coal in place. Further analysis is done to determine which portions of this coal may be developed and which portion of that coal may be recovered. Some in-place coal, such as underground thin seams, is unlikely to be developed by mining methods but is included in the total because of past production. Additionally, some of the coal currently classified as underground may become the target of commercial ISCG development. At such time, the ERCB will split the underground classification into mineable and in situ components.

8.1.2.3 In Situ Coal Gasification

There are three types of coal gasification processes: ISCG, surface-facility gasification from mined coal, and biological modification of in situ coal seams, referred to as biogenic gas. Surface-facility gasification processes conventionally mined coal, and those mineable coal reserves would be included in the tables above. Currently, however, surface-gasification facilities do not exist in Alberta. Biogenic gasification is not included in this report since it is highly speculative at this time.

---

[2] Strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

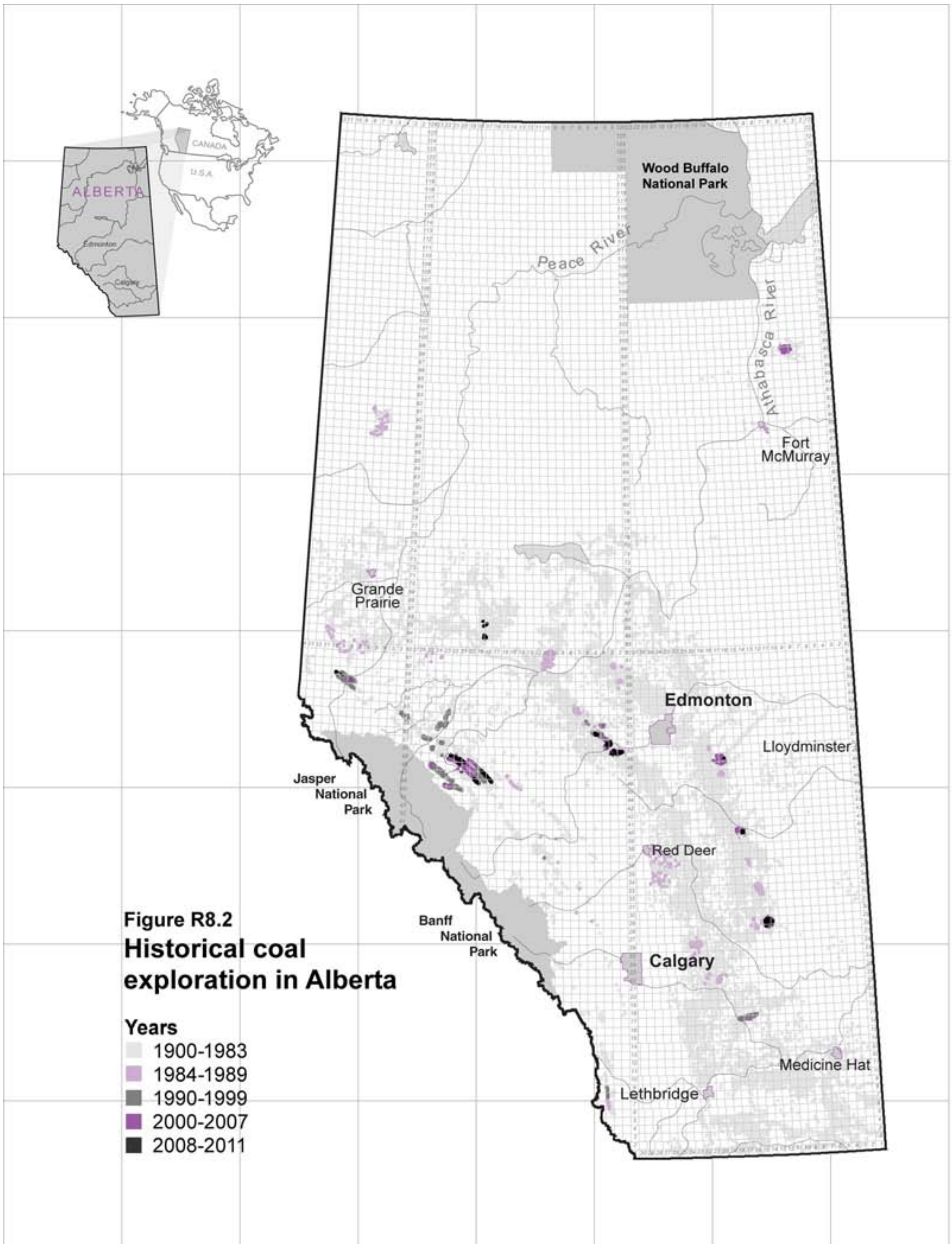


Figure R8.2
Historical coal exploration in Alberta

New developments in coal-extraction technology are occurring in Alberta; two ISCG pilot projects have been approved, one of which was partially operational in 2010 and 2011. The second pilot had not commenced test operations before the end of 2011. ISCG technology uses wellbores to access coal seams at depth. Future development may take place at depths below those currently assumed to be mineable.

ISCG consists of thermal reduction of coal to simpler hydrocarbons that can be produced up a wellbore. Any ISCG-derived gas would, by its nature, incorporate any coalbed methane gas volumes (see **Section 5**) contained within the targeted coals. Currently, ISCG synthetic coal gas is limited to a small quantity, and therefore, neither synthetic coal gas volumes nor their associated coal resource tonnages are yet included in this report. However, Alberta's vast quantities of coal would supply a large resource base should development prove commercial, and the ERCB anticipates detailing such volumes and tonnage in future reports.

8.1.3 Established Reserves

Several techniques, in particular geostatistical methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground-mineable coal. Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reasons, and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal and the thicker underground classes of coal seams.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that, in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region, 70 per cent in the foothills, and 90 per cent in the plains—the three regions designated by the ERCB within Alberta where coals of similar quality and mineability are recovered.

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 metres [m]) and thick (>3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Table 8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2011. During 2011 a new operator acquired a portion of the inactive McLeod River mine permit and announced plans to move the project into production. That mine project will be included in **Table 8.2** once production or significant construction starts.

Table 8.2 Established resources and reserves of raw coal under active development as of December 31, 2011

Rank **Mine**	**Permit area (ha)**[a]	**Initial in-place resources (Mt)**[b]	**Initial reserves (Mt)**	**Cumulative production (Mt)**	**Remaining reserves (Mt)**
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	25	129
Grande Cache	4 250	199	85	32	53
Subtotal	**11 705**	**445**	**239**	**57**	**182**
High-volatile bituminous					
Coal Valley	17 865	572	331	152	179
Obed	7 590	162	137	45	92
Subtotal	**25 455**	**734**	**468**	**197**	**271**
Subbituminous					
Paintearth and Vesta	5 120	163	121	99	22
Sheerness	7 000	196	150	88	62
Dodds	425	2	2	1.4	0.6
Burtonsville Island	150	0.5	0.5	0.2	0.3
Highvale	12 140	1 021	764	399	365
Genesee	7 320	250	176	85	91
Subtotal[c]	**32 155**	**1 633**	**1 214**	**673**	**541**
Total	**69 315**	**2 812**	**1 921**	**927**	**994**

[a] ha = hectares.
[b] Mt = megatonnes; mega = 10^6.
[c] Any discrepancies are due to rounding.

8.1.4 Ultimate Potential

A large degree of uncertainty is associated with estimating an ultimate potential, and new data could substantially alter results. Two methods have been used to estimate the ultimate potential of coal: volume and trend analysis. The volume method gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the trend analysis method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

To avoid large fluctuations in ultimate potentials from year to year, the ERCB has adopted the policy of using the figures published in the 2000 edition of *ST31* and adjusting them slightly to reflect the most recent trends. **Table 8.3** gives quantities by rank for surface- and underground-mineable ultimate in-place resources as well as the ultimate potential. No change to ultimate potential has been made for 2011. While little new coal exploration is occurring outside producing areas (see **Figure R8.2**), data from CBM- and ISCG-licensed wells may help to reduce the amount of uncertainty. It is anticipated that further resource development for both CBM and ISCG will occur primarily in the "subbituminous underground" category in **Table 8.3**, the category with the largest tonnage.

Table 8.3 Ultimate in-place resources and ultimate potentials[a] (Gt)

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	**21**	**3.2**
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	**500**	**160**
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	**1 500**	**470**
Total	**2 000**[b]	**620**

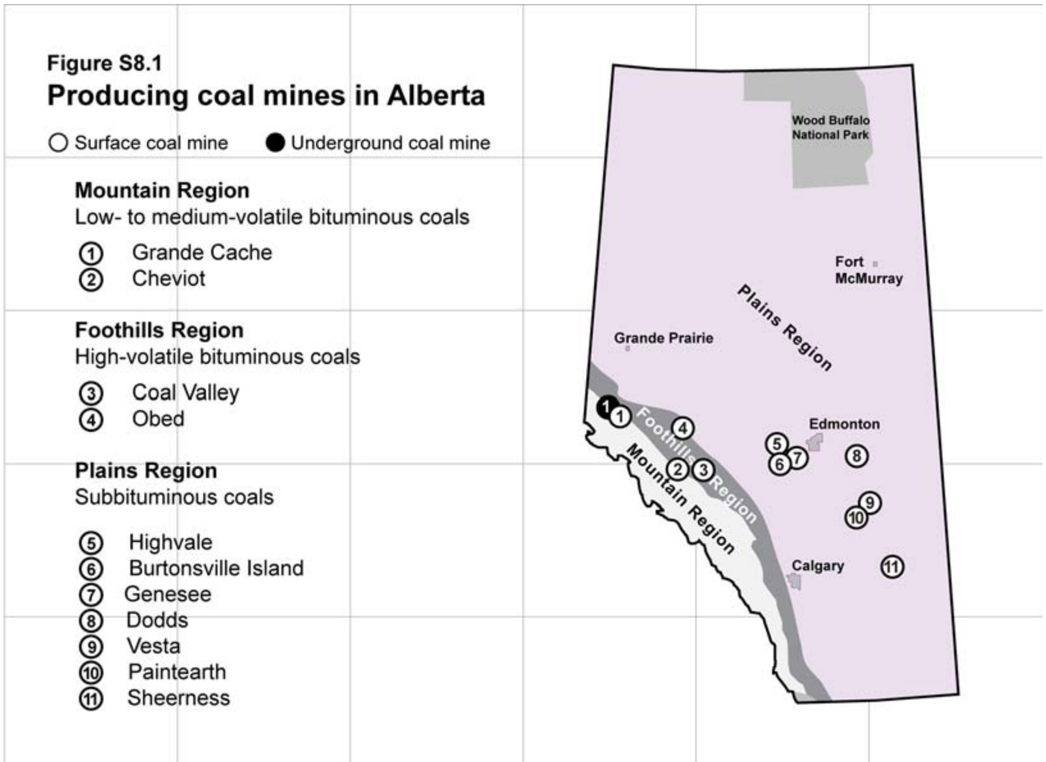
[a] Tonnages have been rounded to two significant figures, and totals are not arithmetic sums but are the result of separate determinations.
[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

8.2 Supply of and Demand for Marketable Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used for electricity generation in Alberta. Metallurgical bituminous coal is exported and used for industrial applications, such as steel production. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of thermal bituminous coal makes it possible to economically transport the coal over long distances. While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. Subbituminous raw coal and clean bituminous coal are collectively known as marketable coal.

8.2.1 Coal Production—2011

The locations of coal mine sites in Alberta are shown in **Figure S8.1**. In 2011, eleven mine sites produced coal in Alberta, as shown in **Table 8.4**. These mines produced 30.1 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 77 per cent of the total, metallurgical bituminous coal 9 per cent, and thermal bituminous coal the remaining 14 per cent. In 2011, subbituminous and metallurgical bituminous coal production decreased by 6 per cent and 11 per cent, respectively, relative to 2010, while thermal bituminous coal remained flat. Overall, total marketable production of coal has decreased by 5 percent, mainly due to weak demand.



Seven mines produce subbituminous coal. Most mines serve nearby electric power plants, while a few mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the coal reserves are dedicated to the power plants.

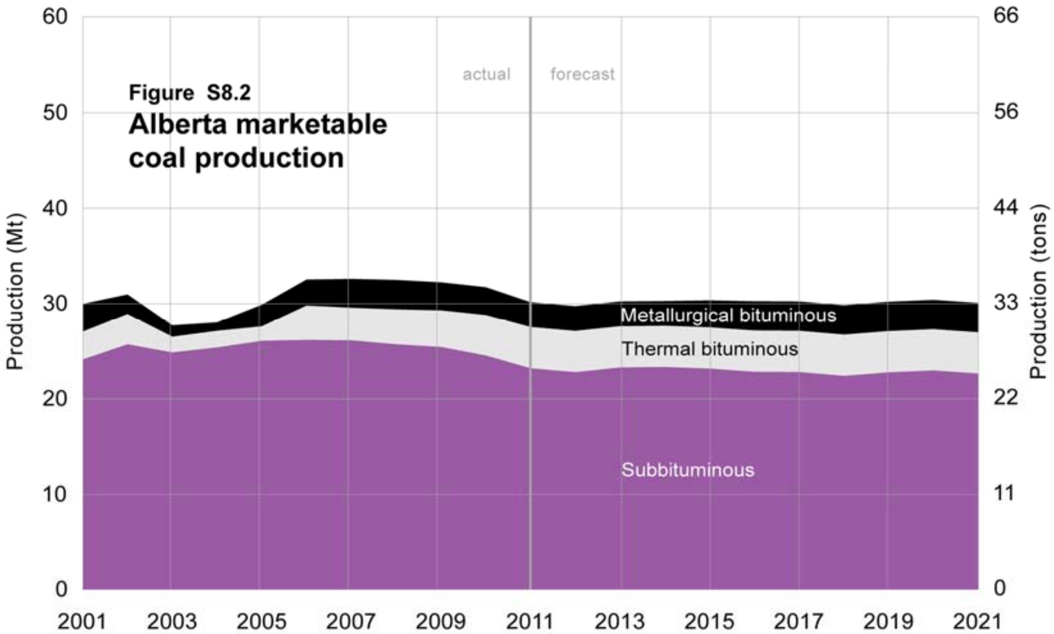
Table 8.4 Alberta coal mines and marketable coal production in 2011

Owner (grouped by coal type)	**Mine**	**Location**	**Production (Mt)**
Subbituminous coal			
Sherritt International Corp.	Genesee	Genesee	5.1
	Sheerness	Sheerness	3.4
	Paintearth & Vesta	Halkirk/Cordel	3.0
	Highvale	Wabamun	11.5
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.10
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.03
Subtotal			**23.1**
Bituminous metallurgical coal			
Teck Resources Limited	Cheviot	Mountain Park	1.2
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.5
Subtotal			**2.6**
Bituminous thermal coal			
Sherritt International Corp.	Coal Valley	Coal Valley	3.3
	Obed	Obed	1.0
Subtotal			**4.3**
Total			**30.1**

Three surface mines and one mine with both surface and underground recovery produce the provincial supply of metallurgical and thermal grade coal.

8.2.2 Coal Production—Forecast

The projected production for each of the three types of marketable coal is shown in **Figure S8.2**. By 2021, total production is expected to decrease very slightly, by about 0.3 per cent, from 30.1 Mt in 2011 to 30.0 Mt in 2021. Subbituminous coal production shows a drop of 2.4 per cent over the forecast period, while thermal and metallurgical bituminous coal production remains flat. An increase in production from both metallurgical and export thermal coal is possible if proposed mines open within the forecast period.



8.2.3 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electricity generation plants, and the production from these mines can be affected by the commissioning and closures of power generation plants.

In 2010, the federal government announced a policy that would require all coal-fired power plants to be retired by the end of either their economic life or their power purchase agreement or meet stringent emissions requirements. New federal regulations arising from the policy are expected to take effect in 2015, and the ERCB has considered this in forecasting the electricity supply generated from coal.

Sundance Units 1 and 2, operated by TransAlta, have been out of service since December 2010, impacting 560 MW of coal-fired capacity. In February 2011, TransAlta announced that the units could not be economically restored to service and declared *force majeure* on both units. As a result, the two units are not currently a part of the ERCB's demand forecast.

The new power generation unit at Keephills plant, with a capacity of 450 MW, began commercial operation in September 2011. Upgrades to increase the capacity of Keephills Units 1 and 2 by 23 MW each are scheduled in 2012.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan being the country that imports the most metallurgical and thermal coal. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export coal producers. Throughout 2011, the demand for metallurgical coal export market was weak, mainly due to a decrease in demand for coal for steelmaking in Japan after the March 2011 earthquake and tsunami. In addition to the relatively weak demand, the oversupply in global coal markets is not expected to improve in the near future. The strong growth in exports from a number of countries will increase global competition in coal markets, which will affect third-quarter price negotiations for Alberta exporters, and therefore price decreases are expected in the near term.

HIGHLIGHTS

In 2011, Alberta's demand for electricity increased by 2.5 per cent, compared with a 2.2 per cent increase in 2010.

In 2011, wind electricity-generating capacity increased by 11.3 per cent with the addition of the Wintering Hills wind power facility.

In 2011, the annual average pool price increased significantly to $76.22/MWh from $50.88/MWh in 2010.

9 // ELECTRICITY

The ERCB forecasts electricity supply and demand, and its forecasts are essential in determining the future domestic demand for some of Alberta's primary energy resources. Of particular importance are the relationships between electricity supply and natural gas and coal resources. Power plants that use these fuels supplied over 90 per cent of the electricity generated within Alberta in 2011.

While the ERCB regulates the oil, gas, and coal industries, the Alberta Utilities Commission (AUC) regulates utilities and oversees the building, operating, and decommissioning of electrical generation facilities, as well as the routing, tolls, and tariffs of regulated utilities.

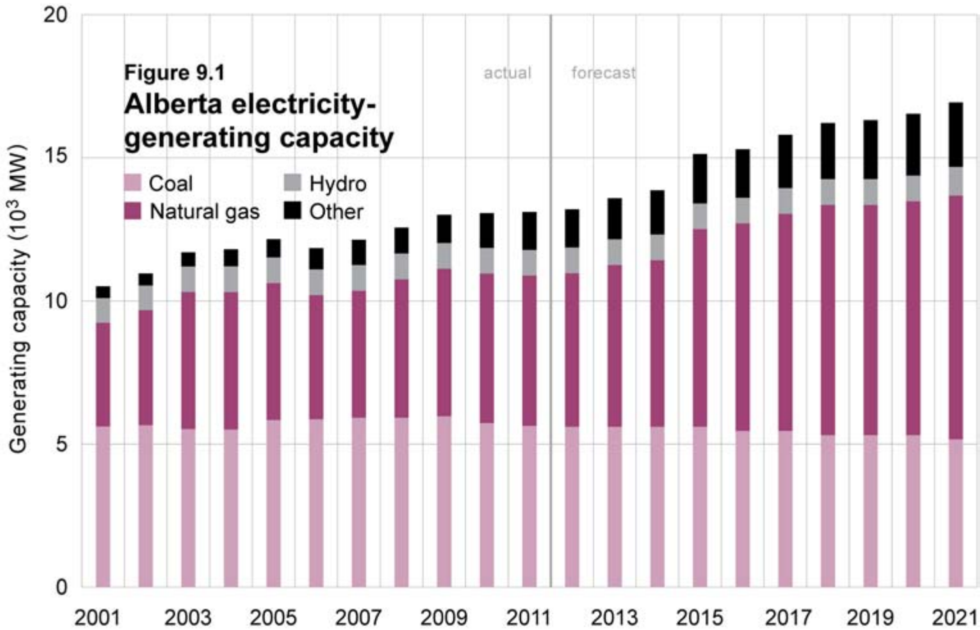
The competitive wholesale electricity market is facilitated by the Alberta Electric System Operator (AESO) and monitored by the Market Surveillance Administrator (MSA). In addition to managing the electricity sold into the Alberta power pool, the AESO is responsible for planning Alberta's transmission system. The MSA monitors Alberta's electricity market for fairness and balance in the public interest by ensuring that the market operates fairly, efficiently, and in an openly competitive manner.

9.1 Electricity-Generating Capacity

9.1.1 Provincial Summary

The ERCB refers to electricity-generating capacity in terms of maximum continuous rating (MCR), which is defined as the maximum output that a generating station is capable of producing continuously under normal conditions over a year and is usually expressed in the number of megawatts (MW).[1] Alberta's fuel mix of available electricity-generating capacity is composed of coal, natural gas, hydroelectric power, and "other," such as wind and biomass. A relatively small amount of capacity is from diesel-fired generators, which are a source of backup power for industrial use. Alberta also relies on transmission interties with neighbouring provinces, enabling the import and export of electricity. The capacity of the various components of Alberta's electricity industry, including a forecast to 2021, is illustrated in **Figure 9.1**.

[1] Mega = 10^6. The AESO reports maximum capability (MC) in terms of the maximum megawatts that a facility has generated for shorter periods of time.



At year-end 2011, Alberta's available power generating capacity was 13 111 MW, slightly higher than the 2010 capacity due to the addition of a coal-fired plant and a wind power facility, as well as small additions to biomass capacity. Coal-fired facilities accounted for 43 per cent of Alberta's total electric generating capacity compared with 53 per cent in 2001. Natural gas–fired facilities accounted for 40 per cent compared with 34 per cent in 2001.

Sundance Units 1 and 2, operated by TransAlta, have been out of service since December 2010, impacting 560 MW of coal-fired capacity. In February 2011, TransAlta announced that the units could not be economically restored to service and declared *force majeure* on both units. The power generating capacity figures for 2011 and for the forecast period do not include the Sundance 1 and 2 plants.

In 2011, Alberta's electric power generating capacity was augmented by a new 450 MW coal-fired unit: Keephills 3. Additional capacity came from Wintering Hills wind power facility (88 MW). Other smaller additions came from increases to generating capacity at two existing biomass generation facilities.

In 2011, 70 per cent of the natural gas–fired capacity in the province was classified as cogeneration unchanged from 2010. Cogeneration is the combined production of electricity and thermal energy using natural gas as a fuel source. Thermal energy is often used in manufacturing, heating buildings, producing steam for in situ oil production, and refining and upgrading crude oil. Therefore, cogeneration plants (often referred to as cogen plants) are often sited alongside an industrial facility.

The increasing shift from coal to natural gas as the source for the province's generation feedstock mix was accelerated with the loss of the Sundance coal-fired units. Over the forecast period, new natural gas–fired cogeneration facilities are the largest contributors to the growth in electricity-generating capacity. Cogeneration is a source of steam and power, both requirements for oil sands projects. A significant number of oil sands operators have installed or are planning to install cogeneration as an economical way of generating both steam and electricity on site to meet their needs. **Table 9.1** details cogeneration facilities associated with oil sands projects that are under construction, have regulatory approval, or have been announced. Although there is some uncertainty in the timing of additional oil sands cogeneration facilities, most are expected to proceed within the forecast period and are included in the forecast.

By 2021, the capacity of natural gas–fired power and cogeneration units is forecast to total more than 8500 MW and account for 50 per cent of Alberta's total available capacity. The ERCB anticipates electricity-generating capacity in Alberta to be close to 17 000 MW by the end of the forecast period, which is 7 per cent higher than last year's forecast of 15 900 MW in 2020. This increase is mainly due to the inclusion of new natural gas generation facilities.

Table 9.1 Oil sands-related cogeneration projects under construction, approved, and announced, 2012–2021

Oil sands cogeneration plants	Fuel / type	Location	Proposed capacity (MW)
Christina Lake in situ cogen 2	Natural gas	Wood Buffalo MD	85
Kearl oil sands cogen Phase 1	Natural gas	Wood Buffalo MD	100
STP McKay in situ cogen	Natural gas	Wood Buffalo MD	17
Nabiye oil sands cogen	Natural gas	Cold Lake	170
Algar	Natural gas	Wood Buffalo MD	85
West Ells	Natural gas	Wood Buffalo MD	15
Dover West – Phase 1	Natural gas	Wood Buffalo MD	100
Firebag in situ cogen 4 and 6	Natural gas	Wood Buffalo MD	160
Joslyn oil sands cogen	Natural gas	Wood Buffalo MD	85
Christina Lake in situ cogen 3	Natural gas	Wood Buffalo MD	80
Horizon oil sands cogen 2	Natural gas	Wood Buffalo MD	85
Taiga – Phase 1	Natural gas	Cold Lake	39
Carmon Creek in situ cogen – Phase 1	Natural gas	Northern Sunrise County	170
Voyager Upgrader	Natural gas	Wood Buffalo MD	13
Narrows Lake – Phase 1A	Natural gas	Wood Buffalo MD	30
MacKay expansion in situ cogen	Natural gas	Wood Buffalo MD	85
Foster Creek – Phase H	Natural gas	Wood Buffalo MD	40
Total Generating Capacity (2012–2021)			**1359**

Source: *Long Term Adequacy Metrics,* February 2012, Alberta Electric System Operator (AESO) Report.

9.1.2 Electricity-generating Capacity by Fuel

9.1.2.1 Coal

In 2011, the capacity of coal-fired generation units was over 5600 MW and accounted for 43 per cent of Alberta's generating capacity, not including Sundance 1 and 2.

The new TransAlta/Capital Power Keephills 3 coal-fired plant, with 450 MW capacity, incorporates supercritical boiler technology, featuring higher boiler temperatures and pressures than older plants. Combined with a high-efficiency turbine, the unit will require less fuel and have lower emissions on a per megawatt-hour (MWh) basis than other plants.

TransAlta has regulatory approval from the AUC to increase the capacity of the Keephills 1 and 2 coal-fired plants by 23 MW each in 2012. Also, Maxim Power Corporation has received approval from the AUC to construct a 500 MW capacity coal-fired plant that also incorporates supercritical boiler technology, to be located next to the existing HR Milner generating station.

On June 23, 2010, the federal minister of environment announced a new regulation that will require coal-fired electricity generation plants to shut down at 45 years of age or at the end of their power purchase agreement (PPA),[2] whichever is later. Under this proposed legislation, companies would be prohibited from making investments to extend the lives of those plants unless emission levels can be reduced to the emission levels of natural gas combined-cycle plants. The new regulation encourages electric utilities to transition towards lower- or non-emitting types of generation, such as high-efficiency natural gas, renewable energy, or thermal power with carbon capture and storage. The proposed regulation is scheduled to take effect on July 15, 2015. The ERCB forecast assumes that this new regulation will be enacted.

9.1.2.2 Natural Gas

In 2011, natural gas–fired generating capacity exceeded 5200 MW and accounted for 40 per cent of Alberta's total electricity capacity. Over the next 10 years, Alberta's natural gas–fired electric capacity is projected to increase by 3265 MW and represent 50 per cent of Alberta's total generating capacity by the end of the forecast period. This projected capacity increase is 26 per cent higher than last year's forecast of 2593 MW by 2020 because of new natural gas generating facilities.

The ERCB 10-year forecast for new natural gas–fired cogeneration power plants that are built on site at oil sands operations amounts to 1858 MW. These plants account for 59 per cent of the increase in natural gas–fired capacity in the province, most of which will be in the Municipal District of Wood Buffalo.

In addition to the proposed oil sands gas cogeneration facilities, regulatory approval has been received for two new natural gas–fired power plants in the Calgary area to be built by ENMAX Corporation. The Shepard plant, designed for 800 MW of generating capacity, is under construction, with an expected in-service date of 2015. The Bonnybrook plant, designed for 165 MW of generating capacity, is expected to start operating within the forecast period. These projects are included in the projection of electricity supply. TransAlta has also proposed constructing a number of gas-fired generation plants. These plants are not included in the ERCB forecast since they are in the early stages of the application process.

[2] PPAs were introduced to facilitate the transition of the electricity-generating industry from a regulated market to a competitive market. PPAs were auctioned off as long-term rights to sell power from utility plants built during the era of full regulation (i.e., before 1996). PPAs allowed the owners of the generating plants to recover their costs and earn a specified rate of return. Electricity-generating units built after January 1, 1996, are not subject to PPAs, and their generation can be bought or sold directly on the market.

9.1.2.3 Hydroelectric Power

Hydroelectric generating capacity in Alberta has been essentially unchanged since 2003 at 900 MW, accounting for 7 per cent of total generating capacity in 2011. About 860 MW of this capacity is located along the Bow and North Saskatchewan Rivers.

The proposed Dunvegan 100 MW power plant located on the Peace River has been approved, but construction has not begun. The plant is forecast to come on stream late in the forecast period.

9.1.2.4 Other

Other generating capacity (including biomass and wind) comprises about 10 per cent of Alberta's current electricity capacity and is up from 9 per cent in 2010. Biomass electricity is derived from plant or animal material, such as wood, straw, peat, or manure. In Alberta, the most common fuel for biomass generation is waste wood. The forestry industry typically burns waste wood as a fuel source to generate electricity and thermal energy. In 2011, Alberta biomass capacity was 359 MW, an increase of 5.4 per cent from 2010, and contributed 2.7 per cent of Alberta's total electricity capacity. The additional capacity came from increased generating capabilities at two existing biomass facilities, which had not been previously reported on the interconnected system.

Wind-powered electric generating capacity increased by 802 MW over the last decade, from 94 MW in 2001 to 896 MW in 2011. In the forecast period, approximately 1000 MW of additional wind-powered capacity is projected to be added.

9.2 Supply of and Demand for Electricity

This section discusses the supply of and demand for electricity within Alberta. On the supply side, the stock of electricity, or capacity, is measured in watts, while the flow of electricity, or generation, is measured in watt hours. In this report, electricity demand is measured in gigawatt[3] hours (GWh).

Electricity generation is the amount of electricity produced within a certain time period. For instance, if an electricity plant with a rated capacity of 100 MW operated at its maximum potential for one day, it would supply 2.4 GWh of electricity. However, if the same plant only supplied 1.8 GWh of electricity on a given day, the plant would be using 75 per cent of its potential capacity.

To forecast electricity generation, the ERCB uses a list of existing and proposed electricity-generating units operating within the province, their electricity-generating capacities and operating characteristics, a merit or stacking order, hourly customer load profiles, and projected electricity demand. The operating capacity of an existing electricity-generating unit is determined using its historical operating parameters, such as outage and capacity utilization rates. In the oil sands sector, the forecast of electricity generation

[3] Giga = 10^9.

from new generation is ramped up in a phased approach that corresponds with the expected on-site load at certain phases of upgraded and nonupgraded bitumen production.

The stacking order of electricity generation refers to the order in which electricity from each generating unit is offered in or sold to the electricity grid. The lowest marginal cost producers, which include wind turbines, run-of-river hydroelectric units, and some base coal-fired generation, are expected to offer in electricity generation first. Higher marginal cost producers, such as natural gas–fired turbines, offer electricity into the grid at times of peak demand.

The electricity generation forecast complements the electricity demand forecast by incorporating hourly load profiles and the ERCB forecast of electricity demand for each year. There is an hourly load profile for each year that corresponds to the forecast total load. By incorporating hourly loads, generating units are dispatched hourly, accounting for periods of high load and low load throughout each year.

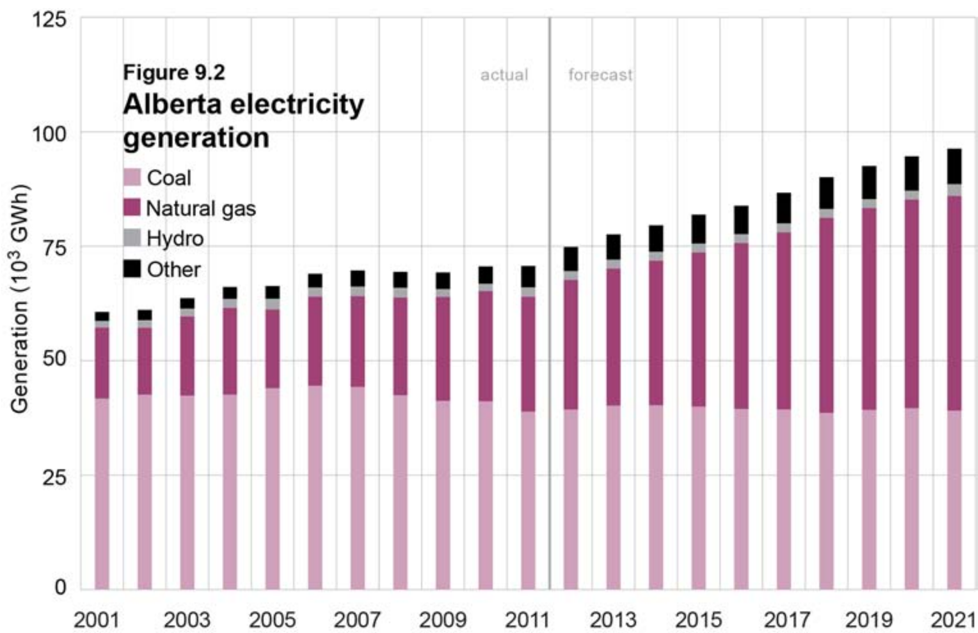
In previous reports, Alberta's total electricity demand was defined as electricity sales reported by electricity distributors to agricultural, residential, commercial, and industrial customers; the direct use of electricity by industrial consumers that obtain their power directly from power plants located on site or near their facilities (often referred to as behind-the-fence load); and purchases of electricity by customers set up to directly purchase electricity from the Alberta power pool. In this report and in the future, references to Alberta's total electricity demand will include estimated transmission and distribution losses.

The ERCB uses customer segments together with current and historical trends to forecast electricity demand. The key driver of residential and commercial electricity demand is population growth. Industrial customers are examined in greater detail to adequately account for industry electricity demand. In the oil sands sector, demand projections are based on upgraded and nonupgraded bitumen production forecasts and the types of projects (in situ or mining).

9.2.1 Electricity Generation

Installed electricity-generating capacity in 2011 was 13 111 MW, enough to supply about 114 800 GWh of electricity if plants were operated at full capacity. However, total electricity-generating capacity is not continuously available to meet demand. Generation units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, or technical limitations (e.g., of wind turbines). The current forecast projects that electricity-generating capacity in Alberta will increase by more than 3828 MW over the forecast period, an increase from last year's total forecast increase of 2879 MW.

Figure 9.2 illustrates the historical and forecast electricity generation within Alberta by fuel type, including electricity from gas cogeneration plants that is not sold into the grid. In 2011, total electricity generation reached 70 685 GWh, similar to the 2010 level of 70 586 GWh. Between 2001 and 2011, electricity generation in Alberta grew by 10 055 GWh, or an average 2.3 per cent per year. By 2021,



total electricity generation is forecast to be close to 96 300 GWh, higher than last year's forecast of over 94 000 GWh by 2020.

In 2011, coal-fired power plants generated almost 55 per cent of the province's electricity, while natural gas and hydro accounted for 36 and 3 per cent, respectively. The remaining 7 per cent was generated by wind and other sources. Natural gas cogeneration plants dedicated to the oil sands sector generated 15 662 GWh of electricity in 2011, of which 11 060 GWh (71 per cent) was used on site. The remaining electricity generated was sold into the power pool. By 2021, coal-fired power plants are forecast to generate 40 per cent of the province's electricity, while natural gas and hydro are forecast to account for 49 and 3 per cent, respectively. The remaining 8 per cent is projected to come from wind power and other renewable sources.

9.2.2 Electricity Transfers

Alberta's transmission lines are connected with British Columbia and Saskatchewan. Alberta is connected with the B.C. transmission system through a 500 kilovolt[4] (kV) line between Langdon, Alberta, and Cranbrook, B.C., and two 138 kV lines between Coleman, Alberta, and Natal, B.C. Since B.C. is connected with the United States Pacific Northwest, the Alberta-B.C. intertie allows Alberta to indirectly trade electricity with the United States. The 230 kV direct current electrical tie with Saskatchewan enables Alberta to import or export about 150 MW of electricity.

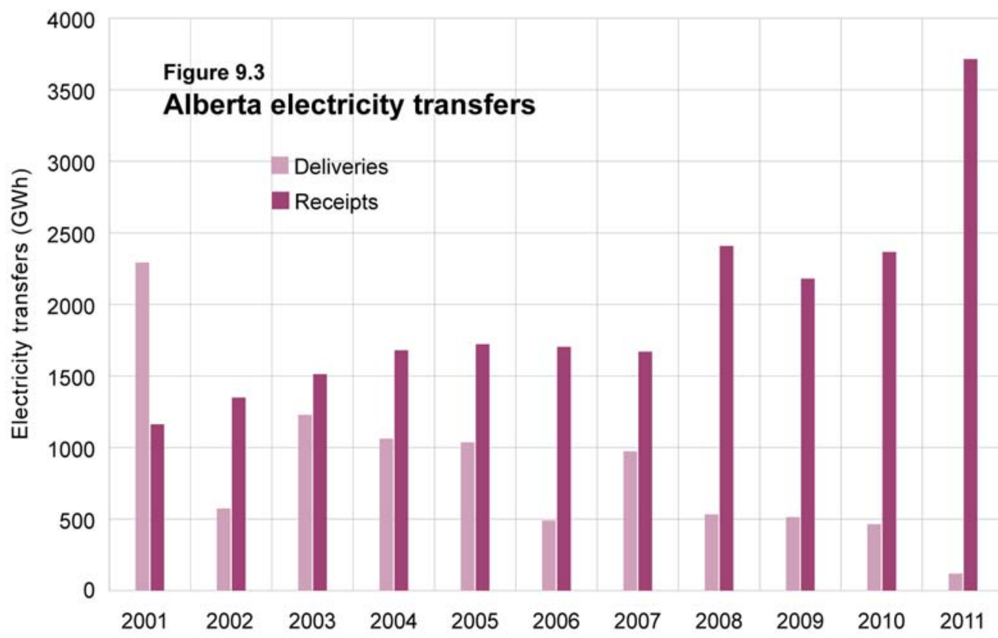
[4] Kilo = 10^3.

The Alberta-B.C. interconnection was designed to operate at transfer capacities of 1200 MW from B.C. to Alberta and 1000 MW from Alberta to B.C. Daily transfers of electricity on the Alberta-B.C. intertie are typically below these capacities.

In addition to the transmission ties, a natural gas–fired electricity generation unit in Fort Nelson (northern B.C.) supplies power to the surrounding communities and sells surplus electricity into the Alberta grid. Some small areas in Alberta are served by neighbouring provincial or U.S. regional utilities.

Figure 9.3 illustrates Alberta’s electricity transfers from 2001 to 2011. Alberta was a net importer of electricity in 2011, importing 3596 GWh, which is about 7 per cent of total Alberta demand. The province’s imports from Saskatchewan and B.C. in 2011 totalled 3715 GWh, an increase of 57 per cent, or 1349 GWh, from 2010 levels. Approximately 85 per cent of the imports came from B.C. Compared with 2010, electricity exports decreased by 74 per cent, or 345 GWh, to 119 GWh. Approximately 60 per cent of exports from Alberta went to B.C.

The ERCB supply and demand projections for electric power show that Alberta will be a net importer of electricity over the forecast period. This is expected since imports offer a low cost power source to meet demand when operational upsets occur or as market differentials dictate.

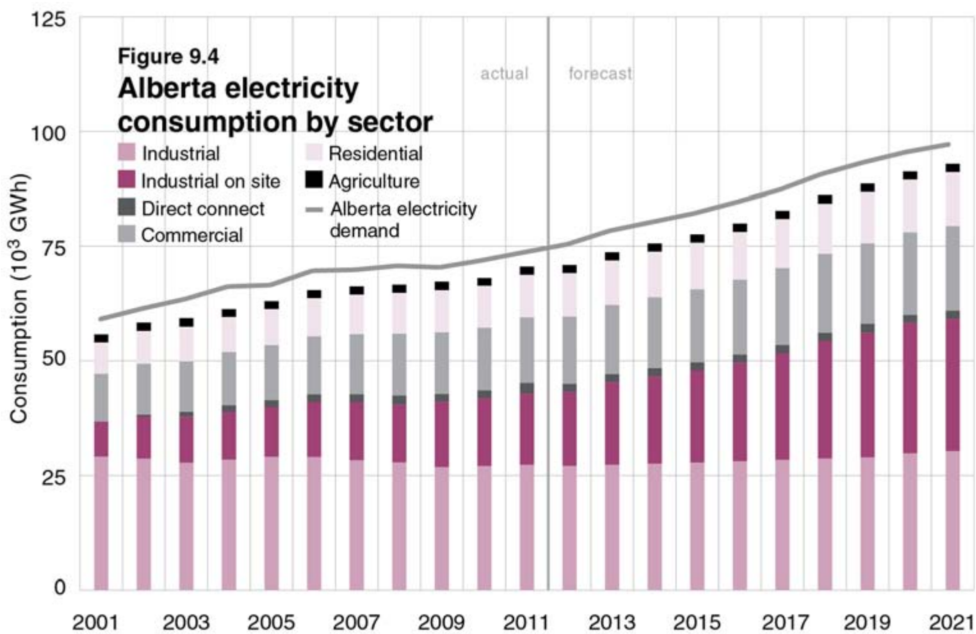


9.2.3 Electricity Demand in Alberta

The ERCB forecasts electricity demand, and its forecasts are essential in determining future domestic demand for some of Alberta's primary energy resources. Alberta electricity demand is the sum of all reported electricity sales (residential, commercial, industrial, and farm), behind-the-fence load, and estimated transmission and distribution losses.[5]

The ERCB 10-year load forecast considers the electricity requirements for the four sectors of the economy—residential, commercial, industrial, and farm—that account for most of Alberta's electricity demand over the forecast period. This demand forecast is generally based on the ERCB's forecasts of economic and population growth, projections of oil sands development, and the expected production of conventional oil and natural gas.

Figure 9.4 illustrates the ERCB's forecast of Alberta's electricity demand. Alberta's total electricity demand amounted to 74 281 GWh in 2011. This represents a 2.5 per cent increase over the 2010 total of 72 488 GWh. This increase was led by a 7.5 per cent growth in electricity demand from the oil sands sector.



Electricity distribution companies, including ATCO Electric, ENMAX Corporation, EPCOR, Fortis Alberta Inc.; cities and towns, including Lethbridge, Medicine Hat, Red Deer, Cardston, Fort Macleod, and Ponoka; and the municipality of Crowsnest Pass report their annual retail sales of electricity to the

[5] In prior years, the ERCB did not include estimated transmission and distribution losses in determining total electricity demand growth rates. Starting with this report, the ERCB will include these losses in determining total demand growth rates.

AUC. In 2011, Alberta's electricity consumption from sales reported by electricity distributors was 52 662 GWh. This is a 2.1 per cent increase over the 51 603 GWh reported sold in 2010. Of the 2011 sales, about 52 per cent of the electricity consumed was sold to industrial customers, 27 per cent to commercial customers, 18 per cent to the residential sector, and 3 per cent to the farm sector.

Residential demand in 2011 was reported to have increased by 2.9 per cent from 2010. Customer details provided by electricity retailers reveal that over 1.32 million residential customers consumed 9333 GWh of electricity in 2011. This resulted in an electricity intensity of 7.1 MWh per residential customer, slightly higher than the 2010 and historical five-year average of 7.0 MWh. Residential demand was 2.47 MWh per capita in 2011, compared with 2.44 MWh in 2010, an increase of 1.3 per cent. Consumption per capita has grown by an average of 0.9 per cent per year from 2002 to 2011.

Commercial demand increased by 3.3 per cent in 2011. The electricity usage of the average commercial customer was estimated to be 85.7 MWh in 2011, higher than the 84 MWh in 2010 but lower than the five-year average of 87.7 MWh. Commercial electricity demand per capita averaged 3.76 MWh in 2011, a 1.7 per cent increase from 2010 and a 1.0 per cent increase per year on average since 2002.

Industrial demand increased by 2.5 per cent in 2011. Industrial demand for the oil sands industry grew by 7.5 per cent, consistent with the 8.2 per cent growth in mined and in situ bitumen production.

Of the total electricity demand from all sectors, 74 per cent was sold through the grid. In 2011, over 45 100 GWh, or 61 per cent, of the total electricity demand of all sectors was used by industrial consumers. Over 29 600 GWh, or 54 per cent of the industrial load, was sold through the grid as sales by electricity distribution companies and direct connect customers, while 15 468 GWh of the electricity requirements of the industrial sector was delivered through on-site power generation or cogeneration. Electricity demand for industries with cogeneration (e.g., oil sands and petrochemicals) increased by 8.5 per cent in 2011, up significantly from the 3 per cent increase reported between 2009 and 2010.

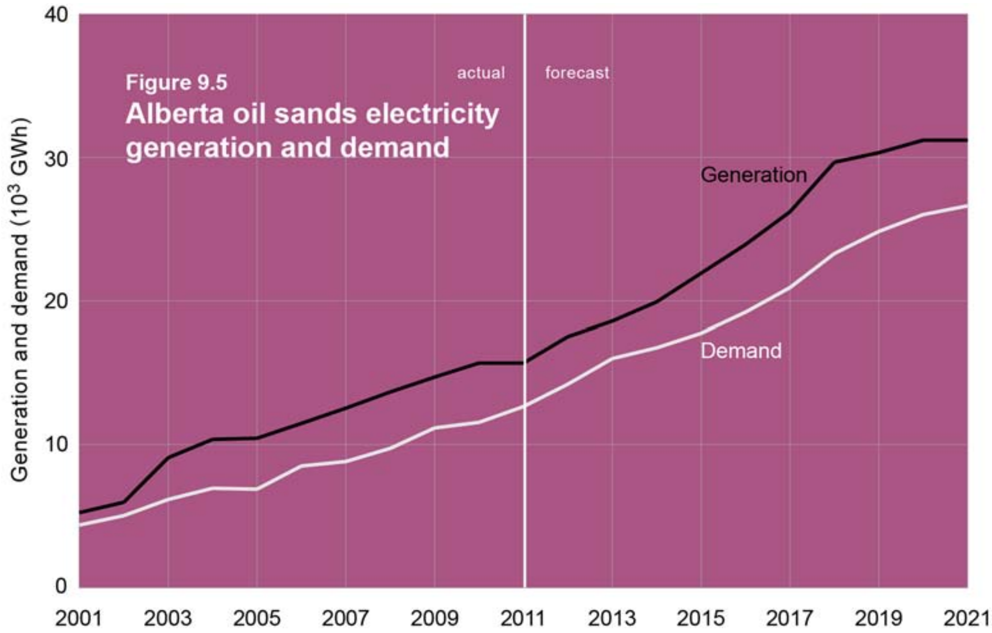
The forecast for Alberta electricity demand growth from 2012 onwards is projected to average 2.8 per cent per year. By 2021, Alberta electricity demand is forecast to be 97 960 GWh. Growth in oil sands electricity demand is projected to grow by 6.8 per cent per year.

Over the next 10 years, growth in residential electricity demand is projected to average 2.3 per cent per year, tracking economic and population growth. Farm load is projected to be relatively constant at a level consistent with the average of the last three years. Electricity demand in the commercial sector is projected to increase by 2.8 per cent per year, based on the ERCB's current economic forecast and population outlook for Alberta.

Alberta electric power generation is expected to match the projected growth in Alberta electricity demand over the next decade. Over the forecast period, load growth will continue to be met primarily by existing and new natural gas–fired power plants.

9.2.4 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the projected electricity supply and demand at oil sands operations.[6] Electricity generation at oil sands operations was forecast by applying the historical operating parameters of existing electricity cogeneration units to the proposed capacities of all current and future cogeneration units. Electricity demand is based on existing electricity intensities, electricity intensities outlined in regulatory applications, and the ERCB supply forecast for upgraded and nonupgraded bitumen.



Electricity cogeneration units at oil sands mines, bitumen upgraders, and in situ thermal projects typically provide required process steam and generate electricity to meet on-site electricity demand. Surplus electricity may be generated and sold to the power pool. **Table 9.2** displays 2011 electricity statistics by type of oil sands facility.

Table 9.2 2011 electricity statistics at oil sands facilities

Project type	Capacity (MW)	Total generation (GWh)	Capacity utilization (per cent)	Generation used on site (GWh)
Mines and upgraders*	1 475	8 702	67	7 480
Thermal in situ	920	6 960	86	3 580

* Mines and upgraders have been combined due to the confidential nature of some statistics.

Data for electricity generation at bitumen mining operations and upgraders indicate an annual capacity utilization of 67 per cent. Of the total electricity generated, 86 per cent was used on site and the

[6] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kWh per barrel.

remaining electricity was sold to the power pool. Thermal in situ gas cogeneration facilities operated collectively at 86 per cent of their installed capacity, and 51 per cent of the total electricity generated was used on site, with the remaining output sold to the power pool. In 2011, while the capacity utilization for bitumen mining operations and upgrading declined by 5 per cent, capacity utilization at in situ gas cogeneration facilities rose by 3 per cent relative to 2010. The decline in the capacity utilization at bitumen mining operations and upgraders was mainly due to a number of plant outages.

In 2011, eight thermal in situ oil sands operators obtained steam and electricity from on-site gas cogeneration facilities with installed electric generating capacities ranging from 13.1 to 220 MW. Cogeneration facilities are incorporated into the plans of some, but not all, of the oil sands projects included in the ERCB forecast of oil sands production and accompanying electricity supply and demand.

Appendix A Terminology, Abbreviations, and Conversion Factors

A.1 Terminology

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Area	The area used to determine the bulk rock volume of the oil-, crude bitumen-, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.
Burner-tip	The location where a fuel is used by a consumer.
Butanes	In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, Section 1(1)(c.1)).
Coalbed Methane	The naturally occurring dry, predominantly methane gas produced during the transformation of organic matter into coal.
Cogeneration Gas Plant	Gas-fired plant used to generate both electricity and steam.
Commingled	Commingled flow describes the production of fluid from two or more separate zones through a single conduit.
Compressibility Factor	A correction factor for nonideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(d.1)).
Connected Wells	Gas wells that are tied into facilities through a pipeline.
Crude Bitumen	A naturally occurring viscous mixture mainly of hydrocarbons heavier than pentane that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well (*Oil Sands Conservation Act*, Section 1(1)(f)).

Crude Oil (Conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen (*Oil and Gas Conservation Act,* Section 1(1)(f.1)).
Crude Oil (Heavy)	Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater.
Crude Oil (Light-Medium)	Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3.
Crude Oil Netback	Crude oil netbacks are calculated from the price of WTI at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate, as well as crude quality differences.
Crude Oil (Synthetic)	A mixture mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds and is derived from crude bitumen. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, Section 1(1)(t.1)).
Datum Depth	The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.
Decline Rate	The annual rate of decline in well productivity.
Deep-cut Facilities	A gas plant adjacent to or within gas field plants that can extract ethane and other natural gas liquids using a turbo-expander.
Density	The mass or amount of matter per unit volume.
Density, Relative (Raw Gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Development Entities (DEs)	A development entity (DE) is an entity consisting of multiple formations in a specific area described in an order of the ERCB from which gas may be produced without segregation in the wellbore subject to certain criteria specified in Section 3.051 of the *Oil and Gas Conservation Regulations* (Order No. DE 2006-2).
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.

Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).
Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).
Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field	(i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or (ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, Section T1T (x)).
Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Field/Strike Area	An administrative geographical boundary used for grouping resource accumulation.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.
Frontier Gas	In this report this refers to gas produced from areas of northern and offshore Canada.

Gas	Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).
Gas (Associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (Marketable)	A mixture mainly of methane originating from raw gas or, if necessary, from the processing of the raw gas for the removal or partial removal of some constituents and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).
Gas (Marketable at 101.325 kPa and 15°C)	The equivalent volume of marketable gas at standard conditions.
Gas (Nonassociated)	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
Gas (Raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(s.1)).
Gas (Solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.
Gas-Oil Ratio (Initial Solution)	The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.
Good Production Practice (GPP)	Production from oil pools at a rate (i) not governed by a base allowable, but (ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain its share of the production (*Oil and Gas Conservation Regulations* 1.020(2)9). This practice is authorized by the ERCB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.

Gross Heating Value (of Dry Gas)	The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.
Horizontal Well	A well in which the lower part of the wellbore is drilled parallel to the zone of interest.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Initial Volume in Place	The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.
Maximum Day Rate	The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.
Maximum Recoverable Thickness	The assumed maximum operational reach of underground coal mining equipment in a single seam.
Mean Formation Depth	The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.
Methane	In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, Section 1(1)(m.1)).
Multilateral Well	A well where two or more production holes, usually horizontal in direction with reference to the zone of interest, are drilled from a single surface location.
Natural Gas Liquids	Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.
Off-gas	Natural gas that is produced from upgrading bitumen. This gas is typically rich in natural gas liquids and olefins.
Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(n.1)).

Oil Sands
(i) sands and other rock materials containing crude bitumen,
(ii) the crude bitumen contained in those sands and other rock materials, and
(iii) any other mineral substances other than natural gas in association with that crude bitumen or those sands and other rock materials referred to in subclauses
(i) and (ii) (*Oil Sands Conservation Act*, Section l(l)(o)).

Oil Sands Deposit
A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(o.1)).

Overburden
In this report overburden is a mining term related to the thickness of material above a mineable occurrence of coal or bitumen.

OPEC Reference Basket Price
OPEC calculates a production-weighted reference price, consisting of 12 different crudes: Saharan Blend (Algeria), Iran Heavy, Iraq Basra Light, Kuwait Export, Libya Es Sider, Bonny Light (Nigeria), Qatar Marine, Arab Light (Saudi Arabia), United Arab Emirates Murban, Merey (Venezuela), Girassol (Angola), and Oriente (Ecuador). The OPEC reference crude has an American Petroleum Institute (API) gravity of 32.7, with an average sulphur content of 1.77 per cent.

Pay Thickness (Average)
The bulk rock volume of a reservoir of oil, oil sands, or gas divided by its area.

Pentanes Plus
A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate, or crude oil (*Oil and Gas Conservation Act*, Section 1(1)(p)).

Pool
A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(q)).

Porosity
The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.

Pressure (Initial)
The reservoir pressure at the reference elevation of a pool upon discovery.

Propane
In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, Section 1(1)(s)).

Recovery (Enhanced)	The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. The artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of (i) aiding in the lifting of fluids in the well, or (ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means (*Oil and Gas Conservation Act*, Section 1(1)(h)).
Recovery (Pool)	In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.
Recovery (Primary)	Recovery of oil by natural depletion processes only measured as a volume thus recovered or as a fraction of the in-place oil.
Refined Petroleum Products	End products in the refining process.
Refinery Light Ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reprocessing Facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Retrograde Condensate Pools	Gas pools that have a dew point such that natural gas liquids will condense out of solution with a drop in reservoir pressure. To limit liquid dropout in the reservoir, dry gas is reinjected to maintain reservoir pressure.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.

Saturation (Gas) The fraction of pore space in the reservoir rock occupied by gas upon discovery.

Saturation (Water) The fraction of pore space in the reservoir rock occupied by water upon discovery.

Shale Gas The naturally occurring dry, predominantly methane gas produced from organic-rich, fine-grained rocks.

Shrinkage Factor (Initial) The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.

Solvent A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.

Specification Product A crude oil or refined petroleum product with defined properties.

Sterilization The rendering of otherwise definable economic ore as unrecoverable.

Straddle Plants These are reprocessing plants on major natural gas transmission lines that process marketable gas by extracting natural gas liquids. This results in gas for export having a lower heat content than the marketable gas flowing within the province.

Strike Area See Field/Strike Area.

Strip Ratio The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) thickness of overburden to thickness of coal, (2) volume of overburden to volume coal, (3) weight of overburden to weight of coal, or (4) cubic yards of overburden to tons of coal. A stripping ratio commonly is used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.

Successful Wells Drilled Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.

Surface Loss A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.

Upgraded Bitumen A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.

Temperature	The initial reservoir temperature upon discovery at the reference elevation of a pool.
Ultimate Potential	An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple equation: Ultimate potential = initial established reserves + additions to existing pools + future discoveries.
Upgrading	The process that converts bitumen and heavy crude oil into a product with a density and viscosity similar to light crude oil.
Well Connections	Refers to the geological (producing) occurrences within a well; there may be more than one per wellbore.
Zone	Any stratum or sequence of strata that is designated by the ERCB as a zone (*Oil and Gas Conservation Act*, Section 1(1)(z)).

A.2 Abbreviations

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
DISC YEAR	discovery year
EOR	enhanced oil recovery
FRAC	fraction
GC	gas cycling
GIP	gas in place
GOR	gas-oil ratio
GPP	good production practice
INJ	injected
I.S.	integrated scheme
KB	kelly bushing
LF	load factor
LOC EX	local experimental project

PROJECT	
LOC U	local utility
MB	material balance
MFD	mean formation depth
MOP	maximum operating pressure
MU	commingling order
NGL	natural gas liquids
NO	number
NON-ASSOC	nonassociated gas
PE	performance estimate
PD	production decline
RF	recovery factor
RGE	range
RPP	refined petroleum production
SA	strike area
SATN	saturation
SF	solvent flood
SG	gas saturation
SL	surface loss
SOLN	solution gas
STP	standard temperature and pressure
SUSP	suspended
SW	water saturation
TEMP	temperature
TOT	total
TR	total record
TVD	true vertical depth
TWP	township
VO	volumetric reserve determination
VOL	volume
WF	waterflood
WM	west of [a certain] meridian
WTR DISP	water disposal
WTR INJ	water injection

A.3 Symbols

International System of Units (SI)

°C	degree Celsius	M	mega
d	day	m	metre
EJ	exajoule	MJ	megajoule
ha	hectare	mol	mole
J	joule	T	tera
kg	kilogram	t	tonne
kPa	kilopascal	TJ	terajoule

Imperial

bbl	barrel	°F	degree Fahrenheit
Btu	British thermal unit	psia	pounds per square inch absolute
cf	cubic foot	psig	pounds per square inch gauge
d	day	M	thousand
MM	million	B	billion
T	trillion		

A.4 Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric	Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	= 35.49373 cubic feet of gas
1 m^3 of ethane (equilibrium pressure and 15°C)	= 6.3301 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	= 6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	= 6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	= 6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	= 6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	= 0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	= 1.102311 short tons (2000 pounds)
1 kilojoule	= 0.9482133 British thermal units (Btu) as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.
[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value (short scale)	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion (trillion)	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4*
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Upgraded bitumen (synthetic crude oil)	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

* Based on the heating value at 1000 Btu/cf.

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Natural Gas Reserves, and Natural Gas Liquids

Table B.1 Initial in-place resources of crude bitumen by deposit

Oil Sands Area **Oil sands deposit**	**Depth/region/zone (m)**	**Resource determination method**	**Initial volume in place (10^6 m^3)**
Athabasca			
Upper Grand Rapids	150–450+	Isopach	5 817
Middle Grand Rapids	150–450+	Isopach	2 171
Lower Grand Rapids	150–450+	Isopach	1 286
Wabiskaw-McMurray	0–750+	Isopach	152 432
Nisku	200–800+	Isopach	16 232
Grosmont	All zones	Isopach	64 537
Subtotal			**242 475**
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350–625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			**29 090**
Peace River			
Bluesky-Gething	300–800+	Isopach	10 968
Belloy	675–700	Building block	282
Upper Debolt	500–800	Building block	1 830
Lower Debolt	500–800	Building block	5 970
Shunda	500–800	Building block	2 510
Subtotal			**21 560**
Total			**293 125**

Table B.2 Basic data of crude bitumen deposits

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150–450+	Isopach	5 817.00	359.00	8.5	0.092	0.58	0.33	0.42
Middle Grand Rapids								
150–450+	Isopach	2 171.00	183.00	6.8	0.084	0.55	0.32	0.45
Lower Grand Rapids								
150–450+	Isopach	1 286.00	134.00	5.6	0.083	0.52	0.33	0.48
Wabiskaw-McMurray								
0–65 (mineable)	Isopach	20 823.00	375.00	25.9	0.101	0.76	0.28	0.24
65–750+ (in situ)	Isopach	131 609.00	4 694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200–800+	Isopach	16 232.00	819.00	14.4	0.057	0.68	0.20	0.32
Grosmont								
D	Isopach	32 860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18 755.00	1 069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4 450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8 472.00	1 274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5 377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/ Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/ Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/ Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1 004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/ Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/ Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/ Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/ St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/ St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27
Lower Grand Rapids 5								
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/ Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/ St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/ St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/ Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./ Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350–625	Isopach	9 422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2 161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1 439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17

(continued)

Table B.2 Basic data of crude bitumen deposits (continued)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/ Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/ St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/ St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300–800+	Isopach	10 968.00	1 016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675–700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500–800	Building Block	1 830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500–800	Building Block	5 970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500–800	Building Block	2 510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		**293 124.67**						

Table B.3 Conventional crude oil reserves as of each year-end (10^6 m^3)

	Changes to initial established reserves							
Year	New discoveries	EOR additions	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves
1968	62.0				119.8	1643.1	430.3	1 212.8
1969	40.5				54.5	1697.5	474.7	1 222.8
1970	8.4				36.7	1734.4	526.5	1 207.9
1971	14.0				22.1	1756.5	582.9	1 173.6
1972	10.8				20.0	1776.0	650.0	1 126.0
1973	5.1				9.2	1785.7	733.7	1 052.0
1974	4.3				38.5	1824.2	812.7	1 011.5
1975	1.6				7.0	1831.1	880.2	950.9
1976	2.5				-18.6	1812.5	941.2	871.3
1977	4.8				19.1	1831.6	1 001.6	830.0
1978	24.9				24.4	1856.1	1 061.6	794.5
1979	19.2				34.3	1890.3	1 130.1	760.2
1980	9.0				22.8	1913.2	1 193.3	719.9
1981	15.0	7.2			32.6	1945.8	1 249.8	696.0
1982	16.8	6.6			6.9	1952.8	1 303.4	649.4
1983	21.4	17.9			64.1	2016.8	1 359.0	657.8
1984	29.1	24.1			42.0	2058.9	1 418.2	640.7
1985	32.7	21.6			64.0	2123.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	2162.4	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	2195.4	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	2231.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	2253.1	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	2256.1	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	2265.6	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	2292.7	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	2331.9	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	2336.5	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2391.6	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2414.1	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2451.6	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2490.1	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2521.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2554.3	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2583.0	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2603.3	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2634.0	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2664.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2703.7	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2730.8	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2751.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2773.1	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2794.9	2 566.5	228.4
2010	3.8	5.8	23.5	+1.7	34.8	2829.7	2592.8	236.9
2011	4.0	6.4	14.0	+9.0	33.5	2863.2	2617.3	245.9

Table B.4 Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

Year	Changes to initial established reserves: New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves @ 37.4 MJ/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0
2010	24.3	25.3	33.2	82.8	5 213.5	4 188.4	1 025.1	1 065.7
2011	20.8	24.0	24.7	69.5	5 283.1	4 338.0	945.1	987.0

[a] At field plant.

Table B.5 Natural gas reserves of gas cycling pools, 2011

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas(10^6 m^3)
Brazeau River Nisku K	1 063	74.17	79	0.90	0.22	34	46.15	746	33
Brazeau River Nisku M	1 621	76.22	124	0.90	0.26	45	41.36	1 080	49
Brazeau River Nisku P	8 862	61.23	543	0.72	0.46	156	45.28	3 446	699
Brazeau River Nisku AA	485	55.65	27	0.63	0.30	9	44.00	214	6
Caroline Beaverhill Lake A	60 888	49.95	3 041	0.62	0.55	620	36.51	16 988	782
Carson Creek Beaverhill Lake B	11 919	55.68	664	0.90	0.18	361	41.06	8 796	273
Harmattan East Commingled Pool 001	45 102	50.26	2 267	0.79	0.10	1 284	40.43	31 752	5 558
Harmattan-Elkton Rundle C	32 864	46.96	1 543	0.88	0.17	988	41.48	23 822	1 248
Kakwa A Cardium A	3 848	55.40	213	0.71	0.32	97	41.13	2 348	825
Kaybob South Beaverhill Lake A	110 632	52.61	5 820	0.72	0.48	1 644	39.68	41 421	259
Pembina Nisku Q2Q	1 160	66.05	77	0.9	0.32	32	44.76	710	150
Ricinus Cardium A	13 295	58.59	779	0.90	0.10	437	40.52	10 789	418
Valhalla MFP8524 Halfway	6 331	53.89	341	0.80	0.10	182	40.00	4 559	2 218
Waterton Rundle-Wabamun A	90 422	48.74[a]	4 407	0.95	0.35	2 190	39.22	55 836	1 512
Wembley MFP8524 Halfway	6 390	53.89	344	0.60	0.18	127	40.00	3 163	1 923

(continued)

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas(10^6 m^3)
Westerose									
D-3	10 617	51.55	547	0.78	0.10	310	41.72	7 419	84
Windfall									
D-3 A	21 955	53.42	1 173	0.71	0.40	399	42.41	9 419	722

[a] Producible raw gas gross heating value is 40.65 MJ/m^3.

Table B.6 Natural gas reserves of multifield pools, 2011

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8515 Banff	
Haro MFP8515 Banff	98
Rainbow MFP8515 Banff	6
Rainbow South MFP8515 Banff	180
Total	284
MFP8516 Viking	
Fenn West MFP8516 Viking	7
Fenn-Big Valley MFP8516 Viking	50
Total	57
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 218
Wembley MFP8524 Halfway	1 923
Total	4 141
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	120
Sousa MFP8528 Bluesky	624
Total	744
MFP8529 Bluesky-Detrital-Debolt	
Cranberry MFP8529 BL-DT-DB	398
Hotchkiss MFP8529 BL-DT-DB	392
Total	790
MFP8541 Second White Specks	
Cherry MFP8541 2WS	22
Granlea MFP8541 2WS	35
Taber MFP8541 2WS	117
Total	174
Commingled MFP9502	
Ansell Commingled MFP9502	13 858
Medicine Lodge Commingled MFP9502	1 303
Minehead Commingled MFP9502	1 385
Sundance Commingled MFP9502	4 916
Total	21 462
Commingled MFP9503	
Hairy Hill Commingled MFP9503	224
Willingdon Commingled MFP9503	10
Total	234
Commingled MFP9504	
Alix Commingled MFP9504	677
Bashaw Commingled MFP9504	2 291
Buffalo Lake Commingled MFP9504	8
Chigwell Commingled MFP9504	100
Chigwell North Commingled MFP9504	215
Clive Commingled MFP9504	428
Donalda Commingled MFP9504	118
Dorenlee Commingled MFP9504	4
Ferintosh Commingled MFP9504	19
Haynes Commingled MFP9504	8
Lacombe Commingled MFP9504	2
Malmo Commingled MFP9504	424
Nevis Commingled MFP9504	1 418
Wood River Commingled MFP9504	77
Total	5 789
Commingled MFP9505	
Bigoray Commingled MFP9505	194
Pembina Commingled MFP9505	772
Total	966
Commingled MFP9506	
Bonnie Glen Commingled MFP9506	44
Ferrybank Commingled MFP9506	185
Total	229
Commingled MFP9508	
Fairydell-Bon Accord Commingled MFP9508	41
Peavey Commingled MFP9508	1
Redwater Commingled MFP9508	1 386
Total	1 428
Commingled MFP9509	
Albers Commingled MFP9509	6
Beaverhill Lake Commingled MFP9509	257
Bellshill Lake Commingled MFP9509	8
Birch Commingled MFP9509	7
Bruce Commingled MFP9509	631
Dinant Commingled MFP9509	1
Edberg Commingled MFP9509	0
Fort Saskatchewan Commingled MFP9509	162
Holmberg Commingled MFP9509	153
Kelsey Commingled MFP9509	94
Killam Commingled MFP9509	86
Killam North Commingled MFP9509	78
Mannville Commingled MFP9509	498
Sedgewick Commingled MFP9509	8
Viking-Kinsella Commingled MFP9509	1 584
Wainwright Commingled MFP9509	381
Total	3 954
Commingled MFP9510	
Chickadee Commingled MFP9510	1 384
Fox Creek Commingled MFP9510	872
Kaybob South Commingled MFP9510	1 886
Windfall Commingled MFP9510	0
Total	4 142
Commingled MFP9511	
Hudson Commingled MFP9511	55
Sedalia Commingled MFP9511	252
Total	307
Commingled MFP9512	
Inland Commingled MFP9512	29
Royal Commingled MFP9512	0
Total	29
Commingled MFP9513	
Elmworth Commingled MFP9513	16 450
Sinclair Commingled MFP9513	4 490
Total	20 940
Commingled MFP9514	
Connorsville Commingled MFP9514	577
Wintering Hills Commingled MFP9514	229
Total	806

(continued)

Table B.6 Natural gas reserves of multifield pools, 2011 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9515	
Craigmyle Commingled MFP9515	7
Dowling Lake Commingled MFP9515	9
Garden Plains Commingled MFP9515	795
Hanna Commingled MFP9515	365
Provost Commingled MFP9515	145
Racosta Commingled MFP9515	79
Richdale Commingled MFP9515	327
Stanmore Commingled MFP9515	28
Sullivan Lake Commingled MFP9515	54
Watts Commingled MFP9515	46
Total	1 855
Commingled MFP9516	
Knopcik Commingled MFP9516	547
Valhalla Commingled MFP9516	18
Total	565
Commingled MFP9517	
Comrey Commingled MFP9517	23
Conrad Commingled MFP9517	105
Forty Mile Commingled MFP9517	54
Pendant D'Oreille Commingled MFP9517	558
Smith Coulee Commingled MFP9517	257
Total	997
Commingled MFP9520	
Gadsby Commingled MFP9520	4
Leahurst Commingled MFP9520	147
Total	151
Commingled MFP9522	
Enchant Commingled MFP9522	218
Grand Forks Commingled MFP9522	8
Little Bow Commingled MFP9522	3
Retlaw Commingled MFP9522	331
Vauxhall Commingled MFP9522	25
Total	585
Commingled MFP9524	
Stirling Commingled MFP9524	87
Warner Commingled MFP9524	19
Total	106
Commingled MFP9525	
Resthaven Commingled MFP9525	2 395
Smoky Commingled MFP9525	172
Total	2 567
Commingled MFP9526	
Garrington Commingled MFP9526	55
Innisfail Commingled MFP9526	21
Markerville Commingled MFP9526	134
Medicine River Commingled MFP9526	115
Penhold Commingled MFP9526	5
Sylvan Lake Commingled MFP9526	479
Tindastoll Commingled MFP9526	67
Total	876
Commingled MFP9527	
Crystal Commingled MFP9527	145
Gilby Commingled MFP9527	35
Minnehik-Buck Lake Commingled MFP9527	123
Westerose South Commingled MFP9527	220
Wilson Creek Commingled MFP9527	324
Total	847

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9529	
Berland River Commingled MFP9529	30
Berland River West Commingled MFP9529	36
Cecilia Commingled MFP9529	6 307
Elmworth Commingled MFP9529	1 167
Fir Commingled MFP9529	7 730
Kaybob South Commingled MFP9529	4 758
Oldman Commingled MFP9529	1 421
Red Rock Commingled MFP9529	4 258
Sundance Commingled MFP9529	55
Wapiti Commingled MFP9529	19 518
Wild River Commingled MFP9529	18 379
Wildhay Commingled MFP9529	890
Total	64 549
Commingled MFP9530	
Gilby Commingled MFP9530	226
Prevo Commingled MFP9530	57
Total	283
Commingled MFP9531	
Nosehill Commingled MFP9531	1 765
Oldman Commingled MFP9531	16
Pine Creek Commingled MFP9531	2 602
Total	4 383
Commingled MFP9532	
Grizzly Commingled MFP9532	180
Waskahigan Commingled MFP9532	42
Total	222
Commingled MFP9533	
Bigstone Commingled MFP9533	154
Placid Commingled MFP9533	651
Total	805
Commingled MFP9534	
Jenner Commingled MFP9534	24
Princess Commingled MFP9534	0
Total	24
Commingled MFP9535	
Carrot Creek Commingled MFP9535	145
Pembina Commingled MFP9535	249
Total	394
Commingled MFP9536	
Chinook Commingled MFP9536	103
Dobson Commingled MFP9536	10
Heathdale Commingled MFP9536	20
Kirkwall Commingled MFP9536	10
Sedalia Commingled MFP9536	1
Sounding Commingled MFP9536	83
Stanmore Commingled MFP9536	68
Total	295
Commingled MFP9537	
Ferrier Commingled MFP9537	274
Pembina Commingled MFP9537	2 071
Willesden Green Commingled MFP9537	1 568
Total	3 913

(continued)

Table B.6 Natural gas reserves of multifield pools, 2011 (continued)

Multifield pool Field and pool	Remaining established reserves ($10^6 m^3$)
Commingled MFP9538	
Carrot Creek Commingled MFP9538	1 192
Edson Commingled MFP9538	790
Rosevear Commingled MFP9538	116
Total	2 098
Commingled MFP9501 (Southeast Alberta Gas System)	
Aerial Commingled MFP9501	108
Alderson Commingled MFP9501	16 069
Armada Commingled MFP9501	42
Atlee-Buffalo Commingled MFP9501	2 098
Badger Commingled MFP9501	63
Bantry Commingled MFP9501	12 959
Berry Commingled MFP9501	71
Bindloss Commingled MFP9501	706
Blackfoot Commingled MFP9501	364
Bow Island Commingled MFP9501	300
Brooks Commingled MFP9501	326
Carbon Commingled MFP9501	455
Cavalier Commingled MFP9501	574
Cessford Commingled MFP9501	6 482
Chain Commingled MFP9501	171
Connemara Commingled MFP9501	4
Connorsville Commingled MFP9501	1 386
Countess Commingled MFP9501	36 212
Craigmyle Commingled MFP9501	561
Crossfield Commingled MFP9501	66
Davey Commingled MFP9501	313
Delia Commingled MFP9501	403
Drumheller Commingled MFP9501	1 538
Elkwater Commingled MFP9501	991
Elnora Commingled MFP9501	242
Enchant Commingled MFP9501	13
Entice Commingled MFP9501	8 098
Erskine Commingled MFP9501	30
Ewing Lake Commingled MFP9501	80
Eyremore Commingled MFP9501	853
Fenn West Commingled MFP9501	23
Fenn-Big Valley Commingled MFP9501	1 045
Gadsby Commingled MFP9501	360
Gartley Commingled MFP9501	20
Ghost Pine Commingled MFP9501	718
Gleichen Commingled MFP9501	356
Hector Commingled MFP9501	24
Herronton Commingled MFP9501	1 371
High River Commingled MFP9501	14
Hussar Commingled MFP9501	4 021
Huxley Commingled MFP9501	415
Jenner Commingled MFP9501	2 064
Joffre Commingled MFP9501	5
Johnson Commingled MFP9501	45
Jumpbush Commingled MFP9501	491
Kitsim Commingled MFP9501	41
Lathom Commingled MFP9501	2 088
Leckie Commingled MFP9501	636
Leo Commingled MFP9501	401
Little Bow Commingled MFP9501	26
Lomond Commingled MFP9501	74
Lone Pine Creek Commingled MFP9501	188
Long Coulee Commingled MFP9501	212
Majorville Commingled MFP9501	487
Matziwin Commingled MFP9501	954
Mcgregor Commingled MFP9501	28
Medicine Hat Commingled MFP9501	44 274
Michichi Commingled MFP9501	290
Mikwan Commingled MFP9501	444
Milo Commingled MFP9501	32
Newell Commingled MFP9501	1 631
Okotoks Commingled MFP9501	145
Pageant Commingled MFP9501	4
Parflesh Commingled MFP9501	922
PenholdCommingled MFP9501	3
Pollockville Commingled MFP9501	2
Princess Commingled MFP9501	8 731
Queenstown Commingled MFP9501	51
Rainier Commingled MFP9501	10
Redland Commingled MFP9501	789
Rich Commingled MFP9501	316
Rockyford Commingled MFP9501	2 154
Ronalane Commingled MFP9501	67
Rowley Commingled MFP9501	427
Rumsey Commingled MFP9501	38
Seiu Lake Commingled MFP9501	324
Shouldice Commingled MFP9501	697
Silver Commingled MFP9501	10
Stettler Commingled MFP9501	101
Stettler North Commingled MFP9501	29
Stewart Commingled MFP9501	632
Suffield Commingled MFP9501	14 158
Swalwell Commingled MFP9501	457
Three Hills Creek Commingled MFP9501	804
Trochu Commingled MFP9501	523
Twining Commingled MFP9501	663
Verger Commingled MFP9501	4 948
Vulcan Commingled MFP9501	121
Wayne-Rosedale Commingled MFP9501	4 335
West Drumheller Commingled MFP9501	57
Wimborne Commingled MFP9501	830
Wintering Hills Commingled MFP9501	3 342
Workman Commingled MFP9501	49
Total	200 095

Table B.7 Remaining raw ethane reserves as of December 31, 2011

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane Gas (10^6 m^3)	Liquid (10^3 m^3)
Ansell	14 953	0.082	1 345	4 782
Brazeau River	8 174	0.077	758	2 696
Caroline	5 906	0.085	685	2 436
Cecilia	6 391	0.062	445	1 582
Countess	38 407	0.007	297	1 055
Dunvegan	6 837	0.044	334	1 186
Edson	4 732	0.073	380	1 349
Elmworth	22 746	0.059	1 461	5 193
Ferrier	9 467	0.084	874	3 108
Fir	8 695	0.057	535	1 904
Garrington	3 657	0.074	320	1 139
Gilby	4 936	0.068	372	1 324
Gold Creek	5 443	0.082	480	1 705
Golden Spike	2 257	0.126	417	1 481
Harmattan East	6 676	0.084	633	2 250
Judy Creek	4 069	0.150	751	2 671
Kaybob South	12 341	0.073	1 028	3 654
Karr	3 466	0.076	291	1 035
Kakwa	11 565	0.082	1 038	3 690
Leduc-Woodbend	3 176	0.137	518	1 842
Medicine River	3 184	0.088	323	1 147
Pembina	22 182	0.082	2 468	8 773
Pine Creek	8 720	0.073	730	2 596
Pouce Coupe South	7 438	0.048	394	1 399
Provost	9 640	0.029	295	1 050
Rainbow	9 605	0.096	1 237	4 396
Rainbow South	2 849	0.099	409	1 453
Red Rock	5 253	0.059	345	1 226
Redwater	3 648	0.094	483	1 717
Ricinus	4 310	0.068	349	1 239
Simonette	2 519	0.087	320	1 138
Sinclair	8 870	0.050	487	1 732
Sundance	5 526	0.071	428	1 520
Swan Hills South	3 239	0.173	799	2 841
Sylvan Lake	3 405	0.078	297	1 057
Valhalla	7 123	0.074	583	2 072
Virginia Hills	1 322	0.177	287	1 022
Westpem	3 809	0.099	423	1 504
Westerose South	5 947	0.083	547	1 943
Wembley	2 625	0.093	301	1 070
Wapiti	24 985	0.055	1 461	5 194
Wild River	19 240	0.070	1 465	5 209
Willesden Green	18 000	0.087	2 151	7 646
Wilson Creek	4 854	0.073	402	1 428
Subtotal	**372 187**	**0.070**	**29 944**	**106 453**
All other fields	**572 871**	**0.030**	**16 974**	**60 389**
Total	**945 058**	**0.052** [a]	**46 918**	**166 842**

[a] Volume weighted average.

Table B.8 Remaining raw reserves of natural gas liquids as of December 31, 2011

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid) Propane	Butanes	Pentanes plus	Total liquids
Ansell	14 953	2 205	1 166	2 452	5 823
Brazeau River	8 174	1 316	782	1 674	3 771
Caroline	5 906	1 015	637	1 187	2 839
Carrot Creek	2 678	480	223	183	886
Cecilia	6 391	495	206	687	1 387
Dunvegan	6 837	575	332	554	1 461
Edson	4 732	503	237	251	991
Elmworth	22 746	1 647	761	846	3 253
Fenn-Big Valley	2 468	887	387	108	1 382
Ferrier	9 467	1 495	742	624	2 862
Fir	8 695	731	359	478	1 567
Garrington	3 657	508	267	379	1 154
Gilby	4 936	652	331	364	1 346
Gold Creek	5 443	521	249	368	1 139
Golden Spike	2 257	1 216	162	565	1 942
Harmattan East	6 676	848	534	916	2 298
Judy Creek	4 069	1 797	748	431	2 976
Kakwa	11 565	1 547	720	764	3 032
Karr	3 466	445	201	204	849
Kaybob	2 669	383	185	262	829
Kaybob South	12 341	1 668	846	1 138	3 652
Leduc-Woodbend	3 176	1 536	881	501	2 918
Medicine River	3 184	530	261	249	1 039
Pembina	22 182	5 126	2 586	1 998	9 709
Pine Creek	8 720	1 126	532	577	2 235
Pouce Coupe South	7 438	530	293	313	1 135
Provost	9 640	619	399	288	1 307
Rainbow	9 605	1 917	1 070	1 117	4 104
Rainbow South	2 849	748	346	416	1 510
Redwater	3 648	1 273	790	313	2 376
Ricinus	4 310	578	293	552	1 423
Simonette	2 519	566	327	330	1 222
Sinclair	8 870	615	261	268	1 144
Sundance	5 526	558	243	226	1 027
Swan Hills South	3 239	1 946	892	377	3 215
Sylvan Lake	3 405	466	226	212	904
Valhalla	7 123	997	547	825	2 368
Virginia Hills	1 322	677	221	87	985
Wapiti	24 985	1 472	610	583	2 666
Waterton	4 289	230	208	1 314	1 752
Wayne-Rosedale	5 975	413	221	248	882
Wembley	2 625	582	341	765	1 688
Westerose South	5 947	1 023	502	500	2 025
Westpem	3 809	669	321	288	1 278

(continued)

Table B.8 Remaining raw reserves of natural gas liquids as of December 31, 2011 (continued)

Field	Remaining reserves of marketable gas (10^6 m^3)	Propane	Butanes	Pentanes plus	Total liquids
		(10^3 m^3 liquid)			
Wild River	19 240	1 694	707	1 067	3 468
Willesden Green	18 000	3 705	1 677	1 513	6 896
Wilson Creek	4 854	653	360	443	1 456
Subtotal	**346 606**	**51 182**	**25 188**	**29 804**	**106 174**
All other fields	**598 452**	**24 320**	**13 702**	**17439**	**54 741**
Total	**945 058**	**75 502**	**38 890**	**46 523**	**160 915**

Appendix C CD—Basic Data Tables

ERCB staff developed the databases used to prepare this reserves report and CD. Input was also obtained from the National Energy Board (NEB) through an ongoing process of crude oil, natural gas, and crude bitumen studies. The crude oil and natural gas reserves data tables present the official reserve estimates of both the ERCB and NEB for the province of Alberta.

Basic Data Tables

The conventional oil and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2011 on the CD that accompanies this report (available for $546 from ERCB Information Services). The individual oil and gas pool values are presented on the first worksheet of each spreadsheet. Oilfield and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data presented in **Tables B.1 and B.2** are included in Excel format on the CD.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet is similar to the data table in last year's report and contains all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are presented in separate columns. The total record contains the summation of the multi-mechanism pool reserves data. These data appear in the pool column, which can be used for determining field and provincial totals. The mechanism type is displayed with the names.

Provincial totals for light-medium and heavy oil pools are presented separately on the provincial total worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet in this report is similar to last year's report and contains all nonconfidential pools in Alberta.

Basic reserves data are split into two columns: pools (individual, undefined, and total records) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total record contains a summation of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Crude Bitumen Resources and Basic Data

The Crude Bitumen In-Place Resources and Basic Data spreadsheet is similar to the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns.

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
BDY	boundary
BELL	Belloy
BER	beyond economic reach
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
COMP	compressibility
DBLT	Debolt
DETR	Detrital
DISC YEAR	discovery year
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton

ERSO	enhanced-recovery scheme is in operation but no additional established reserves are attributed
FALH	Falher
FRAC	fraction
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GOR	gas-oil ratio
GRD RAP or GRD RP	Grand Rapids
GROSS HEAT VALUE	gross heating value
GSMT	Grosmont
ha	hectare
HFWY	Halfway
INJ	injected
I.S.	integrated scheme
JUR or J	Jurassic
KB	kelly bushing
KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LF	load factor
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOC EX PROJECT	local experimental project
LOC U	local utility
LOW or L	lower
LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MOP	maximum operating pressure
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NO.	number
NON-ASSOC	nonassociated gas
NORD	Nordegg

NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
PM-PN SYS	Permo-Penn System
RF	recovery factor
RK CK	Rock Creek
RUND or RUN	Rundle
SA	strike area
SATN	saturation
SD	sandstone
SE ALTA GAS SYS (MU)	Southeastern Alberta Gas System - commingled
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1 Development and exploratory wells, pre-1972–2011; number drilled annually

	Development					Exploratory				Total			
	Successful	Crude bitumen				Successful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
Pre-1972	11 873	*	**	7 869	24 325	1 624	**	3 619	31 639	13 497	**	11 488	55 964
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054

(continued)

Table D.1 Development and exploratory wells, pre-1972–2011; number drilled annually (continued)

	Development					Exploratory				Total			
	Successful	Crude bitumen				Successful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980
2010	1 979	1 336	0	3 408	7 103	280	1 331	391	2 130	2 259	2 697	3 799	9 233
2011	2 748	1 748	0	1 857	6 820	367	2 372	228	3 074	3 115	4 121	2 085	9 894
Total	**71 446**	**21 819**	**615**	**136 306**	**255 359**	**17 311**	**25 085**	**47 997**	**146 574**	**88 757**	**47 519**	**184 303**	**401 933**

Source: pre-1972—ERCB corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2011—*Alberta Drilling Activity Monthly Statistics (ST59)*.
[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.
* Included in oil.
** Not available.

Table D.2 Development and exploratory wells, pre-1972–2011; kilometres drilled annually

	Development					Exploratory				Total			
	Successful	Crude bitumen				Successful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
Pre-1972	18 843	*	**	11 640	36 991	2 611	**	4 059	26 556	21 459	**	15 699	63 547
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906

(continued)

Table D.2 Development and exploratory wells, pre-1972–2011; kilometres drilled annually (continued)

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	10 840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087
2010	3 809	1 336	0	5 134	10 653	514	461	848	1 965	4 323	1 797	5 982	12 618
2011	6 106	1 720	0	4 071	12 425	676	870	594	2 373	6 782	2 590	4 665	14 798
Total	**102 840**	**20 519**	**373**	**142 420**	**303 643**	**24 314**	**6 490**	**59 717**	**145 539**	**127 154**	**27 382**	**202 138**	**449 182**

Source: pre-1972—ERCB corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2011—*Alberta Drilling Activity Monthly Statistics (ST59)*.
[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.
* Included in oil.
** Not available.

Appendix E Crude Bitumen Pay Thickness and Geologic Structure Contour Maps

This appendix contains geological maps from the Crude Bitumen Section that have appeared in previous *ST98: Alberta's Energy Reserves and Supply/Demand Outlook* reports. These are the maps that the most recent determinations of in-place resources are based on. Any new mapping will be described in the main body of *ST98* in the first year of reporting. For year-end 2011, *Section 3 Crude Bitumen* contains new isopach maps of the Athabasca Nisku deposit and the Athabasca Upper, Middle, and Lower Grand Rapids deposits.

Regional Map

Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity is the stratigraphic surface that forms the base on which the bitumen-bearing Cretaceous sediments were deposited. **Figure AE.1** is a structure contour map of that surface as it would have appeared at the end of Bluesky/Wabiskaw time. The parts of the Nisku and Grosmont Formations that are bitumen-bearing are outlined on this map (the Nisku deposit was re-assessed for 2011, but **Figure AE.1** has not been updated). These Devonian carbonate formations subcrop along the sub-Cretaceous surface and contain bitumen in an updip location along the subcrop edge. Of particular note are the areas on this map identified as having a relative subsea elevation of greater than zero. These areas were still emergent at the end of Bluesky/Wabiskaw time and would have existed as islands within the transgressing northern Boreal Sea.

Peace River Oil Sands Area

Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. **Figure AE.2** is the bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 metres (m) thickness. The Bluesky-Gething is mapped as a single bitumen zone, so that the full extent of the deposit at 6 mass per cent can be shown. Also shown on **Figure AE.2** are the paleotopographic highlands as they would have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. As oil migrated updip, it became trapped beneath the overlying Wilrich shales and against these highlands, where it was eventually biodegraded into bitumen.

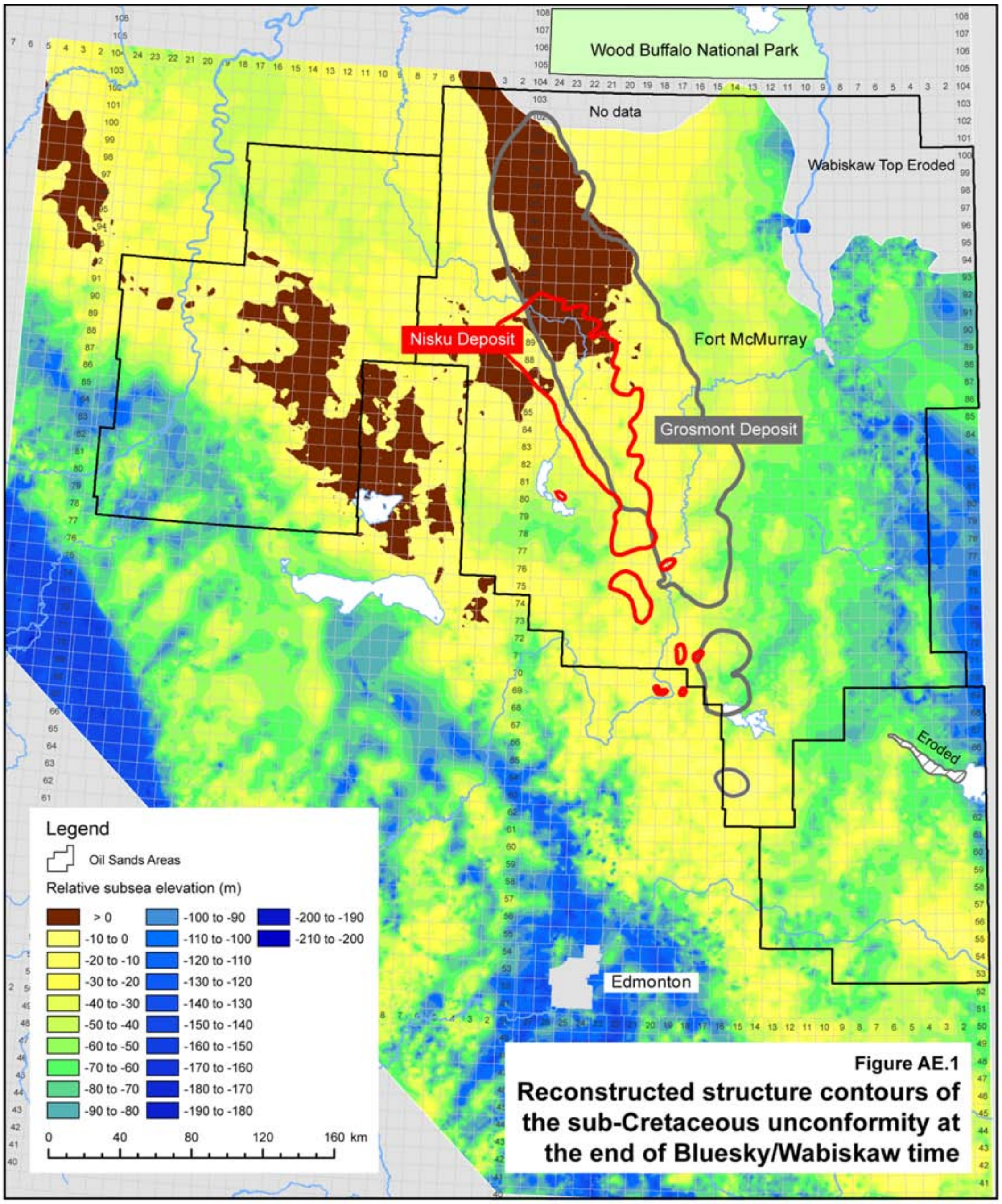


Figure AE.1
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

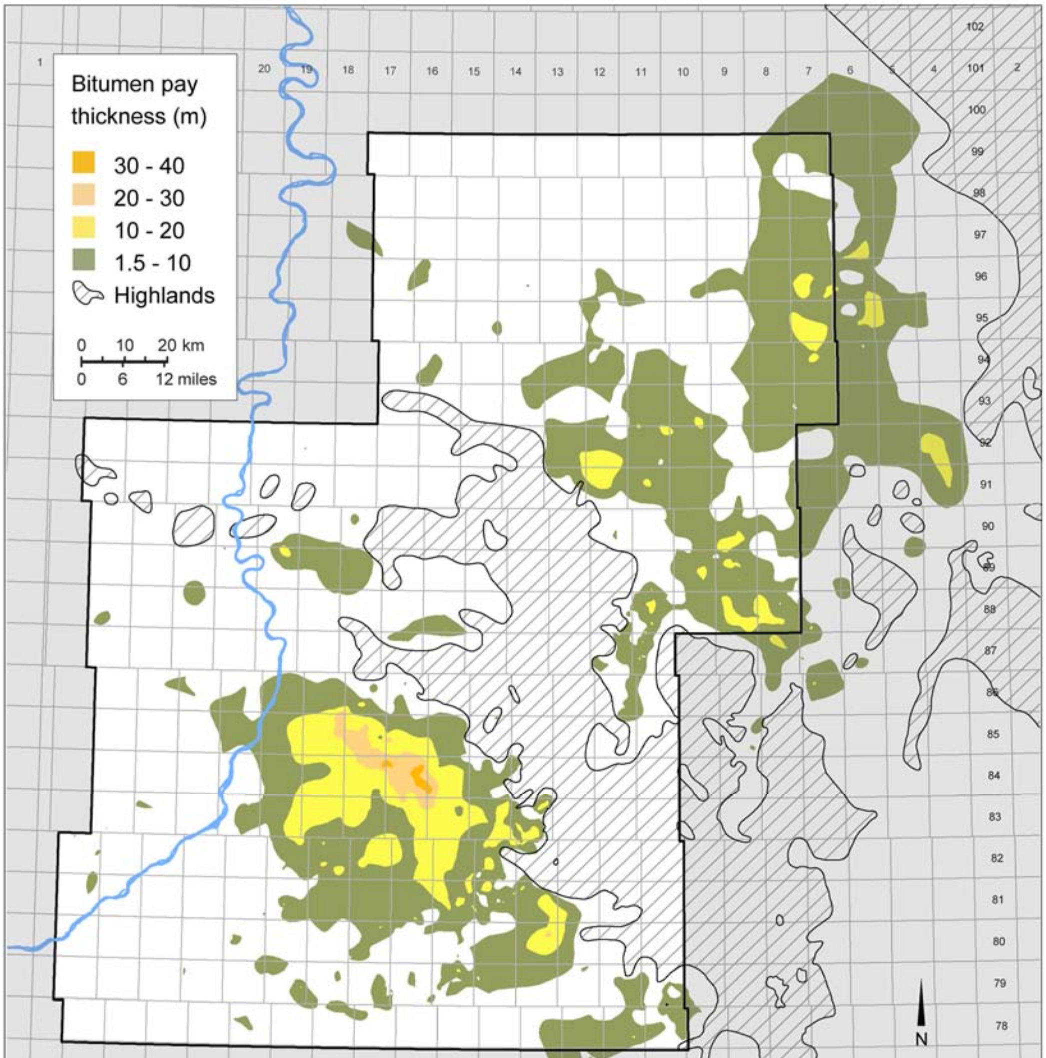


Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

Athabasca Oil Sands Area

Athabasca Grosmont Deposit

In 2009, the ERCB updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Township 62 to 103 and Range 13, West of the 4th Meridian, to 6W5M.

The Grosmont Formation is a late-Devonian shallow marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying

Clearwater Formation. **Figure AE.3** is the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

Athabasca Wabiskaw-McMurray Deposit

In 2003, the ERCB completed a reassessment of the Wabiskaw-McMurray using geological information from over 13 000 wells and bitumen content evaluations from over 9000 wells to augment the over 7000 boreholes already assessed within the surface mineable area (SMA; see below for details). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added.

Figure AE.4 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval. Also shown is the extent of the SMA, an ERCB-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. This designation is for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside the area's boundaries, while in situ activities may occur within the SMA. Because the extent of the SMA is defined using township boundaries, it incorporates a few areas containing deeper bitumen resources that are more amenable to in situ recovery. The ERCB has generated a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is shown in **Figure AE.4**.

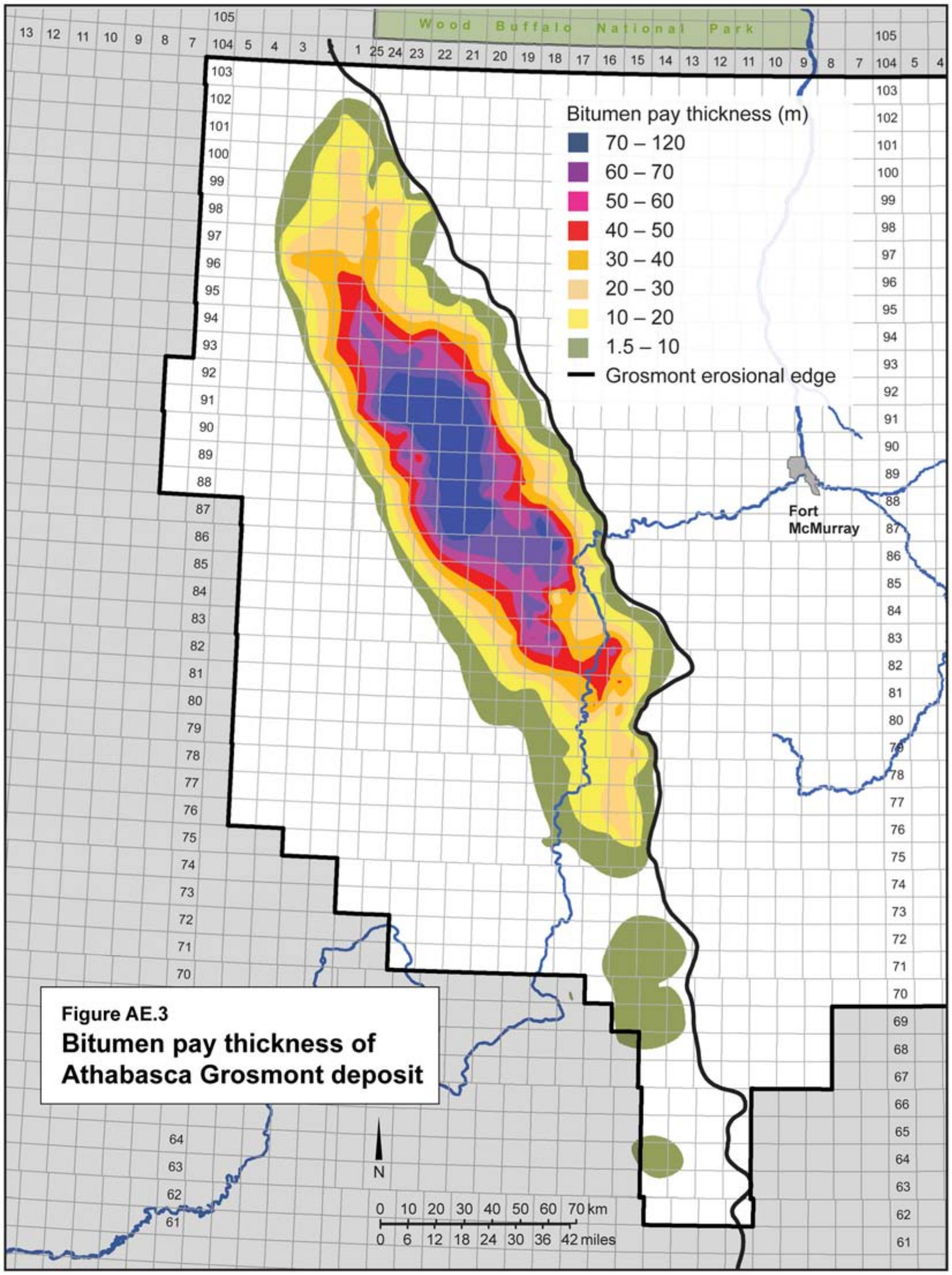


Figure AE.3
Bitumen pay thickness of Athabasca Grosmont deposit

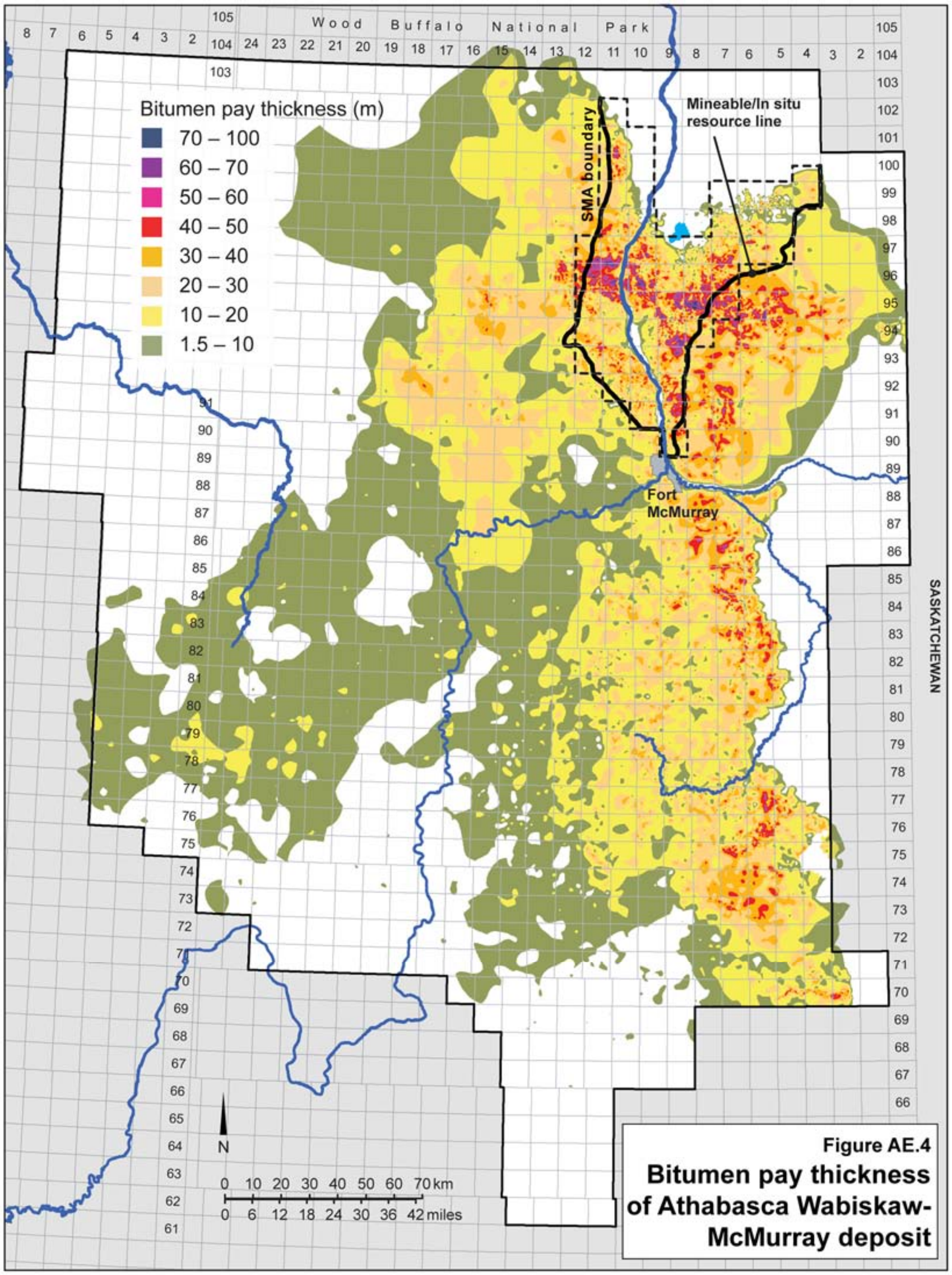


Figure AE.4
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

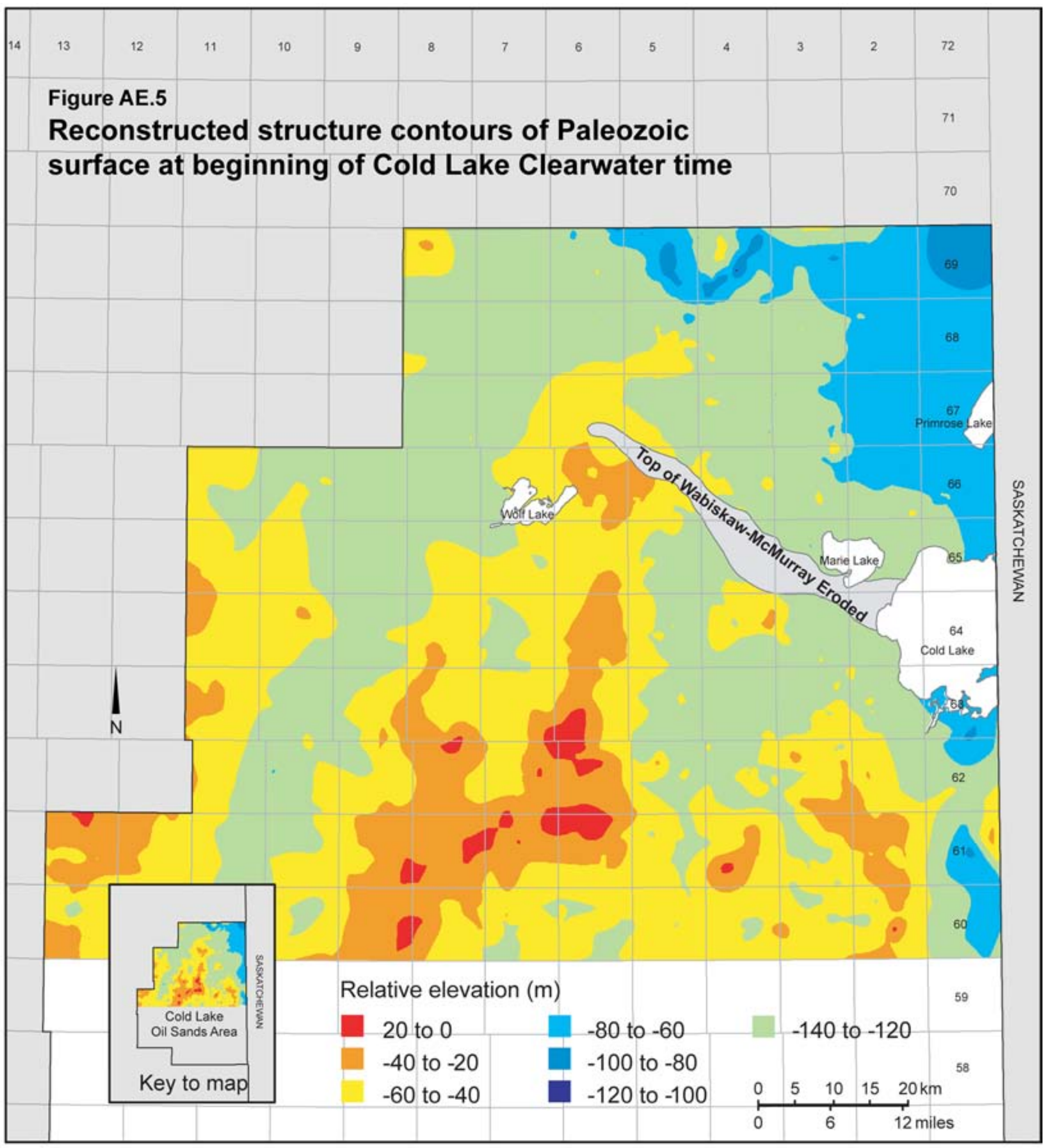
Cold Lake Oil Sands Area

Sub-Cretaceous Unconformity

Figure AE.5 is a map of the reconstructed structure contours for the sub-Cretaceous unconformity in the northern part of the Cold Lake Oil Sands Area as they would have been at the beginning of deposition of the Mannville Clearwater Formation.

Cold Lake Wabiskaw-McMurray Deposit

For year-end 2005, the ERCB reassessed the northern portion of the Cold Lake Wabiskaw-McMurray deposit. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure AE.6** is the bitumen pay thickness map for the Cold Lake Wabiskaw-



McMurray deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Although the Wabiskaw-McMurray contains some regionally mappable internal seals, and therefore several bitumen zones, this map was produced as a single bitumen zone to provide a regional overview of the distribution of the bitumen-saturated sands. A cutoff of 6 mass per cent bitumen was used.

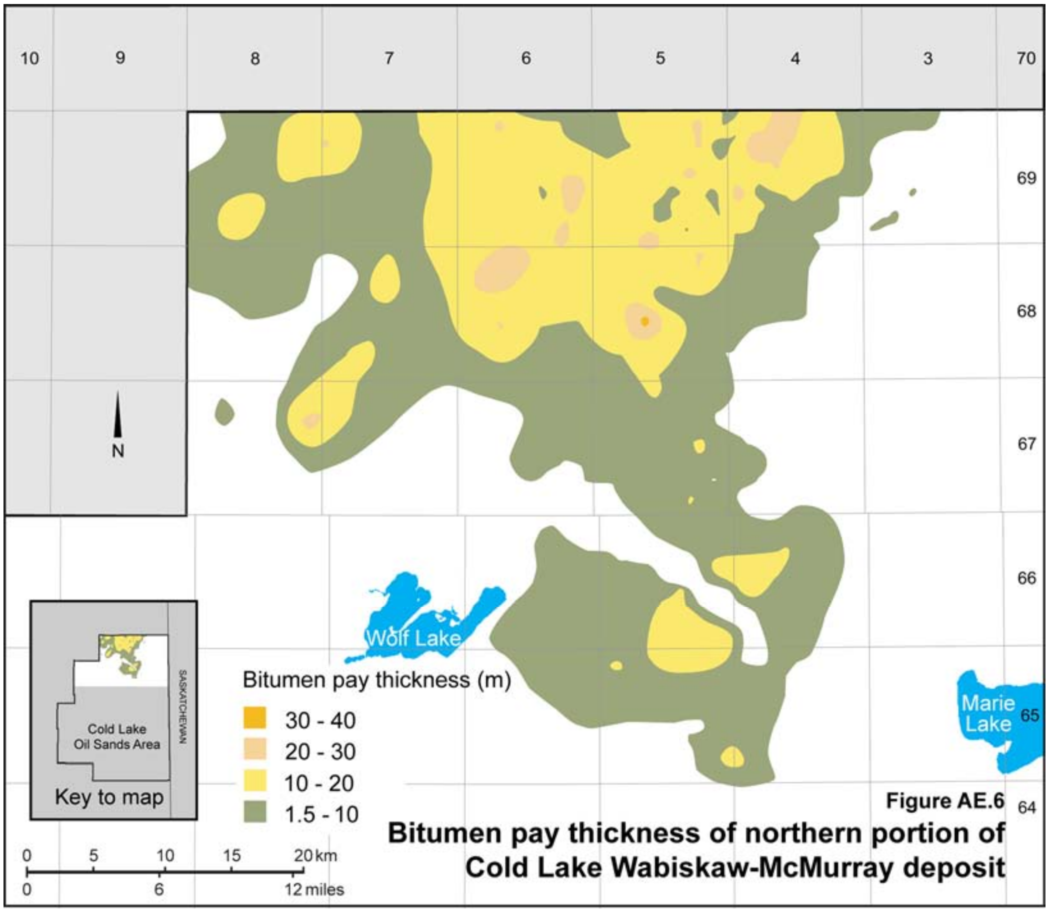


Figure AE.6
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

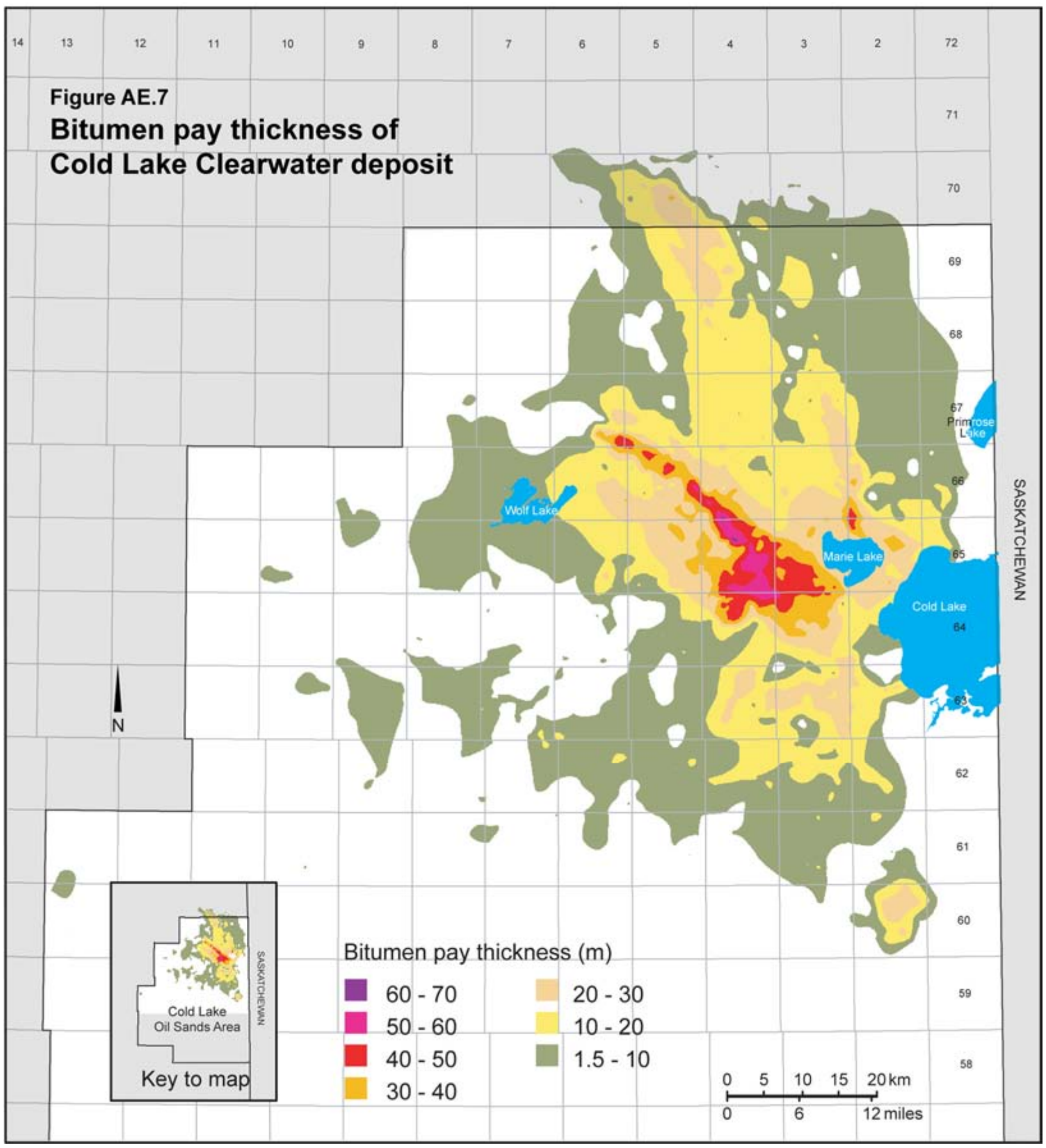
Cold Lake Clearwater Deposit

For year-end 2005, the ERCB completed a reassessment of the Clearwater deposit. **Figure AE.7** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

Cold Lake Upper and Lower Grand Rapids Deposits

A reassessment for year-end 2009 of the Upper and Lower Grand Rapids deposits included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Township 52 to 66 replaced the area used in the previous assessment. Stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster.

Although crude bitumen within both Grand Rapids deposits is pervasive through much of the Cold Lake Oil Sands Area, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figures AE.8** and **AE.9** are maps of the cumulative net pay isopachs for the Lower Grand Rapids deposit and the Upper Grand Rapids deposit, respectively. The net pay interpretations and volumetric calculations were completed for each zone and were then summed for the relevant deposit. The Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids.



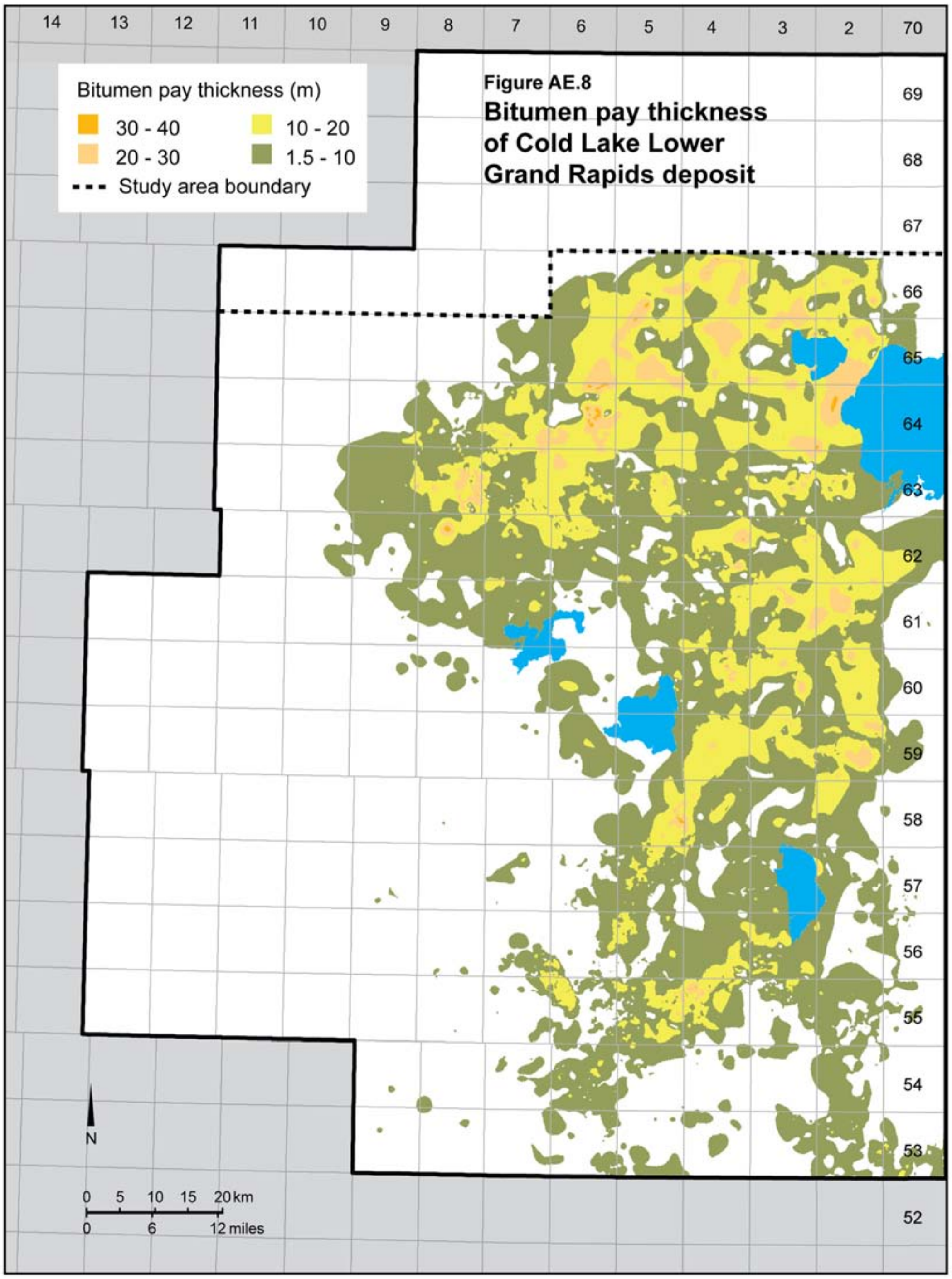


Figure AE.8
Bitumen pay thickness of Cold Lake Lower Grand Rapids deposit
Bitumen pay thickness (m)
30 - 40
20 - 30
10 - 20
1.5 - 10
Study area boundary
14
13
12
11
10
9
8
7
6
5
4
3
2
70
69
68
67
66
65
64
63
62
61
60
59
58
57
56
55
54
53
52
N
0 5 10 15 20 km
0 6 12 miles

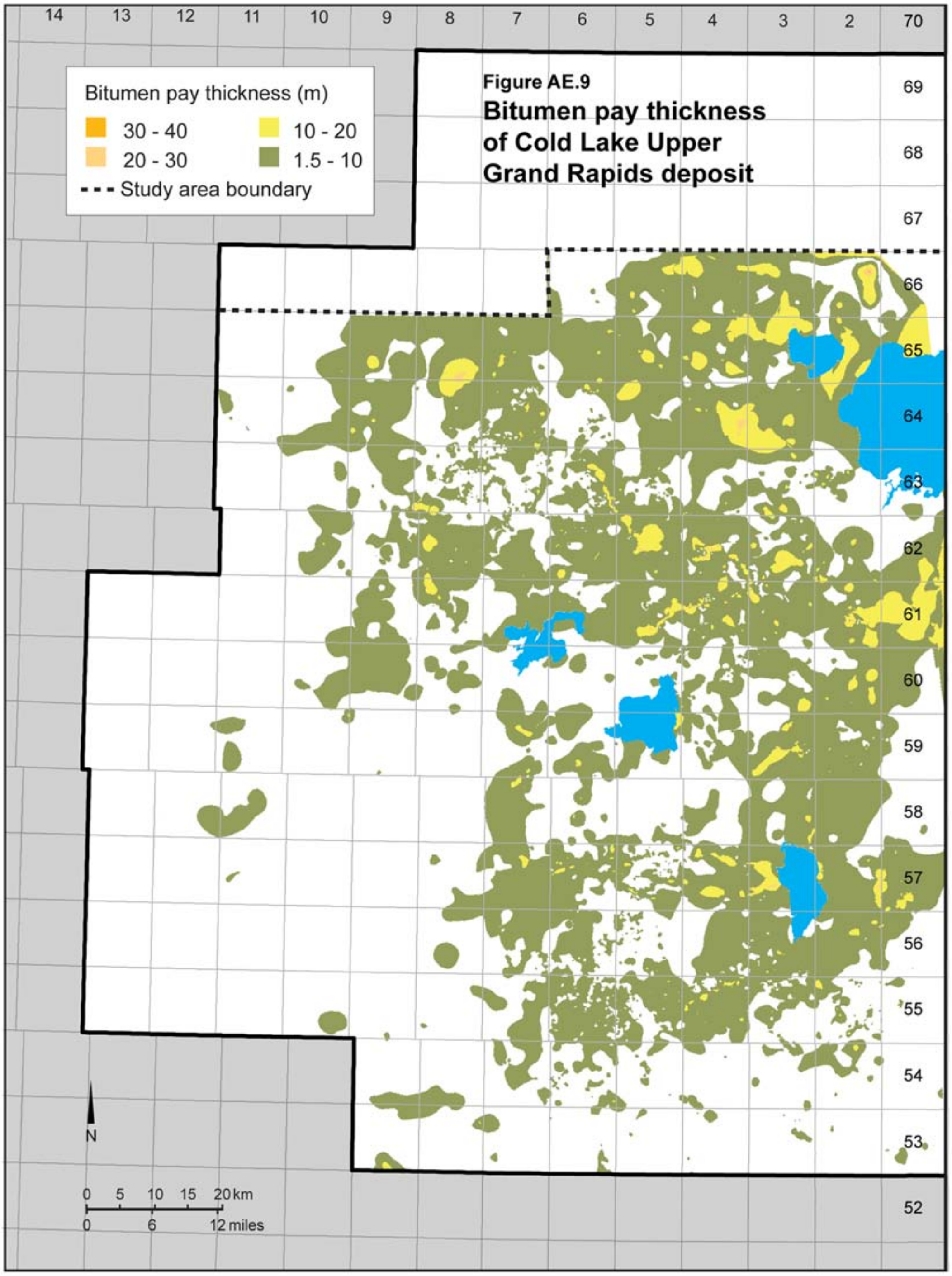


Figure AE.9
Bitumen pay thickness of Cold Lake Upper Grand Rapids deposit

ERCB Energy Resources Conservation Board