ST98-2009

Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018

Energy Resources Conservation Board

ACKNOWLEDGEMENTS

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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 and Oil Sands Areas, $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 and Oil Sands Areas: 60 x 101 cm, $63; 33 x 54 cm, $29

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Overview

The Energy Resources Conservation Board (ERCB) is an independent, quasi-judicial 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.

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 2008 and Supply/Demand Outlook 2009-2018* includes estimates of initial established reserves (recoverable quantities that we have estimated to be in the ground before any production), remaining established reserves (recoverable quantities that we know we have 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. As well, some historical trends on selected commodities are provided for better understanding of supply and price relationships.

Energy Prices and Alberta's Economy

For world energy markets, 2008 will be remembered as a year dominated by record high oil prices, peaking in July, followed by a financial market collapse around the globe with a decline in demand and a resulting oil price slide.

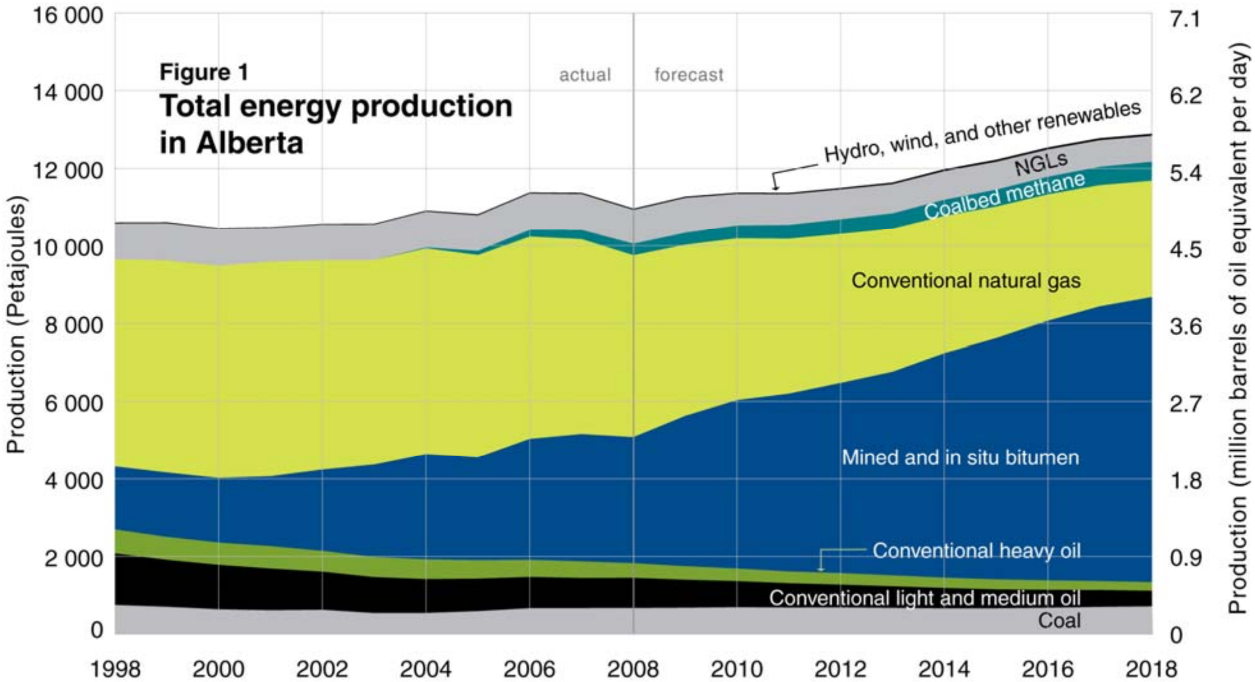
The growth in world oil demand slowed in the United States, Europe, and some Pacific Rim countries. World oil supply grew more than demand, leading to somewhat larger spare capacity in the Organization of Petroleum Exporting Countries (OPEC), particularly Saudi Arabia. By year's end, OPEC had finally curbed its production quotas by some 4 million barrels per day in an attempt to strengthen crude oil prices.

The ERCB is basing its analysis on the expectation that the crude oil price in North America, measured by West Texas Intermediate (WTI) crude oil, will continue to be volatile, averaging US$55 per barrel in 2009 and rising steadily to an average of US$120 per barrel by 2018.

North American natural gas prices and drilling activity were impacted by storage inventory levels that were well above five-year averages, high levels of landed liquefied natural gas (LNG), and growth in U.S. indigenous supply. Industrial natural gas demand also fell, and when combined with the high storage inventory levels and growing supply, a major price decline resulted. While the first half of 2008 experienced price increases, gas prices followed the crude oil price decline in the second half. In 2008, natural gas prices peaked at almost Cdn$10 per gigajoule in July before declining to just over Cdn$6 per gigajoule in December. The average Alberta plant gate natural gas price in 2008 reached Cdn$7.50 per gigajoule, a 27 per cent increase compared with 2007. Natural gas prices in Alberta are expected to average Cdn$4.50 per gigajoule in 2009 and then rise steadily to Cdn$10.00 per gigajoule by 2018.

Energy Production and Reserves in Alberta

While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.3 per cent, is also produced from renewable energy sources, such as hydro and wind power. In 2008, Alberta produced 10 957 petajoules of energy from all sources, including renewable sources. This is equivalent to 4.9 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by these energy sources is illustrated in **Figure 1**.



Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to extract bitumen. Bitumen production accounted for 72 per cent of Alberta's total crude oil and raw bitumen production in 2008. Bitumen production at in situ projects increased by 9 per cent in 2008, while production at mining projects decreased by 8 per cent. As a result, overall raw bitumen production decreased by some 1 per cent compared with 2007.

In 2008, total natural gas production in Alberta declined by 6.5 per cent, crude oil production declined by 3.8 per cent, total natural gas liquids (NGLs) production declined by 6.4 per cent, and sulphur production declined by 11.1 per cent. Coal production remained flat.

The following table summarizes Alberta's energy reserves at the end of 2008.

Reserves and production summary, 2008

	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	275 128	1 731	10 782	67.8	9 046	321	94	103
Initial established	28 092	177	2 773	17.5	5 096	181	35	38
Cumulative production	1 020	6.4	2 540	16.0	3 970	141	1.38	1.52
Remaining established	27 072	170	233	1.5	1 126	40[b]	34	37
Annual production	76	0.477	29.3	0.184	133	4.7	0.038	0.042
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 MJ/m^3. Includes coalbed methane (CBM).
[b] Measured at field gate (or 36.8 trillion cubic feet downstream of straddle plant).
[c] Does not include CBM.

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves for crude bitumen is 27.1 billion cubic metres (m^3) (170.4 billion barrels), slightly less than in 2007 due to reassessment and production. Only 3.6 per cent of the initial established crude bitumen reserves has been produced since commercial production started in 1967.

Crude Bitumen Production

In 2008, Alberta produced 42.0 million m^3 (264 million barrels) from the mineable area and 33.9 million m^3 (213 million barrels) from the in situ area, totalling 75.9 million m^3 (477 million barrels). This is equivalent to 207.4 thousand m^3 (1.31 million barrels) per day. While the bitumen produced from mining was upgraded, bitumen crude produced from in situ operations was mainly marketed as nonupgraded crude bitumen.

Synthetic Crude Oil (SCO) Production[1]

In 2008, all crude bitumen produced from mining, as well as a small portion of in situ production (about 8 per cent), was upgraded in Alberta, yielding 38.0 million m^3 (239 million barrels) of SCO, which equates to about 59 per cent of total crude bitumen produced in Alberta also being upgraded in the province. By 2018, SCO production is forecast to increase by more than double, to 89.0 million m^3 (563 million barrels), which equates to about 61 per cent of total crude bitumen produced in Alberta being upgraded in the province. Over the next ten years, mined bitumen is projected to continue to be the primary source of the bitumen upgraded to SCO in Alberta, with the contribution of in situ production being upgraded to SCO increasing to 28 per cent by the end of the forecast.

[1] The upgrading process produces a variety of lighter products that are collectively referred to as SCO in this report. Naphtha, diesel fuel, and a crude similar to light crude oil in quality are the common products in the upgrading process.

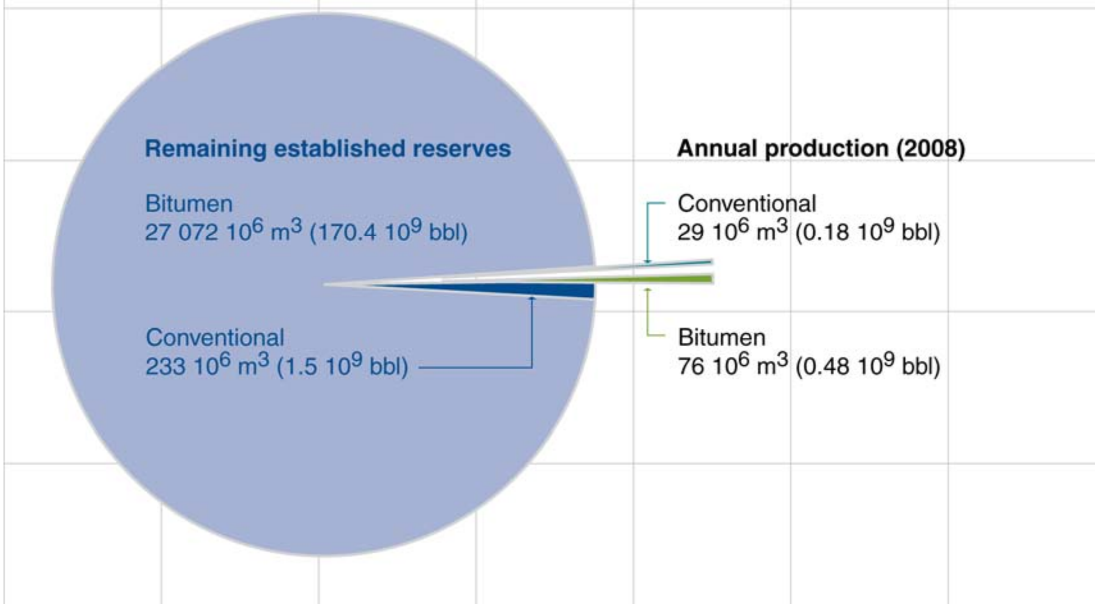
Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 233 million m^3 (1.5 billion barrels), a 3.2 per cent decrease from 2007. Exploratory and development drilling, as well as new enhanced recovery schemes, added total reserves of 20.6 10^6 m^3 (130 million barrels). This replaced 77 per cent of the 2008 production.

Based on its 1988 study, the ERCB estimates the ultimate potential recoverable reserves of crude oil at 3130 million m^3 (19.7 billion barrels). The ERCB believes that this estimate of ultimate potential is still reasonable. Future improvements in technology could improve the current average recovery efficiency of 26 per cent.

Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 2**.

Figure 2
Alberta oil reserves



Crude Oil Production and Well Activity

Alberta's production of conventional crude oil totalled 29.25 million m^3 (184 million barrels) in 2008. This equates to 79.9 10^3 m^3 (503 thousand barrels) per day.

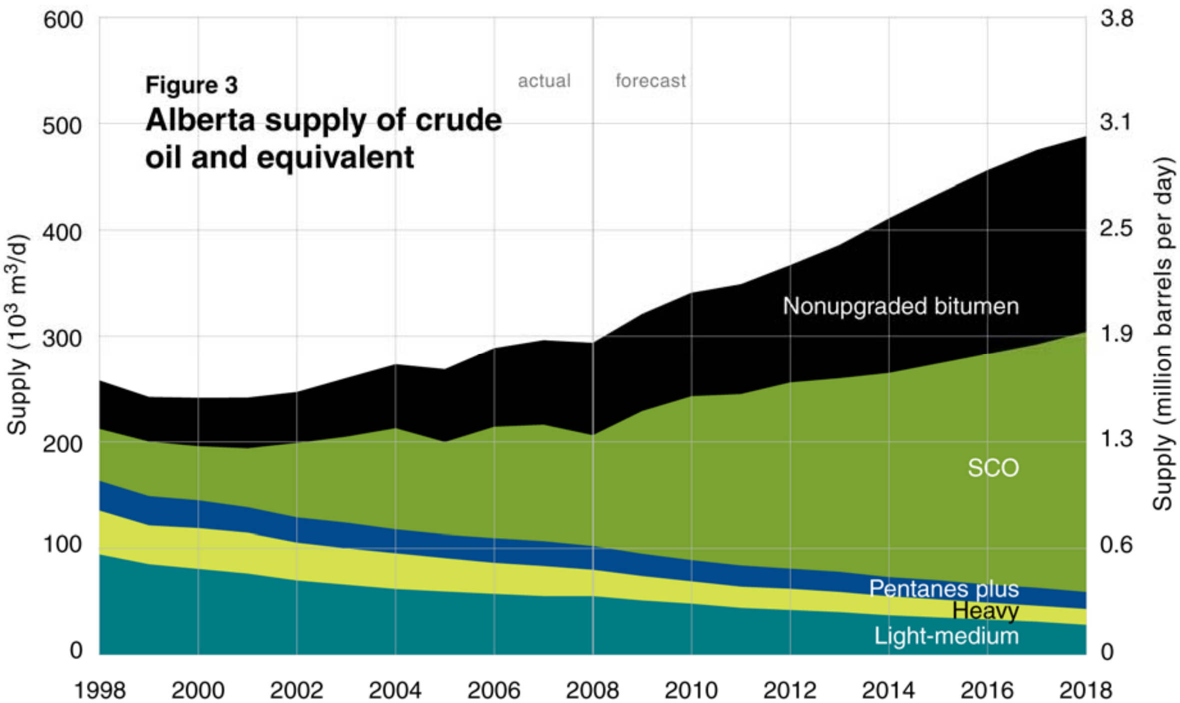
The number of oil wells placed on production decreased slightly to 1738 in 2008 from 1745 in 2007. With the expectation of lower crude oil prices, the ERCB estimates that the number of new wells placed on production will decrease to 1200 wells in 2009 and 2010. It is expected that the number of wells placed on production will increase to 1500 in 2011 and to 1700 in 2012 and remain at this level for the remaining forecast period, as crude oil prices increase and drilling activity returns to recent historical levels.

Total Oil Supply and Demand

Alberta's 2008 supply of crude oil and equivalent was 294 10^3 m^3 (1.85 million barrels) per day, a 1 per cent decrease compared with 2007. Production is forecast to reach 486 10^3 m^3 (3.1 million barrels) per day by 2018.

A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 3**, clearly shows the increasing contribution of bitumen to Alberta's oil production. This ability to shift from conventional oil to bitumen is unique to Alberta, allowing the province to offset the continued decline in conventional oil with bitumen production.

The ERCB estimates that bitumen production will more than double by 2018. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 65 per cent in 2008 to 88 per cent by 2018.



Natural Gas

Natural gas is produced from conventional and unconventional reserves in Alberta. While natural gas production from conventional sources accounts for the majority, natural gas production from coal—CBM—is on the rise. Natural gas production from other sources, such as shale gas, may prove to be an additional significant source in the future.

Unconventional Natural Gas Reserves

In recognition of the potential of unconventional gas sources other than CBM, the ERCB has broadened its CBM section to include shale gas for year-end 2008. However, given the early stage of resource development of shale gas in Alberta, the established reserves and production history are exclusively CBM. CBM has been recognized as a commercial supply of natural gas in Alberta since 2002. Activity in CBM has increased dramatically from a few test wells in 2001 to over 11 000 producing wells in 2008. The growth in

CBM data collection and gas production has increased confidence in publication of CBM reserves estimates, despite continued uncertainty regarding recovery factors and production accounting.

At the end of 2008, the remaining established reserves of CBM in Alberta is estimated to be 28.3 billion m^3 (1005 billion cubic feet), with just over half of that attributed to the deeper, wetter Mannville zone in Central Alberta (15.8 billion m^3). Currently, 97 per cent of producing CBM wells are in the dry Horseshoe Canyon Formation in the area between Edmonton and Calgary.

Conventional Natural Gas Reserves

At the end of 2008, Alberta's remaining established reserves of natural gas stood at 1098 billion m^3 (39 trillion cubic feet [Tcf]) at the field gate. This reserve includes some liquids that are subsequently removed at straddle plants. Reserves from new drilling replaced 81 per cent of production in 2008. This compares with 78 per cent replacement in 2007.[2]

In March 2005, the ERCB (Alberta Energy and Utilities Board [EUB] at the time) and the National Energy Board (NEB) 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).

Total Natural Gas Production and Well Activity

Several major factors have an impact on natural gas production, including natural gas prices, drilling activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. Alberta produced 133 billion m^3 (4.7 Tcf) of marketable natural gas in 2008, of which 8.0 billion m^3 (0.28 Tcf) was CBM.

There were 7907 conventional gas well connections in 2008, a 15 per cent decrease from the 9286 gas well connections in 2007. The ERCB expects a slow recovery in gas well connections, estimating that 6800 connections will occur in 2009. The ERCB estimates that this number will increase to 7500 connections in 2010, 9500 in 2011, and then 10 000 well connections per year to the end of the forecast period.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta, which contains over half of the province's producing gas wells but only 20 per cent of the 2008 natural gas production. The ERCB anticipates that shallow drilling will continue to account for a large share of the activity in the province over the next few years.

CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 1466 successful CBM well connections in Alberta in 2008. The ERCB expects CBM well connections to decrease in 2009 to 1400.

Total Natural Gas Supply and Demand

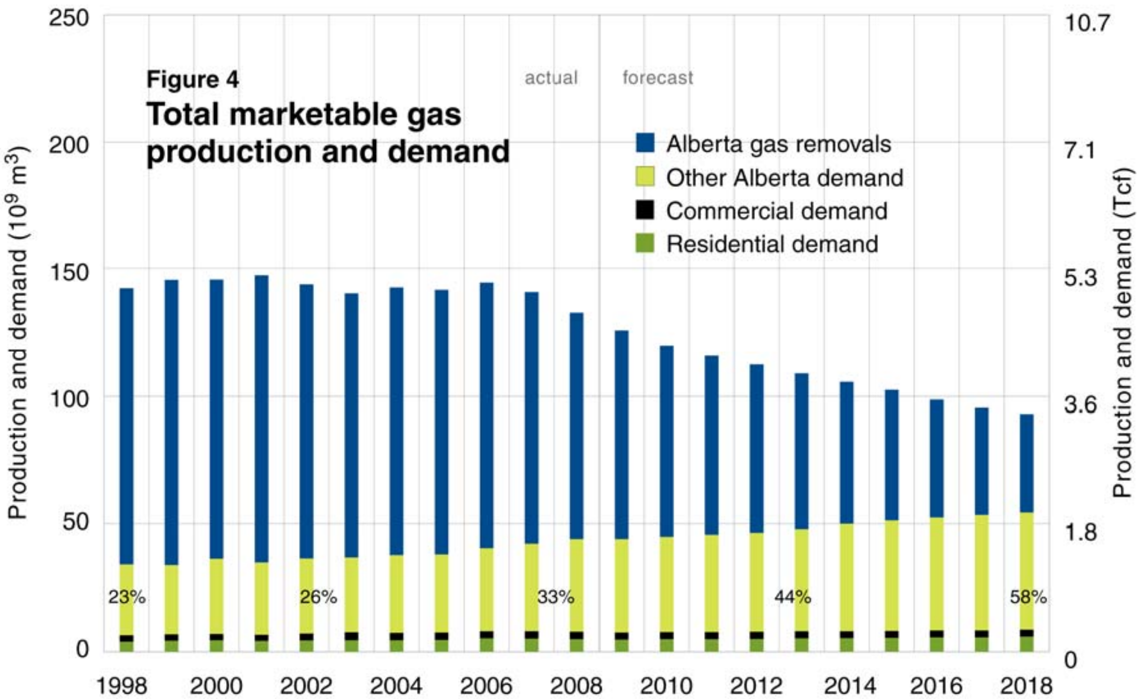
The ERCB expects conventional gas production to decline by 6.0 per cent in 2009 and an average of 4.0 per cent per year thereafter. New pools are smaller, and new wells drilled

[2] The 2007 percentage has been amended to reflect the revised methodology used for 2008.

today are exhibiting lower initial production rates and steeper decline rates. Factoring this in, the ERCB believes that new wells drilled will not be able to sustain production levels over the forecast period. CBM production is forecast to supplement the supply of conventional gas in the province but not to replace the decline in conventional gas production.

Although natural gas supply from conventional sources is declining, sufficient supply exists to easily meet Alberta's demand. If the ERCB's demand forecast is realized, Alberta's natural gas requirement will be 58 per cent of total Alberta production by the end of the forecast period.

As Alberta requirements increase and production declines over time, the volumes available for removal from the province will decline. The ERCB's mandate requires that the natural gas requirements for Alberta's core market (defined as residential, commercial, and institutional gas consumers) are met over the long term before any new gas removal permits are approved. **Figure 4** depicts Alberta's marketable gas production (at 37.4 MJ/m^3) and disposition.



Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 121 million m^3 (762 million barrels) as of year-end 2008. 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.

In 2008, the production of specification ethane decreased to 35.3 thousand m^3 (222 thousand barrels) per day from the 2007 level of 39.7 thousand m^3 (250 thousand barrels) per day. The majority of ethane was used as feedstock for Alberta's petrochemical industry. Although the forecast supply crosses over the demand curve prior to the end of the forecast, incremental ethane volumes required to meet demand are assumed to be available from off-gas or higher extraction rates from existing processing facilities.

The remaining established reserves of other NGLs—propane, butanes, and pentanes plus—is 161 million m^3 (1014 million barrels) in 2008. The supply of propane and butanes is expected to meet demand over the forecast period. Due to the tightness in supply of pentanes plus, alternative sources of diluent are being used by industry to dilute the heavier crude to meet pipeline quality.

The remaining established reserves of sulphur increased in 2008 by 21 per cent, from 154 million tonnes in 2007 to 186 million tonnes, as the bitumen reserves under active development increased. Sulphur is recovered from the processing of natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is expected to gradually increase until 2011 and be flat thereafter. It is projected that with relatively flat production over the forecast period, minimal stockpile withdrawals are required to meet forecast demand.

Coal

The current estimate for remaining established reserves of all types of coal is about 34 billion tonnes (37 billion tons). This massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 59 per cent of the province's electricity generation in 2008. Alberta's total coal production in 2008 was 32.5 million tonnes of marketable coal, most of which was subbituminous coal destined for mine mouth power plants. This total production is almost equal to production in 2007. Alberta's coal reserves represent over a thousand years of supply at current production levels. Subbituminous coal production is expected to increase over the forecast period to meet demand for additional domestic electricity generating capacity.

The small portion of Alberta coal production that was exported from the province in 2008 can be separated into thermal coal exports and metallurgical coal exports. The export market for metallurgical coal remained strong due to the continued, though reduced, demand in the Pacific Rim countries for steel production.

Electricity

Electricity generating capacity in Alberta totalled 12 554 megawatts (MW) in 2008. The Long Lake in situ oil sands project and the Horizon mined oil sands project both started up associated cogeneration units in late 2008, which accounted for over 280 MW of new capacity. By the end of the forecast period, the ERCB expects total electricity generating capacity in Alberta to be over 16 000 MW.

In 2008, total electricity generation reached 66 398 gigawatt hours (GWh), slightly lower than the 66 645 GWh in 2007 due to lower coal-fired generation. As a result, Alberta imported 2400 GWh of electricity and exported 532 GWh. Over the forecast period, total electricity generation is expected to grow by an average of 2.8 per cent per year to over 92 000 GWh by 2018.

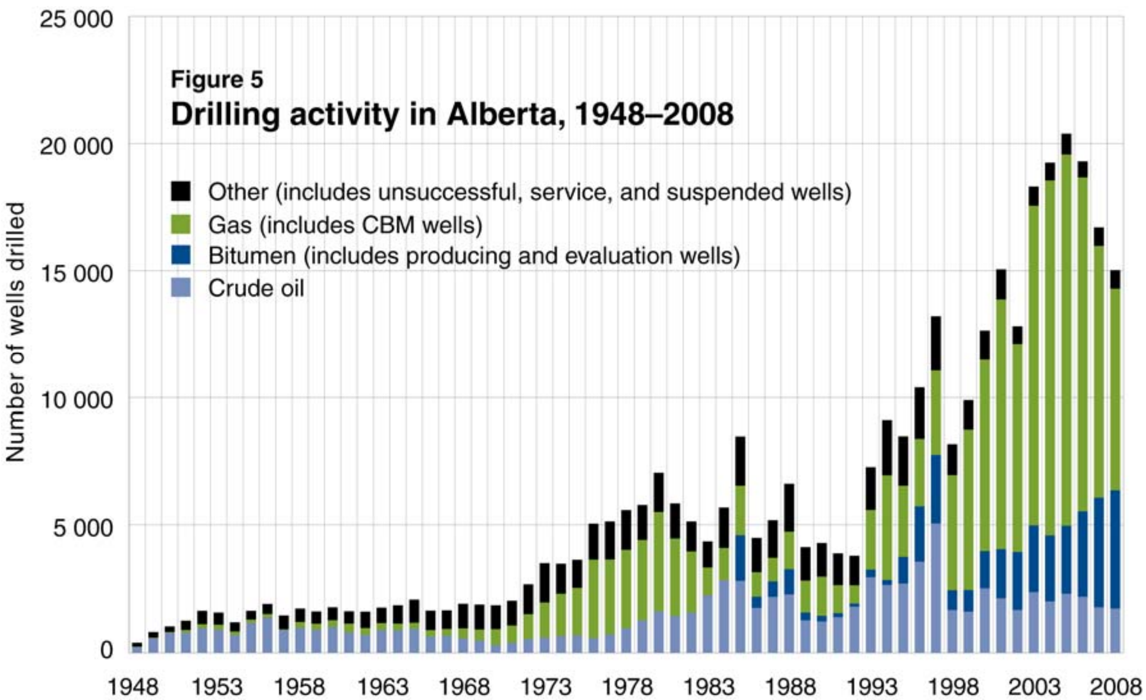
Total electricity demand in Alberta (retail sales and industrial on-site use) increased by less than 1 per cent from 2007. However, expected growth in industrial electricity demand, through both wholesale purchases and on-site generation, will average 3.2 per cent per year over the forecast period, compared to the average 2.8 per cent per year for overall demand. The oil sands sector is expected to dominate load growth.

In 2009 and 2010, prices are projected to remain below the five-year average, although daily prices will continue to be impacted by seasonal temperature influences and unplanned generating plant outages. However, from 2011 to 2018 the average annual pool price is projected to be significantly impacted, as natural gas prices are expected to strengthen in this period.

Energy Trends

Drilling Activity

Drilling activity in the province increased rapidly from 1993, reaching a peak in 2005. Although drilling activity for the past three years, particularly for natural gas, has declined due to increasing costs and soft natural gas prices, it has remained high relative to previous decades. Natural gas drilling remains the dominant force in the province's drilling activity. **Figure 5** illustrates the province's drilling history over the past six decades.



Crude Oil and Bitumen

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 6**. Production from the Turner Valley field, discovered in 1914, accounted for 99 per cent of 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/day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure. Factors affecting current crude oil prices and the forecast are found in Section 1.

Figure 7 shows the historical mined bitumen and SCO production, beginning with the start-up of Great Canadian Oil Sands (Suncor) in 1967. This was followed by Syncrude in 1978 and the Alberta Oils Sands Project (Albian Sands and Shell Scotford Upgrader) in 2003. The figure also shows the price of SCO since 1971, which generally runs at a premium to light crude oil.

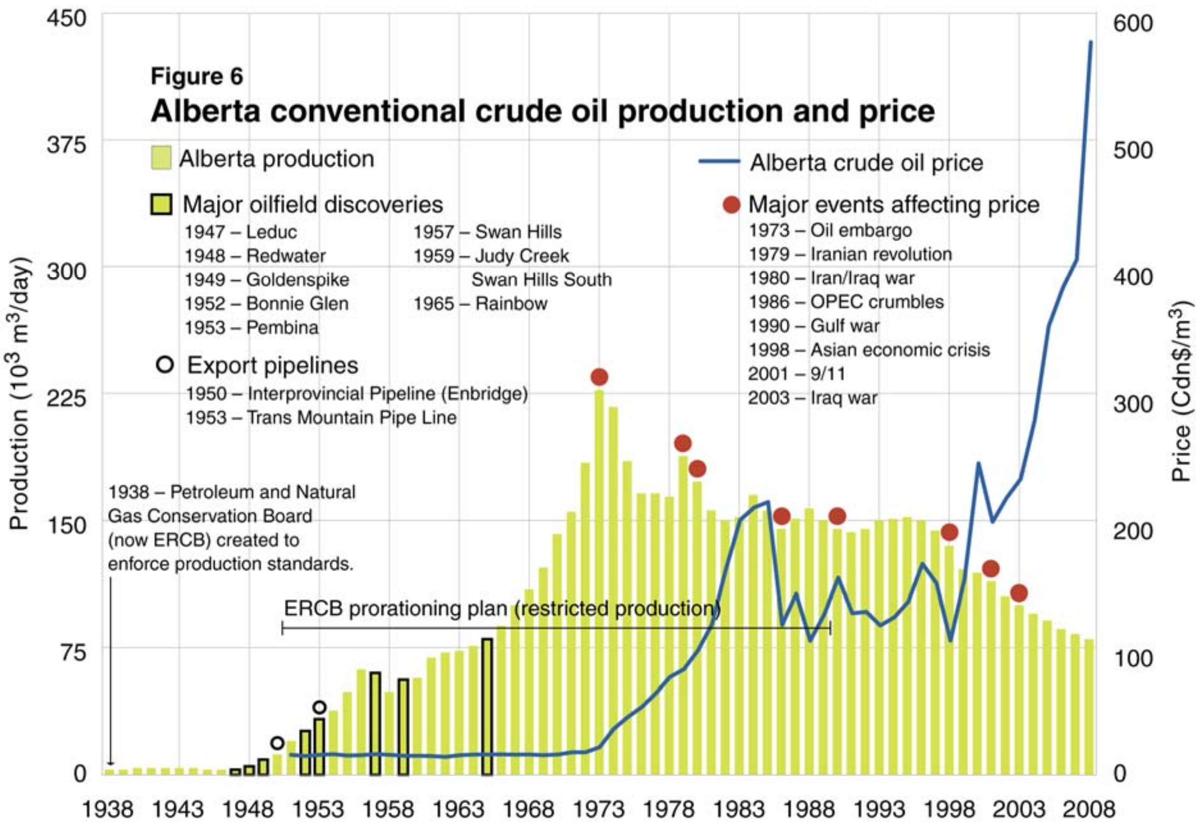


Figure 6
Alberta conventional crude oil production and price
Alberta production
Major oilfield discoveries
1947 – Leduc
1948 – Redwater
1949 – Goldenspike
1952 – Bonnie Glen
1953 – Pembina
1957 – Swan Hills
1959 – Judy Creek
Swan Hills South
1965 – Rainbow
Export pipelines
1950 – Interprovincial Pipeline (Enbridge)
1953 – Trans Mountain Pipe Line
Alberta crude oil price
Major events affecting price
1973 – Oil embargo
1979 – Iranian revolution
1980 – Iran/Iraq war
1986 – OPEC crumbles
1990 – Gulf war
1998 – Asian economic crisis
2001 – 9/11
2003 – Iraq war
1938 – Petroleum and Natural Gas Conservation Board (now ERCB) created to enforce production standards.
ERCB prorationing plan (restricted production)
Production (10^3 m^3/day)
Price (Cdn$/m^3)
0
75
150
225
300
375
450
100
200
300
400
500
600
1938
1943
1948
1953
1958
1963
1968
1973
1978
1983
1988
1993
1998
2003
2008

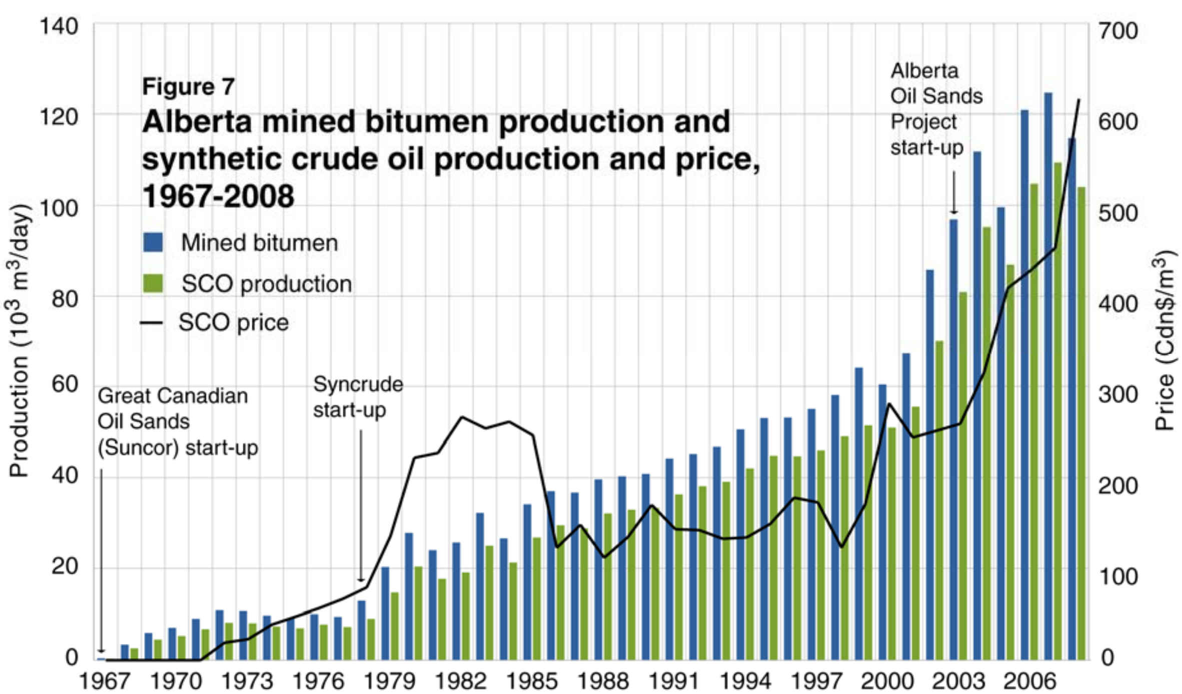
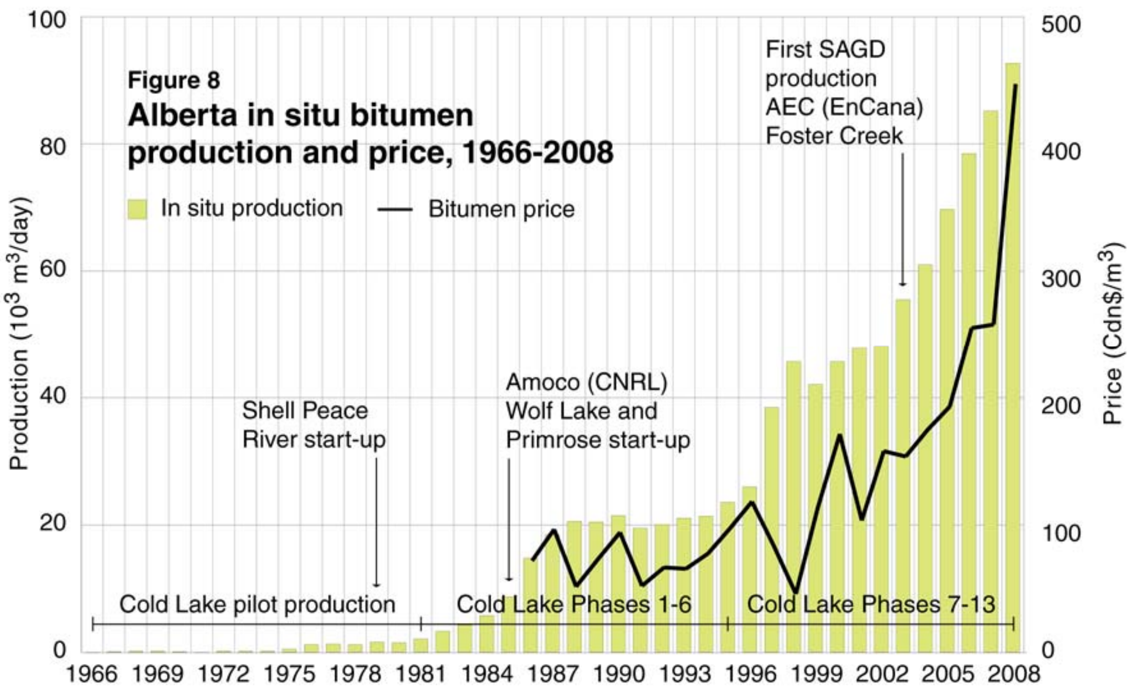


Figure 7
Alberta mined bitumen production and synthetic crude oil production and price, 1967-2008
Mined bitumen
SCO production
SCO price
Great Canadian Oil Sands (Suncor) start-up
Syncrude start-up
Alberta Oil Sands Project start-up
Production (10^3 m^3/day)
Price (Cdn$/m^3)
0
20
40
60
80
100
120
140
100
200
300
400
500
600
700
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006

Historical production and the price of in situ bitumen are shown in **Figure 8**. Imperial's Cold Lake project facility, which uses the cyclic steam stimulation recovery method, has historically accounted for the major portion of in situ production. The price of bitumen generally follows the light crude oil price, but at a discount of between 50 and 60 per cent.



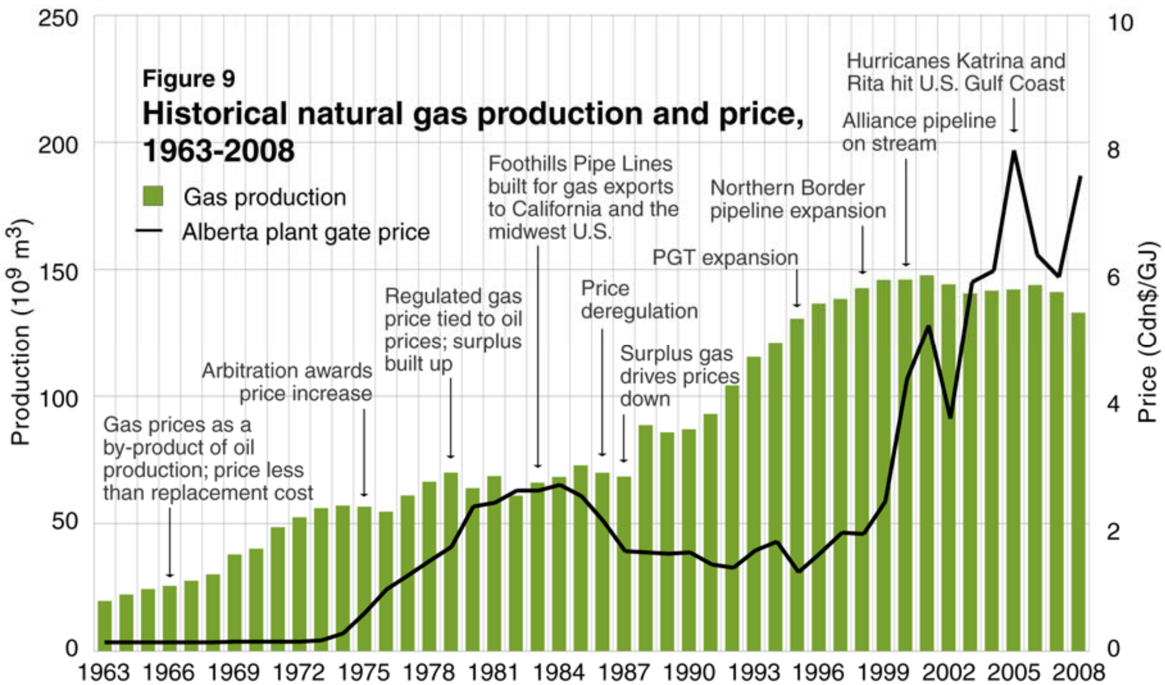
Natural Gas

Natural gas as a commodity has an interesting past, as seen in **Figure 9,** which shows historical gas production and price. 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 due to 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 in the U.S. in the late 1980s and AECO "C" in the early 1990s facilitated natural gas being traded as a true commodity. The development of new export pipelines and expansions to existing pipelines to the U.S. have allowed Alberta gas to be fully integrated into the North American gas marketplace.



Sulphur

Figure 10 illustrates sulphur closing inventories at processing plants and oil sands operations from 1971 to 2008. Sulphur prices in this period are also shown, adding insight into how prices affect the growth or decline in sulphur inventories. Because of logistics costs, Canadian sulphur producers do not remelt and remove inventories unless they are assured a “good price.” When international demand is high and international prices follow, Alberta sulphur blocks are used as an additional source to increase the supply. This is usually sufficient to bring things back into balance, reduce prices, and stop the remelting of inventories. The cycle has been repeated several times in the last 35 years. **Figure 10** also depicts these trends in Alberta’s sulphur market.

Coal

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 11**. The prices for coal are based on 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.

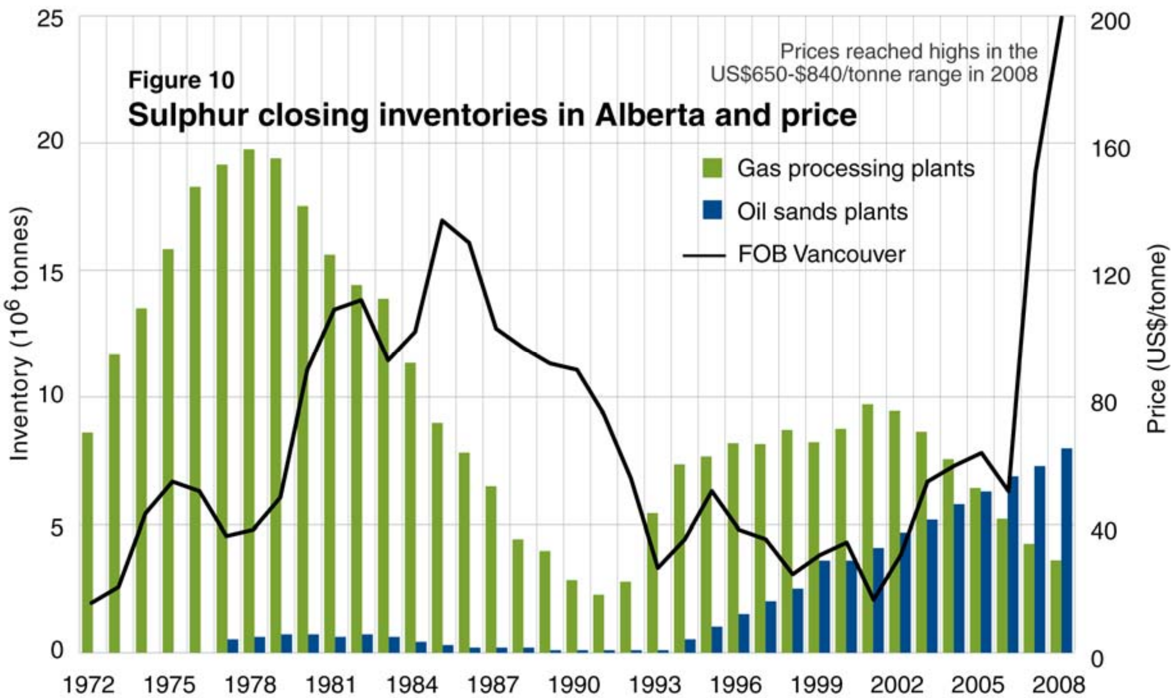


Figure 10
Sulphur closing inventories in Alberta and price
Prices reached highs in the US$650-$840/tonne range in 2008
Gas processing plants
Oil sands plants
FOB Vancouver
Inventory (10^6 tonnes)
Price (US$/tonne)
0
5
10
15
20
25
0
40
80
120
160
200
1972
1975
1978
1981
1984
1987
1990
1993
1996
1999
2002
2005
2008

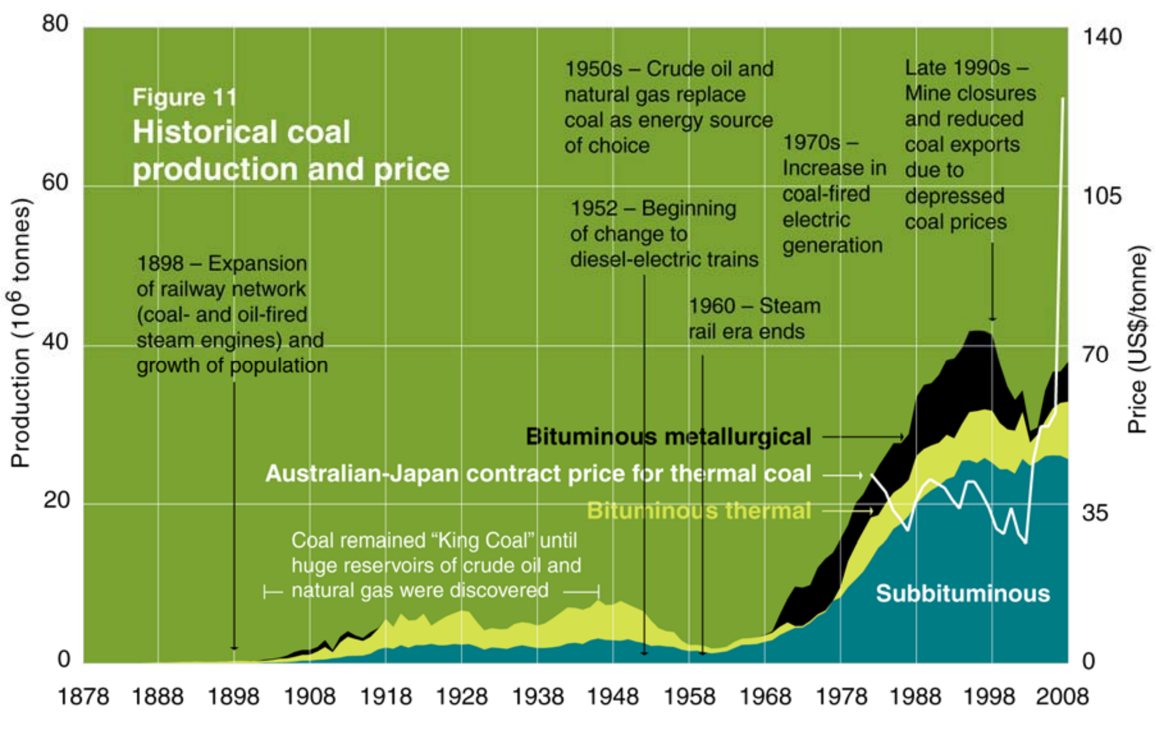


Figure 11
Historical coal production and price
1898 – Expansion of railway network (coal- and oil-fired steam engines) and growth of population
Coal remained "King Coal" until huge reservoirs of crude oil and natural gas were discovered
1950s – Crude oil and natural gas replace coal as energy source of choice
1952 – Beginning of change to diesel-electric trains
1960 – Steam rail era ends
1970s – Increase in coal-fired electric generation
Late 1990s – Mine closures and reduced coal exports due to depressed coal prices
Bituminous metallurgical
Australian-Japan contract price for thermal coal
Bituminous thermal
Subbituminous
Production (10^6 tonnes)
Price (US$/tonne)
0
20
40
60
80
0
35
70
105
140
1878
1888
1898
1908
1918
1928
1938
1948
1958
1968
1978
1988
1998
2008

1 Energy Prices and Economic Performance

Highlights

- The WTI crude oil price at Chicago averaged US$101.04 per barrel (bbl) in 2008, compared to US$73.56/bbl in 2007, an increase of 37 per cent. The WTI price reached a daily high of US$147.27/bbl at Cushing, Oklahoma, on July 11, 2008.
- Oil and natural gas prices diverged, with the average 2008 Alberta gas-to-light-medium-oil price parity of 0.47 on an energy-equivalent basis, compared to the three-year average parity of 0.60.
- In 2008, the Alberta economy contracted by 0.2 per cent, compared to 3.3 per cent growth in 2007.
- The Bank of Canada dropped the target overnight rate throughout 2008, from a high of 3.5 per cent to a low of 1.5 per cent.

Energy production is generally affected by remaining reserves, energy prices, demand, and costs. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. Furthermore, the activity in Alberta's energy sector is heavily influenced by demand and supply conditions and economic activity in the United States, the largest importer of Alberta's fossil fuels.

This section introduces some of the main variables impacting energy supply and demand and sets the stage for discussions in the report. Alberta crude oil prices are determined globally and relate to West Texas Intermediate (WTI) and the Organization of Petroleum Exporting Countries (OPEC) reference basket price.

The section begins with a review of the OPEC crude oil basket reference price and a summary of factors that will play a key role in influencing benchmark oil prices in the years to come. It also discusses the current global oil supply and demand picture, including projections for 2009 and 2010 based on research conducted by the International Energy Agency (IEA).

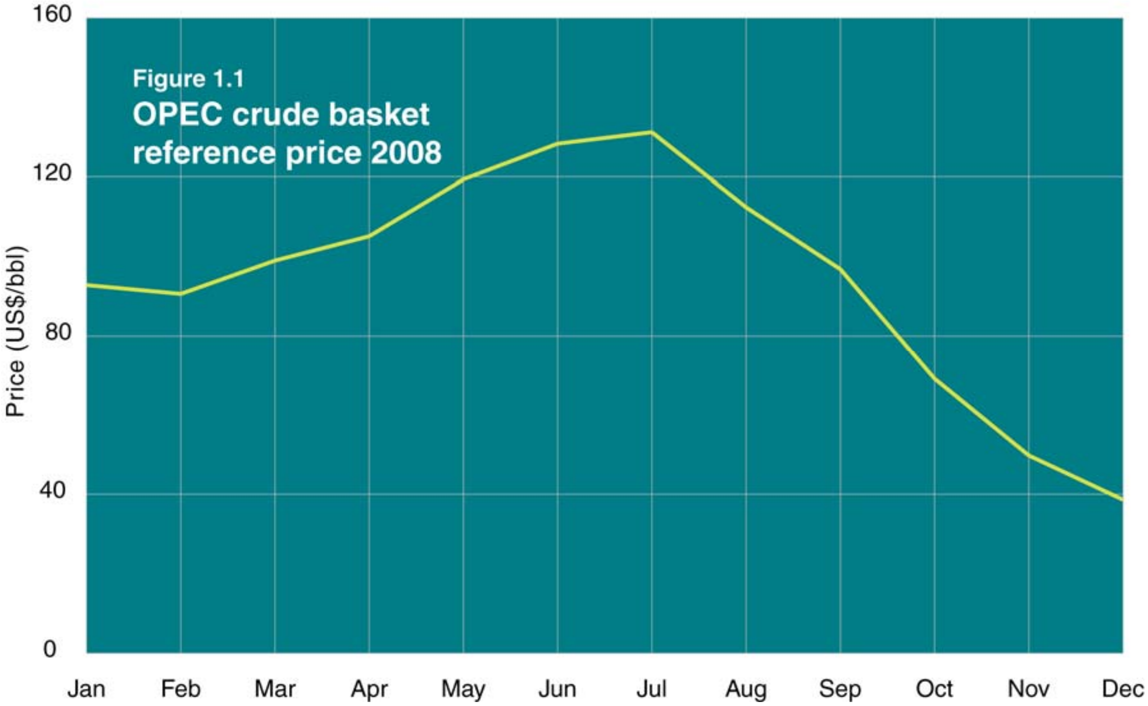
A discussion of North American energy prices is presented, as well as of oil and gas production costs in Alberta. The section concludes with a summary of Canada's recent economic performance and potential, along with the ERCB's outlook on Alberta's economic growth.

1.1 Global Oil Market

In 2008, world oil prices rose to record highs by mid-year and then saw record declines by the end of the year. The volatile prices mirrored the extraordinary volatility experienced in many of the world's commodity and financial markets.

Figure 1.1 depicts the monthly average OPEC crude oil basket reference price for 2008.[1]

[1] OPEC calculates a production-weighted reference price, referred to as the OPEC reference basket price. This consists of 13 different crudes: Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy, Iraq Basra Light, Kuwait Export, Libya Es Sider, Bonny Light (Nigeria), Qatar Marine, Arab Light (Saudi Arabia), United Arab Emirates Murban, BCF 17 (Venezuela), Girassoal (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.



The OPEC reference price averaged US$92.85/bbl in January 2008 and increased to a record high monthly average price of $131.22 in July. The price strength can be attributed to many factors, including continued activity by financial speculators, strong demand growth in Asia, strength in world distillate markets, concerns about supplies resulting from strikes in Nigeria, and Middle East geopolitical concerns.

The high prices led Saudi Arabia to call an Emergency International Energy Meeting in Jeddah in April 2008, resulting in an OPEC agreement to add 0.5 million barrels per day (bbl/d) of incremental oil in an attempt to bring stability to the market.

By the middle of the year, the worldwide financial crisis had begun to significantly impact markets and dramatically change the outlook for world economic growth and the demand for all commodities, including crude oil and natural gas.

In 2008, OPEC's supply of crude oil provided more than 31 million bbl/d. This is equivalent to over 36 per cent of total world oil demand.[2] Starting in the third quarter of 2008, OPEC initiated a series of supply cuts in an effort to put a floor on falling crude oil prices. These cuts resulted in a quota reduction of 4.2 million bbl/d, or nearly 12 per cent of OPEC's capacity by the end of 2008. However, crude oil prices continued to fall. In December, the OPEC reference price averaged US$38.60/bbl, a drop of 71 per cent, or more than US$92/bbl, from July 2008 levels.

Figure 1.2 illustrates growth in oil demand across the globe between 2007 and 2009. Global oil demand is estimated to have decreased by 0.28 million bbl/d in 2008, compared to growth of 1.01 million bbl/d in 2007. According to the IEA, this is the first decline in demand growth since 1983. Although demand registered declines globally, it was most evident in North America.

[2] Statistics obtained from OPEC *Monthly Oil Market Report* (OPEC, March 2009).

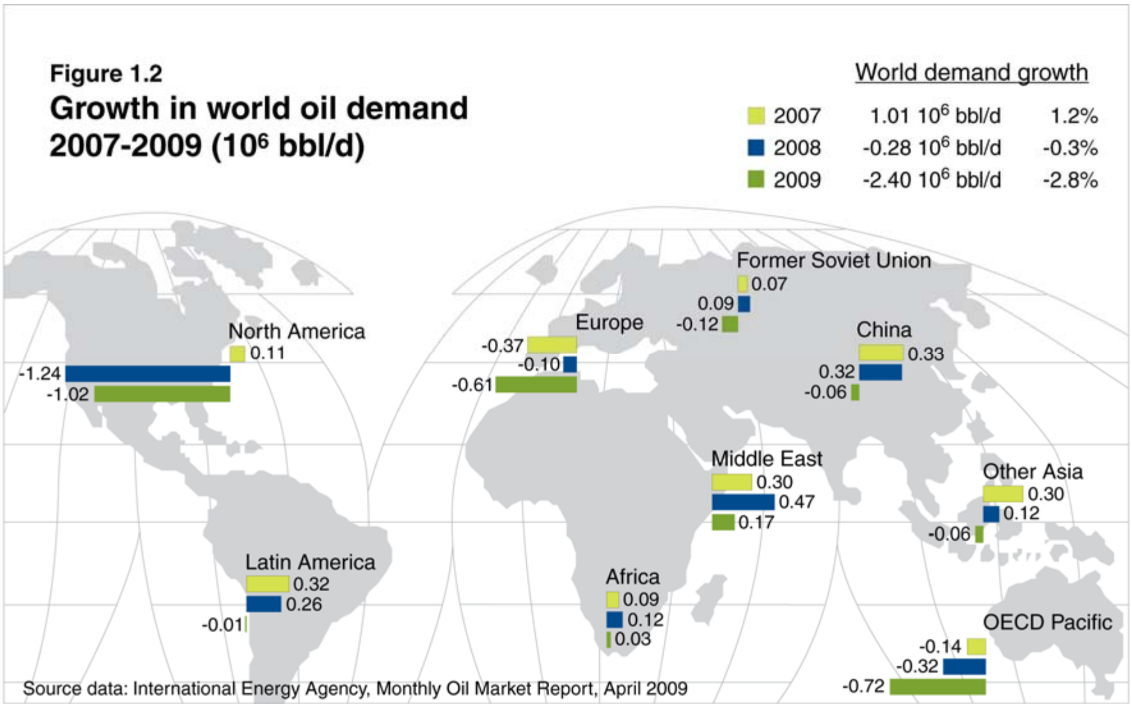


Figure 1.2
Growth in world oil demand 2007-2009 (10^6 bbl/d)

Global crude oil demand is expected to contract by 2.8 per cent, or 2.40 million bbl/d, in 2009. The IEA expects global oil supply from non-OPEC countries to remain flat and OPEC supply to fall, as OPEC members curb output further in their aim to compensate for lower demand. The eventual resumption of global crude oil demand growth will depend largely upon the economic recovery of consuming countries. Although the timing of the economic recovery is uncertain, the ERCB anticipates economic growth to recover in 2010 and onwards.

1.2 North American Energy Prices

1.2.1 North American Crude Oil Prices

North American crude oil prices are determined by international market forces and are most directly related to the WTI crude oil reference price at Cushing, Oklahoma. WTI crude has an API of 40 degrees and a sulphur content of less than 0.5 per cent. The WTI crude oil price ranges between US$4/bbl to $6/bbl higher than the OPEC reference price, reflecting quality differences and the cost of shipping.

The ERCB uses the WTI crude oil price at Chicago as its benchmark for world oil prices. The WTI price at Chicago is determined based on the WTI Cushing price plus transportation tariffs to calculate the netback price at Chicago. The netback price at the Edmonton hub is calculated from the Chicago netback price less transportation and other charges from the wellhead to Chicago and is adjusted for the exchange rate, as well as crude quality. The Edmonton reference price is based on an API of 40 degrees and a sulphur content of 0.5 per cent.

In 2008, the WTI price was influenced by many of the same factors affecting the OPEC reference price. In January 2008, the WTI price at Chicago averaged US$94.28/bbl, more than 1.2 per cent higher than in the previous month. The WTI price reached a daily record high of US$147.27/bbl at Cushing on July 11 and a record monthly average high of

US$134.95/bbl in July. The WTI price at Chicago averaged US$101.04/bbl in 2008, an increase of over 37 per cent from 2007.

The ERCB projects the WTI price at Chicago to range between US$50/bbl and US$60/bbl, with a forecast price of US$55/bbl for 2009. The forecast range is lower than last year's projection and is indicative of supply and demand fundamentals in the global crude market. The lower range of WTI prices is an extension of the lows experienced in the market in late 2008 escalated by the expected inflation rate thereafter. The price forecast increases annually from 2010, reflecting the view that crude oil demand will increase coincident with the recovery in economic growth.

The risks to this price forecast are more heavily weighted to the downside and would involve a deeper and longer economic slowdown than forecast, which would result in a larger than anticipated contraction in crude oil demand. Upside risk includes higher than anticipated demand for gasoline during the driving season, tight inventories, lower spare producing capacity, lower upstream investment, steeper non-OPEC production declines, and renewed geopolitical upheavals.

Figure 1.3 illustrates the ERCB forecast of the WTI price at Chicago. **Figure 1.4** shows the forecast for the wellhead price of crude oil in Alberta based on WTI netbacks from Chicago.

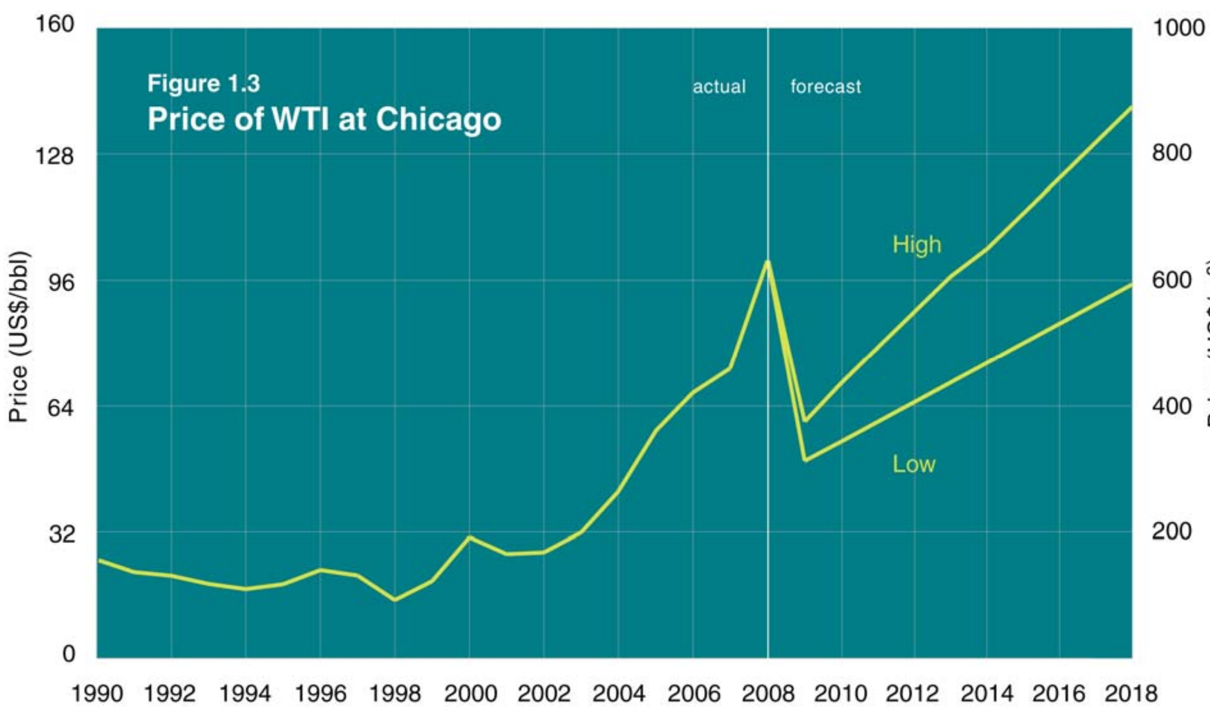
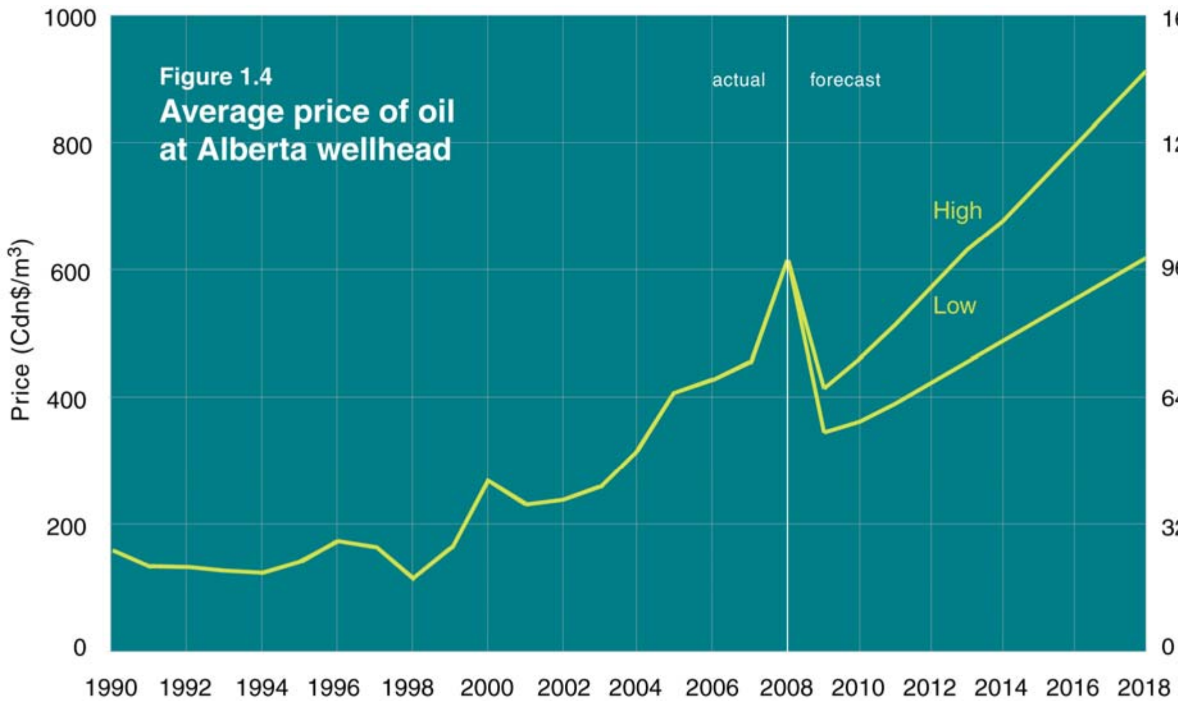
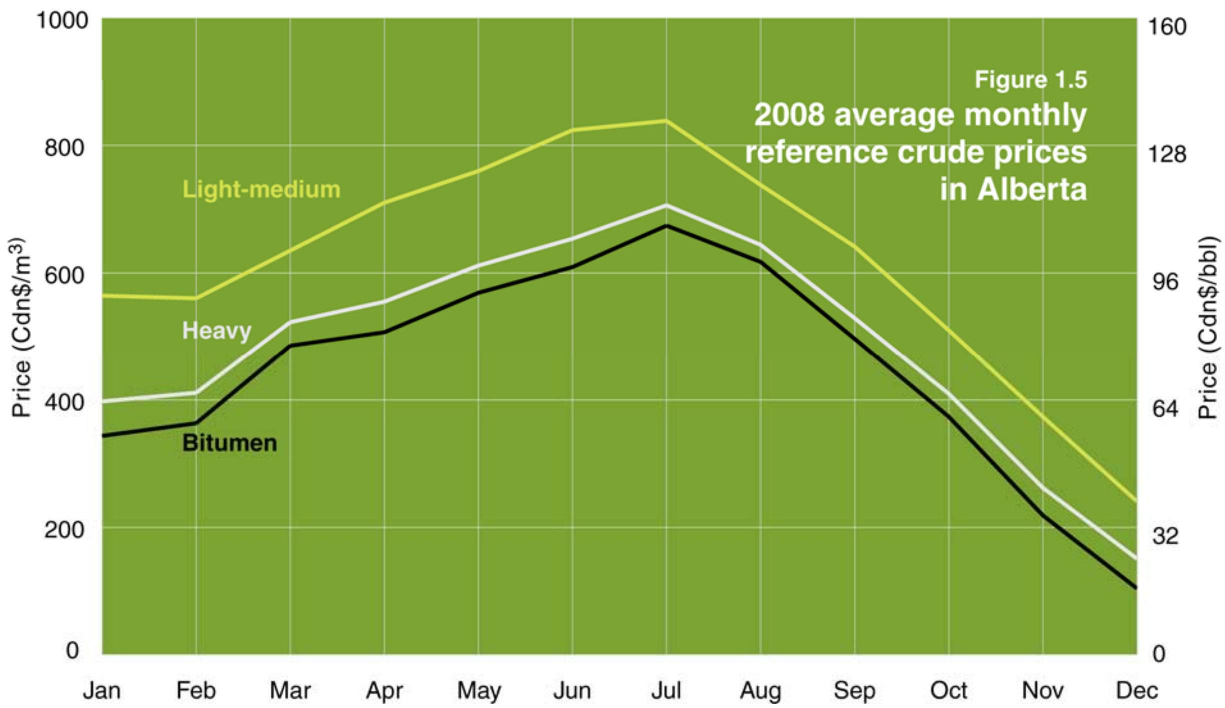


Figure 1.5 illustrates the monthly average price of Alberta light-medium crude, heavy crude, and neat bitumen (net of diluent blending). In 2008, heavy crude and bitumen prices averaged Cdn$75.52/bbl and Cdn$71.01/bbl respectively, while the Alberta light-medium reference price averaged Cdn$97.73/bbl. In 2007, the heavy crude and bitumen prices averaged Cdn$48.43/bbl and Cdn$40.97/bbl respectively, while the Alberta light-medium reference price averaged Cdn$72.58/bbl. During 2008, the price of heavy crude in Alberta increased at a faster rate than light and medium crude, leading to a narrowing of the premium between light and heavy from 67 to 79 per cent. Similarly, the differential between light-medium crude oil and bitumen narrowed from 56 to 73 per cent.





The ERCB focuses on the WTI price forecast rather than the forecast for bitumen, as the majority of bitumen is upgraded to a synthetic crude oil (SCO) product, which is of similar quality to WTI. Forecasts for the price of heavy crude and bitumen can be estimated by applying the appropriate average differentials to the netback price of WTI at the Alberta wellhead. The ERCB expects the bitumen/light-medium differential to average 58 per cent over the forecast period. Wider differentials provide incentives for investment in additional upgrading capacity in North America. The heavy/light-medium differential is expected to remain near the five-year trend, at 68 per cent.

Wider differentials between bitumen and Alberta light-medium are due to short-term increases in the supply of bitumen without an increase to the refinery capacity that can process this crude in North America. Diluent prices also play a role in determining bitumen prices, as more expensive diluent will result in lower neat bitumen prices. While seasonal variations have always existed, the bitumen/light-medium spread may be wider than heavy/light-medium for quite some time due to the lag between increasing production of bitumen without the coincident increase in upgraders and refinery capacity capable of processing bitumen.

Further expansion of upgrading capacity, refinery conversions, and more pipeline access to new markets should help stabilize these differentials over the longer term. There are currently three bitumen upgrading sites in Alberta, with seven additional upgraders and a number of debottlenecking and expansion projects planned during the forecast period. As a result, upgraded bitumen product is expected to increase close to threefold, from 104 thousand cubic metres per day (10^3 m^3/d) (655 10^3 bbl/d) in 2008 to 245 10^3 m^3/d (1540 10^3 bbl/d) by 2018. Details on markets for Alberta bitumen are discussed in more detail in **Section 2.**

After meeting Alberta and Canadian refinery demand, the remaining crude oil is exported. The Petroleum Administration for Defense Districts (PADD) 2 and 4 in the U.S. are the largest importers of Alberta heavy crude and bitumen, with total refinery capacity of 677 10^3 m^3/d (4261 10^3 bbl/d) combined. The expansion at the Flint Hills upgrader, the ConocoPhillips refinery conversion, and other refinery conversions will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta's heavier crudes. However, it is expected that the small-sized expansions and conversions will open up capacity only over the short term, as the growth in Alberta production could quickly fill the gaps. Refinery capacity in the U.S. has increased somewhat from the early 1990s, but only due to increases in existing capacity. No new refineries have been built since the 1970s. At the same time, product demand has increased significantly, resulting in refineries in the U.S. operating at high capacities since 1993.

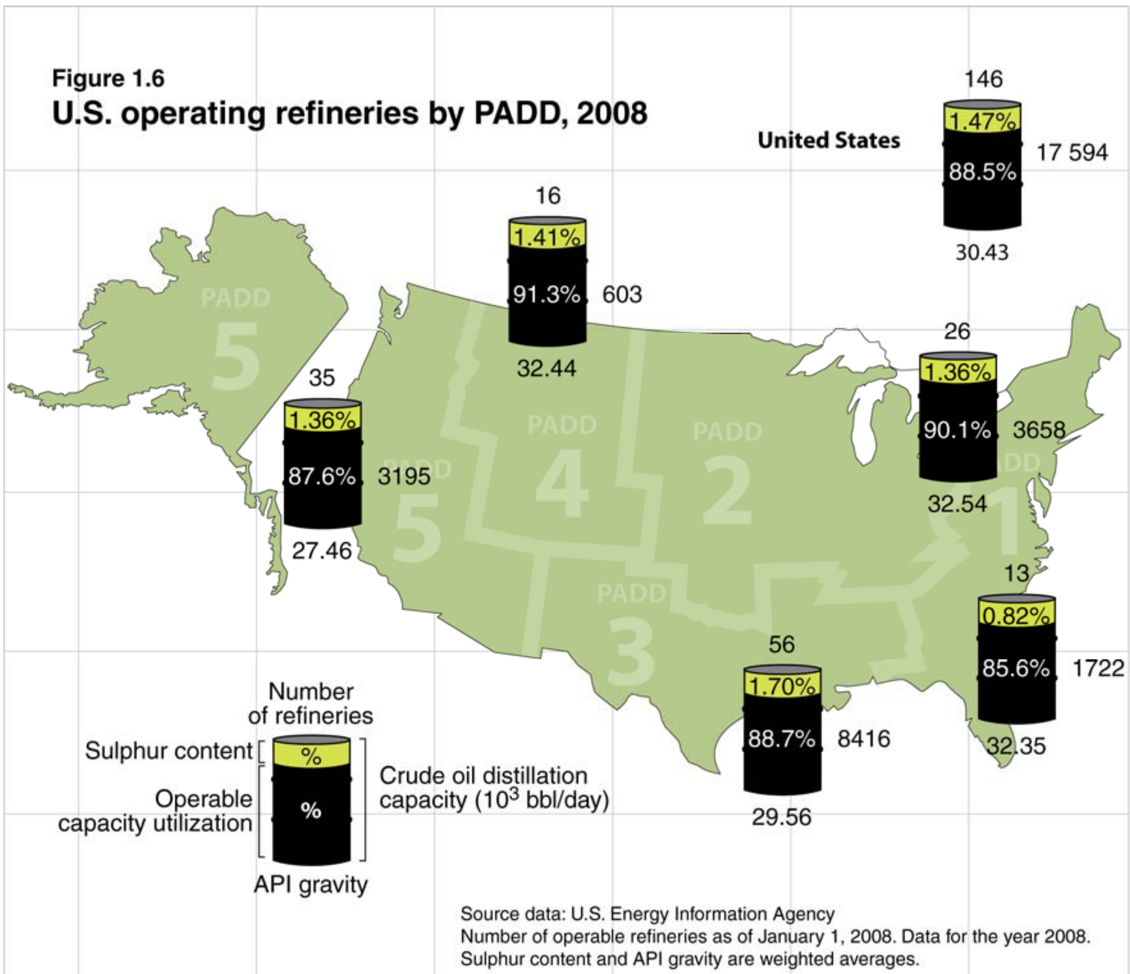
Additional pipeline infrastructure will provide an avenue for Alberta heavy crude to extend to larger markets in the U.S. and East Asia. With expected increases in both non-upgraded and upgraded bitumen over the forecast period, adequate incremental pipeline capacity is essential to market greater volumes of Alberta production. During the past few years, pipeline companies have made strides towards completing existing projects, as well as moving ahead with the necessary steps involved in planning and executing new projects.

In summary, eight new proposed pipelines and pipeline expansions indicate an overall increase in crude oil pipeline capacity of 66 10^3 m^3/d (415 10^3 bbl/d) for the Alberta market and 360 10^3 m^3/d (2265 10^3 bbl/d) for the export market, some with the potential to reach PADD 3, PADD 5, and East Asia. This represents an increase of 15 per cent in Alberta SCO and non-upgraded bitumen pipeline capacity and an 85 per cent increase in export pipeline capacity.

If bitumen production follows the current forecast, additional Alberta pipeline capacity will be required in the 2013 to 2018 timeframe. The proposed Alberta pipeline projects include built-in capacity for future increases in deliveries as production grows in the Athabasca Oil Sands Area (OSA). In addition to increased crude oil pipeline capacity, the

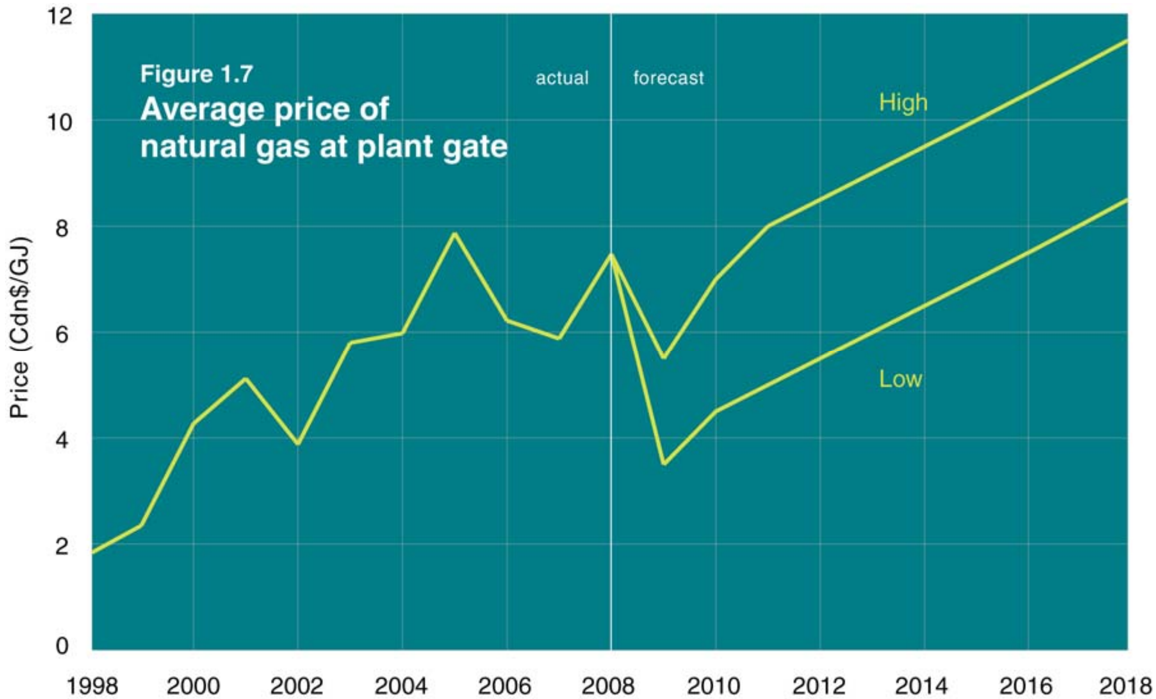
Enbridge Southern Lights pipeline and Gateway Condensate Import pipeline will be dedicated to moving 53 10^3 m^3/d of condensate (diluent) from Chicago and from British Columbia (B.C.) to the Edmonton area, which will aid in easing the current tight supply of diluent to the oil sands.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the U.S., with 56 operating refineries and a net crude oil distillation capacity of 1337 10^3 m^3/d (8.4 million bbl/d), plus the existing capability of refining heavier crudes. PADD 3 was not always viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude production. However, traditional crude inputs to PADD 3 have been on the decline, suggesting a more tangible opportunity for Alberta heavy crude producers. As a result, plans to increase pipeline capacity to the area are under way.



1.2.2 North American Natural Gas Prices

While crude oil prices are determined globally, natural gas prices are set in the North American market with little global gas market influence. Alberta natural gas prices are heavily influenced by events in the U.S., its largest importer. Natural gas prices are also impacted to an extent by crude oil prices, as some substitution does occur due to the price differential between the two commodities. About 10 per cent of industrial users in the U.S. can switch between oil and natural gas for power production. **Figure 1.7** shows historical data and the ERCB forecasts of natural gas prices at the plant gate from 1998 to 2018.



Alberta gas prices trended upward over the first six months of 2008 to a high of Cdn$9.84 per gigajoule (GJ) in July, after which they declined to Cdn$6.25/GJ in November. The observed price decline following the 2008 hurricanes was the result of several supply and demand factors. While natural gas demand was contracting due to the economic slowdown in North America, natural gas production in the U.S. was increasing. Starting in 2006, U.S. production increased after nine years of zero growth. Between 2007 and 2008, total U.S. production increased by approximately 8 per cent, from 1.5 billion (10^9) m^3/d (52.3 billion cubic feet [Bcf]/d) in 2007 to 1.6 10^9 m^3/d (56.3 Bcf/d) in 2008. Over half of the production increase can be attributed to Texas, where horizontal drilling has allowed for successful production of natural gas from the Barnett Shale. Other unconventional shale gas plays, including Fayetteville, Woodford, and Haynesville, also contributed to the 0.1 10^9 m^3/d (4 Bcf/d) increase in total U.S. natural gas production.

As a result of weak demand and growing production, natural gas storage inventory levels are higher than the five-year average, which is contributing to further downward pressure on natural gas prices. The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$3.00/GJ and Cdn$6.00/GJ in 2009, averaging Cdn$4.50/GJ. Upside risks to the forecast exist if an event such as an early hurricane season in the U.S. leads to production disruptions in the Gulf of Mexico or if the summer is particularly hot and cooling requirements soar.

The Alberta gas-to-light-medium-oil price parity on an energy content basis averaged 0.47 for 2008, as the price of natural gas declined and crude oil prices increased. During the 2005 to 2007 period, the parity averaged 0.60.

Over the forecast period, the price of natural gas is expected to increase slowly to reach an average of Cdn$10.00/GJ by 2018, while the top end of this range could surpass

Cdn$11.50/GJ. The gas-to-oil price parity is expected to average 0.52 over the forecast period. A gas-to-oil discount is likely to remain lower than the historical average over the forecast period for a number of reasons. As mentioned earlier, crude oil prices are determined globally, while natural gas prices are determined continentally. Oil prices respond to global events, while natural gas responds mainly to regional supply and demand conditions. Most important, demand for oil globally is particularly inelastic, as refined petroleum products, such as gasoline, diesel, and jet fuel, are fundamental to the transportation sector. In the short term, consumers will be less flexible in changing their demand because there is no substitute for refined products. Furthermore, it is expected that in the rapidly developing economies of China and India, consumers will demand more refined petroleum products for the transportation of goods and services.

Natural gas, on the other hand, competes with other fuel sources for market share, such as coal in the power generation market. Therefore, natural gas is much more vulnerable to competition compared to refined crude oil products. Additionally, natural gas does not have the global trading opportunities enjoyed by crude oil or refined petroleum products. It may, however, become a global commodity if spot liquefied natural gas (LNG) trade develops globally, although this is likely to occur only over the longer term. In the short term, however, LNG imports to the U.S. can cause a drop in U.S. gas prices. During the summer months, the U.S. is the only country with remaining natural gas storage availability. It is common for LNG supplies that cannot be offloaded to higher netback countries due to lack of storage capacity to enter the U.S. marketplace, thereby causing U.S. natural gas prices to fall.

In Alberta, conventional natural gas production is expected to decline throughout the forecast period. Despite the low drilling activity in 2008, coalbed methane (CBM) is expected to provide an increasing share of Alberta's total natural gas production.

1.2.3 Electricity Pool Prices in Alberta

The electricity price paid by consumers consists of a wholesale market price determined in the power pool (pool price), transmission and distribution costs, and a fixed monthly billing charge. Since deregulation, the wholesale or pool price of electricity in Alberta has been determined by the equilibrium between electricity supply and demand.

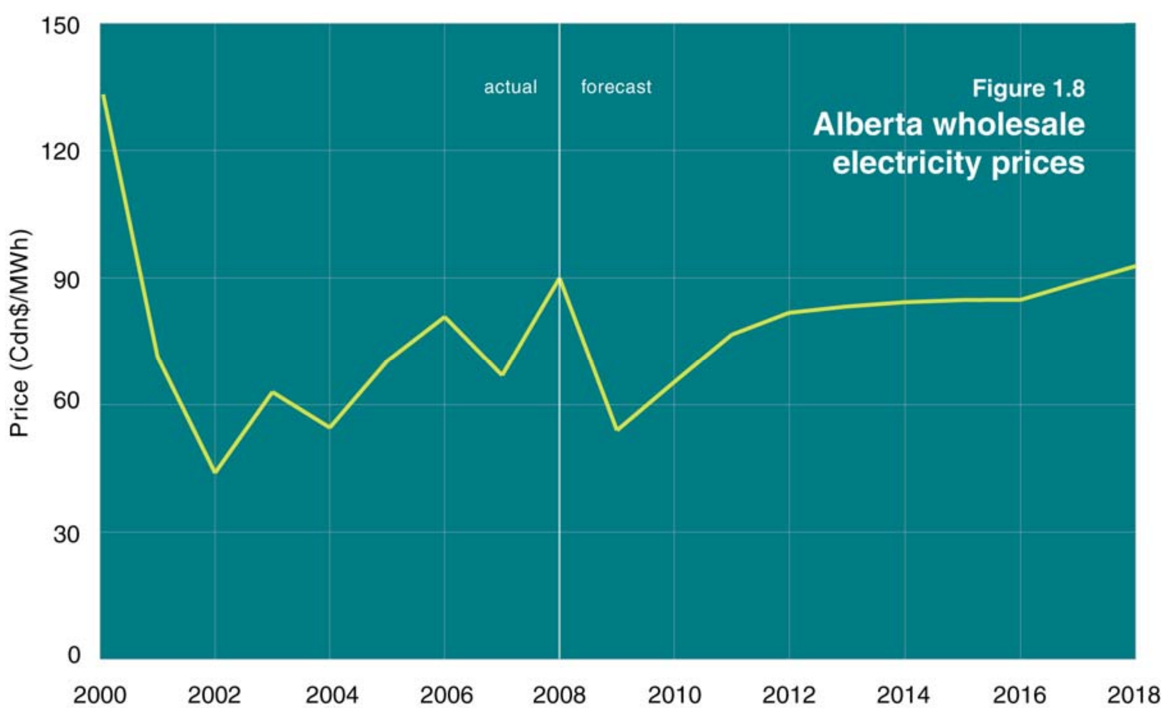
Table 1.1 shows the average pool price and electricity load, along with hourly minimums and maximums experienced during each month in 2008. The 2007 average is included for comparison. In the first half of 2008, the monthly average pool price increased, corresponding to rising Alberta natural gas prices and a transmission outage. The average pool price reached a high of $135.95 per megawatt-hour (MWh) in April 2008.

Electricity prices continued to be strong for the remainder of 2008, despite a continuing decline in the natural gas spot price. An unplanned outage at Genesee 3 contributed to a reduction in supply during the beginning of the winter heating season. The monthly average pool price averaged $89.95/MWh, compared to the 2007 average of $66.95/MWh.

Figure 1.8 illustrates the historical and the ERCB forecast of average annual pool prices in Alberta to 2018.

Table 1.1. Monthly pool prices and electricity load

2008	Price ($/MWh) Average	Min	Max	Load (MW) Average	Min	Max
Jan	80.30	12.12	999.99	8490	7382	9710
Feb	64.89	14.55	398.61	8351	7357	9443
Mar	84.89	15.20	999.36	8061	7153	9000
Apr	135.95	16.23	999.97	7772	6731	8549
May	103.73	7.60	800.60	7480	6486	8494
Jun	83.00	0.00	999.99	7590	6411	8789
Jul	64.51	7.60	931.69	7912	6703	9104
Aug	82.72	7.60	999.98	7972	6788	9541
Sep	93.86	7.60	999.99	7671	6576	8817
Oct	100.51	7.60	999.99	7741	6625	8738
Nov	96.66	13.99	999.99	7992	6900	9254
Dec	88.35	9.50	999.99	8523	7052	9806
2008	89.95	0.00	999.99	7989	6411	9806
2007	66.95	0.00	999.99	7952	6440	9701



The forecast for electricity supply and demand within Alberta is discussed in **Section 9**. Electricity demand growth in the forecast period will be largely supplied by growth in natural gas-fired cogeneration facilities associated with oil sands projects. In 2009 and 2010, prices are projected to remain below the five-year average. Average daily prices will continue to be impacted by seasonal temperature influences and unplanned generating plant outages. However, over the long term, the average annual pool price is projected to be significantly impacted by Alberta natural gas prices and moves higher with natural gas prices.

1.3 Oil and Gas Production Costs in Alberta

For the past 28 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical wells drilled in the previous year. The cost estimates presented here were obtained from the 2008 and 2009 PSAC Well Cost Studies, reflecting expected costs to drill in the upcoming drilling season.

Drilling and completion cost estimates for typical oil and natural gas wells are shown in **Figure 1.9**. **Table 1.2** 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, whether it is an oil or a gas well, whether it is a development or an exploratory well, surface conditions, sweet versus sour production, drilling programs, well location, nearby infrastructure, and completion method.

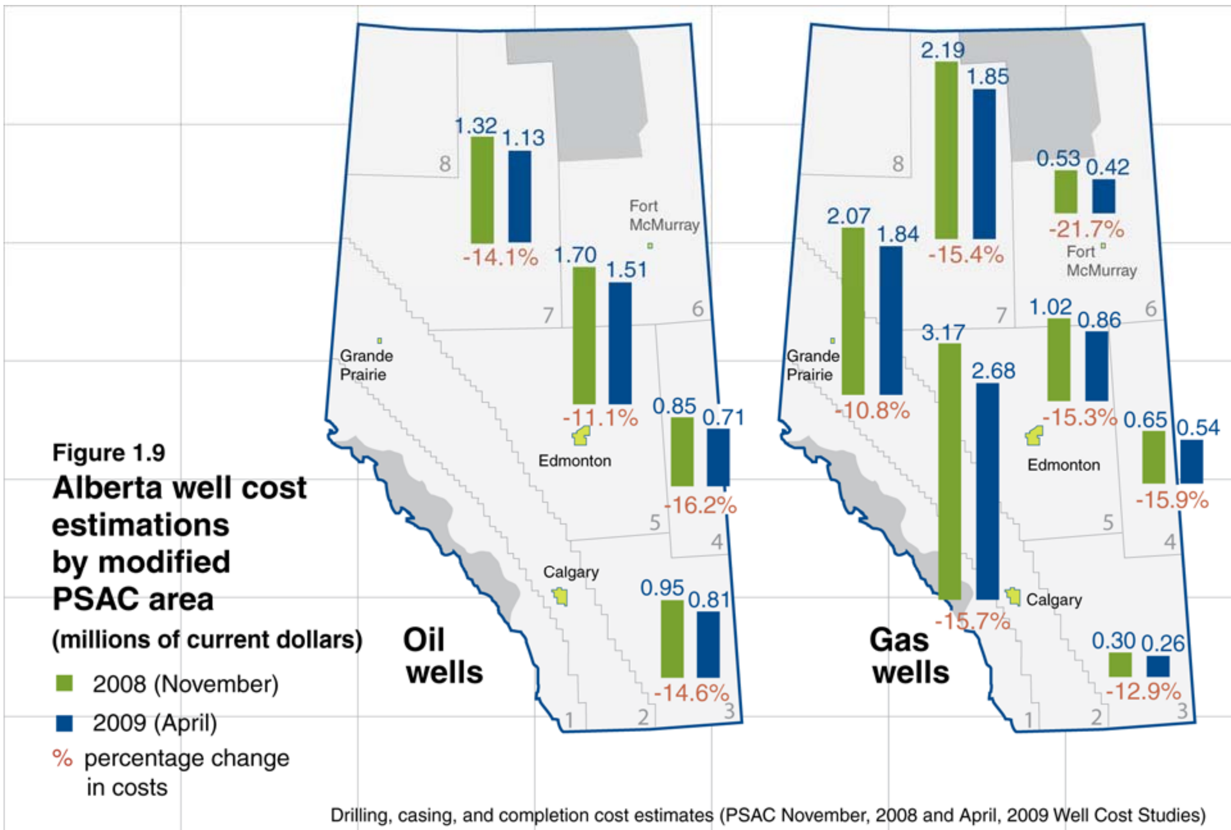


Table 1.2. Alberta median well depths by PSAC area, 2008 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3592	2295	724	575	861	254	933
Oil wells	1090	1914	1071	717	1358	NA	1525

NA – Not applicable.

As illustrated in **Figure 1.9,** the median cost to drill and complete an oil well is forecast to significantly decrease between winter 2008 and summer 2009. Costs to drill and complete an oil well in 2009 are expected to range from as low as $810 000 in Southern Alberta (Area 3) to as high as $1 506 000 in Central Alberta (Area 5). On average, across the modified PSAC areas, oil well costs are anticipated to decline by 15.4 per cent.

Estimated costs to drill and complete a typical gas well are highest in the Foothills area, at over $2.7 million, but could range significantly higher for the deeper sour gas wells. In Southeastern Alberta (Area 3), a typical gas well could cost around $260 000 to drill and complete.

Gas well drilling and completion costs are also projected to decrease in all areas of the province between winter 2008 and summer 2009, with the average cost to drill and complete a gas well across the PSAC areas projected to decrease by 14.0 per cent.

The reduction in well costs for both oil and gas wells can be attributed to a decrease in the overall rig drilling rates, which is coincident with the decline in overall drilling in the province.

1.4 Canadian Economic Performance

The historical performance of major Canadian economic indicators between 1998 and 2008 are depicted in **Figure 1.10**. The most recent annual performance of these indicators and the forecast to 2018 are presented in **Table 1.3**.

Table 1.3. Major Canadian economic indicators, 2008-2018

	2008[a]	2009	2010	2011-2018[b]
Real GDP growth	0.5%	-2.2%	1.3%	2.6%
Prime rate on loans	4.7%	2.6%	3.5%	4.0%
Inflation rate	2.3%	0.5%	1.8%	2.0%
Exchange rate (US/Cdn$)	0.94	0.83	0.87	0.88
Unemployment rate	6.1%	8.6%	9.0%	7.0%

[a] Actual.
[b] Averaged over 2011-2018.

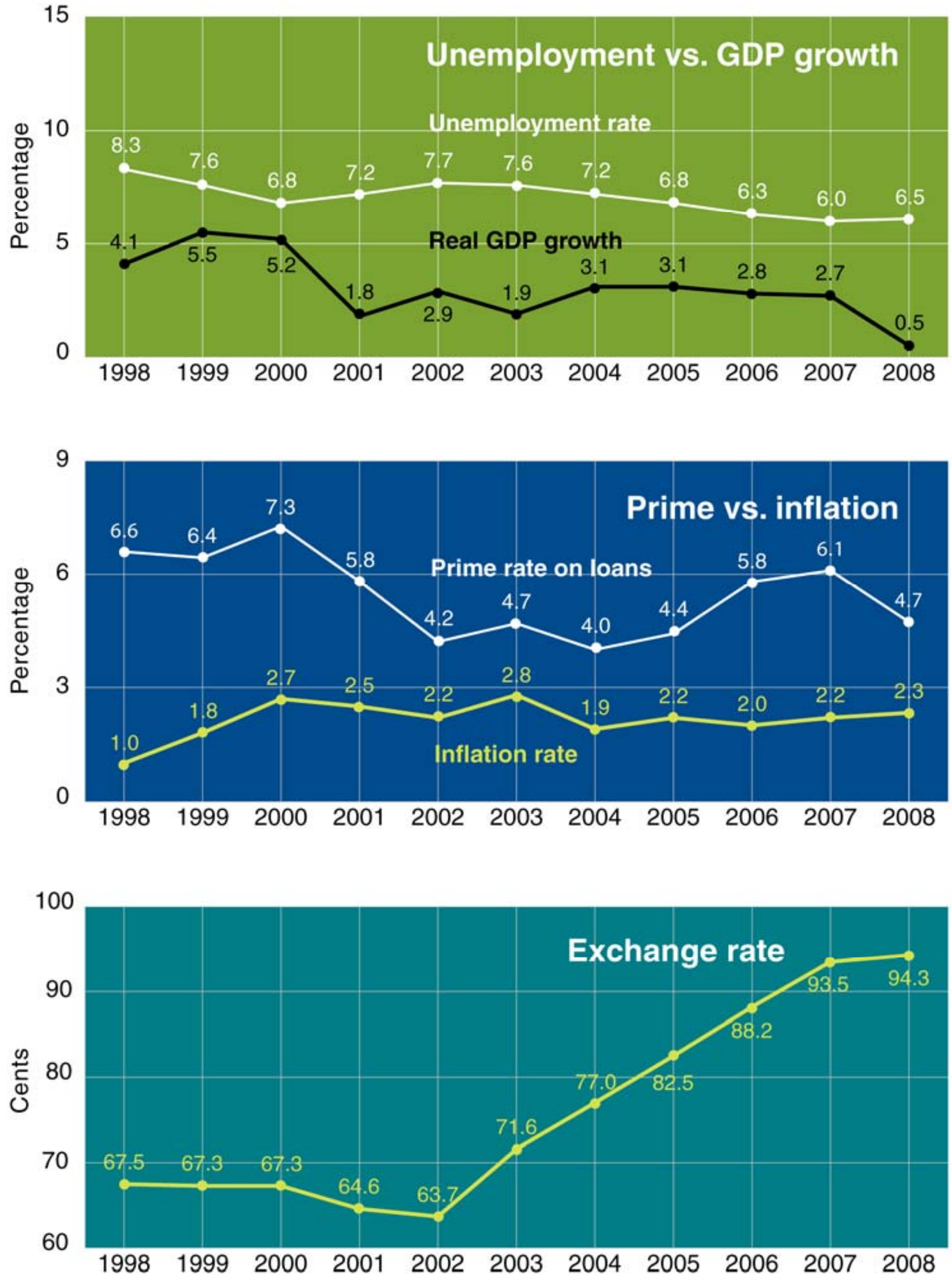
In 2008, Canada's GDP growth rate averaged 0.5 per cent, significantly lower than the 2.7 per cent growth in 2007. Canada's real GDP growth is projected to contract by 2.2 per cent in 2009.

Canadian economic growth in the first half of 2008 was driven by a combination of strong consumer spending and gains to real gross fixed capital formation. However, the credit crisis and global economic downturn have affected Canada in the last half of 2008. With the U.S. economy in recession, many Canadian industries, particularly the auto industry, face challenges. The decline in commodity prices has taken a toll on the economies of the western provinces, and negative growth rates are anticipated throughout the country in 2009.

In 2008, wages, salaries, and supplemental labour income grew at a healthy 5.0 per cent, and real consumer spending increased 3.0 per cent. Personal expenditures on consumer durable goods increased 5.2 per cent, and semi-durable goods (e.g., household furnishings) increased 4.0 per cent. Personal expenditures on consumer nondurable goods and services pumped up domestic demand, increasing 1.2 per cent and 3.1 per cent respectively.

Also in 2008, private investment grew by 0.4 per cent year over year. On the business side, investment in residential structures contracted by 2.9 per cent, while investment in nonresidential structures, machinery, and equipment grew by 1.7. On the nonresidential side, investment in structures advanced by 1.1 per cent and investment in machinery and equipment grew by 2.0 per cent. Corporate profits before income tax increased 6.4 per cent in 2008, much higher than in 2007 (3.3 per cent).

Figure 1.10
Canadian economic indicators



Real government investment rose 5.7 per cent, down from previous years. The federal government was on track to meet the medium-term objective of reducing the federal debt-to-GDP ratio from 29.9 per cent in 2007/08 to 25 per cent by 2011/12. However, the recent economic downturn is drastically changing the ability to reach this objective, as the government has increased its real investment and is expected to continue increasing spending to stimulate the economy.

Canada's exchange rate in relation to the U.S. dollar appreciated by an average of $0.008 in 2008 to US$0.943 relative to 2007. The monthly exchange rate was US$0.99 in January 2008 and depreciated to US$0.82 in December 2008. The appreciation in early 2008 was influenced by the demand for raw commodities, such as crude oil, natural gas, coal, and other minerals. Canada's energy sector, especially the activity in Alberta's oil sands, made Canada attractive to foreign investment, which helped to keep upward pressure on demand for the Canadian dollar. However, due to the recession in the U.S., the subsequent drop in crude oil demand, and tight credit markets, the Canadian dollar (considered by the international financial community to be a petro dollar) depreciated against the U.S. dollar by the end of 2008. The Canadian dollar is projected to average US$0.83 in 2009, US$0.87 in 2010, and US$0.88 from 2011 to 2018.

The reduction in investment, consumption, and manufacturing gains led to economic contraction, which in turn led to higher unemployment. Canada's unemployment rate in 2008 rose 0.1 percentage point to 6.1 per cent. Unemployment rates hit 33-year lows in early 2008, dipping below 6.0 per cent to 5.8 per cent in the first two months. Since then, however, the rate of growth in employment has decelerated relative to the growth in the labour force. In 2008, the number of persons entering the workforce increased by 1.7 per cent, while employment gains were only 1.5 per cent. The unemployment rate is expected to increase by 2.5 percentage points in 2009, as layoffs continue due to the current global recession.

The Bank of Canada keeps Canada's inflation under control by influencing short-term interest rates (monetary policy) to achieve a level of economic stimulus consistent with the inflation-control target range, which is between 1 and 3 per cent. The Bank of Canada's policy aims to keep the 12-month rate of inflation at the midpoint of this range, 2 per cent. The rate of inflation in 2008 reached 2.3 per cent, a 0.23 percentage point increase from the previous year.

The average annual interest rate on prime business loans was 4.7 per cent in 2008, a decrease of 1.4 percentage points over the 2007 average rate. The Bank of Canada dropped the target overnight rate throughout 2008, from 3.5 per cent to 1.5 per cent. These decreases were an attempt to keep the Canadian economy afloat by providing liquidity. The cut in interest rates continued into 2009, when the Bank of Canada lowered the rates further due to the continued weakness in the economy. As of the end of March 2009, the Canadian overnight rate was a full percentage point lower than it was at the end of 2008, at 0.5 per cent. Decreased competitive pressures from a relatively weak Canadian dollar combined with a recent income tax cut has resulted in the expectation of low inflation, which is forecast to be 0.5 per cent in 2009 and to increase to 2 per cent per year over the remainder of the forecast period.

The current lower interest rates, low inflation, and various stimulus packages announced by the federal and provincial governments are expected to strengthen Canadian domestic demand, which provides the foundation of the ERCB forecast for Canada's economic growth in 2010 and for the remainder of the forecast period.

1.5 Alberta Economic Outlook

Alberta real economic growth averaged 4.0 per cent per year over the past five years. Alberta has the highest nominal GDP per capita among the provinces, averaging $75 000 per person, 60 per cent higher than the national average.

The ERCB forecast of Alberta's real GDP and other economic indicators is given in **Table 1.4**. In 2008, Alberta's real GDP experienced its first contraction in two decades. Real GDP declined by 0.2 per cent in 2008 and is forecast to contract by 2.3 per cent in 2009. However, it is projected to rebound and grow by 1.8 per cent in 2010 and to average 3.0 per cent per year over the remainder of the forecast period. Alberta's inflation rate was measured at 3.2 per cent in 2008, compared with the national inflation rate of 2.3.

Table 1.4. Major Alberta economic indicators, 2008-2018 (%)

	2008[a]	2009	2010	2011-2018[b]
Real GDP growth	-0.2	-2.3	1.8	3.0
Real personal disposable income growth	5.7	3.0	3.5	4.0
Inflation rate	3.2	1.0	2.0	2.4
Employment growth	2.8	-0.6	1.4	2.5
Population growth	1.7	1.6	2.0	2.1
Unemployment rate	3.6	6.0	6.2	4.2

[a] Actual.
[b] Averaged over 2011-2018.

The collapse in energy prices has significantly curtailed economic activity in Alberta. That, combined with tightening credit conditions and still-high project costs, has slowed the pace of new project development in the province, with cancellations and delays to many projects announced in recent months. As a result, Alberta's economy is expected to contract in 2009 but to continue to be among the nation's best performers from 2010 onward. The positive economic outlook will continue to contribute to excellent job prospects, low levels of unemployment, real increases in average employment earnings, and growth in personal disposable income.

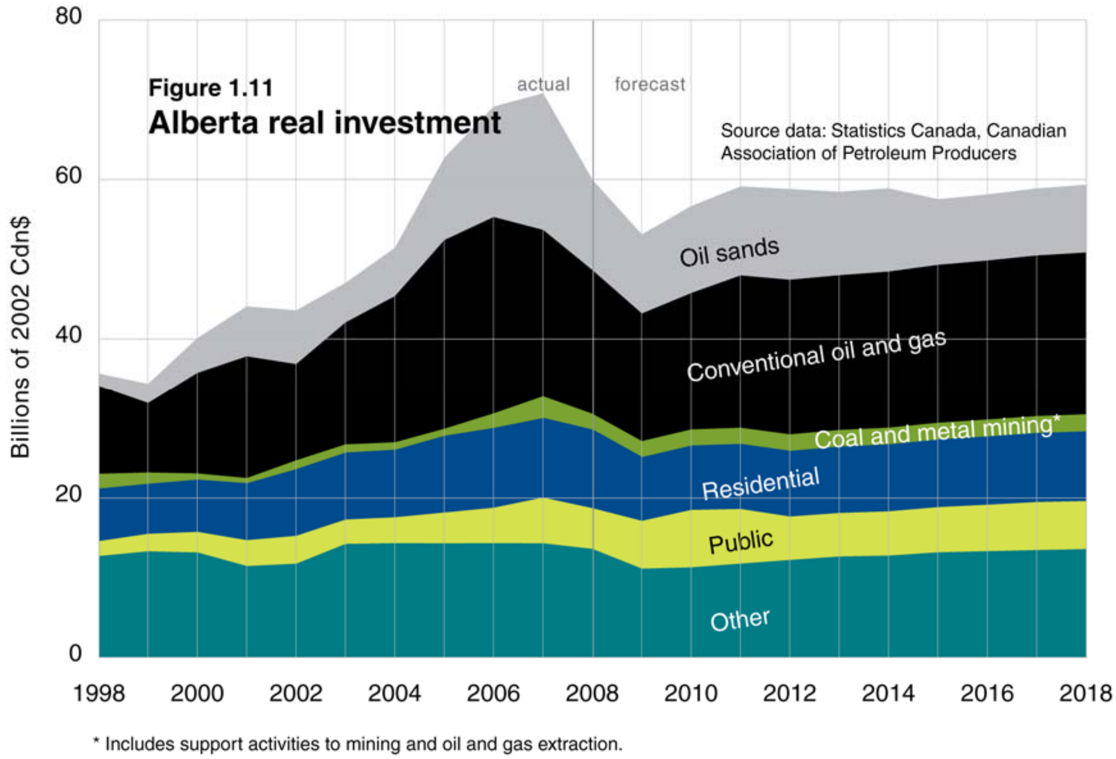
The main contributors to Alberta's future economic growth are large gains in investment expenditure, particularly in the conventional and unconventional oil and gas sectors with the return of sustained high energy prices, and a steady rate of growth in personal consumption. The spin-offs from increased investment and consumption will mean increased output in many of Alberta's major sectors, including unconventional energy resources, petroleum, coal, and chemical product manufacturing, as well as retail and wholesale trade and service industries. Much of Alberta's increased output will be destined for export markets.

Most of the earlier investment in the oil sands sector was focused on surface mining projects. Syncrude Canada Ltd. and Suncor Energy Inc. have been extracting bitumen from surface-mined oil sands for decades, while Shell Canada Ltd. has developed the third surface mining project. Much of the future oils sands-related investment, however, will be geared toward in situ type extraction methods and bitumen upgrading. In addition, investment in much-needed pipeline infrastructure to move the product to new and existing markets is also anticipated.

Total real investment expenditure is expected to contract by an average of 11 per cent in 2009. Over the 2010 to 2018 period, real investment will accelerate, growing by an average of 1.3 per cent. Currently, some oil sands projects have been delayed or cancelled, but once the economy recovers, new oil sands projects are anticipated to continue, resulting in investment growth becoming more pronounced towards the middle to late portion of the forecast period.

From 2009 through 2018, the ERCB expects nominal investment expenditures related to oil sands (surface mining, upgrading, in situ, and support services) to total $99 billion ($97 billion in 2002 dollars). Real investment in conventional oil and gas extraction and unconventional non-oil sands (e.g., CBM and some heavy oil extraction) is expected to average $20 billion per year, consistent with the ERCB projections for drilling and commodity prices and with recent historical trends.

Figure 1.11 illustrates the profile of real investment in Alberta's energy, business, residential, and government sectors from 1998 through 2018.



The ERCB expects the high costs related to construction investment, such as material, labour, and transportation, to decrease in 2009. The recent cancellation and deferral of projects should keep costs lower than what Alberta has experienced in the past few years.

In recent years, Alberta has supplemented the labour force with workers from outside the province. However, this is expected to change as the level of economic activity in the province contracts in the short term. In 2008, employment grew by 2.8 per cent, twice the national average, and as a result the unemployment rate was a mere 3.6 per cent (compared to 6.1 per cent nationally). In 2009, however, employment gains are expected to slow in the near term, and unemployment is expected to increase. Over the forecast period, employment growth is assumed to average 2.5 per cent. The corresponding labour force participation rate will remain fairly consistent with expectations of employment and population growth, at 74 per cent.

Real personal disposable income grew by 5.7 per cent in 2008. Expectations are for real disposable income to slow to 3.0 per cent in 2009 and to average 3.5 per cent per year from 2010 onward. In 2008, real consumer expenditures growth was 2.7 per cent. The increase in earnings will continue to propel consumer expenditures beyond 2010. As personal income increases, real consumption is anticipated to rise and spending is forecast to increase by 5.0 per cent over the remainder of the forecast period.

Real provincial exports, net of inflation, which include interprovincial transactions of goods, declined by 1.0 per cent in 2008 and are projected to decline by 2.1 per cent in 2009. For the remainder of the forecast, real export growth is projected to average 2.5 per cent per year. Canada's strong exchange rate farther out in the forecast period implies that export growth will be weaker compared with the past five-year average.

Starting in 2010, disposable income and prospects for high-paid employment are projected to return to historical levels. Consumers will continue to demand more goods and services, with many of these originating from abroad. Real import growth expanded by 1.6 per cent in 2008 and is expected to grow by more than 3 per cent from 2010 onward. Much of the import growth can be attributed to a strong Canadian dollar, which has made these goods cheaper for Canadians. The current forecast value of the Canadian dollar is still high by historical standards. Albertans will continue to demand imported goods. In addition, businesses will find it more economical to purchase new machinery and equipment from abroad. Investment in machinery and equipment has been strong over the past couple of years, as the price of these imported goods has fallen.

Conventional gas wells connected and oil wells placed on production in Alberta declined in 2008 from previous year highs. In 2007, 9286 conventional gas wells and 1745 conventional oil wells were connected and placed on production in Alberta. In 2008, 7907 conventional gas wells were connected and 1738 conventional oil wells were placed on production. Also in 2007, some 2465 CBM (unconventional gas wells) were placed on production, while in 2008, only 1466 wells were connected for CBM production, a 41 per cent decrease from the 2007 levels. The natural gas price decline that took place in late 2007 and 2008 was the likely cause of the significant slowdown in conventional gas and CBM drilling activity. The ERCB price forecast assumes that the current pace of activity will improve towards late 2010, coincident with an improvement in natural gas and crude oil prices.

The value of Alberta's energy resource production in 2007 and 2008 is depicted in **Figure 1.12.** In 2008**,** the total value of production increased by 34 per cent relative to 2007. Also, for the first year ever, the value of SCO and bitumen production exceeded the value of natural gas production.

The total economic value of Alberta's energy resource production for the period 2008 to 2018 is shown in **Table 1.5.** Production from unconventional energy resources is projected to increase significantly over the coming decade. In particular, crude bitumen and SCO derived from the oil sands will more than offset the decline of conventional resource production.

Despite the current economic contraction, Alberta's future economic growth will continue to provide a strong push for Canada's future economic growth. The province has been leading many other provinces in terms of employment, population, and income growth. As well, Alberta has managed to sustain a considerably low unemployment rate, below 5 per cent per year over the last five years. The ERCB forecast for Alberta's economic growth beyond 2009 is attainable, provided the forecast energy prices materialize and world economies begin to emerge from recession.

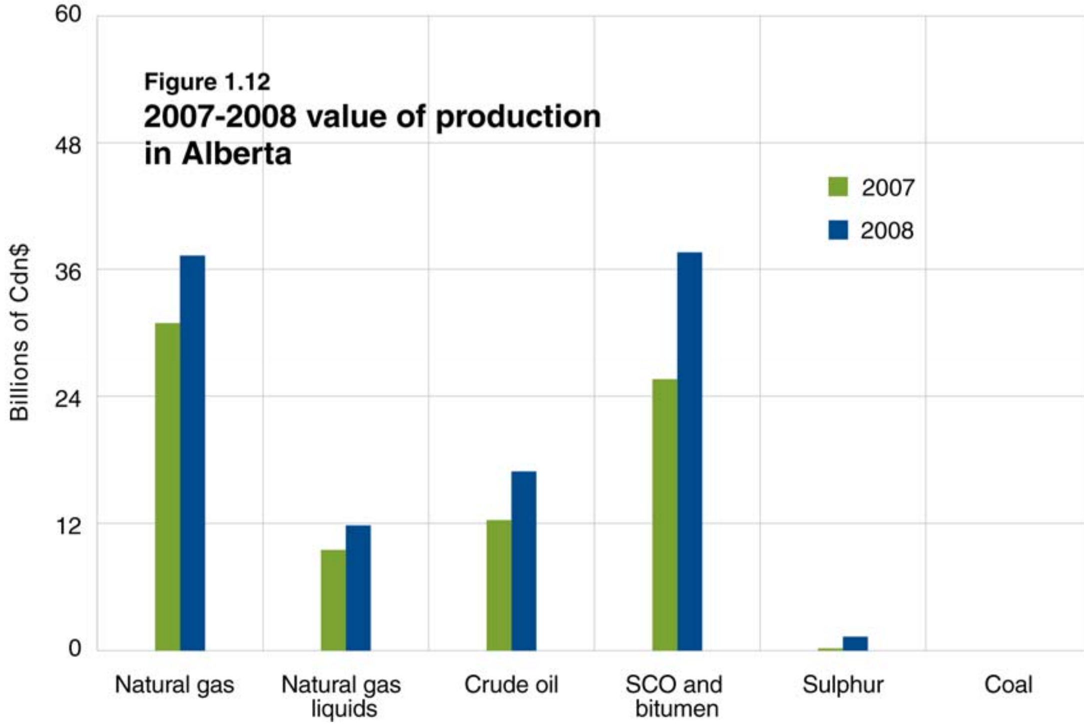


Table 1.5. Value of Alberta energy resource production (millions of current dollars)

	2008	2009[a]	2010[a]	2011-2018[a,b]
Conventional crude oil	16 856	8 781	8 298	10 461
Crude bitumen	14 310	7 099	7 657	20 487
Synthetic crude oil	23 413	17 544	20 470	46 319
Marketable gas	37 308	23 399	24 298	30 647
Natural gas liquids	11 783	7 102	6 832	9 408
Sulphur	1 312	55	82	115
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	10 4982	63 981	67 638	117 438

[a] Values calculated from the ERCB's annual average price and production forecasts.
[b] Annual average over 2011-2018.

2 Crude Bitumen

Highlights

- Remaining established mineable reserves under active development increased by 29 per cent, with the inclusion of the Kearl mine project.
- Remaining established mineable reserves increased by 11 per cent due to an expansion of the ERCB-defined Surface Mineable Area.
- Total bitumen production decreased by 1 per cent, mineable decreased by 8 per cent, while in situ increased by 9 per cent.
- Synthetic crude oil production decreased by 5 per cent.

Crude bitumen, a type of heavy oil, is a viscous mixture of hydrocarbons that in its natural state does not flow to a well. In Alberta, crude bitumen occurs in sand (clastic) and carbonate formations in the northern part of the province. 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. Other heavy oil is deemed to be oil sands if it is located within an oil sands area. Since the bitumen within these deemed oil sands 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 oil sands areas (OSAs) in Alberta are shown in **Figure 2.1**. Each OSA contains a number of bitumen-bearing deposits. The known extent of the largest deposit, the Athabasca Wabiskaw-McMurray, as well as the significant Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 kilometres (km) (30 miles) apart.

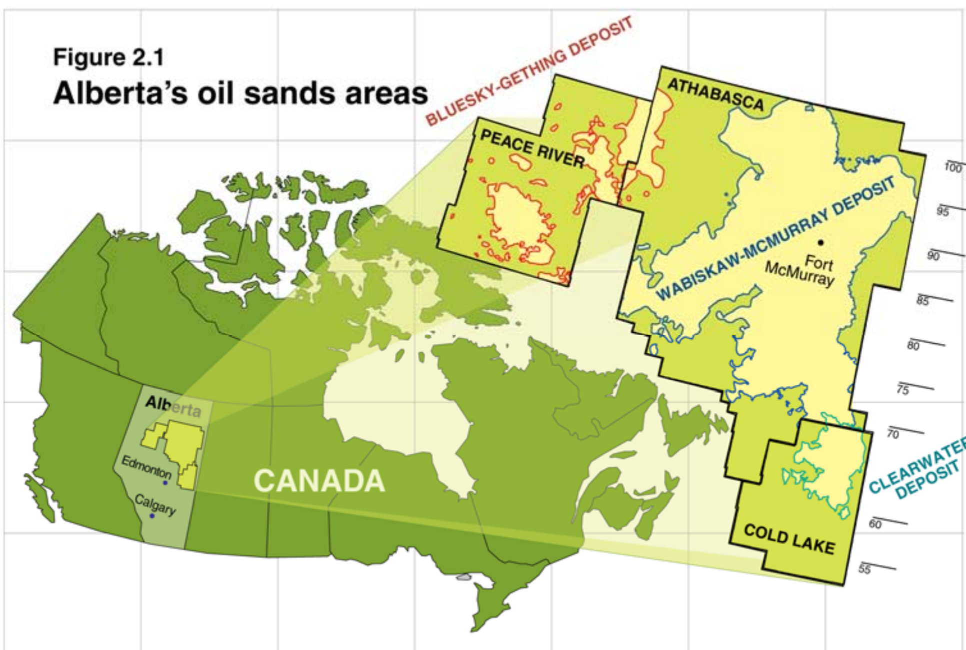


Figure 2.1
Alberta's oil sands areas

Two methods are used for recovery of bitumen, depending on the depth of the deposit. North of Fort McMurray, crude bitumen occurs near the surface and is recovered 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, the bitumen is recovered in situ. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development, whereby steam, water, or other solvents are injected into the reservoir to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore. The vast majority of lands thought to contain bitumen developable by either method are currently leased.

2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

Over the past years, the ERCB has been working towards updating Alberta's resources and reserves of crude bitumen. This initiative continues and will likely be ongoing for some years, as rapid development of the resource continues. The initial step in this review is to update the in-place resources for the most significant of the province's 15 oil sands deposits, those currently with production and consequently containing established reserves. To date, four of the most important deposits have been updated. The largest deposit, the Athabasca Wabiskaw-McMurray (AWM), was significantly updated for year-end 2004 and revised for year-ends 2005, 2007, and 2008 to take into account new drilling. The AWM has the largest cumulative and annual production. The deposit with the second largest production, the Cold Lake Clearwater (CLC), was updated for year-end 2005, as was the northern portion of the Cold Lake Wabiskaw-McMurray (CLWM) deposit. The Peace River Bluesky-Gething (PRBG) deposit was updated for year-end 2006. These four recently updated deposits contain 65 per cent of the total initial in-place bitumen resource and 87 per cent of the in-place resource found in clastics. During 2008, significant work was done on updating both the Upper and Lower Cold Lake Grand Rapids deposits and the Athabasca Grosmont deposit. This work will be completed in 2009 and included in next year's report.

Once the in-place resources of the major deposits have been reassessed, the ERCB will review Alberta's established reserves on both a project and deposit basis. It is anticipated that this work will take some time to complete for in situ deposits. However, for year-end 2008, an initial review of the recoverability of the Bluesky-Gething deposit suggests that based on removal of the more marginal material, a factor of 20 per cent is appropriate for thermal recovery. As a result, the established in situ reserves were reduced to 0.87 billion cubic metres (10^9 m^3), a reduction of a similar 0.87 10^9 m^3 from the original estimate for year-end 1999.

Also as of year-end 2008, the ERCB completed an evaluation of the resources associated with recent drilling north of the existing ERCB-defined Surface Mineable Area (SMA). The results of the evaluation confirm that potentially surface mineable resources occur in this area. Therefore, the existing SMA boundary has been expanded to include the additional resources in 14½ additional townships (see **Figure 2.3, Figure 2.4,** and Section 2.1.3 for more details). As a consequence of its review, the ERCB has reassessed the established reserves that are a result of recovery via mining technology and has increased the initial established mineable reserves from 5.59 10^9 m^3 to 6.16 10^9 m^3, an increase of 0.57 10^9 m^3, or about 10 per cent.

As a result of these two changes, there is a net decrease in the total established reserves of crude bitumen for this year's report and, therefore, the initial established reserves of crude bitumen at December 31, 2008, are 28.09 10^9 m^3. The remaining established reserves at December 31, 2008, are 27.07 10^9 m^3. This overall slight reduction relative to the 2007 remaining established reserve estimate of 27.45 10^9 m^3 is also due to 2008 production of 0.08 10^9 m^3.

Of the total 27.07 10^9 m^3 remaining established reserves, 21.58 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods and 5.49 10^9 m^3 by surface mining methods. Of the in situ and mineable totals, 4.30 10^9 m^3 is within active development areas. **Table 2.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

Table 2.1. 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	20.7	6.16	0.67	5.49	3.74
In situ	254.4	21.94	0.35	21.58	0.56
Total	275.1 (1 731)[a]	28.09 (176.8)[a]	1.02 (6.4)[a]	27.07 (170.4)[a]	4.30 (27.1)[a]

[a] 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 2008 are shown in **Table 2.2**.

Table 2.2. Reserve and production change highlights (10^6 m^3)

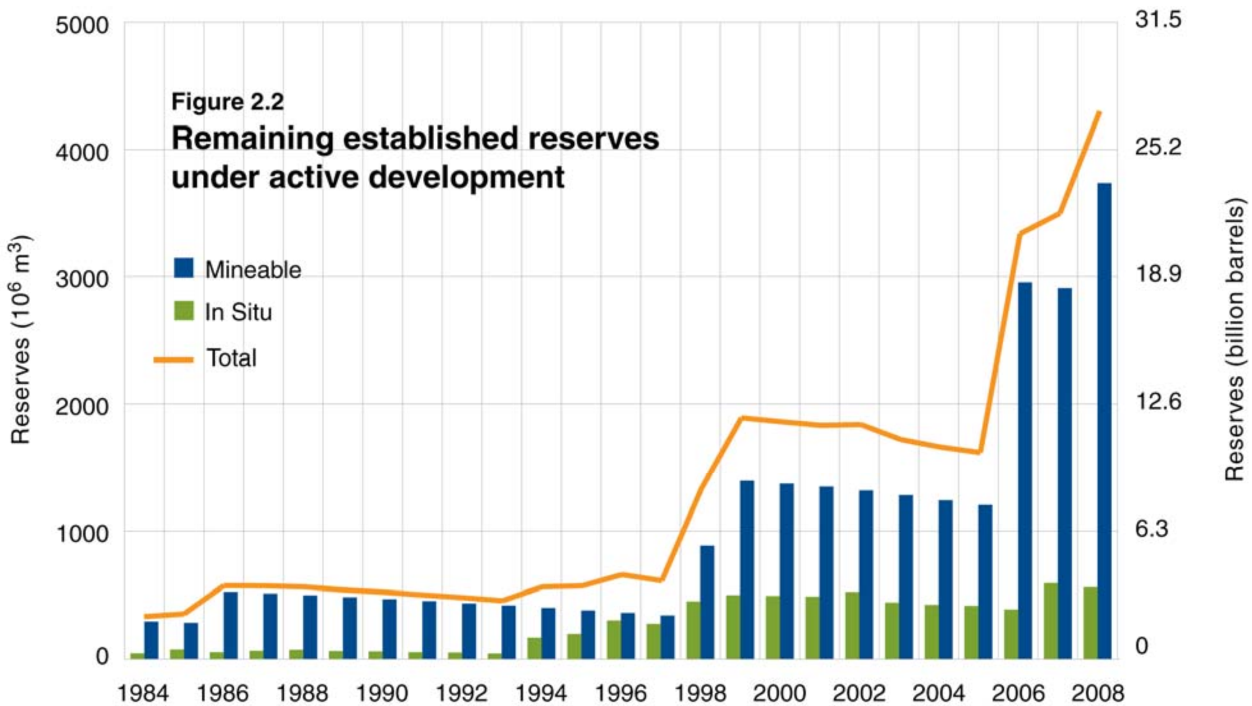
	2008	2007	Change[a]
Initial established reserves			
Mineable	6 157	5 590	+567
In situ	21 935	22 802	-867
Total	28 092 (176 780)[b]	28 392 (178 668)[b]	-300
Cumulative production			
Mineable	670	628	+42[c]
In situ[a]	350	316	+34[c]
Total	1 020	944	+76[c]
Remaining established reserves			
Mineable	5 487	4 962	+525
In situ	21 585	22 486	-901
Total[a]	27 072 (170 361)[b]	27 448 (172 728)[b]	-376
Annual production			
Mineable	42	46	-4
In situ[a]	34	31	+3
Total	76	77	-1

[a] Differences 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.

The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown in **Tables 2.4** and **2.5** respectively.

Crude bitumen production in 2008 totalled 75.9 10^6 m^3, with 33.9 10^6 m^3 coming from in situ operations.

Figure 2.2 shows the remaining established reserves from active development areas. 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. The increase in 2008 is a result of the inclusion of the Kearl mine project.



2.1.2 Initial in-Place Volumes of Crude Bitumen

Alberta's massive crude bitumen resources are contained in sand (clastic) and carbonate formations in the three OSAs, Athabasca, Cold Lake, and Peace River, as shown in **Figure 2.1**. Contained within the OSAs are the 15 oil sands deposits that designate the specific geological zones containing the oil sands. Together the three OSAs occupy an area of about 142 000 km^2 (54 000 square miles).

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 can vary significantly within a reservoir, decreasing as the reservoir shale or clay content increases or as the porosity decreases. Increasing water volume within the pore space of the rock also decreases bitumen saturation. Bitumen saturation is expressed as mass per cent in sands (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water) and per cent pore volume in carbonates (the percentage of the volume of pore spaces that contain bitumen). The selection of appropriate saturation and thickness cutoffs 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 drillhole data, including 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. In the four previous reports, the AWM, CLC, and PRBG deposits, as well as a portion of the CLWM deposit, were also estimated at a 6 mass per cent saturation cutoff. This year's report also uses 6 mass per cent with the latest revision to the AWM deposit. The crude bitumen within the carbonate deposits was determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent.

The ERCB believes that the oil sands quality cutoff of 6 mass per cent more accurately reflects the volumes from which bitumen can be reasonably expected to be recovered; consequently, deposits that are updated in the future will likely be at this level. Based solely on a change from 3 to 6 mass per cent (other factors held constant), the estimated impact on the bitumen resource in place would be a decrease of about 20 per cent for the AWM, about 35 per cent for the CLC, and more than 50 per cent for the PRBG. However, work on these deposits has shown that some or all of these reductions are offset by increases due to new drilling since the previous estimate.

In 2003, the ERCB completed a reassessment of the AWM using geologic information from over 13 000 wells and bitumen content evaluations conducted on over 9000 wells to augment the over 7000 boreholes already available within the SMA. 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 to the latest reassessment, resulting in an increase to the in-place bitumen resources of the AWM of 3.14 10^9 m^3, or 2.1 per cent. Almost all this increase occurs within and surrounding the SMA. The large number of additional SMA boreholes is the result of new drilling, plus the inclusion of a large number of non-licensed drilling by operators.

Figure 2.3 is a bitumen pay thickness map of the AWM deposit revised for year-end 2008 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 in **Figure 2.3** is the extent of the SMA, including the northern expansion area, an ERCB-defined area currently of 51½ townships north of Fort McMurray covering that part of the AWM deposit where the total overburden thickness generally does not exceed 65 m. As such, it is presumed that the main recovery method will be surface mining, unlike in the rest of Alberta's crude bitumen area, where recovery will be through in situ methods. It should be noted, however, that this boundary is simply for resource administration purposes only 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 this boundary and in situ activities may occur inside. 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.

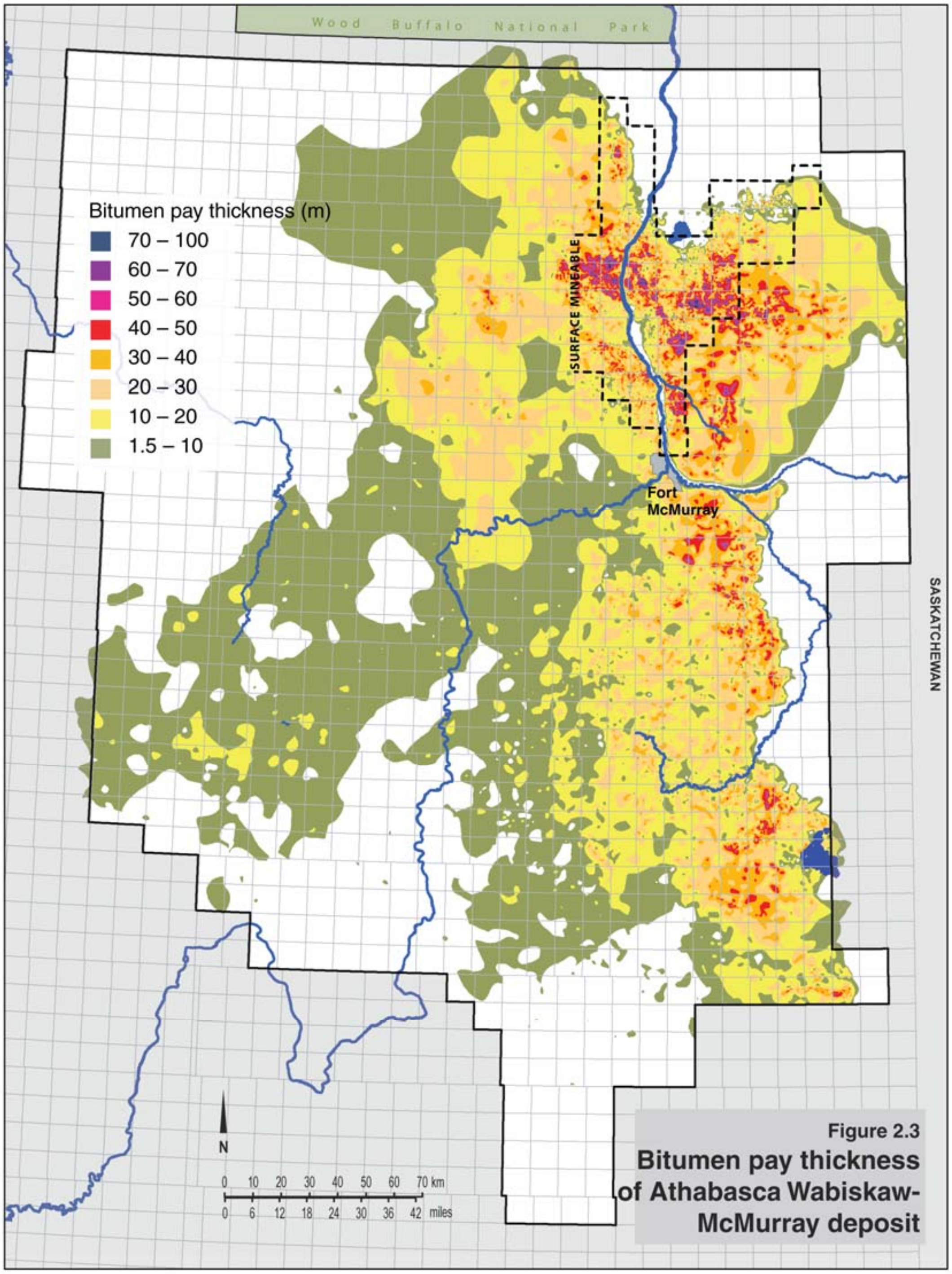


Figure 2.3
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

Because the extent of the SMA is defined using township boundaries, it incorporates a few areas of deeper bitumen resources that are more amenable to in situ recovery. As a result, while the SMA has both mineable and in situ resources, estimates of mineable bitumen exclude those volumes within the SMA but 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.

As discussed in Section 2.1.1, drilling in recent years north of the previous SMA boundary identified in-place bitumen resources that are potentially recoverable by surface mining methods. Consequently, the ERCB has expanded the SMA to include 14½ new townships, as shown in **Figure 2.4**. This expansion has transferred some in-place volumes from in situ to mineable categories and increased the established mineable reserves. No in situ recoverable volumes had previously been identified in this area, so the expansion has had no impact on the established in situ reserves. Together with the SMA expansion, a reassessment of the in-place bitumen within and surrounding the expanded SMA was undertaken. This review resulted in an increase to the in-place bitumen within the SMA but beyond mineable depths. This volume is included, as in previous years, in the in situ total, but because this material is at relatively shallow depths and because the review of in situ recoverability has not yet been completed for the AWM, no increase in initial established in situ reserves has occurred.

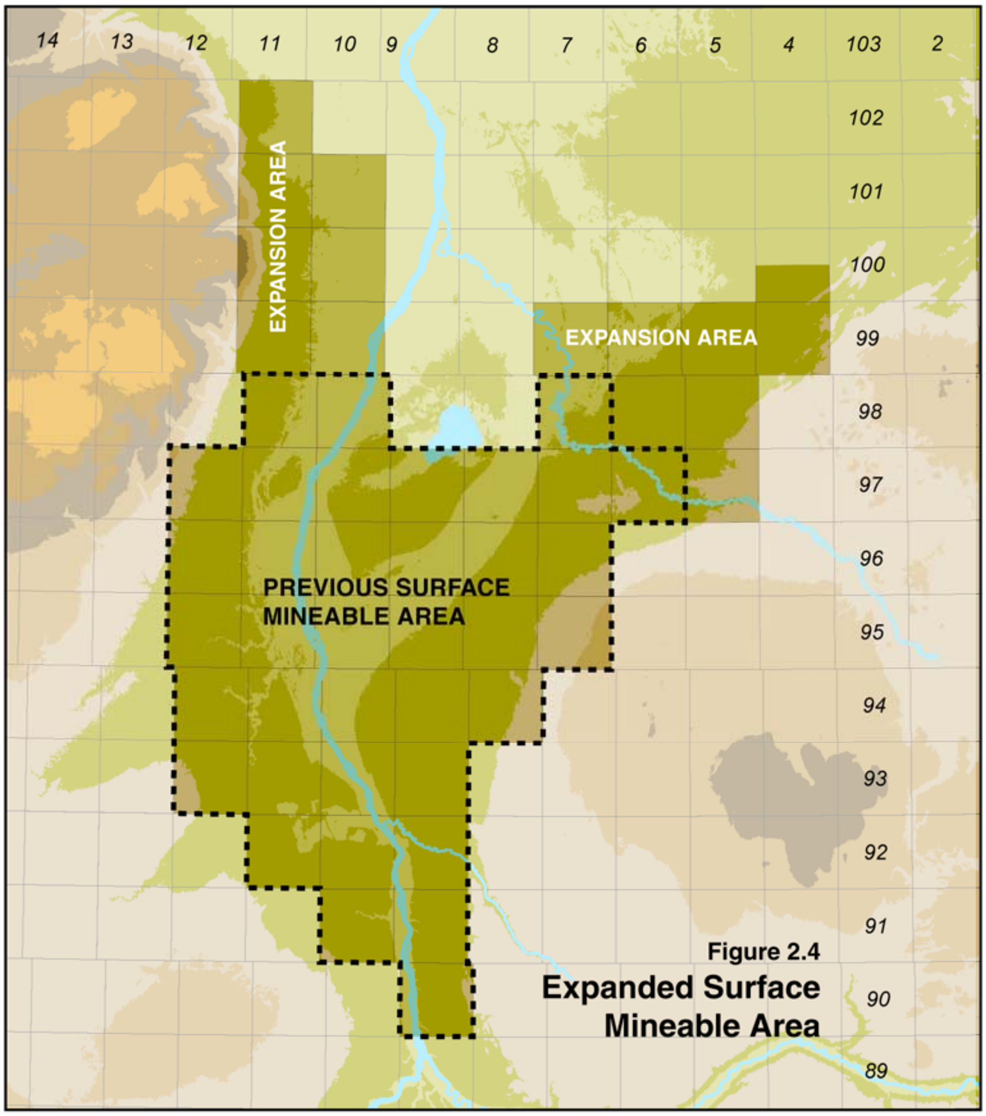
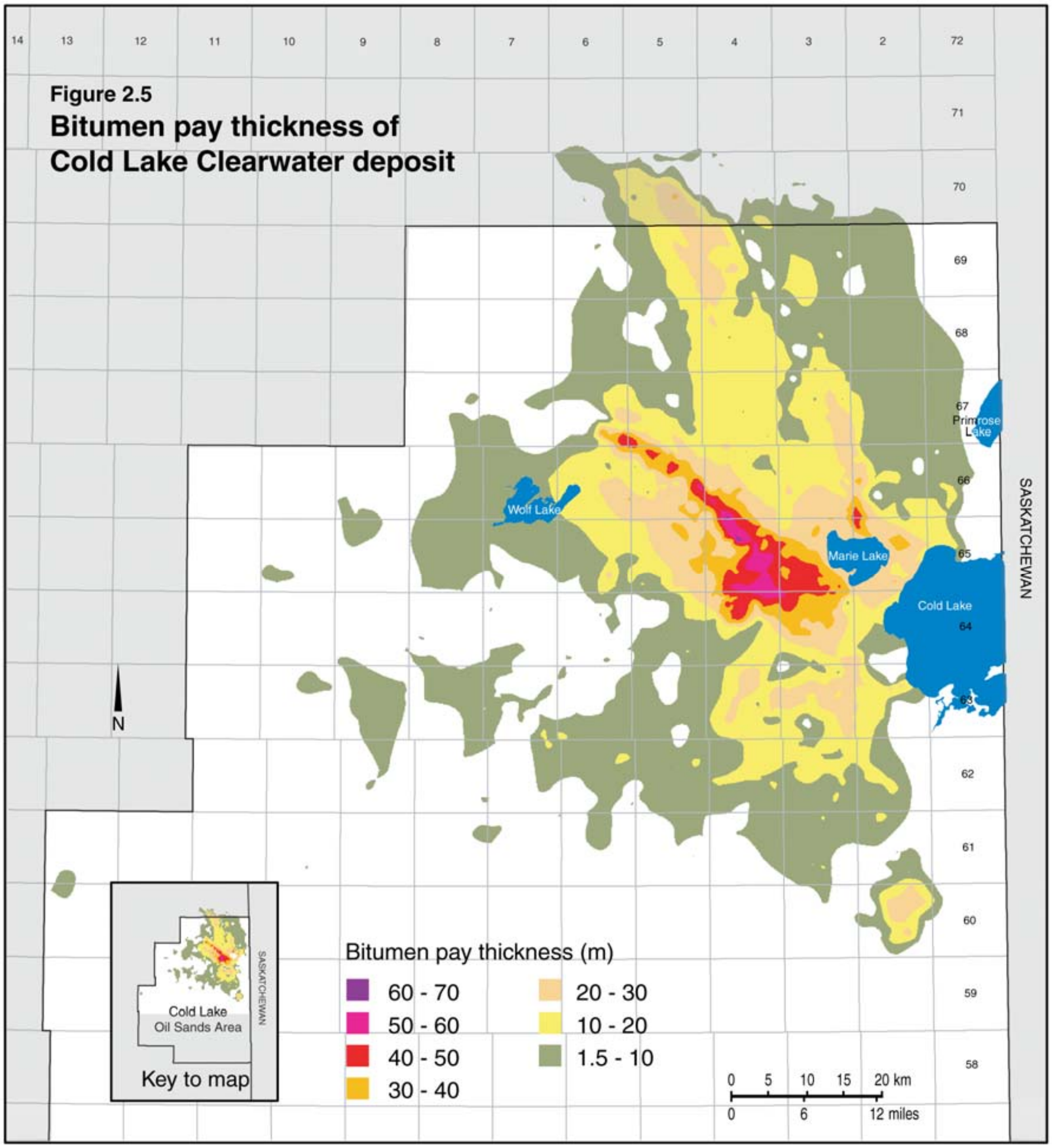


Figure 2.4
Expanded Surface Mineable Area

For year-end 2005, the ERCB completed its reassessment of the CLC deposit. This deposit contains the first commercial in situ bitumen development at Imperial's Cold Lake project, which commenced production in 1985. **Figure 2.5** is a bitumen pay thickness map for the CLC deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the CLC does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

For year-end 2006, the PRBG deposit was reassessed. This deposit contains the in situ bitumen development at Shell Canada's Peace River project, started in 1979. **Figure 2.6** is a bitumen pay thickness map for the PRBG deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Consistent with **Figure 2.3**, the PRBG 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 in **Figure 2.6** are the paleotopographic highlands as they are believed to have existed at the time of the end of the deposition of the Bluesky Formation. These highlands limited the extent of the deposition of the Bluesky and help to explain the bitumen accumulation within the Bluesky-Gething deposit. It is believed that oil migrated updip until it became trapped against these highlands and eventually biodegraded into bitumen.



These highlands, composed of carbonate rocks of Devonian and Mississippian age, were the exposed portion of a major erosional surface known as the sub-Cretaceous unconformity. At the end of Bluesky (and equivalents such as the Wabiskaw) time, the other portions of this surface were covered by sediments of the lower Mannville Group and equivalents. The nature of this unconformity surface is very important in understanding the deposition of the main clastic bitumen reservoirs and the occurrence of bitumen within them. This surface is also important in understanding the extent of karstification of the underlying carbonate rocks. Karsting, along with the nature of the sediments covering this surface, is a major factor in understanding bitumen accumulations in carbonate deposits. The exposed and contoured submerged portions of this surface are shown in **Figure 2.7**. Also shown in the figure are the extents of the Athabasca Grosmont and Nisku deposits. Significantly, these carbonate deposits together hold an estimated 60.8 10^9 m^3 of in-place bitumen resource.

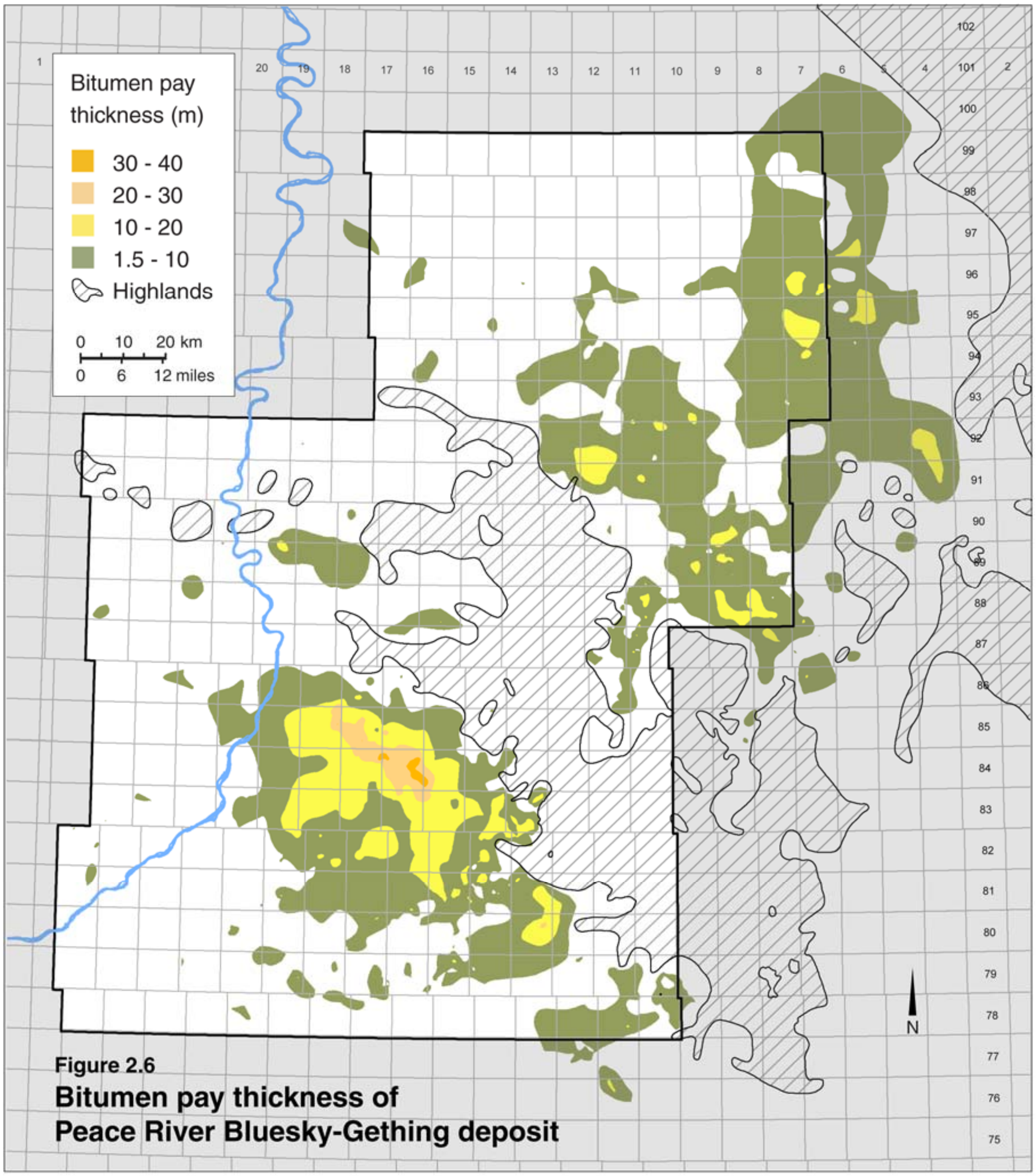


Figure 2.6
Bitumen pay thickness of Peace River Bluesky-Gething deposit

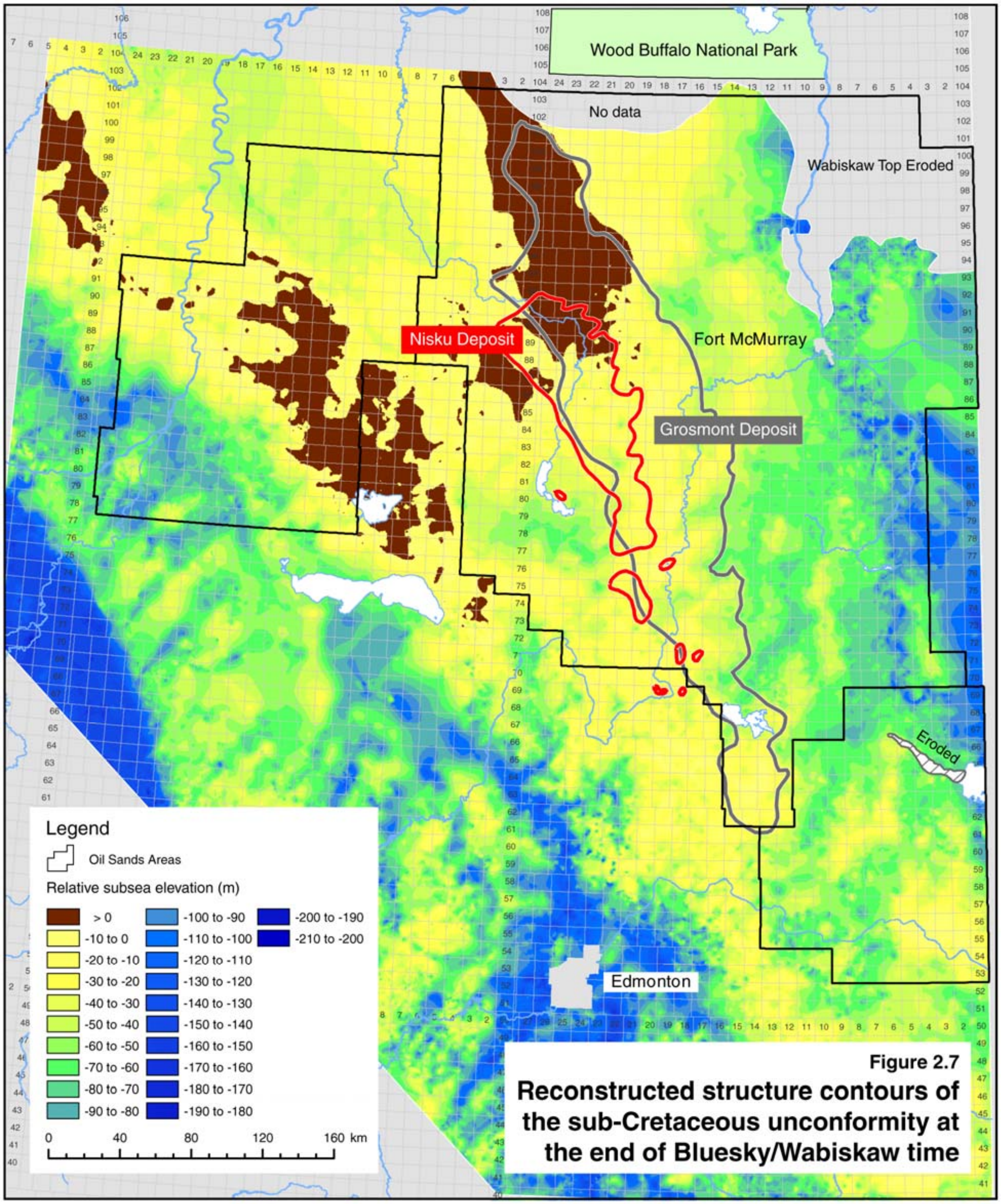


Figure 2.7
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Tables B.1** and **B.2** respectively in **Appendix B** and are summarized by formation in **Table 2.3**. Individual maps to year-end 1995 are shown in EUB *Statistical Series 96-38: Crude Bitumen Reserves Atlas* (1996). The latest maps for the AWM, CLC, and PRBG will be available separately.

Table 2.3. Initial in-place volumes of crude bitumen as of December 31, 2008

Oil sands area / Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha*)	Average pay thickness (m)	Average bitumen saturation Mass (%)	Average bitumen saturation Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	20 728	374	25.8	10.1	76	28
Wabiskaw-McMurray (in situ)	132 319	4 701	13.1	10.2	73	29
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	50 500	4 167	10.4	4.7	68	16
Subtotal	222 555					
Cold Lake						
Grand Rapids	17 304	1 709	5.9	9.5	66	31
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.4	7.3	59	27
Subtotal	31 013					
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	302	23.7	5.1	65	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	21 560					
Total	275 128					

*ha – hectare.

2.1.3 Surface-Mineable Crude Bitumen Reserves

With the expansion of the SMA and the updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the ERCB now estimates that the SMA contains 20.7 10^9 m^3 of initial bitumen in-place resource at depths most suitable to mineable technologies, generally less than 65 m. This is an increase of 4.6 10^9 m^3 relative to the 2007 estimate, with most of this 29 per cent increase coming from the expansion area. Potential mineable areas in this portion of the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[1] This method reduces the initial volume in place of 20.7 10^9 m^3 to 10.3 10^9 m^3 as of December 31, 2008. This latter volume is classified as the initial mineable volume in place.

Factors were applied to this initial mineable volume in place to determine the established reserves. A series of reduction factors was 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, and therefore each factor is set at 90 per cent. A combined mining/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 reserve of

[1] Energy Resources Conservation Board, 1979, *ERCB Report 79-H: Alsands Fort McMurray Project.*

crude bitumen has risen from 5.59 10^9 m^3 in 2007 to 6.16 10^9 m^3 with the inclusion of reserves associated with the expanded SMA. The remaining established mineable crude bitumen reserve as of December 31, 2008, has also increased from 4.96 10^9 m^3 to 5.49 10^9 m^3.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2008, are presented in **Table 2.4**. As of the end of 2008, almost three-quarters of the initial established reserves were under active development. Currently, Suncor, Syncrude, and Albian Sands are the only producers in the SMA, and the cumulative bitumen production from these projects is 670 10^6 m^3. Meanwhile, the Canadian Natural Resources Ltd. Horizon mine completed commissioning and began synthetic crude oil production in early 2009. The Fort Hills mine project (owned by Petro-Canada, UTS Energy, and Teck Cominco) and the Shell Canada Ltd. Jackpine project are considered to be under active development and are included in **Table 2.4**. The recently approved Kearl mine project (Imperial Oil/ ExxonMobil) is proceeding with development and has also been included in the table this year.

Production from the three current surface mining projects amounted to 42.0 10^6 m^3 in 2008, with 19.7 10^6 m^3 from the Syncrude project, 14.4 10^6 m^3 from the Suncor project, and 7.8 10^6 m^3 from the Albian Sands project (as of January 1, 2009, this project is known as Shell Albian Sands).

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2008

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)
Albian Sands	13 581	672	419	49	371
Fort Hills	18 976	699	364	0	364
Horizon	28 482	834	537	0	537
Kearl	19 674	1 324	872	0	872
Jackpine	7 958	361	222	0	222
Suncor	19 155	990	687	250	437
Syncrude	44 037	2 071	1 306	371	935
Total	151 863	6 951	4 407	670	3 738

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

2.1.4 In Situ Crude Bitumen Reserves

The ERCB has determined an in situ initial established reserve for those areas considered amenable to 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. A minimum saturation cutoff of 3 mass per cent was used in all deposits. Future reserves estimates will likely be based on values higher than the 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to the areas meeting 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. These overall recovery factors are currently under review.

For year-end 2008, the recovery factors of the PRBG were reviewed and are considered to be appropriate for both thermal and primary recovery for those areas having bitumen pay thicknesses equal to or greater than 10 m for thermal and 3 m for primary, based on a saturation cutoff of 6 per cent. Therefore, combining the recently updated initial in-place estimates with these confirmed recovery factors yields an initial established reserves estimate of 874 10^6 m^3. This is a decrease of 872 10^6 m^3. This 50 per cent reduction is due primarily to the removal of marginal quality bitumen, with saturations between 3 and 6 per cent, from the in-place estimate.

In 2008, the in situ bitumen production was 33.9 10^6 m^3, an increase from 31.1 10^6 m^3 in 2007. Cumulative production within the in situ areas now totals 350.1 10^6 m^3, of which 259.5 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 22.49 10^9 m^3 in 2007 to 21.58 10^9 m^3 in 2008, due to the lower reassessment of the PRBG and production of 0.03 10^9 m^3.

The ERCB's 2008 estimate of the established in situ crude bitumen reserves under active development is shown in **Table 2.5**.

The ERCB has assigned initial volumes in place and initial and remaining established reserves for commercial projects, primary recovery schemes, and active experimental schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is shown for all active experimental schemes, as well as an estimate of initial volumes in place and cumulative production. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. In a future edition of this report, large thermal projects and primary schemes will be listed individually, similar to Table 2.4. The initial established reserves under primary development are based on a 5 per cent average recovery factor. 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.

That part of the total remaining established reserves of crude bitumen from within active in situ project areas is estimated to be 560.7 10^6 m^3, a slight decrease due to 2008 production.

2.1.5 Ultimate Potential of Crude Bitumen

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

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2008

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	55.8	40	22.3	10.0	12.3
Primary recovery schemes	160.8	5	8.0	6.1	1.9
Subtotal	216.6		30.4	16.1	14.3
Athabasca Oil Sands Area					
Thermal commercial projects	313.7	50	156.9	36.9	120.0
Primary recovery schemes	1 026.2	5	51.3	20.4	30.9
Enhanced recovery schemes[c]	(289.0)[d]	10	28.9	10.3	18.6
Subtotal	1 339.9		237.1	67.6	169.5
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[e]	1 212.8	25	303.2	184.8	118.4
Thermal commercial (SAGD)[f]	33.8	50	16.9	1.0	15.9
Primary production within projects	601.1	5	30.1	13.7	16.4
Primary recovery schemes	4 347.1	5	217.4	52.7	164.7
Lindbergh primary production	1 309.3	5	65.5	7.3	58.2
Subtotal	7 504.1		633.0	259.5	373.5
Experimental schemes (all areas)					
Active	8.1	15[g]	1.2	1.1[h]	0.1
Terminated	87.4	10[g]	9.1	5.8	3.3
Subtotal	95.5		10.3	6.9	3.5
Total	9 116.0		908.7	350.1	560.7

[a] Thermal reserves for this table are assigned only for lands approved for thermal recovery and having completed drilling development.
[b] Cumulative production to December 31, 2008, includes amendments to production reports.
[c] Schemes currently on polymer or waterflood in the Brintnell-Pelican area. Previous primary production is included under primary schemes.
[d] The in-place number is that part of the primary number above that will see incremental production due to polymer or waterflooding.
[e] Cyclic steam simulation projects.
[f] Steam-assisted gravity drainage projects.
[g] Averaged values.
[h] Production from the Athabasca OSA is 0.86 10^6 m^3 and from the Cold Lake OSA is 0.20 10^6 m^3.

2.2 Supply of and Demand for Crude Bitumen

This section discusses production and disposition of crude bitumen. It includes crude bitumen production, upgrading of bitumen to various grades of synthetic crude oil (SCO), and disposition of both SCO and nonupgraded bitumen. The nonupgraded bitumen refers to the portion of crude bitumen production that is not upgraded but is blended with diluent and sent to markets by pipeline. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to SCO and is primarily used by refineries as feedstock.

"Upgrading" is the term given to a process that converts bitumen and heavy crude oil into SCO. Upgraders chemically alter the bitumen by adding hydrogen, subtracting carbon, or both. In upgrading processes, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. Most oil sands coke, a by-product of the upgrading process, is stockpiled, with some burned in small quantities 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.

Crude bitumen must be diluted with some lighter-viscosity product (referred to as a diluent) in order to be transported in pipelines. Pentanes plus are generally used in Alberta as diluent and represent about 30 per cent of the blend volumes. Diluent used to transport bitumen to Alberta destinations is usually recycled. However, the volumes used to dilute bitumen for transport to markets outside Alberta are generally not returned to the province.

SCO is also used as diluent. However, a blend volume of about 50 per cent SCO is required, as the SCO has a higher viscosity and density than pentanes plus. Other products, such as naptha and light crude oil, can also be used as diluent to allow bitumen to meet pipeline specifications. Use of heated and insulated pipelines can decrease the amount of required diluent.

The forecast of crude bitumen and SCO production relies heavily on information provided by project sponsors. Project viability depends largely on the cost of producing and transporting the products and on the market price for bitumen and SCO. Other factors that bear on project economics are refining capacity to handle bitumen or SCO and competition with other supply sources in U.S. and Canadian markets. The forecasts include production from existing projects, expansion to existing projects, and development of new projects. Demand for SCO and nonupgraded bitumen in Alberta is based on refinery demand and SCO used for transportation needs. Alberta SCO and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

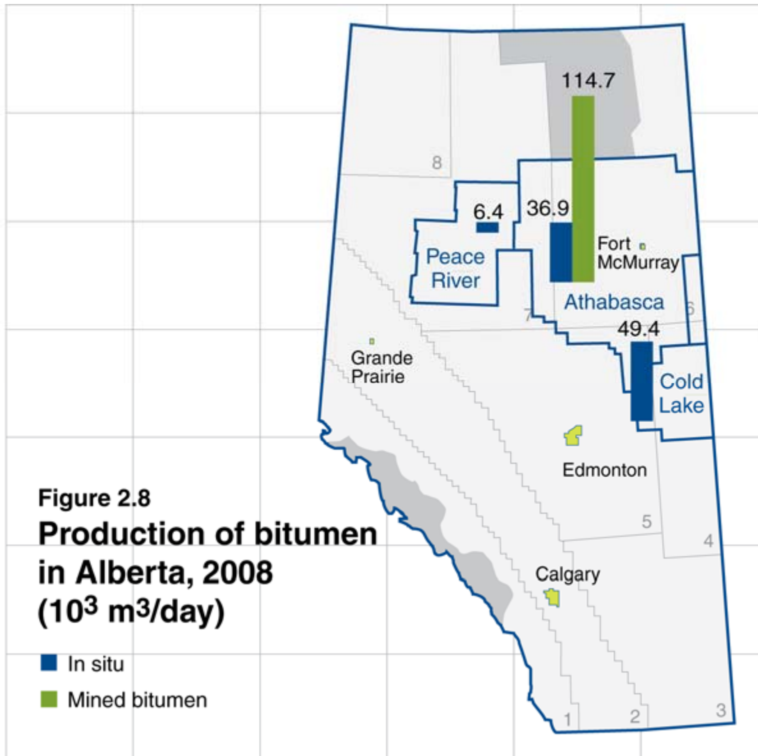
Project sponsors' projections of existing and future bitumen production can change over time for various reasons. Large oil sands production projects are complex, require long lead and construction times, and are very capital intensive, making the projects vulnerable to materials and labour cost increases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

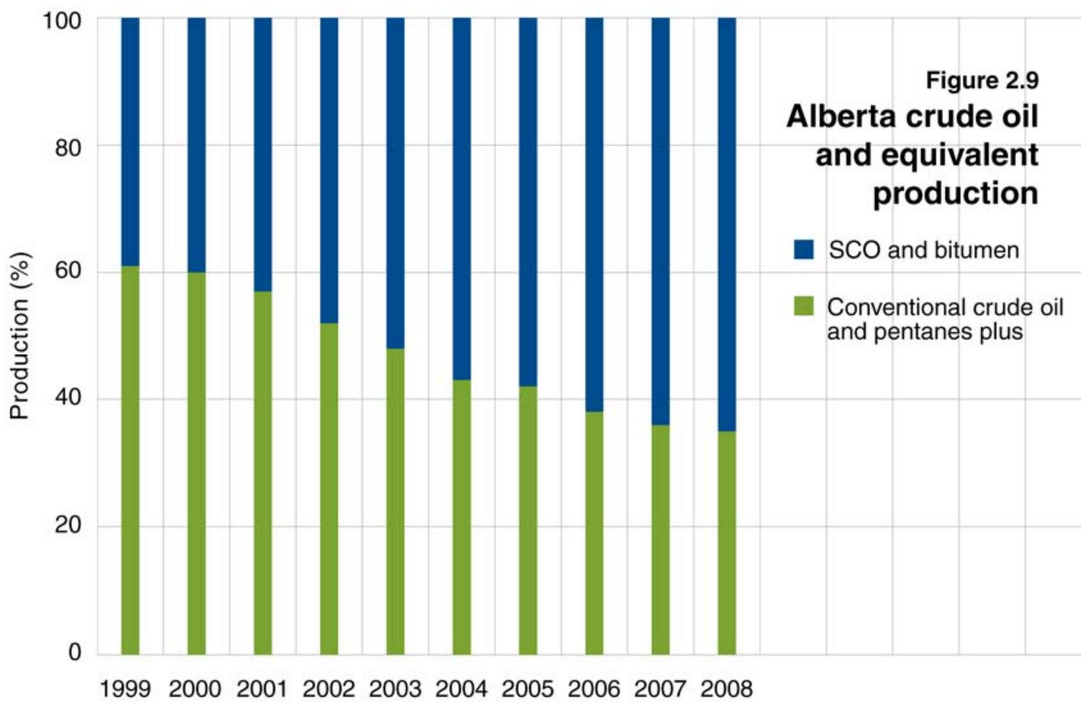
2.2.1 Crude Bitumen Production

Surface mining and in situ production for 2008 are shown graphically by oil sands area (OSA) in **Figure 2.8**. In 2008, Alberta produced 207.4 thousand (10^3) m^3/d of crude bitumen from all three areas, with surface mining accounting for 55 per cent and in situ for 45 per cent. In 2007, total crude bitumen production was 209.9 10^3 m^3/d. **Figure 2.9** shows combined nonupgraded bitumen and SCO production as a percentage of Alberta's total crude oil and equivalent production. Combined SCO and nonupgraded bitumen production volumes have increased from 39 per cent of the production in 1999 to 65 per cent in 2008.

2.2.1.1 Mined Crude Bitumen

Currently, all mined bitumen in Alberta feeds upgraders producing SCO. In 2008, mined crude bitumen production decreased by 8 per cent relative to 2007, to 114.7 10^3 m^3/d, with Syncrude, Suncor, and Shell Albian Sands accounting for 47, 34, and 19 per cent of total mined bitumen respectively.





Syncrude production in 2008 dropped by 8 per cent relative to 2007, to 53.7 10^3 m^3/d, due to two planned coker turnarounds and an operational upset during the first quarter of 2008.

Production at Suncor declined by some 7 per cent, to 39.4 10^3 m^3/d, compared to the 2007 average production. The decrease in production was the result of planned and unplanned maintenance activities in the upgrading and extraction facilities. Suncor completed an expansion to one of the two oil sands upgraders in the third quarter of 2008, which will increase Suncor's SCO capacity to 55.6 10^3 m^3/d from 41.3 10^3 m^3/d.

Shell Albian Sands produced 21.4 10^3 m^3/d in 2008, a decrease of 10 per cent from the 2007 volume of 23.9 10^3 m^3/d. Production at Shell Albian Sands was curtailed mainly due to the execution of the mine tailings management plan, which temporarily led to lower-grade ore being mined and to planned and unplanned maintenance at the mine site and the Scotford Upgrader.

CNRL's Horizon Project commenced mining operations in September and produced about 55 000 m^3 (0.2 10^3 m^3/d) in 2008. First SCO production was achieved in February 2009.

In projecting the future supply of bitumen from mining, the ERCB considered potential production from existing facilities and supply from future projects. The projects considered for the forecast are shown in **Table 2.6.**

Table 2.6. Surface mined bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Suncor			
North Steepbank extension	2010	–	Under construction
Voyageur South Phase 1	TBD*	19.1	Application
Syncrude			
Stage 3 debottleneck	TBD	7.4	Announced
Stage 4 expansion	TBD	22.2	Announced
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD	18.3	Approved
Jackpine Phase 1A	2010	15.9	Under construction
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
Petro-Canada/UTS/Teck Cominco			
Fort Hills Phase 1	TBD	26.2	Approved
Fort Hills debottleneck	TBD	4.0	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	TBD	15.9	Approved
Kearl Phase 2	TBD	15.9	Approved
Kearl Phase 3	TBD	15.9	Approved
Total E&P Canada			
Joslyn Phase 1(North)	TBD	7.9	Application
Joslyn Phase 2(North)	TBD	7.9	Application

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

Due to uncertainties regarding timing and project scope, some projects, such as UTS's Equinox and Frontier, have not been considered in the 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 assumed that the current weak economic conditions, lower forecast oil prices, cost overruns, construction delays, and availability of suitable refinery capacity on a timely basis may affect the timing of production schedules for these projects. Considering these factors, the ERCB forecasts that total mined bitumen production will increase from 114.7 10^3 m^3/d in 2008 to about 249 10^3 m^3/d by 2018. This represents an 11 per cent decline from the 280 10^3 m^3/d forecast for 2017 in last year's report. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure 2.13**.

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 21.5 10^3 m^3/d in 1990 to 92.7 10^3 m^3/d in 2008, up from 2007 production of 85.2 10^3 m^3/d. Production of in situ bitumen, along with the number of bitumen wells on production in each year, is shown in **Figure 2.10**. Corresponding to the increase in production, the number of producing bitumen wells has also increased from 2300 in 1990 to about 9700 in 2008. Well productivity of in situ bitumen wells in 2008 averaged 10 m^3/d.

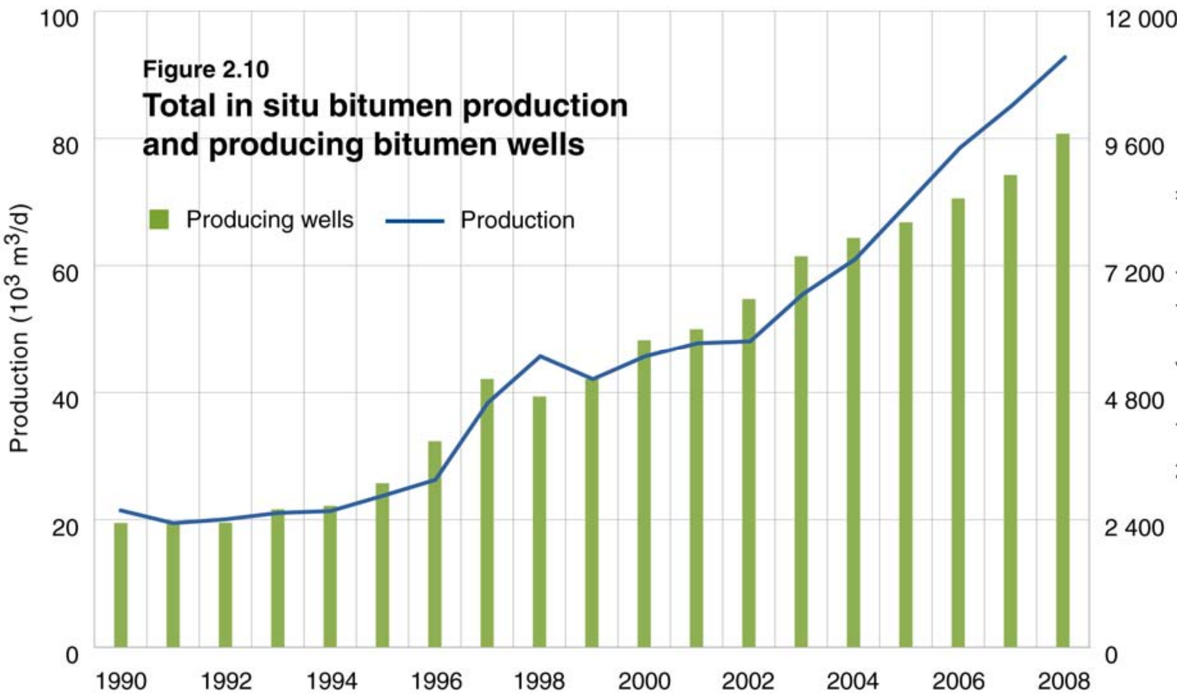
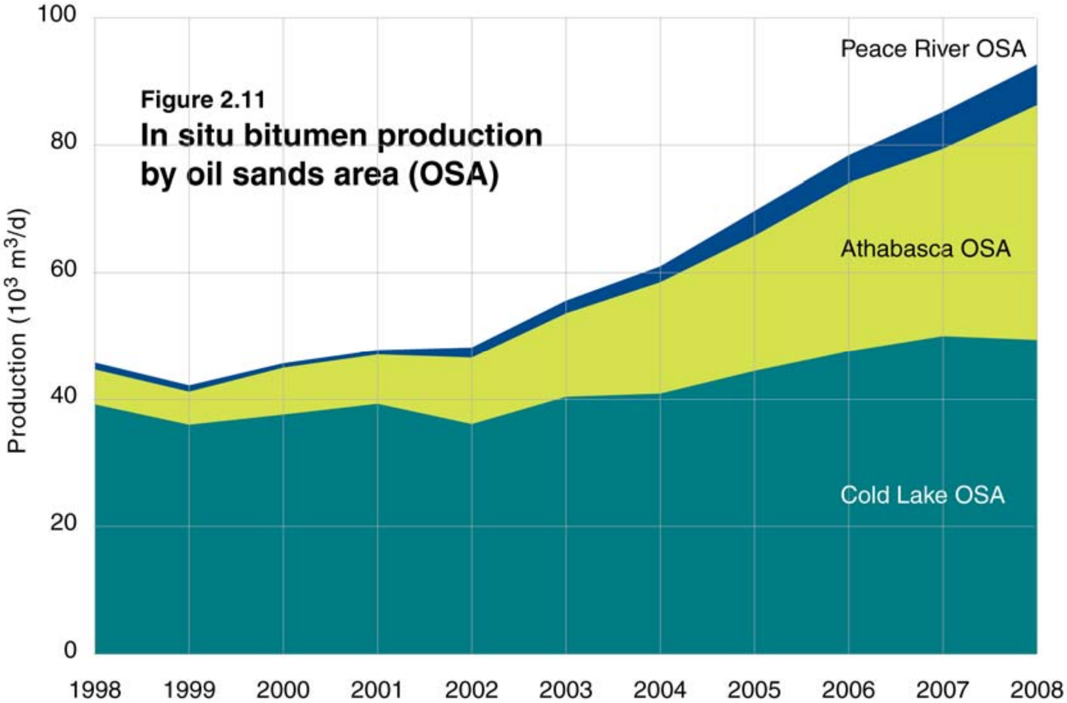


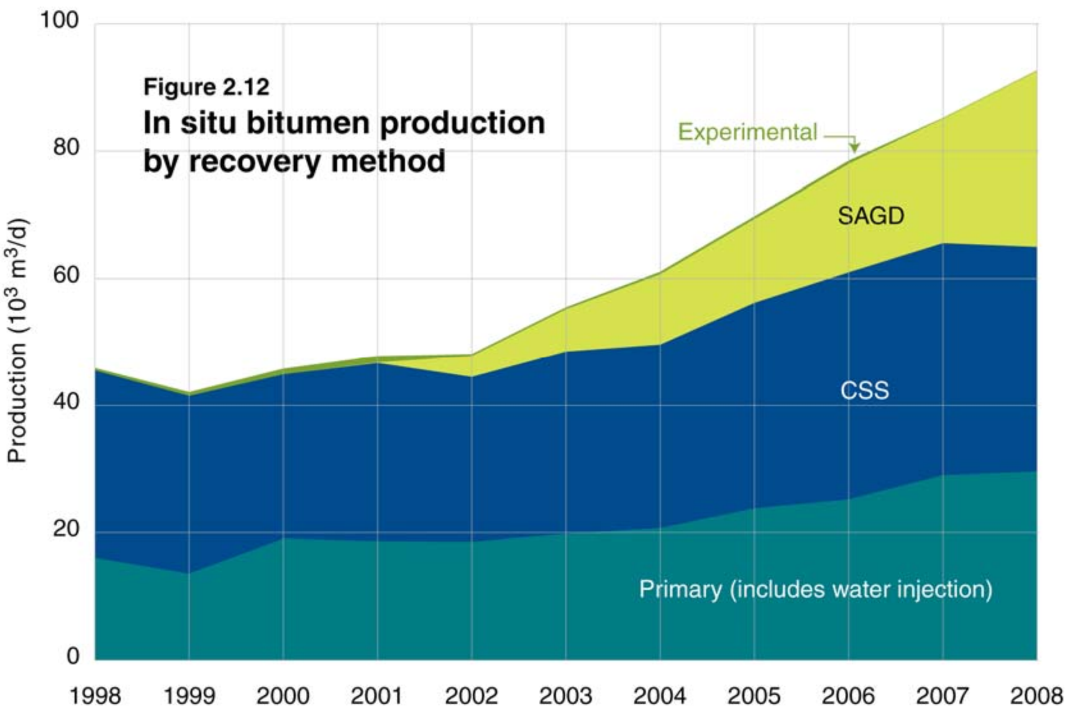
Figure 2.10
Total in situ bitumen production and producing bitumen wells

Currently, there are three main methods to produce in situ bitumen: primary production, cyclic steam stimulation (CSS), and steam-assisted gravity drainage (SAGD).

Figure 2.11 shows in situ production from 1998 to 2008 by OSA. The Cold Lake OSA has been the major source of crude bitumen recovery, accounting for 53 per cent of the production. Production from this area remained flat between 2007 and 2008. The Athabasca and Peace River OSAs contributed 40 and 7 per cent respectively. Production increased from the Athabasca OSA by about 26 per cent in 2008 relative to 2007 and from the Peace River OSA by about 10 per cent. Significant production increases in the Athabasca OSA since 2002 are due to SAGD development, while increases in the Peace River OSA are largely the result of primary production in the Seal area.



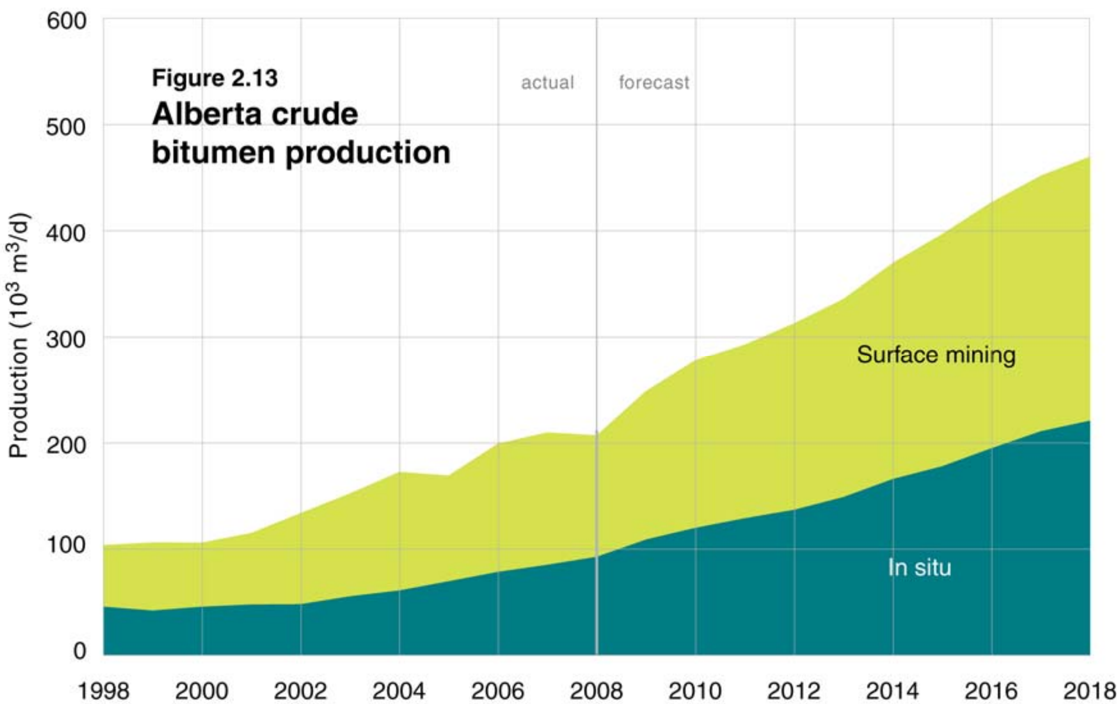
In situ bitumen production by recovery method from 1998 forward is shown in **Figure 2.12**. Primary production includes those schemes that use water injection as a recovery method. In 2008, 38 per cent of in situ production was recovered by CSS, 30 per cent by SAGD, and 31 per cent by primary schemes. Experimental production accounted for less than 1 per cent in 2008. SAGD production was responsible for the bulk of the production increase between 2007 and 2008, increasing by about 42 per cent.



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 projecting the production from existing and future schemes, the ERCB considered all approved projects, projects currently before the ERCB, and projects for which it expects applications within the year. For the purposes of this report, it assumed that the existing projects would continue producing at their current production levels over the forecast period. To this projection the ERCB has added production of crude bitumen from new and expanded schemes. The assumed production from future crude bitumen projects takes into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, pipeline availability, and the ability of North American markets to absorb the increased volumes. The ERCB realizes that key forecast factors, such as diluent requirements, gas prices, and light crude and bitumen price differentials, may delay some new projects and affect existing ones.

As illustrated in **Figure 2.13**, the ERCB expects in situ crude bitumen production to increase to 221 10^3 m^3/d over the forecast period. Relative to last year's forecast of 233 10^3 m^3/d in 2017, this is a decrease of 5 per cent. The 2008 forecast has been reduced as a result of the current price weakness and credit difficulties facing the sector, which have affected the timing expectations for future crude bitumen projects.



In 2008, some 8 per cent of in situ production was upgraded to SCO in Alberta. It is expected that by the end of the forecast period, about 28 per cent of in situ bitumen production will be used as feedstock for SCO production within the province. This is down from the 43 per cent forecast in last year's report, primarily due to changes to the SCO forecast, as well as to many of the SCO projects being delayed, suspended, or cancelled.

2.2.2 Synthetic Crude Oil Production

Currently, all Alberta mined bitumen and a small portion of in situ production are upgraded to SCO. SCO production in 2008 was 103.9 10^3 m^3/d, compared to 109.3 10^3 m^3/d in 2007. The Syncrude, Suncor, and Shell Canada upgraders produced 46.6 10^3 m^3/d, 36.8 10^3 m^3/d, and 20.5 10^3 m^3/d of SCO respectively in 2008.

Alberta's three upgraders produce a variety of synthetic products: Suncor produces light sweet and medium sour crudes plus diesel, Syncrude produces light sweet synthetic crude, and the Shell upgrader produces intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy SCO. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use coking as their primary upgrading technology and achieve volumetric liquid yields (SCO produced/bitumen processed) of 80 to 90 per cent, while the projects that employ hydro-conversion for primary upgrading can achieve volumetric liquid yields of 100 per cent or more.

To forecast SCO production, the ERCB included existing production from Suncor, Syncrude, and Shell Canada, plus their planned expansions and the new production expected from projects listed in **Table 2.7**. Production from future SCO projects takes into account the high engineering and project material cost and the substantial amount of skilled labour associated with expansions and new projects. The ERCB also recognizes that other key factors, such as the forecast of oil prices, the length of the construction period, and the market penetration of new synthetic volumes, affect project timing.

Although this forecast has been reduced, the ERCB still expects significant increases in SCO production based on the projects shown in **Table 2.7**.

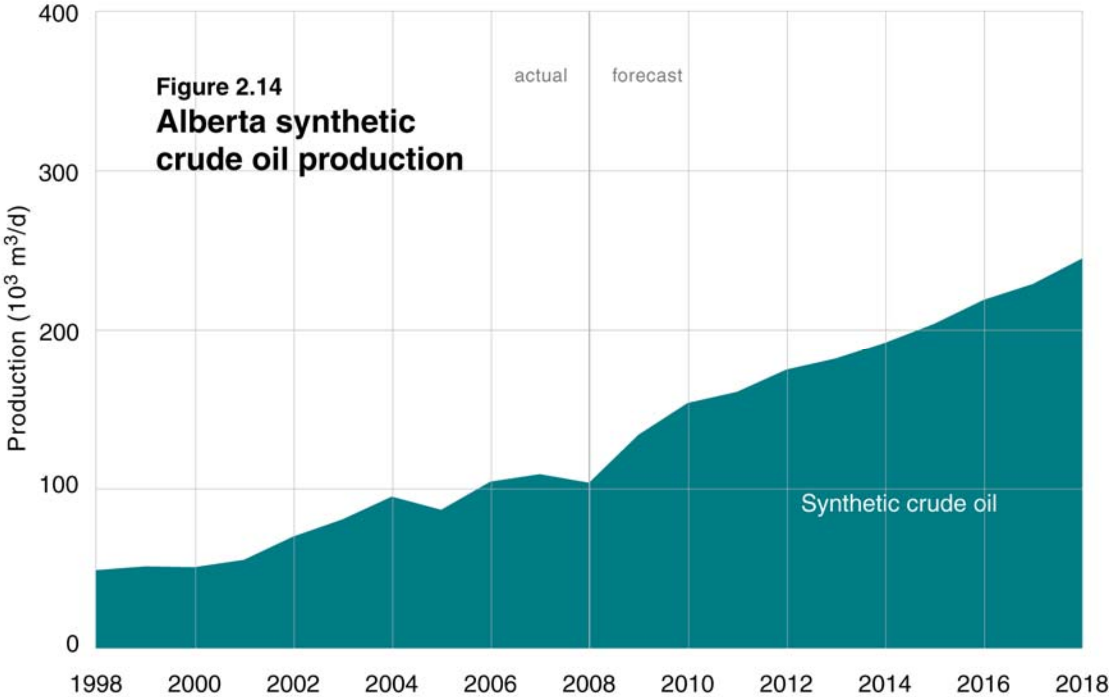
As stated in Section 2.2.1.1: Mined Crude Bitumen, due to uncertainties regarding timing and project scope, some projects, such as Peace River Oil's Bluesky plant, have not been considered in this forecast. If production were to come on stream from those proposed projects, it would be in the latter part of the forecast period.

Figure 2.14 shows the ERCB projection of SCO production, which is expected to increase from 103.9 10^3 m^3/d in 2008 to 245 10^3 m^3/d by 2018. While this is a significant increase over the forecast period, it is a decrease of some 23 per cent when compared to last year's forecast of 318 10^3 m^3/d by 2017.

Table 2.7. Synthetic crude oil projects

Company/project name	Start-up	SCO capacity (10^3 m^3/d)	Status
Athabasca Region			
Suncor			
Voyageur Phase 1	TBD	20.2	Suspended
Voyageur Phase 2	TBD	10.0	Approved
Syncrude			
Stage 3 debottleneck	TBD	6.4	Announced
Stage 4 expansion	TBD	19.1	Announced
CNRL			
Horizon Phase 1	2009	18.1	Operations pending
Horizon Phase 2/3	TBD	18.8	Approved
Horizon Phase 4	TBD	19.9	Announced
Horizon Phase 5	TBD	22.2	Announced
Nexen/OPTI			
Long Lake Phase 1	2009	9.3	Operations pending
Long Lake Phase 2	TBD	9.3	Approved
Long Lake Phases 3 - 6	TBD	9.3	Announced
Value Creation Inc.			
Terre de Grace Pilot	2011	1.3	Application
Terre de Grace Phase 1	TBD	5.3	Announced
Terre de Grace Phase 2	TBD	5.3	Announced
Industrial Heartland Region			
Alberta Oil Sands Project			
Scotford Upgrader 1 Expansion	2010	14.5	Under construction
Shell			
Upgrader 2 Phase 1	TBD	15.9	Application
Upgrader 2 Phase 2	TBD	15.9	Application
Upgrader 2 Phase 3 - 4	TBD	15.9	Application
Petro-Canada/UTS/Teck Cominco			
Sturgeon Upgrader Phase 1	TBD	23.0	Approved
Sturgeon Upgrader Phase 2/3	TBD	23.0	Approved
BA Energy (Value Creation)			
Heartland Upgrader Phase 1	TBD	7.4	Suspended
Heartland Upgrader Phase 2	TBD	7.4	Approved
Heartland Upgrader Phase 3	TBD	7.4	Approved
North West Upgrading			
NW Upgrader Phase 1	TBD	7.4	Approved
NW Upgrader Phase 2	TBD	7.4	Approved
NW Upgrader Phase 3	TBD	7.4	Approved
Total E&P Canada			
Strathcona Upgrader Phase 1	TBD	21.9	Application
Strathcona Upgrader Phase 2	TBD	13.8	Application
Strathcona Upgrader debottlenecking	TBD	7.3	Application
StatoilHydro			
Strathcona Upgrader Phase 1		10.3	Withdrawn
Strathcona Upgrader Phase 2		24.1	Withdrawn

Source: ERCB, company releases, and Strategy West.



2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, adequate incremental pipeline capacity is essential to market the anticipated increased volumes of product. Throughout 2008, pipeline companies made strides towards completing existing projects, as well as moving ahead with the necessary steps involved in planning and executing new projects. The current pipeline systems in the Cold Lake and Athabasca areas are shown in **Table 2.8**. **Figure 2.15** shows the current pipelines and proposed crude pipeline projects within the Athabasca and Cold Lake areas. Numerals in parentheses in Sections 2.2.3.1 and 2.2.3.2 refer to the legend on the map in Figure 2.15.

Table 2.8. Alberta SCO and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty	30.8
Cold Lake Heavy Oil Pipeline	Edmonton	18.7
Husky Oil Pipeline	Hardisty	21.2
Husky Oil Pipeline	Lloydminster	36.0
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	62.0
Corridor Pipeline	Edmonton	47.7
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

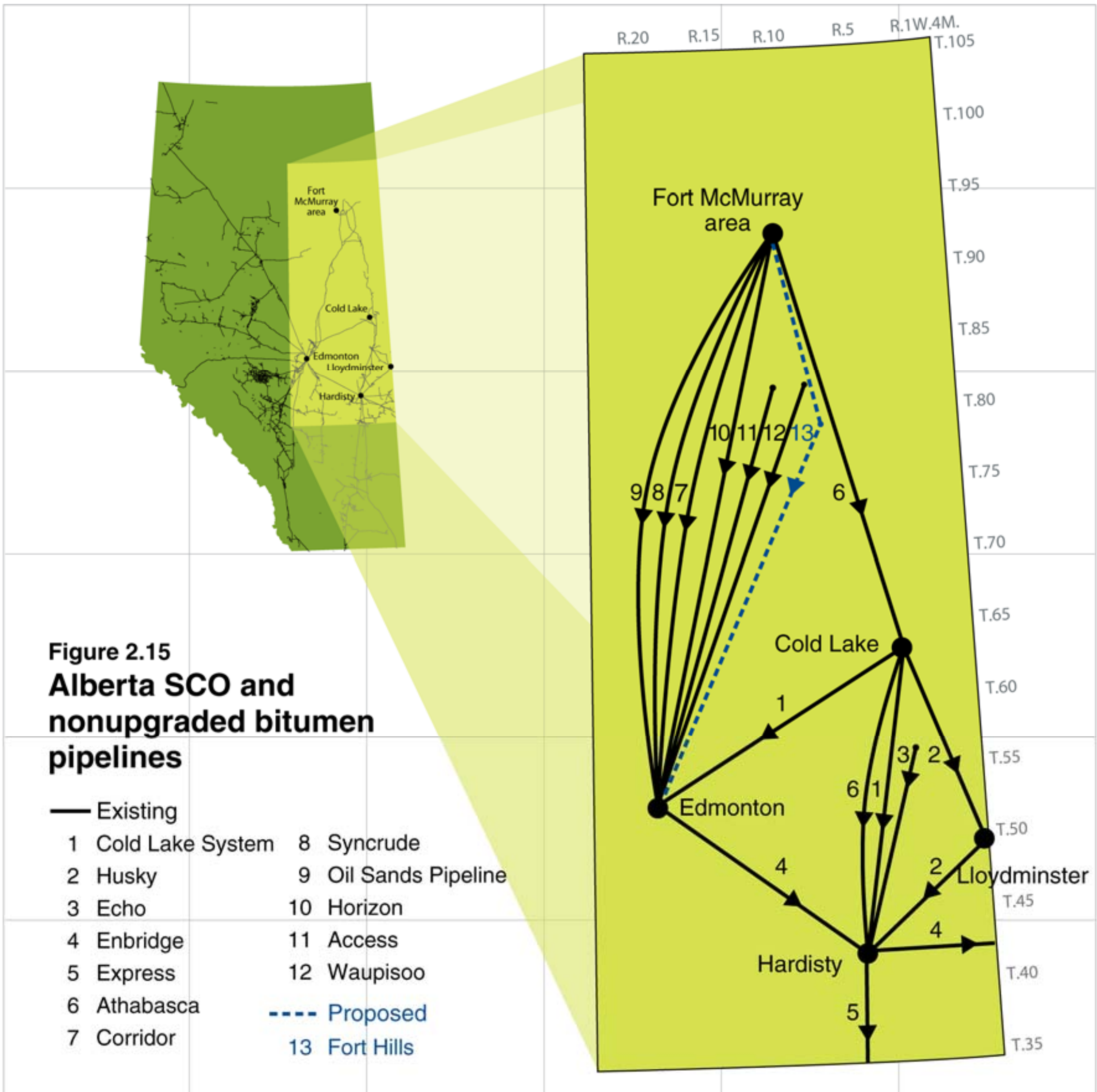


Figure 2.15
Alberta SCO and nonupgraded bitumen pipelines

2.2.3.1 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 to Husky's heavy oil operations in Lloydminster. Heavy and synthetic crude is 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 semiprocessed 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.
- In 2007, Inter Pipeline Fund successfully completed the acquisition of the Corridor pipeline from Kinder Morgan, making Inter Pipeline Canada's largest oil sands gathering business. The Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford Upgrader near Edmonton.
- The Syncrude Pipeline (formerly Alberta Oil Sands Pipeline) (8) is the exclusive transporter for Syncrude.
- The Oil Sands Pipeline (9) transports Suncor synthetic oil to the Edmonton area.
- The Access Pipeline (11) transports diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Capacity of the pipeline is 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d. First diluted bitumen deliveries were made to the Edmonton area in April 2008.
- The Enbridge Waupisoo Pipeline (12) is a 390 km pipeline that moves blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline entered into service in May 2008, with an initial capacity of 55.6 10^3 m^3/d, expandable to 95.3 10^3 m^3/d.
- Pembina Pipeline completed the construction of the Horizon Pipeline (10) in July 2008, with an initial capacity of 39.7 10^3 m^3/d. The project included the twinning of the existing Syncrude Pipeline (8), resulting in two parallel commercially segregated lines, one dedicated to Syncrude and the other to CNRL's new Horizon oil sands development. Also completed was the construction of a new 48 km 20-inch pipeline from the Horizon site 70 km north of Fort McMurray to the Syncrude Pipeline terminal.

2.2.3.2 Proposed Alberta Pipeline Projects

- The Inter Pipeline Corridor pipeline (7) expansion project includes construction of a 42-inch diluted bitumen line, a new 20-inch products pipeline, tankage, and upgrading existing pump stations along the existing pipeline from the Muskeg River mine to the Edmonton region. The expansion will increase diluted bitumen capacity to about 73.9 10^3 m^3/d by 2010 and will support further expansions beyond 2010 by adding intermediate pump stations.
- In 2007, Enbridge announced that it was selected by the Fort Hills Energy L.P. (FHELP) to provide the pipeline and terminal facilities for Phase 1 and subsequent phases of the Fort Hills oil sands project. The scope of the Fort Hills Pipeline System (13) is being reevaluated by the FHELP to reflect changing market conditions. Completion of the initial facilities has been deferred from the originally planned mid-2011 timeframe, and a revised completion date will be subject to sanctioning of the overall project by the FHELP.

2.2.3.3 Existing Export Pipelines

- 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 some shipments of heavy oil. Receipts of heavy crude at Edmonton have averaged between 15 and 20 per cent of total pipeline receipts over the past two years. Without heavy oil receipts, pipeline capacity increases to 63.6 10^3 m^3/d.
- Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake Blend to Montana refineries.
- The Milk River Pipeline delivers Bow River heavy crude to Montana refineries.

Figure 2.16 shows the existing export pipelines leaving Alberta, in addition to the proposed expansions and new pipeline projects expected to transport the increased SCO and nonupgraded bitumen production to established and expanded markets.

Table 2.9 lists the existing export pipelines, with their corresponding destinations and capacities.

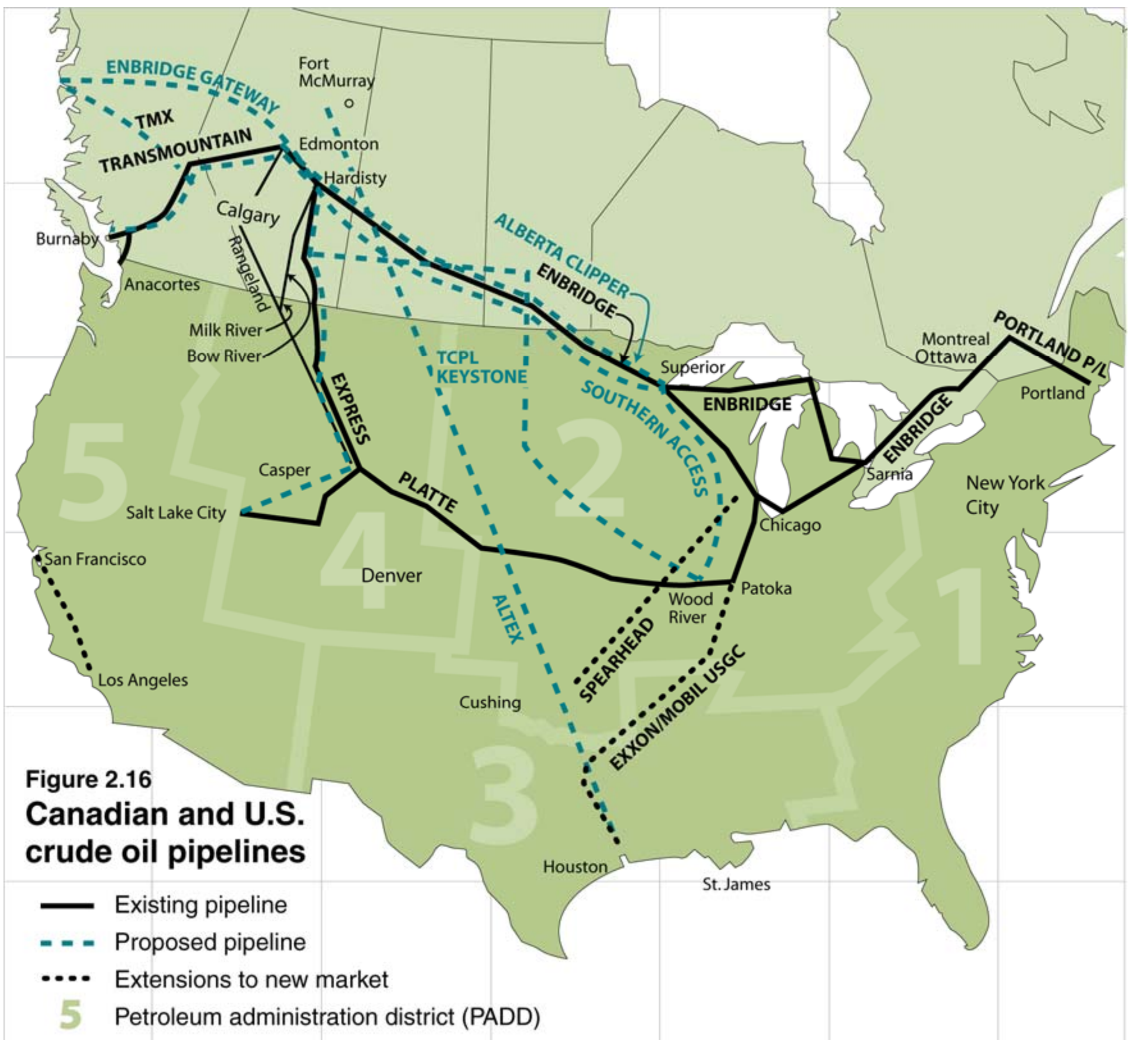


Figure 2.16
Canadian and U.S. crude oil pipelines

Table 2.9. Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Pipeline	Eastern Canada U.S. east coast U.S. midwest	301.9
Kinder Morgan (Express)	U.S. Rocky Mountains U.S. midwest	44.9
Milk River Pipeline	U.S. Rocky Mountains	18.8
Rangeland Pipeline	U.S. Rocky Mountains	13.5
Kinder Morgan (Trans Mountain)	British Columbia U.S. west coast Offshore	47.7

2.2.3.4 Proposed Export Pipeline Projects

Table 2.10 provides a summary of the numerous pipeline expansions and new pipeline projects that will deliver SCO and nonupgraded bitumen to existing and new markets.

Table 2.10. Proposed export pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. west coast Offshore	63.6	2012-2014
Southern Access	U.S. midwest	63.6	2008-2009
Alberta Clipper Pipeline	U.S. midwest	71.5	2010
Kinder Morgan			
Trans Mountain (TMX)	British Columbia U.S. west coast Offshore		
TMX2		15.9	2011
TMX3		47.7	2012
TransCanada Pipeline			
Keystone Pipeline	U.S. midwest	93.8	2010
Keystone Pipeline Expansion	U.S. Gulf Coast	79.5	2012-2013
Altex Energy Ltd.			
Altex Pipeline	U.S. Gulf Coast	39.7	2012

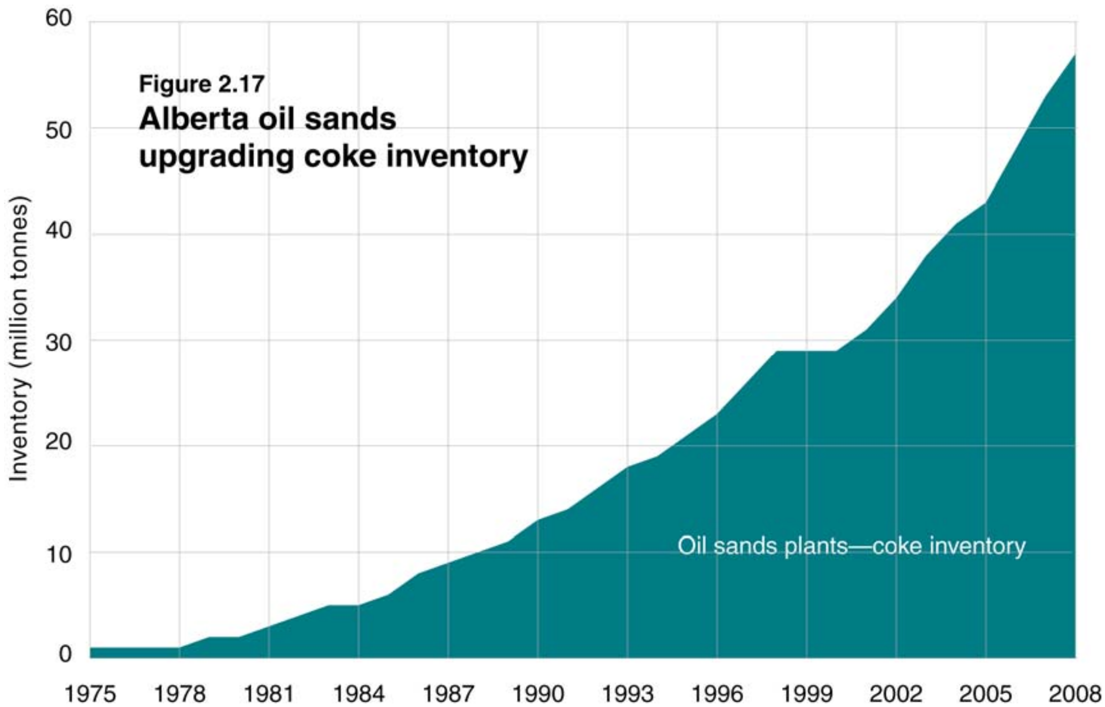
2.2.4 Petroleum Coke

Petroleum coke is a by-product of the oil sands upgrading process and is currently being stockpiled in huge amounts in Alberta. Petroleum coke produced in the delayed coking operation is considered a potential source of energy. It contains high sulphur but has lower ash than conventional fuel coke. Petroleum coke has the potential of becoming a future energy resource through a process called gasification and could possibly reduce the demand for natural gas.

Suncor Energy Inc. and Syncrude Canada Ltd. operate Alberta’s two largest oil sands mines near Fort McMurray. Complete with on-site extraction and upgrading capabilities, Syncrude and Suncor both produce coke but through different processes, which result in coke deposits with different ranges of particle size. Syncrude’s coke is like coarse sand, while Suncor’s is the size of gravel or larger.

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 usage as a site fuel. Suncor has also been delivering small volumes of petroleum coke to Asian markets, mostly Japan, since 1997 through its Energy Marketing Group. Syncrude began using coke as a site fuel in 1995 and accounts for a lower share of the total coke usage as a site fuel. Syncrude is seeking alternative uses for its coke surplus and is looking into ways of using coke as a reclamation material.

Statistics of petroleum coke inventories reported in *ST43: Mineable Oil Sands Annual Statistics* show increases in the total closing inventories, reaching 57 million tonnes in 2008, as illustrated in **Figure 2.17**. In 2008, coke inventories increased by about 8 per cent over 2007 levels. Inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders.



2.2.5 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. In 2008, five Alberta refineries, with a total capacity of 75.5 10^3 m^3/d, used 31.3 10^3 m^3/d of SCO and 3.2 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand consumed 30 per cent of Alberta SCO production and 4 per cent of nonupgraded bitumen production in 2008. This compares to the 32 per cent of Alberta SCO production and 4 per cent of nonupgraded bitumen production consumed in 2007. Additional demand for SCO for use as diesel fuel and plant fuel accounted for 4.1 10^3 m^3/d in 2008, resulting in total Alberta demand of 38.6 10^3 m^3/d in 2008. Total demand for SCO and nonupgraded bitumen in 2007 was 44.1 10^3 m^3/d.

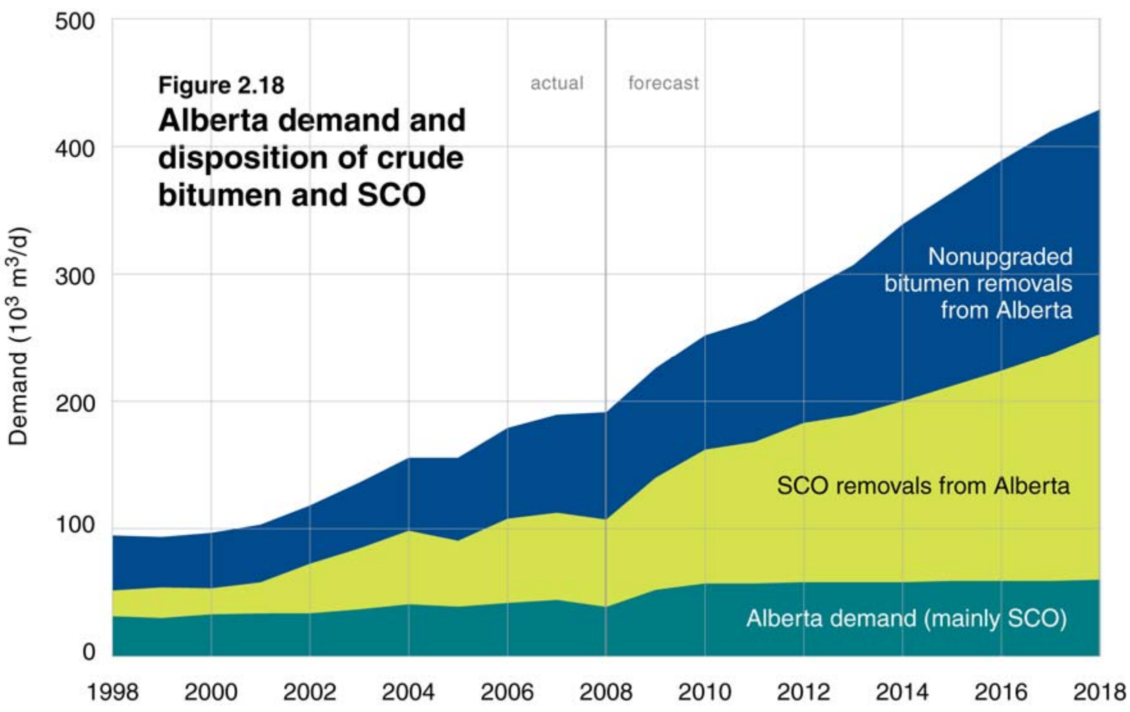
Light sweet SCO has two principal advantages over light crude as a refinery feedstock: it has very low sulphur content, and it produces very little heavy fuel oil. The latter property is particularly desirable in Alberta, where there is virtually no local market for heavy fuel oil. Among the disadvantages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

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

Petro-Canada completed the Refinery Conversion Project (RCP) at its Edmonton refinery in 2008. The new configuration allows the refinery to fully replace light-medium crude oil with nonupgraded bitumen and sour SCO, while continuing to process sweet SCO through its synthetic train.

Refined SCO 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, selling diesel fuel supplied from its oil sands operation. The station is located on Highway 63 north of Fort McMurray. In 2008, the sale of refined SCO as diesel fuel oil accounted for about 6 per cent of Alberta SCO demand, compared to 10 per cent in 2007.

Figure 2.18 shows that in 2018 Alberta demand for SCO and nonupgraded bitumen will increase to about 60 10^3 m^3/d. It is projected that SCO will account for 87 per cent of total Alberta demand and nonupgraded bitumen will account for 13 per cent.



Given the current quality of SCO, western Canada’s nine refineries, with a total capacity of 99.8 10^3 m^3/d, are able to blend up to 39 per cent SCO and a further 3 per cent of blended bitumen with crude oil. These refineries receive SCO from both Alberta and Saskatchewan. In eastern Canada, the four Sarnia-area refineries, with a combined total capacity of 56.6 10^3 m^3/d, are the sole ex-Alberta Canadian market for Alberta SCO.

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, as well as the overall anticipated increase in demand for refined products. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with a refining capacity of 581 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 96 10^3 m^3/d. The refineries in these areas are capable of absorbing a substantial increase in supplies of SCO and nonupgraded bitumen from Alberta. Other potential market regions could be the U.S. east coast, with a refining capacity of 274 10^3 m^3/d, the U.S. Gulf Coast, with a refining capacity of 1337 10^3 m^3/d, the U.S. west coast, with a refining capacity of 508 10^3 m^3/d, and offshore markets in Asia.

The traditional markets for Alberta SCO and nonupgraded bitumen are expanding. These include western Canada, Ontario, the U.S. midwest, the northern Rocky Mountain region, and the U.S. west coast (Washington State). Enbridge's Spearhead pipeline commenced operation in 2006 and delivers western Canadian crude oil to Cushing, Oklahoma. The oil being delivered to Cushing travels through the Enbridge mainline system from Edmonton to Chicago, 2519 km, before entering the Spearhead pipeline for the final 1046 km to Cushing. Enbridge is currently expanding the Spearhead pipeline by adding additional pumping stations that will increase capacity by 10 10^3 m^3/d to 30 10^3 m^3/d. The expansion is expected to be completed in 2009.

Markets were further expanded in 2006 with the reversal of an ExxonMobil Corporation pipeline that moves heavy crude oil from Patoka, Illinois, to Beaumont/Nederland, Texas. Canadian crude can access the line via the Enbridge mainline and Lakehead systems and then the Mustang Pipeline or the Kinder Morgan Express-Platte Pipeline system. The ExxonMobil pipeline has a heavy crude oil capacity of 10.5 10^3 m^3/d. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure 2.16**.

As illustrated in **Figure 2.18**, over the forecast period SCO removals from Alberta will increase from 68.5 10^3 m^3/d in 2008 to 193 10^3 m^3/d in 2018, and the removals of nonupgraded bitumen will increase from 84.3 10^3 m^3/d to 176 10^3 m^3/d over the same period.

3 Crude Oil

Highlights

- Remaining established reserves decreased 3.2 per cent, similar to annual declines in previous years.
- Reserve additions from drilling replaced 77 per cent of production in 2008, compared with 68 per cent last year.
- Production declined 3.8 per cent, compared with the 3.5 per cent decline in 2007.
- Successful oil wells drilled in 2008 fell by less than 1 per cent relative to 2007.

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, it is from formations other than the Mannville or Woodbend. Crude oil is classified as light-medium for oils having a density less than 900 kilograms per cubic metre (kg/m^3) or as heavy crude for oils having a density 900 kg/m^3 or greater. These definitions are slightly changed from previous years to better align with the new Alberta Royalty Framework in that they no longer take into consideration the market destination.

3.1 Reserves of Crude Oil

3.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 233.0 million cubic metres (10^6 m^3) at December 31, 2008. This is a decrease of 7.7 10^6 m^3, or 3.2 per cent, from December 31, 2007, resulting from production, reserve adjustments, and additions from drilling that occurred during 2008.

Table 3.1 shows the changes in Alberta's reserves and cumulative production of light-medium and heavy crude oil as of December 31, 2008**,** while **Figure 3.1** shows the province's remaining conventional oil reserves over time. Remaining reserves represent less than 20 per cent of the peak reserves of 1223 10^6 m^3 reached in 1969.

3.1.2 Reserves Growth

A detailed pool-by-pool list of reservoir parameters and reserves data is available on CD (see **Appendix C**). **Table 3.2** gives a detailed breakdown of this year's changes to initial established reserves, categorized by new discoveries, development of existing pools, new and expansions to enhanced recovery schemes, and revisions to existing reserves. **Figure 3.2** gives a history of reserve additions and revisions from 1990 to 2008.

The initial established reserves attributed to the 438 new oil pools defined in 2008 totalled 6.9 10^6 m^3 (an average of 16 thousand [10^3] m^3 per pool), compared to 6.8 10^6 m^3 in 2007. Also, the ERCB processed about 102 applications for new or amended water and solvent flood schemes, resulting in reserve additions totalling 6.2 10^6 m^3 **(Figure 3.3)**. Revisions to existing reserves resulted in an overall net change of –0.7 10^6 m^3. The total increase in initial established reserves for 2008 amounted to 21.7 10^6 m^3, similar to last year's 20.6 10^6 m^3. These additions replaced 77 per cent of Alberta's 2008 conventional crude oil production of 29.3 10^6 m^3. This compares with a five-year average replacement ratio of 61 per cent.

Note that the change in cumulative production shown in Table 3.1 may not equal reported annual production due to amendments to historical production records and the fact that some producing wells are in pools that were not defined with reserves to be included in the publication of year-end reserves. Also, in 2008, because of the change in the ERCB's definition of light-medium and heavy crude, about 61 10^6 m^3 of reserves was transferred from the heavy crude to light-medium crude category **(Table 3.2)**. Three fields in particular were affected by the change, namely, Alderson, Enchant, and Grand Forks. In these fields the oil density is slightly below 900 kg/m^3, but historically the pools in these fields have been classified as heavy. **Table B.3** in **Appendix B** provides a history of conventional oil reserve growth and cumulative production from 1968 forward.

Table 3.1. Reserve and production change highlights (10^6 m^3)

	2008	2007	Change
Initial established reserves[a]			
Light-medium	2 415.9	2 340.6	+75.3
Heavy	357.2	410.8	–53.6
Total	2 773.1	2 751.4	+21.7
Cumulative production[a]			
Light-medium	2 244.1	2 167.9	+75.9[b]
Heavy	296.0	342.8	–46.9[b]
Total	2 540.1	2 510.7	+29.1[b]
Remaining established reserves[a]			
Light-medium	171.8	172.7	–0.9
Heavy	61.2	68.0	–6.8
Total	233.0 (1 466 10^6 bbl)	240.7	–7.7
Annual Production			
Light-Medium	20.2	20.1	+0.1
Heavy	9.1	10.3	–1.2
Total	29.3	30.4	–1.1

[a] Discrepancies are due to rounding.
[b] May differ from annual production.

Table 3.2. Breakdown of changes in crude oil initial established reserves[a] (10^6 m^3)

	Light-medium	Heavy	Total[a]
New discoveries	6.1	0.8	6.9
Development of existing pools	5.9	3.4	9.3
Enhanced recovery (new/expansion)	3.8	2.4	6.2
Revisions	+59.5	–60.1	–0.7
Total[a]	+75.3	–53.6	+21.7

[a] Discrepancies are due to rounding.

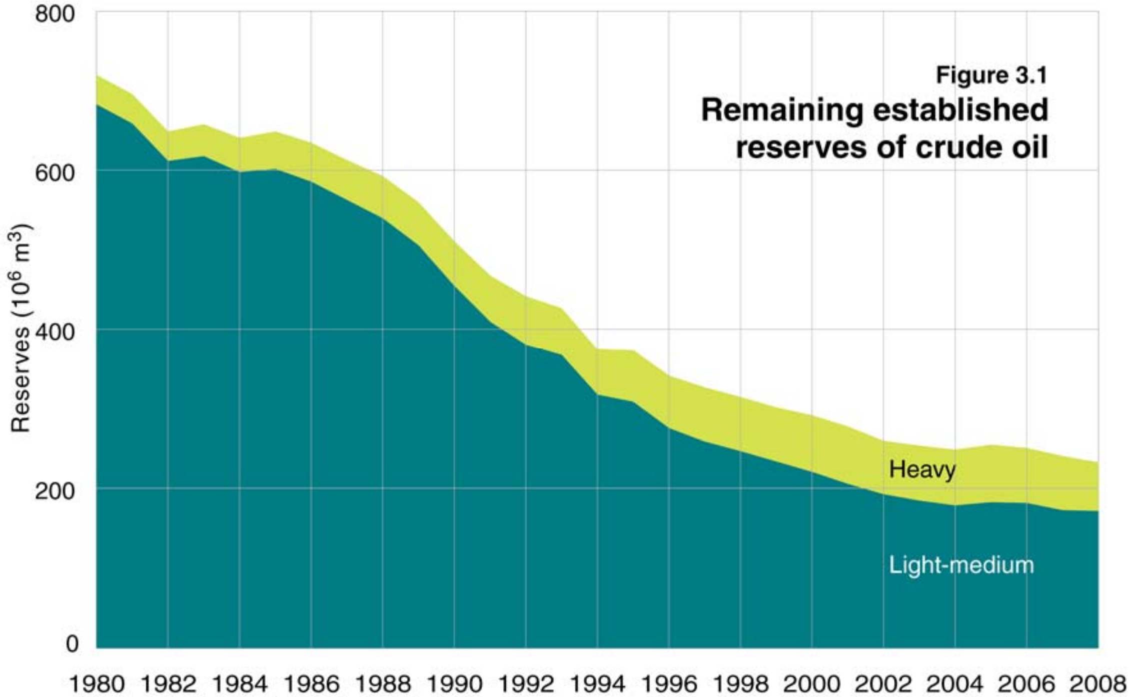


Figure 3.1
Remaining established reserves of crude oil
800
600
400
200
0
Reserves (10^6 m^3)
Heavy
Light-medium
1980 1982 1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008

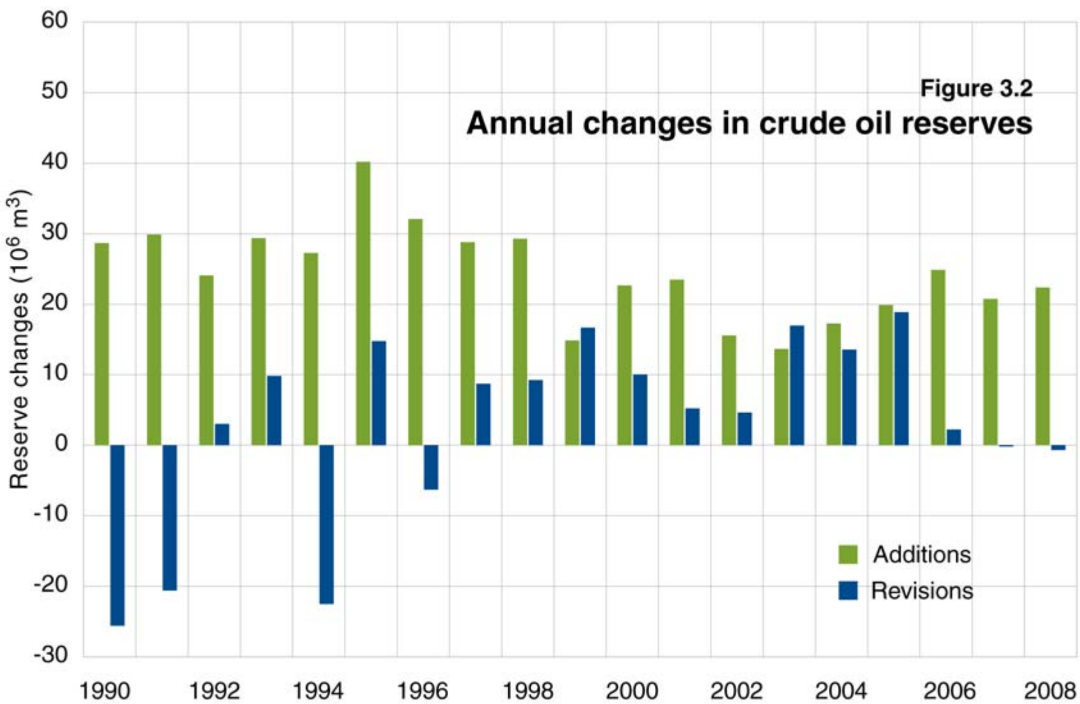
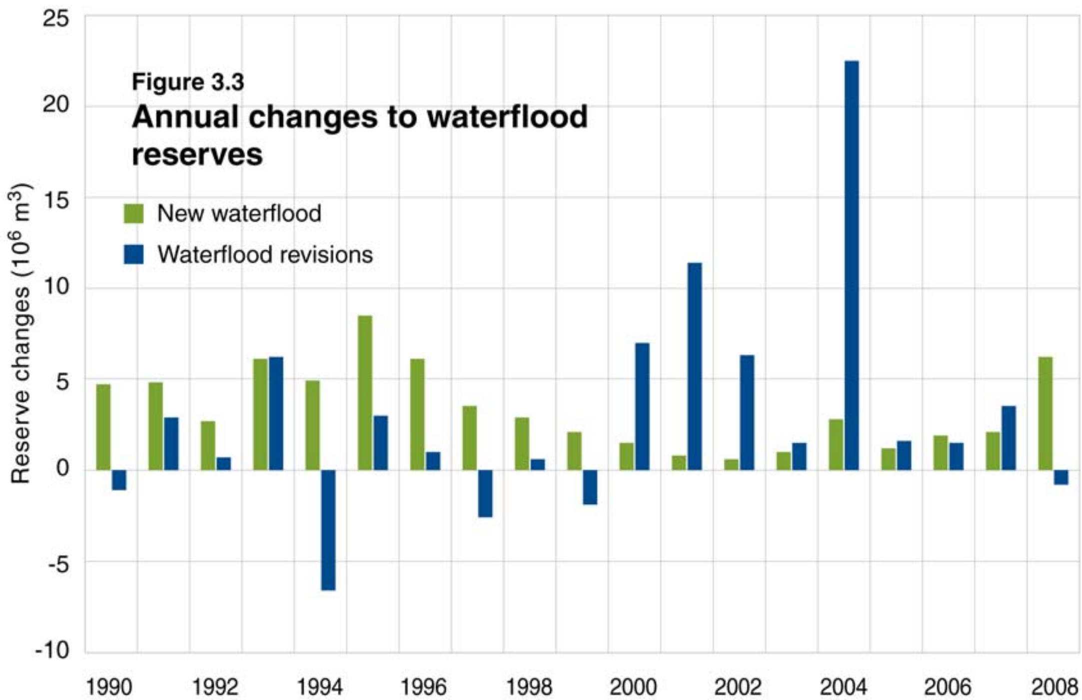
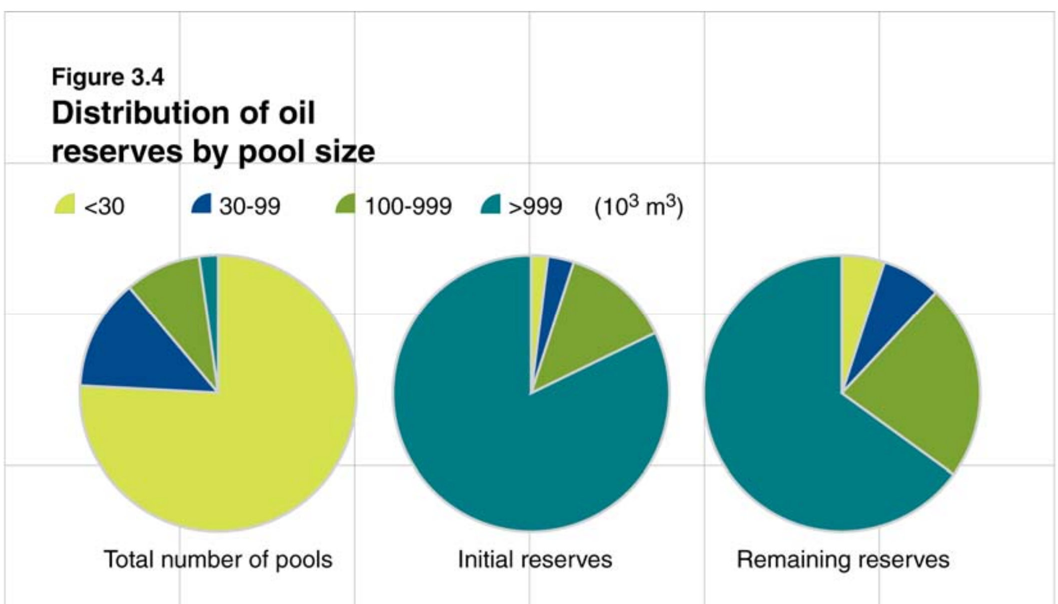


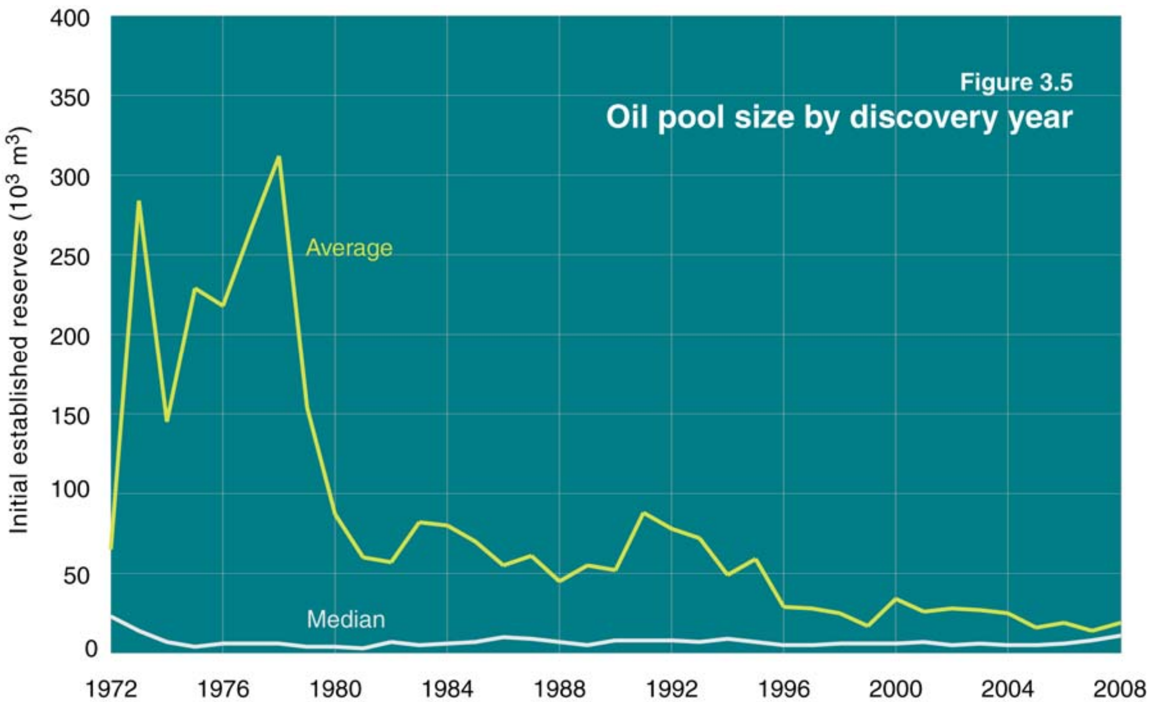
Figure 3.2
Annual changes in crude oil reserves
60
50
40
30
20
10
0
-10
-20
-30
Reserve changes (10^6 m^3)
Additions
Revisions
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008



3.1.3 Oil Pool Size

At December 31, 2008, oil reserves were assigned to 10 093 light-medium and 2631 heavy crude oil pools in the province. While some of these pools contain thousands of wells, the majority consist of a single well. The distribution of reserves by pool size shown in **Figure 3.4** indicates that some 65 per cent of the province's remaining oil reserves are contained in the largest 3 per cent of pools. By contrast, the smallest 75 per cent of pools contain only 6 per cent of remaining reserves. Ninety-five per cent of remaining reserves are contained in pools discovered before 1980. **Figure 3.5** illustrates the historical trends in the size of oil pool discoveries.





While the median pool size has remained basically unchanged over time, with initial established reserves at less than 10 10^3 m^3, the average size has declined from 150 10^3 m^3 in 1970 to about 30 10^3 m^3 over the last few years. The Valhalla Commingled Pool 002 (previously the Doe Creek I and Dunvegan B Pool) 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. Since 2000, the largest oil pools discovered include the Pembina Nisku II, Pembina Nisku HH, and Dixonville Montney C Pools, with initial established reserves estimated at 1480 10^3 m^3, 947 10^3 m^3, and 1193 10^3 m^3 respectively.

3.1.4 Pools with Largest Reserve Changes

The reserves of some 5000 oil pools have been reviewed and updated over the past year and represent a net total revision of –0.7 10^6 m^3. **Table 3.3** lists pools with the largest reserve changes in 2008. Reassessment of tertiary recovery schemes in the Rainbow Keg River B and F Pools resulted in changes in reserves of +2410 10^3 m^3 and –1200 10^3 m^3 respectively. Recognition of new waterflood and tertiary recovery scheme approvals in the Viking-Kinsella Wainwright B Pool led to a 1533 10^3 m^3 increase, while the Provost Commingled Pool 001 (formerly Provost Viking, BR, & Mann MU#1 Pool) saw an increase of 1492 10^3 m^3 as a result of revisions to primary and waterflood reserves.

3.1.5 Distribution by Recovery Mechanism

The distribution of conventional crude oil reserves by recovery mechanism is illustrated in **Figure 3.6** and shown in tabular form in **Table 3.4**. It shows that waterflooding has increased recovery in light-medium pools from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Primary recovery for heavy crude pools has increased from 8 per cent in 1990 to 12 per cent today as a result of improvements in water handling, use of horizontal wells, improved fracturing techniques, and increased drilling density. Incremental recovery from all waterflood projects represents about 25 per cent of the province’s initial established reserves. Pools under solvent flood add another 4 per cent to the province’s reserves and on average realize a 29 per cent improvement in recovery efficiency over primary recovery.

Table 3.3. Major oil reserve changes, 2008

Pool	Initial established reserves (10^3 m^3) 2008	Change	Main reason for change
Bellshill Lake Blairmore	18 510	+590	Pool development and reassessment of reserves
Bonanza Boundary A	1 968	+500	Reassessment of waterflood reserves
Cessford Mannville C	6 396	+919	Pool development and expansion of waterflood
Countess Lower Mannville Z	1 235	–472	Reassessment of waterflood reserves
Dawson Slave Point OOO	91	–250	Reassessment of reserves
Lloydminster Sparky K	4 556	+602	Pool development
Medicine Hat Glauconitic C	4 206	+556	Reassessment of primary reserves
Morgan Commingled Pool 001	7 218	–420	Reassessment of reserves
Progress Halfway B	764	–382	Reassessment of reserves
Provost Commingled Pool 015	1 793	+358	Reassessment of primary and waterflood reserves
Provost Commingled Pool 001	12 350	+1492	Reassessment of primary reserves
Rainbow Keg River F	19 950	–1200	Reassessment of tertiary reserves
Rainbow Keg River B	29 500	+2410	Reassessment of tertiary project
Redwater Lower Viking DD	375	+281	Pool development
Sunset Triassic A	1 391	+406	Reassessment of waterflood reserves
Swalwell D-1 A	1 018	+508	Pool development, reassessment of primary reserves and new waterflood reserves
Taber South Mannville B	3 355	+336	Reassessment of waterflood and tertiary reserves
Twining Commingled Pool 001	7 427	+435	Reassessment of primary and waterflood reserves
Utikuma Lake Keg River Sand A	10 130	+429	Reassessment of primary reserves and new waterflood reserves
Vermillion Sparky A	1 633	+545	Pool development and reassessment of primary and water flood reserves
Viking-Kinsella Wainwright B	10 140	+1533	Reassessment of primary reserves and recognition of new polymer flood
Wildmere Commingled Pool 003	8 103	+802	Reassessment of primary reserves and new waterflood reserves
Wimborne D-3 A	5 460	–390	Reassessment of reserves

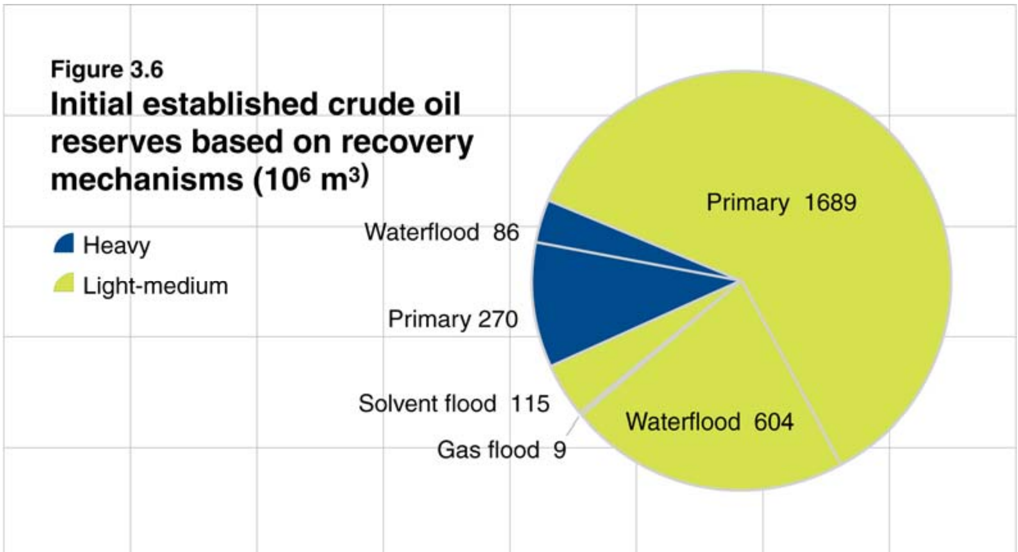


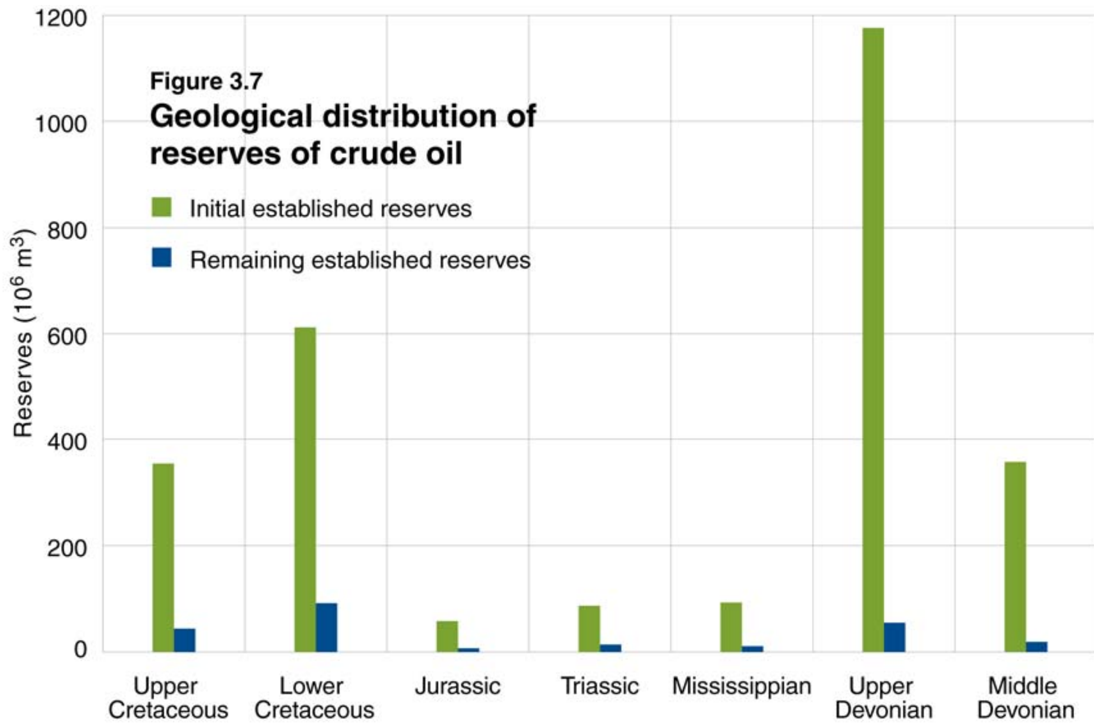
Figure 3.6
Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)

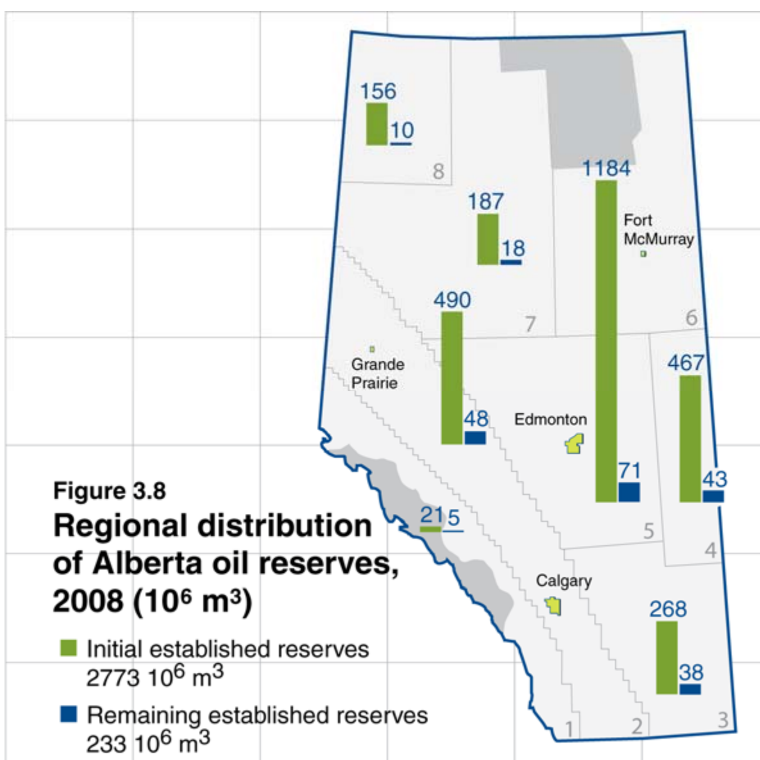
Table 3.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2008

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3) Primary	Waterflood/ gas flood	Solvent flood	Total	Average recovery (%) Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	4 014	866	0	0	866	22	-	-	22
Waterflood	3 436	525	437	0	962	15	13	-	28
Solvent flood	976	264	167	115	546	27	17	12	56
Gas flood	116	34	9	0	43	29	8	-	37
Heavy									
Primary depletion	1 660	197	0	0	197	12	-	-	12
Waterflood	566	73	86	0	159	13	15	-	28
Total	10 768	1 959	699	115	2 773	18			26
Percentage of total initial established reserves		71%	25%	4%	100%				

3.1.6 Distribution by Geological Formation

The distribution of reserves by geological period and Petroleum Services Association of Canada (PSAC) area is depicted graphically in **Figure 3.7** and **Figure 3.8** respectively. About 39 per cent of remaining established reserves is expected to come from formations within the Lower Cretaceous, 22 per cent from the Upper Devonian, and 18 per cent from the Upper Cretaceous. In contrast, in 1990 fully 30 per cent of remaining reserves were contained within the Upper Devonian and only 16 per cent in the Lower Cretaceous. The shallower zones of the Lower Cretaceous are becoming increasingly important as a source of conventional oil.





Reserves Methodology for Oil Pools

The process of quantifying reserves is governed by many geological, engineering, and economic considerations. Initially there is uncertainty in the reserve 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 reserve estimates are normally based on volumetric estimation. An estimate of bulk rock volume is made based on net pay isopach maps derived from geologic and seismic data. These data are combined with 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 knowledge of oil shrinkage, which is 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 in heavy oils to over 50 per cent in the case of light-medium oils producing from highly permeable reef structures with full pressure support from an active underlying aquifer. Provincially the average recovery factor is 26 per cent.

Once there are sufficient production and pressure data, material balance methods can be used as an alternative to volumetric estimation to determine in-place resources. The method of material balance to determine reserves requires good pressure and PVT data to be successful. The analysis of production data when a pool is on decline is the primary method for determining recoverable reserves. When combined with a volumetric estimate of the in-place resource, it also provides a pragmatic estimation 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 injection of fluids that are miscible with the reservoir oil. 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 reserve database. In order 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 prior to the solvent flood.

Reserve 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.

3.1.7 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the ERCB in 1994 at 3130 10^6 m^3, reflecting its estimate of geological prospects at that time. **Figure 3.9** illustrates the historical decline in remaining reserves relative to cumulative oil production. Extrapolation of the decline suggests that the ERCB's estimate of ultimate potential may be low, but there are no immediate plans for an update at this time.

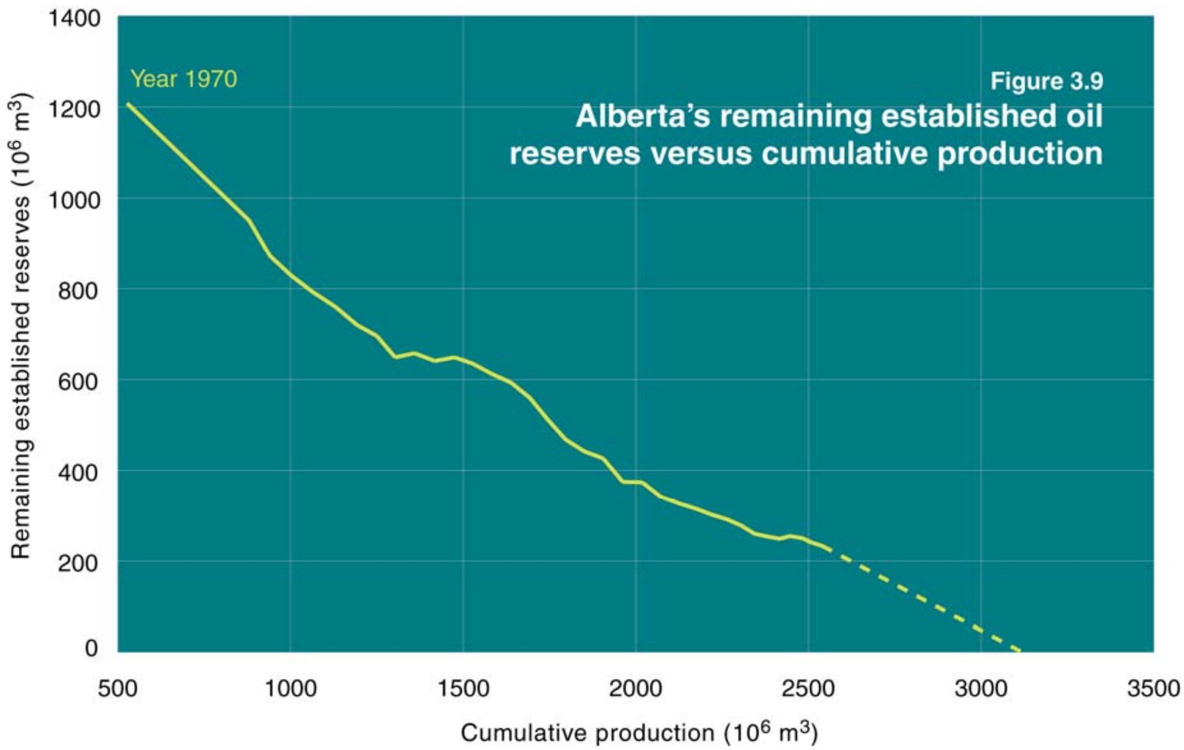
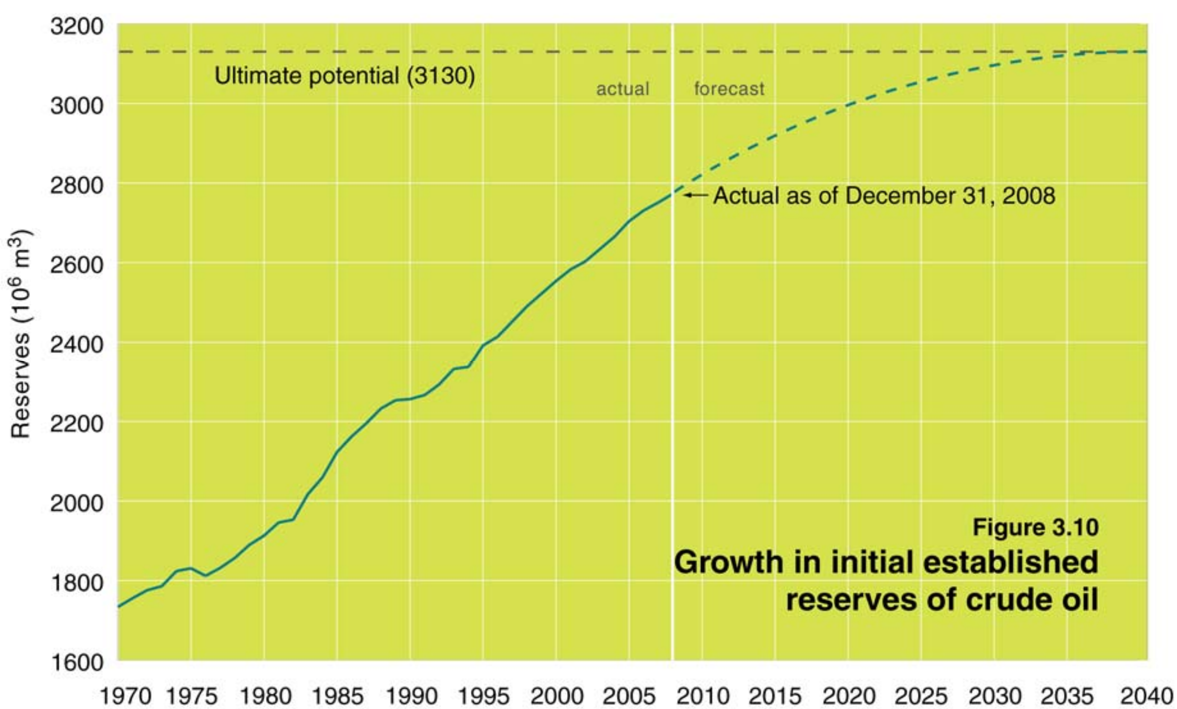


Figure 3.10 shows Alberta's historical and forecast growth of initial established reserves. Approximately 81 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2008. To date, industry has discovered 89 per cent of the ultimate potential, leaving 11 per cent yet to be discovered, which when added to the remaining established reserves, means that 590 10^6 m^3 (3.7 billion barrels) of conventional crude oil is available for future production.



In 2008, both remaining established reserves and annual production of crude oil continued to decline. However, there are 357 10^6 m^3 of yet-to-be-discovered reserves, which at the current rate of annual reserve additions will take over 16 years to find. The discovery of new pools and the development of existing pools will continue to add new reserves and associated production each year.

It is expected that future declines in conventional crude oil production will be more than offset by increases in crude bitumen and synthetic production (see Section 2.2).

3.2 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 utilization. Alberta crude oil supply in excess of Alberta demand is marketed outside the province.

3.2.1 Crude Oil Supply

Since the early 1970s, production of Alberta light-medium and heavy crude oil has been on a downward trend. In 2008, total crude oil production declined to 79.9 10^3 m^3/d. In 2008, the ERCB adjusted its crude oil classification (light-medium/heavy) for conventional oil pools to align with the actual pool density values. This resulted in a significant net change from heavy crude to light-medium crude oil. As a consequence, in 2008 light-medium crude oil production remained at 55.1 10^3 m^3/d, the same level as 2007, while heavy crude oil production experienced a decline of about 12 per cent to 24.8 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 3.8 per cent from 2007 to 2008, compared to the 3.5 per cent decline from 2006 to 2007. This 3.8 per cent decline is less than the 5-year average decline rate of 4.4 per cent.

In 2008, 1788 successful oil wells were drilled, a decrease of less than 1 per cent from 2007. **Figure 3.11** shows the number of successful oil wells drilled in Alberta in 2007 and 2008 by geographical area (modified PSAC area). The majority of oil drilling in 2008, nearly 83 per cent, was development drilling. As shown in the figure, all areas of the province experienced declines in drilling, with the exception of PSAC 2 (Foothills Front) and PSAC 3 (Southeast Alberta), which had increases of 5 per cent and 12 per cent respectively.

Figure 3.12 depicts the distribution of new crude oil wells placed on production, and **Figure 3.13** shows the initial operating day rates of new wells in 2008. 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 placed on production within a short time after being drilled. In 2008, actual wells placed on production decreased slightly to 1738, compared to 2007 levels of 1745, which is less than a 1 per cent decrease.

Historical oil production by geographical area is illustrated in **Figure 3.14**. All areas experienced declines in production, ranging from 9.7 per cent in PSAC 1 (Foothills) to 2.6 per cent in PSAC 5 (Central Alberta). As noted earlier, total production in 2008 declined to 79.9 10^3 m^3/d.

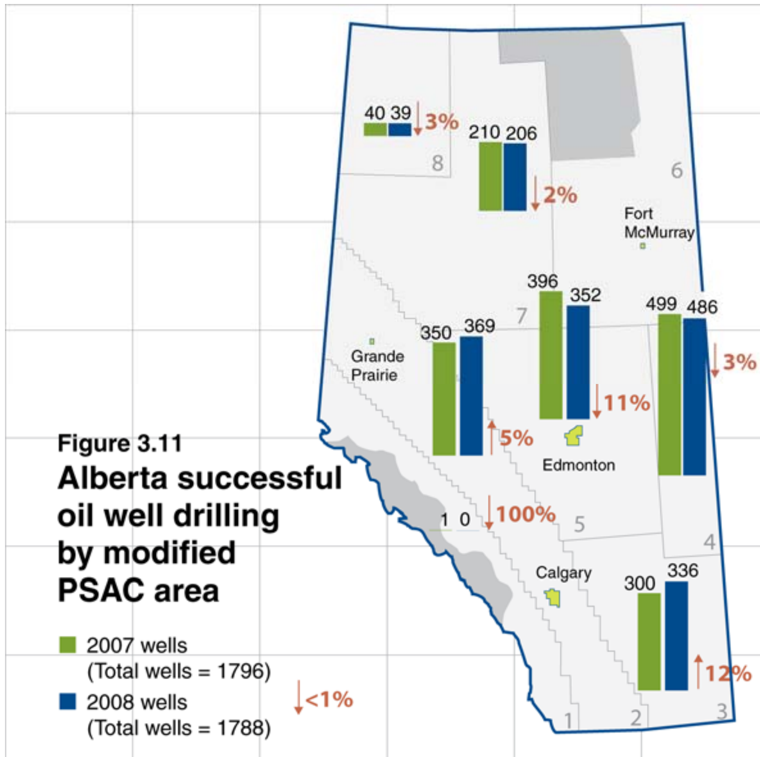


Figure 3.11
Alberta successful oil well drilling by modified PSAC area

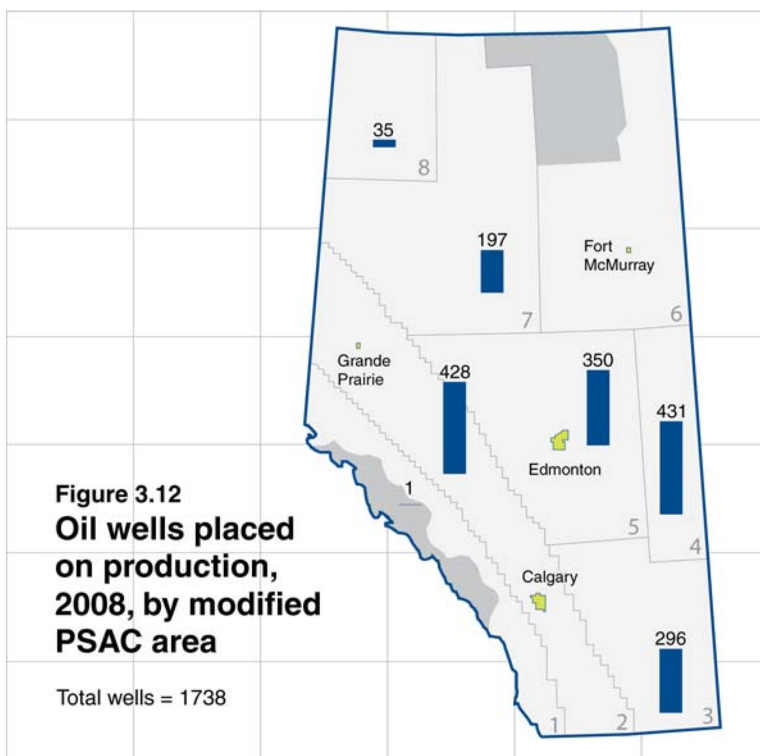


Figure 3.12
Oil wells placed on production, 2008, by modified PSAC area

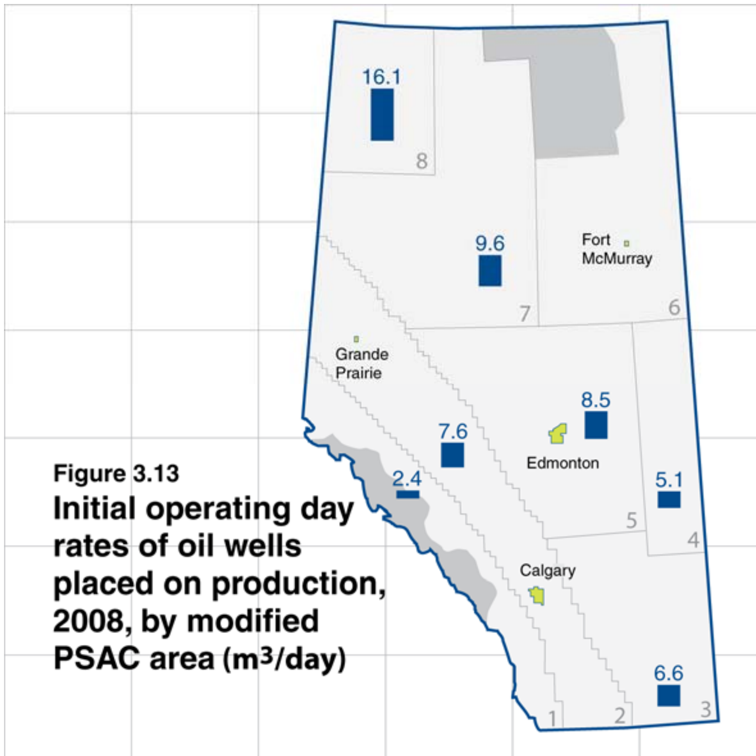


Figure 3.13
Initial operating day rates of oil wells placed on production, 2008, by modified PSAC area (m^3/day)

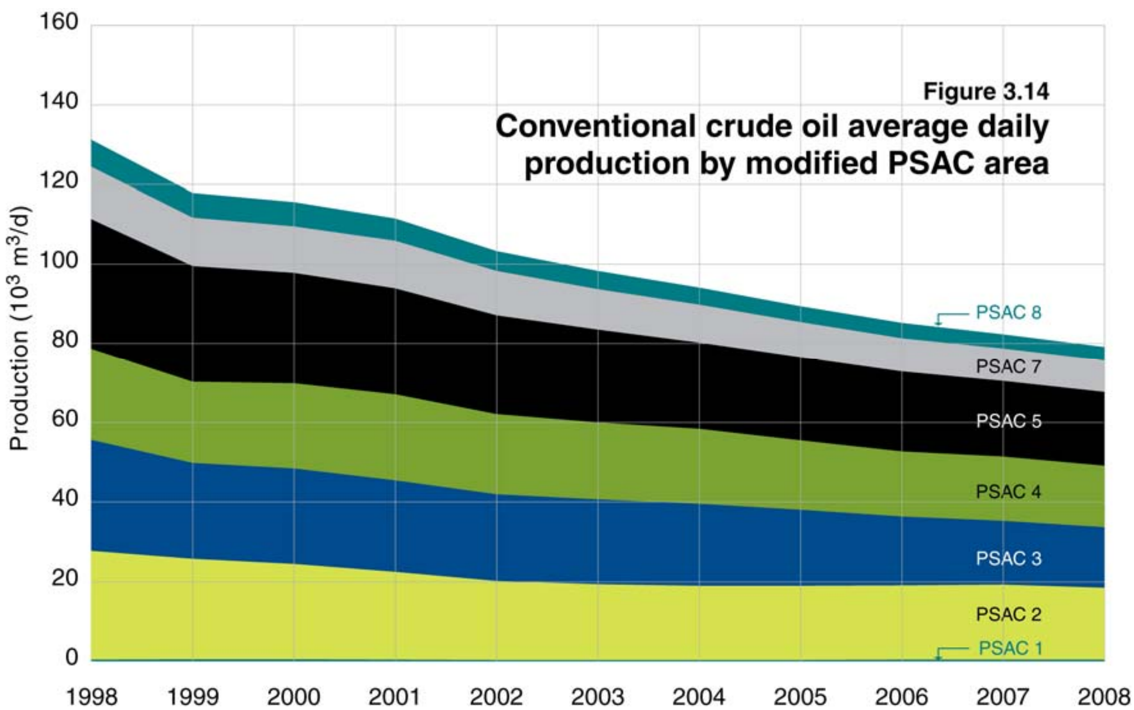


Figure 3.14
Conventional crude oil average daily production by modified PSAC area

Annual ERCB drilling statistics indicate that the number of wells producing oil has generally[1] increased over time from 9900 in 1973 to 39 200 in 2008. In contrast, crude oil production has been on decline since its peak of 227.4 10^3 m^3/d in 1973. **Figure 3.15** shows total crude oil production and the number of wells producing crude oil since 1972. Of the 39 200 wells producing oil in 2008, about 3000 were classified as gas wells. Although these gas wells represented 8 per cent of wells that produced oil, they produced at an average rate of only 0.2 m^3/d and accounted for less than 1 per cent of total production.

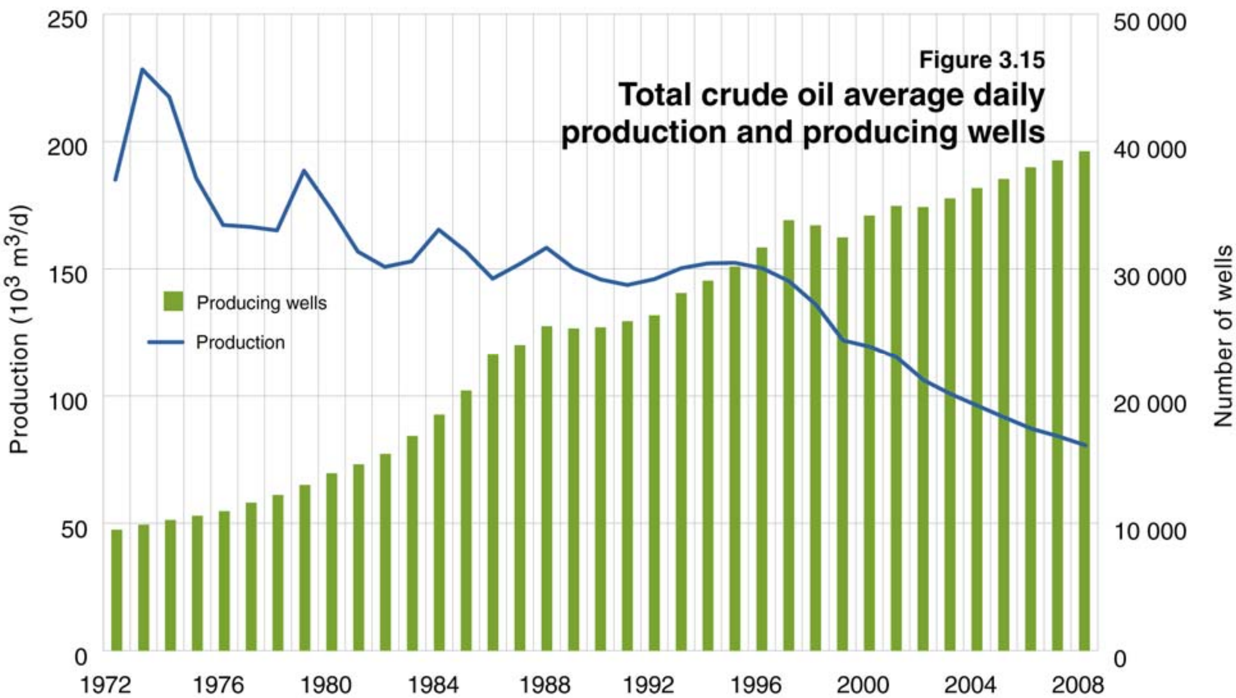


Figure 3.16 depicts producing oil wells and the average daily production rates of those wells by region in 2008. The average well productivity of crude oil producing wells in 2008 was 2.2 m^3/d. The majority of crude oil wells in Alberta, about 67 per cent, produced less than 2 m^3/d per well. In 2008, the 24 200 oil wells in this category operated at an average rate of 0.9 m^3/d and accounted for only 26 per cent of the total crude oil produced. **Figure 3.17** shows the distribution of crude oil producing wells based on their average production rates in 2008.

In 2008, some 322 horizontal wells were brought on production, a 7 per cent increase from 2007, raising the total to 3970 producing horizontal oil wells in Alberta. Horizontal wells accounted for 11 per cent of producing oil wells and about 17 per cent of the total crude oil production. Production from horizontal wells drilled in the past ten years peaked in 1999 at an average rate of 13.0 m^3/d. The current production rate of new horizontal wells is estimated to average about 5.3 m^3/d.

[1] The number of wells producing oil registered declines in 1989, 1998, 1999, and 2002.

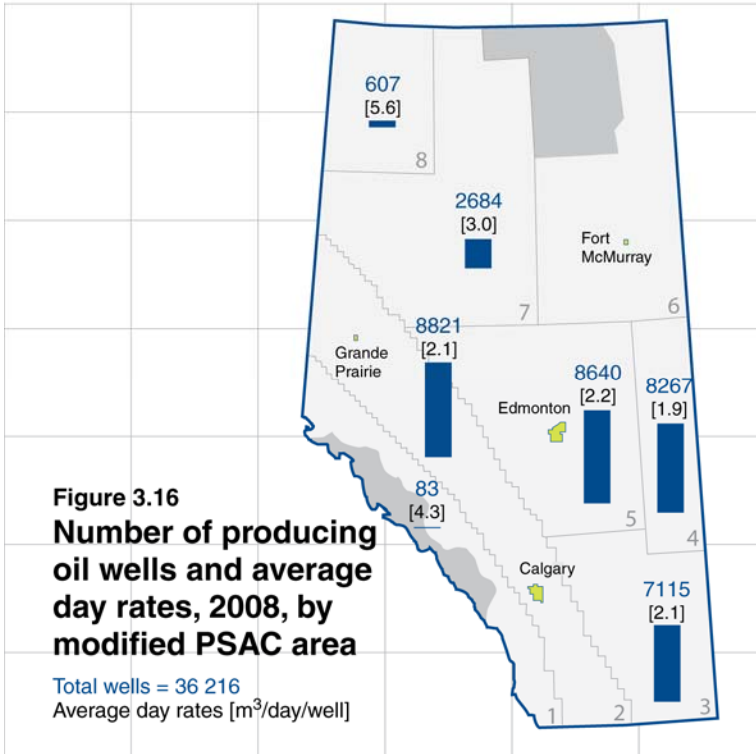


Figure 3.16
Number of producing oil wells and average day rates, 2008, by modified PSAC area
Total wells = 36 216
Average day rates [m3/day/well]
607
[5.6]
8
2684
[3.0]
Fort McMurray
7
6
8821
[2.1]
Grande Prairie
8640
[2.2]
8267
[1.9]
Edmonton
83
[4.3]
5
4
Calgary
7115
[2.1]
1
2
3

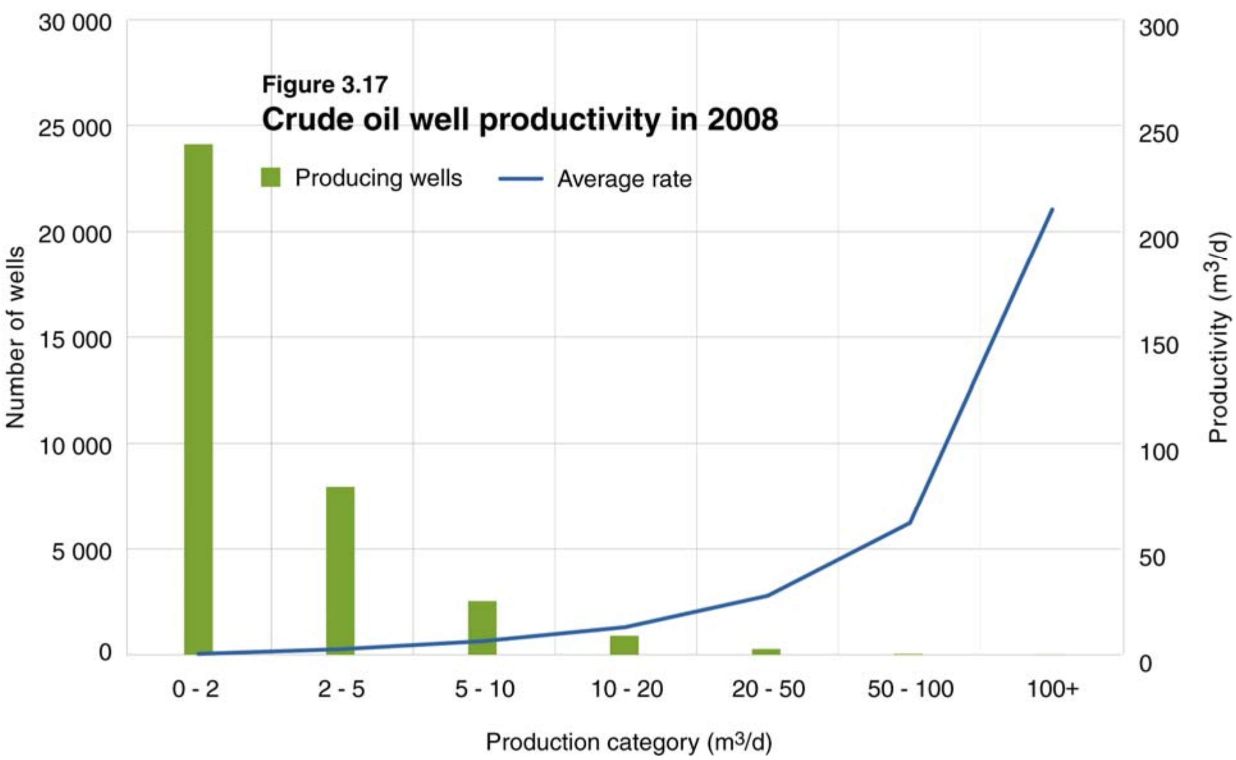


Figure 3.17
Crude oil well productivity in 2008
Producing wells
Average rate
Number of wells
30 000
25 000
20 000
15 000
10 000
5 000
0
Productivity (m3/d)
300
250
200
150
100
50
0
0 - 2
2 - 5
5 - 10
10 - 20
20 - 50
50 - 100
100+
Production category (m3/d)

Crude oil production from existing wells by year placed on production over the period 1999-2008 is depicted in **Figure 3.18**. This figure illustrates that about 35 per cent of crude oil production in 2008 resulted from wells placed on production in the last five years.

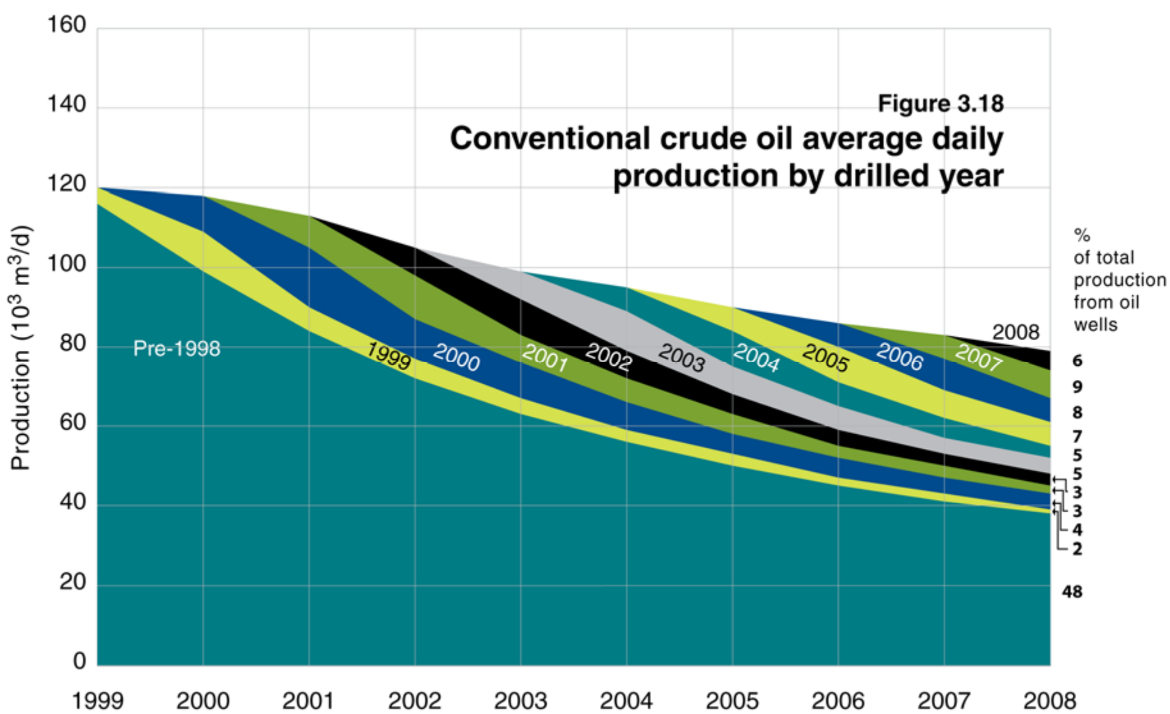
Figure 3.19 compares Alberta crude oil production with crude oil production from Texas onshore and Louisiana onshore from 1953 through 2008. Louisiana onshore production peaked in 1970, while Texas onshore production peaked in 1972 and Alberta production peaked in 1973. The figure shows that Alberta did not experience the same steep decline rates after reaching peak production as did Texas and Louisiana. This difference may be attributed in part to the crude oil prorationing system that existed in Alberta from the early 1950s through the mid-1980s. During this period, due to lack of sufficient markets for Alberta crude oil, production was curtailed to levels below the production capacity, which in turn resulted in a slower decline after its peak in 1973.

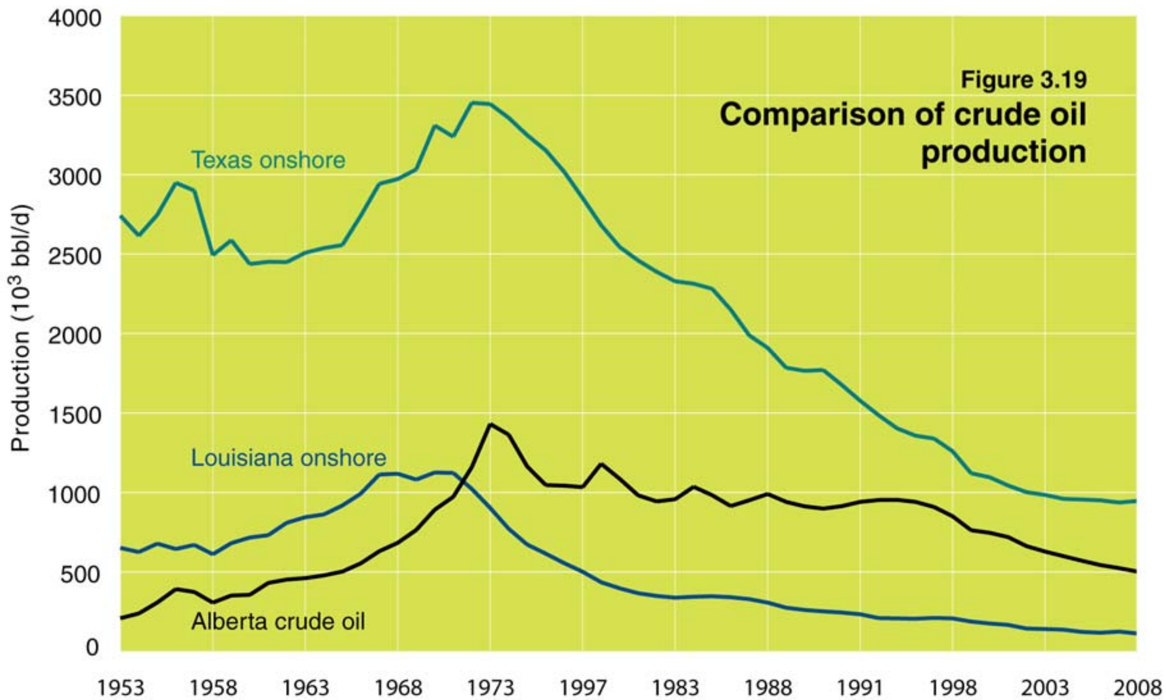
To project crude oil production from the wells drilled prior to 2009, the ERCB assumed the following:

- Production from existing wells in 2009 will be 70.1 10^3 m^3/d.
- Production from existing wells will decline at a rate of 15 per cent per year.

Over the forecast period, production of crude oil from existing wells is expected to decline to 16 10^3 m^3/d by 2018.

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



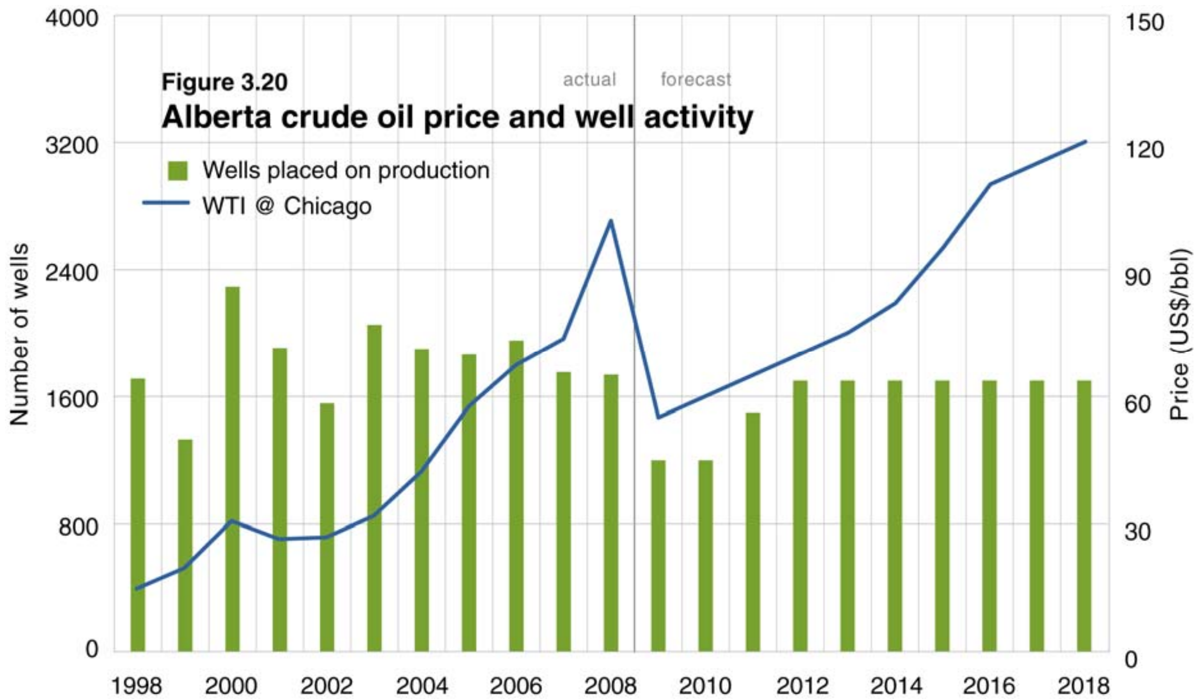


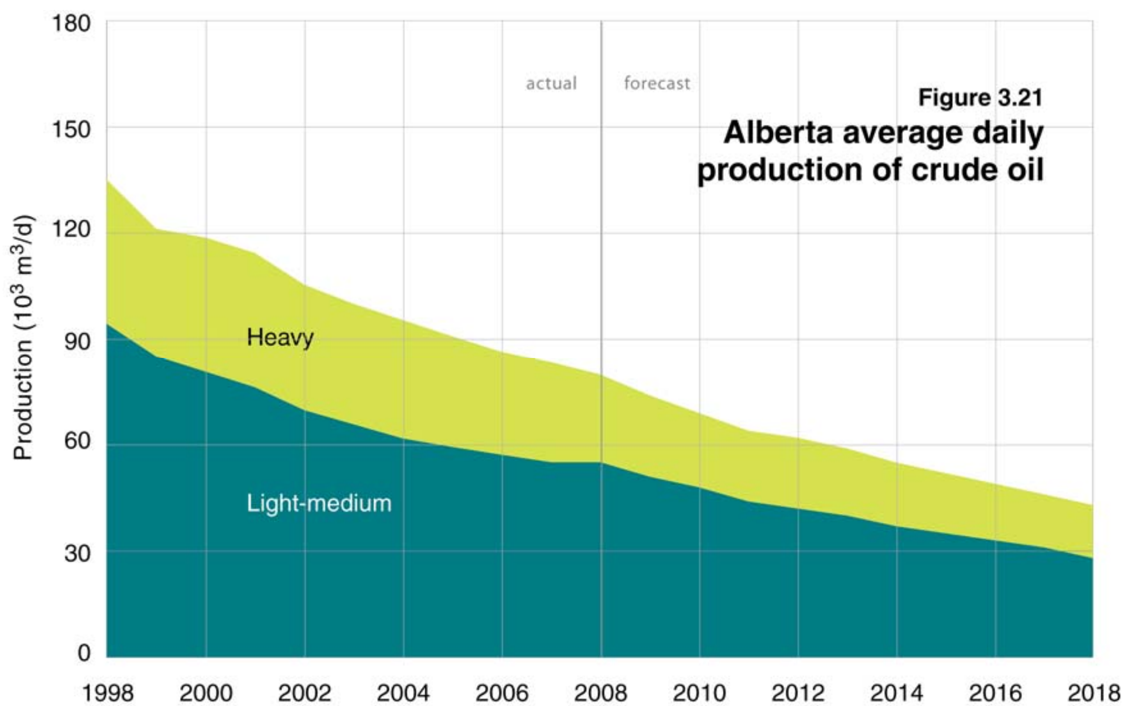
To project crude oil production from new wells, the ERCB considered the following assumptions:

- The number of new oil wells placed on production is projected to decrease from 1738 in 2008 to 1200 in 2009 and 2010 due to the expectation of lower oil prices. It is expected that wells placed on production will increase to 1500 wells in 2011 and to 1700 wells in 2012 and remain at this level for the remaining forecast period, as oil prices increase and well activity returns to recent historical levels. **Figure 3.20** illustrates the ERCB's forecast for wells placed on production for the period 2009-2018.

- The average initial production rate for new wells will be 4.5 m^3/d/well and will decrease to 3.0 m^3/d/well by the end of the forecast period. New well productivities averaged 6.0 m^3/d/well in the early 2000s but have declined over time.
- Production from new wells will decline at a rate of 28 per cent the first year, 23 per cent the second year, 22 per cent the third year, 19 per cent the fourth year, and 16 per cent for the remaining forecast period.

The projection of total production, which comprises production from existing wells and that from new oil wells, is illustrated in **Figure 3.21**. This figure also illustrates the production forecast split for light-medium and heavy crude oil. Light-medium crude oil production is expected to decline from 55.1 10^3 m^3/d in 2008 to 28 10^3 m^3/d in 2018. Over the forecast period, heavy crude production is also expected to decrease, from 24.8 10^3 m^3/d in 2008 to 15 10^3 m^3/d by the end of the forecast period. **Figure 3.21** illustrates that by 2018, heavy crude oil production will constitute a greater portion of total production compared to 2008.





This production forecast assumes that crude oil production will decline at 7 per cent per year for the years 2009 to 2011, which is higher than the recent historical 4 per cent decline. This higher decline rate is considered appropriate mainly due to lower forecast drilling activity levels over that period. Crude oil production decline rates are assumed to moderate by 2012 to 5 per cent and remain in the 5 to 6 per cent range for the remainder of the forecast period, due to the inability of new production to offset declining production from existing wells. New drilling has been finding smaller reserves over time, as would be expected in a mature basin.

The combined ERCB forecasts from existing and future wells indicate that total crude oil production will decline from 79.9 10^3 m^3/d in 2008 to 43 10^3 m^3/d in 2018. By 2018, based on this projection, Alberta will have produced about 88 per cent of the estimated ultimate potential of 3130 10^6 m^3.

3.2.2 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with synthetic crude oil (SCO), 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 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, hence, on Alberta crude oil feedstock requirements.

In 2008, Alberta refineries, with total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 25.4 10^3 m^3/d of crude oil. SCO, bitumen, and pentanes plus constituted the remaining feedstock. Crude oil accounted for roughly 42 per cent of the total crude oil and equivalent feedstock (see Section 2.2.5). **Figure 3.22** illustrates the current capacity and location of Alberta refineries. It is expected that no new crude oil refining capacity will be added over the forecast period.

Refinery utilization for 2008 was about 81 per cent, down significantly from 2007, mainly due to planned shutdowns needed to bring the Petro-Canada Refinery Conversion Project (RCP) on stream. The RCP will fully replace light-medium crude oil with SCO and nonupgraded bitumen. Planned and unplanned refinery outages at Imperial’s Strathcona Refinery and at Shell’s Scotford Refinery also contributed to the decline in utilization. Due to Petro-Canada’s RCP, total crude oil use is expected to decline to 21 10^3 m^3/d in 2009 and remain at this level for the remainder of the forecast period.

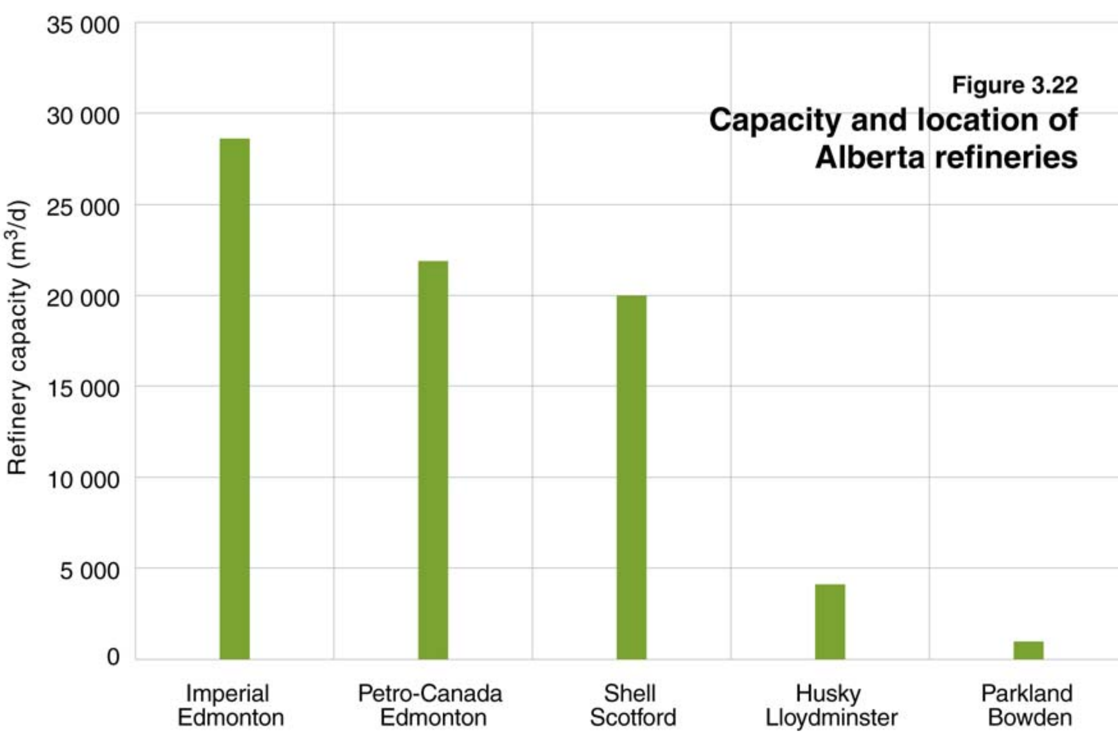
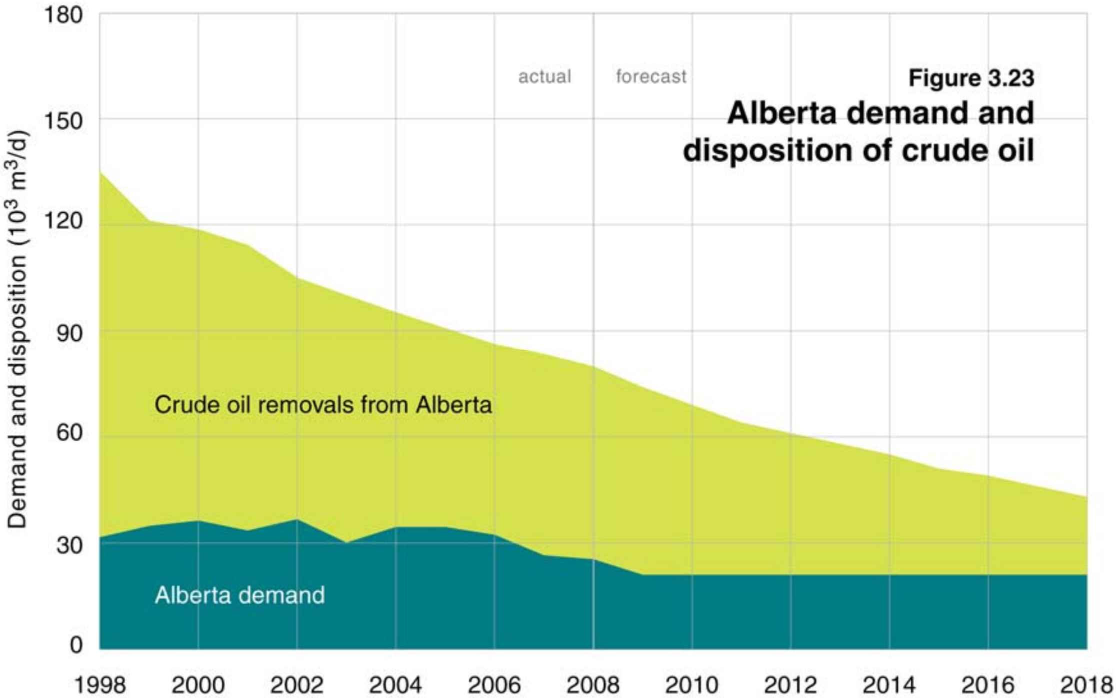


Figure 3.22
Capacity and location of Alberta refineries

Shipments of crude oil outside of Alberta, depicted in **Figure 3.23**, amounted to 68 per cent of total production in 2008. The ERCB expects that by 2018 about 51 per cent of production will be removed from the province, due to the forecast decline in Alberta light-medium and heavy crude oil production.



3.2.3 Crude Oil and Equivalent Supply

Figure 3.24 shows crude oil and equivalent supply. It illustrates that total Alberta crude oil and equivalent is expected to increase from 293.7 10^3 m^3/d in 2008 to 486 10^3 m^3/d in 2018.

Over the forecast period, as illustrated in **Figure 3.25**, the growth in production of nonupgraded bitumen and SCO is expected to significantly offset the decline in conventional crude oil. The share of SCO and nonupgraded bitumen will account for some 88 per cent of total production by 2018, compared to 2008, when the share of SCO and nonupgraded bitumen accounted for some 65 per cent of total production.

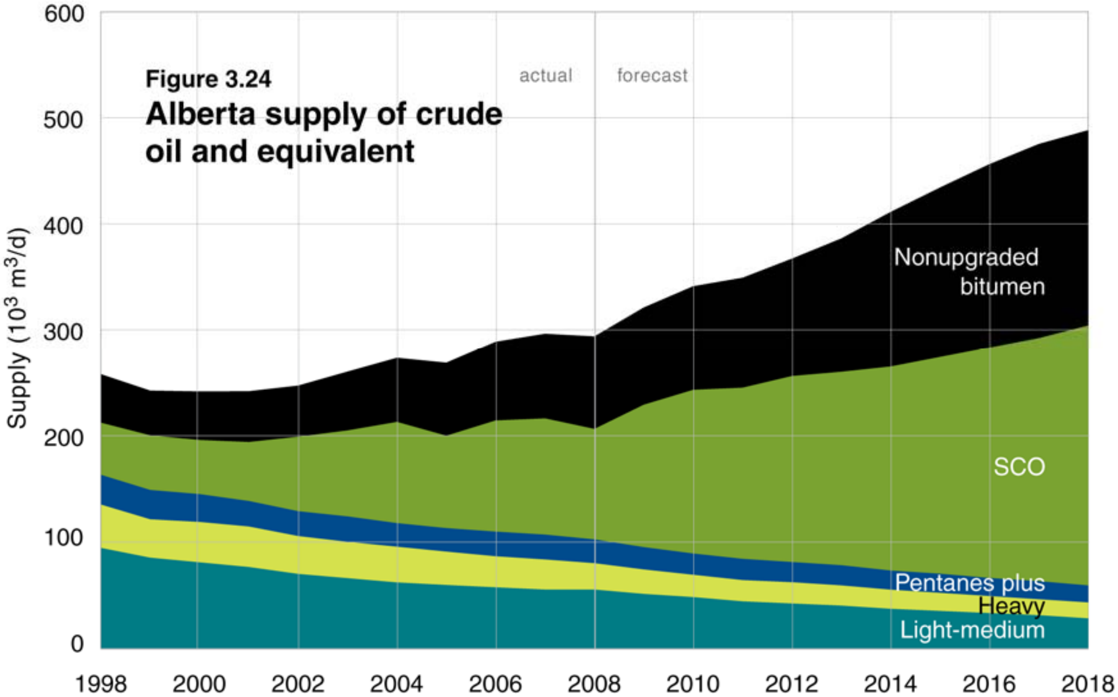


Figure 3.24
Alberta supply of crude oil and equivalent
actual
forecast
Supply (10^3 m^3/d)
Nonupgraded bitumen
SCO
Pentanes plus
Heavy
Light-medium
0
100
200
300
400
500
600
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018

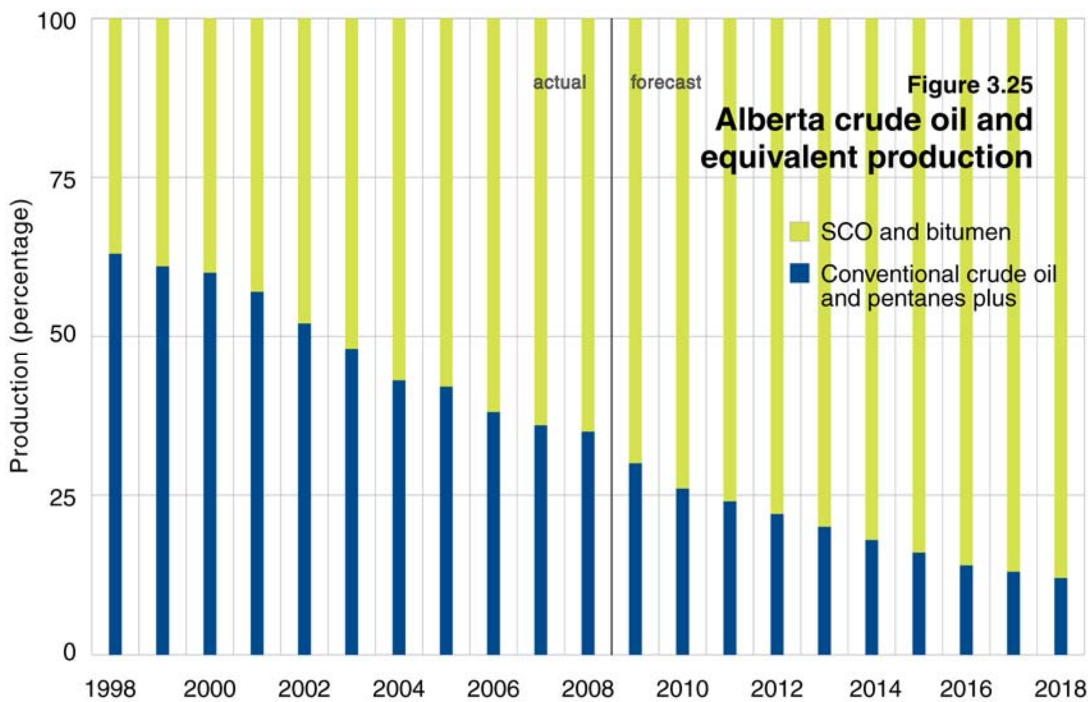


Figure 3.25
Alberta crude oil and equivalent production
actual
forecast
Production (percentage)
SCO and bitumen
Conventional crude oil and pentanes plus
0
25
50
75
100
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018

4 Unconventional Natural Gas

Highlights

- Coalbed methane (CBM) remaining established reserves increased by 16 per cent in 2008.
- Included this year is a brief discussion on shale gas, a new resource type for this report. No reserves have been set at this time.
- Some 1926 CBM wells were drilled in 2008, down 12 per cent from the revised 2007 total.
- There were 1466 new well connections into CBM producing zones in 2008, a decrease of 41 per cent from 2007.
- Total annual gas production from CBM wells for 2008 was 8.0 billion cubic metres, an increase of 8 per cent relative to revised 2007 production.

With the expansion of activity in the exploration and production of different forms of unconventional natural gas in Alberta, the ERCB has expanded the former coalbed methane (CBM) section of this report to include shale gas (SHG) resources and renamed the section Unconventional Natural Gas. CBM and SHG are defined as natural gas in coal and shale respectively.

Other unconventional natural gas resources, such as those defined in other jurisdictions as tight gas and gas (methane) hydrates, are not included in this section. The equivalent of tight gas in Alberta has long been considered to be conventional gas, and the reserves and production from these reservoirs are included in Section 5. Gas hydrates have not been mapped in Alberta and consequently are not included in this report.

Potential exists in Alberta for the production of synthetic gas (syngas) from coal or biomass gasification. There are three types of coal gasification processes: surface facility gasification from mined coal, biological modification of in situ coal seams, referred to as biogenic gas, and in situ coal gasification (ICG).

Surface facility gasification is derived from conventionally mined coal, and those mineable coal reserves are included in Section 8. As gasification facilities do not currently exist in Alberta, there is no production to address in this section. Biogenic gasification is not included in this report, as this process of gas generation is highly speculative at this time. ICG is usually derived from coal at unmineable depths. The resource base for ICG is partially included in Section 8, and that section will be expanded to more fully identify the complete resource base in future reports. Any ICG-derived gas would, by its nature, incorporate any CBM gas volumes contained within the targeted coals. However, ICG syngas is not currently on production in Alberta, and many technical and policy issues need to be resolved before reserves would be included in this report.

4.1 Reserves of Coalbed Methane

CBM is the methane gas found in coal, both as adsorbed gas and as free gas. It may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). Hydrogen sulphide (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 (m^3). This report estimates the initial in-place resources and remaining established reserves of CBM at December 31, 2008.

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. As a result, beginning with this report, the ERCB is starting the transition from a field/pool format for reporting CBM volumes to a deposit/play area format, as highlighted by the following discussion.

Based on thousands of coal holes and oil and gas wells, coal is known to underlie most of central and southern Alberta. Coal seams occur as layers or beds within a number of 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 individual seam is potentially capable of producing some quantity of CBM. For this reason, coal and CBM have a fundamental relationship.

A CBM zone is defined as all coal seams within a formation unless separated by more than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Unlike a coal zone, a CBM zone excludes all non-coal lithologies between the coal seams.

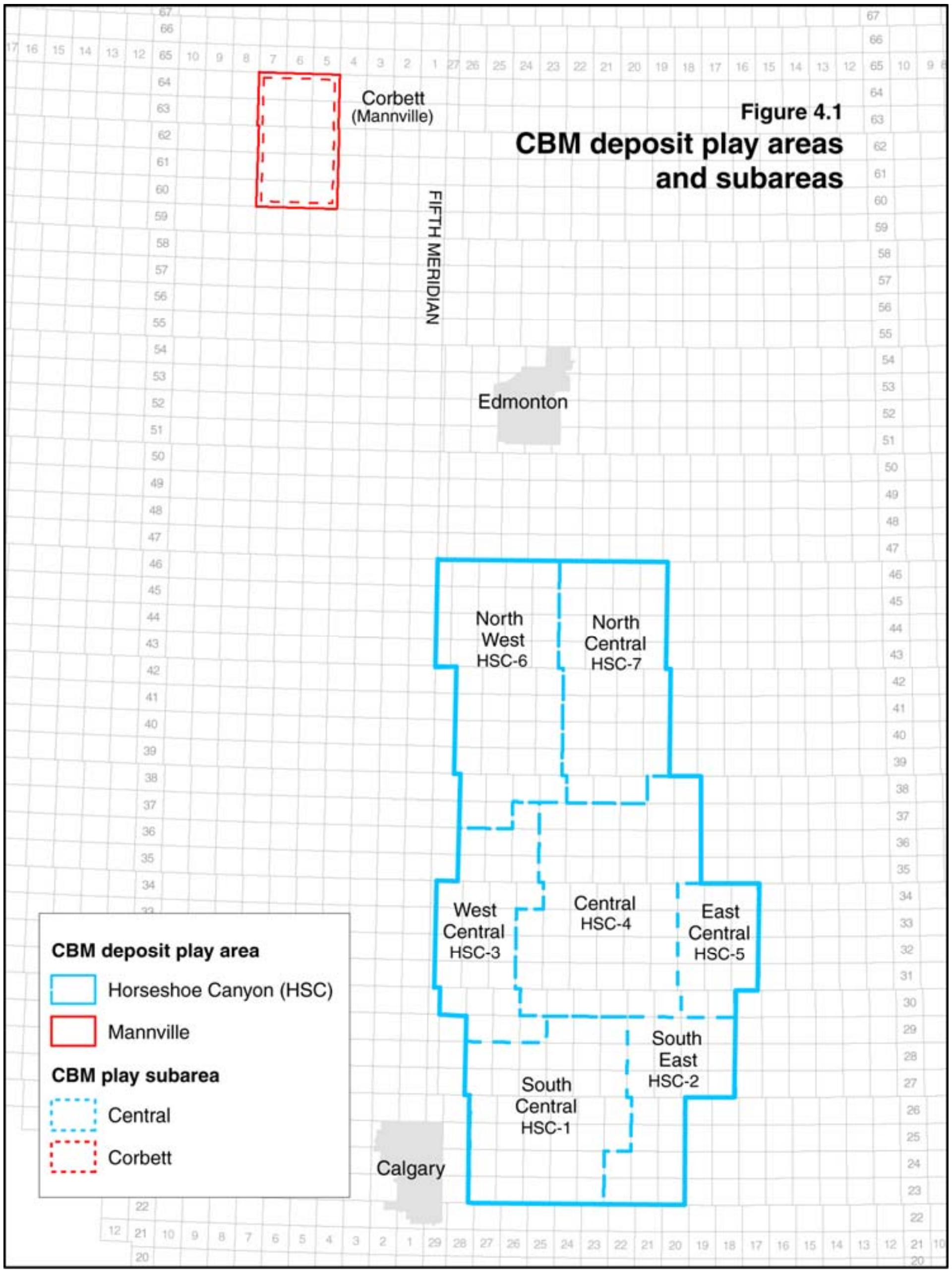
Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. Also for administrative purposes, such as data collection and production reporting, pools are currently vertically grouped into CBM fields, and prior to this report established reserves were published on this basis. However, since multifield pools proved problematic in grouping CBM resource and reserve estimates, the ERCB now groups CBM volumes into deposit-based play areas.

CBM deposits, similar to oil sands deposits, are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike for oil sands deposits, however, the ERCB has yet to formally define CBM deposits through Board orders, as it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe-Canyon (HSC) and the Mannville.

Within each of these deposits, development activities have been concentrated in a single play area. While Mannville activity is clustered almost exclusively around the Corbett area, the more widespread HSC activity is clustered around a large area between Calgary and Edmonton.

While coal zones are regionally extensive, the values of reservoir parameters are generally limited to a more localized scale. As a result, for resource estimation and reporting purposes, the large central Alberta play area of the HSC deposit is divided into subareas that are based on reservoir and production profile differences within the deposit (see **Figure 4.1**).

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. Interest in CBM development in Alberta continues to grow, with ongoing high numbers of CBM completions. The actual CBM production to date continues to be uncertain because of the difficulty in differentiating CBM from conventional gas production where commingled production occurs. Regulations were implemented on October 31, 2006, to assist in appropriate data collection for CBM. The data were first used in 2007 and have significantly increased the understanding of CBM



reserves in 2008. As additional data become available for more areas, the accuracy of CBM production estimates is expected to improve. Further details on CBM regulations are available in ERCB *Directive 062: Coalbed Methane Control Well Requirements and Related Matters.*

In 2008, the ERCB established a new publication, *ST109: Alberta Coalbed Methane Well Locations*, which is a monthly report based on data submitted by industry and evaluations by the ERCB. The method of identifying CBM wells in this report is primarily determined when evaluations for coal in wells match completion intervals. The secondary determination is when the fluid status reported by industry matches one of the CBM codes. The tertiary determination is when the well licence includes CBM as a target. The determinations are collated and posted on the ERCB Web site www.ercb.ca. This new report has resulted in a significant increase in the number of wells with historical CBM production.

4.1.1 Provincial Summary of CBM

The ERCB estimates the remaining established reserves of CBM to be 28.3 billion cubic metres (10^9 m^3) as of December 31, 2008, in areas of Alberta where commercial production is occurring. This increase over last year's 24.3 10^9 m^3 is primarily due to reassessments facilitated by increased availability of reservoir data. A summary of reserves is shown in **Table 4.1**. In 2008, the annual production from all wells listed as CBM (see *ST109*) was 8.0 10^9 m^3. This volume includes the total contribution from wells with commingled conventional gas and CBM production, which are defined as CBM hybrid wells. However, the portion estimated to be attributed to CBM only is 6.2 10^9 m^3, as listed in **Table 4.1**. Note that the correction in cumulative volumes for 2008 more than doubles the CBM-only volume due to additions of historical wells, as noted in *ST109*. Through reporting changes captured in *ST109*, the percentage of hybrid wells decreased based on what was declared by licensees in their data submissions.

Table 4.1. Reserve and production change highlights (10^9 m^3)

	2008	2007	Change
Initial established reserves	47.3	29.8	+17.5
Cumulative production	18.9	5.5	+13.4*
Remaining established reserves	28.3	24.3	+4.0
Annual production	6.2	2.2	+4.0

* Change in cumulative production is a combination of annual production and all adjustments to previous production records. In 2008, a correction to the historical CBM cumulative production, mainly from previously unidentified CBM wells, resulted in a change in cumulative production of 13.4 10^9 m^3, whereas annual production was 6.2 10^9 m^3.

4.1.2 Distribution of CBM Potential by Geologic Strata

The following horizons have CBM potential in the Alberta plains:

- **Ardley Coals of the Scollard Formation** – This is the upper set of coals, which are generally the shallowest, with varying gas contents and quantities of water. These coals continue to the west, outcropping in the Alberta Foothills, where they are referred to as the Coalspur coals. The production history from 42 wells shows the Ardley coals in the area of Development Entity No. 1 to be "dry CBM." Where water is present, it is usually nonsaline or marginally saline, and thus water production and disposal must comply with the *Water Act*. Currently, production is not occurring where these conditions exist.

- **Coals of the HSC Formation and Belly River Group** – This is the middle set of coals, which 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. The HSC play area in central Alberta in **Figure 4.1** is slightly smaller than the geological extent of the HSC Formation. Play areas for the Taber or MacKay zones of the Belly River Group have not been established, as they are not commercially productive at this time. CBM activity will continue in the HSC areas with the existing vertical drilling technology, with new drilling, recompletions of existing wells, and commingling with conventional zones.

- **Coals of the Mannville Group** – This is the lower set of coals within the plains, primarily in the Upper Mannville Formation(s). These generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. These coals continue to the west to outcrop near the Rocky Mountains, where they are referred to as the Luscar coals. The initial reserves for areas other than Corbett (see **Figure 4.1**) within the Mannville have been set at cumulative production. Future Mannville activity is projected to continue using horizontal well drilling to achieve commercial production.

- **Kootenay Coals of the Mist Mountain Formation** – These coals are only present in the foothills of southwestern Alberta. They have varying gas contents and quantities of water, but production of gas is very low due to tectonic disruption. No reserves have been calculated.

4.1.3 CBM Reserves Determination Method

As CBM is natural gas, it is regulated and administered as if it existed in pools. However, since CBM occurrences exist more as deposits (similar to bitumen and shale gas), the ERCB uses three-dimensional block models to estimate this disseminated gas. Based on the analysis of geology, pressure gradients, and related gas content, the ERCB has identified distinct subareas within CBM play areas and determined in-place CBM resources for each of these play subareas.

The most significant resource assessment change since 2007 has been the access to new data from desorption testing of the coals. The resulting gas content data have been used for improved resource modelling. Desorption data are used on a zonal basis by applying gas content trends from core to all coals in the zone to estimate in-place CBM resources. Desorption values from drill cuttings were used in a separate study to validate the continuity of the zonal trends from core.

The method of determining reserves depends on flow meter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. Currently, there are many control wells from which this information has been collected. Analysis has shown that most producing wells have a modest drop in reservoir pressure or a stable pressure profile. However, for reasons still unknown, some wells appear to have either an anomalously large drop in reservoir pressure or an increase in reservoir pressure after the production of methane. Current reserve estimates were 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 4.2**. Future analysis is expected to improve estimates of recovery factors.

CBM data are available on two systems at the ERCB: summarized net pay data on the Basic Well Database, and individual coal seam thickness picks on the Coal Hole Database. Further information is available from ERCB Information Services.

4.1.4 Commingling of CBM with Conventional Gas

Gas commingling is the unsegregated production of gas from more than one interval 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. In this report, wells that commingle CBM and conventional gas are termed CBM hybrid wells.

CBM production from the generally “wet CBM” Scollard, Mannville, and Kootenay coal-bearing formations is not currently approved for commingling with gas from other lithologies because of the potential negative impact of water production on CBM recovery and the mixing of water between aquifers. Early production suggests that certain areas of the Mannville CBM occurrences may be “dry.”

As the HSC 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 becoming fairly 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. With the changes to commingling requirements implemented in 2006, the area in central Alberta called Development Entity No. 1 is now approved for this type of production. 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, however, lack segregated reservoir data from commingled zones, making reserve estimation more difficult. Many hybrid wells report only large 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 in this report, the following analysis 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 over 1150 CBM control wells and 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.

This data analysis process resulted in the estimated contribution of CBM production from CBM hybrid wells being increased in a few areas, as summarized in **Table 4.2**. The *Oil and Gas Conservation Regulations* now stipulate data submission requirements for control wells to capture information on CBM-only production characteristics. Future submission of these annual test results will allow for more complete analysis to improve allocation of production in hybrid wells.

4.1.5 Detail of CBM Reserves and Well Performance

Exploration and development drilling are being conducted for CBM across wide areas of Alberta and in many different horizons. The first commercial production and reserve calculations were for the HSC coals, which are mainly gas-charged, with little or no pumping of water required. This area remains the main focus of industry and currently has the highest established reserves (see **Table 4.2**). New data have supported inclusion of additional areas as part of the contiguous HSC CBM play area (see **Figure 4.1**). To date, the primary method used to extract CBM from the HSC coals is through vertical wellbores, including extensive recompletion of existing wells and commingling of gas flow with conventional reservoirs.

Reserves have been estimated for the deeper Mannville CBM play in only one area. The production profile in this area exhibits significant increasing gas production concurrent with decreasing water production. In 2005, the first commercial success was announced for Mannville CBM production in the Corbett/Thunder and Doris areas, and 2007 saw the addition of the Neerlandia area. This Mannville play area is referred to as Corbett (see **Figure 4.1**), and CBM production in the Corbett play area requires the proper disposal of

Table 4.2. CBM gas in place and reserves by deposit play area, 2008

Deposit and play subareas	Area (km²)	Area of coal (km²)	Average cumulative coal thickness (m)	Coal reservoir volume (10^6 m³)	Estimated gas content (m³ gas/ m³ coal)	Initial gas in place (10^6 m³)	Average Recovery factor (%)	Initial established reserves (10^6 m³)	Gas—net cumulative production (10^6 m³)	Remaining established reserves (10^6 m³)
HSC										
1	3 448	3 343	10	34 489	2.12	73 211	11.8	8 659	4 060	4 599
2	2 050	467	9	3 972	1.79	7 125	11.9	850	256	594
3	2 423	1 327	10	13 772	2.89	39 811	10.9	4 344	1 630	2 713
4	4 567	4 231	10	42 807	1.67	71 379	11.2	8 002	4 958	3 045
5	1 305	492	15	7 411	0.53	3 919	11.0	429	375	54
6	3 914	888	10	9 165	1.53	14 018	13.7	1 923	1 041	882
7	3 262	2 348	11	26 834	0.99	26 558	16.5	4 385	3 781	604
Mannville										
Corbett	1 398	1 008	10	10 021	9.68	97 006	18.6	18 004	2 156	1 5848
Undefined[1]								671	671	0
Total	22 368	14 105		148 470		333 027		47 266	18 928	28 339

[1] Most of the undefined areas are for tests in the Mannville coals, but include a few HSC, Ardley, and Kootenay wells with minor production.

saline water. There is increased gas flow earlier in the production cycle of new Mannville CBM wells in the Corbett area due to progressive dewatering of the deposit.

There are indications of possible large-scale development of other Mannville coals in the areas of Oberlin and Stettler with potential production of "dry CBM" that will be subject to future evaluation. Current industry practice suggests that long-term CBM production from the Mannville will be project-style developments using complex multilateral horizontal wells completed primarily within one seam. The undefined portion of **Table 4.2** includes noncommercial production from these areas, but reserves have not been booked pending commercial production.

Reserves for Kootenay coals, Ardley coals, and the Taber and MacKay coals lower in the Belly River Formation are not calculated due to lack of significant production. The undefined portion of **Table 4.2** also includes production from these coals.

4.1.6 Ultimate CBM Gas in Place

In 2003, the Alberta Geological Survey, in *Earth Sciences Bulletin 2003-03*, estimated that there are some 14 trillion (10^{12}) m³ (500 trillion cubic feet [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 4.3)**. 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 4.3. Ultimate CBM gas in place*

	10^{12} m³	Tcf
Upper Cretaceous/ Tertiary – Plains	4.16	147
Mannville coals	9.06	320
Foothills / Mountains	0.88	31
Total	14.10	500

*AGS *Earth Sciences Bulletin 2003-03*.

The geographic distribution of these CBM resources is shown in **Figure 4.2**, but only a very small portion of this very large resource has been studied in sufficient detail to be included in this report.

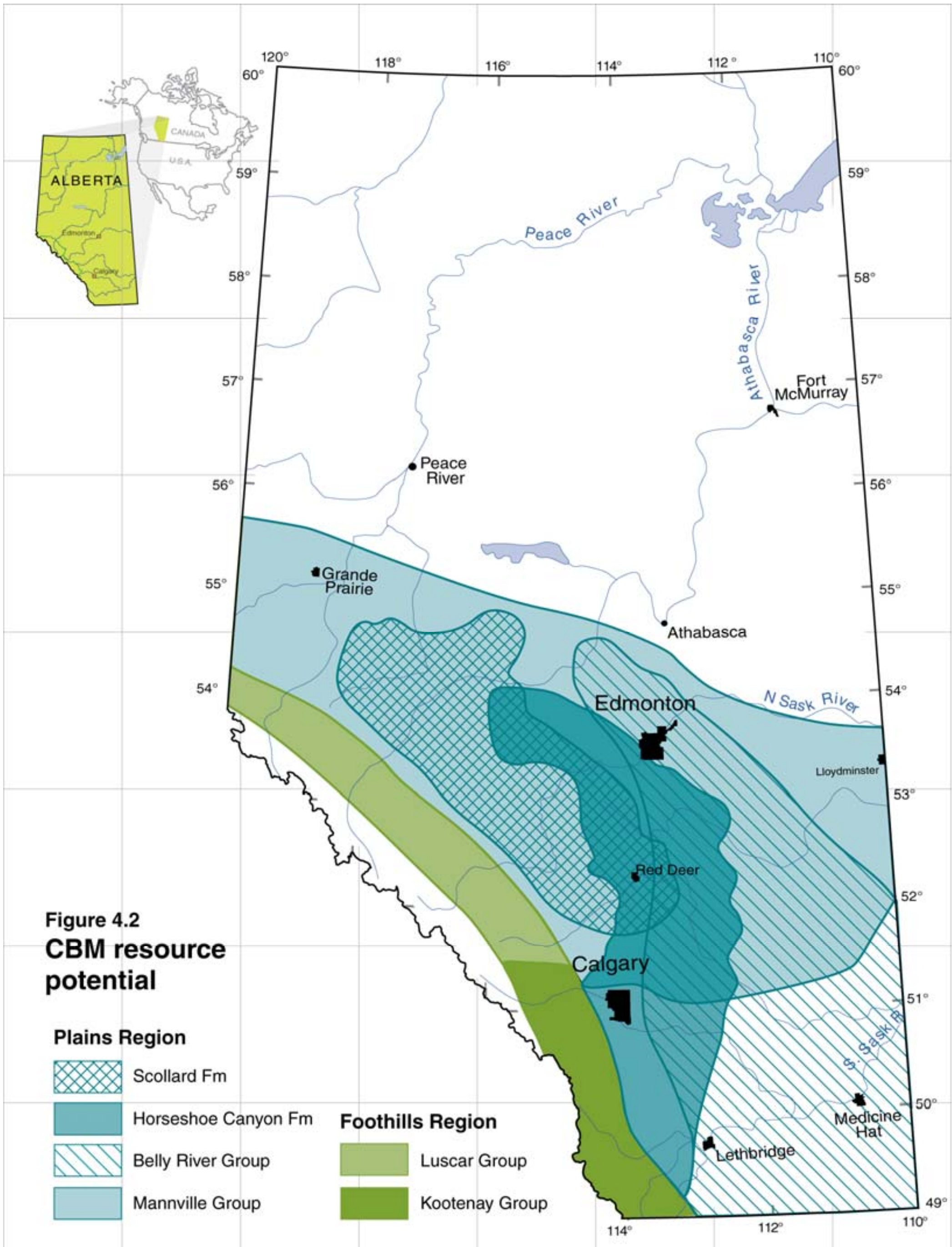


Figure 4.2
CBM resource potential

4.2 Reserves of Shale Gas

Underlying most of Alberta are a number of thick and widespread fine-grained strata occurring at varying depths, having a wide range of gas potential, and exhibiting varying reservoir conditions. Shale gas (SHG) is the natural gas that is found in shale, existing mostly as free gas in the matrix or fractures and/or as adsorbed gas in organic matter and/or clays. SHG is not restricted to shales, as potential SHG strata can also include claystones, mudstones, siltstones, and fine-grained sandstones. Additionally, not all shale has the potential to contain SHG, as the shale must contain organic matter. For shales that have SHG, the shale is the reservoir, source rock, and seal. Typically, these fine-grained rocks have low matrix permeability, and stimulation is required to produce gas from the rock.

There has been significant interest in SHG development over the past few years in Canada, with the main activity being almost exclusively in British Columbia. The shale reservoirs in B.C. generally occur in basins isolated from Alberta. Certain characteristics of SHG production from plays in the U.S. and B.C. may be comparable to Alberta, but not all characteristics are comparable. In Alberta, SHG potential in a specific play varies both vertically and laterally. To date, knowledge is still quite limited, with a number of projects only at the pilot stage or the initial point of long-term development.

The SHG resource in the province is viewed to be significant; however, with the exception of some long-term developments in southeastern Alberta, production data are not yet available to prove its commercial viability. Southeastern Alberta shallow gas has been considered conventional gas for most of its 40+ years of production history and will not be reclassified as SHG in the future. While the ERCB may publish in-place resource estimates in the near future, until data are available to conduct a reasonable assessment of SHG recoverability, the ERCB will not be estimating reserves. The ERCB will monitor anticipated increased SHG exploration and development activity to determine when sufficient data may become available to determine reserve estimates.

4.3 Supply of and Demand for Coalbed Methane

In projecting CBM supply, the ERCB considers both the expected production from existing CBM wells and the expected production from new CBM well connections. This also includes the portion of conventional gas production from hybrid CBM wells. CBM supply is incremental to the conventional natural gas supply needed to meet projected demand.

Total CBM well production increased 8 per cent in 2008 to 8.0 10^9 m^3 from 7.4 10^9 m^3 in 2007. In 2008, the Mannville zone produced 1.2 10^9 m^3 of CBM. The HSC produced 6.8 10^9 m^3 of CBM from CBM-only and hybrid wells.

Based on the *ST109: Alberta Coalbed Methane Well Locations* report, 1926 CBM wells were drilled in 2008, compared to 2183 in 2007, a decrease of 12 per cent. In 2008, 1466 wells were connected for CBM production, a 41 per cent decrease from the 2465 wells connected in 2007. CBM reserves are delineated by play areas and subareas, as described in Section 4.1. **Figure 4.3** shows the drilling and connection counts of CBM wells by subarea. Only 37 per cent of the CBM wells drilled in 2008 went on production in 2008. Of the total well connections for 2008, 46 per cent were from wells drilled in 2008, whereas 34 per cent were from wells drilled in 2007. The remaining 20 per cent were recompletions in older wells.

Figure 4.4 shows the breakdown of the cumulative total CBM producing wells and production by play subarea at year-end. Of these wells, 558, with a total production of 0.4 10^9 m^3, are located outside of these defined areas. They have not been assigned reserves but are included in the undefined category in **Figure 4.4**.

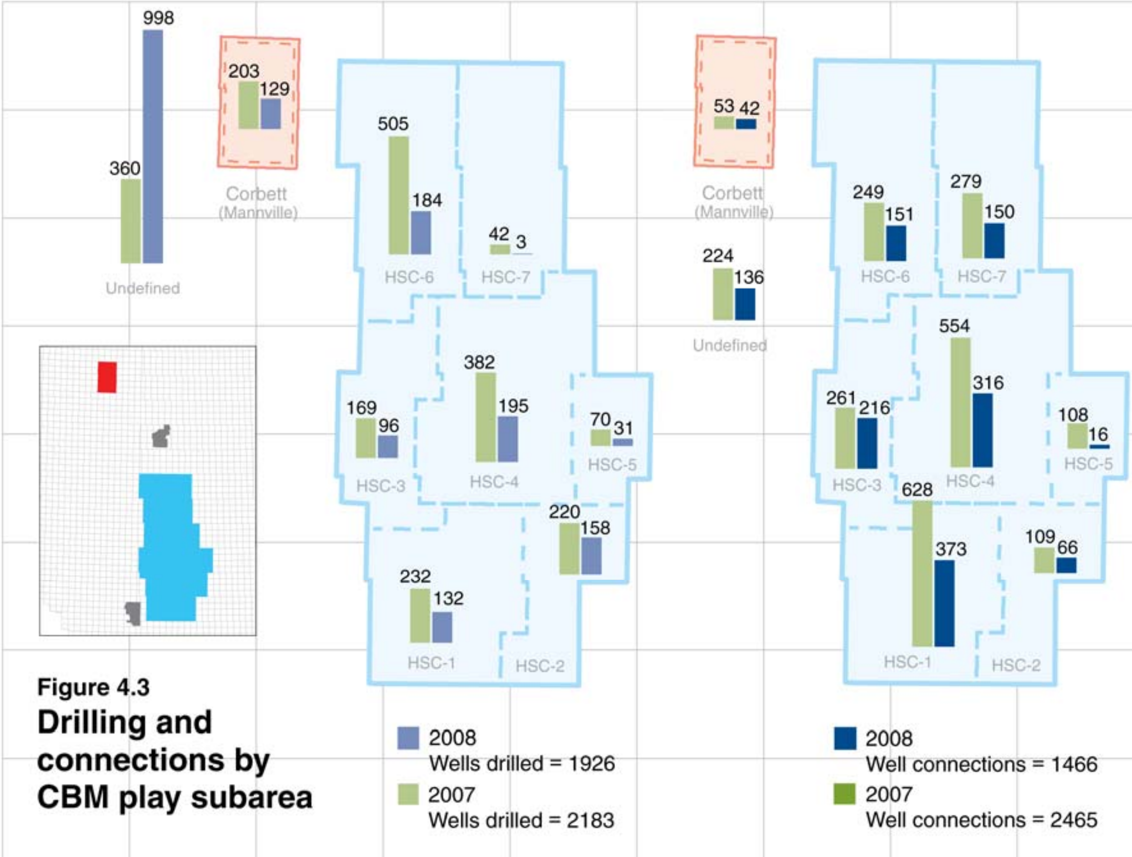


Figure 4.3

Drilling and connections by CBM play subarea

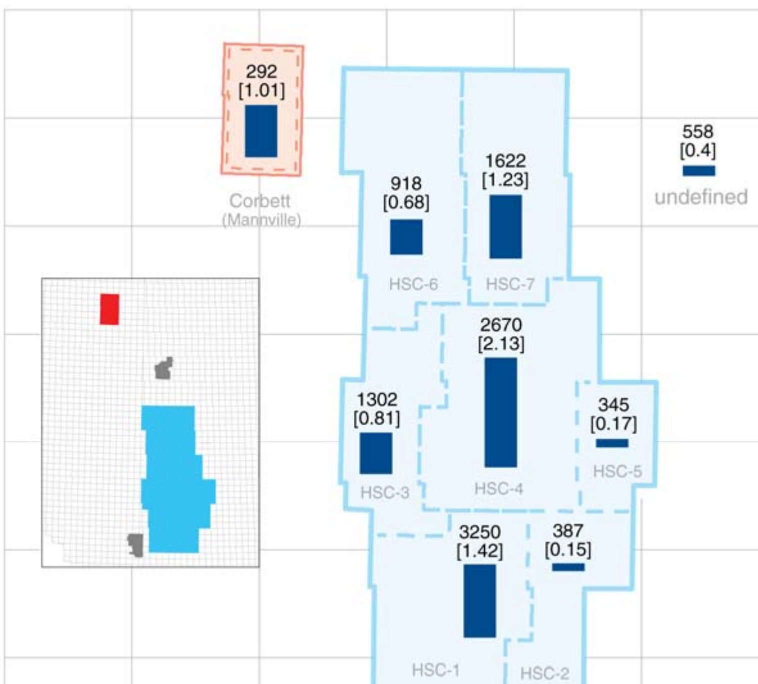


Figure 4.4

Total CBM production, 2008, and number of producing wells by play subarea

Number of wells = 11 344

[Production 10^9 m^3]

Figure 4.5 shows the 2008 area breakdown of CBM average daily production rates. In 2008, the initial average daily production rates within the HSC areas ranged from 1.5 to 2.6 10^3 m^3/d/well. Production from the Mannville zone is typically recovered from horizontal wells and therefore has significantly higher initial rates averaging 16.5 10^3 m^3/d/well in 2008.

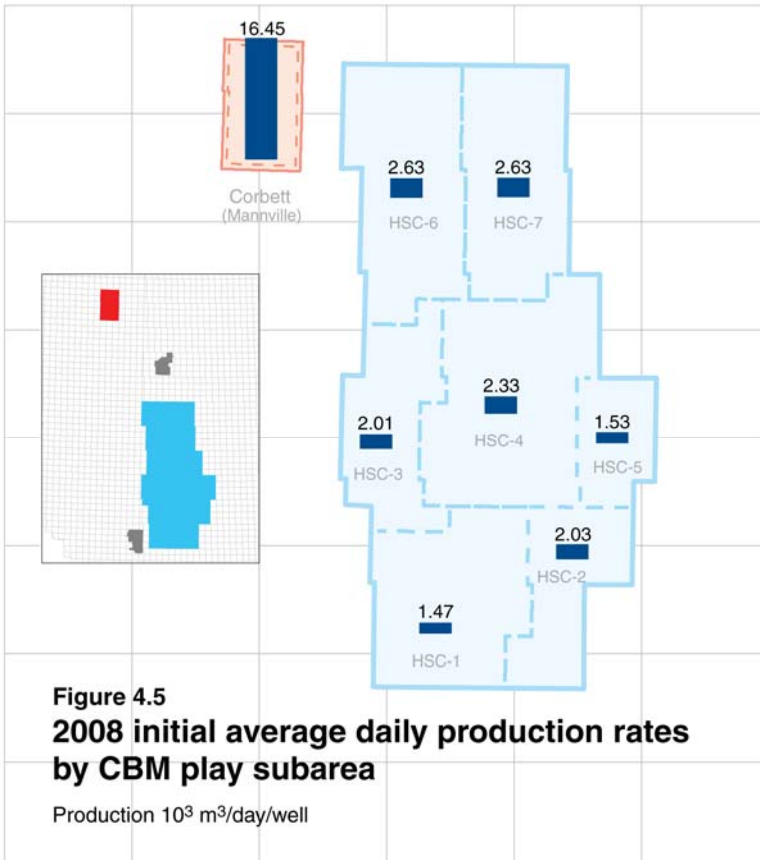


Figure 4.5
2008 initial average daily production rates by CBM play subarea
Production 10^3 m^3/day/well

HSC CBM is produced with very little water, unlike CBM in the Mannville zone. **Figure 4.6** shows the HSC and Mannville CBM gas and water production volumes for the wells within the CBM areas. About 86 per cent of Mannville CBM wells report some volume of water production, compared to only 27 per cent of HSC CBM wells.

To forecast production from new CBM well connections, the ERCB has considered the following assumptions:

- The average initial productivity of new HSC CBM connections is 2.0 10^3 m^3/d. Conventional gas production from hybrid wells is included in the average.
- The average initial productivity of new Mannville CBM connections is 16.5 10^3 m^3/d.
- Production from all new well connections will decline by 15 per cent after the first full year of production and then decline by 10 per cent per year thereafter.
- CBM well connections in 2009 are expected to be 1350 for HSC and 50 for the Mannville. Connections from 2010 to 2018 are projected to be 1500 per year for HSC and 100 per year for Mannville.

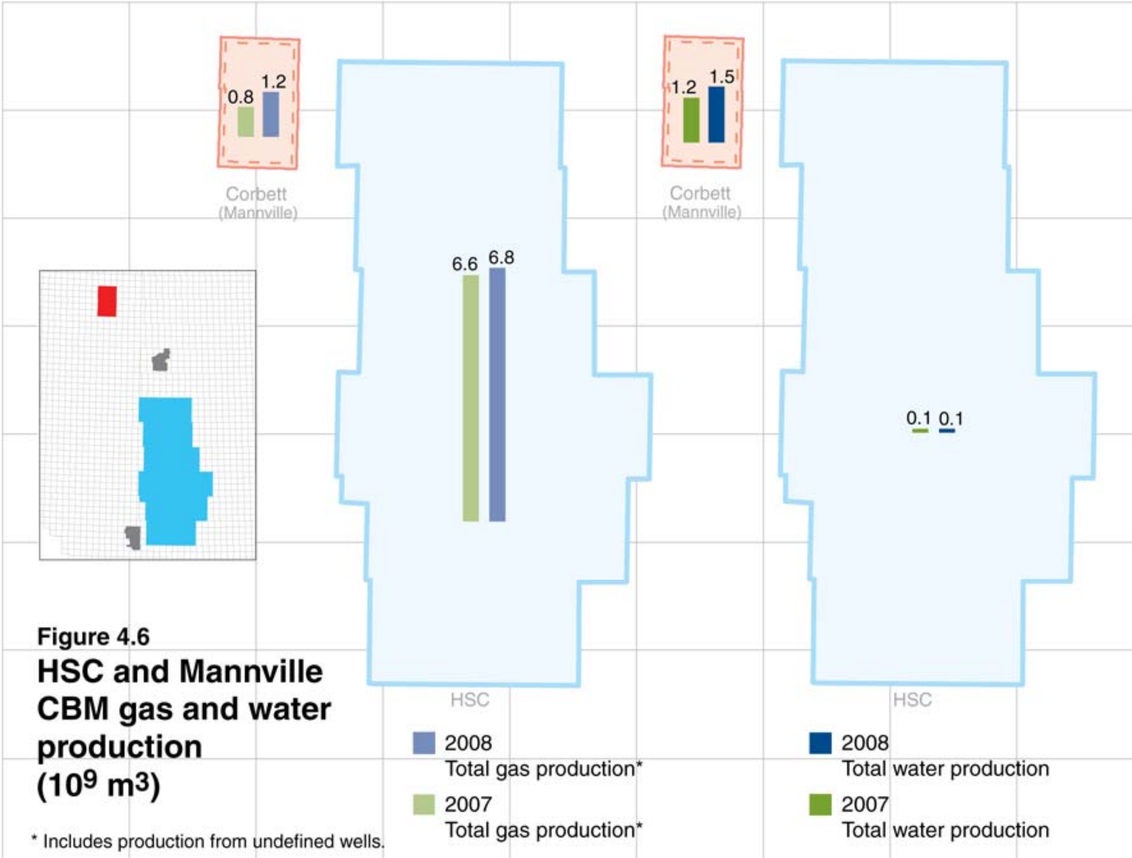


Figure 4.6
HSC and Mannville CBM gas and water production (10^9 m^3)

Based on these assumptions, the ERCB generated the forecast of CBM production to 2018, as shown in **Figure 4.7**. From 2003 to 2006, recognized CBM production experienced a steep incline because of the high number of wells drilled and completed in the HSC play area (the "gold rush" of CBM development). Production from CBM wells, including the commingled conventional gas production from hybrid wells, is expected to increase from 8.0 10^9 m^3 in 2008 to 13.1 10^9 m^3 in 2018. This represents the CBM well production contribution of 6 per cent of total Alberta marketable gas production in 2008 growing to about 14 per cent of total Alberta marketable gas production in 2018. Gas production from CBM may be higher than forecast if commercial production of gas from the Mannville coal seams is accelerated.

See Section 5 for a further discussion of Alberta conventional natural gas supply and demand.

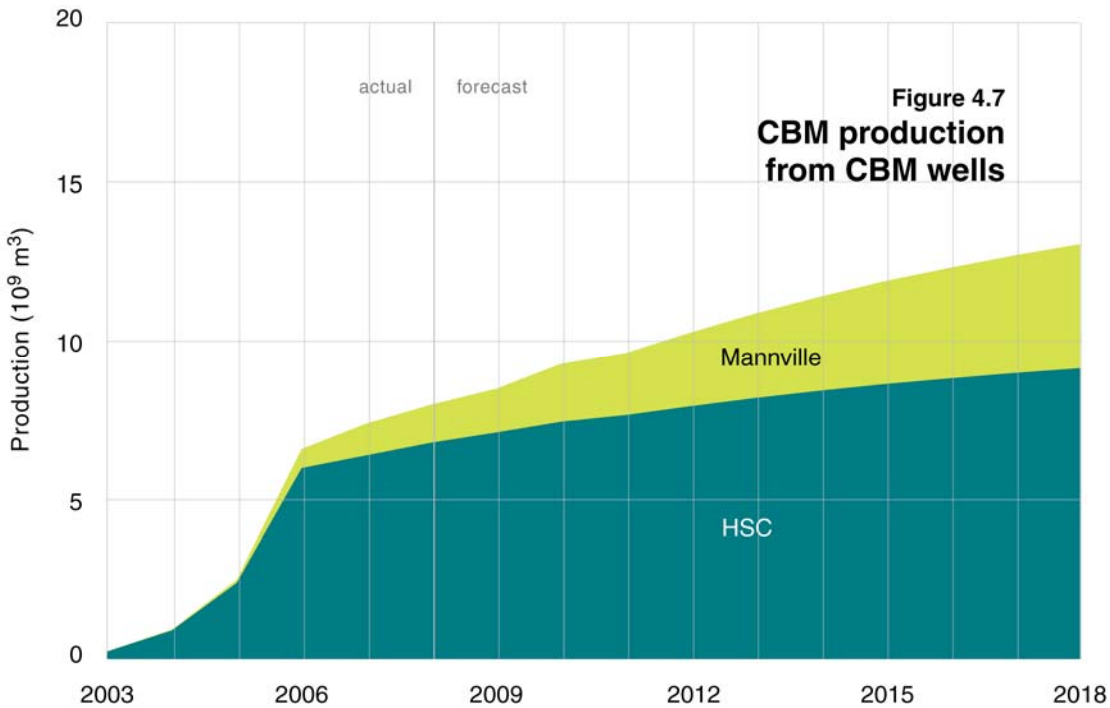


Figure 4.7
CBM production
from CBM wells
actual
forecast
Production (10^9 m^3)
Mannville
HSC
20
15
10
5
0
2003
2006
2009
2012
2015
2018

5 Conventional Natural Gas

Highlights

- Alberta's remaining established conventional gas reserves increased by 2.7 per cent in 2008 to 1098 billion cubic metres.
- Reserve additions as a result of new drilling replaced 81 per cent of conventional gas production.
- Gas well drilling declined 21 per cent in 2008, from 9220 to 7310 wells.
- Alberta produced 125.0 billion cubic metres of conventional marketable gas in 2008, representing a 6.5 per cent decrease from 2007 production levels.

Raw natural gas consists mostly of methane and other hydrocarbon gases, but also contains other nonhydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide. These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component after removal of impurities is about 91 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Ethane and higher paraffin hydrocarbon components, which condense into liquid at different temperature and pressure, are classified as natural gas liquids (NGLs) in this report. When these liquids are removed and metered at the well site, they are reported as condensate or as gas equivalent.

Natural gas volumes can be reported as the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or at 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 at 38.9 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. In this section, gas production excludes those volumes of conventional gas that are produced from wells defined by the ERCB as CBM but that produce both CBM and conventional gas.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

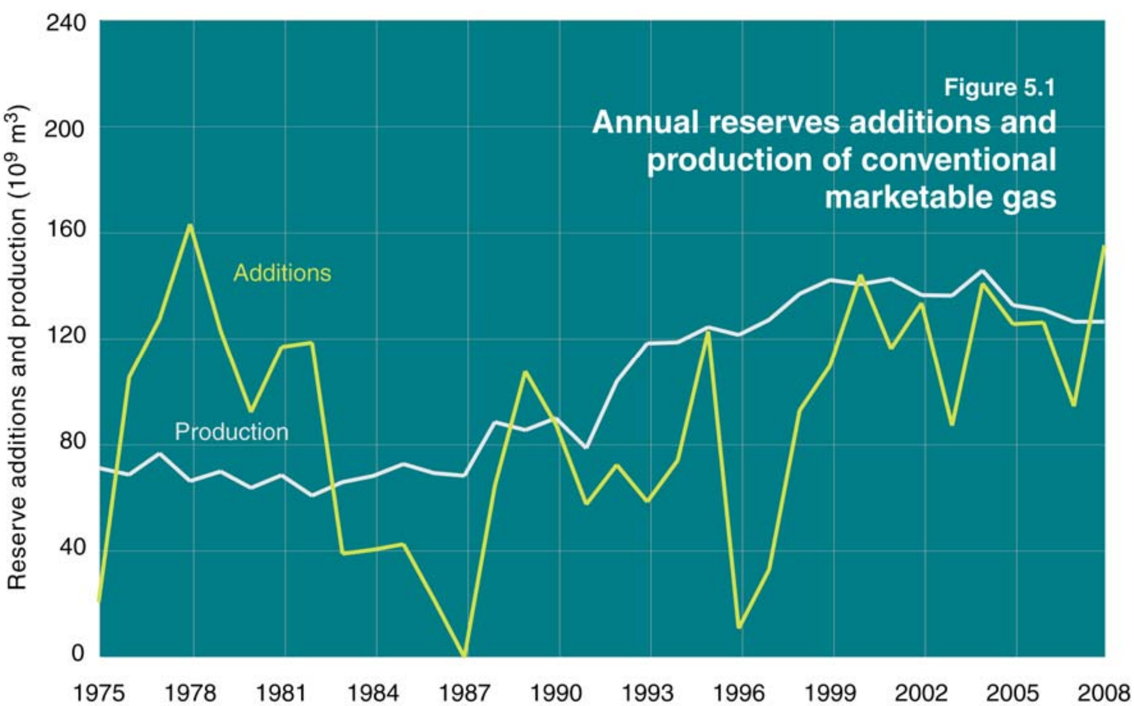
At December 31, 2008, the ERCB estimates the remaining established reserves of marketable gas in Alberta downstream of field plants to be 1098 billion (10^9) m^3, with a total energy content of 42.7 exajoules. 2008 saw the largest positive net revisions to existing reserves since the ERCB began tracking these changes in 1999. The result of this, despite declining gas well drilling, was an increase in remaining established reserves of 28.9 10^9 m^3 since 2007. These reserves include 32.4 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, as discussed in Section 5.1.7. Removal of NGLs results in a 4.1 per cent reduction in the average heating value from 38.9 MJ/m^3 to 37.3 MJ/m^3 for gas downstream of straddle plants. Details of the changes in remaining reserves during 2008 are shown in **Table 5.1**. Total provincial gas in place and raw producible gas reserves for 2008 are 8713 10^9 m^3 and 5942 10^9 m^3 respectively. Using these two values, the average provincial recovery factor is 68.2 per cent. Total initial established marketable reserves is estimated at 5048.7 10^9 m^3, representing an average surface loss of 15.0 per cent. The method used to determine surface loss is discussed in Section 5.1.7.

Table 5.1. Summary of reserves and production changes (10^9 m^3)

	Gross heating value (MJ/m^3)	2008 volume	2007 volume	Change
Initial established reserves		5 048.7	4 893.3	+155.4
Cumulative production		3 950.5	3 823.9	+126.6[a]
Remaining established reserves downstream of field plants				
"as is"	38.9	1 098.2	1 069.3	+28.9
at standard gross heating value	37.4	1 142.3	1 112.2	
Minus liquids removed at straddle plants		32.4	33.5	-1.1
Remaining established reserves "as is"	37.3	1 065.7 (37.8 Tcf)[b]	1 035.5 (36.8 Tcf)[b]	+30.2
at standard gross heating value	37.4	1 062.1	1 031.5	
Annual production	37.4	125.0[c]	133.7	-8.7

[a] May differ from annual production.
[b] Tcf – trillion cubic feet.
[c] Does not include gas from ERCB-defined CBM wells.

Annual reserves additions and the production of natural gas since 1974 are depicted in **Figure 5.1**. It shows that since 1983, reserves additions have failed to keep pace with production. As illustrated in **Figure 5.2**, Alberta's remaining established reserves of marketable gas has decreased by about 41 per cent since 1982.



5.1.2 Annual Change in Marketable Gas Reserves

Figure 5.3 shows the breakdown of annual reserves changes into new pools, development of existing pools, and reassessment of reserves of existing pools from 1999 to 2008. Note that the method used to assess new reserves was revised in 2008 to more accurately reflect the reason for change, and amendments to these numbers were made back to 2003. The revised method means that a portion of reserves additions previously considered as positive reassessments to existing pools are now considered as new reserves. The 155.4 10^9 m^3 increase in initial reserves for 2008 includes the addition of 69.3 10^9 m^3 attributed to new pools booked in 2008, 31.3 10^9 m^3 from the development of existing pools, and a net reassessment of 54.8 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 100.6 10^9 m^3, replacing 81 per cent of Alberta's 2008 production. Historical reserves growth and production data since 1966 are shown in **Appendix B**, **Table B.4**.

During 2008, a review of pools that appeared to have reserves under- or overbooked based on their reserve life index was conducted, as well as a review of a second set of pools that had not been evaluated for several years. Reserves life indices were used to evaluate pools with reserves-to-production ratios over 25 years and less than 2 years, with the majority of the work focusing on reserves with less than 2 years. Total positive revisions to existing pools totalled 118.4 10^9 m^3, while negative revisions totalled 63.6 10^9 m^3. The major reserve changes are summarized below:

- Some 1000 pools were evaluated with low or high reserve life indices, resulting in an overall reserves increase of 23.0 10^9 m^3, or 42 per cent of all reserve revisions for 2008. This increase in reserves was largely a result of infill drilling and completion of previously undeveloped zones.

- The 40 pools with the largest changes listed in **Table 5.2** resulted in a net addition of 11.1 10^9 m^3, or 20 per cent of all revisions for 2008.

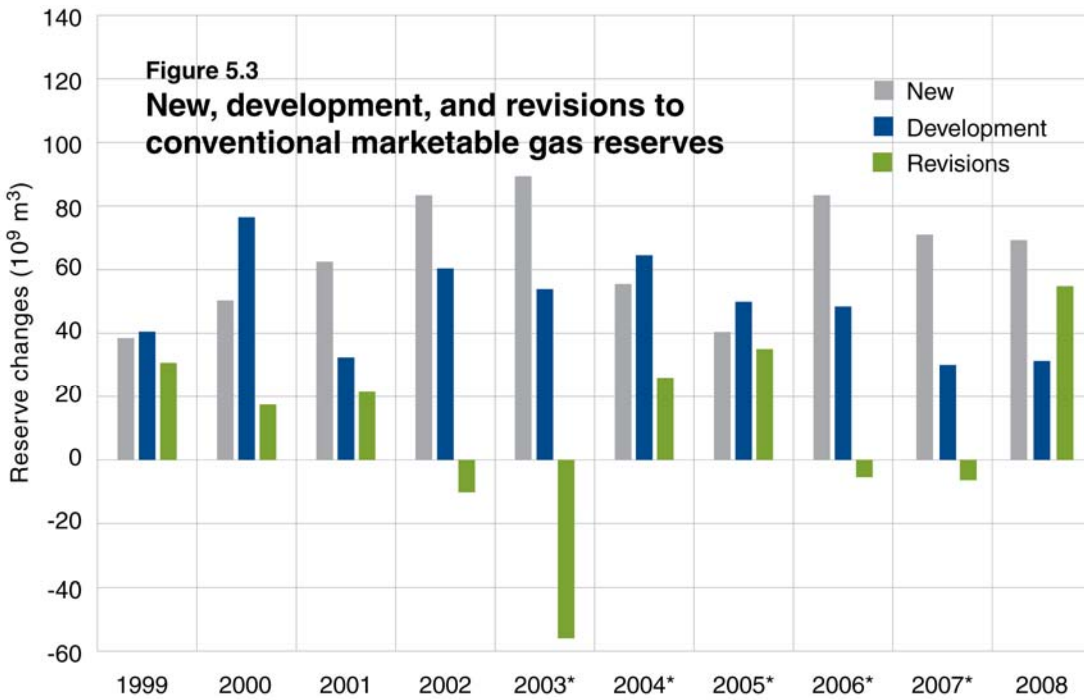


Figure 5.3
New, development, and revisions to conventional marketable gas reserves

*Distribution of changes revised in 2008.

- The review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in a reserves decrease of 2.9 10^9 m^3. This decrease was due largely to reassessments of existing pools.

- Some 500 associated gas pools were reviewed to evaluate the distribution of reserves between the solution gas and associated gas portions of each pool. While many pools were revised, the total net change of these reserves was negligible.

Figure 5.4 illustrates marketable gas reserves growth between 2008 and 2007 by modified Petroleum Services Association of Canada (PSAC) areas. The most significant growth was in Area 2, which accounted for 61 per cent of the total annual increase for 2008. Some pools within Area 2 that contributed to this increase in reserves are the Fir Commingled Pool 001, Medicine Lodge Commingled MFP9502, Pembina Commingled Pool 004, Red Rock Commingled Pool 002, Sundance Commingled MFP9502, and Wilson Creek Commingled Pool 005, for a total reserves increase of 13.3 10^9 m^3.

In 2006, the ERCB created two development entities (DE1 and DE2), which eliminated the need to apply for commingling of certain formations. This has enabled operators to produce reserves from zones that would otherwise have been uneconomic to produce on their own. Further details on development entities are in *Bulletin 2006-38: Implementation of Development Entities for Management of Commingled Production from Two or More Pools in the Wellbore*.

Table 5.2. Major natural gas reserve changes, 2008

Pool	Initial established reserves (10^6 m^3) 2008	Change	Main reasons for change
Armada Southeastern Alberta Gas System (MU)	461	–671	Reevaluation of initial volume in place and recovery factor
Atlee-Buffalo Southeastern Alberta Gas System (MU)	9 314	–765	Reevaluation of initial volume in place and recovery factor
Bantry Southeastern Alberta Gas System (MU)	33 635	+2 776	Development and reevaluation of initial volume in place
Boyer Commingled Pool 001	17 917	–3 466	Reevaluation of initial volume in place and recovery factor
Bruce Commingled MFP9509	4 171	–439	Reevaluation of initial volume in place
Caroline Beaverhill Lake B	1 347	+449	Reevaluation of recovery factor
Caroline Commingled Pool 003	4 417	–569	Reevaluation of initial volume in place and recovery factor
Cavalier Southeastern Alberta Gas System (MU)	2 316	+483	Development and reevaluation of initial volume in place and recovery factor
Chime Commingled Pool 003	1 261	+438	Reevaluation of initial volume in place
Countess Southeastern Alberta Gas System (MU)	60 154	–2 875	Development and reevaluation of initial volume in place
Dunvegan Commingled Pool 002	34 105	–2 034	Reevaluation of recovery factor
Edson Commingled Pool 003	2 694	+680	Development and reevaluation of initial volume in place
Entice Commingled MFP9501	8 490	–720	Reevaluation of initial volume in place
Fenn-Big Valley Commingled MFP9519	2 613	+610	Development and reevaluation of recovery factor
Fir Commingled Pool 001	26 117	+8 361	Reevaluation of initial volume in place
Fox Creek Commingled MFP9510	4 067	+667	Development and reevaluation of initial volume in place
Harmattan-Elkton Rundle B	1 058	–825	Reevaluation of initial volume in place
Herronton Commingled MFP9501	3 596	+461	Reevaluation of initial volume in place
Kaybob South Commingled MFP9510	2 030	+730	Reevaluation of recovery factor
Majorville Southeastern Alberta Gas System (MU)	1 694	–1 015	Reevaluation of initial volume in place and recovery factor

(continued)

Table 5.2. Major natural gas reserve changes, 2008 (concluded)

Pool	Initial established reserves (10^6 m^3) 2008	Change	Main reasons for change
Marten Hills Commingled Pool 001	29 692	+950	Reevaluation of initial volume in place
Medicine Hat Southeastern Alberta Gas System (MU)	156 557	–1 376	Reevaluation of initial volume in place
Medicine Lodge Commingled MFP9502	5 172	+840	Development and reevaluation of initial volume in place
Minnehik-Buck Lake Pekisko A	23 220	+450	Reevaluation of initial volume in place
Nevis Commingled MFP9504	4 275	+935	Development and reevaluation of initial volume in place and recovery factor
Newell Southeastern Alberta Gas System (MU)	2 660	+459	Reevaluation of initial volume in place and recovery factor
Pembina Commingled MFP9505	4 053	+481	Reevaluation of initial volume in place and recovery factor
Pembina Commingled Pool 004	12 144	+784	Development and reevaluation of initial volume in place
Pendant D'Oreille Commingled Pool 002	4 750	+535	Reevaluation of initial volume in place
Pine Creek Commingled Pool 009	13 204	+601	Development and reevaluation of initial volume in place
Princess Southeastern Alberta Gas System (MU)	30 642	–447	Development and reevaluation of initial volume in place
Provost Commingled Pool 001	45 706	–2 832	Reevaluation of initial volume in place
Red Rock Commingled Pool 002	7 655	+1 584	Development and reevaluation of initial volume in place
Sinclair Commingled Pool 021	10 365	–1 084	Reevaluation of recovery factor
Sousa MFP8528 Bluesky	3 066	+773	Development and reevaluation of initial volume in place
Sundance Commingled MFP9502	13 745	+796	Development and reevaluation of initial volume in place
Viking-Kinsella Commingled MFP9509	35 900	+1 950	Reevaluation of initial volume in place
Wayne-Rosedale Commingled Pool 001	11 828	+3 171	Reevaluation of initial volume in place
Westerose South Banff C	160	–603	Reevaluation of initial volume in place
Wilson Creek Commingled Pool 005	5 431	+895	Reevaluation of initial volume in place

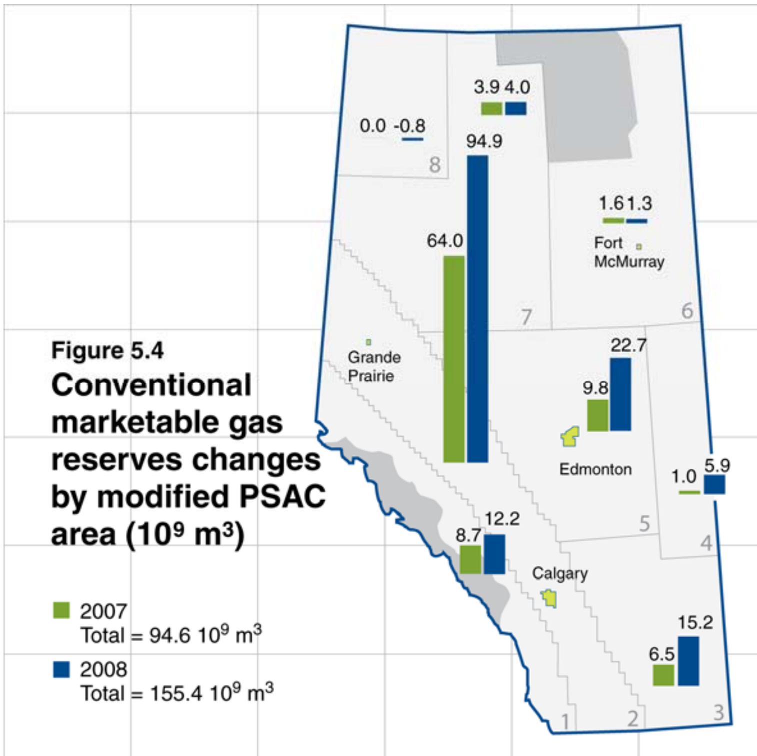


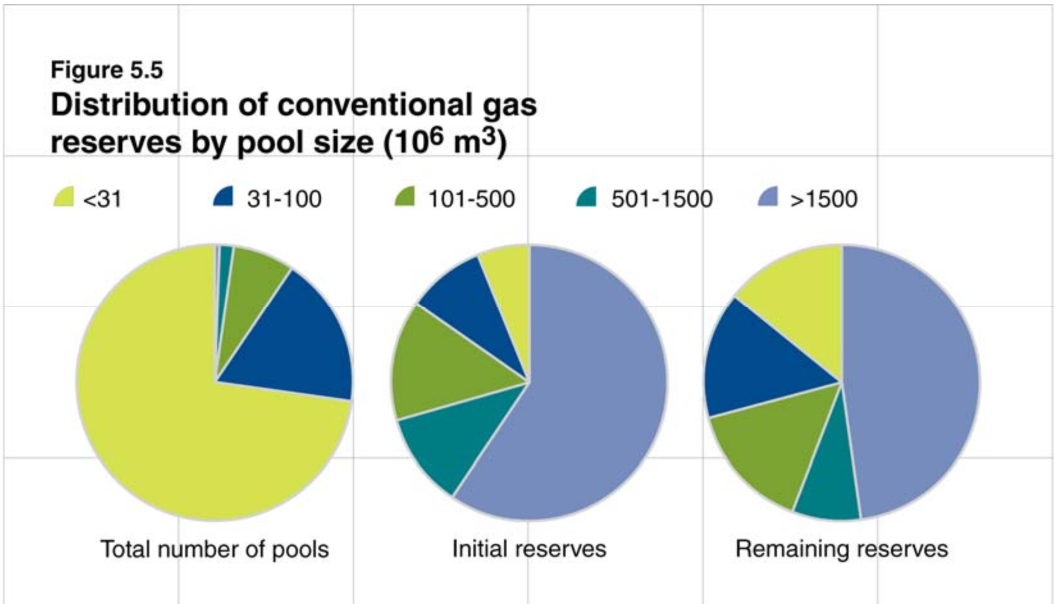
Figure 5.4 Conventional marketable gas reserves changes by modified PSAC area (10^9 m^3)

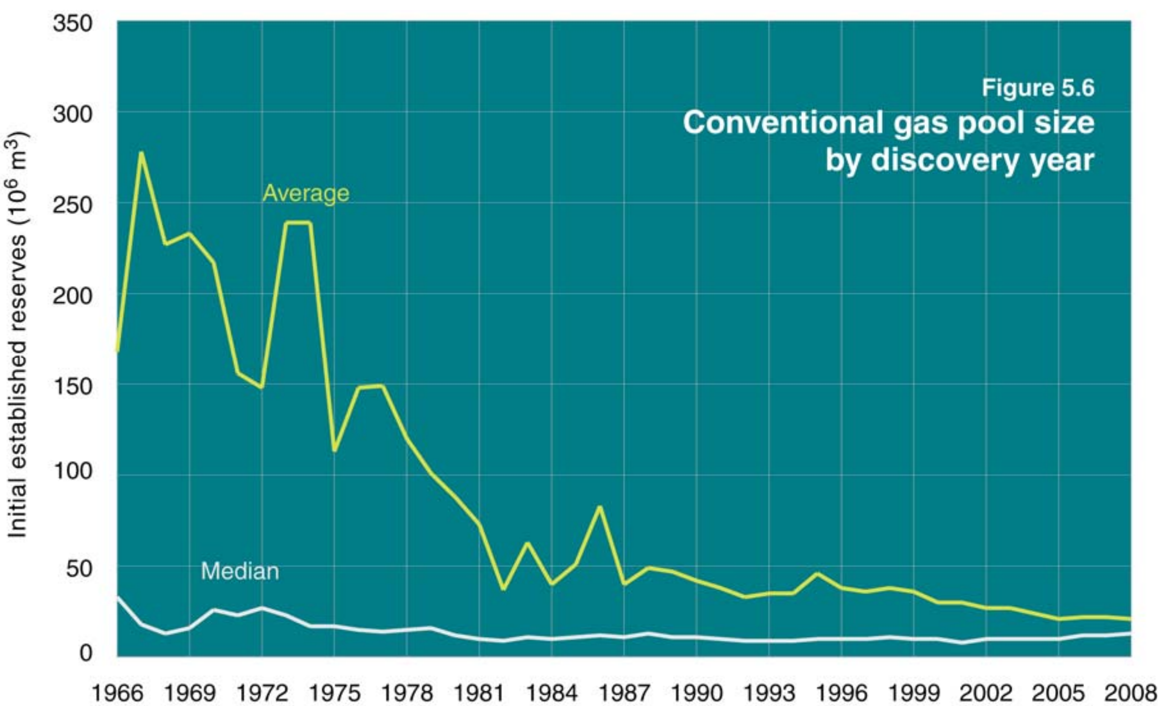
5.1.3 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table 5.3**. For the purposes of this table, commingled pools are considered as one pool and multifield pools are considered on a field basis. The data show that pools with reserves of 30 million (10^6) m^3 or less, while representing 72.6 per cent of all pools, contain only 14 per cent of the province's remaining marketable reserves. Similarly, the largest pools (pools with reserves greater than 1500 10^6 m^3), while representing only 1 per cent of all pools, contain 48 per cent of the remaining reserves. **Figure 5.5** shows by percentage and by size distribution the total number of pools, initial reserves, and remaining reserves, as listed in **Table 5.3**. **Figure 5.6** depicts natural gas pool size by discovery year since 1965 and illustrates that the median pool size has remained fairly constant at about 11 10^6 m^3 for many years, while the average size declined significantly from about 300 10^6 m^3 in 1965 to 45 10^6 m^3 in 1996 and has continued to decline to about 21 10^6 m^3 in 2008.

Table 5.3. Distribution of natural gas reserves by pool size, 2008

Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
3000+	215	0.5	2 645	52	459	42
1501-3000	163	0.3	343	7	67	6
1001-1500	167	0.4	205	4	36	3
501-1000	535	1.1	365	7	59	5
101-500	3 509	7.4	721	14	164	15
31-100	8 495	17.8	450	9	165	15
Less than 31	34 681	72.6	319	6	148	14
Total	44 138	100.0	4 893	100	1 069	100

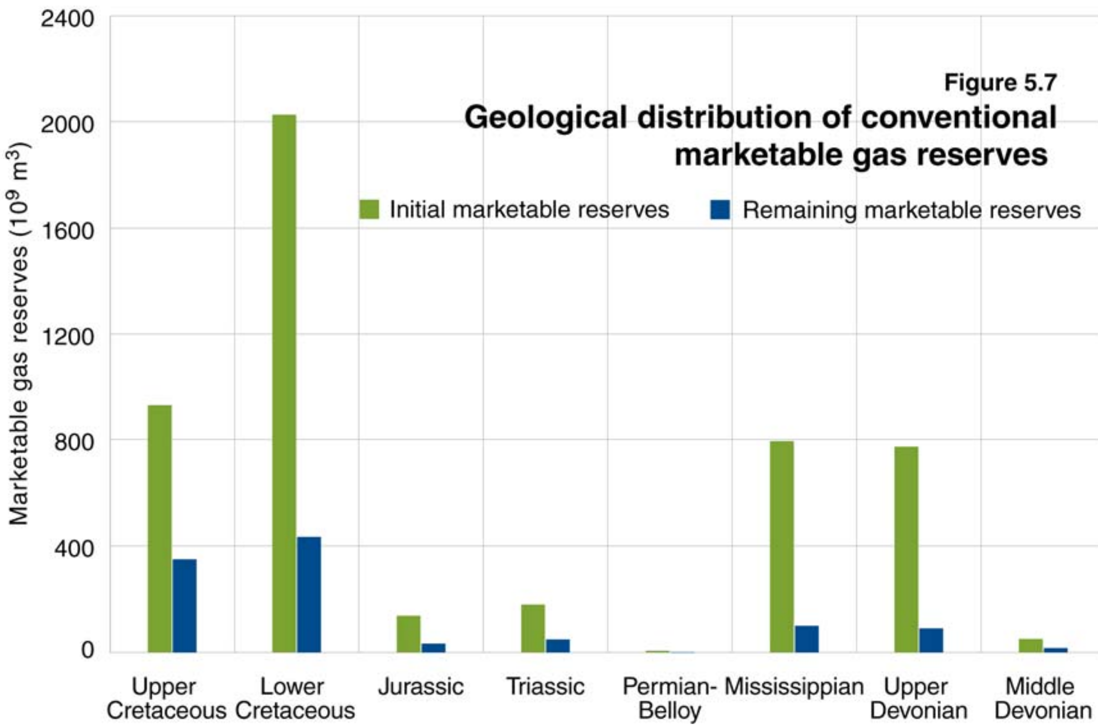




5.1.4 Geological Distribution of Reserves

The distribution of reserves by geological period is shown in **Figure 5.7**. The Upper and Lower Cretaceous period accounts for some 73 per cent of the province's remaining established reserves of marketable gas and is important as a source of future natural gas.

The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 29 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 19 per cent, and the Mississippian Rundle, with 6 per cent. Together, these strata contain 54 per cent of the province's remaining established reserves. The percentages of remaining reserves in these geological strata have remained fairly constant over the last five years.



5.1.5 Reserves of Natural Gas Containing Hydrogen Sulphide

Natural gas that contains greater than 0.01 per cent hydrogen sulphide (H_2S) is referred to as sour in this report. As of December 31, 2008, sour gas accounts for some 20 per cent (221 10^9 m^3) of the province's total remaining established reserves and about 23 per cent of raw natural gas production in 2008. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2008 is 8.6 per cent.

The distribution of reserves for sweet and sour gas (**Table 5.4**) shows that 155 10^9 m^3, or about 70 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 5.8** indicates that the proportion of remaining marketable reserves of sour to sweet gas since 1984 has remained fairly constant, between 20 and 25 per cent of the total. The distribution of sour gas reserves by H_2S content is shown in **Table 5.5** and indicates that 43 10^9 m^3, or 20 per cent, of sour gas contains H_2S concentrations greater than 10 per cent, while 53 per cent (116 10^9 m^3) contains concentration of less than 2 per cent.

5.1.6 Reserves of Gas Cycling Pools

Gas cycling pools are gas pools rich in liquids into which dry gas is reinjected to maintain reservoir pressure and maximize liquid recovery. These pools contain 21.1 10^9 m^3 (1.9 per cent) of remaining established reserves. The four largest pools are Caroline Beaverhill Lake A, Harmattan East Commingled Pool 001, Valhalla MFP8524 Halfway, and Waterton Rundle-Wabamun A, which together account for 62.9 per cent of all remaining reserves of gas cycling pools. The initial energy in place, recovery factor, and surface loss factor (both factors on an energy basis), as well as the initial marketable energy for each pool, are listed in **Appendix B**, **Table B.5**. Reserves of major gas cycling pools are tabulated on both energy content and a volumetric basis. The table also lists raw and marketable gas heating values used to convert from a volumetric to an energy basis. The volumetric reserves 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**).

Table 5.4. Distribution of sweet and sour gas reserves, 2008

Type of gas	Marketable gas (10^9 m^3)			Percentage	
	Initial established reserves	Cumulative production	Remaining established reserves	Initial established reserves	Remaining established reserves
Sweet					
Associated & solution	592	484	107	12	10
Nonassociated	2 801	2 031	769	55	70
Subtotal	3 393	2 516	877	67	80
Sour					
Associated & solution	490	425	65	10	6
Nonassociated	1 166	1 010	155	23	14
Subtotal	1 656	1 435	221	33	20
Total	5 049 (179)[b]	3 950 (140)[b]	1 098[a] (39.0)[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.

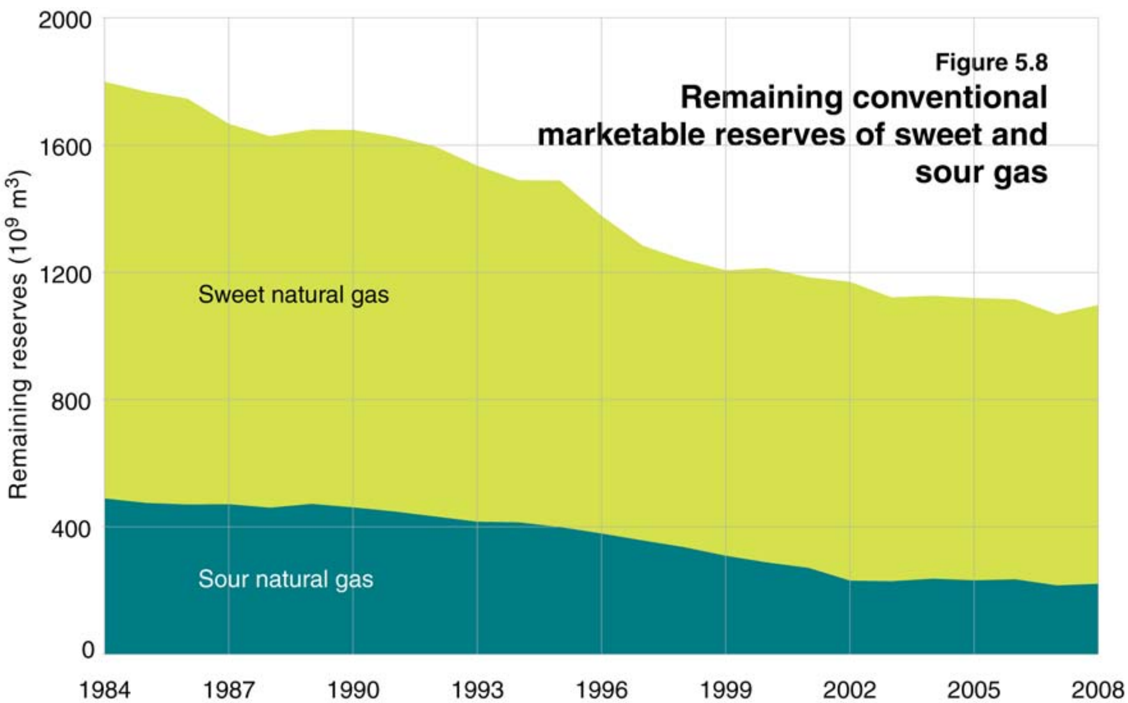


Table 5.5. Distribution of sour gas reserves by H_2S content, 2008

H_2S content in raw gas (%)	Initial established reserves (10^9 m^3) Associated & solution	Initial established reserves (10^9 m^3) Nonassociated	Remaining established reserves (10^9 m^3) Associated & solution	Remaining established reserves (10^9 m^3) Nonassociated	Total	%
Less than 2	362	410	52	64	116	53
2.00-9.99	88	396	8	53	61	28
10.00-19.99	30	207	4	20	24	11
20.00-29.99	11	50	1	8	9	4
Over 30	0	101	0	10	10	5
Total	490	1 166	65	155	220	100
Percentage	30	70	26	74		

5.1.7 Reserves and Accounting Methodology for Gas

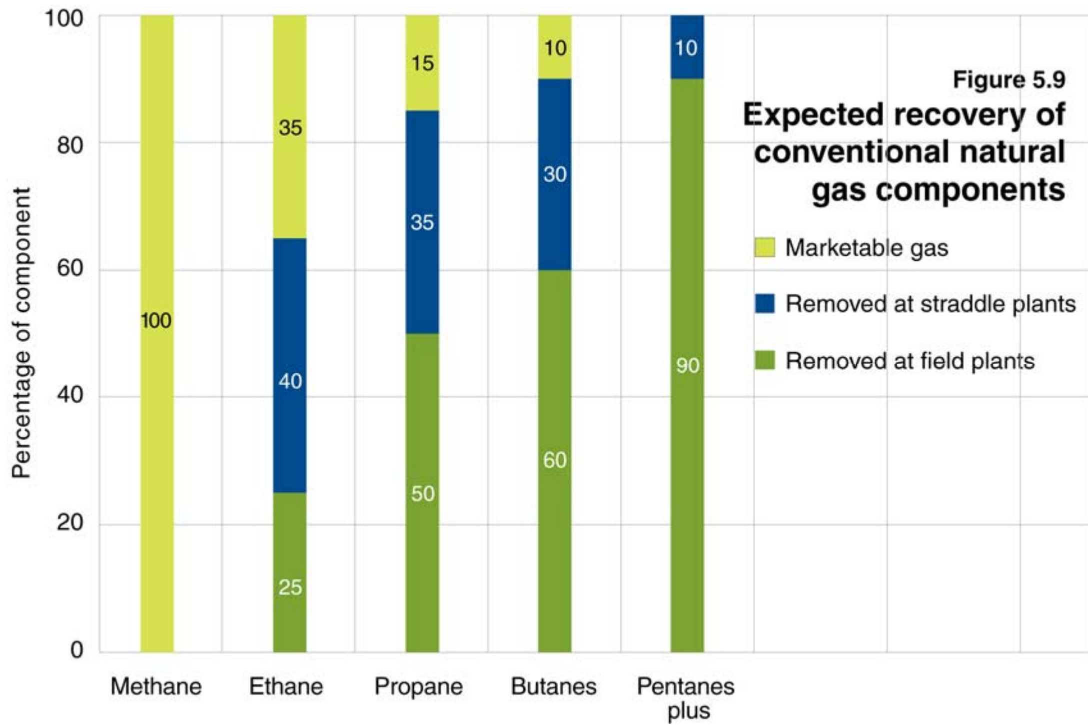
A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools are on CD (see **Appendix C**), which is available from ERCB Information Services.

The process of determining reserves depends on geological, engineering, and economic considerations. The initial estimates contain some uncertainty, which decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserve estimates are normally based on volumetric calculation, which uses bulk rock volume (based on isopach maps derived from geological and geophysical well log data) and initial reservoir parameters to estimate gas in place at reservoir conditions. For single-well pools, drainage area assignments for gas pools are automatically set using criteria outlined in the ERCB's internal report *Alberta Single-Well Gas Pool Drainage Area Study* (December 2004). Drainage areas range from 250 hectares (ha) for gas wells producing from regional sands with good permeability to 64 ha or less. The smaller areas are assigned to wells producing from low-permeability formations (less than 1 millidarcy) or geological structures limited in areal extent.

Converting gas volume in place to specified standard conditions at the surface requires knowledge of reservoir pressure, temperature, and 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 its 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 methods involving analysis of 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 on decline for many years. When combined with an estimate of the in-place resource, it also provides a practical real-life estimation of the pool's recovery factor.

The procedures described above generate an estimate for initial established reserves of raw gas. The raw natural gas reserve 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, as shown in **Figure 5.9**. 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 in pools where the raw gas 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 reserve 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.



For about 80 per cent of Alberta's marketable gas, 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 the removal of these liquids cannot be attributed 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 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 some 32.4 10^9 m^3 of liquid-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 1098.2 10^9 m^3 to 1065.6 10^9 m^3 and the thermal energy content from 42.7 to 39.7 exajoules (10^9 joules).

Figure 5.9 also 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.

5.1.8 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.

5.1.9 Ultimate Potential

In March 2005, the 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 Boards adopted the medium case representing an ultimate potential of 6276 10^9 m^3 as-is volume (223 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 5.10** shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth to 2008 equals 5.2 trillion (10^{12}) m^3. **Figure 5.11** plots production and remaining established reserves of marketable gas compared to the estimate of ultimate potential.

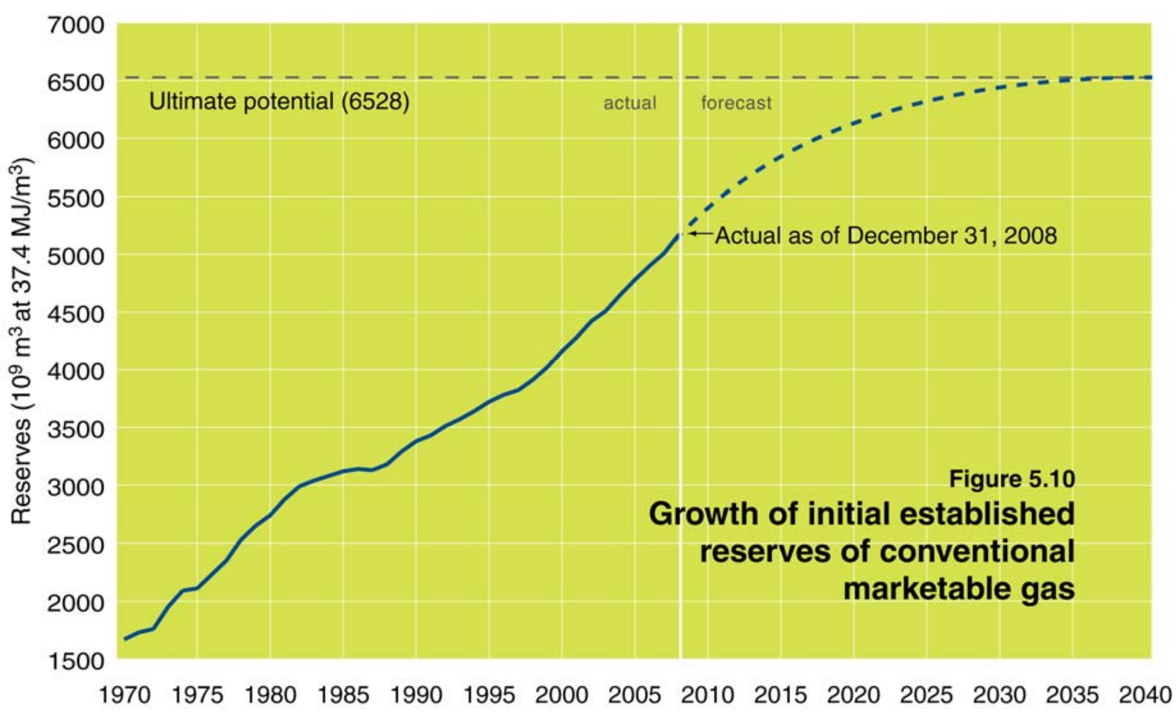


Figure 5.10
Growth of initial established reserves of conventional marketable gas

Table 5.6 provides details on 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 5049 10^9 m^3, or 80 per cent of the ultimate potential of 6276 10^9 m^3 (as-is volumes) has been discovered as of year-end 2008. This leaves 1227 10^9 m^3, or 20 per cent, as yet-to-be-discovered reserves. Cumulative

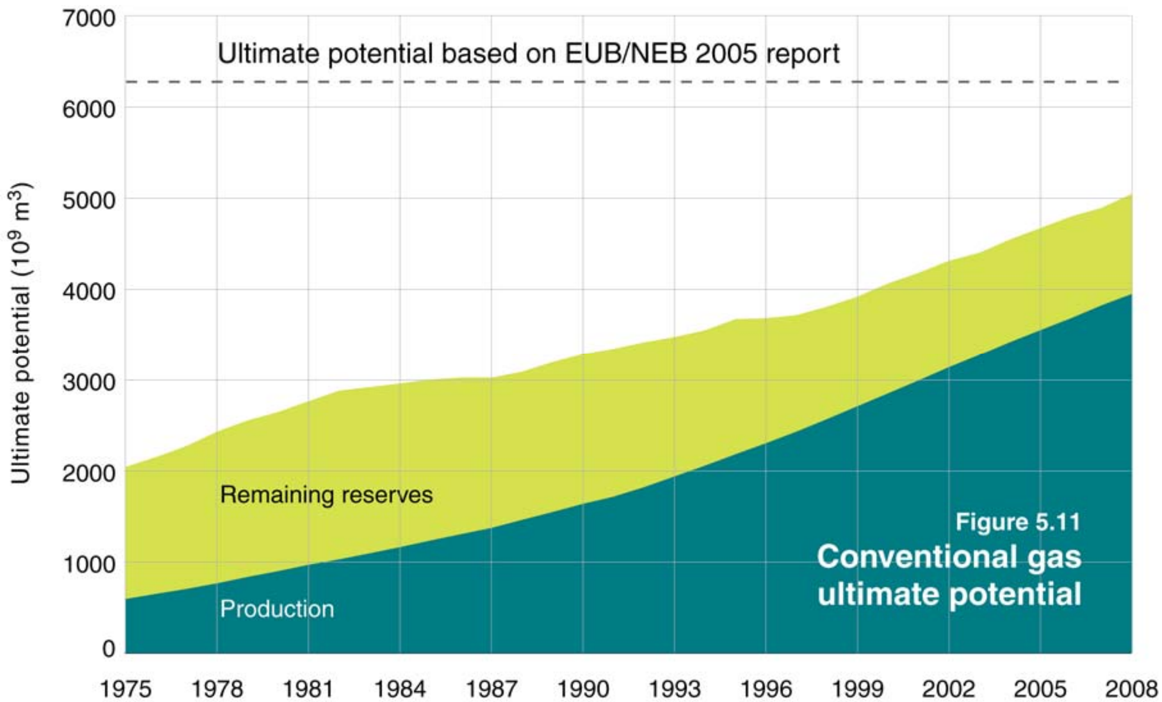


Figure 5.11
Conventional gas ultimate potential

Table 5.6. Remaining ultimate potential of marketable gas, 2008 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	at 37.4 MJ/m^3
Yet to be established		
Ultimate potential	6 276	6 528
Minus initial established	–5 049	–5 170
	1 227	1 358
Remaining established		
Initial established	5 049	5 170
Minus cumulative production	–3 951	–4 109
	1 098	1 061
Remaining ultimate potential		
Yet to be established	1 227	1 358
Plus remaining established	+1 098	+1 061
	2 325	2 419

production of 3951 10^9 m^3 at year-end 2008 represents 63 per cent of the ultimate potential, leaving 2325 10^9 m^3, or 37 per cent, available for future use.

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure 5.12**. It shows that the Western Plains (Area 2) contains about 40 per cent of the remaining established reserves and 28 per cent of the yet-to-be-established reserves. Although the majority of gas wells are being drilled in the Southern Plains (Areas 3, 4, and 5), **Figure 5.12** shows that based on the EUB/NEB 2005 Report, Alberta natural gas supplies will continue to depend on significant new discoveries in the Western Plains.

Figure 5.13 shows by geological period the discovered and ultimate potential gas in place for year-end 2005 (EUB/NEB 2005 Report). It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous.

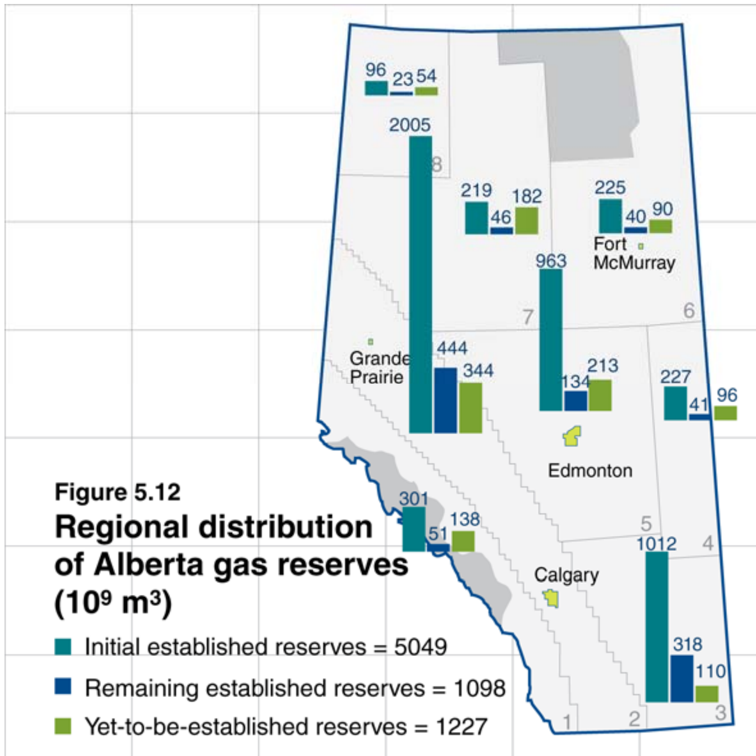


Figure 5.12
Regional distribution of Alberta gas reserves (10^9 m^3)

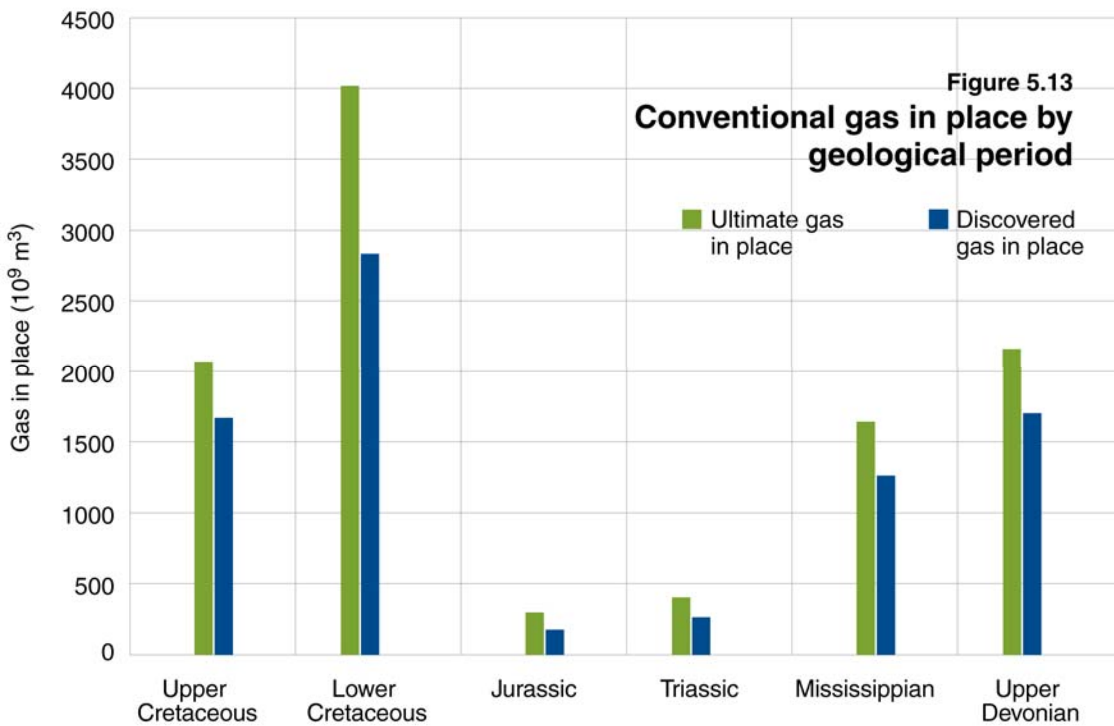


Figure 5.13
Conventional gas in place by geological period

5.2 Supply of and Demand for Conventional Natural Gas

In projecting natural gas production, the ERCB considers three components: expected production from existing gas wells, expected production from new gas well connections and new zone connections from existing wells (excluding production from a commingled zone), 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 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 environmental factors that influence natural gas consumption in the province.

5.2.1 Natural Gas Supply

Alberta produced 125.0 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its conventional gas and oil wells in 2008, a decrease of 6.5 per cent from last year. As noted in Section 4, Alberta also produced 8.0 10^9 m^3 of CBM. CBM production increased by 8 per cent in 2008 over 2007 levels of 7.4 10^9 m^3. Overall, total natural gas production decreased to 133.0 10^9 m^3 in 2008, down by 5.3 per cent from 140.5 10^9 m^3 in 2007.

Major factors affecting Alberta natural gas production are natural gas prices and their volatility, drilling activity, the location of Alberta’s reserves, the production characteristics of today’s wells, and market demand. In 2008, natural gas prices rose significantly in the first half of the year, following crude oil price increases, and fell in August in tandem with crude oil prices. Natural gas prices in Alberta averaged $7.47 per gigajoule (GJ) in 2008, reaching a high of $9.84/GJ in July and a low of $6.25/GJ in November. The 8 per cent growth in U.S. gas production between 2007 and 2008, in conjunction with weakening demand, significantly contributed to steadily weakening natural gas prices through 2008. These factors, combined with high drilling and development costs, resulted in decreased investment in Alberta’s conventional oil and gas development, which led to reduced levels of conventional gas drilling activity and declining natural gas production in 2008. The number of conventional gas wells drilled in 2008 declined by 21 per cent over the previous year, falling to levels not seen since the late 1990s.

The conventional marketable natural gas production volumes for 2008 stated in **Table 5.7** have been calculated based on “Supply and Disposition of Marketable Gas” in *ST3: Alberta Energy Resource Industries Monthly Statistics.*

Table 5.7. Marketable conventional natural gas volumes (10^9 m^3)

Marketable conventional gas production	2008
Total gas production	157 666.3
Minus production from CBM wells	-8 010.1
Total conventional gas production	149 656.6
Minus storage withdrawals	-5 582.9
Raw gas production	144 073.7
Minus injection total	-8 564.0
Net raw gas production	135 509.7
Minus processing shrinkage – raw	-8 444.2
Minus flared – raw	-539.8
Minus vented – raw	-468.7
Minus fuel – raw	-12 162.7
Plus storage injections	6 334.1
Calculated marketable gas production at as-is conditions	120 228.0
Calculated marketable gas production at 37.4 MJ/m^3	125 037.1

The number of successful gas wells drilled in Alberta in the last two years is shown by geographical area (modified PSAC area) in **Figure 5.14**. In 2008, some 7310 conventional natural gas wells were drilled in the province, a decrease of 21 per cent from 2007 levels. The drilling focus in recent years has been heavily weighted towards the shallow gas plays in Area 3 (Southeastern Alberta) due to the lower risk, lower cost of drilling, and short tie-in times. In 2008, 49 per cent of all conventional natural gas wells were drilled in this area.

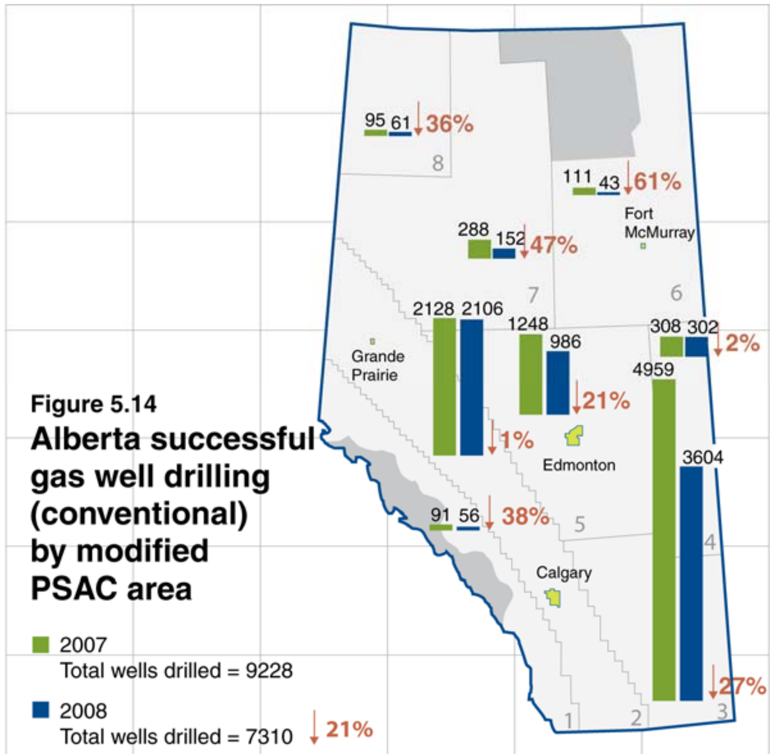
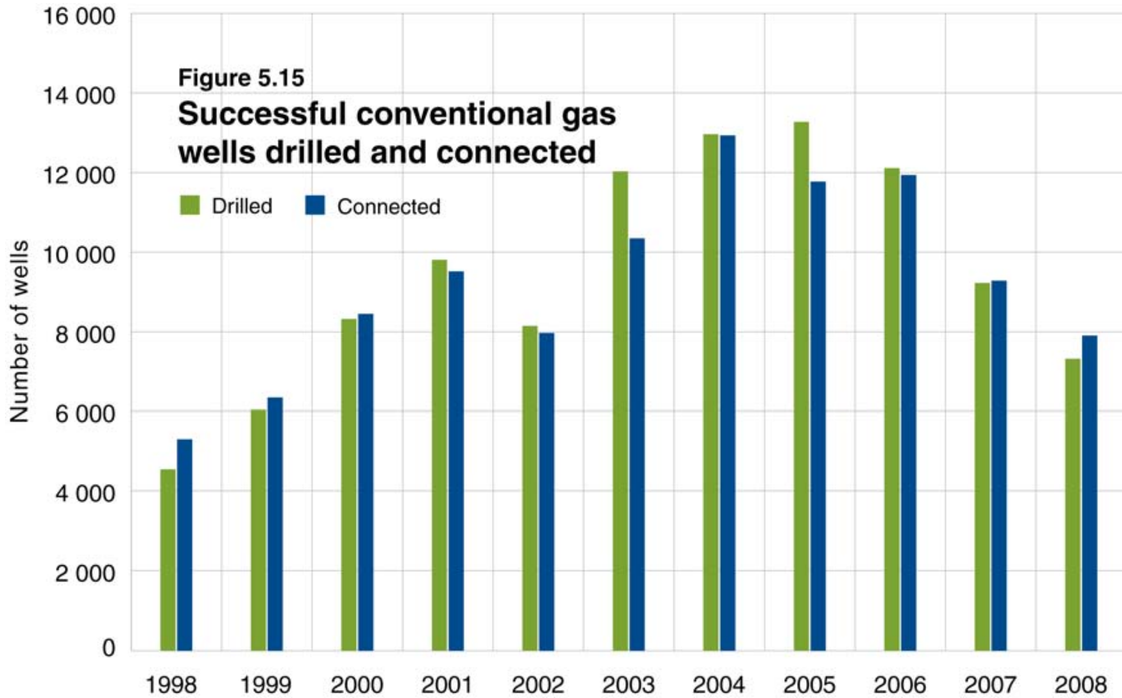


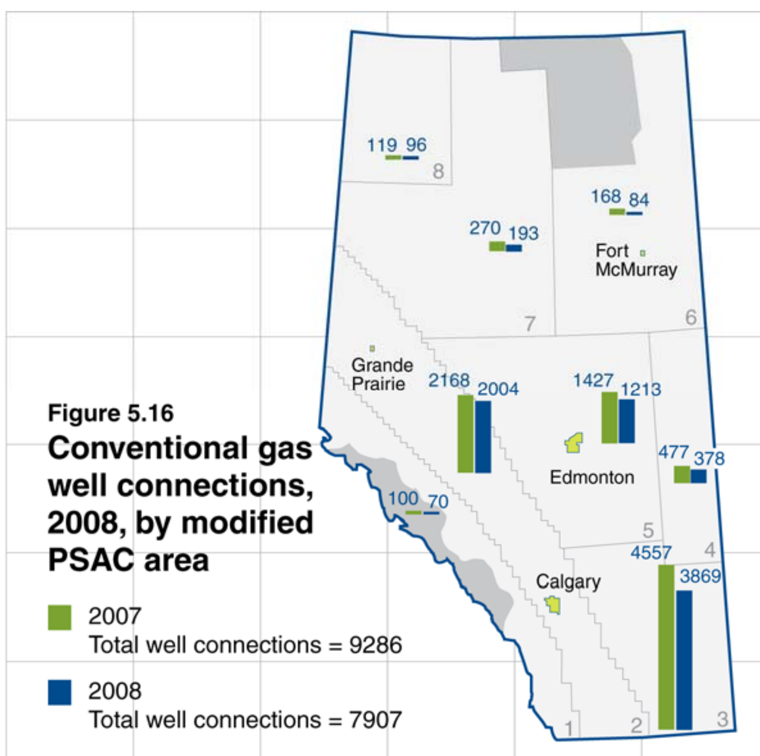
Figure 5.14
Alberta successful gas well drilling (conventional) by modified PSAC area

Drilling levels in 2008 were down in all areas of the province, with Area 2 (Western Plains) experiencing the least impact on well activity levels. Note that the gas well drilling numbers represent wellbores that contain one or more geological occurrence capable of producing natural gas.

The number of successful natural gas wells drilled in Alberta from 1998 to 2008 is shown in **Figure 5.15**, along with the number of wells connected (placed on production) in each year. Both of these numbers are used as indicators of industry activity and future production. The definition of a gas well connection differs from that of a drilled well. While gas well drilling levels represent wellbores, well connections refer to geological (producing) occurrences within a well, and there may be more than one per well. As commingling of gas zones increases, there will be less difference between the number of successful wells drilled and the numbers of new well connections (less segregated production from single wells).

The number of natural gas wells connected in a given year historically tends to follow natural gas well drilling activity, indicating that most natural gas wells are connected shortly after being drilled. In 2008, the number of new well connections was 8 per cent greater than the number of wells drilled due to time delays and recompletions in additional well zones. The distribution of natural gas well connections and the initial operating day rates of the connected wells in 2008 are illustrated in **Figures 5.16** and **5.17** respectively.





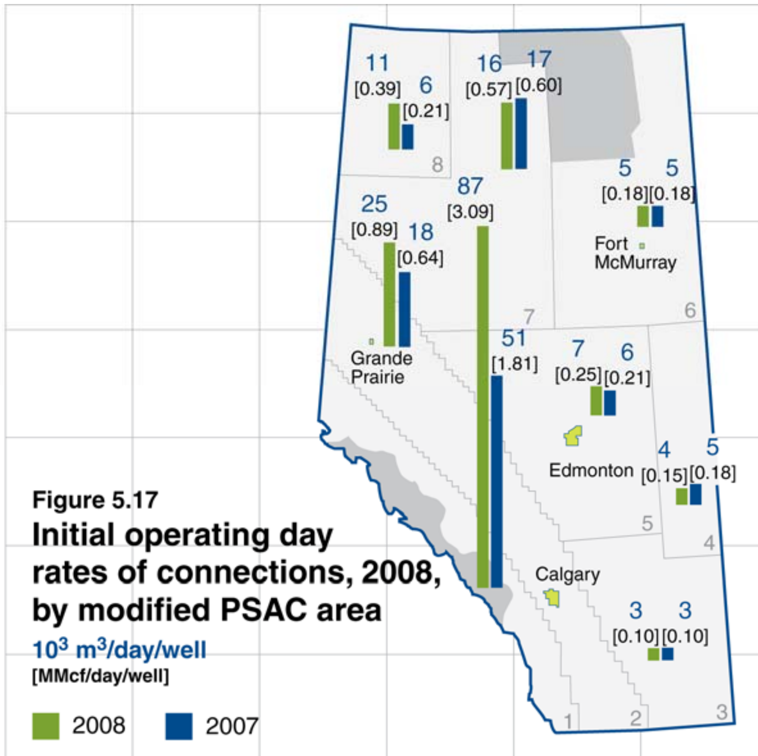
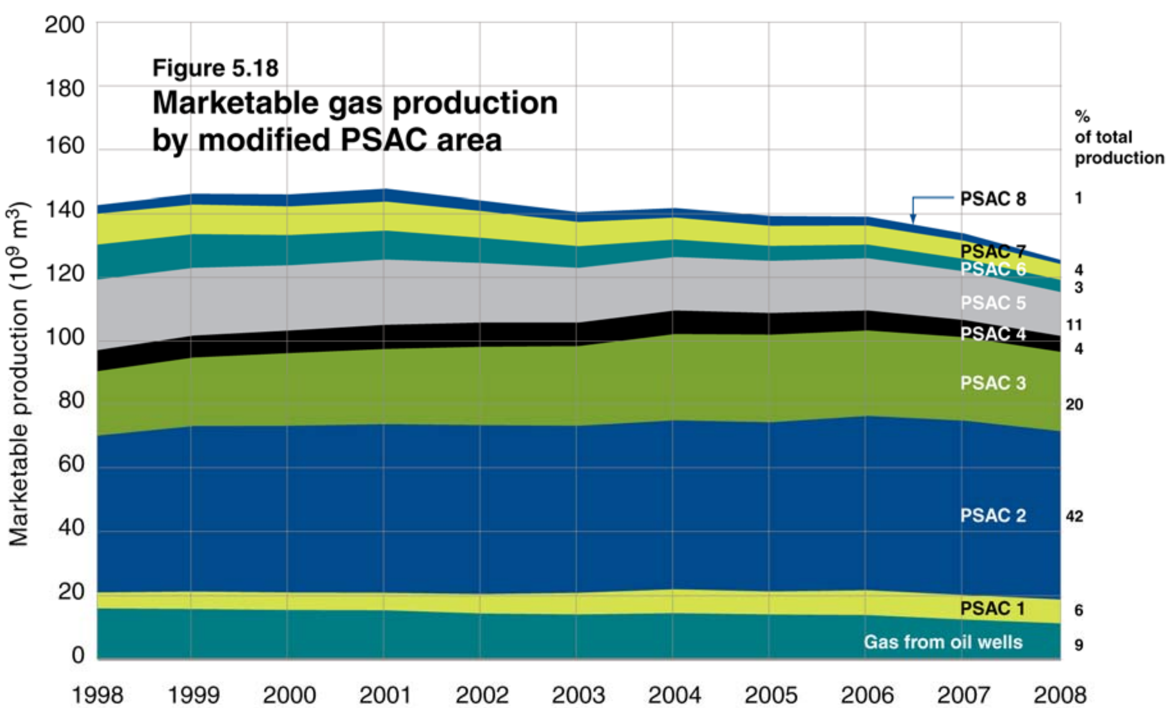
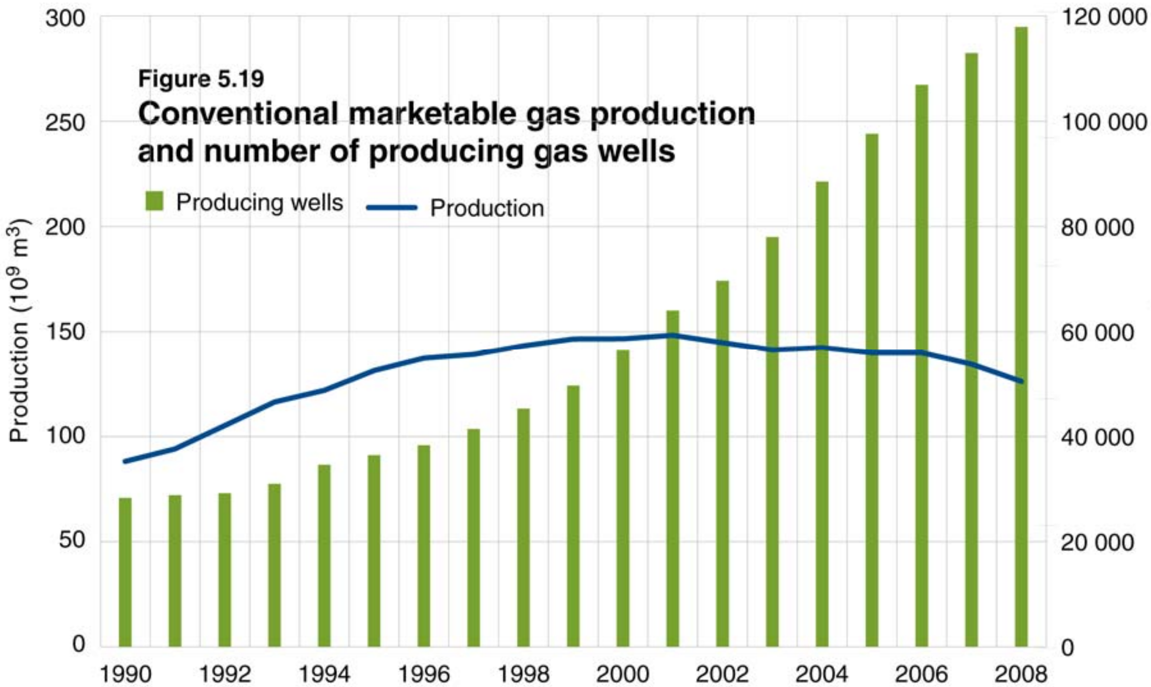
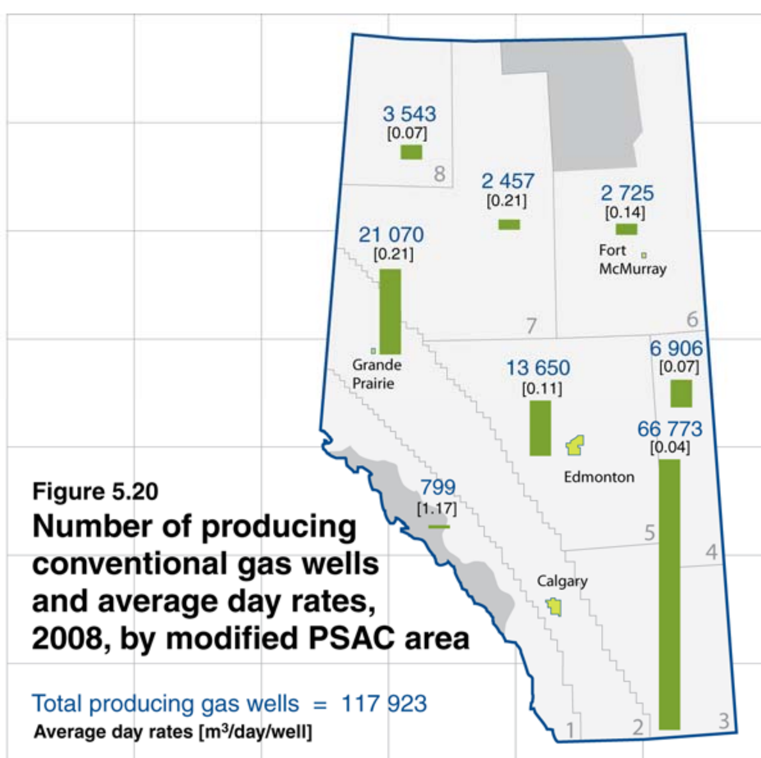


Figure 5.18 illustrates historical gas production from gas wells by geographical area. All areas of the province experienced decreases in production in 2008.

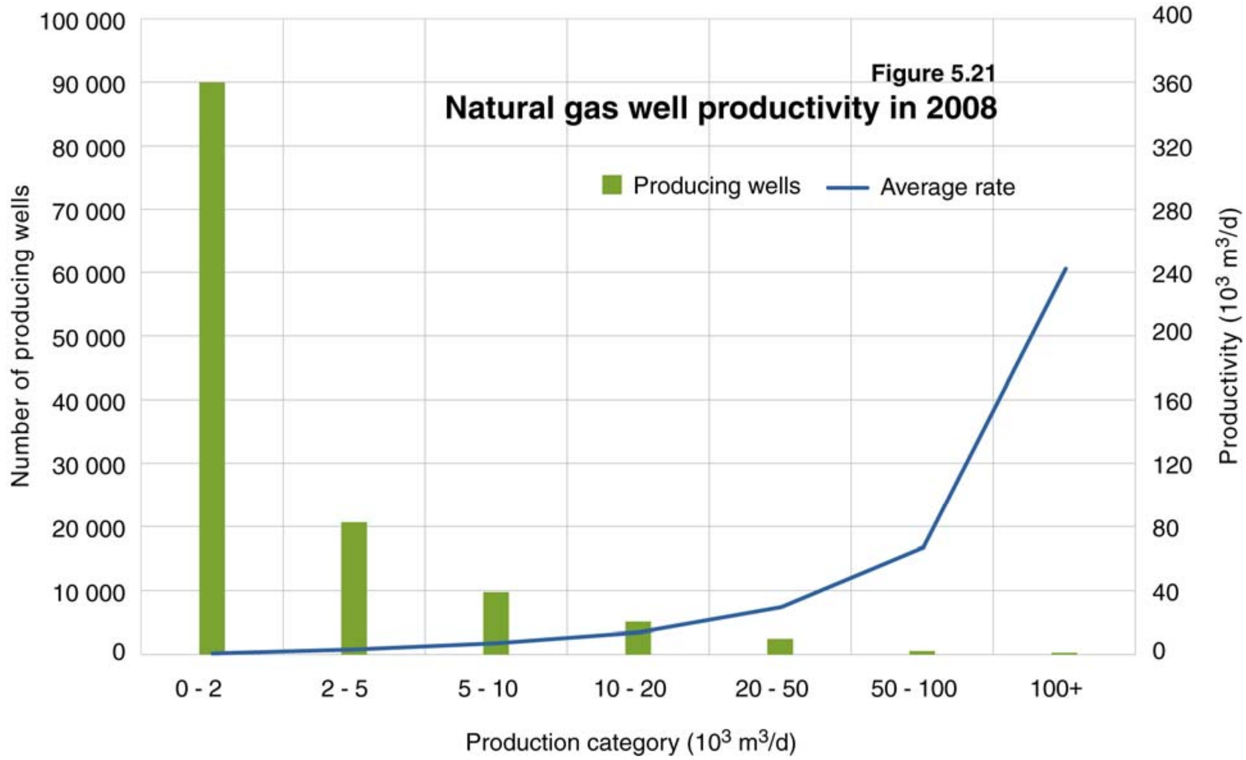


Conventional marketable gas production in Alberta from 1990 to 2008 is shown in **Figure 5.19**, along with the number of gas wells on production in each year. The number of producing gas wells has increased significantly year over year, while gas production has decreased since reaching its peak in 2001. By 2008, the total number of producing gas wells increased to 117 923, from 28 400 wells in 1990. It now takes an increasing number of new gas wells each year to offset production declines in existing wells. **Figure 5.20** illustrates the number of producing gas wells and average well productivity by area.





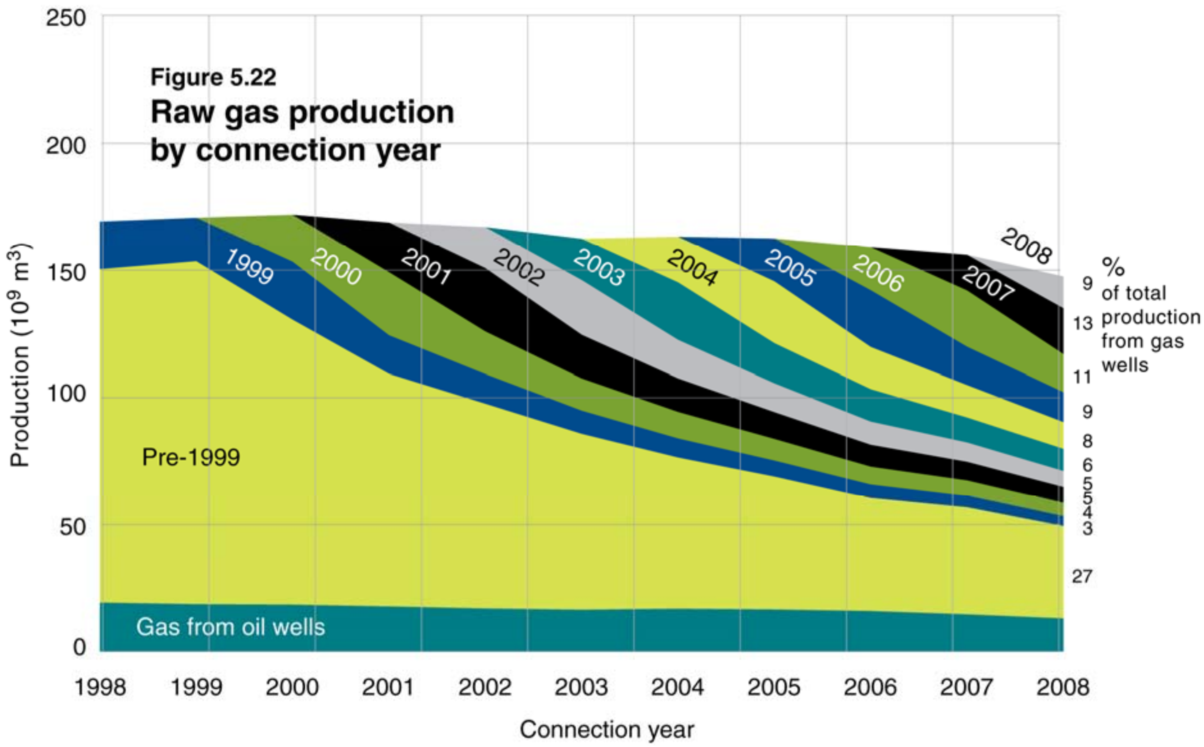
Average gas well productivity has been declining over time. As shown in **Figure 5.21**, about 70 per cent of the operating gas wells produce less than 2 10^3 m^3/d. In 2008, these 90 140 gas wells operated at an average rate of 0.7 10^3 m^3/d per well and produced less than 15 per cent of the total gas production. Less than 1 per cent of the total gas wells produced at rates over 100 10^3 m^3/d but contributed 15 per cent of total production.

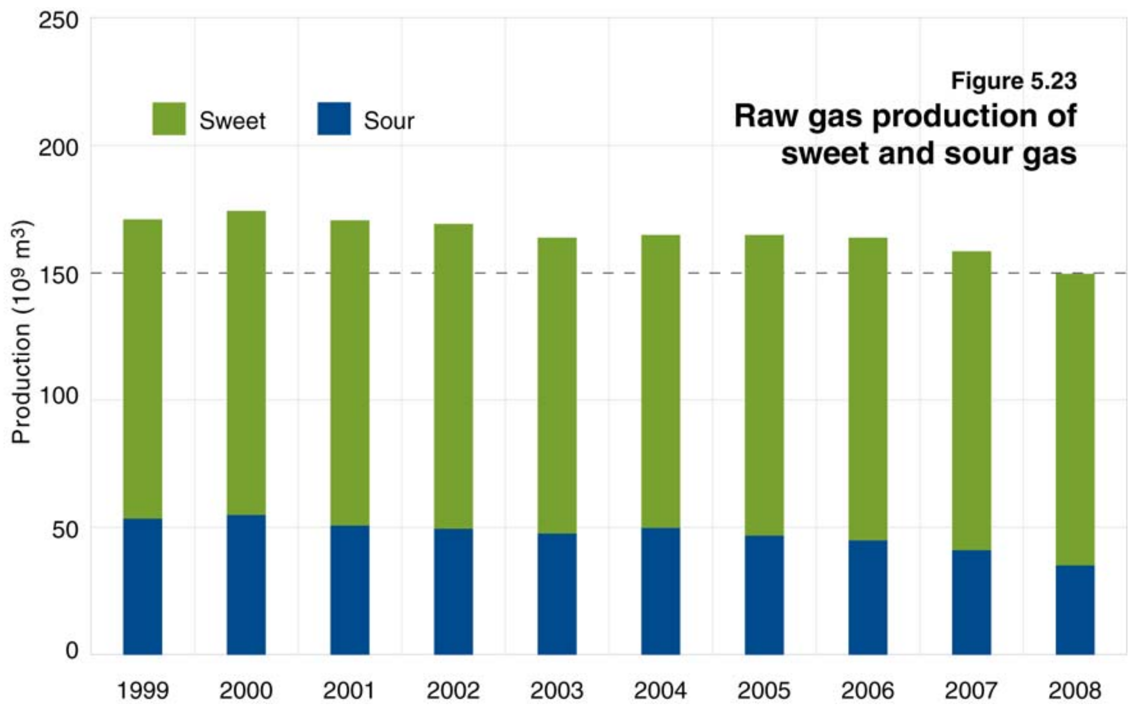


The historical raw gas production by connection year in Alberta is presented in **Figure 5.22**. The bottom band represents gas production from oil wells. Each band above represents production from new gas well connections by year. The percentages on the right-hand side of the figure represent the share of that band's production to the total production from gas wells in 2008. For example, 9 per cent of gas production in 2008 came from wells connected in that year. The figure shows that in 2008, 50 per cent of gas production came from gas wells connected in the last five years.

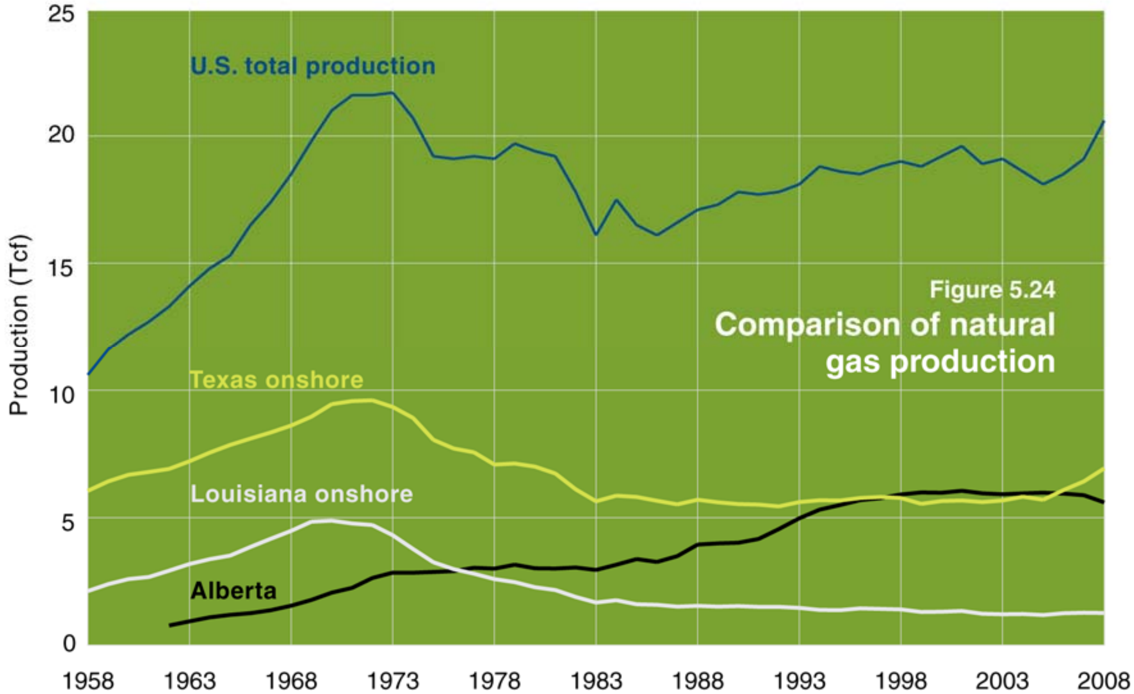
Figure 5.23 indicates the proportion of sweet versus sour gas production in the province since 1999. The percentage of sour gas relative to total gas production is decreasing, from 31 per cent in 1999 to 23 per cent in 2008.

Figure 5.24 presents a comparison of raw natural gas production in Alberta to both Texas and Louisiana onshore, as well as total U.S. gas production over the past 40 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta appears to be at that stage today. It is interesting to note that for both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production. However, over time production rates have been maintained at significant levels.





U.S. gas production as a whole reached peak production in 1973 at 21.7 Tcf. By 1986 gas production had declined to 16.1 Tcf. However, since then gas production has increased and in 2008 reached 20.6 Tcf, an increase of 8 per cent over 2007 levels. Several factors are responsible for this increase in production over the last 20 years, including the production of gas from unconventional sources.



The long-term outlook for North American gas supply has changed with the recent growth in supply from unconventional production, particularly from shale gas. With the success of the Barnett shales in Texas and other shale gas plays in the U.S., as well as the Horn River shale play in northeastern British Columbia, it appears that shale gas production will continue to grow.

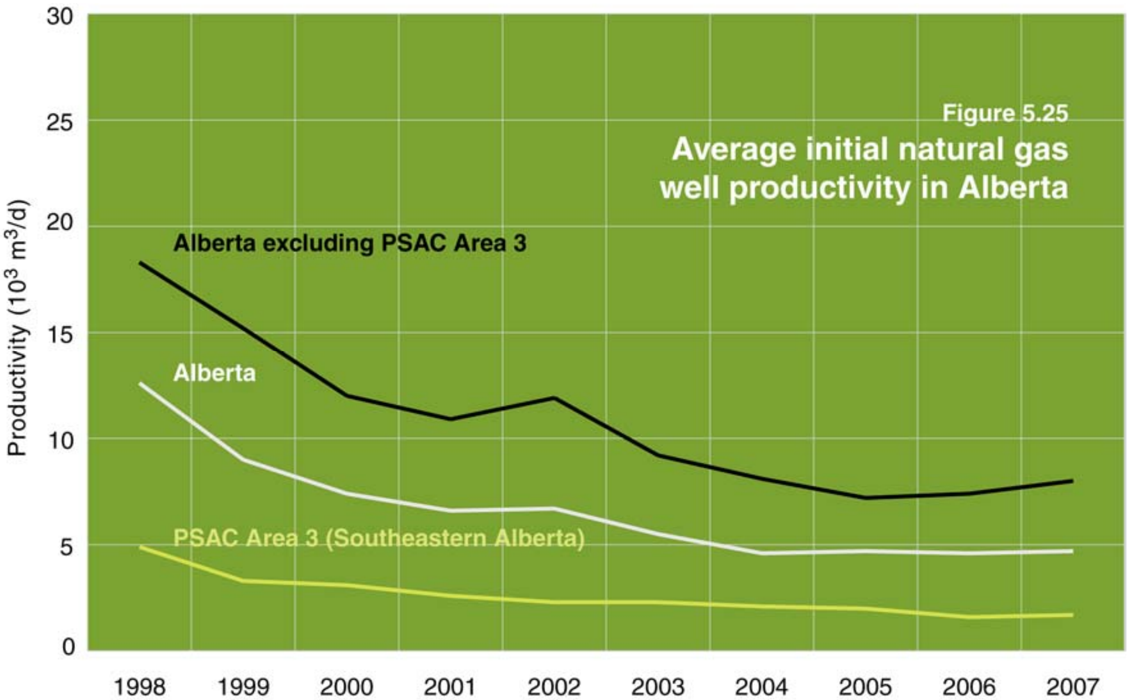
Table 5.8 shows decline rates for gas wells connected from 1998 to 2007 with respect to the first, second, third, and fourth year of decline, as well as initial well productivity by year. Wells are exhibiting steep declines in production in the first three years and settling at about 16 per cent in the fourth year.

Table 5.8. Production decline rates for new well connections (%)

Year wells connected	Initial well productivity	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1998	12.6	32	29	21	19
1999	9.0	34	23	21	17
2000	7.4	33	24	17	18
2001	6.6	31	23	21	18
2002	6.7	30	25	20	16
2003	5.5	31	19	22	12
2004	4.6	32	23	17	
2005	4.7	33	22		
2006	4.6	33			
2007	4.7				
3-year average	4.7	33	21	20	16

New well connections today start producing at much lower rates than new wells placed on production several years earlier. However, initial productivity rates for the province have stabilized from 2004 onward. **Figure 5.25** shows the average initial productivity (peak rate) of new wells by connection year for the province and for wells in Southeastern Alberta (Area 3). Average initial productivity for new wells excluding

Southeastern Alberta are also shown in the figure. The trend of higher initial productivity wells over the last two years is apparent for all areas excluding Southeastern Alberta. Although the number of new well connections per year overall has declined by 33 per cent since 2005, the average initial productivity rates of new wells outside of Southeastern Alberta is 11 per cent higher than in 2005, at 8.0 10^3 m^3/d. Average new well initial productivity in Southeastern Alberta has stabilized recently at 1.5 10^3 m^3/d.



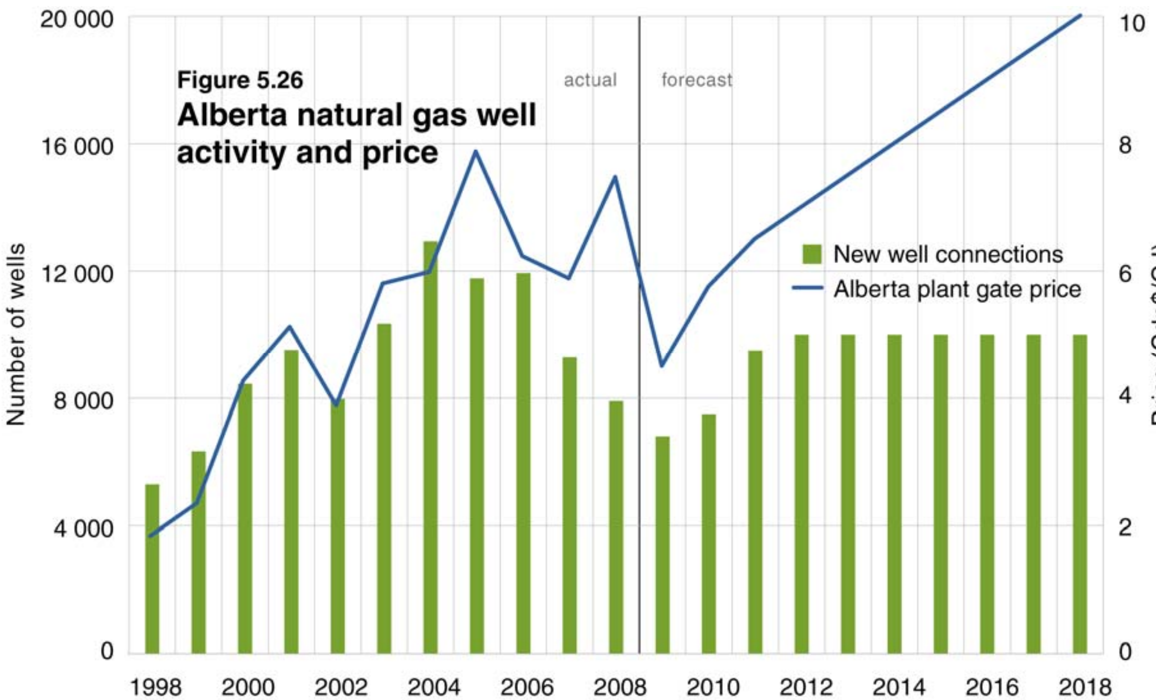
Based on the projection of natural gas prices provided in Section 1.2 and current estimates of reserves and drilling activity, the ERCB expects the number of new conventional gas well connections in the province to decline to 6800 in 2009. This represents a 14 per cent decrease in well connections year over year. For 2010, well connections are expected to increase moderately to 7500, as North American gas supply becomes more balanced with demand, resulting in stronger natural gas prices. By 2011, well connections will rebound to 9500 and become steady at 10 000 per year thereafter until 2018. Drilling activity in Southeastern Alberta is expected to remain strong throughout the forecast period. Spacing requirements by the ERCB are allowing for reduced baseline well densities in designated areas in the province. **Figure 5.26** illustrates historical and forecast new well connections and plant gate prices. (See Section 1 for the discussion of price forecasts.) However, the increased emphasis by industry in commingling gas production from separate zones, recompleting existing wells in new zones, and targeting unconventional gas plays indicates that industry may not experience the high levels of new well connections for conventional gas observed over the 2004-2006 time period.

As stated earlier in this section, in projecting natural gas production, the ERCB considered three components: expected production from existing gas wells, expected production from new gas well connections and new zone connections from existing wells (excluding production from a commingled zone), and gas production from oil wells.

Based on observed performance, gas production from existing gas wells at year-end 2008 is assumed to decline by 16 per cent per year over the forecast period.

To project production from new gas well connections, the ERCB considered the following assumptions:

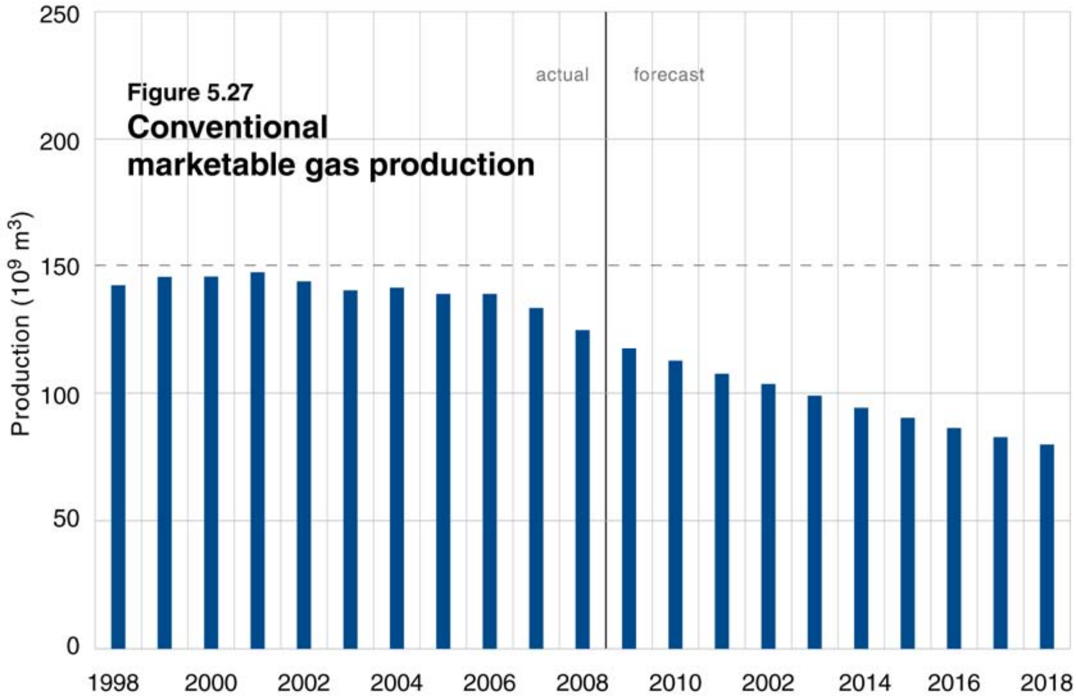
- The average initial productivity of new natural gas wells in Southeastern Alberta will be 1.5 10^3 m^3/d.
- The average initial productivity of new natural gas wells in the rest of the province will be 7.5 10^3 m^3/d in 2009 and will decrease to 4.0 10^3 m^3/d by 2018.
- Production from new wells will decline at a rate of 33 per cent the first year, 21 per cent the second year, 20 per cent the third year, and 16 per cent the fourth year and thereafter.
- Gas production from oil wells will decline by 3 per cent per year.



Based on the remaining established and yet-to-be-established reserves and the assumptions described above, the ERCB generated the forecast of natural gas production to 2018, as shown in **Figure 5.27**. The production of natural gas from conventional reserves is expected to decrease from 125.0 10^9 m^3 in 2008 to 80.0 10^9 m^3 by 2018. If conventional natural gas production rates follow the projection, Alberta will have recovered 78 per cent of the 6276 10^9 m^3 ultimate potential by 2018.

Gas production from sources other than conventional gas and oil wells includes processed gas from bitumen upgrading operations (including synthetic gas), natural gas from bitumen wells, and CBM. **Figure 5.28** shows the production from the first two categories.

In 2008, some 4.3 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 11.2 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells from primary and thermal schemes was 0.9 10^9 m^3 in 2008 and is forecast to increase to 1.3 10^9 m^3 by 2018. This gas is used mainly as fuel to create steam for its on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.



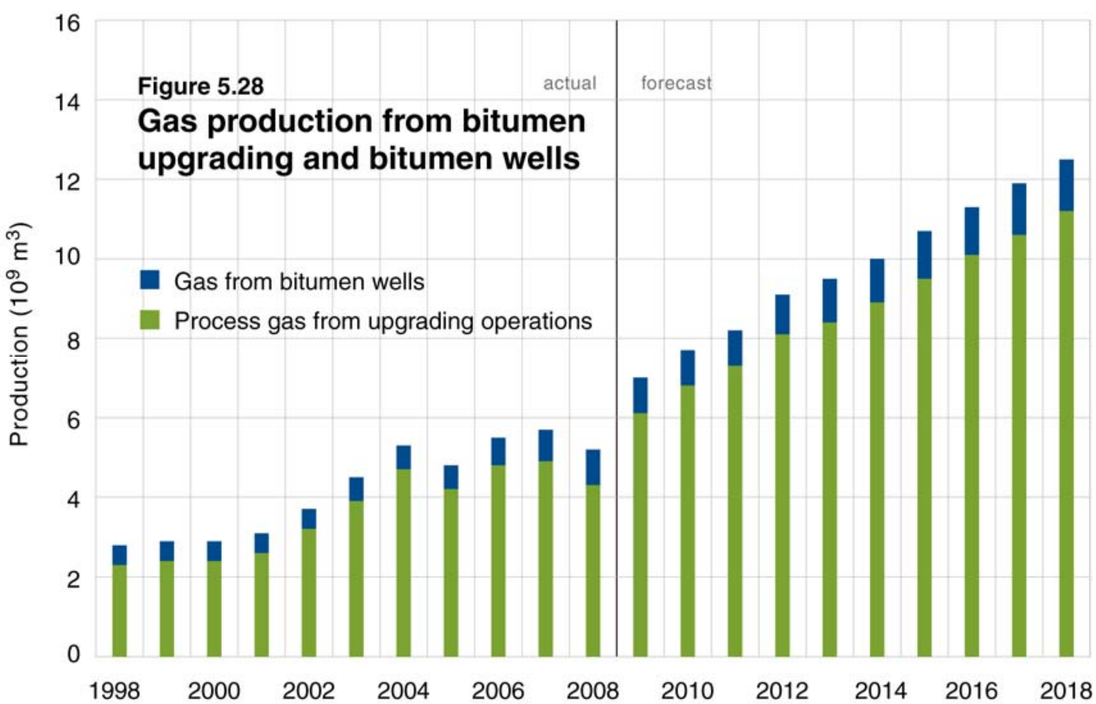
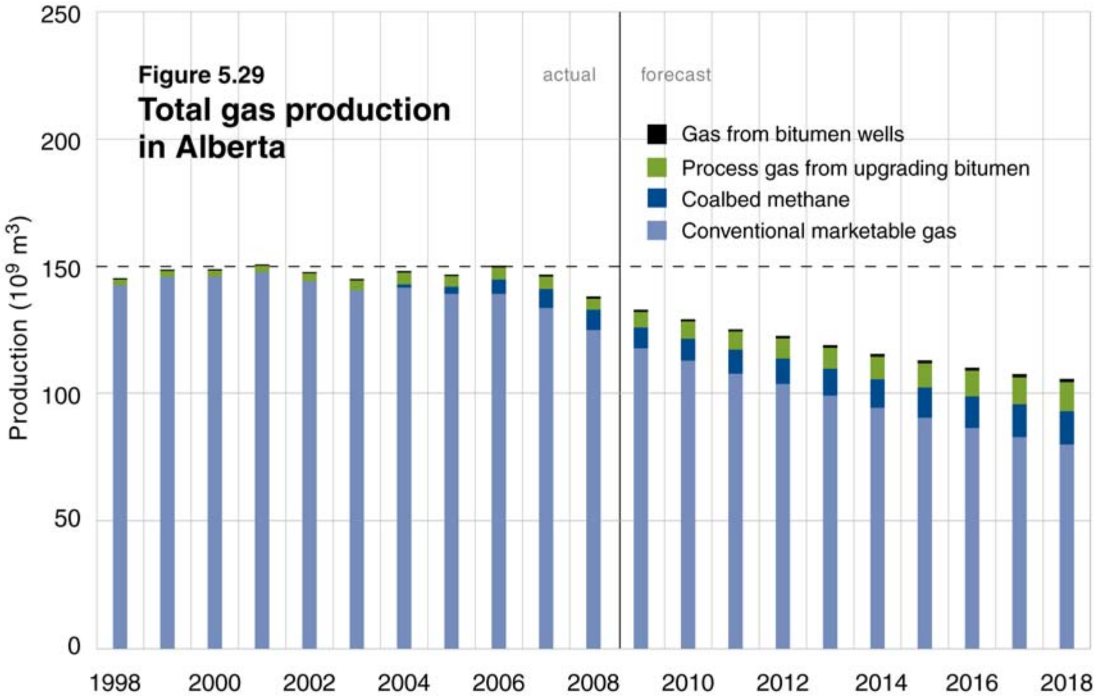


Figure 5.29 shows the forecast of conventional natural gas production, along with gas production from other sources. In 2008, conventional natural gas production is reported at 125.0 10^9 m^3, and it is forecast to decline to 80.0 10^9 m^3 by 2018. While the production of conventional gas in Alberta is expected to decline by 6 per cent in 2009 and 4 per cent

per year thereafter on average, CBM production is expected to grow over time and offset part of the decline.



5.2.2 Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability and is not used in the ERCB's 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; 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 production generally begins at high withdrawal rates. **Figure 5.30** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province.

Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table 5.9**. **Figure 5.31** presents the location of these facilities in the Alberta pipeline systems.

In 2008, natural gas injections for all storage schemes exceeded withdrawals by 751 10^6 m^3. Marketable gas production volumes determined for 2008 were adjusted to account for the imbalance in injection and withdrawal volumes to 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.

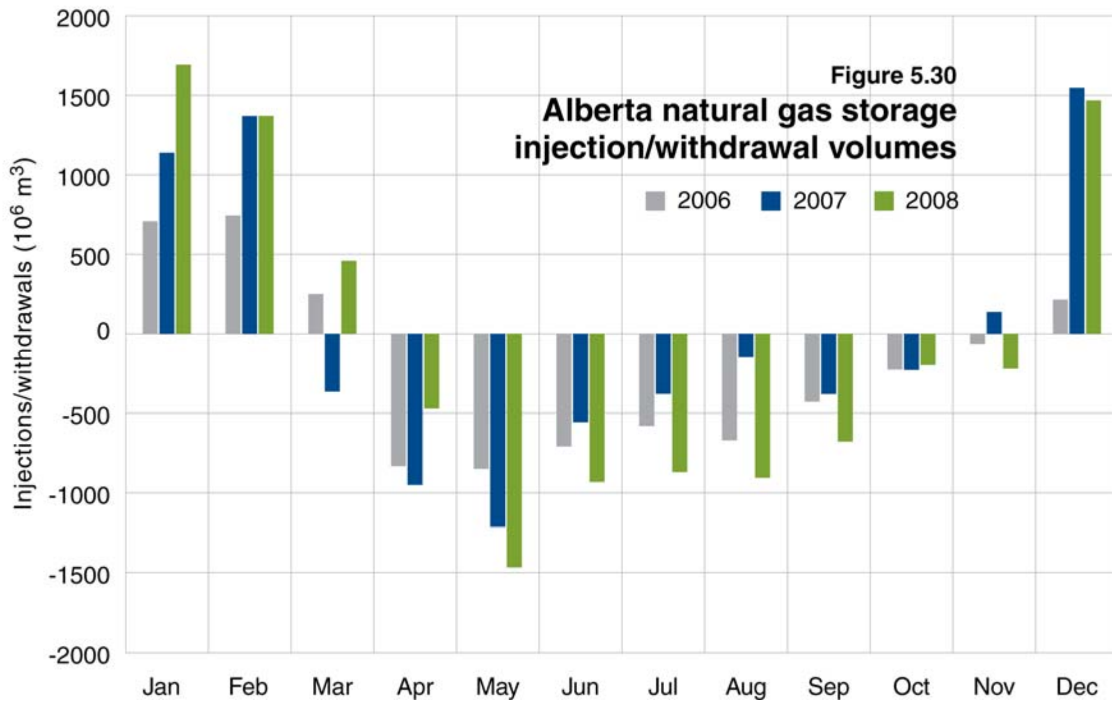


Table 5.9. Commercial natural gas storage pools as of December 31, 2008

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2008 (10^6 m^3)	Withdrawal volumes, 2008 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	959	775
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	817	23 950	1 180	1 086
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	988	732
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	750	771
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	152	140
McLeod Cardium A	Iberdrola Canada Energy Services Ltd.	986	16 900	523	476
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	129	38
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 395	50 715	1 653	1 565

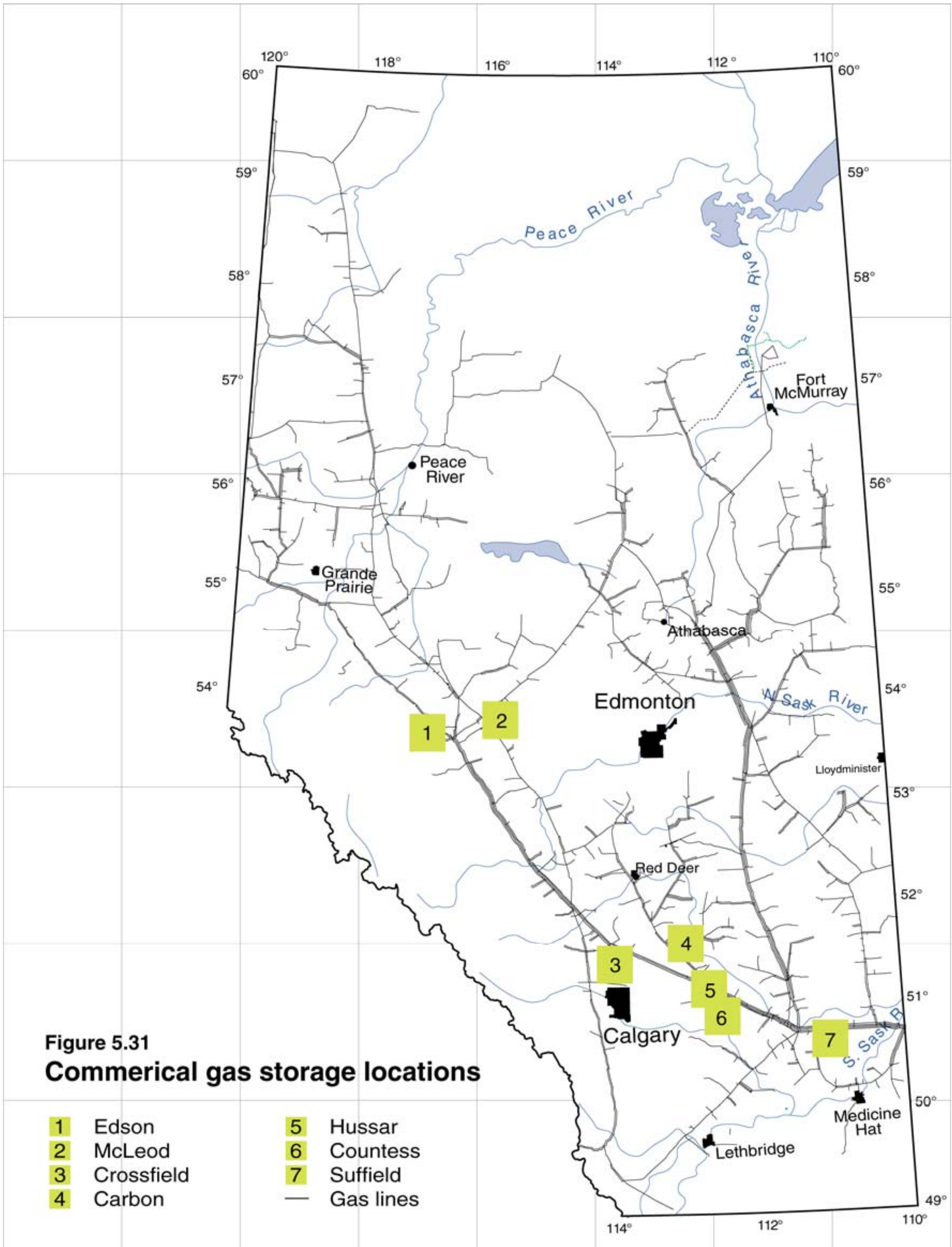


Figure 5.31
Commerical gas storage locations

5.2.3 Alberta Natural Gas Demand

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, economic activity, and environmental issues 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 the recent historical trends in meeting that demand. Excess pipeline capacity to the U.S. allows gas to move to areas of the U.S. 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 5.32**, with removal points identified.

Figure 5.32
Major gas pipelines in Canada and Alberta export points

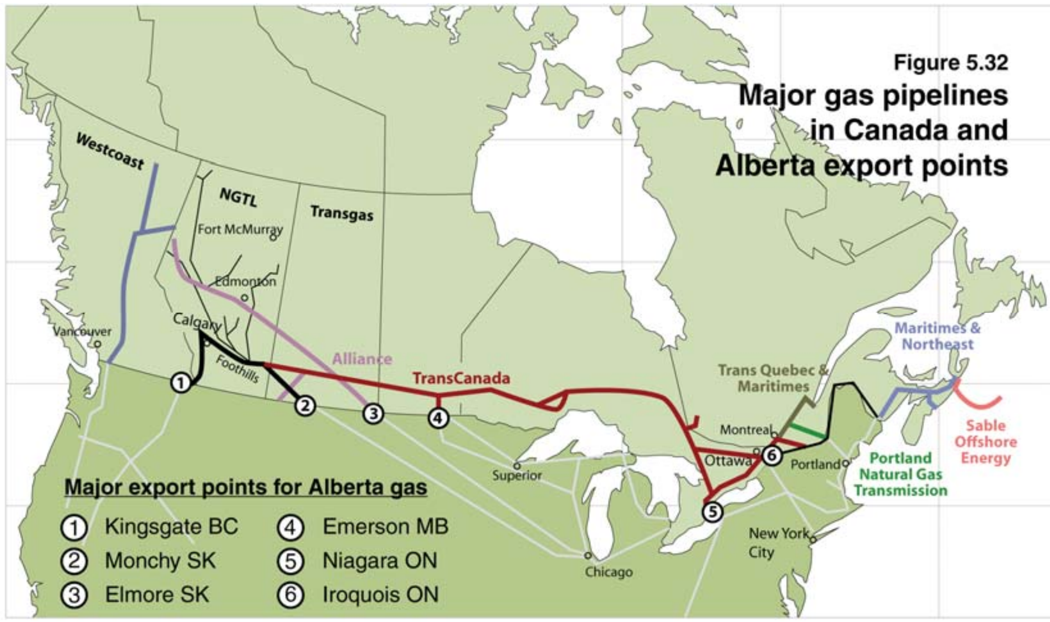


Figure 5.33 illustrates the breakdown of marketable natural gas demand in Alberta by sector. By the end of the forecast period, domestic demand will reach 54.4 10^9 m^3, compared to 44.1 10^9 m^3 in 2008, representing 58 per cent of total natural gas production.

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. Exports of gas from Alberta are 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 5.10** is performed annually to determine what volume of gas is available for export after accounting for Alberta's future requirements. Using the 2008 remaining established reserves number, surplus natural gas is currently calculated to be 297 10^9 m^3. This represents a 45 per cent increase in surplus over the year 2007, due mainly to a decrease in remaining permit commitments and an increase in remaining reserves year over year. **Figure 5.34** illustrates historical "available for permitting" volumes from 1998 to 2008.

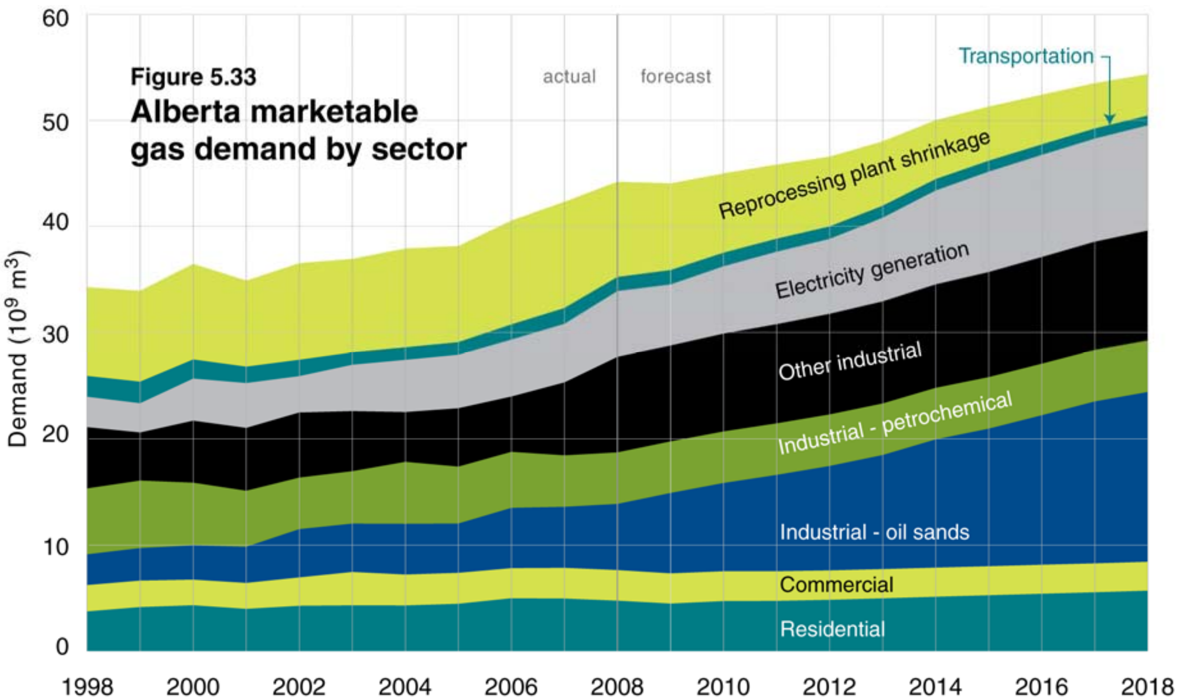


Table 5.10. Estimate of gas reserves available for inclusion in permits as at December 31, 2008

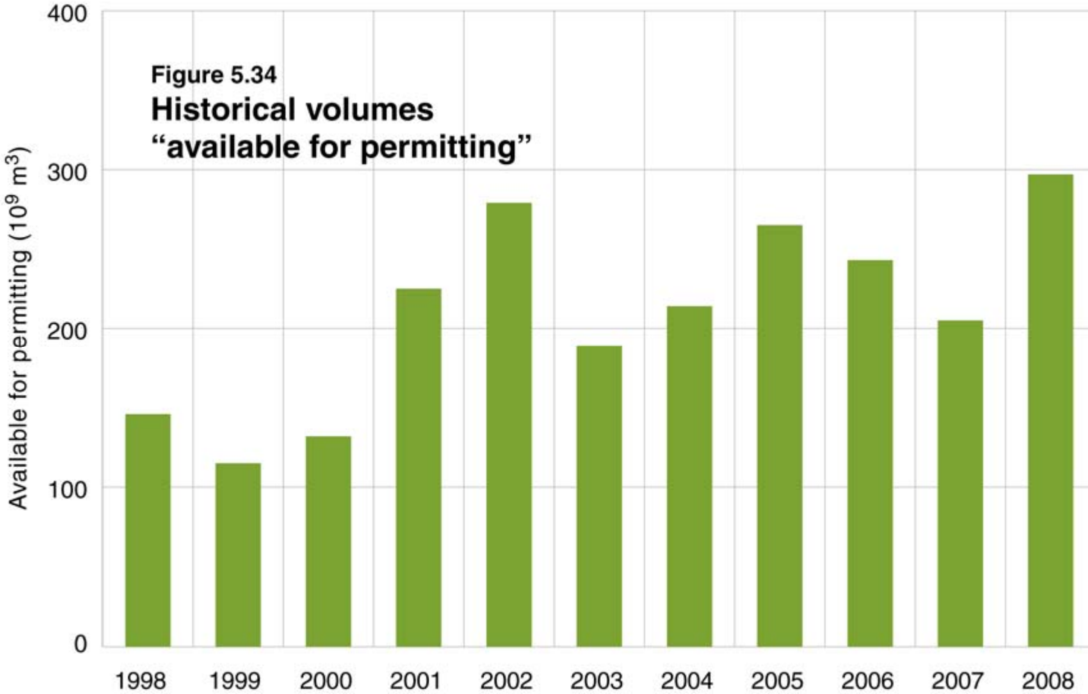
	10^9 m^3 at 37.4 MJ/m^3
Reserves (as at year-end 2008)	
1. Total remaining established reserves[a]	1119
Alberta requirements	
2. Core market requirements[b]	114
3. Contracted for non-core markets[b]	126
4. Permit-related fuel and shrinkage	53
Permit requirements	
5. Remaining permit commitments[c]	529
6. Total requirements	822
Available	
7. Available for permits	297

[a] Previous estimates of gas available for permitting have included gas in the Beyond Economic Reach and Deferred categories that would become available over the next 20 years. However, in 1999 the ERCB discontinued estimating reserves in these categories on the basis that the methods used did not result in accurate volumes and the effort did not add significant reserves to the total volume of reserves.

[b] For these estimates, 15 years of core market requirements and 5 years of non-core requirements were used.

[c] The remaining permit commitments are split approximately 38 per cent under short-term permits and 62 per cent under long-term permits.

Residential gas requirements are expected to grow moderately over the forecast period, at an average annual rate of 1.8 per cent. 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 energy use per household from rising significantly.



Commercial gas demand in Alberta has fluctuated over the past 10 years and is expected to remain flat over the forecast period. This is largely due to gains in energy efficiencies and a shift to electricity.

The significant increase in Alberta demand is due to increased development in the industrial sector. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil, shown in **Figure 5.35**, are expected to increase annually from 10.2 10^9 m^3 in 2008 to 23.6 10^9 m^3 by 2018. **Table 5.11** outlines the average purchased gas use rates for oil sands operations.

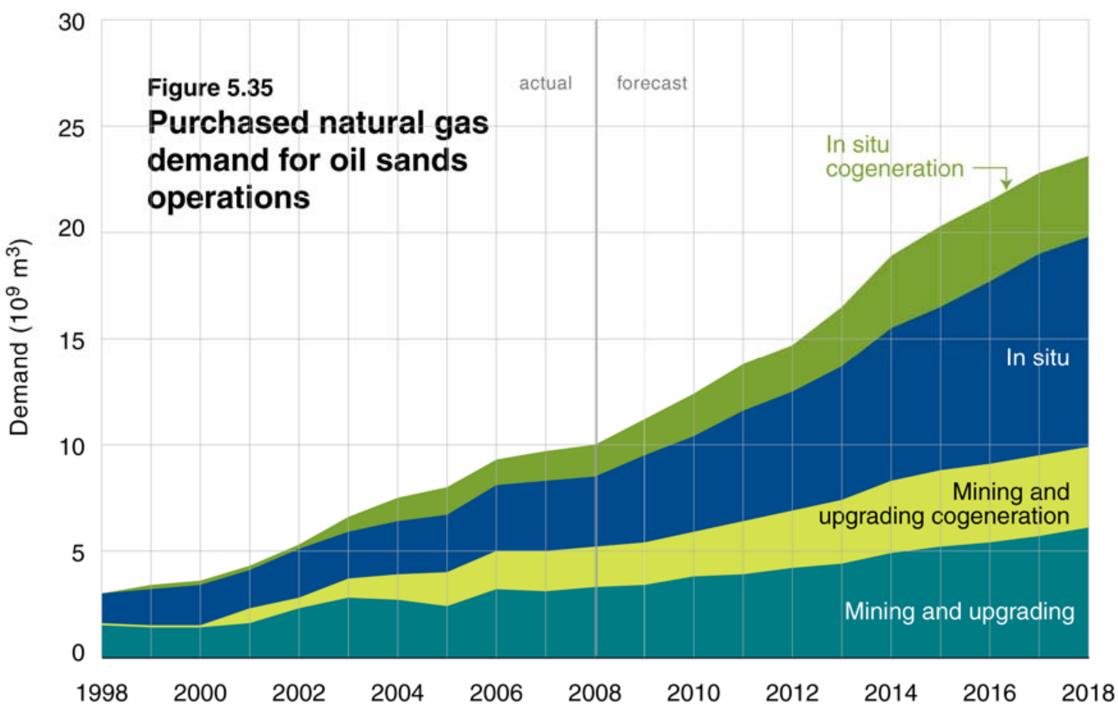


Table 5.11. 2008 oil sands average purchased gas use rates*

	Excluding purchased gas for electricity generation		Including purchased gas for electricity generation	
Extraction method	(m³/m³)	(mcf/bbl)	(m³/m³)	(mcf/bbl)
In situ - SAGD	139	0.78	251	1.41
- CSS	159	0.89	204	1.14
Mining	18	0.10	80	0.45
Upgrading	29	0.16	51	0.29
Mining with upgrading	90	0.51	133	0.75

* Expressed as cubic metres of natural gas per cubic metre of bitumen/synthetic crude oil 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. Therefore, total gas demand in this sector is the sum of purchased gas, process gas, and solution gas produced at bitumen wells, as illustrated in **Figure 5.36.** 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 5.37**, is 16.0 10^9 m^3 in 2008 and is forecast to increase to 36.7 10^9 m^3 in 2018.

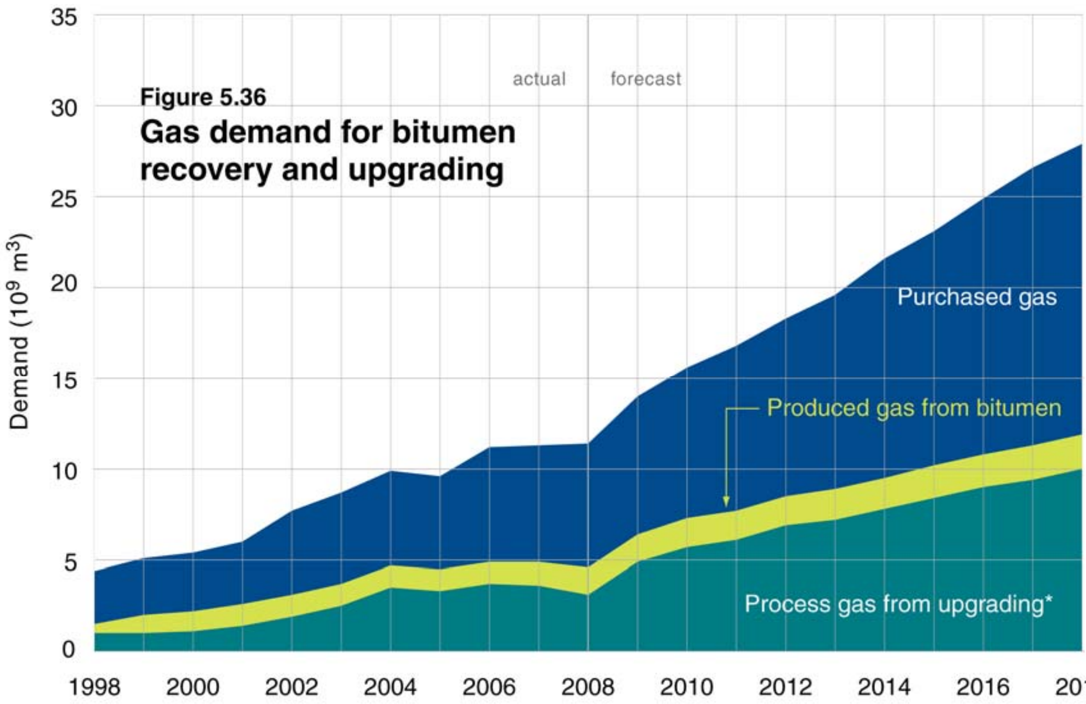
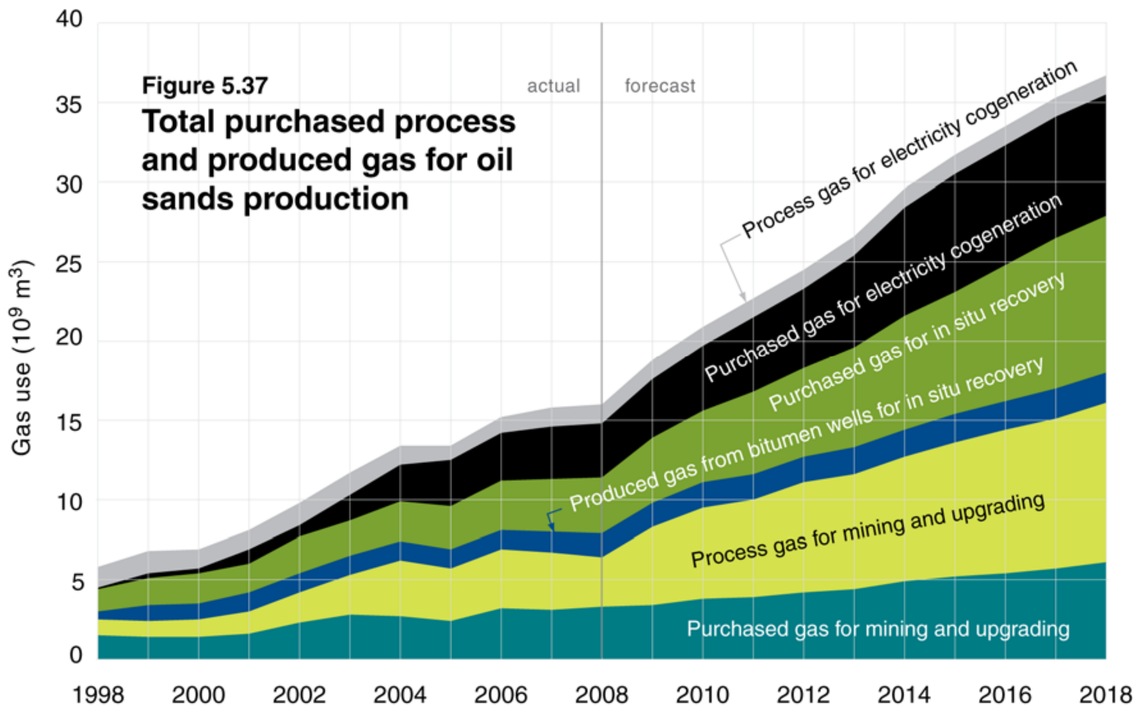


Figure 5.36
Gas demand for bitumen recovery and upgrading

* Does not include process gas for electricity generation.

The potential high usage of natural gas in bitumen production and upgrading has exposed the companies involved in the business to the risk of volatile gas prices. The Opti Canada Inc./Nexen Inc. Long Lake Project began commercial operations in January 2009, employing technology that produces synthetic gas by burning ashphaltines in its new bitumen upgrader. Other companies are exploring the option of self-sufficiency for their gas requirements. The existing bitumen gasification technology is one attractive alternative being pursued. If implemented, natural gas requirements for this sector could decrease substantially.



The electricity generating industry will also require increased volumes of natural gas to fuel some of the new plants expected to come on stream over the next few years. Natural gas requirements for electricity generation are expected to increase over the forecast period, from some 6.2 10^9 m^3 in 2008 to 9.9 10^9 m^3 by 2018.

Figure 5.38 shows Alberta natural gas demand and production. Gas removals from the province represent the difference between natural gas production from conventional reserves and coal seams and Alberta demand. In 2008, some 33 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the U.S. By the end of forecast period, domestic demand represents 58 per cent of total natural gas production.

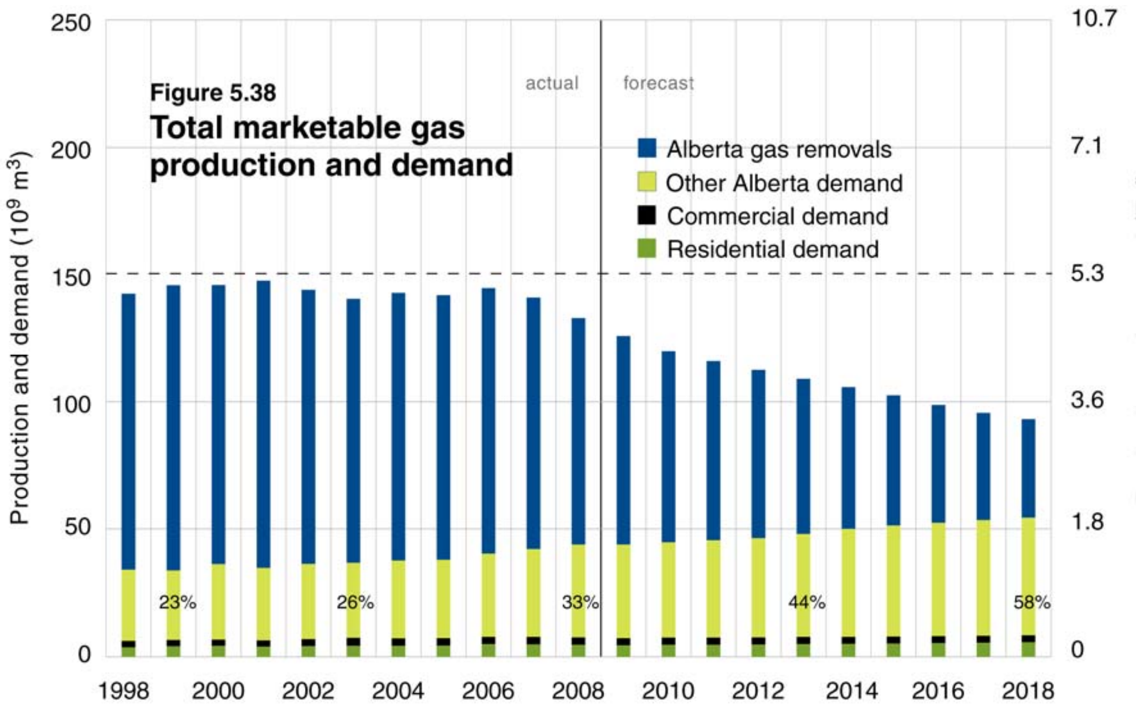


Figure 5.38
Total marketable gas production and demand
actual
forecast
Alberta gas removals
Other Alberta demand
Commercial demand
Residential demand
Production and demand (10^9 m^3)
Production and demand (Tcf)
0
50
100
150
200
250
0
1.8
3.6
5.3
7.1
10.7
23%
26%
33%
44%
58%
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018

6 Natural Gas Liquids

Highlights

- Total remaining extractable NGL reserves have increased by 3 per cent from 2007, mainly due to reassessment of existing natural gas reserves.
- Approximately 56 per cent of total ethane in the gas stream was extracted in 2008, compared to about 60 per cent in 2007.
- Of the total ethane extracted, straddle plants recovered 76 per cent and the remaining was removed at field and other facilities, similar to in 2007.

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, all ethane production, the majority of propane and butanes production, and all pentanes plus production are from the natural gas stream. The majority 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 NGL supply are crude oil refineries, where small volumes of propane and butanes are recovered, and 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. The majority of the off-gases produced from oil sands upgraders are presently being used as fuel for oil sands operations.

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from raw natural gas using existing technology and projected market conditions. The liquids 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, discussed in Section 5.1. The ERCB's projections on the overall recovery of each NGL component are explained in Section 5.1.7. As shown graphically in Figure 5.9, the estimated reserves of liquid ethane are based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream.

6.1 Reserves of Natural Gas Liquids

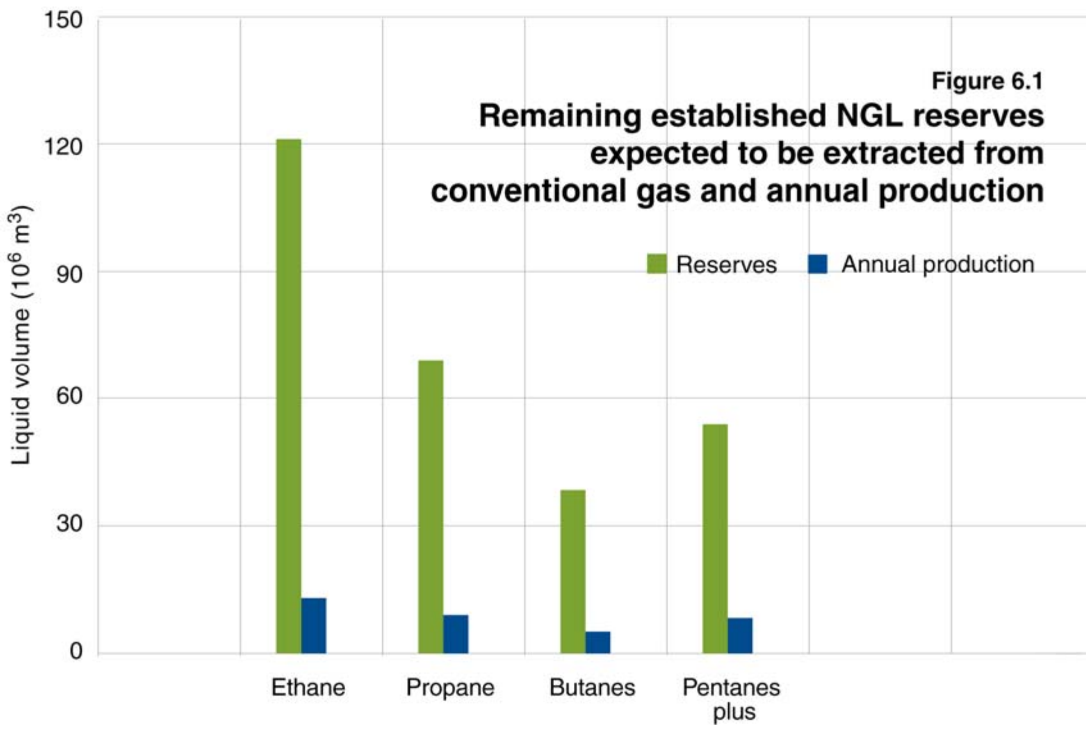
6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2008 are summarized in **Tables 6.1** and **6.2**. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2008 production.

Total remaining reserves of extractable NGLs have increased by 3.4 per cent compared to 2007. Fields that have contributed significantly to this increase are Fir, Kakwa, Pembina, Pine Creek, and Wayne Rosedale. 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 of extractable NGLs as of December 31, 2008 (10^6 m^3 liquid)

	2008	2007	Change
Cumulative net production			
Ethane	267.3	254.4	+12.9
Propane	270.9	262.0	+8.9
Butanes	155.1	150.1	+5.0
Pentanes plus	337.3	329.1	+8.2
Total	1030.6	995.6	+35.0
Remaining (expected to be extracted)			
Ethane	121.1	115.5	+5.6
Propane	69.0	66.0	+3.0
Butanes	38.4	37.2	+1.2
Pentanes plus	53.8	54.4	-0.6
Total	282.3	273.1	+9.2
Annual production	35.0	37.4	-2.4



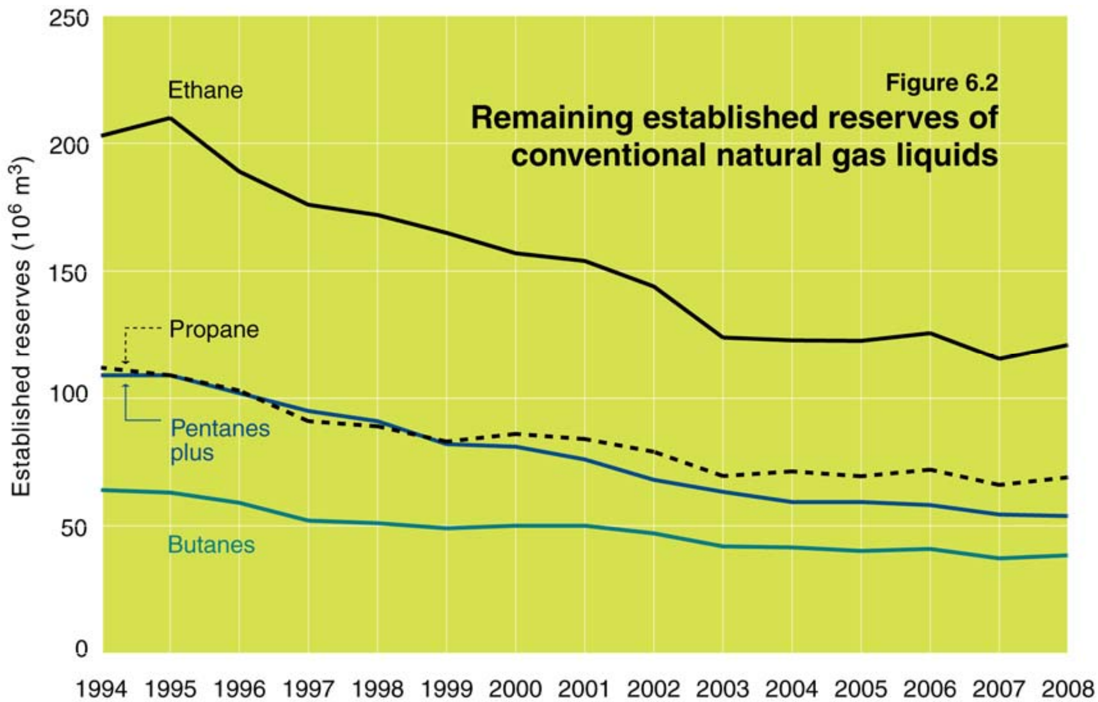
6.1.2 Ethane

As of December 31, 2008, the ERCB estimates remaining established reserves of extractable ethane to be 121.1 million cubic metres (10^6 m^3) in liquefied form. The 47.4 10^6 m^3 recoverable from field plants and listed in **Table 6.2** includes 3.6 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. At the end of 2008, only six 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, 2008 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	185.5	81.2	42.6	53.8	363.2
Liquids expected to remain in dry marketable gas	64.4	12.2	4.3	0	80.9
Remaining established recoverable from					
Field plants	47.4	40.6	25.6	48.5	162.1
Straddle plants	73.6	28.4	12.8	5.4	120.2
Total	121.1	69.0	38.4	53.8	282.3

As shown in **Table 6.2**, an additional 64.4 10^6 m^3 (liquid) of ethane is estimated to remain in the marketable gas stream and be available for potential recovery. **Figure 6.2** shows the remaining established reserves of ethane declining from 1995 to 2003, then in general levelling off from 2003 to 2008. During 2008, the extraction of specification ethane was 12.9 10^6 m^3, compared to 14.5 10^6 m^3 in 2007.



For individual gas pools, the ethane content of gas in Alberta falls 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 nine largest—Ansell, Caroline, Elmworth, Ferrier, Kaybob South, Pembina, Wapiti, Wild River, and Willesden Green—account for 25 per cent of total ethane reserves but only 13 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2008, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 69.0 10^6 m^3, 38.4 10^6 m^3, and 53.8 10^6 m^3 respectively. The breakdown in the liquids reserves at year-end 2008 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, Caroline, Ferrier, Kaybob South, Pembina, Valhalla, Wild River, and Willesden Green—account for about 26 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 for liquid ethane is considered to be the reserves that could be recovered as liquid from the remaining ultimate potential of natural gas, using existing cryogenic technology and projected market demand. Historically, only a fraction of the ethane volumes that could be extracted had been recovered, as production is based largely on demand. The percentage recovered has increased over time, averaging about 58 per cent over the last 5 years. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on remaining ultimate potential for ethane gas of 142 billion (10^9) m^3, the ERCB estimates the remaining ultimate potential of liquid ethane to be 354 10^6 m^3. The other 30 per cent, or 43 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 reserves together, the remaining ultimate potential reserves are 426 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is 37 per cent, similar to that of conventional marketable gas.

6.2 Supply of and Demand for Natural Gas Liquids

For the purpose of forecasting ethane and other NGLs, the richness and production volumes from established and future reserves of conventional natural gas have an impact on future production. For ethane, demand also plays a major role in future extraction. The NGL content from new gas reserves is assumed to be similar to existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will play a role in supplementing supplies from conventional gas production.

6.2.1 Supply of Ethane and Other Natural Gas Liquids

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 pipeline hydrocarbon dewpoint specifications, as well as removal of other gas contaminants. The field plants may also recover additional volumes of NGLs, depending on the capability of the plant and the economics of NGL extraction and marketing. Generally, the heavier hydrocarbon constituents (butanes and pentanes plus) must be removed at field plants, with the removal of lighter components dependent on economics. Fractionation of the NGLs into pure products may take place at field plants, but may also occur at more centralized NGL fractionation plants. These centralized, large-scale NGL processing facilities realize economies of scale by fractionating NGL mix streams received from many gas plants.

Gas processing plants for NGL extraction, referred to as straddle plants, are located on rate-regulated main gas transmission pipelines and process gas (that may have been processed in the field) to recover NGLs that remain in the common gas stream. These 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 6.3** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

There are about 550 active gas processing plants in the province that recover NGL mix or pure products, 10 processing plants that fractionate NGL mix streams into separate products, and 9 straddle plants. Recovery rates for 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 small number of field plants also have the capability to extract ethane as a discrete product or as a C_2+ mix.

Ethane recovery at straddle plants varies from 40 to 90 per cent and averages 65 per cent. Percentages recovered for propane, butanes, and pentanes plus are 98.5, 99.5, and 99.8 respectively at Alberta straddle plants. **Table 6.3** outlines the current straddle plants, including the location, operator, natural gas approved volumes, natural gas receipts, and ethane production.

Table 6.3. Straddle plants in Alberta, 2008

Area of straddle plant	Location	Operator	2008 gas approved volumes (10^3 m^3/d)	2008 gas receipts (10^3 m^3/d)	2008 ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	60 492	4 797
Empress	04-12-020-01W4M	BP Canada Energy Company	176 750	68 652	7 158
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	48 398	7 691
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 239	1 980
Empress	01-10-020-01W4M	ATCO Midstream Ltd.	31 000	15 534	1 006
Ft. Saskatchewan	01-03-055-22W4M	ATCO Midstream Ltd.	1 051	692	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	29 743	3 349
Joffre (JEEP)	03-29-038-25W4M	Taylor Management Company Inc.	7 066	268	705
Atim (Villeneuve)	08-05-054-26W4M	ATCO Midstream Ltd.	1 133	788	0
Total			400 219	232 806	26 686

In 2008, ethane volumes extracted at Alberta processing facilities decreased by 11 per cent to 35.3 thousand (10^3) m^3/d from 2007 levels of 39.7 10^3 m^3/d. About 56 per cent of total ethane in the gas stream was extracted, 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 2008.

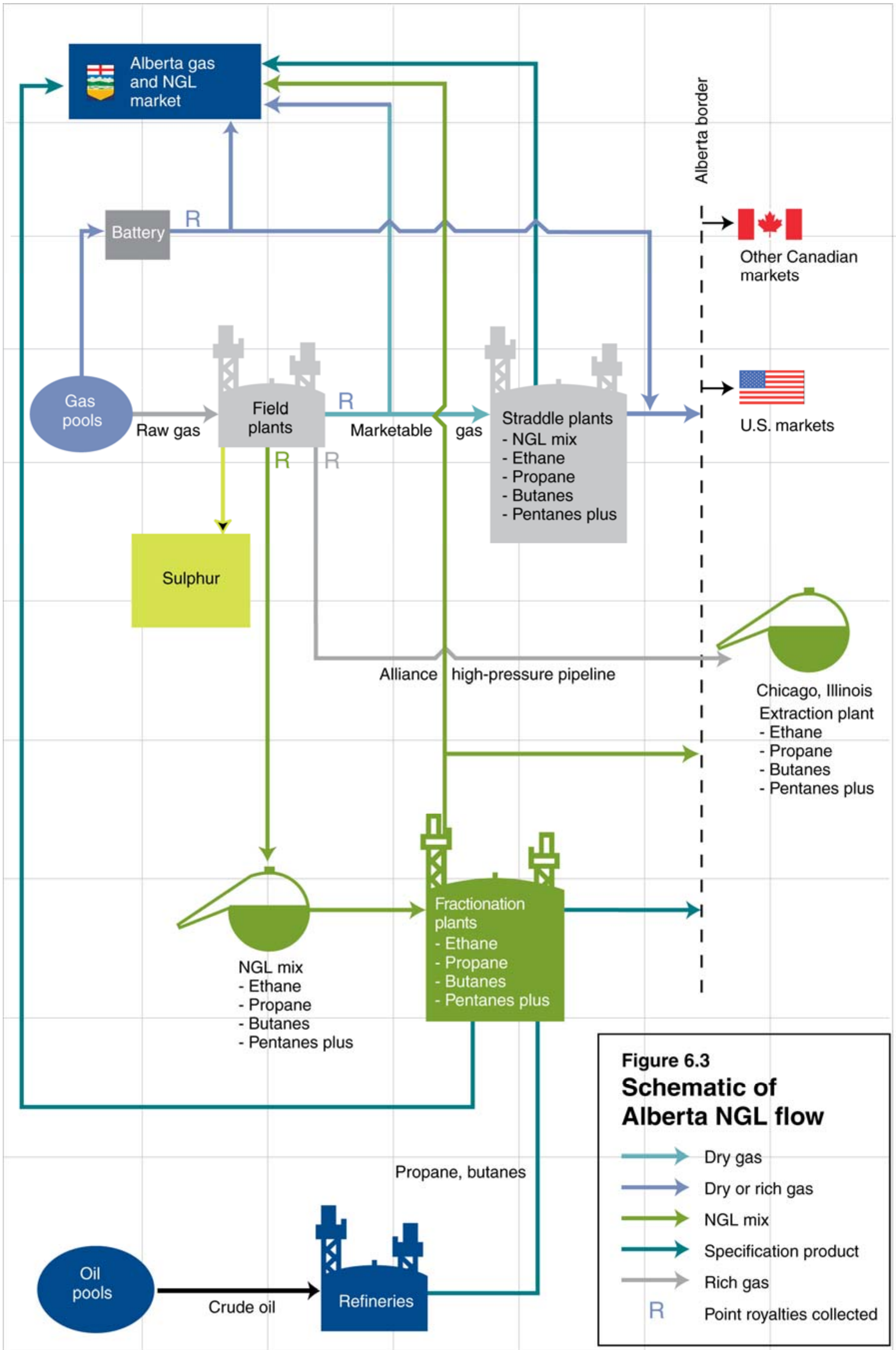


Figure 6.3
Schematic of Alberta NGL flow

Table 6.4. Ethane extraction volumes at gas plants in Alberta, 2008

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	0.6	5
Fractionation plants	2.5	19
Straddle plants	9.8	76
Total	12.9	100

Table 6.5 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2008. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butane volumes recovered at crude oil refineries were 0.7 10^3 m^3/d and 2.1 10^3 m^3/d respectively.

Table 6.5. Liquid production at ethane extraction plants in Alberta, 2008 and 2018

	2008			2018		
Gas liquid	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)
Ethane	12.9	35.3	103	13.9	38.2	174
Propane	8.9	24.5	72	5.8	15.8	72
Butanes	5.0	13.5	40	3.2	8.8	40
Pentanes plus	8.2	22.4	65	5.2	14.3	65

As conventional gas production declines, less ethane will be available for use by the petrochemical sector. In response to the forecast decline in economically recoverable ethane and tightness in the ethane supply and demand balance in Alberta, the provincial government implemented the Incremental Ethane Extraction Policy (IEEP), which will provide incentives for value-added production and the use of ethane in the province. The IEEP, first announced in September 2006, is a ten-year initiative to encourage increased production of ethane extraction from natural gas and from off-gas.

By providing incentives to extract additional ethane, Alberta's petrochemical producers can continue to increase production of higher-value petrochemical products, such as ethylene and polypropylene. IEEP provides royalty credits to encourage petrochemical companies to significantly increase the amount of ethane they consume compared to historical levels.

Petrochemical facilities will only be eligible for royalty credits on ethane consumed above historic levels to a maximum of the annual value of royalties collected on ethane extracted in Alberta, which is $35 million. The credit level has been set at $1.80 per barrel of ethane. Regardless of the incremental ethane extracted, no single project may receive more than $10.5 million. This is to ensure that multiple projects can benefit from the policy. An industry-wide ethane consumption baseline will be established based primarily on historical consumption. On an annual basis, this baseline may be either adjusted or renewed, based on actual consumption.

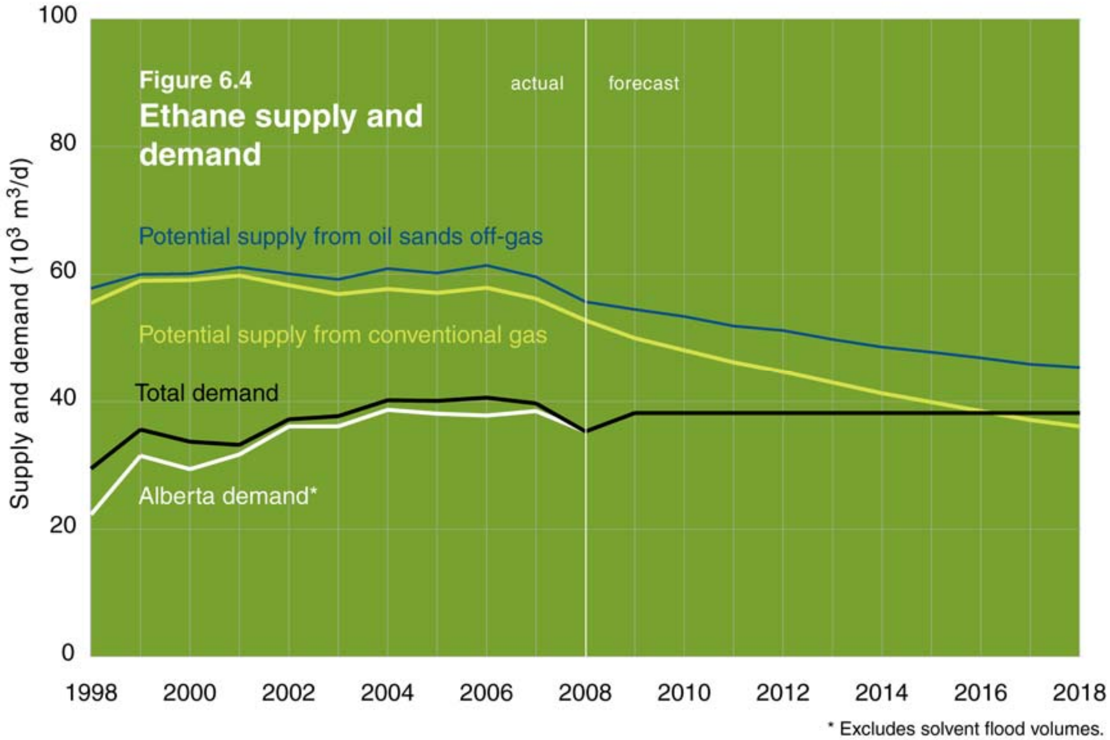
The provincial government has estimated that between 9.48 10^3 and 13.43 10^3 m^3/d of additional ethane production is expected to be recovered as a result of IEEP over the next few years. A number of new projects, including off-gas facilities and expansions to existing facilities, are expected to take advantage of this program, as discussed below. As additional bitumen upgrading capacity is added in the province, there will be opportunities to expand the use of off-gases and other by-products of upgrading for petrochemical production. Currently, C_3+ is being extracted from Suncor's off-gases and sent for fractionation into specification products at Redwater, Alberta.

The following projects are in various stages of development:

- The Inter Pipeline Fund (Inter Pipeline) Empress straddle plant deep-cut initiative is expected to be completed early in the second quarter of 2009. This project is anticipated to increase ethane production by about 1106 m^3/d.
- Also proposed is a project to increase ethane recovery capacity at the Cochrane straddle plant operated by Inter Pipeline. The project has been approved to increase ethane recovery by 2433 m^3/d from the current design capacity of 10 268 m^3/d.
- Aux Sable Canada (Aux Sable) started construction in August 2007 to build the first phase of a plant to process off-gas from the BA Energy upgrader in Strathcona County. Construction at the BA Energy site was halted in early 2008 due to escalating costs, and BA Energy Inc. is currently looking for new partners to help finance the project. At this time it is uncertain when the upgrader and the contingent off-gas plant next to the BA Energy site will start up. The off-gas plant was expected to recover NGL, including an ethane/ethylene stream that would be sold to the petrochemical industry.
- NOVA Chemicals Corp. (NOVA) and Aux Sable announced plans in 2007 to build a new ethane extraction facility in Fort Saskatchewan that was expected to provide NOVA with 6350 m^3/d of ethane feedstock. Natural gas carrying the ethane was to be supplied from the Alliance pipeline, which runs from northeast British Columbia to Chicago. Aux Sable expected the new plant to be in service by 2010, but has since delayed the timing, citing regulatory uncertainty, cost escalations, and environmental considerations. Aux Sable is currently looking at alternative ways to extract ethane from the gas stream in order to improve the economics of the project.

Recovered ethane volumes are expected to increase in 2009 to 38.2 10^3 m^3/d and remain at this level over the forecast period, as shown in **Figure 6.4**. Ethane supply is, to a large degree, a function of ethane demand. The four ethylene plants in the province that use ethane as a feedstock had been operating collectively at an 80 per cent capacity utilization rate from 2003 through 2007. Although the collective utilization rate was down in 2008, it is expected to return to historical levels in 2009 and the remainder of the forecast period. The ERCB expects that all ethane recovered in the province will be used locally, even though export permits are in place to move small volumes of ethane outside of Alberta. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue through the forecast period. Possible incremental ethane volumes generated due to the IEEP incentive program are not included in the forecast at this time due to the preliminary status of the program. However, if incremental volumes materialize, future ERCB forecasts will be modified to reflect the change in recovered ethane volumes.

Figure 6.4 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 gas are calculated based on the volume-weighted ethane content of conventional gas in Alberta of 0.05 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is some 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast. The ethane supply volumes from oil sands off-gas are calculated assuming a 12 per cent ethane content in the off-gas production volumes and an 80 per cent recovery rate of ethane. Although the forecast supply crosses over the demand curve prior to the end of the forecast, based on these assumptions incremental ethane volumes required to meet demand are assumed to be available from off-gas or higher extraction rates from existing processing facilities.



Over the forecast period, the ratios of propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas are expected to remain constant, as shown in **Table 6.5**. **Figures 6.4** to **6.7** show forecast production volumes to 2018 for ethane, propane, butanes, and pentanes plus respectively. As conventional gas production declines, so too will the NGL volumes available for extraction.

6.2.2 Demand for Ethane and Other Natural Gas Liquids

All of the ethane extracted in 2008 was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline allows for a range of feedstocks to be transported from Fort Saskatchewan to Joffre. These feedstocks supplement the ethane supplies now used at the petrochemical plants at Joffre, where three of the four ethylene plants are located. The fourth is located in Fort Saskatchewan. To acquire ethane, the petrochemical industry pays a fee to NGL processing facility owners to extract and deliver ethane from natural gas streams processed at their facilities. 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 North America has been challenged in the last few years by high and volatile energy prices. Since ethane prices follow natural gas prices, feedstock costs have fluctuated throughout the years. Nonetheless, the Alberta ethylene industry has maintained its historical cost advantage for ethylene production compared to a typical ethane/propane cracker in the U.S. Gulf Coast.

As also shown in **Figure 6.4**, Alberta demand for ethane is projected to increase from the 2008 level of 35.3 10^3 m^3/d to 38.2 10^3 m^3/d in 2009 and remain flat for the rest of the forecast period. For the purposes of this forecast, it was assumed that the existing ethylene plants will continue to operate at an 80 per cent capacity utilization rate and that no new ethylene plants requiring ethane as feedstock will be built in Alberta over the forecast period. Small volumes of ethane have historically been exported from the province, primarily for use as a buffer for pipeline ethylene shipments to eastern Canada. In 2008, however, no volumes were removed from the province, and this is expected to remain the case in the future.

Figure 6.5 shows Alberta demand for propane compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta propane demand was 2.8 10^3 m^3/d in 2007 and increased slightly to 3.0 10^3 m^3/d in 2008. 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 experience moderate growth of 1 per cent throughout the forecast. 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. Alberta demand for propane is forecast to increase from 2008 levels by 5 per cent per year over the forecast period.

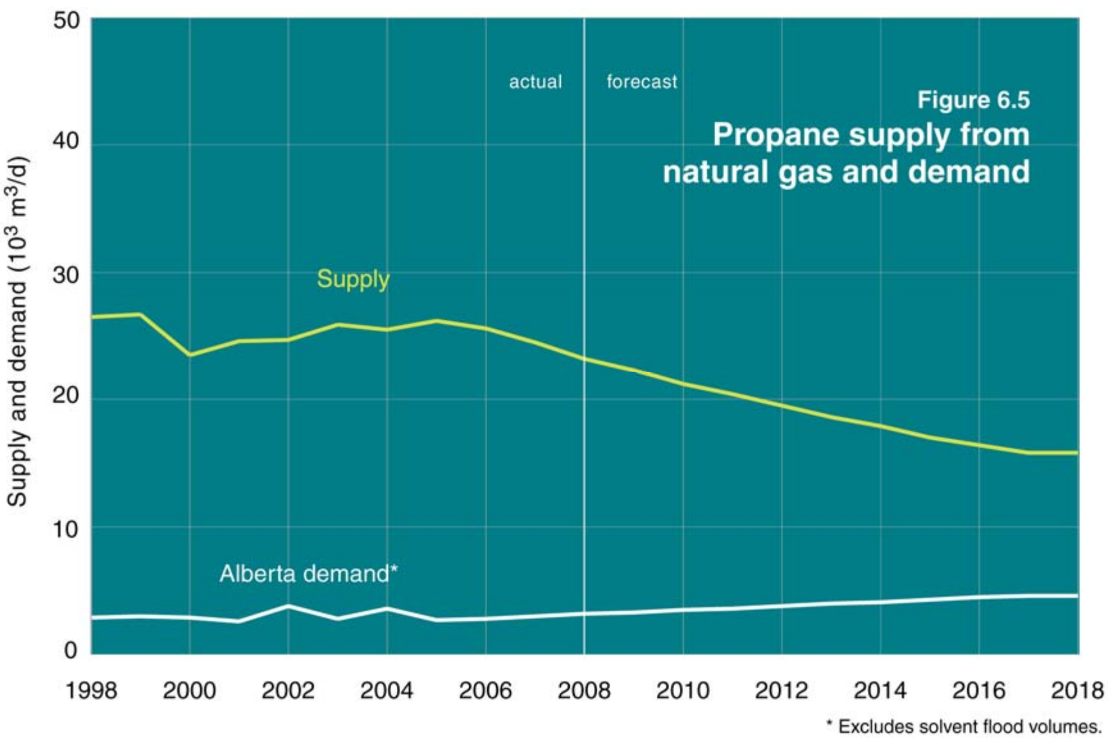


Figure 6.6 shows Alberta demand for butanes compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Butanes are used as refinery feedstock, as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate. In 2008, Alberta demand, excluding solvent flood demand, was 5.1 10^3 m^3/d, down from the 2007 demand level of 5.4 10^3 m^3/d. Alberta demand for butanes is forecast to remain constant at 2008 levels for the reminder of the forecast period.

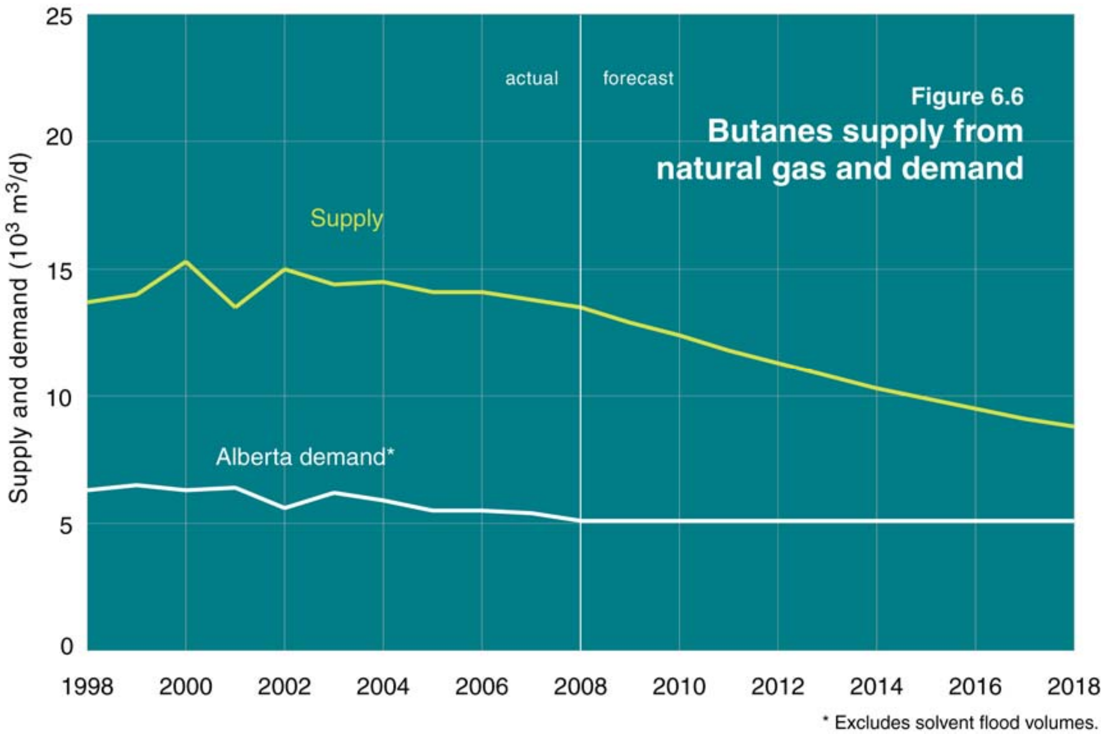
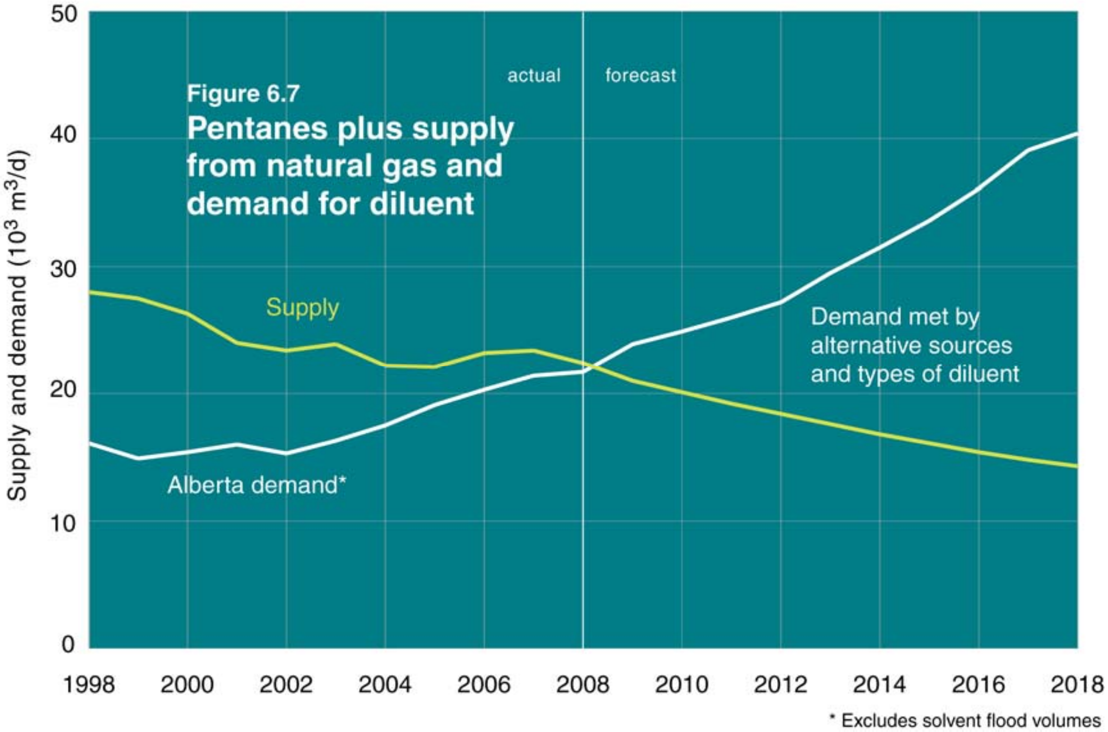


Figure 6.7 shows Alberta demand for pentanes plus as diluent compared to the total available supply. Pentanes plus are also used as feedstock for the refinery in Lloydminster; these small volumes (0.8 10^3 m^3/d in 2008) are not included in the figure. The largest use of Alberta pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate the transportation to market by pipeline. Diluent increases the API gravity and reduces the viscosity of heavy crude oil and bitumen. Typically, heavy crude oil requires 5.5 per cent of diluent to be added for Bow River and 17 per cent for Lloydminster heavy crudes respectively.

The required diluent for bitumen varies from a low of 17 per cent to as high as 31.6 per cent, depending on the producing regions of the province.

Demand for pentanes plus is expected to remain strong due to continued high diluent requirements. The anticipated increase in availability of synthetic product to use as diluent will likely not materialize due to the delay of several planned bitumen upgraders. As a result, pentanes plus demand as diluent is forecast to increase from 21.7 10^3 m^3/d in 2008 to 40.4 10^3 m^3/d in 2018. This increased demand is largely in response to an anticipated increase in diluent required for bitumen transport, which is forecast to grow to 39.1 10^3 m^3/d in 2018 from 19.6 10^3 m^3/d in 2008. Conversely, the diluent requirement for transport of heavy crude is expected to decline from 2.1 10^3 m^3/d in 2008 to 1.3 10^3 m^3/d by the end of the forecast period, due to declining heavy crude oil production. However, despite the reduced heavy crude diluent requirement, shortages of Alberta pentanes plus as diluent occurred in 2008. Industry has been using and assessing alternative sources and types of diluent in an attempt to reduce the demand of pentanes plus in light of the tight supply of available diluent in Alberta. Examples of current and future alternative sources of pentanes plus from outside Alberta are discussed on the following page.



- Alberta pentanes plus supply is augmented by up to 6.0 10^3 m^3 of pentanes plus from outside of Alberta, including the U.S.

- EnCana Corporation (EnCana) imports up to 4.0 10^3 m^3/d of offshore condensate to help transport its growing oil sands production to U.S. markets. With access to the Kitimat, B.C., terminal facility, EnCana imports diluent and transports it by rail to an Alberta pipeline connection that feeds its oil sands operation.

- Enbridge Inc. (Enbridge) is proceeding with the Southern Lights Pipeline, which will transport diluent from Chicago to Edmonton through a 28.6 10^3 m^3/d, 20 inch diameter pipeline. The pipeline, currently under construction, is expected to be in service by late 2010.

- Enbridge has shipper support for a proposed condensate pipeline capable of initially transporting 23.8 10^3 m^3/d from Kitimat to Edmonton. The Gateway Condensate Import Pipeline is expected to be in service in the 2012-2014 timeframe.

- New bitumen upgraders, similar to OPTI Canada Inc./Nexen Inc.'s Long Lake project, located in the field or in the Edmonton area, will upgrade in situ bitumen to synthetic crude oil. These projects will reduce Alberta's requirements for pentanes plus as diluent.

- The use of light crude oil, synthetic crude oil, or naphtha as diluent is an attractive alternative for moving in situ bitumen from the field to upgrading facilities.

7 Sulphur

Highlights

- Remaining established sulphur reserves increased by 20 per cent in 2008 relative to 2007 as the result of the increase in bitumen reserves under active development.
- Sulphur prices have declined dramatically coincident with the fall in crude oil prices to a current range of US$40-200 per tonne Free on Board (FOB) Vancouver, compared to US$150-350 per tonne last year.
- Exports to China declined by 30 per cent in 2008 from 2007; however, China continues to be the major export market.

Sulphur is a chemical element sometimes present in the form of hydrogen sulphide (H_2S) in conventional natural gas (sour gas), crude oil, and bitumen. The sulphur is extracted and sold primarily for use in making fertilizer. As mentioned in Section 5.1.5, 20 per cent of the remaining established reserves of natural gas contain H_2S.

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, 2008, to be 185.6 million tonnes (10^6 t), an increase of 20 per cent since 2007. This large increase is a result of the increase in bitumen reserves under active development. **Table 7.1** shows the changes in sulphur reserves during the past year.

Table 7.1. Reserves and production highlights (10^6 t)

	2008	2007	Change
Initial established reserves from			
Natural gas	268.1	266.6	+1.5
Crude bitumen[a]	178.5	143.1	+35.4
Total	446.6	409.7	+36.9
Cumulative net production from			
Natural gas	239.8	235.6	+4.2
Crude bitumen[b]	21.2	19.8	+1.4
Total	261.0	255.4	+5.6
Remaining established reserves from			
Natural gas	28.3	31.0	-2.7
Crude bitumen[a]	157.3	123.3	+34.0
Total	185.6	154.3	31.3
Annual production	5.6	6.3	-0.7

[a] Reserves of elemental sulphur from bitumen under active development as of December 31, 2008. Reserves from the entire surface mineable area are larger.
[b] Production from surface mineable area only.

7.1.2 Sulphur from Natural Gas

The ERCB recognizes 28.3 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2008, a decrease of 8.7 per cent from 2007. Remaining established sulphur reserves has 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 flaring of solution gas.

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 2008 are Caroline, Crossfield East, and Waterton, which together account for 8.7 10^6 t (31 per cent) of remaining established reserves 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 ultra-high H_2S pools currently not on production. Based on the initial established reserves of 268.1 10^6 t, this leaves 126.7 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 upgrading operations in which bitumen is converted to synthetic crude oil (SCO), 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 products including coke.

It is currently estimated that some 222.4 10^6 t of elemental sulphur will be recoverable from the 5.49 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by multiplying the remaining established reserves of crude bitumen by a factor of 40.5 t/1000 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 yields a higher elemental sulphur recovery than does an alternative carbon-rejection technology, since a larger percentage of the sulphur in the bitumen remains in upgrading residues, as opposed to being converted to H_2S.

If less of the mineable crude bitumen reserves is upgraded with the hydrogen-addition technology than currently estimated, or if less of the mineable reserves is upgraded in Alberta, as has been announced, the total sulphur reserves will be less. However, if some of the in situ crude bitumen reserves is upgraded in Alberta, as is currently planned, the sulphur reserves will be higher.

In January 2009, the Long Lake Upgrader began producing synthetic crude from bitumen produced by in situ methods, with the resulting production of elemental sulphur. Consequently, the ERCB will include such projects in future reports as a new entry in Table 7.1. At the same time, however, those mining projects that proceed without their production reporting to an Alberta upgrader will have their sulphur reserves deleted from the provincial total. If all the future bitumen production were to report to an Alberta upgrader, the ultimate sulphur recovered could be in excess of 2 billion tonnes.

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2008

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[a] (%)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Benjamin	3 604	5.2	223	302
Bighorn	3 294	7.6	303	410
Blackstone	2 050	10.2	276	374
Brazeau River	11 420	5.4	774	1 050
Burnt Timber	2 028	23.4	791	1 073
Caroline	8 611	18.9	2 752	3 732
Cecilia	10 862	1.5	191	259
Coleman	1 374	26.7	547	742
Crossfield	3 775	14.3	787	1 068
Crossfield East	2 782	27.8	1 337	1 812
Elmworth	15 739	2.6	493	669
Garrington	3 464	5.2	235	319
Hanlan	4 187	8.5	461	625
Jumping Pound West	4 958	6.6	411	557
Kaybob South	12 877	1.6	250	339
La Glace	2 302	6.2	166	225
Limestone	4 455	12.4	757	1 026
Marsh	1 059	18.9	285	387
Moose	2 851	13.3	503	682
Okotoks	1 859	19.9	531	720
Panther River	1 742	6.6	151	204
Pembina	21 888	1.9	511	693
Pine Creek	7 267	3.0	254	344
Quirk Creek	1 213	9.5	153	208
Rainbow	7 953	1.6	163	222
Rainbow South	2 906	6.4	268	363
Ricinus West	1 243	32.9	732	993
Waterton	6 310	22.4	2 338	3 170
Windfall	2 385	12.6	391	530
Subtotal	156 311	8.3	17 033	23 097
All other fields	941 855	0.4	3 798	5 170
Total	1 098 166	1.7	20 831	28 267

[a] Volume-weighted average.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only a portion of the surface-mineable established crude bitumen reserves is under active development at the Suncor, Syncrude, Albian Sands, Shell Jackpine, CNRL Horizon, Petro-Canada/UTS Energy/Tech Cominco Fort Hills, and Imperial Kearl projects. The ERCB estimate of the initial established sulphur reserves from these active projects is

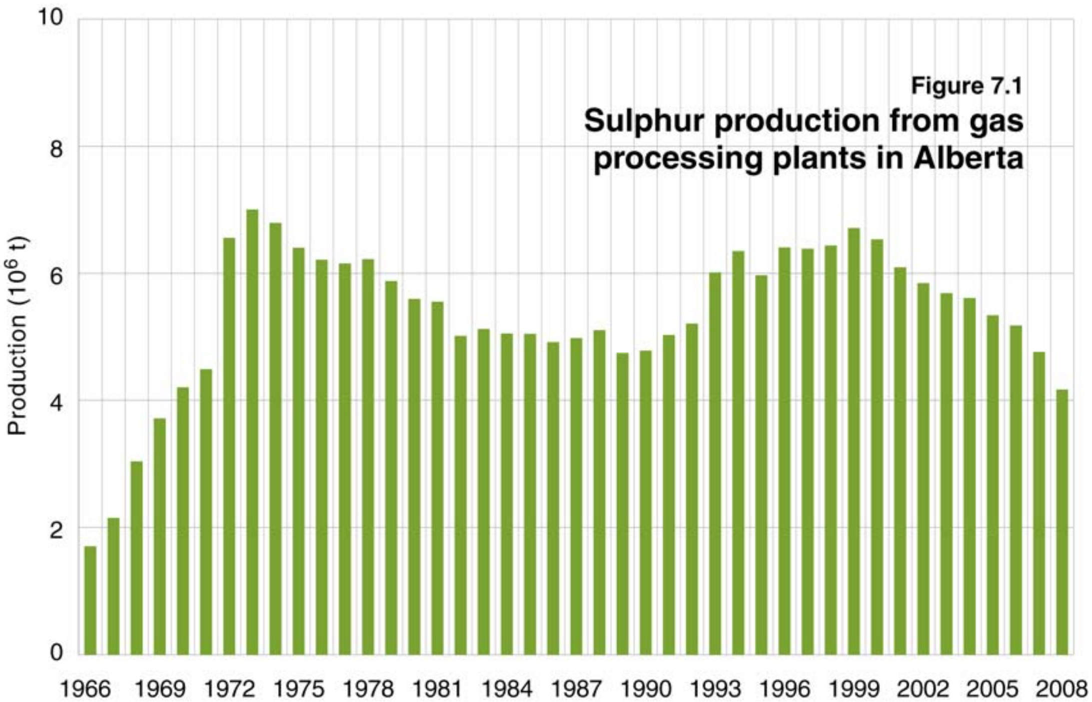
178.5 10^6 t, representing 80 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. This estimate has increased in 2008 due to the addition of the approved Imperial Kearl project. A total of 21.2 10^6 t of elemental sulphur has been produced from these projects, leaving remaining established reserves of 157.3 10^6 t. During 2008, 1.4 10^6 t of elemental sulphur was produced from the three currently producing projects.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Supply

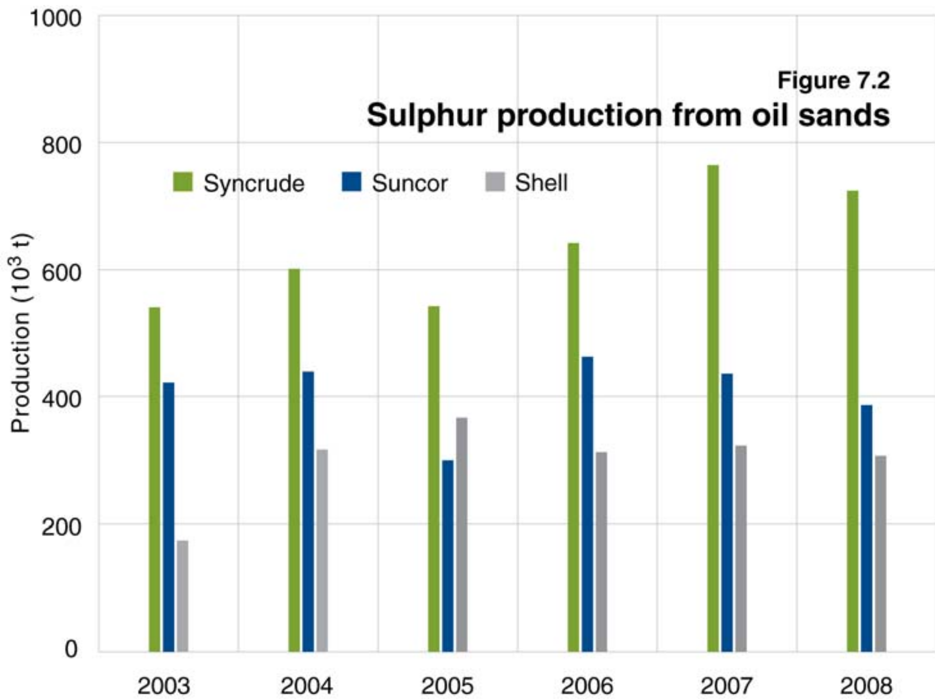
There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to SCO, and refining of crude oil into petroleum products. In 2008, Alberta produced 5.6 10^6 t of sulphur, of which 4.2 10^6 t was derived from sour gas, 1.4 10^6 t from upgrading of bitumen to SCO, and just 12 thousand (10^3) t from oil refining.

Figure 7.1 shows sulphur production from gas processing plants from 1966 onward. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional gas declines, less sulphur will be recovered from gas processing plants.



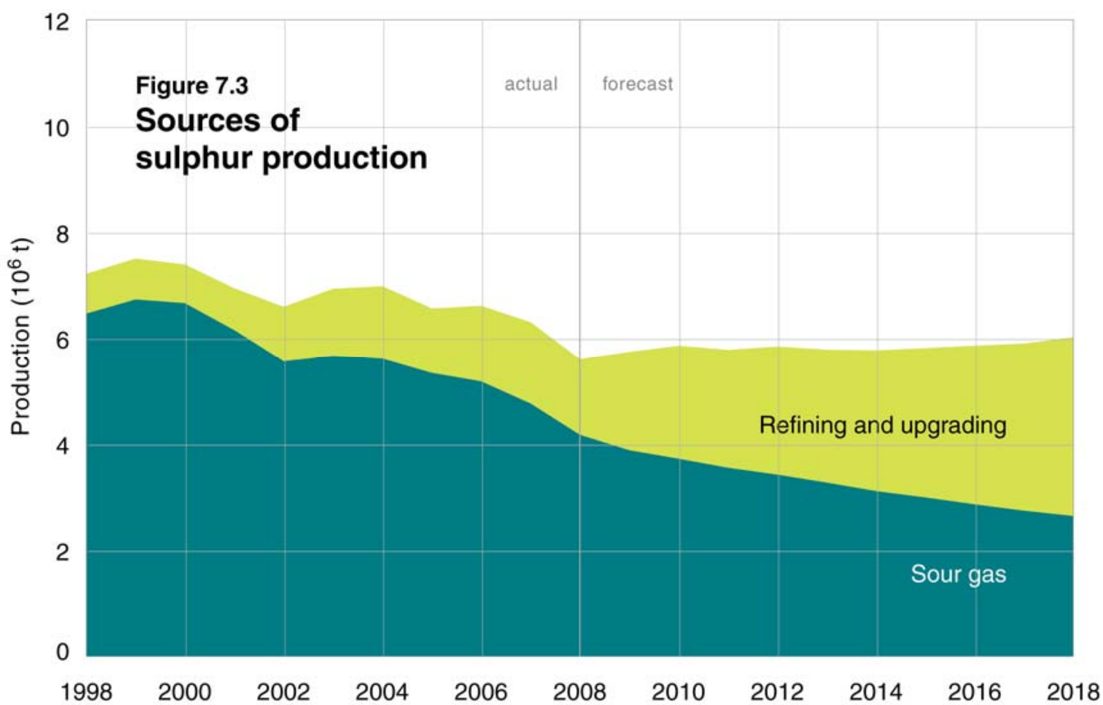
Inventory blocks of sulphur in Alberta at gas processing plants are 3.6 10^6 t at year-end 2008, down from 4.0 10^6 t at year-end 2007, a decrease of 10 per cent. Sulphur stockpiles have been drawn down in recent years to meet high demand. **Figure 10** in the Overview section illustrates sulphur closing inventories at gas processing plants and oil sands operations from 1971 to 2008, along with sulphur prices.

Sulphur production from the three existing oil sands upgrader operations is shown in **Figure 7.2** for the period 2003-2008. Total production in 2008 of 1.4 10^6 t is down slightly relative to 2007 production of 1.5 10^6 t.



Alberta refineries are expected to replace conventional crude and synthetic crude with bitumen, as integration of bitumen upgrading and refining takes place. With this integration, sulphur recovery from Alberta refineries, although small relative to the sulphur recoveries from the other two sources, is anticipated to increase.

Total Alberta sulphur production from sour gas and crude oil and bitumen upgrading and refining is depicted in **Figure 7.3**. Sulphur production from sour gas is expected to decrease from 4.2 10^6 t in 2008 to 2.6 10^6 t, or about 40 per cent, by the end of the forecast period. However, sulphur recovery in the bitumen upgrading industry is expected

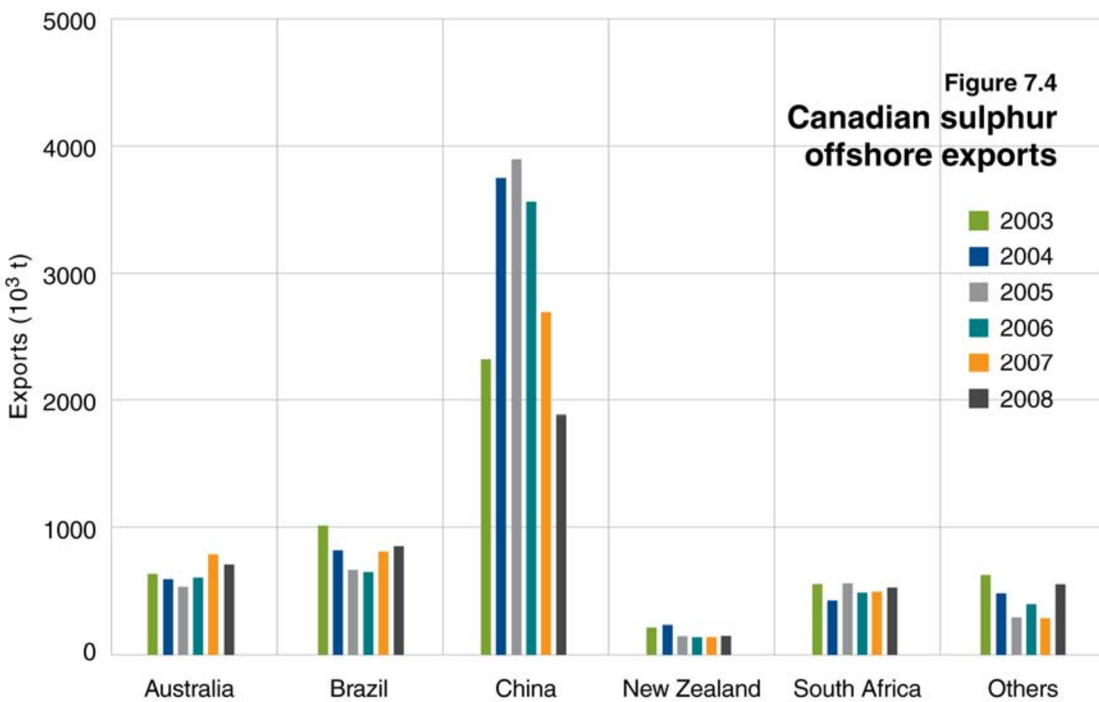


to increase from 1.4 10^6 t to 3.3 10^6 t, and sulphur recovery from Alberta refineries is forecast to increase from 12 10^3 t in 2008 to 32 10^3 t by 2018. Sulphur production from bitumen upgrading operations is determined based on the ERCB's forecast of SCO production. This year's forecast of sulphur production from bitumen upgrading is lower than last year's, corresponding with the decrease in SCO production. The total sulphur production of 6.0 10^6 t in 2018 represents an increase of about 7 per cent from 2008 levels.

7.2.2 Sulphur Demand

Disposition of sulphur within Alberta in 2008 was 461 10^3 t, up from 204 10^3 t in 2007. It is used in production of phosphate fertilizer and kraft pulp and in other chemical operations. A portion of the sulphur volume may include sulphur dispositions between gas processing plants in Alberta for transportation purposes, and although they were reported as Alberta sales, the volumes may not have been consumed in the province. Some 92 per cent of the sulphur marketed by Alberta producers was shipped outside the province, primarily to the U.S. and China.

China's imports of sulphur have increased since 1995, and exports from Canada have grown substantially. China is the world's largest importer of sulphur, which is used primarily for making sulphuric acid to produce phosphate fertilizers. **Figure 7.4** shows the export volumes sent to markets outside of North America in the last five years. Clearly, China accounts for the majority of Canadian exports to foreign countries.



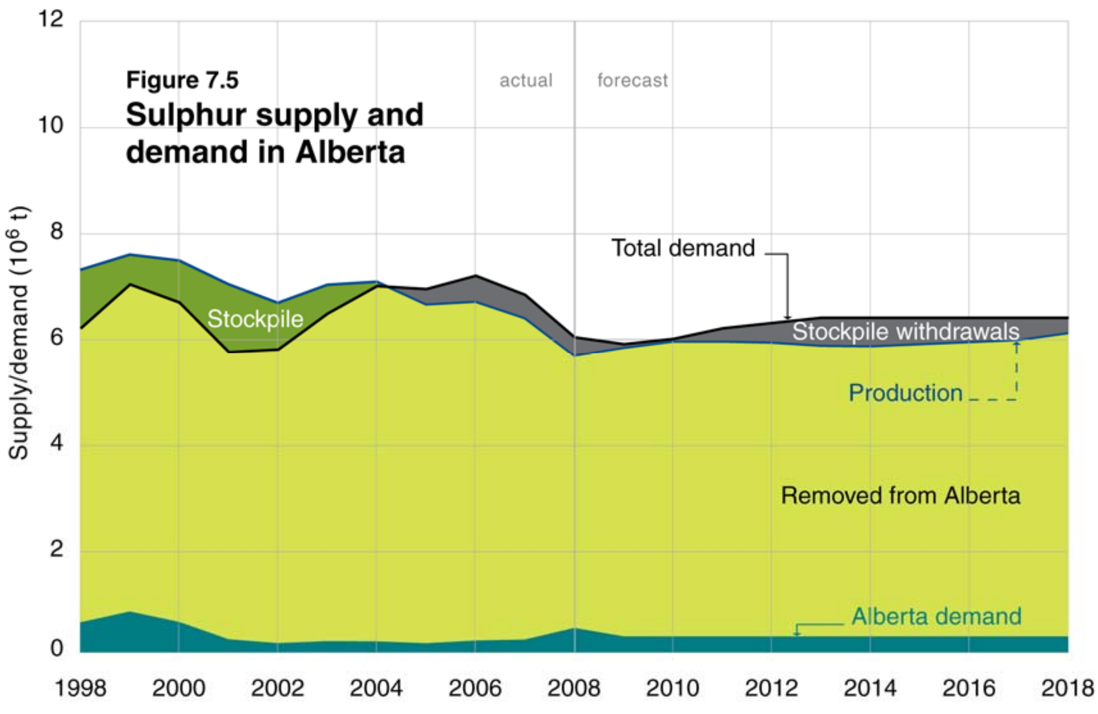
While China has been one of the fastest growing sulphur markets, Canadian supply to the market has declined by 30 per cent in 2008 over 2007. Canada's share of exports into the China market has dropped, while competitive supplies from the Middle East have increased. Increased global demand for sulphur since 2001 resulted in major price changes, from US$16/t in 2001 to US$50/t in 2006. In 2007, the Alberta sulphur prices increased sharply, from US$50/t at mid-year to between $US150/t to $350/t FOB

Vancouver**.** Prices reached highs of US$800/t in early 2008, before falling in August in tandem with crude oil prices.

In 2008, the Alberta plant gate price for North American sales averaged Cdn$263/t, while the Alberta plant gate price for offshore sales averaged Cdn$297/t. Demand for sulphur has fallen dramatically with the downturn in the world economy. January 2009 Alberta gas plant gate prices averaged Cdn$20 per tonne for both North American and offshore sales. Prices are expected to remain at this level for the next few years until demand recovers.

Because elemental sulphur (in contrast to sulphuric acid) 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.

In the past few years, supply and demand have generally been in balance and are forecast to remain so over the forecast period. (Based on forecast production, minimal stockpile withdrawals are required to meet forecast demand.) Changes to the sulphur inventory are illustrated in **Figure 7.5** as the difference between total supply and total demand.



8 Coal

Highlights

- Alberta marketable coal production has remained flat in 2008 relative to 2007.
- Export markets remained strong in 2008.

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 mountain region.

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 following reserves and production information summarizes and marginally updates the material found in EUB *Statistical Series 2000-31: Reserves of Coal*. See that report 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 at December 31, 2008, to be 33.4 gigatonnes[1] (Gt) (36.8 billion tons). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods, and 10.8 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 2008. **Table 8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

Minor changes in remaining established reserves from December 31, 2007, to December 31, 2008, resulted from increases in cumulative production. During 2008, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.005 Gt, 0.007 Gt, and 0.026 Gt respectively.

8.1.2 Initial in-Place Resources

Several techniques, in particular the block kriging, grid, polygon, and cross-section methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground-mineable coal. There was no change to the in-place resource estimate over the previous year.

In general, shallow coal is mined more cheaply by surface than by underground methods; such coal is therefore 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

[1] Giga = 10^9.

[2] Strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

Table 8.1. Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2008[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	0.235	0.576
Underground	5.06	0.738	0.108	0.630
Subtotal	6.83[c]	1.56[c]	0.343[d]	1.217[c]
High-volatile bituminous				
Surface	2.56	1.89	0.166	1.724
Underground	3.30	0.962	0.047	0.915
Subtotal	5.90[c]	2.88[c]	0.213[d]	2.667[c]
Subbituminous[e]				
Surface	13.6	8.99	0.754	8.236
Underground	67.0	21.2	0.068	21.132
Subtotal	80.7[c]	30.3[c]	0.822	29.478[c]
Total[c]	93.7[c]	34.8[c]	1.379	33.421[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] Difference due to rounding.
[e] Includes minor lignite.

between surface- and underground-mineable coal is very broadly based on depth and strip ratio, designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

8.1.3 Reserves Methodology

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, as well as the thicker underground classes.

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 2008.

Table 8.2. Established resources and reserves of raw coal under active development as of December 31, 2008

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[d] (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	18	136
Grande Cache	4 250	199	85	26	59
Subtotal	11 705	445	239	44	195
High-volatile bituminous					
Coal Valley	17 865	572	331	128	203
Subtotal	17 865	572	331	128	203
Subbituminous					
Vesta	2 410	69	54	44	10
Paintearth	2 710	94	67	46	21
Sheerness	7 000	196	150	78	72
Dodds	425	2	2	1	1
Burtonsville Island[c]	150	0.5	0.5	0.1	0.4
Whitewood	3 330	193	120	80	41
Highvale	12 140	1 021	764	363	401
Genesee	7 320	250	176	69	107
Subtotal[d]	35 485	1 826	1 334	681	653
Total	65 055	2 843	1 904	853	1 051

[a] ha = hectares.
[b] Mt = megatonnes; mega = 10^6.
[c] Formerly known as Keephills mine.
[d] Differences are due to rounding.

8.1.4 Ultimate Potential

A large degree of uncertainty is inevitably associated with estimating an ultimate potential, and new data could substantially alter results. Two methods have been used to estimate ultimate potential of coal. The first, the volume method, gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the second method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

To avoid large fluctuations of ultimate potentials from year to year, the ERCB has adopted the policy of using the figures published in *Statistical Series 2000-31* 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 2008.

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 making. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of bituminous thermal 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 Supply

The locations of coal mine sites in Alberta are shown in **Figure 8.1**. In 2008, eleven mine sites supplied coal in Alberta, as shown in **Table 8.4**. The operating mines produced 32.5 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 79.1 per cent of the total, bituminous metallurgical 9.5 per cent, and bituminous thermal coal the remaining 11.4 per cent.

Figure 8.1
Producing coal mines in Alberta

○ Surface coal mine ● Underground coal mine

Mountain Region
Low- to medium-volatile bituminous coals
1. Grande Cache
2. Cheviot

Foothills Region
High-volatile bituminous coals
3. Coal Valley

Plains Region
Subbituminous coals
4. Highvale
5. Whitewood
6. Burtonsville Island
7. Genesee
8. Dodds
9. Vesta
10. Paintearth
11. Sheerness

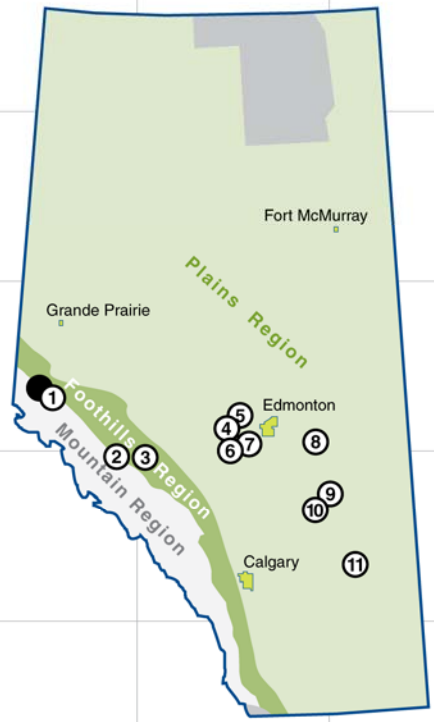


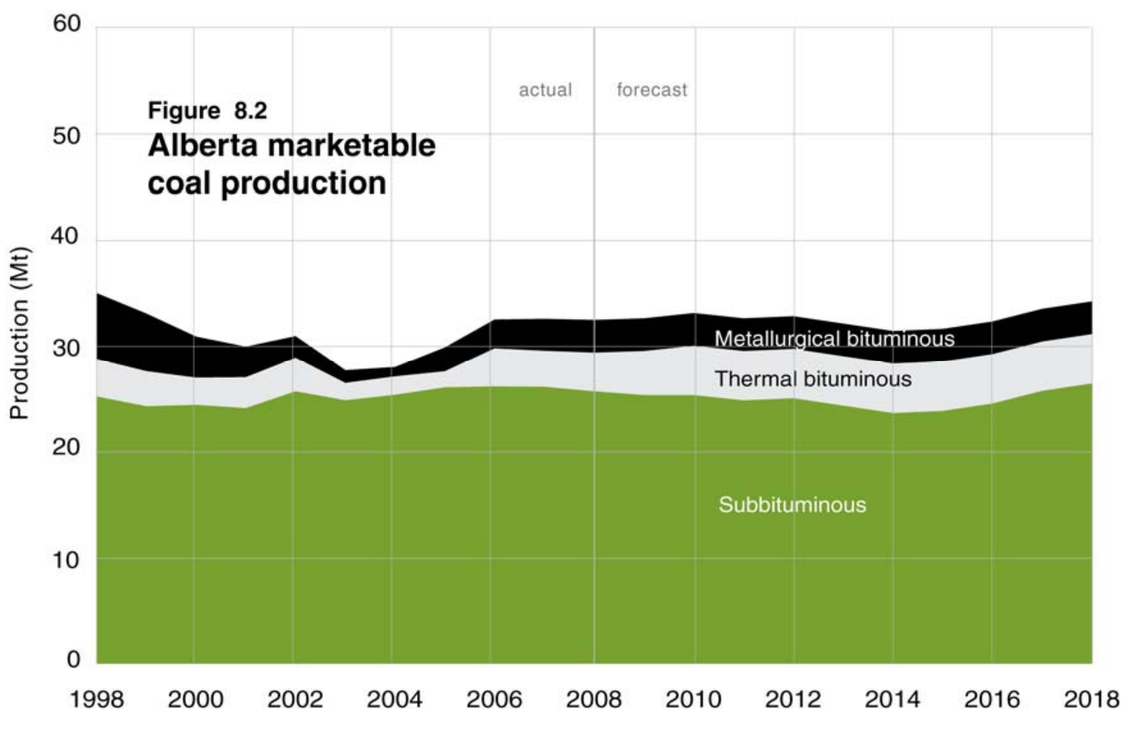
Table 8.4. Alberta coal mines and marketable coal production in 2008

Operator/owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Sherritt International Corp. / EPCOR Generation	Genesee	Genesee	5.2
Sherritt International Corp.	Sheerness	Sheerness	3.8
	Paintearth	Halkirk	1.8
	Vesta	Cordel	1.2
Sherritt International Corp. / TransAlta Utilities Corp.	Highvale	Wabamun	12.1
	Whitewood	Wabamun	1.5
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.104
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.030
Subtotal			25.7
Bituminous metallurgical coal			
Teck Cominco Ltd. /Elk Valley	Cheviot	Mountain Park	1.7
Grande Cache	Grande Cache	Grande Cache	1.4
Subtotal			3.1
Bituminous thermal coal			
Sherritt International Corp.	Coal Valley	Coal Valley	3.7
Total			32.5

Six large mines and two small mines produce subbituminous coal. The large mines serve nearby electric power plants, while the small mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the coal reserves have been dedicated to the power plants.

Three surface mines and one underground mine produce the provincial metallurgical and thermal grade coal.

The forecast Alberta production for each of the three types of marketable coal is shown in **Figure 8.2**. By 2018, total production is expected to increase by about 5 per cent, from 32.5 Mt in 2008 to 34.2 Mt in 2018. Provincial thermal grade coal is expected to have the largest production increase, about 21 per cent between 2008 and 2018. Growth of about 3 per cent is forecast for subbituminous coal production, while production from metallurgical grade coal is assumed to remain flat over the forecast period. Subbituminous coal production is expected to increase due to uprates (the process of increasing the maximum generating level at which a power plant may operate) to existing power generating units, as well as to the new Keephills 3 unit, which is to be in service in 2011. There is also potential for an additional power generating plant in the forecast period. In 2003, the Obed Mountain mine was suspended due to declining export thermal coal prices. This mine is expected to resume operations in the latter part of 2009, despite the current weak price environment.



8.2.2 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electric generation plants, and their production ties in with electricity generation. Plant uprates are expected to occur at existing power plants, despite the current economic downturn.

In 2009, TransAlta plans to upgrade Sundance Unit 5 to increase the capacity of the unit by 53 megawatts (MW). The rate of coal use by the power plant is expected to increase by about 7 per cent. A new power generation unit at the Keephills plant site with a capacity of 450 MW is planned to be in service in 2011. Within the forecast period, there is also the potential for an additional plant that would be fuelled by subbituminous coal. By 2010, the last remaining generation unit at the Wabamun plant site (279 MW) will cease operations.

Alberta's metallurgical coal primarily serves the Asian steel industry (mainly Japan), creating the competitive disadvantage of export coal producers having to move their product long distances from mine to port. Throughout 2008, the demand for metallurgical coal in export markets was strong, due to the strong demand for steel. Late in 2008, however, the worldwide economic slowdown resulted in declining global steel production, which in turn is negatively impacting the demand for metallurgical coal. Alberta's metallurgical coal shipments, however, have not yet registered a decline. The 2009 forecast assumes flat production to export markets.

9 Electricity

Highlights

- In 2008, electricity generating capacity increased by over 400 MW, primarily from natural gas-fired cogeneration and peaking facilities.
- Electricity demand increased by 0.4 per cent in 2008, following a similar 0.4 per cent increase in 2007.
- The annual average pool price increased to $90/MWh in 2008 from $67/MWh in 2007.
- A needs application was filed for $1.8 billion in transmission investment required to connect up to 2700 MW of wind capacity in southern Alberta.

The ERCB forecasts electric power supply and demand, as it is 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, as power plants that use these fuels supply over 90 per cent of the electricity generated within Alberta.

While the ERCB regulates the oil and gas industry, the Alberta Utilities Commission (AUC) regulates utilities, which includes overseeing the building, operating, and decommissioning of electricity generating facilities and the routing, tolls, and tariffs of electricity transmission through transmission lines.

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 the planning of 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.

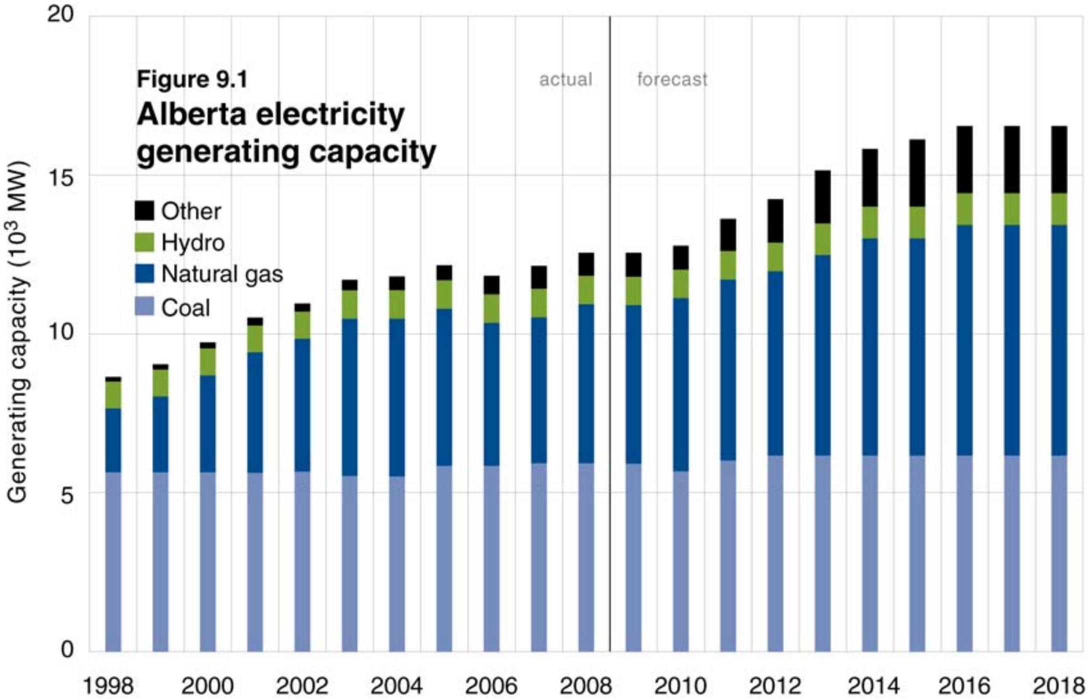
9.1 Electricity Generating Capacity

9.1.1 Provincial Summary

Capacity refers to the maximum potential supply of electric power, often expressed in megawatts (MW), that can be produced each hour. Alberta's fuel mix of available electricity generating capacity is composed of coal, natural gas, hydroelectric power, and renewable energy, such as wind and biomass. A relatively small amount of capacity is obtained from diesel and fuel oil-fired generators, which are used as a source of backup power for industrial use. Alberta also relies on transmission interties with neighbouring provinces, which enable the import and export of electricity.

A large majority of the natural gas-fired capacity in the province is classified as cogeneration. Cogeneration is the combined production of electricity and thermal energy using natural gas as a fuel source. Thermal energy is often used in manufacturing processes, heating buildings, the production of steam for in situ oil production, and crude oil refining and upgrading processes. Therefore, cogeneration plants are often sited alongside an industrial facility.

The structure of Alberta's electricity industry, as illustrated in **Figure 9.1**, has changed since the years of deregulation. In 1998, Alberta's electric power generation capacity was



more than 8600 MW, with coal-fired facilities accounting for 65 per cent. Between 1998 and 2008, electric power generation capacity had increased to over 12 000 MW. In 2008, coal-fired facilities accounted for 47 per cent of Alberta's total electric generation capacity and natural gas-fired facilities accounted for 40 per cent.

In 2008, Alberta's electric power generation capacity increased by over 400 MW. Most of the increase was due to additional capacity from natural gas-fired generators. The Long Lake in situ oil sands project and the Horizon mined oil sands project both started up associated cogeneration units in late 2008, which accounted for over 280 MW of new capacity. Both oil sands projects are in the initial phase of start-up, and as a result these projects are currently exporting more power to the provincial grid than will be expected once the projects ramp up to full production and demand for on-site electricity increases.

Four natural gas-fired peaking units also came on stream in 2008: the ATCO Valley View 2 plant (45 MW), the EPCOR Clover Bar 1 plant (43 MW), and two smaller 7 MW peaking units. Investment in peaking capacity has been quite strong recently, and more peaking projects are scheduled to come on line in 2009: the ENMAX Crossfield plant (120 MW) and the EPCOR Clover Bar 2 plant (100 MW). The Grand Prairie Generation peaking plant (93 MW) was given interim authorization to participate in the Alberta electricity market on December 23, 2008, and received commercial operation designation on February 25, 2009.

New proposed power projects considered in the electricity forecast are summarized in **Table 9.1**. Projects, capacities, and planned start-ups are based on information obtained as of February 28, 2009. Currently, considerable uncertainty surrounds the exact timing of additional oil sands-related facilities, but most are still projected to proceed within the forecast period. By the end of the forecast period, the ERCB projects electricity generating capacity in Alberta to be over 16 000 MW.

Table 9.1. Proposed power plant additions greater than 5 MW, 2009-2018

Power project	Fuel / type	Location	Proposed capacity (MW)
2009			
Sundance 5 uprate	Coal	Parkland County	53
Crossfield Energy Centre	Natural gas	Rocky View MD	120
Deerland peaking station (Phase 1)	Natural gas	Lamont County	90
Firebag in situ cogen 2	Natural gas	Wood Buffalo MD	170
Clover Bar power plant 2	Natural gas	Strathcona County	100
Prairie Home wind turbines	Wind	Warner County	14
Old Man River wind farm	Wind	Pincher Creek MD	47
Ghost Pine wind farm	Wind	Kneehill County	81
2010			
Deerland peaking station (Phase 2)	Natural gas	Lamont County	90
Clover Bar Power Plant 3	Natural gas	Strathcona County	100
Irma generation facility	Natural gas	Wainwright MD	8
Morinville generation facility	Natural gas	Sturgeon County	8
Kettles Hill wind farm 2	Wind	Pincher Creek MD	77
Wild Rose wind farm 1	Wind	Cypress County	137
Castle Rock Ridge wind farm	Wind	Pincher Creek MD	115
Blue Trail wind farm	Wind	Willow Creek MD	66
Sundance Forest Industries	Biomass	Yellowhead County	10
2011–2018			
Keephills 3	Coal	Parkland County	450
Carmon Creek in situ cogen	Natural gas	Northern Sunrise County	185
Christina Lake in situ cogen 2	Natural gas	Wood Buffalo MD	85
Firebag in situ cogen 3 and 4	Natural gas	Wood Buffalo MD	170
Kearl oil sands cogen 1 and 2	Natural gas	Wood Buffalo MD	170
Fort Hills oil sands cogen	Natural gas	Wood Buffalo MD	170
MacKay expansion in situ cogen	Natural gas	Wood Buffalo MD	165
Jackpine oils sands cogen	Natural gas	Wood Buffalo MD	160
Horizon oil sands cogen 2	Natural gas	Wood Buffalo MD	86
Joslyn oil sands cogen	Natural gas	Wood Buffalo MD	85
Long Lake South in situ cogen	Natural gas/syngas	Wood Buffalo MD	85
Dunvegan hydro project	Hydro	Fairview MD	100
Summerview wind farm 2	Wind	Pincher Creek MD	62
Heritage wind farm	Wind	Pincher Creek MD	297
University of Calgary	Natural gas	City of Calgary	18
Medicine Hat Box Springs	Wind	Medicine Hat	16
Halkirk Wind Project	Wind	Paintearth County	150
Blackspring Ridge Project	Wind	Vulcan County	300
Maxim HR Milner	Coal	Greenview MD	500
Saddlebrook Power Station	Gas	Foothills MD	338
Total proposed generation (2009-2018)			4 878

An additional coal-fired unit at Keephills is the only new power plant project currently being constructed that will provide an increase to Alberta's baseload capacity. Keephills 3 is scheduled to be completed in early 2011, after the retirement of Wabamun 4. The addition of 450 MW at Keephills will add about 170 MW of baseload coal capacity to the Alberta market after accounting for the Wabamun retirement.

New natural gas-fired cogeneration facilities will offer the largest contribution to electricity generating capacity over the forecast period. Their commissioning will coincide with the development of Alberta's oil sands resources. Cogeneration is a source of steam and power, both requirements for oil sands projects. Because there are greater efficiencies associated with cogeneration compared to purchasing electricity and using steam generators, combining cogeneration with an oil sands facility can reduce costs over the life of an oil sands project. If the plant is able to sell power that is in excess of the project requirements, cogeneration can supplement project revenues. By 2018, the capacity of natural gas-fired power and cogeneration units is forecast to total more than 7200 MW, accounting for 44 per cent of Alberta's total available capacity.

9.1.2 Electricity Generating Capacity by Fuel

Coal

In 2008, the capacity of coal-fired generation units was over 5900 MW and accounted for 47 per cent of Alberta's generating capacity.

TransAlta Corporation is forecast to complete an uprate to current capacity at its Sundance Unit 5 coal-fired plant in 2009, which will enable it to produce an additional 53 MW of electricity using less fuel on a per megawatt hour (MWh) basis. A similar project was completed at Sundance Unit 4 in 2007. TransAlta has also filed regulatory applications with the AUC to uprate Keephills 1 and 2 by 23 MW each in 2011 and 2012 respectively.

The construction of Keephills 3 (450 MW) commenced in February 2007 and is expected to reach commercial operation in the second quarter of 2011. Keephills 3 incorporates supercritical boiler technology featuring higher boiler temperatures and pressures. Combined with a high-efficiency turbine, the unit will require less fuel and emissions will be lower on a per MWh basis. TransAlta and EPCOR have equal ownership in the Keephills 3 power plant. EPCOR is managing the construction, and TransAlta will operate the facility. The capital cost of Keephills 3, including mine capital, is expected to be about $1.6 billion.

As indicated in Table 9.1, MAXIM Power Corp. has filed an application for construction of a 500 MW coal-fired facility.

Although some power purchase agreements (PPAs)[1] expire within the forecast period, according to the legislation the PPA may extend beyond the current expiration date. Operators of power plants that have PPAs expiring prior to 2019 have one year after the expiry of the PPA to determine whether to decommission the plant or continue to operate and be responsible for decommissioning costs. Until public notification of a plant

[1] 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 (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.

decommissioning occurs, power plants operating under PPAs will remain in the forecast regardless of the expiration of the PPA.

Natural Gas

In 2008, natural gas-fired generating capacity approached 5000 MW and accounted for 40 per cent of Alberta's current total electricity capacity. Over the next 10 years, Alberta's natural gas-fired electric capacity is projected to increase by 2200 MW, representing 44 per cent of Alberta's total generating capacity.

The ERCB's 10-year forecast for new natural gas-fired cogeneration power plants that coincide with the development of the oil sands amounts to an additional 1600 MW. These plants will account for 73 per cent of the increase in natural gas-fired capacity. Table 9.1 lists the cogeneration projects, most of which will be sited in the Municipal District of Wood Buffalo.

In addition to proposed oil sands cogeneration facilities, a number of natural gas-fired peaking facilities have recently been built or proposed. These peaking plants are a response to high, volatile prices in Alberta in recent years, particularly when concurrent forced outages have occurred at baseload coal plants. Peaking plants are designed to be available on short notice and can respond quickly to varying market conditions. However, only one of the peaking stations is to be sited in the southern region of the province. ENMAX Green Power's 120 MW Crossfield Energy Centre will be sited outside of Calgary in the Municipal District of Rocky View and is expected to be operational in 2009. In September 2008, TransCanada applied to the AUC to build a 338 MW combined cycle plant south of Calgary.

Hydroelectric Power

Hydroelectric generation capacity in Alberta has been essentially unchanged since 2003 at almost 900 MW, accounting for 7 per cent of total generation capacity in 2008. About 800 MW of this capacity is owned by TransAlta, which operates 26 generating units along the Bow and North Saskatchewan rivers.

In 2006, Glacier Power, a subsidiary of Canadian Hydro Developers Inc., filed a regulatory application with the EUB to construct and operate the Dunvegan 100 MW hydroelectric power plant on the Peace River. In late 2008, a joint panel of the Natural Resources Conservation Board, AUC, and the Canadian Environmental Assessment Agency approved the project. The project still requires approval from the Department of Fisheries and Oceans, as well as Transport Canada. The current forecast projects Dunvegan to commence operations in 2013.

Renewable Power

About 6 per cent of Alberta's current electricity capacity is classified as renewable power, which includes biomass and wind. 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. Forestry industries typically burn waste wood as a fuel source to generate electricity and thermal energy. In 2008, Alberta biomass capacity amounted to 184 MW, less than 2 per cent of Alberta's total capacity.

Wind-powered electric generation capacity has increased significantly over the last decade, from 23 MW in 1997 to 525 MW in 2007 as reported to the ERCB. No new projects were added in 2008. Transmission infrastructure is currently a significant barrier for new wind capacity in southern Alberta, but the AESO has recently applied for a transmission upgrade that would accommodate 1200 MW of new wind generation in southern Alberta in its first phase. The AESO is also seeking regulatory approval for additional future expansion phases that could accommodate up to 2700 MW of wind capacity in total. The current financial crisis, low natural gas prices, and slower projected electricity demand growth are factors that may impact the timing of additional wind-powered electric generation projects.

9.2 Supply of and Demand for Electricity

This section discusses the supply 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 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. Alternatively, 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.

In order to forecast electricity generation, the ERCB uses a defined list of existing and proposed electricity generating units operating within the geographical boundaries of the province, their electricity generating capacities and operating characteristics, a merit or stacking order, hourly customer load profiles, and projected electricity demand. The proposed generating units and generating capacities are discussed in the previous section.

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 from new generation is ramped up in a phased approach that corresponds with the expected on-site load at certain phases of bitumen or synthetic crude oil (SCO) 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, hydroelectric dams, and an amount of base coal-fired generation, are expected to offer in electricity generation first. Higher marginal cost producers, such as natural gas-fired turbines (under a regime of high natural gas prices), 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.

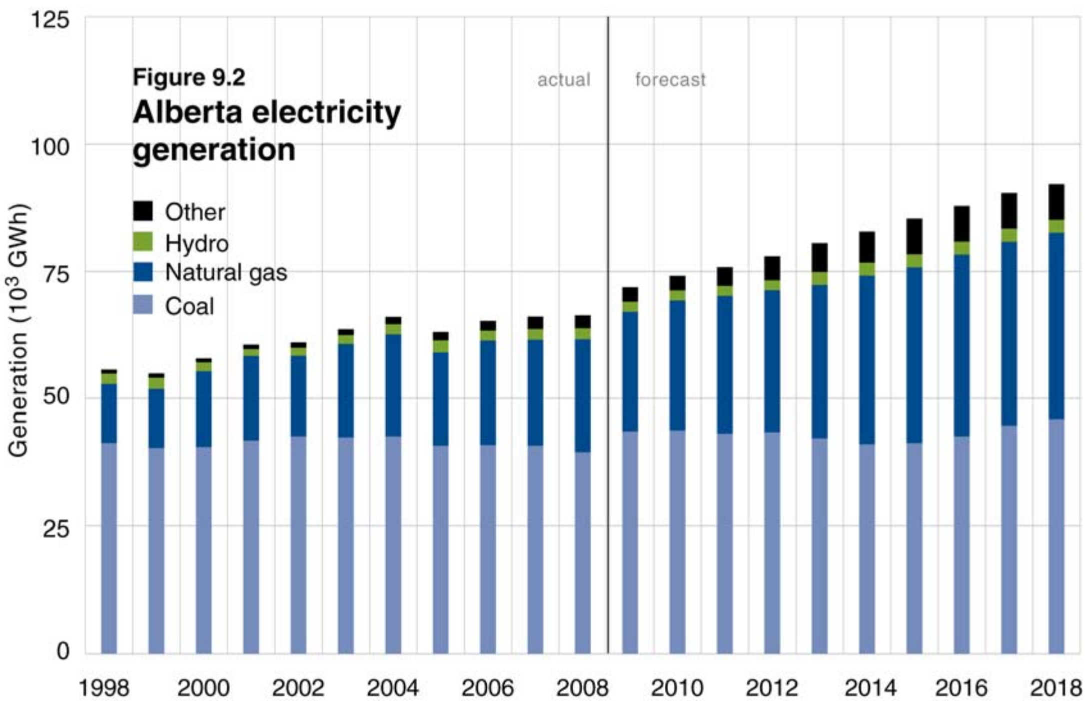
In this report, Alberta’s electricity demand is characterized by the Alberta Internal Load (AIL). The AIL forecast includes electricity sales reported by electricity distributors to agricultural, residential, commercial, and industrial customers; the direct use of electricity by industrial consumers that obtain their power directly from power plants located on site or near their facilities; and purchases of electricity by customers set up to directly purchase electricity from the Alberta power pool.

The ERCB uses customer segments and econometric modelling to forecast electricity demand. The key drivers of electricity demand include Alberta's gross domestic product, industrial demand, and housing stock. Industrial customers are examined in detail in order to adequately account for electricity demand in these industries. In the oil sands sector, bitumen and SCO production forecasts and the types of projects (in situ vs. mining) are also important drivers.

9.2.1 Electricity Generation

Alberta installed electricity generation capacity in 2008 was 12 562 MW, enough to supply about 110 000 GWh of electricity if operated at full capacity. However, total electricity generation capacity is not continuously available to meet demand. Generation units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, technical limitations (for instance, of wind turbines), or economic reasons. The current forecast projects that electric power generation capacity in Alberta will increase by almost 4000 MW over the next ten years.

Figure 9.2 illustrates total electric generation within the geographical boundaries of Alberta by fuel type, including electricity from cogeneration plants that is not sold into the Alberta Interconnected Electric System (AIES). In 2008, total electricity generation reached 66 398 GWh, a small decline from the 66 645 GWh produced in 2007. (Electricity generation in 2007 has been revised upwards from the 66 143 GWh reported last year.) The decline in electricity generation in 2008 was due to a 3 per cent drop in electricity generation from coal, due to higher plant outages. In 2009 and beyond, coal-fired plants are projected to run at higher utilization rates compared to 2008. Between 1998 and 2008, electricity generation in Alberta grew by 10 769 GWh or, on average, 2 per cent per year. By 2018, total electricity generation is forecast to be over 92 000 GWh.



In 2008, coal-fired power plants generated 59 per cent of the province's electricity, while natural gas and hydro accounted for 34 and 3 per cent respectively. The remaining 4 per cent was generated by wind and other renewable sources. Natural gas cogeneration plants dedicated to the oil sands sector generated 13 671 GWh of electricity, of which 8689 GWh (64 per cent) of the electricity generated was used on site, with the remaining sold into the power pool. By 2018, coal-fired power plants are forecast to generate 50 per cent of the province's electricity, while natural gas and hydro are forecast to account for 40 and 3 per cent respectively. The remaining 7 per cent is assumed to be generated by wind and other renewable sources.

Electric power generation from wind turbines contributed 1473 GWh, or 2 per cent, of total electricity generation in 2008 and is included in the "other" category in **Figure 9.2**. Wind generation constituted 58 per cent of the electricity generated in the "other" category, with electricity generation from biomass accounting for most of the remaining generation in this category. By 2018, wind generation is forecast to constitute 85 per cent of the "other" category.

9.2.2 Electricity Transfers

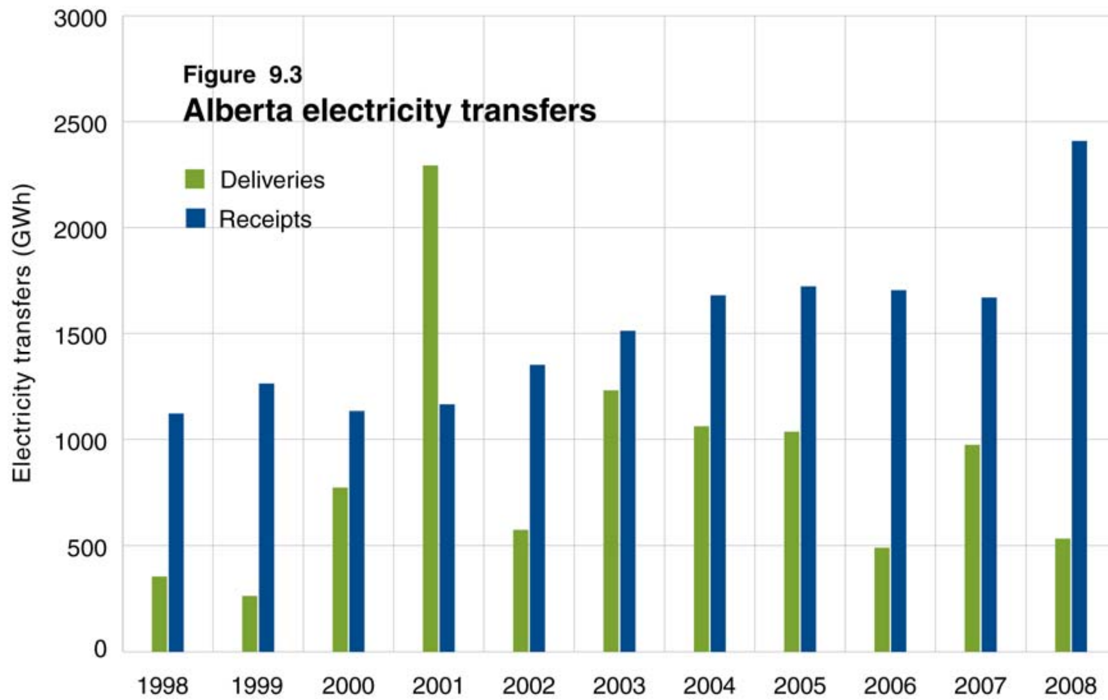
Alberta's transmission lines are connected with British Columbia (B.C.) and Saskatchewan. Alberta is interconnected with the B.C. transmission system through a 500 kilovolt (kV) line between Langdon, Alberta, and Cranbrook, B.C., and two 138 kV lines between Pocaterra and Coleman, Alberta, and Natal, B.C. Since B.C. is connected with the United States (U.S.) Pacific Northwest, the Alberta-B.C. intertie allows Alberta to indirectly trade electricity with the U.S. The 230 kV direct current electrical tie with Saskatchewan enables Alberta to import or export about 150 MW.

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. Operations on the Alberta-B.C. intertie are typically below these capacities and range between 0 and 750 MW, depending on system load and real-time operation conditions.

In addition to the transmission ties, a natural gas-fired electricity generation unit in Fort Nelson (northern B.C.) supplies power to its surrounding communities and sells surplus electricity generation into the Alberta grid.

Figure 9.3 illustrates Alberta's electricity transfers from 1998 to 2008. Over the last decade, Alberta has generally been a net importer of electricity, except in 2001, when the electricity price differentials between Alberta and the Pacific Northwest favoured Alberta and resulted in net exports for the year. In 2008, Alberta imported 2400 GWh of electricity from both Saskatchewan and B.C., an increase of 44 per cent, or 739 GWh, from 2007. Electricity exports decreased 46 per cent, or 442 GWh, to 532 GWh in 2008 relative to 2007. As a result, Alberta's net imports of electricity were 1876 GWh in 2008. The exports went almost exclusively to the B.C. side, which absorbed 496 GWh of power. The imports were also weighted toward the B.C. tie.

In 2006, Montana Alberta Tie Ltd. (MATL) filed regulatory applications to build a 230 kV merchant electric transmission line between Lethbridge, Alberta, and Great Falls, Montana. The MATL line is expected to carry generation from wind turbines in Alberta and Montana. Construction was planned to commence in 2009, with completion in 2010, but could be delayed due to the current economic climate.



The ERCB supply/demand projection for electric power projects forecasts that Alberta will be a net importer for the forecast period as a result of market price differentials and operational upsets. The net imports over the forecast period are projected to average less than 0.5 per cent of total demand per year.

9.2.3 Electricity Demand in Alberta

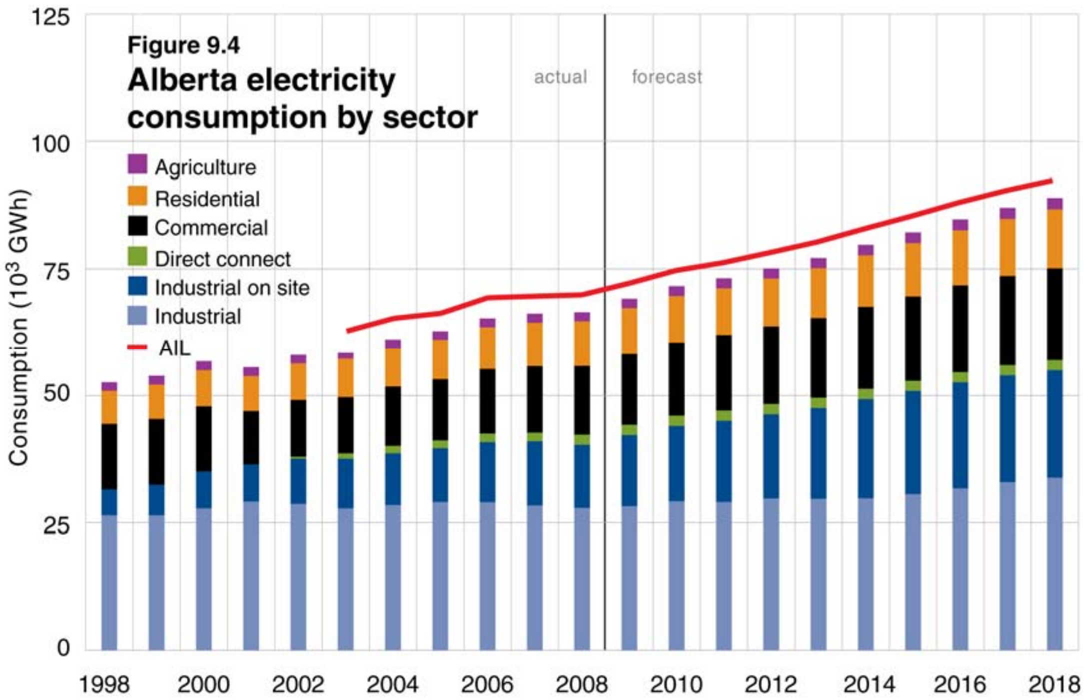
The demand outlook for electricity is often reported as two series. The first, the AIES, is the sum of all electricity sales (residential, commercial, industrial, and farm) and transmission and distribution losses.[2] The second, AIL, incorporates AIES and behind-the-fence load, which can be characterized as industrial load from on-site generation prior to sales to the power pool.

The ERCB 10-year load forecast is prepared from the examination of four sectors of the economy, residential, commercial, industrial, and farm, which account for the majority of the AIL forecast presented in this section. These forecasts are generated primarily from the ERCB economic growth forecast, oil sands development, population, and housing stock.

Annual AIL energy consumption has shown little growth in Alberta since 2006. In 2006, total AIL energy consumption was 69 363 GWh, in 2007 it was 69 654 GWh, and in 2008 it was 69 940 GWh. This represents less than 1 per cent growth over two years, or a 0.4 per cent annual average increase.

Figure 9.4 illustrates Alberta's electricity demand. It includes retail sales from electricity distribution companies by sector, direct connect sales, and industrial on-site electricity volumes. Alberta's total electricity demand for all sectors (excluding transmission and

[2] Most of Alberta's electricity is sold through electricity distribution companies. However, a few customers purchase a small amount of power directly from the power pool. In 2008, direct connect sales were about 2027 GWh, or 2 per cent of total AIL demand.



distribution losses) amounted to 66 454 GWh in 2008. Compared to 2007, this is an increase of 291 GWh, or 0.4 per cent.

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 are required to report their annual retail sales of electricity to the ERCB.

In 2008, Alberta's electricity consumption from sales reported by electricity distributors was 52 041 GWh. This is a slight increase from the sale of 51 838 GWh reported in 2007. From these sales, about 54 per cent of the electricity consumed is sold to industrial customers, 26 per cent to commercial customers, 17 per cent to the residential sector, and 3 per cent to the agricultural sector.

Details on customers provided by electricity retailers reveal that over 1.2 million residential customers consumed 8833 GWh of electricity in 2007. This resulted in an electricity intensity of just over 7.0 MWh per residential customer, slightly higher than the historical 10-year average of 6.9 MWh per residential customer. The electricity usage of the average commercial customer was estimated to be 90.3 MWh in 2008, slightly higher than the 2007 estimate of 90.2 MWh per customer.

Of the total electricity demand from all sectors, 83 per cent was sold through the AIES. In 2008, over 42 000 GWh, or 64 per cent, of the total electricity demand of all sectors was used by industrial consumers. About 30 000 GWh, or 70 per cent of industrial load, was sold through the AIES as sales by electricity distribution companies and direct connect customers, while 12 387 GWh of the electricity requirements of the industrial sector was delivered through on-site power generation or cogeneration.

Between 1998 and 2006, electricity demand grew by almost 4 per cent per year in response to rapid growth in all sectors, as the Alberta economy grew in response to the massive investments in the oil sands. However, increasing cost pressures, lower oil prices, and the crisis in financial markets have resulted in the slowing down of oil sands investments. Although AIL demand is projected to increase in 2009 as two oil sands projects come on line, as discussed below, slower projected economic growth rates will result in lower growth rates for electricity demand. The forecast for AIL growth from 2009 onward is projected to average 2.8 per cent. By 2018, the AIL demand is forecast to be 92 600 GWh. Although oil sands project timing has become more uncertain, most of the proposed projects are delayed but still projected to come on stream during the forecast period. Hence, industrial demand will continue to lead growth in electricity demand over the forecast period. In 2009, electricity demand may grow by 380 MW alone, due to projects like OPTI/Nexen Long Lake and CNRL Horizon commencing their first year of SCO production. The expected growth in industrial loads over the forecast period is projected to average 3.2 per cent per year.

Over the next 10 years, growth in residential electricity demand is projected to average 2.8 per cent per year, tracking the lower economic growth rate, population growth, and accompanying housing starts. Farm load is projected to continue to grow at about 2 per cent per year. Electricity demand in the commercial sector will also increase at a slower rate than previously experienced, averaging about 2.9 per cent per year, based on the ERCB's current economic forecast for Alberta.

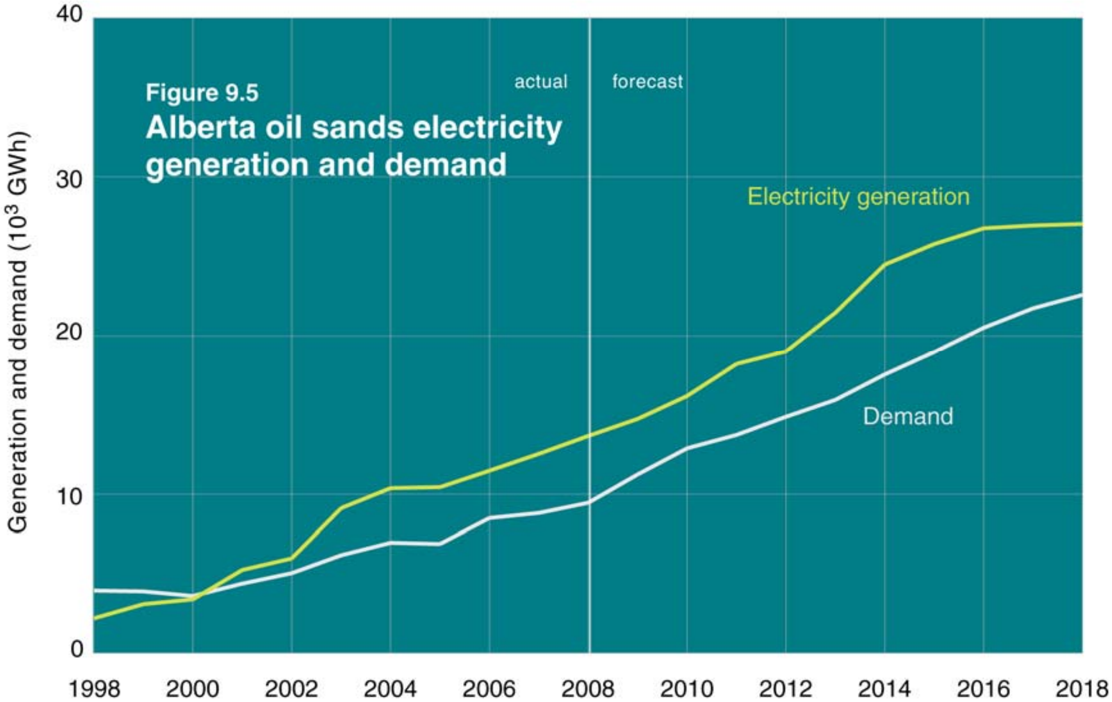
Both Alberta electric power generation and AIL demand are projected to increase at 2.8 per cent a year over the next decade. Over the coming years, load growth will be met by existing and new natural gas-fired and coal-fired power plants. Substantial growth could occur in wind-powered generation, albeit from a relatively low base, when current transmission constraints can be overcome. More efficient machinery and equipment at existing coal-fired units and the commissioning of 450 MW at Keephills are expected to alleviate some of the pressure to meet Alberta's increasing demand. However, the commissioning of the Keephills 3 coal-fired facility will not occur until mid-2011, so over the next few years natural gas-fired plants will play an increasing role in meeting that electricity requirement, particularly during periods of peak demand.

9.2.4 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the balance between electricity supply and demand[3] within Alberta's oil sands sector. Electricity generation from the oil sands 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 bitumen and SCO.

A dedicated and reliable source of electricity and thermal energy is important to oil sands operators. While mining, upgrading, and thermal in situ operators require electricity, over the longer term upgrading operations are expected to be much more intensive users of electricity. With public emphasis on the environment and emissions, the oil sands may require a system for carbon capture and storage (CCS). A carbon dioxide (CO_2) pipeline system will provide a method to collect emissions from the source plant and move the CO_2 to storage sites, thus lowering emission intensities. The initial build-out of the CCS system may be most amenable to upgrading facilities, but on-site collection and compression of CO_2 are expected to increase electricity demand for these facilities.

[3] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kWh/bbl.



However, an increased electricity load due to CCS has not been incorporated into the 10-year forecast due to the uncertainty regarding the timing of CCS in the province.

Electricity cogeneration units at the oil sands mines and upgraders are designed to meet on-site electricity demand. Any additional thermal requirements could be provided through the use of boilers. From operational start-up until target production rates are achieved, surplus electricity may be generated and sold to the power pool. **Table 9.2** displays 2008 electricity statistics by type of oil sands facility.

Table 9.2. 2008 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*	1430	8567	68	6484
Thermal in situ	760	5104	77	2205

* Mines and upgraders have been combined due to the confidential nature of some statistics.

Data for mines and upgraders indicate an annual capacity utilization of 68 per cent. Of the total electricity generated, 76 per cent was used on site and the remaining electricity was sold to the power pool.

Currently, five thermal in situ oil sands producers are obtaining steam from on-site cogeneration facilities. The installed electricity generation capacity at each of these thermal operations ranges between 80 and 170 MW. In 2008, thermal in situ cogeneration facilities operated at 77 per cent of their installed capacity and 43 per cent of the electricity generated was used on site, with the remaining output sold to the power pool.

For 2008, annual capacity utilization was lower than 2007 due to the fact that the Long Lake in situ oil sands project and the Horizon mining oil sands project were not in commercial production, although their cogeneration facilities did come on stream late in 2008.

Currently, all oil sands mines and bitumen upgraders obtain electricity from an on-site cogeneration facility. However, the lack of upgrader projects that include on-site cogeneration facilities from the list of new upgrader capacity illustrates that many new upgraders sited in the Edmonton region will rely increasingly on purchasing electricity from the AIES. When CCS mechanisms are implemented, the loads will provide further potential for increased electricity demand in the Edmonton area.

Thermal in situ operations have lower requirements for electricity but are more intense users of steam. Large thermal requirements and the potential to further enhance the economics of a project via increased revenues from electricity sales have led many in situ oil sands operators to install cogeneration plants. However, in the initial phases of production, there may be fewer wellbores to steam and thus lower total steam requirements. Therefore, investments in a cogeneration facility at a thermal in situ project site may be postponed until secondary phases, when bitumen production is known to be sustainable at high levels. In this case, the alternative to the cogeneration of electricity and thermal energy is to obtain thermal energy from steam generators and boilers and electricity from the provincial power grid.

Appendix A Terminology, Abbreviations, and Conversion Factors

1.1 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.
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)).
Cogeneration Gas Plant	Gas-fired plant used to generate both electricity and steam.
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 (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 turboexpander.
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.
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 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.
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.

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)).

Natural Gas Liquids
Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

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.

Off-gas	Natural gas that is produced from bitumen production in the oil sands. 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.
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.

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.

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.
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. Less than 5 per cent of wells drilled in 2008 were 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.
Synthetic Crude Oil	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.
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)).

1.2 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 PROJECT	local experimental 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
SCO	synthetic crude oil
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

1.3 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		

1.4 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 (14.65 psia and 60°F)
1 m^3 of ethane (equilibrium pressure and 15°C)	=	6.33 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	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion	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
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
Hydroelectricity (per megawatt-hour of output)	10.5**
Nuclear electricity (per megawatt-hour of output)	10.5**

* Based on the heating value at 1000 Btu/cf.

** Based on the thermal efficiency of coal generation.

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+	Building block	5 274
Middle Grand Rapids	150 - 450+	Building block	2 354
Lower Grand Rapids	150 - 450+	Building block	1 050
Wabiskaw-McMurray	0 - 750+	Isopach	153 047
Nisku	200 - 800+	Isopach	10 330
Grosmont	All zones	Isopach	50 500
Subtotal			219 420
Cold Lake			
Upper Grand Rapids	300 – 600	Building block	6 186
Upper Grand Rapids	All zones	Isopach	534
Lower Grand Rapids	300 – 600	Building block	8 933
Lower Grand Rapids	All zones	Isopach	1 651
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			31 013
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			275 128

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+	Building Block	5274.00	334.00	9.0	0.062	0.55	0.30	0.45
Middle Grand Rapids								
150 - 450+	Building Block	2354.00	182.00	5.0	0.077	0.68	0.30	0.32
Lower Grand Rapids								
150 - 450+	Building Block	1050.00	173.00	6.0	0.051	0.45	0.30	0.55
Wabiskaw-McMurray								
0 - 65 (mineable)	3-D Model	20728.00	374.00	25.8	0.101	0.76	0.28	0.24
65 - 750+ (in situ)	Isopach	132319.00	4701.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200 - 800+	Isopach	10330.00	499.00	8.0	0.057	0.63	0.21	0.37
Grosmont								
D	Isopach	19890.00	1063.00	16.0	0.058	0.67	0.20	0.33
C	Isopach	15390.00	1189.00	10.0	0.050	0.75	0.16	0.25
B	Isopach	5380.00	976.00	5.0	0.043	0.69	0.15	0.31
A	Isopach	9840.00	939.00	10.0	0.035	0.60	0.14	0.40
Cold Lake								
Upper Grand Rapids								
300 - 600	Building Block	6186.40	812.00	6.0	0.081	0.58	0.30	0.42
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
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

(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 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								
300 – 600	Building Block	8932.70	708.00	6.0	0.106	0.73	0.31	0.27
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
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

(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)
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	5.50	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
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

(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 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
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

(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 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	9422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1439.00	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
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	10968.16	1015.75	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	1830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500 – 800	Building Block	5970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500 - 800	Building Block	2510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		275128.15						

Table B.3. Conventional crude oil reserves as of each year-end (10^6 m^3)

Year	Initial established: New discoveries	EOR additions	Development	Net revisions	Net total additions	Cumulative production	Remaining established
1968	62.0				119.8	430.3	1 212.8
1969	40.5				54.5	474.7	1 222.8
1970	8.4				36.7	526.5	1 207.9
1971	14.0				22.1	582.9	1 173.6
1972	10.8				20.0	650.0	1 126.0
1973	5.1				9.2	733.7	1 052.0
1974	4.3				38.5	812.7	1 011.5
1975	1.6				7.0	880.2	950.9
1976	2.5				-18.6	941.2	871.3
1977	4.8				19.1	1 001.6	830.0
1978	24.9				24.4	1 061.6	794.5
1979	19.2				34.3	1 130.1	760.2
1980	9.0				22.8	1 193.3	719.9
1981	15.0	7.2			32.6	1 249.8	696.0
1982	16.8	6.6			6.9	1 303.4	649.4
1983	21.4	17.9			64.1	1 359.0	657.8
1984	29.1	24.1			42.0	1 418.2	640.7
1985	32.7	21.6			64.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 540.1	233.0

Table B.4. Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

Year	Initial established: New discoveries	Development	Revisions	Net additions	Cumulative	Cumulative production	Remaining actual[a]	Remaining @ 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[a]	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[b]	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004[b]	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005[b]	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006[b]	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007[b]	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

[a] At field plant.

[b] Distribution of changes revised in 2008.

Table B.5. Natural gas reserves of gas cycling pools, 2008

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 J	557	74.44	41	0.73	0.50	15	41.10	365	0
Brazeau River Nisku K	1 360	74.17	101	0.75	0.60	30	42.15	718	10
Brazeau River Nisku M	1 945	76.22	148	0.75	0.60	44	43.33	1 076	53
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435	972
Brazeau River Nisku S	1921	54.64	105	0.80	0.57	36	41.38	873	12
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200	188
Caroline Beaverhill Lake A	61 977	49.95	3 096	0.84	0.76	621	36.51	17 000	1 911
Carson Creek Beaverhill Lake B	11 436	55.68	637	0.90	0.39	350	41.54	8 426	44
Harmattan East Commingled Pool 001	44 923	50.26	2 258	0.79	0.26	1 320	41.57	31 752	6 273
Harmattan-Elkton Rundle C	33 012	46.96	1 550	0.89	0.27	1 007	42.16	23 885	1 064
Kakwa A Cardium A	3 848	55.40	213	0.71	0.32	103	43.87	2348	1 182
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 639	39.68	41 300	679
Ricinus Cardium A	13 295	58.59	779	0.85	0.32	450	42.0	10 775	603
Valhalla MFP8524 Halfway	6 331	53.89	341	0.80	0.33	183	40.00	4 572	2 656
Waterton Rundle-Wabamun A	90 422	48.74[a]	4 407	0.95	0.35	2 721	48.73	55 836	2 437
Wembley MFP8524 Halfway	6 662	53.89	359	0.60	0.33	144	44.10	3 265	1 808

(continued)

Table B.5. Natural gas reserves of gas cycling pools, 2008 (concluded)

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	10 823	51.55	558	0.78	0.25	326	42.78	7 620	30
Westpem Nisku E	1 160	66.05	77	0.90	0.54	32	44.76	709	152
Windfall D-3 A	25 790	53.42	1 338	0.61	0.53	384	40.58	9 462	1 011

[a] Producible raw gas gross heating value is 40.65 MJ/m^3.

Table B.6. Natural gas reserves of multifield pools, 2008

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8506 Belly River	
Brant Commingled MFP9501	474
Centron Commingled MFP9501	1 982
Cessford Commingled MFP9501	15
Craigmyle Commingled MFP9501	443
Crossfield Commingled MFP9501	108
Dalemead Commingled MFP9501	35
Delia Commingled MFP9501	3
Entice Commingled MFP9501	3 728
Gayford Commingled MFP9501	581
Ghost Pine Commingled MFP9501	392
Gladys Commingled MFP9501	350
Herronton Commingled MFP9501	783
Irricana Commingled MFP9501	226
Lomond Commingled MFP9501	58
Majorville Commingled MFP9501	153
Matziwin Commingled MFP9501	27
Michichi Commingled MFP9501	150
Milo Commingled MFP9501	71
Okotoks Commingled MFP9526	6
Parflesh Commingled MFP9501	804
Queenstown Commingled MFP9501	67
Redland Commingled MFP9501	780
Rockyford Commingled MFP9501	982
Rowley Commingled MFP9501	44
Seiu Lake Commingled MFP9501	64
Silver Commingled MFP9501	1
Strathmore Commingled MFP9501	1 765
Swalwell Commingled MFP9501	314
Twining Commingled MFP9501	455
Vulcan Commingled MFP9501	24
Wayne-Rosedale Commingled MFP9501	1 074
West Drumheller Commingled MFP9501	54
Total	16 013
MFP8507 Cardium	
Ansell Commingled MFP9502	14 395
Medicine Lodge Commingled MFP9502	1 954
Minehead Commingled MFP9502	1 787
Sundance Commingled MFP9502	7 531
Total	25 667
MFP8508 Viking	
Hairy Hill Commingled MFP9503	182
Willingdon Commingled MFP9503	21
Total	203
MFP8509 Belly River	
Bashaw Commingled MFP9504	373
Nevis Commingled MFP9504	1 514
Total	1 887
MFP8510 Glaucintic	
Bigoray Commingled MFP9505	264
Pembina Commingled MFP9505	689
Total	953
MFP8511 Viking	
Carbon Commingled MFP9507	565
Ghost Pine Commingled MFP9507	91
Total	656
MFP8512 Glauconitic	
Bonnie Glen Commingled MFP9506	98
Ferrybank Commingled MFP9506	329
Total	427
MFP8514 Upper Viking	
Fairydell-Bon Accord Commingled MFP9508	65
Peavey Commingled MFP9508	2
Redwater Commingled MFP9508	595
Total	662
MFP8515 Banff	
Haro MFP8515 Banff	129
Rainbow MFP8515 Banff	8
Rainbow South MFP8515 Banff	216
Total	353
MFP8516 Viking	
Fenn West MFP8516 Viking	11
Fenn-Big Valley MFP8516 Viking	58
Total	69
MFP8517 Gething	
Fox Creek Commingled MFP9510	1 095
Kaybob South Commingled MFP9510	982
Total	2 077
MFP8518 U&M Viking	
Albers Commingled MFP9509	10
Beaverhill Lake Commingled MFP9509	330
Bellshill Lake Commingled MFP9509	12
Birch Commingled MFP9509	9
Bruce Commingled MFP9509	438
Dinant Commingled MFP9509	2
Fort Saskatchewan Commingled MFP9509	113
Holmberg Commingled MFP9509	9
Killam Commingled MFP9509	232
Killam North Commingled MFP9509	212
Mannville Commingled MFP9509	441
Sedgewick Commingled MFP9509	4
Viking-Kinsella Commingled MFP9509	2 920
Wainwright Commingled MFP9509	428
Total	5 160
MFP8519 Glauconitic	
Seiu Lake Commingled MFP9521	69
Wintering Hills Commingled MFP9521	31
Total	100
MFP8521 Viking	
Hudson Commingled MFP9511	125
Sedalia Commingled MFP9511	169
Total	294
MFP8522 Cadomin	
Elmworth Commingled MFP9513	8 760
Sinclair Commingled MFP9513	2 876
Total	11 636

(continued)

Table B.6. Natural gas reserves of multifield pools, 2008 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8522 Cadomin	
Elmworth Commingled MFP9513	8 760
Sinclair Commingled MFP9513	2 876
Total	11 636
MFP8523 Upper Viking	
Inland Commingled MFP9512	158
Royal Commingled MFP9512	31
Total	189
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 656
Wembley MFP8524 Halfway	1 808
Total	4 464
MFP8526 Ellerslie	
Connorsville Commingled MFP9514	579
Wintering Hills Commingled MFP9514	268
Total	847
MFP8527 2WS	
Craigmyle Commingled MFP9515	8
Dowling Lake Commingled MFP9515	14
Garden Plains Commingled MFP9515	988
Hanna Commingled MFP9515	482
Provost Commingled MFP9515	189
Richdale Commingled MFP9515	235
Sullivan Lake Commingled MFP9515	125
Watts Commingled MFP9515	60
Total	2 101
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	194
Sousa MFP8528 Bluesky	1 278
Total	1 472
MFP8529 Bl-Dt-Db	
Cranberry MFP8529 Bl-Dt-Db	316
Hotchkiss MFP8529 Bl-Dt-Db	372
Total	688
MFP8530 Halfway	
Knopcik Commingled MFP9516	1 013
Valhalla Commingled MFP9516	44
Total	1 057
MFP8531 2WS	
Conrad Commingled MFP9517	344
Pendant D'Oreille Commingled MFP9517	279
Smith Coulee Commingled MFP9517	269
Total	892
MFP8532 2WS	
Enchant Commingled MFP9522	596
Grand Forks Commingled MFP9522	12
Retlaw Commingled MFP9522	524
Vauxhall Commingled MFP9522	32
Total	1 164
MFP8534 Bsl Belly Riv	
Bruce Commingled MFP9518	269
Holmberg Commingled MFP9518	150
Total	419
MFP8535 Bsl Belly Riv	
Fenn West Commingled MFP9519	10
Fenn-Big Valley Commingled MFP9519	615
Gadsby Commingled MFP9519	459
Total	1 084
MFP8536 Milk River	
Chinook Commingled MFP9527	203
Dobson Commingled MFP9527	43
Heathdale Commingled MFP9527	94
Kirkwall Commingled MFP9527	15
Sedalia Commingled MFP9527	8
Sounding Commingled MFP9527	175
Stanmore Commingled MFP9527	91
Total	629
MFP8538 Viking	
Gadsby Commingled MFP9520	7
Leahurst Commingled MFP9520	152
Total	159
MFP8539 Lwr Edmonton	
Erskine MFP8539 Lwr Edmonton	33
Stettler North MFP8539 Lwr Edmonton	36
Total	69
MFP8541 2WS	
Cherry MFP8541 2WS	50
Granlea MFP8541 2WS	58
Taber MFP8541 2WS	136
Total	244
MFP8548 Milk River	
Provost MFP8548 Milk River	203
Racosta MFP8548 Milk River	188
Richdale MFP8548 Milk River	124
Stanmore MFP8548 Milk River	52
Total	567
MFP8552 Bow Island	
Stirling Commingled MFP9524	123
Warner Commingled MFP9524	35
Total	158

(continued)

Table B.6. Natural gas reserves of multifield pools, 2008 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Southeastern Alberta Gas System (MU)	
Aerial SE Alberta Gas System(MU)	233
Alderson SE Alberta Gas System(MU)	18 628
Armada SE Alberta Gas System(MU)	409
Atlee-Buffalo SE Alberta Gas System(MU)	4 215
Bantry SE Alberta Gas System(MU)	12 914
Berry SE Alberta Gas System(MU)	6
Bindloss SE Alberta Gas System(MU)	953
Blackfoot SE Alberta Gas System(MU)	707
Bow Island SE Alberta Gas System(MU)	1 215
Brooks SE Alberta Gas System(MU)	318
Cavalier SE Alberta Gas System(MU)	354
Cessford SE Alberta Gas System(MU)	8 823
Connorsville SE Alberta Gas System(MU)	2 190
Countess SE Alberta Gas System(MU)	31 569
Drumheller SE Alberta Gas System(MU)	1 981
Elkwater SE Alberta Gas System(MU)	1 419
Enchant SE Alberta Gas System(MU)	115
Eyremore SE Alberta Gas System(MU)	2 871
Farrow SE Alberta Gas System(MU)	842
Gleichen SE Alberta Gas System(MU)	704
Herronton SE Alberta Gas System(MU)	2
Hussar SE Alberta Gas System(MU)	7 133
Jenner SE Alberta Gas System(MU)	2 737
Johnson SE Alberta Gas System(MU)	309
Jumpbush SE Alberta Gas System(MU)	1 204
Kitsim SE Alberta Gas System(MU)	379
Lathom SE Alberta Gas System(MU)	2 461
Leckie SE Alberta Gas System(MU)	674
Long Coulee SE Alberta Gas System(MU)	127
Majorville SE Alberta Gas System(MU)	1 467
Matziwin SE Alberta Gas System(MU)	1 123
Mcgregor SE Alberta Gas System(MU)	313
Medicine Hat SE Alberta Gas System(MU)	40 706
Newell SE Alberta Gas System(MU)	1 059
Pollockville SE Alberta Gas System(MU)	14
Princess SE Alberta Gas System(MU)	11 862
Rainier SE Alberta Gas System(MU)	202
Ronalane SE Alberta Gas System(MU)	106
Seiu Lake SE Alberta Gas System(MU)	303
Shouldice SE Alberta Gas System(MU)	1 240
Suffield SE Alberta Gas System(MU)	13 482
Verger SE Alberta Gas System(MU)	4 915
Wayne-Rosedale SE Alberta Gas System(MU)	1 073
Wintering Hills SE Alberta Gas System(MU)	1 895
Total	185 252

Table B.7. Remaining raw ethane reserves as of December 31, 2008

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	16 658	0.082	1 507	5 359
Brazeau River	11 420	0.070	998	3 546
Caroline	8 611	0.083	1 215	4 319
Carrot Creek	3 329	0.089	336	1 193
Cecilia	10 862	0.058	724	2 573
Countess	39 500	0.010	424	1 509
Dunvegan	8 458	0.044	412	1 464
Edson	7 705	0.077	659	2 344
Elmworth	15 739	0.058	1 092	3 881
Ferrier	13 665	0.086	1 303	4 634
Fir	13 292	0.057	839	2 981
Garrington	3 464	0.073	331	1 175
Gilby	5 432	0.064	396	1 408
Gold Creek	5 092	0.081	460	1 636
Harmattan East	7 366	0.085	704	2 502
Hussar	10 948	0.029	338	1 202
Judy Creek	2 506	0.144	442	1 571
Kaybob South	12 877	0.074	1 128	4 010
Karr	7 138	0.082	651	2 315
Kakwa	9 710	0.084	913	3 247
Leduc-Woodbend	2 541	0.110	331	1 175
Medicine River	4 348	0.080	413	1 467
Pembina	21 888	0.080	2 152	7 652
Pine Creek	7 267	0.073	622	2 211
Pouce Coupe South	6 292	0.049	354	1 260
Leland	3 762	0.071	289	1 028
Provost	14 067	0.029	453	1 609
Rainbow	7 953	0.067	681	2 420
Rainbow South	2 906	0.091	380	1 352
Red Rock	4 378	0.061	297	1 058
Ricinus	4 854	0.073	406	1 443
Sinclair	8 693	0.048	481	1 709
Sundance	11 494	0.071	898	3 191
Swan Hills South	2 749	0.174	684	2 432
Sylvan Lake	4 842	0.063	356	1 266
Valhalla	8 790	0.074	752	2 674
Virginia Hills	1 462	0.171	305	1 085
Waterton	6 310	0.029	302	1 074
Wayne-Rosedale	8 936	0.044	429	1 525
Westpem	3 965	0.104	507	1 804
Westerose South	7 423	0.077	635	2 256

(continued)

Table B.7. Remaining raw ethane reserves as of December 31, 2008 (concluded)

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)
Wembley	2 804	0.094	339	1 205
Wapiti	17 062	0.056	1 107	3 934
Wild River	24 977	0.070	1 878	6 677
Willesden Green	13 526	0.086	1 439	5 115
Wilson Creek	3 533	0.069	283	1 005
Smokey	4 696	0.075	385	1 370
Subtotal	425 290	0.065	32 027	113 862
All other fields	672 876	0.030	20 147	71 622
Total	1 098 166	0.052[a]	52 174	185 484

[a] Volume weighted average.

Table B.8. Remaining established reserves of natural gas liquids as of December 31, 2008

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ante Creek North	1 468	268	147	505	920
Ansell	16 658	2 432	1 284	2 643	6 359
Brazeau River	11 420	1 670	965	1 912	4 547
Caroline	8 611	1 840	1 352	2 983	6 175
Carrot Creek	3 329	594	268	204	1 065
Cecilia	10 862	892	347	886	2 124
Countess	39 500	556	309	256	1 120
Crossfield East	2 782	205	105	659	969
Dunvegan	8 458	705	408	684	1 798
Edson	7 705	885	397	384	1 667
Elmworth	15 739	1 271	602	682	2 554
Ferrier	13 665	2 275	1 141	900	4 315
Fir	13 292	1 152	536	662	2 349
Garrington	3 464	521	277	394	1 192
Gilby	5 432	641	321	359	1 321
Gold Creek	5 092	545	270	379	1 194
Harmattan East	7 366	930	576	950	2 456
Hussar	10 948	522	284	312	1 118
Judy Creek	2 506	1 059	439	255	1 752
Kaybob	2 860	424	202	283	909
Kaybob South	12 877	1 796	923	1 357	4 075
Karr	7 138	1 038	461	513	2 013
Kakwa	9 710	1 492	714	738	2 944
Knopcik	3 592	406	203	286	895
Leduc-Woodbend	2 541	966	569	343	1 878
McLeod	2 753	476	220	234	930
Medicine River	4 348	697	348	334	1 380
Peco	1 668	297	160	347	804
Pembina	21 888	4 106	2 027	1 779	7 912
Pine Creek	7 267	1 004	478	525	2 007
Pouce Coupe South	6 292	491	270	290	1 051
Provost	14 067	909	594	421	1 923
Rainbow	7 953	1 121	743	953	2 818
Rainbow South	2 906	690	329	345	1 364
Ricinus	4 854	667	336	608	1 610

(continued)

Table B.8. Remaining established reserves of natural gas liquids as of December 31, 2008 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Sinclair	8 693	664	276	338	1 279
Sundance	11 494	1 111	477	481	2 069
Swan Hills	771	443	243	201	887
Swan Hills South	2 749	1 673	766	319	2 758
Sylvan Lake	4 842	547	272	279	1 098
Valhalla	8 790	1 283	688	993	2 964
Virginia Hills	1 462	712	233	89	1 034
Waterton	6 310	341	309	1 985	2 635
Wayne-Rosedale	8 936	745	395	464	1 604
Westpem	3 965	840	440	525	1 806
Westerose South	7 423	1 194	582	561	2 337
Wembley	2 804	643	377	823	1 843
Wapiti	17 062	1 147	487	469	2 102
Wild River	24 977	2 063	889	1 392	4 344
Willesden Green	13 526	2 447	1 154	1 157	4 758
Wilson Creek	3 533	489	256	303	1 049
Smokey	4 696	561	257	189	1 008
Subtotal	433 044	52 444	26 702	35 932	115 078
All other fields	665 122	28 763	15 946	17 916	62 625
Total	1 098 166	81 207	42 648	53 848	177 703

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 2008 on the CD that accompanies this report (available for $500 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.

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.

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, 1972-2008, 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	oil	bitumen	Gas	Total[a]
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	5 473	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
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

[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.

Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2008 - Alberta Drilling Activity Monthly Statistics (ST59).

Table D.2. Development and exploratory wells, 1972-2008, 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	oil	bitumen	Gas	Total[a]
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
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	1 0840	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

[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.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2008 - Alberta Drilling Activity Monthly Statistics (ST59).