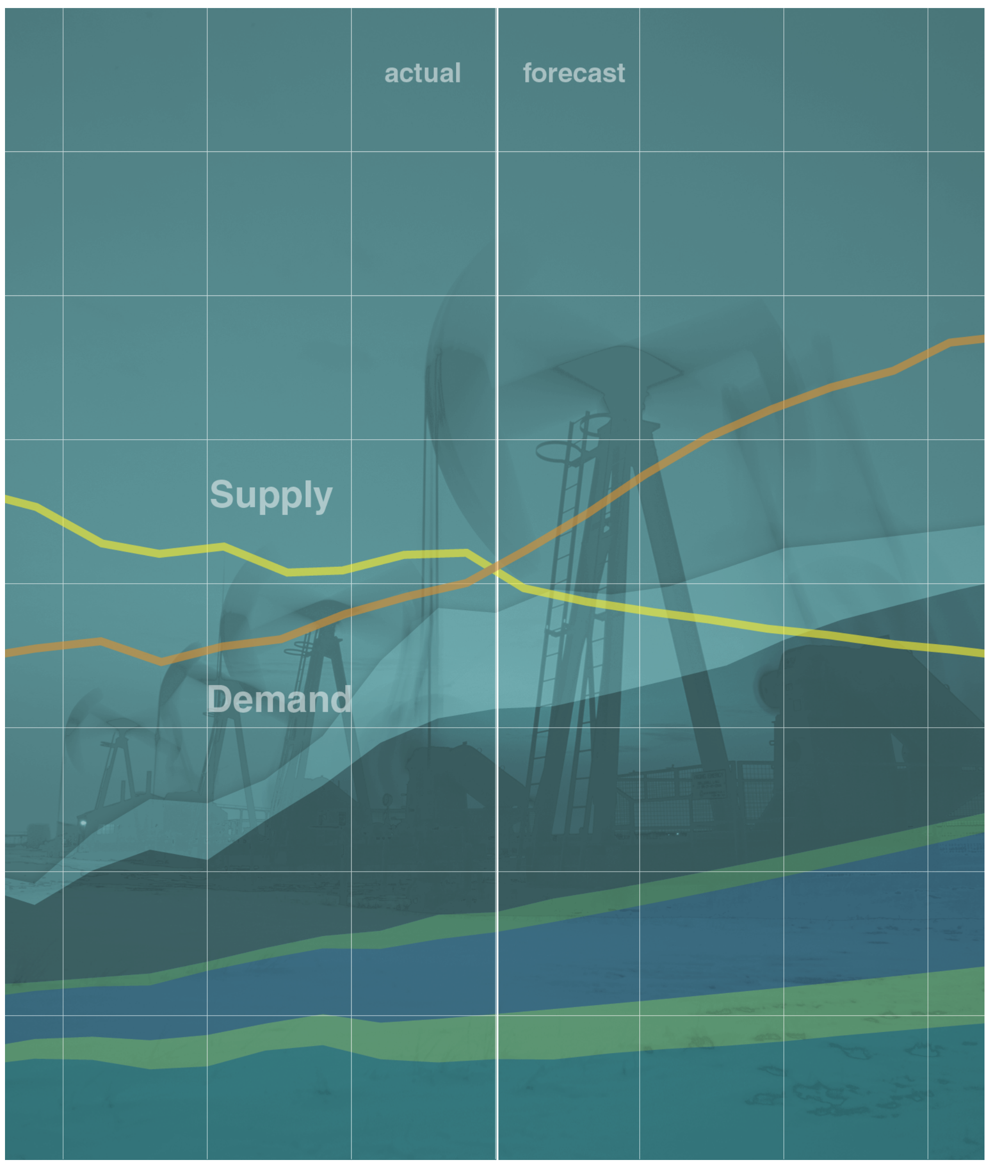
ST98-2008

Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017



Energy Resources Conservation Board

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The graphs and data for each graph in this report are available for download in a PowerPoint file.

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Overview

On January 1, 2008, the Alberta Energy and Utilities Board (EUB) was realigned into two separate regulatory bodies: the Energy Resources Conservation Board (ERCB), which regulates the oil and gas industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry. Throughout this report references are made to both the EUB and ERCB.

The 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 2007 and Supply/Demand Outlook 2008-2017* includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (reserves 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, 2007 will be remembered as a year dominated by geopolitics, highly volatile crude oil markets around the globe, and the decline of the United States dollar relative to other currencies. Continued decline in Nigeria's production due to political unrest and ongoing tension in the Middle East were among the geopolitical events in 2007. These factors caused world crude oil prices to skyrocket to their highest levels yet.

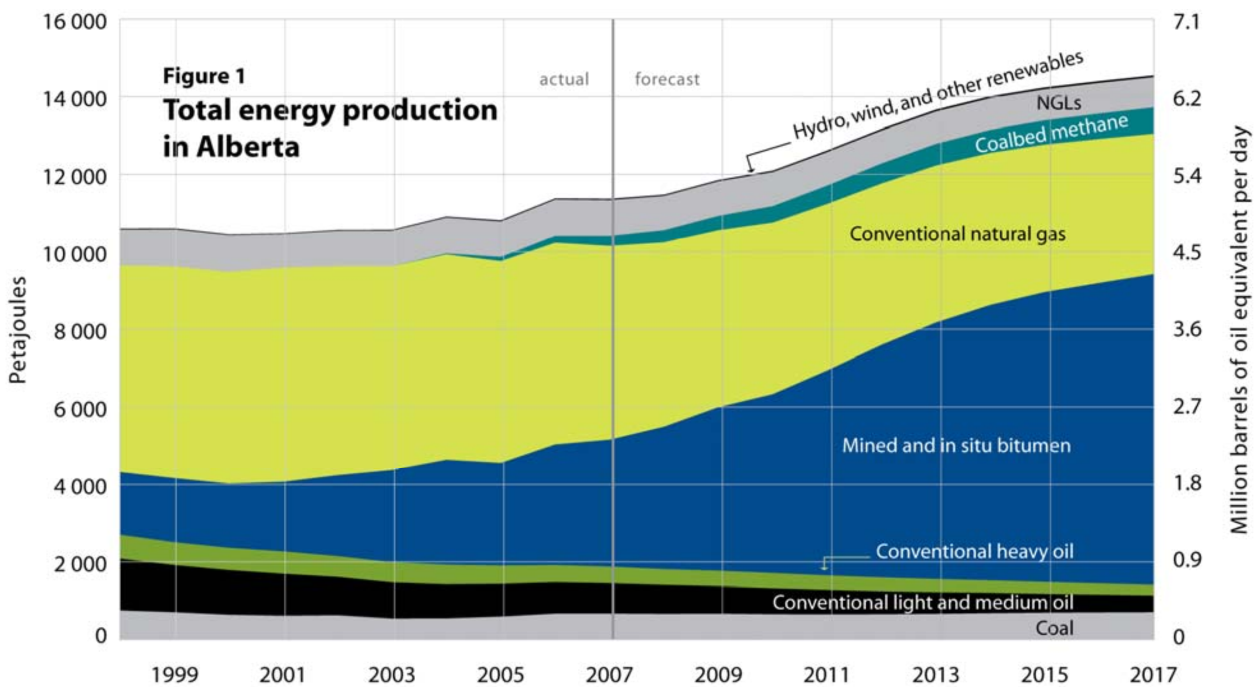
The growth in world oil demand also slowed, as demand in the U.S., Europe, and some Pacific countries declined. World oil supply grew more than demand, leading to somewhat larger spare capacity in the Organization of Petroleum Exporting Countries (OPEC), particularly Saudi Arabia. The increase in excess capacity, however, did not result in a decline in the crude oil price in 2007.

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$105 per barrel in 2008 and rising steadily to an average of US$138 per barrel by 2017.

North American natural gas prices and drilling activity were impacted by warmer-than-usual weather, high levels of inventory, and excess supply of liquid natural gas (LNG) in 2007. Natural gas storage levels in North America remained well above their five-year average. Further LNG imports into the U.S. augmented supply. As a result, average natural gas prices in 2007 declined again, similar to 2006. The Alberta price of natural gas at the plant gate is expected to average Cdn$8.00 per gigajoule in 2008 and then rise steadily to Cdn$9.05 per gigajoule by 2017.

Energy Production 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 2007, Alberta produced 11 367 petajoules of energy from all sources, including renewable sources such as hydro and wind power. This is equivalent to 5.1 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. Raw bitumen production surpassed conventional crude oil production in 2001 for the first time. Production of bitumen has continued its growth, accounting for 72 per cent of Alberta's total crude oil and raw bitumen production in 2007. The value-added process of upgrading raw bitumen to synthetic crude oil (SCO) continued to expand in 2007.[1] Bitumen production at in situ projects increased by 9 per cent in 2007, while production at mining projects increased by 3 per cent. As a result, overall raw bitumen production increased by some 5 per cent compared with 2006.

Total natural gas production in Alberta, which peaked in 2001, declined by 2.4 per cent in 2007.

[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.

The following table summarizes Alberta's energy reserves at the end of 2007.

Reserves and production summary, 2007

	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	271 993	1 712	10 532	66.3	8 700	309	94	103
Initial established	28 392	179	2751	17.3	4 923	175	35	38
Cumulative production	944	5.9	2511	15.8	3 829	136	1.34	1.48
Remaining established	**27 448**	**173**	**241**	**1.5**	**1 094**	**39[b]**	**34**	**37**
Annual production	76.6	0.482	30.4	0.191	135	4.8	0.037	0.041
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Includes coalbed methane (CBM). Expressed as "as is" gas.
[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 27.4 billion cubic metres (m^3) (173 billion barrels), slightly less than in 2006 due to production. Only 3.3 per cent of the initial established crude bitumen reserves has been produced since commercial production started in 1967.

Crude Bitumen Production

In 2007, Alberta produced 45.5 million m^3 (286 million barrels) from the mineable area and 31.1 million m^3 (196 million barrels) from the in situ area, totalling 76.6 million m^3 (482 million barrels). This is equivalent to 209.9 thousand m^3 (1.32 million barrels) per day. Bitumen produced from mining was upgraded, yielding 40.0 million m^3 (251 million barrels) of SCO. In situ production was mainly marketed as nonupgraded crude bitumen.

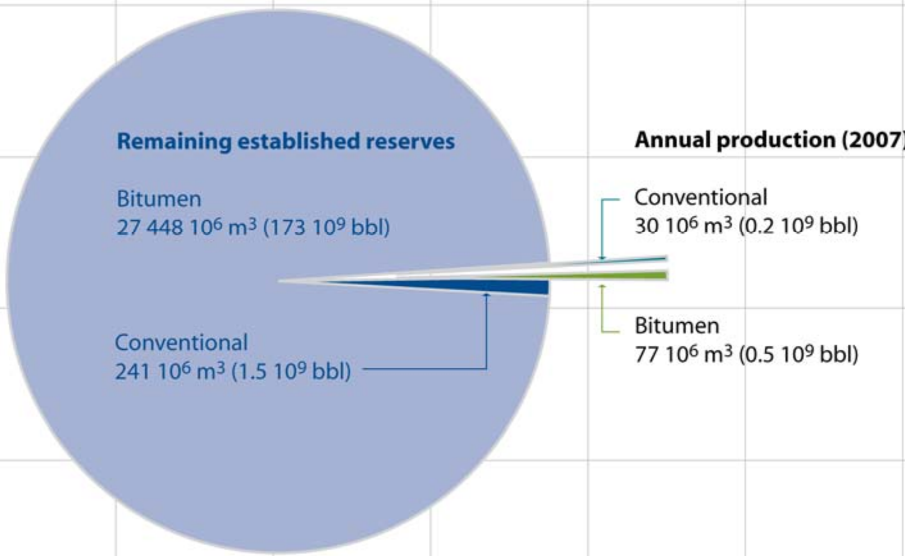
Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 241 million m^3 (1.5 billion barrels), a 4 per cent decrease from 2006. 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 68 per cent of the 2007 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 30.4 million m^3 (191 million barrels) in 2007. This equates to 83 400 m^3 (524 800 barrels) per day.

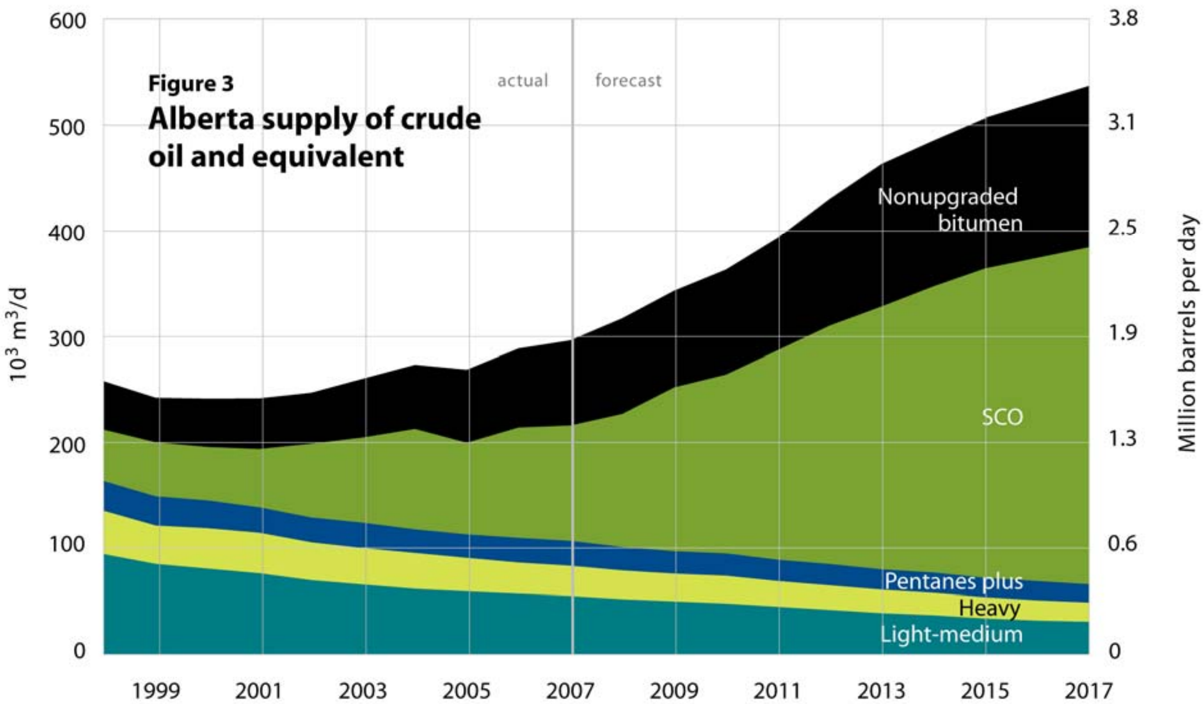
The number of oil wells placed on production decreased by 11 per cent to 1745 in 2007 from 1956 in 2006. With the expectation that crude oil prices will remain strong, the ERCB estimates that the number of new wells placed on production will increase to 1900 wells in 2008 and remain around this level over the forecast period.

Total Oil Supply and Demand

Alberta's 2007 supply of crude oil and equivalent was 296 000 m^3 (1.86 million barrels) per day, a 3 per cent increase compared with 2006. Production is forecast to reach 535 000 m^3 (3.4 million barrels) per day by 2017.

A comparison of conventional oil and bitumen production, as illustrated in **Figure 3**, over the last 10 years 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 2017. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 64 per cent in 2007 to 88 per cent by 2017. In 2007, 62 per cent of bitumen produced in the province was upgraded to SCO. This percentage is expected to increase to 70 per cent by 2017.



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—coalbed methane (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.

Coalbed Methane Reserves

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 9000 wells producing CBM in 2007. The growth in CBM data collection and gas production has increased confidence in publication of CBM reserves estimates, despite continued uncertainty in recovery factors and production accounting.

At the end of 2007, the remaining established reserves of CBM in Alberta is estimated to be 24.3 billion m^3 (860 billion cubic feet). This is limited mainly to the "dry CBM" trend of central Alberta, as other CBM resource development has shown commercial producibility in only three fields.

Conventional Natural Gas Reserves

At the end of 2007, Alberta's remaining established reserves of natural gas stood at 1069.3 billion m^3 (38 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 51 per cent of production in 2007. This compares with 68 per cent replacement in 2006.

In March 2005, the EUB 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).

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 135.3 billion m^3 (4.8 Tcf) of marketable natural gas in 2007, of which 2.2 billion m^3 (0.08 Tcf) was CBM.

There were 10 796 gas well connections in 2007, a 17 per cent decrease from the 12 932 gas wells placed on production in 2006. The ERCB expects a slow recovery in gas well connections in 2008, estimating 9800 successful wells placed on production. For 2009, the ERCB estimates this number will increase to 11 000 wells and then to 12 500 wells 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 2007 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.

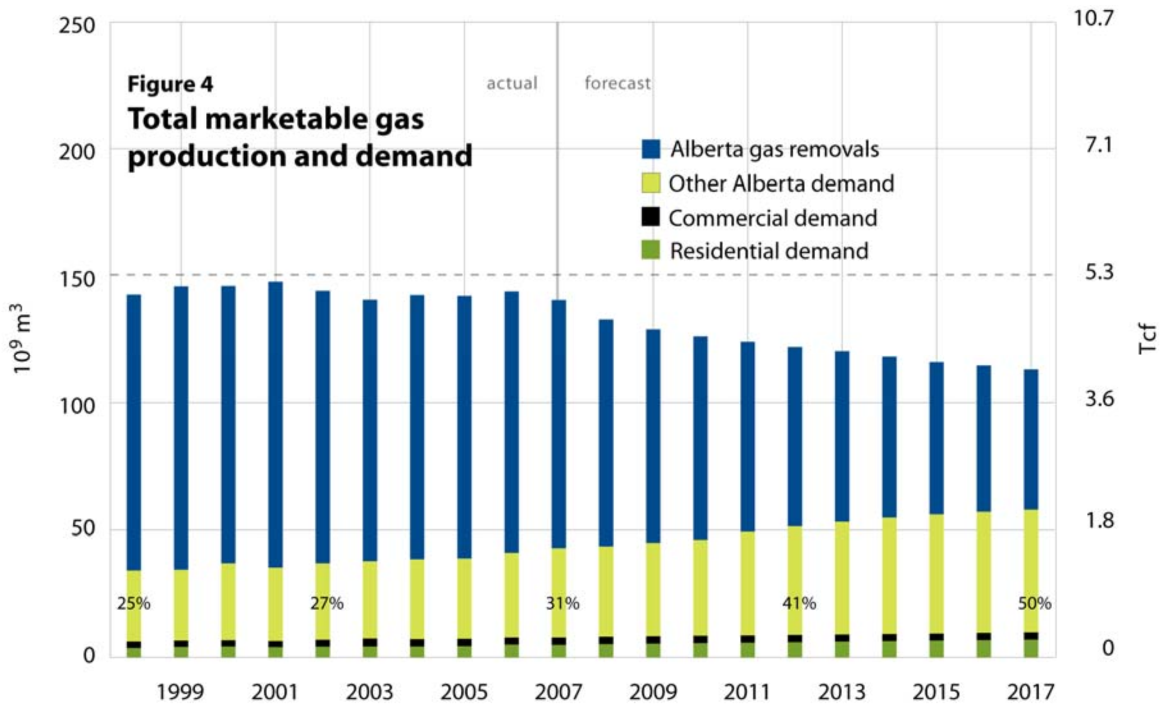
CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 2259 successful CBM well connections in Alberta in 2007. The ERCB expects CBM well connections to increase in 2008 to 2500. The commodity price declines that took place in late 2006 and 2007 are responsible for a slowdown in CBM and shallow conventional gas well activity, which is expected to continue well into 2008. CBM well connections are expected to remain at 2500 wells per year over the forecast period.

Natural Gas Supply and Demand

The ERCB expects conventional gas production to decline by an average of 3.3 per cent per year over the forecast period. New pools are smaller, and new wells drilled 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 50 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 and disposition.



Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 116 million m^3 (730 million barrels) as of year-end 2007. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

In 2007, the production of specification ethane decreased slightly to 39.7 thousand m^3 (250 thousand barrels) per day from the 2006 level of 40.6 thousand m^3 (255 thousand barrels) per day. The majority of ethane was used as feedstock for Alberta's petrochemical industry. The supply of ethane is expected to meet demand over the forecast period.

The remaining established reserves of other natural gas liquids (NGLs)—propane, butanes, and pentanes plus—is 158 million m^3 (994 million barrels) in 2007. The supply of propane and butanes is expected to meet demand over the forecast period. However, shortage of pentanes plus as a diluent for heavy oil and nonupgraded bitumen occurred in 2007. Alternative sources of diluent are being used by industry to dilute the heavier crude to meet pipeline quality.

The remaining established reserves of sulphur decreased in 2007 by 4 million tonnes to 154 million tonnes. Sulphur is recovered from the processing of natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is expected to remain at 2007 levels, and Alberta's sulphur inventory is expected to grow over the forecast period.

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 62 per cent of the province's electricity generation in 2007. Alberta's total coal production in 2007 was 32.5 million tonnes of marketable coal, most of which was subbituminous coal destined for mine mouth power plants. 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 electrical generating capacity.

The small portion of Alberta coal production that was exported from the province can be separated into thermal coal exports and metallurgical coal exports. Export markets remain strong due to the continued demand in the Pacific Rim countries for steel production.

Electricity

Electricity generating capacity within Alberta totalled 12 143 megawatts (MW) in 2007, due to an increase of 294 MW, mainly from the addition of capacity from wind turbines. Three new wind projects were commissioned in 2007, including Alberta Wind Energy's (AWE's) Oldman River project, the Taber Wind Farm operated by ENMAX, and the Kettles Hill Wind Farm expansion. This brought total wind-powered capacity to 525 MW. By the end of the forecast period, the ERCB expects total electricity generating capacity in Alberta to be near 16 000 MW, of which wind-powered capacity will be 9 per cent, an increase from 4 per cent in 2007.

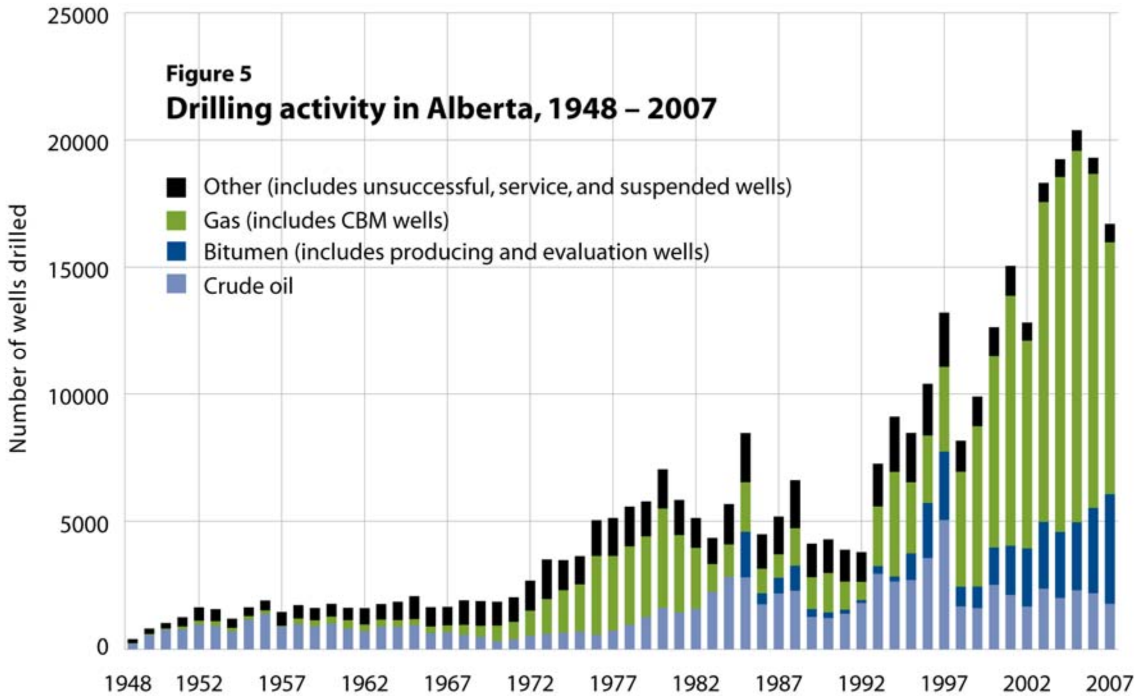
In 2007, total electricity generation reached 66 143 gigawatt hours (GWh). Between 1998 and 2007, electricity generation in Alberta grew by 10 514 GWh or, on average, 2 per cent per year. In 2007, Alberta imported 1669 GWh of electricity, a decrease of 2 per cent from 2006. Electricity exports almost doubled from 484 GWh in 2006 to 973 GWh in 2007. As a result, Alberta's net imports of electricity were about 696 GWh in 2007. Over the forecast period, total electricity generation is expected to grow by an average of 4 per cent per year, or a total of 27 terawatt hours.

Although electricity prices in 2007 were somewhat lower than in 2006, the electricity market is expected to continue to exhibit a tightness that will result in elevated electricity average prices over the forecast period. In Alberta, total electricity demand (retail sales and industrial on-site use) increased by 1 per cent from 2006. However, expected growth in industrial electricity demand, through both retail sales and on-site generation, will average 4 per cent over the forecast. The oil sands sector is expected to dominate load growth.

Energy Trends

Drilling Activity

The drilling activity in the province increased rapidly, starting in 1993. Although drilling activity for the past two years, particularly for natural gas, has declined due to increasing costs and soft natural gas prices, drilling has remained high relative to previous decades. Drilling for natural gas remains the dominant force in the province's drilling activity. **Figure 5** illustrates the drilling history over the past several decades in the province.



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: Economics.

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. Also shown in the figure is the price of SCO since 1971. The price of SCO generally runs at a premium to light crude oil.

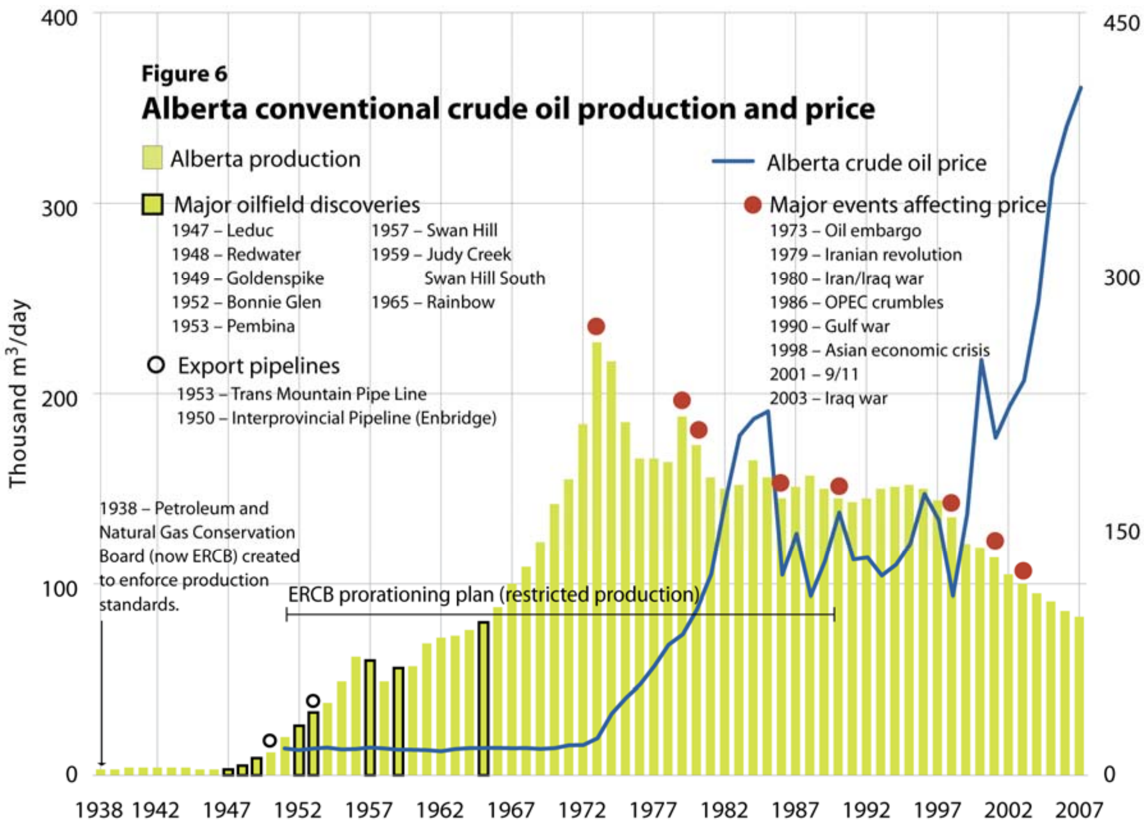


Figure 6
Alberta conventional crude oil production and price
Alberta production
Major oilfield discoveries
1947 – Leduc
1948 – Redwater
1949 – Goldenspike
1952 – Bonnie Glen
1953 – Pembina
1957 – Swan Hill
1959 – Judy Creek
Swan Hill South
1965 – Rainbow
Export pipelines
1953 – Trans Mountain Pipe Line
1950 – Interprovincial Pipeline (Enbridge)
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)
Thousand m3/day
Cdn$/m3
0
100
200
300
400
0
150
300
450
1938
1942
1947
1952
1957
1962
1967
1972
1977
1982
1987
1992
1997
2002
2007

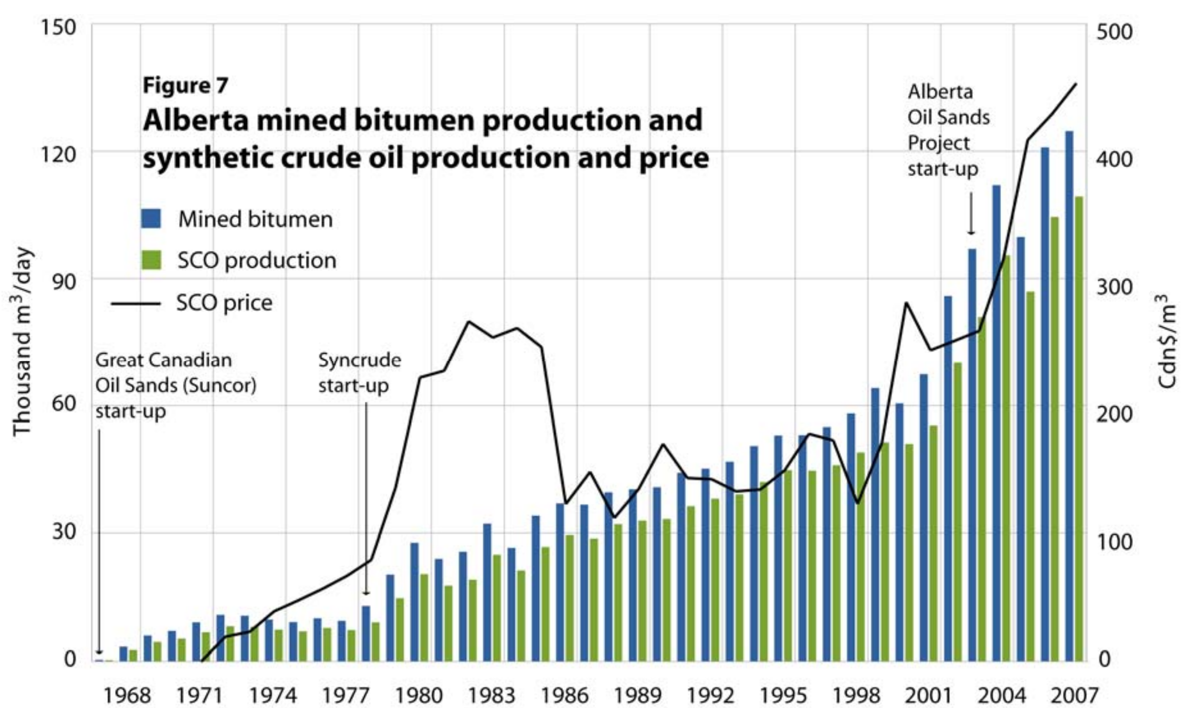
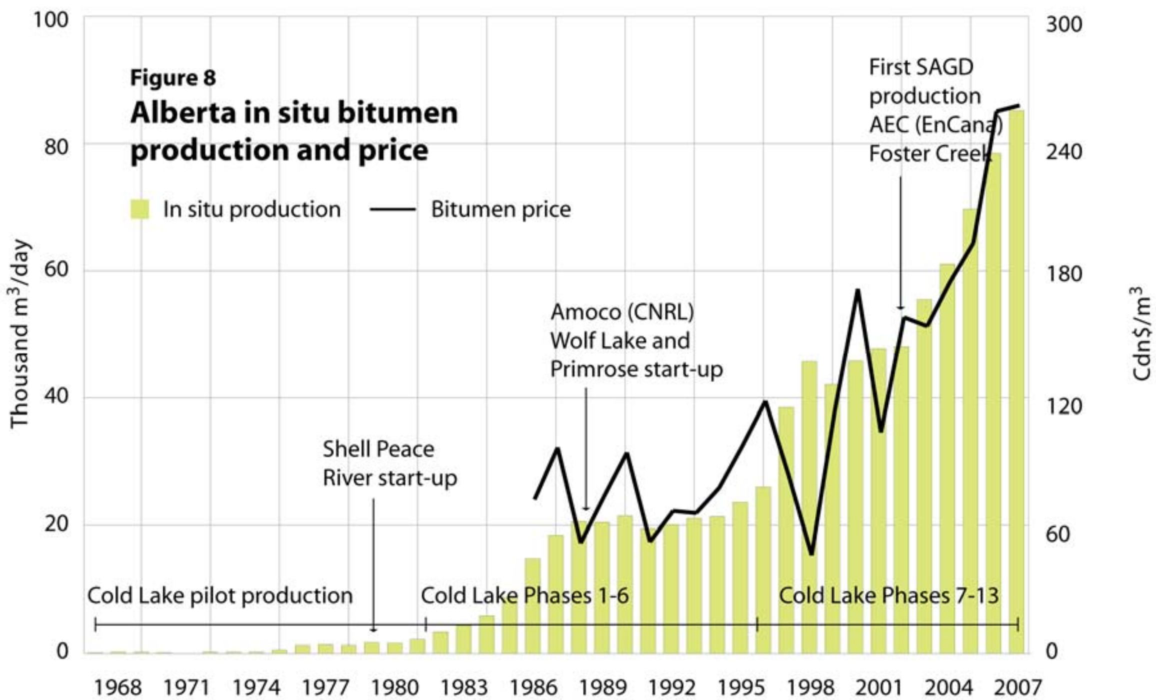


Figure 7
Alberta mined bitumen production and synthetic crude oil production and price
Mined bitumen
SCO production
SCO price
Great Canadian Oil Sands (Suncor) start-up
Syncrude start-up
Alberta Oil Sands Project start-up
Thousand m3/day
Cdn$/m3
0
30
60
90
120
150
0
100
200
300
400
500
1968
1971
1974
1977
1980
1983
1986
1989
1992
1995
1998
2001
2004
2007

Historical production and price of in situ bitumen are shown in **Figure 8**. Imperial's Cold Lake, 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.



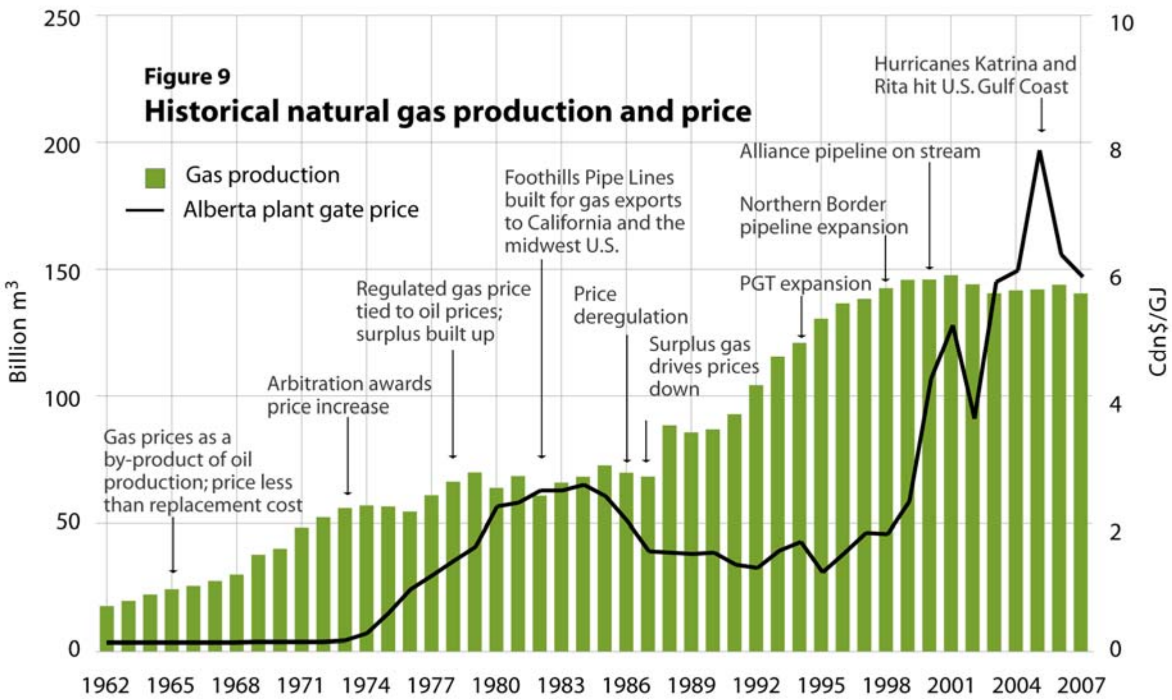
Natural Gas

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, western Canadian producers started asking for higher prices. The federal government at the time objected to higher gas prices, as it believed that would have a negative impact on the Canadian economy. The disagreements were resolved through arbitration and 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 brought on a vibrant gas industry, 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. has 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 2007. Sulphur prices in this period are also shown, adding insight into understanding how prices affect the growth or decline in sulphur inventories. Because of the 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 remelts block and adds to 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** depicts the trends in Alberta sulphur market.

Coal

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical 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.

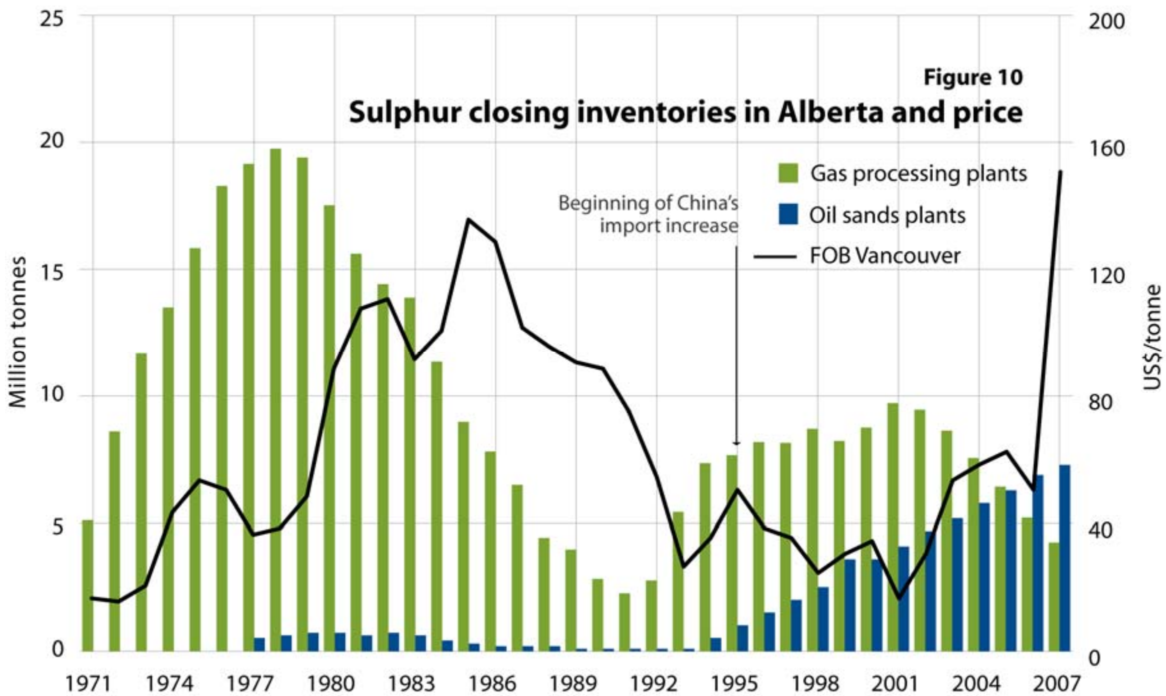


Figure 10
Sulphur closing inventories in Alberta and price
Gas processing plants
Oil sands plants
FOB Vancouver
Beginning of China's import increase
Million tonnes
US$/tonne
25
20
15
10
5
0
200
160
120
80
40
0
1971
1974
1977
1980
1983
1986
1989
1992
1995
1998
2001
2004
2007

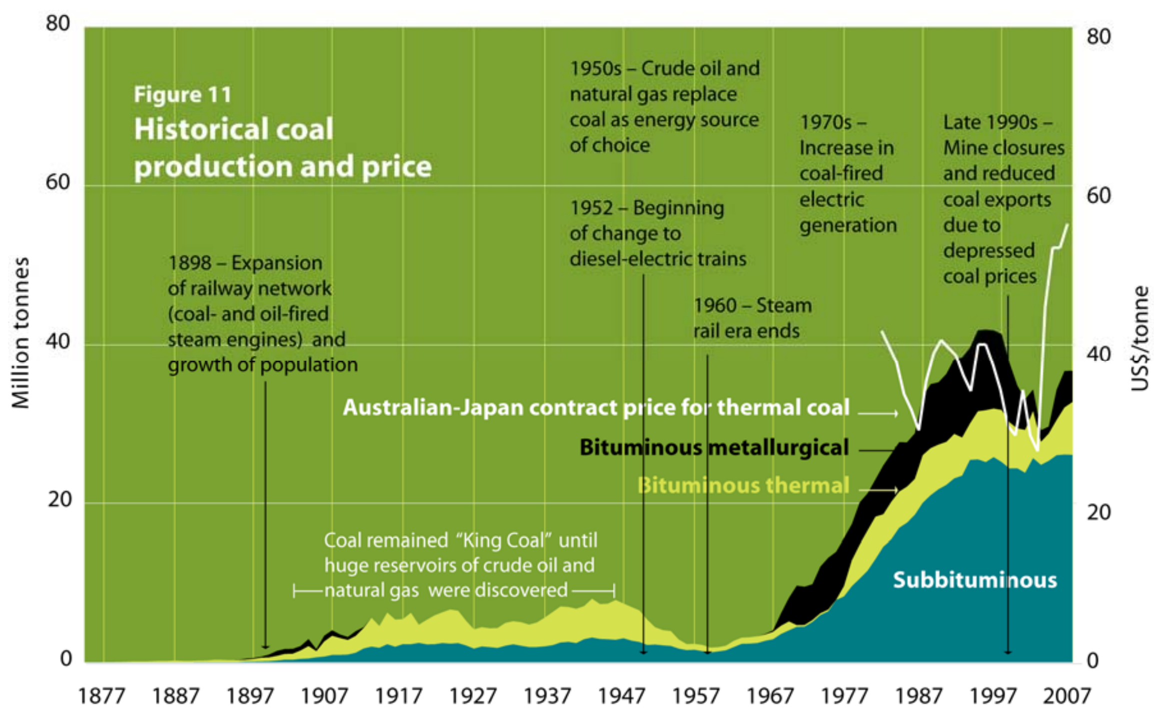


Figure 11
Historical coal production and price
1898 – Expansion of railway network (coal- and oil-fired steam engines) and growth of population
1950s – Crude oil and natural gas replace coal as energy source of choice
1952 – Beginning of change to diesel-electric trains
1960 – Steam rail era ends
1970s – Increase in coal-fired electric generation
Late 1990s – Mine closures and reduced coal exports due to depressed coal prices
Australian-Japan contract price for thermal coal
Bituminous metallurgical
Bituminous thermal
Subbituminous
Coal remained "King Coal" until huge reservoirs of crude oil and natural gas were discovered
Million tonnes
US$/tonne
80
60
40
20
0
1877
1887
1897
1907
1917
1927
1937
1947
1957
1967
1977
1987
1997
2007

1 Energy Prices and Economic Performance

Highlights

- OPEC reference prices climbed $36 per barrel, or 72 per cent, between January and December 2007.
- Oil and natural gas prices diverged, and the Alberta gas-to-light-medium-oil price parity declined to 0.50 on an energy equivalent basis.
- The Canadian dollar exchange rate reached new highs, averaging $0.93 per U.S. dollar in 2007.
- Alberta real GDP growth averaged 3.3 per cent in 2007, unemployment continued to remain low, at 3.5 per cent, while inflation and personal disposable income growth were measured at 5.0 and 4.0 per cent respectively.

Energy production is generally affected by remaining reserves, energy prices, demand, costs, and other factors. 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 requirements and sets the stage for supply and demand 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 discussion of the current global oil supply and demand picture, with projections for 2008 and 2009 based on research conducted by the International Energy Agency (IEA).

A review of the OPEC crude oil basket reference price and summary of factors that will play a key role in influencing benchmark oil prices in the years to come are included. A discussion of North American energy prices is presented, including natural gas and electricity prices 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 2007, the rising prices observed in the global oil market were characterized by tightness in supply and growth in demand, which were influenced mainly by weather conditions, geopolitics, persistent refinery outages, and a weakening of the U.S. dollar. These factors assisted in elevating the average monthly global reference price of crude oil by US$36 per barrel (bbl) between January and December 2007.

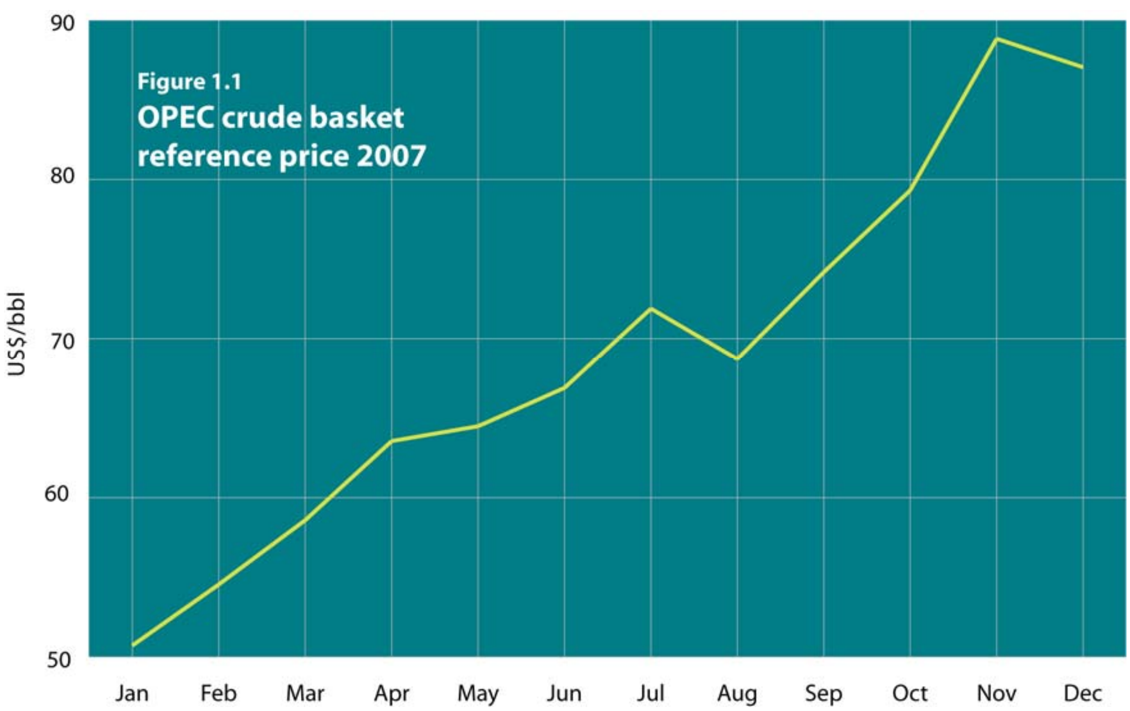
OPEC's supply of crude oil provided as much as 31 million barrels a day (bbl/d) in 2007. This is equivalent to over one-third of total world oil demand.[1] OPEC continually monitors crude oil supply, demand, and their effect on crude oil prices. When the fundamentals leading crude oil create an imbalance in the global market, OPEC can raise

[1] Statistics obtained from OPEC Monthly Oil Market Report (OPEC, March 2008).

or lower the crude oil output of its member countries in an attempt to balance global supply and demand.

In order to monitor world oil market conditions, 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. Angola’s medium-sweet Girassoal crude (30.8° API, 0.34 per cent sulphur) was added to the reference basket effective January 1, 2007. Ecuador’s Oriente (23.8° API, 1.4 per cent sulphur) was added effective October 19, 2007.

Figure 1.1 depicts the monthly average OPEC crude oil basket reference price for 2007. The OPEC reference price averaged US$50.73/bbl in January 2007, a decrease of over 12 per cent from the previous month. The decline reflected reduced demand due to mild winter weather in much of the Northern Hemisphere, combined with ample OPEC supply. However, prices remained volatile, consistent with an apparent supply overhang in the global crude oil market; this rationalized a decision to reduce OPEC production by a further 0.5 million bbl/d effective February 1, 2007. Combined with the last cut to production effective November 1, 2006, OPEC production declined by 1.7 million bbl/d.



The OPEC reference price climbed steadily into the spring, as cuts to OPEC production seemed to be cycling their way through the market in an attempt to stabilize prices. The OPEC reference price increased further than expected, influenced on the demand side by colder weather in North America and improved refinery margins in Europe. On the supply side, geopolitical situations in the Middle East and West Africa raised concerns about supply certainty.

The OPEC price continued to rise over the early summer months, due to supply disruptions from West Africa and the positive outlook of a healthy and resilient U.S. economy amid the preliminary news of the subprime mortgage housing crisis. Also contributing to the price escalation were supply uncertainties arising from stormy weather in the U.S. Gulf of Mexico and rebel attacks on Mexico's pipeline infrastructure.

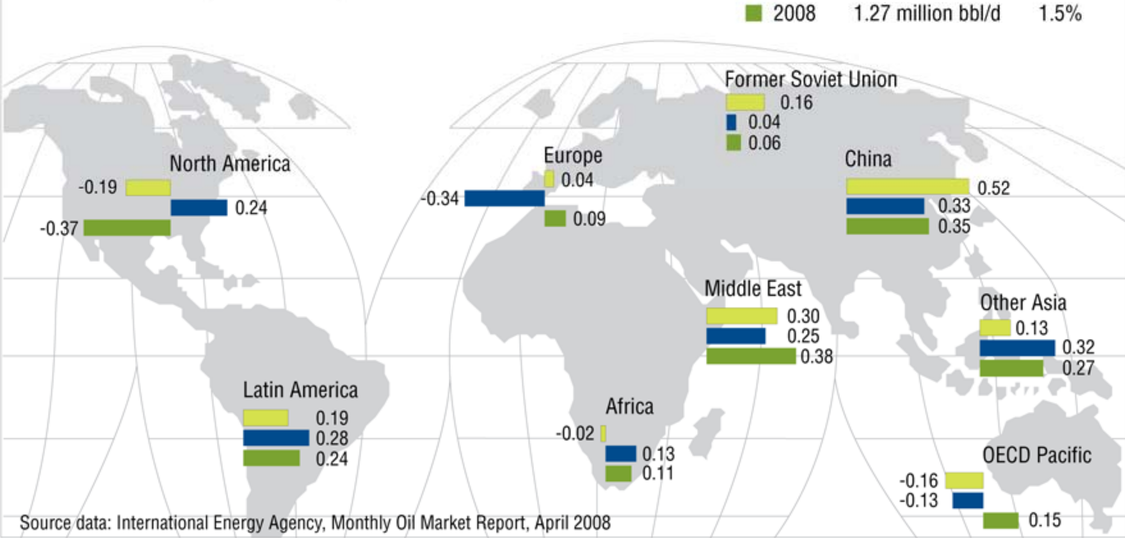
In August, the OPEC reference price averaged US$68.71/bbl, declining 4 per cent from the previous month and becoming the first month of decline on record since January 2007. The decline illustrated concerns that the economic upheaval in the U.S. might have an adverse affect on energy demand. This sentiment was reversed when the U.S. Federal Reserve lowered interest rates two-quarters of a percentage point in mid-September.

The OPEC reference price continued its climb into the fall. September, October, and November observed month-to-month increases of 8, 7, and 12 per cent respectively. Middle East political tensions and increased speculation on energy futures were at the crux of the growth, while profit taking and slower economic growth provided a ceiling on further price escalation.

Although the price escalation observed in the fall was not due to market fundamentals, OPEC decided to increase volumes of crude supply by 0.5 million bbl/d effective November 1 in order to keep crude supplies adequate over the higher-demand winter season. The OPEC reference price decreased roughly 2 per cent in December.

Figure 1.2 illustrates growth in oil demand across the globe between 2006 and 2008. Growth in global oil demand increased slightly between 2006 and 2007, from 1.0 to 1.1 million bbl/d. In 2007, demand weakness was most evident in Europe. However, continued growth in China, India and the Middle East offset any possible decrease in demand. According to the IEA, global oil demand exceeded production by an estimated 0.3 million bbl/d in 2007. Global crude oil supply reached 85.6 million bbl/d, where 31 million bbl/d (36 per cent) of crude was produced by OPEC members.

Figure 1.2
Growth in world oil demand 2006-2008 (10^6 bbl/d)



Source data: International Energy Agency, Monthly Oil Market Report, April 2008

Global crude oil demand is expected to grow by 1.5 per cent, or 1.3 million bbl/d, in 2008. The IEA expects that non-OPEC countries will produce roughly 0.5 million bbl/d; the remaining supply additions will be met by inventory withdrawals and production from OPEC members. Supply from Europe and North America has fallen off in recent years, as it is becoming increasingly difficult and expensive to find and produce large sources of crude. With more crude oil originating from politically unstable nations and average growth in global oil demand above 1 per cent, the OPEC reference price of oil is expected to remain well above US$50/bbl.

The IEA outlook assumes that the North American market, specifically the U.S., will experience the only contraction, resulting in a decline in crude oil demand of 0.4 million bbl/d in 2008. Overall, the Organisation for Economic Co-operation and Development (OECD)[2] will experience a contraction in crude oil demand, declining 0.3 per cent. Growth will occur from increased transportation fuel use, which will be capped by weaker economic growth, notably in the U.S., and higher oil prices.

Overall in 2007, the OPEC reference basket averaged US$69.08/bbl, a 13.1 per cent year-over-year increase from 2006. In the near term, the certainty of an economic slowdown in the U.S. will dampen North American crude demand in 2008. However, global growth in oil demand remains positive. According to the IEA, global oil demand is expected to increase by 1.27 million bbl/d in 2008. In addition, OPEC is reluctant to increase production, as it expects an additional 1 million bbl/d of non-OPEC production to come on stream in 2008.

Despite the slowdown in the U.S., global economic growth, in particular that of highly populated developing nations, remains positive and will continue to play a key role in the strength of crude oil prices going forward. The World Bank estimates China's economy to grow by 9.2 per cent in 2008, which complements the forecast for China's crude oil demand. India's economic growth may rival that of China's in future years. The IEA's recent forecasts expect India's demand for oil to increase at an annual rate of 0.1 million bbl/d, or 4.7 per cent. Ahead of this, consumption in the Middle East, a region most notable for its crude oil exports, is set to grow by an additional 0.4 million bbl/d (6.1 per cent) in 2008.

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 reference price of WTI. WTI is a reference crude with an API of 40 and sulphur content of less than 0.5 per cent. The WTI crude oil price is set in Cushing, Oklahoma, and ranges between US$6/bbl to $7/bbl higher than the OPEC reference price, reflecting quality differences and the cost of shipping.

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

[2] The OECD includes 30 countries across North America, Europe, and the Pacific.

In 2007, the WTI price was influenced by many of the same factors affecting the OPEC reference price. The WTI price started to climb as geopolitical risk, combined with cuts in OPEC production, cycled their way through the North American market. A mild winter decreased heating demand from its normal level and caused inventories of crude oil and products to swell well beyond five-year averages; however, this did little to deflate prices.

The probable risk of a destructive hurricane season was priced into WTI early in spring 2007. However, the mild hurricane season resulted in no impact on production, and inventories of crude oil grew accordingly. With bulging inventories, mild weather, and low demand growth caused by a decelerating U.S. economy, oil prices should have declined.

Once again, in mid-October geopolitics, combined with the declining strength of the U.S. dollar, overwhelmed the stable demand-supply conditions. The WTI price moved up, averaging US$80.93/bbl in September and US$86.99/bbl in October. Another daily record spot price of US$99.16/bbl (at Cushing) was reached on November 20.

The WTI price averaged US$73.56/bbl in 2007, an increase of 9.2 per cent on 2006. The ERCB expects the WTI price to range between US$86/bbl and US$125/bbl, with a forecast price of US$105/bbl for 2008. The forecast range is higher than last year's and is indicative of supply and demand fundamentals in the global crude market, such as increased demand from developing economies, as well as a risk premium set by geopolitical tensions. The bottom end of the WTI price range is an extension of the lows experienced in the market in early 2007, as well as expected inflation in Canada.

Most of the risks to this forecast are downward and include a larger than expected economic slowdown in the U.S., which would quell oil demand. The slowing U.S. economy could impact the global economy and further weaken demand for oil. Upside risk includes higher than anticipated demand for gasoline during the driving season, tight inventories, lower spare producing capacity, and renewed geopolitical upheavals.

Figure 1.3 illustrates the ERCB forecast of 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 2007, heavy crude and bitumen prices averaged Cdn$48.47 and Cdn$40.97/bbl respectively, while the Alberta light-medium reference price averaged Cdn$72.58/bbl. During the year, the price of light and medium crude in Alberta increased at a faster rate than heavy crude, leading to a widening of the premium between light and heavy from 68 to 67 per cent. Similarly, the differential between light-medium crude oil and bitumen widened from 59 to 56 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 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 56 per cent over the forecast period. Wider differentials are noticeable 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 66 per cent.

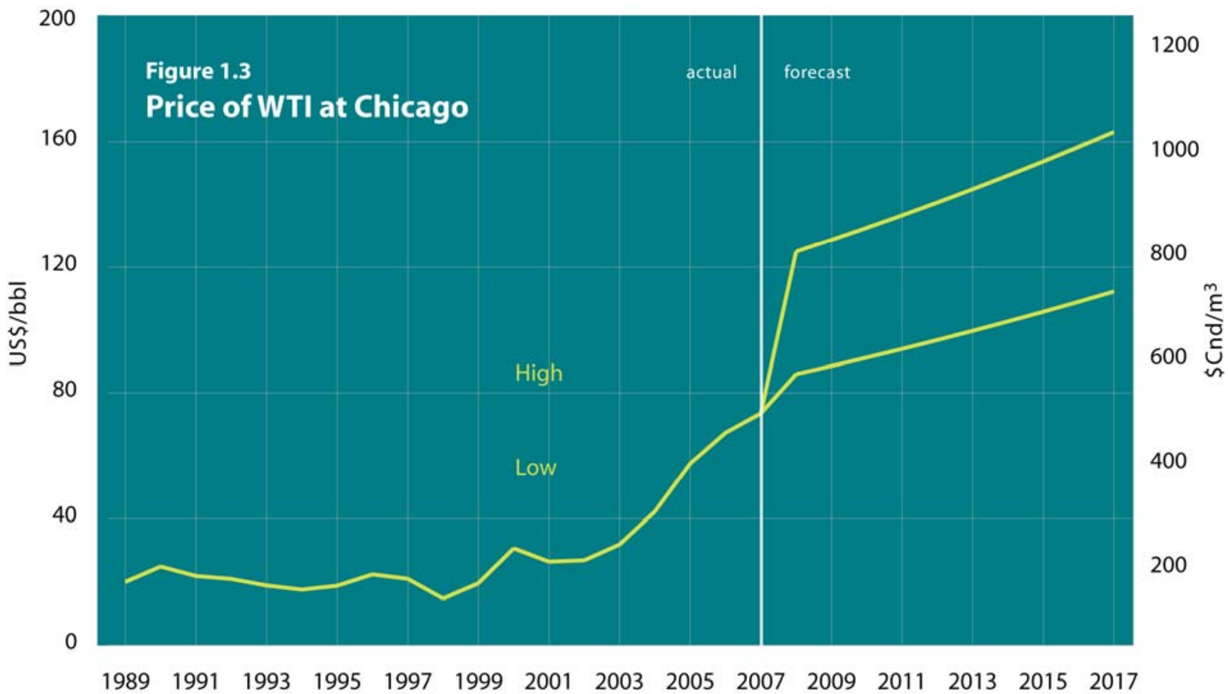


Figure 1.3
Price of WTI at Chicago
actual
forecast
High
Low
US$/bbl
$Cnd/m3
200
160
120
80
40
0
1200
1000
800
600
400
200
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017

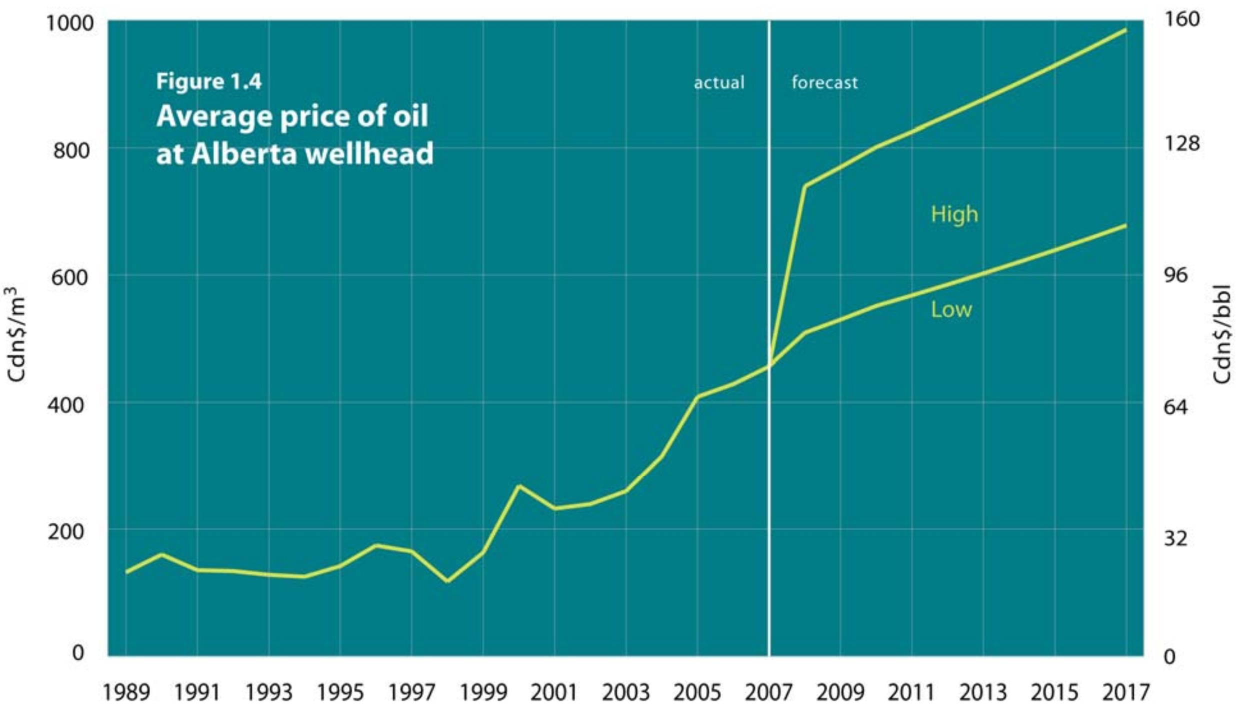
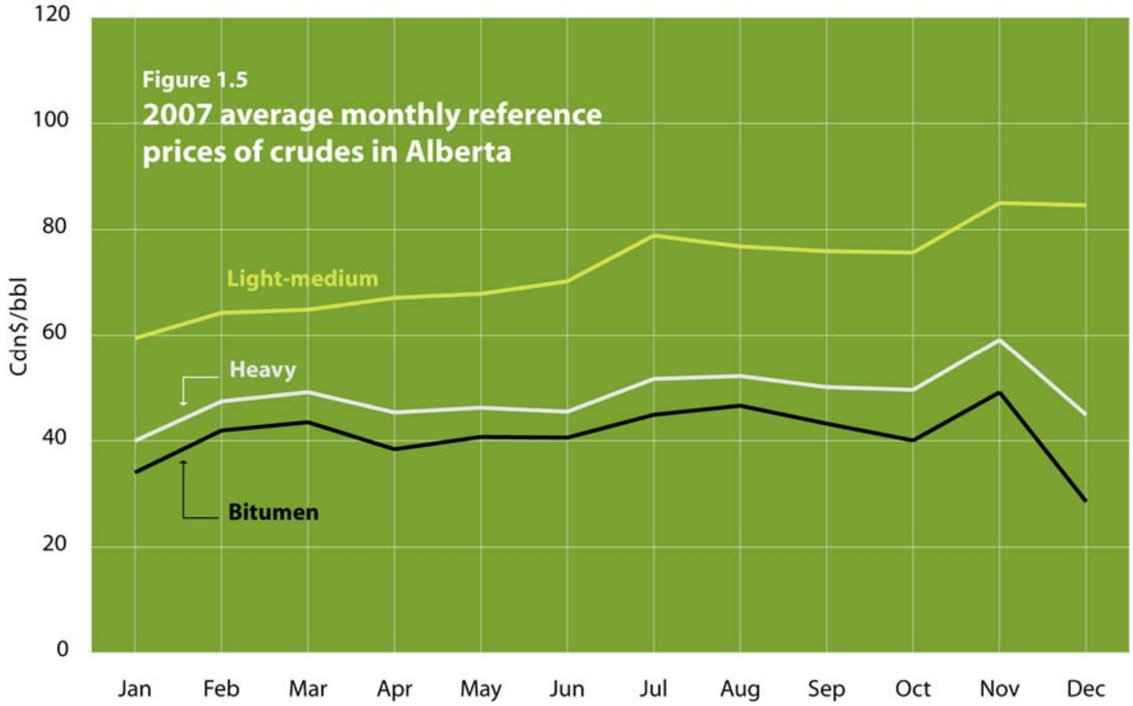


Figure 1.4
Average price of oil
at Alberta wellhead
actual
forecast
High
Low
Cdn$/m3
Cdn$/bbl
1000
800
600
400
200
0
160
128
96
64
32
0
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017



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

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 eight 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 109 thousand cubic metres per day (10^3 m^3/d) (686 10^3 bbl/d) in 2007 to 318 10^3 m^3/d (2001 10^3 bbl/d) by 2017. Details on markets for Alberta bitumen are discussed in more detail in Section 2.

After meeting Alberta and Canadian refinery demand, 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 665 10^3 m^3/d (4185 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 and has resulted 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 with planning and executing new projects.

In summary, twelve proposed new pipelines and pipeline expansions indicate an overall increase in crude oil pipeline capacity of 185 10^3 m^3/d (1164 10^3 bbl/d) for the Alberta market and 390 10^3 m^3/d (1824 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 60 per cent in Alberta SCO and non-upgraded bitumen pipeline capacity and a 90 per cent increase in export pipeline capacity.

If production follows our current forecast, additional Alberta crude oil pipeline capacity will be required in the 2010 to 2013 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 BC to the Edmonton area, further easing transportation constraints.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the U.S., with 55 operating refineries and net crude oil distillation capacity of 1328 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 because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude production. 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 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 1997 to 2017.

Alberta gas prices trended upward the first three months in 2007 to a high of Cdn$6.92 per gigajoule (GJ) in March, after which it declined to Cdn$4.42/GJ in September. Warm winter weather in the U.S. northeast early in the year and the absence of major tropical storms in key production areas, along with higher liquefied natural gas (LNG) imports and growth in marketed natural gas production from the U.S. (4 per cent year over year), allowed storage levels of natural gas to reach record levels. Since September, prices have slowly moved upward, as colder temperatures greeted the U.S. northeast and eastern Canada.

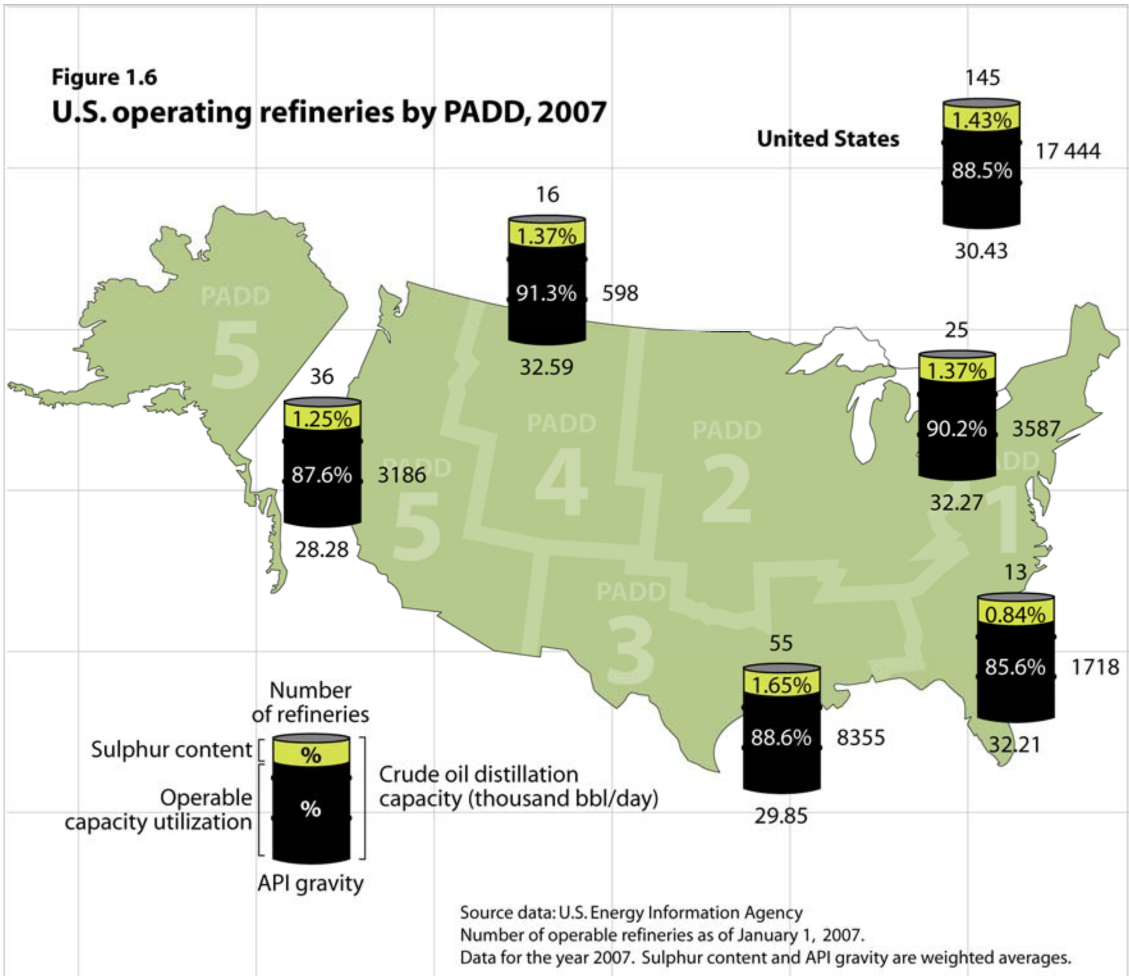


Figure 1.6
U.S. operating refineries by PADD, 2007
United States
145
1.43%
88.5%
17 444
30.43
PADD 5
36
1.25%
87.6%
3186
28.28
PADD 4
16
1.37%
91.3%
598
32.59
PADD 2
PADD 3
55
1.65%
88.6%
8355
29.85
PADD 1
25
1.37%
90.2%
3587
32.27
13
0.84%
85.6%
1718
32.21
Number of refineries
Sulphur content
%
Operable capacity utilization
%
Crude oil distillation capacity (thousand bbl/day)
API gravity
Source data: U.S. Energy Information Agency
Number of operable refineries as of January 1, 2007.
Data for the year 2007. Sulphur content and API gravity are weighted averages.

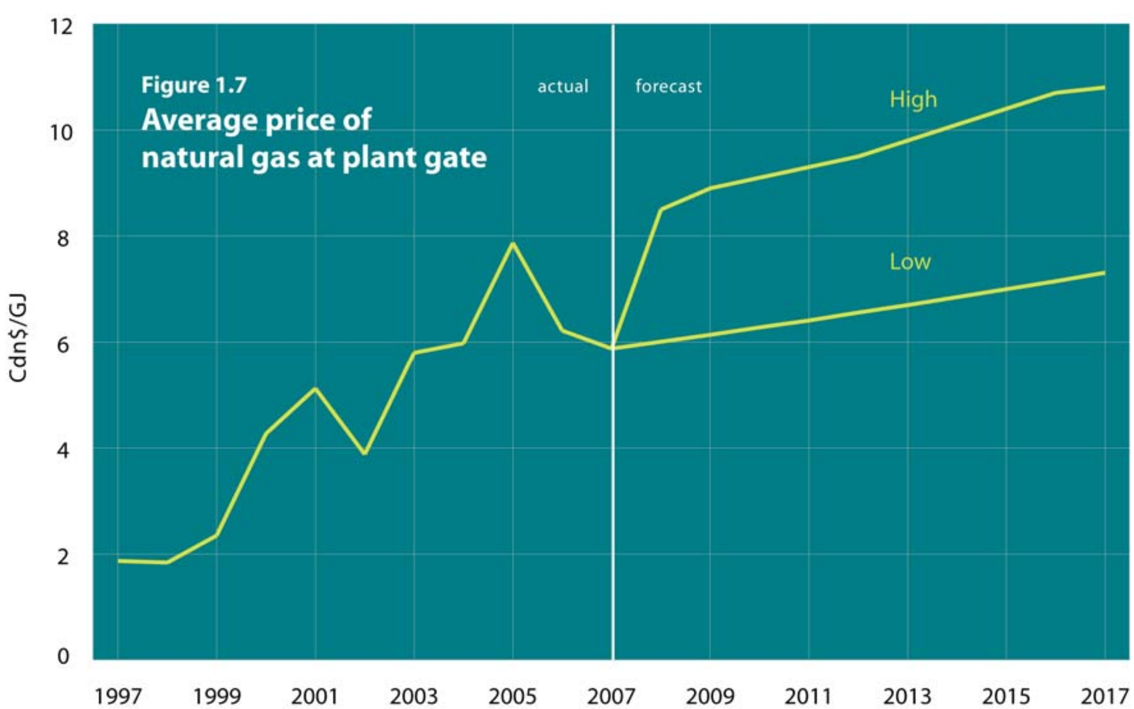


Figure 1.7
Average price of natural gas at plant gate
actual
forecast
High
Low
Cdn$/GJ
0
2
4
6
8
10
12
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017

As the 2007-2008 winter heating season came to a close in the United States, storage levels appeared likely to remain above their five-year average into the summer cooling season. This will keep prices stable. The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$6.00/GJ and Cdn$8.50/GJ, averaging Cdn$8.00/GJ in 2008. 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 0.50 for 2007, as the price of natural gas declined and crude oil prices increased. During the 2004 to 2006 period, the parity averaged 0.68.

Over the forecast period, the price of natural gas is expected to increase slowly to reach an average of Cdn$9.06/GJ by 2017, while the top end of this range could surpass Cdn$10.00/GJ. The gas-to-oil price parity is expected to average 0.44 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 instantaneously to global events, such as demand or supply shocks in various nations or geopolitics, 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, as more consumers become wealthier in the rapidly developing economies of China and India, they too will demand more refined petroleum products for the transportation of goods and services.

Natural gas, on the other hand, does not have the wide-ranging demand of crude oil or refined petroleum products. It may, however, have the potential to become a global commodity if the trade in LNG is developed globally, but this is likely to occur over the longer term. As of March 2008, there are six operating LNG import terminals in the U.S. and one in Mexico. Another 27 projects are in various stages of construction and regulatory review, and 21 additional LNG projects remain in the planning stages in North America. The location and construction of LNG liquefaction facilities continue to remain highly contentious issues.

Despite the impact that intercontinental trade in LNG could have on gas prices in North America, the ERCB believes that LNG will not capture a high market share in North America over the forecast period, primarily due to the risk and regulatory requirements for construction of gasification terminals. Furthermore, while substantial natural gas reserves exist worldwide that could be tapped into for liquefaction purposes, lining up supply for specific projects is proving to be more difficult than expected.

The LNG landed price on the U.S. east coast is in the US$6.00 to US$8.00/GJ range and is competitive with gas prices set at the Henry Hub pricing point. It is expected that LNG suppliers will not price their gas at its marginal cost (about US$5.00/GJ), but rather at the market price in North America, in order to maximize their revenue.

Similar to previous forecasts, the ERCB believes the current forecast for natural gas prices will be more a reflection of future supply and demand conditions in both the U.S.

and Canada. Despite the low drilling activity in 2007, coalbed methane (CBM) is expected to provide an increasing share of Alberta's total natural gas production, as conventional supply continues to decline. However, CBM is not expected to offset the downward trend in conventional 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 2007. The 2006 average is included for comparison. The monthly average pool price was stable heading into 2007. Over the first half of 2007, mild average temperatures kept demand relatively low, coal-fired outages were not outside their normal pattern, and the monthly pool price was actually trending downward.

Table 1.1. Monthly pool prices and electricity load

	Price ($/MWh)			Load (MW)		
2007	Average	Min	Max	Average	Min	Max
Jan	60.75	6.77	674.37	8284	7029	9466
Feb	73.38	6.79	516.06	8367	7201	9478
Mar	56.72	6.26	638.84	8062	6991	9080
Apr	51.67	5.25	717.89	7766	6658	8729
May	48.37	0.00	738.60	7446	6440	8374
Jun	49.87	5.25	505.47	7601	6510	8729
Jul	155.73	6.95	999.99	8048	6635	9321
Aug	71.10	9.30	998.46	7761	6716	9083
Sep	49.17	7.00	667.76	7614	6653	8697
Oct	64.74	6.95	787.73	7885	6748	9077
Nov	54.24	11.23	531.32	8222	7048	9525
Dec	66.28	6.95	946.66	8391	7154	9701
2007	66.95	0.00	999.99	7952	6440	9701
2006	80.79	5.42	999.99	7919	6351	9661

Although the average pool price for 2007 was 17 per cent lower than for 2006, prices continued to show extreme volatility during the year. For example, in July the available supply of electricity was limited due to the unavailability of coal-fired power plants that were off line for maintenance and upgrades. Coal-fired turnarounds normally occur in the spring and fall, with some overlap into Alberta's short summer period. In July, as much as 12 per cent of Alberta's total generating capacity was unavailable on certain days.

In addition to limited supply due to coal-fired plant maintenance schedules, there now appears to be a summer peak load period. Increased demand for industrial cooling and air conditioning is also driving up the pool price. Maximum and average electricity loads in July were actually very close to winter load levels. The 2007 pool price would likely have approached the 2006 average if not for the softening of natural gas prices in the latter half of 2007.

Figure 1.8 illustrates the historical and the ERCB forecast of average annual pool prices in Alberta to 2017. The average hourly pool price of electricity in 2007 was $66.95 per megawatt hour (MWh), which is a decrease of 17 per cent from $80.79/MWh in 2006. The average annual pool price in 2007 was nearer the 2005 average ($70.36/MWh).

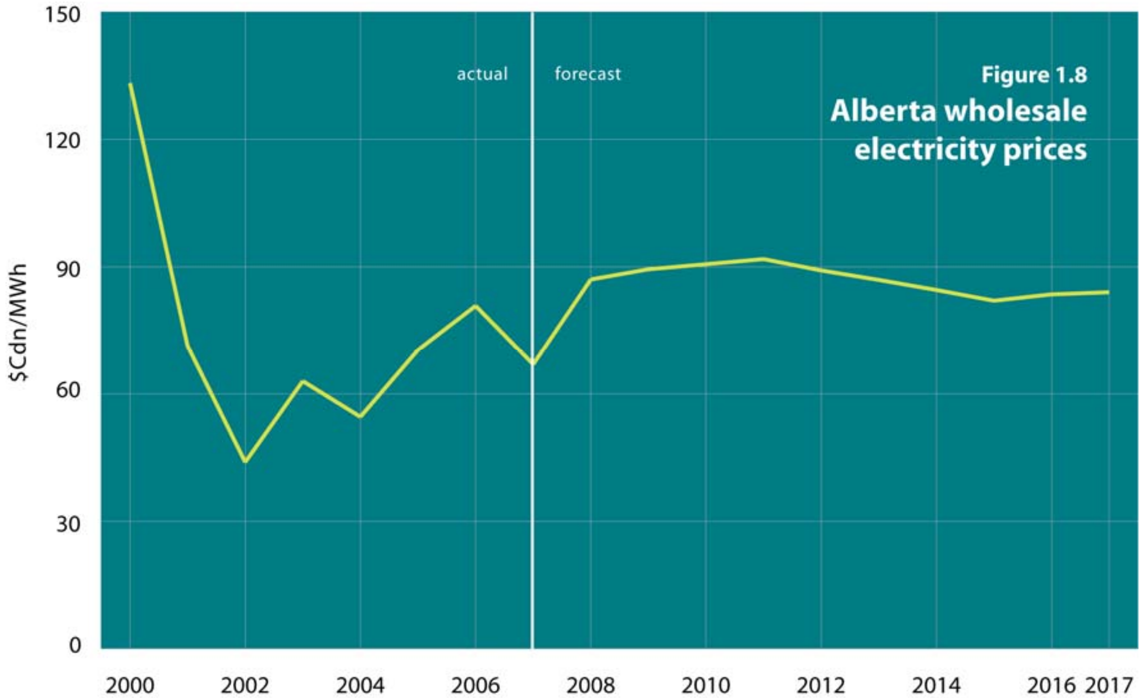


Figure 1.8
Alberta wholesale electricity prices

Expectations for the rate of growth in electricity supply and demand, discussed in **Section 9**, indicate that power pool prices will remain above historical averages going forward. Capacity at lower-cost coal-fired generating stations will not increase substantially before 2011. Until then, natural gas-fired generation will supply an increasing amount of the electricity needed at the margin. From 2008, the average annual pool price is expected to grow alongside the forecast for natural gas prices. In 2012, growth in the pool price will be curbed due to the commissioning of new coal-fired capacity at Keephills 3.

The rolling daily average pool price was $73/MWh near the end of March 2008, which is higher than the same period over the two previous years. The average annual pool price is expected to fluctuate between $82/MWh and $92/MWh over the forecast period.

1.3 Oil and Gas Production Costs in Alberta

For the past 26 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical wells reflecting the most popular wells drilled in the previous year. The cost estimates presented here were obtained from the 2007 and 2008 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 the drilling costs. Many other factors influence well costs, including the economic environment, oil versus gas well, surface conditions, sweet versus sour production, development versus exploratory wells, drilling program, well location and nearby infrastructure, and completion method.

Table 1.2. Alberta median well depths by PSAC area, 2007 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3580	2323	707	685	886	429	935
Oil wells	3494	2104	1228	788	1579	NA	2016

NA – Not applicable.

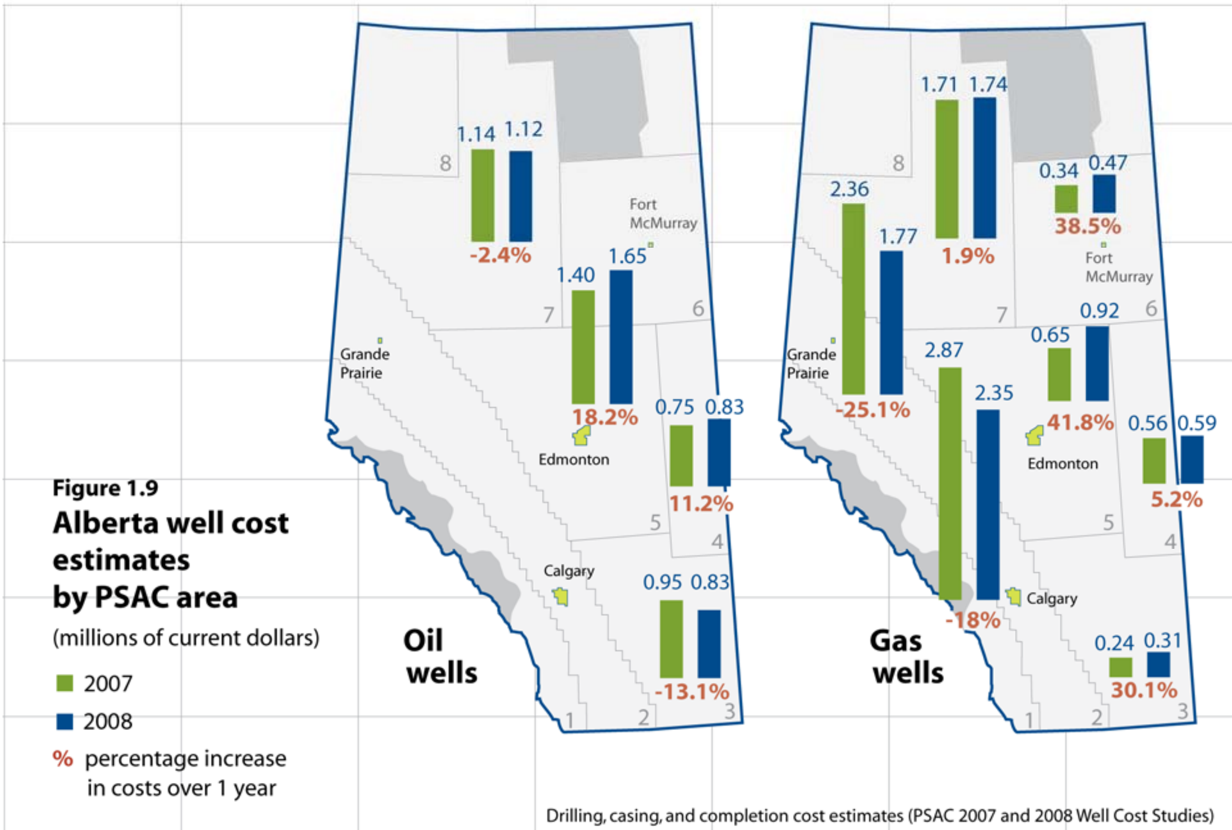


Figure 1.9
Alberta well cost estimates by PSAC area
(millions of current dollars)

Costs to drill and complete an oil well in 2008 are expected to range from as low as \$830 000 in East Central (PSAC Area 4) and Southern Alberta (Area 3) to as high as \$1 651 000 in Central Alberta (Area 5). Typical wells in Areas 4 and 5 are expected to exhibit a significant increase in costs, while Areas 3 and 7 will decrease 13.1 and 2.4 per cent respectively (**Figure 1.9**). On average, across the four PSAC areas, oil well costs will rise 4.4 per cent.

Estimated costs to drill and complete a typical gas well are highest in the Foothills area, at close to \$2.5 million, but could range significantly higher for the deeper sour gas wells. In Southeastern Alberta (Area 3), a typical gas well could cost around \$310 000 to drill and complete.

Costs to drill and complete a well for natural gas production in Alberta have also risen with time. However, going into 2008, wells with depths of 2500 to 2700 m in PSAC Areas 1 and 2 are expected to decline by 18.0 and 25.1 per cent respectively. In these areas, PSAC changed a number of assumptions, including the amount of infrastructure in place and the type of drilling rig required. On the other hand, PSAC estimates double-digit growth for costs to drill and complete a gas well in PSAC Areas 3, 5, and 6. Between 2007 and 2008, the average cost of drilling and completing a gas well outside PSAC Areas 1 and 2 is expected to increase 15.3 per cent.

1.4 Canadian Economic Performance

Canadian economic growth, interest rates, inflation, unemployment rates, and currency exchange rates (particularly vis-à-vis the U.S. dollar) are key indicators that affect Alberta's economy but are beyond the province's control. The Canadian performance of the above economic indicators between 1998 and 2007 are depicted in **Figure 1.10**. Canada's most recent annual performance of these indicators and the forecast to 2017 are presented in **Table 1.3**.

Table 1.3. Major Canadian economic indicators, 2007-2017

	2007[a]	2008	2009	2010-2017[b]
Real GDP growth	2.7%	1.7%	2.4%	2.7%
Prime rate on loans	6.1%	5.5%	5.6%	5.7%
Inflation rate	2.2%	1.8%	2.0%	2.0%
Exchange rate (US/Cdn$)	0.94	0.97	0.96	0.95
Unemployment rate	6.0%	6.1%	6.3%	6.5%

[a] Actual.
[b] Averaged over 2010-2017.

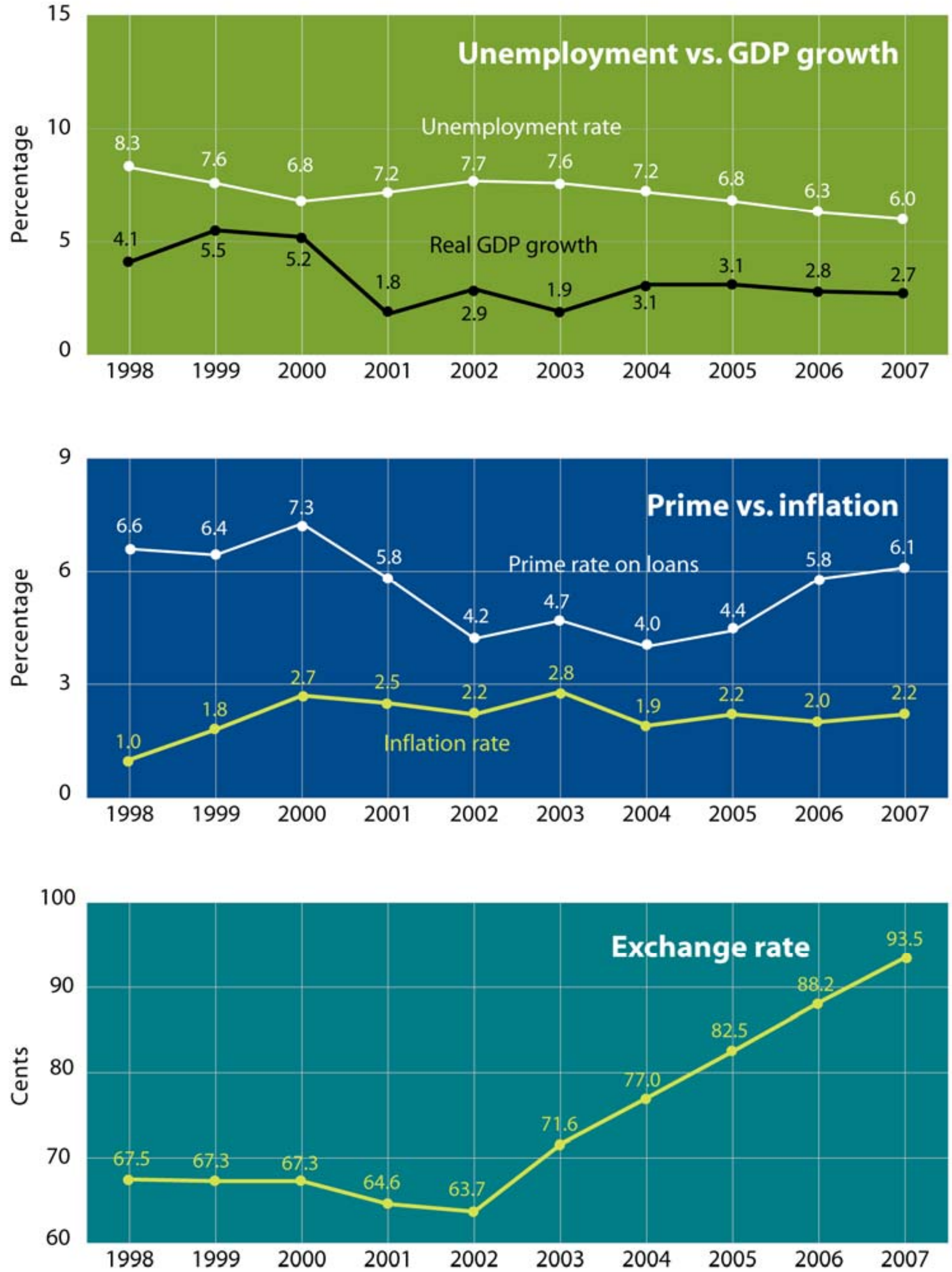
Economic growth, the percentage change of gross domestic product (GDP) between two points in time, usually a year or a quarter, measures the rate of expansion (or contraction) of an economy and its capacity to produce goods and services. In 2007, Canada's GDP growth rate averaged 2.7 per cent.

The foundation to Canada's economic growth in 2007 was a combination of strong consumer spending and gains to real gross fixed capital formation. However, a number of economic conditions had a softening effect on growth. The continued appreciation of the Canadian dollar against the U.S. dollar and a slowing of the U.S. economy affected exports. As well, higher energy prices continued to impact Canadian industries and consumers.

Low interest rates, competitive pressures on Canadian businesses from the appreciation of the Canadian dollar, and low inflation favoured greater spending out of personal incomes. Wages, salaries, and supplemental labour income grew at a healthy 6.1 per cent, and real consumer spending increased 4.7 per cent in 2007. Personal expenditures on consumer durable goods increased 7.7 per cent, and semi-durable goods (e.g., household furnishings) increased 6.1 per cent. Personal expenditures on consumer nondurable goods and services plumped up domestic demand, increasing 3.1 per cent and 4.5 per cent respectively.

Real investment in both the private and public sectors remained strong, above 4.0 per cent year over year. On the business side, investment in residential structures picked up but was outpaced by investment in nonresidential structures, machinery, and equipment, 3.2 per cent compared to 4.4 per cent. On the nonresidential side, investment in structures advanced by 3.9 per cent and investment in machinery and equipment grew by 5.1 per cent. Corporate profits before income tax increased 5.8 per cent in 2007, slightly higher than in 2006 (5.0 per cent).

Figure 1.10
Canadian economic indicators



Real government investment rose by 4.5 per cent, down from previous years. Despite recent sizeable budget surpluses, the federal government vows to maintain strong fiscal management by focusing on federal debt reduction and responsible public spending. The government is 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.

Canada’s exchange rate in relation to the U.S. dollar appreciated by an average of $0.053 in 2007. The appreciation was influenced by demand for raw commodities, such as crude oil, natural gas, coal, and other minerals. Canada’s energy sector, especially activity in Alberta’s oil sands, has made Canada a target of foreign investment and has helped to keep upward pressure on demand for the Canadian dollar.

The appreciation in the Canadian dollar dampened real exports to the U.S., Canada’s largest trading partner. The value of real export growth in Canada only increased by 0.9 per cent in 2007. Real exports of services declined 1.3 per cent, while exports of goods increased 1.3 per cent. Real imports have averaged increases of over 5 per cent per year since the Canadian dollar began its appreciation, with imported goods exhibiting higher growth rates than services. Although Canadian exports continue to benefit from high commodity prices, Canada’s trade surplus has narrowed, which may impede economic growth.

In addition to investment, consumption, and manufacturing gains, economic growth typically implies growth in the labour force and possibly a reduction in the unemployment rate. Canada’s unemployment rate in 2007 fell 0.3 percentage points to 6.0 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. The rate of growth in employment has accelerated relative to the growth in the labour force. In 2007, the number of persons entering the work force increased by 2 per cent, while employment gains were stronger at 2.3 per cent. The unemployment rate is expected to increase by 0.1 percentage point in 2008, as more people enter the labour force.

In some cases growth can be so strong that it can create inflationary pressures within the economy as it operates at or close to capacity. The inflation rate is used to monitor changes in the cost of living in a society, as it measures the rate at which the price of goods and services is increasing. Low inflation enables an economy to function more effectively by allowing individuals to be more confident in their spending and investment decisions. It also encourages longer-term investments, sustained job creation, and higher productivity, which result in improvements in the standard of living.

Inflation is expressed in terms of changes in the total consumer price index (CPI) or the core CPI. The core CPI, a variation on the total CPI, excludes the eight components from the total CPI reference basket that exhibit the most price volatility (fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, intercity transportation, and tobacco products), as well as the effect of changes in indirect taxes on the remaining components.

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, at 2 per cent.

The average annual interest rate on prime business loans was 6.1 per cent in 2007, an increase of 0.3 percentage point over the 2006 average rate. The rise in interest rates came about from the Bank of Canada’s decision to increase the target overnight rate a quarter of a percentage point in July 2007 in an effort to keep the Canadian economy from growing past its potential and to keep the level of inflation in check. The rise in interest rates lasted until December, when the Bank of Canada, while citing some upside risk of inflationary pressure, lowered the rates down a quarter of a percentage point due to the effects of the subprime mortgage crisis in the U.S. The rate of inflation in 2007 reached 2.2 per cent, a 0.2 percentage point increase from the previous year.

The Bank of Canada has reduced rates further in 2008. As of the end of April, rates are one and one-quarter percentage point lower. The subprime crisis has led to the tightening of credit conditions and weakening of the U.S. housing sector, and it is expected to have significant spillover effects on the global economy. Although domestic demand is expected to remain strong, exports from Canada, especially to the U.S., will have a drag on Canada's economic growth in 2008. As a result, the Bank of Canada has pursued further monetary stimulus, lowering rates to keep the economy and inflation in balance.

Canada's real GDP growth is expected to decelerate to 1.7 per cent in 2008. The Canadian dollar is expected to average US$0.97. Increased competitive pressures from a strong Canadian dollar and the 1 percentage point cut in the goods and services tax (GST) corroborate the outlook of low inflation, forecast at 1.8 per cent in 2008. Expectations of lower interest rates, low inflation, and gainful employment complement the strength in Canadian domestic demand, which provides the foundation of the ERCB forecast for Canada's economic growth in 2008. It is expected that the U.S. subprime crisis will play out into 2009, suppressing any outlook of remarkable economic growth for Canada over the next several quarters.

1.5 Alberta Economic Outlook

Alberta real economic growth averaged 4.7 per cent per year over the past five years and is expected to grow by a further 3.5 per cent in 2008. Alberta has the highest nominal GDP per capita among the provinces, averaging $75 000 per person, which is 61 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**. Real annual economic growth in Alberta for 2007 was 3.3 per cent. Real GDP is set to grow a further 3.5 per cent in 2008, 3.6 per cent in 2009, and an average of 3.5 per cent per year over the remainder of the forecast period. Alberta's inflation was measured at 5.0 per cent in 2007, above the national average of 2.2 per cent. The province is dealing with exceptional economic growth and strong population growth, which are feeding cost increases throughout the province.

Despite the deceleration in economic growth, in part due to soft natural gas prices and a slowdown in drilling activity, Alberta's economy will continue to be among the nation's best performers in 2008. 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.

Table 1.4. Major Alberta economic indicators, 2007-2017 (%)

	2007[a]	2008	2009	2010-2017[b]
Real GDP growth	3.3	3.5	3.6	3.5
Real personal disposable income growth	4.0	3.9	3.8	4.0
Inflation rate	5.0	4.4	4.3	4.0
Employment growth	4.7	2.7	3.5	3.0
Population growth	3.1	2.6	2.5	2.4
Unemployment rate	3.5	3.6	3.6	3.6

[a] Actual.
[b] Averaged over 2010-2017.

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

Investment in construction and machinery and equipment in the province has been defying most expectations over the past few years, and the bulk of expenditure, particularly in the province's energy sector, is yet to come. Since the early part of the decade, global oil and North American natural gas prices have skyrocketed due to increasing demand, dwindling spare capacity, and geopolitics (in the case of crude oil). The stubbornly high oil prices have caused exploration, drilling, and extraction to surge in Alberta. High crude oil prices have made previously uneconomic unconventional crude oil extraction profitable. The oil sands sector in particular has become the target of interest for investors worldwide and has contributed to massive investment in the sector.

Most of the investment in the oil sands sector has recently been 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.

From 2008 through 2017 the ERCB expects nominal investment expenditure related to oil sands (surface mining, upgrading, in situ, and support services) to reach $116 billion ($87 billion in 1997 dollars). Real investment in conventional oil and gas extraction and nonconventional non-oil sands (e.g., CBM and some heavy oil extraction) is expected to average $25 billion per year, consistent with the ERCB drilling, commodity price, and recent historical estimates.

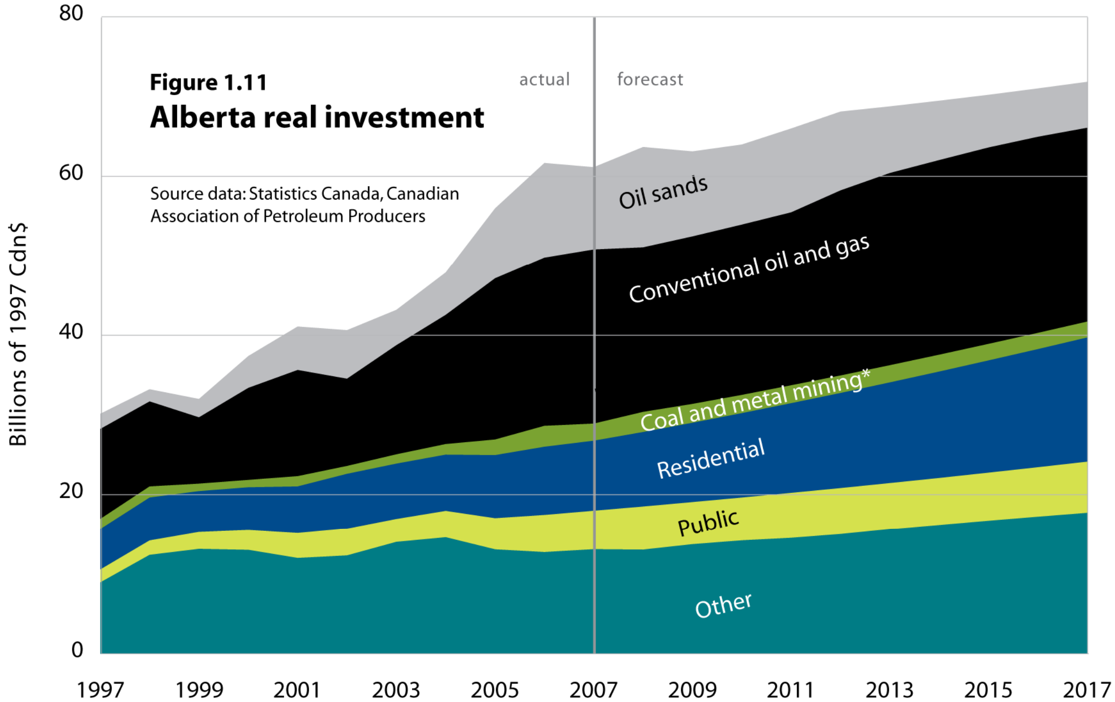
Figure 1.11 illustrates the profile of real investment in Alberta's energy, business, residential, and government sectors from 1997 through 2017. Historically, much of the volatility in Alberta's investment was strongly influenced by resource prices, interest rates and, of course, economic performance. While this trend is expected to continue, investment in the oil sands and conventional oil and gas will provide the basis of investment and economic growth well into the long term.

Total real investment expenditure is expected to grow by an average of 4.1 per cent in 2008. Over the 2009 to 2017 period, real investment will decelerate, growing by an average of 1.4 per cent. In the event that oil sands projects are delayed or as new oil sands projects are announced and approved, investment growth may become more pronounced towards the end of the forecast period.

The ERCB expects the deflator related to construction investment to continue exhibiting inflationary pressure well above the CPI, as capital, labour, and material are priced at a premium in the province. Construction-related costs have escalated sharply in the province over the past few years, and not only for construction related to the energy sector. Material and labour costs for infrastructure projects in transportation, education, and health care have also grown significantly.

Figure 1.11
Alberta real investment

Source data: Statistics Canada, Canadian Association of Petroleum Producers



* Includes support activities to mining and oil and gas extraction.

In recent years, Alberta has come to rely on labour from outside of the province to fill its growing need for workers. Given the ongoing high level of economic activity, the province faces a growing labour shortage. Alberta has intensified efforts to draw foreign workers to the province, particularly for specialized trades, including such industries as manufacturing, hospitality, engineering, health care, and emergency services. In 2007 employment grew by 4.7 per cent, twice the pace of the national average, and as a result the unemployment rate was a mere 3.5 per cent (compared to 6.0 per cent nationally). While employment gains are expected to slow in the near term, unemployment should remain at an all-time low. Over the forecast period, employment growth will average 3.0 per cent. The corresponding labour force participation rate will remain fairly consistent with expectations of employment and population growth, at 81 per cent.

Real personal disposable income grew by 4.0 per cent in 2007. Over the rest of the forecast period, its growth will average 4.0 per cent. The increase in earnings will continue to propel consumer expenditures, which have also been expanding at a fast pace in the province recently. In 2006, real consumer expenditures surged by 8.2 per cent, and 2007 growth was 6.4 per cent. As personal income increases, real consumption will be rising and spending will advance by 5.3 per cent in 2008. Over the remainder of the forecast, real consumption growth will average 5.5 per cent.

Real provincial exports, net of inflation, which include interprovincial transactions of goods, grew by 1.2 per cent in 2007 and are set to grow by 4.8 per cent in 2008. Over the remainder of the forecast, real export growth will average 4.2 per cent. Canada's strong exchange rate farther out in the forecast period implies that export growth will be weaker compared with the near term.

As disposable income and prospects for high-paid employment grow over the forecast period, consumers will continue to demand more goods and services, with many of these originating from abroad. Real import growth expanded by 4.8 per cent in 2007, following

7.8 per cent in 2006. Much of the import growth can be attributed to a strong Canadian dollar, which has made these goods cheaper for Canadians. As the ERCB expects the exchange rate to remain above US$0.95 over the forecast, 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.

Today's energy prices are the driving force fuelling the current pace of exploration and development activity. The assumption that prices will remain high by historical standards will increase the likelihood of further investment in upstream and downstream oil and gas infrastructure. If current prices are sustained, the effect could provide long-term stability to the current level of economic activity in Alberta, thus adding to its economic potential and standard of living.

Conventional gas wells connected and oil wells placed on production in Alberta declined in 2007 from previous year highs. In 2006, 12 932 conventional gas wells and 1956 conventional oil wells were connected and placed on production in Alberta. In 2007, 10 796 conventional gas wells were connected and 1745 conventional oil wells were placed on production. Also in 2006, some 2929 CBM (unconventional gas wells) were placed on production. In 2007, only 2259 wells were connected for CBM production, a 23 per cent decrease from the 2006 levels. The natural gas price decline that took place in late 2006 and 2007 is the likely determinant 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 2008.

Energy prices are also providing greater incentives to commercially develop Alberta's unconventional energy resources, such as CBM and crude bitumen. Production rates from unconventional resources are expected to increase significantly over the coming decade. As a result, the total economic value of Alberta's produced unconventional resources (shown in **Table 1.5**), in particular crude bitumen and SCO derived from the oil sands, will more than offset the decline of conventional resource production.

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

	2007	2008[a]	2009[a]	2010-2017[a,b]
Conventional crude oil	12 334	16 135	16 073	14 465
Crude bitumen	7 539	11 514	12 017	20 157
Synthetic crude oil	18 056	28 808	36 658	70 349
Marketable gas	30 930	40 584	37 135	38 211
Natural gas liquids	9 522	11 322	11 448	11 695
Sulphur	211	225	225	225
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	78 592	108 588	113 535	155 102

[a] Values calculated from the ERCB's annual average price and production forecasts.
[b] Annual average over 2010-2017.

CBM production accounted for 5 per cent of marketable natural gas production in 2007. By 2017, gas production from CBM wells will increase to 16 per cent of marketable gas production. However, the additional marketable gas production from unconventional sources will fall short of offsetting the decline in conventional natural gas production.

Investment in refineries and upgraders within Alberta will enable increased volumes of crude bitumen to be upgraded into higher-valued SCO product, further providing long-term stability for GDP growth and employment. As well, investments in pipeline infrastructure will improve access to markets outside of Alberta. As a result, exports of Alberta's SCO product will increase from 63 per cent of the total SCO production in 2007 to 84 per cent of SCO production by 2017.

Higher energy and commodity prices are leading to increased revenues at oil and gas companies and higher operating expenditures. Today in Alberta, these companies are competing with each other for skilled workers, drilling contracts, and support services. Equipment and labour are increasingly scarce and have driven costs up significantly, especially during periods of high seasonal demand. Many of these limitations are acknowledged by industry, and in some cases, when supply cannot respond to the increasing demands, unique solutions are being applied. For instance, companies in the energy sector are responding to the tight labour market by sponsoring training and apprenticeships, by luring migrants from within Canada and internationally, and even by providing free accommodations and air transportation to draw workers from other regions of the province and country to remote areas.

In other sectors, such as services, wages and salaries in Alberta are higher than the industry standards. In 2007, the average salary of an employee in Alberta's retail sector was nearly 9 per cent greater than the Canada average. Similarly, an average premium of 10 per cent was paid to employees in Alberta's accommodation and food services industry. Other methods of compensating for the tight labour market in non-energy industries include asking more of their existing employees (increased labour productivity), utilizing new technology, and substituting capital investment for labour, such as self-checkouts in grocery stores. Still, service industries may find themselves at large odds when competing for employees and some have resorted to shortening their business hours.

Alberta's current and future economic growth will continue to provide a strong push for Canada's future economic growth. The province is 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 annum over the last four years. The ERCB forecast for Alberta's economic growth is attainable; however, strong growth will imply continued tightness in the labour market, inflationary pressure, and significant costs for labour and materials. While population growth can alleviate the current labour shortage, increased capital and labour productivity are fundamental to reduce the constraints of the tight labour market and help Alberta maintain its full potential into the future.

2 Crude Bitumen

Highlights

- Remaining established in situ reserves under active development increased by 53 per cent, with the inclusion of new and expanded projects in Athabasca and Cold Lake.
- Athabasca Wabiskaw-McMurray in-place resources were revised, as was the northeastern areal extent.
- Map showing reconstructed sub-Cretaceous unconformity surface with location of Grosmont and Nisku deposits is added to the report.
- Bitumen production increased by 5 per cent, mineable by 3 per cent, and in situ by 9 per cent.
- Synthetic crude oil production increased by 4 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 as of the end of 2007 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.

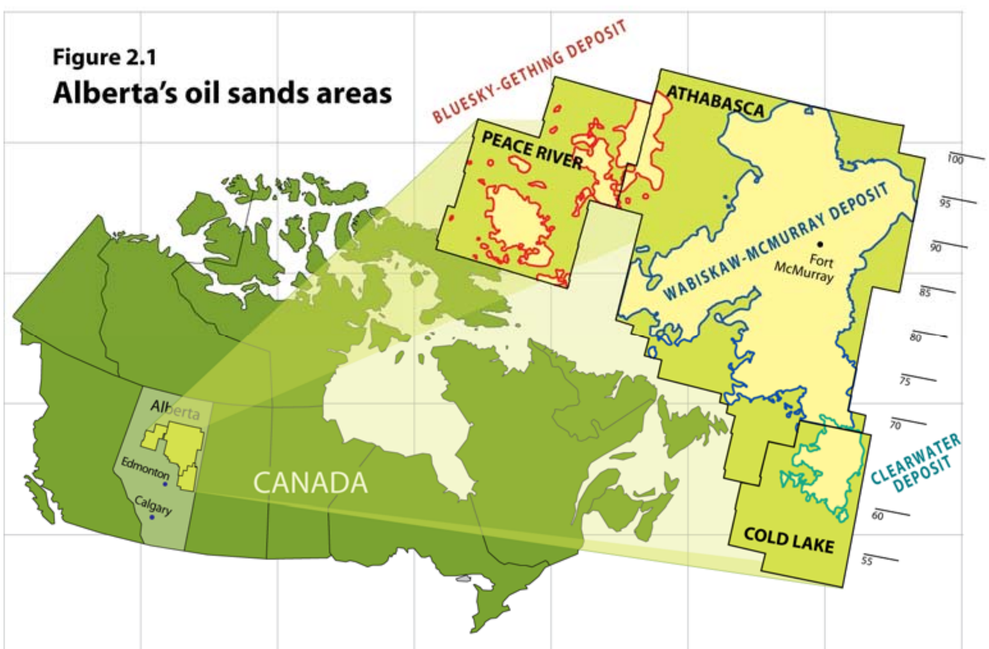


Figure 2.1
Alberta's oil sands areas

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, revised for year-end 2005, and revised again for year-end 2007, 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 deposits contain 64 per cent of the total initial in-place bitumen resource and 87 per cent of the in-place resource found in clastics.

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. This work is anticipated to take some time to complete. (See Section 2.1.6 for more on the ongoing review.) As a result, there are no significant changes to the estimate of the established reserves of crude bitumen for this year's report and, therefore, the remaining established reserves of crude bitumen at December 31, 2007, are 27.45 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.08 10^9 m^3.

Of the total 27.45 10^9 m^3 remaining established reserves, 22.49 10^9 m^3, or about 82 per cent, is considered recoverable by in situ methods and 4.96 10^9 m^3 by surface mining methods. Of the in situ and mineable totals, 3.50 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.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative production for 2007 are shown in **Table 2.2**. 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 2007 totalled 76.6 10^6 m^3, with 31.1 10^6 m^3 coming from in situ operations. Production from the three current surface mining projects amounted to 45.5 10^6 m^3 in 2007, with 21.3 10^6 m^3 from the Syncrude Canada Ltd. project, 15.5 10^6 m^3 from the Suncor Energy Inc. project, and 8.7 10^6 m^3 from the Albian Sands Energy Inc. project.

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	16.1	5.59	0.63	4.96	2.91
In situ	255.9	22.80	0.32	22.49	0.59
Total	272.0 (1 712)[a]	28.39 (178.7)[a]	0.94 (5.9)[a]	27.45 (172.7)[a]	3.50 (22.0)[a]

[a] Imperial equivalent in billions of barrels.

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

	2007	2006	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 802	22 802	0
Total	28 392 (178 668)[b]	28 392 (178 668)[b]	0
Cumulative production			
Mineable	628	582	+46[c]
In situ[a]	316	282	+34[c]
Total	944	864	+80[c]
Remaining established reserves			
Mineable	4 962	5 008	-46
In situ	22 486	22 520	-34
Total[a]	27 448 (172 730)[b]	27 528 (173 231)[b]	-80
Annual production			
Mineable	46	44	+2
In situ[a]	31	29	+2
Total	77	73	+4

[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. In 2007 a correction to in situ cumulative production, mainly from the Cold Lake and Athabasca areas, resulted in a change in cumulative production of 34 10^6 m^3, whereas annual production was 31 10^6 m^3.

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 projects. The intervening years between additions are characterized by a slow decline due to annual production.

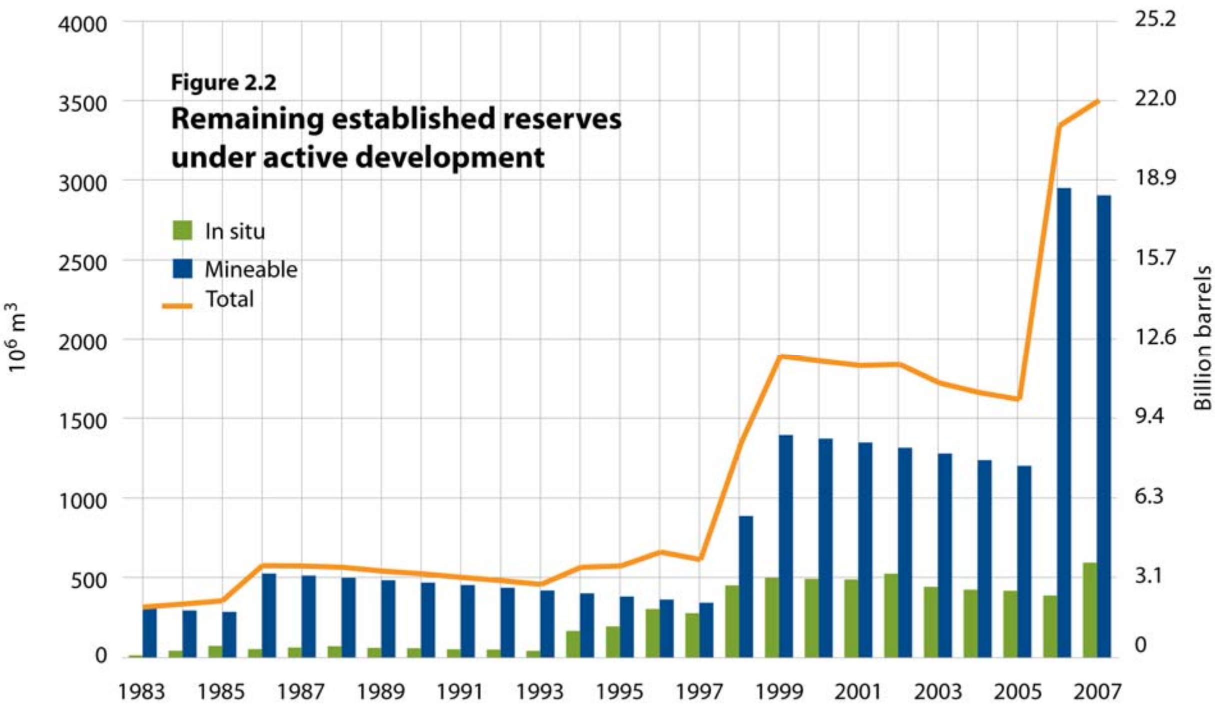


Figure 2.2
Remaining established reserves under active development

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, which designate the specific geological zones containing the oil sands. Together the three OSAs occupy an area of about 140 000 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, cutoffs were increased to 6 mass per cent and 3.0 m for areas amenable to surface mining. In the three previous reports, the AWM, CLC, and PRBG deposits, as well as a portion of the CLWM deposit, were 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 this reduction is offset by increases due to new drilling since the previous estimate.

In 2003, the ERCB completed a regional geological study of part of the Wabiskaw-McMurray deposit of the Athabasca OSA.[1] The purpose of that study was to identify where gas pools are associated with recoverable bitumen. To support both that study and the reassessment of the AWM, geologic information from over 13 000 wells and bitumen content evaluations conducted on over 9000 wells were used to augment the over 7000 boreholes already available within the Surface Mineable Area (SMA). The stratigraphic framework developed for the regional geological study was used to define 21 stratigraphic intervals, which were subsequently combined into 12 zones within the AWM. In 2005, nearly 700 new wells, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised.

In 2007, approximately 2700 additional wells were added to the latest reassessment, resulting in an increase to the in-place bitumen resources of the AWM of 1.70 10^9 m^3, or 1.3 per cent. While most of the new drilling is within in situ project areas, where drilling density is high, a significant number of wells were drilled in areas with light drilling densities and in areas of no previous drilling. These wells have refined the western and northeastern limits of the AWM. In addition, the nature of the bitumen accumulations near the Alberta-Saskatchewan boundary and near the Wabiskaw-McMurray subcrop is now better understood. Almost all of the additional wells are located outside the current boundary of the SMA. New drilling within the SMA will be evaluated in due course and the results incorporated in a future assessment of the AWM.

Figure 2.3 is a bitumen pay thickness map, revised for year-end 2007, for the AWM deposit 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.

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. In its review, the ERCB used stratigraphic information from more than 8000 wells and detailed petrophysical evaluations from almost 2600 wells to define the regional stratigraphy and estimate the in-place resources for the CLC.

Figure 2.4 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.

1 EUB, 2003, *Report 2003-A: Athabasca Wabiskaw-McMurray Regional Geological Study.*

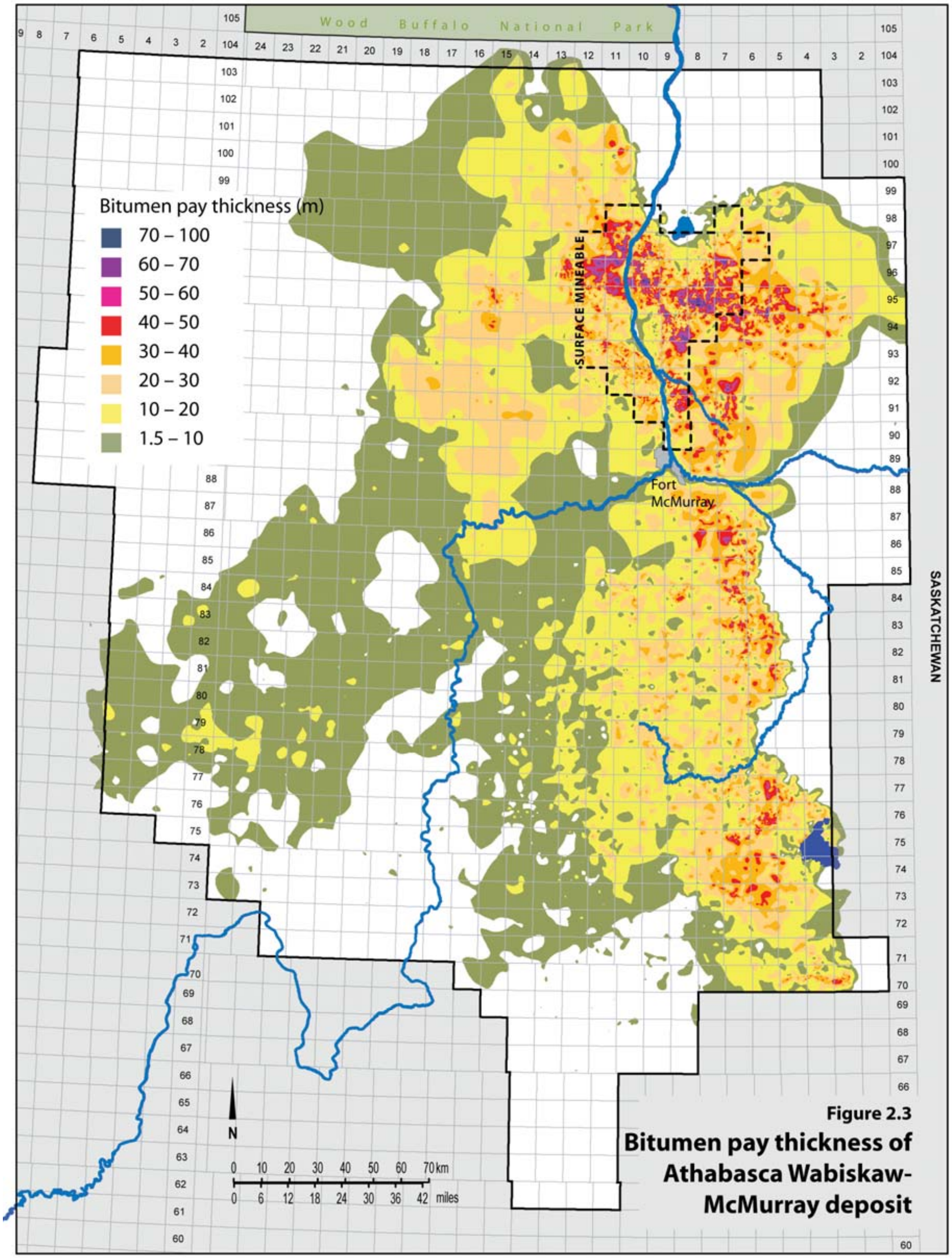


Figure 2.3
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

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. To complete its review, the ERCB used stratigraphic information from more than 6500 wells and detailed petrophysical evaluations from almost 1800 wells. The relatively large number of stratigraphic wells was needed to fully define the deposit and the related paleography because of the series of highlands that existed in the area at the time of deposition.

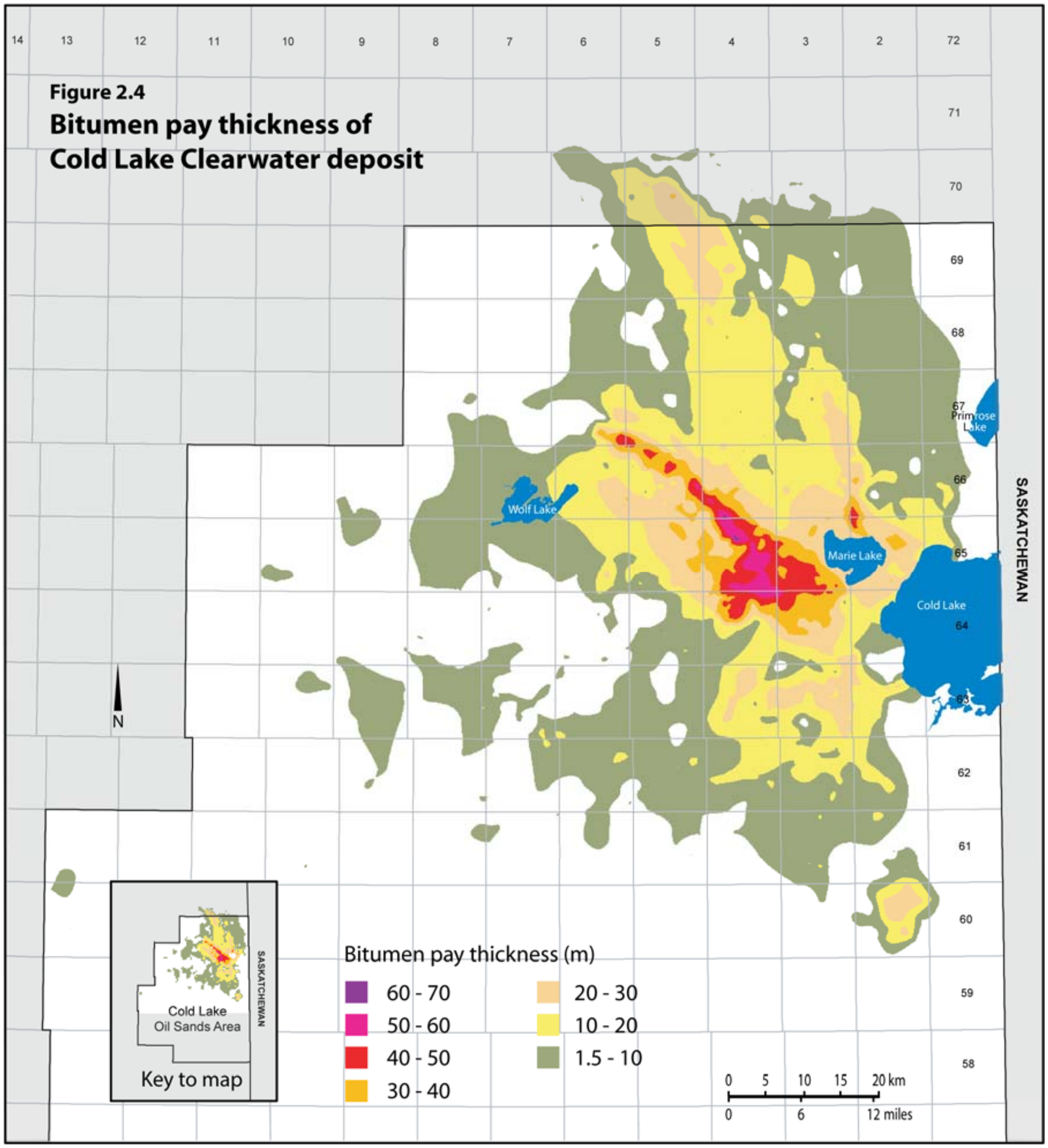


Figure 2.5 is a bitumen pay thickness map for the PRBG deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Consistent with **Figure 2.3**, the PRBG is mapped as a single bitumen zone so that the full extent of the deposit can be shown. Also shown on **Figure 2.5** are the paleotopographic highlands as they are believed to have existed at the time of the end of the deposition of the Bluesky Formation and equivalents, such as the Wabiskaw member. 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-Wabiskaw-Glauconitic-Cummings time, the other

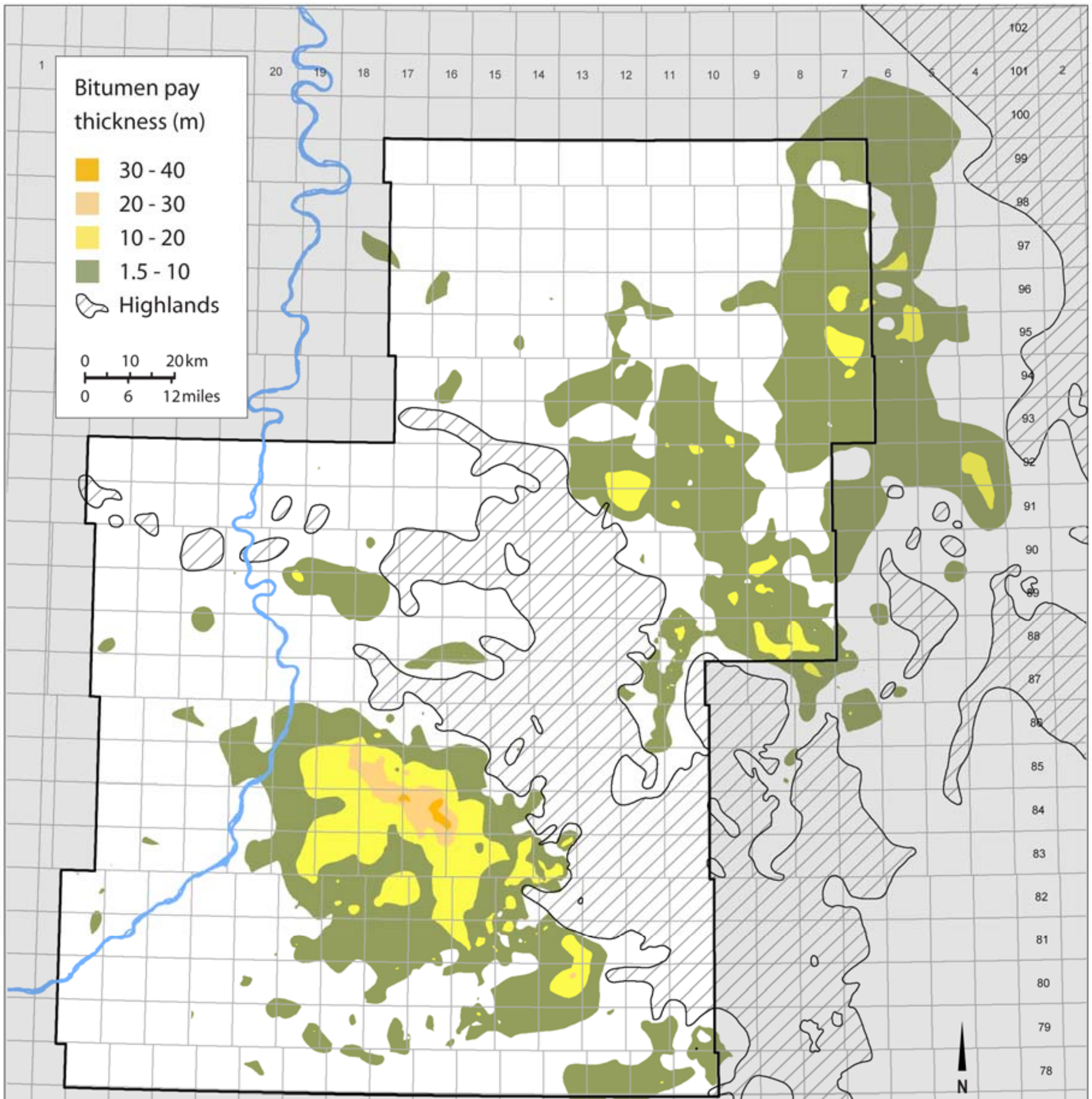


Figure 2.5
Bitumen pay thickness of Peace River Bluesky-Gething deposit

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. Because of the importance of this surface, the ERCB completed a preliminary study of this surface in 2007. The exposed and contoured submerged portions of this surface are shown in **Figure 2.6**. 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, and work is currently under way to update this estimate.

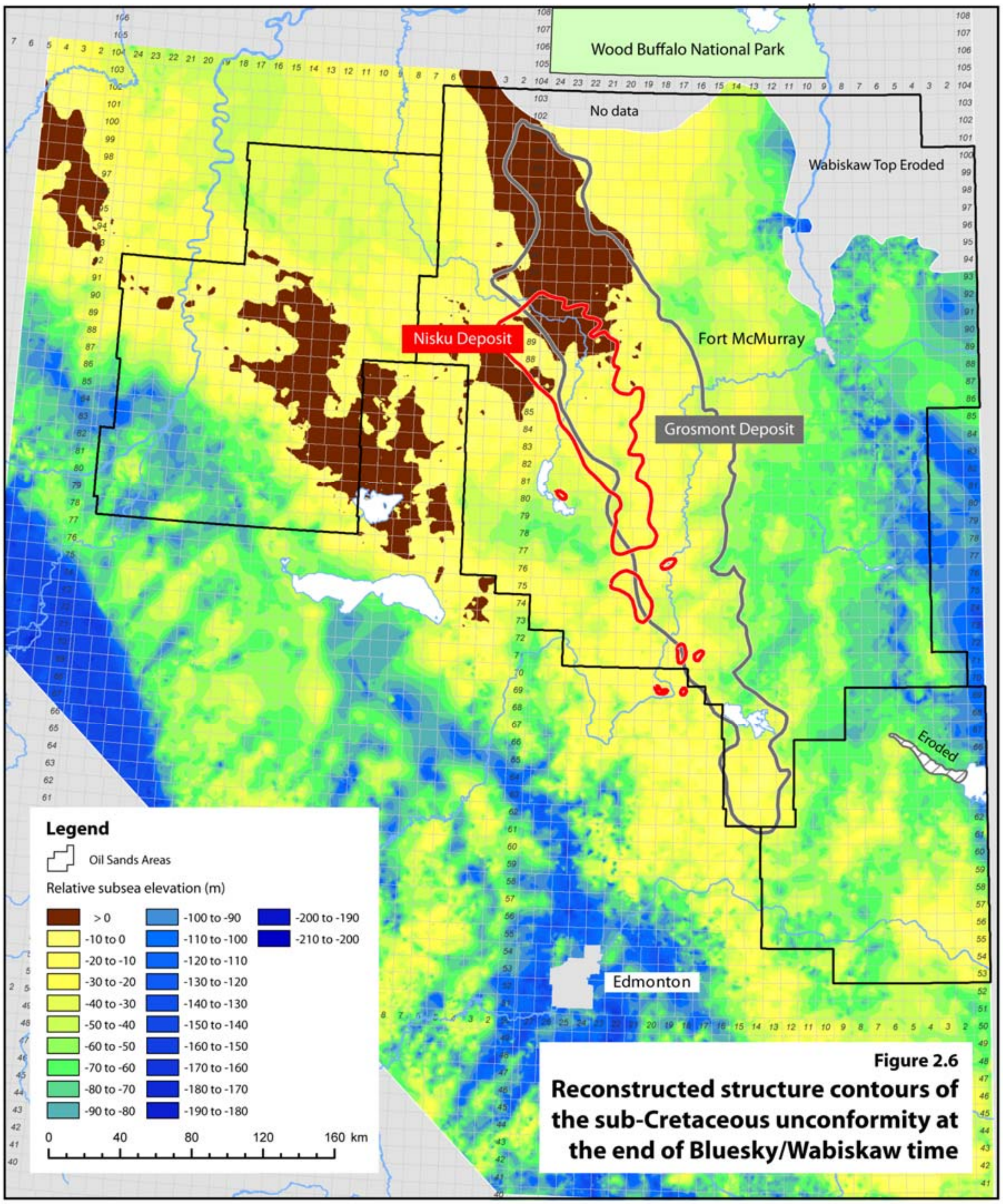


Figure 2.6
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

Also shown in **Figure 2.3** is the extent of the SMA, an ERCB-defined area currently of 37 townships north of Fort McMurray covering that part of the AWM deposit where the total overburden generally does not exceed 75 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.

Because the boundary of the SMA was originally defined using complete townships, it incorporates a few areas of deeper bitumen resources that are more amenable to in situ recovery. Previously, the in-place resources in those areas in excess of 80 m in depth (1.39 10^9 m^3) were removed from the mineable total and incorporated into the in situ total. This change did not affect the established mineable reserves because no quantity of resource economically amenable to mining exists beyond 80 m in depth. Presently there are a few areas between 40 and 80 m of depth that are being developed or considered for in situ extraction. When fully evaluated, these quantities will also be excluded from the mineable total.

The estimate of the initial volume in place of crude bitumen within the SMA was therefore reduced to 16.1 10^9 m^3, to exclude the bitumen resource beyond 80 m in depth. Notwithstanding this reduction, more than 40 per cent of the above volume has been estimated to be beyond the economic range of current commercial mining. However, it is believed that significant portions of this amount will be subjected to future recovery operations, either by in situ technology or by mining methods operating under enhanced economic conditions.

Drilling in recent years north of the current SMA boundary has better identified in-place bitumen resources that are potentially recoverable by surface mining methods. The ERCB is considering some expansion of the SMA, but no changes were made in 2007. Expansion of the SMA boundary in the future would have the impact of transferring some in-place volumes from in situ to mineable categories and increasing the established mineable reserves. No in situ recoverable volumes have been identified in this area, so expansion would have no impact on the established in situ reserves.

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

				Average bitumen saturation		
Oil sands area Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Mass (%)	Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	16 087	256	30.5	9.7	69	30
Wabiskaw-McMurray (in situ)	133 825	4 792	13.0	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	219 420					
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	271 993					

2.1.3 Surface-Mineable Crude Bitumen Reserves

Potential mineable areas within 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.[2] This method reduces the initial volume in place of 16.1 10^9 m^3 to 9.4 10^9 m^3 as of December 31, 2007. 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 area 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 area, 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 the mining operations and the extraction facilities. The resulting initial established reserve of crude bitumen is estimated to be 5.59 10^9 m^3, unchanged from 2006. The remaining established mineable crude bitumen reserve as of December 31, 2007, is 4.96 10^9 m^3, slightly lower than last year's estimate due to the production of 45.5 10^6 m^3 in 2007.

As of the end of 2007, almost two-thirds 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 628 10^6 m^3. However, the Fort Hills mine project (owned by Petro-Canada, UTS Energy, and Teck Cominco), the Canadian Natural Resources Ltd. Horizon, and the Shell Canada Ltd. Jackpine projects are considered to be under active development and are included in **Table 2.4**. The recently approved Kearl Mine (Imperial Oil/ ExxonMobil) is not yet under active development but will be included when it reaches active status. The remaining established crude bitumen reserves from deposits under active development as of December 31, 2007, are presented in **Table 2.4**.

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2007

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	41	378
Fort Hills	18 976	699	364	0	364
Horizon	28 482	834	537	0	537
Jackpine	7 958	361	222	0	222
Suncor	19 155	990	687	235	452
Syncrude	44 037	2 071	1 306	351	955
Total	132 189	5 627	3 535	628	2 907

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

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

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 except the AWM, where 15.0 m was used for the Wabiskaw zones. For 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.

In 2007, the in situ bitumen production was 31.1 10^6 m^3, an increase from 28.7 10^6 m^3 in 2006. Cumulative production within the in situ areas now totals 316.1 10^6 m^3, of which 241.3 10^6 m^3 is from the Cold Lake OSA. Due to production, the remaining established reserves of crude bitumen from in situ areas decreased to 22.49 10^9 m^3.

The ERCB's 2007 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 592.6 10^6 m^3, an increase of 53 per cent. This large increase is mainly the result of the addition of new thermal developments and the expansion of existing thermal developments that have occurred over several years in the Athabasca and Cold Lake OSAs. A smaller increase is due to a reassessment of enhanced recovery schemes in Athabasca's Brintnell area. Part of this increase is due to increasing the incremental enhanced recovery factor from 5 per cent to 10 per cent to better reflect actual recoveries. Commercial thermal projects in Peace River and primary recovery schemes in the Cold Lake, Athabasca, and Peace River OSAs were not reassessed in 2007. It is anticipated that as these projects and schemes are added or updated and as recently approved or announced projects become active, the established reserves totals in **Table 2.5** will increase.

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2007

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	9.4	12.9
Primary recovery schemes	120.6	5	6.0	4.3	1.7
Subtotal	176.4		28.4	13.7	14.6
Athabasca Oil Sands Area					
Thermal commercial projects	313.7	50	156.9	27.0	129.9
Primary recovery schemes	1 026.2	5	51.3	19.3	32.0
Enhanced recovery schemes[c]	(289.0)[d]	10	28.9	7.9	21.0
Subtotal	1 339.9		237.1	54.2	182.9
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[e]	1 212.8	25	303.2	173.0	130.2
Thermal commercial (SAGD)[f]	33.8	50	16.9	0.5	16.4
Primary production within projects	601.1	5	30.1	13.6	16.5
Primary recovery schemes	4 347.1	5	217.4	47.3	170.1
Lindbergh primary production	1 309.3	5	65.5	6.9	58.6
Subtotal	7 504.1		633.0	241.3	391.7
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	316.1	592.6

[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, 2007, 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.

2.1.5 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. Nearly 11 10^9 m^3 is expected from within the surface-mineable boundary. The total ultimate potential crude bitumen is therefore unchanged at 50 10^9 m^3.

2.1.6 Ongoing Review of In Situ Resources and Reserves

In 2003, the EUB initiated a project to update its resource and reserves numbers for in situ bitumen. There are a number of components to this project, including

- updating the geological framework for each deposit,
- reviewing established mass per cent bitumen and thickness cutoffs,

- reevaluating all wells to provide data on a detailed incremental thickness basis and storing these evaluations in a new database,
- evaluating all recent drilling,
- remapping deposits and recalculating in-place resource volumes, and
- reviewing recovery factors, changing them where appropriate, and calculating new established reserves volumes.

The EUB held a series of bitumen conservation proceedings from 1997 to 2005 to determine the need to shut in gas production to protect potentially recoverable bitumen. As a result of the proceedings, the ERCB has accepted that bitumen exceeding 6 mass per cent and 10 m thickness is potentially recoverable. This removes much of the poorer quality component of the bitumen resource (with low potential for recoverability) from the reserve category.

Given the relatively early stage of steam-assisted gravity drainage (SAGD) development, it is not yet possible to refine the current deposit-wide recovery factor of 20 per cent with any greater degree of certainty. Furthermore, the impact of the uncertainty in the deposit-wide recovery factor is noteworthy because a minor change in the recovery factor on a resource of this magnitude has a significant impact on the recoverable component. While a great deal of study and effort have gone into updating the resources of the AWM, the CLC, and the PRBG, the ERCB has not completed its review of recovery factors that should be applied on a deposit-wide basis. The ERCB will therefore retain the existing established reserves figure for the province, except for adjustments due to production, until a geological reassessment of other deposits is complete and until further work provides refinement of deposit-wide recovery factors for those deposits with commercial production. The ERCB is also considering providing low, best, and high estimates for established bitumen reserves volumes in future updates to take into account uncertainty in some variables, such as the recovery factor. A range in estimates would consider the relative early stage of development of a very large resource and the long timeframes associated with full development.

In parallel with this work, the ERCB is also continuing with the review of its resource/reserve categories, terminology, and definitions. This is particularly relevant for bitumen, considering the high level of interest in the resource both nationally and globally in recent years.

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 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.

As discussed earlier, two methods are used for recovery of bitumen, depending on the depth of the deposit. The near-surface deposits of bitumen are mined, while the deeper deposits are recovered in situ. Currently, there are three main methods to produce in situ bitumen: primary production, cyclic steam stimulation (CSS), and SAGD.

"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.

Bitumen crude 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 are marketed outside the province.

2.2.1 Crude Bitumen Production

Surface mining and in situ production for 2007 are shown graphically by OSA in **Figure 2.7.** In 2007, Alberta produced 209.9 thousand (10^3) m^3/d of crude bitumen from all three regions, with surface mining accounting for 59 per cent and in situ for 41 per cent. **Figure 2.8** 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 37 per cent of the production in 1998 to 64 per cent in 2007.

2.2.1.1 Mined Crude Bitumen

Currently, all mined bitumen in Alberta feeds upgraders producing SCO. In 2007, mined crude bitumen production increased by 3 per cent over the past year, to a level of 124.7 10^3 m^3/d, with Syncrude, Suncor, and Albian Sands accounting for 47, 34, and 19 per cent respectively.

Syncrude increased production by 18 per cent to 58.4 10^3 m^3/d, with the continued ramp-up of the Stage 3 expansion that commenced operation in 2006. This expansion, which includes a second train at the Aurora Mine and a new coker at the upgrading facilities, increases Syncrude's SCO capacity to 55.6 10^3 m^3/d from 39.7 10^3 m^3/d.

Production at Suncor declined by some 12 per cent, to 42.4 10^3 m^3/d, compared to the 2006 average production. The decrease in production was the result of planned and unplanned maintenance and a 50-day shutdown of Upgrader 2. This shutdown was required to tie in new facilities related to a planned expansion in 2008.

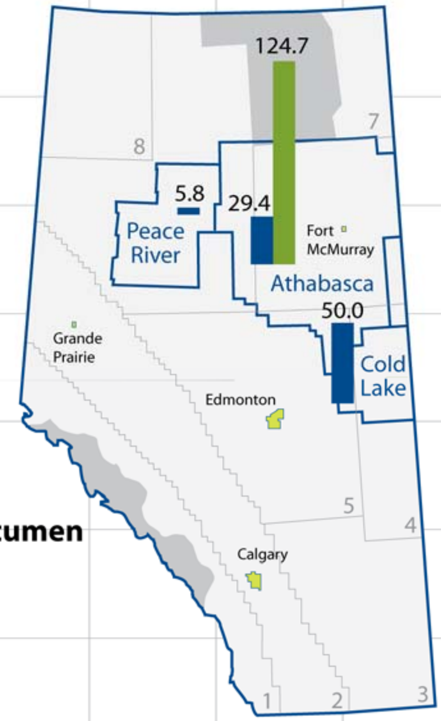


Figure 2.7
Production of bitumen in Alberta, 2007
(10^3 m^3/day)

In situ
Mined bitumen

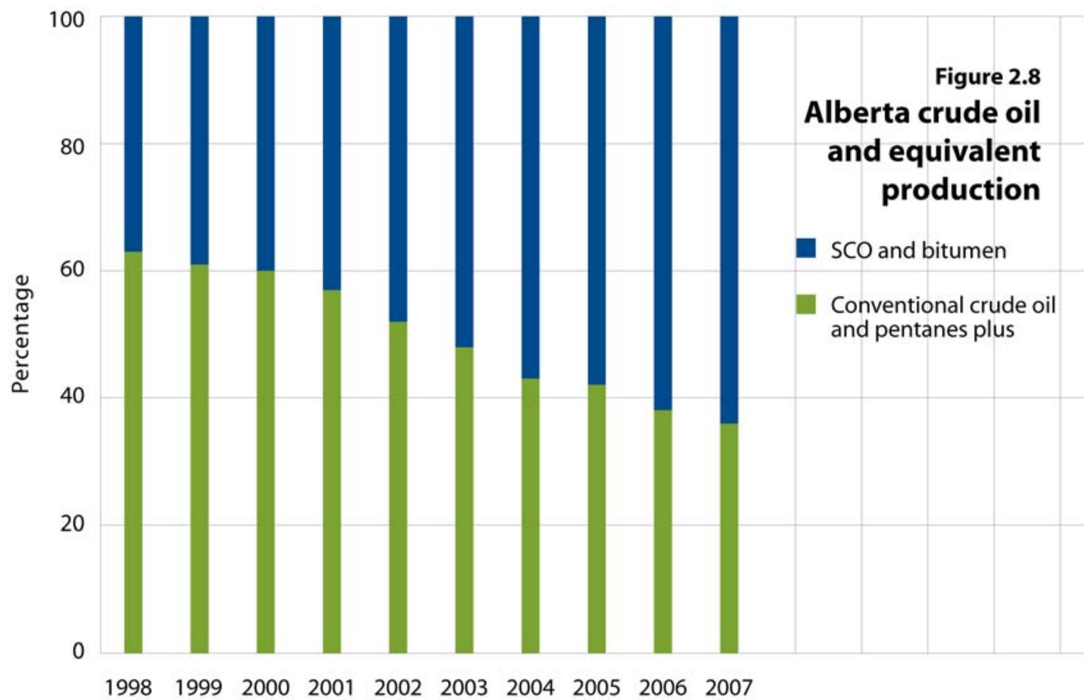


Figure 2.8
Alberta crude oil and equivalent production

Albian Sands produced 23.9 10^3 m^3/d in 2007, a slight increase over the 2006 volume of 23.2 10^3 m^3/d. Production at Albian Sands was curtailed by an unplanned shutdown in September and a fire in November at the Scotford Upgrader. The upgrader returned to full operation in late December 2007.

In projecting the future supply of bitumen from mining, the ERCB considered potential production from existing facilities and supply from future projects. The forecast includes

- the existing production and expected expansions of Suncor, including the Voyageur and Voyageur South projects;
- the existing and expected expansions of Syncrude, including the ramp-up in production of Stage 3 and the Stage 3 debottleneck of the four-stage project that began in 1996;
- the existing Albian Sands project and its debottlenecking projects and expansion (approved by the EUB in November 2006), scheduled for completion by year-end 2010;
- the CNRL Horizon project (approved by the EUB in January 2004), with proposed production beginning in the third quarter of 2008;
- the Shell Canada Jackpine Mine (approved by the EUB in February 2004), with production now expected to coincide with the Muskeg Mine expansion (late 2010);
- the Petro-Canada/UTS Energy/Teck Cominco Fort Hills project (originally TrueNorth Energy's Fort Hills Oil Sands Project, approved by the EUB in October 2002), with production proposed by 2011;
- the proposed Imperial Oil/ExxonMobil Kearl Mine (approved by the EUB in February 2007), a multiphased project with start-up announced for 2011 (current plans do not include any on-site upgrading facilities); and
- the Deer Creek (Total E&P Canada) Joslyn North Mine Project, a proposed multistaged development, with production expected in 2013.

In projecting total mined bitumen over the forecast period, the ERCB assumed that potential market restrictions, 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 assumed that total mined bitumen production will increase from 124.7 10^3 m^3/d in 2007 to about 280 10^3 m^3/d by 2017.

Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure 2.12** Due to uncertainties regarding timing and project scope, some projects, such as Synenco's Northern Lights and 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.

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 85.2 10^3 m^3/d in 2007. Production of in situ bitumen, along with the number of bitumen wells on production in each year, is shown in **Figure 2.9**. Corresponding to the increase in production, the number of producing bitumen wells has also increased from 2300 to about 8900 over the same period. The average well productivity of in situ bitumen wells in 2007 averaged 10 m^3/d.

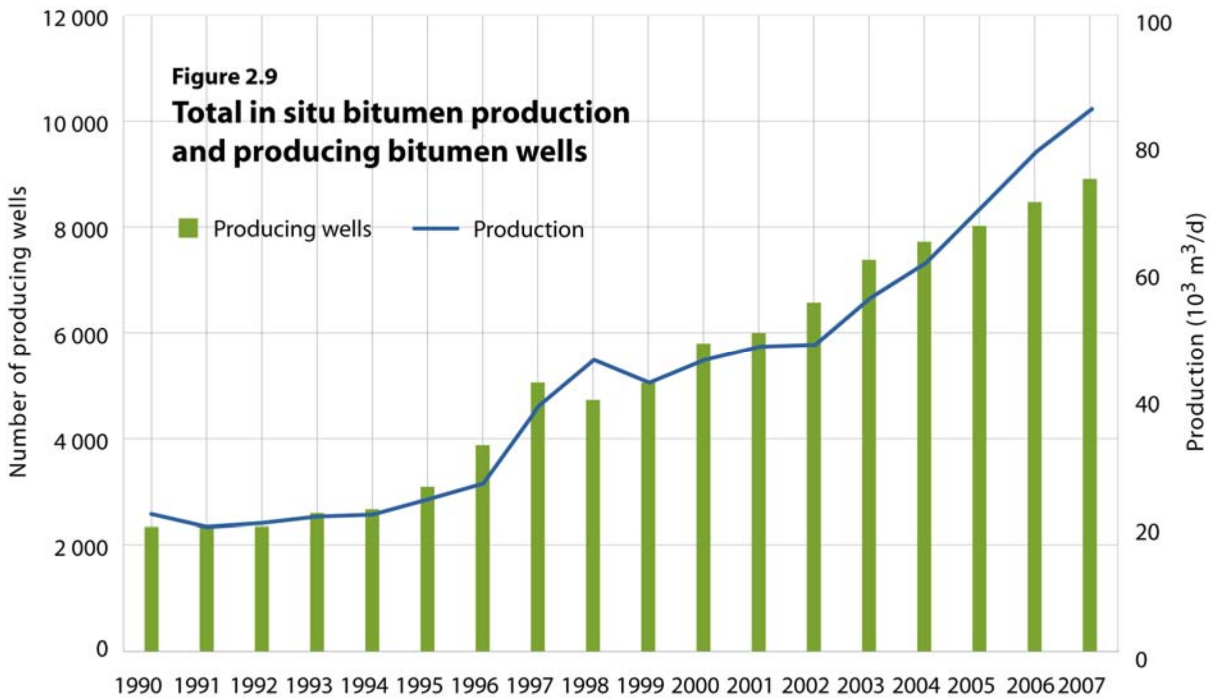
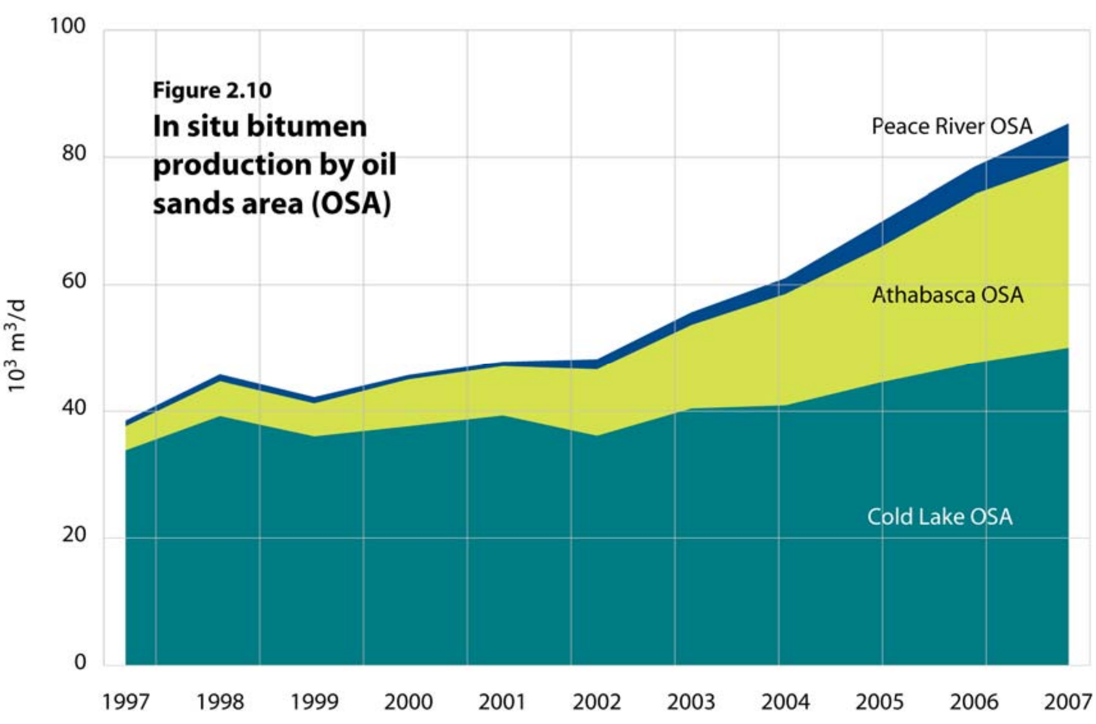
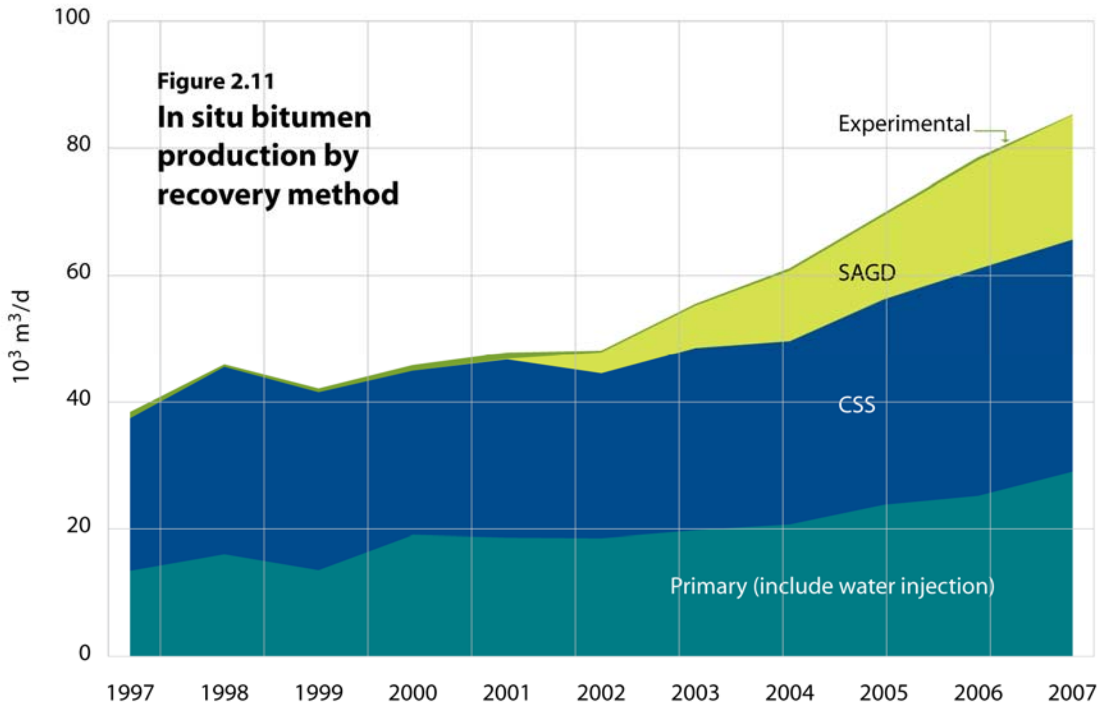


Figure 2.10 shows in situ production from 1997 to 2007 by OSA. The Cold Lake OSA has been the major source of crude bitumen recovery, accounting for 59 per cent of the production total. The Athabasca and Peace River OSAs contributed 35 and 7 per cent respectively. Significant production increases in the Athabasca OSA since 2002 are due to SAGD development, while recent increases in the Peace River OSA are largely the result of primary production in the Seal area.



Total in situ bitumen production by recovery method from 1997 forward is shown in **Figure 2.11.** Primary production includes those schemes that use water injection as a recovery method. In 2007, 43 per cent of in situ production was recovered by CSS, 23 per cent by SAGD, and 33 per cent by primary schemes. Experimental production accounts for the remaining 1 per cent.

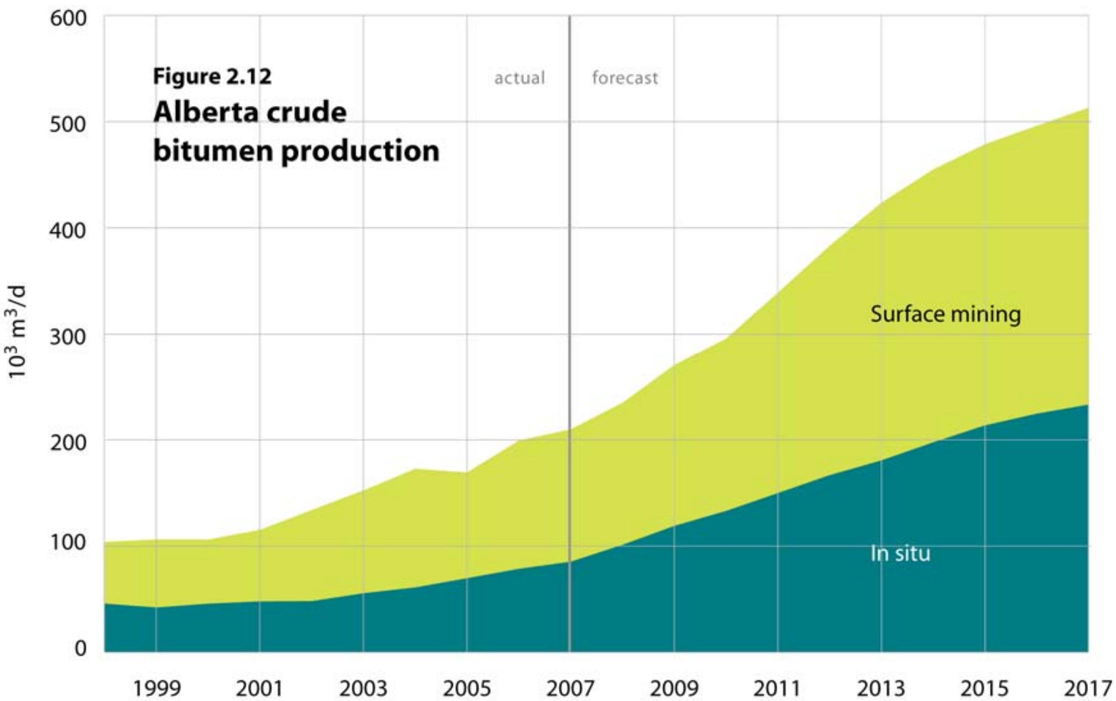


Similar to surface mining, the future supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects.

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, project modifications, natural gas prices, pipeline availability, and the ability of North American markets to absorb the increased volumes. The ERCB also 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 2.12,** the ERCB's in situ crude bitumen production is expected to increase to 233 10^3 m^3/d over the forecast period.

In 2007, some 6 per cent of in situ production was upgraded to SCO in Alberta. It is expected that by the end of the forecast period, about 43 per cent of in situ bitumen production will be used as feedstock for SCO production within the province.



2.2.2 Synthetic Crude Oil Production

Currently, all Alberta mined bitumen and a small portion of in situ production is upgraded to SCO. The Syncrude, Suncor, and Shell Canada upgraders produced 49.3 10^3 m^3/d, 37.4 10^3 m^3/d, and 22.6 10^3 m^3/d of SCO respectively in 2007.

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 / bitumen feed) 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 project 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 below. 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 in the industry. The ERCB also recognizes that key factors, such as the length of the construction period and the market penetration of new synthetic volumes, has affected project timing.

The ERCB expects significant increases in SCO production based on the following projects:

Suncor

- future expansions of the Firebag In Situ Oil Sands Operation
- expansion of the existing upgrader (the construction of a pair of coke drums, a sulphur recovery plant, and other crude oil processing equipment) in the second quarter of 2008
- Voyageur Phase One—establishment of a third upgrader by 2010 and further development of the oil sands mining facilities
- Voyageur Phase Two—expansion of the third oil sands upgrader by 2012
- Voyageur South – an expanded mining operation located directly south of the proposed Voyageur upgrader

Syncrude

- Stage 3, including the upgrader expansion and a second train of production at Aurora, which commenced late August 2006 and continues to ramp up production
- Stage 3 debottleneck estimated to be on stream in 2013

Shell

- the debottlenecking projects to increase bitumen processing capacity at the Scotford Upgrader
- an expansion to the upgrader to correspond with the expansion of the Muskeg Mine by late 2010
- upgrading of crude bitumen from the Jackpine Mine

OPTI

- an in situ bitumen recovery and field upgrading facility located about 40 km southeast of Fort McMurray
- Phase 1 expected to commence in mid-2008
- Phase 2 scheduled for start-up in 2011, followed by Phases 3 and 4 at approximately two-year intervals
- at year-end 2007, upgrader construction nearly completed and commissioning started

CNRL

- located within the Municipality of Wood Buffalo, about 70 km north of Fort McMurray
- five-phase project expected to begin operation in the third quarter of 2008
- at year-end 2007, 90 per cent of project construction completed

PetroCanada/UTS/Teck Cominco

- plans include a mine and extraction facility, with an associated upgrader to be built in the Alberta Industrial Heartland Area of Sturgeon County by 2012

Total

- upgrader to be constructed in Strathcona County in association with the mine and extraction project, with start-up expected in 2014

BA Energy

- a merchant upgrader located near Fort Saskatchewan capable of processing bitumen blends from the Athabasca oil sands mining and in situ operations
- designed to be built in three phases, with start-up expected in the second quarter of 2009

NorthWest Upgrading

- a merchant upgrader, located within the Industrial Heartland Area of Sturgeon County, to process bitumen produced by oil sands in situ and mining operations
- development of upgrader to be done in three phases, with the first phase expected to come on stream in 2011

Peace River Oil

- Bluesky plant located in the south-central quadrant of the Peace River Arch
- proposed upgrader to be built in phases, with the first phase announced to come on stream in 2012

StatoilHydro (formerly North American Oil Sands Corporation)

- plans include an upgrader to be built in Strathcona County in association with the Kai Kos Dehseh Project, a SAGD project located near Conklin, Alberta
- start-up expected in 2014

Value Creation Inc.

- an in situ bitumen recovery and field upgrading facility located about 90 km northwest of Fort McMurray
- designed to be built in stages, with start-up of phase 1 announced for 2011

Similar to the Mined Crude Bitumen section (2.2.1.1), due to uncertainties regarding timing and project scope, some projects, such as Synenco's Northern Lights Upgrader, have not been considered in this forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period. **Figure 2.13** shows the ERCB projection of SCO production, which is expected to increase from 109.3 10^3 m^3/d in 2007 to 318 10^3 m^3/d by 2017.

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 greater volumes of product. Throughout 2007, 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 described in **Table 2.6**. **Figure 2.14** shows the current pipelines and proposed crude pipeline projects within the Athabasca and Cold Lake regions. Numerals in parentheses in Sections 2.2.3.1 and 2.2.3.2 below refer to the legend on the map.

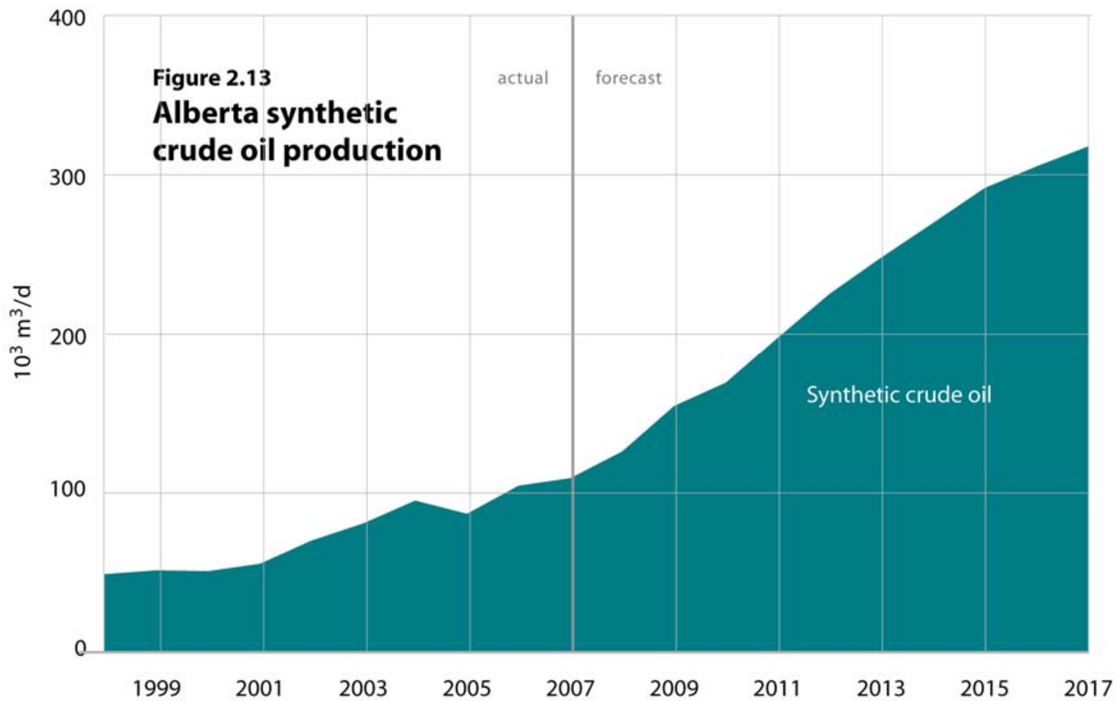


Table 2.6. Alberta SCO and nonupgraded bitumen pipelines

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	44.2
Syncrude Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0

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.

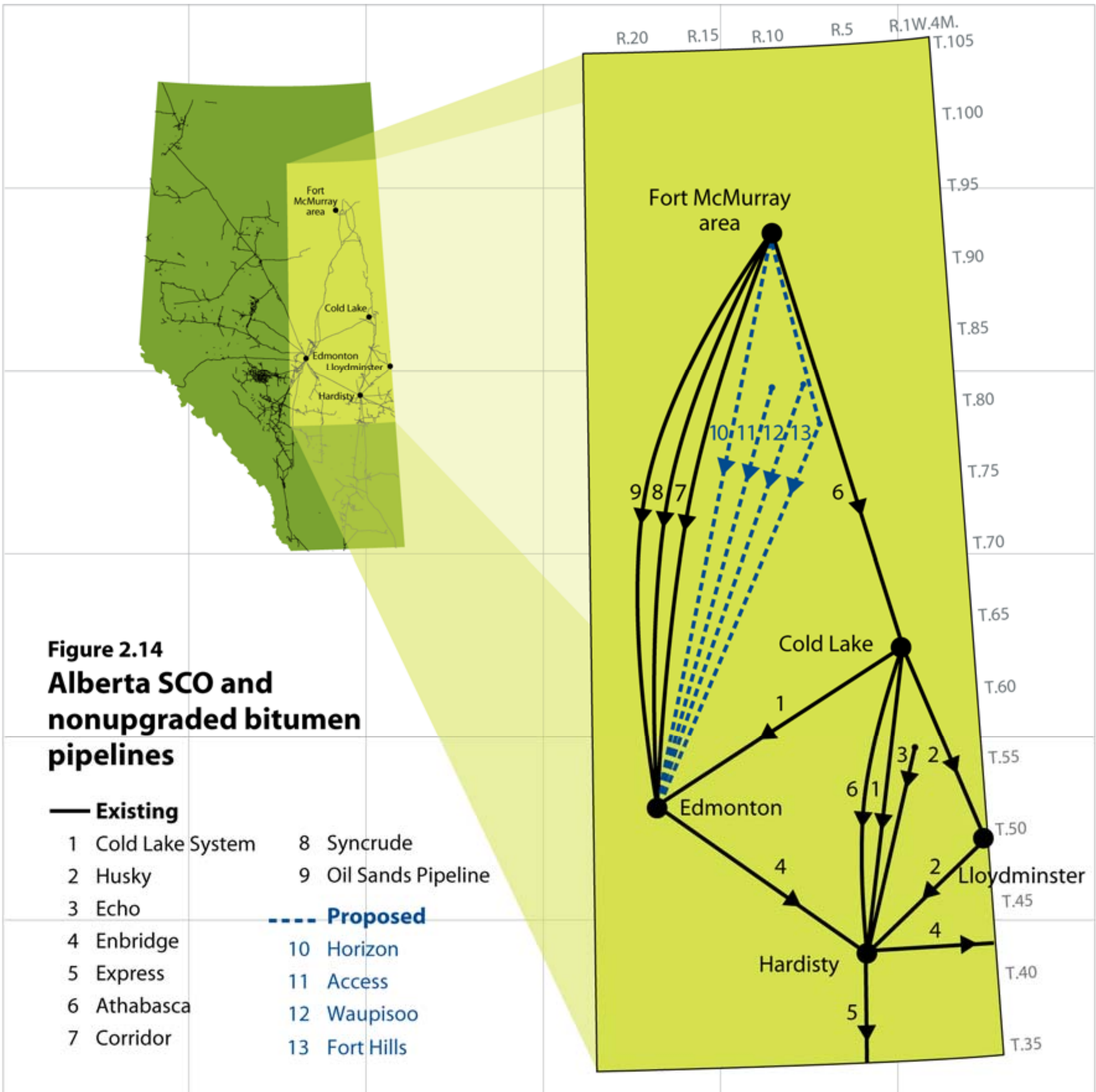


Figure 2.14
Alberta SCO and nonupgraded bitumen pipelines

- 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 and 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. An expansion of the Corridor pipeline was completed in 2006, increasing capacity to 44.2 10^3 m^3/d by upgrading existing pump station facilities.

- The Syncrude Pipeline (formerly Alberta Oil Sands Pipeline) (8) is the exclusive transporter for Syncrude; an expansion to increase capacity to 61.8 10^3 m^3/d was completed in 2004.

- The Oil Sands Pipeline (9) transports Suncor synthetic oil to the Edmonton area.

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 2009 and will support further expansions beyond 2009 by adding intermediate pump stations.

- Pembina Pipeline expects the construction of the Horizon Pipeline (10) to be completed in July 2008 and to have an initial capacity of 39.7 10^3 m^3/d. The project includes 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 included is the construction of a new 48 km 20-inch pipeline from the Horizon site 70 km north of Fort McMurray to the AOSPL terminal.

- The Access Pipeline project (11) will transport diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Access obtained approval from the EUB in December 2005. Initial capacity of the pipeline will be 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d. Construction is complete and start-up is expected in 2008.

- Enbridge received approval for the Waupisoo Pipeline (12) from the EUB in February 2007. The 390 km pipeline will move blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline is expected to be in service in 2008, with an initial capacity of 55.6 10^3 m^3/d, expandable to 95.3 10^3 m^3/d.

- In 2007, Enbridge announced it will provide the pipeline and terminal facilities for phase 1 and subsequent phases of the Fort Hills oil sands project. The preliminary plan for the Fort Hills Pipeline System (13) includes a blended bitumen pipeline from the mine site north of Fort McMurray to the upgrader site in Sturgeon county, with a capacity of 40 10^3 m^3/d. The plan also includes a parallel 11 10^3 m^3/d diluent return pipeline. Completion of the pipeline is estimated to be in mid-2011.

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 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 35.8 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 the past two years. Pipeline capacity increases to 45.3 10^3 m^3/d without heavy oil.

- Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake Blend to Montana refineries.

- Milk River Pipeline delivers Bow River heavy crude into Montana refineries.

Figure 2.15 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 2.7 lists the export pipelines, with their corresponding destinations and capacities.

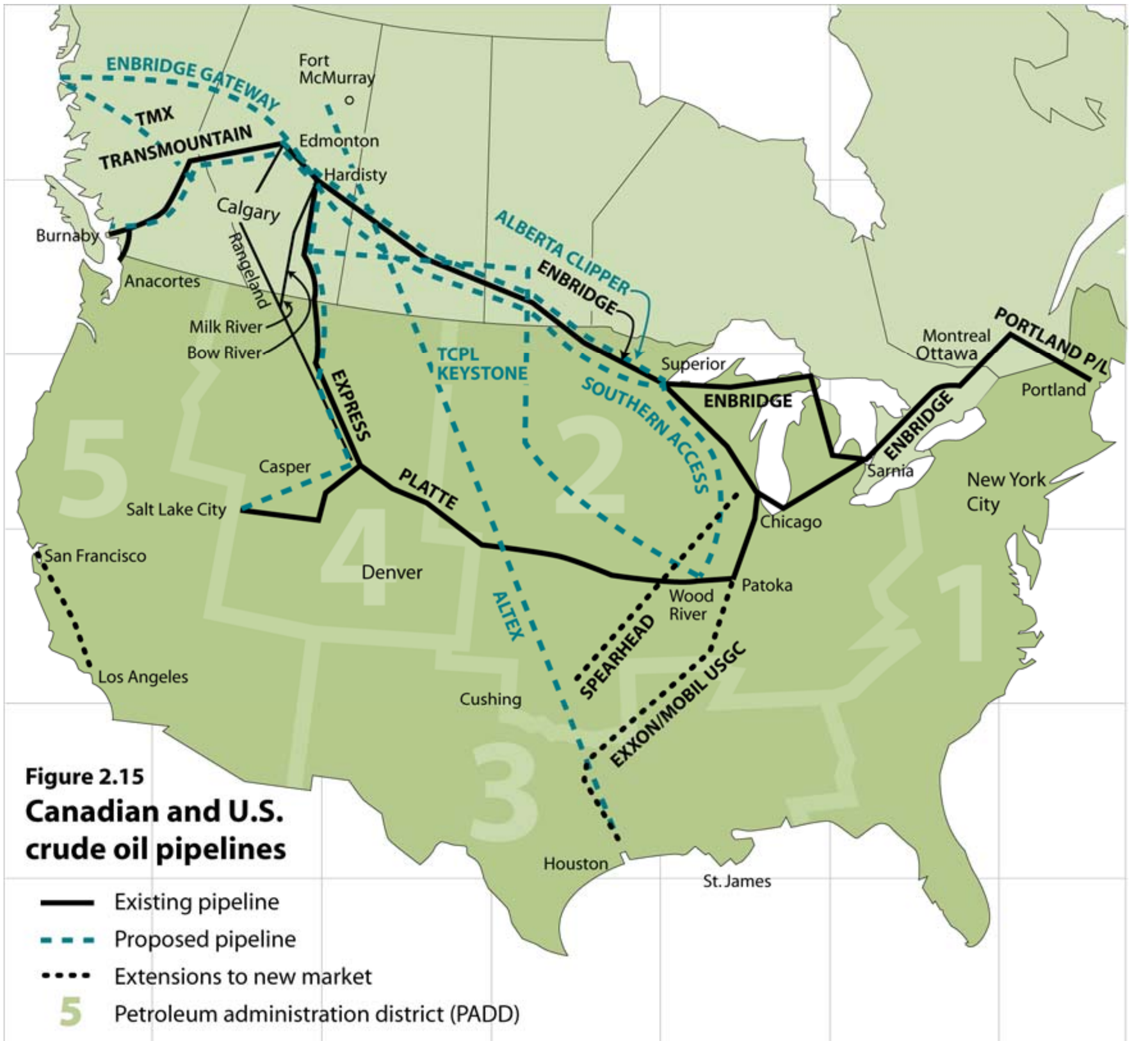


Figure 2.15
Canadian and U.S. crude oil pipelines

Table 2.7. 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	35.8

2.2.3.4 Proposed Export Pipeline Projects

Table 2.8. 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 2.8. Proposed export pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. west coast	63.6	2012-2014
	Offshore		
Southern Access	U.S. midwest	50.1	2008-2009
Alberta Clipper Pipeline	U.S. midwest	71.5	2010
Kinder Morgan			
Trans Mountain (TMX)	British Columbia U.S. west coast Offshore		
TMX1 Pump Stn. Exp.		5.6	2007
TMX1 Anchor Loop Exp.		6.3	2008
TMX2		15.9	2010
TMX3		47.7	2012
TransCanada Pipeline			
Keystone Pipeline	U.S. midwest	93.8	2010
Altex Energy Ltd.			
Altex Pipeline	U.S. Gulf Coast	39.7	2012

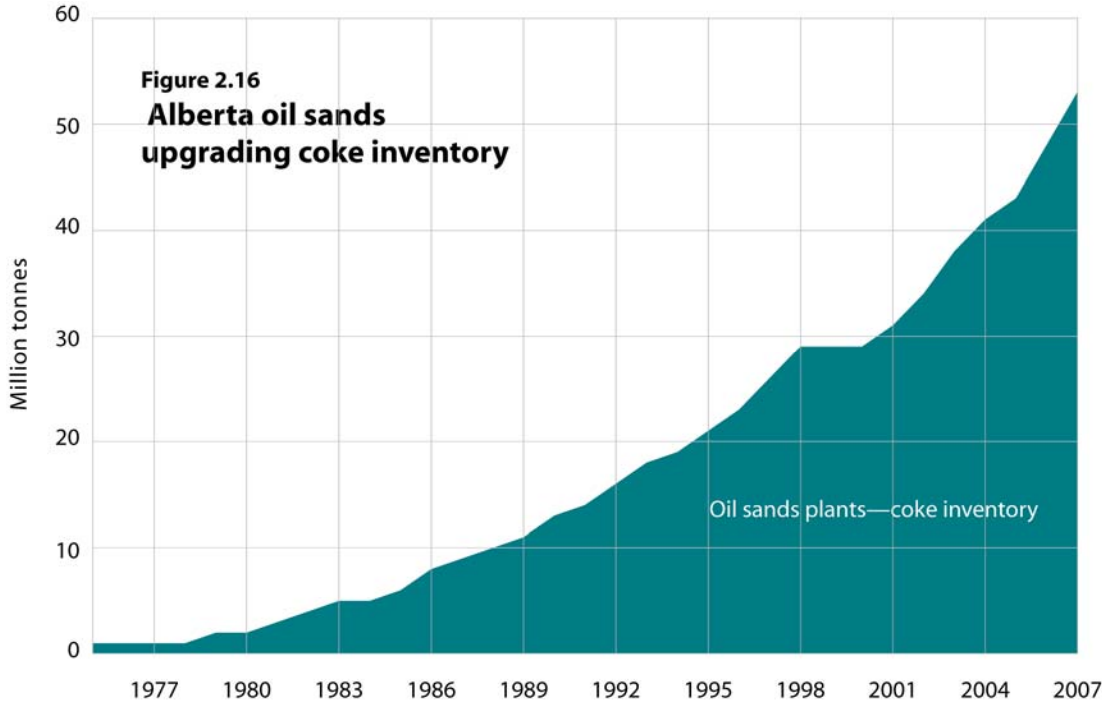
2.2.4 Petroleum Coke

Petroleum coke is a by-product of the oil sands upgrading process that 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. It 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 since 1997, mostly Japan, 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 53 million tonnes in 2007, as shown in **Figure 2.16**. 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

Light sweet SCO has two principal advantages over light crude: 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, the need to limit SCO intake to a fraction of total crude requirements, and the high level of aromatics (benzene) that must be recovered.

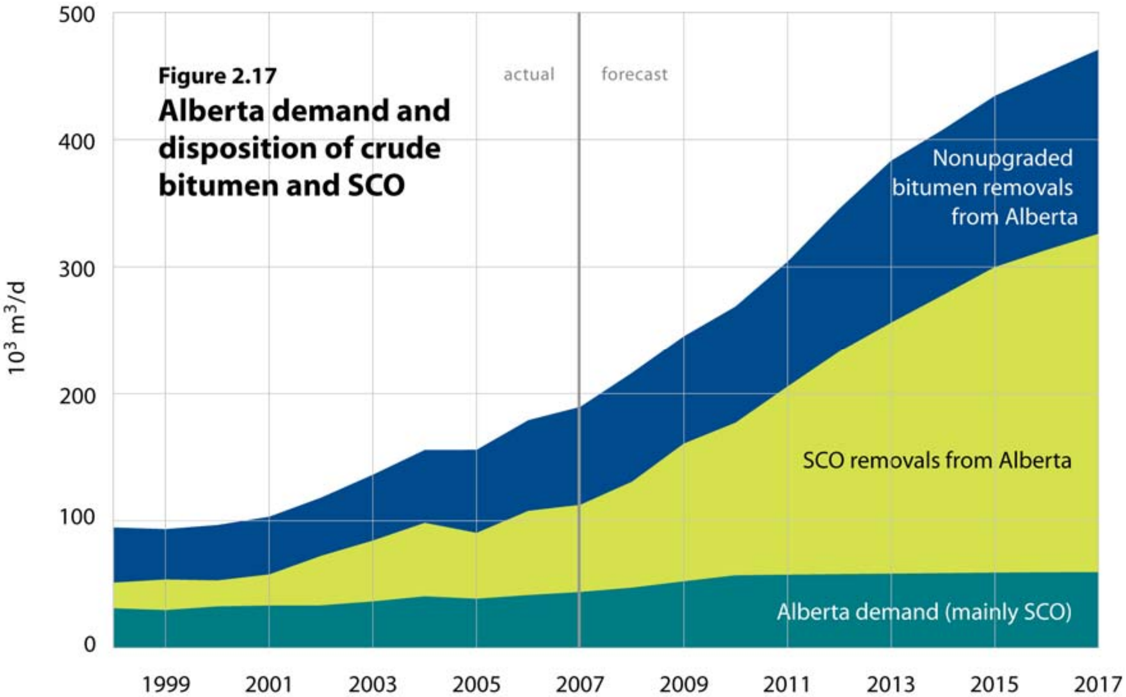
Overall demand for Alberta SCO and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, expansion of refineries currently processing SCO and blended bitumen, altering the configuration of current light crude oil refineries, and the availability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

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. In 2007, five Alberta refineries, with a total capacity of 75.5 10^3 m^3/d, used 35.5 10^3 m^3/d of SCO and 3.2 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand represents 32 per cent of Alberta SCO production and 4 per cent of nonupgraded bitumen production.

Petro-Canada, in addition to the announced joint venture with UTS and Teck Cominco in the Fort Hills project, continues to reconfigure its Edmonton refinery to fully replace light-medium crude oil with SCO and nonupgraded bitumen in late 2008.

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 2007, the sale of SCO as diesel fuel oil accounted for about 10 per cent of Alberta SCO demand.

Figure 2.17 shows that in 2017 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 100.5 10^3 m^3/d, are able to blend up to 35 per cent SCO and a further 4 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 increased markets for the future growth of refined products. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with a refining capacity of 570 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 95 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 273 10^3 m^3/d, the U.S. Gulf Coast, with a refining capacity of 1328 10^3 m^3/d, the U.S. west coast, with a refining capacity of 506 10^3 m^3/d, and 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 Spearhead 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 early 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. ExxonMobil is proposing to expand the pipeline capacity from 10.5 10^3 m^3/d to 15 10^3 m^3/d, with start-up expected in late 2008. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure 2.15**.

As illustrated in **Figure 2.17,** over the forecast period SCO removals from Alberta will increase from 68.4 10^3 m^3/d to 266 10^3 m^3/d, and the removals of nonupgraded bitumen will increase from 76.9 10^3 m^3/d to 145 10^3 m^3/d.

3 Crude Oil

Highlights

- Remaining established reserves are down 3.8 per cent, similar to the trend in the past decade.
- Reserve additions due to drilling in 2007 replaced 68 per cent of production, less than the 79 per cent last year.
- Production declined 3.5 per cent, compared with the average 5 per cent in the past decade.
- Despite high crude oil prices, drilling declined by 17 per cent in 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 may be classified as light-medium for oils having a density generally 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.

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 240.7 million cubic metres (10^6 m^3) at December 31, 2007. This is a decrease of 9.4 10^6 m^3, or 3.8 per cent, from December 31, 2006, resulting from all reserve adjustments, production, and additions due to drilling that occurred during 2007.

The changes in reserves and cumulative production for light-medium and heavy crude oil to December 31, 2007, are shown in **Table 3.1. Figure 3.1** shows the province's remaining conventional oil reserves over time. Remaining reserves have declined to less than 20 per cent of the peak reserves of 1223 10^6 m^3 reported in 1969.

3.1.2 Reserves Growth

A detailed pool-by-pool listing of reservoir parameters and reserves data is available on CD (see Appendix C). **Table 3.2** gives a detailed breakdown of this year's reserves changes, including additions, revisions, and enhanced recovery, while **Figure 3.2** gives a history of these changes back to 1990. The initial established reserves attributed to the 462 new oil pools booked in 2007 totalled 6.8 10^6 m^3 (an average of 15 thousand [10^3] m^3 per pool), down from 8.2 10^6 m^3 in 2006. The ERCB processed about 90 applications for new or amended water and solvent flood schemes, resulting in reserve additions totalling 2.2 10^6 m^3, compared to 1.9 10^6 m^3 last year **(Figure 3.3)**. Reserve revisions resulted in an overall net change of -0.2 10^6 m^3. The total increase in initial established reserves for 2007 amounted to 20.6 10^6 m^3, compared to last year's 27.1 10^6 m^3. These additions replaced 68 per cent of Alberta's 2007 conventional crude oil production of 30.4 10^6 m^3. This compares with last year's 79 per cent replacement ratio. **Table B.3** in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.

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

	2007	2006	Change
Initial established reserves[a]			
Light-medium	2 340.6	2 329.6	+11.0
Heavy	410.8	401.2	+9.6
Total	2 751.4	2 730.8	+20.6
Cumulative production[a]			
Light-medium	2 167.9	2 148.0	+19.9[b]
Heavy	342.8	332.7	+10.1[b]
Total	2 510.7	2 480.7	+30.0[b]
Remaining established reserves[a]			
Light-medium	172.7	181.6	-8.9
Heavy	68.0	68.5	-0.5
Total	240.7 (1 515 10^6 bbl)	250.1	-9.4
Annual Production			
Light-Medium	20.1	20.9	-0.8
Heavy	10.3	10.6	-0.3
Total	30.4	31.5	-1.1

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

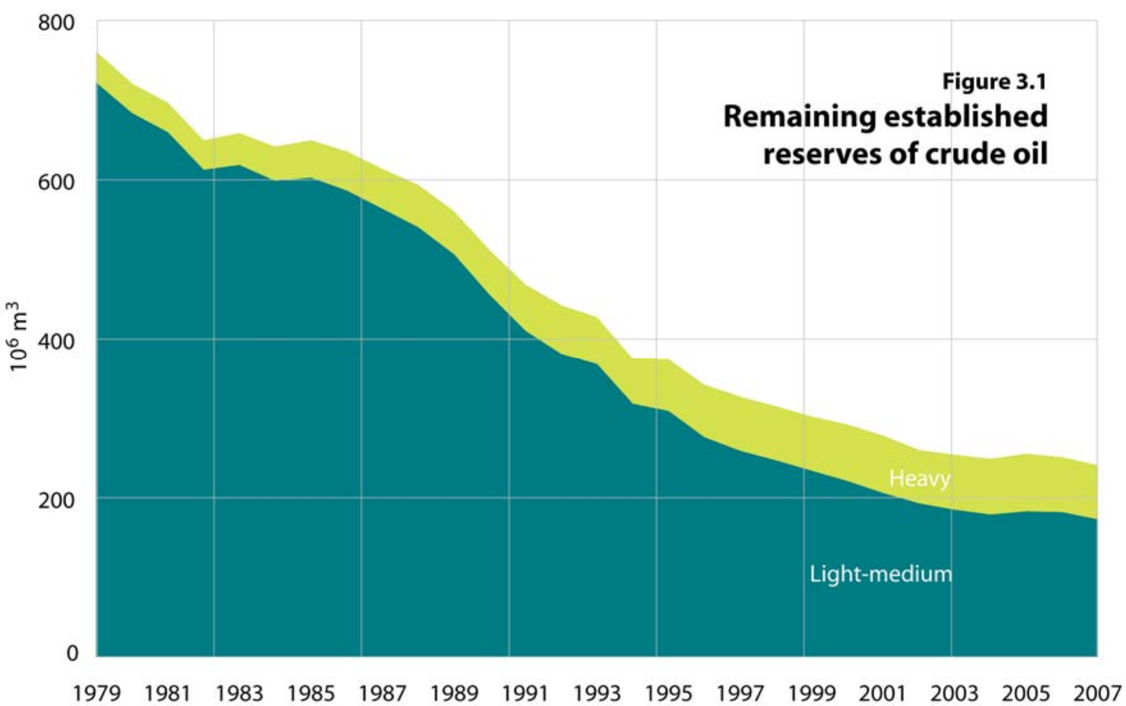
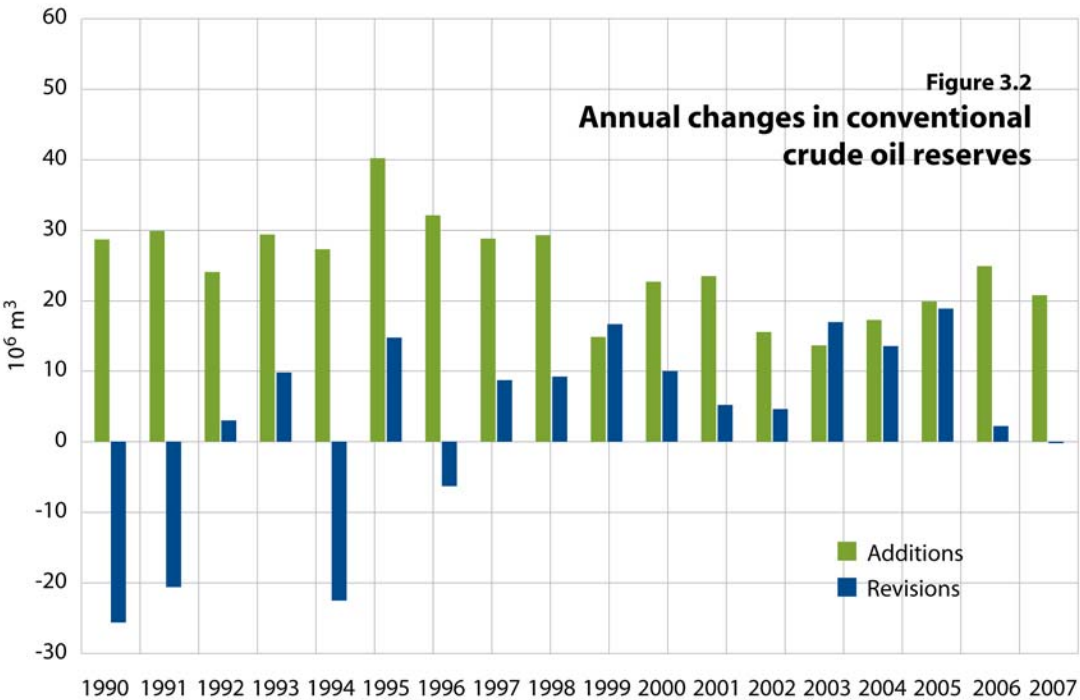
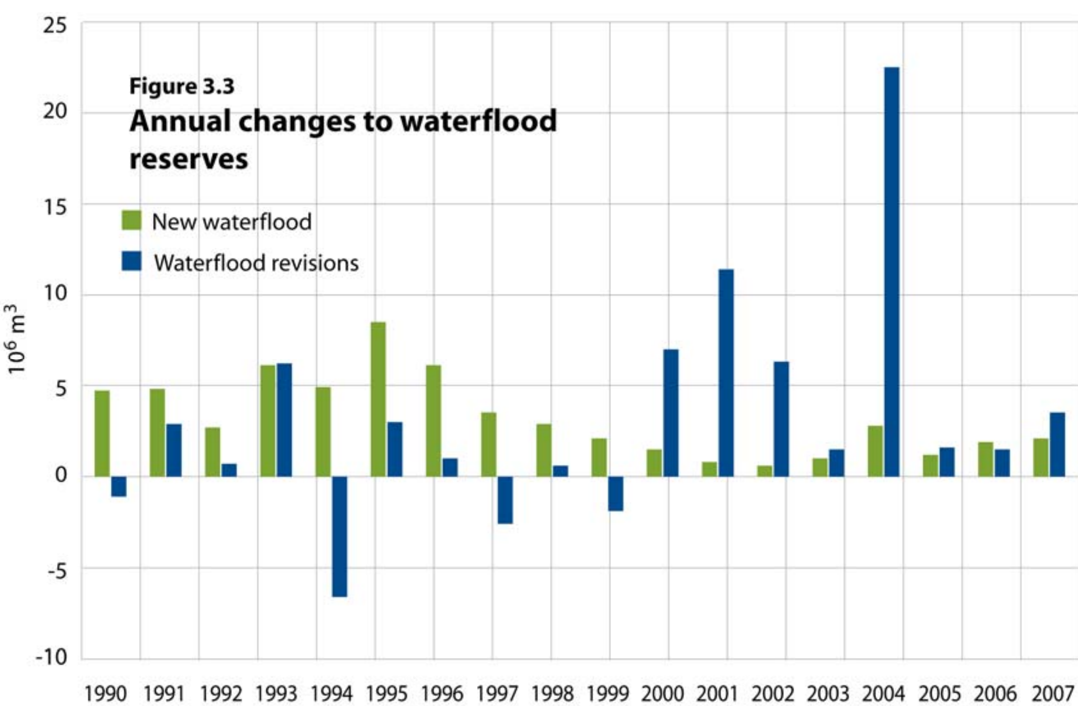


Table 3.2. Breakdown of changes in crude oil initial established reserves[a] (10^6 m^3)

	Light-medium	Heavy	Total
New discoveries	5.9	0.9	6.8
Development of existing pools	6.0	5.8	11.8
Enhanced recovery (new/expansion)	1.7	0.5	2.2
Revisions	-2.5	+2.3	-0.2
Total[a]	+11.0	+9.6	+20.6

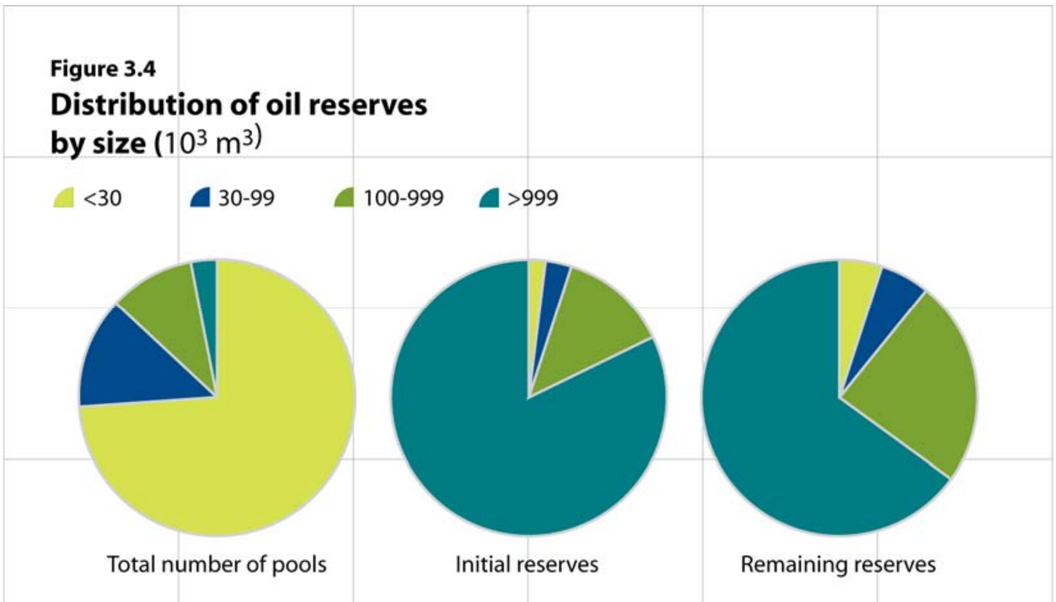
[a] Discrepancies are due to rounding.

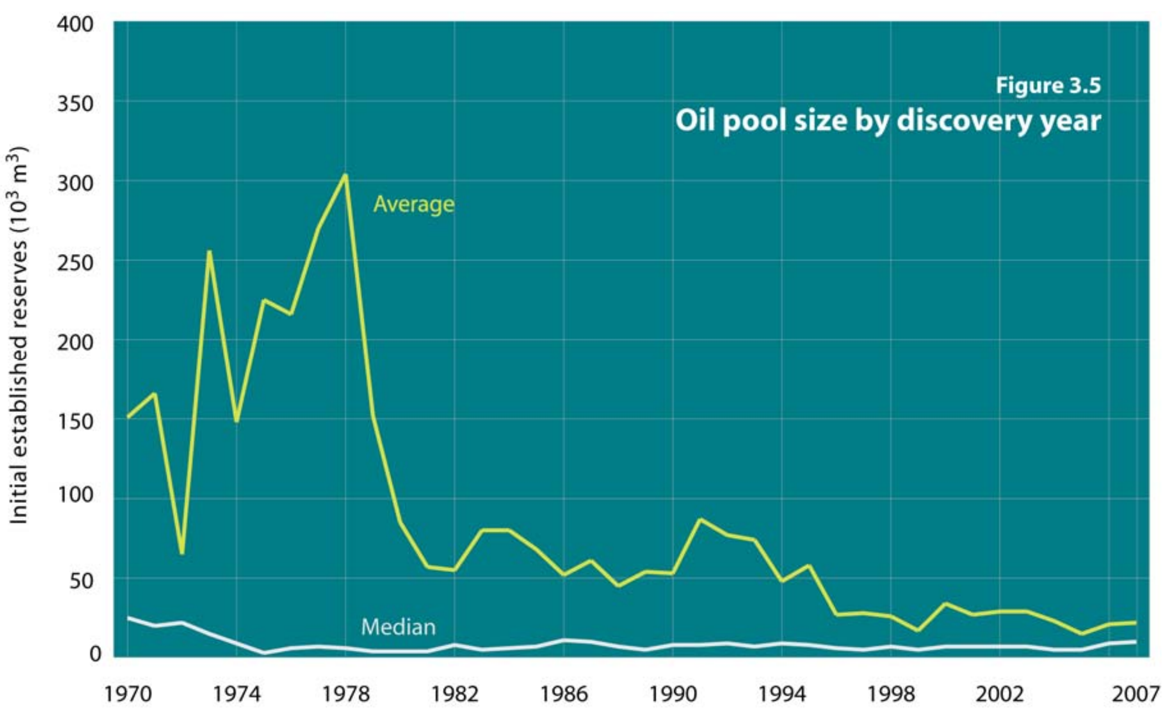




3.1.3 Oil Pool Size

At December 31, 2007, oil reserves were assigned to 9485 light-medium and 2758 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 63 per cent of the province's remaining oil reserves is contained in the largest 3 per cent of pools. By contrast, the smallest 74 per cent of pools contain only 6 per cent of its 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 fairly constant over time (below 10 10^3 m^3 initial established reserves per pool), the average has declined from 150 10^3 m^3 in 1970 to about 30 10^3 m^3 over the last few years. The Valhalla Doe Creek I and Dunvegan B Pool discovered in 1977 is the last major (over 10 10^6 m^3) oil discovery in Alberta. Its initial established reserve is estimated at 12 630 10^3 m^3. The largest pools discovered since 2000 include the Pembina Nisku II and Dixonville Montney C Pools, with initial established reserves estimated at 1315 10^3 m^3 and 947 10^3 m^3 respectively.

3.1.4 Pools with Largest Reserve Changes

The reserves of some 3240 oil pools changed over the past year, for a net total revision of minus 0.2 10^6 m^3. **Table 3.3** lists pools with the largest reserve change in 2007. Pool development in the Sturgeon Lake D-3 and Jenner Upper Mannville MM Pools resulted in reserve increases of 850 10^3 m^3 and 529 10^3 m^3 respectively. Reassessment of the primary reserves in the Cherhill Banff A Pool resulted in an increase of 723 10^3 m^3. Review of the Mitsue Gilwood A Pool resulted in a reserve write-down of 623 10^3 m^3.

3.1.5 Distribution by Recovery Mechanism

The distribution of conventional crude oil reserves by recovery mechanism is illustrated in **Figure 3.6**. **Table 3.4** shows reserves broken down by recovery mechanism. It shows that waterflooding has increased recovery in light-medium pools by an average 12 per cent. Primary recovery for heavy crude pools has increased from 8 per cent in 1990 to 12 per cent today, due to improvements in water handling, use of horizontal wells, 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 added another 4 per cent to the province's reserves and on average realized a 29 per cent improvement in recovery efficiency over primary recovery.

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

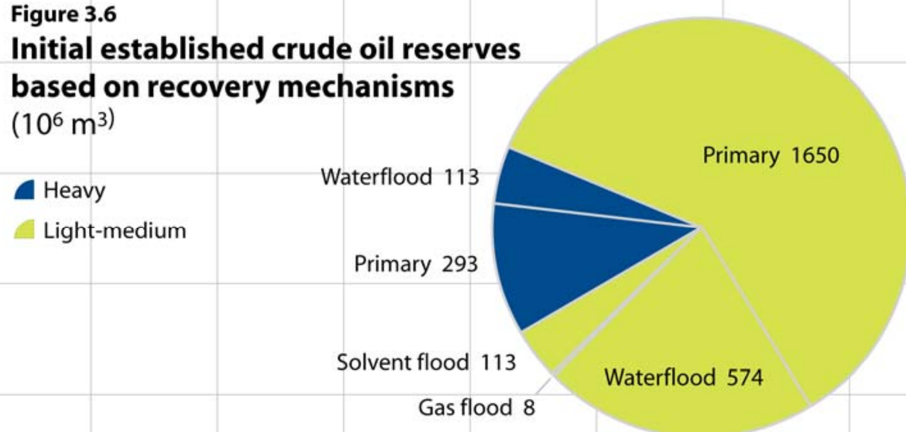


Table 3.3. Major oil reserve changes, 2007

Pool	Initial established reserves (10^3 m^3) 2007	Change	Main reason for change
Astotin Upper Mannville H	170	-162	Reassessment of reserves
Bellshill Lake Ellerslie A	1 551	+350	Reassessment of reserves
Chauvin Mannville A	2 432	+399	Reassessment of primary and waterflood reserves
Cherhill Banff A	3 783	+723	Reassessment of primary reserves
Dawson Slave Point II	500	-172	Reassessment of primary reserves
Duhamel D-3 B	1 253	-225	Reassessment of waterflood reserves
Grand Forks Upper Mannville K	7 398	+340	Reassessment of primary and waterflood reserves
Harmattan-Elkton Rundle C	92 820	+278	Reassessment of primary reserves
Hayter Dina A	5 523	+368	Reassessment of primary reserves
Home-Glen Rimbey D-3	3 878	+394	Reassessment of reserves
Innisfail D-3	13 700	+300	Reassessment of reserves
Jenner Upper Mannville MM	1 076	+529	Pool development
Lloydminster Sparky G	2 213	-174	Reassessment of reserves
Lloydminster Sparky W4W, Gen Pet III & JJJ	2 062	+779	Pool development and reassessment
Lloydminster Sparky C and General Petroleum A	2 844	+845	Pool development
Loon Granite Wash P	1 238	+347	Reassessment of reserves
Marwayne Sparky D	1 241	-293	Reassessment of reserves
Mitsue Gilwood A	63 800	-623	Reassessment of primary reserves
Princess Pekisko A	255	-200	Reassessment of reserves
Provost Dina N	4 034	+472	Reassessment of reserves
Rainbow South Keg River E	3 324	-294	Reassessment of tertiary reserves
Sturgeon Lake South D-3	28 030	+850	Reassessment of reserves
Taber North Glauconitic A	6 227	+300	New waterflood
Willesden Green Cardium U	835	+367	Reassessment of reserves

Table 3.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2007

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Waterflood/ gas flood	Solvent flood	Total	Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	3 830	860	0	0	860	22	-	-	22
Waterflood	3 281	496	407	0	903	15	12	-	28
Solvent flood	962	260	167	113	540	27	17	12	56
Gas flood	117	34	8	0	42	29	7	-	36
Heavy									
Primary depletion	1 663	202	0	0	202	12	-	-	12
Waterflood	679	91	113	0	204	13	17	-	30
Total	10 532	1 943	695	113	2 751	18			26
Percentage of total initial established reserves		71%	25%	4%	100%				

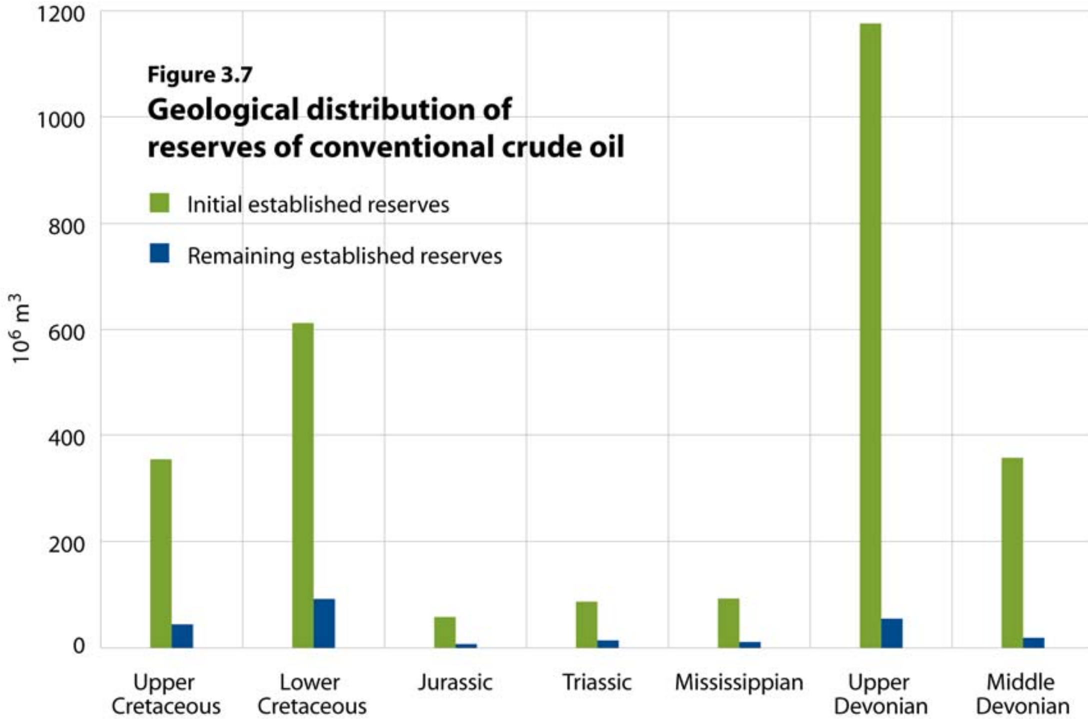
3.1.6 Distribution by Geological Formation

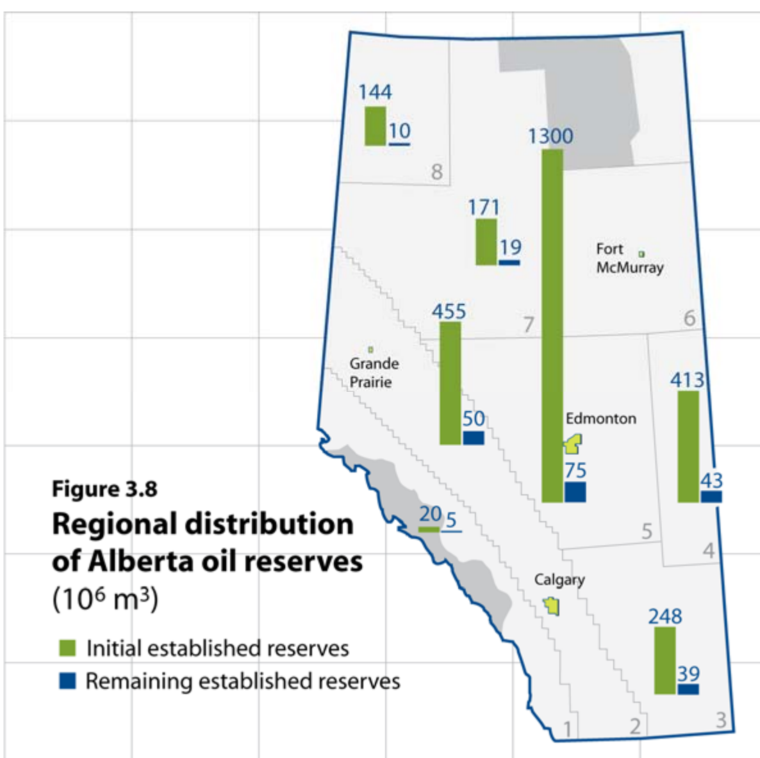
The distribution of reserves by geological period and Petroleum Services Association of Canada (PSAC) area is depicted graphically in **Figure 3.7** and **Figure 3.8** respectively. About 39 per cent of remaining established reserves are expected to come from formations within the Lower Cretaceous, 22 per cent from the Upper Devonian, and 18 per cent from Upper Cretaceous. By 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. A detailed breakdown of reserves by geological period and formation is presented in tabular form in Appendix B, **Tables B.4** and **B.5**.

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 volumetrics. An estimate of bulk rock volume is made based on 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 or small reef structures.

Converting volume in place to standard conditions at the surface requires knowledge of oil shrinkage 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 volumetrics to estimate in-place resources. Material balance can be very complex to perform in oil pools and is often precluded because of the lack of good pressure and PVT data. Analysis of production decline is a primary method for determining recoverable reserves, especially given the mature state of our conventional oil resources. 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 increase oil recoveries considerably. However, irregularities in rock quality can lead to channelling, which causes injected water to have low sweep efficiency and bypass some areas in the pool.

Less frequently, tertiary recovery techniques may be applied through injection of fluids that are miscible with the reservoir oil. This improves recovery efficiency by reducing the residual oil saturation at abandonment.

Incremental recovery over primary is estimated for pools approved for waterflood and is displayed separately in the reserve database. In order to accommodate the 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.

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. **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 80 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2007. Known discoveries represent 88 per cent of the ultimate potential, leaving 12 per cent yet to be discovered. This added to remaining established reserves means that 619 10^6 m^3 of conventional crude oil is available for future production.

In 2007, the remaining established reserves increased marginally, while annual production of crude oil continued to decline. However, there are 379 10^6 m^3 yet to be discovered, which at the current rate of annual reserve additions will take over 18 years to find. The discovery of new pools and development of existing pools will continue to bring on new reserves and associated production each year.

Any future decline in conventional crude oil production will be more than offset by increases in crude bitumen and synthetic production (see Section 2.2).

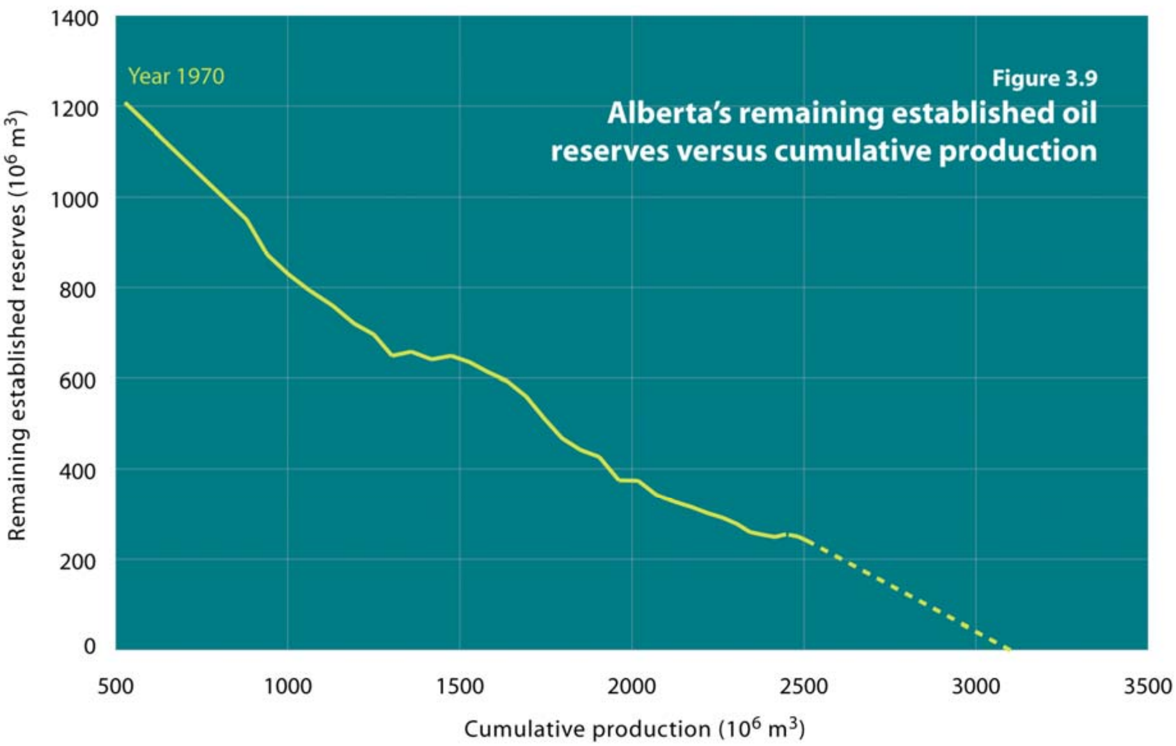


Figure 3.9
Alberta's remaining established oil reserves versus cumulative production
Year 1970
Remaining established reserves (10⁶ m³)
Cumulative production (10⁶ m³)
0
200
400
600
800
1000
1200
1400
500
1000
1500
2000
2500
3000
3500

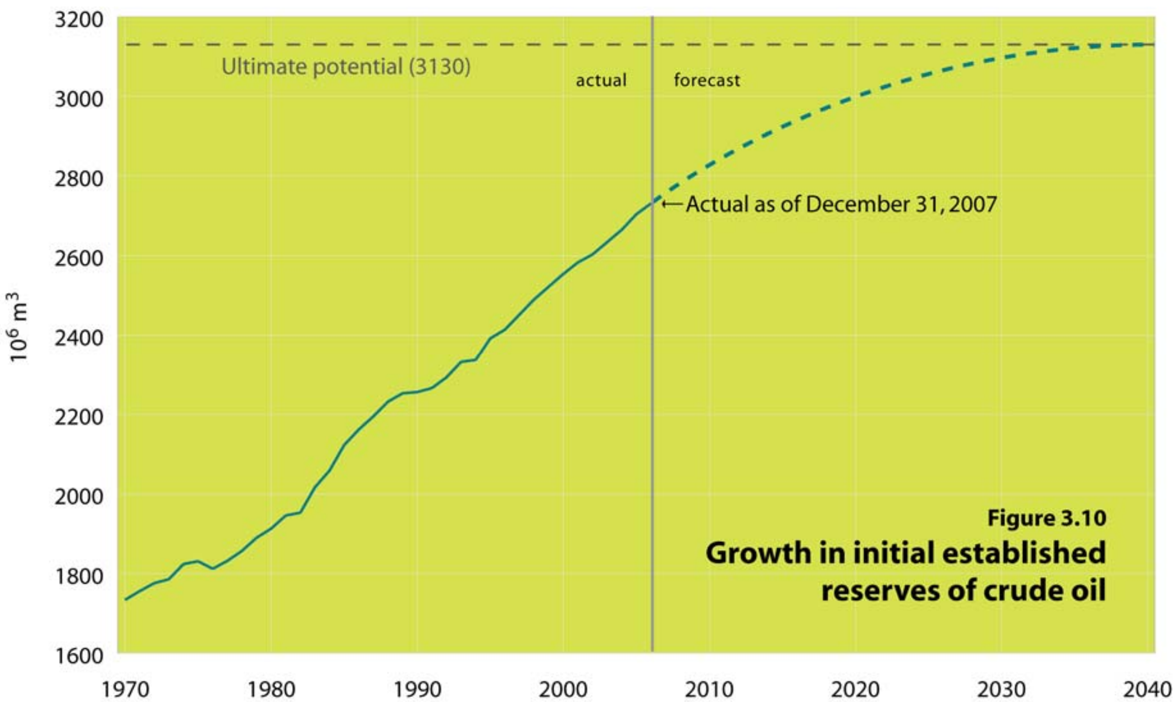


Figure 3.10
Growth in initial established reserves of crude oil
Ultimate potential (3130)
actual
forecast
←Actual as of December 31, 2007
10⁶ m³
1600
1800
2000
2200
2400
2600
2800
3000
3200
1970
1980
1990
2000
2010
2020
2030
2040

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 2007, total crude oil production declined to 83.4 10^3 m^3/day. Light-medium crude oil production declined by about 4 per cent to 55.1 10^3 m^3/d from its 2006 level, while heavy crude oil production experienced a decline of about 3 per cent to 28.3 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 3.5 per cent from 2006 to 2007 compared to the 5 per cent decline from 2005 to 2006.

In 2007, 1791 successful oil wells were drilled, a decrease of some 17 per cent over 2006. **Figure 3.11** shows the number of successful oil wells drilled in Alberta in 2006 and 2007 by geographical area (modified PSAC area). The majority of oil drilling in 2007, nearly 78 per cent, was development drilling. As shown in the figure, all areas of the province experienced declines in drilling with the exception of PSAC 3 (Southeast Alberta), where drilling levels remained similar to 2006, and PSAC 8 (Northwest Alberta), with an increase of 58 per cent.

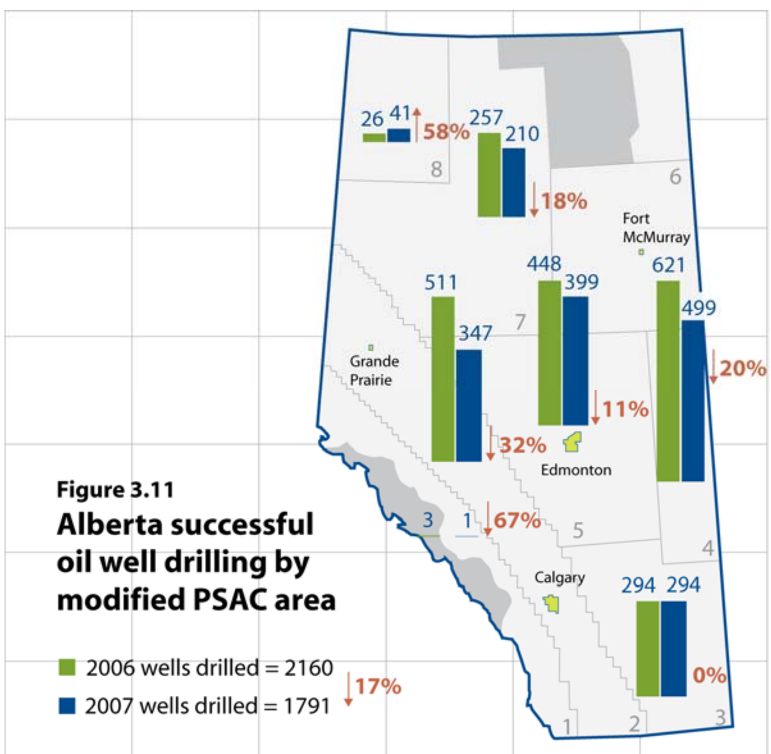


Figure 3.11
Alberta successful oil well drilling by modified PSAC area

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 2007. In 2007, actual wells placed on production decreased by 11 per cent over 2006 levels.

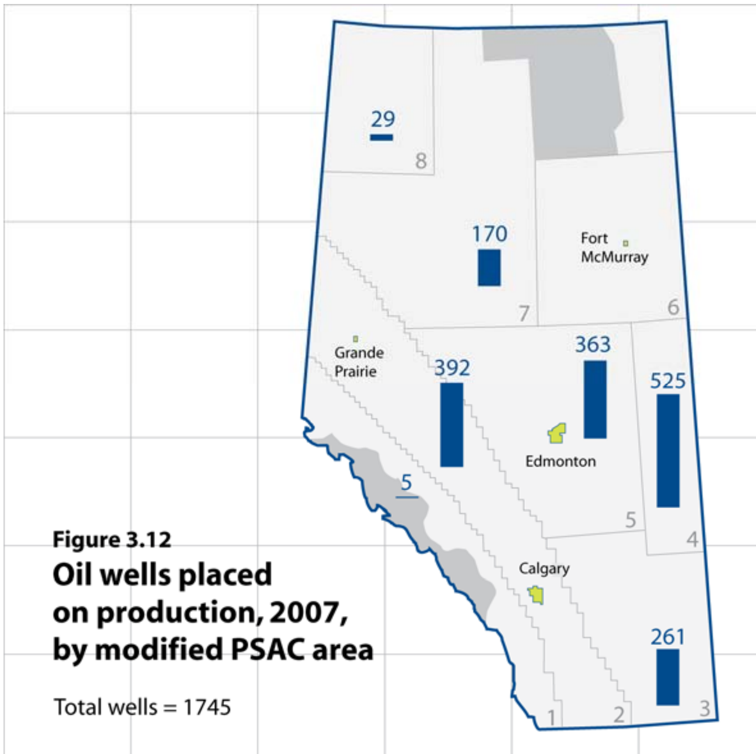


Figure 3.12
Oil wells placed on production, 2007, by modified PSAC area
Total wells = 1745

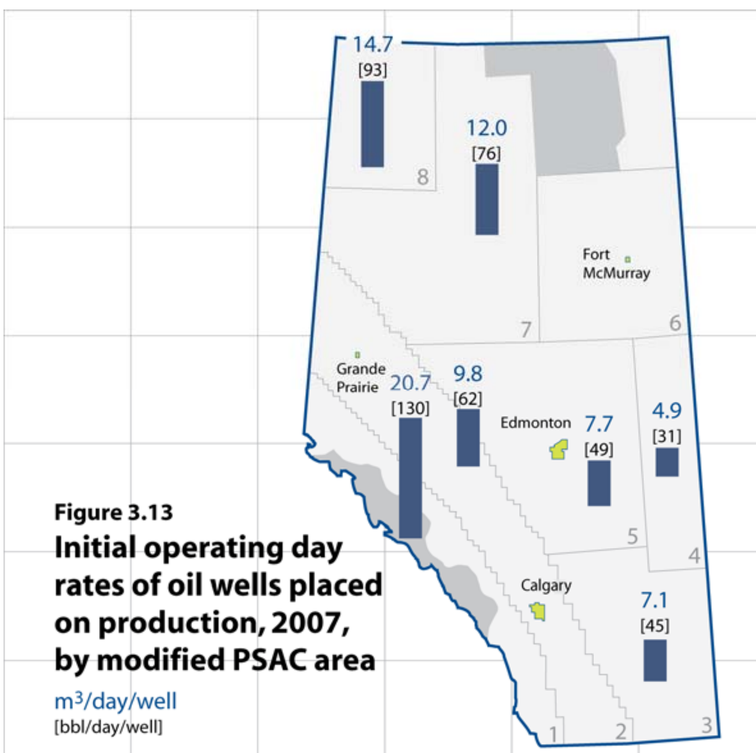
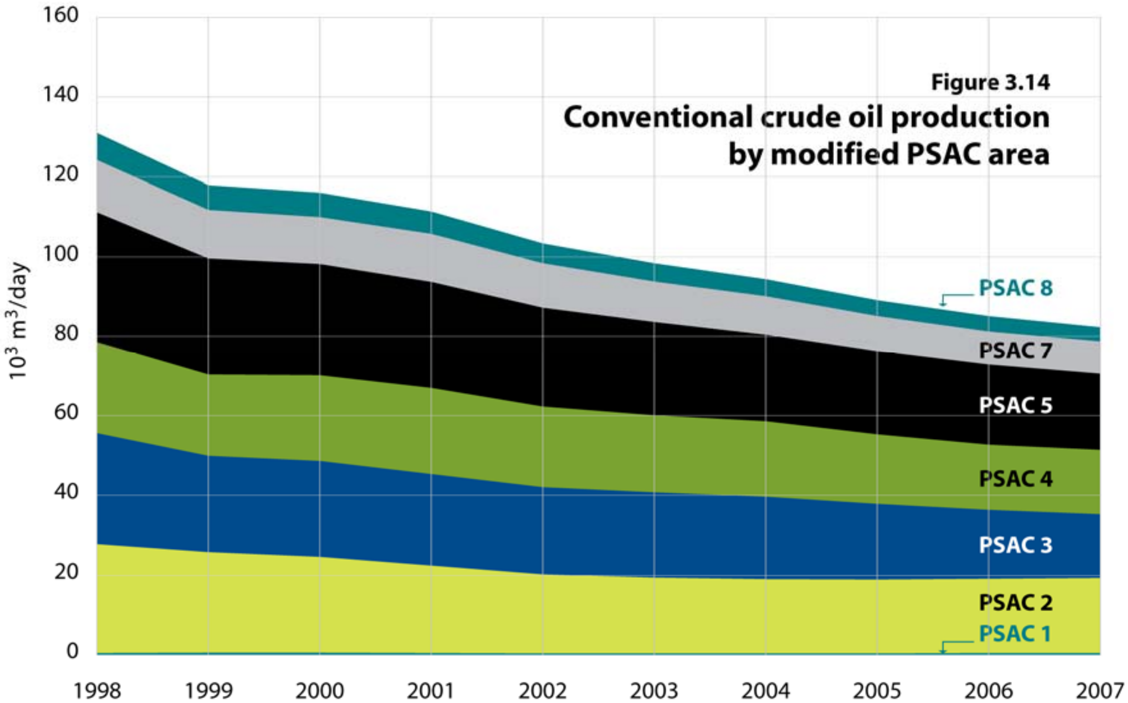


Figure 3.13
Initial operating day rates of oil wells placed on production, 2007, by modified PSAC area
m3/day/well
[bbl/day/well]

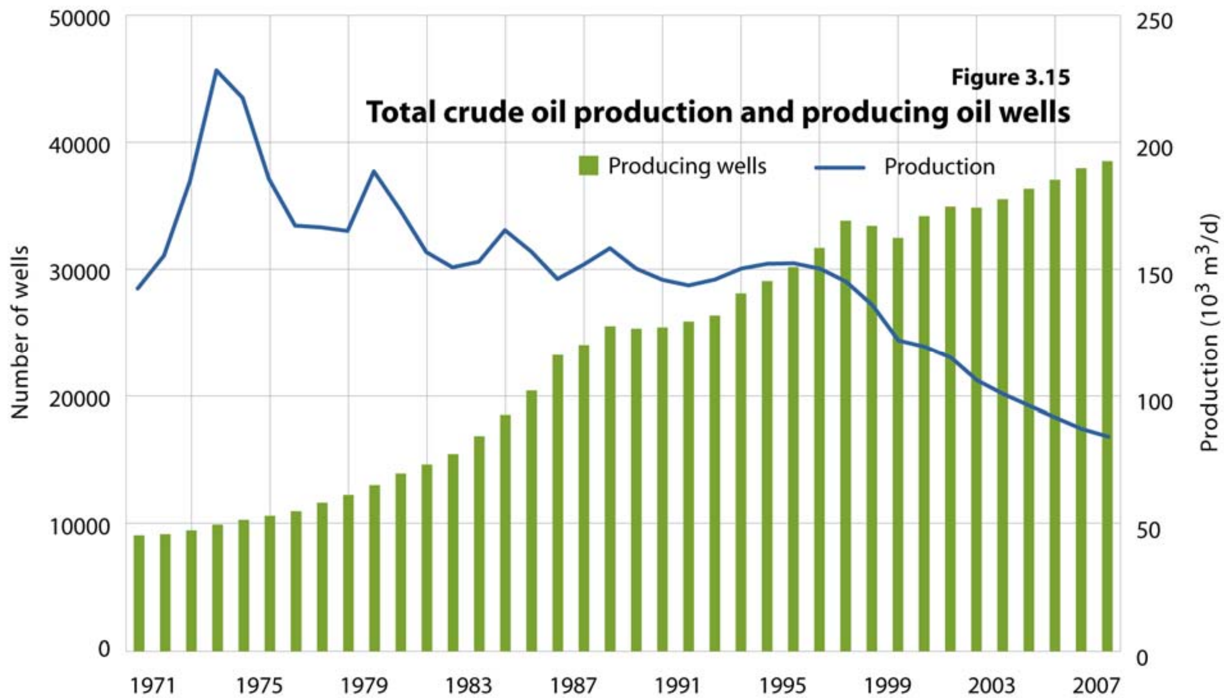
Historical oil production by geographical area is illustrated in **Figure 3.14**. Most areas experienced declines in production, ranging from 7.5 per cent in PSAC 3 (Southeast Alberta) to 1.1 per cent in PSAC 4 (East-Central Alberta). The one exception was PSAC 2 (Foothills Front), with an increase in production of 0.9 per cent.



Annual ERCB drilling statistics indicate that except for 1999 and 2002, the number of wells producing oil has increased over time from 9100 in 1970 to 38 500 in 2007. 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 1970. Of the 38 500 wells producing oil in 2007, about 2900 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 the total production.

Figure 3.16 depicts producing oil wells and the average daily production rates of those wells by region in 2007. The average well productivity of crude oil producing wells in 2007 was 2.3 m^3/d. The majority of crude oil wells in Alberta, about 66 per cent, produced less than 2 m^3/d per well. In 2007, the 23 100 oil wells in this category operated at an average rate of 0.9 m^3/d and accounted for only 24 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 2007.

In 2007, some 301 horizontal wells were brought on production, a 2 per cent increase from 2006, raising the total to 3780 producing horizontal oil wells in Alberta. Horizontal wells accounted for 11 per cent of producing oil wells and about 18 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 averaged about 7.2 m^3/d.



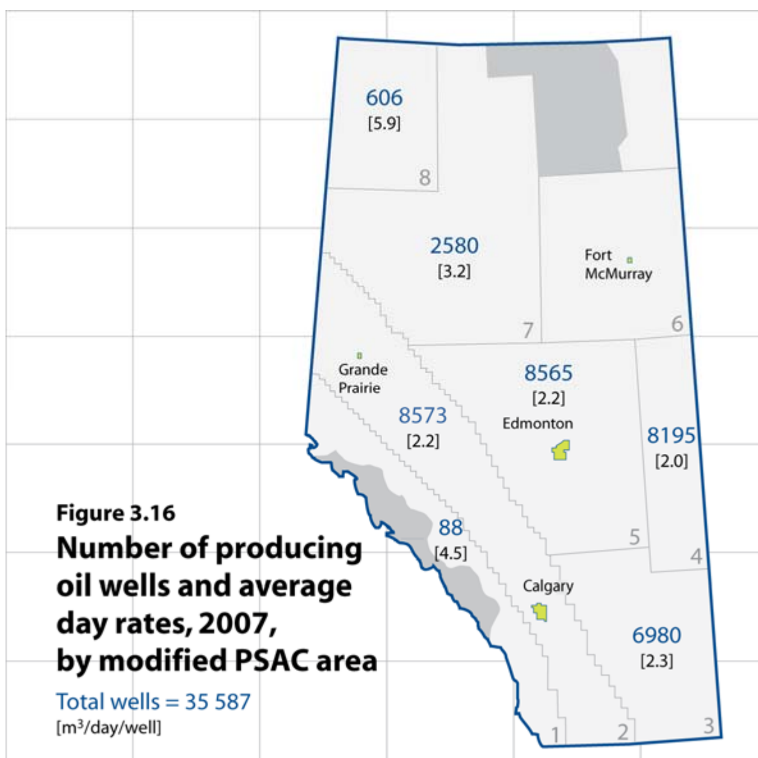


Figure 3.16
Number of producing oil wells and average day rates, 2007, by modified PSAC area
Total wells = 35 587
[m^3/day/well]

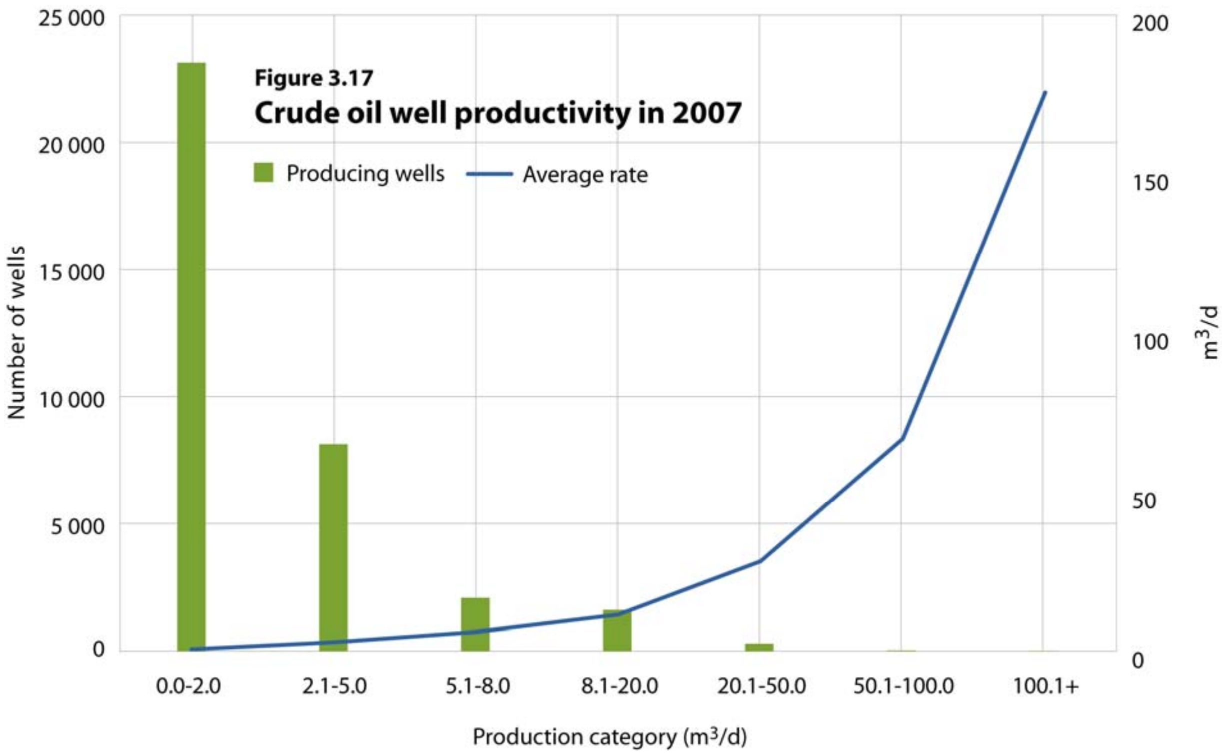


Figure 3.17
Crude oil well productivity in 2007

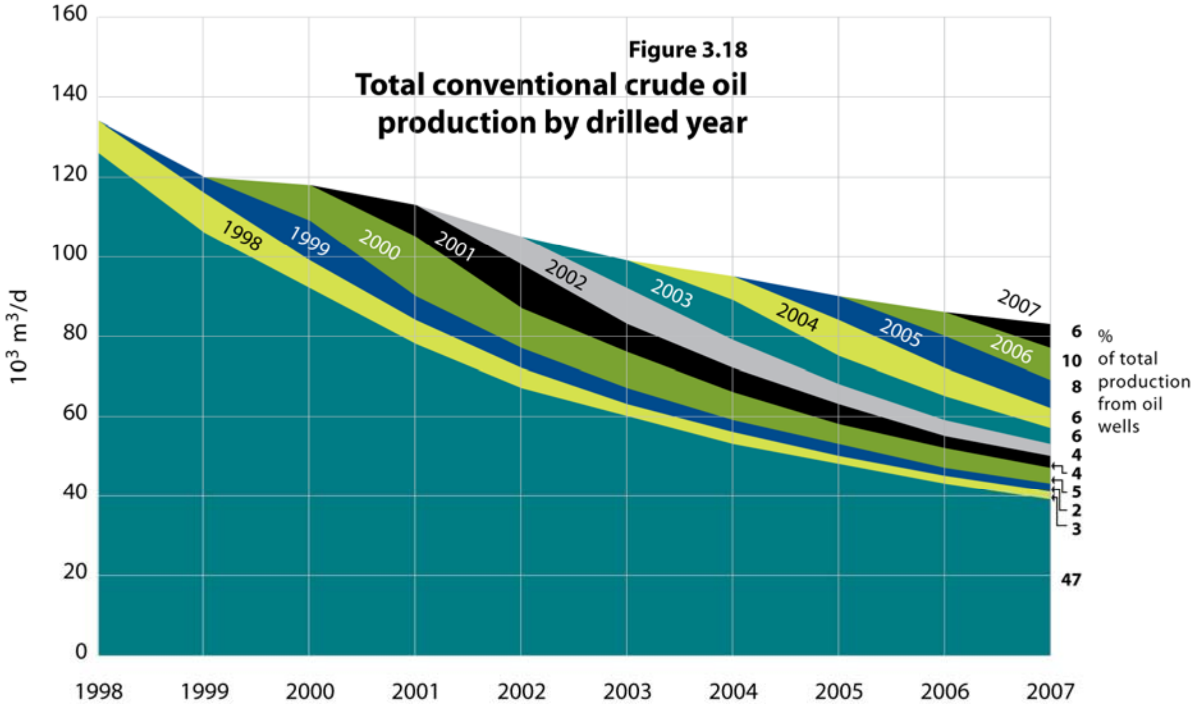
To project crude oil production from the wells drilled prior to 2008, the ERCB assumed the following:

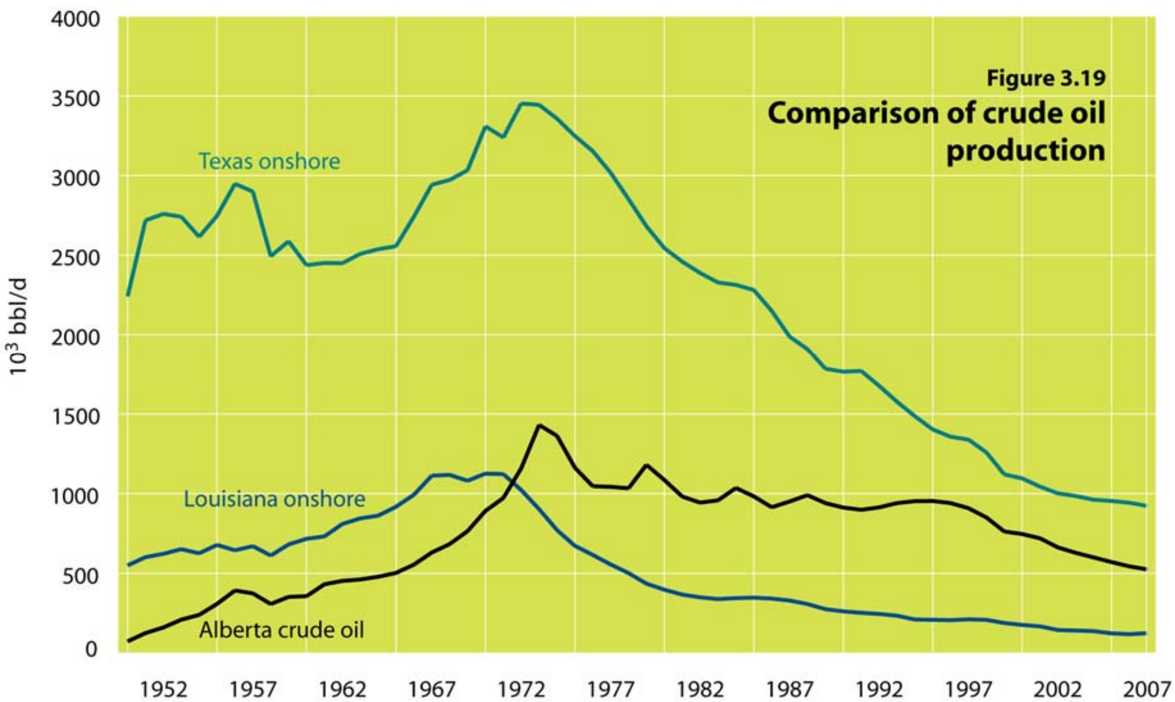
- Production from existing wells in 2008 will be 72.8 10^3 m^3/d.
- Production from existing wells will decline at a rate of about 15 per cent per year.

Crude oil production from existing wells by year placed on production over the period 1998-2007 is depicted in **Figure 3.18**. This figure illustrates that about 35 per cent of crude oil production in 2007 resulted from wells placed on production in the last five years. Over the forecast period, production of crude oil from existing wells is expected to decline to 17 10^3 m^3/d by 2017.

Figure 3.19 compares Alberta crude oil production with crude oil production from Texas onshore and Louisiana onshore from 1950 through 2007. 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. Within 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.

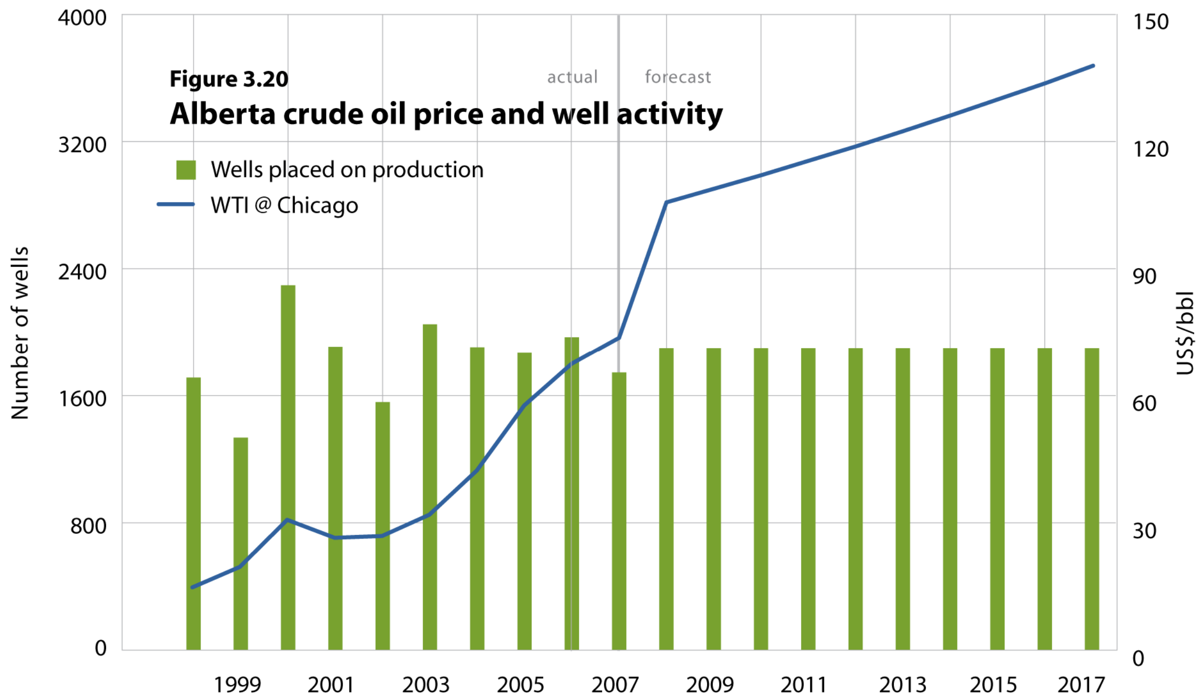
Total production from new wells is a function of the number of new wells that will be drilled successfully, initial production rate, and the expected average decline rate for these new wells.





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 increase to 1900 wells in 2008 and remain at this level over the forecast period due to expectation of continued high oil prices. **Figure 3.20** illustrates the ERCB's forecast for wells placed on production for the period 2008-2017.



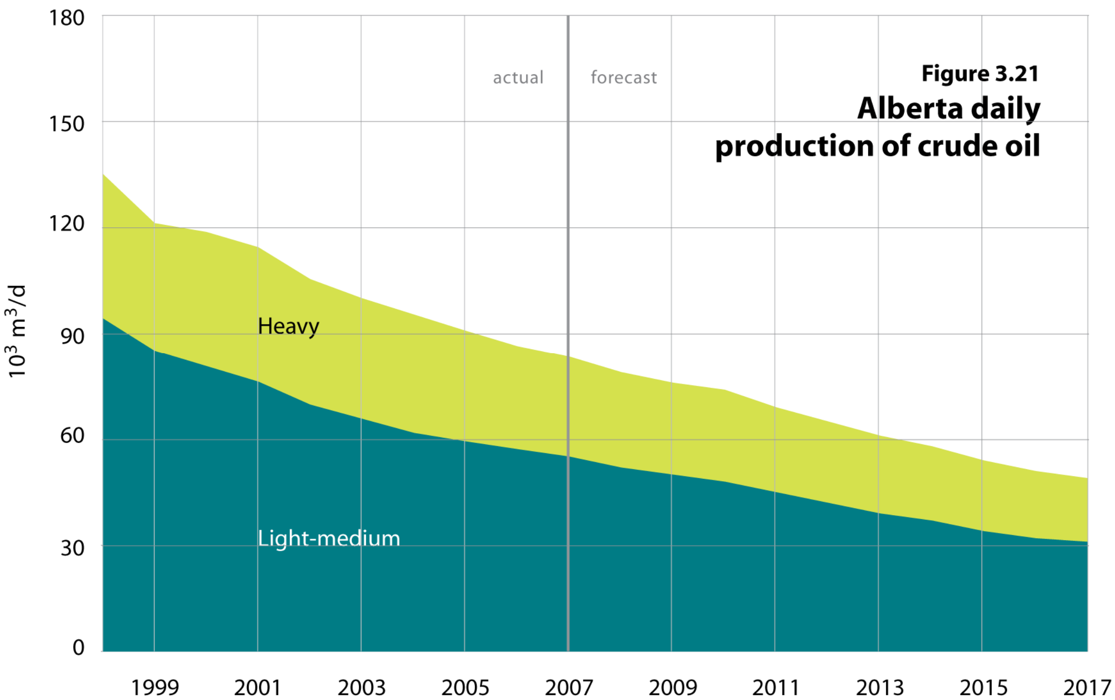
- The average initial production rate for new wells will be 4.5 m^3/d/well and will decrease to 3.0 m^3/d/well by the end of the forecast period. New well productivities averaged 8.0 m^3/d/well in the mid-1990s but have declined over time.
- Production from new wells will decline at a rate of 28 per cent the first year, 25 per cent the second year, 22 per cent the third year, 20 per cent the fourth year, and 18 per cent for the remaining forecast period.

The projection of the above two components, production from existing wells and production from new oil wells, is illustrated in **Figure 3.21**. Light-medium crude oil production is expected to decline from 55.1 10^3 m^3/d in 2007 to 31 10^3 m^3/d in 2017.

Although crude oil wells placed on production are expected to continue at about 1900 wells per year, light-medium crude oil production will continue to decline by almost 5 per cent per year, due to the inability of new well 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.

Over the forecast period, heavy crude production is also expected to decrease, from 28.3 10^3 m^3/d in 2007 to 18 10^3 m^3/d by the end of the forecast period. **Figure 3.21** illustrates that by 2017, heavy crude oil production will constitute a greater portion of total production compared to 2007.

The combined ERCB forecasts from existing and future wells indicate that total crude oil production will decline from 83.4 10^3 m^3/d in 2007 to 49 10^3 m^3/d in 2017. By 2017, if crude oil production follows the projection, Alberta will have produced about 88 per cent of the estimated ultimate potential of 3130 10^6 m^3.

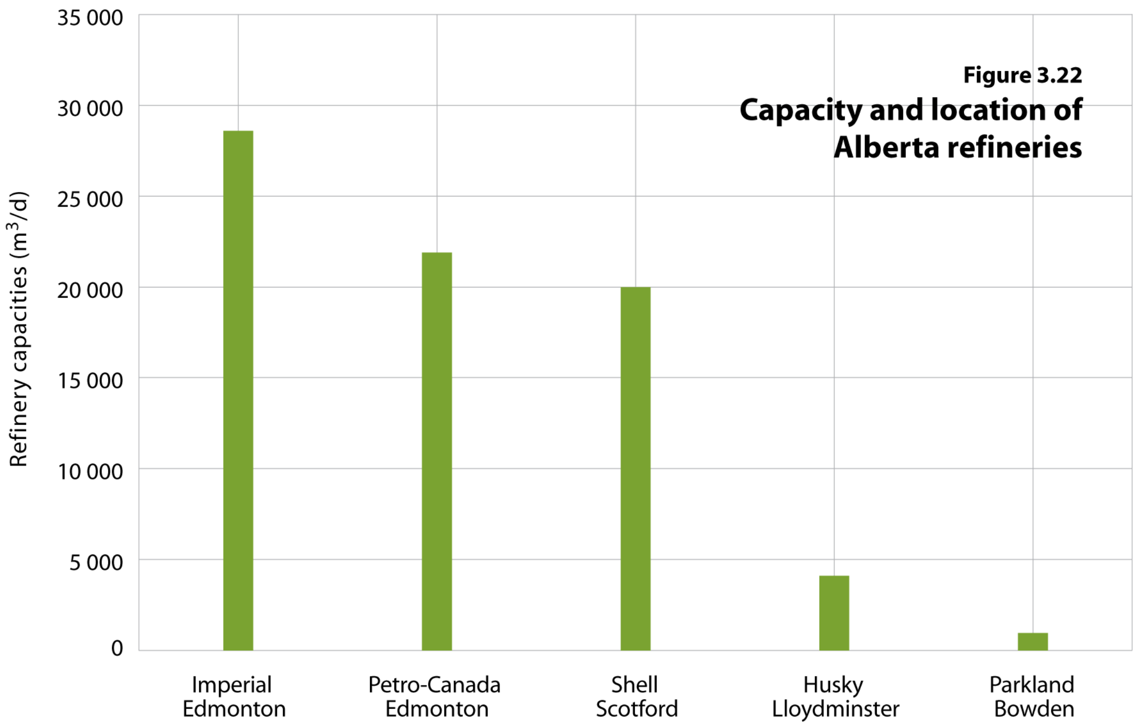


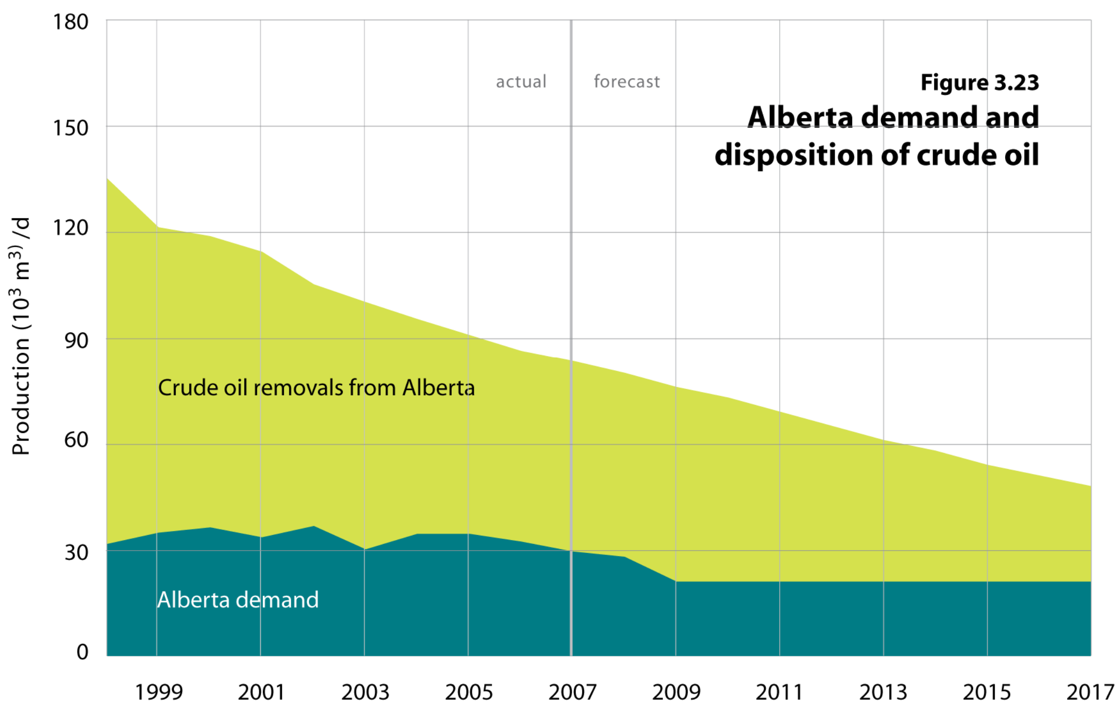
3.2.2 Crude Oil Demand

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 within 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 2007, Alberta refineries, with total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 29.5 10^3 m^3/d of crude oil. SCO, bitumen, and pentanes plus constituted the remaining feedstock. Crude oil accounted for roughly 43 per cent of the total crude oil and equivalent feedstock (see Section 2.2.4). **Figure 3.22** illustrates the 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 2007 was about 94 per cent and is expected to remain at or above this level, as demand for refined petroleum products increases in western Canada. Total crude oil use is expected be 28 10^3 m^3/d in 2008 and decline to 21 10^3 m^3/d for the remainder of the forecast period. This decline is the result of the Petro-Canada Refinery Conversion project, set to fully replace light-medium crude oil with SCO and nonupgraded bitumen in late 2008.

Shipments of crude oil outside of Alberta, depicted in **Figure 3.23**, amounted to 65 per cent of total production in 2007. The ERCB expects that by 2017 about 56 per cent of production will be removed from the province.





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 296.2 10^3 m^3/d in 2007 to 535 10^3 m^3/d in 2017. 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 2017.

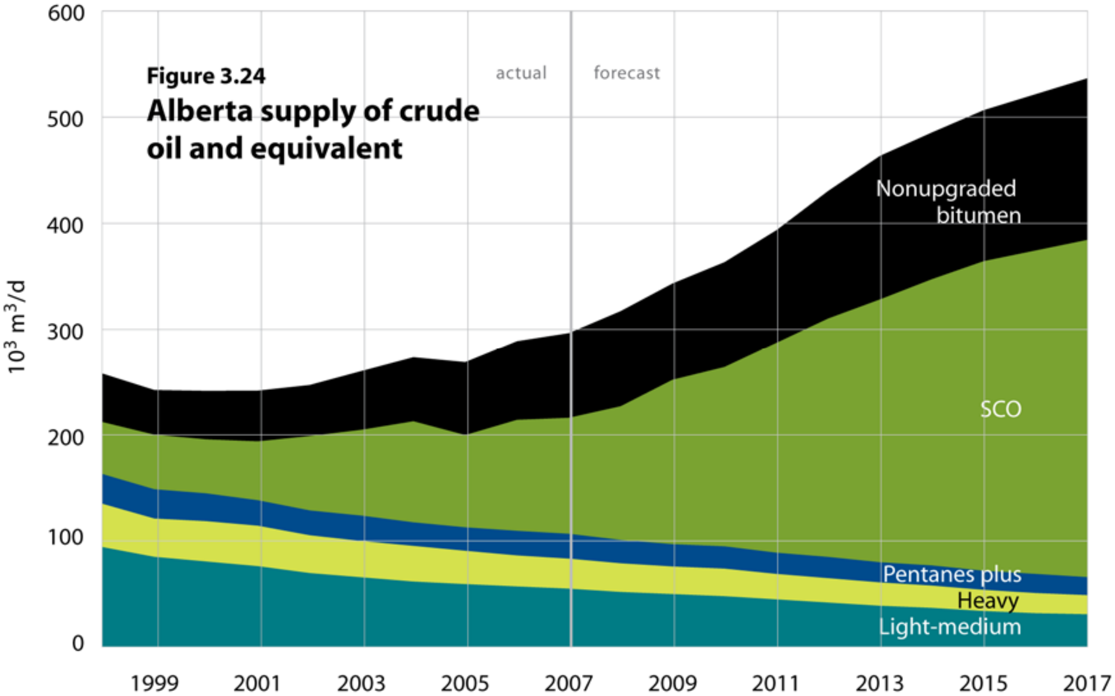


Figure 3.24
Alberta supply of crude oil and equivalent
actual
forecast
Nonupgraded bitumen
SCO
Pentanes plus
Heavy
Light-medium
10³ m³/d
600
500
400
300
200
100
0
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017

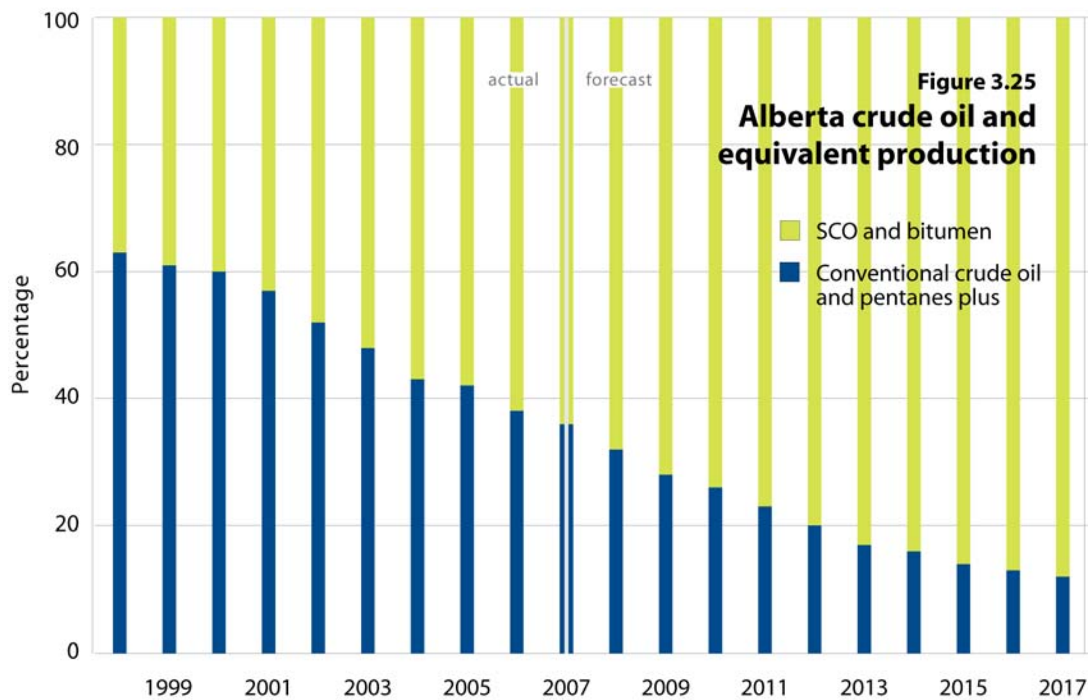


Figure 3.25
Alberta crude oil and equivalent production
actual
forecast
SCO and bitumen
Conventional crude oil and pentanes plus
Percentage
100
80
60
40
20
0
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017

4 Coalbed Methane

Highlights

- Some 2055 coalbed methane (CBM) wells were drilled in 2007, down 24 per cent from 2006.
- Recompletions of existing conventional wells to include coal seams increased by approximately 110 per cent.
- Water production from Mannville CBM wells is declining, while gas production is increasing.
- Total annual gas production for 2007 from 9339 wells producing some CBM is 6.8 billion cubic metres (10^9 m^3), of which 2.2 10^9 m^3 is estimated to be CBM.

Coalbed methane (CBM), also known as natural gas from coal (NGC), 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 considered to be a concern with respect to CBM, as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is usually about 37 megajoules/m^3.

From thousands of coal holes and oil and gas wells, coal is known to underlie most of central and southern Alberta. Individual coal seams are grouped into coal zones, which 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.

CBM zones are known to be laterally extensive over regional distances, but the values of reservoir parameters are generally limited to a more localized scale. A CBM zone is defined as all coals within a formation unless separated by more than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. CBM pools consist of several individual producing coal seams considered as one pool for administrative purposes.

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. New regulations were implemented on October 31, 2006, to assist in appropriate data collection for CBM. The new data were first used in selected fields in 2007, and as additional data become available for more areas in the future, the accuracy of CBM production estimates is expected to improve. Further details on the new regulations are available in ERCB *Directive 062: Coalbed Methane Control Well Requirements and Related Matters.*

4.1 Reserves of Coalbed Methane

4.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of CBM to be 24.3 billion cubic metres (10^9 m^3), as of December 31, 2007, in areas of Alberta where commercial production is occurring. This slight decrease over last year is primarily due to sustained production with corresponding low drilling activity. A summary of reserves is shown in **Table 4.1**. In 2007, the annual production from all wells listed as CBM (to be published in an upcoming ERCB bulletin on CBM) was 6.8 10^9 m^3. This volume represents the total contribution from wells with commingled conventional gas and CBM production. However, the portion estimated to be attributed to CBM only is captured in **Table 4.1**.

Table 4.1. Changes in CBM reserves, 2007 (10^6 m^3)

	2007	2006	Change
Initial established reserves	29 812	27 961	1 851
Cumulative production	5 468	3 311	2 157
Remaining established reserves	24 343	24 650	-307

4.1.2 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 reserves calculation were for the Horseshoe Canyon 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 Appendix B, **Table B.6**). Additional data have been collected under new regulations (implemented in October 2006), which has resulted in a more accurate production split of commingled wells. New data have also been collected on desorption testing of these coals, with resulting gas content data being used for reserves modelling. Previous analysis depended on very few data points to establish trends of gas content as a general application. That practice has been superseded by use of real desorption readings directly in the models. This has resulted in a drop in initial established reserves for some pools. To date, the primary method used to extract CBM from the Horseshoe Canyon 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 areas with a significant increase in 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 fields, and 2007 saw the addition of the Neerlandia field (see Appendix B, **Table B.6**). In these fields, CBM production requires the disposal of saline water. There are no indications of large-scale development beyond the current fields at this time.

Current industry practice suggests that long-term CBM production from the Mannville will be project-style developments using complex multilateral horizontal wells that are completed primarily within one seam. In other regions of the province, active exploration and pilot programs with vertical wells are currently testing CBM production, but these have no commercial gas production. Appendix B, **Table B.7** lists production from these areas, but reserves have not been booked pending commercial production.

Reserves for Ardley coals are not calculated due to lack of production.

4.1.3 Commingling of CBM with Conventional Gas

Commingling is the unsegregated production of gas from more than one interval in a wellbore. For CBM, this includes CBM/CBM and CBM/conventional gas commingling. The former case does not affect the calculation of remaining CBM reserves, but

CBM/conventional gas commingling, which occurs in several areas, does complicate the calculation, as discussed further below.

CBM production from the generally "wet CBM" Scollard, Mannville, and Kootenay coal-bearing formations is not currently being 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.

As the Horseshoe Canyon and Belly River CBM pools are generally "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 (see **Figure 4.1**). 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.

However, with CBM/conventional commingling, the lack of segregated data affects reserves calculations. Many 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:

- The completions were checked for most wells, and ones found to be only in coal were assigned as CBM-only production.
- The CBM production contribution from commingled CBM/sandstone wells was interpolated from 750 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 not included. There is an auditing process in place to correct this.

This process resulted in the estimated contribution of CBM production being reduced in a few fields, as summarized in Appendix B, **Table B.6**. 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 test results will allow for more complete analysis to improve allocation of production in commingled wells.

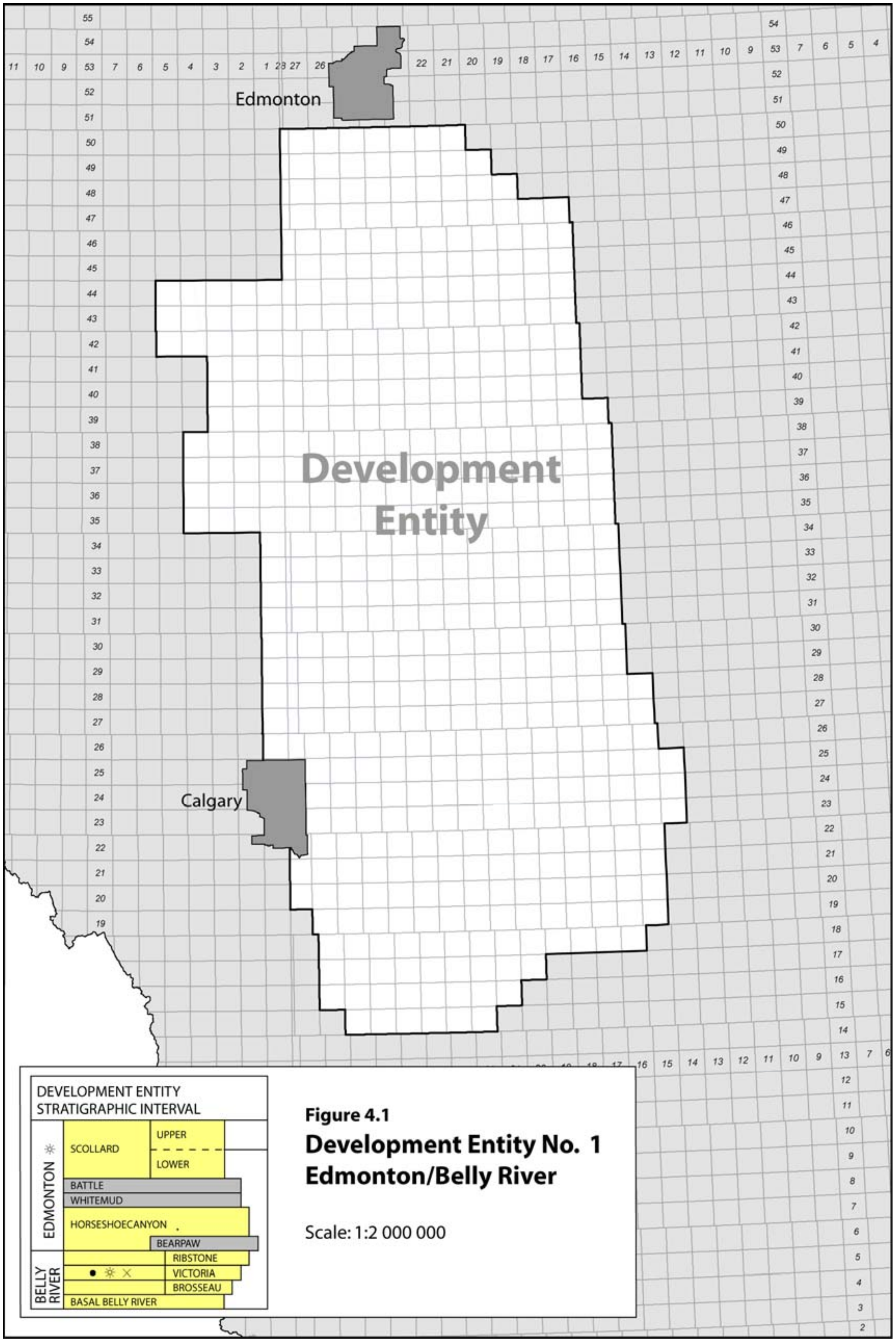


Figure 4.1
Development Entity No. 1 Edmonton/Belly River

Scale: 1:2 000 000

4.1.4 Distribution of Production 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 Horseshoe Canyon Formation and Belly River Group** – This is the middle set of coals, which generally have low gas contents and low water volumes, 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.

- **Coals of the Mannville Group** – This is the lower set of coals, primarily in the Upper Mannville Formation(s). These generally have high gas contents and high volumes 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. A few Mannville pilots have been abandoned (e.g., Fenn Big Valley). The initial reserves for other areas within the Mannville have been set at cumulative 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.

4.1.5 Reserves Determination Method

Reserves estimations use a three-dimensional deposit block model constructed by developing a three-dimensional gridded seam model, with subsequent application of measured gas contents and recovery factors to each coal intersection. CBM exists as deposits (similar to coal and bitumen) of disseminated gas with gas content and reserve values that can be calculated using a deposit model. As CBM is natural gas, it is regulated and administered as if it existed in pools, but the pool resource and reserve estimation method is not directly applicable.

Analysis of the Upper Cretaceous “dry CBM” trend, where most CBM pools are geologically distinct and show different pressure gradients, originally concluded that it was more appropriate to use separate gas content formulas for each CBM pool. These formulas were created due to the paucity of desorption data at the time. A more evenly distributed sampling of each coal zone has resulted from the implementation of the control well requirements. The additional data have been directly used by the block modelling process and has resulted in changes to gas content: up to 60 per cent less in some areas and up to 50 per cent more in other areas when compared to the original results from the equation method.

The method of determining reserves depends on flowmeter logs and pressure measurements in each CBM zone. Currently, there are many control wells from which this information is collected, but less than a dozen have yielded consistent data over the past three years. Future analysis is expected to improve estimates of recovery factors on a seam-by-seam basis. This analysis will be based on flowmeter data, with modifications determined by changes to the reservoir pressures. Current calculations were completed by taking flowmeter results, calculating zero recovery from seams with no flow, and prorating the percentage of the flow based on the daily volume for the well. Pressure variation analysis was not used for 2007.

CBM data are available on two systems at the ERCB: summarized pool style 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.

4.1.6 Gas in-Place Ultimate Potential

In 2003, the Alberta Geological Survey, in *Earth Sciences Bulletin 2003-03,* estimated that there are some 14 trillion m^3 (500 trillion cubic feet) of gas in place within all of the coal in Alberta, as summarized in **Table 4.2**. Only a very small portion of that coal resource has been studied in detail for this report. The geographic distribution of these resources is shown in **Figure 4.2**.

Table 4.2. CBM resources gas-in-place summary—constrained potential (depth and thickness restrictions)*

	10^{12} m^3	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*.

4.2 Supply of and Demand for Coalbed Methane

As mentioned previously, commercial production of CBM in Alberta began in 2002, with small volumes recovered to date. In 2007, 6.8 10^9 m^3 was produced, mostly from the CBM wells of the dry coals and commingled sandstones of the Horseshoe Canyon Formation. Commercial production from the Mannville Group is in its early stages, and much of the success to date has come as a result of horizontal drilling. CBM has the potential to become a significant supply source in Alberta over the next 10 years.

There were 2055 CBM wells drilled in the province in 2007, compared to 2721 in 2006. In 2007, 2259 wells were connected for CBM production in the province, a 23 per cent decrease from the 2929 wells connected in 2006. The natural gas price declines that took place in late 2006 and 2007 were responsible for the slowdown in CBM and conventional gas drilling activity.

Figure 4.3 shows the location of CBM wells by geographical area. A large portion of the well connections have been in Southeastern Alberta (PSAC Area 3) and Central Alberta (PSAC Area 5), accounting for 45 and 37 per cent respectively of all CBM wells connected in 2007.

Figures 4.4 and **4.5** illustrate the number of producing CBM wells by geographic area and their average well productivities respectively.

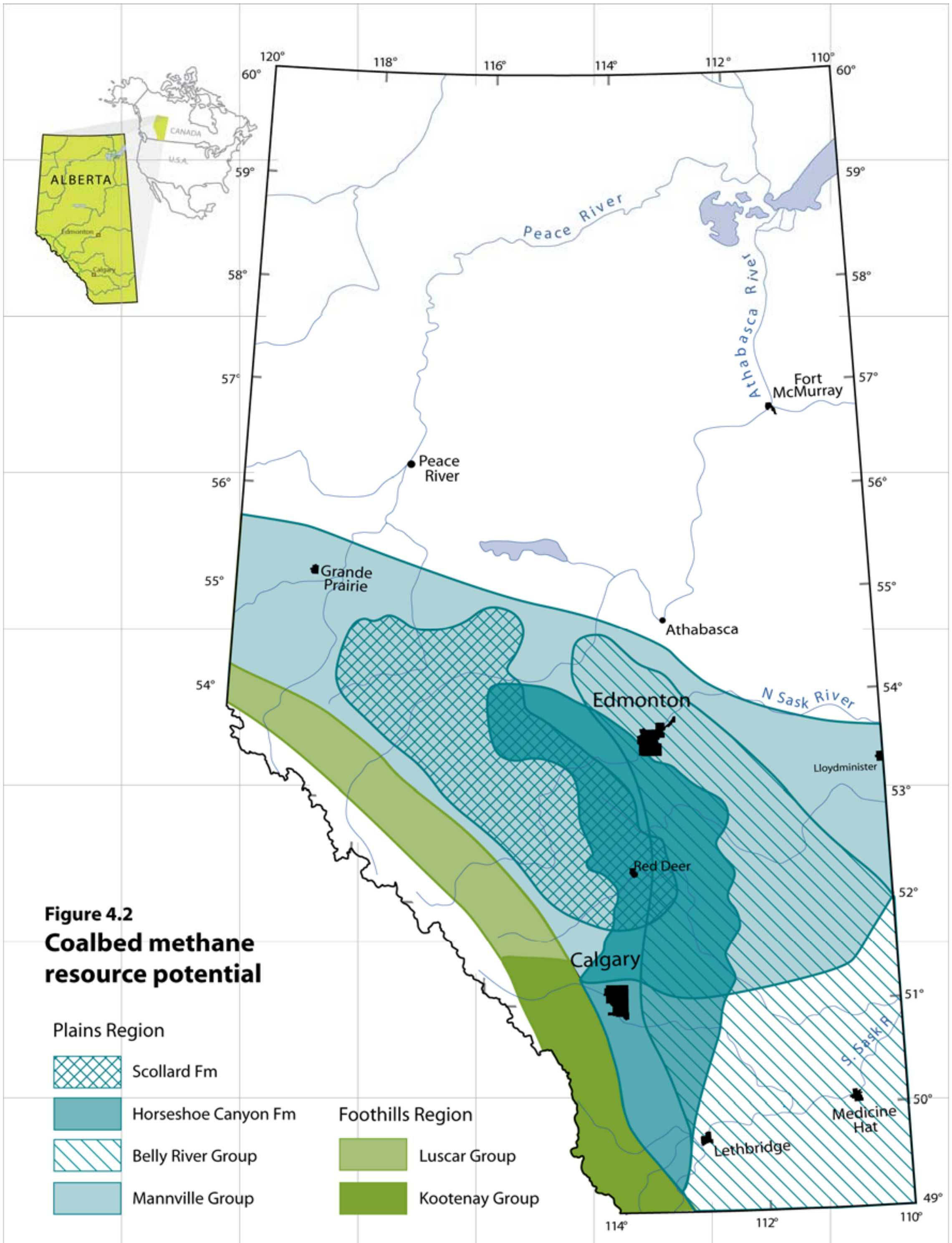


Figure 4.2
Coalbed methane resource potential

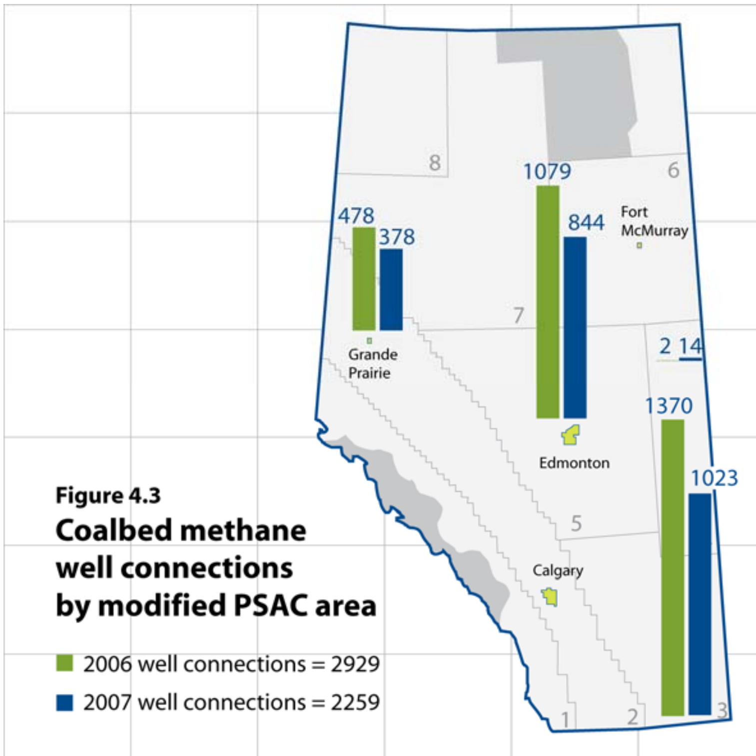


Figure 4.3
Coalbed methane well connections by modified PSAC area

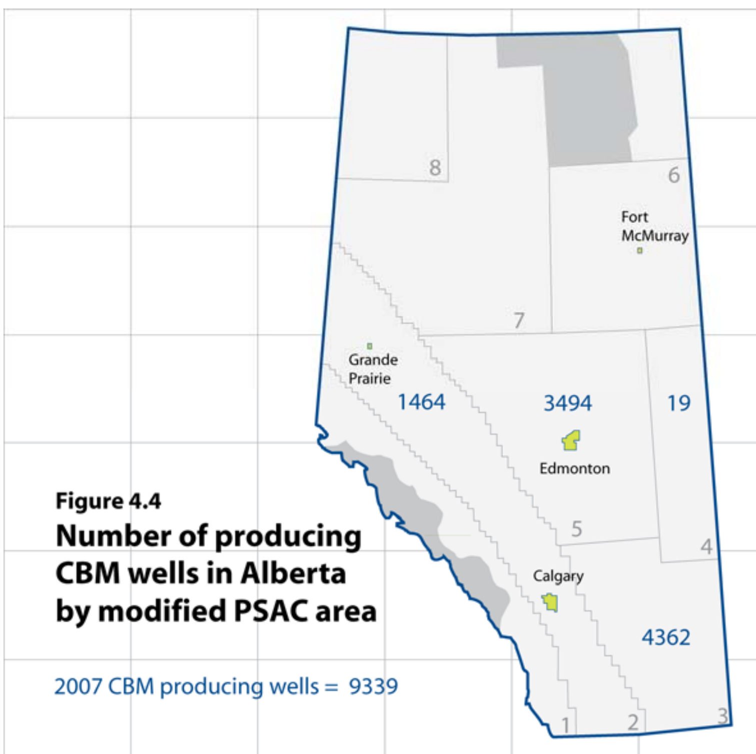
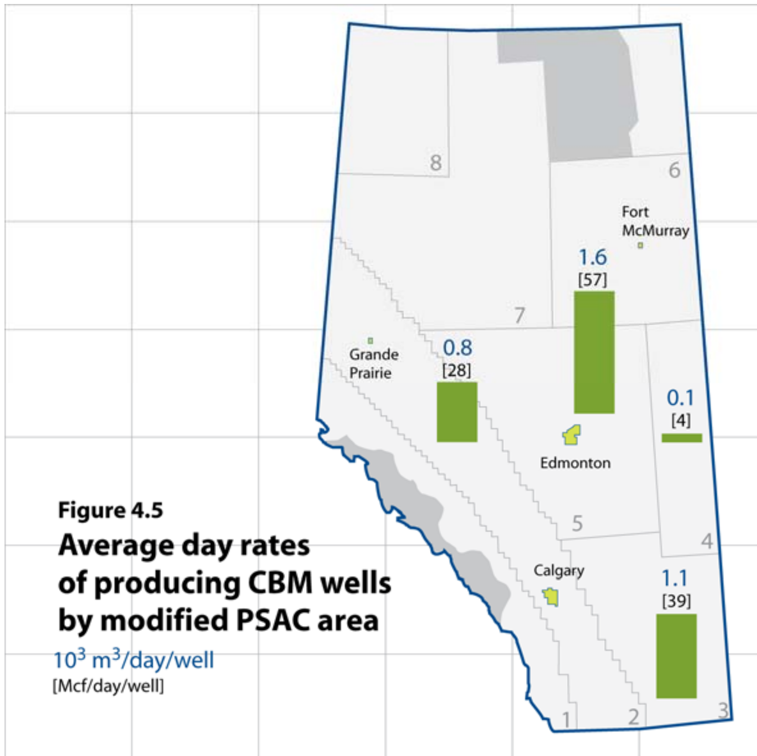


Figure 4.4
Number of producing CBM wells in Alberta by modified PSAC area



Future drilling and CBM connections are expected to continue to be significant in the Horseshoe Canyon Formation in areas of Southeastern and Central Alberta. Conventional supply will be commingled with CBM production in the same wellbore where deemed appropriate.

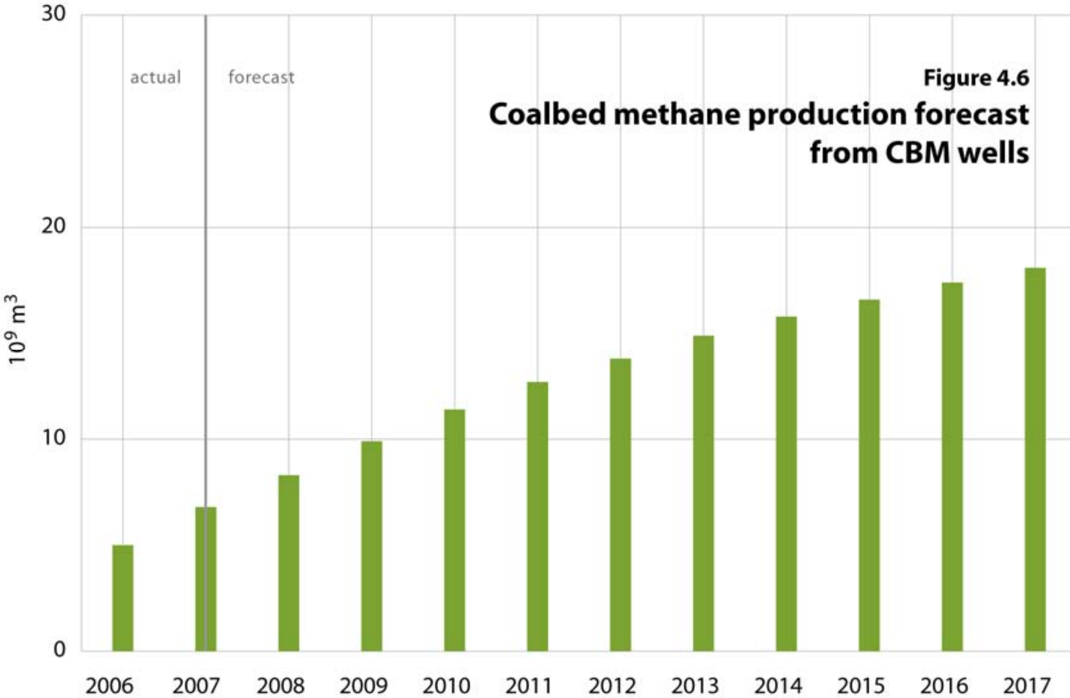
In projecting CBM production, the ERCB considered expected production from existing wells and expected production from new well connections. Limited historical production data suggest that CBM production does not behave in the same manner as conventional production in that CBM production declines more slowly.

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

- The average initial productivity of new CBM connections will be 2.8 10^3 m^3/d.
- Production from 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.

CBM well connections are expected to increase in 2008 to 2500 and remain at that level for the forecast period. The well connection numbers are higher than last year's forecast, as many of the new CBM connections tend to be recompletions into existing conventional wells.

Based on the assumptions described above, the ERCB generated the forecast of CBM production to 2017, as shown in **Figure 4.6**. The production of CBM is expected to increase from 6.8 10^9 m^3 in 2007 to 18.11 10^9 m^3 in 2017. This represents an increase from 5 per cent in 2007 to about 16 per cent in 2017 of total Alberta marketable gas production. 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 natural gas supply and demand.

5 Conventional Natural Gas

Highlights

- Gas well drilling declined 24 per cent in 2007, from 12 116 to 9220 wells.
- Alberta's remaining established conventional gas reserves declined by 4 per cent in 2007 to 1069 billion cubic metres.
- Reserves from new drilling replaced 52 per cent of conventional gas production.
- Alberta produced 133.7 billion cubic metres of conventional marketable gas in 2007.

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.

Natural gas volumes can be reported based either on the actual metered volume and 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 heating value of about 37.5 MJ/m^3 for coalbed methane, which consists mostly of methane with very minor amounts of ethane. In this section, gas production excludes those volumes of conventional gas that are produced from wells coded as CBM but that produce both CBM and conventional gas. Collectively, it is estimated that 70 per cent of the production from these wells is conventional gas.

5.1 Reserves of Natural Gas

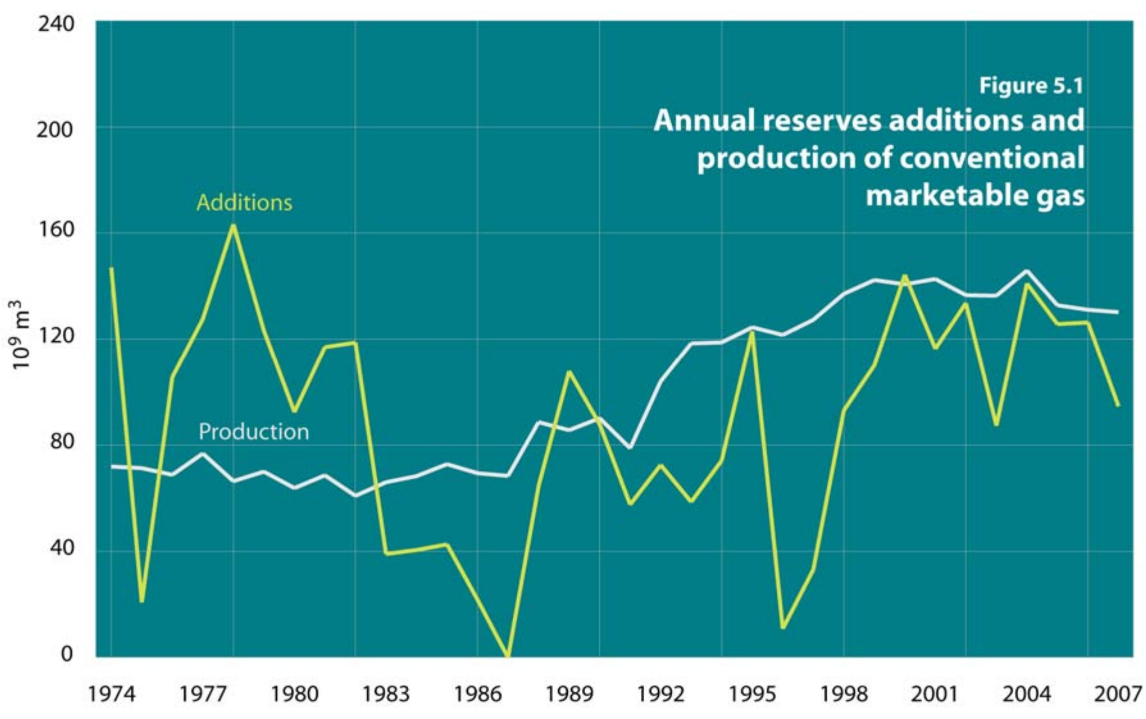
5.1.1 Provincial Summary

At December 31, 2007, the ERCB estimates the remaining established reserves of marketable gas in Alberta downstream of field plants to be 1069 billion (10^9) m^3, having a total energy content of 41.6 exajoules. This decrease of 45.9 10^9 m^3 since December 31, 2006, is the result of all reserves additions less production that occurred during 2007. These reserves include 33.5 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 will result in a 4.1 per cent reduction in 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 2007 are shown in **Table 5.1**. Total provincial gas in place and raw producible gas for 2007 is 8432 10^9 m^3 and 5765 10^9 m^3 respectively. This gives an average provincial recovery factor of 68 per cent. Total initial established marketable reserves is estimated at 4893 10^9 m^3, resulting in an average surface loss of 15.1 per cent. This surface loss estimate 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)	2007 volume	2006 volume	Change
Initial established reserves		4 893.3	4 798.7	+94.6
Cumulative production		3 823.9	3 683.5	
Remaining established reserves downstream of field plants				
“as is”	38.9	1 069.3	1 115.2	-45.9
at standard gross heating value	37.4	1 112.2	1 136.3	
Minus liquids removed at straddle plants		33.5	35.4	-1.9
Remaining established reserves “as is”	37.3	1 035.5 (36.8 Tcf)[a]	1 079.6 (38.3 Tcf)[a]	-44.1
at standard gross heating value	37.4	1 031.5	1 075.7	
Annual production	37.4	133.7	139.2	-5.5

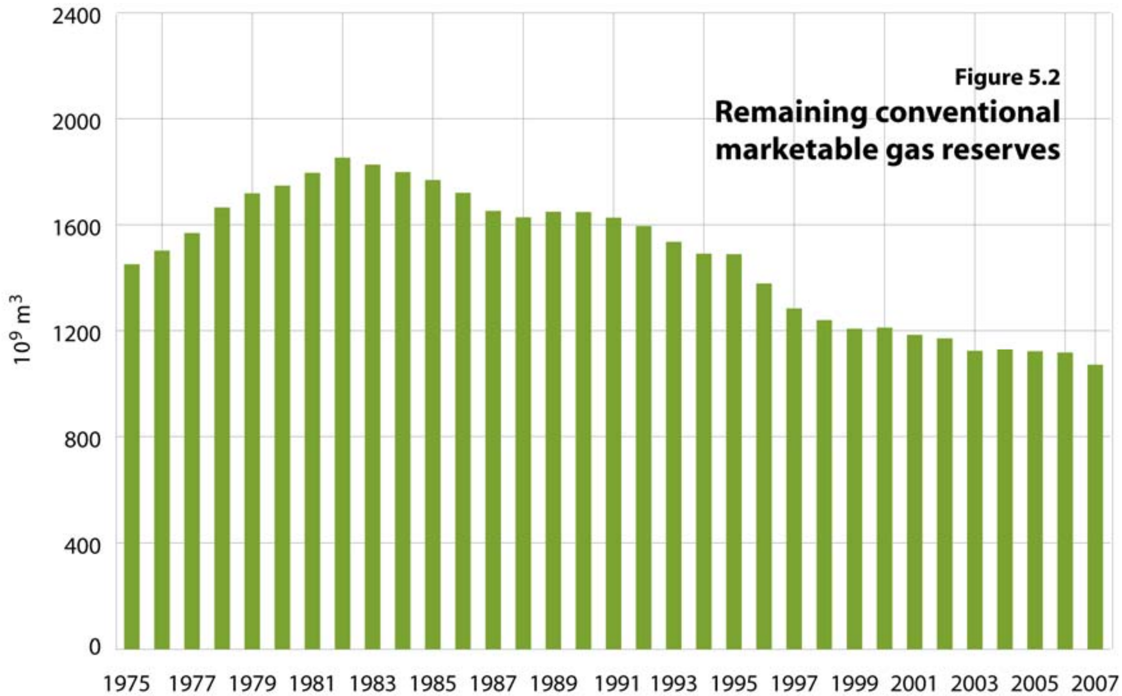
[a] Tcf – trillion cubic feet.

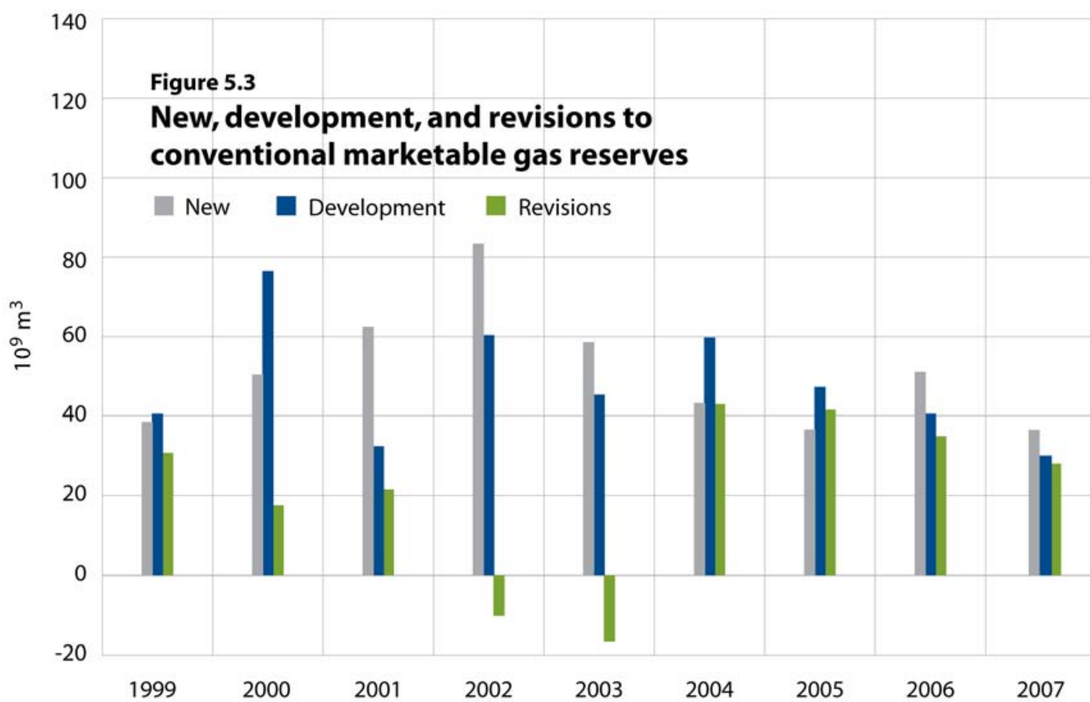
Annual reserves additions and production of natural gas since 1974 are depicted in **Figure 5.1**. It shows that total reserves additions have failed to keep pace with production. As illustrated in **Figure 5.2**, Alberta’s remaining established reserves of marketable gas decreased by about 42 per cent since 1982.



5.1.2 Annual Change in Marketable Gas Reserves

Figure 5.3 shows the breakdown of annual reserves additions into new, development, and reassessment from 1999 to 2007. Initial established reserves increased by 94.6 10^9 m^3 from year-end 2006. This increase includes the addition of 36.5 10^9 m^3 attributed to new pools booked in 2007, 30.0 10^9 m^3 from development of existing pools, and a positive net reassessment of 28.1 10^9 m^3. Reserves added through drilling alone totalled 66.5 10^9 m^3, replacing 52 per cent of Alberta's 2007 production of 128.5 10^9 m^3. These breakdowns are not available prior to 1999. Historical reserves growth and production data since 1966 are shown in Appendix B, **Table B.8**.





During 2007, a review of pools that had not been reevaluated for some time or appeared to have reserves under- or overbooked based on their reserve life index was conducted. This resulted in large reserve changes, as summarized below.

- Review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in a reserves addition of 11.6 10^9 m^3. This addition is due largely to new discoveries and development of existing pools.

- Reserves life indices were used to evaluate pools with reserves-to-production ratios over 25 years and less than 2 years. Some 4500 pools were evaluated, resulting in an overall reserves reduction of 5.4 10^9 m^3.

- Revision of a large number of oil pools with solution gas resulted in a reserves reduction of 2.9 10^9 m^3.

- The 39 pools with significant changes listed in **Table 5.2** resulted in net addition of 21.3 10^9 m^3, or 22.5 per cent of all additions for 2007.

Figure 5.4 illustrates a comparison in marketable gas reserves growth between 2007 and 2006 by modified Petroleum Services Association of Canada (PSAC) areas. The most significant growth was in Area 2, which accounted for 68 per cent of the total annual change for 2007. Some pools within PSAC Area 2 that contributed to this increase in reserves are the Ansell Belly River, Cardium, Viking and Mannville MU#1; Elmworth Smoky, Fort St. John, Bullhead and Triassic MU#1; Pembina Belly River, Colorado, Mannville and Jurassic MU#1; Sinclair Doe Creek, Fort St. John and Bullhead MU#1; Sinclair Doig A and Waterton Rundle Wabamun A, for a total of 20.1 10^9 m^3.

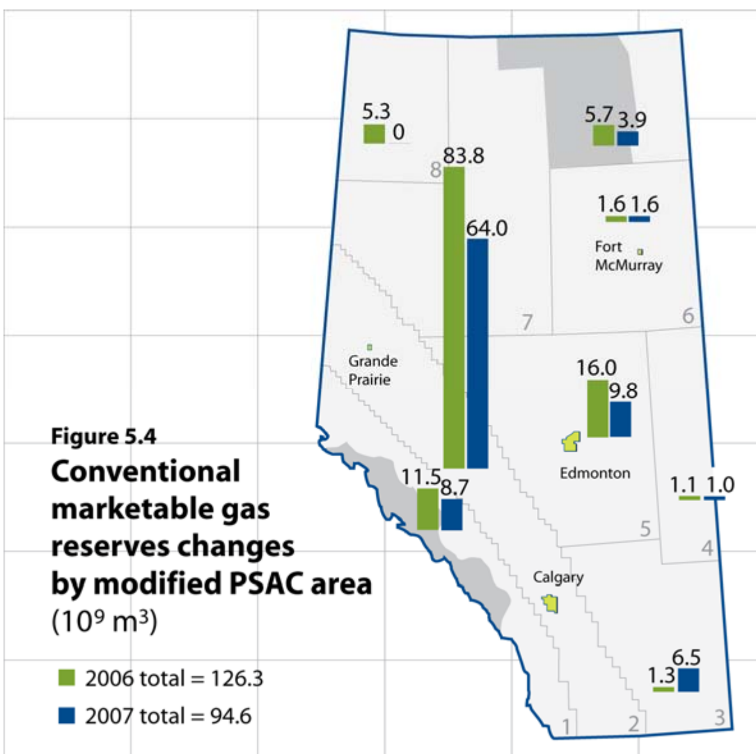


Figure 5.4
Conventional marketable gas reserves changes by modified PSAC area
(10^9 m^3)

Table 5.2. Major natural gas reserve changes, 2007

Pool	Initial established reserves (10^6 m^3) 2007	Change	Main reasons for change
Alderson Southeastern Alberta Gas System (MU)	61 964	+865	Reevaluation of initial volume in place
Ansell Belly River, Cardium, Viking & Mannville MU#1	23 687	+6 644	Development and reevaluation of initial volume in place
Bighorn Turner Valley B, G & I	1 373	+675	Reevaluation of initial volume in place
Bonnie Glen D3 A	7 814	-1 320	Reevaluation of initial volume in place
Cavalier Southeastern Alberta Gas System (MU)	3 023	+540	Reevaluation of initial volume in place
Cecilia Smokey, Dunvagen, Fort St. John & Bullhead MU#1	3 259	-1 396	Reevaluation of initial volume in place
Chinchaga Debolt – Detrital A	5 415	-665	Reevaluation of initial volume in place
Elmworth Smokey, Fort St. John, Bullhead & Triassic MU#1	46 156	+3 025	Reevaluation of initial volume in place
Entice Edmonton & Belly River MU#1	8 814	+3 559	Development and reevaluation of initial volume in place
Fir Dunvagen, Fort St. John & Bullhead MU#1	2 137	+1 227	Development and reevaluation of initial volume in place
Garrington Second White Specks, Mannville & Rundle MU#1	5 404	+855	Reevaluation of initial volume in place
Gold Creek Dunvagen, Fort St. John & Blairmore MU#1	4 700	+775	Addition of new pool, development and reevaluation of initial volume in place
Grand Rapids B, SS & F2F	808	+619	Reevaluation of initial volume in place
Harley Cardium A	36	-517	Reevaluation of initial volume in place
Harmattan Elkton Rundle B	1 883	+832	Reevaluation of initial volume in place
Harmattan Elkton Rundle C	20 959	-1 083	Reevaluation of initial volume in place
Hotchkiss Bluesky & Rundle MU#1	6 650	+570	Reevaluation of initial volume in place and recovery factor
Joarcam Viking	2 150	+608	Reevaluation of initial volume in place
Karr Dunvagen, Fort St. John & Bullhead MU#1	14 105	+1 632	Reevaluation of initial volume in place

(continued)

Table 5.2. Major natural gas reserve changes, 2007 (concluded)

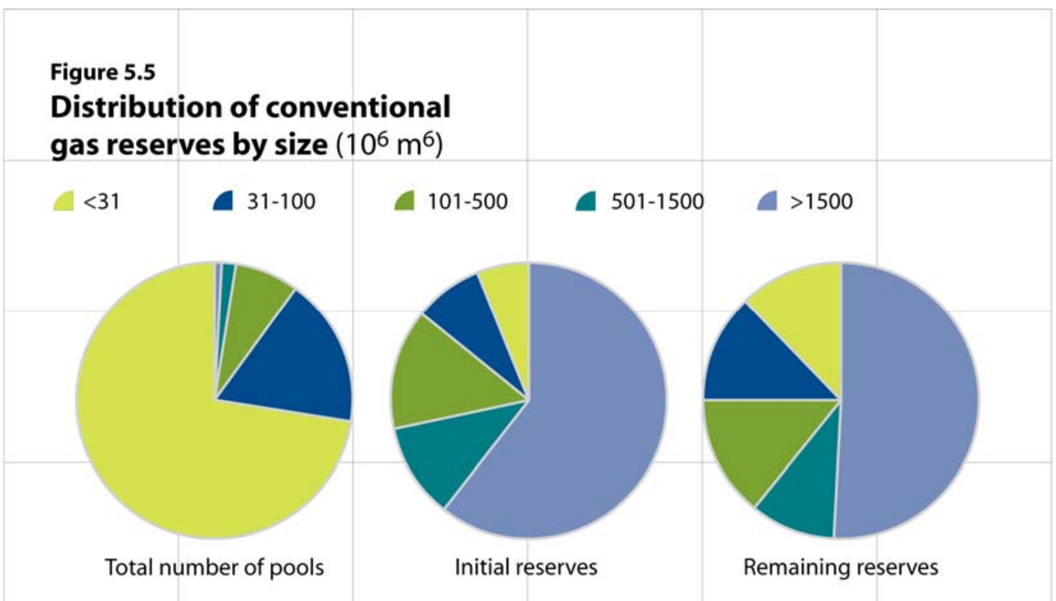
Pool	Initial established reserves (10^6 m^3) 2007	Change	Main reasons for change
Lookout Butte Rundle A	7 110	+714	Reevaluation of initial volume in place
Markerville Pekisko A	2 945	+589	Reevaluation of initial volume in place and recovery factor
Medicine Lodge Cardium, Viking & Mannville Mu#1	2 246	-576	Reevaluation of initial volume in place
Nevis Edmonton & Belly River MU#1	3 325	+662	Reevaluation of initial volume in place
Okotoks Wabamun B	6 908	-544	Reevaluation of initial volume in place
Pembina Belly River, Colorado, Mannville & Jurassic MU#1	11 312	+2 762	Reevaluation of initial volume in place and recovery factor
Saddle Hills Wabamun A	2 025	-624	Reevaluation of initial volume in place and recovery factor
Saxon Dunvagen B & Gething K	126	-530	Addition of new pool and reevaluation of initial volume in place
Sinclair Doe Creek, Fort St. John & Bullhead MU#1	12 631	+3 130	Reevaluation of initial volume in place
Sinclair Doig A	11 449	+2 836	Reevaluation of initial volume in place
Sousa Bluesky C	2 060	+530	Reevaluation of initial volume in place
Wapiti Cadotte, Notikewan & Falher MU#1	628	+604	Reevaluation of initial volume in place
Wapiti Fort St. John & Bullhead MU#1	6 465	+568	Reevaluation of initial volume in place
Wapiti Fort St. John, Bullhead & Nikanassin MU#1	21 804	-3 622	Reevaluation of initial volume in place
Wapiti Smokey, Dunvagen, Fort St. John & Bullhead MU#1	5 419	+1 090	Addition of new pools and reevaluation of initial volume in place
Waskahigan Dunvagen, Fort St. John & Bullhead MU#1	1 018	+853	Reevaluation of initial volume in place
Waterton Rundle- Wabamun A	55 836	+ 2 317	Reevaluation of initial volume in place
Wayne-Rosedale Viking U & Lower Mannville MU#1	8 657	+557	Reevaluation of initial volume in place
Wembley Halfway B	1 598	-2 535	Reevaluation of initial volume in place
Wild River Smoky, Fort St. John, Bullhead & Jurassic MU #2	31 703	+1 680	Reevaluation of initial volume in place

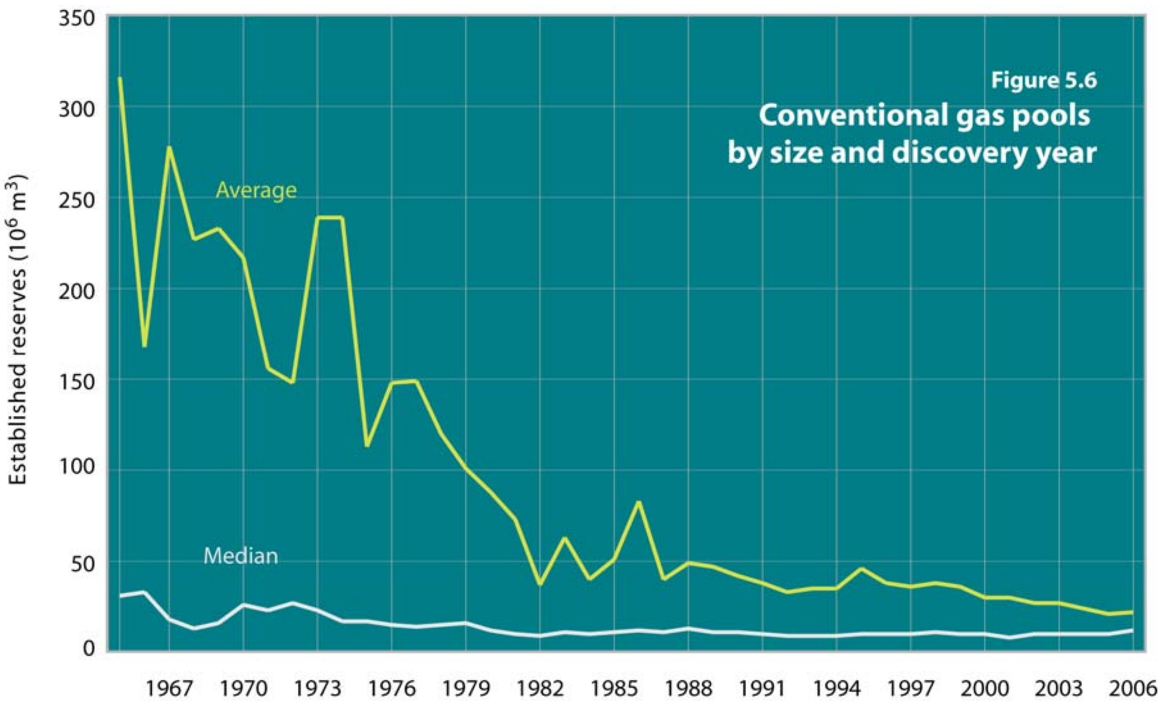
5.1.3 Distribution of Natural Gas Reserves by Pool Size

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 72.5 per cent of all pools, contain only 12 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 51 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 16 10^6 m^3 for many years, while the average size declined from about 300 10^6 m^3 in 1965 to 45 10^6 m^3 in 1996 and has continued to decline to about 22 10^6 m^3 in 2007.

Table 5.3. Distribution of natural gas reserves by pool size, 2007

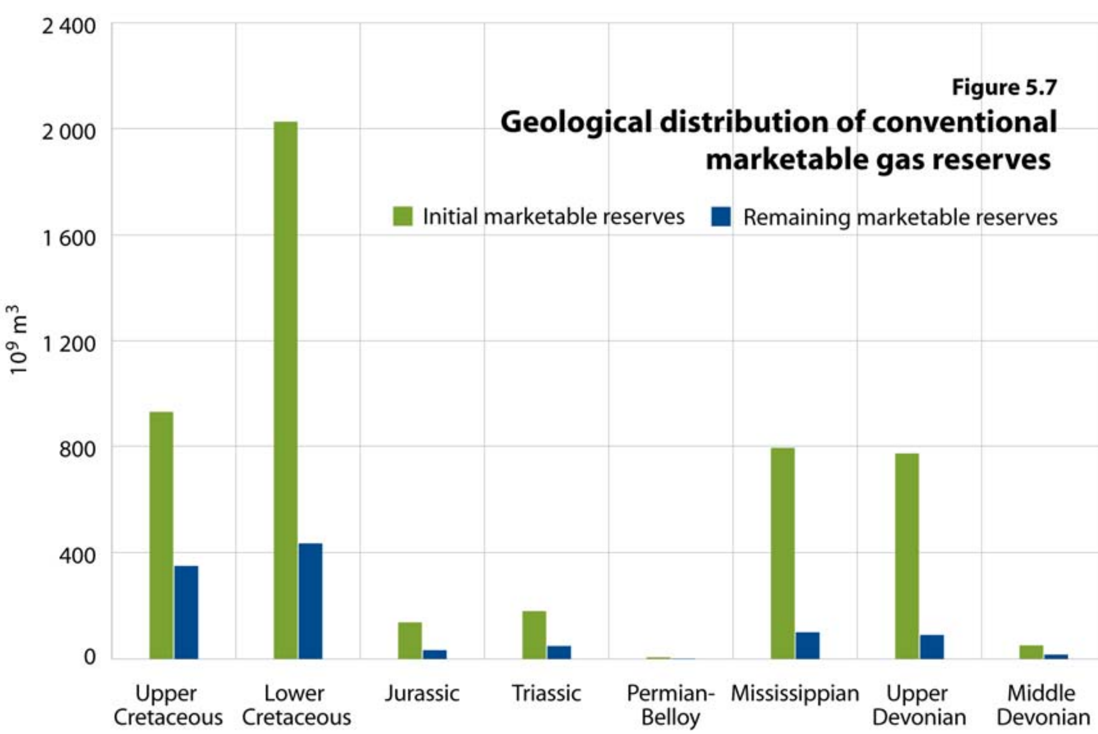
Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
3000+	209	0.5	2 594	53	476	45
1501-3000	161	0.4	338	7	69	6
1001-1500	174	0.4	213	4	41	4
501-1000	526	1.2	360	8	62	6
101-500	3 344	7.6	690	14	152	14
31-100	7 724	17.5	409	8	140	13
Less than 31	32 000	72.4	289	6	129	12
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**, and a detailed breakdown of gas in place and marketable gas reserves by formation is given in Appendix B, **Table B.9**. The Upper and Lower Cretaceous period accounts for some 73.2 per cent, an increase of 2.7 per cent over last year, 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 18.6 per cent, and the Mississippian Rundle, with 6.5 per cent. Together, these strata contain 54.1 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, 2007, sour gas accounts for some 20 per cent (216 10^9 m^3) of the province's total remaining established reserves and about 25 per cent of natural gas marketed in 2007. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2007 is 8.8 per cent.

The distribution of reserves for sweet and sour gas (**Table 5.4**) shows that 160 10^9 m^3, or about 74 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 49 10^9 m^3, or 23 per cent, of sour gas contains H_2S concentrations greater than 10 per cent, while 47 per cent (103 10^9 m^3) contains concentration of less than 2 per cent.

Table 5.4. Distribution of sweet and sour gas reserves, 2007

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	Initial established reserves	Cumulative production	Remaining established reserves	Initial established reserves	Remaining established reserves
Sweet					
Associated & solution	581	467	113	12	11
Nonassociated	2 696	1 955	740	55	69
Subtotal	3 277	2 424	853	67	80
Sour					
Associated & solution	472	416	56	10	5
Nonassociated	1 144	984	160	23	15
Subtotal	1 616	1 400	216	33	20
Total	4 893 (172)[b]	3 824 (136)[b]	1 069[a] (38.0)[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.

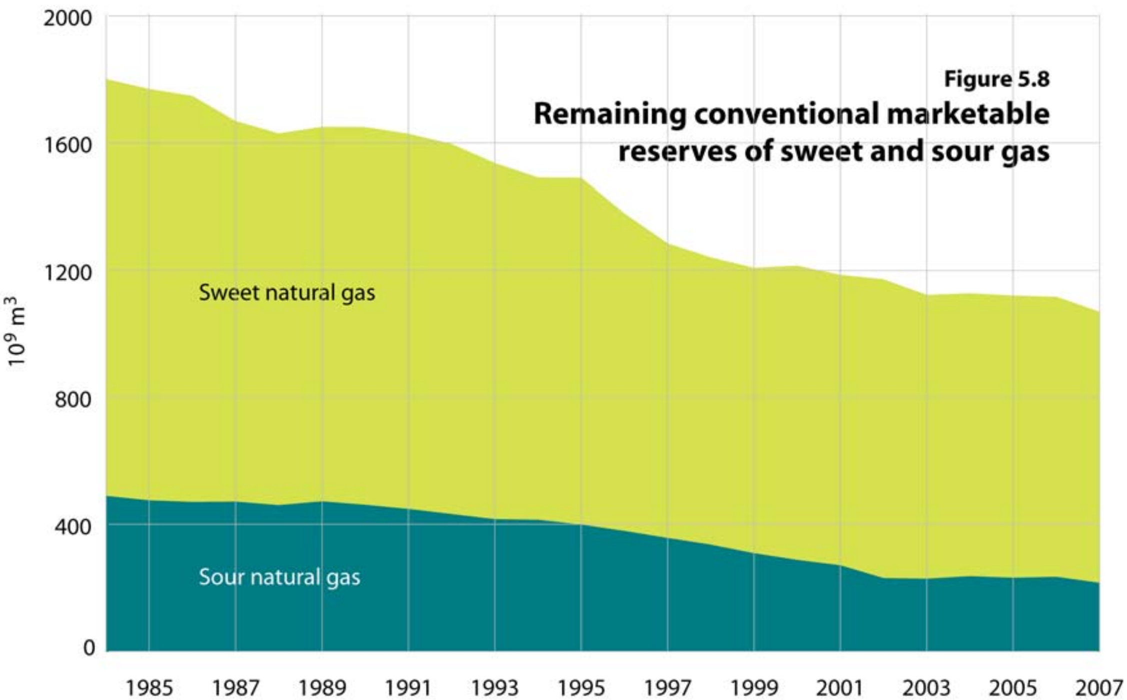


Table 5.5. Distribution of sour gas reserves by H_2S content, 2007

H_2S content in raw gas	Initial established reserves (10^9 m^3) Associated & solution	Nonassociated	Remaining established reserves (10^9 m^3) Associated & solution	Nonassociated	Total	%
Less than 2	345	393	43	60	103	47
2.00-9.99	88	390	8	56	64	30
10.00-19.99	29	208	4	24	28	13
20.00-29.99	11	50	1	9	10	5
Over 30	0	102	0	11	11	5
Total	473	1 143	56	160	216	100
Percentage	29	71	26	74		

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 23.5 10^9 m^3 (2.2 per cent) of remaining established reserves. The four largest pools are Caroline Beaverhill Lake A, Harmattan East Lower Mannville and Rundle, Valhalla Halfway B, and Waterton Rundle-Wabamun A, which together account for 61.2 per cent of all remaining reserves of gas cycling pools. Reserves of major gas cycling pools are tabulated on both energy content and a volumetric basis. 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.10**. 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).

5.1.7 Reserves and Accounting Methodology for Gas

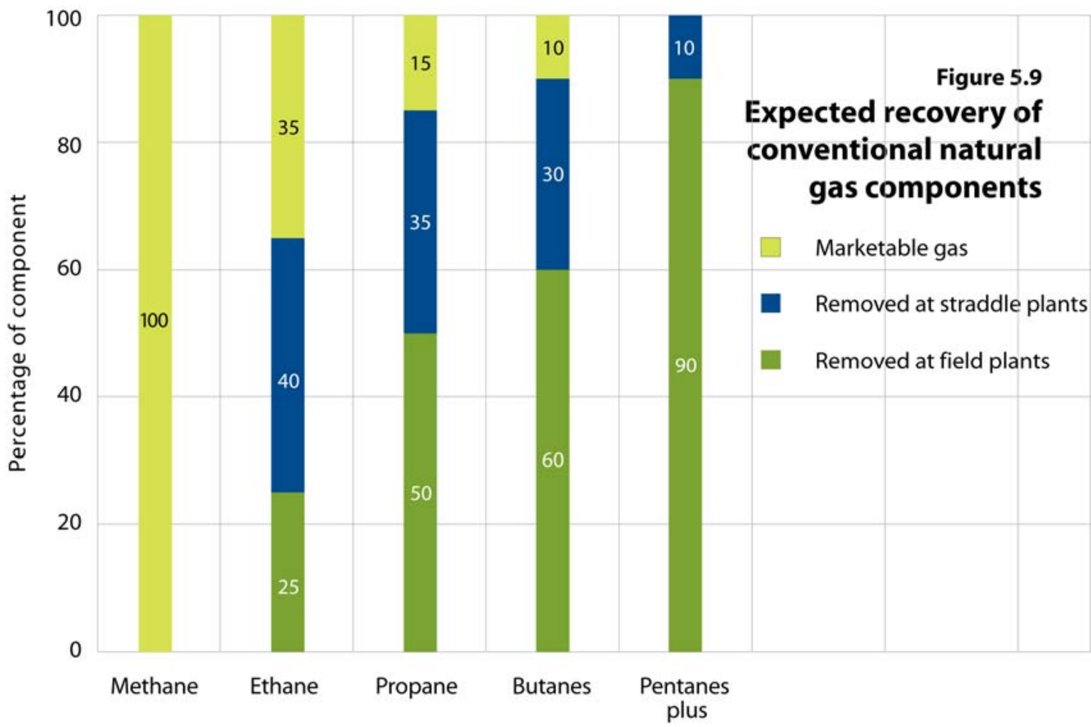
A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools is on CD (see Appendix C) and available from ERCB Information Services.

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 volumetrics, 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 based on the ERCB 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 "tight" formations (less than 1 millidarcy permeability) or geological structures limited in areal extent.

Converting 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 50 to 90 per cent. However, so-called unconventional tight gas reservoirs may only recover 30 per cent or less of the in-place volume.

Once there are sufficient production and pressure data, material balance methods can be used as an alternative to volumetrics to estimate in-place resources. Material balance (P/Z decline) is most accurate when applied to good-quality nonassociated noncommingled gas pools. Analysis of production decline is a primary method for determining recoverable reserves, especially given the mature state of Alberta's conventional gas resources. When combined with an estimate of the in-place resource, it also provides a practical real-life estimation of the pool's recovery efficiency.

The procedures described above generate an estimate for initial established reserves of the raw commodity. 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 recoverable reserves and recovery factor based on the most reasonable interpretation of available information from volumetric estimates, production decline, and material balance.



For about 80 per cent of Alberta's marketable gas (notable exceptions being Alliance Pipeline and some of the mostly dry Southeastern Alberta gas), additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. As the removal of these liquids cannot be tracked back to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These reserves therefore represent the volume and average heating content of gas available for sale after removal of liquids from both field and straddle plants.

It is expected that some 33.5 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 1069.0 10^9 m^3 to 1035.5 10^9 m^3 and the thermal energy content from 41.6 to 38.6 exajoules.

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.11**. 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 (223 Tcf). This estimate does not include unconventional gas, such as coalbed methane (CBM). **Figure 5.10** shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth to 2007 equals 5.0 trillion (10^{12}) m^3. **Figure 5.11** plots production and remaining established reserves of marketable gas compared to the estimate of ultimate potential.

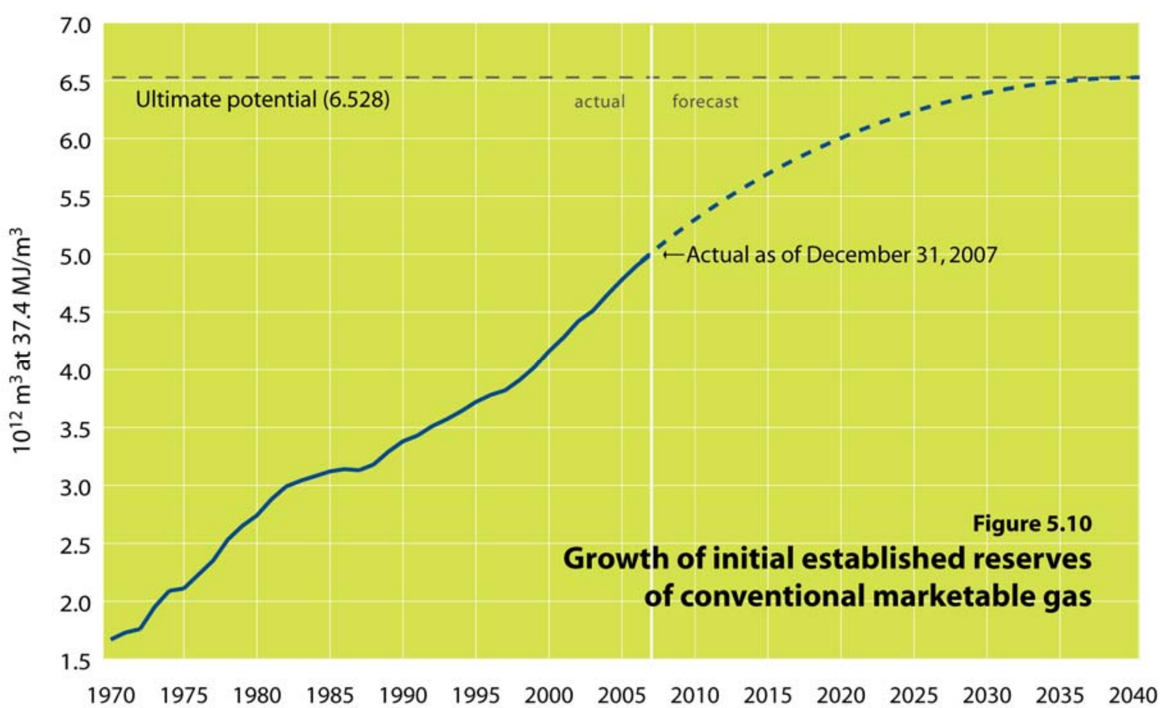


Figure 5.10
Growth of initial established reserves of conventional marketable gas

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 4893 10^9 m^3, or 77.9 per cent of the ultimate potential of 6276 10^9 m^3 (as-is volumes) has been discovered as of year-end 2007. This leaves 1383 10^9 m^3, or 22.0 per cent, as yet-to-be-discovered reserves. Cumulative production of 3824 10^9 m^3 at year-end 2007 represents 60.9 per cent of the ultimate potential, leaving 2452 10^9 m^3, or 39.1 per cent, available for future use.

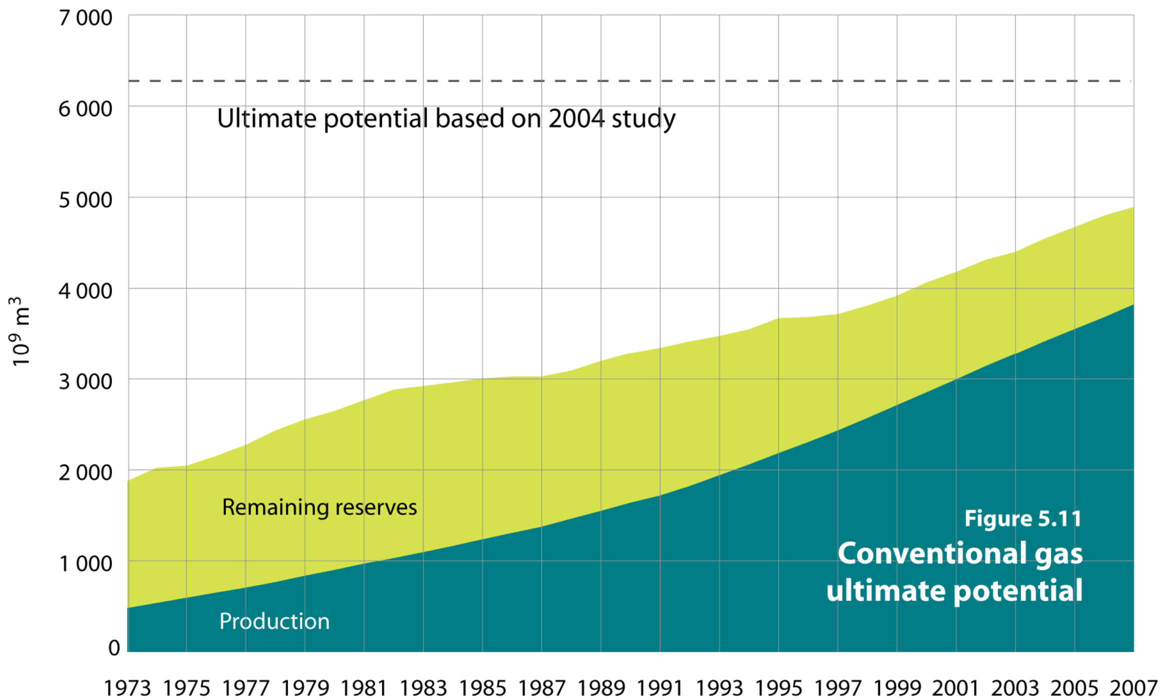


Figure 5.11
Conventional gas ultimate potential

Table 5.6. Remaining ultimate potential of marketable gas, 2007 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	**@ 37.4 MJ/m^3**
Yet to be established		
Ultimate potential	6 276	6 528
Minus initial established	-4 893	-5 090
	1 383	1 438
Remaining established		
Initial established	4 893	5 089
Minus cumulative production	-3 824	-3 978
	1 069	1 111
Remaining ultimate potential		
Yet to be established	1 383	1 437
Plus remaining established	+1 069	+1 111
	2 452	2 546

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 40.6 per cent of the remaining established reserves and 29.7 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.

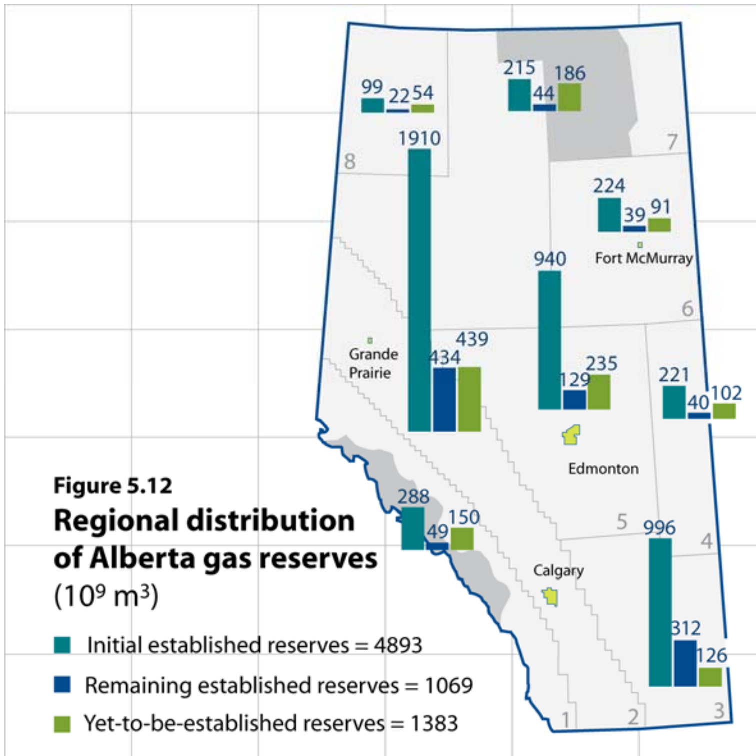


Figure 5.12
Regional distribution of Alberta gas reserves
(10^9 m^3)

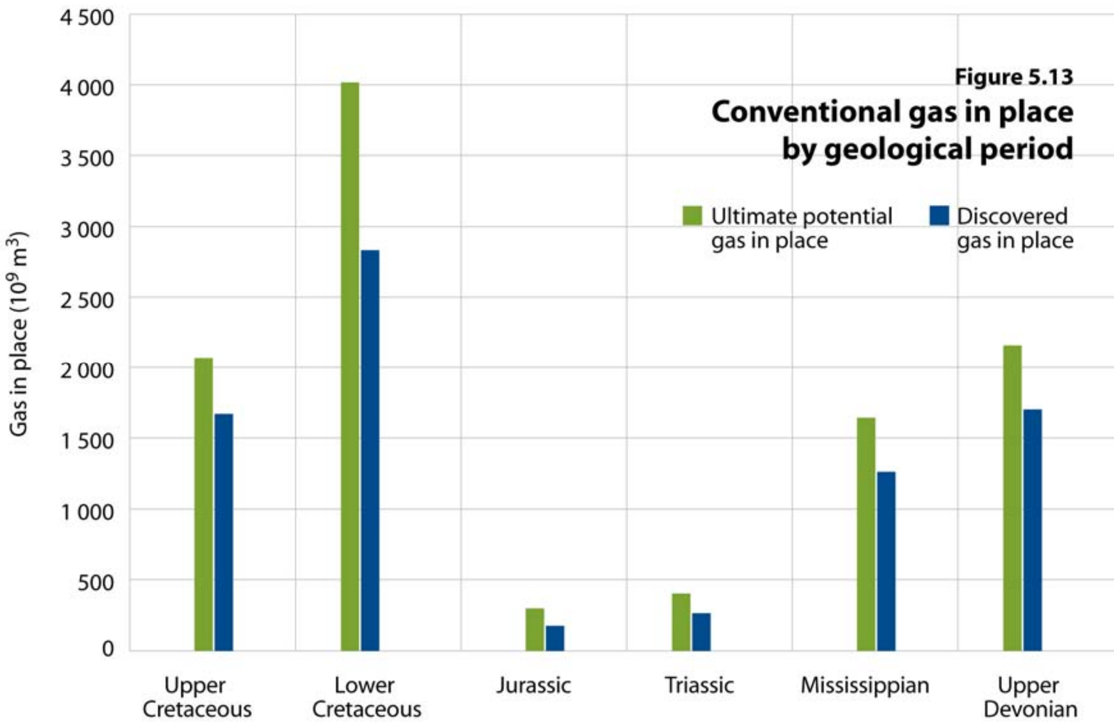


Figure 5.13
Conventional gas in place by geological period

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 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 reviews the projected demand for Alberta natural gas annually. 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 133.7 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its conventional gas and oil wells in 2007, a decrease of 4.0 per cent from last year. As noted in Section 4, Alberta also produced 6.8 10^9 m^3 of CBM. The CBM volume includes some production of conventional gas, as the coals are often interbedded with conventional gas reservoirs. CBM production increased by 36 per cent in 2007 over 2006 levels of 5.0 10^9 m^3. Overall, total natural gas production decreased to 140.5 10^9 m^3 in 2007, or 2.4 per cent, compared to 143.9 10^9 m^3 in 2006.

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 2007, factors such as the higher value of the Canadian dollar, the lower than expected price of natural gas, and higher drilling and development costs resulted in lower production and well connections in 2007 than expected.

Natural gas prices in Alberta averaged $5.88 per gigajoule (GJ), reaching a low of $4.42/GJ in September. Growth in U.S. domestic gas production, record high liquefied natural gas (LNG) imports to the U.S., and U.S. storage volumes that exceeded their 5-year average throughout the year are responsible for lower natural gas prices in North America. Drilling activity in Alberta declined by 24 per cent from the previous year as a result of lower natural gas prices and some investment being diverted to oil sands development.

Gas supply in Alberta was also impacted by the ongoing high decline rate of production from existing gas wells and lower initial productivities of new gas wells. Also, the drilling focus in recent years has been heavily weighted towards the shallow gas plays of Southeastern Alberta. This region has seen an increasing percentage of natural gas wells over the last 10 years due to the lower risk, lower cost of drilling, and quick tie-in times.

The conventional marketable natural gas production volumes for 2007 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 natural gas volumes (10^9 m^3)

Marketable gas production	2007
Total gas production	165 594.7
Minus CBM production	-6 834.0
Total conventional gas production	158 760.7
Minus storage withdrawals	-5 625.9
Raw gas production	153 134.8
Minus injection total	-8 005.6
Net raw gas production	145 129.2
Minus processing shrinkage – raw	-9 299.2
Minus flared – raw	-550.8
Minus vented – raw	-400.5
Minus fuel – raw	-12 003.6
Plus storage injections	5 655.1
Calculated marketable gas production at as-is conditions	128 530.2
Calculated marketable gas production @ 37.4 MJ/m^3	133 671.4

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 2007, some 9220 conventional natural gas wells were drilled in the province, a decrease of 24 per cent from 2006 levels. A large portion of gas drilling continues to take place in Southeastern Alberta, representing 54 per cent of all conventional natural gas wells drilled in 2007. The natural gas price declines that took place in late 2006 and 2007 are responsible for the slowdown in gas drilling, which is expected to continue well into 2008.

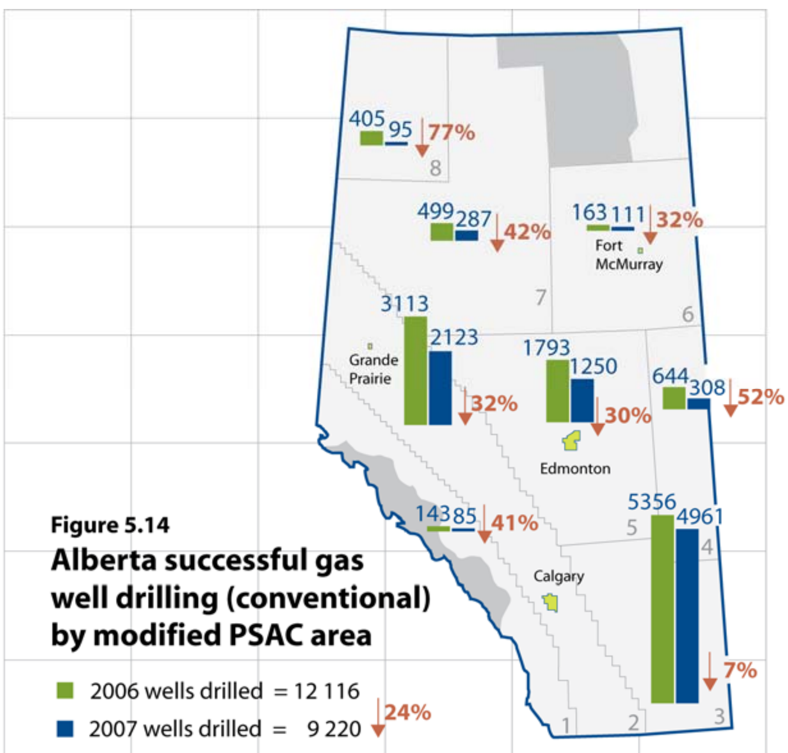
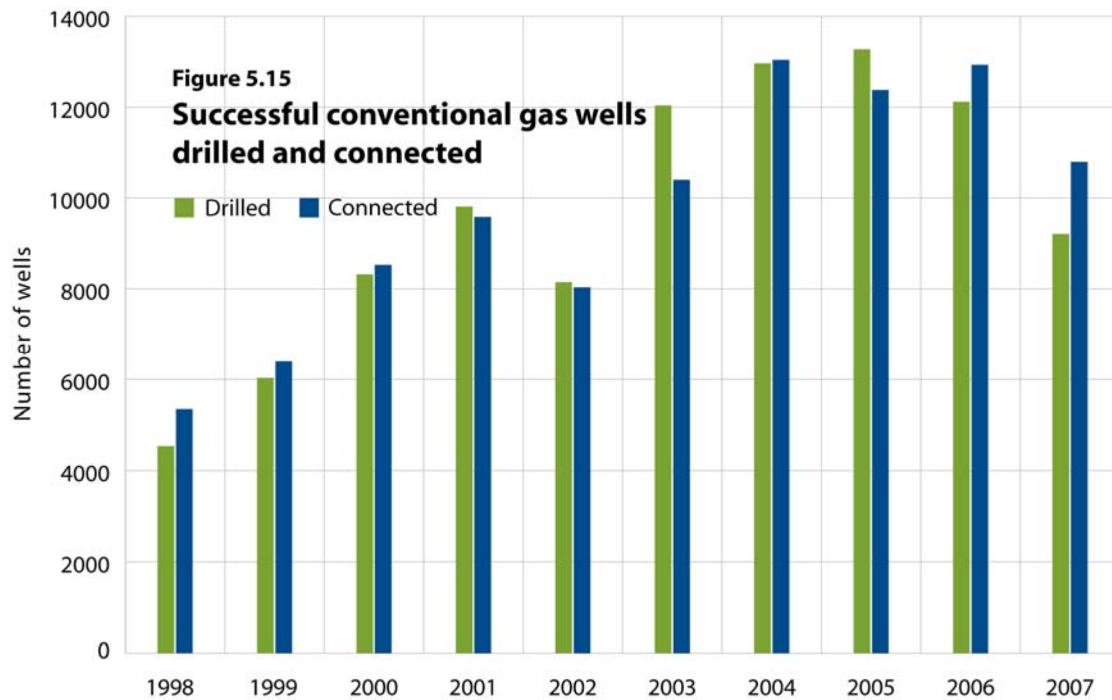


Figure 5.14
Alberta successful gas well drilling (conventional) by modified PSAC area

Drilling levels were down in all areas of the province, with Area 3 (Southeastern Alberta) 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 2007 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.



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 2006 and 2007 the number of new well connections was greater than the number of gas wells drilled. This was due to the time delay in bringing gas wells drilled in the previous year on production. As well, drilling activity levels fell in 2007 to levels last seen in 2002. This trend is likely to reverse in 2008 as the inventory of drilled wells not yet placed on production diminishes. The distribution of natural gas well connections and the initial operating day rates of the connected wells in 2007 are illustrated in **Figures 5.16** and **5.17** respectively.

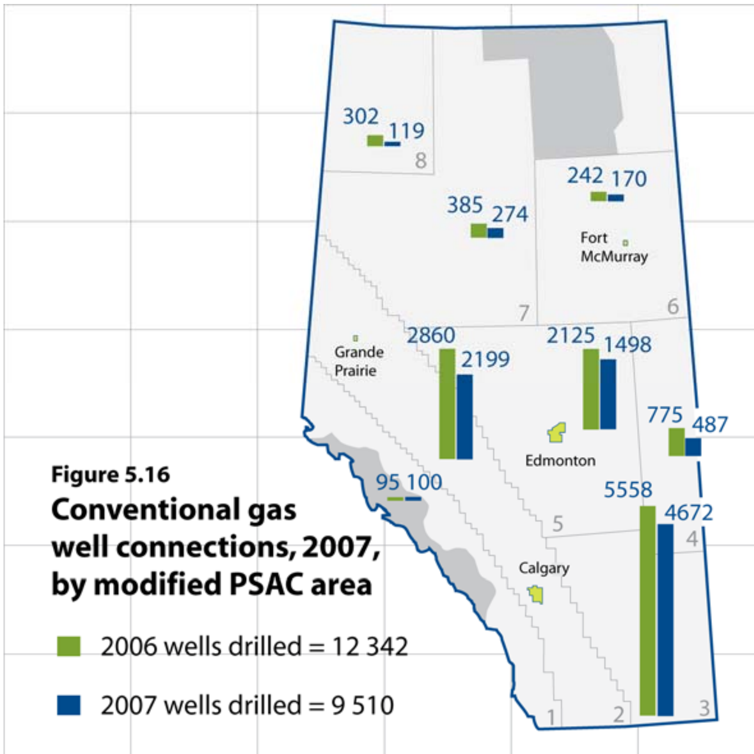


Figure 5.16

Conventional gas well connections, 2007, by modified PSAC area

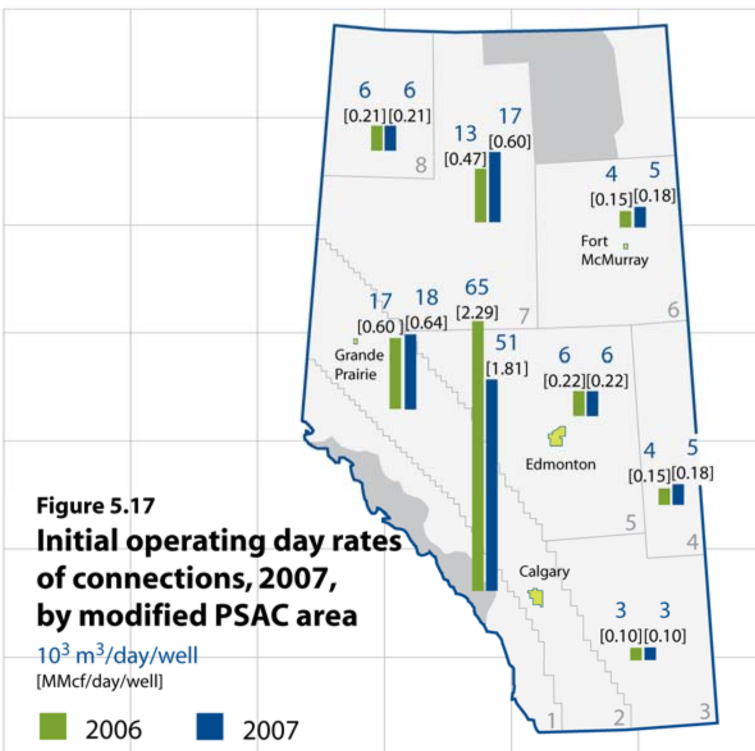
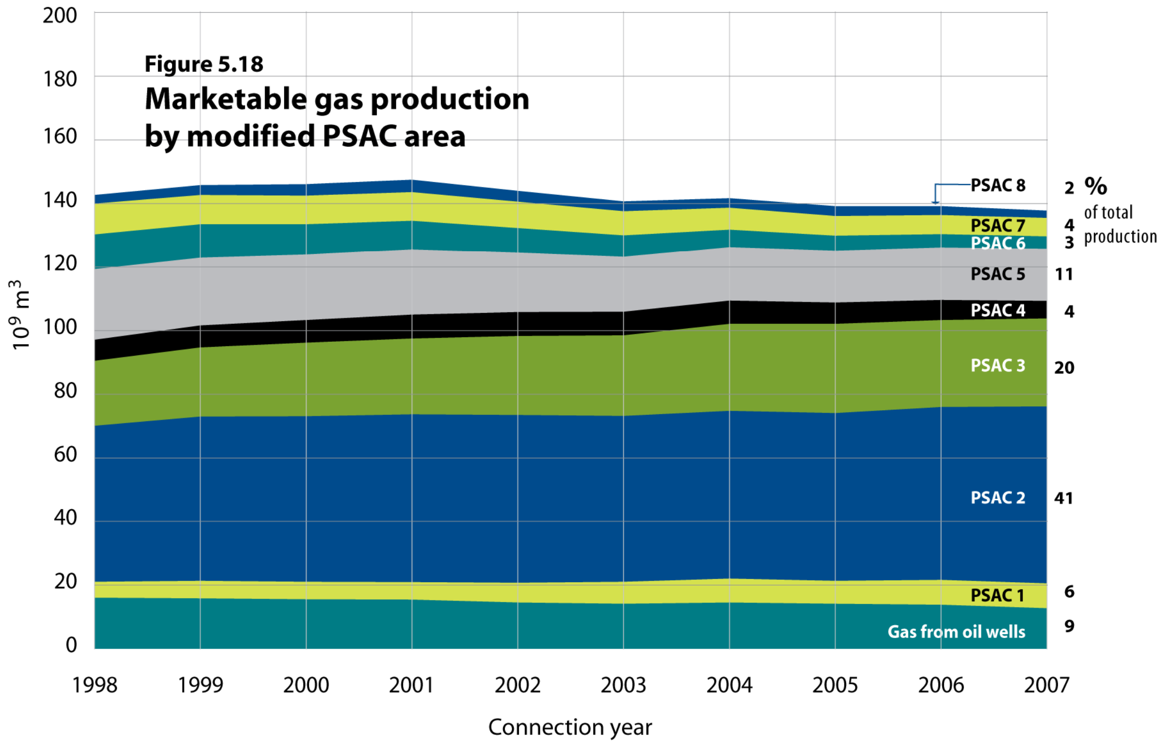


Figure 5.17

Initial operating day rates of connections, 2007, by modified PSAC area

Figure 5.18 illustrates historical gas production from gas wells by geographical area. All areas of the province experienced decreases in production in 2007.



Conventional marketable gas production in Alberta from 1990 to 2007 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 is decreasing, after reaching its peak in 2001. By 2007, the total number of producing gas wells increased to 114 094, 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. **Figures 5.20** and **5.21** illustrate the number of producing gas wells and average well productivity by area respectively.

Average gas well productivity has been declining over time. As shown in **Figure 5.22**, about 67 per cent of the operating gas wells produce less than 2 thousand (10^3) m^3/d. In 2007, these 82 600 gas wells operated at an average rate of 0.8 10^3 m^3/d per well and produced less than 14 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 5.23**. 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 2007. For example, 10 per cent of gas production in 2007 came from wells connected in that year. The figure shows that in 2007, 53 per cent of gas production came from gas wells connected in the last five years.

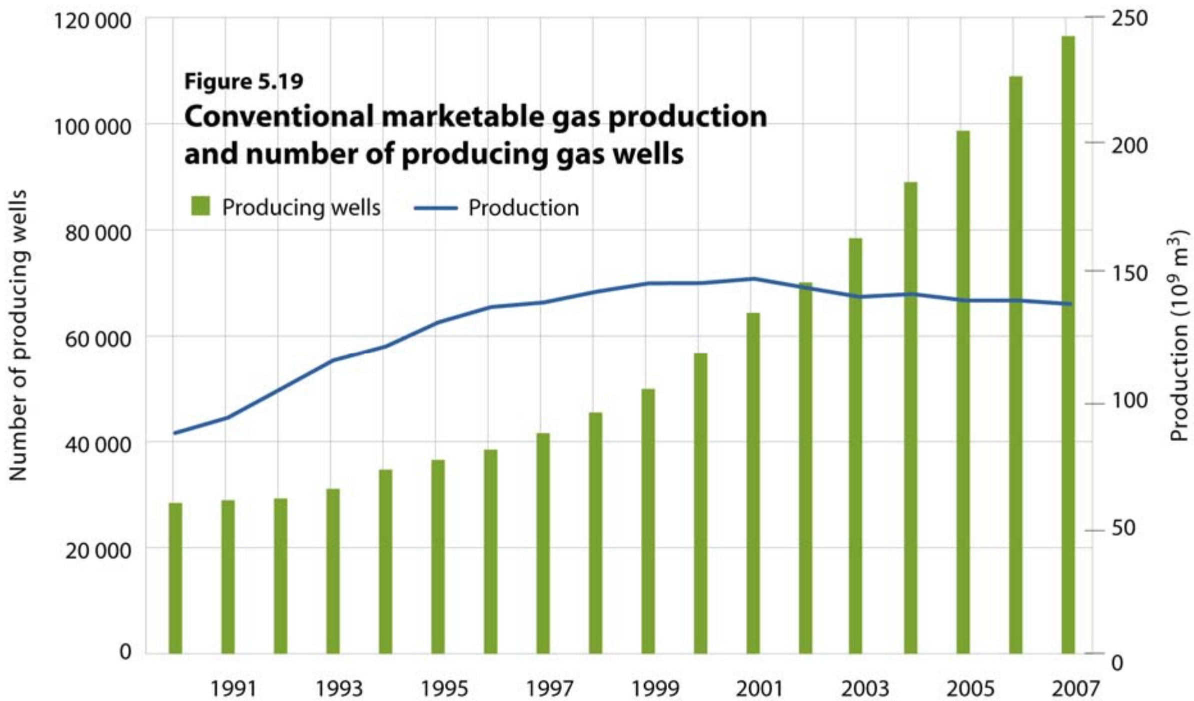


Figure 5.19
Conventional marketable gas production and number of producing gas wells
Producing wells
Production
Number of producing wells
Production (10⁹ m³)
120 000
100 000
80 000
60 000
40 000
20 000
0
250
200
150
100
50
0
1991
1993
1995
1997
1999
2001
2003
2005
2007

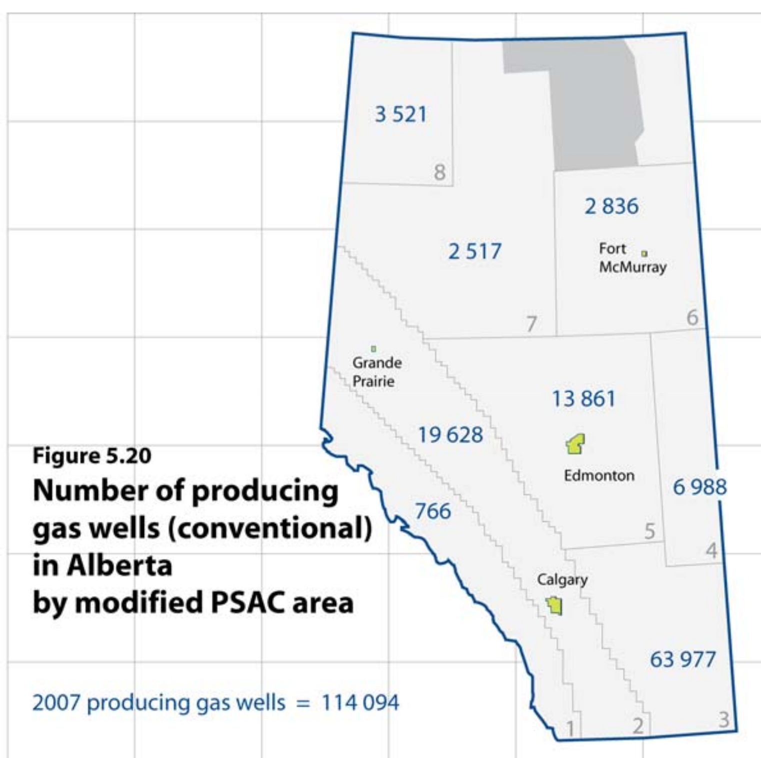


Figure 5.20
Number of producing gas wells (conventional) in Alberta by modified PSAC area
3 521
8
2 836
2 517
Fort McMurray
7
6
Grande Prairie
13 861
19 628
Edmonton
6 988
766
5
4
Calgary
63 977
2007 producing gas wells = 114 094
1
2
3

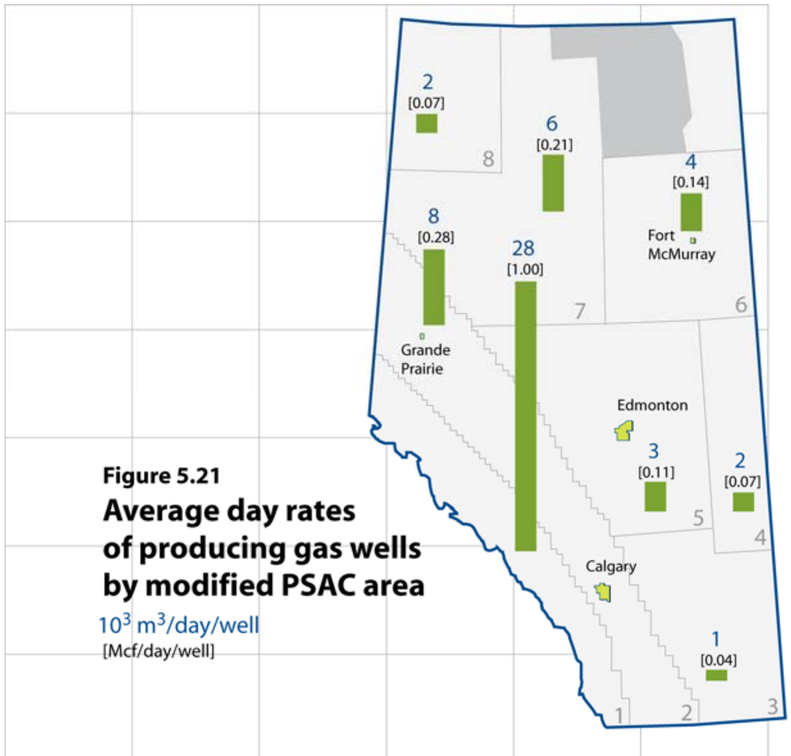


Figure 5.21
Average day rates of producing gas wells by modified PSAC area
10³ m³/day/well
[Mcf/day/well]
2
[0.07]
6
[0.21]
4
[0.14]
8
[0.28]
28
[1.00]
3
[0.11]
2
[0.07]
1
[0.04]
Fort McMurray
Grande Prairie
Edmonton
Calgary
1
2
3
4
5
6
7
8

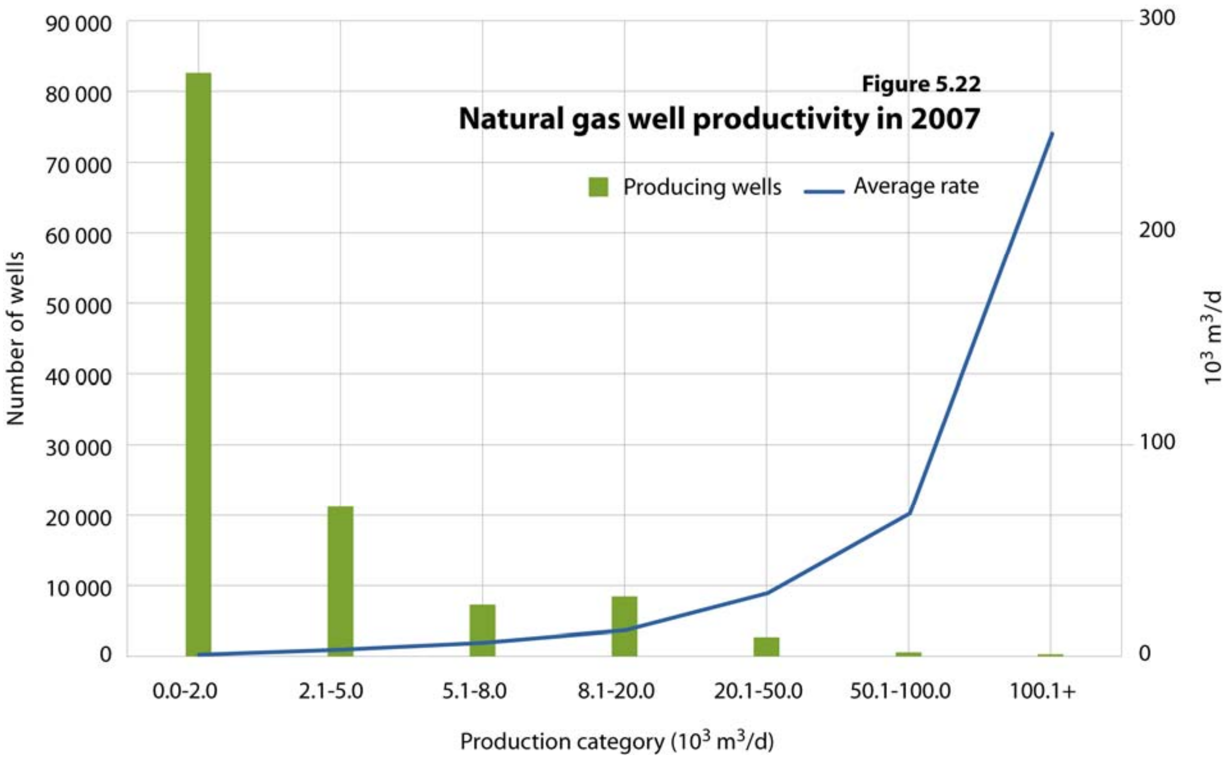


Figure 5.22
Natural gas well productivity in 2007
Producing wells
Average rate
Number of wells
90 000
80 000
70 000
60 000
50 000
40 000
30 000
20 000
10 000
0
300
200
100
0
10³ m³/d
0.0-2.0
2.1-5.0
5.1-8.0
8.1-20.0
20.1-50.0
50.1-100.0
100.1+
Production category (10³ m³/d)

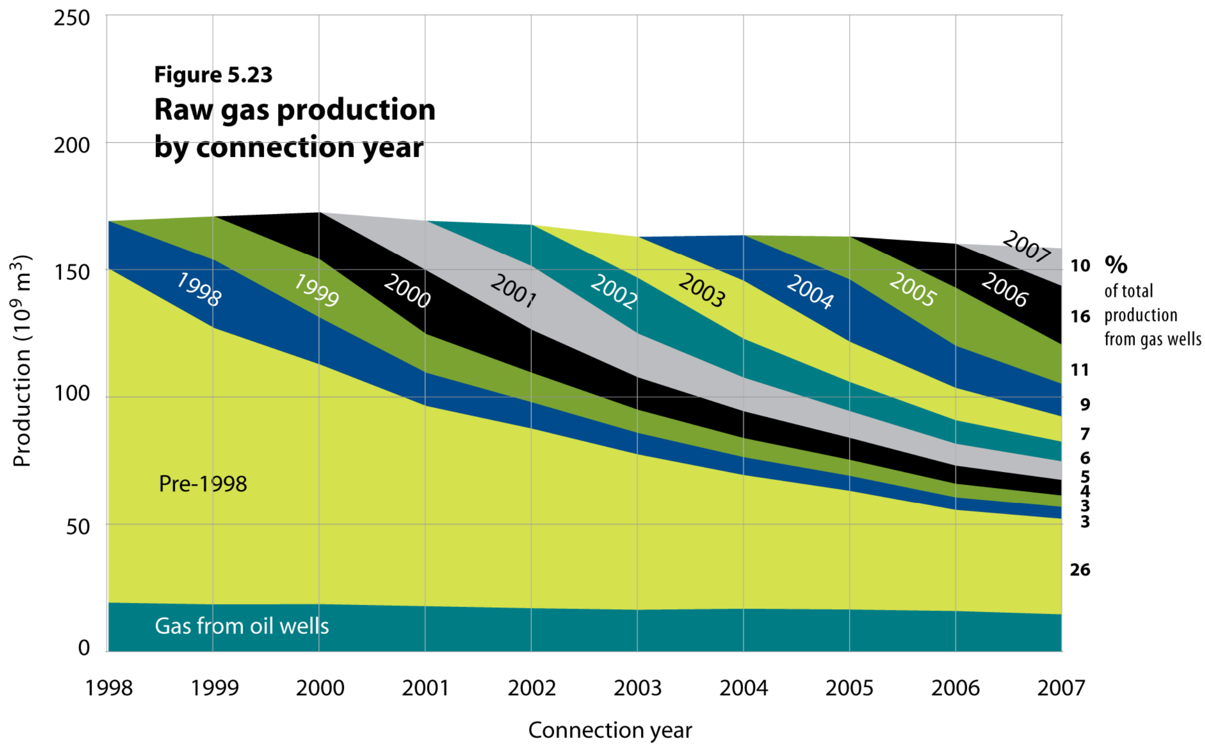


Figure 5.24 indicates the proportion of sweet versus sour gas production in the province since 1998. The percentage of sour gas relative to total gas production is decreasing, from 30 per cent in 1998 to 25 per cent in 2007.

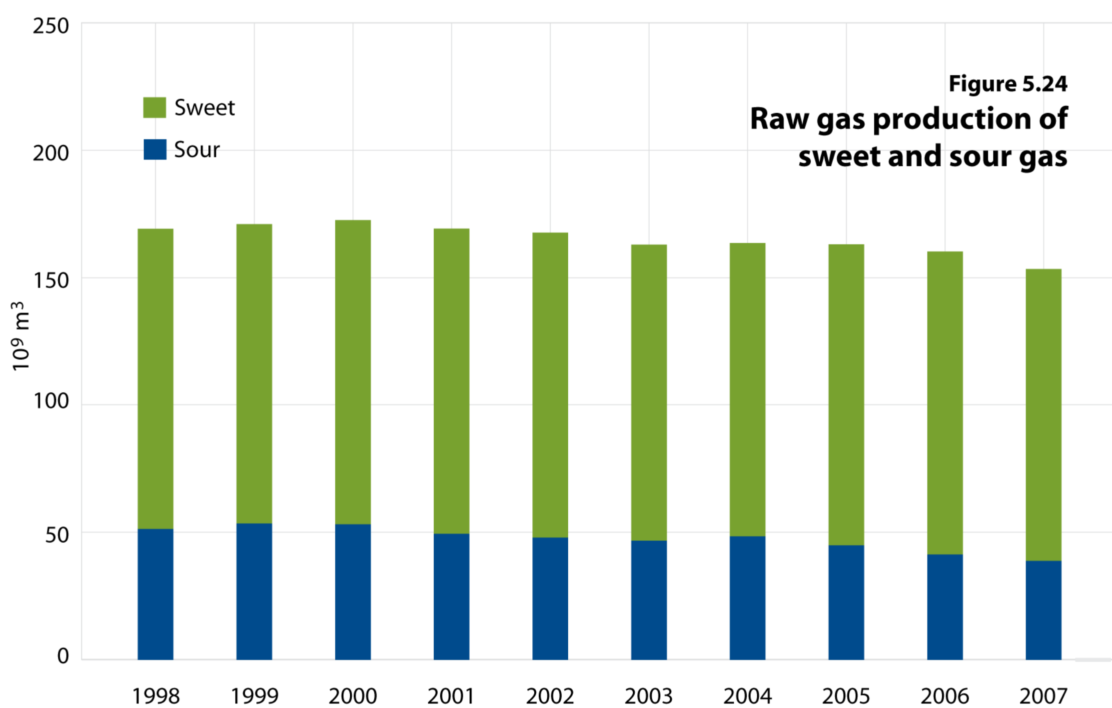


Figure 5.25 presents a comparison of raw natural gas production in Alberta to both Texas and Louisiana onshore, as well as total U.S. gas production over the past 40 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta appears to be at that stage today. 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.

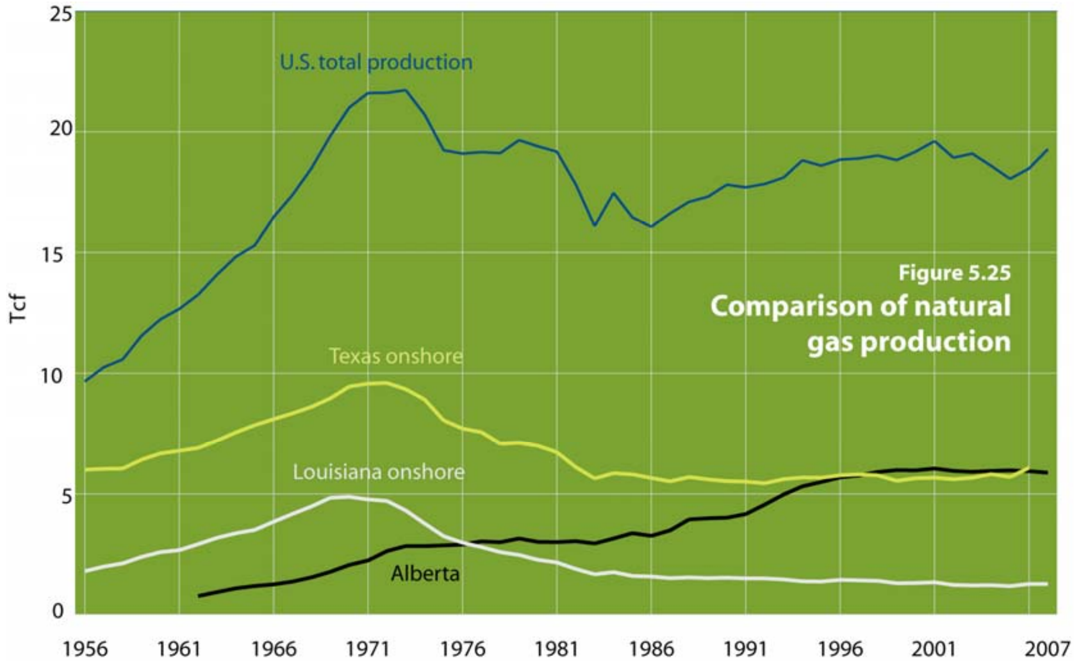


Figure 5.25
Comparison of natural gas production

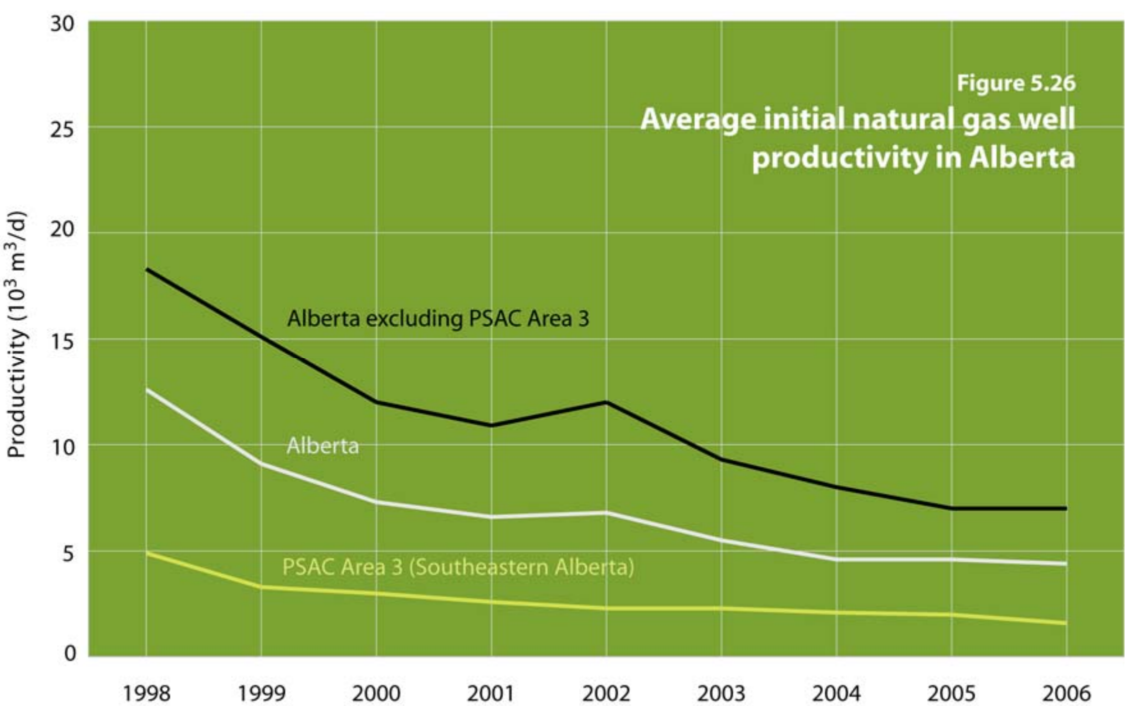
U.S. gas production as a whole reached peak production in 1973 at 21.7 Tcf. By 1986 gas production had declined to 16.1 Tcf. However, since then gas production has increased and in 2007 reached 19.3 Tcf, an increase of 4 per cent over 2006 levels. Several factors are responsible for this increase in production over the last 20 years, including the production of gas from unconventional sources. Alberta production is also influenced by unconventional production from sources such as CBM and shale gas.

Table 5.8 shows decline rates for gas wells connected from 1996 to 2005 with respect to the first, second, third, and fourth year of decline. Wells connected from the mid-1990s forward exhibit steeper declines in production in the first three years compared to wells connected in years earlier than 1995. However, by the fourth year of production the decline rates stabilize at about 18 per cent.

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

Year wells connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1996	32	26	21	19
1997	32	25	24	18
1998	32	29	21	19
1999	34	24	21	17
2000	33	24	17	18
2001	31	23	21	18
2002	30	25	19	16
2003	31	19	22	
2004	32	22		
2005	32			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 5.26** 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. This chart shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average.



Based on the projection of natural gas prices provided in Section 1.2 and current estimates of reserves and drilling activity, the ERCB expects that the number of new gas well connections in the province will be 9800 in 2008. This is a 3 per cent increase from the number of well connections in 2007. For 2009, well connections are expected to increase to 11 000 and then 12 500 per year for each year to 2017. Drilling activity in the southeastern part of 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 within the province. **Figure 5.27** illustrates historical and forecast new well connections and plant gate prices.

In projecting natural gas production, the ERCB considered three components: expected production from existing gas wells, expected production from new gas well connections, and gas production from oil wells.

Based on observed performance, gas production from existing gas wells at year-end 2007 is assumed to decline by 18 per cent per year initially and move to 16 per cent by the second half of 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 7.0 10^3 m^3/d in 2008 and will decrease to 5.0 10^3 m^3/d by 2017.
- Production from new wells will decline at a rate of 32 per cent the first year, 22 per cent the second year, 21 per cent the third year, and 17 per cent the fourth year and thereafter.
- Gas production from oil wells will decline by 3 per cent per year.

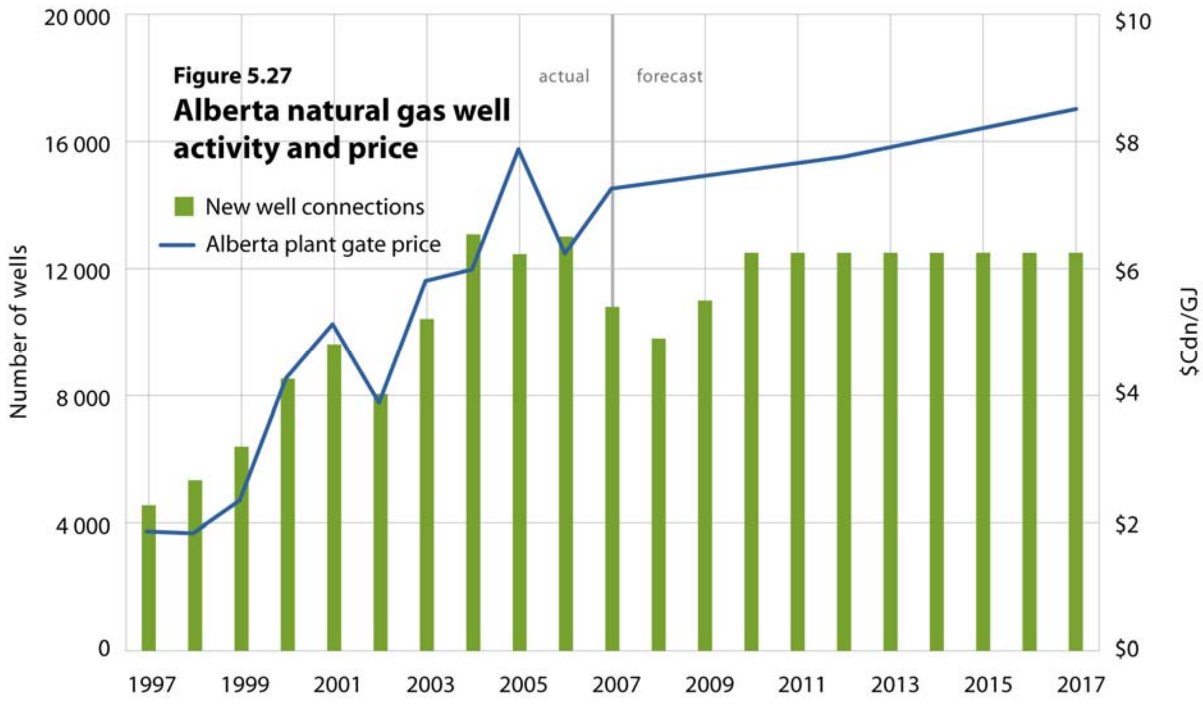
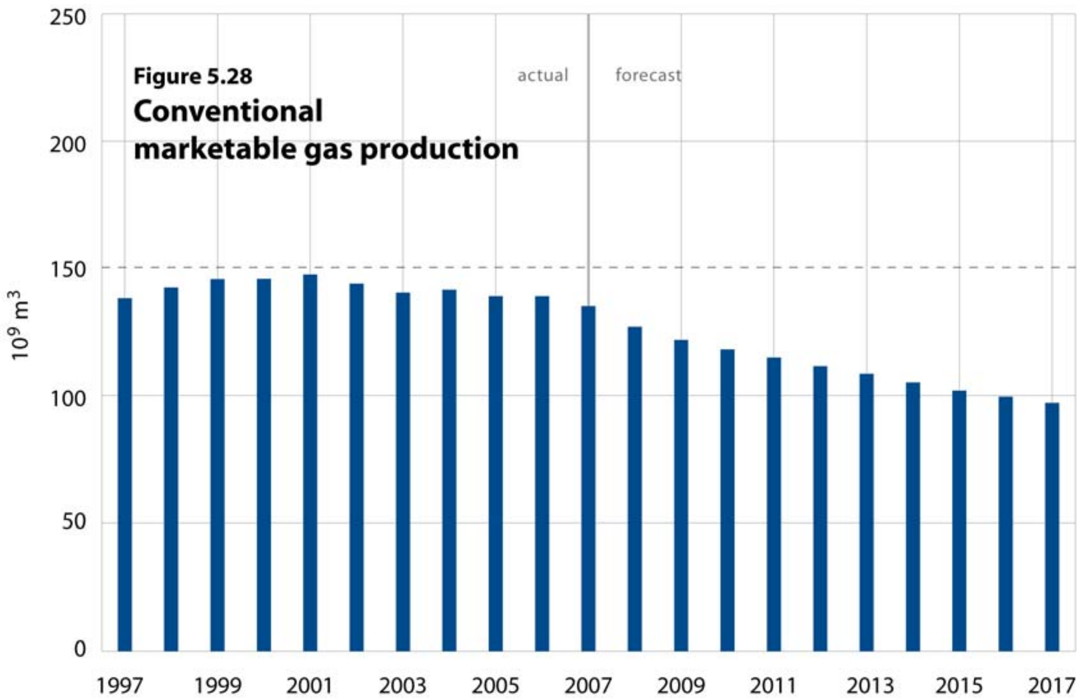
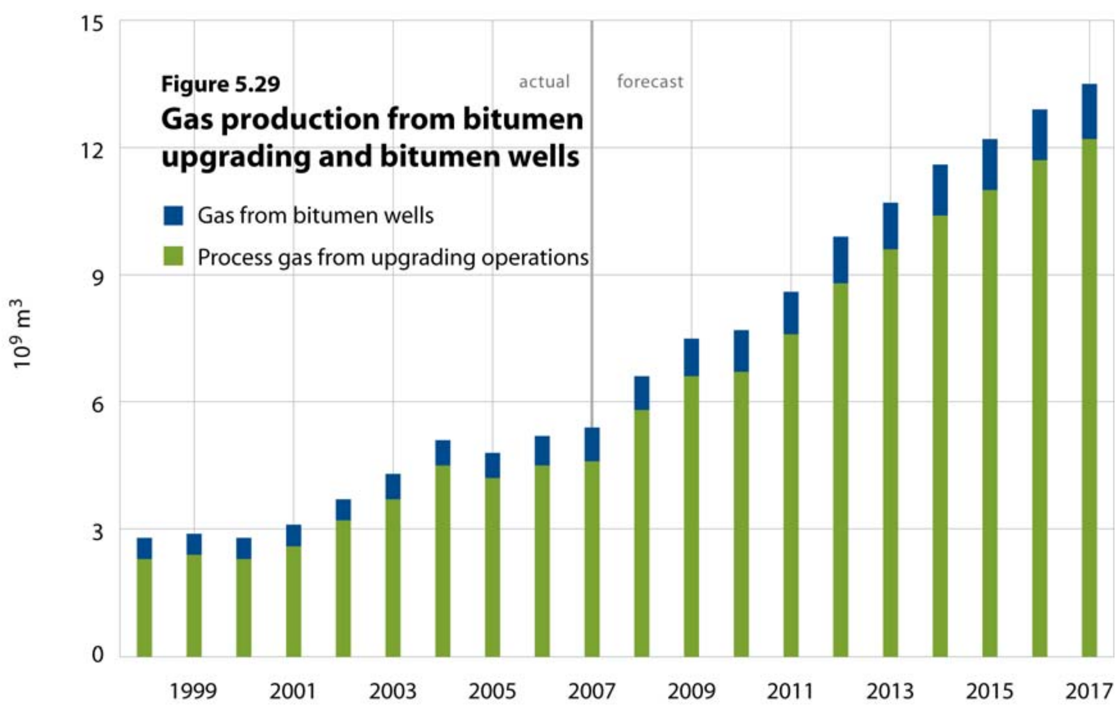


Figure 5.27
Alberta natural gas well activity and price

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 2017, as shown in **Figure 5.28**. The production of natural gas from conventional reserves is expected to decrease from 133.7 10^9 m^3 in 2007 to 97.0 10^9 m^3 by the end of the forecast period. If conventional natural gas production rates follow the projection, Alberta will have recovered 76 per cent of the 6276 10^9 m^3 ultimate potential by 2017.

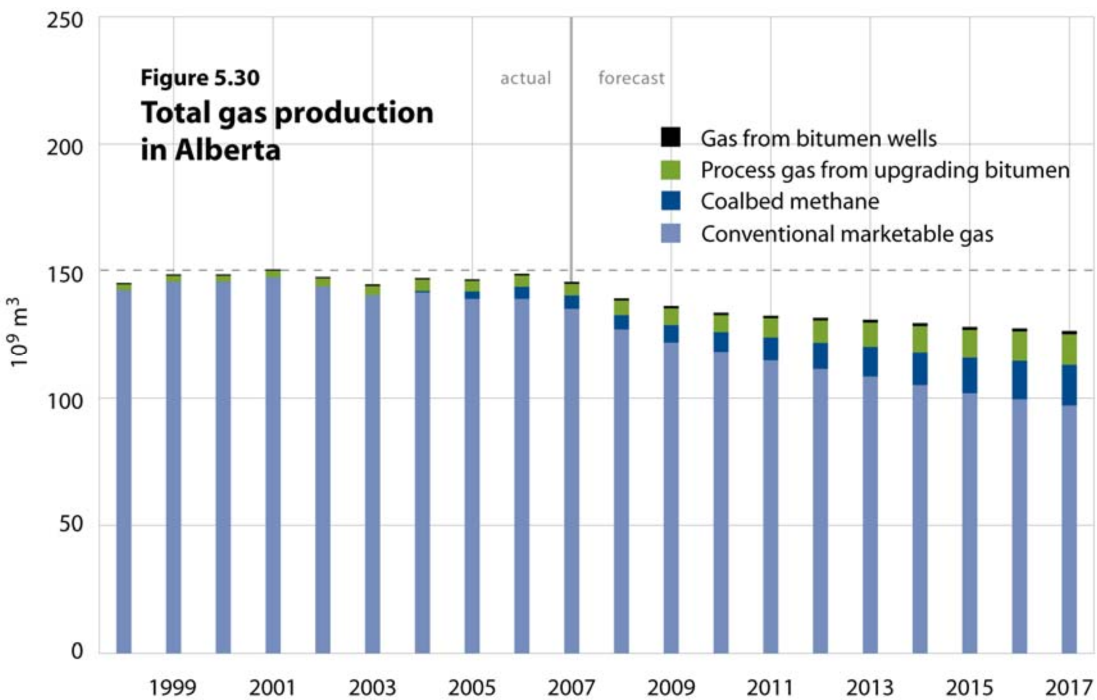
Gas production from sources other than conventional gas and oil wells includes processed gas from bitumen upgrading operations (including synthetic gas), natural gas from bitumen wells, and CBM. **Figure 5.29** shows the production from the first two categories.





In 2007, some 4.6 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 12.2 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells from primary and thermal schemes was 0.8 10^9 m^3 in 2007 and is forecast to increase to 1.3 10^9 m^3 by 2017. This gas was 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 5.30 shows the forecast of conventional natural gas production, along with gas production from other sources. While the production of conventional gas in Alberta is expected to decline over the forecast period by about 3.2 per cent per year, CBM production is expected to grow over time and offset a 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 5.31** 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 5.32** presents the location of these facilities in the Alberta pipeline systems.

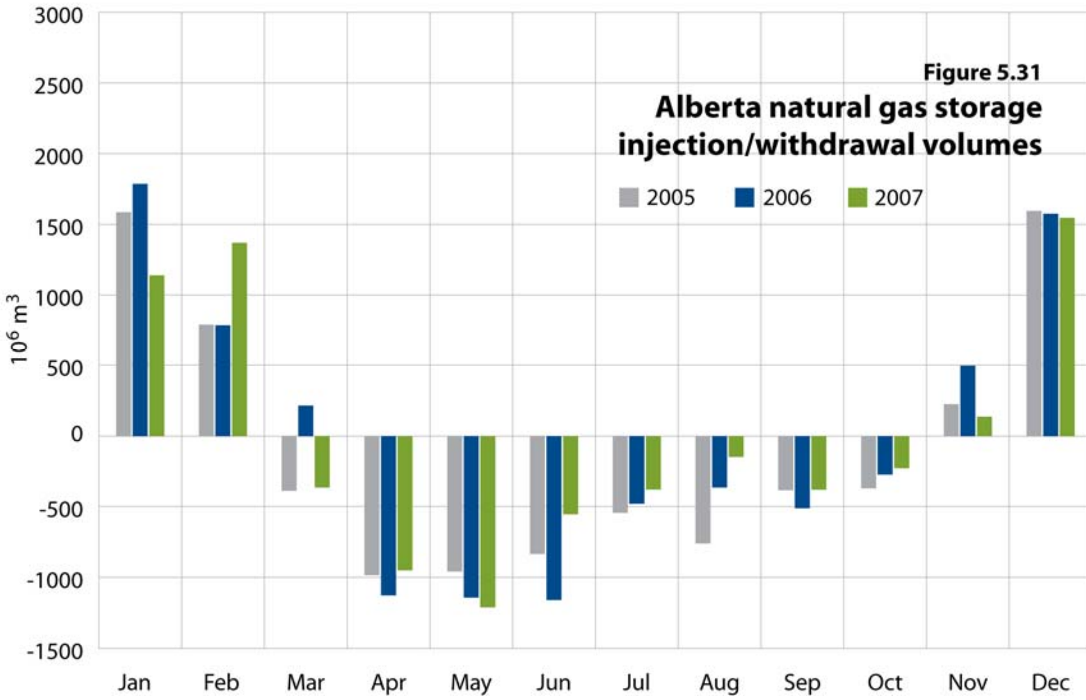


Table 5.9. Commercial natural gas storage pools as of December 31, 2007

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2007 (10^6 m^3)	Withdrawal volumes, 2007 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	731	876
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	817	23 950	695	635
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	766	847
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	1 042	509
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	208	164
McLeod Cardium A	PPM Corp Energy Canada Ltd.	986	16 900	550	633
McLeod Cardium D	PPM Corp Energy Canada Ltd.	282	4 230	210	242
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 395	50 715	1 454	1 720

In 2007, natural gas injections for all storage schemes exceeded withdrawals by 29 10^6 m^3. Marketable gas production volumes determined for 2007 were adjusted to account for the small 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.

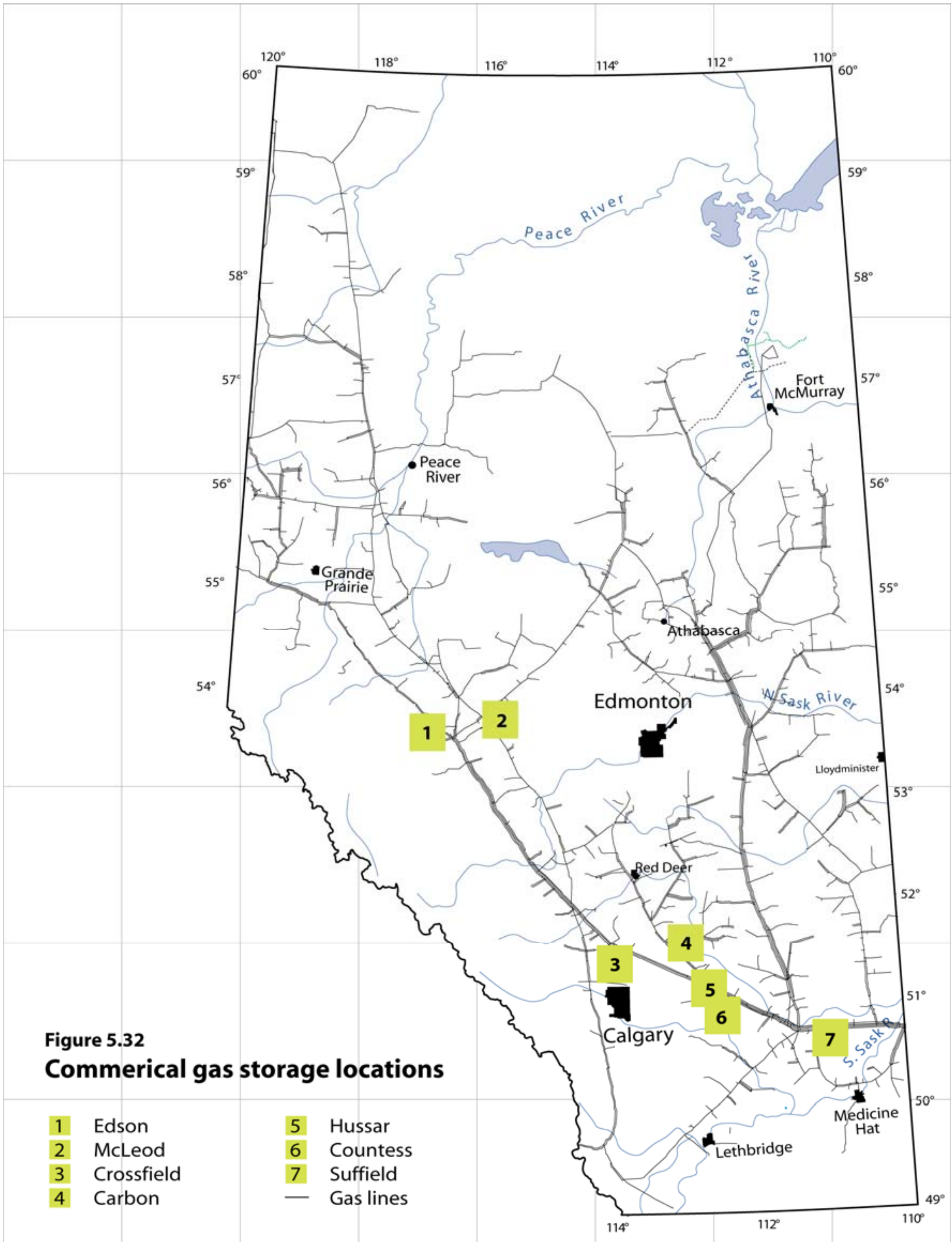


Figure 5.32
Commerical gas storage locations

5.2.3 Alberta Natural Gas Demand

The ERCB reviews the projected demand for Alberta natural gas periodically. 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 on a less rigorous basis. 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 5.33**, with removal points identified.

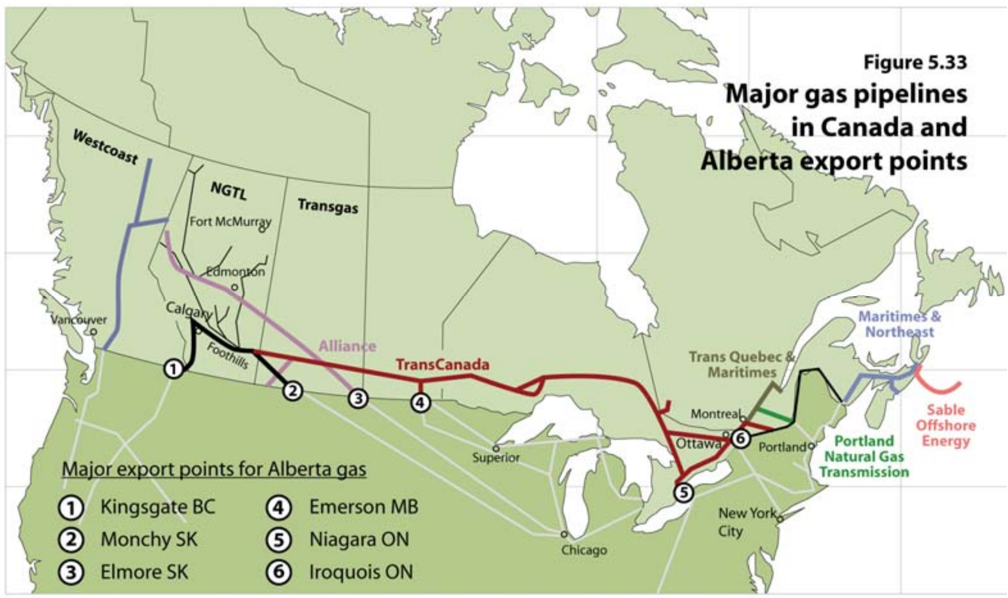


Figure 5.34 illustrates the breakdown of marketable natural gas demand in Alberta by sector. By the end of forecast period, domestic demand will reach 57.9 10^9 m^3, compared to 42.9 10^9 m^3 in 2007, representing 51 per cent of total natural gas production.

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 on an annual basis to determine what volume of gas is available for exports after accounting for Alberta's future requirements. Using the 2007 remaining established reserves number, surplus natural gas is currently calculated to be 205 10^9 m^3. This represents a 16 per cent decrease in surplus over the year 2006, due mainly to the decline in reserves estimates year over year. **Figure 5.35** illustrates historical "available for permitting" volumes from 1998 to 2007.

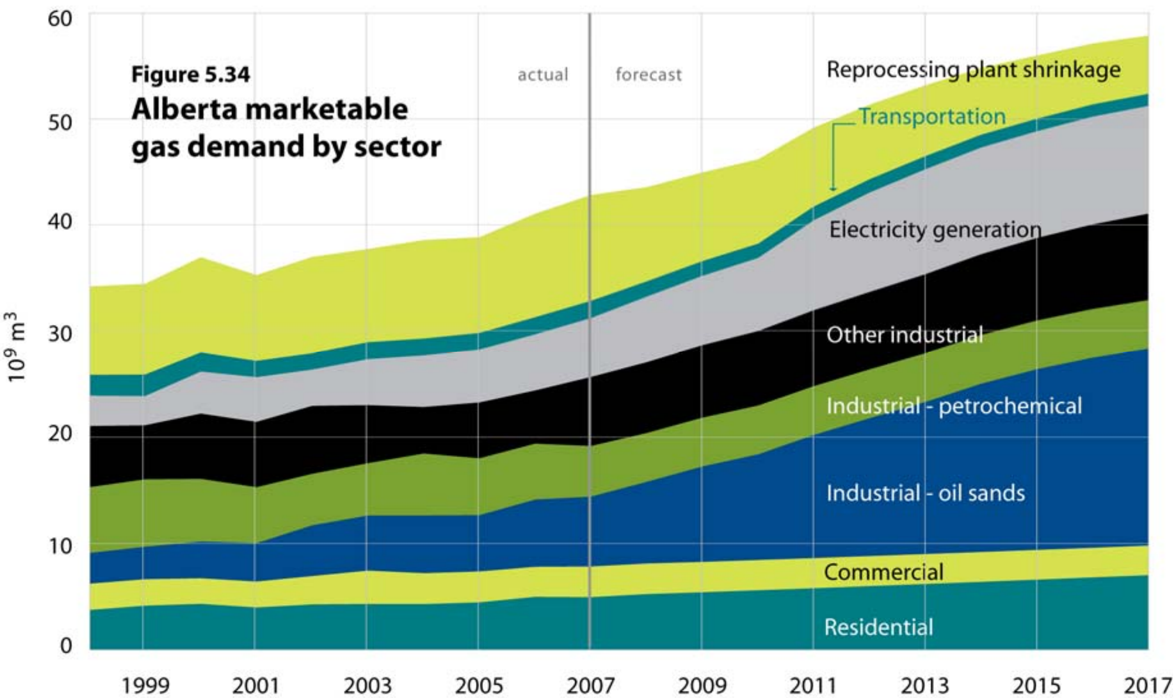


Table 5.10. Estimate of gas reserves available for inclusion in permits as at December 31, 2007

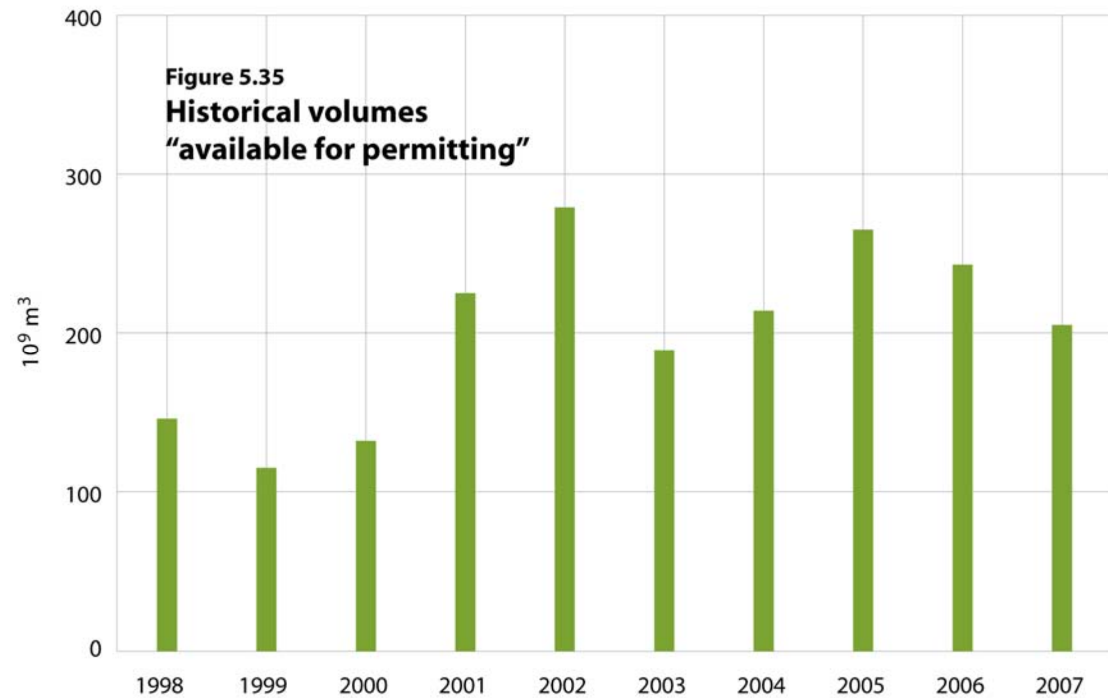
	10^9 m^3 at 37.4 MJ/m^3
Reserves (as at year-end 2007)	
1. Total remaining established reserves[a]	1 088
Alberta requirements	
2. Core market requirements[b]	112
3. Contracted for non-core markets[b]	111
4. Permit-related fuel and shrinkage	60
Permit requirements	
5. Remaining permit commitments[c]	600
6. Total requirements	883
Available	
7. Available for permits	205

[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 40 per cent under short-term permits and 60 per cent under long-term permits.

Residential gas requirements are expected to grow moderately over the forecast period, at an average annual rate of 3.6 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 5.36**, are expected to increase annually from 9.9 10^9 m^3 in 2007 to 26.1 10^9 m^3 by 2017. **Table 5.11** outlines the average purchased gas use rates for oil sands operations.

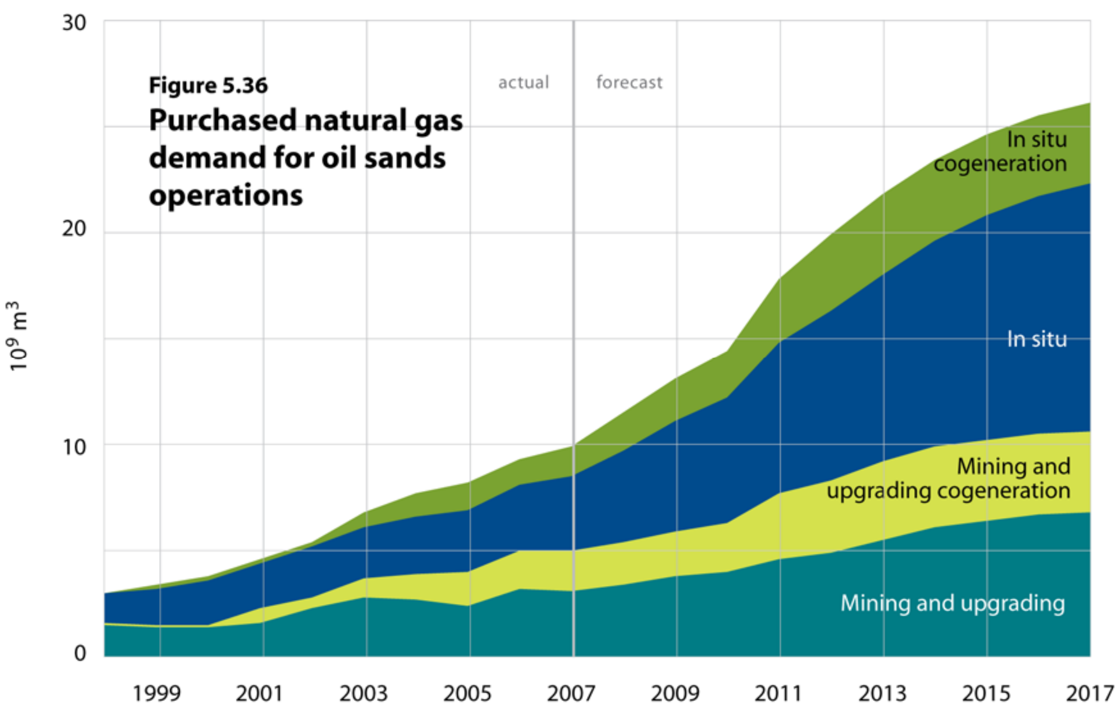
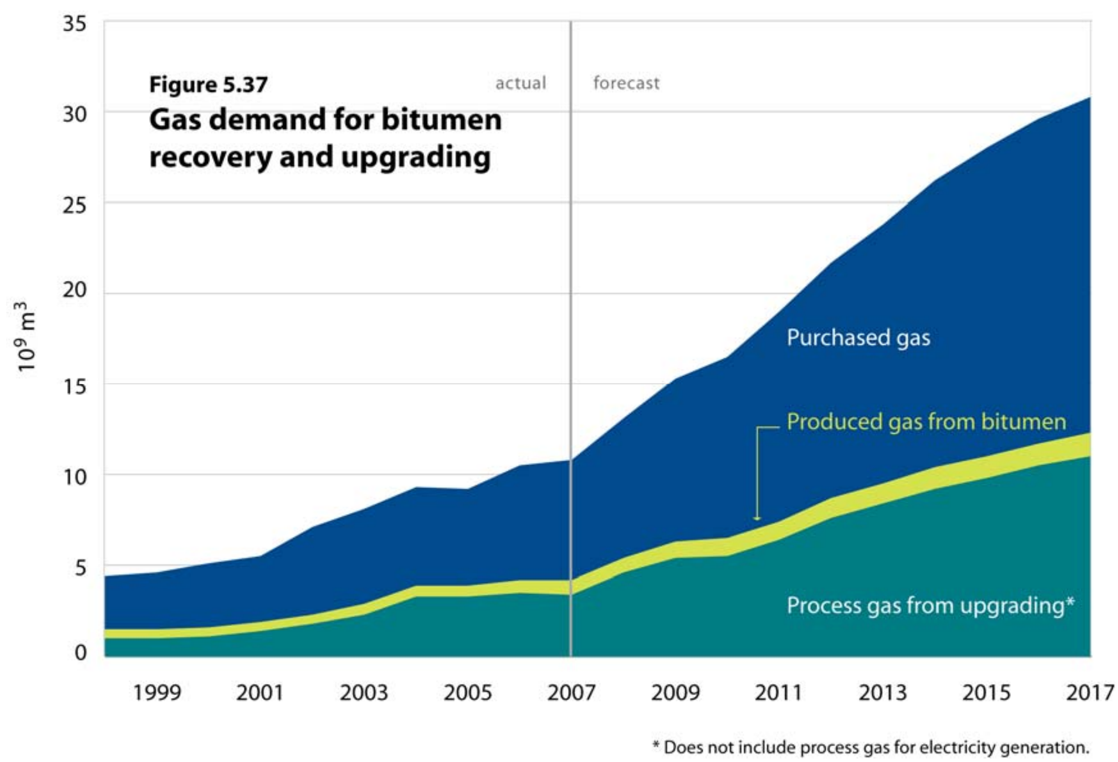


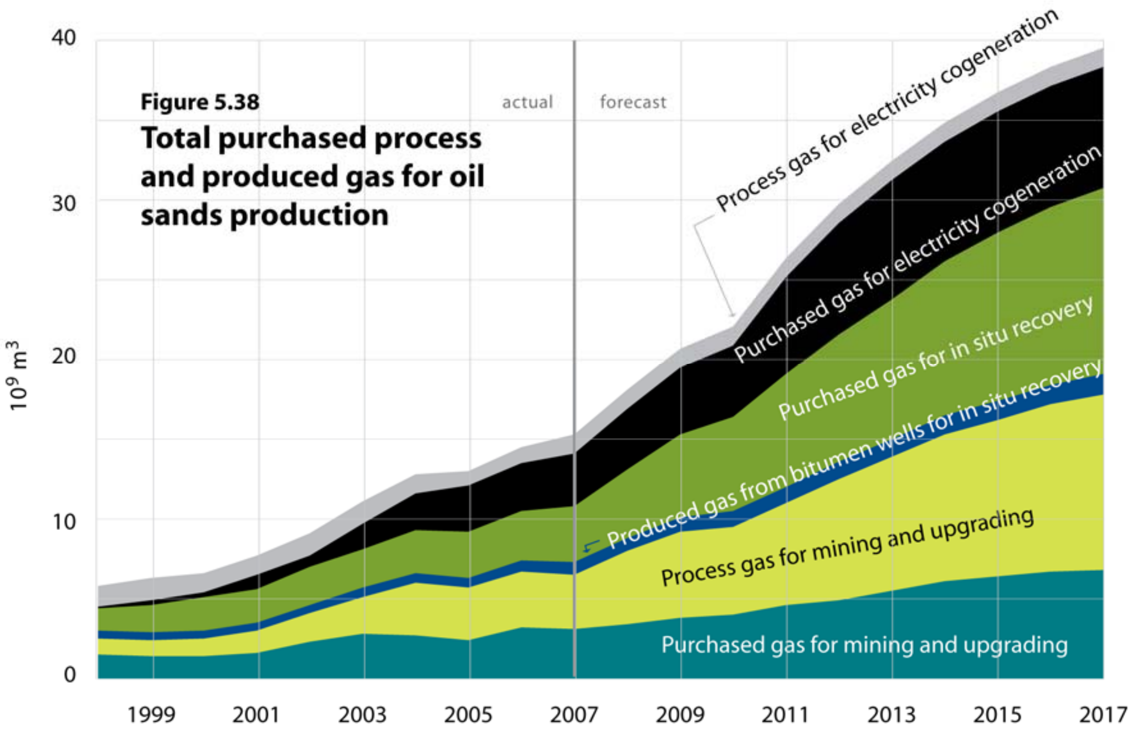
Table 5.11. 2007 oil sands average purchased gas use rates*

Extraction method	Excluding purchased gas for electricity generation (m^3/m^3)	(mcf/bbl)	Including purchased gas for electricity generation (m^3/m^3)	(mcf/bbl)
In situ - SAGD	151	0.85	254	1.43
- CSS	191	1.07	233	1.36
Mining	15	0.09	68	0.38
Upgrading	32	0.18	53	0.30
Mining with upgrading	79	0.44	120	0.67

* 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 5.37.** Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, is shown in **Figure 5.38.**





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 will be employing technology that will produce synthetic gas by burning ashphaltines in its new bitumen upgrader expected to start up in 2008. Other companies are now 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 5.6 10^9 m^3 in 2007 to 10.21 10^9 m^3 by 2017. Electricity demand can be met from existing electricity plants and plants announced to be built over the forecast period.

Figure 5.39 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 2007, some 31 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 50 per cent of total natural gas production.

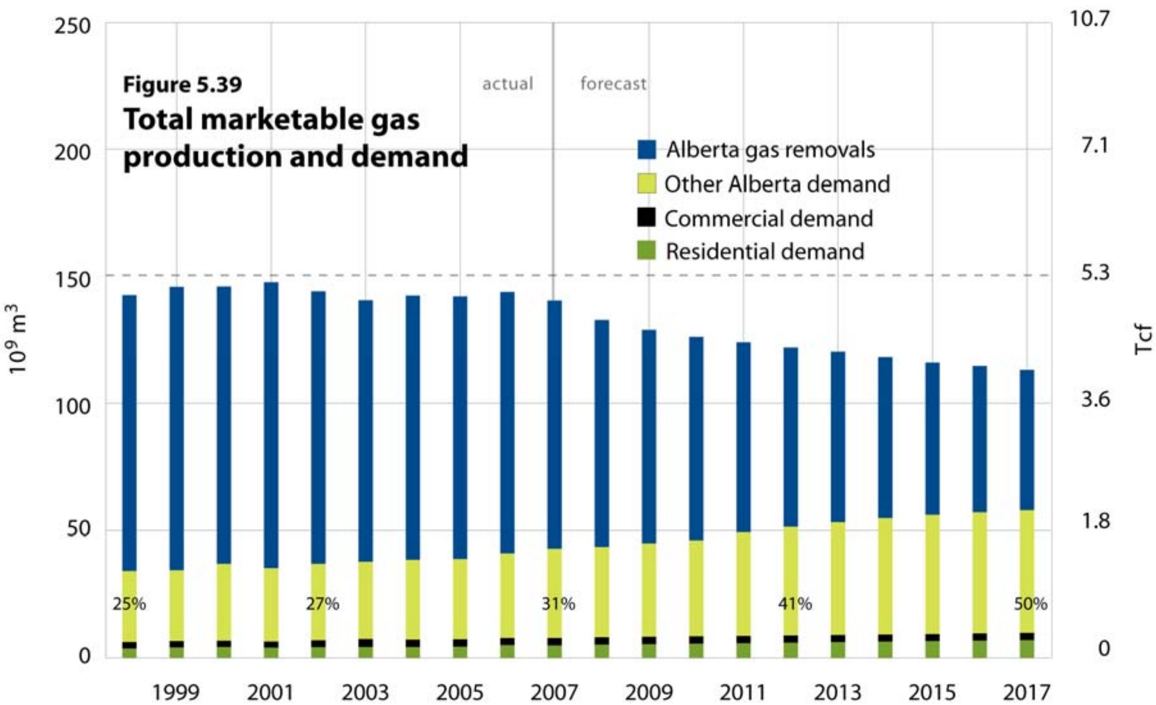


Figure 5.39
Total marketable gas production and demand
actual
forecast
Alberta gas removals
Other Alberta demand
Commercial demand
Residential demand
250
200
150
100
50
0
10^9 m^3
10.7
7.1
5.3
3.6
1.8
0
Tcf
25%
27%
31%
41%
50%
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017

6 Natural Gas Liquids

Highlights

- Total remaining extractable NGL reserves have decreased by 8 per cent from 2006, mainly due to reassessment of existing reserves.
- Approximately 60 per cent of total ethane in the gas stream was extracted in 2007.
- Of the total ethane extracted, straddle plants recovered 75 per cent and the remaining was removed at field and other facilities.

Natural gas consists mainly of methane and small amounts of heavier gaseous hydrocarbons—ethane (C_2), propane (C_3), butanes (C_4), and pentanes plus (C_5^+). These when processed and purified are collectively referred to as natural gas liquids (NGLs).

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from raw natural gas using existing technology and market conditions. The liquids reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be removed 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 and shown graphically in Figure 5.9.

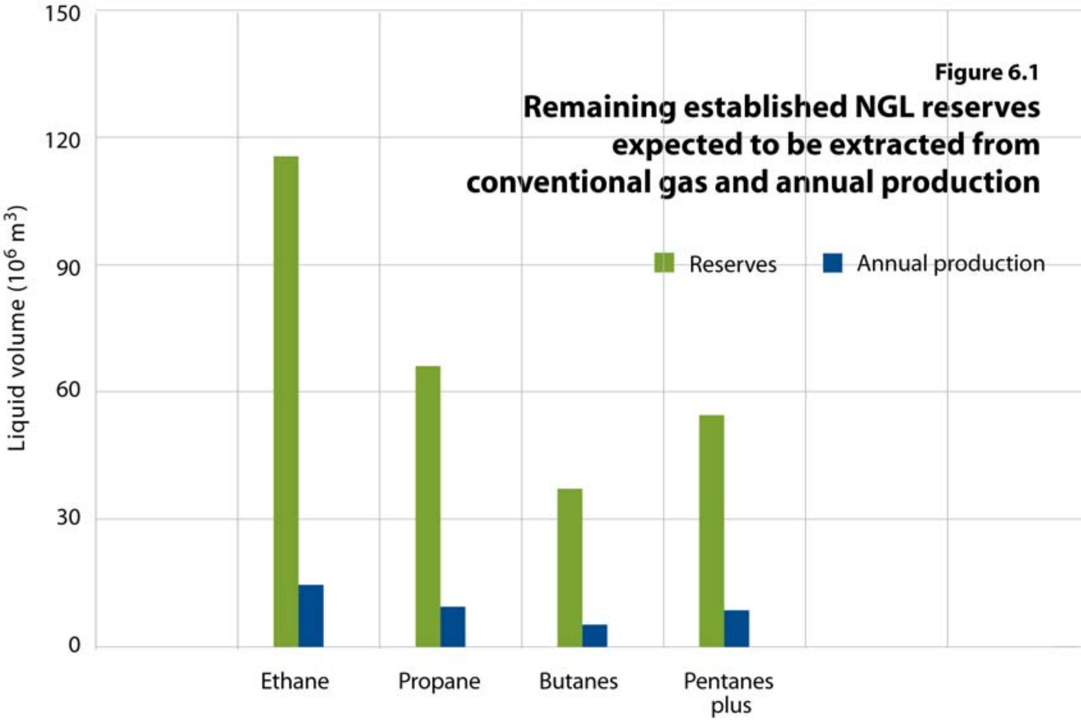
6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2007 are summarized in **Tables 6.1** and **6.2**. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2007 production.

Table 6.1. Established reserves and production of extractable NGLs as of December 31, 2007 (10^6 m^3 liquid)

	2007	2006	Change
Cumulative net production			
Ethane	254.4	239.9	+14.5
Propane	262.0	252.7	+9.3
Butanes	150.1	145.0	+5.1
Pentanes plus	329.1	320.6	+8.5
Total	995.6	958.2	+37.4
Remaining (expected to be extracted)			
Ethane	115.5	125.1	-9.6
Propane	66.0	72.0	-6.0
Butanes	37.2	40.9	-3.7
Pentanes plus	54.4	58.1	-3.7
Total	273.1	296.1	-23.0
Annual production	37.4	38.0	-0.6



Total remaining reserves of extractable NGLs have decreased by 7.8 per cent since 2006. Fields that have contributed significantly to this decrease are Bonnie Glen, Harmattan-Elkton, Rainbow, Waterton, and Wembley, mainly because of downward adjustment to reserves in these fields. These fields together with others containing large NGL volumes are listed in Appendix B, **Tables B.12** and **B.13**.

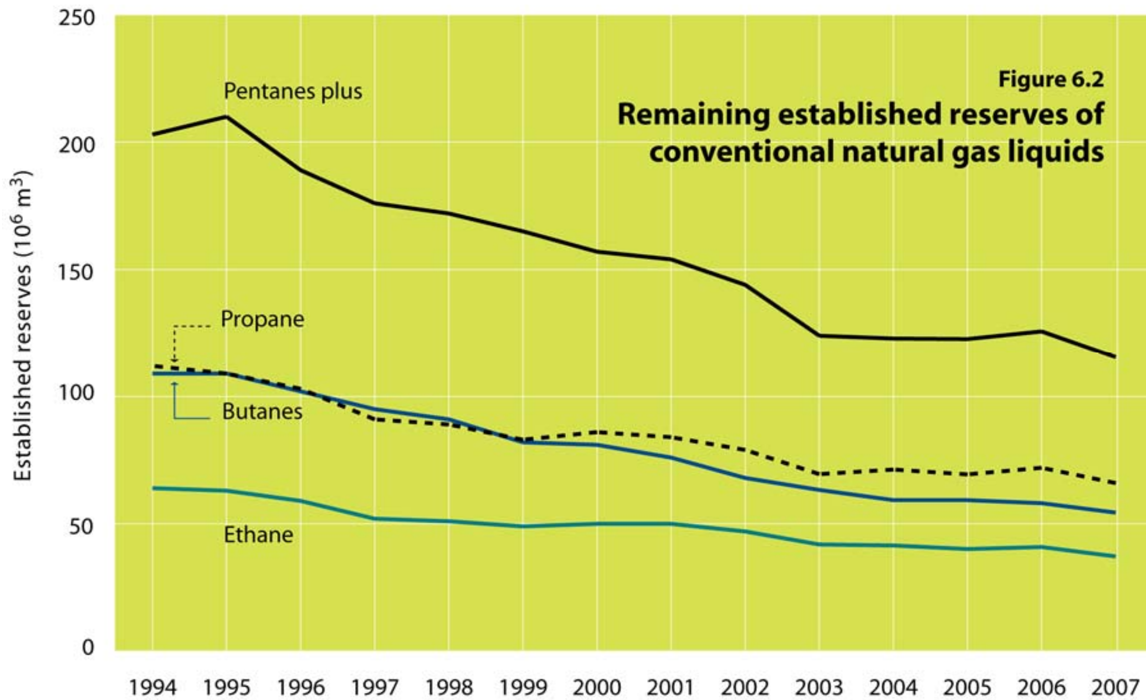
6.1.2 Ethane

As of December 31, 2007, the ERCB estimates remaining established reserves of extractable ethane to be 115.5 million cubic metres (10^6 m^3) in liquefied form. This estimate includes 3.5 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. This volume is included in the 36.5 10^6 m^3 listed under field plants in **Table 6.2** and represents about 3 per cent of the total ethane reserves, slightly lower than the previous year. At the end of 2007, only six pools were still actively injecting solvent, the largest being the Rainbow Keg River F and Judy Creek Beaverhill Lake A pools.

Table 6.2. Reserves of NGLs as of December 31, 2007 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	177.0	77.6	41.3	54.4	350.3
Liquids expected to remain in dry marketable gas	61.5	11.6	4.1	0	77.2
Remaining established recoverable from					
Field plants	36.5	38.8	24.8	49.0	149.1
Straddle plants	79.0	27.2	12.4	5.4	124.0
Total	115.5	66.0	37.2	54.4	273.1

As shown in **Table 6.2**, an additional 61.5 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 levelling off from 2003 to 2006, and declining in 2007 as a result of negative reserves revision. During 2007, the extraction of specification ethane was 14.5 10^6 m^3, compared to 14.8 10^6 m^3 in 2006.



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.12**, the volume-weighted average ethane content of all remaining raw gas was 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves. The nine largest fields—Ansell, Caroline, Countess, Elmworth, Ferrier, Pembina, Wapiti, Wild River, and Willesden Green—account for 25 per cent of total ethane reserves but only 17 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2007, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 66.0 10^6 m^3, 37.2 10^6 m^3, and 54.4 10^6 m^3 respectively. The breakdown in the liquids reserves during the past year are shown in **Table 6.2**. Appendix B, **Table B.13**, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The nine largest fields—Ansell, Brazeau River, Caroline, Ferrier, Kaybob South, Pembina, Rainbow, Wild River, and Willesden Green—account for about 26 per cent of the total 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 those reserves that could reasonably be recovered as liquid from the remaining ultimate potential of natural gas. Historically, only a fraction of the ethane that could be extracted had been recovered. However, the recovery has increased over time to 60 per cent. 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 150 billion (10^9) m^3, the ERCB estimates remaining ultimate potential of liquid ethane to be 373 10^6 m^3. The other 30 per cent, or 45 10^9 m^3, of ethane gas is expected to be sold for its heating value as part of the marketable gas.

For liquid propane, butanes, and pentanes plus together, the remaining ultimate potential reserves are 453 10^6 m^3. This assumes that remaining ultimate potential as a percentage of initial ultimate potential is 38 per cent, similar to that of 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. Gas processing plants in the field extract ethane, propane, butanes, and pentanes plus as products or recover an NGL mix from raw gas production. NGL mixes are sent from these field plants to fractionation plants for the recovery of individual NGL specification products. Straddle plants (on NOVA Gas Transmission Lines and ATCO systems) recover NGL products from gas processed in the field. To compensate for the liquids removed, lean make-up gas volumes are purchased by the straddle plants and added to the marketable gas stream leaving the plants. Although some pentanes plus is recovered as condensate at the field level, the majority of the supply is recovered from the processing of natural gas. The other source of NGL supply is from crude oil refineries, where small volumes of propane and butanes are recovered. **Figure 6.3** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Ethane and other NGL production volumes are a function of raw gas production, liquid content, gas plant recovery efficiencies, and prices. High gas prices relative to NGL prices may cause gas processors to reduce liquid recovery.

In 2007, ethane volumes extracted at Alberta processing facilities decreased marginally to 39.7 from 2006 levels of 40.6 thousand (10^3) m^3/d. About 60 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 6.3** shows the volumes of specification ethane extracted at the three types of processing facilities during 2007.

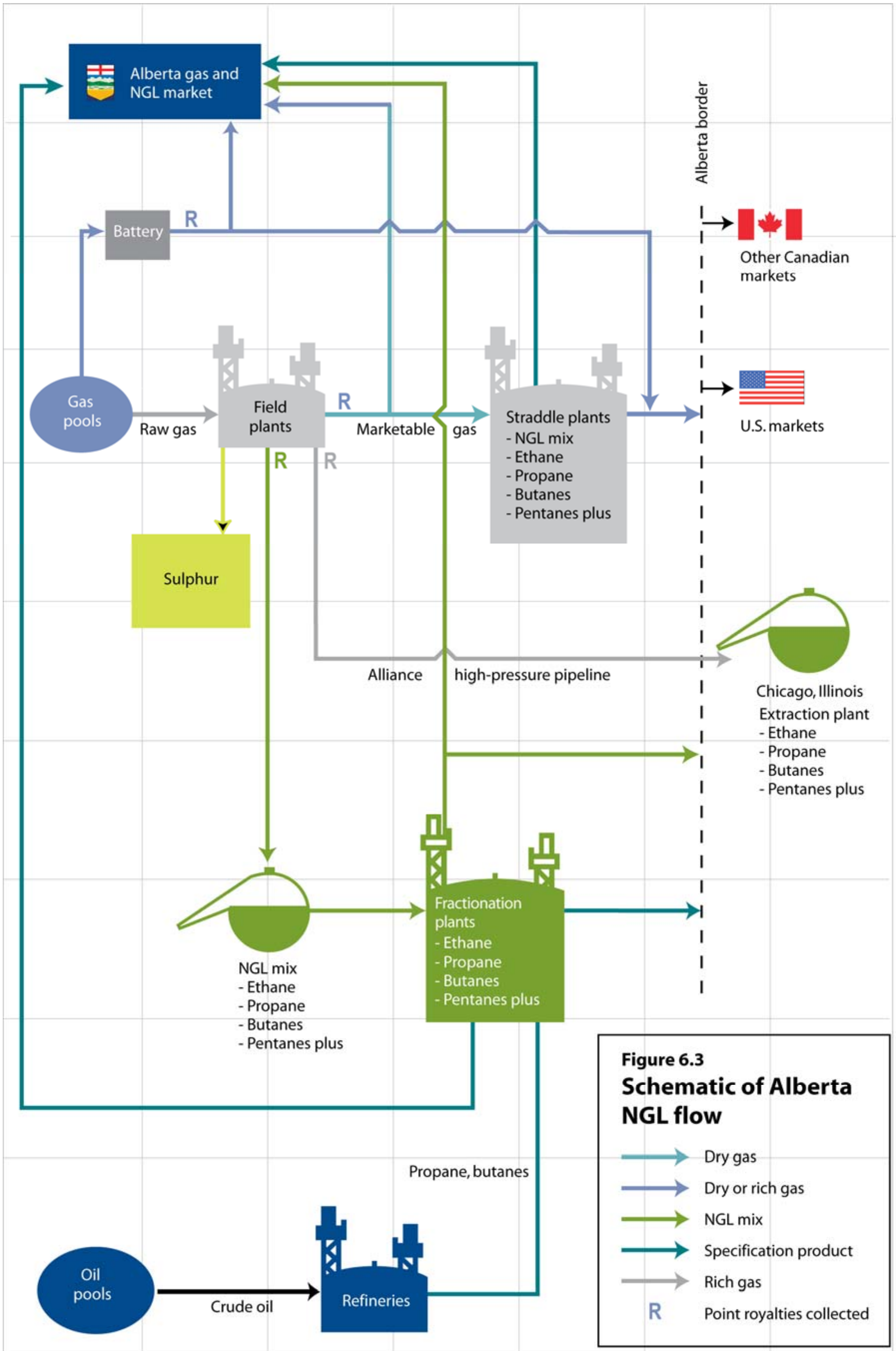


Figure 6.3
Schematic of Alberta NGL flow

Table 6.3. Ethane extraction volumes at gas plants in Alberta, 2007

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	0.9	6
Fractionation plants	2.7	19
Straddle plants	10.9	75
Total	14.5	100

Table 6.4 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2007. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butanes volumes recovered at crude oil refineries were 0.9 10^3 m^3/d and 2.4 10^3 m^3/d respectively.

Table 6.4. Liquid production at ethane extraction plants in Alberta, 2007 and 2017

	2007			2017		
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	14.5	39.7	105	14.5	39.7	132
Propane	9.3	25.6	69	6.7	18.3	69
Butanes	5.0	13.8	37	3.6	9.8	37
Pentanes plus	8.5	23.4	63	5.8	15.9	63

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 a new policy that will provide incentives for value-added production and the use of ethane in the province. The Incremental Ethane Extraction Policy (IEEP), first announced in September 2006, is a ten-year initiative to encourage increased production of ethane extraction from natural gas and from gases produced as by-products of bitumen upgrading. Off-gases are a mixture of hydrogen and light gases, including ethane, ethylene, and other light hydrocarbons. The majority of the off-gases produced from oil sands upgraders are presently being used as fuel for oil sands operations.

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, up 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 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 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 five years. A number of new projects including off-gas facilities and expansions to existing facilities are expected to take advantage of this program. As more bitumen upgrading capacity is added in the province, there will be additional opportunities to expand the use of off-gases and other by-products of upgrading for petrochemical production. Currently some NGLs (C_3^+) are being extracted from Suncor's off-gases and sent for fractionation into specification products at Redwater, Alberta.

The following projects have recently been announced:

- Inter Pipeline Fund (Inter Pipeline) has planned investments to increase ethane production at its Empress straddle plant in southern Alberta. Upon completion, facility enhancements will allow the extraction of 1106 m^3/d of additional ethane. Initial production of incremental ethane is anticipated by the end of 2008.

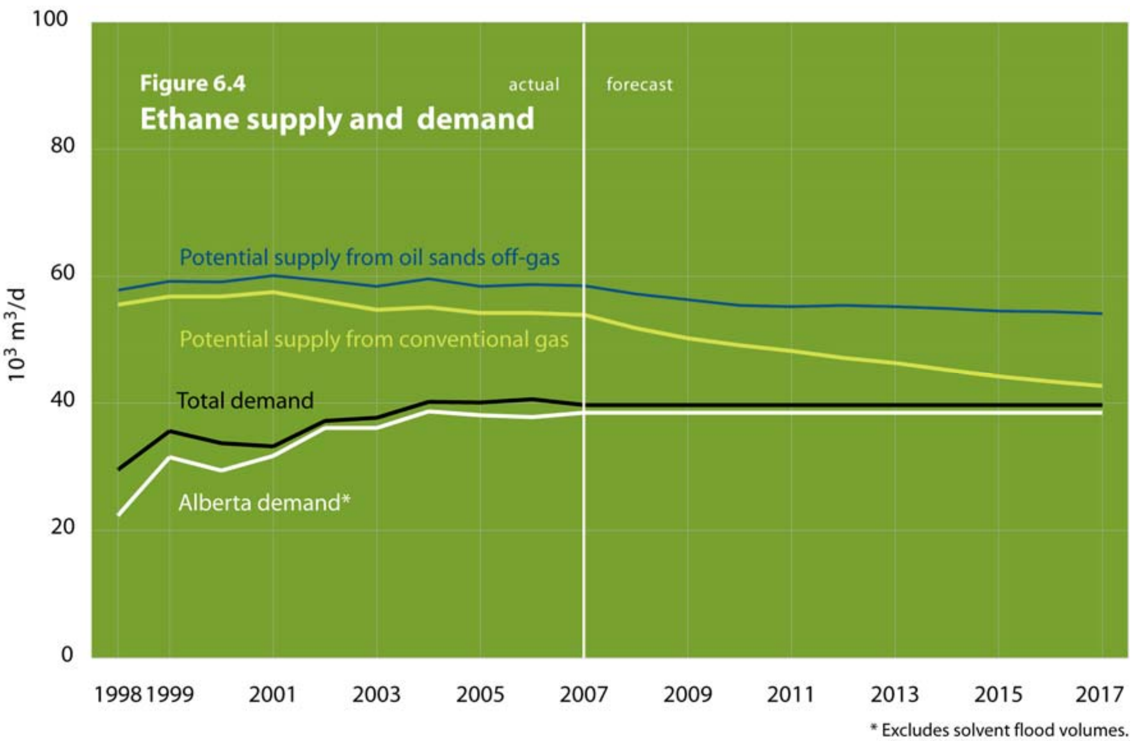
- Also announced is a proposed project to increase ethane recovery capacity at the Cochrane straddle plant operated by Inter Pipeline. The project has been approved to increase ethane recovery of 2433 m^3/d from the current design capacity of 10 268 m^3/d. The ethane recovery project is expected to be operational by the fourth quarter of 2008.

- 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. The plant located next to the BA Energy site will start up just before the upgrader sometime in mid-2009, with its second phase following that summer. The plant will recover NGLs, including an ethane/ethylene stream that will be sold to the petrochemical industry. The Heartland plant will be the first in Canada to recover off-gas from an upgrader and convert it into feedstock.

- In 2007, NOVA Chemicals Corp. (NOVA) and Aux Sable announced plans 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 as reasons for the delay. 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 remain at 2007 levels of 39.7 10^3 m^3/d for the remainder of 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 have been operating collectively at an 80 per cent capacity utilization rate for the past four years. In previous forecasts, the ERCB increased throughput volumes at the ethylene plants to 90 per cent of ethylene plant capacity in the early years of the forecast. However, based on the consistent historical ethylene plant capacity utilization rate of 80 per cent, the current forecast assumption has been modified to keep utilization rates at this historical level for the entire forecast. 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 a12 per cent ethane content in the off-gas production volumes and an 80 per cent recovery rate of ethane.

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 6.4**. **Figures 6.4** to **6.7** show forecast production volumes to 2017 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

Of the ethane extracted in 2007, about 97 per cent was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas in the province, with four plants using ethane as feedstock for the production of ethylene. 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 fluctuate 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 shown in **Figure 6.4**, Alberta demand for ethane is projected to remain at 2007 levels of 38.5 10^3 m^3/d for the remainder 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 are exported from the province primarily for their use as a buffer for ethylene shipments to eastern Canada and these volumes are forecast to remain at current levels.

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. In the second half of 2005, construction of the new Joffre feedstock pipeline was completed. It 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.

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. 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. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue throughout the forecast period.

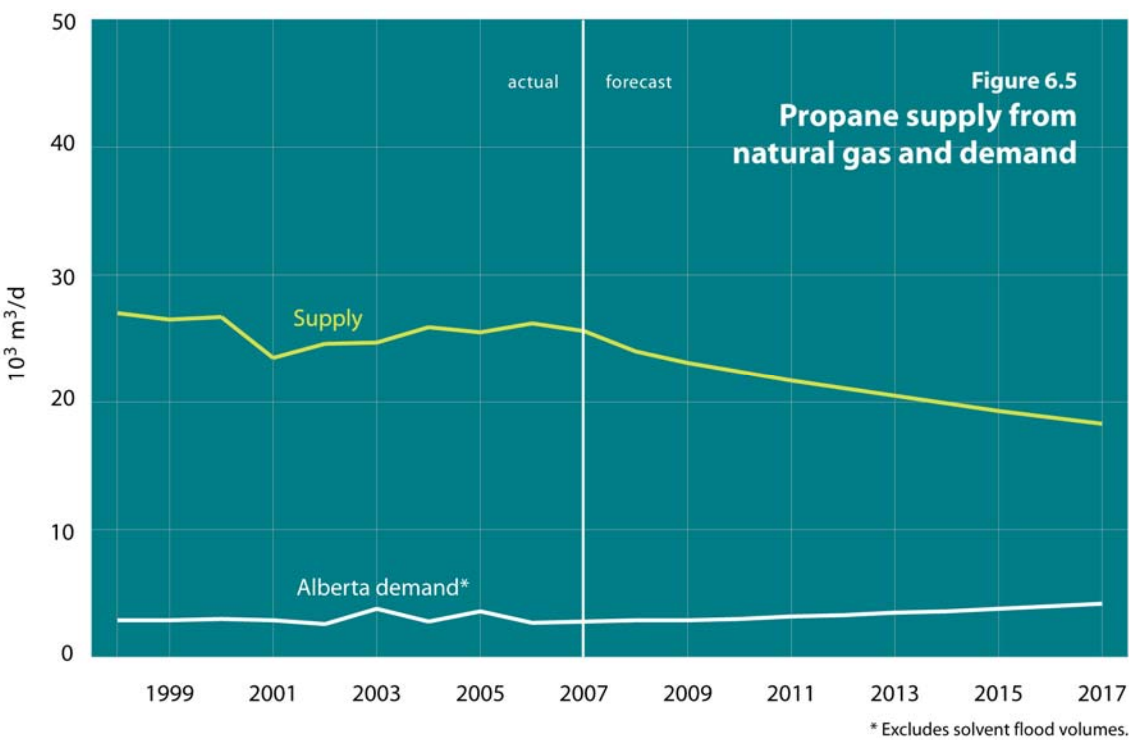
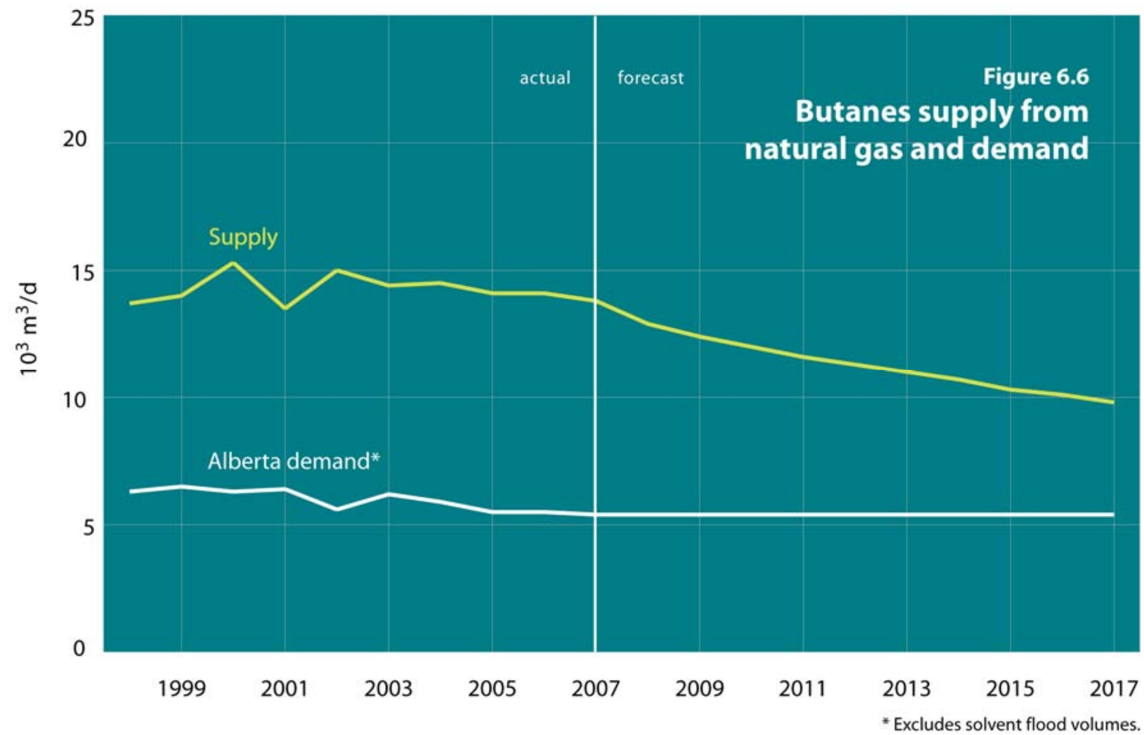


Figure 6.6 shows Alberta demand for butanes compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta demand for butanes will increase as refinery requirements grow. Butanes are used in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

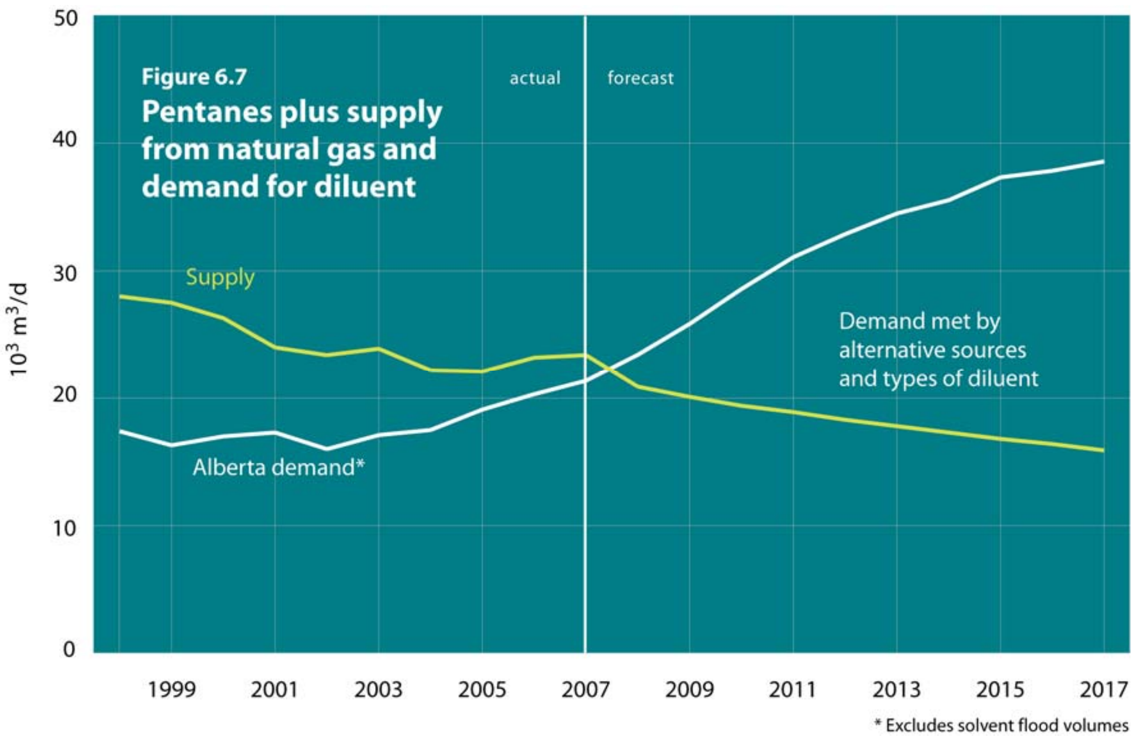
Figure 6.7 shows Alberta demand for pentanes plus compared to the total available supply. The largest use of Alberta pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate the transportation to market by pipeline. Diluent increases the API gravity and reduces the viscosity 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.



Over the forecast period, pentanes plus demand as diluent is expected to increase from 22.6 10^3 m^3/d to 37.7 10^3 m^3/d. This increased demand is largely in response to an anticipated 15.9 10^3 m^3/d increase in diluent required for bitumen transport, rising to 36.2 10^3 m^3/d in 2017 from 20.3 10^3 m^3/d in 2008. Conversely, the diluent requirement for transport of heavy crude is expected to decline from 2.3 10^3 m^3/d in 2008 to 1.5 10^3 m^3/d by the end of the forecast period, due to declining crude oil production. However, despite the reduced heavy crude diluent requirement, shortages of Alberta pentanes plus as diluent occurred in 2007. Industry has been using and assessing alternative sources and types of diluent and is seeking to reduce the demand in light of the tight supply of available diluent from Alberta.

- 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 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. 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 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.

- Several new bitumen upgraders, similar to OPTI/Nexen's Long Lake project, will be located in the field or in the Edmonton area, where they 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

- Sulphur prices increased dramatically to a current range of US$150 to $350 per tonne Free on Board (FOB) Vancouver.
- Remaining established sulphur reserves decreased by 3 per cent in 2007.
- China continues to be the major foreign importer; however, exports to China declined 24 per cent in 2007 over 2006.

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 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, 2007, to be 154.3 million tonnes (10^6 t), a decrease of 3 per cent since 2006. **Table 7.1** shows the changes in sulphur reserves during the past year.

Table 7.1. Reserves of sulphur as of December 31, 2007 (10^6 t)

	2007	2006	Change
Initial established reserves from			
Natural gas	266.6	264.6	+2.0
Crude bitumen[a]	143.1	143.1	+0.0
Total	409.7	407.7	+2.0
Cumulative net production from			
Natural gas	235.6	230.8	+4.8
Crude bitumen[b]	19.8	18.3	+1.5
Total	255.4	249.1	+6.3
Remaining established reserves from			
Natural gas	31.0	33.8	-2.8
Crude bitumen[a]	123.3	124.8	-1.5
Total	154.3	158.6	-4.3
Annual Production	6.3	6.6	-0.3

[a] Reserves of elemental sulphur from bitumen under active development as of December 31, 2007. 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 31 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2007, a decrease of 8.3 per cent from 2006. 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 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 266.67 10^6 t, this leaves 128.2 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

The ERCB's sulphur reserves 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 2007 are Caroline, Crossfield East, and Waterton, which together account for 9.6 10^6 t (31 per cent) of remaining established reserves from natural 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 208 10^6 t of elemental sulphur will be recoverable from the 5.0 billion (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 production 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 are upgraded with the hydrogen-addition technology than currently estimated or if less of the mineable reserves is upgraded in Alberta, as has been announced, then the total sulphur reserves will be less. However, if some of the in situ crude bitumen reserves are upgraded in Alberta, as is currently planned, the sulphur reserves will be higher.

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, and Petro-Canada/UTS Energy/Tech Cominco Fort Hills projects. The ERCB estimate of the initial established sulphur reserves from these active projects is 143.1 10^6 t, representing 69 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. This estimate remains unchanged from last year. A total of 19.8 10^6 t of elemental sulphur has been produced from these projects, leaving remaining established reserves of 123.3 10^6 t. During 2007, 1.5 10^6 t of elemental sulphur was produced from the six active projects.

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2007

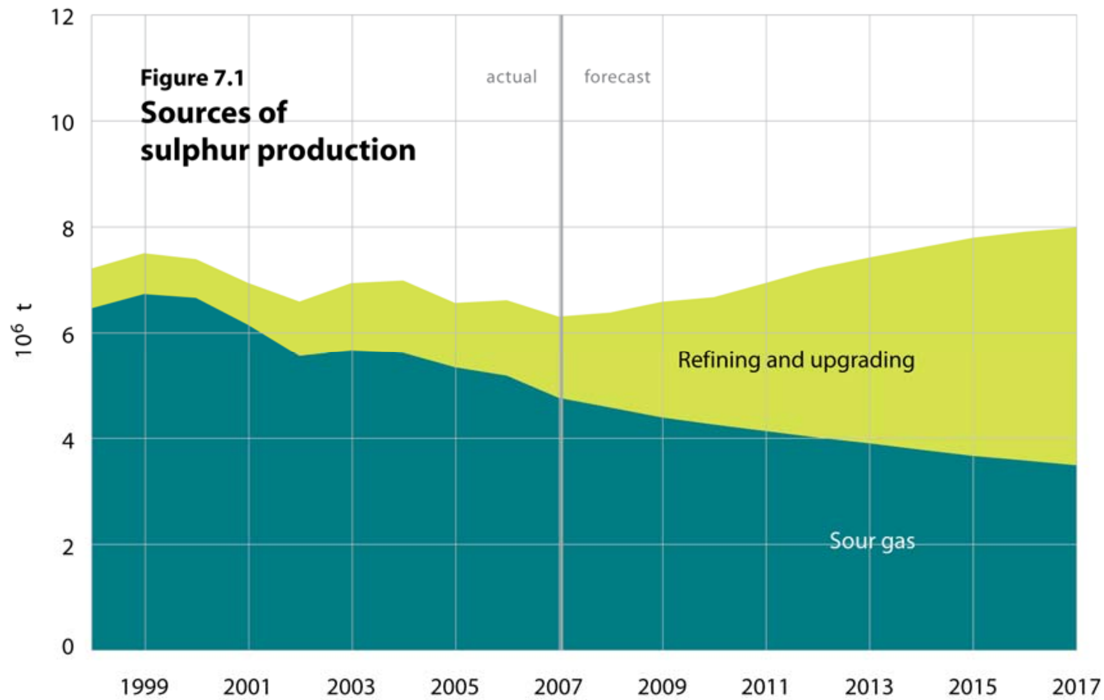
Field	Remaining reserves of marketable gas ($10^6 m^3$)	H_2S content[a] (%)	Remaining established reserves of sulphur Gas ($10^6 m^3$)	Remaining established reserves of sulphur Solid (10^3 t)
Benjamin	4 036	5.1	246	334
Bighorn	4 044	7.7	379	514
Blackstone	2 307	10.6	324	439
Brazeau River	9 853	6.6	844	1 144
Burnt Timber	2 044	22.8	771	1 045
Caroline	8 117	19.7	2 842	3 853
Cecilia	11 865	1.6	215	292
Coleman	1 466	26.6	584	792
Crossfield	3 890	13.0	727	986
Crossfield East	3 193	30.3	1 754	2 378
Elmworth	15 708	2.6	493	669
Garrington	3 567	5.2	247	335
Hanlan	4 817	8.8	555	753
Jumping Pound West	5 459	6.6	451	616
Kaybob South	11 142	2.3	314	426
La Glace	2 299	6.0	160	217
Limestone	7 307	12.6	1 146	1 554
Marsh	1 103	19.7	314	426
Moose	3 401	13.3	598	810
Okotoks	1 661	23.1	587	796
Pembina	19 384	1.9	455	616
Pine Creek	5 040	4.7	283	383
Quirk Creek	1 289	9.6	164	222
Rainbow	8 669	1.6	175.5	238
Rainbow South	2 955	6.4	278	377
Ricinus West	1 716	33.1	1 020	1 383
Sinclair	10 231	1.3	155	211
Waterton	6 787	22.2	2 482	3 365
Windfall	2 385	12.4	409	555
Subtotal	165 744	8.7	18 973	25 728
All other fields	903 356	0.4	3 870	5 268
Total	1 069 100	2.0	22 843	30 996

[a] Volume-weighted average.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Supply

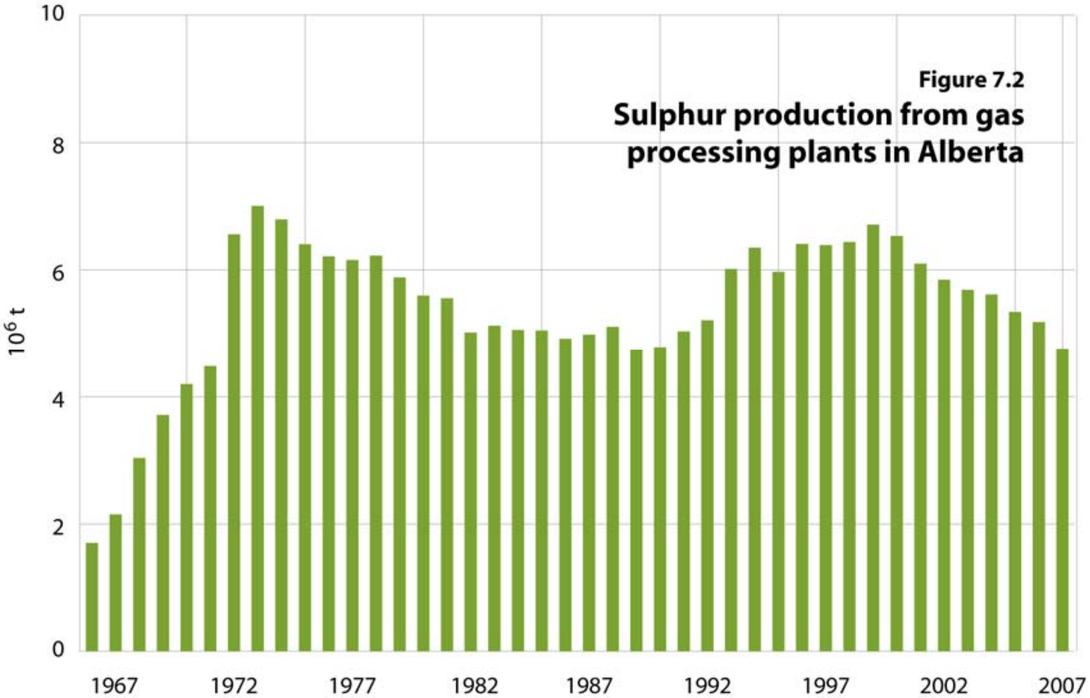
There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to SCO, and refining of crude oil into petroleum products. In 2007, Alberta produced 6.3 10^6 t of sulphur, of which 4.8 10^6 t was derived from sour gas, 1.5 10^6 t from upgrading of bitumen to SCO, and just 16 thousand (10^3) t from oil refining. Sulphur production from these sources is depicted in **Figure 7.1**.



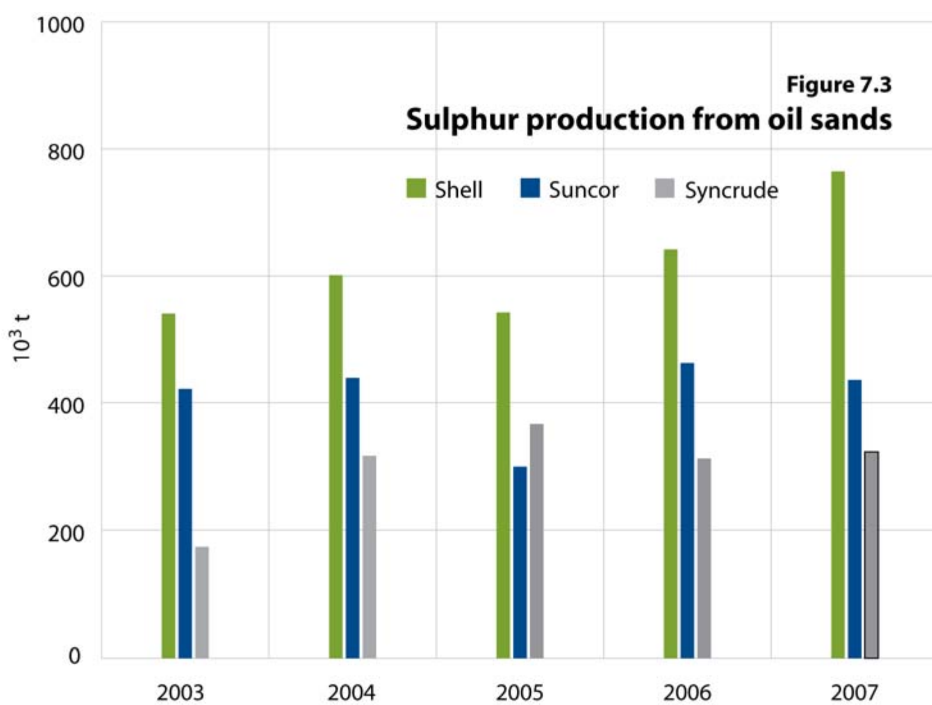
Sulphur production from sour gas is expected to decrease from 4.8 10^6 t in 2007 to 3.5 10^6 t, or some 27 per cent, by the end of the forecast period. However, sulphur recovery in the bitumen upgrading industry is expected to increase from 1.5 10^6 t to 4.4 10^6 t.

Figure 7.2 shows sulphur production from gas processing plants from 1966 forward. 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 4.0 10^6 t at year-end 2007, down from 5.1 10^6 t at year-end 2006, a decrease of 22 per cent. Sulphur stockpiles are being drawn down to meet high demand. The high price of sulphur on the world market has brought increased interest in the levels of sulphur available from stockpiles. As a result, gas plant operators are surveying their inventories. Eight gas processing plants in Alberta reported inventory adjustments in 2007, with the largest being Shell Caroline at 89.5 10^3 t, Amoco Kaybob at 50.3 10^3 t, and Husky Strachen at 3.7 10^3 t. **Figure 10** in the Overview section illustrates sulphur closing inventories at gas processing plants and oil sands operations from 1971 to 2007, along with sulphur prices.



Sulphur production from the three existing oil sands upgrader operations is shown in **Figure 7.3** for the period 2003-2007. The Alberta refineries are expected to replace conventional crude and synthetic crude with bitumen, as integration of bitumen upgrading and refining takes place in this forecast period. With this integration, the sulphur recovery will increase from 16 10^3 t in 2007 to 57 10^3 t by 2017. Total sulphur production is expected to reach 8.0 10^6 t by the end of the forecast period.

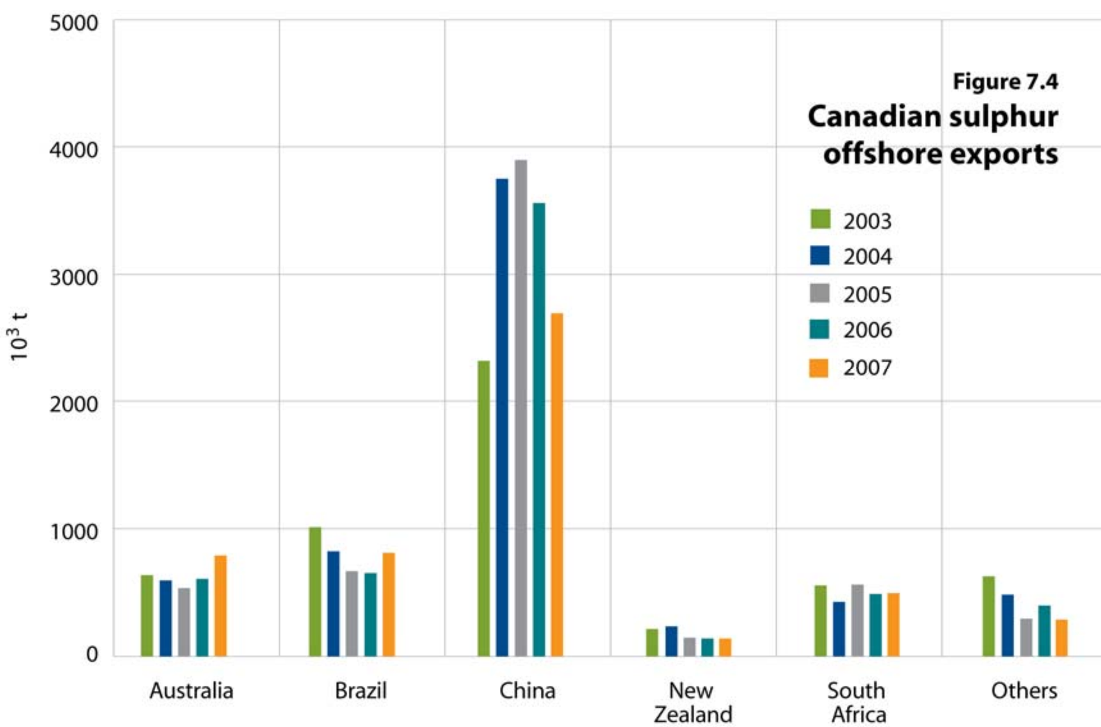


7.2.2 Sulphur Demand

Demand for sulphur within the province in 2007 was about 204 10^3 t, slightly higher than in 2006. It was used in production of phosphate fertilizer and kraft pulp and in other chemical operations. Some 96 per cent of the sulphur marketed by Alberta producers was shipped outside the province, primarily to the U.S. and China.

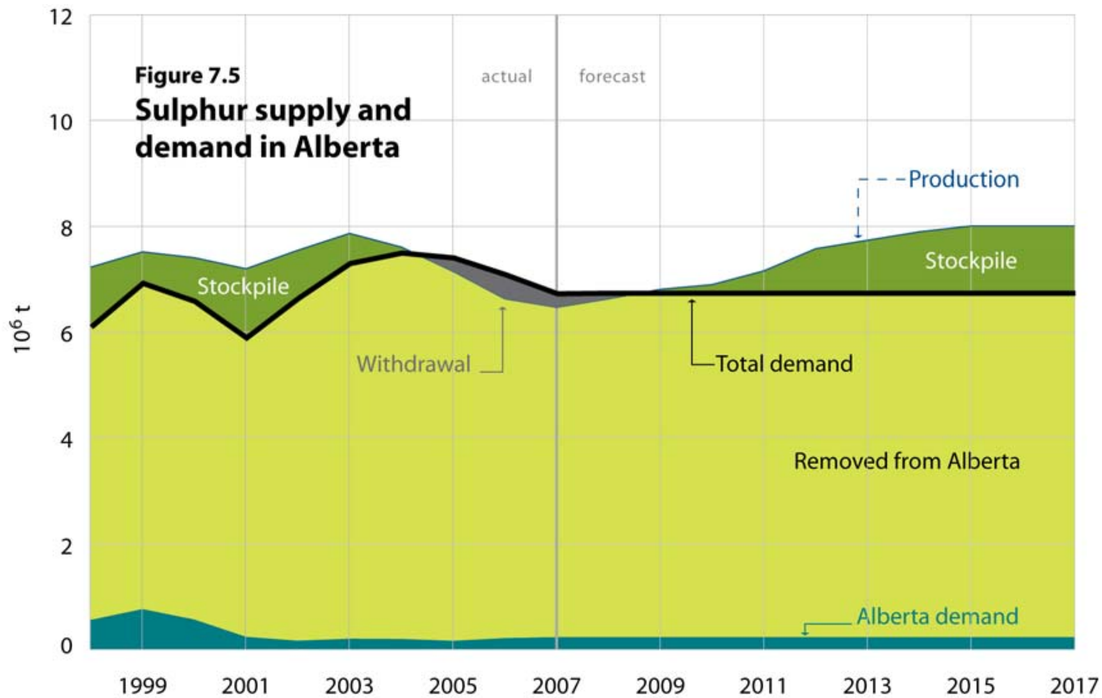
China's imports of sulphur have soared since 1995, and exports from Canada have increased substantially. China is now the world's largest importer of sulphur, which is used primarily for making sulphuric acid to produce phosphate fertilizers. **Figure 7.4** shows the export volumes sent to markets outside 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 24 per cent in 2007 over 2006. Canada's share of exports into the China market has fallen, while competitive supplies from the Middle East have increased. There appears to be a question of availability of product at Vancouver from Alberta, and it takes shippers time to respond and direct the sulphur to the highest priced markets. Increased global demand for sulphur has 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 are expected to moderate in 2009 as new supplies become available.



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 been in balance and are forecast to remain so until 2011. Sulphur stockpiles thereafter are expected to grow. Changes to the sulphur inventory are illustrated in **Figure 7.5** as the difference between total supply and total demand.



8 Coal

Highlights

- Export metallurgical markets remained strong, as demand from the Pacific Rim countries continued to grow due to high levels of steel production.
- The established coal reserves estimates remained the same as 2006.
- In 2007 TransAlta completed an upgrade on Unit 4 of its Sundance plant to increase electricity generating capacity using new technology that uses less coal on a per MW basis.

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 coal 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. Reserves within this report refer to raw coal unless otherwise noted.

The following information summarizes and marginally updates the material found in EUB *Statistical Series 2000-31: Reserves of Coal*. Those seeking more detailed information or a greater understanding of the parameters and procedures used to calculate established coal reserves are referred to that report.

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, 2007, to be 33.5 gigatonnes (Gt). 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 2007. **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, 2006, to December 31, 2007, resulted from increases in cumulative production. During 2007, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.004 Gt, 0.007 Gt, and 0.026 Gt respectively.

Table 8.1. Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2007[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	0.229	0.582
Underground	5.06	0.738	0.108	0.630
Subtotal	6.83[c]	1.56[c]	0.337[d]	1.223[c]
High-volatile bituminous				
Surface	2.56	1.89	0.159	1.731
Underground	3.30	0.962	0.047	0.915
Subtotal	5.90[c]	2.88[c]	0.206[d]	2.674[c]
Subbituminous[e]				
Surface	13.6	8.99	0.729	8.261
Underground	67.0	21.2	0.068	21.132
Subtotal	80.7[c]	30.3[c]	0.797	29.503[c]
Total[c]	93.7[c]	34.8[c]	1.340	33.5[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.

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, the advantage passes to underground mining; this coal is considered underground-mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio, 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 allowed for where, 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 2007.

Table 8.2. Established resources and reserves of raw coal under active development as of December 31, 2007

Rank Mine	Permit area (ha)	Initial in-place resources (Mt)[a]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[c] (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	15	139
Grande Cache	4 250	199	85	24	61
Subtotal	11 705	445	239	39	200
High-volatile bituminous					
Coal Valley	17 865	572	331	121	210
Subtotal	17 865	572	331	121	210
Subbituminous					
Vesta	2 410	69	54	43	11
Paintearth	2 710	94	67	44	23
Sheerness	7 000	196	150	74	76
Dodds	425	2	2	1	1
Burtonsville Island[b]	150	0.5	0.5	0.08	0.4
Whitewood	3 330	193	120	78	42
Highvale	12 140	1 021	764	351	413
Genesee	7 320	250	176	64	112
Subtotal[c]	35 485	1 826	1 334	655	678
Total	65 055	2 843	1 904	815	1088

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

8.1.4 Ultimate Potential

A large degree of uncertainty is inevitably associated with the estimation of an ultimate potential. New data could substantially alter results derived from the current best fit. Two methods have been used to estimate ultimate potentials. 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: Reserves of Coal 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 potentials. No change to ultimate potential has been made for 2007.

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.

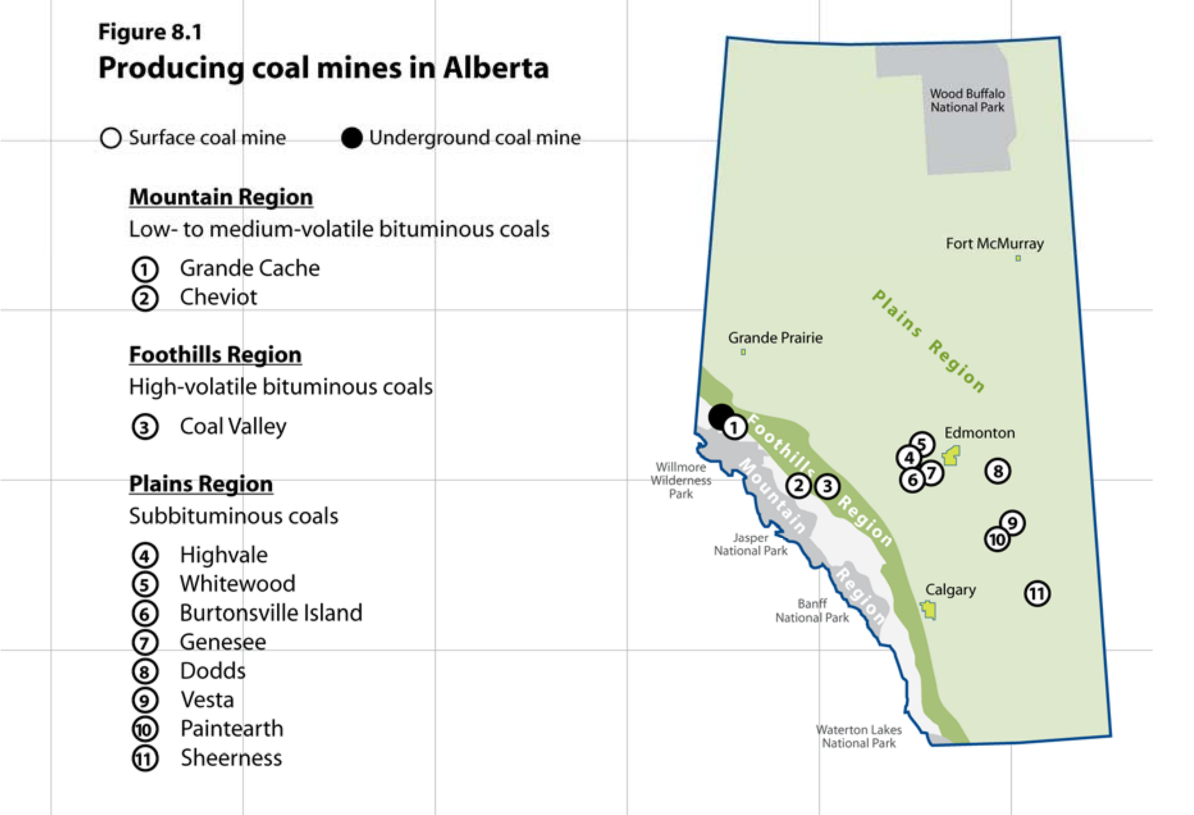
8.2 Supply of and Demand for Marketable Coal

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 2007, 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 80.3 per cent of the total, bituminous metallurgical 9.2 per cent, and bituminous thermal coal the remaining 10.5 per cent.

Figure 8.1
Producing coal mines in Alberta



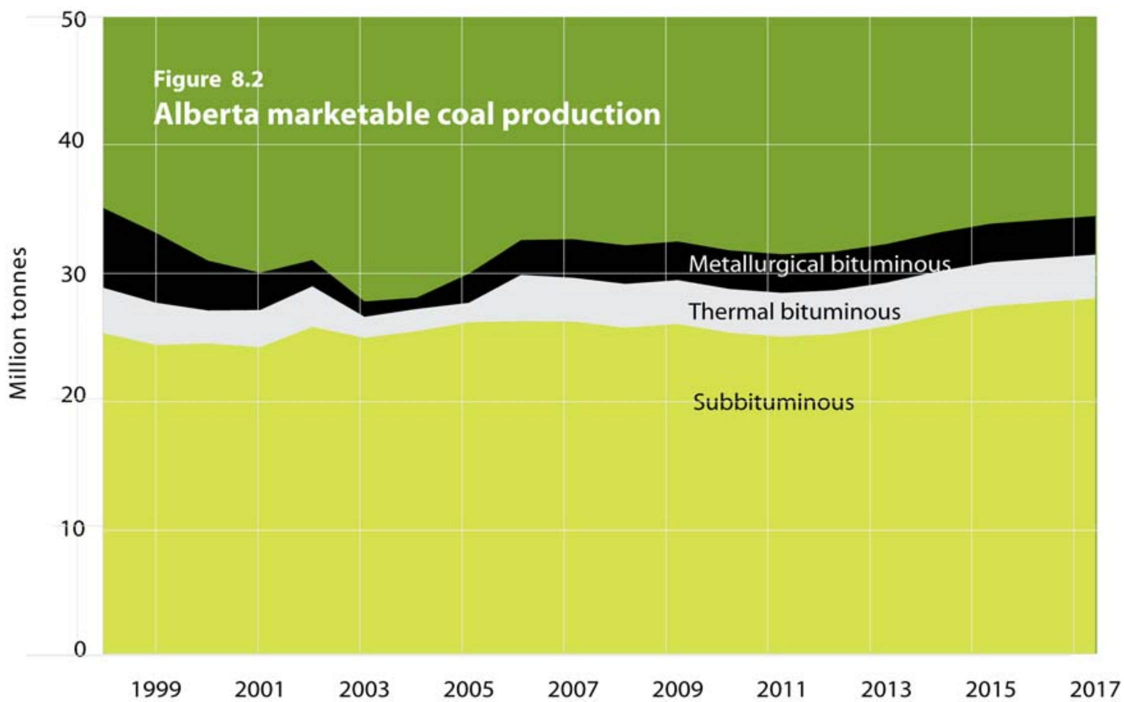
Six large mines and two small mines produce subbituminous coal. The large mines serve nearby electric power plants, while the small mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the reserves have been dedicated to the power plants.

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

Forecast Alberta production for each of the three types of marketable coal is shown in **Figure 8.2**.

Table 8.4. Alberta coal mines and marketable coal production in 2007

Operator/owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Prairie Mines and Royalties / EPCOR Generation	Genesee	Genesee	5.1
Prairie Mines and Royalties	Sheerness	Sheerness	4.0
	Paintearth	Halkirk	1.7
	Vesta	Cordel	1.2
Prairie Mines and Royalties/ TransAlta Utilities Corp.	Highvale	Wabamun	12.7
	Whitewood	Wabamun	1.3
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.102
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.016
Bituminous metallurgical coal			
Cardinal River Coals Ltd./Elk Valley	Cheviot	Mountain Park	1.8
Grande Cache	Grande Cache	Grande Cache	1.2
Bituminous thermal coal			
Coal Valley Resources Inc.	Coal Valley	Coal Valley	3.4
Total			32.5



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.

Although in 2007 TransAlta completed an upgrade on Unit 4 of its Sundance plant to increase electric generating capacity, the introduction of new technology will use less coal as fuel on a per MW basis. A similar upgrade is planned to be completed at the Sundance Unit 5 in 2009.

One power generation unit at the Keephills plant site with a capacity of 450 MW is planned to be in service in 2011, with the potential for an additional plant fuelled by subbituminous coal within the forecast period.

The last remaining generation unit at the Wabamun plant site (279 MW) will cease operations by 2010.

Alberta's metallurgical coal primarily serves the Asian steel industry, mainly Japan, but export coal producers have the competitive disadvantage of long distances from mine to port. Export markets are expected to remain strong over the next few years due to high levels of steel production in the Pacific Rim countries.

Late 2007/early 2008 saw a series of severe weather events disrupt international coal supplies. Coal production problems were experienced in China due to heavy snowfall and winter storms, resulting in China's decision to ban coal exports from the country.

Major torrential rain flooded some of the largest producing mines in Australia. Severe power shortages in South Africa forced the shutdown of several major mines. Prices of coal have increased as a result of these supply disruptions.

9 Electricity

Highlights

- The Alberta Government and the Alberta Electric System Operator removed the 900 megawatt (MW) threshold on wind power generation projects.
- Between 2006 and 2007, generating capacity increased 2.6 per cent and generation increased 1.3 per cent.
- Annual average pool price declined to $67/MW hour from $81/MW hour in 2006.

On January 1, 2008, the EUB was realigned into two separate regulatory bodies: the ERCB, which regulates the oil and gas industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry. Under the umbrella of the *Alberta Utilities Commission Act*, the AUC is governed by more than 20 pieces of legislation that regulate Alberta's energy resource and utility sectors.

The AUC regulates investor-owned electric, natural gas, water, and certain municipality owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates. It also oversees the building, operating, and decommissioning of electricity generating facilities and the routing, tolls, and tariffs of energy transmission through pipeline and transmission lines.

While the utilities sector is the focus of the AUC, the ERCB continues to forecast electricity supply and demand as it is essential in determining the future domestic demand for 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. Because of this and the fact that the ERCB analysis of electricity capacity, supply, and demand complement the other sections of the *ST98* annual report, the ERCB will continue to offer a perspective on the supply and demand for this growing sector of the economy, despite the realignment of the EUB into two distinct regulatory bodies.

The basic electricity infrastructure involves electricity generation, transmission, and distribution. The *Electric Utilities Act* and its supporting regulations establish the framework for the future of Alberta's electric industry. This framework was set to facilitate the transition of Alberta's electric industry from a vertically integrated and heavily regulated utility structure to one that features competition in the generation and retail market. The transmission and distribution components of the electric industry in Alberta remain regulated natural monopolies.

The competitive wholesale 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 and ensuring that electricity generating and distribution companies, along with large industrial consumers, receive fair and open transmission access to the power grid. 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.

Along with the AESO and the MSA, the Balancing Pool was established in 1999 in order to help manage the financial accounts arising from the transition to a competitive generation market on behalf of electricity consumers and to meet any obligations and responsibilities associated with both sold and unsold Power Purchase Arrangements (PPAs). 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 utilities 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.

9.1 Electricity Generating Capacity

9.1.1 Provincial Summary

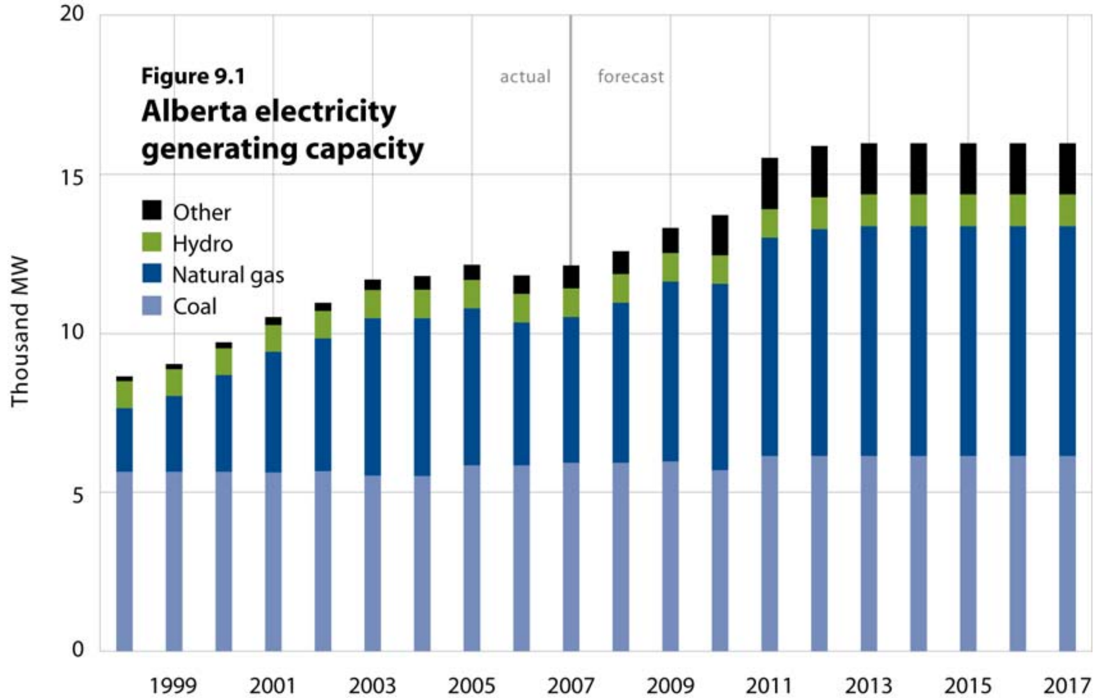
Capacity refers to the maximum potential supply of electricity, often expressed in megawatts (MW), that can be produced each hour. Alberta's fuel mix of available electricity generating capacity is composed of coal, natural gas, hydroelectric power, and renewable energy, such as wind and biomass. A relatively 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 or for heating buildings. 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 generating capacity was slightly more than 8600 MW, with coal-fired facilities accounting for 65 per cent. Between 1998 and 2007, electricity generating capacity increased 3511 MW to a total of 12 143 MW. About 74 per cent of the incremental generating capacity was natural gas fired. In 2007, coal-fired facilities accounted for 49 per cent of Alberta's total electric generating capacity, and natural gas-fired facilities accounted for 38 per cent.

In 2007, Alberta's electricity generating capacity increased 294 MW. Most of the contribution was due to additional capacity from wind turbines. Three new wind projects were commissioned in 2007, including Alberta Wind Energy's (AWE's) two wind turbines totalling 3.6 MW for the Oldman River project (with plans to expand the capacity by another 47 MW by 2009), the Taber Wind Farm operated by ENMAX at 81.4 MW, and a 54 MW Kettles Hill wind farm expansion (previous capacity at 9 MW).

An 85 MW cogeneration plant was commissioned at Suncor's Firebag thermal in situ oil sands project, which is the first in a series of cogeneration plants proposed by Suncor to be installed in stages. The steam from the cogeneration will be used at the in situ operation, while most of the power will supplement Suncor's main oil sands plant.



TransAlta spent $58 million on a capacity uprate at Unit 4 of its Sundance coal-fired power plant. This uprate consisted of a new turbine and modifications to the boiler, electrostatic precipitators, and several auxiliary systems, enabling Unit 4 to achieve greater efficiencies and an additional 54 MW of capacity. Unit 4 will be able to produce 14 per cent more power but will only require about a 7 per cent increase in fuel consumption. TransAlta is planning a similar uprate at Sundance Unit 5.

The current forecast indicates that electricity generating capacity in Alberta has the potential to increase by more than 4000 MW over the next ten years. New power projects considered in the electricity forecast are summarized in **Table 9.1**. Projects, capacities, and planned startups are based on information obtained from the AUC regulatory database as of February 29, 2008. By the end of the forecast period, the ERCB expects electricity generating capacity in Alberta to be near 16 000 MW.

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. 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 a requirement of oil sands projects. Because there are greater efficiencies associated with cogeneration compared to purchasing electricity and using steam generators, combining cogeneration with the oil sands facility can reduce costs over the life of an oil sands project. If the plant is able to sell additional power to other customers, then cogeneration would supplement project revenues. By 2017, the capacity of natural gas-fired power and cogeneration units are forecast to total more than 7000 MW, accounting for 45 per cent of Alberta's total available capacity.

Table 9.1. Proposed power plant additions greater than 5 MW, 2008-2017

Power project	Fuel / type	Location	Proposed capacity (MW)
2008			
Bantry power generation project	Natural gas	Forty Mile County	7
Parkland power generation project	Natural gas	Parkland County	7
Clover Bar power plant 1	Natural gas	Strathcona County	43
Caroline power generation project	Natural gas	Clearwater MD	22
Westlock (Dapp) addition	Natural gas	Westlock County	14
Horizon oil sands cogen 1	Natural gas	Wood Buffalo MD	101
Christina Lake in situ cogen 1	Natural gas	Wood Buffalo MD	85
Long Lake in situ cogen	Natural gas/syngas	Wood Buffalo MD	170
2009			
Sundance 5 uprate	Coal	Parkland County	53
Valleyview power plant	Natural gas	Greenview MD	45
Crossfield Energy Centre	Natural gas	Rocky View MD	120
Deerland peaking station	Natural gas	Lamont County	90
Northern Prairie power project	Natural gas	Grande Prairie County	85
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
2010			
Deerland peaking station	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	201
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
2011–2017			
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
Total proposed generation (2008-2017)			4118

9.1.2 Electricity Generating Capacity by Fuel

Coal

In 2007, coal-fired generating units accounted for 49 per cent of Alberta's generating capacity. The current capacity of Alberta's coal generation is 5918 MW. The development of an additional 503 MW of coal-fired electricity capacity will occur over the next decade. With the decommissioning of TransAlta Corporation's Wabamun Unit 4 in 2010, the net total coal-fired capacity is expected to increase to 6142 MW by 2017, accounting for 38 per cent of Alberta's electric capacity.

In May 2007, TransAlta applied to the EUB to complete an uprate to capacity at Unit 5 at its Sundance coal-fired plant. Using existing infrastructure, Sundance Unit 5 will be retrofitted with a new turbine, and modifications to the boiler and electrostatic precipitators will be made in order to achieve higher operating efficiencies. At project completion, Unit 5 will be able to produce an additional 53 MW of electricity but will use less fuel on a per MW basis. A similar project was completed on Sundance Unit 4 in 2007. Work on the Unit 5 uprate project is expected to proceed in 2008 and is forecast to be completed in 2009.

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 air emissions will be lower on a per MW 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.

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

Natural Gas

Natural gas-fired generating capacity accounts for 38 per cent of Alberta's current total electricity capacity. The current capacity of Alberta's natural gas-fired generation is 4604 MW. Over the next 10 years, Alberta's natural gas-fired electric capacity is expected to increase by 2625 MW, representing 45 per cent of Alberta's total generating capacity.

The ERCB's 10-year forecast of new natural gas-fired cogeneration power plants that coincide with the development of the oil sands amount to an additional 1887 MW. These plants will account for 72 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 the oil sands cogeneration plant proposals, an increased number of regulatory applications for natural gas peaking stations were filed in 2007. With electricity loads ever increasing, the peaking stations are a solution to meet new peak electricity demands and can be constructed relatively quickly. However, only one of the regulatory applications in the queue proposed a peaking station 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.

Hydroelectric Power

Electricity from hydro sources accounted for 7 per cent of total capacity in 2007. The current capacity of Alberta's hydroelectric generation is approximately 900 MW. 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 a 100 MW hydroelectric power plant on the Peace River. The current forecast expects Dunvegan to commence operations in 2012.

Renewable Power

About 6 per cent of Alberta's current electricity capacity is classified as renewable power that 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 2007, Alberta biomass capacity amounted to 184 MW, less than 2 per cent of Alberta's total capacity.

Alberta's wind farms and turbines have the current potential to supply a maximum of 525 MW of electricity to the grid. Capacity growth for wind development rose steadily over the past few years. Between 2006 and 2007 wind turbine capacity increased 36 per cent, while the previous year wind capacity connected to the Alberta power grid increased 40 per cent. In 2007 three new wind projects were connected to the Alberta electricity grid: the Taber Wind Farm owned by ENMAX is Alberta's largest wind farm at 81.4 MW; AWE commissioned two turbines totalling 3.6 MW, the first in a suite of projects; and Kettles Hill expanded its wind farm from 9 MW to a total capacity of 63 MW. An additional 879 MW of wind power capacity is forecast. Within the next 10 years wind capacity is forecast to top 1400 MW, reaching 9 per cent of total capacity by 2017.

9.2 Supply of and Demand for Electricity

This section discusses the supply of and demand for electricity within Alberta. On the supply side, the stock of electricity, or capacity, is measured in watts, while the flow of electricity, or generation, is measured in watt hours. In this report, electricity demand is measured in gigawatt 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 expected 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 expected total load. By incorporating hourly loads, generating units are dispatched hourly, accounting for periods of high load and low load throughout each year.

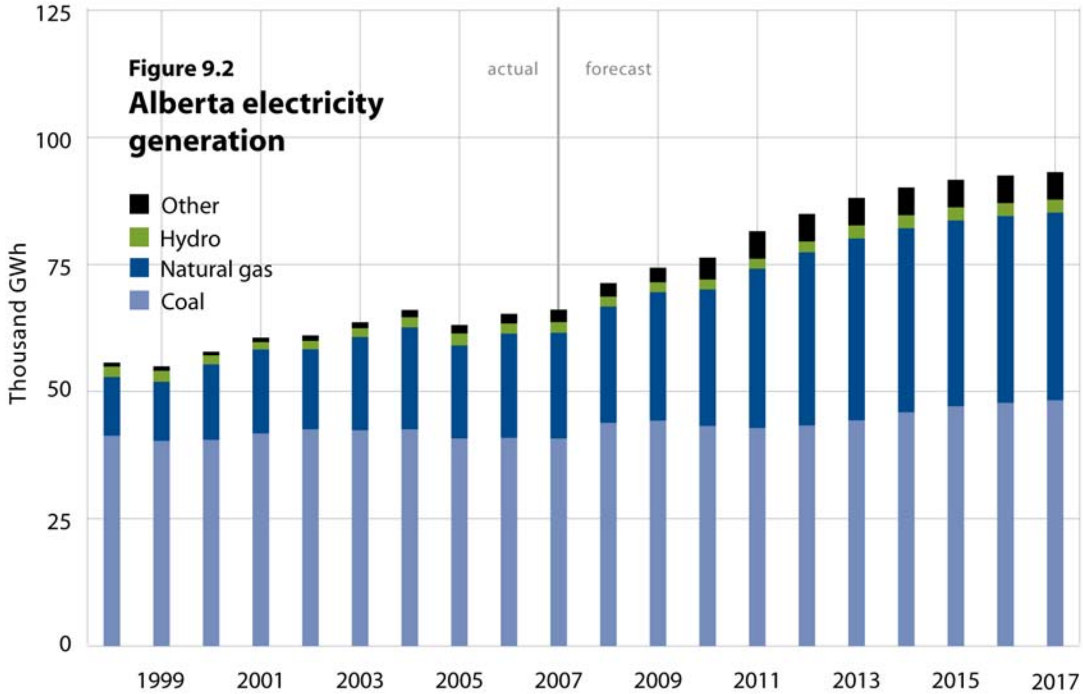
In this report, Alberta's electricity demand is characterized by the Alberta Internal Load (AIL). The AIL forecast includes electricity sales reported by electricity distributors to agricultural, residential, commercial, and industrial customers; the direct use of electricity by industrial consumers 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. Industrial customers are examined in detail in order to adequately account for electricity demand growth or contraction within these industries. The key drivers of electricity demand include Alberta's gross domestic product, housing stock, household income, and heating degree days. Within the oil sands sector, expectations for bitumen and SCO production and the types of projects (in situ vs. mining) are also important drivers.

9.2.1 Electricity Generation

Alberta installed electricity generation capacity in 2007 was 12 143 MW, enough to supply over 106 000 GWh of electricity if operated at full capacity. However, total electricity generating capacity is not continuously available to meet demand. Generating units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, technical limitations (for instance, of wind turbines), or economic reasons.

Figure 9.2 illustrates total electricity 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 2007, total electricity generation reached 66 143 GWh. Between 1998 and 2007, electricity generation in Alberta grew by 10 514 GWh or, on average, 2 per cent per year.



In 2007, coal-fired power plants generated 62 per cent of the province's electricity, while natural gas and hydro accounted for 32 and 3 per cent respectively. The remaining 3 per cent was generated by wind and other renewable sources. Natural gas cogeneration plants dedicated to the oil sands sector generated 12 543 GWh of electricity. In the oil sands, 7800 GWh (62 per cent) of the electricity generated was used on site, with the remaining sold into the power pool.

Wind turbines contributed 1430 GWh, or 2 per cent, of total electricity generation in 2007, 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.

The capacity additions discussed in the previous section, as well as the decommissioning of 279 MW (Unit 4) at TransAlta's Wabamun coal-fired power plant in 2010 and apparent electricity loads from residential, farm, commercial, and industrial sectors, suggest that electricity generation in Alberta will grow by an additional 27 terawatt hours (TWh) over the next 10 years, or an average of 4 per cent per year.

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.

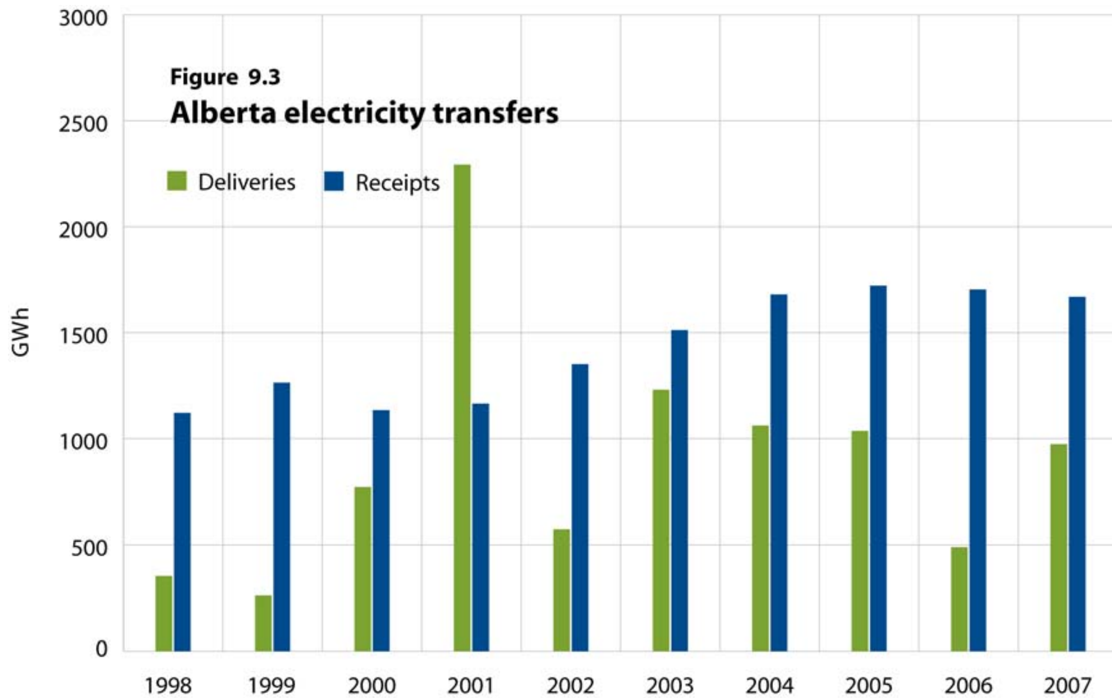
The Alberta-B.C. interconnection was designed to operate at transfer capacities of 1200 MW from B.C. to Alberta and 1000 MW from Alberta to B.C. Operations on the Alberta-

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.

Over the last decade, Alberta has generally been a net importer of electricity. However, in 2001 the electricity price differentials between Alberta and the Pacific Northwest favoured Alberta and resulted in net exports for the year. Net imports of electricity into Alberta for other years were relatively small, at about 1 per cent of Alberta generation in 2007.

Figure 9.3 illustrates Alberta's electricity transfers from 1998 to 2007. In 2007, Alberta imported 1669 GWh of electricity, a decrease of 2 per cent, or 35 GWh, from 2006. Electricity exports increased 99 per cent, or 484 GWh, to 973 GWh in 2007. As a result, Alberta's net imports of electricity were about 696 GWh in 2007.



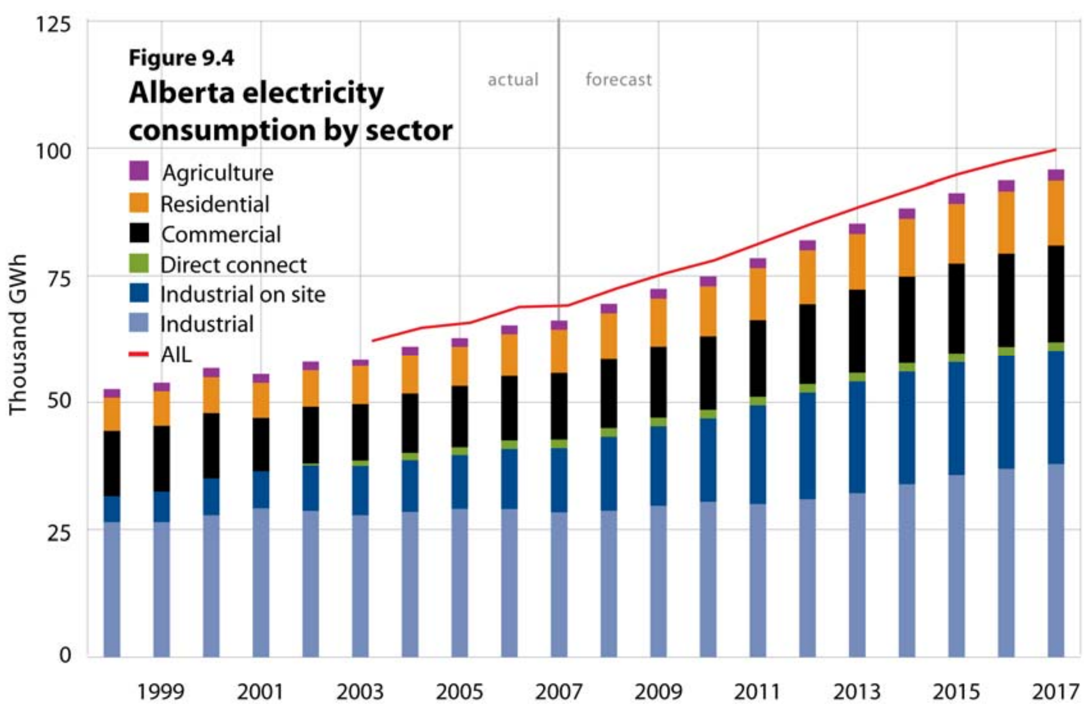
In 2006, Montana Alberta Tie Ltd. (MATL) filed regulatory applications to build a 230 kV merchant electric transmission line between Lethbridge, Alberta, and Great Falls, Montana. The transmission line is expected to provide new direct import and export opportunities between Alberta and Montana. The proposed MATL system is capable of transferring 300 MW of electricity in each direction. The MATL project has acquired regulatory approval from the National Energy Board and EUB for the construction and operation of the transmission line and related facilities within Alberta and the connection to the AIES. The MATL line is expected to carry generation from wind turbines in Alberta and Montana. Construction is planned to commence in 2008, with a completion date of 2009.

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.[1] 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 from the ERCB economic growth forecast, oil sands development, population, housing stock, and heating degree days.

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 distribution losses) amounted to 66 168 GWh in 2007. Compared to 2006, this is an increase of 938 GWh, or 1 per cent.



Electricity distribution companies, including ATCO Electric, ENMAX Corporation, EPCOR, Fortis Alberta Inc., the cities of Lethbridge, Medicine Hat, Red Deer, Cardston, Fort Macleod, Ponoka, and the municipality of Crowsnest Pass, are required to report their annual retail sales of electricity to the ERCB.

[1] 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 2007, direct connect sales were about 1711 GWh, or 2 per cent of total AIL demand.

In 2007, Alberta's electricity consumption from sales reported by electricity distributors was 51 838 GWh. This is a slight increase from the sale of 51 731 GWh (revised from *ST98-2007*) in 2006. From these sales, about 55 per cent of the electricity consumed is sold to industrial customers, 25 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 8558 GWh of electricity in 2007. This is equal to an electricity intensity of 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 90.2 MWh in 2007.

Of the total electricity demand from all sectors, 81 per cent was sold through the AIES. In 2007, almost 43 000 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 12 619 GWh of the electricity requirements of the industrial sector was delivered through on-site power generation or cogeneration.

With many new oil sands projects in the forecast, industrial demand will continue to steer the electricity load forecast. AIL is expected to grow by 3500 MW, or 4 per cent per year, over the next 10 years. Over the next year, 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.

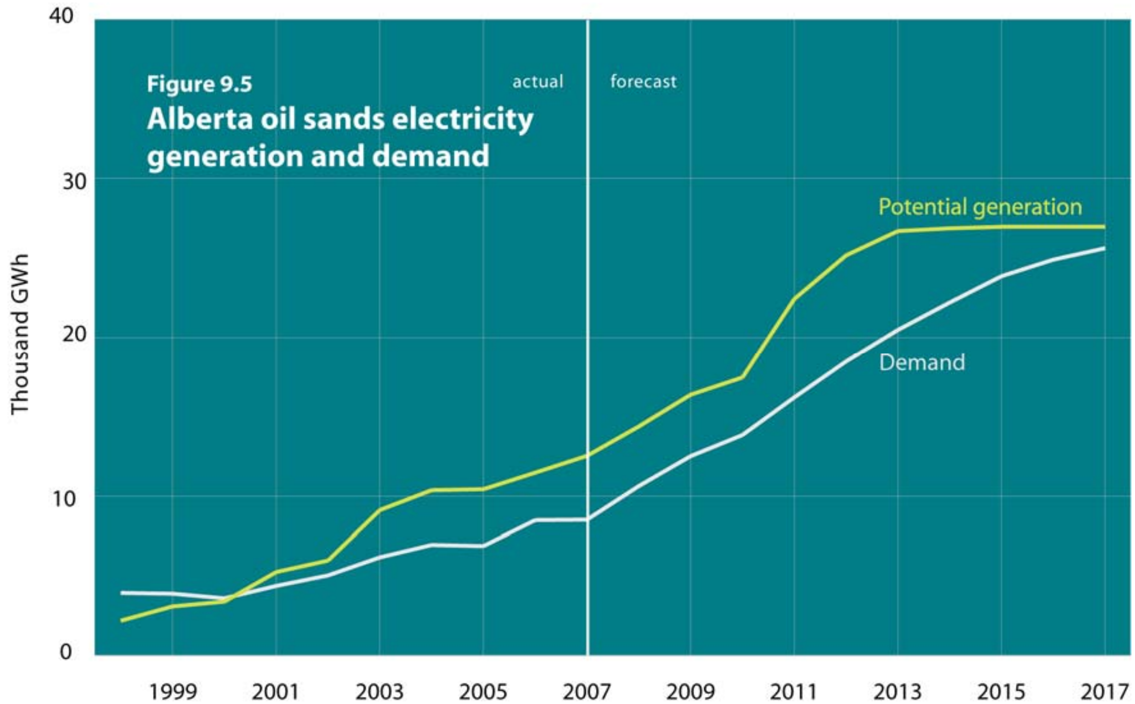
Over the next 10 years, growth in residential electricity demand will be comparable to its previous year, averaging 4 per cent per year. These trends are expected to continue due to the expected growth of provincial population and housing stock. Farm load will continue to grow at about 2 per cent per year. Electricity demand in the commercial sector will also continue its recent course, at about 4 per cent per year, based on the ERCB's current economic forecast for Alberta.

The expected growth in industrial loads will average 4 per cent per year. Over the first half of the forecast period, industrial load growth is expected to average 5 per cent annually. The oil sands sector is expected to dominate industrial load growth. For example, the ERCB expects the oil sands industry to account for 89 per cent of industrial load growth. By the end of the forecast period, electricity demand from industrial consumers will increase slightly, accounting for 65 per cent of total electricity demand from all sectors. On-site generation and cogeneration will provide greater amounts of the industrial load (36 per cent), leaving 64 per cent of the industrial load to be served through sales on the AIES.

Both Alberta electricity generation and AIL demand are expected to grow at average rates of 4 per cent a year over the next decade. Over the coming years, load growth will be met by existing and new natural gas- and coal-fired power plants. 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 loads. 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. This outlook, along with the strengthening of natural gas prices, complements the electricity price forecast discussed in Section 1 on economics.

9.2.4 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the balance between electricity supply and demand[2] 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 of 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 very long term upgrading operations are expected to be much more intensive users of electricity. With public emphasis on the environment and emissions, the oil sands will 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, where on-site compression of CO_2 is expected to increase electricity loads.

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 2007 electricity statistics by type of oil sands facility. Data at mines and upgraders confirm that capacity utilization averages 73 per cent; of the total electricity generated, 71 per cent is utilized on-site and the remaining is sold to the power pool. Currently, all oil sands mines and bitumen upgraders obtain electricity from an on-site

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

cogeneration facility. However, the lack of upgrader projects from the list of new capacity illustrates that many new upgraders sited in the Edmonton region will rely increasingly on purchasing electricity from the AIES. When carbon capture and storage mechanisms are implemented, the loads will provide further potential for increased electricity generating capacity in the Edmonton area.

Table 9.2. 2007 electricity statistics at oil sands facilities

Project type	Capacity (MW)	Total generation (GWh)	Capacity utilization (%)	Generation used on site (GWh)
Mines and upgraders*	1316	8360.6	73	5958.5
Thermal in situ	580	4182.5	82	1839.3

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

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.

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. On average, thermal in situ cogeneration facilities operate at 82 per cent of their installed capacity. An average of 44 per cent of the electricity generated is used on site, and the remainder is available to be sold to the power pool.

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, but the ERCB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchaser's classification.

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, but the ERCB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchaser's classification.

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.
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 2003 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
ha	hectare
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
d	day
EJ	exajoule
ha	hectare
J	joule
kg	kilogram
kPa	kilopascal
M	mega
m	metre
MJ	megajoule
mol	mole
T	tera
t	tonne
TJ	terajoule

Imperial

bbl	barrel
Btu	British thermal unit
cf	cubic foot
d	day
°F	degree Fahrenheit
psia	pounds per square inch absolute
psig	pounds per square inch gauge

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, Coalbed Methane, and Natural Gas Reserves

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	149 912
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			271 993

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 - 20	3-D Model	4953.00	75.00	32.1	0.097			
20 - 40	3-D Model	5283.00	82.00	31.3	0.097			
40 - 80	3-D Model	5851.00	99.00	28.7	0.096			
50 - 750+	Isopach	133825.00	4792.00	13.0	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

(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 H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
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

(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 E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/Seibert Lk A	Isopach	6.61	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

(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	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake Nn	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake Pp	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh Dd	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh Ee	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh Ff	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh Gg	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh Hh	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh Ii	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh Jj	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh Kk	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh Mm	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh Nn	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh Pp	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
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

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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 H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350 – 625	Isopach	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		271993.15						

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

	Initial established						
Year	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

Table B.4. Conventional crude oil reserves by geological period as of December 31, 2007

Geological period	Initial volume in-place (10^6 m^3)		Initial established reserves (10^6 m^3)		Remaining established reserves (10^6 m^3)		Average recovery (%)	
	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy
Cretaceous								
Upper	2153	0	355	0	43	-	16	-
Lower	1 307	2 099	252	360	30	61	19	17
Jurassic	107	110	21	36	3	4	20	33
Triassic	420	30	83	3	13	1	20	10
Mississippian	483	70	84	9	10	1	17	13
Devonian								
Upper	2 658	33	1 173	3	53	1	44	9
Middle	972	0	358	0	19	0	37	-
Other	80	10	14	0	3		9	
Total	8 179	2 352	2340	411	173	68	29	17

Table B.5. Distribution of conventional crude oil reserves by formation as of December 31, 2007

Geological formation	Initial volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)	Remaining established reserves (10^6 m^3)	Initial volume in-place (%)	Initial established reserves (%)	Remaining established reserves (%)
Upper Cretaceous						
Belly River	302	47	9	3	2	4
Cardium	1 705	294	31	16	11	13
Second White Specks	42	5	1	0	0	0
Doe Creek	79	7	2	1	0	1
Dunvegan	24	2	0	0	0	0
Lower Cretaceous						
Viking	355	68	5	3	2	2
Upper Mannville	2 054	318	56	20	12	25
Lower Mannville	997	226	30	9	8	12
Jurassic	217	57	7	2	2	3
Triassic	450	86	14	4	3	6
Mississippian						
Rundle	350	62	7	3	2	3
Pekisko	97	16	2	1	1	1
Banff	106	14	2	1	1	1
Upper Devonian						
Wabamun	70	8	2	1	0	0
Nisku	474	213	12	5	8	5
Leduc	824	511	9	8	19	4
Beaverhill Lake	1 142	408	23	11	15	10
Slave Point	181	36	8	2	1	3
Middle Devonian						
Gilwood	309	134	5	3	5	2
Sulphur Point	9	2	0	0	0	0
Muskeg	61	10	1	1	0	0
Keg River	494	179	10	5	7	4
Keg River SS	43	18	1	0	1	0
Granite Wash	56	14	2	1	1	1

Table B.6. Upper Cretaceous and Mannville CBM in place and established reserves, 2007 (10^6 m^3), deposit block model method

Field/strike area	Block model area (ha)	average coal thickness (m)	Coal reservoir volume (10^6 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas In place (10^6 m^3)	Adjusted average recovery factor	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Corbett / Thunder	12611	10	1301	12.80	16647	15.60%	2597	487	2110	733
Doris	4226	10	418	12.80	5346	15.60%	834	190	644	357
Aerial	1664	7	251	0.63	1	4%	1	1	0	0
Ardenode	13108	9	1384	3.19	4660	4%	226	87	139	0
Bashaw	72175	10	7401	1.20	8784	21%	1698	261	1437	2
Bittern Lake	20374	16	1296.81	1.42	1871	7%	187	11	176	2
Blackfoot	2093	5	400	2.19	825	8%	75	0	75	0
Brant	370	5	74	no data	67	6%	4	3	1	0
Buffalo Lake	8422	10	624	1.04	645	11%	89	16	72	0
Carbon	25537	11	2314	1.93	4341	10%	469	43	426	0
Cavalier	21901	12	1823	1.74	3037	11%	374	15	359	0
Centron	34558	15	2291	2.26	4671	5%	277	52	224	0
Chain	17936	35	512.42	0.93	480	25%	98	23	75	0
Chigwell	38352	12	3094	2.04	6392	10%	684	61	623	0
Clive-Alix	19205	10	1832	1.66	3014	25%	894	113	781	0
Craigmyle	2480	7	356	0.84	307	10%	25	31	-7	0
Crossfield	1375	11	125	no data	275	4%	11	13	-2	0
Davey	1528	11	139	no data	333	6%	20	19	1	0
Delia	28207	12	2296	0.86	1949	7%	135	46	89	0
Donalda	6060	11	146	0.84	121	6%	10	0	9	0
Dorenlee	2177	11	198	no data	475	4%	19	6	13	0
Drumheller/W	3719	7	531	no data	1275	4%	51	17	34	0
Elnora	24395	9	2699	1.63	4392	16%	761	164	597	1
Entice	69650	11	6115	2.36	14421	19%	3021	385	2637	1
Erskine	20930	14	1218	0.96	1158	7%	111	48	63	0
Ewing Lake	10765	16	657	1.00	655	6%	43	36	7	0
Fenn West	5132	6	855	no data	1625	4%	65	36	29	0
Fenn BV	43182	16	2718	0.74	1918	14%	308	80	227	0
Ferintosh	10596	11	592	1.11	648	11%	65	33	33	0
Ferrybank	17321	11	816	2.16	1793	4.58%	103	18	85	0
Foster	12636	9	1438	3.94	5653	5%	346	23	323	0
Gadsby	5893	11	536	no data	1125	4%	45	17	28	0
Gayford	19448	7	2766	2.25	6584	10.17%	867	135	732	0
Ghostpine	79931	10	8038	1.61	12438	7.12%	955	172	784	0
Herronton	38314	6	1770	2.03	3334	4%	95	1	94	0
Hussar	13594	6	2266	no data	1813	8%	145	43	102	0
Huxley	11842	6	1974	no data	3750	8%	300	103	197	0
Irricana	19411	7	2823	2.47	6778	20%	1352	134	1218	1
Joffre	3993	10	386	2.06	778	5%	47	74	-27	1
Lacombe	8125	11	739	no data	1625	4%	65	30	35	0
Lone Pine	3750	6	625	no data	1188	8%	95	42	53	0
Malmo	20964	14	2002	1.36	2655	11%	319	101	218	1
Manito	7106	6	475	0.83	379	8%	37	5	31	0
Michichi	579	6	96	no data	183	12%	22	5	17	0
Mikwan	62724	13	4805	1.23	5799	4.30%	249	130	120	1
Morningside	526	6	88	no data	167	12%	20	13	7	0
Neerlandia	2395	10	239	no data	3066	15.60%	478	145	333	293
Nevis	51662	9	5962	1.29	7637	19%	1564	293	1270	1
New Norway	10786	14	1035	1.32	1361	8%	123	17	106	0
Oberlin	6042	12	516	1.04	539	15%	86	47	39	0
Parflesh	19219	8	2346	1.89	4327	6%	283	41	242	0
Penhold	14583	14	1042	no data	2500	4%	100	15	85	0
Redland	15822	9	1821	1.92	3163	8%	247	85	162	0
Rich	21176	9	2353	no data	4000	7%	280	138	142	2

(continued)

Field/strike area	Block model area (ha)	average coal thickness (m)	Coal reservoir volume (10^6 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas In place (10^6 m^3)	Adjusted average recovery factor	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Rockyford	37804	8	4746	1.09	4713	12%	575	124	452	1
Rowley	28726	11	2515	1.04	2576	11%	292	60	232	0
Rumsey	4864	9	567	1.16	661	16%	105	65	40	0
Stettler/N	13185	6	510	0.86	435	4.66%	28	3	26	0
Stewart	789	6	132	no data	250	8%	20	13	7	0
Strathmore	73934	10	7230	2.47	18545	7%	1296	210	1086	1
Swalwell	4454	17	265	2.80	732	5%	35	71	-36	0
Thorsby	938	6	156	no data	125	8%	10	1	9	0
Three H Ck	54425	15	3707	2.33	8521	4%	434	117	317	0
Trochu	12630	9	1423	1.35	1870	17%	344	131	213	0
Twining	98609	10	9418	2.84	30135	7%	2556	266	2290	1
Vulcan	938	6	156	no data	125	4%	5	2	3	0
Wayne	7500	9	833	no data	1000	8%	80	65	15	0
Westrose / S	18464	5	3768	no data	3014	4%	121	4	116	0
Wetaskiwin	1310	11	119	no data	250	4%	10	4	6	9
Wimborne	35512	10	3387	2.92	18037	9%	1875	104	1771	1
Wood River	5722	11	525	1.76	882	12%	108	15	93	0
Workman	9495	12	788	4.07	3329	11%	454	15	439	0
Total	1399871	10	130861		268166		29717	5374	24343	1415

Table B.7. Noncommercial CBM production, 2007 (10^6 m^3), production extrapolation method—other CBM areas

Field/strike area	Coal zone	Initial gas In place (10^6 m^3)	Initial established reserves (10^6 m^3)	Gas - net cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - net cumulative production (10^3 m^3)
Canmore	Mist Mtn	not calc	not recorded	not recorded	0	not recorded
Fenn BV / W	Upper Mann	not calc	12	12	0	1
Coleman / Livingstone	Mist Mtn	not calc	0	0	0	0
Redwater	Upper Mann	not calc	not recorded	not recorded	0	not recorded
Pine Creek / Brazeau	Ardley	not calc	not recorded	not recorded	0	not recorded
Pembina	Ardley	not calc	4	4	0	7
Manola/ Mellow	Upper Mann	not calc	3	3	0	5
Drumheller	Upper Mann	not calc	0	0	0	0
Norris	Upper Mann	not calc	2	2	0	19
Battle South	Upper Mann	not calc	0	0	0	0
Kelsey	Upper Mann	not calc	1	1	0	11
Swan Hills / Swan Hills S	Upper Mann	not calc	0	0	0	16
Provost	Upper Mann	not calc	1	1	0	43
Miscellaneous	Upper Mann	not calc	21	21	0	28
Miscellaneous	Scollard or HSC	not calc	51	51	0	11
Total		not calc	95	95	0	140

Table B.8. Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

	Initial established							
Year	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	58.6	45.3	-16.7	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	43.2	59.8	42.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	36.6	47.2	41.9	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	51.0	40.5	34.8	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	36.5	30.0	28.1	94.6	4 893.3	3 823.9	1 069.3	1 112.2

[a] At field plant.

Table B.9. Geological distribution of established natural gas reserves, 2007

Geological period	Gas in place Initial volume (10^9 m^3)	Marketable gas Initial established reserves (10^9 m^3)	Marketable gas Remaining established reserves (10^9 m^3)	Gas in Place Initial volume (%)	Marketable gas Initial established reserves (%)	Marketable gas Remaining established reserves (%)
Upper Cretaceous						
Belly River	160	92	33	1.9	1.9	3.1
Milk River & Med Hat	1019	530	199	12.1	10.9	18.6
Cardium	371	119	41	4.4	2.4	3.8
Second White Specks	36	19	11	0.4	0.4	1.1
Other	315	168	64	3.7	3.4	6.0
Subtotal	1 901	928	348	22.5	19.0	32.6
Lower Cretaceous						
Viking	450	300	48	5.3	6.1	4.5
Basal Colorado	33	27	2	0.4	0.6	0.2
Mannville	2 129	1 390	310	25.2	28.4	29.0
Other	479	309	74	5.7	6.3	6.9
Subtotal	3 091	2 026	434	36.6	41.4	40.6
Jurassic						
Jurassic	102	64	16	1.2	1.3	1.5
Other	116	72	17	1.4	1.5	1.6
Subtotal	218	136	33	2.6	2.8	3.1
Triassic						
Triassic	264	164	46	3.1	3.4	4.3
Other	21	14	3	0.2	0.3	0.3
Subtotal	285	178	49	3.3	3.7	4.6
Permian						
Belloy	9	6	1	0.1	0.1	0.1
Subtotal	9	6	1	0.1	0.1	0.1
Mississippian						
Rundle	894	555	70	10.6	11.3	6.5
Other	350	238	28	4.2	4.8	2.6
Subtotal	1 244	793	98	14.8	16.1	9.1
Upper Devonian						
Wabamun	277	129	20	3.3	2.6	1.9
Nisku	131	64	15	1.6	1.3	1.4
Leduc	470	246	11	5.6	5.0	1.0
Beaverhill Lake	500	227	29	5.9	4.6	2.7
Other	181	106	13	2.1	2.2	1.2
Subtotal	1 559	772	88	18.5	15.7	8.2
Middle Devonian						
Sulphur Point	15	9	3	0.2	0.2	0.3
Muskeg	6	2	1	0.1	0.0	0.1
Keg River	65	25	10	0.8	0.6	0.9
Other	35	15	2	0.4	0.3	0.2
Subtotal	121	51	16	1.5	1.1	1.5
Confidential						
Subtotal	4	2	2	0.1	0.1	0.2
Total	8 432 (299)[a]	4 892 (173)[a]	1 069 (38)[a]	100.0	100.0	100.0

[a] Imperial equivalent in trillions of cubic feet at 14.65 pounds per square inch absolute and 60°F.

Table B.10. Natural gas reserves of retrograde pools, 2007

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	0.75	0.50	16	41.01	380	15
Brazeau River Nisku K	1 360	74.17	101	0.75	0.60	30	42.15	718	17
Brazeau River Nisku M	1 945	76.22	148	0.75	0.60	44	43.33	1 076	55
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435	1 107
Brazeau River Nisku S	1921	54.64	105	0.80	0.57	36	41.38	873	30
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200	225
Caroline Beaverhill Lake A	61 977	49.95	3 096	0.84	0.76	621	36.51	17 000	2 361
Carson Creek Beaverhill Lake B	11 436	55.68	637	0.90	0.39	350	41.54	8 426	93
Harmattan East Lower Mannville C & Rundle	45 031	50.26	2 263	0.79	0.26	1 323	41.63	31 783	6 618
Harmattan-Elkton Rundle C	23 012	46.96	1 081	0.86	0.27	679	28.42	23 895	1 225
Kakwa A Cardium A	3 848	55.40	213	0.85	0.32	123	49.92	2464	1 489
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 639	39.68	41 300	882
Ricinus Cardium A	13 295	58.59	779	0.85	0.32	450	42.0	10 775	769
Valhalla Halfway B	6 331	53.89	341	0.80	0.33	183	40.00	4 572	2 839
Waterton Rundle-Wabamun A	90 422	48.74[a]	4 407	0.95	0.35	2 721	48.73	55 836	2 648
Wembley Halfway B	6 662	53.89	359	0.67	0.33	161	49.31	3 265	1 846

(continued)

Table B.10. Natural gas reserves of retrograde pools, 2007 (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	10 771	51.55	555	0.90	0.25	375	49.19	7 623	53
Westpem Nisku E	1 160	66.05	77	0.90	0.54	32	44.76	709	153
Windfall D-3 A	25 790	53.42	1 338	0.60	0.53	425	44.92	9 462	1 035

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

Table B.11. Natural gas reserves of multifield pools, 2007

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Belly River Pool No. 1	
Bashaw Edmonton & Belly River MU#1	930
Nevis Edmonton & Belly River MU#1	886
Total	1 816
Belly River Pool No. 6	
Aerial Belly River III & Basal Belly River E	37
Ardenode Edmonton & Belly River MU#1	1 763
Brant Edmonton & Belly River MU#1	361
Centron Edmonton & Belly River MU#1	2 177
Cessford Belly River III & Basal Belly River C & K	19
Crossfield Lower Edmonton A, Belly River III & Basal Belly River G	130
Dalmead Lower Edmonton & Belly River III	61
Entice Edmonton & Belly River MU#1	4 831
Gayford Edmonton & Belly River MU# 2	424
Ghost Pine Belly River III	714
Gladys Edmonton & Belly River MU#1	509
Herronton Edmonton & Belly River MU#1	596
Irricana Belly River III	222
Lomond Belly River III & Basal Belly River A	202
Majorville Belly River MU#1	74
Matziwin Belly River III & Basal BellyRriver F	30
Michichi Edmonton, Belly River & Mannville MU#1	65
Milo Belly River III & Basal Belly River A &B	80
Okotoks Belly River III	364
Parflesh Edmonton, Belly River & Mannville MU#1	990
Queenstown Belly River III	8
Redland Edmonton Belly River, Viking & Mannville MU#1	396
Rockyford Edmonton, Belly River, Colorado & Mannville MU#1	1 387
Rowley Belly River III & Basal Belly River G	46
Seiu Lake Belly River III & Viking C	86
Strathmore Edmonton & Belly River MU#1	1 721
Swalwell Belly River III & Basal Belly River A	16
Twining Belly River III	58
Vulcan Belly River III	373
Wayne-Rosedale Belly River MU#1	1 129
West Drumheller Belly River III, Basal Belly River B & C	3
Total	18 872
Basal Belly River Pool No. 1	
Bruce Belly River M & A2A & Basal Belly River B	65
Holmberg Basal Belly River B	109
Total	174
Basal Belly River Pool No. 2	
Fenn West Basal River B	8
Fee-Big Valley Edmonton & Mannville MU#1	88
Gadsby Edmonton, Belly River & Mannville MU#1	372
Total	468
Basal Belly River Pool No.5	
Hussar Basal Belly River B	77
Total	77

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Cardium Pool No. 1	
Ansell Belly River, Cardium, Viking, & Mannville MU#1	12 898
Minehead Belly River, Cardiun, Viking & Mannville MU# 1	1 945
Sundance Belly River, Cardium, Viking, & Mannville MU#1	7 358
Total	22 201
Southeastern Alberta Gas System (MU)	
Aerial Medicine Hat	219
Alderson Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River Colorado, First White Specks & Fish Scales	20 139
Armada Milk River, Medicine Hat and Belly River	1 074
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River and Basal Belly River	5 145
Bantry Milk River, Medicine Hat, Fish Scale, Second White Specks, First White Specks, Belly River, Basal Belly River / and Colorado	11 261
Berry Medicine Hat	85
Bindloss Milk River and Medicine Hat	1 032
Blackfoot Medicine Hat, Belly River and Basal Belly River	1 412
Bow Island Milk River, Medicine Hat, Second White Specks and Colorado	1 649
Brooks Milk River, Medicine Hat, Second White Specks and Basal Belly River	337
Cavalier Belly River and Viking	425
Cessford Milk River, Medicine Hat, Second White Specks and First White Specks	9 431
Connorsville Milk River, Medicine Hat, Belly River, Colorado and First White Specks	2 452
Countess Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River, Colorado, Fish Scale, Bow Island, Viking, Basal Colodaro, Mannville and Pekisko	34 764
Drumheller Medicine Hat, Belly River, Basal Belly River Viking Basal Colorado Mannville and Pekisko	1 792
Elkwater Medicine Hat & second White Specks	1 390
Enchant Second White Specks	163
Eyremore Milk River, Medicine Hat, Second White Specks, and Colorado	2 692
Farrow, Milk River, Medicine Hat, Belly River and Basal Belly River	970
Gleichen Medicine Hat and Belly River	563
Herronton	25
Hussar Milk River, Medicine Hat, Belly River, Basal Belly River, Edmonton, Viking, Glauconitic and Second White Specks	3 864
Jenner Milk River, Medicine Hat, Second White Specks and Colorado	3 023
Johnson Milk River, Medicine Hat and Second White Specks	335
Jumpbush Belly River & Medicine Hat	489
Kitsim Milk River, Medicine Hat and Second White Specks	508

(continued)

Table B.11. Natural gas reserves of multifield pools, 2007 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Lathom Milk River , First White Specks, Medicine Hat, Fish Scale, Second White Specks and Belly River	1 694
Leckie Milk River, Medicine Hat, Belly River, and Second White Specks	782
Long Coulee Medicine Hat	121
Majorville Milk River and Medicine Hat	2 400
Matziwin Milk River, Medicine Hat, First White Specks, Fish Scale and Second White Specks	964
McGregor Milk River and Medicine Hat	345
Medicine Hat Milk River, Medicine Hat, Fish Scale, Second White Specks, Belly River, and Colorado	42 739
Newell Milk River, Medicine Hat and Second White Specks	551
Pollockville Milk River and Medicine Hat	27
Princess Milk River, Medicine Hat, Second White Specks, and Colorado	13 071
Rainier Milk River, Medicine Hat and Second White Specks	335
Ronalane Second White Specks	115
Seiu Lake Medicine Hat	505
Shouldice Medicine Hat and Belly River and Basakl Belly River	1 043
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	15 675
Verger Milk River, Medicine Hat, Fish Scale, Belly River, Basal Belly River Second White Specks and Colorado	5 656
Wayne-Rosedale Medicine Hat, Milk River, First White Specks, Belly River and Basal Belly River	1 065
Wintering Hills Milk River, Medicine Hat, Second White Specks, Belly River, Basal Belly River and Colorado	2 350
Total	194 677
Second White Specks Pool No. 2	
Craigmyle Second White Specks E	1
Dowling Lake Second White Specks E	5
Garden Plains Second White Specks E	1 364
Hanna Second White Specks E	622
Provost Second White Specks & Viking	33
Richdale Second White Specks E	133
Sullivan Lake Second White Specks E	171
Watts Medicine Hat B & C and Second White Specks E	8
Total	2 337
Second White Specks Pool No. 3	
Conrad Second White Specks J & Barons A, E, F I & J	359
Pendant D'Oreille Medicine Hat E & Second White Specks J	421
Smith Coulee Medicine Hat A & Second White Specks J	336
Total	1 116
Second White Specks Pool No. 4	
Enchant Basal Belly River B and Second White Specks B	627
Grand Forks	15
Retlaw Basal Belly River I & K and Second White Specks B	503
Vauxhall Second White Specks B	35
Total	1 180
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	73
Peavey Upper Viking A	2
Redwater Viking and Mannnville MU#1	392
Westlock Middle Viking B	200
Total	667
Viking Pool No. 2	
Albers Upper & Middle Viking A & Colony A	12
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	206
Bellshill Lake Upper and Middle Viking A	14
Birch Upper and Middle Viking A	1
Bruce Viking & Mannvillie MU#1	930
Dinant Upper & Middle Viking A	19
Fort Saskatchewan Upper and Middle Viking A	128
Holmberg Upper and Middle Viking A	3
Killam Colony, Viking & Mannville MU#1	200
Killam North Viking Mannville & Nisku MU#1	231
Mannville Viking & Mannville MU#1	500
Sedgewick Upper and Middle Viking A	7
Viking-Kinsella Viking, Colony, Mannville & Wabamun MU#1	1 602
Wainwright Colony, Viking & Mannville MU#1	213
Total	4 066
Viking Pool No. 3	
Carbon Edmonton Belly River, Viking, Mannville & Rundle MU #1	400
Ghost Pine Viking D	13
Total	413
Viking Pool No. 5	
Hudson Viking A	48
Sedalia Viking A & F, Upper Mannville D & AA, and Lower Mannville B	172
Total	220
Viking Pool No. 6	
Hairy Hill Viking & Mannville MU#1	133
Willingdon Viking & Mannville MU#1	4
Total	137

(continued)

Table B.11. Natural gas reserves of multifield pools, 2007 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Viking Pool No. 7	
Inland Viking and Upper Mannville MU#1	78
Royal Upper Viking C and Lower Viking A	34
Total	112
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	89
Ferrybank Viking C, Glauconitic A, & Lower Mannville W	167
Total	256
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	347
Pembina Glauconitic I & D and Ostracod C	273
Total	620
Glauconitic Pool No. 6	
Hussar Viking L, Glauconitic III, and Ostracod OO	1 143
Wintering Hills Upper Mannville I, Glauconitic III & Lower Mannville I	32
Total	1 175
Bluesky Pool No.1	
Rainbow Bluesky C	203
Sousa Bluesky C	660
Total	863
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	248
Hotchkiss Bluesky-Detrital-Debolt A	223
Total	471
Gething Pool No. 1	
Fox Creek Viking, Upper Mannville & Gething MU#1	718
Kaybob South Notikewin , Bluesky ,and Gething MU#1	329
Total	1 047
Ellerslie Pool No. 1	
Connorsville Colorado, Glauconitic and Ellerslie MU#1	592
Wintering Hills Upper Mannville & Ellerslie MU#1	144
Total	736
Cadomin Pool No. 1	
Elmworth Smokey, Fort St John, Bullhear & Triassic MU#1	9 865
Sinclair Doe Creek, Fort St John & Bullhead MU#1	3 340
Total	13 205
Halfway Pool No. 1	
Valhalla Halfway B	2 893
Wembley Halfway B	1 846
Total	4 739
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	948
Valhalla Halfway N	33
Total	981
Banff Pool No. 1	
Haro Banff E	114
Rainbow Banff E	14
Rainbw South Banff E	113
Total	241

Table B.12. Remaining raw ethane reserves as of December 31, 2007

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	15 664	0.082	1416	5 033
Brazeau River	9 853	0.065	826	2 938
Caroline	8 117	0.084	1 214	4 316
Cecilia	11 865	0.057	776	2 759
Countess	43 863	0.024	1 134	4 030
Dunvegan	11 068	0.044	544	1 933
Edson	6 486	0.070	508	1 807
Elmworth	15 708	0.057	1 067	3 794
Ferrier	13 078	0.086	1 250	4 442
Fir	5 228	0.061	353	1 255
Garrington	3 567	0.071	336	1 194
Gilby	4 998	0.065	369	1 312
Gold Creek	4 392	0.083	407	1 447
Harmattan East	7 203	0.084	677	2 408
Hussar	9 604	0.033	342	1 217
Judy Creek	2 728	0.144	482	1 715
Kaybob South	11 142	0.076	1 039	3 693
Karr	6 724	0.083	619	2 200
Kakwa	7 739	0.086	747	2 656
Leduc-Woodbend	2 701	0.107	340	1 209
Medicine River	4 387	0.085	442	1 573
Pembina	19 384	0.082	2 001	7 115
Pine Creek	5 040	0.072	438	1 556
Pouce Coupe South	5 878	0.050	333	1 184
Provost	15 532	0.028	477	1 696
Rainbow	8 669	0.069	746	2 654
Rainbow South	2 955	0.097	426	1 514
Ricinus	4 554	0.071	371	1 319
Sinclair	10 231	0.043	505	1 794
Sundance	9 001	0.072	721	2 563
Swan Hills South	2 806	0.174	698	2 483
Sylvan Lake	4 953	0.062	358	1 273
Valhalla	8 359	0.075	736	2 615
Virginia Hills	1 526	0.168	311	1 106
Waterton	6 787	0.029	323	1 149
Westpem	3 414	0.107	457	1 624
Westerose South	7 771	0.080	687	2 441

(continued)

Table B.12. Remaining raw ethane reserves as of December 31, 2007 (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	2 792	0.094	334	1 187
Wapiti	17 020	0.056	1 081	3 843
Wild River	25 803	0.069	1 930	6 863
Willesden Green	12 278	0.087	1 357	4 824
Smokey	4 235	0.076	353	1 256
Subtotal	385 103	0.065	29 531	104 990
All other fields	684 226	0.029	20 341	72 311
Total	1 069 329	0.052[a]	49 872	177 301

[a] Volume weighted average.

Table B.13. Remaining established reserves of natural gas liquids as of December 31, 2007

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ante Creek North	1 517	281	155	540	976
Ansell	15 664	2 291	1 212	2 559	6 061
Brazeau River	9 853	1 352	853	2 073	4 279
Caroline	8 117	1 882	1 488	3 540	6 910
Carrot Creek	2 705	482	219	178	879
Cecilia	11 865	932	362	1 000	2 294
Countess	43 863	1 689	912	742	3 343
Crossfield East	3 193	186	100	836	1 122
Dunvegan	11 068	939	543	914	2 396
Edson	6 486	661	316	329	1 305
Elmworth	15 708	1 218	563	661	2 442
Ferrier	13 078	2 214	1 117	872	4 203
Fir	5 228	400	173	239	812
Garrington	3 567	521	276	396	1 193
Gilby	4 998	594	300	345	1 239
Gold Creek	4 392	458	226	363	1 047
Harmattan East	7 203	886	566	971	2 423
Hussar	9 604	528	290	558	1 376
Judy Creek	2 728	1 155	479	278	1 912
Kaybob	2 853	421	201	285	907
Kaybob South	11 142	1 696	889	1 418	4 003
Karr	6 724	990	438	497	1 925
Kakwa	7 739	1 260	605	675	2 539
Knopcik	3 359	393	196	271	859
Leduc-Woodbend	2 701	988	582	354	1 924
McLeod	2 502	444	204	225	873
Medicine River	4 387	744	372	410	1 526
Moose	3 401	281	202	452	934
Peco	1 877	339	185	394	918
Pembina	19 384	3 884	1 907	1 670	7 460
Pine Creek	5 040	705	332	375	1 411
Pouce Coupe South	5 878	474	266	296	1 035
Provost	15 532	997	647	471	2 115
Rainbow	8 669	1 194	776	1 014	2 983
Rainbow South	2 955	795	376	420	1 591
Ricinus	4 554	620	316	600	1 535

(continued)

Table B.13. Remaining established reserves of natural gas liquids as of December 31, 2007 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Sinclair	10 231	733	285	350	1 368
Sundance	9 001	913	392	404	1 709
Swan Hills	885	509	279	231	1 018
Swan Hills South	2 806	1 708	782	326	2 815
Sylvan Lake	4 953	550	273	277	1 100
Valhalla	8 359	1 261	679	996	2 936
Virginia Hills	1 526	724	238	94	1 056
Waterton	6 787	367	332	2 137	2 836
Wayne-Rosedale	5 897	415	224	231	870
Westpem	3 414	769	412	492	1 673
Westerose South	7 771	1 272	611	579	2 462
Wembley	2 792	637	374	840	1 851
Wapiti	17 020	1 072	454	442	1 967
Wild River	25 803	2 103	903	1 447	4 452
Willesden Green	12 278	2 329	1 092	1 094	4 516
Wilson Creek	3 276	480	250	305	1 035
Smokey	4 235	543	248	175	966
Subtotal	416 568	51 279	26 472	37 641	115 380
All other fields	652 761	26 312	14 822	16 771	57 918
Total	1 069 329	77 591	41 294	54 412	173 298

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 2007 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.

Abbreviations Used in the Reserves and Basic Data Files

The abbreviations are divided into two groups (General Abbreviations and Abbreviations of Company Names) for easy reference.

General Abbreviations

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

Abbreviations of Company Names

AEC	Alberta Energy Company Ltd.
AEL	Anderson Exploration Ltd.
ALTAGAS	AltaGas Marketing Inc.
ALTROAN	Altana Exploration Company/Roan Resources Ltd.
AMOCO	Amoco Canada Petroleum Company Ltd.
APACHE	Apache Canada Ltd.
BARRING	Barrington Petroleum Ltd.
BEAU	Beau Canada Exploration Ltd.
BLUERGE	Blue Range Resource Corporation
CAN88	Canadian 88 Energy Corp.
CANOR	Canor Energy Ltd.
CANOXY	Canadian Occidental Petroleum Ltd.
CANST	Canstates Gas Marketing
CDNFRST	Canadian Forest Oil Ltd.
CENTRA	Centra Gas Alberta Inc.
CGGS	Canadian Gas Gathering Systems Inc.
CHEL	Canadian Hunter Exploration Ltd.
CHEVRON	Chevron Canada Resources
CMG	Canadian-Montana Gas Company Limited
CNRL	Canadian Natural Resources Limited
CNWE	Canada Northwest Energy Limited
CONOCO	Conoco Canada Limited
CRESTAR	Crestar Energy Inc.
CTYMEDH	City of Medicine Hat
CWNG	Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited
DART	Dartmouth Power Associates Limited Partnership
DIRECT	Direct Energy Marketing Limited
DUKE	Duke Energy Marketing Limited Partnership
DYNALTA	Dynalta Energy Corporation
ENCAL	Encal Energy Ltd.
ENGAGE	Engage Energy Canada, L.P.
ENRMARK	EnerMark Inc.
GARDNER	Gardiner Oil and Gas Limited
GULF	Gulf Canada Resources Limited
HUSKY	Husky Oil Ltd.

IOL	Imperial Oil Resources Limited
LOMALTA	Lomalta Petroleums Ltd.
MARTHON	Marathon International Petroleum Canada, Ltd.
METGAZ	Metro Gaz Marketing
MOBIL	Mobil Oil Canada
NOVERGZ	Novergaz
NRTHSTR	Northstar Energy Corporation
PANALTA	Pan-Alberta Gas Ltd.
PANCDN	PanCanadian Petroleum Limited
PARAMNT	Paramount Resources Ltd.
PAWTUCK	Pawtucket Power Associates Limited Partnership
PCOG	Petro-Canada Oil and Gas
PENWEST	Penn West Petroleum Ltd.
PETRMET	Petromet
PIONEER	Pioneer Natural Resources Canada Ltd.
POCO	Poco Petroleums Ltd.
PROGAS	ProGas Limited
QUEBEC	3091-9070 Quebec
RANGER	Ranger Oil Limited
RENENER	Renaissance Energy Ltd.
RIFE	Rife Resources Ltd.
RIOALTO	Rio Alta Exploration Ltd.
SASKEN	SaskEnergy Incorporated
SHELL	Shell Canada Limited
SHERRIT	Sherritt Inc.
SIMPLOT	Simplot Canada Limited
SUMMIT	Summit Resources Limited
SUNCOR	Suncor Energy Inc. (Oil Sands Group)
SYNCRUDE	Syncrude Canada Ltd.
TALISMA	Talisman Energy Inc.
TCPL	TransCanada PipeLines Limited
ULSTER	Ulster Petroleums Ltd.
UNPACF	Union Pacific Resources Inc.
WAINOCO	Wainoco Oil Corporation
WASCANA	Wascana Energy Inc.

Appendix D Drilling Activity in Alberta

Table D.1. Development and exploratory wells, 1972-2007, number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total	Successful oil	Crude 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

[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.
* Not available.
** Included in Oil.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2007 - Alberta Drilling Activity Monthly Statistics (ST59).

Table D.2. Development and exploratory wells, 1972-2007, 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	2 472	834	4	6 848	1 0840	603	253	3 219	4 857	3 075	1 091	10 067	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

[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production .
* Not available.
** Included in Oil.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2007 - Alberta Drilling Activity Monthly Statistics (ST59).