ST98-2010

Alberta's Energy Reserves 2009 and Supply/Demand Outlook 2010-2019

Energy Resources Conservation Board

ACKNOWLEDGEMENTS

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

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

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Overview

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

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

Every year the ERCB issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources—crude bitumen, crude oil, natural gas, natural gas liquids, coal, and sulphur. This year's *Alberta Energy Reserves 2009 and Supply/Demand Outlook 2010-2019* includes estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources. As well, some historical trends on selected commodities are provided for better understanding of supply and price relationships.

Energy Prices and Alberta's Economy

The year 2008 will be remembered as a year when the price of crude oil reached a record high level followed by its collapse. The slide in crude oil prices continued in early 2009 before it stopped. Prices then revitalized gradually, alongside slow global demand growth. While North America and Europe did not observe demand growth, the emerging Asian market demand for oil resulted in overall price improvements.

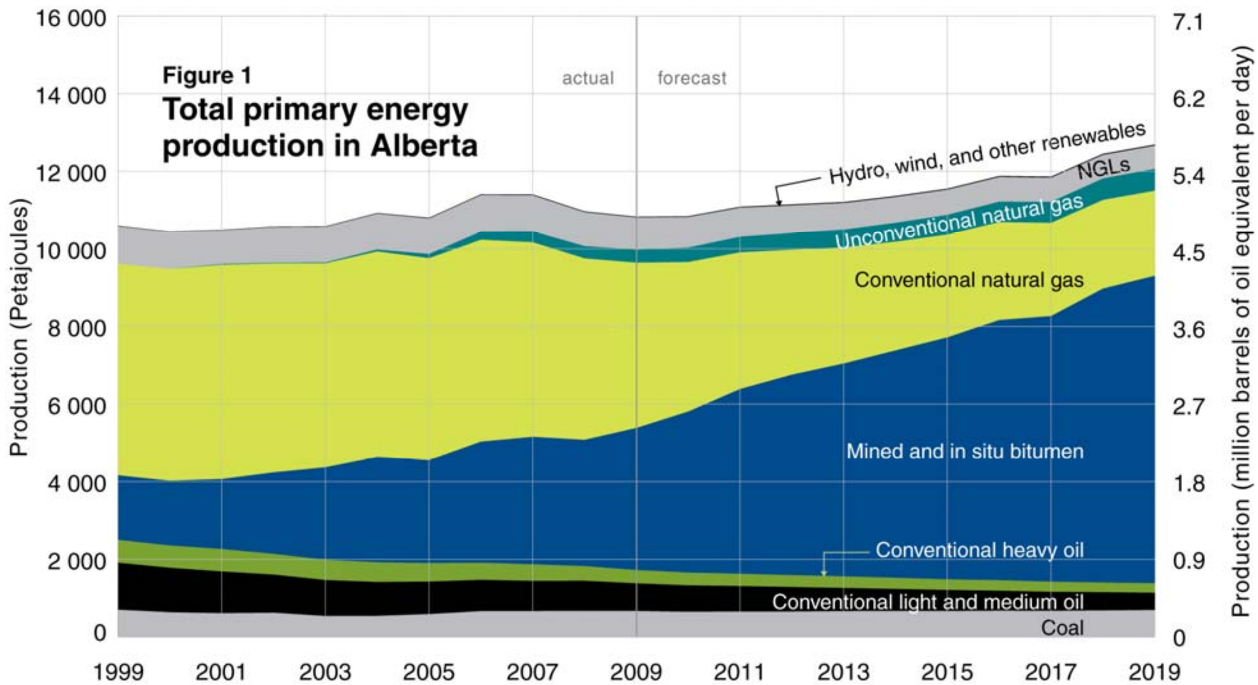
The ERCB bases its analysis on the expectation that the crude oil price in North America, measured by West Texas Intermediate (WTI) crude oil, will continue to be volatile. The ERCB expects WTI to average US$78 per barrel in 2010 and rise steadily to an average of US$122 per barrel by 2019.

North American natural gas prices and drilling activity were impacted by storage inventory levels well above five-year averages. Furthermore, high levels of U.S. indigenous supply from shale gas changed the dynamics of the North American gas market in 2009. Industrial natural gas demand also fell. When falling demand combined with high storage inventory levels and growing supply in the early part of 2009, prices declined, continuing the trend that started in mid-2008. The later part of 2009, however, witnessed minor price increases.

The ERCB bases its analysis on the expectation that natural gas prices in Alberta will average Cdn$4.25 per gigajoule in 2010 and then rise steadily to Cdn$7.50 per gigajoule by 2019.

Energy Production and Reserves in Alberta

In 2009, Alberta produced 10 828 petajoules of energy from all sources, including renewable sources. This is equivalent to over 4.8 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by these energy sources is illustrated in **Figure 1**.



Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to extract bitumen. Bitumen production accounted for 76 per cent of Alberta's total crude oil and raw bitumen production in 2009. Bitumen production at both mining and in situ projects increased by 14 per cent in 2009, resulting in an overall raw bitumen production increase of 14 per cent compared with 2008.

In 2009, total marketable natural gas production in Alberta declined by 7.5 per cent, crude oil production declined by 8.6 per cent, total natural gas liquids (NGLs) production declined by 4.4 per cent, and sulphur production declined by 6.6 per cent. Coal production remained flat.

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

The following table summarizes Alberta's energy reserves at the end of 2009.

Reserves and production summary, 2009

	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	286 627	1 804	10 851	68.3	9 308	330	94	103
Initial established	28 092	177	2 795	17.6	5 221	185	35	38
Cumulative production	1 099	6.9	2 567	16.2	4 101	146	1.42	1.56
Remaining established	26 992	170	228	1.4	1 120[b]	39.8[b]	33	37
Annual production	86.4	0.544	26.8	0.169	123	4.4	0.032[d]	0.036[d]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Expressed as "as is" gas, except for annual production, which is at 37.4 MJ/m^3. Includes unconventional natural gas.
[b] Measured at field gate (or 36.4 trillion cubic feet downstream of straddle plant).
[c] Does not include CBM.
[d] Annual production is marketable.

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves for crude bitumen is 27.0 billion cubic metres (m^3) (169.9 billion barrels), slightly less than in 2008 due to production. Only 3.9 per cent of the initial established crude bitumen reserves has been produced since commercial production started in 1967.

Crude Bitumen Production

In 2009, Alberta produced 47.9 million m^3 (302 million barrels) from the mineable area and 38.5 million m^3 (242 million barrels) from the in situ area, totalling 86.4 million m^3 (544 million barrels). This is equivalent to 236.7 thousand m^3 (1.49 million barrels) per day. While the bitumen produced from mining was upgraded, bitumen crude produced from in situ operations was mainly marketed as nonupgraded crude bitumen. It is projected that by 2019 total raw bitumen production will reach 506.7 thousand m^3 (3.2 million barrels) per day. Production from in situ bitumen projects is now projected to surpass that of bitumen from mining projects by 2015.

Synthetic Crude Oil (SCO) Production[1]

In 2009, all crude bitumen produced from mining, as well as a small portion of in situ production (about 12 per cent), was upgraded in Alberta, yielding 44.4 million m^3 (279 million barrels) of SCO. About 60.6 per cent of total crude bitumen produced in Alberta was upgraded in the province in 2009. By 2019, SCO production is forecast to almost double to 78.5 million m^3 (494 million barrels). While this is a significant increase compared to 2009, it is expected that only 50 per cent of total crude bitumen produced in Alberta will be upgraded in the province by the end of forecast period due to expected narrow price differentials of bitumen relative to light crude oil. Over the next 10 years, mined bitumen is projected to continue to be the primary source of the bitumen upgraded to SCO in Alberta. However, it is projected that bitumen from in situ production will be

[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.

increasingly upgraded to SCO in the province. The portion of in situ production upgraded in the province will increase from 12 per cent in 2009 to 18 per cent by the end of the forecast.

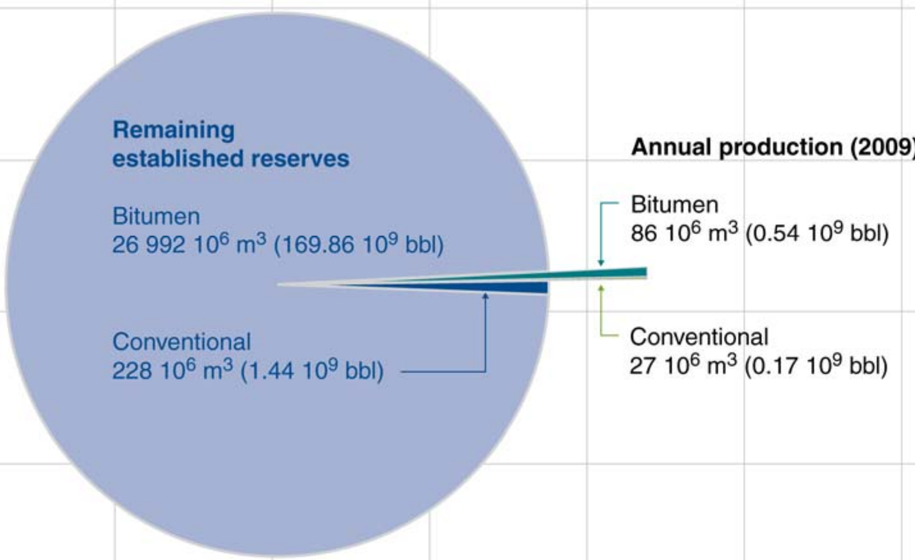
Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 228.4 million m^3 (1.4 billion barrels), a 2.0 per cent decrease from 2008. Exploratory and development drilling, as well as new enhanced recovery schemes, added total reserves of 16.2 10^6 m^3 (102 million barrels). This replaced 60 per cent of the 2009 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 26.75 million m^3 (168 million barrels) in 2009. This equates to 73.3 10^3 m^3 (461 thousand barrels) per day.

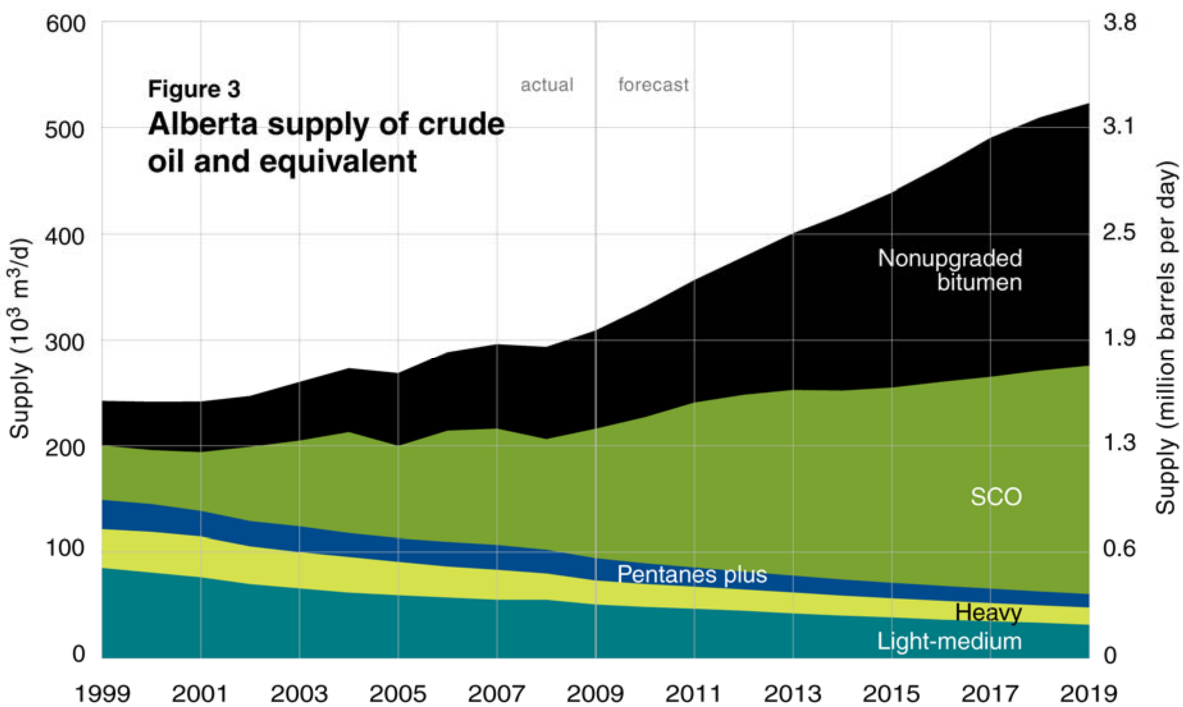
The number of oil wells placed on production decreased by 41 per cent to 1046 in 2009. The ERCB estimates that the number of new wells placed on production will increase to 1500 wells in 2010, increasing to 1700 wells in 2011. It is expected that the number of wells placed on production will reach 2000 wells by 2013 and remain at this level for the remaining forecast period, as crude oil prices increase and drilling activity returns to recent historical levels.

Total Oil Supply and Demand

Alberta's 2009 supply of crude oil and equivalent reached 306.6 10^3 m^3 (1.9 million barrels) per day, a 4.4 per cent increase compared with 2008. Production is forecast to reach 526 10^3 m^3 (3.3 million barrels) per day by 2019.

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

The ERCB estimates that bitumen production will more than double by 2019. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 69 per cent in 2009 to 89 per cent by 2019.



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 coalbed methane, or CBM, is increasing. Natural gas production from other sources, such as shale gas, may prove to be an additional significant source in the future.

Unconventional Natural Gas Reserves

In recognition of the potential of unconventional gas sources other than CBM, the ERCB has broadened its unconventional section to include shale gas. However, given the early stage of resource development of shale gas in Alberta, the established reserves and production history are exclusively CBM. CBM has been recognized as a commercial supply of natural gas in Alberta since 2002. Activity in CBM has increased dramatically from a few test wells in 2001 to over 14 000 producing connections in 2009. The growth in CBM data collection and gas production has increased confidence in publication of CBM reserves estimates, despite continued uncertainty regarding recovery factors and production accounting.

At the end of 2009, the remaining established reserves of CBM in Alberta is estimated to be 64.5 billion m^3 (2.3 trillion cubic feet), with just over half of that attributed to the Mannville zone in central Alberta (36.5 billion m^3). Currently, 97 per cent of producing CBM connections are in the Horseshoe Canyon Formation in the area between Edmonton and Calgary. In 2009, CBM and CBM hybrid well connections contributed 7 per cent of the total Alberta marketable gas production and is projected to reach 20 per cent by 2019.

Conventional Natural Gas Reserves

At the end of 2009, Alberta's remaining established reserves of conventional natural gas stood at 1056 billion m^3 (37.5 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 54 per cent of production in 2009. This compares with 81 per cent replacement in 2008.

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

Total Natural Gas Production and Well Activity

Several major factors have an impact on natural gas production, including natural gas prices, drilling activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. Alberta produced 123 billion m^3 (4.4 Tcf) of marketable natural gas in 2009 a decline of 7.5 per cent compared with 2008. Of the total gas produced in the province, 9.0 billion m^3 (0.32 Tcf) was from unconventional sources, primarily CBM.

There were 3768 conventional gas connections in 2009, a 50 per cent decrease from the 7490 gas connections in 2008. The ERCB expects a slow recovery in conventional gas connections, estimating that 2800 connections will occur in 2010. The ERCB estimates that this number will increase gradually to 5000 connections in 2015 and remain at this level to the end of the forecast period.

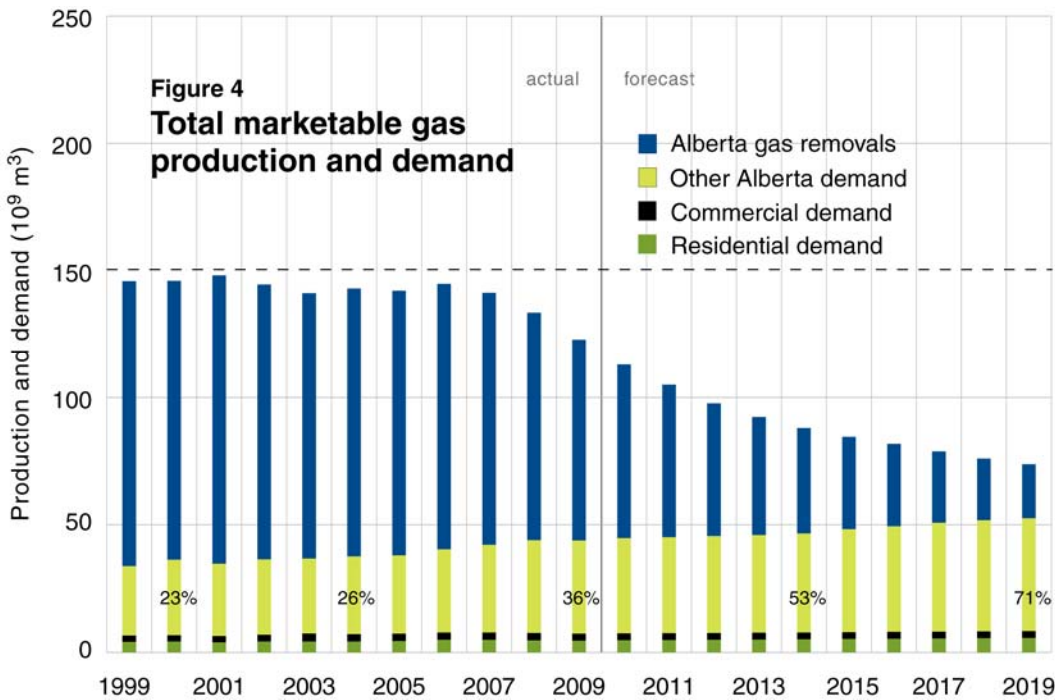
CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 1848 successful new CBM connections in Alberta in 2009, an increase of 2 per cent compared with 2008. The ERCB expects CBM connections to decrease in 2010 to 1750.

Total Natural Gas Supply and Demand

Today, new pools are smaller and new connections are exhibiting lower initial production rates and steeper decline rates. Factoring this in, the ERCB believes that new connections will not be able to sustain production levels over the forecast period. CBM production is forecast to supplement the 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 meet Alberta's demand. If the ERCB's demand forecast is realized, Alberta's natural gas requirement will be 71 per cent of total Alberta production by the end of the forecast period. Alberta's requirements by the end of the forecast are noticeably higher than last year's 58 per cent, due mainly to a decrease in total forecast marketable gas production.

Therefore, 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 small industrial gas consumers) be met over the long term before any new gas removal permits are approved. Alberta's marketable gas production (at 37.4 MJ/m^3) and demand are shown in **Figure 4**.



Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane are estimated at 117 million m^3 (741 million barrels) as of year-end 2009. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

In 2009, the production of specification ethane decreased to 35.1 thousand m^3 (221 thousand barrels) per day from 35.3 thousand m^3 (222 thousand barrels) per day in 2008. The majority of ethane was used as feedstock for Alberta's petrochemical industry. Although the forecast supply crosses over the demand curve prior to the end of the forecast, incremental ethane volumes required to meet demand are assumed to be available from off-gas or higher extraction rates from existing processing facilities.

The remaining established reserves of other NGLs—propane, butanes, and pentanes plus—is 154 million m^3 (969 million barrels) in 2009. The supply of propane and butanes is expected to meet demand over the forecast period. Due to the tightness in supply of pentanes plus, alternative sources of diluent are being used by industry to dilute the heavier crude to meet pipeline quality.

The remaining established reserves of sulphur decreased in 2009 by 2.4 per cent, from 186 million tonnes in 2008 to 181 million tonnes, due to production. About 93 per cent of total marketed sulphur in 2009 was shipped outside the province, with 18 per cent going to the U.S., 80 per cent going offshore, and the remainder going to the rest of Canada. Sulphur is recovered from the processing of natural gas and upgrading of bitumen. Sulphur demand is expected to increase to 5.5 million tonnes in 2010 and remain flat thereafter. It is projected that with relatively flat production over the forecast period, minimal stockpile withdrawals are required to meet forecast demand.

Coal

The current estimate for remaining established reserves of all types of coal is about 33.4 billion tonnes (36.8 billion tons). This massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 60 per cent of the province's electricity generation in 2009. Alberta's total marketable coal production in 2009 was 32.2 million tonnes (35.5 million tons), most of which was subbituminous coal destined for mine mouth power plants. This total production is slightly lower than production in 2008. Alberta's coal reserves represent over a thousand years of supply at current production levels. Subbituminous coal production is expected to increase over the forecast period to meet demand for additional domestic electricity generating capacity.

The small portion of Alberta coal production that was exported from the province in 2009 can be separated into thermal coal exports and metallurgical coal exports. The export market for metallurgical coal remained strong in 2009 due to the continued, though reduced, demand in the Pacific Rim countries for steel production.

Electricity

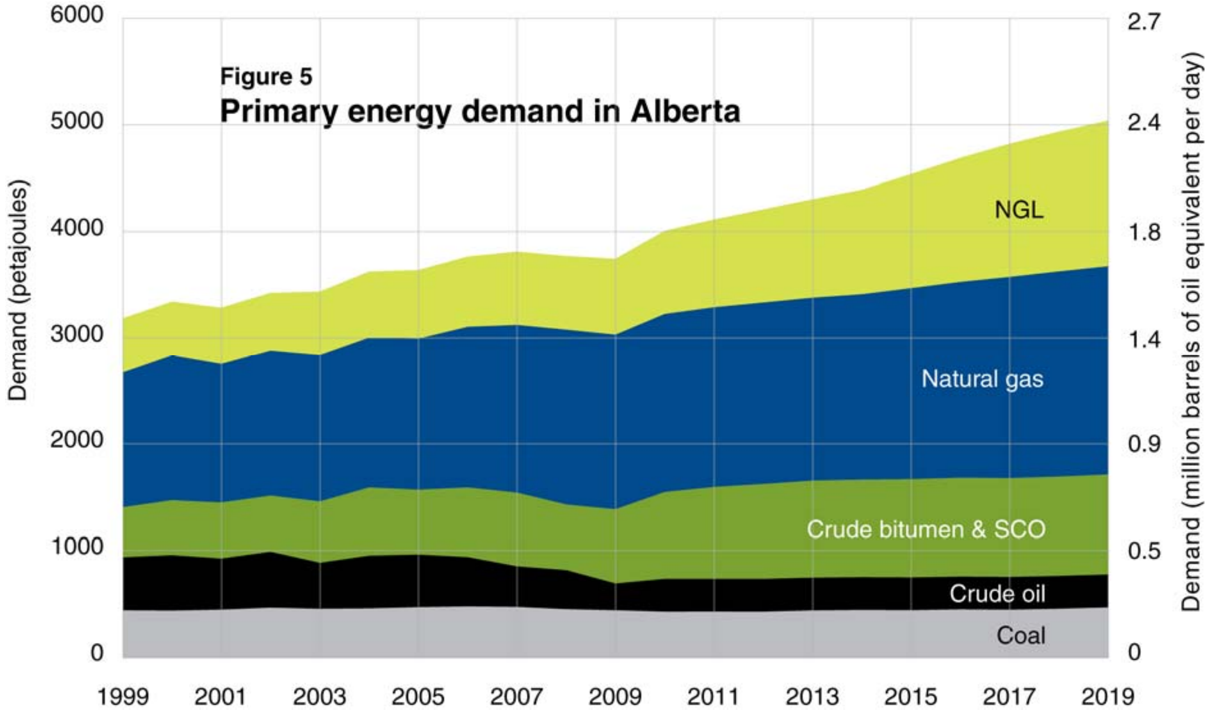
Electricity generating capacity in Alberta reached just under 13 000 megawatts (MW) in 2009, with new additions increasing capacity by 628 MW. Most of the increase was due to additional capacity from new natural gas-fired power plants. By the end of the forecast period, the ERCB expects total electricity generating capacity in Alberta to be over 15 500 MW.

In 2009, total electricity generation reached 69 262 gigawatt hours (GWh), slightly lower than the 69 392 GWh in 2008. Alberta imported 2180 GWh of electricity and exported 513 GWh. Over the forecast period, total electricity generation is expected to grow by an average of 2.4 per cent per year to over 88 000 GWh by 2019.

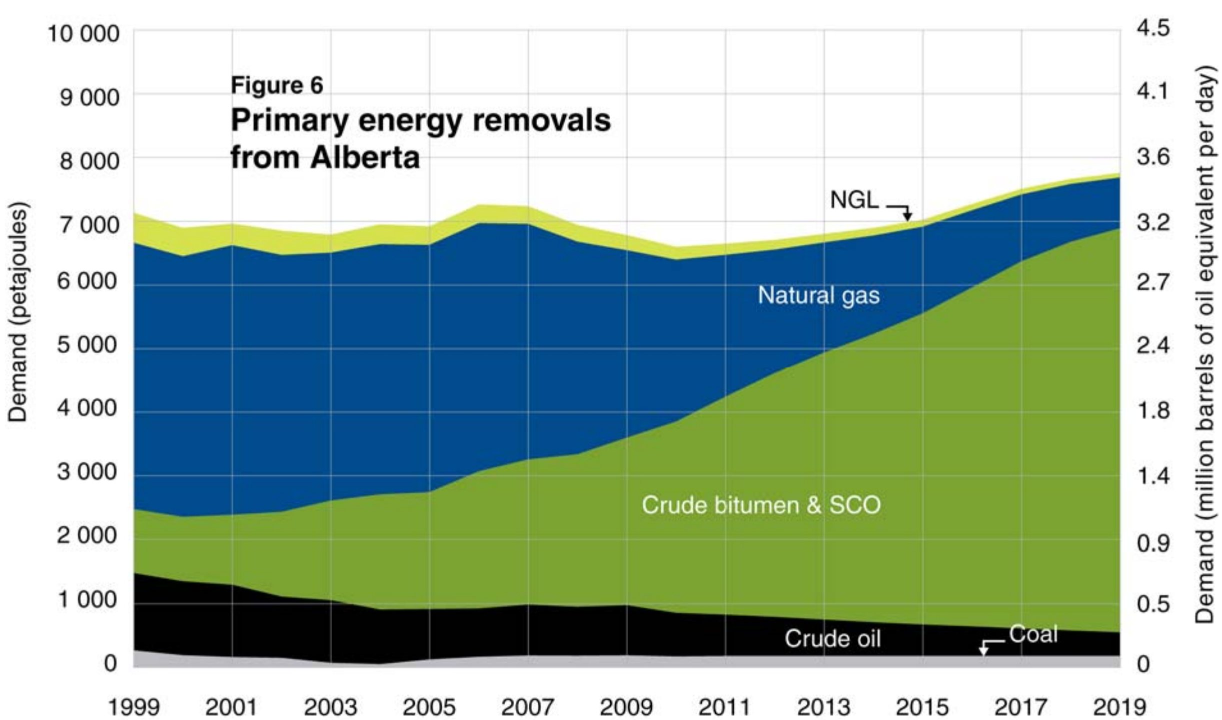
Total electricity demand in Alberta (retail sales, direct connect sales, and industrial on-site use) reached 67 207 GWh in 2009, an increase of only 0.5 per cent from 2008. However, expected growth in industrial electricity demand, through both wholesale purchases and on-site generation, will average 2.4 per cent per year over the forecast period, similar to the average growth in overall demand. The oil sands sector is expected to dominate load growth.

Primary Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 5**. While 2010 demand for coal, conventional crude oil, and natural gas are expected to be fairly flat at 2009 levels, more bitumen and SCO will be consumed in the province. Total primary energy consumption in 2009 was equivalent to 1.7 million barrels per day of crude oil. It is projected that this amount will increase to 2.3 million barrels per day by 2019.



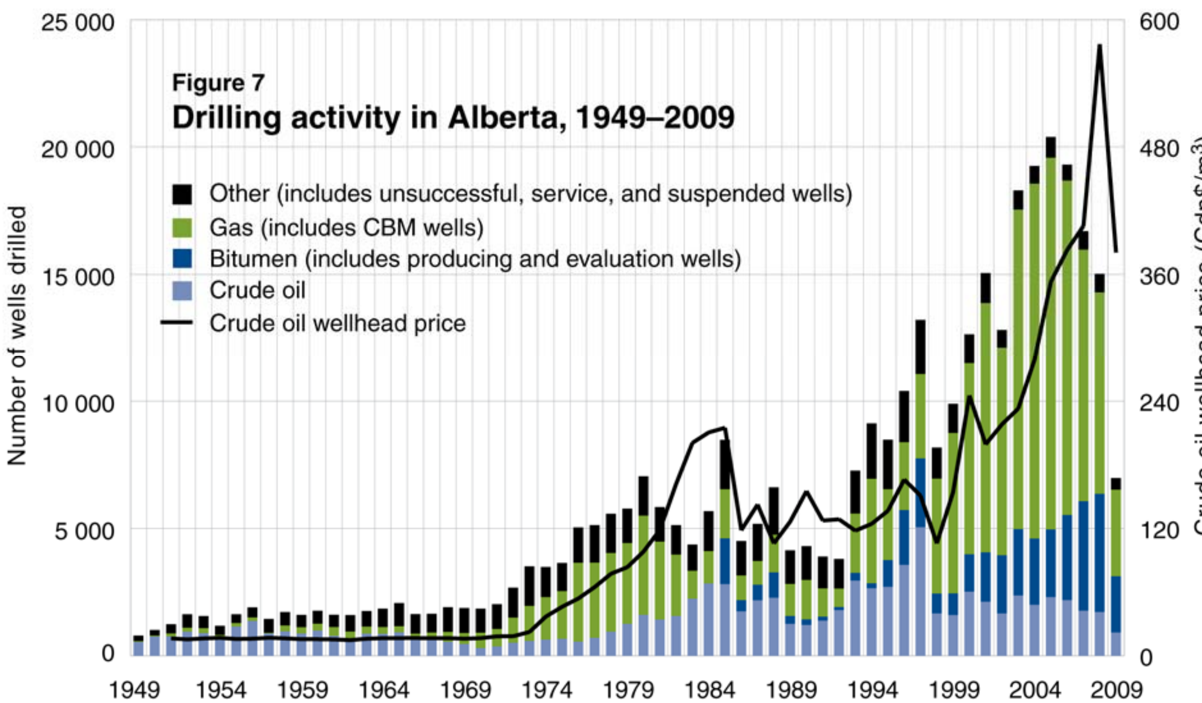
The primary energy removals from Alberta are shown in **Figure 6**. The majority of shipments are to the United States. The total primary energy removals from the province are expected to reach 3.5 million barrels of crude oil equivalent by 2019, up from 3 million barrels in 2009.



Energy Trends

Drilling Activity

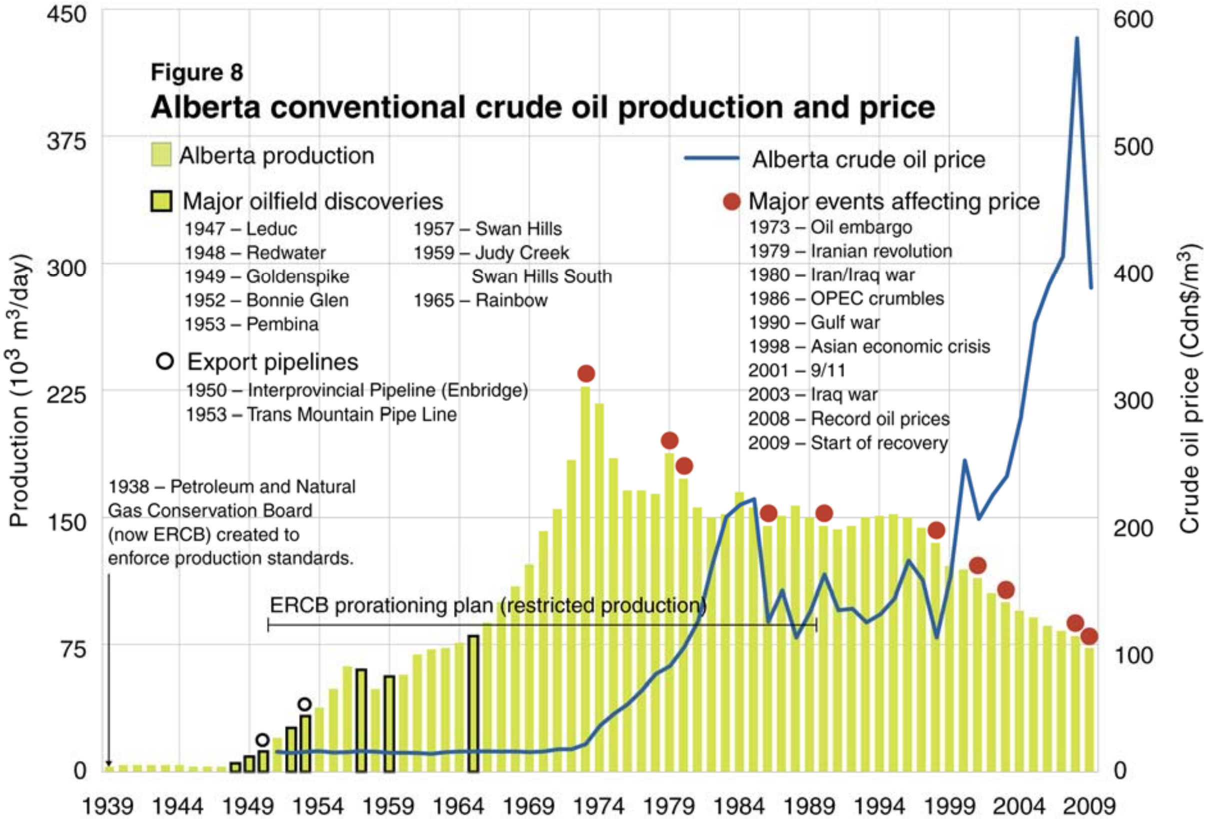
Drilling activity in the province increased rapidly from 1993, reaching a peak in 2005. Although drilling activity in 2007 and 2008, particularly for natural gas, declined due to increasing costs and soft natural gas prices, drilling has remained high relative to the average number of wells drilled over the previous decades. In 2009, drilling activity was cut by over half relative to 2008 drilling levels, due to weak prices. The trend toward well recompletions and commingling in existing conventional gas wells, which has increased the production volumes without new drilling, also contributed to lower drilling activity in 2009. While this trend is expected to continue, natural gas drilling remains the dominant force in the province's drilling activity. **Figure 7** illustrates the province's drilling history over the past six decades.

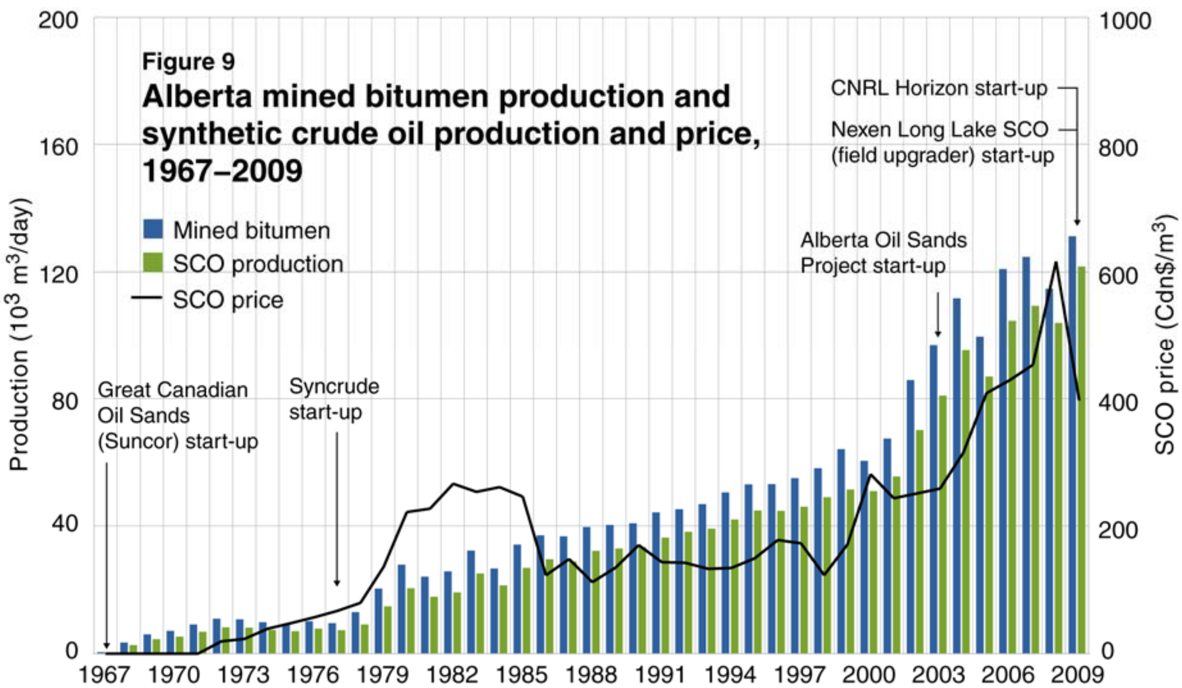


Crude Oil and Bitumen

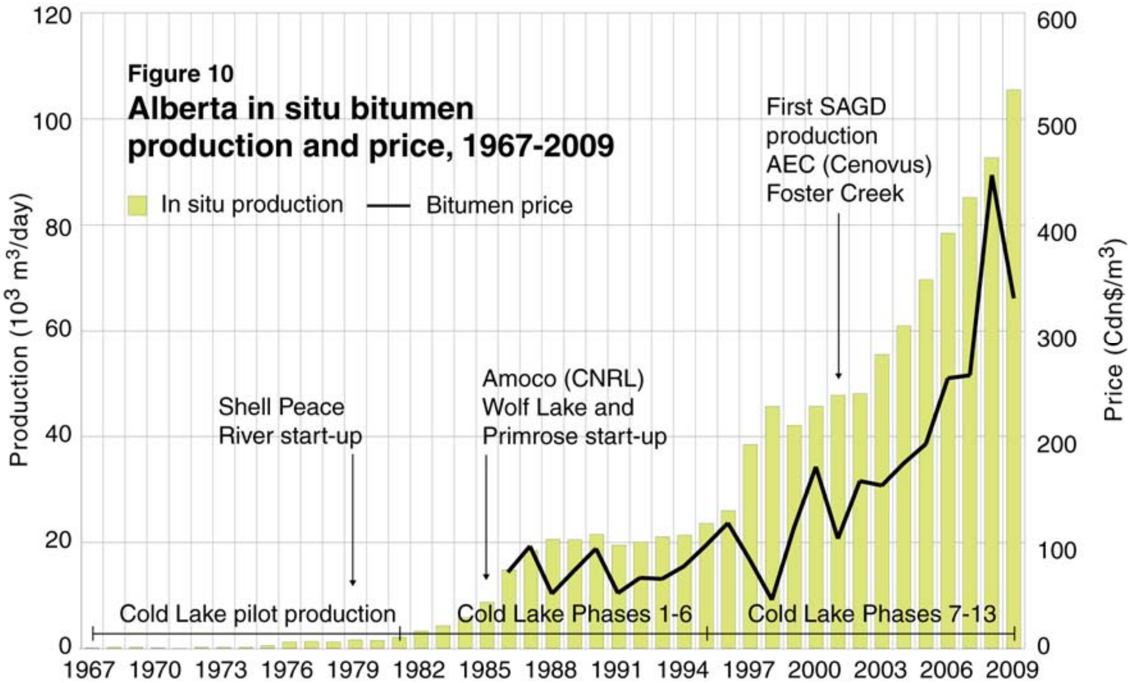
Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 8**. Production from the Turner Valley field, discovered in 1914, accounted for 99 per cent of production in 1938 and 89 per cent of production in 1946. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with peak production of 227.4 thousand m^3/day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure. Factors affecting current crude oil prices and the forecast are found in Section 1.

Figure 9 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 (Shell Albian Sands and Shell Scotford Upgrader) in 2003. In 2009, the Horizon Project (CNRL) commenced mining operations in late 2008 and produced SCO in 2009. SCO from the Long Lake project (Nexen/OPTI) also came on stream in 2009. This is the first project that is based on in situ bitumen recovery and field upgrading. The figure also shows the price of SCO since 1971, which generally runs at a premium to light crude oil.





Historical production and the price of in situ bitumen are shown in **Figure 10**. Imperial's Cold Lake project facility, which uses the cyclic steam stimulation recovery method, has historically accounted for the major portion of in situ production. With the exception of the past few months, historically the price of bitumen has followed the light crude oil price, but at a discount of between 50 and 60 per cent. However, in the past two years the differentials have narrowed due to a global shortage of heavier crude oil supply. Both Figures 9 and 10 demonstrate that unlike conventional resources of oil and gas, bitumen reserves are less mature and production responds to price increases more directly.



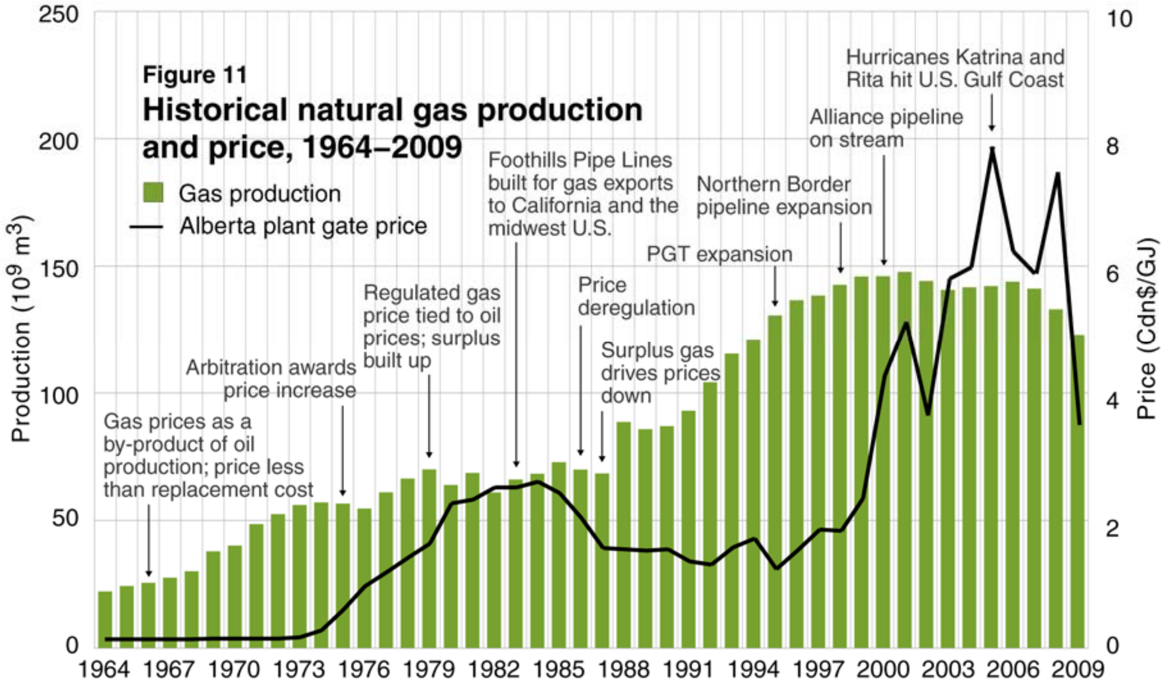
Natural Gas

Natural gas as a commodity has an interesting past, as seen in **Figure 11,** which shows historical gas production and price. In the 1950s and 1960s, it was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when OPEC increased crude oil prices, natural gas prices started to increase.

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

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

In the early 1990s, natural gas prices became more market responsive. Development of trading points in Chicago, New York, and the Henry Hub in the U.S. in the late 1980s and AECO "C" in the early 1990s facilitated natural gas being traded as a true commodity. The development of new export pipelines and expansions to existing pipelines to the U.S. have allowed Alberta gas to be fully integrated into the North American gas marketplace.



Sulphur

Figure 12 illustrates sulphur closing inventories at processing plants and oil sands operations from 1973 to 2009. Sulphur prices in this period are also shown, adding insight into how prices affect the growth or decline in sulphur inventories. Because of logistics costs, Canadian sulphur producers do not remelt and remove inventories unless they are assured a "good price." When international demand is high and international prices follow, Alberta sulphur blocks are used as an additional source to increase the supply. This is usually sufficient to bring things back into balance, reduce prices, and stop the remelting of inventories.

Coal

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 13**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and generally cost-of-service contracts with the mining companies determines the cost (price) of subbituminous coal.

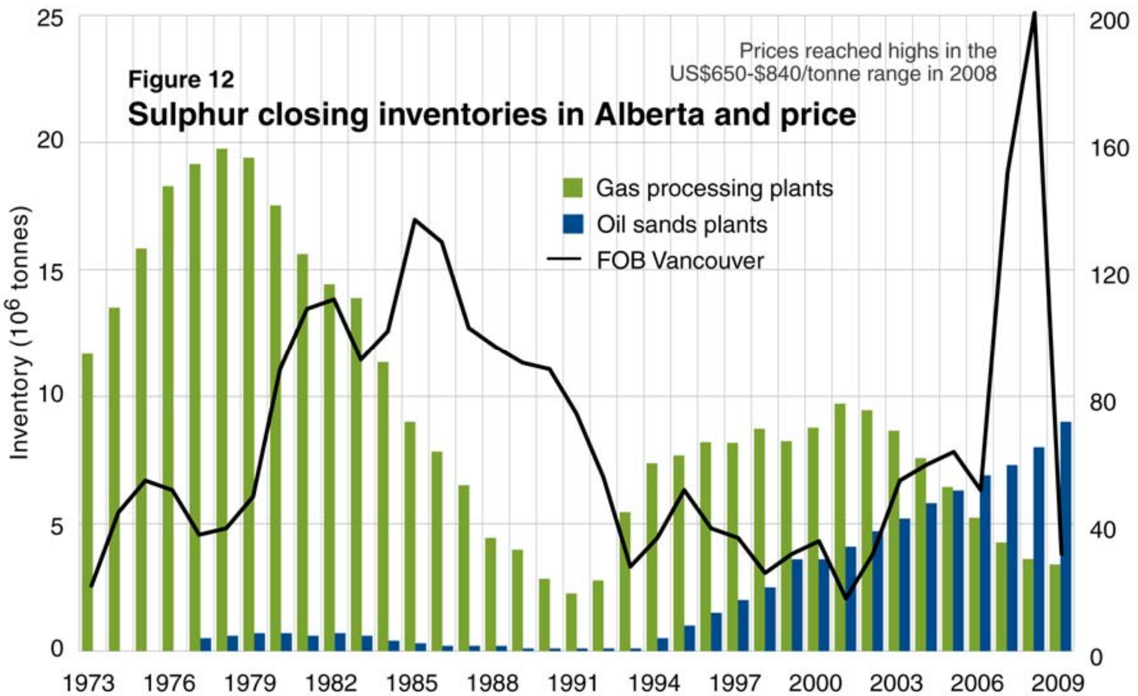


Figure 12
Sulphur closing inventories in Alberta and price
Prices reached highs in the
US$650-$840/tonne range in 2008
Gas processing plants
Oil sands plants
FOB Vancouver
Inventory (10^6 tonnes)
Price (US$/tonne)
25
20
15
10
5
0
200
160
120
80
40
0
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009

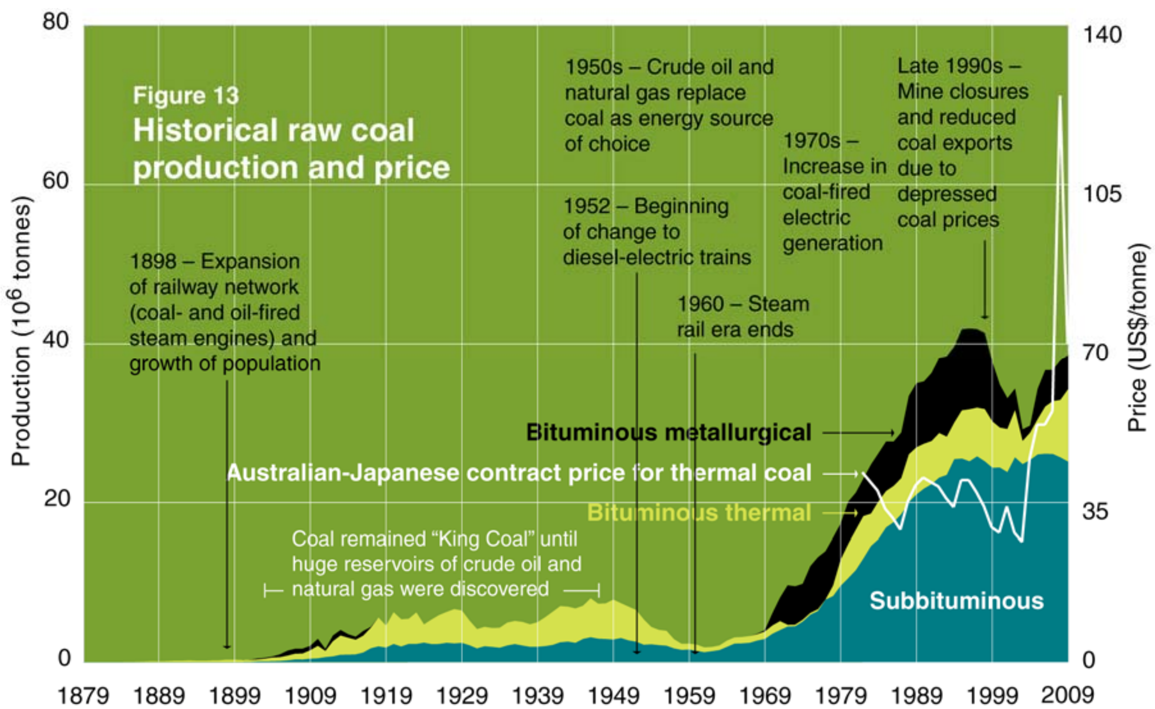


Figure 13
Historical raw coal production and price
1898 – Expansion of railway network (coal- and oil-fired steam engines) and growth of population
1950s – Crude oil and natural gas replace coal as energy source of choice
1952 – Beginning of change to diesel-electric trains
1960 – Steam rail era ends
1970s – Increase in coal-fired electric generation
Late 1990s – Mine closures and reduced coal exports due to depressed coal prices
Bituminous metallurgical
Australian-Japanese contract price for thermal coal
Bituminous thermal
Subbituminous
Coal remained "King Coal" until huge reservoirs of crude oil and natural gas were discovered
Production (10^6 tonnes)
Price (US$/tonne)
80
60
40
20
0
140
105
70
35
0
1879
1889
1899
1909
1919
1929
1939
1949
1959
1969
1979
1989
1999
2009

1 Energy Prices and Economic Performance

Highlights

- The spot price of WTI crude oil at Cushing, Oklahoma, averaged US$61.95 per barrel (bbl) in 2009, compared to US$99.67/bbl in 2008, a decrease of 38 per cent.
- Alberta wellhead natural gas prices averaged $3.65 per gigajoule (GJ) in 2009, compared to 7.47/GJ in 2008, a decrease of 51 per cent.
- There were 6980 wells drilled in Alberta in 2009, compared to 15 021 in 2008, a 54 per cent drop.
- Capital spending in the oil sands is estimated to have dropped to $10 billion in 2009, compared to $18.5 billion in 2008.

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

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

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

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

1.1 Global Oil Market

The impact of the financial crisis of 2008 extended into 2009. Global oil demand is estimated to have decreased by 0.3 million (10^6) bbl/d in 2008, followed by another decline of 1.3 10^6 bbl/d in 2009, to a total of 84.9 10^6 bbl/d. The largest decreases in oil demand were in North America and Europe. However, oil demand growth and economic growth continued in Asia and the Middle East, despite the worldwide financial crisis.

Figure 1.1 illustrates historical growth in oil demand across the globe between 2008 and 2009, along with the most recent forecast for 2010 by the IEA.

As shown in **Figure 1.1, t**he IEA projects global crude oil demand to increase to 1.7 10^6 bbl/d in 2010, or by 2.0 per cent. The recovery in the world economy has resulted in world oil demand resuming its long-term growth trajectory.

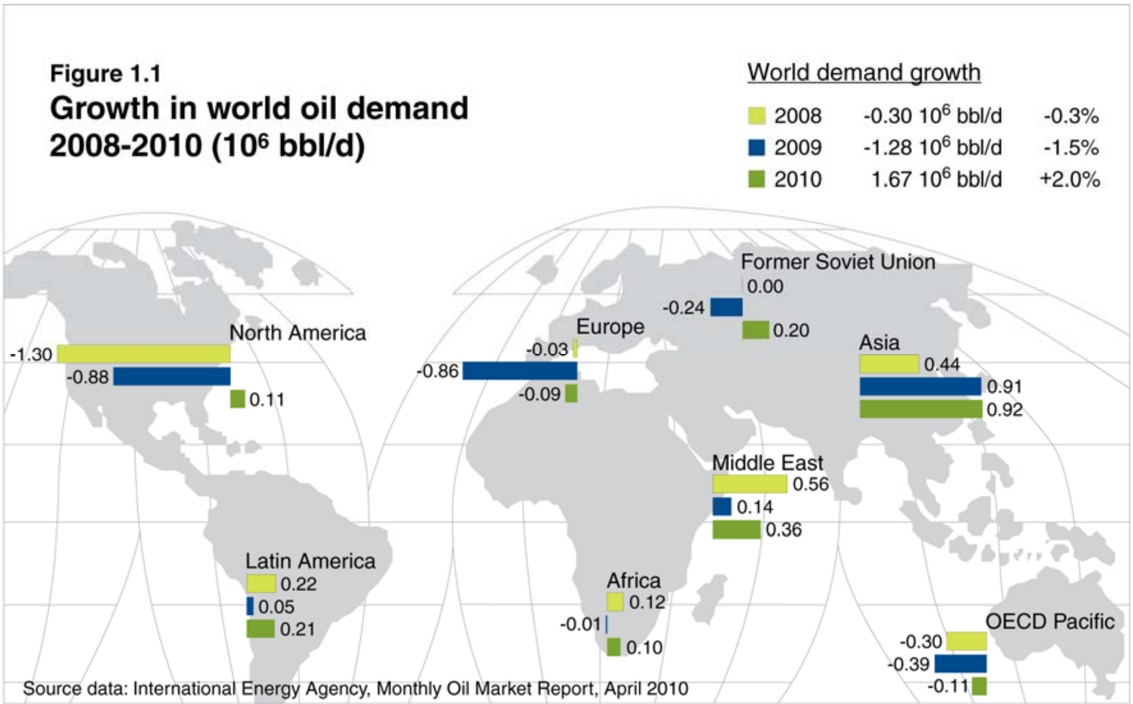


Figure 1.1
Growth in world oil demand 2008-2010 (10^6 bbl/d)

Figure 1.2 depicts the monthly average OPEC crude oil basket reference price and the monthly average WTI price at Cushing for 2009.[1] The OPEC reference price averaged US$41.52/bbl in January 2009 and gradually increased to average US$74.01/bbl in December 2009, with a yearly average of US$61.06/bbl. Prices recovered throughout the year as it became clearer that the world economy was recovering from the financial crisis. The price movements mirrored the trend in many of the world's commodity and financial markets.

From 2003 to 2008, WTI averaged between US$3/bbl to $6/bbl higher than the OPEC reference price on an average annual basis, reflecting quality differences, the cost of shipping, and localized market conditions. In 2009, the premium of WTI to the OPEC basket narrowed, averaging approximately US$1/bbl, as WTI prices were impacted by high North American crude oil storage levels and depressed market conditions.

In 2009, OPEC produced 28.7 10^6 bbl/d, compared to 31.2 10^6 bbl/d in 2008. OPEC production levels in 2009 were equivalent to over 34 per cent of total world oil demand.[2] Including OPEC natural gas liquids, OPEC produced 33.4 10^6 bbl/d, or 39 per cent of total oil demand.

1.2 North American Energy Prices

1.2.1 North American Crude Oil Prices

North American crude oil prices are determined by international market forces and are most directly related to the WTI crude oil price at Cushing, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) for light crude oil contracts. WTI crude has an API of 40 degrees and a sulphur content of less than 0.5 per cent.

[1] OPEC calculates a production-weighted reference price, referred to as the OPEC reference basket price.
[2] Statistics obtained from OPEC *Monthly Oil Market Report* (April 2010).

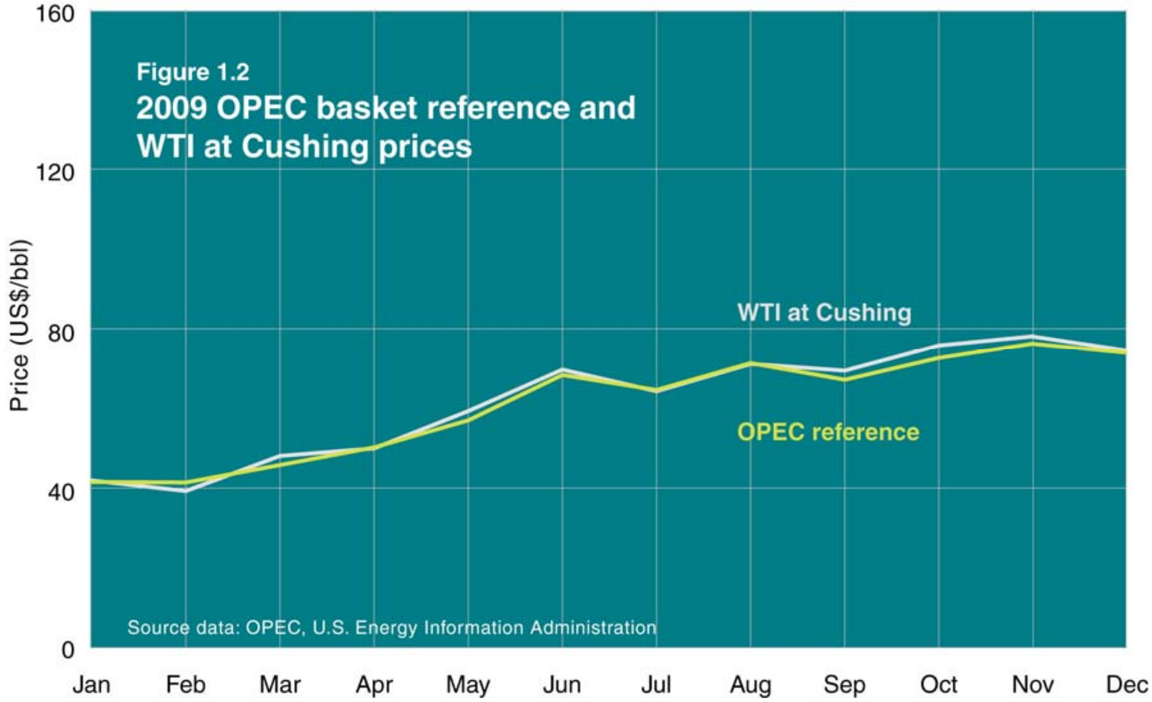
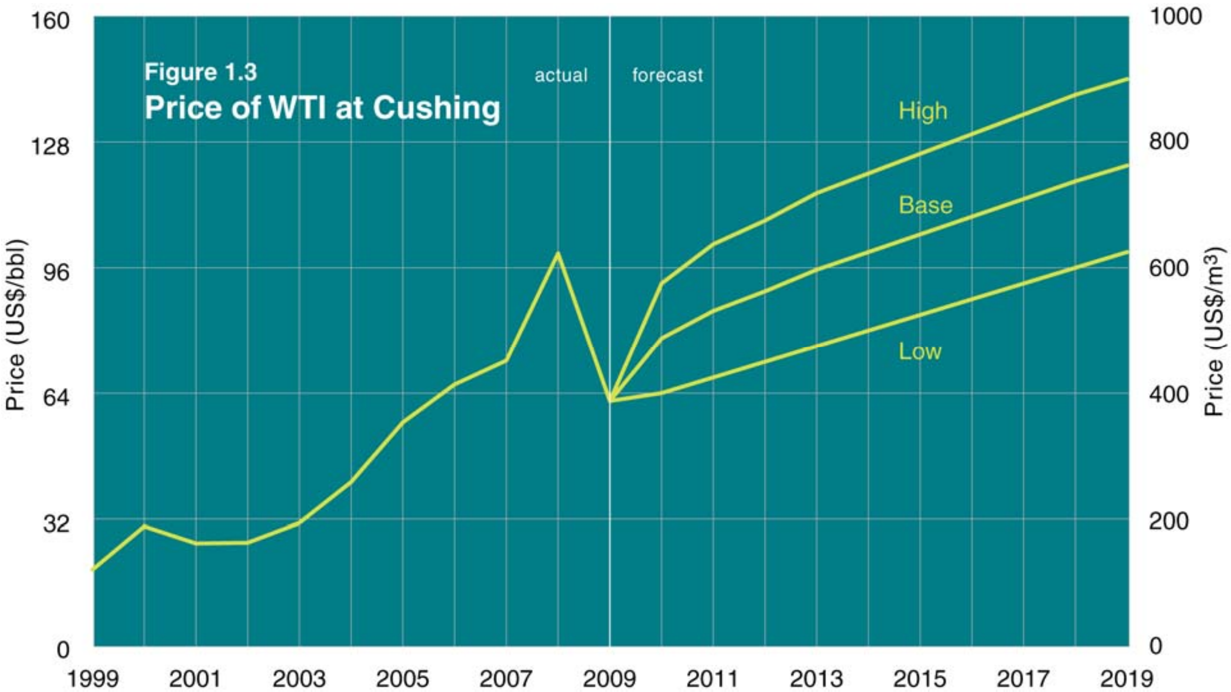


Figure 1.3 shows actual and forecast WTI prices at Cushing from 1999 to 2019. As illustrated, the forecast price of WTI is expected to increase throughout the forecast period, as increasing crude oil demand, in combination with declining U.S. conventional production, puts upward pressure on prices.



The ERCB calculates light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI Cushing price is adjusted for transportation and other charges between Edmonton and Cushing and for the exchange rate, as well as crude quality. The Edmonton reference price is based on an API of 40 degrees and a sulphur content of 0.5

per cent. **Figure 1.4** shows actual and forecast prices for Alberta light crude at Edmonton in Canadian dollars from 1999 to 2019.

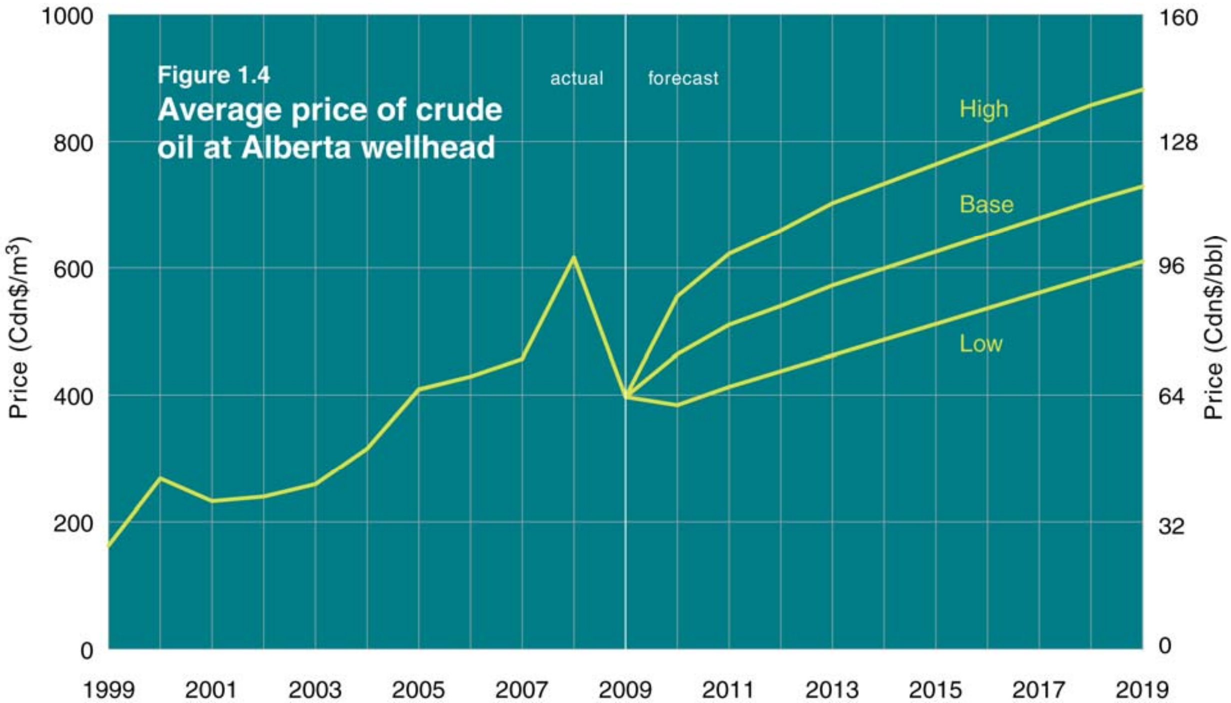
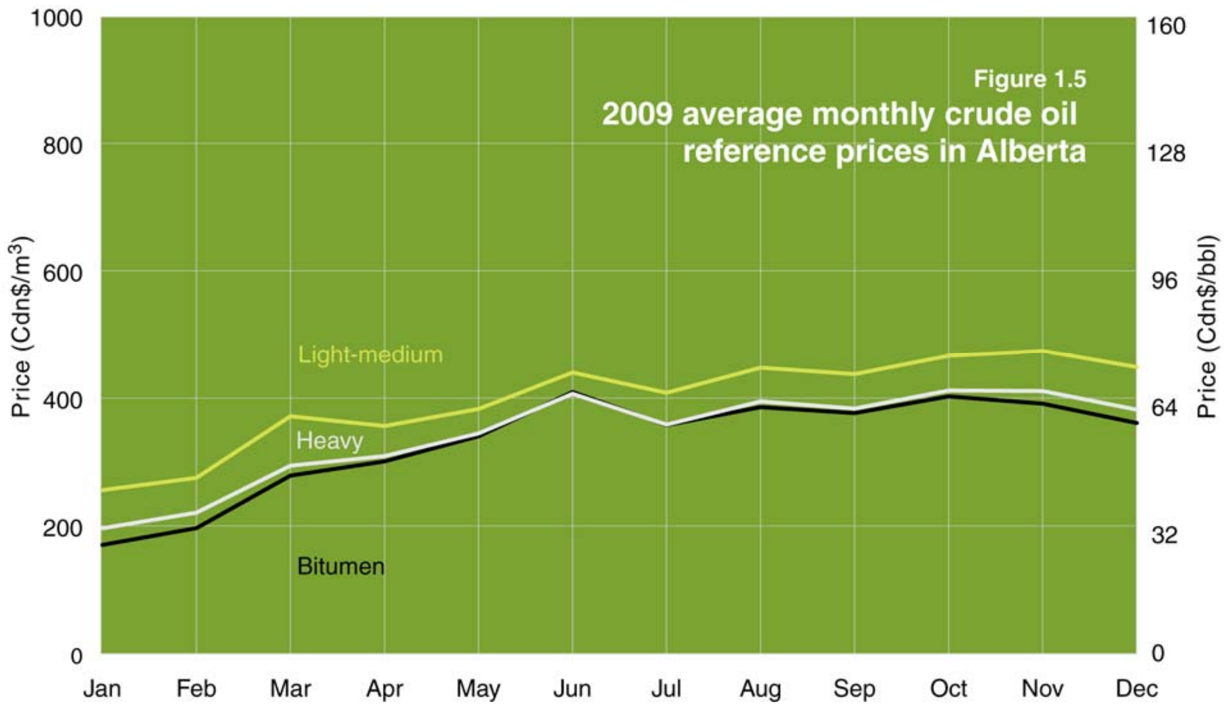


Figure 1.5 illustrates the monthly average price of Alberta light-medium crude, heavy crude, and bitumen. In 2009, heavy crude and bitumen prices averaged Cdn$54.46/bbl and Cdn$52.57/bbl respectively, while the Alberta light-medium reference price averaged Cdn$63.09/bbl. This compares with 2008, when the heavy crude and bitumen prices averaged Cdn$77.38/bbl and Cdn$71.01/bbl respectively, while the Alberta light-medium reference price averaged Cdn$97.93/bbl. In 2008 and 2009, the price of heavy crude in Alberta increased at a faster rate than light and medium crude, leading to a continuing narrowing of the discount between light and heavy from 21 to 14 per cent. Similarly, the discount between light-medium crude oil and bitumen narrowed from 27 to 17 per cent for the same period.

Differentials between Alberta light and heavy crudes narrowed significantly in 2008 and 2009. The bitumen/light-medium differential averaged 22 per cent over the 2008 to 2009 time period, compared to 44 per cent over the five-year average from 2003 to 2007. This is consistent with North American and world trends and is a result of a number of factors. First, the OPEC production cutbacks have fallen disproportionately on OPEC heavy crude oils. In addition, Mexican heavy oil production has fallen, while Venezuelan heavy oil production has remained constant or diminished slightly. On the demand side, new sophisticated international refineries capable of processing heavy crude oils and their products have recently begun operation. These factors have resulted in more heavy oil demand and less production, thereby giving rise to tighter differentials. This trend is expected to continue in the near term, but as OPEC production increases, the increased production will consist of heavier crude oil.



The ERCB expects the bitumen/light-medium differential to average 26 per cent over the forecast period, compared to the five-year average of 36 per cent and the 2009 average of 17 per cent. The heavy/light-medium differential is expected to average 21 per cent, narrower than the most recent five-year average of 28 per cent, but wider than the 2009 average of 14 per cent.

Crude oil production in Alberta, after meeting Alberta and Canadian refinery demand, is exported to the U.S. The Petroleum Administration for Defense Districts (PADDs) 2 and 4 in the U.S. are the largest importers of Alberta heavy crude and bitumen, with a combined total refinery capacity of 682 10^3 cubic metres per day (m^3/d) (4294 10^3 bbl/d). Increased heavy oil upgrading capabilities at the Flint Hills refinery at Pine Bend and the BP refinery at Whiting, as well as the ConocoPhillips refinery conversion project at Wood River and other refinery conversions, will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta's heavier crudes.

Total refinery capacity in the U.S. has increased somewhat from the early 1990s, but only due to changes in existing refineries. No new refineries have been built since the 1970s. Prior to the global economic recession, product demand had increased significantly, resulting in refineries in the U.S. operating at high capacities since 1993. More recently, however, depressed refinery margins due to falling product demand have resulted in some U.S. refineries being shut down.

Additional pipeline infrastructure could provide an avenue for increasing Alberta heavy crude exports to new or expanding markets in the U.S. and Asia. With expected increases in both upgraded and non-upgraded bitumen supply over the forecast period, adequate incremental pipeline capacity is essential to transport growing volumes to market. During the past few years, pipeline companies have made strides towards completing existing projects, as well as moving ahead with planning and construction of new projects. This has culminated with the imminent start-up of the TransCanada Keystone pipeline in 2010, providing deliveries to Wood River and then to Cushing. In addition, the Enbridge

Alberta Clipper project has just been approved to go into service as well. Additional pipeline projects are discussed in **Section 2.2.3**.

Figure 1.6 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the U.S., with 56 operating refineries and a net crude oil distillation capacity of 1341 10^3 m^3/d (8.4 million bbl/d). PADD 3 was not previously viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude production. However, traditional crude inputs to PADD 3 have been on the decline, suggesting a more tangible market opportunity for Alberta heavy crude producers. As a result, plans to increase pipeline capacity to the area are under way, such as the recently approved TransCanada Keystone XL project.

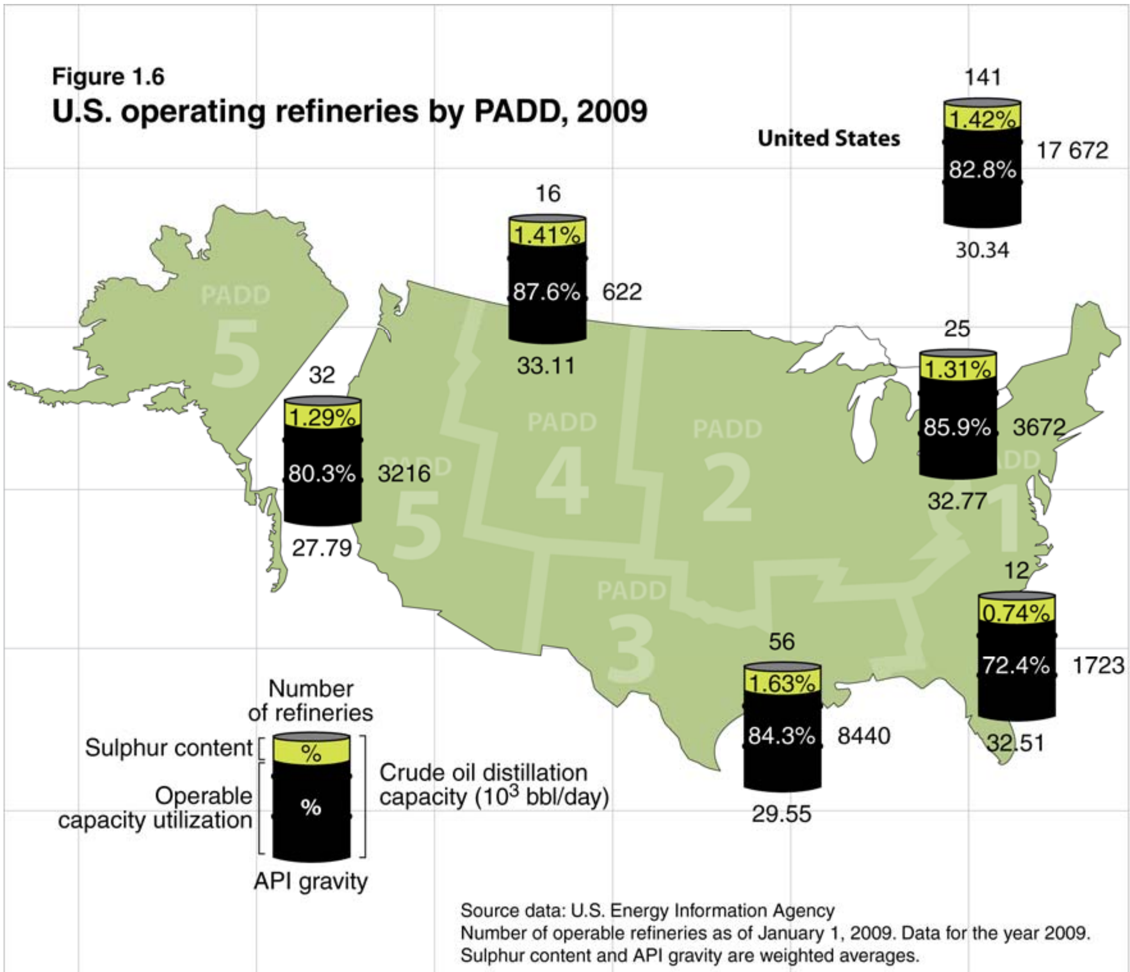


Figure 1.6
U.S. operating refineries by PADD, 2009

1.2.2 North American Natural Gas Prices

While North American crude oil prices closely track international prices, natural gas prices are set in the North American market with little global gas market influence aside from the occasional impact of liquid natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by events in the U.S., its largest importer. The most significant change in the market recently has been the increase in U.S. natural gas supply from shale gas—an unconventional supply source that has become economic due to horizontal drilling and multilateral fracturing of the wellbore.

Figure 1.7 shows monthly data for the average Alberta natural gas price at the plant gate for 2009. As shown, prices averaged above Cdn$5.00/GJ in January due to the seasonal winter impact. However, as the lingering impact of weak demand due to the economic recession collided with increasing supply from shale gas, prices declined to less than Cdn$3.00/GJ in September. The average Alberta gas price for 2009 was Cdn$3.65/GJ, compared to Cdn$7.47 for 2008, a decline of over 50 per cent. This followed the broader downward price trend in the U.S.

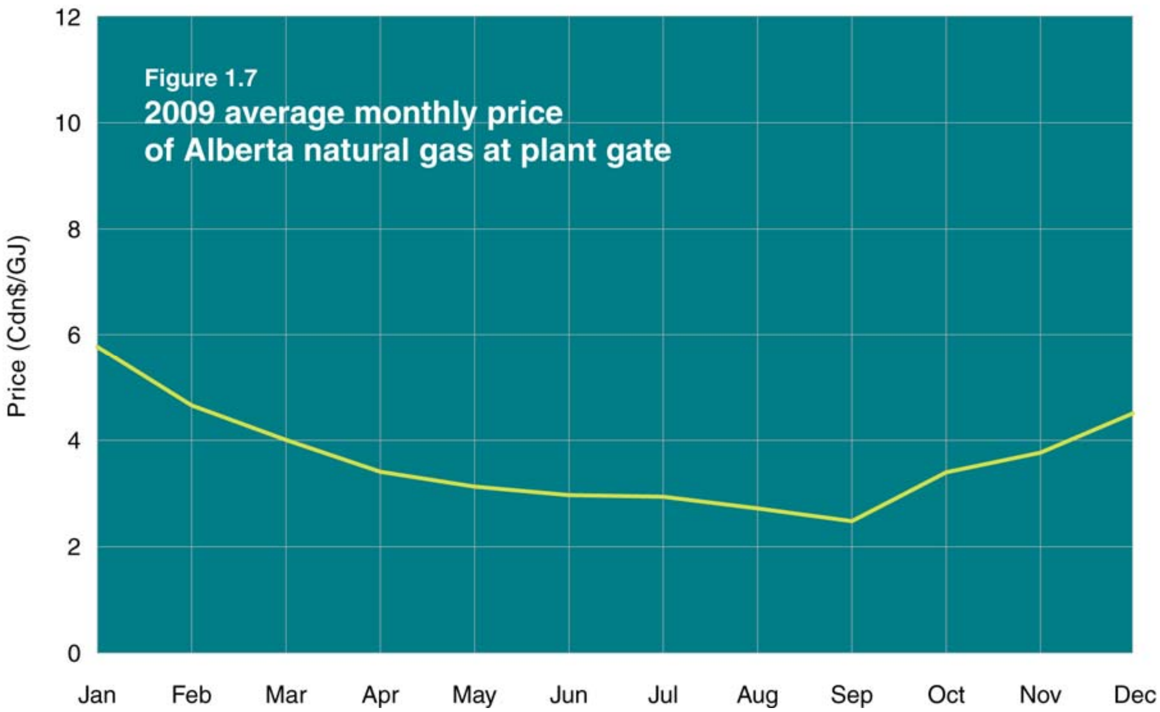
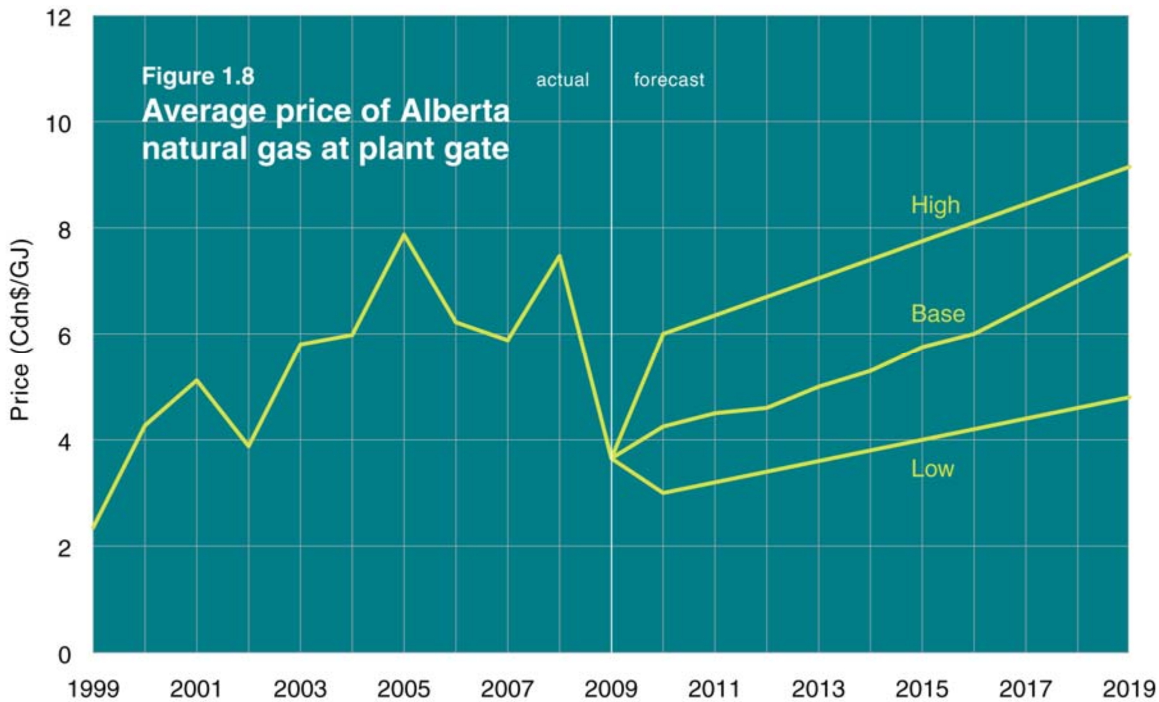


Figure 1.8 shows the historical and forecast average price of Alberta natural gas price at the plant gate for 1999 to 2019. The ERCB expects natural gas prices at the Alberta wellhead to range between Cdn$3.00/GJ and Cdn$6.00/GJ in 2010, with a base price of Cdn$4.25/GJ. In the near term, prices are projected to remain depressed, as U.S. production of shale gas exceeds the decline of conventional supplies. Over the forecast period, the price of natural gas is expected to increase slowly to reach an average of Cdn$7.50/GJ by 2019, while the top end of this range could surpass Cdn$9.00/GJ. This forecast is lower than the prior year's forecast of a base case price of Cdn$10.00/GJ in 2018. Although Alberta conventional natural gas production is expected to decline throughout the forecast period, coalbed methane (CBM) is expected to provide an increasing share of Alberta's total natural gas production.

The current forecast acknowledges that the principal agent of change in the North American natural gas market is the emergence of shale gas as a major contributor to supply growth. Prior to the emergence of shale gas, North American conventional gas supplies were declining and projected to decline further. As a result, a number of LNG regasification facilities were built to make up the shortfall.

Starting in 2006, however, U.S. production increased after nine years of zero growth. Between 2007 and 2009, total U.S. production increased by approximately 9.7 per cent, from 1.49 billion (10^9) m^3/d (52.8 billion cubic feet [Bcf]/d) in 2007 to 1.63 10^9 m^3/d (57.9 Bcf/d) in 2009. Over half of the production increase can be attributed to Texas, where horizontal drilling has allowed for successful production of natural gas from the



Barnett Shale. Other unconventional shale gas plays, including Fayetteville, Woodford, and Haynesville, also contributed to the 0.14 10^9 m^3/d (5 Bcf/d) increase in total U.S. natural gas production. The Marcellus play is expected to have a future impact as well.

The Alberta gas-to-light-medium-oil price parity on an energy content basis averaged 0.47 for 2008 and 0.35 for 2009, as the price of natural gas declined and crude oil prices increased. During the 2005 to 2007 period, the parity averaged 0.60. The gas-to-oil price parity is expected to average 0.35 over the forecast period.

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 2009. The 2008 average is included for comparison. The 2009 average pool price averaged $47.81 per megawatt-hour (MWh), compared to the 2008 average of $89.95/MWh. Monthly pool prices were high in January 2009 and September 2009, reflecting the significant impact of coal-fired power plant outages. Otherwise, monthly pool prices ranged between $31.53/MWh to $92.97/MWh, reflecting lower natural gas prices.

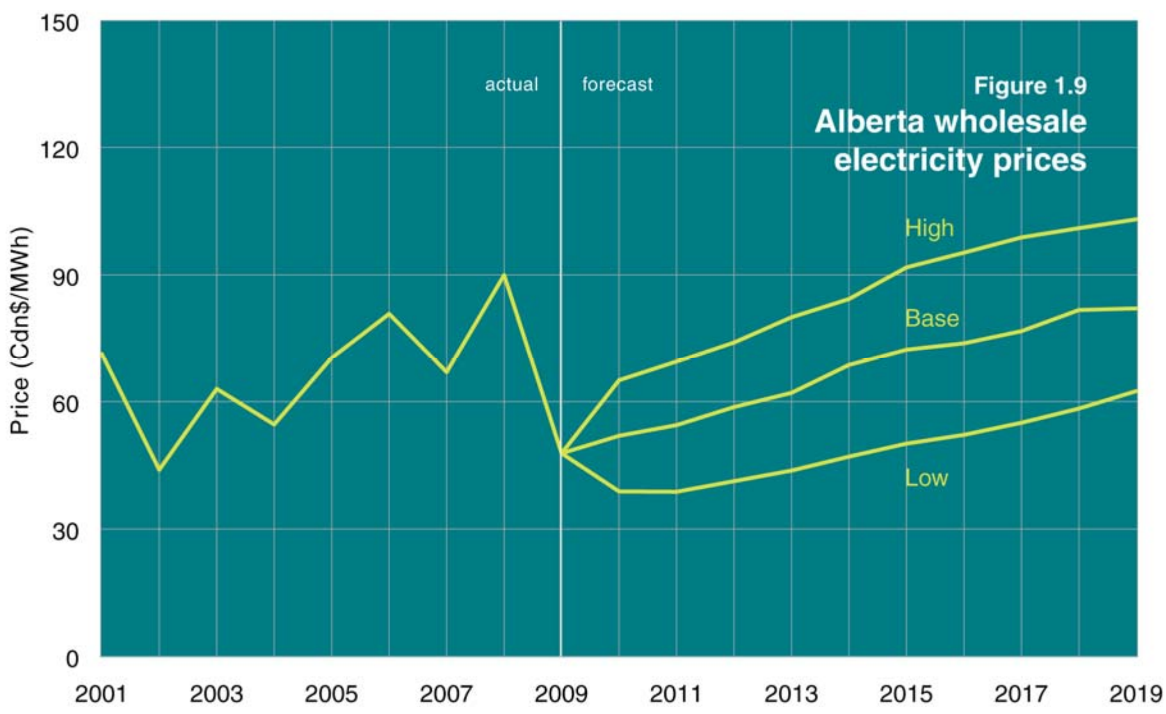
The forecast for electricity supply and demand within Alberta is discussed in **Section 9**. Preliminary estimates suggest that in 2009 Alberta sectoral electricity demand increased by 0.5 per cent, similar to the last two years of growth, averaging less than 1 per cent per year. Up until 2006, the 10-year average annual growth in demand was 2.7 per cent per year.

Table 1.1. Monthly pool prices and electricity load

2009	Price ($/MWh) Average	Min	Max	Load (MW) Average	Min	Max
Jan	92.97	7.85	999.99	8 442	7 250	9 753
Feb	52.84	10.12	436.80	8 373	7 321	9 465
Mar	43.21	12.85	749.67	8 175	6 952	9 307
Apr	31.53	7.85	774.13	7 626	6 690	8 507
May	31.91	6.34	337.19	7 418	6 454	8 375
Jun	33.48	0.10	732.00	7 722	6 580	8 863
Jul	41.39	2.93	599.88	7 806	6 463	9 070
Aug	34.60	7.85	473.95	7 745	6 640	9 062
Sep	73.25	7.56	999.99	7 659	6 489	9 108
Oct	34.93	7.85	79.63	7 966	6 689	8 942
Nov	50.16	11.62	717.01	8 125	7 076	9 561
Dec	53.86	12.97	873.57	8 727	7 423	10 236
2009	47.81	0.10	999.99	7 981	6 454	10 236
2008	89.95	0.00	999.99	7 963	6 411	9 806

Electricity supply growth in the forecast period will largely come from growth in natural gas-fired cogeneration facilities associated with oil sands projects. Further wind power projects are challenged due to the impact of the financial crisis, the natural gas price and accompanying electricity price outlook, and the lower forecast demand trajectory. Average daily prices will continue to be impacted by seasonal temperature influences and unplanned generating plant outages. However, over the long term, the average annual electricity pool price will reflect Alberta natural gas prices and move higher as natural gas prices move higher.

Figure 1.9 illustrates the historical and the ERCB forecast of average annual pool prices in Alberta to 2019. As illustrated, electricity prices are projected to remain in the range of prices from 2002 to 2008, as pool costs reflect the natural gas price forecast.



1.3 Oil and Gas Production Costs in Alberta

For the past 30 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical wells drilled in the previous year. The cost estimates presented here were obtained from the 2009 and 2010 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 1.10**. **Table 1.2** outlines the median well depth for each area, a major factor contributing to drilling costs. Many other factors influence well costs, including the economic environment, whether it is an oil or a gas well, whether it is a development or an exploratory well, surface conditions, sweet versus sour production, drilling programs, well location, nearby infrastructure, and completion method.

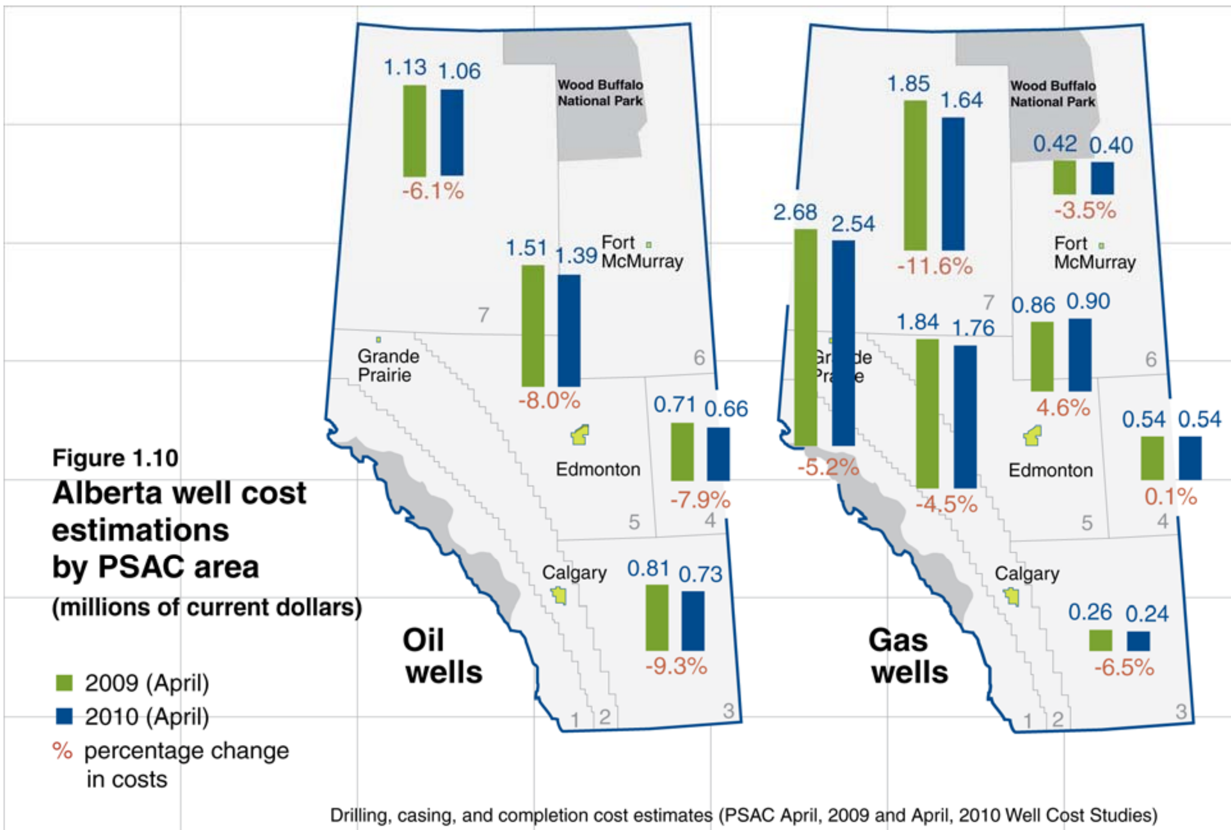


Figure 1.10
Alberta well cost estimations by PSAC area
(millions of current dollars)

Table 1.2. Alberta median well depths by PSAC area, 2009 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3 621	2 640	784	722	866	518	1 519
Oil wells	NA	2 243	1 260	728	1 695	1 137	1 608

NA – Not applicable.

As illustrated in **Figure 1.10,** the median cost to drill and complete an oil well is forecast to decrease between summer 2009 and summer 2010. Costs to drill and complete an oil well in 2010 are expected to range from as low as $660 000 in East Central Alberta (Area 4) to as high as $1 386 000 in Central Alberta (Area 5). On average, across the modified PSAC areas, oil well costs are anticipated to decline by 7.8 per cent.

Estimated costs to drill and complete a typical gas well are highest in the Foothills area, at over $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 $240 000 to drill and complete.

Gas well drilling and completion costs are also projected to decrease in most areas of the province between summer 2009 and summer 2010, with the average cost to drill and complete a gas well across the PSAC areas projected to decrease by 3.8 per cent.

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

1.4 Alberta and Canadian Economic Performance

The historical performance of major economic indicators for Alberta and Canada between 1999 and 2009 are depicted in **Figure 1.11**.

Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the last decade, particularly in the 2003-2007 timeframe. Average Alberta GDP growth from 1999 to 2009 was 2.6 per cent, compared to a Canadian average of 2.4 per cent. Similarly, the unemployment rate in Alberta averaged 4.7 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2003, inflation in Alberta has averaged 2.8 per cent per year, while Canadian inflation has averaged 1.9 per cent.

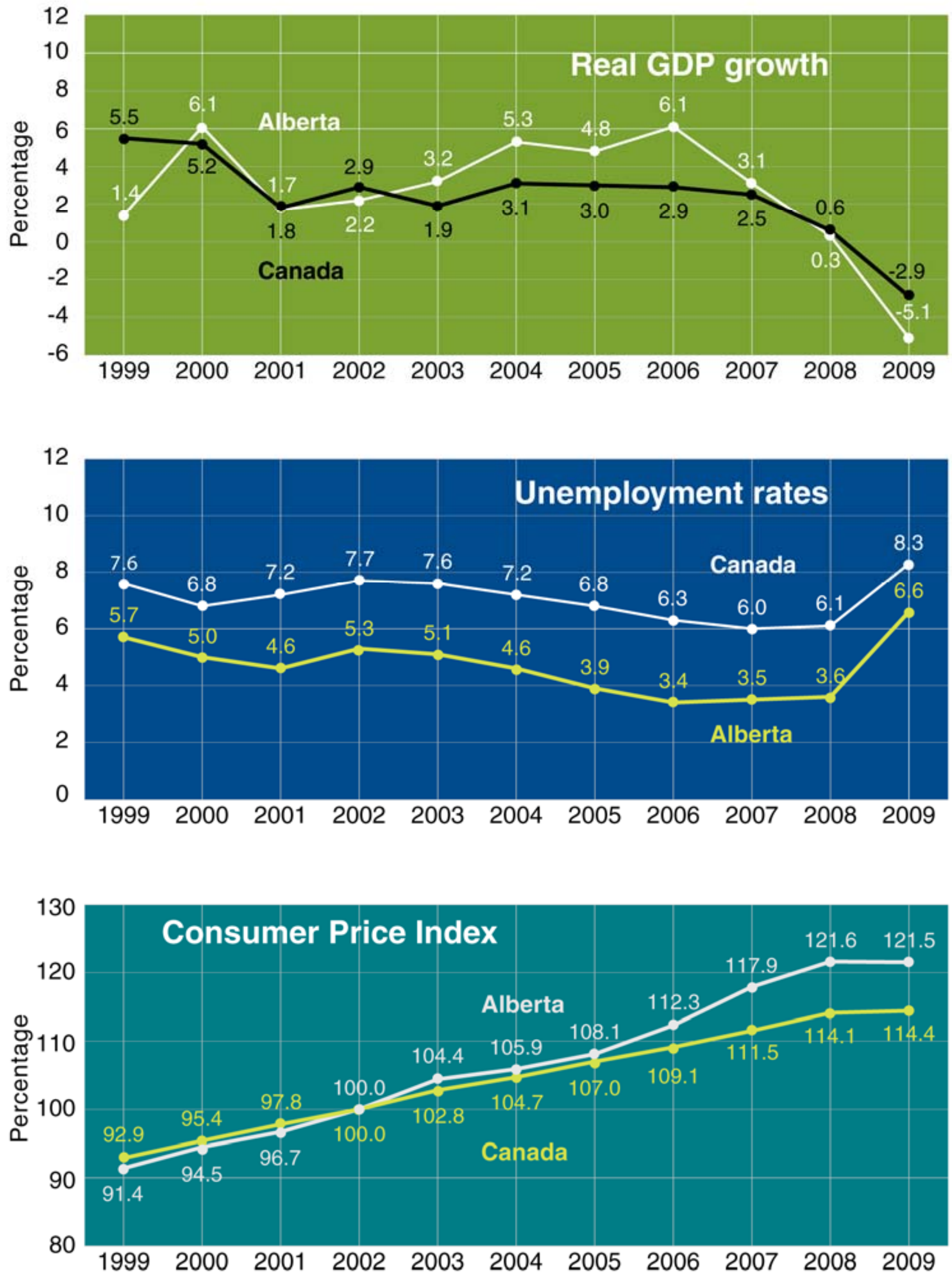
Figure 1.12 illustrates the historical performance of the US/Canadian dollar exchange rate between 1999 and 2009. The dollar exchange rate is an economic parameter that impacts both the Canadian and Alberta economies. The appreciation of the Canadian dollar over the historical period provided a headwind for all exporting industries.

The US/Canadian dollar exchange rate averaged US$0.876 in 2009, compared to US$0.943 in 2008. The exchange rate began the year averaging US$0.816 in January 2009 and averaged US$0.948 in December 2009, as the financial system stabilized. The US/Canadian dollar exchange rate is projected to average US$0.98 in 2010, then decrease slightly to US$0.97 for the remainder of the forecast period.

1.5 The Alberta Economy in 2009 and the Economic Outlook

The ERCB forecast of Alberta real GDP and other economic indicators is given in **Table 1.3**. In 2009, Statistics Canada estimates that Alberta real GDP contracted by 5.1 per cent, following growth of 0.3 per cent in 2008. Real GDP is forecast to increase by 2.6 per cent in 2010 and to resume growth at a 3.1 per cent trend from 2011 to 2019. Alberta's inflation rate fell to -0.1 per cent in 2009, compared to the national inflation rate of 0.3 per cent.

Figure 1.11
Alberta and Canada economic indicators



Source data: Statistics Canada

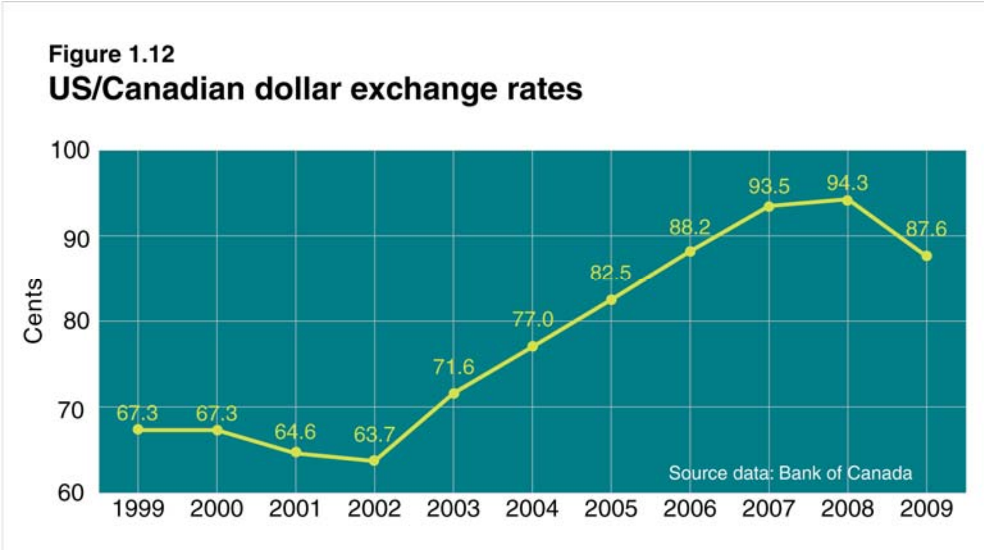


Table 1.3. Major Alberta economic indicators, 2009-2019 (%)

	2009	2010	2011-2019[b]
Real GDP growth	-5.1	2.6	3.1
Population growth	2.6	1.8	2.0
Inflation rate	-0.1	2.0	2.4
Unemployment rate	6.6	6.8	5.5

[a] Actual.
[b] Averaged over 2011-2019.

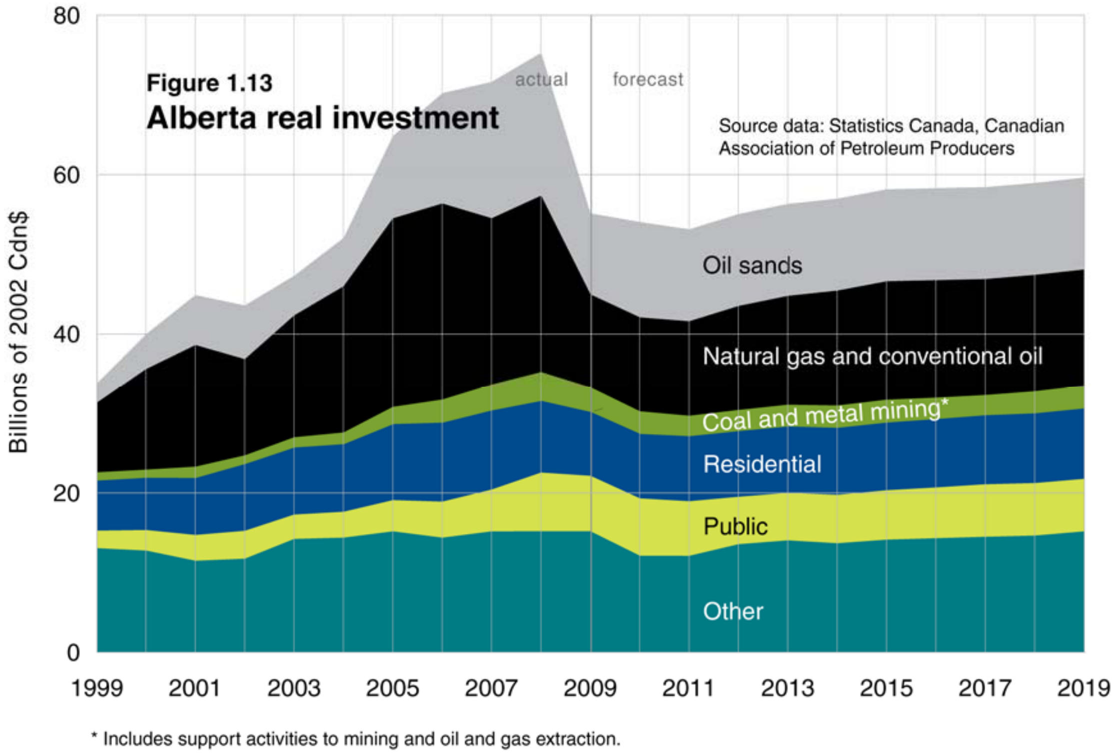
The steep contraction in GDP in 2009 can be largely attributed to a sharp decrease in drilling activity and to the slowdown in construction activity in the Alberta oil sands area. The drop in oil and gas prices in the third quarter of 2008, combined with the impact of the financial crisis, resulted in a significant slowdown in drilling activity in 2009. There were 6980 total wells drilled in Alberta in 2009, compared to 15 021 in 2008—a drop of 8041 wells, or 54 per cent. Bitumen evaluation wells declined to 1272 wells in 2009, compared to the record-level drilling of 3472 wells in 2008—a drop of 2200, or 63 per cent.

The Canadian Association of Petroleum Producers (CAPP) estimates that oil sands capital expenditures dropped to $10 billion in 2009, compared to $18.1 billion in 2008. Both the Horizon mined oil sands project and the Long Lake in situ project were completed in 2008 and moved into project start-up in 2009, while Suncor Energy Inc. significantly curtailed construction activity in 2009 compared to 2008. The commencement of the Kearl Lake project, resumed spending on the Suncor Firebag project, and the announcement of a number of other in situ projects will stabilize spending in this area.

Most of the earlier investment in the oil sands sector was focused on surface mining projects. Syncrude Canada Ltd. and Suncor Energy Inc. have been extracting bitumen from surface-mined oil sands for decades. Shell Canada Ltd. developed the third surface mining project, and the recently completed Canadian Natural Resources Limited Horizon project is the fourth oil sands mining project.

Total real investment expenditure is estimated to have decreased by 26 per cent in 2009. From 2009 through 2019, the ERCB expects nominal investment expenditures related to oil sands (surface mining, upgrading, in situ, and support services) to total $148 billion ($114 billion in 2002 dollars). Real investment in conventional oil and gas extraction and unconventional non-oil sands (e.g., CBM and some heavy oil extraction) is expected to average $14 billion per year, consistent with the ERCB projections for drilling and commodity prices and with recent historical trends.

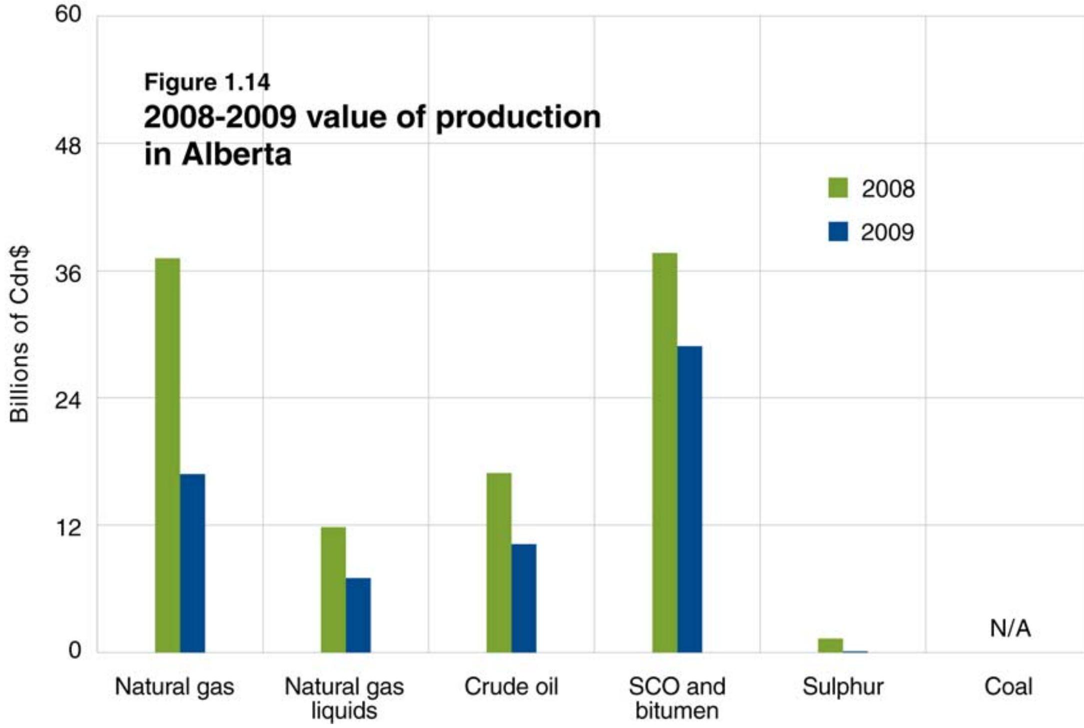
Figure 1.13 illustrates the profile of real investment in Alberta's energy, business, residential, and government sectors from 1999 through 2019.



The high cost inflation related to the peak in investment spending in 2007 and 2008 has been ended by the steep downturn of 2009. The recent cancellation and deferral of projects should keep 2010 costs lower than what Alberta has experienced in the past few years.

The continued development of the mined oil sands and in-situ projects will result in further increases in bitumen and synthetic crude oil production. During the forecast period, in situ bitumen production is forecast to increase at an average annual growth rate of 9.7 per cent. Synthetic crude oil production is projected to increase at an average annual growth rate of 5.9 per cent. Virtually all of this production increase will be exported, providing powerful export-led economic growth for the province.

The value of Alberta's energy resource production in 2008 and 2009 is depicted in **Figure 1.14.** In 2009**,** the total value of production decreased by 40 per cent relative to 2008. The value of synthetic crude oil (SCO) and bitumen production exceeded the value of natural gas production for the second year, the beginning of a trend that is anticipated to continue throughout the forecast period.



The total economic value of Alberta's energy resource production for the period 2009 to 2019 is shown in **Table 1.4.** Production from unconventional energy resources is projected to increase significantly over the coming decade. In particular, crude bitumen and SCO derived from the oil sands will more than offset the decline of conventional resource production.

Continued growth in non-conventional crude oil production from mining and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. It is also anticipated that Alberta's economic growth will continue to be a strong contributor to Canadian economic growth.

Table 1.4. Value of Alberta energy resource production (millions of current dollars)

	2009	2010[a]	2011[a]	2012-2019[a,b]
Conventional crude oil	10 193	11 275	11 834	11 843
Crude bitumen	11 285	15 037	18 114	36 108
Synthetic crude oil	17 637	23 752	29 161	44 977
Marketable gas	16 794	17 980	17 690	18 573
Natural gas liquids	7 010	7 368	7 367	6 702
Sulphur	137	120	129	134
Coal	n/a	n/a	n/a	n/a
Total (excludes coal)	63 056	75 532	84 295	118 337

[a] Values calculated from the ERCB's annual average price and production forecasts.
[b] Annual average over 2012-2019.

2 Crude Bitumen

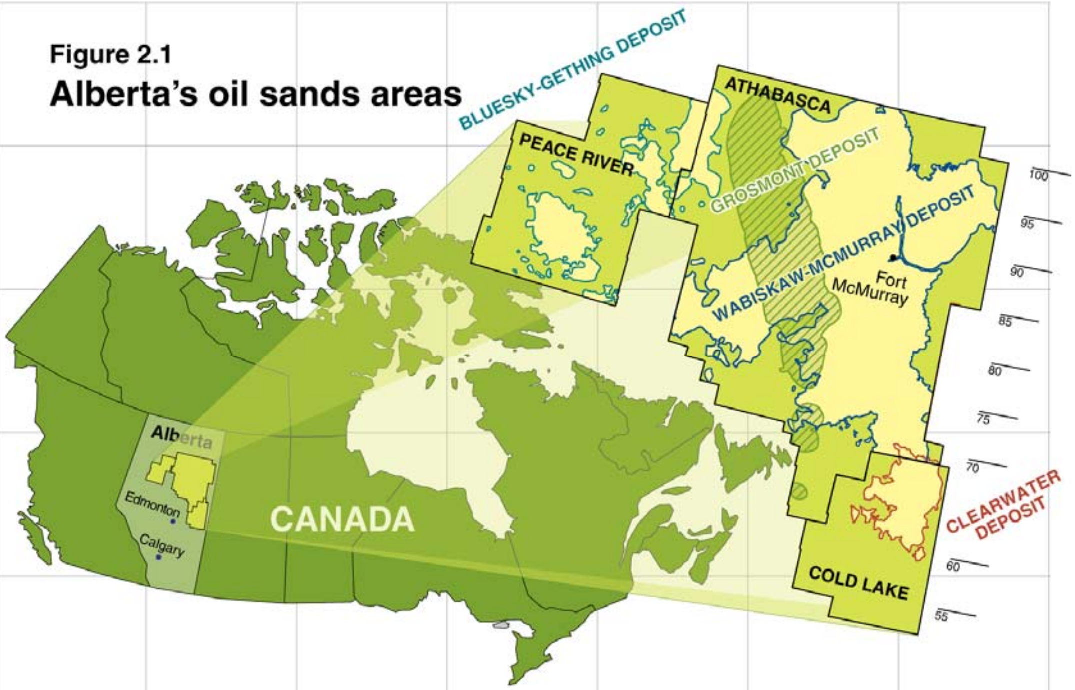
Highlights

- Athabasca Grosmont deposit was updated with initial in-place resources increasing 28 per cent to 64.5 billion cubic metres.
- Cold Lake Upper and Lower Grand Rapids deposits were updated with initial in-place resources decreasing 20 and 5 per cent to 5.4 and 10.0 billion cubic metres respectively.
- Total bitumen production increased by 14 per cent, with both mineable and in situ increasing by 14 per cent.
- Synthetic crude oil production increased by 17 per cent.

Crude bitumen is a type of extra heavy oil that in its natural state does not flow to a well. In Alberta, crude bitumen occurs in sand (clastic) and carbonate formations in the northern part of the province. The crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. Other heavy oil is deemed to be oil sands if it is located within an oil sands area. Since the bitumen within these deemed oil sands will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated oil sands areas (OSAs) in Alberta are shown in **Figure 2.1**. Together they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Contained within the OSAs are 15 oil sands deposits that designate the specific geological zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

Figure 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 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

The ERCB is continuing its update of Alberta's crude bitumen resources and reserves on both a project and deposit basis and anticipates that this work will take some time to complete. While significant changes were made to the in-place resource in 2009, there are no changes to the estimate of the initial established reserves of crude bitumen for this year's report. The remaining established reserves at December 31, 2009, are 26.99 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.086 10^9 m^3.

Of the total 26.99 10^9 m^3 remaining established reserves, 21.55 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods and 5.44 10^9 m^3 by surface mining methods. Of the in situ and mineable totals, 4.22 10^9 m^3 is within active development areas. **Table 2.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

Table 2.1. In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.72	5.44	3.69
In situ	265.8	21.94	0.38	21.55	0.53
Total	286.6 (1 804)[b]	28.09[a] (176.8)[b]	1.10 (6.9)[b]	26.99 (169.9)[b]	4.22 (26.5)[b]

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

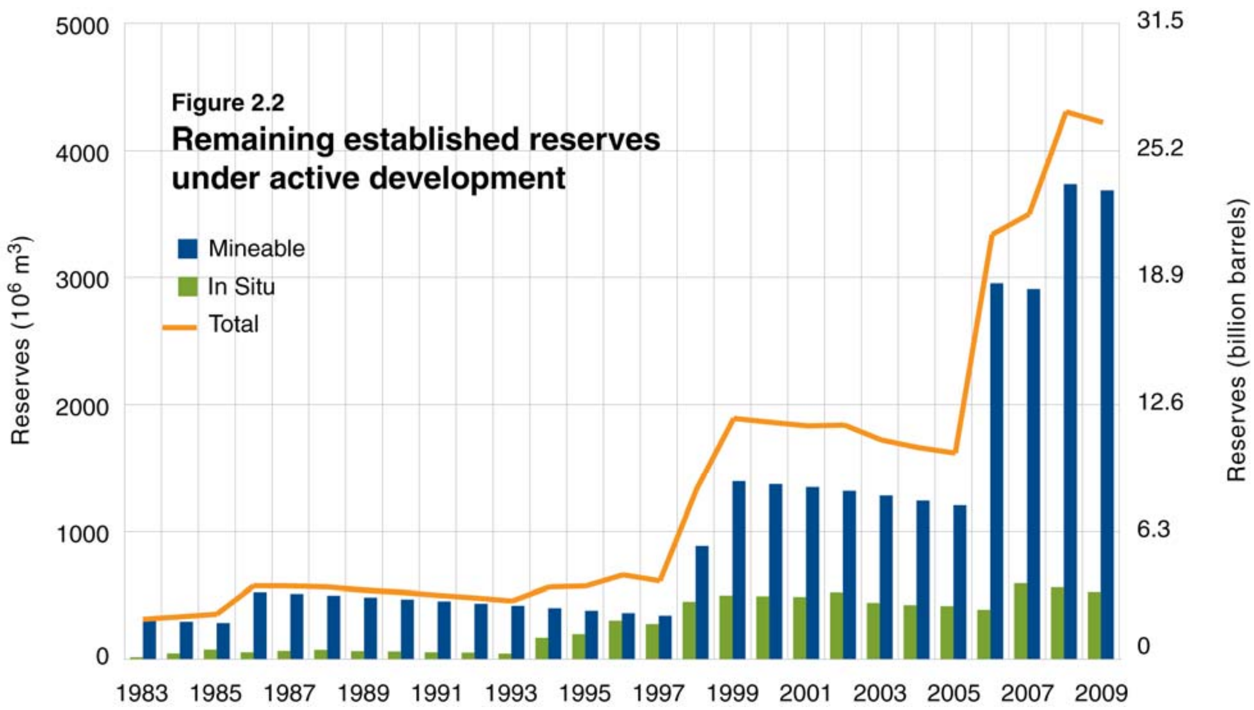
The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative and annual production for 2009 are shown in **Table 2.2.** Crude bitumen production in 2009 totalled 86.4 10^6 m^3, with 38.5 10^6 m^3 coming from in situ operations.

The remaining established reserves from active development areas is presented in **Figure 2.2**. These project reserves have a stair-step configuration representing start-up of new large mining projects. The intervening years between additions are characterized by a slow decline due to annual production.

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

	2009	2008	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total	28 092 (176 780)[b]	28 092 (176 780)[b]	0
Cumulative production			
Mineable	718	670	+48[c]
In situ[a]	382	350	+31[c]
Total[a]	1 099	1 020	+80[c]
Remaining established reserves			
Mineable	5 439	5 487	-48
In situ	21 554	21 585	-31
Total[a]	26 992 (169 859)[b]	27 072 (170 361)[b]	-80
Annual production			
Mineable	48	42	+6
In situ[a]	39	34	+5
Total[a]	86	76	+11

[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.



2.1.2 Initial in-Place Volumes of Crude Bitumen

The recent effort to update the province's crude bitumen resources and reserves began in 2003, and since then 7 of the 15 deposits have been updated. The largest deposit, the

Athabasca Wabiskaw-McMurray (Wabiskaw-McMurray), was significantly updated for year-end 2004 and subsequently revised, including in 2009, to take new drilling into account. The Wabiskaw-McMurray has the largest cumulative and annual production. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005, as was the northern portion of the Cold Lake Wabiskaw-McMurray (CLWM) deposit. The Peace River Bluesky-Gething deposit was updated for year-end 2006. This year, in addition to updating the Wabiskaw-McMurray for year-end 2009, the ERCB has also completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit.

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 considerably 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 space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies, depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data, including geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. In the five previous reports, the Wabiskaw-McMurray, Clearwater, and Bluesky-Gething deposits, as well as a portion of the CLWM deposit, were also estimated at a 6 mass per cent saturation cutoff. This year’s report also uses 6 mass per cent with the latest revision to the Grand Rapids deposits. The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. For this year’s revision of the Grosmont, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values. The ERCB believes that the oil sands quality cutoff of 6 mass per cent and the new carbonate bitumen cutoffs more accurately reflect the volumes from which bitumen can be reasonably expected to be recovered; consequently, deposits that are updated in the future will likely use these cutoffs.

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 Wabiskaw-McMurray, about 35 per cent for the Clearwater, more than 50 per cent for the Bluesky-Gething, and about 35 and 40 per cent of the Upper and Lower Grand Rapids deposits respectively. The Grosmont deposit would have decreased by about 15 per cent based on the new pore volume and porosity cutoffs. However, work on many of these deposits has shown that some or all of these reductions are offset by increases due to new drilling since the previous estimate.

Athabasca Wabiskaw-McMurray Deposit

In 2003, the ERCB completed a reassessment of the Wabiskaw-McMurray using geologic information from over 13 000 wells and bitumen content evaluations conducted on over 9000 wells to augment the over 7000 boreholes already available within the

Surface Mineable Area (SMA). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added to the latest reassessment, resulting in a minor decrease to the in-place bitumen resources of the Wabiskaw-McMurray of 0.62 10^9 m^3, or 0.4 per cent.

Figure 2.3 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval.

Figure 2.3 also shows the extent of the SMA, an ERCB-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. As such, it is presumed that the main recovery method will be surface mining, unlike in the rest of Alberta's crude bitumen area, where recovery will be through in situ methods. It should be noted, however, that this boundary is simply for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside this boundary and in situ activities may occur inside. It should also be noted that while the ERCB has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment purposes, mining might not actually take place, in which case the estimate of mineable reserves would have to be reduced. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resource occurs at a depth of less than 25 m of overburden.

Because the extent of the SMA is defined using township boundaries, it incorporates a few areas of deeper bitumen resources that are more amenable to in situ recovery. As a result, while the SMA has both mineable and in situ resources, estimates of mineable bitumen exclude those volumes within the SMA but beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA and those deeper areas, generally greater than 65 m, within the SMA. For resource assessment purposes, the ERCB has created a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is also shown in **Figure 2.3**.

Cold Lake Upper and Lower Grand Rapids Deposits

The Upper and Lower Grand Rapids reassessment for year-end 2009 included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Township 52 to 66 was chosen to replace the area of the previous assessment. As a result of this reassessment, in-place bitumen resources decreased from 6.72 10^9 m^3 to 5.38 10^9 m^3 for the Upper Grand Rapids and from 10.58 10^9 m^3 to 10.00 10^9 m^3 for the Lower Grand Rapids. This represents a decrease of 20 and 5.5 per cent respectively for the two deposits. Decreases are mainly a result of using the higher 6 mass per cent saturation cutoff.

The stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster. The Grand Rapids Formation was deposited in a shallow marine environment with little

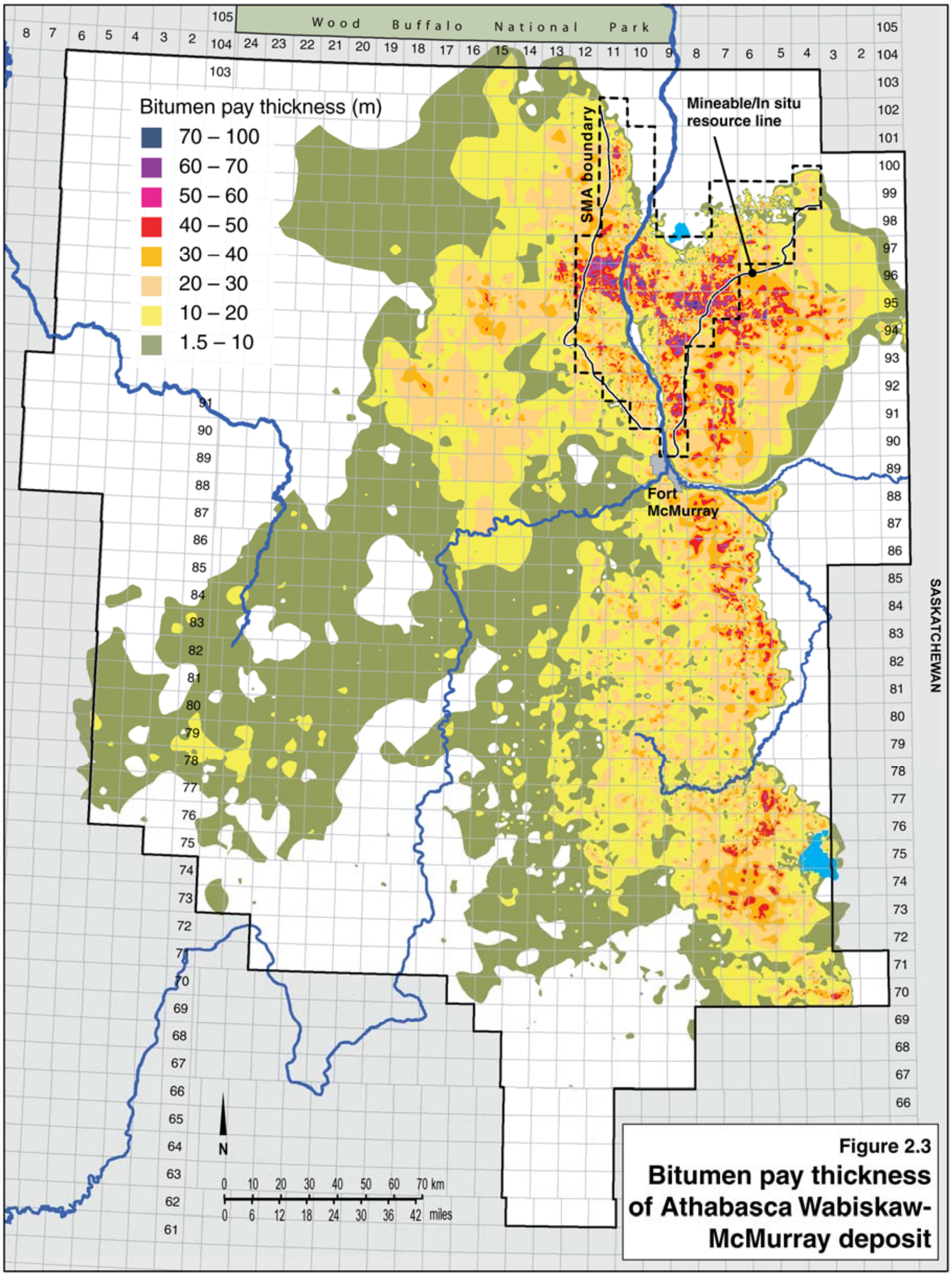
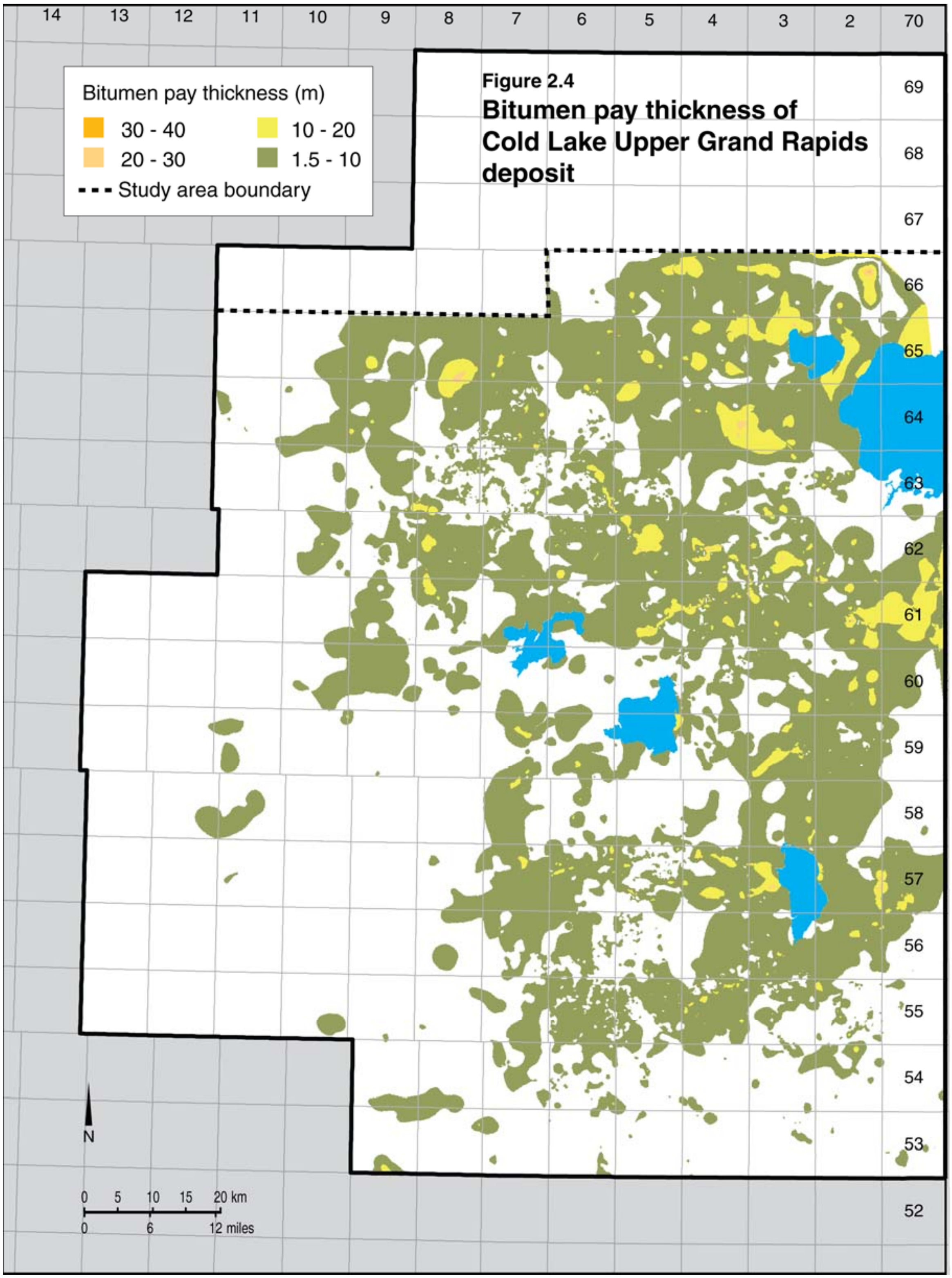
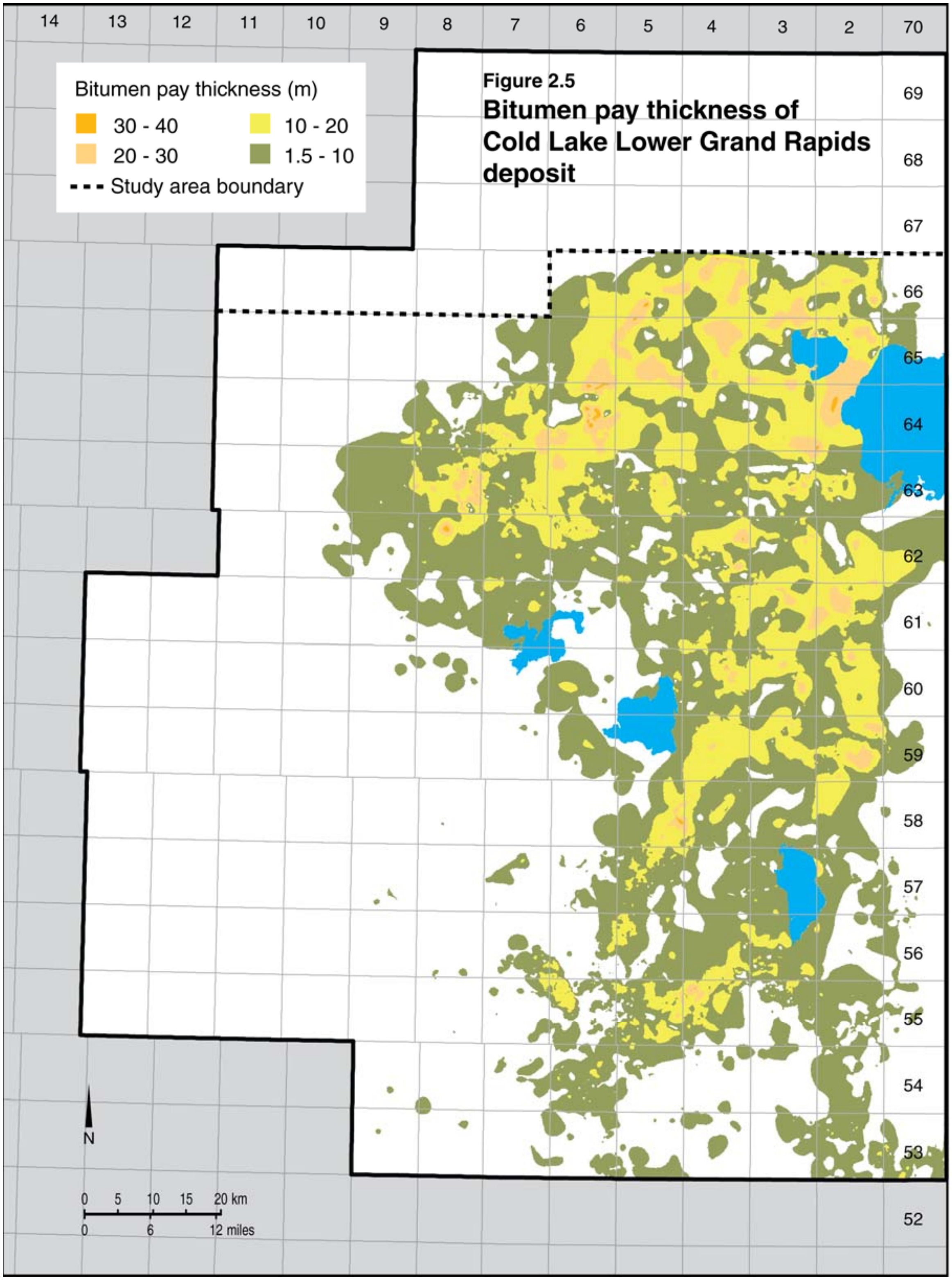


Figure 2.3 Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

accommodation space and had multiple small channels, making correlations difficult. The sands consist of Lower Cretaceous sands and shales that were deposited as a series of regional coarsening-upward sequences with incised channels or valleys containing estuarine fills. The Grand Rapids is conformably overlain by the Colorado Group and conformably overlies the Clearwater Formation within the study area.

Although crude bitumen within both Grand Rapids deposits is pervasive through much of the Cold Lake OSA, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figures 2.4** and **2.5** show respectively the cumulative net pay isopachs for each of the Upper Grand Rapids and the Lower Grand Rapids deposits. The net pay interpretations and volumetric calculations were completed





for each zone and were then summed for the deposit; the Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids. In the future, the assessment will be extended to Township 70 and will include an update to the sector pooling that is referred to in Appendix B.2. The sector pooling is therefore unchanged this year, but the individual volumes are now included in the new deposit totals.

Athabasca Grosmont Deposit

This year's resource assessment of the Athabasca Grosmont deposit updates the previous 1990 assessment. Over 1330 wells were used within the study area. The area reviewed extends from Township 62 to 103 and Ranges 13W4M to 6W5M, with the Grosmont Formation spanning over 300 townships. As a result of this reassessment, in-place bitumen resources increased significantly, from 50.5 10^9 m^3 to 64.5 10^9 m^3, or 27.8 per cent.

The Grosmont Formation is a late-Devonian shallow marine to peritidal platform carbonate. There are four recognizable units within the deposit: the Grosmont A, B, C, and D. The Grosmont A is the oldest unit and has an erosional edge that subcrops along the eastern extent of the formation; the Grosmont D is the youngest unit and subcrops to the west. The A, B, and C units are separated by shale beds thought to be Ireton shale clinoforms. The C and D units are separated by a thin lime mud termed the CD marl. The A and B are more marine in nature, while the upper two units, C and D, are thought to be peritidal.

Generally the Grosmont C and D units offer the best bitumen potential, since these units have been dolomitized and later karsted. The karsting resulted in the leaching of vug walls, causing brecciation, which further enhanced porosity. The majority of the Grosmont A and B units were not dolomitized and remain as limestone due to the high shale content within these units. The Grosmont A and B have a smaller bitumen potential, but contain significant accumulations of gas. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying Clearwater Formation. **Figure 2.6** shows the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

Initial in-place resources for the Grosmont A and B units decreased respectively 14 and 17 per cent to 8.5 10^9 m^3 and 4.5 10^9 m^3. This decrease is mainly a result of using the higher saturation and porosity cutoffs. The initial in-place resources for Grosmont C and D units increased respectively 22 and 65 per cent to 18.8 10^9 m^3 and 32.9 10^9 m^3. These significant increases were mainly due to an increase in thickness resulting from the petrophysical reevaluation of wells and in the case of the Grosmont D an increase in areal extent.

Cold Lake Clearwater Deposit

For year-end 2005, the ERCB completed its reassessment of the Clearwater deposit. This deposit contains the first commercial in situ bitumen development at Imperial's Cold Lake project, which commenced production in 1985. **Figure 2.7** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

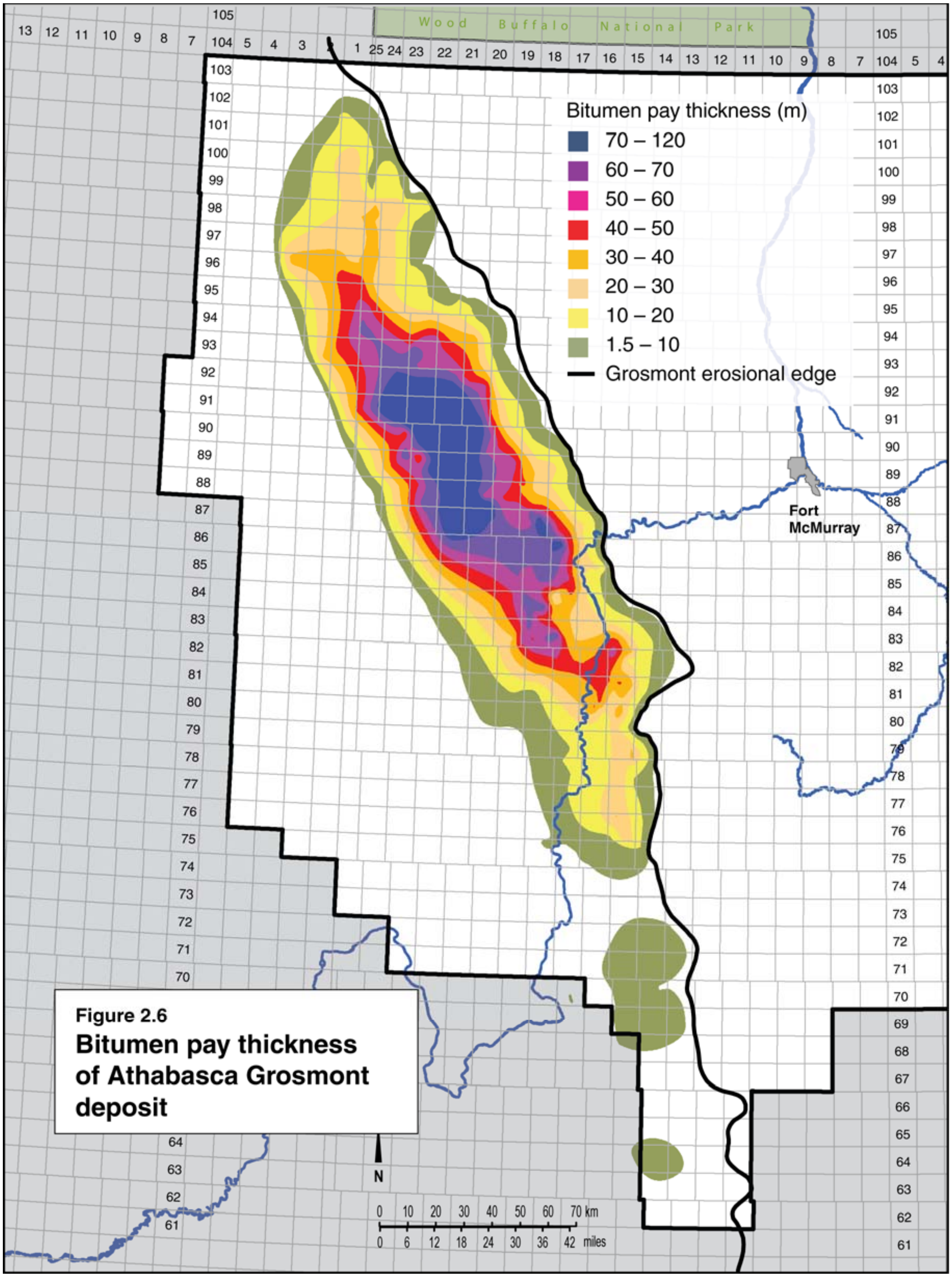
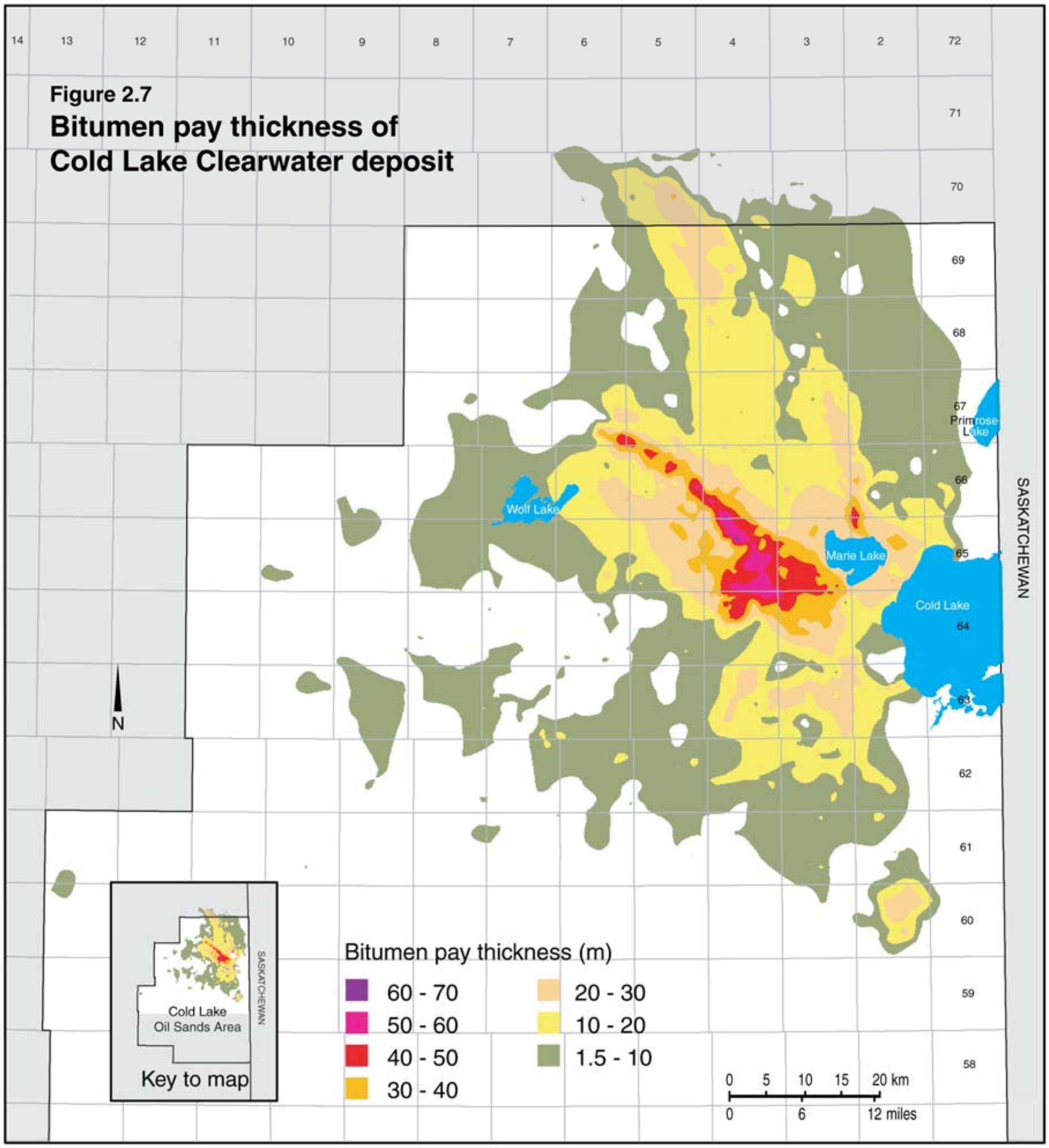


Figure 2.6
Bitumen pay thickness of Athabasca Grosmont deposit



Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. This deposit includes the in situ bitumen development at Shell Canada's Peace River project, started in 1979. **Figure 2.8** is a bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Consistent with **Figure 2.3**, the Bluesky-Gething is mapped as a single bitumen zone, so that the full extent of the deposit, at 6 mass per cent, can be shown. **Figure 2.8** also shows the paleotopographic highlands as they are believed to have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. As oil migrated updip, it became trapped beneath the overlying Wilrich shales and against these highlands, where it was eventually biodegraded into bitumen.

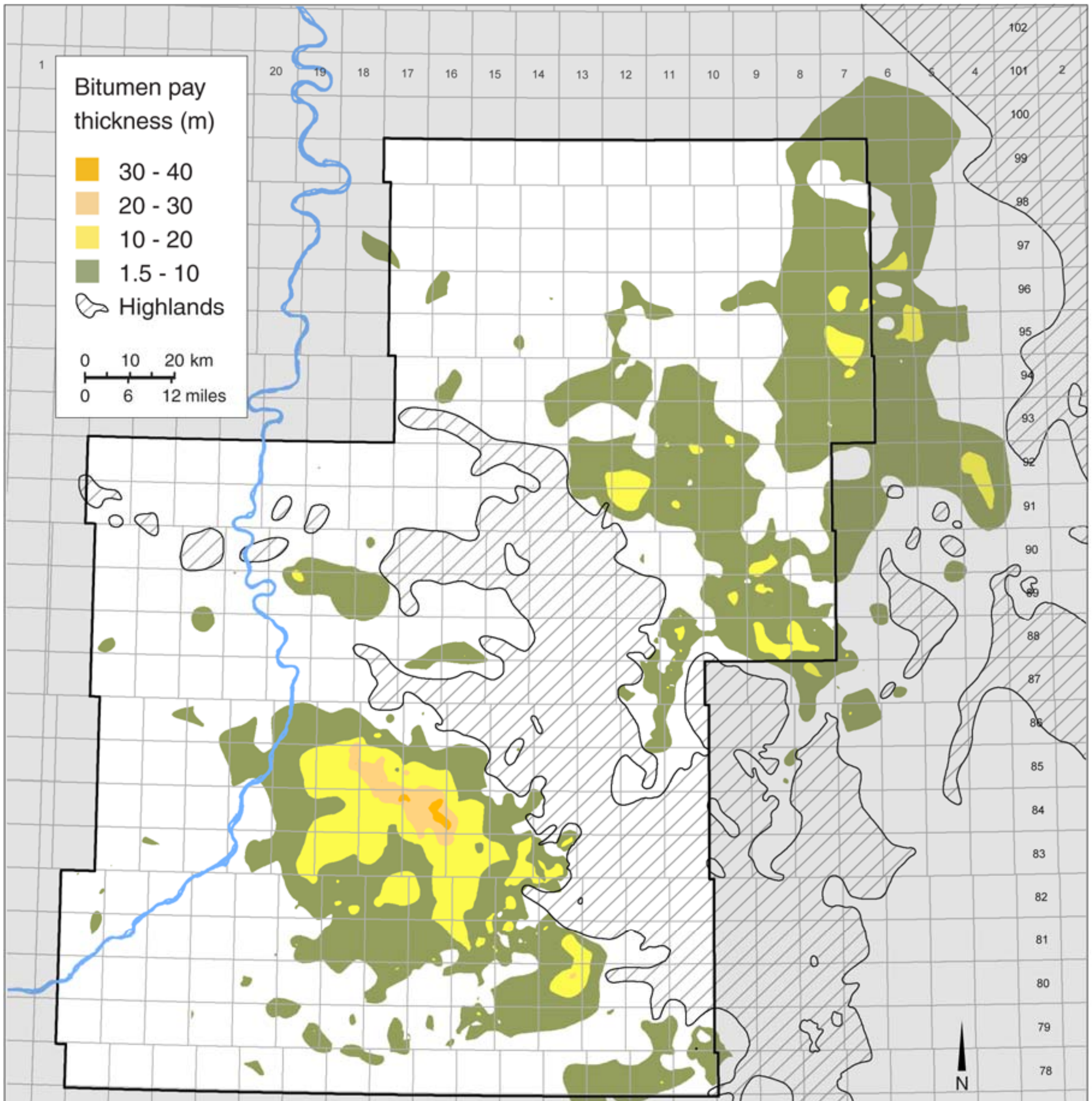


Figure 2.8
Bitumen pay thickness of Peace River Bluesky-Gething deposit

At the end of Bluesky time, these highlands were the exposed portion of a major erosional surface known as the sub-Cretaceous unconformity. Within the oil sands areas, the rest of this surface was covered initially by sediments of the lower Mannville Group and equivalents and then by sediments of the lowermost upper Mannville (the Bluesky/Wabiskaw and equivalents). The exposed and contoured submerged portions of this surface are shown in **Figure 2.9**. The configuration of the sub-Cretaceous unconformity surface is very important in understanding the thickness, lithology, and extent of the deposition of the main clastic bitumen reservoirs and subsequently the occurrence of bitumen within them.

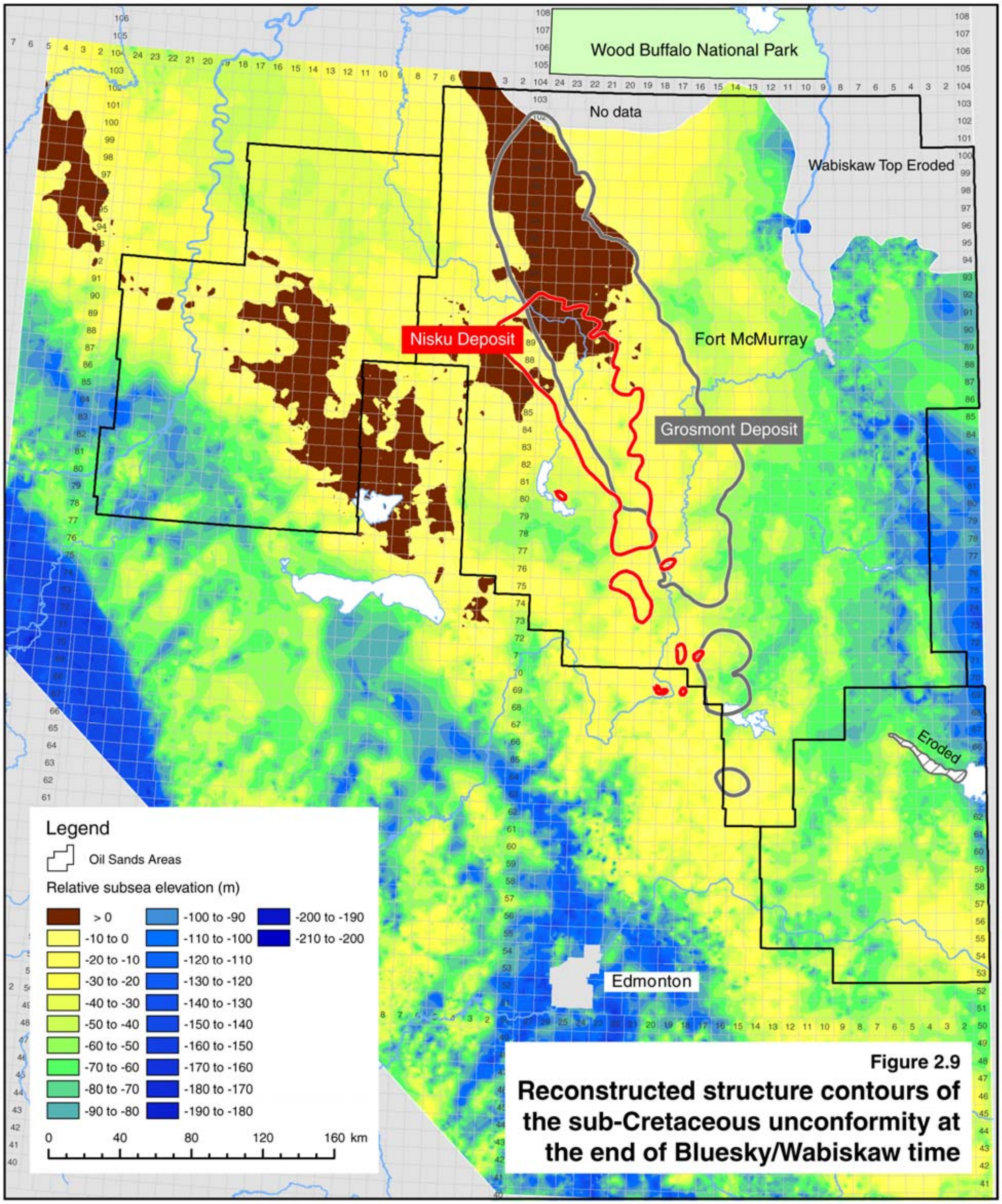


Figure 2.9
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

The nature of the unconformity surface is also important in understanding the extent of the subaerial exposure of the underlying carbonate rocks and the resulting degree of karsting. Karsting, dolomitization, and the sealing properties of overlying sediments are major factors in understanding bitumen accumulations in carbonate deposits. In general, the thickest bitumen pay of the Grosmont (**see Figure 2.6**) and Nisku deposits occurs in an area coincident with significant paleohighlands. This relationship between paleotopography and carbonate bitumen accumulation is evident in **Figure 2.9**, where the extents of the Athabasca Grosmont and Nisku deposits are shown. Significantly, these carbonate deposits together hold an estimated 74.9 10^9 m^3 of in-place bitumen resource.

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**.

Table 2.3. Initial in-place volumes of crude bitumen as of December 31, 2009

Oil sands area Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha*)	Average pay thickness (m)	Average bitumen saturation Mass (%)	Average bitumen saturation Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	527	9.6	6.5	57	30
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	235 977					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	29 090					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	21 560					
Total	286 627					

*ha – hectare.

2.1.3 Surface-Mineable Crude Bitumen Reserves

With the recent expansion of the SMA and the current updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the ERCB now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resource at depths most suitable to mineable technologies, generally less than 65 m. This is a minor increase of 0.1 10^9 m^3 relative to the 2008 estimate, and consequently the established reserves were not revised from last year. For year-end 2008, potential mineable areas in the total in-place portion of the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[1] As of December 31, 2008, this method reduced the initial volume in place of 20.7 10^9 m^3 to 10.3 10^9 m^3. This latter volume is classified as the initial mineable volume in place.

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

Factors were applied to this initial mineable volume in place to determine the established reserves. A series of reduction factors was applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume, and therefore each factor is set at 90 per cent. A combined mining/extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserve of crude bitumen is 6.16 10^9 m^3. The remaining established mineable crude bitumen reserve as of December 31, 2009, has decreased from 5.49 10^9 m^3 to 5.44 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2009, are presented in **Table 2.4**. As of the end of 2009, almost three-quarters of the initial established reserves were under active development. Currently, Suncor, Syncrude, Shell Albian Sands, and Canadian Natural Resources Limited (CNRL) are the only producers in the SMA, and the cumulative bitumen production from these projects is 718 10^6 m^3. The Fort Hills mine project (owned by Suncor, UTS Energy, and Teck), the Shell Canada Ltd. Jackpine project, and the Imperial Oil/ ExxonMobil Kearl project are considered to be under active development and are included in **Table 2.4**.

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2009

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)
Shell Albian Sands	13 581	672	419	57	362
Fort Hills	18 976	699	364	0	364
Horizon	28 482	834	537	4	533
Kearl	19 674	1 324	872	0	872
Jackpine	7 958	361	222	0	222
Suncor	19 155	990	687	267	420
Syncrude	44 037	2 071	1 306	390	916
Total	151 863	6 951	4 407	718	3 689

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

Production from the four current surface mining projects amounted to 47.9 10^6 m^3 in 2009, with 19.4 10^6 m^3 from the Syncrude project, 16.8 10^6 m^3 from the Suncor project, 8.1 10^6 m^3 from the Shell Albian Sands project, and 3.6 10^6 m^3 from the CNRL Horizon 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 with commercial development. For deposits with primary development, a minimum zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. A minimum saturation cutoff of 3 mass per cent was used in all deposits. Future reserves estimates will likely be based on values higher than the 3 mass per cent.

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

While the volume of the in-place crude bitumen in the Athabasca Grosmont deposit was reassessed in 2009, no reserves were estimated. This is because there are no commercial projects currently operating in the Grosmont. While exploration has occurred, and there has been some experimentation with recovery methods, commercial operations have yet to be established. The ERCB estimates reserves only in those deposits where commercial operations are in place. As these projects come to fruition, the ERCB will determine when the publication of reserves estimates is appropriate.

In 2009, the in situ bitumen production was 38.5 10^6 m^3, an increase from 33.9 10^6 m^3 in 2008. Cumulative production within the in situ areas now totals 381.5 10^6 m^3,[2] of which 277.9 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.59 10^9 m^3 in 2008 to 21.55 10^9 m^3 in 2009, due to production of 0.039 10^9 m^3.

The ERCB's 2009 estimate of the established in situ crude bitumen reserves under active development is shown in **Table 2.5**. It should be noted that in this year's table the information on experimental schemes has been removed due to the limited number of experimental schemes and the confidential nature of the associated production data.

The ERCB has assigned initial volumes in place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. 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 527.0 10^6 m^3, a slight decrease due to 2009 production and removal of experimental schemes.

2.1.5 Ultimate Potential of Crude Bitumen

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

[2] This does not include some 7 10^6 m^3 produced from active and terminated experimental schemes.

the ultimate potential from within the area of expansion has yet to be estimated, the total ultimate potential crude bitumen is unchanged at 50 10^9 m^3.

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2009

Development	Initial volume in place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	55.8	40	22.3	10.4	11.9
Primary recovery schemes	160.8	10	16.1	8.3	7.8
Subtotal	216.6		38.4	18.7	19.7
Athabasca Oil Sands Area					
Thermal commercial projects	313.7	50	156.9	50.0	106.9
Primary recovery schemes	1 026.2	5	51.3	21.9	29.4
Enhanced recovery schemes[c]	(289.0)[d]	10	28.9	13.0	15.9
Subtotal	1 339.9		237.1	84.9	152.2
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[e]	1 212.8	25	303.2	197.7	105.5
Thermal commercial (SAGD)[f]	33.8	50	16.9	1.5	15.4
Primary production within projects	601.1	5	30.1	13.7	16.4
Primary recovery schemes	4 347.1	5	217.4	57.3	160.1
Lindbergh primary production	1 309.3	5	65.5	7.7	57.8
Subtotal[g]	7 504.1		633.0	277.9	355.1
Total[g]	9 060.7		908.5	381.5	527.0

[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, 2009, 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] Differences are due to rounding.

2.2 Supply of and Demand for Crude Bitumen

This section discusses production and disposition of crude bitumen. It includes crude bitumen production, upgrading of bitumen to various grades of synthetic crude oil (SCO), and disposition of both SCO and nonupgraded bitumen. The nonupgraded bitumen refers to the portion of crude bitumen production that is not upgraded but is blended with some lighter-viscosity product (referred to as a diluent) in order to meet pipeline specifications for transport in pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to SCO and is primarily used by refineries as feedstock.

Upgrading is the term given to a process that converts bitumen and heavy crude oil into SCO. Upgraders chemically alter the bitumen by adding hydrogen, subtracting carbon, or both. In upgrading processes, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. Most oil sands coke, a by-product of the upgrading process, is stockpiled, with some burned in small quantities to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Pentanes plus are generally used in Alberta as diluent and represent about 30 per cent of the blend volumes. Pentanes plus used as diluent 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. If SCO is used as diluent, 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.

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

2.2.1 Crude Bitumen Production

Surface mining and in situ production for 2009 are shown graphically by oil sands area (OSA) in **Figure 2.10**. In 2009, Alberta produced 236.7 thousand (10^3) m^3/d of crude bitumen from all three areas, with surface mining accounting for 55 per cent and in situ for 45 per cent. This compares to 2008 crude bitumen production of 207.4 10^3 m^3/d. **Figure 2.11** shows combined nonupgraded bitumen and SCO production as a percentage of Alberta's total crude oil and equivalent production. Combined SCO and nonupgraded bitumen production volumes have increased from 39 per cent of the province's total crude oil production in 1999 to 69 per cent in 2009.

2.2.1.1 Mined Crude Bitumen

Currently, all mined bitumen in Alberta feeds upgraders producing SCO. In 2009, mined crude bitumen production increased by 14 per cent relative to 2008, to 131.2 10^3 m^3/d, with Syncrude, Suncor, Shell Albian Sands, and CNRL's Horizon accounting for 40, 35, 17, and 8 per cent of total mined bitumen respectively.

Syncrude production in 2009 dropped by 1 per cent relative to 2008, to 53.1 10^3 m^3/d, due to an extended turnaround that began in mid-March and was completed in early June. In addition, unplanned outages in the mining and upgrading operations and first-quarter bitumen production constraints reduced 2009 production.

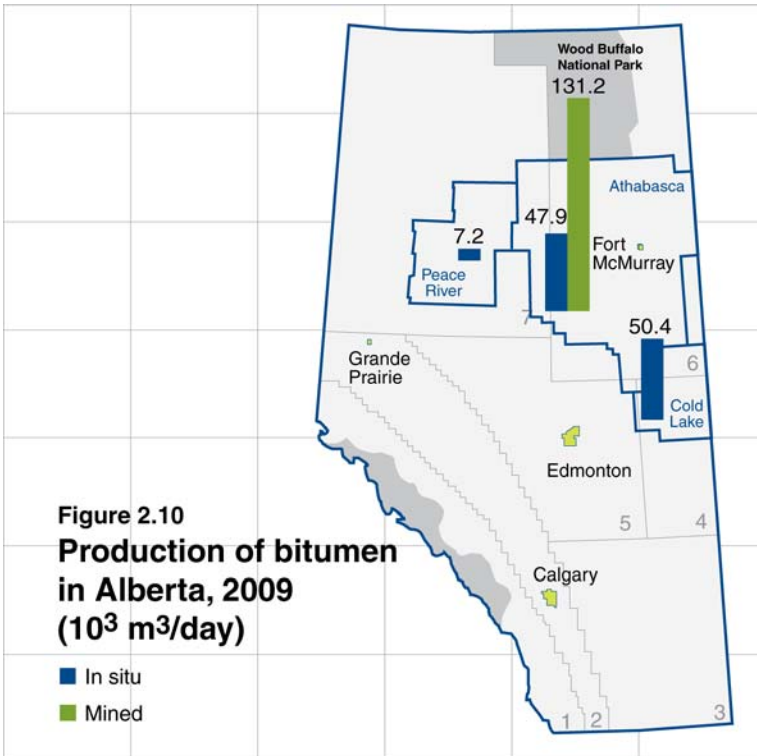


Figure 2.10
Production of bitumen in Alberta, 2009 (10^3 m^3/day)

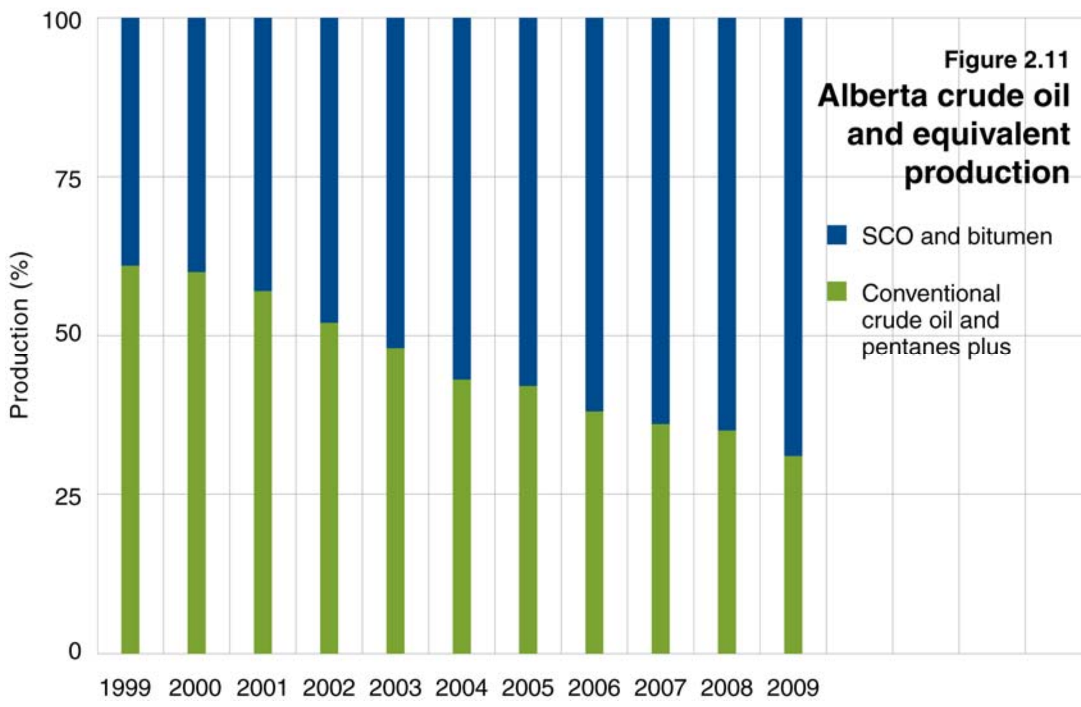


Figure 2.11
Alberta crude oil and equivalent production

Production at Suncor increased by some 17 per cent, to 46.0 10^3 m^3/d, compared to the 2008 average production. The increase in production was the result of improved upgrader reliability and increased bitumen supply. During the third quarter of 2009, the Steepbank extraction plant was completed. Suncor's production was, however, curtailed late in 2009 following a December fire at one of the two upgraders.

Shell Albian Sands produced 22.2 10^3 m^3/d in 2009, an increase of 4 per cent from the 2008 volume of 21.4 10^3 m^3/d.

CNRL's Horizon Project commenced mining operations in September 2008 and produced about 55 000 m^3 (0.2 10^3 m^3/d) in that year. The ramp-up of production continued through 2009 and averaged 9.9 10^3 m^3/d. First SCO production was achieved in February 2009.

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

Table 2.6. Surface mined bitumen projects

Company/project name	Start-up	Capacity (10^3 m^3/d)	Status
Suncor			
North Steepbank extension	2012	–	Approved
Voyageur South Phase 1	TBD*	19.1	Application
Syncrude			
Stage 3 debottleneck	TBD	7.4	Announced
Stage 4 expansion	TBD	22.2	Announced
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD	18.3	Approved
Jackpine Phase 1A	2010	15.9	Under construction
Jackpine Phase 1B	TBD	15.9	Approved
Jackpine Phase 2	TBD	15.9	Application
Pierre River Phase 1	TBD	15.9	Application
Pierre River Phase 2	TBD	15.9	Application
CNRL			
Horizon Phase 2/3	TBD	21.5	Approved
Suncor/UTS/Teck			
Fort Hills Phase 1	TBD	26.2	Approved
Fort Hills debottleneck	TBD	4.0	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	2012	15.9	Under construction
Kearl Phase 2	TBD	15.9	Approved
Kearl Phase 3	TBD	15.9	Approved
Total E&P Canada			
Joslyn (North)	TBD	15.9	Application

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

Due to uncertainties regarding timing and project scope, some projects, such as UTS's Equinox and Frontier, have not been considered in the 10-year forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the ERCB incorporated positive factors, such as the increasing crude oil price forecast, strengthening economic conditions, and reduced construction costs. However, it is felt that these positive factors will be tempered by the current tight light/bitumen differential, anticipated construction delays, and availability of suitable refinery capacity on a timely basis, which may affect the production schedules of these projects. Therefore, although the ERCB forecasts that total mined bitumen production will increase from 131.2 10^3 m^3/d in 2009 to about 236

10^3 m^3/d by 2019, this represents a 5 per cent decline from the 249 10^3 m^3/d forecast for 2018 in last year's report. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure 2.16**, which shows that the percentage of mined bitumen to total production decreases from 55 in 2009 to 47 in 2019.

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased to 105.5 10^3 m^3/d in 2009, up from 2008 production of 92.7 10^3 m^3/d and almost a five-fold increase from 1991. Production of in situ bitumen, along with the number of bitumen wells on production in each year, is shown in **Figure 2.12**. Corresponding to the increase in production, the number of producing bitumen wells has also increased from 2300 in 1991 to about 9700 in 2009. Well productivity of in situ bitumen wells on a yearly basis remained relatively flat between 1991 and 2004 at a level of 8.0 m^3/d. Productivity began to climb in 2005, averaging 8.7 m^3/d and reaching 10.9 m^3/d by 2009, as more steam-assisted gravity drainage (SAGD) wells came on production.

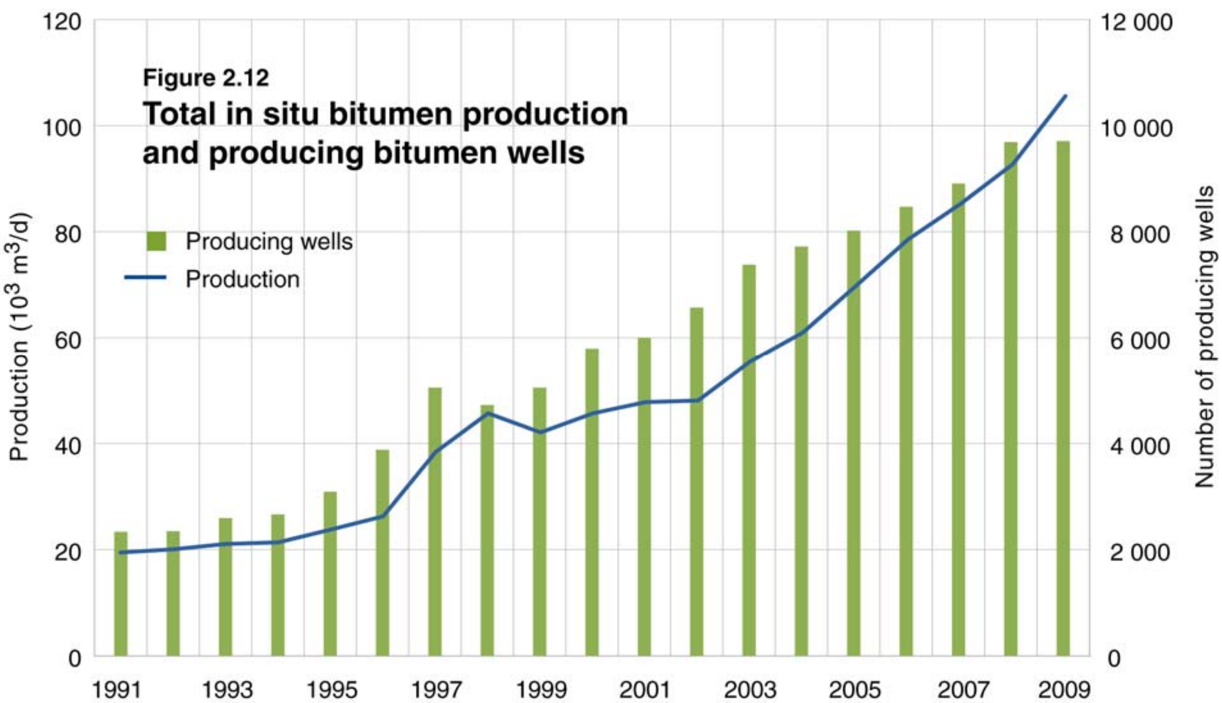


Figure 2.13 shows in situ production from 1999 to 2009 by OSA. The Cold Lake OSA continues to be the major source of crude bitumen recovery, accounting for 48 per cent of production. Production from this area increased slightly (2 per cent) between 2008 and 2009. In 2009, the Athabasca and Peace River OSAs contributed 45 and 7 per cent respectively. Production increased from the Athabasca OSA by about 30 per cent in 2009 relative to 2008 and from the Peace River OSA by about 13 per cent. Significant production increases in the Athabasca OSA since 2002 are due to SAGD development, while increases in the Peace River OSA are largely the result of primary production in the Seal area.

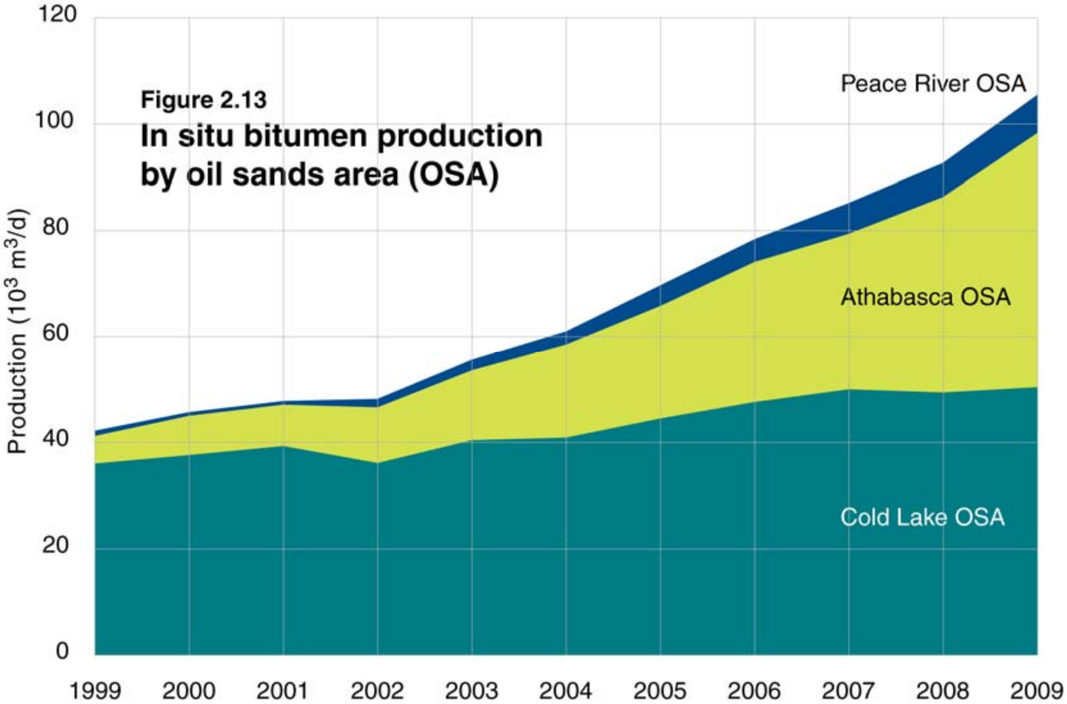


Figure 2.13
In situ bitumen production by oil sands area (OSA)

Currently, there are three main methods to produce in situ bitumen: primary production, cyclic steam stimulation (CSS), and SAGD. In situ bitumen production by recovery method from 1999 forward is shown in **Figure 2.14**. Primary production includes those schemes that use water and polymer injection as a recovery method. In 2009, 32 per cent of in situ production was recovered by CSS, 37 per cent by SAGD, and 31 per cent by primary schemes. Experimental production, which has historically accounted for less than 1 per cent, is included with SAGD production. SAGD production increased by 39 per cent in 2009 relative to 2008. Primary production has been growing since 2003 and increased by 11 per cent from 2008 to 2009.

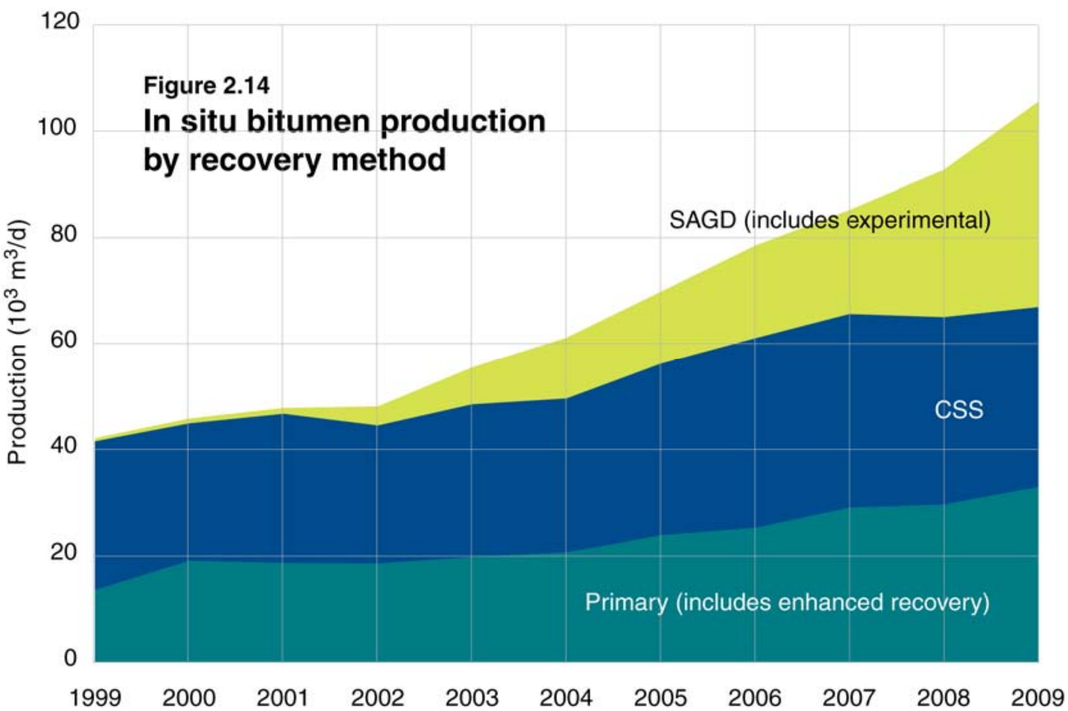


Figure 2.14
In situ bitumen production by recovery method

As discussed earlier, total in situ well productivity has been increasing, in large part due to the influence of increasing SAGD drilling. **Figure 2.15** shows the average well productivity by SAGD, CSS, and primary (including enhanced recovery) method for 2009. SAGD technology has been used for in situ bitumen recovery since 2001 and is the choice technology for most new projects.

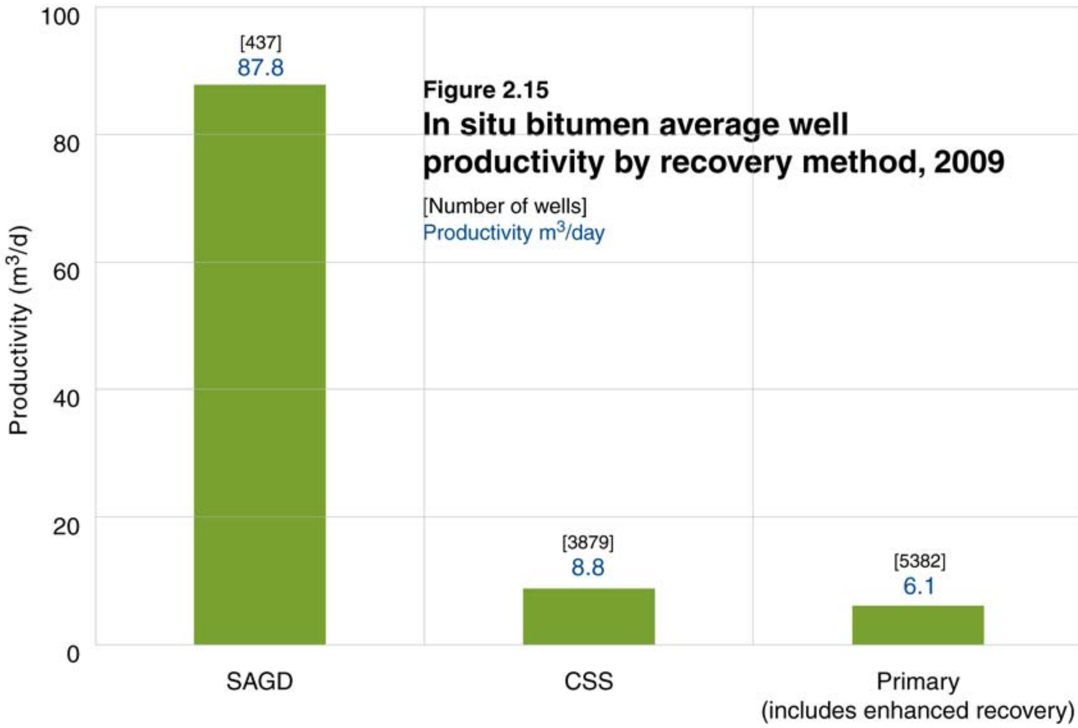
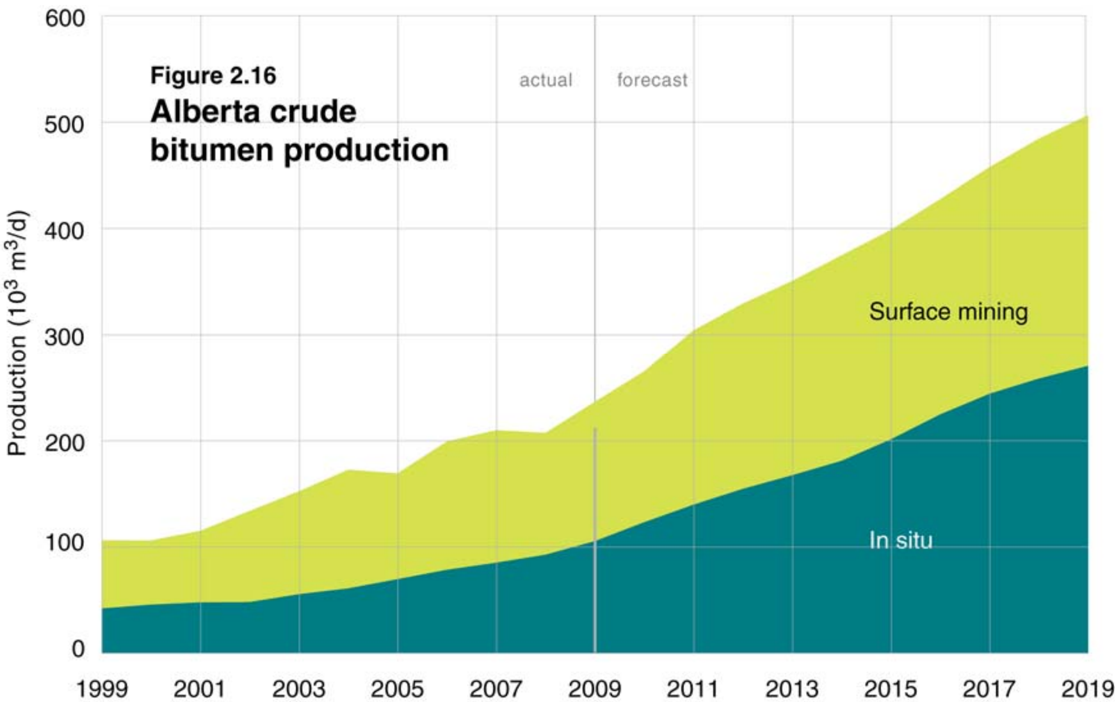


Figure 2.15
In situ bitumen average well productivity by recovery method, 2009

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 12 to 18 months. For the purposes of this report, it assumed that the existing projects would continue producing at their current or projected production levels over the forecast period. To this projection the ERCB has added production of crude bitumen from new and expanded schemes. The assumed production from future crude bitumen projects takes into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, pipeline availability, and the ability of North American markets to absorb the increased volumes.

As illustrated in **Figure 2.16**, the ERCB expects in situ crude bitumen production to increase to 271 10^3 m^3/d over the forecast period. Relative to last year's forecast of 221 10^3 m^3/d in 2018, this is an increase of 23 per cent. The 2009 forecast has been increased mainly due to projects that were delayed in last year's forecast as a result of weak prices and credit difficulties. With an improved price environment and more receptive capital markets, many of these deferred projects are now moving forward and new projects are being announced and moving through the regulatory approval process. Based on this projection, in situ bitumen production will exceed mined bitumen production by 2015 and will account for 53 per cent of total bitumen production by 2019.



In 2009, some 12 per cent of in situ production was upgraded to SCO in Alberta. It is expected that by the end of the forecast period, about 18 per cent of in situ bitumen production will be used as feedstock for SCO production within the province. This is significantly down from the 28 per cent forecast last year, primarily due to changes to the SCO forecast, as many of the SCO projects have been delayed, suspended, or cancelled.

2.2.2 Synthetic Crude Oil Production

Currently, all Alberta mined bitumen and a portion of in situ production are upgraded to SCO. SCO production in 2009 was 121.7 10^3 m^3/d, compared to 103.9 10^3 m^3/d in 2008. The Syncrude, Suncor, and Shell Canada upgraders produced 45.3 10^3 m^3/d, 45.3 10^3 m^3/d, and 22.0 10^3 m^3/d of SCO respectively in 2009.

Two new upgrading complexes were brought on stream in 2009. CNRL’s Horizon project, located northeast of Fort McMurray, includes a mine, on-site extraction, and upgrading facilities. SCO was first produced there in February 2009, and overall average production in 2009 was 8.3 10^3 m^3/d.

The second facility to begin operations in 2009 was the Nexen Long Lake Project, located 40 km southeast of Fort McMurray. This is the first project based on in situ bitumen recovery and field upgrading. The Long Lake project is the only facility to employ gasification technology that takes waste product (asphaltenes) and transforms it into syngas used for creating steam for the reservoir and hydrogen for the upgrader. Production from Long Lake averaged 0.8 10^3 m^3/d in 2009.

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

Most of the projects use coking as their primary upgrading technology and achieve volumetric liquid yields (SCO produced/bitumen processed) of 80 to 90 per cent, while the projects that employ hydro-conversion for primary upgrading can achieve volumetric liquid yields of 100 per cent or more. CNRL's Horizon project uses delayed coking as its primary upgrading technology. The Nexen Long Lake project uses OrCrude™ for its primary upgrading technology. The OrCrude process is a carbon rejection upgrading process that uses conventional thermal cracking, distillation, and solvent deasphalting equipment in a new and novel combination of these proven technologies to upgrade the bitumen. A key aspect of the process is the removal of coke precursors (asphaltenes) prior to thermal cracking of the upgrader feed.

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

Although this forecast has been reduced relative to last year's projection, the ERCB still expects significant increases in SCO production based on the projects shown in **Table 2.7**.

As stated in Section 2.2.1.1: Mined Crude Bitumen, due to uncertainties regarding timing and project scope, some projects, such as Suncor's (formerly Petro-Canada's) Sturgeon upgrader, have not been considered in this forecast. If production were to come on stream from those proposed projects, it would be in the latter part of the forecast period.

Figure 2.17 shows the ERCB projection of SCO production, which is expected to increase from 121.7 10^3 m^3/d in 2009 to 215 10^3 m^3/d by 2019. While this is a significant increase over the forecast period, it is a decrease of some 12 per cent when compared to last year's forecast of 245 10^3 m^3/d by 2018.

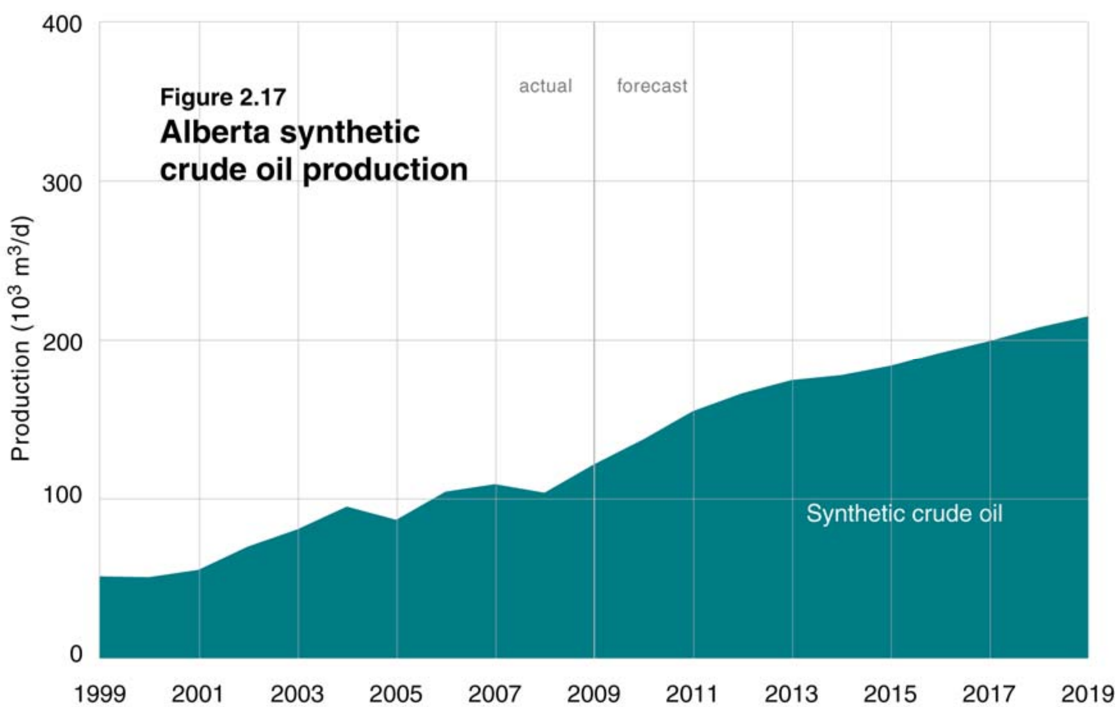


Table 2.7. Synthetic crude oil projects

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

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

2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, it is expected that incremental pipeline capacity will be available to carry these products outside Alberta to current and expanded markets. The completion of major pipeline projects in 2010 are expected to add about 165 10^3 m^3/d in incremental capacity exiting western Canada. This incremental capacity would allow the forecast increase in production to proceed to markets without curtailment through 2016. In addition, if the proposed projects currently under regulatory review or that have been announced are completed, they would provide enough transportation capacity throughout the forecast period.

Within Alberta, the current pipeline systems' ability to expand and proposed projects scheduled for service should provide adequate transportation capacity for the expected increase in production of SCO and nonupgraded bitumen over the forecast period. The current pipeline systems in the Cold Lake and Athabasca areas are shown in **Table 2.8**. **Figure 2.18** shows the current pipelines and proposed crude pipeline projects in the Athabasca and Cold Lake areas. Numerals in parentheses in Sections 2.2.3.1 and 2.2.3.2 refer to the legend on the map in **Figure 2.18**.

Table 2.8. Alberta SCO and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty Edmonton	73.0
Husky Oil Pipeline	Hardisty Lloydminster	78.0
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	62.0
Corridor Pipeline	Edmonton	47.7
Syncrude Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0
Access Pipeline	Edmonton	23.8
Waupisoo Pipeline	Edmonton	55.6
Horizon Pipeline	Edmonton	39.7

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 are then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge (4) or the Kinder Morgan Express pipeline (5) systems.
- The Echo pipeline system (3) is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending. This pipeline delivers Cold Lake crude to Hardisty.
- The Enbridge Pipeline (4), described below, is an existing export pipeline.
- The Kinder Morgan Express Pipeline (5), described below, is an existing export pipeline.
- The Athabasca Pipeline (6) delivers semiprocessed product and bitumen blends to Hardisty. Its current capacity is 62 10^3 m^3/d, but it has the potential to carry 90.6 10^3 m^3/d.
- The Inter Pipeline Fund Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford Upgrader near Edmonton.
- The Syncrude Pipeline (formerly Alberta Oil Sands Pipeline) (8) is the exclusive transporter for Syncrude.

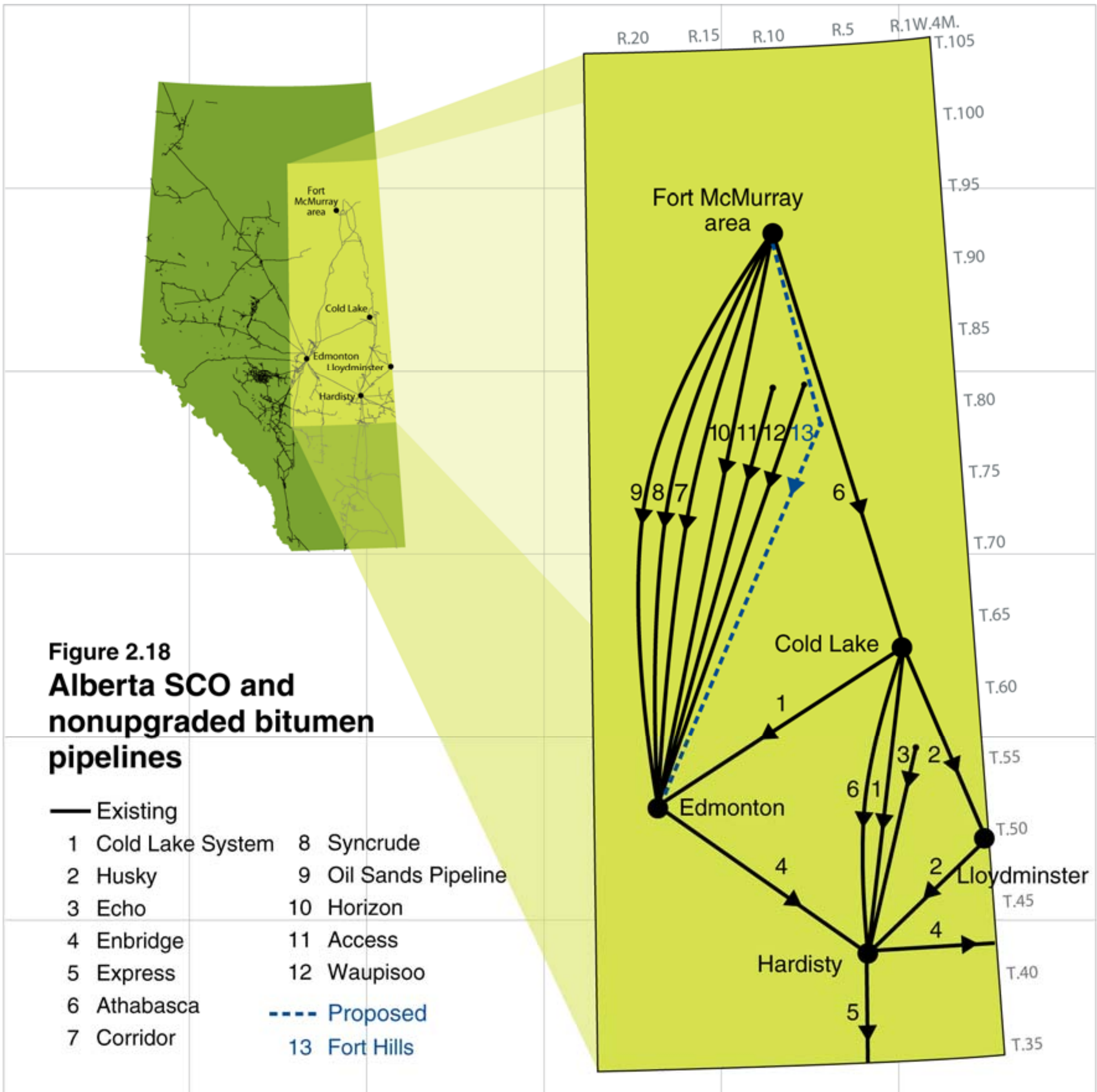


Figure 2.18
Alberta SCO and nonupgraded bitumen pipelines

- The Oil Sands Pipeline (9) transports Suncor synthetic oil to the Edmonton area.
- The Access Pipeline (11) transports diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Capacity of the pipeline is 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d.
- The Enbridge Waupisoo Pipeline (12) moves blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline has current capacity of 55.6 10^3 m^3/d and is expandable to 95.3 10^3 m^3/d.
- Pembina Pipeline's Horizon Pipeline (10) is the exclusive transporter for CNRL's Horizon oil sands development. With an initial capacity of 39.7 10^3 m^3/d, it transports SCO to the Edmonton area.

2.2.3.2 Proposed Alberta Pipeline Projects

- The Inter Pipeline Corridor pipeline (7) expansion project is expected to be in service late in 2010 and increase capacity to transport bitumen blend from 47.7 10^3 m^3/d to about 73.9 10^3 m^3/d. With the addition of intermediate pump stations, further expansions are possible beyond 2010.
- Enbridge's announced Fort Hills Pipeline system has been deferred past its planned in-service date of 2011. Fort Hills Energy L.P. has until June 2011 to give notice to Enbridge to proceed with the pipeline.

2.2.3.3 Existing Export Pipelines

- The Enbridge Pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the U.S. midwest.
- The Kinder Morgan Express Pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends east into Wood River, Illinois.
- The Kinder Morgan Trans Mountain pipeline system transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State. Trans Mountain's current capacity is 47.7 10^3 m^3/d, assuming heavy oil represents some 20 per cent (historical average) of the total throughput. Without heavy oil receipts, pipeline capacity increases to 63.6 10^3 m^3/d.
- Rangeland Pipeline is a gathering system that serves as another export route for Cold Lake Blend to Montana refineries.
- The Milk River Pipeline delivers Bow River heavy crude to Montana refineries.

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

Table 2.9. Export pipelines

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

2.2.3.4 Proposed Export Pipeline Projects

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

Table 2.10. Proposed export pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. west coast Offshore	83.3	2015-2016
Alberta Clipper Pipeline	U.S. midwest	71.5	2010
Kinder Morgan			
Trans Mountain (TMX)	British Columbia U.S. west coast Offshore		
TMX2		12.7	2012
TMX3		47.7	2013
TransCanada Pipeline			
Keystone Pipeline	U.S. midwest	93.8	2010
Keystone XL Pipeline	U.S. Gulf Coast	111.3	2012
Altex Energy Ltd.			
Altex Pipeline	U.S. Gulf Coast	40.0	2013-2014

Figure 2.19 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.

2.2.4 Petroleum Coke

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

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. The CNRL Horizon project, which commenced operations in 2009, has an oil sands mine, on-site extraction, and upgrading capabilities that use delayed coking technology and also produces coke.

Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke usage as a site fuel. In 2009, Suncor used about 26 per cent of its annual coke production as site fuel and sold about 7 per cent through its Energy Marketing Group. Syncrude began using coke as a site fuel in 1995 and in 2009 used some 21 per cent of its annual coke production as site fuel. Syncrude is seeking alternative uses for its coke surplus and is looking into ways of using coke as a reclamation material. To date, all of CNRL’s Horizon project coke production has been stockpiled and accounts for about 1 per cent of the total inventories.

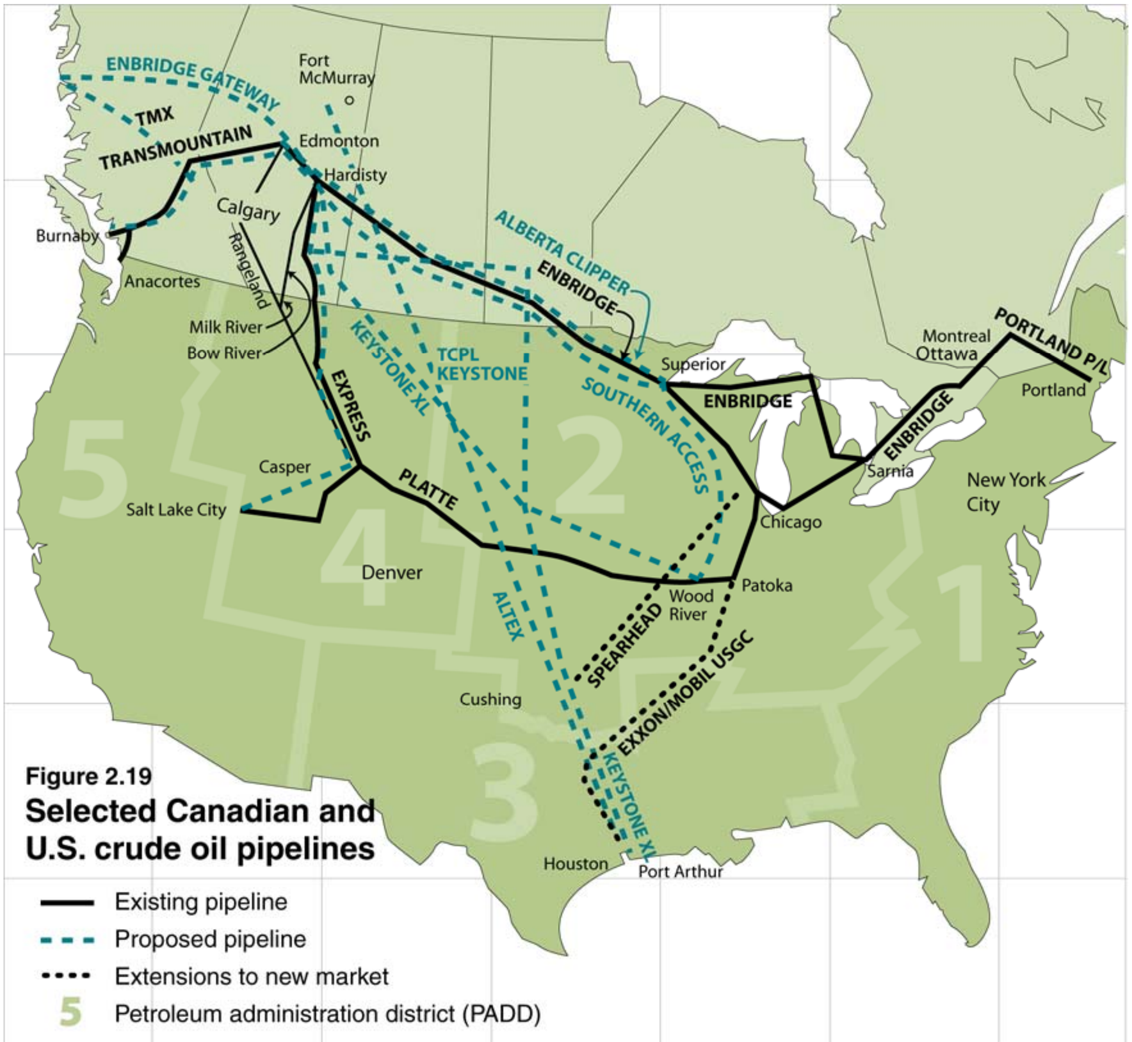
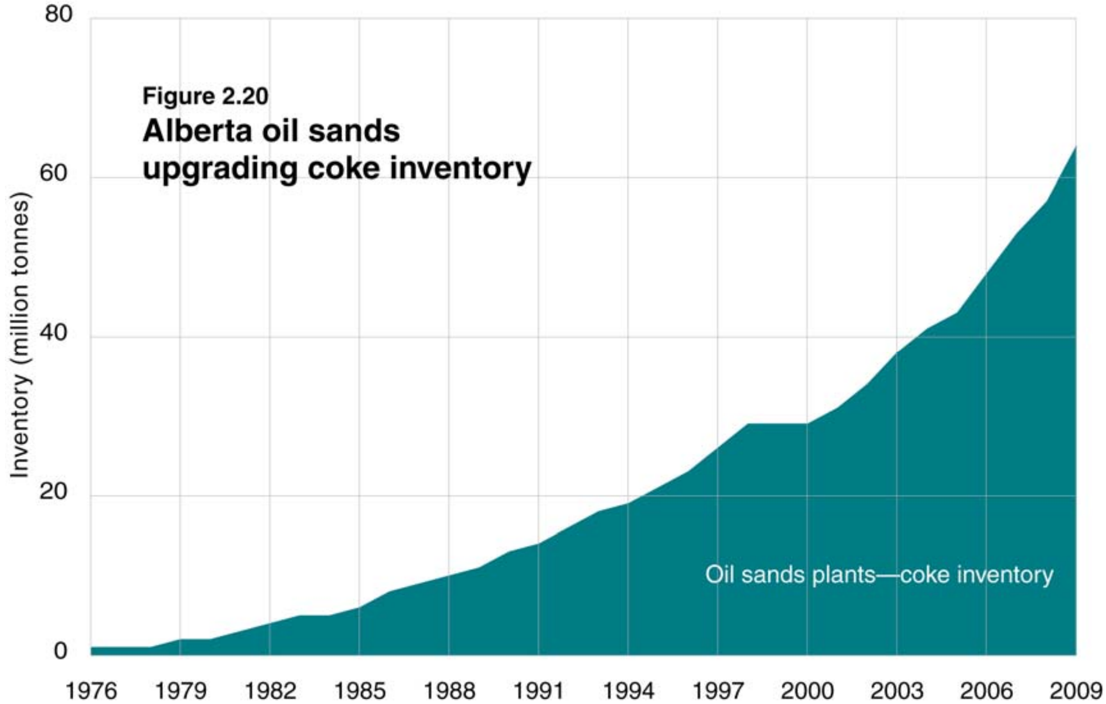


Figure 2.19
Selected Canadian and U.S. crude oil pipelines

Statistics on petroleum coke inventories reported in *ST43: Mineable Oil Sands Annual Statistics* show increases in the total closing inventories, reaching 64 million tonnes in 2009, as illustrated in **Figure 2.20**. In 2009, coke inventories increased by about 12 per cent over 2008 levels, and increases in inventories are expected to continue coincident with mining growth, unless significant alternative uses are found. Inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders.

2.2.5 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. In 2009, 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 2.3 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand consumed 29 per cent of Alberta SCO production and 3 per cent of nonupgraded bitumen production in 2009. This compares to the 30 per cent of Alberta SCO production and 4 per cent of nonupgraded bitumen production consumed in 2008. Additional demand for SCO for use as diesel fuel and plant fuel accounted for 6.6 10^3 m^3/d in 2009, resulting in total Alberta demand of 44.4 10^3 m^3/d in 2009. Total demand for SCO and nonupgraded bitumen in 2008 was 38.6 10^3 m^3/d. The increase in 2009 was due mostly to the changed configuration of the Suncor (Petro-Canada) refinery, which fully replaced light-medium crude oil with nonupgraded bitumen and sour SCO. The refinery continues to process sweet SCO through it synthetic train.

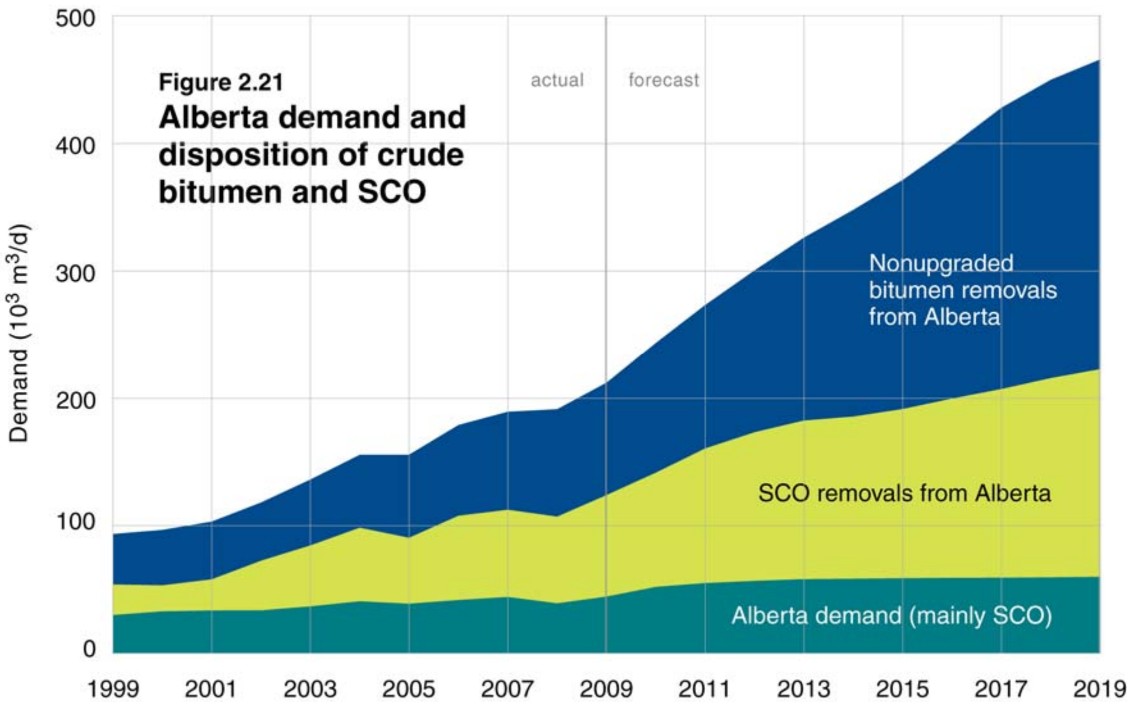


Light sweet SCO has two principal advantages over light crude as a refinery feedstock: it has very low sulphur content, and it produces very little heavy fuel oil. The latter property is particularly desirable in Alberta, where there is virtually no local market for heavy fuel oil. Among the disadvantages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

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

Refined SCO is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor also operates a Suncor Energy-branded "cardlock" station, selling diesel fuel supplied from its oil sands operation. The station is located on Highway 63 north of Fort McMurray. In 2009, the sale of refined SCO as diesel fuel oil accounted for about 11 per cent of Alberta SCO demand, compared to 6 per cent in 2008.

Figure 2.21 shows that in 2019 Alberta demand for SCO and nonupgraded bitumen will increase to about 60 10^3 m^3/d. It is projected that SCO will account for 87 per cent of total Alberta demand and nonupgraded bitumen will account for 13 per cent.



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

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, as well as the overall anticipated increase in demand for refined products. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with a refining capacity of 584 10^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 99 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 market regions that currently receive either SCO or nonupgraded bitumen or both are the U.S. east coast, with a refining capacity of 274 10^3 m^3/d, the U.S. Gulf Coast, with a refining capacity of 1341 10^3 m^3/d, and the U.S. west coast, with a refining capacity of 511 10^3 m^3/d.

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 2519 km through the Enbridge mainline system from Edmonton to Chicago, before entering the Spearhead pipeline for the final 1046 km to Cushing. The Spearhead Pipeline expansion was completed in 2009 and increased capacity from 20 10^3 m^3/d to 31 10^3 m^3/d.

Markets were further expanded in 2006 with the reversal of an ExxonMobil Corporation pipeline that moves heavy crude oil from Patoka, Illinois, to Beaumont/Nederland, Texas. Canadian crude can access the line via the Enbridge mainline and Lakehead systems and then the Mustang Pipeline or the Kinder Morgan Express-Platte Pipeline system. The ExxonMobil pipeline has a heavy crude oil capacity of 10.5 10^3 m^3/d, which was expanded to 15 10^3 m^3/d during 2009. The Spearhead pipeline and the ExxonMobil pipeline are shown in **Figure 2.19**.

As illustrated in **Figure 2.21**, over the forecast period SCO removals from Alberta will increase from 79.6 10^3 m^3/d in 2009 to 163 10^3 m^3/d in 2019, and the removals of nonupgraded bitumen will increase from 88.2 10^3 m^3/d to 243 10^3 m^3/d over the same period.

3 Crude Oil

Highlights

- Remaining established reserves decreased 2 per cent, less than the drop in 2008 but still similar to annual declines in previous years.
- Reserves additions from drilling replaced 60 per cent of production in 2009, compared with 77 per cent last year.
- Production declined 8.6 per cent, compared with the 3.8 per cent decline in 2008.
- The number of successful oil wells drilled in 2009 was the lowest in over thirty years.

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

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 228.4 million cubic metres (10^6 m^3) at December 31, 2009, representing about 30 per cent of Canada's remaining conventional reserves. This is a year-over-year decrease of 4.6 10^6 m^3, or 2 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2009.

Table 3.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2009, while **Figure 3.1** shows the province's remaining conventional oil reserves over time. Remaining reserves have decreased to 19 per cent of the peak reserves of 1223 10^6 m^3 reached in 1969.

3.1.2 Reserves Growth

A detailed pool-by-pool list of reservoir parameters and reserves data is available on CD (see **Appendix C**) through the ERCB's Information Services. **Table 3.2** gives a detailed breakdown of this year's changes to initial established reserves, categorized by new discoveries, development of existing pools, new and expansions to enhanced oil recovery (EOR) schemes, and revisions to existing reserves. **Figure 3.2** gives a history of reserves additions and net revisions from 1991 to 2009. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

The initial established reserves attributed to the 380 new oil pools defined in 2009 totalled 4.0 10^6 m^3 (an average of 10 thousand [10^3] m^3 per pool), compared to 6.9 10^6 m^3 in 2008. The drop in new reserves can be attributed to fewer wells being drilled through 2009 and the general trend to smaller pool discoveries. The ERCB processed 107 applications for new EOR schemes or expansions to existing schemes, resulting in reserves additions totalling 4.8 10^6 m^3, compared to 6.2 10^6 m^3 in 2008 **(Figure 3.3)**. Development of existing pools resulted in an increase in initial established reserves of 7.4 10^6 m^3, compared to 9.3 10^6 m^3 in 2008. Therefore, total reserves growth from new drilling plus new and expansions to EOR schemes (but excluding revisions) amounted to 16.2 10^6 m^3, replacing 60 per cent of Alberta's 2009 conventional crude oil production of 26.8 10^6 m^3. This compares with a five-year average replacement ratio of 69 per cent. Revisions to existing reserves resulted in an overall net change of +5.6 10^6 m^3. The total increase in initial established reserves for 2009 amounted to 21.8 10^6 m^3, similar to last year's 21.7 10^6 m^3.

Note that the change in cumulative production shown in **Table 3.1** may not equal reported annual production due to amendments to historical production records and the fact that some producing wells are in pools that were not included in the publication of year-end reserves. **Table 3.2** shows the breakdown in reserves additions in 2009 for heavy and light-medium crude. **Table B.3** in **Appendix B** provides a history of conventional oil reserves growth and cumulative production from 1968 forward.

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

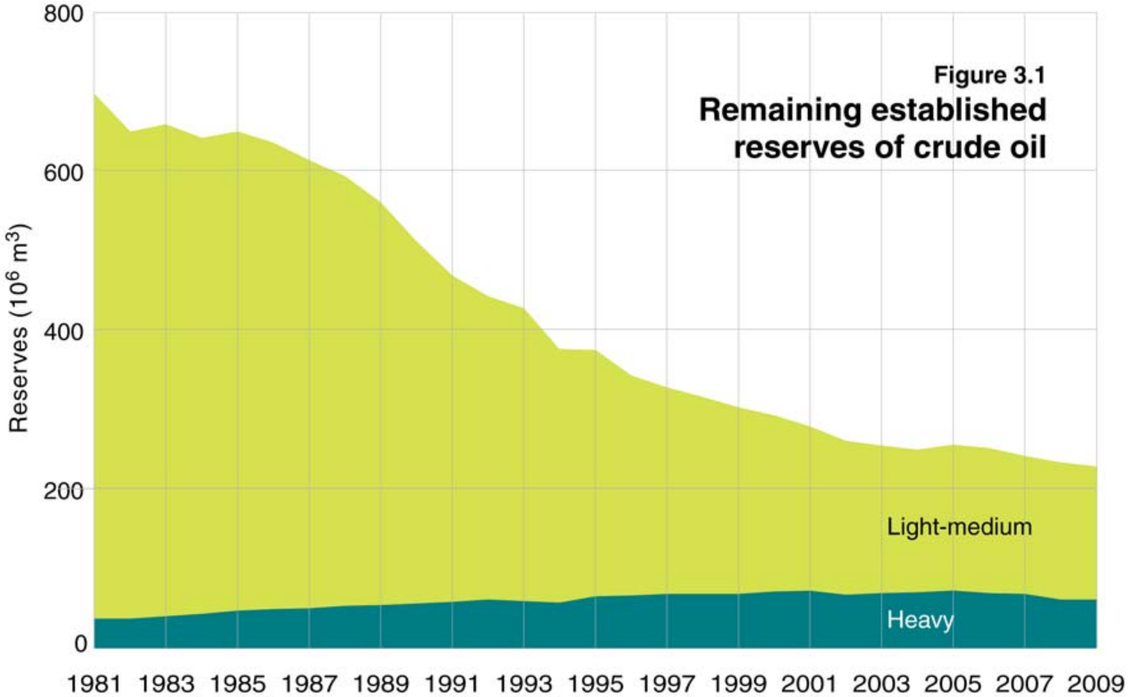
	2009	2008	Change
Initial established reserves[a]			
Light-medium	2 429.3	2 415.9	+13.4
Heavy	365.6	357.2	+8.4
Total	2 794.9	2 773.1	+21.8
Cumulative production[a]			
Light-medium	2 262.2	2 244.1	+18.1
Heavy	304.3	296.0	+ 8.3
Total	2 566.5	2 540.1	+26.4[b]
Remaining established reserves[b]			
Light-medium	167.1	171.8	–4.7
Heavy	61.3	61.2	+0.1
Total	228.4 (1 437 10^6 bbl)	233.0	–4.6
Annual Production			
Light-medium	18.5	20.2	–1.7
Heavy	8.3	9.1	–0.8
Total	26.8	29.3	–2.5

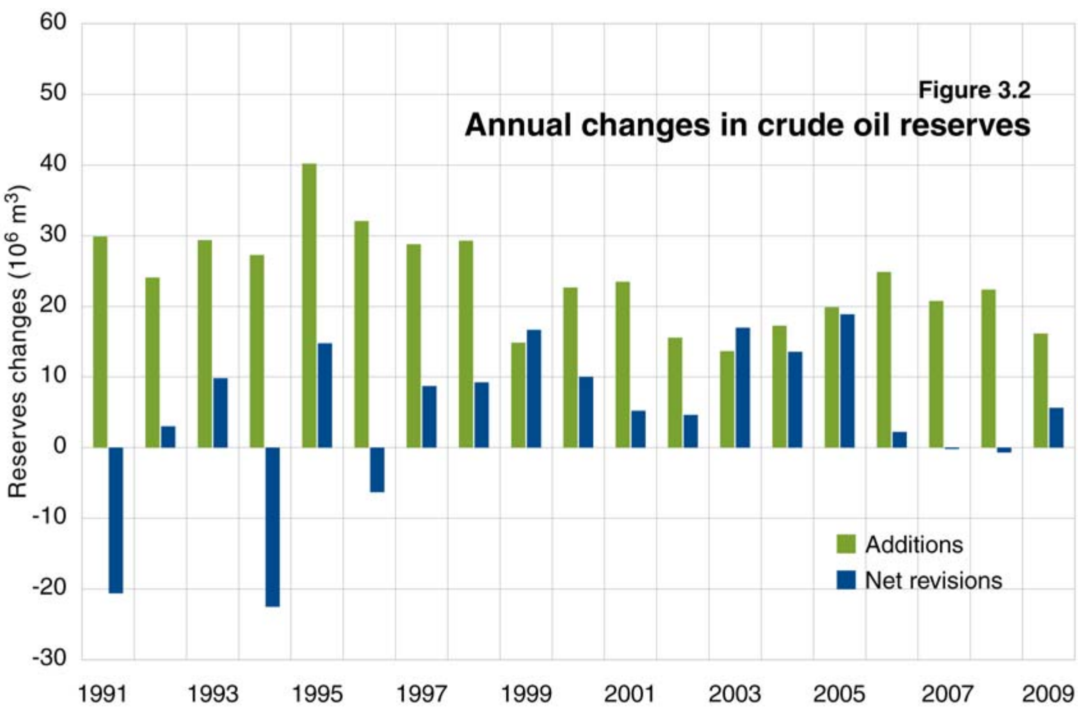
[a] Any discrepancies are due to rounding.
[b] May differ from annual production

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

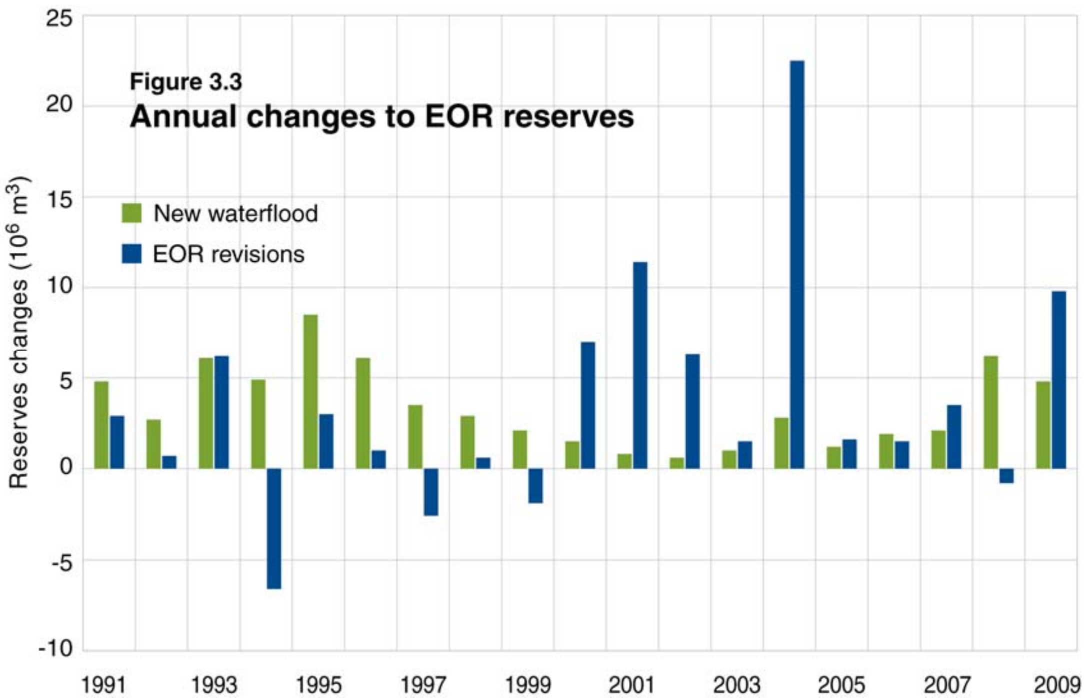
	Light-medium	Heavy	Total[a]
New discoveries	3.1	0.8	4.0
Development of existing pools	4.3	3.1	7.4
Enhanced recovery (new/expansion)	1.5	3.3	4.8
Revisions	+4.6	+1.0	+5.6
Total[a]	+13.5	+8.3	+21.8

[a] Any discrepancies are due to rounding.





There is potential for significant reserves growth from new horizontal wells in the Cardium Formation at Pembina, the province’s largest reservoir and where oil was first discovered in 1953. These wells are being drilled on the periphery of the main pool, where the flanks of the reservoir have much lower permeability than the centre as a result

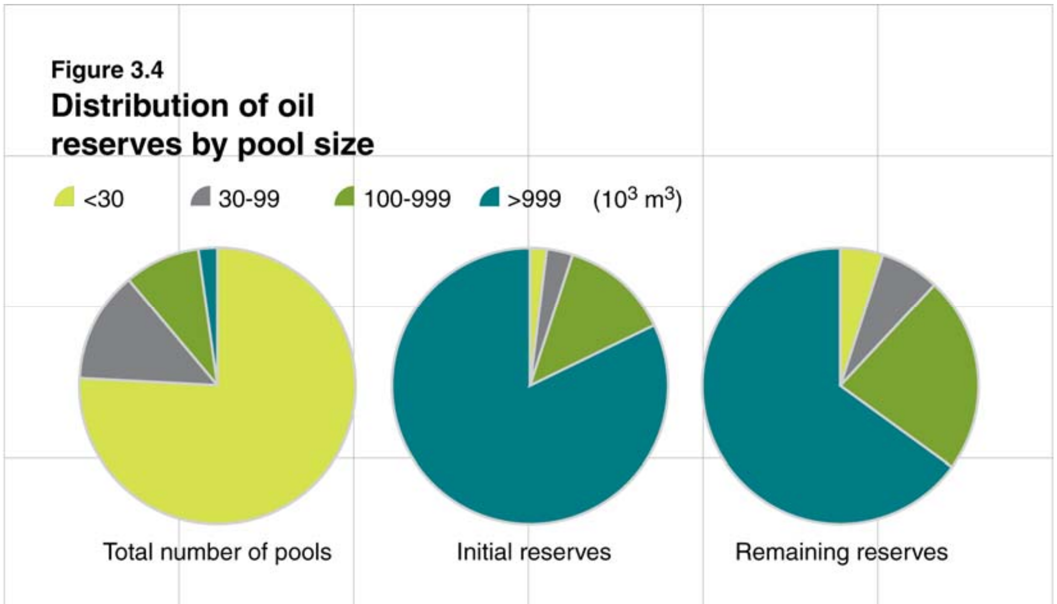


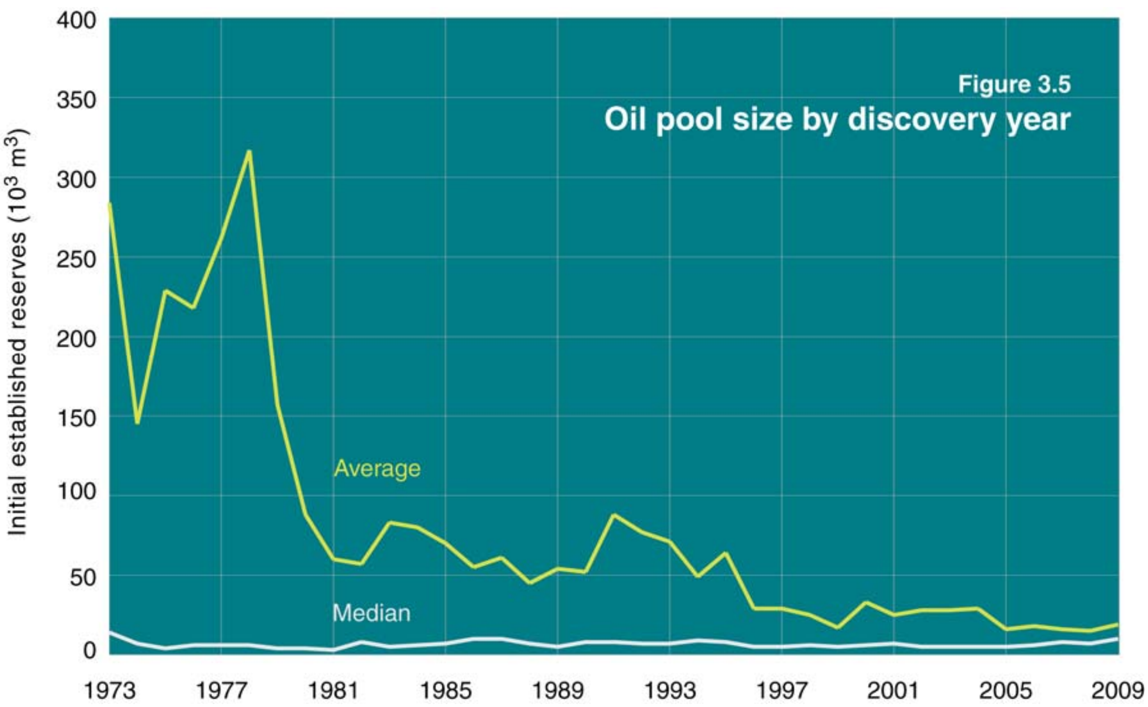
of a change to a shalier facies. Vertical wells previously drilled in these flanks produced small amounts of oil, but most were abandoned due to poor productivity. Pembina Cardium pool operators are taking advantage of new drilling techniques, such as horizontal multistage fracturing, to exploit resources that were previously uneconomic. These techniques are also being used in other formations, including the Montney and Glauconitic.

3.1.3 Oil Pool Size

At December 31, 2009, oil reserves were assigned to 9332 light-medium and 2688 heavy crude oil pools in the province. While many of these pools contain thousands of wells, the majority consist of a single well. The distribution of reserves by pool size shown in **Figure 3.4** indicates that some 65 per cent of the province's remaining oil reserves are contained in the largest 3 per cent of pools, with the largest of these in terms of remaining reserves being the Pembina Cardium, Swan Hills Commingled Pool 001, Ferrier Commingled Pool 001, and the Turner Valley Rundle Pool. By contrast, the smallest 75 per cent of pools contain only 6 per cent of remaining reserves. Ninety-five per cent of remaining reserves are contained in pools discovered before 1980. **Figure 3.5** illustrates the historical trends in the size of oil pool discoveries.

While the median pool size has remained basically unchanged over time, with initial established reserves at less than 10 10^3 m^3, the average size has declined from 150 10^3 m^3 in 1970 to about 30 10^3 m^3 over the last few years. The Valhalla Commingled Pool 002 (previously the Doe Creek I and Dunvegan B Pool) discovered in 1977 is the last major oil discovery (over 10 10^6 m^3) in Alberta. Initial established reserves for the pool are estimated at 12 630 10^3 m^3. Since the beginning of 2000, the largest oil pools discovered include the Pembina Nisku II, Dixonville Montney C and Killam North Upper Mannville F2F Pools, with initial established reserves currently estimated at 1807 10^3 m^3, 1569 10^3 m^3, and 1365 10^3 m^3 respectively.





3.1.4 Pools with Largest Reserves Changes

The review and updating of oil pools over the past year has resulted in a net total reserves revision of +5.6 10^6 m^3. **Table 3.3** lists pools with the largest reserves changes in 2009. Reassessment of tertiary recovery in the Swan Hills Commingled Pool 001 (Beaverhill Lake Formation) and the waterflood in Wainwright Commingled Pool 003 resulted in positive revisions of 4910 10^3 m^3 and 2160 10^3 m^3 respectively. A review of the waterflood in the Mitsue Gilwood A Pool led to a 1323 10^3 m^3 increase, while the Pembina Nisku HH Pool saw a decrease of 540 10^3 m^3 as a result of revisions to primary and waterflood reserves.

Table 3.3. Major oil reserves changes, 2009

Pool	Initial established reserves (10^3 m^3) 2009	Change	Main reason for change
Ante Creek North Triassic E	2 398	+666	New waterflood
Bellshill Lake Blairmore	19 490	+980	Reassessment of reserves
Chinchaga North Slave Point A	2 359	+307	Reassessment of reserves
Dixonville Montney C	1 569	+376	Reassessment of primary and waterflood reserves
Jenner Upper Mannnville MM	775	−301	Reassessment of reserves
Killam North Upper Mannville F2F	1 365	+895	Reassessment of primary and waterflood reserves
Kleskun Beaverhill Lake A	976	+371	New waterflood
Lloydminster Commingled Pool 07	374	−201	Reassessment of reserves
Lloydminster Commingled Pool 11	3 487	−469	Reassessment of reserves
Mitsue Gilwood A	65 120	+1 323	Reassessment of waterflood reserves
Pembina Nisku HH	407	-540	Reassessment of primary and waterflood reserves
Pembina Nisku L2L	399	+399	New pool
Provost Mannville L	3 041	+261	Pool development
Provost Upper Mannville A	1 103	-255	Reassessment of waterflood reserves
Provost Upper Mannville BB	2 566	+406	Reassessment of primary reserves
Rainbow Keg River N	1 663	+286	Reassessment of primary and gas flood reserves
Red Earth Commingled Pool 001	6 971	-686	Reassessment of primary and waterflood reserves
Rycroft Montney C	360	+322	Reassessment of reserves
Sawn Lake Slave Point J	1 514	+429	Reassessment of waterflood reserves
Suffield Upper Mannville A	8 817	+662	New waterflood
Swan Hills Commingled Pool 001	154 700	+4 910	Reassessment of solvent flood reserves
Wainwright Commingled Pool 003	19 740	+2 160	Reassessment of waterflood reserves
Wildmere Commingled Pool 003	8 600	+497	New waterflood reserves and reassessment of primary reserves
Willesden Green Cardium U	419	−416	Reassessment of primary and waterflood reserves

3.1.5 Distribution by Recovery Mechanism

Alberta's total initial volume in place and initial established reserves of conventional crude oil currently stand at 10 851 10^6 m^3 and 2795 10^6 m^3 respectively, yielding an overall recovery efficiency of 26 per cent. **Figure 3.6** and **Table 3.4** show the distribution of the volume and reserves by recovery mechanism and crude oil density.

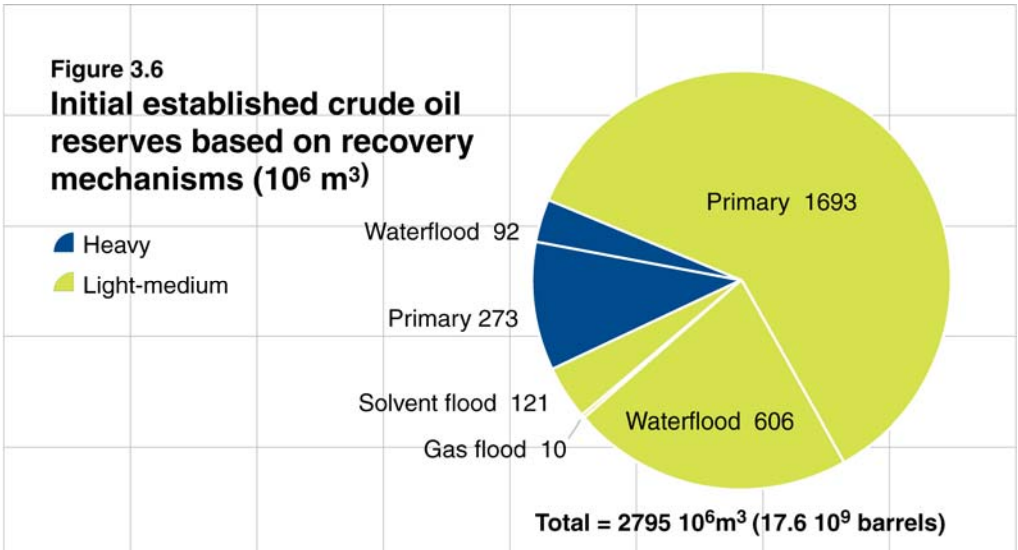


Figure 3.6
Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)

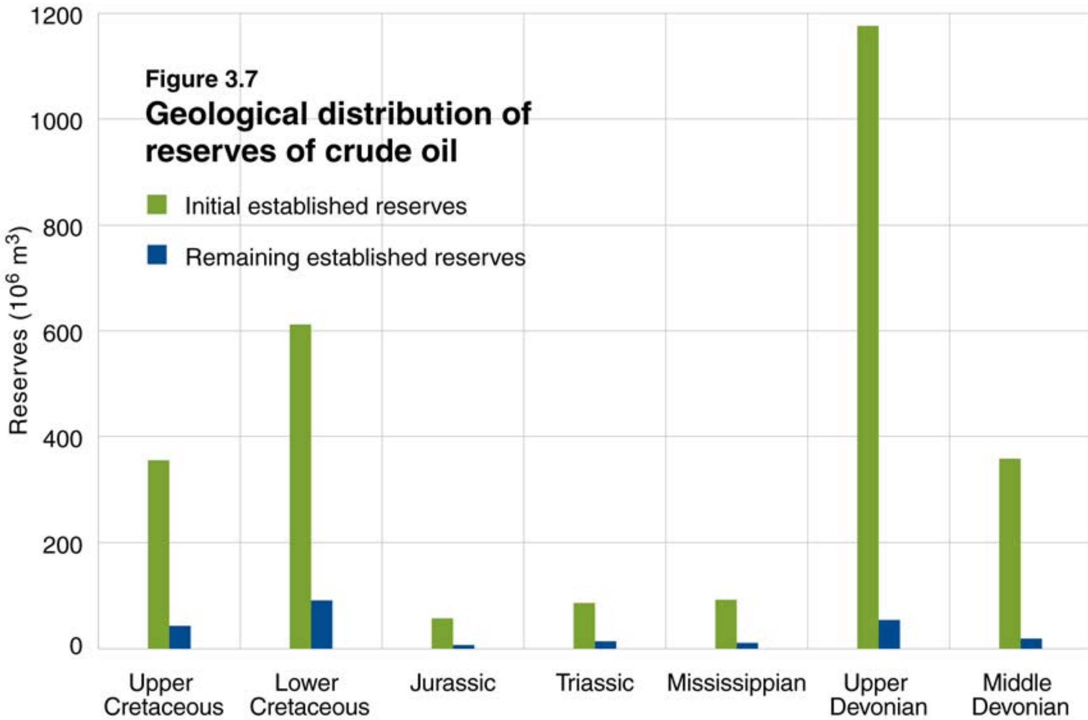
Table 3.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2009

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3) Primary	Waterflood/ gas flood	Solvent flood	Total	Average recovery (%) Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	4 045	870	0	0	870	22	-	-	22
Waterflood	3 440	522	437	0	959	15	13	-	28
Solvent flood	979	266	169	121	556	27	17	12	57
Gas flood	118	35	10	0	45	30	8	-	38
Heavy									
Primary depletion	1 610	190	0	0	190	12	-	-	12
Waterflood	659	83	92	0	175	13	14	-	27
Total	10 851	1 966	708	121	2 795	18			26
Percentage of total initial established reserves		71%	25%	4%	100%				

Waterflooding has increased recovery from light-medium pools from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Pools under solvent flood, on average, realize a 12 per cent higher recovery factor over projected waterflood recovery. Primary recovery for heavy crude pools has increased from 8 per cent in 1990 to 12 per cent in 2009 as a result of improvements in water handling, use of horizontal wells, improved fracturing techniques, including multistage fracturing, and increased drilling density. Incremental recovery from all waterflood projects represents about 25 per cent of the province's initial established reserves. Pools under solvent flood add another 4 per cent to the province's reserves.

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 in the Lower Cretaceous, 22 per cent from the Upper Devonian, and 18 per cent from the Upper Cretaceous. In contrast, in 1990 fully 30 per cent of remaining reserves were contained in 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.

3.1.7 Significant Active Oil Play—Central Alberta Nisku Fairway

Beginning with this report, the ERCB will provide a series of short backgrounds on the geology and in-place potential of a number of reservoirs. The first to be profiled is the Nisku Formation, the reservoir of the previously mentioned Pembina Nisku II Pool.

The Upper Devonian Nisku reef trend is one of Alberta's most recent active oil plays. Located in central Alberta between Township 52, Range 16, West of the 5th Meridian, and Township 46-05W5M, it is about 100 kilometres (km) southwest of Edmonton. **Figure 3.9** shows that it spans an area up to 150 km long and 30 km wide.

The Nisku Formation dips at about 15 m/km to the southwest and thickens to the northwest. The depth of the Nisku ranges from 2000 m in the northeast to 3500 m in the southwest.

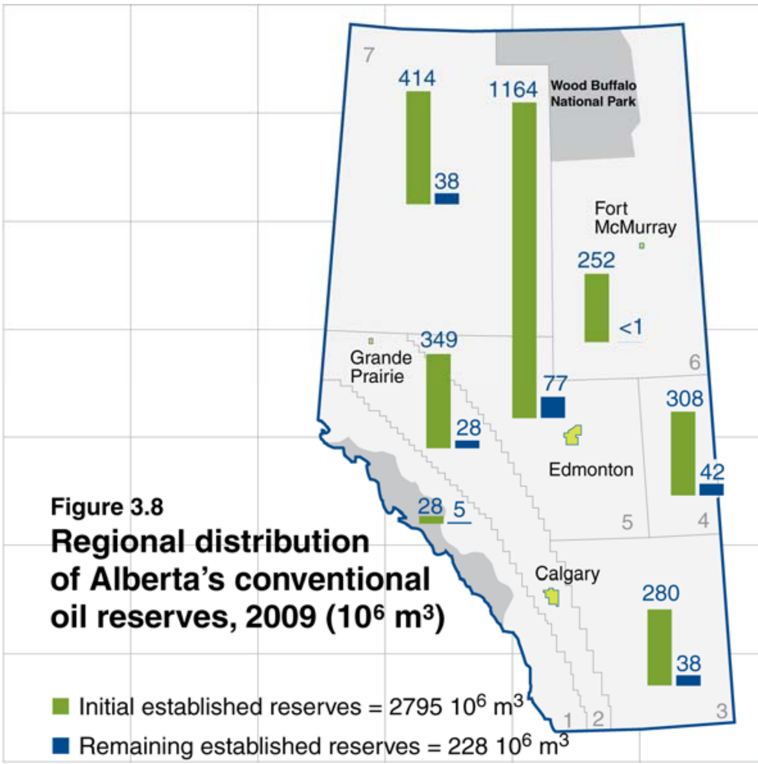


Figure 3.8
Regional distribution of Alberta's conventional oil reserves, 2009 (10^6 m^3)

The Nisku reef was deposited following a major late Devonian (Leduc) reef development on the Alberta shelf of the Western Canada Sedimentary Basin. The Nisku Formation overlies the thick basin-fill shales of the Ireton Formation. It forms a shelf-to-basin ramp, which rims a regionally extensive shale basin. In Pembina, the Nisku Formation is subdivided into several shale and carbonate units, as shown in **Figure 3.10,** with the Zeta Lake member representing the carbonate reef buildups. After burial, the Zeta Lake reefs were predominately dolomitized, increasing their reservoir quality.

Hydrocarbons in the Pembina area are sourced from the older Duvernay Formation. Hydrocarbons then migrated updip from the southwest to northeast and became trapped in the porous reefs.

Four trends, indicated in **Figures 3.9** and **3.10**, have been identified by integrating seismic interpretations, core and core data analysis, and well log characteristics in the Pembina fairway.

The Nisku pinnacle reef trend of the West Pembina area was discovered in January 1977. Further exploration in the 1980s yielded several wet wells to the northeast. These led explorers to believe that the Nisku bank edge accumulations did not extend to the northeast past Township 48-10W5M.

The Nisku reef play exploration was rejuvenated in 2000. Current exploration and development of the bank edge patch reef (outer and inner) fairways began in June 2001. Within these fairways, initial daily oil production rate is between 125 and 250 cubic metres/day (m^3/d) oil.

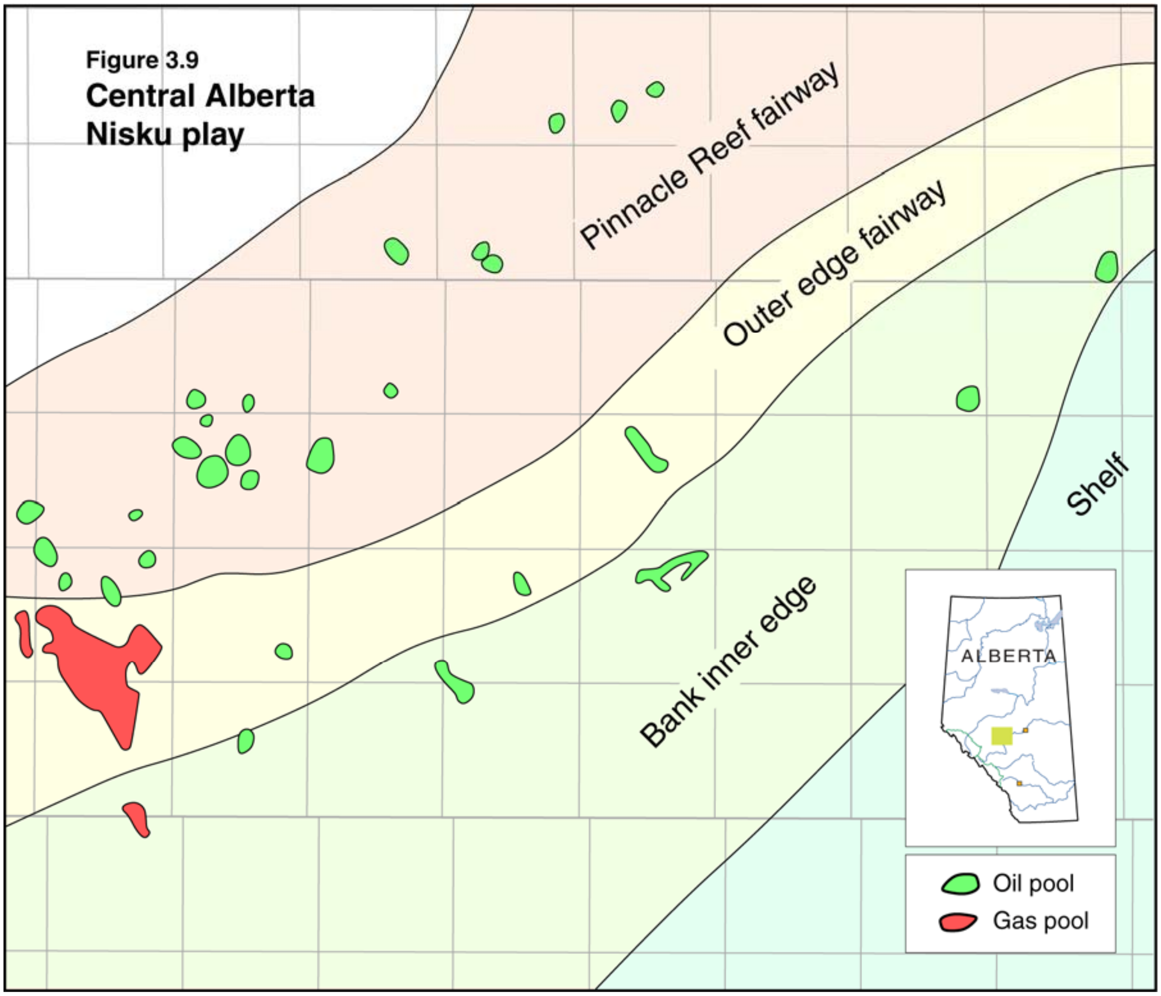


Figure 3.9
Central Alberta
Nisku play
Pinnacle Reef fairway
Outer edge fairway
Bank inner edge
Shelf
ALBERTA
Oil pool
Gas pool

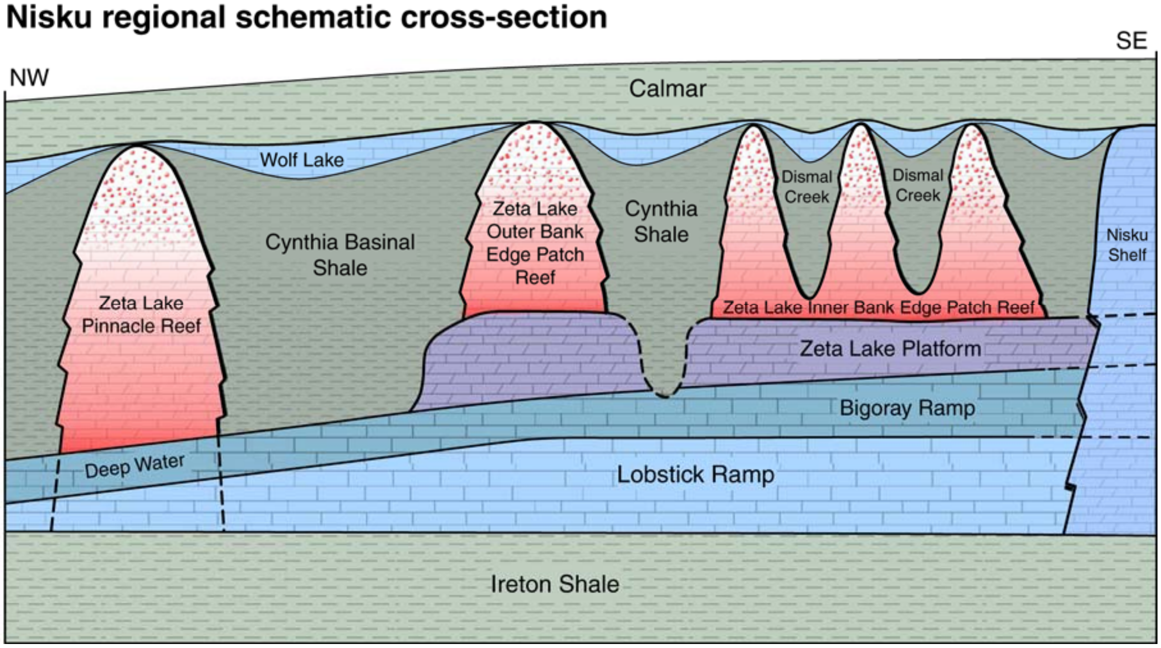


Figure 3.10
Nisku regional schematic cross-section
NW
SE
Calmar
Wolf Lake
Cynthia Basinal
Shale
Zeta Lake
Outer Bank
Edge Patch
Reef
Cynthia
Shale
Dismal
Creek
Dismal
Creek
Nisku
Shelf
Zeta Lake
Pinnacle Reef
Zeta Lake Inner Bank Edge Patch Reef
Zeta Lake Platform
Bigoray Ramp
Deep Water
Lobstick Ramp
Ireton Shale

There are currently about 134 Nisku pools, most of which are single-well pools. The success rate for economic wells is about 33 per cent. The primary recovery factor is estimated to be about 20 per cent. Pools being exploited by EOR (waterflood) have been estimated to have a 40 per cent recovery factor. The natural gas associated with Nisku oil is sour. The oil is light, ranging from 835 to 815 kg/m^3 (38-42º API).

Nisku pools are purely stratigraphic traps. Hydrocarbons in the porous Zeta Lake member were sealed laterally by the off-reef Nisku equivalents—the Cynthia/Dismal Creek shale and the Calmar shale, which provides the upper seal. The structural relief on the reef bank provides the closure as oil and gas is trapped in the local highs of the patch buildups.

The patch reefs have been interpreted as one hydrodynamic system, with each pool having its own unique oil/water (or gas/water) contact due to its spill point. The Nisku bank edge is connected through the regionally extensive Bigoray platform. Gas is predominantly encountered in the southwest down dip end. Oil occurs mainly at the updip east and northeast ends of the patch reef fairways, with some possibility of free gas updip of the Nisku trend. This suggests the possibility of more than one episode/stage of hydrocarbon migration.

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

Converting volume in place to standard conditions at the surface requires data on oil shrinkage, which is obtained from pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir drive mechanism. Recoveries range from 5 per cent in heavy oils to over 50 per cent in the case of light-medium oils producing from highly permeable reefs with full pressure support from an active underlying aquifer. Provincially, 26 per cent of the in-place resource is expected to be recovered.

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

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

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

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

3.1.9 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the ERCB in 1994 at 3130 10^6 m^3, reflecting its estimate of geological prospects at that time. It does not include potential oil from very low permeability reservoirs, referred to by industry as "tight oil," which is now starting to be exploited using horizontal, multistage fracturing. **Figure 3.11** 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.

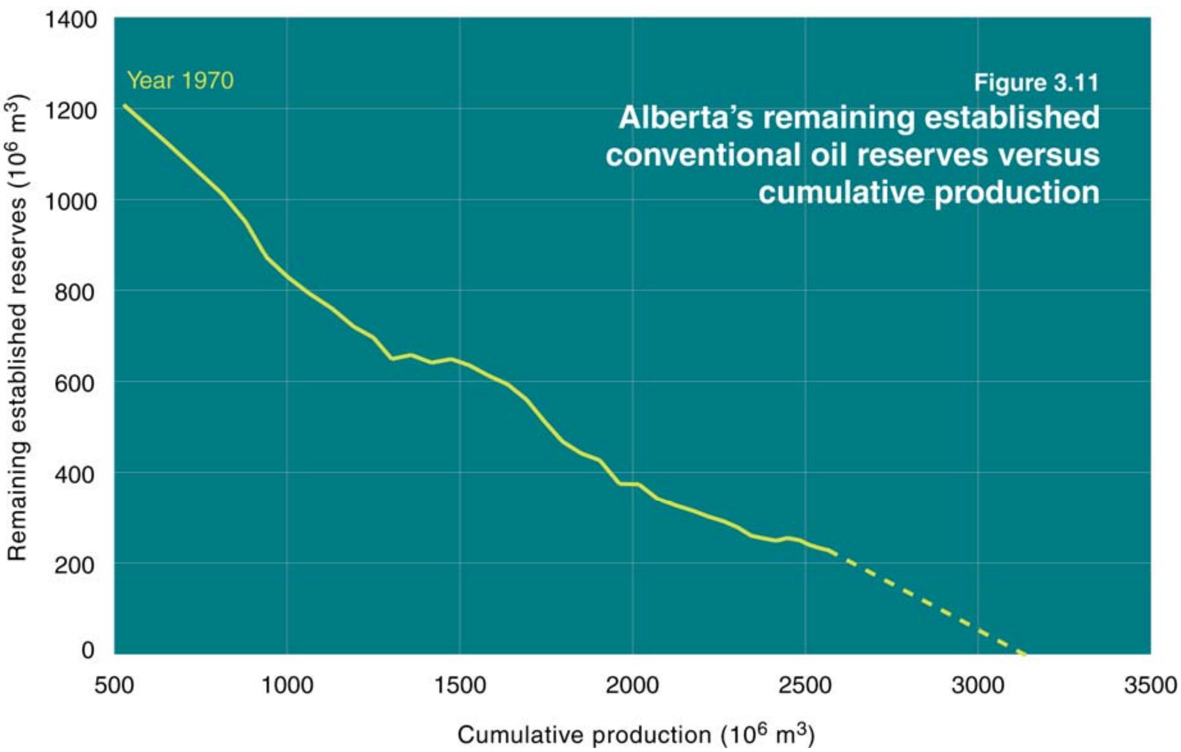
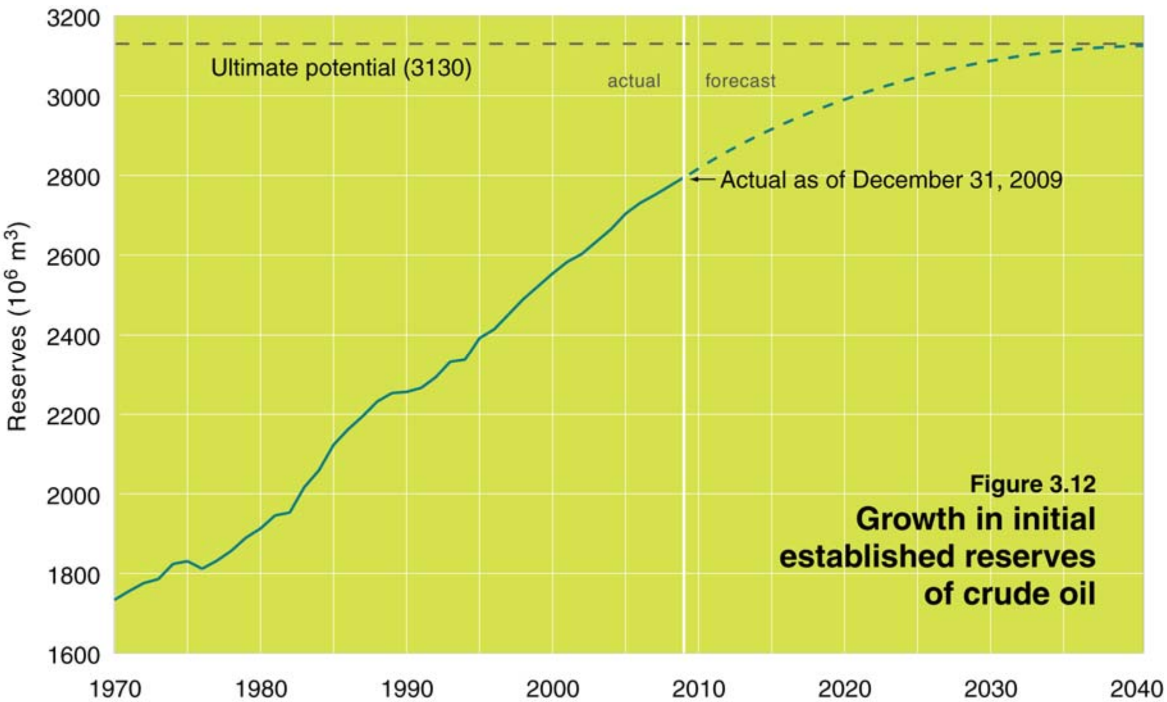


Figure 3.12 shows Alberta's historical and forecast growth of initial established reserves. Approximately 82 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2009. To date, industry has discovered 89 per cent of the ultimate potential, leaving 11 per cent yet to be discovered, which when added to the



remaining established reserves means that 564 10^6 m^3 (3.5 billion barrels) of conventional crude oil is available for future production.

In 2009, both remaining established reserves and annual production of crude oil continued to decline. However, the ERCB estimates that there are 335 10^6 m^3 of reserves yet to be discovered, which at current rates of reserves growth will require over 20 years to find and develop. The discovery of new pools and the development of existing pools will continue to add new reserves and associated production each year.

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

3.2 Supply of and Demand for Crude Oil

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

3.2.1 Crude Oil Supply

Since the early 1970s, production of Alberta light-medium and heavy crude oil has been on a downward trend. This was certainly evident in 2009, as the oil industry reduced its upstream activities in light of low crude oil prices and weakened economic conditions that continued from 2008. In 2009, total crude oil production declined by 8.6[1] per cent to 73.3 10^3 m^3/d from 79.9 10^3 m^3/d. This is compared to the 3.8 per cent decline from 2007 to 2008 and is considerably higher than the 5-year average decline rate of 5.1 per cent. Light-medium crude oil production declined by 8.5 per cent from its 2008 level to 50.6

[1] Nonrounded production numbers were used to calculate the percentage change; therefore, percentages may appear different from those calculated using rounded production numbers.

10^3 m^3/d, while heavy crude oil production experienced a decline of 8.8 per cent to 22.7 10^3 m^3/d.

In 2009, 949 successful oil wells were drilled, a decrease of 47 per cent from 2008.[2] The last time Alberta experienced this low level of drilling was in the 1970s. For instance, the number of wells drilled between 1972 and 1978 averaged 655 wells per year, although by 1979 the count rose to 1250. Well counts remained above this level through to 2008. **Figure 3.13** shows the number of successful oil wells drilled in Alberta in 2008 and 2009 by geographical area (PSAC area). Previously the ERCB used a modified version of the PSAC area, but from this year forward will use the same area delineations as PSAC. The majority of oil drilling in 2009, over 86 per cent, was development drilling. As shown in the figure, all areas of the province that had drilling activity experienced major declines from last year's levels with the exception of a minor increase in PSAC 6 (Northeastern Alberta).

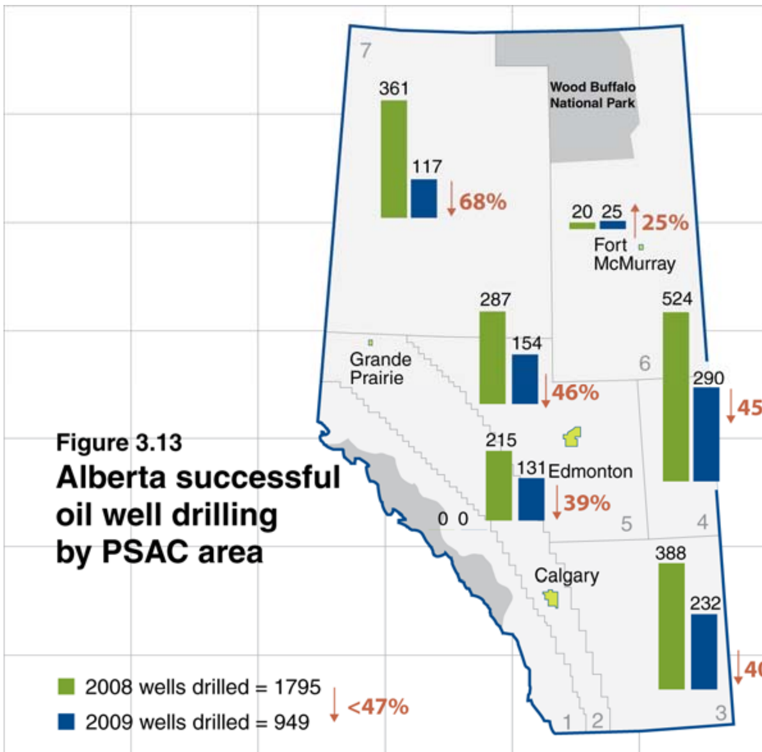


Figure 3.13
Alberta successful oil well drilling by PSAC area

Figure 3.14 depicts the distribution of new crude oil wells placed on production, and **Figure 3.15** shows the initial operating day rates of new wells in 2009. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are placed on production within a short time after being drilled. In 2009, wells placed on production decreased by 41 per cent to 1046, compared to 2008 levels. This drop follows the reduction seen in successful oil well drilling.

[2] Although the overall success ratio for conventional crude oil wells is unavailable, for all drilling activity (excluding oil sands evaluation wells), less than 2 per cent of development wells and less than 7 per cent of exploratory wells drilled in 2009 were abandoned at the time of drilling. Overall, less than 3 per cent of all wells drilled in 2009 were abandoned at the time of drilling.

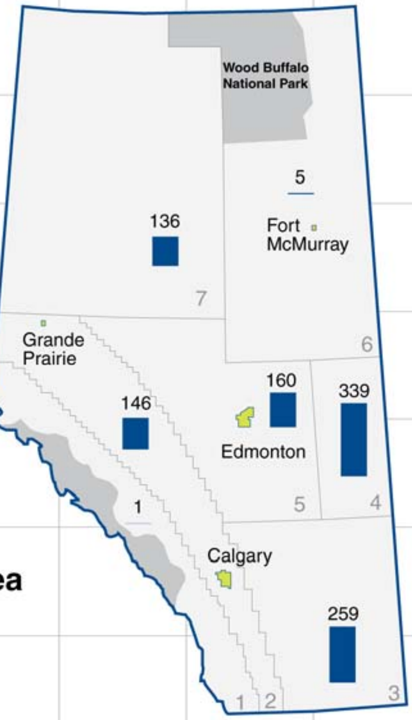


Figure 3.14
Oil wells placed on production, 2009, by PSAC area

Total wells = 1046

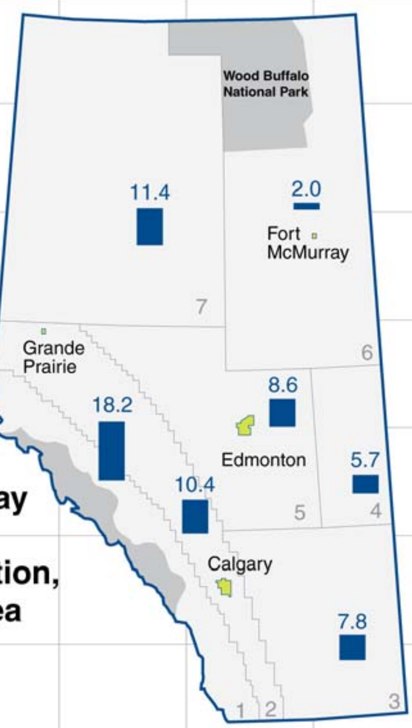
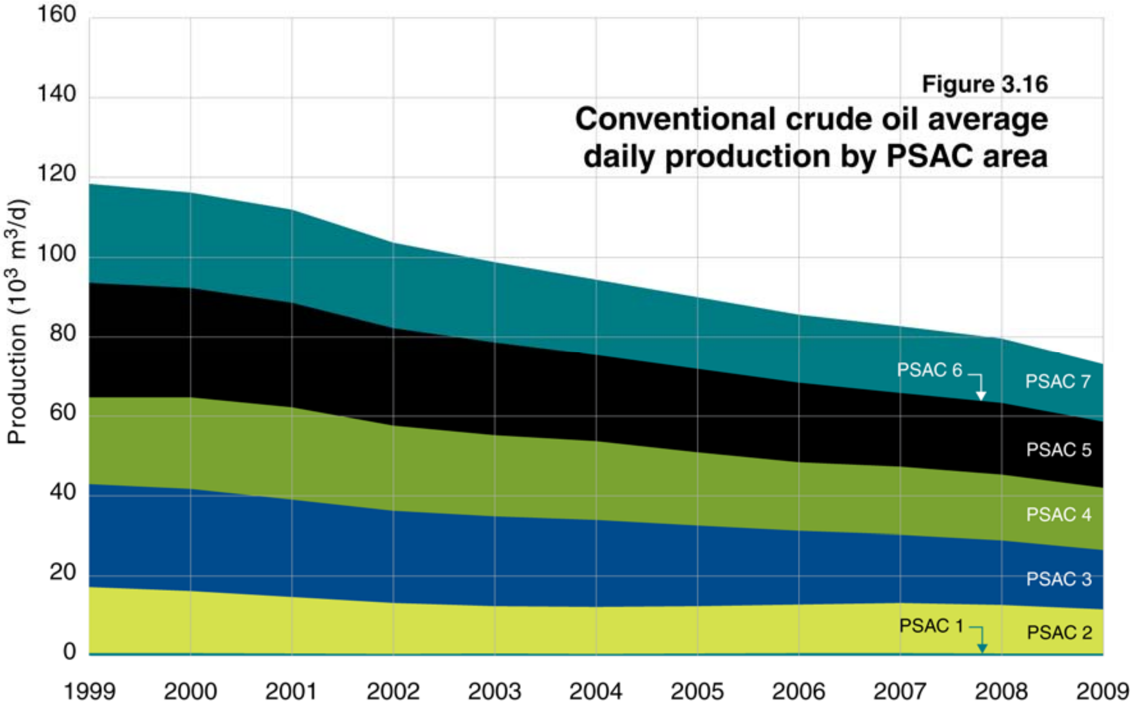
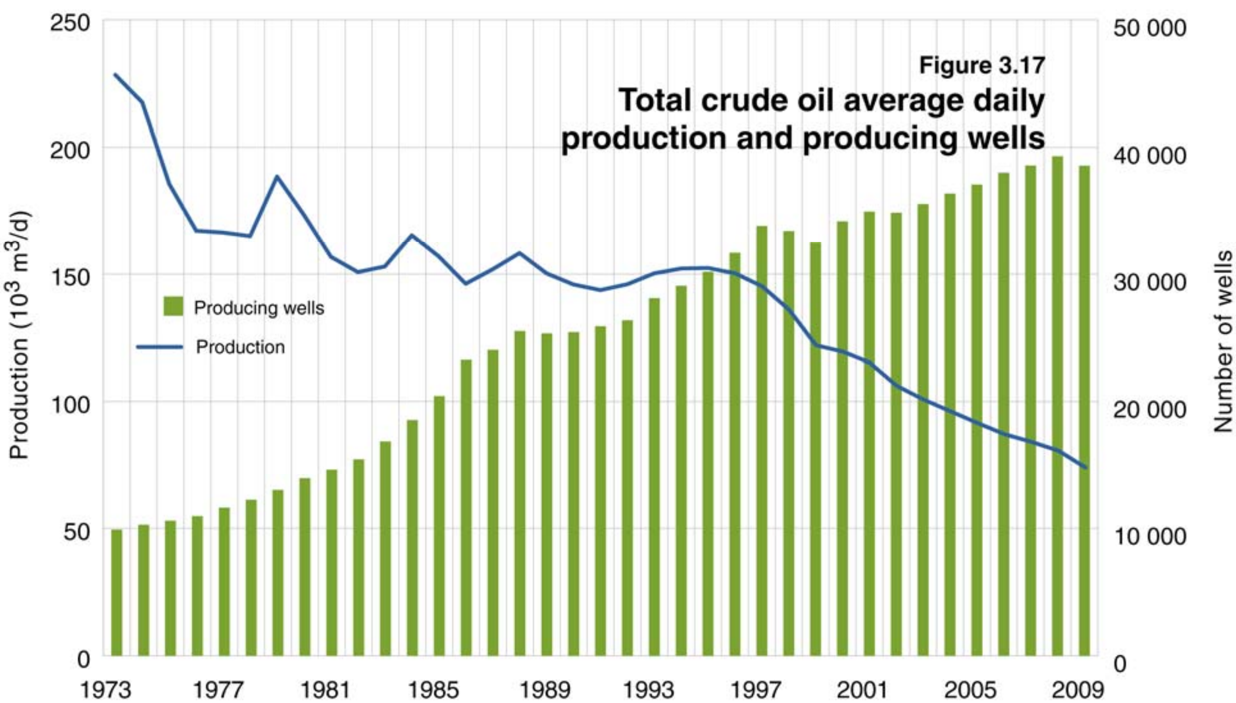


Figure 3.15
Initial operating day rates of oil wells placed on production, 2009, by PSAC area (m^3/day)

Historical oil production by PSAC area is illustrated in **Figure 3.16**. Most areas experienced declines in production, ranging from 11 per cent in PSAC 7 (Northwestern Alberta) to 6 per cent in PSAC 4 (East Central Alberta).



Annual ERCB drilling statistics indicate that the number of wells producing oil has increased over time from 9900 in 1973 to 38 600 in 2009. The average production rate of oil producing wells, however, has been on decline since 1973. The average daily production rate per well in 1973 was 23 m^3/d. This average declined to 5.5 m^3/d by 1991 and 1.9 m^3/d in 2009. New annual drilling has been finding smaller reserves over time, as would be expected in a mature basin. As a result of this declining average productivity per well, the high drilling activity levels have not been enough to stem production declines. **Figure 3.17** illustrates this trend, showing that total crude oil production has been declining, while the number of wells producing crude oil has been increasing.



Of the 38 600 wells producing oil in 2009, about 3100 were classified as gas wells. Although these gas wells represented 8 per cent of wells that produced oil, they produced at an average rate of only 0.2 m^3/d and accounted for less than 1 per cent of total production. Also included were about 4100 producing horizontal oil wells that accounted for 11 per cent of producing oil wells, but about 18 per cent of the total crude oil production due to the higher average production per well.

Figure 3.18 depicts producing oil wells and the average daily production rates of those wells by region in 2009. The average well productivity of crude oil producing wells in 2009 was 2.1 m^3/d. The majority of crude oil wells in Alberta, about 70 per cent, produced less than 2 m^3/d per well, again a characteristic of a maturing basin. In 2009, the 24 400 oil wells in this category operated at an average rate of 0.9 m^3/d and accounted for only 27 per cent of the total crude oil produced. **Figure 3.19** shows the distribution of crude oil producing wells (including horizontal oil wells) based on their average production rates in 2009.

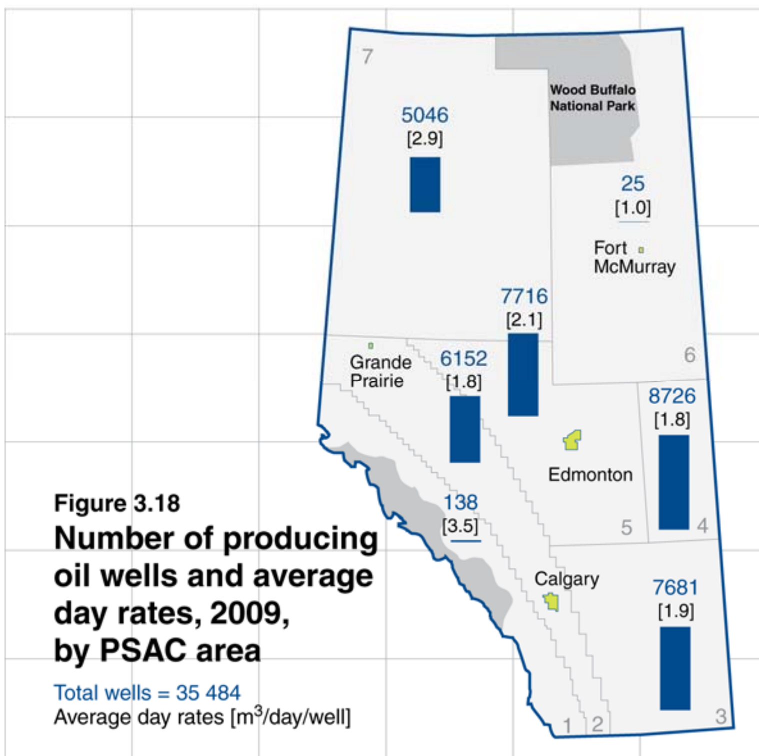


Figure 3.18
Number of producing oil wells and average day rates, 2009, by PSAC area

In 2009, some 267 horizontal oil wells were brought on production, a 26 per cent decrease from 2008, raising the total to 4115. Initial production from horizontal wells drilled in the past ten years peaked in 2000 at an average rate per well of 10.4 m^3/d. The initial production rate per well of new horizontal wells is 6.1 m^3/d. This initial production rate of new horizontal wells is higher than the initial rate per well of 3.3 m^3/d of vertical wells, which account for the majority of crude oil wells in Alberta.

Crude oil production from existing wells by year placed on production over the period 2000 to 2009 is depicted in **Figure 3.20**. This figure illustrates that about 33 per cent of crude oil production in 2009 represents wells placed on production in the last five years.

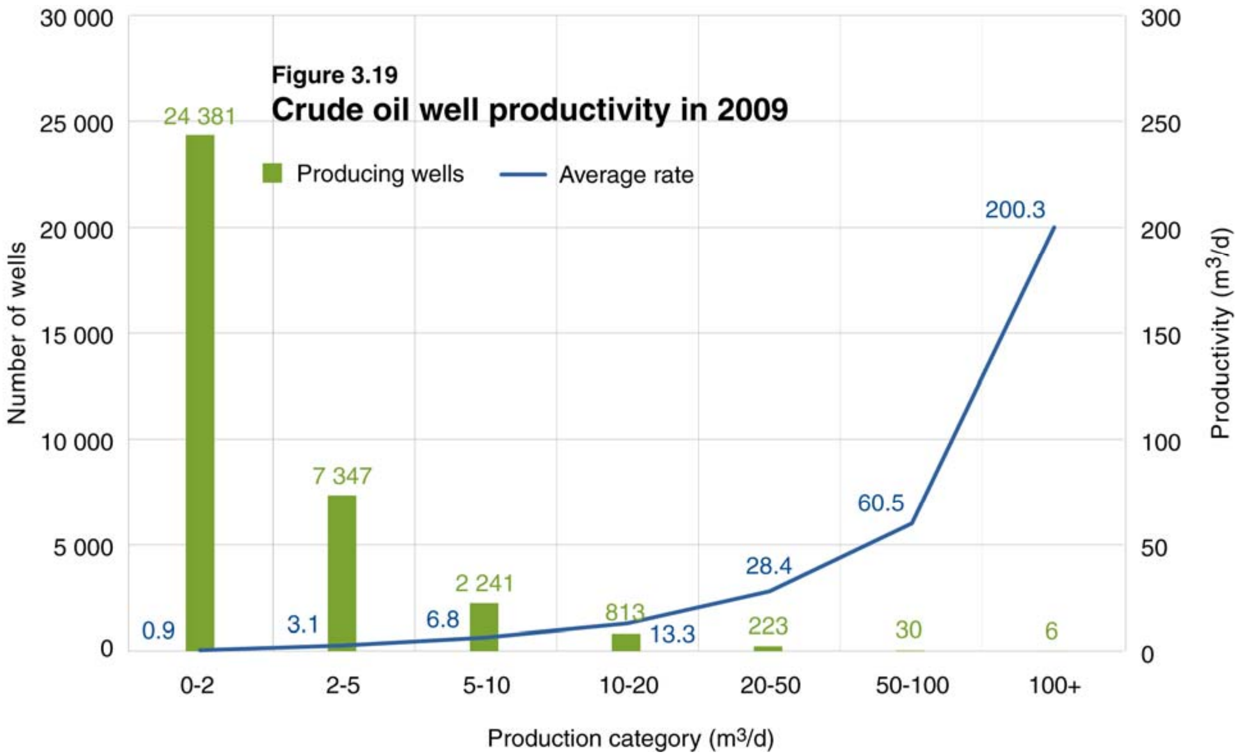


Figure 3.19
Crude oil well productivity in 2009

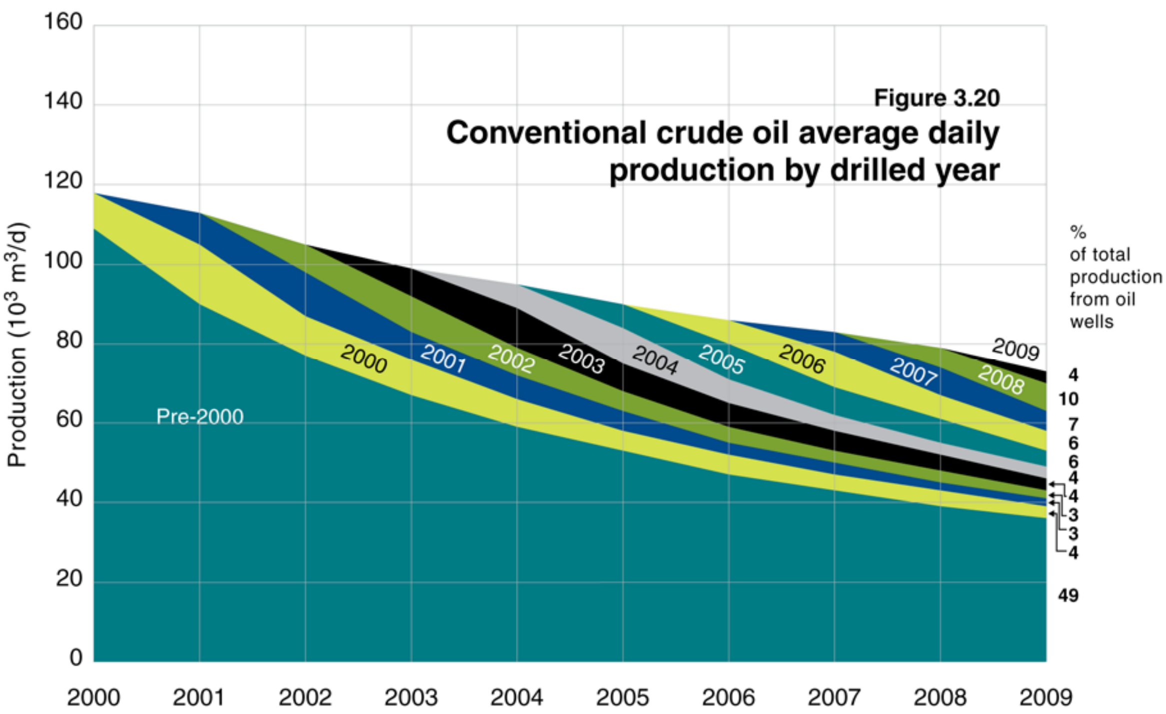


Figure 3.20
Conventional crude oil average daily production by drilled year

To project crude oil production from wells drilled prior to 2010, the ERCB assumes the following:

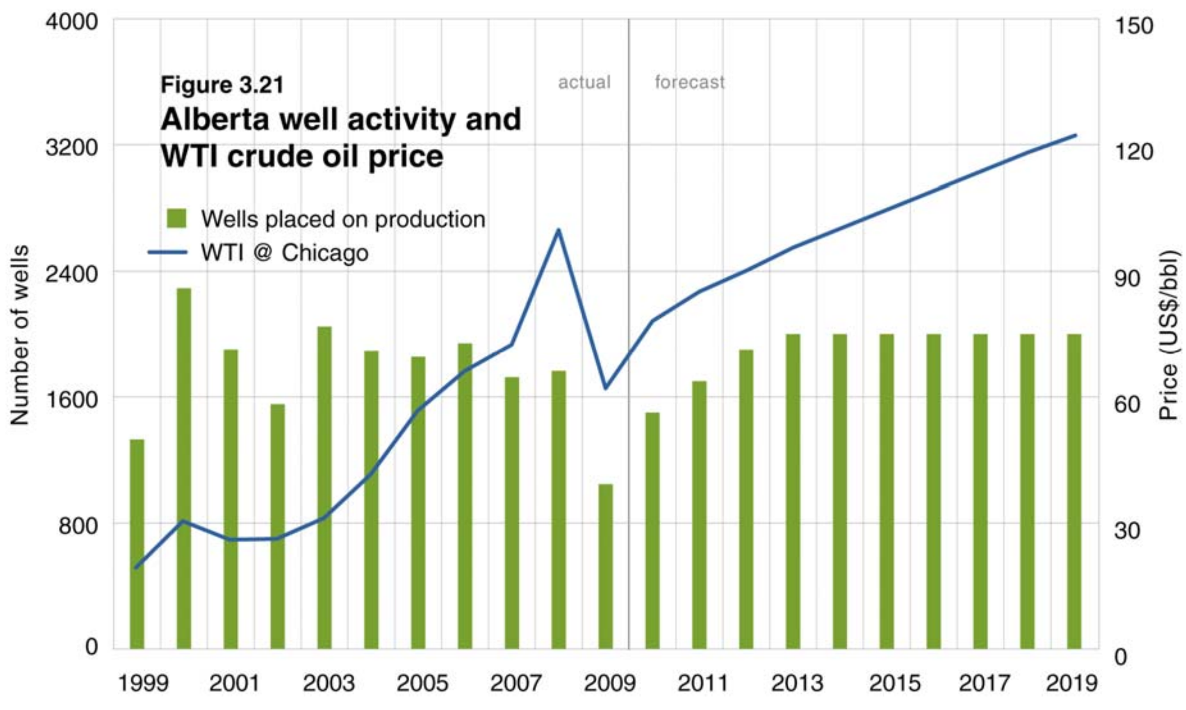
- Production from existing wells in 2010 will be 65.9 10^3 m^3/d.
- Production from existing wells will decline at a rate of 15.5 per cent per year.

Over the forecast period, production of crude oil from existing wells is expected to decline to 14.5 10^3 m^3/d by 2019.

Total production from new wells is a function of the number and type of new wells that will be drilled successfully, initial production rate, and the expected average decline rate for these new wells. The forecast for production from new wells acknowledges industry's continued drilling interest in targeting the Cardium tight oil and other emerging plays using multistage horizontal drilling. Multistage horizontal wells have been used successfully to unlock the Bakken tight oil play in southeastern Saskatchewan for a number of years. This technology was introduced into the Cardium Formation in late 2008.

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 from 1046 in 2009 to 1500 in 2010, 1700 in 2011, 1900 in 2012, and level out at 2000 for the remainder of the forecast period. The primary assumptions for the drilling increase in 2010 to 2012 include the price forecast as set out in Section 1 and industry interest in employing the new drilling and completion technology in the Cardium resource. Although the crude oil price forecast continues to rise over the entire forecast period, after 2013 well activity is expected to return to historical activity levels based on the historical 5- and 10-year average trend, despite an environment of increasing prices over the period. Therefore, the forecast well count remains constant at 2000 wells per year to account for the expected continued interest in new drilling and completion technology tempered by the historical drilling trend. **Figure 3.21** illustrates the ERCB's forecast for wells placed on production for the period 2010 to 2019.



- The average initial production rate for new wells is projected to be 5.5 m^3/d/well and will decrease to 4.0 m^3/d/well by the end of the forecast period. The estimated initial production rates are higher than projected in our 2009 forecast to account for the expected higher production rates from wells using horizontal, multistage fracturing technology.
- Production from new wells will decline at a rate of 40 per cent the first year, 25 per cent the second year, 21 per cent the third year, 19 per cent the fourth year, and 16 per cent for the remaining forecast period. First-year decline rates are higher than projected in our 2009 forecast to account for the production profile of these new wells. Although actual data are limited, it appears that first-year decline rates for these new wells may be in excess of 50 per cent.

The projection of total production, which comprises production from existing wells and that from new oil wells, is illustrated in **Figure 3.22**. This figure also illustrates the production forecast split for light-medium and heavy crude oil. Light-medium crude oil production is expected to decline from 50.6 10^3 m^3/d in 2009 to 32 10^3 m^3/d in 2019. Over the forecast period, heavy crude production is also expected to decrease, from 22.7 10^3 m^3/d in 2009 to 16 10^3 m^3/d by the end of the forecast period. **Figure 3.22** illustrates that by 2019, heavy crude oil production will constitute a greater portion of total conventional crude oil production in Alberta (34 per cent) compared to 2009 (31 per cent).

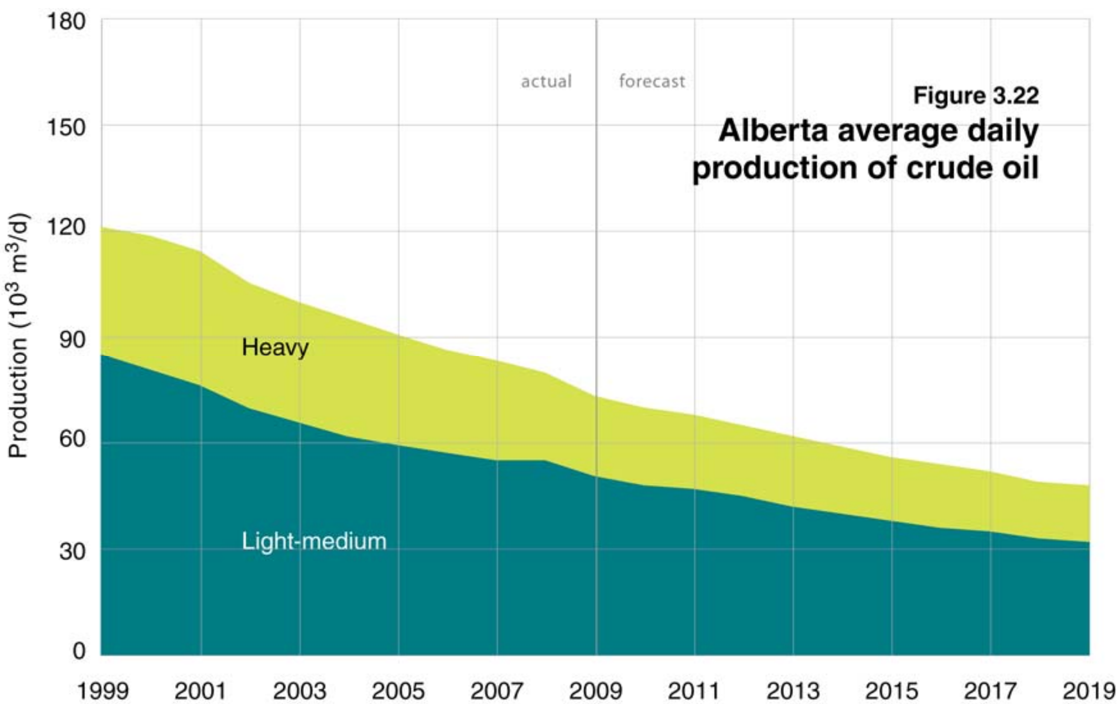


Figure 3.22
Alberta average daily production of crude oil

This production forecast assumes that crude oil production will reduce its decline from 8.6 per cent in 2009 to 4.5 per cent in 2010 due primarily to the expected overall increase in drilling. Crude oil production decline rates are assumed to further moderate to the 3.5 to 4.0 per cent range for the remainder of the forecast period as production from increased wells drilled and wells drilled with new technology somewhat offset declining production from existing wells.

The combined ERCB forecasts for existing and future wells indicate that total crude oil production will decline from 73.3 10^3 m^3/d in 2009 to 48 10^3 m^3/d in 2019. By 2019, based on this projection, Alberta will have produced about 89 per cent of the estimated ultimate potential of 3130 10^6 m^3.

3.2.2 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with synthetic crude oil (SCO), bitumen, and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta refineries are domestic demand for RPPs, shipments to other western Canadian provinces, exports to the United States, and competition from other feedstocks. Since Alberta is a "swing" supplier of RPPs in western Canada, a refinery closure or expansion in this market may have a significant impact on the demand for Alberta RPPs and, hence, on Alberta crude oil feedstock requirements.

In 2009, Alberta refineries, with a total inlet capacity of 75.5 10^3 m^3/d of crude oil and equivalent, processed 17.3 10^3 m^3/d of conventional crude oil. This is a substantial decrease (32 per cent) from the 25.4 10^3 m^3/d reported for 2008. The reason for the decline in conventional crude oil processing between 2008 and 2009 was due to Suncor's (formerly Petro-Canada's) Edmonton refinery fully replacing light-medium crude oil with SCO and nonupgraded bitumen in 2009. This resulted in conventional crude oil accounting for roughly 31 per cent of the total crude oil and equivalent feedstock to Alberta refineries (see Section 2.2.5).

SCO, bitumen, and pentanes plus constitute the remaining feedstock processed through Alberta refineries. **Figure 3.23** illustrates the current capacity and location of Alberta refineries. It is expected that no new crude oil refining capacity will be added over the forecast period.

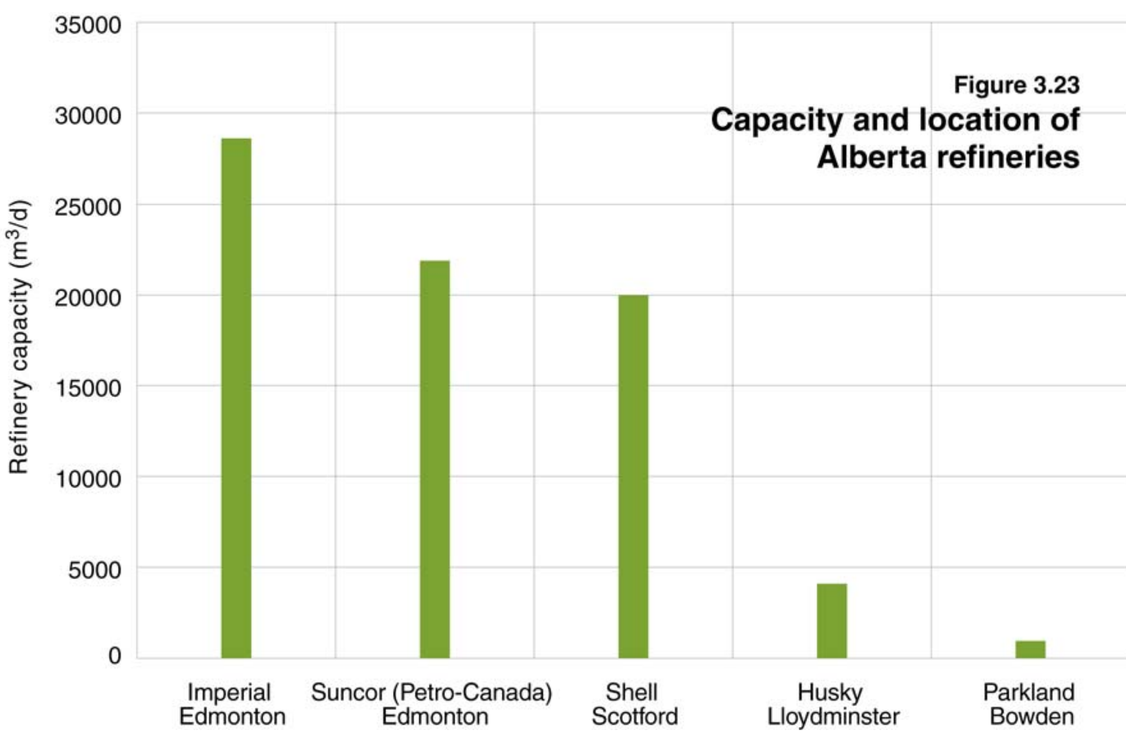
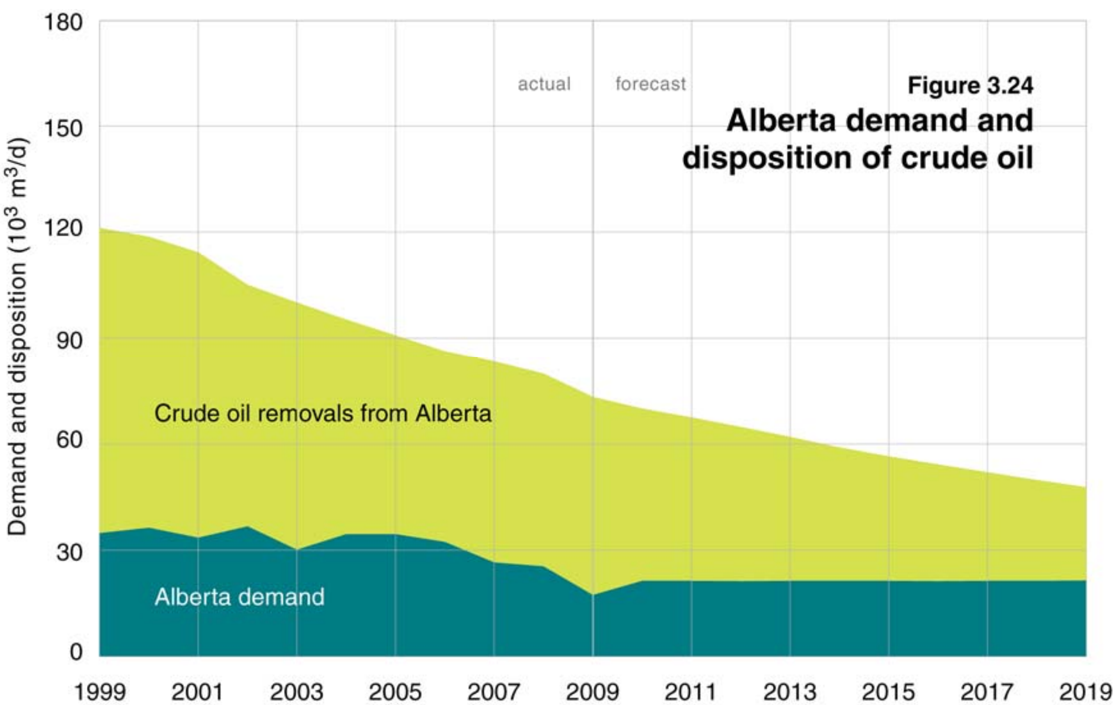


Figure 3.23
Capacity and location of Alberta refineries

Refinery utilization for 2009 was about 73 per cent, down from 81 per cent in 2008, mainly due to planned and unplanned outages at the Edmonton-area refineries. Suncor's Edmonton refinery output was constrained in 2009 by a fire in January, a month-long planned maintenance turnaround in April, and a storm-related power outage in July. The storm also affected Imperial's Strathcona refinery. In addition, the Strathcona refinery had a scheduled maintenance turnaround that started in mid-March and lasted through April. A planned routine maintenance turnaround scheduled for September for the Shell Scotford refinery was extended into mid-October. The forecast assumes that total crude oil use in Alberta's refineries will increase to 21 10^3 m^3/d in 2010, based on an improved utilization rate of 90 per cent and remain at this level for the remainder of the forecast period.

Shipments of crude oil outside of Alberta, depicted in **Figure 3.24**, amounted to 76 per cent of total production in 2009. The ERCB expects that by 2019 about 55 per cent of production will be removed from the province, due to the forecast decline in Alberta light-medium and heavy crude oil production.



3.2.3 Crude Oil and Equivalent Supply

Figure 3.25 shows crude oil and equivalent supply. It illustrates that total Alberta crude oil and equivalent is expected to increase from 306.6 10^3 m^3/d in 2009 to 526 10^3 m^3/d in 2019.

Over the forecast period, as illustrated in **Figure 3.26**, the growth in production of nonupgraded bitumen and SCO is expected to significantly more than offset the decline in conventional crude oil. The share of SCO and nonupgraded bitumen will account for some 89 per cent of total production by 2019, compared to 2009, when the share of SCO and nonupgraded bitumen accounted for some 69 per cent of total production. Since 2003, the share of SCO and nonupgraded bitumen has accounted for over 50 per cent of total production.

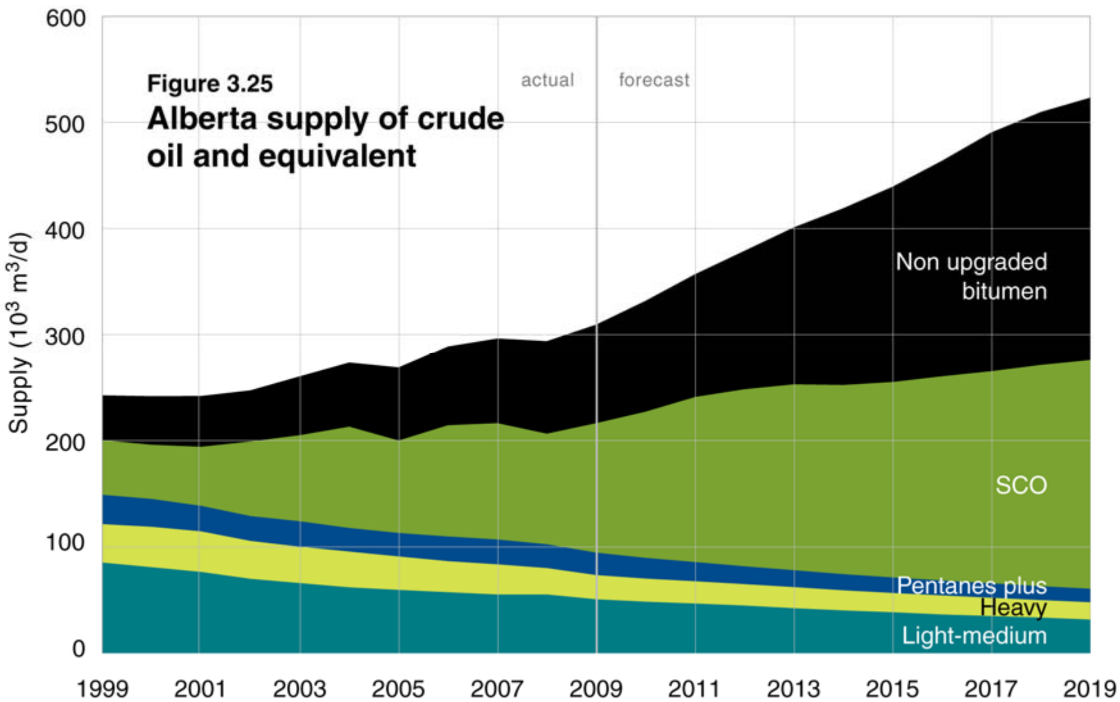


Figure 3.25
Alberta supply of crude oil and equivalent
actual
forecast
Supply (10^3 m^3/d)
Non upgraded bitumen
SCO
Pentanes plus
Heavy
Light-medium
0
100
200
300
400
500
600
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019

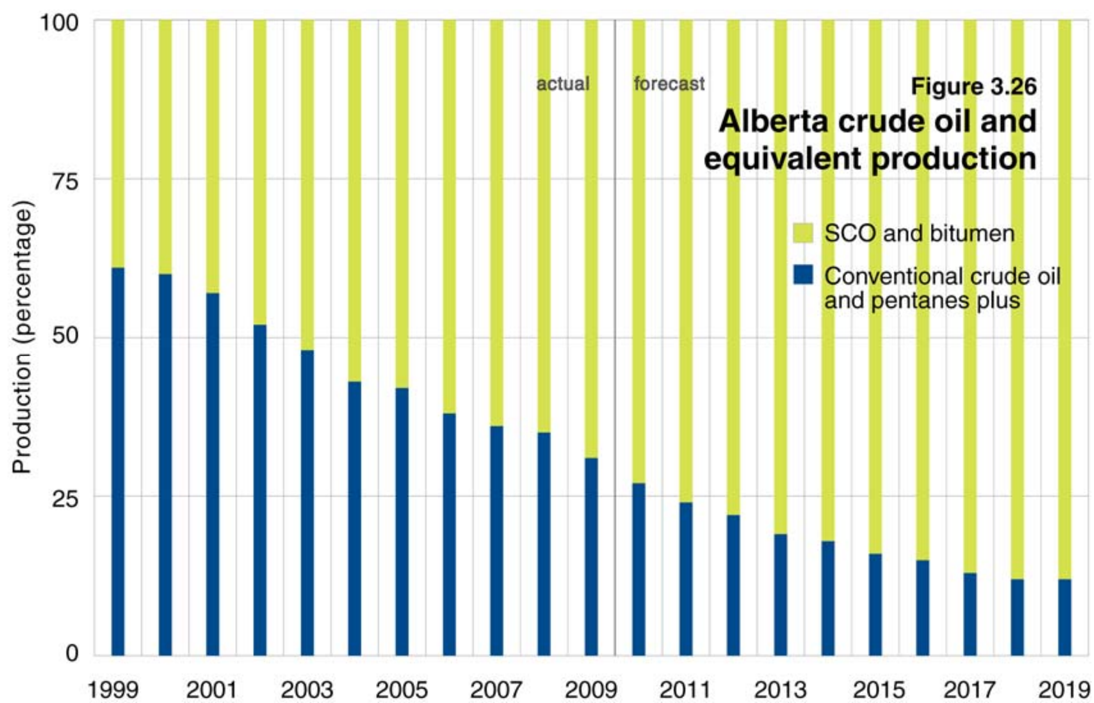


Figure 3.26
Alberta crude oil and equivalent production
actual
forecast
Production (percentage)
SCO and bitumen
Conventional crude oil and pentanes plus
0
25
50
75
100
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019

4 Unconventional Natural Gas

Highlights

- Coalbed methane (CBM) initial established reserves have increased by 90 per cent in 2009.
- The shale gas description has been expanded in this year's report but no reserves have been assigned.
- Gas production for 2009 from 14 120 CBM connections was 9 billion cubic metres, an increase of 6 per cent.
- In 2009, there were 250 connections that produced 0.08 billion cubic metres of shale gas.

Unconventional gas is described in this section as Alberta's unconventional gas reserves found as coalbed methane (CBM) and shale gas.

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

4.1 Reserves of Coalbed Methane

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

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). Hydrogen sulphide (H_2S) is not normally associated with CBM production, as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 megajoules per cubic metre. This report estimates the initial in-place resources and remaining established reserves of CBM at December 31, 2009.

4.1.1 Provincial Summary of CBM

The ERCB estimates the initial established reserves of CBM to be 90.0 billion cubic metres (10^9 m^3) as of December 31, 2009, an increase of 42.7 10^9 m^3 from 2008. This increase of 90 per cent is due to the reevaluation of gas content and recovery factor. Remaining established reserves in 2009 are 64.5 10^9 m^3, up from 28.3 10^9 m^3 in 2008.

A summary of reserves and production is shown in **Table 4.1**. In 2009, the annual production from all wells listed as CBM was 9.0 10^9 m^3. This volume represents the total contribution from wells with commingled conventional gas and CBM production, which are defined as CBM hybrid wells. However, the portion estimated to be attributed to CBM only is 6.5 10^9 m^3, as listed in **Table 4.1**.

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

	2009	2008	Change
Initial established reserves	90.0	47.3	+42.7
Cumulative production	25.5	18.9	+6.6*
Remaining established reserves	64.5 (2.3 Tcf)[a]	28.3 (1.0 Tcf)[a]	+36.2
Annual production	6.5	6.2	+0.3

* Change in cumulative production is a combination of annual production and all adjustments to previous production records. In 2009, a correction to the historical CBM cumulative production, mainly from previously unidentified CBM wells, resulted in the revisions seen above.

[a] Tcf- trillion cubic feet.

4.1.2 Distribution of CBM Potential by Geologic Strata

Based on thousands of coal holes and oil and gas wells, coal is known to underlie most of central and southern Alberta (**Figure 4.1**), one of the largest geographical extents of continuous coal in North America. Coal seams occur as layers or beds within a number of Cretaceous coal zones (**Figure 4.2**). While individual coal seams can be laterally discontinuous, coal zones can be correlated very well over regional distances. All coal seams contain CBM to some extent, and each individual seam is potentially capable of producing some quantity of CBM. For this reason, coal and CBM have a fundamental relationship.

The following horizons have CBM potential in Alberta:

- **Ardley Coals of the Scollard Formation** – This is the upper set of coals (**Figures 4.1** and **4.2**), 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 a few wells shows the Ardley coals in the area of Development Entity No. 1[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 (**Figures 4.1** and **4.2**), which generally have low gas content and low water volume, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, and they constitute the majority of CBM reserves booked. The Horseshoe Canyon play area in central Alberta in **Figure 4.3** is smaller than the geological extent of the Horseshoe Canyon Formation. Play areas for the Taber or MacKay zones of the Belly River Group have not been established, as they are not commercially productive at this time. CBM activity will continue in the Horseshoe Canyon areas with the existing vertical drilling technology by new drilling, recompletions of existing wells, and commingling with conventional zones.

- **Coals of the Mannville Group** – This is the lower set of coals within the plains (**Figures 4.1** and **4.2**), primarily in the upper Mannville formations. These generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. These coals continue to the west to outcrop near the Rocky Mountains, where they are referred to as the Luscar coals. The initial reserves for areas other than Corbett (see **Figure 4.3**) within the Mannville have been set at

[1] Development entities are discussed in Section 5.1.5.

cumulative production. Future Mannville activity is projected to continue using horizontal well drilling to achieve commercial production.

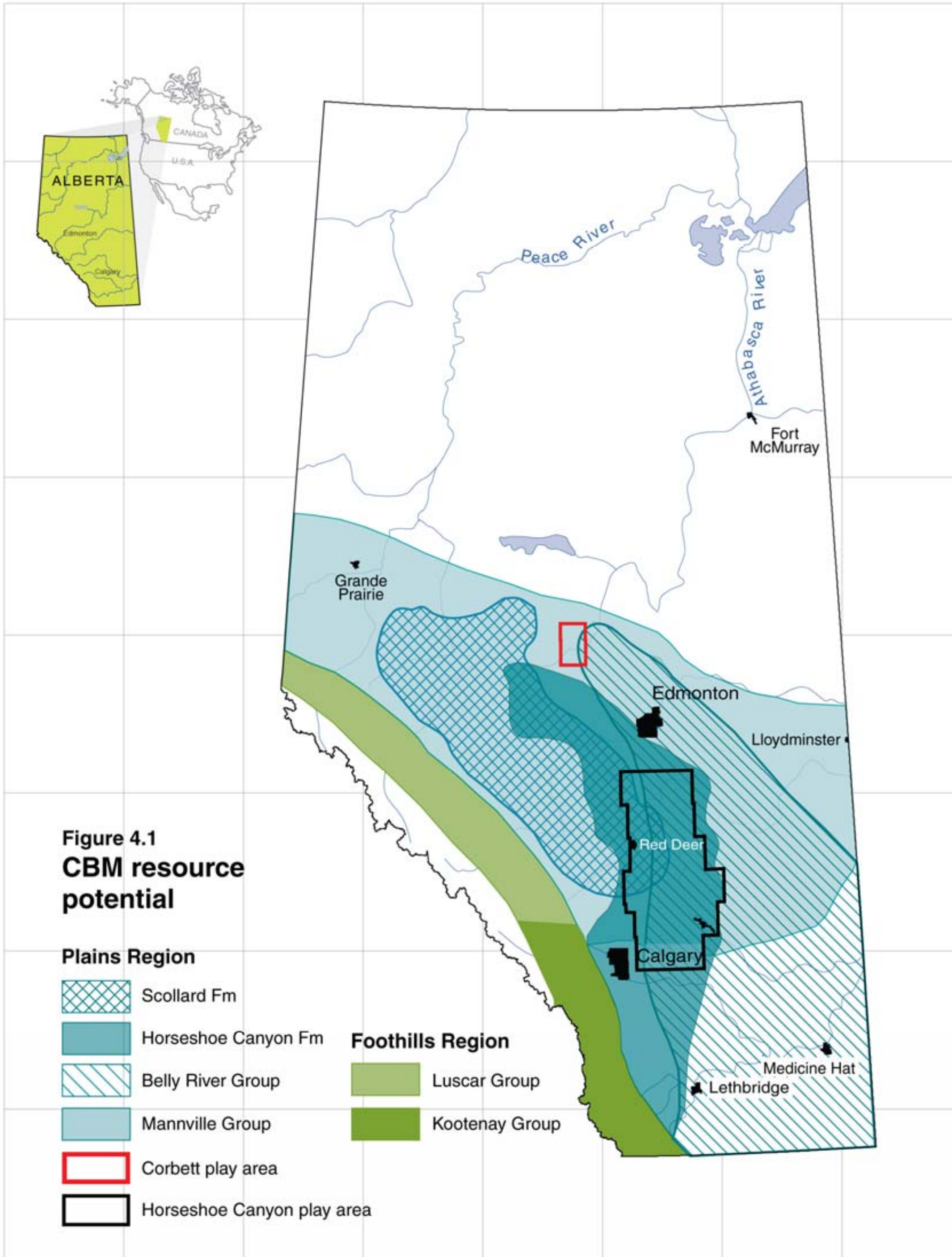
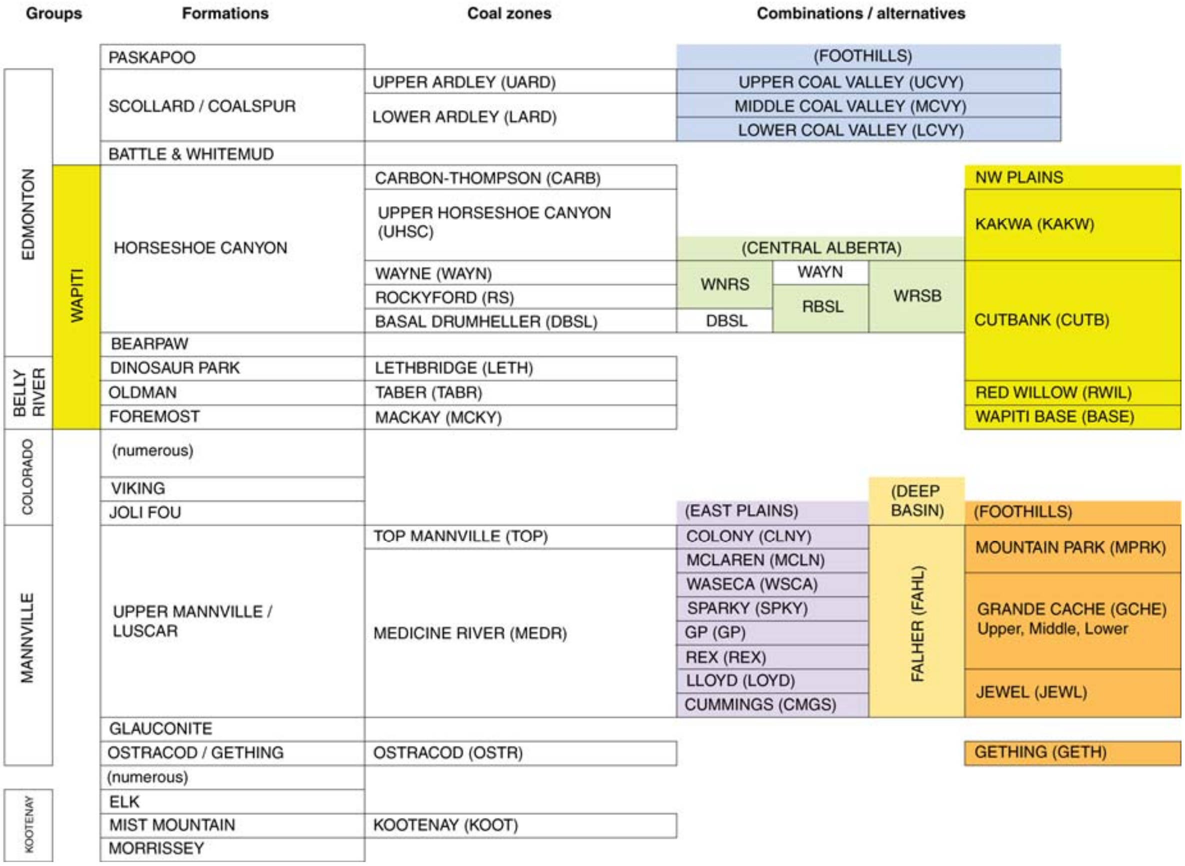


Figure 4.1
CBM resource potential

- **Kootenay Coals of the Mist Mountain Formation** – These coals are only present in the foothills of southwestern Alberta (**Figures 4.1** and **4.2**). They have varying gas content and quantities of water, but production of gas is very low due to tectonic disruption. No reserves have been calculated.

Figure 4.2
CBM zones of Alberta

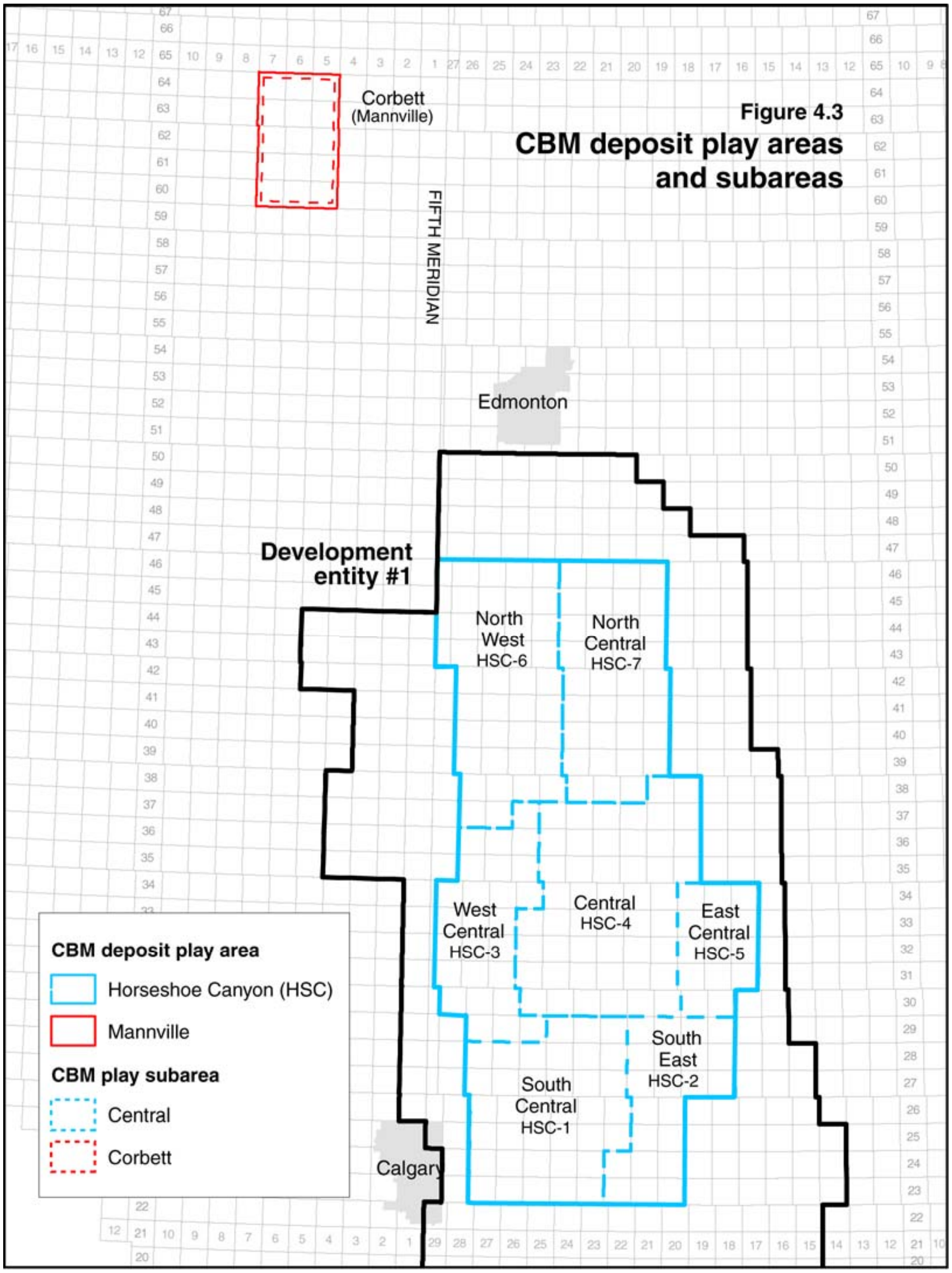


An individual CBM zone is defined as all coal seams within a formation not separated by more than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool (see **Figure 4.2**).

The ERCB assesses CBM deposits for reserve determination within these formations in a manner similar to assessing oil sands deposits (see **Figure 4.3**). CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the ERCB has yet to formally define CBM deposits (i.e., through Board orders), as it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities to date have been concentrated mainly in a single smaller play area.

While Mannville activity is clustered almost exclusively around the Corbett area, the more widespread Horseshoe Canyon occurs under a large area between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is found completely within the ERCB-designated Development Entity No. 1, as shown in **Figure 4.3.**

While coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by control well data within the deposit (see **Figure 4.3**).



Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries are being converted to multifield CBM pools that will be used for the broad geographic limits of the CBM deposit areas. As multifield pools are still problematic in grouping CBM resource and reserves estimates, the ERCB now groups CBM volumes into deposit-based play areas.

4.1.3 CBM Reserves Determination Method

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The ERCB uses three-dimensional block models to estimate this disseminated gas volume. Based on the analysis of geology, pressure gradients, and related gas content, the ERCB has identified distinct subareas within CBM play areas and determined in-place CBM resources for each of these play subareas (**Figure 4.3**).

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

Current reserves estimates are determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table 4.2**. The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero, which becomes the recovery factor. Future analysis is expected to improve estimates of recovery factors.

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

4.1.4 Commingling of CBM with Conventional Gas

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. Much of this is not from new drilling, but from recompletions of existing declining conventional gas wells (see Section 4.2). 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.

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

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

As the Horseshoe Canyon and Belly River formations generally contain “dry CBM,” with little or no pumping of water required, the commingling of CBM and other conventional gas pools is 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. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

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

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from over 1800 CBM control wells and other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. There is an administrative process in place to correct for the CBM production in these cases.

This process resulted in the estimated contribution of CBM production from CBM hybrid wells being increased in a few areas.

4.1.5 Detail of CBM Reserves and Well Performance

Exploration and development drilling are being conducted for CBM across wide areas of Alberta and in many different horizons. The first commercial production and reserves calculations 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 **Table 4.2**). New data have supported inclusion of additional areas as part of the contiguous Horseshoe Canyon CBM play area (see **Figure 4.3**). 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.

Subarea 4 has the greatest aerial extent of the Horseshoe Canyon subareas (see **Figure 4.3**), which, combined with its relative greater coal thickness (26 m) and high recovery factor, results in the largest initial established reserves of CBM of the Horseshoe Canyon play. Deeper coal and higher gas content exist in subareas 1 and 3, but the recovery factor is also less because of the reduced permeability at those depths. The assigned average recovery factors for subareas 4 and 6 have increased noticeably relative to the 2008 estimates, as a result of the latest analysis of flowmeter and pressure data.

The ERCB has significantly increased its reserves estimate and assigned average recovery factor for the Corbett play area (see **Figure 4.3**) of the Mannville CBM deposit. This is based on the analysis of the production profiles of new multilateral horizontal wells, which show increasing gas flow with decreasing water production. Ongoing Mannville CBM production in adjacent areas should also see increased gas flow due to progressive dewatering of the deposit outside the current play area, which still requires the proper disposal of saline water.

Table 4.2. CBM gas in place and reserves by deposit play area, 2009

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas / m^3 coal)	Initial gas in place (10^9 m^3)	Average recovery factor %	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
1	30.1	34.49	2.65	91.30	9	7.82	4.99	2.83
2	9.0	3.97	1.79	7.11	12	0.85	0.42	0.42
3	17.0	13.77	3.25	44.81	18	8.11	2.10	6.00
4	26.0	42.81	1.69	72.17	25	18.23	6.77	11.46
5	18.7	7.41	0.70	5.21	12	0.63	0.45	0.18
6	10.4	9.17	2.01	18.46	26	4.83	1.70	3.13
7	28.0	44.02	1.13	49.86	18	8.79	4.79	4.00
Undefined[b]	-	-	-	-	-	0.37	0.37	0.00
Subtotal	19.9[c]	155.64	1.89[c]	288.93	17[c]	49.62	21.59	28.02
Mannville								
Corbett	4.8	10.02	12.62	126.42	32	39.99	3.48	36.50
Undefined[b]	-	-	-	-	-	0.38	0.38	0.00
Total	12.3[c]	165.66	7.25[c]	415.35	24[c]	89.99	25.46	64.53

[a] Includes Upper Belly River CBM.

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

[c] Average.

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

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

4.1.6 Ultimate CBM Gas in Place

In 2003, the Alberta Geological Survey (AGS), in *Earth Sciences Bulletin 2003-03*, estimated that there are some 14 trillion (10^{12}) m^3 (500 trillion cubic feet [Tcf]) of gas in place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta’s ultimate CBM gas in place (see **Table 4.3)**. However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion of these large values—the ultimate potential—has yet to be determined.

Table 4.3. Ultimate CBM gas in place*

	10^{12} 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*.

The geographic distribution of these CBM resources is shown in **Figure 4.1**, but only a very small portion of this very large resource has been studied in sufficient detail to be included in this report. Care must therefore be taken in comparing these unconstrained in-place resource numbers against the more constrained ultimate recoverable numbers of other basins.

Although not a type of natural gas, potential exists in Alberta for the production of syngas from coal or biomass gasification. There are three types of coal gasification processes: surface facility gasification from mined coal, biological modification of in situ coal seams, referred to as biogenic gas, and in situ coal gasification (ICG).

Surface facility gasification is derived from conventionally mined coal, and those mineable coal reserves are included in Section 8. Currently, gasification facilities do not exist in Alberta and therefore there is no production to address in this section. Biogenic gasification is not included in this report, as this process of gas generation is highly speculative at this time. ICG is usually derived from coal at unmineable depths. The resource base for ICG will be included in Section 8 in future reports, and that section will be expanded to more fully identify the complete resource base. Any ICG-derived gas would, by its nature, incorporate any CBM gas volumes contained within the targeted coals. Currently, ICG syngas is limited to a small quantity of experimental production; it would need to achieve a commercial level of production before reserves would be included in this report. Biomass gasification is in its infancy and, as such, is not included in this report.

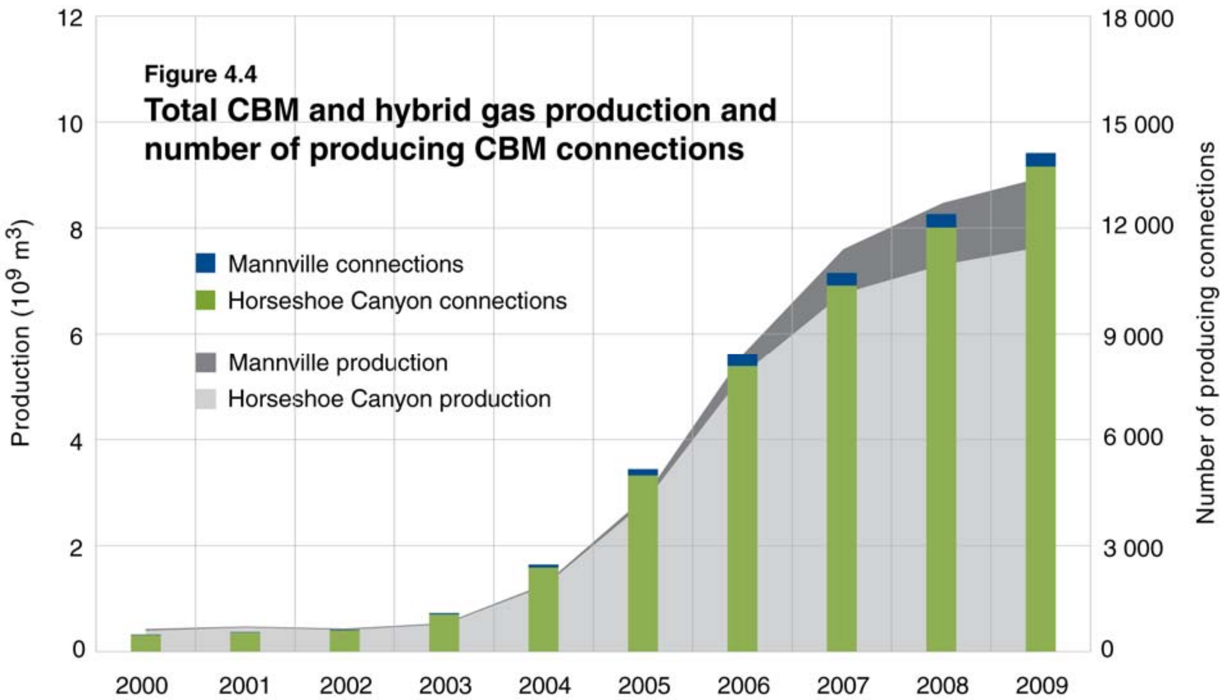
4.2 Supply of Coalbed Methane

The number of unconventional gas zones connected or commingled within existing conventional gas wells has increased unconventional gas volumes without new drilling. Therefore, this section discusses unconventional gas connections rather than gas wells or drilling activity, as done previously.

Total production from CBM-identified connections increased 5.7 per cent in 2009 to 8.95 10^9 m^3 from the revised 2008 volume of 8.47 10^9 m^3. In 2009, the Horseshoe Canyon zone produced 7.64 10^9 m^3 of CBM from 13 736 CBM-only and hybrid connections, while the Mannville zone produced 1.31 10^9 m^3 of CBM from 384 connections. There were 122 connections that had previously been identified as producing but did not report production in 2009. Total CBM production and producing connection counts are shown in **Figure 4.4**, which clearly illustrates the tremendous growth in development over the last few years. More significantly, this figure shows the production contribution from the Mannville connections relative to the Horseshoe Canyon. Mannville zone production accounts for 15 per cent of the total CBM produced, but for only 3 per cent of the total producing CBM connections. A limited number of industry participants have adopted the technological advances required to unlock the Mannville CBM potential in Alberta, and they will continue to dominate this development until other industry players can obtain the necessary land positions, development skills, and economies of scale.

In 2009, there were 1848 new connections for CBM production, a 2 per cent increase from the revised 2008 connection count of 1807. Of these new connections, 98 per cent were in the Horseshoe Canyon zone, and the majority were recompletions.

In 2009, 70 per cent of CBM connections were recompletions in existing conventional wells compared to new drilling, and there are thousands more existing conventional wells with potential for recompletion into CBM zones. Recent changes to ERCB commingling regulations and well test data requirements have greatly improved the economics of



producing CBM along with the conventional gas from existing wells. Once a well is recompleted into the CBM zone, the connection status changes from conventional gas to hybrid CBM, and the conventional portion of gas production from these hybrid CBM connections is classified as CBM production.

Mannville CBM connections are primarily multilateral horizontal wells drilled specifically targeting the CBM zone. A multilateral well is one in which there is more than one branch drilled from a single main borehole. These types of wells will continue to be drilled, as they have proven to be cost effective due to their high productivity compared to vertical wells.

The *ST109: Alberta Coalbed Methane Well Locations* report lists connections that the ERCB has identified as being CBM due to licensing and has confirmed based on detailed geological evaluations. These connection designations are reevaluated from time to time and adjusted if required based on new information, causing changes in historical numbers, such as the revised 2008 reported numbers. All counts and volumes in this section are based on current connection designations as of December 31, 2009.

Figures 4.5 and **4.6** show the volume of production by year connected for the Horseshoe Canyon and Mannville plays, which had continued growth in 2009 despite the challenging economic conditions. In the Mannville play, the majority of development occurred in 2006, while Horseshoe Canyon development began a year earlier. Note the similarity in the growth curves, but recognize the difference in scale between the Horseshoe Canyon and Mannville production figures.

Figure 4.7 shows the CBM connections and production by these plays and subareas, as described in Section 4.1. There were 1100 CBM-coded connections, with a total production of 0.41 10^9 m^3, located outside of these defined areas. Horseshoe Canyon defined areas 1, 3, 4, and 7 represent the main avenue of CBM development for that play.

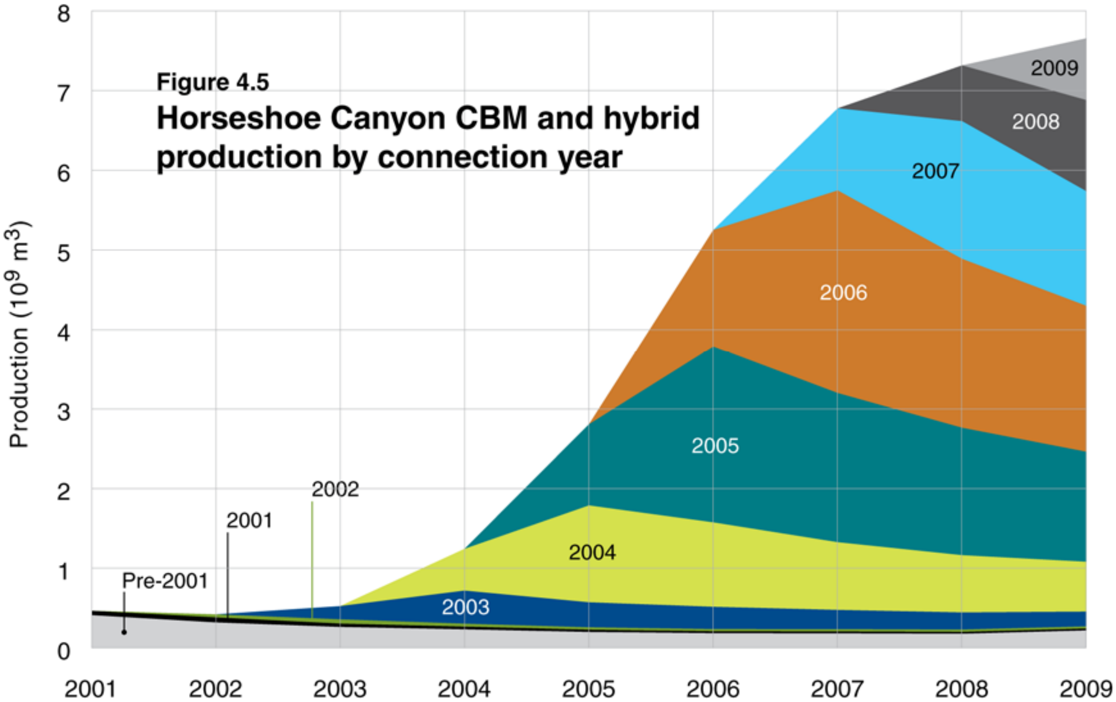


Figure 4.5
Horseshoe Canyon CBM and hybrid production by connection year
Production (10^9 m^3)
8
7
6
5
4
3
2
1
0
2001
2002
2003
2004
2005
2006
2007
2008
2009
Pre-2001
2001
2002
2003
2004
2005
2006
2007
2008
2009

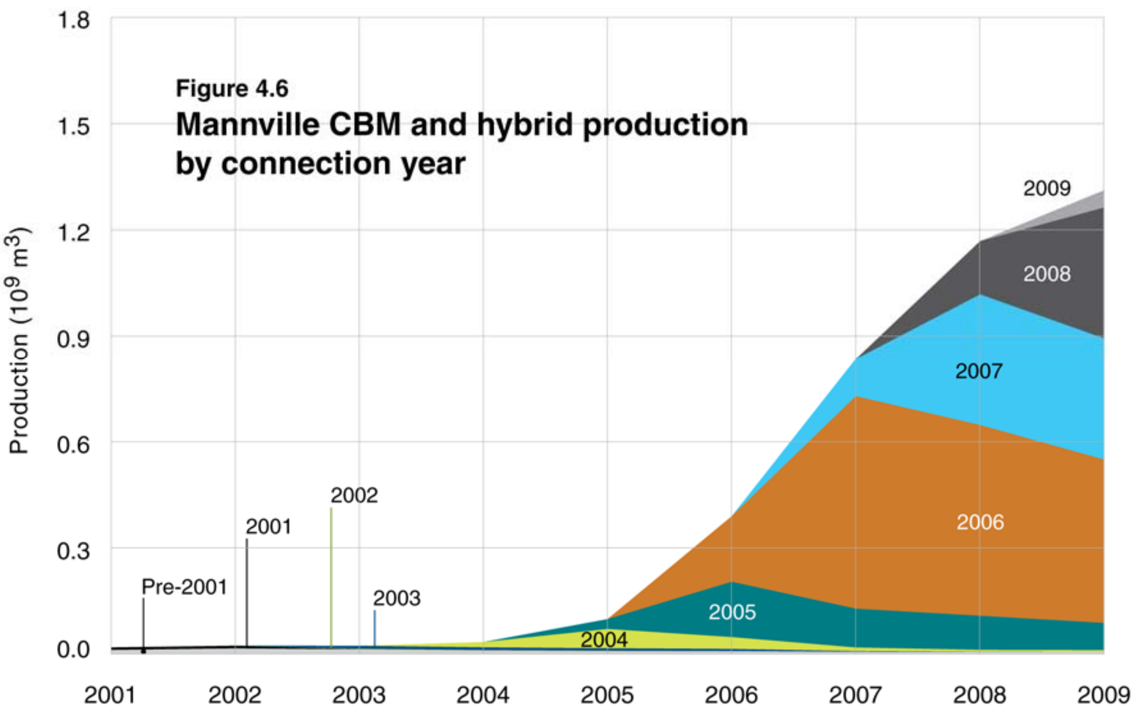


Figure 4.6
Mannville CBM and hybrid production by connection year
Production (10^9 m^3)
1.8
1.5
1.2
0.9
0.6
0.3
0.0
2001
2002
2003
2004
2005
2006
2007
2008
2009
Pre-2001
2001
2002
2003
2004
2005
2006
2007
2008
2009

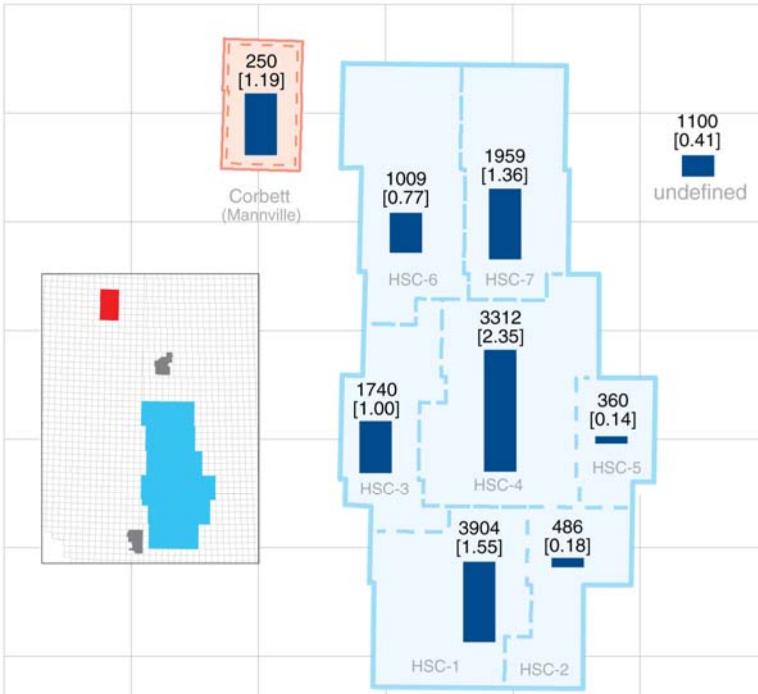


Figure 4.7
Total CBM and hybrid production, 2009, and the number of producing CBM and hybrid connections by play and subarea

Number of connections = 14 120
[Production 10^9 m^3]

Initial average daily production rates are calculated using the first full calendar year of production for current new connections. The 2009 area breakdown of these rates is shown in **Figure 4.8**. These rates within the defined Horseshoe Canyon areas ranged from 1.3 to 2.7 10^3 m^3/day/connection and includes the portion of conventional gas production along with the CBM. The production rate for the defined Mannville area is 17.4 10^3 m^3/day/connection, which is at about six times greater productivity than anywhere in the Horseshoe Canyon area.

In projecting CBM supply, the ERCB considers expected production from both existing CBM connections and expected production from new CBM well connections, which includes new drilling and conventional well recompletions into a CBM zone (hybrid connections).

To forecast production from CBM connections, the ERCB assumed the following:

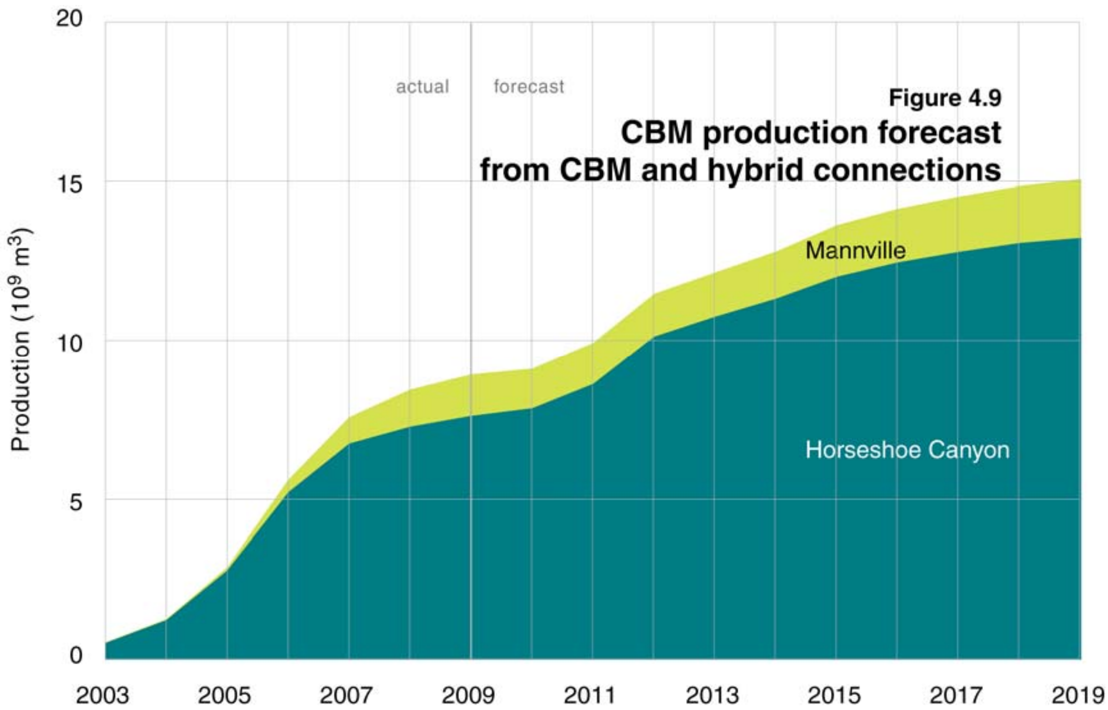
- All gas production from identified CBM and hybrid connections is included.
- Only the Horseshoe Canyon and Mannville plays are forecast.
- All existing CBM and hybrid producing connections are expected to decline annually based on historical trends.

Figure 4.8
Initial CBM average daily production rates by play and subarea, 2009
Production 10^3 m^3/day/connection

- The forecast recognizes that recompletions and new connections within the Horseshoe Canyon play will reduce over time as the numbers of higher level economic opportunities are actualized.
- New connections in the Mannville play will be limited while the price for natural gas remains low.

Based on these assumptions, the projected CBM connections are anticipated to fall in 2010 to 1750 and then to slowly decrease to 1300, where they will remain constant for the remainder of the forecast. Despite a projected decrease in annual new well connections, production will continue to grow due to production increases from prior connections that are still in the early years of their production life. The previously considered conventional gas portion from recompleted hybrid-identified connections also increases the total production volume.

Figure 4.9 illustrates the ERCB forecast of CBM production to 2019. Production from CBM connections, which includes the commingled conventional gas production from hybrid connections, is expected to increase from 9.0 10^9 m^3 in 2009 to 15.1 10^9 m^3 in 2019. In 2009, CBM production contributed 7 per cent of the total Alberta marketable gas production, and it is projected to contribute 20 per cent of the total Alberta marketable gas production in 2019. CBM and hybrid gas production may be higher than forecast if commercial production from the Mannville play is accelerated.



4.3 Reserves of Shale Gas

Shale gas is natural gas that is found in shale and other related rock types, existing mostly as free gas in the matrix and fractures and as adsorbed gas on organic matter and clays. Shale gas is not restricted to shale, as claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential shale gas strata. Additionally, not all shale has the potential to contain shale gas, as the shale must contain organic matter. Shales are the traditional source rocks for hydrocarbon accumulations, a seal for reservoirs, and more recently a productive reservoir itself of unconventional gas. Typically, these fine-grained rocks have low matrix permeability, and stimulation is required to produce gas from the rock. Currently, the stimulation of shales in Alberta is different from British Columbia and some United States shale plays, as the nature of the geology is more favourable to vertical wells with multiple stimulations in some shallow thick formations (e.g., Colorado shales) and horizontal completions in deeper thin formations have not been tested to date.

Conventional gas occurs as discrete accumulations, or pools, due to the buoyancy of gas that is constrained in structural or stratigraphic traps, whereas shale gas occurs as laterally continuous accumulations, or deposits, with indistinct boundaries. Thus shale gas may occur downdip of conventional pools where oil, gas, and water occur. Shale gas most often occurs within thick deposits of generally fine-grained rock or fine-grained rock interbedded/interlaminated with coarser strata within defined stratigraphic zones.

Based on oil and gas wells, shale is known to underlie most of the province. Shale occurs as layers or beds within a number of zones throughout the stratigraphic column. While individual shale layers or beds within a zone can pinch out and may be discontinuous, shale-rich zones are normally correlated over long distances. All organic-rich shale zones may contain shale gas to some extent, although not necessarily in economic quantities. Shale gas may also be contained in thin silt, sand, and calcareous beds interbedded or interlaminated in shale.

To facilitate more orderly shale gas development, the ERCB released *Bulletin 2009-23: Shale Gas Development—Definition of Shale and Identification of Geological Strata*, which clarified the definition of shale and defined the geological strata from which any gas production will be considered to be shale gas. As part of this clarification, in southeast Alberta, where shallow gas has been considered conventional gas for most of its 40 plus years of production history, the ERCB will not reclassify any gas production as shale gas, as this would be administratively unwieldy. Also, other strata that have some potential for shale gas, but where shale is not the primary lithology, is excluded from the shale gas designation. For example, the Montney Formation is not currently designated as a shale gas unit in Alberta and may not be in the future if there are no productive shale-rich zones. The list of strata may also be modified as additional information becomes available.

Development activities to date for shale gas production have mainly been concentrated in east-central Alberta within the Colorado Group shales. Activity is clustered around the Wildmere area (**Figure 4.10**), where a number of shale gas zones are being commingled. Shale gas activity in the area is based on existing vertical drilling technology for new wells and recompletions of existing wells. Farther west of this area, bordering the foothills belt, there is limited testing within Colorado, Smoky, and Fort St. John shales. In the Northwestern Plains, there are a few wells with limited testing within the Fernie Gordondale (Nordegg) shales.

While the ERCB expects to publish in-place resource estimates in the near future, the estimation of established reserves will likely be delayed until sufficient data are available to conduct a reasonable assessment of shale gas recoverability. The ERCB will monitor the anticipated increased shale gas exploration and development activity for such data. Also, as additional data become available from more areas, the ERCB anticipates that play areas (areas of significant industry activity) of the different deposits will be identified. Additionally, these play areas may be subdivided based on differences in reservoir parameters and production profiles.

4.3.1 Provincial Summary of Shale Gas

There are four major horizons—Colorado, Fernie, Banff/Exshaw, and Woodbend/ Muskwa—with shale gas potential in Alberta (**Figure 4.11**). These four have been included in a number of estimates of shale gas resources in the Western Canada Sedimentary Basin (WCSB), which includes Alberta, Saskatchewan, and British Columbia. The values of the estimates are largely dependent on the methodology, formations used, and extrapolation of data points to a large resource volume. They range from 80 to 30 000 Tcf, and the scale of the estimates, notwithstanding the large variability of the values, proclaims the large potential for shale gas to be added to the provincial resource base.

The ERCB has begun to study these four horizons, together with the Montney Formation, for resource potential. The first step in this process was to collect shale samples in each formation and run a series of tests to understand their geological and geochemical characteristics relating to shale gas. The data generated from the sample program have been released to the public in a number of reports available on the AGS Web site www.ags.gov.ab.ca. A large-scale resource assessment of shale gas potential in Alberta is under way using data generated by the AGS/ERCB and from other public sources.

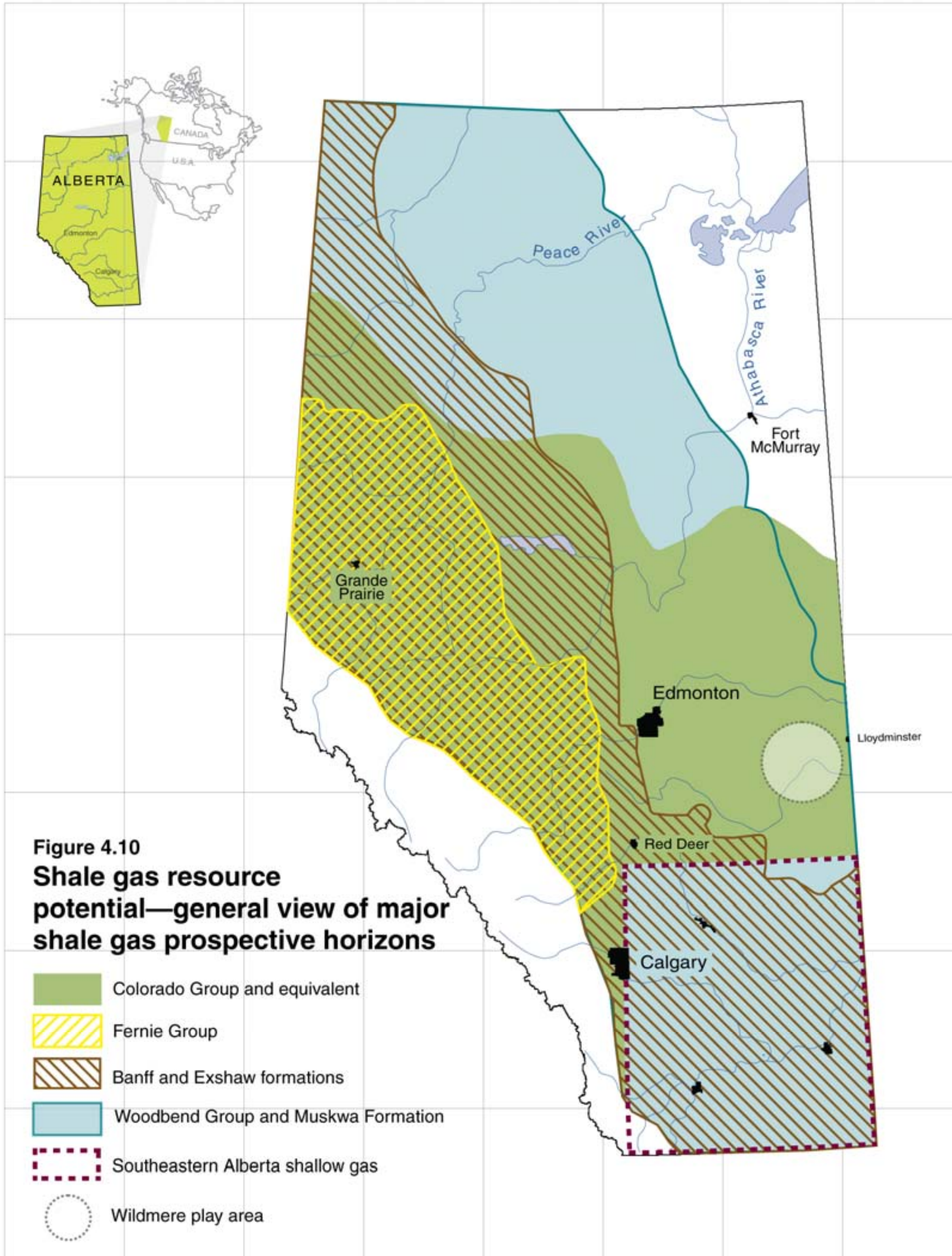
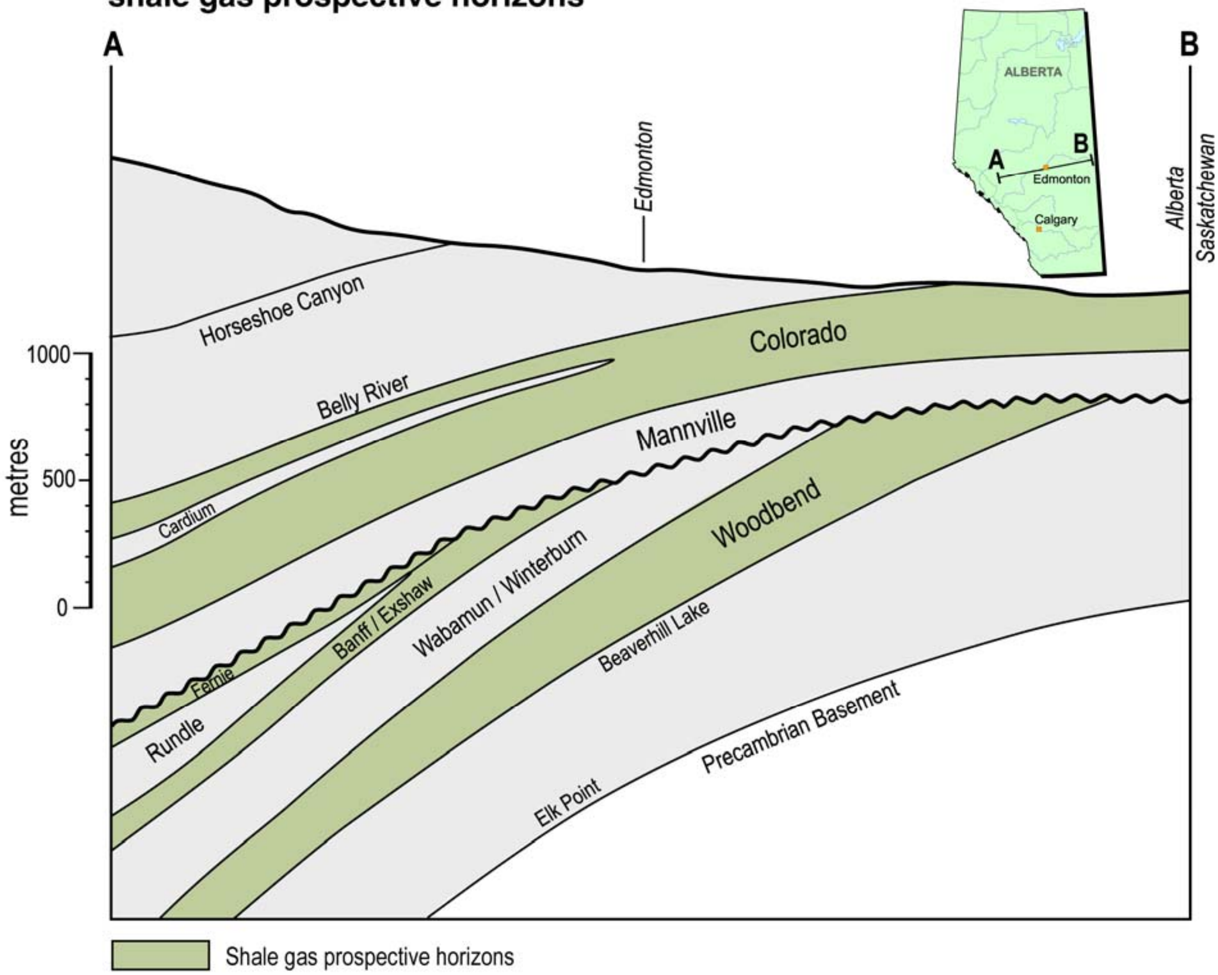


Figure 4.10
Shale gas resource potential—general view of major shale gas prospective horizons

Figure 4.11
General schematic cross-section of central Alberta's significant shale gas prospective horizons



4.3.2 Distribution of Shale Gas Potential by Geologic Strata

The geographic distribution of major potential shale gas horizons is shown in **Figure 4.10** and is described as follows:

- **Shales of the Colorado Group and equivalents** – The shales of the Colorado Group are the most widespread and thickest of any in Alberta. Encased within the Colorado Group shale are well-known producing conventional formations, such as the Viking, Cardium, Dunvegan, and Badheart. The Colorado Group contains both black shale and silty shale with a relatively low organic content. A hybrid play has been proposed by industry for some parts of the Colorado strata where black shale is combined with low organic silty shale and perhaps thin sandstone layers to constitute a hydrocarbon reservoir. The Colorado shale deepens from outcrop in north-central Alberta and is shallow to a few hundred metres where shale gas is being produced and then to a few thousand metres deep in the foothills. The variation in depth means that a number of different types of shale gas plays are possible in Alberta. Biogenic shale gas or a combination of biogenic and thermogenic may be more prospective in eastern and northern Alberta, with thermogenic shale gas more prospective in the deeper areas of the basin.

- **Shales of the Fernie Group** – The Fernie Group shales are well-known source rocks and are very rich in organic matter. The main shales are the Gordondale Member and the Poker Chip Shale Member. The Gordondale Member, informally used where the Nordegg Member is fine-grained and organic rich, is located in west-central and north-central Alberta. In the subsurface of west-central Alberta, the Gordondale Member is 20 to 25 m thick. The Poker Chip Shale Member is located in the eastern foothills and southern Alberta. It may be too thin (2 to 15 m) to be regarded as containing economic quantities of shale gas.

- **Shales of the Banff and Exshaw formations** – The Exshaw shale is a well-known source rock and is very rich in organic matter. The formation is less than 5 to 10 m thick in much of Alberta and as such is probably too thin to presently be regarded as containing economic quantities of shale gas. The lower Banff contains organic-rich black shale that is up to about 5 m thick, but the shale is generally separated from the Exshaw by at least a few metres of limestone, so the drilling prospects for shale gas at present are limited.

- **Shales of the Woodbend Group and Muskwa Formation** – The Duvernay Formation of the Woodbend Group is located south of the Peace River Arch and is a relative equivalent to the Muskwa Formation in northwestern Alberta. The Duvernay is renowned for being a source rock for much of the Leduc and Swan Hills oil and gas fields. Near the foothills, the Duvernay Formation is up to 60 to 70 m thick and is largely composed of carbonate rocks, with the percentage of shale increasing to the east. The Duvernay Formation is generally very rich in organic matter and has excellent potential for shale gas. Geochemical data generated from the sample collection will help distinguish the areas that are gas prone from oil prone. The Muskwa is located in northwestern Alberta, north of the Peace River Arch, and is equivalent to the strata from which shale gas is producing in the Horn River Basin in British Columbia. The Muskwa shale in Alberta is organic rich but may be slightly less mature, thinner, and shallower than equivalent shale in British Columbia. The Muskwa thins to the east and onlaps the Peace River Arch to the south. The top of the Muskwa is diachronous, and eastward of the 6th Meridian the Muskwa merges with the less prospective Fort Simpson shale and carbonates. The most prospective area for Muskwa shale gas is likely north of about Township 100, where the Muskwa thickens to more the 20 m. East of about Range 15W5M, the Muskwa in most areas is too thin (<10 m) to be presently prospective for shale gas.

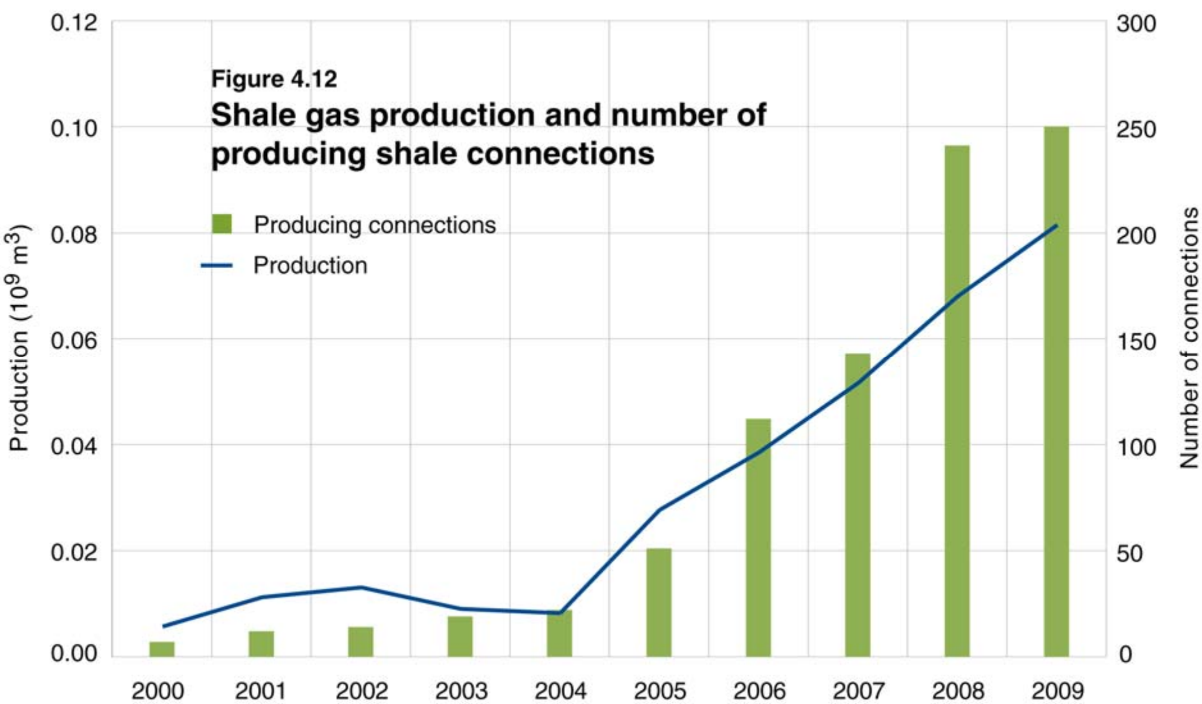
4.3.3 Shale Gas Potential in Mixed Lithology Strata

Strata that are not predominantly shale are considered as mixed lithology strata (see *Bulletin 2009-23*). One such strata of interest is the Triassic Montney Formation, which has received much attention in British Columbia. To date, the activity is within conventional gas in Alberta. Generally over most of British Columbia, the Montney Formation is composed of predominantly shaley deepwater facies that transition into predominantly silty and sandy shallow-water facies in Alberta. Production from sands in the Montney Formation is within a number of conventional gas pools existing in the foothills and northwestern Alberta. Along the western edge of Alberta where the Montney Formation can be greater than 200 m thick, conventional gas pools exist. Here, the organic content throughout the Montney Formation is low (1 to 2 weight per cent), which is still a source rock; however, the silt content is high compared to the more organic-rich-shale-dominated strata to the west. Potential classification as shale gas will be determined in the future on a case-by-case basis.

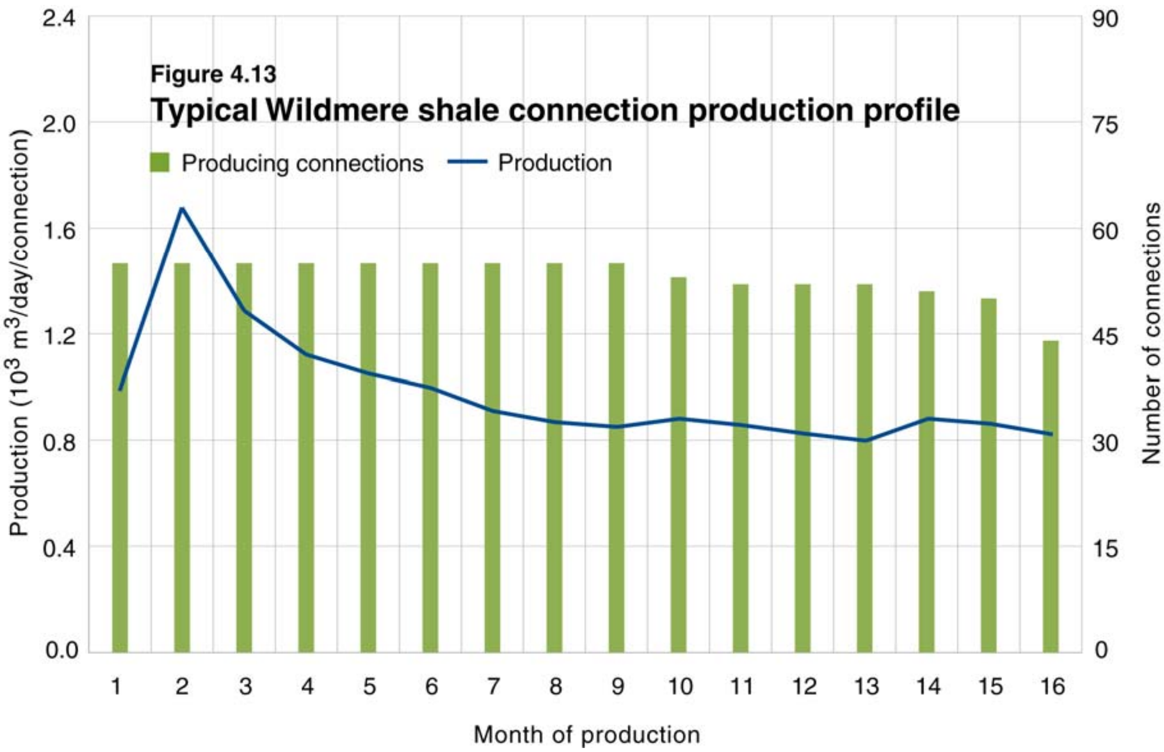
4.4 Supply of Shale Gas

Due to shale gas development being in its early stages in Alberta, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time. Shale gas has the potential to become a significant supply source in Alberta, but commercial shale gas production is in its infancy and it will take more time to establish the producibility of the resource. However, the small number of shale gas connections in the province and their associated production volumes have been identified and are discussed below.

The ERCB currently recognizes 250 producing shale gas connections in 2009, with a total annual production of 0.081 10^9 m^3. This compares to CBM 2009 production of 9.0 10^9 m^3 and conventional natural gas production of 113.9 10^9 m^3 in 2009. Initial productivity of shale connections is calculated using the first full calendar year of production. The current initial productivity rate for all shale gas connections is 1.13 10^3 m^3/day/connection. After the initial production phase, average shale connection productivity then declines to 0.74 10^3 m^3/day/connection. Shale gas production in Alberta from 2000 to 2009 is shown in **Figure 4.12**, along with the number of shale gas connections on production in each year.



Most of the producing shale connections in Alberta are vertical, because the shallow depth and thickness of the shale zones preclude the need for horizontal drilling. The Colorado shale in east-central Alberta, particularly in the Wildmere area, has had the most shale development in the province to date. **Figure 4.13** shows the normalized median production profile for typical Wildmere shale gas connections based on analysis of 55 existing connections. The production profile indicates a rapid production increase, followed by a rapid decline, with production stabilizing thereafter. The decline seems to be less dramatic and flatter than observed in other shale plays.



Shale gas exploration and production, although in its infancy, is anticipated to continue as conventional natural gas production declines, but the pace of development will be affected by the natural gas price environment, supply costs, and technology. Although the economic viability of shale gas development is not clear, the ERCB believes that based on existing technology and the current price forecast, shale gas development is not anticipated to contribute significantly to Alberta's natural gas supply over the forecast period.

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

5 Conventional Natural Gas

Highlights

- Alberta's remaining established conventional natural gas reserves decreased by 3.9 per cent in 2009 to 1056 billion cubic metres.
- Reserve additions as a result of new drilling replaced 54 per cent of conventional gas production.
- Alberta produced 113.9 billion cubic metres of conventional marketable gas in 2009, representing a decrease of 9 per cent from revised 2008 production levels.
- There were 3768 new conventional gas well connections in 2009, down just over 50 per cent from the revised 2008 count for new connections of 7490.

Raw natural gas consists mostly of methane and other hydrocarbon gases, but also contains other non-hydrocarbons, 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 92 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. Liquids that are recovered from gas wells are reported as condensate or gas equivalent. Marketable gas volumes are determined by applying a surface loss or shrinkage factor to the raw gas volume, as described in Section 5.1.8.

Natural gas volumes can be reported as the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or at the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated at 38.9 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for coalbed methane (CBM), which consists mostly of methane. In this section, gas production excludes those volumes of conventional gas that are produced from wells defined by the ERCB as CBM but that produce both CBM and conventional gas.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

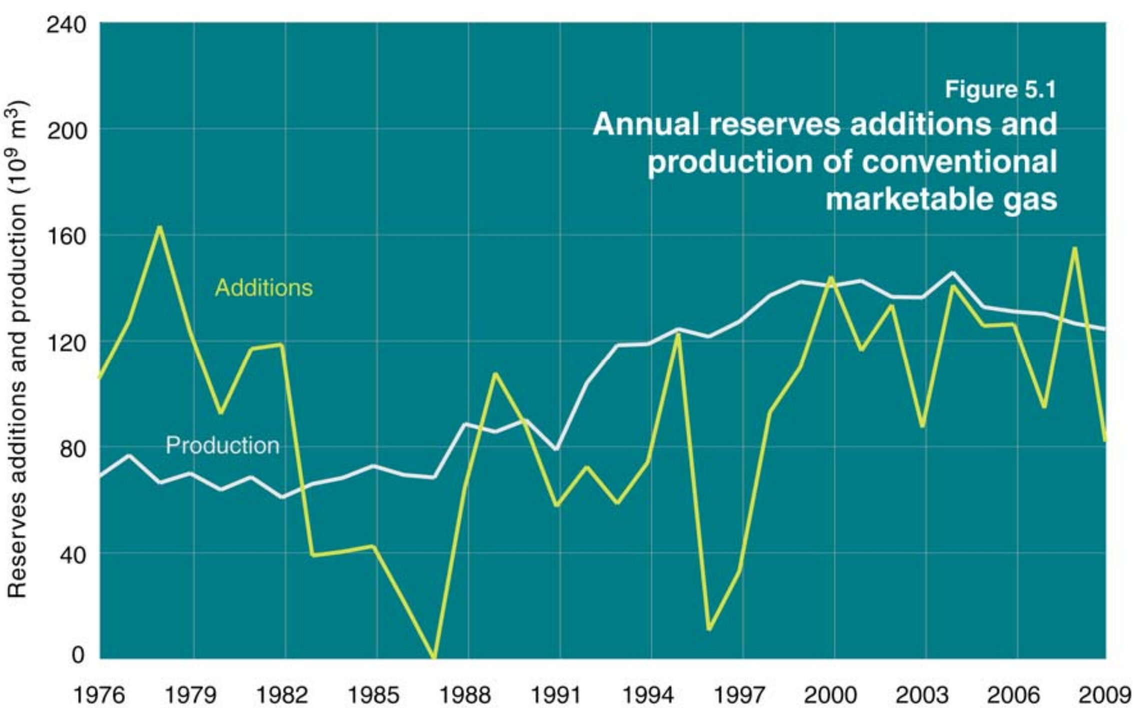
At December 31, 2009, the ERCB estimates the remaining established reserves of marketable gas in Alberta downstream of field plants to be 1056 billion (10^9) m^3, with a total energy content of 41.1 exajoules. This decrease of 42.5 10^9 m^3 since December 31 2008, is a result of all reserves additions less production that occurred during 2009. These reserves include 31.3 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants Removal of NGLs results in a 4.1 per cent reduction in the average heating value from 38.9 MJ/m^3 to 37.3 MJ/m^3 for gas downstream of straddle plants. Details of the changes in marketable reserves during 2009 are shown in **Table 5.1**. Total provincial initial gas in place and raw producible gas reserves for 2009 are 8893.1 10^9 m^3 and 6032.3 10^9 m^3 respectively, which translates to an average provincial recovery factor of 68 per cent. Total initial established marketable reserves is estimated at 5130.7 10^9 m^3, representing an average surface loss of 15 per cent.

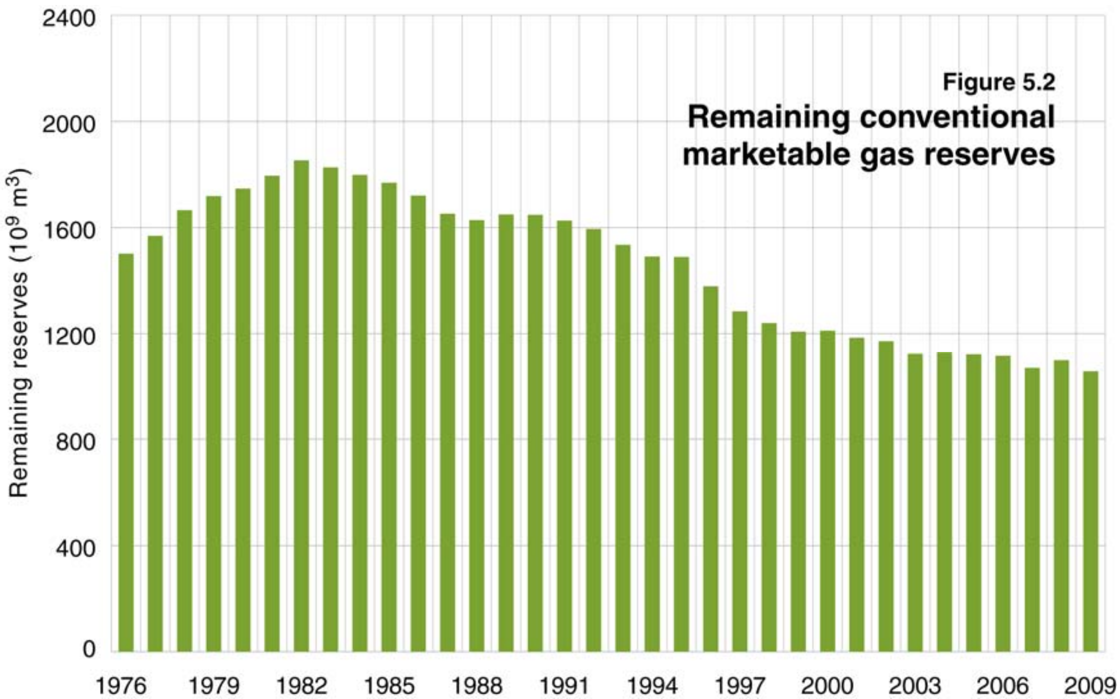
Table 5.1. Reserve and production changes in marketable gas (10^9 m^3 STP)

	Gross heating value (MJ/m^3)	2009 volume	2008 volume	Change
Initial established reserves		5 130.7	5 048.7	+82.0
Cumulative production		4 075.0	3 950.5	+124.5[a]
Remaining established reserves downstream of field plants				
"as is"	38.9	1 055.7	1 098.2	-42.5
at standard gross heating value	37.4	1 098.0	1 142.3	
Minus liquids removed at straddle plants		31.3	32.4	-1.2[d]
Remaining established reserves "as is"	37.3	1 024.5[d] (36.4 Tcf)[b]	1 065.7[d] (37.8 Tcf)[b]	-41.3[d]
at standard gross heating value	37.4	1 021.0	1 062.1	
Annual production	37.4	113.9[c]	125.0	-11.1

[a] May differ from annual production.
[b] Tcf – trillion cubic feet.
[c] Does not include conventional gas from ERCB-defined unconventional wells.
[d] Any discrepancies are due to rounding.

Annual reserves additions and the production of natural gas since 1976 are depicted in **Figure 5.1**. It shows that since 1983, reserves additions have failed to keep pace with production. As illustrated in **Figure 5.2**, Alberta's remaining established reserves of marketable gas have decreased by about 43 per cent since 1982.



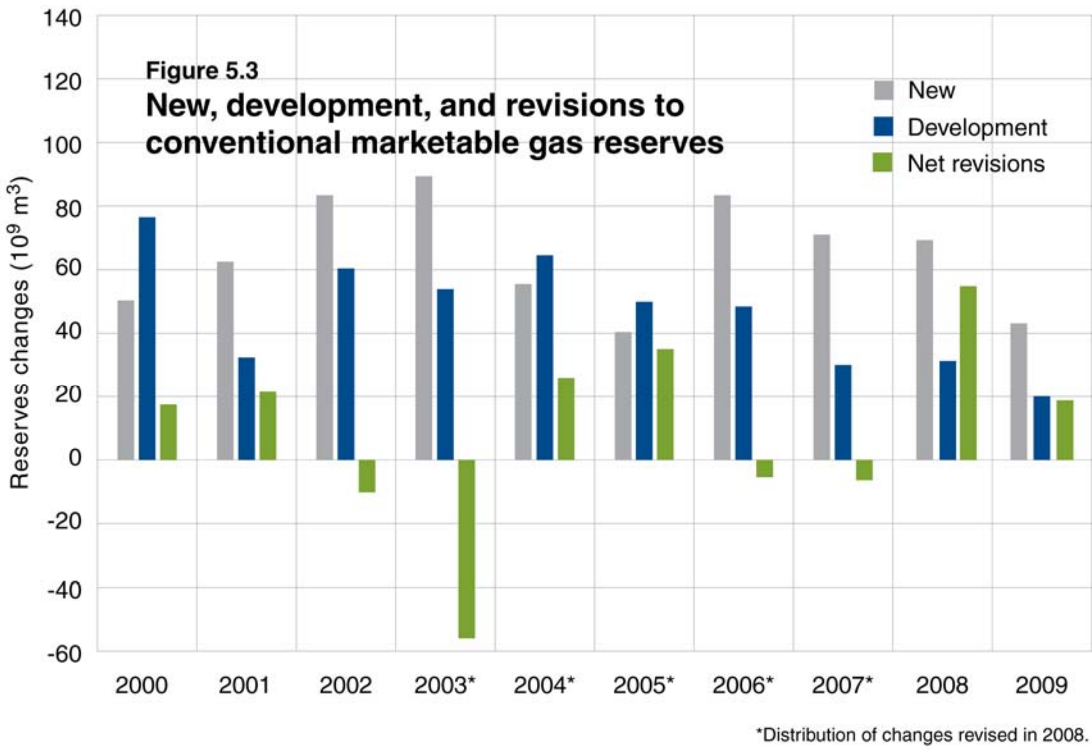


5.1.2 Annual Change in Marketable Gas Reserves

Figure 5.3 shows the breakdown of annual reserves changes into new pools, development of existing pools, and reassessment of reserves of existing pools from 2000 to 2009. Note that the method used to assess new reserves was revised in 2008 to more accurately reflect the reason for change, and amendments to these numbers were made back to 2003. The revised method means that a portion of reserves additions previously considered as positive reassessments to existing pools are now considered as new reserves. The 82.0 10^9 m^3 increase in initial reserves for 2009 includes the addition of 43.1 10^9 m^3 attributed to new pools booked in 2009, 20.1 10^9 m^3 from the development of existing pools, and a net reassessment of 18.8 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 63.2 10^9 m^3, replacing 54 per cent of Alberta's 2009 production. Historical reserves growth and production data since 1966 are shown in **Appendix B**, **Table B.4**.

During 2009, a review of pools that appeared to have reserves under- or overbooked based on their reserves-to-production ratios was conducted, as well as a review of large pools that had not been evaluated for several years. Positive revisions to existing pools totalled 130.2 10^9 m^3, while negative revisions totalled 111.4 10^9 m^3. The major reserves changes are summarized below:

- Some 800 pools were evaluated with low or high reserves life indices, resulting in an overall reserves decrease of 18.2 10^9 m^3.
- The 40 pools with the largest changes listed in **Table 5.2** resulted in a net addition of 31.4 10^9 m^3. This increase in reserves was largely a result of infill drilling and completion of previously undeveloped zones.



- The review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in a reserves decrease of 0.6 10^9 m^3.

- Some 200 associated gas pools were reviewed to more accurately reflect reserves of solution and associated gas in each pool. While many pools were revised, the net change to these reserves was negligible.

Figure 5.4 illustrates marketable gas reserves growth between 2008 and 2009 by Petroleum Services Association of Canada (PSAC) area. The most significant growth was in Area 2, which accounted for 60 per cent of the total annual increase for 2009. Some pools in Area 2 that contributed to this increase in reserves are the Crossfield East Elkton D, Elmworth Commingled MFP9513, Kakwa Commingled Pool 005, Red Rock Commingled MFP9529, Wapiti Commingled MFP9529, and Wild River Commingled MFP9529, for a total reserves increase of 18.1 10^9 m^3.

Table 5.2. Major natural gas reserve changes, 2009

Pool	Initial established reserves (10^6 m^3) 2009	Change	Main reasons for change
Bantry Southeastern Alberta Gas System	36 054	-887	Reevaluation of initial volume in place
Bashaw Commingled MFP9504	6 311	+1 565	Reevaluation of initial volume in place
Bow Island Southeastern Alberta Gas System	2 319	-1 617	Reevaluation of initial volume in place and recovery factor
Burnt Timber Wabamun A	2 750	-500	Reevaluation of initial volume in place and recovery factor
Carrot Creek Commingled Pool 006	2 308	-705	Reevaluation of recovery factor
Cessford Southeastern Alberta Gas System	17 904	-1 037	Reevaluation of initial volume in place
Countess Southeastern Alberta Gas System	68 132	+856	Development and reevaluation of initial volume in place
Crossfield East Elkton A	1 479	+422	Reevaluation of initial volume in place and recovery factor
Crossfield East Elkton D	2 268	+1 184	Reevaluation of initial volume in place and recovery factor
Drumheller Southeastern Alberta Gas System	6 397	+794	Development and reevaluation of initial volume in place
Elkwater Southeastern Alberta Gas System	2 670	-504	Reevaluation of initial volume in place and recovery factor
Elmworth Commingled MFP9513	56 963	+6 498	Reevaluation of initial volume in place
Ferrier Commingled Pool 001	21 870	+638	Reevaluation of initial volume in place and recovery factor
Fisher Commingled Pool 011	9 114	+469	Reevaluation of initial volume in place and recovery factor
Hanlan Commingled Pool 001	32 340	+4 114	Reevaluation of initial volume in place and recovery factor
Jumpbush Southeastern Alberta Gas System	1 558	-462	Reevaluation of initial volume in place
Kakwa Commingled Pool 005	13 650	+2 335	Reevaluation of initial volume in place and recovery factor
Kaybob South Commingled Pool 011	2 430	+735	Reevaluation of initial volume in place and recovery factor
Kirby Upper Mannville S2S	779	+540	Reevaluation of initial volume in place and recovery factor
Lawrence Commingled Pool 001	141	-453	Reevaluation of recovery factor
Medicine Hat Southeastern Alberta Gas System	159 748	+717	Development, reevaluation of initial volume in place, and recovery factor
Newby Commingled Pool 007	90	-473	Reevaluation of initial volume in place and recovery factor

(continued)

Table 5.2. Major natural gas reserve changes, 2009 (concluded)

Pool	Initial established reserves (10^6 m^3) 2009	Change	Main reasons for change
Pendant D'Oreille Commingled MFP9517	6 304	+409	Development and reevaluation of initial volume in place
Pendant D'Oreille Commingled MFP9528	1 543	-599	Reevaluation of recovery factor
Pouce Coupe South Commingled Pool 012	10 893	+864	Development, reevaluation of initial volume in place, and recovery factor
Rainbow South Keg River B	960	+500	Reevaluation of initial volume in place and recovery factor
Red Rock Commingled MFP9529	11 527	+2 185	Development, reevaluation of initial volume in place, and recovery factor
Ricinus West D-3 B	2 930	+631	Reevaluation of recovery factor
Sinclair Commingled MFP9513	14 648	+1 468	Reevaluation of initial volume in place and recovery factor
Suffield Southeastern Alberta Gas System	73 243	+5 257	Reevaluation of recovery factor
Suffield Upper Mannville I	1 410	+922	Reevaluation of initial volume in place and recovery factor
Twining Commingled Pool 001	9 695	+1 255	Reevaluation of initial volume in place and recovery factor
Vulcan Commingled Pool 005	95	-439	Reevaluation of initial volume in place and recovery factor
Wapiti Commingled Pool 011	2 206	404	Reevaluation of initial volume in place and recovery factor
Wapiti Commingled MFP9529	40 791	+2 104	Development, reevaluation of initial volume in place, and recovery factor
Wembley Doig E	1 586	-473	Reevaluation of initial volume in place and recovery factor
Wild River Commingled MFP9529	36 326	+3 787	Development, reevaluation of initial volume in place, and recovery factor
Wild River Nisku B	926	-663	Reevaluation of initial volume in place and recovery factor
Wildcat Hills Rundle A	25 608	+958	Reevaluation of initial volume in place and recovery factor

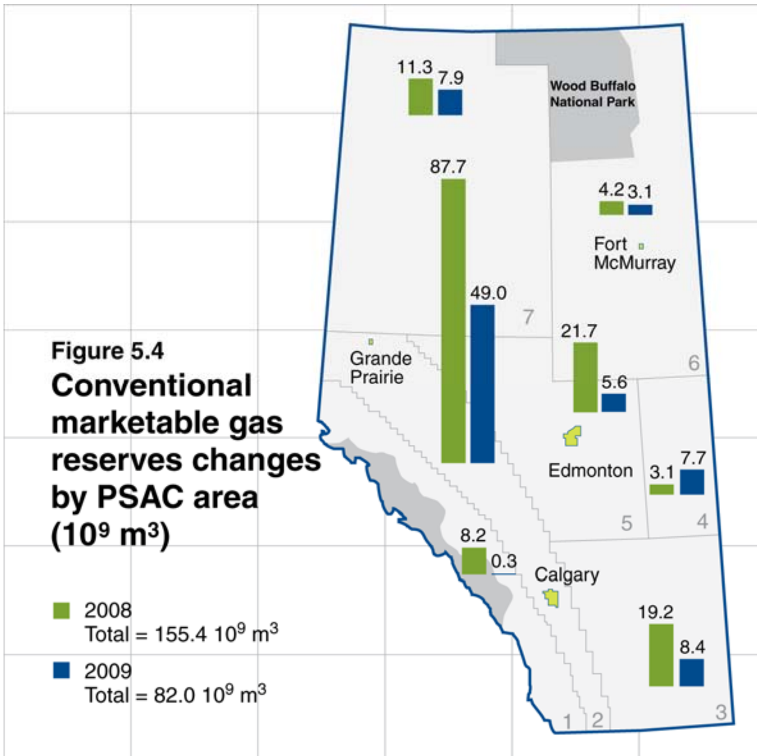


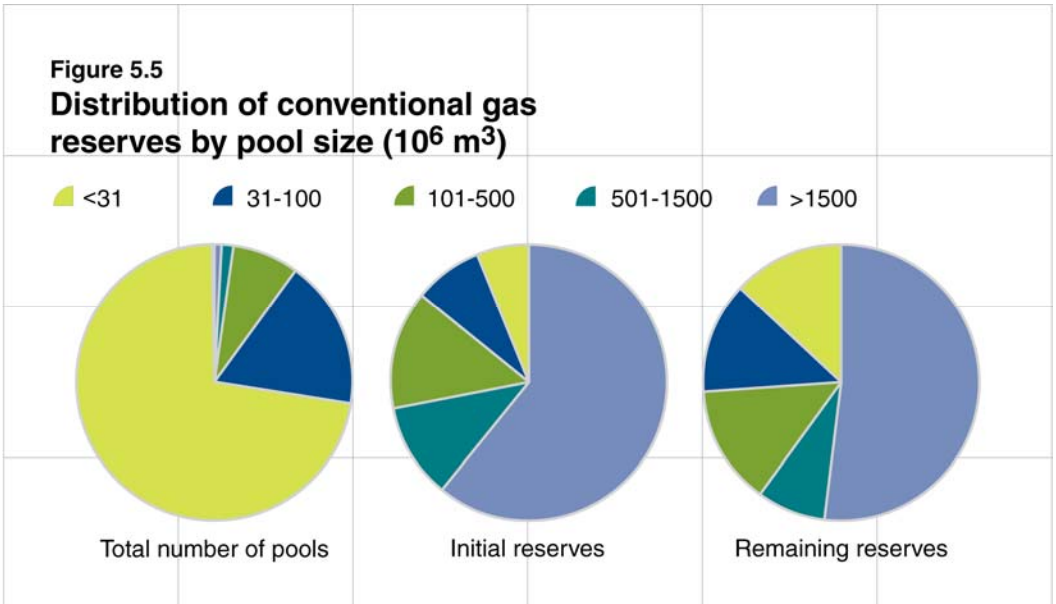
Figure 5.4
Conventional marketable gas reserves changes by PSAC area (10^9 m^3)

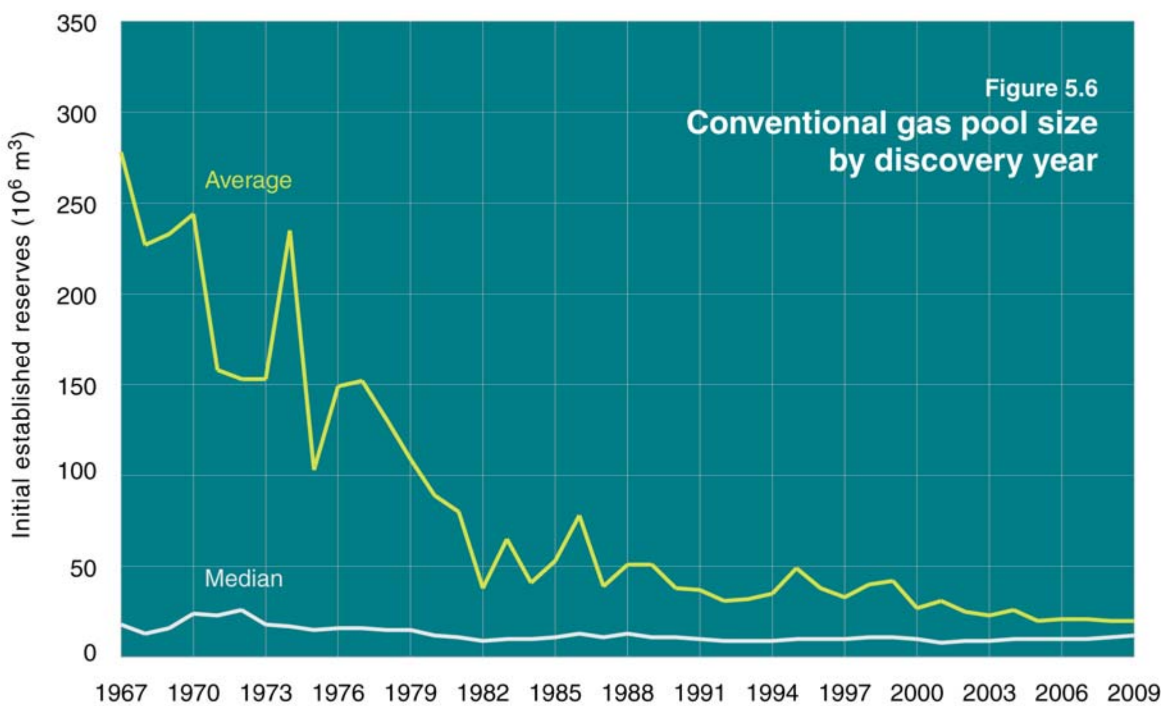
5.1.3 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table 5.3**, and graphically represented in **Figure 5.5**. Commingled pools are considered as one pool, whereas each field in a multifield pool is counted as a separate pool. The data show that pools with reserves of 30 million (10^6) m^3 or less, while representing 72.6 per cent of all pools, contain only 13 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 1500 10^6 m^3, while representing only 1 per cent of all pools, contain 52 per cent of the remaining reserves. **Figure 5.6** depicts natural gas pool size by discovery year since 1967 and illustrates that while the median pool size has remained fairly constant at about 10 10^6 m^3 for many years, the average size declined significantly, from about 250 10^6 m^3 in 1970 to 50 10^6 m^3 in 1995, and has continued to decline to about 20 10^6 m^3 in 2009.

Table 5.3. Distribution of natural gas reserves by pool size, 2009

Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
3000+	216	0.5	2 754	54	484	46
1501-3000	168	0.4	359	7	67	6
1001-1500	173	0.4	212	4	32	3
501-1000	530	1.2	363	7	54	5
101-500	3 486	7.6	713	14	146	14
31-100	8 049	17.5	424	8	138	13
Less than 31	33 433	72.6	306	6	134	13
Total	46 055	100.0	5 131	100	1 056	100

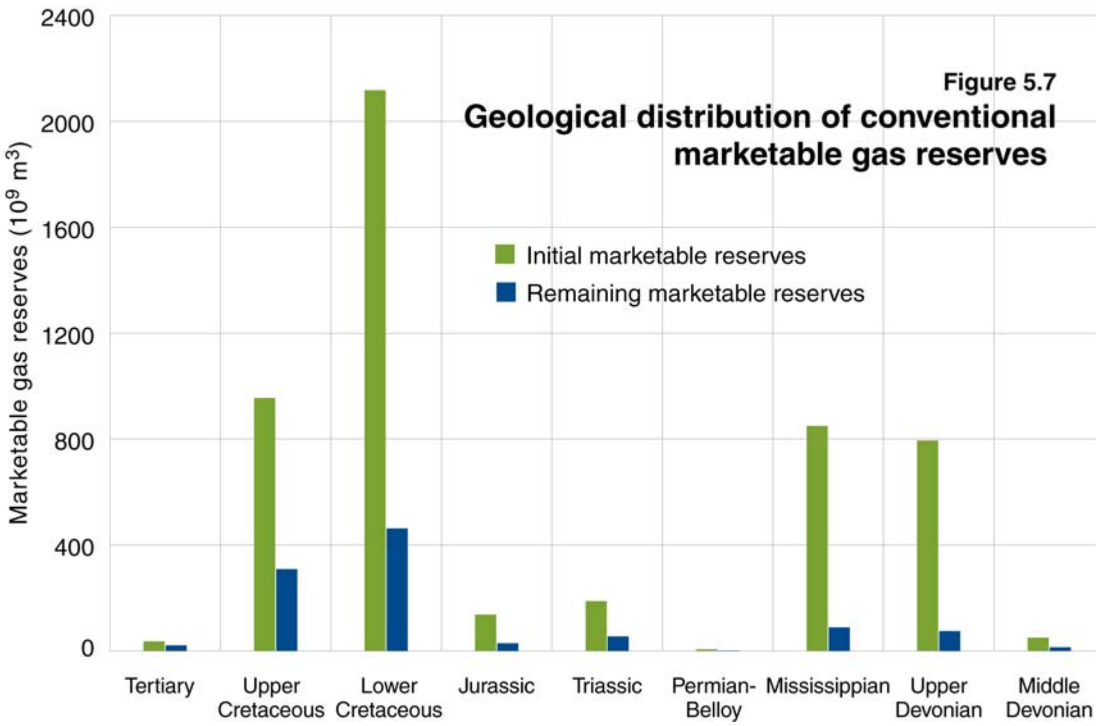




5.1.4 Geological Distribution of Reserves

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

The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 36 per cent, the Upper Cretaceous Belly River, Milk River, and Medicine Hat, with 17 per cent, and the Mississippian Rundle, with 8 per cent. Together, these strata contain 61 per cent of the province's remaining established reserves.



5.1.5 Deep Basin Play Area

Located south of Grande Prairie in northwest Alberta, the Deep Basin is one of the leading natural gas exploration and development areas in western Canada. It is the deepest part of the Western Canada Sedimentary Basin, consisting of a thick, undeformed, and continuous succession of carbonate and siliciclastic rocks ranging in age generally from Devonian to Tertiary. Most Deep Basin plays are abnormally high-pressured, low-permeability, gas-saturated reservoirs that grade updip into porous tight water-saturated rocks, as shown in **Figure 5.8**. This contrast in reservoir qualities between gas- and water-saturated sands created a unique trapping mechanism (water over gas), which is also dynamic as gas generation from coals and shales migrates to the upper layers in a continuous process.

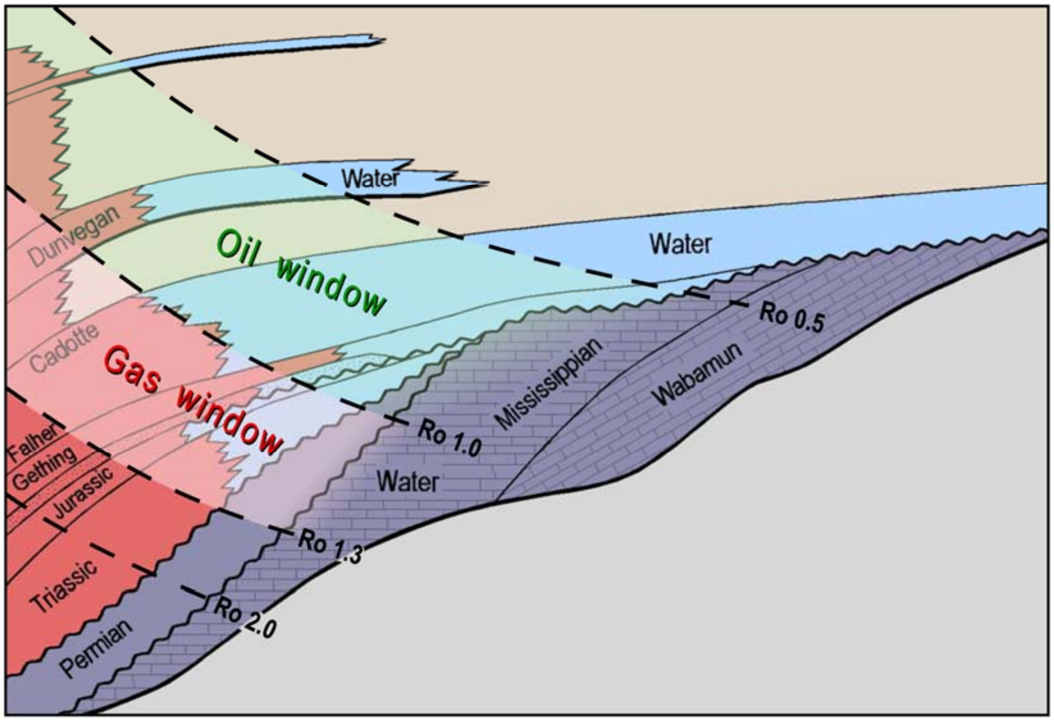
Drilling activity in the Deep Basin has typically targeted sweet, gas-bearing formations of Cretaceous age, such as the Cardium, Cadotte, Falher, Gething, and Cadomin. The main lithologies of these formations are sandstones and shales. High-quality reservoir rocks (e.g., conglomerates) have been the major exploration targets; however, much of gas deposits are found in poor-quality sandstones, which were often bypassed, since producing them was originally considered to be uneconomical.

Increasing activity to develop these and other poor-quality reservoirs triggered an industry request to lessen the regulatory burden of commingling in these plays in an effort to improve the project economics.

In 2006, the ERCB issued orders creating two development entities (DE No. 1 and DE No. 2),[1] which eliminated the need to apply for commingling of certain formations. This

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

Figure 5.8
Deep Basin gas trap



has enabled operators to produce reserves from zones that would otherwise have been uneconomic to produce on their own. Further details on development entities are in *Bulletin 2006-38: Implementation of Development Entities for Management of Commingled Production from Two or More Pools in the Wellbore.*

DE No. 2 as first introduced in 2006 covered the Deep Basin stratigraphy from the top of the Smoky Group to the base of the Nikanassin Formation and geographically extended from Grande Prairie to Edson, encompassing 275 townships. Its purpose was to enable increased and more efficient exploitation of the Deep Basin gas plays and to maximize economic recovery of gas resources. The success of DE No. 2 has been demonstrated by increased drilling activity, reduced operating costs, and enhanced well productivity.

The realized benefits from the DEs led to the desire to revise DE No. 2. Cooperative work by the ERCB and industry resulted in the expansion of DE No. 2 boundaries (192 additional townships) and the addition of the Rock Creek Member to the designated strata. The updated order was approved and released in April 2009, as shown in **Figure 5.9**.

DE No. 2 has been proven to be a successful project for the industry as well as the ERCB. It allows companies to drill and produce more gas, and the decreased number of commingling applications allows the ERCB to manage its work more effectively and minimize the turn-around time for other commingling applications.

5.1.6 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, 2009, sour gas accounts for some 20 per cent (211 10^9 m^3) of the province's total remaining established reserves and about 22 per cent

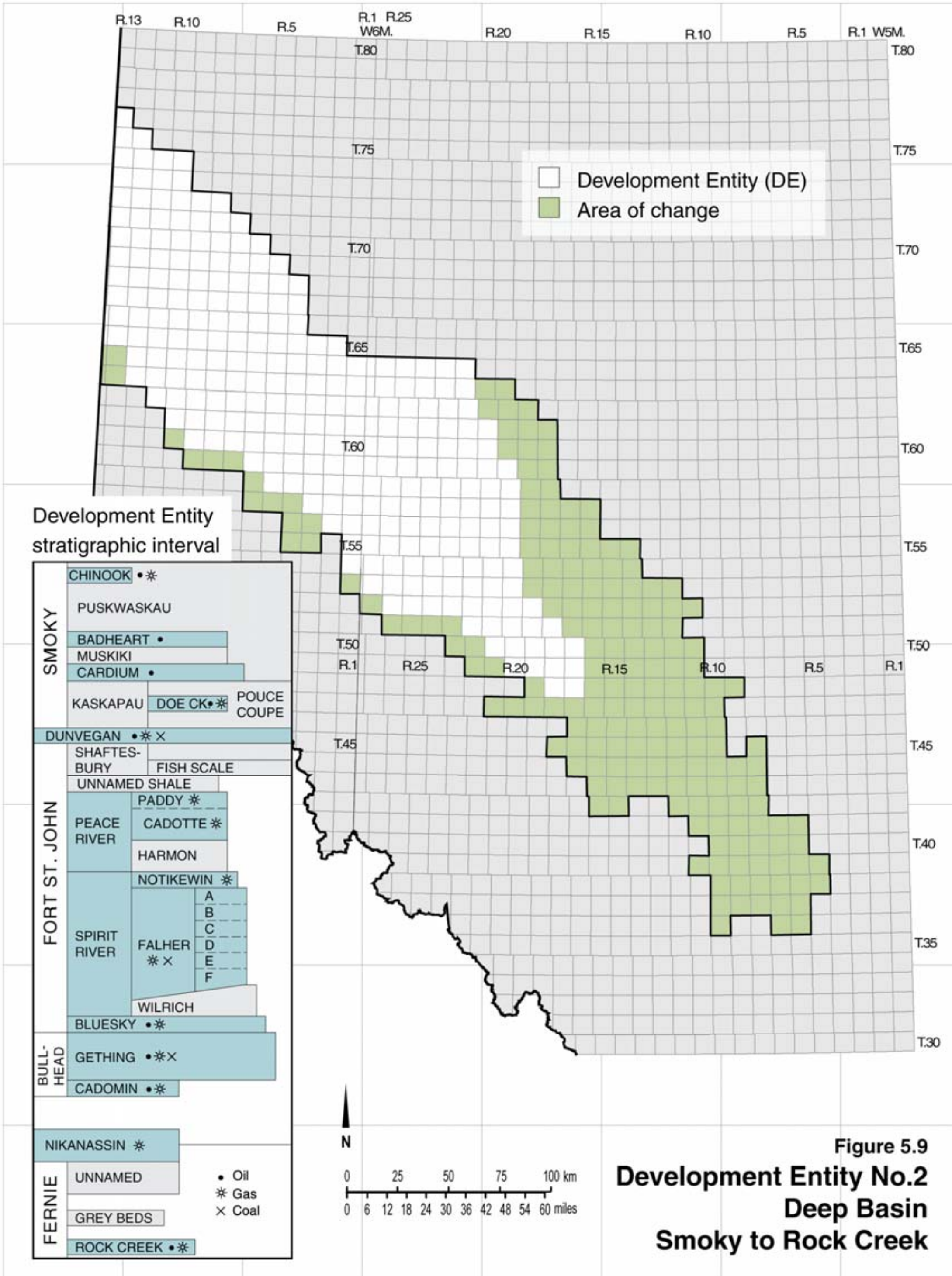


Figure 5.9
Development Entity No.2
Deep Basin
Smoky to Rock Creek

of raw natural gas production in 2009. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2009 is 8.6 per cent.

The distribution of reserves of sweet and sour gas (**Table 5.4**) shows that 147 10^9 m^3, or about 70 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 5.10** 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 37 10^9 m^3, or 18 per cent, of sour gas contains H_2S concentrations greater than 10 per cent, while 54 per cent (114 10^9 m^3) contains concentrations of less than 2 per cent.

5.1.7 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 19.4 10^9 m^3 (1.8 per cent) of remaining gas reserves. The four largest pools are Harmattan East Commingled Pool 001, Valhalla MFP8524 Halfway, Waterton Rundle-Wabamun A, and Wembley MFP8524 Halfway, which together account for over 60 per cent of all remaining reserves of gas cycling pools. Surface loss and recovery factor are calculated on an energy basis in cycling pools. Reserves of major gas cycling pools are tabulated on both an energy content and a volumetric basis in **Appendix B**, **Table B.5**. The table also lists raw and marketable gas heating values used to convert from a volumetric to an energy basis. The detailed reservoir parameters of these pools are included in the Gas Reserves and Basic Data table, which is on the companion CD to this report (see **Appendix C**).

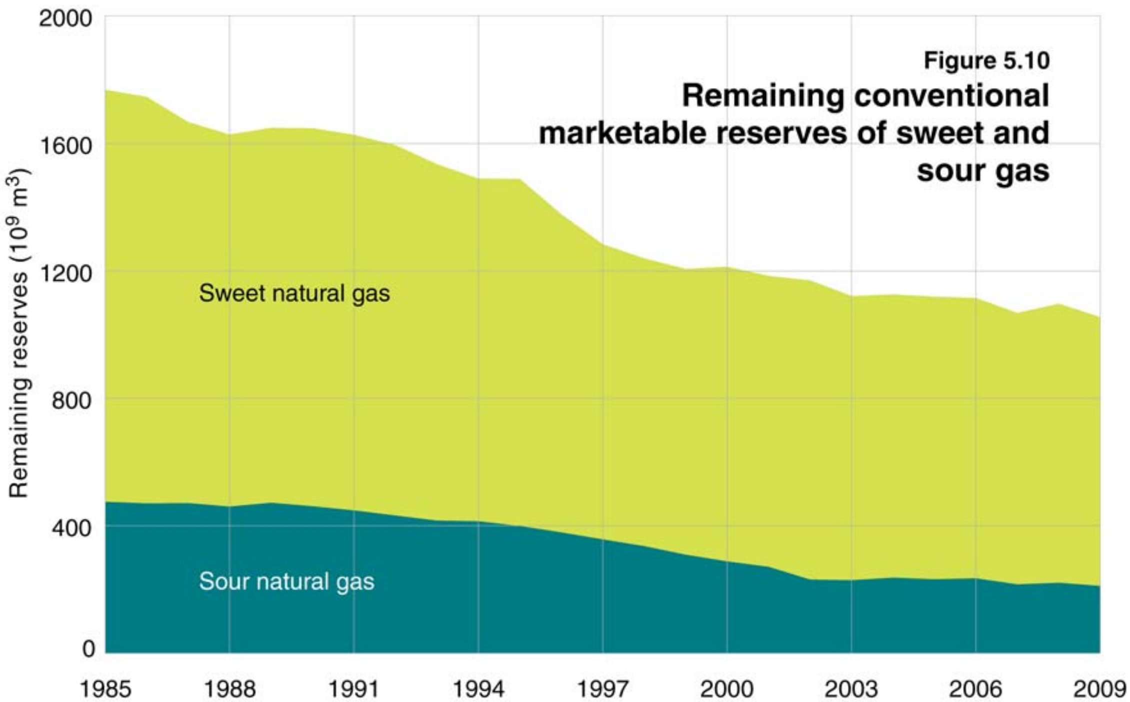
Table 5.4. Distribution of sweet and sour gas reserves, 2009

	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	862	673	189	17	18
Nonassociated	2 590	1 934	656	50	62
Subtotal	3 452	2 607	845	67	80
Sour					
Associated & solution	496	432	64	10	6
Nonassociated	1 183	1 036	147	23	14
Subtotal	1 679	1 468	211	33	20
Total	5 131 (182)[b]	4 075 (145)[b]	1 056[a] (37.5)[b]	100	100

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

Table 5.5. Distribution of sour gas reserves by H_2S content, 2009

	Initial established reserves (10^9 m^3)		Remaining established reserves (10^9 m^3)			
H_2S content in raw gas (%)	Associated & solution	Nonassociated	Associated & solution	Nonassociated	Total	%
Less than 2	368	426	51	63	114	54
2.00-9.99	87	398	7	52	59	28
10.00-19.99	30	207	4	16	20	10
20.00-29.99	11	49	1	7	8	4
Over 30	0	102	0	9	9	4
Total	496	1 183	64	147	211	100
Percentage	30	70	30	70		



5.1.8 Reserves and Accounting Methodology for Gas

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

The process of determining reserves depends on geological, engineering, and economic considerations. The initial estimates contain some uncertainty, which decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculation, which uses bulk rock volume (based on isopach maps derived from geological and geophysical well log data) and initial reservoir parameters to estimate gas in place at reservoir conditions. For single-well pools, drainage area assignments for gas pools are automatically set using criteria outlined in the ERCB's internal report *Alberta Single-Well Gas Pool Drainage Area Study* (December 2004), which is on the ERCB Web site www.ercb.ca. Drainage areas range from 200 hectares (ha) for gas wells producing from regional sands with good permeability to 32 ha or less. The smaller areas are assigned to wells producing from low-permeability formations (less than 1 millidarcy) or geological structures limited in areal extent.

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

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

The procedures described above generate an estimate for initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants, as shown in **Figure 5.11**. 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 reserves numbers published by the ERCB represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric estimates, production decline analysis, and material balance analysis.

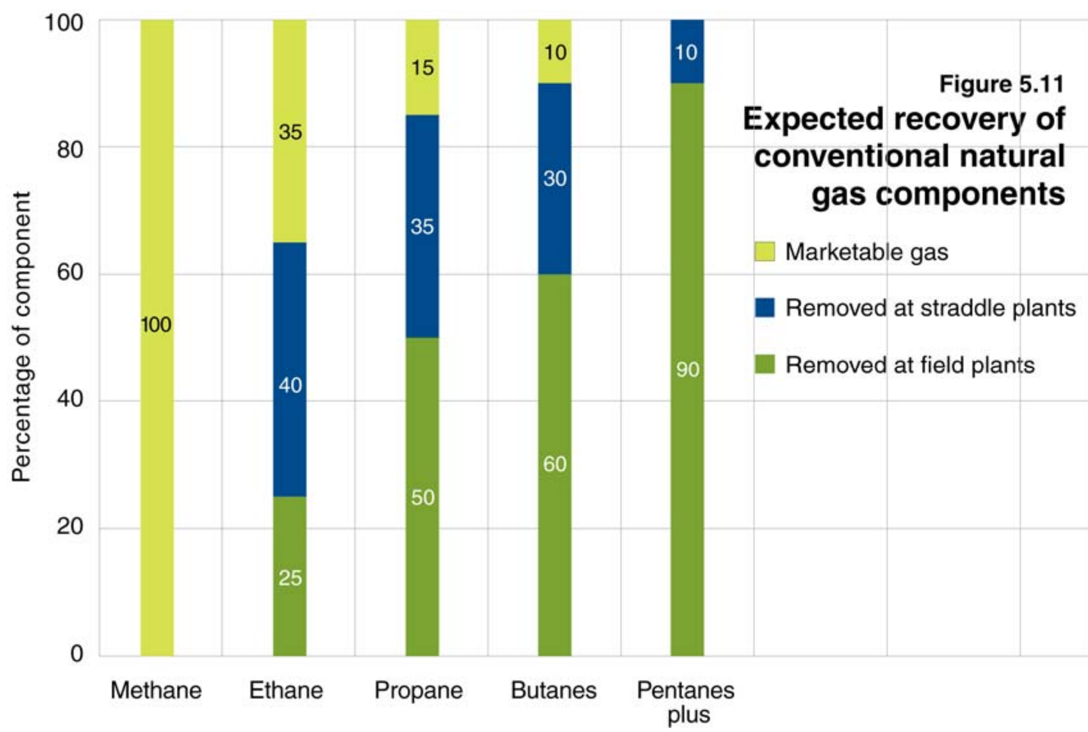


Figure 5.11
Expected recovery of conventional natural gas components

For about 80 per cent of Alberta's marketable gas, additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago on the Alliance Pipeline and some of the dry southeastern Alberta gas. As the removal of these liquids cannot be attributed to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These reserves therefore represent the volume and average heat content of gas after removal of liquids from both field and straddle plants.

It is expected that some 31.3 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 1055.7 10^9 m^3 to 1024.5 10^9 m^3 and the thermal energy content from 41.1 to 38.2 exajoules (10^9 joules).

Figure 5.11 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.

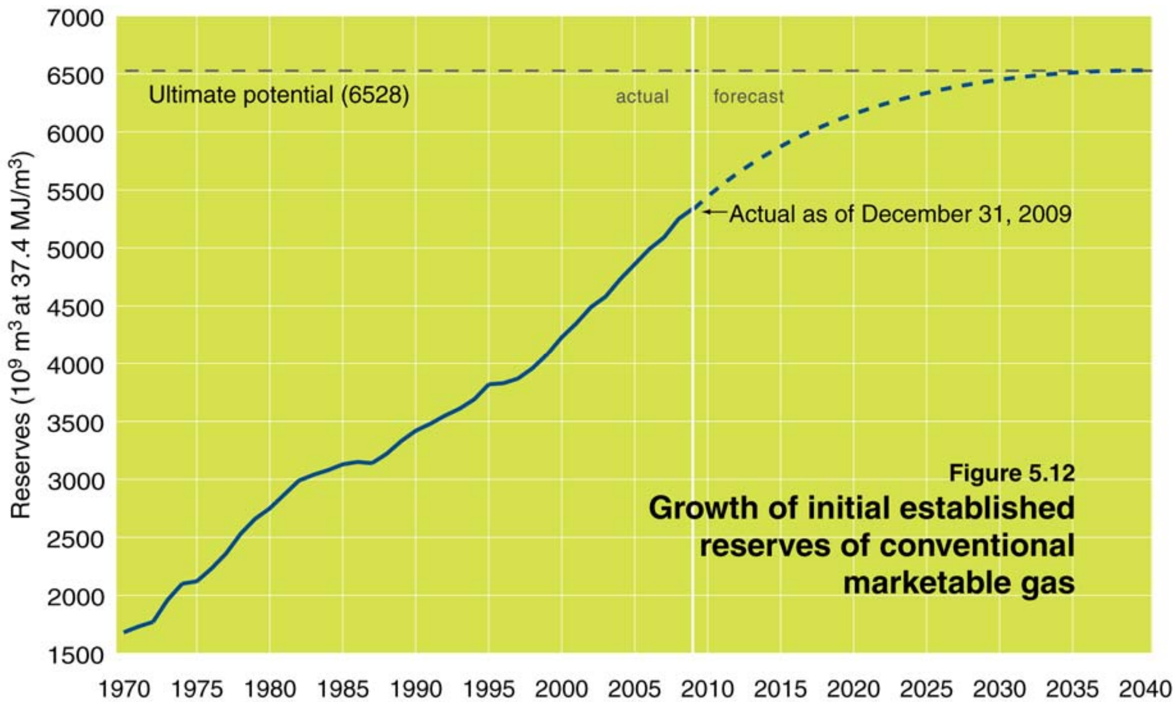
5.1.9 Multifield Pools

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

5.1.10 Ultimate Potential

In March 2005, the EUB and the National Energy Board (NEB) jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas* (EUB/NEB 2005 Report), an updated estimate of the ultimate potential for conventional natural gas. The boards adopted the medium case representing an ultimate potential of 6276 10^9 m^3 as-is volume (223 Tcf) or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3. This estimate does not include unconventional gas, such as CBM. **Figure 5.12** shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth to 2009 equals 5336 10^9 m^3. **Figure 5.13** plots production and remaining established reserves of marketable gas compared to the estimate of ultimate potential.

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 5131 10^9 m^3, or 82 per cent of the ultimate potential of 6276 10^9 m^3 (as-is volumes) has been discovered as of year-end 2009. This leaves 1145 10^9 m^3, or 18 per cent, as yet-to-be-discovered reserves. Cumulative production of 4075 10^9 m^3 at year-end 2009 represents 65 per cent of the ultimate potential, leaving 2201 10^9 m^3, or 35 per cent, available for future use.


Reserves (10^9 m^3 at 37.4 MJ/m^3)
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1970
1975
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
2040
Ultimate potential (6528)
actual
forecast
Actual as of December 31, 2009
Figure 5.12
Growth of initial established reserves of conventional marketable gas

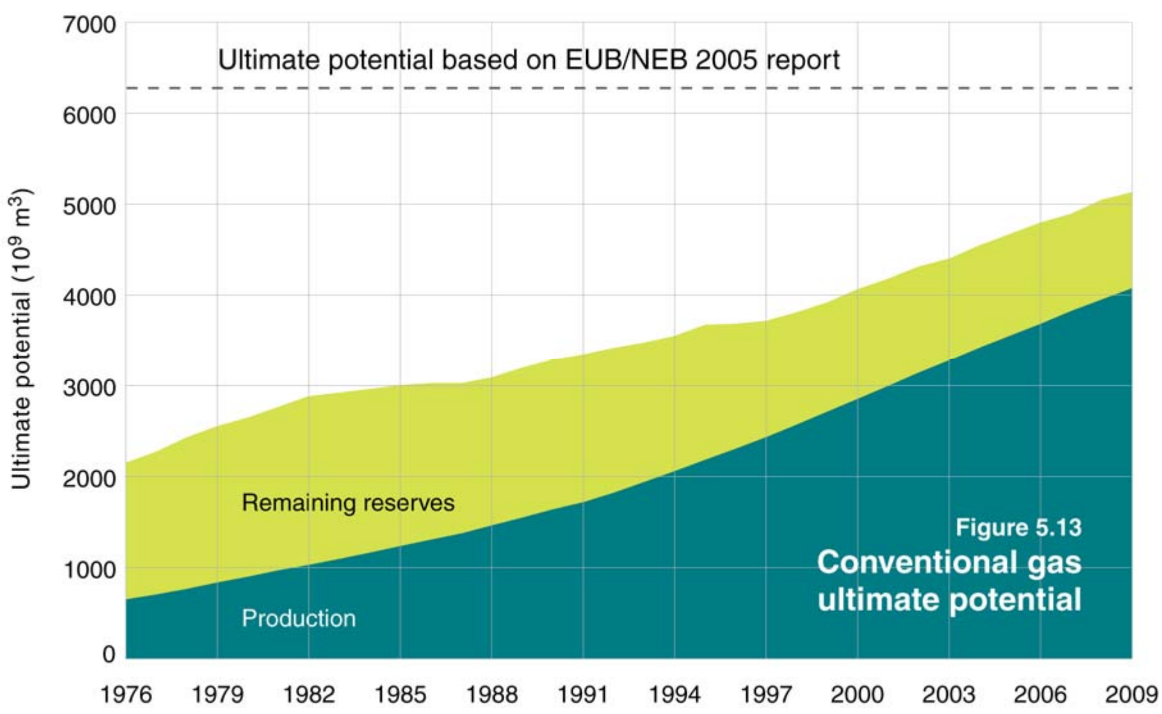

Ultimate potential (10^9 m^3)
7000
6000
5000
4000
3000
2000
1000
0
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
Ultimate potential based on EUB/NEB 2005 report
Remaining reserves
Production
Figure 5.13
Conventional gas ultimate potential

Table 5.6. Remaining ultimate potential of marketable gas, 2009 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m³)	at 37.4 MJ/m³
Yet to be established		
Ultimate potential	6 276	6 528
Minus initial established	–5 131	–5 336
	1 145	1 192
Remaining established		
Initial established	5 131	5 336
Minus cumulative production	–4 075	–4 238
	1 056	1 098
Remaining ultimate potential		
Yet to be established	1 145	1 192
Plus remaining established	+1 056	+1 098
	2 201	2 290

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure 5.14**. It shows that the Western Plains (Area 2) contains 36 per cent of the remaining established reserves and 21 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 5.14** shows that based on the EUB/NEB 2005 Report, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in the Western Plains.

Figure 5.15 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.

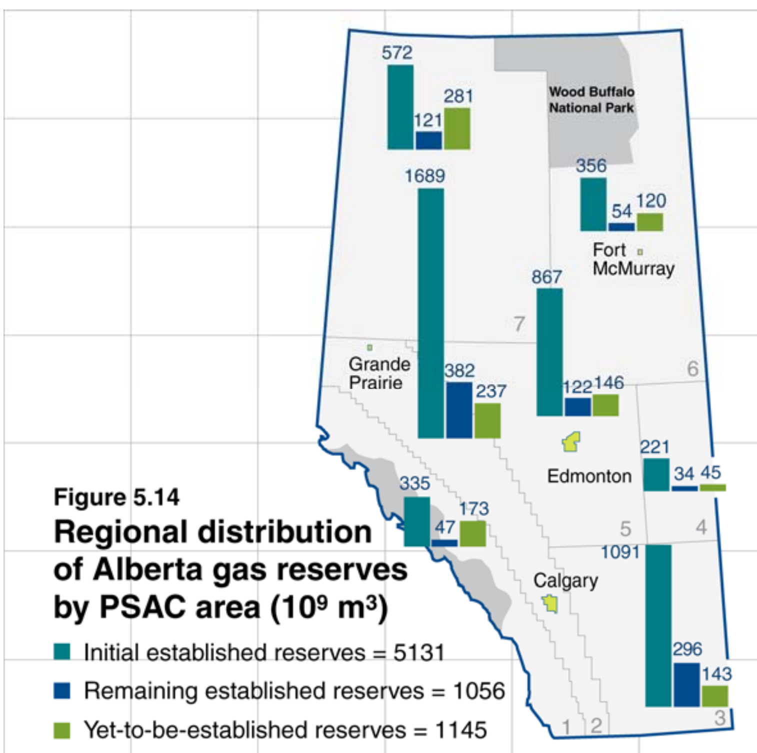
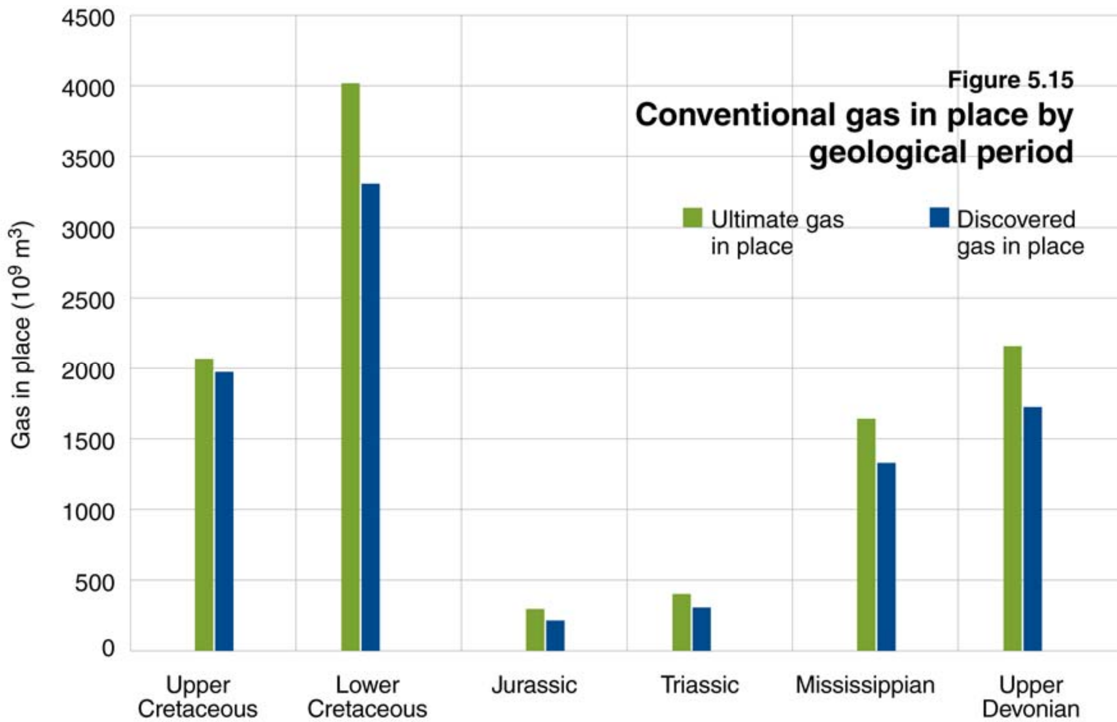


Figure 5.14
Regional distribution of Alberta gas reserves by PSAC area (10^9 m^3)



5.2 Supply of and Demand for Conventional Natural Gas

5.2.1 Conventional Natural Gas Supply

The number of conventional gas connections in a given year historically tended to follow natural gas well drilling activity, indicating that most natural gas wells were connected shortly after being drilled. Recently, however, well recompletions and commingling in existing conventional gas wells have increased connection counts and production without increasing drilling. This trend indicates that well connections, rather than just drilling activity, will more accurately represent the conventional gas environment in Alberta, and therefore this section discusses conventional gas well connections, not drilling activity, as done previously.

In 2009, Alberta produced 113.9 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from conventional gas and oil connections, a decrease of 9 per cent from 2008. The total marketable natural gas production in Alberta in 2009, including unconventional production, was 123.0 10^9 m^3.

Major factors affecting Alberta natural gas production are natural gas prices and their volatility, basin maturity, drilling and connection activity, the location of Alberta’s reserves, well production characteristics, and market demand. In 2009, natural gas prices in Alberta averaged $3.65 per gigajoule (GJ), beginning at a high of $5.77/GJ in January and falling to $2.48/GJ in September as a result of the gas supply demand imbalance in North America. By December, when cold weather conditions increased gas demand, prices rose back up to $4.51/GJ. The 4 per cent growth in U.S. gas production between 2008 and 2009, in conjunction with weakening demand and excess storage volumes, significantly contributed to low natural gas prices throughout 2009. These factors, combined with Alberta’s relatively high drilling and development costs, resulted in decreased investment in Alberta’s conventional gas development, leading to reduced levels of conventional gas drilling activity and accelerating Alberta's already declining natural gas production.

The conventional marketable natural gas production volumes for 2009 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. Conventional marketable natural gas volumes (10^6 m^3)

Conventional marketable gas production	2009
Total gas production	146 631.6
Minus production from CBM connections	-8 952.7
Minus production from shale connections	- 81.3
Total conventional raw gas production	137 597.6
Minus storage withdrawals	-5 953.9
Raw gas production	131 643.7
Minus injection total	-8 841.8
Net raw gas production	122 801.9
Minus processing shrinkage – raw	-7 721.5
Minus flared – raw	- 460.9
Minus vented – raw	- 411.7
Minus fuel – raw	-11 233.7
Plus storage injections	6 585.1
Calculated marketable gas production at as-is conditions	109 559.2
Conventional marketable gas production at 37.4 MJ/m^3	113 941.6

The number of new conventional gas connections in Alberta in the last two years is shown in **Figure 5.16** by a geographical delineation set by the PSAC. Previously, the ERCB used a modified version of this breakdown, but is now incorporating the PSAC definition. Gas connections include recompletions, commingling within existing wellbores, and tie-ins of new drilled wells. In 2009, 3768 conventional gas zones were connected in the province, a decrease of 50 per cent from 2008 levels. This is the third straight year of significant reductions in conventional gas connections.

Figure 5.17 illustrates the initial average daily production rates for conventional gas connections by PSAC area. Initial average daily production rates per connection are calculated using the first full calendar year of production. Initial production rates range from 1.77 thousand (10^3) m^3/day/connection in PSAC Area 3 (Southeastern Alberta) to 49.8 10^3 m^3/day/connection in PSAC Area 1 (Foothills). For the last decade, conventional gas activity has focused on the shallow gas plays in PSAC Area 3 due to the lower cost of drilling, existing infrastructure, and short tie-in times, despite the low production rates of these connections.

Figure 5.18 illustrates the number of total producing conventional gas connections and the average daily connection productivity by PSAC area. Total average daily connection productivity is calculated using the total number of producing connections in the year by PSAC area and the total annual production for each PSAC area. These average productivity rates have been declining over time. The ERCB believes these rates are indicative of future production volumes.

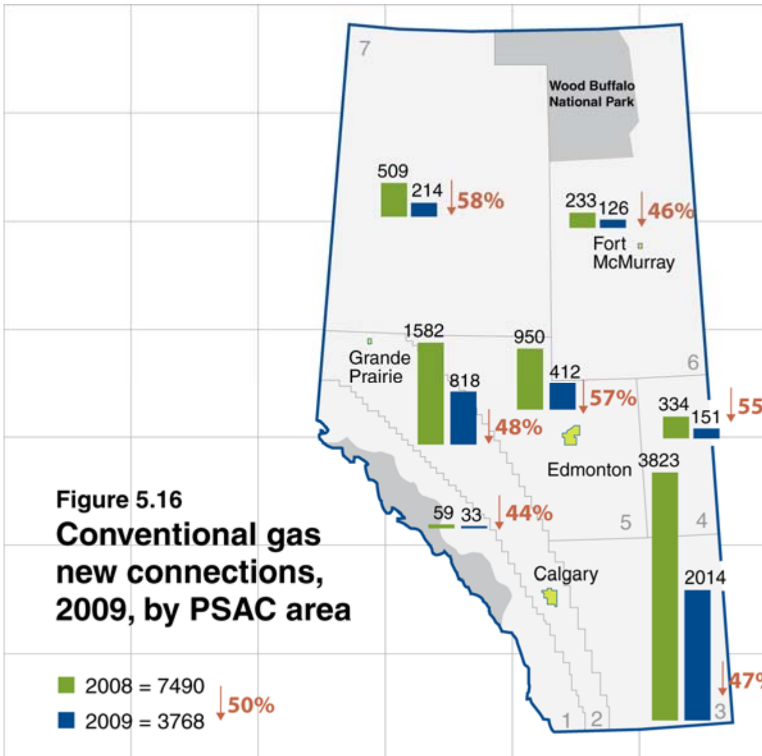


Figure 5.16
Conventional gas new connections, 2009, by PSAC area

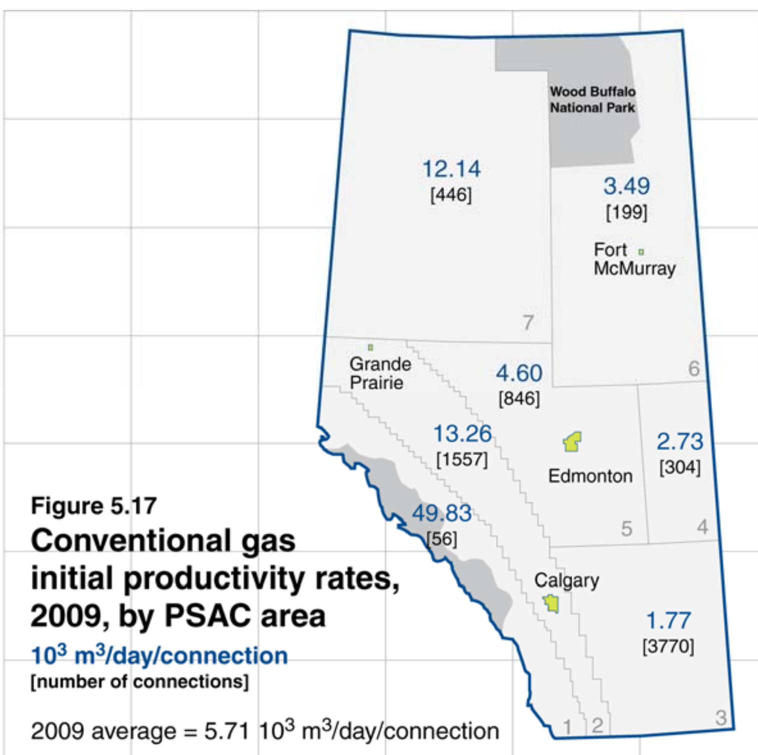


Figure 5.17
Conventional gas initial productivity rates, 2009, by PSAC area
10^3 m^3/day/connection
[number of connections]
2009 average = 5.71 10^3 m^3/day/connection

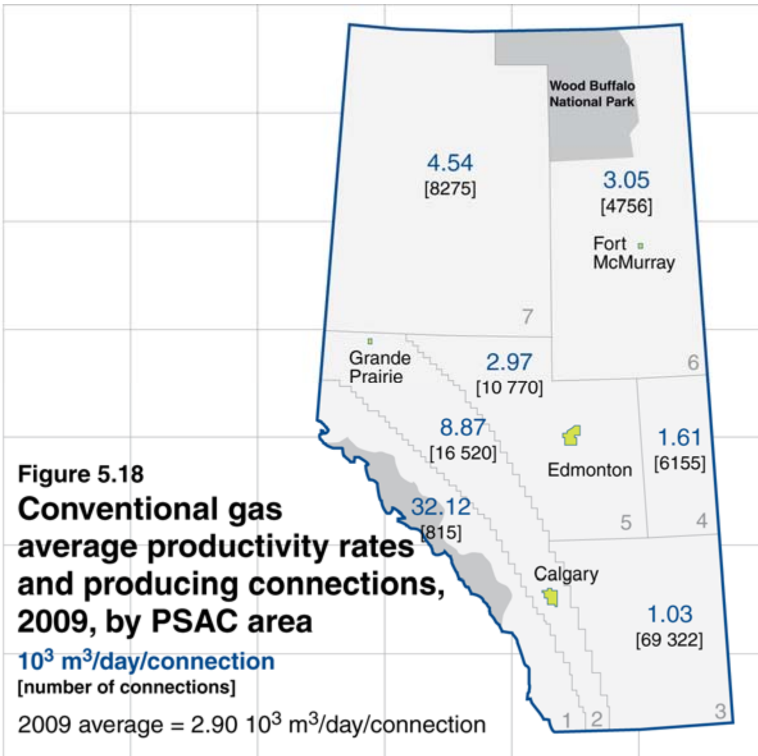


Figure 5.18
Conventional gas average productivity rates and producing connections, 2009, by PSAC area
10^3 m^3/day/connection
[number of connections]
2009 average = 2.90 10^3 m^3/day/connection

As shown in **Figure 5.19**, 81 519 producing conventional gas connections, or about 70 per cent, produce less than 2 10^3 m^3/day. In 2009, these conventional gas connections produced at an average rate of 0.7 10^3 m^3/day/connection, less than 18 per cent of the total natural gas production. Less than 1 per cent of the conventional gas connections produced at rates over 50 10^3 m^3/day but contributed 19 per cent of total production.

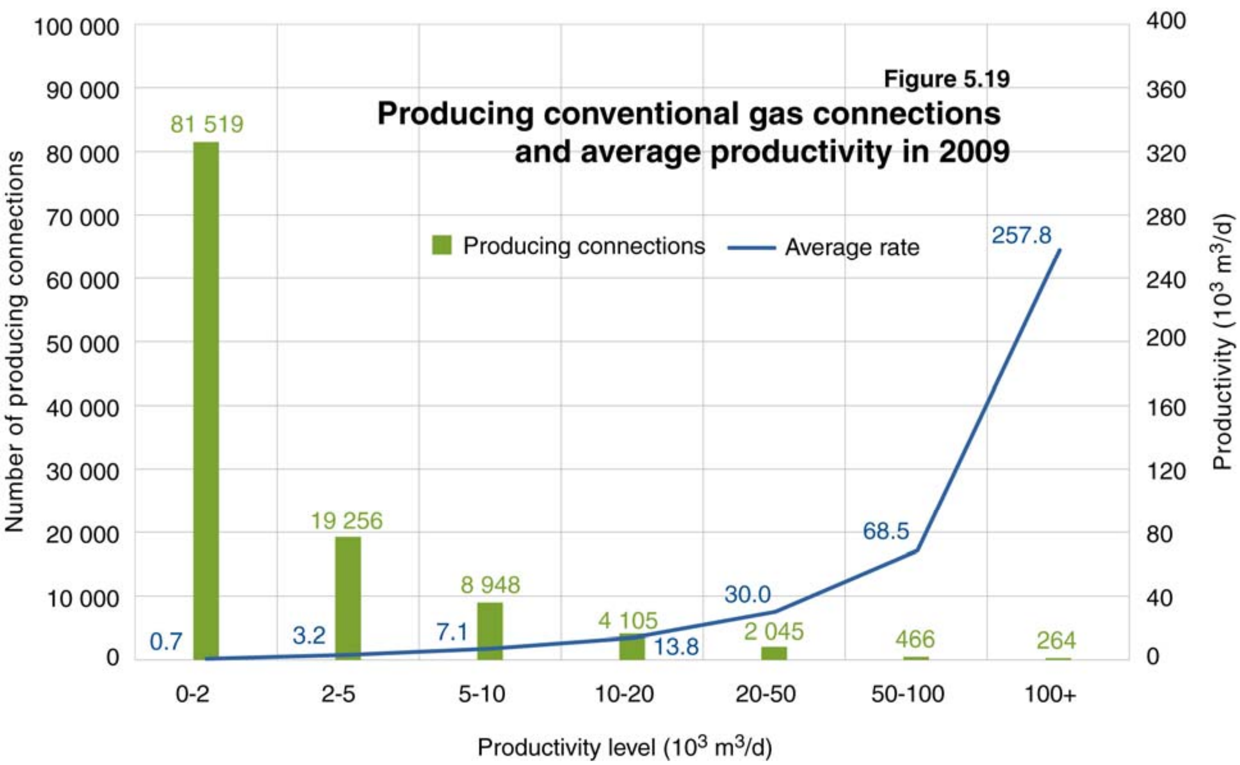


Figure 5.19
Producing conventional gas connections and average productivity in 2009

The historical conventional raw gas production by connection year is presented in **Figure 5.20**. Natural gas production from oil wells has remained relatively stable. Each band represents production from new conventional gas connections by year. The percentages on the right-hand side of the figure represent the share of that area's production to the total production from conventional gas connections in 2009. For example, 7 per cent of gas production in 2009 came from the connections in 2009 and 45 per cent of gas production in 2009 came from the connections of the last five years. The figure also illustrates the production decline in connections that are at least a decade old. Since 2001, natural gas production has been declining, and from 2006 onward, the drop has been accelerated due to the decline in productivity over time and fewer new connections, particularly in 2009.

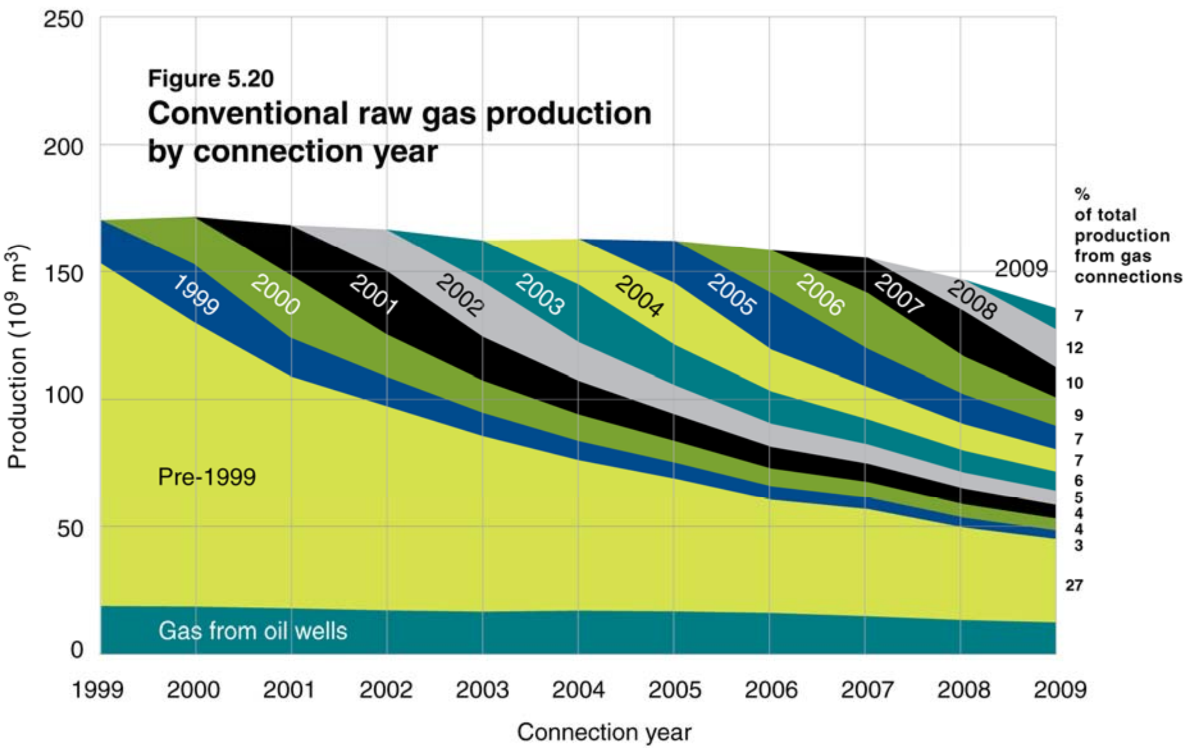
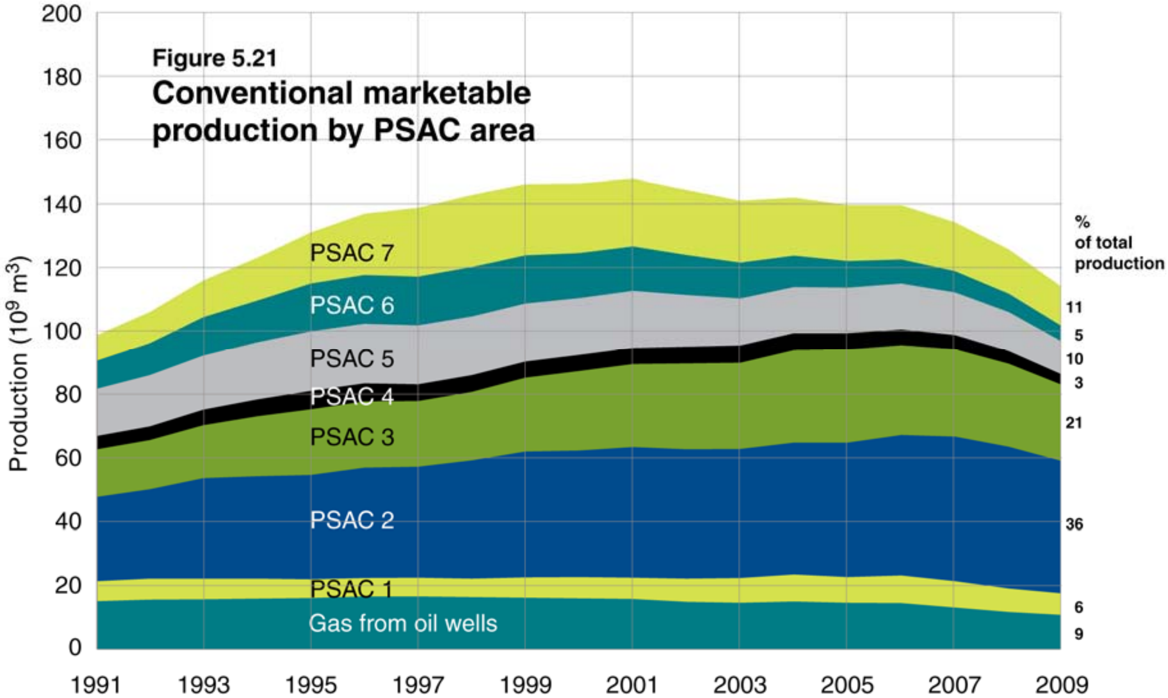


Figure 5.20
Conventional raw gas production by connection year

Figure 5.21 illustrates historical conventional marketable gas production from conventional gas connections by PSAC area from 1999. All areas of the province experienced decreases in production in 2009 relative to 2008.

Conventional marketable gas production in Alberta from 1990 to 2009 is shown in **Figure 5.22**, along with the number of conventional gas connections brought on production in each year. The number of producing gas connections has been increasing year over year, while gas production has decreased since reaching its peak in 2001. By 2009, the total number of producing gas connections had increased to 116 603, from 28 819 connections in 1991. The number of new conventional gas connections each year has not been adequate to offset production declines in existing connections. Exacerbating the annual production declines in 2009 were the low number of new connections and the number of conventional connections now designated as CBM due to their recompletion into a CBM zone.



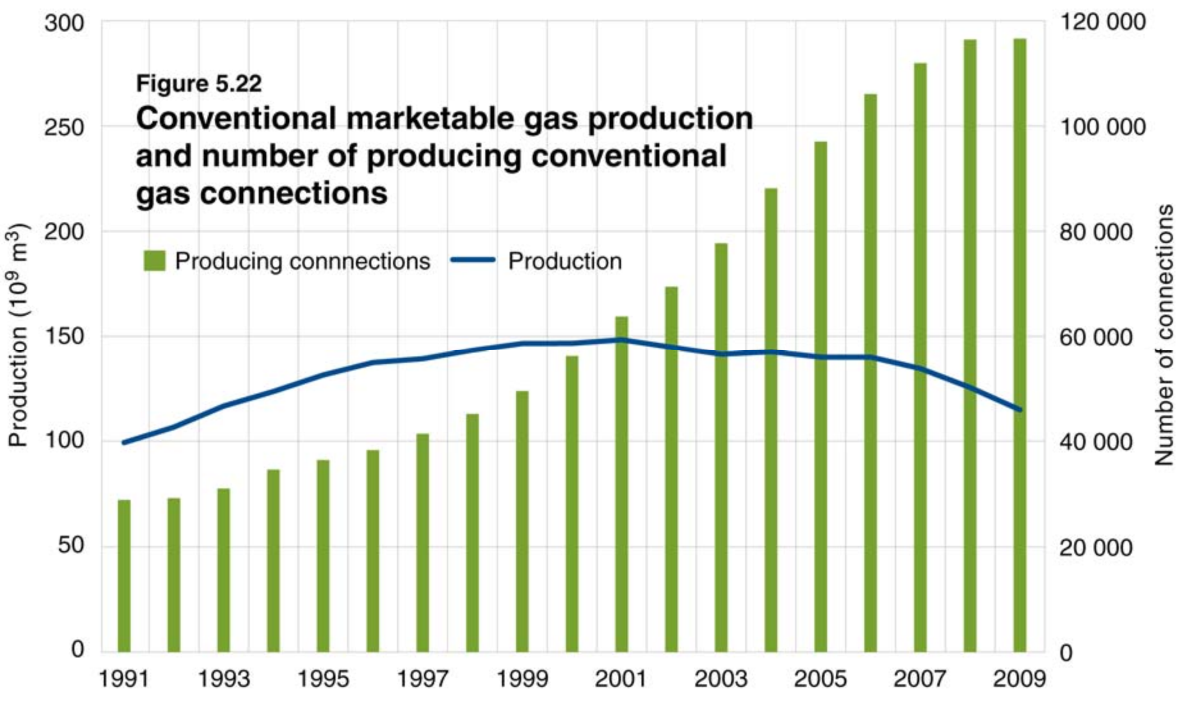


Figure 5.23 indicates the proportion of sweet versus sour gas production in the province since 1999. The percentage of sour gas relative to total gas production is decreasing, from 31 per cent in 1999 to 23 per cent in 2009. This is due to the decline in production from sour gas pools in the province, particularly the Caroline Beaverhill Lake A Pool.

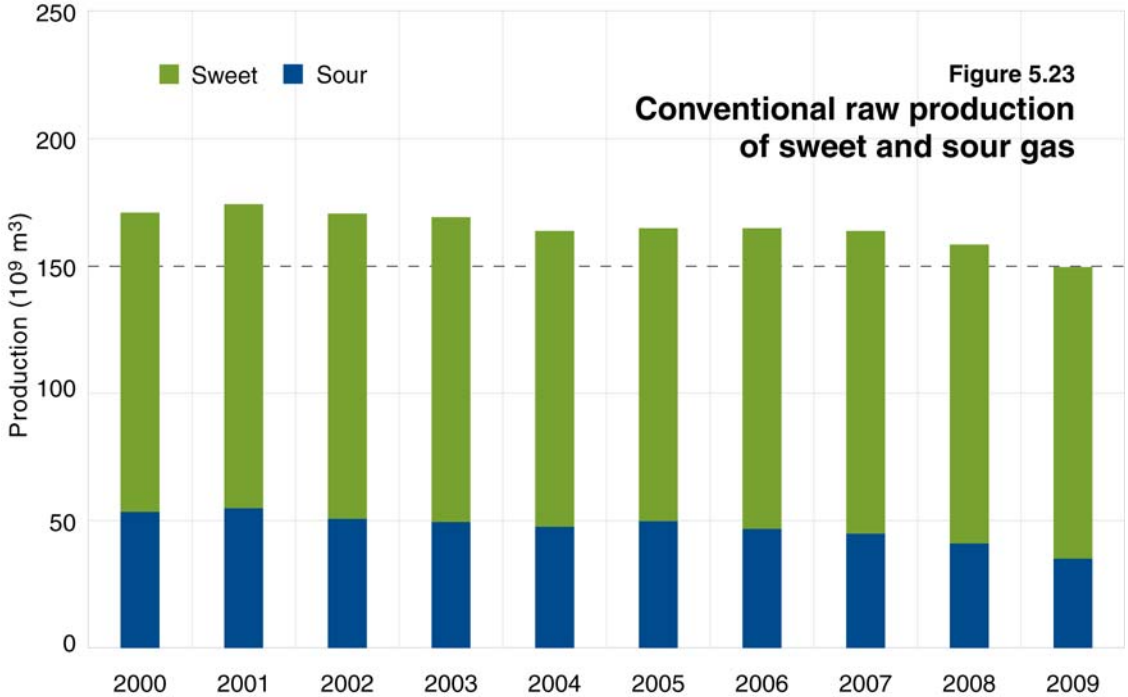
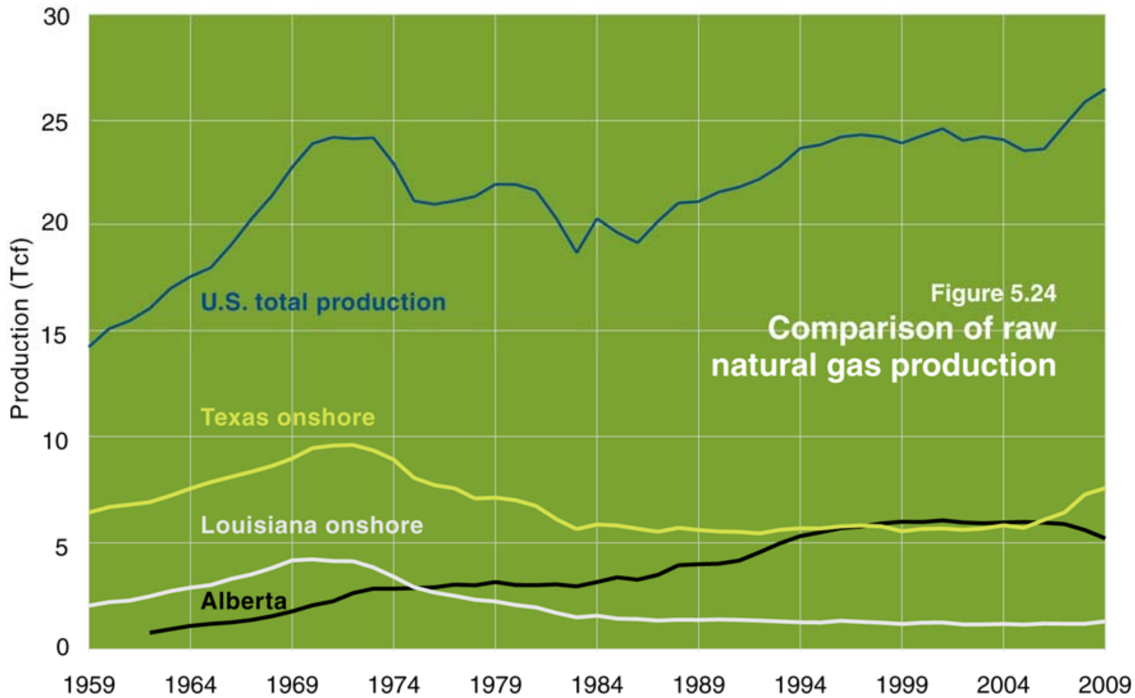
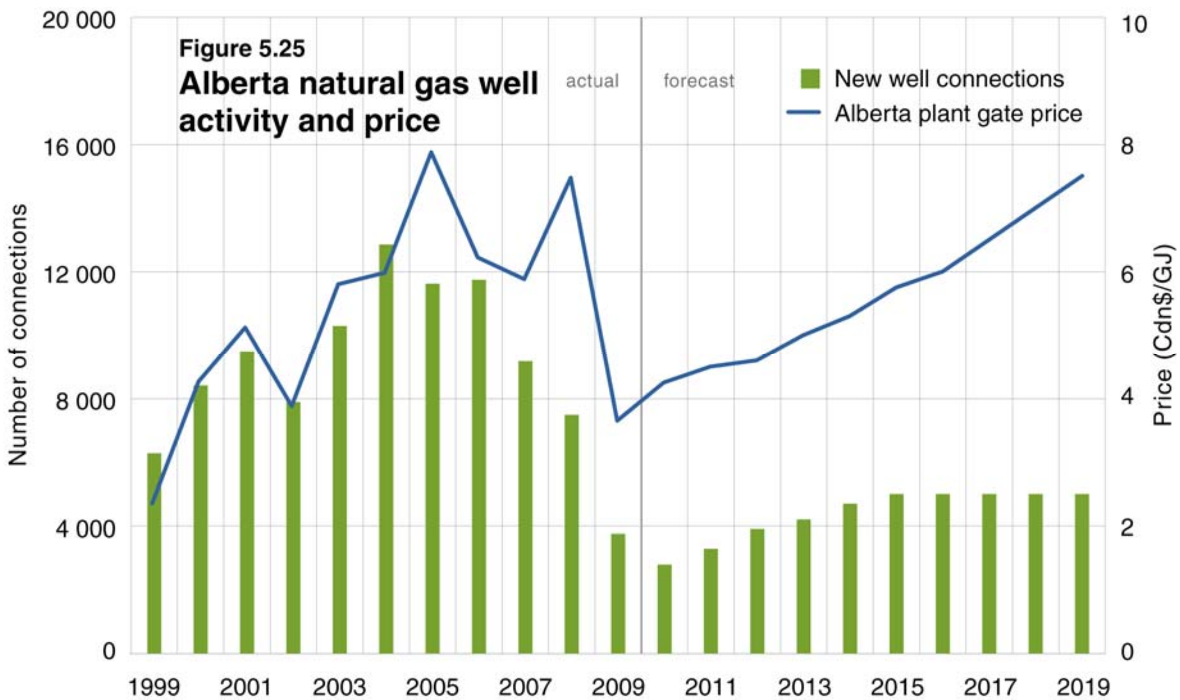


Figure 5.24 presents a comparison of raw natural gas production in Alberta (conventional and unconventional) to both Texas and Louisiana onshore (which also includes conventional and unconventional), as well as total U.S. gas production over the past 50 years, with the U.S. data sourced from the Energy Information Administration. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production experienced a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates have stabilized. Only recently has Texas seen an increase again in production, due primarily to the success in the Barnett shale play.



The long-term outlook for North American gas supply has changed with the recent growth in supply from unconventional production, particularly from shale gas. With the success of the Barnett shales in Texas and the expected potential of other shale gas plays in the U.S., particularly the Haynesville and Marcellus shales, as well as the Horn River shale play in northeastern British Columbia, shale gas production will likely continue to grow and become a significant source of natural gas supply.

Figure 5.25 illustrates historical and forecast new conventional gas connections and plant gate prices. (See Section 1 for the discussion of price forecasts.) In Alberta, the ERCB expects the number of new conventional gas connections in the province to decrease by 26 per cent in 2010 to 2800, as industry activity levels continue to be impacted by the low price environment. New conventional gas connections are expected to increase steadily as forecast natural gas prices improve, reaching 5000 new well connections per year by 2015 and remaining at this level thereafter. Conventional gas connections are forecast to remain flat due to the reduced opportunities available in Alberta's maturing conventional resource basin.



In projecting conventional natural gas supply, the ERCB considers three components: expected production from existing conventional gas connections, expected production from new conventional gas connections in new and existing wells, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province.

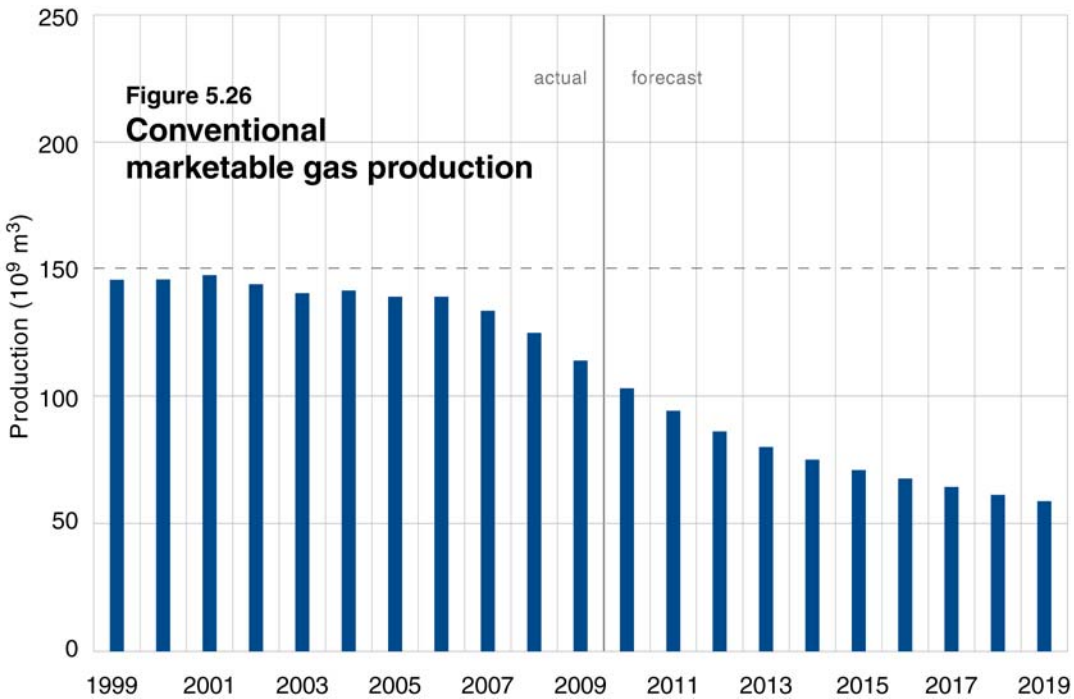
The ERCB based its projection on the following:

- Gas production from existing conventional gas connections at year-end 2009, based on observed performance, is assumed to decline by 16 per cent per year over the forecast period.
- To project production from new conventional gas connections, the ERCB considered the following assumptions:

- The average initial productivity of a new conventional gas connection in Southeastern Alberta will be 1.5 10^3 m^3/day.
- The average initial productivity of a new conventional gas connection in the rest of the province will be 8.0 10^3 m^3/day in 2010, decreasing to 7.0 10^3 m^3/day by 2019.

- Gas production from oil wells, based on observed performance, is assumed to decline by 4 per cent per year over the forecast period.

Based on the remaining established and yet-to-be-established reserves and the assumptions described above, the ERCB forecasts conventional marketable gas production to 2019 as shown in **Figure 5.26**. The production of marketable gas from conventional reserves is expected to decrease from 113.9 10^9 m^3 in 2009 to 58.7 10^9 m^3 by 2019. These volumes are substantially lower than forecast in prior years as a result of lower expectations for new conventional gas connections over the forecast period based on 2009 production. If conventional natural gas production rates follow the projection, Alberta will have recovered 77 per cent of the 6276 10^9 m^3 (as-is) ultimate potential by 2019.



Gas production from conventional and unconventional (CBM and shale) connections is not the only source of natural gas for fuel in Alberta. **Figure 5.27** shows process gas production (rich in liquids) from bitumen upgrading operations (including synthetic gas) and raw natural gas from bitumen wells. These sources are used primarily as fuel in oil sands development.

In 2009, some 4.5 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 7.7 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells from primary and thermal schemes was 1.5 10^9 m^3 in 2009 and is forecast to increase to 2.5 10^9 m^3 by 2019. This gas is used mainly as fuel to create steam for on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.

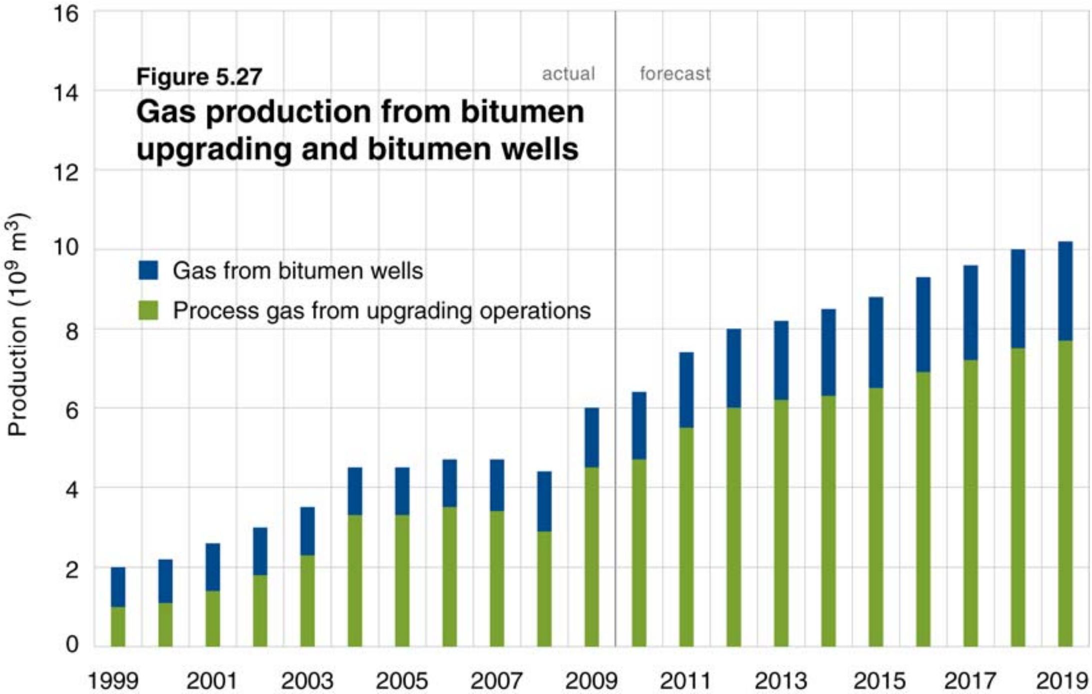
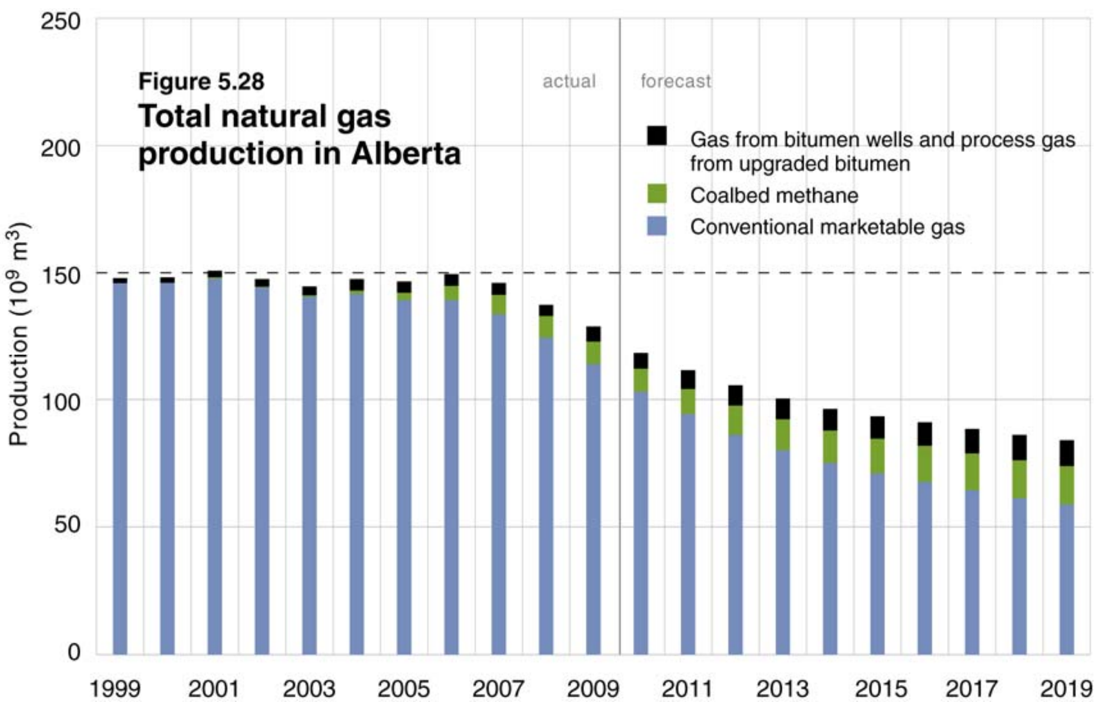


Figure 5.28 shows the total forecast of conventional marketable gas production, along with natural gas production from other sources. In 2009, total natural gas production is reported at 128.9 10^9 m^3, and it is forecast to decline to 84.0 10^9 m^3 by 2019.



5.2.2 Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the ERCB does not use these volumes in the long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; 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 5.29** illustrates the monthly natural gas injection into and withdrawal rates from the storage facilities in the province.

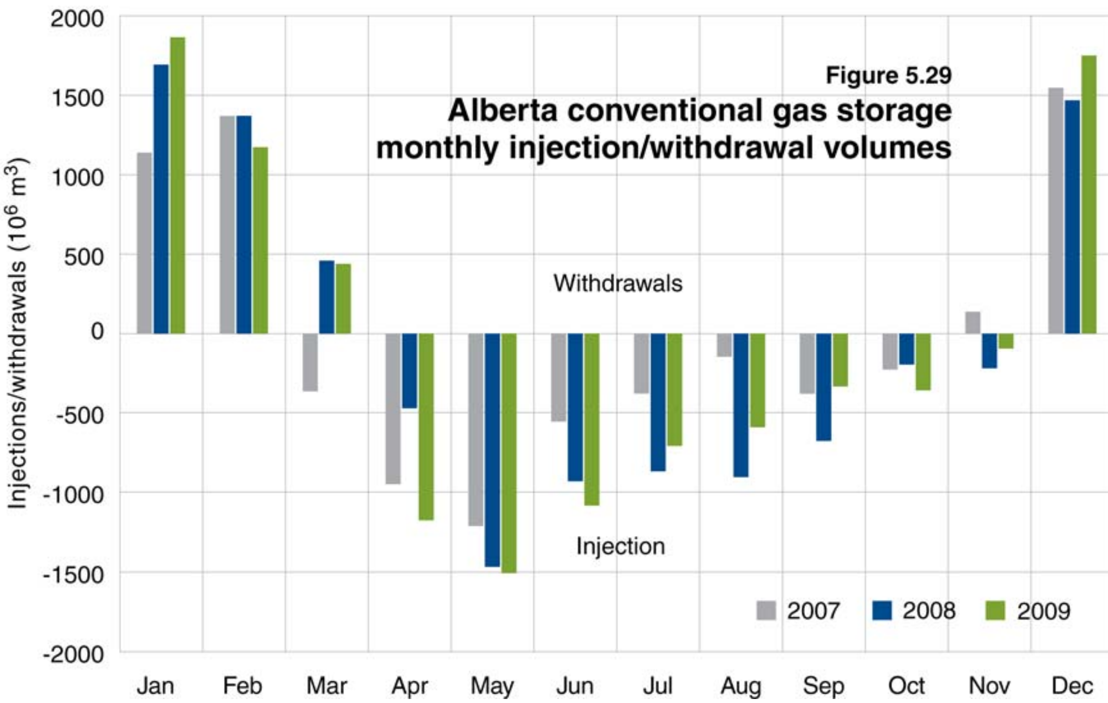


Figure 5.29
Alberta conventional gas storage monthly injection/withdrawal volumes

Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table 5.8.**

A new commercial gas storage scheme is being developed by Paramount Energy Operating Corp. using the Warwick Upper Mannville K Pool. Because the scheme was approved by the ERCB on October 26, 2009, and is only expected to be operating in 2010, it is not included in **Table 5.8**.

In 2009, natural gas injections for all storage schemes exceeded withdrawals by 631 10^6 m^3. Marketable gas production volumes determined for 2009 were adjusted to account for the imbalance in injection and withdrawal volumes to these storage pools. For the purpose of projecting future natural gas production, the ERCB assumes that injections and withdrawals are balanced for each year during the forecast period.

Table 5.8. Commercial natural gas storage pools as of December 31, 2009

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2009 (10^6 m^3)	Withdrawal volumes, 2009 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	828	886
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	35 217	1 414	1 182
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	691	525
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	656	519
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	292	305
McLeod Cardium A	Iberdrola Canada Energy Services Ltd.	986	16 900	519	574
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	226	275
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	50 713	1 959	1 688
Total				6 585	5 954

Figure 5.30 shows the location of the existing and future gas storage facilities in the Alberta pipeline systems.

5.2.3 Alberta Natural Gas Demand

The Alberta *Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by “setting aside” large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the ERCB for a permit authorizing the removal. 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 5.9** is performed annually to determine what volume of gas is available for export after accounting for Alberta’s future requirements. Using the 2009 remaining established reserves number, surplus natural gas is currently calculated to be 557 10^9 m^3. This is the second straight year when there has been a significant increase in the available natural gas for permits due to the volumes that had been previously committed to long-term permits that have now ended. **Figure 5.31** illustrates historical “available for permitting” volumes from 1999 to 2009.

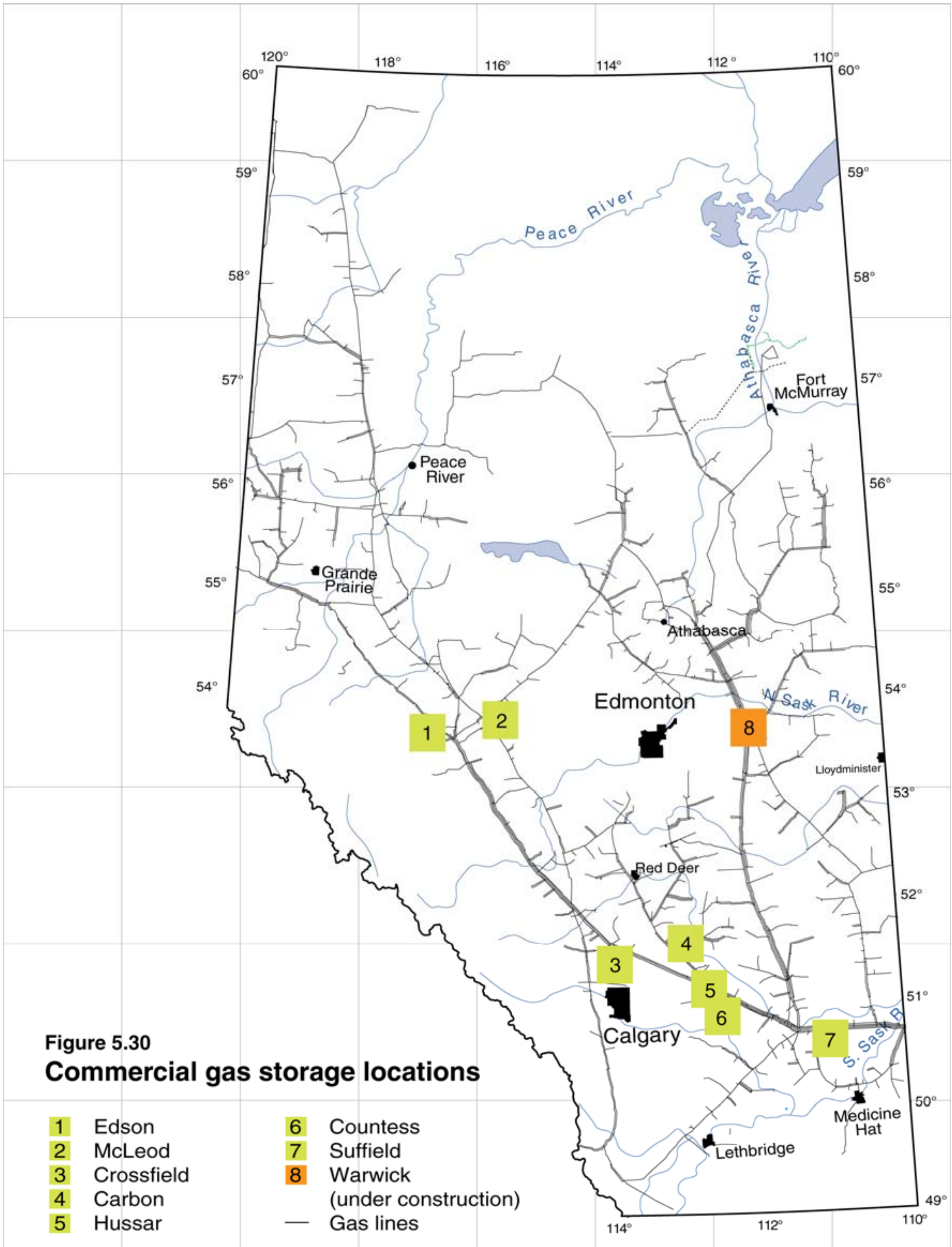


Figure 5.30
Commercial gas storage locations

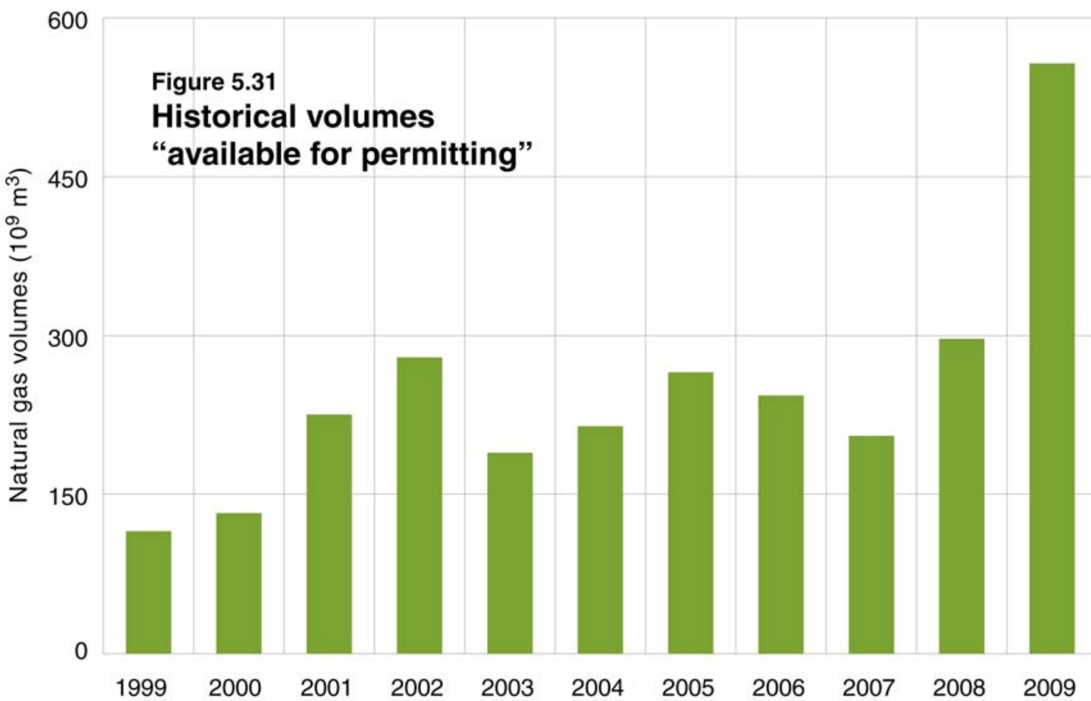
1 Edson
2 McLeod
3 Crossfield
4 Carbon
5 Hussar
6 Countess
7 Suffield
8 Warwick (under construction)
— Gas lines

Table 5.9 Estimate of gas reserves available for inclusion in permits as at December 31, 2009

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as at year-end 2009)	
1. Total remaining established reserves	1098
Alberta requirements	
2. Core market requirements	121
3. Contracted for non-core markets[a]	130
4. Permit-related fuel and shrinkage	26
Permit requirements	
5. Remaining permit commitments[b]	264
6. Total requirements	541
Available	
7. Available for permits	557

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

[b] The remaining permit commitments are split approximately 88 per cent under short-term permits and 12 per cent under long-term permits.



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

Forecasting demand for Alberta natural gas in markets outside the province is done less rigorously. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets and the recent historical trends in meeting that demand. Excess pipeline capacity to the U.S. allows gas to move to areas of the U.S. that provide for the highest netback to the producer. The major natural gas pipelines in Canada that move Alberta gas to market are illustrated in **Figure 5.32**, with removal points identified.

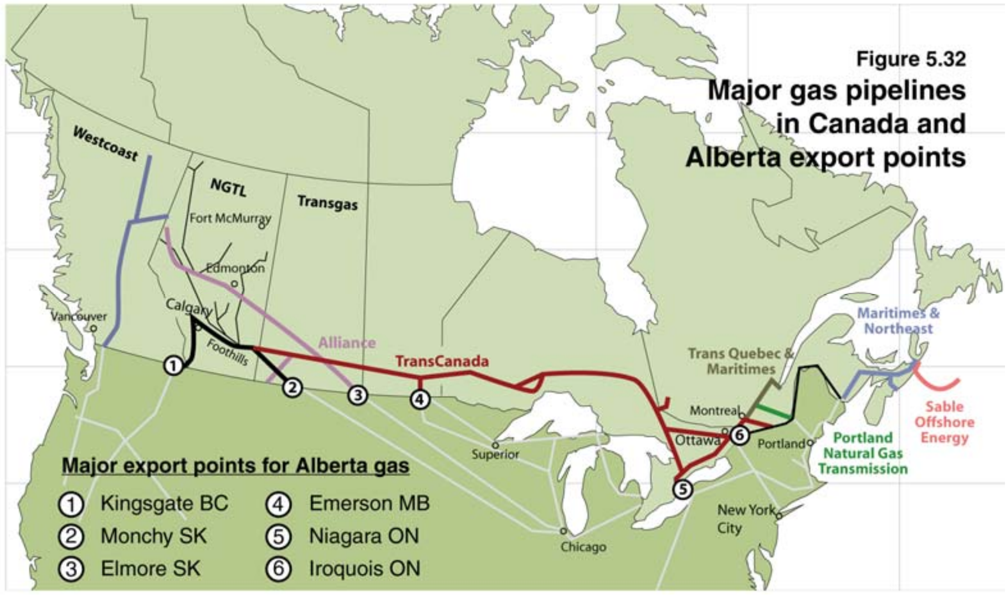
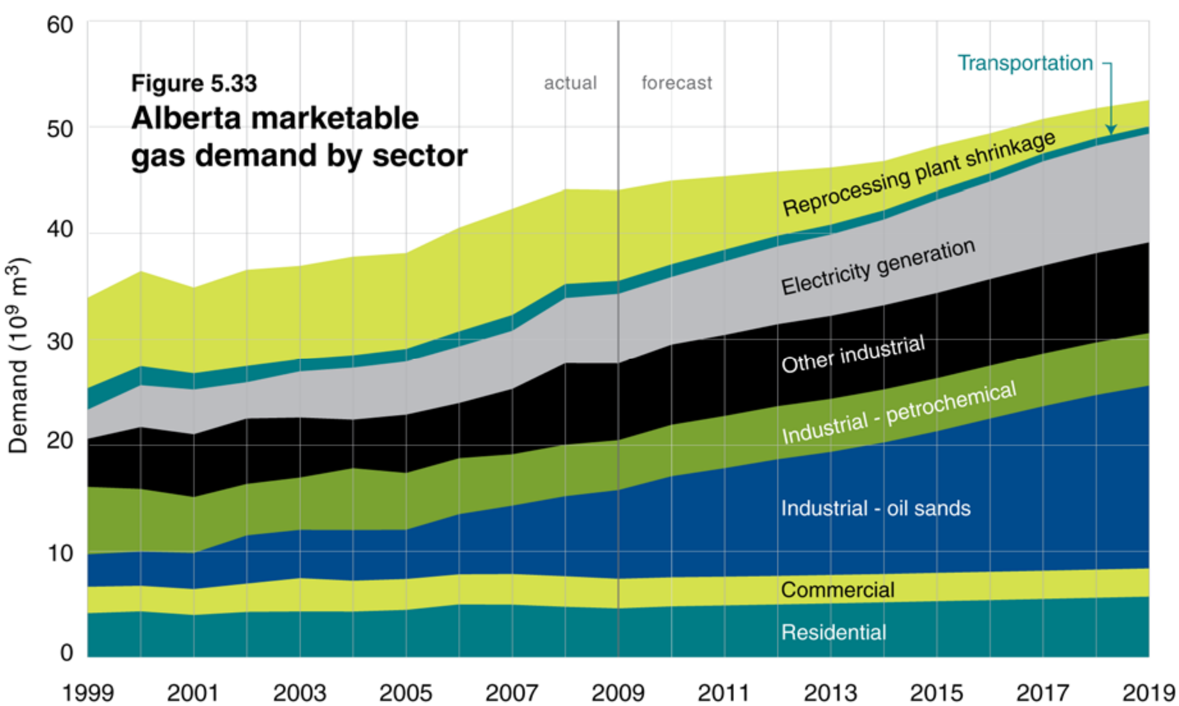


Figure 5.33 illustrates the breakdown of marketable natural gas demand in Alberta by sector. In 2009, Alberta domestic demand was 44.0 10^9 m^3, which represented 36 per cent of the total Alberta natural gas production. By the end of the forecast period, demand will reach 52.5 10^9 m^3, or 71 per cent of total production.



Residential gas requirements are expected to grow moderately over the forecast period, at an average annual rate of 2 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 but is expected to remain flat over the forecast period. This is largely due to gains in energy efficiencies and a shift towards electricity.

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 about 6.6 10^9 m^3 in 2009 to 10.2 10^9 m^3 by 2019.

The significant increase in Alberta demand is due to increased development in the industrial sector. Gas demand for oil sands operations will increase from 8.4 10^9 m^3 in 2009 to 17.2 10^9 m^3 in 2019.

The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil, shown in **Figure 5.34,** are expected to increase annually from 12.3 10^9 m^3 in 2009 to 24.1 10^9 m^3 by 2019. **Table 5.10** outlines the average purchased gas use rates for oil sands operations.

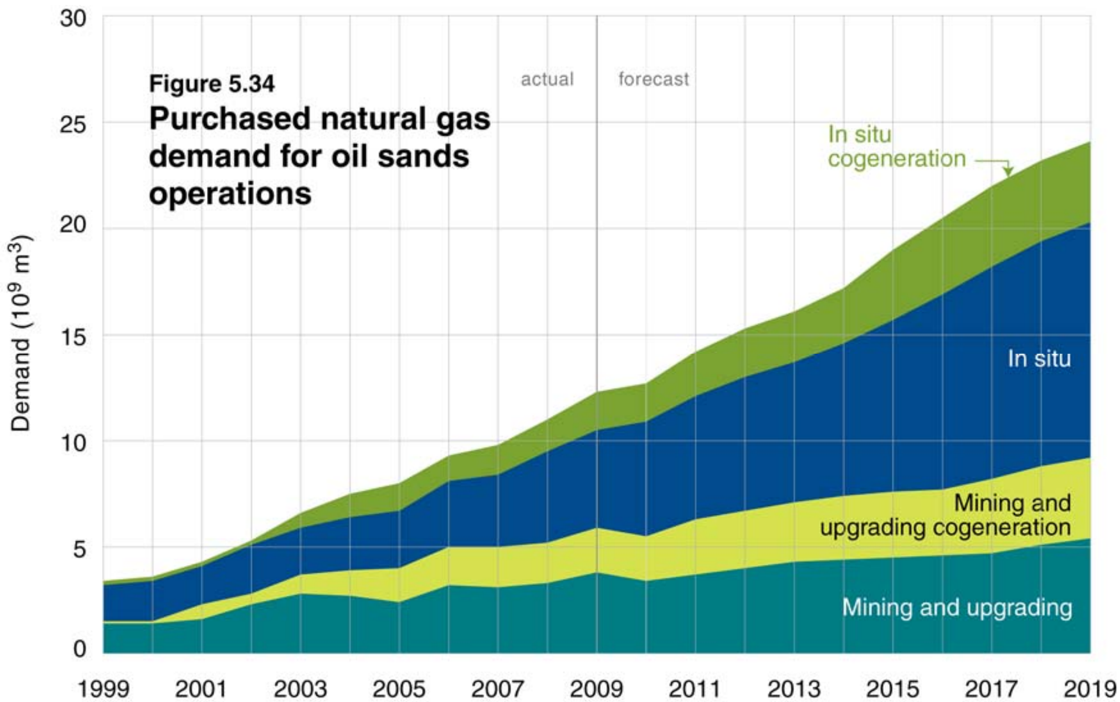
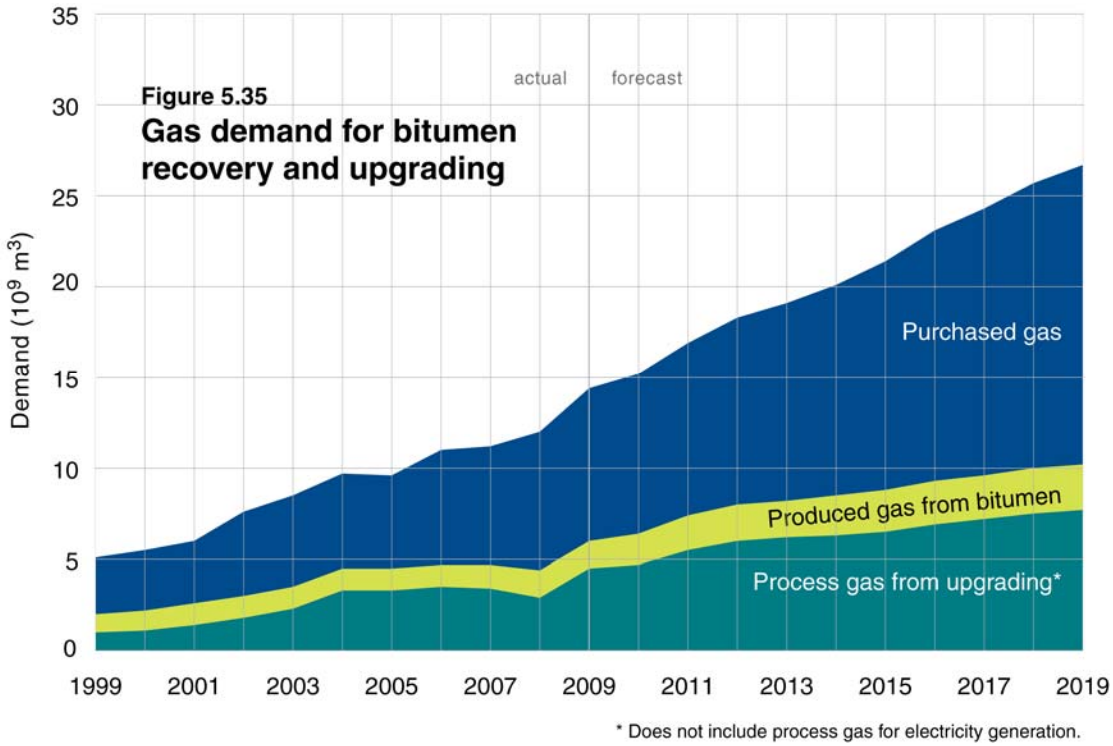


Table 5.10. 2009 oil sands average purchased gas use rates*

	Excluding purchased gas for electricity generation		Including purchased gas for electricity generation	
Extraction method	(m^3/m^3)	(mcf/bbl)	(m^3/m^3)	(mcf/bbl)
In situ - SAGD	138	0.78	233	1.31
- CSS	202	1.14	256	1.44
Mining with upgrading	86	0.48	117	0.66

* 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. **Figure 5.35** illustrates the total gas demand in this sector, which is the sum of purchased gas, process gas, and solution gas produced at bitumen wells. This demand is expected to nearly double from 14.4 10^9 m^3 in 2009 to 26.7 10^9 m^3 by 2019.



Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, as shown in **Figure 5.36**, was 19.3 10^9 m^3 in 2009 and is forecast to increase to 35.3 10^9 m^3 in 2019.

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

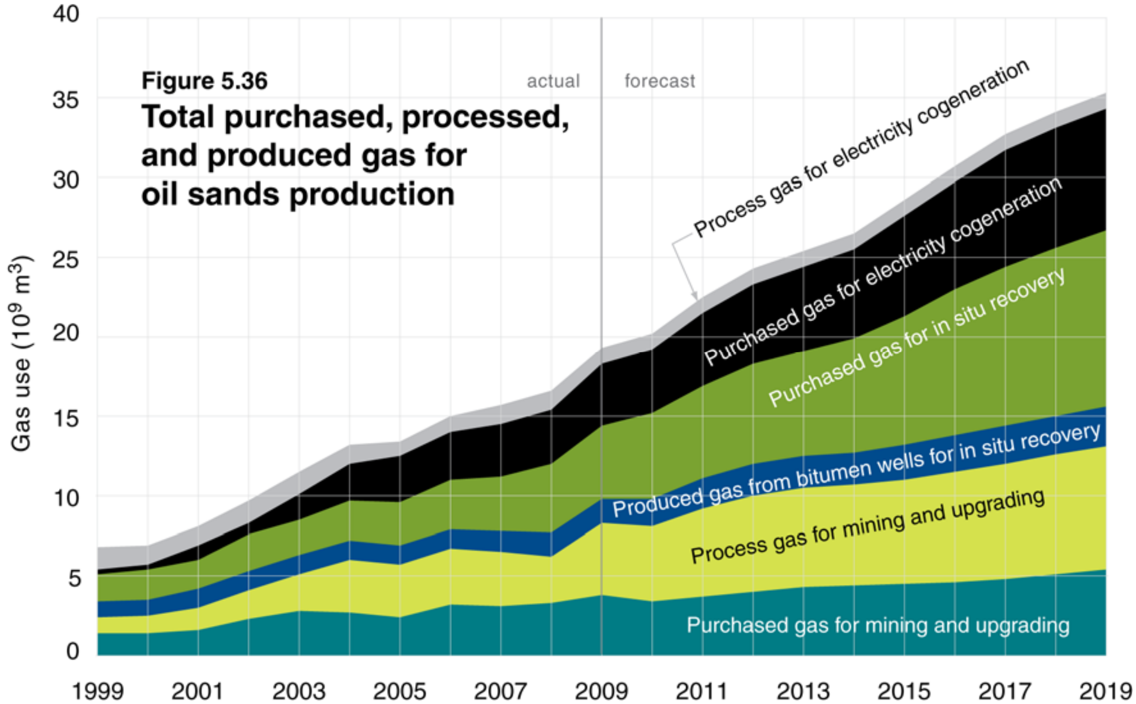
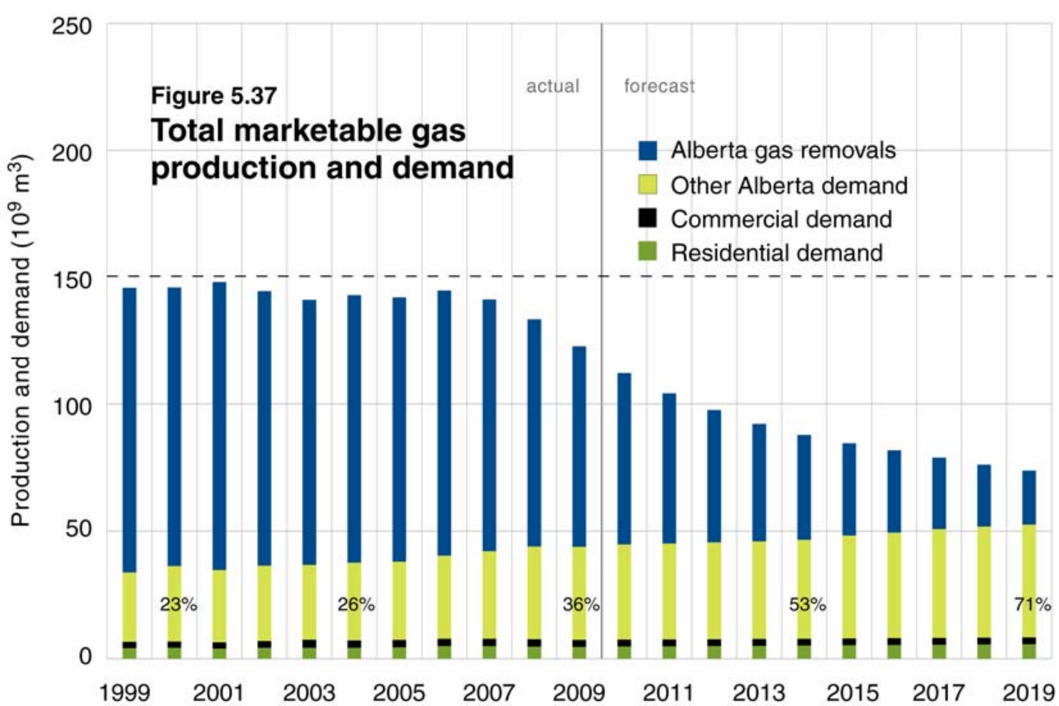


Figure 5.37 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading (**Figure 5.27**) is considered to be used on site and therefore is not included as production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional, CBM, and shale sources only, minus Alberta demand. In 2009, some 36 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the U.S. By the end of the forecast period, domestic demand will represent 71 per cent of total natural gas production, nearly twice than what is used today.



6 Natural Gas Liquids

Highlights

- Total remaining extractable NGL reserves have decreased by 4 per cent from 2008 due to decreasing natural gas reserves.
- Approximately 56 per cent of total ethane in the gas stream was extracted in 2009, similar to 2008.
- Of the total ethane extracted, straddle plants recovered 73 per cent and the remaining was removed at field and other facilities.

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

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in more detail in Section 6.2.1. Initial reserves for NGLs are not calculated, since historically only a fraction of the liquid volume that could have been extracted was recovered and much was flared for lack of a market demand. The ERCB's projections on the overall recovery of each NGL component are explained in Section 5.1.8. As shown graphically in **Figure 5.11**, the estimated reserves of liquid ethane are based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the ERCB's calculations assume that the composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict and the volume is not expected to be significant. The liquids reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in Section 5.1.

6.1 Reserves of Natural Gas Liquids

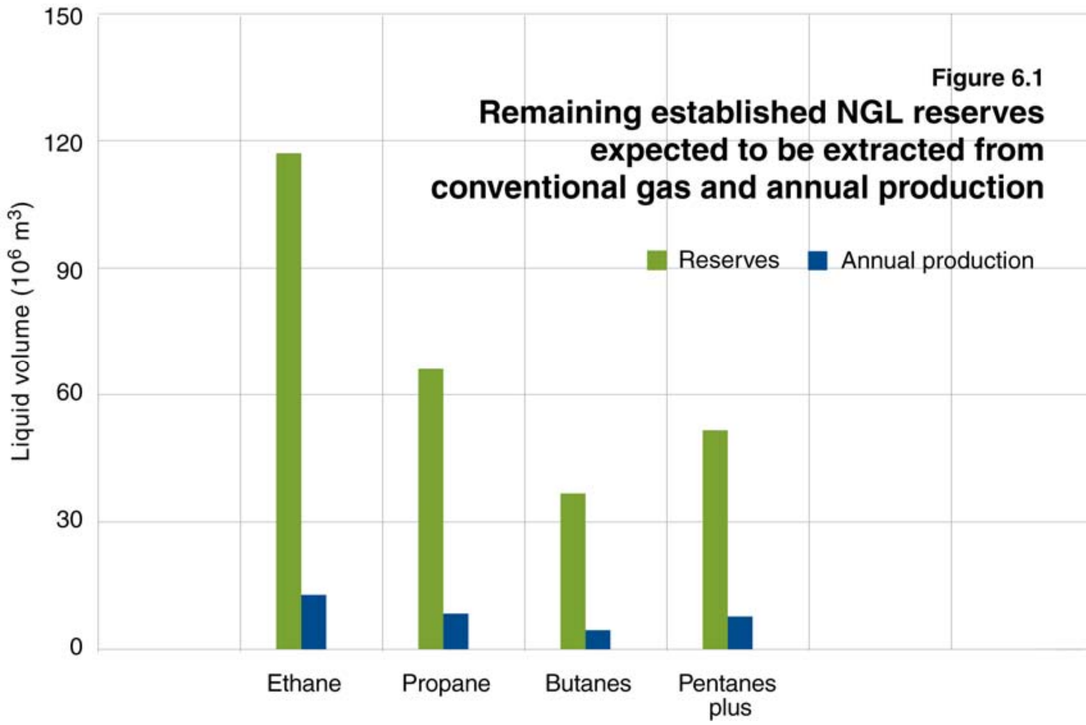
6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2009 are summarized in **Tables 6.1** and **6.2**. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2009 production.

Total remaining reserves of extractable NGLs have decreased by 3.9 per cent compared to 2008 due to the decline in natural gas reserves. Fields that have contributed significantly to this decrease are Ansell, Caroline, Ferrier,

Table 6.1. Established reserves and production of extractable NGLs as of December 31, 2009 (10^6 m^3 liquid)

	2009	2008	Change
Cumulative net production			
Ethane	280.1	267.3	+12.8
Propane	279.3	270.9	+8.4
Butanes	159.6	155.1	+4.5
Pentanes plus	345.0	337.3	+7.7
Total	1064.0	1030.6	+33.4
Remaining (expected to be extracted)			
Ethane	117.0	121.1	-4.1
Propane	66.1	69.0	-2.9
Butanes	36.7	38.4	-1.7
Pentanes plus	51.6	53.8	-2.2
Total	271.4	282.3	-10.9
Annual production	33.4	35.0	-1.6



Karr, and Pembina. These fields and others containing large NGL volumes are listed in **Appendix B**, **Tables B.7** and **B.8**.

6.1.2 Ethane

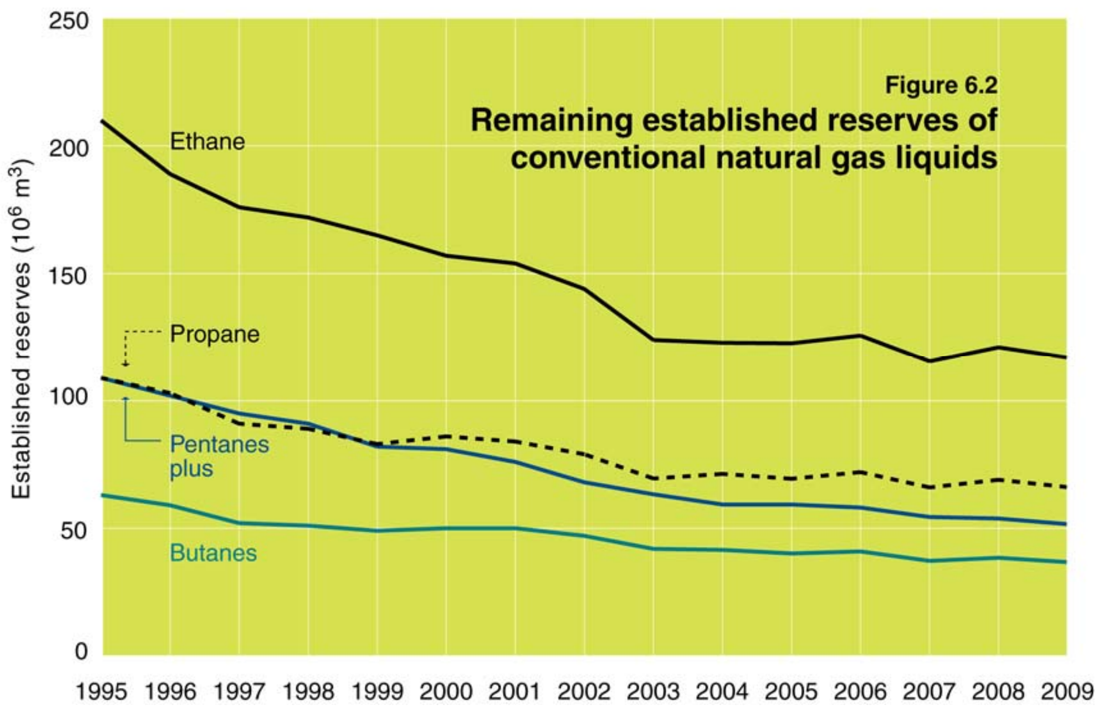
As of December 31, 2009, the ERCB estimates remaining established reserves of extractable ethane to be 117.0 million cubic metres (10^6 m^3) in liquefied form. Of that, 45.8 10^6 m^3 is expected to be recovered from field plants and 71.2 10^6 m^3 from straddle

Table 6.2. Reserves of NGLs as of December 31, 2009 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	179.3	77.8	40.8	51.6	349.4
Liquids expected to remain in dry marketable gas	62.3	11.7	4.1	0	78.0
Remaining established recoverable from					
Field plants	45.8	38.9	24.5	46.4	155.6
Straddle plants	71.2	27.2	12.2	5.2	115.8
Total	117.0	66.1	36.7	51.6	271.4

plants that deliver gas outside the province, as shown in **Table 6.2.** It is estimated that 3.2 10^6 m^3 is recoverable from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. At the end of 2009, only six pools were still actively injecting solvent, the largest being the Rainbow Keg River B and Rainbow Keg River F pools.

Thirty-five per cent of the total raw ethane reserves or 62.3 10^6 m^3 (liquid) is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure 6.2** shows the remaining established reserves of ethane declining rapidly from 1995 to 2003, then levelling off thereafter as more ethane is extracted from raw gas. During 2009, the extraction of specification ethane was 12.8 10^6 m^3, compared to 12.9 10^6 m^3 in 2008.



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

25 per cent of total ethane reserves but only 14 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2009, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 66.1 10^6 m^3, 36.7 10^6 m^3, and 51.6 10^6 m^3 respectively. The breakdown in the liquids reserves at year-end 2009 is shown in **Table 6.2**. **Table B.8** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The largest of these fields—Ansell, Brazeau River, Caroline, Elmworth, Ferrier, Kaybob South, Pembina, Wild River, and Willesden Green—account for about 25 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.

6.1.4 Ultimate Potential

The remaining ultimate potential for liquid ethane is determined based on the reserves that could be recovered as liquid from the remaining ultimate potential of natural gas, using existing cryogenic technology and projected market demand. Historically, only a small percentage of the ethane volumes that could be extracted had been recovered. That percentage has increased over time, averaging about 58 per cent over the last five years. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on remaining ultimate potential for ethane gas of 135 billion (10^9) m^3, the ERCB estimates the remaining ultimate potential of liquid ethane to be 335 10^6 m^3. The other 30 per cent, or 40 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus reserves together, the remaining ultimate potential reserves are 354.8 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas, or about 35 per cent.

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 reserves and future additions 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 and will be needed to meet the forecast ethane demand.

6.2.1 Supply of Ethane and Other Natural Gas Liquids

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

Gas processing plants for NGL extraction, referred to as straddle plants, are located on rate-regulated main gas transmission pipelines and process gas (that may have been processed in the field) to recover NGLs that remain in the common gas stream. These plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure 6.3** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

There are about 550 active gas processing plants in the province that recover NGL mix or pure products, 10 processing plants that fractionate NGL mix streams into separate products, and 9 straddle plants. Recovery rates for field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A small number of field plants also have the capability to extract ethane as a discrete product or as a C_2+ mix.

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

Table 6.3. Straddle plants in Alberta, 2009

Area of straddle plant	Location	Operator	2009 gas approved volumes (10^3 m^3/d)	2009 gas receipts (10^3 m^3/d)	2009 ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	54 516	4 549
Empress	04-12-020-01W4M	BP Canada Energy Company	176 750	47 327	5 470
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	53 159	7 992
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 130	1 950
Empress	01-10-020-01W4M	ATCO Midstream Ltd.	31 000	13 970	909
Ft. Saskatchewan	01-03-055-22W4M	ATCO Midstream Ltd.	1 051	609	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	31 910	3 912
Joffre (JEEP)	03-29-038-25W4M	Taylor Management Company Inc.	7 066	277	696
Atim (Villeneuve)	08-05-054-26W4M	ATCO Midstream Ltd.	1 133	974	0
Total			400 219	210 872	25 478

In 2009, ethane volumes extracted at Alberta processing facilities decreased marginally to 35.1 thousand (10^3) m^3/d from 2008 levels of 35.3 10^3 m^3/d. About 56 per cent of total ethane in the gas stream was extracted, while the remainder was left in the gas stream and sold for its heating value. **Table 6.4** shows the volumes of specification ethane extracted at the three types of processing facilities during 2009.

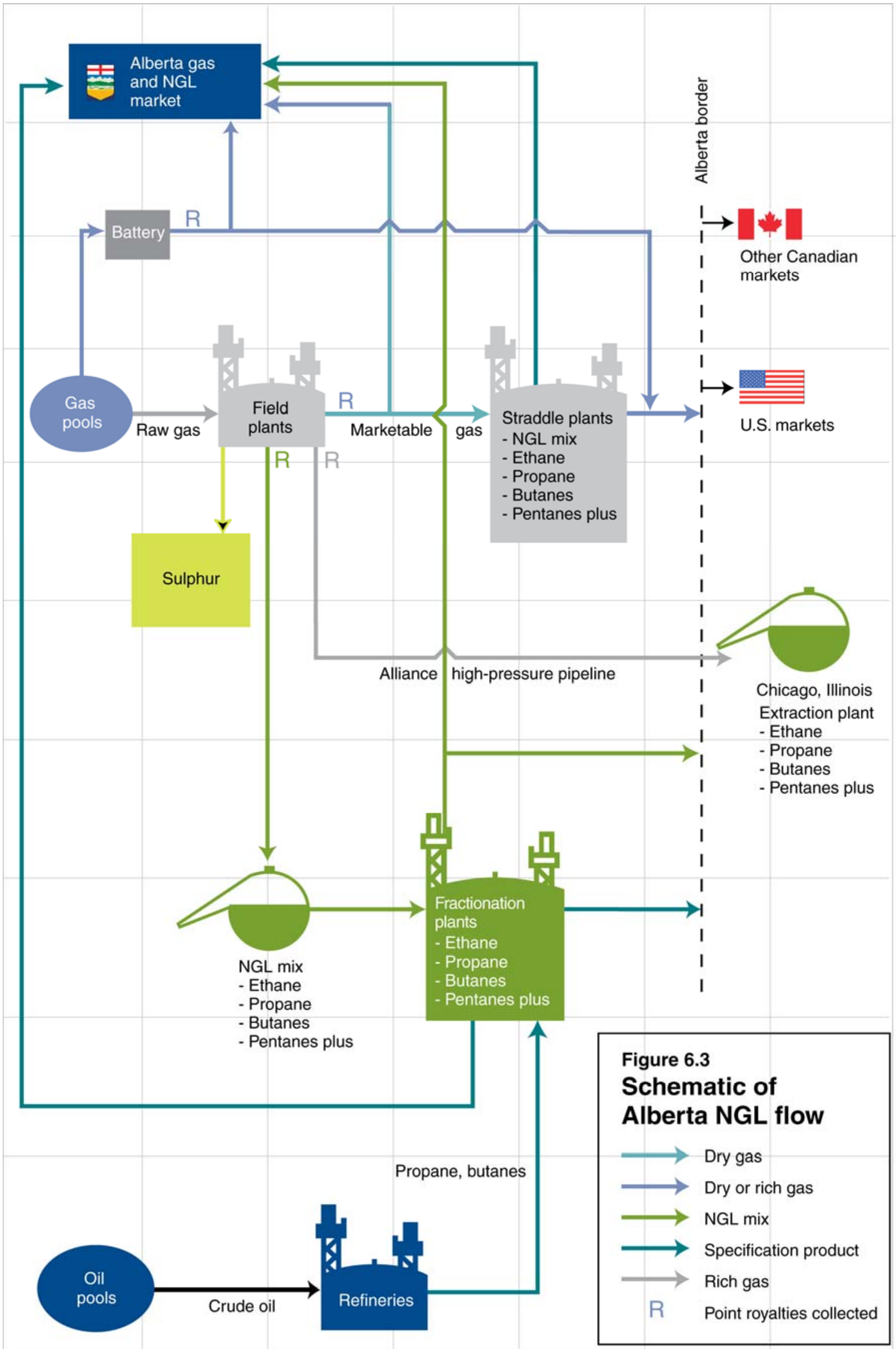


Figure 6.3
Schematic of Alberta NGL flow

Table 6.4. Ethane extraction volumes at gas plants in Alberta, 2009

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	0.7	5
Fractionation plants	2.8	22
Straddle plants	9.3	73
Total	12.8	100

Table 6.5 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2009. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butane volumes recovered at crude oil refineries were 0.6 10^3 m^3/d and 1.8 10^3 m^3/d respectively, down slightly from 2008.

Table 6.5. Liquid production at ethane extraction plants in Alberta, 2009 and 2019

	2009			2019		
Gas liquid	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)	Yearly production (10^6 m^3)	Daily production (10^3 m^3/d)	Liquid/ gas ratio ($m^3/10^6$ m^3)
Ethane	12.8	35.1	112	12.8	35.1	188
Propane	8.4	22.9	68	5.0	13.7	68
Butanes	4.5	12.4	37	2.7	7.5	37
Pentanes plus	7.7	21.0	63	4.6	12.7	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 the Incremental Ethane Extraction Policy (IEEP), which will provide incentives for value-added production and the use of ethane in the province. The IEEP, first announced in September 2006, is a 10-year initiative to encourage increased production of ethane extraction from natural gas and from oil sands off-gas. IEEP provides royalty credits to encourage petrochemical companies to significantly increase the amount of ethane they consume compared to historical levels.

The provincial government has estimated that between 9.48 10^3 m^3/d and 13.43 10^3 m^3/d of additional ethane production is expected to be recovered as a result of IEEP over the next few years. A number of projects, including off-gas facilities and expansions to existing facilities, have been accepted as of December 2009 to receive credits under the program, as shown in **Table 6.6.**

Table 6.6. IEEP Projects as of December 31, 2009

Project	Ethane (m^3/d)	Start-up date
Rimbey Plant Expansion	790	August 2009
Empress V Expansion	1 100	Q4 2009
Heartland Off Gas Plant	350	Delayed

The gas processing plant expansions have been completed. However, the construction of the Heartland Off Gas Plant was halted in late 2008 as a result of the BA Energy Inc. decision to indefinitely postpone the completion of the bitumen upgrader, which was the intended source of off-gas feedstock for the project.

The Alberta government is expecting to open a new round of applications under the IEEP in the spring of 2010.

As additional bitumen upgrading capacity is added in the province, there will be opportunities to expand the use of off-gases and other by-products of upgrading for petrochemical production. Currently, Williams Companies, Inc., processes off-gas volumes from Suncor Energy Inc.'s oil sands facility in the Fort McMurray area, extracts a C_3+ and olefins mix, and transports the volumes to Redwater, Alberta, via the Suncor Oil Sands Pipe Line. The mix is sent for fractionation into specification products in Redwater. Current production is reported to be 2200 m^3/d.

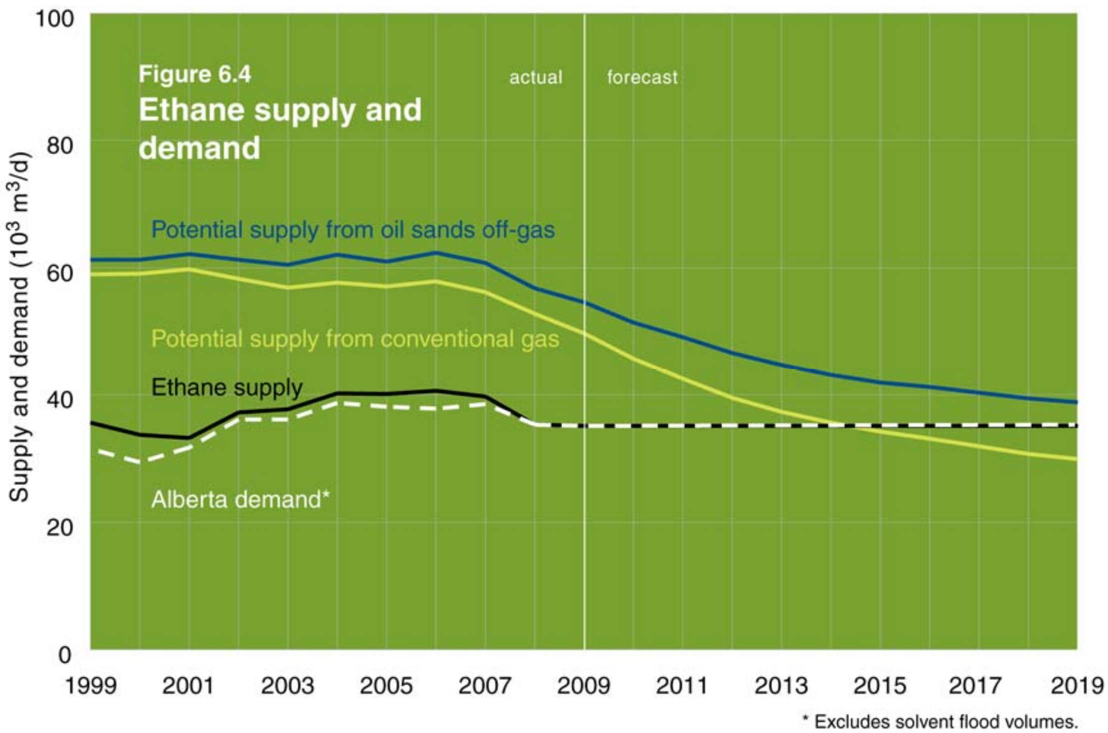
Williams has announced plans to build a pipeline to transport 6795 m^3/d of off-gas liquids. The new 12-inch proposed pipeline will provide additional capacity for Suncor liquids, as well as liquids from the other oil sands producers' off-gas. Construction on this pipeline is expected to begin in 2010, with an anticipated in-service date of April 2012. The pipeline is expected to support the future removal of ethane, in addition to other natural gas liquids and olefins. The pipeline has the future capability to transport up to 19 750 m^3/d by installing additional pump stations.

Recovered ethane volumes are expected to remain at 2009 levels over the forecast period, as shown in **Figure 6.4**. New ethane supplies are expected from enhanced deep-cut recovery at field operations and from oil sands off-gas. 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 a 75 per cent capacity utilization rate over the past two years.

The ERCB expects that all ethane recovered in the province will be used locally, even though export permits are in place to move small volumes of ethane outside of Alberta. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue through the forecast period.

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 average ethane content of conventional gas in Alberta of 0.052 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is some 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast.

Given the potential for ethane supply from off-gas from bitumen upgraders, oil sands off-gas is receiving considerable attention as another source of ethane. The ethane supply volumes from oil sands off-gas are calculated assuming a 12 per cent ethane content in the off-gas production volumes and an 80 per cent recovery rate of ethane. The forecast supply from conventional natural gas crosses over the demand curve around 2015, which is earlier than last year's forecast due to this year's lower natural gas forecast. This forecast assumes that incremental ethane volumes required to meet demand will be available from off-gas or higher extraction rates from existing processing facilities.



Over the forecast period, the ratios of propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas are expected to remain constant, as shown in **Table 6.5**. **Figures 6.4** to **6.7** show forecast production volumes to 2019 for ethane, propane, butanes, and pentanes plus respectively. As conventional gas production declines, so too will the NGL volumes available for extraction.

6.2.2 Demand for Ethane and Other Natural Gas Liquids

All of the ethane extracted in 2009 was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline allows for a range of feedstocks to be transported from Fort Saskatchewan to Joffre. These feedstocks supplement the ethane supplies now used at the petrochemical plants at Joffre, where three of the four ethylene plants are located. The fourth is located in Fort Saskatchewan. To acquire ethane, the petrochemical industry pays a fee to NGL processing facility owners to extract and deliver ethane from natural gas streams processed at their facilities. The industry adds value to NGLs by upgrading them to be used in the manufacture of products such as plastic, rope, and building materials.

The petrochemical industry in North America has been challenged in the last few years by high and volatile energy prices. Since ethane prices follow natural gas prices, feedstock costs have fluctuated throughout the years. Nonetheless, the Alberta ethylene industry has maintained its historical cost advantage for ethylene production compared to a typical ethane/propane cracking plant in the U.S. Gulf Coast.

As also shown in **Figure 6.4**, Alberta demand for ethane is projected to remain at 2009 levels of 35.1 10^3 m^3/d over the forecast period. For the purposes of this forecast, it was assumed that the existing ethylene plants will continue to operate at a 75 per cent capacity utilization rate and that no new ethylene plants requiring ethane as feedstock will be built in Alberta over the forecast period. Small volumes of ethane have historically been exported from the province, primarily for use as a buffer for pipeline ethylene shipments to eastern Canada. In 2008 and 2009, however, no volumes were removed from the province, and this is expected to remain the case in the future.

Figure 6.5 shows Alberta demand for propane compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Alberta propane demand was 3.0 10^3 m^3/d in 2008 and increased slightly to 3.2 10^3 m^3/d in 2009. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Alberta propane demand is forecast to experience moderate growth of 2.5 per cent throughout the forecast. As mentioned earlier, small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue throughout the forecast period.

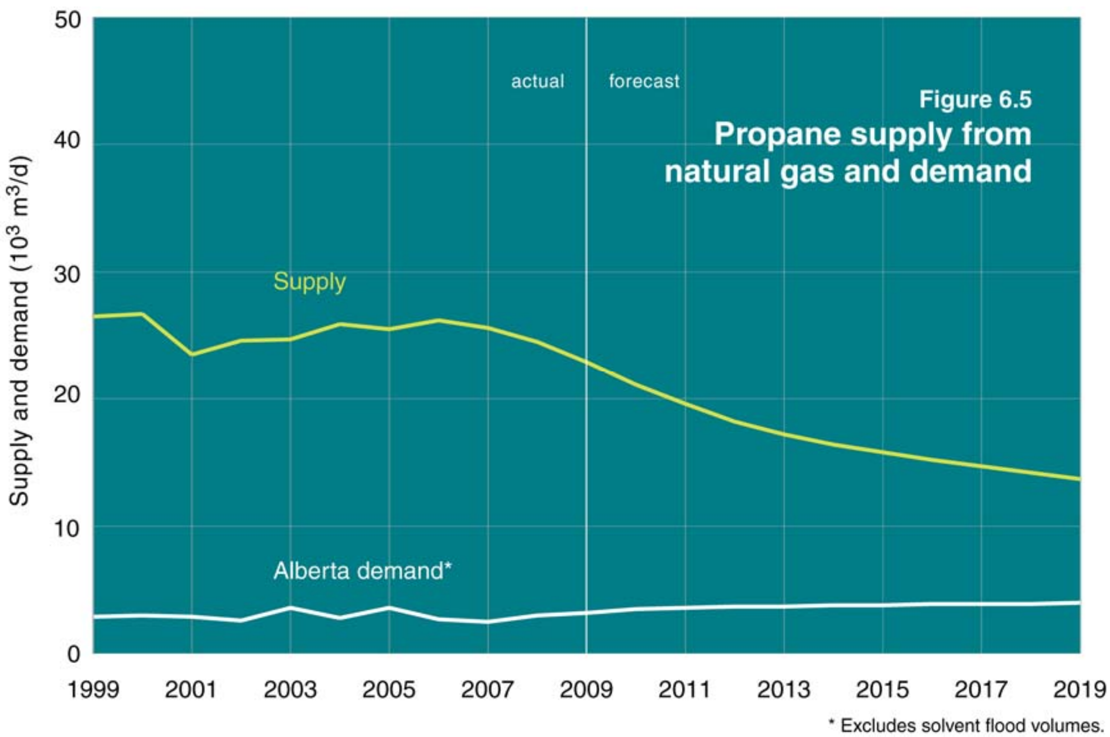
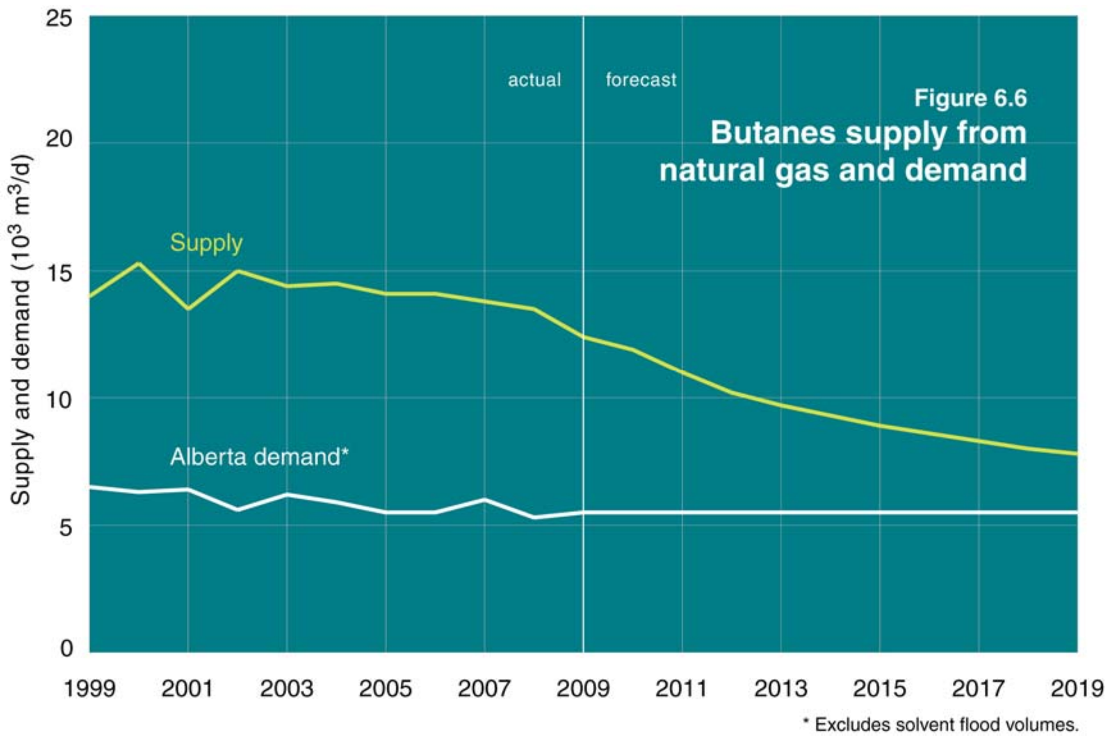


Figure 6.6 shows Alberta demand for butanes compared to the total available supply from gas processing plants. As with propane, the difference between Alberta butane requirements and total supply represents volumes used by ex-Alberta markets. Butanes are used as refinery feedstock, as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate. In 2009, Alberta demand, excluding solvent flood demand, was 5.5 10^3 m^3/d, up from the 2008 demand level of 5.3 10^3 m^3/d. Alberta demand for butanes is forecast to remain constant at 5.5 10^3 m^3/d over the forecast period.

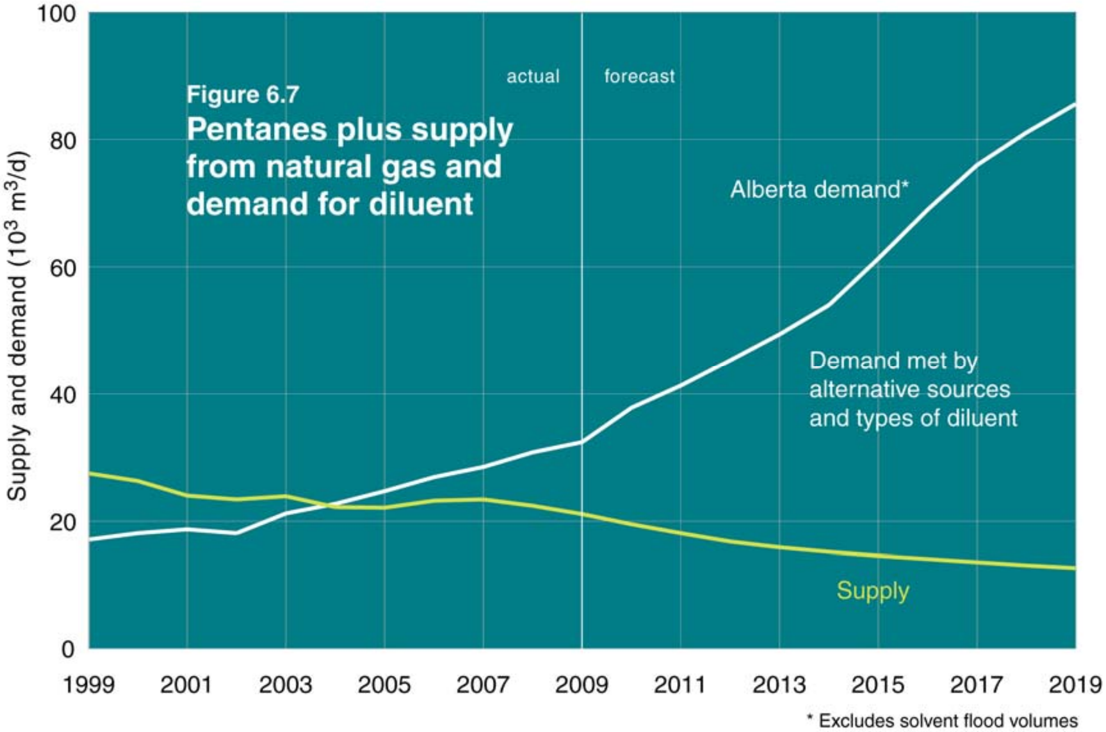


The largest use of Alberta pentanes plus is for diluent in the blending of heavy crude oil and bitumen to facilitate the transportation to market by pipeline. Diluent increases the API gravity and reduces the viscosity of heavy crude oil and bitumen.

Figure 6.7 shows the ERCB estimate of Alberta demand for pentanes plus used for diluent compared to the total available supply. Pentanes plus are also used as feedstock for the refinery in Lloydminster; these small volumes (0.8 10^3 m^3/d in 2009) are not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production. There has been a substantial increase in the estimated pentanes plus historical demand and forecast demand for diluent relative to last year, resulting from a significant revision to the amount of diluent required per unit of bitumen. Previous forecasts assumed a lower diluent-to-bitumen ratio for blending, which resulted in a lower assumed demand.

Demand for pentanes plus is expected to remain strong, due to continued high diluent requirements. The anticipated increase in availability of synthetic product to use as diluent will likely not materialize, due to the delay of several planned bitumen upgraders. As a result, pentanes plus demand as diluent is forecast to increase from 32.4 10^3 m^3/d in 2009 to 85.6 10^3 m^3/d in 2019.

As illustrated in **Figure 6.7**, the diluent demand is now estimated to have exceeded Alberta supply around 2005, compared to the previous forecast where the demand exceeded supply around 2009. The current estimated demand reflects the inadequate Alberta supply of pentanes plus since 2005, which resulted in the use and assessment of alternative sources (imports) and types of diluent. Examples of current and future alternative sources of pentanes plus from outside Alberta are discussed below.



- In 2009, Alberta pentanes plus supply was augmented by 9.8 10^3 m^3/d of pentanes plus from outside of Alberta, including the U.S.

- Cenovus (previously EnCana Corporation) has the ability to import 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, Cenovus 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, currently under construction, is expected to be in service by the second half of 2010.

- Enbridge is commercially pursuing a condensate pipeline capable of initially transporting 23.8 10^3 m^3/d from Kitimat to Edmonton.

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

These current and future sources of and alternatives to diluent will be called upon as production from in situ and nonupgraded bitumen increases.

7 Sulphur

Highlights

- Remaining established sulphur reserves decreased by 2.4 per cent in 2009 relative to 2008 due to the decrease in remaining natural gas and crude bitumen reserves.
- Sulphur prices have declined despite the rise in crude oil prices to a current range of US$28-42 per tonne Free on Board (FOB) Vancouver, compared to US$40-200 per tonne last year.
- Exports to China have rebounded in 2009 after falling significantly in 2008.

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

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2009, to be 181.2 million tonnes (10^6 t), down 2.4 per cent from 2008. **Table 7.1** shows the changes in sulphur reserves during the past year. The ERCB does not estimate sulphur reserves from sour crude oil, as only a very small portion of Alberta's sour crude oil is refined in the province.

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

	2009	2008	Change
Initial established reserves from			
Natural gas	268.9	268.1	+0.8
Crude bitumen[a]	178.5	178.5	0.0
Total	447.4	446.6	+0.8
Cumulative net production from			
Natural gas	243.4	239.8	+3.6
Crude bitumen[b]	22.8	21.2	+1.6
Total	266.2	261.0	+5.2
Remaining established reserves from			
Natural gas	25.5	28.3	-2.8
Crude bitumen[a]	155.7	157.3	-1.6
Total	181.2	185.6	-4.4
Annual production	5.2	5.6	-0.4

[a] Reserves of elemental sulphur from bitumen under active development as of December 31, 2009. 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 25.5 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2009, an decrease of 10 per cent from 2008. Remaining established sulphur reserves has been calculated using a provincial recovery factor of 97 per cent, which was determined taking into account plant efficiency, acid gas flaring at plants, acid gas injection, and flaring of solution gas.

The ERCB's sulphur reserve estimates from natural gas are shown in **Table 7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2009 are Caroline, Crossfield East, and Waterton. Together, these account for 7.3 10^6 t, or 29 per cent, of the remaining established reserves of sulphur from natural gas.

The ERCB estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from ultra-high H_2S pools currently not on production. Based on the initial established reserves of 268.9 10^6 t, this leaves 125.9 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current upgrading operations in which bitumen is converted to synthetic crude oil (SCO), an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in products including coke.

It is currently estimated that some 220.3 10^6 t of elemental sulphur will be recoverable from the 5.44 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by using a factor of 40.5 tonnes of sulphur per 10^3 m^3 of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology yields a higher elemental sulphur recovery than does an alternative carbon-rejection technology, since a larger percentage of the sulphur in the bitumen remains in upgrading residues, as opposed to being converted to H_2S.

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

In 2009, the Long Lake Upgrader began producing synthetic crude from bitumen produced by in situ methods, resulting in the production of a small quantity of elemental sulphur, most of which was not marketed. The ERCB will include such projects in future reports as a new entry in **Table 7.1** when their production levels warrant it. At the same time, however, those mining projects that proceed without their production reporting to an Alberta upgrader will have their sulphur reserves deleted from the provincial total. If all the future bitumen production were to report to an Alberta upgrader, the ultimate sulphur recovered could be in excess of 2 billion tonnes.

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2009

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[a] (%)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Benjamin	2 744	5.5	179	243
Bighorn	2 590	7.1	223	303
Blackstone	1 762	10.1	235	319
Brazeau River	11 137	5.1	709	962
Burnt Timber	1 377	20.3	437	593
Caroline	8 023	16.4	2 079	2 818
Coleman	1 201	26.5	473	642
Crossfield	3 506	14.3	733	993
Crossfield East	2 367	29.3	1 237	1 678
Elmworth	21 239	1.7	426	577
Garrington	3 303	5.2	221	299
Hanlan	7 736	8.8	899	1 219
Jumping Pound West	4 540	6.5	375	508
Kaybob South	14 221	1.4	227	308
Lambert	955	11.7	149	202
Limestone	3 867	12.4	658	893
Marsh	1 021	19.6	289	392
Moose	2 389	13.2	418	567
Okotoks	1 640	20.2	479	649
Panther River	2 272	6.8	200	272
Pembina	20 279	1.5	379	514
Pine Creek	6 819	2.8	219	297
Quirk Creek	1 245	9.3	153	208
Rainbow	7 174	1.7	153	207
Rainbow South	3 245	6.2	287	389
Ricinus West	1 567	32.7	910	1 235
Waterton	5 703	22.3	2 101	2 849
Wildcat Hills	4 716	3.0	162	220
Windfall	2 314	12.3	395	535
Subtotal	150 952	7.9	15 406	20 891
All other fields	904 761	0.3	3 360	4 575
Total	1 055 713	1.6	18 766	25 466

[a] Volume-weighted average.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only a portion of the surface-mineable established crude bitumen reserves are under active development at the Suncor, Syncrude, Shell, Albian Sands, Shell Jackpine, CNRL Horizon, Suncor/UTS Energy/Teck Fort Hills, and Imperial Kearl projects. The ERCB estimate of the initial established sulphur reserves from these active projects is 178.5 10^6 t, representing 81 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface-mineable area. A total of 22.8 10^6 t of elemental sulphur has been produced from these projects, leaving remaining established reserves of 155.7 10^6 t. During 2009, 1.6 10^6 t of elemental sulphur was produced from the currently producing projects.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Supply

There are three sources of sulphur production in Alberta: processing of sour natural gas, upgrading of bitumen to SCO, and refining of crude oil into petroleum products. In 2009, Alberta produced 5.2 10^6 t of sulphur, of which 3.6 10^6 t was derived from sour gas, 1.6 10^6 t from upgrading of bitumen to SCO, and just 11 thousand (10^3) t from oil refining. The total sulphur production in 2009 represents a decrease of 6.6 per cent from 2008 levels.

Figure 7.1 shows sulphur production from gas processing plants from 1967 onward. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional sour gas production declines, less sulphur will be recovered from gas processing plants. This trend is evident in the steep decline in sulphur production from gas processing plants since 1999, as shown in **Figure 7.1**.

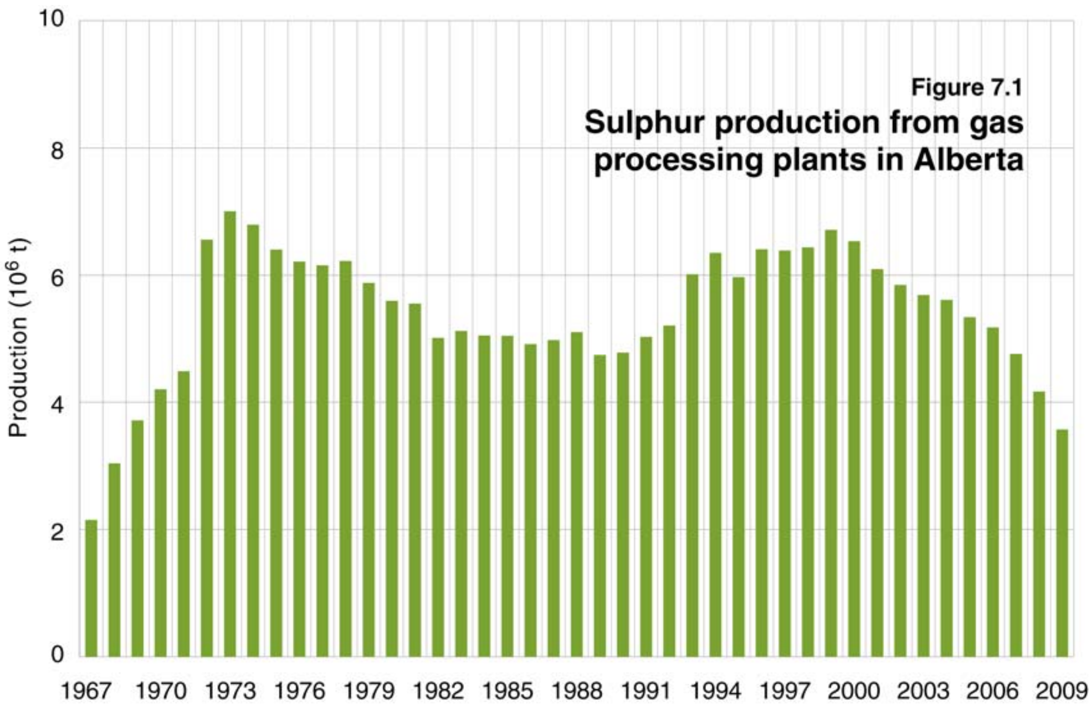
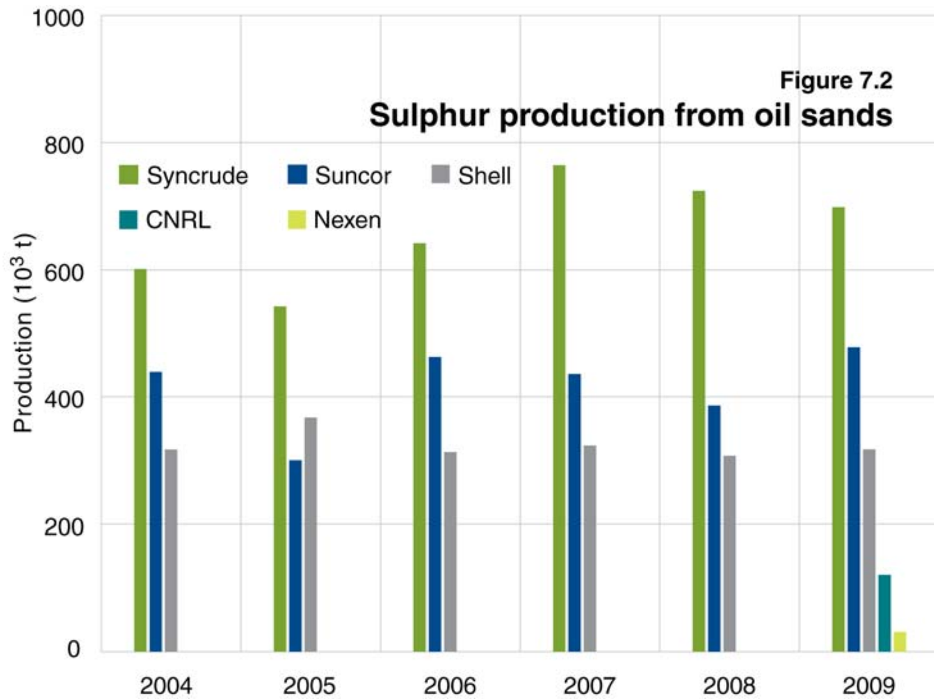


Figure 7.1
Sulphur production from gas processing plants in Alberta

Inventory blocks of sulphur in Alberta at gas processing plants are 3.4 10^6 t at year-end 2009, down marginally from 3.5 10^6 t at year-end 2008. Sulphur stockpiles have been drawn down in recent years, as shown in **Figure 12** in the Overview section. The figure illustrates sulphur closing inventories at gas processing plants and oil sands operations from 1971 to 2009, along with sulphur prices.

Sulphur production from the three existing and two new oil sands upgrader operations for the period 2004-2009 is shown in **Figure 7.2**. Nexen/OPTI and CNRL Horizon started production in January 2009 and February 2009 respectively. Total production of 1.6 10^6 t



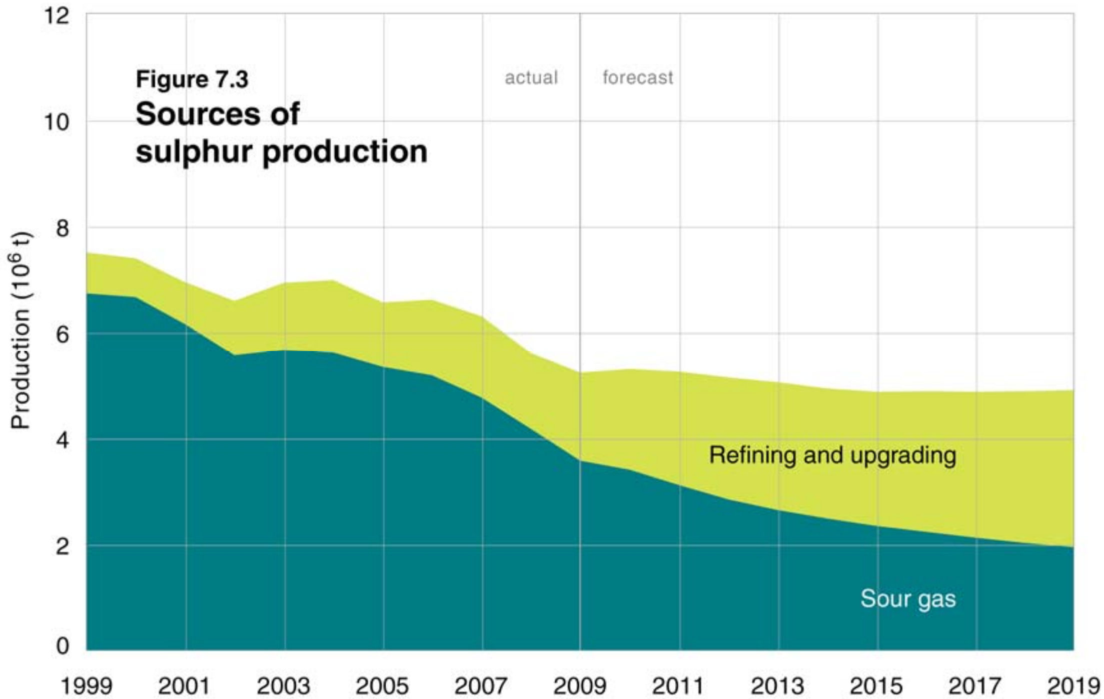
in 2009 is up 14 per cent relative to 2008 production of 1.4 10^6 t, due to the increased Suncor production and the added production from the two new oil sands upgraders.

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

Total Alberta sulphur production from sour gas, crude oil, and bitumen upgrading and refining is depicted in **Figure 7.3**. Sulphur production from sour gas is expected to decrease from 3.57 10^6 t in 2009 to 1.94 10^6 t, or by about 45 per cent, by the end of the forecast period. However, sulphur recovery in the bitumen upgrading industry is expected to increase from 1.6 10^6 t to 2.9 10^6 t. Sulphur recovery from Alberta refineries is forecast to increase from 11 10^3 t in 2009 to 33 10^3 t by 2019, resulting in an increase in sulphur production from upgrading and refineries of 78 per cent by the end of the forecast period. This year’s forecast of sulphur production from bitumen upgrading is lower than last year’s forecast due to this year’s lowered SCO production forecast.

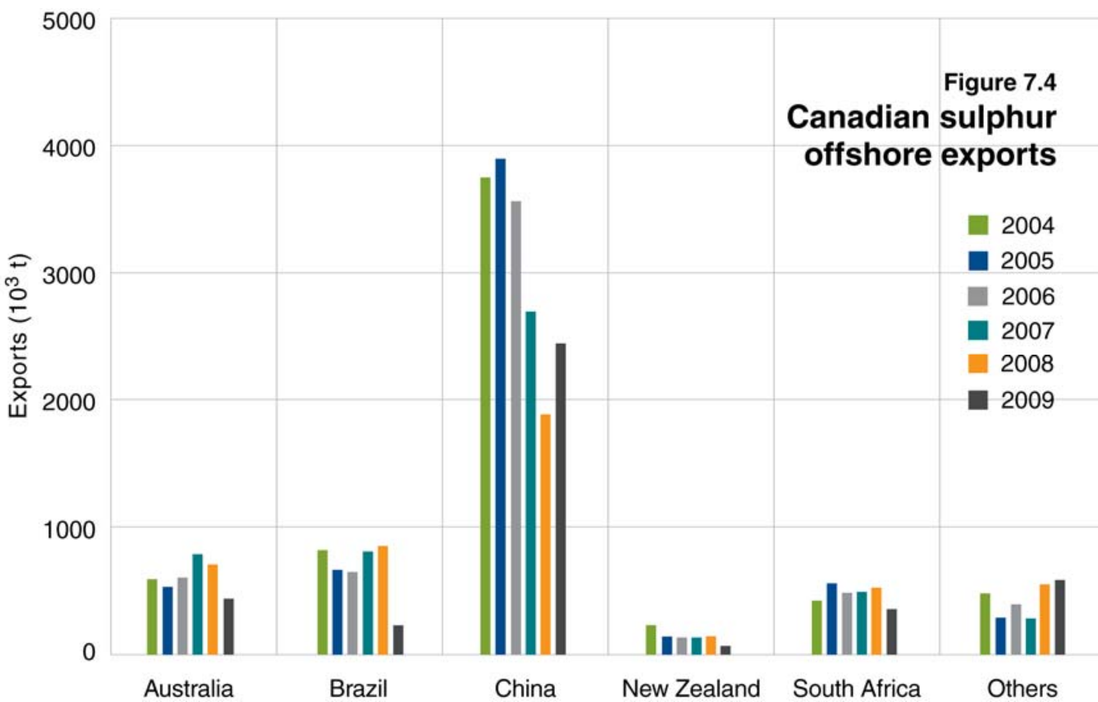
7.2.2 Sulphur Demand

Disposition of sulphur within Alberta in 2009 was 336 10^3 t, down from 461 10^3 t in 2008. Most of Canada’s sulphur production comes from Alberta. Sulphur is used in production of phosphate fertilizer and kraft pulp and in other chemical operations. About 93 per cent of the sulphur marketed by Alberta producers was shipped outside the province. Exports to offshore constituted just over 80 per cent, with 18 per cent going to the U.S. and the remainder to the rest of Canada.



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

China has been one of the fastest growing sulphur markets, and although demand for sulphur in China declined in 2008, Canadian supply to the market has rebounded and



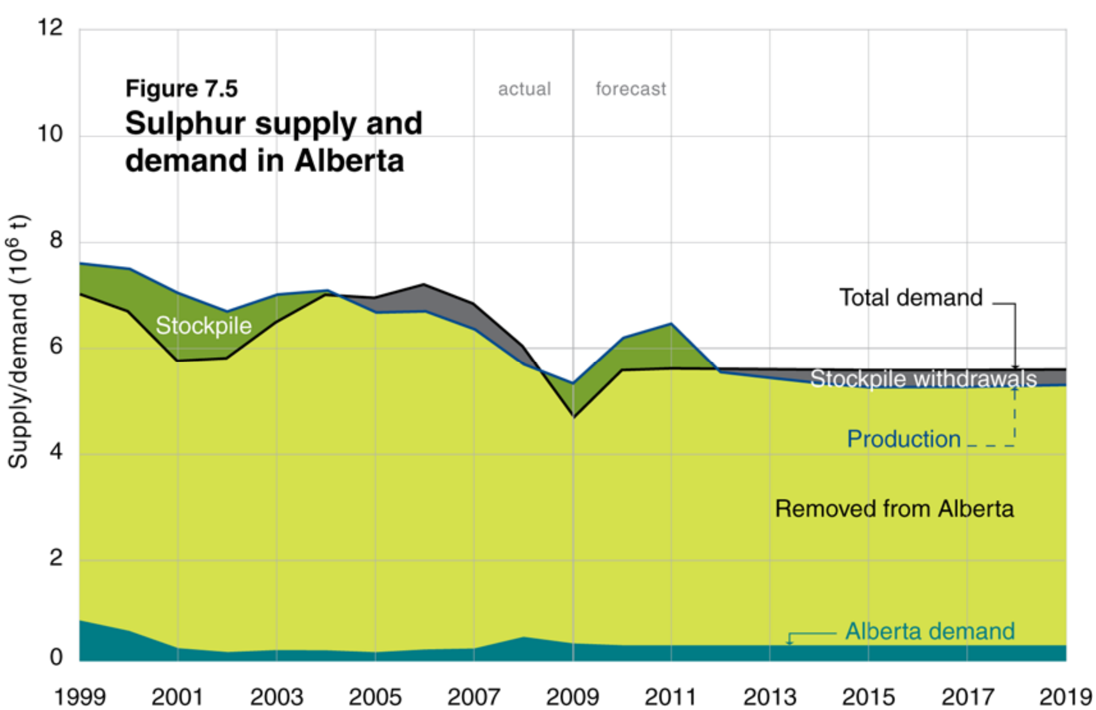
increased by 30 per cent in 2009 over 2008. Meanwhile, Canada's share of exports to other major importers has dropped, as illustrated in **Figure 7.4**.

Increased global demand for sulphur since 2001 resulted in major price changes, from US$16/t in 2001 to US$50/t in 2006. In 2007, the Alberta sulphur prices increased sharply, from US$50/t at mid-year to between $US150/t and US$350/t FOB Vancouver. Prices reached highs of US$800/t in early 2008, before falling in August in tandem with crude oil prices. Prices since the drop have remained relatively low despite the increase in crude oil prices.

In 2009, the Alberta plant gate price for North American sales averaged Cdn$26/t, while the Alberta plant gate price for offshore sales fell into negative territory. Demand for sulphur fell with the downturn in the world economy, but prices are now showing improvement as global economies strengthen, and prices are expected to recover to prerecession levels.

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.

Figure 7.5 shows historical and forecast Alberta total supply, total demand, and the resultant sulphur inventory. In the early part of this decade, weak global sulphur demand resulted in a reduced call on Alberta exports, and as a consequence, Alberta built a significant stockpile of sulphur. Since 2004, supply and demand have generally been in balance, although in 2009 there was a net addition to the sulphur stockpile, which could be associated with another decrease in demand. The forecast assumes that, on average, supply and demand will generally balance over the forecast period, as declining production from natural gas processing plants is replaced by sulphur recovery from the bitumen upgrading industry and the global call on Alberta sulphur supplies will approximate supply.



8 Coal

Highlights

- Remaining established reserves under active development increased by 95 million tonnes (9 per cent of the total) due to the reopening of the Obed mine in 2009.
- Alberta marketable coal production remained flat in 2009 relative to 2008.
- Export markets remained strong in 2009 as a result of new demand from China and recovering demand in traditional Asian markets.

Coal is a combustible sedimentary rock with greater than 50 per cent organic matter. Coal occurs in many formations across central and southern Alberta, with lower-energy-content coals in the plains region, shifting to higher-energy-content coals in the mountain region.

Production of coal from mines is called raw coal. Some coal, particularly that from the mountain and foothills regions of Alberta, needs to be processed prior to marketing; this processed coal is referred to as clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are termed marketable coal. In this report, “reserves” refers to raw coal unless otherwise noted.

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

8.1 Reserves of Coal

8.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of all types of coal in Alberta at December 31, 2009, to be 33.4 gigatonnes[1] (Gt) (36.8 billion tons). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods, and 10.7 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 2009. **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, 2008, to December 31, 2009, resulted from additions to cumulative production. During 2009, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.004 Gt, 0.009 Gt, and 0.025 Gt respectively.

8.1.2 Initial in-Place Resources

There was no change to the in-place resource estimate over the previous year.

In general, shallow coal is mined more cheaply by surface than by underground methods; such coal is therefore classified as surface-mineable. At some stage of increasing depth and strip ratio,[2] the economic advantage passes to underground mining; this coal is

[1] Giga = 10^9.
[2] Strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

Table 8.1. Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2009[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	0.238	0.573
Underground	5.06	0.738	0.109	0.629
Subtotal	6.83[c]	1.56[c]	0.347	1.213[c]
High-volatile bituminous				
Surface	2.56	1.89	0.177	1.713
Underground	3.30	0.962	0.047	0.915
Subtotal	5.90[c]	2.88[c]	0.224	2.656[c]
Subbituminous[e]				
Surface	13.6	8.99	0.779	8.211
Underground	67.0	21.2	0.068	21.132
Subtotal	80.7[c]	30.3[c]	0.847	29.453[c]
Total[c]	93.7[c]	34.8[c]	1.417[d]	33.383[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] Any discrepancies are due to rounding.
[e] Includes minor lignite.

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

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. Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reasons and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal, as well as the thicker underground classes.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region, 70 per cent in the foothills, and 90 per cent in the plains—the three regions designated by the ERCB within Alberta where coals of similar quality and mineability are recovered.

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 metres [m]) and thick (>3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Table 8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2009.

Table 8.2. Established resources and reserves of raw coal under active development as of December 31, 2009

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[d] (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	20	134
Grande Cache	4 250	199	85	28	57
Subtotal	11 705	445	239	48	191
High-volatile bituminous					
Coal Valley	17 865	572	331	137	194
Obed[d]	7 590	162	137	42	95
Subtotal	25 455	734	468	179	289
Subbituminous					
Vesta	2 410	69	54	46	8
Paintearth	2 710	94	67	47	20
Sheerness	7 000	196	150	81	69
Dodds	425	2	2	1	1
Burtonsville Island	150	0.5	0.5	0.1	0.4
Whitewood	3 330	193	120	81	39
Highvale	12 140	1 021	764	375	389
Genesee	7 320	250	176	74	102
Subtotal[c]	35 485	1 826	1 334	706 [c]	628
Total	72 645	3 005	2 041	933	1 108

[a] ha = hectares.
[b] Mt = megatonnes; mega = 10^6.
[c] Any discrepancies are due to rounding.
[d] Resumed operations mid-2009.

8.1.4 Ultimate Potential

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

To avoid large fluctuations of ultimate potentials from year to year, the ERCB has adopted the policy of using the figures published in *Statistical Series 2000-31* and adjusting them slightly to reflect the most recent trends. **Table 8.3** gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potential. No change to ultimate potential has been made for 2009.

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 2009, twelve mine sites supplied coal in Alberta, as shown in **Table 8.4**. The operating mines produced 32.2 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 78.0 per cent of the total, bituminous metallurgical 9.3 per cent, and bituminous thermal coal the remaining 12.7 per cent.

Figure 8.1
Producing coal mines in Alberta

○ Surface coal mine ● Underground coal mine

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

Foothills Region
High-volatile bituminous coals
3. Coal Valley
4. Obed

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

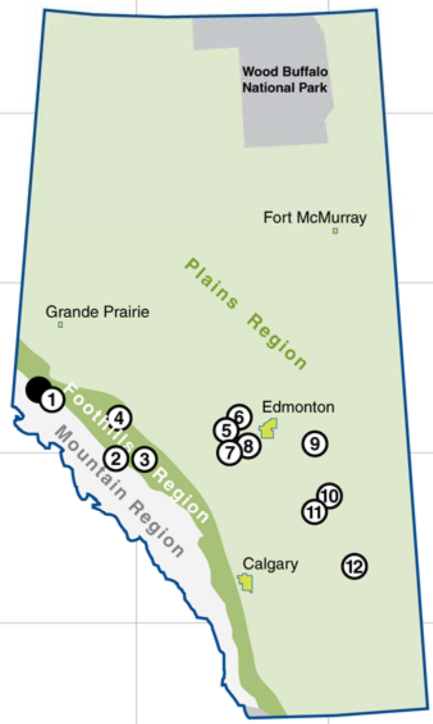


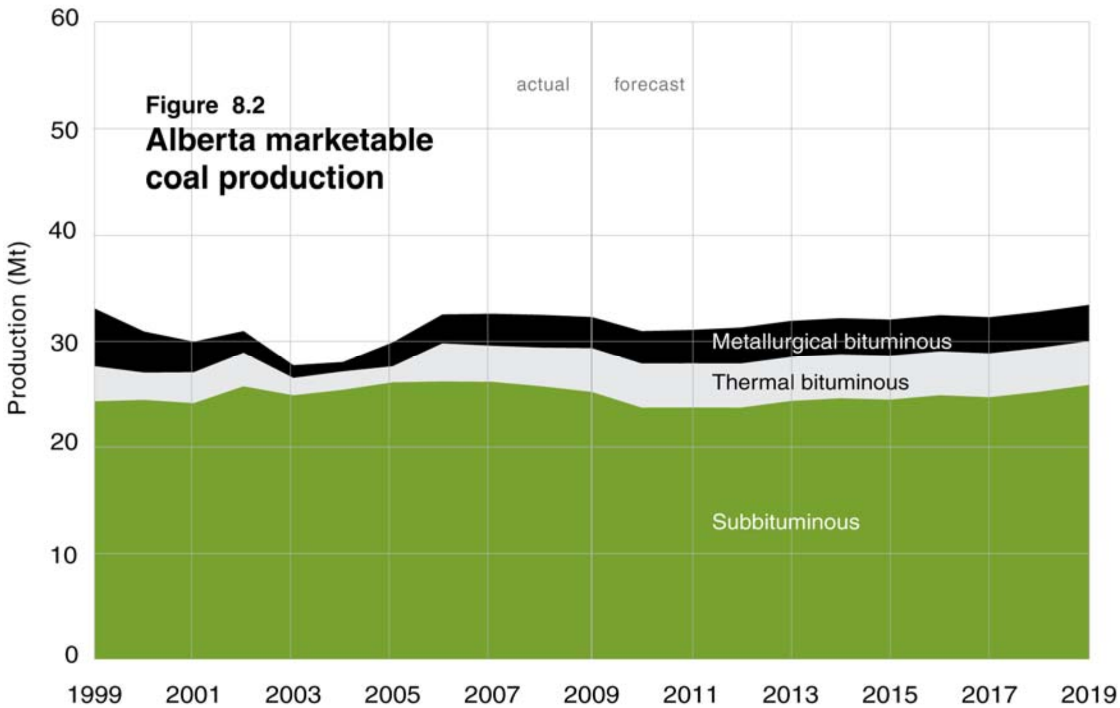
Table 8.4. Alberta coal mines and marketable coal production in 2009

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Sherritt International Corp.	Genesee	Genesee	5.3
Sherritt International Corp.	Sheerness	Sheerness	3.3
	Paintearth	Halkirk	1.7
	Vesta	Cordel	1.3
Sherritt International Corp.	Highvale	Wabamun	12.1
	Whitewood	Wabamun	1.3
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.108
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.021
Subtotal			25.1
Bituminous metallurgical coal			
Teck Resources Limited	Cheviot	Mountain Park	1.6
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.4
Subtotal			3.0
Bituminous thermal coal			
Sherritt International Corp.	Coal Valley	Coal Valley	3.6
	Obed	Obed	0.5
Subtotal			4.1
Total			32.2

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

Four surface mines and one underground mine produce the provincial supply of metallurgical and thermal grade coal.

The projected production for each of the three types of marketable coal is shown in **Figure 8.2**. By 2019, total production is expected to increase by about 3.6 per cent, from 32.2 Mt in 2009 to 33.4 Mt in 2019. The largest increase in production is expected to come from metallurgical grade coal as a result of the planned opening of new mines. Production is expected to increase by some 16 per cent between 2009 and 2019. Growth of just over 2.5 per cent is forecast for subbituminous coal production, while production from thermal grade coal is assumed to remain flat over the forecast period. The Obed Mountain mine, which had been suspended in 2003 due to declining export thermal coal prices, resumed operations in mid-2009.



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 in that the production at these mines can be affected by the commissioning and closures of power generation plants.

The remaining power generation unit at the Wabamun plant site (279 MW) was decommissioned on March 31, 2010. In 2009, an uprate was completed on the Sundance 5 unit, allowing a 53 MW increase in capacity. A new power generation unit at the Keephills plant site with a capacity of 450 MW is planned to be in service in 2011. Upgrades to increase capacity by 23 MW to each of Keephills Units 1 and 2 are scheduled for late 2011 and 2012 respectively.

Alberta’s metallurgical coal primarily serves the Asian steel industry. This creates a competitive disadvantage for Alberta export coal producers, due to the long distances required to transport coal from mine to port. In the latter half of 2009, Alberta coal producers started to receive stronger netback prices as a result of significant new market demand in China, as well as recovering demand from other Asian destinations associated with growth in the call for steel due to the global economic recovery. The forecast assumes a 16 per cent increase in metallurgical coal production to meet export market demand.

9 Electricity

Highlights

- Electricity generating capacity increased by nearly 5 per cent, due mainly to the addition of new natural gas generation.
- In 2009 the annual average pool price decreased to $47.81/MWh from $89.95/MWh in 2008.
- Electricity demand increased by 0.5 per cent in 2009, following a 0.4 per cent increase in 2008.
- Electricity demand for industries with cogeneration (e.g., oil sands and petrochemicals) increased by 10 per cent in 2009.

The ERCB forecasts electric power supply and demand, as it is essential in determining the future domestic demand for some of Alberta's primary energy resources. Of particular importance are the relationships between electricity supply and natural gas and coal resources, as power plants that use these fuels supply over 90 per cent of the electricity generated within Alberta.

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

The competitive wholesale electricity market is facilitated by the Alberta Electric System Operator (AESO) and monitored by the Market Surveillance Administrator (MSA). In addition to managing the electricity sold into the Alberta power pool, the AESO is responsible for the planning of Alberta's transmission system. The MSA monitors Alberta's electricity market for fairness and balance in the public interest by ensuring that the market operates fairly, efficiently, and in an openly competitive manner.

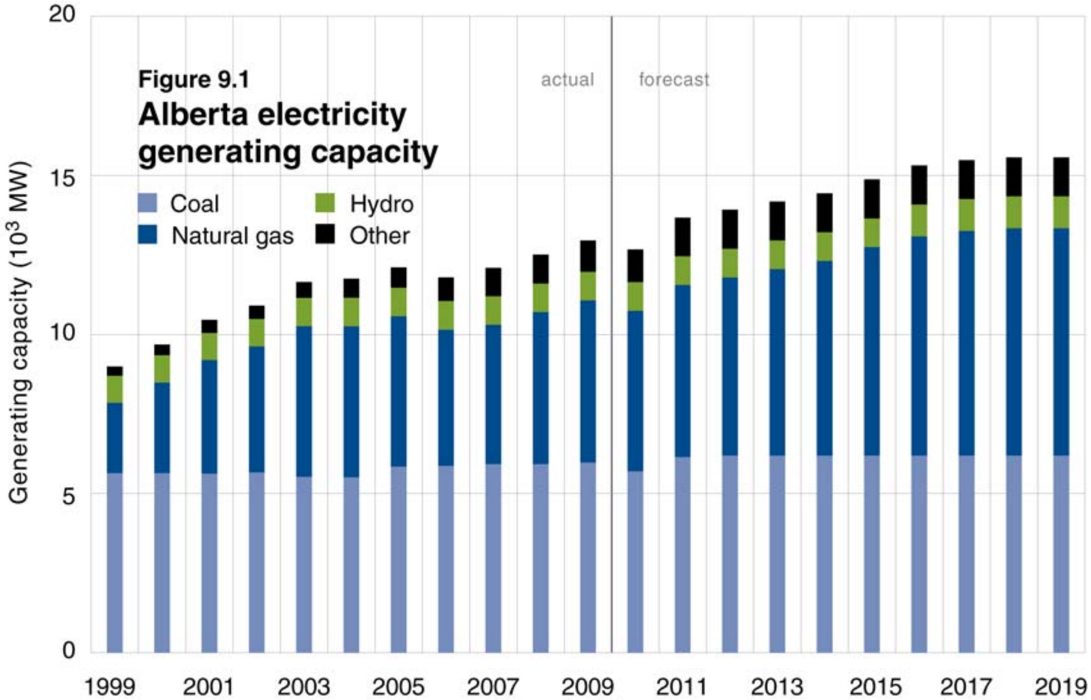
9.1 Electricity Generating Capacity

9.1.1 Provincial Summary

Capacity refers to the maximum potential supply of electric power, often expressed in megawatts[1] (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 "other," 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. The capacity of the various components of Alberta's electricity industry, including a forecast to 2019, is illustrated in **Figure 9.1**.

In 2009, over 70 per cent of the natural gas-fired capacity in the province was classified as cogeneration. Cogeneration is the combined production of electricity and thermal energy using natural gas as a fuel source. Thermal energy is often used in manufacturing processes, heating buildings, the production of steam for in situ oil production, and crude oil refining and upgrading processes. Therefore, cogeneration plants (often referred to as cogen plants) are often sited alongside an industrial facility.

[1] mega = 10^6.



In 1999, Alberta's electric power generation capacity was just under 9000 MW, with coal-fired facilities accounting for 63 per cent. Electric power generation capacity has increased to about 13 000 MW since then, and at the end of 2009 Alberta had 107 electric power generating facilities with a capacity of 5 MW or more. In 2009, coal-fired facilities accounted for 46 per cent of Alberta's total electric generation capacity, down 17 per cent from 1999 levels, and natural gas-fired facilities accounted for 39 per cent, up 14 per cent from 1999.

In 2009, Alberta's electric power generation capacity increased by 628 MW, or about 5 per cent, mostly due to additional capacity from natural gas-fired generators. Three companies brought natural gas-fired peaking units on stream in 2009. Capital Power (previously EPCOR) brought on the Clover Bar 2 and 3 units (101 MW each), and ENMAX brought on the Crossfield Peaking facility (3 units with 40 MW capacity per unit). In addition, MEG Energy commissioned a 94 MW gas-fired cogeneration unit to supply the Christina Lake SAGD (steam-assisted gravity drainage) project. TransAlta commissioned the 66 MW Blue Trail Wind Farm and also completed a project at the Sundance facilities that allowed a capacity uprate of 53 MW. The Grand Prairie Generation peaking plant (93 MW) was given interim authorization to participate in the Alberta electricity market on December 23, 2008. The plant received commercial operation designation on February 25, 2009, and is included in new capacity in 2009.

In early 2010, TransAlta retired the 279 MW Wabamun 4 facility as planned on March 31. TransAlta also commissioned the 66 MW Summerview 2 Wind Farm in the first quarter of 2010. Both of these changes are included in the capacity forecast shown in **Figure 9.1**.

Power projects for which applications have been submitted to the regulatory process and that are considered in our forecast are summarized in **Table 9.1**. Projects, capacities, and applied-for start-up dates are based on information obtained as of February 28, 2010. A number of projects have missed their applied-for start-up dates. These projects are also included in **Table 9.1** and are also considered in the forecast. Although considerable uncertainty surrounds the exact timing of additional oil sands-related facilities, the

Table 9.1. Power plant applications greater than 5 MW, 2009-2019

Power plant by applied-for in-service date	Fuel / type	Location	Proposed capacity (MW)
Past applied-for in-service date			
Deerland peaking station (Phase 1)	Natural gas	Lamont County	90
Firebag in situ cogen 2	Natural gas	Wood Buffalo MD	170
Prairie Home 1 wind turbines	Wind	Warner County	9
2010			
Summerview 2	Wind	Pincher Creek MD	66
Deerland peaking station (Phase 2)	Natural gas	Lamont County	90
Irma generation facility	Natural gas	Wainwright MD	8
Morinville generation facility	Natural gas	Sturgeon County	8
Castle Rock Ridge Wind Farm	Wind	Pincher Creek MD	115
Ardenville Wind Farm	Wind	Pincher Creek MD	66
Connacher Algar	Natural gas	Wood Buffalo MD	15
2011–2019			
Keephills 3	Coal	Parkland County	450
Keephills 1 uprate	Coal	Parkland County	23
Keephills 2 uprate	Coal	Parkland County	23
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
Ghost Pine Wind Farm	Wind	Kneehill County	81
Heritage Wind Farm	Wind	Pincher Creek MD	300
Old Man 1 River Wind Farm	Wind	Pincher Creek MD	46
Old Man 2 River Wind Farm	Wind	Pincher Creek MD	46
Wild Rose Wind Farm 1	Wind	Cypress County	204
University of Calgary	Natural gas	City of Calgary	18
Medicine Hat Box Springs	Wind	Medicine Hat	16
Hand Hills	Wind	Starland County	99
Wintering Hills	Wind	Wheatland County	99
Halkirk Wind Project	Wind	Paintearth County	150
Blackspring Ridge Project	Wind	Vulcan County	300
Maxim HR Milner	Coal	Greenview MD	500
Saddlebrook Power Station	Gas	Foothills MD	338
Enmax Shepard Project	Gas	Calgary	800
Weyerhauser Uprate	Biomass	Grand Prairie	16
TransCanada	Gas	Calgary	40
Mustus Energy	Biomass	Mackenzie County	35
Total proposed generation (2009-2019)			5682

majority are expected to proceed with start-up within the forecast period and are therefore included. The current economic environment presents challenges to wind project developers, and many of the applied-for projects will likely be delayed. As a result of all these factors, the ERCB projects electricity generating capacity in Alberta to be over 15 500 MW by the end of the forecast period, which is slightly lower than last year's forecast of 16 000 MW in 2018.

An additional coal-fired unit at Keephills is the only new coal-fired power plant project currently being constructed that will provide an increase to Alberta's baseload capacity. Keephills 3 is scheduled to be completed in early 2011, after the retirement of Wabamun 4. The addition of 450 MW at Keephills will add 170 MW of baseload coal capacity to the Alberta market after accounting for the retirement of Wabamun 4 in 2010.

As was the case in 2009, new natural gas-fired cogeneration facilities will offer the largest contribution to electricity generating capacity over the forecast period. Their commissioning will coincide with the development of Alberta's oil sands resources. Cogeneration is a source of steam and power, both requirements for oil sands projects. Because there are greater efficiencies associated with cogeneration compared to purchasing electricity and using steam generators, combining cogeneration with an oil sands facility can reduce costs over the life of an oil sands project. If the plant is able to sell power that is in excess of the project requirements, cogeneration can supplement project revenues. By 2019, the capacity of natural gas-fired power and cogeneration units is forecast to total more than 7100 MW, accounting for 46 per cent of Alberta's total available capacity.

9.1.2 Electricity Generating Capacity by Fuel

Coal

In 2009, the capacity of coal-fired generation units was over 5900 MW and accounted for 46 per cent of Alberta's generating capacity.

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

Keephills 3 (450 MW) commenced construction in February 2007 and is expected to reach commercial operation in 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 have lower emissions on a per MWh basis. TransAlta and Capital Power have equal ownership in the Keephills 3 power plant. Capital Power is managing the construction, and TransAlta will operate the facility. The capital cost of Keephills 3, including mine capital, is expected to be about $1.9 billion.

Although some power purchase agreements (PPAs)[2] expire within the forecast period, according to the legislation the PPA may extend beyond the current expiration date.

[2] PPAs were introduced to facilitate the transition of the electricity generating industry from a regulated market to a competitive market. PPAs were auctioned off as long-term rights to sell power from utility plants built during the era of full regulation (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.

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

In 2009, natural gas-fired generating capacity exceeded 5000 MW and accounted for 39 per cent of Alberta's current total electricity capacity. Over the next 10 years, Alberta's natural gas-fired electric capacity is projected to increase by 2052 MW, representing 46 per cent of Alberta's total generating capacity.

The ERCB's 10-year forecast for new natural gas-fired cogeneration power plants that coincide with the development of the oil sands amounts to an additional 1518 MW. These plants will account for 76 per cent of the increase in natural gas-fired capacity. **Table 9.1** lists the cogeneration projects, most of which will be sited in the Municipal District of Wood Buffalo.

In addition to proposed oil sands cogeneration facilities, a number of natural gas-fired peaking facilities have recently been built or proposed. These peaking plants are a response to high, volatile prices in Alberta in recent years, particularly when concurrent forced outages have occurred at baseload coal plants. Peaking plants are designed to be available on short notice and can respond quickly to varying market conditions. In September 2008, TransCanada applied to the AUC to build a 338 MW combined cycle plant south of Calgary. In August 2009, ENMAX applied to build the 800 MW Shepard facility in Calgary. These projects are considered in the 10-year forecast.

Hydroelectric Power

Hydroelectric generation capacity in Alberta has been essentially unchanged since 2003 at almost 900 MW, accounting for 7 per cent of total generation capacity in 2009. About 860 MW of this capacity is owned by TransAlta along the Bow and North Saskatchewan rivers.

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

Other

About 8 per cent of Alberta's current electricity capacity is classified as "other," which includes biomass and wind.[3] 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 2009, Alberta biomass capacity amounted to 323 MW, 2.5 per cent of Alberta's total capacity sources.

[3] Some projects have been reclassified as renewable, depending upon the percentage of renewable fuels consumed, since the last report.

Wind-powered electric generation capacity has increased significantly over the last decade, from 23 MW in 1997 to 591 MW in 2009 as reported to the ERCB. Transmission infrastructure has been a significant barrier for new wind capacity in southern Alberta, but the AESO applied for a transmission upgrade that would accommodate 1200 MW of new wind generation in southern Alberta in its first phase. In September 2009, the AESO received regulatory approval for additional future expansion phases that could accommodate up to 2700 MW of wind capacity in total. Lower than expected electricity demand, lower natural gas prices, and the deadline for the federal government ecoENERGY subsidy are factors that may impact the timing of additional wind-powered electric generation projects.

9.2 Supply of and Demand for Electricity

This section discusses the supply and demand for electricity within Alberta. On the supply side, the stock of electricity, or capacity, is measured in watts, while the flow of electricity, or generation, is measured in watt hours. In this report, electricity demand is measured in gigawatt hours (GWh).

Electricity generation is the amount of electricity produced within a certain time period. For instance, if an electricity plant with a rated capacity of 100 MW operated at its maximum potential for one day, it would supply 2.4 GWh of electricity. Alternatively, if the same plant only supplied 1.8 GWh of electricity on a given day, the plant would be using 75 per cent of its potential capacity.

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

The operating capacity of an existing electricity generating unit is determined using its historical operating parameters, such as outage and capacity utilization rates. In the oil sands sector, the forecast of electricity generation from new generation is ramped up in a phased approach that corresponds with the expected on-site load at certain phases of bitumen or synthetic crude oil (SCO) production.

The stacking order of electricity generation refers to the order in which electricity from each generating unit is offered in or sold to the electricity grid. The lowest marginal cost producers, which include wind turbines, hydroelectric dams, and an amount of base coal-fired generation, are expected to offer in electricity generation first. Higher marginal cost producers, such as natural gas-fired turbines (under a regime of high natural gas prices), offer electricity into the grid at times of peak demand.

The electricity generation forecast complements the electricity demand forecast by incorporating hourly load profiles and the ERCB forecast of electricity demand for each year. There is an hourly load profile for each year that corresponds to the forecast total load. By incorporating hourly loads, generating units are dispatched hourly, accounting for periods of high load and low load throughout each year.

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

The ERCB uses customer segments and econometric modelling to forecast electricity demand. The key driver of residential and commercial electricity demand is population. Industrial customers are examined in greater detail in order to adequately account for electricity demand in this sector. This report incorporates new projections for non-oil sands industrial demand that are based on expected conventional crude oil and natural gas production in the province. The anticipated decline in conventional natural gas production is expected to result in an increased number of natural gas plant consolidations, which will result in reduced electricity demand for processing. On the other hand, declining crude oil production tends to increase electricity demand as more water handling is required. In the oil sands sector, projections are based on bitumen and SCO production forecasts and the types of projects (in situ or mining).

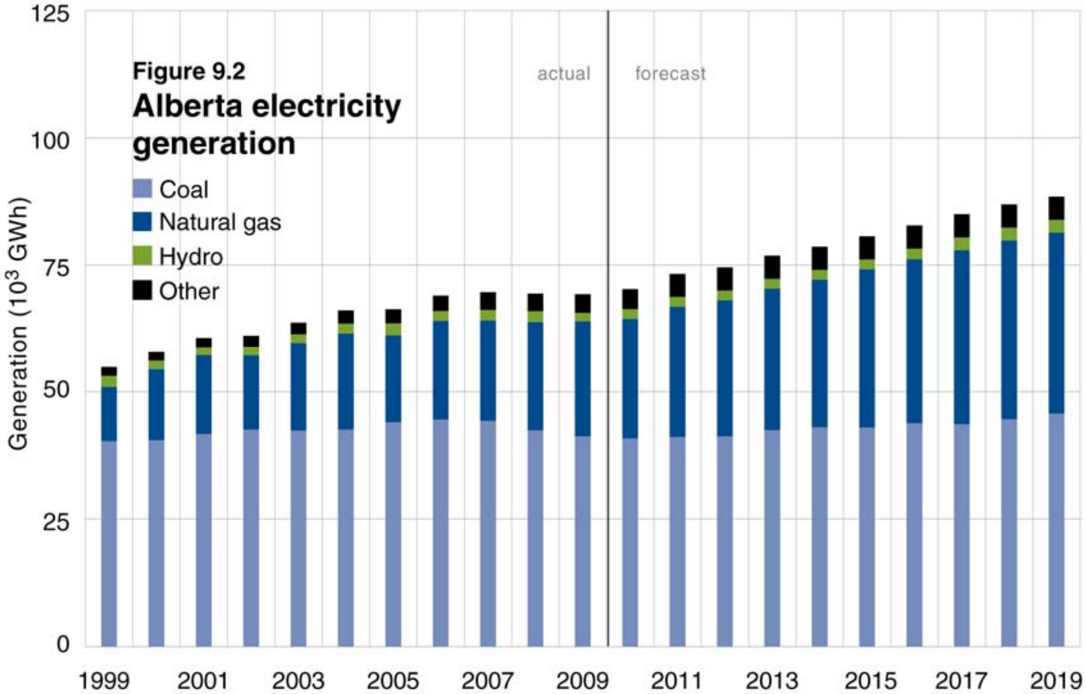
9.2.1 Electricity Generation

Alberta installed electricity generation capacity in 2009 was 13 007 MW, enough to supply about 114 000 GWh of electricity if operated at full capacity. However, total electricity generation capacity is not continuously available to meet demand. Generation units are sometimes unavailable due to scheduled and unscheduled maintenance, forced outages, technical limitations (for instance, of wind turbines), or economic reasons. The current forecast projects that electric power generation capacity in Alberta will increase by over 2400 MW over the next 10 years, a significant reduction from last year's forecast increase of almost 4000 MW, which is consistent with the reduced electricity demand forecast.

Figure 9.2 illustrates total electric generation, actual and forecast to 2019, 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 2009, total electricity generation reached 69 262 GWh, a small decline from the 69 392 GWh[4] reported in 2008. The decline in electricity generation in 2009 was due to a 3 per cent drop in electricity generation from coal, due to higher plant outages. Between 1999 and 2009, electricity generation in Alberta grew by 14 376 GWh, or an average 2.4 per cent per year. By 2019, total electricity generation is forecast to be over 88 000 GWh, lower than last year's forecast of over 92 000 GWh in 2018. This reduction is due to the lower electricity demand forecast and unfavourable economic conditions, which caused a delay of wind projects included in last year's forecast.

In 2009, coal-fired power plants generated almost 60 per cent of the province's electricity, while natural gas and hydro accounted for 33 and 2 per cent respectively. Hydro generation was impacted by low water flows. The remaining 5 per cent was generated by wind and other renewable sources. Natural gas cogeneration plants dedicated to the oil sands sector generated 14 613 GWh of electricity in 2009, of which 9649 GWh (66 per cent) of the electricity generated was used on site, with the remaining sold into the power pool. By 2019, coal-fired power plants are forecast to generate 52 per cent of the province's electricity, while natural gas and hydro are forecast to account for 40 and 3 per cent respectively. The remaining 5 per cent is projected to be generated by wind and other renewable sources.

[4] Note that the historical data have been revised since the last report to reflect a reporting discrepancy that occurred from 2005.



Electric power generation from wind turbines contributed 1558 GWh, or 2 per cent, of total electricity generation in 2009 and is included in the “other” category in **Figure 9.2**. Wind generation constituted 43 per cent of the electricity generated in the “other” category, with electricity generation from biomass accounting for most of the remaining generation in this category. By 2019, wind generation is forecast to constitute 74 per cent of the “other” category.

9.2.2 Electricity Transfers

Alberta’s transmission lines are connected with British Columbia (B.C.) and Saskatchewan. Alberta is interconnected with the B.C. transmission system through a 500 kilovolt[5] (kV) line between Langdon, Alberta, and Cranbrook, B.C., and two 138 kV lines between Pocaterra and Coleman, Alberta, and Natal, B.C. Since B.C. is connected with the United States (U.S.) Pacific Northwest, the Alberta-B.C. intertie allows Alberta to indirectly trade electricity with the U.S. The 230 kV direct current electrical tie with Saskatchewan enables Alberta to import or export about 150 MW.

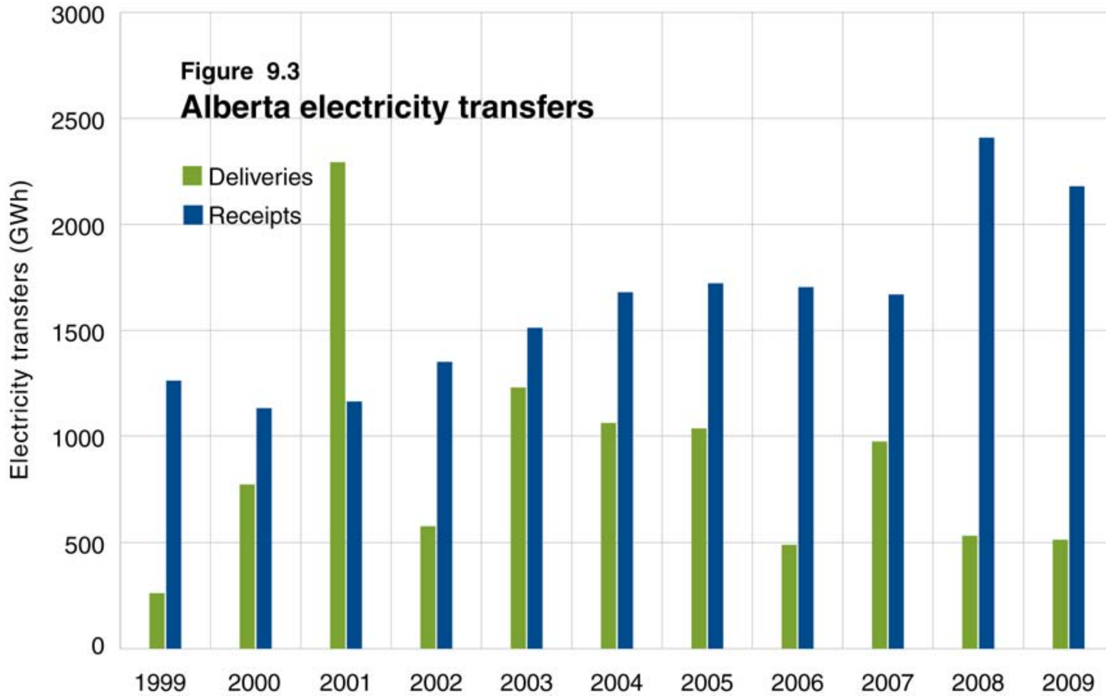
The Alberta-B.C. interconnection was designed to operate at transfer capacities of 1200 MW from B.C. to Alberta and 1000 MW from Alberta to B.C. Operations on the Alberta-B.C. intertie are typically below these capacities and range between 0 and 750 MW, depending on system load and real-time operation conditions.

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

Figure 9.3 illustrates Alberta’s electricity transfers from 1999 to 2009. Over the last decade, Alberta has generally been a net importer of electricity, except in 2001, when the electricity price differentials between Alberta and the Pacific Northwest favoured Alberta

[5] kilo = 10^3.

and resulted in net exports for the year. In 2009, Alberta imported 2180 GWh of electricity from both Saskatchewan and B.C., a decrease of 10 per cent, or 229 GWh, from 2008. Electricity exports decreased 4 per cent, or 19 GWh, to 513 GWh in 2009 relative to 2008. As a result, Alberta's net imports of electricity were 1667 GWh in 2009. The exports went almost exclusively to the B.C. side (95 per cent), which absorbed 487 GWh of power. The imports were also weighted toward the B.C. tie (69 per cent).



In December 2009, Montana Alberta Tie Ltd. (MATL) began construction of a 230 kV merchant electric transmission line between Lethbridge, Alberta, and Great Falls, Montana, on December 1. Construction is expected to take 18 months, which would make the line available for service in 2011.

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

9.2.3 Electricity Demand in Alberta

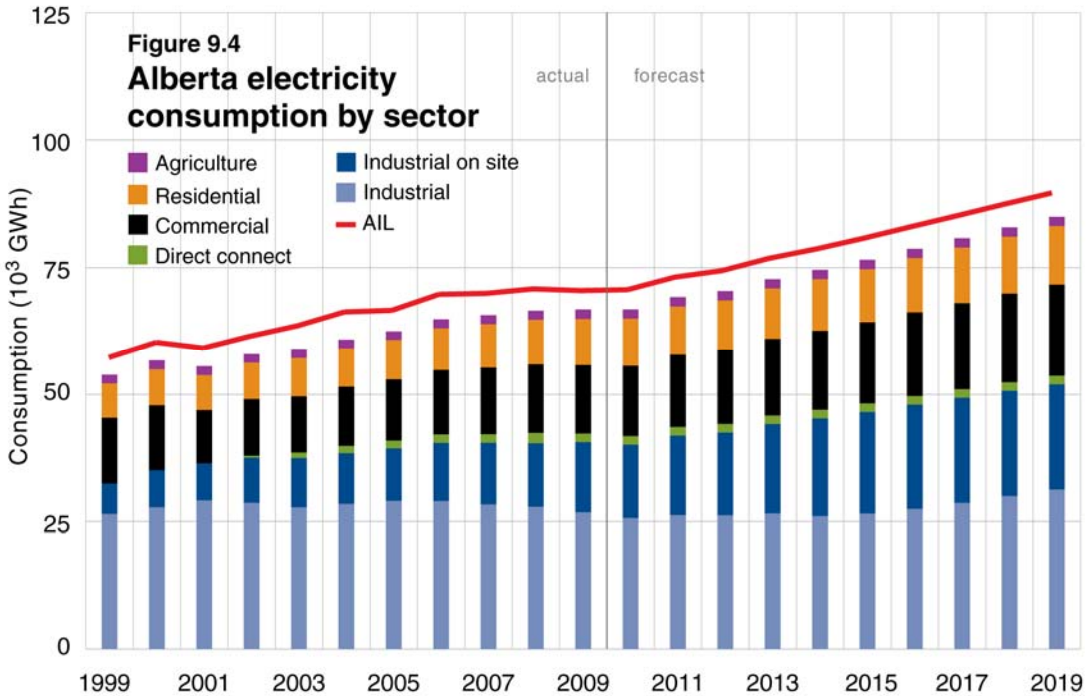
The demand for electricity is often reported as two series. The first, the AIES, is the sum of all reported electricity sales (residential, commercial, industrial, and farm) and transmission and distribution losses.[6] The second, AIL, incorporates AIES and behind-the-fence load, which can be characterized 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

[6] 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 2009, direct connect sales were about 1703 GWh, or 2 per cent of total AIL demand.

of the AIL forecast presented in this section. These forecasts are generated primarily from the ERCB forecast of economic and population growth, projections of oil sands development, and the expected production of conventional oil and natural gas.

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 67 207 GWh in 2009. Compared to 2008, this is an increase of 348 GWh, or 0.5 per cent.



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

In 2009, Alberta's electricity consumption from sales reported by electricity distributors was 51 328 GWh. This is a 1.4 per cent decrease from the sale of 52 041 GWh reported in 2008. From these sales, about 52 per cent of the electricity consumed is sold to industrial customers, 26 per cent to commercial customers, 18 per cent to the residential sector, and 4 per cent to the farm sector.

Details on customers provided by electricity retailers reveal that over 1.28 million residential customers consumed 9090 GWh of electricity in 2009. This resulted in an electricity intensity of 7.1 MWh per residential customer, slightly higher than the 7.0 MWh per customer of 2008 and higher than the historical five-year average of 6.9 MWh per residential customer. Residential demand was 2.47 MWh per capita in 2009, compared to 2.46 MWh in 2008, an increase of 0.5 per cent. Consumption per capita has demonstrated growth averaging 0.4 per cent per year over the period 1999 to 2009.

The electricity usage of the average commercial customer was estimated to be 84.2 MWh in 2009, significantly lower than the 90.3 MWh in 2008 and lower than the five-year average of 86.8 MWh. Commercial electricity demand per capita averaged 3.67 MWh per capita in 2009, compared to 3.76 MWh in 2008, a drop of 2.4 per cent. In 2008, electricity demand reflected a record summer peak demand, which was not duplicated in 2009. Despite the drop, commercial electricity demand per capita has increased by 0.9 per cent per year on average since 2002.

Of the total electricity demand from all sectors, 76 per cent was sold through the AIES. In 2009, over 42 000 GWh, or 63.5 per cent, of the total electricity demand of all sectors was used by industrial consumers. About 28 500 GWh, or 67 per cent of industrial load, was sold through the AIES as sales by electricity distribution companies and direct connect customers, while 14 176 GWh of the electricity requirements of the industrial sector was delivered through on-site power generation or cogeneration. Electricity demand for industries with cogeneration (e.g., oil sands and petrochemicals) increased by 10 per cent in 2009.

Between 1998 and 2006, electricity demand grew by almost 4 per cent per year in response to rapid growth in all sectors, as the Alberta economy grew in response to the massive investments in the oil sands. However, increasing cost pressures, lower oil prices, and the recent financial crisis have resulted in the slowing down of oil sands investments. In addition, Alberta conventional natural gas production began to decline in 2006 and is projected to continue to decline throughout the forecast period. The decline in conventional natural gas production will likely prompt additional natural gas plant consolidations, resulting in lower electricity demand. More important, the increase in new natural gas plants constructed in the 1999-to-2009 period is unlikely to be repeated, as conventional natural gas well drilling is forecast to be significantly lower.

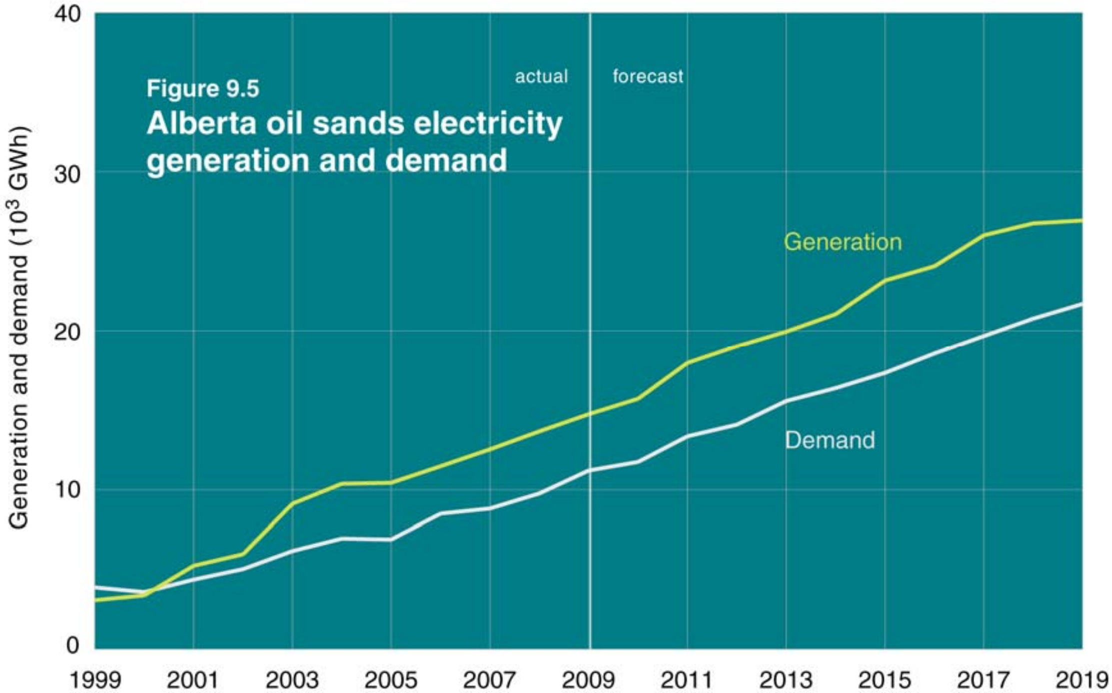
The forecast for AIL growth from 2010 onward is projected to average 2.4 per cent. By 2019, the AIL demand is forecast to be 90 304 GWh. Although oil sands project timing has become more uncertain, most of the proposed projects are delayed but still projected to come on stream during the forecast period. However, growth in oil sands electricity demand will be partially offset by lower growth in the conventional natural gas processing sector, with the result that total industrial electricity demand will grow by only 2.4 per cent per year.

Over the next 10 years, growth in residential electricity demand is also projected to average 2.4 per cent per year, tracking the lower economic growth rate and population growth. Farm load is projected to be relatively constant at a level consistent with the average of the last 3 years. Electricity demand in the commercial sector will increase at 2.9 per cent per year, based on the ERCB’s current economic forecast and population outlook for Alberta.

Alberta electric power generation is expected to match the projected growth in AIL demand of 2.4 per cent a year over the next decade. Over the forecast period, load growth will continue to be met primarily by existing and new natural gas-fired and coal-fired power plants. While significant amount of wind power development had been proposed, the recent financial crisis, lower than expected Alberta electricity demand, lower forecasts for natural gas prices and related electricity prices, and the March 31, 2011, deadline for the federal government ecoENERGY subsidy all have negatively impacted the outlook for further wind power developments during the forecast period. As a result, a number of wind projects that were included in last year’s forecast period have been delayed beyond the end of the forecast period for this current outlook.

9.2.4 Oil Sands Electricity Supply and Demand

Figure 9.5 depicts the balance between electricity supply and demand[7] within Alberta's oil sands sector. Electricity generation from the oil sands was forecast by applying the historical operating parameters of existing electricity cogeneration units to the proposed capacities of all current and future cogeneration units. Electricity demand is based on existing electricity intensities, electricity intensities outlined in regulatory applications, and the ERCB supply forecast for bitumen and SCO.



Electricity cogeneration units at the oil sands mines, upgraders, and in situ projects typically provide required process steam and generate electricity to meet on-site electricity demand. Surplus electricity may be generated and sold to the power pool. **Table 9.2** displays 2009 electricity statistics by type of oil sands facility.

Table 9.2. 2009 electricity statistics at oil sands facilities

Project type	Capacity (MW)	Total generation (GWh)	Capacity utilization (per cent)	Generation used on site (GWh)
Mines and upgraders*	1430	9108	73	6912
Thermal in situ	760	5505	82	2737

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

Data for mining operations and upgraders indicate an annual capacity utilization of 73 per cent. Of the total electricity generated, 76 per cent was used on site and the remaining electricity was sold to the power pool.

Currently, seven thermal in situ oil sands producers are obtaining steam from on-site cogeneration facilities. One facility was in start-up during the fourth quarter of 2009 and is not included in these statistics due to lack of sufficient data. The installed electric

[7] Historical electricity demand for in situ oil sands projects that do not operate cogeneration units was estimated using an assumption of 10 kilowatt hours per barrel.

generation capacity at each of these thermal operations ranges between 80 and 180 MW. In 2009, thermal in situ cogeneration facilities operated at 82 per cent of their installed capacity and 50 per cent of the electricity generated was used on site, with the remaining output sold to the power pool.

In 2009, annual capacity utilization increased compared to 2008, as both the Long Lake in situ oil sands project and the Horizon mining oil sands project had a full year of operations. Both projects did not ramp up to full capacity as expected, and so further improvements in operating rates are projected.

Currently, all oil sands mining operations and bitumen upgraders obtain electricity from on-site cogeneration facilities. However, the lack of upgrader projects that include on-site cogeneration facilities from the list of new upgrader capacity illustrates that many new upgraders sited in the Edmonton region will rely increasingly on purchasing electricity from the AIES.

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. Given the current outlook for natural gas pricing and for electricity pricing, this alternative may prove to be more attractive for some developers.

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.
Cogeneration Gas Plant	Gas-fired plant used to generate both electricity and steam.
Commingled	Commingled flow describes the production of fluid from two or more separate zones through a single conduit.
Compressibility Factor	A correction factor for nonideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(d.1)).
Connected Wells	Gas wells that are tied into facilities through a pipeline.
Crude Bitumen	A naturally occurring viscous mixture mainly of hydrocarbons heavier than pentane that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well (*Oil Sands Conservation Act*, Section 1(1)(f)).
Crude Oil (Conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen (*Oil and Gas Conservation Act*, Section 1(1)(f.1)).

Crude Oil (Heavy)	Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater.
Crude Oil (Light-Medium)	Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3.
Crude Oil (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.
Development Entities (DEs)	A development entity (DE) is an entity consisting of multiple formations in a specific area described in an order of the ERCB from which gas may be produced without segregation in the wellbore subject to certain criteria specified in Section 3.051 of the *Oil and Gas Conservation Regulations* (Order No. DE 2006-2).
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.
Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).
Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).

Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field	(i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or (ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, Section T1T (x)).
Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Field/Strike Area	An administrative geographical boundary used for grouping resource accumulation.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.
Frontier Gas	In this report this refers to gas produced from areas of northern and offshore Canada.
Gas	Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).
Gas (Associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (Marketable)	A mixture mainly of methane originating from raw gas or, if necessary, from the processing of the raw gas for the removal or partial removal of some constituents and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).
Gas (Marketable at 101.325 kPa and 15°C)	The equivalent volume of marketable gas at standard conditions.
Gas (Nonassociated)	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
Gas (Raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components that is recovered or is recoverable at a well from an underground reservoir and is gaseous at

the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(s.1)).

Gas (Solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.
Gas-Oil Ratio (Initial Solution)	The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.
Good Production Practice (GPP)	Production from oil pools at a rate (i) not governed by a base allowable, but (ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain its share of the production (*Oil and Gas Conservation Regulations* 1.020(2)9). This practice is authorized by the ERCB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.
Gross Heating Value (of Dry Gas)	The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.
Horizontal Well	A well in which the lower part of the wellbore is drilled parallel to the zone of interest.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Initial Volume in Place	The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.
Maximum Day Rate	The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.
Maximum Recoverable Thickness	The assumed maximum operational reach of underground coal mining equipment in a single seam.
Mean Formation Depth	The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.

Methane In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, Section 1(1)(m.1)).

Multilateral Well A well where two or more production holes, usually horizontal in direction with reference to the zone of interest, are drilled from a single surface location.

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

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.

OPEC Reference Basket Price OPEC calculates a production-weighted reference price, consisting of 12 different crudes: Saharan Blend (Algeria), Iran Heavy, Iraq Basra Light, Kuwait Export, Libya Es Sider, Bonny Light (Nigeria), Qatar Marine, Arab Light (Saudi Arabia), United Arab Emirates Murban, Merey (Venezuela), Girassol (Angola), and Oriente (Ecuador). The OPEC reference crude has an American Petroleum Institute (API) gravity of 32.7°, with an average sulphur content of 1.77 per cent.

Pay Thickness (Average) The bulk rock volume of a reservoir of oil, oil sands, or gas divided by its area.

Pentanes Plus — A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate, or crude oil (*Oil and Gas Conservation Act*, Section 1(1)(p)).

Pool — A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(q)).

Porosity — The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.

Pressure (Initial) — The reservoir pressure at the reference elevation of a pool upon discovery.

Propane — In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, Section 1(1)(s)).

Recovery (Enhanced) — The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. The artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of
(i) aiding in the lifting of fluids in the well, or
(ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means (*Oil and Gas Conservation Act*, Section 1(1)(h)).

Recovery (Pool) — In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.

Recovery (Primary) — Recovery of oil by natural depletion processes only measured as a volume thus recovered or as a fraction of the in-place oil.

Refined Petroleum Products — End products in the refining process.

Refinery Light Ends — Light oil products produced at a refinery; includes gasoline and aviation fuel.

Remaining Established Reserves — Initial established reserves less cumulative production.

Reprocessing Facilities — Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.

Reservoir — A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Retrograde Condensate Pools	Gas pools that have a dew point such that natural gas liquids will condense out of solution with a drop in reservoir pressure. To limit liquid dropout in the reservoir, dry gas is reinjected to maintain reservoir pressure.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (Gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (Water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shale Gas	The naturally occurring dry, predominantly methane gas produced from organic-rich, fine-grained rocks.
Shrinkage Factor (Initial)	The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.
Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.
Specification Product	A crude oil or refined petroleum product with defined properties.
Sterilization	The rendering of otherwise definable economic ore as unrecoverable.
Straddle Plants	These are reprocessing plants on major natural gas transmission lines that process marketable gas by extracting natural gas liquids. This results in gas for export having a lower heat content than the marketable gas flowing within the province.
Strike Area	See Field/Strike Area
Strip Ratio	The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) thickness of overburden to thickness of coal, (2) volume of overburden to volume coal, (3) weight of overburden to weight of coal, or (4) cubic yards of overburden to tons of coal. A stripping ratio commonly is used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.

Successful Wells Drilled Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.

Surface Loss A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.

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.

Well Connections Refers to the geological (producing) occurrences within a well; there may be more than one per wellbore.

Zone Any stratum or sequence of strata that is designated by the ERCB as a zone (*Oil and Gas Conservation Act*, Section 1(1)(z)).

1.2 Abbreviations

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
DISC YEAR	discovery year
EOR	enhanced oil recovery
FRAC	fraction
GC	gas cycling
GIP	gas in place
GOR	gas-oil ratio
GPP	good production practice
INJ	injected
I.S.	integrated scheme
KB	kelly bushing
LF	load factor
LOC EX PROJECT	local experimental project
LOC U	local utility
MB	material balance
MFD	mean formation depth
MOP	maximum operating pressure
MU	commingling order
NGL	natural gas liquids
NO	number
NON-ASSOC	nonassociated gas
PE	performance estimate
PD	production decline
RF	recovery factor
RGE	range
RPP	refined petroleum production
SA	strike area
SATN	saturation
SCO	synthetic crude oil
SF	solvent flood
SG	gas saturation
SL	surface loss
SOLN	solution gas
STP	standard temperature and pressure
SUSP	suspended
SW	water saturation
TEMP	temperature
TOT	total
TR	total record
TVD	true vertical depth
TWP	township
VO	volumetric reserve determination
VOL	volume
WF	waterflood
WM	west of [a certain] meridian
WTR DISP	water disposal
WTR INJ	water injection

1.3 Symbols

International System of Units (SI)

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

Imperial

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

1.4 Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric		Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	=	35.49373 cubic feet of gas (14.65 psia and 60°F)
1 m^3 of ethane (equilibrium pressure and 15°C)	=	6.33 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	=	6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	=	6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	=	6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	=	6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	=	0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	=	1.102311 short tons (2000 pounds)
1 kilojoule	=	0.9482133 British thermal units (Btu as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.
[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value	Scientific notation
kilo	thousand	10^{3}
mega	million	10^{6}
giga	billion	10^{9}
tera	thousand billion	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4*
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Synthetic crude oil	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

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

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Natural Gas Reserves, and Natural Gas Liquids

Table B.1. Initial in-place resources of crude bitumen by deposit

Oil Sands Area Oil sands deposit	Depth / region / zone (m)	Resource determination method	Initial volume in place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150 - 450+	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	152 432
Nisku	200 - 800+	Isopach	10 330
Grosmont	All zones	Isopach	64 537
Subtotal			235 977
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350 – 625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			29 090
Peace River			
Bluesky-Gething	300 - 800+	Isopach	10 968
Belloy	675 - 700	Building block	282
Upper Debolt	500 - 800	Building block	1 830
Lower Debolt	500 - 800	Building block	5 970
Shunda	500 - 800	Building block	2 510
Subtotal			21 560
Total			286 627

Table B.2. Basic data of crude bitumen deposits

Oil Sands Area / Oil sands deposit / Depth / region / zone / Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150 - 450+	Building Block	5274.00	334.00	9.0	0.062	0.55	0.30	0.45
Middle Grand Rapids								
150 - 450+	Building Block	2354.00	182.00	5.0	0.077	0.68	0.30	0.32
Lower Grand Rapids								
150 - 450+	Building Block	1050.00	173.00	6.0	0.051	0.45	0.30	0.55
Wabiskaw-McMurray								
0 - 65 (mineable)	Isopach	20823.00	375.00	25.9	0.101	0.76	0.28	0.24
65 - 750+ (in situ)	Isopach	131609.00	4694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200 - 800+	Isopach	10330.00	499.00	8.0	0.057	0.63	0.21	0.37
Grosmont								
D	Isopach	32860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18755.00	1069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8472.00	1274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27
Lower Grand Rapids 5								
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15

(continued)

Oil Sands Area Oil sands deposit Depth / region / zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350 – 625	Isopach	9422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300 - 800+	Isopach	10968.00	1016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675 – 700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500 – 800	Building Block	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		286626.67						

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

Year	Initial established: New discoveries	Initial established: EOR additions	Initial established: Development	Initial established: Net revisions	Net total additions	Cumulative production	Remaining established
1968	62.0				119.8	430.3	1 212.8
1969	40.5				54.5	474.7	1 222.8
1970	8.4				36.7	526.5	1 207.9
1971	14.0				22.1	582.9	1 173.6
1972	10.8				20.0	650.0	1 126.0
1973	5.1				9.2	733.7	1 052.0
1974	4.3				38.5	812.7	1 011.5
1975	1.6				7.0	880.2	950.9
1976	2.5				-18.6	941.2	871.3
1977	4.8				19.1	1 001.6	830.0
1978	24.9				24.4	1 061.6	794.5
1979	19.2				34.3	1 130.1	760.2
1980	9.0				22.8	1 193.3	719.9
1981	15.0	7.2			32.6	1 249.8	696.0
1982	16.8	6.6			6.9	1 303.4	649.4
1983	21.4	17.9			64.1	1 359.0	657.8
1984	29.1	24.1			42.0	1 418.2	640.7
1985	32.7	21.6			64.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2 566.5	228.4

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

Year	Initial established: New discoveries	Development	Revisions	Net additions	Cumulative	Cumulative production	Remaining actual[a]	Remaining @ 37.4 MJ/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0

[a] At field plant.

Table B.5. Natural gas reserves of gas cycling pools, 2009

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas (10^6 m^3)
Brazeau River Nisku J	557	74.44	41	0.73	0.50	15	41.10	365	0
Brazeau River Nisku K	1 421	74.17	105	0.75	0.60	31	42.15	746	34
Brazeau River Nisku M	1 945	76.22	148	0.75	0.60	44	43.33	1 076	49
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435	868
Brazeau River Nisku S	2035	54.64	111	0.80	0.57	38	41.38	928	55
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200	161
Caroline Beaverhill Lake A	61 977	49.95	3 096	0.84	0.76	621	36.51	17 000	1 359
Carson Creek Beaverhill Lake B	11 919	55.68	664	0.90	0.39	365	41.54	8 796	353
Harmattan East Commingled Pool 001	44 923	50.26	2 258	0.79	0.26	1 320	41.57	31 752	5 947
Harmattan-Elkton Rundle C	33 012	46.96	1 550	0.89	0.27	1 007	42.16	23 885	935
Kakwa A Cardium A	3 848	55.40	213	0.71	0.32	103	43.87	2348	1 034
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 639	39.68	41 300	514
Ricinus Cardium A	13 295	58.59	779	0.85	0.32	450	42.0	10 775	461
Valhalla MFP8524 Halfway	6 331	53.89	341	0.80	0.33	183	40.00	4 572	2 475
Waterton Rundle-Wabamun A	90 422	48.74[a]	4 407	0.95	0.35	2 721	48.73	55 836	2 189
Wembley MFP8524 Halfway	6 662	53.89	359	0.60	0.33	144	44.10	3 265	1 770

(continued)

Table B.5. Natural gas reserves of gas cycling pools, 2009 (concluded)

Pool	Raw gas initial volume in place (10^6 m^3)	Raw gas gross heating value (MJ/m^3)	Initial energy in place (10^9 MJ)	Recovery factor (fraction)	Fuel and shrinkage (surface loss factor) (fraction)	Initial marketable gas energy (10^9 MJ)	Marketable gas gross heating value (MJ/m^3)	Initial established reserves of marketable gas (10^6 m^3)	Remaining established reserves of marketable gas (10^6 m^3)
Westerose D-3	10 823	51.55	558	0.78	0.25	326	42.78	7 620	19
Westpem Nisku E	1 160	66.05	77	0.90	0.54	32	44.76	709	151
Windfall D-3 A	25 836	53.42	1 380	0.61	0.53	385	40.58	9 488	1 013

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

Table B.6. Natural gas reserves of multifield pools, 2009

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8507 Cardium	
Ansell Commingled MFP9502	12 253
Medicine Lodge Commingled MFP9502	1 464
Minehead Commingled MFP9502	3 018
Sundance Commingled MFP9502	7 802
Total	24 537
MFP8508 Viking	
Hairy Hill Commingled MFP9503	271
Willingdon Commingled MFP9503	4
Total	
MFP8509 Belly River	
Alix Commingled MFP9504	305
Bashaw Commingled MFP9504	1 779
Buffalo Commingled MFP9504	17
Chigwell Commingled MFP9504	38
Chigwell North Commingled MFP9504	222
Clive Commingled MFP9504	528
Donalda Commingled MFP9504	210
Dorenlee Commingled MFP9504	7
Ferintosh Commingled MFP9504	44
Haynes Commingled MFP9504	1
Lacombe Commingled MFP9504	17
Malmo Commingled MFP9504	389
Manito Commingled MFP9504	72
Mikwan Commingled MFP9504	3
Nevis Commingled MFP9504	1 476
Wood River Commingled MFP9504	125
Total	5 233
MFP8510 Glaucontic	
Bigoray Commingled MFP9505	174
Pembina Commingled MFP9505	919
Total	1 093
MFP8512 Glauconitic	
Bonnie Glen Commingled MFP9506	83
Ferrybank Commingled MFP9506	178
Total	261
MFP8514 Upper Viking	
Fairydell-Bon Accord Commingled MFP9508	57
Peavey Commingled MFP9508	7
Redwater Commingled MFP9508	573
Total	632
MFP8515 Banff	
Haro MFP8515 Banff	127
Rainbow MFP8515 Banff	7
Rainbow South MFP8515 Banff	203
Total	337
MFP8516 Viking	
Fenn West MFP8516 Viking	9
Fenn-Big Valley MFP8516 Viking	55
Total	64
MFP8517 Gething	
Fox Creek Commingled MFP9510	1 037
Kaybob South Commingled MFP9510	917
Total	1 954
MFP8518 U&M Viking	
Albers Commingled MFP9509	8
Beaverhill Lake Commingled MFP9509	301
Bellshill Lake Commingled MFP9509	12
Birch Commingled MFP9509	8
Bruce Commingled MFP9509	393
Dinant Commingled MFP9509	2
Fort Saskatchewan Commingled MFP9509	207
Holmberg Commingled MFP9509	9
Killam Commingled MFP9509	187
Killam North Commingled MFP9509	194
Mannville Commingled MFP9509	415
Sedgewick Commingled MFP9509	11
Viking-Kinsella Commingled MFP9509	2 451
Wainwright Commingled MFP9509	381
Total	4 579
MFP8521 Viking	
Hudson Commingled MFP9511	45
Sedalia Commingled MFP9511	173
Total	218
MFP8522 Cadomin	
Elmworth Commingled MFP9513	15 146
Sinclair Commingled MFP9513	4 055
Total	19 201
MFP8523 Upper Viking	
Inland Commingled MFP9512	147
Royal Commingled MFP9512	0
Total	147
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 475
Wembley MFP8524 Halfway	1 770
Total	4 245
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8526 Ellerslie	
Connorsville Commingled MFP9514	625
Wintering Hills Commingled MFP9514	253
Total	878

(continued)

Table B.6. Natural gas reserves of multifield pools, 2009 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8527 2WS	
Craigmyle Commingled MFP9515	8
Dowling Lake Commingled MFP9515	13
Garden Plains Commingled MFP9515	925
Hanna Commingled MFP9515	444
Provost Commingled MFP9515	208
Racosta Commingled MFP9515	98
Richdale Commingled MFP9515	360
Stanmore Commingled MFP9515	31
Sullivan Lake Commingled MFP9515	66
Watts Commingled MFP9515	55
Total	2 208
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	187
Sousa MFP8528 Bluesky	820
Total	1 007
MFP8529 Bl-Dt-Db	
Cranberry MFP8529 Bl-Dt-Db	455
Hotchkiss MFP8529 Bl-Dt-Db	468
Total	923
MFP8530 Halfway	
Knopcik Commingled MFP9516	923
Valhalla Commingled MFP9516	40
Total	963
MFP8531 2WS	
Conrad Commingled MFP9517	290
Pendant D'Oreille Commingled MFP9517	1 363
Smith Coulee Commingled MFP9517	402
Total	2 055
MFP8532 2WS	
Enchant Commingled MFP9522	559
Grand Forks Commingled MFP9522	10
Retlaw Commingled MFP9522	146
Vauxhall Commingled MFP9522	29
Total	744
MFP8534 Basal Belly River	
Bruce Commingled MFP9518	246
Holmberg Commingled MFP9518	136
Total	382
MFP8535 Basal Belly River	
Fenn West Commingled MFP9519	10
Fenn-Big Valley Commingled MFP9519	838
Gadsby Commingled MFP9519	343
Total	1 191
MFP8538 Viking	
Gadsby Commingled MFP9520	6
Leahurst Commingled MFP9520	136
Total	142
MFP8539 Lower Edmonton	
Erskine MFP8539 Lower Edmonton	31
Stettler North MFP8539 Lower Edmonton	33
Total	64
MFP8541 2WS	
Cherry MFP8541 2WS	42
Granlea MFP8541 2WS	54
Taber MFP8541 2WS	137
Total	233
MFP8552 Bow Island	
Stirling Commingled MFP9524	110
Warner Commingled MFP9524	28
Total	138
MFP 8554 Dunvegan	
Berland River Commingled MFP9529	10
Berland River West Commingled MFP9529	46
Cecilia Commingled MFP9529	7 633
Fir Commingled MFP9529	9 746
Oldman Commingled MFP9529	1 801
Red Rock Commingled MFP9529	5 273
Wapiti Commingled MFP9529	11 800
Wild River Commingled MFP9529	22 026
WildHay Commingled MFP9529	1 111
Total	59 446
MFP8558 Belly River	
Elnora MFP8558 Belly River	29
Rich MFP8558 Belly River	99
Total	128
MFP8562 Edmonton	
Garrington Commingled MFP9526	9
Innisfail Commingled MFP9526	27
Lanaway Commingled MFP9526	324
Markerville Commingled MFP9526	223
Medicine River Commingled MFP9526	132
Penhold Commingled MFP9526	5
Sylvan Lake Commingled MFP9526	767
Tindastoll Commingled MFP9526	157
Total	1 664
MFP8564 Edmonton	
Gilby Commingled MFP9527	9
Minnehik-Buck Lake Commingled MFP9527	114
Westerose South Commingled MFP9527	464
Wilson Creek Commingled MFP9527	470
Total	1 057
MFP8567 Medicine Hat	
Comrey Commingled MFP9528	17
Forty Mile Commingled MFP9528	1
Pendant D'Oreille Commingled MFP9528	748
Total	766

(continued)

Table B.6. Natural gas reserves of multifield pools, 2009 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8574 Edmonton	
Chinook Commingled MFP9530	156
Dobson Commingled MFP9530	23
Gilby Commingled MFP9530	253
Heathdale Commingled MFP9530	66
Kirkwall Commingled MFP9530	12
Prevo Commingled MFP9530	97
Sedalia Commingled MFP9530	7
Sounding Commingled MFP9530	103
Stanmore Commingled MFP9530	76
Total	793
MFP8575 Falher	
Resthaven Commingled MFP9525	1 573
Smoky Commingled MFP9525	253
Total	1 826
MFP8583 Falher	
Nosehill MFP8583 Falher	9
Pine Creek MFP8583 Falher	9
Total	18
Southeastern Alberta Gas System (MU)	
Aerial SE Alberta Gas System(MU)	173
Alderson SE Alberta Gas System(MU)	17 353
Ardenode SE Alberta Gas System(MU)	1 538
Armada SE Alberta Gas System(MU)	266
Atlee-Buffalo SE Alberta Gas System(MU)	4 060
Bantry SE Alberta Gas System(MU)	12 824
Berry SE Alberta Gas System(MU)	6
Bindloss SE Alberta Gas System(MU)	796
Blackfoot SE Alberta Gas System(MU)	573
Bow Island SE Alberta Gas System(MU)	420
Brant Alberta SE AlbertaGas System(MU)	684
Brooks SE Alberta Gas System(MU)	293
Carbon SE Alberta Gas System(MU)	569
Cavalier SE Alberta Gas System(MU)	193
Centron SE Alberta Gas System(MU)	1 780
Cessford SE Alberta Gas System(MU)	7 198
Chain SE Alberta Gas System(MU)	19
Connemara SE Alberta Gas System(MU)	19
Connorsville SE Alberta Gas System(MU)	1 844
Countess SE Alberta Gas System(MU)	31 604
Craigmyle SE Alberta Gas System(MU)	270
Crossfield SE Alberta Gas System(MU)	225
Dalemead SE Alberta Gas System(MU)	145
Davey SE Alberta Gas System(MU)	337
Delia SE Alberta Gas System(MU)	90
Drumheller SE Alberta Gas System(MU)	2 461
Elkwater SE Alberta Gas System(MU)	1 708
Enchant SE Alberta Gas System(MU)	52
Entice SE Alberta Gas System(MU)	4 074
Eyremore SE Alberta Gas System(MU)	2 450
Farrow SE Alberta Gas System(MU)	668
Fenn West SE Alberta Gas System(MU)	13
Fenn-Big Valley SE Alberta Gas System(MU)	49
Gayford SE Alberta Gas System(MU)	502
Ghost Pine SE Alberta Gas System(MU)	563
Gladys SE Alberta Gas System(MU)	366
Gleichen SE Alberta Gas System(MU)	509
Herronton SE Alberta Gas System(MU)	908
Hussar SE Alberta Gas System(MU)	4 632
Irricana SE Alberta Gas System(MU)	267
Jenner SE Alberta Gas System(MU)	2 492
Johnson SE Alberta Gas System(MU)	302
Jumpbush SE Alberta Gas System(MU)	783
Kitsim SE Alberta Gas System(MU)	279
Lathom SE Alberta Gas System(MU)	2 379
Leckie SE Alberta Gas System(MU)	505
Lomond SE Alberta Gas System(MU)	62
Lone Pine Creek SE Alberta Gas System(MU)	245
Long Coulee SE Alberta Gas System(MU)	166
Majorville SE Alberta Gas System(MU)	1 332
Matziwin SE Alberta Gas System(MU)	612
Mcgregor SE Alberta Gas System(MU)	220
Medicine Hat SE Alberta Gas System(MU)	41 130
Michichi SE Alberta Gas System(MU)	151
Milo SE Alberta Gas System(MU)	71
Newell SE Alberta Gas System(MU)	1 022
Okotoks SE Alberta Gas System(MU)	429
Pageant SE Alberta Gas System(MU)	88
Parflesh SE Alberta Gas System(MU)	910
Pollockville SE Alberta Gas System(MU)	4
Princess SE Alberta Gas System(MU)	10 940
Queenstown SE Alberta Gas System(MU)	101
Rainier SE Alberta Gas System(MU)	76
Redland SE Alberta Gas System(MU)	703
Rich SE Alberta Gas System(MU)	51
Rockyford SE Alberta Gas System(MU)	1 366
Ronalane SE Alberta Gas System(MU)	58
Rowley SE Alberta Gas System(MU)	257
Rumsey SE Alberta Gas System(MU)	5
Seiu Lake SE Alberta Gas System(MU)	330
Shouldice SE Alberta Gas System(MU)	850
Silver SE Alberta Gas System(MU)	51
Stewart SE Alberta Gas System(MU)	321
Strathmore SE Alberta Gas System(MU)	1 786
Suffield SE Alberta Gas System(MU)	16 825
Swalwell SE Alberta Gas System(MU)	301
Trochu SE Alberta Gas System(MU)	238
Twining SE Alberta Gas System(MU)	978
Verger SE Alberta Gas System(MU)	4 261
Vulcan SE Alberta Gas System(MU)	88
Wayne-Rosedale SE Alberta Gas System(MU)	2 111
West Drumheller SE Alberta Gas System(MU)	79
Wimborne SE Alberta Gas System(MU)	868
Wintering Hills SE Alberta Gas System(MU)	2 662
Workman SE Alberta Gas System(MU)	353
Total	201 342

Table B.7. Remaining raw ethane reserves as of December 31, 2009

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Ansell	14 494	0.082	1 308	4 651
Brazeau River	11 137	0.073	1 007	3 578
Caroline	8 023	0.084	1 069	3 799
Carrot Creek	3 213	0.090	329	1 168
Cecilia	12 494	0.066	935	3 323
Countess	34 339	0.009	331	1 178
Dunvegan	8 511	0.044	413	1 467
Edson	7 930	0.077	685	2 433
Elmworth	21 239	0.058	1 459	5 185
Ferrier	10 752	0.086	1 034	3 677
Fir	12 255	0.057	773	2 749
Garrington	3 303	0.075	322	1 146
Gilby	5 321	0.067	407	1 448
Gold Creek	5 117	0.081	464	1 648
Harmattan East	7 061	0.086	679	2 415
Hussar	8 677	0.035	332	1 179
Judy Creek	2 418	0.143	422	1 499
Kaybob South	14 221	0.072	1 196	4 251
Karr	4 682	0.077	397	1 413
Kakwa	9 355	0.085	888	3 157
Knopcik	3 803	0.067	289	1 027
Leduc-Woodbend	2 370	0.113	318	1 129
Medicine River	3 924	0.082	384	1 366
Minehead	3 358	0.077	283	1 006
Pembina	20 279	0.080	1 988	7 066
Pine Creek	6 819	0.070	557	1 978
Pouce Coupe South	6 830	0.049	384	1 363
Leland	3 938	0.068	287	1 020
Provost	15 834	0.028	488	1 736
Rainbow	7 174	0.065	586	2 084
Rainbow South	3 245	0.094	435	1 545
Red Rock	7 078	0.059	472	1 679
Ricinus	4 015	0.076	345	1 225
Sinclair	8 710	0.048	484	1 719
Sundance	11 544	0.070	891	3 166
Swan Hills South	2 698	0.174	671	2 387
Sylvan Lake	4 132	0.072	350	1 244
Valhalla	8 078	0.075	703	2 500
Virginia Hills	1 510	0.166	305	1 085
Waterton	5 703	0.030	283	1 008
Wayne-Rosedale	8 740	0.044	419	1 490

(continued)

Table B.7. Remaining raw ethane reserves as of December 31, 2009 (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)
Westpem	3 789	0.103	482	1 713
Westerose South	6 928	0.079	609	2 165
Wembley	2 661	0.094	318	1 132
Wapiti	17 854	0.057	1 173	4 169
Wild River	27 075	0.070	2 058	7 315
Willesden Green	13 121	0.085	1 378	4 900
Wilson Creek	4 100	0.068	319	1 133
Subtotal	419 852	0.065	31 704	112 712
All other fields	635 861	0.029	18 372	65 311
Total	1 055 713	0.052[a]	50 076	178 023

[a] Volume weighted average.

Table B.8. Remaining raw reserves of natural gas liquids as of December 31, 2009

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	14 494	2 073	1 086	2 212	5 371
Brazeau River	11 137	1 767	1 055	2 203	5 025
Caroline	8 023	1 599	1 114	2 333	5 047
Carrot Creek	3 213	593	272	212	1 077
Cecilia	12 494	1 113	443	997	2 552
Countess	34 339	430	244	205	878
Crossfield East	2 367	152	79	598	828
Dunvegan	8 511	707	408	676	1 791
Edson	7 930	905	409	388	1 701
Elmworth	21 239	1 610	728	841	3 179
Ferrier	10 752	1 801	909	763	3 473
Fir	12 255	1 031	481	607	2 118
Garrington	3 303	514	272	378	1 165
Gilby	5 321	704	360	381	1 444
Gold Creek	5 117	545	274	422	1 242
Harmattan East	7 061	906	561	925	2 391
Hussar	8 677	526	286	290	1 102
Judy Creek	2 418	1 001	414	248	1 664
Kakwa	9 355	1 320	611	668	2 600
Karr	4 682	615	279	279	1 172
Kaybob	2 979	421	201	278	900
Kaybob South	14 221	1 877	967	1 367	4 210
Knopcik	3 803	443	217	281	941
Leduc-Woodbend	2 370	943	556	334	1 834
Medicine River	3 924	645	319	307	1 271
Minehead	3 358	391	208	254	853
Pembina	20 279	3 815	1 873	1 631	7 319
Pine Creek	6 819	830	383	432	1 645
Pouce Coupe South	6 830	533	290	312	1 135
Provost	15 834	1 010	659	469	2 138
Rainbow	7 174	976	663	841	2 480
Rainbow South	3 245	806	391	465	1 662
Red Rock	7 078	563	246	200	1 010
Ricinus	4 015	570	286	510	1 366
Sinclair	8 710	625	260	283	1 167
Sundance	11 544	1 099	474	470	2 042
Swan Hills South	2 698	1 642	752	313	2 707
Sylvan Lake	4 132	538	261	249	1 048

(continued)

Table B.8. Remaining raw reserves of natural gas liquids as of December 31, 2009 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Valhalla	8 078	1 194	638	926	2 758
Virginia Hills	1 510	708	233	96	1 037
Wapiti	17 854	1 190	504	479	2 173
Waterton	5 703	316	286	1 817	2 420
Wayne-Rosedale	8 740	729	388	465	1 583
Wembley	2 661	601	351	748	1 700
Westerose South	6 928	1 137	553	537	2 227
Westpem	3 789	803	421	499	1 723
Wild River	27 075	2 505	1 012	1 474	4 991
Willesden Green	13 121	2 324	1 084	1 043	4 452
Wilson Creek	4 100	549	286	343	1 178
Subtotal	421 260	59 697	25 045	33 048	107 790
All other fields	634 453	38 092	15 769	18 158	72 019
Total	1 055 713	77 789	40 814	51 559	170 162

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 2009 on the CD that accompanies this report (available for $546 from ERCB Information Services). The individual oil and gas pool values are presented on the first worksheet of each spreadsheet. Oilfield, and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data presented in Tables B.1 and B.2 are included in Excel format on the CD.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet is similar to the data table in last year's report and contains all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are presented in separate columns. The total record contains the summation of the multi-mechanism pool reserves data. These data appear in the pool column, which can be used for determining field and provincial totals. The mechanism type is displayed with the names.

Provincial totals for light-medium and heavy oil pools are presented separately on the provincial total worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet in this report is similar to last year's report and contains all nonconfidential pools in Alberta.

Basic reserves data are split into two columns: pools (individual, undefined, and total records) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total record contains a summation of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Crude Bitumen Resources and Basic Data

The Crude Bitumen In-Place Resources and Basic Data spreadsheet is similar to the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns.

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
BDY	boundary
BELL	Belloy
BER	beyond economic reach
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
COMP	compressibility
DBLT	Debolt
DETR	Detrital
DISC YEAR	discovery year
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton
ERSO	enhanced-recovery scheme is in operation but no additional established reserves are attributed
FALH	Falher
FRAC	fraction
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GOR	gas-oil ratio
GRD RAP or GRD RP	Grand Rapids
GROSS HEAT VALUE	gross heating value
GSMT	Grosmont
ha	hectare
HFWY	Halfway
INJ	injected
I.S.	integrated scheme

JUR or J	Jurassic
KB	kelly bushing
KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LF	load factor
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOC EX PROJECT	local experimental project
LOC U	local utility
LOW or L	lower
LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MOP	maximum operating pressure
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NO.	number
NON-ASSOC	nonassociated gas
NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
PM-PN SYS	Permo-Penn System
RF	recovery factor
RK CK	Rock Creek
RUND or RUN	Rundle
SA	strike area
SATN	saturation
SD	sandstone
SE ALTA GAS SYS (MU)	Southeastern Alberta Gas System - commingled
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total

TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1. Development and exploratory wells, 1972-2009, number drilled annually

	Development					Exploratory				Total			
	Successful	Crude bitumen				Successful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5 473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980

[a] Includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

* Included in Oil.

** Not available.

Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2009 - Alberta Drilling Activity Monthly Statistics (ST59).

Table D.2. Development and exploratory wells, 1972-2009, kilometres drilled annually

	Development					Exploratory				Total			
	Successful	Crude bitumen				Successful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	1 0840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087

[a] Includes unsuccessful, service, and suspended wells.
[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.
* Included in Oil.
** Not available.
Source: 1972 - 1999 - Alberta Oil and Gas Industry Annual Statistics (ST17); 2000 - 2009 - Alberta Drilling Activity Monthly Statistics (ST59).