ST98-2005

Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014

Alberta Energy and Utilities Board

ACKNOWLEDGEMENTS

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Overview

The Alberta Energy and Utilities Board (EUB) 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 and utilities services take place in a manner that is fair, responsible, and in the public interest. As part of its legislated mandate, the EUB provides for the appraisal of the reserves and their productive capacity and the requirements for energy resources and energy in Alberta.

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

Every year the EUB issues a report providing stakeholders with one of the most reliable sources of 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 Reserves 2004 and Supply/Demand Outlook 2005-2014* includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (reserves that have been discovered and reserves that are ultimately expected to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources.

Raw bitumen production, which surpassed conventional crude oil production in 2001 for the first time, continued its growth and accounted for 69 per cent of Alberta's total crude oil and bitumen production in 2004. The value-added process of upgrading raw bitumen to synthetic crude oil (SCO, a product similar to light crude oil) was expanded in 2004. Last year, SCO production in Alberta equalled light and medium crude oil production for the first time.

Natural gas production from all sources in Alberta increased by 1 per cent in 2004 compared with 2003. The EUB has concluded that natural gas production in the province peaked in 2001. Natural gas production in 2005 is expected to stay similar to 2004 due to continued high levels of drilling.

Coalbed methane (CBM) development activity significantly increased in 2004. The 2004 production accounted for 80 per cent of the cumulative CBM production to date. However, it contributed to only 0.5 per cent the provincial total natural gas production. The EUB anticipates that CBM development activity will continue to increase over the next number of years. Recognizing this potential, this year's report includes an expanded section on CBM that describes the reserve calculation approach and provides a 10-year supply forecast.

The following table summarizes Alberta's energy reserves at the end of 2004.

Reserves and production Summary 2004

	Crude bitumen		Crude oil		Natural gas[a]		Coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in place	269 945	1 699	10 001	62.9	7 910	277	94	103
Initial established	28 392	179	2 665	16.8	4 555	161	35	38
Cumulative production	730	4.6	2 416	15.2	3 420	121	1.23	1.35
Remaining established	**27 662**	**174**	**249**	**1.6**	**1 134**	**40**	**34**	**37**
Annual production	63.4	0.399	35	0.220	137	4.9	0.028	0.030
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276	223	620	683

[a] includes CBM

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total in situ and mineable remaining established reserves are 27.7 billion cubic metres (m^3) (174 billion barrels), similar to 2003. Only 2.6 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

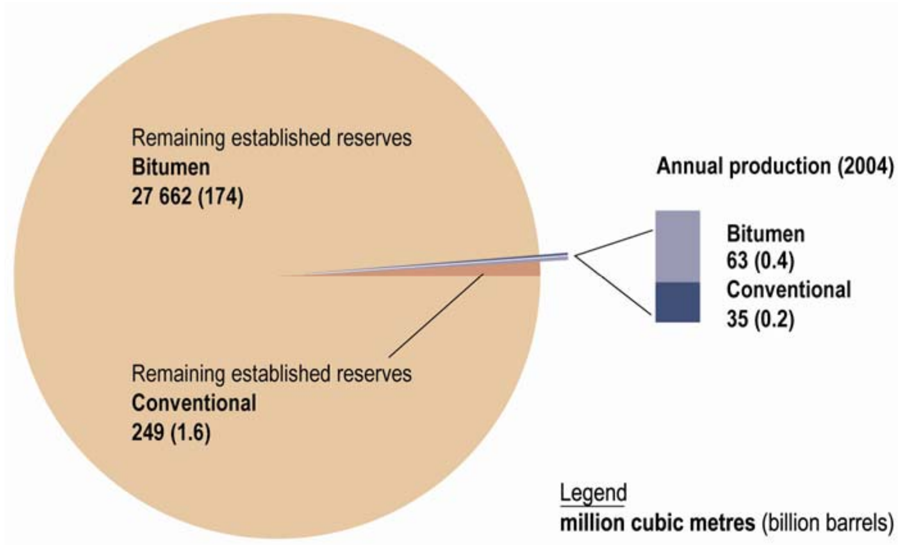
In 2004, Alberta produced 40.9 million m^3 (257 million barrels) from the mineable area and 22.5 million m^3 (141million barrels) from the in situ area, totaling 63.4 million m^3 (399 million barrels). Bitumen produced from mining was upgraded, yielding 34.8 million m^3 (219 million barrels) of SCO, reaching the level of conventional crude oil production. In situ production was mainly marketed as nonupgraded crude bitumen.

Crude Oil Reserves

Alberta's remaining established reserves of conventional crude oil was estimated at 249 million m^3 (1.6 billion barrels)—a 2 per cent reduction from 2003. Of the 30.9 million m^3 (194 million barrels) added to initial established reserves, exploratory and development drilling, along with new enhanced recovery schemes, added reserves of 17.3 million m^3 (109 million barrels). This replaced 49 per cent of 2004 production. Positive revisions accounted for the remaining 13.6 million m^3 (86 million barrels).

Based on its 1988 study, the EUB estimates the ultimate potential recoverable reserves of crude oil at 3130 million m^3 (19.7 billion barrels). The EUB 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.

The following figure shows annual production and remaining established reserves for crude bitumen and crude oil.



Alberta's oil reserves and production

Crude Oil Production and Drilling

Alberta's production of conventional crude oil totaled 34.9 million m^3 (220 million barrels) in 2004. This equates to 95 400 m^3/day (600 000 barrels/day).

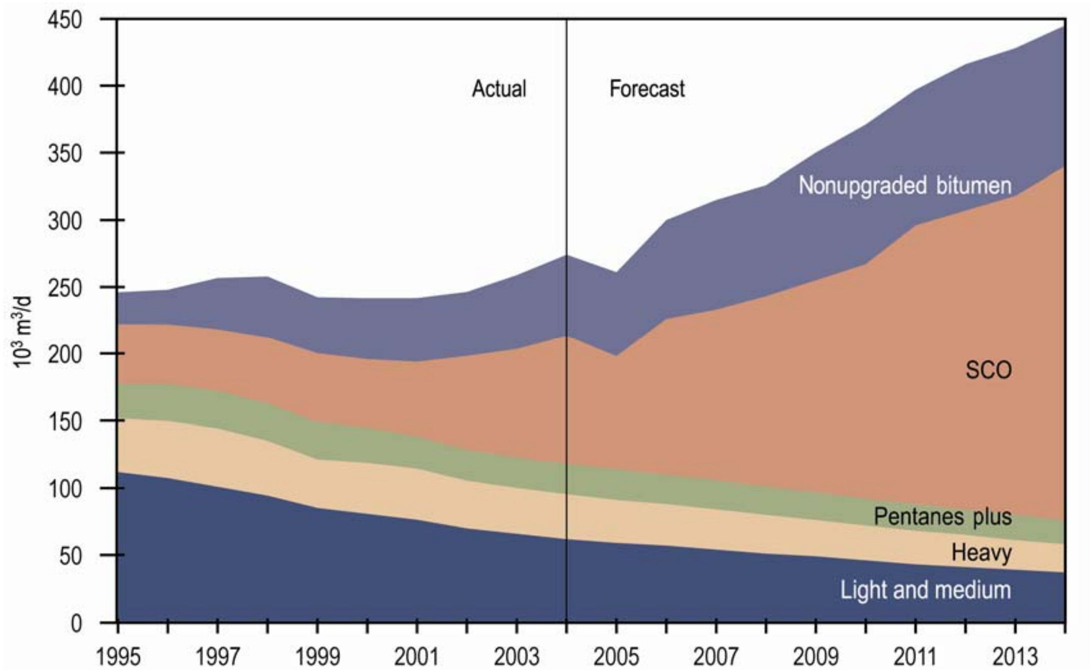
Despite high crude oil prices, the number of oil wells placed on production declined by 8 per cent to 1910 in 2004 from 2070 in 2003, mainly due to industry's emphasis on gas drilling. With the expectation that crude oil prices will remain strong, the EUB estimates that 2000 successful oil wells will be drilled in 2005 and further projects that a similar level of successful oil wells per year will be drilled over the remainder of the forecast period.

Total Oil Supply and Demand

Alberta's 2004 production from conventional oil, oil sands sources, and pentanes plus was 274 100 m^3/day (1.72 million barrels/day)—a 5.8 per cent increase compared to 2003. Production is forecast to reach 446 000 m^3/day (2.8 million barrels/day) by 2014.

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

The EUB estimates that bitumen production will more than double by 2014. The share of nonupgraded bitumen and SCO production in the overall Alberta crude oil and equivalent supply is expected to increase from 57 per cent in 2004 to some 83 per cent by 2014.



Alberta's total crude oil and equivalent supply

Natural Gas

Coalbed Methane Reserves

Coalbed methane (CBM) in Alberta has been a commercial supply of natural gas for only the past few years. Activity in CBM has increased dramatically from a few test wells in 2001 to over 3300 wells in 2004. The increase in CBM data collection and gas production has increased confidence in publication of CBM reserves estimates, despite continuing uncertainty in recovery factors and production accounting. The EUB is reporting CBM reserves as a separate section for the first time, due to a change in estimation method based on the inherent relationship between coal deposits and CBM.

At the end of 2004, the remaining established reserves of CBM in Alberta are estimated to be 7.4 billion m^3 (263 billion cubic feet). This reserve number is limited to the "dry CBM" trend of central Alberta, as the other CBM resource development has not yet shown commercial producibility.

Conventional Natural Gas Reserves

At the end of 2004, Alberta's remaining established reserves of natural gas stood at 1127 billion m^3 (40 trillion cubic feet [tcf]) at the field gate. This reserve includes liquids that are subsequently removed at straddle plants. Production from new drilling replaced 75 per cent of production in 2004. This compares to 77 per cent replacement in 2003.

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 billion m^3, or 223 tcf (6528 billion m^3 or 232 tcf at 37.4 megajoules per m^3). The estimate, which does not include unconventional gas, such as CBM, updates the 5600 billion m^3 stated in the Energy Resources and Conservation Board (now the EUB) *Report 92-A: Ultimate Potential and Supply of Natural Gas in Alberta* (EUB 1992 Report). The primary reason for this increase is a better understanding of the geology of the province as a result of significant increased drilling since 1992.

Natural Gas Production and Drilling

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 137 billion m^3 (4.9 tcf) of marketable natural gas in 2004, of which 0.6 billion m^3 (0.02 tcf) is from CBM.

There were 12 960 successful conventional natural gas wells drilled in Alberta in 2004, a 7 per cent increase from the 12 060 gas wells drilled in 2003. The EUB expects strong drilling over the forecast period, estimating 12 000 successful wells per year.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta, which contains over half of the province's producing gas wells but only 18 per cent of 2004 natural gas production. The EUB anticipates that shallow drilling will continue to account for a large share of the activity in the province over the next few years.

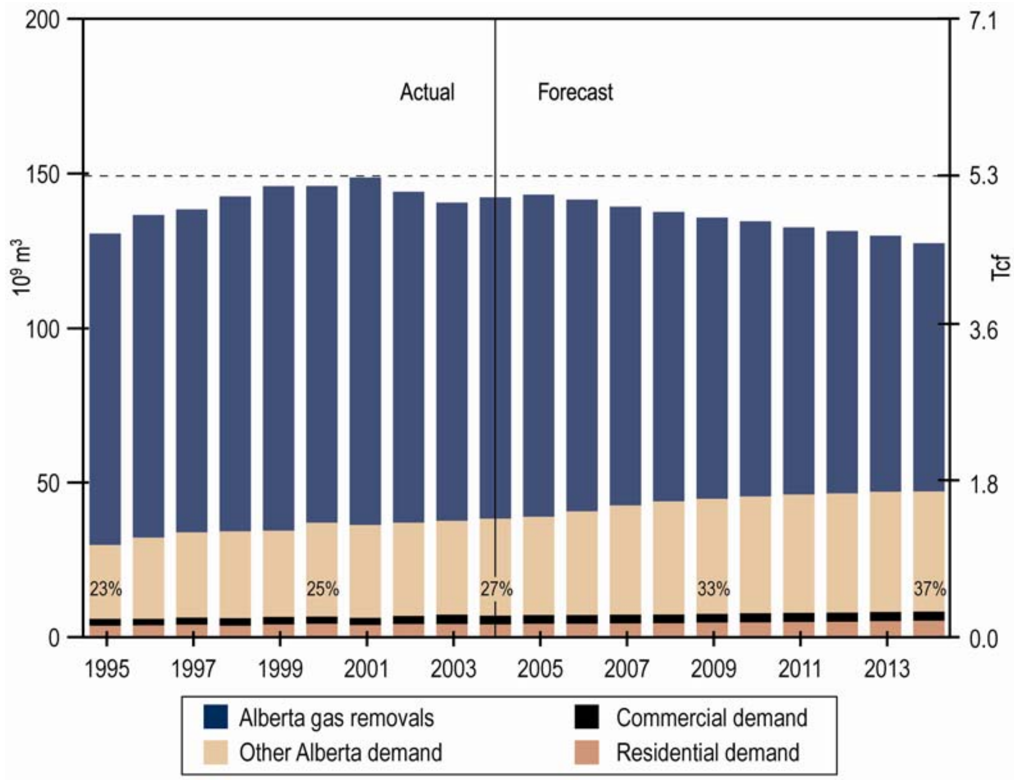
CBM production in the province is forecast to supplement the supply of conventional natural gas. There were 1200 successful CBM well connections in Alberta in 2004. The EUB expects strong drilling of CBM wells over the forecast period, estimating 2000 well connections in 2005, increasing to 2500 wells per year thereafter.

Natural Gas Supply and Demand

The EUB expects conventional gas production to remain flat in 2005 and decline by an average of 2.5 per cent per year over the remainder of the forecast period. New pools are smaller and new wells drilled today are exhibiting lower initial production rates and steeper decline rates. Factoring this in, the EUB believes that new wells drilled will not be able to sustain production levels over the forecast period. CBM production is forecast to supplement the supply of conventional gas in the province. It is expected to increase from 0.6 10^9 m^3 in 2004 to 15.2 10^9 m^3 in 2014.

Although natural gas supply from conventional sources is declining, sufficient supply exists to easily meet Alberta's demand. If the EUB's demand forecast is realized, Alberta's natural gas requirement will be 37 per cent of total Alberta production by the end of the forecast period.

As Alberta requirements increase and production declines over time, the volumes available for removal from the province will decline. The EUB's mandate requires that the natural gas requirements for Alberta's core market (defined as residential, commercial, and institutional gas consumers) are met over the long term before any new gas removal permits are approved.



Marketable gas production and demand

Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 123 million m^3 (774 million barrels) as of year-end 2004. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

The production of specification ethane increased from 37.5 thousand m^3/day (236 thousand barrels/day) in 2003 to 40.1 thousand m^3/day (252 thousand barrels/day) in 2004. The majority of ethane was used as feedstock for Alberta's petrochemical industry. The supply of ethane is expected to meet demand over the forecast period.

The remaining established reserves of other natural gas liquids (NGLs)—propane, butanes, and pentanes plus—decreased to 172 million m^3 (1.1 billion barrels) in 2004. The supply of propane and butanes is expected to meet demand over the forecast period. However, a shortage of pentanes plus as a diluent for heavy oil and nonupgraded bitumen is expected by 2007. Alternative sources of diluent will be required.

The remaining established reserves of sulphur are 85 million tonnes from natural gas and upgrading of bitumen from mining areas under active development. Sulphur demand is not expected to increase significantly, and Alberta's sulphur inventory will continue to grow over the forecast period.

Coal

The current estimate for remaining established reserves of all types of coal is about 34 billion tonnes (37 billion tons). Most of this massive energy resource continues to help meet the energy needs of Albertans, supplying fuel for about 64 percent of the province's electricity generation in 2004. Alberta's total coal production in 2004 was 28 million tonnes of marketable coal, most of which was sub-bituminous coal destined for mine mouth power plants. Alberta's coal reserves represent over a thousand years of supply at current production levels. Sub-bituminous coal production is expected to increase over the forecast period to meet demand for additional domestic electrical generating capacity.

The small portion of Alberta coal production that was exported from the province can be separated into thermal coal exports and metallurgical coal exports. The thermal coal market in early 2003 saw declining prices which influenced the closure of the Obed mine and reduced operations at the remaining mine at Coal Valley. The Obed mine remained closed and supply of thermal bituminous coal is reduced. Since that time thermal coal prices have grown to such a level that the Coal Valley mine has dramatically increased reserves, capacity, and production.

Similarly, low market prices for metallurgical coal had influenced the closure of two mines and reduced coal production at the remaining Cardinal River mine, which was nearing its reserves limits. With the international market seeing almost double prices for metallurgical coal, the mine at Grande Cache has re-opened and the Cheviot mine will add coal supply to Cardinal River production. This will stabilize production over the forecast period.

1 Energy Prices and Economic Performance

This section discusses major forecast assumptions that affect Alberta's energy supply and demand. Energy production is generally affected by energy prices, demand, and other factors. Energy demand, in turn, is determined by such factors as economic activity, the types of industry operating in the province, standard of living, seasonal temperatures, and population. This section presents some of the main variables and sets the stage for supply and demand discussions in the report.

1.1 Global Oil Market

The oil market in 2004 was characterized as a market with extremely high average prices not seen in over twenty years. The Organization of Petroleum Exporting Countries (OPEC) basket price of crude was relatively high in the first few months of the year, due to continued uncertainties in the Middle East and labour unrest in Venezuela. The uncertainties, combined with high economic growth in developing countries, such as India and China, as well as signs of economic recovery in the United States, has put extreme pressure on the global supply of crude oil in the latter part of 2004. The diminishing global excess capacity in crude oil production, in particular that of OPEC, caused a tight supply and demand balance that has not been seen for over two decades. This tight supply situation and extreme speculative demand led to a jittery market, which resulted in crude oil prices exceeding US$55 per barrel.

Over the past ten years, global demand for crude oil has increased by an average of 1.5 per cent per year. The trend over the previous three years, which saw virtually no growth, was reversed in 2004, as global oil demand increased by over 2 per cent. Strong growth in the U.S. demand for oil and continued strong demand in China were mostly responsible for this increase. China, after several years of growth in demand exceeding 6 per cent a year, moved into the number-two spot, surpassing Japan as the world's second largest importer of crude after the United States. China's seemingly insatiable demand for oil has made it a major driver of global oil demand growth.

Several factors played a role in continued strength of average crude oil prices in 2004:

- lack of investments in major oil producing countries to maintain a reasonable level of excess capacity,
- the sluggish growth in Iraq's crude oil production,
- lack of alternative energy sources, and
- overall tension in the Middle Eastern oil-producing countries.

While nonrenewable energy sources and more efficient energy use are increasingly contributing to lower the global demand, crude oil is still the dominant fuel. However, global crude production increases are expected to be limited in the immediate future.

If high economic growth in China and other developing countries continues, the global demand for oil will increase by 1.75 to 2.00 per cent in 2005, followed by an increase of 1.50 to 1.75 per cent in 2006. High energy prices, however, will most likely dampen the global economic growth somewhat, which may result in slower growth in global demand for crude oil. The slower growth in global demand should result in stabilizing international crude oil prices within OPEC's new target range of US$40 to US$50, which is significantly higher than last year's target range of US$26 to US$28 per barrel. The higher price level, which is driven mainly by the new reality of supply and demand fundamentals is the reason the EUB long-term forecast of West Texas Intermediate (WTI) has changed from the US$28 to US$50 range.

While current global oil production capability slightly exceeds the potential demand, further increases in production capacity are urgently needed to avoid further price increases. New investment is required not only to maintain production from existing oil-producing fields, which have been in decline for some time, but also to increase capacity. The necessary condition for the investment, however, is political stability. Therefore, long-term stability in the market for oil will rely on the state of world politics. The continued threat of terrorism, political unrest in the Persian Gulf countries, and continued political instability in Venezuela will create a very volatile global market.

1.2 Energy Prices

The price of Alberta crude oil is determined by international market forces and is most directly related to the reference price of WTI. The North American crude oil price is set in Chicago and is usually US$2.20-3.00 higher than the OPEC reference price, reflecting quality differences and cost of shipping to the Chicago market. The EUB uses WTI crude price as its benchmark for world oil prices, as Alberta crude oil prices are based on WTI netbacks to Edmonton. Netbacks are calculated based on WTI at Chicago less transportation and other charges from Edmonton to Chicago and are adjusted for exchange rate, as well as crude oil quality. In 2004, the price of WTI crude oil began at US$34.00 per barrel and rose to over US$55 per barrel in October, before retreating to the mid-40s by the end of the year, and averaging US$42.40 for the year.

The EUB forecasts that the price of WTI will average between US$55 and US$60 per barrel for 2005 and 2006, before it stabilizes at US$50 by 2009, and remain at this level to the end of the forecast period. These price levels are believed to be sufficient to stimulate exploration outside of OPEC countries and can foster continued improvements in exploration and recovery technology. **Figure 1.1** illustrates the EUB forecast of WTI at Chicago. **Figure 1.2** shows the forecast for the wellhead price of crude oil in Alberta on a yearly basis in both current and constant Canadian dollars.

The average annual differential between prices of light-medium crude and heavy conventional crude and bitumen widened further in 2004. The heavy crude to light-medium crude price differential widened from 68 per cent to 66 per cent, while bitumen price differentials widened from 70 per cent to 65 per cent. The forecast calls for conventional heavy to average 70 per cent of the light-medium price and the bitumen price to revert to 60 per cent of the light-medium price.

While crude oil prices are determined globally, natural gas prices are set in the North American market with little global gas market influence. Nevertheless, natural gas prices are impacted to some extent by crude oil prices, as substitution could occur due to the price differential between the two commodities. **Figure 1.3** shows both the historical and the EUB forecast of natural gas prices at the plant gate from 1995 to 2014.

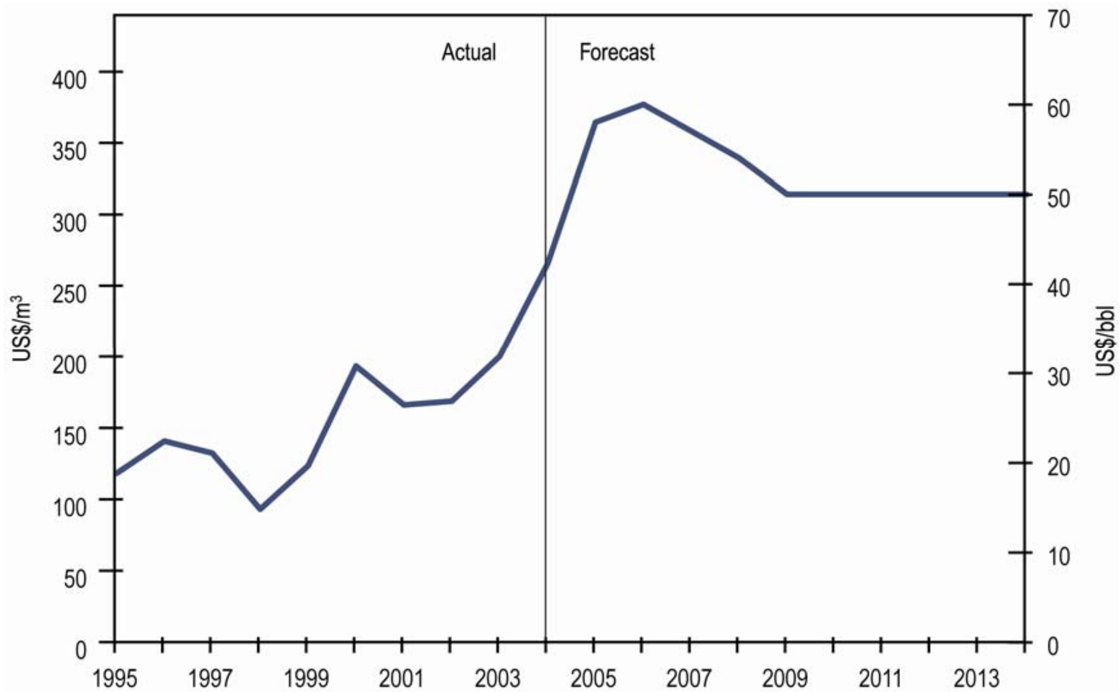


Figure 1.1. Price of WTI at Chicago

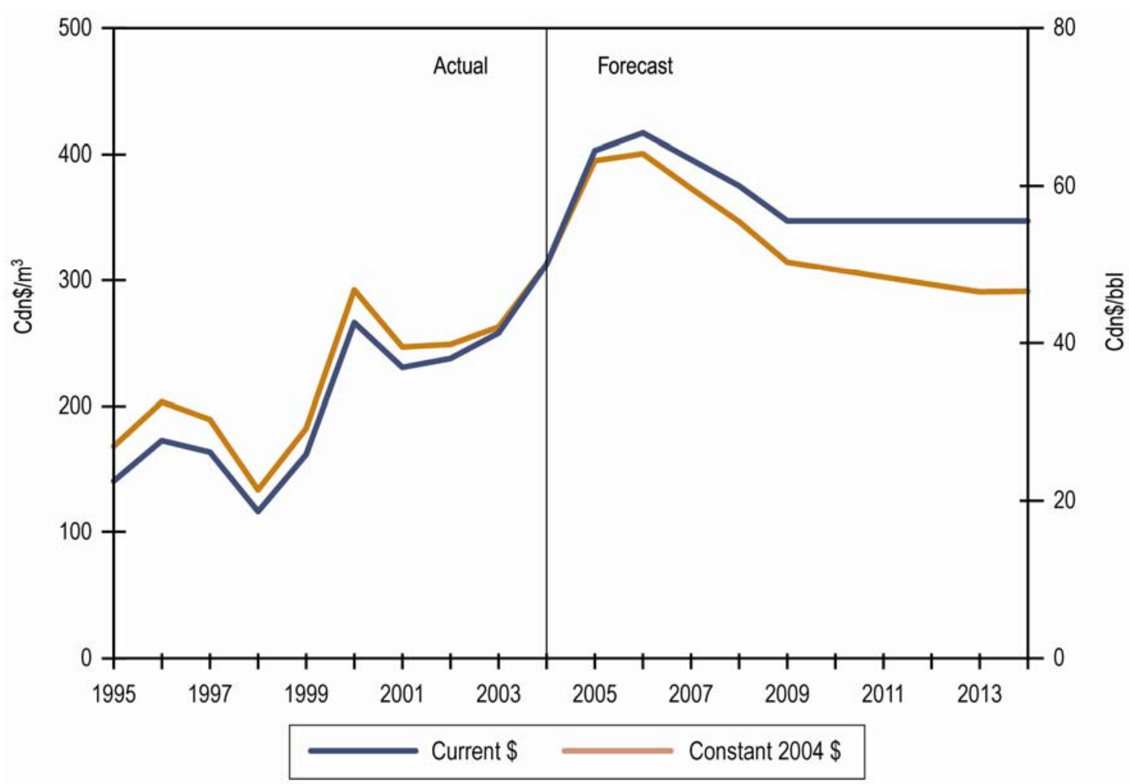


Figure 1.2. Average price of oil at Alberta wellhead

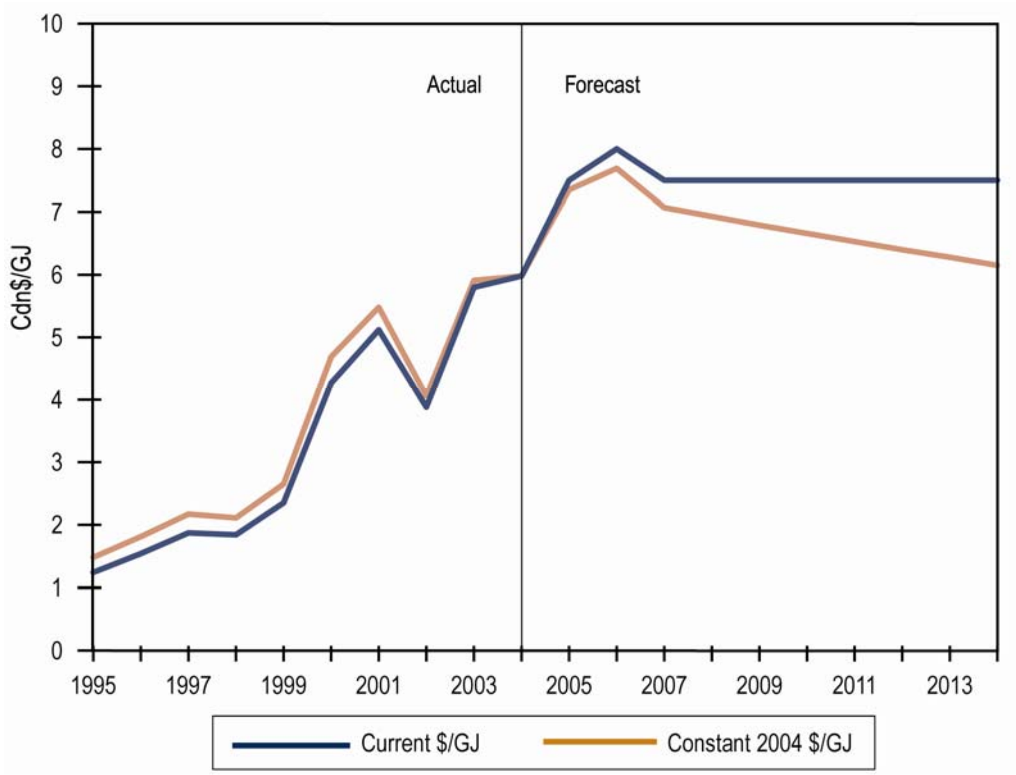


Figure 1.3. Average price of natural gas at plant gate

The year 2004 was fairly uneventful for natural gas prices compared to the rough upward ride experienced by crude oil prices. Alberta plant gate natural gas prices were at their lowest in September (Cdn$5.21 per gigajoule [GJ]), when storage levels reached a comfortable position, and highest in December (Cdn$6.70/GJ).

The gas to oil price parity on an energy basis was close to 1.00 for Alberta gas at the start of the year, but fluctuated downward to just under 0.50 by September. Crude oil prices were selling at a very high premium to natural gas in Alberta, and it appeared that the two commodities were no longer linked. By late October the gas to oil parity moved upwards and ended the year at 0.77.

Natural gas prices are estimated to average $7.50/GJ and $8.00/GJ for 2005 and 2006 respectively and remain within the $7.00 to $8.00/GJ price range within the forecast period, as shown in **Figure 1.3**. The gas to oil price parity is expected to average between 0.70-0.90 over the forecast period.

Factors supporting high future gas prices include high oil prices, increased demand for electricity generation, and uncertainty about gas supply. The rise in demand in the United States will also put pressure on the North American market, which will result in strong prices in 2005. Until significant new supply is available, prices will continue to experience volatility.

The EUB believes that intercontinental trade in liquefied natural gas (LNG) will not capture a high market share in North America over the forecast period due primarily to the risk and regulatory requirement for construction of gasification terminals. The LNG cost at the gasification plant gate on the U.S. east coast is in the US$4.00 to $5.00/GJ range, but its small market share will not drastically affect rising natural gas prices in North America. It is also possible that LNG suppliers will not price their gas at their marginal cost, but rather at a level that the market can bear in order to maximize their revenue.

Costs to drill and complete a well for natural gas production in Alberta have risen with time. Drilling and completion cost estimates for typical natural gas wells are shown in **Figure 1.4** by Petroleum Services Association of Canada (PSAC) area for 2002 and 2004. Table 1.1 outlines the median well depth for each area, a major factor contributing to the drilling costs. Many other factors influence well costs, including surface conditions, sweet versus sour production, and completion method. Gas well drilling and completion costs have risen over the two-year period in all areas of the province, with the exception of the Foothills region (Area 1), by 4.8 to 12.3 per cent. Recent costs to drill and complete a typical gas well are the highest in the Foothills area at close to $2 million, but could range significantly higher for deeper wells. In Southeastern Alberta (Area 3), a typical well could cost around $200 000 to drill and complete.

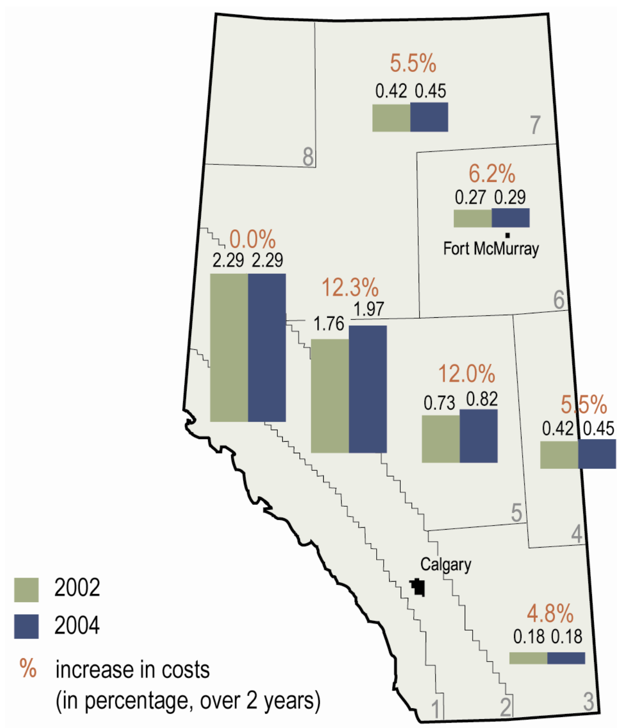


Figure 1.4. Alberta gas well cost estimations

Table 1.1 Alberta median well depths by PSAC area, 2002-2004 (m)

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells	3 187	2 283	693	709	939	454	770
Oil wells	NA	NA	1 306	807	1 482	NA	1 688

NA – Not applicable.

Oil well drilling and completion costs have also increased over time in most areas of the province, as illustrated in **Figure 1.5**. With the exception of East Central Alberta (Area 4), which has experienced a 2.1 per cent decrease in costs, other oil-prone areas of the province have exhibited increases of 4.3 to 13.2 per cent in drilling and completion costs. Costs to drill an oil well do not vary substantially across the province, as they do for natural gas wells. They range from as low as $520 000 in East Central Alberta to as high as $850 000 in Northwestern Alberta (Area 7).

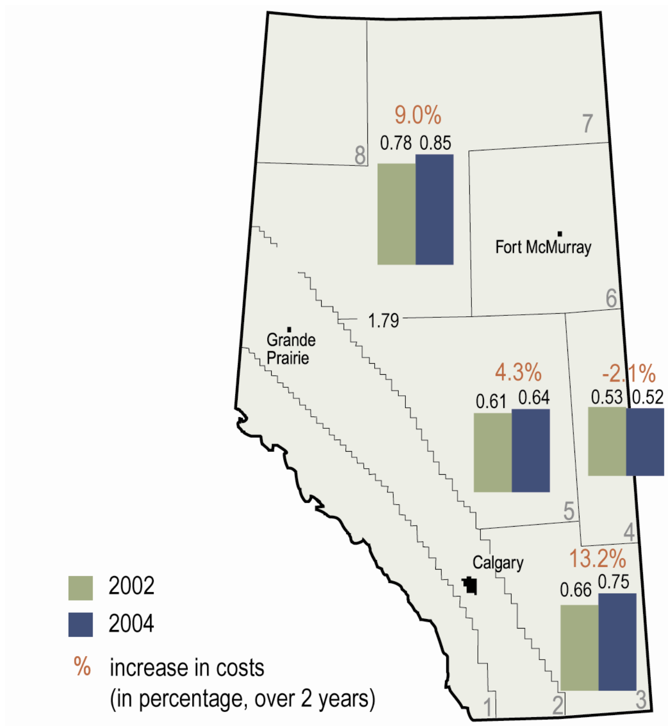


Figure 1.5. Alberta oil well cost estimations

1.3 Canadian Economic Performance

Canadian economic growth, interest rates, inflation, unemployment rates, and currency exchange rates (particularly vis-à-vis the U.S. dollar) are key variables that affect Alberta's economy but are beyond the province's control. The most important economic indicator that can identify whether the economy is slowing down or expanding is the real gross domestic product (GDP).The performance of the above economic indicators in 2004 are depicted in **Figure 1.6.**

In 2004, the performance of global economies continued to improve, led by China and India, again surpassing the previous year. The Canadian economy achieved a real growth rate of 2.7 per cent, despite numerous hurdles, such as the rapid increase in the value of the dollar versus the U.S. dollar and continued border closures to Alberta beef as a result of mad cow disease. However, lower exports in the fourth quarter due to exchange rate appreciation offset the steady growth in domestic demand. The slowdown in real GDP at year-end in Canada was also part of a deceleration in the G7 (major industrial countries), with the notable exception of the U.S.

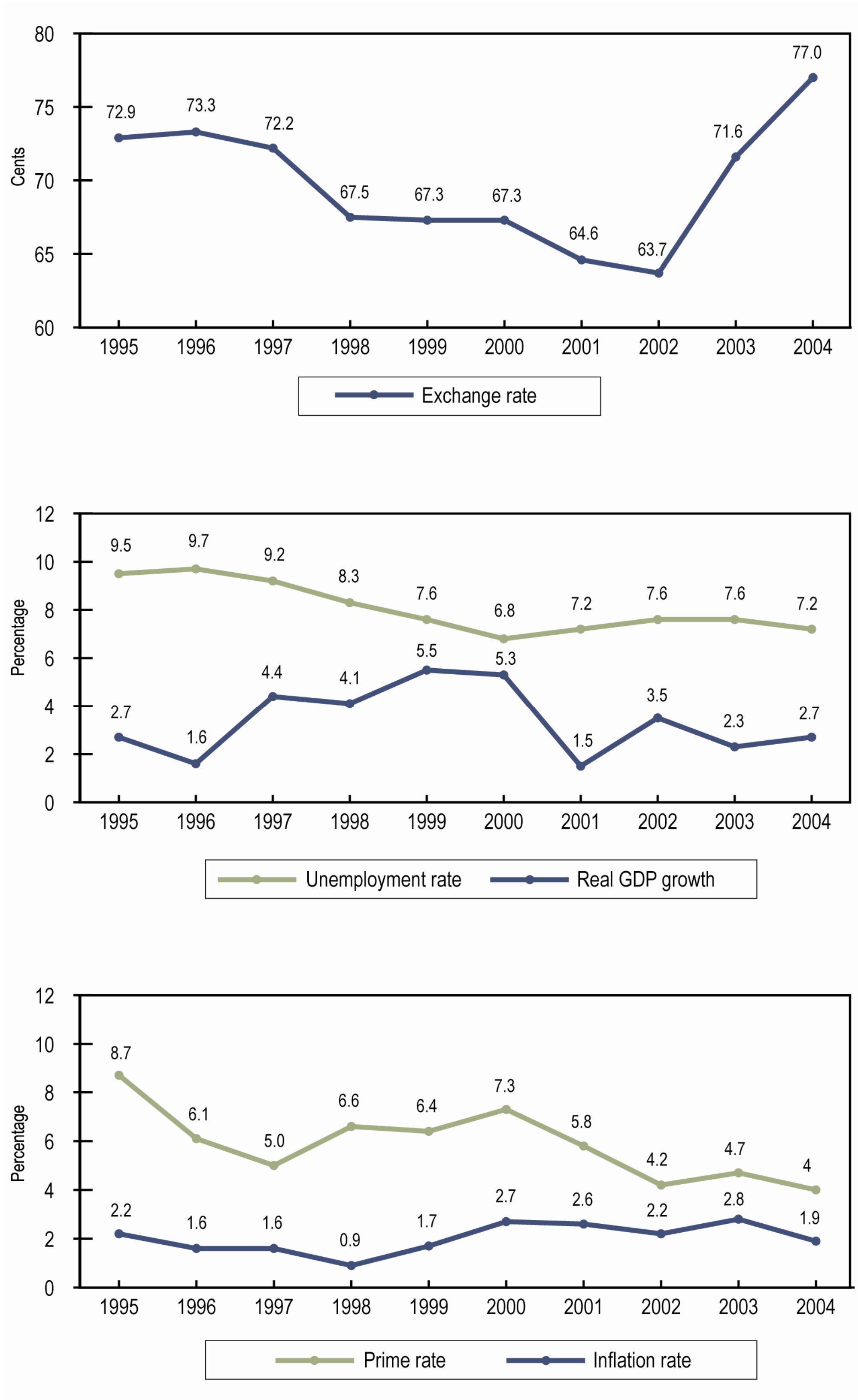


Figure 1.6. Canadian economic indicators, 2004

During 2004, the growth in the Canadian economy had a marginal impact on the unemployment rate, which averaged 7.2 per cent, compared to 7.6 per cent in 2003. With increased GDP growth over the forecast period, it is expected that the unemployment rate in Canada will gradually decline to an average of 7.0 per cent.

The Bank of Canada attempts to control the inflation rate, which is expressed in terms of the core consumer price index (CPI), a measure of consumer prices that excludes transitory influences of volatile components, such as prices for food and energy. The Bank of Canada focuses on the core CPI, and not the total CPI, because it has very little control over the prices of food and energy. The Bank of Canada's main goal is low and stable inflation. It has set the inflation control target within a range of 1 to 3 per cent until 2006.

The most important factors affecting exchange rates are interest rate differentials between countries, inflation, net exports, and economic growth. The Canadian dollar had a very strong year in 2004, as the currency continued to appreciate since hitting a record low of US61.8 cents in February 2002. The average value of the Canadian dollar reached US77.0 cents in 2004. The Canadian dollar has kept its strength in the early part of 2005 and is expected to average around US82 cents over the forecast period.

The Canadian economic indicators assumed from 2005 to 2014 are presented in Table 1.2.

Table 1.2. Major Canadian economic indicators, 2005-2014

	2005	2006	2007	2008-2014[a]
GDP growth rate	2.6%	2.7%	3.0%	3.0%
Prime rate on loans	4.2%	4.2%	5.0%	6.3%
Inflation rate	2%	2%	2%	2%
Exchange rate	0.82	0.82	0.82	0.82
Unemployment rate	7.1%	7.0%	7.0%	7.0%

[a] Averages over 2008-2014.

1.4 Alberta Economic Outlook

The Alberta economy has experienced prosperous growth each year since 1986. Real GDP has increased annually at an average rate of 3.5 per cent, reaching almost $133 billion in 2004. Since 1992, Alberta GDP per capita has been the highest among the provinces and has been on average 14 per cent higher than the GDP per capita of the second highest province, Ontario.

Over the forecast period, expansion of the oil sands industry will offset the economic impact of declining conventional production activities. At current crude oil price levels, the proposed oil sands projects are all commercially viable. Bitumen can be produced and upgraded in the province at US$26 to US$28 per barrel of WTI equivalent. However, market restrictions for Alberta oil sands products may cause slower growth in the level of production. It is expected that the capital injection into this sector will continue to be the engine of economic growth for the province. Alberta will continue to be Canada's leading producer of crude oil, bitumen, natural gas, natural gas liquids, sulphur, and coal.

The direct and indirect impacts of oil sands expansions, along with the expansion of other sectors, particularly the service sector, will cause Alberta's GDP to grow at an average annual rate of 3.7 per cent through 2010. As a result of the slower growth in oil sands development after 2010, the economic growth of Alberta may decline to an average of 2.9 to 3.2 per cent from 2011 on, as shown in **Figure 1.7**. However, further economic diversification may enhance economic growth beyond this range.

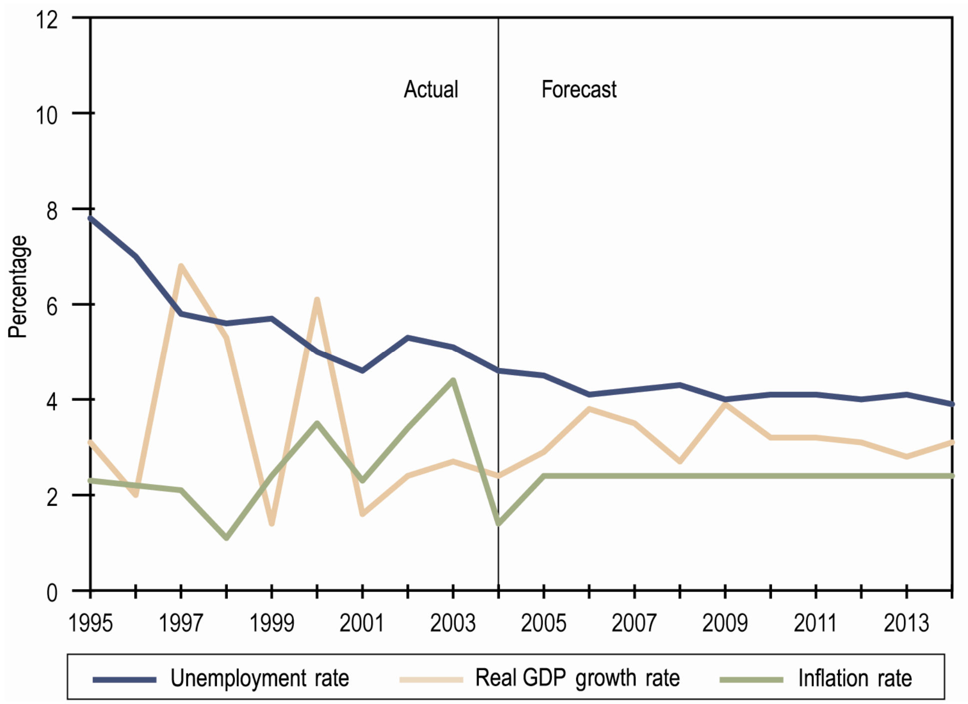


Figure 1.7. Alberta unemployment, inflation, and GDP growth rates

In the last decade, the Alberta unemployment rate has gradually declined from 8.0 per cent in 1995 to 4.7 per cent in 2004; currently, Alberta has the second lowest unemployment rate in Canada. The positive effects of continued strength in the Alberta economy on employment demand are expected to be partly offset by increases in the participation rate, as people, especially those over the age of 55, enter or re-enter the workforce. As a result, both the labour force and total employment are forecast to grow at roughly the same pace, and therefore the unemployment rate will fluctuate in a tight range of 4.6 to 4.9 per cent over the forecast period.

While Alberta's inflation rates of 3.4 and 4.4 per cent in 2002 and 2003 respectively were the highest in the country in both years, the preliminary numbers (at the time of writing) by Statistics Canada indicate that the inflation rate in Alberta has dropped to only 1.4 per cent in 2004. This rate was the lowest among all provinces for 2004.

Alberta's population has increased from 2.7 million in 1994 to slightly over 3.2 million in 2004, representing an average annual growth rate of 1.7 per cent. It is expected that over the forecast period, as Alberta GDP grows faster than that of the rest of Canada, population growth will continue at the pace of 1.7 per cent a year.

2 Crude Bitumen

Crude bitumen, a type of heavy oil, is a viscous mixture of hydrocarbons that in its natural state does not flow to a well. In Alberta, crude bitumen occurs in sand 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 these deemed oil sands will flow to a well, they are amenable to primary development and are considered to be primary crude bitumen in this report.

North of Fort McMurray, crude bitumen occurs near the surface and is recovered by open pit mining. The oil sands are excavated and the bitumen is extracted from the mined material in large facilities. At greater depths, the bitumen is recovered in situ. In situ recovery takes place both by primary development and by enhanced development where steam, water, or other solvents are injected into the reservoir to mobilize the bitumen and to bring it to a vertical or horizontal wellbore.

The three designated oil sands areas (OSAs) in Alberta are shown in **Figure 2.1**. Each oil sands area contains a number of bitumen-bearing deposits. The known extent of the largest deposit, the Athabasca Wabiskaw-McMurray, is shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

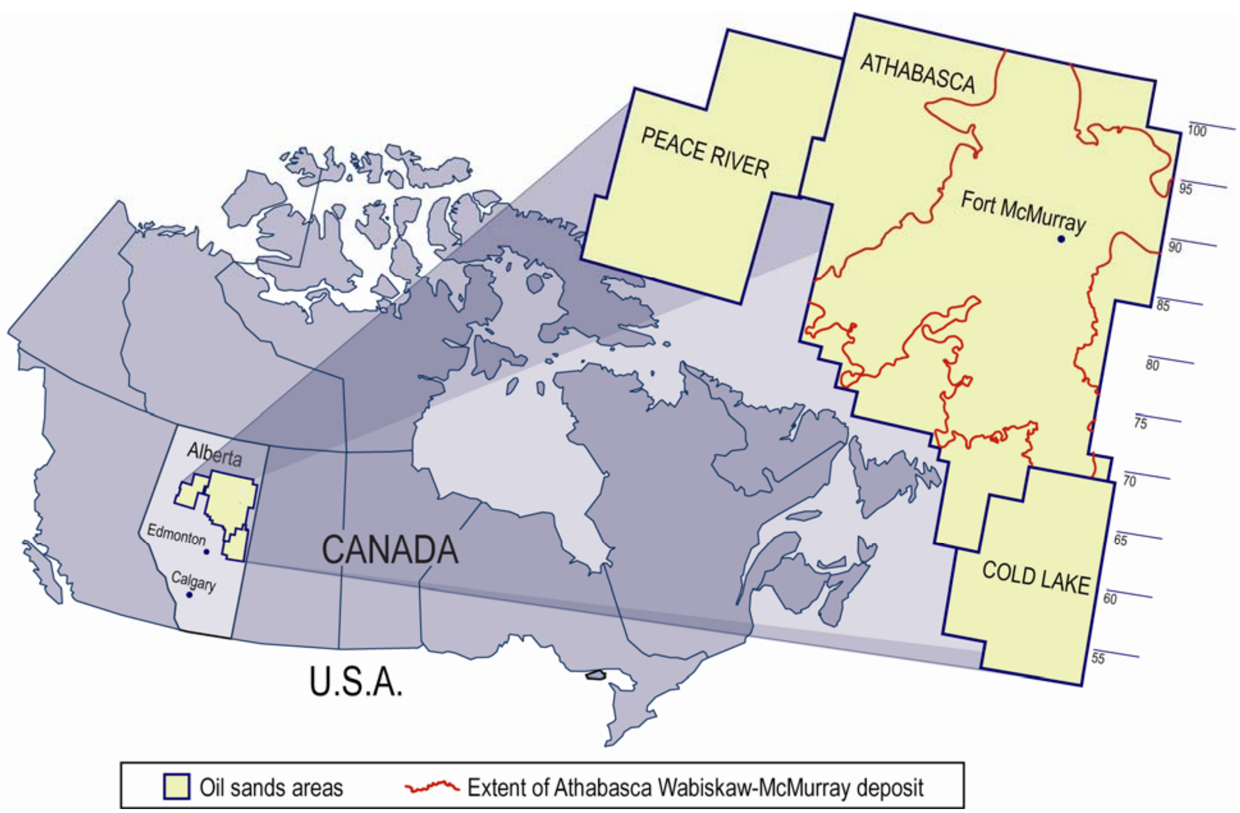


Figure 2.1. Alberta's three oil sands areas

2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

The EUB is engaged in a significant project to update the established reserves of each of Alberta's 15 oil sands deposits over the next few years. The reserves for the largest deposit, the Athabasca Wabiskaw-McMurray (AWM), are in the process of being updated. Initial results and a discussion of the study are presented later in Section 2.1.6.

The EUB estimates the remaining established reserves of crude bitumen in Alberta at December 31, 2004, to be 27.66 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to production of 0.06 10^9 m^3.

Of the total 27.66 10^9 m^3 remaining established reserves, 22.57 10^9 m^3, or about 82 per cent, is considered recoverable by in situ methods and 5.09 10^9 m^3 recoverable by surface mining methods. Of the in situ and mineable totals, 1.66 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	17.5	5.59	0.50	5.09	1.24
In situ	252.5	22.80	0.23	22.57	0.42
Total	269.9	28.39	0.73	27.66	1.66
	(1 699)[a]	(178.7)[a]	(4.6)[a]	(174.1)[a]	(10.5)[a]

[a] Imperial equivalent in billions of barrels.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative production for 2004 are shown in Table 2.2. The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown later in the text in Tables 2.4 and 2.5 respectively.

Crude bitumen production in 2004 totalled 63.4 10^6 m^3, with 22.5 10^6 m^3 coming from in situ operations. Production from the three current surface mining projects amounted to 40.9 10^6 m^3 in 2004, with 16.7 10^6 m^3 from the Syncrude Canada Ltd. project, 15.7 10^6 m^3 from the Suncor Energy Inc. project, and 8.5 10^6 m^3 from the Albian Sands Energy Inc. project.

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

	2004	2003	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 802	22 802	0
Total	28 392 (178 668)[b]	28 392 (178 668)[b]	0
Cumulative production			
Mineable	502	461	+41
In situ[a]	228	206	+23
Total	730	667	+63
Remaining established reserves			
Mineable	5 088	5 129	-41
In situ	22 574	22 597	-23
Total[a]	27 662 (174 075)[b]	27 726 (174 474)[b]	-63

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

Figure 2.2 compares the relative size of Alberta's initial and remaining established crude oil and crude bitumen reserves. It shows that while most of Alberta's known conventional crude oil reserves have been produced, most of the crude bitumen has yet to be tapped.

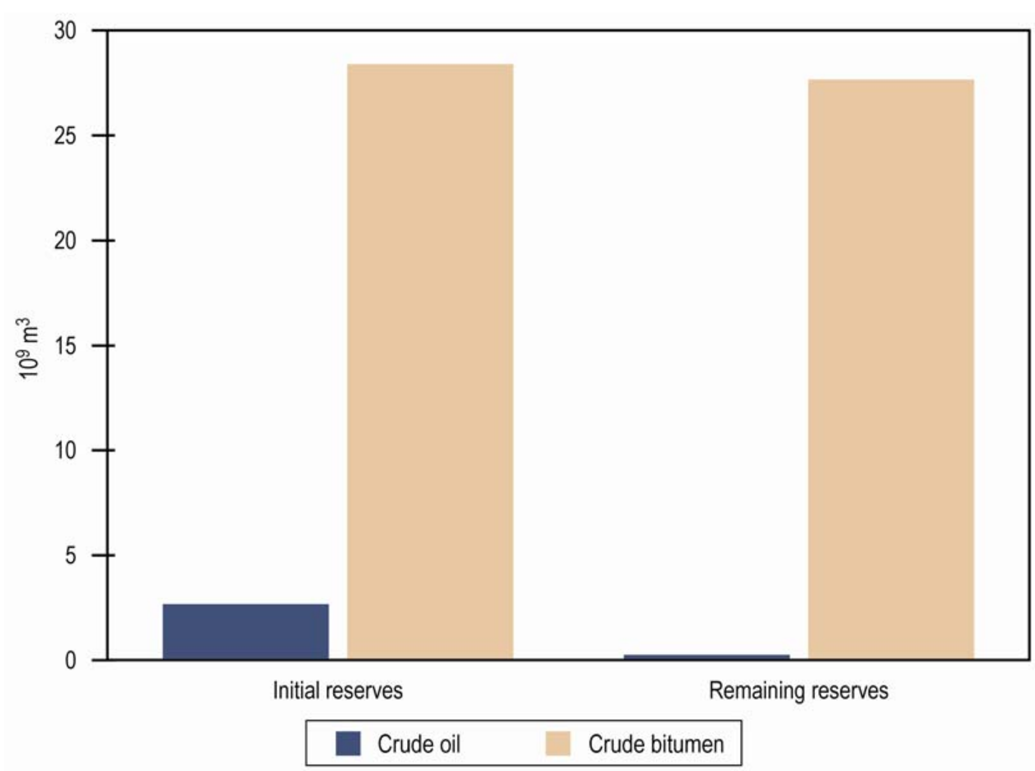


Figure 2.2. Comparison of Alberta's crude oil and crude bitumen reserves

2.1.2 Initial in-Place Volumes of Crude Bitumen

Alberta's massive crude bitumen resources are contained in sand and carbonate formations in the three oil sands areas (OSAs): Athabasca, Cold Lake, and Peace River, as shown in **Figure 2.1**. Contained within the OSAs are the 15 oil sands deposits, which designate the specific geological zones containing the oil sands. Together the three OSAs occupy an area of about 140 000 km^2 (54 000 square miles).

The quality of an oil sands deposit is primarily dependent upon the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation can vary significantly within a reservoir, decreasing as the reservoir shale or clay content increases or as the porosity decreases. Increasing water volume within the pore space of the rock also decreases bitumen saturation. Bitumen saturation is expressed as mass per cent in sands (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water) and per cent pore volume in carbonates (the percentage of the volume of pore spaces that contain bitumen). The selection of appropriate saturation and thickness cutoffs varies, depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data, including geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, cutoffs were increased to 6 mass per cent and 3.0 m for areas amenable to surface mining. With this year's report, the entire AWM deposit is now estimated using 6 mass per cent, with 1.5 m retained for in situ and 3.0 m used for surface mineable. The crude bitumen within the carbonate deposits was determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent.

The oil sands quality cutoff of 6 mass per cent for the AWM more accurately reflects the volumes from which bitumen can be reasonably expected to be recovered. Based solely on a change from 3 to 6 mass per cent (other factors held constant), the expected impact on the bitumen resource in place within the AWM would be a decrease of about 20 per cent. However, the reassessment work completed to date on the in situ portion of the AWM has increased the initial in-place volume from 118.9 10^9 m^3 to 130.5 10^9 m^3, a net increase of some 10 per cent. This increase is due to additional drilling since 1995 (the last regional update), which has expanded the known extent of the deposit, particularly to the northeast. This expansion offsets the decrease that could have been expected due to increasing the mass bitumen per cent cutoff.

In 2003, the EUB completed a regional geological study of part of the Wabiskaw-McMurray deposit of the Athabasca OSA.[1] The purpose of that study was to identify where gas pools are associated with recoverable bitumen. To support both that study and the ongoing work on reserves of the AWM, geologic information from over 13 000 wells and bitumen content evaluations conducted on over 9000 wells were used. Where available, core and core analysis were also used. The stratigraphic framework developed for the regional geological study was used in the update of the resources and reserves of the AWM; 21 stratigraphic intervals were identified and combined into up to 12 zones. Three distinct regions of the AWM deposit were identified where bitumen zones of a

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

similar nature can be found.

Figure 2.3 is a bitumen pay thickness map for the AWM deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map the deposit is treated as a single bitumen zone. The figure also shows the current boundary of the Surface Mineable Area (SMA).

The SMA is an EUB-defined area of 37 townships north of Fort McMurray covering that part of the AWM deposit where the total overburden generally does not exceed 75 m. As such, it is presumed that the main recovery method will be surface mining, unlike the rest of Alberta's crude bitumen area, where recovery will be through in situ methods.

The present definition of the SMA boundary incorporates a few areas of deeper bitumen resources more amenable to in situ recovery. For the first time, the in-place resources in those areas presently designated as being capable of in situ production are excluded from the SMA in this report. The in-place resource and the resultant established reserves are included with the in situ numbers.

The estimate of the initial volume in place of crude bitumen within the SMA is reduced to 17.5 10^9 m^3, which excludes the bitumen resource reassessed as in situ. Notwithstanding this reduction, almost half of the above volume has been estimated to be beyond the economic range of current commercial mining. Some additional portions of this nonmineable volume can be recovered by in situ methods, but they have not yet been fully delineated.

The crude bitumen resource volumes are presented on a deposit basis in the table Crude Bitumen Resources and Basic Data, provided on CD (see Appendix C) and summarized by formation in Table 2.3. Individual maps to year-end 1995 are shown in EUB *Statistical Series 96-38: Crude Bitumen Reserves Atlas* (1996).

2.1.3 Surface-Mineable Crude Bitumen Reserves

Potential mineable areas within the SMA were identified using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 mass per cent bitumen, and a minimum saturated zone thickness cutoff of 3.0 m. The ESR criteria are fully explained in *ERCB Report 79-H*, Appendix III.[2] This method reduces the initial in place of 17.5 10^9 m^3 to 9.4 10^9 m^3 as of December 31, 2004. This latter volume is classified as the initial mineable volume in place.

Factors were applied to this initial mineable volume in place to determine the established reserves. A series of area reduction factors were applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total area, and therefore each factor is set at 90 per cent. A combined mining/extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by the mining operations and the extraction facilities. The resulting initial established reserve of crude bitumen is estimated to be 5.59 10^9 m^3, unchanged from December 31, 2003.

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

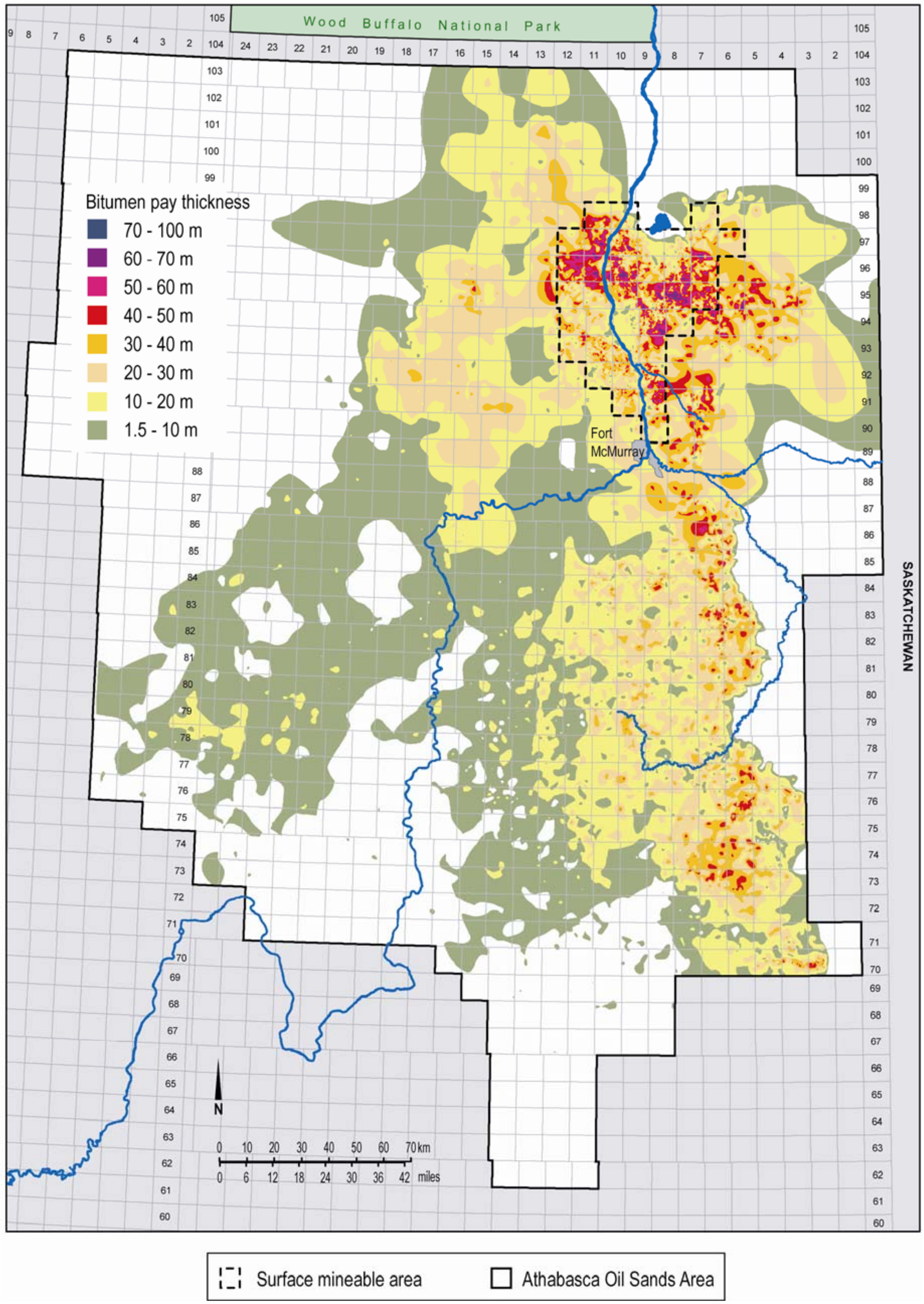

Figure 2.3. Bitumen pay thickness map of the Athabasca Wabiskaw-McMurray deposit

Table 2.3. Initial in-place volumes of crude bitumen

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 (%)	Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (SMA)	17 480	280	30.5	9.7	69	30
Wabiskaw-McMurray (non-SMA)	130 492	4 626	13.2	10.2	73	29
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	50 500	4 167	10.4	4.7	68	16
Subtotal	217 480					
Cold Lake						
Grand Rapids	17 304	1 709	5.9	9.5	66	31
Clearwater	11 051	589	15.0	8.9	64	30
Wabiskaw-McMurray	3 592	658	5.8	6.3	54	26
Subtotal	31 947					
Peace River						
Bluesky-Gething	9 926	1 254	8.7	6.4	60	23
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	302	23.7	5.1	65	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	20 518					
Total	269 945					

The remaining established mineable crude bitumen reserve as of December 31, 2004, is 5.09 10^9 m^3, slightly lower than last year's estimate due to the production of nearly 40.9 10^6 m^3 in 2004.

About a quarter of the initial established reserves is under active development. Currently, Suncor, Syncrude, and Albian Sands are the only producers in the SMA, and the cumulative bitumen production from these projects is 502 10^6 m^3. The Fort Hills mine project, currently owned by UTS Energy and Petro-Canada, received EUB approval in late 2002 but is not yet under active development (either producing or under construction), and as a result established reserves for this project, totalling about 400 10^6 m^3 initial reserves, are not yet included in Table 2.3. The Canadian Natural Resources Ltd. (CNRL) Horizon and Shell Canada Ltd. Jackpine projects were approved in early 2004, and their reserves will be included in a future edition of this report when appropriate.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2004, are presented in Table 2.4.

2.1.4 In Situ Crude Bitumen Reserves

The EUB 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

Table 2.4. Mineable crude bitumen reserves in areas under active development as of December 31, 2004

Development	Project area[a] (ha)	Initial mineable volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
Albian Sands	10 096	574	178	13	165
Suncor	15 370	878	604	191	413
Syncrude	21 672	1 433	959	298	661
Total	47 138	2 885	1 741	502	1 239

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

deposits except the AWM, where 15.0 m was used for the Wabiskaw zones. For primary development, a minimum zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. A minimum saturation cutoff of 3 mass per cent was used in all deposits except for the AWM, where 6 mass per cent was used. Future reserves estimates for other deposits 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. Reserves determination for the AWM is discussed further in Section 2.1.6.

In 2004, the in situ bitumen production was 22.5 10^6 m^3, an increase from 20.4 10^6 m^3 in 2003. Cumulative production within the in situ areas now totals 228 10^6 m^3, of which 187 10^6 m^3 is from the Cold Lake OSA. Due to production, the remaining established reserves of crude bitumen from in situ areas decreased to 22.57 10^9 m^3.

The EUB's 2004 estimate of the established in situ crude bitumen reserves under active development is shown in Table 2.5.

The EUB has assigned initial volumes in place and initial and remaining established reserves for commercial projects, primary recovery schemes, and active experimental schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is shown for all active experimental schemes, as well as an estimate of initial volumes in place and cumulative production. An aggregate reserve is also shown for all commercial and primary recovery schemes within a given oil sands deposit and area. 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 422.0 10^6 m^3. This decrease of 18.9 10^6 m^3 from 2003 is the result of 22.5 10^6 m^3 production and to a positive reassessment of 3.6 10^6 m^3 to the enhanced recovery schemes in the Athabasca OSA. Expansions to the commercial

Table 2.5. In situ crude bitumen reserves[a] in areas under active development as of December 31, 2004

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	21.6	40	8.6	8.0	0.7
Primary recovery schemes	27.9	5	1.4	0.7	0.7
Subtotal	49.5		10.0	8.7	1.3
Athabasca Oil Sands Area					
Thermal commercial projects	155.6	50	77.8	7.9	69.9
Primary recovery schemes	628.6	5	31.4	15.9	15.5
Enhanced recovery schemes[c]	(136.7)[d]	5	6.8	1.9	4.9
Subtotal	784.2		116.1	25.7	90.4
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25	200.7	135.3	65.4
Primary production within projects	601.1	5	30.1	12.7	17.4
Primary recovery schemes	4 347.1	5	217.4	34.0	183.4
Lindbergh primary production	1 309.3	5	65.5	5.4	60.1
Subtotal	7 060.3		513.6	187.4	326.2
Experimental Schemes (all areas)					
Active	8.1	15[e]	1.2	1.1[f]	0.1
Terminated	87.4	10[e]	9.1	5.1	4.0
Subtotal	95.5		10.3	6.2	4.1
Total	7 989.5		650.0	228.0	422.0

[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, 2004, includes amendments to production reports.
[c] Schemes currently on 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 waterflooding.
[e] Averaged values.
[f] Production from the Athabasca OSA is 0.86 10^6 m^3 and from the Cold Lake OSA is 0.20 10^6 m^3.

thermal projects and the primary recovery schemes in the Athabasca, Cold Lake, and Peace River OSAs were not assessed in 2004. Additionally, the increased drilling activity in the Cold Lake OSA in recent years has not yet been assessed.

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 some 6 10^9 m^3. Nearly 11 10^9 m^3 is expected from within the surface-mineable boundary, with a little more than 10 10^9 m^3 coming from surface mining and about 0.4 10^9 m^3 from in situ methods. The total ultimate potential crude bitumen is therefore about 50 10^9 m^3.

2.1.6 Review of in Situ Resources and Reserves

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

- updating the geological framework for each deposit,
- reviewing established mass per cent bitumen and thickness cutoffs,
- re-evaluating all wells to provide data on a detailed incremental thickness basis and storing these evaluations in a new database,
- evaluating all recent drilling,
- remapping deposits and recalculating in-place resource volumes, and
- reviewing recovery factors, changing them where appropriate, and calculating new established reserves volumes.

The project to date has focused on the AWM deposit because it is Alberta's largest deposit, has demonstrated commercial production using SAGD technology, and has been the focus of a significant hearing process to reconcile gas production and bitumen conservation. As stated earlier, the EUB completed a regional geological study in 2003 throughout a significant part of the AWM in response to the bitumen conservation issue. This study formed the basis for updating the geological framework for the entire AWM.

The EUB held a series of bitumen conservation proceedings from 1997 to 2005 to determine the need to shut in gas production to protect potentially recoverable bitumen. The EUB has accepted that bitumen exceeding 6 mass per cent and 10 m thickness is potentially recoverable. The EUB has adopted these cutoffs for the AWM and will likely use the same for future updates of other deposits, rather than the 3 mass per cent cutoff currently used. This removes much of the poorer quality component of the bitumen resource (with low potential recoverability) from the reserve category. **Figure 2.4** is a recoverable bitumen pay thickness map of the AWM deposit based on cutoffs of 6 mass per cent and 10 m thickness. Areas and intervals not considered recoverable for various reasons (explained below) have been removed. **Figure 2.4** also shows the two areas inside the SMA where the bitumen resources have been transferred from the mineable total to the in situ total.

All historic well evaluations for the AWM have now been redone on the incremental thickness basis and stored in the EUB's corporate database. This will significantly improve timely updates of resource information, facilitate the flexibility of computer mapping and volume calculations, and support electronic dissemination of relevant information to EUB customers. Work continues on updating recent drilling information.

Given the relatively early stage of SAGD development, it is not yet possible to refine the current deposit-wide recovery factor of 20 per cent with any greater degree of certainty. Furthermore, the impact of the uncertainty in the deposit-wide recovery factor is noteworthy because a minor change in the recovery factor on a resource of this magnitude has a significant impact on the recoverable component. Expected recovery factors reported by oil sands operators in applications filed with the EUB typically exceed 60 per cent for exploitable bitumen in place. However, the EUB believes it is prudent to continue using a deposit-wide recovery factor of around 20 per cent to take into account those areas containing identified potentially recoverable bitumen where recovery operations, for whatever reason, will not be established. The impact of different recovery factors on established reserves estimates is shown in Table 2.6.

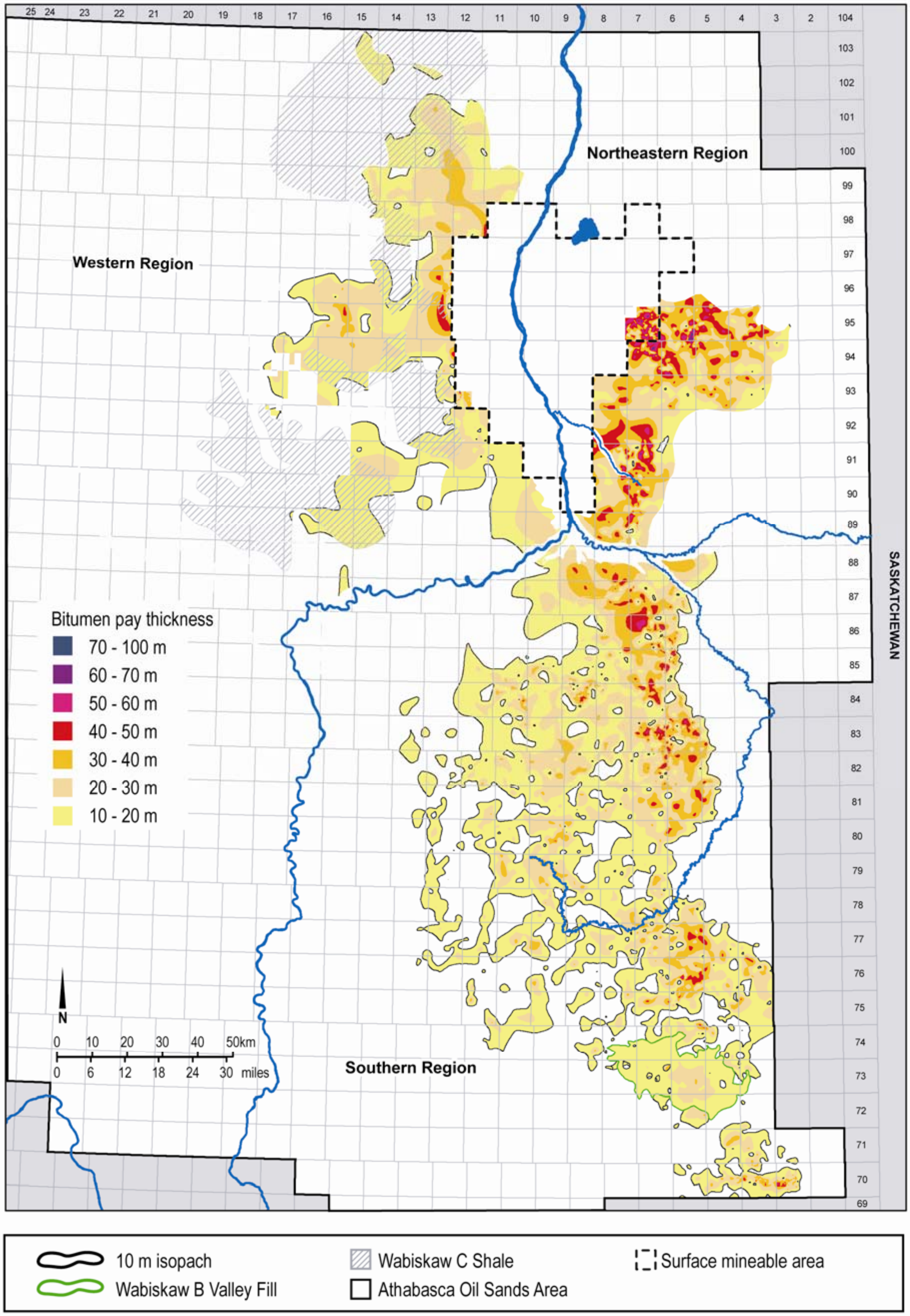

Figure 2.4. Bitumen pay thickness map within in situ recoverable areas of the Athabasca Wabiskaw-McMurray deposit

Table 2.6. Impact of recovery factors on Athabasca Wabiskaw-McMurray reserves estimates

Bitumen saturation cutoff (mass %)	Thickness cutoff (m)	Recovery factor (%)	Remaining established reserves, AWM only (10^9 m^3)	Comment
3	10	20	15.6 (98.2)[a]	Current reserves estimate
6	10	20	13.4 (84.3)	Estimate with revised cutoffs in AWM and unchanged recovery factor
6	10	23.3	15.6 (98.2)	Recovery factor chosen to match current reserves estimate
6	10	25	16.7 (105.1)	Impact on reserve of increasing recovery factor by 5%

[a]Imperial equivalent in billions of barrels.

In addition to the changes in cutoffs and updated well evaluations described above, a number of other revisions resulted in refinements to the AWM reserves:

- subdividing the AWM deposit into defined stratigraphic zones and evaluating the bitumen content in these zones;
- identifying and mapping units that would act as regional barriers to vertical fluid movement from one bitumen zone into another (regional mudstones and sealing shales);
- excluding bitumen intervals less than 10 m in thickness and separated from other bitumen intervals by a regional sealing shale—this was increased to 15 m for the Wabiskaw Member in the western region of the Athabasca OSA;
- excluding bitumen resources in river valleys and areas lacking at least 50 m of cover above the bitumen zones for environmental and technical engineering reasons;
- In the western region, excluding bitumen resources outside of the boundaries of the northern regional geological study area and beneath the area of four gas fields (Liege, Ells, Tar, and Saleski)—these are areas where the pressure in gas caps overlying the bitumen resource was considered too low to allow bitumen recovery using current technologies;
- excluding an area in the extreme northeast because erosional downcutting removed shale or clay barriers between the oil sands and overlying freshwater-bearing quaternary sediments—even though throughout much of this area thick bitumen exists at depths greater than 50 m, the potential in situ reserves are considered unrecoverable by standard in situ methods and are excluded until such time as development is proposed for this area;
- adding significant new reserves as the result of evaluating wells drilled since the last regional update—most significant is the expansion of the deposit to the northeast.

To summarize, the changes identified above would result in a net decrease in established reserves for the AWM (after taking into account some increase due to new drilling) if a 20 per cent recovery factor were used. However, minor variations in the deposit-wide recovery factor can impact reserves estimates and offset any of the changes noted above. While a great deal of study and effort have gone into updating the resources of the AWM, the EUB has not yet completed a review of recovery factors that should be applied on a deposit-wide basis. The EUB has therefore decided to retain the existing established reserves figure for the province, except for adjustments due to production, until a review of other deposits is complete and until further work provides refinement of deposit-wide recovery factors for those deposits with commercial production. The EUB is also considering providing a low, best, and high estimate for established reserves volumes in future updates to take into account uncertainty in some of the variables, particularly the recovery factor.

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

2.2 Supply of and Demand for Crude Bitumen

This section discusses production and disposition of crude bitumen. It includes crude bitumen production by surface mining and in situ methods, upgrading of bitumen to synthetic crude oil (SCO), and disposition of both SCO and nonupgraded bitumen. The nonupgraded bitumen refers to the portion of crude bitumen production that is not upgraded but blended with diluent and sent to markets by pipeline; upgraded bitumen refers to the portion of crude bitumen production upgraded to SCO, which is used by refineries as feedstock.

Upgrading is the term given to a process that converts bitumen and heavy crude oil into SCO, which has a density and viscosity similar to conventional light-medium crude oil. Upgraders chemically add hydrogen to bitumen, subtract carbon from it, or both. In upgrading processes, essentially all the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. Most oil sands coke 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 for use mainly to manufacture fertilizers.

Two methods are used for recovery of bitumen, depending on the depth of the deposit. The shallow-depth deposits in Athabasca (Fort McMurray) are currently recovered by surface mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted using hot water.

Unlike the mineable area of Athabasca, other oil sands deposits are located deeper below the surface. For these deposits, in situ methods have been proven technically and economically feasible. These methods typically use heat from injected steam to reduce the viscosity of the bitumen, allowing it to be separated from the sand and pumped to the surface. A number of these deeper deposits can also be put on production with primary recovery, similar to conventional crude oil production.

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

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

2.2.1 Crude Bitumen Production

Production of surface mining and in situ production for 2004 is shown graphically by oil sands area in **Figure 2.5.** In 2004, Alberta produced 173.1 thousand (10^3) m^3/d of crude bitumen from all three regions, with surface mining accounting for 65 per cent and in situ for 35 per cent. **Figure 2.6** 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 28 per cent of all production in 1995 to 57 per cent in 2004.

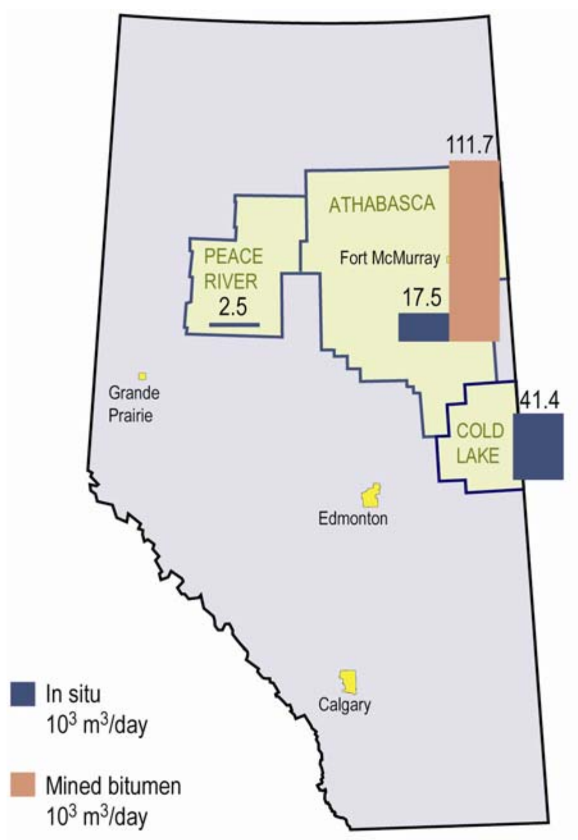

Figure 2.5. Production of bitumen in Alberta, 2004 (10^3 m^3/d)

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 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.

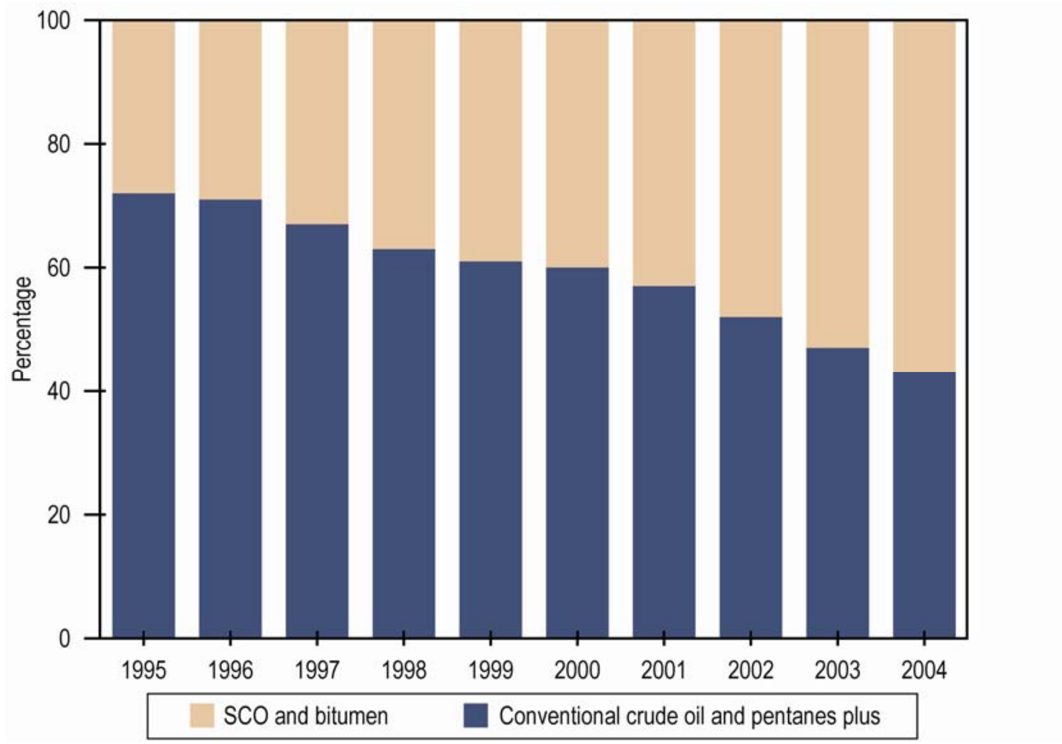

Figure 2.6. Alberta crude oil and equivalent production

2.2.1.1 Mined Crude Bitumen

Crude bitumen production increased by 15 per cent over the past year, reaching a level of 111.7 10^3 m^3/d in 2004, with Syncrude, Suncor, and Albian Sands accounting for 41, 38, and 21 per cent respectively. The primary reason for this increase was the full-year operation of the Albian Sands project, which produced about 23.1 10^3 m^3/d on average in 2004, a 74 per cent increase over 2003. Syncrude increased production by 12 per cent over 2003 to 45.6 10^3 m^3/d. Suncor's production remained consistent with the 2003 level of 43.0 10^3 m^3/d, as production was restricted by unscheduled maintenance in June 2004.

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

- the existing production and expected expansions of Suncor, including the Voyageur projects;
- the existing and expected expansions of Syncrude, including stages three and four of the five-stage project that began in 1996;
- the existing Albian Sands project, its debottlenecking projects, and expansion scheduled for completion by 2010;
- the CNRL Horizon Project (approved by the EUB in January 2004), with proposed production beginning in 2008;
- the Shell Jackpine Mine Phase One (approved by the EUB in February 2004), with production expected two to three years after the Muskeg Mine expansion;
- the UTS Energy Corporation (UTS)/Petro-Canada Fort Hills project (originally TrueNorth Energy's Fort Hills Oil Sands Project, approved by the EUB in October 2002), with production proposed by 2009-2010;

- the proposed Imperial Oil/ExxonMobil Kearl Mine, a multiphased project with start-up expected by late 2010 (current plans do not include any on-site upgrading facilities);
- the Deer Creek Joslyn Project, a proposed multistaged development, with production expected in 2011; and
- the Synenco Northern Lights Project proposed as a two-staged project with initial start-up in 2009.

In projecting total mined bitumen over the forecast period, the EUB assumed that potential market restrictions, cost overruns, construction delays, and availability of suitable refinery capacity on a timely basis may affect the timing of production schedules for these projects. The EUB assumed that total mined bitumen production will decline from 111.7 10^3 m^3/d in 2004 to 95 10^3 m^3/d in 2005 and increase to about 260 10^3 m^3/d by 2014. The decline in the production forecast in 2005 is primarily the result of a fire at Suncor's upgrader facility in January 2005, which damaged one of their two upgraders, thus reducing mined bitumen feedstock. Full production is scheduled to return by the third quarter of 2005.

Figure 2.7 illustrates total mined bitumen production over the forecast period.

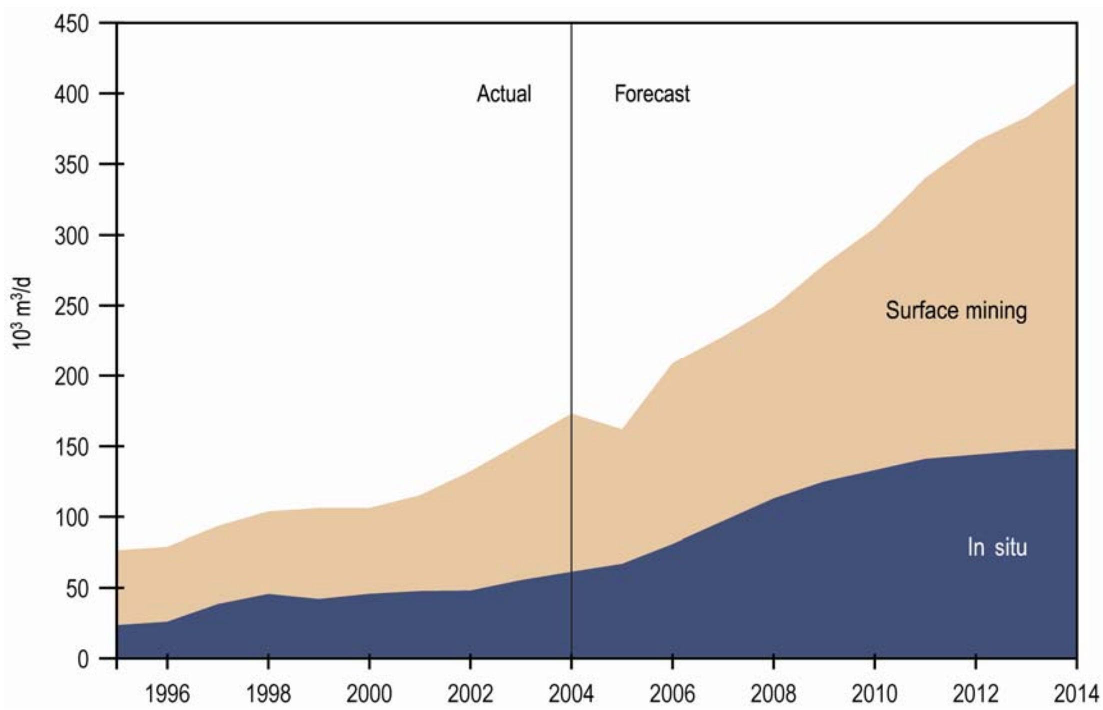

Figure 2.7. Alberta crude bitumen production

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 23.6 10^3 m^3/d in 1995 to 61.4 10^3 m^3/d in 2004. Production of in situ bitumen, along with the number of bitumen wells on production in each year, is shown in **Figure 2.8.** Corresponding to the increase in production, the number of producing bitumen wells has also increased from 3100 wells to about 7700 wells over the last ten years. The average well productivity of in situ bitumen wells in 2004 averaged some 8.7 m^3/d.

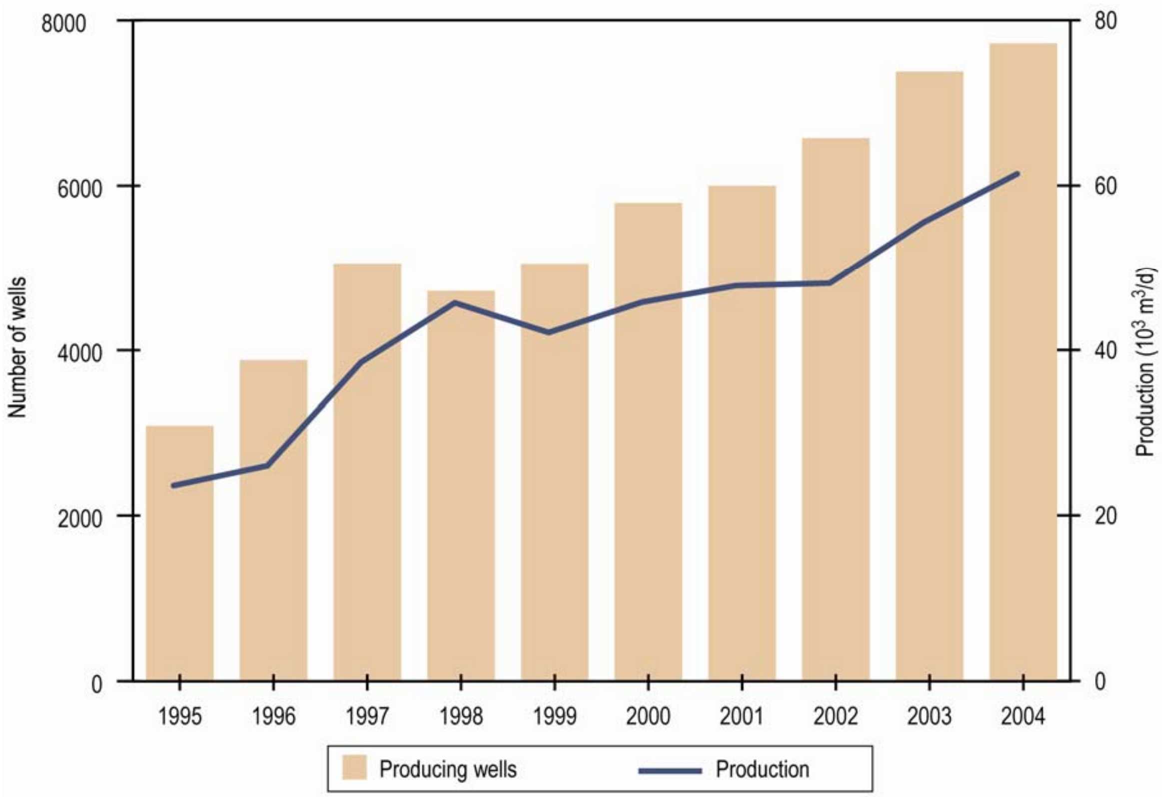

Figure 2.8. Total in situ bitumen production and producing bitumen wells

The majority of in situ bitumen, 94 per cent, was marketed in nonupgraded form outside of Alberta, and the remaining 6 per cent was used in Alberta by refineries and upgraders.

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

Figure 2.7 illustrates the EUB's in situ crude bitumen forecast. It shows that in situ crude bitumen production is expected to rise to 148 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period, about 25 per cent of in situ bitumen production will be used as feedstock for SCO production within the province.

2.2.2 Synthetic Crude Oil Production

A large portion of Alberta's bitumen production is upgraded to SCO. The three major upgraders, Suncor, Syncrude, and Shell Canada, produced 35.0 10^3 m^3/d, 38.5 10^3 m^3/d, and 21.7 10^3 m^3/d of SCO respectively in 2004.

The existing Suncor and Syncrude plants use different technologies for the conversion of crude bitumen to SCO. Therefore, the SCO yield through upgrading can vary, depending on the type of technology, the use of products as fuel in the upgrading, the extent of gas liquids recovery, and the extent of residue upgrading. The overall liquid yield factor for the current Suncor delayed coking operation is about 0.81, while that for the current fluid coking/hydrocracking operation at Syncrude is 0.85. The overall liquid yield factor for the Albian Sands project, via the Shell upgrader using a hydrocracking process, is approximately at or above 0.90. The OPTI/Nexen Long Lake Project will use a new upgrading technology that will have a liquid yield factor of about 0.85. CNRL will use delayed coking with a liquid yield factor of about 0.86.

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

The EUB expects significant increases in SCO production over the forecast period based on the following projects.

Suncor

- the continued operation and future expansions of the Firebag In Situ Oil Sands Operation
- modification of the upgrader (the addition of a vacuum tower) to increase SCO production capacity starting late in 2005
- expansion of the existing upgrader (the construction of a pair of coke drums, a sulphur recovery plant and other crude oil processing equipment) by 2008
- Voyageur Phase One—establishment of a third upgrader by 2010 and further development of the oil sands mining facilities
- Voyageur Phase Two—expansion of the third oil sands upgrader by 2012

Syncrude expansions

- stage three, including the upgrader expansion and a second train of production at Aurora in 2006
- stage four, debottlenecking of the stage-three expansion by 2001

Shell

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

- upgrading of crude bitumen from the Jackpine Mine

The proposed OPTI/Nexen Long Lake Project is an in situ bitumen recovery and field upgrading facility located about 40 km southeast of Fort McMurray. Phase I of this project is expected to commence in 2007. In the second phase, scheduled for completion by 2011, the capacity of all components is planned to double.

CNRL is proposing to develop its oil sands leases within the Regional Municipality of Wood Buffalo in northeastern Alberta. The three-phase project is expected to begin operation in 2008.

The proposed UTS/Petro-Canada Fort Hills project plans for the completion of a mine and extraction facility by 2009 and an upgrader within two years of the first production. Alternatively, a mine and extraction facility with an upgrader may be constructed by 2010.

The Deer Creek Joslyn Project is proposing production of the initial phase of mineable development commencing in 2011.

The Synenco Northern Lights Project is proposing a fully integrated oil sands project that involves a two-staged development, with start-up expected by 2009.

Two other projects being considered involve upgrading bitumen feedstock to SCO by independent operations located in the Edmonton vicinity. The first project is the BA Energy Heartland Upgrader near Fort Saskatchewan, Alberta. This upgrader, capable of processing bitumen blends from the Athabasca oil sands mining and in situ operations, will be built in three phases, with the first phase start-up in 2007. The second project is the proposed NorthWest Upgrader within the Industrial Heartland Area of Sturgeon County. NorthWest Upgrading Inc. plans to develop the upgrader in three phases, with the first phase expected to come on stream in early 2010.

Figure 2.9 shows the EUB projection of SCO production. It is expected that the SCO production will decrease from 95.2 10^3 m^3/d in 2004 to 84 10^3 m^3/d in 2005 and then increase to 264 10^3 m^3/d by 2014. As mentioned earlier, a fire at Suncor that damaged one of the two oil sands upgraders is the reason for the decline from 2004 to 2005. Return to full production is expected in the third quarter of 2005.

2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, adequate incremental pipeline capacity is essential to market greater volumes of product. The current pipeline systems in the Cold Lake and Athabasca areas are described in Table 2.7.

The Cold Lake pipeline system is capable of delivering heavy crude from the Cold Lake area to Hardisty and Edmonton. The Husky pipeline 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 or the Express pipeline systems. The Echo pipeline system 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.

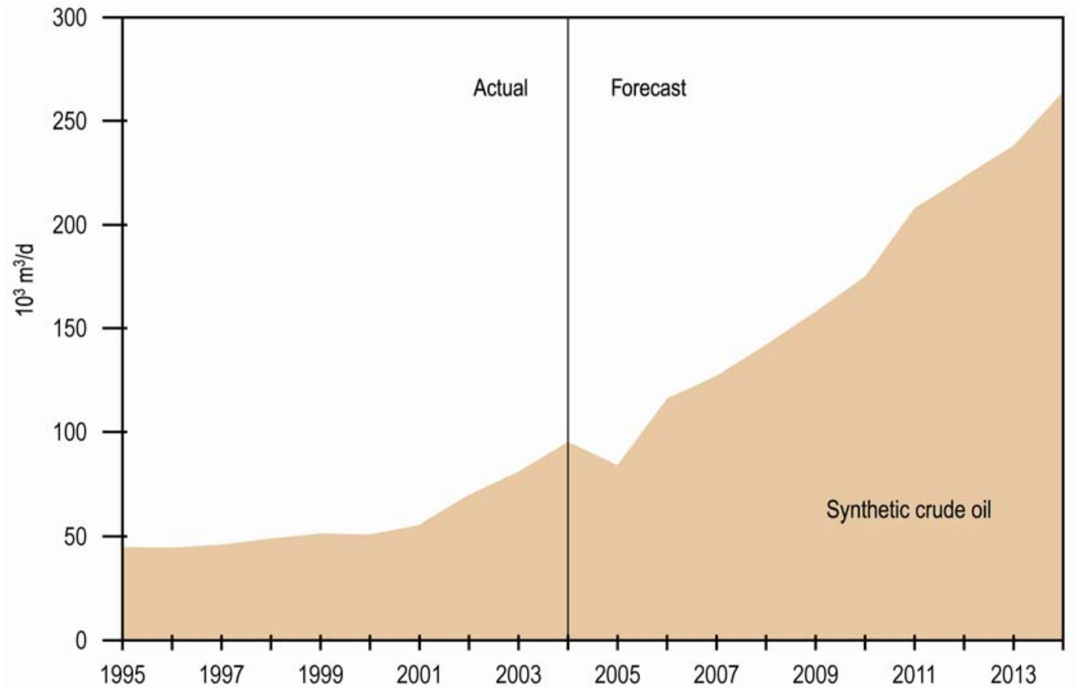

Figure 2.9. Alberta synthetic crude oil production

Table 2.7. 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	36.7
Cold Lake Heavy Oil Pipeline	Edmonton	36.7
Husky Oil Pipeline	Hardisty	21.2
Husky Oil Pipeline	Lloydminster	36.0
Echo Pipeline	Hardisty	12.0
Fort McMurray area pipelines		
Athabasca Pipeline	Hardisty	37.4
Terasen Pipelines (Corridor)	Edmonton	33.6
Alberta Oil Sands Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	19.7

The Athabasca pipeline delivers semiprocessed product and bitumen blends to Hardisty and has the potential to carry 90.6 10^3 m^3/d. The Terasen Corridor pipeline transports diluted bitumen from the Albian Sands mining project to the Shell Scotford upgrader. Capacity of the pipeline can be increased by 11.9 10^3 m^3/d through the addition of four pump stations. Further expansion of the Corridor system is linked to the production growth plans for the Athabasca Oil Sands Project and would require looping of the current system. The Alberta Oil Sands pipeline is the exclusive transporter for Syncrude, and an expansion to increase capacity to 61.8 10^3 m^3/d was completed in 2004. The Oil Sands Pipeline transports Suncor synthetic oil to the Edmonton area.

The proposed Access and Waupisoo pipeline projects will add additional bitumen capacity to Edmonton of 163 10^3 m^3/d and 33.4 10^3 m^3/d respectively. The Access Pipeline Project will transport diluent and bitumen for 303 km from the Christina Lake area. Enbridge plans to construct the 390 km Waupisoo Pipeline to move blended bitumen from Fort McMurray to Edmonton and will design it to be expandable to a capacity in excess of 49.3 10^3 m^3/d.

Table 2.8 lists the export pipelines, with their corresponding destinations and capacities. The Enbridge Pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the United States midwest. The Terasen Express pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends into Wood River, Illinois. Plans are under way to increase capacity to 44.5 10^3 m^3/d in 2005. The Terasen 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. Terasen completed the expansion of the Trans Mountain pipeline, which added 4.3 10^3 m^3/d of additional capacity, in October 2004. Rangeland is a gathering system and serves as another export route for Cold Lake Blend. Milk River Pipeline delivers Bow River heavy and Manyberries light oil. Both pipelines deliver primarily into Montana refineries.

Table 2.8. Export pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Pipeline (includes Terrace Expansion)	Eastern Canada U.S. east coast U.S. midwest	312.2
Terasen Pipelines (Express)	U.S. Rocky Mountains U.S. midwest	27.3
Milk River Pipeline	U.S. Rocky Mountains	16.8
Rangeland Pipeline	U.S. Rocky Mountains	10.3
Terasen Pipelines (Trans Mountain)	British Columbia U.S. west coast Offshore	44.6
Total		411.2

Three new export pipeline projects have been announced and include the following: Enbridge's Gateway Pipeline is a proposed 63.6 10^3 m^3/d pipeline running from Edmonton to the west coast of British Columbia, where ships will take crude oil and petroleum products to refineries in California and the Far East. Pending regulatory approvals, construction on the 1200 km pipeline could begin by 2008 and be operational by 2009-2010.

Terasens's Trans Mountain Expansion (TMX) project is a proposed staged expansion of the existing Trans Mountain system between Edmonton and Burnaby (Vancouver) and/or Prince Rupert/Kitimat, British Columbia. The expansion will see the looping of the existing pipeline in stages to eventually create a dual pipeline system with an initial incremental capacity of 11.9 10^3 m^3/d, increasing to 99.3 10^3 m^3/d. The first stage could be in service by late 2006, with the final stage completed by 2010.

TransCanada Corporation recently announced the Keystone Project, which proposes to convert a natural gas pipeline to crude oil service. The 1300 km of pipe to be converted originates near Hardisty, Alberta, and terminates at Oak Bluff, Manitoba. The project also includes construction of a 70 km pipeline to connect Hardisty terminal with existing pipe, and an additional 1700 km will be built to connect Oak Bluff to Wood River. The total length of proposed pipeline is 3000 km from Hardisty to Wood River and could be in service, with a capacity of 69.1 10^3 m^3/d, by 2008 or 2009, depending on regulatory proceedings and commercial support.

2.2.4 Demand for Synthetic Crude Oil and Nonupgraded Bitumen

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

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

Alberta oil refineries use SCO, bitumen, and other feedstocks to produce a wide variety of refined petroleum products. In 2004, five Alberta refineries, with a total capacity of 73.0 10^3 m^3/d, used 31.6 10^3 m^3/d of SCO and 3.2 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand represents 33 per cent of Alberta SCO production and 5 per cent of nonupgraded bitumen production.

Petro-Canada, in addition to the announced joint venture with UTS in the Fort Hills project, continues to announce plans to reconfigure the Edmonton refinery and has an agreement with Suncor to supply it with feedstock by 2008. The company will process 8.4 10^3 m^3/d of bitumen, providing for existing and future steam-assisted gravity drainage (SAGD) production from Petro-Canada leases.

The agreement calls for Petro-Canada to ship a minimum of 4.3 10^3 m^3/d of bitumen from its MacKay River oil sands facility to the Suncor plant north of Fort McMurray, where it will be processed into sour crude oil on a fee-for-service basis. That product will be combined with an additional 4.1 10^3 m^3/d of sour crude purchased from Suncor for upgrading and refining into finished product at Edmonton. The agreement takes effect in 2008, subject to regulatory approval.

Central to the refinery reconfiguration is an expansion of the existing coker at Edmonton, allowing for direct bitumen upgrading. Initially, Petro-Canada intends to purchase 4.1 10^3 m^3/d of bitumen from other producers to fill out that bitumen processing capability. In due course, this external feedstock will be replaced by supply from Petro-Canada's next SAGD development.

SCO is also used by the oil sands upgraders as diesel 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 recently announced that it plans to open a Suncor Energy branded "cardlock" station selling diesel fuel supplied from Suncor's oil sands operation. The station will be located on Highway 63 north of Fort McMurray. In 2004, the sale of SCO as diesel fuel oil accounted for about 5 per cent of Alberta demand.

Figure 2.10 shows that in 2014 demand for SCO and nonupgraded bitumen will increase to about 56 10^3 m^3/d. It is projected that SCO will account for 86 per cent of total Alberta demand and nonupgraded bitumen will constitute 14 per cent.

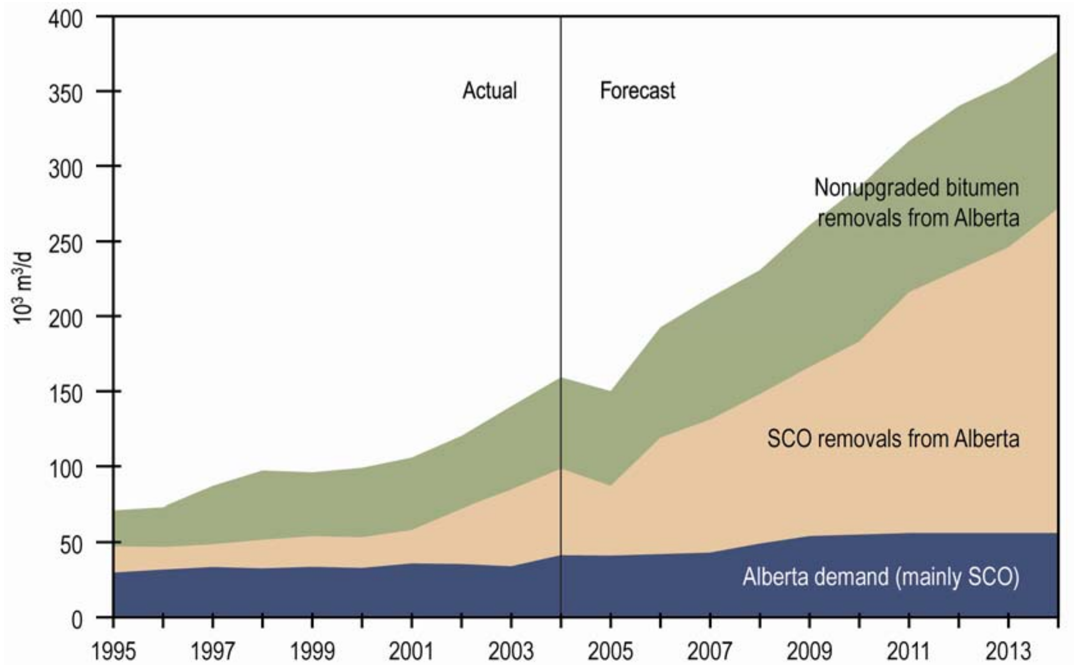

Figure 2.10. Alberta demand for and disposition of crude bitumen and SCO

Given the current quality of SCO, western Canada's nine refineries, with a total capacity of 95 10^3 m^3/d, are able to blend up to 30 per cent SCO and a further 4 per cent blended bitumen with crude oil. These refineries receive SCO from both Alberta and Saskatchewan. In eastern Canada, the four Sarnia-area refineries are the sole ex-Alberta Canadian market for Alberta SCO.

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, as well as increased markets for refined products' future growth. The largest export markets for Alberta SCO and nonupgraded bitumen are the U.S. midwest, with refining capacity of 560 10^3 m^3/d, and the U.S. Rocky Mountain region, with refining capacity of 92 10^3 m^3/d. The refineries in these areas are capable of absorbing a substantial increase in supplies of SCO and nonupgraded bitumen from Alberta. Other potential market regions could be the U.S. east coast, with refining capacity of 277 10^3 m^3/d, the U.S. west coast, with refining capacity of 503 10^3 m^3/d, and the Far East.

A number of pipeline projects that have been announced will provide increased access to markets in the U.S. midwest.

The Enbridge Spearhead Pipeline is the reversal of the current pipeline that transports light and heavy crude oil from Cushing, Oklahoma, to Chicago, Illinois. Enbridge expects the pipeline to be in service by January 2006, with an initial capacity of 9.5 10^3 m^3/d, increasing to 19.9 10^3 m^3/d.

Enbridge's Southern Access Pipeline is a proposed 1000 km pipeline that will have an initial capacity of 39.7 103 m^3/d and will interconnect with the Enbridge's announced

Spearhead project, a joint venture with BP pipelines. It will provide service to any of the Chicago, Wood River, or Cushing market hubs from the interconnection point in Illinois. Enbridge expects the pipeline to be in service in 2007.

The TransCanada Keystone Pipeline project, described in the pipeline section, will move various grades of heavy crude oil to markets in the U.S. midwest and potentially the U.S. Gulf Coast.

Koch Pipelines' Minnesota Pipeline Expansion/Wood River Pipeline Reversal will be completed in two parts, the first being a new pipeline on the Minnesota Pipeline right-of-way that runs from Clearbrook, Minnesota, to the Pine Bend refinery in St. Paul. The second part of the project involves the reversal of the Wood River Pipeline, which is currently shipping crude from its southern connection in Wood River to its delivery point in St. Paul. An expansion is planned once the pipeline is reversed. The first stage of the project could be completed in two or three years and be in full service by 2009-2010, subject to regulatory approvals.

Figure 2.10 shows that over the forecast period removals from Alberta of SCO will increase from 57.1 10^3 m^3/d to 216 10^3 m^3/d and the removals of nonupgraded bitumen will increase from 57.6 10^3 m^3/d to 97 10^3 m^3/d.

3 Crude Oil

3.1 Reserves of Crude Oil

3.1.1 Provincial Summary

The EUB estimates the remaining established reserves of conventional crude oil in Alberta to be 249.2 million cubic metres (10^6 m^3) at December 31, 2004. This is a decrease of 4.7 10^6 m^3 from December 31, 2003, resulting from all reserve adjustments and production, as well as additions that occurred during 2004. The changes in reserves and cumulative production for light-medium and heavy crude oil to December 31, 2004, are shown in Table 3.1. **Figure 3.1** shows that the province's remaining conventional oil reserves have declined by half since 1990. Detailed pool-by-pool reserves data are available on CD. See Appendix C.

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

	2004	2003	Change
Initial established reserves[a]			
Light-medium	2 284.4	2 267.5	+16.9
Heavy	380.6	366.6	+14.0
Total	2 664.9	2 634.0	+30.9
Cumulative production[a]			
Light-medium	2 105.4	2 082.0	+23.3[b]
Heavy	310.3	298.1	+12.3[b]
Total	2 415.7	2 380.1	+35.6[b] (224 10^6 bbls)
Remaining established reserves[a]			
Light-medium	179.0	185.4	-6.4
Heavy	70.2	68.5	+1.7
Total	249.2 (1 568 10^6 bbls)	253.9	-4.7

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

3.1.2 Reserves Growth

A detailed breakdown of this year's reserves changes, including additions, revisions, and enhanced recovery, is presented in Table 3.2, while **Figure 3.2** gives a history of these changes back to 1988. The initial established reserves attributed to the 276 new oil pools booked in 2004 totalled 6.1 10^6 m^3 (an average of 22 thousand [10^3] m^3 per pool), down slightly from 6.9 10^6 m^3 in 2003. Reserve additions from new waterfloods increased slightly to 3.2 10^6 m^3 **(Figure 3.3)**. Net reserve revisions totalled 13.6 10^6 m^3, mostly due to positive revisions to heavy crude pools under waterflood. The resulting total increase in initial established reserves for 2004 amounted to 30.9 10^6 m^3, similar to last year's 30.8 10^6 m^3. Table B.1 in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.

Reserve additions resulting from drilling and new enhanced recovery schemes were the highest since 2001, totalling 17.3 10^6 m^3. These additions replaced 49 per cent of Alberta's 2004 conventional crude oil production of 34.9 10^6 m^3.

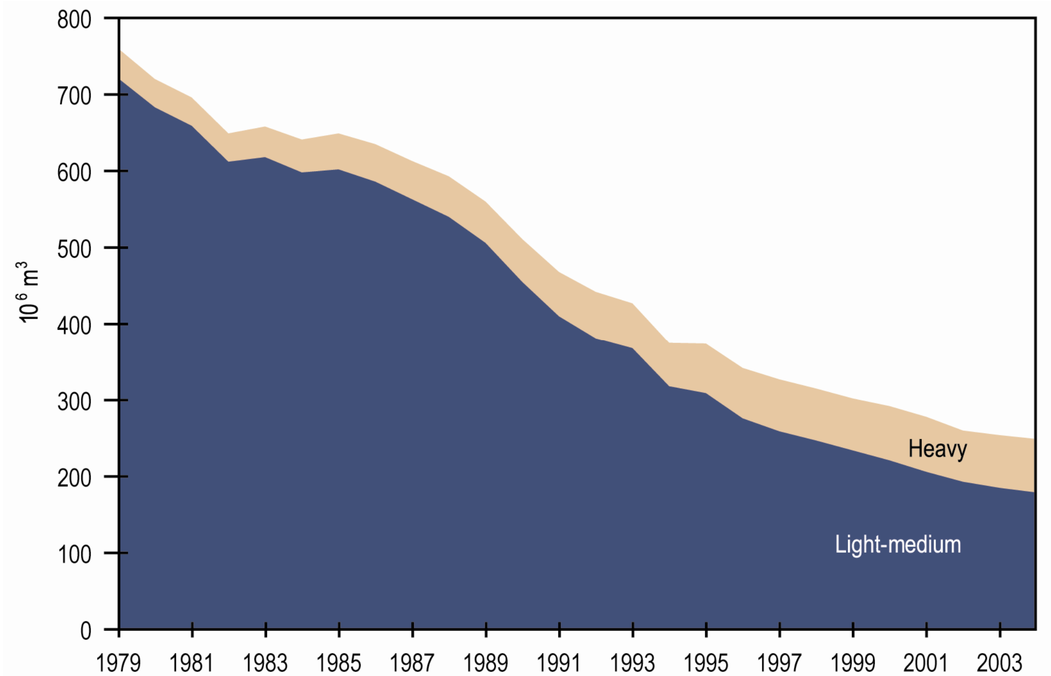

Figure 3.1. Remaining established reserves of crude oil

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

	Light-medium	Heavy	Total
New discoveries	4.7	1.4	6.1
Development of existing pools	4.1	3.9	8.0
Enhanced recovery (new/expansion)	2.0	1.1	3.2
Reassessment	+6.1	+7.5	+13.6
Total[a]	16.9	14.0	30.9

[a] Discrepancies are due to rounding.

3.1.3 Oil Pool Size

At December 31, 2004, oil reserves were assigned to 8462 light-medium and 2552 heavy crude oil pools in the province, about 60 per cent of which are single-well pools. The distribution of reserves by pool size shown in **Figure 3.4** indicates that some 87 per cent of the province’s remaining oil reserves is contained in the largest 13 per cent of pools. By contrast, the smallest 74 per cent of pools contain only 2 per cent of the province’s initial reserves and 6 per cent of its remaining reserves. **Figure 3.5** illustrates the historical trends in the size of oil pools.

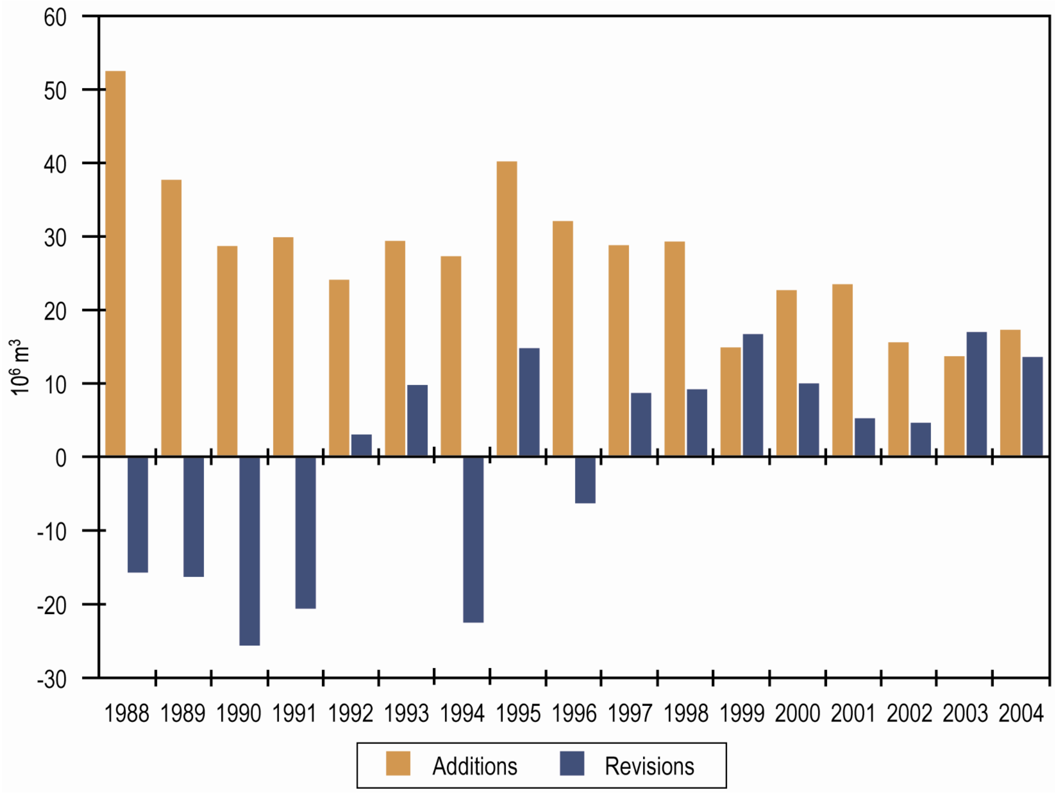

Figure 3.2. Annual changes in conventional crude oil reserves

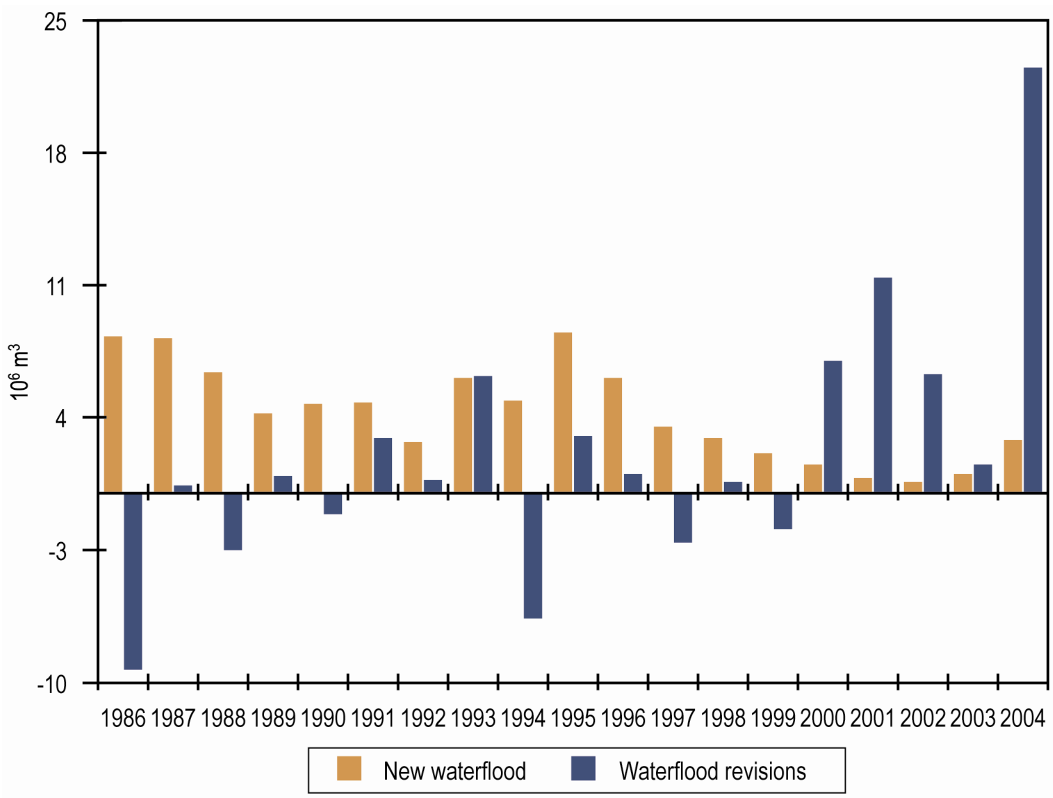

Figure 3.3. Annual changes to waterflood reserves

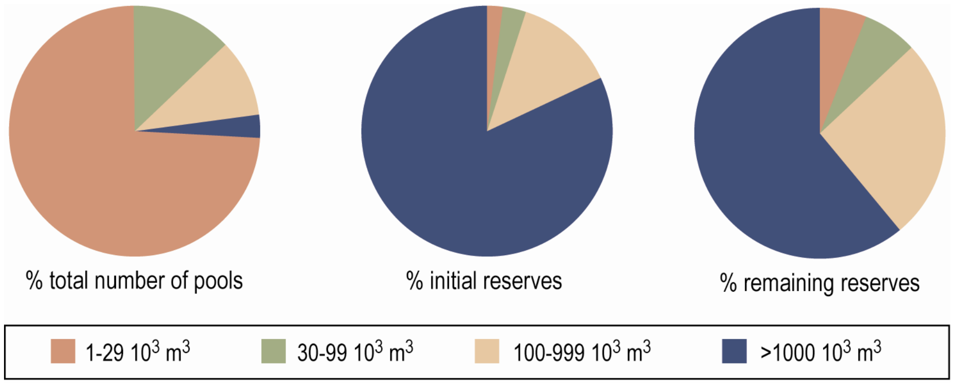

Figure 3.4. Distribution of oil reserves by size

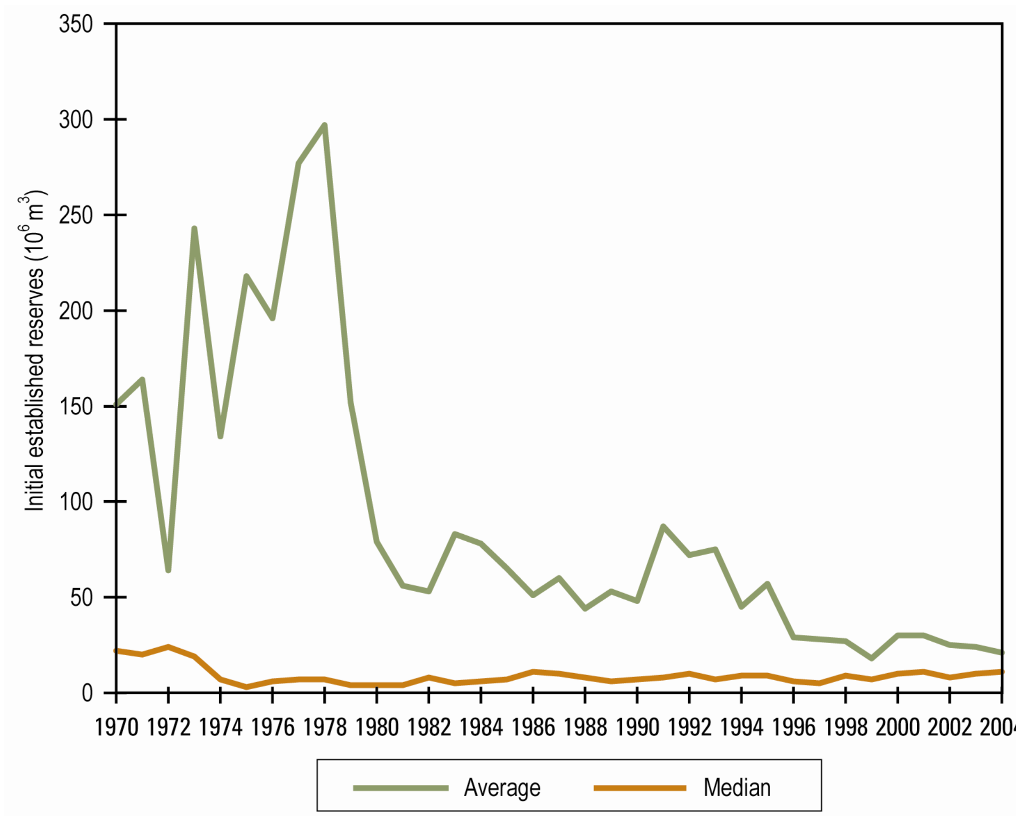

Figure 3.5. Oil pool size by discovery year

While the median pool size has remained fairly constant over time (below 10 10^3 m^3 initial established reserves per pool), the average has declined from 150 10^3 m^3 in 1970 to about 30 10^3 m^3 over the last few years. The Valhalla Doe Creek I Pool discovered in 1977 is the last major (over 10 10^6 m^3) oil discovery in Alberta. Its initial established reserve now stands at 13 820 10^3 m^3.

3.1.4 Pools with Largest Reserve Changes

Some 1900 oil pools were re-evaluated over the past year, resulting in positive revisions totalling 47.3 10^6 m^3 and negative revisions totalling 33.7 10^6 m^3, for a net total of plus

13.6 10^6 m^3. Intensive exploration in the Pembina area resulted in the discovery of the Pembina Nisku HH Pool, with initial established reserves of 716 10^3 m^3. Reserves in the heavy oil Suffield Upper Mannville J and Chauvin South MU#1 Pools were increased by 691 and 820 10^3 m^3 respectively, with the implementation of new waterfloods. The Wildmere Lloydminster C Pool saw an increase of 827 10^3 m^3, as horizontal development drilling added new reserves. Otherwise, a revision in the recovery factor for the Sturgeon Lake South Triassic F Pool reduced reserves by 667 10^3 m^3. Table 3.3 lists those pools having the largest reserve changes in 2004.

3.1.5 Distribution by Recovery Type and Geological Formation

The distribution of conventional crude oil reserves by drive mechanism is illustrated in **Figure 3.6**. With the recent elimination of projects, enhanced recovery recognition and project status are no longer required for the EUB to book incremental waterflood reserves. Therefore, many previously approved and operational waterfloods that had not received project status have been recognized and reserves booked. This is a major reason behind the overall net positive revisions to heavy crude of 7.5 10^6 m^3. However, although incremental initial waterflood reserves for heavy oil pools increased in absolute terms from 93 10^6 m^3 to 106 10^6 m^3, the average incremental waterflood recovery decreased from 23 per cent to 19 per cent. This is due to the fact that many of the new pools recognized as waterflood were already somewhat depleted when injection commenced and therefore had below-average incremental recoveries. Incremental recovery from all waterflood projects represents 25 per cent of the province's initial established reserves. Pools under solvent flood added another 4 per cent to the province's reserves and on average realized a 30 per cent improvement in recovery efficiency over primary, as shown in Table 3.4.

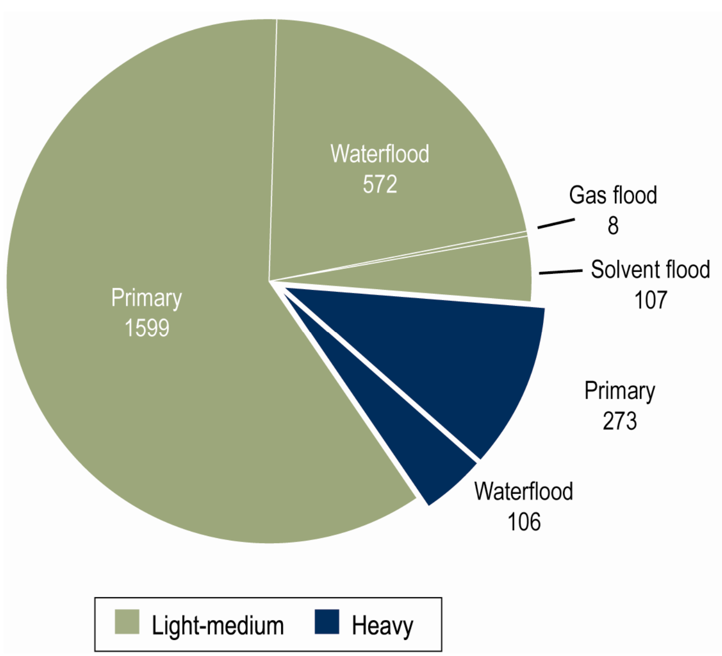

Figure 3.6. Initial established crude oil reserves based on various recovery mechanisms (10^6 m^3)

Table 3.3. Major oil reserve changes, 2004

Pool	Initial established reserves (10^3 m^3) 2004	Change	Main reason for change
Acheson D-3 A	21 680	+480	Reassessment of waterflood reserves
Ante Creek Montney B	327	+288	Reassessment of reserves
Chauvin South MU #1	14 740	+820	New waterflood
Clair Doe Creek A	684	+471	Reassessment of reserves
Grand Forks Sawtooth WW	3 024	+487	Reassessment of waterflood reserves
Jenner Upper Mannville OO	1 509	-283	Reassessment of primary reserves
Lloydminster Sparky G	1 639	+344	Pool development
Marwayne Spky C & GenPet A&C	1 003	-217	Pools commingled and reassessment of reserves
Pembina Nisku HH	716	+716	New pool
Provost Vik, BR & Mann MU #1	10 710	+700	Reassessment of reserves
Provost Upper Mannville T8T	1 972	+789	Reassessment of reserves
Red Earth KegR C & GrWh T2T & H4H	615	+145	Commingling and pool development
Ronalane Sawtooh B	1 793	+268	Reassessment of reserves
Sturgeon Lake D-3	4 743	-271	Reassessment of reserves
Sturgeon Lake South Triassic F	997	-667	Reassessment of reserves
Suffield Upper Mannville J	7 807	+691	New waterflood
Suffield Upper Mannville CCC	1 516	+380	Pool development
Suffield Upper Mannville N2N	292	+292	New pool
Suffield Upper Mannville V	675	+338	Pool development and reassessment of reserves
Swalwell D-1 A	510	-340	Reassessment of reserves
Utikuma Lake Keg River Sand A	9 704	+504	Reassessment of reserves
Wayne Rosedale Nisku A	1 973	-238	Reassessment of reserves
Wildmere Lloydminster C	868	+827	Pool development and reassessment of reserves
Worsley Clharlie Lake H & J	1 033	+523	Reassessment of reserves

Table 3.4. Conventional crude oil reserves by recovery mechanism as of December 31, 2004

Crude oil type and pool type	Initial volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Waterflood/ gas flood	Solvent flood	Total	Primary	Waterflood/ gas flood	Solvent flood	Total
Light-medium									
Primary depletion	3 815	867	0	0	867	23	-	-	23
Waterflood	2 996	441	406	0	847	15	14	-	28
Solvent flood	930	257	166	107	530	28	18	12	57
Gas flood	116	34	8	0	42	29	7	-	36
Heavy									
Primary depletion	1 593	207	0	0	207	13	-	-	13
Waterflood	551	66	106	0	172	12	19	-	31
Total	10 001	1 872	686	107	2 665	19			27
Percentage of total initial established reserves		70%	26%	4%	100%				

The distribution of reserves by geological period and PSAC area is depicted graphically in **Figure 3.7** and **Figure 3.8** respectively. Thirty seven per cent of remaining established reserves will come from formations within the Lower Cretaceous and about 20 per cent each from the Upper Devonian and Upper Cretaceous. This contrasts with 1990, when

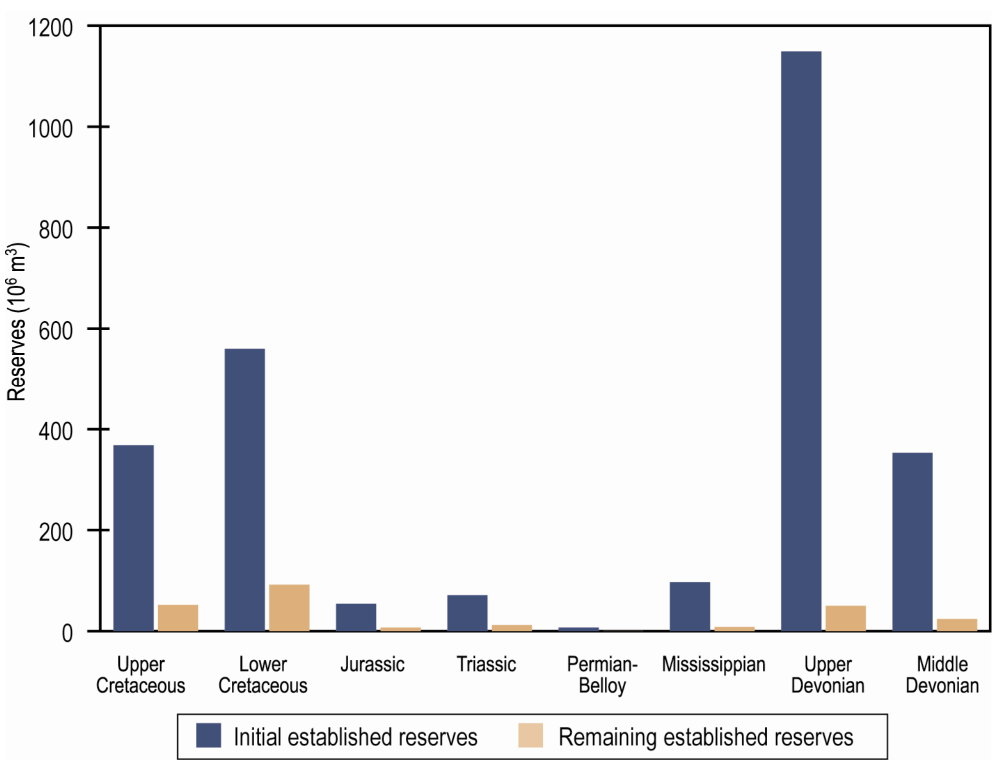

Figure 3.7. Geological distribution of reserves of conventional crude oil

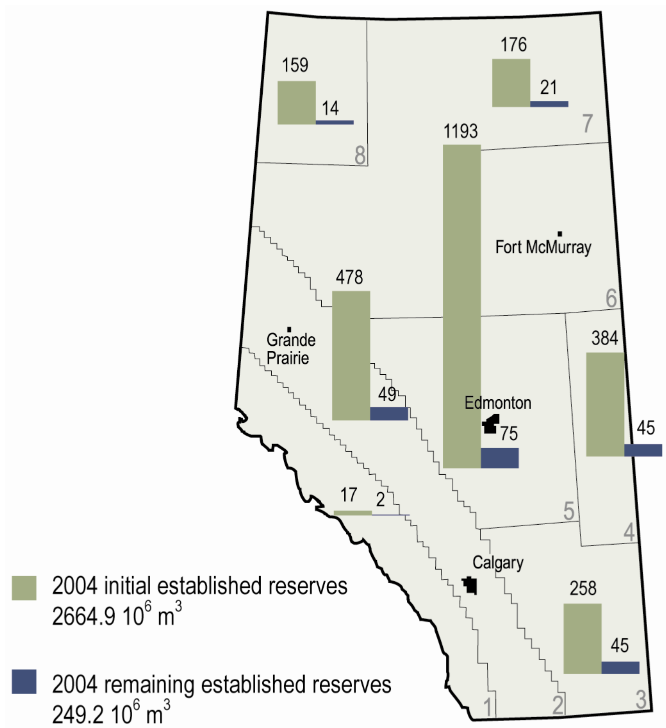

Figure 3.8. Regional distribution of Alberta oil reserves (10^6 m^3)

fully 30 per cent of remaining reserves were expected to be recovered from the Upper Devonian and only 16 per cent from the Lower Cretaceous. The shallower zones of the Lower Cretaceous are becoming increasingly important as a source of future conventional oil. A detailed breakdown of reserves by geological period and formation is presented in tabular form in Appendix B, Tables B.2 and B.3.

3.1.6 Ultimate Potential

The ultimate potential of conventional crude oil was estimated by the EUB in 1994 at 3130 10^6 m^3, reflecting its estimate of geological prospects. **Figure 3.9** illustrates the historical relationship between remaining reserves and cumulative oil production. Extrapolation of the decline suggests that the EUB's estimate of ultimate potential is still reasonable. **Figure 3.10** shows Alberta's historical and forecast growth of initial established reserves. Approximately 77 per cent of the estimated ultimate potential for conventional crude oil has been produced to December 31, 2004. Known discoveries represent 85 per cent of the ultimate potential, leaving 15 per cent (465 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves means there is 714 10^6 m^3 of conventional crude oil that is available for future production.

In 2004, both the remaining established reserves and the annual production of crude oil declined. However, there are 465 10^6 m^3 yet to be discovered, which at the current rate of annual reserve additions will take over 26 years to find. Additions to existing pools and the discovery of new pools will continue to bring on new reserves and associated production each year and serve to mitigate the impact of these declines.

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

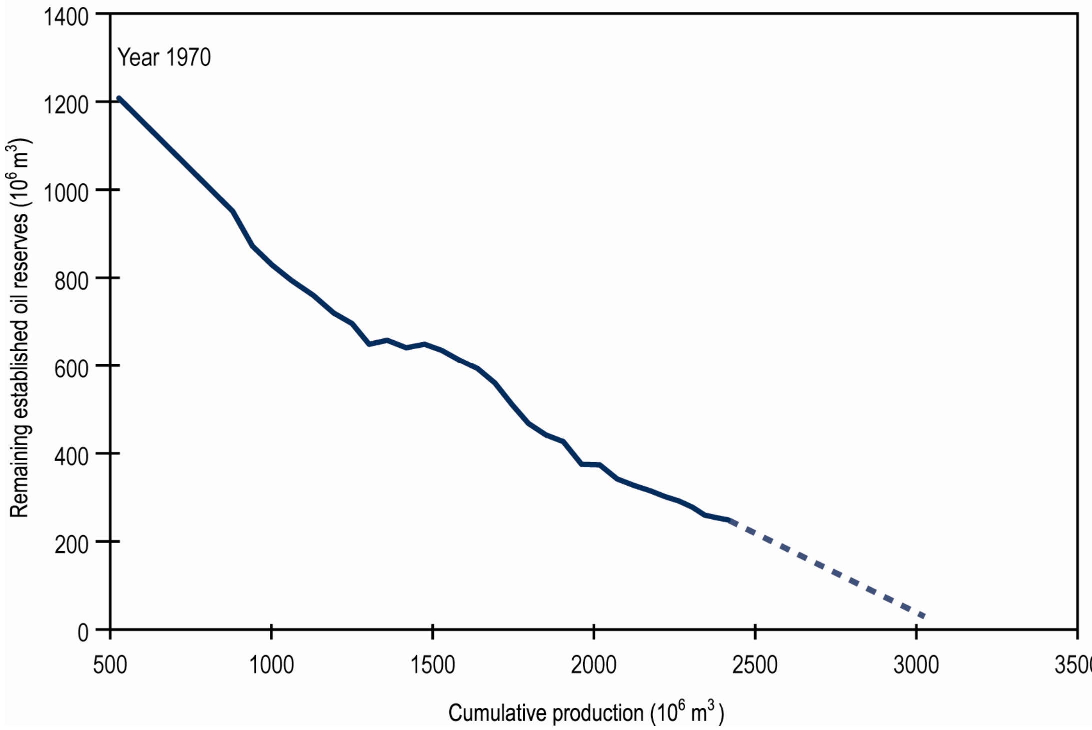

Figure 3.9. Alberta's remaining established oil reserves versus cumulative production

3.2 Supply of and Demand for Crude Oil

3.2.1 Crude Oil Supply

Over the past several decades, production of light-medium and heavy crude oil has been on decline in Alberta. In 2004, total crude oil production declined to 95.4 10^3 m^3/d. Light-medium crude oil production declined by about 6 per cent to 61.8 10^3 m^3/d from its 2003 level. Heavy crude oil production experienced a decline of some 2 per cent below 2003 levels to 33.6 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 5 per cent from 2003 to 2004, consistent with the decline from 2002 to 2003.

The number of successful oil wells drilled in 2004 was 1949, a decrease of some 17 per cent over 2003 levels. **Figure 3.11** shows the number of successful oil wells drilled in Alberta in 2003 and 2004 by geographical area (modified PSAC area). The majority of oil drilling in 2004, some 79 per cent, was development drilling. As shown in the chart, drilling levels were down in most areas, with the exception of PSAC 7 (Northwestern Alberta) and PSAC 1 (Foothills Area).

Figure 3.12 depicts the distribution of new crude oil wells placed on production and **Figure 3.13** shows the initial operating day rates of the new wells in 2004. 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. The number of new crude oil wells in 2004 decreased some 8 per cent from the 2003 levels.

Historical oil production by geographical area is illustrated in **Figure 3.14**. All areas experienced declines in production, ranging from 2.4 per cent in PSAC 4 (Central Alberta) to 22.5 per cent in PSAC 1 (Foothills Area).

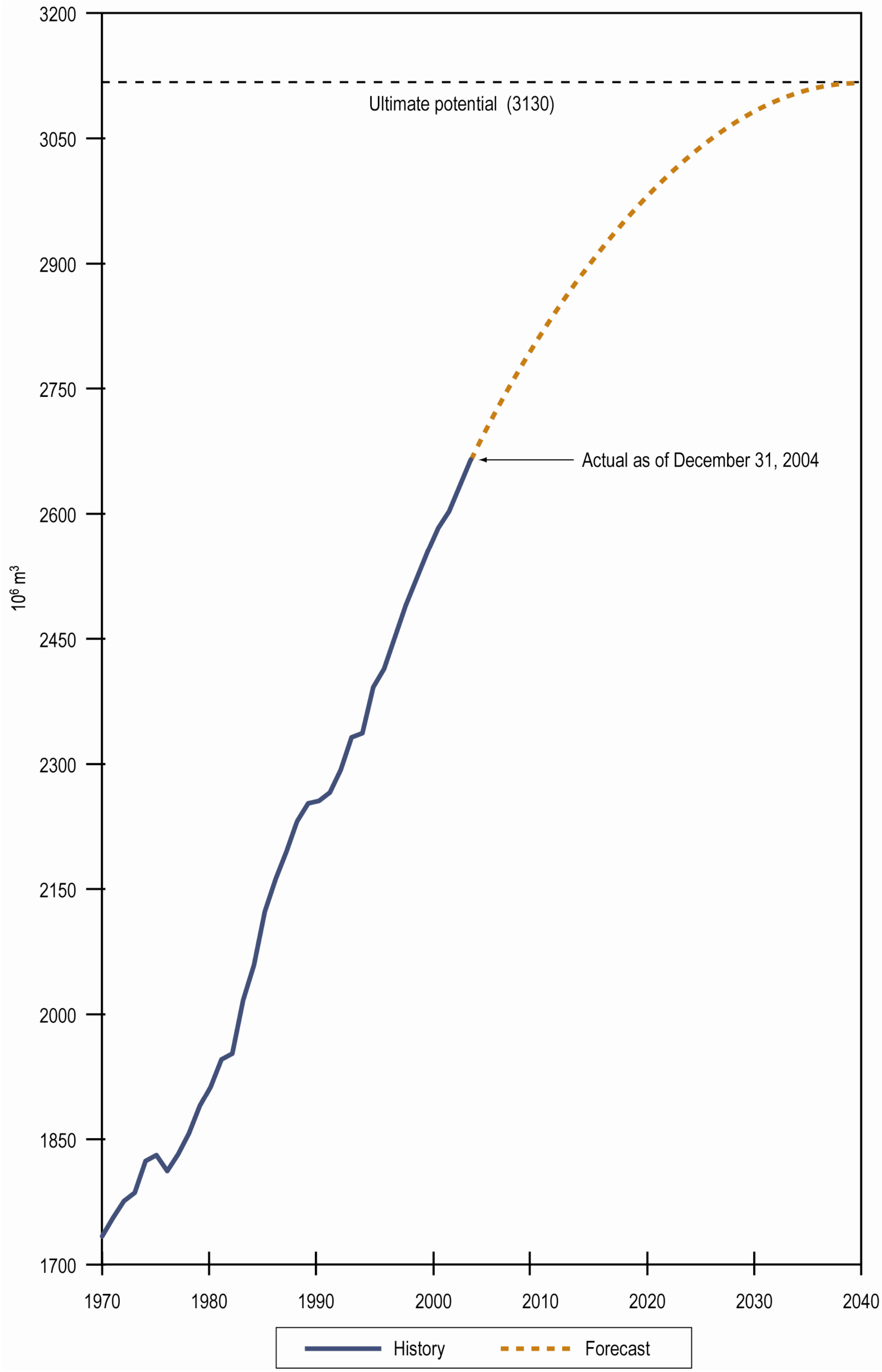

Figure 3.10. Growth in initial established reserves of crude oil

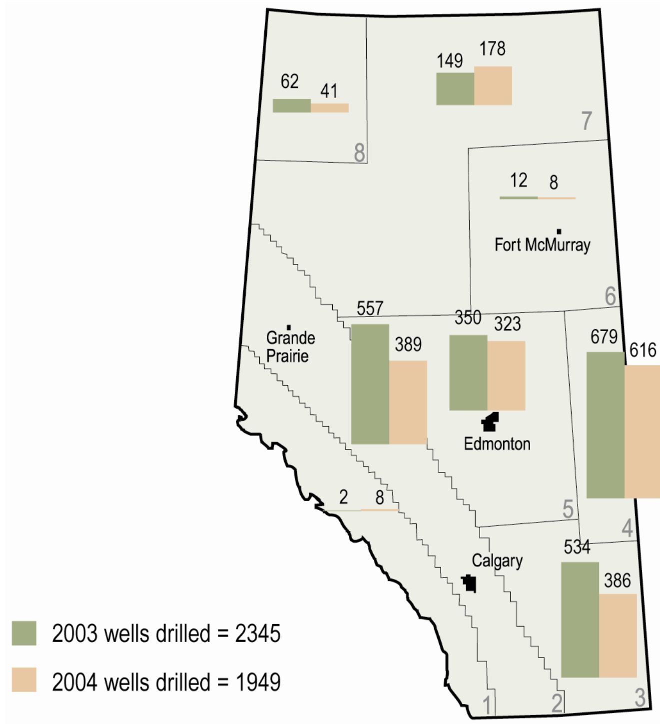

Figure 3.11. Alberta successful oil well drilling by modified PSAC area

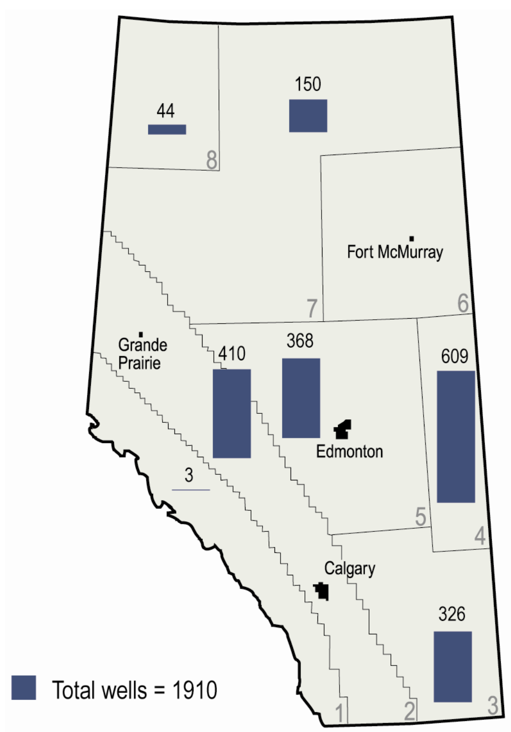

Figure 3.12. Oil wells placed on production, 2004, by modified PSAC area

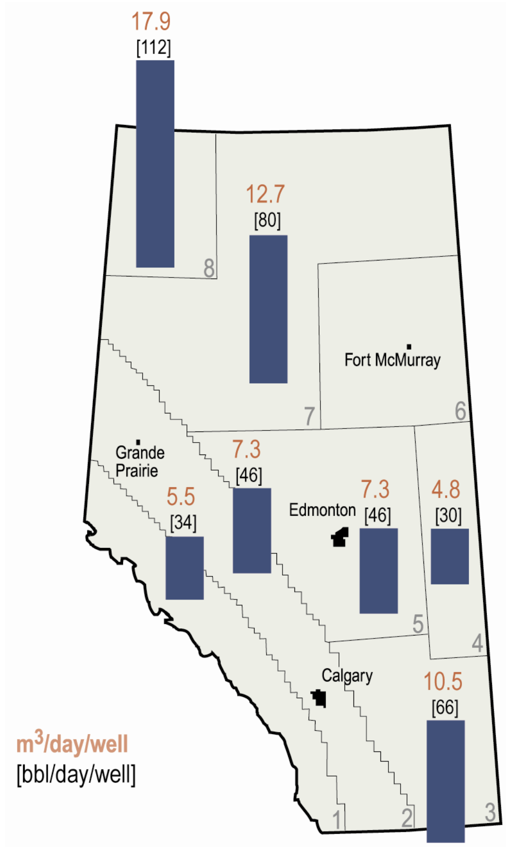

Figure 3.13. Initial operating day rates of oil wells placed on production, 2004, by modified PSAC area

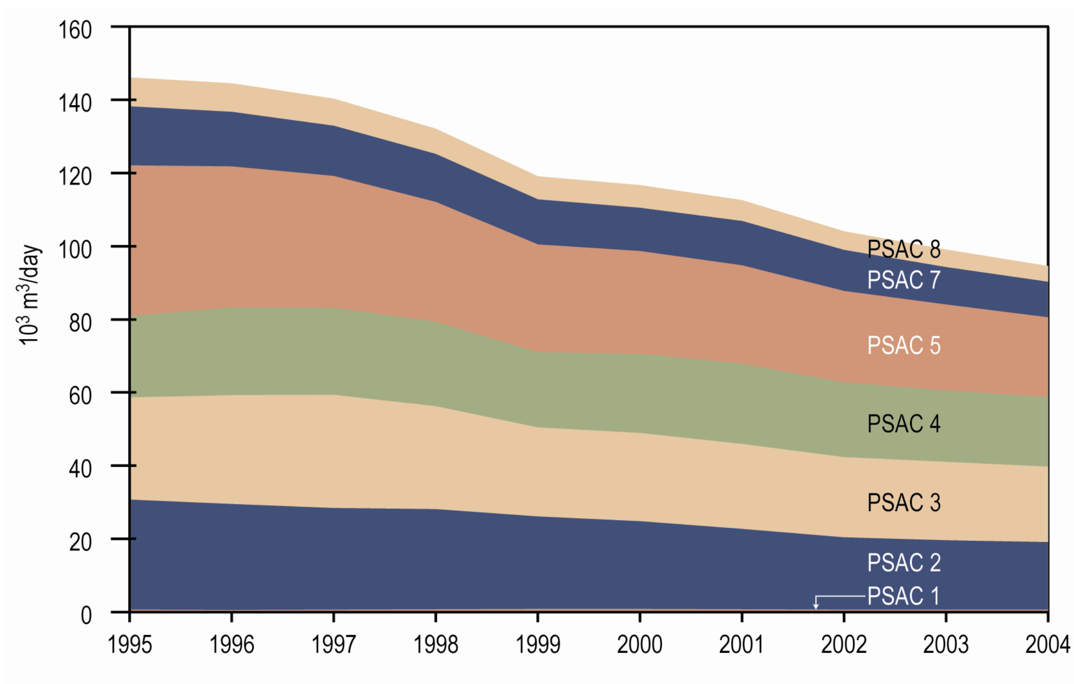

Figure 3.14. Conventional crude oil production by modified PSAC area

While the number of crude oil producing wells has increased, crude oil production has been on decline since its peak of 227.4 10^3 m^3/d in 1973. **Figure 3.15** shows total crude oil production and the number of crude oil producing wells since 1973. As illustrated in this figure, while the number of total producing wells has increased from 9900 in 1973 to 36 400 in 2004, crude oil production has been on decline. Of the 36 400 wells producing oil in 2004, about 2300 were gas wells. Although this represents about 6 per cent of the total number of wells, they produce at an average rate of about 0.3 m^3/d and account for less than 1 per cent of the total production.

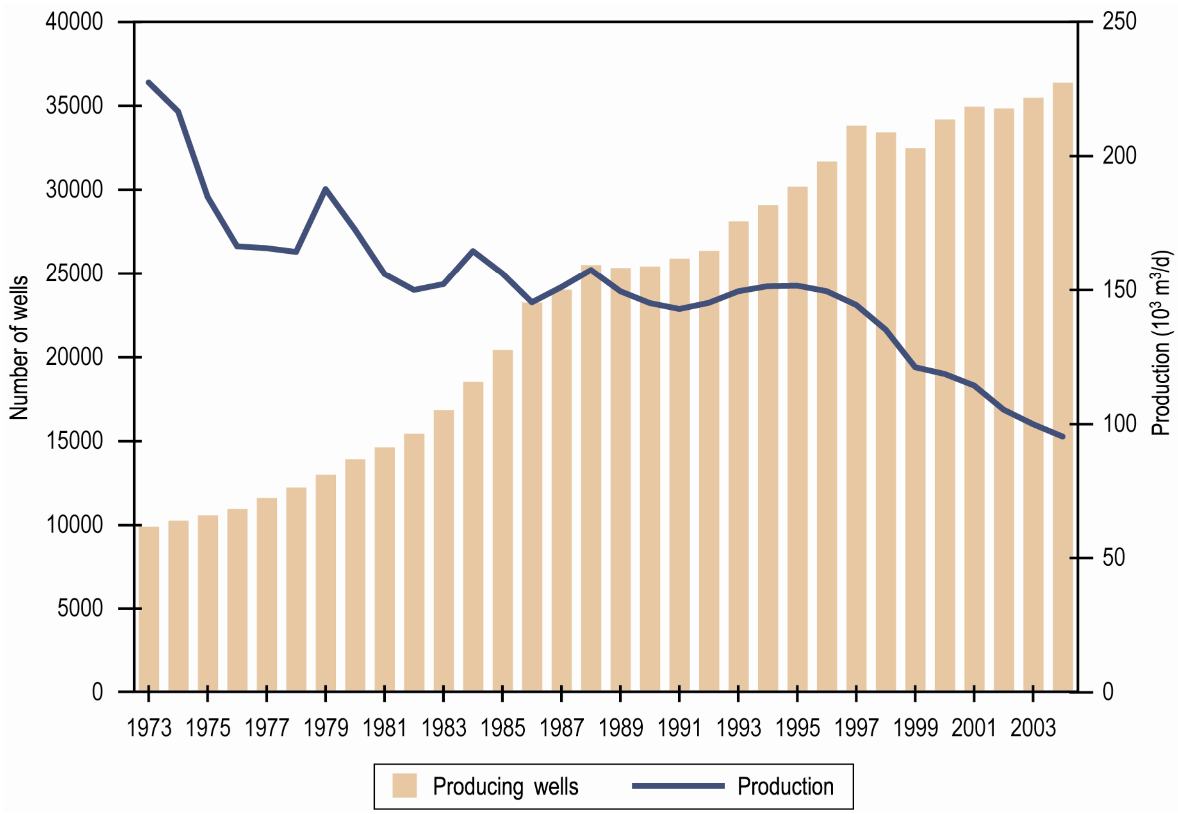

Figure 3.15. Total crude oil production and producing oil wells

The average well productivity of crude oil producing wells in 2004 was 3.0 m^3/d. The majority of crude oil wells in Alberta, about 58 per cent, produced less than 2 m^3/d per well. In 2004, the 19 800 oil wells in this category operated at an average rate of 1 m^3/d and produced only 19 per cent of the total crude oil produced. **Figure 3.16** depicts the distribution of crude oil producing wells based on their average production rates in 2004.

In 2004, some 290 horizontal wells were brought on production, a 21 per cent decrease from 2003, raising the total to 3300 producing horizontal wells in Alberta. Horizontal wells account for 10 per cent of producing oil wells and about 18 per cent of the total crude oil production. Production from horizontal wells drilled in the past seven years peaked in 1999 at an average rate of 13.0 m^3/d. The rate of new horizontal wells brought on production averaged about 9.5 m^3/d.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2004 year-end and expected production from new wells. Total production of crude oil is the sum of these two components.

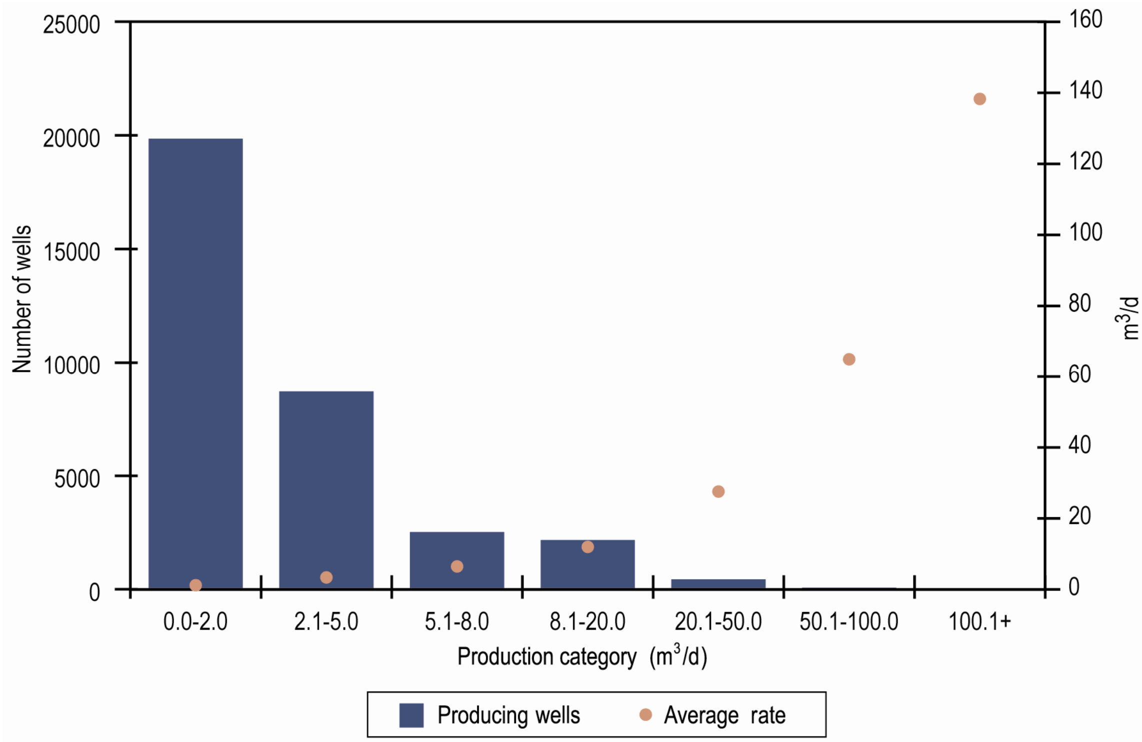

Figure 3.16. Crude oil well productivity in 2004

To project crude oil production from the wells drilled prior to 2005, the EUB considered the following assumptions:

- Production from existing wells in 2005 will be 83.8 10^3 m^3/d.
- Production from the existing wells will decline at a rate of about 15 per cent per year.

Crude oil production from existing wells by year placed on production over the period 1995-2004 is depicted in **Figure 3.17**. This figure illustrates that about 30 per cent of crude oil production in 2004 resulted from wells placed on production in the last four years. Over the forecast period, production of crude oil from existing wells is expected to decline to 19 10^3 m^3/d by 2014.

Figure 3.18 compares the production from 1950 through 2004 for Alberta crude oil and the production from Texas onshore and Louisiana onshore. Louisiana onshore reached peak production in 1970, while Texas onshore reached peak production in 1972 and Alberta in 1973. The figure shows that Alberta did not experience the same steep decline rates after reaching peak production as did Texas and Louisiana onshore production. This was likely due in part to the oil prorationing that existed in Alberta from the early 1950s to the mid-1980s.

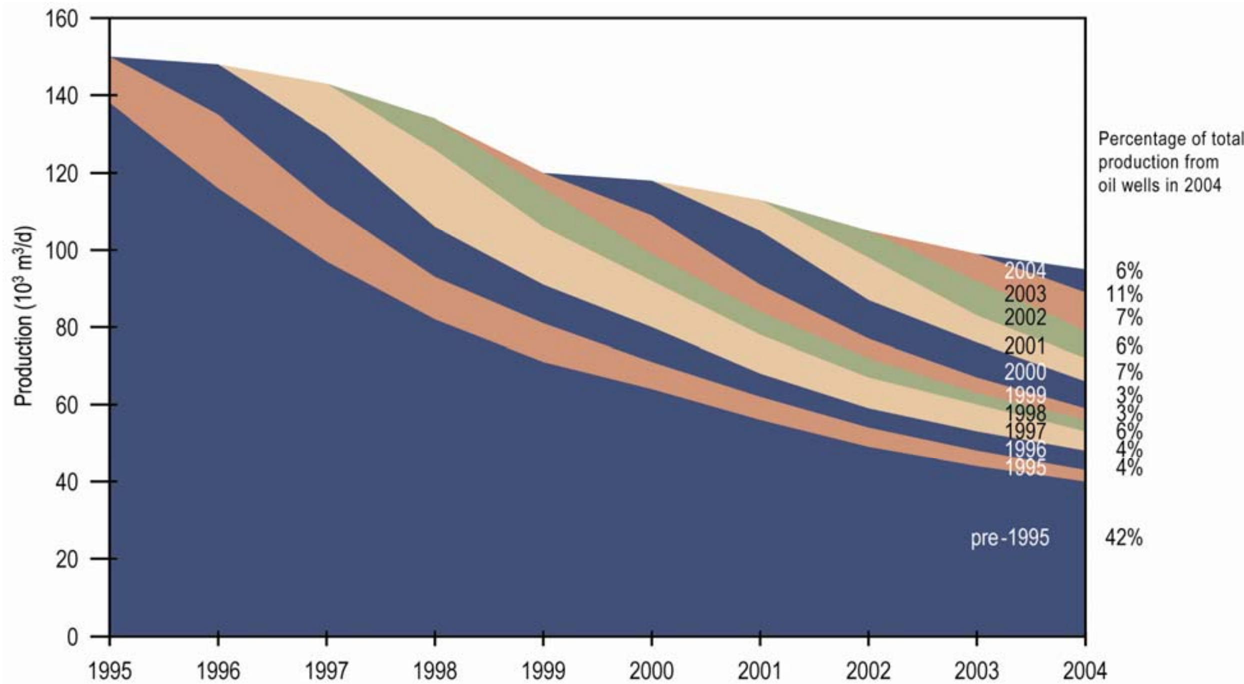

Figure 3.17. Total conventional crude oil production by year placed on production

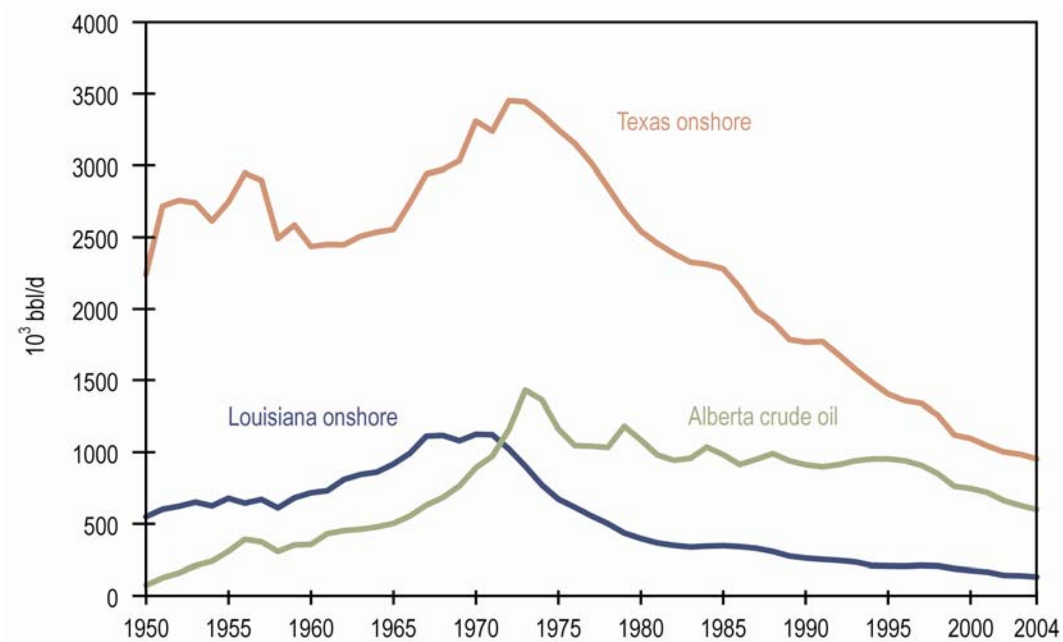

Figure 3.18. Comparison of crude oil production

Total production from new wells is a function of the number of new wells that will be drilled successfully, initial production rate, and the decline rate for these new wells. The EUB believes that global crude oil prices will play a role in drilling activity over the forecast period. As discussed in Section 1, the EUB expects that crude oil prices will remain above historic levels. However, crude oil drilling is not expected to return to the record highs of the mid-1990s, as industry has turned its focus to natural gas drilling and oil sands project development.

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

- The number of new oil wells placed on production is projected to decrease slightly to 1900 wells in 2005, and then increase to 2000 in 2006 and remain at this level over the forecast period. **Figure 3.19** illustrates the EUB's forecast for wells placed on production for the period 2005 to 2014, along with the historical data.
- New well productivities have declined over time and averaged 8.0 m^3/d/well in the mid-1990s. Based on recent history, it is assumed that the average initial production rate for new wells will be 5 m^3/d/well and will decrease to 4 m^3/d/well by the end of the forecast period.
- Production from new wells will decline at a rate of 27 per cent the first year, 22 per cent the second and third year, 18 per cent the fourth year, and 16 per cent by the end of the forecast period.

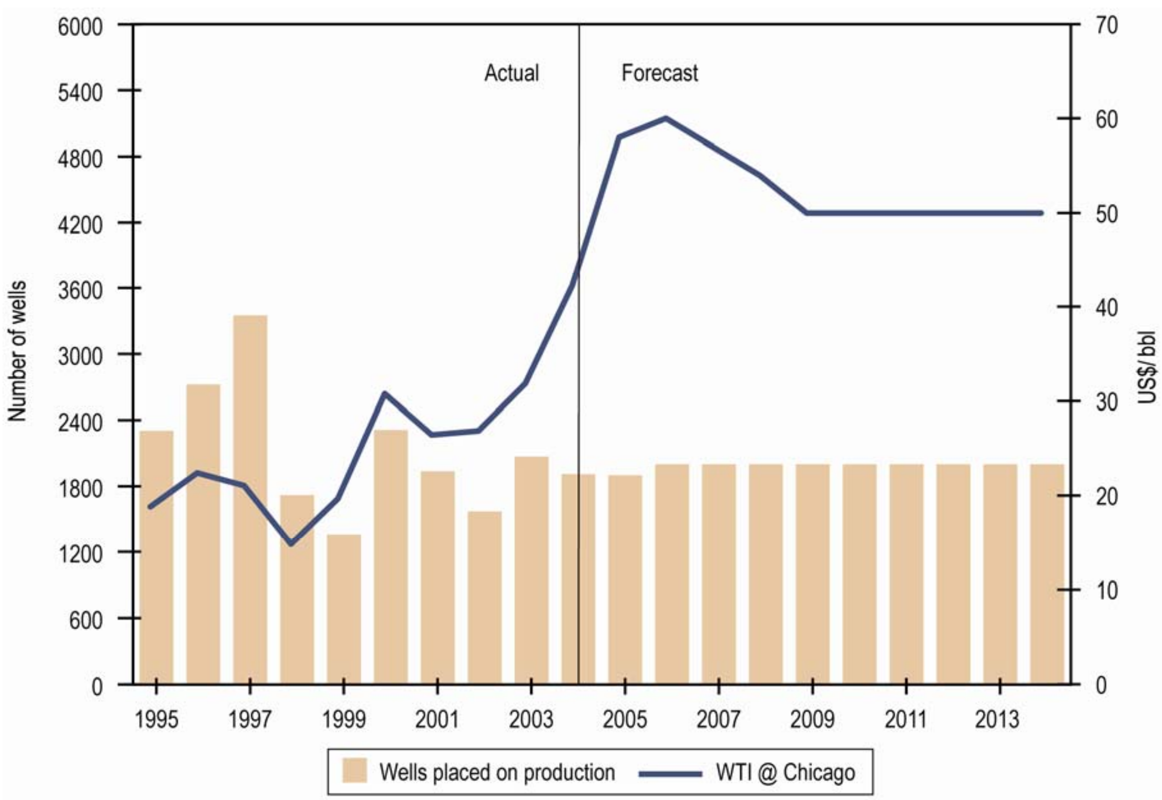

Figure 3.19. Alberta crude oil price and well activity

The projection of the above two components, production from existing wells and production from new oil wells, is illustrated in **Figure 3.20.** Light-medium crude oil production is expected to decline from 61.8 10^3 m^3/d in 2004 to 37 10^3 m^3/d in 2014.

Although crude oil wells placed on production are expected to continue at about 2000 wells per year, light-medium crude oil production will continue to decline by almost 5 per cent a year, due to the failure of new well production to offset declining production

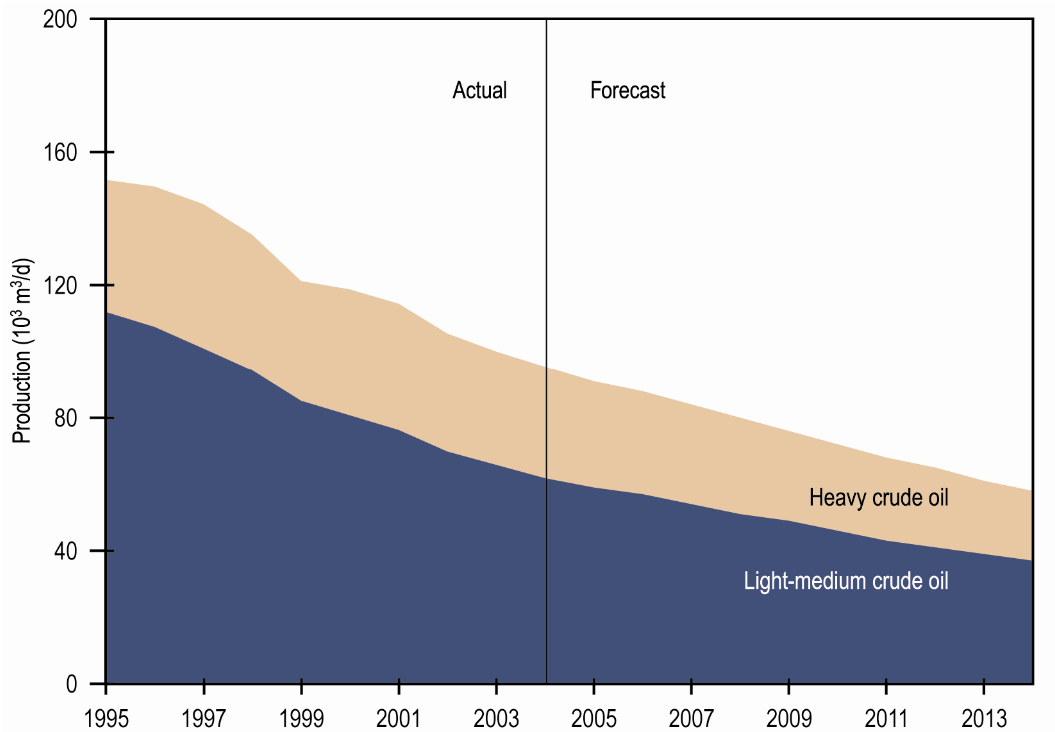

Figure 3.20. Alberta daily production of crude oil

from existing wells. New drilling has been finding smaller reserves over time, as would be expected in a mature basin.

Over the forecast period, heavy crude production is also expected to decrease, from 33.6 10^3 m^3/d in 2004 to 22 10^3 m^3/d by the end of the forecast period. **Figure 3.20** illustrates that by 2014, heavy crude oil production will constitute a greater portion of total production compared to 2004.

The combined forecasts from existing and future wells indicate that total crude oil production will decline from 95.4 10^3 m^3/d in 2004 to 59 10^3 m^3/d in 2014. By 2014, if crude oil production follows the projection, Alberta will have produced some 86 per cent of the estimated ultimate potential of 3130 10^6 m^3.

3.2.2 Crude Oil Demand

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

In 2004, Alberta refineries, with total inlet capacity of 73.0 10^3 m^3/d of crude oil and equivalent, processed 31.8 10^3 m^3/d of crude oil. Synthetic crude oil, bitumen, and pentanes plus constituted the remaining feedstock. Crude oil accounts for roughly 47 per cent of their total crude oil and equivalent feedstock (see Section 2.2.4). **Figure 3.21** illustrates the capacity and location of Alberta refineries. It is expected that no new crude oil refining capacity will be added over the forecast period. Total crude oil use will reach 35 10^3 m^3/d in 2007, decline to 28 10^3 m^3/d in 2008, and further decline to 22 10^3 m^3/d for the remainder of the forecast period. This decline is the result of the Petro-Canada Refinery Conversion project set to fully replace light-medium crude oil with SCO and nonupgraded bitumen by 2008.

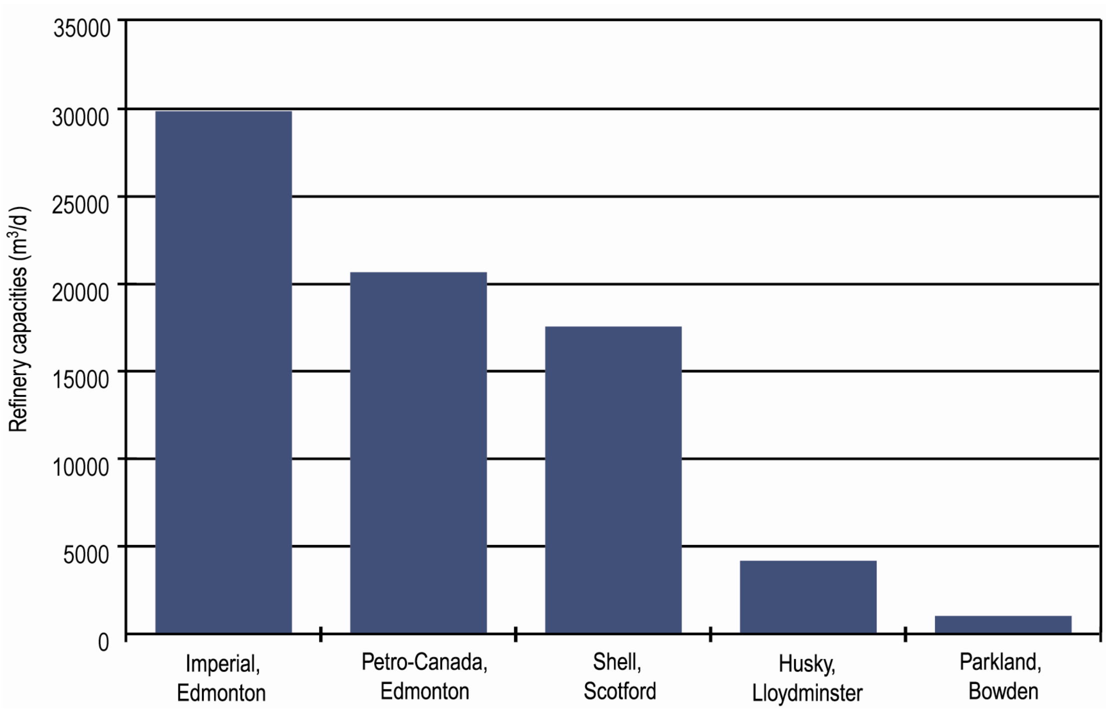

Figure 3.21. Capacity and location of Alberta refineries

Shipments of crude oil outside of Alberta, depicted in **Figure 3.22**, amounted to 67 per cent of total production in 2004. With the decline in demand for light-medium crude in Alberta, the EUB expects that by 2014 some 63 per cent of production will be removed from the province.

3.2.3 Crude Oil and Equivalent Supply

Figure 3.23 shows crude oil and equivalent supply. It illustrates that total Alberta crude oil and equivalent is expected to increase from 274.1 10^3 m^3/day in 2004 to 446 10^3 m^3/d in 2014. Over the forecast period, the growth in production of nonupgraded bitumen and SCO is expected to significantly offset the decline in conventional crude oil. The share of SCO and nonupgraded bitumen will account for over 83 per cent of total production.

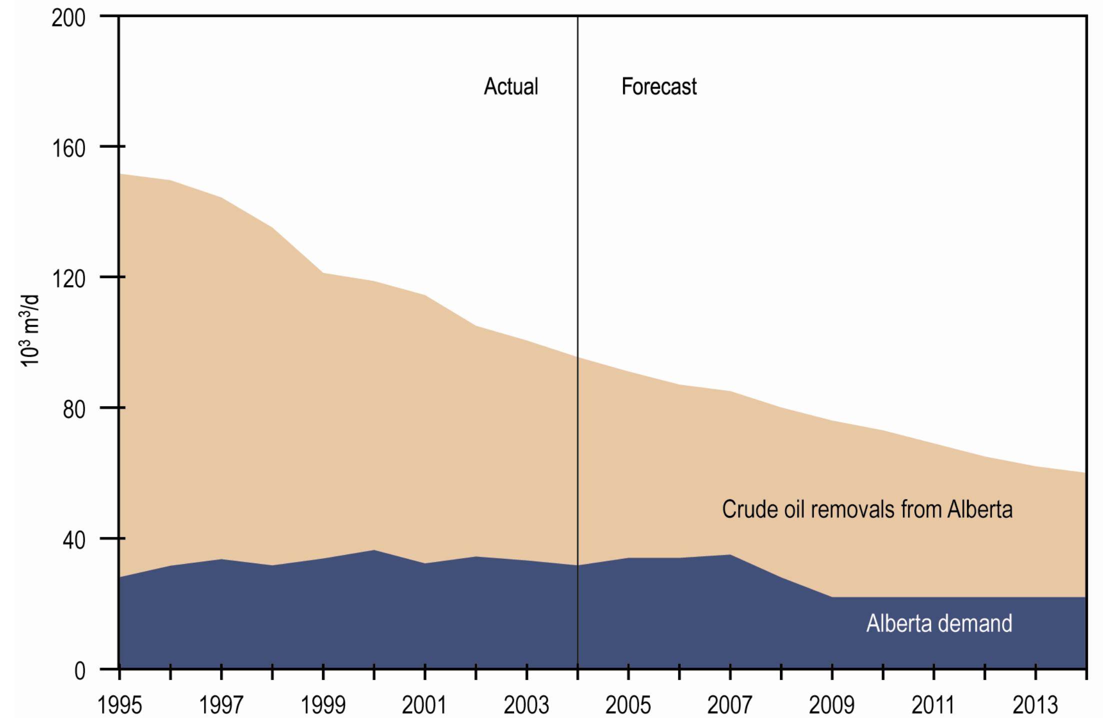

Figure 3.22. Alberta demand and disposition of crude oil

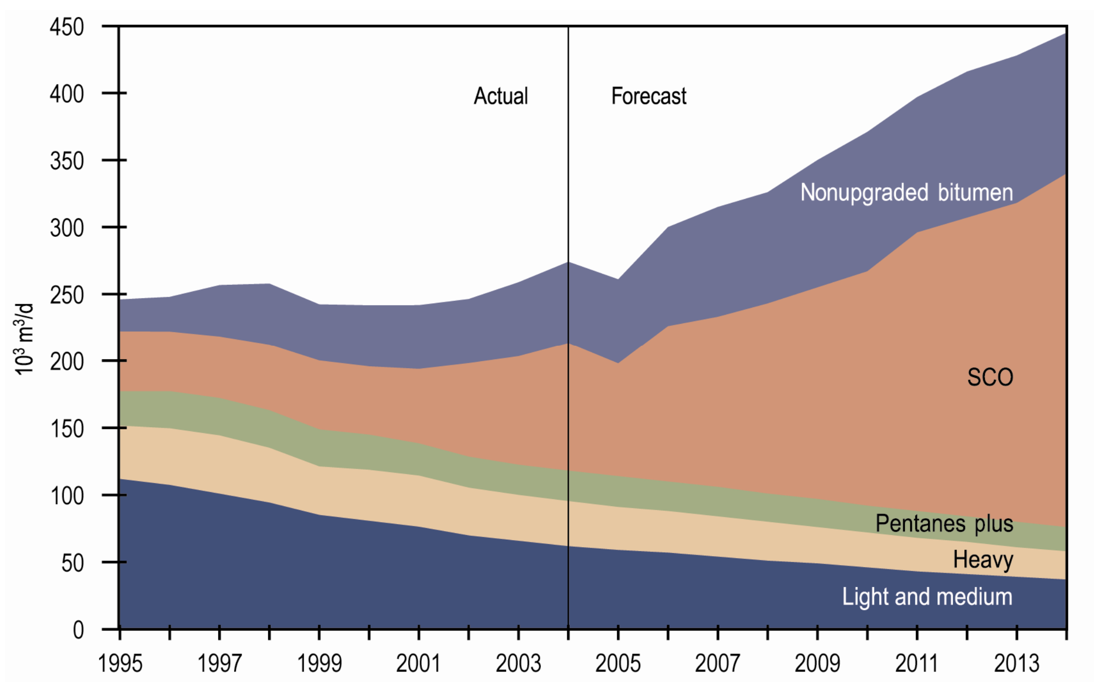

Figure 3.23. Alberta supply of crude oil and equivalent

4 Coalbed Methane

Coalbed methane (CBM), also known as natural gas from coal (NGC), is the methane gas found in coal, both as adsorbed gas and as free gas. 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.

Coal is known, from thousands of coalholes and oil and gas wells, to underlie most of central and southern Alberta. Individual coal seams are grouped into coal zones, which can be correlated very well over regional distances.

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the EUB until 1995. Significant development with commercial production commenced in early 2002. Interest in CBM development in Alberta continues to grow, with 2004 having the highest number of CBM completions. The actual CBM production to date continues to remain uncertain because of the current inability to completely differentiate CBM from conventional gas production. However, the production accounting change to new CBM-specific codes required by EUB *Bulletin 2004-21* will allow for better segregation from conventional gas volumes from this time forward.

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

4.1 Reserves of Coalbed Methane

4.1.1 Provincial Summary

As of December 31, 2004, the EUB estimates the remaining established reserves of CBM to be 7.42 billion cubic metres (10^9 m^3) in areas of Alberta where commercial production is occurring. The gas that is usually produced from coals in Alberta consists primarily of methane (usually about 95 per cent), with very little natural gas liquids. The heating value of CBM is usually about 38 megajoules per cubic metre. A summary of reserves is shown in Table 4.1.

Table 4.1. Changes in coalbed methane reserves, 2004 (10^6 m^3)

	2004	2003	Change
Initial established reserves	8 176	1 081	7 094
Cumulative production	755	120	635
Remaining established reserves	7 421	971	+6 449

4.1.2 Detail of CBM Reserves

Exploration and development are being conducted for CBM across wide areas of Alberta and in many different horizons, but commercial production has been limited to coals that are mainly gas-charged, with little or no pumping of water required. This is the “dry CBM” trend of the Upper Cretaceous Horseshoe Canyon and Belly River coals of central and southern Alberta. Reserves have been calculated for areas within this trend that have sufficient data. Reserves were calculated in one of two ways: the first is a detailed geological evaluation using a deposit block model method discussed in Section 4.1.6. This yields a remaining established reserve of 6.4 10^9 m^3, as shown in Table 4.2. Using the second method for areas that have not yet undergone a detailed geological evaluation but have CBM production, remaining established reserves were estimated assuming a 15-year producing life. This results in an additional remaining established reserves of 1.0 10^9 m^3, as shown in Table 4.3.

Current industry practice suggests that long-term CBM production will be from project-style developments combining recompletions of existing wells with the drilling of new development wells. Numerous areas with other coal horizons exist across Alberta. Active exploration and pilot programs of various sizes are currently testing CBM production, but these have no commercial gas production. Table 4.4 lists production from these areas, but reserves have not been booked, pending commercial production.

Water production volumes are tabulated for all CBM pools, as the issues between CBM development and water are considered crucial to further decisions by government, industry, and landowners.

Table 4.2. Upper Cretaceous CBM in place and established reserves, 2004 (10^6 m^3), deposit block model method

Field/ strike area	Block model area (ha)	Average coal thickness (m)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas In place (10^6 m^3)	Adjusted average recovery factor	Initial established reserves (10^6 m^3)	Gas - cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - cumulative production (10^3 m^3)
Ardenode	14 848	11	2.50	4 177	4%	178	2	176	0.0
Bashaw	68 384	11	1.05	8 183	2%	181	27	154	3.2
Carbon	5 192	15	1.22	946	9%	88	2	86	0.0
Centron	9 088	16	2.43	3 606	4%	145	2	143	0.0
Clive-Alix	17 488	14	1.40	3 366	4%	135	20	114	6.3
Entice	58 921	16	1.81	18 254	11%	2 169	134	2 034	0.4
Gayford	11 704	19	1.23	2 712	10%	274	61	212	0.1
Ghostpine	63 360	12	1.14	8 765	6%	482	6	476	0.1
Irricana	4 984	20	2.45	2 499	15%	383	71	312	0.6
Manito	5 400	11	0.94	577	4%	23	4	19	0.0
Nevis	35 848	14	1.14	5 544	4%	209	35	174	0.9
Parflesh	9 290	13	1.17	1 411	9%	125	1	124	0.0
Redland	14 448	14	1.09	2 133	11%	225	17	209	0.1
Rockyford	21 024	14	1.09	3 289	11%	368	52	316	0.3
Strathmore	41 608	14	2.25	13 426	5%	687	44	643	0.4
Trochu	12 024	14	1.04	1 695	6%	93	12	81	0.0
Twining	92 664	14	1.45	19 026	5%	977	10	967	18.3
Wimborne	14 800	11	1.65	2 621	6%	144	3	141	0.1
Total	501 075			102 230		6 886	505	6 381	30.8
Average		14	1.50		8%				

Note that the Bashaw and Nevis Fields have very little data to calculate CBM reserves. Once data are collected in a more rigorous fashion, the reserves should increase dramatically. Larger reserves for fields such as Entice and Irricana are due to higher-density infill drilling.

Table 4.3. Upper Cretaceous CBM in place and established reserves, 2004 (10^6 m^3), production extrapolation method

Field/strike area	Initial gas in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Gas - cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - cumulative production (10^3 m^3)
Chigwell	not calc	98	7	91	0.9
Delia	not calc	109	7	102	0.0
Donalda	not calc	35	2	33	0.0
Mikwan	not calc	61	4	57	0.0
Rowley	not calc	119	8	111	0.0
Rumsey	not calc	146	10	136	0.0
Swalwell	not calc	31	2	29	0.0
Three H Ck	not calc	117	8	110	1.3
Wetwin	not calc	13	1	13	0.4
Fenn BV	not calc	383	26	357	3.0
Total	~16 000	1 114	74	1 039	5.7

Table 4.4. Noncommercial CBM production, 2004 (10^6 m^3), production extrapolation method—other CBM areas

Field/strike area	Coal zone	Initial gas in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Gas - cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)	Water - cumulative production (10^3 m^3)
Canmore	Kootenay	not calc	not recorded	not recorded	0	not recorded
Fenn BV	Mannville	not calc	9	9	0	438.8
Coleman / Livingstone	Kootenay	not calc	0	0	0	0.0
Redwater	Mannville	not calc	not recorded	not recorded	0	not recorded
Pine Creek/Brazeau	Ardley	not calc	not recorded	not recorded	0	not recorded
Pembina	Ardley	not calc	15	15	0	89.5
Corbett/Thunder	Mannville	not calc	22	22	0	347.4
Manola/Mellow	Mannville	not calc	16	16	0	14.9
Drumheller	Mannville	not calc	0	0	0	0.0
Norris	Mannville	not calc	4	4	0	48.0
Strome	Mannville	not calc	0	0	0	4.9
Battle South	Mannville	not calc	0	0	0	5.3
Kelsey	Mannville	not calc	1	1	0	95.9
Swan Hills / Swan Hills S	Mannville	not calc	0	0	0	10.5
Miscellaneous	All	not calc	109	109	0	146.8
Total		not calc	176	176	0	1 202.0

The 118 10^9 m^3 initial in-place volume (Tables 4.2 and 4.3) encompasses the areas of commercial CBM production. This volume is expected to increase with further evaluation to include areas of known resources drilled but not yet producing. The remaining established reserves is set at 7.42 10^9 m^3 based on the two methods, as shown in Tables 4.2 and 4.3. Recent additional requirements placed on industry to gather testing data on designated CBM pools and greater identification of CBM-specific activity resulting from *Bulletin 2004-21* may enable a more complete assessment of CBM reserves for additional regions of the province for the next year-end.

4.1.3 Commingling of CBM with Conventional Gas

Commingling is the unsegregated production of gas from more than one pool. There are currently two types of commingling related to CBM production: producing gas from two or more CBM pools unsegregated in the same wellbore, and producing gas from CBM pools with conventional pools unsegregated in the same wellbore. The former case does not affect calculation of CBM reserves. Only the latter case is of concern in determining production to calculate remaining reserves. In several areas CBM production has been commingled with conventional gas.

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

As the Horseshoe Canyon and Belly River CBM pools are generally "dry CBM," with little or no pumping of water required, the commingling of CBM and other conventional gas pools is becoming fairly common (CBM/conventional commingling). As 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.

However, CBM/conventional commingling creates a lack of segregated data, thereby affecting reserves calculations. Many wells report only large CBM production even though analysis of the well indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints in this report, the following analysis was completed:

- The commingled CBM/conventional wells showing production trends that more resemble sandstone gas reservoir decline rates had a small percentage of production assigned as CBM.
- The commingled CBM/conventional wells showing production trends that more resemble CBM had all production assigned as CBM.
- Wells that were recompleted to CBM after conventional production and reported as one production occurrence were culled from the production tally, as the sandstone contribution is generally far larger than the CBM production.

To further resolve these issues, commingling approvals now stipulate data submission requirements as follows:

- submission of initial segregated pressures for each CBM zone;
- submission of some initial flow meter data or logs to show individual seam CBM contributions and relative conventional contributions;
- desorption data gathered preferentially from core wells, with future possibilities of using core-supported cuttings data, but with no less than one data point per 36 sections of development;
- ongoing annual segregated pressure testing and flow meter analysis on "control wells" (flowing CBM-only observation wells), with each control well representing production from four sections of CBM development.

Future submission of these test results will allow for more complete analysis to resolve the issues described above.

4.1.4 Distribution of Production by Geologic Strata

Horizons with CBM potential in the Alberta plains are:

- Ardley coals of the Scollard Formation – This is the upper set of coals that 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. Where water is present, it is usually nonsaline or marginally saline, and thus water production and disposal must comply with the *Water Act*.
- Coals of the Horseshoe Canyon Formation and Belly River Group – This is the middle set of coals, which generally have low gas contents and low water volumes, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, which are the only coals to have CBM reserves booked at this time.
- Coals of the Mannville Group – This is the lower set of coals, primarily in the Upper Mannville Formation(s). These generally have high gas contents and high volumes of saline water, which requires 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. Mannville coals are the focus of a number of pilot projects that have not had commercial success as of yet. Thus the initial reserves have been set at cumulative production. A few of the pilots have been abandoned (e.g., Fenn Big Valley).
- Kootenay coals of the Mist Mountain Formation – These coals are only present in the foothills of southwestern Alberta. They have varying gas content and quantities of water, but production of gas is very low due to tectonic disruption.

4.1.5 Hydrogen Sulphide Content

Hydrogen sulphide (H_2S) is not normally considered to be an issue with respect to CBM, as the coal adsorption coefficient for H_2S is far greater than for methane. However, commingling CBM production with conventional sandstone gas from the Upper Cretaceous may result in trace amounts of H_2S being produced.

4.1.6 Reserves Accounting Methods

Three methods of reserves calculation, conventional pool volumetrics, decline curve analysis, and deposit block modelling, were considered and compared to determine the best method. These methods are described below, although the first two were dismissed as not providing accurate enough results.

The EUB's in-place resource calculation was determined using a three-dimensional deposit block model. CBM exists as deposits (similar to coal and bitumen) of disseminated gas with gas content and reserve values that can be calculated using a deposit model. As CBM is natural gas, it is regulated and administered as if it existed in pools, but the pool resource and reserve calculation method is not directly applicable.

Analysis of the Upper Cretaceous "dry CBM" trend, where most CBM pools are geologically distinct and show different pressure gradients, concludes that it is more appropriate to use separate gas content formulas for each CBM pool. Where block modelling was done, information on the gas content of coals, while still quite limited, does indicate that a reliable relationship exists among gas content, formation pressure, depth from surface, and ash content of the coal. The CBM deposit block models were constructed by developing a three-dimensional gridded seam model, with subsequent application of measured gas contents and recovery factors to each coal intersection.

Production flow logs and other criteria indicate that the individual block recovery factors need to be assigned on a different basis for each coal seam. Coals shown not to produce any gas had their recovery factor set to zero. The results are highly varied from gas field to gas field, and some areas have no or limited useful data, while other fields have good information.

CBM data are available on two systems at the EUB: summarized pool style net pay data on the *Basic Well Database*, and individual coal seam thickness picks on the *Coal Hole Database.* For further information, contact EUB Information Services.

Pool volumetric CBM reserves estimates, based mainly on pool-wide general gas content and average recovery factor, was determined to be only partially adequate, as individual seam gas contents, recoveries, and pressures cannot be averaged across the pool area. The result was a reserves estimate of 1.39 10^9 m^3, considerably lower than reserves calculated using the block model and overly pessimistic when compared to actual production. Decline analysis of CBM production from the Horseshoe Canyon Formation was attempted on the very few wells with more than six months of data. The results were inconclusive, with a wide scatter, but the statistical average decline is about 10 per cent. This decline may extrapolate to a well life of 20+ years, with a cumulative volume of about 10 10^6 m^3 per well on average. The decline analysis extrapolates to a very large reserve estimate, which is not supported by the production data currently available.

4.1.7 Ultimate Potential

As the thickness and correlatability of coal as a host rock can be determined from the large number of available oil and gas wells, the EUB believes that a regional estimation of CBM resources can be established with some degree of confidence. In 2003, the Alberta Geological Survey (*Earth Sciences Bulletin 2003-03*) estimated that there are some 14 trillion m^3 (500 trillion cubic feet) of gas in place within all of the coal in Alberta, which is summarized in Table 4.5. The geographic distribution of these resources is shown in **Figure 4.1**. Only a very small portion of that coal resource has been studied in detail for this report.

Table 4.5. CBM resources gas-in-place summary—constrained potential (depth and thickness restrictions)

	10^{12} m^3	TCF
Upper Cretaceous/Tertiary - Plains	4.16	147
Mannville coals	9.06	320
Foothills/Mountains	0.88	31
Total	14	500

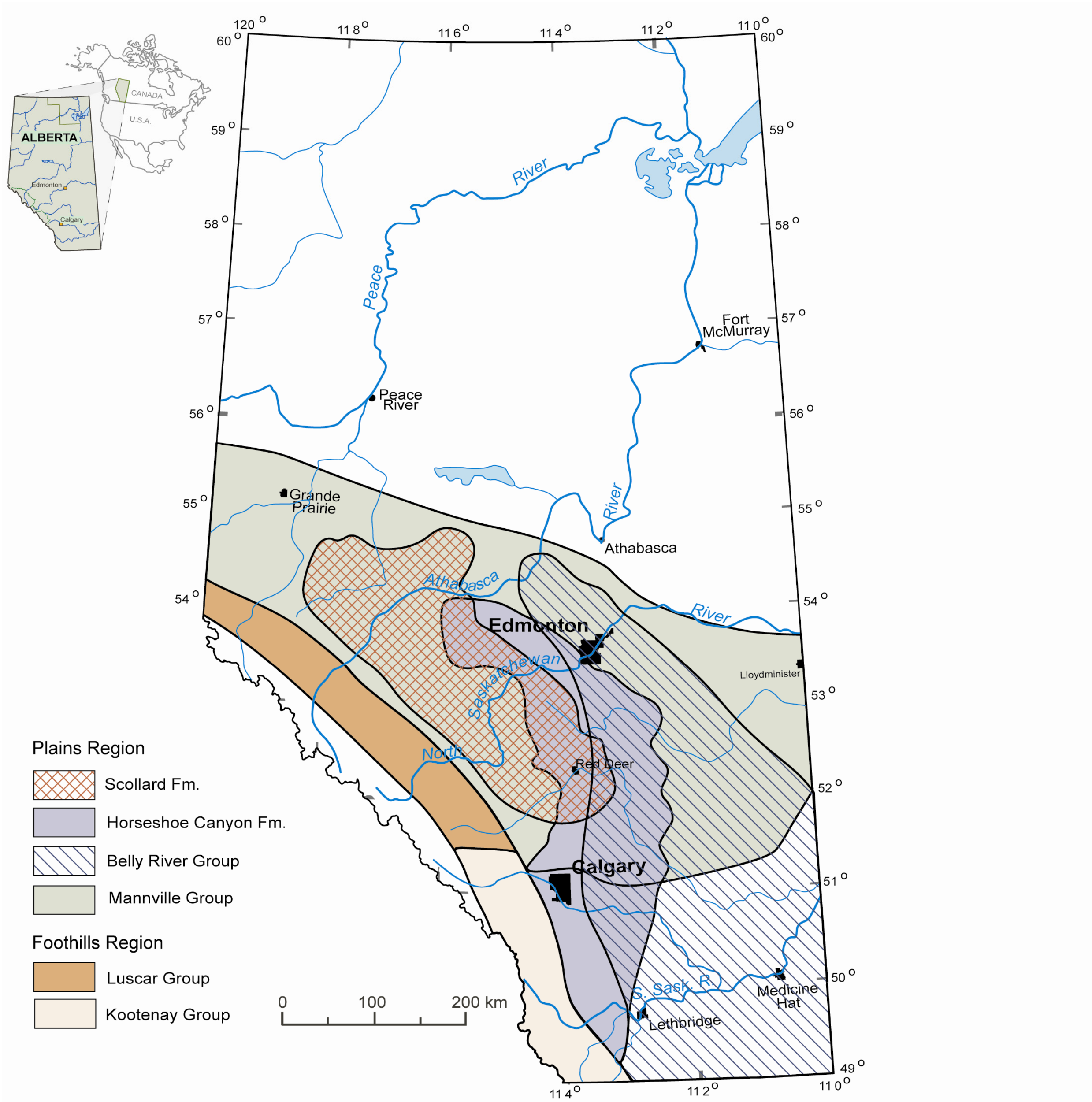

Figure 4.1. Coal-bearing strata with CBM potential (from AGS *Earth Sciences Bulletin 2003-03*)

4.2 Supply of and Demand for Coalbed Methane

As mentioned previously, commercial production of CBM in Alberta began in 2002, with very small volumes recovered to date. In 2004, some 0.6 10^9 m^3 was produced, mostly from the generally dry coals of the Horseshoe Canyon Formation. CBM has the potential to become a significant supply source in Alberta over the next 10 years.

In 2004, 1174 successful wells licensed as CBM were drilled in the province. **Figure 4.2** illustrates the location of these wells by geographical area. A large portion of the drilling has taken place in Central Alberta (PSAC Area 5) and Southeastern Alberta (PSAC Area 3), accounting for 52 and 35 per cent respectively of all CBM wells drilled in 2004.

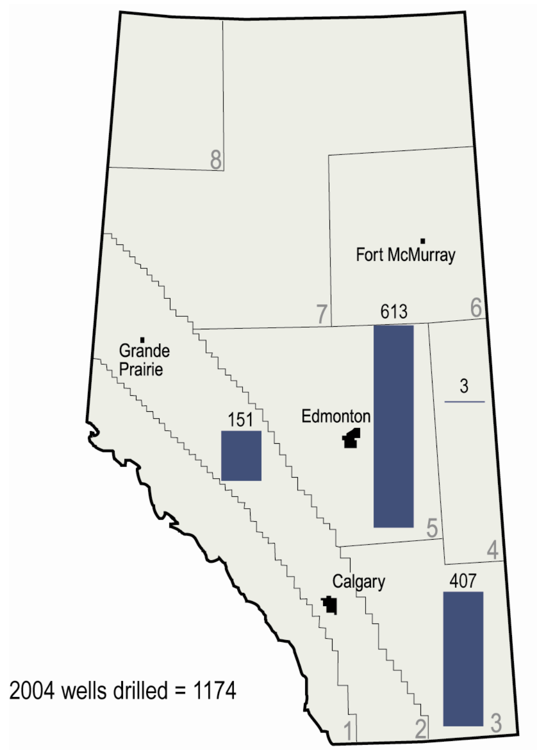

Figure 4.2. Alberta successful CBM well drilling

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

In projecting CBM production, the EUB considered expected production from existing wells and expected production from new well connections.

Limited historical production data suggest that CBM production does not behave in the same manner as conventional production in that CBM production declines more slowly. Therefore, an annual decline rate of 10 per cent was applied to production from existing wells after two years of production.

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

- The average initial productivity of new CBM connections will be 2.5 10^3 m^3/d.
- Production from new well connections will decline by 10 per cent per year after two years of production.
- The number of new CBM well connections in the province will increase from 1205 in 2004 to 2000 in 2005. By 2006, the number of CBM connections will be 2500 annually.

Based on the assumptions described above, the EUB generated the forecast of CBM production to 2014, as shown in **Figure 4.3**. The production of CBM is expected to increase from 0.6 10^9 m^3 in 2004 to 15.2 10^9 m^3 in 2014. This represents an increase from less than 0.5 per cent in 2004 to about 12 per cent in 2014 of total Alberta marketable gas production.

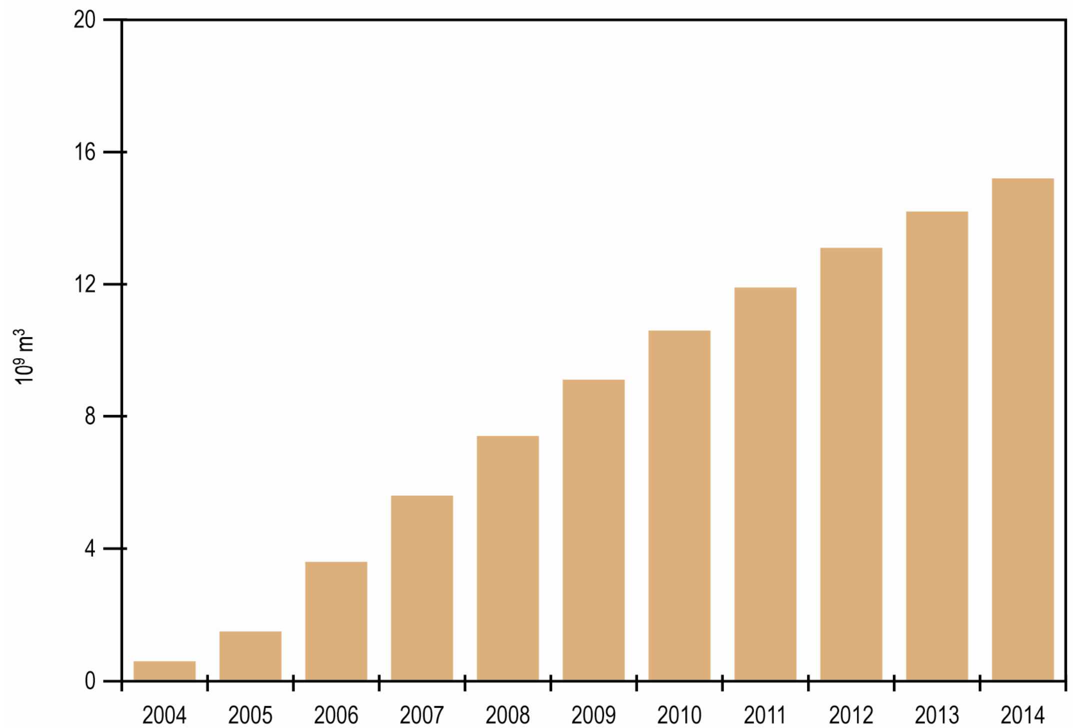

Figure 4.3. Coalbed methane production forecast

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

5 Conventional Natural Gas

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

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

At December 31, 2004, the EUB estimates the remaining established reserves of marketable gas in Alberta to be 1092.3 billion cubic metres (10^9 m^3), having a total energy content of 40.7 exajoules. This increase of 4.7 10^9 m^3 since December 31, 2003, is the result of all reserves additions less production that occurred during 2004. These reserves exclude 34.7 million (10^6) m^3 of ethane and other natural gas liquids, which are present in marketable gas leaving the field plant and are subsequently recovered at reprocessing plants, as discussed in Section 5.1.8. Removal of natural gas liquids results in a 4.4 per cent reduction in heating value from 38.9 megajoules (MJ)/m^3 to 37.2 MJ/m^3 for gas downstream of straddle plants. Details of the changes in remaining reserves during 2004 are shown in Table 5.1. Total provincial gas in place and raw producible for 2004 is 7792 10^9 m^3 and 5377 10^9 m^3 respectively. This gives an average provincial recovery factor of 69 per cent.

Detailed pool-by-pool reserves data are available on CD. See Appendix C.

Table 5.1. Reserve change highlights of marketable gas (10^9 m^3)

	Gross heating value (MJ/m^3)	2004 volume	2003 volume	Change
Initial established reserves		4 546.7	4 400.8	+145.9
Cumulative production		3 419.6	3 278.6	+141.0[a]
Remaining established reserves downstream of field plants				
"as is"	38.9	1 127.0	1 122.2	+4.9
at standard gross heating value	37.4	1 172.3	1 166.7	
Minus liquids removed at straddle plants		34.7	34.6	+0.1
Remaining established reserves "as is"	37.2	1 092.3 (38.8 tcf)	1 087.6 (38.6 tcf)	+4.7
at standard gross heating value	37.4	1 087.6	1 082.7	

[a] May differ from actual annual production.

Annual reserves additions and production of natural gas since 1974 are depicted in **Figure 5.1**. It shows that total reserves additions have failed to keep pace with production, which has increased significantly since 1992. As illustrated in **Figure 5.2**, Alberta's remaining established reserves of marketable gas has been in general decline since 1982.

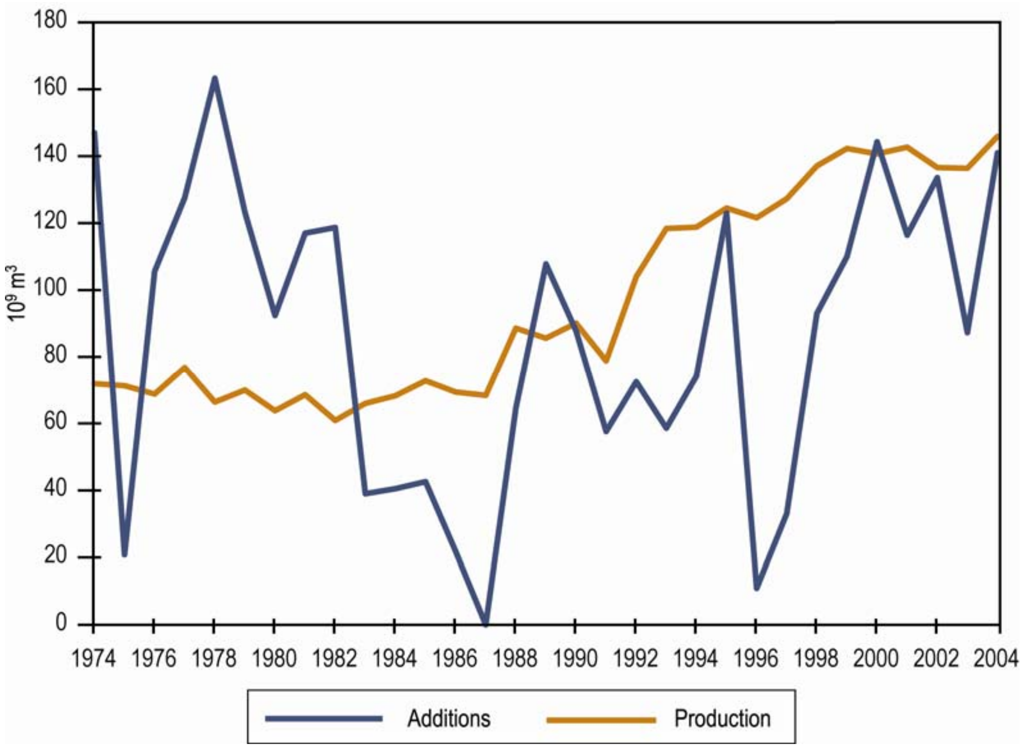

Figure 5.1. Annual reserves additions and production of marketable gas

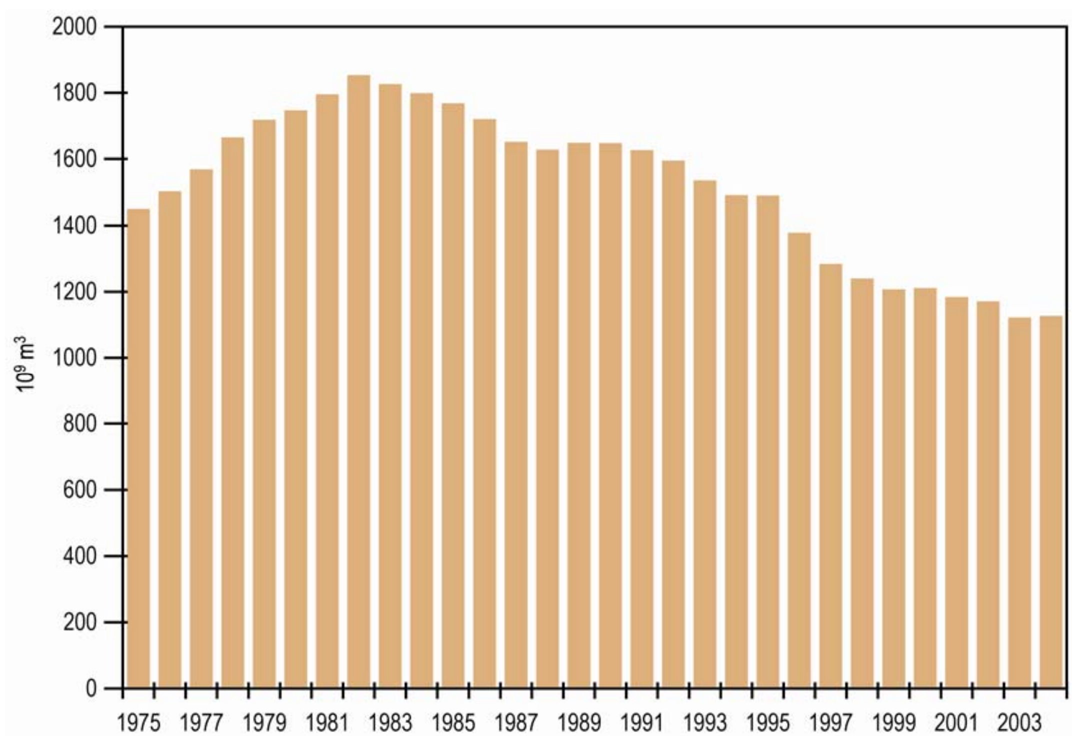

Figure 5.2. Remaining marketable gas reserves

5.1.2 Reserves in Nonproducing Pools

Nonproducing pools are those that have never been placed on production because they are uneconomic to tie in, are gas cap to an oil pool, or are "behind pipe," awaiting depletion of other producing zones in the wellbore.

At year-end 2004, 8718 pools out of a total of 41 743 pools in the province were classified as nonproducing. These pools had aggregate marketable reserves of 72 10^9 m^3, or about 6 per cent of the province's remaining established reserves. This is down significantly from the 435 10^9 m^3 estimated in 1995. This decrease is the result of the deletion of inactive pools, pools being placed on production, and reassessment of pool reserves. A breakdown of these reserves is shown by modified Petroleum Services Association of Canada (PSAC) area in **Figure 5.3.**

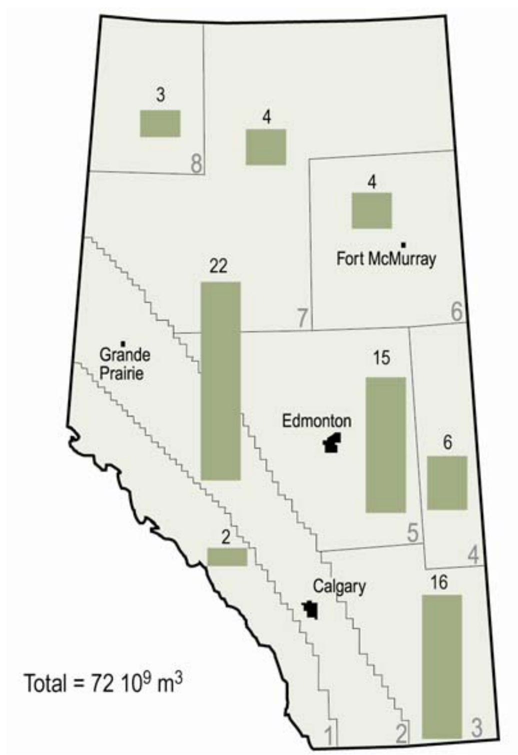

Figure 5.3. Unconnected gas reserves, 2004, by modified PSAC area (10^9 m^3)

5.1.3 Annual Change in Marketable Gas Reserves

Figure 5.4 shows the breakdown of annual reserves additions into new, development, and reassessment from 1999 to 2004. Initial established reserves increased by 145.9 10^9 m^3 from year-end 2003. This increase includes the addition of 46.1 10^9 m^3 attributed to new pools booked in 2004, 59.8 10^9 m^3 from development of existing pools, and positive net reassessment of 40.0 10^9 m^3. The drop in new pool reserves from previous years is partly the result of smaller areas being assigned to single-well pools, as recommended in EUB *Report 2004-A: Alberta Single-Well Gas Pool Drainage Area Study.* Reserves added through drilling alone totalled 105.9 10^9 m^3, replacing 77 per cent of Alberta's 2004 production of 136.3 10^9 m^3. These breakdowns are not available prior to 1999. Historical reserves growth and production data since 1966 are shown in Appendix B, Table B.4.

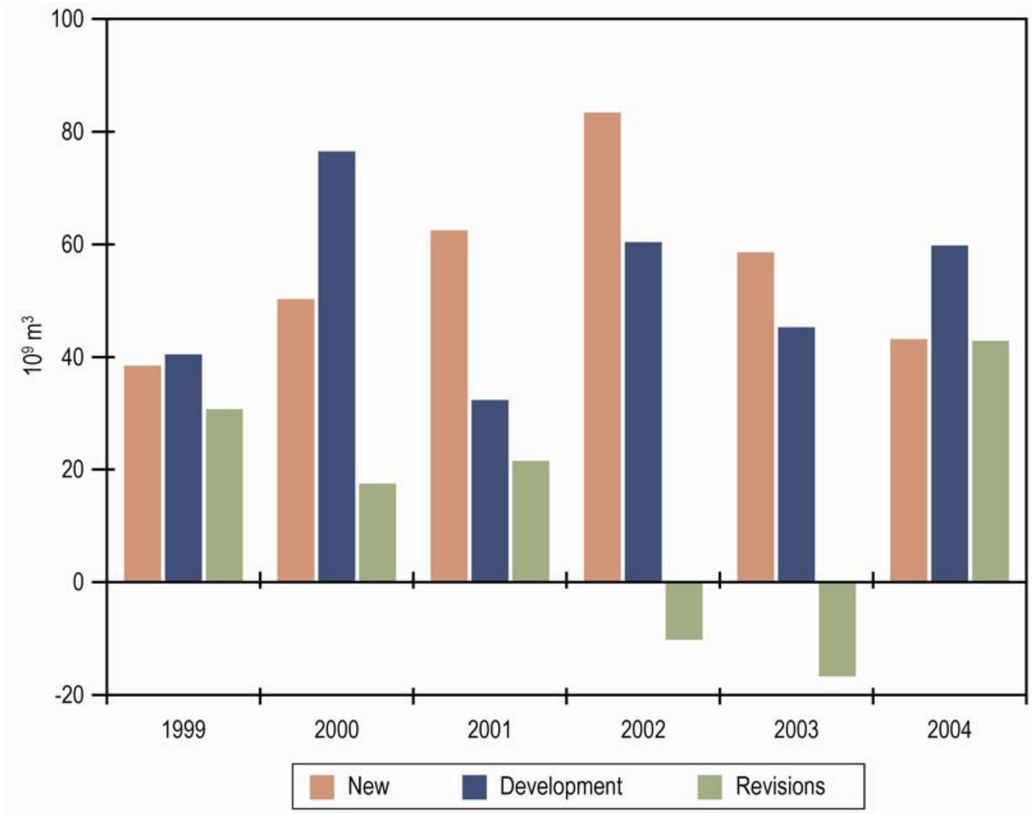

Figure 5.4. New, development, and revisions to marketable gas reserves

During 2004, EUB staff carried out a number of projects to review pools that had not been re-evaluated for some time or appeared to have reserves under- or overbooked based on their life index. This resulted in total positive net revisions of 40.0 10^9 m^3, arrived at from positive reassessments totalling 155.3 10^9 m^3 and negative reassessments totalling 115.3 10^9 m^3. The projects that resulted in large reserve changes are summarized below:

- Review of shallow gas pools within the Southeastern Alberta Gas System (MU) resulted in reserves additions of 27.6 10^9 m^3, equivalent to 2 per cent of Alberta's remaining reserves. This addition was due mainly to continued aggressive development, re-evaluation of existing pools, and new reserves from horizons that were previously thought to be uneconomic.

- Review of 440 producing pools with a remaining constant rate life of over 25 years resulted in a reserves reduction of 41.9 10^9 m^3. Additionally, reserves of 2100 pools with minimal production rates were adjusted to reflect a constant rate life of three years. This resulted in a further reduction of 22.3 10^9 m^3.

- Review of 675 producing pools with a remaining constant rate life of less than 2 years resulted in a reserves addition of 60.5 10^9 m^3. Production decline analysis was used in estimating reserves for these pools.

- Recognition of some 870 previously unbooked gas wells drilled prior to July 2002, many of which have now been placed on production, resulted in a positive reassessment of 14.1 10^9 m^3.

Figure 5.5 depicts the changes in marketable gas reserves for 2004 by modified PSAC areas. Significant changes were made in the following areas:

- Area 2, the Western Plains area, added 71 10^9 m^3, compared to 19 10^9 m^3 last year. This accounts for about 49 per cent of the total annual change for 2004.

- Area 3 added a net 40.1 10^9 m^3, mainly from development of existing pools and exploration of previously undeveloped horizons in the Cretaceous.

- Area 6 saw marginal growth of 3.7 10^9 m^3, compared to 21 10^9 m^3 in 2003, and Area 7 saw minimal growth.

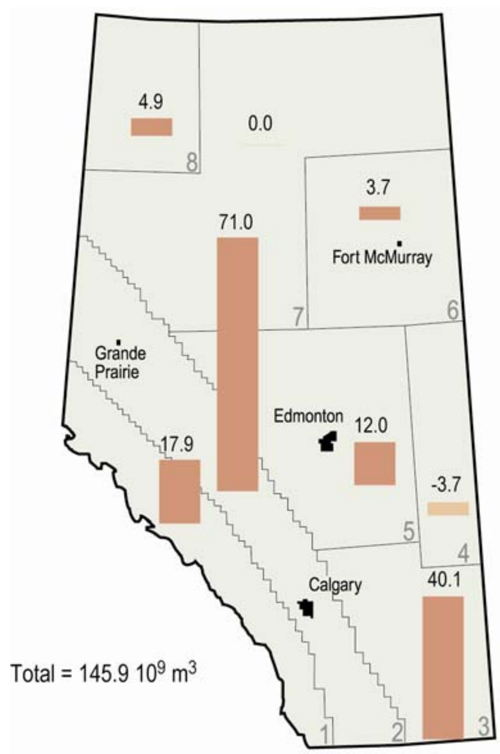

Figure 5.5. Marketable gas reserves changes, 2004, by modified PSAC area (10^9 m^3)

Pools with major changes in reserves are listed in Table 5.2. Of particular interest are a number of fields in the Southeastern Alberta Gas System (MU), where reserves were revised upward in 2004, such as in the Bantry and Countess fields, where reserves of 4.2 10^9 m^3 and 5.6 10^9 m^3 were added respectively. It should be noted that fields in the Southeastern Alberta Gas System (MU) had significant reserves additions for many years due to increased drilling in the area. Other pools with significant reserve changes include Blackstone Beaverhill Lake Pool, with an increase of 5.1 10^9 m^3; Boyer Bluesky A and Gething A and M Pool, with an increase of 3.8 10^9 m^3; and Pouce Coupe South Halfway, Doig, and Montney MU#1 Pool, with an increase of 5.5 10^9 m^3. Together, reserves additions for these three pools total 14.4 10^9 m^3.

Table 5.2. Major natural gas reserve changes, 2004

Pool	Initial established reserves (10^6 m^3) 2004	Change	Main reasons for change
Alderson Southeastern Alberta Gas System (MU)	59 589	+2 403	New pools, development of existing pools, and re-evaluation of initial volume in place
Atlee-Buffalo Southeastern Alberta Gas System (MU)	10 672	+1 451	New pools, development of existing pools, and re-evaluation of initial volume in place
Bantry Southeastern Alberta Gas System (MU)	33 346	+4 211	New pools, development of existing pools, and re-evaluation of initial volume in place
Benjamin Rundle A,B,C,Q,& R	8 476	-972	Re-evaluation of initial volume in place
Blackstone Beaverhill Lake A	21 073	+5 109	Re-evaluation of initial volume in place
Boyer Bluesky A, Gething A and M	20 720	+3 793	Re-evaluation of initial volume in place
Burnt Timber Wabamun A	2 700	+560	Re-evaluation of initial volume in place
Coleman Rundle A and Paliser B	7 440	+1 812	Re-evaluation of initial volume in place
Countess Southeastern Alberta Gas System (MU)	35 149	+5 581	New pools, development of existing pools, and re-evaluation of initial volume in place
Dunvagen Debolt and Elkton MU#1	36 993	+993	Re-evaluation of initial volume in place
Deanne Glauconitic A	1 530	+576	Re-evaluation of initial volume in place
Elmworth Dunvagen, Fort St. John, and Bullhead MU#1	37 462	+1 275	Re-evaluation of initial volume in place
Findlay Dunvagen A	1 473	+825	Re-evaluation of initial volume in place
Fir D-1 A	510	-688	Re-evaluation of initial volume in place
Fox Creek Viking C, Notikewin C, Gething D and H	3 400	+680	Development and re-evaluation of initial volume in place
Garrington Second White Specks, Viking, and Mannville MU#1	198	-1352	Re-evaluation of initial volume in place
Hanlan Beaverhill Lake A	28 650	+1 875	Re-evaluation of initial volume in place
Hussar Southeastern Alberta Gas System (MU)	10 015	+3565	New pools, development of existing pools, and re-evaluation of initial volume in place
High River Cutbank A	2 475	+1 464	Re-evaluation of initial volume in place
Kaybob South Upper Mannvile Q and Gething D	3 142	+1 607	Re-evaluation of initial volume in place
Leland Cadotte A and Cadomin A	3 111	+1873	Re-evaluation of initial volume in place

(continued)

Table 5.2. Major natural gas reserve changes, 2004 (concluded)

Pool	Initial established reserves (10^6 m^3) 2004	Change	Main reasons for change
Limestone Wabamun A	7 250	+740	Re-evaluation of initial volume in place
Majorville Southeastern Alberta Gas System (MU)	1 484	+1 030	New reserves and pool development
Marten Hills Wabiskaw A and Wabamun A	28 500	+1 710	Re-evaluation of initial volume in place
Medicine Hat Southeastern Alberta Gas System (MU)	155 467	+1 225	New pools, development of existing pools, and re-evaluation of initial volume in place
Medicine Lodge Cardium J & K, Viking A and Notikenin A	3 064	-952	Re-evaluation of initial volume in place and recovery factor
Niton Basal Quartz A & Rock Creek F	9 000	+977	Development and re-evaluation of initial volume in place
Narraway Cadotte E and Falher C	99	-575	Re-evaluation of initial volume in place
Okotoks Wabamun B	7 452	+1 790	Re-evaluation of initial volume in place
Pembina Cardium, Viking, Mannville, and Jurassic MU#1	8 356	-2028	Re-evaluation of initial volume in place
Pincher Creek Rundle A	10 650	+994	Re-evaluation of initial volume in-place
Pouce Coupe South Halfway, Doig, and Montney MU#1	9 148	+5 563	Re-evaluation of initial volume in place and recovery factor
Provost Viking, Belly River and Mannville MU#1	51 980	+763	Re-evaluation of initial volume in place
Rockyford Belly River, Viking and Mannville MU#1	2 348	+763	New pools, development of existing pools, and re-evaluation of initial volume in place
Sinclair Doe Creek, Fort St. John and Bullhead MU#1	8 925	+1 360	Pool development and re-evaluation of initial volume in place
Smokey Leduc A	570	-960	Re-evaluation of initial volume in place
Stolberg Rundle A, B, C & D	7 820	+1 865	Re-evaluation of initial volume in place
Wapiti Fort St. John, Bullhead and Nikanassin MU#1	14 743	+3 033	Pool development and re-evaluation of initial volume in place
Wildcat Hills Rundle F	360	-777	Re-evaluation of initial volume in place
Wilson Creek Mannville, Jurassic, and Rundle MU#1	4 477	+2 055	Re-evaluation of initial volume in place

5.1.4 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in Table 5.3. For the purposes of this table, commingled pools are considered as one and the Southeastern Alberta Gas System (MU) is considered on a field basis. The data show that pools with reserves of 30 10^6 m^3 or less, while representing 69.5 per cent of all pools, contain only 10 per cent of the province's remaining marketable reserves. Similarly, the largest 1 per cent of pools contain 53 per cent of the remaining reserves. **Figure 5.6** shows by percentage the total number of pools, initial reserves, and remaining reserves by size distribution, as listed in Table 5.3. **Figure 5.7** depicts natural gas pool size by discovery year since 1965 and illustrates that the median pool size has remained fairly constant at about 16 10^6 m^3 for many years, while the average size has declined from about 300 10^6 m^3 in 1965 to 45 10^6 m^3 in 1987 and has since declined to about 25 10^6 m^3 in 2004.

Table 5.3. Distribution of natural gas reserves by pool size, 2004

Reserve range	Pools		Initial established marketable reserves		Remaining established marketable reserves	
(10^6 m^3)	#	%	10^9 m^3	%	10^9 m^3	%
3000+	188	0.5	2 403	53	524	46
1500-3000	163	0.5	342	8	75	7
1000-1500	151	0.4	184	4	42	4
500-1000	491	1.3	341	7	66	6
100-500	3 212	8.8	669	15	170	15
30-100	6 954	19.0	371	8	138	12
Less than 30	30 584	69.5	237	5	112	10
Total	41 743	100.0	4 547	100	1 127	100

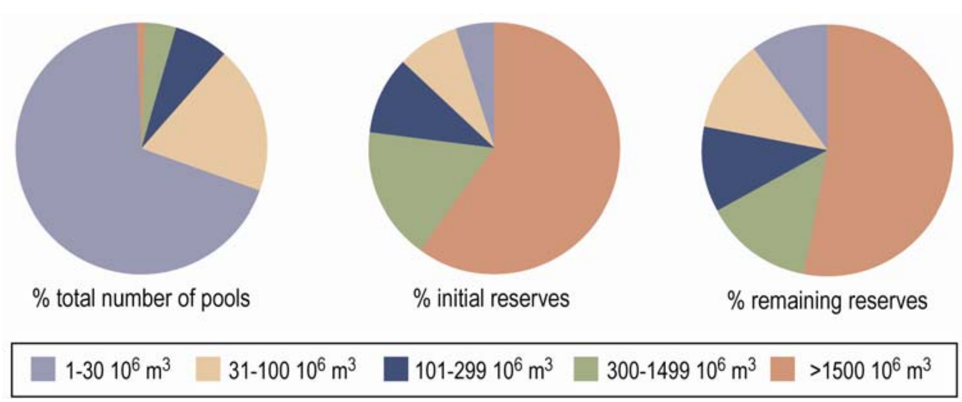

Figure 5.6. Distribution of gas reserves by size

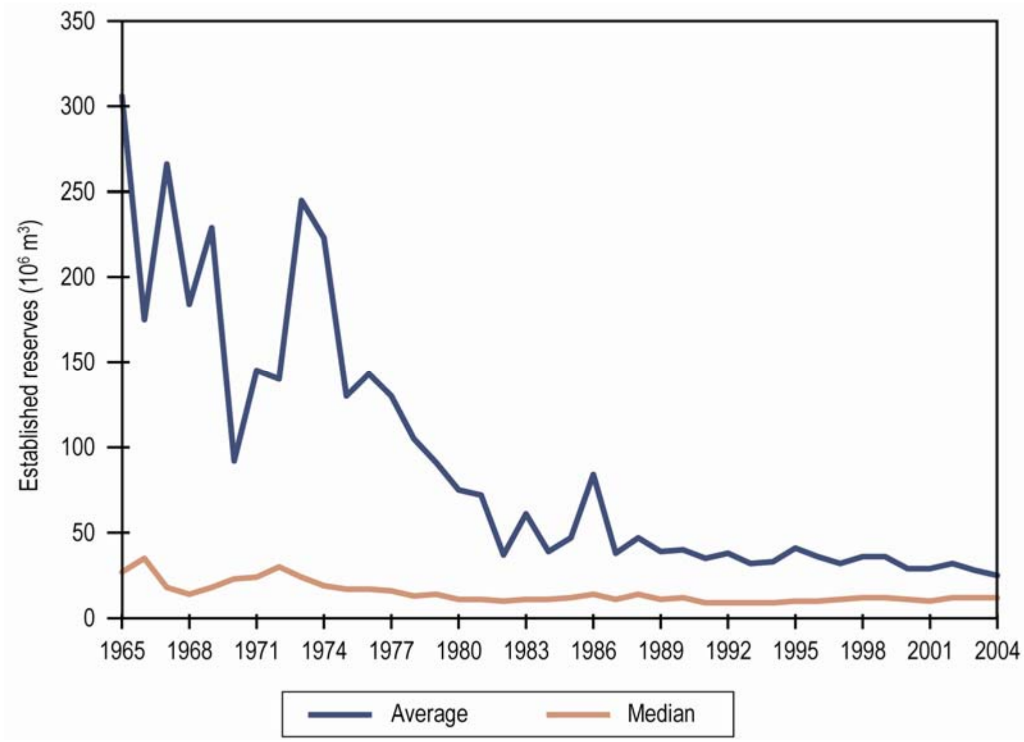

Figure 5.7. Gas pools by size and discovery year

5.1.5 Geological Distribution of Reserves

The distribution of reserves by geological period is shown graphically in **Figure 5.8**, and a detailed breakdown of gas in place and marketable gas reserves by formation is given in Appendix B, Table B.5. The Upper and Lower Cretaceous period contains some 70 per cent of the province's remaining established reserves of marketable gas. The geologic strata containing the largest remaining reserves are the Lower Cretaceous Mannville, with 26.3 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 21.7 per cent, and the Mississippian Rundle, with 8.3 per cent.

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, 2004, sour gas accounts for some 21 per cent (237 10^9 m^3) of the province's total remaining established reserves and about 33 per cent of natural gas marketed in 2004. This 33 per cent is similar to previous years. In 2003 the percentage was 31 but incorrectly reported as 26. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2004 is 9.2 per cent.

The distribution of reserves for sweet and sour gas (Table 5.4) shows that 172 10^9 m^3, or about 73 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 5.9** 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 52 10^9 m^3, or 22 per cent, of sour gas contains H_2S concentrations greater than 10 per cent.

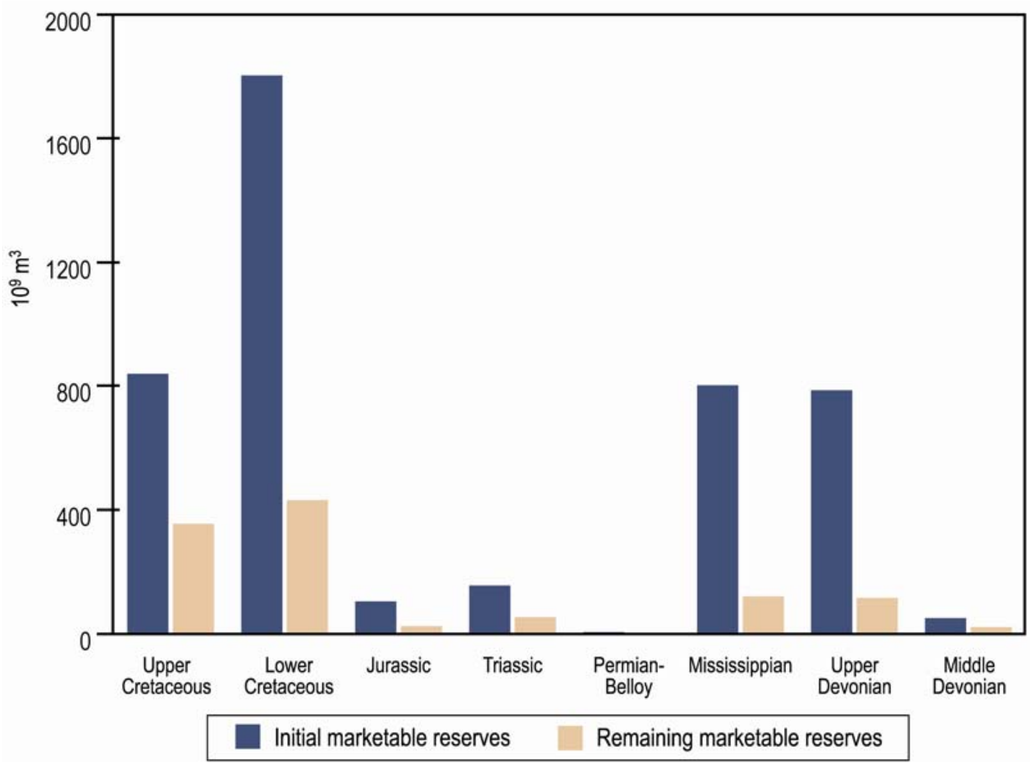

Figure 5.8. Geological distribution of marketable gas reserves

Table 5.4. Distribution of sweet and sour gas reserves, 2004 (10^9 m^3)

	Marketable gas			Percentage	
Type of gas	**Initial established reserves**	**Cumulative production**	**Remaining established reserves**	**Initial established reserves**	**Remaining established reserves**
Sweet					
Associated & solution	598	450	148	13	13
Nonassociated	2 483	1 740	742	51	66
Subtotal	3 081	2 190	890	64	79
Sour					
Associated & solution	394	330	65	10	6
Nonassociated	1 072	900	172	26	15
Subtotal	1 466	1 230	237	36	21
Total	4 547 (161)[b]	3 420 (121)[a]	1 127[a] (40)[b]	100	100

[a] Reserves estimated at field plants.
[b] Imperial equivalent in trillions of cubic feet at 14.65 pounds per square inch absolute and 60 F.

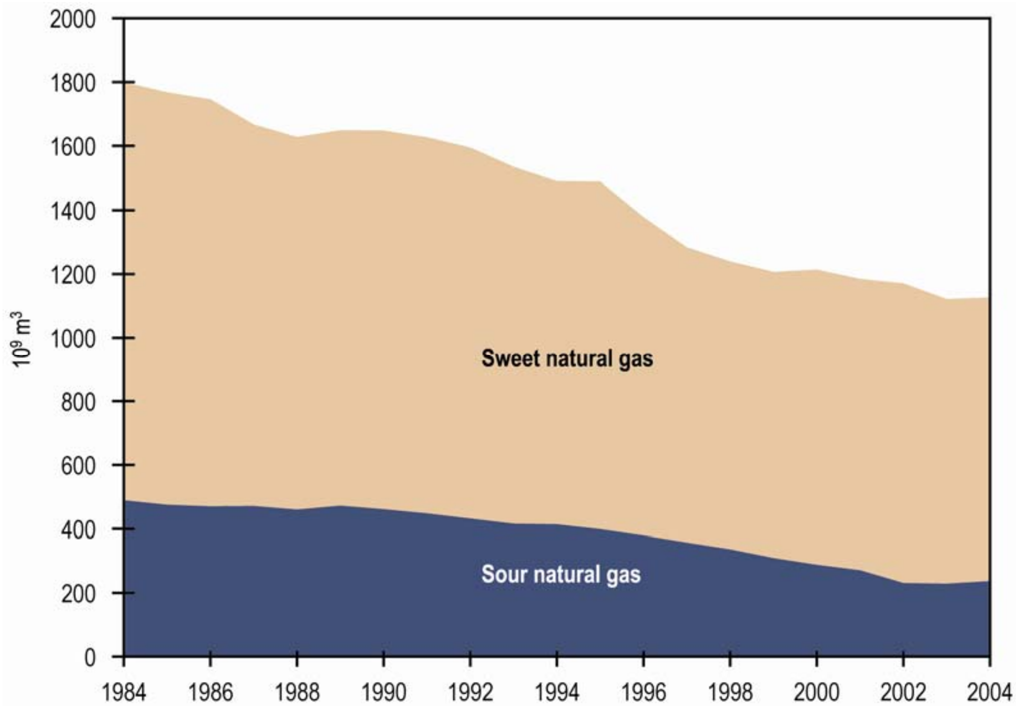

Figure 5.9. Remaining marketable reserves of sweet and sour gas

Table 5.5. Distribution of sour gas reserves by H_2S content, 2004

	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	266	365	47	66	113	48
2.00-9.99	91	364	11	60	71	30
10.00-19.99	26	200	4	26	30	12
20.00-29.99	11	47	2	9	11	5
Over 30	0	96	0	11	11	5
Total	394	1 072	64	172	236	100
Percentage	27	73	27	73		

5.1.7 Reserves of Retrograde Condensate Pools

Retrograde gas pools are pools rich in liquids that reinject dry gas to maintain reservoir pressure and maximize liquid recovery. Reserves of major retrograde condensate pools are tabulated on both energy content and a volumetric basis. The initial energy in place, recovery factor, and surface loss factor (both factors on an energy basis), as well as the initial marketable energy for each pool, are listed in Appendix B, Table B.6. The table also lists raw- and marketable-gas heating values used to convert from a volumetric to an energy basis. The volumetric reserves of these pools are included in the Gas Reserves and Basic Data table, which is on the companion CD to this report (see Appendix C).

5.1.8 Reserves Accounting Methods

The EUB books remaining marketable gas reserves on a pool-by-pool basis initially on volumetric determination of in-place resources and application of recovery efficiency and surface loss. Subsequent reassessment of reserves is made as new information becomes available using additional geological data, material balance, and production decline analysis. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids at field plants, as shown in **Figure 5.10.** A minimum 5 per cent is added to account for loss due to lease fuel (4 per cent) and flaring. Therefore, marketable gas reserves of individual pools on the EUB's gas reserves database reflect expected recovery after processing at field plants.

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

It is expected that some 34.7 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 1127 10^9 m^3 to 1092.3 10^9 m^3 and the thermal energy content from 43.9 to 40.7 exajoules.

Figure 5.10 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 20 per cent is expected to be removed at field plants and an additional 45 per cent at straddle plants. Therefore, the EUB estimates reserves of liquid ethane that will be extracted based on 65 per cent of the total

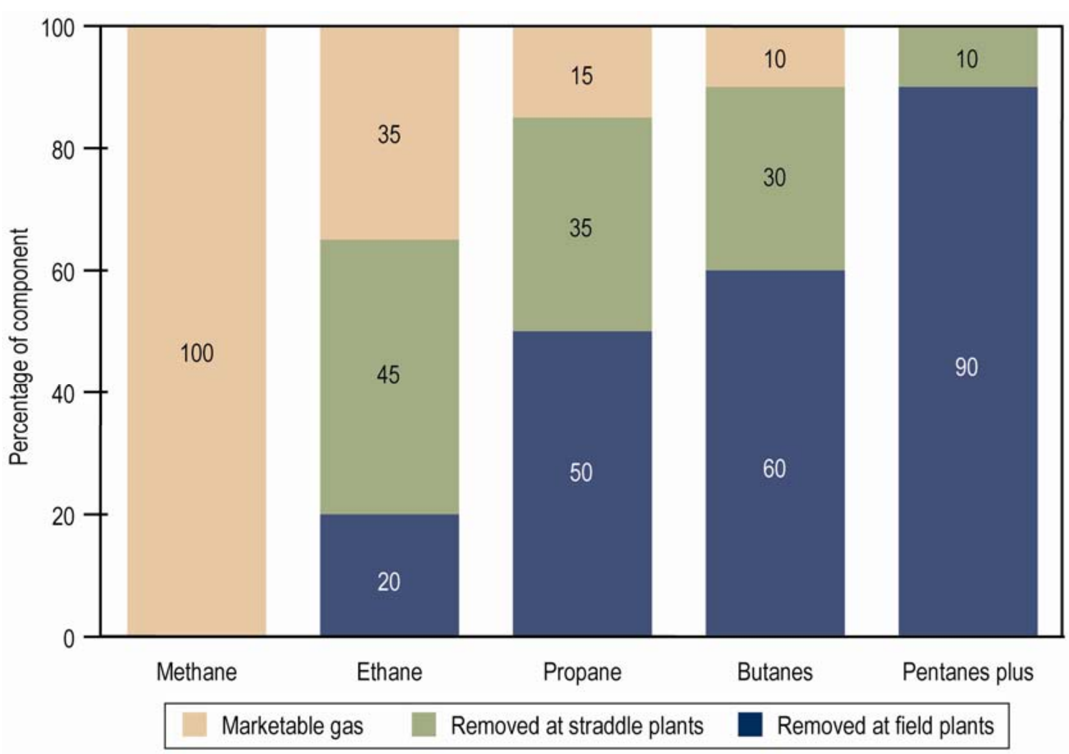

Figure 5.10. Expected recovery of natural gas components

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.7. 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, or 223 tcf. The estimate, which does not include unconventional gas, such as CBM, is about 12 per cent higher than the 5600 10^9 m^3 stated in the Energy Resources and Conservation Board (now the EUB) *Report 92-A: Ultimate Potential and Supply of Natural Gas in Alberta* (EUB 1992 Report). The primary reason for this increase is a better understanding of the geology of the province as a result of increased drilling since 1992. **Figure 5.11** shows the historical and forecast growth in initial established reserves of marketable gas. **Figure 5.12** 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 4547 10^9 m^3, or 72.5 per cent of the ultimate potential of 6276 10^9 m^3, has been discovered as of year-end 2004. This leaves 1729 10^9 m^3, or 27.5 per cent, yet to be discovered. Cumulative production of 3420 10^9 m^3 at year-end 2004 represents 54.5 per cent of the ultimate potential, leaving 2856 10^9 m^3, or 45.5 per cent, available for future use.

Table 5.6. Remaining ultimate potential of marketable gas, 2004 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	@ 37.4 MJ/m^3
Yet to be established		
Ultimate potential	6 276	6 528
Minus initial established	–4 547	–4 729
	1 729	1 799
Remaining established		
Initial established	4 547	4 729
Minus cumulative production	–3 420	–3 557
	1 127	1 172
Remaining ultimate potential		
Yet to be established	1 729	1 799
Plus remaining established	+1 127	+1 172
	2 856	2 971

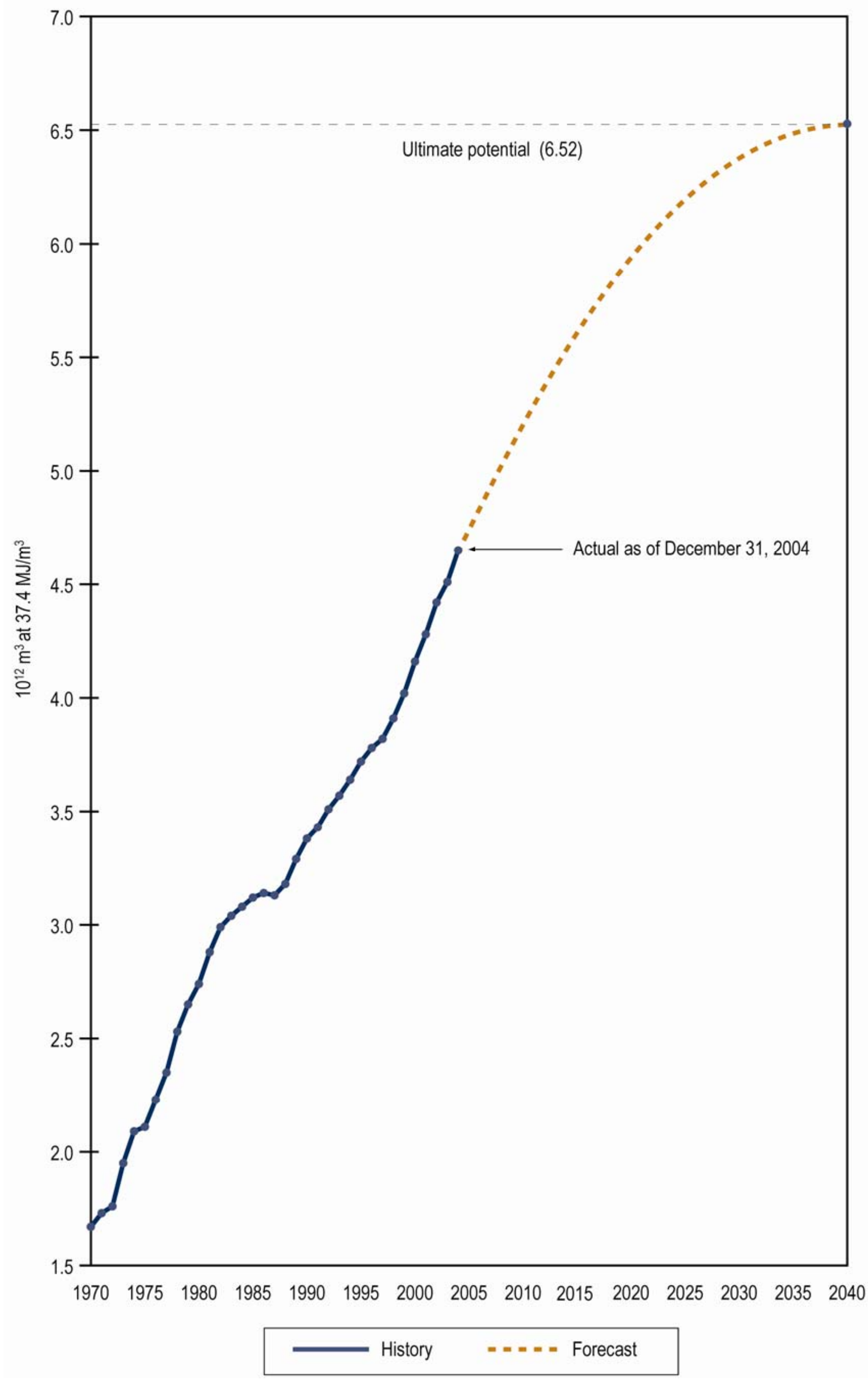

Figure 5.11. Growth of initial established reserves of marketable gas

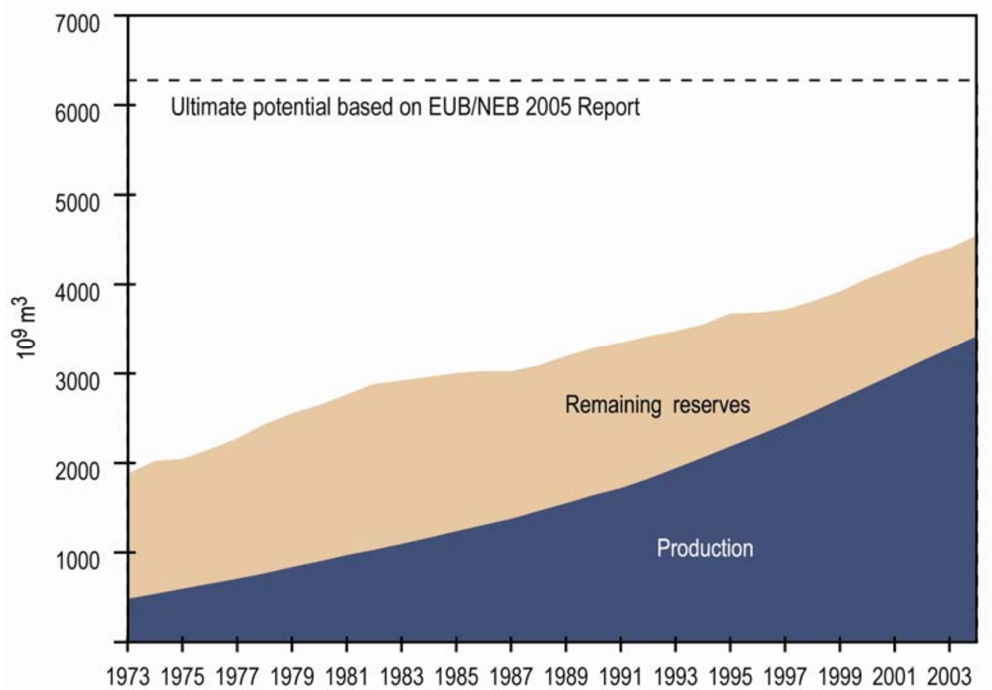

Figure 5.12. Gas ultimate potential

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure 5.13**. It shows that the Western Plains (Area 2) contains about 36 per cent of the remaining established reserves

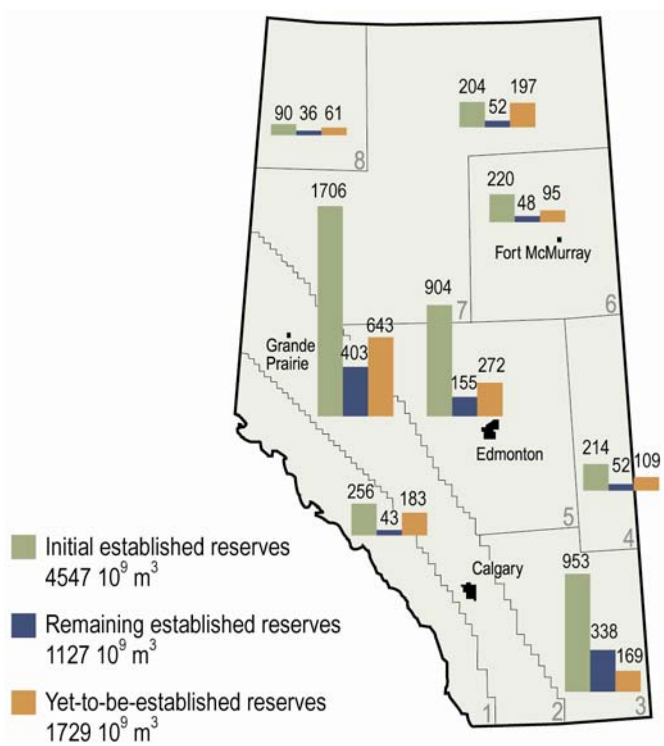

Figure 5.13. Regional distribution of Alberta gas reserves (10^9 m^3)

and 37 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 5.13** shows that based on the EUB/NEB 2005 ultimate potential study, Alberta natural gas supplies will depend on significant new discoveries in the Western Plains.

Figure 5.14 compares the regional distribution of ultimate potential of marketable gas by PSAC area in the EUB 1992 Report and the EUB/NEB 2005 Report. It shows that in the EUB/NEB 2005 Report, the ultimate potential increased in all areas except Area 1 (Foothills) and Area 2 (Western Plains), which had marginal changes.

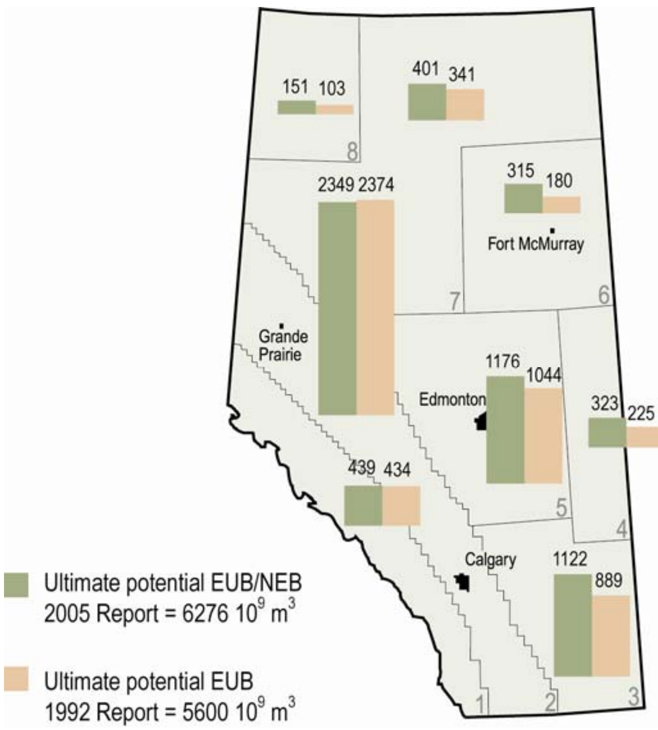

Figure 5.14. Regional distribution of Alberta's ultimate potential for conventional natural gas

Figure 5.15 compares by geological period the discovered and yet-to-be discovered gas in place for year-end 1991 (EUB 1992 Report) and year-end 2004 (EUB/NEB 2005 Report). It shows that while discovered reserves have increased in each period, the ultimate potential has decreased significantly in the Devonian and slightly in the Jurassic and Mississippian. It also shows that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous.

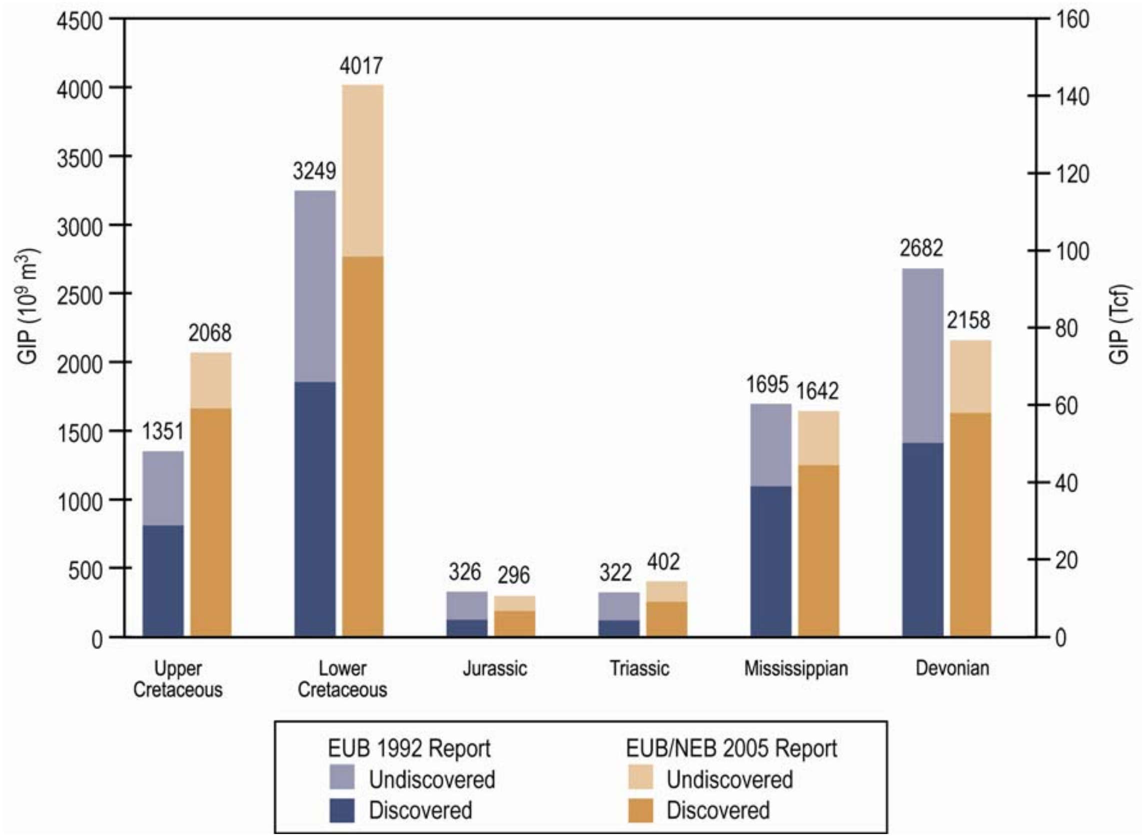

Figure 5.15 Gas in place by geological period

5.2 Supply of and Demand for Natural Gas

5.2.1 Natural Gas Supply

Alberta produced 141.7 10^9m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its conventional gas and oil wells in 2004. As noted in Section 4, Alberta also produced some 0.6 10^9 m^3 of coalbed methane. Total natural gas production increased 1.2 per cent from last year.[1]

Natural gas prices and their volatility, drilling activity, the location of Alberta's reserves, the production characteristics of today's wells, and market demand are the major factors affecting Alberta natural gas production.

Market forces are driving record levels of drilling, and industry is challenged to replace production from existing wells. The high decline rate of production from existing wells and the lower initial productivities of new gas wells are having an impact on current production levels.

The drilling focus in recent years has been heavily weighted towards the shallow gas plays of southeastern Alberta. This region has seen an increasing number of natural gas wells since 1995 due to the lower risk, low cost of drilling, and quick tie-in times.

[1] Natural gas produced in Alberta has an average heating value of about 38.9 MJ/m^3.

The conventional marketable natural gas production volumes for 2004 stated in Table 5.7 have been calculated based on “Supply and Disposition of Marketable Gas” in *ST-3: Alberta Energy Resource Industries Monthly Statistics.*

Table 5.7. Marketable natural gas volumes (10^6 m^3)

Marketable gas production[a]	2004
Total gas production	167 726.2
Minus coalbed methane production	-596.7
Total conventional gas production	167 129.5
Minus storage withdrawals	-4 787.0
Raw gas production	162 342.5
Minus injection total	-8 703.7
Minus processing shrinkage – raw	-10 955.2
Minus flared – raw	-623.1
Minus vented – raw	-397.9
Minus fuel – raw	-11 222.8
Plus storage injection	+5 816.0
Calculated marketable gas production at as-is conditions	136 255.8
Calculated marketable gas production @37.4 MJ/m^3	141 706.0

High demand for Alberta natural gas in recent years has led to a considerable increase in the level of drilling in the province. Producers are using strategies such as infill drilling to maximize production levels. The number of successful gas wells drilled in Alberta in the last two years is shown by geographical area (modified PSAC area) in **Figure 5.16**. In 2004, some 12 960 conventional natural gas wells were drilled in the province, an increase of 7 per cent from 2003 levels and an all-time high. A large portion of gas drilling has taken place in Southeastern Alberta, representing 51 per cent of all natural gas wells drilled in 2004. Drilling levels were up in all areas of the province, with the exception of Area 6 (Northeastern Alberta) and Area 8 (Northwestern Alberta). Note that the gas well drilling numbers represent wellbores that contain one or more geological occurrence capable of producing natural gas.

The number of successful natural gas wells drilled in Alberta from 1995 to 2004 is shown in **Figure 5.17**, along with the number of wells connected (placed on production) in each year. Both of these numbers are used as indicators of industry activity and future production. The definition of a gas well connection differs from that of a drilled well. While gas well drilling levels represent wellbores, well connections refer to geological (producing) occurrences within a well, and there may be more than one per well.

The number of natural gas wells connected in a given year historically tends to follow natural gas well drilling activity, indicating that most natural gas wells are connected shortly after being drilled. However, in the period 1994-2000, a much larger number of natural gas wells were connected than drilled. Alberta had a large inventory of nonassociated gas wells that had been drilled in previous years and were left shut in. Many of these wells were placed on production during the 1990s. In 2004 the number of gas well connections increased by 25 per cent from 2003 levels. In 2003 the number of new wells connected was less than the number of gas wells drilled. This was due primarily to the time delay in bringing gas wells drilled onto production. The distribution of natural gas well connections and the initial operating day rates of the connected wells in the year 2004 are illustrated in **Figures 5.18** and **5.19** respectively.

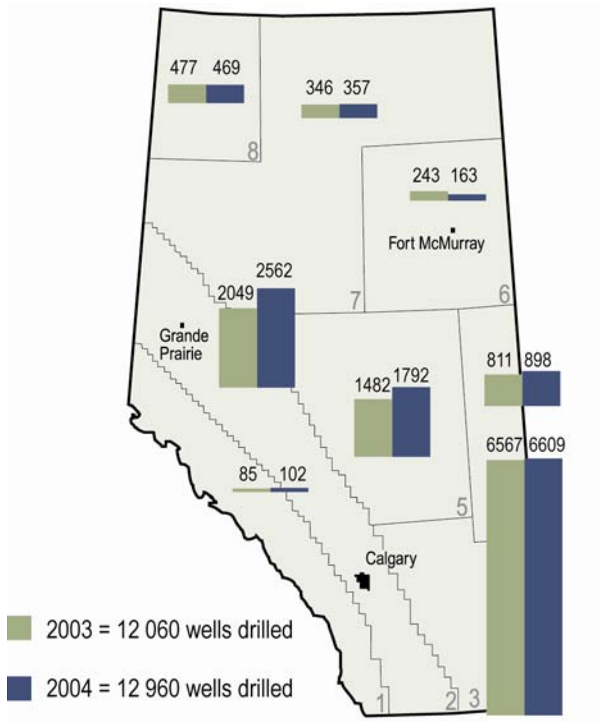

Figure 5.16. Alberta successful gas well drilling by modified PSAC area

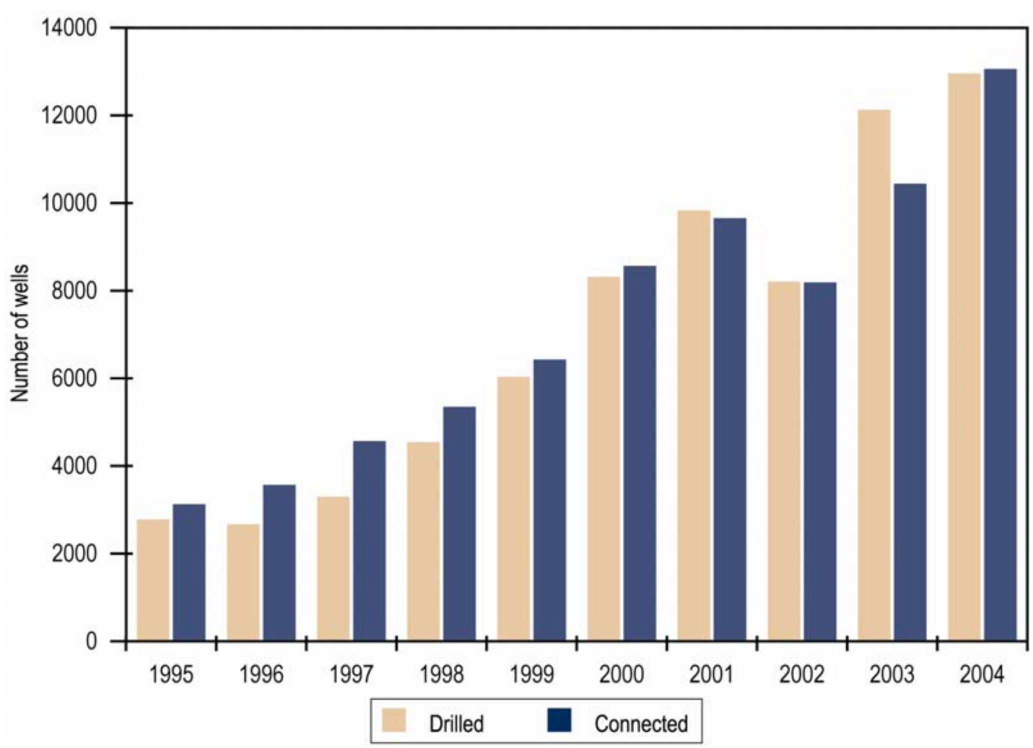

Figure 5.17. Successful conventional gas wells drilled and connected

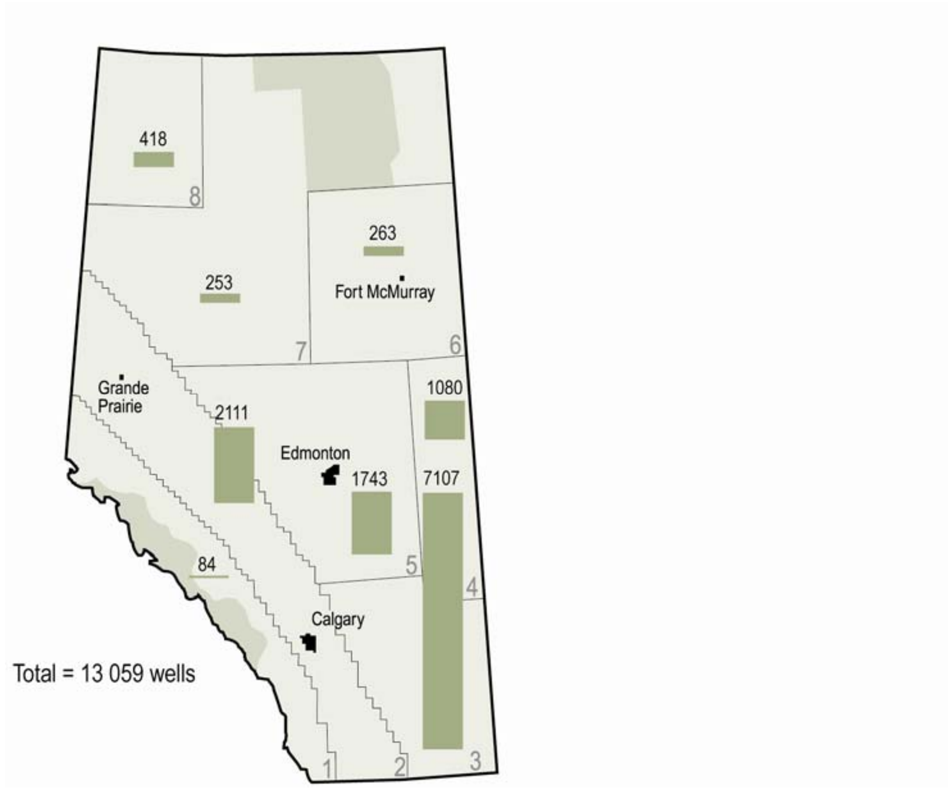

Figure 5.18. Conventional gas well connections, 2004, by modified PSAC area

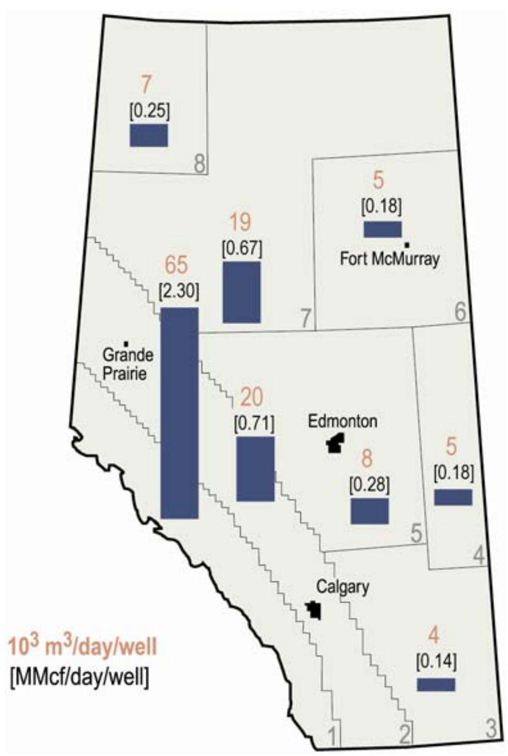

Figure 5.19. Initial operating day rates of connections, 2004, by modified PSAC area

Figure 5.20 illustrates historical gas production from gas wells by geographical area. Area 1 (Foothills), Area 2 (Western Plains), and Area 3 (Southeastern Alberta) experienced increases in production in 2004. Gas production from oil wells increased by some 3 per cent in 2004 over 2003.

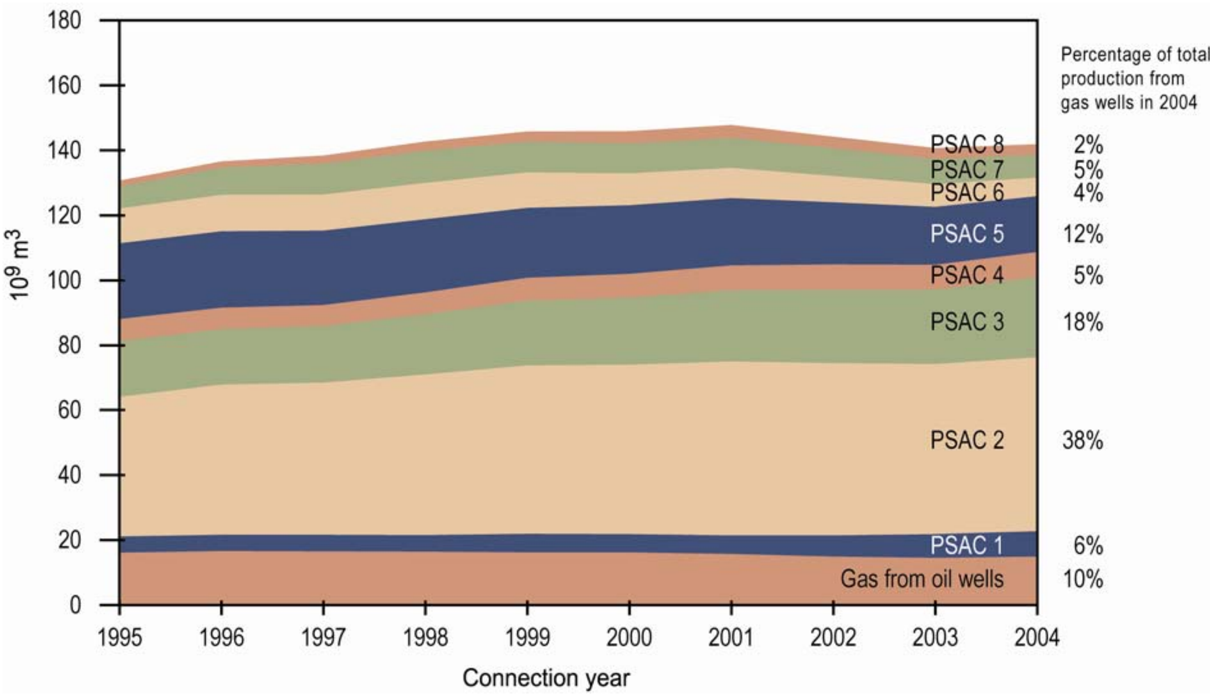

Figure 5.20. Marketable gas production by modified PSAC area

Conventional marketable gas production in Alberta from 1995 to 2004 is shown in **Figure 5.21**, along with the number of gas wells on production in each year. The number of producing gas wells has increased significantly year over year, while gas production has stabilized after reaching its peak in 2001. By 2004, the total number of producing gas wells increased to 89 200, from 37 000 wells in 1995. It now takes an increasing number of new gas wells each year to offset production declines in existing wells. A large number of new wells are drilled in southeastern Alberta, where well productivity is low.

Average gas well productivity has been declining over time. As shown in **Figure 5.22**, about 60 per cent of the operating gas wells produce less than 1 thousand (10^3) m^3/d. In 2004, these 54 100 gas wells operated at an average rate of 0.8 10^3 m^3/d per well and produced less than 10 per cent of the total gas production. Less than 1 per cent of the total gas wells produced at rates over 100 10^3 m^3/d but contributed 19 per cent of the total production.

The historical raw gas production by connection year in Alberta is presented in **Figure 5.23**. Generally, a surface loss factor of around 13 per cent can be applied to raw gas production to yield marketable gas production. The bottom band in **Figure 5.23** represents gas production from oil wells. Each band above represents production from new gas well connections by year. The percentages on the right-hand side of the figure represent the share of that band's production to the total production from gas wells in 2004. For example, 13 per cent of gas production in 2004 came from wells connected in that year. The figure shows that in 2004, almost 50 per cent of gas production came from gas wells connected in the last four years.

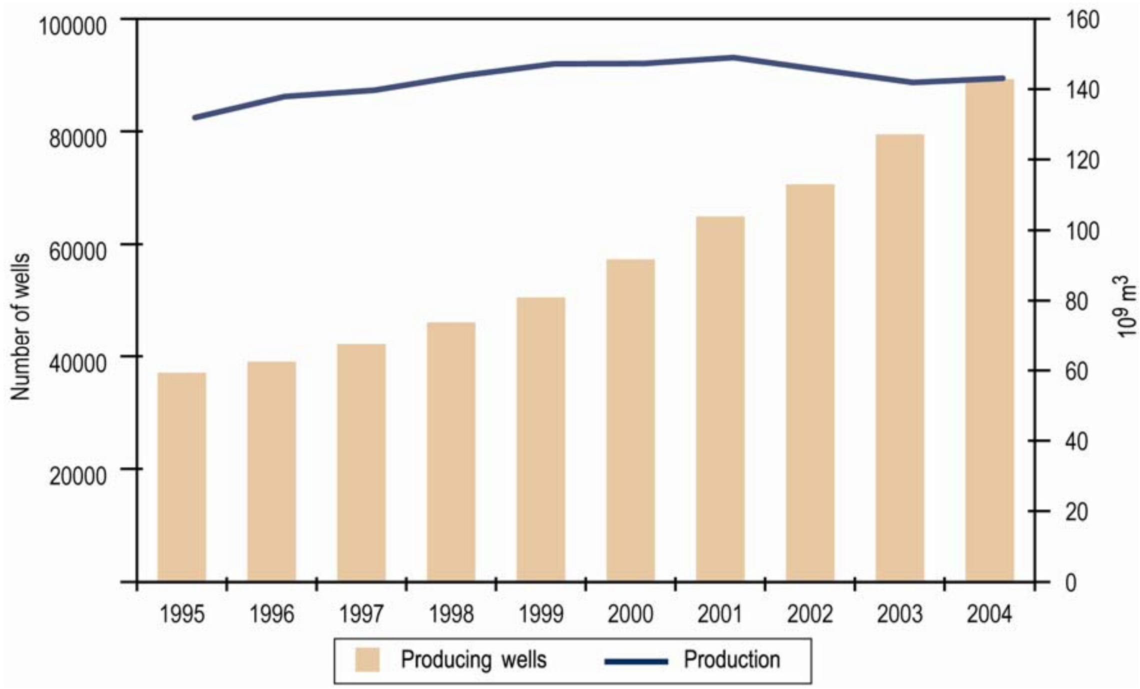

Figure 5.21. Conventional marketable gas production and the number of producing gas wells

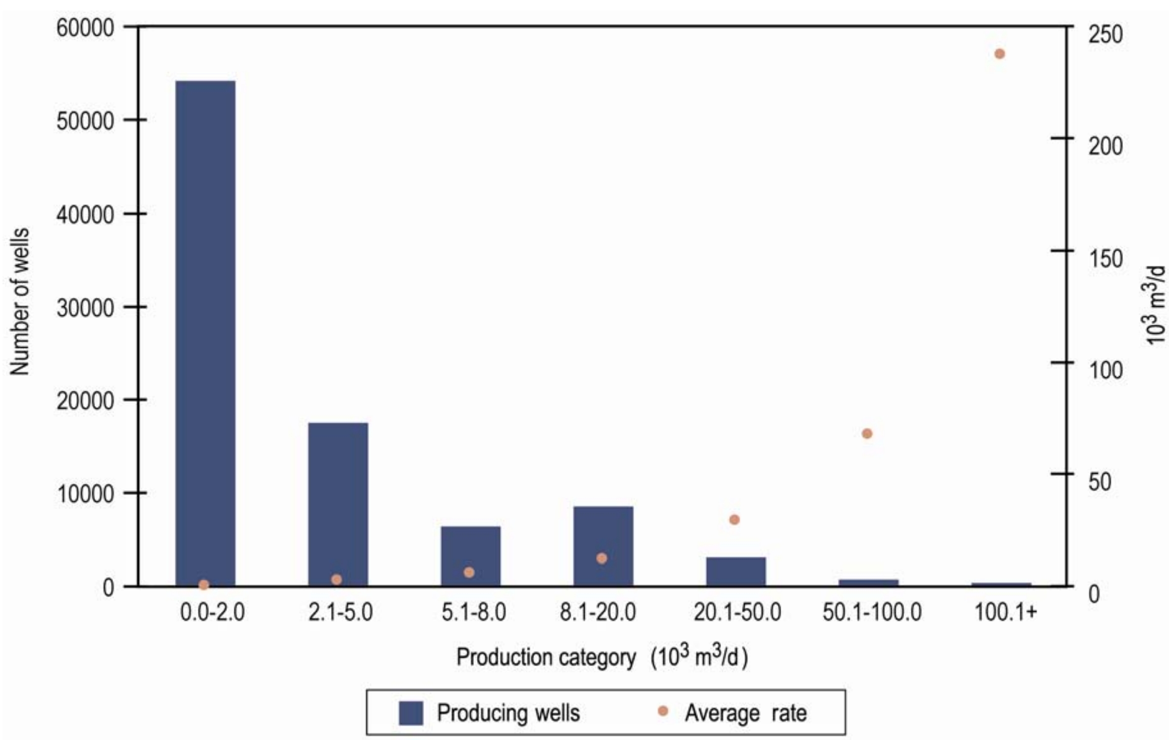

Figure 5.22. Natural gas well productivity in 2004

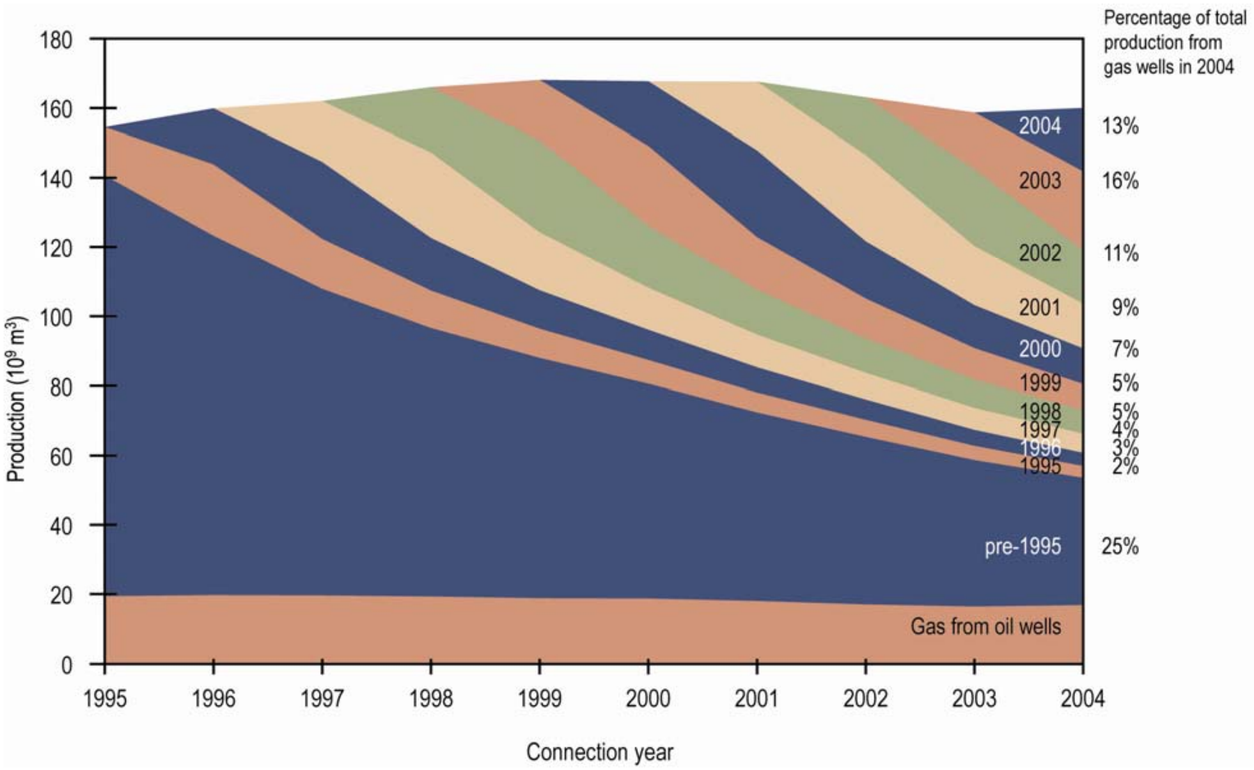

Figure 5.23. Raw gas production by connection year

Declines in natural gas production from new gas well connections from 1995 to 2002 have been evaluated after the wells drilled in a given year completed a full year of production.

Table 5.8 shows decline rates for gas wells connected from 1995 to 2002 with respect to the first, second, third, and fourth year of decline. Wells connected from the mid-1990s forward are exhibiting steeper declines in production in the first three years compared to wells connected in the earlier years. However, by the fourth year of production the decline rates have not changed significantly over time. The decline rates tend to stabilize at some 18 per cent from the fourth year forward.

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

Year wells connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1995	30	25	23	19
1996	31	27	21	18
1997	32	28	23	19
1998	32	28	24	18
1999	34	25	21	17
2000	34	25	17	
2001	32	25		
2002	32			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 5.24** shows the average initial productivity (peak rate) of new wells by connection year for the province and for wells in Southeastern Alberta (Area 3). Average initial productivities for new wells excluding Southeastern

Alberta are also shown in the figure. This chart shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average.

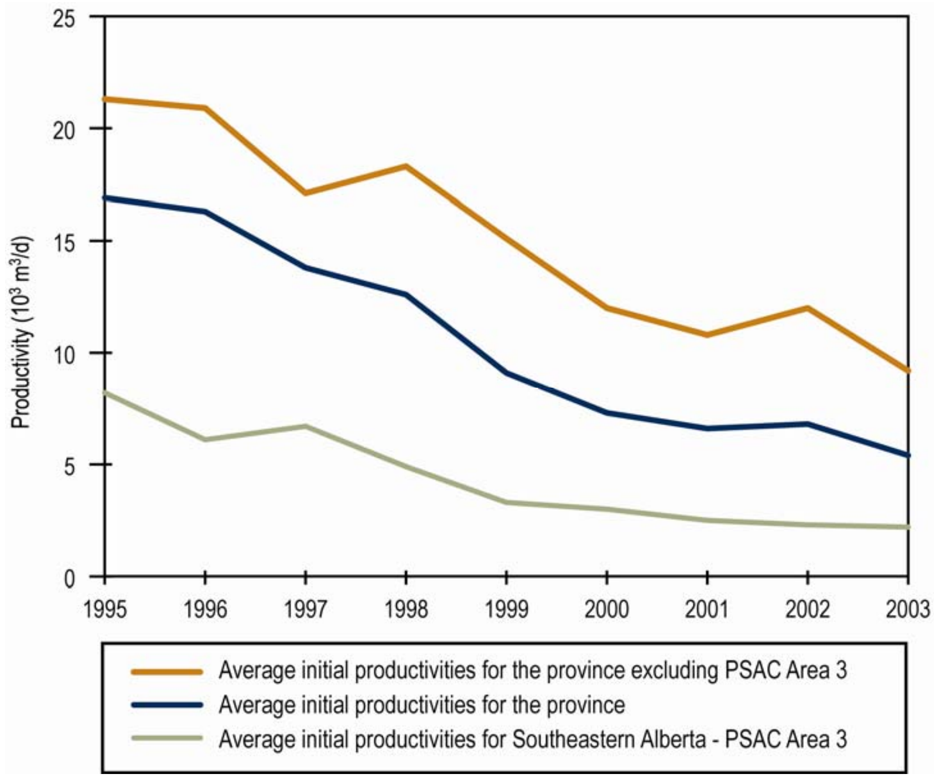

Figure 5.24. Average initial natural gas well productivity in Alberta

Based on the projection of natural gas prices provided in Section 1.2 and current estimates of reserves, the EUB expects that the number of new gas well connections in the province will remain high, at 12 000 wells per year. This high level of drilling activity is expected to be a challenge, but industry has shown that it is capable of drilling at a higher rate. **Figure 5.25** illustrates historical and forecast new well connections and prices.

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

Based on observed performance, gas production from existing gas wells at year-end 2004 is assumed to decline by 18 per cent per year initially and move to 16 per cent by the second half of the forecast period.

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

- The average initial productivity of new natural gas wells in Southeastern Alberta will be 2.0 10^3 m^3/d in 2005 and will decrease to 1.5 10^3 m^3/d by 2014.
- The average initial productivity of new natural gas wells in the rest of the province will be 8.5 10^3 m^3/d in 2005 and will decrease to 6.0 10^3 m^3/d by 2014.

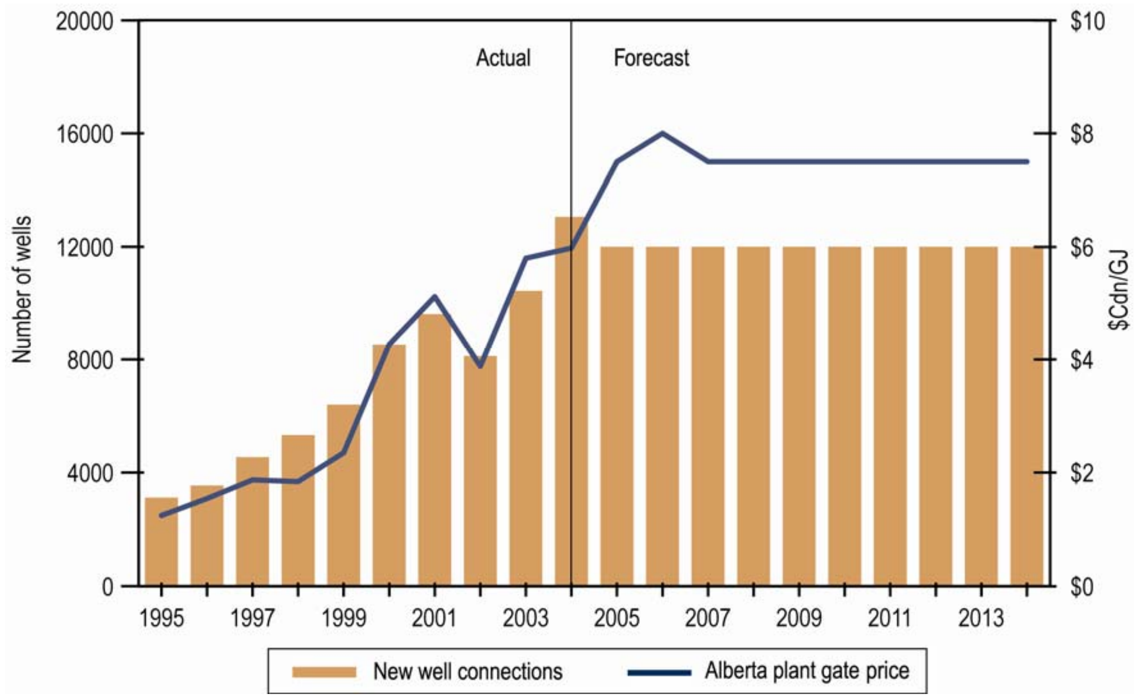

Figure 5.25. Alberta natural gas well activity and price

- Production from new wells will decline at a rate of 32 per cent the first year, 25 per cent the second year, 21 per cent the third year, and 18 per cent the fourth year and thereafter.
- Gas production from oil wells will decline by 2 per cent per year.

Based on the remaining established and yet-to-be-established reserves and the assumptions described above, the EUB generated the forecast of natural gas production to 2014, as shown in **Figure 5.26**. The production of natural gas from conventional reserves is expected to decrease from 141.7 10^9 m^3 to 112.3 10^9 m^3 by the end of the forecast period.

If conventional natural gas production rates follow the projection, Alberta will have recovered some 76 per cent of the 6276 10^9 m^3 of ultimate potential by 2014.

Figure 5.27 presents a comparison of raw natural gas production in Alberta to both Texas and Louisiana onshore over the past 40-year period. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta appears to be at that stage today. It is interesting to note that for the U.S. states represented here, gas production declined somewhat steeply after reaching peak production. However, over time production rates have been maintained at significant levels.

Gas production from sources other than conventional gas and oil wells includes processed gas from bitumen upgrading operations, natural gas from bitumen wells, and coalbed methane. **Figure 5.28** shows the historical and forecast volumes of production from the first two categories. In 2004, some 4.8 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 9.8 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells in thermal schemes was 1.4 10^9 m^3 in 2004 and is forecast to increase to 3.2 10^9 m^3 by 2014. This gas was used as fuel to create steam for its in situ operations.

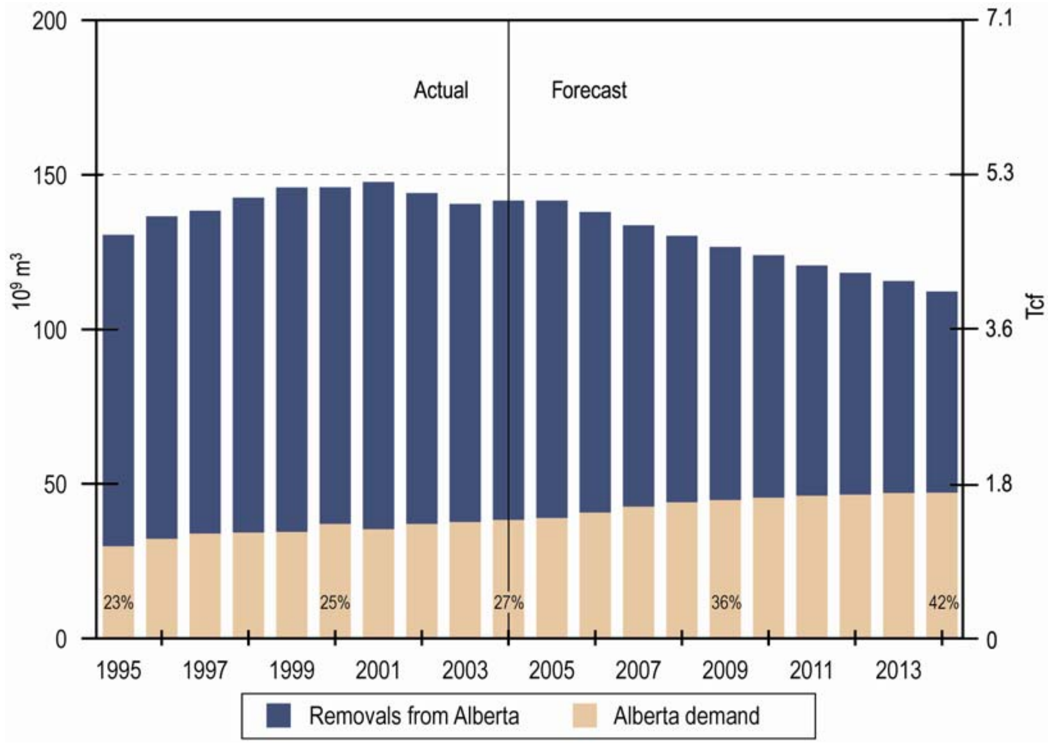

Figure 5.26. Disposition of conventional marketable gas production

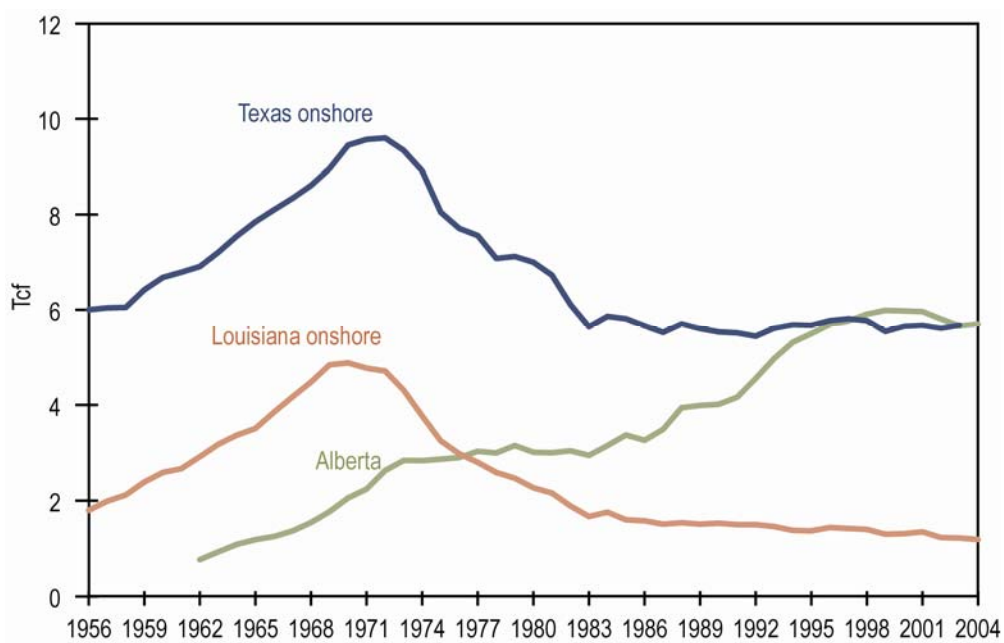

Figure 5.27. Comparison of natural gas production

Figure 5.29 shows the forecast of conventional natural gas production, along with gas production from other sources.

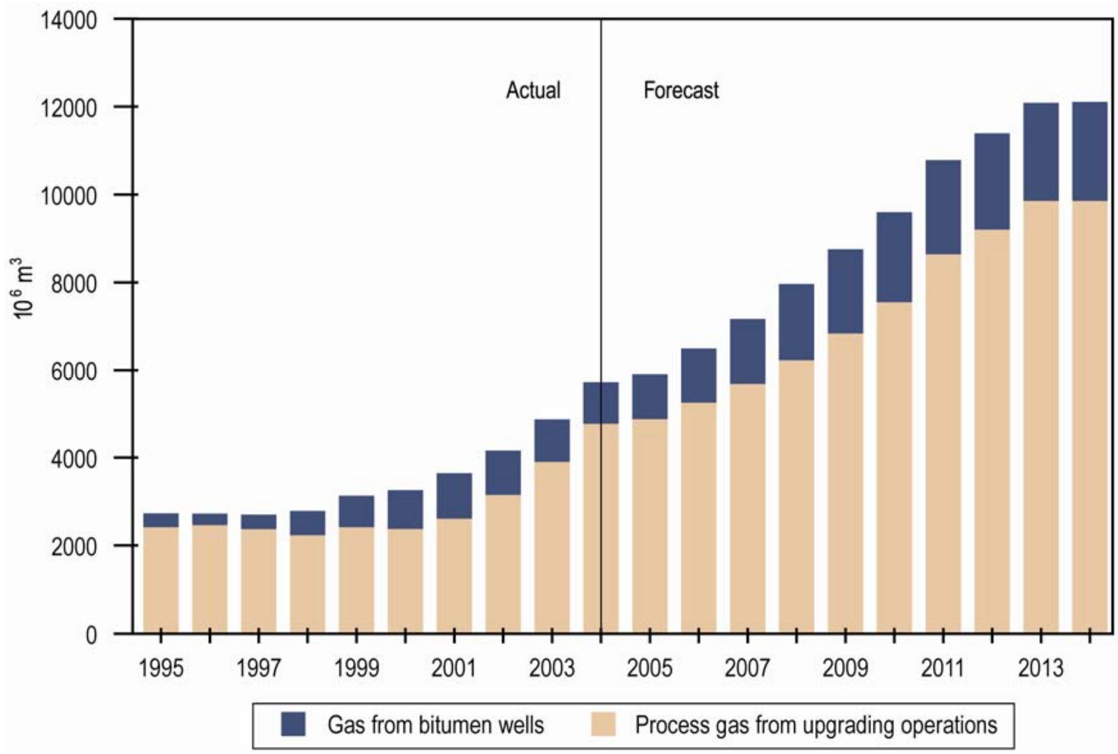

Figure 5.28. Gas production from bitumen upgrading and bitumen wells

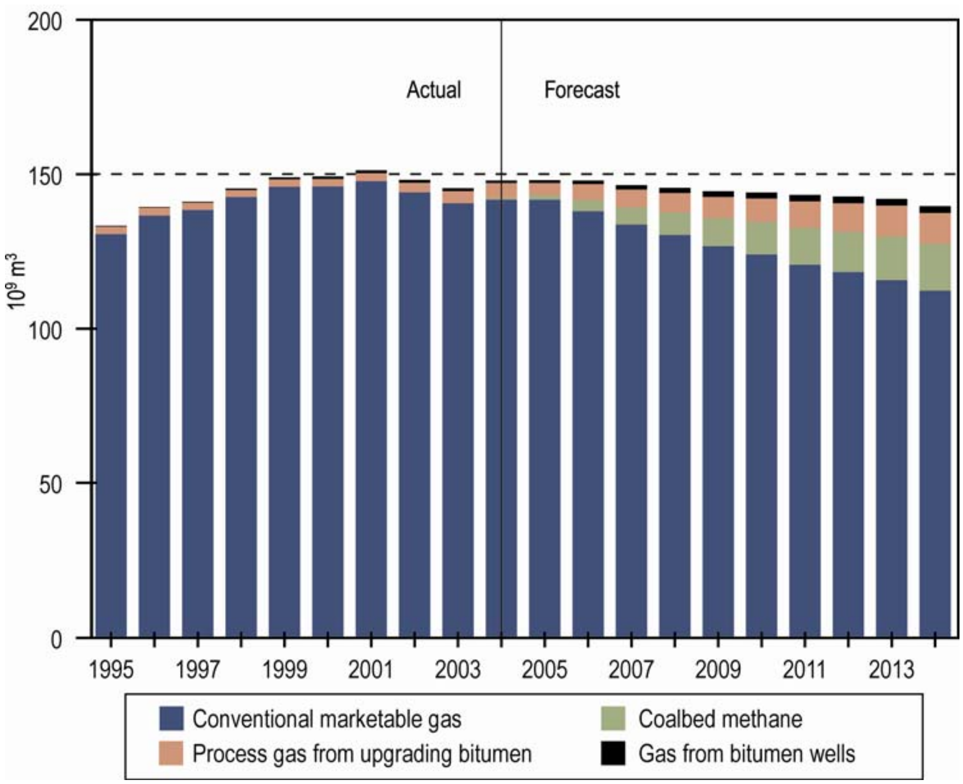

Figure 5.29. Total gas production in Alberta

5.2.2 Natural Gas Storage

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

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas supply rises, injection slows or ends, and production generally begins at high withdrawal rates. **Figure 5.30** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province.

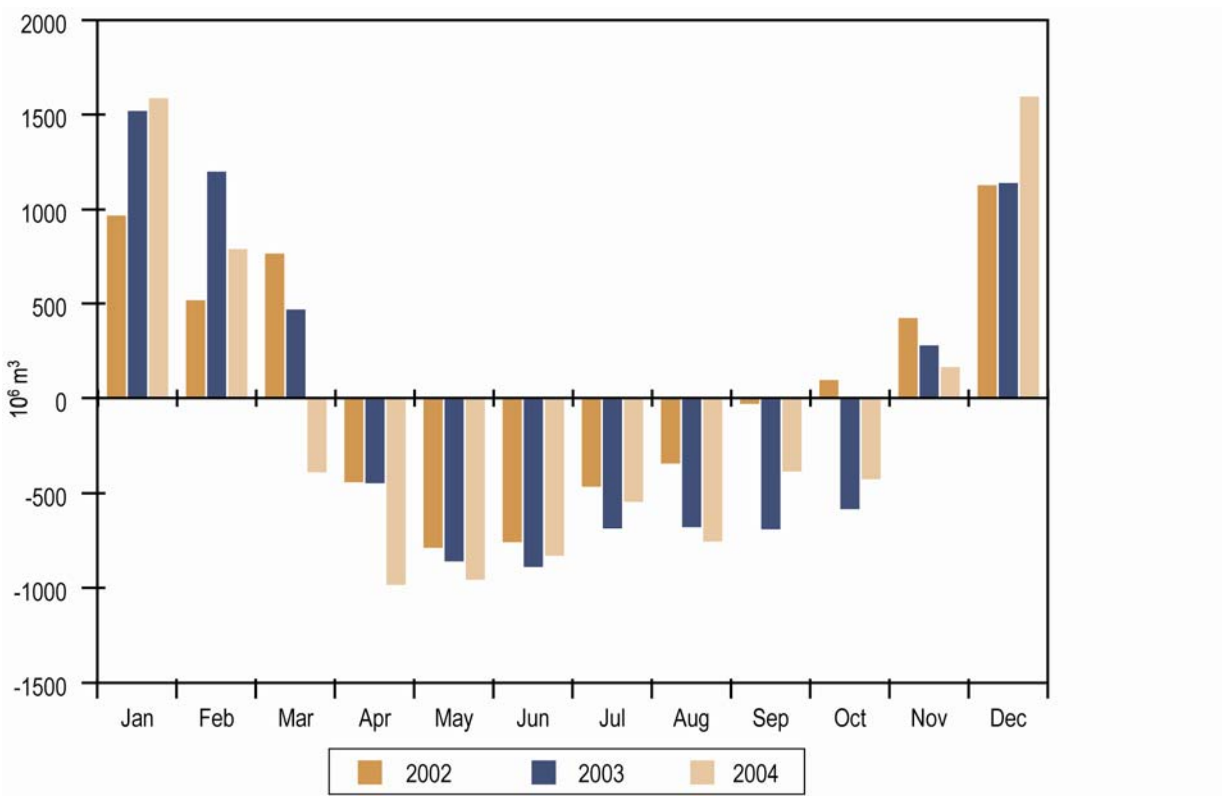

Figure 5.30. Alberta natural gas storage withdrawal volumes

Commercial natural gas storage pools, along with the operators and storage information, are listed in Table 5.9. EnCana temporarily ceased commercial storage operations at the Sinclair Gething D and Paddy C Pools as of April 1, 2004.

In 2004 natural gas injections exceeded withdrawals by 1029 10^6 m^3.

Marketable gas production volumes determined for 2004 were adjusted to account for the small imbalance in injection and withdrawal volumes to these storage pools. For the purpose of projecting future natural gas production, the EUB assumes that injections and withdrawals are balanced for each year during the forecast period.

Table 5.9. Commercial natural gas storage pools as of December 31, 2004

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2004 (10^6 m^3)	Withdrawal volumes, 2004 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	962	930
Countess Bow Island N & Upper Mannville M5M	EnCana Gas Storage	817	23 950	828	201
Crossfield East Elkton A & D	CrossAlta Gas Storage & Services Ltd.	1 197	14 790	1 399	653
Hussar Glauconitic R	Husky Energy	423	5 635	330	209
McLeod Cardium A	Pacific Corp Energy Canada Ltd.	986	16 900	501	425
McLeod Cardium D	Pacific Corp Energy Canada Ltd.	282	4 230	225	119
Sinclair Gething D & Paddy C	EnCana Gas Storage	282	5 634	0	114
Suffield Upper Mannville I & K, and Bow Island N & BB & GG	EnCana Gas Storage	2 395	50 715	1 571	2 136

5.2.3 Alberta Natural Gas Demand

The EUB reviews the projected demand for Alberta natural gas periodically. The focus of these reviews is on intra-Alberta natural gas use, and a detailed analysis is undertaken of many factors, such as population, economic activity, and environmental issues, that influence natural gas consumption in the province. Forecasting demand for Alberta natural gas in markets outside the province is done on a less rigorous basis. For Canadian ex-Alberta markets, historical demand growth and published estimates of other organizations are used in developing the forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets and the recent historical trends in meeting that demand.

Figure 5.26 shows Alberta natural gas demand and production. Gas removals from the province represent the difference between natural gas production and Alberta demand. In 2004, some 28 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the United States.

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 exports are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the EUB 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.

By the end of forecast period, domestic demand will reach 47 10^9 m^3, compared to 38 10^9 m^3 in 2004, representing 42 per cent of total production. **Figure 5.31** illustrates the breakdown of marketable natural gas demand in Alberta by sector.

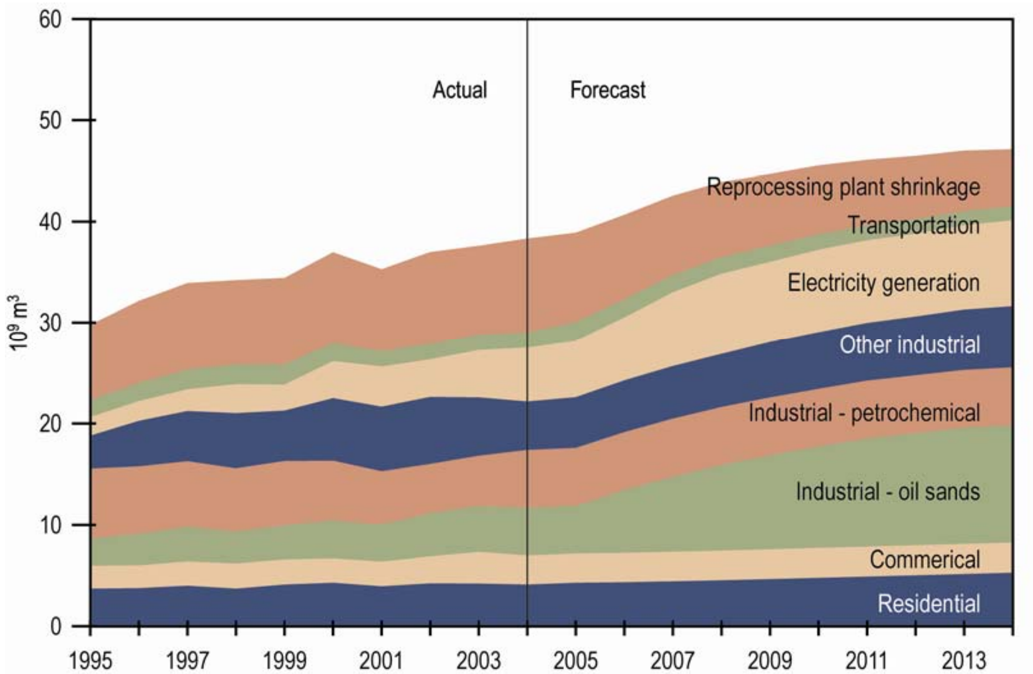

Figure 5.31. Alberta gas demand by sector

Residential gas requirements are expected to grow moderately over the forecast period at an average annual rate of 2.5 per cent. The key variables that impact residential gas demand are natural gas prices, population, the number of households, energy efficiencies, and the weather. Energy efficiency improvements prevent energy use per household from rising significantly. Commercial gas demand in Alberta has fluctuated over the past 10 years and is expected to remain flat over the forecast period. This is largely due to gains in energy efficiencies and a shift to electricity.

The significant increase in Alberta demand is due to increased development in the industrial sector. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil, shown in **Figure 5.31**, are expected to increase annually from 4.7 10^9 m^3 in 2004 to 12 10^9 m^3 by 2014. As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. Therefore, total gas demand in this sector is the sum of purchased gas, process gas, and solution gas produced at bitumen wells (see **Figure 5.28** for the latter two).

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. These companies are now exploring the option of self-sufficiency for their gas requirements. The existing bitumen gasification technology is one attractive alternative being pursued. If implemented, natural gas requirements for this sector could decrease substantially.

The electricity generating industry will also require increased volumes of natural gas to fuel some of the new plants expected to come on stream over the next few years. Natural gas requirements for electricity generation are expected to increase over the forecast period, from some 5.3 10^9 m^3 in 2004 to 8.5 10^9 m^3 by 2014.

6 Natural Gas Liquids

The EUB estimates remaining reserves of natural gas liquids (NGLs) based on volumes that are expected to be recovered from raw natural gas using existing technology and market conditions. The liquids reserves expected not to be removed from natural gas are included as part of the province's gas reserves discussed in Section 5.1. The EUB's projections on the overall recovery of each NGL component are explained in Section 5.1.8 and shown graphically in **Figure 5.10**.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs are summarized in Tables 6.1 and 6.2. **Figure 6.1** shows remaining established reserves of extractable NGLs compared to 2004 production.

Table 6.1. Established reserves and production of extractable NGLs as of December 31, 2004 (10^6 m^3 liquid)

	2004	2003	Change
Cumulative net production[a]			
Ethane	211.1	196.4	+14.7
Propane	231.2	222.9	+8.3[b]
Butanes	132.4	127.8	+4.6[b]
Pentanes plus	303.6	295.3	+8.3[b]
Total	878.3	842.4	+35.9
Remaining (expected to be extracted)			
Ethane	122.9	124.0	-1.1
Propane	71.3	69.4	+1.8
Butanes	41.5	41.9	-0.4
Pentanes plus	59.3	63.2	-3.9
Total	295.0	298.5	-3.6

[a] Production minus those volumes returned to the formation or injected to enhance the recovery of oil.
[b] May differ slightly with actual production as reported in *Statistical Series (ST) 3: Oil and Gas Monthly Statistics*.

Table 6.2. Reserves of NGLs as of December 31, 2004 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining raw reserves	185.6	83.6	46.0	59.3	374.5
Liquids expected to remain in dry marketable gas	62.6	12.3	4.5	0	79.4
Remaining established recoverable from					
Field plants	35.8	41.0	26.9	52.9	156.6
Straddle plants	80.5	28.7	13.4	5.9	128.5
Solvent floods	6.6	1.6	1.2	0.5	9.9
Total	122.9	71.3	41.5	59.3	295.0

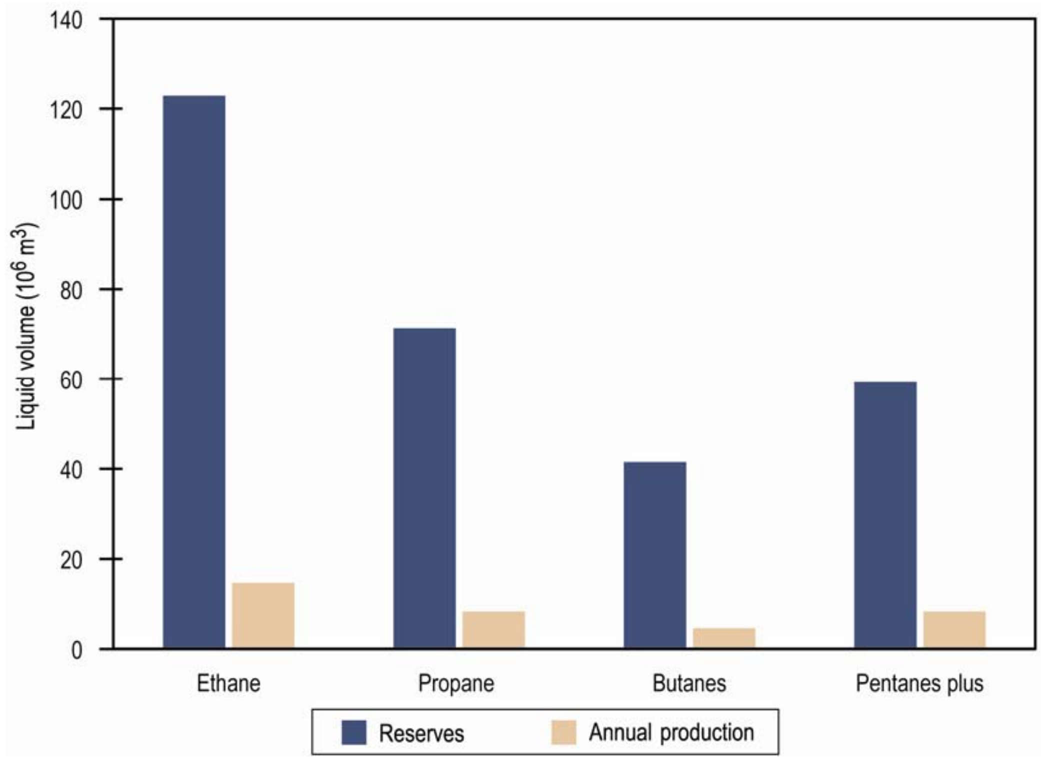

Figure 6.1. Remaining established NGL reserves expected to be extracted and annual production

6.1.2 Ethane

As of December 31, 2004, the EUB estimates remaining established reserves of extractable ethane to be 122.9 million cubic metres (10^6 m^3) in liquefied form. This estimate includes 6.6 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. This year the ethane volume remaining in solvent floods represents about 5 per cent of the total ethane reserves, compared to about 6 per cent last year. Presently there are only 10 pools under solvent flood, the largest being the Rainbow Keg River A, Rainbow Keg River F, and Judy Creek Beaverhill Lake A pools.

A review and adjustment of injected and produced solvent volumes from these 10 pools in 2004 resulted in a downward adjustment of ethane reserves from 8.3 10^6 m^3 to 6.6 10^6 m^3.

As shown in Table 6.2, there is an additional 62.6 10^6 m^3 (liquid) of ethane estimated to remain in the marketable gas stream and available for potential recovery. Ethane reserves are reported in **Figure 6.2**.

During 2004, the extraction of specification ethane was 14.7 10^6 m^3, compared to 13.7 10^6 m^3 produced in 2003. Although the EUB believes that ethane extraction at crude oil refineries and at plants producing synthetic crude oil might become viable in the future, it has not attempted to estimate the prospective reserves from those sources.

For individual gas pools, the ethane content of gas in Alberta falls within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in Appendix B, Table B.8, the volume-weighted average ethane content of all remaining raw gas was 0.052 mol/mol. Also listed

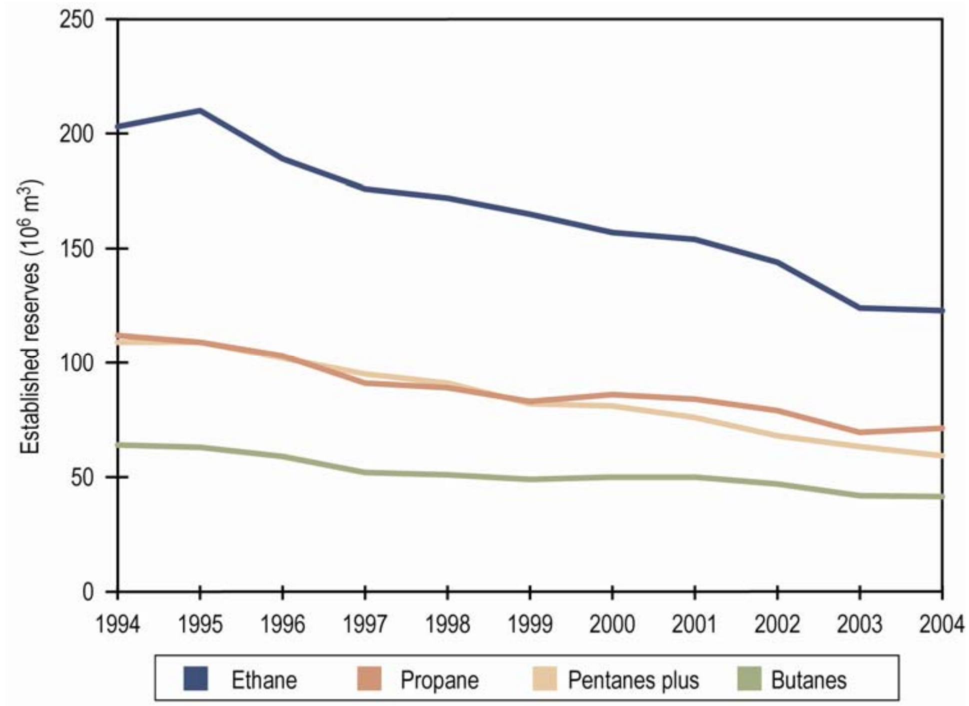

Figure 6.2. Remaining established reserves of natural gas liquids

in this table are ethane volumes recoverable from fields containing the largest ethane reserves and from solvent floods. The four largest fields, the Caroline, Ferrier, Pembina, and Wild River, account for 11.8 per cent of total ethane reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2004, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 71.3 10^6 m^3, 41.5 10^6 m^3, and 59.3 10^6 m^3 respectively. The overall changes in the reserves during the past year are shown in Table 6.2. Appendix B, Table B.9, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The six largest fields, the Ansell, Brazeau River, Caroline, Ferrier, Kaybob South, and Pembina, account for about 19 per cent of the total liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table. During 2004, propane and butanes recovery at crude oil refineries was 0.4 10^6 m^3 and 1.3 10^6 m^3 respectively.

A review and adjustment of injected and produced solvent volumes from these 10 pools in 2004 resulted in an increase in propane from 0.1 10^6 m^3 to 1.6 10^6 m^3.

6.1.4 Ultimate Potential

The remaining ultimate potential for liquid ethane is considered to be those reserves that could reasonably be recovered as liquid from the remaining ultimate potential of natural gas. Historically, only a fraction of the ethane that could be extracted had been recovered. However, the recovery has increased over time to about 50 per cent currently due to increased market demand. The EUB 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 183 10^9 m^3, the EUB estimates remaining ultimate potential of liquid ethane to be

455 10^6 m^3. The other 30 per cent, or 54.9 10^9 m^3, of ethane gas is expected to be sold for its heating value as part of the marketable gas.

For liquid propane, butanes, and pentanes plus together, the remaining ultimate potential reserves are 533 10^6 m^3. This assumes that remaining ultimate potential as a percentage of initial ultimate potential is similar to that of marketable gas, which currently stands at 45.5 per cent.

6.2 Supply of and Demand for Natural Gas Liquids

6.2.1 Supply of Ethane and Other Natural Gas Liquids

Ethane and other NGLs are recovered from several sources, including gas processing plants in the field that extract ethane, propane, butanes, and pentanes plus as products or recover an NGL mix from raw gas production. NGL mixes are sent from these field plants to fractionation plants to recover individual NGL specification products. Straddle plants (on NOVA Gas Transmission Lines and ATCO systems) recover NGL products from gas processed in the field. To compensate for the liquids removed, lean make-up gas volumes are purchased by the straddle plants and added to the marketable gas stream leaving the plants. Although some pentanes plus is recovered as condensate, the majority of the supply is recovered from the processing of natural gas.

The other source of NGL supply is from crude oil refineries, where small volumes of propane and butanes are recovered. **Figure 6.3** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

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

Table 6.3 lists the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2004. Ratios of the liquid production in m^3 to 10^6 m^3 marketable gas production are shown as well. Propane and butanes volumes recovered at crude oil refineries were 0.4 10^6 m^3 (1.1 10^3 m^3/d) and 1.2 10^6 m^3 (3.3 10^3 m^3/d) respectively.

Table 6.3. Ethane extraction volumes at gas plants in Alberta, 2004

Gas plants	Volume (10^6 m^3)	Percentage of total
Field plants	0.7	5
Fractionation plants	3.4	23
Straddle plants	10.6	72
Total	14.7	100

For the purpose of forecasting ethane and other NGLs, the richness and gas production volumes from established and new reserves 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.

Ethane extracted at Alberta processing facilities increased by 6 per cent, from 37.5 10^3 m^3/d in 2003 to 40.1 10^3 m^3/d in 2004. Some 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 2004.

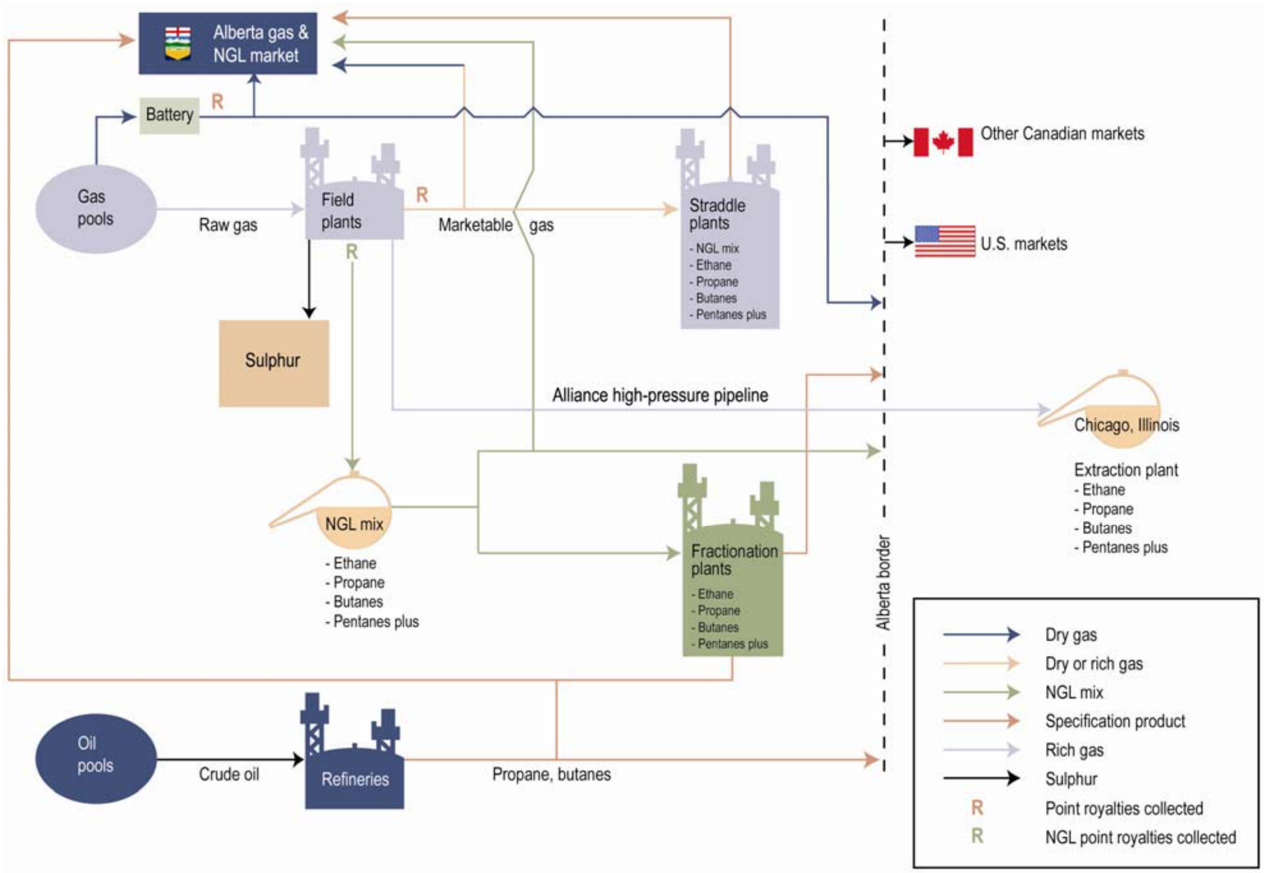

Figure 6.3. Schematic of Alberta NGL flows

It is expected that ethane recovery will increase to 41.2 10^3 m^3/d in 2005 and hold there for the remainder of the forecast period, as shown in **Figure 6.4**. Current processing plant capacity for ethane in Alberta is some 60 10^3 m^3/d and is not a restraint to recovering the volumes forecast. Based on the historical ethane content of marketable gas in Alberta, adequate volumes of ethane are available to meet the forecast demand. In fact, additional volumes of ethane are available for extraction, should the demand increase further.

Over the forecast period, ratios of propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas are expected to remain constant, as shown in Table 6.4. **Figures 6.4** to **6.7** show forecast production volumes to 2014 for propane, butanes, and pentanes plus respectively. No attempt has been made to include ethane and other NGL production from the solvent flood banks injected into pools throughout the province to enhance oil recovery.

Table 6.4. Liquid production at gas plants in Alberta, 2004 and 2014

	2004			**2014**		
Gas Liquid	**Yearly production (10^6 m^3)**	**Daily production (10^3 m^3/d)**	**Liquid/ gas ratio ($m^3/10^6$ m^3)**	**Yearly production (10^6 m^3)**	**Daily production (10^3 m^3/d)**	**Liquid/ gas ratio ($m^3/10^6$ m^3)**
Ethane	14.7	40.1	104	15.1	41.4	134
Propane	8.3	22.7	59	6.6	18.1	59
Butanes	4.6	12.6	32	3.6	9.9	32
Pentanes plus	8.3	22.7	59	6.6	18.1	59

6.2.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in 2004, some 97 per cent was used in Alberta as feedstock, while the remainder was removed from the province. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas in the province, with four plants using ethane as feedstock for the production of ethylene. Small volumes of ethane are exported from the province by the Cochin pipeline under removal permits.

With global economics strengthening, demand for petrochemical products is growing rapidly, despite record high prices. Even with robust industry prospects for new growth opportunities, global capacity growth is likely to lag demand. The historic 6 cents per pound cash cost advantage in Alberta for ethylene compared to U.S. ethylene production, which relies on natural gas liquids as feedstock, turned into a 10 cent per pound cost advantage in the last 6 months of 2004.

As shown in **Figure 6.4**, Alberta demand for ethane is projected to be 39.4 10^3 m^3/d for the forecast period, with all four ethylene plants running at 90 per cent of capacity. 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. For purposes of this forecast, it was assumed that no new ethylene plants will be built during the forecast period requiring Alberta ethane as feedstock.

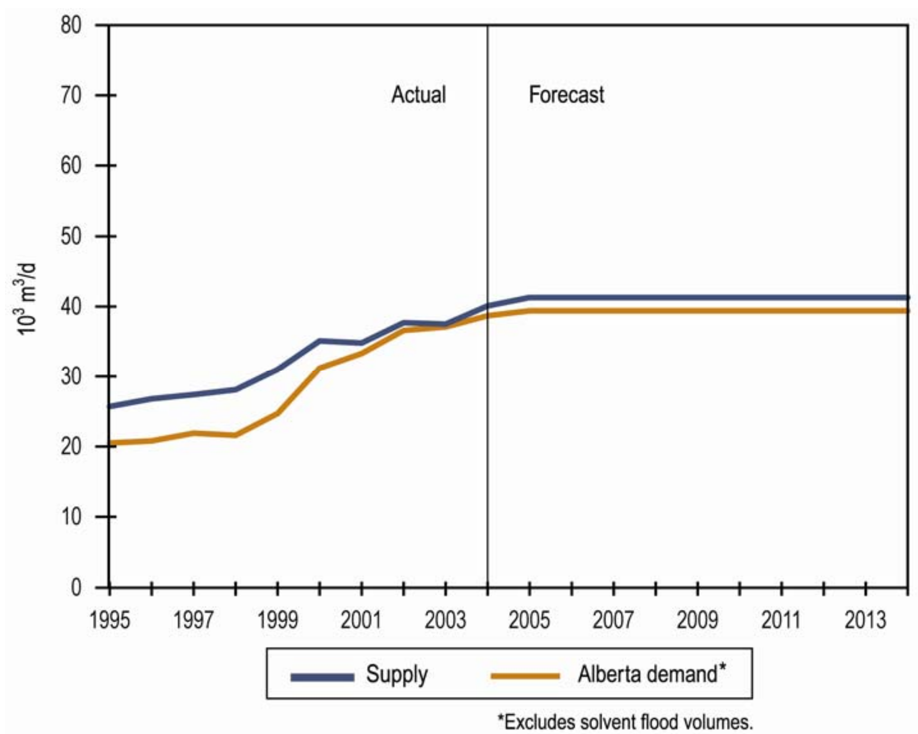

Figure 6.4. Ethane supply and demand

Construction of the Joffre feedstock pipeline is complete, and commercial operations will begin in 2005 to transport a wide range of feedstocks, such as propane and other natural gas liquids, from Fort Saskatchewan to Joffre, Alberta. These feedstocks will supplement the ethane supplies now used at the petrochemical plants at Joffre. Three of the four ethylene plants are located there, with the fourth in Fort Saskatchewan.

For longer term growth opportunities, the petrochemical industry may consider an additional source of ethane from process gas from Fort McMurray oil sands upgraders. The majority of the process gas from oil sands upgraders is presently being used as fuel for oil sands operations. Currently some natural gas liquids (C3+) are being extracted from Suncor's process gas volumes and sent for fractionation into specification products at Redwater.

Figure 6.5 shows Alberta demand for propane compared to the total available supply from gas processing plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Small volumes of propane are currently being used to supplement ethane supplies at petrochemical facilities, and this is expected to continue through the forecast period.

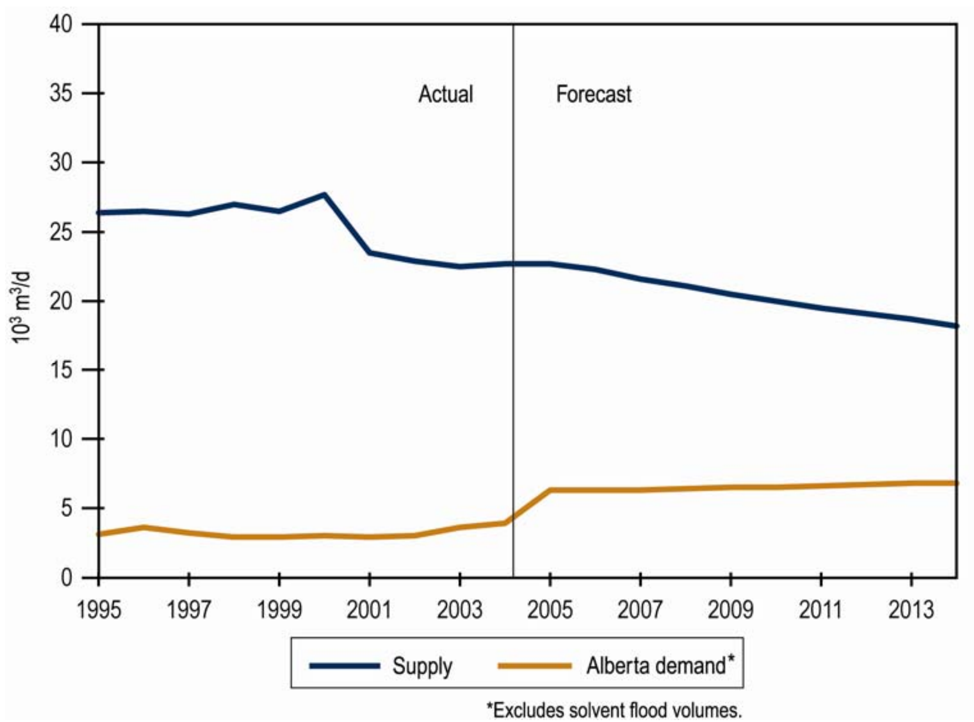

Figure 6.5. Propane supply and demand from natural gas production

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

Figure 6.7 shows Alberta demand for pentanes plus compared to the total available supply. Alberta pentanes plus is used as diluent for transporting heavy crude oil and bitumen. Diluent is required to increase the API gravity and reduce the viscosity of heavy crude oil and bitumen to facilitate transportation through pipelines. It is assumed that heavy crude oil requires some 5.5 per cent diluent for Bow River and 17 per cent for

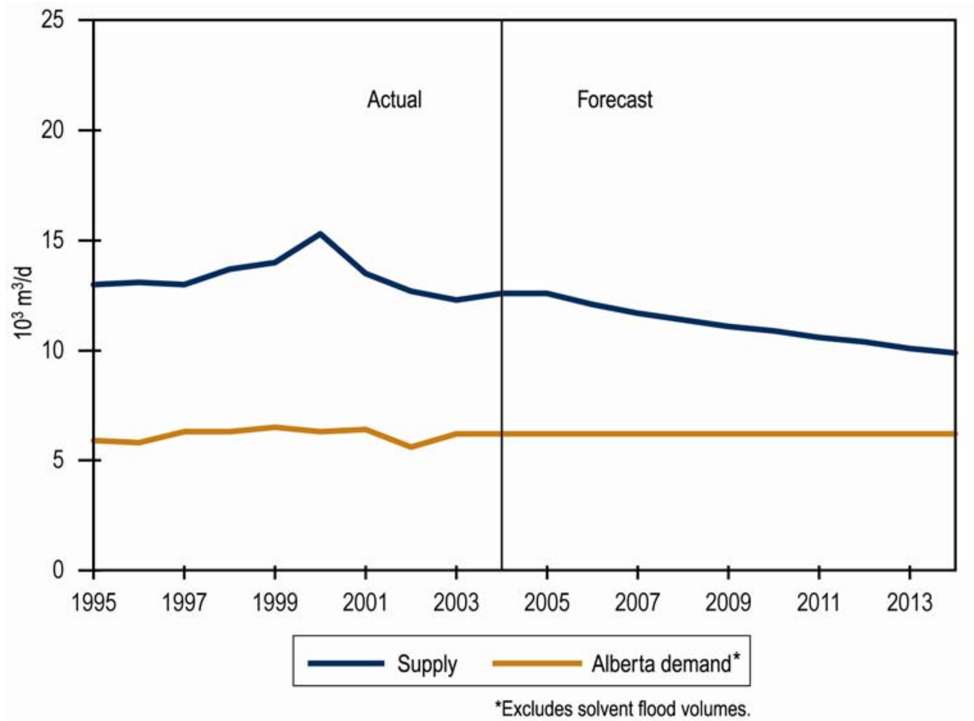

Figure 6.6. Butanes supply and demand from natural gas production

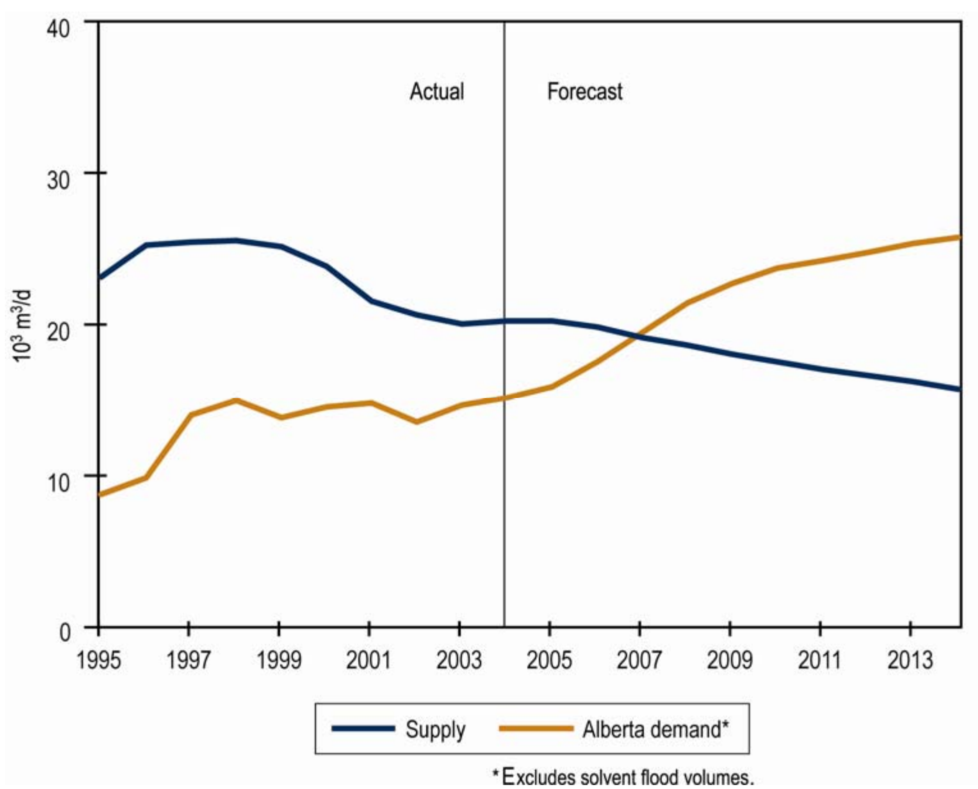

Figure 6.7. Pentanes plus supply and demand

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

Over the forecast period, pentanes plus demand as diluent is expected to increase from 18.4 10^3 m^3/d to 28.2 10^3 m^3/d. The diluent requirement for heavy crude oil is expected to decline from 2.8 10^3 m^3/d in 2004 to 1.9 10^3 m^3/d by the end of the forecast period, due to declining crude oil production. However, diluent requirements for bitumen are expected to increase dramatically, from 13.9 10^3 m^3/d in 2004 to 25.5 10^3 m^3/d by 2014. Shortages of pentanes plus as diluent are forecast to occur by 2007 if alternatives are not considered.

Several steps were taken to reduce the pentanes plus diluent requirements in past years, including the Enbridge pipeline system implementing a new viscosity standard in 1999, which reduced the diluent requirement by about 10 per cent. In the forecast period, diluent requirements for pentanes plus are expected to be offset by future upgrading of in situ bitumen production to synthetic crude oil (SCO) from projects such as OPTI/Nexen's Long Lake project and Petro-Canada's MacKay River project. In addition, SCO is being used as a diluent for some crude bitumen production. As well, small volumes of pentanes plus from outside of Alberta are being brought into the province by rail for use as diluent.

Industry is currently using and assessing alternatives to pentanes plus due to its limited supply, such as

- upgrading increasing volumes of bitumen to SCO within Alberta;
- blending increasing volumes of bitumen with SCO or light sweet oil;
- blending refinery naptha and distillates, due to their low viscosity and density; and
- heating bitumen and insulating pipelines, with little or no diluent required to move bitumen through pipelines.

7 Sulphur

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The EUB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2004, to be some 85.1 million tonnes (10^6 t). The changes in sulphur reserves during the past year are shown in Table 7.1.

Table 7.1. Reserves of sulphur as of December 31, 2004 (10^6 t)

	2004	2003	Change
Initial established reserves			
Natural gas	251.5	244.7	+6.8
Crude bitumen[a]	67.7	67.7	0.0
Total	319.2	312.4	+6.8
Cumulative net production			
Natural gas	218.4	212.8	+5.6
Crude bitumen[b]	15.7	14.5	+1.2
Total	234.1	227.3	+6.8
Remaining established reserves			
Natural gas	33.1	31.9	+1.2
Crude bitumen[a]	52.0	53.2	-1.2
Total	85.1	85.1	0.0

[a] Reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2004. Reserves from the entire surface mineable area are larger.
[b] Production from surface mineable area only.

7.1.2 Sulphur from Natural Gas

The EUB recognizes 33.1 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2004. This estimate 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 EUB estimates the ultimate potential for sulphur from natural gas to be 328 10^6 t, with an additional 40 10^6 t from ultra-high hydrogen sulphide (H_2S) pools. Based on the initial established reserves of 244.3 10^6 t, this leaves 123.8 10^6 t yet to be established from future discoveries of conventional gas.

The EUB's sulphur reserves estimates from natural gas are shown in Table 7.2. Fields containing the largest recoverable sulphur reserves are listed individually and those containing less are grouped under "All other fields." Fields with the most notable change in sulphur reserves over the past year are

- Blackstone, Coleman, and Okotoks fields, which had a combined increase of about 3.5 10^6 t as a result of positive revisions to gas reserves in these fields, and
- Caroline field, which had a decrease of 1.6 10^6 t as a result of production.

Table 7.2. Remaining established reserves of sulphur from natural gas as of December 31, 2004

Field	Remaining reserves of marketable gas ($10^6\ m^3$)	H_2S content[a] (%)	Remaining established reserves of sulphur Gas ($10^6\ m^3$)	Remaining established reserves of sulphur Solid (10^3 t)
Benjamin	2 613	4.8	150	203
Bighorn	2 341	7.2	204	276
Blackstone	6 994	10.5	971	1 317
Brazeau River	11 216	6.1	877	1 189
Burnt Timber	2 257	14.1	438	594
Caroline	9 521	20.3	3 610	4 895
Cecilia	4 403	3.4	176	238
Coleman	2 228	26.7	883	1 198
Crossfield	4 329	15.1	989	1 340
Crossfield East	3 196	27.9	1 553	2 106
Elmworth	10 798	1.5	193	262
Garrington	4 155	5.6	310	421
Hanlan	5 330	8.9	626	849
Jumping Pound West	5 418	6.3	434	588
Kaybob South	10 714	3.6	482	654
La Glace	2 811	6.4	210	285
Lambert	622	18.5	175	237
Limestone	7 144	9.3	862	1 169
Lone Pine Creek	1 672	7.8	167	227
Moose	2 668	10.7	368	500
Obed	935	12.7	157	212
Okotoks	2 507	32.9	1 662	2 254
Pine Creek	4 319	6.7	362	491
Rainbow	7 677	2.1	207	280
Rainbow South	3 856	5.6	318	431
Ricinus West	686	27.8	313	425
Waterton	5 926	22.7	2 224	3 016
Wildcat Hills	6 223	3.1	225	305
Windfall	2 821	12.3	487	661
Subtotal	135 380	10.6	19 633	26 622
All other fields	991 402	0.4	4 776	6 497
Total	1 126 782	1.9	24 409	33 119

[a] Volume-weighted average.

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, an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in products including coke.

It is currently estimated that some 208 10^6 t of elemental sulphur will be recoverable from the 5.1 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the surface-mineable area. These sulphur reserves were estimated by multiplying the remaining established reserves of crude bitumen by a factor of 40.5 t/1000 m^3 of crude bitumen. This ratio was revised from previous estimates to reflect both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology yields a higher elemental sulphur production than does an alternative carbon-rejection technology, since a larger percentage of the sulphur in the bitumen remains in upgrading residues, as opposed to being converted to H_2S.

If less of the mineable crude bitumen reserves 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, then the total sulphur reserves will be less. However, if some of the in situ crude bitumen reserves are upgraded in Alberta, as is currently planned, then the sulphur reserves will be higher. The EUB is reviewing these future development scenarios and will report the changes in a future edition of this report.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only a portion of the surface-mineable established crude bitumen reserves is under active development at the Suncor, Syncrude, and Albian Sands projects. The EUB has estimated the initial established sulphur reserves from these projects to be 67.7 10^6 t. A total of 15.7 10^6 t of elemental sulphur has been produced from these projects, leaving a remaining established reserve of 52 10^6 t. During 2004, 1.2 10^6 t of elemental sulphur were produced from the three active 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 synthetic crude oil (SCO), and refining of crude oil into refined petroleum products. In 2004, Alberta produced 6.9 10^6 t of sulphur, of which 5.6 10^6 t was derived from sour gas, 1.3 10^6 t from upgrading of bitumen to SCO, and just 11 thousand (10^3) t from oil refining. Sulphur production from these sources is depicted in **Figure 7.1**.

While sulphur production from sour gas is expected to decrease from 5.6 10^6 t in 2004 to 4.5 10^6 t, or some 20 per cent, sulphur recovery in the bitumen upgrading industry is expected to increase to 4.0 10^6 t from 1.3 10^6 t by the end of the forecast period. **Figure 7.2** shows sulphur production from oil sands upgrader operations for 2003 and 2004. The Alberta refineries are also expected to replace conventional crude and synthetic crude with bitumen, as integration of bitumen upgrading and refining takes place in this forecast period. With this integration, the sulphur recovery will increase from 20 10^3 t in 2004 to 54 10^3 t by 2014. Total sulphur production is expected to reach 8.5 10^6 t by the end of forecast period.

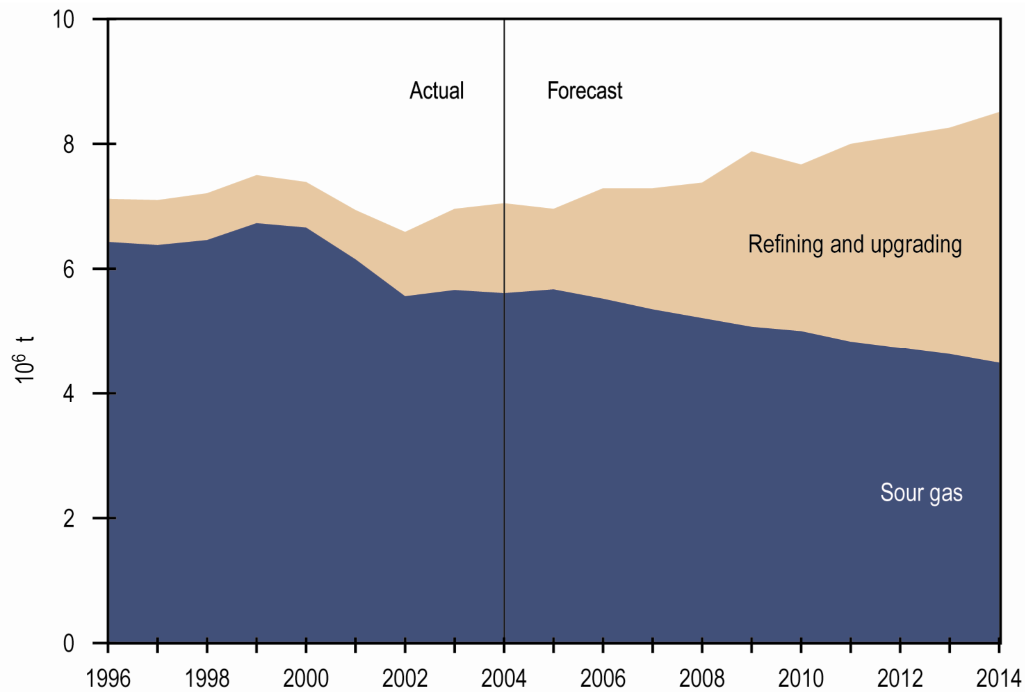

Figure 7.1. Sources of Alberta sulphur production

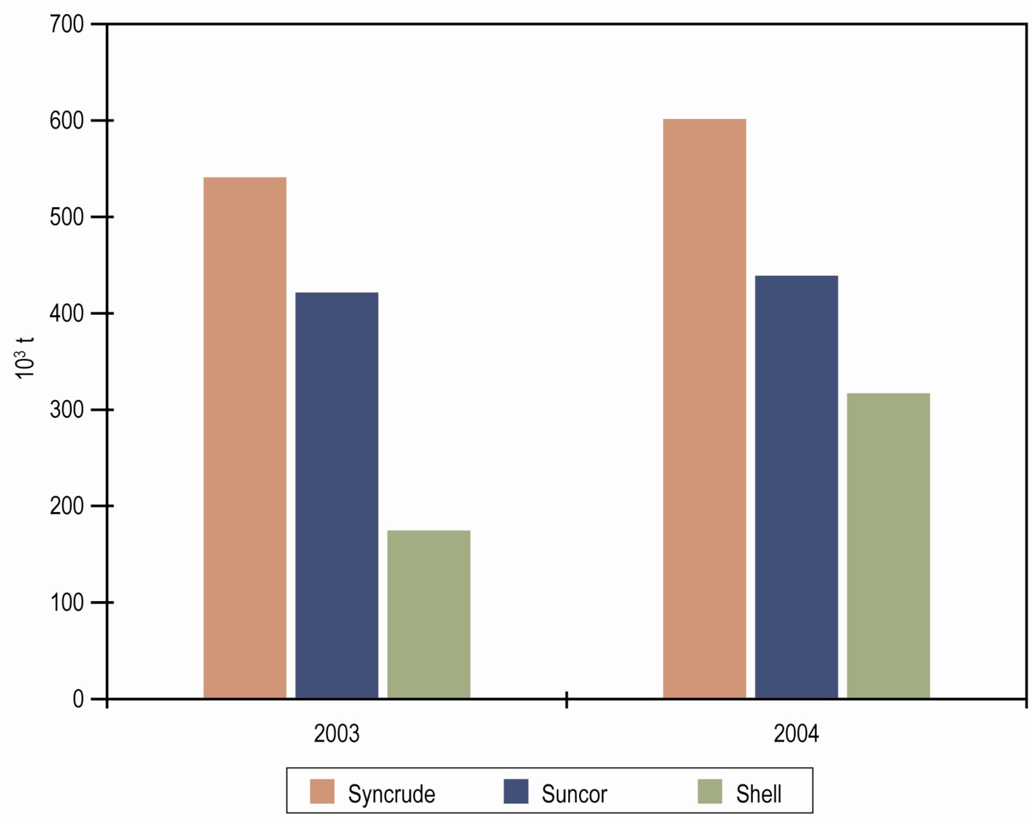

Figure 7.2. Sulphur production from oil sands

7.2.2 Sulphur Demand

Demand for sulphur within the province in 2004 was only about 250 10^3 t. It was used in production of phosphate fertilizer and kraft pulp and in other chemical operations. Some 97 per cent of the sulphur marketed by Alberta producers was shipped outside the province, primarily to United States, Asia Pacific, and North Africa.

In the early 1990s, a number of traditionally sulphur-importing countries installed sulphur-recovery equipment in oil refineries and other sulphur-emitting facilities, largely for environmental reasons. Consequently, many of these countries became self-sufficient in sulphur and the price declined significantly. Under such low price conditions, many of Alberta's competitors ceased production of sulphur, enabling Alberta's market share to rise throughout the late 1990s. In the last three years, China has increased its sulphur imports from Canada substantially. **Figure 7.3** outlines the export volumes sent to markets outside of North America in 2003 and 2004. Clearly China accounts for the majority of exports to foreign countries.

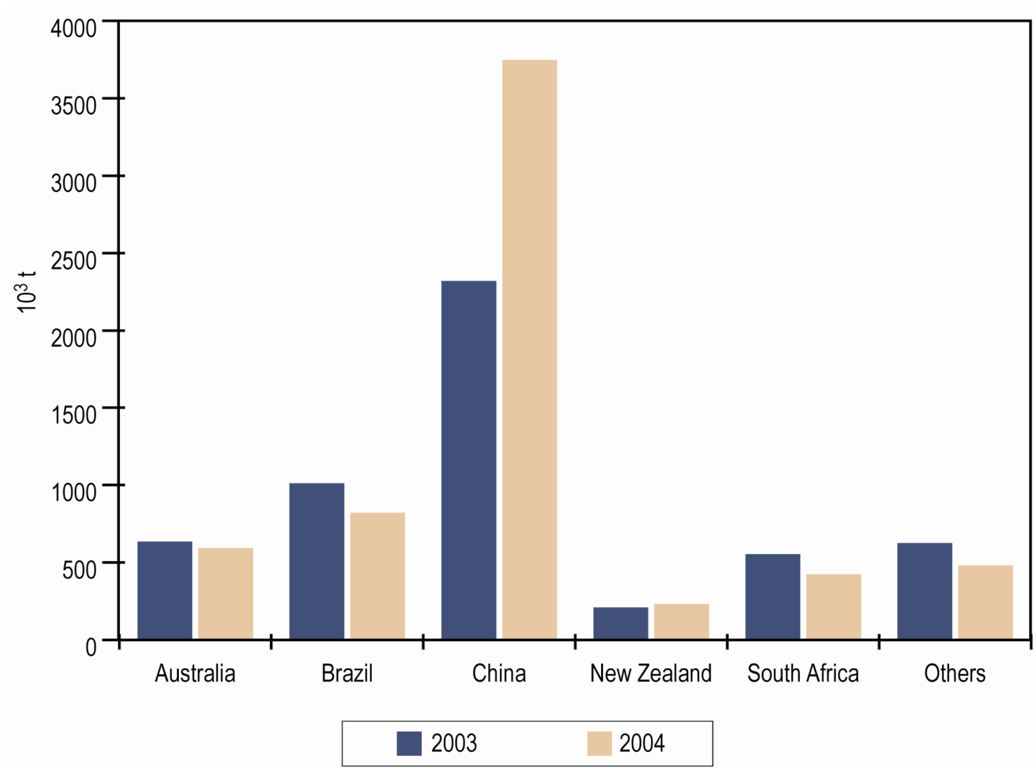

Figure 7.3. Canadian offshore sulphur exports

Increased global demand for sulphur resulted in a major price change, from Cdn$16/t in 2001 to $40/t in 2004. The export demand for sulphur is expected to increase over the next few years. Demand for Alberta sulphur is expected to rise slowly, reaching 7.4 10^6 t per year by the end of the forecast period. **Figure 7.4** depicts the Alberta demand and sulphur removal.

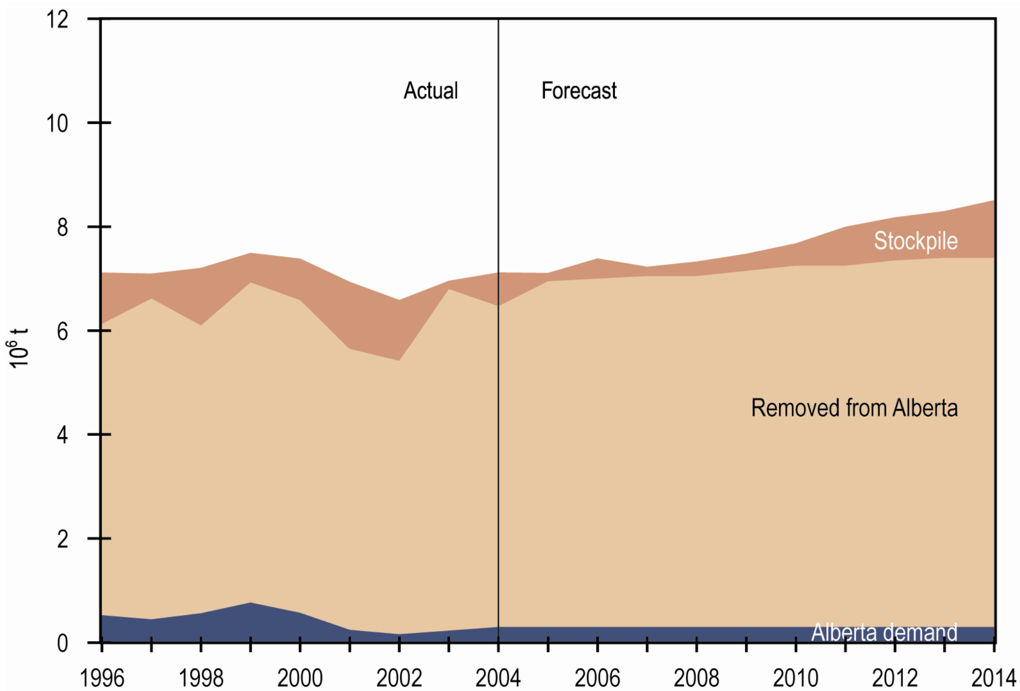

Figure 7.4. Sulphur demand and supply in Alberta

7.2.3 Imbalances between Sulphur Supply and Demand

Because elemental sulphur (in contrast to sulphuric acid and the energy resources described in this document) 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, as was the case over the period 1985-1991, sulphur is withdrawn from stockpiles; if supply exceeds demand, as has been the case since 1992, sulphur is added to stockpiles. Sulphur stockpiles are expected to grow until markets recover from the current glut. Changes to the sulphur inventory are illustrated in **Figure 7.4** as the difference between total supply and total demand.

8 Coal

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

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

8.1 Reserves of Coal

8.1.1 Provincial Summary

The EUB estimates the remaining established reserves of all types of coal in Alberta at December 31, 2004, to be 33.6 gigatonnes (Gt).[1] Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods, 10.8 Gt is recoverable by surface mining methods, and 1.16 Gt is within permit boundaries of mines active in 2004. Table 8.1 gives a summary by rank of resources and reserves from 244 coal deposits.

Table 8.1. Established initial in-place resources and remaining reserves of coal in Alberta as of December 31, 2004[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves	Remaining reserves in active mines
Low- and medium-volatile bituminous[b]					
Surface	1.74	0.811	0.219	0.592	
Underground	5.06	0.738	0.105	0.634	
Subtotal	6.83[c]	1.56[c]	0.324[d]	1.24[c]	0.179
High-volatile bituminous					
Surface	2.56	1.89	0.142	1.75	
Underground	3.30	0.962	0.047	0.914	
Subtotal	5.90[c]	2.88[c]	0.189[d]	2.69[c]	0.227
Subbituminous[e]					
Surface	13.6	8.99	0.651	8.34	
Underground	67.0	21.2	0.068	21.1	
Subtotal	80.7[c]	30.3[c]	0.720	29.6[c]	0.755
Total[c]	93.7[c]	34.8[c]	1.23	33.6[c]	1.161

[a] Tonnages have been rounded to three significant figures.
[b] Includes minor amounts of semi-anthracite.
[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.
[d] Difference due to rounding.
[e] Includes minor lignite.

[1] Giga = 10^9; 1 tonne = 1000 kilograms.

Minor changes in remaining established reserves from December 31, 2003, to December 31, 2004, resulted from increases in cumulative production. During 2004, the low- and medium-volatile, high-volatile, and subbituminous production tonnages were 0.001 Gt, 0.003 Gt, and 0.021 Gt respectively, a decrease for all three coal ranks from 2003.

8.1.2 Initial in-Place Resources

Several techniques, in particular the block kriging, grid, polygon, and cross-section methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground-mineable coal.

In general, shallow coal is mined more cheaply by surface than by underground methods; such coal is therefore classified as surface-mineable. At some stage of increasing depth and strip ratio, the advantage passes to underground mining; this coal is considered underground-mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio, designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

8.1.3 Established Reserves

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

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

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that in addition to the coal previously excluded, only a percentage of the remaining deposit areas would be mined. Thus a "deposit factor" has been allowed for where, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region,[2] 70 per cent in the foothills, and 90 per cent in the plains.

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 considered recoverable by underground methods.

Any developer wishing to mine coal in Alberta must first obtain a permit and licence from the EUB. An application for a permit must include extensive information on such matters as coal reserves, proposed mining methods, and marketing of coal. Coal reserves within the applied-for mine area must be at least sufficient to meet the marketing plans of the applicant.

[2] The EUB has designated three regions within Alberta where coals of similar quality and mineability are recovered.

Table 8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2004.

Table 8.2. Established resources and reserves of coal under active development as of December 31, 2004

Rank Mine	Permit area (ha)	Initial in-place resources (Mt)[a]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves[b] (Mt)
Low- and medium-volatile bituminous					
Luscar	4 998	332	130	99	31
Cheviot	7 455	246	154	7	148
Grande Cache	4 250	199	85	20	65
Subtotal	16 703	777	369	126	244
High-volatile bituminous					
Coal Valley	17 695	572	331	104	227
Subtotal	17 695	572	331	104	227
Subbituminous					
Vesta	2 410	69	54	39	16
Paintearth	2 710	94	67	39	29
Sheerness	7 000	196	150	62	91
Dodds	140	2	2	1	1
Keephills	150	0.5	0.5	0.01	0.5
Whitewood	3 300	193	120	75	45
Highvale	12 140	1 021	764	313	464
Genesee	7 320	250	176	48	133
Subtotal[b]	35 170	1 826	1 334	577	780
Total	69 568	3 175	2 034	807	1 251

[a] Mt = megatonnes; mega = 10^6.
[b] Differences are due to rounding.

8.1.4 Ultimate Potential

A combination of two methods has been used to estimate ultimate potentials. The first, the volume method, gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the second method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

A large degree of uncertainty is inevitably associated with estimation of an ultimate potential. New data could substantially alter results derived from the current best fit. To avoid large fluctuations of ultimate potentials from year to year, the EUB has adopted the policy of using the figures published in the previous *ST 31: Reserves of Coal* report and adjusting them slightly to reflect the most recent trends. Table 8.3 gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potentials.

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 results 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 coal and clean bituminous coal are collectively known as marketable coal.

8.2.1 Coal Supply

In 2004, twelve mine sites supplied coal in Alberta, as shown in Table 8.4. Together they produced 27.8 Mt of marketable coal. Subbituminous coal accounted for 91.0 per cent of the total, bituminous metallurgical 2.9 per cent, and bituminous thermal coal the remaining 6.1 per cent. The increase in coal production is mainly due to a substantial increase in thermal coal production at the Coal Valley mine and subbituminous coal production at the Sheerness mine.

Six large mines and two small mines produce subbituminous coal. The large mines serve nearby electric power plants, while the small mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the reserves have been dedicated to the power plants. In 2004, subbituminous coal production increased slightly due to the commissioning of the Genesee 3 power generation plant, with 450 megawatt (MW) capacity. Two smaller power generation units at Wabamun were decommissioned, which somewhat offset the above increase.

Table 8.4. Alberta coal mines and marketable coal production in 2004

Company (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Epcor Generation Inc.	Genesee	Genesee	4.1
Luscar Ltd.	Sheerness	Sheerness	3.8
	Paintearth	Halkirk	1.4
	Vesta	Cordel	1.5
TransAlta Utilities Corp.	Highvale	Wabamun	12.8
	Whitewood	Wabamun	1.6
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.05
Keephills Aggregate Ltd.	Gravel pit	Burtonsville	0.001
Bituminous metallurgical coal			
Cardinal River Coals Ltd.	Luscar/Cheviot	Luscar/Cheviot	0.6
Grande Cache	Grande Cache	Grande Cache	0.2
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.7
Total			27.8

Two power generation units, each with 450 MW capacity, have been approved by the EUB. These units are scheduled to be operational within the forecast period. A second operator is in the process of applying for a permit to construct two 500 MW generation units, which are anticipated to be commissioned in the later part of the forecast period. All four units will be fuelled by subbituminous coal.

Alberta's only operating preparation plant producing clean metallurgical coal for export is at the Luscar mine. Raw coal production at the Luscar mine finished in 2004, and at the beginning of the year new production from the Cheviot mine is sending its raw coal for preparation to this plant. The Grande Cache coal mine started operations in 2004. Both of these changes are reflected in the tables above.

Although metallurgical grade coal underlies much of the mountain region, very few areas have been sufficiently explored to identify economically recoverable reserves at current prices. Without higher, stable prices, it is unlikely that any additional mines, other than the Cheviot mine and the Grande Cache coal mine, will come on stream over the next decade.

While in early 2003 Alberta's two producing thermal bituminous coal mines, Luscar and Coal Valley mines, were negatively impacted by declining export thermal coal prices, recent record high crude oil prices have resulted in improved economics in the coal markets and hence thermal coal market at the Coal Valley mine. It is uncertain at this time what the long-term plans are for Luscar mine at Obed Mountain.

Historical and forecast Alberta production for each of the three types of marketable coal are shown in **Figure 8.1**.

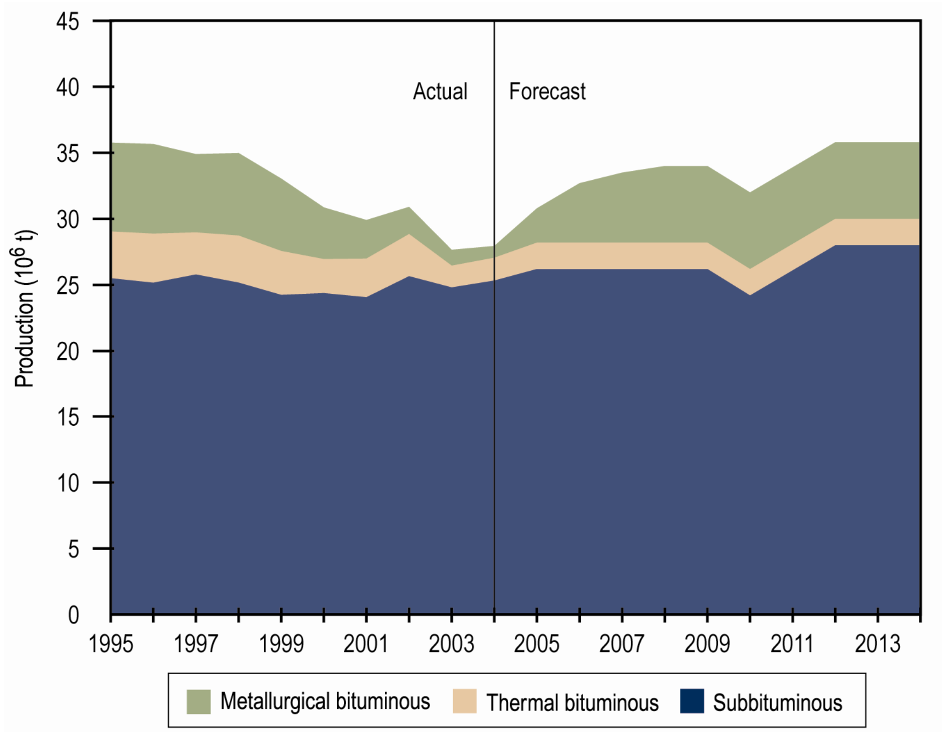

Figure 8.1. Alberta marketable coal production

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. While at this point there is some excess power generation capacity in Alberta, it is expected that high economic growth in the province will result in higher demand for electricity, which in turn will drive the increase in coal demand. Subbituminous coal production is expected to increase, with potentially four units to be commissioned in the second half of the forecast period to meet demand for additional electrical generating capacity. Beyond that, it is expected that the demand for additional subbituminous coal will level off, barring strong increases in electricity demand.

Although the North American steel industry has been going through reorganization and production declines, Asian steel production has been steady in recent years. Alberta's metallurgical coal primarily serves the latter market, mainly Japan, but export coal producers have the competitive disadvantage of long distances from mine to port. Recently the international market for coal has strengthened, and this stronger market means that, on an annual basis, coal production will increase.

Coal prices, which were depressed for a number of years before 2004, have rebounded to have spot market prices at more than 50 per cent higher for thermal export coal and more than double for metallurgical coal. This has led to increased planning and investment in the production of coal. Currently, the EUB has no indication if this will be an ongoing trend or a temporary fluctuation.

Appendix A Terminology, Abbreviations, and Conversion Factors

1.1 Terminology

Area The area used to determine the bulk rock volume of the oil-, crude bitumen-, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.

Burner-tip The location where a fuel is used by a consumer.

Butanes In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, Section 1(1)(c.1)).

Coalbed Methane The naturally occurring dry, predominantly methane gas produced during the transformation of organic matter into coal.

Compressibility Factor A correction factor for nonideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.

Condensate A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(d.1)).

Cogeneration Gas Plant Gas-fired plant used to generate both electricity and steam.

Connected Wells Gas wells that are tied into facilities through a pipeline.

Crude Bitumen A naturally occurring viscous mixture mainly of hydrocarbons heavier than pentane that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well (*Oil Sands Conservation Act*, Section 1(1)(f)).

Crude Oil (Conventional) A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen (*Oil and Gas Conservation Act*, Section 1(1)(f.1)).

Crude Oil (Heavy) Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater, but the EUB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchasers' classification.

Crude Oil (Light-Medium)	Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3, but the EUB may classify crude oil otherwise than in accordance with this criterion in a particular case, having regard to its market utilization and purchasers' classification.
Crude Oil (Synthetic)	A mixture mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds and is derived from crude bitumen. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, Section 1(1)(t.1)).
Datum Depth	The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.
Decline Rate	The annual rate of decline in well productivity.
Deep-cut Facilities	A gas plant adjacent to or within gas field plants that can extract ethane and other natural gas liquids using a turboexpander.
Density	The mass or amount of matter per unit volume.
Density, Relative (Raw Gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.
Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).
Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).
Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.

Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.
Frontier Gas	In this report this refers to gas produced from areas of northern and offshore Canada.
Gas	Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).
Gas (Associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (Marketable)	A mixture mainly of methane originating from raw gas, or if necessary, from the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).
Gas (Marketable at 101.325 kPa and 15°C)	The equivalent volume of marketable gas at standard conditions.
Gas (Nonassociated)	Gas that is not in communication in a reservoir with an accumulation 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 Regulation* 1.020(2)9). This practice is authorized by the EUB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.
Gross Heating Value (of Dry Gas)	The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Initial Volume in Place	The volume of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in a reservoir before any volume has been produced.
Maximum Day Rate	The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.
Maximum Recoverable Thickness	The assumed maximum operational reach of underground coal mining equipment in a single seam.
Mean Formation Depth	The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.
Methane	In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, Section 1(1)(m.1)).
Natural Gas Liquids	Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.
Off-gas	Natural gas that is produced from the bitumen production in the oil sands. This gas is typically rich in natural gas liquids and olefins.

Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(n.1)).
Oil Sands	(i) sands and other rock materials containing crude bitumen, (ii) the crude bitumen contained in those sands and other rock materials, and (iii) any other mineral substances other than natural gas in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (*Oil Sands Conservation Act*, Section l(l)(o)).
Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(o.1)).
Overburden	In this report overburden is a mining term related to the thickness of material above a mineable occurrence of coal or bitumen.
Pay Thickness (Average)	The bulk rock volume of a reservoir of oil, oil sands, or gas divided by its area.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate, or crude oil (*Oil and Gas Conservation Act*, Section 1(1)(p)).
Pool	A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, Section 1(1)(q)).
Porosity	The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.
Pressure (Initial)	The reservoir pressure at the reference elevation of a pool upon discovery.
Propane	In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, Section 1(1)(s)).
Recovery (Enhanced)	The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. The artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of (i) aiding in the lifting of fluids in the well, or (ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means (*Oil and Gas Conservation Act*, Section 1(1)(h)).

Recovery (Pool)	In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.
Recovery (Primary)	Recovery of oil by natural depletion processes only measured as a volume thus recovered or as a fraction of the in-place oil.
Refined Petroleum Products	End products in the refining process.
Refinery Light Ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reprocessing Facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Retrograde Condensate Pools	Gas pools that have a dew point such that natural gas liquids will condense out of solution with a drop in reservoir pressure. To limit liquid dropout in the reservoir, dry gas is reinjected to maintain reservoir pressure.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (Gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (Water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shrinkage Factor (Initial)	The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.
Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.
Specification Product	A crude oil or refined petroleum product with defined properties.

Sterilization	The rendering of otherwise definable economic ore as unrecoverable.
Successful Wells Drilled	Wells drilled for gas or oil that are cased and not abandoned at the time of drilling. Less than 5 per cent of wells drilled in 2003 were abandoned at the time of drilling.
Surface Loss	A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.
Temperature	The initial reservoir temperature upon discovery at the reference elevation of a pool.
Ultimate Potential	An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple equation: Ultimate potential = initial established reserves + additions to existing pools + future discoveries.
Upgrading	The process that converts bitumen and heavy crude oil into a product with a density and viscosity similar to light crude oil.
Zone	Any stratum or sequence of strata that is designated by the EUB as a zone (*Oil and Gas Conservation Act*, Section 1(1)(z)).

1.2 Abbreviations

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

1.3 Symbols

International System of Units (SI)

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

Imperial

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

1.4 Conversion Factors

Metric and Imperial Equivalent Units[a]

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

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.

[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

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

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4*
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Synthetic crude oil	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Hydroelectricity (per megawatt-hour of output)	10.5**
Nuclear electricity (per megawatt-hour of output)	10.5**

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

**Based on the thermal efficiency of coal generation.

Appendix B Summary of Conventional Crude Oil and Natural Gas Reserves

Table B.1. Conventional crude oil reserves as of each year-end ($10^6\ m^3$)

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

Table B.2. Conventional crude oil reserves by geological period as of December 31, 2004

	Initial volume in-place (10^6 m^3)		Initial established reserves (10^6 m^3)		Remaining established reserves (10^6 m^3)		Average recovery (%)	
Geological period	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy
Cretaceous								
Upper	2 183	0	368	0	52	-	17	-
Lower	1 239	1 904	228	332	29	63	18	17
Jurassic	102	106	20	35	3	4	20	33
Triassic	353	25	69	2	12	1	20	8
Permian	14	0	8	0	0	-	56	
Mississippian	455	69	89	8	7	1	20	12
Devonian								
Upper	2 474	29	1 144	3	50	1	46	10
Middle	974	0	353	0	24	-	36	-
Other	62	11	5	1	2	-	8	8
Total	7 856	2 144	2 284	381	179	70	29	18

Table B.3. Distribution of conventional crude oil reserves by formation as of December 31, 2004

Geological formation	Initial volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)	Remaining established reserves (10^6 m^3)	Initial volume in-place (%)	Initial established reserves (%)	Remaining established reserves (%)
Upper Cretaceous						
Belly River	351	54	12	4	2	5
Chinook	5	1	0	0	0	0
Cardium	1 689	289	33	17	11	13
Second White Specks	35	3	1	0	0	0
Doe Creek	85	20	6	1	1	2
Dunvegan	18	1	0	0	0	0
Lower Cretaceous						
Viking	337	67	5	3	3	2
Upper Mannville	1 965	302	55	20	11	22
Lower Mannville	840	191	32	8	7	13
Jurassic	208	54	7	2	2	3
Triassic	378	71	12	4	3	5
Permian-Belloy	14	7	0	0	0	0
Mississippian						
Rundle	324	69	4	3	3	2
Pekisko	92	15	2	1	1	1
Banff	108	13	2	1	0	1
Upper Devonian						
Wabamun	61	7	1	1	0	0
Nisku	467	208	12	5	8	5
Leduc	827	504	11	8	19	4
Beaverhill Lake	989	395	18	10	15	7
Slave Point	160	35	8	2	1	3
Middle Devonian						
Gilwood	305	131	5	3	5	2
Sulphur Point	9	1	0	0	0	0
Muskeg	61	10	1	1	0	0
Keg River	499	179	15	5	7	6
Keg River SS	44	18	1	0	1	0
Granite Wash	56	14	2	1	1	1

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

	Initial established							
Year	New discoveries	Development	Revisions	Net additions	Cumulative	Cumulative production	Remaining actual[a]	Remaining @ 37.4 MJ/m^3
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2[a]	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	58.6	45.3	-16.7	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	43.2	59.8	42.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3

[a] At field plant.

Table B.5. Geological distribution of established natural gas reserves, 2004

Geological period	Gas in place Initial volume (10^9 m^3)	Marketable gas Initial established reserves (10^9 m^3)	Marketable gas Remaining established reserves (10^9 m^3)	Gas in Place Initial volume (%)	Marketable gas Initial established reserves (%)	Marketable gas Remaining established reserves (%)
Upper Cretaceous						
Belly River	134	79	25	1.7	1.7	2.2
Milk River & Med Hat	862	514	241	11.1	11.3	21.7
Cardium	448	90	33	5.8	2.0	2.9
Second White Specks	23	13	8	0.3	0.3	0.1
Other	263	144	49	3.3	3.1	4.5
Subtotal	1 730	840	355	22.2	18.4	31.4
Lower Cretaceous						
Viking	406	278	58	5.2	6.1	5.2
Basal Colorado	40	33	2	0.5	0.7	
Mannville	1 887	1 241	299	24.2	27.3	26.8
Other	386	250	72	5.0	5.5	6.4
Subtotal	2 719	1 802	431	34.9	39.6	38.4
Jurassic						
Jurassic	73	42	12	1.0	0.9	1.1
Other	100	62	13	1.2	1.4	1.1
Subtotal	173	105	25	2.2	2.3	2.2
Triassic						
Triassic	208	125	48	2.7	2.7	4.5
Other	45	31	6	0.6	0.7	0.1
Subtotal	254	156	54	3.3	3.4	4.6
Permian						
Belloy	9	6	2	0.1	0.1	
Subtotal	9	6	2	0.1	0.1	
Mississippian						
Rundle	920	575	91	11.8	12.6	8.3
Other	333	226	30	4.3	5.0	2.7
Subtotal	1 253	801	121	16.1	17.6	11.0
Upper Devonian						
Wabamun	244	120	23	3.1	2.6	2.1
Nisku	124	59	17	1.6	1.3	1.5
Leduc	460	241	16	5.9	5.3	1.4
Beaverhill Lake	486	226	40	6.3	5.0	3.6
Other	221	139	20	2.8	3.1	1.8
Subtotal	1 535	785	116	19.7	17.3	10.4
Middle Devonian						
Sulphur Point	14	9	4	0.2	0.2	0.1
Muskeg	8	2	1	0.1	0.0	
Keg River	64	26	14	0.8	0.6	1.4
Other	33	14	3	0.4	0.3	0.1
Subtotal	119	51	22	1.5	1.1	1.6
Confidential						
Subtotal	2	1	1	0.0	0.0	0.0
Total	7792 (277)[a]	4 547 (161)[a]	1 127 (40)[a]	100.00	100.00	100.00

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

Table B.6. Natural gas reserves of retrograde pools, 2004

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)
Brazeau River Nisku J	557	74.44	41	0.75	0.50	15	41.01	380
Brazeau River Nisku K	1 360	74.17	101	0.75	0.60	30	42.15	718
Brazeau River Nisku M	1 832	76.22	140	0.75	0.60	42	41.36	1 013
Brazeau River Nisku P	8 663	61.23	530	0.74	0.65	137	40.00	3 435
Brazeau River Nisku S	1 665	54.64	90	0.80	0.57	31	41.38	756
Brazeau River Nisku W	1 895	55.65	105	0.72	0.35	49	41.13	1 200
Caroline Beaverhill Lake A	64 707	49.95	3 232	0.77	0.76	597	36.51	16 360
Carson Creek Beaverhill Lake B	11 350	55.68	631	0.90	0.39	346	41.65	8 330
Harmattan East Rundle	36 252	50.26	1 822	0.85	0.26	1 146	40.93	28 000
Harmattan-Elkton Rundle C	31 326	46.96	1 471	0.90	0.27	966	41.48	23 300
Kakwa A Cardium A	1 120	55.40	62	0.85	0.32	35	42.71	840
Kaybob South Beaverhill Lake A	103 728	52.61	5 457	0.77	0.61	1 638	39.68	41 300
Ricinus Cardium A	8 316	58.59	487	0.85	0.32	281	40.52	6 950
Valhalla Halfway B	6 331	53.89	341	0.80	0.33	182	40.00	4 572
Waterton Rundle-Wabamun A	86 670	48.74[a]	4 224	0.78	0.35	2 142	39.25	53 519
Wembley Halfway B	5 740	53.89	309	0.80	0.33	165	40.12	4 133
Westerose D-3	5 230	51.55	270	0.90	0.25	182	41.72	4 369
Westpem Nisku E	1 160	66.05	76	0.90	0.54	31	44.76	709
Windfall D-3 A	21 288	53.42	1 137	0.60	0.53	320	42.42	7 560

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

Table B.7. Natural gas reserves of multifield pools, 2004

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Edmonton Pool No. 1	
Bashaw Edmonton D	100
Nevis Edmonton D	142
Total	242
Belly River Pool No. 1	
Bashaw Edmonton & Belly River MU#1	202
Nevis Belly River C,O & Z	209
Total	411
Belly River Pool No. 2	
Bruce Belly River J	47
Holmberg Belly River J	20
Total	67
Belly River Pool No. 3	
Fenn West Belly River J	3
Fenn-Big Valley Edmonton & Belly River MU#1	198
Gadsby Edmonton C, Belly River B & J & Mannville J	695
Total	896
Belly River Pool No. 4	
Michichi Belly River B	105
Watts Belly River B & I	4
Total	109
Belly River Pool No. 6	
Aerial Belly River III	22
Ardenode Edmonton & Belly River MU#1	1 861
Brant Edmonton & Belly River MU#1	894
Carbon Belly River, Viking, Mannville & Rundle MU #1	328
Centron Edmonton & Belly River MU#1	1 069
Cessford Belly River III	134
Crossfield Belly River III	85
Dalmead Belly River III	34
Entice Edmonton & Belly River MU#!	1 917
Gayford Belly River MU#1	482
Ghost Pine Belly River III	322
Gladys Belly River III	587
Herronton Belly River A, B, I & III	1 664
Irricana Belly River III	188
Jumpbush Belly River D, F & III & Medicine Hat A	213
Lomond Belly River A & III	144
Majorville Belly River F, M, O & III	184
Matziwin Belly River J & III	54
Michichi Belly River B, R & III & Upper Mannville J	144
Milo Belly River G, H & III	99
Okotoks Belly River III	125
Parflesh Belly River U & Lower Mannville MU#1	508
Queenstown Belly River III	125
Redland Belly River C, D, J, M & III & Viking D	535
Rockyford Belly River, Viking & Mannville MU#1	721
Rowley Belly River T & III	4
Seiu Lake Belly River III & Viking C	99
Strathmore Edmonton & Belly River MU#1	2 314
Swalwell Belly River H & III	180
Twining Belly River III	68
Vulcan Belly River III	42
Wayne-Rosedale Belly River MU#1	358
West Drumheller Belly River III	48
Total	15 552
Cardium Pool No. 1	
Ansell Cardium, Viking, & Mannville MU#1	9 641
Sundance Belly River, Cardium, Viking, & Mannville MU#1	3 705
Total	13 346
Southeastern Alberta Gas System (MU)	
Aerial Medicine Hat	22
Alderson Milk River, Medicine Hat, Second White Specks, Belly River and Colorado	25 215
Armada Medicine Hat and Belly River	645
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River	6 222
Bantry Milk River, Medicine Hat, Fish Scale, Second White Specks, First White Specks, Belly River and Colorado	16 438
Bassano Milk River, Medicine Hat, Second White Specks and Belly River	2 454
Berry Medicine Hat	72
Bindloss Milk River and Medicine Hat	1 168
Blackfoot Medicine Hat and Belly River	889
Bow Island Milk River, Medicine Hat, Second White Specks and Colorado	1 686
Brooks Milk River, Medicine Hat and Second White Specks	161
Cavalier Belly River and Viking	342
Cessford Milk River, Medicine Hat, Second White Specks and First White Specks	13 907
Connorsville Milk River, Medicine Hat, Belly River, Colorado and First White Specks	1 877
Countess Milk River, Medicine Hat, Second White Specks, Belly River, Colorado and Fish Scale	26 039
Drumheller Medicine Hat, Belly River, Viking Basal Colorado, Upper Mannville, Lower Mannville and Pekisko	280
Enchant Second White Specks	63
Eyremore Milk River, Medicine Hat, Second White Specks, Belly River and Colorado	3 009
Farrow Edmonton, Milk River, Medicine Hat and Belly River	2 237
Gleichen Milk River, Medicine Hat and Belly River	1 820
Hussar Milk River, Medicine Hat, Belly River, Edmonton, Viking and Glauconitic	4 677
Jenner Milk River, Medicine Hat, Belly River, Second White Specks and Colorado	4 395
Johnson Milk River, Medicine Hat and Second White Specks	662
Kitsim Milk River, Medicine Hat and Second White Specks	1 114

(continued)

Table B.7. Natural gas reserves of multifield pools, 2004 (continued)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Lathom Milk River , First White Specks, Medicine Hat, Fish Scale, Second White Specks and Belly River	1 267
Leckie Milk River, Medicine Hat, Belly River, and Second White Specks	1 047
Majorville Milk River, Medicine Hat and Belly River	1 272
Matziwin Milk River, Medicine Hat, First White Specks, Fish Scale, Second White Specks and Belly River	1 278
Medicine Hat Milk River, Medicine Hat, Fish Scale, Second White Specks, Belly River, and Colorado	62 412
Newell Milk River, Medicine Hat and Second White Specks	1 526
Princess Milk River, Medicine Hat, Fish Scale, Second White Specks, Belly River and Colorado	12 752
Rainier Milk River, Medicine Hat and Second White Specks	374
Scandia Milk River and Second White Specks	22
Seiu Lake Medicine Hat	770
Shouldice Medicine Hat and Belly River	1 455
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	21 760
Verger Milk River, Medicine Hat, Fish Scale, Belly River, Second White Specks and Colorado	9 804
Wayne-Rosedale Medicine Hat, Milk River, First White Specks and Belly River	2 090
Wintering Hills Milk River, Medicine Hat, Second White Specks, Belly River, and Colorado	4 511
Total	237 734
Second White Specks Pool No. 2	
Dowling Lake Second White Specks E	11
Garden Plains Second White Specks E	1 642
Hanna White Specks E	1 437
Provost White Specks E	65
Richdale White Specks E	166
Sullivan Lake Second White Specks E	154
Watts Medicine Hat B & C and Second White Specks E	29
Total	3 504
Second White Specks Pool No. 3	
Conrad Second White Specks J, & Barons A	177
Foremost Second White Specks J	22
Pendant D'Oreille Medicine Hat E & Second White Specks J	54
Smith Coulee Medicine Hat A & Second White Specks J	548
Total	801
Second White Specks Pool No. 4	
Enchant Second White Specks B	72
Retlaw Second White Specks B	17
Vauxhall Second White Specks B	151
Total	240
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	120
Peavey Upper Viking A	3
Redwater Upper Viking A, Middle Viking A, and Lower Viking A	383
Westlock Middle Viking B	207
Total	713
Viking Pool No. 2	
Albers Upper & Middle Viking A & Colony A	7
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	217
Bellshill Lake Upper and Middle Viking A	24
Birch Upper and Middle Viking A	4
Bruce Viking & Mannvillie MU#1	1 144
Dinant Upper and Middle Viking A	19
Fort Saskatchewan Upper and Middle Viking A	74
Holmberg Upper and Middle Viking A	4
Killam Colony, Viking & Mannville MU#1	305
Killam North Viking Mannville & Nisku MU#1	145
Mannville Viking & Mannville MU#1	823
Sedgewick Upper and Middle Viking A	10
Viking-Kinsella Viking, Colony, Mannville & Wabamun MU#1	8 783
Wainwright Colony B & F, Viking & Mannville MU#1	175
Total	11 734
Viking Pool No. 3	
Carbon Belly River, Mannville & Rundle MU #1	328
Ghost Pine Viking D	295
Total	623
Viking Pool No. 4	
Fenn West Viking B	66
Fenn-Big Valley Viking B	9
Total	75
Viking Pool No. 5	
Hudson Viking A	37
Sedalia Viking A & F, Upper Mannville D, and Lower Mannville B	34
Total	71

(continued)

Table B.7. Natural gas reserves of multifield pools, 2004 (concluded)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Viking Pool No. 6	
Hairy Hill Viking A	8
Willingdon Viking A & J and Mannville MMM & X2X	9
Total	17
Viking Pool No. 7	
Inland Upper Viking C & E, Middle Viking F, G, & I, and Upper Mannville A & V	99
Royal Upper Viking C and Lower Viking A	34
Total	133
Viking Pool No. 13	
Chigwell Viking G	11
Nelson Viking G	18
Total	29
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	89
Ferrybank Viking C, Glauconitic A, & Lower Mannville W	67
Total	156
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	137
Pembina Glauconitic I & D and Ostracod C	511
Total	648
Glauconitic Pool No. 6	
Bassano Glauconitic III	111
Countess Bow Island, Viking, Upper Mannville, & Glauconitic MU#1	720
Hussar Viking L, Glauconitic III, and Ostracod OO	265
Wintering Hills Upper Mannville I, Glauconitic III & Lower Mannville W	38
Total	1 134
Bluesky Pool No.1	
Rainbow Bluesky C	139
Sousa Bluesky C	21
Total	360
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	139
Hotchkiss Bluesky-Detrital-Debolt A	386
Total	525
Wabiskaw Pool No. 1	
Marten Hills Wabiskaw A and Wabamun A	1 590
McMullen Wabiskaw A and Wabamun A	204
Total	1 794
Gething Pool No. 1	
Fox Creek Viking C, Notikewin C and Gething D & H	1 118
Kaybob South Notikewin J, Bluesky CC, and Gething E, H, Q	82
Total	1 200
Ellerslie Pool No. 1	
Connorsville Basal Colorado,Glauconitic and Ellerslie MU#1	651
Wintering Hills Upper Mannville and Ellerslie A	155
Total	806
Cadomin Pool No. 1	
Elmworth Dunvegan , Fort St John & Bullhead MU#1	6 087
Sinclair Doe Creek, Fort St John & Bullhead MU#1	1 606
Total	7 693
Halfway Pool No. 1	
Valhalla Halfway B	3 200
Wembley Halfway B	4 675
Total	7 875
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	2 304
Valhalla Halfway N	50
Total	2 354
Banff Pool No. 1	
Haro Banff E	64
Rainbow Banff E	14
Rainbow South Banff E	77
Total	155

Table B.8. Remaining raw ethane reserves as of December 31, 2004

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	11 101	0.082	1 009	3 586
Brazeau River	11 216	0.064	910	3 236
Caroline	9 521	0.088	1 557	5 536
Countess	32 637	0.011	378	1 343
Dunvegan	14 294	0.044	703	2 499
Edson	5 431	0.075	469	1 669
Elmworth	10 798	0.058	735	2 614
Ferrier	13 980	0.081	1 274	4 530
Fir	5 479	0.060	363	1 292
Garrington	4 155	0.078	436	1 550
Gilby	5 928	0.080	561	1 995
Gold Creek	4 030	0.078	361	1 284
Harmattan East	7 387	0.083	688	2 448
Harmattan-Elkton	3 900	0.076	361	1 282
Hussar	8 631	0.031	283	1 007
Judy Creek	3 387	0.144	606	2 153
Kaybob South	10 714	0.077	1 047	3 724
Karr	5 327	0.083	494	1 755
Kakwa	4 107	0.091	430	1 529
Leduc-Woodbend	3 468	0.106	437	1 552
McLeod	3 187	0.082	293	1 042
Medicine River	4 366	0.085	449	1 597
Pembina	18 188	0.090	2 069	7 354
Pine Creek	4 319	0.060	324	1 152
Pouce Coupe South	6 162	0.050	342	1 214
Hamburg	4 006	0.068	296	1 052
Provost	23 229	0.025	645	2 294
Rainbow	7 677	0.081	806	2 866
Rainbow South	3 856	0.105	600	2 135
Ricinus	6 330	0.080	576	2 049
Sundance	6 026	0.072	487	1 732
Swan Hills	1 498	0.148	311	1 104
Swan Hills South	2 626	0.174	650	2 312
Sylvan Lake	5 207	0.074	458	1 628
Valhalla	9 558	0.076	869	3 089
Virginia Hills	1 655	0.160	322	1 146
Waterton	5 926	0.031	302	1 075
Westpem	3 241	0.104	438	1 558
Westerose South	5 630	0.080	505	1 795

(continued)

Table B.8. Remaining raw ethane reserves as of December 31, 2004 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Wembley	5 413	0.094	608	2 162
Wapiti	15 345	0.055	969	3 446
Wild River	17 595	0.069	1 308	4 649
Willesden Green	9 859	0.087	1 135	4 037
Wilson Creek	3 317	0.075	290	1 030
Wizard Lake	3 442	0.110	472	1 678
Subtotal	353 149	0.068	28 630	101 776
All other fields	773 893	0.028	21 671	77 178
Solvent floods			1 857	6 615
TOTAL	1 127 042	0.052[a]	52 158	185 569

[a] Volume weighted average.

Table B.9. Remaining established reserves of natural gas liquids as of December 31, 2004

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ante Creek	1 952	449	203	151	802
Ante Creek North	1 813	302	171	563	1 036
Ansell	11 101	1 678	896	1 926	4 500
Bonnie Glen	1 815	415	232	365	1 011
Brazeau River	11 216	1 466	946	2 287	4 699
Caroline	9 521	2 383	2 006	5 056	9 445
Carrot Creek	2 662	466	211	164	841
Cecilia	4 403	310	137	764	1 211
Countess	32 637	522	307	247	1 076
Crossfield East	3 196	235	114	769	1 118
Dunvegan	14 294	1 218	705	1 205	3 128
Edson	5 431	634	297	313	1 244
Elmworth	10 798	931	425	492	1 847
Ferrier	13 980	2 372	1 260	1 015	4 647
Fir	5 479	562	261	270	1 093
Garrington	4 155	664	354	501	1 518
Gilby	5 928	944	477	498	1 919
Gold Creek	4 030	467	249	484	1 200
Harmattan East	7 387	894	579	1 019	2 492
Harmattan -Elkton	3 900	483	247	243	973
Hussar	8 631	433	238	225	897
Judy Creek	3 387	1 451	601	348	2 400
Kaybob	3 068	443	218	315	976
Kaybob South	10 714	1 682	928	1 689	4 298
Karr	5 327	791	333	325	1 449
Kakwa	4 107	812	409	608	1 829
Knopcik	4 181	383	227	466	1 076
Leduc-Woodbend	3 468	1 174	667	405	2 246
McLeod	3 187	564	260	279	1 104
Medicine River	4 366	704	340	328	1 372
Peco	2 082	426	246	452	1 123
Pembina	18 188	4 064	1 914	1 551	7 529
Pine Creek	4 319	560	272	439	1 271
Pouce Coupe South	6 162	469	274	335	1 077
Hamburg	4 006	365	207	252	825
Provost	23 229	1 391	885	663	2 938

(continued)

Table B.9. Remaining established reserves of natural gas liquids as of December 31, 2004 (concluded)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid) Propane	Butanes	Pentanes plus	Total liquids
Rainbow	7 677	1 293	798	888	2 979
Rainbow South	3 856	1 206	568	787	2 560
Redwater	1 902	758	433	213	1 403
Ricinus	6 330	988	498	921	2 407
Sundance	6 026	671	285	257	1 213
Swan Hills	1 498	854	468	388	1 710
Swan Hills South	2 626	1 589	727	304	2 620
Sylvan Lake	5 207	701	339	329	1 369
Valhalla	9 558	1 496	799	1 173	3 468
Virginia Hills	1 655	748	249	109	1 106
Waterton	5 926	300	263	1 421	1 984
Wayne-Rosedale	5 947	441	243	246	929
Westpem	3 241	810	459	747	2 015
Westerose South	5 630	903	443	474	1 820
Wembley	5 413	1 185	705	1 590	3 480
Wapiti	15 345	991	426	390	1 807
Wild River	17 595	1 242	533	906	2 681
Willesden Green	9 859	2 030	950	927	3 907
Wilson Creek	3 317	472	255	335	1 063
Windfall	2 821	289	202	412	903
Wizard Lake	3 442	1 210	501	254	1 964
Zama	3 406	418	232	239	889
Subtotal	392 397	53 699	28 469	40 315	122 483
All other fields	734 645	28 290	16 302	18 452	63 044
Solvent floods		1 632	1 245	516	3 393
TOTAL	1 127 042	83 621	46 016	59 283	188 920

Appendix C CD—Basic Data Tables

EUB 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 and the crude bitumen resources data table present the official reserve estimates of both the EUB and NEB for the province of Alberta.

Basic Data Tables

The conventional oil, crude bitumen, and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2004 on the CD that accompanies this report (available for $500 from EUB Information Services). The individual oil and gas pools and crude bitumen deposit/pool values are presented on the first worksheet of each spreadsheet. Oilfield, crude bitumen deposit, and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. Crude bitumen provincial totals are included with the deposit information. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first.

Crude Bitumen Reserves and Basic Data

The crude bitumen reserves 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 reserve determination method are listed in separate columns.

Crude Oil Reserves and Basic Data

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

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

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

Natural Gas Reserves and Basic Data

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

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

Abbreviations Used in the Reserves and Basic Data Files

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

General Abbreviations

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

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

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

Abbreviations of Company Names

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

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