Statistical Series **2003-98**

Alberta's Reserves 2002 and Supply/Demand Outlook 2003-2012

- Crude Bitumen
- Crude Oil
- Natural Gas and Liquids
- Coal
- Sulphur

Alberta Energy and Utilities Board

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ALBERTA ENERGY AND UTILITIES BOARD
Statistical Series 2003-98: Alberta’s Reserves 2002 and Supply/Demand Outlook 2003-2012

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Contents

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Overview

Providing information to support good decision-making is a key EUB service. 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 Alberta Energy and Utilities Board (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 report entitled *Alberta Reserves 2002 and Supply/Demand Outlook 2003-2012* includes estimates of initial reserves, remaining established reserves (reserves we know we have), and ultimate potential (reserves that are ultimately expected to be recovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources.

Reserve supply, costs of development, energy demands, conservation, and social, economic, and environmental considerations influence the development of Alberta's energy resources. Changes in energy prices, drilling activity, and planned investments of billions of dollars for oil sands projects all contributed to the energy development picture in 2002 and will shape the forecast for the years to come.

Raw bitumen production, which surpassed conventional crude oil production in 2001 for the first time, continued its growth. Nonupgraded bitumen and synthetic crude oil production accounted for 48 per cent of Alberta's crude oil and equivalent production in 2002. Increased bitumen production from oil sands mining was the main contributor to this growth. In situ bitumen production remained similar to that of 2001. Several steam-assisted gravity drainage (SAGD) schemes have either been approved recently by the EUB or are under review. The EUB expects higher volumes of commercial production from these schemes to occur over the next few years.

While natural gas production declined in 2002 due mainly to lower drilling, the EUB expects that production will increase slightly in 2003 before declining over the remainder of the forecast period. Coalbed methane (CBM) development activity continued to grow in 2002, with CBM production contributing minor volumes to the provincial total for natural gas. The EUB anticipates that this activity will likely continue to increase over the next number of years and is beginning to calculate CBM reserves. However, sufficient uncertainties exist regarding production volumes, test data, and economics to preclude the publication of CBM reserves this year. The following table summarizes Alberta's energy reserves at the end of 2002.

Reserves and Production Summary 2002

	Crude bitumen		Crude oil		Natural gas		Coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place	259 205	1 631	9 852	62.0	7 344	261	94	103
Initial established	28 330	178	2 603	16.4	4 314	153	35	38
Cumulative production	610	3.8	2 343	14.7	3 142	112	1.18	1.3
Remaining established	27 720	174	260	1.6	1 171	42	34	37
Annual production	48.1	0.303	38	0.264	136	4.8	0.034	0.037
Ultimate potential (recoverable)	50 000	315	3 130	19.7	5 600	200	620	683

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

Alberta’s oil sands contain the largest crude bitumen resource in the world; approximately 50 billion cubic metres (m^3) (315 billion barrels) are considered potentially recoverable under anticipated technology and economic conditions.

The total in situ and mineable remaining established reserves are 27.7 billion m^3 (174 billion barrels), down slightly from 2001 due to production. To date, only 2 per cent of the initial established crude bitumen reserve has been produced.

Crude Bitumen Production

In 2002, Alberta produced 30.7 million m^3 (193 million barrels) from the mineable area and 17.4 million m^3 (109 million barrels) from the in situ area, totalling 48.1 million m^3 (303 million barrels). Bitumen produced from mining was upgraded, yielding 25.6 million m^3 (161 million barrels) of synthetic crude oil (SCO). In situ production was marketed as nonupgraded crude bitumen.

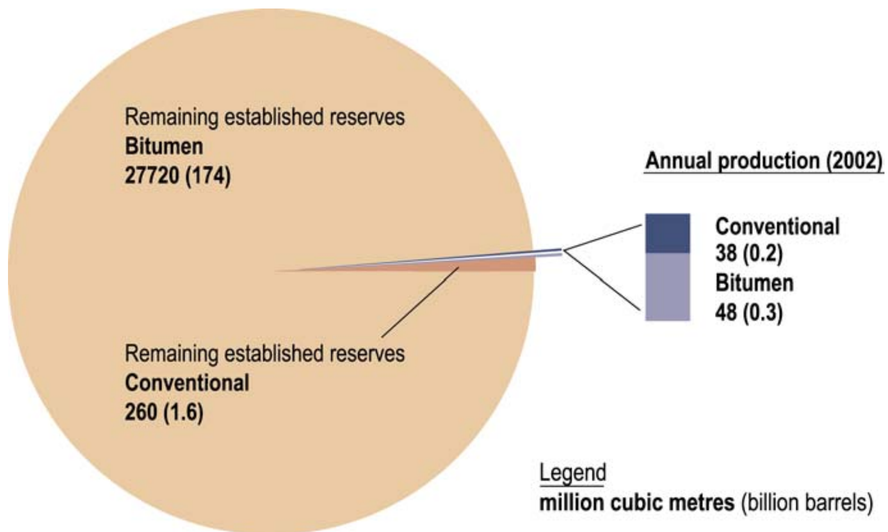
Total raw bitumen production, which exceeded total conventional crude oil production for the first time in 2001, continued to grow in 2002.

Crude Oil Reserves

Alberta’s remaining established reserves of conventional crude oil was estimated at 260 million m^3 (1.6 billion barrels)—a 6.4 per cent reduction from 2001. Of the 20.2 million m^3 (127 million barrels) added to initial established reserves, exploratory and development drilling, along with new enhanced recovery schemes, added reserves of 15.6 million m^3 (98 million barrels). This replaced 41 per cent of 2002 production. Positive revisions accounted for the remaining 4.6 million m^3 (29 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

Crude Oil Production and Drilling

Alberta's production of conventional crude oil totalled 38 million m^3 (241 million barrels) in 2002. Despite declining production over the past two decades, Alberta still produces 105 000 m^3/day (660 400 barrels/day) of conventional crude oil.

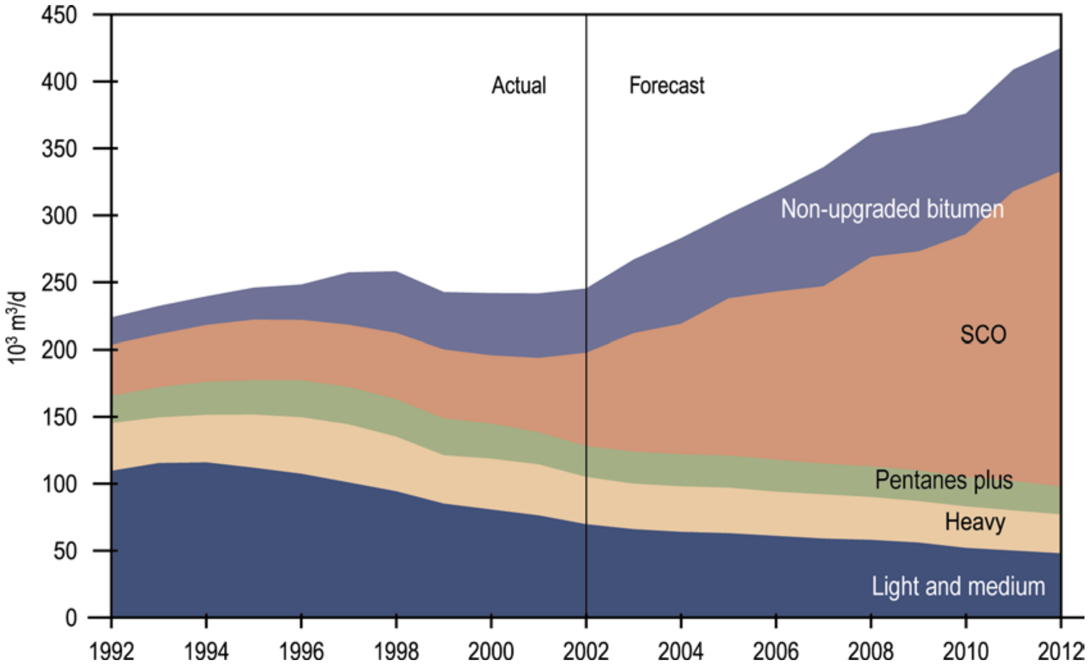
The number of successful oil wells drilled decreased by 25 per cent to 1661 in 2002 from 2220 in 2001. With the expectation that crude oil prices will remain strong, the EUB estimates that 2000 and 2100 successful oil wells will be drilled in 2003 and 2004 respectively, plateauing at about 2200 wells per year over the remainder of the forecast period.

Total Oil Supply and Demand

Alberta's 2002 production from conventional oil, oil sands sources, and pentanes plus was 245 500 m^3/day (1.54 million barrels/day)—about the same as in 2001. Production is forecast to reach 425 000 m^3/day (2.7 million barrels/day) by 2012.

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

Although conventional oil production will continue to decline, the EUB estimates that production of bitumen will triple by 2012. The share of nonupgraded bitumen and synthetic crude oil production in the overall Alberta crude oil and equivalent supply is expected to increase from 48 per cent in 2002 to some 77 per cent by 2012.



Alberta's total oil supply

Natural Gas

Natural Gas Reserves

At the end of 2002, Alberta's remaining established reserves of natural gas stood at 1171 billion m^3 (42 trillion cubic feet) at the field gate. This reserve includes liquids that are subsequently removed at straddle plants. Despite a trend since 1982 where drilling generally has not replaced production, new drilling replaced 105 per cent of production in 2002. This compared to 67 per cent replacement in 2001. However, it should be noted that due to a time lag in evaluating wells, some of the reserves added in 2002 were from wells drilled in 2001.

The 2002 natural gas reserve estimates do not include coalbed methane (CBM), which has potential to add to Alberta's reserves in the future. Over the past several years CBM activity has continued to increase, and while 2002 saw minor volumes of CBM production being reported, the EUB is not publishing CBM reserves due to several uncertainties. CBM is methane gas found in coal, and this relationship allows for in-place volumes to be calculated with some degree of confidence. However, the EUB believes that there is insufficient information regarding CBM test data, the accuracy of CBM production, and the profitability of CBM projects to determine reliable recovery factors. Without a reliable recovery factor, it is not possible to estimate established CBM reserves. The EUB believes that enough information may become available over the next year to publish CBM reserves in the next report.

In 1992, the EUB estimated Alberta's ultimate marketable gas potential at approximately 5600 billion m^3 (200 trillion cubic feet). To bring this estimate up to date, the EUB has undertaken an ultimate potential study targeted for completion in late 2003.

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 136 billion m^3 (4.8 trillion cubic feet) of marketable natural gas in 2002.[1] The increasing trend in annual production evident over the past several years began to show significant flattening in 1999. The decline in natural gas production in 2002 was a reflection of low drilling activity caused by low gas prices in the early part of the year.

There were 8064 successful gas wells drilled in Alberta in 2002, a 17 per cent decrease from the 9750 gas wells drilled in 2002. The EUB expects strong drilling over the forecast period, estimating 9500 to 11 000 wells for the period 2003 to 2006 and some 10 000 successful wells per year over the remainder of the forecast period.

Much of Alberta's gas development has centred on shallow gas in southeastern Alberta, which contains over half of the province's producing gas wells but only 16 per cent of 2002 natural gas production. Over time, the EUB anticipates that the focus of exploration activity will shift to the western portion of the province and correspondingly higher-productivity wells.

Natural Gas Supply and Demand

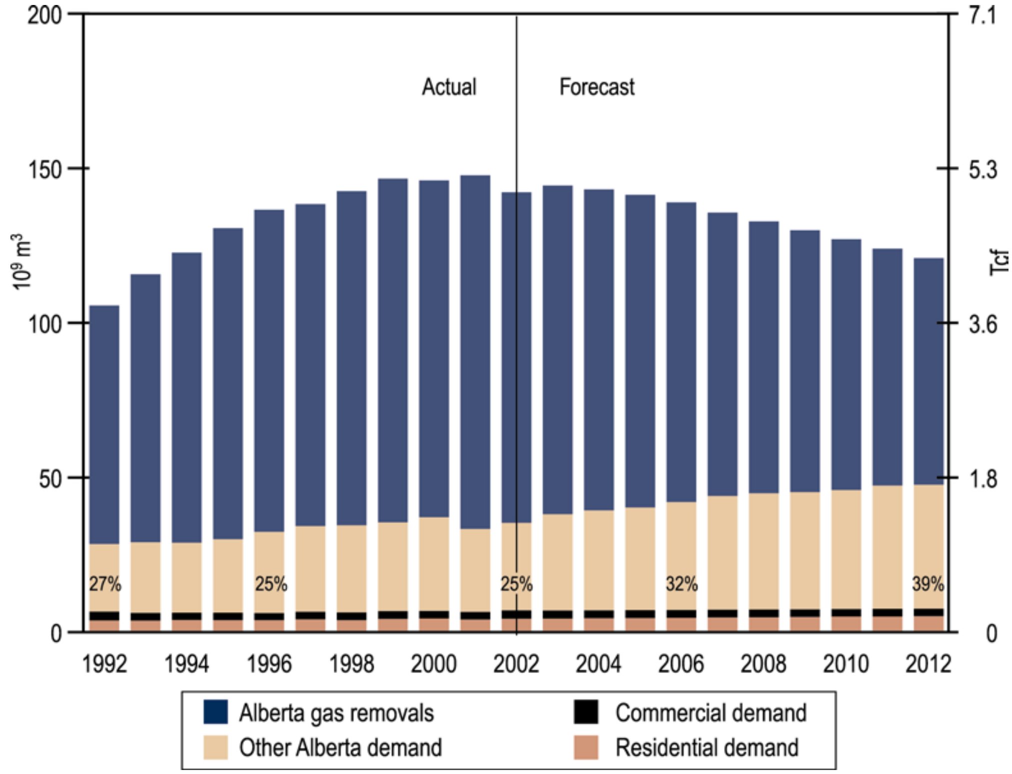
The EUB expects gas production to increase by 1.5 per cent in 2003 but decline by about 2 per cent per year over the forecast period. New pools are smaller and new wells drilled today are exhibiting lower initial production rates and steeper decline rates. Factoring this in, the EUB believes that new wells drilled will not be able to sustain production levels over most of the forecast period. Future supply is shown in the figure below.

Although natural gas supply from conventional sources is expected to start declining by 2004, supply exists to easily meet Alberta's demand. If the EUB's demand forecast is realized, Alberta's natural gas requirement will be only 39 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.

Other potential sources, such as frontier gas and coalbed methane, offer options for supplementing the supply of conventional gas in the future.

[1] Based on the actual average heating value of gas production 39 MJ/m^3. Based on the gross heating value of 37.4 MJ/m^3, gas production was 142 billion m^3.



Marketable conventional gas production and demand

Ethane, Other Natural Gas Liquids, and Sulphur

Remaining established reserves of extractable ethane is estimated at 165 million m^3 (1.0 billion barrels) as of year-end 2002. This estimate considers the ethane recovery from raw gas based on existing technology and market conditions.

The production of specification ethane increased from 12.7 million m^3 (79.9 million barrels) in 2001 to 13.7 million m^3 (86.7 million barrels) in 2002. 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 slightly to 194 million m^3 (1.2 billion barrels) in 2002. 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 2006. Alternative sources of diluent will be required.

The remaining established reserves of sulphur is 94 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 resources for all types of coal is about 34 billion tonnes. This massive resource continues to help meet the energy needs of

Albertans, supplying fuel for about 75 per cent of the province's electricity generation. Alberta's coal reserves represent over a thousand years of supply at current production levels.

Alberta's total coal production in 2002 was 31 million tonnes of raw coal, down slightly from 2001. Recent closures of Coal Valley, Obed Mountain, and Cardinal River coal mines will result in substantial reduction in both metallurgical and thermal bituminous coal production over the forecast period.

Subbituminous coal production is expected to increase over the forecast period to meet demand for additional electrical generating capacity.

1 Energy Prices and Economic Performance

This section discusses major forecast assumptions that affect Alberta's energy supply and demand. Energy production is generally impacted by energy prices, demand, and other factors. Energy demand, in turn, is affected or determined by such factors as economic activity, the types of industry operating in the province, standard of living, temperatures, and population growth. 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 2002 was characterized as one of tightening fundamentals and rising political tension, which resulted in high oil prices. In 2002, the Organization of Petroleum Exporting Countries (OPEC) crude oil basket price started from the low US$20 per barrel range, when the global market was glutted with oversupply of oil. However, several factors resulted in prices moving up to a US$25 per barrel range in early spring 2002. Due to oversupply of crude oil, OPEC decreased its quota by 1.5 million barrels per day (10^6 bbl/d) and aggressively encouraged the non-OPEC producers to lower their production to stabilize the prices.

A small number of non-OPEC countries cooperated with OPEC and restricted their production. Mexico, Norway, Oman, Angola, and Russia restricted their oil exports by 0.5 million barrels per day to assist OPEC in raising prices. Furthermore, the conflict between Israel and the Palestinians, Iraq's suspension of oil exports, which resulted in 1.8 10^6 bbl/d of reduction in OPEC's production, and mounting tensions between the United States and Iraq, resulted in a general rise in crude oil prices by September 2002.

Prices began falling after September, when production of crude oil by OPEC member states rose to 2.3 10^6 bbl/d, raising speculation that there would be an oversupply situation. Adding to this, in October Iraq agreed to United Nations inspections, and statements from the United States indicated a more conciliatory approach to the situation with Iraq. Prices stated rising again in December, as the unexpectedly long general strike in Venezuela, which started near the end of November, caused a surge in U.S. crude oil prices. Venezuela accounts for about 14 per cent of U.S. imports, and the strike worsened an already low inventory situation due to colder than normal weather in the United States.

Over the past ten years global demand for crude oil has increased by an average of 1.4 per cent per year. The global oil demand in 2002 increased only marginally (by 400 000 bbl/d) to 76.8 10^6 bbl/d. This was the second year in a row in which there was virtually no growth in global crude oil demand. High crude oil prices in 2002 and the sluggish economic recovery in both the U.S. and global markets resulted in weak demand for crude oil and products. After a period of poor global demand growth in 2001 and 2002, a much more robust outlook is projected for 2003, as the global economy continues to improve.[1] Despite the uncertainty and concerns about the Iraq situation, the global demand for oil is expected to increase by between 0.75 and 1.5 per cent in 2003, followed by a 1.0 and 1.5 per cent increase in 2004. If a 1.0 to 1.5 per cent growth rate in global demand is realized over the next few years, global crude oil production will increase by 8 10^6 to 12 10^6 bbl/d by the end of the forecast period to meet the demand. This growth in global demand should result in international crude oil prices stabilizing within OPEC's target range of US $22 to US $28.

[1] The world economy grew by 2.8 per cent in 2002 and is expected to grow by 3.7 per cent in 2003.

While the current global oil production capability exceeds the potential demand of 76 10^6 to 77 10^6 bbl/d by roughly 10 per cent, the uncertainty of oil supply from Iraq will continue to be a major issue. Concern about whether Iraq's production capability will be jeopardized and how fast Iraq can resume production has created a speculative environment in the global oil market. A somewhat similar situation exists regarding Venezuela. The effect of strikes both on the country's oil production and its sustainable production capacity once production resumes is also a source of concern. Long-term stability in Iraq and Venezuela, as well as in several other oil producing countries, are issues for the global market in 2003 and beyond.

1.2 Energy Prices

The price of Alberta crude oil is determined by international market forces and is most closely associated with the reference price of West Texas Intermediate (WTI) crude oil. The North American crude oil price is set in Chicago and is usually US$1.50-2.00 higher than the OPEC reference price, a reflection of 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 net backs in Edmonton. Net backs are calculated based on WTI at Chicago, less transportation and other charges from Edmonton to Chicago, and adjusted for exchange rate and crude oil quality. In 2002, the price of WTI crude oil began at US$20.11 per barrel, rose steadily to a peak of US$30.08 per barrel in September, then declined to US$26.59 per barrel in November, and finished at US$29.79 in December.

The EUB recognizes that key issues, such as OPEC compliance with major production cuts and Middle East political stability, will play a major role in shaping the global market over the next few years. The EUB forecasts that the price of WTI will average between US$29 and US$31 per barrel for 2003, declining to US$24 by 2005 due to resumption of Iraqi oil production, and thereafter rising by 1.5 per cent per year to the end of the forecast period. These price levels are sufficient to stimulate exploration outside of OPEC countries and can foster continued improvements in exploration and recovery technology. This increase in non-OPEC production will reduce OPEC's power to increase prices without lowering its market share. **Figure 1.1** illustrates the EUB forecast of WTI at Chicago.

Wellhead oil prices in Alberta are expected to move in tandem with WTI after adjusting for transportation tariffs, exchange rates, and quality differentials. Since Alberta prices are quoted in Canadian dollars, they will vary inversely with the value of the Canadian dollar expressed in U.S. funds. The forecast wellhead price of crude oil in Alberta is shown on a yearly basis in both current and constant Canadian dollars in **Figure 1.2.**

Differentials between prices of light-medium crude and heavy conventional crude or bitumen improved substantially in 2002. The heavy crude to light-medium crude price differential improved from 57 per cent to 73 per cent, while bitumen price differentials moved from 45 per cent to 66 per cent. The forecast calls for conventional heavy to average 75 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, the North American market determines natural gas prices. Nevertheless, natural gas prices are influenced by crude prices, as potential substitution could occur due to the price differential between crude oil and natural gas in the market. **Figure 1.3** shows the historical and EUB forecast of natural gas prices at the plant gate from 1992 to 2012.

The average plant gate natural gas price was $1.62 per gigajoule (GJ) over the decade 1990-1999; then prices climbed to $4.27/GJ in 2000 and $5.12/GJ in 2001. The volatility in gas prices that Alberta experienced over the 12-month period starting in mid-2000 showed unprecedented price spikes during the winter months as North American gas demand escalated. The Alberta reference price peaked in January 2001 at over $11.00/GJ. Prices moderated by the spring and by September had returned to levels around $3.00/GJ. The gas industry by this time faced lower demand, as many companies that had been major consumers of natural gas switched to fuel oil or chose to suspend operations rather than pay the going price.

In 2002, the Alberta plant gate price averaged $3.88/GJ. While gas prices regained some strength in the first half of 2002, by early summer prices weakened, as the Alberta market temporarily disconnected from the rest of North America due primarily to weak demand in the California market, as well as high storage levels in Alberta compared with previous year levels. Increased demand later in the year reduced the basis price differential between AECO and NYMEX as the market came more into balance.[2]

The volatility in gas prices seen in recent years is expected to continue in the near term as supply and demand fundamentals change. Prices appear to have turned a corner to a new and higher than historical price level near $4.00-$5.00/GJ. Gas prices are estimated to average $5.50/GJ to $6.50/GJ for 2003, $5.00/GJ in 2004, and $4.50 by 2005 as crude oil prices decline. Thereafter, prices are expected to increase by some 1.5 per cent per year. Factors supporting future gas prices include high oil prices, increased demand from electricity generation, and uncertainty about gas supply.

A recent review of the economics of intercontinental trade in liquefied natural gas (LNG) concluded that although LNG would not capture a high market share in North America, it would tend to put an upper limit of US$3.50/GJ to $4.00/GJ on the city gate price of natural gas in major east coast consuming areas of the United States. This is broadly consistent with the plant gate natural gas price forecast returning to levels of $4.50/GJ by 2005 and slowly rising thereafter, as shown in **Figure 1.3.**

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 impact the Alberta economy but are beyond the province’s control. The most important economic indicator that can identify whether the economy is contracting or expanding is the real gross domestic product (GDP). In this section the performance of the above economic indicators in 2002 and the first quarter of 2003 is reviewed. These economic indicators for 2002 are depicted in **Figure 1.4.**

In 2002, the performance of global economies remained weak. Even though Canadian economic growth decelerated over all four quarters, the Canadian economy managed to outpace all Group of 7 countries with a GDP growth rate of 3.4 per cent. The first two quarters of 2002 saw a broad-based recovery over most industries. In the third quarter,

[2] AECO is a natural gas trading hub in Alberta established by Alberta Energy Company, now EnCana. NYMEX is New York Mercantile Exchange, where North American natural gas is traded.

increased interest rates caused the economy to decelerate, with reductions in consumer spending and sharp declines in business investment. The economy further decelerated in the fourth quarter, as continued weakness in the U.S. caused exports to decline sharply.

During 2002, the overall growth in the Canadian economy enabled the unemployment rate to fall from a three-year high in December 2001 of 8.0 per cent to 7.4 per cent in February 2003.

This past year was very different from the previous year for the Bank of Canada. Instead of reducing interest rates to 40-year lows, as it did throughout 2001, the Bank of Canada saw fit to increase them beginning in April 2002. The sharp rate reductions in 2001 had achieved their purpose in successfully jump-starting the Canadian economy, which had narrowly missed falling into a recession in 2001. However, due to the robust recovery and potential inflating impacts in the first quarter, the Bank of Canada increased the bank rate by 25 basis points in April 2002. The rapid economic growth in the first and second quarters of 2002 led to a sharp increase in the inflation rate. In order to combat the sudden increase in inflation, the Bank of Canada raised the bank rate by another 50 basis points to 3.0 per cent in July. The bank rate remained at 3.0 per cent until continued inflation fears caused the Bank to raise the bank rate again in March 2003 to 3.25 per cent.

The Bank of Canada attempts to control the inflation rate that is expressed in terms of the core consumer price index (CPI), which is 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. Since the Bank of Canada's main goal is low, stable inflation, it has set the inflation control target within a range of 1 to 3 per cent until 2006.

The interest rate cuts that followed September 11, 2001, were successful in jump-starting the Canadian economy. As a result, the fast rate of economic growth caused inflation in the second quarter of 2002 to reach an annualized rate of 4.5 per cent and thereby surpass the Bank's target range. The Bank of Canada's tightening of monetary policy has been able to lower the inflation rate, but not to a point where it is within the Bank's desired target range. The inflation rate in January 2003 was at 3.3 per cent.

The most important factors affecting exchange rates are interest rate differentials between countries, inflation, net exports, and economic growth. The value of the Canadian dollar expressed in U.S. funds hit a new record low in February 2002, when it fell to 61.8 cents. With strong economic growth in the first quarter and increases in interest rates, the Canadian dollar started to appreciate and hit a new 52-week high in June 2002 of 65.29 cents. Due to continued weakness in the U.S. economy, along with a 25 basis point increase to the Bank rate in March 2003, the Canadian dollar reached highs that it had not seen since mid-2000 when it hit a value of 68.23 cents on March 10, 2003.

In the short term, continued upward pressure on the Canadian dollar is expected as Canadian interest rates remain higher than the U.S. rates. In the longer term, as the American economy recovers, it is expected that the Canadian dollar will come off of its recent highs and will stabilize at an average value of 68 cents.

The Canadian economic indicators assumed from 2003 to 2012 are presented in Table 1.1.

Table 1.1. Major Canadian economic indicators, 2003-2012

	2003	2004	2005	2006-2012[a]
GDP growth rate	2.9%	3.3%	3.0%	3.0%
Prime rate on loans	5.0%	6.4%	6.3%	6.3%
Inflation rate	2.5%	2.3%	2.3%	2.3%
Exchange rate	67.5	68.8	68.0	68.0
Unemployment rate	7.4%	7.1%	7.0%	7.0%

[a] Averages over 2006-2012.

1.4 Alberta Economic Outlook

The Alberta economy, based on Statistics Canada data, last experienced a contraction on a year-over-year basis in 1986, when real provincial GDP declined 1.2 per cent relative to 1985. Since then, Alberta real GDP has increased annually and reached almost $124 billion in 2001. Since 1992, Alberta GDP per capita continues to be 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. 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 economic sectors, particularly the service sector, will boost the Alberta GDP to grow at an annual average of 4 per cent over the forecast period, as shown in **Figure 1.5.**

In the last decade, the Alberta unemployment rate has gradually declined from 9.4 per cent in 1992 to 5.4 per cent in 2002; currently, Manitoba and Alberta share the lowest unemployment rate in Canada. Over the forecast period, the unemployment rate will fluctuate in the range of 4.2 to 5.5 per cent.

In eight of the last ten years, Alberta's inflation rate has been higher than that of the rest of Canada. As Alberta's economy continues to grow faster than the rest of Canada, it is expected that the trend over the last decade will continue over the forecast period. As a result, Alberta's inflation rate is projected to stabilize at 2.6 per cent a year.

Alberta's population increased from 2.6 million in 1992 to slightly more than 3.1 million in 2002, representing an average annual growth rate of 1.7 per cent. However, the economic expansion in Alberta over the last six years has fostered a large increase in net migration into Alberta. As a result, the Alberta population over the last six years has increased by almost 2 per cent per year. It is expected that as the Alberta economy continues to grow at pace higher than the rest of Canada, migration into Alberta coupled with birth rates will cause the population to grow at an average annual rate of 1.9 per cent.

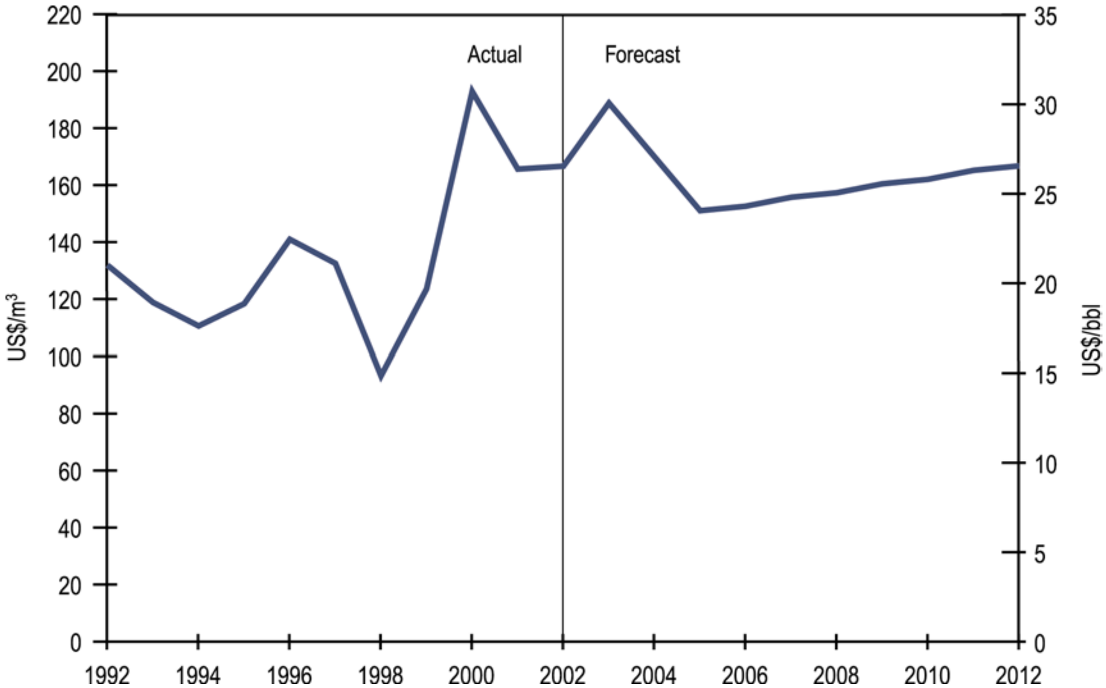


Figure 1.1. Price of WTI at Chicago

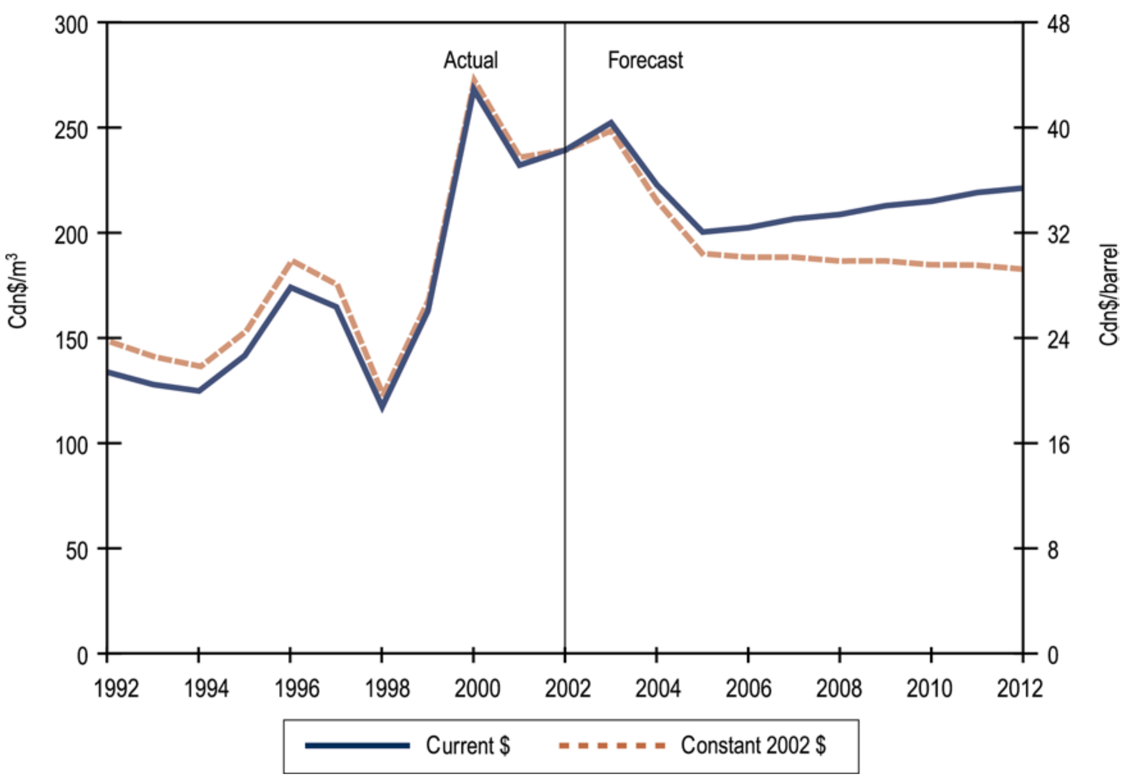


Figure 1.2. Average price of oil at Alberta wellhead

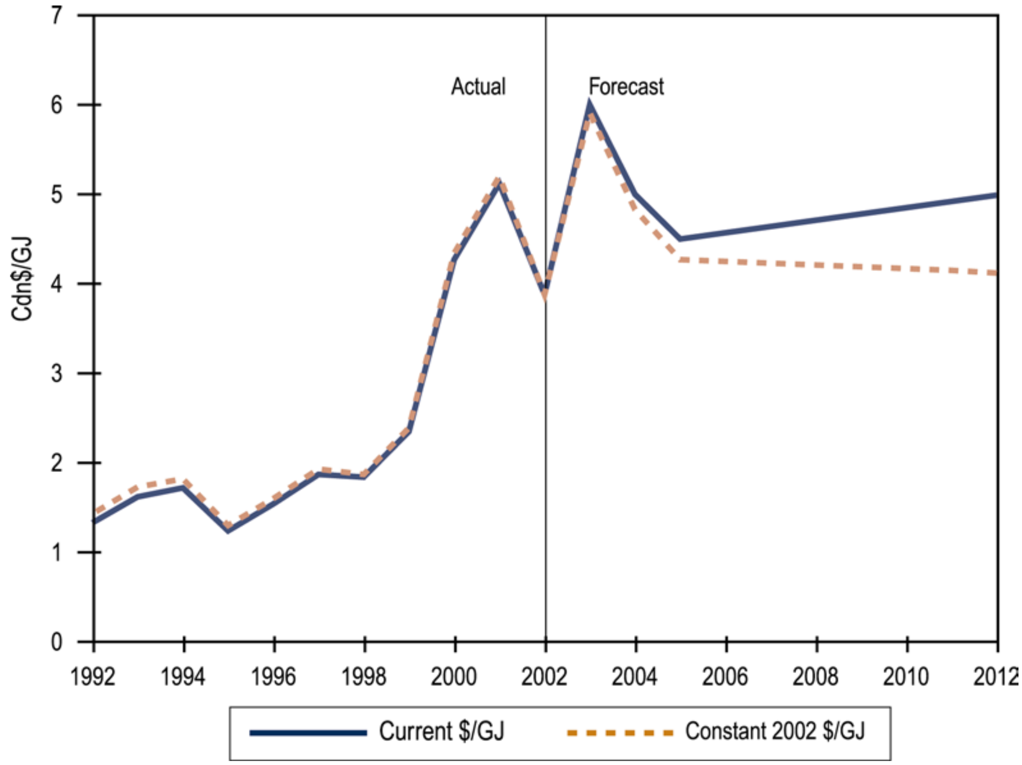


Figure 1.3. Average price of natural gas at plant gate

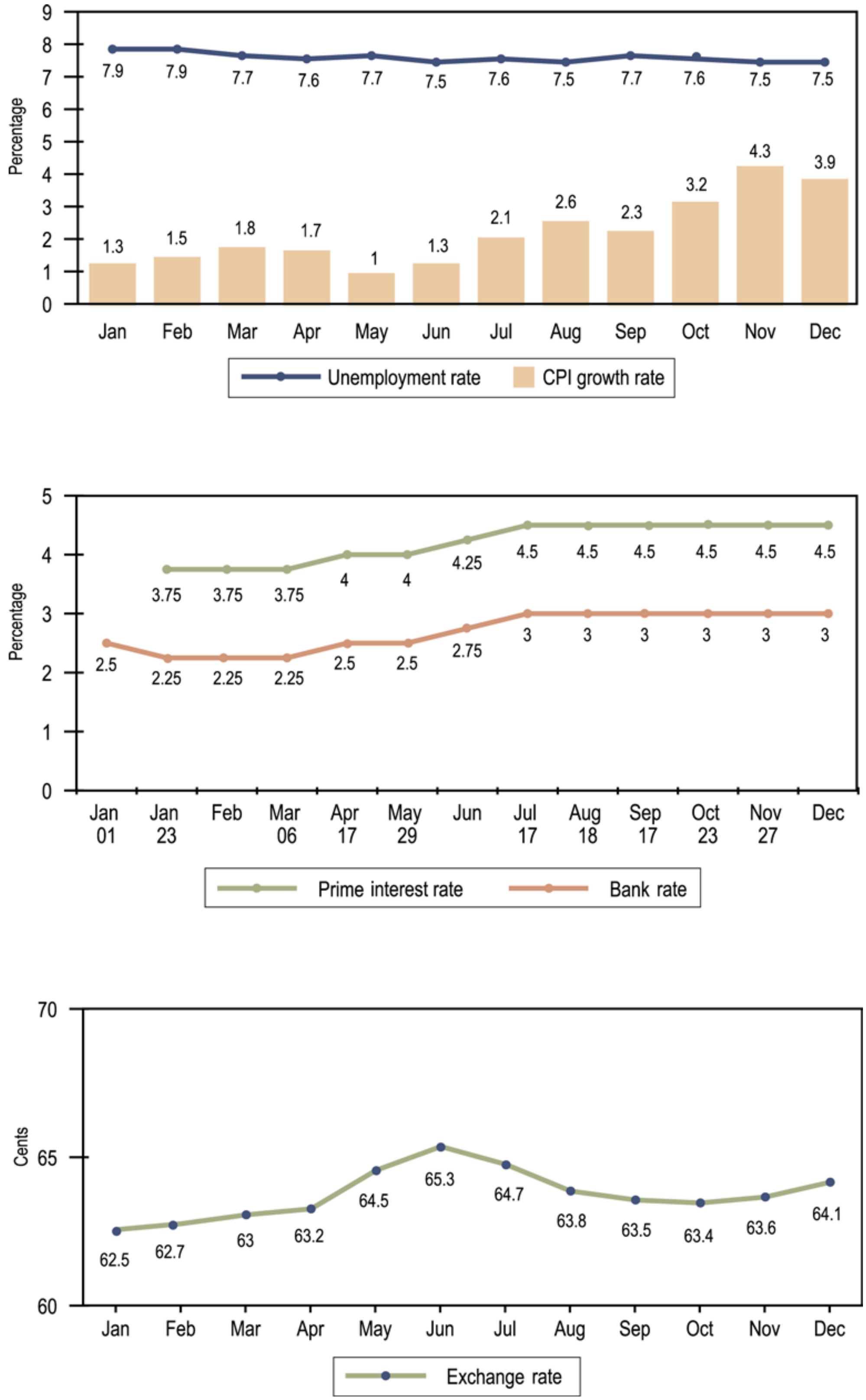


Figure 1.4. Canadian unemployment, inflation, interest, and Canada-U.S. exchange rates, 2002

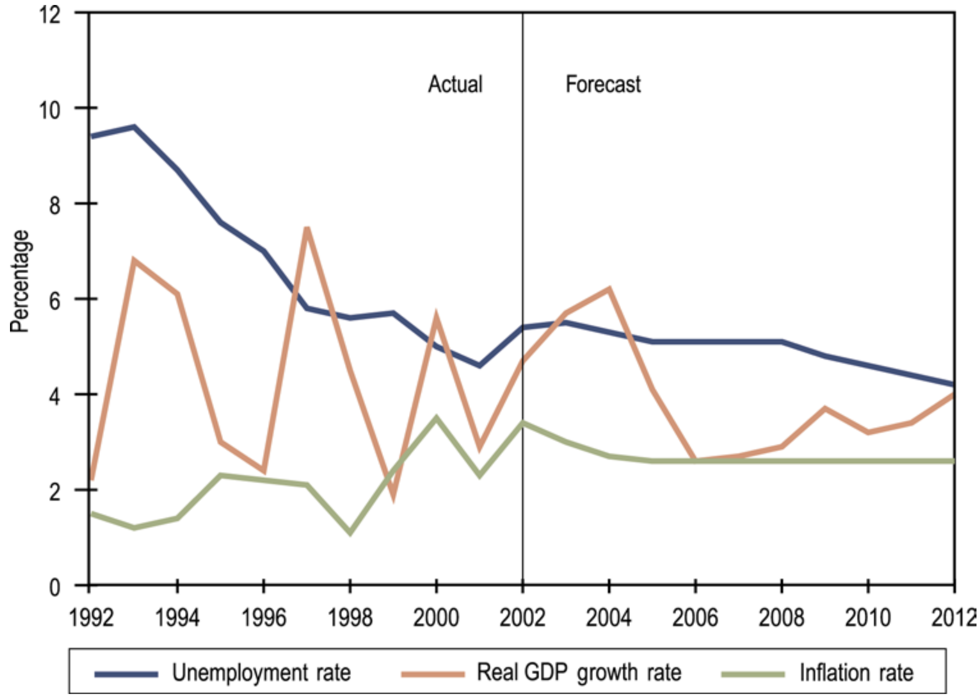


Figure 1.5. Alberta GDP growth, unemployment, and inflation rates

2 Crude Bitumen

2.1 Reserves of Crude Bitumen

2.1.1 Provincial Summary

The EUB estimates Alberta's crude bitumen reserves by separately calculating those reserves likely to be recovered by mining methods and those by in situ methods. As of December 31, 2002, remaining established reserves of crude bitumen are estimated to be 27.72 billion cubic metres (10^9 m^3), of which 1.84 10^9 m^3 are within active development areas. Other than a slight decrease due to production, these numbers are unchanged from last year. The EUB continues to be engaged in a significant project to update these reserves, but given the scale of the resources and the effort required to produce accurate estimates, the new values will not be available until the report scheduled for release in 2004. 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[a]	Remaining established reserves under active development
Mineable	18.0	5.59	0.43	5.17	1.32
In situ	241.2	22.74	0.19	22.56	0.52
Total[a]	259.2 (1 631)[b]	28.33 (178.3)[b]	0.61 (3.8)[b]	27.72 (174.4)[b]	1.84 (11.6)[b]

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

Figure 2.1 compares the relative size of Alberta's remaining established crude oil and crude bitumen reserves with Saudi Arabia's proven remaining crude oil reserves. It illustrates that the Alberta bitumen reserves are over two-thirds of Saudi Arabia's total oil reserves.

The changes in established crude bitumen reserves for 2002 are shown in Table 2.2. The portion of established crude bitumen reserves within approved surface-mineable and in situ areas under active development are shown in Tables 2.3 and 2.4 respectively.

Crude bitumen production from in situ operations totalled 17.4 million cubic metres (10^6 m^3) in 2002. Production from the three current surface mining projects amounted to 30.7 10^6 m^3 in 2002, with 15.7 10^6 m^3 from the Syncrude Canada Ltd. Project, 15.0 10^6 m^3 from the Suncor Energy Inc. project (a large increase from last year's 8.9 10^6 m^3, due to a major expansion), and 0.03 10^6 m^3 from the Albian Sands Energy Inc. project, which began commercial bitumen production at the end of 2002.

Table 2.2. Change in established crude bitumen reserves (10^6 m^3)

	2002	2001	Change[a]
Initial established reserves			
Mineable	5 590	5 590	0
In situ	22 740	22 740	0
Total	28 330 (178 280)[b]	28 330 (178 280)[b]	0
Cumulative production			
Mineable	425	395	+31
In situ	185	167	+17
Total[a]	610	562	+48
Remaining established reserves			
Mineable	5 165	5 195	-31
In situ	22 555	22 573	-17
Total	27 720 (174 439)[b]	27 768 (174 741)[b]	-48

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

Table 2.3. Mineable crude bitumen reserves in areas under active development as of December 31, 2002

Development	Project area[b] (ha)	Initial mineable volume in-place[c] (10^6 m^3)	Initial established mineable reserve[c] (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established mineable reserve (10^6 m^3)
Albian Sands	10 096	574	178	0[d]	178
Suncor	15 370	878	604	159	445
Syncrude	21 672	1 433	959	266	693
Total	47 138	2 885	1 741	425	1 316

[a]TrueNorth Energy's Fort Hills project, approved in late 2002, is not included.
[b]The project areas correspond to the areas defined in the project approval.
[c]Definitions are given in Figure 2.2.
[d]Albian's actual production for 2002 was just under 35 000 m^3.

Table 2.4. In situ crude bitumen reserves in areas under active development as of December 31, 2002

Development	Initial volume in-place[a] (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	6.9	1.7
Subtotal	21.6		8.6	6.9	1.7
Athabasca Oil Sands Area					
Thermal commercial projects	107.2	50	53.6	1.4	52.2
Primary recovery schemes	2 435.5	5	121.7	13.3	108.4
Subtotal	2 542.7		175.3	14.7	160.6
Cold Lake Oil Sands Area					
Thermal commercial projects	802.8	25	200.7	115.9	84.8
Primary production within projects	601.1	5	30.1	12.0	18.1
Primary recovery schemes	4 347.1	5	217.3	25.4	191.9
Lindbergh primary production	1 309.3	5	65.4	4.3	61.1
Subtotal	7 060.3		513.5	157.6	355.9
Experimental Schemes (all areas)					
Active	8.1	15	1.2	0.8	0.4
Terminated	87.4	10	9.1	5.1	4.0
Subtotal	95.5		10.3	5.9	4.4
Total	9 720.1		707.7	185.1	522.6

[a]Thermal reserves are assigned only for lands approved for thermal recovery and having completed drilling development.
[b]Cumulative production to December 31, 2002, includes amendments to production reports.

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 Athabasca, Cold Lake, and Peace River oil sands areas. EUB-designated oil sands areas (OSAs) define the areal extent of crude bitumen occurrence, and oil sands deposits (OSDs) contain the specific geological zones declared as oil sands deposits.

Initial in-place volumes of crude bitumen in each deposit were determined using drillhole data and geophysical logs. The 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, and 6 mass per cent and 3.0 m for surface-mineable areas. 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 volumetric resources are presented on a deposit basis in the table Crude Bitumen Resources and Basic Data, located on the accompanying CD-ROM and summarized by formation in Table 2.5. Individual maps to year-end 1995 are shown in EUB *Statistical Series 96-38*.[1]

Table 2.5. 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 (%)	Average bitumen saturation: Pore volume (%)	Average porosity (%)
Athabasca						
Grand Rapids	8 678	689	7.2	6.3	56	30
Wabiskaw-McMurray (mineable)	17 998	286	30.5	9.7	69	30
Wabiskaw-McMurray (in situ)	119 234	4 329	19.0	7.9	62	28
Nisku	10 330	499	8.0	5.7	63	21
Grosmont	50 500	4 167	10.4	4.7	68	16
Subtotal	206 740					
Cold Lake						
Grand Rapids	17 304	1 709	5.8	9.5	61	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	328	22.5	5.3	65	19
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	20 518					
Total	259 205					

The surface mineable area (SMA) is an EUB-defined area of 37 townships[2] north of Fort McMurray covering that part of the Athabasca Wabiskaw-McMurray deposit where the total overburden generally does not exceed 75 m. As such, it is presumed that the primary method of recovery will be through the use of surface-mining techniques, unlike the rest of Alberta's crude bitumen area, where recovery will be through in situ methods.

The estimate of the initial volume in-place of crude bitumen within the SMA remains unchanged at 18.0 10^9 m^3.

Calculation of in situ resources includes a continuing conversion from the former manual process to an automated mapping and resource evaluation system. As a result, the resources for a number of the pools have been determined from geological maps instead of by the original building-block method.

The initial volume of crude bitumen in-place for in situ areas for the designated deposits as of December 31, 2002, is 241.2 10^9 m^3, unchanged from last year.

[1] EUB, 1996, *Crude Bitumen Reserves Atlas, Statistical Series 96-38.*

[2] The boundary of the SMA is currently under review and is expected to change.

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.[3]

The initial mineable volume in-place of crude bitumen is estimated as of December 31, 2002, to be 9.4 10^9 m^3. Reduction factors were applied to this initial mineable resource volume to determine the established mineable reserve volume. These factors account for ore sterilization due to environmental protection corridors along major rivers (10 per cent), small isolated ore bodies (10 per cent), location of surface facilities (plant sites, tailings ponds, waste dumps) (10 per cent), and mining/extraction losses (18 per cent). The resulting initial established mineable reserve of crude bitumen is estimated to be 5.6 10^9 m^3, unchanged from December 31, 2001.

About a quarter of the initial established mineable reserve 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 425 10^6 m^3. TrueNorth Energy received EUB approval for its Fort Hills Mine in late 2002, but the reserves for this project are not yet included in Table 2.3.

The remaining established mineable crude bitumen reserve as of December 31, 2002, is 5.17 10^9 m^3, slightly lower than last year due to the production of nearly 31 10^6 m^3 in 2002. The crude bitumen reserves categories are presented in **Figure 2.2**.

Table 2.3 shows the remaining established mineable crude bitumen reserves from deposits under active development as of December 31, 2002.

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 attributable to thermal development were determined using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum zone thickness of 10.0 m. For primary development, the same saturation cutoff of 3 mass per cent was used, with a minimum zone thickness of 3.0 m. Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to the areas within the cutoffs. The recovery factor for thermal development is lower than some of the active project recovery factors to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas.

The EUB's 2002 estimate of initial established reserves for in situ areas remains unchanged at 22.74 10^9 m^3. This estimate will be significantly refined and the results released in the report scheduled for 2004. Cumulative production within the in situ areas now totals 185 10^6 m^3, of which 158 10^6 m^3 is from the Cold Lake OSA. As a result of the 17.4 10^6 m^3 production in 2002, remaining established reserves of crude bitumen from in situ areas are now slightly lower, at 22.56 10^9 m^3.

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

The EUB's 2002 estimate of the established in situ crude bitumen reserves under active development is shown in Table 2.4. 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 areas is estimated to be 522.6 10^6 m^3, an increase of 35.9 10^6 m^3 from 2001. The increase is due to the addition this year of six commercial thermal projects in the Athabasca Oil Sands Area. The six projects are the Devon Canada Corporation Dover Project, EnCana Corporation Foster Creek and Christina Lake Projects, Petro-Canada McKay River Project, Suncor Energy Inc. Firebag Project, and Japan Canada Oil Sands Limited Hangingstone Project.

2.1.5 Ultimate Potential of Crude Bitumen

The EUB estimates the ultimate in-place volume of crude bitumen to be about 400 10^9 m^3, consisting of 22 10^9 m^3 within the SMA in deposits that may eventually be amenable to surface mining (as well as some limited in situ recovery), and the remainder being deeper deposits that will require the use of in situ recovery or underground mining techniques.

Although drilling and log analyses indicate the large ultimate in-place volume, knowledge of variations in quality and the effect of this on recovery potential is still limited. In addition, there has been little experimentation to date to establish the expected recovery factor for some types of resources, particularly carbonates. Therefore, the portions of in-place volumes for the Cretaceous sand and Paleozoic carbonate deposits that will require the use of in situ recovery methods were broken down into established and probable categories, and different recovery factors were applied to each category in establishing the ultimate potential of crude bitumen for the in situ areas. The recovery factors selected reflect the EUB's current knowledge respecting the quality of the in-place resources, the amount of experimentation done to date to establish recovery techniques, and a projection of future improvements in those techniques.

The ultimate potential (which is the portion of ultimate in-place volume that is potentially recoverable) of crude bitumen from Cretaceous sediments by in situ recovery methods is estimated to be 33 10^9 m^3 and from carbonate sediments some 6 10^9 m^3. Nearly 11 10^9 m^3 are 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. For current projects, it is also assumed that tailings ponds and discard sites will either be located on nonmineable areas or be removed from the mineable areas in order to recover underlying economic mineable ore. The total ultimate potential crude bitumen is therefore about 50 10^9 m^3.

2.2 Supply of and Demand for Crude Bitumen

In this report, crude bitumen refers to total bitumen production; nonupgraded bitumen refers to the portion of crude bitumen production blended with diluent and sent to markets by pipeline; upgraded bitumen refers to the portion of crude bitumen production upgraded to synthetic crude oil (SCO), which is used by refineries as feedstock. 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 SCO, and disposition of both SCO and blended bitumen.

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, either in elemental form or as a constituent of oil sands coke, is removed. 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 in the manufacturing of 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 in the earth. For these deposits, in situ methods have been proven technically and economically feasible. These methods typically use heat from 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 currently used in Alberta as diluent. 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 not returned to the province. Other products such as naptha, light crude oil, and synthetic oil can also be used as diluent to allow bitumen to meet pipeline specifications. Use of heated and insulated pipelines may decrease the amount of diluent required over time.

2.2.1 Crude Bitumen Production

In 2002, Alberta produced 131.8 thousand (10^3) m^3/d of crude bitumen, with surface mining accounting for 64 per cent and in situ for 36 per cent. In the same year, nonupgraded bitumen and SCO accounted for 48 per cent of Alberta's total crude oil and equivalent production, compared with 43 per cent in 2001.

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 price buyers are willing to pay. Other factors that bear on project economics are refining capacity to handle bitumen or SCO and competition with other supply sources in the U.S. and Canadian markets.

2.2.1.1 Mined Crude Bitumen

Crude bitumen production increased by 25 per cent over the past year, reaching a level of 84.2 $10^3 m^3/d$, in 2002, with Syncrude and Suncor each accounting for roughly 50 per cent. The primary reason for this increase was Suncor's major expansion of Project Millennium. Increased production due to the expansion began late in 2001 and continued through 2002, raising Suncor's mining production 69 per cent to 41.2 $10^3 m^3/d$. Syncrude's production remained close to 2001 levels.

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

- the existing production and expected expansions of Suncor, including completion of the Millennium and Voyageur projects;
- the existing and expected expansions of Syncrude, including stages three and four of the four-stage project that began in 1996;
- the Albian Sands project, which began production in December 2002, and its expansion planned for 2008;
- the Canadian Natural Resources Limited (CNRL) Horizon Project, with proposed production beginning in 2008;
- the Shell Jackpine Mine Project, with production expected in late 2010.

Last year's forecast included the TrueNorth Energy Fort Hills Oil Sands Project; however, in January 2003 the board of directors of TrueNorth Energy announced their decision to defer construction of the $3.5 billion Fort Hills Oil Sands Project.

The EUB is aware of other announced projects, but they have not been considered in this forecast because of uncertainties about timing and project scope. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the EUB assumed that potential market restrictions, cost overruns, construction delays, and availability of suitable refinery capacity on a timely basis may impact the timing of production schedules for these projects. The EUB assumed that total mined bitumen production will increase from 84.2
$10^3 m^3/d$ in 2002 to some 248 $10^3 m^3/d$ by 2012. **Figure 2.3** illustrates total mined bitumen production over the forecast period.

2.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production has increased from 20.1 $10^3 m^3/d$ in 1992 to 47.6 $10^3 m^3/d$ in 2002. To date, the majority of in situ bitumen has been marketed in nonupgraded form outside of Alberta and only a small amount (5 per cent) is used in Alberta refineries.

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 projects. **Figure 2.3** illustrates the EUB's in situ crude bitumen forecast. It shows that in situ crude bitumen production is expected to rise to 123 10^3 m^3/d over the forecast period.

It is expected that by the end of the forecast period some 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 two major upgraders, Suncor and Syncrude, produced 32.7 10^3 m^3/d and 37.1 10^3 m^3/d of SCO respectively in 2002. The EUB expects significant increases in the SCO production over the forecast period based on the following projects:

Suncor

- completion of the Millennium project;
- the addition of an in situ bitumen recovery operation (Firebag In Situ Oil Sands Operation), with start-up expected in 2004;
- modification of the upgrader (the addition of a vacuum tower) to increase capacity of SCO starting in 2005; and
- Voyageur, which involves expanding the existing facility and constructing a new upgrader by 2008.

Syncrude expansions

- stage two, which consists of the Aurora Train 1 and additional debottlenecking of the upgrader at Mildred Lake in 2002;
- stage three, which includes the upgrader expansion and a second train of production at Aurora by 2005; and
- stage four, which includes Aurora Train 3 and further upgrader expansion in 2009.

Shell

- the start-up of the new upgrader at Scotford, near Edmonton, in 2003, using crude bitumen from the Albian Sands project;

- an expansion in 2008 to correspond with the expansion of the Muskeg Mine; and
- 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 approximately 40 kilometres (km) southeast of Fort McMurray. Phase I of this project will commence in 2006. The second phase is expected to double the capacity of all components by 2010.

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

The conversion of crude bitumen to SCO uses different technologies at the Suncor and Syncrude existing plants. 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 proposed overall liquid yield factor for the Albian Sands project, via the Shell upgrader using a hydrocracking process, is anticipated to be at or above 0.90. The OPTI/Nexen - Long Lake Project will use a new field upgrading technology and hydrocracking that will have a liquid yield factor of about 0.85. CNRL will use delayed coking with an about 0.86 liquid yield factor.

To project SCO production over the forecast period, the EUB included existing production from Suncor and Syncrude and their planned expansions, plus the new production expected from Shell Canada, OPTI/Nexen, and CNRL. 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. **Figure 2.4** shows the EUB projection of SCO production. It is expected that the SCO production will increase from 69.7 10^3 m^3/d in 2002 to 235 10^3 m^3/d in 2012.

2.2.3 Pipelines

With the expected increase in both SCO and nonupgraded bitumen over the forecast period, pipeline capacity availability is essential to move new production to markets. The current pipeline systems in the Cold Lake and Athabasca areas are tabulated in Table 2.6.

The Cold Lake pipeline system is capable of delivering heavy crude from the Cold Lake area to Hardisty or Edmonton. The Cold Lake system became Canada’s largest heavy oil gathering pipeline through its recent expansion. 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.

Table 2.6. Alberta SCO and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3)
Cold Lake Area Pipelines		
Cold Lake Heavy Oil Pipeline	Hardisty	31.8
Cold Lake Heavy Oil Pipeline	Edmonton	37.3
Husky Oil Pipeline	Hardisty	21.2
Husky Oil Pipeline	Lloydminster	24.3
Echo Pipeline	Hardisty	9.1
Fort McMurray Area Pipelines		
Athabasca Pipeline	Hardisty	21.0
Corridor Pipeline	Edmonton	34.0
Alberta Oil Sands Pipeline	Edmonton	43.7
Oil Sands Pipeline	Edmonton	20.7

The Athabasca pipeline delivers semi-processed product and bitumen blends to Hardisty and has the potential to carry 90.6 10^3 m^3/d. The Corridor pipeline will transport diluted bitumen from the Albian Muskeg River mining project to the Shell Scotford upgrader. Capacity of the pipeline can be increased by 15.9 10^3 m^3/d through the addition of four pump stations. The Alberta Oil Sands pipeline is the exclusive transporter for Syncrude. An expansion to increase capacity to 61.8 10^3 m^3/d is planned for 2004. The Oil Sands Pipeline transports Suncor synthetic oil to the Edmonton area.

Table 2.7 lists the export pipelines and their destination and capacities. Enbridge is scheduled to complete the third and final phase of the Terrace Expansion project by mid-2003, bringing an additional 22.3 10^3 m^3/d of capacity to the system. The Express pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends into Wood River, Illinois. Future capacity is expected to increase to 44.8 10^3 m^3/d. Taresen Pipeline (TransMountain) has currently 39.3 10^3 m^3/d of capacity for moving light and medium and refined crude oil. Taresen Pipeline can ship up to 4800 m^3/d of heavy crude; however, this will result in a reduced total capacity to 33.1 10^3 m^3/d. Taresen may decide to expand its system to ship up to 4800 m^3/d of heavy oil shipments and maintain an average pumping rate of 38.5 10^3 m^3/d. 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.

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

Table 2.7. 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
Express Pipeline	U.S. Rocky Mountains U.S. midwest	27.3
Milk River Pipeline	U.S. Rocky Mountains	15.9
Rangeland Pipeline	U.S. Rocky Mountains	10.3
Taresen Pipeline (TransMountain)	British Columbia U.S. west coast Offshore	39.3
Total		405.0

SCO intake to a fraction of total crude requirements, and the high level of aromatics (benzene) that may have undesirable environmental properties.

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 2002, five Alberta refineries, with total capacity of 70.3 10^3 m^3/d, used 26.7 10^3 m^3/d of SCO and 2.4 10^3 m^3/d of nonupgraded bitumen. The Alberta refinery demand for SCO represents 38 per cent of Alberta SCO production and 5 per cent of nonupgraded bitumen production.

Alberta's demand for SCO and nonupgraded bitumen will experience major changes during the forecast period due to Petro-Canada's Refinery Feed Conversion Program. The scope of the program involves two phases. In Phase 1, Alberta light-medium crude will be replaced with approximately 13.5 10^3 m^3/d of bitumen. In Phase 2, the remainder of the refinery will be converted to process a total of 27.0 10^3 m^3/d of bitumen. The supply of bitumen from Petro-Canada's commercial projects of MacKay River and Meadow Creek, together with other Petro-Canada holdings, is expected to exceed 27.0 10^3 m^3/d. **Figure 2.5** shows that in 2012 demand for SCO and nonupgraded bitumen will increase to some 49.0 10^3 m^3/d. It is projected that SCO will account for 47 per cent and nonupgraded bitumen will constitute 53 per cent.

Given the current quality of SCO, western Canada's nine refineries, with total capacity of 92 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 extra-provincial Canadian market for Alberta SCO.

Demand for Alberta SCO will come primarily from existing markets vacated by declining light crude supplies, plus 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 575 10^3 m^3/d, and the U.S. Rocky Mountain region, with refining capacity of 85.8 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, U.S. west coast, and the Far East.

Figure 2.5 shows that over the forecast period removals from Alberta of SCO will increase from 43.8 10^3 m^3/d to 212 10^3 m^3/d and the removals of nonupgraded bitumen will increase from 45.2 10^3 m^3/d to 66 10^3 m^3/d.

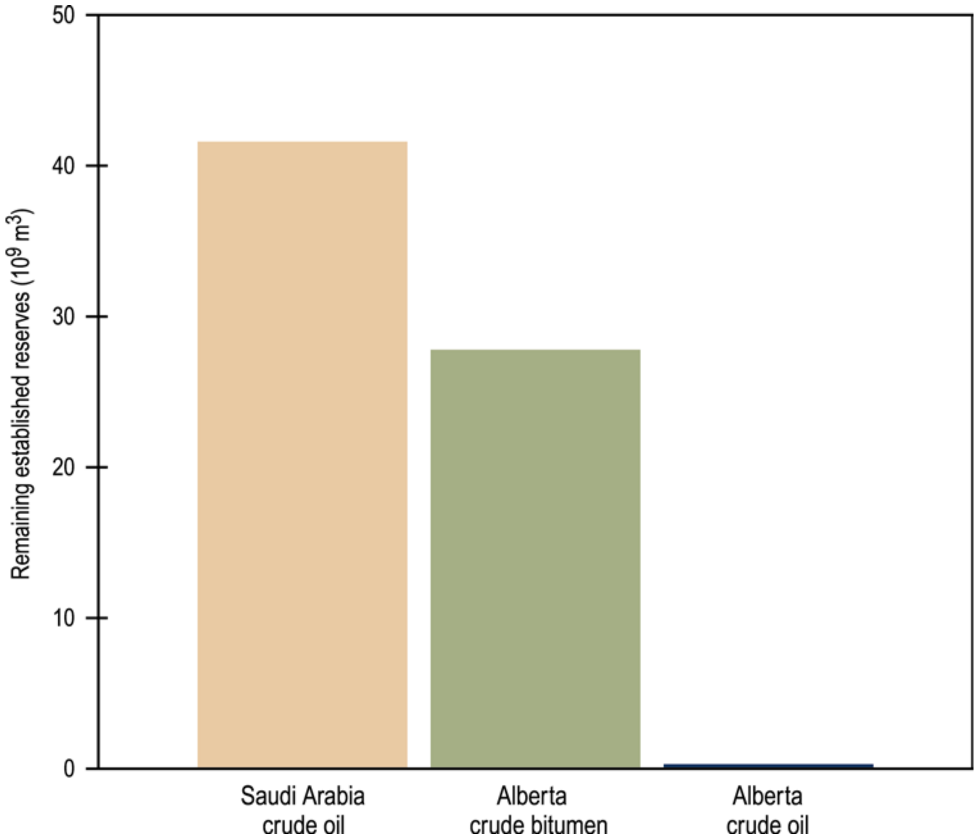
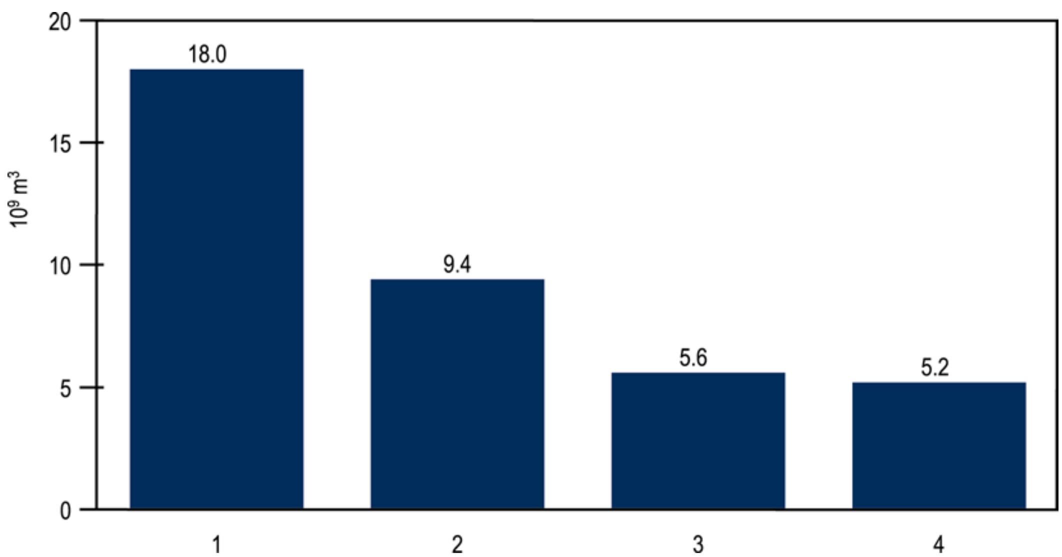


Figure 2.1. Comparison of Alberta and Saudi Arabia oil reserves



1. **Initial volume in-place** - gross resource volume of crude bitumen established to exist within the surface-mineable area.
2. **Initial mineable volume in-place** – resource volume of crude bitumen calculated using minimum saturation and thickness criteria and based upon the application of economic-strip-ratio criteria within the surface mineable area.
3. **Initial established mineable reserve** – recoverable volume of crude bitumen established within category 2 but excluding mining, extraction, and isolation ore losses and areas unavailable because of placement of mine surface facilities and environmental buffer zones.
4. **Remaining established mineable reserve** – recoverable volume of crude bitumen established within category 3 minus cumulative production.

Figure 2.2. Crude bitumen resource and reserve categories

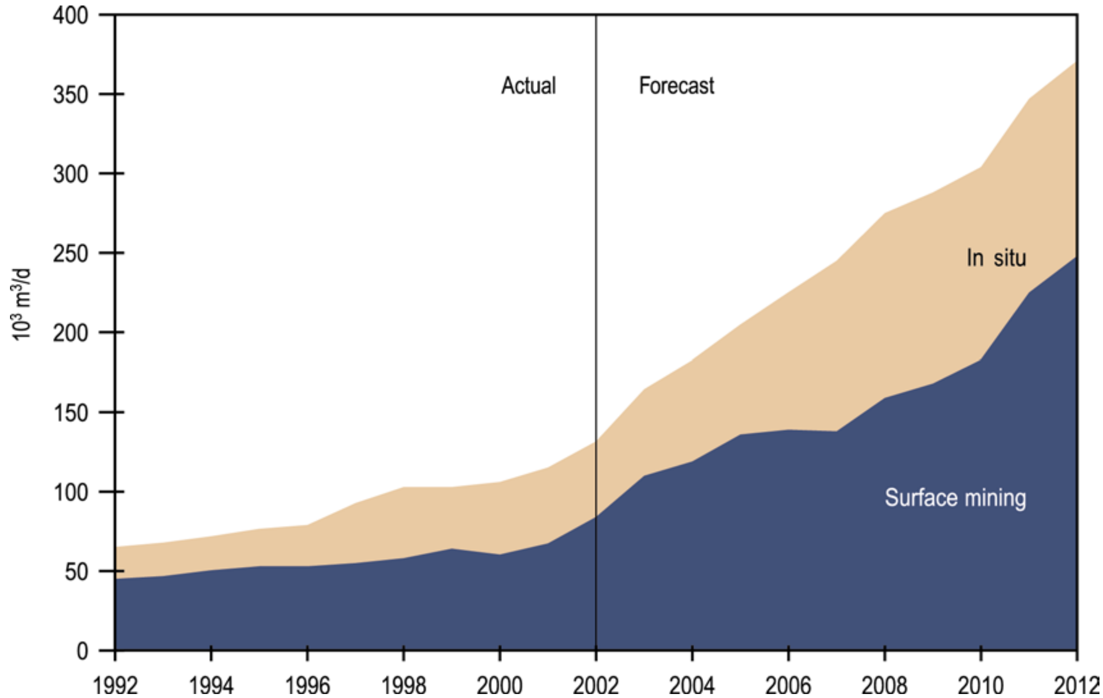


Figure 2.3. Alberta crude bitumen production

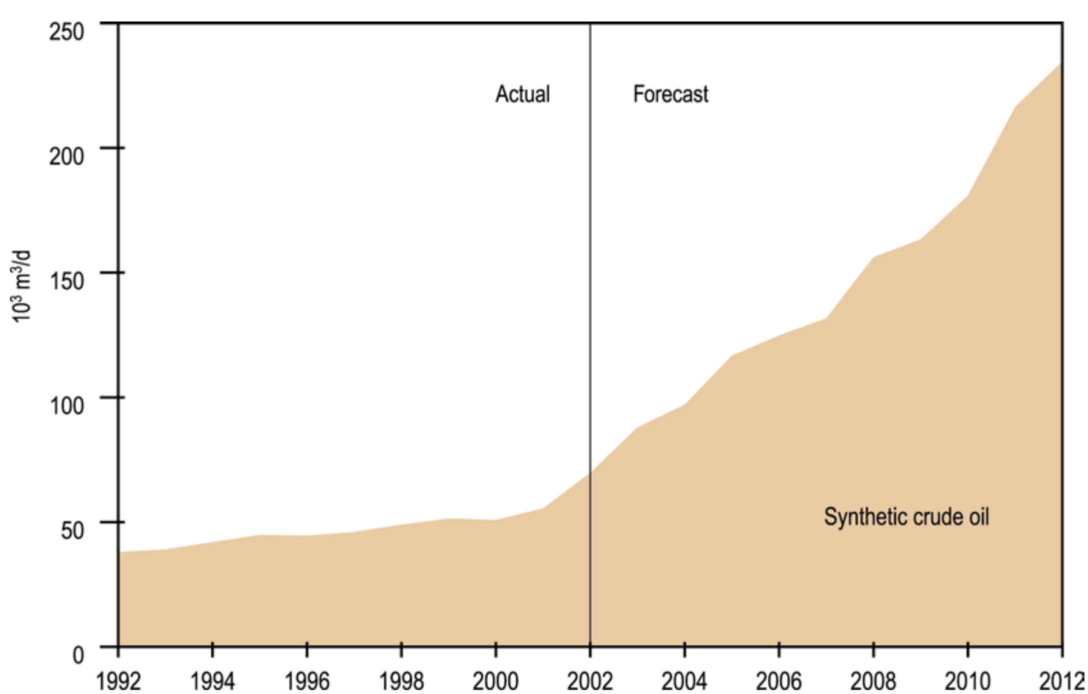


Figure 2.4. Alberta synthetic crude oil production

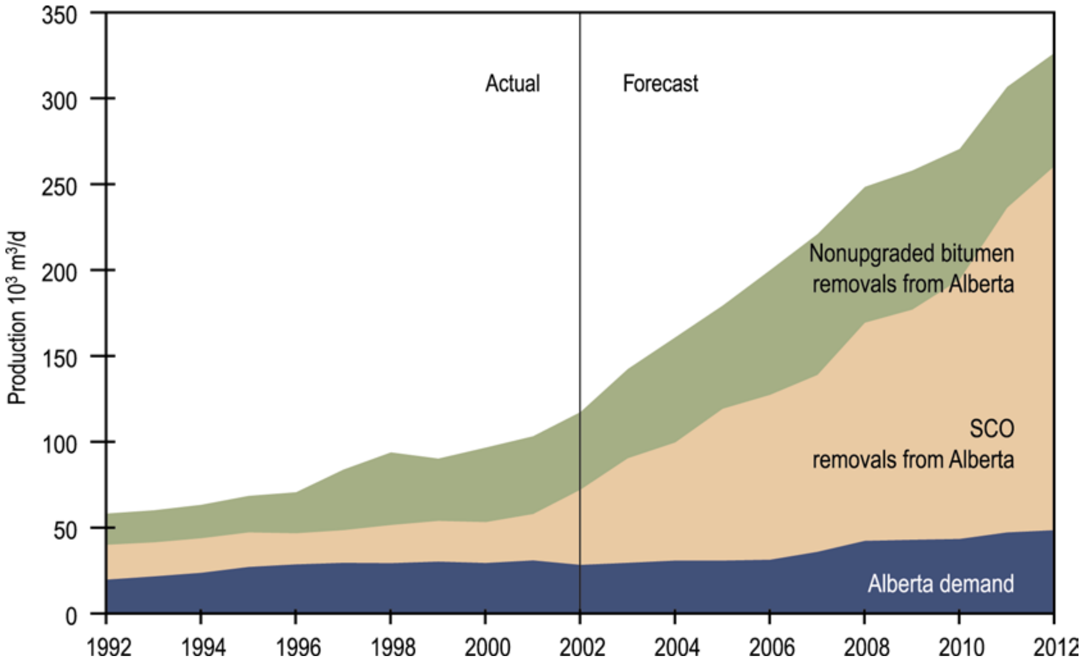


Figure 2.5. Alberta demand and exports of crude bitumen and SCO

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 260 million cubic metres (10^6 m^3), or 1.64 billion barrels, at year-end 2002. This is a decrease from year-end 2001 of 18.1 10^6 m^3, resulting from all reserve adjustments and production that occurred during 2002. **Figure 3.1** shows that the province's remaining conventional oil reserves have been reduced by half since 1990. The changes in reserves and cumulative production for light-medium and heavy crude oil to year-end 2002 are shown in Table 3.1

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

	2002	2001	Change
Initial established reserves[a]			
Light-medium	2 251.3	2 238.9	+12.4
Heavy	352.0	344.2	+7.8
Total	2 603.3	2 583.0	+20.2
Cumulative production[a]			
Light-medium	2 058.2	2032.8	+25.4
Heavy	284.8	271.9	+12.9
Total	2 343.0	2304.7	+38.3 (241 10^6 bbls)
Remaining established reserves[a]			
Light-medium	193.3	206.1	-13.0
Heavy	67.2	72.3	-5.1
Total	260.3 (1 638 10^6 bbls)	278.3	-18.1

[a] Discrepancies are due to rounding.

3.1.2 Reserves Growth

A breakdown of the year's reserves changes, including additions, revisions, and enhanced recovery, is presented in Table 3.2, while a detailed history of these changes is shown in **Figures 3.2**. The initial established reserves attributed to the 269 new oil pools booked in 2002 totalled 7.0 10^6 m^3 (26 thousand [10^3] m^3 per pool), down from 9.1 10^6 m^3 in 2001, while development of existing pools during 2002 added another 8.1 10^6 m^3. New and expanded water flood schemes added initial established reserves of 0.6 10^6 m^3. Reserve additions from new waterfloods continue to decline due to smaller pools and lack of suitable quality candidates for such schemes **(Figure 3.3)**. Net reserve revisions were positive for both light-medium (1.1 10^6 m^3) and heavy crude (3.4 10^6 m^3). The resulting total increase in initial established reserves for 2002 amounted to 20.2 10^6 m^3, down from last year's total of 28.6 10^6 m^3. Table B.1 in Appendix B provides a history of conventional oil reserve growth and cumulative production starting in 1968.

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

	Light-medium	Heavy	Total
New discoveries	6.2	0.8	7.0
Development of existing pools	4.9	3.2	8.1
Enhanced recovery (new/expansion)	0.2	0.3	0.6
Reassessment	+1.1	+3.4	+4.6
Total	12.4	7.8	20.2

Reserve additions resulting from drilling and new enhanced recovery schemes totalled 15.6 10^6 m^3, down significantly from 23.5 10^6 m^3 in 2001. These additions replaced 41 per cent of Alberta's 2002 conventional crude oil production of 38.3 10^6 m^3.

3.1.3 Oil Pool Size

At year-end 2002, oil reserves were assigned to some 7500 light-medium and 2500 heavy crude oil pools in the province. Sixty-one per cent of these pools consist of a single well. The distribution of reserves by pool size shown in Table 3.3 indicates that some 89 per cent of the remaining reserves is contained in the largest 14 per cent of pools. By contrast, the smallest 72 per cent of pools contain less than 5 per cent of the province's remaining reserves. **Figure 3.4** illustrates the historical trends in the size of new single-well oil pools. While the median pool size has remaining fairly constant over time, at near 10 10^3 m^3 per pool, the average has declined from 80 10^3 m^3 to about 30 10^3 m^3 since 1980.

Table 3.3. Distribution of oil reserves by pool size

Pool size range[a]	Pools		Initial established reserves		Remaining established reserves	
(10^3 m^3)	No.	%	10^6 m^3	%	10^6 m^3	%
1000 or more	289	3	2 151	83	170	65
100-999	1 070	11	328	12	61	23
30-99	1 391	14	76	3	17	7
1-29	71 841	72	48	2	12	5
Total	9 934	100	2 603	100	260	100

[a] Based on initial established reserves.

3.1.4 Pools with Largest Reserve Changes

Some 1800 oil pools were re-evaluated over the past year, resulting in positive revisions totalling 24.6 10^6 m^3 and negative revisions totalling 20.0 10^6 m^3, for a net total of plus 4.6 10^6 m^3. The Ferrier Belly River Q, Cardium G&L Pool saw an increase in reserves of 7197 10^3 m^3 due to recognition of a higher recovery factor for the pool's waterflood operation. Likewise, upward revision to the recovery efficiency in the Chauvin South Mannville MU #1 waterflood increased reserves by 2140 10^6 m^3. Table 3.4 lists those pools having the largest reserve changes in 2002.

Table 3.4. Major oil reserve changes, 2002

Pool	Initial established reserves (10^3 m^3) 2002	Change	Main reason for change
Alderson Lower Mannville C5C	32	-186	Reassessment of reserves
Astotin Upper Mannville H	332	+221	Reassessment of reserves
Auburndale Wainwright B	631	+206	Pool development
Bonnie Glen D-3 A	82 700	-300	Reassessment of reserves
Boundary Lake South Triassic E	4 725	+651	Reassessment of waterflood reserves
Chauvin South Mannville MU #1	13 370	+2 140	Reassessment of waterflood reserves
Cyn Pem Viking A	17	-185	Reassessment of reserves
Cyn Pem Viking B	174	+174	New pool
Dawson Slave Point DDD	163	+163	New pool
Dawson Slave Point FFF	148	+148	New pool
Elnora Nisku A	210	+174	Pool development and reassessment of reserves
Enchant Arcs CC & EE	268	+112	New waterflood
Fenn West D-2 I	114	-400	Reassessment of primary reserves
Ferrier Belly River Q, Cardium G&L	19 400	+7 197	Reassessment of waterflood reserves
Girouxville East BVHL B and Giwood D	10 180	+242	Reassessment of waterflood reserves
Hamburg Slave Point AA	142	+142	New pool
Homglen-Rimbey D-3	3484	+523	Reassessment of reserves
Jenner Upper Mannville OO	1 792	+443	Pool development and reassessment of reserves
Joffre Viking	6 682	+149	Reassessment of solvent and waterflood
Judy Creek Beaverhill Lake B	18 900	-1 788	Reassessment of water and solvent flood reserves
Kelsey Lower Manville B	465	+167	Reassessment of reserves
Lloydminster Sparky K	4 537	+1 125	Reassessment of reserves
Lloydminster Sparky ZZZ	924	+487	Pool development and reassessment of reserves
McKinley Cadotte D	250	+125	New waterflood
Normandville Beaverhill Lake B	149	+124	Pool development and reassessment of reserves
Norris Upper Mannville H	198	-272	Reassessment of reserves

(continued)

Table 3.4. Major oil reserve changes, 2002 (concluded)

Pool	Initial established reserves (10^3 m^3) 2002	Change	Main reason for change
Peco Belly River C,H,J,K,O	486	+156	Pool development and reassessment of reserves
Pembina Nisku GG	256	+256	New pool
Pembina Nisku M	2 550	+150	Reassessment of solvent flood reserves
Penny Barons A	396	+171	Pool development and reassessment of reserves
Provost Blairmore	1 674	+216	Reassessment of reserves
Provost Cummings Y	368	+128	Reassessment of reserves
Provost Dlina C8C	214	+131	Pool development
Provost Dina N	3 562	+869	Pool development and reassessment of reserves
Provost Lloydminster O	5 316	+279	Reassessment of waterflood reserves
Provost Blairmore B	3 251	+401	Pool development
Sturgeon Lake South D-3	27 180	-620	Reassessment of reserves
Sturgeon Lake South Triassic A	1 072	+343	Reassessment of primary reserves
Suffield Upper Mannville D	1 271	+172	Pool development and reassessment of reserves
Suffield Upper Mannville FF	628	+251	Reassessment of reserves
Suffield Upper Mannville GGG	75	-113	Reassessment of reserves
Suffield Upper Mannville OOO	89	-147	Reassessment of reserves
Swalwell D-1 A	850	+252	Pool development
Swimming McLaren D	399	+371	Pool development
Virginia Hills Belloy A	7 316	+166	Reassessment of waterflood reserves
Wayne Rosedale Nisku E	271	+133	Pool development and reassessment of reserves
Wayne Rosedale Nisku F	+166	+166	New pool
West Drumheller D-2 A	5 020	+201	Reassessment of reserves
Wildmere Lloyd A & Sparky E	5 930	+600	Reassessment of waterflood reserves
Willesden Green Cardium U	522	+307	Pool development and reassessment of reserves

3.1.5 Distribution by Recovery Type and Geological Formation

The distribution of conventional crude oil reserves by drive mechanism is illustrated in **Figure 3.5**. Table 3.5 shows that waterflood projects have added 654 10^6 m^3, or 25 per cent, to 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 increase in recovery efficiency over primary.

The distribution of reserves by geological period, depicted graphically in **Figure 3.6**, indicates that 34 per cent of remaining established reserves will come from formations within the Lower Cretaceous and 21 per cent from the Upper Devonian. This contrasts with 1990, when 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. A detailed breakdown of reserves by geological period and formation is presented in tabular form in Appendix B (Tables B.2 and B.3).

Table 3.5. Conventional crude oil reserves by recovery mechanism as of December 31, 2002

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	3 867	866	0	0	866	22	-	-	23
Waterflood	2 892	425	390	0	815	15	13	-	28
Solvent flood	928	256	164	110	530	28	18	12	57
Gas flood	112	33	8	0	41	39	7	-	36
Heavy									
Primary depletion	1 655	211	0	0	211	13	-	-	13
Waterflood	397	48	92	0	140	12	23	-	35
Total	9 852	1 839	654	110	2 603	19			26
Percentage of total initial established reserves		71%	25%	4%	100%				

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 3.7** shows Alberta's historical and forecast growth of initial established reserves. **Figure 3.8** 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. Approximately 75 per cent of the estimated ultimate potential for conventional crude oil has been produced to year-end 2002. Remaining established reserves of 260 10^6 m^3 represent 8 per cent of the ultimate potential. Known discoveries represent 83 per cent of the ultimate potential, leaving 17 per cent (527 10^6 m^3) of the ultimate potential yet to be discovered. This added to remaining established reserves yields 787 10^6 m^3 of conventional crude oil that is available for future production.

In 2002, both the remaining established reserves and the annual production of crude oil declined. However, there are 527 10^6 m^3 yet to be discovered, which will mitigate the impact of these declines. At the current rate of annual reserve growth, it will take over 30 years to find the projected reserves yet to be discovered. Additions to existing pools and the discovery of new pools will continue to bring on new reserves and associated production each year.

Any future decline in conventional crude oil production within Alberta will be more than offset by increases in crude bitumen and synthetic production, as discussed in Section 2.2. In fact, starting in 2001 crude bitumen production has exceeded conventional crude oil production.

3.2 Supply of and Demand for Crude Oil

3.2.1 Crude Oil Supply

Over the past several years, production of light-medium and heavy crude oil has been on decline in Alberta. In 2002, total crude oil production declined to 105.0 10^3 m^3/d. Light-medium crude oil production declined by approximately 6.6 10^3 m^3/d (9 per cent) to 69.7 10^3 m^3/d from its 2001 level. Heavy crude oil production experienced a decline of some 2.8 10^3 m^3/d (7 per cent) below 2001 levels to 35.3 10^3 m^3/d. This resulted in an overall decline in total crude oil production of 8 per cent from 2001 to 2002, compared to the 4 per cent decline from 2000 to 2001.

While the higher decline rate in 2002 reflects industry's reaction to the uncertainty in the market place in 2002, over time average oil well productivity in Alberta has declined. **Figure 3.9** shows total crude oil production and the number of producing wells by year. As illustrated in this figure, while the number of total producing wells has increased from 26 400 in 1992 to 34 600 in 2002, crude oil production has been on decline.

With regard to average well productivity, as illustrated in **Figure 3.10,** roughly half the crude oil wells produce less than 2 m^3/d per well. In 2002, these 17 700 oil wells operated at an average rate of 1 m^3/d and produced only 16 per cent of the total crude oil production.

The number of successful oil wells brought on production in 2002 declined to 1661, compared to 2220 in 2001, a decline of 25 per cent. Both vertical and horizontal well drilling declined in 2002. However, it should be noted that the number of total producing horizontal wells has not changed appreciably over the past five years. In 2002, some 282 horizontal wells were drilled, representing 17 per cent of the total successful oil wells drilled. In 2002 there were 2850 active horizontal wells, producing approximately 16 per cent of the total crude oil production. Production from horizontal wells drilled in the past five years peaked at an average rate of some 12.0 m^3/d.

In projecting crude oil production, the EUB considered two components: expected crude oil production from existing wells at 2002 year-end and expected production from new wells. Total production of crude oil is the sum of these two components.

To project crude oil production from the wells drilled prior to 2003, the EUB considered the following assumptions:

- Production from existing wells in 2003 would be 93.8 10^3 m^3/d.

- Production from the existing wells will decline at a rate of approximately 15 per cent per annum.

Crude oil production from existing wells over the period 1996-2002 is depicted in **Figure 3.11**. This figure illustrates that approximately 50 per cent of crude oil production in 2002 resulted from wells drilled before 1996. Over the forecast period, production of crude oil from existing wells is expected to decline to 25 10^3 m^3/d by 2012.

Figure 3.12 compares the production from 1950 through 2001 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 chart 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 prorationing that existed in Alberta from 1973 to the mid-1980s.

Production from new wells is assumed to be a function of the number of new wells that will be drilled successfully, peak production, and the decline rate for these new wells. The EUB believes that global crude oil prices will play a major role in drilling activity over the forecast period. As discussed in Section 1, the EUB expects that crude oil prices will be stable, resulting in healthy activity in drilling for crude oil over the forecast period. However, the EUB does not expect the high drilling rates experienced in the mid-1990s, when industry was more focused on oil than natural gas.

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

- Drilling is projected to increase to 2000 successful wells in 2003, and then increase to 2100 wells in 2004. In 2005, drilling is projected to reach to 2200 successful wells and remain at this level over the forecast period. **Figure 3.13** illustrates the EUB's crude oil drilling forecast for successful wells for the period 2003 to 2012, along with the historical data.

- Based on recent historical data, it is assumed that the average initial production rate for new wells will be 5.0 m^3/d/well and will decrease to 4.5 m^3/d/well by the end of the forecast period. This is a decline from an average of 8.0 m^3/d/well in the mid-1990s.

- Production from new wells will decline at a rate of 25 per cent per year.

The projection of the above two components, production from existing wellbores and production from future successful oil wells, is illustrated in **Figure 3.14.** Light-medium crude oil production is expected to decline from 69.7 10^3 m^3/d in 2002 to 48 10^3 m^3/d in 2012. Although crude oil drilling is expected to remain at the level of 2005, light crude oil production will continue to decline by almost 4 per cent a year, due to the failure of new wells to offset declining production from existing wells. New drilling has been finding smaller reserves over time.

Over the forecast period, heavy crude production is also expected to decrease, from 35.3 10^3 m^3/d in 2002 to 29 10^3 m^3/d by the end of the forecast period. **Figure 3.14** illustrates that by 2012 heavy crude oil production will constitute a greater portion of total production compared to 2002, although total production will be smaller.

The combined forecasts from existing and future wells indicate that total crude oil production will decline from 105.0 10^3 m^3/d in 2002 to 77 10^3 m^3/d in 2012. In the first two years of the forecast period, initial established reserves growth is expected to be about 20 10^6 m^3/year and 21 10^6 m^3/year, followed by 22 10^6 m^3/year through 2008 and 20 10^6 m^3/year for the remainder of the forecast period. By 2012, if crude oil production follows the projection, Alberta will have produced some 85 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 2002, Alberta refineries, with total inlet capacity 70.3 10^3 m^3/d of crude oil and equivalent, only processed 34.4 10^3 m^3/d of crude oil. Synthetic crude oil, bitumen, and pentanes plus constituted the remaining feedstock. This accounts for over 50 per cent of their total crude oil and equivalent feedstock. **Figure 3.15** 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. However, it is assumed that capacity utilization will increase from the 2002 level of 91 per cent to almost full capacity by 2005, as demand for refined petroleum products increases in western Canada. Total crude oil use will reach 37 10^3 m^3/d in 2005, decline to 30 10^3 m^3/d in 2007, and further decline to 24 10^3 m^3/d for the remainder of the forecast period. This decline is the result of the Petro-Canada Refinery Feed Conversion Program set to fully replace light-medium crude oil with bitumen by 2007.

Shipments of crude oil outside of Alberta, depicted in **Figure 3.16**, amounted to 68 per cent of total production in 2002; with the decline in demand for light-medium crude in Alberta, this is expected to increase slightly to 69 per cent of production by 2012.

3.2.3 Crude Oil and Equivalent Supply

Figure 3.17 shows crude oil and equivalent production. It illustrates that total Alberta crude oil and equivalent is expected to increase from 245.5 10^3 m^3/day in 2002 to 425 10^3 m^3/d in 2012. 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 77 per cent of total production.

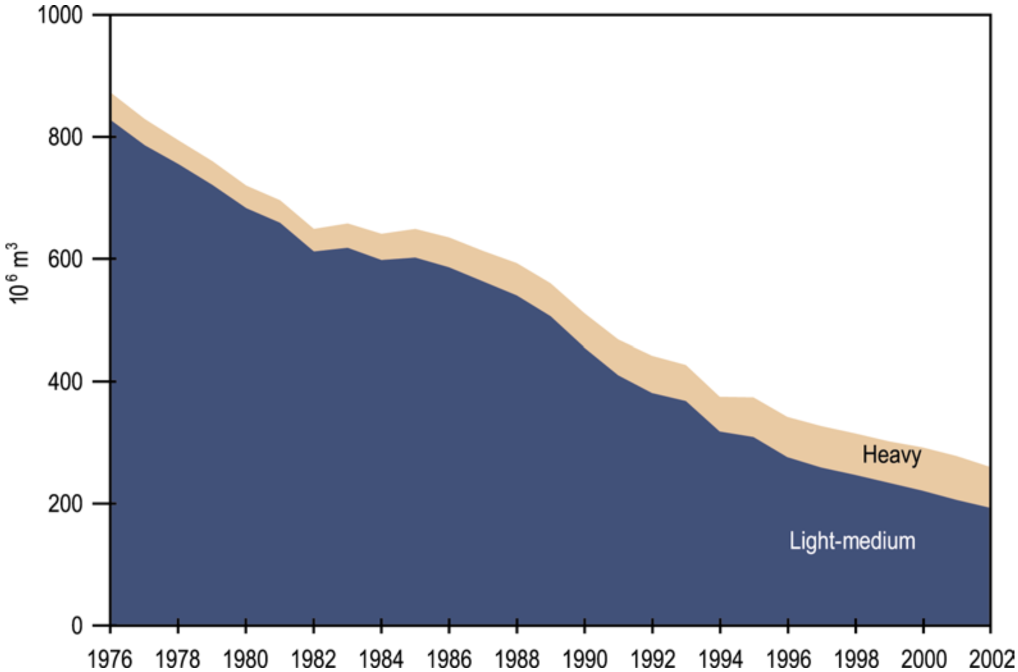


Figure 3.1. Remaining established reserves of crude oil

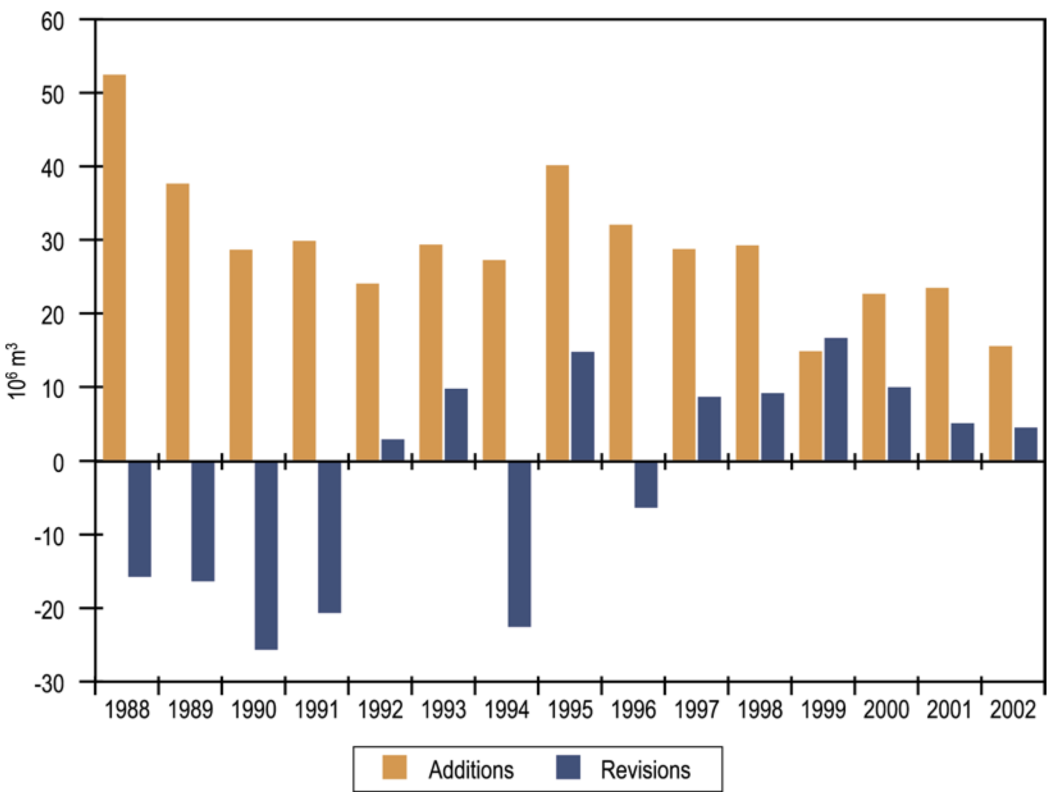


Figure 3.2. Annual changes in conventional crude oil reserves

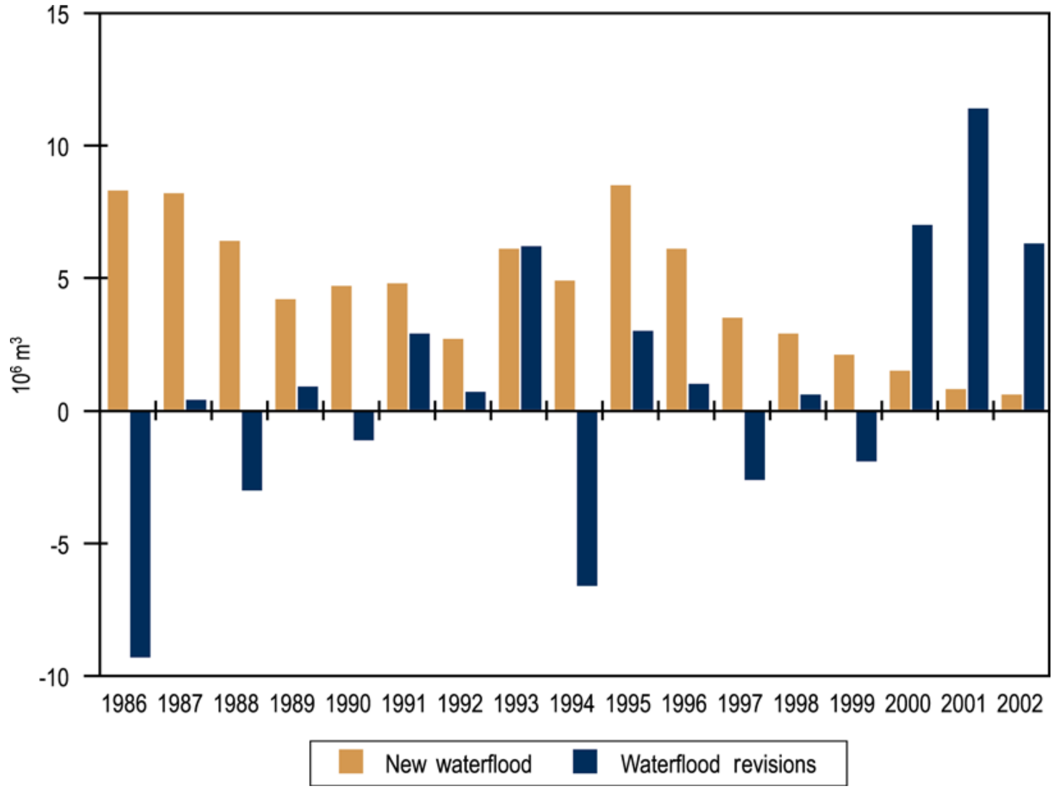


Figure 3.3. Changes to waterflood reserves

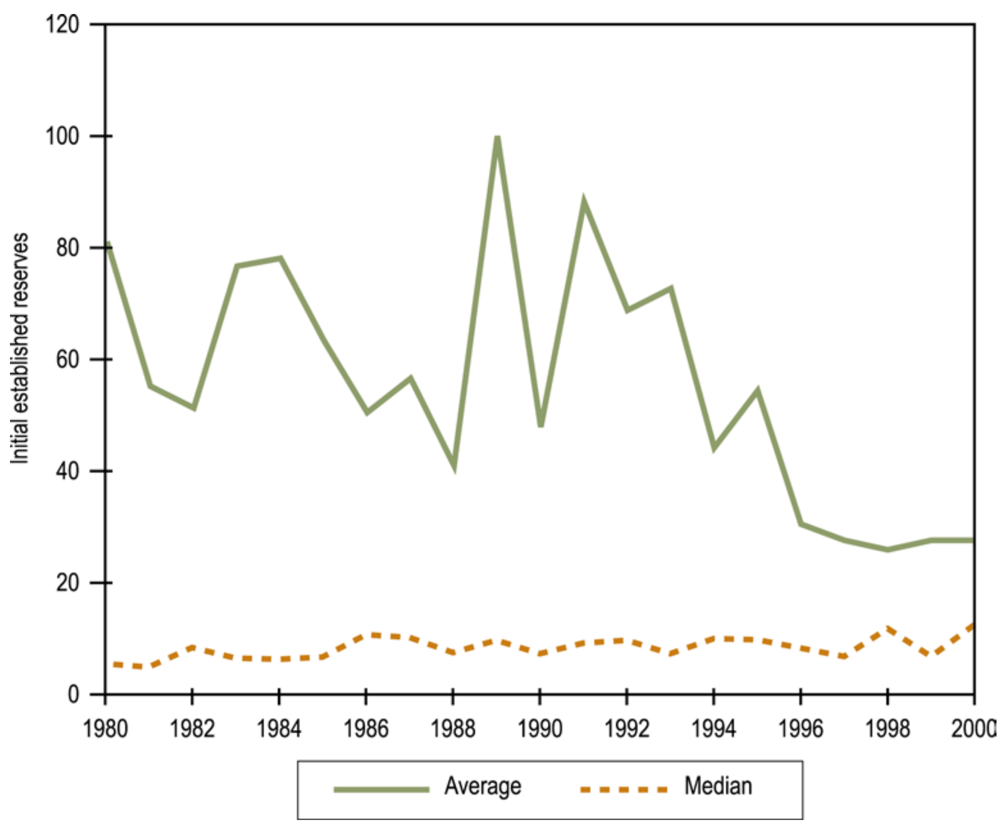


Figure 3.4. Oil pools discovered by size and discovery year

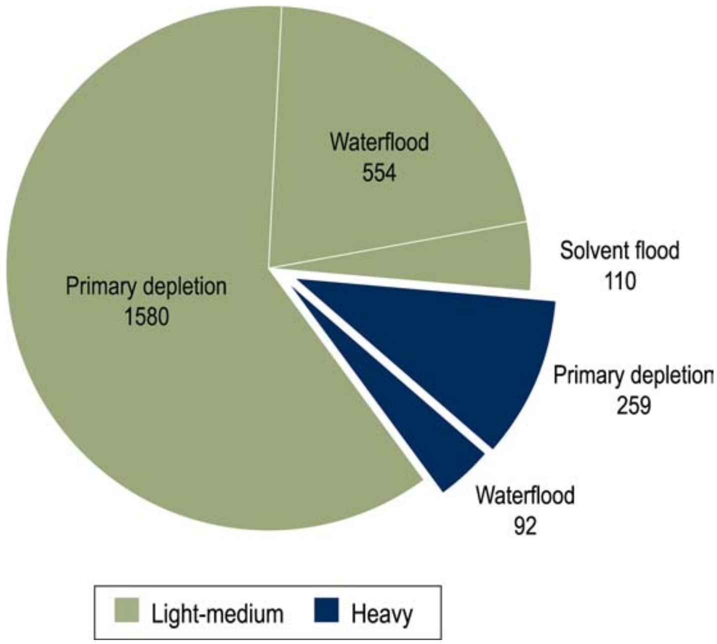


Figure 3.5. Initial established crude oil reserves (primary and incremental over primary) based on various recovery mechanisms (10^6 m^3)

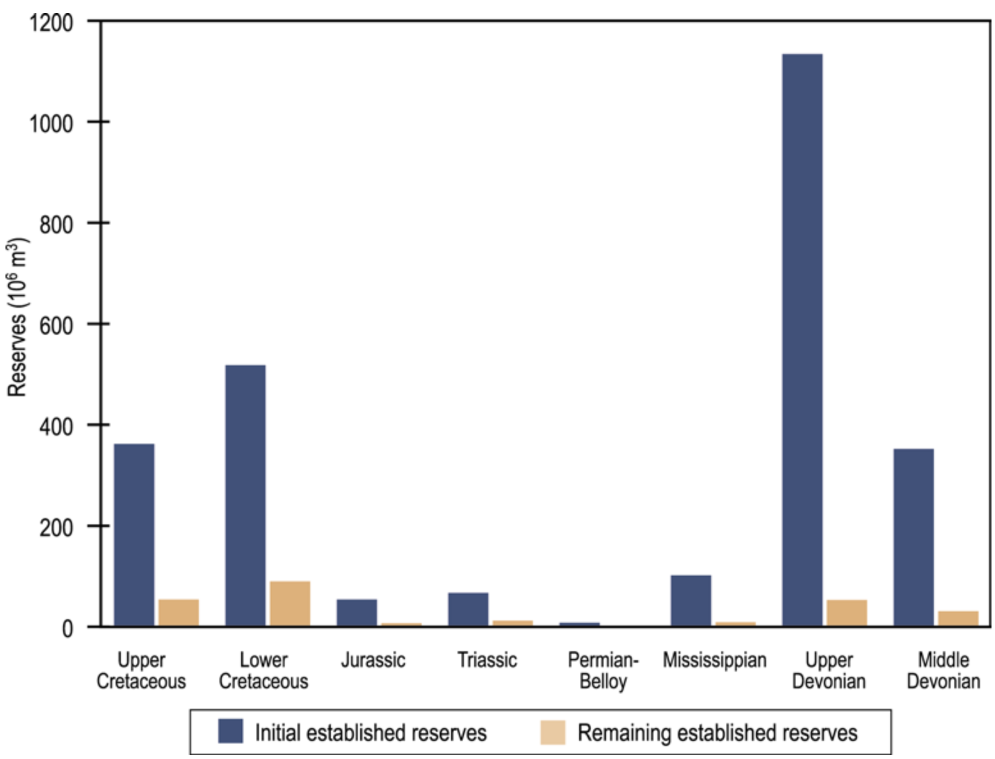


Figure 3.6. Geological distribution of reserves of conventional crude oil

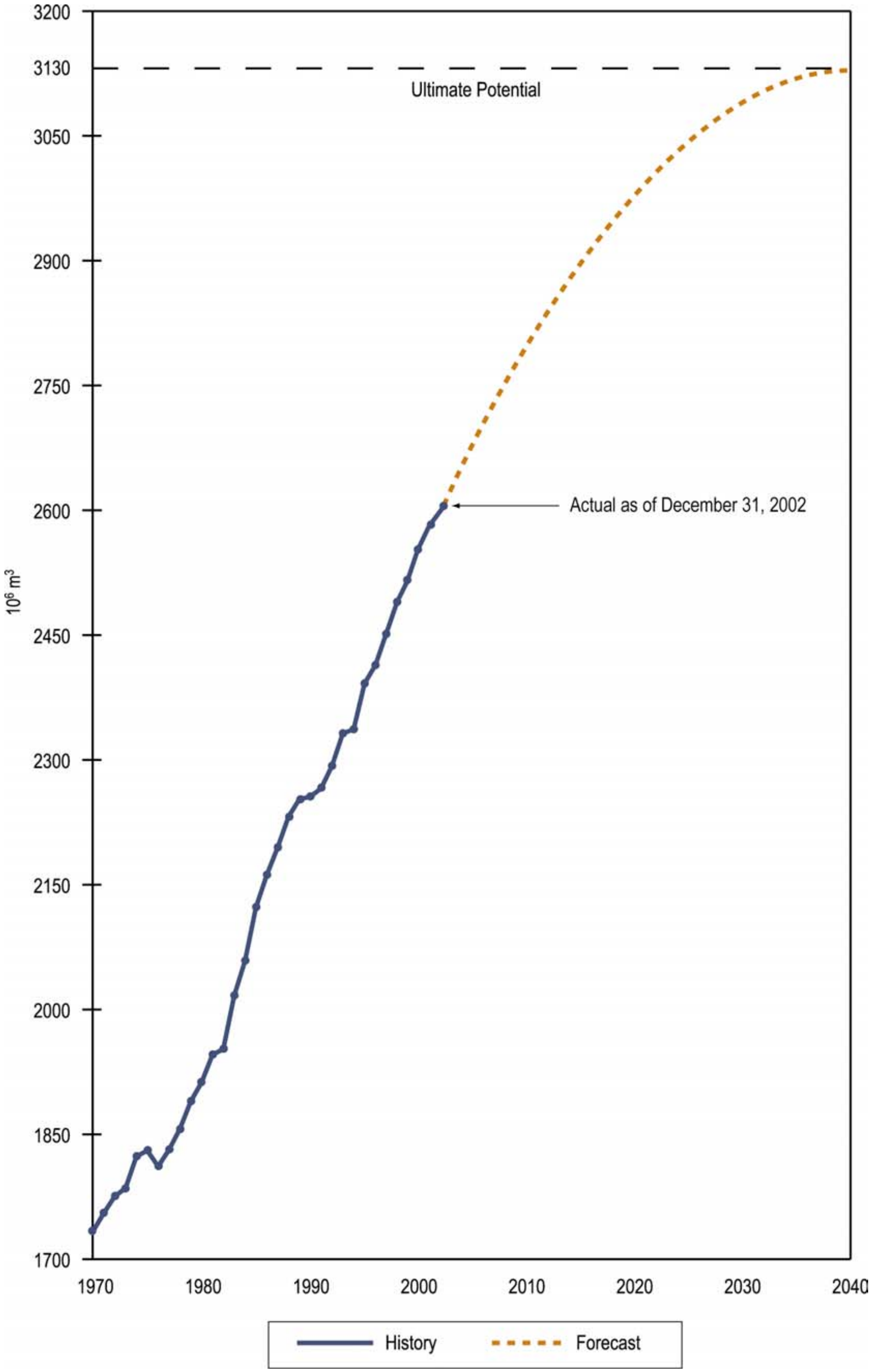


Figure 3.7. Growth in initial established reserves of crude oil

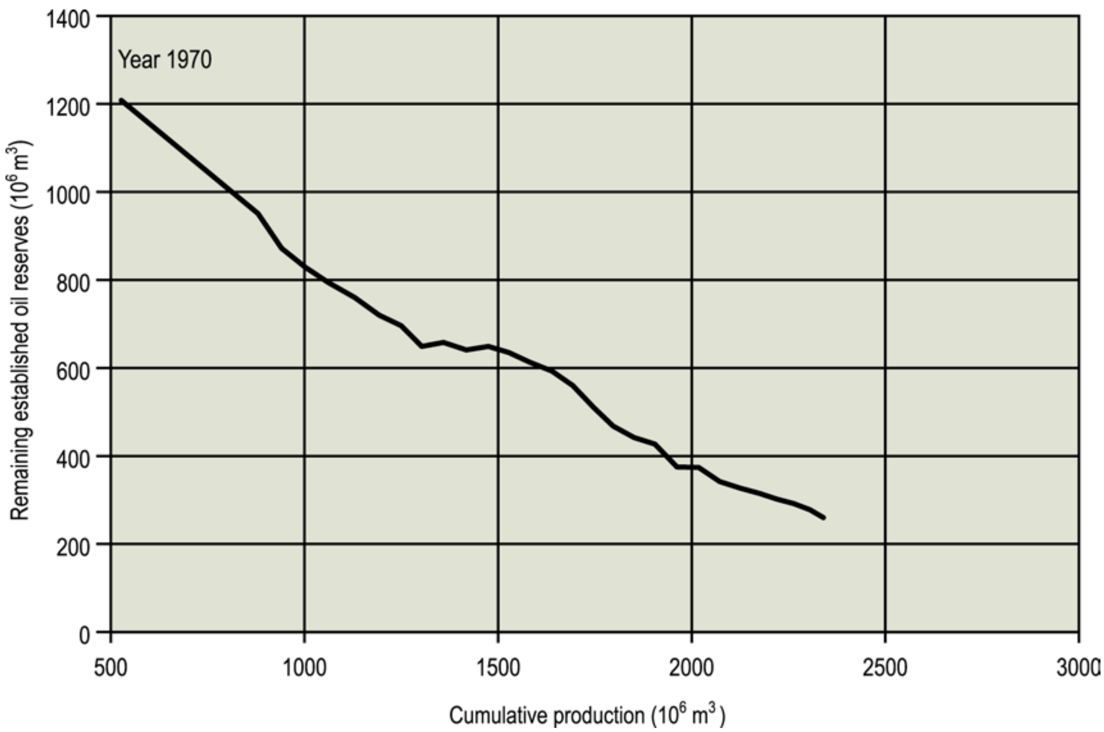


Figure 3.8. Alberta's remaining established oil reserves versus cumulative production

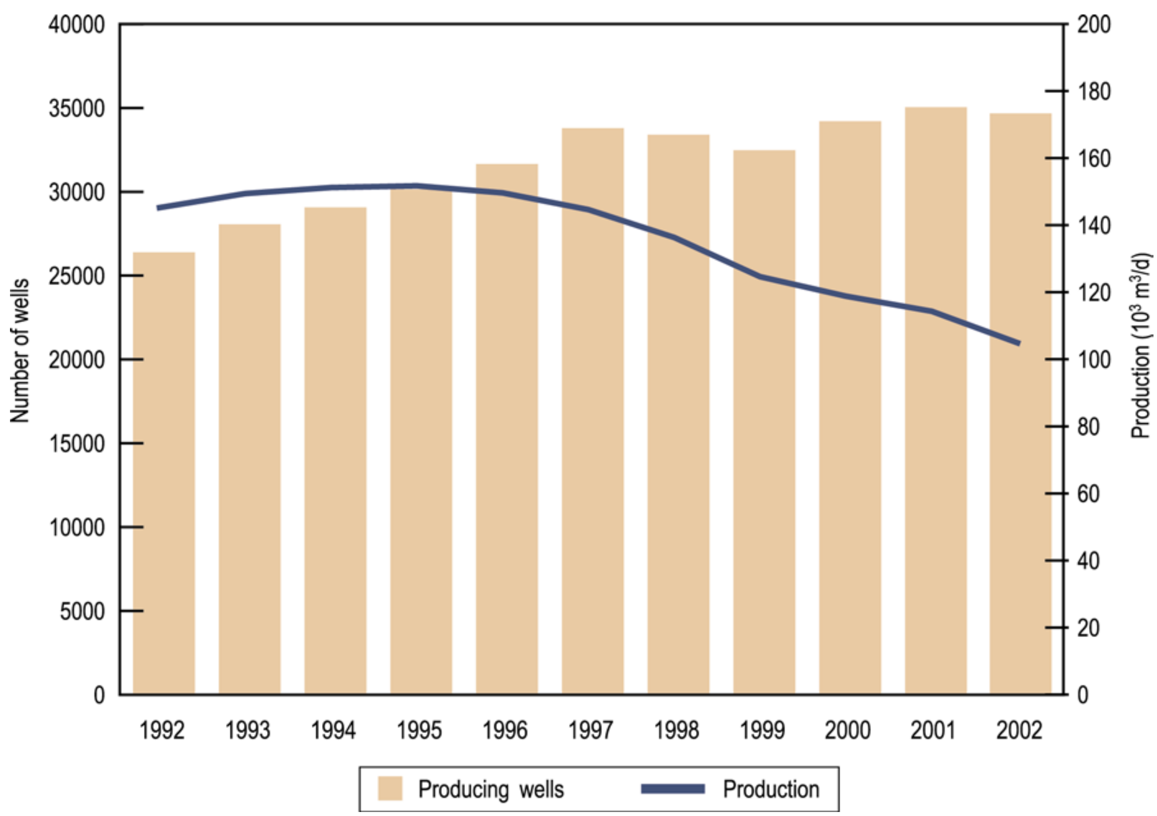


Figure 3.9. Total crude oil production and producing oil wells

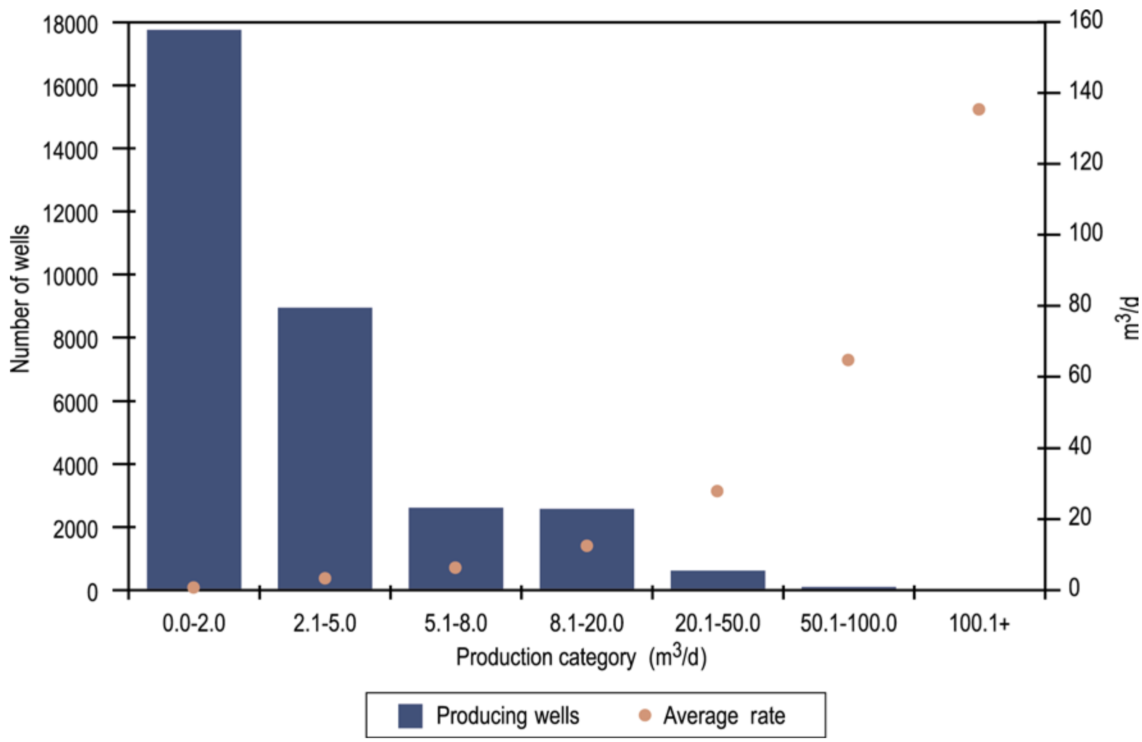


Figure 3.10. Crude oil well productivity in 2002

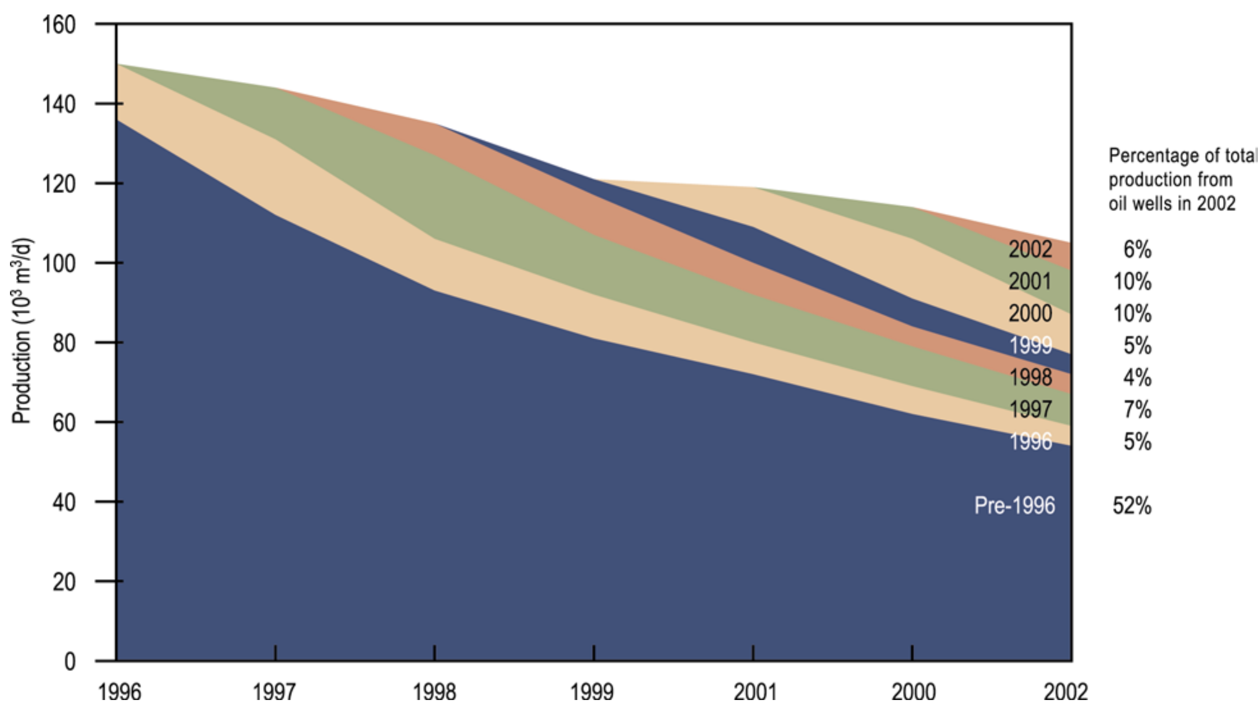


Figure 3.11. Total conventional crude oil production by drilled year

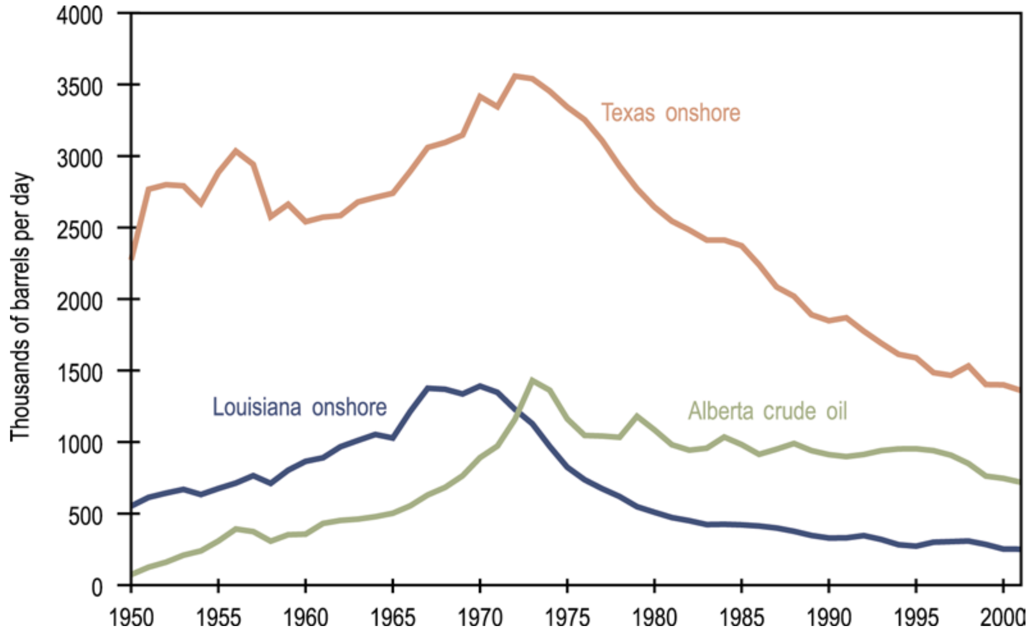


Figure 3.12. Comparison of crude oil production

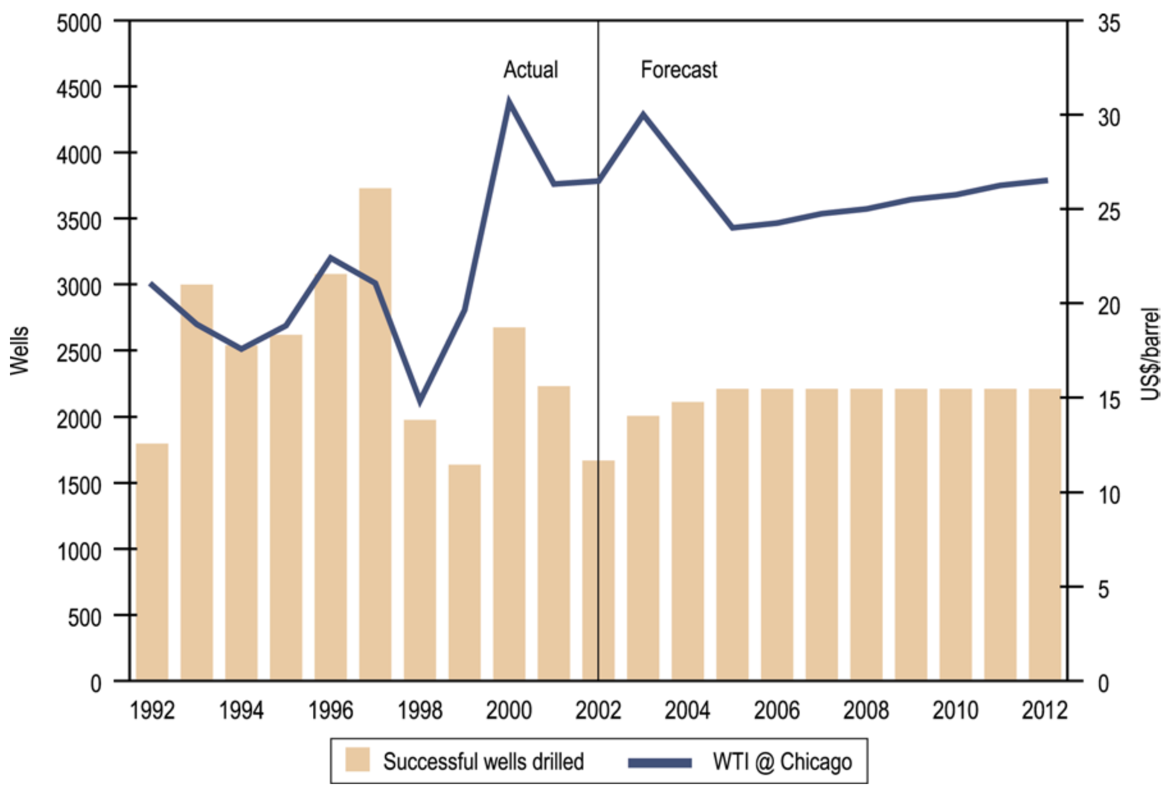


Figure 3.13. Alberta crude oil price and drilling activity

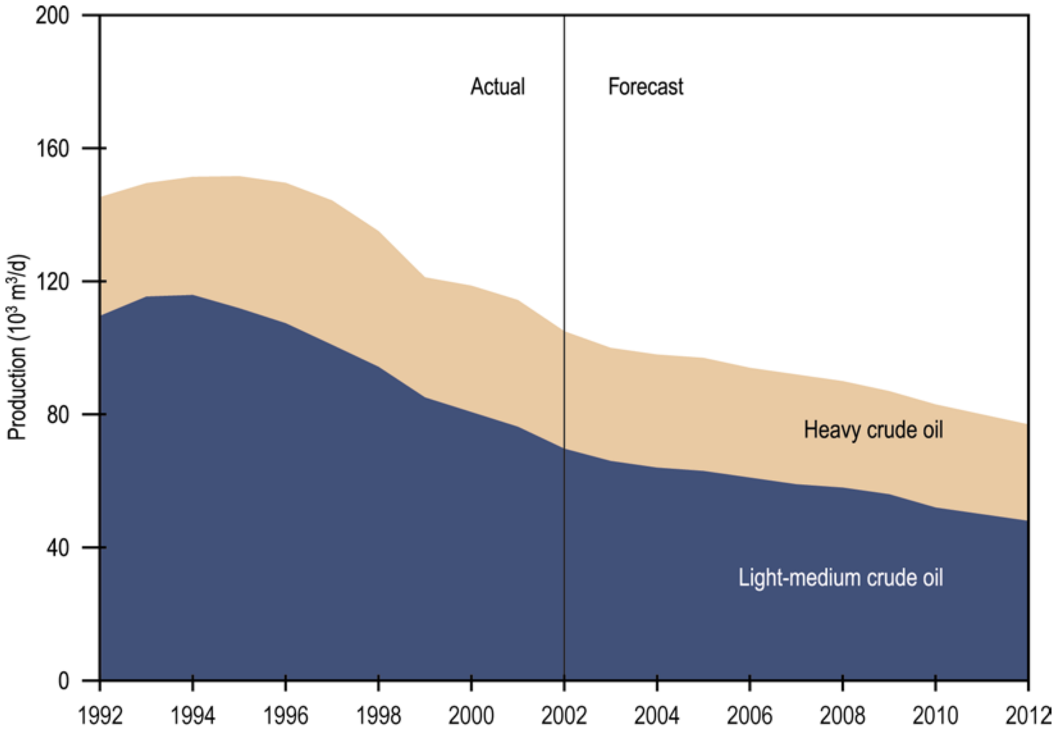


Figure 3.14 Alberta daily production of crude oil

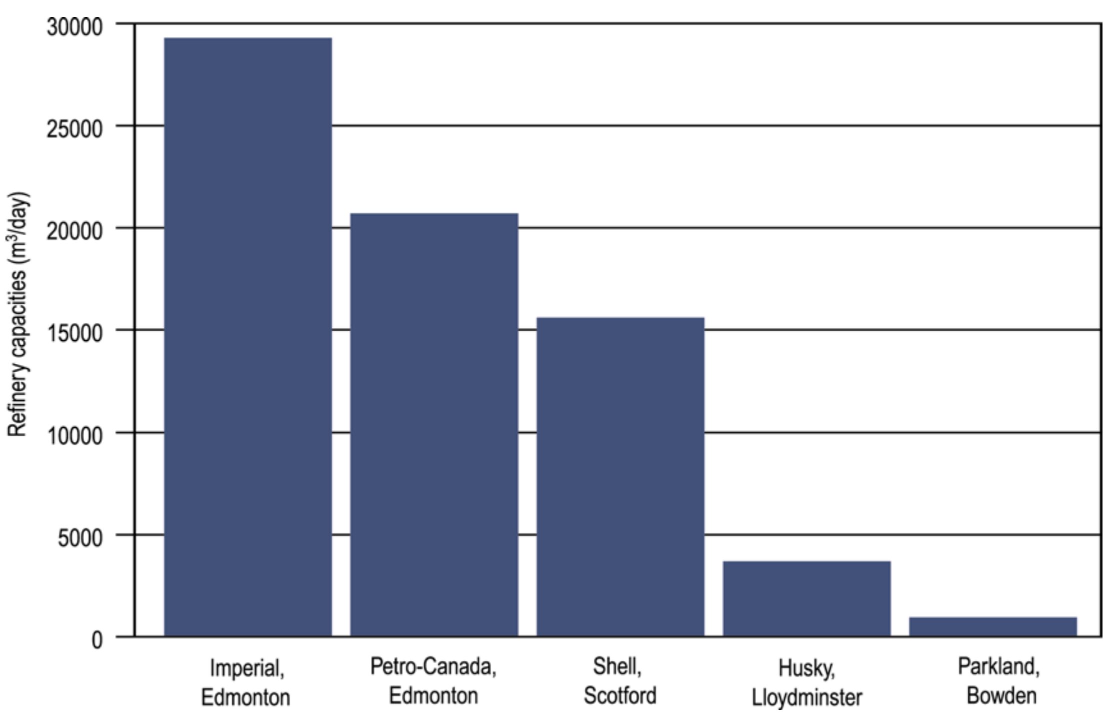


Figure 3.15. Capacity and location of Alberta refineries

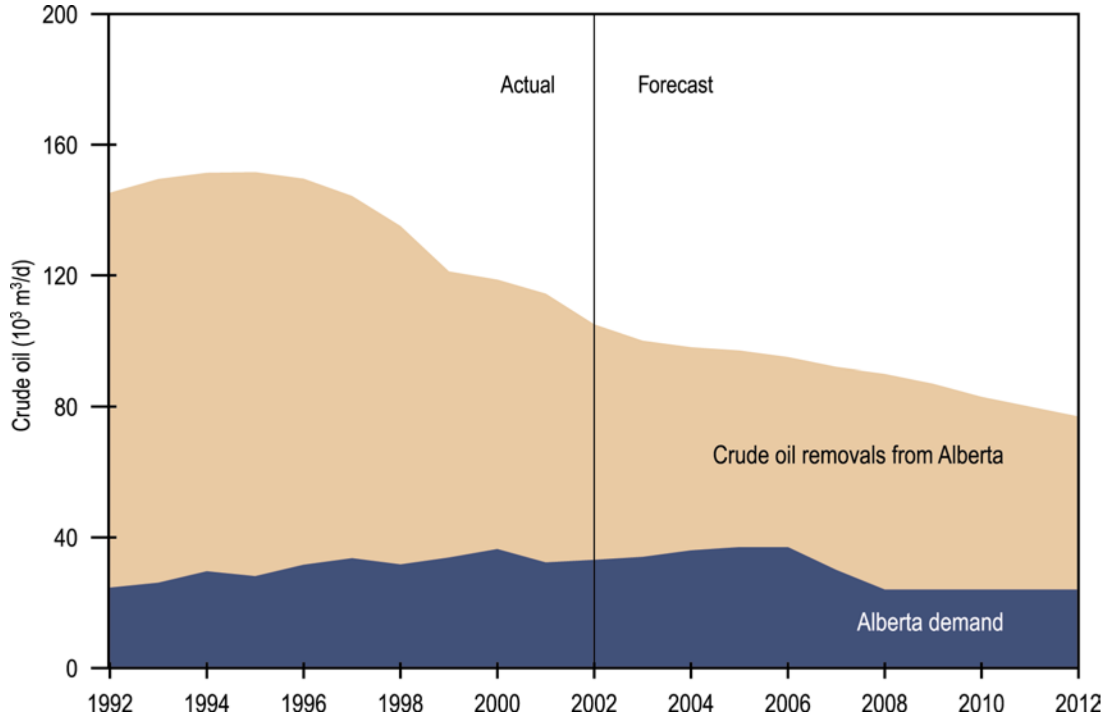


Figure 3.16. Alberta demand and exports of crude oil

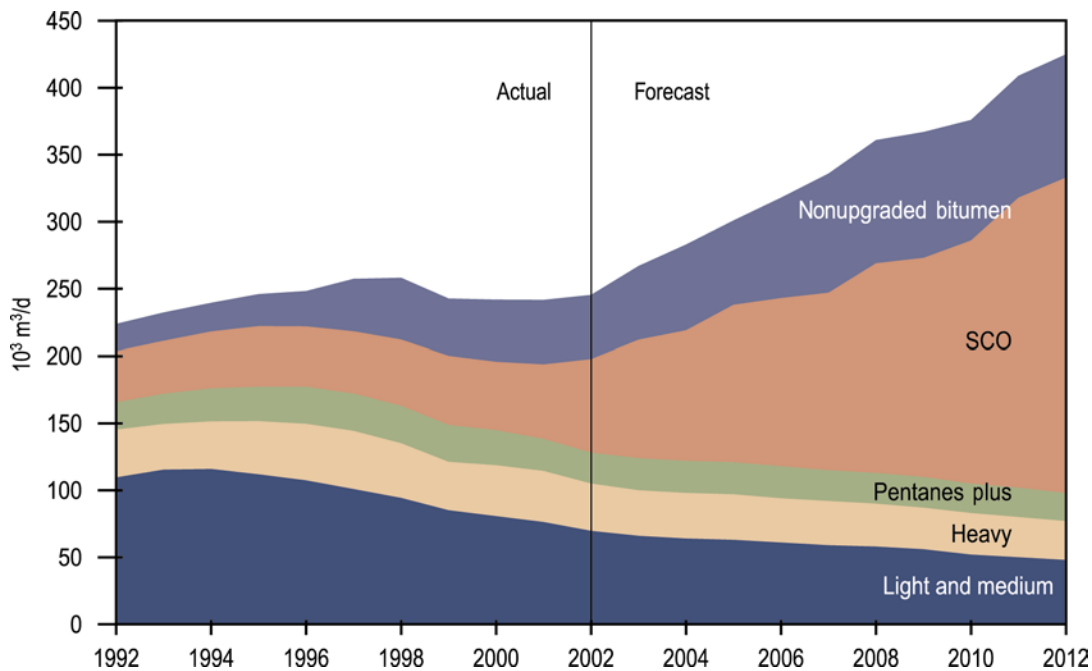


Figure 3.17. Alberta supply of crude oil and equivalent

4 Natural Gas and Liquids

Raw natural gas consists mostly of methane and other hydrocarbon gases, but also contains impurities, such as hydrogen, 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 approximately 91 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Ethane and higher paraffin hydrocarbon components are classified as natural gas liquids (NGLs) in this report.

4.1 Reserves of Marketable Gas

4.1.1 Provincial Summary

The EUB estimates the remaining established reserves of marketable gas in Alberta at December 31, 2002, to be 1131.3 billion cubic metres (10^9 m^3), having a gross heating value of 38 megajoules (MJ) /m^3 and total energy content of 43 exajoules. This represents a net decrease of 10.1 10^9 m^3 since December 31, 2001, which is the result of all reserves additions less marketed production that occurred during 2002. This 1131.3 10^9 m^3 of marketable reserves excludes 40.1 10^9 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 4.1.7. Details of the changes in remaining reserves during 2002 are shown in Table 4.1. Annual reserves additions and production of natural gas since 1974 are depicted in **Figure 4.1**. Over the years, additions have fluctuated as a result of economic factors and reassessment of existing pools. As illustrated in **Figure 4.2**, Alberta's remaining established reserves of marketable gas has been in general decline since 1983.

Table 4.1. Reserves of marketable gas (10^9 m^3)

	2002	2001	Change
Initial established reserves	4 313.5	4 179.9	+133.6
Cumulative production	3 142.1	3 005.7[a]	136.4 (4.8 tcf) (142.2)[b]
Remaining established reserves downstream of field plants	1 171.4	1 184.4	
Minus adjustment for liquids removed at straddle plants	40.1	43.0	
Remaining established reserves	1 131.3 (40.2 tcf) (1 149)[b]	1 141.4 (40.5 tcf) (1 161)[b]	-10.1

[a]Adjusted from 2995.5 to account for surface loss adjustment in 2002.
[b] On basis of 37.4 MJ/m^3 in 10^9 m^3.

At year-end 2002, natural gas reserves were assigned to 31 482 pools in the province. Of these, 7300 pools have never been placed on production and had aggregate initial established reserves of marketable gas of 120 10^9 m^3, or about 10 per cent of the province's remaining established reserves. This is significantly less than in 1994, when approximately 30 per cent of the province's reserves were attributed to nonproducing pools. This decrease resulted primarily from the deletion of reserves from those pools that were abandoned or deemed uneconomic and to a lesser extent the placement of some of these pools on production.

4.1.2 Growth of Marketable Gas Reserves

Initial established reserves increased by 133.6 10^9 m^3 from year-end 2001. This increase includes the addition of 83.4 10^9 m^3 attributed to new pools booked in 2002, development of existing pools, which added another 60.4 10^9 m^3, and negative net reassessment of 10.2 10^9 m^3. Therefore, reserves added through drilling alone totalled 143.8 10^9 m^3, replacing 105 per cent of Alberta's 2002 production of 136.4 10^9 m^3. **Figure 4.3** illustrates the breakdown of annual reserves additions into new, development, and reassessment. These breakdowns are not available prior to 1999. However, reserves growth and production data since 1966 are shown in Appendix B, Table B.4. **Figure 4.4** depicts the growth of marketable gas reserves for 2002 by Petroleum Services Association of Canada (PSAC) areas and shows that established reserves of 76 10^9 m^3 were added to Area 3 (Southeastern Alberta), compared to 18 10^9 m^3 in 2001. Annual growth in Area 2 (Western Plains) decreased from 61 10^9 m^3 in 2001 to 24 10^9 m^3 in 2002.[1]

The EUB evaluates and revises the natural gas reserves on an annual basis. Net negative revisions of 10.2 10^9 m^3 from reassessments resulted from the review of some 5300 gas pools. This comprised positive reassessments totalling 138.4 10^9 m^3 and negative reassessments totalling 148.6 10^9 m^3. During the year, EUB staff undertook a number of projects in order to review pools that had not been re-evaluated for some time. The projects that resulted in significant reserve changes are summarized below:

- A positive reassessment of 29.4 10^9 m^3 resulted from recognition of some 1200 previously unbooked producing gas wells drilled prior to 2001.

- 91 mostly single-well and two-well pools in the Western Plains (PSAC Area 2) were reviewed, resulting in a reserves reduction of 27.2 10^9 m^3. Reserves revisions were based mainly on production decline analysis. The drainage area based on the new estimated gas in place (GIP) averaged 35 hectares per well, compared to the standard 150 to 200 hectares areal assignments.

- 167 mostly single-well pools that had not produced in the last 12 months had reserves reduced by 25.7 10^9 m^3. Most of these wells had watered-out, were abandoned, or were producing at marginal rates.

- 281 producing pools with a remaining constant rate life of over 25 years were reviewed, resulting in a reserves reduction of 73.7 10^9 m^3. Original reserves were overbooked in these pools because of large areal assignments. Production decline analysis used in estimating reserves indicated smaller drainage areas.

- Review of shallow gas pools in Southeastern Alberta resulted in reserves additions of 59 10^9 m^3, equivalent to 5 per cent of Alberta's remaining reserves. This addition was due mainly to reassessment and development of existing pools in the Southeastern Alberta Gas System (MU).

[1] The EUB has divided the province into 8 areas. This breakdown is a modified version of the PSAC areas, with PSAC Area 7 divided into Areas 7 and 8.

- The algorithm that estimates pool surface loss was revised to more accurately reflect NGLs recovered at the field plants. This resulted in the addition of 13 10^9 m^3 to marketable reserves.

Pools that had significant changes in reserves are listed in Table 4.2. Of particular interest are a number of fields in the Southeastern Alberta Gas System (MU), where significant reserves were added in 2002. Conversely, a number of pools in the Western Plains region had negative revisions during 2002. Five of these pools, the Burmis Rundle A, Burmis Wabamun A, Cordel Turner Valley L, Gold Creek Wabamun J, and Gold Greek Wabamun K together had reserves reduced by 10.1 10^9 m^3.

Table 4.2. Major natural gas reserve changes, 2002

Pool	Initial established reserves (10^6 m^3) 2002	Change	Main reasons for change
Alderson Southeastern Alberta Gas System (MU)	49 714	+5 947	Pool development and re-evaluation of initial volume in-place
Ansell Viking A and Cadomin B	37	-608	Re-evaluation of initial volume in-place
Ansell Cardium G, Viking B and Notikewin A	6 188	-1 308	Re-evaluation of initial volume in-place
Atlee-Buffalo Southeastern Alberta Gas System (MU)	7 518	+2 515	Pool development and re-evaluation of initial volume In-place
Bantry Southeastern Alberta Gas System (MU)	28 224	+3 277	Pool development and re-evaluation of initial volume In-place
Bassano Southeastern Alberta Gas System (MU)	2 747	+2 133	Pool development and re-evaluation of initial volume in-place
Belloy Debolt G, K, M & O	143	541	Re-evaluation of initial volume in-place
Benjamin Rundle M	74	-893	Re-evaluation of initial volume in-place
Bighorn Turner Valley C	616	+616	New pool
Bigstone Dunvegan A	10 260	+3 110	Re-evaluation of initial volume in-place
Bigstone Dunvegan B	1 964	+578	Pool development
Bindloss Southeastern Alberta Gas System (MU)	2 178	+1 681	Re-evaluation of initial volume in-place
Bow Island Southeastern Alberta Gas System (MU)	678	+658	Re-evaluation of initial volume in-place
Brown Creek Turner Valley A, B, C, & D	1 129	+537	Re-evaluation of initial volume in-place
Burmis Rundle A and Wabamun A	816	-4 717	Re-evaluation of initial volume in-place

(continued)

Table 4.2. Major natural gas reserve changes, 2002 (continued)

Pool	Initial established reserves (10^6 m^3) 2002	Change	Main reasons for change
Caroline Basal Mannville MU#3	2 267	+772	Re-evaluation of initial volume in-place
Cessford Southeastern Alberta Gas System (MU)	18 566	+7 302	Pool development and re-evaluation of initial volume in-place
Clive D-3 A	1 228	-473	Re-evaluation of initial volume in-place
Connorsville Basal Colorado, Glauconitic and Ellerslie MU#1	2 160	-1 145	Re-evaluation of initial volume in-place
Cordell Turner Valley L	270	-2 887	Re-evaluation of initial volume in-place
Countess Southeastern Alberta Gas System (MU)	25 359	+10 280	Pool development and re-evaluation of initial volume in-place
Cranberry Slave Point A	10 690	+594	Surface loss adjustment
Crossfield East Wabamun A	14 135	+1 413	Surface loss adjustment
Culp Debolt D & E	110	-629	Re-evaluation of initial volume in-place
Doe Doig B	369	-589	Re-evaluation of initial volume in-place
Esther Viking A	5	-1 001	Re-evaluation of initial volume in-place
Estuary Southeastern Alberta Gas System (MU)	805	-734	Re-evaluation of initial volume in place
Eyremore Southeastern Alberta Gas System (MU)	2 479	+1 407	Pool development and re-evaluation of initial volume in-place
Ferrier Belly River Q and Cardium G & L	21 232	+4 087	Re-evaluation of initial volume in-place
Ferrier Glauconitic I and Ellerslie H	315	-639	Re-evaluation of initial volume in-place
Garden Plains Second White Specks E	2 985	+1 818	Re-evaluation of initial volume in-place
Garrington Leduc F	184	-542	Re-evaluation of initial volume in-place
Garrington Second White Specks. Viking and Mannville MU#1	1 550	+786	Re-evaluation of initial volume in-place
Gladys Wabamun A	375	-616	Re-evaluation of initial volume in-place
Gleichen Southeastern Alberta Gas System (MU)	2 041	-698	Re-evaluation of initial volume in place
Gold Creek Wabamun G	178	-638	Re-evaluation of initial volume in-place

(continued)

Table 4.2. Major natural gas reserve changes, 2002 (continued)

Pool	Initial established reserves (10^6 m^3) 2002	Change	Main reasons for change
Gold Creek Wabamun J	30	-1 070	Re-evaluation of initial volume in-place
Gold Creek Wabamun K	111	-1 391	Re-evaluation of initial volume in-place
Grande Prairie Montney E	456	-618	Re-evaluation of initial volume in-place
Hamburg Slave Point BB	629	+629	New pool
Hanna Second White Specks E	1 751	+1 420	Re-evaluation of initial volume in-place and recovery factor
Harmatton – Elkton Shunda B	1 113	-595	Re-evaluation of initial volume in-place
Homeglen – Rimby D-3	25 586	+667	Re-evaluation of initial volume in-place
Hotchkiss Banff B	508	+508	New pool
Hylo Lower Mannville A	258	-522	Re-evaluation of initial volume in-place
Jenner Southeastern Alberta Gas System (MU)	8 011	+2 876	Pool development and re-evaluation of initial volume in-place
Karr Wabamun B	59	-707	Re-evaluation of initial volume in-place and recovery factor
Kitsim Southeastern Alberta Gas System (MU)	917	+635	Pool development and re-evaluation of initial volume in-place
Lanaway Ostracod C, Nordegg A and Elkton A	184	-508	Re-evaluation of initial volume in-place
Lapp Slave Point D	69	-506	Reserves set at production, pool abandoned
Lapp Slave Point E	30	-792	Reserves set at production, pool abandoned
Leckie Southeastern Alberta Gas System (MU)	1 401	+1 015	Pool development and re-evaluation of initial volume in-place
Lone Pine Creek Wabamun A	11 485	+820	Re-evaluation of initial volume in-place
Lovett River Rundle B & C	1 604	1 312	Re-evaluation of initial volume in-place
Lovett River Rundle M	180	-1 561	Re-evaluation of initial volume in-place
Lynx Cadotte B	713	+713	New pool
Medicine Hat Southeastern Alberta Gas System (MU)	139 198	+13 960	Pool development and re-evaluation of initial volume in-place
Medicine River Pekisko AA	659	+659	New pool

(continued)

Table 4.2. Major natural gas reserve changes, 2002 (continued)

Pool	Initial established reserves (10^6 m^3) 2002	Change	Main reasons for change
Minehead Cardium I	130	-816	Re-evaluation of initial volume in-place
Newell Southeastern Alberta Gas System (MU)	2 275	+878	Pool development and re-evaluation of initial volume in-place
Pouce Coupe South Cadomin E	43	-736	Reserves set at production, pool abandoned
Princess Southeastern Alberta Gas System (MU)	27 798	+2 898	Pool development and re-evaluation of initial volume in-place
St Albert – Big Lake Glauconitic D, E & F	7	-509	Re-evaluation of initial volume in-place and recovery factor
St Albert – Big Lake Glauconitic A, B & C	106	-708	Re-evaluation of initial volume in-place and recovery factor
Saddle Hills Wabamun A	1 302	+1 302	New pool
Saddle Hills Belloy B	542	+542	New pool
Sinclair Halfway H	99	-786	Re-evaluation of initial volume in-place
Sinclair Montney A	715	-850	Re-evaluation of initial volume in-place
Stolberg Rundle A, B, C & D	5 955	+2 083	Re-evaluation of initial volume in-place
Suffield Southeastern Alberta Gas System (MU)	63 327	+1400	Pool development
Sundance Cardium G	1 273	+962	Re-evaluation of initial volume in-place
Sundance Notikewin A, Gething A and Cadomin A	37	-1 079	Re-evaluation of initial volume in-place
Twinning Lower Mannville and Rundle A	8 440	-3 111	Re-evaluation of initial volume in-place
Verger Southeastern Alberta Gas System (MU)	17 631	+2 256	Pool development and re-evaluation of initial volume in-place
Voyager Rundle F	164	-1 037	Re-evaluation of initial volume in-place
Wapiti Fort St John, Bullhead and Nikanassin MU#1	11 455	+2 676	Re-evaluation of initial volume in-place
Wapiti Cadotte B & I and Cadomin A	48	-4 024	Re-evaluation of initial volume in-place
Wayne-Rosedale Southeastern Alberta Gas System (MU)	1 330	+523	Re-evaluation of initial volume in-place

(continued)

Table 4.2. Major natural gas reserve changes, 2002 (concluded)

Pool	Initial established reserves (10^6 m^3) 2002	Change	Main reasons for change
Westpem Ellerslie B and Rock Creek G	28	-998	Re-evaluation of initial volume in-place
Wildcat Hills Rundle B	1 148	+746	Re-evaluation of initial volume in-place
Wild River Cardium, Dunvagen, Fort St. John and Bullhead MU#1	1 066	-1 241	Re-evaluation of initial volume in-place
Wilson Creek Glauconitic B, Rock Creek C and Pekisko B	2 348	+614	Re-evaluation of initial volume in-place
Wintering Hills Upper Mannville A and Ellerslie A	990	+1 028	Re-evaluation of initial volume in-place

4.1.3 Distribution of Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in Table 4.3. 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 million (10^6) m^3 or less, while representing 60 per cent of all pools, contain only 9 per cent of the province's remaining marketable reserves. Similarly, the largest 1 per cent of pools contains 37 per cent of the remaining reserves. **Figure 4.5** depicts natural gas pool size by discovery year since 1965 and illustrates that the median pool size has remained fairly constant at about 18 10^6 m^3 in recent years, while the average has declined from about 300 10^6 m^3 in 1965 to 45.0 10^6 m^3 in 1987 and has remained fairly constant since then.

Table 4.3. Distribution of natural gas reserves by pool size, 2002

Reserve range (10^6 m^3)	Pools #	Pools %	Initial established marketable reserves 10^9 m^3	Initial established marketable reserves %	Remaining established marketable reserves 10^9 m^3	Remaining established marketable reserves %
1500+	327	1	2 412	56	428	37
300-1499	1 299	4	765	18	202	17
100-299	3 015	10	502	11	207	18
31-100	7 938	25	432	10	226	19
Less than 30	18 903	60	203	5	108	9
Total	31 482	100	4 314	100	1 171[a]	100

[a] Reserves estimated at field plants.

4.1.4 Geological Distribution of Reserves

The distribution of reserves by geological period and formation is shown graphically in **Figure 4.6**. The Upper and Lower Cretaceous period contains some 69.3 per cent of the province's remaining established reserves. The formations containing the largest remaining reserves of natural gas are the Lower Cretaceous Mannville, with 33.4 per cent, the Upper Cretaceous Milk River and Medicine Hat, with 16.1 per cent, and the Mississippian Rundle, with 7.6 per cent. Table B.5 in Appendix B gives a detailed breakdown of reserves by formation.

4.1.5 Reserves of Natural Gas Containing Hydrogen Sulphide

Natural gas that contains greater than 0.01 per cent hydrogen sulphide (H_2S) is referred to as sour in this report. As of December 31, 2002, sour gas accounts for some 20 per cent (231 10^9 m^3) of the province's total remaining established reserves and about 32 per cent of natural gas marketed in 2002. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2002 is 9.2 per cent.

The distribution of reserves for sweet and sour gas (Table 4.4) shows that 164 10^9 m^3, or about 71 per cent, of remaining sour gas reserves occurs in nonassociated pools. **Figure 4.7** 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 4.5**.** and indicates that 49 10^9 m^3, or 21 per cent, of sour gas contains H_2S concentrations greater than 10 per cent.

Table 4.4. Distribution of sweet and sour gas reserves, 2002 (10^6 m^3)

	Raw gas		Marketable gas		
Type of gas	Initial volume in-place	Initial producible	Initial established reserves	Net cumulative production	Remaining established reserves
Sweet					
Associated	526	419	584	431	152
Solution	781	296			
Nonassociated	3 582	2 524	2 360	1 572	788
Subtotal	4 889	3 239	2 944	2 003	940
Sour					
Associated	446	357	388	321	67
Solution	310	178			
Nonassociated	1 699	1 339	982	818	164
Subtotal	2 455	1 874	1 370	1 139	231
Total	7 344	5 113	4 314	3 142	1 171[a]
	(261)[b]	(181)[b]	(153)[b]	(112)[a]	(42)[b]
Sour gas % of total	33.4	36.7	31.8	36.2	19.7

[a] Reserves estimated at field plants.

[b] Imperial equivalent in billions of cubic feet at 14.65 pounds per square inch absolute and 60˚F.

Table 4.5. Distribution of sour gas reserves by H_2S content, 2002

	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	251	316	44	63	107	46
2.00-9.99	99	348	16	60	76	33
10.00-19.99	27	182	5	22	27	12
20.00-29.99	11	45	2	10	12	5
Over 30	0	91	0	10	10	4
Total	388	982	67	165	231	100
Per cent	28	72	29	71		

4.1.6 Reserves of Retrograde Condensate Pools

Retrograde gas pools, which are pools rich in liquids, are required to reinject dry gas so as to maintain pressure and maximize liquid recovery. Reserves of major retrograde condensate pools are tabulated both on energy content and on 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).

4.1.7 Reserves Accounting Methods

The EUB books remaining marketable gas reserves on a pool-by-pool basis initially on volumetric determination of in-place reserves and application of recovery efficiency and surface loss. Subsequent reassessment of reserves is made using additional geological, 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 4.8**. A minimum 5 per cent is added to account for loss due to lease fuel (4 per cent) and flaring. Reserves of individual pools on the EUB's gas reserves database therefore reflect expected recovery after processing at field plants. Additional liquids contained in the gas stream leaving the field plants are extracted downstream at reprocessing and 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.

The remaining established reserves of natural gas discussed in Section 4.1.1 excludes liquids expected to be removed from the gas stream. It is expected that some 40.1 10^9 m^3 will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas estimated at the field plant from 1171.4 10^9 m^3 to 1131.3 10^9 m^3 and the thermal energy content from 47 to 43 exajoules. This 1131.3 10^9 m^3 of marketable gas is composed of approximately 98 per cent methane and represents the volume and average heating content of marketable gas available after all processing.

Figure 4.8 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 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 reserve is booked as part of the marketable gas and represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in Section 4.2.

4.1.8 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in Appendix B, Table B.7. Each multifield pool shows the individual initial established reserves assigned to each field and the total initial established reserves for the multifield pool.

4.1.9 Reserves of Coalbed Methane

Coalbed methane (CBM) is the methane gas that is found in coal, both as adsorbed gas and as free gas. All coal layers contain CBM to some greater or lesser extent. For this reason, coal and CBM have a fundamental relationship. Coal is known, from thousands of data points, to underlie most of central and southern Alberta, and while some individual coals may not correlate particularly well, coal zones correlate very well.[2]

Interest in CBM development in Alberta continued to grow in 2002, which saw the highest number of CBM completions and an increase in the number of CBM pilot projects. Despite these increases, there is still very little production data available to prove the economic viability of many of these projects. As well, the actual CBM production to date remains uncertain because of the inability to completely differentiate CBM from conventional gas production. In addition to the uncertainty in production, there is only limited data from CBM testing in areas of current CBM production. More production and test data are required before the EUB can develop a reasonable estimate of CBM reserves.

In the few areas studied in detail to date, information on the gas content of coals, while very limited, does indicate a good relationship between gas content, depth from surface, and ash content of the coal. As the thickness and correlatability of the individual coals and coal zones can be determined from the large number of available oil and gas wells, the EUB believes that the estimation of CBM resources can be established with some degree of confidence for large areas and not just immediately surrounding wellbores. Current industry practice suggests that CBM production will likely be from project style developments combining recompletions in existing wells and new infill development wells. The assignment of an accurate recovery factor to adequately describe the economic recovery of CBM is one of the biggest challenges in defining CBM reserves.

The EUB has used the above knowledge to calculate resources and reserves for a few areas of Alberta currently producing identified CBM. However, the EUB believes that these estimates do not yet have a high enough level of accuracy to warrant their publication at this time. It is anticipated that sufficient additional production and testing data may become available in the next year to increase the level of confidence in the estimates to allow their publication in the next reserves report.

4.1.10 Ultimate Potential

In 1992, the EUB (then the ERCB) issued *ERCB 92-A*,[3] which presented the results of its detailed review of Alberta's ultimate potential of marketable gas reserves. This review took into consideration geological prospects, technology, and economics. The EUB

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[2] For the purpose of CBM administration, the EUB has defined a single coal zone to contain all coal within a formation unless separated by more than 30 m of non-coal-bearing strata.

[3] EUB, 1992, *Ultimate Potential and Supply of Natural Gas in Alberta, Report 92-A*.

adopted an estimate of 5600 10^9 m^3 (200 trillion cubic feet) as Alberta's ultimate potential for marketable gas. To bring this estimate up to date, the EUB has undertaken an ultimate potential study targeted for completion in 2003. **Figure 4.9** shows the historical and forecast growth in initial established reserves of marketable gas.

Figure 4.10 plots production and remaining established reserves of marketable gas compared to the 1992 estimate of ultimate potential.

Table 4.6 provides details on the ultimate potential of marketable gas, with all values converted to the standard heating value of 37.4 MJ/m^3. It shows initial established reserves of 4636 10^9 m^3 (at the field gate), or that 82.8 per cent of the ultimate potential of 5600 10^9 m^3 has been discovered as of year-end 2002. This leaves 1258 10^9 m^3, or 22 per cent, of marketable gas yet to be discovered. Cumulative production of 3378 10^9 m^3 at year-end 2002 represents 57.6 per cent of the ultimate potential, leaving 2222 10^9 m^3, or 42.4 per cent, available for future use.

The regional distribution of remaining reserves and yet-to-be-established reserves is shown by PSAC area in **Figure 4.11**. It shows that the Western Plains contains about 37 per cent of the remaining established reserves and 50 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) and the Northern Plains (Areas 6, 7, and 8), it shows that, based on 1992 ultimate potential study, Alberta natural gas supplies will depend on significant reserves being discovered in the Western Plains.

Table 4.6. Remaining ultimate potential of marketable gas, 2002 (10^9 m^3 at 37.4 MJ/m^3)

Yet to be established	
Ultimate potential	5 600
Minus initial established	4 636
	964
Remaining established	
Initial established	4 636
Minus cumulative production	3 378
	1 258
Remaining ultimate potential	
Yet to be established	964
Plus remaining established	1 258
	2 222

4.2 Natural Gas Liquids

The EUB estimates remaining reserves of natural gas liquids (NGLs) that are expected to be recovered from raw natural gas based on existing technology and market conditions. The liquids reserves that are not removed from natural gas are included as part of the province's marketable gas reserves discussed in Section 4.1. The EUB's projections on the overall recovery of each NGL component are explained in Section 4.1.7 and shown graphically in **Figure 4.8**. Estimates of the remaining established reserves of extractable NGLs are summarized in Tables 4.7 and 4.8. **Figure 4.12** shows remaining established reserves of extractable NGLs compared to 2002 production.

Table 4.7. Established reserves and production of extractable NGLs as of December 31, 2002 (10^6 m^3 liquid)

	2002	2001	Change
Cumulative net production[a]			
Ethane	182.7	169.0	+13.7
Propane	214.7	206.3	+8.4[b]
Butanes	123.3	118.7	+4.6[b]
Pentanes plus	287.1	278.7	+8.4[b]
Total	807.8	772.7	+35.1
Remaining (expected to be extracted)			
Ethane	165.1	173.7	-8.6
Propane	79.3	84.1	-4.8
Butanes	46.9	49.9	-3.0
Pentanes plus	67.8	77.5	-10.0
Total	359.1	382.5	-26.4

[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 4.8. Reserves of NGLs as of December 31, 2002 (10^6 m^3)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total remaining reserves	238.4	93.3	51.9	67.8	451.4
Liquids expected to remain in marketable gas	73.3	14.0	5.0	0	92.3
Remaining established recoverable from					
Field plants	41.9	46.6	30.1	60.4	179.0
Straddle plants	94.2	32.6	15.1	6.7	148.6
Solvent floods	29.0	0.1	1.7	0.7	31.5
Total	165.1	79.3	46.9	67.8	359.1

4.2.1 Ethane

As of December 31, 2002, the EUB estimates remaining established reserves of extractable ethane to be 165.1 10^6 m^3 in liquefied form, about a 5 per cent drop from last year. This estimate includes 29 10^6 m^3 of recoverable reserves from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. As shown in Table 4.8, there is an additional 73.3 10^6 m^3 (liquid) of ethane estimated to remain in the marketable gas stream and available for potential recovery. This yields a total remaining ethane reserve of 238.4 10^6 m^3.

During 2002, the extraction of specification ethane was 13.7 10^6 m^3, about 7.8 per cent more than in 2001. 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 gas was 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves and from solvent floods. The three largest fields, the Caroline, Ferrier, and Pembina, account for 10.3 per cent of total ethane reserves.

4.2.2 Other Natural Gas Liquids

As of December 31, 2002, the EUB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 79.3 10^6 m^3, 46.9 10^6 m^3, and 67.8 10^6 m^3 respectively. The overall changes in the reserves during the past year are shown in Table 4.7. Appendix B, Table B.9, lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The three largest fields, the Brazeau River, Caroline, and Pembina fields account for about 14 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 2002, propane and butanes recovery at crude oil refineries was 0.4 10^6 m^3 and 1.1 10^6 m^3 respectively.

4.2.3 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 has been recovered. However, the recovery has increased over time to about 50 per cent 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 155.6 10^9 m^3, the EUB estimates remaining ultimate potential of liquid ethane to be 387 10^6 m^3. The other 30 per cent, or 46.7 10^9 m^3, of ethane gas is expected to be sold for its heating value as part of marketable gas.

For liquid propane, butanes, and pentanes plus together, the remaining ultimate potential reserves are 472 10^6 m^3. This assumes that remaining ultimate potential as a percentage of ultimate potential is similar to that of marketable gas, which currently stands at 42 per cent.

4.3 Supply of and Demand for Natural Gas

4.3.1 Natural Gas Supply

Alberta produced 142.2 10^9 m^3 (standardized to 37.4 MJ/m^3) of marketable natural gas from its gas and conventional oil wells in 2002, a decrease of 3.8 per cent from last year.[4] This is the first year that Alberta gas production has not grown since 1986. The EUB's previous assessment was for production to increase in 2002 over 2001, assuming a continuation of high drilling activity. Due to lower than expected prices in the early part of 2002, producers cut back on their drilling programs. This had a direct impact on gas production. High gas storage levels by the summer period compared to previous years and weak demand in some markets may have also contributed to reduced gas production. Major factors affecting Alberta natural gas production include natural gas prices and their volatility, drilling activity, the location of Alberta's reserves, the production characteristics of today's wells, and market demand.

The marketable natural gas production volume for 2002 was determined using the EUB's

[4] Natural gas produced in Alberta has an average heating value of approximately 39.0 MJ/m^3.

December 2002 Statistical Series ST-3 report. The following calculation is based on the section "Supply and Disposition of Marketable Gas" in ST-3, with volumes given in millions of cubic metres:

Total Gas Production	169 742.1	10^6 m^3
Minus Storage Withdrawals	- 4 639.9	
Raw Gas Production	165 102.2	
Minus Injection Total	- 8 630.8	
Minus Processing Shrinkage – Raw	- 10 810.1	
Minus Flared – Raw	- 1 294.7	
Minus Fuel – Raw	- 11 523.8	
Plus Storage Injection	+ 3 574.5	
Calculated Marketable Gas Production at as-is conditions	136 417.3	
Calculated Marketable Gas Production @37.4 MJ/m^3	142 146.8	10^6 m^3

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 increase or stabilize production levels. The number of successful gas wells drilling in Alberta in the last two years is shown by geographical area (modified PSAC area) in **Figure 4.13**. In 2002, some 8064 natural gas wells were drilled in the province, a decrease of 17 per cent from 2001 levels. A large portion of gas drilling has taken place in Southeastern Alberta, representing 52 per cent of all natural gas wells drilled in 2002. Drilling levels were down in all areas of the province, with the exception of Area 1 (Foothills). It should be noted 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 1992 to 2002 is shown in **Figure 4.14**, 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 years 1992-2000, 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 2002 the number of gas well connections fell by 21 per cent from 2001 levels. Also, the number of new wells connected fell below the number of gas wells drilled for the first time in ten years. The distribution of natural gas well connections and the initial maximum day production of the connected wells in the year 2002 are illustrated in **Figures 4.15** and **4.16** respectively.

Figure 4.17 illustrates historical gas production from gas wells by geographical area. Prior to 2002, production increased in most areas over time, most notably in Area 2 (Western Plains) and Area 3 (Southeastern Alberta). While most areas experienced a decline in production in 2002, Area 1 (Foothills) increased production by some 14 per cent. Gas production from oil wells has held fairly constant over the historical period.

The number of gas wells on production in Alberta from 1992 to 2002 is shown in **Figure**

4.18, along with the marketable gas production in each year. Prior to 1996 the annual growth in gas production was consistent with the annual increase in the number of gas producing wells. From 1996 forward, the number of producing gas wells increased substantially year over year, while gas production slowed and then declined in 2002. By 2002, the total number of producing gas wells increased to 70 000, from 29 800 wells in 1992. The large number of gas wells placed on production in Southeastern Alberta, where production rates are low, was a key contributing factor behind this increase.

Average gas well productivities have been declining over time. As shown in **Figure 4.19**, about 35 per cent of the operating gas wells produce less than 1 10^3 m^3/d. In 2002, these 25 000 gas wells operated at an average rate of 0.5 10^3 m^3/d per well and produced less than 3 per cent of the total gas production. Less than 1 per cent of the total gas wells produced at rates over 110 10^3 m^3/d but contributed 20 per cent of the total production. The historical raw gas production by drilling vintage in Alberta is presented in **Figure 4.20**.

Generally, a surface loss factor of around 15 per cent can be applied to raw gas production to yield marketable gas production. The bottom band represents gas production from oil wells. Each band thereafter represents production from new gas well connections by year. The percentages shown on the right-hand side of the chart by each band represent the share of that band's production to the total production from gas wells in 2002. For example, 11 per cent of gas production in 2002 came from wells connected in that year. This figure shows that in 2002, only about 37 per cent of gas production came from gas wells drilled prior to 1996.

Declines in natural gas production from new gas well connections from 1992 to 2000 have been evaluated after the wells drilled in a given year complete a full year of production. Table 4.9 shows decline rates for gas wells connected from 1992 to 2000 with respect to the first, second, third, and fourth year of decline. More recently connected wells are exhibiting steeper declines in production in the first three years compared to wells connected in the early 1990s. 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 4.9. Production decline rates for new well connections (%)

Year wells Connected	First-year decline	Second-year decline	Third-year decline	Fourth-year decline
1992	29	23	17	19
1993	25	17	18	16
1994	26	23	16	15
1995	30	25	23	19
1996	31	27	21	18
1997	32	28	23	20
1998	32	28	24	
1999	34	25		
2000	35			

New well connections today start producing at much lower rates than new wells placed on production in previous years. **Figure 4.21** shows the average initial productivities (peak rate) of new wells by connection year. Average initial productivities for new wells excluding Southeastern Alberta (Area 3) are also shown in the figure. This chart shows the impact that the low-productivity wells in Southeastern Alberta have on the provincial average. Production data give some indication that initial productivities were levelling off for new wells outside of Southeastern 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 increase to 9500 in 2003 and further increase to 10 500 in 2004, with roughly half of the wells being connected in Southeastern Alberta. By 2005, some 11 000 natural gas wells are forecast to be connected annually, falling to 10 000 per year from 2007 onward. **Figure 4.22** illustrates the new well connections forecast.

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 producing wells at year-end 2002 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 2.5 10^3 m^3/d in 2003 and will decrease to 1.5 10^3 m^3/d by 2012.

- The average initial productivity of new natural gas wells in the rest of the province will be 10 10^3 m^3/d in 2003 and will decrease to 8 10^3 m^3/d by 2012.

- Production from new wells will decline at a rate of 34 per cent the first year, 27 per cent the second year, 23 per cent the third year, and 18 per cent in the fourth year and thereafter.

Gas production from oil wells was held constant at historical levels.

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 2012 as shown in **Figure 4.23**. The production of natural gas from conventional reserves is expected to increase slightly, from 142.2 10^9 m^3 in 2002 to 144.4 10^9 m^3 in 2003. Production levels are expected to decline to 121.0 10^9 m^3 by the end of the forecast period.

If conventional natural gas production rates follow the projection, Alberta will have recovered some 84 per cent of the 5600 10^9 m^3 of ultimate potential by 2012. This ultimate potential is under review and is targeted for completion later this year.

Figure 4.24 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 levels have been maintained at significant levels.

Gas production from sources other than conventional gas and oil wells include process gas from bitumen upgrading operations, natural gas from bitumen wells, and coalbed methane from coal seams. **Figure 4.25** shows the historical and forecast volumes of production from the first two categories. In 2002, some 3.1 10^9 m^3 of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 7.8 10^9 m^3 by the end of the forecast period. Natural gas production from bitumen wells was over 1 10^9 m^3 in 2002 and is forecast to increase to 2.5 10^9 m^3 by 2012. This gas is used as fuel by the owner of the well to create steam for its in situ operations.

In the past few years a number of companies have been exploring to establish coalbed methane production. At current prices, companies are assessing the potential for coalbed methane production and there have been some pilot projects for the purpose of producing this resource commercially. However, due to lack of sufficient information and uncertainty surrounding its potential, the EUB has made no allowance for coalbed methane production over the forecast period at this time.

Figure 4.26 shows the forecast of conventional natural gas production, along with gas production from other sources.

4.3.2 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 the winter approaches, the demand for natural gas supply rises, injection slows or ends, and production generally begins at high withdrawal rates. **Figure 4.27** illustrates the natural gas injection into and withdrawal rates from the storage facilities in the province. Commercial natural gas storage pools, along with the operators and storage information, are listed in Table 4.10. A new storage pool, the McLeod Cardium D Pool, was approved in June 2002.

As **Figure 4.27** illustrates, 2002 natural gas withdrawals exceeded injections by 1065 10^6 m^3 (1110 10^6 m^3 at 37.4 MJ/m^3). This volume represents 0.8 per cent of marketable gas production in the province in 2002.

Marketable gas production volumes determined for 2002 were reduced to account for production from these storage pools, as the natural gas had already been processed as marketable gas. 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 4.10. Commercial natural gas storage pools as of December 31, 2002

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2002 (10^6 m^3)	Withdrawal volumes, 2002 (10^6 m^3)
Carbon Glauconitic	ATCO	1 127	15 500	743	1 025
Crossfield East Elkton A & D	Amoco Canada Petroleum Limited	1 197	14 790	578	966
Hussar Glauconitic R	Husky Oil Operations Ltd.	423	5 635	227	149
McLeod Cardium A	Texaco Canada Petroleum Inc.	986	16 900	450	619
McLeod Cardium D	Texaco Canada Petroleum Inc.	282	4 230	133	0
Sinclair Gething D	Alberta Energy Company Ltd.	282	5 634	177	222
Suffield Upper Mannville I & K, and Bow Island N & BB	Alberta Energy Company Ltd.	2 395	50 715	1 267	1 660

4.3.3 Alberta Natural Gas Demand

The EUB reviews the projected demand for Alberta natural gas on a periodic basis. 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.

With the official start-up of the Alliance pipeline in December 2000, Alberta will continue to have excess take-away capacity available for some time, depending on when new natural gas supplies are developed and how they are transported to market. The Alliance
pipeline has firm service capacity to move 37.5 10^6 m^3/d of liquids rich natural gas from British Columbia and Alberta to the Chicago area, with physical capacity at some 45 10^6 m^3/d. Alliance is running close to physical capacity today, with more than 80 per cent of the natural gas sourced from Alberta.

Figure 4.23 shows Alberta natural gas demand and production. Gas removals from the province represent the difference between natural gas production and Alberta demand. In the year 2002, some 25 per cent of Alberta production was used domestically, up from 23 per cent in 2001. The remainder was sent to other Canadian provinces and the United States.

The 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 35 10^9 m^3 in 2002, representing 39 per cent of total production. **Figure 4.28** illustrates the breakdown of natural gas demand in Alberta by sector.

Residential gas requirements are expected to grow moderately over the forecast period at an average annual rate of 1.5 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, but has shown an overall decline rate of 0.5 per cent. This has been 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 natural gas requirements for bitumen recovery and upgrading to synthetic crude oil are expected to increase annually from 4 10^9 m^3 in 2002 to 12 10^9 m^3 by 2012. 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 gasification technology is one attractive alternative now 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 triple over the forecast period, from some 3 10^9 m^3 in 2002 to 9 10^9 m^3 by 2012.

4.4 Supply of and Demand for Natural Gas Liquids

4.4.1 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 that has been 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 plant. Although some pentanes plus is recovered in the field as gas 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 4.29** 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 is a function of raw gas production, as well as its liquid content, gas plant recovery efficiencies, and prices. For further details, see Section 4.1.7. High gas prices may cause gas processors to reduce liquid recovery.

Ethane extracted at Alberta processing facilities increased from 12.7 10^6 m^3 (34.8 10^3 m^3/d) in 2001 to 13.7 10^6 m^3 (37.7 10^3 m^3/d) in 2002. Table 4.11 outlines the volumes of ethane, propane, butanes, and pentanes plus recovered from natural gas processing in 2002. 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 (1.0 10^3 m^3/d) and 1.1 10^6 m^3 (3.0 10^3 m^3/d) respectively.

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 production. The NGL content from the new reserves is assumed to be somewhat higher than existing reserves, as a large portion of yet to be discovered gas is in the deeper part of the basin.

In 2002, ethane extraction in Alberta was 37.7 10^3 m^3/d, or 52 per cent recovery of the total ethane in the gas stream. It is expected that ethane recovery will increase to 45.9 10^3 m^3/d in 2003 and hold there for the remainder of the forecast period, as shown in **Figure 4.30**. Current processing plant capacity for ethane in Alberta is some 60 10^3 m^3/d and therefore 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 in the future.

Over the forecast period, ratios of ethane, propane, butanes, and pentanes plus in m^3 (liquid) to 10^6 m^3 marketable gas increase, as shown in Table 4.11. **Figures 4.31** to **4.33** show forecast production volumes to 2012 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 4.11. Liquid production at gas plants in Alberta, 2002 and 2012

	2002			2012		
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	13.7	37.7	97	16.8	45.9	138
Propane	8.4	22.9	59	7.7	21.2	64
Butanes	4.6	12.7	33	4.4	12.0	36
Pentanes plus	8.4	23.1	59	7.7	21.2	64

4.4.2 Demand for Ethane and Other Natural Gas Liquids

Of the ethane extracted in the year 2002, 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.

As shown in **Figure 4.30**, Alberta demand for ethane is projected to be 42.5 $10^3\ m^3/d$ for the forecast period, with all four ethylene plants running at 90 per cent of capacity. Supplies are tighter than they have been historically, due in part to the large increase in demand by the fourth ethylene plant placed on production in October 2000 and the Alliance pipeline that came on stream in December 2000. 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. It is noted that alternative feedstock to ethane such as propane and butanes are being considered by the petrochemical industry in an effort to enhance operating flexibility and longer-term growth opportunities. Globally, naptha is by far the most common feedstock used for ethylene production.

Figure 4.31 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 as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying.

Figure 4.32 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 4.33 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 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 17.8 $10^3\ m^3/d$ to 31.3 $10^3\ m^3/d$. The diluent requirement for heavy crude oil is expected to decline from 3.0 $10^3\ m^3/d$ in 2002 to 2.6 $10^3\ m^3/d$ by the end of the forecast, due to declining crude oil production. However, diluent requirements for bitumen are expected to increase quite dramatically, from 12.9 $10^3\ m^3/d$ in 2002 to 28.7 $10^3\ m^3/d$ by 2012. Shortages of pentanes plus as diluent are forecast to occur by 2006 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 addition, industry may consider alternatives to pentanes plus, such as
- upgrading of bitumen to SCO within Alberta;
- blending 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.

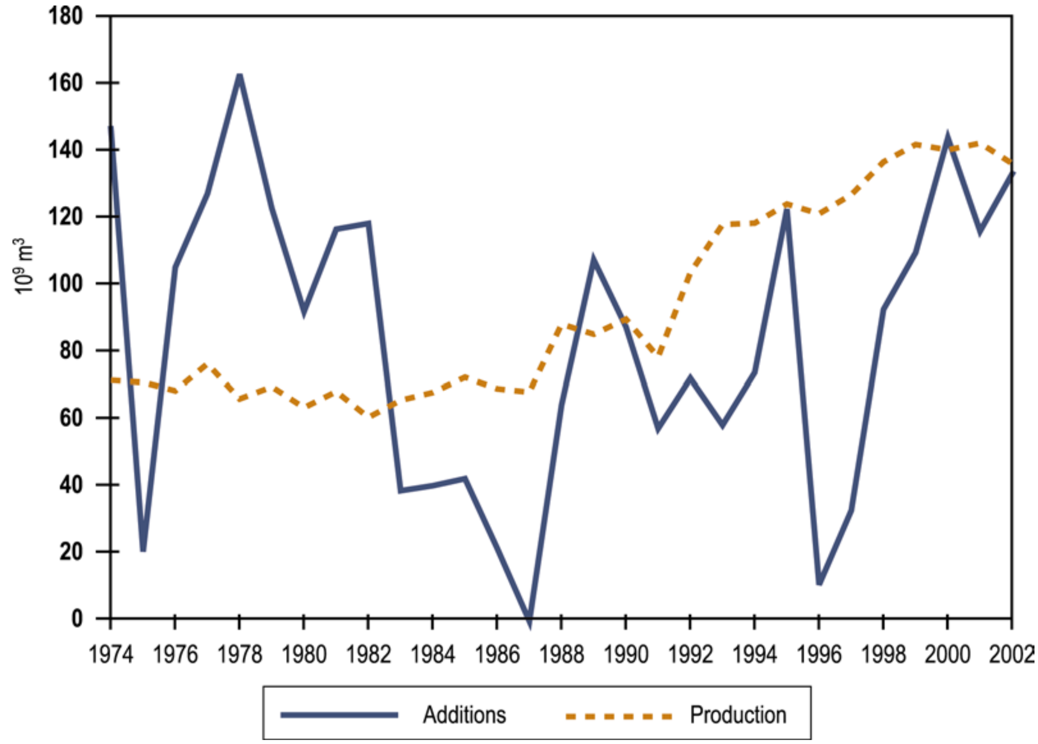

Figure 4.1. Annual additions and production of marketable gas reserves

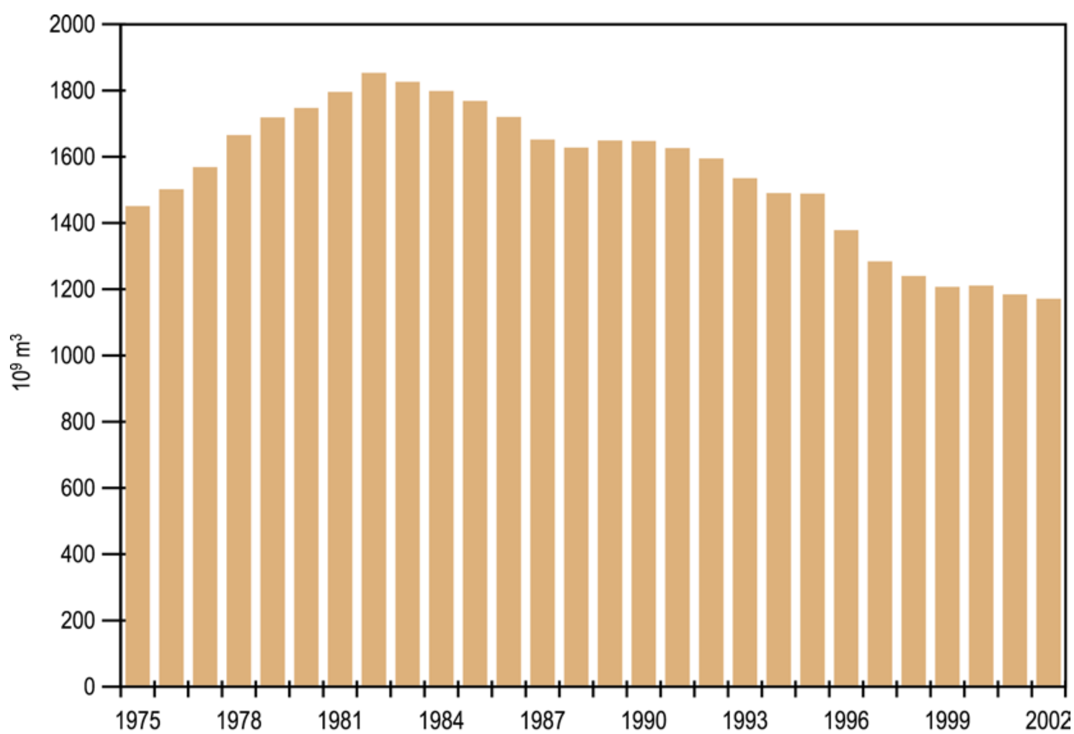

Figure 4.2. Remaining established marketable gas reserves

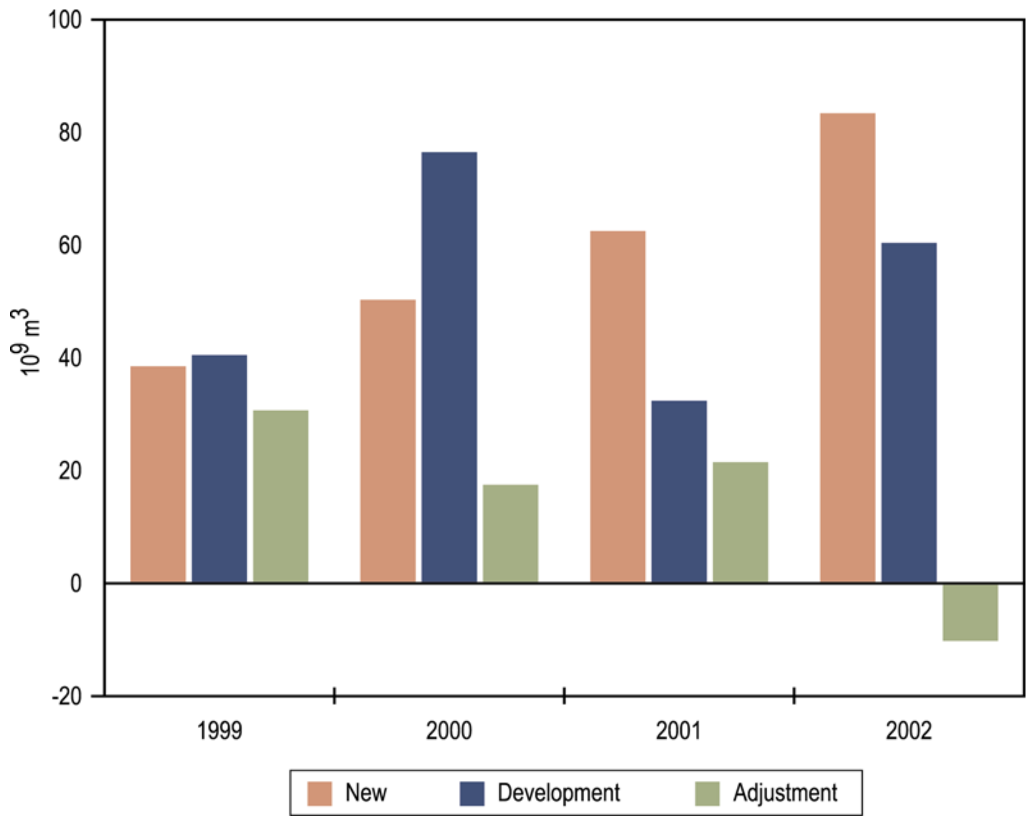

Figure 4.3. Total marketable gas reserves additions, new development, and adjustments

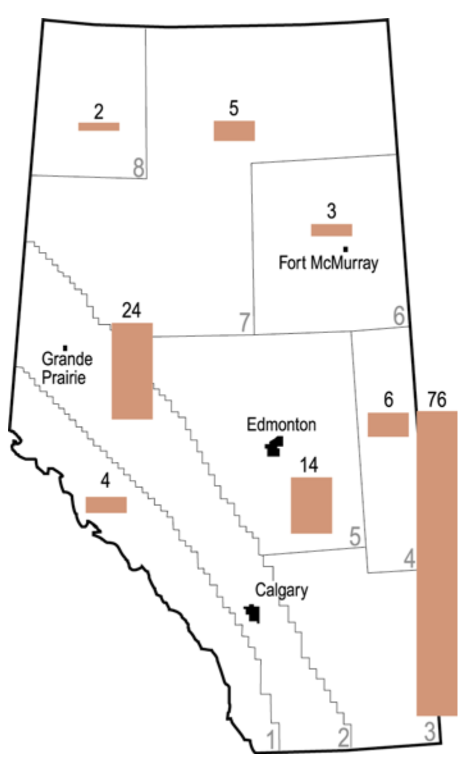

Figure 4.4. Marketable gas reserves additions, 2002 (10^9 m^3)

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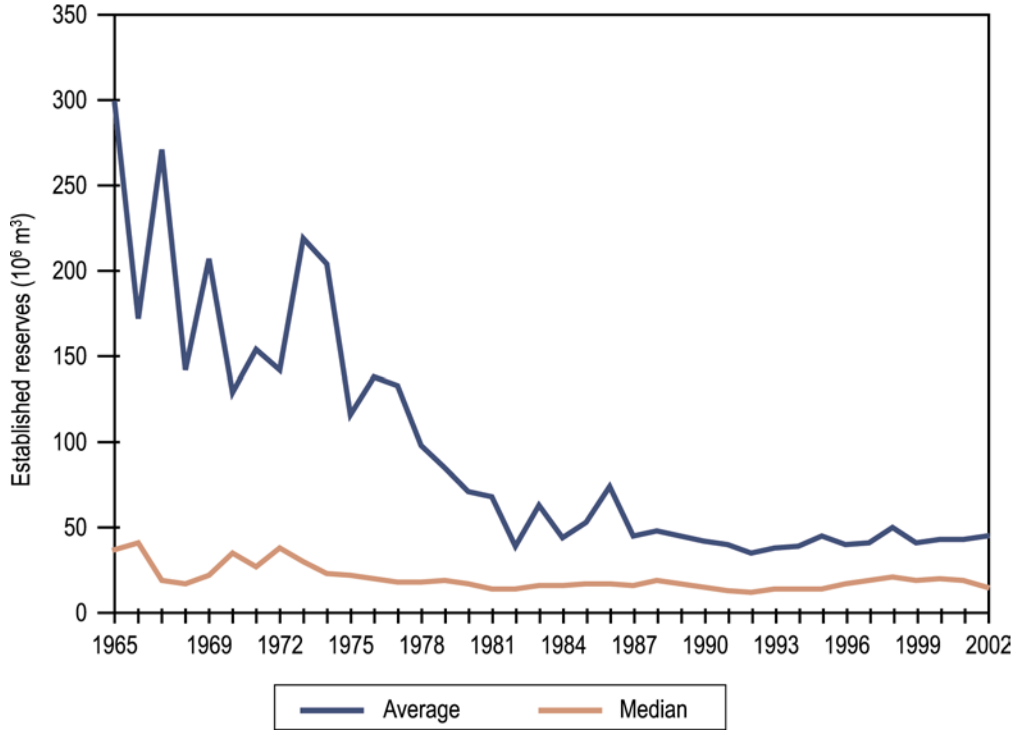

Figure 4.5. Gas pools by size and discovery year errata

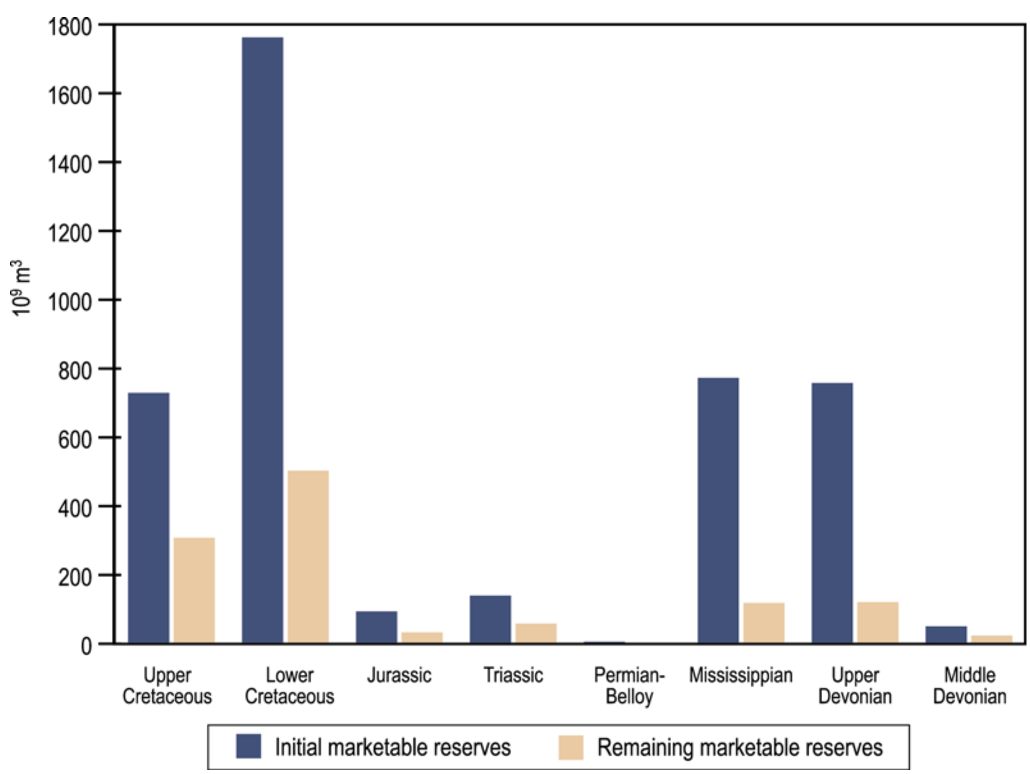

Figure 4.6. Geological distribution of marketable gas reserves

ERRATUM This page includes a revised Figure 4.8

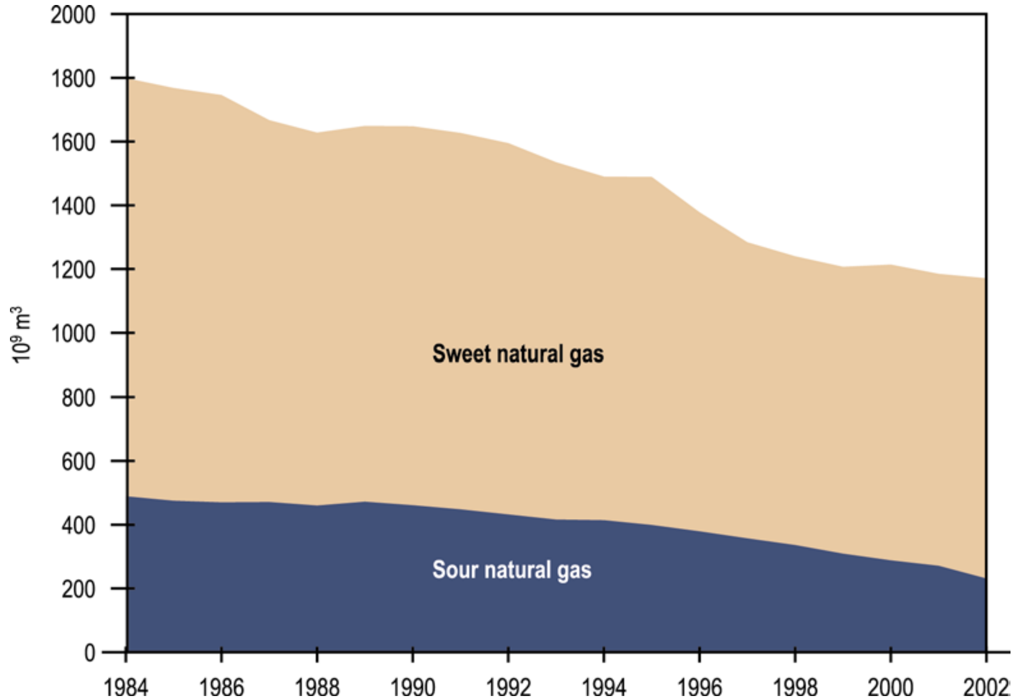

Figure 4.7. Remaining marketable reserves of sweet and sour gas

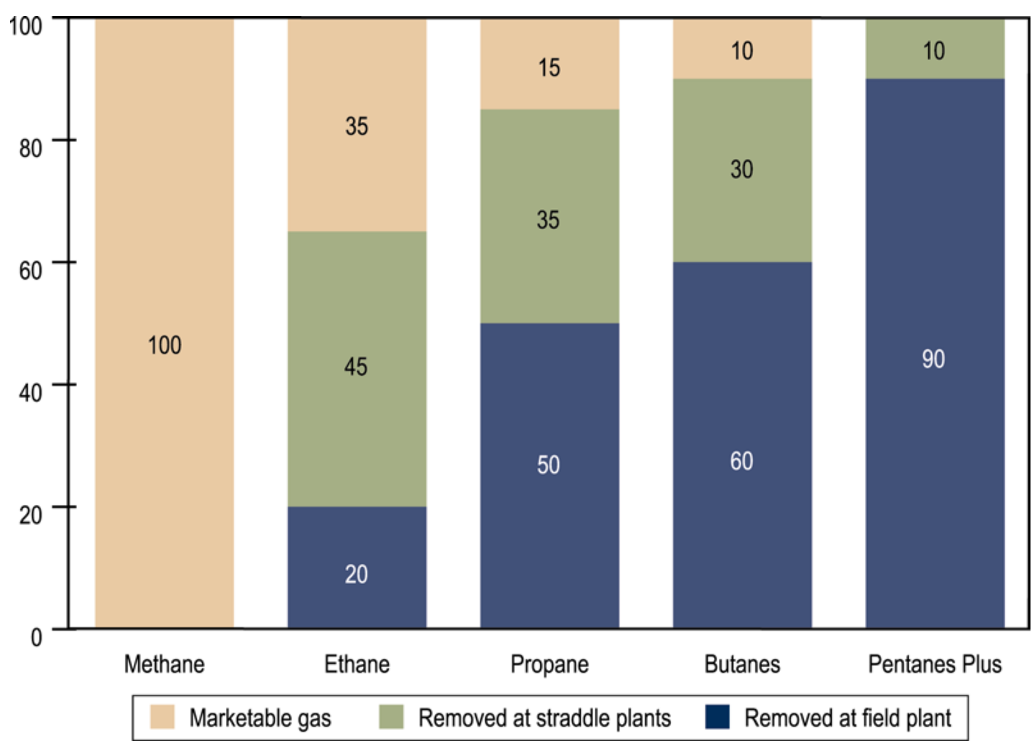

Figure 4.8. Natural gas components errata

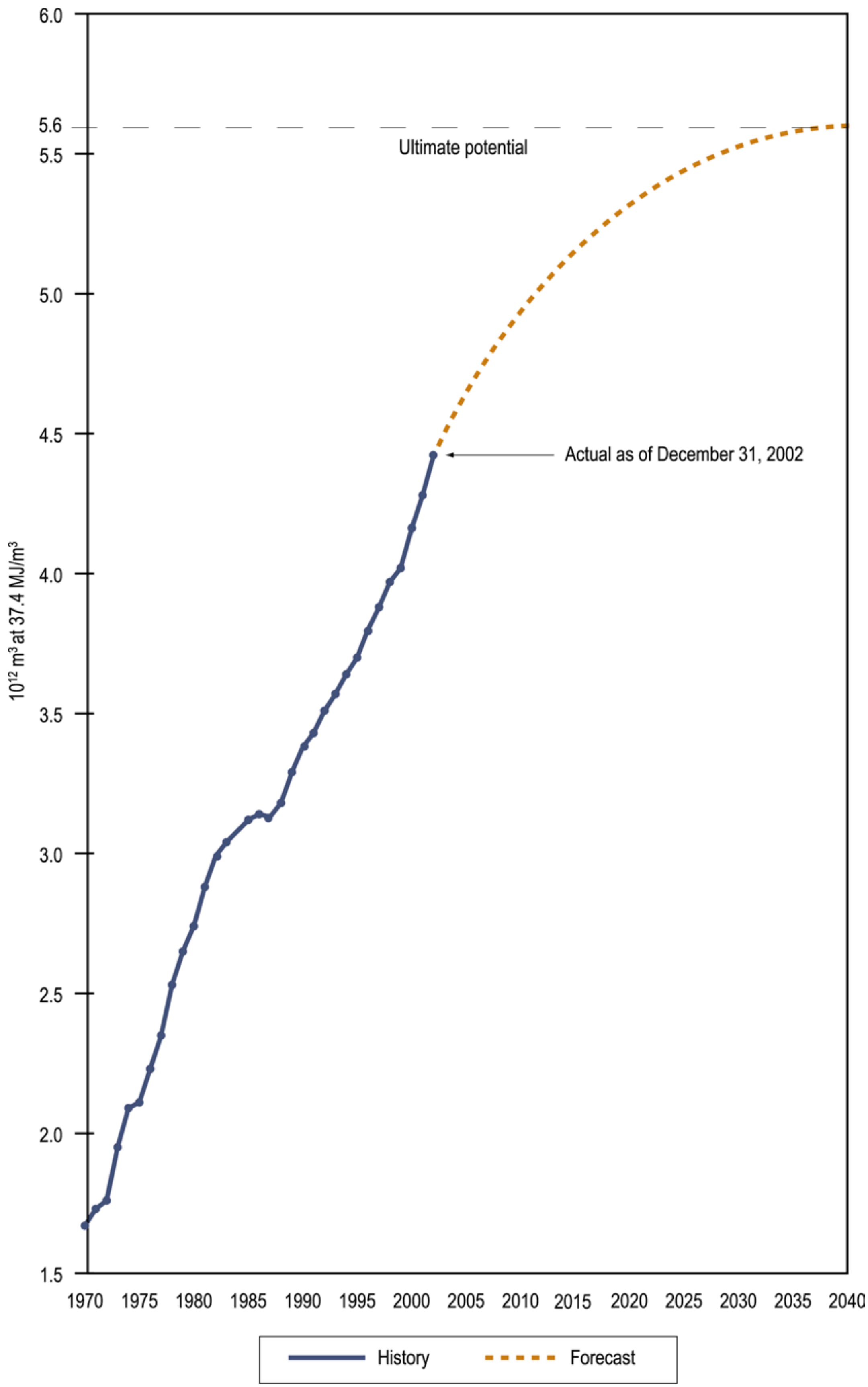

Figure 4.9. Growth of initial established reserves of marketable gas

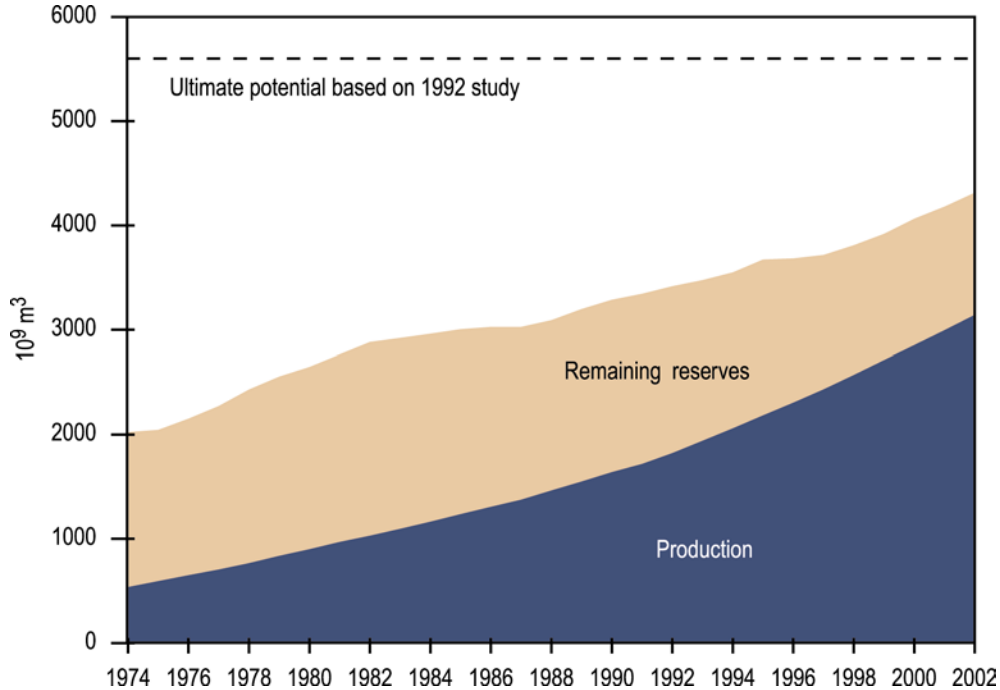

Figure 4.10. Gas ultimate potential

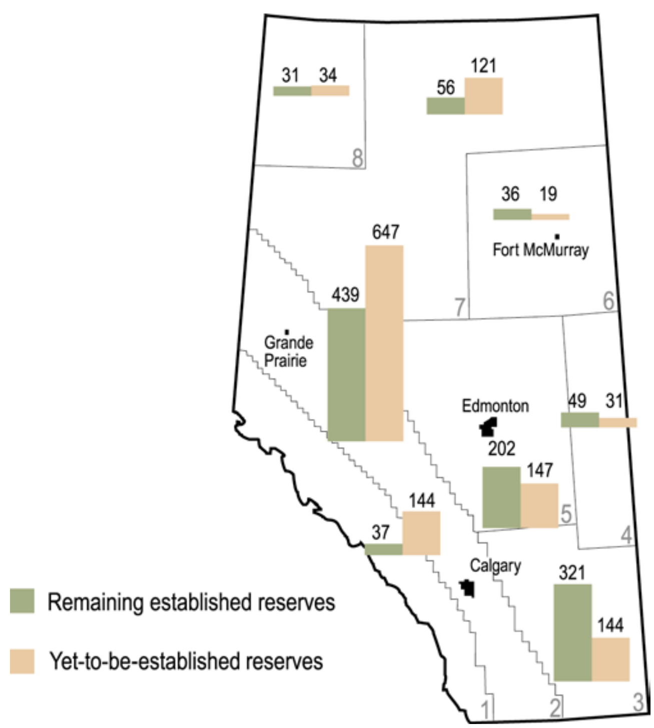

Figure 4.11. Regional distribution of Alberta gas reserves (10^9 m^3)

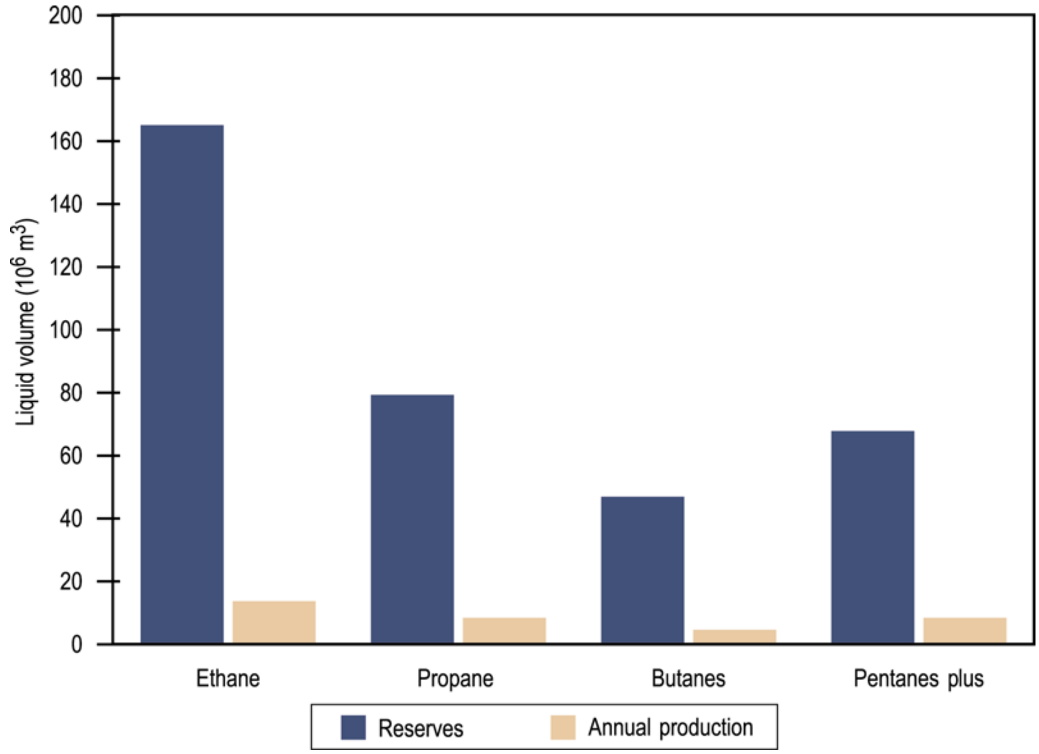

Figure 4.12. Remaining established NGL reserves expected to be extracted and annual production

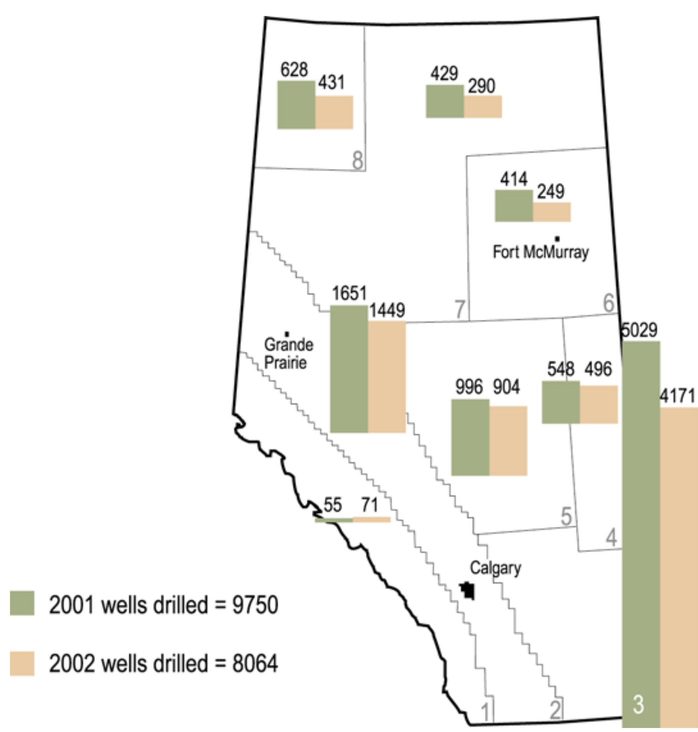

Figure 4.13. Alberta successful gas well drilling

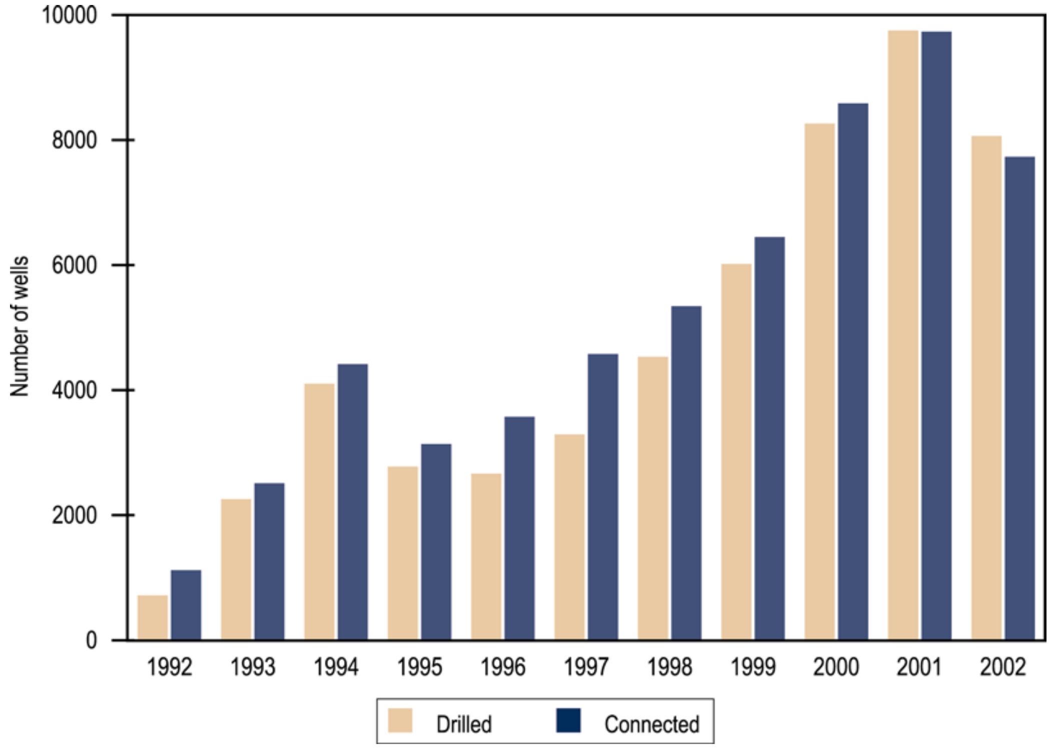

Figure 4.14. Gas wells drilled and connected

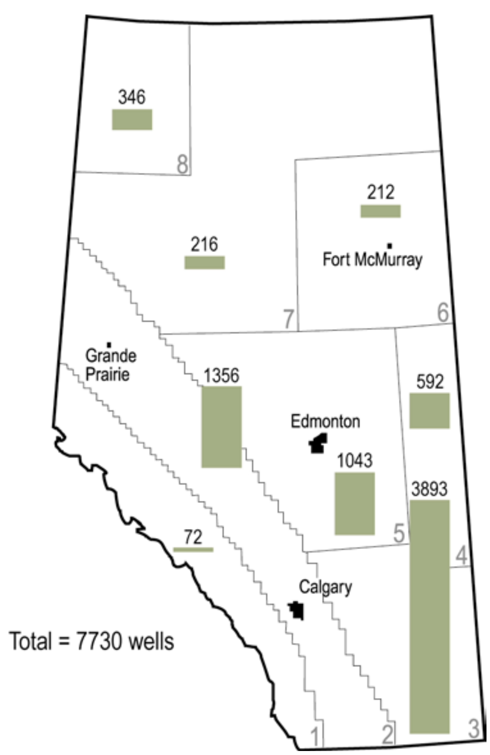

Figure 4.15. Gas well connections, 2002

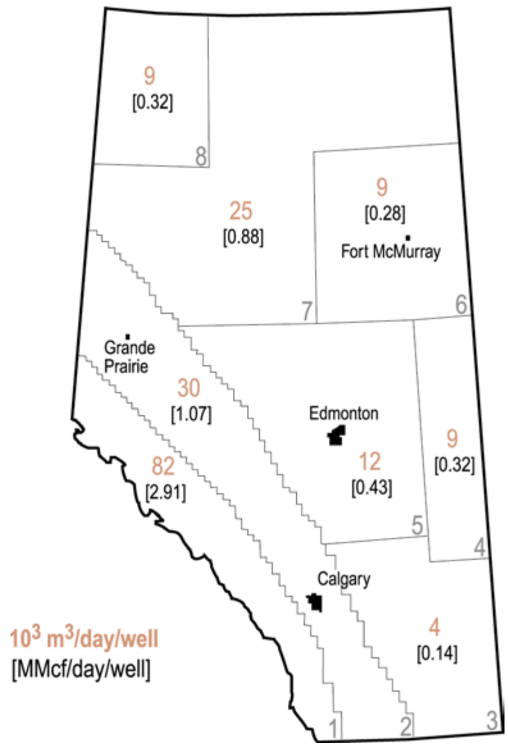

Figure 4.16. Initial operating day rates of connections, 2002

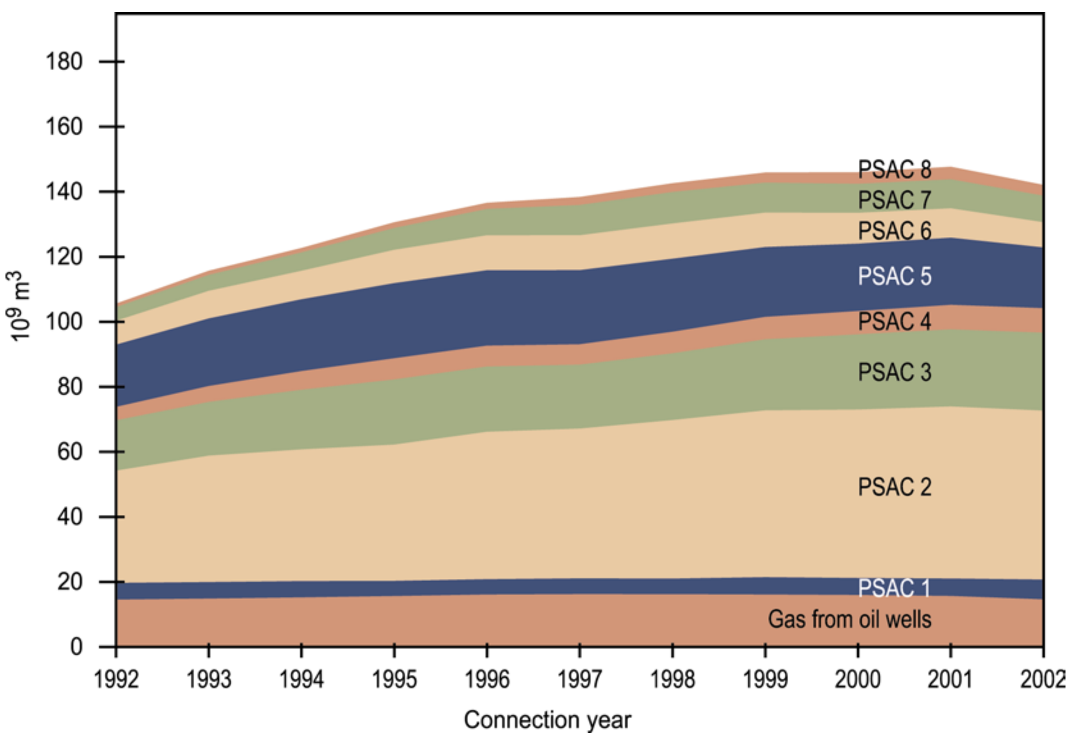

Figure 4.17. Marketable gas production by modified PSAC area

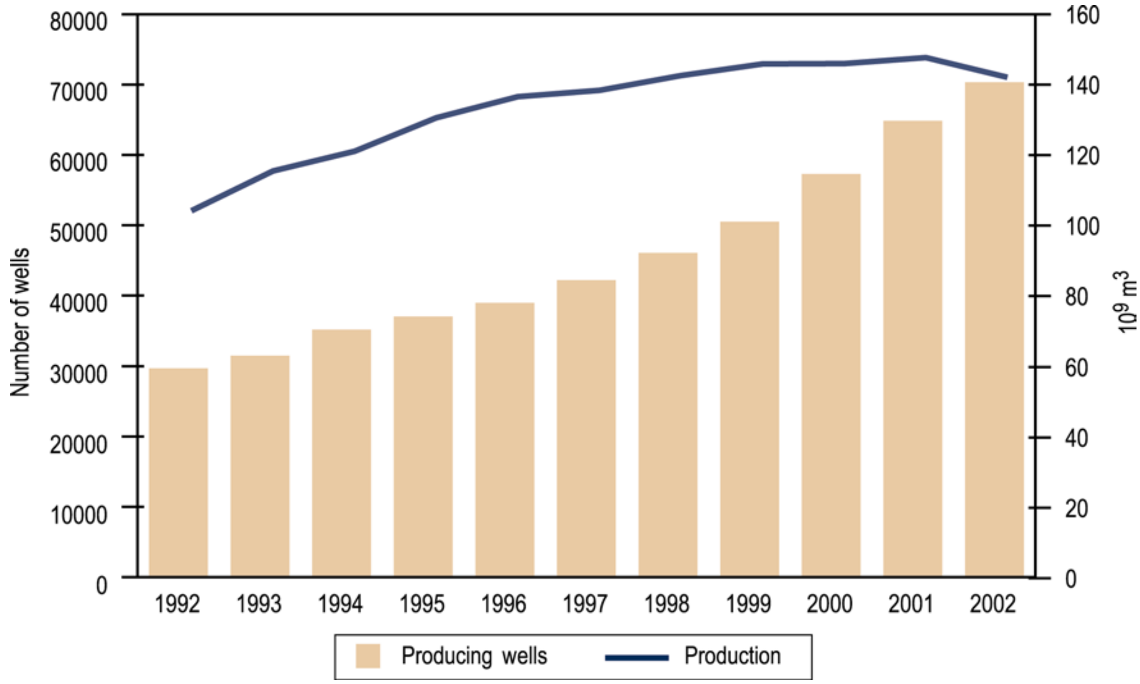

Figure 4.18. Marketable gas production and the number of producing gas wells

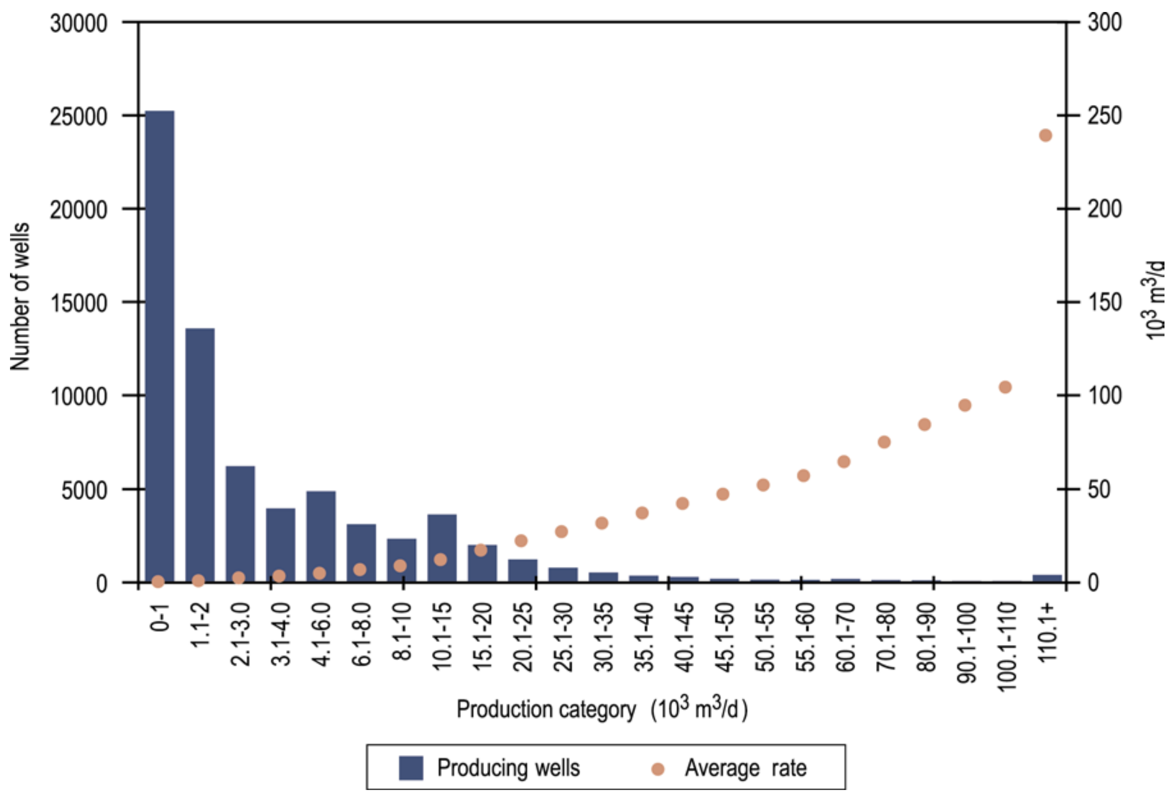

Figure 4.19. Natural gas well productivity in 2002

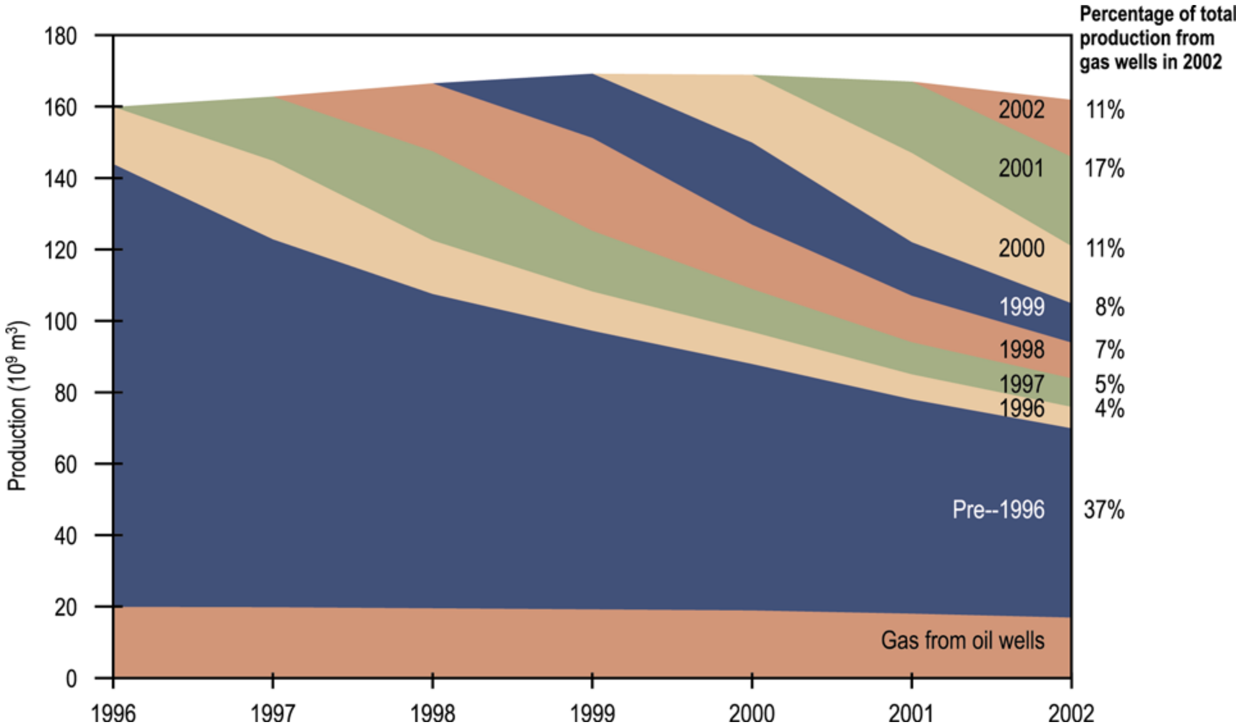

Figure 4.20. Raw gas production by connection year

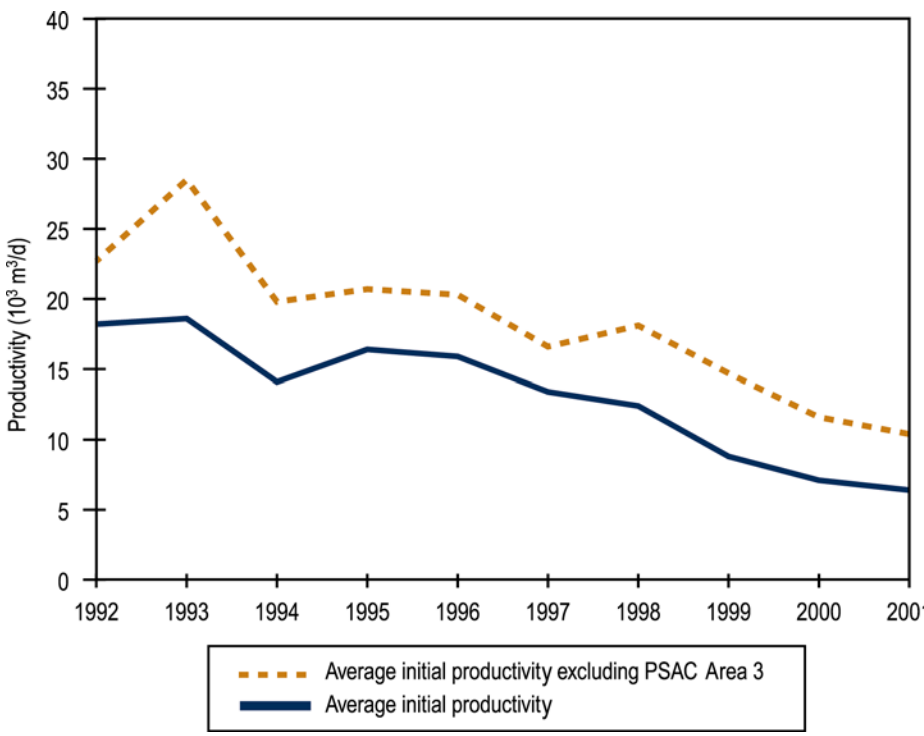

Figure 4.21. Average initial natural gas well productivity in Alberta

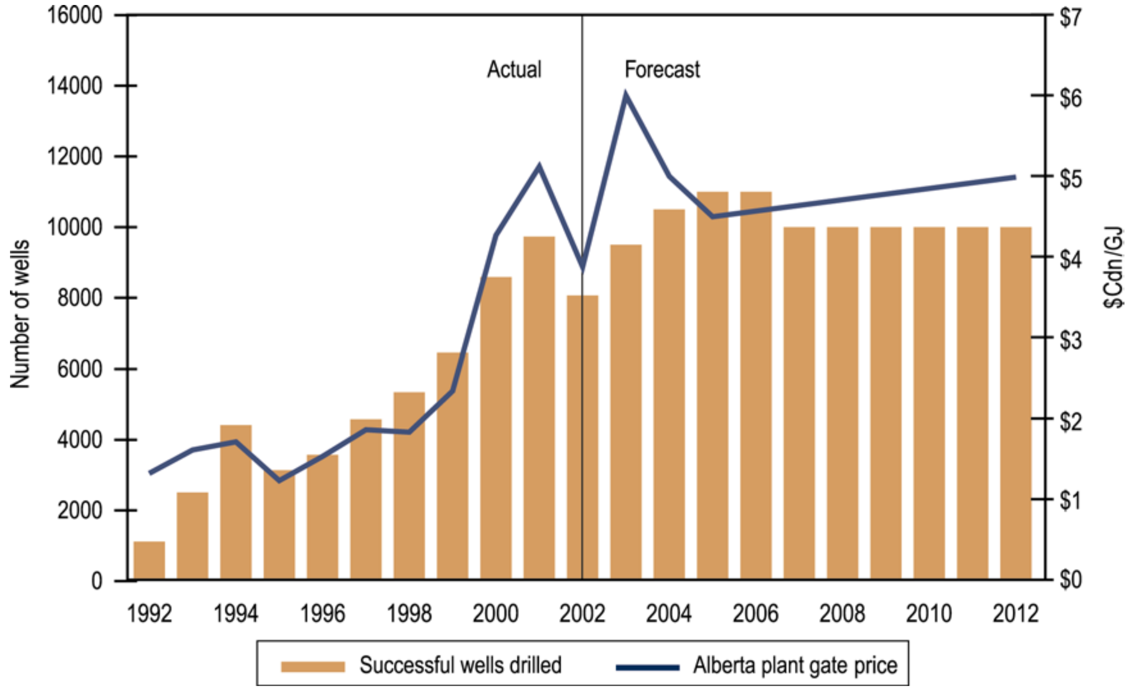

Figure 4.22. Alberta natural gas well activity and price

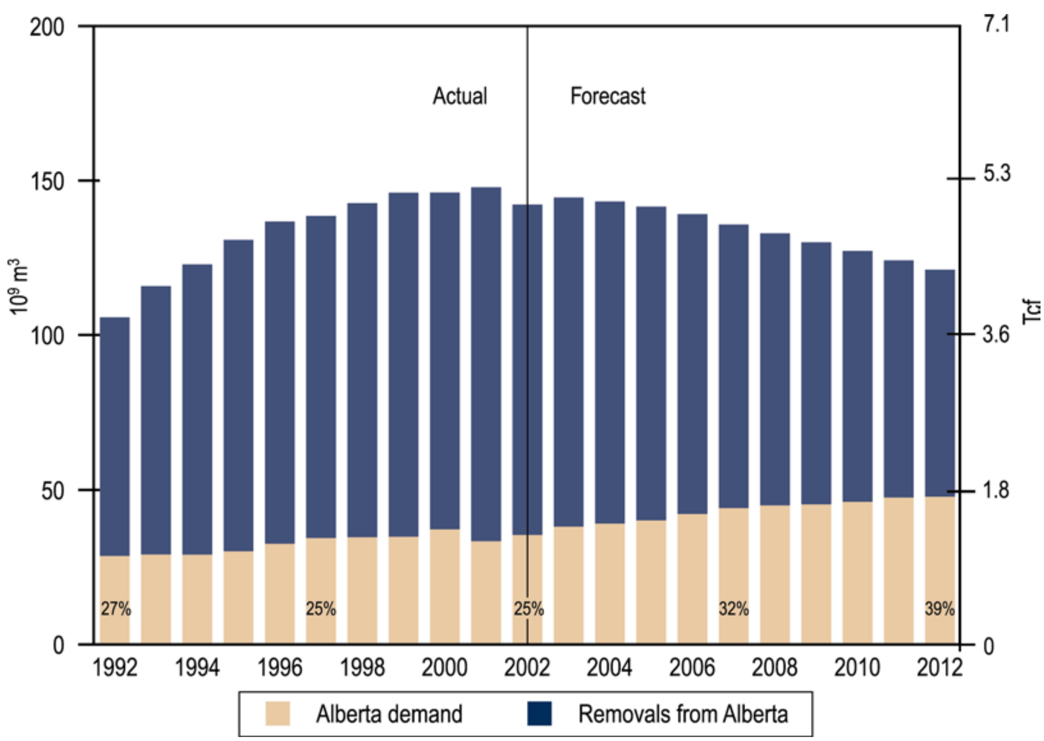

Figure 4.23. Disposition of conventional marketable gas production

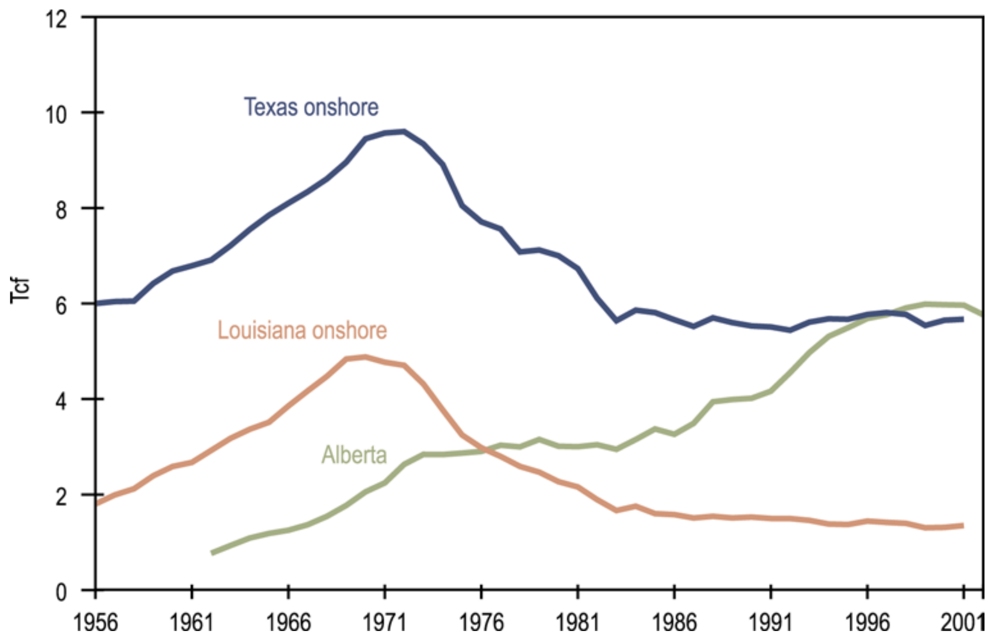

Figure 4.24. Comparison of raw natural gas production

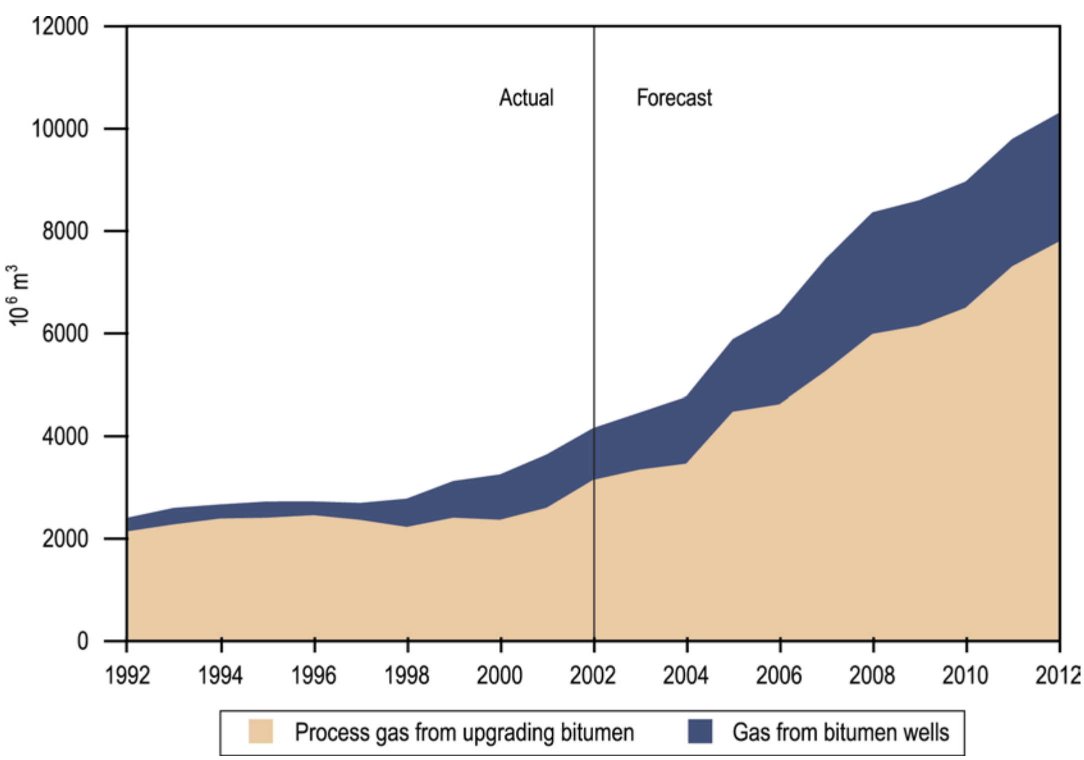

Figure 4.25. Gas production from bitumen upgrading and bitumen wells

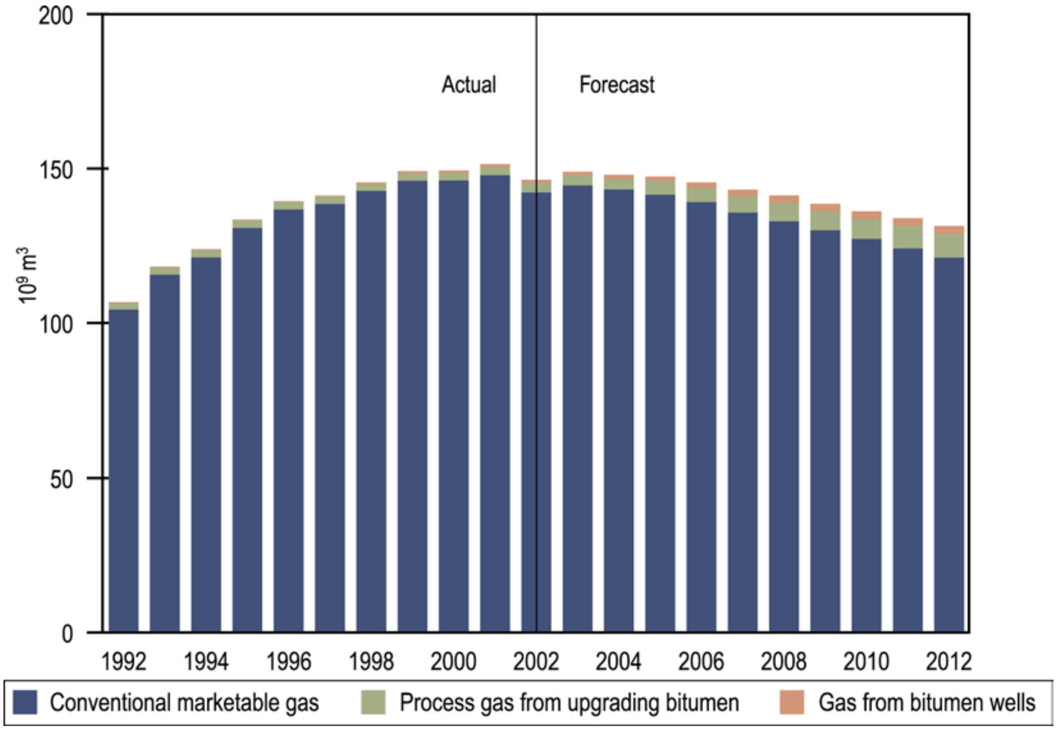

Figure 4.26. Total gas production in Alberta

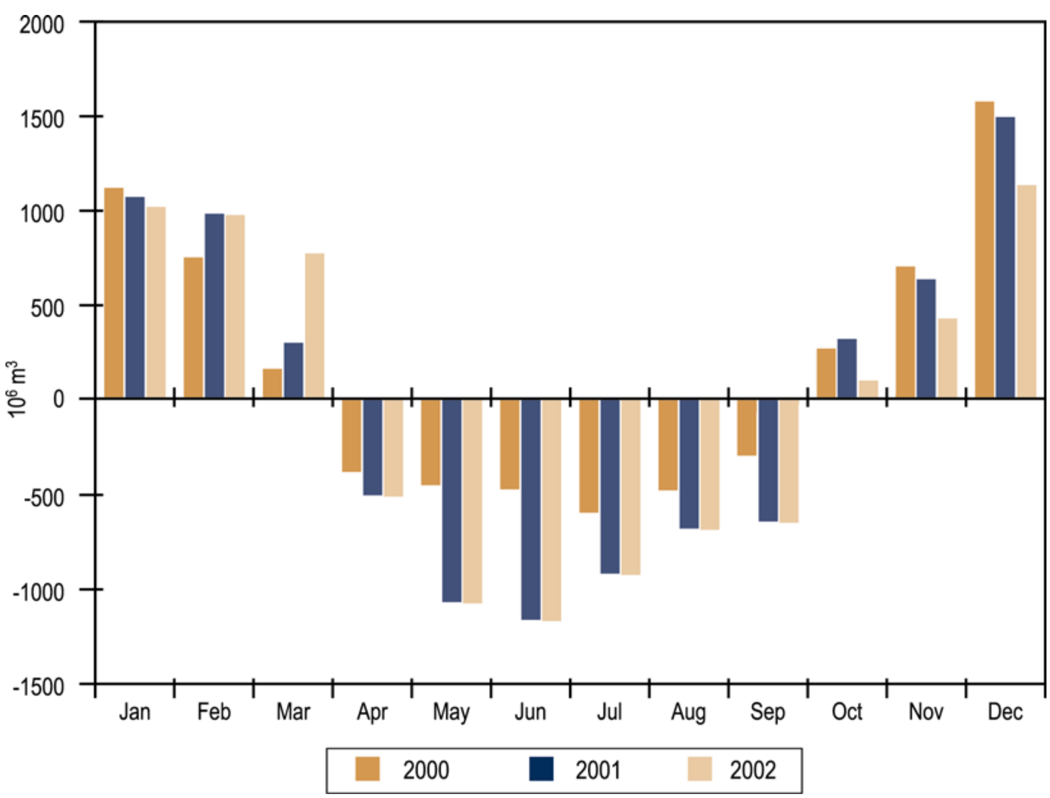

Figure 4.27. Alberta natural gas storage injection/withdrawal volumes

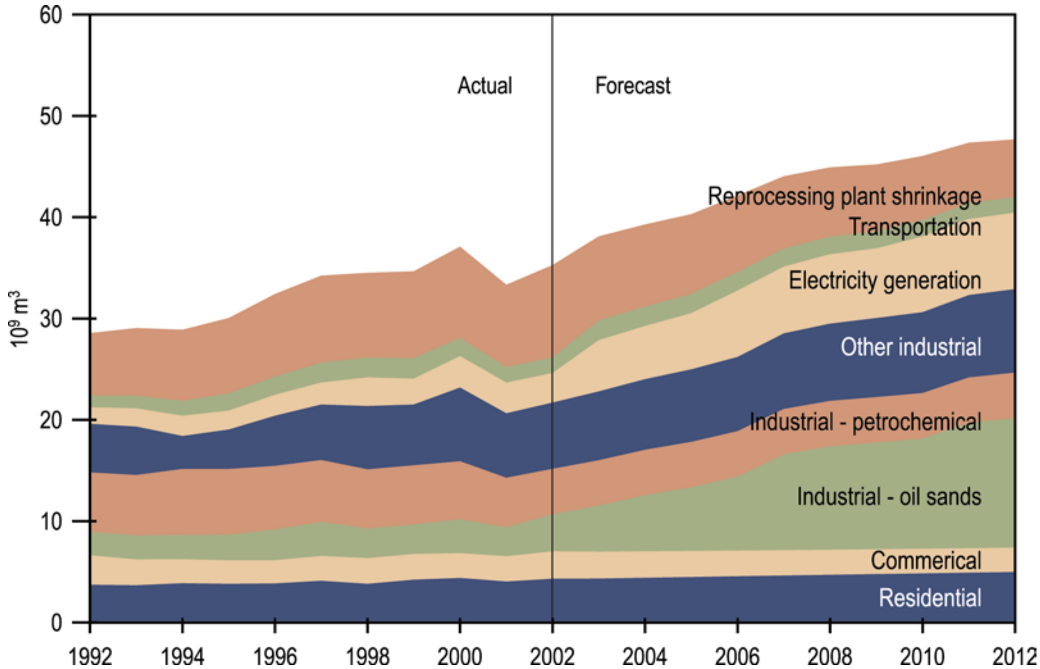

Figure 4.28. Alberta gas demand by sector

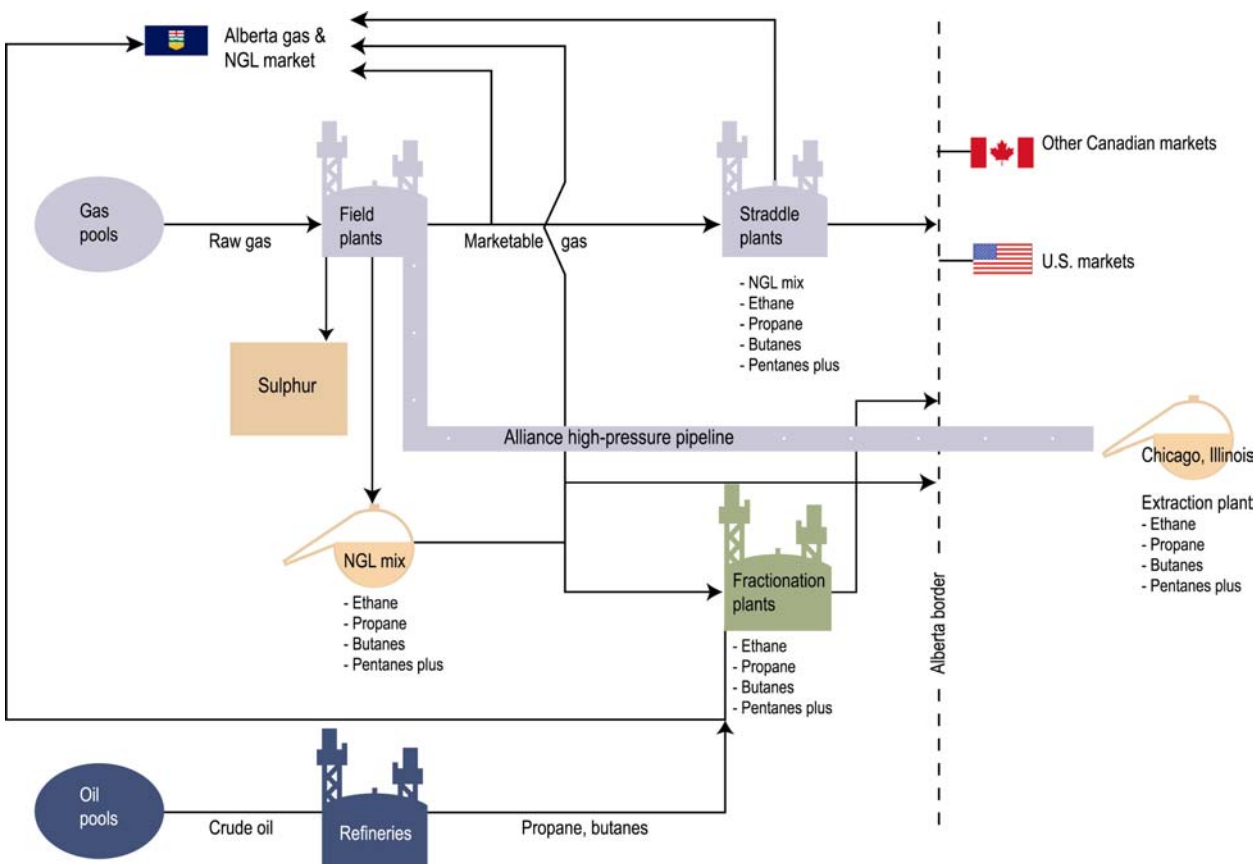

Figure 4.29. Schematic of Alberta NGL flows

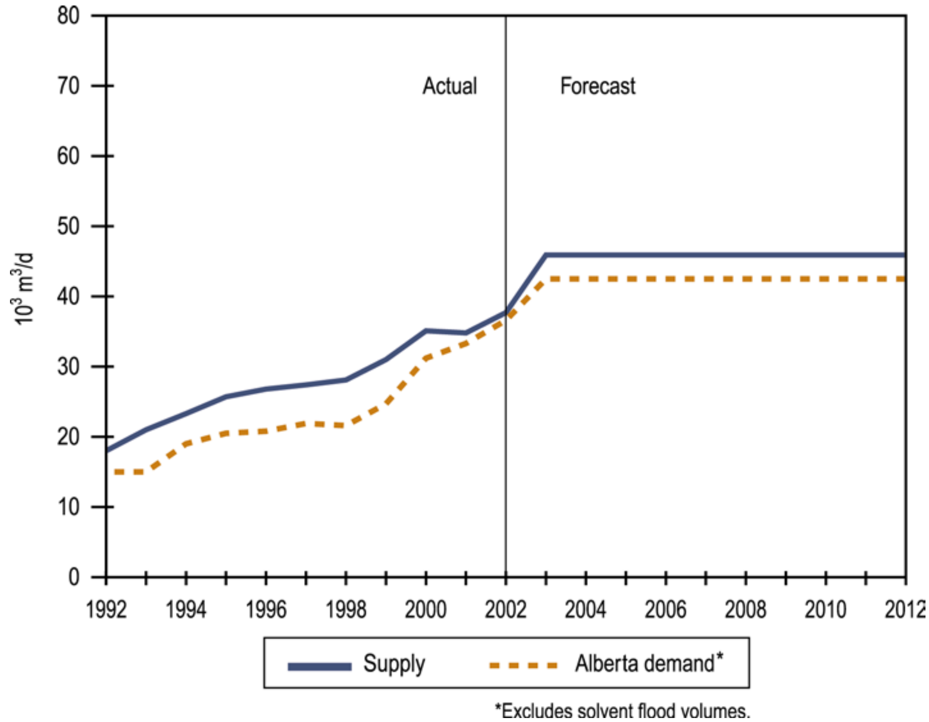

Figure 4.30. Ethane supply and demand

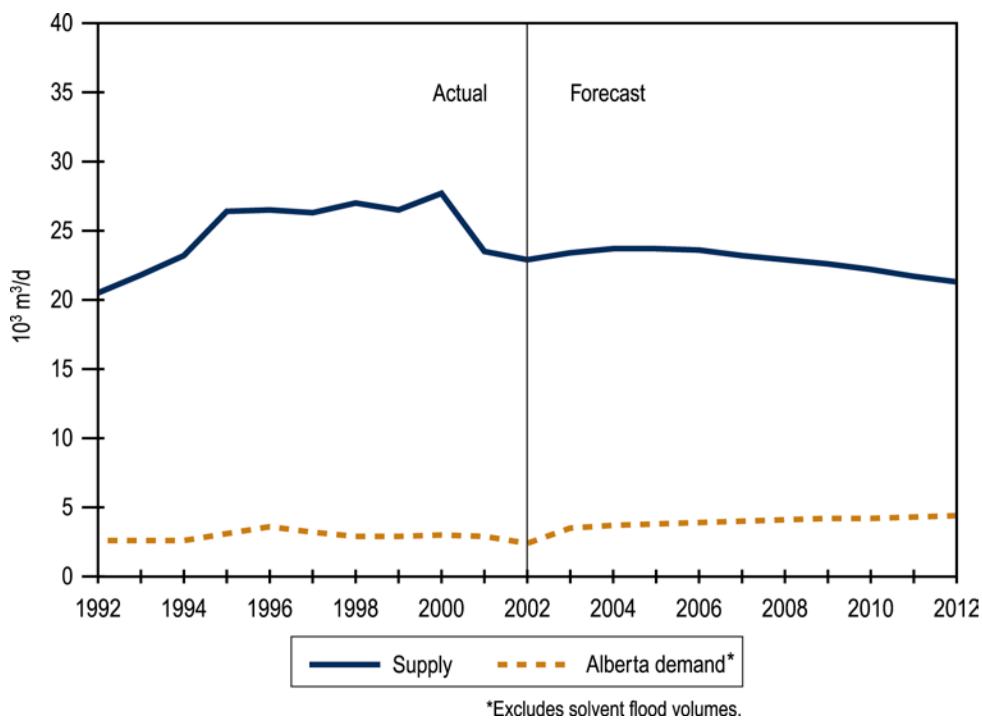

Figure 4.31. Propane supply and demand from natural gas production

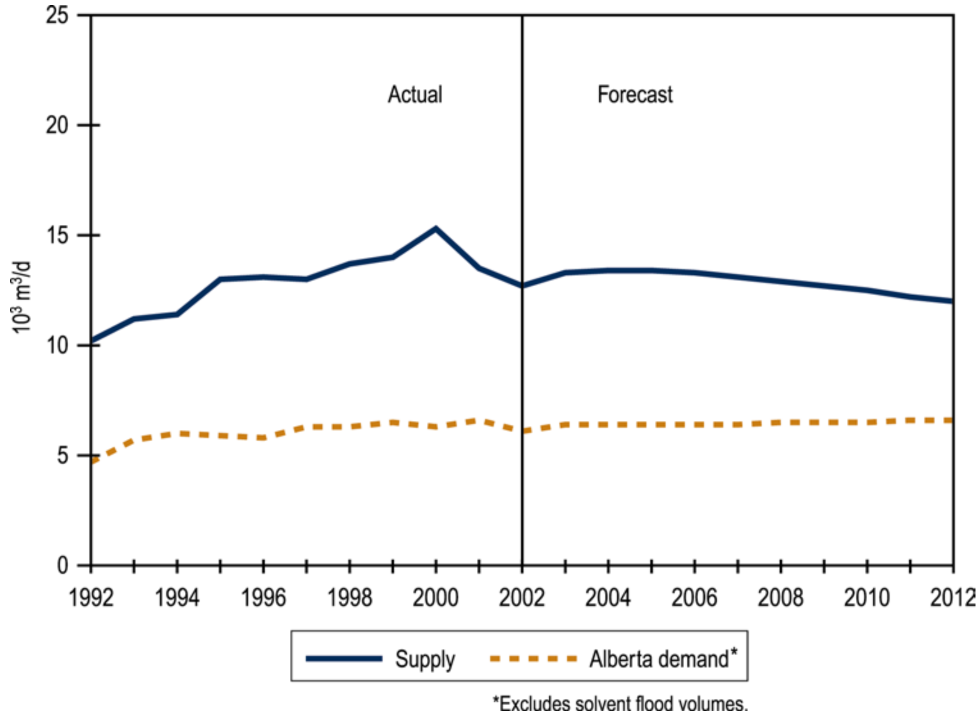

Figure 4.32. Butanes supply and demand from natural gas production

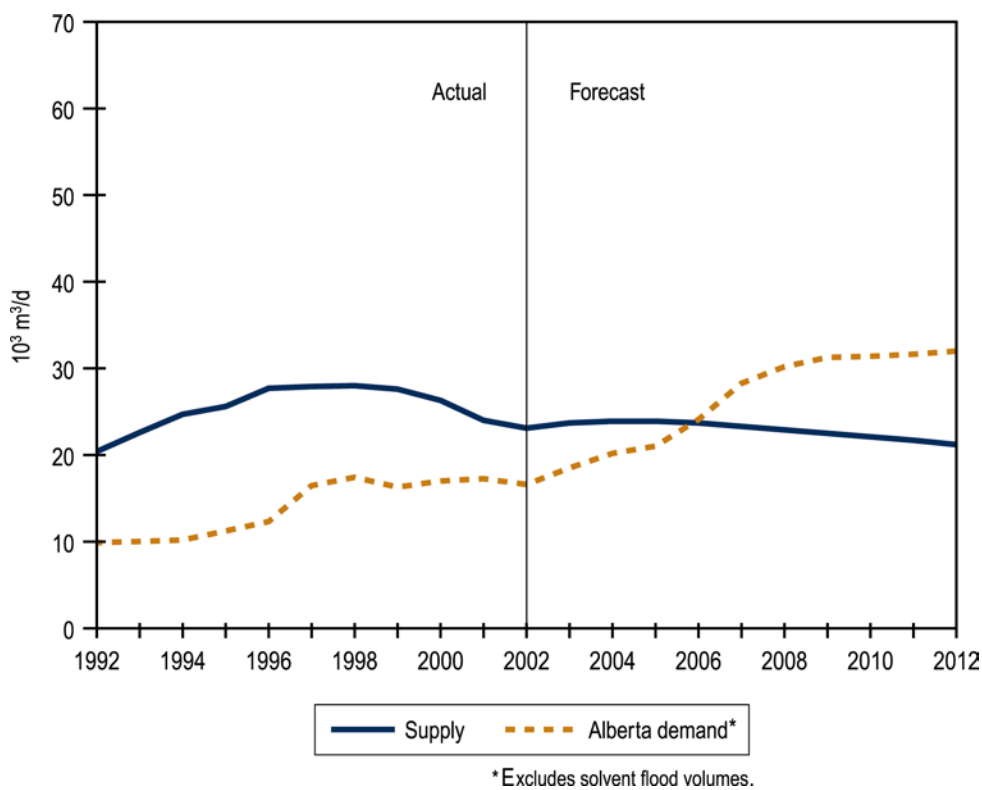

Figure 4.33. Pentanes plus supply and demand

5 Coal

5.1 Reserves of Coal

5.1.1 Provincial Summary

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.

The significant amount of data generated in the exploration for coal has been used by the EUB to estimate coal reserves throughout the province. The EUB currently estimates that Alberta's established initial in-place resources of all types of coal total about 94 gigatonnes (Gt).[1] Of this amount, about 34 Gt, or approximately 36 per cent, are considered remaining to be recovered (by surface and underground methods), and of these reserves, 1.0 Gt are within permit boundaries of mines that were active in 2002. Table 5.1 gives a breakdown by rank of resources and reserves from 244 coal deposits.

Table 5.1. Established initial in-place resources and remaining reserves of coal in Alberta as of December 31, 2002 (Gt)

Rank Classification	Initial in-place resources	Cumulative production	Remaining reserves	Remaining reserves in active mines
Low- and medium-volatile bituminous[a]				
Surface	1.74	0.217	0.594	
Underground	5.06	0.105	0.634	
Subtotal	6.83[b]	0.322	1.24[b]	0.049
High-volatile bituminous				
Surface	2.56	0.135	1.76	
Underground	3.30	0.047	0.914	
Subtotal	5.90[b]	0.183	2.69[b]	0.165
Subbituminous[c]				
Surface	13.6	0.605	8.39	
Underground	67.0	0.068	21.1	
Subtotal	80.7[b]	0.673	29.6[b]	0.783
Total[b]	93.7	1.18	33.6	0.997

[a] Includes minor amounts of semi-anthracite.
[b] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.
[c] Includes minor lignite.

Minor changes in remaining established reserves from December 31, 2001, to December 31, 2002, resulted from increases in cumulative production. During 2002 the low- and medium-volatile, high-volatile, and subbituminous production were 0.003 Gt, 0.005 Gt, and 0.026 Gt respectively.

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

5.1.2 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.

5.1.3 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 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.

Table 5.2 shows the established resources and reserves within the current permit boundaries of those mines active in 2002. Grande Cache Coal received EUB approval to mine coal in the Smoky River Coal Field in January 2003 and is not yet included in Table 5.2.

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

Table 5.2. Established resources and reserves of coal under active development as of December 31, 2002

Rank Mine	Permit area (ha)	Initial in-place resources (10^6 t)	Initial reserve (10^6 t)	Cumulative production (10^6 t)	Remaining reserves[a] (10^6 t)
Low- and medium-volatile bituminous					
Gregg River[b]	3 540	103	62	46	16
Luscar	5 050	32	130	97	33
Subtotal[a]	8 590	435	192	143	49
High-volatile bituminous					
Coal Valley[c]	6 400	349	167	99	68
Obed	7 590	162	137	40	97
Subtotal	13 990	511	304	139	165
Subbituminous					
Vesta	2 410	69	54	36	18
Paintearth	2 710	94	67	36	31
Sheerness	7 000	196	150	55	95
Dodds	140	2	2	1	1
Whitewood[c]	2 800	163	98	72	26
Highvale	12 140	1 021	764	288	476
Genesee	7 320	250	176	40	136
Subtotal[a]	34 520	1 795	1 311	528	783
Total	57 100	2 741	1 807	810	997

[a] Differences are due to rounding.
[b] Limited operations in 2002.
[c] Does not include area of expansion approved in 2001.

5.1.4 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 *Reserves of Coal* report and adjusting them slightly to reflect the most recent trends. Table 5.3 gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potentials.

5.2 Supply of and Demand for Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used for electricity

Table 5.3. 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.

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. Historical and forecast of Alberta production for each of the three types of marketable coal are shown in **Figure 5.1**.

5.2.1 Coal Supply

In 2002, ten mine sites supplied coal in Alberta, as shown in Table 5.4. Together they produced 31.0 10^6 t of marketable coal. Subbituminous coal accounted for 83.0 per cent of the total, bituminous metallurgical was 6.7 per cent, and bituminous thermal coal constituted the remaining 10.3 per cent.

Five large mines and a very small one produce subbituminous coal. The large mines serve nearby electric power plants, while the small mine supplies 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. Over the past few years, subbituminous coal production has stabilized, as no new coal-fired power plants have been built and no substantial generating capacity has been taken out of operation.

Table 5.4. Alberta coal mines and marketable coal production in 2002

Company (grouped by coal type)	Mine	Location	Production in 2002 (10^6 t)
Subbituminous coal			
Epcor Generation Inc.	Genesee	Genesee	3.6
Luscar Ltd.	Sheerness	Sheerness	3.6
	Paintearth	Halkirk	1.6
	Vesta	Cordel	1.4
TransAlta Utilities Corp.	Highvale	Wabamun	12.7
	Whitewood	Wabamun	2.8
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.04
Bituminous metallurgical coal			
Cardinal River Coals Ltd.	Luscar	Luscar	2.1
Bituminous thermal coal			
Luscar Ltd.	Coal Valley	Coal Valley	1.8
	Obed Mtn.	Hinton	1.4

Two operators, however, received regulatory approval in 2001/2002 for three new coal-fired generating units with 450 to 490 megawatt (MW) capacity. These units are scheduled for commissioning between 2005 and 2008. A third operator has also applied for permit to construct two 500 MW generation units for commissioning in the later part of the forecast period. All five units will be fuelled by subbituminous coal.

Alberta's only operating preparation plant producing clean metallurgical coal for export is at the Luscar Mine, which is slated for closure due to the exhaustion of coal reserves expected in late 2003 or early 2004. Meanwhile, other operators have proposed to begin mining in the vicinity of the defunct Smoky River Mine, to supply coal to the H.R. Milner Power Plant or to produce export grade metallurgical coal. The proposed Cheviot Mine, which has obtained regulatory approvals, is incorporated in the forecast; it is assumed that operation will start in 2005.

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 proposed Cheviot Mine and the restarting of mining in the Smoky River area, will come on stream over the next decade.

In late 2002 and 2003, a significant rationalization of Canada's coal industry occurred whereby the assets of the large coal companies were combined to form a single operating metallurgical coal company (Fording Canadian Coal Trust) and a single operating thermal coal company (Luscar Coal Ltd.). The impacts of these changes on Alberta's metallurgical coal production are uncertain at this time, but it is assumed that the new owners of the Cheviot mine will continue with the planning for the starting of this mine.

In early 2003, Alberta's two producing thermal bituminous coal mines were negatively impacted by declining export thermal coal prices. Luscar announced the indefinite suspension of operations at the Obed Mountain mine and a reduction in operations at the Coal Valley mine. It is uncertain at this time what the total impacts of this announcement will be, but it is assumed that production will rebound to 2002 levels by the latter half of the forecast period.

5.2.2 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electric generation plants, and their production ties in with electricity generation. Subbituminous coal production is expected to increase, with potentially five 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 in Japan. While prices of thermal coal entering international markets have been falling in recent months and caused the announced reduction in coal production, it is expected that price recovery will occur in the latter half of the forecast period. The combination of soft metallurgical prices and the announced industry restructuring may have the impact of delaying the starting of the Cheviot Mine. Alberta's export coal producers, as always, have the competitive disadvantage of long distances from mine to port.

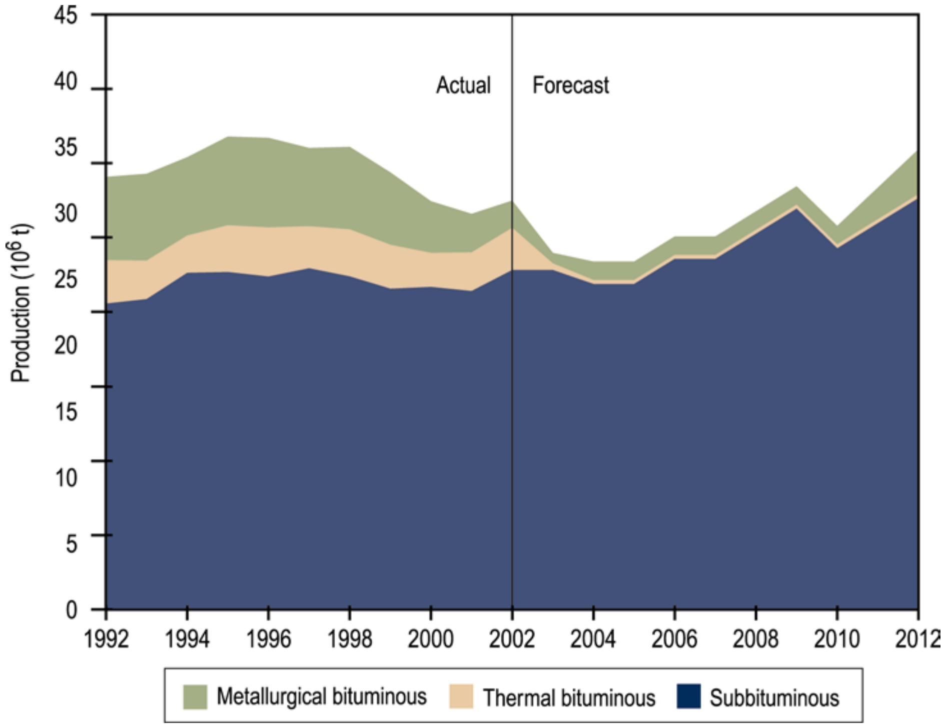

Figure 5.1. Alberta marketable coal production

6 Sulphur

6.1 Reserves of Sulphur

6.1.1 Provincial Summary

The EUB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2002, to be some 86.9 million tonnes (10^6 t). The changes in sulphur reserves during the past year are shown in Table 6.1.

Table 6.1. Reserves of sulphur as of December 31, 2002 (10^6 t)

	2002	2001	Change
Initial established reserves			
Natural gas	238.7	240.0	-1.3
Crude bitumen[a]	67.7	67.7	0.0
Total	306.4	307.7	-1.3
Cumulative net production			
Natural gas	207.1	201.5	+5.6
Crude bitumen[b]	13.4	12.4	+1.0
Total	220.5	213.9	+6.6
Remaining established reserves			
Natural gas	31.6	38.5	-6.9
Crude bitumen[a]	54.3	55.3	-1.0
Total	85.9	93.8	-7.9

[a] Recoverable reserves of elemental sulphur under active development at Suncor, Syncrude, and Albian Sands operations as of December 31, 2002.
[b] Production from surface mineable area only.

6.1.2 Sulphur from Natural Gas

The EUB recognizes 31.6 10^6 t of remaining established sulphur from natural gas reserves at year-end 2002. 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 309 10^6 t, with an additional 40 10^6 t from ultra-high H_2S pools. Based on the established reserves of 238.6 10^6 t, this leaves 111 10^6 t yet to be established from future discoveries of conventional gas.

The EUB's sulphur reserve estimates from natural gas are shown in Table 6.2. Fields containing the largest recoverable sulphur reserves are listed individually and those containing less are grouped under "All other fields." Sulphur reserves declined most notably in the Caroline, Waterton, Brazeau River, and Limestone fields, as a result of production.

Table 6.2. Remaining established reserves of sulphur from natural gas as of December 31, 2002

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[a] (mol/mol)	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Berland River	876	0.140	162	220
Bighorn	2 008	0.072	175	237
Blackstone	3 173	0.107	454	615
Brazeau River	10 806	0.058	801	1 086
Caroline	12 836	0.240	6 182	8 383
Coleman	863	0.255	328	445
Crossfield	4 716	0.158	1 095	1 485
Elmworth	14 885	0.009	161	218
Fir	4 958	0.075	444	603
Garrington	6 638	0.063	419	569
Hanlan	6 849	0.086	772	1 047
Jumping Pound West	6 717	0.063	536	727
Kaybob South	12 953	0.043	705	955
La Glace	3 297	0.069	266	360
Lambert	2 043	0.086	220	298
Limestone	3 787	0.074	358	485
Lone Pine Creek	1 799	0.077	175	237
Moose	2 297	0.120	366	496
Okotoks	673	0.302	387	525
Pine Creek	6 696	0.058	470	637
Rainbow	9 501	0.018	188	255
Rainbow South	3 423	0.063	266	360
Ricinus West	1 192	0.252	474	643
Simonette	3 363	0.046	181	245
Sundance	3 147	0.044	162	220
Waterton	4 946	0.244	2 069	2 806
Wildcat Hills	7 184	0.028	233	316
Willesden Green	13 136	0.013	190	258
Windfall	3 783	0.116	589	798
Zama	3 628	0.036	154	208
Subtotal	162 713	0.090	18 980	25 736
All other fields	1 008 684	0.005	5 049	5 847
Total	1 171 397	0.018	24 030	31 583

[a] Volume weighted average.

6.1.3 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 209 10^6 t of elemental sulphur will be recoverable from the 5.2 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 technologies 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.

6.1.4 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 approved 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 13.4 10^6 t of elemental sulphur has been produced from these projects, leaving a remaining established reserve of 54.3 10^6 t. During 2002, 1.0 10^6 t of elemental sulphur were produced at the Suncor and Syncrude projects. The Albian Sands project upgrader has started operation in 2003.

6.2 Supply of and Demand for Sulphur

6.2.1 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 2002, Alberta produced 6.6 10^6 t of sulphur, of which 5.6 10^6 t was derived from sour gas, 1.0 10^6 t from upgrading of bitumen to SCO, and just 10 10^3 t from oil refining. Sulphur production from these sources is depicted in **Figure 6.1**. While sulphur production from sour gas is expected to increase to 6.4 10^6 t from 5.6 10^6 t in 2002, or some 14 per cent, sulphur recovery in bitumen upgrading industry is expected to increase threefold to 3.2 10^6 t by the end of the forecast period. 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 14 10^3 t in 2002 to 29 10^3 t by 2012. Total sulphur production is expected to reach 9.9 10^6 t by the end of forecast period.

6.2.2 Sulphur Demand

Demand for sulphur within the province in 2002 was only about 160 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 2002, China increased its sulphur imports from Canada substantially. Increased global demand for sulphur resulted in a major price change, from $16/t in 2001 to $36/t in 2002. The export demand for sulphur is expected to increase over the next few years. Demand for Alberta sulphur, both domestic and export, is expected to rise slowly, reaching 7.9 10^6 t per year by the end of the forecast period. **Figure 6.2** depicts the Alberta demand and sulphur removal.

6.2.3 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 grow until markets recover from the current glut. Changes to the sulphur inventory are illustrated in **Figure 6.2** as the difference between total supply and total demand.

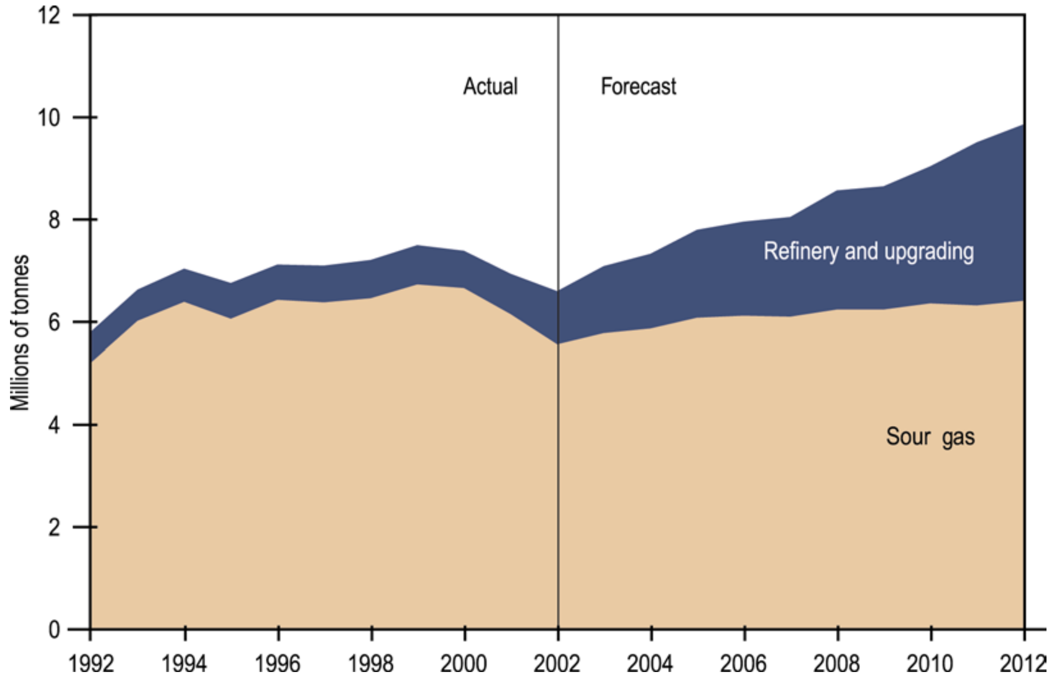

Figure 6.1. Sources of Alberta sulphur production

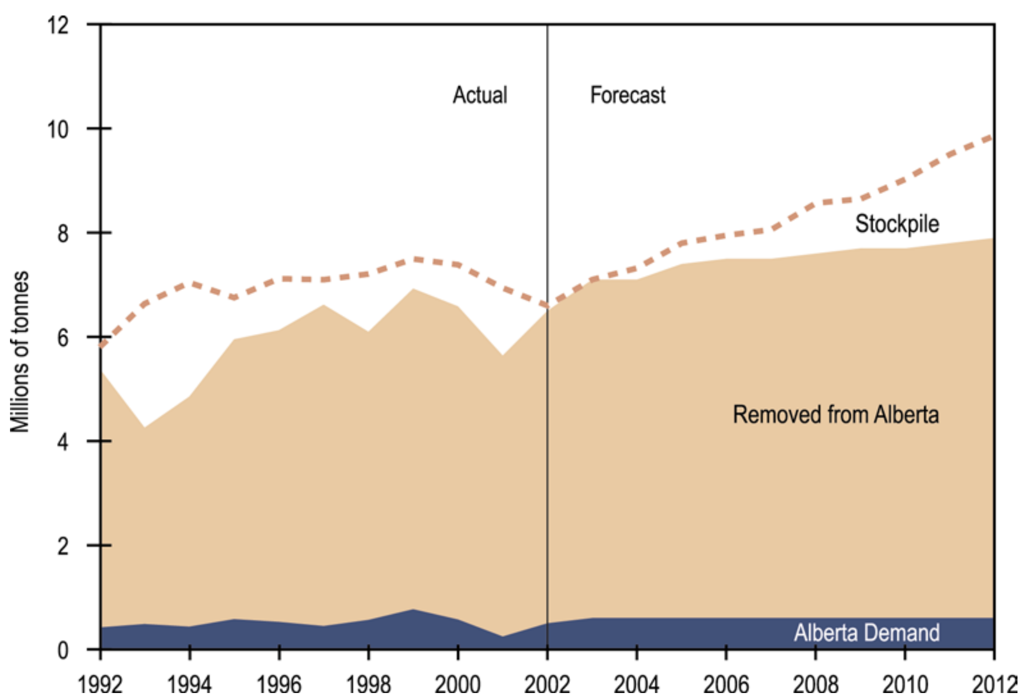

Figure 6.2. Sulphur demand and supply in Alberta

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)).
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.
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	stb	stock-tank barrel

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 pressure and 15°C)	=	6.3000 Canadian barrels of propane (equilibrium (equilibrium pressure and 60°F)
1 m^3 of butanes pressure and 15°C)	=	6.2968 Canadian barrels of butanes (equilibrium (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus pressure and 15°C)	=	6.2929 Canadian barrels of oil or pentanes (equilibrium plus (equilibrium pressure and 60°F)
1 m^3 of water and 15°C)	=	6.2901 Canadian barrels of water (equilibrium pressure (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.

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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
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Bitumen	42.8
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Refined petroleum products (per cubic metre)	
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Diesel	38.7
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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	New EOR schemes	Development	Net revisions	Net 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

Table B.2. Conventional crude oil reserves by geological period as of December 31, 2002

Geological period	Initial volume in-place (10^6 m^3)		Initial established reserves (10^6 m^3)		Remaining established reserves (10^6 m^3)		Average recovery (%)	
	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy	Light-medium	Heavy
Cretaceous								
Upper	2 167	0	362	0	54	-	17	-
Lower	1 086	1 819	211	307	29	61	19	17
Jurassic	108	105	21	33	3	4	19	31
Triassic	330	24	65	2	12	0	20	8
Permian	14	0	8	0	1	-	58	
Mississippian	605	63	95	7	8	21	16	11
Devonian								
Upper	2 477	28	1 132	2	55	1	46	7
Middle	965	0	352	0	31	-	36	-
Other	48	13	5	1	3	-	10	8
Total	7 800	2 052	2 251	352	193	67	29	17

Table B.3. Distribution of conventional crude oil reserves by formation as of December 31, 2002

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	352	53	13	4	2	5
Chinook	5	1	0	0	0	0
Cardium	1 680	287	37	17	11	14
Second White Specks	34	3	1	0	0	0
Doe Creek	73	16	3	1	1	1
Dunvegan	23	2	0	0	0	0
Lower Cretaceous						
Viking	336	65	5	3	2	2
Upper Mannville	1 660	267	53	17	10	20
Lower Mannville	909	186	32	9	7	12
Jurassic	213	54	7	2	2	3
Triassic	354	68	12	4	3	5
Permian-Belloy	14	8	1	0	0	0
Mississippian						
Rundle	470	76	5	5	3	2
Pekisko	90	14	2	1	1	1
Banff	108	12	2	1	0	1
Upper Devonian						
Wabamun	61	7	1	1	0	0
Nisku	460	204	12	5	8	5
Leduc	836	502	13	8	19	5
Beaverhill Lake	988	392	22	10	15	8
Slave Point	160	30	6	2	1	2
Middle Devonian						
Gilwood	305	131	7	3	5	3
Sulphur Point	9	1	0	0	0	0
Muskeg	57	9	1	1	0	0
Keg River	497	180	20	5	7	8
Keg River SS	44	17	1	0	1	0
Granite Wash	53	13	2	1	0	1

Table B.4. Summary of marketable natural gas reserves as of each year-end, 2002 (10^9 m^3)

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

[a] At field plant.

Table B.5. Geological distribution of established natural gas reserves, 2002

Geological period	Raw gas Initial volume in-place (10^9 m^3)	Marketable gas Initial established reserves (10^9 m^3)	Marketable gas Remaining established reserves (10^9 m^3)	Raw gas Initial volume in-place (%)	Marketable gas Initial established reserves (%)	Marketable gas Remaining established reserves (%)
Upper Cretaceous						
Belly River	197	119	50	2.7	2.8	4.3
Milk River & Med Hat	696	426	189	9.5	9.9	16.1
Cardium	404	80	33	5.5	1.9	2.8
Second White Specks	22	13	9	0.3	0.3	0.8
Other	160	91	27	2.1	2.0	2.3
Subtotal	1 479	729	308	20.1	16.9	26.3
Lower Cretaceous						
Viking	391	276	58	5.3	6.4	4.9
Basal Colorado	40	33	3	0.6	0.8	0.3
Mannville	1 963	1 278	392	26.7	29.6	33.4
Other	274	175	50	3.7	4.0	4.4
Subtotal	2 668	1 762	503	36.3	40.8	43.0
Jurassic						
Jurassic	91	59	23	1.2	1.4	2.0
Other	56	35	10	0.8	0.8	0.8
Subtotal	147	94	33	2.0	2.2	2.8
Triassic						
Triassic	193	119	55	2.6	2.7	4.7
Other	30	21	4	0.4	0.5	0.4
Subtotal	223	140	59	3.0	3.2	5.1
Permian						
Belloy	9	6	3	0.1	0.1	0.3
Subtotal	9	6	3	0.1	0.1	0.3
Mississippian						
Rundle	903	568	89	12.3	13.2	7.6
Other	303	205	30	4.1	4.8	2.5
Subtotal	1 206	773	119	16.4	18.0	10.1
Upper Devonian						
Wabamun	228	112	22	3.1	2.6	1.9
Nisku	123	59	20	1.7	1.4	1.7
Leduc	469	245	26	6.4	5.7	2.2
Beaverhill Lake	478	218	43	6.5	5.0	3.7
Other	197	124	10	2.7	2.9	0.8
Subtotal	1 495	758	121	20.4	17.6	10.3
Middle Devonian						
Sulphur Point	14	8	4	0.2	0.2	0.3
Muskeg	5	2	1	0.1	0.1	0.1
Keg River	62	26	15	0.9	0.6	1.3
Other	34	15	4	0.5	0.3	0.3
Subtotal	115	51	24	1.7	1.2	2.0
Confidential						
Subtotal	2	1	1	0.0	0.0	0.1
Total	7 344 (261)[a]	4 314 (153)[a]	1 171 (42)[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, 2002

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	85 726	48.74[a]	4 178	0.78	0.35	2 118	39.25	51 514
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, 2002

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Edmonton Pool No. 1	
Bashaw Edmonton D	228
Nevis Edmonton D	796
Total	1 024
Belly River Pool No. 1	
Bashaw Belly River C, H, L, M & Q	2 698
Nevis Belly River C	1 710
Total	4 408
Belly River Pool No. 2	
Bruce Belly River J	765
Holmberg Belly River J	124
Total	889
Belly River Pool No. 3	
Fenn West Belly River J	23
Fenn-Big Valley Edmonton A, Belly River J, L, M, N, Z & JJ	1 502
Gadsby Belly River J	1 782
Total	3 307
Belly River Pool No. 4	
Michichi Belly River B & G	144
Watts Belly River B & I	77
Total	221
Belly River Pool No. 5	
Ardenode Edmonton & Belly River MU#1	2 801
Centron Edmonton O and Belly River N, Q & AAA	366
Entice Edmonton & Belly River MU#1	4 712
Gayford Belly River AAA	578
Strathmore Belly River MU#1	5 948
Total	14 405
Cardium Pool No. 1	
Ansell Cardium G, Viking B and Notekewan A	6 188
Sundance Cardium G	1 273
Total	7 416
Southeastern Alberta Gas System (MU)	
Alderson Milk River, Medicine Hat, Second White Specks, Belly River and Colorado	49 714
Atlee-Buffalo Milk River, Medicine Hat, Second White Specks and Belly River	7 518
Bantry Milk River, Medicine Hat, Second White Specks and Belly River	28 246
Bassano Milk River, Medicine Hat, Second White Specks and Belly River	2 747
Berry Medicine Hat	71
Bindloss Milk River and Medicine Hat	2 178
Blackfoot Medicine Hat and Belly River	914
Bow Island Milk River and Second White Specks	678
Brooks Milk River, Medicine Hat and Second White Specks	904
Cavalier Belly River	510
Cessford Milk River, Medicine Hat, Second White Specks and Belly River	18 566
Connorsville Milk River, Medicine Hat and Belly River	1 559
Countess Milk River, Medicine Hat, Second White Specks and Belly River	25 359
Drumheller Medicine Hat	267
Enchant Second White Specks	150
Estuary Medicine Hat and Belly River	805
Eyremore Milk River, Medicine Hat, Second White Specks and Belly River	2 479
Farrow Milk River, Medicine Hat and Belly River	2 083
Gleichen Medicine Hat and Belly River	2 041
Hussar Milk River, Medicine Hat and Belly River	4 836
Jenner Milk River, Medicine Hat, Second White Specks and Colorado	8 011
Johnson Milk River, Medicine Hat and Second White Specks	751
Kitsim Milk River, Medicine Hat and Second White Specks	917
Lathom Milk River and Medicine Hat	713
Leckie Milk River, Medicine Hat and Second White Specks	1 401
Matziwin Milk River, Medicine Hat, Second White Specks and Belly River	3 263
Medicine Hat Milk River, Medicine Hat, Second White Specks and Colorado	139 198
Newell Milk River, Medicine Hat and Second White Specks	2 275
Princess Milk River, Medicine Hat, Second White Specks and Belly River	27 798
Rainier Milk River, Medicine Hat and Second White Specks	601
Seiu Lake Medicine Hat	450
Shouldice Medicine Hat and Belly River	1 386
Suffield Milk River, Medicine Hat, Second White Specks and Colorado	63 327
Verger Milk River, Medicine Hat, Belly River, Second White Specks and Colorado	17 631
Wayne-Rosedale Medicine Hat	1330
Wintering Hills Milk River, Medicine Hat, Second White Specks and Belly River	3 967
Total	424 644

(continued)

Table B.7. Natural gas reserves of multifield pools, 2002 (continued)

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Second White Specks Pool No. 2	
Garden Plains Second White Specks E	2 985
Hanna Second White Specks E	1 751
Provost Second White Specks E	114
Richdale Second White Specks E & Viking E	664
Sullivan Lake Second White Specks E	353
Total	5 807
Second White Specks Pool No. 3	
Conrad Second White Specks J	186
Forest Second White Specks J	130
Pendant D'Oreille Second White Specks J	494
Smith Coulee Second White Specks J	904
Total	1 714
Viking Pool No. 1	
Fairydell-Bon Accord Upper Viking A & C, and Middle Viking A & B,	3 610
Redwater Upper Viking A, Middle Viking A, and Lower Viking A	830
Westlock Middle Viking B	381
Total	4 821
Viking Pool No. 2	
Beaverhill Lake Upper Viking A, Middle Viking A, and Lower Viking A	5 083
Bellshill Lake Upper and Middle Viking A	184
Birch Upper and Middle Viking A	23
Bruce Upper, Middle A, Lower Viking B, Upper Mannville Z, PP, G4G & B6B, and Ellerslie W, JJJ, KKK, LLL & MMM	3 491
Dinant Upper and Middle Viking A	31
Fort Saskatchewan Upper and Middle Viking A	8 119
Holmberg Upper and Middle Viking A	19
Killam Upper and Middle Viking A, Rex B, and Glauconitic Q	2 289
Killam North Upper and Middle Viking A, Upper Mannville T, Basal Mannville C, L & U, and Nisku A	1 416
Mannville Upper and Middle Viking A, and Upper Mannville K	380
Sedgewick Upper and Middle Viking A	68
Viking-Kinsella Upper and Middle Viking A, Upper Mannville VV, YY, CCC, LLL, MMM, ZZZ, H2H, M2M & A5A Colony G, G2G & N2N, Glauconitic J, and Wabamun I	29 366
Wainwright Upper and Middle Viking A, and Colony G, R, V, & W	1 786
Total	52 252

Multifield pool Field and pool	Initial established reserves (10^6 m^3)
Viking Pool No. 3	
Carbon Belly River B and Viking D	1 980
Ghost Pine Viking D	295
Total	2 275
Viking Pool No. 4	
Fenn-Big Valley Viking B	749
Fenn West Viking B	185
Total	934
Viking Pool No. 5	
Hudson Viking A	854
Sedalia Viking A & F, Upper Mannville D, and Lower Mannville B	580
Total	1 434
Viking Pool No. 6	
Hairy Hill Viking A	190
Willingdon Viking A & J and Mannville MM &X2X	232
Total	422
Viking Pool No. 7	
Inland Upper Viking C & E, Middle Viking F, G, & I, and Upper Mannville A & V	415
Royal Upper Viking C and Lower Viking A	43
Total	458
Viking Pool No. 13	
Chigwell Viking G	218
Nelson Viking G	157
Total	375
St. Edouard Pool No. 3	
Ukalta St. Edouard B	54
Whitford St. Edouard B	80
Total	134
Glauconitic Pool No. 3	
Bonnie Glen Glauconitic A and Lower Mannville F	1 440
Ferrybank Glauconitic A & Lower Mannville W	1 188
Total	2 628

(continued)

Table B.7. Natural gas reserves of multifield pools, 2002 (concluded)

Multifield pool / Field and pool	Initial established reserves (10^6 m^3)
Glauconitic Pool No. 5	
Bigoray Glauconitic I and Ostracod D	1 238
Pembina Glauconitic I & D and Ostracod C	3 572
Total	4 810
Glauconitic Pool No. 6	
Bassano Glauconitic III	432
Countess Bow Island MM and Glauconitic III	2 023
Hussar Viking L, Glauconitic III, and Ostracod OO	1 152
Wintering Hills Glauconitic III and Lower Mannville W	17
Total	3 624
Bluesky Pool No.1	
Rainbow Bluesky C	1 068
Sousa Bluesky C	886
Total	1 954
Bluesky-Detrital-Debolt Pool No. 1	
Cranberry Bluesky-Detrital-Debolt A	2 024
Hotchkiss Bluesky-Detrital-Debolt A	4 959
Total	6 983
Wabiskaw Pool No. 1	
Marten Hills Wabiskaw A and Wabamun A	26 790
McMullen Wabiskaw A and Wabamun A	1 143
Total	27 933
Gething Pool No. 1	
Fox Creek Viking C, Notikewin C and Gething D & H	2 720
Kaybob South Gething H	841
Total	3 561
Ellerslie Pool No. 1	
Connorsville Basal Colorado E Glauconitic A, B, C, E, I & U and Ellerslie A	2 160
Wintering Hills Upper Mannville A and Ellerslie A	990
Total	3 150
Cadomin Pool No. 1	
Elmworth Dunvegan A	366
Elmworth Dunvegan I	62
Elmworth Dunvegan T	31
Elmworth Cadotte A	3 022
Elmworth Cadotte D	563
Elmworth Cadotte F	60
Elmworth Cadotte G	46
Elmworth Cadotte I	79
Elmworth Cadotte J	229
Elmworth Cadotte K	27
Elmworth Cadotte M	17
Elmworth Cadotte N	44
Elmworth Falher A-1	6 996
Elmworth Falher A-2	1 850
Elmworth Falher A-4	218
Elmworth Falher A-5	222
Elmworth Falher A-7	132
Elmworth Falher A-10	6 360
Elmworth Falher A-16	86
Elmworth Falher A-21	58
Elmworth Falher A-40	30
Elmworth Falher A-43	56
Elmworth Falher B-1	2 456
Elmworth Falher B-2	604
Elmworth Falher B-3	2 819
Elmworth Falher B-4	3 037
Elmworth Falher B-9	1 041
Elmworth Falher B-13	46
Elmworth Falher B-14	119
Elmworth Falher B-15	210
Elmworth Falher B-16	126
Elmworth Falher C-2	36
Elmworth Falher C-3	27
Elmworth Falher D-2	652
Elmworth Falher D-3	20
Elmworth Falher D-5	32
Elmworth Falher D-6	43
Elmworth Bluesky A	104
Elmworth Gething A	22
Elmworth Gething I	8
Elmworth Cadomin A	4 926
Sinclair Doe Creek N & O, Dunvagen A, Paddy A, Notikewin A, B, & C, Falher A, Bluesky G, Gething O and Cadomin A	7 255
Total	44 137
Halfway Pool No. 1	
Valhalla Halfway B	4 572
Wembley Halfway B	4 133
Total	8 705
Halfway Pool No. 2	
Knopcik Halfway N & Montney A	5 447
Valhalla Halfway N	115
Total	5 562
Banff Pool No. 1	
Haro Banff E	87
Rainbow Banff E	6
Rainbow South Banff E	84
Total	194

Table B.8. Remaining raw ethane reserves as of December 31, 2002

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)
Bigstone	5 063	0.080	434	1 543
Bonnie Glen	2 585	0.104	347	1 234
Brazeau River	10 806	0.081	1 115	3 964
Caroline	12 836	0.085	2 192	7 792
Carrot Creek	4 035	0.089	397	1 411
Cessford	18 083	0.015	284	1 011
Countess	26 548	0.013	371	1 317
Dunvegan	9 268	0.043	445	1 581
Edson	5 339	0.087	514	1 828
Elmworth	14 885	0.057	987	3 510
Ferrier	15 266	0.084	1 428	5 077
Garrington	6 638	0.080	528	1 878
Gilby	5 683	0.081	517	1 838
Gold Creek	5 000	0.074	418	1 486
Harmattan East	5 784	0.090	575	2 044
Harmattan-Elkton	4 567	0.075	413	1 469
Hussar	8 305	0.036	317	1 127
Judy Creek	3 697	0.137	563	2 001
Jumping Pound West	6 717	0.036	308	1 094
Kaybob	4 546	0.076	382	1 360
Kaybob South	12 953	0.075	1 221	4 342
Karr	6 142	0.078	529	1 879
Kakwa	4 646	0.093	481	1 711
Knopcik	4 490	0.056	285	1 014
Leduc-Woodbend	5 085	0.095	539	1 915
McLeod	6 170	0.072	495	1 761
Medicine River	6 338	0.088	630	2 240
Narraway	4 618	0.069	364	1 293
Peco	2 919	0.096	348	1 237
Pembina	22 839	0.088	2 284	8 118
Pine Creek	6 696	0.069	555	1 975
Hamburg	4 526	0.083	413	1 469
Provost	14 007	0.027	404	1 437
Rainbow	9 501	0.082	873	3 102
Rainbow South	3 423	0.095	399	1 420
Ricinus	12 010	0.079	1 013	3 602
Simonette	3 363	0.074	289	1 028
Sinclair	6 130	0.041	283	1 007
Swan Hills South	2 367	0.171	536	1 907

(continued)

Table B.8. Remaining raw ethane reserves as of December 31, 2002 (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)
Sylvan Lake	7 087	0.081	646	2 296
Valhalla	12 780	0.073	1 033	3 671
Viking-Kinsella	10 892	0.026	294	1 045
Virginia Hills	1 935	0.150	349	1 240
Wembley	6 049	0.092	629	2 235
Wapiti	17 961	0.056	1 164	4 139
Wildcat Hills	7 184	0.040	326	1 159
Willesden Green	13 136	0.085	1 263	4 489
Wilson Creek	3 314	0.076	285	1 012
Wizard Lake	6 365	0.205	1 450	5 155
Subtotal	400 577	0.069	31 916	113 459
All other fields	770 820	0.032	26 868	95 672
Solvent floods			8 290	29 300
TOTAL	1 171 397	0.052[a]	67 074	238 431

[a] Volume weighted average.

Table B.9. Remaining established reserves of natural gas liquids as of December 31,2002

Field	Remaining reserves of marketable gas ($10^6 m^3$)	($10^3 m^3$ liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	3 034	345	172	292	809
Ante Creek North	2 098	323	180	667	1 171
Bigstone	5 063	719	309	246	1 274
Bonnie Glen	2 585	563	315	529	1 407
Brazeau River	10 806	1 919	1 201	3 353	6 473
Carbon	3 451	392	243	168	803
Caroline	12 836	3 353	3 049	8 766	15 168
Carrot Creek	4 035	720	332	274	1 326
Cessford	18 083	405	238	202	845
Countess	26 548	507	294	225	1 026
Cranberry	2 654	386	214	369	968
Crossfield	4 716	320	200	333	853
Crossfield East	2 413	455	191	165	810
Cyn-Pem	2 181	396	314	213	923
Dunvegan	9 268	753	436	807	1 996
Edson	5 339	714	338	384	1 436
Elmworth	14 885	1 161	516	619	2 297
Ferrier	15 266	2 571	1 304	1 280	5 155
Garrington	6 638	865	501	699	2 065
Ghost Pine	3 981	441	252	196	889
Gilby	5 683	814	409	479	1 702
Gold Creek	5 000	602	306	479	1 387
Hamburg	4 526	538	313	496	1 348
Harmattan East	5 784	993	594	1 514	3 100
Harmattan -Elkton	4 567	555	284	288	1 127
Hussar	8 305	486	268	265	1 019
Judy Creek	3 697	1 335	556	326	2 216
Jumping Pound West	6 717	276	233	492	1 001
Kakwa	4 646	996	541	959	2 496
Karr	6 142	788	341	389	1 518
Kaybob	4 546	613	285	412	1 309
Kaybob South	12 953	1 861	1 079	2 455	5 395
Knopcik	4 490	433	240	462	1 135
Leduc-Woodbend	5 085	984	432	281	1 697
McLeod	6 170	1 039	483	544	2 065
Medicine River	6 338	1 015	497	502	2 015

(continued)

Table B.9. Remaining established reserves of natural gas liquids as of December 31,2002 (concluded)

Field	Remaining reserves of marketable gas ($10^6 m^3$)	10^3 m^3 Liquids			
		Propane	Butanes	Pentanes plus	Total liquids
Minnehik-Buck Lake	2 689	397	206	327	930
Narraway	4 618	466	212	174	852
Peco	2 919	548	330	696	1 573
Pembina	22 839	4 405	2 126	2 022	8 553
Pine Creek	6 696	930	457	889	2 276
Provost	14 007	779	479	350	1 609
Rainbow	9 501	1 490	877	978	3 345
Rainbow South	3 423	781	363	449	1 592
Redwater	2 539	564	313	133	1 010
Ricinus	12 010	1 749	922	2 286	4 957
Simonette	3 363	488	259	528	1 275
Swan Hills	1 160	656	359	289	1 304
Swan Hills South	2 367	1 306	598	241	2 145
Sylvan Lake	7 087	1 012	508	587	2 107
Turner Valley	1 845	339	206	521	1 065
Valhalla	12 780	1 644	884	2 020	4 549
Virginia Hills	1 935	798	269	121	1 188
Wapiti	17 961	1 170	503	487	2 160
Waterton	4 946	240	212	1 056	1 508
Wayne-Rosedale	5 569	465	253	229	947
Wembley	6 049	1 210	713	1 811	3 734
Westpem	2 291	489	277	559	1 326
Wildcat Hills	7 184	335	175	307	817
Willesden Green	13 136	2 222	1 069	1 161	4 452
Wilson Creek	3 314	505	271	334	1 109
Windfall	3 783	401	270	577	1 248
Wizard Lake	6 365	2 990	1 505	757	5 252
Zama	3 628	444	244	236	924
Subtotal	436 533	59 458	32 317	50 249	142 024
All other fields	734 864	33 795	17 832	16 886	68 513
Solvent floods		68	1 739	666	2 473
TOTAL	1 171 397	93 321	51 888	67 801	213 010

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 natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2002 on the CD that accompanies this report. 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.