CBE Attachments 26 through 32

Attachment 26

Energy Resources Conservation Board

ST98-2013

Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022

ACKNOWLEDGEMENTS

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

- CD with detailed data tables for crude oil and natural gas, as well as map of Designated Fields, Oil Sands Areas, and Development Entities, $546
- CD with Field and Pool Code Conversion File, $459
- CD with Gas Pool Reserve File (ASCII format), $3095
- CD with Oil Pool Reserves File (ASCII format), $1834
- Map-90: Map of Designated Fields, Oil Sands Areas, and Development Entities: 60 x 101 cm, $63; 33 x 54 cm, $29

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HIGHLIGHTS

In 2012, compared with 2011, remaining established reserves of conventional crude oil increased by 9.5 per cent and production rose by 14 per cent.

Total bitumen production increased by 10 per cent. Production from in situ projects exceeded mined production for the first time in 2012.

Alberta's remaining established reserves of conventional natural gas decreased by 3.1 per cent, and marketable gas production declined by 5.6 per cent.

OVERVIEW

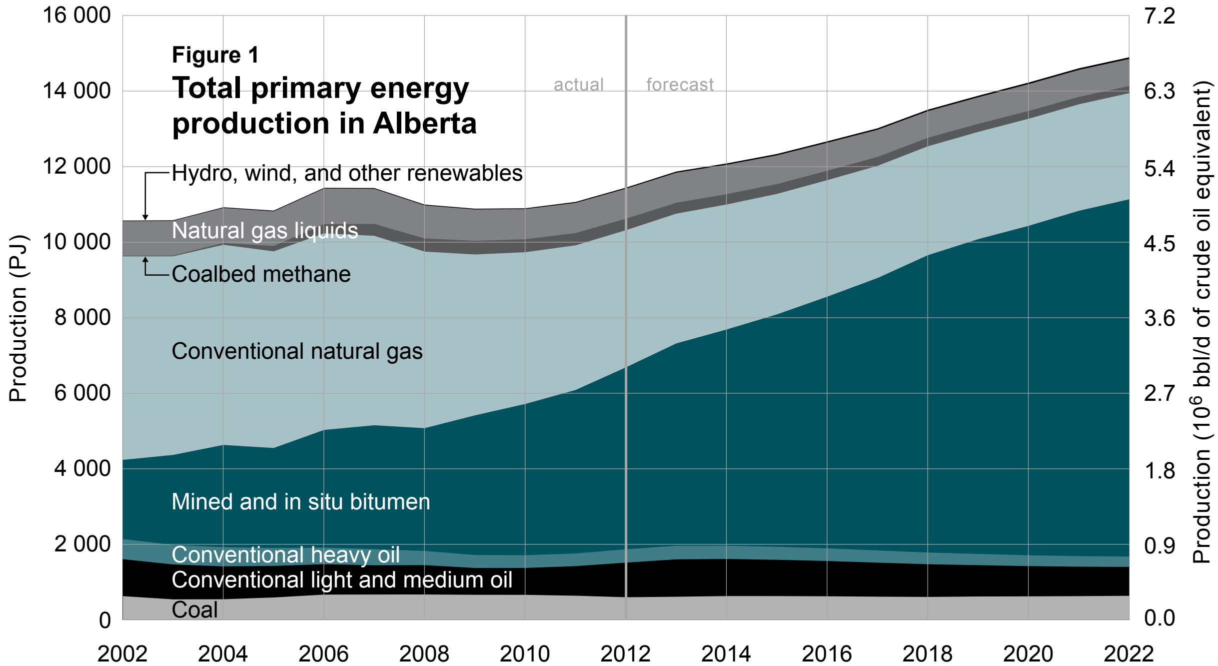
The Energy Resources Conservation Board (ERCB) is a quasi-judicial regulatory agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources take place in a manner that is fair, responsible, and in the public interest. As part of its legislated mandate, the ERCB provides for the appraisal of the province's energy reserves and their productive capacity and the requirements for energy resources and energy in Alberta. The ERCB no longer publishes an analysis of Alberta's electricity supply and demand outlook. The Alberta Electric System Operator (AESO) provides a forecast of electricity supply and demand as part of its legislated mandate.

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

Every year the ERCB issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, coal, and sulphur. This year's report (*ST98-2013: Alberta Energy Reserves 2012 and Supply/Demand Outlook 2013–2022*) includes estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources from 2013 to 2022 (the forecast period); additionally, this report provides some historical trends on energy commodities so that supply and price relationships may be better understood.

Summary of Energy Reserves, Production, and Demand in Alberta

In 2012, Alberta produced 11 442 petajoules of energy from all sources, including renewable sources. This is equivalent to more than 5.1 million barrels per day of conventional light-medium crude oil. In 2022, Alberta is projected to have produced 14 892 petajoules of energy from all sources, which is equivalent to over 6.7 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by energy source is illustrated in **Figure 1**.



Reserves

Reserves are the recoverable quantities of energy resource commodities that are known with reasonable certainty. In-place resources are the larger quantities existing in the ground from which a portion has been, or may be, recovered as reserves. The ERCB also estimates a quantity (the ultimate potential) from discovered and undiscovered in-place resources that may be ultimately recovered when all future resource extraction activities have ceased within Alberta. The ERCB's current reserves and resource classification system is discussed in **Section 2.3**.

Table 1 summarizes Alberta's energy reserves, resources, and production at the end of 2012. As detailed in the recent study *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential* (ERCB/AGS Open File Report 2012-06), the ERCB has estimated the in-place natural gas, natural gas liquids, and crude oil resources in six key geological formations where shale is the predominate rock type. These quantities are shown as a separate line in the table. Recoverable quantities related to these estimates have yet to be established by the ERCB. A summary of the study results is given in **Section 2.2.1**.

Production

Raw bitumen in Alberta is produced either by mining the ore or by various in situ techniques using wells to produce bitumen. Bitumen production accounted for 78 per cent of Alberta's total crude oil and bitumen production in 2012. Bitumen production increased by 4 per cent at mining projects and by 17 per cent at in situ projects in 2012, resulting in an overall raw bitumen production increase of 10 per cent relative to 2011.

Table 1 Reserves, resources, and production summary, 2012

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	12 026	75.7	9 591	340	94	103
Initial established reserves	28 092	177	2 922	18.4	5 442	193	35	38
Cumulative production	1 406	8.8	2 653	16.7	4 470	159	1.53	1.68
Remaining established reserves	**26 686**	**168**	**269**	**1.7**	**972**[b]	**34.5**[b]	**33**	**37**
Annual production	112	0.705	32.3	0.203	105.3	3.7	0.028[c]	0.031[c]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[d]	223[d]	620	683
Shale/siltstone initial in-place resources[e]			67 320	423.6	96 461	3 424		

[a] Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.

[b] Measured at field gate.

[c] Annual production is marketable.

[d] Does not include unconventional natural gas.

[e] Values based on the medium estimate and include only unconventional deposits; no assumption about recoverability was made in determining these resource estimates.

In 2012, crude oil production increased by about 14 per cent, total marketable natural gas production in Alberta declined by over 5 per cent, total natural gas liquids[1] (NGLs) production decreased by 1 per cent, sulphur production declined by 8 per cent, and coal production declined by 6 per cent.

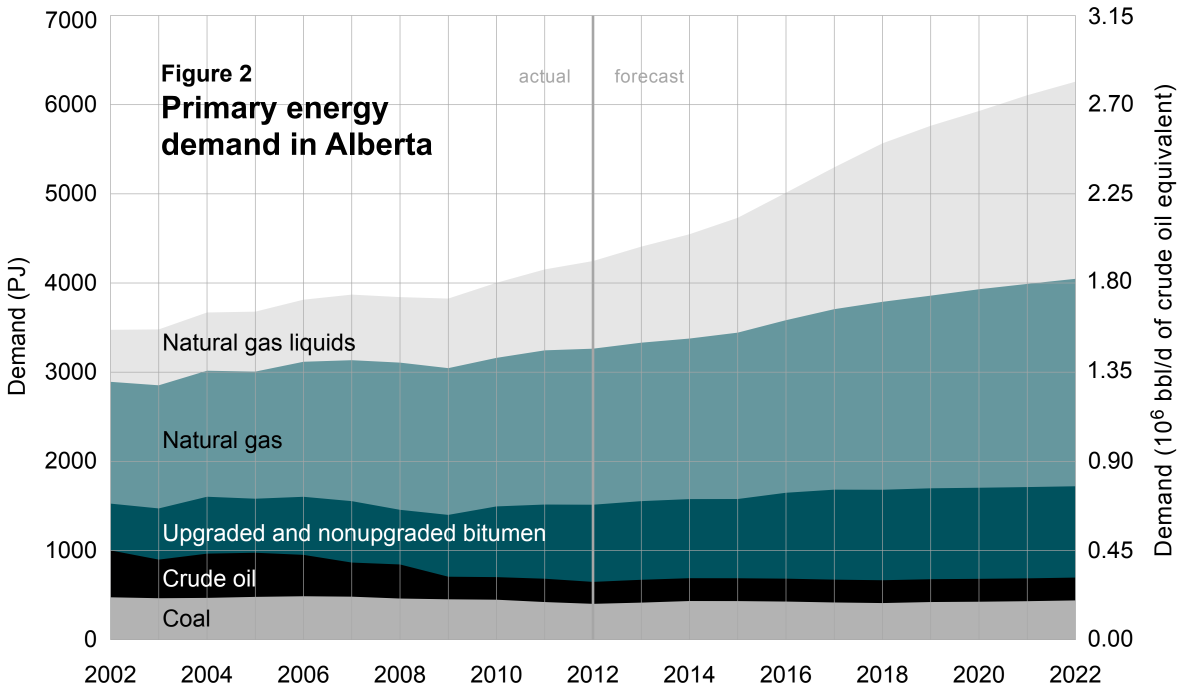
While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 2**. In 2012, demand for conventional crude oil and coal was lower relative to 2011, while 2012 demand for natural gas, NGLs, and upgraded[2] and nonupgraded bitumen increased relative to 2011. Demand for NGLs is projected to increase as demand for pentanes plus as a diluent increases throughout the forecast period in conjunction with the crude bitumen production forecast. Total primary energy consumption in 2012 was 4236 petajoules, equivalent to about 1.9 million barrels per day of crude oil. This amount is projected to increase to 6248 petajoules, or 2.8 million barrels per day, by 2022.

[1] Natural gas liquids refers to ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate. See discussion in **Section 6**.

[2] Upgraded bitumen was formerly referred to as synthetic crude oil (SCO) in this report. This change was made so that the other types of upgraded products could be included in bitumen production discussions. Nevertheless, the vast majority of upgraded bitumen is, in fact, SCO. See discussion in **Section 3.2.1.3**.



The primary energy removals from Alberta are shown in **Figure 3**. Most shipments are to the United States. Natural gas removals from Alberta are projected to decrease over the forecast period as Alberta domestic gas supply continues to decrease due to low natural gas prices and increasing intra-Alberta demand. Total primary energy removals from the province are expected to reach 9684 petajoules in 2022, equivalent to 4.3 million barrels per day of crude oil, up from 7211 petajoules, or 3.2 million barrels per day, in 2012.

Alberta Hydrocarbon Production within the Canadian Context

Alberta is Canada's largest producer of marketable natural gas. In 2012, Alberta produced 70 per cent of Canada's total production, down from 71 per cent in 2011. Over the same period, Canada's second largest contributor, British Columbia, increased its share from 24 per cent to 25 per cent. **Figure 4** shows the percentage contributed by region in Canada for 2010, 2011, and 2012.

Alberta is also the largest contributor to Canadian oil and equivalent[3] production and is the only contributor of upgraded and nonupgraded bitumen, which are the marketed components of raw bitumen production. **Figure 5** illustrates the contribution percentage breakdown by category and region in Canada for 2012.

Only two provinces, Alberta and Saskatchewan, contribute to conventional heavy crude oil production in Canada. In 2012, Alberta accounted for 76 per cent of Canada's oil and equivalent production, with marketed bitumen representing more than 55 per cent of the total.

[3] Oil and equivalent includes light-medium and heavy crude oil, condensate (pentanes plus), and upgraded and nonupgraded bitumen.

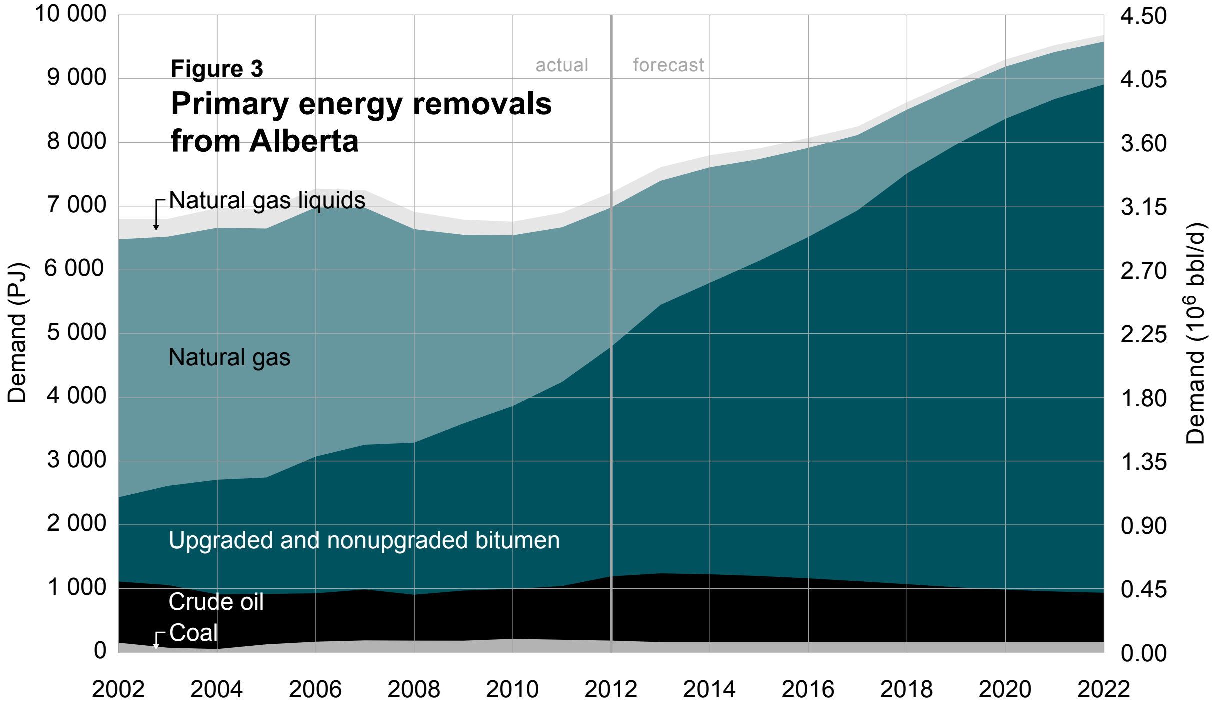


Figure 3
Primary energy removals from Alberta

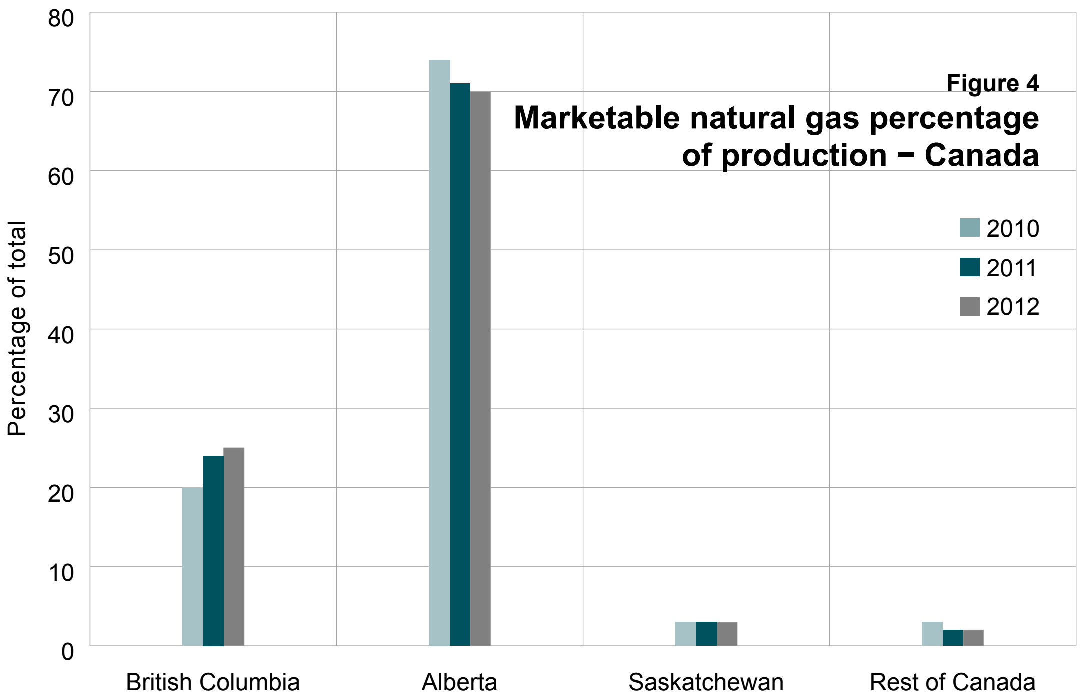


Figure 4
Marketable natural gas percentage of production − Canada

Source: National Energy Board.

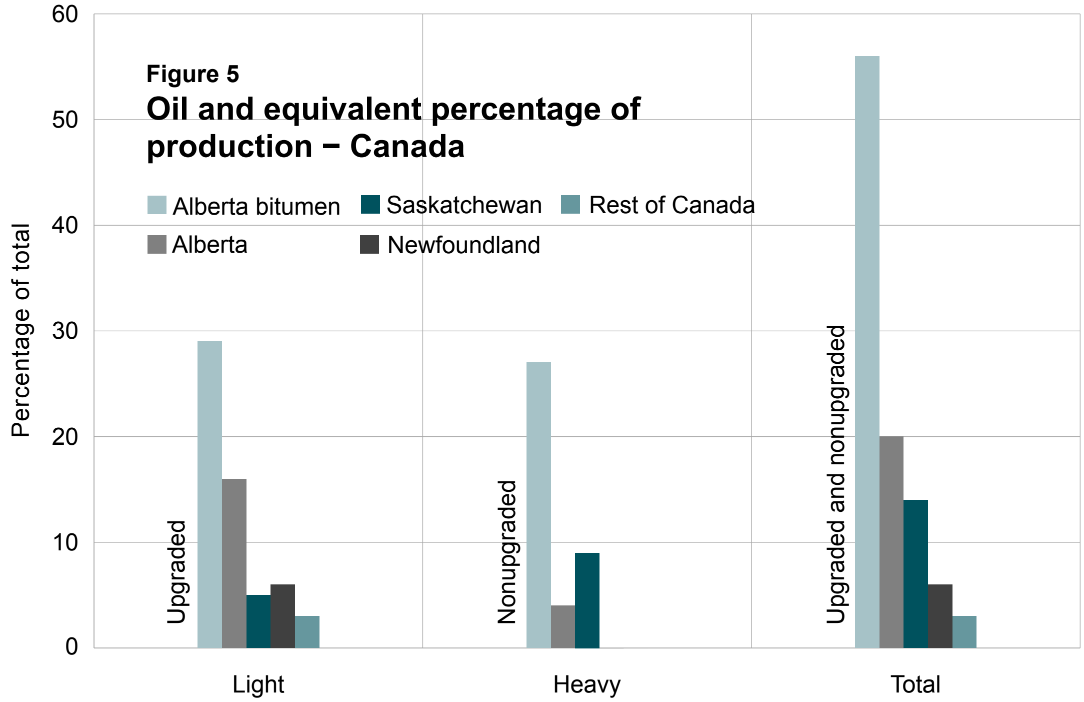


Figure 5
Oil and equivalent percentage of production − Canada

Source: National Energy Board.

Oil and Gas Prices and Alberta's Economy

Crude Oil Prices – 2012

Crude oil prices strengthened at the beginning of the year in response to supply disruptions and production declines in the Middle East and North Africa. Continued tension in the Middle East kept prices elevated. Prices, however, began to fall in April and reached yearly lows in June due to reports of high global crude oil stocks, declining Chinese exports, and renewed fears over another European recession. Prices began to recover in July as North Sea production was cut due to a strike, reducing supply. Market confidence also gained on speculation that the European Central Bank would pass stimulus measures. By the fourth quarter of 2012, prices began to fall again as Europe entered into another recession. Global economic growth estimates were reduced, and mounting fears over the ability of the United States to avert a "fiscal cliff" weakened market confidence.

In the first quarter of 2012, Brent Blend[4] (Brent) prices averaged US$118.50/bbl and reached a high of US$125.45/bbl in March. Prices then fell and reached a low of US$95.16/bbl in June. Brent prices in the second half of 2012 recovered and ranged between US$102.62/bbl and US$113.36/bbl, with a yearly average of US$111.66/bbl. The West Texas Intermediate (WTI) price averaged US$94.21/bbl in 2012 and reached a yearly high of US$106.21/bbl in March and a low of US$82.41/bbl in June.

[4] Brent Blend is a blend of light sweet crude oil from 15 different oil fields in the North Sea. Brent blend futures are traded on the Intercontinental Exchange, Inc., and are considered a global benchmark for oil prices.

In 2012, the differential between Brent and WTI ranged from US$10.37 per barrel to US$22.33 per barrel and averaged US$17.45 per barrel. This discount reflects the significant increases in U.S. supplies and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast. Other methods of transportation used to transport crude are generally more costly and include rail, truck, and barge.

Heavier Canadian crudes, such as Western Canadian Select (WCS),[5] have shown deeper discounts compared with other world benchmark prices. In 2012, WCS averaged US$73.14/bbl, trading at US$21.07/bbl under the price of WTI. Heavy Canadian crudes have been discounted due to concerns of oversupply and transportation constraints. The deep discount on heavy Canadian crudes is not expected to be alleviated until demand for Canadian crudes is increased by the addition of heavy refinery capacity and the alleviation of pipeline constraints.

Crude Oil Prices – Forecast

The ERCB bases its analysis on the expectation that the crude oil price in North America, measured by WTI crude oil, will continue to be volatile. The ERCB projects WTI to average US$90.00/bbl in 2013, with a range from US$80.00/bbl to US$100.00/bbl. The price of WTI is expected to increase throughout the forecast period as increasing crude oil demand exerts upward pressure on supplies and price. In 2022, WTI prices are projected to be US$119.46/bbl, with a range from US$89.25/bbl to US$148.83/bbl.

Natural Gas Prices – 2012

While historically North American crude oil prices have closely tracked international prices, natural gas prices in North America are reflective of domestic supply and demand with little global gas market influence aside from the impact of liquefied natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price. The most significant recent change in the market has been the increase in U.S. natural gas supply from shale gas, which has become economic due to horizontal drilling and multistage fracturing technology. Natural gas producers in North America have been, and are expected to continue to be, challenged by a weaker price environment.

The average Alberta reference price of natural gas in 2012 was Cdn$2.14 per gigajoule (GJ), compared with Cdn$3.28/GJ in 2011—a 35 per cent decrease. Natural gas prices in 2012 were affected by warmer-than-expected winter temperatures, which led to higher-than-average storage inventories. This, combined with strong natural gas production in the United States, resulted in the low natural gas prices. The monthly Alberta reference price for natural gas was highest in December at Cdn$2.98/GJ and lowest in May at Cdn$1.58/GJ. In 2012, U.S. natural gas prices at Henry Hub decreased by 31 per cent over 2011.

Natural Gas Prices – Forecast

The ERCB projects natural gas prices at the Alberta wellhead to average Cdn$3.26/GJ in 2013, with a range between Cdn$2.31/GJ and Cdn$4.21/GJ. In the near term, prices are projected to remain weak due to increasing

[5] Western Canadian Select is a type of marketed crude oil produced in western Canada and made up of heavy Canadian conventional crude oil and crude bitumen blended with diluents.

gas supply in North America. Longer term, a combination of LNG exports and increased domestic demand is to contribute to a strengthening of natural gas prices. Over the forecast period, the price of natural gas is projected to increase slowly, reaching an average of Cdn$4.88/GJ in 2022.

Alberta's Economy – 2012

Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003–2007 timeframe. Average Alberta GDP growth from 2002 to 2012 was 2.9 per cent, compared with a Canadian average of 2.0 per cent. Similarly, the unemployment rate in Alberta averaged 4.8 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

In 2012, the total value of Alberta's energy resource production decreased by 7.3 per cent relative to 2011. The value of upgraded and nonupgraded bitumen production has significantly exceeded the value of natural gas production, a trend that is expected to continue throughout the forecast period. In 2012, combined upgraded and nonupgraded bitumen revenues were greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur.

Alberta's Economy – Forecast

Economic growth is projected to continue to increase in 2013 as oil and gas activity continues to remain strong. Real GDP is forecast to increase by 3.0 per cent in 2013 and to continue to grow at a trend of 3.0 per cent from 2014 to 2022.

The ERCB estimates that oil sands capital expenditures decreased to $20.4 billion in 2012, compared with $22.7 billion in 2011. Oil sands expenditures are predicted to increase to $21.6 billion in 2013 and peak in 2015 at $23.4 billion. In 2012, some oil sands companies announced that they were cutting their capital budget spending and delaying the development of upcoming projects as a result of increased pressure from lower-cost conventional oil development in Canada and the United States.

Conventional oil and gas expenditures have rebounded significantly since the 2009 level of $12 billion and reached $25.8 billion in 2011 as activity in conventional basins shifted to the application of capital-intensive horizontal wells and multistage fracturing in conventional oil and liquids-rich gas plays. Investment in conventional oil and gas is expected to increase over the forecast period as producers continue to use the more costly horizontal wells and multistage fracturing technology.

Production from upgraded and nonupgraded bitumen derived from the oil sands is projected to more than offset the decline in conventional resource production, increasing from 61 per cent of total energy revenues in 2012 to an average of 71 per cent of total energy revenues from 2015 to 2022.

Continued investment in oil sands mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. Alberta's economic growth will continue to be a strong contributor to Canadian economic growth.

Commodity Discussion

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

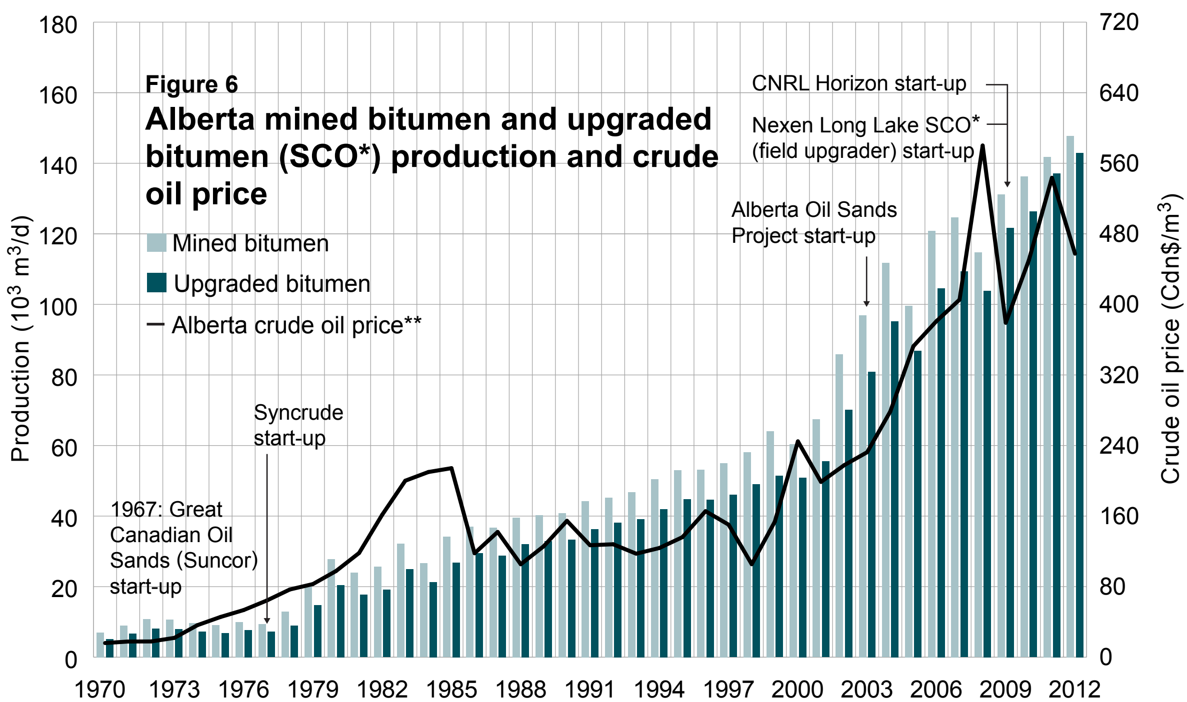
The total remaining established reserves of in situ and mineable crude bitumen is 26.7 billion cubic metres (m^3) (167.9 billion barrels), slightly less than in 2011 due to 0.12 billion m^3 of production. Only 5.3 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

Figure 6 shows the historical mined bitumen and upgraded bitumen production, beginning with the start-up of Great Canadian Oil Sands (Suncor) in 1967. This was followed by Syncrude in 1978 and the Alberta Oil Sands Project (Shell Muskeg River Mine and Shell Scotford Upgrader) in 2003. The Horizon Project (CNRL) commenced mining operations in late 2008 and produced upgraded bitumen in 2009. The figure also shows the average Alberta wellhead price of crude oil.

Historical in situ production and the price of heavy crude oil are shown in **Figure 7**. Regionally, in situ production growth in 2012 was strongest in Athabasca (29 per cent increase), followed by Peace River (23 per cent increase), then Cold Lake (3 per cent increase).

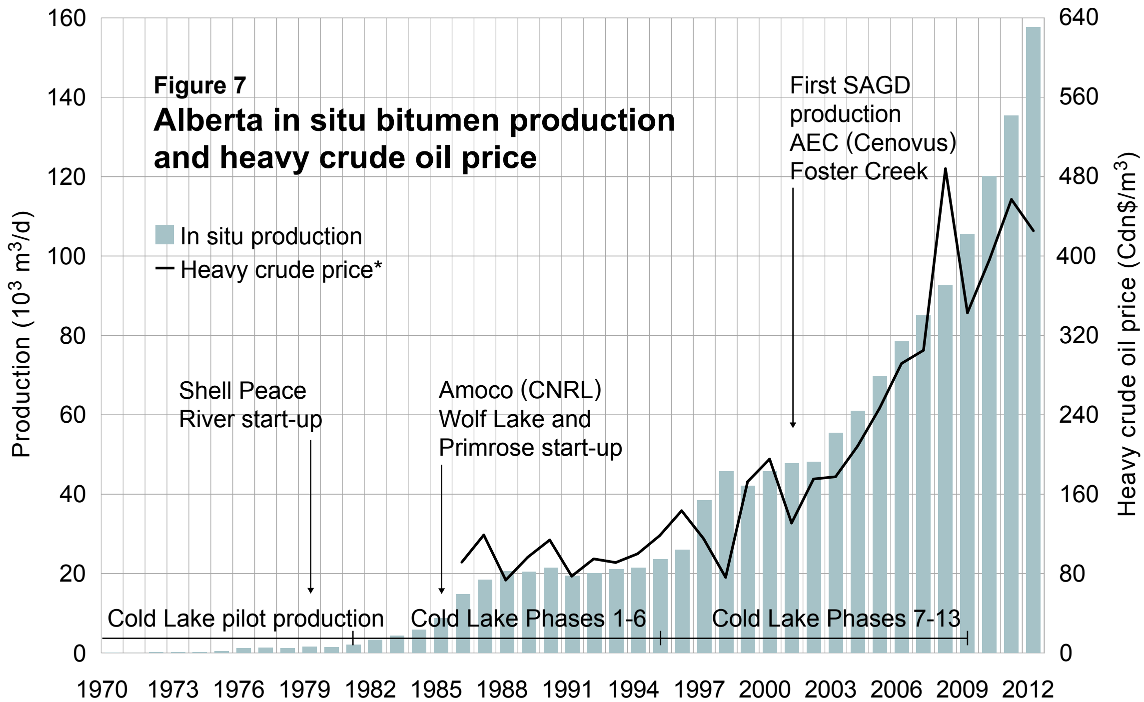
In 2012, Alberta produced 54.1 million m^3 (340 million barrels) from mining and 57.7 million m^3 (363 million barrels) from in situ, totalling 111.8 million m^3 (704 million barrels). This is equivalent to 305.5 thousand m^3



* Synthetic crude oil.

** Source: CAPP *Statistical Handbook*.

Figure 7
Alberta in situ bitumen production and heavy crude oil price



* Source: ERCB's *ST3: Alberta Energy Resource Industries Monthly Statistics.*

(1.9 million barrels) per day. Total raw bitumen production is projected to reach 605.4 thousand m^3 (3.8 million barrels) per day by 2022.

Production from in situ projects exceeded mined production for the first time in 2012, a trend that is expected to continue. In 2012, total in situ production accounted for 52 per cent of total bitumen production, compared with 49 per cent in 2011.

The ERCB projects that mined bitumen production will reach 255 thousand m^3 per day in 2022. This is slightly lower than the end of the forecast period in last year's report. The percentage of mined bitumen to total production over the forecast period is expected to decrease from 48 per cent in 2012 to 42 per cent in 2022.

The ERCB expects in situ crude bitumen production to increase to 351 thousand m^3 per day in 2022. This represents an increase of 8 per cent when compared to the end of the forecast period in last year's report. Based on this projection, in situ bitumen will account for 58 per cent of total bitumen produced in 2022. The current forecast has increased over last year's primarily due to the addition of new proposed projects and accelerated development schedules for existing and approved projects.

Upgraded Bitumen (SCO) Production

In 2012, all crude bitumen produced from mining, as well as a small portion of in situ production (about 7 per cent), was upgraded in Alberta, yielding 52.3 million m^3 (329 million barrels) of upgraded bitumen. In 2012, the percentage of crude bitumen upgraded was 52 per cent of total crude bitumen. Over the forecast period, this percentage is expected to decline to 38 per cent as a result of in situ production growth outpacing the growth in upgrading capacity. In 2022, upgraded bitumen production is forecast to increase to 73.3 million m^3 (461.2 million barrels). This represents a decrease of 10 per cent over last year's forecast due to the cancellation of the Voyageur upgrader.

Over the next 10 years, mined bitumen is projected to continue to be the primary source of crude bitumen to be upgraded in Alberta. However, the percentage of in situ bitumen upgraded is expected to vary throughout the forecast period, before reaching about 9 per cent in 2022.

Crude Oil Reserves

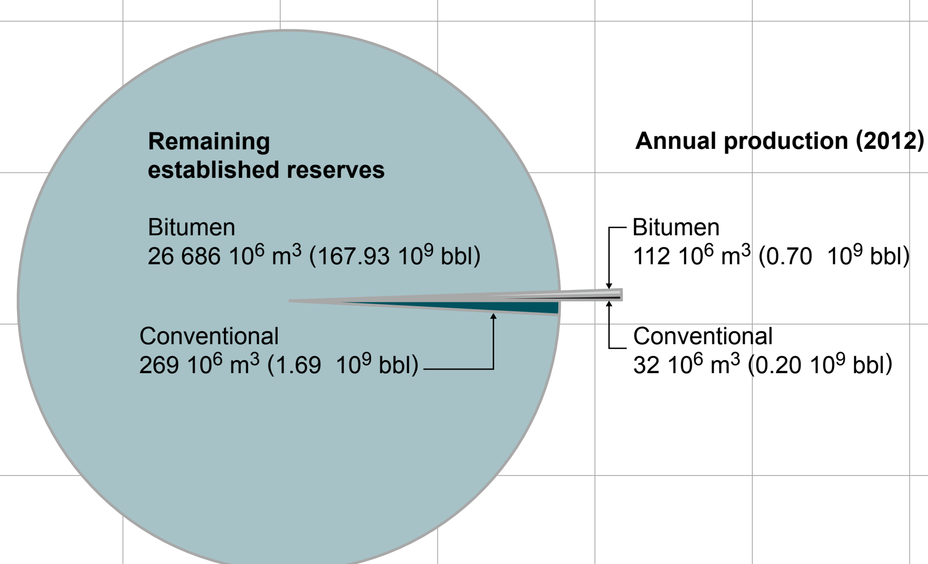
The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 269.2 million m^3 (1.7 billion barrels), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 23.3 million m^3, or 9.5 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2012.

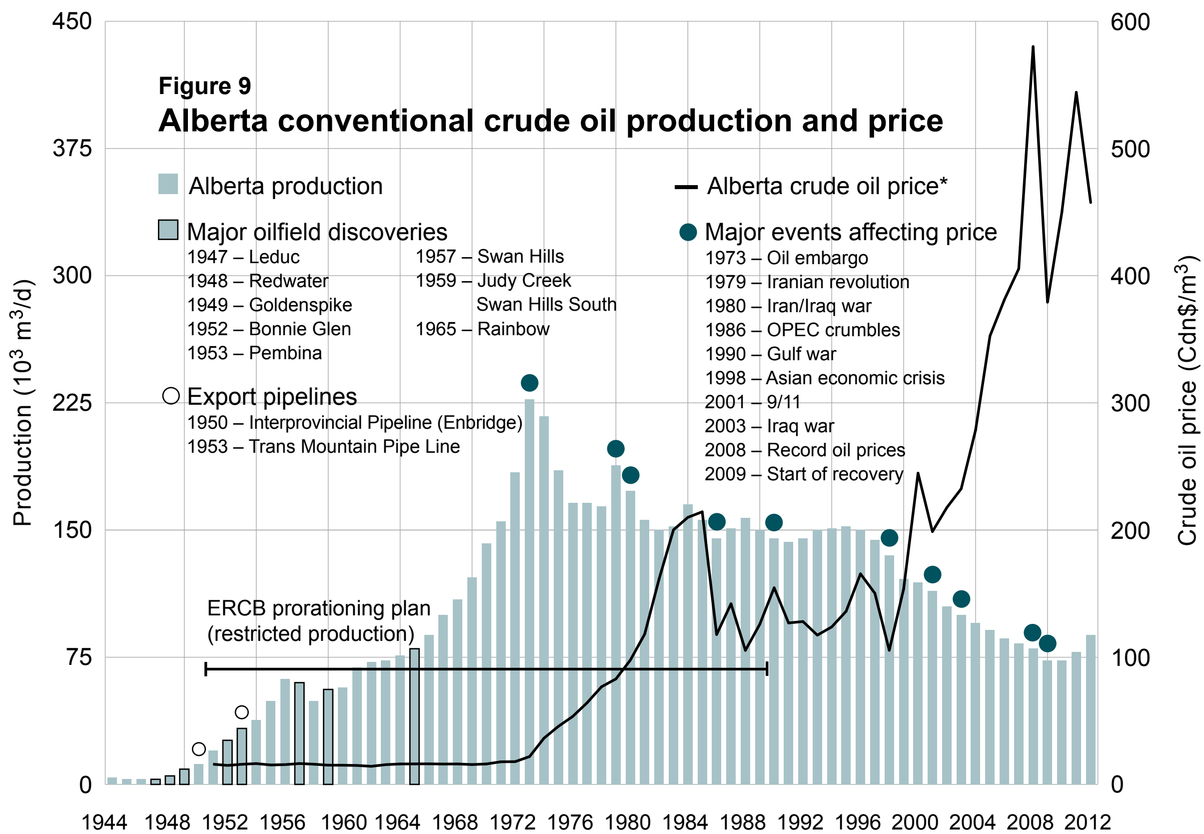
Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 8**.

Crude Oil Production

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 9**. The first major oilfield discovered in Alberta was in Turner Valley in 1914. Collectively, Turner Valley oilfields became a major producer of oil and gas, and for a time, the largest producer in the British Empire. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with

Figure 8
Alberta oil reserves





* Source: CAPP *Statistical Handbook*.

peak production of 227.4 thousand m³ per day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure.

Starting in 2010, total crude oil production in Alberta reversed the downward trend that was the norm since the early 1970s. Since 2010, light-medium crude oil production has begun to increase as a result of increased horizontal drilling activity and the introduction of multistage hydraulic fracturing technology. Alberta's production of conventional crude oil totalled 32.4 million m³ (204 million barrels) in 2012, an increase of 14 per cent.

Total Oil Supply and Demand

Figure 10 shows crude oil and equivalent supply. In 2012, Alberta's supply of crude oil and equivalent reached 392.6 thousand m³ (2.5 million barrels) per day, a 10 per cent increase compared with 2011. Production is forecast to reach 665.1 thousand m³ (4.2 million barrels) per day in 2022.

A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 11**, clearly shows the increasing contribution of bitumen to Alberta's oil production.

The ERCB estimates that bitumen production will double by 2022. Over the forecast period, as illustrated in **Figure 11**, the growth in production of upgraded and nonupgraded bitumen is expected to more than offset the

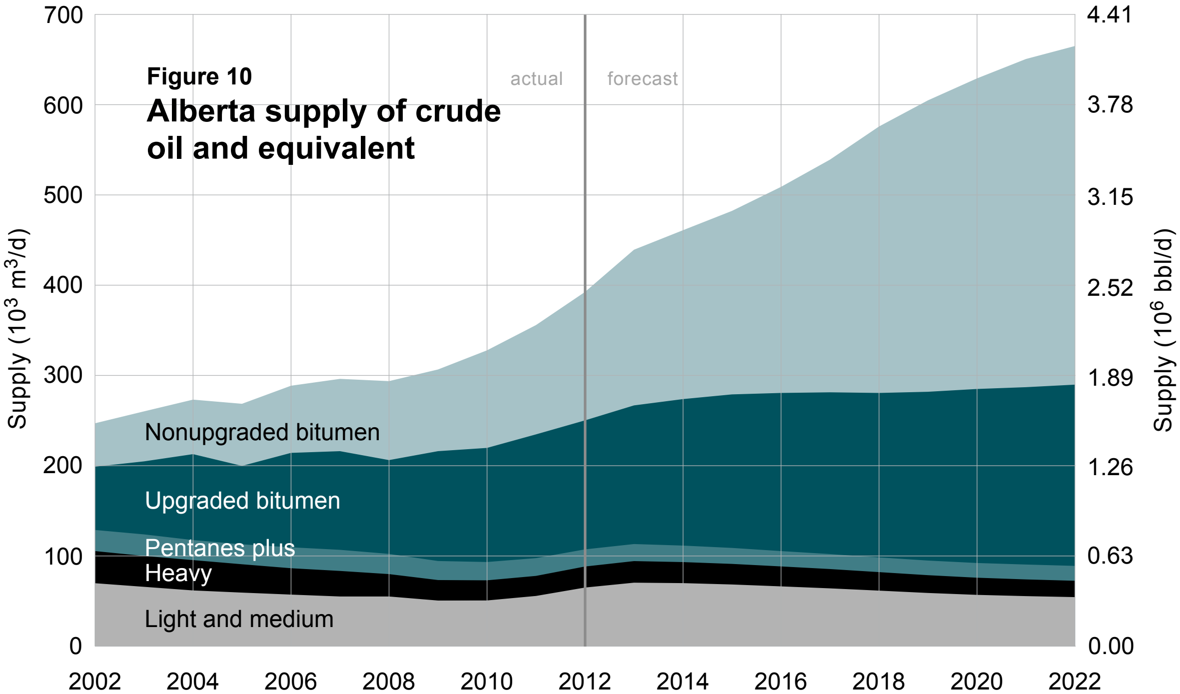


Figure 10
Alberta supply of crude oil and equivalent

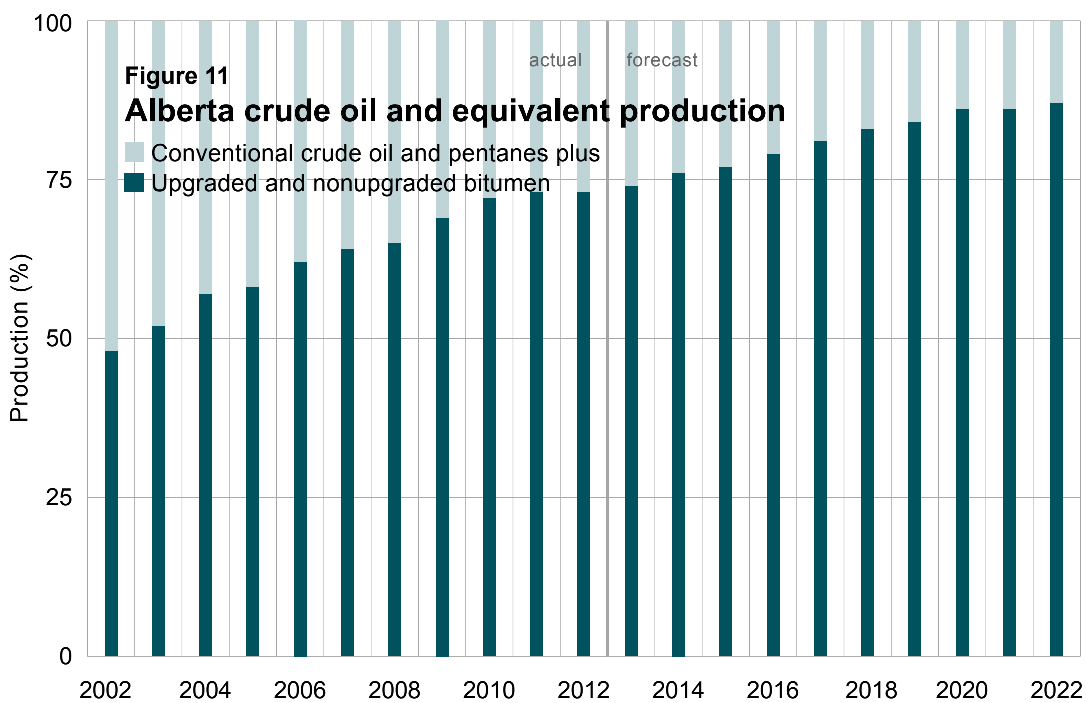


Figure 11
Alberta crude oil and equivalent production

projected long-term decline in conventional crude oil. Upgraded and nonupgraded bitumen will account for 87 per cent of total production in 2022, compared with about 73 per cent in 2012. Since 2003, upgraded and nonupgraded bitumen has accounted for more than 50 per cent of total production.

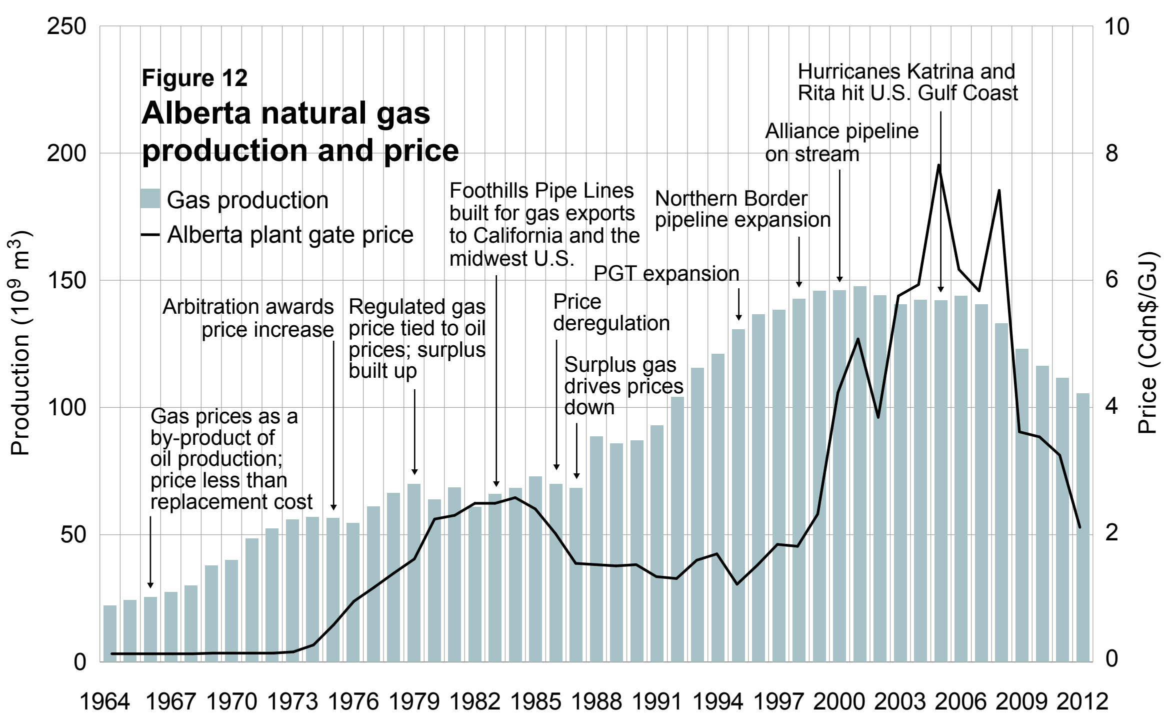
Demand for oil produced in Alberta is from oil refineries, most of which are outside the province. Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products. Crude oil shipments outside of Alberta amounted to 81 per cent of total production in 2012. The ERCB expects that by 2022, this figure will slowly decrease to about 76 per cent of production due to the decline expected in Alberta light-medium and heavy crude oil production over the forecast period.

Natural Gas

Historical gas production and prices are shown in **Figure 12**. In the 1950s and 1960s, natural gas was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when the Organization of the Petroleum Exporting Countries (OPEC) increased crude oil prices, natural gas prices started to increase.

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

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



In the early 1990s, natural gas prices became more market responsive. Development of trading points in Chicago, New York, and the Henry Hub (near Erath, Louisiana) in the United States in the late 1980s and the AECO-C hub[6] (near Suffield, Alberta) in the early 1990s facilitated natural gas being traded as a true commodity. More recently, shale gas production in the United States has significantly contributed to the growth in natural gas production, reversing the trend of annual U.S. production declines. Increased supply and lagging demand has resulted in low gas prices in North America and contributed to the reduction in natural gas activity in Alberta.

Natural gas is produced from conventional and unconventional reserves in Alberta, where unconventional gas is defined as coalbed methane (CBM) and shale gas. Marketable gas is the gas that remains after the raw gas is processed to remove constituents and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume. Most marketable natural gas in Alberta is produced from conventional sources.

Conventional Natural Gas Reserves

As of December 31, 2012, the ERCB estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 916 billion m^3, with a total energy content of about 36 exajoules. This decrease of 29.4 billion m^3 since December 31, 2011, is the result of all reserves additions less production during 2012. These reserves include 28.9 billion m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value, from 39.1 megajoules per m^3 to 37.4 megajoules per m^3, for gas downstream of straddle plants. Reserves added through drilling (new plus development) totalled 24.2 billion m^3, replacing 25 per cent of Alberta's 2012 production, which is the lowest replacement ratio in the last 15 years.

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

Unconventional Natural Gas Reserves

The ERCB estimates the initial established reserves of CBM to be 101.3 billion m^3 as of December 31, 2012, relatively unchanged from 2011. Remaining established reserves in 2012 are 56.7 billion m^3, down from 62.0 billion m^3 in 2011 due to production.

Total Natural Gas Production

Several major factors affect natural gas production, including natural gas prices, drilling and connection activity, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. In 2012, total

[6] The Alberta Energy Company storage facility (AECO-C) hub is the main pricing point for Alberta natural gas and represents the major pricing point for Canadian gas.

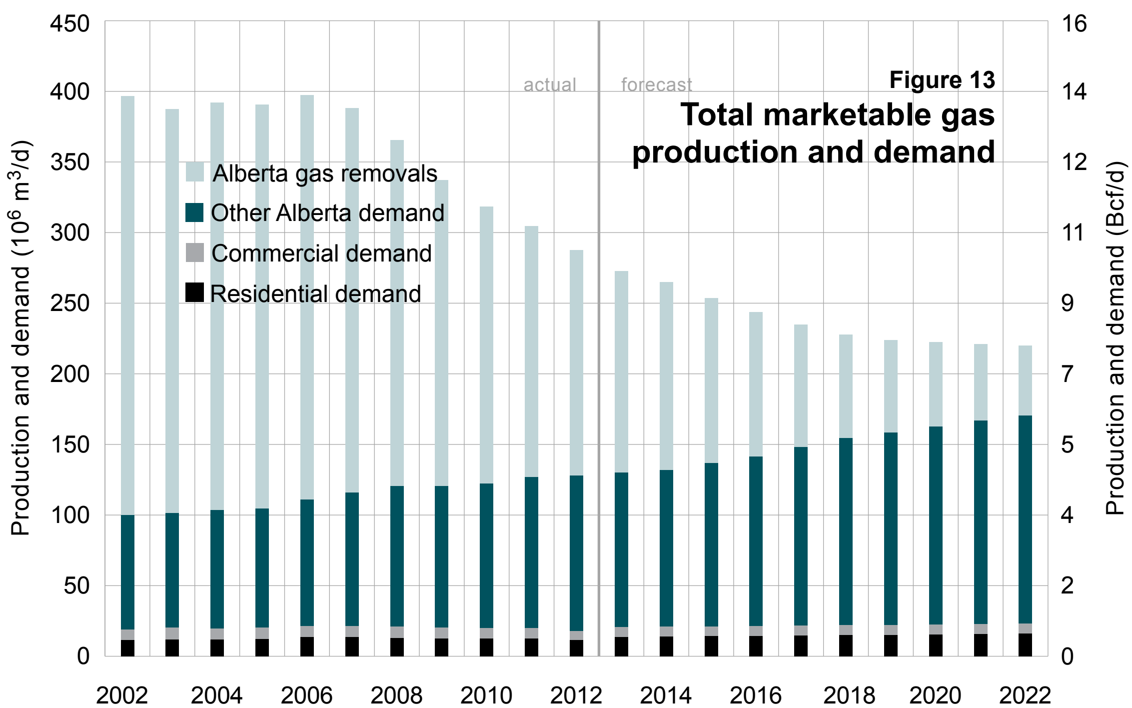
marketable natural gas production in Alberta, including unconventional production, declined by 5.6 per cent to 287.7 million m^3 per day from 304.7 million m^3 per day. Total production from identified CBM and CBM hybrid connections decreased 6.7 per cent in 2012 to 22.3 million from the 2011 volume of 23.9 million m^3 per day. In 2012, natural gas from conventional gas and oil connections, at 265.2 million m^3 per day (standardized to 37.4 megajoules per m^3), represented 92.2 per cent of production. The remaining 7.8 per cent of gas supply came from CBM and minor shale gas connections at 22.3 million m^3 per day and 0.2 million m^3 per day, respectively.

Total Natural Gas Supply and Demand

The ERCB believes that new connections will not be able to sustain production levels over the forecast period.

Despite declining natural gas supply from conventional sources, sufficient supply exists to meet Alberta's demand. In 2012, about 44 per cent of Alberta production was consumed within Alberta. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand in Alberta is forecast to represent about 78 per cent of total Alberta natural gas production, not including potential shale gas production or natural gas supply from British Columbia that connects to the pipeline network in Alberta.

Therefore, as Alberta requirements continue to increase and production continues to decline, less gas is forecast to be available for removal from the province. Alberta's historical and forecast marketable gas production (at 37.4 megajoules per m^3) and demand are shown in **Figure 13**.



Ethane and Other Natural Gas Liquids

Ethane Reserves

As of December 31, 2012, the ERCB estimates remaining established reserves of extractable ethane to be 108.1 million m^3 in liquefied form. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

Ethane Production

In 2012, ethane volumes extracted at Alberta processing facilities decreased to 34.0 thousand m^3 per day from 35.2 thousand m^3 per day in 2011. About 70 per cent of total ethane in the gas stream was extracted in 2012, while the remainder was left in the gas stream and sold for its heating value. The ERCB expects that Alberta ethane supply will slightly increase over the next two years. New ethane supplies are expected to come from liquids-rich natural gas and oil sands off-gas. The ERCB expects that ethane imports from the United States will start later in 2013 or in 2014 to augment the overall provincial supply, as a result of increasing ethane demand. Ethane imports from the United States are projected to continue to increase throughout the forecast period.

Propane, Butane, and Pentanes Plus Reserves

As of December 31, 2012, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 63.7 million m^3, 34.6 million m^3, and 45.5 million m^3, respectively. Cumulatively, these NGLs reserves equate to 70 per cent of Alberta's remaining light-medium crude oil reserves, a decrease from 82 per cent in 2011 due to the reserves estimate for light-medium crude oil significantly increasing.

Propane, Butane, and Pentanes Plus Production

The supply of propane and butanes is expected to meet demand over the forecast period. The decline in production for butanes and pentanes plus in Alberta has been moderating and the production of propane has slightly increased as a result of the increased focus by industry on developing liquids-rich gas pools since the prices of these NGLs track the price of crude oil. Propane production increased by 5 per cent, while butane and pentanes plus production declined by 0.7 per cent and 2.8 per cent, respectively, in 2012 over 2011. This compares to the decline rates for propane, butanes, and pentanes plus in 2011 of 0.5 per cent, 0.3 per cent, and 3 per cent, respectively. In 2012, the amount of propane and other NGLs in the raw natural gas stream increased as natural gas producers focused on drilling liquids-rich plays.

Due to the tightness of the supply of pentanes plus, alternative sources of diluent[7] are being used by industry to dilute heavier crudes to meet pipeline quality.

[7] Condensates and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable bitumen to meet pipeline specifications.

Sulphur

Sulphur Reserves

The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2012, to be 120.9 million tonnes, down 30 per cent from 2011. The significant decrease is mainly due to the reduction in sulphur reserves derived from crude bitumen reserves under active development.

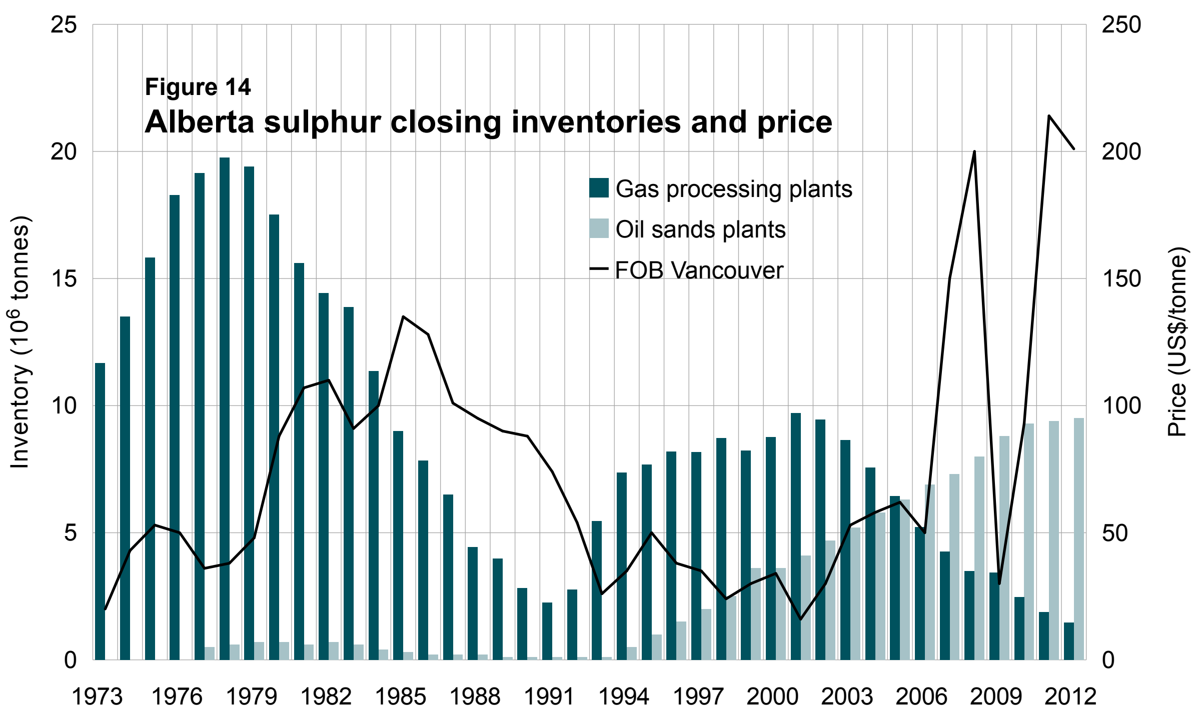
Sulphur Production

There are three sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading, and crude oil refinement into petroleum products. In 2012, Alberta produced 4.37 million tonnes of sulphur, of which 2.41 million tonnes were derived from sour gas, 1.96 million tonnes from upgrading of bitumen, and just 19 thousand tonnes from oil refining. The total sulphur production in 2012 represents a decrease of 7.6 per cent from 2011 levels due to a decline in natural gas production and lower sulphur content of the gas stream. Most of Canada's sulphur is produced in Alberta.

Figure 14 illustrates historical sulphur closing inventories at processing plants and oil sands operations and sulphur prices. When international demand is high, Alberta sulphur blocks are used as an additional source to increase the supply.

Sulphur is used in the production of phosphate fertilizer and kraft pulp, as well as in other chemical operations. Alberta produces more sulphur than any other province, and the majority of Alberta production is shipped outside the province.

Canadian exports in 2012 were 3.7 million tonnes, an 11 per cent decrease from 4.1 million tonnes in 2011. Nearly half of Canadian exports are sent to the United States, 1569 thousands tonnes in 2012, down from 1667 thousands tonnes in 2011.



In 2012, sulphur prices averaged US$201 per tonne, a decrease of 6 per cent over last year's average price of US$214 per tonne. In 2012, declining demand for sulphur from China, the world's largest sulphur importer, affected domestic Chinese and international prices. Weaker global demand for phosphate fertilizers also exerted downward pressure on the global sulphur price.

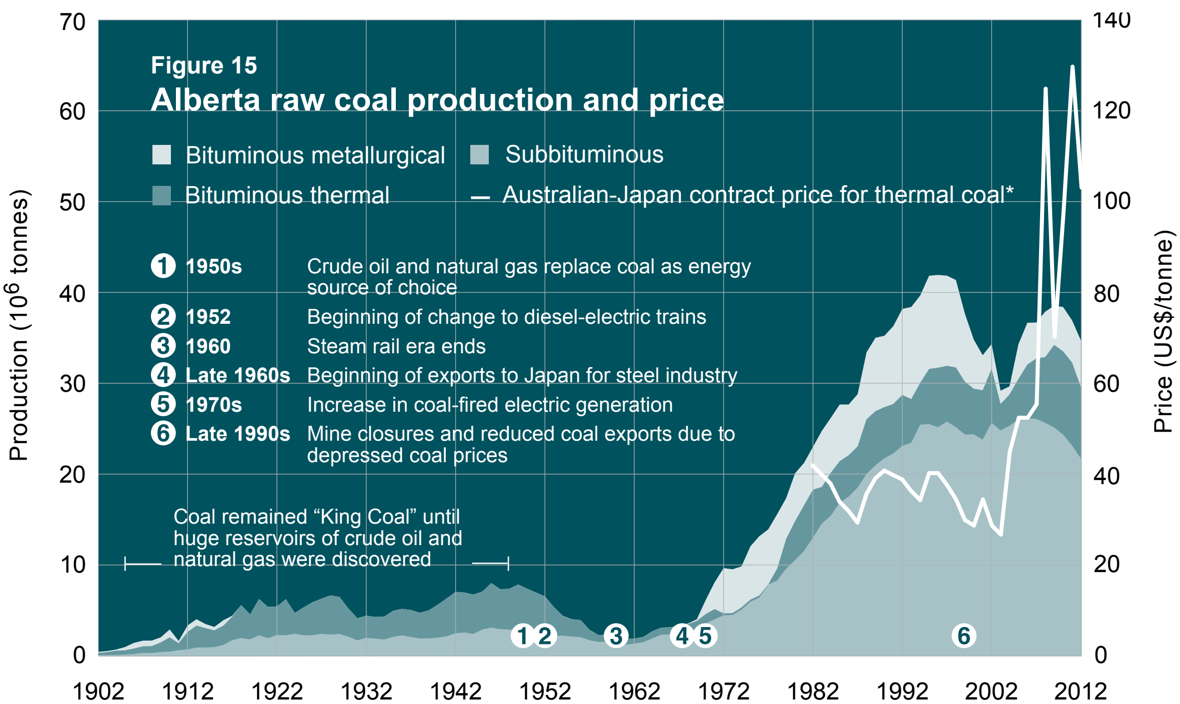
Coal

Coal Reserves

The ERCB estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2012, to be 33.3 billion tonnes (36.7 billion tons). Of this amount, 22.7 billion tonnes (or about 68 per cent) is considered recoverable by underground mining methods, and 10.4 billion tonnes is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2012. Alberta's coal reserves represent more than a thousand years of supply at current production levels.

Coal Production

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 15**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and cost-of-service contracts with the mining companies generally determine the price.



*Source: Australian Bureau of Agricultural and Resource Economics (ABARE).

In 2012, ten mines produced coal in Alberta. These mines produced 28.2 million tonnes of marketable coal. Subbituminous coal accounted for 77 per cent of the total, metallurgical bituminous coal 10 per cent, and thermal bituminous coal the remaining 13 per cent. Overall, total marketable production of coal has decreased by 6 per cent relative to 2011, mainly due to weaker demand.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan being the country that imports the most metallurgical and thermal coal. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export coal producers. The demand for metallurgical coal exports improved in 2012 from the 2011 level. The general decline in metallurgical coal demand in Asia stems from weakening steel prices and high inventories weighing on the market. Despite weak demand and the oversupply in global coal markets, North American metallurgical coal is becoming more competitive. Australia implemented taxes on mining profits and carbon emissions on July 1, 2012. As result, the 16 per cent increase in Alberta metallurgical coal production projected by the ERCB over the forecast period is expected to meet export market demand.

Electricity

The ERCB no longer publishes a perspective on supply and demand for Alberta's electricity sector. Information on electricity, including the market outlook, is provided by the AESO.

Oil and Gas Activity

Crude Oil

In 2012, 2854 successful oil wells were drilled, a decrease of 10.2 per cent from 2011. The number of new wells placed on production for 2012 was 3107. From this total, 2379 new horizontal oil wells (including those using multistage fracturing technology) were brought on production in 2012, an increase of 31 per cent from the 2011 level of 1818 horizontal wells. This raises the total number of horizontal wells to 9664.

- The number of new vertical oil wells placed on production is projected to be 728 in 2013 and is expected to decline to 520 wells in 2022. This well count is about 50 per cent lower than last year's forecast and reflects the view that many new wells will be horizontal wells, with many of those using multistage fracturing technology.
- The number of new horizontal oil wells is projected to decrease from 2379 in 2012 to 2310 in 2013, and to decline gradually to 2080 in 2022. The forecast number of horizontal oil wells has significantly increased relative to last year's forecast and reflects actual activity in 2012, industry's projection of increased horizontal drillings, and anticipated continued strong crude oil prices.

Natural Gas

The number of new gas well connections dropped significantly in 2012 and has not been this low since 1992. In 2012, 1189 new conventional natural gas connections were placed on production in the province, a decrease of 49 per cent from 2011. This is the sixth straight year of reductions in conventional gas connections.

The number of horizontal gas wells drilled and connected in the province is increasing as a percentage of the total. In 2012, about 53 per cent of new gas connections were horizontal wells compared with 25 per cent in 2011 based on the revised well connection counts.

The numbers of new conventional gas connections over the forecast period are projected to be 1100 in 2013 and gradually increase to 1425 by 2022. The forecast number of connections is significantly lower than last year's forecast of 3800 largely due to the shift from vertical and directional wells to more capital-intensive, but highly productive, horizontal wells. The natural gas price forecast is also lower relative to last year's forecast. Finally, much lower drilling activity in 2012 compared with 2011 is reflected in the lower projection for conventional gas connections over the forecast period.

In 2012, there were 433 new connections for CBM and CBM hybrid production—all of them in the Horseshoe Canyon Formation. Overall, new CBM and CBM hybrid connections decreased by 58 per cent in 2012 over 2011. Natural gas producers drilled fewer CBM wells because gas from the Horseshoe Canyon Formation produces dry gas with lower productivity, which, with a low gas price environment, became uneconomical to drill.

Over the forecast period, almost all new CBM production will be from the Horseshoe Canyon. The number of new CBM and CBM hybrid connections is forecast to be 230 in 2013 and will increase slightly to 245 in 2022. This forecast is significantly lower than last year's projection due to the very low level of activity reported in 2012 and the expectation that return on investment will not improve over the forecast period because of the continuing low gas price environment.

Figure 16 illustrates the province's drilling history over the past six decades, together with the price of natural gas. Historically, most drilling in Alberta is related to successful gas wells relative to crude oil wells, although this trend reversed in 2011 and continued in 2012.

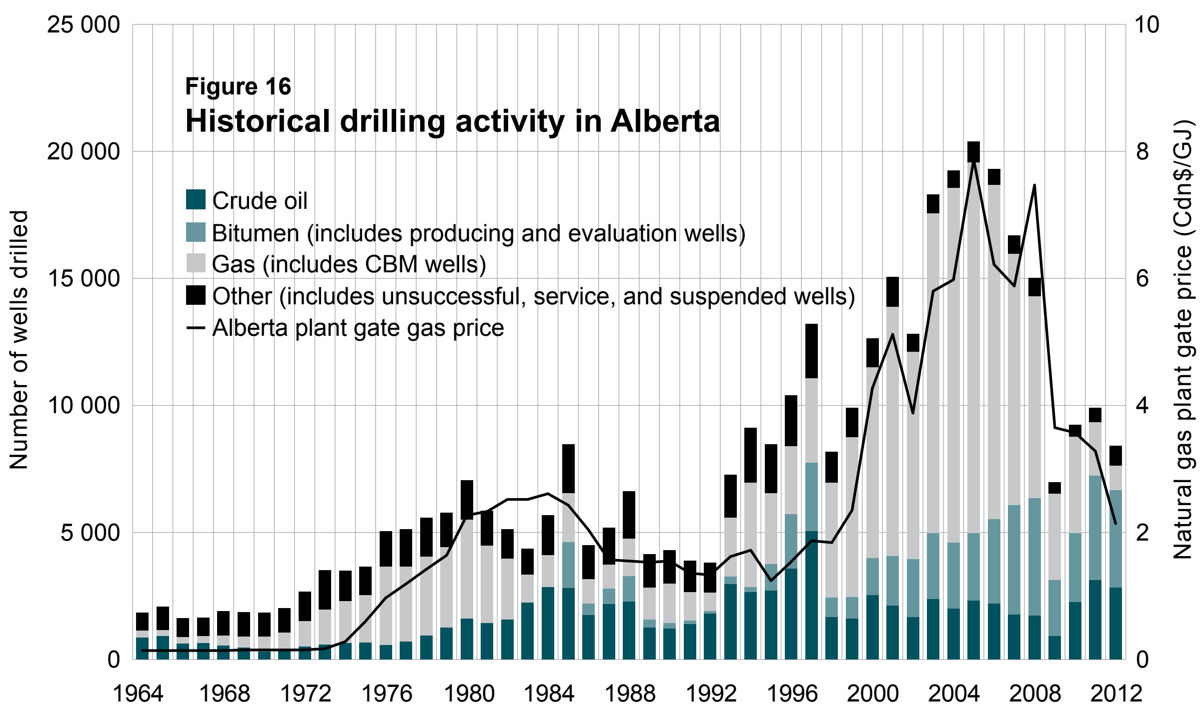


Figure 16
Historical drilling activity in Alberta

HIGHLIGHTS

WTI crude oil prices averaged US$94.21 per barrel in 2012, compared with US$95.11 per barrel in 2011, a decrease of 0.9 per cent.

Alberta wellhead natural gas prices averaged $2.14 per gigajoule in 2012, compared with $3.28 per gigajoule in 2011, a decrease of 35 per cent.

There were 8422 wells drilled in Alberta in 2012, compared with 9894 in 2011, a 15 per cent decrease.

1 ECONOMICS

Energy production is determined by energy prices, technology, costs, demand, and remaining reserves. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. This section introduces some of the main variables affecting Alberta's energy sector and sets the stage for later discussions in this report.

1.1 Energy Prices

1.1.1 World Oil Market[1]

In 2012, world oil demand rose modestly by 1.0 million (10^6) barrels per day (bbl/d) to 89.8 10^6 bbl/d (14.3 10^6 cubic metres per day [m^3/d]), a 1.1 per cent change from 2011. International Energy Agency (IEA) data report that net oil consumption in the Organisation for Economic Co-operation and Development (OECD) dropped by 0.4 10^6 bbl/d (0.06 10^6 m^3/d) to 46.0 10^6 bbl/d (7.3 10^6 m^3/d). OECD European demand slowed due to high commodity prices and a weak economy. In the third quarter of 2012, OECD European oil demand fell to levels not seen since the onset of the 2008–2009 financial crisis. This decline was offset by an increase in demand from both OECD and non-OECD Asian countries; demand in the Asian-Pacific region rose by 1.0 10^6 bbl/d (0.16 10^6 m^3/d) to 29.5 10^6 bbl/d (4.7 10^6 m^3/d). Total non-OECD global demand increased by 1.4 10^6 bbl/d (0.22 10^6 m^3/d) to 43.8 10^6 bbl/d (7.0 10^6 m^3/d).

Figure 1.1 illustrates changes in oil demand across the globe in 2011 and 2012, along with the most recent forecast for 2013 by the IEA. The IEA projects global crude oil demand to increase by 0.8 10^6 bbl/d (0.13 10^6 m^3/d) in 2013, or 0.9 per cent, to reach 90.7 10^6 bbl/d (14.4 10^6 m^3/d). Developing economies' growth will continue to offset declining growth in OECD countries in 2013. Demand in OECD countries is projected to decline by 0.4 10^6 bbl/d (0.06 10^6 m^3/d) in 2013, while non-OECD demand will increase by 1.3 10^6 bbl/d (0.2 10^6 m^3/d).

In 2012, the Organization of Petroleum Exporting Countries (OPEC) produced 31.4 10^6 bbl/d (5.0 10^6 m^3/d), compared with 29.9 10^6 bbl/d (4.8 10^6 m^3/d) in 2011. OPEC production in 2012 satisfied approximately 35 per cent of total world oil demand. Non-OPEC oil production increased from 52.7 10^6 bbl/d (8.4 10^6 m^3/d) in 2011 to 53.4 10^6 bbl/d (8.5 10^6 m^3/d). In 2012, the world's top three oil producing

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[1] Statistics obtained from the International Energy Agency's *Oil Market Report* (February 2013).

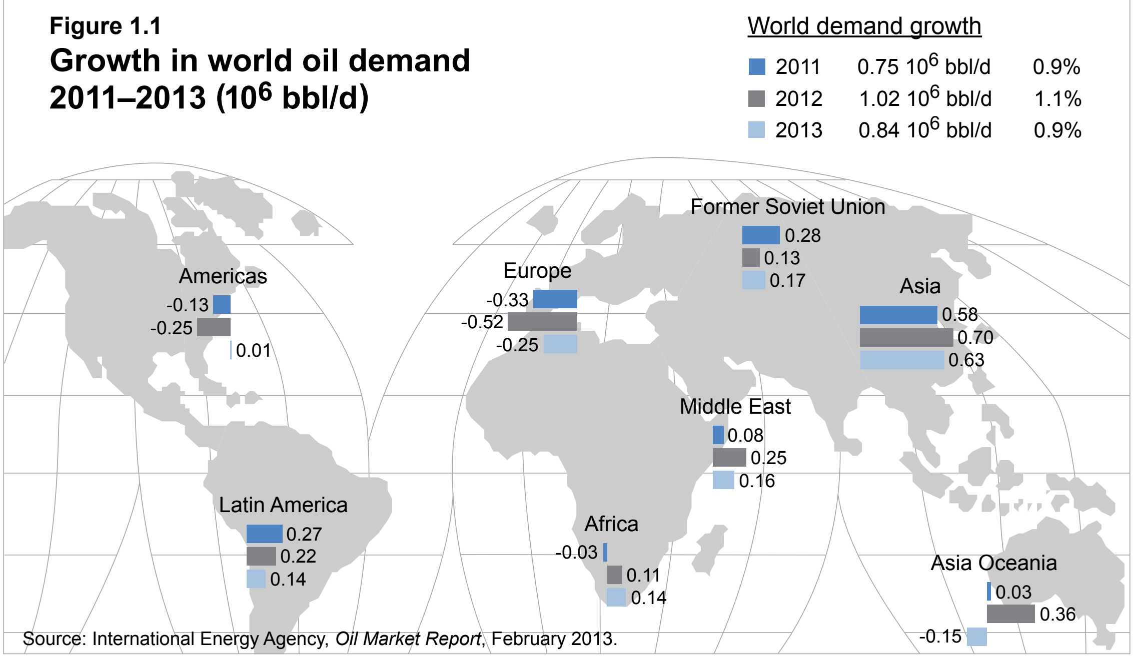

Figure 1.1
Growth in world oil demand 2011–2013 (10^6 bbl/d)

Source: International Energy Agency, *Oil Market Report*, February 2013.

countries (Russia, Saudi Arabia, and the United States) produced 33 per cent of total oil supply: Russia produced 10.7 10^6 bbl/d (1.7 10^6 m^3/d), Saudi Arabia produced 9.6 10^6 bbl/d (1.5 10^6 m^3/d), and the United States produced 9.1 10^6 bbl/d (1.4 10^6 m^3/d), in 2012.

1.1.2 International Oil Prices

Monthly average world oil prices for 2012, represented by the price of Brent Blend (Brent)[2] and the price of West Texas Intermediate (WTI),[3] are shown in **Figure 1.2.** In the first quarter of 2012, Brent prices averaged US$118.50/bbl and reached a high of US$125.45/bbl in March. Prices then fell, reaching a low of US$95.16/bbl in June. Brent prices in the second half of 2012 recovered and ranged between US$102.62/bbl and US$113.36/bbl, with a yearly average of US$111.66/bbl. The WTI price averaged US$94.21/bbl in 2012 and reached a yearly high of US$106.21/bbl in March and a low of US$82.41/bbl in June.

In the first quarter of 2012, crude oil prices strengthened in response to supply disruptions and production declines in Libya, South Sudan, Syria, Yemen, and the North Sea. Continued tension in the Middle East kept prices elevated. Prices began to fall in April and reached yearly lows in June 2012 on reports of high global crude oil stocks, declining Chinese exports, and renewed fears over another European recession. Prices in July began to recover as North Sea production was cut due to a strike, reducing supply. Market confidence also gained on

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[2] Brent Blend is a blend of light sweet crude oil from 15 different oil fields in the North Sea. Brent Blend futures are traded on the IntercontinentalExchange Inc. and are considered a global benchmark for oil prices.

[3] WTI is a light sweet grade of crude oil that is typically referenced for pricing purposes at Cushing, Oklahoma.

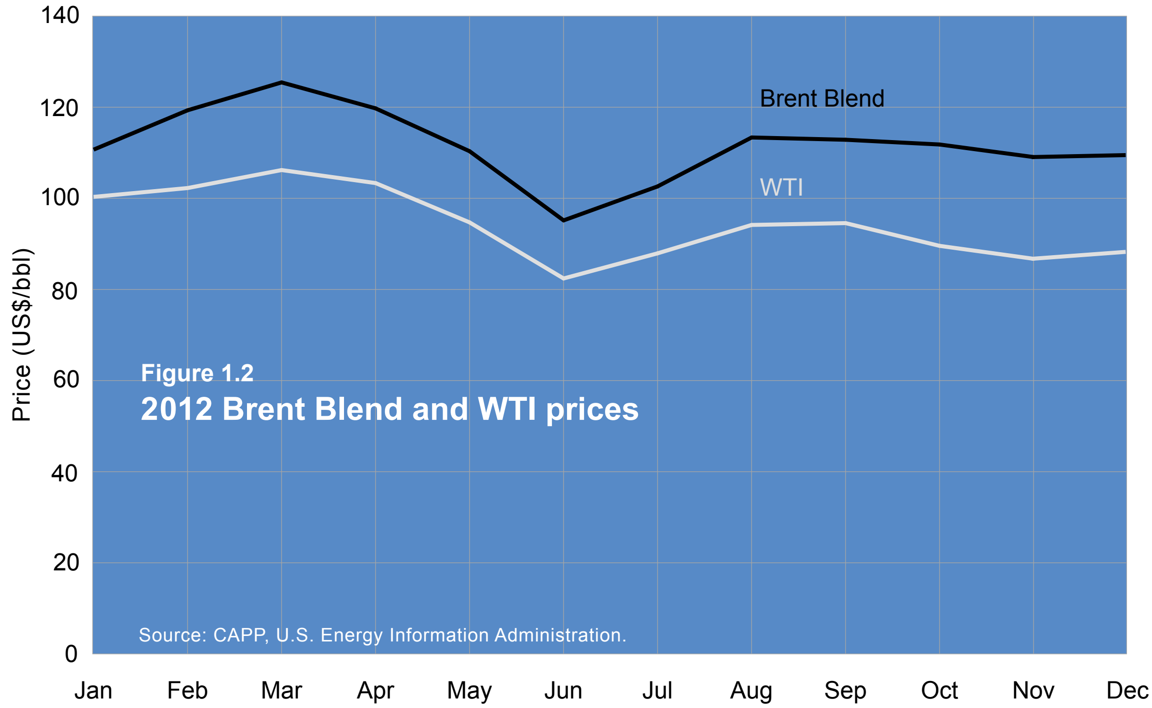


Figure 1.2
2012 Brent Blend and WTI prices

speculation that the European Central Bank would pass stimulus measures. By the fourth quarter of 2012, prices began to fall again as Europe entered into another recession. Global economic growth estimates were reduced and mounting fears over the ability of the U.S. congress to avert a "fiscal cliff" weakened market confidence.

Prices recovered slightly and remained steady into early 2013 as market confidence was restored when the U.S. Congress approved a deal to delay mandated tax increases and spending cuts. Recent data from China also indicated that stimulus plans have resulted in improvements to the economy. Continued political unrest in the Middle East has helped to keep crude oil prices in early 2013 steady. Increasing global oil supply and weak global economic activity are expected to keep prices lower throughout 2013.

Another significant market condition, highlighted in **Figure 1.2**, is the disconnect between the price of WTI and Brent. WTI began 2012 trading at a US$10.37/bbl discount to Brent. By the fourth quarter, however, the discount had widened to US$21.94/bbl, resulting in an average 2012 discount of US$17.45/bbl. This discount reflects the significant increases in North American mid-continent supplies and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast.

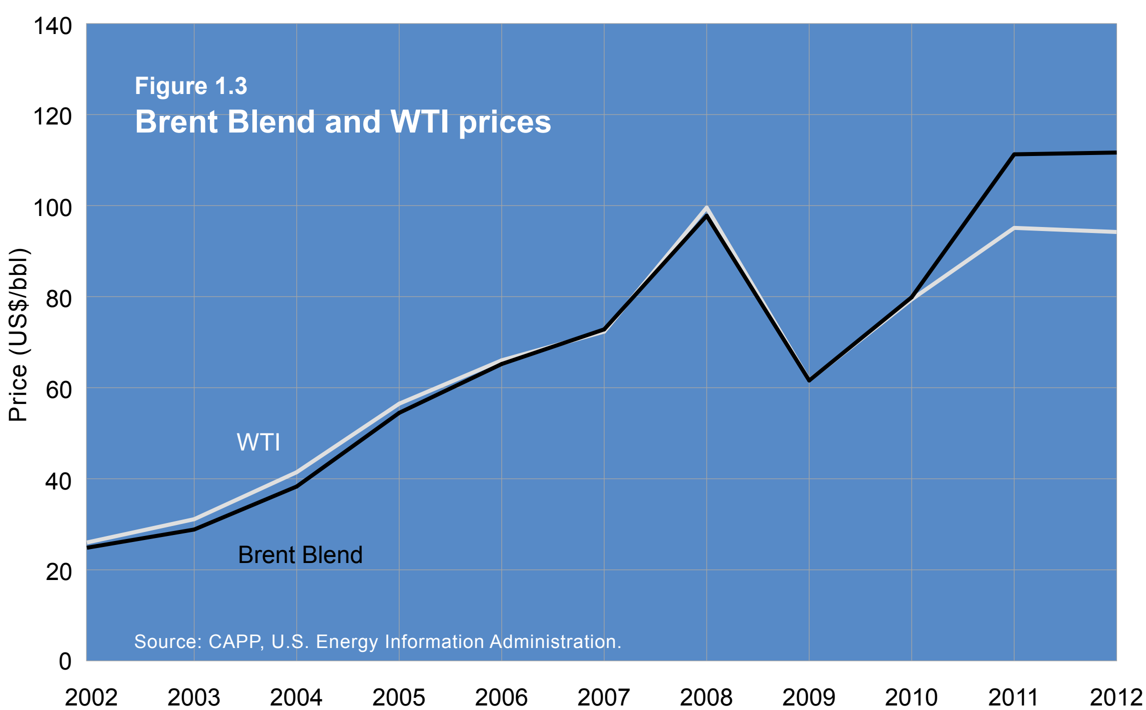
Bakken light oil production from the Williston Basin hit record high production levels in 2012, up 58 per cent over 2011 levels. Texas oil production was up by 36 per cent over 2011 levels, and production from the Canadian oil sands increased by 10 per cent. Crude oil inventory held at the Cushing storage hub hit a record high of 49.8 10^6 barrels (7.9 10^6 m^3) on December 28, 2012. Inventory levels have continued to rise in early 2013, with crude oil ending stocks reaching 51.9 10^6 barrels (8.2 10^6 m^3), up 78.2 per cent from a year ago. Limited pipeline capacity has restricted crude oil movements out of the U.S. mid-continent. Crude prices in the region are relatively low compared with U.S. crude prices outside of the region. U.S. crudes such as Louisiana Light Sweet and Alaska North Slope trade at a premium to WTI. The transportation constraints have also resulted in producers competing with each other for pipeline space and using more expensive transportation alternatives, such as rail, truck, or barge. Rail transportation is discussed in more detail in **Section 3.2.4.5**.

Figure 1.3 depicts the yearly average Brent price and the yearly average WTI price from 2002 to 2012. The historical relationship between the two benchmark prices has been reversed. From 2002 to 2006, WTI averaged US$0.81/bbl to $3.14/bbl higher than Brent annually, reflecting quality differences, the cost of shipping, and localized market conditions. From 2007 to 2009, prices were relatively on par. WTI crude prices started to trade at a discount to Brent in 2010, with the discount widening over the last three years. The 2012 WTI discount averaged US$17.45/bbl, compared with the 2011 average of US$16.15/bbl.

1.1.3 North American Crude Oil Prices

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

As discussed earlier, the increase in crude oil production has been a contributing factor to the WTI discount relative to the Brent price. Unconventional oil production has significantly added to the U.S. supply growth over the last six years. Multistage fracturing completion technology is being used to access crude oil in reservoirs previously considered uneconomic. This new technology has resulted in a substantial increase in U.S. domestic production.



As illustrated in **Figure 1.4**, since 2009 the declining trend in crude oil production in the United States has reversed, and production has increased from 5.00 10^6 bbl/d (0.79 10^6 m^3/d) in 2008 to 6.47 10^6 bbl/d (1.03 10^6 m^3/d) in 2012, a 29 per cent increase. **Figure 1.4** also shows that U.S. gas production has increased in recent years as well.

New plays, like the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas, are drilled using horizontal wells and multistage hydraulic fracturing techniques. In North Dakota, crude oil production averaged 662 10^3 bbl/d (105 10^3 m^3/d) in 2012, an increase of 114 per cent from 2010 levels. Production from the Bakken accounts for 90 per cent of North Dakota's total oil production, which has surpassed Alberta's conventional crude oil production. The transportation infrastructure, which includes oil pipelines, truck, and rail, is constrained in the U.S. mid-continent region due to the significant growth in crude oil production in 2012. The increased supply of light crude has also depressed Canadian light crude prices, which are competing with Bakken crude for pipeline space. In Texas, onshore production of crude oil averaged 1986 10^3 bbl/d (316 10^3 m^3/d) in 2012, an increase of 70 per cent from 2010 levels. U.S. crude oil production is further discussed in **Section 4.2.1.2**.

In 2012, the WTI price averaged US$94.21/bbl, down US$0.90/bbl from 2011. The ERCB projects WTI to average US$90.00/bbl in 2013, with a range from US$80.00/bbl to US$100.00/bbl. **Figure 1.5** shows historical and forecast WTI prices at Cushing.

As illustrated in **Figure 1.5**, the price of WTI is expected to increase throughout the forecast period. The near-term WTI forecast reflects the expected increase in world oil supply, moderating demand in OECD countries, concern over the European recession and global economic activity, and the continued WTI discount due to pipeline constraints in parts of North America. The long-term forecast reflects expectations that transportation

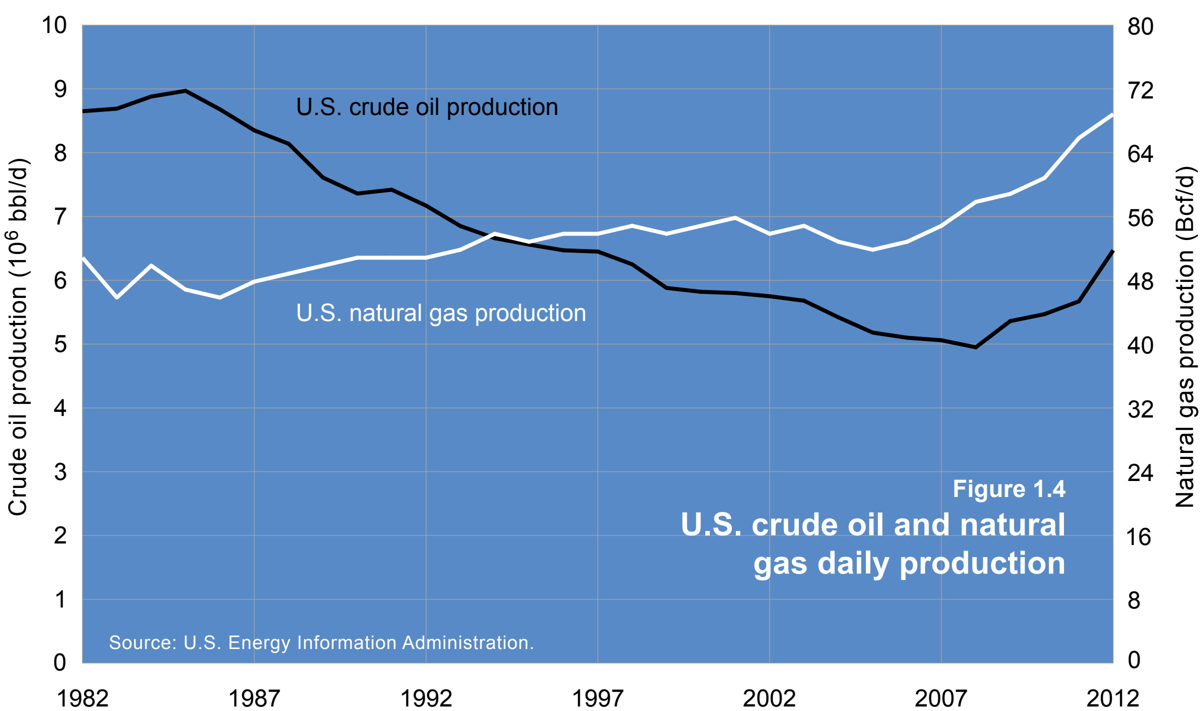
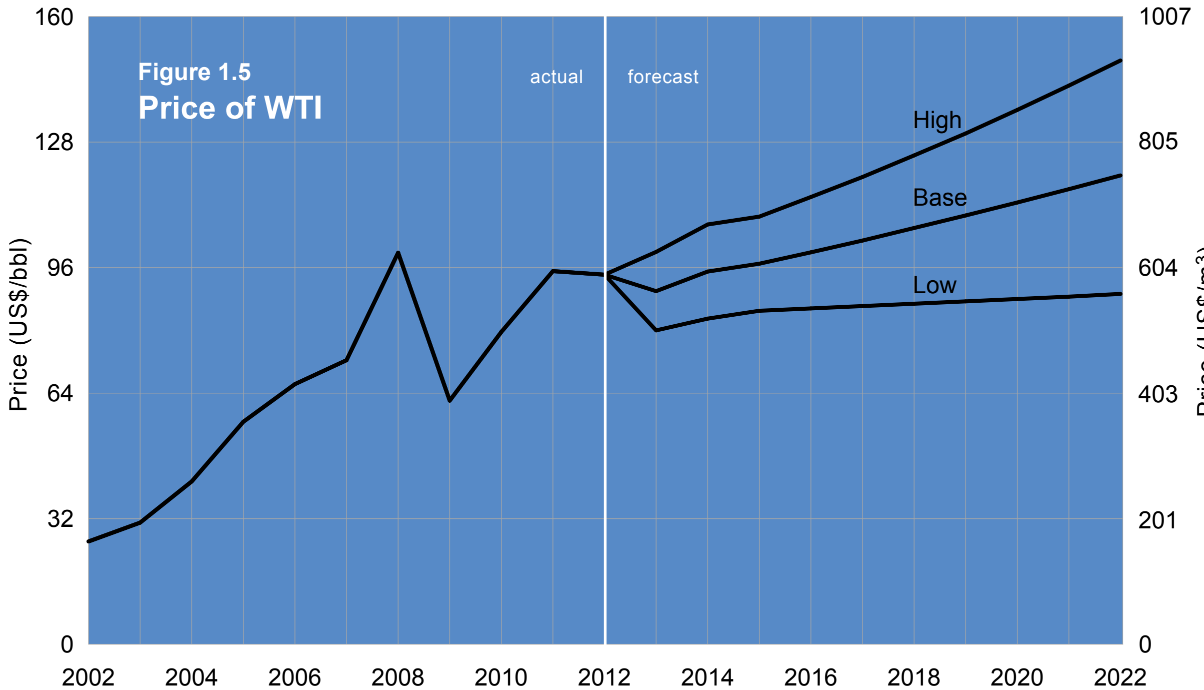


Figure 1.4
U.S. crude oil and natural gas daily production



constraints will be alleviated and that current global economic conditions will improve. By 2022, WTI prices are projected to be US$119.46/bbl, with a range from US$89.25/bbl to US$148.83/bbl.

The ERCB calculates light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI price is adjusted for transportation and other charges between Edmonton and Cushing, including the exchange rate, as well as for crude oil quality. **Figure 1.6** shows historical and the ERCB's forecast prices for Alberta light-medium crude oil in Canadian dollars.

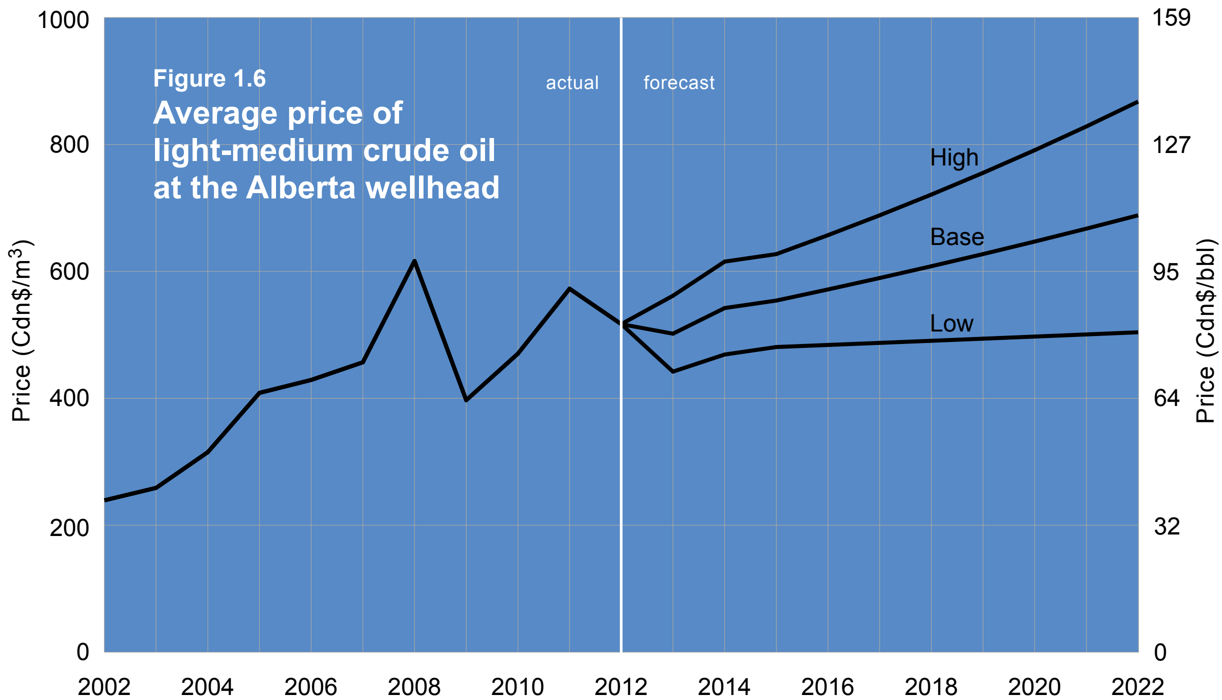
Table 1.1 compares 2011 and 2012 Alberta light-medium and heavy crude oil prices. In 2012, the average price of light-medium crude oil averaged Cdn$82.14/bbl, down Cdn$8.86/bbl from 2011. The ERCB projects the price of light-medium crude oil to average Cdn$79.74/bbl in 2013, with a range of Cdn$70.24/bbl to Cdn$89.24/bbl.

As illustrated in **Figure 1.6**, the forecast price of light-medium crude oil is expected to increase moderately throughout the forecast period from 2013 to reach an average of Cdn$109.38/bbl in 2022, with a range from Cdn$80.10/bbl to Cdn$137.85/bbl.

Table 1.1 Alberta wellhead annual average crude oil prices[a]

	Average annual price (Cdn$/bbl)	
	2011	**2012**
Alberta light-medium crude oil price	91.00	82.14
Alberta heavy crude oil price	72.59	67.59

[a] Prices from ERCB report *ST3: Alberta Energy Resource Industries Monthly Statistics*, which reflect Alberta Petroleum Marketing Commission (APMC) prices. The APMC average price represents the value of the average Crown sales in the province in dollar per cubic metre with respect to royalty oil delivered to the APMC at the field delivery point to which the oil was required to be delivered in that month.



In 2012, Alberta light-medium crude oil was priced at a discount relative to WTI due to increased production from the Bakken play in the United States. Demand for light crudes also fell as refineries in both the United States and Canada went down for unscheduled maintenance. In the short-term, the Alberta light-medium forecast reflects the expectation that light crude oil production will continue to increase in North America. Given the previously discussed pipeline constraints present in the U.S. mid-continent, Canadian light crudes are competing for pipeline space with production from the Bakken Formation in North Dakota. The long-term forecast for Alberta light-medium reflects the expectation that transportation constraints will be alleviated and demand for Canadian crudes will increase. The ability to diversify Canadian crude oil markets and increase access to U.S. Gulf Coast refineries will increase demand for Canadian crudes and help reduce the current light-medium crude oil discount.

Figure 1.7 illustrates the average annual price of Alberta light-medium and heavy crude oils. The differential between Alberta heavy and light-medium crudes averaged Cdn$16.86/bbl, or 25.9 per cent, from 2002 to 2012. The heavy/light-medium differential in 2012 averaged Cdn$14.55/bbl, or 17.7 per cent, compared with $18.40/bbl, or 20.2 per cent, in 2011. The heavy/light-medium differential narrowed in 2012 due to the depressed light-medium price resulting from continued increases in light sweet crude oil production in North America. The heavy/light-medium differential is expected to average 18.5 per cent over the forecast period, wider than the most recent five-year average of 17.7 per cent. The differential in 2013 and 2014, at 20.6 per cent, is projected to remain wider than the five-year average as increased oil sands supply and tight pipeline space depress the price of heavy crudes.

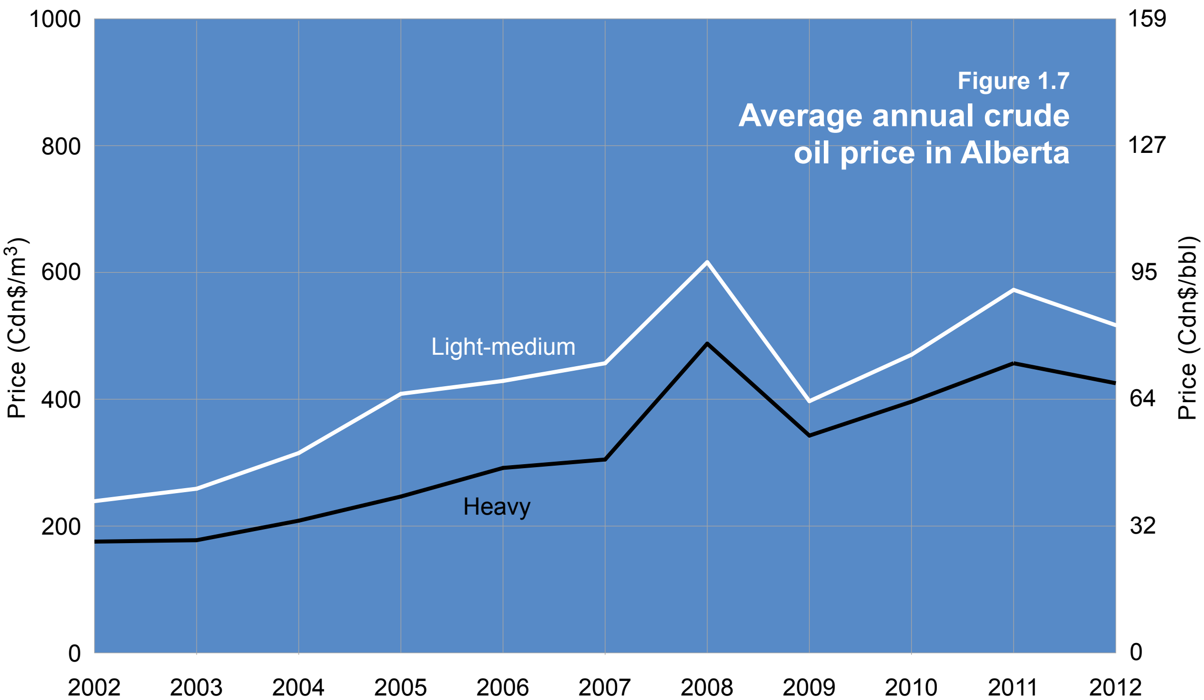


Figure 1.7
Average annual crude oil price in Alberta

Heavier Canadian crudes, such as Western Canadian Select (WCS),[4] have shown deeper discounts compared with other world benchmark prices. In 2012, WCS averaged US$73.14/bbl, trading at US$21.07/bbl under the price of WTI. As illustrated in **Figure 1.8**, in the last months of 2012, the discount between WCS and WTI widened. In December, the WCS discount averaged US$30.39/bbl. Heavy Canadian crudes have been discounted due to concerns over oversupply and pipeline constraints.

In late 2012, pipeline companies announced apportionment[5] on many U.S. mid-continent pipelines. Producers are competing for pipeline space to transport their product to U.S. refineries. In response, some oil sands companies have begun using rail to transport crude bitumen and hedge against the risk of pipeline constraints. Rail use in the oil sands is further discussed in **Section 3.2.4.5**.

The market is also concerned with the rapid growth of production from the oil sands at a time when pipelines are already running full. Heavy Canadian crude prices fell as the market reacted to increased supplies. The concern was that added supply would compete for already tight space on pipelines carrying crude to the U.S. mid-continent. Also of concern is the series of closures to refineries in the U.S. Gulf Coast and the U.S. Midwest due to scheduled maintenance. Planned maintenance for refineries in the U.S. Midwest will reduce heavy refining

[4] Western Canadian Select is produced out of western Canada and is made up of existing Canadian heavy conventional crude oil and crude bitumen blended with diluents.

[5] When shippers nominate more oil or oil products in a given month than the pipeline can transport, shipper volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by such factors as growing supply, increased demand, pipeline reconfigurations, reduced pipeline capacity, or refinery maintenance.

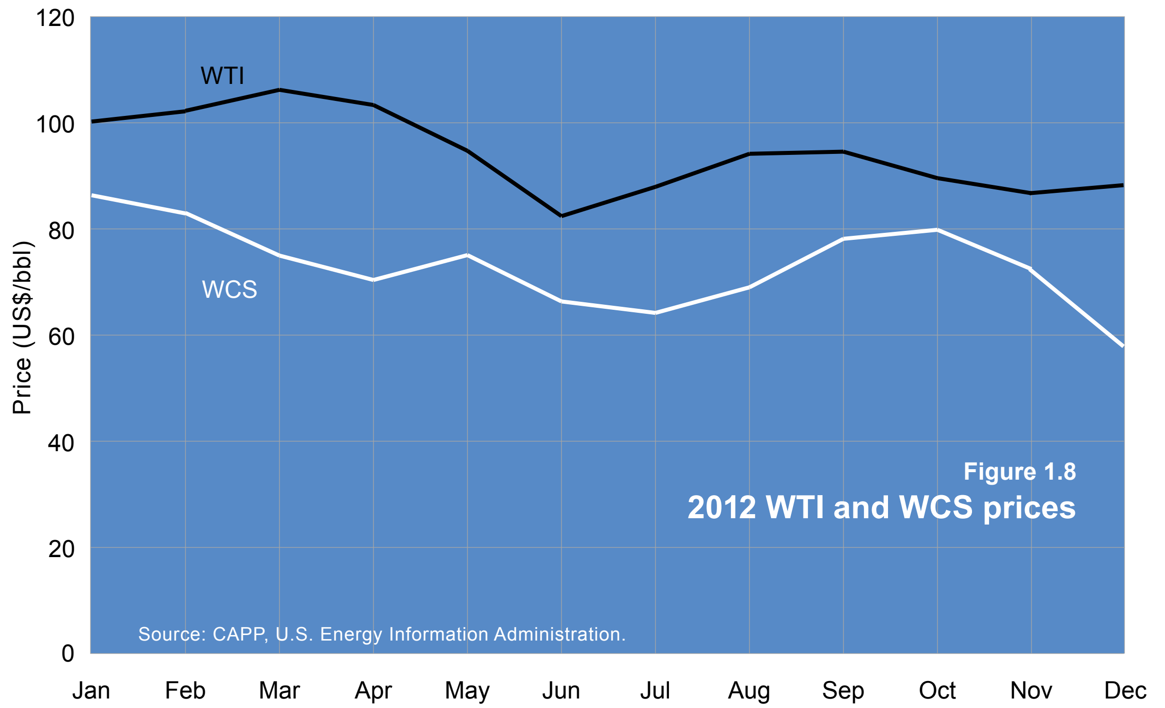


Figure 1.8
2012 WTI and WCS prices

capacity by 313 10^3 bbl/d (50 10^3 m^3/d) in the first quarter of 2013, approximately three times the average planned capacity reduction since 2008, and will significantly affect the demand for heavy Canadian crudes.

The deep discount on Canadian heavier crudes is not expected to be alleviated until demand for Canadian crudes is increased by the addition of heavier refinery capacity and the alleviation of pipeline constraints. British Petroleum's (BP) refinery modernization project at Whiting, Indiana, to increase heavy oil refinery capacity is expected to ease the heavy oil discount seen in recent months. Market diversification and the ability to transport Canadian crude to the U.S. Gulf Coast would also improve the discount between heavy Canadian crudes and other world benchmarks.

With increased production from the oil sands, Canada has become the United States' leading crude oil supplier. Total crude oil production in Alberta exceeds volumes required by Alberta and ex-Alberta domestic refinery demand, and the excess production is exported to the United States. The Petroleum Administration for Defense Districts (PADDs) 2 and 4 in the United States are the largest importers of Alberta heavy crude oil and upgraded bitumen, with a combined total refinery capacity of 4288 10^3 bbl/d (681 10^3 m^3/d). Increased heavy oil upgrading capabilities at the Wood River refinery conversion project in Illinois (completed in 2011), Marathon Petroleum Corporation's Detroit heavy oil upgrade project (completed in 2012), and the BP refinery modernization project at Whiting, Indiana (due on stream in 2013), will allow PADD 2 and PADD 4 to take on increasing amounts of Alberta's heavier crudes.

Total refinery capacity in the United States increased marginally during the 1990s and 2000s with the de-bottlenecking of existing refineries. No new refineries have been built since the 1970s. Before the global economic recession in 2008 and 2009, product demand had increased significantly, resulting in U.S. refineries operating at high utilization rates since about 1993. More recently, depressed refinery margins have resulted in some U.S. refiners operating at lower utilization rates, temporarily idling, or shutting down.

With expected increases in both nonupgraded and upgraded crude oil bitumen supply over the forecast period, incremental pipeline capacity will be required to transport growing volumes to market. Consequently, many pipeline companies are moving ahead with planning and constructing new projects.

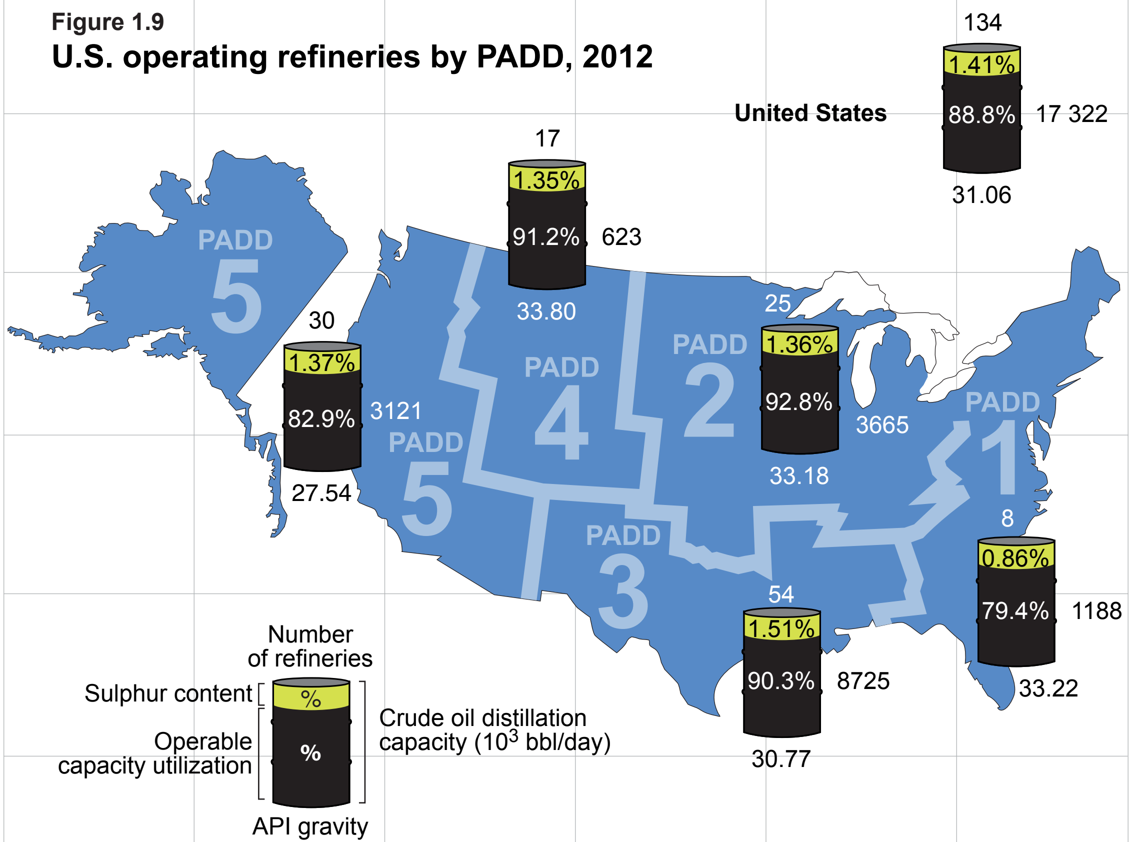
In June 2012, Enbridge Inc. (Enbridge) and Enterprise Products Partners LP's (Enterprise) Seaway Pipeline was reversed, transporting crude oil from Cushing to the Gulf Coast. Initial pipeline capacity was 150 10^3 bbl/d (24 10^3 m^3/d). In early 2013, the companies completed the first expansion, adding 250 10^3 bbl/d (40 10^3 m^3/d). Enbridge and Enterprise also plans to twin the pipeline, more than doubling Seaway's capacity to 850 10^3 bbl/d (135 10^3 m^3/d) by the first quarter of 2014.

In January 2012, the proposed 830 10^3 bbl/d (132 10^3 m^3/d) capacity Keystone XL project by TransCanada Corporation (TransCanada) was denied a U.S. regulatory permit. TransCanada has since announced it plans to build the southern leg of the Keystone XL project, the Gulf Coast project. Construction on the 830 10^3 bbl/d (132 10^3 m^3/d) Gulf Coast Project began in August 2012, and the company expects the pipeline to be completed in 2013. The company has also re-applied for regulatory approval, excluding the southern portion, and expects an in-service date of late 2015. If approved by the U.S. State Department, the Keystone XL project in its entirety will deliver Canadian crude oil to Gulf Coast refineries in PADD 3, the largest refining region in the United States, as illustrated in **Figure 1.9**.

Other projects have been announced to move Canadian crude to the B.C. coast. Enbridge's 525 10^3 bbl/d (83 10^3 m^3/d) Northern Gateway project will transport crude oil from Edmonton, Alberta, to a terminal in Kitimat, British Columbia. Enbridge has applied to the National Energy Board (NEB) for approval and hearings are currently under way. Kinder Morgan has announced plans to increase capacity on its Trans Mountain pipeline, which transports crude oil from Edmonton to the Greater Vancouver area. The pipeline capacity would increase from 300 10^3 bbl/d (48 10^3 m^3/d) to 890 10^3 bbl/d (141 10^3 m^3/d) by 2017. Kinder Morgan plans to submit an application to the NEB in late 2013. Both these projects will allow Canadian crude oil to be transported to overseas markets, as well as to the western United States PADD 5 region. In California (PADD 5), 90 per cent of its refinery capacity is able to process heavier crudes; however, California's Low Carbon Fuel Standard would have to be met. Additional pipeline projects are discussed in **Section 3.2.4**.

Figure 1.9 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the United States, with 54 operating refineries and a net crude oil distillation capacity of 8.7 10^6 bbl/d (1383 10^3 m^3/d). PADD 3 was not previously viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude oil production. However, traditional crude oil inputs to PADD 3 have been on the decline, suggesting a significant market opportunity for Alberta heavy crude oil producers. As a result, projects such as the discussed TransCanada Keystone XL project are under way to increase pipeline capacity to the area.

Figure 1.9
U.S. operating refineries by PADD, 2012



Source: U.S. Energy Information Agency.
Number of operating refineries as of February 28, 2013. Data for the year 2012.
Sulphur content and API gravity are weighted averages.

1.1.4 North American Natural Gas Prices

The long-term outlook for U.S. gas supply has changed with the growth in supply from shale gas. As illustrated previously in **Figure 1.4**, U.S. conventional gas supplies had a stable rate of increase from 1986 to 2001 and then began to decline from 2001 to 2005. Natural gas production in the United States has significantly increased since 2006. Multistage hydraulic fracturing technology has allowed for the economic development of shale gas plays that are responsible for the increase in production. When combined with horizontal drilling, this new completion technique results in high initial production rates. Total U.S. marketed gas production was 69.14 billion cubic feet per day (bcf/d) (1.9 billion [10^9] m^3/d) in 2012, a 33.3 per cent increase from 2005 levels.

Increased U.S. natural gas production has resulted in low natural gas prices, as shale gas production has more than offset production declines from conventional resources and has exceeded demand growth in the United States. Projects to convert some of the liquefied natural gas (LNG) regasification terminals to liquefaction terminals are occurring to enable exports of domestic natural gas supplies to markets offering higher prices. In addition, new LNG export terminals have been proposed in both the United States and Canada.

In Canada, there have been several LNG export projects proposed on the B.C. coast as Canadian natural gas producers reach for new gas markets in Asia. Under increased competition from U.S. shale gas production, western Canada's gas exports have fallen by 21 per cent since 2007. Asian markets, with natural gas prices linked to crude oil prices, provide an attractive alternative to U.S. exports. To date, the NEB has approved export licences for Kitimat LNG Operating General Partnership, B.C LNG Export Co-operative LLC, and LNG Canada Development Inc. to export LNG from the B.C. coast to Asia-Pacific markets.

While North American crude oil prices have historically tracked international prices, natural gas prices in North America basically reflect the North American supply and demand situation, with little influence from the global gas market aside from the impact of LNG imports. Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price. The Alberta reference price forecast for natural gas was derived from the Henry Hub price, taking into account transportation differentials and the exchange rate.

Figure 1.10 shows the monthly Alberta reference price for natural gas in 2012. In the first quarter of 2012, natural gas prices fell to Cdn$2.17 per gigajoule (GJ) as a result of warmer-than-expected weather and strong natural gas production in North America. As producers continued to drill, storage inventory levels increased and reached record highs going into the summer. In May, Alberta gas storage levels were 11 881 10^6 m^3 (422 bcf), 36 per cent higher than the five-year May average of 8738 10^6 m^3 (310 bcf). In May, the price of natural gas hit a low of Cdn$1.58/GJ.

Natural gas prices began to rally as higher-than-expected seasonal temperatures in the summer increased demand due to air conditioning use and concerns moderated over storage levels in the United States. Alberta storage levels continued to climb until October, when they reached a high of 13 148 10^6 m^3 (467 bcf), 9.5 per cent higher

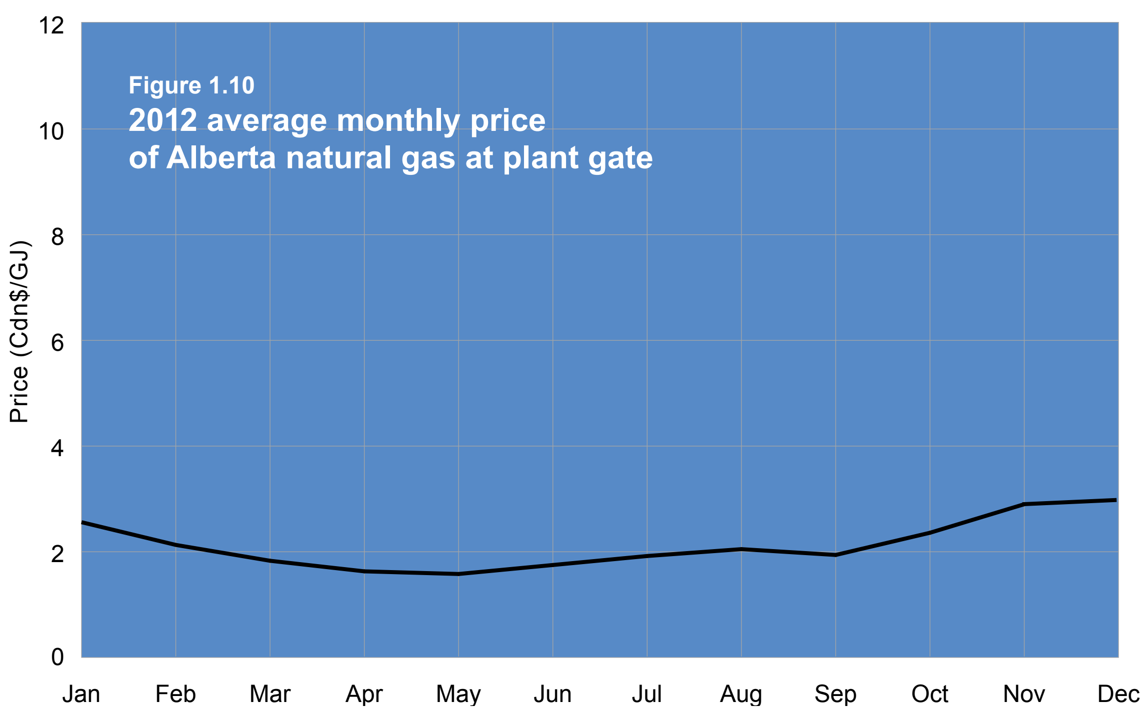


Figure 1.10
2012 average monthly price of Alberta natural gas at plant gate

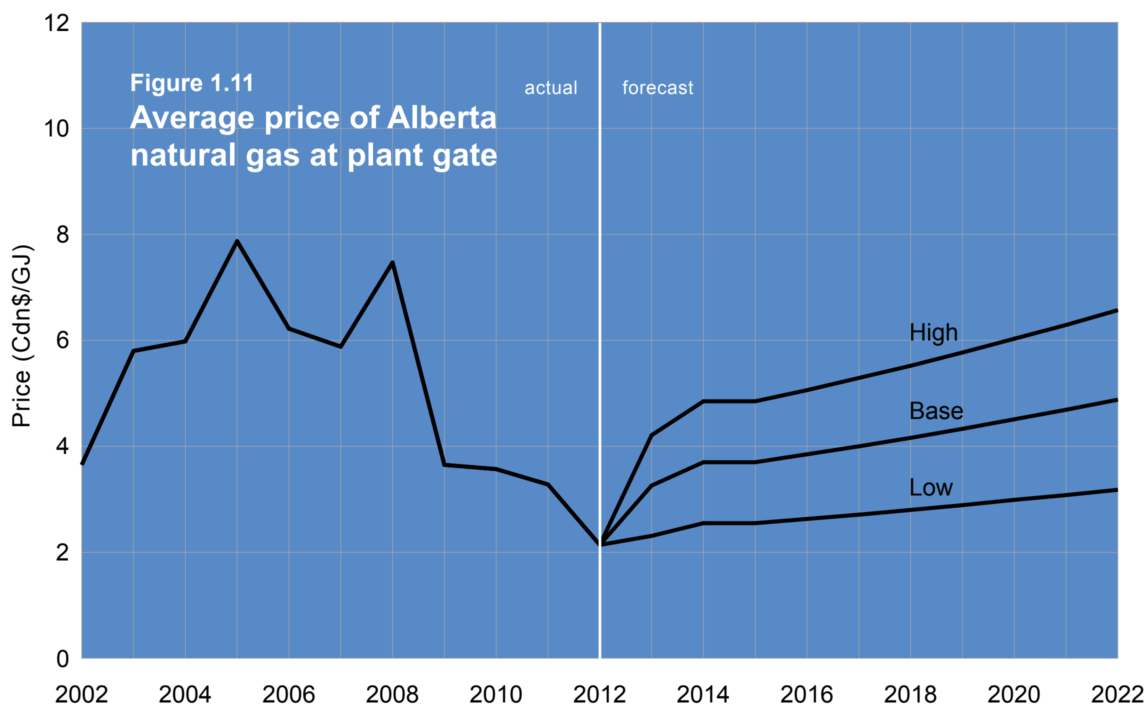
than the five-year October average of 12 003 10^6 m^3 (426 bcf). Natural gas prices reached their high in December, averaging Cdn$2.98/GJ. Natural gas prices started to decrease again going into 2013 as mild winter conditions reduced demand.

The average Alberta reference price of natural gas in 2012 was Cdn$2.14/GJ, compared with Cdn$3.28/GJ in 2011, a 34.8 per cent decrease. In 2012, U.S. natural gas prices at Henry Hub decreased by 31.1 per cent compared with 2011 levels.

Figure 1.11 shows the historical and forecast average price of Alberta natural gas at the plant gate. The ERCB projects a base price of Cdn$3.26/GJ for natural gas at the Alberta wellhead, with a range between Cdn$2.31/GJ and Cdn$4.21/GJ in 2013. Over the forecast period, the price of natural gas is projected to increase slowly to reach an average of Cdn$4.88/GJ by 2022, with a range from Cdn$3.18/GJ to Cdn$6.57/GJ.

The forecast assumes that continued shale gas production in the United States will keep prices low in the short and medium term. As previously discussed, horizontal multistage fracturing technology has resulted in higher initial production rates for wells and will contribute to the increased natural gas supply. Additional demand for natural gas will arise from environmental incentives to switch fuel for electricity generation and, in the short term, price incentives, as well as LNG export projects.

The Alberta price parity of gas to light-medium oil on an energy content basis averaged 0.53 from 2002 to 2011. In 2012, the price parity averaged 0.16, compared with 0.22 in 2011. Over the forecast period, the gas-to-oil price parity is projected to average 0.26, as North American gas prices are projected to increase slowly relative to crude oil prices.



1.2 Oil and Gas Drilling and Completion Costs in Alberta

For over 30 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical oil and gas wells for the upcoming drilling season. PSAC defines a typical oil and gas well as a well that reflects the most common well type to be drilled in 2013 in western Canada. The cost estimates in **Figure 1.12** were obtained from the 2012 and 2013 PSAC Well Cost Studies. **Table 1.2** outlines the median well depth for each area, a major contributor to drilling costs. Many other factors influence well costs, including the economic environment, the type of commodity produced, the type of well (development versus exploratory), surface conditions, the type of production (sweet versus sour), drilling programs, well location, nearby infrastructure, and completion method.

Table 1.2 Alberta median well depths by PSAC area, 2012 (m)*

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells							
Horizontal	3 651	2 508	1 294	671	1 970	259	2 063
Vertical	3 262	2 520	661	714	1 030	508	805
Oil wells							
Horizontal	2 426	1 923	957	756	1 375	622	1 477
Vertical	2 387	2 049	1 051	786	1 576	643	1 629

* PSAC defines the areas in Alberta as AB1, AB2, etc., and are referred to as Area 1, Area 2, etc. in this report. The PSAC area map is located in **Appendix A.2.**

As illustrated in **Figure 1.12**, the estimated cost to drill and complete a typical oil well increased from the previous year. The estimated cost of drilling and completing a typical oil well in the winter of 2012–2013 ranged from as low as $0.81 million in Area 4 (East-Central Alberta) to as high as $3.72 million in Area 5 (Central Alberta). According to PSAC data, an average vertical oil well in Area 3 cost $0.93 million. Completion costs represented 47.9 per cent of total drilling and completion costs. For an average horizontal well located in Area 5, completion costs represented 69.9 per cent of total drilling and completion costs. Of total completion costs, completion fluids represented 43.9 per cent. The average estimated cost to drill and complete an oil well across the PSAC areas increased by 8.1 per cent from the previous year.

Gas well drilling and completion costs are also projected to increase. Estimated costs to drill and complete a typical gas well in the winter of 2012–2013 were highest in Area 2 (Foothills Front) at over $4.61 million. In Area 3 (Southeastern Alberta), a typical gas well was estimated to cost $0.29 million to drill and complete. According to PSAC data, completion costs for an average vertical well in Area 3 represented 50.2 per cent of total drilling and completion costs. For an average horizontal well located in Area 1, completion costs represented 54.7 per cent of total drilling and completion costs, and completion fluids represented 41.9 per cent of completion costs. The average estimated cost to drill and complete a typical gas well across the PSAC areas increased by 9.8 per cent from the previous year.

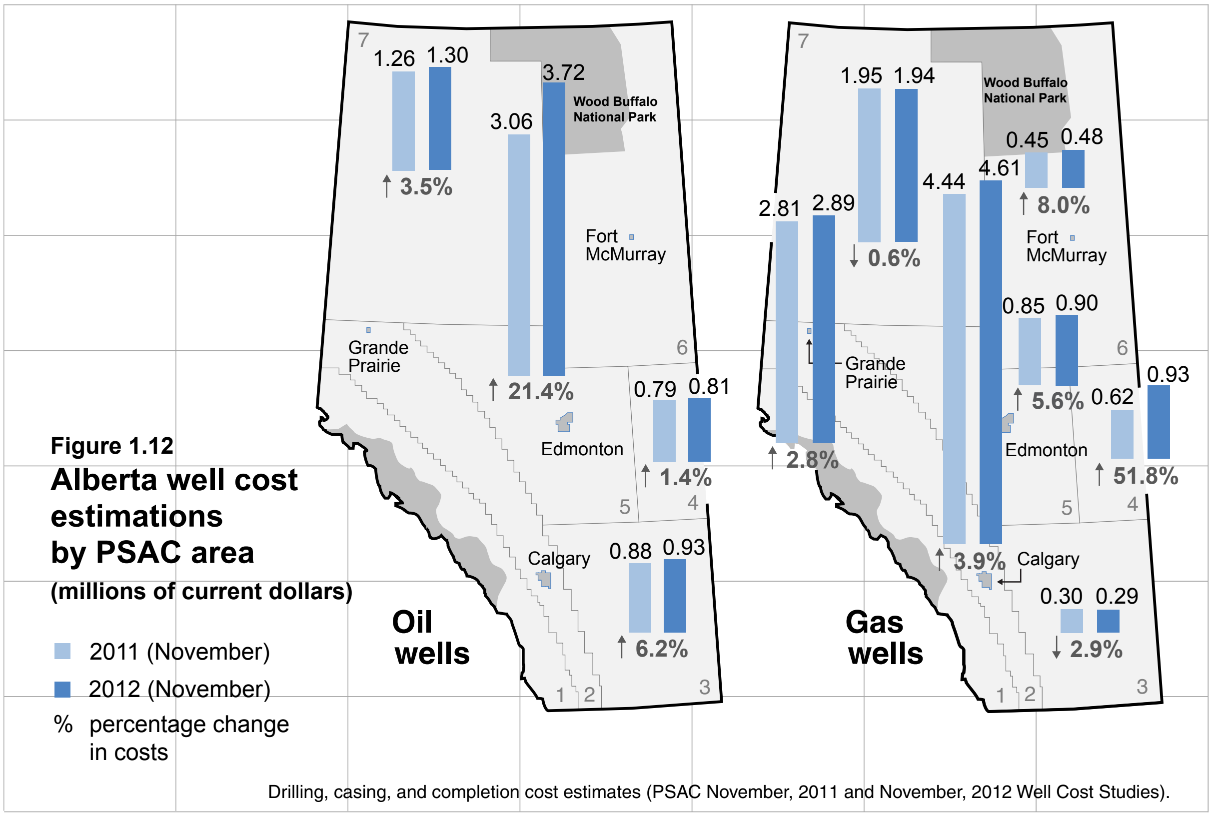


Figure 1.12
Alberta well cost estimations by PSAC area
(millions of current dollars)

1.3 Economic Performance

1.3.1 Alberta and Canada

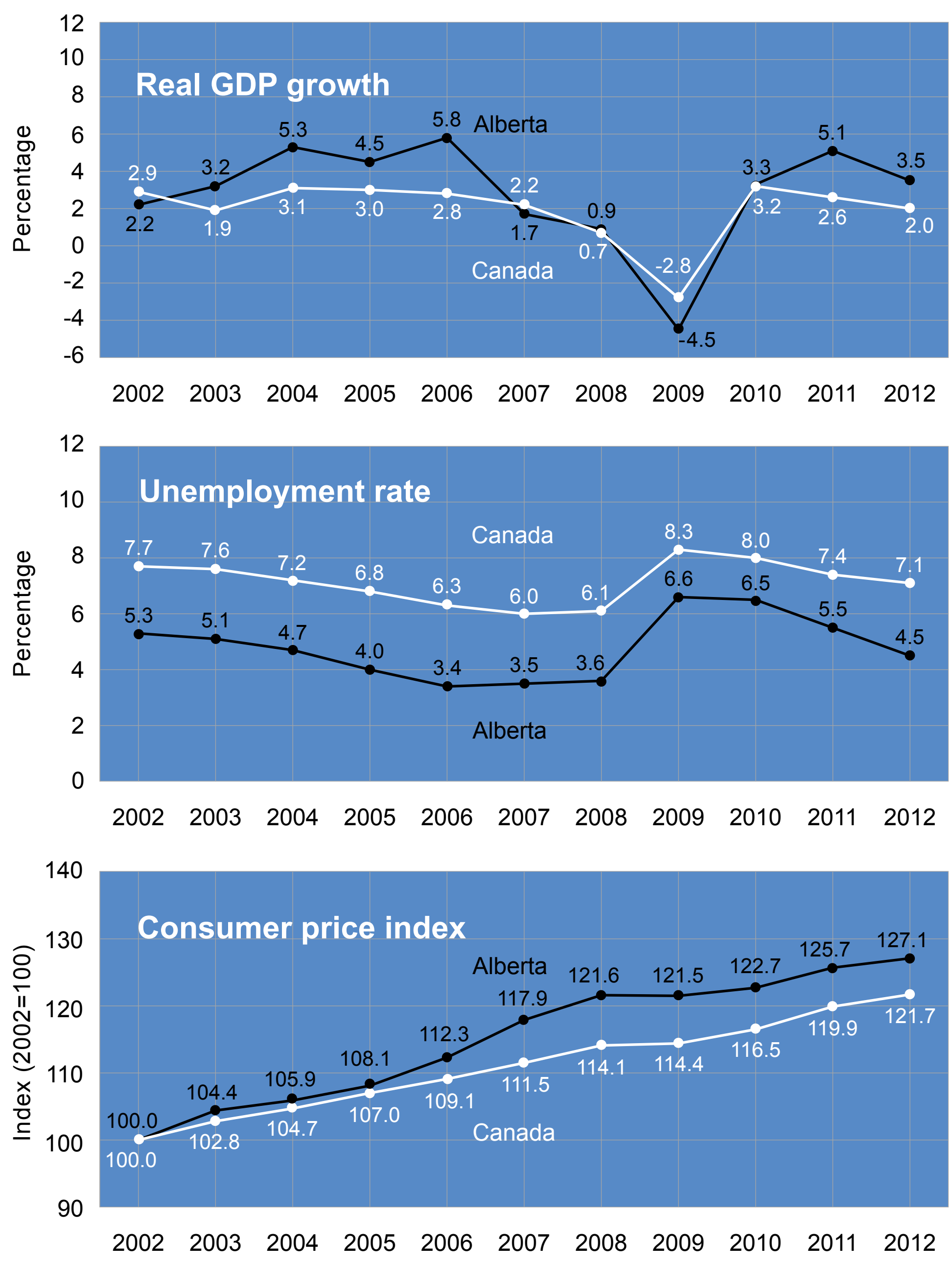
Figure 1.13 depicts the historical performance of major economic indicators for Alberta and Canada. Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003–2007 timeframe. Average Alberta GDP growth from 2002 to 2012 was 2.9 per cent, compared with a Canadian average of 2.0 per cent. Over the same period, the unemployment rate in Alberta averaged 4.8 per cent while the Canadian unemployment rate averaged 7.1 per cent.

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2002, inflation in Alberta has averaged 2.5 per cent per year, while Canadian inflation has averaged 2.0 per cent. In 2012, Alberta inflation was unusually low and averaged around 1.1 per cent due to relatively weak energy, electricity, and housing prices.

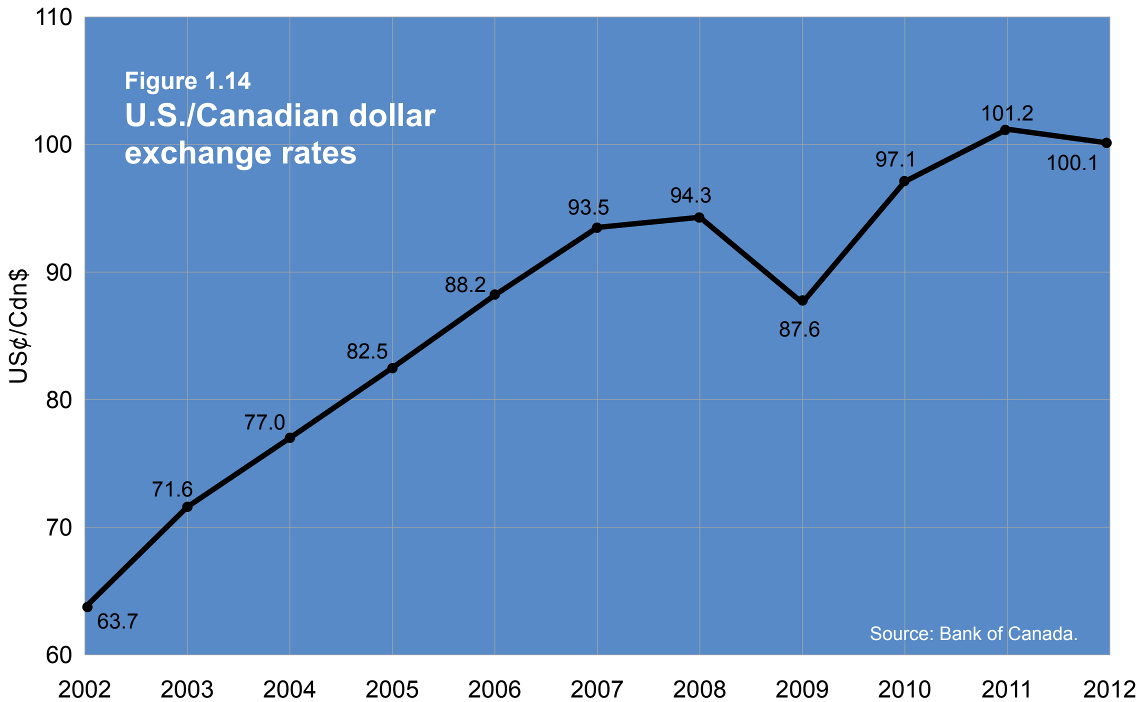
Figure 1.14 illustrates the historical performance of the U.S./Canadian dollar exchange rate between 2000 and 2012. The exchange rate is an economic parameter that affects both the Canadian and Alberta economies.

The U.S./Canadian dollar exchange rate averaged US\$1.00 in 2012, compared with US\$1.01 in 2011. The exchange rate began the year averaging US\$0.99 in January 2012 and averaged US\$1.01 in December 2012, exhibiting relative stability. The US/Canadian dollar exchange rate is projected to average US\$0.98 for the

Figure 1.13
Alberta and Canada economic indicators



Source: Statistics Canada.



remainder of the forecast period as the U.S. dollar is expected to strengthen compared with the Canadian dollar. Throughout 2012, the Bank of Canada kept the bank rate at 1.00 per cent. The Bank of Canada also expressed concern over Canadian household debt, which could trigger financial instability if interest rates were to rise, increasing the potential for personal bankruptcies and home foreclosures.

1.3.2 The Alberta Economy in 2012 and the Economic Outlook

The ERCB forecast of Alberta real GDP and other economic indicators is shown in **Table 1.3**. Alberta real GDP is estimated to have increased by 3.5 per cent in 2012, compared with 5.1 per cent in 2011. Real GDP is forecast to increase by 3.0 per cent in 2013 and to continue to grow at a trend of 3.0 per cent from 2014 to 2022 based on the expectation of strong hydrocarbon development and exports. Alberta's inflation rate was 1.1 per cent in 2012, compared with the national inflation rate of 1.5 per cent.

Table 1.3 Major Alberta economic indicators, 2012–2022 (per cent)

	2012	2013	2014–2022[a]
Real GDP growth	3.5	3.0	3.0
Population growth	2.5	2.0	1.7
Inflation rate	1.1	2.2	2.4
Unemployment rate	4.5	4.5	4.4

[a] Average over 2014–2022.

Economic growth is projected to slow in 2013 as oil and gas activity continues to recover from low prices and continued Canadian crude oil discounts. There were 8422 wells drilled in Alberta in 2012, compared with 9894 in 2011, a decrease of 1472 wells, or 15 per cent.

The ERCB estimates that oil sands capital expenditures decreased to $20.4 billion in 2012, compared with $22.7 billion in 2011. Investment is predicted to increase to $21.6 billion in 2013 and peak in 2015 at $23.4 billion. In 2012, some oil sands companies announced that they were cutting their capital budget spending and delaying the development of upcoming projects as a result of increased pressure from lower-cost conventional oil development in Canada and the United States.

Conventional oil and gas expenditures have rebounded significantly since the 2009 level of $12 billion and reached $25.8 billion in 2011 as activity in conventional basins has shifted to the application of capital-intensive horizontal wells and multistage fracturing to conventional oil and liquids-rich gas plays. Conventional oil and gas expenditures are estimated to decrease to $21.5 billion in 2012. As natural gas prices decreased, producers drilled fewer dry gas wells in Alberta. As a result, gas well connections were down by 51 per cent, lowering drilling costs in 2012. Alberta land sales also significantly declined from 2011 levels as companies cut back on their capital spending plans. Investment in conventional oil and gas is expected to increase over the forecast period as producers continue to use the more costly horizontal wells and multistage fracturing technology.

Figure 1.15 profiles the historical and projected investment in Alberta's conventional oil and gas industry and in the oil sands industry.[6] The sharp decline in 2009 was followed by an immediate rebound in 2010. This rebound in conventional oil and gas spending occurred in a relatively mature oil and gas basin in an environment of depressed gas prices. The continued application of horizontal wells combined with multistage fracturing technology is expected to maintain conventional oil and gas investment throughout the forecast period close to current levels.

The forecast of capital spending for oil sands is consistent with the ERCB's forecast for upgraded and nonupgraded bitumen production.

As shown in **Figure 1.15**, oil sands–related expenditures are projected to increase by the middle of the decade to meet the anticipated increases in upgraded and nonupgraded bitumen production. Combined with the recovery in conventional oil and gas expenditures, total oil and gas investment is projected to exceed the levels of capital spending experienced during the 2006–2008 peak.

During the forecast period, nonupgraded bitumen production is forecast to increase at an average annual rate of 7 per cent. Upgraded bitumen production is projected to increase at an average annual rate of 3 per cent. Virtually all of this crude bitumen production increase will leave the province, providing export-led economic growth for the province.

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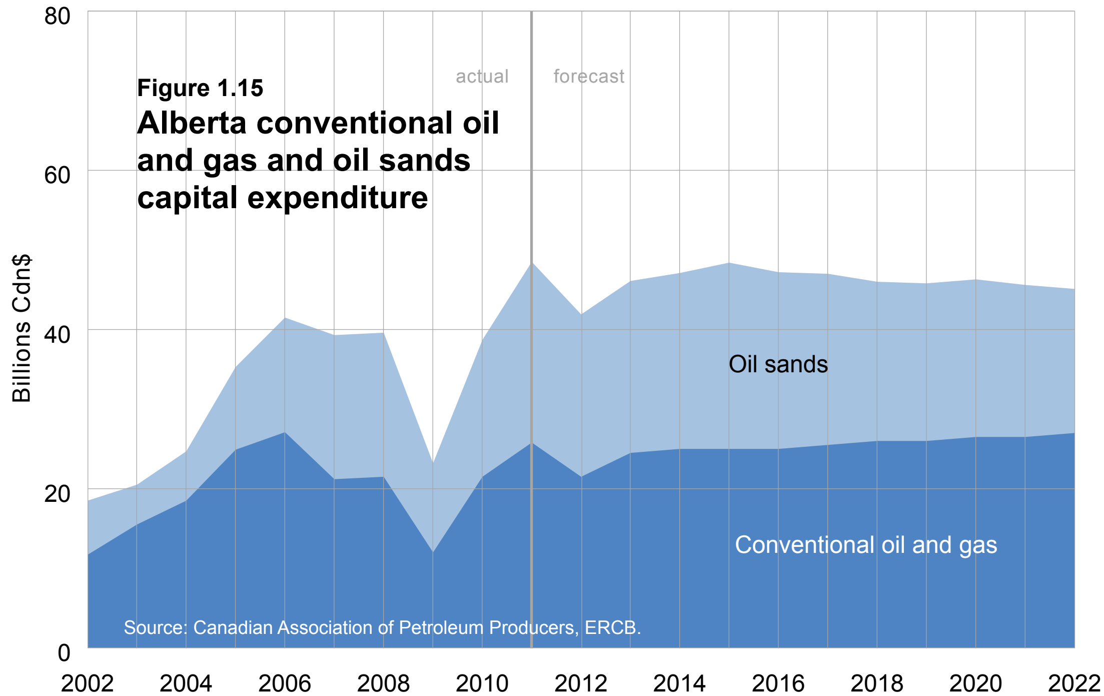
[6] Historical statistics obtained from the Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook* (2011 data). Capital expenditures for 2012 are estimates.

Figure 1.15
Alberta conventional oil and gas and oil sands capital expenditure



Source: Canadian Association of Petroleum Producers, ERCB.

The value of Alberta's energy resource production for 2009 to 2012 is depicted in **Figure 1.16**. In 2012, the total value of production decreased by 7 per cent relative to 2011. However, the total value of Alberta's energy resource production increased by 34 per cent relative to 2009 levels. The value of upgraded and nonupgraded bitumen production has significantly exceeded the value of natural gas production, a trend that is expected to continue throughout the forecast period. Since 2009, the value of upgraded and nonupgraded bitumen production has increased by 78 per cent, whereas the value of natural gas production has decreased by 50 per cent. In 2012, combined upgraded and nonupgraded bitumen revenues were greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur.

The total economic value of Alberta's energy resource production for 2012 to 2022 is shown in **Table 1.4**. Production from upgraded and nonupgraded bitumen derived from the oil sands will more than offset the decline in conventional resource production, increasing from 61 per cent of total revenues in 2012 to an average of 71 per cent of total annual revenues from 2015 to 2022.

Based on the projected price and production forecasts, investment in mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. In turn, Alberta's economic growth will continue to be a strong contributor to Canada's economic growth.

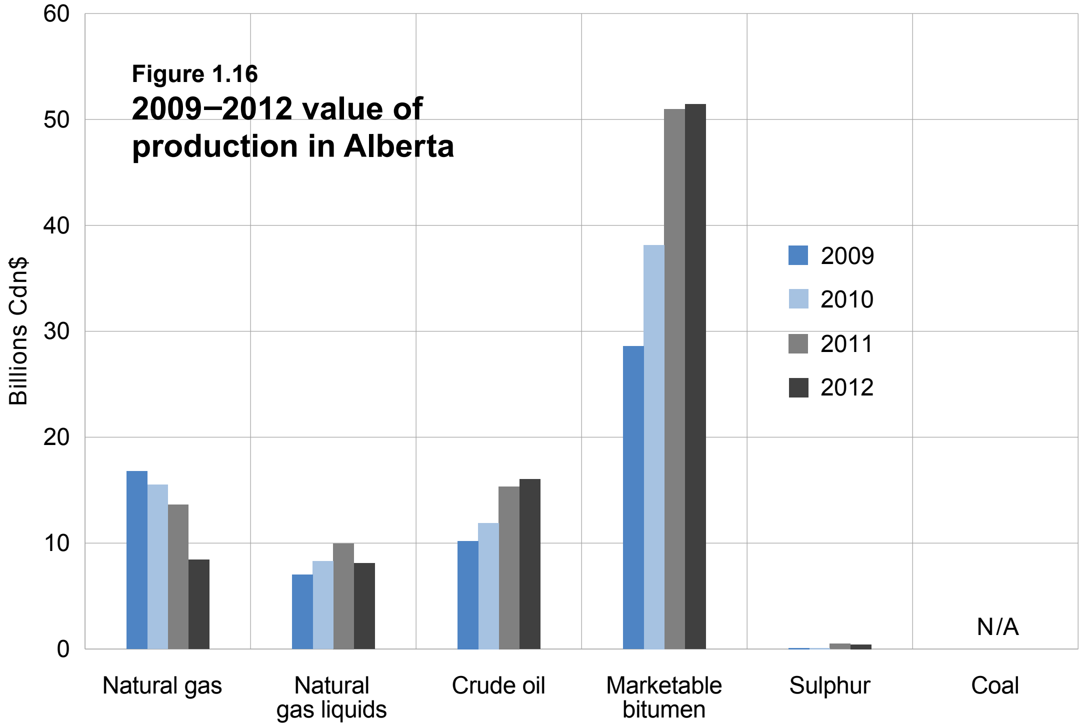


Figure 1.16
2009–2012 value of production in Alberta

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

	2012	2013[a]	2014[a]	2015–2022[a,b]
Conventional crude oil	16 020	16 367	17 487	17 399
Nonupgraded bitumen	20 882	24 334	28 514	53 844
Upgraded bitumen	30 554	31 280	35 721	46 314
Marketable gas	8 432	12 151	13 274	13 399
Natural gas liquids	8 105	8 319	8 718	9 133
Sulphur	435	285	287	291
Coal	n/a	n/a	n/a	n/a
Total	**84 427**	**92 737**	**104 003**	**140 380**

[a] Values calculated from the ERCB's annual average price and production forecasts; columns may not add up due to rounding.

[b] Annual average over 2015–2022.

HIGHLIGHTS

A discussion of the geological framework of the Western Canada Sedimentary Basin is included.

A discussion of Alberta's petroleum systems is included.

Alberta's shale- and siltstone-hosted hydrocarbons are discussed.

The methods the ERCB uses to estimate resources and determine reserves are given.

The reserves framework employed in the report is detailed.

2 RESOURCE ENDOWMENT

Of Alberta's many natural resources, this report focuses on energy resources—namely, petroleum hydrocarbons and coal. Resource appraisal is performed by the Energy Resources Conservation Board (ERCB) in the fulfillment of its legislated mandate.

The resource appraisal function includes geological survey, resource estimation, and reserve determination activities at the ERCB. These activities are done in a framework that provides consistent year-to-year comparisons of energy development in Alberta.

2.1 Geological Framework of Alberta[1]

2.1.1 Western Canada Sedimentary Basin

The overall stratigraphic sequence of Alberta consists of a northeast-thinning wedge of sedimentary rocks. This wedge comprises three thick packages of rock most simply described as a carbonate succession sandwiched between two clastic successions. These sedimentary strata lie overtop a crystalline basement of igneous and metamorphic rock of Precambrian age that forms the foundation of the modern North American continent.[2] The thickness of the sedimentary wedge tapers to zero in northeastern Alberta where the crystalline basement is exposed as part of the Canadian Shield.

The lower clastic succession is restricted to the Rocky Mountains. It is composed of thick metamorphic quartzite and slate rocks of Precambrian age and overlying sedimentary strata of Cambrian to Ordovician age. The middle carbonate succession is composed mainly of limestones, dolostones, and evaporites of Devonian to Mississippian age. The upper clastic succession is Triassic to Tertiary in age.

Both the middle carbonate and the upper clastic successions cover most of Alberta. Just beneath the modern land surface is a major unconformity that separates the youngest bedrock from gravels, thick glacial deposits, and modern alluvium.

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[1] The *Geological Atlas of the Western Canada Sedimentary Basin* contains a full description of Alberta's geological history and forms the basis for the summary in this section. The atlas is available through the ERCB's Alberta Geological Survey, a co-sponsor of the atlas.

[2] The crystalline basement is the North American craton (Laurentia) and is commonly referred to as the Precambrian Shield in western Canada. Laurentia was created almost 2 billion years ago by the amalgamation of older continents; some from Earth's original crust formed about 4 billion years ago.

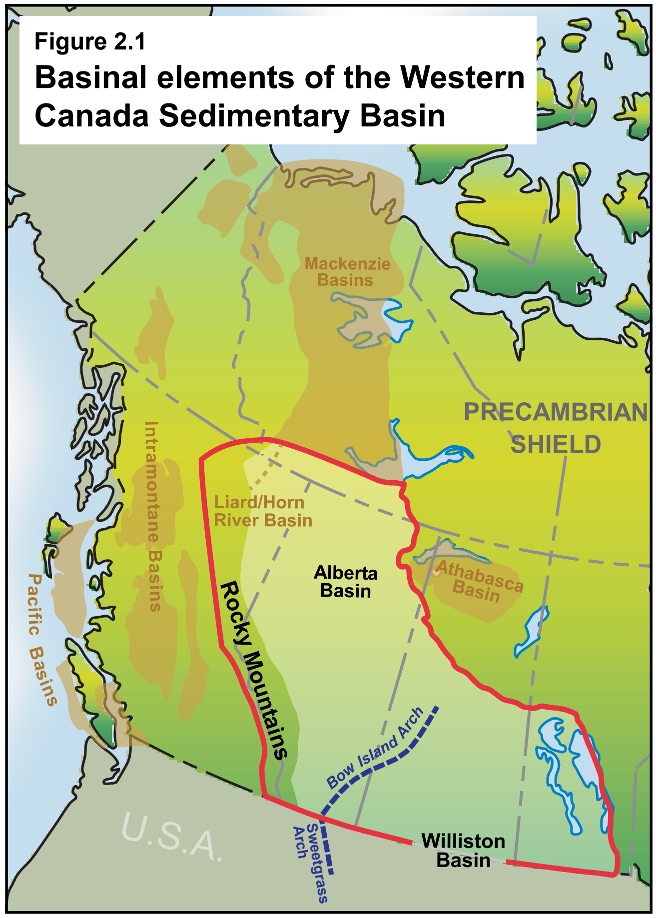


Figure 2.1
Basinal elements of the Western Canada Sedimentary Basin

The continental margin and structural trough that received sediments that comprise these three thick packages are collectively known as the Western Canada Sedimentary Basin (WCSB). The WCSB is often divided into regional basinal and sub-basinal elements including the Alberta Basin, the Williston Basin, and the Liard/Horn River Basin, as shown on **Figure 2.1**.

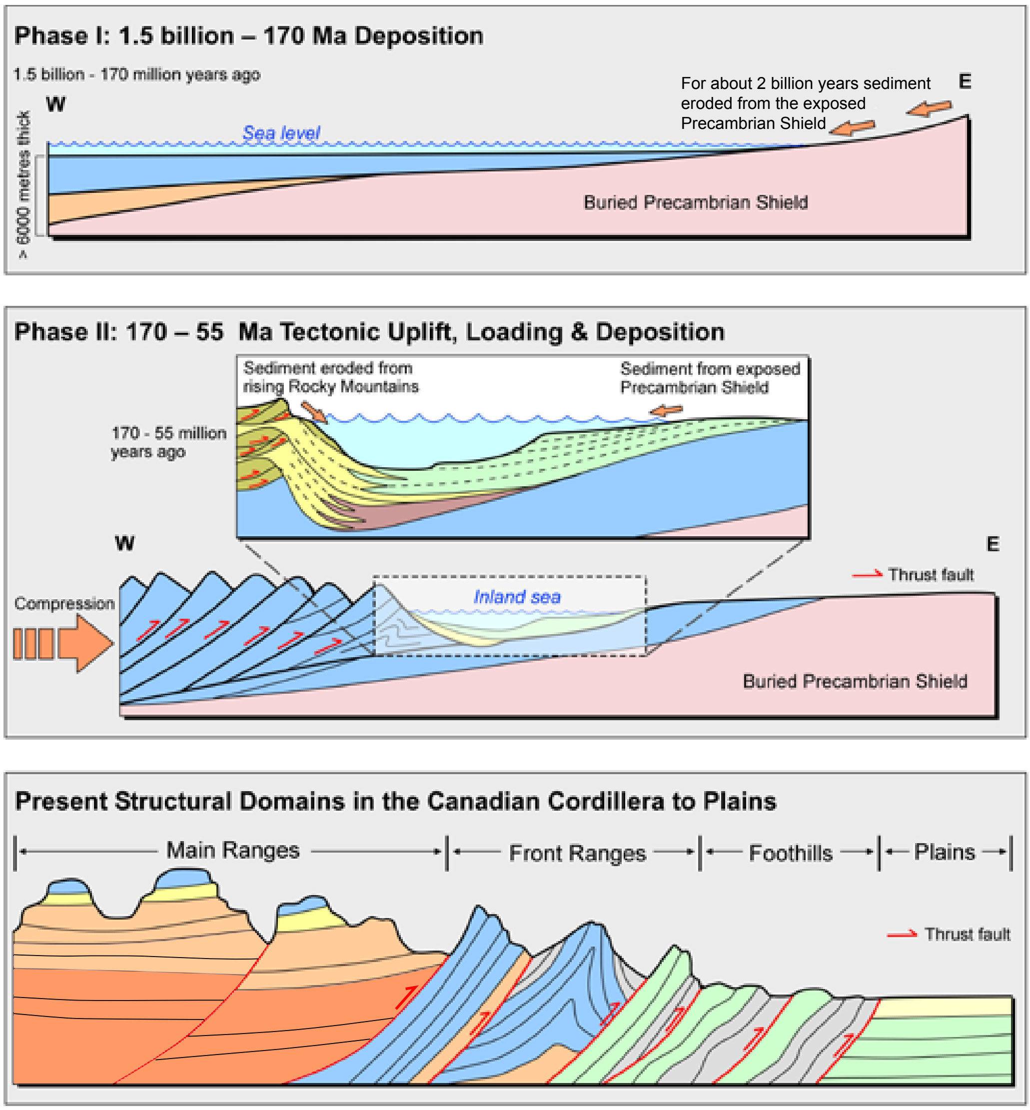
The geological origin and structure of Alberta's strata ultimately determine the type and extent of Alberta's energy resources. The overall geological history of Alberta falls into two main phases:

- Phase I lasted from 1.5 billion years ago to about 170 million years ago. It was characterized first by deposition in a shallow sea lying along the passive continental margin of the proto-Pacific ocean.[3] This was followed by deposition within a shallow, interior continental seaway. This seaway marked the formation of an intracratonic basin, formed indirectly in association with uplift and mountain building far to the southwest of Alberta. The lower clastic and middle carbonate successions were deposited during Phase I.
- Phase II started about 170 million years ago and continues to the present day. It is characterized by uplift and structural deformation, which formed the Rocky Mountains and mountain ranges farther west. Loading of the

[3] During phase I, the continental mass (Laurentia) alternated between being a separate continent and existing as part of larger "supercontinents."

mountains onto the crust caused the shallow seaway of Phase I to deepen into a depositional trough called a foreland basin. Sediments from the rising mountains were shed eastward into the basin, gradually filling it in and causing the seas to retreat. Uplift abated about 55 million years ago, and the Alberta basin has undergone erosion ever since, with the exception of deposition related to glacial advances and retreats over the last two million years. The upper clastic succession was deposited during Phase II. These events are shown in **Figure 2.2**.

Figure 2.2
Geologic evolution of Alberta



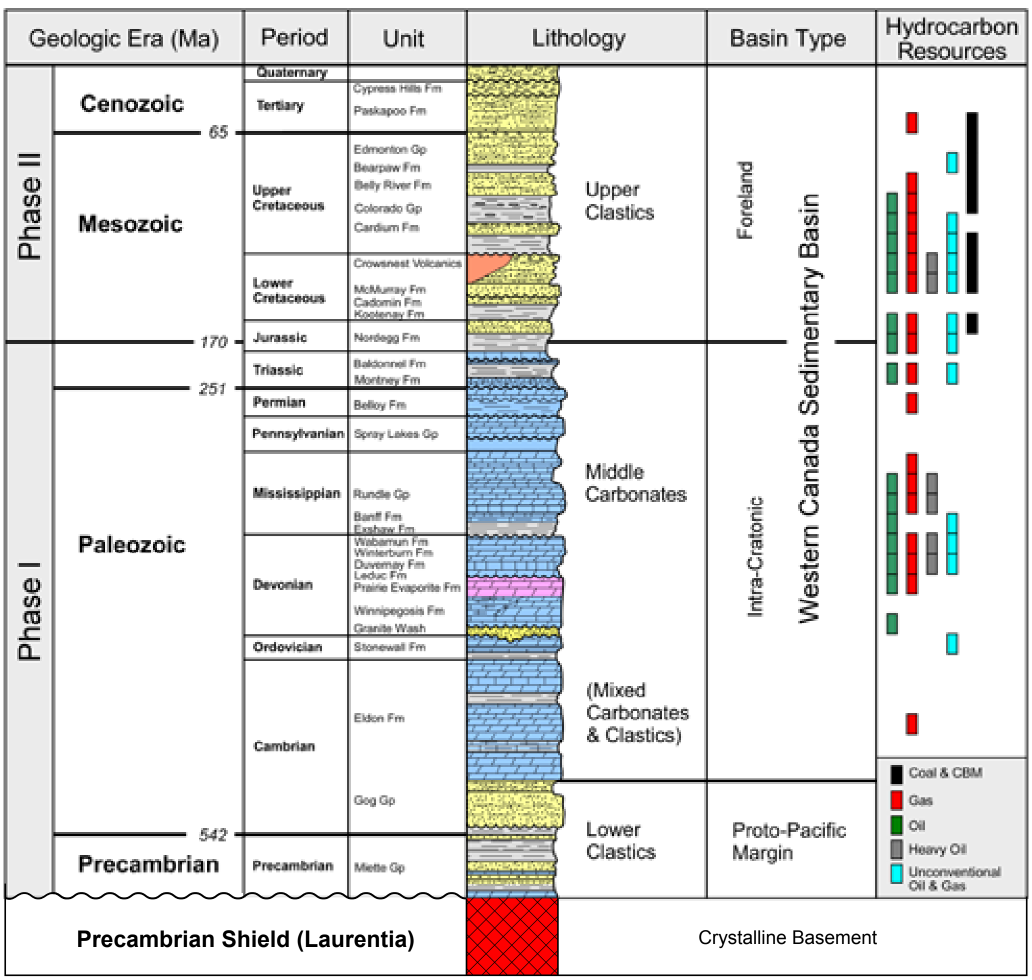
* Drawings not to scale.

The geological record of events in Phases I and II is preserved in the strata of the WCSB. A simplified version of Alberta's strata is shown in **Figure 2.3**. The stratigraphy is formalized in ERCB's Table of Formations. The Alberta Geological Survey of the ERCB has begun a multi-year major review of the Table of Formations to ensure that it is fully aligned with the most recent North American Stratigraphic Code, released in 2005.

2.1.2 Alberta's Petroleum Systems

Petroleum is a naturally occurring organic mixture consisting predominantly of chain and ring molecules of carbon and hydrogen, with varying amounts of sulphur, nitrogen, and oxygen as impurities. Petroleum forms underground by the action of heat and pressure over millions of years on buried organic matter that originated as dead algal, plankton, and plant remains. Rock units sufficiently rich in organic matter to generate petroleum during burial are called source rocks. After petroleum generation begins, the petroleum is driven from the source rock and migrates along permeable strata and fractures until it is trapped by favourable geological configurations of low-permeability rock or escapes to the surface.

Figure 2.3
Generalized stratigraphic column of Alberta



Not all of the petroleum generated in source rocks will migrate; much is left within the source beds themselves. Many of these source rocks are shales and are the targets for many recent unconventional plays. Coal beds are a special type of source rock in which the organic material content is well over 50 per cent of total rock mass. Coalbeds can produce substantial amounts of methane.

The linked assemblage of source rock, migration routes, and ultimate traps is called a petroleum system. The Alberta Basin component of the WCSB contains at least eight petroleum systems associated with the following major source rocks:

- Middle Devonian System—sourced by basinal marine laminites of the Keg River/Winnipegosis formations
- Upper Devonian System—sourced by basinal marine laminites of the Leduc-equivalent Duvernay and Cooking Lake–equivalent Majeau Lake formations
- Upper Devonian System—sourced by basinal laminites of the Cynthia Member of the Nisku Group
- Uppermost Devonian and lowermost Mississippian System—sourced by the basinwide marine mudstones of the Exshaw Formation[4]
- Middle Triassic System—sourced by the marine phosphatic siltstones at the base of the Doig Formation
- Lower Jurassic System—sourced by the marine lime muds of the Nordegg (Gordondale) Member of the Fernie Group
- Lower Cretaceous System—sourced by the continental coals and carbonaceous shales of the Mannville Group
- Upper Cretaceous System—sourced by the marine mudstones of the Colorado Group, principally the First and Second White Speckled Shales and the Fish Scales Zone

The Exshaw, Nordegg, and Duvernay source rocks are thought to have supplied most of the hydrocarbons in the Alberta Basin, and hydrocarbon accumulations within upper systems can be sourced from lower systems. For example, a likely source for the Lower Cretaceous crude bitumen deposits is the Lower Mississippian Exshaw Formation.

Conventional oil and gas pools are found throughout the middle carbonate and upper clastic successions. Little oil and gas is known to occur in the lower clastic succession, and the crystalline basement has none. Coals and coalbed methane (CBM) are found within the Jurassic-, Cretaceous-, and Tertiary-age portions of the upper clastic succession. Heavy oil pools and crude bitumen[5] deposits occur mostly in Cretaceous-age strata at the shallow updip edge of the Alberta Basin, near the contact of the sedimentary successions with the underlying

[4] The Exshaw Formation of the Alberta Basin is generally equivalent to the Bakken Formation found within the Williston Basin centered in North Dakota.

[5] Crude bitumen is extra heavy oil that in its natural state will not flow to a well. Most bitumen in Alberta has been formed by the biodegradation of lighter crude oils.

crystalline rocks of the Precambrian basement. There is also bitumen in the middle carbonate succession directly underneath.

In addition to these accumulations, there is widespread biogenic generation of methane in the shallow subsurface, mostly found in unconsolidated glacial deposits and shallow coal-bearing bedrock units. This gas is pervasive but does not occur in commercial quantities and sometimes is a geological hazard in shallow water wells in Alberta.

2.1.3 Energy Resource Occurrences – Plays, Deposits, and Pools

Estimates of potential volumes of hydrocarbon generation and migration can be quantified for petroleum systems through detailed basin analysis. Petroleum-system analyses are not generally performed at scales applicable to issues of resource conservation and industry regulation. Instead, each petroleum system can be subdivided into geological plays.

A geological play can be defined as a set of known or postulated oil and/or gas accumulations (pools and deposits[6]) within a petroleum system sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

It is common practice for industry to categorize exploration and development opportunities in terms of geological plays. The ERCB does not currently designate or otherwise formally declare geological plays. The ERCB does designate oil sands areas, coal fields, oil and gas pools and fields, and strike areas. These constructs were originally congruous with geological plays, but some have devolved into administrative entities as more geological plays became recognized within and across their boundaries. The ERCB is considering designating play areas where unconventional resource development is expected to take place.

The ERCB has begun assembling a catalogue of geological plays in Alberta from various past studies and summarizing Alberta's energy resources and reserves in a geological-play context.

2.2 Resource Endowment of Alberta's Energy Resources

Alberta has access to a treasure trove of energy resources: coal, bitumen, and conventional and unconventional oil and gas. Coal seams underlie nearly half of Alberta and have been commercially developed for nearly 150 years by several thousand small, and several dozen large, surface and underground mines. Recently, natural gas from some of those coal seams, known as coalbed methane or CBM, has begun to be recovered, and the full extent of development potential is still unknown. Other ways of exploiting Alberta's vast coal resources (the largest in Canada), such as through in situ gasification or remote mining, hold out the potential for additional future development.

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[6] In general, pools are discrete accumulations of hydrocarbons, whereas deposits are widespread continuous accumulations of hydrocarbons and coal. Pools also can be commingled into larger administrative units.

The ERCB has conducted numerous assessments of the extent of Alberta's oil sands. Consequently the ERCB is confident that there are approximately two trillion barrels of crude bitumen in place. It forms one of the very largest known petroleum accumulations in the world, ranking with the Middle East, Venezuela, Russia, and the United States. While only a relatively small portion (less than ten per cent) is known to be recoverable with current technology and anticipated economics, this figure is large enough to assure a source of production for many decades into the future. Additionally, should other portions of the oil sands prove commercial, as seems reasonable given the history of worldwide resource extraction, bitumen production could occur for a long period of time.

Conventional oil and gas have been produced for more than 100 years and, after the discovery of oil at Leduc in 1947, has been extensively developed, adding substantial wealth to the province. The WCSB is predominately a gas-prone basin with commercial quantities of natural gas having been found throughout almost the entire province. Oil pools are also widely distributed throughout the province but tend to be in several large clusters. Alberta produces almost three-quarters of Canada's natural gas and almost half of Canada's oil.

As the conventional production of oil and gas continues to decline, "unconventional" recovery methods and the exploitation of "unconventional" reservoirs are on the rise. Reserves and production of crude oil have increased in the last several years, breaking a trend of decades of decline. Natural gas reserves and production continue to decline, but an increasingly higher percentage comes from unconventional sources.

Adding to this resource legacy is a new study demonstrating that shale gas and other hydrocarbons are significant in Alberta and could potentially be developed for many decades to come.

2.2.1 Shale Hydrocarbons

In 2012, the ERCB released the report *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential* (ERCB/AGS Open File Report 2012-06). The report provides baseline data, information, and understanding of the geology, distribution, reservoir characteristics, and hydrocarbon resource potential of key shale and siltstone units in Alberta.

Initially, the study focused on shale gas in the formations for which industry had shown interest. Later it was determined that many of the formations analyzed also contained a significant amount of natural gas liquids and oil. Therefore, the study was expanded to include all shale- and siltstone-hosted hydrocarbons.

Hydrocarbons hosted in conventional reservoirs were not included in the evaluation. In cases where conventional, tight (low permeability), and shale resources were present in a rock formation, only the shale- and siltstone-hosted hydrocarbons were evaluated

In the report, natural gas refers to methane (C_1), natural gas liquids refer to C_2 to C_6 hydrocarbons, and oil refers to C_7 and larger hydrocarbons.

Five units showing immediate potential in Alberta were included in the study: the Duvernay Formation, the Muskwa Formation, the Montney Formation, the Nordegg Member, and the basal Banff and Exshaw formations (sometimes referred to as the Alberta Bakken by industry). Strictly speaking, the Montney Formation is not a "shale" target. In Alberta, the Montney Formation is dominated by siltstone and is included here because it is a target for unconventional resource development. The study also included an assessment of the Wilrich Formation. The assessments of the basal Banff/Exshaw, north Nordegg, and Wilrich are considered preliminary.

In addition, preliminary work without resource evaluation was done for the Rierdon Formation, the Colorado Group (and equivalent strata of the Smoky and Fort St. John groups), other Fernie Formation units, and the Bantry Shale member.

The study concluded that shale- and siltstone-hosted hydrocarbon resources are very large and present a very important potential energy supply for Alberta and the world. The results demonstrate the size and distribution of shale gas resources in Alberta and may be used to assist in the planning of resource development and environmental stewardship.

Table 2.1 summarizes the study's estimates of Alberta's shale- and siltstone-hosted hydrocarbon resource endowment for the six investigated units for which available data allowed at least a preliminary determination. The values represent the medium estimate (P_{50}) along with the P_{90} to P_{10} range of resource estimates for natural gas, natural gas liquids, and oil. The P_{50} value is considered to be the best estimate because it minimizes the expected variance from the unknown true value. The range of uncertainty is summarized by the P_{90} (low estimate) and P_{10} (high estimate) values.

The United States, arguably the world leader in the development of shale-hosted hydrocarbons, may contain up to 750 trillion cubic feet (Tcf) of technically recoverable gas and 24 billion barrels of technically recoverable oil.[7]

However, the resource estimates in **Table 2.1** must not be confused with recoverable reserves. Recoverable reserves for shales resources are generally determined after drilling and completing a well. Typically, recoverable reserves form a small percentage of unconventional resources, perhaps less than 5 per cent of the resource estimate. If as little as 1 per cent of the total natural gas estimate (3424 Tcf) from **Table 2.1** were to become recoverable by industry through drilling and completion, then Alberta will have added more than 34 Tcf to its reserve endowment. To put this in perspective, Alberta produced 3.3 Tcf of gas during 2012 and had approximately 36 Tcf of remaining established natural gas reserves at the end of 2012.

Geological and reservoir engineering constraints, recovery factors, and additional economic factors, as well as social and environmental considerations, will ultimately determine the potential recovery of this large resource.

Maps of the distribution of the P_{50} hydrocarbon resources in each formation can be found in **Appendix F**. More discussion on Alberta's shale gas resources is given in **Section 5.1.5**.

[7] U.S. Department of Energy, 2011.

Table 2.1 Summary of estimates of Alberta shale- and siltstone-hosted hydrocarbon resource endowment[a]

Formation	Average Adsorbed Gas Content (per cent)	Natural Gas (10^9 m^3)	Natural Gas Liquids (10^6 m^3)	Crude Oil (10^6 m^3)
Duvernay	6.8 (5.6–8.5)	12 479 (9 934–15 219)	1 798 (1 190–2 589)	9 803 (7 004–13 172)
Muskwa	6.9 (4.1–10.5)	11 812 (8 132–14 839)	2 350 (949–4 181)	18 296 (11 884–25 412)
Montney	17.7 (10.8–26.0)	60 095 (45 917–79 684)	4 583 (1 852–8 631)	21 653 (12 496–35 035)
Banff/Exshaw[b]	5.7 (3.2–10.0)	993 (446–1 975)	15 (5–35)	3 946 (1 426–7 143)
Nordegg[b]	18.2 (4.6–34.8)	4 164 (1 968–7 905)	228 (77–555)	6 011 (3 161–10 550)
Wilrich[b]	33.7 (6.2–59.2)	6 918 (3 237–16 007)	327 (109–707)	7 611 (3 206–27 380)
Total		**96 461** **(3 406 Tcf)**	**9 301** **(58.6 10^9 bbls)**	**67 320** **(423.6 10^9 bbls)**

[a] The medium estimate (P_{50}) with low (P_{90}) and high (P_{10}) estimates below is shown. Data and interpretations were subjected to geostatistical analysis to provide a probabilistic resource evaluation, indicating P_{10}, P_{50}, and P_{90} confidence results of initial petroleum-in-place.

[b] Estimates based on preliminary data.

2.3 Resource Appraisal Methodologies

The ERCB uses the term "resource appraisal" to encompass all aspects of quantifying Alberta's in-place resources and recoverable reserves. To add clarity to the major components of resource appraisal, this report uses the phrase "resource estimation" to describe activities related to quantifying the amount of energy resources in the ground and the phrase "reserves determination" to describe activities related to quantifying the recoverable portion of these in-place resources (i.e., the established reserves).

2.3.1 Resource Estimation

The ERCB generates its own resource estimates. The in-place resources estimation process starts with the receipt by the ERCB of raw data submitted by energy resource industries, either as required by legislation or through regulatory applications or submissions, the vast majority of which is well or borehole data. ERCB geological staff use pertinent data such as geophysical well logs, cores and drill cuttings, core analysis, and well test data (such as pressure), together with industry or academic information such as reports, seismic data, or regional studies, to estimate petrophysical information and various geological surfaces and zones. These geological and petrophysical evaluations are used for both regulatory and resource appraisal purposes. Several techniques, including geostatistics, are used in generating a volumetric estimate of in-place resources for the various energy resources. As the ERCB's play catalogue is compiled, resource estimates for each play will be reported.

2.3.2 Reserves Determination

The ERCB determines two types of estimates of the recoverable portion of Alberta's in-place resources. The portion determined recoverable from known accumulations or deposits using today's technology is classified as "established reserves." The portion determined from known and unknown resources using reasonably foreseeable technology is classified as the "ultimate potential." Established reserves are determined on an ongoing basis, whereas ultimate potentials usually result from major studies conducted periodically. These terms are defined in a following section.

In determining the established reserves of an energy resource, consideration is given to geology, pressures, production, technology, and economics. Geological factors are mainly considered when estimating in-place quantities. However, additional considerations are usually required to reduce the in-place quantity to a more likely developable quantity and to assure the existence and extent of the recoverable portion.

Alberta's production of oil and gas has predominantly come from conventional pools in which hydrocarbons have accumulated in concentrated quantities in porous and permeable reservoirs drainable by vertical wells. The ERCB determines reserves of conventional pools through accepted practice of geology-based volumetric estimation, production decline analysis, and material balance methodology.

Initially there is a higher level of uncertainty in the reserves estimates, but this level decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. Analysis of production decline data is a primary method of determining recoverable reserves. It also provides a realistic estimation of the pool's recovery efficiency when it is combined with a volumetric or a material balance estimate of the in-place resource.

The determination of reserves in deposits is similar to the methods used to determine pool reserves. One or more factors are applied against an in-place volume or tonnage to determine the recoverable portion of the resource. These reserves are often estimated by three-dimensional geological models that routinely involve the data from hundreds or thousands of wells and drillholes.

2.3.3 Ultimate Potential

Ultimate potential estimates represent recoverable quantities. They are determined for each energy resource commodity over the entire province on the basis of a future end-of-the-day timescale. These estimates are the result of considering all development of an energy resource up to the time of the estimate and looking forward to cessation of exploration activity and the type of technology that might reasonably be expected to be used in the future. Future-based economic circumstances are also considered. These estimates form a reasonable and credible basis for longer term production forecasts and government policy decisions regarding energy resources.

2.4 Resources and Reserves Classification System

The ERCB reports the reserves of Alberta by commodity (crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal) based on the Inter-Provincial Advisory Committee on Energy (IPACE) system for uniform terminology and definitions in the estimating and publishing of hydrocarbon reserves information in Canada. The IPACE system was adopted by most government and national bodies for the use of reserves reporting in Canada in 1978 and has been in use since that time. The IPACE system was designed as a simple categorization of reserves to facilitate understanding and transparency in reporting to the public. The key reserves definitions in the IPACE system are as follows:

- Initial volume in-place—the gross volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
- Established reserves—those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
- Initial established reserves—established reserves prior to the deduction of any production.
- Remaining established reserves—initial established reserves less cumulative production.
- Ultimate potential—an estimate of the initial established reserves which will have become 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.

The IPACE system was designed, and is most appropriate, for use with conventional oil and gas resources. Consequently, the ERCB has introduced alterations to the IPACE system to make it compatible for all energy resources, including coal. More recently, alterations have also been applied to unconventional resources, such as crude bitumen, to more fully report the resource endowment of Alberta.

Since 1978, and particularly since 1997, the mineral and petroleum industries have strived for tighter definitions of reserves to better suit the financial markets. These efforts include the promulgation of National Instrument (NI) 51-101 in 2003 for petroleum reserve reporting to Canadian securities regulators, the creation of and updates to the *Canadian Oil and Gas Evaluation Handbook* (COGEH),[8] the Petroleum Resources Management System (PRMS),[9] the "United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009" (UNFC-2009), and NI 43-101[10] for Canadian minerals (including coal) securities reporting. These efforts are under review by the ERCB, and a decision to either maintain or modify the IPACE system, or to adopt one or more of these newer frameworks, will be considered in the future.

[8] The COGEH was prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the then Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (now part of the Society of Petroleum Engineers). COGEH forms the technical basis of NI 51-101.

[9] The PRMS was prepared by the Society of Petroleum Engineers and reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

[10] The technical basis of NI 43-101 is the "CIM Definition Standards on Mineral Resources and Mineral Reserves," prepared by the Canadian Institute of Mining, Metallurgy and Petroleum, known as CIM. This standard is itself based other international standards that have now been coalesced as the "International Template for Reporting of Exploration Results, Mineral Resources and Mineral Reserves," prepared by the Committee for Mineral Reserves International Reporting Standards, know as CRIRSCO.

HIGHLIGHTS

Total bitumen production increased by 10 per cent, mineable production increased by 4 per cent, and in situ production increased by 17 per cent.

Upgraded bitumen production increased by 4 per cent.

3 CRUDE BITUMEN

Crude bitumen is extra heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern Alberta. The crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes, the geological formations and the geographic areas containing the bitumen are designated as oil sands areas (OSAs). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated OSAs in Alberta are shown in **Figure R3.1**. Combined, they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Contained within the OSAs are 15 oil sands deposits designated according to the specific geological zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are approximately 50 km (30 miles) apart.

Depending on the depth of the deposit, one of two methods is used to recover bitumen. North of Fort McMurray, crude bitumen occurs near the surface and can be recovered economically by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted from the mined material in large facilities using hot water. At greater depths, where it is not economical to recover the bitumen by mining, in situ methods are employed. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development. Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are the two main methods of enhanced development whereby the reservoir is heated to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore.

3.1 Reserves of Crude Bitumen

3.1.1 Provincial Summary

The ERCB continually updates Alberta's crude bitumen resources and reserves on both a project and deposit basis. The remaining established reserves at December 31, 2012, are 26.68 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to 0.12 10^9 m^3 of production. Of the total 26.68 10^9 m^3 remaining

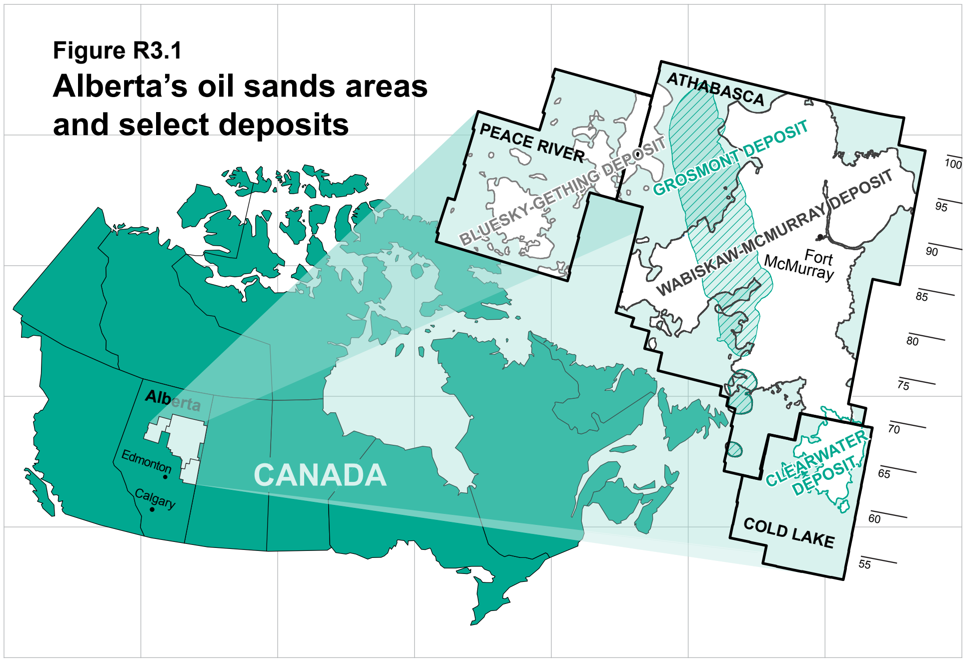


Figure R3.1
Alberta's oil sands areas and select deposits

established reserves, 21.40 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods, while the remaining 5.28 10^9 m^3 is recoverable by surface mining methods. Of the in situ and mineable totals, 4.11 10^9 m^3 is the remaining established reserve within active development areas. **Table R3.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative and annual production for 2012 are shown in **Table R3.2**. Crude bitumen production in 2012 totalled 112 10^6 m^3, with in situ operations contributing 58 10^6 m^3.

The remaining established reserves in active development areas are presented in **Figure R3.2**. These project reserves have a stair-step configuration representing start-up of new large mining projects. The intervening years between additions are characterized by a slow decline due to annual production.

Table R3.1 In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.87	5.28	3.69
In situ	272.3	21.94	0.53	21.40	0.42
Total	**293.1**	**28.09** [a]	**1.40**	**26.68**[a]	**4.11**
	(1 845)[b]	(176.8)[b]	(8.8)[b]	(167.9)[b]	(25.9)[b]

[a] Any discrepancies are due to rounding.

[b] Imperial equivalent in billions of barrels.

Table R3.2 Reserve and production change highlights (10^6 m^3)

	2012	2011	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total[a]	**28 092**	**28 092**	**0**
	(176 780)[b]	(176 780)[b]	
Cumulative production			
Mineable	874	820	+54[c]
In situ	532	474	+58[c]
Total[a]	**1 406**	**1 294**	**+112[c]**
Remaining established reserves			
Mineable	5 283	5 337	-54
In situ	21 403	21 461	-58
Total[a]	**26 686**	**26 798**	**-112**
	(167 932)[b]	(168 637)[b]	
Annual production			
Mineable	54	52	+2
In situ	58	49	+9
Total[a]	**112**	**101**	**+11**

[a] Any discrepancies are due to rounding.

[b] Imperial equivalent in millions of barrels.

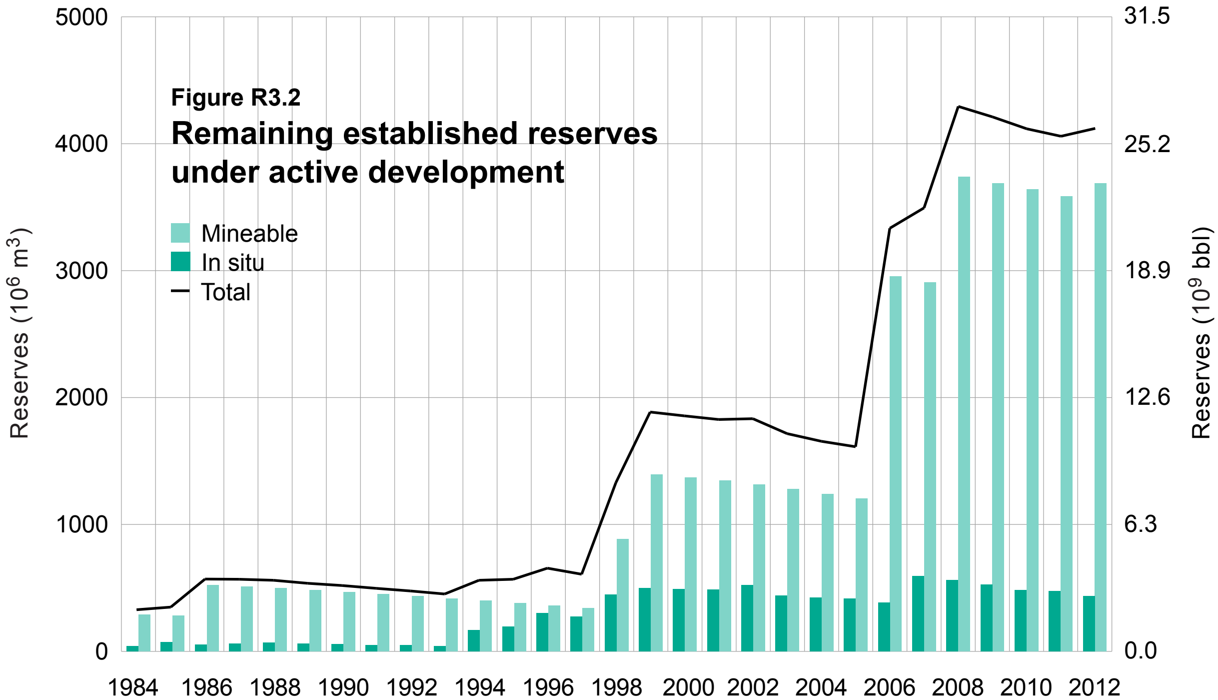
[c] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

3.1.2 Initial In-Place Volumes of Crude Bitumen

Efforts to update the province's crude bitumen resources and reserves began in 2003, and since then 11 of the 15 deposits have been updated. The Athabasca Wabiskaw-McMurray deposit, with the largest cumulative and annual production, was updated for year-end 2004 and subsequently revised in 2009 to take new drilling into account. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005. The northern portion of the Cold Lake Wabiskaw-McMurray deposit was also updated for year-end 2005. The Peace River Bluesky-Gething deposit was updated for year-end 2006.

In 2009, the ERCB completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit. The Athabasca Upper, Middle, and Lower Grand Rapids deposits and the Athabasca Nisku deposit were reassessed for year-end 2011. Bitumen pay thickness maps for these deposits are presented in **Appendix E**. Also included in **Appendix E** are two structure contour maps of the sub-Cretaceous unconformity. One is a regional map covering all the OSAs, the other is a map detailing the Cold Lake OSA.

Recently, industry has been actively exploring the Leduc Formation for potential bitumen resources west of Fort McMurray. Preliminary results indicate bitumen pay thickness may exceed 100 m.



The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation decreases as the shale or clay content within the reservoir increases or as the porosity decreases. The relative amount of bitumen is expressed as mass per cent in clastics (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water). In carbonates, the relative amount of bitumen is expressed as bitumen saturation (the percentage of the volume of pore space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 mfor in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. The Athabasca Wabiskaw-McMurray; Athabasca Upper, Middle, and Lower Grand Rapids; Cold Lake Clearwater; Cold Lake Upper and Lower Grand Rapids; and the Peace River Bluesky-Gething deposits, as well as a portion of the Cold Lake Wabiskaw-McMurray deposit, were estimated using a 6 mass per cent saturation cutoff.

The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. In the revision of the Athabasca Grosmont and Nisku deposits, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values.

The ERCB believes that in measuring the quality of an oil sands area, cutoffs of 6 mass per cent for clastic bitumen deposits, and a pore volume of 50 per cent and porosity of 8 per cent for carbonate bitumen deposits, more accurately reflect the volumes from which bitumen can reasonably be expected to be recovered.

Within the Athabasca OSA is the ERCB-defined surface mineable area (SMA). It encompasses an area of 51½ townships north of Fort McMurray, covering the part of the Athabasca Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. Given the thinner overburden, it is presumed that the main recovery method will be surface mining. Outside of the SMA, in the designated OSAs, in situ technology is the only viable recovery mechanism to date.

The defined boundaries of the SMA are simply for resource administration purposes and carry no regulatory authority. While the ERCB has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment purposes, surface mining may not actually take place, possibly reducing the estimate of mineable reserves. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resource occurs at a depth of less than 25 m of overburden. Since the boundaries of the SMA are defined using the boundaries of townships, a few areas of deeper bitumen resources more amenable to in situ recovery are included (i.e., the extent of the SMA covers both mineable and in situ resources). Estimates of mineable bitumen exclude those volumes within the SMA that are beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA, as well as deeper areas, generally greater than 65 m, within the SMA.

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Appendix B** (**Tables B.1** and **B.2)** and are summarized by formation in **Table R3.3**.

The in-place resource values in **Table R3.3** represent the total crude bitumen accumulated throughout the deposit where the cumulative thickness is equal to or greater than 1.5 m; however, current and anticipated recovery operations often only develop the better-quality portion of this total. This developable portion (also known as mineable and exploitable) varies depending on the type of recovery technology employed. Recovery factors are normally applied against this developable portion to determine the established reserves. The parameters used to reduce the total in-place volumes to a developable subset are given in **Section 3.1.3**.

3.1.3 Established Reserves

There are two types of established reserves of crude bitumen: mineable reserves that are anticipated to be recovered by surface mining operations and in situ reserves that are anticipated to be recovered through wellbores using in situ recovery methods.

3.1.3.1 Surface-Mineable Crude Bitumen Reserves

With the 2008 expansion of the SMA and the subsequent updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the ERCB now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resource at depths most suitable to mining technologies, generally less than 65 m. For year-end 2008, economic criteria were applied to potentially mineable areas in the total in-place portion of the SMA. Economic strip ratio (ESR) criteria, along with a minimum saturation cutoff of 7 mass per cent bitumen

Table R3.3 Initial in-place volumes of crude bitumen as of December 31, 2012

Oil sands area / Oil sands deposit	Initial volume in place (10^6 m^3)	Area (10^3 ha*)	Average pay thickness (m)	Average reservoir parameters: Mass (%)	Pore volume oil (%)	Average porosity (%)
Athabasca						
Upper Grand Rapids	5 817	359	8.5	9.2	58	33
Middle Grand Rapids	2 171	183	6.8	8.4	55	32
Lower Grand Rapids	1 286	134	5.6	8.3	52	33
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	16 232	819	14.4	5.7	68	20
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	**242 475**					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	**29 090**					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**293 125**					

* ha = hectare.

and a minimum saturated interval thickness cutoff of 3.0 m, were applied. The ESR criteria are fully explained in Appendix III of *ERCB Report 79-H: Alsands Fort McMurray Project*. This method reduced the total initial mineable bitumen in-place resource of 20.8 10^9 m^3 to an initial mineable bitumen in-place resource of 10.3 10^9 m^3 as of December 31, 2008.

Factors were then applied to the initial mineable volume in place to determine the established reserves. A series of reduction factors were applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume; therefore, each factor is set at 90 per cent. A combined mining and extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserves of crude bitumen is 6.16 10^9 m^3. As of December 31, 2012, the remaining established mineable crude bitumen reserve has decreased from 5.34 10^9 m^3 year-end 2011 to 5.28 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2012, are presented in **Table R3.4**. At the end of 2012, almost three quarters of the initial established reserves were under active development. Currently, Canadian Natural Resources Limited (CNRL Horizon), Shell Canada Energy Limited (Shell Muskeg River and Shell Jackpine), Suncor Energy Inc. (Suncor), and Syncrude Canada Ltd. (Syncrude) are the only producers in the SMA, with a combined cumulative bitumen production of 874 10^6 m^3. The Fort Hills (owned by Suncor, Total E&P Canada Ltd. [Total], and Teck Resources Ltd. [Teck]) and Imperial Oil/ExxonMobil Kearl projects are not yet producing bitumen but are considered to be under active development and are included in **Table R3.4**. Total's Joslyn North mine project was added to **Table R3.4** for 2012 as it was approved in 2010 and activity has begun at the site. The ERCB has adjusted the initial mineable volume in place and the initial established reserves for the Fort Hills mine based on recent drilling information and changes to the project area. In 2012, a hearing on the Shell Jackpine Expansion Mine project was held before a joint ERCB/federal panel and a decision is pending. Mine project applications currently under review are Shell Pierre River and Teck Frontier.

Production from the five current surface mining operations amounted to 53.78 10^6 m^3 in 2012, with 19.28 10^6 m^3 from the Syncrude project, 15.48 10^6 m^3 from the Suncor project, 7.45 10^6 m^3 from the Shell Muskeg River project, 5.58 10^6 m^3 from the Shell Jackpine project, and 5.98 10^6 m^3 from the CNRL Horizon project.

3.1.3.2 In Situ Crude Bitumen Reserves

The ERCB has determined an in situ initial established reserve for those areas considered suitable for in situ recovery methods. Reserves are estimated using cutoffs appropriate to the type of development and differences in reservoir characteristics. For each oil sands deposit with commercial development, the areas with potential for

Table R3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2012

Development	Project area[a] (ha)	Initial mineable volume in place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
CNRL Horizon	28 482	834	537	19	518
Fort Hills	17 864	556	382	0	382
Imperial/Exxon Kearl	19 674	1 324	872	0	872
Shell Muskeg River	13 581	672	419	78	341
Shell Jackpine	7 958	361	222	12	210
Suncor	19 155	990	687	315	372
Syncrude	44 037	2 071	1 306	449	857
Total Joslyn North	8 604	274	139	0	139
Total	**159 355**	**7 100**	**4 564**	**874**	**3 690**

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

thermal development were determined using a minimum continuous zone thickness of 10.0 m. For deposits with primary development, a minimum continuous zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. While some reserve estimates have been updated using a minimum saturation cutoff of 6 mass per cent bitumen, much of the current data is still based on the 3 mass per cent bitumen cutoff for most deposits. Future reserve estimates will be based on values higher than 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to areas that met the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the recovery factors for projects under active development to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer-quality resource areas.

The volume of the in-place crude bitumen was reassessed in the Athabasca Grosmont deposit in 2009 and the Athabasca Nisku and Upper, Middle, and Lower Grand Rapids deposits in 2011. No reserves were estimated as there are no commercial projects currently operating within these deposits. Exploration has occurred and different recovery methods have been experimented with, but commercial operations have yet to be established. The ERCB estimates reserves only in deposits where commercial operations are in place.

In 2012, the in situ bitumen produced was 57.72 10^6 m^3, an increase from 49.20 10^6 m^3 in 2011. Cumulative production within in situ areas now totals 532.1 10^6 m^3, of which 343.1 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.46 10^9 m^3 in 2011 to 21.40 10^9 m^3 in 2012 due to production of 0.06 10^9 m^3.

The ERCB's 2012 estimate of the established in situ crude bitumen reserves under active development is shown in **Table R3.5**. Information on experimental schemes has been removed from the table due to the limited number of experimental schemes and the confidential nature of the associated production data.

The ERCB has assigned initial volumes in place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is also shown for all commercial projects and primary recovery schemes within a given oil sands deposit and area. Initial established reserves under primary development are based on a 5 per cent average recovery factor. In Peace River, however, a 10 per cent recovery factor, based on production, is used. Primary schemes in Athabasca undergoing enhanced recovery by polymer injection or waterflooding have an additional 10 per cent recovery factor applied. The application of various steaming strategies and project designs are reflected in the recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake OSAs, respectively.

The remaining established reserves of crude bitumen within active in situ project areas is estimated to be 418.6 10^6 m^3, a decrease from 2011's 476.4 10^6 m^3 due to production.

3.1.4 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ methods is estimated to be 33 10^9 m^3 from Cretaceous clastic sediments and 6 10^9 m^3 from Paleozoic carbonate sediments. Nearly 11 10^9 m^3 of bitumen was

Table R3.5 In situ crude bitumen reserves[a] in areas under active development as of December 31, 2012

Development	Initial volume in place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	63.7	40	25.5	11.5	14.0
Primary recovery schemes	160.8	10	16.1	14.8	1.3
Subtotal[c]	**224.5**		**41.6**	**26.3**	**15.3**
Athabasca Oil Sands Area					
Thermal commercial projects	391.8	50	195.9	116.5	79.3
Primary recovery schemes	1 026.2	5	51.3	24.1	27.2
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	22.3	6.6
Subtotal[c]	**1 418.0**		**276.1**	**162.9**	**113.4**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	241.2	62.0
Thermal commercial (SAGD)[g]	33.8	50	16.9	3.5	13.4
Primary recovery schemes	6 257.5	5	312.9	98.0	214.9
Subtotal[c]	**7 504.1**		**633.0**	**342.7**	**290.3**
Total[c]	**9 146.6**		**950.7**	**531.9**	**418.6**

[a] Thermal reserves are reported only for lands on which thermal recovery is approved and drilling development has occurred.

[b] Includes amendments to production reports.

[c] Any discrepancies are due to rounding.

[d] Schemes currently on polymer injection or waterflooding in the Brintnell-Pelican area. Previous primary production is included under primary recovery schemes.

[e] The in-place number is that part of the initial volume in place for primary recovery schemes that will see incremental production due to polymer injection or waterflooding.

[f] Cyclic steam stimulation projects.

[g] Steam-assisted gravity drainage projects.

expected to be recovered within the original boundaries of the SMA. The ultimate potential from within the area of expansion has yet to be estimated, leaving the total ultimate potential crude bitumen unchanged at 50 10^9 m^3.

3.2 Supply of and Demand for Crude Bitumen

This section includes crude bitumen production, upgrading, and disposition of both upgraded and nonupgraded bitumen. Nonupgraded bitumen refers to crude bitumen that is blended with a lighter-viscosity product (referred to as a diluent) in order to meet specifications for transport through pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to synthetic crude oil or other petroleum products. Most upgraded bitumen is used by refineries as feedstock.

Upgraders chemically alter the bitumen by adding hydrogen, subtracting carbon, or both. In upgrading, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. The bitumen upgrading process produces off-gas that is high in natural gas liquids (NGLs) and olefins. The off-gas is used primarily as fuel in oil sands operations. There are increasing volumes of off-gas being processed to remove the NGLs and olefins, which are used as feedstock in the petrochemical industry. Most oil sands coke recovered as a by-product of the upgrading process is stockpiled, and a small amount is burned to generate electricity. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Condensates[1] and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable the bitumen to meet pipeline specifications. Heated and insulated pipelines can decrease the amount of diluent needed to move bitumen through them. Condensates are lighter than upgraded bitumen as a diluent, which means a smaller volume of condensates is required to move bitumen through a pipeline. On average, a blend of bitumen and condensates will contain 30 per cent condensates, whereas a blend using upgraded bitumen will contain up to 50 per cent upgraded bitumen to meet pipeline specifications.

If condensates are used as a diluent to transport bitumen to destinations within Alberta, they are usually recycled. However, if they are used to transport bitumen to markets outside Alberta, they are generally not returned to the province. Instead, the condensates are used as part of the feedstock for upgraders and refineries downstream. In July 2010, Southern Lights pipeline began delivering additional imported diluent from the U.S. Petroleum Administration Defense District (PADD) 2 to Alberta. In 2012, Kinder Morgan announced plans to partially reverse the flow of the western portion of the Cochin pipeline system to deliver light condensate to Alberta.

The forecast of crude bitumen and upgraded bitumen production relies heavily on information provided by project proponents. This includes data on production capacity submitted during a project's application process, in addition to other publicly available materials, such as quarterly reports, presentations, and press releases, which provide information on schedules for bringing the resource on stream. A project's viability depends largely on the cost-price relationship between production, operating and transportation costs (supply), and the market price for bitumen and upgraded bitumen (demand). Other factors include the refining capacity to handle bitumen or upgraded bitumen and competition with other sources of supply in U.S. and Canadian markets. The forecasts for crude bitumen and upgraded bitumen include production from existing projects, expansions of existing projects, and new projects that have been granted approval. Demand for upgraded bitumen and nonupgraded bitumen in Alberta is based on refinery demand and transportation needs. Alberta upgraded and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

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

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[1] The term condensates, as used here, applies to Alberta production of condensates and pentanes plus in addition to imported volumes of condensate.

3.2.1 Crude Bitumen Production – 2012

Surface mining and in situ production for 2012 are shown graphically by oil sands area (OSA) in **Figure S3.1**. In 2012, Alberta produced 305.5 thousand (10^3) m^3/d of crude bitumen from all three OSAs, compared with 277.2 10^3 m^3/d in 2011. Of this 28.3 10^3 m^3/d increase in production, 22.3 10^3 m^3/d was from in situ schemes and 6.0 10^3 m^3/d was from mining. Regionally, in situ production growth was strongest in Athabasca (28.5 per cent increase) followed by Peace River (23.1 per cent increase) then Cold Lake (2.5 per cent increase). Combined, production for all three in situ areas grew by 16.5 per cent, compared with 4.2 per cent growth for mined bitumen production.

Overall, the increase in crude bitumen production of 28.3 10^3 m^3/d represents an annual increase of 10.2 per cent, higher than the production increase of 8.2 per cent between 2010 and 2011. Production from in situ projects exceeded mined production for the first time in 2012, a trend that is expected to continue. In 2012, in situ production accounted for 52 per cent of total bitumen production, compared with 49 per cent in 2011. **Figure S3.2** shows combined upgraded bitumen and nonupgraded bitumen production as a percentage of Alberta's total crude oil and equivalent production. The combined volume of upgraded bitumen and nonupgraded bitumen has increased from 48 per cent of the province's total crude oil production in 2002 to 73 per cent in 2012.

3.2.1.1 Mined Crude Bitumen

Annual mined production growth was 6.0 10^3 m^3/d in 2012 as daily volumes grew to 147.8 10^3 m^3/d, up from 141.8 10^3 m^3/d in 2011. Production growth in 2012 at 4.2 per cent was very similar to growth in 2011 at 4.1 per

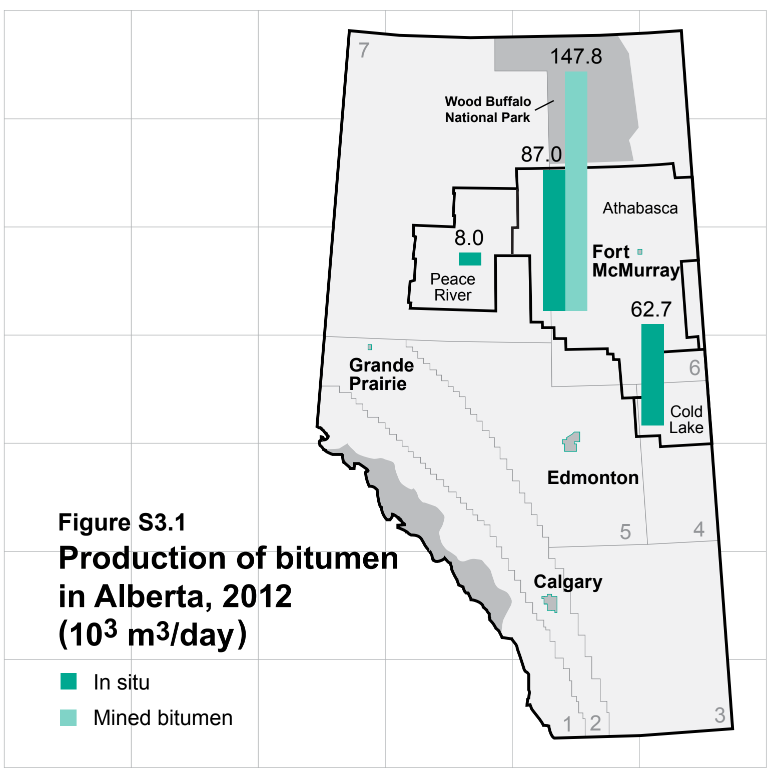


Figure S3.1
Production of bitumen in Alberta, 2012 (10^3 m^3/day)

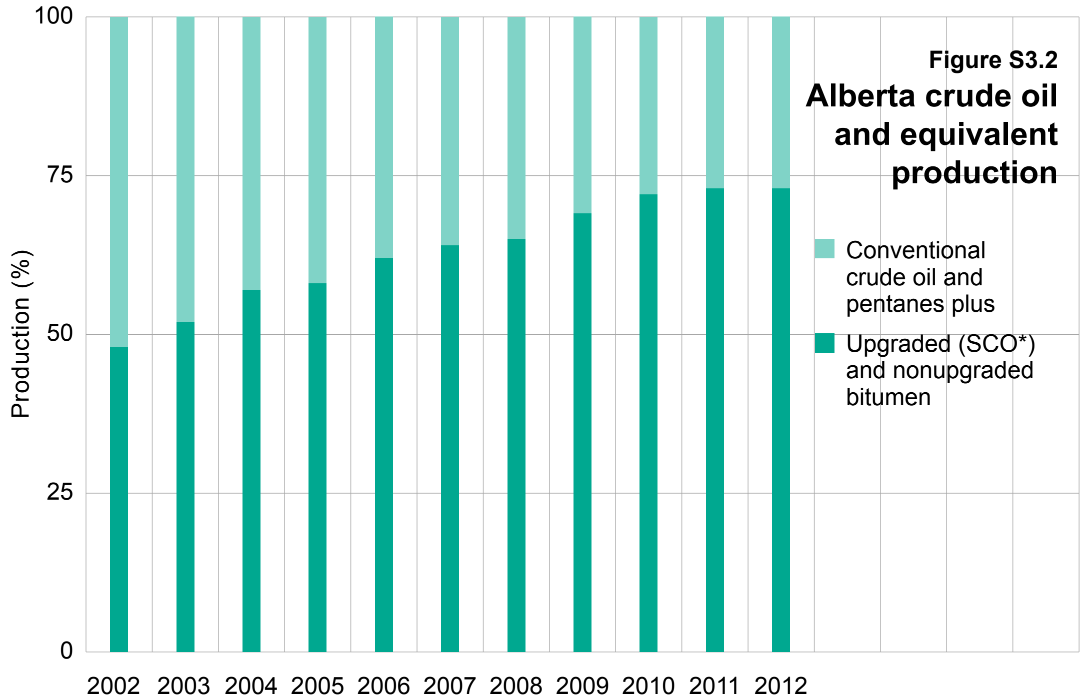


Figure S3.2
Alberta crude oil and equivalent production

*Synthetic crude oil.

cent. Production gains at Shell and CNRL of 2.4 10^3 m^3/d and 8.8 10^3 m^3/d, respectively, were sufficient to offset Suncor and Syncrude production declines of 3.4 10^3 m^3/d and 1.8 10^3 m^3/d, respectively. At present, all mined bitumen in Alberta serves as feedstock for upgraders.

Syncrude (Mildred Lake and Aurora), Suncor, Shell (Muskeg River and Jackpine), and CNRL (Horizon) account for 36, 29, 24, and 11 per cent of total mined bitumen, respectively.

Syncrude's mined bitumen production in 2012 decreased by 3.3 per cent from 2011 levels. Production in 2012 averaged 53.3 10^3 m^3/d, a decrease of 1.8 10^3 m^3/d from 55.1 10^3 m^3/d in 2011. The decline was a result of decreased production at its Aurora mine, which saw production fall by 2.2 10^3 m^3/d. Production at its Mildred Lake mine increased by 0.4 10^3 m^3/d.

Mined bitumen production at Suncor decreased by 7.5 per cent in 2012. Production in 2012 averaged 42.3 10^3 m^3/d, down from 45.8 10^3 m^3/d in 2011.

Shell's Muskeg River and Jackpine mining projects produced 35.8 10^3 m^3/d in 2012, a 7.3 per cent increase over 2011 production of 33.4 10^3 m^3/d.

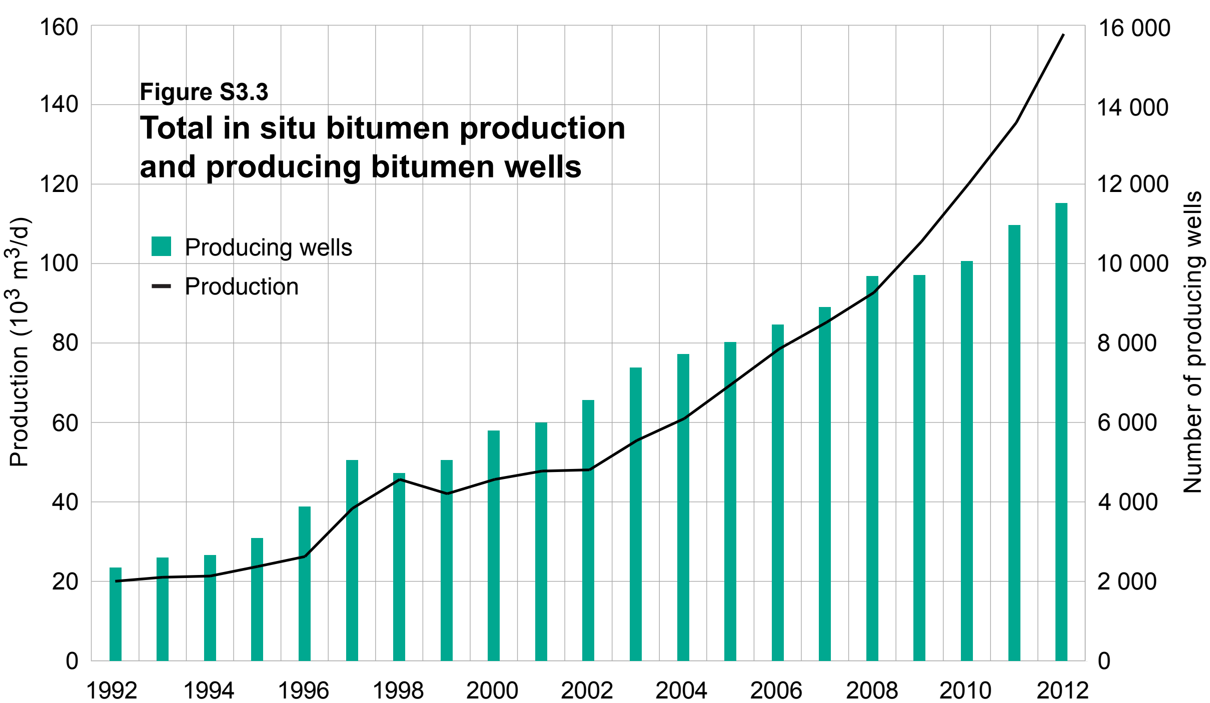
Following decreased production of 7.6 10^3 m^3/d in 2011 due to a coker fire, CNRL's Horizon project produced 16.4 10^3 m^3/d in 2012, an increase of 115.8 per cent.

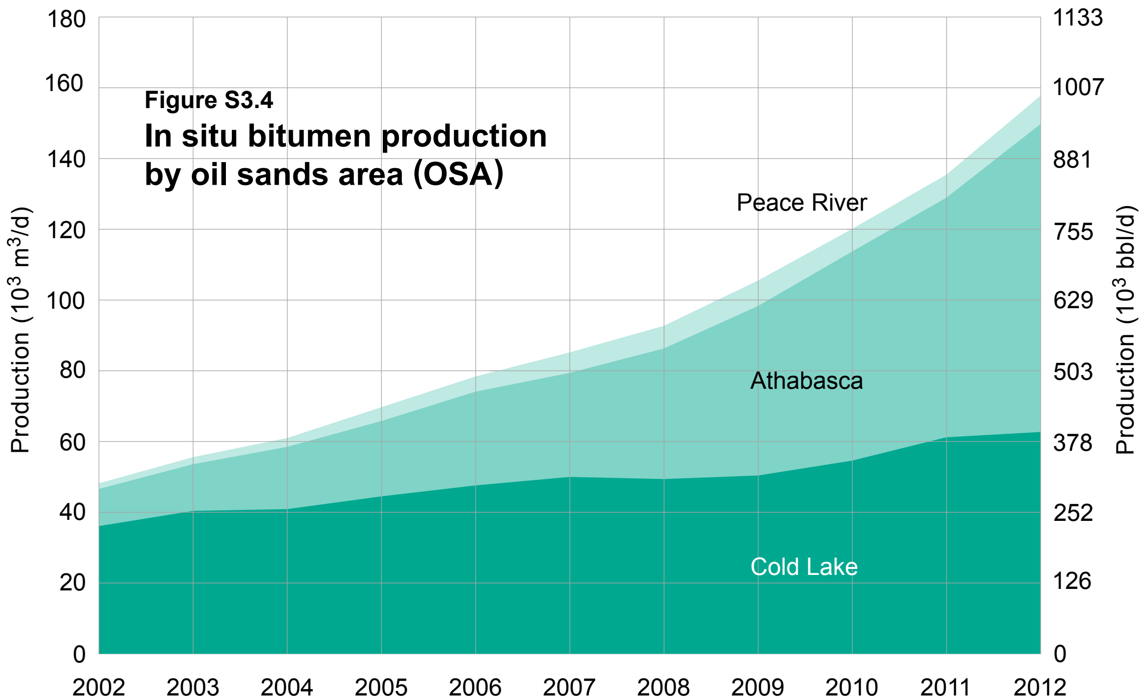
3.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production for 2012 increased to 157.7 10^3 m^3/d from 135.4 10^3 m^3/d in 2011. This represents a 16.5 per cent increase, higher than the increase of 12.7 per cent from 2010 to 2011. Since 2002, in situ crude production has grown an average of 11.5 per cent per year.

Annual total in situ bitumen production, along with the number of bitumen wells on production for each year, is shown in **Figure S3.3**. The number of producing bitumen wells has increased along with in situ crude bitumen production from 2300 in 1992 to about 11 500 in 2012. The average annual productivity of in situ bitumen wells remained relatively flat between 1992 and 2004 at a level of 8.0 m^3/d but began to climb in 2005 to average 8.7 m^3/d, reaching 12.3 m^3/d by 2011 and 13.7 m^3/d in 2012. This change is due to the increase in steam-assisted gravity drainage (SAGD) wells, which have higher average productivity rates than cyclic steam stimulation (CSS) wells.

Figure S3.4 shows historical in situ production by OSA. For the third year, production from the Athabasca OSA was higher than that from the Cold Lake OSA, with the Athabasca and Cold Lake OSAs accounting for 55 per cent and 40 per cent of total in situ production, respectively. In 2012, the Athabasca, Cold Lake, and Peace River OSAs produced 87.0 10^3 m^3/d, 62.7 10^3 m^3/d, and 8.0 10^3 m^3/d, respectively. In 2012, annual production growth rates for the Athabasca, Cold Lake, and Peace River OSAs were 29 per cent, 3 per cent, and 23 per cent, respectively. Significant increases in production within the Athabasca OSA since 2002 are due to SAGD development, while increases in the Peace River OSA are largely the result of increased primary production of bitumen in the Seal area located southeast of Shell's Peace River thermal in situ bitumen production project.





Currently, there are three main methods for producing in situ bitumen: primary production, CSS, and SAGD. In situ bitumen production by recovery method per year is shown in **Figure S3.5**. Primary production includes those schemes that use water and polymer injection (considered as enhanced recovery) as a recovery method. In 2012, 26 per cent of in situ production was recovered by CSS, 49 per cent by SAGD, and 25 per cent by primary schemes. SAGD production was responsible for 80 per cent of the total increase in production between 2011 and 2012. CSS experienced a slight decline, falling by 1.0 10^3 m^3/d, a 2 per cent decrease over 2011 production levels.

SAGD technology has been in use since 2001 and is the preferred method of recovery for most new projects in the Athabasca OSA. As discussed earlier, the total productivity of in situ wells has been increasing, largely due to an increase in the use of SAGD as a method of recovery. **Figure S3.6** shows the average well productivity in 2012 by recovery method for SAGD, CSS, and primary (including enhanced recovery). This is calculated by dividing the average daily production on a monthly basis by the average producing well count for the respective month, which is then adjusted to produce an annual average.

3.2.1.3 Upgraded Bitumen

Currently, all Alberta mined bitumen and a portion of in situ production (7 per cent) are upgraded. Upgraded bitumen production in 2012 was 142.9 10^3 m^3/d, compared with 137.1 10^3 m^3/d in 2011. **Table S3.1** shows upgraded bitumen production in 2012 by individual operator.

Alberta's five upgraders produce a variety of upgraded products: Suncor produces light sweet and medium sour crudes, including diesel; Syncrude, CNRL Horizon, and Nexen Inc. (Nexen) Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as

Figure S3.5

In situ bitumen production by recovery method

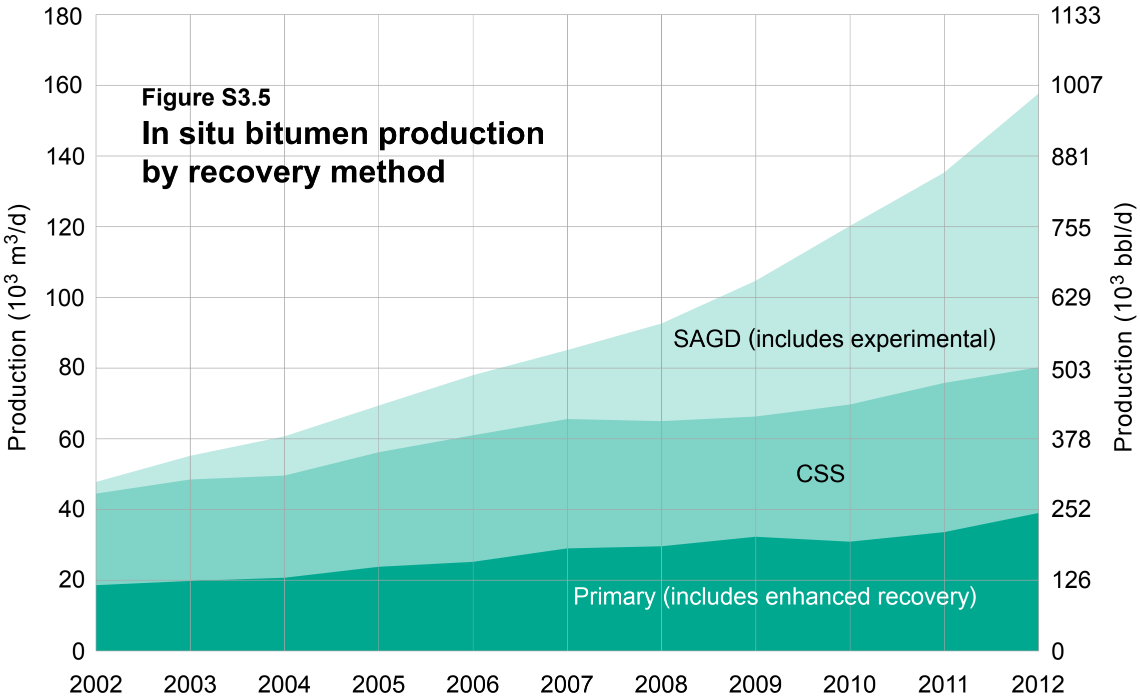


Figure S3.6

In situ bitumen average well productivity by recovery method

[Number of wells]

Productivity m^3/day

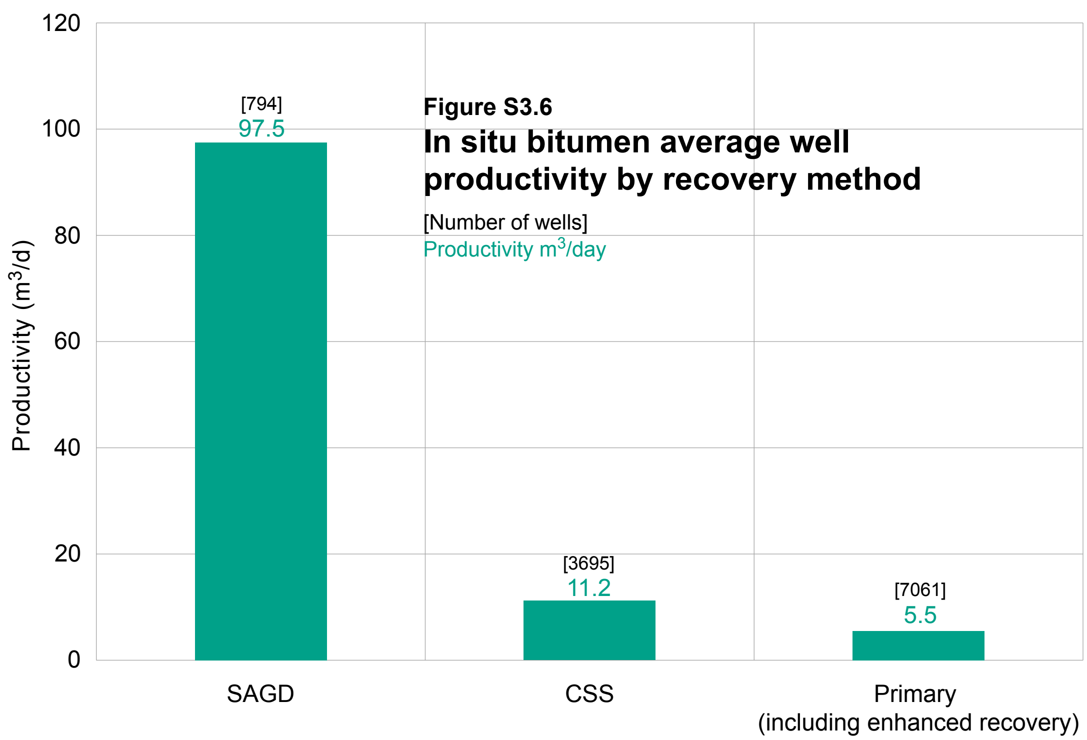


Table S3.1 Upgraded bitumen production in 2012[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	46.2
Suncor	44.8
Shell Canada Scotford	33.8
CNRL Horizon	13.4
Nexen Long Lake	4.7
Total	**142.9**

[a] Any discrepancies are due to rounding.

sweet and heavy synthetic crude oil. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use delayed coking as their primary upgrading technology and achieve volumetric liquid yields (upgraded bitumen produced/bitumen processed) of 80 to 90 per cent, whereas projects employing hydrogen-addition can achieve volumetric liquid yields of 100 per cent or more. The Nexen Long Lake project uses OrCrude™, a carbon rejection upgrading process using conventional thermal cracking, distillation, and solvent deasphalting equipment. A key aspect of this process is the removal of coke precursors (asphaltenes) prior to thermal cracking of the upgrader feed.

3.2.1.4 Gasification

Gasification allows companies to convert materials that would otherwise be low-value products into energy sources and reduces the reliance on external energy sources. Gasification can be used to convert asphaltenes, petroleum coke, and vacuum distillation bottoms into a synthetic gas (syn gas) fuel.

The Nexen Long Lake project integrates the gasification of asphaltenes to produce a syn gas that is used in the SAGD and upgrading operations, significantly reducing the amount of natural gas that is required.

Gasification of low-value products is also being planned for the proposed North West Upgrader. The gasifier will produce syn gas and hydrogen from refinery bottoms.

3.2.1.5 Petroleum Coke

Petroleum coke is a by-product of the oil sands upgrading process that is currently being stockpiled in Alberta and is considered a potential source of energy. It is high in sulphur but has a lower ash content than conventional fuel coke.

Suncor and Syncrude operate Alberta's two largest oil sands mines near Fort McMurray. Built with the capacity for both on-site extraction and upgrading, Syncrude and Suncor both produce coke. The CNRL Horizon project, which started operations in 2009, has an oil sands mine and on-site extraction facilities. It also has upgrading capabilities using delayed coking technology that produces coke.

Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke used as site fuel. In 2012, Suncor used approximately 16 per cent of its annual coke production as site fuel and sold approximately 23 per cent through its Energy Marketing Group. Syncrude began using coke as a site fuel in 1995 and by 2012 used 21 per cent of its annual coke production as site fuel. At CNRL’s Horizon project, all coke produced is stockpiled, accounting for approximately 4 per cent of total coke inventories.

Suncor and Syncrude are exploring new ways to use their coke surplus, including using it as a reclamation material. In August 2009, Suncor applied to the ERCB for permission to use coke inventories for capping two tailings ponds. Suncor estimated that it could use about 40 million tonnes of the coke stockpiled for non-energy use for reclamation. In July 2011, Suncor received partial approval to begin a full-scale operational test on one of the ponds.

Statistics of coke inventories reported in *ST39: Alberta Mineable Oil Sands Plant Statistics* show general increases in the total closing inventories per year, as illustrated in **Figure S3.7**. In 2012, coke inventories reached 76 million tonnes, up 4 million tonnes from 2011. This represents a change of approximately 6 per cent, which is consistent with the 2011 rate of growth. Coke inventories are expected to continue their growth with the recent addition of CNRL’s Horizon project, unless significant alternative uses are found. Inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders.

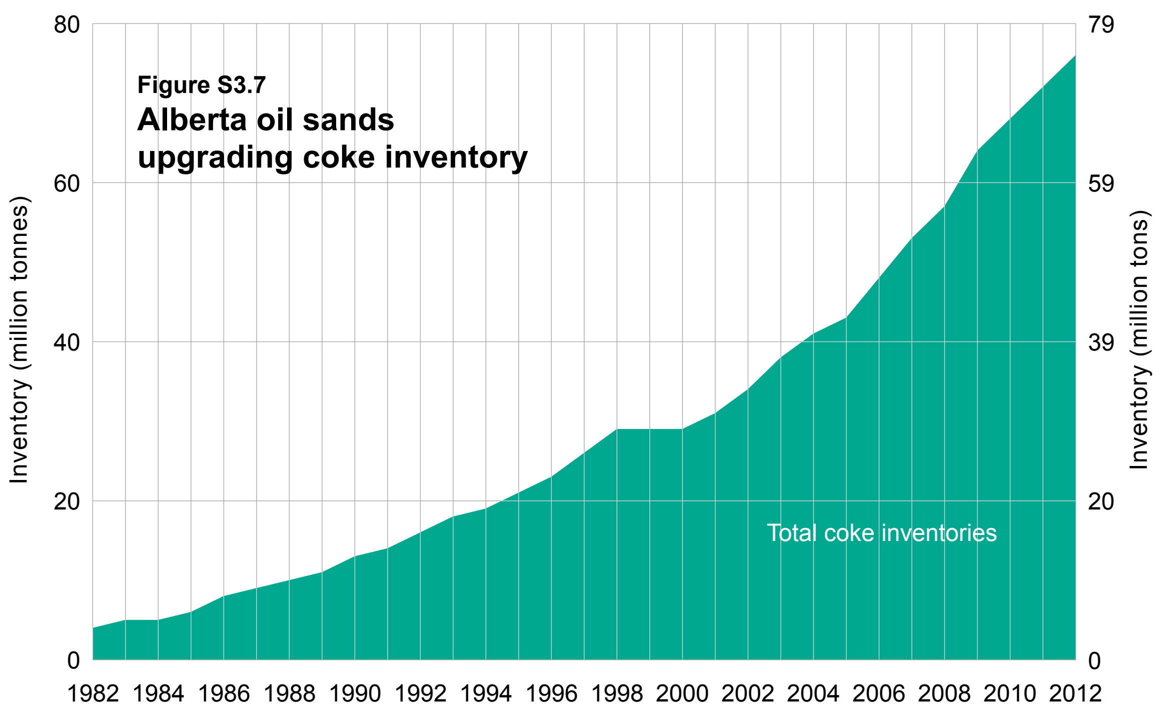


Figure S3.7
Alberta oil sands upgrading coke inventory

3.2.2 Crude Bitumen Production – Forecast

3.2.2.1 Mined Crude Bitumen

In projecting the future supply of bitumen from mining, the ERCB considered potential production from existing facilities and supply from future projects. Production from future mining projects considers the high cost of engineering and materials and the substantial amount of skilled labour required for expansions to existing and new projects. The ERCB also recognizes that other key factors, such as the forecast of oil prices and the length of the construction period, will affect project timing. Projects that have been approved are considered for inclusion in our forecast. Announced projects are generally not included in our forecasts. The projects actually considered for the forecast are shown in **Table S3.2**.

Table S3.2 Surface mined bitumen projects

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD*	18.3	Approved
Jackpine Phase 1B	TBD	15.9	Approved
Jackpine Phase 2	TBD	15.9	Application
Pierre River Phase 1	TBD	15.9	Application
Pierre River Phase 2	TBD	15.9	Application
CNRL			
Horizon Phase 2/3	TBD	21.5	Approved
Suncor/Total E&P Canada			
Fort Hills Phase 1	TBD	26.2	Approved
Fort Hills debottleneck	TBD	4.0	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	2013	17.5	Under construction
Kearl Phase 2	TBD	17.5	Approved
Kearl Phase 1 debottleneck 1	TBD	4.5	Approved
Kearl Phase 1 debottleneck 2		5.0	Approved
Kearl Phase 2 debottleneck 1		4.5	Approved
Kearl Phase 2 debottleneck 2		5.0	Approved
Total E&P Canada/Suncor			Approved
Joslyn (North)	TBD	15.9	Approved
Teck Resources Limited			
Frontier Phase 1	TBD	11.9	Application
Frontier Phase 2	TBD	13.3	Application
Frontier Phase 3	TBD	12.6	Application
Frontier Phase 4	TBD	6.3	Application

Source: ERCB and company releases.

* To be determined.

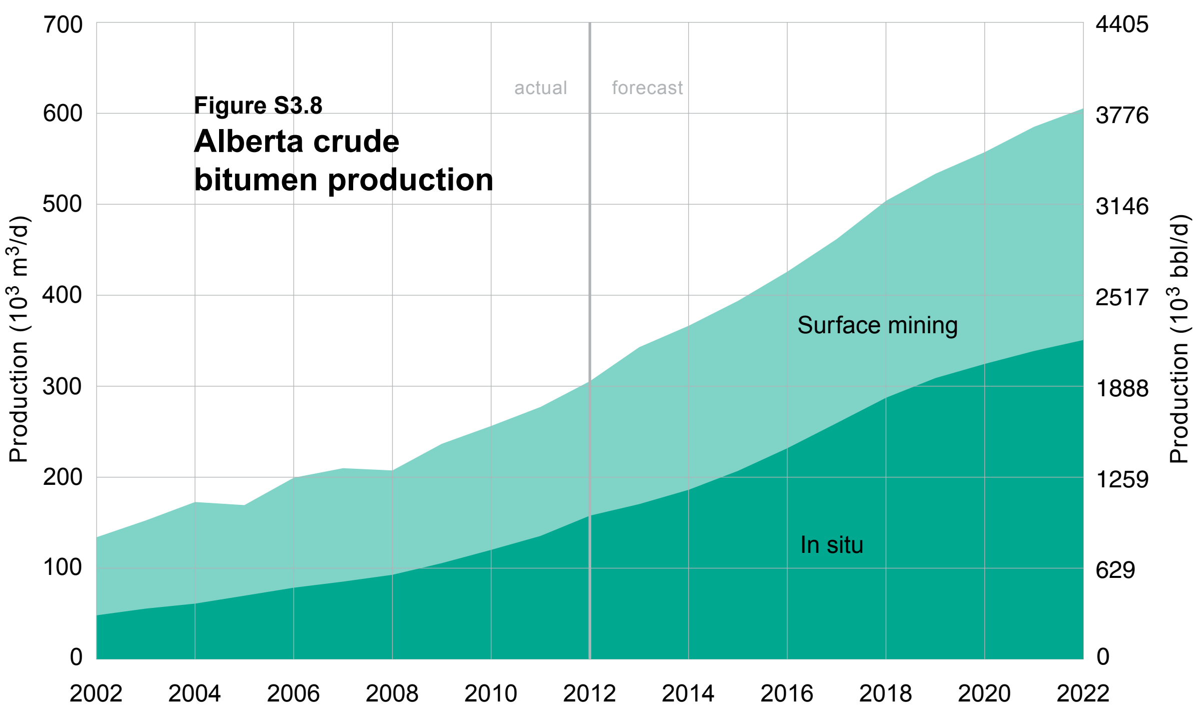
Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. Due to uncertainties regarding timing and project scope, some projects, including Teck's Equinox project, have not been considered in the ten-year forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the ERCB considered factors such as the crude oil price environment, the availability of export capacity, and the availability of refinery capacity.

By 2022, mined bitumen is expected to reach 254.6 10^3 m^3/d. This is slightly lower compared with the end of the forecast period in last year's report. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure S3.8**, which shows that the percentage of mined bitumen to total production is expected to decrease from 48 per cent in 2012 to 42 per cent in 2022.

3.2.2.2 In Situ Bitumen

Similar to surface mining, the forecasted supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects. In forecasting production from existing and future schemes, the ERCB considered all approved projects and projects currently before the ERCB for approval. The forecast assumes that existing projects will continue producing at their current or projected production levels over the forecast period. To this projection, the ERCB has added crude bitumen production from new and expanded schemes. The production forecasts for future crude bitumen projects take into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, pipeline availability, and the ability of North American markets to absorb the increased volumes.



The current forecast has increased over last year's primarily due to the addition of new proposed projects and the accelerated development schedules for existing and approved projects. Factors that may affect the pace of development were considered in the forecast, such as the availability of labour and equipment. As illustrated in **Figure S3.8**, the ERCB expects in situ crude bitumen production to increase to 350.8 10^3 m^3/d by 2022. This represents an increase of 8 per cent when compared to the end of the forecast period in last year's report. Based on this projection, in situ bitumen will account for 58 per cent of total bitumen produced by 2022.

Projects that have been approved are considered for inclusion in this forecast. Announced projects are generally not included in the forecast. Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. The projects considered for the forecast are shown in **Table S3.3.**

In 2012, approximately 7 per cent of in situ production in Alberta was upgraded. The percentage of in situ bitumen upgraded is expected to vary throughout the forecast period, before reaching about 9 per cent in 2022, which is lower than the projection in the 2011 forecast as a result of a reduction in the ERCB's forecast for upgrading.

3.2.2.3 Upgraded Bitumen

To forecast upgraded bitumen production, the ERCB includes existing production from the Suncor, Syncrude, Shell, CNRL, and Nexen projects plus their planned expansions, as well as the new production expected from projects listed in **Table S3.4** on page 3-24. Production from future upgrading projects considers the high cost of engineering and materials and the substantial amount of skilled labour required for expansions to existing and new projects. The ERCB also recognizes that other key factors, such as oil price forecasts, the price differential between light crude oil and bitumen, the length of the construction period, and the market penetration of new upgraded volumes, will affect project timing.

Companies have begun to express interest in partial upgrading. Partial upgrading involves the removal of asphaltenes, along with other heavier organic compounds, to lower the viscosity of the crude bitumen sufficiently for it to flow in pipelines without the need for diluent. Partial upgrading offers significant cost savings over the building of a full upgrader and produces a crude oil consistent with traditional heavy oils. Current partial upgrading proposals include Value Creation's Terre de Grace and Advanced TriStar projects and MEG's HI-Q demonstration pilot project.

Over the forecast period, the percentage of crude bitumen upgraded is expected to decline from 52 per cent of total crude bitumen in 2012 to 38 per cent in 2022. This is a result of the in situ production growth outpacing the growth in upgrading capacity.

Figure S3.9 on page 3-24 shows the ERCB's projection of upgraded bitumen production, which is expected to increase from 142.9 10^3 m^3/d in 2012 to 153.6 10^3 m^3/d in 2013. This increase assumes operators are able to reach their planned production targets. Production is forecast to increase to 200.8 10^3 m^3/d by 2022. This represents a decrease of 10 per cent over last year's end of forecast projection of 223.5 10^3 m^3/d by 2021. This decrease is due to the cancellation of the Voyageur upgrader.

Table S3.3 In situ crude bitumen projects

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Athabasca Region			
Alberta Oil Sands			
Clearwater West	TBD*	1.6	Application
Athabasca Oil			
Dover Clastics	TBD	1.9	Application
Hangingstone	TBD	1.9	Approved
BlackPearl			
Blackrod Commercial Phase 1–3	TBD	12.8	Application
Cavalier			
Hoole Grand Rapids	TBD	1.6	Application
Cenovus			
Christina Lake Phase E	2013	6.4	Under construction
Christina Lake Phase F	2016	7.9	Under construction
Christina Lake Phase G	TBD	7.9	Approved
Foster Creek Phase F	2014	5.6	Under construction
Foster Creek Phase G	2015	5.6	Under construction
Foster Creek Phase H	TBD	5.6	Approved
Narrows Lake Phase 1A–1B	TBD	10.3	Approved
Pelican Lake Grand Rapids Phases A–C	TBD	9.5	Application
Telephone Lake Phases A–B	TBD	7.2	Application
CNRL			
Grouse Stage 1	TBD	7.9	Application
Kirby South Phase 1	2014	7.2	Under construction
Kirby North and South Phase 2	TBD	15.2	Application
Connacher			
Great Divide Expansion Phases 1–3	TBD	3.8	Application
ConocoPhillips			
Surmont Phase 2	2014	17.3	Under construction
Devon			
Jackfish 3	2014	5.6	Under construction
Pike 1 Phases A–C	TBD	16.8	Application
Walleye	TBD	1.4	Application
Dover Op. Co.			
Dover Phases 1–5	TBD	40.0	Application
MacKay River Phase 1	2014	5.6	Under construction
MacKay River Phases 2–4	TBD	18.4	Approved

(continued on next page)

Table S3.3 (*continued*)

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Grizzly Oil Sands			
Algar Phases 1–2	TBD	0.9	Approved
May River Phase 1	TBD	1.6	Approved
Harvest			
BlackGold Phase 1	2014	1.6	Under construction
BlackGold Phase 2	TBD	3.2	Application
Husky			
Sunrise Phase 1	2014	9.5	Under construction
Sunrise Phases 2–4	TBD	22.2	Approved
Ivanhoe			
Tamarack Phases 1–2	TBD	3.2	Application
JACOS			
Hangingstone Expansion	TBD	5.6	Approved
Koch Exploration			
Muskwa	TBD	1.6	Application
Laricina			
Germain Phases 2–4	TBD	23.8	Application
Saleski Phase 1	TBD	2.0	Application
Marathon			
Birchwood	TBD	1.9	Application
MEG			
Christina Lake Phase 3A–3C	TBD	23.7	Approved
Surmont Phases 1-3	TBD	19.5	Application
Nexen			
Kinosis Phase 1A	2014	3.2	Approved
Kinosis Phases 1-2	TBD	19.0	Approved
Statoil			
Kai Kos Dehseh Leismer Commercial	TBD	1.6	Approved
Kai Kos Dehseh Leismer Expansion	TBD	3.2	Approved
Kai Kos Dehseh Corner	TBD	6.4	Approved
Suncor			
Firebag Phases 5–6	TBD	19.8	Approved
MacKay Phase 2	TBD	6.4	Approved
Sunshine Oilsands			
Legend Lake	TBD	1.6	Application
Thickwood	TBD	1.6	Application
West Ells Phases 1–2	TBD	1.6	Approved

(continued on next page)

Table S3.3 (*continued*)

Company **Project**	**Start-up**	**Capacity** **(10^3 m^3/d)**	**Status**
Surmont Energy			
Wildwood	TBD	1.9	Application
Value Creation			
Terre de Grace Phase 1	TBD	1.6	Approved
Advanced TriStar	TBD	11.9	Application
Cold Lake Region			
Husky			
Caribou Lake Phase 1	TBD	1.6	Approved
Imperial			
Cold Lake Phases 14–16	TBD	4.8	Approved
Koch Exploration			
Gemini Phase 2 (incl. pilot)	TBD	1.8	Application
Osum			
Taiga Phase 1–2	TBD	7.2	Application
Pengrowth			
Lindbergh	TBD	2.0	Application
Shell			
Orion (Hilda Lake) Phase 2	TBD	1.6	Approved
Peace River Region			
Penn West			
Seal Main Commercial	TBD	1.6	Application
Shell Peace River			
Carmon Creek Phases 1–2	TBD	10.6	Application

Source: ERCB and company releases.

* To be determined.

3.2.3 Supply Costs

The supply cost for a resource or project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as earn a specified return on investment. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used for comparative project economics.

The supply cost calculation determines a value received per unit of production. For SAGD and standalone mining, this entails solving for a bitumen price at plant gate. In order to provide a more meaningful comparison, the results of the supply cost analysis have been converted to a West Texas Intermediate (WTI) price, which is directly comparable to current market prices.

Table S3.4 Upgraded bitumen projects

Company Project	Start-up	Upgrading capacity (10^3 m^3/d)	Status
Athabasca Region			
CNRL			
Horizon Phase 2A	2014	1.6	Approved
Horizon Phase 2B/3	TBD	19.9	Approved
Nexen/OPTI			
Long Lake Phase 2	TBD	9.3	Approved
Value Creation			
Terre de Grace Pilot	TBD	1.3	Application
Advanced TriStar	TBD	10.2	Application
Industrial Heartland Region			
Shell			
Upgrader 2 Phases 1–4	TBD	47.7	Withdrawn
North West Upgrading			
NW Upgrader Phase 1	2016	7.4	Approved
NW Upgrader Phase 2–3	TBD	14.8	Approved

Source: ERCB and company releases.

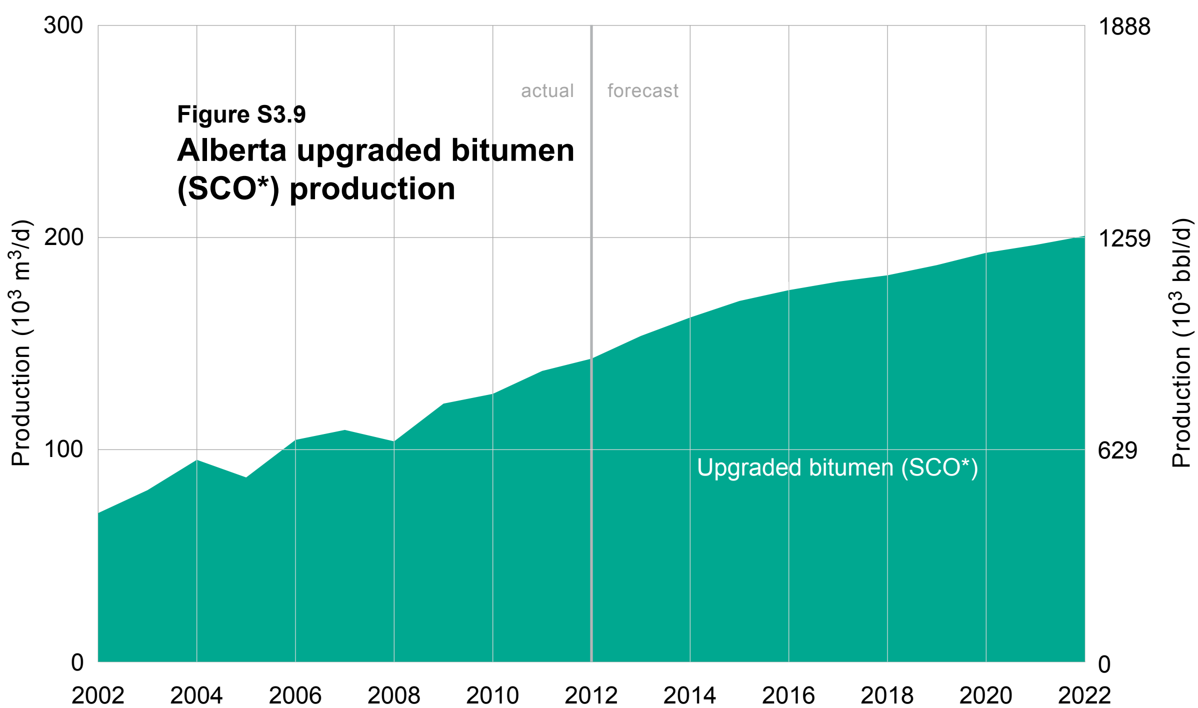


Figure S3.9
Alberta upgraded bitumen (SCO*) production

*Synthetic crude oil.

3.2.3.1 Assumptions

Although each project is unique in its location and the quality of its reserves, the supply cost analysis relies on more generic project specifications and capital and operating cost estimates. Data selected for the analysis are provided in **Table S3.5** in both metric and imperial units since North American price data are based on a US$ WTI. The input cost data, and the resultant supply cost outputs, are in 2012 dollars.

Table S3.5 Supply cost project data, 2012

Project type	Production (10^3 m^3/d)	Production (bbl/d)	Capital cost range (millions of dollars)	Capacity Utilization	Estimated supply cost ($US WTI equivalent per barrel)	Purchased natural gas requirement (10^3 m^3 gas/ m^3 oil)	Purchased natural gas requirement (mcf/bbl)
In situ SAGD	4.8	30 000	750–1 500	90%	50–80	0.177–0.354	1.0–2.0
Standalone mine	15.9	100 000	5 500–7 500	90%	70–85	0.071–0.106	0.4–0.6

The generic projects represent proposed project types, including in situ SAGD (with and without cogeneration) and standalone mining with cogeneration. An integrated mine was not considered for this analysis as there are currently no proposed integrated bitumen projects in Alberta. Although significant production currently comes from CSS projects, few new CSS projects have been proposed, and therefore supply costs have not been determined for this recovery method. The wide range in SAGD capital costs represents the current economic environment in which producers are pursuing additional phases, as well as green field development, with the lower range of the capital cost being applicable to phased additions where portions of the infrastructure are already in place.

A major component of operating costs is purchased natural gas for fuel and feedstock. This analysis assumes an average value of Cdn$4.75 per gigajoule real Alberta reference price over a project's 30- to 40-year life. For 2012 and beyond, the analysis assumes a nominal discount rate of 10 per cent, whereas the 10 per cent discount rate used in the past had been real.

3.2.3.2 Results

The supply cost calculation for 2012 has changed significantly from previous years. Among the changes were the addition of a capacity utilization factor, a change in the discount rate used, and for SAGD the gas use rate for the high case was increased from 0.265 10^3 m^3/m^3 to 0.354 10^3 m^3/m^3. As a result, the 2012 results are not comparable to those calculated last year. As illustrated in **Table S3.5**, even with the inclusion of a capacity utilization factor and a wider price differential, the ongoing development of many in situ and mining projects is still supported. However, some higher cost projects may be delayed or cancelled.

A major risk to the capital cost assumptions in this analysis would be the re-emergence of cost escalation that occurred in the last decade. When too many projects proceed, resources such as labour quickly become scarce, which results in an escalation in capital and supply costs.

3.2.4 Pipelines

Currently, pipeline capacity leaving Alberta has become tight, making it increasingly sensitive to service disruptions and increased shipments. As a consequence, Enbridge's Mainline and Lakehead pipeline systems experienced apportionment in the fourth quarter of 2012 and the first quarter of 2013.[2] Additional capacity leaving Alberta, as well as new pipelines further downstream, are expected to add incremental capacity in the short to medium term. However, capacity is expected to remain tight for 2013.

The inability to access additional markets, limited takeaway capacity, and oversupply at Cushing, Oklahoma, continue to affect the ability of Enbridge to take advantage of unused capacity on the Mainline system prior to Superior, Wisconsin. This is expected to change as pipelines aimed at accessing additional markets and expanding capacity are pursued.

The reversal of Enbridge's line 9A, aimed at providing eastbound capacity between Sarnia, Ontario, and Westover, Ontario, is expected to be complete in 2013. In addition, Enbridge has announced plans to pursue the reversal of line 9B between Westover and Montreal, Quebec, providing 38.2 10^3 m^3/d of capacity between Sarnia and Montreal by 2014, pending National Energy Board (NEB) approval. The reversal of lines 9A and 9B will provide producers with access to additional refining capacity in Westover and Montreal. Additionally, expansion to Enbridge's line 62 (Spearhead North) running between Flanagan, Illinois and Chicago, Illinois, is expected to be complete by 2014, providing the ability to move an additional 47.7 10^3 m^3/d of heavy crude into the Chicago area and points east. In addition to Enbridge's plans, TransCanada is currently gauging interest in the conversion of part of its mainline system from gas transmission to oil, and expects to be in a position in 2013 to make a decision. The converted pipeline, referred to as the Mainline Conversion project, could carry between 79.5 10^3 m^3/d and 159.0 10^3 m^3/d and would initially move oil from Alberta to Montreal.

Projects aimed at providing takeaway capacity from Cushing continue to move forward. In 2012, the Seaway pipeline, which runs from Cushing to the Gulf Coast, was successfully reversed and shipped its first volumes. In early 2013, the pipeline's expansion to 63.6 10^3 m^3/d was completed and Enbridge has announced plans to twin the pipeline, which would add an additional 71.5 10^3 m^3/d of capacity in 2014. Following the denial of a U.S. regulatory permit for its Keystone XL pipeline in early 2012, TransCanada announced plans to go ahead with the southern leg of the Keystone project. The southern leg (the Gulf Coast Project), with a planned in-service date of late 2013, includes the development of a 131.9 10^3 m^3/d pipeline between Cushing and Nederland, Texas. Further, Enbridge has entered into an agreement with Energy Transfer Partners to jointly develop a project to provide crude oil pipeline access to the eastern Gulf Coast refinery market from the hub at Patoka, Illinois. Dubbed the Eastern Gulf Access project, it would entail converting a natural gas pipeline to crude service, with an initial capacity of 39.7 10^3 m^3/d.

In response to announced and actual additions of takeaway capacity at Superior and Cushing, Enbridge has announced its intention to further expand its Mainline and Lakehead systems. This will include expansions of

[2] When shippers nominate more oil or oil products in a given month than the pipeline can transport, shipper volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations, reduced pipeline capacity or refinery maintenance.

the Alberta Clipper line and the Southern Access line, with a targeted in-service date of mid-2014. The Alberta Clipper line is being expanded by 19.1 10^3 m^3/d, increasing capacity from 71.5 10^3 m^3/d to 90.6 10^3 m^3/d. The Southern Access line is being expanded by 25.4 10^3 m^3/d, increasing capacity from 63.6 10^3 m^3/d to 89.0 10^3 m^3/d. Supporting the expansion of the Southern Access pipeline is the proposed Flanagan South project, which would mirror the Spearhead pipeline. Flanagan South is being proposed with an initial design capacity of 93.0 10^3 m^3/d that is expandable to 127.1 10^3 m^3/d. Pending regulatory approval, Enbridge plans to have the Flanagan South pipeline in service by mid-2014.

Among the factors affecting the availability of pipeline capacity for Alberta crude oil production is competition from U.S. Bakken light oil production from the Williston Basin, centred in northwestern North Dakota. This competition for capacity is expected to increase due to production growth in the Bakken (and equivalents) light oil of both the Williston and Alberta basins. In May 2011, Enbridge completed the Portal link, which has the capacity to deliver 4.0 10^3 m^3/d of U.S. Bakken production into Enbridge's Steelman Terminal in Saskatchewan. Currently, Enbridge is proposing the Bakken pipeline project that would see the Portal Link expanded to 23.0 10^3 m^3/d by 2013. In addition to the proposed Bakken pipeline project, Plains All American Pipeline has plans to reverse its Wascana pipeline, which would see U.S. Bakken production flow into Enbridge's system in Regina, Saskatchewan. More recently, Enbridge has been talking with producers about development of the Sandpiper pipeline, which would take light oil production from the Bakken to the mainline at Superior. The Sandpiper is targeted to be in service between 2014 and 2016, with an initial capacity of 35.8 10^3 m^3/d. In addition, Enbridge has announced an extension to its Southern Access pipeline from Flanagan to Patoka. The extension will transport light crude, have an initial capacity of 47.7 10^3 m^3/d, and be in service between 2014 and 2016.

At present, rail plays a significant role in moving crude oil to market, transporting in 2012 over 14.3 10^3 m^3/d of crude oil. With continued growth in production and new terminals in planning or under construction, rail movements are expected to continue growing into the foreseeable future.

Future possible pipeline capacity additions include the Keystone XL pipeline, the Northern Gateway pipeline, and an expansion to the Trans Mountain pipeline. The northern leg of the Keystone XL pipeline would run from Hardisty, Alberta, to Steele City, Nebraska, and have an initial capacity of 131.9 10^3 m^3/d. Pending approval, TransCanada intends to have the pipeline in service by 2015. The review process for Enbridge's Northern Gateway project is currently ongoing, with a decision expected in mid-2014. The proposed pipeline would run from Bruderheim, Alberta, to Kitimat, British Columbia, with an initial capacity of 83.4 10^3 m^3/d. In addition, Kinder Morgan has been gauging interest in expanding its Trans Mountain pipeline, which continues to experience apportionment. The Trans Mountain pipeline moves crude oil from Edmonton, Alberta, to marketing terminals and refineries in the central British Columbia region, the Greater Vancouver area, and international destinations, including the western United States. In 2013, Kinder Morgan announced that it would proceed with plans to increase capacity from 47.7 10^3 m^3/d to 141.4.1 10^3 m^3/d by 2017. Kinder Morgan intends to submit an application to the NEB for the proposed expansion project late in 2013. Further information regarding the proposed removal pipelines can be found below under **Section 3.2.4.4**.

Within Alberta, the current pipeline system's ability to expand, in addition to proposed projects, should provide adequate transportation capacity for the expected increases in upgraded and nonupgraded bitumen production over the forecast period. The current pipeline systems in the Cold Lake and Athabasca areas are described in **Table S3.6**. **Figure S3.10** shows the current pipelines and proposed crude oil pipeline projects within the Athabasca and Cold Lake areas. Numerals within parentheses in the following sections on existing and proposed pipelines in Alberta refer to the legend on this map.

Table S3.6 Alberta upgraded and nonupgraded bitumen pipelines

Name	Destination	Current capacity (10^3 m^3/d)
Cold Lake Area pipelines		
Cold Lake Pipeline	Hardisty	103.3
	Edmonton	
Husky Pipeline	Hardisty	78.0
	Lloydminster	
Echo Pipeline	Hardisty	12.0
Fort McMurray Area pipelines		
Athabasca Pipeline	Hardisty	62.0
Corridor Pipeline	Edmonton	73.9
Syncrude Pipeline	Edmonton	61.8
Oil Sands Pipeline	Edmonton	23.0
Access Pipeline	Edmonton	23.8
Waupisoo Pipeline	Edmonton	55.6
Horizon Pipeline	Edmonton	39.7

3.2.4.1 Existing Alberta Pipelines

- The Cold Lake pipeline system (1) is capable of delivering heavy crude from the Cold Lake area to Hardisty and Edmonton.
- The Husky pipeline (2) moves Cold Lake crude oil to Husky's heavy oil operations in Lloydminster. Heavy crude oil and upgraded bitumen are then transported to Husky's terminal facilities at Hardisty, where oil is delivered into the Enbridge (4) or the Kinder Morgan Express (5) pipeline systems.
- The Echo pipeline (3) is an insulated pipeline able to handle high-temperature crude, thereby eliminating the requirement for diluent blending. This pipeline delivers Cold Lake crude to Hardisty.
- The Enbridge pipeline (4) is an existing export pipeline.
- The Kinder Morgan Express pipeline (5) is an existing export pipeline.
- The Athabasca pipeline (6) delivers upgraded product and bitumen blends to Hardisty. Its current capacity is 62 10^3 m^3/d but it has the potential to carry 90.6 10^3 m^3/d.

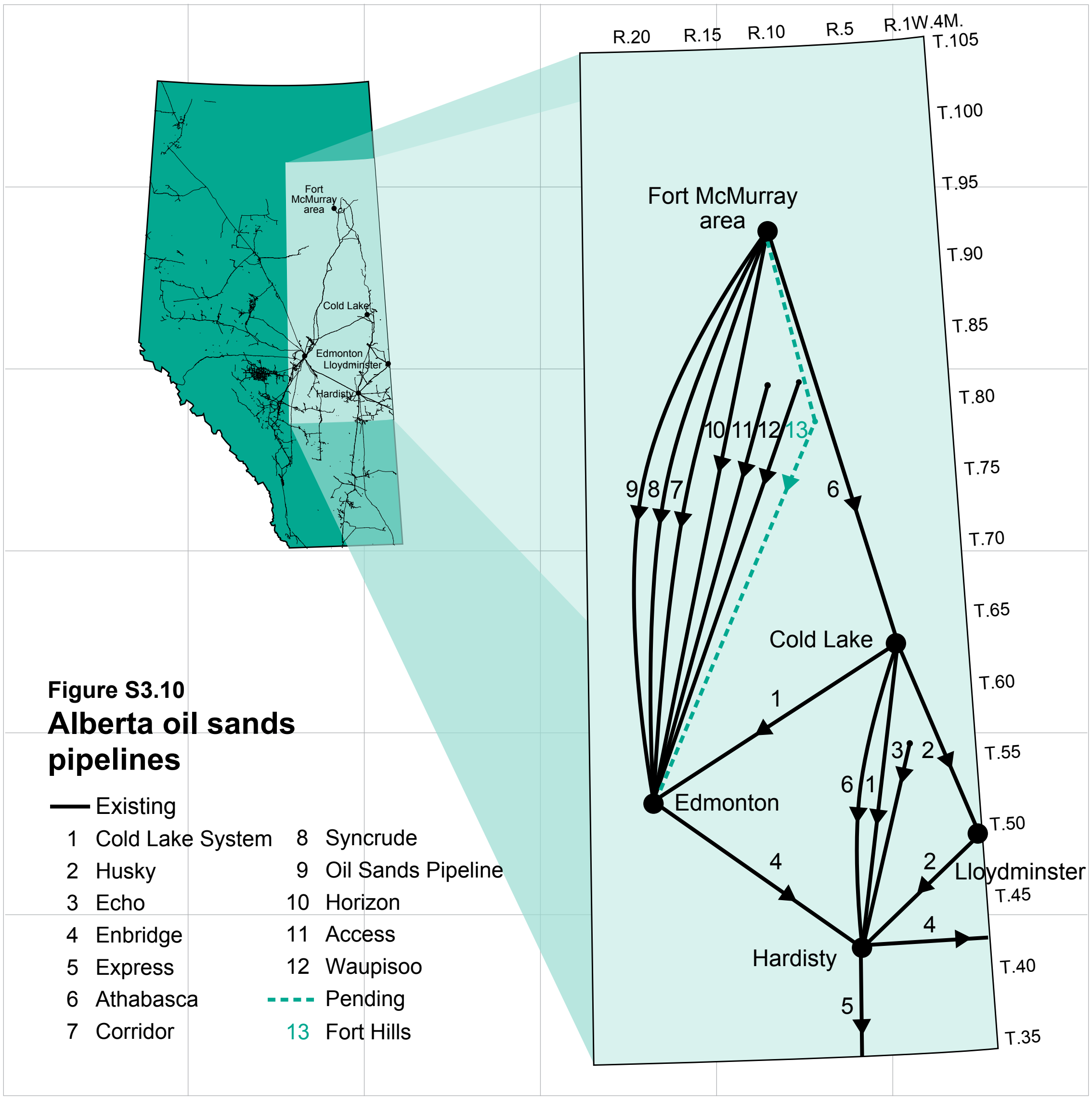


Figure S3.10
Alberta oil sands pipelines

- The Inter Pipeline Fund Corridor pipeline (7) transports diluted bitumen from the Albian Sands mining project to the Shell Scotford Upgrader near Edmonton.
- The Syncrude pipeline (formerly Alberta Oil Sands pipeline) (8) is the exclusive transporter for Syncrude. It runs from the Syncrude mine site north of Fort McMurray to the Edmonton area.
- The Oil Sands pipeline (9) transports Suncor upgraded bitumen to the Edmonton area.
- Pembina Pipeline's Horizon pipeline (10) is the exclusive transporter for CNRL's Horizon oil sands development. With an initial capacity of 39.7 10^3 m^3/d, it transports upgraded bitumen to the Edmonton area.
- The Access pipeline (11) transports diluted bitumen from the Christina Lake area to facilities in the Edmonton area. The capacity of the pipeline is 23.8 10^3 m^3/d, expandable to 63.9 10^3 m^3/d.

- The Enbridge Waupisoo pipeline (12) moves blended bitumen from the Cheecham Terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline has a current capacity of 55.6 10^3 m^3/d and is expandable to 95.3 10^3 m^3/d.

- The Rainbow pipeline system (not shown on **Figure S3.10**), owned by Plains Midstream and with a capacity of 31.7 10^3 m^3/d, transports Peace River oil sands crude oil and condensate from Rainbow Lake to Edmonton.

3.2.4.2 Proposed Alberta Pipeline Projects

- Access Pipeline intends to twin its existing pipeline (11), with the new pipeline being capable of transporting 55.6 10^3 m^3/d. The line is scheduled to be in service by 2015.

- Enbridge is proposing to expand its existing Waupisoo (12) line from the Cheecham Terminal to the Edmonton Terminal. This expansion would increase the line's capacity for transporting oil sands derived crude oil from 38.1 10^3 m^3/d to 87.4 10^3 m^3/d by 2013.

- Enbridge also intends to expand its capacity to move bitumen from the Christina Lake region by expanding the capacity of its Athabasca system (6), which moves product to the Hardisty Terminal.

- Enbridge has announced that the Fort Hills pipeline system (13) has been commercially secured and is currently pending based on customer timing.

- Inter Pipeline has announced that it intends to proceed with an integrated expansion of its Cold Lake (1) and Polaris (7) pipeline systems.

- Plains Midstream has announced that it intends to build a new pipeline, called the Rainbow Pipeline II. The line will mirror the existing line for much of the route and will connect the Enbridge Terminal, near Edmonton, to the existing Plains Nipisi Terminal.

3.2.4.3 Existing Removal Pipelines

Table S3.7 lists the existing removal pipelines with their corresponding destinations and capacities, and **Figure S3.11** shows the existing removal pipelines leaving Alberta.

- The Enbridge pipeline, the world's longest crude oil and products pipeline system, delivers western Canadian crude oil to eastern Canada and the U.S. Midwest.

- The Kinder Morgan Express pipeline begins at Hardisty and moves south to Casper, Wyoming, where it connects to the Platte pipeline, which extends east into Wood River, Illinois.

- The Kinder Morgan Trans Mountain pipeline system transports crude oil and refined products from Edmonton to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State. Trans Mountain's current capacity is 47.7 10^3 m^3/d, assuming that heavy oil represents some 20 per cent (historical average) of the total throughput.

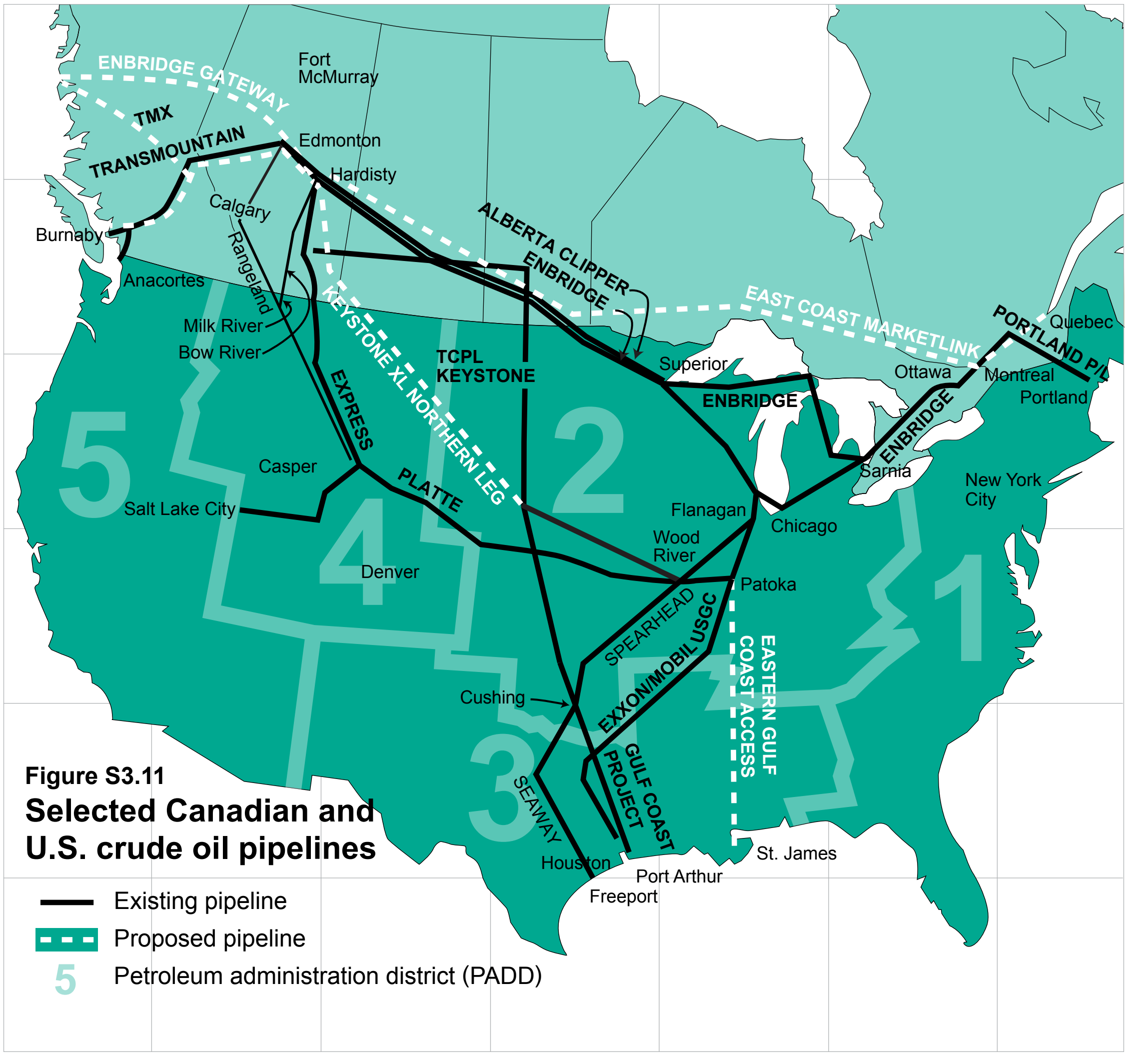


Figure S3.11
Selected Canadian and U.S. crude oil pipelines

- The Rangeland pipeline is a gathering system that serves as another export route for Cold Lake blended bitumen to Montana refineries.
- The Milk River pipeline delivers Bow River heavy crude oil to Montana refineries.
- TransCanada's Keystone pipeline, which commenced commercial operations in June 2011, ships crude oil to markets in the U.S. Midwest.
- Enbridge's Alberta Clipper pipeline, which was also completed in 2011, ships crude oil from Hardisty, Alberta, to Superior, Wisconsin.

3.2.4.4 Proposed Removal Pipeline Projects

Table S3.8 provides a summary of the pipeline expansions and new pipeline projects that are proposed to move upgraded and nonupgraded bitumen to existing and new markets. **Figure S3.11** shows the proposed removal pipeline expansions and new pipeline removal projects.

Table S3.7 Removal pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Enbridge Pipeline	Eastern Canada U.S. East Coast U.S. Midwest	301.9
Alberta Clipper Pipeline	U.S. Midwest	71.5
Kinder Morgan Canada		
Express Pipeline	U.S. Rocky Mountains U.S. Midwest	44.9
Trans Mountain Pipeline	British Columbia U.S. West Coast Offshore	47.7
Plains Midstream Canada		
Milk River Pipeline	U.S. Rocky Mountains	18.8
Pacific Energy Partners, L.P.		
Rangeland Pipeline	U.S. Rocky Mountains	13.5
TransCanada Corporation		
Keystone Pipeline	U.S. Midwest	93.8

Table S3.8 Proposed removal pipeline projects

Name	Destination	Incremental capacity (10^3 m^3/d)	Start-up date
Enbridge			
Gateway Pipeline	U.S. West Coast Offshore	83.3	2017
Kinder Morgan			
Trans Mountain Expansion	British Columbia U.S. West Coast Offshore	87.4	TBD
TransCanada Pipeline			
Keystone XL Pipeline	U.S. Gulf Coast	111.3	2015

3.2.4.5 Rail Transportation

Rail shipments, while growing, still represent a small portion of total volumes of crude bitumen moved from Alberta. Increasingly rail is being considered as producers seek to ensure that transportation is available for their production. Currently rail is being used to service projects with limited pipeline capacity or to export volumes to areas not serviced by pipeline. This may change in the future as companies such as Southern Pacific, MEG Energy, and Cenovus contract rail transport to secure transportation for their production and to access higher value markets.

Rail continues to play an important role in supplying the diluent needed to transport bitumen through pipelines. Currently, Canada's two main rail providers handle diluent at the Alberta Diluent Terminal in Edmonton, in addition to shipping crude oil from the Bakken play in Saskatchewan.

In the short term, it is anticipated that rail will continue to grow as producers seek to bypass short-term pipeline bottlenecks to take advantage of higher prices in PADD areas with refineries capable of handling heavier crudes. In the longer term, however, growth in shipments of bitumen by rail will depend on several factors, such as the availability and supply of diluent, the prices offered by other commodity producers already using rail, and the development of handling facilities to fill cars with bitumen. Currently, Canexus is expanding its rail terminal capacity at its Bruderheim facility, northeast of Edmonton. In addition, Keyera has announced that it will proceed with construction of the Keyera South Cheecham Rail and Truck Terminal, located southeast of Fort McMurray.

3.2.5 Demand for Upgraded Bitumen and Nonupgraded Bitumen

Alberta oil refineries use bitumen (both upgraded and nonupgraded) and other feedstocks to produce a wide variety of refined petroleum products. Overall, total Alberta demand for upgraded and nonupgraded bitumen was 55.2 10^3 m^3/d in 2012, which is 2 per cent above the 2011 level of 54.2 10^3 m^3/d. This increase was primarily due to higher capacity utilization rates of refineries.

In 2012, the five refineries in Alberta, with a total capacity of 74.6 10^3 m^3/d, used 46.5 10^3 m^3/d of upgraded bitumen and 2.9 10^3 m^3/d of nonupgraded bitumen. Additional demand for upgraded bitumen as diesel fuel and plant fuel accounted for 5.8 10^3 m^3/d in 2012, compared with 5.9 10^3 m^3/d in 2011, a decrease of 2 per cent. Alberta refineries consumed 32 per cent of Alberta upgraded bitumen production and 2 per cent of nonupgraded bitumen production in 2012, compared with the 33 per cent of Alberta upgraded bitumen production and 2 per cent of nonupgraded bitumen production consumed in 2011.

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

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

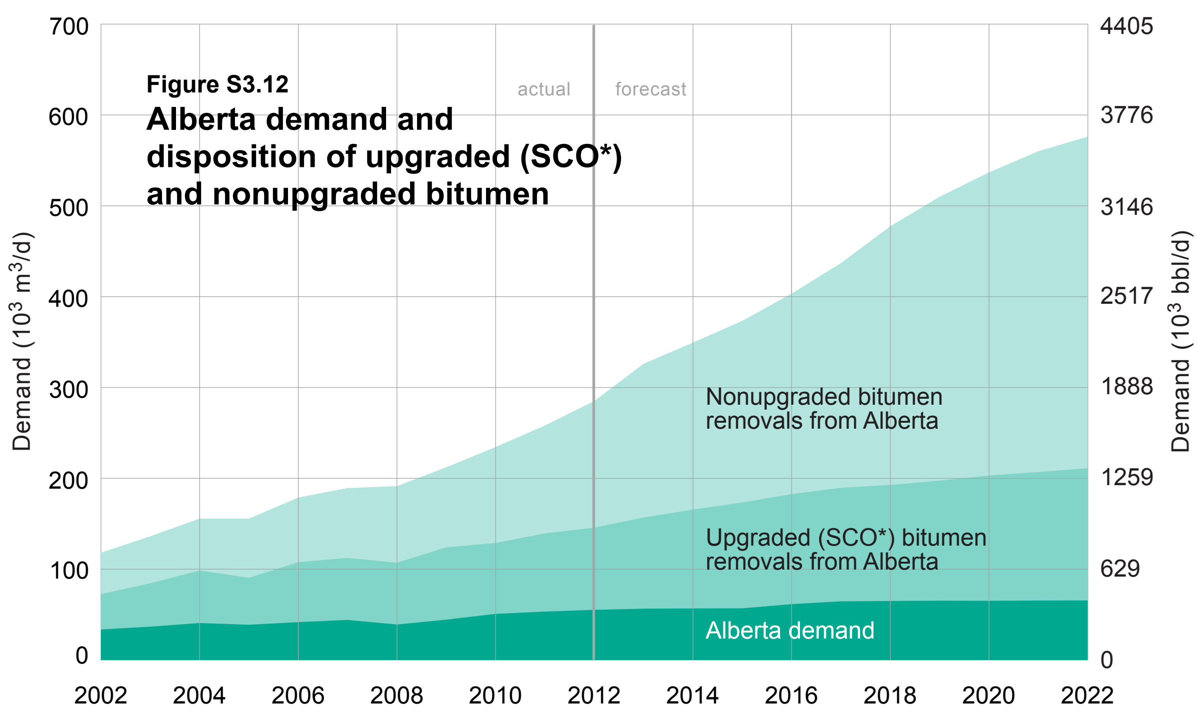
Upgraded bitumen is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor also operates a Suncor Energy-branded "cardlock" station where it sells diesel fuel supplied from its oil sands operation in the Fort McMurray area. In 2012, the sale of refined upgraded bitumen as diesel fuel oil accounted for about 8 per cent of Alberta upgraded bitumen demand, similar to 2011.

Figure S3.12 shows that by 2022, Alberta demand for upgraded and nonupgraded bitumen will increase to about 65.6 10^3 m^3/d. It is projected that, on average, upgraded bitumen will account for approximately 84 per cent of total Alberta demand, and nonupgraded bitumen will account for approximately 16 per cent throughout the forecast period.

As illustrated in **Figure S3.12**, removals of upgraded bitumen from Alberta will increase from 90.5 10^3 m^3/d in 2012 to 145.6 10^3 m^3/d in 2022, with removals of nonupgraded bitumen increasing from 139.4 10^3 m^3/d to 364.9 10^3 m^3/d over the same period.

Given the current quality of upgraded bitumen, western Canada's eight refineries, with a total capacity of 99.8 10^3 m^3/d, are able to blend up to 34 per cent upgraded bitumen and a further 2 per cent of blended bitumen with crude oil. These refineries receive upgraded bitumen from both Alberta and Saskatchewan. The four refineries in the Sarnia area of eastern Canada, with a combined total capacity of 56.6 10^3 m^3/d, are currently the sole ex-Alberta Canadian market for Alberta upgraded bitumen.

With resurgent light oil supplies in western Canada and the U.S. Midwest, and an oversupplied U.S. Midwest market, discounting of upgraded bitumen and western Canada light oil is expected to continue in the short term. The largest export markets for Alberta upgraded and nonupgraded bitumen have traditionally been the U.S. Midwest, with a refining capacity of 569^3 m^3/d, and the U.S. Rocky Mountain region, with a refining capacity of 98 10^3 m^3/d. However, these markets are now currently oversupplied due to the increase in light oil production and limited pipeline capacity to other markets. As such, there is increasing interest in accessing other market regions going forward. Among the other regions is the U.S. Gulf Coast, with a refining capacity of 1399 10^3 m^3/d. Access to this region is of particular importance for nonupgraded bitumen, as this region has traditionally been served by heavy oil and maintains refineries capable of handling the nonupgraded bitumen.



*Synthetic crude oil.

HIGHLIGHTS

Remaining established reserves increased almost 10 per cent year over year.

Reserves additions from new drilling and enhanced recovery schemes replaced 189 per cent of production in 2012.

Production increased 14 per cent in 2012 compared with 2011.

There were 3107 oil wells placed on production in 2012, a decrease of 1 per cent from 2011.

4 CRUDE OIL

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

4.1 Reserves of Crude Oil

4.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of conventional crude oil in Alberta to be 269.2 million cubic metres (10^6 m^3), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 23.3 10^6 m^3, or 9.5 per cent, resulting from production, reserves adjustments, and additions from drilling that occurred during 2012.

Table R4.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2012, while **Figure R4.1** shows the province's remaining conventional oil reserves over time. Remaining reserves have decreased to 22 per cent of the peak reserves of 1223 10^6 m^3 set in 1969.

4.1.2 In-Place Resources

The total initial in-place and remaining in-place resources for conventional oil in Alberta stand at 12 026 10^6 m^3 and 9374 10^6 m^3, respectively. Sixty-four per cent of remaining in-place resources (6014 10^6 m^3) are in the largest 200 pools. This remaining resource in place represents a substantial potential for increased recovery through enhanced oil recovery (EOR) or new drilling and completion techniques, such as high-density drilling and multistage fracturing. On average, 25 per cent of the total oil in place in these pools is expected to be recovered with today's technology. Additionally, the new shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.1** identified 67 320 10^6 m^3 of unconventional in-place shale oil resources in six key shale formations in Alberta.

4.1.3 Established Reserves

The initial established reserves attributed to the 323 new oil pools defined in 2012 totalled 5.8 10^6 m^3 (an average of 18 thousand [10^3] m^3 per pool), up from 4.0 10^6 m^3 in 2011. **Table R4.2** breaks down the changes to initial established reserves in 2012 into the following categories: new discoveries, development of existing pools, new

Table R4.1 Reserves and production change highlights (10^6 m^3)

	2012	2011	Change
Initial established reserves[a]			
Light-medium	2 525.0	2 474.7	+50.4
Heavy	396.7	388.5	+8.2
Total	**2 921.7**	**2 863.2**	**+58.5**
Cumulative production[a]			
Light-medium	2 320.5	2 296.7	+23.8
Heavy	332.0	320.6	+11.4
Total	**2 652.5**	**2 617.3**	**+35.2**[b]
Remaining established reserves[b]			
Light-medium	204.5	178.0	+26.5
Heavy	64.7	67.9	-3.2
Total	**269.2**	**245.9**	**+23.3**
	(1 694 10^6 bbl[c])		
Annual production			
Light-medium	23.8	20.3	+3.5
Heavy	8.5	8.1	+0.4
Total	**32.3**	**28.4**	**+3.9**

[a] Any discrepancies are due to rounding.

[b] May differ from annual production due to amendments to reported production and other reasons.

[c] bbl = barrels.

and expansions to EOR schemes, and revisions to existing reserves. **Figure R4.2** shows the history of additions and net revisions to reserves. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

The ERCB processed 53 applications, significantly fewer than the 130 in 2011, for new EOR schemes or expansions to existing schemes, resulting in reserves additions totalling 2.2 10^6 m^3, compared with 6.4 10^6 m^3 in 2011 (**Figure R4.3**). Development of existing pools added established reserves of 52.9 10^6 m^3, the largest increase in over 25 years. This is discussed in more detail in **Section 4.1.3.1**. Total reserves growth from new

Table R4.2 Breakdown of changes in crude oil initial established reserves (10^6 m^3)

	Light-medium	Heavy	Total[a]
New discoveries	5.3	0.5	**5.8**
Development of existing pools	46.4	6.5	**52.9**
Enhanced recovery (new/expansion)	1.6	0.6	**2.2**
Revisions	-2.9	+0.6	**-2.4**
Total[a]	**+50.4**	**+8.2**	**+58.5**

[a] Any discrepancies are due to rounding.

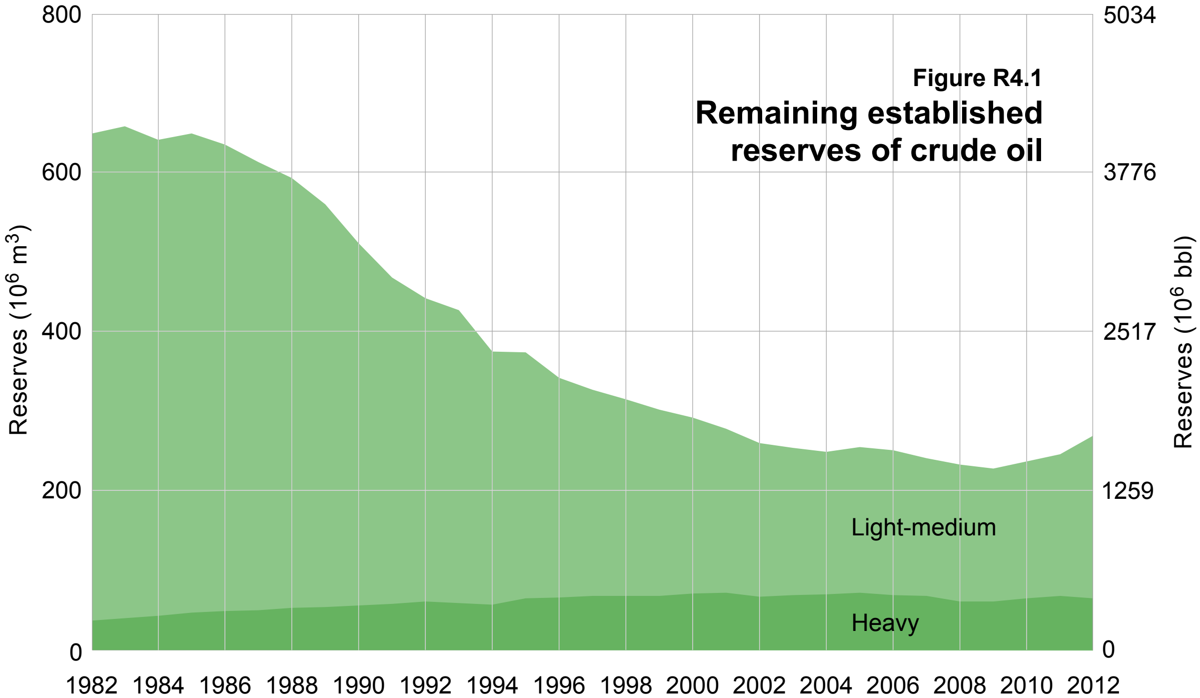


Figure R4.1
Remaining established reserves of crude oil
Reserves (10^6 m^3)
Reserves (10^6 bbl)
800
600
400
200
0
5034
3776
2517
1259
0
Light-medium
Heavy
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012

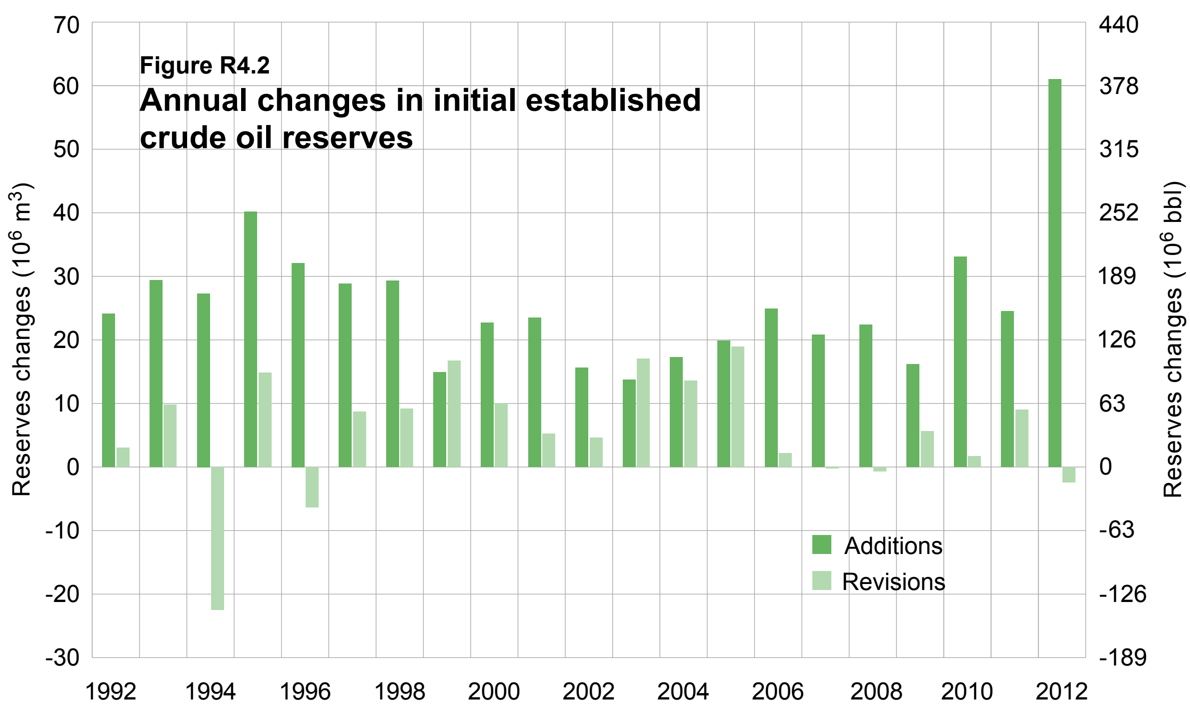
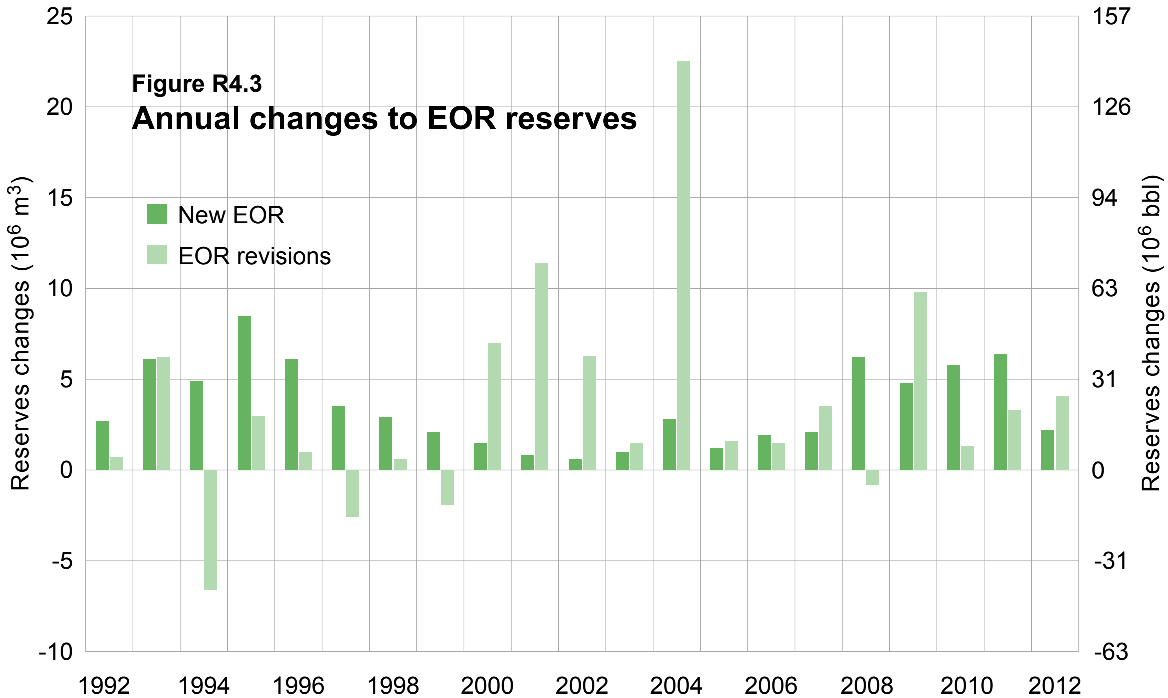


Figure R4.2
Annual changes in initial established crude oil reserves
Reserves changes (10^6 m^3)
Reserves changes (10^6 bbl)
70
60
50
40
30
20
10
0
-10
-20
-30
440
378
315
252
189
126
63
0
-63
-126
-189
Additions
Revisions
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012



drilling plus new and expanded EOR schemes (excluding revisions) amounted to 61 10^6 m^3, replacing 189 per cent of the 32.3 10^6 m^3 total conventional crude oil production in Alberta. This compares with a previous five-year average replacement ratio of about 83 per cent. Revisions to existing reserves resulted in an overall net change of −2.4 10^6 m^3. The total increase in initial established reserves for 2012 amounted to 58.5 10^6 m^3, compared with 2011's 33.5 10^6 m^3. **Table B.3** in **Appendix B** provides a history of conventional oil reserves growth and cumulative production from 1968 to 2012.

As of December 31, 2012, oil reserves were assigned to 10 570 light-medium and 2804 heavy crude oil pools in the province. While some of these pools contain thousands of wells, most consist of a single well. About 70 per cent of the province's remaining oil reserves are recoverable from the largest 3 per cent of pools (400 pools), most discovered before 1980. The largest of these pools in terms of remaining reserves include Pembina Cardium, Swan Hills Commingled Pool 001, Redwater Commingled Multifield Pool 9508, Ferrier Commingled Pool 001, and Evi Commingled Pool 001. In contrast, the smallest 75 per cent of pools contain only 5 per cent of remaining reserves.

While the median pool size has consistently been less than 10 10^3 m^3 since the mid-1970s, the average size has declined from 155 10^3 m^3 in 1970 to about 20 10^3 m^3 today. The largest oil pools discovered over the past ten years include the Judy Creek Beaverhill H Pool and Pembina Cardium JJJ Pool, with currently booked remaining reserves of 1040 10^6 m^3 and 900 10^6 m^3, respectively.

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

4.1.3.1 Largest Reserves Changes

Table R4.3 lists pools with the largest reserves changes in 2012. By far the most significant change was to the Pembina Cardium, which saw initial established reserves increase by 15 400 10^3 m^3 to 251 200 10^3 m^3 as a result of extensions to the primary area. This compares with a total increase due to pool development of 52.9 10^6 m^3. There continues to be potential for significant reserves growth from new horizontal drilling in the Cardium Formation at Pembina, Willesden Green, and other fields. Horizontal, multistage fractured wells are being drilled on the periphery of the main pools where permeability declines to less than 1 millidarcy (mD) as a result of a change to a shalier facies. Horizontal drilling is also coaxing new reserves from the tighter platform facies in

Table R4.3 Major oil reserves changes, 2012

	Initial established reserves (10^3 m^3)		
Pool	**2012**	**Change**	**Main reason for change**
Ante Creek North Triassic E	2 883	+485	Pool development
Brazeau River Cardium LL	567	+501	Pool development and reassessment of reserves
Carson Creek Beaverhill C	448	+448	Reassessment of produced fluid and reserves
Evi Commingled Pool 001	6 454	+6 172	Pool development and amalgamation of pools
Garrington Commingled Pool 002	11 760	+4 701	Pool development and reassessment of reserves
Harmattan East Cardium C	563	+561	Pool development and reassessment of reserves
Innisfail D-3	13 700	-350	Reassessment of reserves
Judy Creek Beaverhill Lake A	60 405	+1 700	Reassessment of tertiary scheme
Judy Creek Beaverhill Lake H	1 265	+1 142	Pool development
Kaybob Triassic G	1 305	+1 071	Pool development
Killam North Upper Manville F2F	1 146	-266	Reassessment of waterflood reserves
Lloydminster Lloydminster F	1 258	+328	Pool development and new waterflood scheme
Lloydminster Commingled Pool 012	9 477	+2 550	Pool development and reassessment of reserves
Lochend Commingled Pool 001	1 416	+407	Pool development and reassessment of reserves
Mooney Bluesky A	2 463	+1 046	Development of chemical flood reserves
Morgan Commingled Pool 0018	8 008	+616	Pool development and reassessment of EOR scheme
Nipisi Slave Point D	556	+377	Pool development
Pembina Cardium	251 200	+15 400	Pool development and reassessment of reserves
Pouce Coupe South Boundary B	2 892	+423	Reassessment of waterflood reserves
Red Earth Commingled Pool 001	7 383	+412	Pool development
Redwater Commingled MFP9508	7 304	+509	Reassessment of reserves
Rycroft Montney C	670	+310	Pool development and reassessment of reserves
Sawn Lake Slave Point J	1 848	+334	Pool development
Spirit River Commingled Pool 005	654	+501	Pool development and reassessment of reserves
Wipiti Commingled Pool 001	2 322	+488	Pool development
Wayne-Rosedale Commingled MFP9501	1 616	+1 321	Pool development and reassessment of reserves

the Beaverhill Lake and Slave Point formations as demonstrated by the 1700 10^3 m^3 and 6172 10^3 m^3 increase in reserves in the Judy Creek Beaverhill Lake A Pool and Evi Commingled Pool 001, respectively. The largest negative revision was to Innisfail D-3 Pool, where reserves were revised downwards by 350 10^3 m^3.

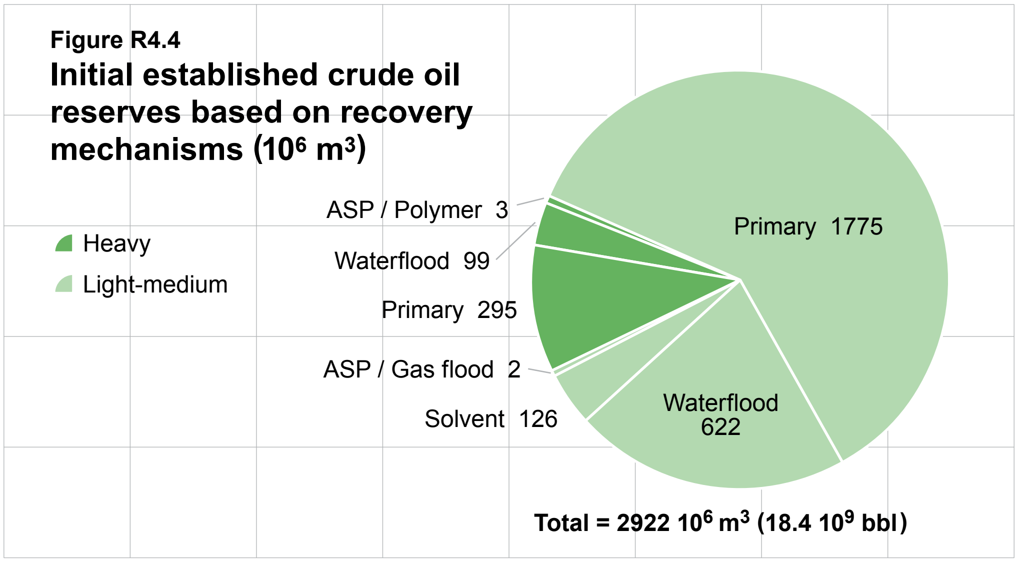
4.1.1. Distribution by Recovery Mechanism

The overall recovery efficiency for Alberta's conventional crude oil averages 24 per cent based on total initial volume in place and initial established reserves of 12 026 10^6 m^3 and 2922 10^6 m^3, respectively. **Figure R4.4** and **Table R4.4** show the distribution of in-place volumes and reserves by recovery mechanism and crude oil classification.

In light-medium pools under waterflood, recovery increased from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Pools under solvent flood, on average, recovered 12 per cent more than projected theoretical waterflood recovery. Primary recovery in heavy crude pools has increased from an average 8 per cent in 1990 to 11 per cent in 2012 as a result of improved water handling, increased drilling density, and the use of horizontal wells with multistage fracturing. Incremental recovery from all waterflood projects represents about 25 per cent of the province's initial established reserves, while solvent floods are projected to add 5 per cent to the province's recoverable reserves. Alkali surfactant polymer (ASP) flooding is proving to be very effective and becoming more accepted, typically adding 3 to 10 per cent recovery over waterflood. Polymer flooding is most effective and used mainly in heavy oil pools.

Table R4.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2012

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	4 917	947	0	0	**947**	19	-	-	**19**
Waterflood	3 419	515	429	0	**944**	15	13	-	**28**
Solvent flood	1032	273	177	126	**576**	26	17	12	**56**
ASP	21	3	6	2	**11**	14	29	10	**52**
Gas flood	126	37	10	0	**47**	29	8	-	**37**
Heavy									
Primary	1 764	201	0	0	**201**	11	-	-	**11**
Waterflood	695	88	91	0	**179**	13	13	-	**26**
Polymer	22	2	2	1	**5**	9	9	5	**23**
ASP	30	4	6	2	**12**	13	20	7	**40**
Total	**12 026**	**2 070**	**721**	**131**	**2 922**	**17**	**6**	**1**	**24**
Percentage of total initial established reserves		71%	25%	5%	**100%**				



4.1.2. Distribution by Geological Formation and Area

The distribution of reserves by geological period (**Figure R4.5**) shows that the Cretaceous and Upper Devonian ages provide the major source for remaining conventional oil. **Figure R4.6** depicts reserves by Petroleum Services Association of Canada (PSAC) area with the central part of the province (PSAC 5) containing most of the remaining reserves.

4.1.3. Oil Reserves Methodology

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

Converting volume in place to standard conditions at the surface requires applying oil shrinkage data obtained from pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir-drive mechanism. Recoveries range from 5 per cent for heavy oils to over 50 per cent for light-medium oils producing from highly permeable reefs with full pressure support from an active underlying aquifer. Provincially, 25 per cent of the in-place resource is recovered on average.

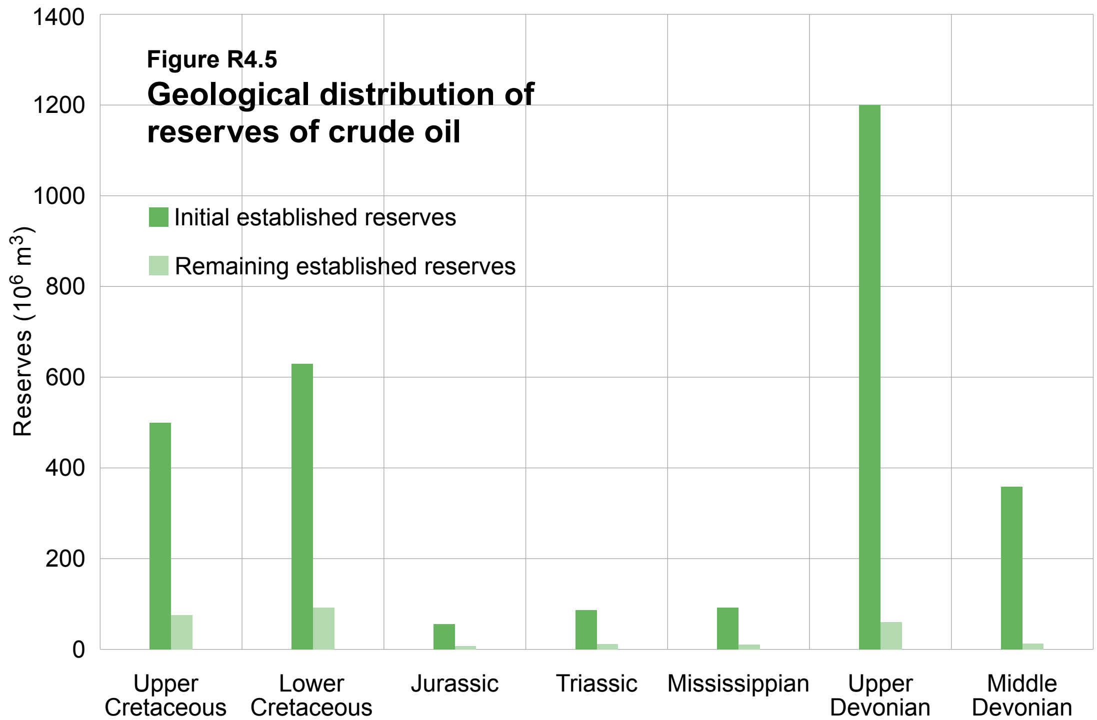


Figure R4.5
Geological distribution of reserves of crude oil

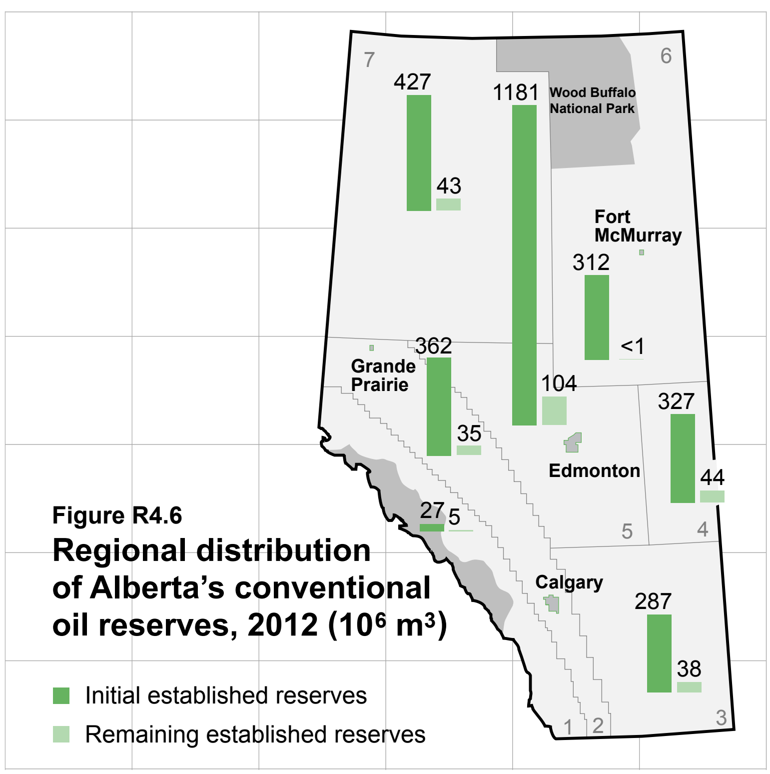


Figure R4.6
Regional distribution of Alberta's conventional oil reserves, 2012 (10^6 m^3)

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

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

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

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

4.1.4 Ultimate Potential

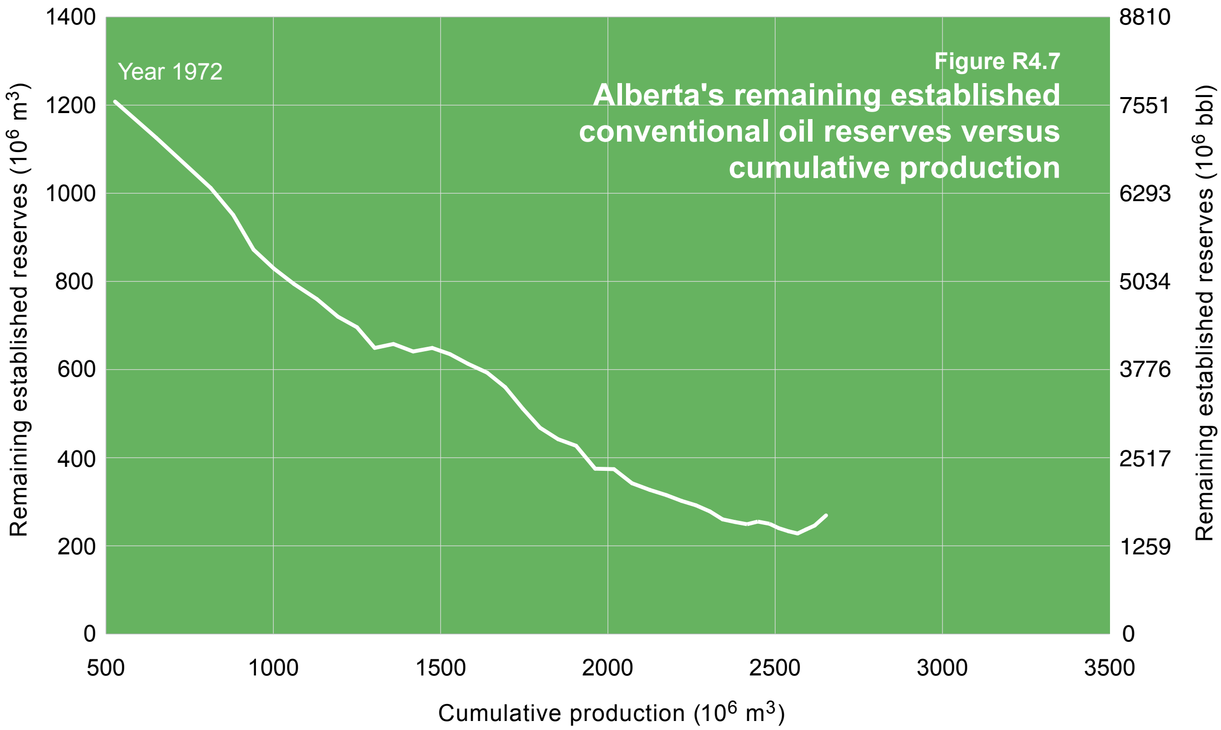
In 1994, based on the geological prospects at that time, the ERCB estimated the ultimate potential of conventional crude oil to be 3130 10^6 m^3. This estimate does not include potential oil from very low permeability reservoirs, referred to by industry as "tight oil." **Figure R4.7** illustrates the historical decline in remaining established reserves relative to cumulative oil production.

4.2 Supply of and Demand for Crude Oil

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

4.2.1 Crude Oil Production – 2012

Starting in 2010, total crude oil production in Alberta reversed the downward trend that was the norm since the early 1970s. Since 2010, light-medium crude oil production has increased as a result of increased horizontal drilling activity with the introduction of multistage hydraulic fracturing technology. The successful application of this technology and increased drilling resulted in total crude oil production increasing by 14 per cent in 2012



to 88.4 10^3 m^3/d from 77.9 10^3 m^3/d. Light-medium crude oil production increased in 2012 to 65.1 10^3 m^3/d, an increase of 17 per cent from 2011. Heavy crude oil production also increased, rising 6 per cent to 23.3 10^3 m^3/d.

4.2.1.1 Drilling Activity

In 2012, 2854 successful oil wells were drilled, an decrease of 10.2 per cent from 2011. **Figure S4.1** shows the number of successful oil wells drilled in Alberta in 2011 and 2012 by PSAC geographical area. As shown in the figure, most areas of the province in which drilling occurred, in particular PSAC Areas 3, 4, and 7, experienced substantial decreases over last year's levels.

Figure S4.2 depicts the distribution of new crude oil wells placed on production, and **Figure S4.3** shows the initial operating day rates of new wells in 2012. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are put on production shortly after being drilled. In 2012, however, the number of wells placed on production decreased by 1 per cent, from 3138 in 2011 to 3107.

4.2.1.2 Production Characteristics

Historical oil production by PSAC area is illustrated in **Figure S4.4**. In 2012, PSAC Areas 2, 4, and 5 experienced increases in production when compared with 2011, ranging from a 2 per cent increase in PSAC Area 4 to a 27 per cent increase in PSAC Area 2.

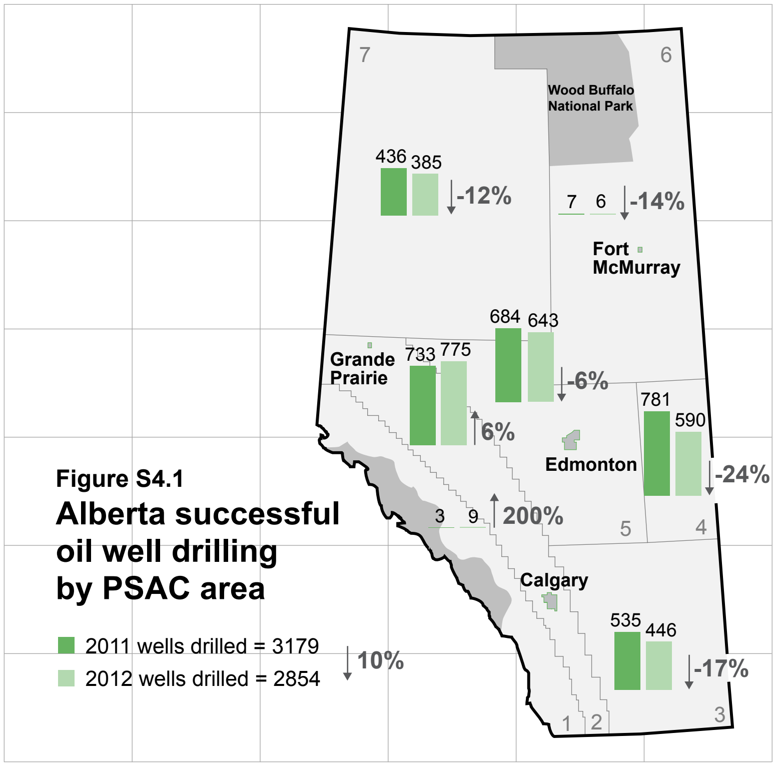


Figure S4.1
Alberta successful oil well drilling by PSAC area

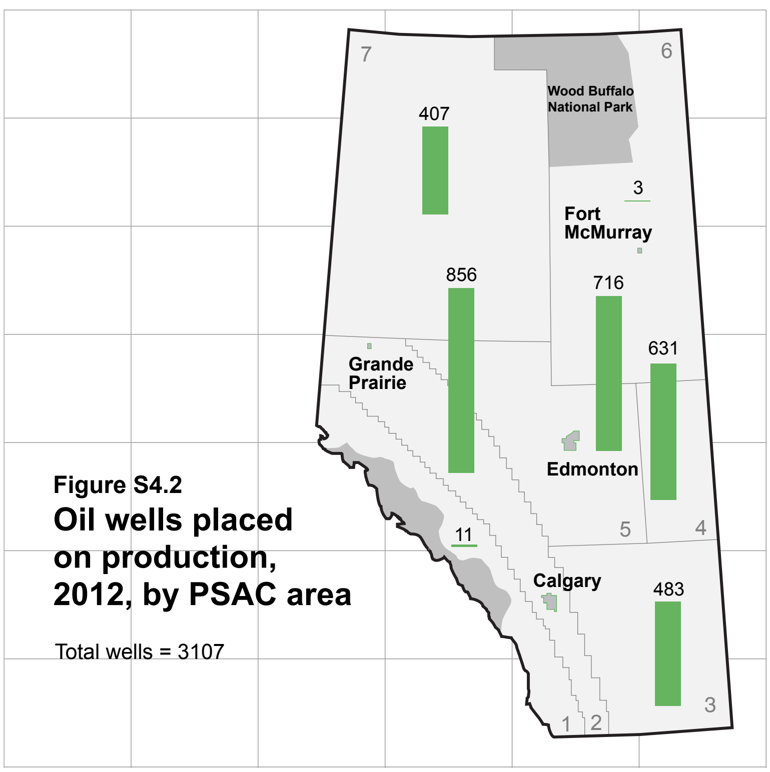


Figure S4.2
Oil wells placed on production, 2012, by PSAC area

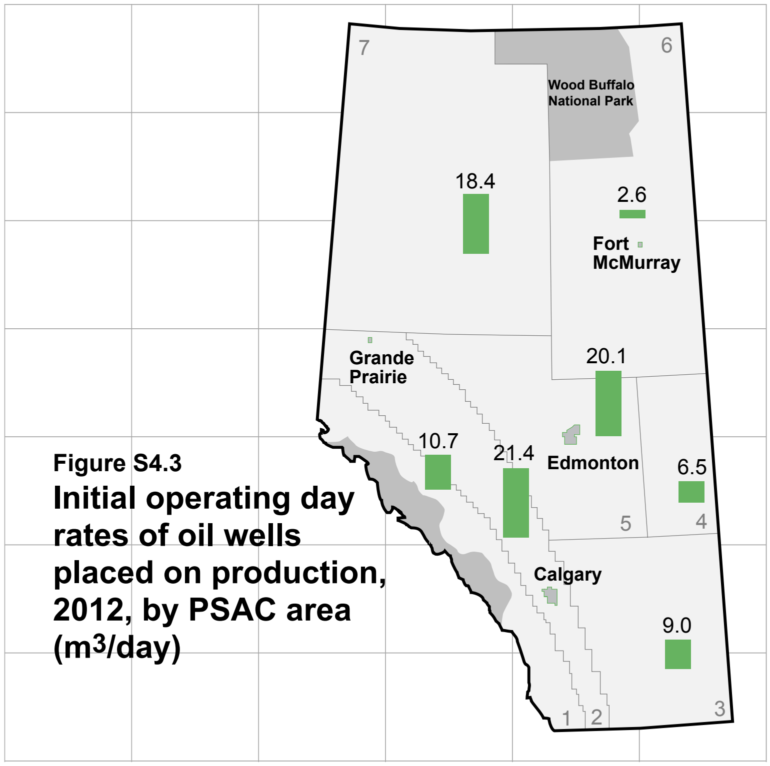


Figure S4.3
Initial operating day rates of oil wells placed on production, 2012, by PSAC area (m^3/day)

Figure S4.5 shows the total average daily production rate and the number of wells producing crude oil. Initial average daily production rates were calculated for new wells, using the first full calendar year of production. The number of wells producing oil has increased over time from 9100 in 1970 to 41 883 in 2012. The average annual production rate of crude oil producing wells, however, has been on the decline since 1973.

In addition to the 41 883 crude producing oil wells in 2012, there were about 2720 wells classified as gas wells that were producing oil. Although these gas wells represented 6 per cent of the total wells that produced oil, they produced at a very low average rate of 0.2 m^3/d and accounted for less than 1 per cent of total production. About 9664 producing horizontal oil wells, despite representing only 22 per cent of producing oil wells, contributed about 47 per cent to the total crude oil production because of the higher average production rate per well.

The average daily production rate per well in 1973 for all producing oil wells was 23 m^3/d. This average declined to 5.5 m^3/d by 1991, reaching the lowest level of 1.9 m^3/d by 2009 where it remained until 2011 when it began to increase as a result of increased drilling activity.

Figure S4.6 depicts producing oil wells and the average daily production rates of those wells by region in 2012. The average well productivity of producing oil wells in 2012 was 2.0 m^3/d. Roughly 44 per cent of producing oil wells produce at rates less than 1 m^3/d per well, a characteristic typical of mature basins. In 2012, the 17 060 oil wells in this category produced at an average rate of 0.5 m^3/d and accounted for only 10 per cent of the total crude oil produced. **Figure S4.7** shows the distribution of crude oil producing wells (including horizontal oil wells) based on their average production rates in 2012.

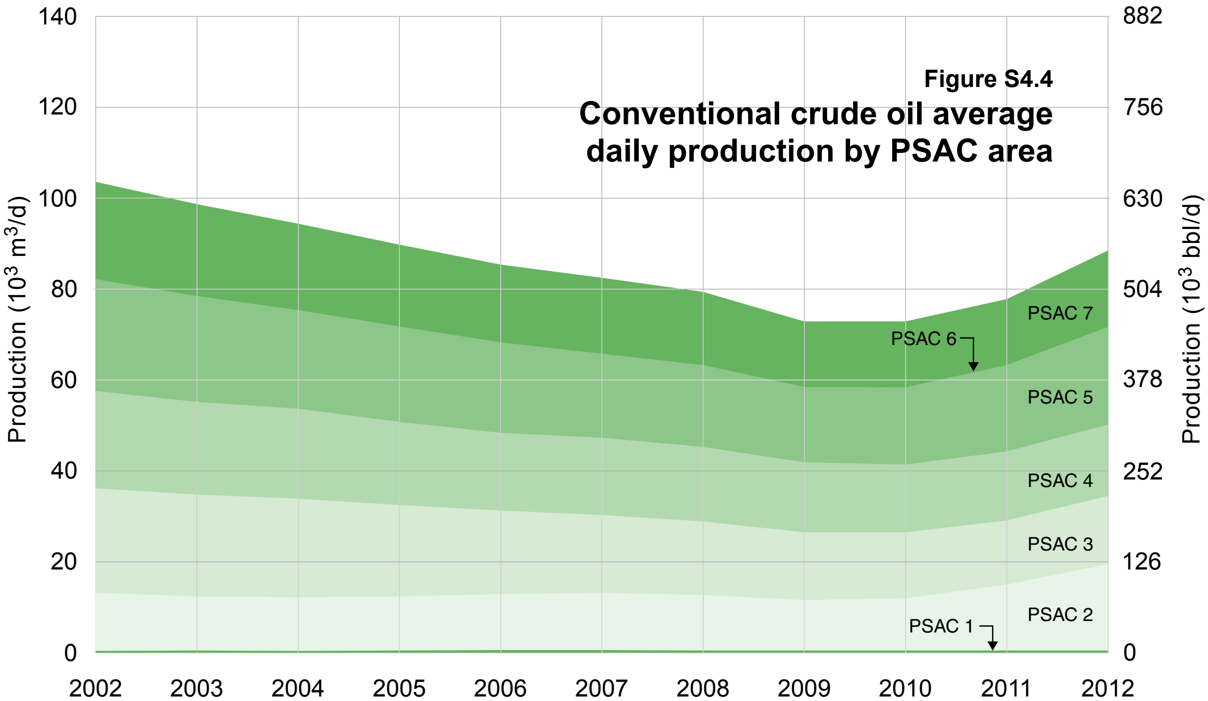


Figure S4.4
Conventional crude oil average daily production by PSAC area
Production (10^3 m^3/d)
Production (10^3 bbl/d)
140
120
100
80
60
40
20
0
882
756
630
504
378
252
126
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
PSAC 7
PSAC 6
PSAC 5
PSAC 4
PSAC 3
PSAC 2
PSAC 1

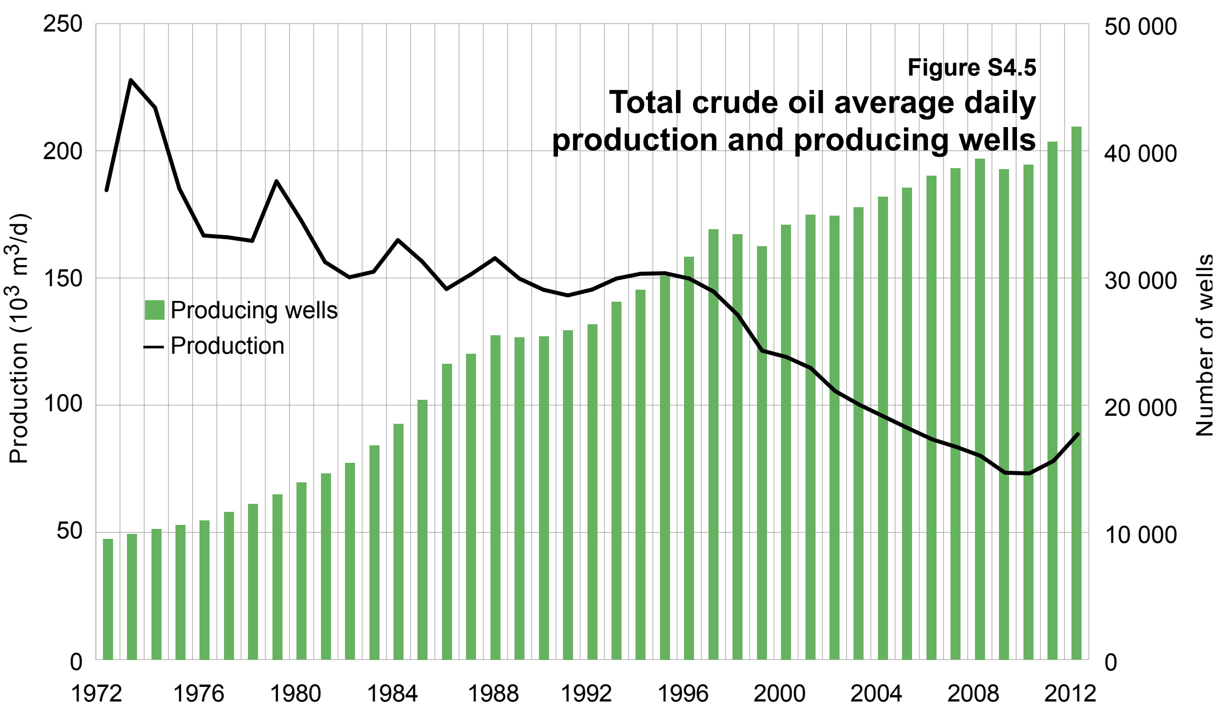


Figure S4.5
Total crude oil average daily production and producing wells
Production (10^3 m^3/d)
Number of wells
Producing wells
Production
250
200
150
100
50
0
50 000
40 000
30 000
20 000
10 000
0
1972
1976
1980
1984
1988
1992
1996
2000
2004
2008
2012

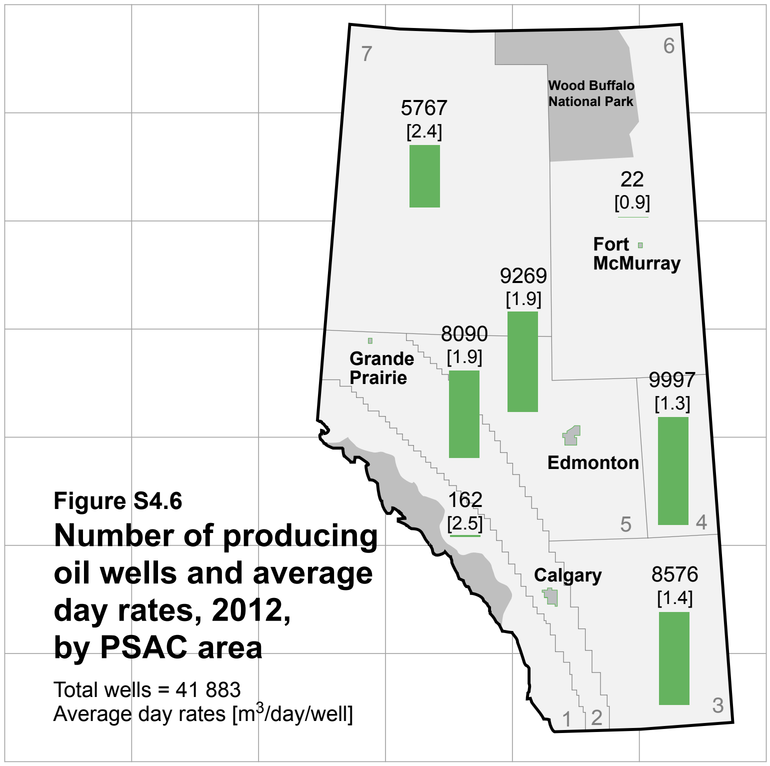


Figure S4.6
Number of producing oil wells and average day rates, 2012, by PSAC area
Total wells = 41 883
Average day rates [m^3/day/well]

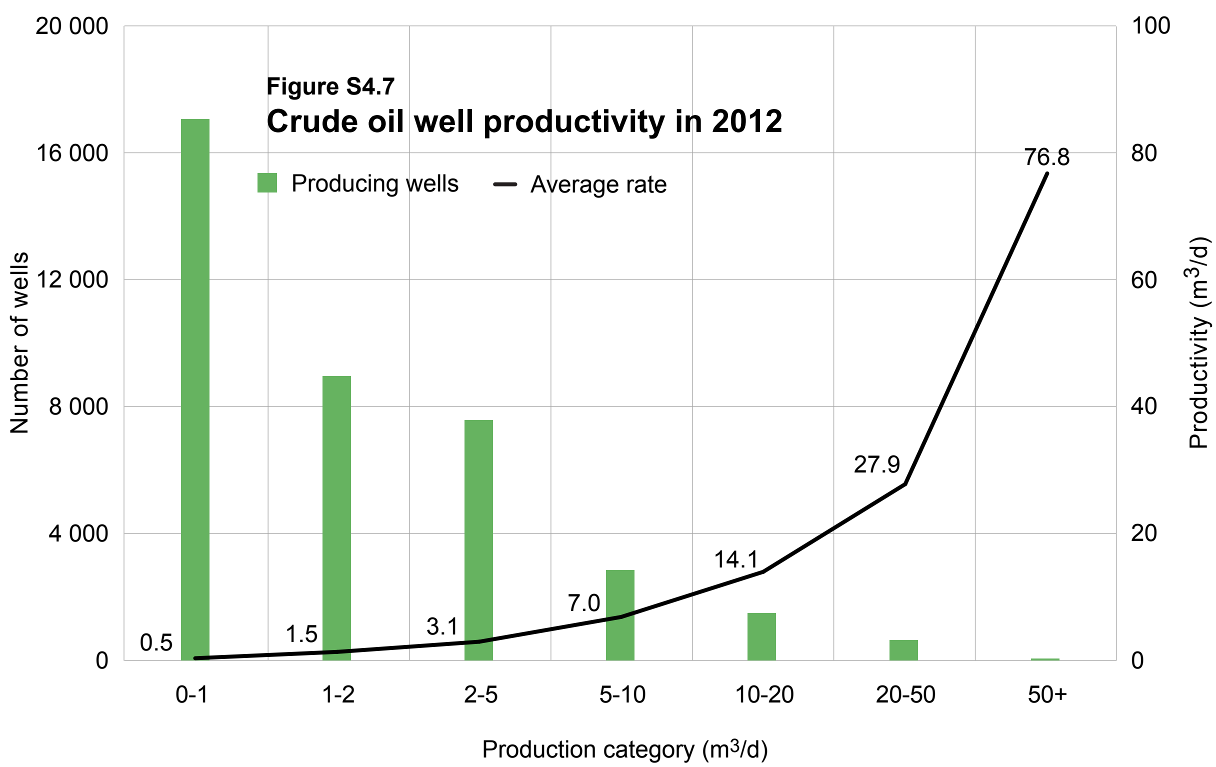


Figure S4.7
Crude oil well productivity in 2012

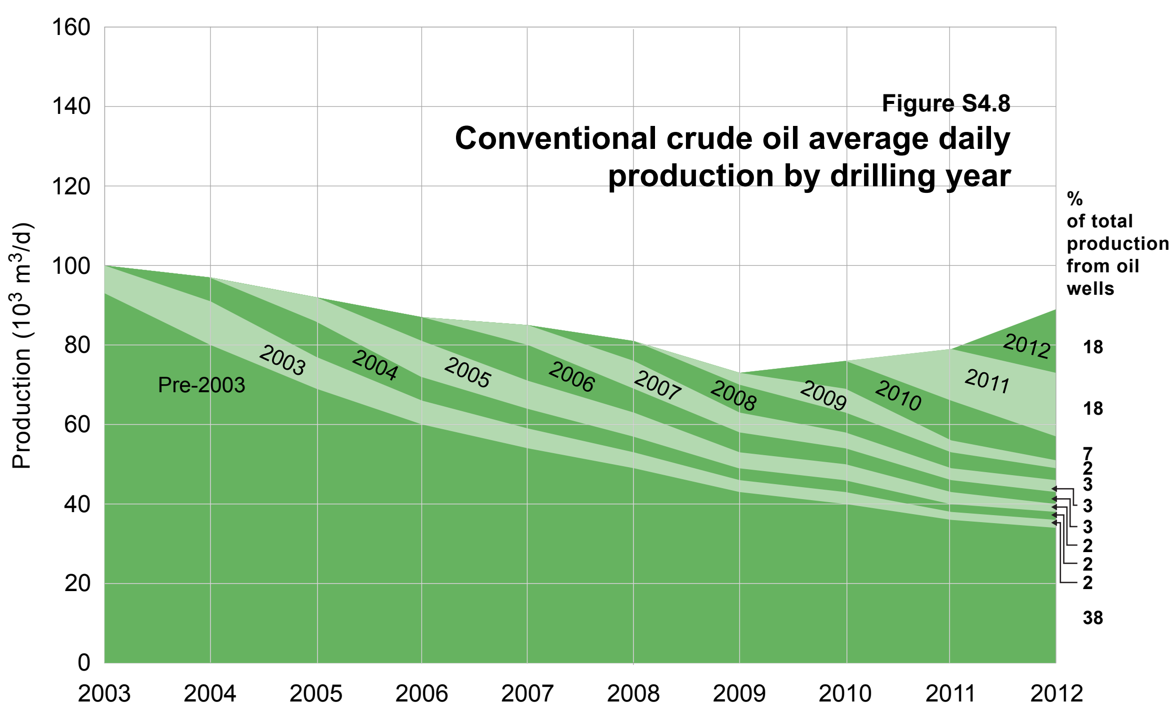
In 2012, 2379 new horizontal oil wells (including those using multistage fracturing technology) were brought on production, an increase of 31 per cent from the 2011 level of 1818 horizontal wells. This raises the total number of horizontal wells to 9664.

For all types of completion for new horizontal wells, the initial production rate was 6.5 m^3/d, compared with 3.3 m^3/d for vertical wells.

Crude oil production from existing wells placed on production from 2003 to 2012 is depicted in **Figure S4.8**. This figure illustrates that wells placed on production in the last five years represent 48 per cent of crude oil production in 2012.

Figure S4.9 compares historical Alberta crude oil production with crude oil production from Texas onshore and North Dakota. North Dakota production has been relatively flat since 1981; however, since around 2007, production has escalated rapidly, and 2012 production levels are approximately five times the 2007 production levels due to the successful application of horizontal multistage fracturing technology. North Dakota's oil production surpassed Alberta's conventional oil production in 2012, which may result in reduced U.S. demand for Alberta's crude oil. Since 2010, Texas onshore and Alberta production have also reversed the downward production trend, exhibiting significant growth in 2012.

Figure S4.10 shows the oil production profiles for the first 35 months for a representative sample set of vertical and horizontal oil wells in the Pembina Field that are producing crude oil from the Cardium Formation. Oil wells that were placed on production within the 2010 to 2012 period were used to illustrate the difference in production profiles by well type.



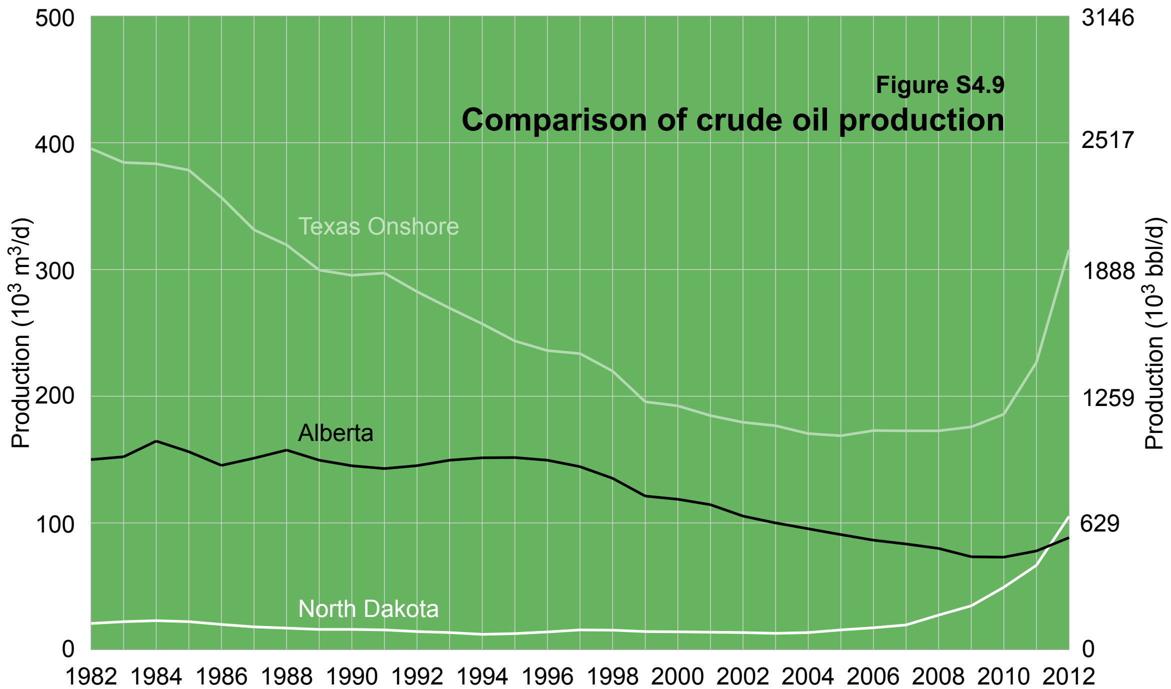


Figure S4.9
Comparison of crude oil production
Texas Onshore
Alberta
North Dakota
Production (10^3 m^3/d)
Production (10^3 bbl/d)
500
400
300
200
100
0
3146
2517
1888
1259
629
0
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012

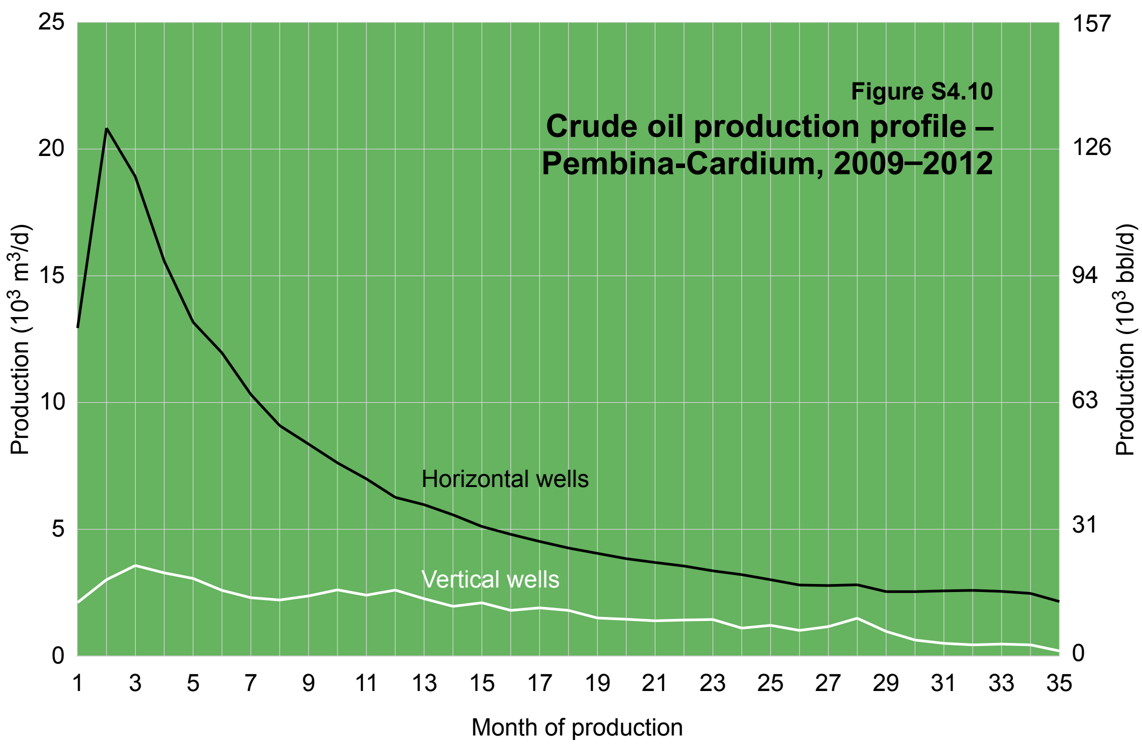


Figure S4.10
Crude oil production profile – Pembina-Cardium, 2009–2012
Horizontal wells
Vertical wells
Production (10^3 m^3/d)
Production (10^3 bbl/d)
Month of production
25
20
15
10
5
0
157
126
94
63
31
0
1
3
5
7
9
11
13
15
17
19
21
23
25
27
29
31
33
35

Total production from new wells is a function of the number of new wells that are anticipated to be placed on production, initial production rates, and the expected average decline rates for these new wells.

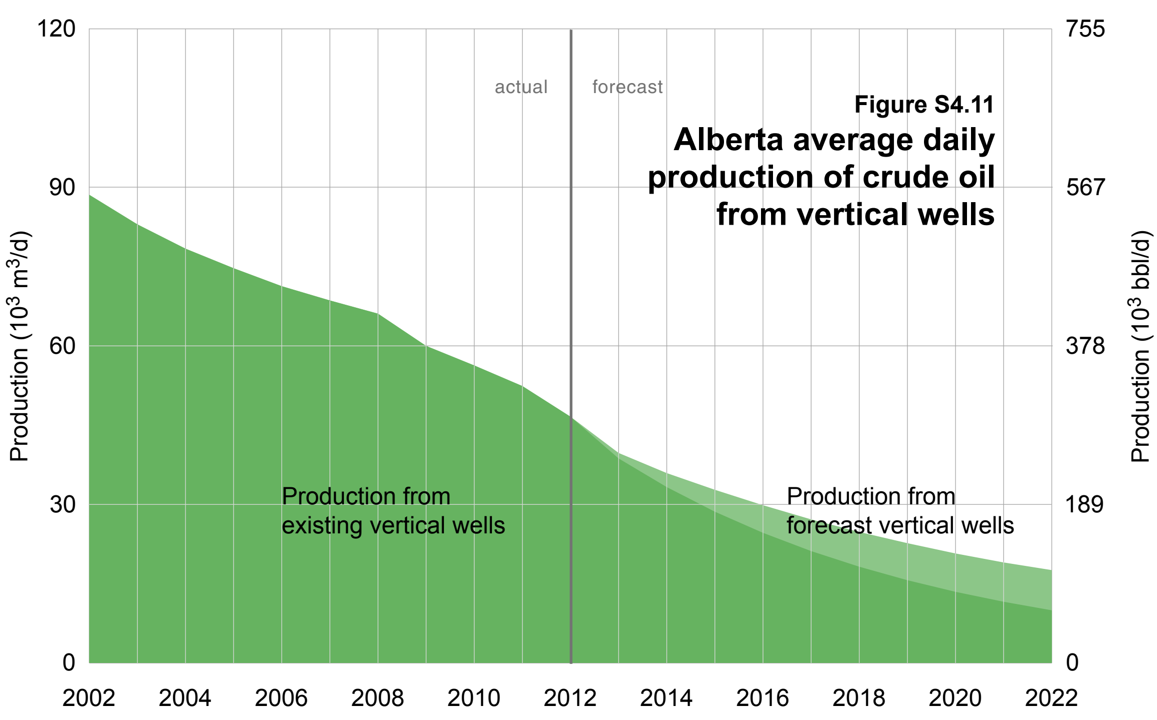
4.2.2 Crude Oil Production – Forecast

In projecting crude oil production over the forecast period, the ERCB has separated production from vertical wells from horizontal wells. The forecast for production from new vertical wells acknowledges industry's continued interest in drilling for oil using conventional technology. The horizontal category of wells includes traditional and multistage-fractured horizontal wells.

To forecast production from each category, production from existing and new wells placed on production each year has been analyzed. The number of wells placed on production and the average productivity of the wells in each category were the main factors used to project oil production over the forecast period.

4.2.2.1 Vertical Wells

- **Figure S4.11** illustrates the projected crude oil production from vertical wells. The ERCB based its projection on the following assumptions:
- Production from existing vertical wells will decline by 14.0 per cent per year.
- The number of new vertical oil wells placed on production is projected to decrease from 728 in 2012 to 690 in 2013 and is expected to decline to 520 wells in 2022. This well count is about 50 per cent lower than last year's forecast and reflects the view that many new wells will be horizontal wells using multistage fracturing technology.



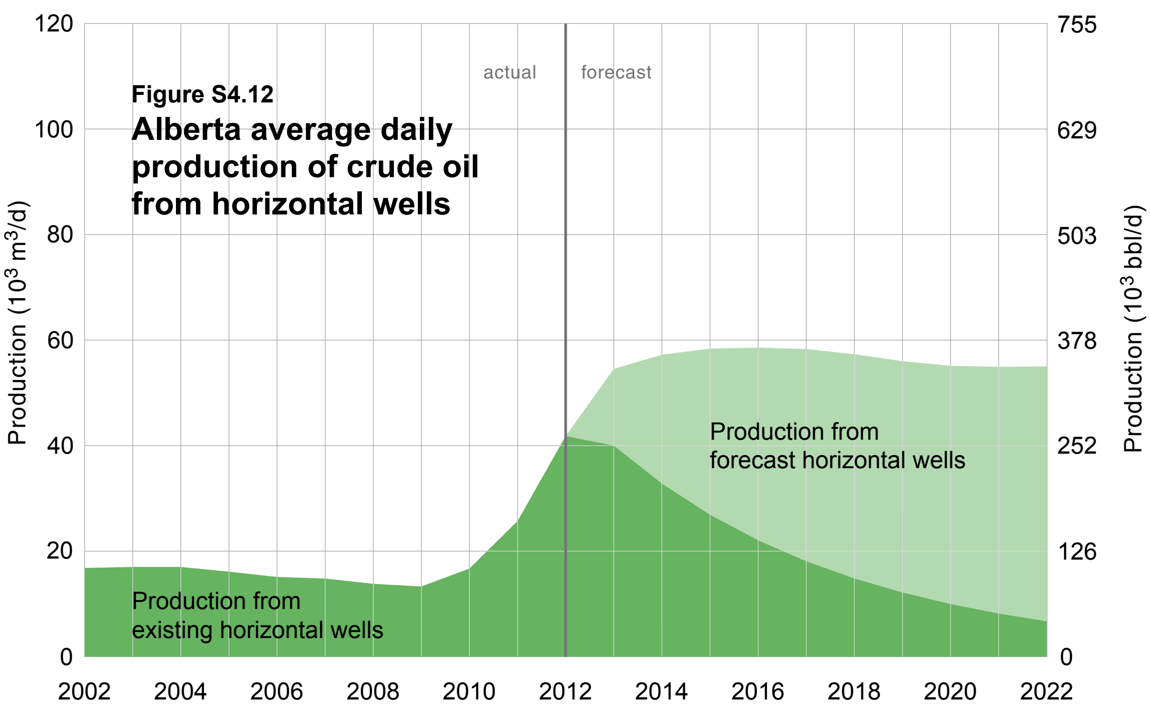
- The average initial production rate for new vertical wells is projected to be 3.0 m^3/d per well and is expected to remain constant for the forecast period.
- Production from new wells will decline at a rate of 27 per cent the first year, 22 per cent the second year, 21 per cent the third year, 19 per cent the fourth year, 17 per cent the fifth year, and 16 per cent over the rest of the forecast period.

4.1.4. Horizontal Wells

A methodology similar to that used for vertical wells is used to project crude oil production from horizontal wells (both traditional and multistage fractured). Potential crude oil production from existing and new wells is combined to project total production in this category of wells over the forecast period.

Figure S4.12 illustrates the projected crude oil production from horizontal wells. The ERCB based its projection on the following assumptions:

- Production from existing wells will decline at a rate of 18.0 per cent per year.
- The number of new horizontal oil wells placed on production is projected to decrease from 2379 in 2012 to 2310 in 2013 and 2014 and to decline gradually to 2080 in 2022. The forecast number of horizontal oil wells has significantly increased relative to the forecast made in last year's report and reflects actual activity in 2012, industry's projection of increased horizontal drilling, and the expectation of continued strong crude oil prices.
- The average initial production rate for new conventional horizontal wells is projected to be 7.0 m^3/d per well in 2013 and decline to 5.0 m^3/d per well by the end of forecast period



- Production from new wells will decline at a rate of 40 per cent the first year, 24 per cent the second year, 18 per cent the third year, 15 per cent the fourth year, 12 per cent the fifth year, and 10 per cent over the remaining forecast period.

The projected total crude oil production, which comprises production from both existing wells and new vertical and horizontal wells, is illustrated in **Figure S4.13**. Based on actual activities and industry projections, the production forecast is higher than what was forecast last year, with production in 2013 forecast at 94.3 10^3 m^3/d compared with last year's forecast of 87.1 10^3 m^3/d for the same year.

Figure S4.14 illustrates the split for light-medium and heavy crude oil. Light-medium crude oil production is expected to increase from 65.03 10^3 m^3/d in 2012 to 70.5 10^3 m^3/d in 2013, and decline to 54.4 10^3 m^3/d in 2022. Over the forecast period, heavy crude oil production is also expected to follow the same trend, reaching 23.8 10^3 m^3/d in 2013 and declining to 18.1 10^3 m^3/d. **Figure S4.14** also illustrates that by 2022, heavy crude oil production will hold the same proportion of total conventional crude oil production in Alberta (25 per cent) for the remainder of the forecast period.

This production forecast assumes that crude oil production will increase by only 6.6 per cent in 2013, down from the actual increase of 14 per cent in 2012, due to an anticipated decrease in the number of wells placed on production for 2013. Crude oil production is expected to peak in 2013 and begin declining at an average rate of between 2 to 4 per cent over the remainder of the forecast period. This is a reflection of the lower levels of drilling activity expected over time and lower average initial production rates forecast for new horizontal wells. The combined forecasts for existing and future wells indicate that total crude oil production will increase from 88.4 10^3 m^3/d in 2012 to 94.3 m^3/d in 2013, before declining to 72.6 10^3 m^3/d in 2022.

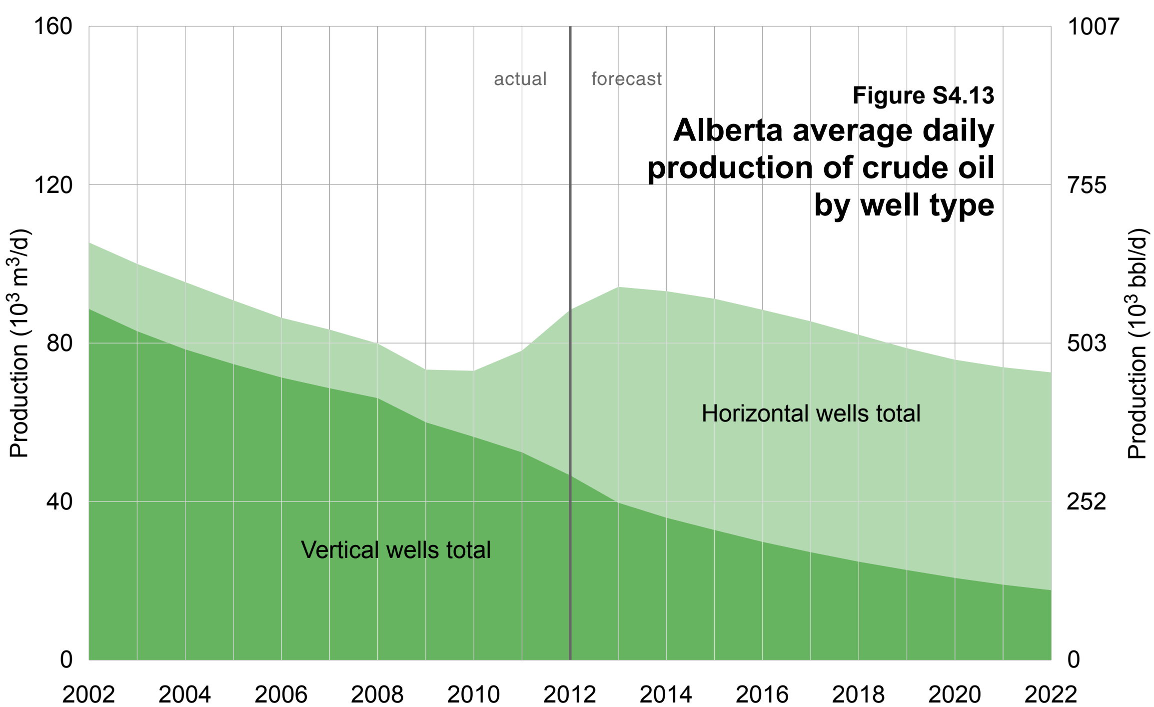


Figure S4.13
Alberta average daily production of crude oil by well type

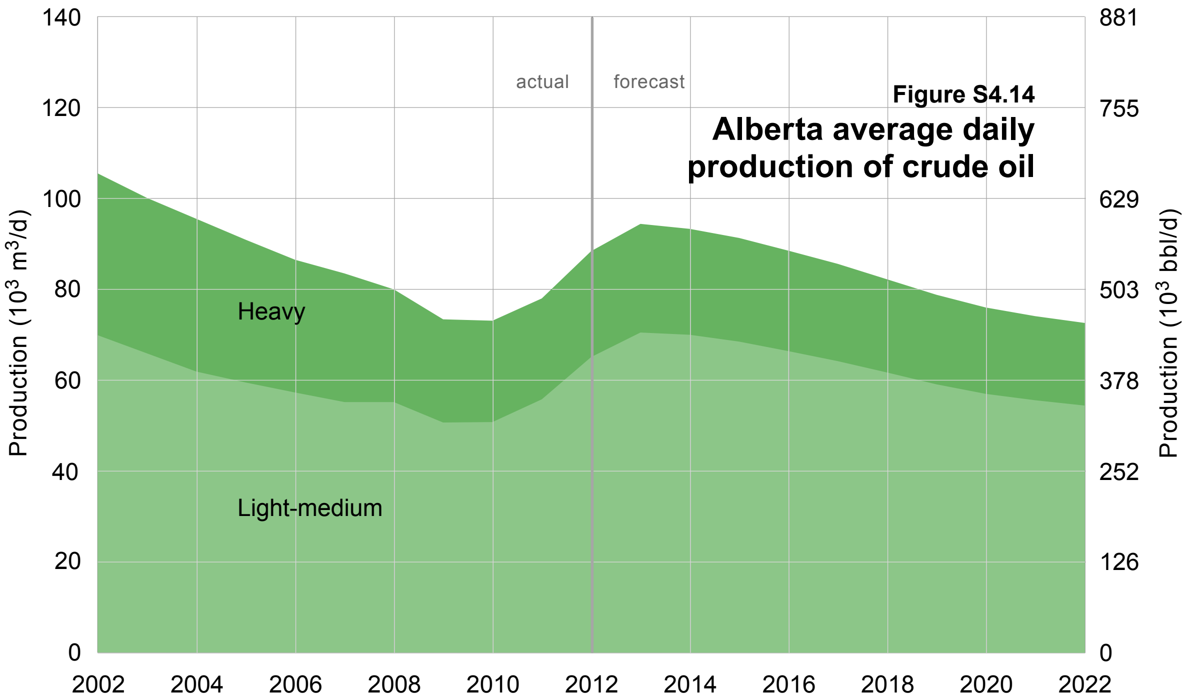


Figure S4.15 illustrates the annual number of new wells expected to be placed on production from 2013 to 2022 and includes the forecast for WTI crude oil price. In spite of a strong crude oil price forecast, oil drilling activity is expected to moderate, with an estimated 2600 wells placed on production at the end of the forecast period. Over the longer term, investment dollars are expected to be more evenly distributed between gas and oil drilling.

4.2.3 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded 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 Albertan demand for RPPs, shipments to other western Canadian provinces, exports to the United States,

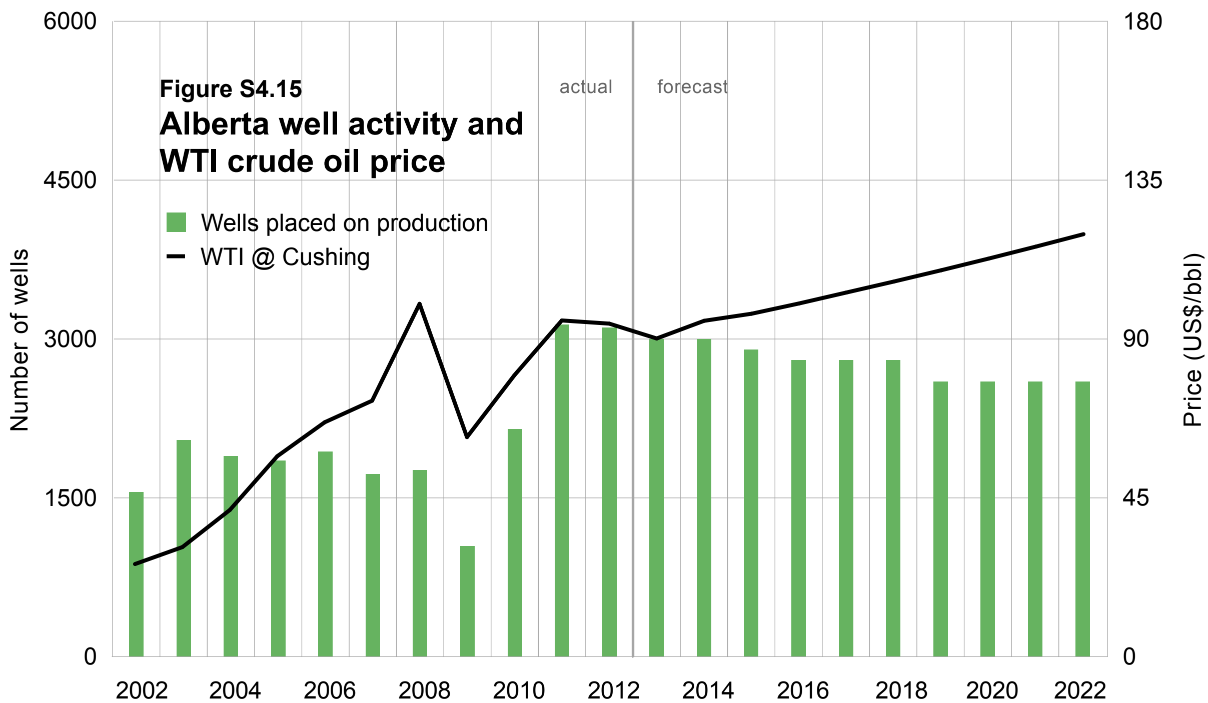
and competition from other feedstocks. Since Alberta is a "swing" supplier of RPPs in western Canada, a refinery closure or expansion in this market may have a significant impact on the demand for Alberta RPPs and on Alberta crude oil feedstock requirements.

In 2012, Alberta operating refineries, with a total inlet capacity of 74.6 10^3 m^3/d of crude oil and equivalent, processed 17 10^3 m^3/d of conventional crude oil. This is a 6 per cent decrease in crude oil processed relative to 2011.

Both upgraded and nonupgraded bitumen, together with pentanes plus, constitute the remaining feedstock processed through Alberta refineries. **Figure S4.16** illustrates the current capacity and location of refineries in Alberta. Additions to crude oil refining capacity are not expected over the forecast period.

In 2012, the refinery utilization capacity was about 89 per cent, up from 88 per cent in 2011 and 84 per cent in 2010. The forecast assumes that total crude oil use in Alberta's refineries will increase to 17.5 10^3 m^3/d in 2013 and will remain at this level for the remainder of the forecast period.

Shipments of crude oil outside of Alberta, depicted in **Figure S4.17**, amounted to 81 per cent of total production in 2012. The ERCB expects that by 2022, this figure will slowly decrease to about 76 per cent of production due to the decline expected in Alberta light-medium and heavy crude oil production in 2022. Currently, conventional crude oil removals are experiencing pipeline constraints and the issue is expected to continue in the near future. Also, light crude oil production from North Dakota and Texas offshore has been on the rise and could significantly affect Alberta crude oil demand in the United States.



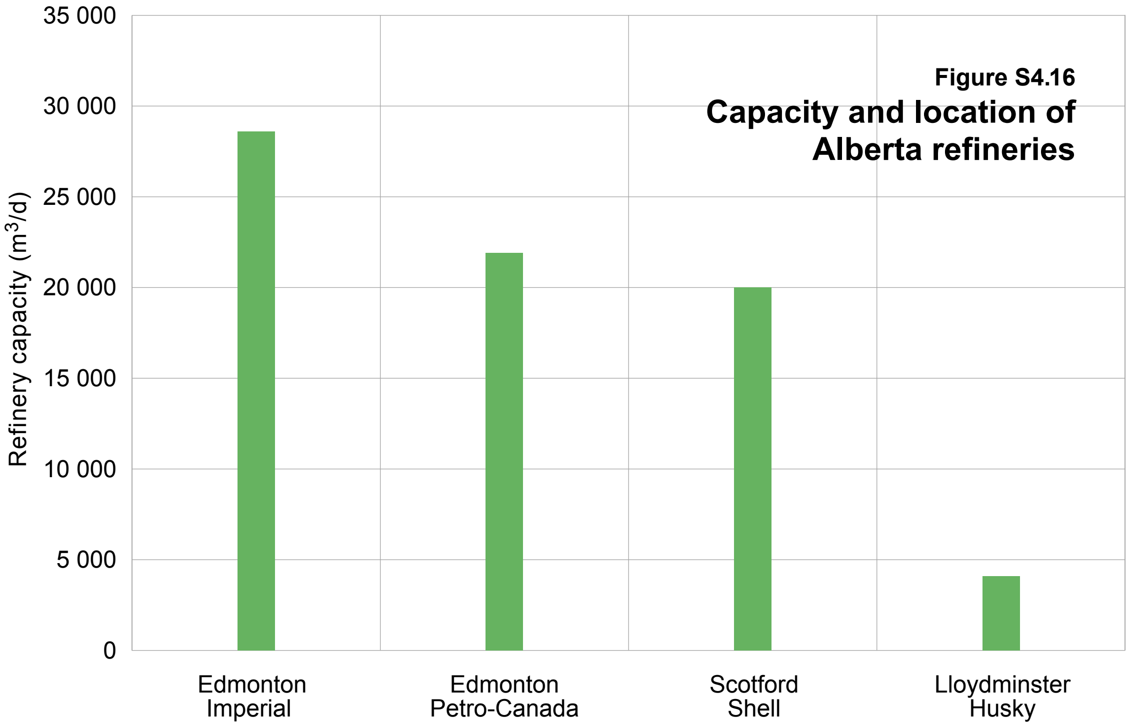


Figure S4.16
Capacity and location of Alberta refineries
Refinery capacity (m3/d)
35 000
30 000
25 000
20 000
15 000
10 000
5 000
0
Edmonton Imperial
Edmonton Petro-Canada
Scotford Shell
Lloydminster Husky

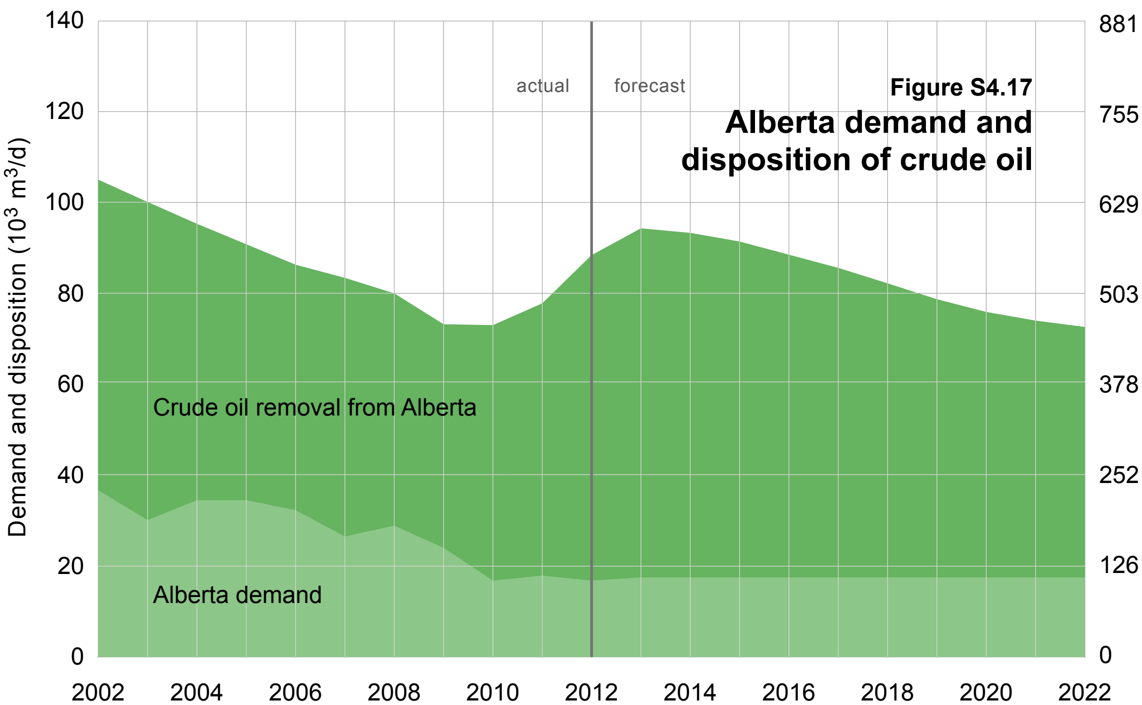


Figure S4.17
Alberta demand and disposition of crude oil
Demand and disposition (103 m3/d)
actual
forecast
Crude oil removal from Alberta
Alberta demand
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

HIGHLIGHTS

Alberta's remaining established conventional natural gas reserves decreased by 3.1 per cent in 2012 to 916 billion cubic metres.

Reserves additions as a result of new drilling replaced 25 per cent of conventional gas production.

Marketable gas production declined by 5.6 per cent in 2012, compared with a 4.6 per cent decline in 2011.

There were 1189 new conventional gas well connections and 433 coalbed methane (CBM) and CBM hybrid connections in 2012, down 49 per cent and 58 per cent, respectively, from 2011.

5 NATURAL GAS

Raw natural gas consists mostly of methane and other hydrocarbon gases, but it also contains non-hydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide (H_2S). These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. Hydrocarbon components that exist in gaseous form in the reservoir, but which condense and are recovered as a liquid at the surface, may be reported as gas equivalent or condensate. Such liquids, as well as ethane, which is primarily produced as a gas, are referred to as natural gas liquids (NGLs) and are reported in **Section 6**. Marketable gas is the gas that remains after the raw gas is processed to remove constituents and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume, as described in **Section 5.1.3.5**.

In this section, natural gas volumes are referred to as either the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated to be 39.1 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for coalbed methane (CBM), which consists mostly of methane.

This section discusses conventional and unconventional natural gas, with unconventional gas being defined as CBM and shale gas.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

As of December 31, 2012, the ERCB estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 916 billion (10^9) m^3, with a total energy content of about 36 exajoules. This decrease of 29.4 10^9 m^3 since December 31, 2011, is a result of all reserves additions less production during 2012. These reserves include 28.9 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value, from 39.1 MJ/m^3 to 37.3 MJ/m^3, for gas downstream of straddle plants. Details of the changes in marketable reserves during 2012 are shown in **Table R5.1**. Total provincial initial gas in place and raw

Table R5.1 Reserve and production changes in marketable conventional gas (10^9 m^3)

	Gross heating value (MJ/m^3)	2012 volume	2011 volume	Change
Initial established reserves		5 341.1	5 283.1	+58.0
Cumulative production		4 425.4	4 338.0	+87.4[a]
Remaining established reserves downstream of field plants				
As is	39.1	915.7	945.1	-29.4
At standard gross heating value	37.4	957.2	987.0	
Minus liquids removed at straddle plants		28.9	29.4	-0.5[b]
Remaining established reserves				
As is	37.3	886.7[b]	915.6[b]	-28.9[b]
		(31.5 Tcf)[c]	(32.5 Tcf)[c]	
At standard gross heating value	37.4	885.2	913.8	
Annual production	37.4	97.1[d]	102.4[d]	-5.3[d]

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

[b] Any discrepancies are due to rounding.

[c] Tcf = trillion cubic feet.

[d] Does not include conventional gas from ERCB-defined unconventional wells.

producible gas reserves for 2012 were 9290.5 and 6182.4 10^9 m^3, respectively, which translates into an average provincial recovery factor of 67 per cent. Total initial established marketable reserves were estimated to be 5341.1 10^9 m^3, representing an average surface loss of 14 per cent.

Annual historical reserves additions and natural gas production are depicted in **Figure R5.1**. It shows that since 1983, reserves additions have generally not kept pace with production. As illustrated in **Figure R5.2**, Alberta's remaining established reserves of marketable conventional gas have decreased by about 51 per cent since 1982.

The ERCB estimates the initial established reserves of CBM to be 101.3 10^9 m^3 as of December 31, 2012, relatively unchanged from 2011. Remaining established reserves in 2012 were 56.7 10^9 m^3, down from 62.0 10^9 m^3 in 2011 due to production.

A summary of CBM reserves and production is shown in **Table R5.2**. In 2012, the annual production from all wells listed as CBM was 8.1 10^9 m^3. This volume represents the total contribution from CBM wells, including wells commingled with conventional gas.[1] The portion of production estimated to be attributed to only CBM is 5.6 10^9 m^3.

5.1.2 In-Place Resource

The ERCB estimates the initial in-place resource of conventional and CBM natural gas in Alberta to be 9591 10^9 m^3, consisting of 9290 10^9 m^3 of conventional natural gas and 301 10^9 m^3 of CBM. With conventional

[1] Wells commingled with conventional gas are defined as CBM hybrid wells.

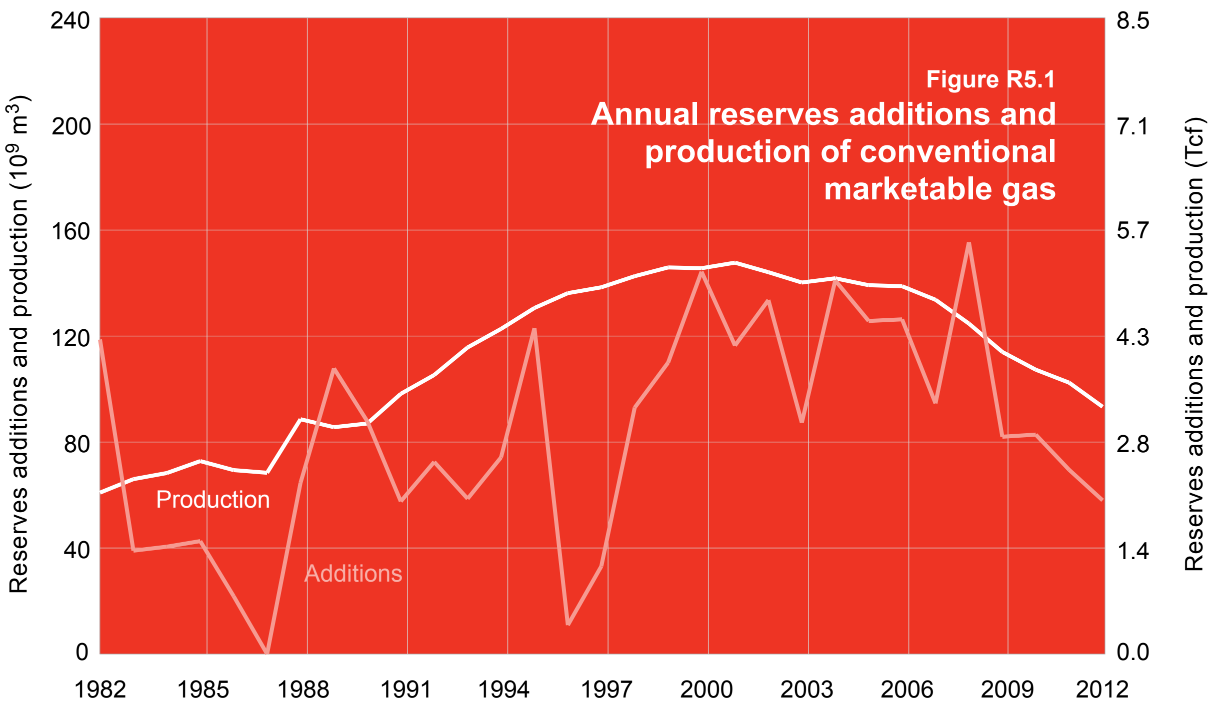


Figure R5.1
Annual reserves additions and production of conventional marketable gas
Reserves additions and production (10^9 m^3)
Reserves additions and production (Tcf)
Production
Additions
240
200
160
120
80
40
0
8.5
7.1
5.7
4.3
2.8
1.4
0.0
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
2012

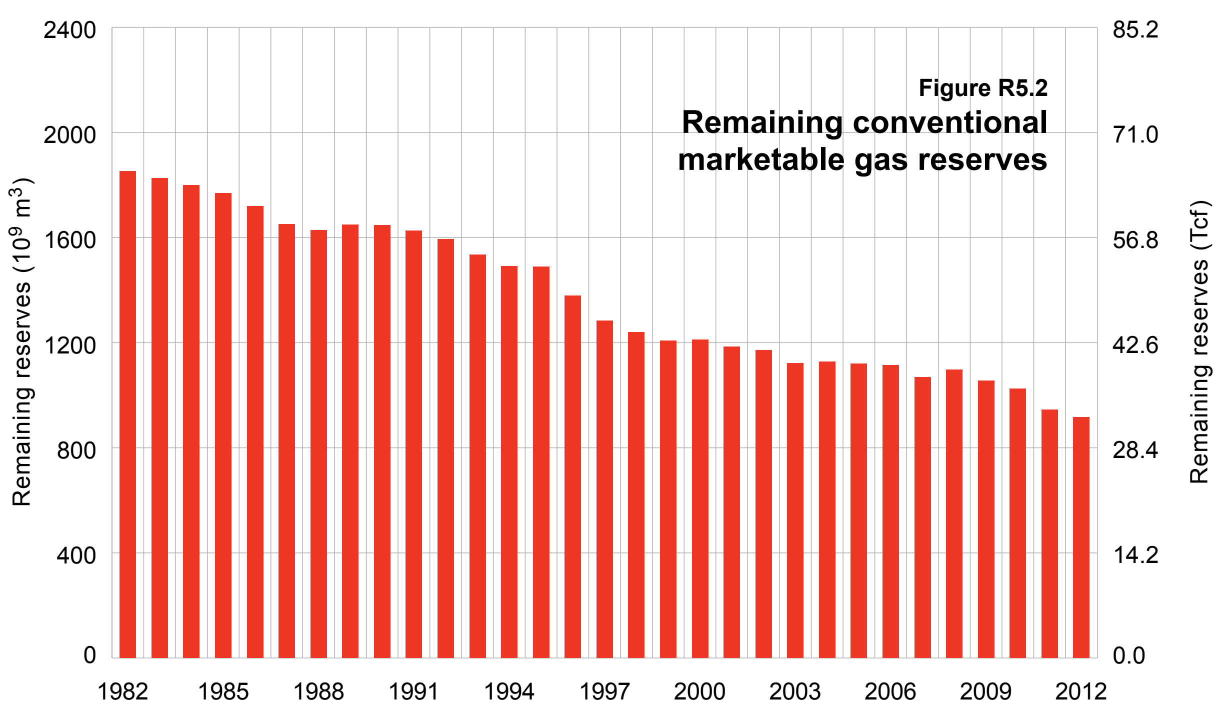


Figure R5.2
Remaining conventional marketable gas reserves
Remaining reserves (10^9 m^3)
Remaining reserves (Tcf)
2400
2000
1600
1200
800
400
0
85.2
71.0
56.8
42.6
28.4
14.2
0.0
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
2012

Table R5.2 CBM reserve and production change highlights (10^9 m^3)

	2012	2011	Change
Initial established reserves	101.3	100.9	+0.4
Cumulative production	44.5	38.9	+5.6[a]
Remaining established reserves	56.7	62.0	-5.3
	(2.0 Tcf)[b]	(2.2 Tcf)[b]	
Annual production	5.6	6.0	-0.4

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

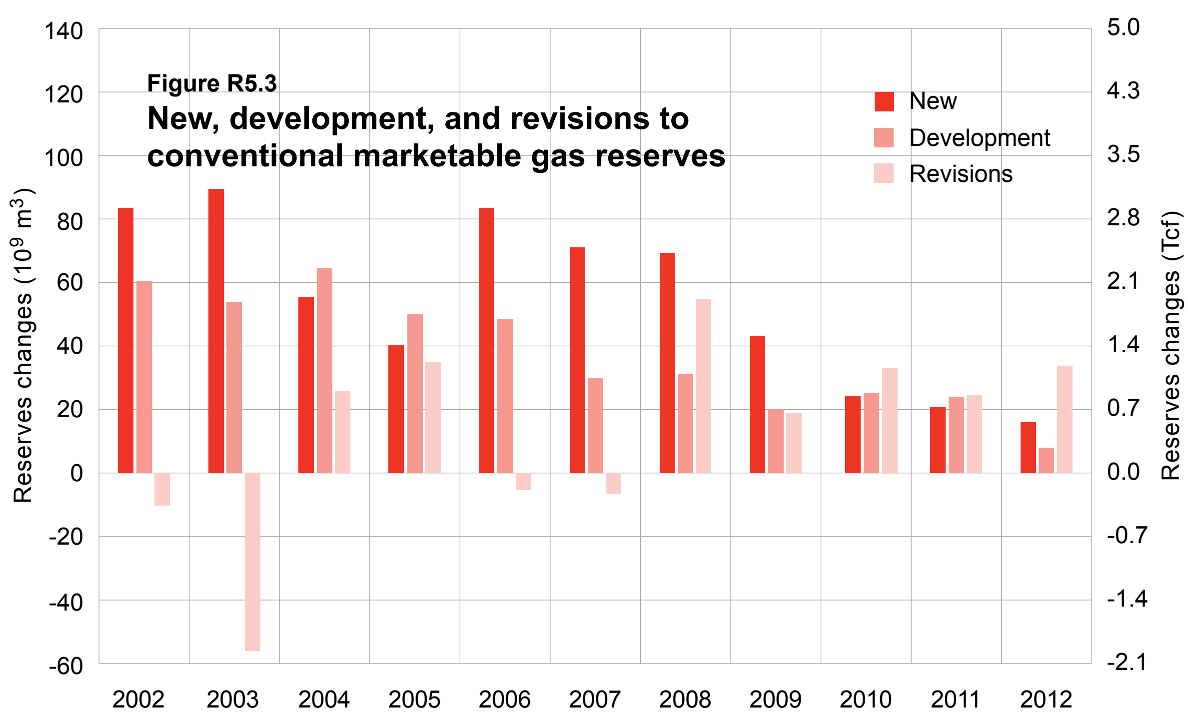
[b] Tcf = trillion cubic feet.

cumulative raw production of 5165 10^9 m^3, 4125 10^9 m^3 of this gas remains in the ground. CBM cumulative raw production is 45 10^9 m^3, and 256 10^9 m^3 remains in the ground. As of December 31, 2012, 4381 10^9 m^3 of natural gas remains unproduced in Alberta. With current technologies, 1074 10^9 m^3 is still expected to be produced.

Additionally, the new shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.1** has identified 95 944 10^9 m^3 (3406 trillion cubic feet [Tcf]) of unconventional in-place shale gas resources in six key shale formations in Alberta. This very large resource represents a huge potential for future development, but the technical, economic, environmental, and social constraints on recoverability were not studied in the report. Consequently, the ERCB has not determined any established reserves from this resource.

5.1.3 Established Reserves of Conventional Natural Gas

Figure R5.3 breaks down the historical annual reserves changes according to new pools, development of existing pools, and reassessment of reserves of existing pools. The 58.0 10^9 m^3 increase in initial reserves for 2012



includes the addition of 16.2 10^9 m^3 attributed to new pools booked in 2012, 8.0 10^9 m^3 from the development of existing pools, and a net reassessment of 33.8 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 24.2 10^9 m^3, replacing 25 per cent of Alberta's 2012 production, which is the lowest replacement ratio in the last 15 years. Historical reserves growth and production data since 1966 are shown in **Appendix B**, **Table B.4**.

During 2012, a review was done of pools that appeared to have reserves under- or overbooked based on their reserves-to-production ratios; another review was done of large pools that had not been evaluated for several years. Positive revisions to existing pools totalled 126 10^9 m^3, while negative revisions totalled 92 10^9 m^3. The major reserves changes are summarized below.

- The 20 pools with the largest changes listed in **Table R5.3** resulted in a net addition of 47.7 10^9 m^3. This increase in reserves was largely a result of infill drilling and completion of previously undeveloped zones.
- Despite the low number of wells being drilled in southeast Alberta, this area still contributes significant volumes of gas to the provincial total. The review of shallow gas pools within the Southeastern Alberta Gas System resulted in a reserves increase of 7.2 10^9 m^3.
- Approximately 4500 pools were evaluated with low or high reserves life indices, resulting in an overall reserves decrease of 4.5 10^9 m^3.

Figure R5.4 illustrates initial marketable gas reserves growth between 2011 and 2012 by areas defined by the Petroleum Services Association of Canada (PSAC). The most significant growth was in PSAC Area 2 (Foothills Front), which accounted for 89 per cent of the total annual increase for 2012. Among the pools in PSAC Area 2 that contributed to this increase in reserves were the Brazeau River Commingled Pool 044, Fir Commingled MFP 9529, Kaybob South Commingled MFP9529, Sundance Commingled MFP 9502, and Wapiti Commingled MFP 9529, for a total reserves increase of 24.5 10^9 m^3.

5.1.3.1 Distribution of Conventional Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table R5.4** on page 5-8. Commingled pools are considered as one pool, whereas each pool in a multifield pool is counted as a separate pool. The data show that pools with reserves of less than 30 million (10^6) m^3, while representing 76 per cent of all pools, contain only 10 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 3000 10^6 m^3, while representing only 0.5 per cent of all pools, contain 55 per cent of the remaining reserves.

5.1.3.2 Geological Distribution of Conventional Natural Gas Reserves

The distribution of reserves by geological period is shown in **Figure R5.5**. The Upper and Lower Cretaceous period accounts for about 73 per cent of the province's remaining established reserves of marketable gas and is important as a future source of natural gas.

Table R5.3 Major natural gas reserve changes, 2012

Pool name	Initial established reserves (10^6 m^3) 2012	Change	Main reasons for change
Atlee-Buffalo Southeastern Alberta Gas System	6 080	-1 490	Re-evaluation of initial volume in place
Bantry Southeastern Alberta Gas System	44 377	+6 868	Re-evaluation of initial volume in place
Benjamin Commingled Pool 001	13 398	+1 890	Re-evaluation of initial volume in place
Brazeau River Commingled Pool 044	33 300	+2 700	Re-evaluation of initial volume in place
Edson Commingled Pool 003	3 692	+1 216	Development and re-evaluation of initial volume in place
Edson Commingled MFP[a] 9502	10 010	+1 325	Re-evaluation of initial volume in place
Fir Commingled MFP 9529	36 807	+4 838	Re-evaluation of initial volume in place
Hussar Southeastern Alberta Gas System	23 798	+2 795	Re-evaluation of initial volume in place and recovery factor
Kaybob South Commingled MFP 9529	22 475	+4 699	Development and re-evaluation of initial volume in place
Pembina Cardium	28 531	+3 276	Development and re-evaluation of initial volume in place
Pembina Cardium JJJ	1 625	+1 611	Development and re-evaluation of initial volume in place
Red Rock Commingled MFP 9529	15 527	+2 058	Re-evaluation of initial volume in place
Sundance Commingled MFP 9502	23 037	+6 703	Development and re-evaluation of initial volume in place and recovery factor
Twining Southeastern Alberta Gas System	2 850	+1 282	Re-evaluation of initial volume in place and recovery factor
Wapiti Commingled MFP 9529	71 567	+5 558	Re-evaluation of initial volume in place
Waterton Commingled Pool 001	9 250	-1 610	Re-evaluation of initial volume in place and surface loss
Waterton Wabamun C	3 075	+1 012	Re-evaluation of initial volume in place and recovery factor
Wild River Commingled MFP 9529	38 376	+1 579	Re-evaluation of initial volume in place
Willesden Green Commingled Pool 006	6 234	+2 499	Development and re-evaluation of initial volume in place
Willesden Green Commingled MFP 9537	552	-1 133	Re-evaluation of initial volume in place

[a] MFP (multifield pool) is defined in Section 5.1.3.6.

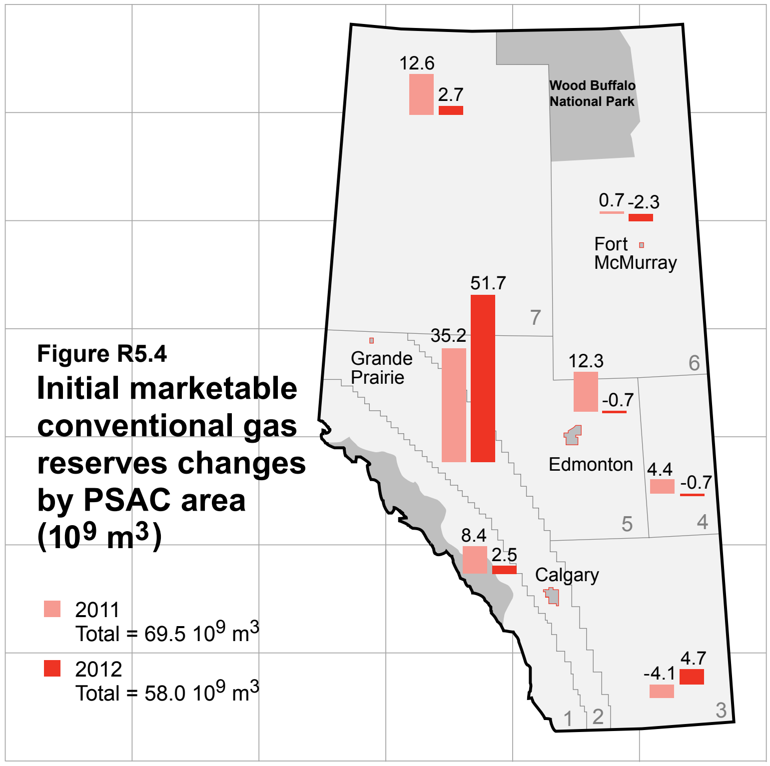


Figure R5.4
Initial marketable conventional gas reserves changes by PSAC area (10^9 m^3)

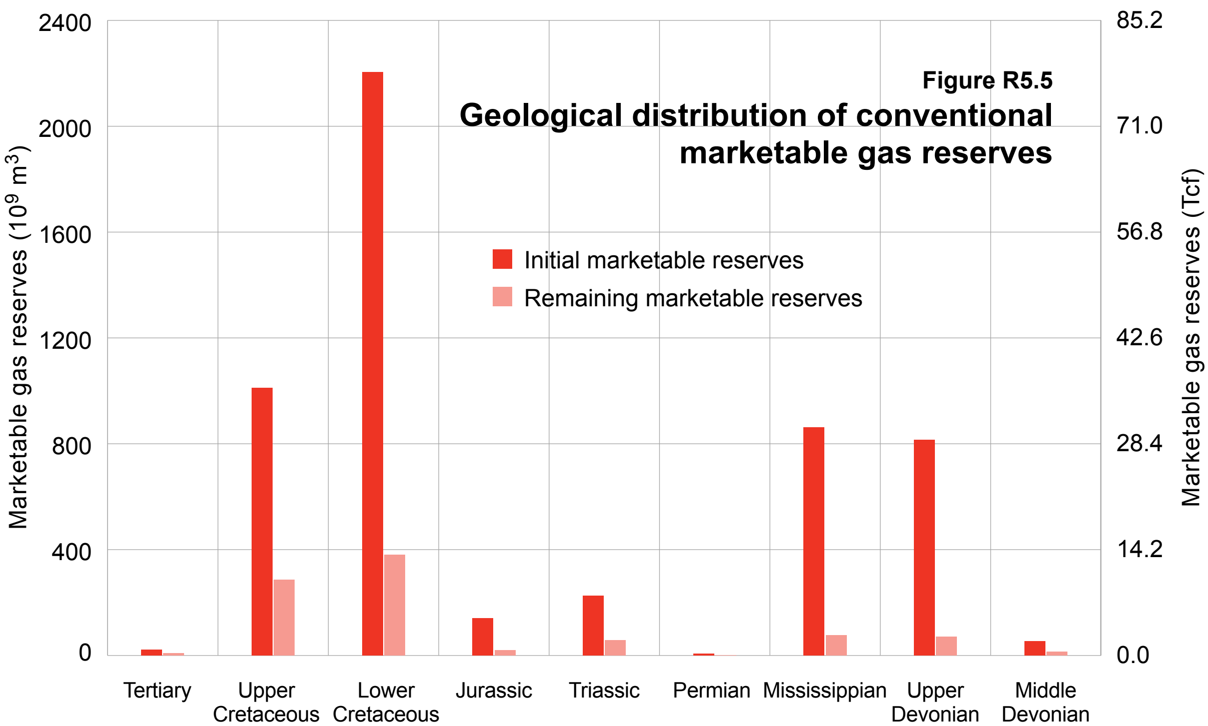


Figure R5.5
Geological distribution of conventional marketable gas reserves

Table R5.4 Distribution of natural gas reserves by pool size, 2012

Reserve range (10^6 m^3)	Pools		Initial established marketable reserves		Remaining established marketable reserves	
	#	%	10^9 m^3	%	10^9 m^3	%
3000+	228	0.5	3 015	57	501	55
1501–3000	167	0.4	358	7	61	7
1001–1500	189	0.4	232	4	34	4
501–1000	535	1.1	369	7	47	5
101–500	3 336	7.0	697	13	102	11
30–100	7 132	15.0	380	7	77	8
Less than 30	35 948	75.6	290	5	94	10
Total	**47 535**	**100.0**	**5 341**	**100**	**916**	**100**

The geological strata containing the largest remaining reserves are the Lower Cretaceous Viking, Mannville, Glauconitic, and Ellerslie, with 35 per cent; the Upper Cretaceous Belly River, Milk River, and Medicine Hat, with 18 per cent; and the Mississippian Rundle, with 8 per cent. Together, these strata contain 61 per cent of the province's remaining established marketable gas reserves.

5.1.3.3 Gas Commingling

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. As shown in **Table R5.5**, 27 per cent (15 947) of all gas pools in Alberta are commingled. This represents 575 10^9 m^3, about 63 per cent of remaining established reserves. In comparison, in 2001, commingled pools represented only 33 per cent of remaining reserves.

In 2006, the ERCB issued orders establishing two development entities (DEs No. 1 and 2)[2] that allow for the commingling of gas of certain formations within these areas without an application to the ERCB. Subsequently, the ERCB amended the area described as DE No. 2 in August 2010. The commingling of gas of certain formations within these areas has enabled operators to produce reserves from zones that would otherwise have been uneconomic to produce on their own.

Table R5.6 shows that DEs No. 1 and 2 have remaining established reserves of 64 10^9 m^3 and 222 10^9 m^3, respectively. The commingled gas reserves of DEs No. 1 and 2 account for about 31 per cent of Alberta's remaining established reserves.

5.1.3.4 Reserves of Conventional Natural Gas Containing Hydrogen Sulphide

Hydrogen sulphide (H_2S) is a naturally occurring substance present in many oil and gas reservoirs worldwide. Natural gas that contains more than 0.01 per cent H_2S is referred to as sour in this report.

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

Table R5.5 Pool reserves as of December 31, 2012 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
Commingled pools	4 145	15 947	2 880	2 305	575
Noncommingled pools		43 390	2 462	2 121	341
Total			**5 342**	**4 426**	**916**

Table R5.6 Commingled pool reserves within development entities as of December 31, 2012 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
DE No. 1	782	2 170	391	327	64
DE No. 2	798	3 919	855	633	222
Total	**1 580**	**6 089**	**1 246**	**960**	**286**

In oil and gas reservoirs, H_2S is primarily generated through thermal and biological processes, both of which involve a reaction between dissolved sulphates and hydrocarbons. Thermally generated H_2S produces the highest concentrations of H_2S and occurs in reservoirs that have undergone diagenesis due to deep burial. Biologically generated H_2S is commonly found in shallower, lower-temperature reservoirs, but can also occur in sewers, swamps, composts, and manure piles.

In Alberta, sour gas is found in several regions and formations across the province. The maps in **Figure R5.6** and **Figure R5.7** show the distribution of both 2012 and historical development of H_2S-bearing hydrocarbons within the clastic and carbonate successions of the Western Canada Sedimentary Basin (WCSB). The division of these two maps reflects Alberta's basin architecture, which consists of a Cretaceous- to Permian-aged clastic wedge overlying a primarily Mississippian- and Devonian-aged carbonate succession (as discussed previously in **Section 2.1**).

The highlighted wells on the maps in **Figure R5.6** and **Figure R5.7** showcase areas of new sour gas development contrasted against historical production. As shown by these maps, in 2012, much of the H_2S-bearing hydrocarbon development in the province was focused on the production of oil containing a percentage of H_2S in solution.

Prominent sour gas production for 2012 included the Triassic-focused activity in the northwest, development of Lower Cretaceous- and Jurassic-aged strata east of the foothills, and Cretaceous-aged enhanced oil recovery near the Saskatchewan border (**Figure R5.6**). Sour development within the carbonate-dominated strata (**Figure R5.7**) was focused on the oil-rich Devonian and Mississippian strata of the central and eastern plains.

As of December 31, 2012, sour gas accounted for about 22 per cent (201 10^9 m^3) of the province's total remaining established gas reserves and about 18 per cent of raw natural gas production in 2012. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2012 was 8.3 per cent.

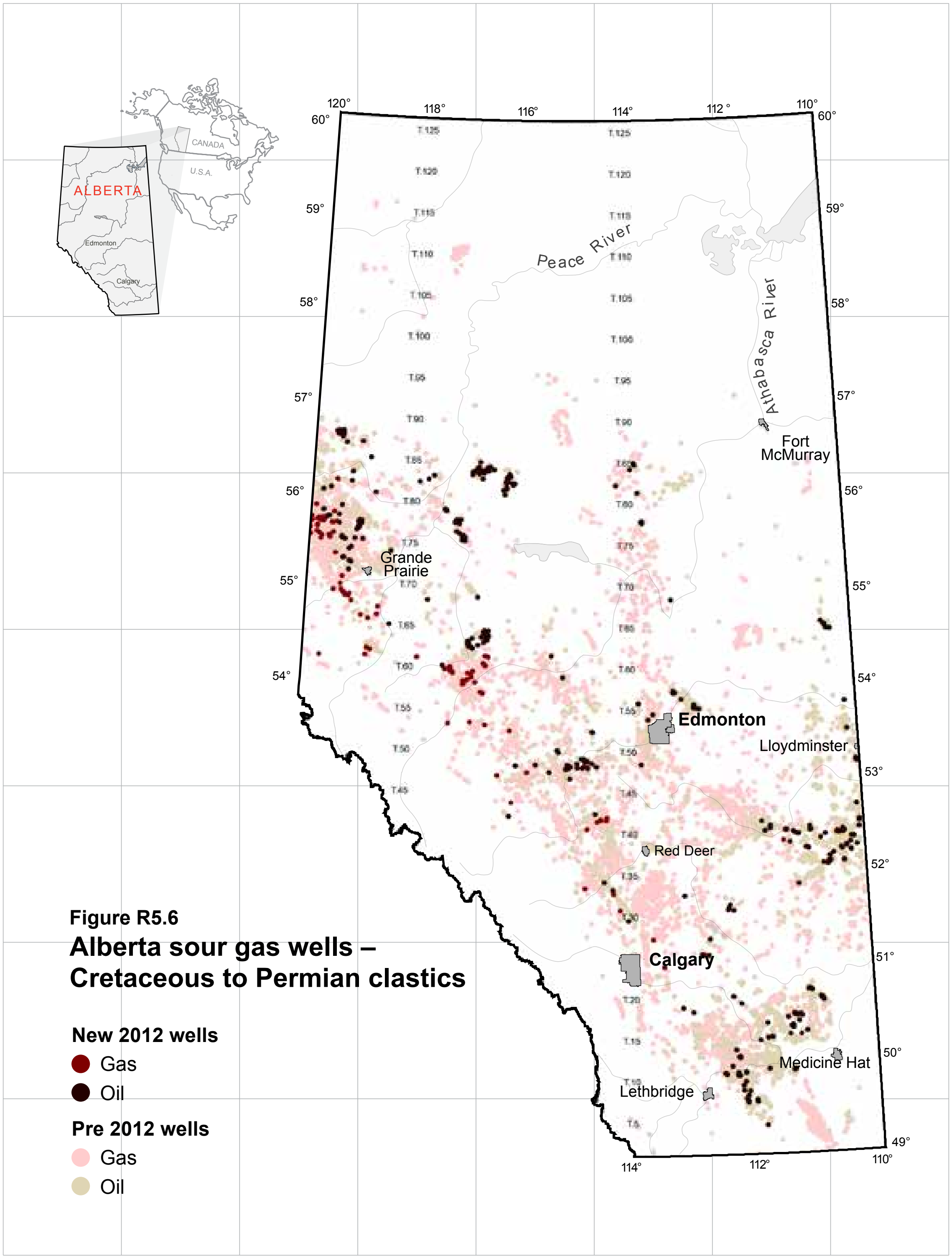


Figure R5.6

Alberta sour gas wells – Cretaceous to Permian clastics

New 2012 wells
- Gas
- Oil

Pre 2012 wells
- Gas
- Oil

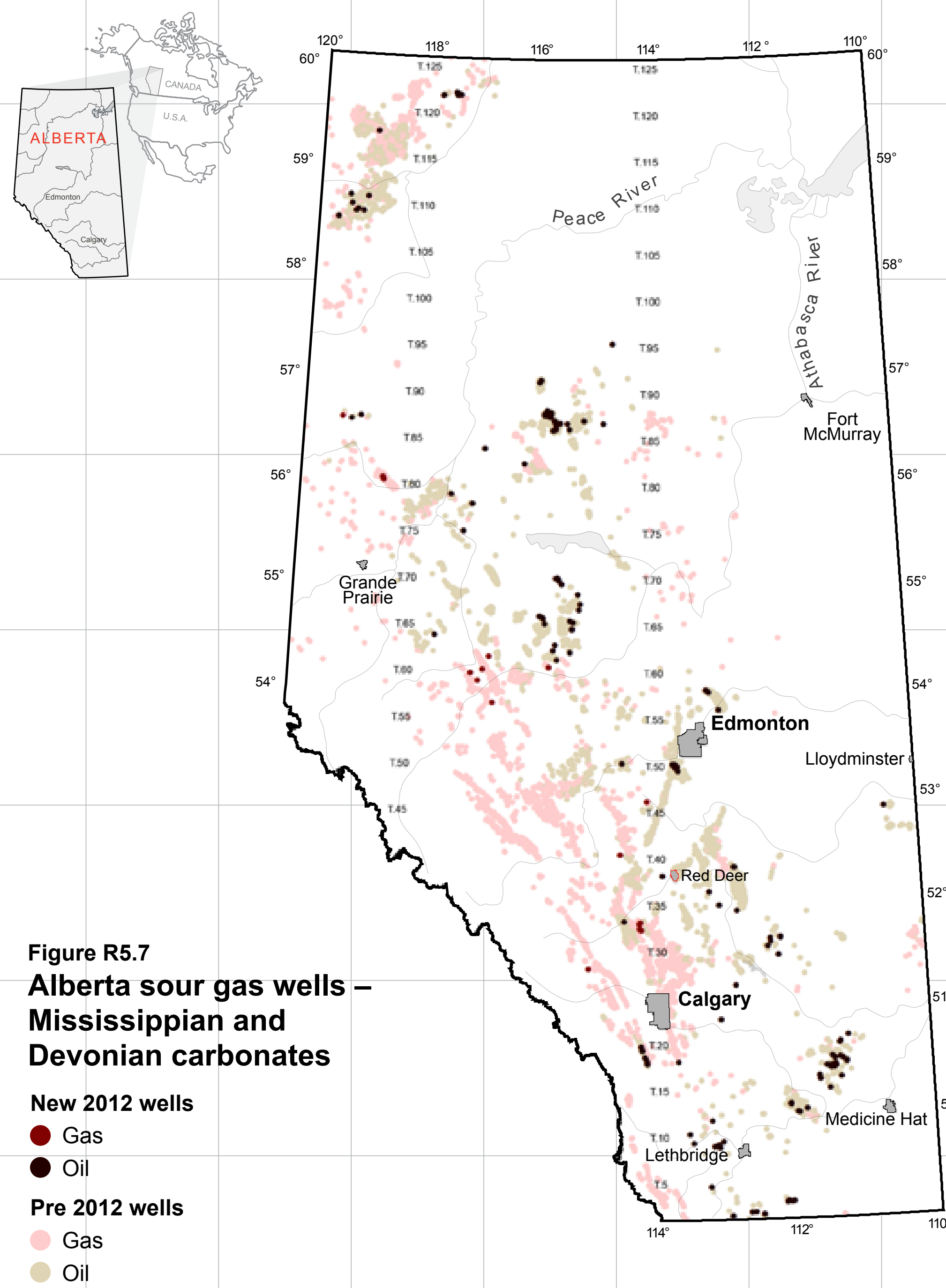


Figure R5.7
Alberta sour gas wells – Mississippian and Devonian carbonates

The distribution of reserves of sweet and sour gas provided in **Table R5.7** shows that 123 10^9 m^3, or about 61 per cent, of remaining sour gas reserves are in nonassociated pools. Since 2002, sour gas has consistently accounted for about 20 per cent of the total remaining marketable reserves. The distribution of sour gas reserves by H_2S content, shown in **Table R5.8**, indicates that 14 per cent (29 10^9 m^3) of remaining sour gas contains H_2S concentrations greater than 10 per cent, while 59 per cent (119 10^9 m^3) contains concentrations less than 2 per cent.

Table R5.7 Distribution of sweet and sour gas reserves, 2012

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	**Initial established reserves**	**Cumulative production**	**Remaining established reserves**	**Initial established reserves**	**Remaining established reserves**
Sweet					
Associated and solution	849	671	178	16	19
Nonassociated	2 723	2 186	537	51	59
Subtotal	**3 572**	**2 857**	**715**	**67**	**78**
Sour					
Associated and solution	557	479	78	10	9
Nonassociated	1 212	1 089	123	23	13
Subtotal	**1 769**	**1 568**	**201**	**33**	**22**
Total	**5 341**	**4 425**	**916**[a]	**100**	**100**
	(190)[b]	**(157)**[b]	**(32.5)**[b]		

[a] Reserves estimated at field plants.

[b] Imperial equivalent in Tcf at 14.65 pounds per square inch absolute and 60˚F.

Table R5.8 Distribution of sour gas reserves by H_2S content, 2012

	Initial established reserves (10^9 m^3)		Remaining established reserves (10^9 m^3)			
H_2S content in raw gas (%)	**Associated and solution**	**Nonassociated**	**Associated and solution**	**Nonassociated**	**Total**	**%**
Less than 2	422	441	63	56	**119**	59
2–10	92	409	10	43	**53**	26
10–20	32	209	4	12	**16**	8
20–30	11	49	1	5	**6**	3
Over 30	0	104	0	7	**7**	3
Total	**557**	**1 212**	**78**	**123**	**201**	**100**
Percentage	31	69	39	61		

5.1.3.5 Reserves Methodology for Conventional Natural Gas

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

The process of determining reserves takes into consideration geological, engineering, and economic factors. Though initial estimates contain a level of uncertainty, this level of uncertainty decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculation, which uses bulk rock volume (based on isopach maps derived from geological interpretation of well log data) and initial reservoir parameters to estimate gas in place at reservoir conditions. Drainage areas for single-well pools range from 200 hectares (ha), for gas wells producing from regional sands with good permeability, to 32 ha or less. The smaller areas are assigned to wells producing from low-permeability formations (less than 1 millidarcy) or from geological structures limited in areal extent.

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

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

The procedures described above generate an estimate of initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants. Typically, 5 per cent is added to account for loss due to lease fuel (estimated at 4 per cent) and flaring. Surface losses range from 3 per cent for pools containing sweet dry gas to over 30 per cent for pools with raw gas that contains high concentrations of H_2S and gas liquids. Therefore, marketable gas reserves of individual pools in the ERCB's gas reserves database reflect expected marketable reserves after processing at field plants. The pool reserves numbers published by the ERCB represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric estimates, production decline analysis, and material balance analysis.

Additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago through the Alliance Pipeline and some of the dry southeastern Alberta gas. As removal of these liquids cannot be traced back to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These provincial reserves, therefore, represent the volume and average heat content of gas after removal of liquids from both field and straddle plants.

It is expected that about 28.9 10^9 m^3 of liquids-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 915.7 10^9 m^3 to 886.7 10^9 m^3 and the total thermal energy content from 35.8 to 33.1 exajoules (10^9 joules).

Figure R5.8 shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants. Therefore, the ERCB estimates the reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source for future ethane supply.

Reserves of NGLs are discussed in more detail in **Section 6**.

5.1.3.6 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in **Appendix B**, **Table B.5**. For each multifield pool, the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool are shown.

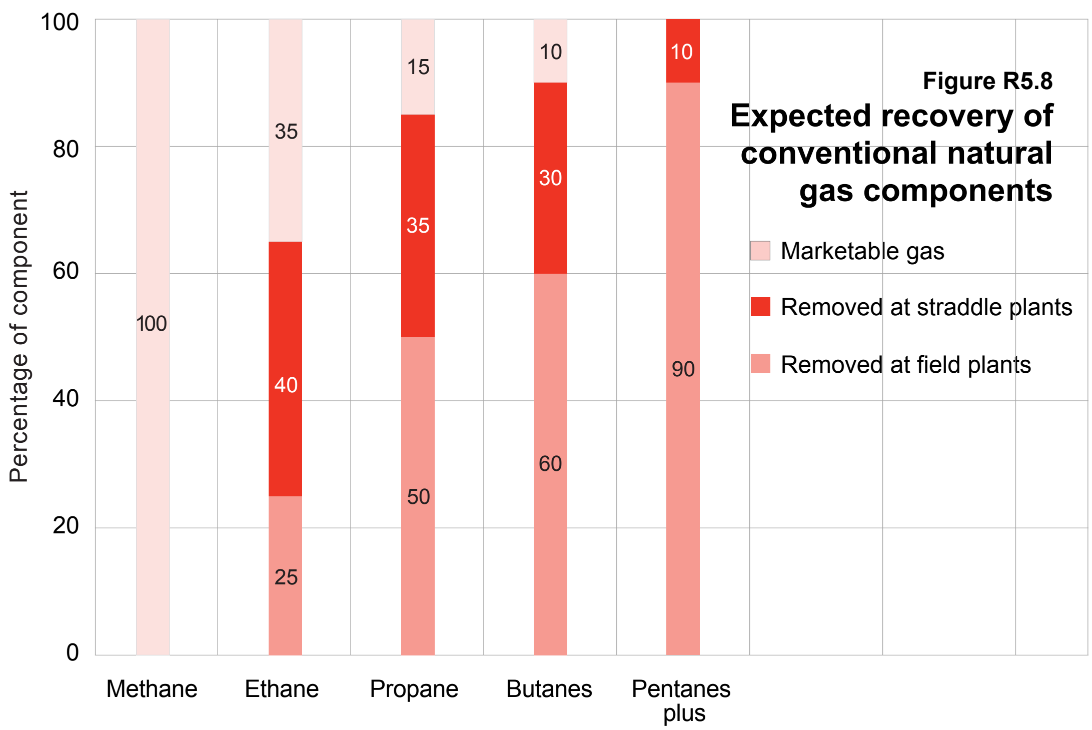


Figure R5.8
Expected recovery of conventional natural gas components

5.1.4 Established Reserves of CBM

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

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). H_2S is not normally associated with CBM production as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 megajoules per cubic metre.

5.1.4.1 CBM Potential by Geological Strata

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

The ERCB recognizes CBM reserves in the following horizons in Alberta:

- **Coals of the Horseshoe Canyon Formation and Belly River Group** – Horseshoe Canyon coals generally have low gas content and low water volume, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, and they constitute the majority of CBM reserves booked. Reserves from the Taber or MacKay coal zones of the Belly River Group have not yet been established.

- **Coals of the Mannville Group** – Mannville coals generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. The initial reserves for areas other than the Corbett area within the Mannville Group have been set at cumulative production.

The Ardley coals of the Scollard Formation and the Kootenay coals of the Mist Mountain Formation also show potential for production, but at this time no CBM reserves have been calculated for these coals.

An individual CBM zone is defined as all coal seams within a formation separated by less than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries have been converted to multifield CBM pools. However, as multifield pools are still problematic in grouping CBM resource and reserves estimates, the ERCB groups CBM volumes into deposit-based play areas.

5.1.4.2 CBM Deposits, Play Areas, and Play Subareas

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The ERCB assesses CBM deposits for reserve determination in a manner similar to the way it assesses oil sands deposits. CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the ERCB has yet to formally define CBM deposits (e.g., through Board orders) because it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities have until now been concentrated mainly in a single smaller play area.

While Mannville activity is clustered almost exclusively in the Corbett area, the more widespread Horseshoe Canyon play occurs over a large area in central Alberta between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is within the ERCB-designated DE No. 1 and the Southeastern Alberta Gas System. The current play areas for the Horseshoe Canyon and Mannville deposits are shown in **Figure R5.9**.

Although coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by data from control wells within the deposit. The location of the Horseshoe Canyon play subareas is also shown on **Figure R5.9**.

5.1.4.3 CBM Reserves Determination Method

The ERCB uses three-dimensional block models to estimate in-place CBM resources for each play area or subarea. Desorption data are used on a zonal basis by applying gas content trends from core to all coals in each zone to estimate in-place CBM resources. Desorption values from drill cuttings are used to validate the continuity of the zonal trends from core.

Current reserves estimates are determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table R5.9**. The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero, which becomes the recovery factor. Future analysis is expected to improve estimates of recovery factors. CBM data are available on two systems from the ERCB: summarized net pay data on the Integrated Geological Database and individual coal seam thickness picks on the Coal Hole Database.

5.1.4.4 Detail of CBM Reserves and Well Performance

CBM reserve values remain unchanged from 2011. The ERCB is currently reviewing the reserves determination process for CBM in Alberta.

Horseshoe Canyon coals, which are mainly gas charged, with little or no pumping of water required, remain the main focus of industry and currently have the highest established reserves (see **Table R5.9**). New data have supported the inclusion of additional areas within many of the Horseshoe Canyon CBM play subareas. In subarea 1, coals are deeper and have higher gas content, which results in this area having the largest initial established reserves of CBM in the Horseshoe Canyon play.

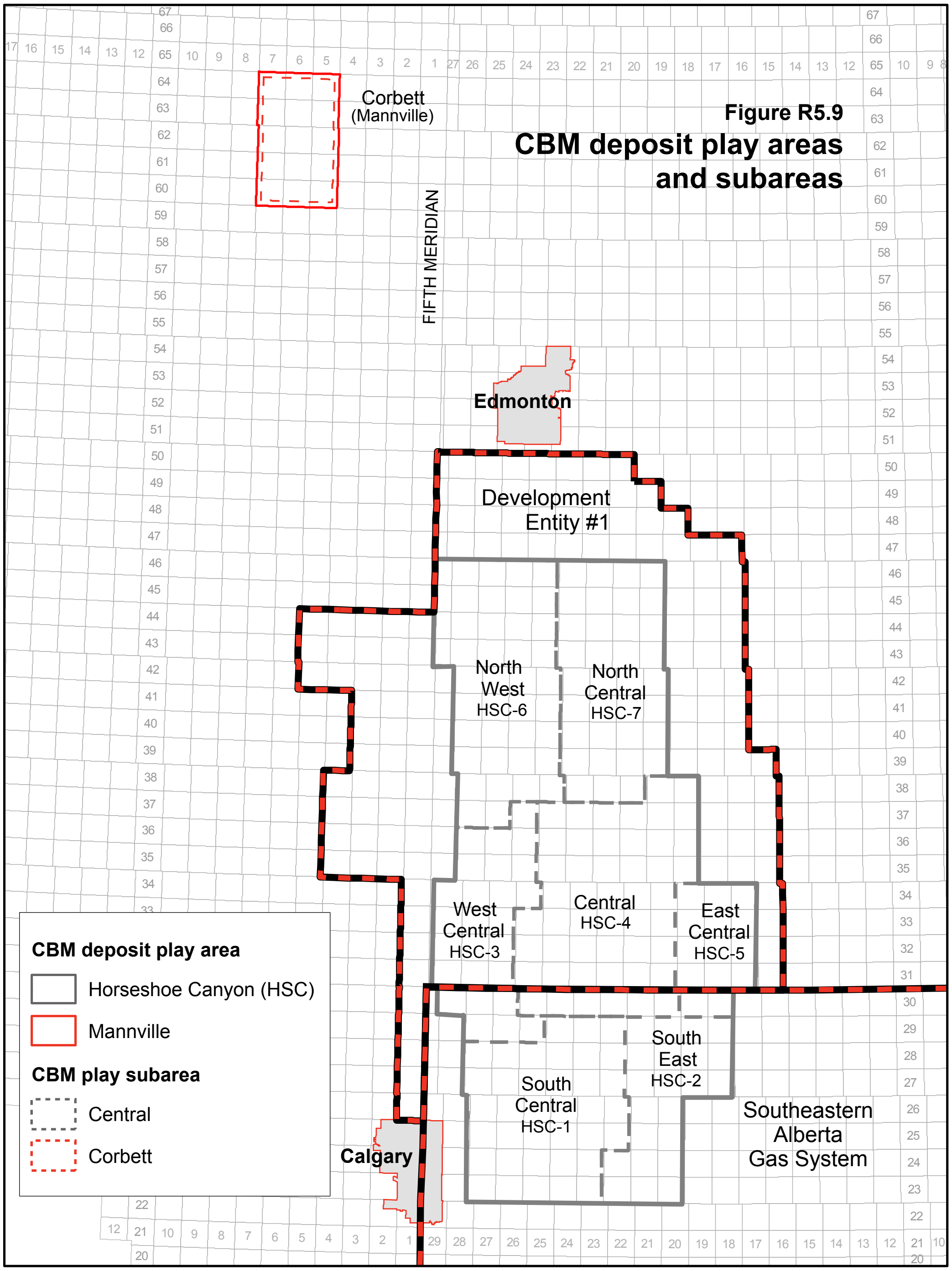


Figure R5.9
CBM deposit play areas and subareas
Corbett (Mannville)
FIFTH MERIDIAN
Edmonton
Development Entity #1
North West HSC-6
North Central HSC-7
West Central HSC-3
Central HSC-4
East Central HSC-5
South East HSC-2
South Central HSC-1
Southeastern Alberta Gas System
Calgary
CBM deposit play area
Horseshoe Canyon (HSC)
Mannville
CBM play subarea
Central
Corbett

Table R5.9 CBM gas in place and reserves by deposit play area, 2012

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas in place (10^9 m^3)	Average recovery factor (%)	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
HSC-1	10.1	35.37	2.95	104.38	27	28.56	6.83	21.73
HSC-2	4.3	9.04	1.06	9.61	25	2.37	0.52	1.85
HSC-3	5.8	13.91	2.41	33.56	30	10.19	4.65	5.54
HSC-4	6.4	28.39	1.72	48.84	34	16.47	12.76	3.71
HSC-5	3.0	3.93	1.11	4.37	26	1.13	0.75	0.38
HSC-6	3.5	8.67	1.57	13.58	30	4.14	3.55	0.59
HSC-7	4.4	14.74	1.30	19.19	32	8.31	7.57	0.74
Undefined[b]	-	-	-	-	-	1.30	1.30	0.00
Subtotal	**5.4**[c]	**114.05**	**2.05**[c]	**233.53**	**31**[c]	**72.47**	**37.93**	**34.54**
Mannville								
Corbett	4.9	6.97	9.73	67.86	42	28.18	5.98	22.20
Undefined[b]	-	-	-	-	-	0.63	0.63	0.00
Total		**121.02**		**301.39**	**33**[c]	**101.28**	**44.54**	**56.74**

[a] Includes Upper Belly River CBM.

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

[c] Weighted average.

The row labelled "undefined" in **Table R5.9** includes noncommercial production from these areas, but reserves have not been booked pending commercial production.

5.1.4.5 Commingling of CBM with Conventional Natural Gas

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the ERCB until 1995. Significant development with commercial production commenced in 2002. The actual CBM production to date continues to be uncertain because of the difficulty differentiating CBM from conventional gas production where commingled production occurs.

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

As the Horseshoe Canyon and Belly River formations generally contain "dry CBM" with little or no pumping of water required, the commingling of CBM and other conventional gas pools is common. Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

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

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from more than 1300 CBM control wells and numerous other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. There is an administrative process in place to correct for the CBM production in these cases.

5.1.5 Shale Gas Resources

Shales are the traditional source rocks for conventional hydrocarbon accumulations, as well as a seal for conventional reservoirs. More recently, organic-rich shales have become a target for production of gas, natural gas liquids, and oil.

Typically, these fine-grained rocks have extremely low matrix permeability, and stimulation is required to produce fluids from the rock. Shale gas or shale oil is not restricted to shale since claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential shale gas strata. The ERCB's recent study on shale- and siltstone-hosted hydrocarbon resources is discussed in **Section 2.2.1**.

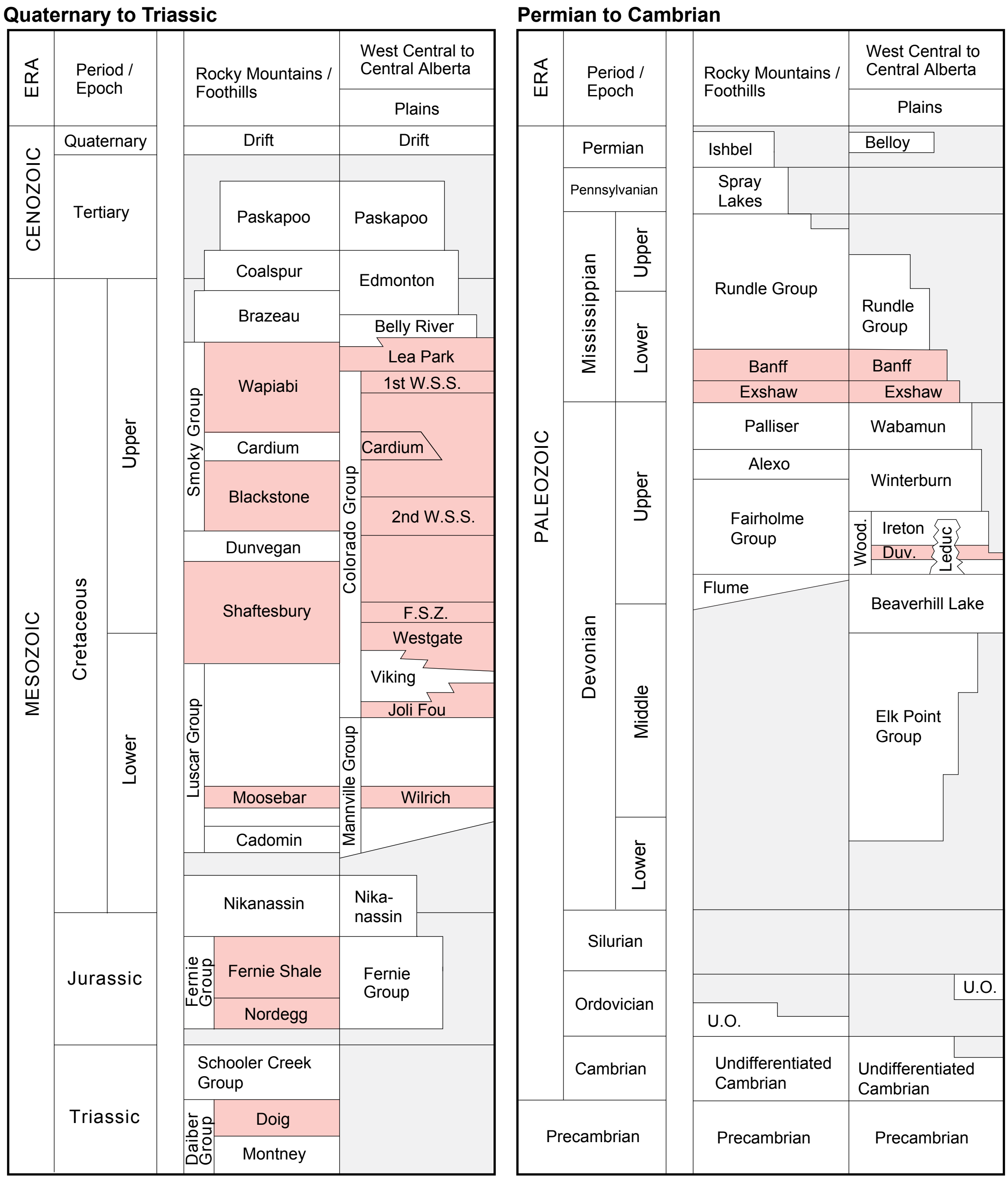
More than 15 shale formations exhibit potential for shale gas, natural gas liquids, or oil. The generalized stratigraphic chart of formations shown in **Figure R5.10** details the formations (indicated with red shading) that have organic matter that could potentially produce gas or oil. Not all of these formations are source rocks (i.e., are organic rich); some contain small amounts of organic matter and may be more like low-permeability strata or aquitards than organic-rich shale.

Exploration for shale gas, natural gas liquids, and oil is taking place in many of the formations highlighted in **Figure R5.10**. Receiving most of the attention are the Duvernay (Woodbend Group), Banff/Exshaw, and Nordegg (Fernie Group) formations as these strata are rich in natural gas liquids and oil. The depth from the surface to the shale formations increases westwards in Alberta. Typically, the deeper formations have a higher formation pressure, which is favourable for shale gas exploration.

The geographic distribution of significant shale gas horizons in the upper half of the WCSB is shown in **Figure R5.11**. The lower half of the WCSB is shown in **Figure R5.12**.

Figure R5.10

Potential shale gas strata



Abbreviations:
1st W.S.S. – First White Speckled Shale
2nd W.S.S. – Second White Speckled Shale
Duv. – Duvernay
F.S.Z. – Fish Scales Zone
U.O. – Undifferentiated Ordovician
Wood. – Woodbend Group

Potential shale gas strata
Absent

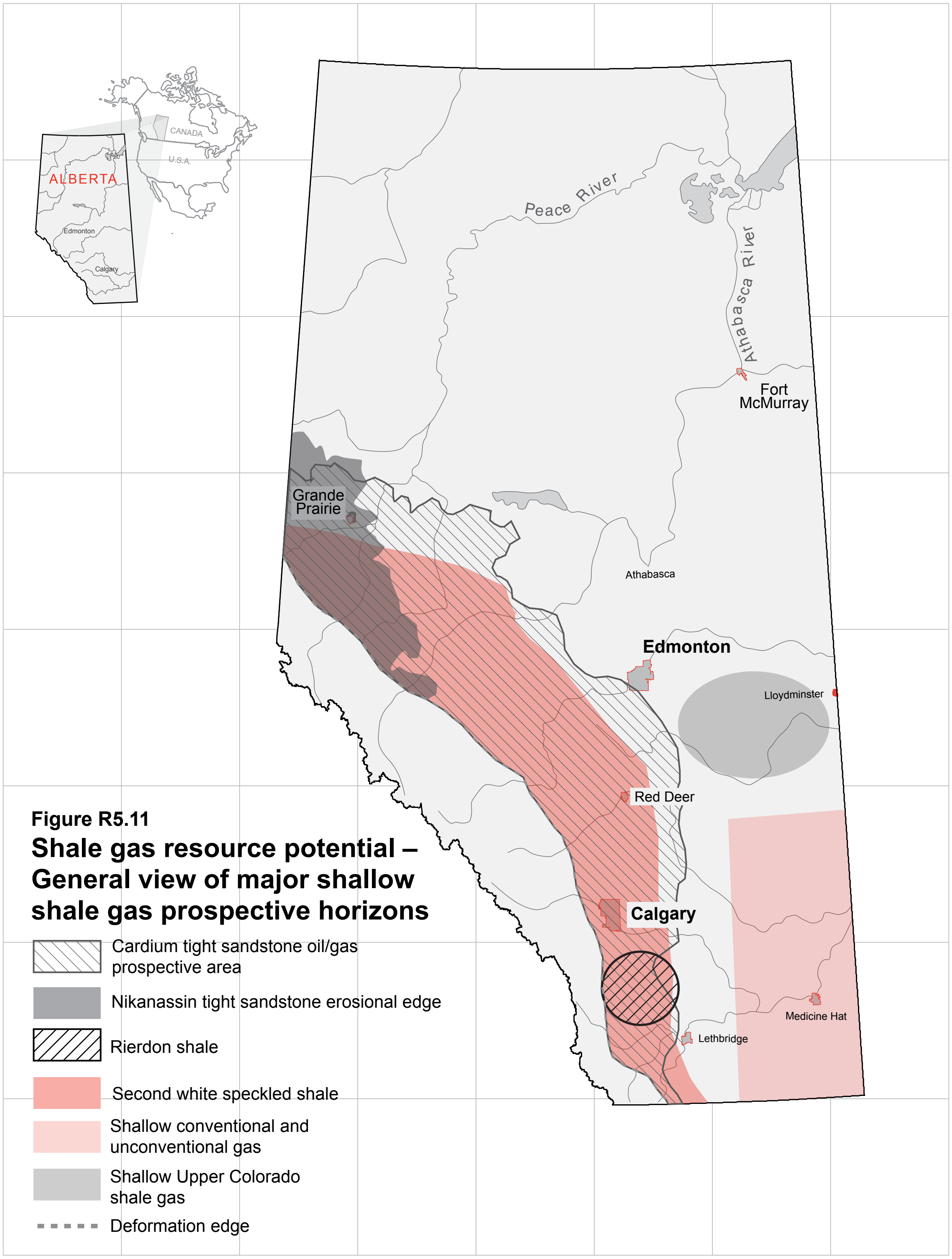


Figure R5.11

Shale gas resource potential – General view of major shallow shale gas prospective horizons

- Cardium tight sandstone oil/gas prospective area
- Nikanassin tight sandstone erosional edge
- Rierdon shale
- Second white speckled shale
- Shallow conventional and unconventional gas
- Shallow Upper Colorado shale gas
- Deformation edge

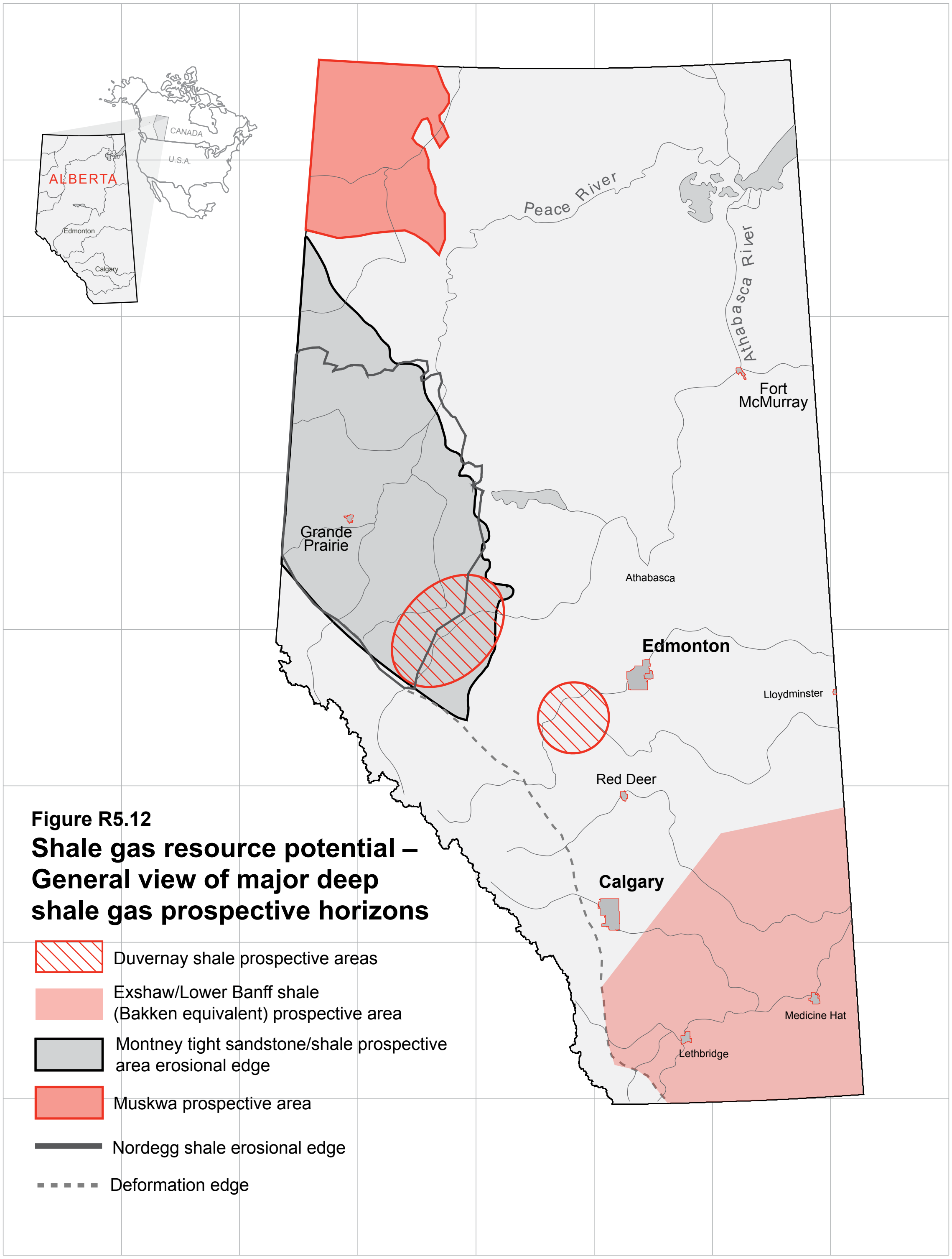


Figure R5.12

Shale gas resource potential – General view of major deep shale gas prospective horizons

5.1.6 Ultimate Potential of Conventional Natural Gas

The Alberta Energy and Utilities Board (EUB) and the National Energy Board (NEB) jointly released *Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas* (EUB/NEB 2005 Report), an updated estimate of the ultimate potential for conventional natural gas. The EUB's successor, the ERCB, has adopted the medium case, representing an ultimate potential of 6276 10^9 m^3 "as is" volume (223 Tcf) or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3. This estimate does not include unconventional gas, such as CBM.

Figure R5.13 shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth up to 2012 equalled 5583 10^9 m^3. **Figure R5.14** plots production and remaining established reserves of marketable gas compared with the estimate of ultimate potential.

Table R5.10 on page 5-26 provides details about the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 5341 10^9 m^3, or 85 per cent of the ultimate potential of 6276 10^9 m^3 ("as is" volumes), have been discovered as of year-end 2012. This leaves 935 10^9 m^3, or 15 per cent, as yet-to-be-discovered reserves. Cumulative production of 4425 10^9 m^3 at year-end 2012 represents 71 per cent of the ultimate potential, leaving 1851 10^9 m^3, or 29 per cent, available for future use.

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure R5.15**. It shows that the PSAC Area 2 (Foothills Front) contains 38 per cent of the remaining established reserves and 12 per cent of the yet-to-be-established reserves. Although most gas wells have been drilled in the southern plains (PSAC Areas 3, 4, and 5), **Figure R5.15** shows that, based on the EUB/NEB 2005 report, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in all PSAC Areas.

Figure R5.16 shows by geological period the discovered and ultimate potential gas in place for year-end 2005. It illustrates that 57 per cent of the ultimate potential gas in place is in the Upper and Lower Cretaceous. Discovered gas in place represents the known value as of December 2012. Current methods of evaluating gas in place have changed from discrete pooling of wells in 2005 to more of a block-type model in areas such as the development entities and southeastern Alberta. This has resulted in the current discovered gas in place being greater than the 2005 forecasted ultimate gas in place for the Upper Cretaceous.

5.1.7 Ultimate CBM Gas in Place

The Alberta Geological Survey (AGS), in *Earth Sciences Report 2003-03*, estimated that there are 14 trillion (10^{12}) m^3 (500 Tcf) of gas in place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta's ultimate CBM gas in place (see **Table R5.11** on page 5-26**)**. However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion—the ultimate potential—has yet to be determined.

Although not a type of natural gas, there is potential in Alberta for the production of synthetic gas from coal and other sources. Synthetic gas from coal is discussed in **Section 8**.

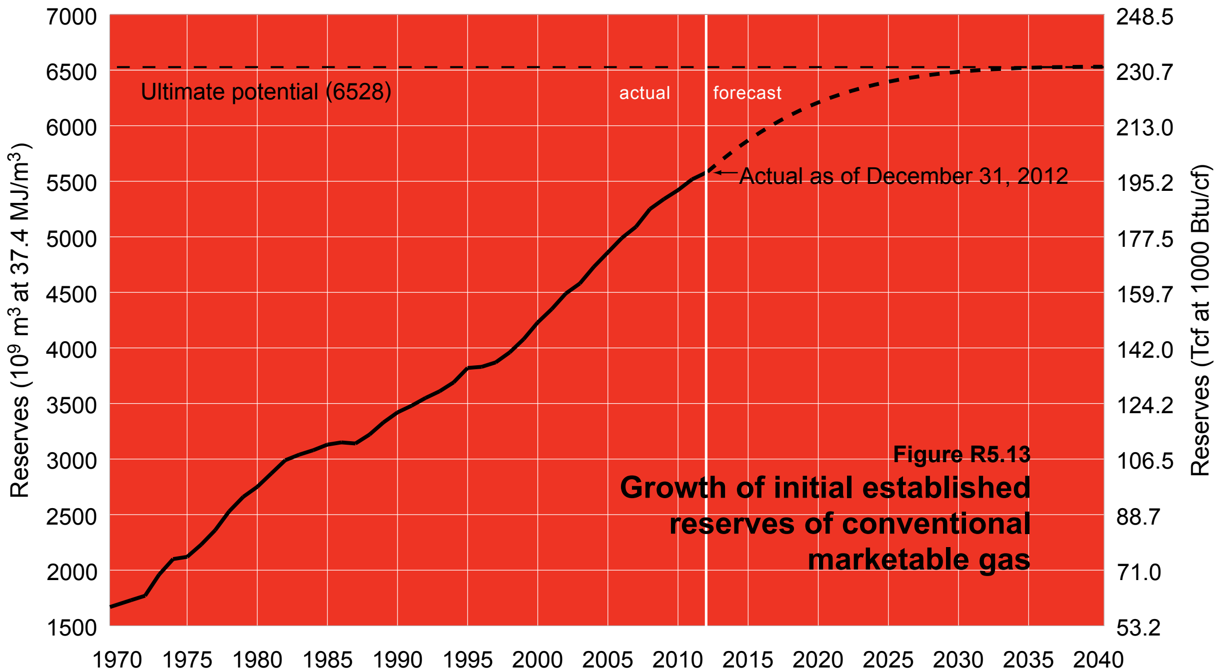


Figure R5.13

Growth of initial established reserves of conventional marketable gas

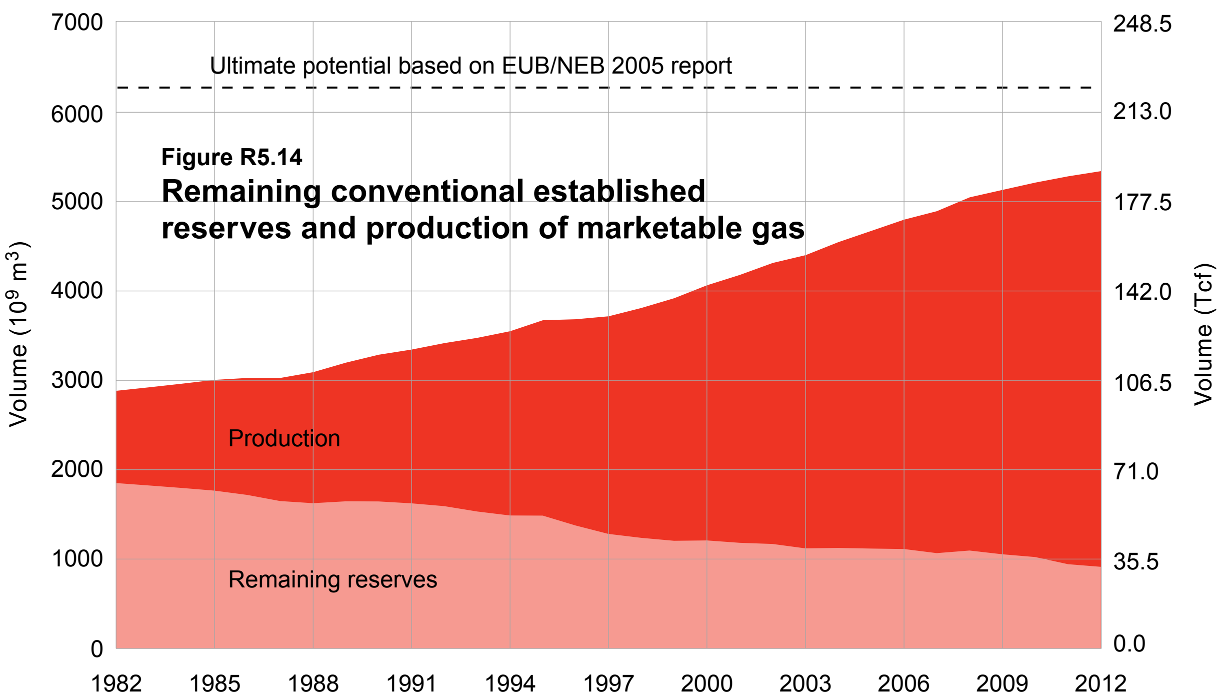


Figure R5.14

Remaining conventional established reserves and production of marketable gas

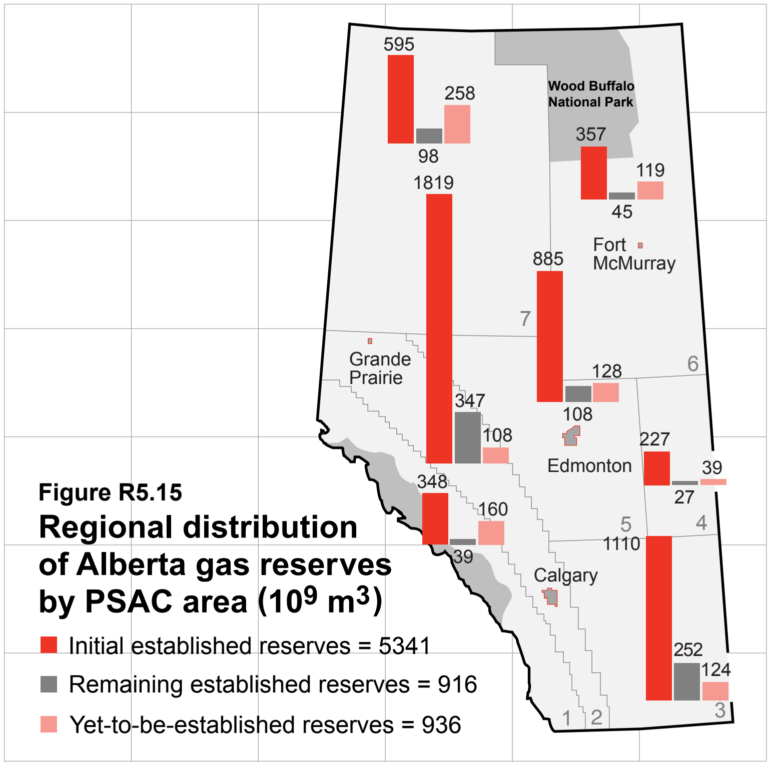


Figure R5.15
Regional distribution of Alberta gas reserves by PSAC area (10^9 m^3)

Initial established reserves = 5341
Remaining established reserves = 916
Yet-to-be-established reserves = 936

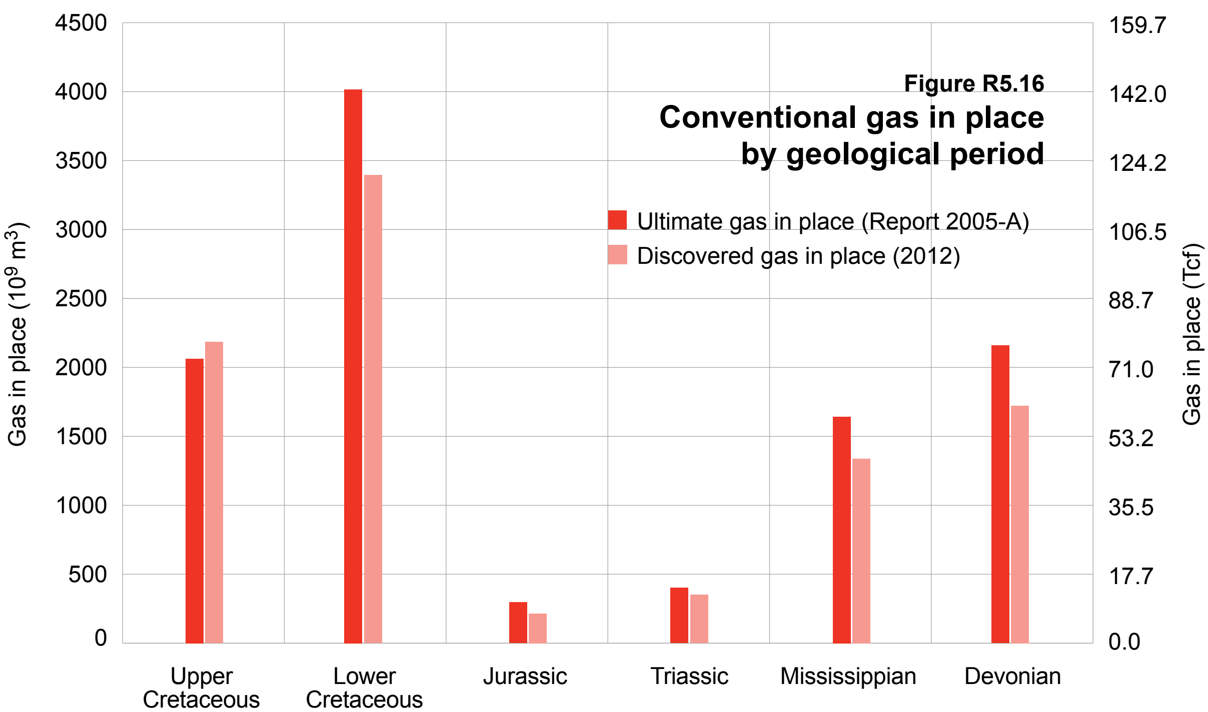


Figure R5.16
Conventional gas in place by geological period

Table R5.10 Remaining ultimate potential of marketable conventional gas, 2012 (10^9 m^3)

	Gross heating value	
	As is (38.9 MJ/m^3)	**at 37.4 MJ/m^3**
Ultimate potential	6 276	6 528
Minus initial established reserves	-5 341	-5 583
Yet-to-be-established reserves	**935**	**945**
Initial established reserves	5 341	5 583
Minus cumulative production	-4 425	-4 626
Remaining established reserves	**916**	**957**
Yet-to-be-established reserves	935	945
Plus remaining established reserves	+916	+957
Remaining ultimate potential	**1 851**	**1 902**

Table R5.11 Ultimate CBM gas in place

Area	**10^{12} m^3**	**Tcf***
Upper Cretaceous/Tertiary – Plains	4.16	148
Mannville coals – Plains	9.06	321
Foothills/Mountains	0.88	31
Total	**14.10**	**500**

Source: EUB/AGS *Earth Sciences Report 2003-03: Production Potential of Coalbed Methane Resources in Alberta*.

* Tcf = trillion cubic feet.

5.2 Supply of and Demand for Natural Gas

In projecting marketable natural gas production, the ERCB considers three components: expected production from existing connections, expected production from new connections, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be established reserves of natural gas in the province. The ERCB projects conventional gas production from oil wells and gas connections separately from CBM connections. The forecasts are combined and referred to as total gas production in Alberta.

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

5.2.1 Marketable Natural Gas Production – 2012

With weak drilling activity for natural gas for the fourth year in a row, Alberta's production continued to slide. In 2012, total marketable natural gas production in Alberta, including unconventional production, declined by 5.6 per cent to 287.7 10^6 m^3/d from the revised 2011 volume of 304.7 10^6 m^3/d. This decline in production is more than the 4.6 per cent production decrease reported from 2010 to 2011. In 2012, natural gas from conventional gas and oil connections, at 265.2 10^6 m^3/d (standardized to 37.4 MJ/m^3), represented 92.2 per cent of production.

The remaining 7.8 per cent of gas supply came from CBM and shale gas connections at 22.3 10^6 m^3/d and 0.2 10^6 m^3/d, respectively.

Total production from identified CBM and CBM hybrid connections decreased 6.7 per cent in 2012 to 22.3 10^6 m^3/d from 23.9 10^6 m^3/d in 2011. Gas production from connections completed in the Horseshoe Canyon play area was 20.2 10^6 m^3/d, representing 91 per cent of total CBM production. Gas production from the Mannville Group was 2.0 10^6 m^3/d. Total production volume includes production from connections outside the defined CBM subareas.

Marketable natural gas production volumes for conventional gas are calculated based on production data from the Supply and Disposition of Marketable Gas section of *ST3: Alberta Energy Resource Industries Monthly Statistics*, as shown in **Table S5.1**. Gas production from CBM and shale gas connections is determined separately.

Major factors affecting Alberta natural gas production are basin maturity, drilling and connection activity, the location of Alberta's reserves, well production characteristics, gas liquids content, market demand, and natural gas prices and their volatility.

Three related themes were instrumental in shaping Alberta's natural gas industry and activity levels over the past year. First, North American gas production has been increasing as a result of shale gas production. In 2012, U.S. marketed gas production from the lower 48 states reached 1931 10^6 m^3/d, up by 5.1 per cent from 1837 10^6 m^3/d

Table S5.1 Conventional marketable natural gas volumes (10^6 m^3)

Conventional marketable gas production	2012
Total raw gas production including storage withdrawals	125 966
Minus production from CBM and hybrid connections	-8 147
Minus production from shale gas connections	-78
Total conventional raw gas production	117 741
Minus storage withdrawals	-3 422
Net raw gas production	114 319
Minus total injection	-5 712
Net raw gas production	108 607
Minus processing shrinkage—raw	-6 749
Minus flared—raw	-801
Minus vented—raw	-472
Minus fuel—raw	-10 183
Plus storage injections	2 936
Conventional marketable gas production at "as is" conditions	93 338
Conventional marketable gas production at 37.4 MJ/m^3	97 072
Daily rate of conventional marketable gas at 37.4 MJ/m^3	(265.2 10^6 m^3/d)

in 2011. Consequently, in 2012, the AECO-C[3] daily price averaged $2.27/GJ, down 34.8 per cent from the 2011 daily average of $3.48/GJ. Alberta's relatively high drilling and development costs led to reduced investment in Alberta's conventional gas development, which resulted in a year-over-year reduction in both gas drilling activity and production.

The second factor shaping Alberta's natural gas industry in 2012 was the increase in well productivity. To combat the low price of natural gas, producers in Alberta are drilling more horizontal gas wells, instead of vertical wells, and using multistage fracturing technology, which substantially improves well productivity when used in combination with horizontal wells.

The third factor affecting natural gas activity in Alberta is the competition for investment dollars among commodities, and in the current price environment, investment has been flowing to the crude oil and oil sands industry, or has focused on liquids-rich gas. The resurgence in crude oil drilling activity is a result of high crude oil prices and the application of multistage fracturing technology in horizontal wells.

Natural gas producers in Alberta and elsewhere are developing liquids-rich gas plays as a way to offset the low natural gas prices. Propane, butanes, and pentanes plus are by-products of natural gas and are priced relative to crude oil. Natural gas producers with a steady stream of liquids-rich output can therefore continue to drill new wells economically.

5.2.2 Natural Gas Connections – 2012

Gas-well connections include newly drilled wells placed on production and recompletions into new zones of existing wells. This section identifies recompletions as those connections that went on production at least one year after the finished drilling date.

5.2.2.1 Conventional Natural Gas Connections

The number of gas well connections dropped significantly in 2012 and has not been this low since 1992. **Figure S5.1** shows the number of new conventional gas connections in Alberta in the last two years by PSAC area. In 2012, 1189 new conventional gas connections were placed on production in the province, a decrease of 48.5 per cent from 2011. This is the sixth straight year of reductions in new conventional gas connections. The continuing low natural gas price, as well as natural gas producers' focus on high-capital horizontal wells with the application of multistage fracturing technology, is reflected in this decrease.

New conventional gas connection activity for 2012 and 2011 is shown in **Table S5.2**. The table provides information on the number of vertical or directional wells versus horizontal wells drilled in the province. The table also breaks down the number of new gas connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2012, roughly 17 per cent of gas connections were recompletions into existing wellbores.

[3] The Alberta Energy Company storage facility (AECO-C) hub is the main pricing point for Alberta natural gas and represents the major pricing point for Canadian gas.

Table S5.2 Conventional gas connections by well type

	New connections		Recompletions		Total	
Well type	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Vertical/directional wells	366	1 229	188	504	554	1 733
Horizontal wells	622	564	13	13	635	577
Total	**988**	**1 793**	**201**	**517**	**1 189**	**2 310**

The number of horizontal gas wells drilled and connected in the province is increasing as a percentage of the total. In 2012, about 53 per cent of new gas connections were horizontal wells, compared with 25 per cent in 2011 based on the revised well-connection counts.

Despite low well production rates, conventional gas activity has traditionally been focused on the shallow gas plays in southeastern Alberta, accounting for 50 per cent of activity, because of the lower cost of drilling, existing infrastructure, and short tie-in times. However, with very low natural gas prices, the trend is changing significantly. The share of new connections in southeastern Alberta (an area containing mostly dry gas) dropped from 41 per cent in 2011 to 20 per cent in 2012, after peaking in 2004 at 56 per cent. Meanwhile, the share in PSAC Area 2 (an area of more liquids-rich gas) increased from 39 per cent in 2011 to 62 per cent in 2012, up from 12 per cent in 2004.

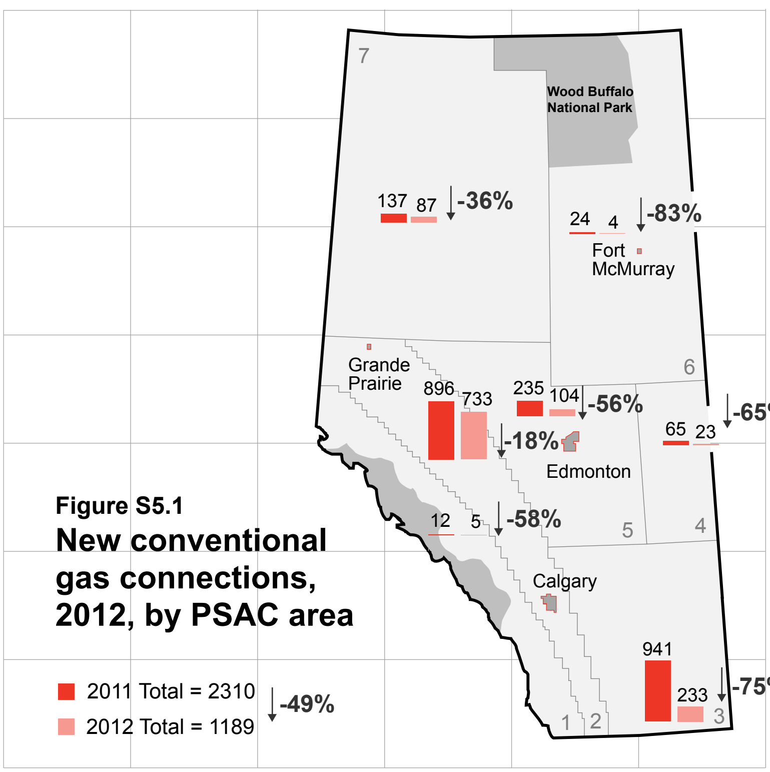


Figure S5.1
New conventional gas connections, 2012, by PSAC area

Figure S5.2 illustrates the number of producing conventional gas connections and the average daily connection productivity by PSAC area in 2012. These rates are calculated using the annual gas production volume and the number of producing gas connections for each PSAC area.

5.2.2.2 Coalbed Methane Connections

The ERCB identifies CBM and CBM hybrid connections using licensing data, production reporting, and detailed geological evaluations. These designations are re-evaluated annually and adjusted if required based on new information. Historical numbers are also updated annually as a result. All connections and volumes in this section are based on CBM connection designations as of December 31, 2012.

In 2012, there were 433 new connections for CBM and CBM hybrid production: all of them in the Horseshoe Canyon play area. Overall, new CBM and CBM hybrid connections decreased by 58 per cent in 2012 over 2011.

New CBM and CBM hybrid connection activity for 2012 and 2011 is shown in **Table S5.3**. The table shows the number of CBM and CBM hybrid connections in vertical or directional wells and horizontal wells within the ERCB-defined CBM play areas. Most CBM and CBM hybrid connections in the Horseshoe Canyon play area are in vertically drilled wells.

The table also breaks down the number of new CBM and CBM hybrid connections placed on production versus connections recompleted in existing wellbores and placed on production. In 2012, about 22 per cent of the new connections were recompletions into existing vertical wells in the Horseshoe Canyon play area.

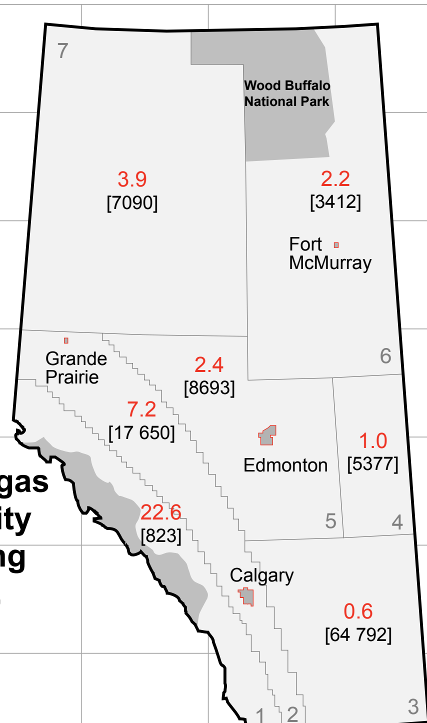


Figure S5.2
Conventional raw gas average productivity rates and producing connections, 2012, by PSAC area

10^3 m^3/d/connection
[number of connections]

2012 average = 2.3 10^3 m^3/d/connection

Table S5.3 CBM and CBM hybrid connections by well type and CBM play area

	New connections		Recompletions		Total	
CBM play subarea	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Vertical/directional wells						
Horseshoe Canyon	262	716	75	237	**337**	**953**
Mannville Corbett	0	4	0	0	**0**	**4**
Undefined[a]	75	10	21	48	**96**	**58**
Subtotal	**337**	**730**	**96**	**285**	**433**	**1 015**
Horizontal wells						
Horseshoe Canyon	0	3	0	1	**0**	**4**
Mannville Corbett	0	4	0	0	**0**	**4**
Undefined[a]	0	0	0	0	**0**	**0**
Subtotal	**0**	**7**	**0**	**1**	**0**	**8**
Total	**337**	**737**	**96**	**286**	**433**	**1 023**

[a] Includes connections outside defined play subarea boundaries.

5.2.2.3 Shale Gas Connections

The ERCB identifies shale gas connections using the designation submitted by the operator to PETRINEX (formerly known as the Petroleum Registry of Alberta). These designations are evaluated and adjusted if required based on new information, resulting in revisions to historical annual numbers. All shale gas connections and volumes in this section are based on current connection designations as of December 31, 2012.

The ERCB currently recognizes 95 producing shale and commingled shale gas connections in 2012. Horizontal gas wells drilled in low permeability gas-bearing formations in northwest Alberta are reported as conventional gas, and reserves associated with this development are included in the conventional gas category in this report; however, as the play extends into British Columbia, it becomes generally shalier and is defined as shale gas.

Most producing shale gas connections in Alberta are shallow vertical wells, although the trend may have started to change in 2011. **Table S5.4** identifies the type of shale connection in 2012 and 2011. About 95 per cent of the designated shale gas connections have been made in the last six years, with most in 2008.

The average initial daily productivity rate for wells connected in 2011 was 6.5 10^3 m^3/d, significantly higher than the 2.3 10^3 m^3/d for wells connected in 2010. The figure for 2012 is not available as initial productivity rate is calculated using the first full calendar year following the connection date of a well.

Table S5.4 Shale gas connections by well type

	New Connections		Recompletions		Total	
Well type	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Vertical wells	0	0	1	1	1	1
Horizontal wells	10	20	0	0	10	20
Total	**10**	**20**	**1**	**1**	**11**	**21**

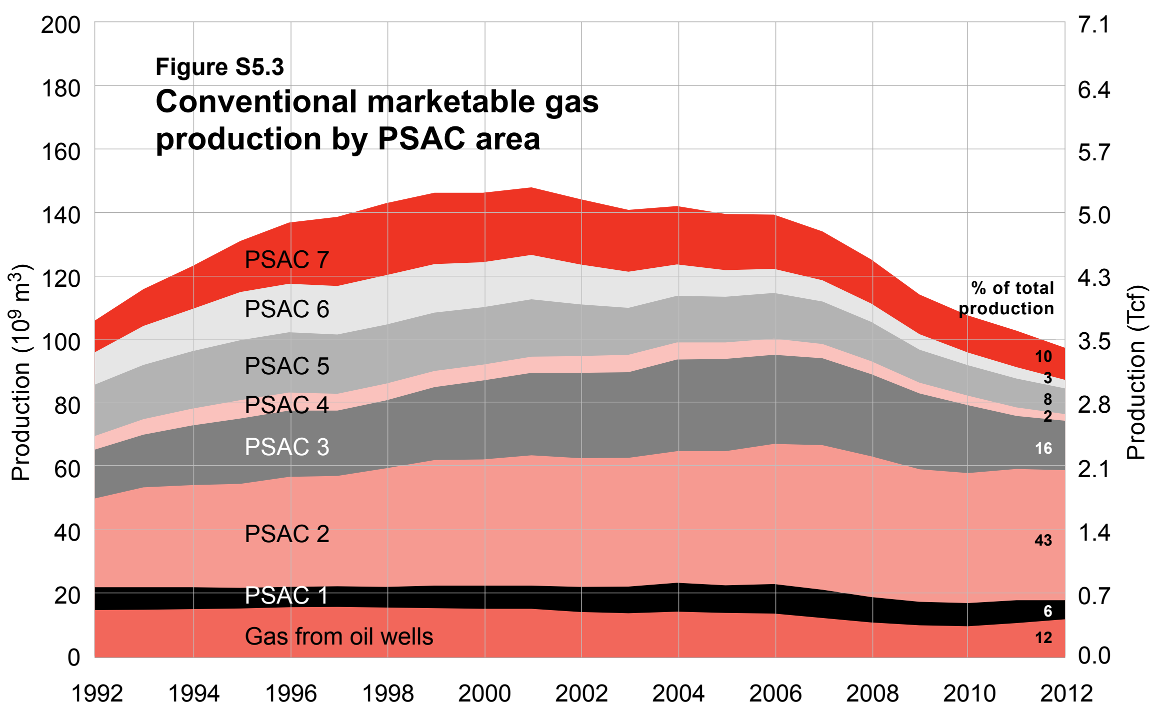
5.2.3 Production Trends

5.2.3.1 Conventional Gas

Figure S5.3 illustrates historical conventional marketable gas production, including gas from oil wells, by PSAC area. Production in all areas of the province except for PSAC Area 2 (Foothills Front) decreased from 2011 to 2012. The top three producing areas in the province—PSAC Area 2, PSAC Area 3 (Southeastern Alberta) and PSAC 7 (Northwestern Alberta)—are responsible for 42 per cent, 16 per cent, and 10 per cent of gas production in 2012, respectively.

Figure S5.4 shows that from 1992 to 2009, the total number of producing conventional gas connections increased, while gas production decreased since reaching its peak in 2001. The numbers of new conventional gas connections each year had not been adequate to offset production declines in existing connections. The year 2010 was the first year in recent history in which the number of conventional gas well connections dropped over the previous year, and this trend continued in 2011 and 2012. In 2012, conventional gas well connections continued to decline to 108 550, after reaching a high of 113 450 connections in 2009.

Historical conventional raw gas production by connection year is presented in **Figure S5.5**. Natural gas production from oil wells has remained relatively stable, as shown by the band on the bottom of the chart. Each band above the gas production from oil wells represents production from new conventional gas connections by year. The percentages on the right-hand side of the figure represent the area's shares of total production from conventional gas connections in 2012. About 8 per cent of conventional gas production in 2012 came from the connections in 2012. Connections before 2002 contributed 31 per cent of gas production in 2012.



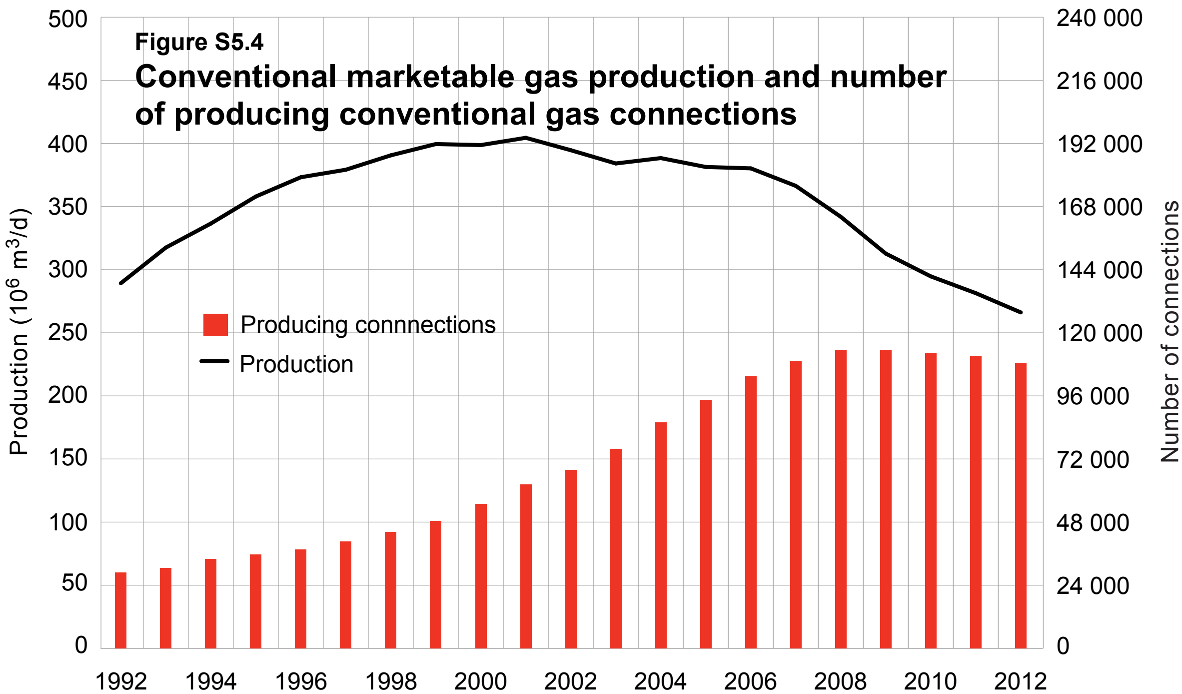


Figure S5.4
Conventional marketable gas production and number of producing conventional gas connections

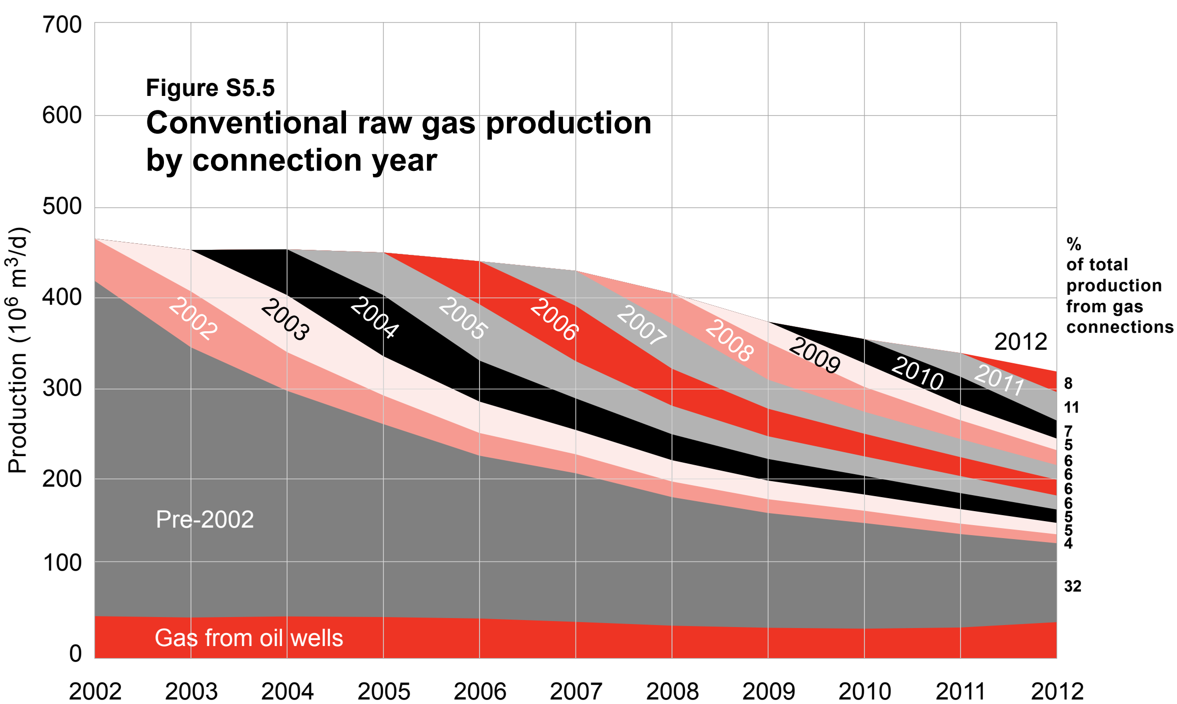


Figure S5.5
Conventional raw gas production by connection year

The percentage of sour gas relative to total gas production decreased from 31 per cent in 2000 to 18 per cent in 2012 because of a decline in production from the large sour gas pools in the province.

Figure S5.6 compares total raw natural gas production in Alberta with both Texas and Louisiana onshore production and total U.S. gas production over the past 50 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production has a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates stabilized. Only recently have they seen an increase again in gas production because of growth in shale gas production from the Barnett, Haynesville, and Eagle Ford shale plays.

The long-term outlook for North American gas supply has changed with the recent growth in supply from shale gas production. With the success of the Barnett and Eagle Ford shales in Texas, and the expected potential of other shale gas plays in the United States—particularly the Marcellus, Haynesville, Woodford, and Fayetteville shales, as well as the Horn River and Montney shale plays in northeastern British Columbia—shale gas production continues to grow and has become a significant source of natural gas production in North America. The U.S. Energy Information Administration expects that shale gas production in the United States will increase from 8.1 Tcf (228.2 10^9 m^3) in 2012 (34 per cent of total U.S. dry gas production) to 15.3 Tcf (431.1 10^9 m^3) in 2035 (49 per cent of total U.S. dry gas production).

5.2.3.2 Coalbed Methane

Total CBM and CBM hybrid production and numbers of producing connections are shown in **Figure S5.7**. This figure shows that Mannville CBM connections account for 9.2 per cent of the total CBM produced but represent

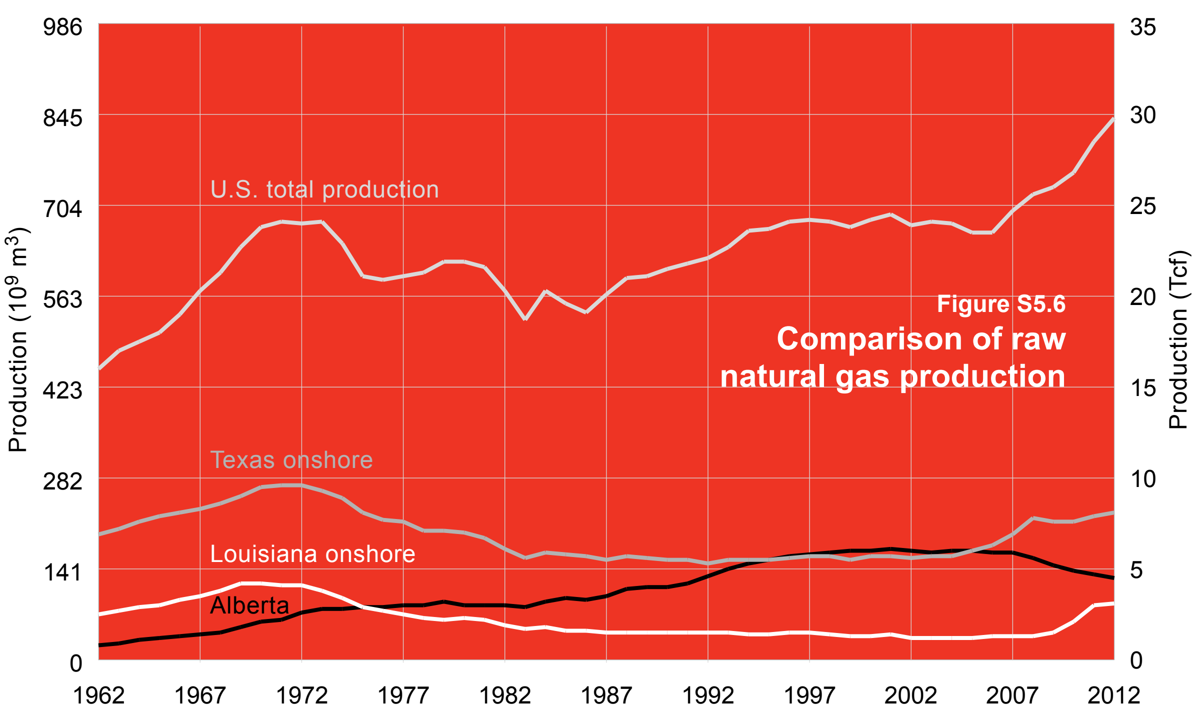
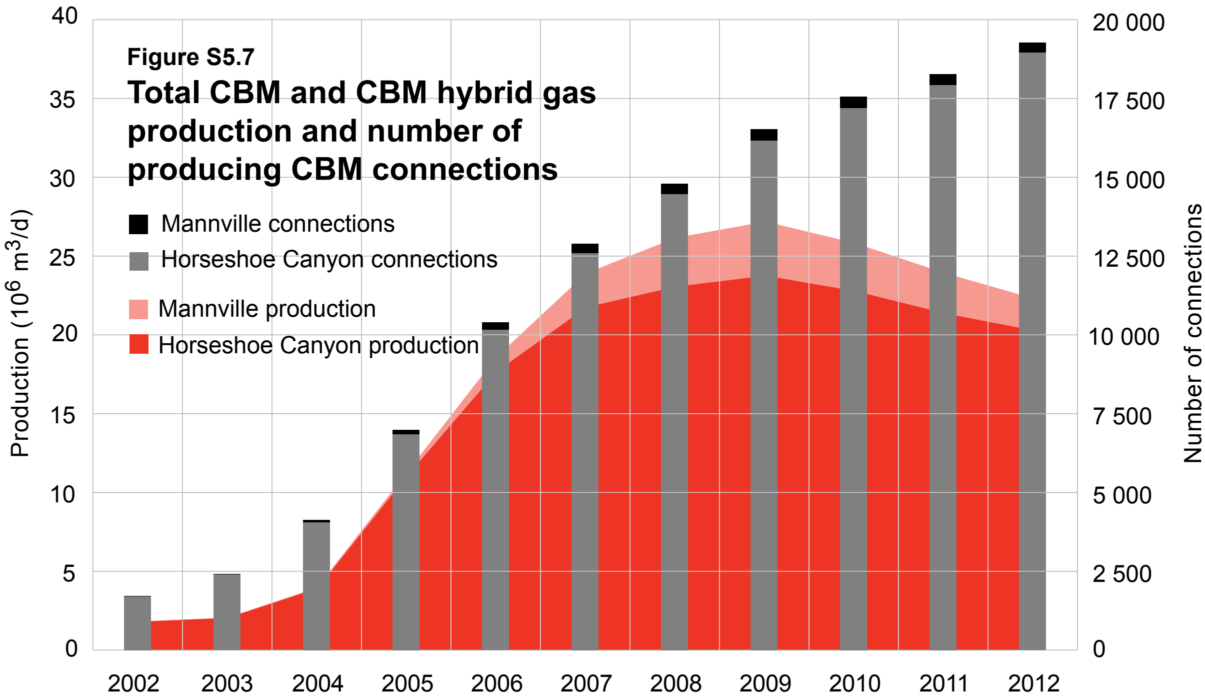


Figure S5.6
Comparison of raw natural gas production



only 1.7 per cent of the total producing CBM connections. The chart illustrates the much higher productivity rates of the horizontal Mannville CBM connections compared with the vertical CBM and CBM hybrid Horseshoe Canyon connections.

Although these high productivity rates would normally indicate resource development, there have been low levels of activity in the Mannville CBM play due to the limited number of industry participants in the area, the high cost of development and maintenance, and the low gas price environment.

5.2.3.3 Shale Gas

Shale gas production in Alberta is shown in **Figure S5.8** along with the number of producing shale gas connections in each year.

5.2.4 Production Characteristics of New Connections

5.2.4.1 Conventional Gas

As shown in **Figure S5.9**, 69 523 producing gas connections, or about 64 per cent, produce less than 1.0 10^3 m^3/d of raw gas. In 2012, these gas connections produced at an average rate of 0.4 10^3 m^3/d and contributed less than 10 per cent of the total natural gas production.

Less than 1 per cent of the conventional gas connections produced at rates over 50 10^3 m^3/d, but they contributed 21 per cent of total production, down from 31 per cent in 2011. The percentage of gas production from wells in this category decreased dramatically in 2012 due to a decline in the number of new gas connections, which contain more high productive horizontal wells.

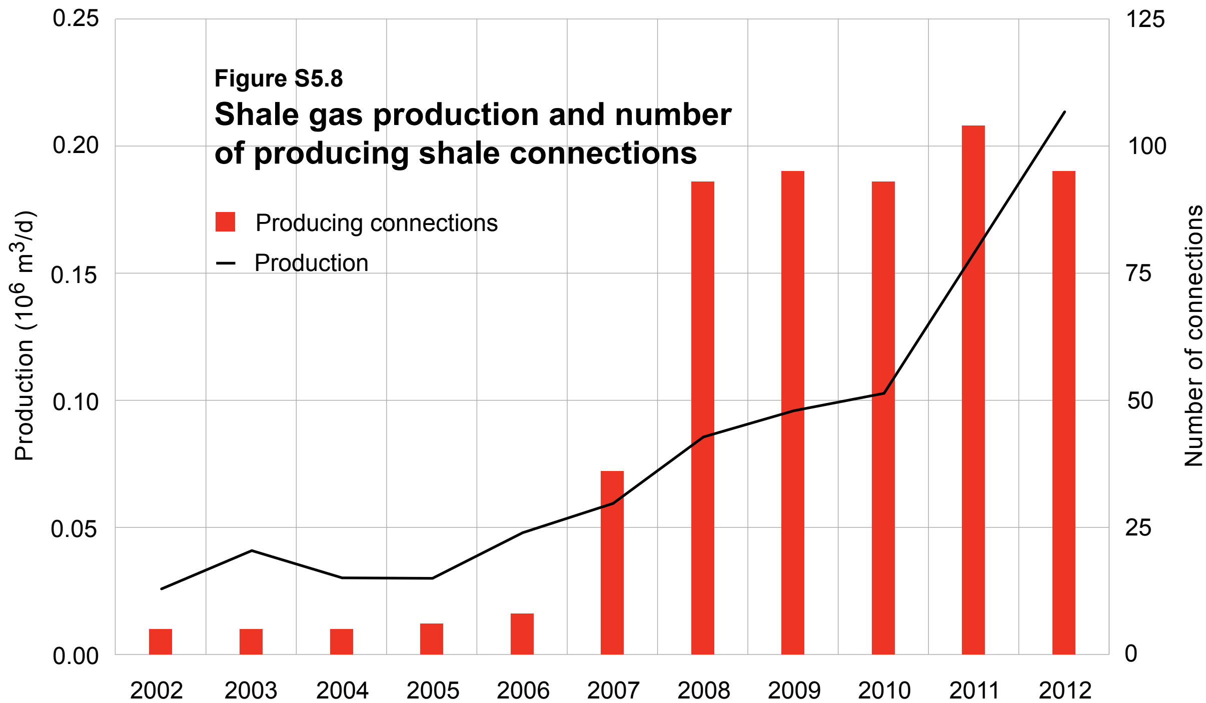


Figure S5.8
Shale gas production and number of producing shale connections
Producing connections
Production
Production (10^6 m^3/d)
Number of connections
0.25
0.20
0.15
0.10
0.05
0.00
125
100
75
50
25
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012

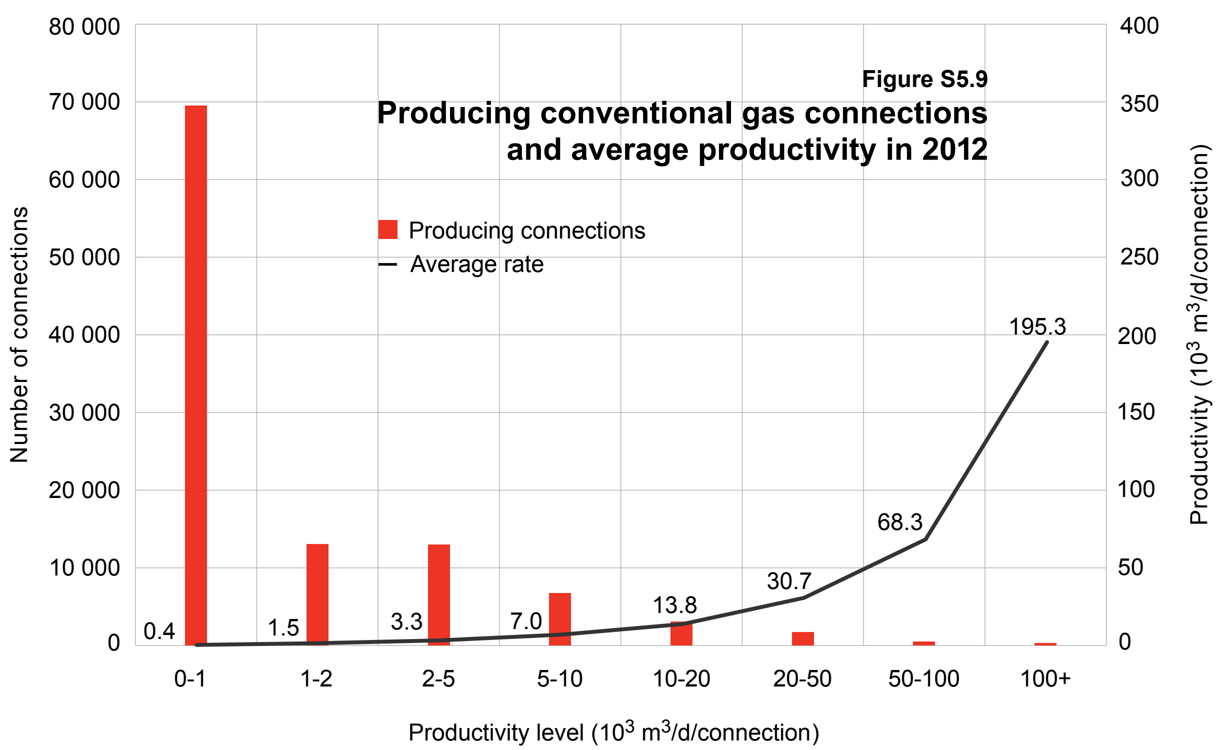


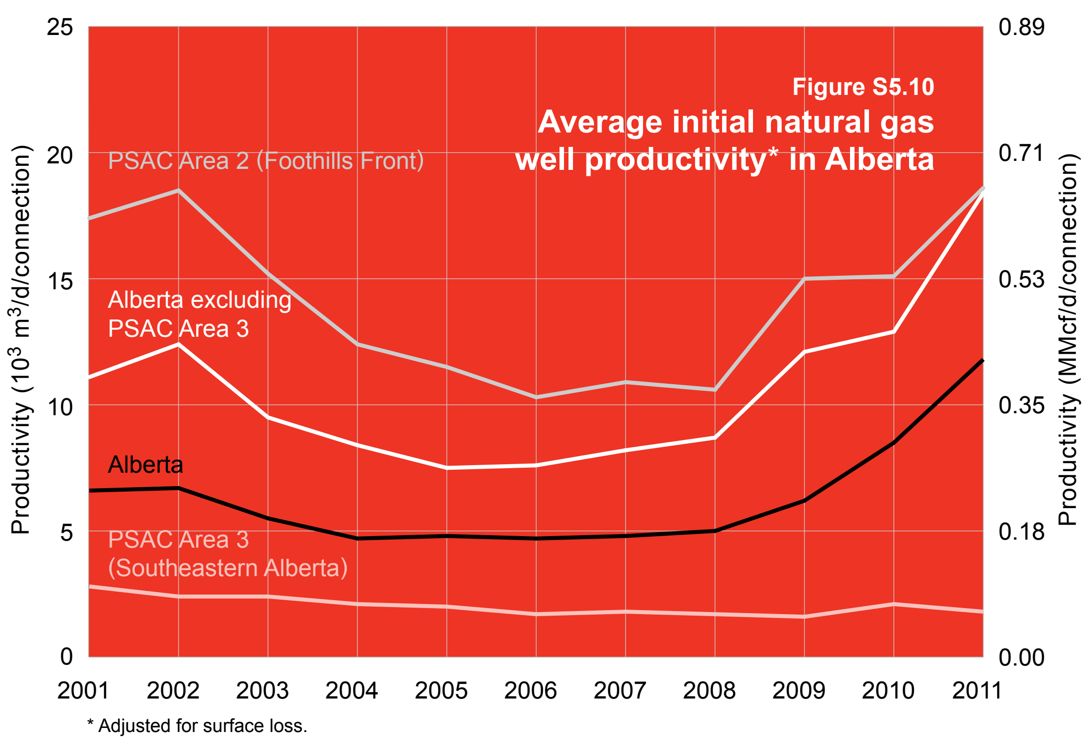
Figure S5.9
Producing conventional gas connections and average productivity in 2012
Producing connections
Average rate
Number of connections
Productivity (10^3 m^3/d/connection)
Productivity level (10^3 m^3/d/connection)
80 000
70 000
60 000
50 000
40 000
30 000
20 000
10 000
0
400
350
300
250
200
150
100
50
0
0.4
1.5
3.3
7.0
13.8
30.7
68.3
195.3
0-1
1-2
2-5
5-10
10-20
20-50
50-100
100+

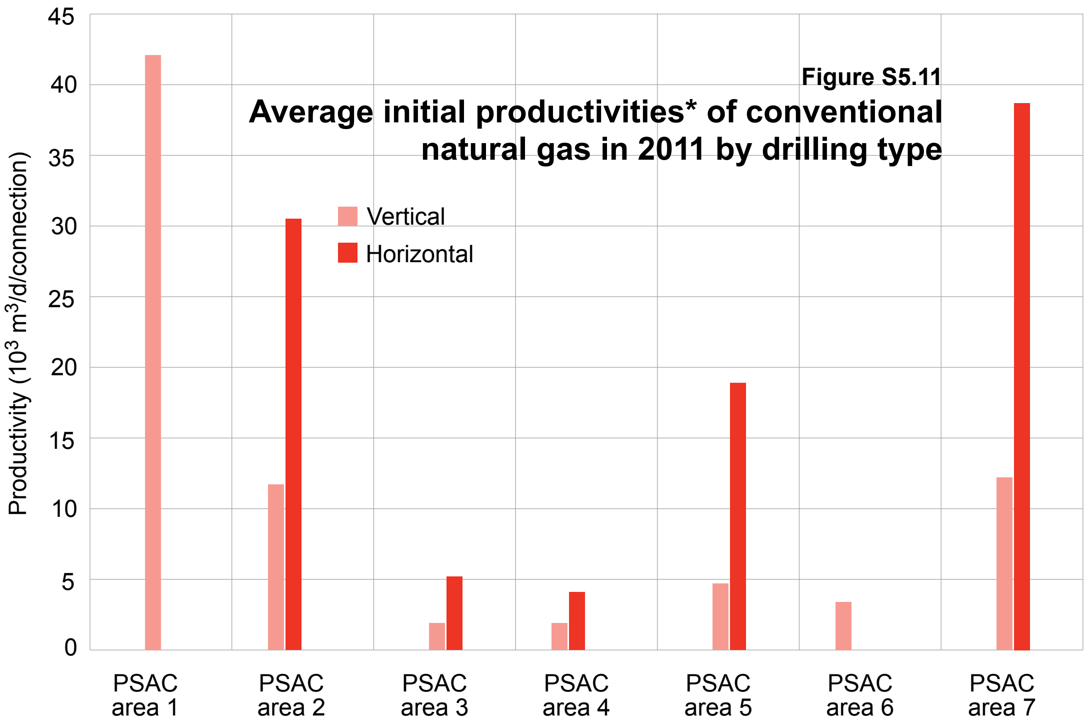
Average initial productivity of new conventional gas connections in some areas of the province is higher than in past years. **Figure S5.10** shows the average initial productivity of new connections by connection year for all the wells in Alberta, for all the wells in Alberta excluding PSAC Area 3, and for wells in PSAC Area 2 and in PSAC Area 3. Well productivity has been adjusted for surface losses to reflect sales gas rates as opposed to raw gas rates shown in the previous chart. Initial average daily production rates are calculated using the first full calendar year of production for gas connections.

This figure illustrates the improvement in average initial well productivity of recent connections. This is a result of horizontal drilling and new completion techniques. Average initial well productivity increased in all areas of the province with the exception of PSAC Area 3, PSAC Area 4 (East-Central Alberta), and PSAC Area 6 (Northeastern Alberta).

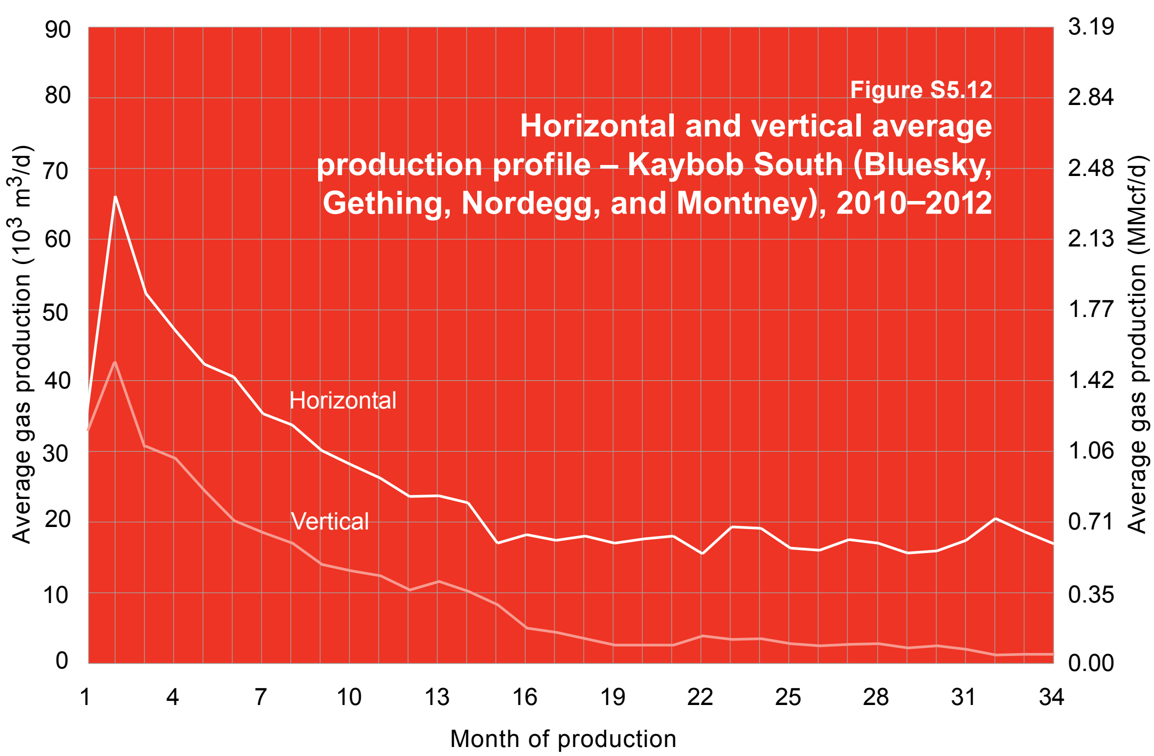
Figure S5.11 shows average initial well productivity by well type for wells connected in 2011 in selected PSAC areas. PSAC Area 2, PSAC Area 5 (central Alberta), and PSAC Area 7 are where most horizontal wells have been brought on production. There were no horizontal gas wells connected in PSAC Area 1 (Foothills) or PSAC Area 6 in 2011.

Figure S5.12 shows typical gas production profiles for vertical and horizontal wells in the Kaybob South Field that are producing commingled gas from the Bluesky, Gething, Nordegg, and Montney formations. Wells that were placed on production within the 2010 to 2012 time period were used to illustrate the difference in production profiles by well type. The initial productivity of horizontal wells that are completed using multistage fracturing technology is significantly higher than the initial productivity of vertical wells. New horizontal wells





* Adjusted for surface loss.



have much higher initial productivity than vertical wells, as illustrated earlier in **Figure S5.11**, and they continue to produce at much higher rates.

5.2.5 Supply Costs

Table S5.5 summarizes the estimated costs for conventional and CBM natural gas from selected areas in Alberta based on 2012 estimated costs and production profiles. The supply costs are based on representative wells in each PSAC area. Supply costs for different geological plays and PSAC areas vary significantly because of differing discovered reserves, production rates, well types, drilling and operating costs, royalties, etc. Therefore, the results may not be reflective of wells that differ from the representative well profiles used in the analysis.

The supply cost estimate for an average horizontal or vertical well in each PSAC area includes the following data: initial productivities, production decline rates, vertical drilled depths and total measured depths of the wells, gas composition, shrinkage, capital cost, operating costs, royalties and taxes, and a 10 per cent nominal rate of return. The supply costs in **Table S5.5** are not risked (i.e., assumes a 100 per cent success rate). The table shows that vertical wells have higher supply costs compared with horizontal ones, as vertical wells have lower initial productivities. Furthermore, liquids-rich gas improves the economics of development of gas wells, and therefore liquids-rich gas wells have lower supply costs than lean gas production such as CBM. The representative wells in PSAC Areas 1, 2, 5, and 7 are assumed to have liquids-rich gas production.

Table S5.5 Natural gas supply costs for PSAC areas and CBM play areas[a]

Area	Type of well	Type of gas	Total measured depth (m)	Initial productivity (10^3 m^3/d)	Total capital cost $000	Fixed operating cost ($000/year)	Variable operating cost ($/$10^3$ m^3)	Natural gas supply cost ($/GJ)
PSAC 1	Directional	Sour gas	4500	57.6	17970	202	53.2	7.23
PSAC 2	Vertical	Sweet gas	2500	14.6	2734	54	35.5	3.77
PSAC 2	Horizontal	Sweet gas	4200	38.1	4858	45	31.9	1.63
PSAC 3	Vertical	Sweet gas	560	2.0	411	11	49.7	6.98
PSAC 4	Vertical	Sweet gas	900	2.0	879	31	30.2	14.72
PSAC 5	Vertical	Sweet gas	1150	5.0	2219	56	39.0	11.44
PSAC 5	Horizontal	Sweet gas	2600	20.3	3482	45	31.9	3.36
PSAC 6	Vertical	Sweet gas	500	3.5	615	35	35.5	7.06
PSAC 7	Vertical	Sweet gas	2300	13.1	2589	63	30.2	5.82
PSAC 7	Horizontal	Sweet gas	3500	41.6	7236	63	33.7	4.88
CBM-HSC[b]	Vertical	CBM	250	1.3	608	21	40.8	10.19
CBM-MAN[c]	Horizontal	CBM	2400	8.9	2051	28	31.9	6.97

[a] Data from petroCube and the 2012 PSAC Well Cost Study have been used to estimate the supply costs in PSAC areas and CBM play areas.

[b] Horseshoe Canyon.

[c] Mannville Corbett.

The average AECO-C daily natural gas price in 2012 was $2.27/GJ, lower than the supply cost in many areas. Therefore, based on the assumptions used in the analysis, new gas developments were uneconomical in 2012 for most of the representative wells. However, some horizontal liquids-rich gas developments, mainly in PSAC Area 2, were found to yield positive returns. These findings are consistent with the shift in gas development in Alberta towards horizontal, liquids-rich gas drilling. In addition to the higher initial productivity for horizontal wells, the new royalty framework released by the Government of Alberta, effective January 2011, and royalty holiday programs have also provided incentives for deep horizontal drillings.

The results in **Table S5.5** also indicate high supply costs for vertical wells in PSAC Areas 4 and 5, as well as CBM wells producing from the Horseshoe Canyon play area. This is because of low initial well productivity, low gas liquids content, and/or relatively high capital costs per metre of drilling. The results are corroborated with the reduction of drilling activity in these areas.

5.2.6 Marketable Natural Gas Production – Forecast

In projecting conventional gas and CBM supply, the ERCB considers three components: expected production from existing conventional gas and CBM connections, expected production from new conventional gas and CBM connections in new and existing wells, and gas production from oil wells. The ERCB also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. Since shale gas development is in its early stages in Alberta, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time.

To forecast gas production, production data from existing wells and new wells drilled and connected each year have been analyzed. The number of new connections and the average productivity for the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.6.1 Conventional Gas

To project natural gas production from existing conventional gas connections, the ERCB assumes the following:

- Decline rates for gas production from existing conventional gas connections at year-end 2012 vary depending on such factors as the ages, types, and geological and geographical locations of the wells. Overall, however, it is assumed that rates will decline by 14 per cent per year over the forecast period based on observed performance. This is lower than last year's forecast of a 16 per cent annual decline. Decline rates are typically higher at the early stage of production and stabilize as gas production continues over time. The ERCB lowered the decline rate from last year's forecast because recently more gas has been produced from wells that have been producing for eight years or more. In 2012, 51 per cent of total conventional gas production was from wells that were eight years or older, compared with 39 per cent in 2008.
- Production from existing conventional gas connections will be 228.1 10^6 m^3/d in 2013.
- Over the forecast period, production of conventional gas from existing wells is expected to decline from 228.1 10^6 m^3/d to 59.3 10^6 m^3/d.

Analyses on the initial productivities, decline rates, the numbers of connections, the remaining reserves, and return on investment were conducted for each PSAC area. For PSAC Areas 2, 5, and 7, further analyses were conducted for vertical wells, as well as horizontal wells since horizontal wells are predominantly located in these areas. To project natural gas production from new conventional gas connections, the ERCB made the following assumptions:

- The numbers of new conventional gas connections over the forecast period are projected to start at 1100 in 2013 and to gradually increase to 1425 by 2022. The number of forecast connections is significantly lower relative to last year's forecast of 3800 largely due to a shift from vertical and directional wells to more capital-intensive but highly productive horizontal wells. The natural gas price forecast is also lower relative to last year's forecast. Finally, much lower drilling activity in 2012 compared with 2011 is reflected in the lower projection for the conventional gas connections over the forecast period.

- Conventional gas connections in PSAC Area 3 will represent 18 per cent of all new conventional gas connections in 2013. This will gradually decline to 16 per cent of new connections in 2022. This year's forecast percentage of PSAC Area 3 compared with all new conventional gas connections is significantly lower than the last forecast due to a large decrease from 41 per cent in 2011 to 19 per cent in 2012. The ERCB also expects that the shift in new connections from PSAC Area 3 to PSAC Areas 2, 5, and 7 will continue as the gas producers will see a much higher return on investment on the liquids-rich gas in the latter three areas than the dry gas in PSAC Area 3. The persisting low gas prices will not improve the profitability in PSAC Area 3 for the forecast period.

- The ERCB expects that PSAC Areas 2, 5, and 7 will represent 78 per cent of all new conventional connections in 2013, increasing slightly to 79 per cent in 2022. Horizontal wells, on the other hand, are projected to represent 67 per cent of the new connections in these PSAC areas in 2013, increasing to 72 per cent in 2022.

- The average initial productivity of a new conventional gas connection in PSAC Area 3 will be 2.0 10^3 m^3/d over the forecast period.

- The average initial productivity of a new conventional gas connection in the rest of the province will be 22.7 10^3 m^3/d in 2013, gradually increasing to 24.6 10^3 m^3/d by 2022. This forecast initial productivity is significantly higher than the previous forecast and will continue to increase over the forecast period due to the expectation that new conventional gas connections will increasingly use horizontal wells with multistage fracturing technology. The ERCB expects that PSAC Areas 2, 5, and 7, where the majority of horizontal wells have been drilled to date, will experience the main growth in drilling activities over the forecast period.

- Production from new gas wells, although it varies according to factors such as well type and geological and geographical locations, will generally decline by 35 per cent in the first year, 24 per cent in the second year, 19 per cent in the third year, and 16 per cent in the fourth year. The decline rate will then continue to decrease gradually every year reaching 12 per cent in the tenth year.

- Gas production from oil wells, based on observed performance, will be 33.7 10^3 m^3/d in 2013, and it will gradually decrease to 28.6 10^3 m^3/d in 2022. This forecast reflects recent actual performance.

Tables S5.6, **S5.7**, and **S5.8** show the ERCB's forecast initial productivities, declines rates, and the numbers of new gas well connections.

Based on the remaining established and yet-to-be-established reserves, and the assumptions described above, the ERCB forecasts conventional marketable gas production to 2022. The production of marketable gas from conventional reserves is expected to decrease from 265.2 10^6 m^3/d in 2012 to 205.9 10^6 m^3/d by 2022.

If conventional natural gas production rates follow the projection, Alberta will have recovered 80 per cent of the 6528 10^9 m^3 ultimate potential by 2022.

5.2.6.2 Coalbed Methane

In projecting CBM supply, the ERCB considers expected production from existing CBM connections and expected production from new CBM connections. These new CBM connections include CBM connections into new wells drilled and recompletions into existing wells. Continual reclassification of CBM connections results in revisions to historical data and, therefore, changes to annual forecasts.

To forecast production from CBM and CBM hybrid connections before 2013, the ERCB assumed the following:

- All gas production from identified CBM and hybrid connections is included.
- All existing CBM and hybrid producing connections are expected to decline annually based on historical trends.
- Over the forecast period, production of existing CBM and CBM hybrid wells is expected to decline from 20.8 10^6 m^3/d to 12.3 10^6 m^3/d.

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

- Over the forecast period, the majority of new CBM and CBM hybrid production will be from the Horseshoe Canyon play area.
- The number of new CBM and CBM hybrid connections will be 230 in 2013 and will increase slightly to 245 in 2022. This forecast is significantly lower than last year's projection and is due to the very low level of activity reported in 2012 and the expectation that return on investment will not improve over the forecast period because of continuing low gas prices.
- The average initial productivity of a new gas connection in the Horseshoe Canyon play area will be 1.3 10^3 m^3/d and gradually decrease to 0.8 10^3 m^3/d in 2022.
- The percentage of recompletions in existing wells versus new connections within the Horseshoe Canyon play area will remain at 2012 levels over the forecast period.

Table S5.6 Forecast initial productivity for new gas wells (10^3 m^3/d)

Area	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PSAC 1	57.6	57.6	58.2	58.2	58.8	58.2	57.6	57.0	56.4	55.9
PSAC 2 vertical well	14.6	14.6	14.5	14.5	14.5	14.5	14.3	14.3	14.3	14.3
PSAC 2 horizontal well	38.1	38.9	39.6	40.4	41.2	41.0	41.0	41.0	40.0	40.0
PSAC 3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PSAC 4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PSAC 5 vertical well	5.0	5.0	5.0	5.0	5.0	5.0	4.9	4.9	4.8	4.8
PSAC 5 horizontal well	20.3	20.3	20.3	20.1	20.1	19.9	19.9	19.7	19.7	19.7
PSAC 6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
PSAC 7 vertical well	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
PSAC 7 horizontal well	41.6	42.4	43.3	44.1	45.0	45.0	44.6	44.1	43.7	43.3

Table S5.7 Forecast decline rates for new gas wells

Area	Year 1	Year 2	Year 3	Year 4	Years 5–9	Year 10
PSAC 1	25%	22%	15%	15%	Gradual decline	11%
PSAC 2	34%	24%t	18%	16%	Gradual decline	12%
PSAC 3	33%	22%	17%	15%	Gradual decline	11%
PSAC 4	37%	30%	26%	21%	Gradual decline	16%
PSAC 5	38%	27%	22%	21%	Gradual decline	13%
PSAC 6	38%	31%	22%	20%	Gradual decline	16%
PSAC 7	39%	28%	24%	21%	Gradual decline	14%

Table S5.8 Forecast number of new gas well connections

Area	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PSAC 1	10	10	10	10	10	10	15	15	15	15
PSAC 2 vertical well	220	220	220	220	220	220	220	220	220	230
PSAC 2 horizontal well	450	450	450	460	460	480	500	520	530	550
PSAC 3	200	200	200	200	210	220	230	230	230	230
PSAC 4	30	30	30	30	30	30	30	30	50	50
PSAC 5 vertical well	50	50	50	50	50	60	60	60	60	60
PSAC 5 horizontal well	60	60	60	60	80	80	90	100	100	100
PSAC 6	5	10	10	10	10	10	10	10	10	10
PSAC 7 vertical well	15	15	15	20	20	20	20	20	20	20
PSAC 7 horizontal well	60	60	60	80	80	100	130	160	160	160
Total	1100	1105	1105	1140	1170	1230	1305	1365	1395	1425

Production from CBM connections, which includes commingled production from conventional gas formations, is expected to decrease from 22.3 10^6 m^3/d in 2012 to 13.8 10^6 m^3/d in 2022, lower than last year's forecast. In 2012, CBM production contributed 7.8 per cent of the total Alberta marketable gas production, similar to the previous year, and it is projected to contribute 6.3 per cent of the total Alberta marketable gas production in 2022, compared with last year's expectation of a 7.6 per cent contribution in 2021.

5.2.6.3 Shale Gas

As mentioned earlier, the ERCB does not have sufficient information to confidently forecast shale gas supply at this time. The economic viability of shale development in Alberta is currently unclear; however, it has the potential to become a significant supply source. Commercial shale gas production is in its infancy, and it will take time to establish the producibility of the resource. The pace of shale gas development will be affected by the natural gas price environment, supply costs, and technology.

5.2.6.4 Total Gas Production

The ERCB's forecast of conventional gas production from gas wells in each PSAC area, conventional oil wells, as well as CBM production, are shown in **Figure S5.13**. The ERCB forecasts that the total marketable gas production will decline from 272.8 10^6 m^3/d in 2013 to 219.7 10^6 m^3/d in 2022. This compares with last year's forecast of 205.6 10^6 m^3/d in 2021.

Figure S5.14 illustrates historical and forecast new connections for conventional gas and coalbed methane wells, along with plant gate gas prices (see **Section 1** for discussion on price forecasts).

Figure S5.15 shows process gas production (rich in liquids) from bitumen upgrading and raw natural gas from bitumen wells. Gas from these sources is used primarily as fuel in oil sands development.

In 2012, about 15.0 10^6 m^3/d of process gas was generated at oil sands upgrading facilities, compared with a revised volume of 16.4 10^6 m^3/d in 2011, and was primarily used as fuel. This number is expected to reach 25.5 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells increased by 0.6 10^6 m^3/d to 5.9 10^6 m^3/d in 2012 and is forecast to increase to 10.2 10^6 m^3/d by 2022. This gas is used mainly as fuel to create steam for on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.

5.2.7 Commercial Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the ERCB does not use volumes of commercially stored natural gas in the long-term production projection. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; traditionally 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

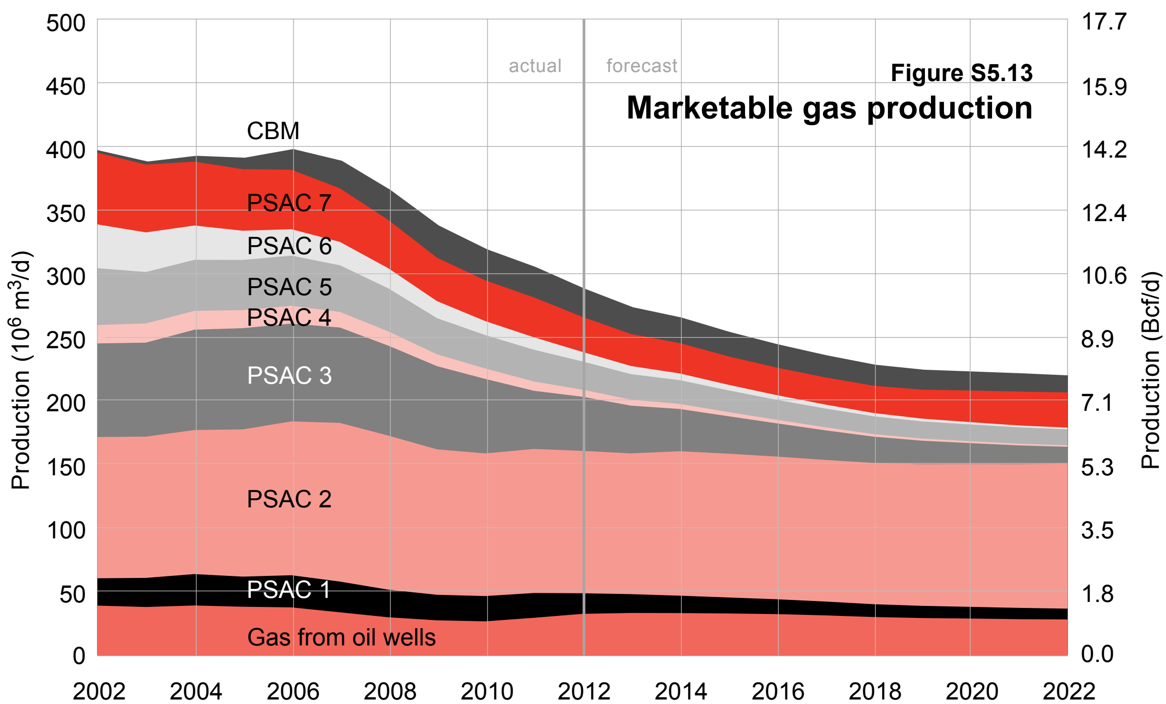


Figure S5.13
Marketable gas production
actual
forecast
CBM
PSAC 7
PSAC 6
PSAC 5
PSAC 4
PSAC 3
PSAC 2
PSAC 1
Gas from oil wells
Production (10^6 m^3/d)
Production (Bcf/d)
500
450
400
350
300
250
200
150
100
50
0
17.7
15.9
14.2
12.4
10.6
8.9
7.1
5.3
3.5
1.8
0.0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

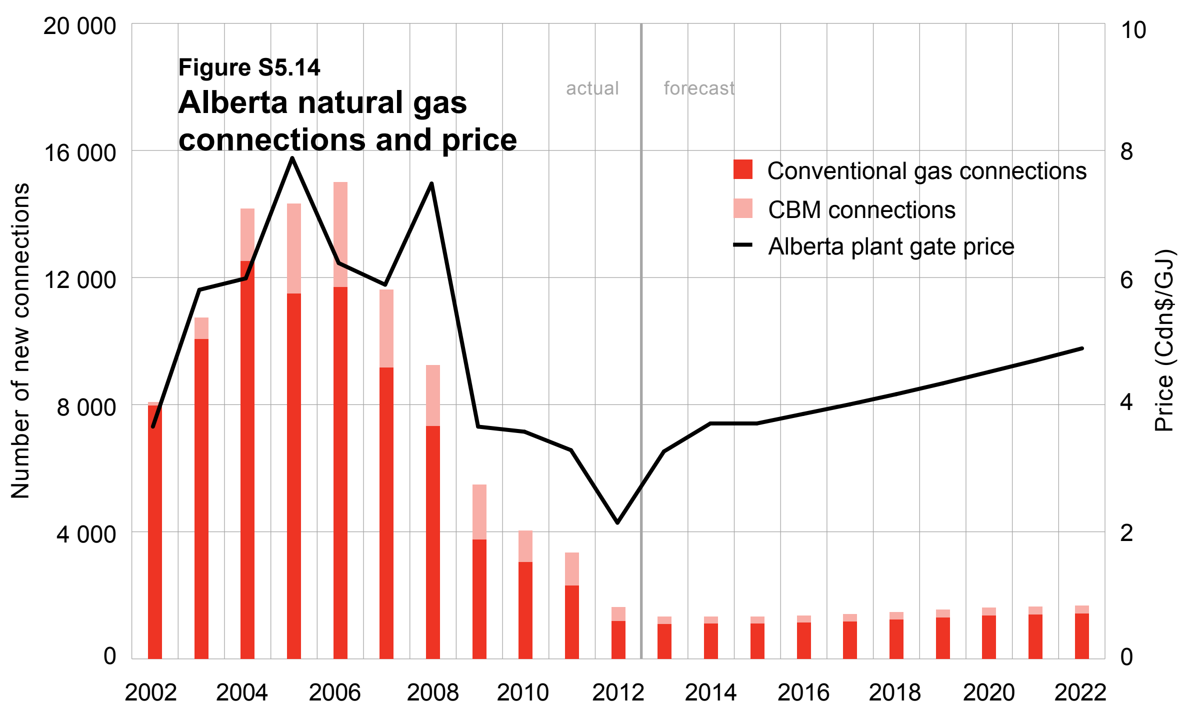
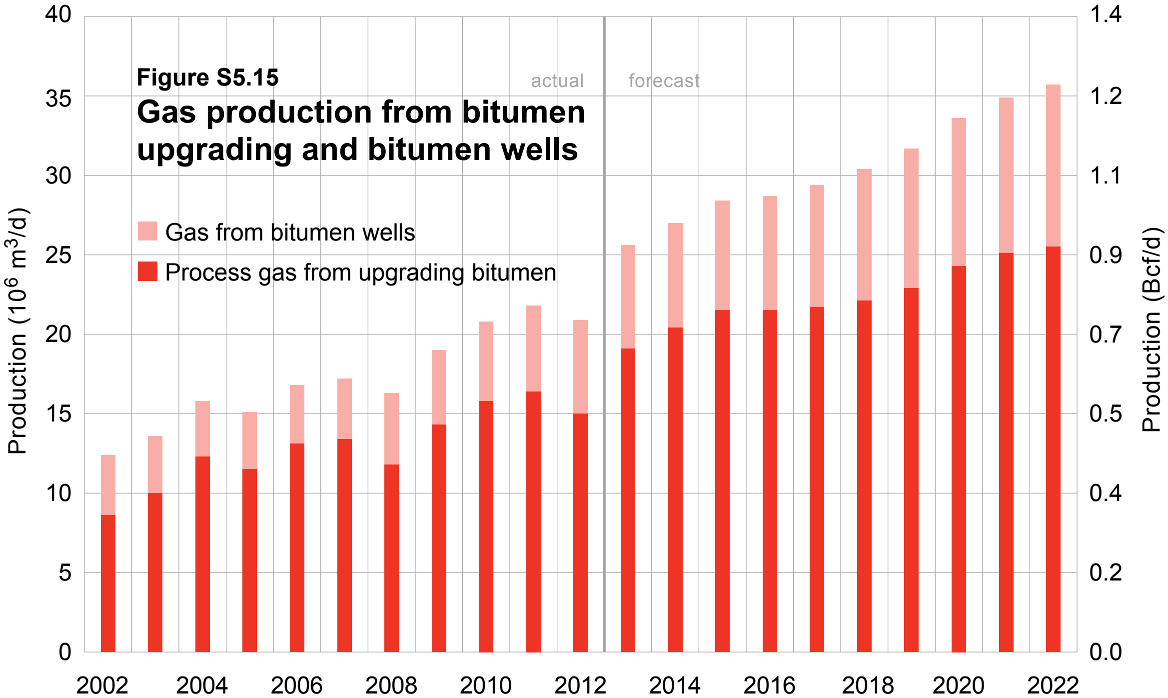


Figure S5.14
Alberta natural gas connections and price
actual
forecast
Conventional gas connections
CBM connections
Alberta plant gate price
Number of new connections
Price (Cdn$/GJ)
20 000
16 000
12 000
8 000
4 000
0
10
8
6
4
2
0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022



fee-for-service, buy-sell, or other contractual arrangements. There are other gas storage schemes in the province that are not included in this category.

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas rises, injection slows or ends, and storage withdrawals generally begin at high withdrawal rates. Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table S5.9**.

In 2012, natural gas injections for all storage schemes exceeded withdrawals by 487 10^6 m^3. This compares with 2687 10^6 m^3 net injection in 2011. The increase in the U.S.-marketed gas production discussed earlier in this section has reduced the volume of Alberta export gas entering Canadian and U.S. markets. Even though the intra-Alberta demand has been steadily increasing, as mentioned later in this section, the decrease in the export demand contributed to the continued trend of net injection in 2012. Very high inventories of working gas throughout the year, however, caused a large reduction in injection volumes, as well as withdrawal volumes, in 2012.

Marketable gas production volumes determined for 2012 were adjusted to account for the imbalance between volumes injected and volumes withdrawn from these storage pools. For the purpose of projecting future natural gas production, the ERCB assumes that injections and withdrawals are balanced for each year during the forecast period.

Figure S5.16 shows the location of existing gas storage facilities along the pipeline systems within Alberta.

Table S5.9 Commercial natural gas storage pools as of December 31, 2012

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2012 (10^6 m^3)	Withdrawal volumes, 2012 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	684	624
Carrot Creek CCC	Iberdrola Canada Energy Services Ltd.	986	16 900	352	312
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	35 217	554	302
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	362	284
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	593	335
Hussar Glauconitic R	Husky Oil Operations Ltd	423	5 635	17	93
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	10	14
Nisku E	Wild Rose Energy Ltd.	940	11 000	0	0
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	50 713	473	550
Warwick Glauconitic-Nisku A	Warwick Gas Storage Inc.	881	3 300	378	422
Total		**11 417**	**178 676**	**3 423**	**2 936**
Difference					**487**

5.2.8 Alberta Natural Gas Demand

The *Alberta Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the ERCB for a permit authorizing the removal. Removal of gas from Alberta is only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.

The calculation in **Table S5.10** is done annually to determine what volume of gas is available for removal from Alberta after accounting for Alberta's future requirements. Using the 2012 remaining established reserves number, surplus natural gas is currently calculated to be 440 10^9 m^3. **Figure S5.17** illustrates historical "available for permitting" volumes.

Gas removals from Alberta have declined since 2001, from 311.5 10^6 m^3/d in 2001 to 159.6 10^6 m^3/d in 2012. Based on the ERCB's projection of gas production, this rate is forecast to drop to 49.3 10^6 m^3/d by 2022. This is higher than last year's projection of 38.1 10^6 m^3/d by 2021 mainly because this year's natural gas supply forecast is slightly higher.

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

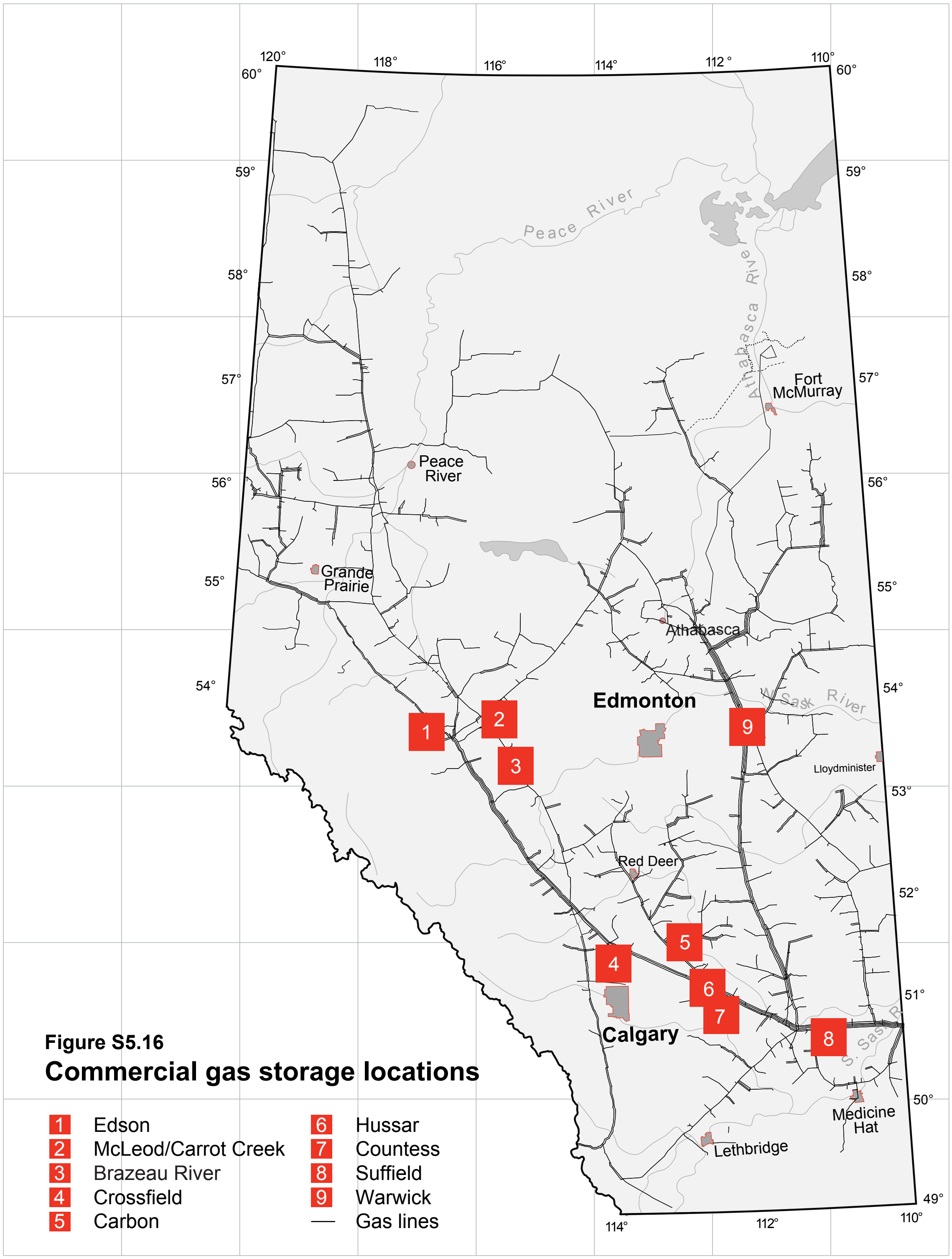


Figure S5.16
Commercial gas storage locations

1 Edson
2 McLeod/Carrot Creek
3 Brazeau River
4 Crossfield
5 Carbon
6 Hussar
7 Countess
8 Suffield
9 Warwick
— Gas lines

Table S5.10 Estimate of gas reserves available for inclusion in removal permits as of December 31, 2012

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2012)	
1. Total remaining established reserves	957
Alberta requirements	
2. Core market requirements	105
3. Contracted for noncore markets[a]	147
4. Permit-related fuel and shrinkage	24
Permit requirements	
5. Remaining permit commitments[b]	241
6. Total requirements	517
Available	
7. Available for removal permits	440

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

[b] The remaining permit commitments are split approximately 96 per cent under short-term permits and 4 per cent under long-term permits.

Forecasting demand for Alberta natural gas in markets outside the province is done less rigorously. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on removal pipeline capacity available to serve such markets and on the recent historical trends in meeting that demand. Excess pipeline capacity to the United States allows gas to move to areas of the United States that provide for the highest netback to the producer. The major natural gas pipelines in Canada that move Alberta gas to market are illustrated in **Figure S5.18**, with export points identified.

Figure S5.19 illustrates the breakdown of marketable natural gas demand in Alberta by sector. In 2012, demand within Alberta was 127.9 10^6 m^3/d, which represented 44 per cent of the total Alberta natural gas production. By the end of the forecast period, demand will reach 170.4 10^6 m^3/d, or 78 per cent of total Alberta production.

Residential gas requirements are expected to grow moderately at an average annual rate of four per cent over the forecast period. The key variables that affect residential gas demand are natural gas prices, population, the number of households, energy efficiency, and the weather. Improvements in energy efficiency prevent household energy use from rising significantly.

Commercial gas demand in Alberta has declined gradually since 2003 and is expected to continue to decline at an average annual rate of 0.5 per cent per year over the forecast period. This is largely due to gains in energy efficiency and a shift towards electricity.

The electricity-generating industry will require increased volumes of natural gas to fuel new industrial on-site and gas-fired generation plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 21.6 10^6 m^3/d in 2012 to 37.3 10^6 m^3/d by 2022. The projected increase in gas demand in this sector is due to the assumption that gas will be the preferred feedstock for new power plants.

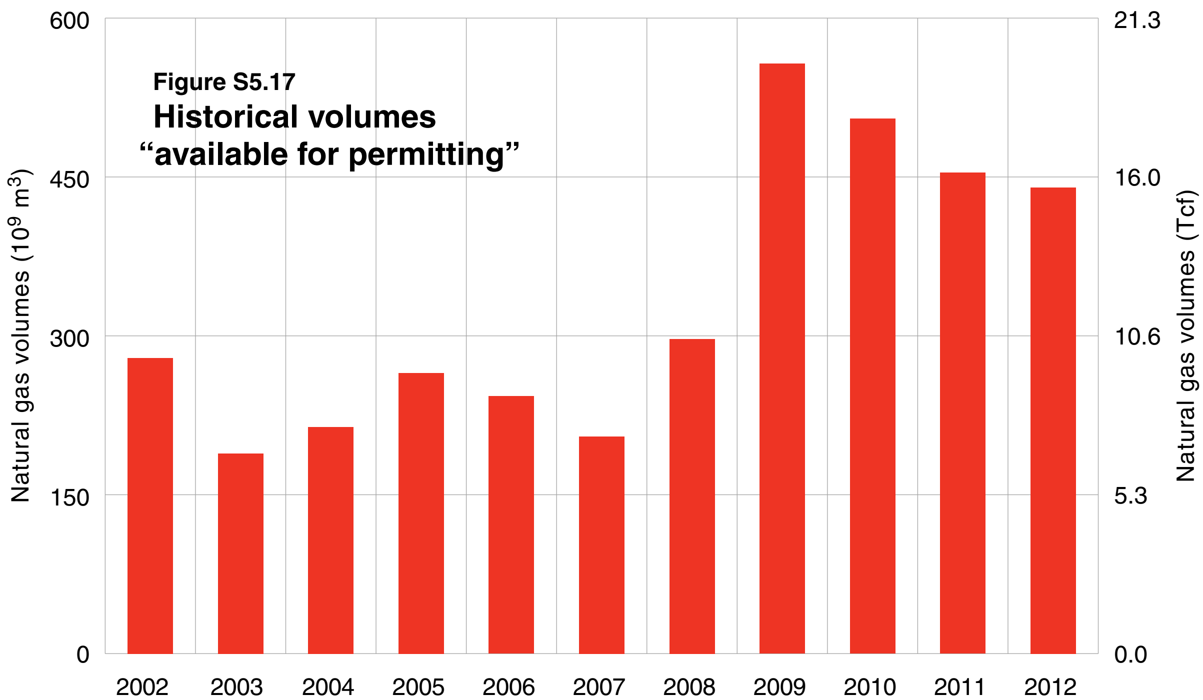


Figure S5.17
Historical volumes
"available for permitting"
Natural gas volumes (10⁹ m³)
Natural gas volumes (Tcf)
600
450
300
150
0
21.3
16.0
10.6
5.3
0.0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012

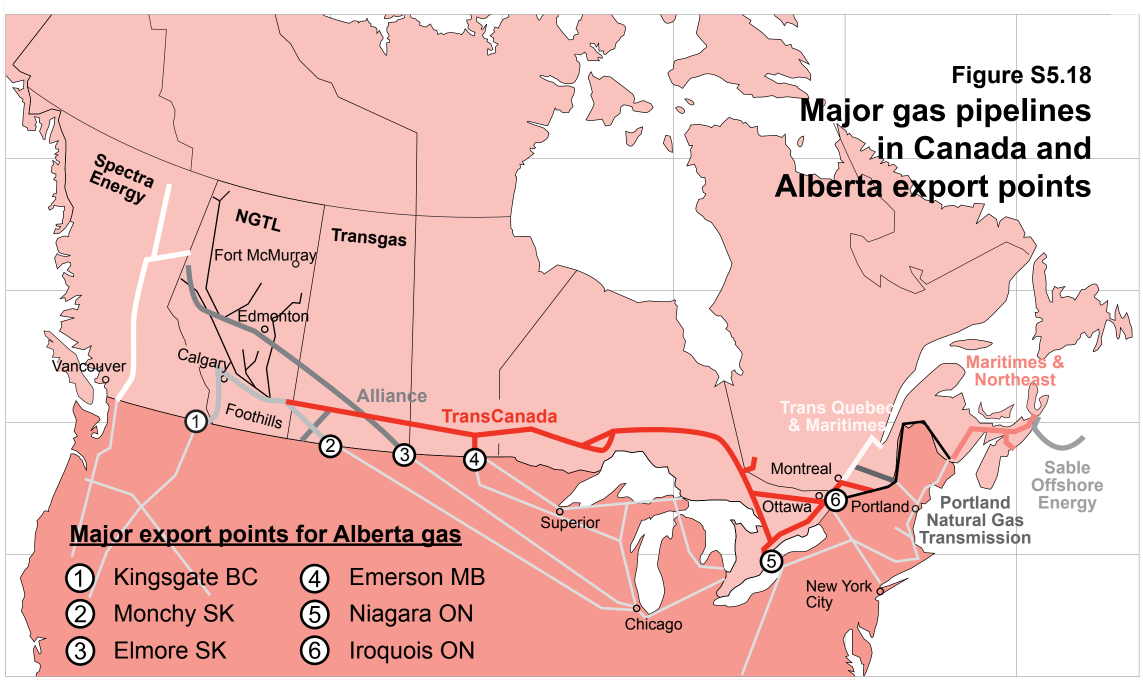


Figure S5.18
Major gas pipelines
in Canada and
Alberta export points
Spectra Energy
NGTL
Transgas
Fort McMurray
Edmonton
Calgary
Vancouver
Foothills
Alliance
TransCanada
Superior
Chicago
Montreal
Ottawa
Portland
New York City
Trans Quebec & Maritimes
Maritimes & Northeast
Sable Offshore Energy
Portland Natural Gas Transmission
Major export points for Alberta gas
1 Kingsgate BC
2 Monchy SK
3 Elmore SK
4 Emerson MB
5 Niagara ON
6 Iroquois ON

Table S5.11 Average use rates of purchased gas for oil sands operations, 2012[a]

	Excluding purchased gas for cogeneration		Including purchased gas for cogeneration	
Extraction method	**(m^3/m^3)**	**(mcf/bbl)**[b]	**(m^3/m^3)**	**(mcf/bbl)**
In situ				
SAGD	150	0.84	208	1.17
CSS	176	0.99	221	1.24
Mining with upgrading	108	0.60	148	0.82

[a] Expressed as cubic metres of natural gas per cubic metre of upgraded/nonupgraded bitumen production. Rates are an average of typical schemes with sustained production.

[b] Million cubic feet per barrel.

Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations will increase from 31.8 10^6 m^3/d in 2012 to 68.2 10^6 m^3/d in 2022. **Table S5.11** outlines the average purchased gas use rates for oil sands operations. Gas production from and demand for the oil sands operations are sourced from the PETRINEX.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.20** shows total gas use by the oil sands sector, including gas used for in situ recovery, mining and upgrading, and electricity cogeneration. The gas supply sources include purchased gas, process gas from mining and upgrading operations, and produced gas from bitumen wells. Gas use by the oil sands sector was 66.4 10^6 m^3/d in 2012 and is forecast to increase to 128.0 10^6 m^3/d by 2022.

Figure S5.21 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading (**Figure S5.15**) is considered to be used on site and is not included as marketable production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional and CBM production only (and do not include imports from British Columbia), minus Alberta demand.

In 2012, about 44 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand will represent 78 per cent of total Alberta natural gas production. However, the forecast does not include any potential shale gas production that may occur in Alberta. Additionally, natural gas supply from British Columbia that moves through Alberta to market is also not included in this analysis. The B.C. supply is expected to increase over the forecast period and provides Alberta with an additional source of natural gas if needed.

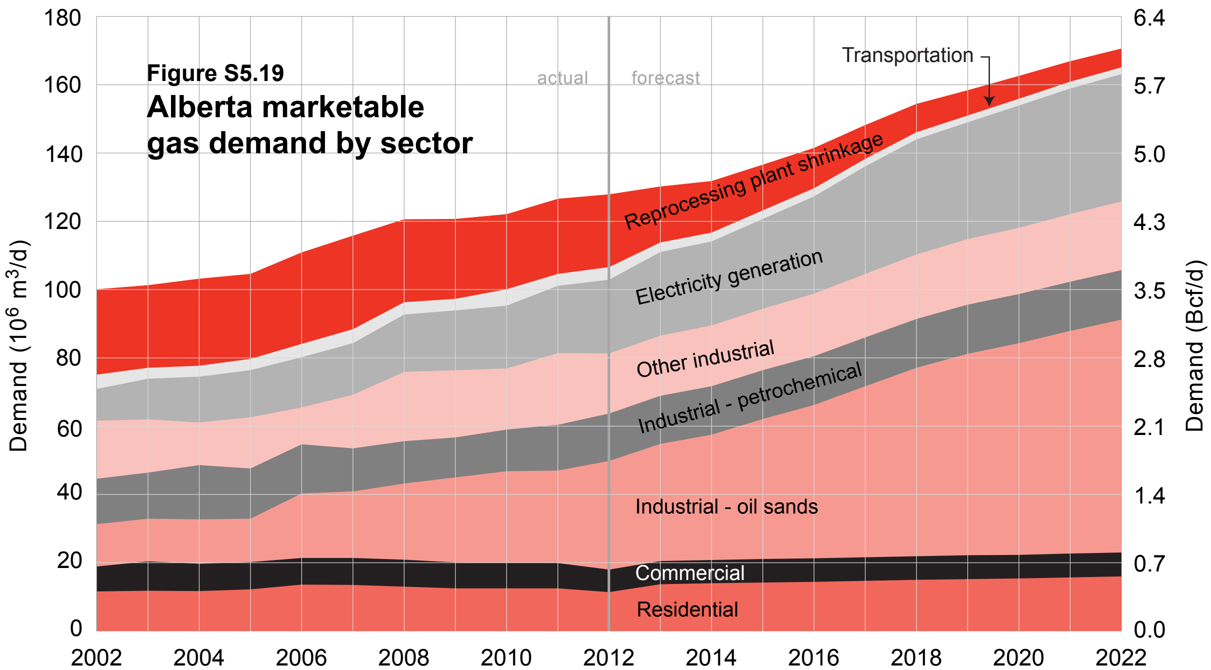


Figure S5.19
Alberta marketable gas demand by sector
actual
forecast
Transportation
Reprocessing plant shrinkage
Electricity generation
Other industrial
Industrial - petrochemical
Industrial - oil sands
Commercial
Residential
Demand (10^6 m^3/d)
Demand (Bcf/d)
180
160
140
120
100
80
60
40
20
0
6.4
5.7
5.0
4.3
3.5
2.8
2.1
1.4
0.7
0.0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

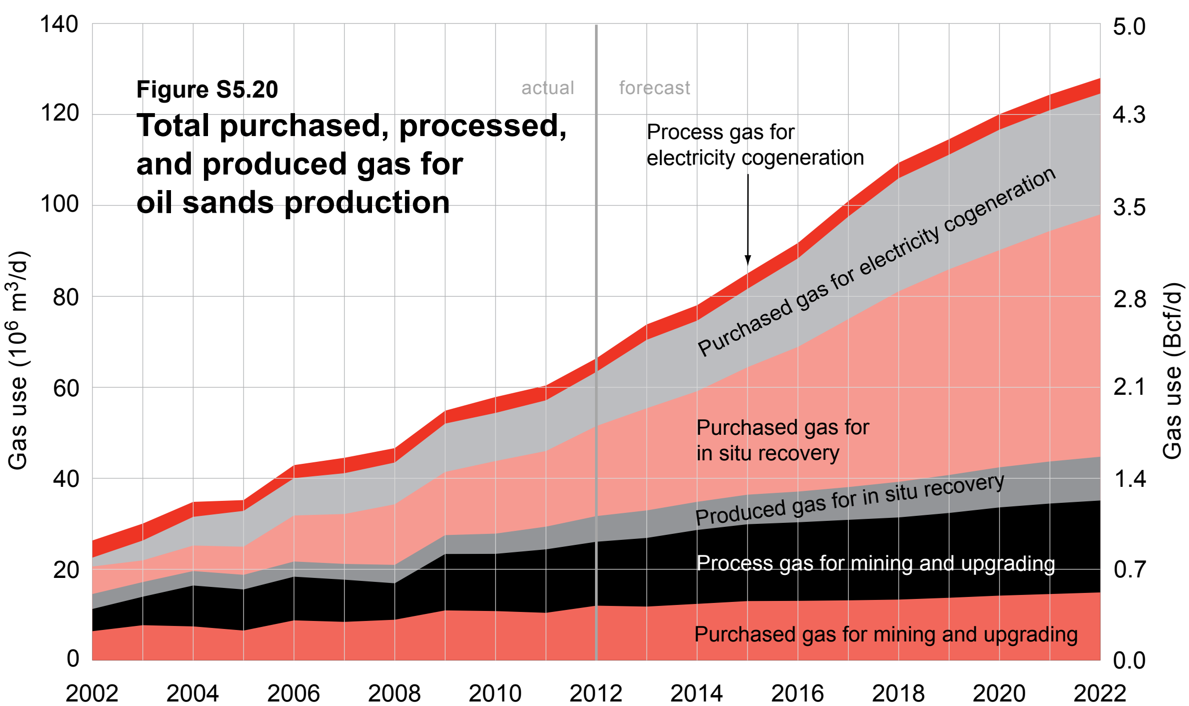


Figure S5.20
Total purchased, processed, and produced gas for oil sands production
actual
forecast
Process gas for electricity cogeneration
Purchased gas for electricity cogeneration
Purchased gas for in situ recovery
Produced gas for in situ recovery
Process gas for mining and upgrading
Purchased gas for mining and upgrading
Gas use (10^6 m^3/d)
Gas use (Bcf/d)
140
120
100
80
60
40
20
0
5.0
4.3
3.5
2.8
2.1
1.4
0.7
0.0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

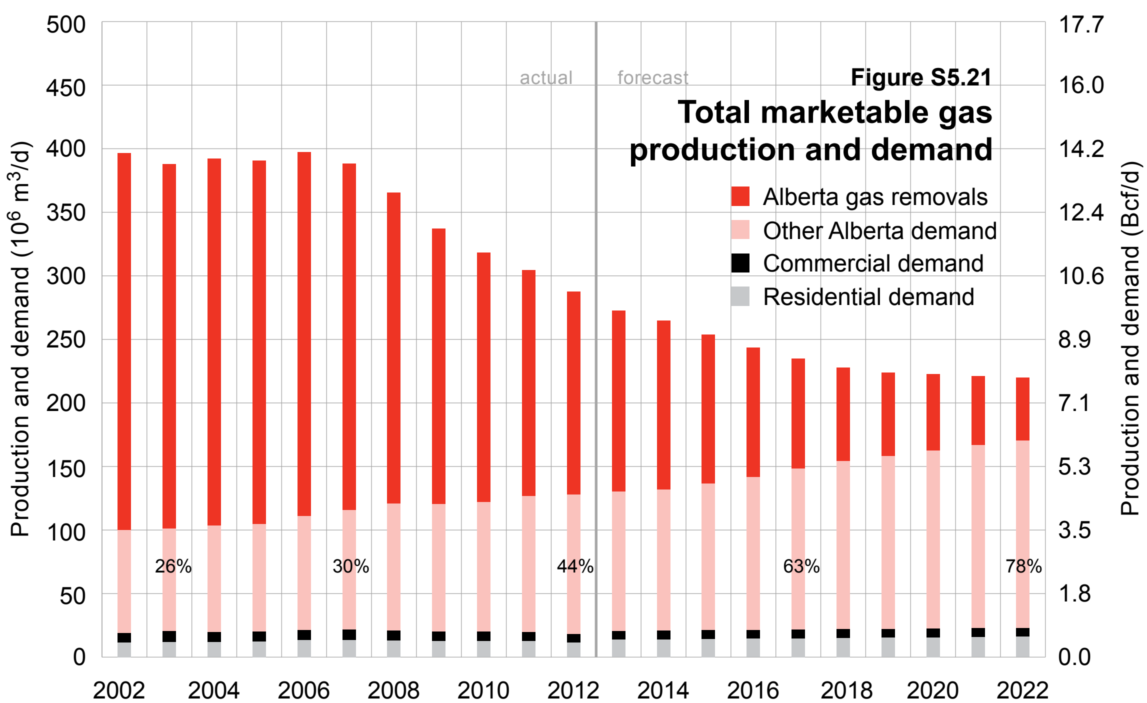


Figure S5.21
Total marketable gas production and demand
Alberta gas removals
Other Alberta demand
Commercial demand
Residential demand
actual
forecast
26%
30%
44%
63%
78%
Production and demand (10^6 m^3/d)
Production and demand (Bcf/d)
500
450
400
350
300
250
200
150
100
50
0
17.7
16.0
14.2
12.4
10.6
8.9
7.1
5.3
3.5
1.8
0.0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

HIGHLIGHTS

Total remaining extractable NGL reserves have decreased by 1 per cent from 2011 as a result of decreasing natural gas reserves.

Approximately 70 per cent of total ethane in the gas stream was extracted in 2012, compared with 68 per cent in 2011 and 63 per cent in 2010.

6 NATURAL GAS LIQUIDS

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

The ERCB estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in **Section 6.2.1**. Initial reserves for NGLs are not calculated since historically only a fraction of the liquid volume that could have been extracted was recovered, and much was flared for lack of market demand. The ERCB's projections for the overall recovery of each NGL component are explained in **Section 5.1.3.5**. As shown graphically in **Figure R5.8**, the estimate of the reserves of liquid ethane is based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the ERCB's calculations assume that the composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict and the volume is not expected to be significant. The NGL reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in **Section 5.1**.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2012 are summarized in **Tables R6.1** and **R6.2**. **Figure R6.1** shows remaining established reserves of extractable NGLs compared with 2012 production.

Total remaining reserves of extractable NGLs have decreased by 1.0 per cent compared with 2011 because of the decline in natural gas reserves. Fields that have contributed significantly to this decrease are Fir, Pembina, and Sundance. These fields and others containing large NGL volumes are listed in **Appendix B**, **Tables B.6** and **B.7**.

Table R6.1 Established reserves and production change highlights of extractable NGLs (10^6 m^3 liquid)[a]

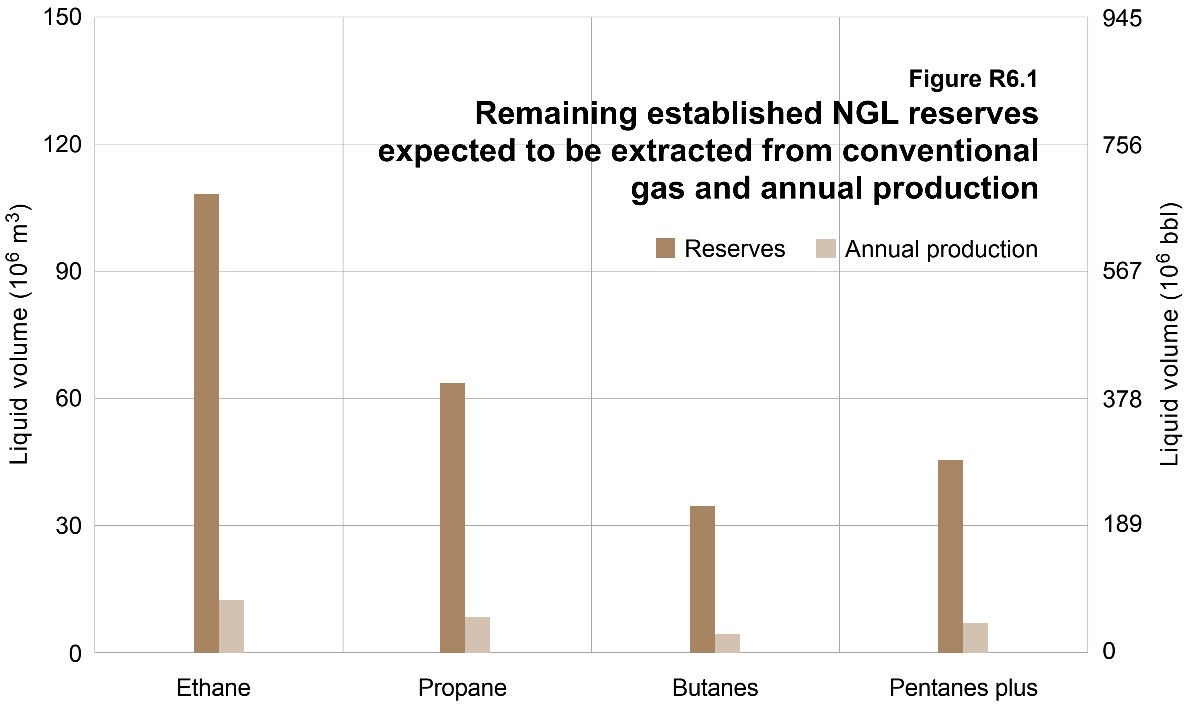
	2012	2011	Change
Cumulative net production			
Ethane	318.0	305.5	+12.5
Propane	303.4	295.1	+8.3
Butanes	172.8	168.4	+4.4
Pentanes plus	366.6	359.6	+7.0
Total	**1 160.8**	**1128.6**	**+32.2**
Remaining (expected to be extracted)			
Ethane	108.1	108.8	-0.8
Propane	63.7	64.2	-0.5
Butanes	34.6	35.0	-0.4
Pentanes plus	45.5	46.5	-0.9
Total	**252.0**	**254.5**	**-2.5**
	(1 590 10^6 bbl[b])	**(1 602 10^6 bbl)**	
Annual production	**32.2**	**32.4**	**-0.2**

[a] 10^6 m^3 = million cubic metres

[b] bbl = barrels

Table R6.2 Reserves of NGLs as of December 31, 2012 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total NGLs in remaining raw gas	164.9	75.0	38.5	45.5	323.9
Liquids expected to remain in dry marketable gas	56.8	11.2	3.8	0.0	71.9
Remaining established reserves recoverable from					
Field plants	43.1	37.5	23.1	41.0	144.7
Straddle plants	64.9	26.2	11.5	4.6	107.3
Total	**108.1**	**63.7**	**34.6**	**45.5**	**252.0**

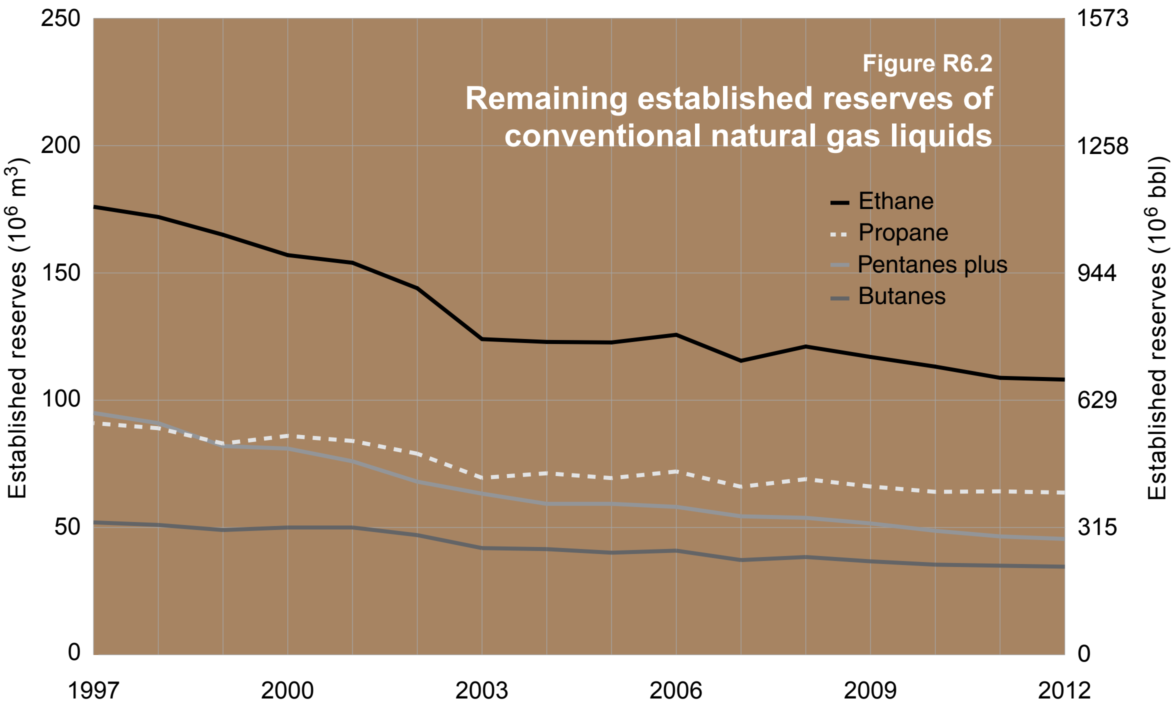


6.1.2 Ethane

As of December 31, 2012, the ERCB estimates remaining established reserves of extractable ethane to be 108.1 10^6 m^3 in liquefied form. Of that, 43.1 10^6 m^3 is expected to be recovered from field plants and 64.9 10^6 m^3 from straddle plants that deliver gas outside the province, as shown in **Table R6.2.** It is estimated that 6.4 10^6 m^3 is recoverable from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. At the end of 2012, only four pools were still actively injecting solvent: Rainbow Keg River B, Rainbow Keg River F, Judy Creek Beaverhill Lake A, and Swan Hills Beaverhill Lake A&B Pools.

Thirty-five per cent of the total raw ethane, or 56.8 10^6 m^3 (liquid), is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure R6.2** shows the remaining established reserves of ethane declining rapidly from 1996 to 2003 then levelling off as more ethane is extracted from raw gas. In 2012, the extraction of specification ethane was 12.5 10^6 m^3, compared with 12.9 10^6 m^3 in 2011.

For individual gas pools, the ethane content of gas in Alberta varies considerably, falling within the range of 0.0025 to 0.20 mole per mole (mol/mol). As shown in **Appendix B**, **Table B.6**, the volume-weighted average ethane content of all remaining raw gas is 0.052 mol/mol. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves. Of these fields, the eight largest—in alphabetical order, Ansell, Elmworth, Kaybob South, Pembina, Rainbow, Wapiti, Wild River, and Willesden Green—account for 28 per cent of total ethane reserves but only 17 per cent of remaining established marketable gas reserves.



6.1.3 Other Natural Gas Liquids

As of December 31, 2012, the ERCB estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 63.7 10^6 m^3, 34.6 10^6 m^3, and 45.5 10^6 m^3, respectively. The breakdown in the liquids reserves at year-end 2012 is shown in **Table R6.2**. **Table B.7** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The largest of these fields—in alphabetical order, Ansell, Brazeau River, Kaybob South, Pembina, Rainbow, Swan Hills South, Wild River, and Willesden Green—account for about 27 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.

6.1.4 Ultimate Potential

The remaining ultimate potential of liquid ethane is determined based on projected market demand and the volumes that could be recovered as liquid from the remaining ultimate potential of natural gas using existing cryogenic technology. The percentage of ethane volumes that have been extracted have been generally increasing over time. In 2012, there was a substantial increase for the fourth year in a row as the percentage recovered was 70 per cent, up from 68 per cent in 2011 and 63 per cent in 2010. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on a remaining ethane gas ultimate potential of 111 billion (10^9) m^3, the ERCB estimates the remaining ultimate potential of liquid ethane to be 277 10^6 m^3. The other 30 per cent, or 33 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus combined, the remaining ultimate potential is 321 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas—about 30 per cent.

Additionally, 9301 10^6 m^3 of unconventional, in-place NGLs in six key shale formations in Alberta have been identified by the new shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.1**. This very large resource represents a huge potential for future development, but the technical, economic, environmental, and social constraints on recoverability were not included in the study. Consequently, the ERCB has not yet determined this resource's ultimate potential, but anticipates that the increase to the ultimate potential of natural gas liquids could be substantial.

6.2 Supply of and Demand for Natural Gas Liquids

In forecasting ethane and other NGLs, the ERCB recognized that NGL content, gas plant recovery efficiencies, NGL prices, and gas production volumes from remaining established reserves and future gas reserves additions affect future production. For ethane, demand also plays a major role in future extraction. The NGL content from new gas reserves is expected to be more liquids rich than existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will supplement supplies from conventional gas production and will be needed to meet the forecast ethane demand.

Ethane and other NGLs are recovered mainly from the processing of natural gas. Field gas processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which may require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Removal of other gas contaminants, such as H_2S and CO_2, is also required. Field plants generally recover additional volumes of NGLs—more than what is required to meet pipeline specifications, depending on the plant's extraction capability—to obtain full value for the NGL components. Generally, the heavier NGLs (butanes and pentanes plus) are removed at field plants. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products. Liquids that are heavy enough to be naturally collected at the field level due to the drop in pressure and temperature are called condensate. The properties of condensate and pentanes plus are similar, and the terminology is often used interchangeably as both are marketed in the same way in western Canada.

Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure S6.1** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Figure S6.2 shows the pipeline systems that move ethane and ethane plus (C_2+) mix NGLs from the processing plants to the markets. Gas processing plants capable of extracting C_2+ mix NGLs are typically tied to C_2+ mix

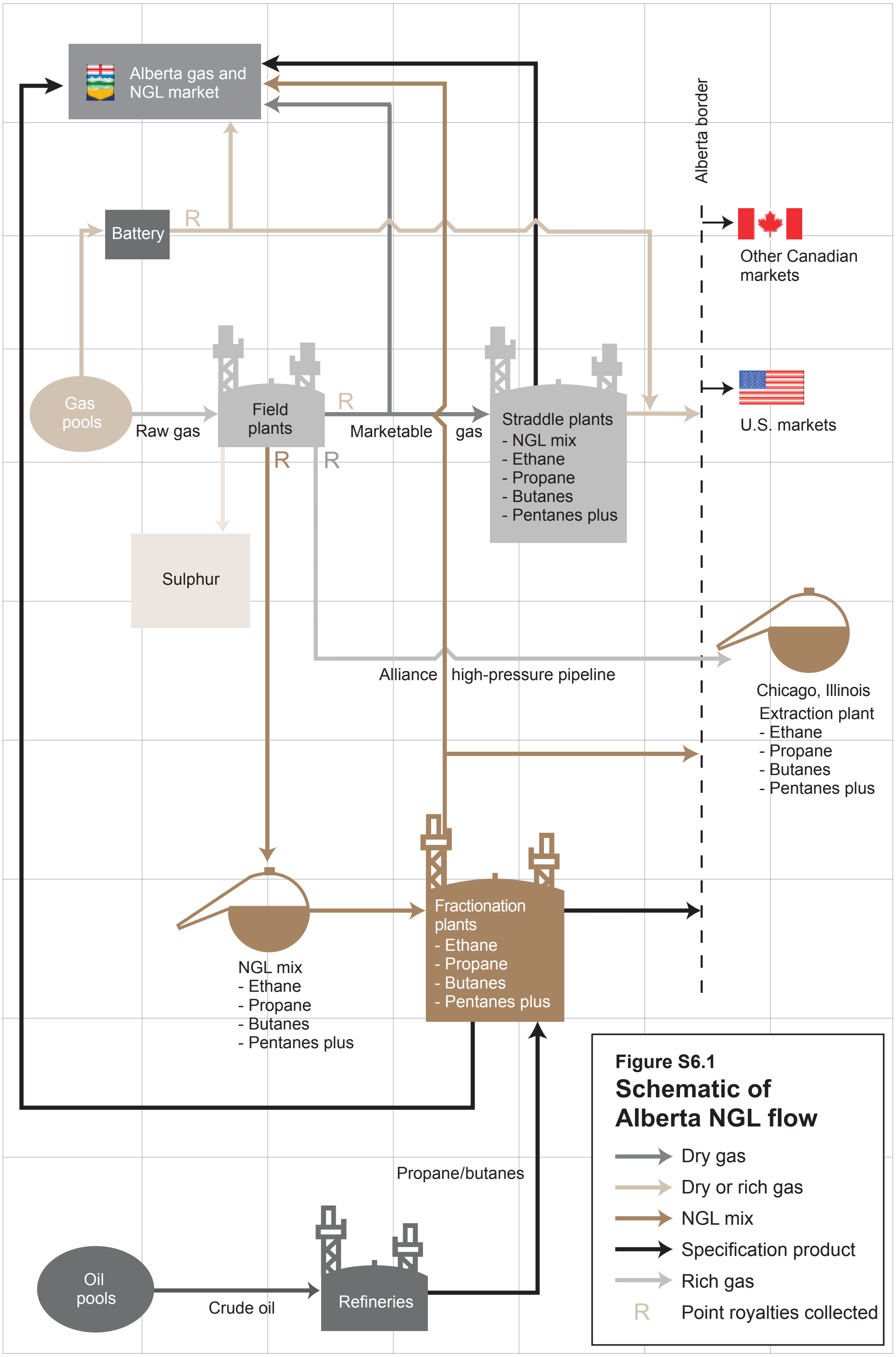


Figure S6.1
Schematic of Alberta NGL flow

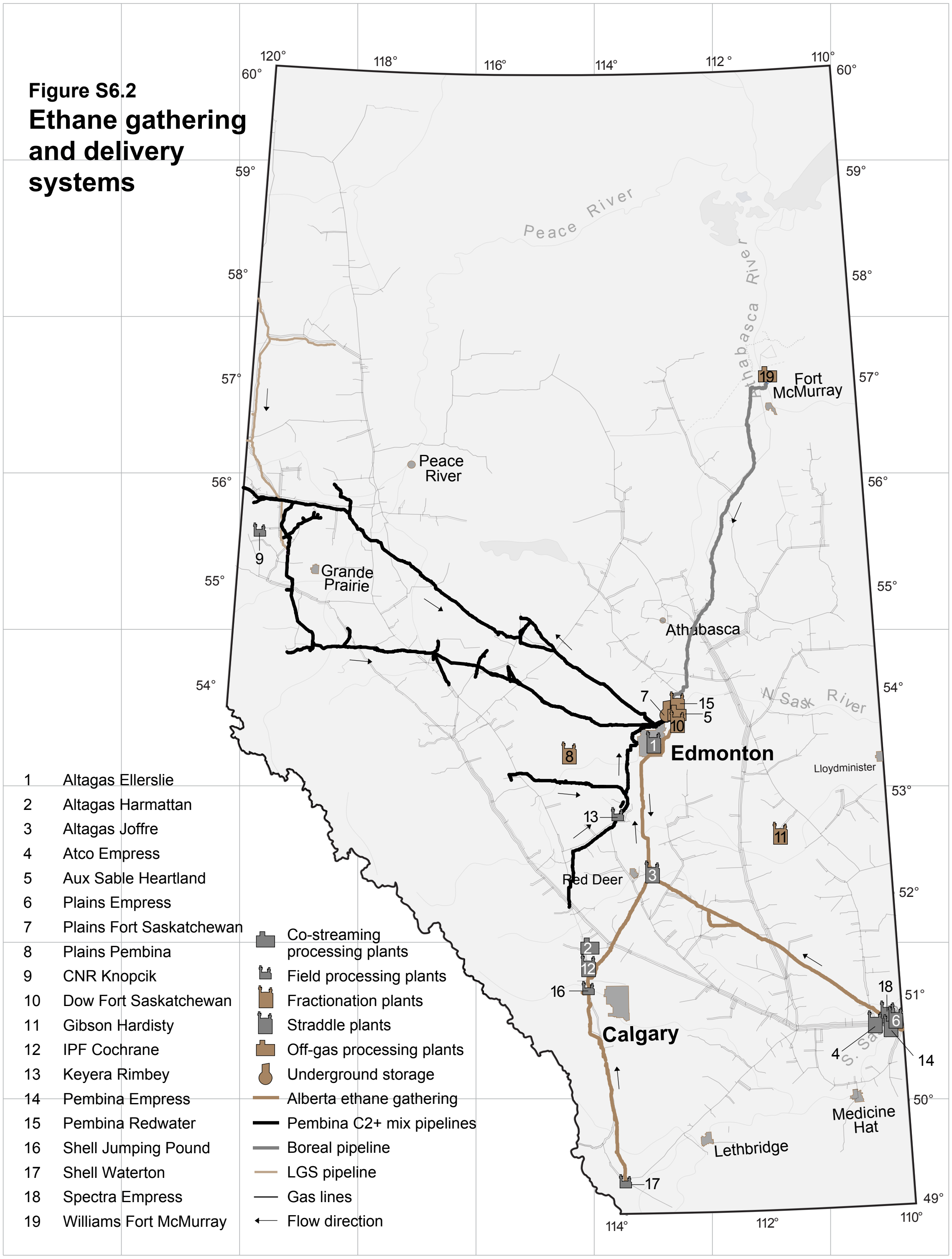


Figure S6.2
Ethane gathering and delivery systems

NGL gathering systems that move liquids to NGL fractionators in the Fort Saskatchewan area. Ethane recovered at field processing plants, NGL fractionators, and the straddle plants is shipped on the Alberta Ethane Gathering System to the Alberta ethane market.

6.2.1 Ethane and Other Natural Gas Liquids Production – 2012

In Alberta, there are about 510 active gas processing plants that recover NGL mix or specification products, 8 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants. After receiving approval from the ERCB in December 2010, the Harmattan-Elkton gas plant started reprocessing marketable gas in 2012. The plant also continues to process raw gas from nearby pools (costreaming).

Recovery efficiencies of NGL specification products at field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A few field plants are also capable of extracting ethane as a specification product or as a C_2+ mix NGL and are referred to as deep-cut facilities.

Ethane recovery at straddle plants varies from 40 to 90 per cent and averages 65 per cent. The average percentages of propane, butanes, and pentanes plus recovered at Alberta straddle plants are 98.5, 99.5, and 99.8, respectively. **Table S6.1** outlines information for 2012 about the straddle plants operating in Alberta, including the plant location, operator name, approved natural gas throughput volumes, natural gas receipts (actual throughput volumes), and the volume of specification ethane recovered (unless otherwise noted).

Table S6.1 Straddle plants in Alberta, 2012

Area of straddle plant	Location	Operator	Gas approved volumes (10^3 m^3/d)	Gas receipts (10^3 m^3/d)	Ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	37 889	3 886
Empress	04-12-020-01W4M	BP Canada Energy Company	176 750	39 005	5 247
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	49 763	8 210
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 454	1 451
Empress	01-10-020-01W4M	ATCO Midstream Ltd.	31 000	13 105	962
Fort Saskatchewan*	01-03-055-22W4M	ATCO Midstream Ltd.	1 051	690	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	32 503	4 477
Joffre (JEEP)	03-29-038-25W4M	Taylor Management Company Inc.	7 066	329	868
Atim* (Villeneuve)	08-05-054-26W4M	ATCO Midstream Ltd.	1 133	964	0
Total			**400 219**	**182 702**	**25 101**

* These plants are approved to recover a C_2+ mix and not specification ethane.

In 2012, ethane volumes extracted at Alberta processing facilities decreased 3.3 per cent to 34.0 thousand (10^3) m^3/d from 35.2 10^3 m^3/d in 2011. About 70 per cent of total ethane in the gas stream was extracted in 2012, while the remainder was left in the gas stream and sold for its heating value. **Table S6.2** shows the volumes of specification ethane extracted at the three types of processing facilities during 2012. This table excludes less than 0.1 10^3 m^3/d of ethane produced from off-gas in 2012.

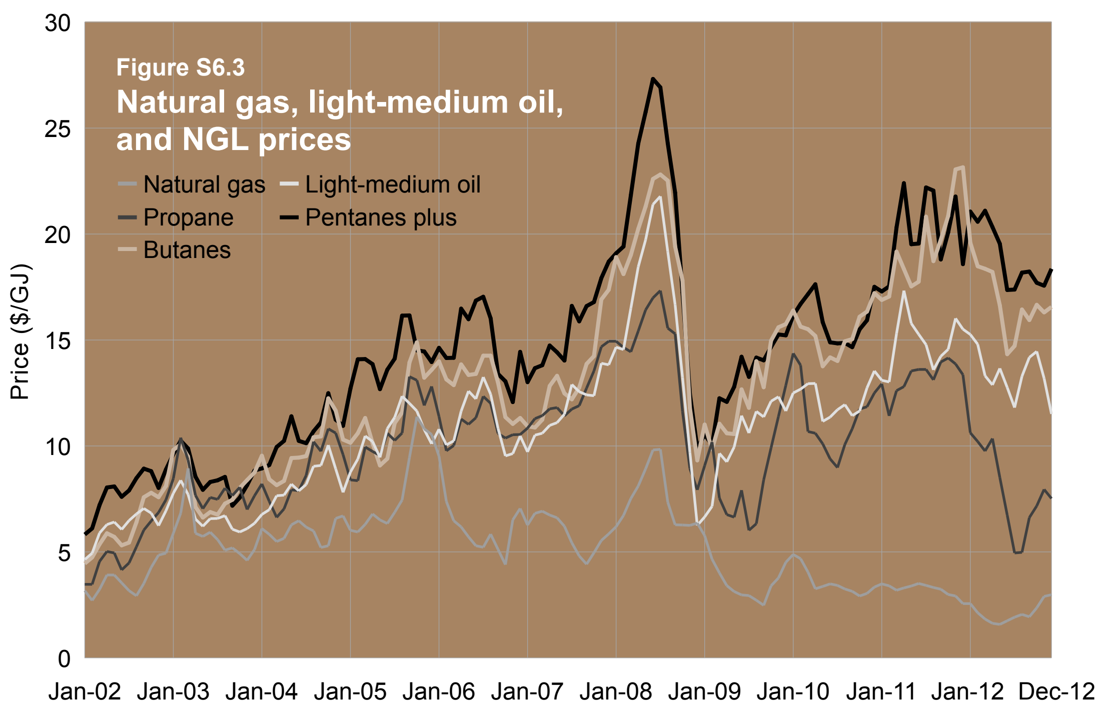
Table S6.2 Ethane extraction volumes at gas plants in Alberta, 2012

Gas plants	Volume (10^3 m^3/d)	Percentage of total
Field plants	2.2	6
Fractionation plants	6.7	20
Straddle plants	25.1	74
Total	**34.0**	**100**

The C_2+ mix NGLs shipped from British Columbia to the Redwater fractionation plant for fractionation into specification products are included in Alberta production volumes.

Propane production increased by 4.8 per cent in 2012 to 22.6 10^3 m^3/d, compared with a 0.5 per cent decrease in 2011. Butanes and pentanes plus declined by 0.7 per cent and 2.8 per cent, respectively, in 2012 over 2011. In 2012, 12.0 10^3 m^3/d of butanes and 19.1 10^3 m^3/d of pentanes plus were produced.

Figure S6.3 shows the historical natural gas and liquids prices in Canadian dollars per gigajoule ($/GJ). The figure shows that propane, butanes, and pentanes plus prices follow the light/medium crude oil price.



In 2012, gas production from PSAC Area 2 (Foothills Front) held steady, whereas gas production decreased in all the other PSAC areas. This area has the largest remaining extractable liquids reserves in the province. Production from PSAC Area 3 (Southeastern Alberta), known for its dry gas production, experienced a 14 per cent decrease in production. Overall, conventional gas production in the province decreased by 5.3 per cent. The shift by industry to develop pools with gas liquids is expected to continue over the forecast period.

6.2.2 Ethane and Other Natural Gas Liquids – Recent Developments

As conventional gas production declines, less ethane will be available for use by the petrochemical sector. To address the tight supply of ethane in Alberta, the provincial government implemented the Incremental Ethane Extraction Policy (IEEP) in September 2006 and amended and extended the program in March 2011. The program, initially designed to encourage extraction of ethane from natural gas, has been revised to also encourage ethane extraction from off-gases that result from bitumen upgrading or refining. Alberta's petrochemical industry is the largest in Canada and depends on the availability of competitively priced ethane to remain viable. The capture of ethane from oil sands off-gases are part of the additional sources of ethane feedstock. Most off-gas is currently consumed as fuel in oil sands operations.

IEEP is in effect until December 31, 2016. Fractionation credits are provided to petrochemical companies that consume incremental ethane for value-added upgrading, in Alberta, to ethylene and derivatives. The credit value for ethane or ethylene from natural gas remains unchanged at $1.80 per barrel (bbl). The government program recognizes that capture of off-gas from bitumen upgrading or refining, including ethane or ethylene, is considerably more capital intensive than conventional-sourced ethane and, as a result, provides a credit value for off-gas ethane of $5.00/bbl. The credit is owned by the company that consumes the ethane or ethylene and can be sold to either a natural gas or bitumen royalty payer to be applied against its royalty obligation.

Seven IEEP projects have been approved to date, one project is under review by the provincial government, and eight new projects were submitted by the petrochemical companies in 2012. The latter represents a significant increase compared with the four projects submitted in 2011. The 2012 IEEP projects are described in **Table S6.3.**

Williams Companies Inc. (Williams) receives a large portion of the off-gas produced at Suncor's upgrading facility in the Fort McMurray area and extracts C_3+ mix NGLs and olefins at its Fort McMurray liquids extraction plant. NGLs and olefins production was 2054 m^3/d in 2012, up from 1853 m^3/d in 2011. Williams then sends the liquid mix from Fort McMurray to its Redwater fractionation plant near Edmonton through the Boreal Pipeline, which started operating in June 2012.

The 12-inch Boreal Pipeline, owned and operated by Williams, currently has the capacity to ship 6795 m^3/d of off-gas liquids and will have the potential to transport up to 19 750 m^3/d with the construction of additional pump stations. Williams entered into a long-term agreement with Canadian Natural Resources Ltd. (CNRL) to capture the off-gas produced from the upgrader at CNRL's Horizon project and to extract up to 2384 m^3/d of NGLs and olefins by 2018. Williams will extend the Boreal Pipeline to the proposed liquids extraction plant adjacent to CNRL's upgrader to transport NGLs and olefins to the Redwater fractionation plant.

Table S6.3 IEEP projects as of December 31, 2012

Feedstock Type	Date approved	Project name	Company	Submission year
Conventional	April 14, 2008	Empress V Deep Cut - IPF/Dow	Dow	2008
Conventional	April 14, 2008	Rimbey Ethane Extraction - Keyera/Dow	Dow	2008
Conventional	Sept 14, 2010	Hidden Lake Streaming - TCPL/NOVA	Nova	2010
Off-gas	Sept 14, 2010	Williams Off-Gas Ethane Extraction	Nova	2010
Conventional	Dec 7, 2011	Musreau Deep Cut	Dow	2011
Conventional	July 26, 2011	Shell Waterton Incremental NGL Recovery	Shell	2011
Off-gas	July 26, 2011	Scotford Fuel Gas Recovery (Refinery)	Shell	2011
Conventional	Under review	Harmattan Plant Costream	Nova	2011
Conventional	Newly submitted	Shell Jumping Pound	Shell	2012
Off-gas	Newly submitted	Shell Scotford Upgrader Off-Gas	Shell	2012
Off-gas	Newly submitted	Williams Off-Gas Ethane Extraction (incremental)	Nova	2012
Conventional	Newly submitted	AltaGas-Gordondale Deep Cut	Nova	2012
Conventional	Newly submitted	Judy Creek Ethane Extraction	Nova	2012
Conventional	Newly submitted	Resthaven Facility Phase 1	Dow	2012
Conventional	Newly submitted	Rimbey Turbo Expander	Dow	2012
Conventional	Newly submitted	Project Turbo (Saturn Plant)	Dow	2012

Source: Alberta Department of Energy.

The Boreal Pipeline will start shipping C_2+ mix NGLs and olefins once ethane and ethylene fractionation capacity is added at Williams' Redwater fractionation plant. Ethane and ethylene fractionation is designed to produce up to 2702 m^3/d of ethane and ethylene and is expected to start in mid-2013.

The Aux Sable Heartland off-gas processing plant started operating in September 2011. This processing plant receives off-gas from the Shell Scotford upgrader and refinery and extracts ethane, a C_3+ mix, and hydrogen. Total liquids production was 55 m^3/d in 2012. The ethane is shipped on the Alberta Ethane Gathering System to meet petrochemical demand. The C_3+ mix and hydrogen is shipped back to Shell's facilities for their refining operations.

Nova Chemicals signed a deal with Hess Corporation to purchase and transport ethane produced at the Tioga gas plant in North Dakota via a new pipeline to Alberta. The Vantage Pipeline, approved by the National Energy Board (NEB) in January 2012, is expected to start up in 2013. The pipeline will have a capacity of 6300 m^3/d, which could be expanded to 9500 m^3/d with the addition of two additional pump stations.

As more producers are focusing on the liquids-rich natural gas plays, midstream companies are either building new liquids extraction facilities or expanding their existing extraction capacities. Altagas Ltd.'s new deep-cut natural gas processing facility in the Gordondale area came on stream in October 2012. This deep-cut facility is capable of processing Montney liquids-rich gas and recovering up to 477 m^3/d of C_2+ mix.

A deep-cut facility at Musreau gas processing plant operated by Pembina Pipeline Corporation (Pembina) started operating in February 2012, and the expansion of its shallow-cut facility at this site came on stream in September 2012. The aggregate processing capacity is now up to 11 553 10^3 m^3/d of natural gas and 2066 m^3/d of C_2+ mix.

Pembina’s Resthaven and Saturn projects are also underway. The Saturn deep-cut plant is designed to produce up to 2145 m^3/d of C_2+ mix NGLs, and it is expected to be in service in late 2013.The Resthaven project is to develop a combined shallow-cut and deep-cut facility at an existing gas processing plant. Pembina expects this facility to be in service in 2014. Once operational, the total plant capacity will be 2066 m^3/d, with the potential of up to 2861 m^3/d of C_2+ mix.

In response to the anticipated increase in liquids-rich natural gas production, Pembina is also undertaking several pipeline expansion projects. The Phase 1 NGL Expansion, announced in November 2011, will increase Pembina’s Peace and Northern NGL Pipeline Systems by 8264 m^3/d, or up to 26 542 m^3/d, in 2013. The Phase 2 NGL Expansion, announced in November 2012, will add 8423 m^3/d of capacity to its Northern NGL Pipeline System by mid-2015.

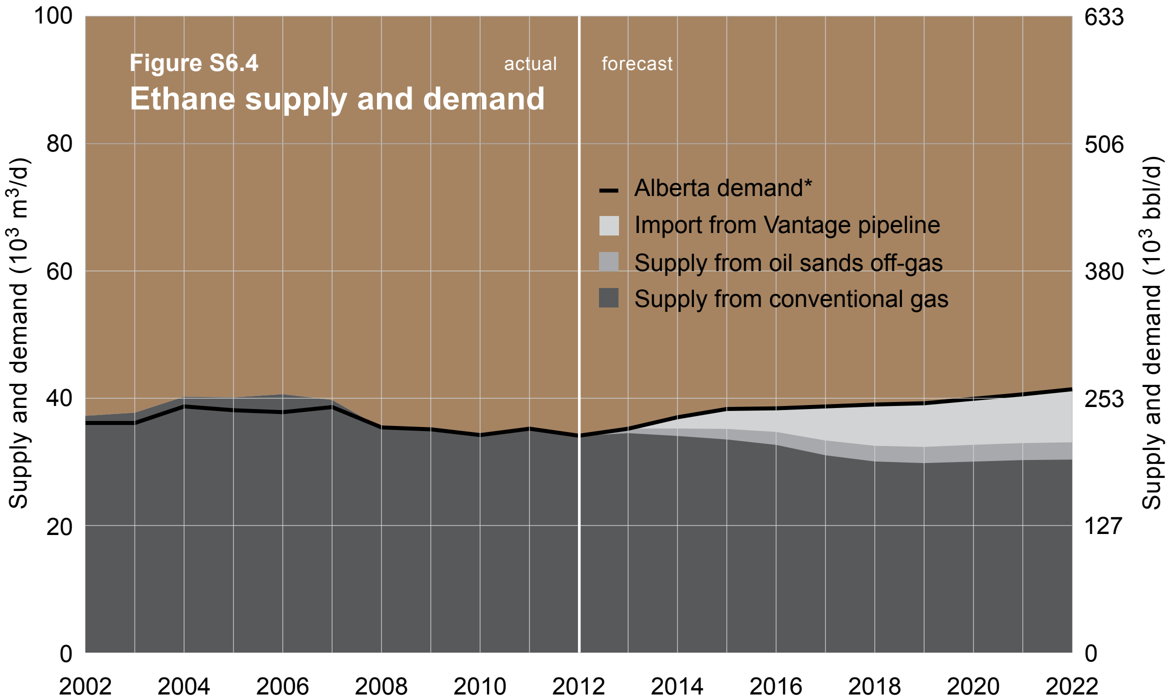
Keyera Corp. (Keyera) is targeting 2014 to complete the addition of 4768 m^3/d of de-ethanization capacity to accept C_2+ mix NGLs at its Fort Saskatchewan fractionation plant. Keyera’s de-ethanizer will be the third facility to fractionate C_2+ mix of conventional NGLs in Fort Saskatchewan area.

6.2.3 Ethane and Other Natural Gas Liquids Production – Forecast

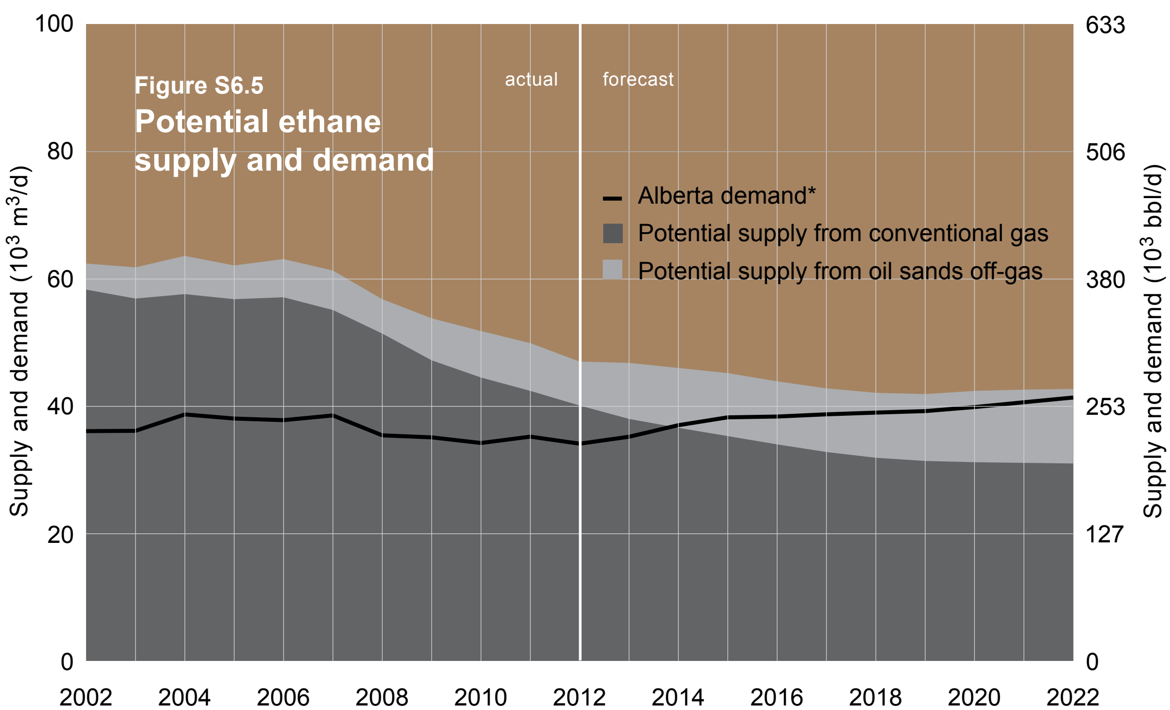
The ERCB expects that the Alberta ethane supply will gradually increase over the next two years. New ethane supplies are expected to come from liquids-rich natural gas supplies and from oil sands off-gas. As discussed, gas producers are focusing on the liquids-rich gas stream with higher ethane content, and the midstream companies have announced a number of projects to maximize liquids recovery.

Figure S6.4 shows the ERCB’s ethane supply and demand forecast. The ERCB expects ethane production from conventional gas to increase from 34.0 10^3 m^3/d in 2012 to 34.5 10^3 m^3/d in 2013. This is because fractionation and ethylene production capacities were reduced in 2012 due to maintenance work; demand is expected to recover in 2013. Ethane production from conventional gas, however, will continue to decline until 2019, then slightly recover for the rest of the forecast period as liquids-rich gas production from PSAC Area 2 and PSAC Area 7 (Northwestern Alberta) is also expected to start increasing in 2019. Small volumes of ethane were produced from off-gas in 2012, and the ERCB expects the ethane from off-gas to continue to grow gradually over the forecast period.

Figure S6.5 shows the potential ethane supply from conventional natural gas and the potential ethane volumes that could be recovered from oil sands off-gas production. The ethane supply volumes from conventional natural gas are calculated based on the volume-weighted average ethane content of conventional gas in Alberta of 0.052 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is about 70 10^3 m^3/d and is not a constraint to recovering the additional volumes forecast. Potential ethane supply from oil sands off-gas is calculated assuming an average



* Excludes solvent flood volumes.



* Excludes solvent flood volumes.

ethane content of 16.2 per cent in the off-gas production volumes and an 80 per cent recovery rate of ethane. In 2022, 30.3 10^3 m^3/d of ethane is expected to be produced out of a total potential of 31.0 10^3 m^3/d of ethane from conventional gas, but only 2.7 10^3 m^3/d of ethane out of a total potential of 11.7 10^3 m^3/d of ethane from oil sands off-gas is projected to be extracted by 2022. As a result, the ERCB expects imports of ethane from the United States will start later in 2013 or in 2014 to augment supply, and these imports will continue to increase throughout the forecast period, reaching 8.3 10^3 m^3/d in 2022.

Figures S6.4 to **S6.7** show forecast production volumes to 2022 for ethane, propane, butanes, and pentanes plus.

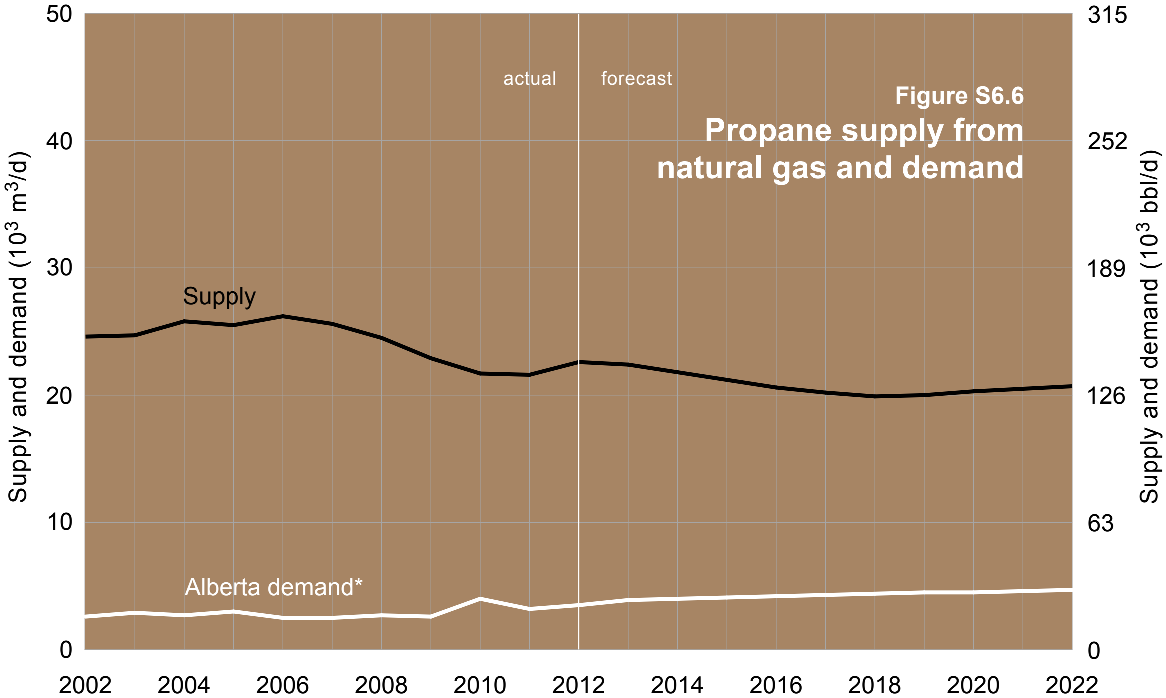
6.2.4 Demand for Ethane and Other Natural Gas Liquids

The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline transports a range of feedstock from Fort Saskatchewan to Joffre. Currently small volumes of propane supplement the ethane supplies used at the petrochemical plants at Joffre, where three of the four plants are located. The fourth is in Fort Saskatchewan. The plants in the province that use ethane as a feedstock operated collectively at 72 per cent of their capacity in 2012. The industry adds value to NGLs by upgrading them to be used in the manufacture of products such as plastic, rope, and building materials.

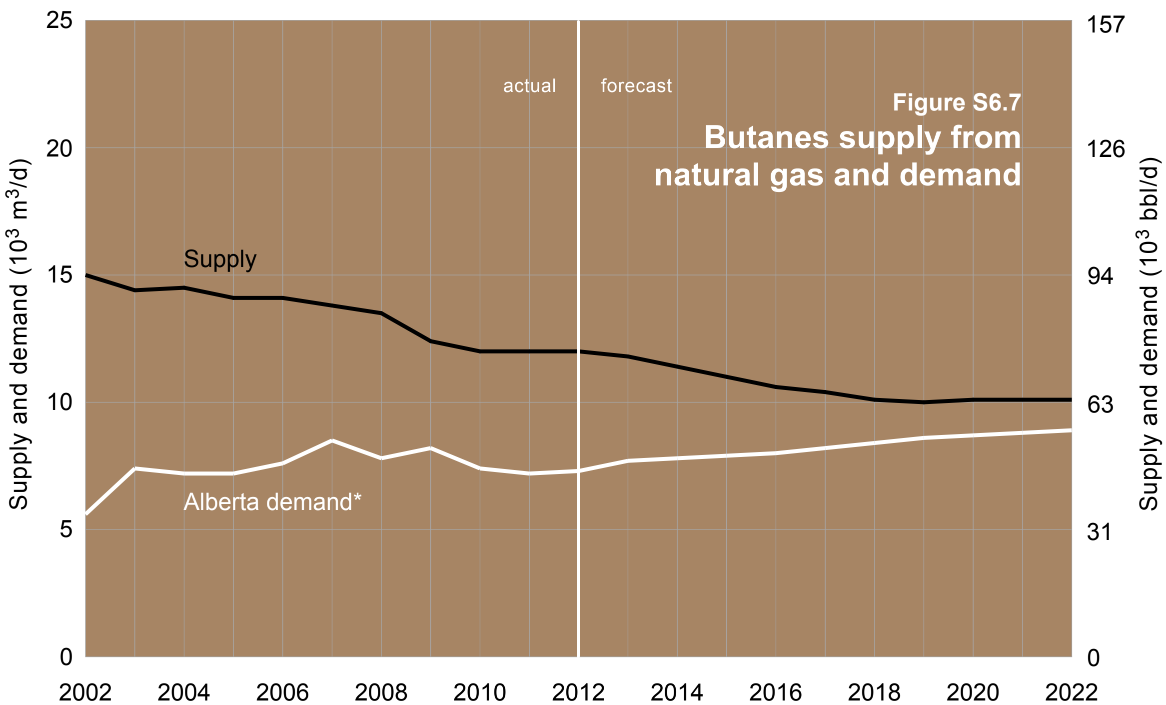
The petrochemical industry in Alberta continues to benefit from the low gas price environment since the price of ethane, the primary feedstock for ethylene production, is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost advantage compared with a typical propane or naphtha cracking plant in the U.S. Gulf Coast, as prices of propane and other heavier gas liquids are linked to crude oil, which averaged US$94.21/bbl West Texas Intermediate in 2012.

The recent development of liquids-rich shale gas plays in North America is providing opportunities for the petrochemical industry outside of Alberta to change their feedstock slate. Ethylene producers across the continent are shifting their feedstock from heavier feedstock such as naphtha and condensate to lighter NGLs, especially ethane, as more supplies become available. The U.S. ethylene production capacity could increase by 35 per cent in the next few years from the current level based on the announcements by the ethylene producers, and all of the new capacity is projected to use ethane as feedstock. Ethane provides a price advantage and generally yields higher margins than the other, heavier feedstocks. Despite these changes across North America, the Alberta feedstock advantage over the other regions in North America is expected to continue over the forecast period mainly because Alberta ethane has been and will continue to be priced lower than the U.S. Gulf Coast, where the majority of the U.S. ethylene production capacity is located.

The ERCB expects that ethane demand by the ethylene producers in the province will increase for the next few years, judging by the continued investment in Alberta infrastructure such as extraction facilities and pipelines, as well as projects to expand polyethylene and ethylene glycol production. As shown in **Figure S6.4** and **Figure S6.5**, Alberta demand for ethane is projected to gradually increase from the 2012 level of 34.1 10^3 m^3/d to 41.4 10^3 m^3/d in 2022.



* Excludes solvent flood volumes.



* Excludes solvent flood volumes.

For the purpose of this forecast, it is assumed that the existing ethylene plants will increase their throughput from 72 per cent to 88 per cent of capacity in 2022, and that no new ethylene plants requiring ethane as feedstock will be built in Alberta over the forecast period.

Historically, small volumes of ethane were exported from the province, primarily for use as a buffer for pipeline ethylene shipments to eastern Canada. Since 2008 and the end of ethylene deliveries to Ontario in the Cochin pipeline, however, there have been no ethane removals from the province, and this is expected to remain the case over the forecast period.

Demand for NGL mix streams in the form of C_2+ mix and C_3+ mix exists in Alberta as solvent for injection into enhanced oil recovery (EOR) schemes for conventional oil fields. Most of the NGL mix solvent is extracted at deep-cut facilities located adjacent to the injection facilities. Historically, small volumes of specification ethane were also delivered from Fort Saskatchewan to be used for injection at EOR schemes. In 2012, the ethane volumes in the solvent used for this purpose were equivalent to 3 per cent of total ethane demand in Alberta. Propane and butanes injected as solvent were equivalent to 27 per cent and 6 per cent of the provincial total demand for the products, respectively. Small volumes of pentanes plus were injected as solvent in 2012. The ERCB expects that the demand for NGL mix volumes for injection will remain unchanged over the forecast period. The supply and demand figures in this section exclude solvent flood volumes for fields producing conventional oil.

Figure S6.6 shows Alberta's demand for propane compared with the total available supply from gas processing and straddle plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Alberta propane demand is forecast to grow by an average of 3.1 per cent over the forecast period. This is significantly higher than the 1.8 per cent in last year's forecast because propane demand by petrochemical sector has grown in recent years, and it is expected to continue to grow moderately over the forecast period.

Figure S6.7 shows Alberta demand for butanes compared with the total available supply from gas processing plants. As with propane, the difference between Alberta butane requirements and total supply represents volumes used by markets outside of Alberta. Butanes are used as refinery feedstock, as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

In recent years, butanes have been blended with conventional light/medium crude oil to benefit from the higher price of crude oil. Alberta producers and shippers are also blending butanes with crude oil to reduce the viscosity of the crude oil to minimize the penalties under the pipeline equalization process.

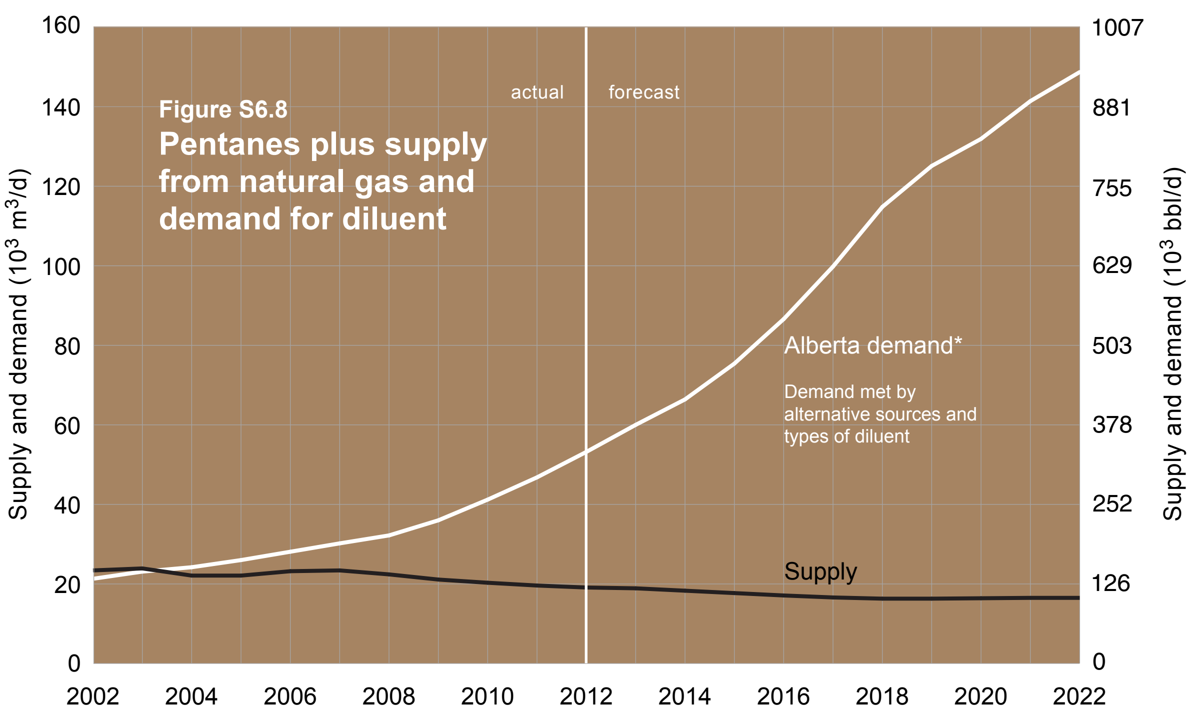
Butanes are also used as diluent (to reduce viscosity) and blended with heavy crude oil and bitumen to facilitate pipeline transportation of the product to market. In 2012, Alberta demand, excluding solvent flood demand, was 7.3 10^3 m^3/d, compared with 7.2 10^3 m^3/d for 2011. Alberta demand for butanes over the forecast period is expected to increase as nonupgraded bitumen and conventional heavy oil production increase. Another potential growth in demand for butanes is the increasing use for the solvent aided process (SAP). SAP is a process whereby in-situ bitumen producers inject butanes as a solvent to enhance, along with steam-assisted gravity drainage (SAGD), bitumen recovery.

The largest use of Alberta pentanes plus is as diluent in the blending of heavy crude oil and bitumen. **Figure S6.8** shows the ERCB estimate of Alberta demand for pentanes plus used for diluent compared with the total available supply. Pentanes plus is also used as feedstock for the refinery in Lloydminster; this small volume (0.9 10^3 m^3/d in 2012) is not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production.

Demand for pentanes plus is expected to remain strong due to continued high diluent requirements. As a result, pentanes plus demand as diluent is forecast to increase from 53.2 10^3 m^3/d in 2012 to 148.7 10^3 m^3/d in 2022.

As illustrated in **Figure S6.8**, diluent demand is estimated to have exceeded Alberta supply around 2004. The current estimated demand reflects the inadequate Alberta supply of pentanes plus since 2004, which has resulted in the assessment and use of alternative sources (imports) and types of diluent. Alberta currently imports offshore condensate by rail from Kitimat, British Columbia.

Alberta imports of pentanes plus are expected to increase over the next 10 years with growing oil sands demand. The following list outlines current and future sources of diluent from outside Alberta that will be needed to facilitate transportation of nonupgraded bitumen to markets.



* Excludes solvent flood volumes.

- Alberta imports pentanes plus on trucks, rail cars, and pipelines, including Enbridge Inc.'s Southern Lights Pipeline, which transports diluent from Chicago to Edmonton and has a capacity to deliver 28.6 10^3 m^3/d.
- Enbridge is proposing to build a condensate pipeline capable of initially transporting 23.8 10^3 m^3/d of offshore condensate from Kitimat to Edmonton.
- Kinder Morgan Energy Partners, L.P., is proposing to reverse the western leg of the Cochin Pipeline to supply condensate from Kankakee County, Illinois, to Fort Saskatchewan, with a capacity of 15.1 10^3 m^3/d.

HIGHLIGHTS

Remaining established sulphur reserves decreased 30.2 per cent mainly due to the deletion of sulphur reserves from two mining projects.

Sulphur production from gas processing declined 18.5 per cent from 2011 to 2012, while sulphur production from crude bitumen increased by 11 per cent.

Total sulphur production fell from 4.7 million tonnes in 2011 to 4.4 million tonnes in 2012.

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7 SULPHUR

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

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2012, to be 120.9 million tonnes (10^6 t), down 30 per cent from 2011. This significant decrease is mainly due to the reduction in sulphur reserves derived from crude bitumen reserves under active development, as detailed in **Section 7.1.4**. **Table R7.1** shows the changes in sulphur reserves over the past year. The ERCB does not estimate sulphur reserves from sour crude oil since only a very small portion of Alberta's sour crude oil is refined in the province.

7.1.2 Sulphur from Natural Gas

The ERCB estimates that there are 20.8 10^6 t of remaining established sulphur from natural gas reserves in sour gas pools at year-end 2012, a decrease of 0.5 per cent from 2011. Remaining established sulphur reserves have been calculated using a provincial recovery factor of 97 per cent, which takes into account plant efficiency, acid-gas flaring at plants, acid-gas injection, and solution-gas flaring.

The ERCB's sulphur reserve estimates from natural gas are shown in **Table R7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2012 are Caroline, Crossfield East, Okotoks, and Waterton. Combined, these account for 6.3 10^6 t, or 30 per cent, of the remaining established reserves of sulphur from natural gas.

The ERCB estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from pools with ultrahigh concentrations of H_2S currently not on production. Based on initial established reserves of 272.8 10^6 t, this leaves 122.0 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

Table R7.1 Reserve and production change highlights (10^6 tonnes)

	2012	2011	Change[a]
Initial established reserves from			
Natural gas	272.8	270.5	+2.3
Crude bitumen[b]	128.4	178.5	-50.1
Total	**401.2**	**449.0**	**-47.8**
Cumulative production from			
Natural gas	252.0	249.6	+2.4
Crude bitumen	28.3	26.3	+2.0
Total	**280.3**	**275.9**	**+4.4**
Remaining established reserves from			
Natural gas	20.8	20.9	-0.1
Crude bitumen[b]	100.1	152.2	-52.1
Total	**120.9**	**173.1**	**-52.2**
Annual production	4.4	4.8	-0.4

[a] Any discrepancies are due to rounding.

[b] Reserves of elemental sulphur from bitumen mines under active development as of December 31, 2012. Reserves from the entire surface mineable area are larger.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current bitumen upgrading operations, 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 the by-products from upgrading bitumen, such as coke.

It is currently estimated that 213.8 10^6 t of sulphur could be recovered from the 5.28 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the entire surface mineable area. These sulphur reserves were estimated by using a factor of 40.5 tonnes of sulphur per thousand cubic metres of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology recovers more sulphur than alternative carbon-rejection technology. With the latter technology, more of the sulphur in the bitumen remains in upgrading residues and less is converted to H_2S.

If less of the mineable crude bitumen reserves are upgraded with the hydrogen-addition technology than is currently estimated, or if less of the mineable reserves are upgraded in Alberta, the total sulphur reserves will be less.

In 2012, the Nexen Long Lake upgrader continued to upgrade in situ bitumen, resulting in the production of small quantities of sulphur, most of which was not marketed. The ERCB will include in situ upgrading projects in future reports as they come on stream.

Table R7.2 Remaining established reserves of sulphur from natural gas as of December 31, 2012[a]

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content[b] (%)	Remaining established reserves of sulphur Gas (10^6 m^3)	Solid (10^3 t)
Benjamin	3 122	5.0	185	251
Bighorn	2 782	6.8	227	308
Brazeau River	8 572	3.7	377	511
Burnt Timber	1 089	17.8	284	385
Caroline	5 464	12.6	930	1 262
Coleman	747	26.6	296	402
Crossfield	2 487	17.3	659	894
Crossfield East	2 022	28.3	996	1 350
Elmworth	20 903	1.4	325	441
Hanlan	6 320	8.9	748	1 014
Jumping Pound West	3 635	6.7	304	412
Kaybob South	15 229	1.0	168	227
La Glace	2 227	6.4	165	223
Limestone	3 399	12.5	573	777
Lone Pine Creek	1 609	8.2	163	221
Marsh	930	15.7	196	266
Moose	2 343	12.8	389	527
Okotoks	1 608	31.8	938	1 271
Panther River	2 278	5.3	149	203
Pembina	24 021	0.7	246	333
Pine Creek	7 727	4.1	363	492
Quirk Creek	1 264	9.3	157	213
Rainbow	8 959	2.0	246	334
Rainbow South	2 679	6.4	253	342
Ricinus	4 119	3.7	173	234
Ricinus West	1 062	32.3	596	808
Simonette	2 550	9.0	333	451
Waterton	5 132	21.6	1 775	2 407
Wimborne	1 616	9.2	178	242
Windfall	1 655	12.9	303	410
Subtotal	**147 550**	**6.7**	**12 691**	**17 211**
All other fields	768 133	0.3	2 637	3 595
Total	**915 683**	**1.5**	**15 329**	**20 806**

[a] Any discrepancies are due to rounding.

[b] Volume-weighted average.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only some of the production from established surface-mineable crude bitumen reserves will be upgraded by the existing Suncor, Syncrude, Shell Muskeg River, Shell Jackpine, and CNRL Horizon mining projects. The ERCB's estimate of the initial established sulphur reserves in 2012 from these active projects is 128.4 10^6 t, representing 60 per cent of estimated recoverable sulphur from the remaining established crude bitumen in the total surface mineable area. A total of 28.3 10^6 t of sulphur has been produced from these projects, leaving 100.1 10^6 t of remaining established reserves. This is a decrease of 34 per cent from the remaining reserves in 2011. This large decrease in remaining reserves is due primarily to the deletion of the sulphur reserves attributed to the Kearl and Fort Hills mining projects, as well as to the production of 2.0 10^6 t of sulphur in 2012. The sulphur reserves for Kearl were removed as an upgrader has not yet been built. The sulphur reserves for Fort Hills were removed because the project is not yet producing. The Joslyn North mining project was added to the crude bitumen reserves under active development in 2012, but sulphur reserves have not been included for this project as, similar to Fort Hills, it is not yet producing. Once these three projects report crude bitumen production to an upgrader, their accompanying sulphur reserves will be included in this section.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Production – 2012

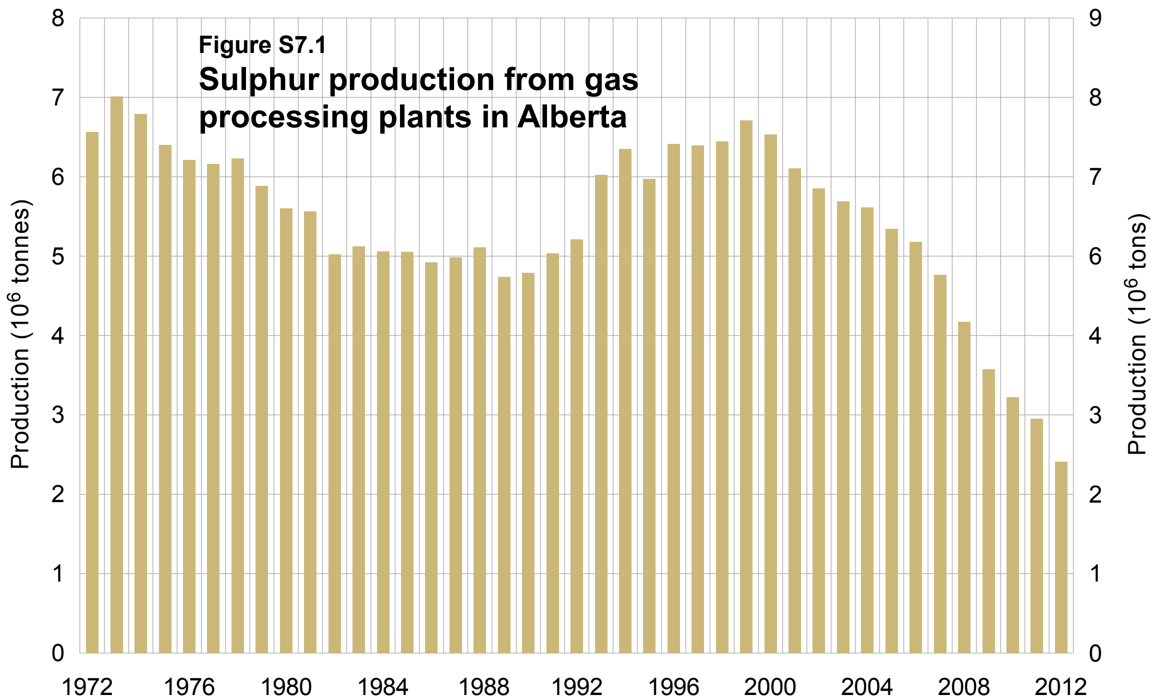
There are three sources of sulphur production in Alberta: sour natural gas processing, crude bitumen upgrading, and crude oil refining into petroleum products. In 2012, Alberta produced 4.37 10^6 t of sulphur, of which 2.41 10^6 t were derived from sour gas, 1.96 10^6 t from bitumen upgrading, and just 19 thousand (10^3) t from oil refining. The total sulphur production in 2012 represents a decrease of 7.6 per cent from the 2011 level due to a decline in natural gas production and lower sulphur content in the gas stream. Most of Canada's sulphur is produced in Alberta.

7.2.1.1 Sulphur Production from Natural Gas

Figure S7.1 shows historical sulphur production from gas processing plants. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. As conventional sour gas production declines, less sulphur will be recovered from gas processing plants. This trend is evident in the steep decline in sulphur production from gas processing plants since 2000.

Table S7.1 shows the changes in sulphur production from major gas processing plants over the past year. In early 2011, declining gas reserves led to the planned closure of the Nexen Balzac gas plant. The plant and sour gas wells tied in to the facility were shut down at the end of April 2011. The Shell Caroline gas plant had a major turnaround in 2012, which resulted in significantly lower gas production.

Sulphur stockpiles stored as solid blocks at gas processing plants have been drawn down significantly in recent years as the result of an increase in global sulphur demand. **Figure 14** in the Overview section illustrates historical sulphur closing inventories at gas processing plants and oil sands operations, as well as sulphur prices.



Inventory blocks of sulphur at gas processing plants in Alberta were 1.46 10^6 t at year-end 2012, down from 1.88 10^6 t at year-end 2011 and 2.47 10^6 t in 2010.

7.2.1.2 Sulphur Production from Crude Bitumen Upgrading

Historical sulphur production from the five oil sands upgrader operations is shown in **Figure S7.2**. Total production in 2012 was 1.96 10^6 t, up 11 per cent from 2011 production of 1.77 10^6 t. All of the crude bitumen upgraders experienced increases in sulphur production.

Table S7.1 Sulphur production from gas processing plants (10^3 tonnes)

Major plants	2012	2011	Change	Per cent change
Shell Caroline	498	583	-85	-15
Shell Waterton	280	416	-136	-33
Husky Strachan	257	303	-46	-15
Shell Jumping Pound	186	180	6	3
Semcams Kaybob South	67	153	-86	-56
Keyera Strachan	132	185	-53	-29
Suncor Hanlan	131	138	-7	-5
Shell Burnt Timber	119	138	-19	-14
Nexen Balzac	0	25	-25	-100
Total	**1670**	**2121**	**-451**	**-21**

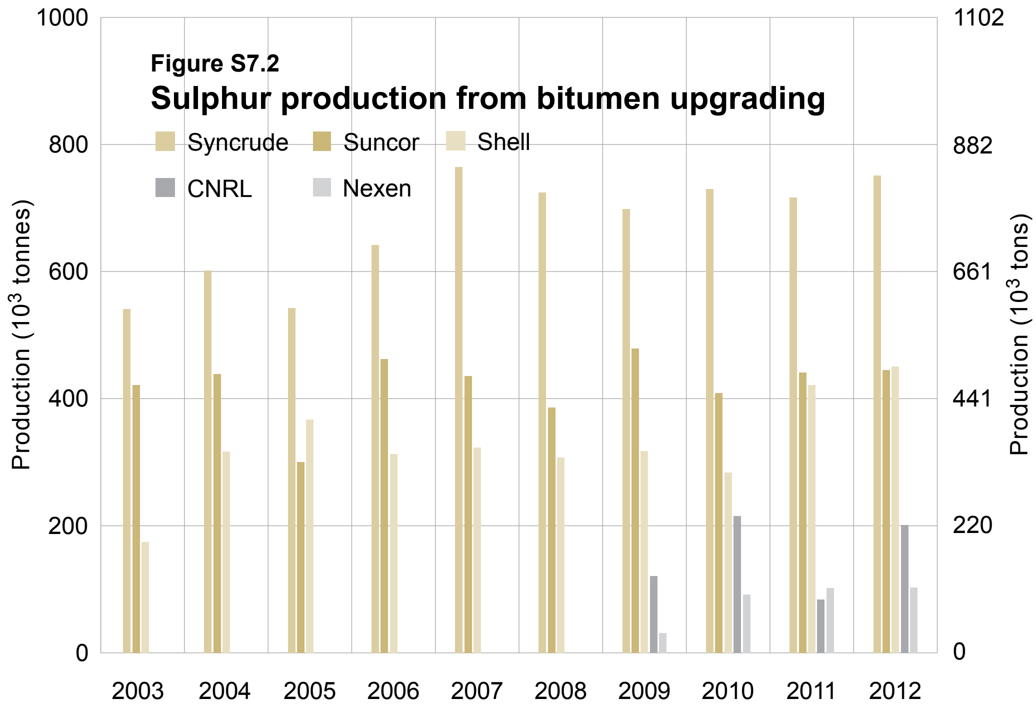


Figure S7.2
Sulphur production from bitumen upgrading

7.2.2 Sulphur Production – Forecast

Total Alberta sulphur production from sour gas, crude oil, and bitumen upgrading and refining is depicted in **Figure S7.3**. Sulphur production from sour gas is expected to decrease from 2.41 10^6 t in 2012 to 1.88 10^6 t—about 22 per cent—by the end of the forecast period; however, sulphur recovery from bitumen upgrading and refining is expected to increase from 1.97 10^6 t in 2012 to 2.73 10^6 t (about 39 per cent). The large increase in sulphur from bitumen upgrading in 2012 reflects resumption of operations by CNRL following a fire at the Horizon upgrader in 2011 and the increase in production from Shell's Scotford upgrader expansion as it continues to ramp up. The sulphur production forecast takes into account the return of Suncor, Syncrude, and CNRL to upgraded bitumen production targets following disruptions at their respective facilities in early 2012.

Sulphur recovery from Alberta refineries was at its highest since 2003, with a production level of 19 10^3 t in 2012. The forecast remains unchanged at 17 10^3 t for the forecast period. The forecast is based on the assumption that Alberta refineries will continue to recover volumes of sulphur similar to what has been recovered historically.

7.2.3 Sulphur Demand

Disposition of sulphur within Alberta averaged 460 10^3 t per year between 2008 and 2010. More recent data on disposition of sulphur within the province may include Alberta plant-to-plant transfers, which are likely to cause the disposition volume to appear higher than actual. The ERCB considers the 2008–2010 average to be representative of 2011 and 2012 disposition and has also used that figure in the forecast period to 2022.

Sulphur is used in the production of phosphate fertilizer and kraft pulp and in other chemical operations. Alberta produces more sulphur than any other province in Canada, and the majority of Alberta production is shipped outside the province. Canadian exports in 2012 were 3.7 10^6 t, an 11 per cent decrease from 4.1 10^6 t in 2011. **Figure S7.4** shows the historical Canadian export volumes.

In 2012, sulphur prices averaged US$201 per tonne, declining 6 per cent from the previous year's average price of US$214 per tonne.

China is the world's largest importer of sulphur, which is used primarily for making sulphuric acid to produce phosphate fertilizer. Exports to China have significantly decreased from 823 10^3 t in 2011 to 665 10^3 t in 2012. Nearly half of Canadian exports are sent to the United States: 1569 10^3 t in 2012, down from 1667 10^3 t in 2011.

Because sulphur is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles. **Figure S7.5** shows the historical and forecast total sulphur supply and demand, including inventory additions and withdrawals.

In the early part of the previous decade, weak global sulphur demand resulted in less demand for Alberta exports, and as a result, Alberta built a significant stockpile of sulphur. Since 2004, supply and demand have generally been in balance, with small withdrawals from inventory stockpiles. The forecast assumes that, on average, this situation will continue as declining production from natural gas processing plants is replaced by increasing sulphur recovery from bitumen upgrading. The forecast also assumes that demand will remain approximately constant in the first half of the forecast period and rise slightly in the second half.

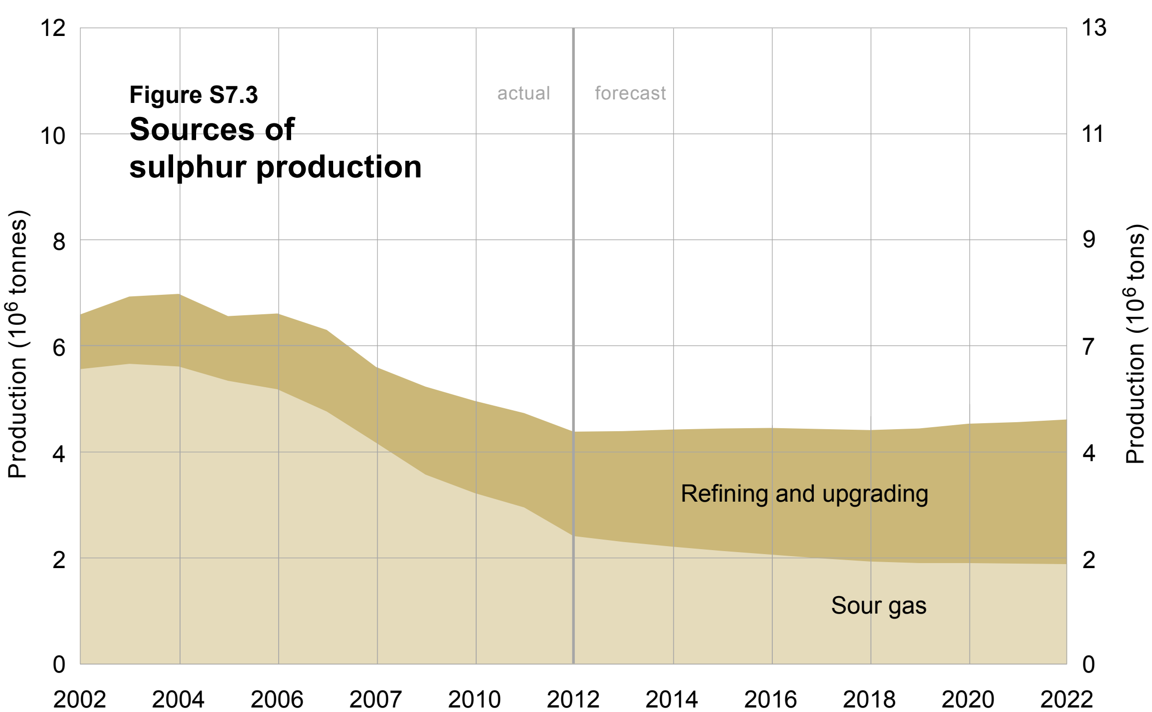


Figure S7.3
Sources of sulphur production

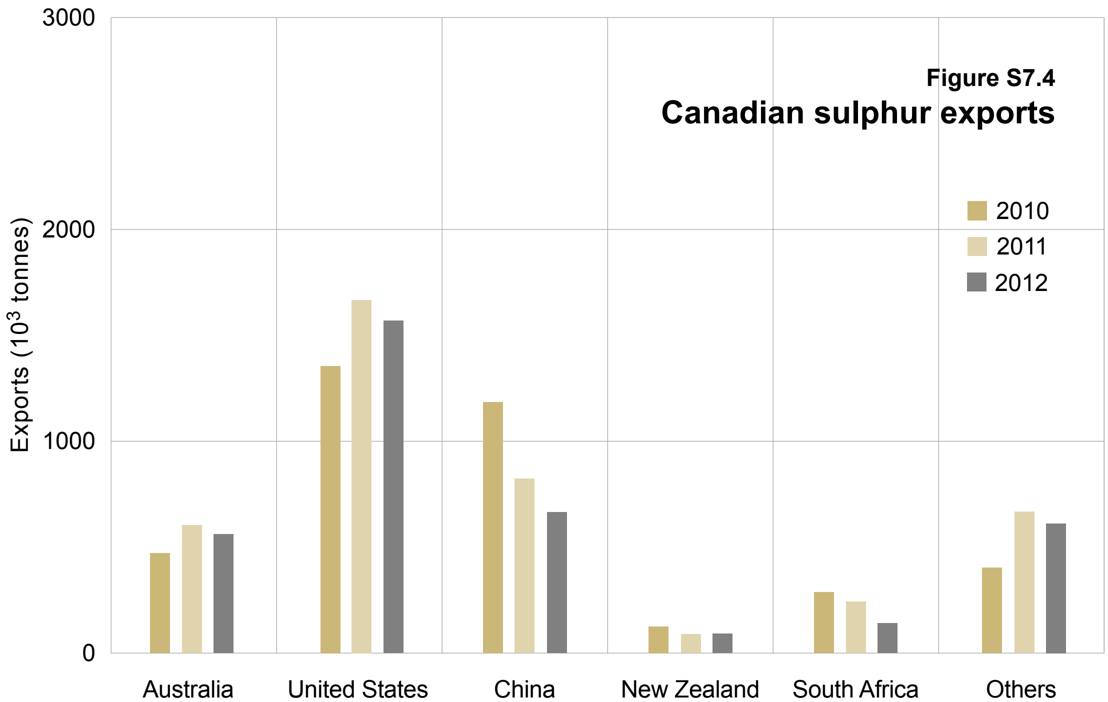


Figure S7.4
Canadian sulphur exports
3000
2000
1000
0
Exports (10^3 tonnes)
2010
2011
2012
Australia
United States
China
New Zealand
South Africa
Others

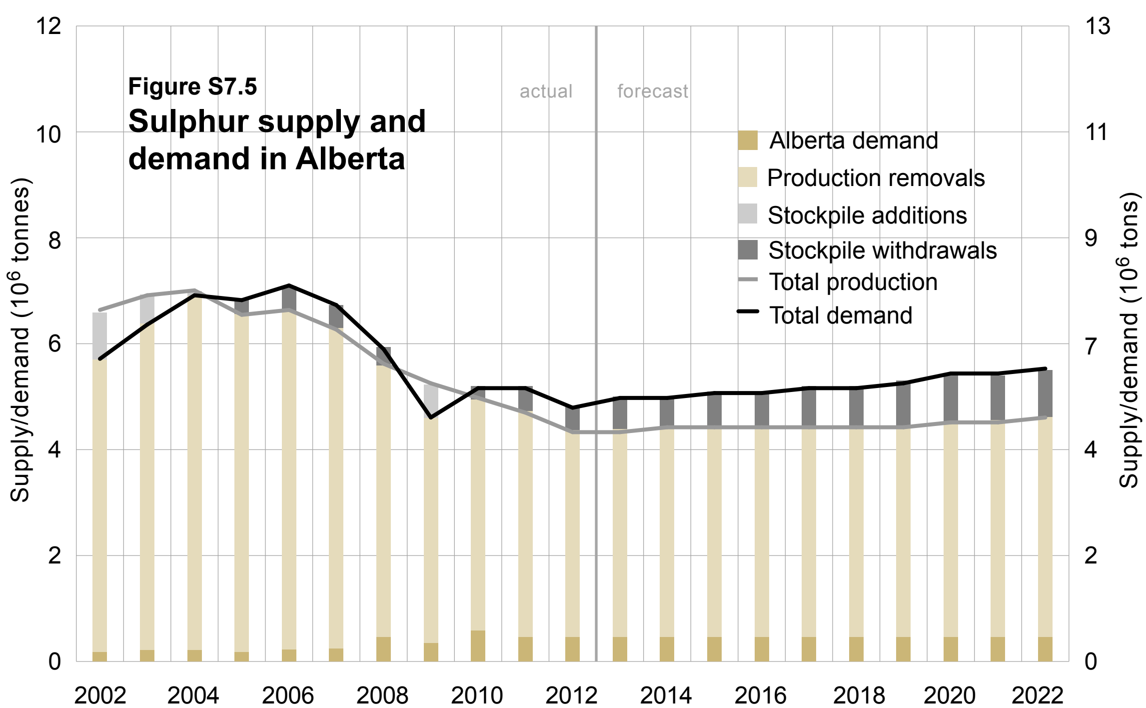


Figure S7.5
Sulphur supply and demand in Alberta
actual
forecast
Alberta demand
Production removals
Stockpile additions
Stockpile withdrawals
Total production
Total demand
Supply/demand (10^6 tonnes)
Supply/demand (10^6 tons)
12
10
8
6
4
2
0
13
11
9
7
4
2
0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022

HIGHLIGHTS

Remaining established reserves under active development decreased slightly in 2012 due to production but still represent decades of supply.

Overall coal production was 6 per cent lower tin 2012. While metallurgical bituminous coal production increased 15 per cent, thermal bituminous coal production decreased 16 per cent and subbituminous coal decreased 6 per cent, mainly as a result of weaker demand.

8 COAL

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

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

The possible commercial production of synthetic gas from coal (synthetic coal gas) in Alberta is still being investigated, and legislation is in place for regulating in situ coal gasification (ISCG) development. A discussion of ISCG is found in **Section 8.1.2.3**.

The following coal reserves and production information summarizes and nominally updates the material found in the ERCB serial publication *ST31: Reserves of Coal, Province of Alberta* (2000 edition). See that publication for more detailed information and a greater understanding of the parameters and procedures used to calculate established coal reserves.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The ERCB estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2012, to be 33.3 gigatonnes[1] (Gt) (36.7 billion tons). Of this amount, 22.7 Gt (or about 68 per cent) is considered recoverable by underground mining methods and 10.4 Gt is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2012. **Table R8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

Minor changes in remaining established reserves from December 31, 2011, to December 31, 2012, resulted from additions to cumulative production. During 2012,

[1] Giga = 10^9.

Table R8.1 Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2012[a] (Gt)

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.250	0.561
Underground	5.06	0.738	0.111	0.627
Subtotal	**6.83**[c]	**1.56**[c]	**0.361**	**1.20**[c]
High-volatile bituminous				
Surface	2.56	1.89	0.203	1.687
Underground	3.30	0.962	0.0470	0.915
Subtotal	**5.90**[c]	**2.88**[c]	**0.250**	**2.63**[c]
Subbituminous[d]				
Surface	13.6	8.99	0.848	8.14
Underground	67.0	21.2	0.0680	21.1
Subtotal	**80.7**[c]	**30.3**[c]	**0.916**	**29.4**
Total	**93.7**[c]	**34.8**[c]	**1.53**[e]	**33.3**[c]

[a] Tonnages have been rounded to three significant figures.

[b] Includes minor amounts of semi-anthracite.

[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.

[d] Includes minor lignite.

[e] Any discrepancies are due to rounding.

the low- and medium-volatile bituminous, high-volatile bituminous, and subbituminous production tonnages were 0.005 Gt, 0.008 Gt, and 0.022 Gt, respectively.

8.1.2 In-Place Resources

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

The ERCB estimates the initial in-place resource of coal to be 94 10^9 tonnes, of which the largest component, 81 10^9 tonnes, is the subbituminous coal of the plains region. Most of this subbituminous coal exists at depths greater than 60 metres (m), but less than 600 m.[2] There is significantly greater resource potential for coal, as mentioned in **Section 8.1.4**.

8.1.2.1 Geology and Coal Occurrence

Coal occurs extensively in Alberta through the nonmarine units of the sequence of Jurassic- to Paleocene-aged formations. The coal-bearing formations underlie about 300 000 square kilometres—almost half of Alberta. **Figure R8.1** shows the subcrops of most of the coal-bearing formations, and their equivalents, in Alberta.

[2] Coal is known to exist below a depth of 600 m, but that is beyond what is considered potentially mineable.

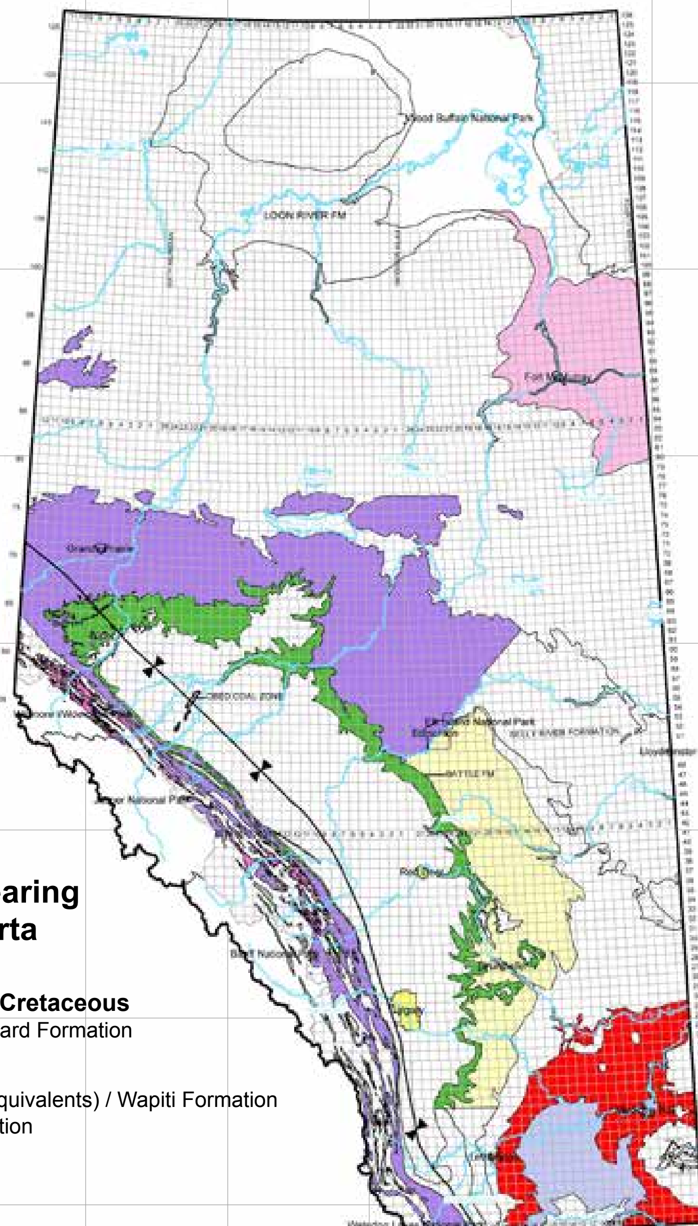


Figure R8.1
Significant coal-bearing formations in Alberta

Paleocene and Upper Cretaceous
- Coalspur Formation / Scollard Formation

Upper Cretaceous
- Brazeau Formation (and equivalents) / Wapiti Formation
- Horseshoe Canyon Formation
- Oldman Formation
- Foremost Formation

Lower Cretaceous
- Luscar Group
- Mannville Group

Lower Cretaceous and Upper Jurassic
- Kootenay Group

Coal, with or without thin clastic layers called partings, occurs in layered accumulations called seams. Coal maturity, or rank, is measured on the basis of calorific value for lower-ranked coals and carbon content for higher-ranked coals. Coals of all rank groups, from lignite to semi-anthracite, occur in Alberta.

The ERCB has subdivided Alberta's coal-bearing regions into three designated regions (broadly shown in **Figure S8.1** in **Section 8.2.1**) based on rank, geology, and topography, so as to group coals by method of recovery and market. The mountain region exhibits complex geological structures and steep topography with higher-ranked coal amenable to export for metallurgical purposes. The foothills region exhibits moderately complex structures and hilly topography with moderate-ranked coals amenable to export for thermal purposes. The plains region is the largest and exhibits generally flat-lying seams and flat or incised plateau topography with lower-ranked coals amenable for domestic thermal purposes. The plains region contains about 88 per cent of Alberta's coal, most of which is subbituminous.

Figure R8.2 shows periods of exploration for coal in Alberta. Recent coal exploration has been predominately within areas for which mine permits have been issued by the ERCB. While very significant coal resources were identified from holes drilled in the 1970s and 1980s, very few areas, other than currently producing areas, have seen follow-up drilling due to lack of markets.

8.1.2.2 Coal Mineability

In general, shallow coal is mined more economically by surface than by underground methods and is classified as surface mineable. At some stage of increasing depth and strip ratio,[3] the economic 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 and is designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

These classifications are used to categorize total coal in place. Further analysis is done to determine which portions of this coal may be developed and which portion of that coal may be recovered. Some in-place coal, such as underground thin seams, is unlikely to be developed by mining methods but is included in the total because of past production. Additionally, some of the coal currently classified as underground may become the target of commercial ISCG development. At such time, the ERCB will split the underground classification into mineable and in situ components.

8.1.2.3 In Situ Coal Gasification

There are two main types of coal gasification processes: ISCG and surface-facility gasification from mined coal. Surface-facility gasification processes conventionally mined coal, and those mineable coal reserves would be included in the tables above. Currently, however, there are no surface-gasification facilities in Alberta.

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

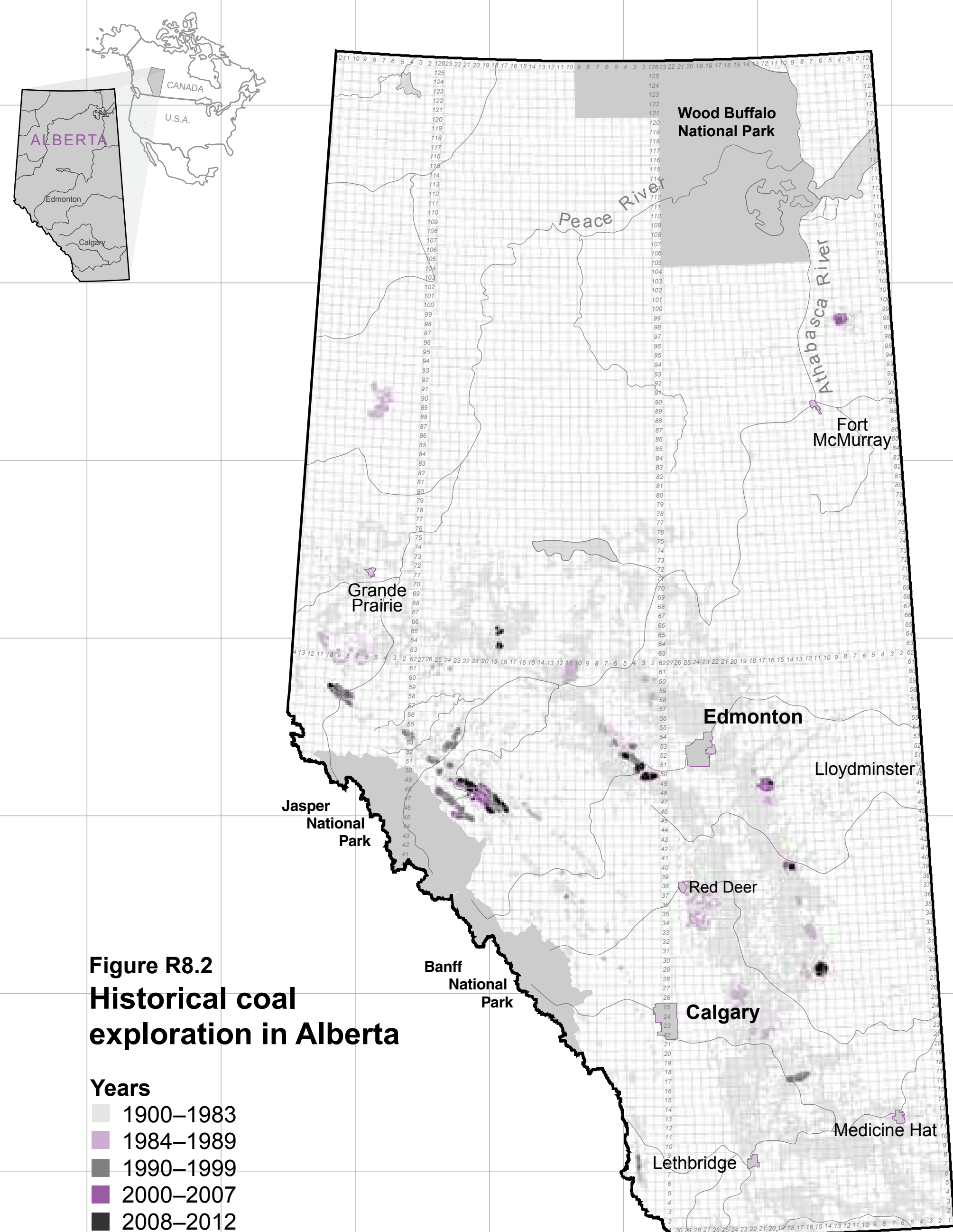


Figure R8.2
Historical coal exploration in Alberta

Years
- 1900–1983
- 1984–1989
- 1990–1999
- 2000–2007
- 2008–2012

ISCG uses wellbores to access coal seams at depth. ISCG consists of thermal reduction of coal to simpler hydrocarbons that can be produced up a wellbore. Any ISCG-derived gas would, by its nature, incorporate any coalbed methane gas (see **Section 5**) contained within the targeted coals. Currently, ISCG synthetic coal gas is limited to a small quantity. Therefore, neither synthetic coal gas volumes nor their associated coal resource tonnages are yet included in this report. However, Alberta's vast quantities of coal could supply a large resource base should development prove commercial.

Two ISCG pilot projects have been approved but neither was operational in 2012. Future ISCG development may take place at depths below those currently assumed to be mineable.

8.1.3 Established Reserves

Several techniques, in particular geostatistical methods, have been used for calculating in-place volumes, with separate volumes calculated for surface- and underground-mineable coal. Certain parts of deposits are considered nonrecoverable for technical, environmental, or safety reasons, and therefore have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal and the thicker underground classes of coal seams.

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 portion of the remaining deposit areas would be mined. Thus a "deposit factor" has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered to be mineable in the mountain region, 70 per cent in the foothills, and 90 per cent in the plains—the three regions in Alberta designated by the ERCB where coals of similar quality and mineability are recovered.

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

Table R8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2012. In 2011, a new operator acquired a portion of the inactive McLeod River mine permit and filed an application to produce coal. A second application, by a different operator, for a new mine permit on the same geological trend was received in 2012. These mine projects will be included in **Table R8.2** once production or significant construction starts. In 2012, the Vesta mine was incorporated into the adjacent Paintearth mine.

8.1.4 Ultimate Potential

A large degree of uncertainty is associated with estimating an ultimate potential, and new data could substantially alter results. Two methods have been used to estimate the ultimate potential of coal: volumetric and trend analysis. The volumetric method gives a broad estimate of area, coal thickness, and recovery ratio for each coal-

Table R8.2 Established resources and reserves of raw coal under active development as of December 31, 2012

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves (Mt)
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	28	126
Grande Cache	4 250	199	85	35	50
Subtotal	**11 705**	**445**	**239**	**63**	**176**
High-volatile bituminous					
Coal Valley	17 865	572	331	159	172
Obed	7 590	162	137	46	91
Subtotal	**25 455**	**734**	**468**	**205**	**264**
Subbituminous					
Paintearth	5 120	163	121	102	19
Sheerness	7 000	196	150	91	59
Dodds	425	2.0	2.0	1.5	0.5
Burtonsville Island	150	0.5	0.5	0.2	0.3
Highvale	12 140	1 021	764	410	355
Genesee	7 320	250	176	90	86
Subtotal[c]	**32 155**	**1 633**	**1 214**	**694**	**519**
Total	**69 315**	**2 812**	**1 921**	**962**	**959**

[a] ha = hectares.

[b] Mt = megatonnes; mega = 10^6.

[c] Any discrepancies are due to rounding.

bearing horizon, while the trend analysis method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

To avoid large fluctuations in ultimate potential from year to year, the ERCB has adopted the policy of using the figures published in the 2000 edition of *ST31* and adjusting them slightly to reflect the most recent trends. **Table R8.3** gives quantities by rank for surface- and underground-mineable ultimate in- place resources, as well as the ultimate potential. No change to ultimate potential has been made for 2012.

8.2 Supply of and Demand for Marketable Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used for electricity generation in Alberta. Metallurgical bituminous coal is exported and used for industrial applications, such as steel production. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of thermal bituminous coal makes it possible to economically transport the coal over long distances. While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. Subbituminous raw coal and clean bituminous coal are collectively known as marketable coal.

Table R8.3 Ultimate in-place resources and ultimate potential[a] (Gt)

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	**21**	**3.2**
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	**500**	**160**
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	**1 500**	**470**
Total	**2 000**[b]	**620**

[a] Tonnages have been rounded to two significant figures, and totals are not arithmetic sums but are the result of separate determinations.

[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

8.2.1 Coal Production – 2012

The locations of coal mine sites in Alberta are shown in **Figure S8.1**. In 2012, ten mine sites produced coal in Alberta, as shown in **Table S8.1**.[4] These mines produced 28.2 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 77 per cent of the total, metallurgical bituminous coal 10 per cent, and thermal bituminous coal the remaining 13 per cent. In 2012, while subbituminous and thermal bituminous coal production decreased by 6 and 16 per cent, respectively, metallurgical bituminous coal increased by 15 per cent relative to 2011. Overall, total marketable production of coal has decreased by 6 per cent, mainly due to weaker demand.

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

Three surface mines and one mine with both surface and underground recovery produce the provincial supply of metallurgical and thermal grade coal.

8.2.2 Coal Production – Forecast

The projected production for each of the three types of marketable coal is shown in **Figure S8.2**. Total production is expected to increase over the forecast period by about 9 per cent, from 28.2 Mt in 2012 to 30.9 Mt in 2022. Subbituminous and metallurgical bituminous coal production is forecast to increase by 10 and 16 per cent,

[4] With the merger of the Vesta and Paintearth mines in 2012, there are now ten producing mines sites in Alberta.

Figure S8.1
Producing coal mines in Alberta

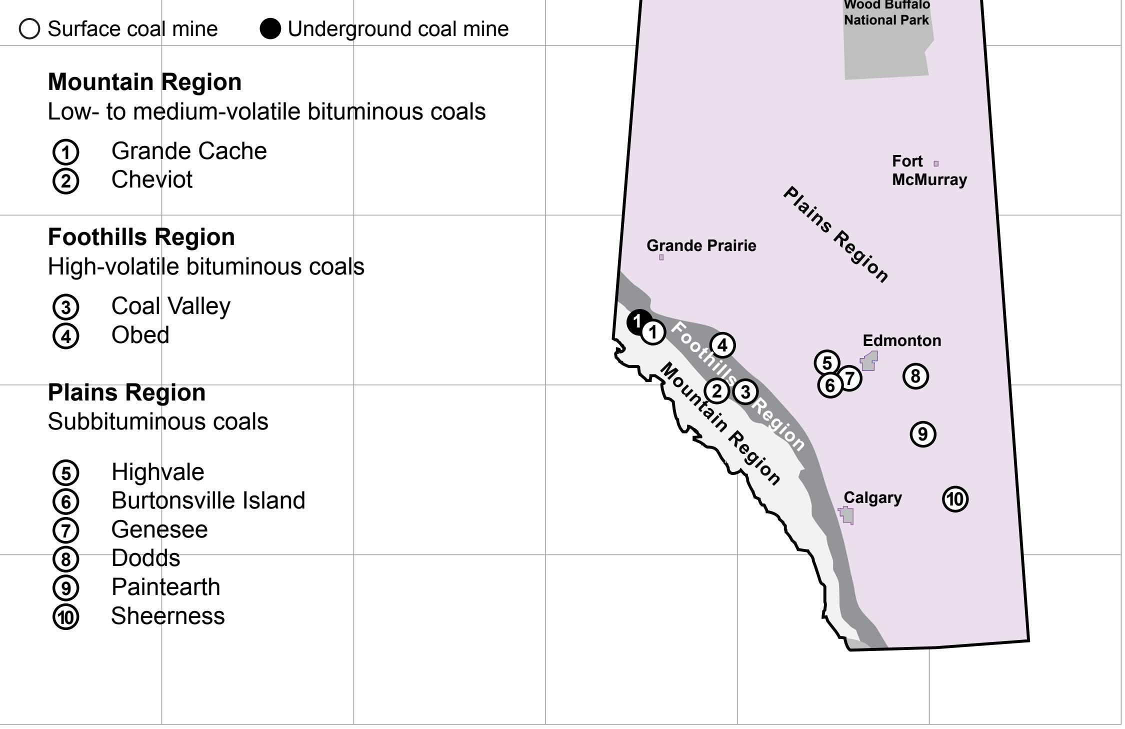


Table S8.1 Alberta coal mines and marketable coal production in 2012

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Sherritt International Corp.	Genesee	Genesee	4.8
	Sheerness	Sheerness	3.2
	Paintearth	Halkirk/Cordel	2.9
	Highvale	Wabamun	10.6
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.08
Keephills Aggregate Ltd.	Burtonsville Island	Burtonsville Island	0.03
Subtotal			**21.6**
Bituminous metallurgical coal			
Teck Resources Limited	Cheviot	Mountain Park	1.4
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.6
Subtotal			**3.0**
Bituminous thermal coal			
Sherritt International Corp.	Coal Valley	Coal Valley	3.4
	Obed	Obed	0.2
Subtotal			**3.6**
Total			**28.2**

respectively, by 2022, while bituminous thermal coal production will remain flat. An increase in production of both metallurgical and export thermal coal is possible if proposed mines open within the forecast period.

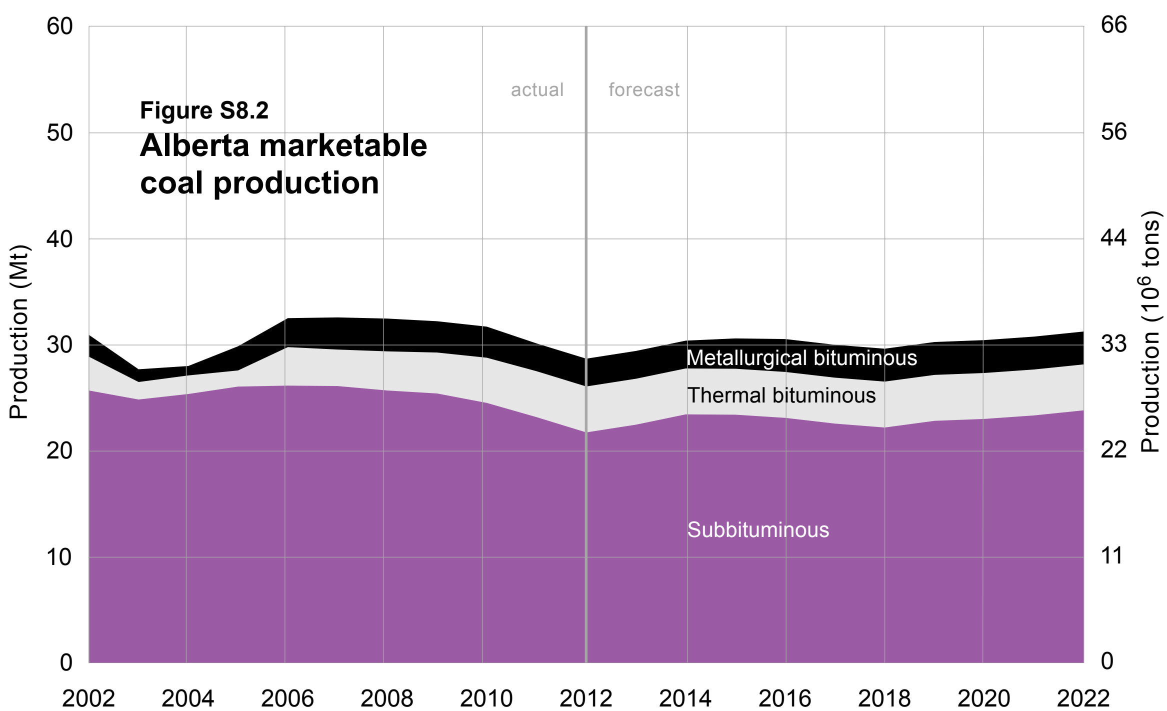
8.2.3 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electricity generation plants, and the production from these mines can be affected by the commissioning and closures of power generation plants.

In 2012, the federal government issued new regulations for coal-fired plants that require all coal-fired power plants to either be retired by the end of their economic life (after 50 years of operation) or meet stringent emissions requirements. The new federal regulations come into effect in July 2015. The ERCB has considered this in forecasting the demand for coal.

Sundance Units 1 and 2, operated by TransAlta, have been out of service since December 2010. Following a hearing to determine the future of the plants, an arbitration panel ordered the units to be rebuilt and service restored. Based on this decision, both units are expected to be restored to service by fall 2013. The two units have been included in the ERCB's demand forecast starting in 2014. Also, the upgrades to increase the capacity of Keephills Units 1 and 2 by 23 megawatts were completed in 2012.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan importing the most from Alberta. Japan also imports the most thermal coal from Alberta. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export-coal producers. However, the demand for metallurgical coal exports improved in 2012 from the 2011 level, and North American metallurgical coal is becoming more competitive. Australia, the world's largest metallurgical coal exporter, implemented taxes on mining profits and carbon emissions on July 1, 2012. Consequently, the ERCB expects a 16 per cent increase in Alberta metallurgical coal production over the forecast period.



Appendix A Terminology and Conversion Factors

A.1 Terminology

Alberta Natural Gas Reference Price (ARP) The Alberta Natural Gas Reference Price is a monthly weighted average field price of all Alberta gas sales, as determined by the Alberta Department of Energy through a survey of actual sales transactions. This price is used for royalty purposes.

API Gravity A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.

Brent Blend (Brent) Brent Blend is a grade of light sweet crude oil derived from a mix of 15 different oil fields in the North Sea. Brent blend futures are traded on the IntercontinentalExchange, Inc (ICE) and are considered a global benchmark for oil prices.

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

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

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

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

Commingled Commingled flow describes the production of fluid from two or more separate zones through a single conduit.

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

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

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

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

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

Crude Oil (Heavy) Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m^3 or greater.

Crude Oil (Light-Medium) Crude oil is deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3.

Crude Oil Netback Crude oil netbacks are calculated from the price of WTI at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate, as well as crude quality differences.

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 turbo-expander.
Density	The mass or amount of matter per unit volume.
Density, Relative (Raw Gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Development Entities (DEs)	A development entity (DE) is an entity consisting of multiple formations in a specific area described in an order of the ERCB from which gas may be produced without segregation in the wellbore subject to certain criteria specified in Section 3.051 of the *Oil and Gas Conservation Regulations* (Order No. DE 2006-2).
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transportation in pipelines.
Discovery Year	The year when drilling was completed of the well in which the oil or gas pool was discovered.
Economic Strip Ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, Section 1(1)(h.1)).
Extraction	The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).
Feedstock	In this report feedstock refers to raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field	(i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or (ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, Section T1T (x)).
Field Plant	A natural gas facility that processes raw gas and is located near the source of the gas upstream of the pipelines that move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Field Plant Gate	The point at which the gas exits the field plant and enters the pipeline.
Field or Strike Area	An administrative geographical boundary used for grouping resource accumulation.
Fractionation Plant	A processing facility that takes a natural gas liquids stream and separates out the component parts as specification products.

Gas — Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(j.1)).

Gas (Associated) — Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.

Gas (Marketable) — A mixture mainly of methane originating from raw gas or, if necessary, from the processing of the raw gas for the removal or partial removal of some constituents and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, Section 1(1)(m)).

Gas (Marketable at 101.325 kPa and 15°C) — The equivalent volume of marketable gas at standard conditions.

Gas (Nonassociated) — Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas (Raw) — A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these components that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, Section 1(1)(s.1)).

Gas (Solution) — Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas-Oil Ratio (Initial Solution) — The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Good Production Practice (GPP) — Production from oil pools at a rate
(i) not governed by a base allowable, but
(ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain its share of the production (*Oil and Gas Conservation Regulations* 1.020(2)9).

This practice is authorized by the ERCB either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.

Gross Heating Value (of Dry Gas) — The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Henry Hub Price — The Henry Hub is a distribution hub on a main natural gas pipeline system in the Untied States near Erath, Louisiana. It is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

Horizontal Well — A well in which the lower part of the wellbore is drilled parallel to the zone of interest.

Initial Established Reserves — Established reserves prior to the deduction of any production.

Initial Volume in Place — The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.

Maximum Day Rate — The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as maximum day rate.

Maximum Recoverable Thickness The assumed maximum operational reach of underground coal mining equipment in a single seam.

Mean Formation Depth The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.

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

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

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

Off-gas Natural gas that is produced from upgrading bitumen. 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.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Rich Gas	Natural gas that contains a relatively high concentration of natural gas liquids.
Sales Gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (Gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (Water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shale Gas	The naturally occurring dry, predominantly methane gas produced from organic-rich, fine-grained rocks.
Shrinkage Factor (Initial)	The volume occupied by 1 cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.
Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.
Specification Product	A crude oil or refined petroleum product with defined properties.
Sterilization	The rendering of otherwise definable economic ore as unrecoverable.
Straddle Plants	These are reprocessing plants on major natural gas transmission lines that process marketable gas by extracting natural gas liquids. This results in gas for export having a lower heat content than the marketable gas flowing within the province.
Strike Area	See Field or Strike Area.
Strip Ratio	The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) thickness of overburden to thickness of coal, (2) volume of overburden to volume coal, (3) weight of overburden to weight of coal, or (4) cubic yards of overburden to tons of coal. A stripping ratio commonly is used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.
Successful Wells Drilled	Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.

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

Upgraded Bitumen A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.

Temperature The initial reservoir temperature upon discovery at the reference elevation of a pool.

Ultimate Potential An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple equation: Ultimate potential = initial established reserves + additions to existing pools + future discoveries.

Upgrading The process that converts bitumen and heavy crude oil into a product with a density and viscosity similar to light crude oil.

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

Western Canadian Select (WCS) Western Canadian Select is a grade of heavy crude oil derived from of a mix of heavy crude oil and crude bitumen blended with diluents. The price of WCS is often used as a representative price for Canadian heavy crude oils.

West Texas Intermediate (WTI) West Texas Intermediate is a light sweet crude oil that is typically referenced for pricing purposes at Cushing, Oklahoma.

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

A.2 PSAC Areas

The Petroleum Services Association of Canada (PSAC) has sectioned Canada into a number of geographic regions based on the predominate type of geological interest to the oil and gas industry. **Figure AA.1** shows the PSAC areas in Alberta. In discussing historical, current, and future oil and gas activity in Alberta, the ERCB often references such activity by PSAC area.

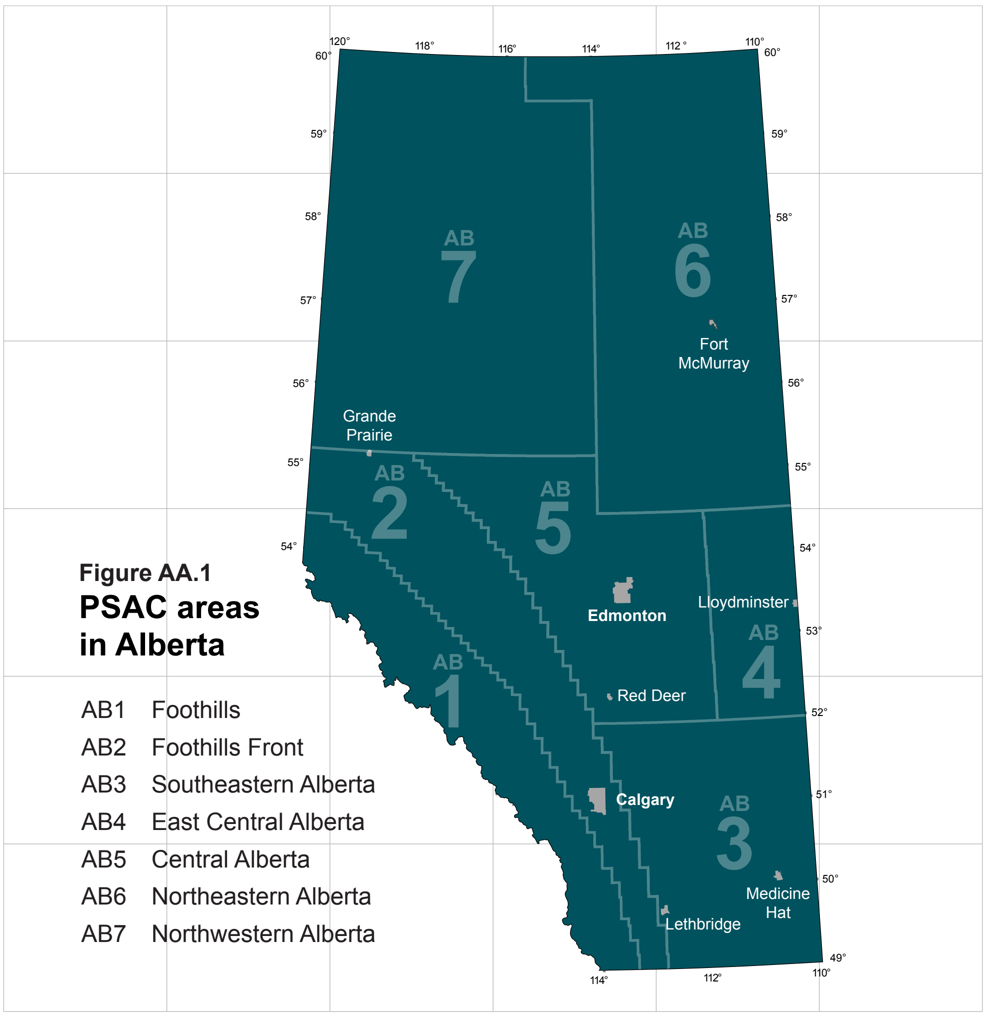


Figure AA.1
PSAC areas in Alberta

A.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	M	thousand
MM	million	B	billion
T	trillion		

A.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
1 m^3 of ethane (equilibrium pressure and 15°C)	= 6.3301 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	= 6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	= 6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	= 6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	= 6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	= 0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	= 1.102311 short tons (2000 pounds)
1 kilojoule	= 0.9482133 British thermal units (Btu) as defined in the federal *Gas Inspection Act* (60-61°F)

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

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

Value and Scientific Notation

Term	Value (short scale)	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion (trillion)	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
Upgraded bitumen (synthetic crude oil)	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

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

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

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

Oil Sands Area Oil sands deposit	Depth/region/zone (m)	Resource determination method	Initial volume in place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150–450+	Isopach	5 817
Middle Grand Rapids	150–450+	Isopach	2 171
Lower Grand Rapids	150–450+	Isopach	1 286
Wabiskaw-McMurray	0–750+	Isopach	152 432
Nisku	200–800+	Isopach	16 232
Grosmont	All zones	Isopach	64 537
Subtotal			**242 475**
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350–625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			**29 090**
Peace River			
Bluesky-Gething	300–800+	Isopach	10 968
Belloy	675–700	Building block	282
Upper Debolt	500–800	Building block	1 830
Lower Debolt	500–800	Building block	5 970
Shunda	500–800	Building block	2 510
Subtotal			**21 560**
Total			**293 125**

Table B.2 Basic data of crude bitumen deposits

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150–450+	Isopach	5 817.00	359.00	8.5	0.092	0.58	0.33	0.42
Middle Grand Rapids								
150–450+	Isopach	2 171.00	183.00	6.8	0.084	0.55	0.32	0.45
Lower Grand Rapids								
150–450+	Isopach	1 286.00	134.00	5.6	0.083	0.52	0.33	0.48
Wabiskaw-McMurray								
0–65 (mineable)	Isopach	20 823.00	375.00	25.9	0.101	0.76	0.28	0.24
65–750+ (in situ)	Isopach	131 609.00	4 694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200–800+	Isopach	16 232.00	819.00	14.4	0.057	0.68	0.20	0.32
Grosmont								
D	Isopach	32 860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18 755.00	1 069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4 450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8 472.00	1 274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5 377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/ Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/ Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/ Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/ Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1 004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/ Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/ Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/ Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/ St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/ St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27

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Table B.2 (*continued*)

Oil Sands Area / Oil sands deposit / Depth/region/zone / Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Lower Grand Rapids 5								
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/ Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/ St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/ St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/ Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./ Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350–625	Isopach	9 422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2 161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1 439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18

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Table B.2 (*continued*)

Oil Sands Area / Oil sands deposit / Depth/region/zone / Sector-pool	Resource determination method	Initial volume in place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation (mass fraction)	Bitumen saturation (pore volume fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/ Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/ St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/ St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300–800+	Isopach	10 968.00	1 016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675–700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500–800	Building Block	1 830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500–800	Building Block	5 970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500–800	Building Block	2 510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		**293 124.67**						

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

	Changes to initial established reserves							
Year	New discoveries	EOR additions	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves
1968	62.0				119.8	1 643.1	430.3	1 212.8
1969	40.5				54.5	1 697.5	474.7	1 222.8
1970	8.4				36.7	1 734.4	526.5	1 207.9
1971	14.0				22.1	1 756.5	582.9	1 173.6
1972	10.8				20.0	1 776.0	650.0	1 126.0
1973	5.1				9.2	1 785.7	733.7	1 052.0
1974	4.3				38.5	1 824.2	812.7	1 011.5
1975	1.6				7.0	1 831.1	880.2	950.9
1976	2.5				-18.6	1 812.5	941.2	871.3
1977	4.8				19.1	1 831.6	1 001.6	830.0
1978	24.9				24.4	1 856.1	1 061.6	794.5
1979	19.2				34.3	1 890.3	1 130.1	760.2
1980	9.0				22.8	1 913.2	1 193.3	719.9
1981	15.0	7.2			32.6	1 945.8	1 249.8	696.0
1982	16.8	6.6			6.9	1 952.8	1 303.4	649.4
1983	21.4	17.9			64.1	2 016.8	1 359.0	657.8
1984	29.1	24.1			42.0	2 058.9	1 418.2	640.7
1985	32.7	21.6			64.0	2 123.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	2 162.4	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	2 195.4	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	2 231.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	2 253.1	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	2 256.1	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	2 265.6	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	2 292.7	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	2 331.9	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	2 336.5	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 391.6	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 414.1	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 451.6	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 490.1	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 521.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 554.3	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 583.0	2 304.7	278.3
2002	7.0	0.6	8.1	4.6	20.2	2 603.3	2 343.0	260.3

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Table B.3 (*continued*)

Year	Changes to initial established reserves					Initial established reserves	Cumulative production	Remaining established reserves
	New discoveries	EOR additions	Development	Revisions	Net changes			
2003	6.9	1.0	5.9	17.1	30.8	2 634.0	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 664.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 703.7	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 730.8	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 751.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 773.1	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2 794.9	2 566.5	228.4
2010	3.8	5.8	23.5	+1.7	34.8	2 829.7	2 592.8	236.9
2011	4.0	6.4	14.0	+9.0	33.5	2 863.2	2 617.3	245.9
2012	5.8	2.2	52.9	-2.4	58.5	2 921.7	2 652.5	269.2

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

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

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Table B.4 (*continued*)

Year	Changes to initial established reserves: New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves at 37.4 MJ/m³
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0
2010	24.3	25.3	33.2	82.8	5 213.5	4 188.4	1 025.1	1 065.7
2011	20.8	24.0	24.7	69.5	5 283.1	4 338.0	945.1	987.0
2012	16.2	8.0	33.8	58.0	5 341.1	4 425.4	915.7	957.2

[a] At field plant.

Table B.5 Natural gas reserves of multifield pools, 2012

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8515 Banff	
Haro MFP8515 Banff	898
Rainbow MFP8515 Banff	6
Rainbow South MFP8515 Banff	76
Total	171
MFP8516 Viking	
Fenn West MFP8516 Viking	6
Fenn-Big Valley MFP8516 Viking	3
Total	9
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 162
Wembley MFP8524 Halfway	1 910
Total	4 072
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	105
Sousa MFP8528 Bluesky	562
Total	667
MFP8529 Bluesky-Detrital-Debolt	
Cranberry MFP8529 BL-DT-DB	175
Hotchkiss MFP8529 BL-DT-DB	357
Total	532
MFP8541 Second White Specks	
Cherry MFP8541 2WS	17
Granlea MFP8541 2WS	29
Taber MFP8541 2WS	110
Total	156
Commingled MFP9502	
Ansell Commingled MFP9502	14 360
Edson Commingled MFP9502	1 955
Medicine Lodge Commingled MFP9502	1 291
Minehead Commingled MFP9502	1 798
Sundance Commingled MFP9502	9 930
Wild River Commingled MFP9502	3
Total	29 337
Commingled MFP9503	
Hairy Hill Commingled MFP9503	211
Willingdon Commingled MFP9503	10
Total	221
Commingled MFP9504	
Alix Commingled MFP9504	384
Bashaw Commingled MFP9504	1 954
Buffalo Lake Commingled MFP9504	7
Chigwell Commingled MFP9504	88
Chigwell North Commingled MFP9504	134
Clive Commingled MFP9504	409
Donalda Commingled MFP9504	101
Dorenlee Commingled MFP9504	2
Ferintosh Commingled MFP9504	3
Haynes Commingled MFP9504	69
Lacombe Commingled MFP9504	7
Malmo Commingled MFP9504	365
Nevis Commingled MFP9504	1 385
Wood River Commingled MFP9504	116
Total	5 024
Commingled MFP9505	
Bigoray Commingled MFP9505	171
Pembina Commingled MFP9505	727
Total	898
Commingled MFP9506	
Bonnie Glen Commingled MFP9506	33
Ferrybank Commingled MFP9506	167
Total	200
Commingled MFP9508	
Fairydell-Bon Accord Commingled MFP9508	68
Peavey Commingled MFP9508	1
Redwater Commingled MFP9508	1 397
Total	1 460
Commingled MFP9509	
Albers Commingled MFP9509	4
Beaverhill Lake Commingled MFP9509	292
Bellshill Lake Commingled MFP9509	4
Birch Commingled MFP9509	6
Bruce Commingled MFP9509	648
Dinant Commingled MFP9509	0
Edberg Commingled MFP9509	0
Fort Saskatchewan Commingled MFP9509	54
Holmberg Commingled MFP9509	137
Kelsey Commingled MFP9509	90
Killam Commingled MFP9509	242
Killam North Commingled MFP9509	70
Mannville Commingled MFP9509	478
Sedgewick Commingled MFP9509	6
Viking-Kinsella Commingled MFP9509	1 512
Wainwright Commingled MFP9509	351
Total	3 894

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Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9510	
Chickadee Commingled MFP9510	1 214
Fox Creek Commingled MFP9510	892
Kaybob South Commingled MFP9510	1 543
Windfall Commingled MFP9510	0
Total	3 649
Commingled MFP9511	
Hudson Commingled MFP9511	50
Sedalia Commingled MFP9511	131
Total	181
Commingled MFP9512	
Inland Commingled MFP9512	19
Royal Commingled MFP9512	0
Total	19
Commingled MFP9513	
Elmworth Commingled MFP9513	15 799
Sinclair Commingled MFP9513	4 347
Total	20 146
Commingled MFP9514	
Connorsville Commingled MFP9514	541
Wintering Hills Commingled MFP9514	133
Total	674
Commingled MFP9515	
Craigmyle Commingled MFP9515	2
Dowling Lake Commingled MFP9515	7
Garden Plains Commingled MFP9515	725
Hanna Commingled MFP9515	499
Provost Commingled MFP9515	3 738
Racosta Commingled MFP9515	70
Richdale Commingled MFP9515	371
Stanmore Commingled MFP9515	26
Sullivan Lake Commingled MFP9515	48
Watts Commingled MFP9515	41
Total	5 527
Commingled MFP9516	
Knopcik Commingled MFP9516	442
Valhalla Commingled MFP9516	29
Total	471
Commingled MFP9517	
Comrey Commingled MFP9517	18
Conrad Commingled MFP9517	93
Forty Mile Commingled MFP9517	48
Pendant D'Oreille Commingled MFP9517	491
Smith Coulee Commingled MFP9517	398
Total	1 048

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9520	
Gadsby Commingled MFP9520	3
Leahurst Commingled MFP9520	40
Total	43
Commingled MFP9522	
Enchant Commingled MFP9522	205
Grand Forks Commingled MFP9522	8
Little Bow Commingled MFP9522	3
Retlaw Commingled MFP9522	304
Vauxhall Commingled MFP9522	23
Total	543
Commingled MFP9524	
Stirling Commingled MFP9524	86
Warner Commingled MFP9524	14
Total	100
Commingled MFP9525	
Resthaven Commingled MFP9525	1 982
Smoky Commingled MFP9525	143
Total	2 125
Commingled MFP9526	
Garrington Commingled MFP9526	48
Innisfail Commingled MFP9526	17
Markerville Commingled MFP9526	190
Medicine River Commingled MFP9526	181
Penhold Commingled MFP9526	4
Sylvan Lake Commingled MFP9526	675
Tindastoll Commingled MFP9526	50
Total	1 165
Commingled MFP9527	
Crystal Commingled MFP9527	37
Gilby Commingled MFP9527	40
Minnehik-Buck Lake Commingled MFP9527	184
Westerose South Commingled MFP9527	162
Wilson Creek Commingled MFP9527	271
Total	694
Commingled MFP9529	
Berland River Commingled MFP9529	23
Berland River West Commingled MFP9529	64
Cecilia Commingled MFP9529	5 667
Elmworth Commingled MFP9529	486
Fir Commingled MFP9529	11 157
Kaybob South Commingled MFP9529	8 238
Oldman Commingled MFP9529	1 224
Red Rock Commingled MFP9529	4 560

(continued on next page)

Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Sundance Commingled MFP9529	298
Wapiti Commingled MFP9529	25 357
Wild River Commingled MFP9529	18 102
Wildhay Commingled MFP9529	820
Total	75 996
Commingled MFP9530	
Gilby Commingled MFP9530	218
Prevo Commingled MFP9530	41
Total	259
Commingled MFP9531	
Nosehill Commingled MFP9531	1 387
Oldman Commingled MFP9531	18
Pine Creek Commingled MFP9531	1 820
Total	3 225
Commingled MFP9532	
Grizzly Commingled MFP9532	153
Waskahigan Commingled MFP9532	49
Total	202
Commingled MFP9533	
Bigstone Commingled MFP9533	140
Placid Commingled MFP9533	752
Total	892
Commingled MFP9534	
Jenner Commingled MFP9534	1
Princess Commingled MFP9534	0
Total	1
Commingled MFP9536	
Chinook Commingled MFP9536	130
Dobson Commingled MFP9536	11
Heathdale Commingled MFP9536	10
Kirkwall Commingled MFP9536	10
Sedalia Commingled MFP9536	3
Sounding Commingled MFP9536	75
Stanmore Commingled MFP9536	63
Total	302
Commingled MFP9537	
Ferrier Commingled MFP9537	326
Pembina Commingled MFP9537	1 307
Willesden Green Commingled MFP9537	263
Total	1 896
Commingled MFP9538	
Carrot Creek Commingled MFP9538	735
Edson Commingled MFP9538	608
Pembina Commingled MFP9535	224
Rosevear Commingled MFP9538	91
Total	1 658

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9501 (Southeast Alberta Gas System)	
Aerial Commingled MFP9501	94
Alderson Commingled MFP9501	14 638
Armada Commingled MFP9501	36
Atlee-Buffalo Commingled MFP9501	531
Badger Commingled MFP9501	36
Bantry Commingled MFP9501	19 164
Berry Commingled MFP9501	71
Bindloss Commingled MFP9501	669
Blackfoot Commingled MFP9501	366
Bow Island Commingled MFP9501	314
Brooks Commingled MFP9501	274
Carbon Commingled MFP9501	675
Cavalier Commingled MFP9501	525
Cessford Commingled MFP9501	5 961
Chain Commingled MFP9501	187
Connemara Commingled MFP9501	3
Connorsville Commingled MFP9501	733
Countess Commingled MFP9501	35 380
Craigmyle Commingled MFP9501	649
Crossfield Commingled MFP9501	50
Davey Commingled MFP9501	233
Delia Commingled MFP9501	352
Drumheller Commingled MFP9501	1 707
Elkwater Commingled MFP9501	747
Elnora Commingled MFP9501	246
Enchant Commingled MFP9501	11
Entice Commingled MFP9501	6 965
Erskine Commingled MFP9501	28
Ewing Lake Commingled MFP9501	95
Eyremore Commingled MFP9501	761
Fenn West Commingled MFP9501	118
Fenn-Big Valley Commingled MFP9501	1 002
Gadsby Commingled MFP9501	520
Gartley Commingled MFP9501	9
Ghost Pine Commingled MFP9501	954
Gleichen Commingled MFP9501	375
Herronton Commingled MFP9501	1 158
High River Commingled MFP9501	12
Hussar Commingled MFP9501	6 465
Huxley Commingled MFP9501	416
Jenner Commingled MFP9501	1 972
Joffre Commingled MFP9501	3
Johnson Commingled MFP9501	197
Jumpbush Commingled MFP9501	453
Kitsim Commingled MFP9501	39

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Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Lathom Commingled MFP9501	2 220
Leckie Commingled MFP9501	594
Leo Commingled MFP9501	285
Little Bow Commingled MFP9501	0
Lomond Commingled MFP9501	70
Lone Pine Creek Commingled MFP9501	35
Long Coulee Commingled MFP9501	16
Majorville Commingled MFP9501	458
Matziwin Commingled MFP9501	877
Mcgregor Commingled MFP9501	24
Medicine Hat Commingled MFP9501	42 927
Michichi Commingled MFP9501	276
Mikwan Commingled MFP9501	432
Milo Commingled MFP9501	46
Newell Commingled MFP9501	1 510
Okotoks Commingled MFP9501	116
Pageant Commingled MFP9501	10
Parflesh Commingled MFP9501	871
PenholdCommingled MFP9501	3
Pollockville Commingled MFP9501	2
Princess Commingled MFP9501	8 274
Queenstown Commingled MFP9501	47
Rainier Commingled MFP9501	10
Redland Commingled MFP9501	598
Rich Commingled MFP9501	309
Rockyford Commingled MFP9501	1 748
Ronalane Commingled MFP9501	64
Rowley Commingled MFP9501	470
Rumsey Commingled MFP9501	29
Seiu Lake Commingled MFP9501	699
Shouldice Commingled MFP9501	640
Silver Commingled MFP9501	9
Stettler Commingled MFP9501	93
Stettler North Commingled MFP9501	27
Stewart Commingled MFP9501	5452
Suffield Commingled MFP9501	12 852
Swalwell Commingled MFP9501	428
Three Hills Creek Commingled MFP9501	722
Trochu Commingled MFP9501	513
Twining Commingled MFP9501	1 760
Verger Commingled MFP9501	4 741
Vulcan Commingled MFP9501	68
Wayne-Rosedale Commingled MFP9501	4 911
West Drumheller Commingled MFP9501	50
Wimborne Commingled MFP9501	739
Wintering Hills Commingled MFP9501	2 994
Workman Commingled MFP9501	64
Total	199 370

Table B.6 Remaining raw ethane reserves as of December 31, 2012

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Ansell	15 487	0.082	1 399	4 972
Brazeau River	8 572	0.069	702	2 495
Caroline	5 464	0.085	627	2 231
Cecilia	5 744	0.062	399	1 420
Countess	37 306	0.007	284	1 009
Dunvegan	6 168	0.044	299	1 062
Edson	6 517	0.081	575	2 042
Elmworth	20 903	0.060	1 356	4 820
Ferrier	8 338	0.083	770	2 737
Fir	12 238	0.057	754	2 682
Garrington	3 474	0.076	313	1 113
Gilby	4 007	0.071	316	1 124
Golden Spike	2 221	0.127	414	1 472
Harmattan East	7 379	0.085	703	2 499
Judy Creek	3 515	0.157	689	2 450
Kaybob	3 297	0.089	332	1 181
Kaybob South	15 229	0.070	1 213	4 312
Kakwa	9 361	0.082	839	2 985
Leduc-Woodbend	2 903	0.142	491	1 746
Medicine River	2 971	0.087	292	1 038
Pembina	24 021	0.080	2 754	9 790
Pine Creek	7 727	0.071	634	2 255
Pouce Coupe South	7 693	0.047	401	1 425
Rainbow	8 959	0.098	1 184	4 210
Rainbow South	2 679	0.102	399	1 418
Red Rock	5 294	0.059	333	1 185
Redwater	3 629	0.092	470	1 671
Ricinus	4 119	0.067	318	1 131
Simonette	2 550	0.088	326	1 160
Sinclair	8 556	0.050	470	1 671
Sundance	10 827	0.072	839	2 983
Swan Hills South	3 297	0.173	806	2 864
Sylvan Lake	3 682	0.075	309	1 098
Valhalla	6 874	0.073	552	1 963
Westpem	3 166	0.100	355	1 261

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Table B.6 (*continued*)

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)
Westerose South	5 536	0.084	518	1 841
Wembley	2 642	0.093	301	1 071
Wapiti	29 225	0.055	1 705	6 063
Wild River	18 744	0.071	1 446	5 140
Willesden Green	19 511	0.087	2 284	8 121
Wilson Creek	4 088	0.073	338	1 202
Subtotal	**363 913**	**0.070**	**29 509**	**104 907**
All other fields	**551 770**	**0.030**	**18 516**	**59 980**
Total	**915 683**	**0.047**[a]	**48 024**	**164 887**

[a] Volume weighted average.

Table B.7 Remaining raw reserves of natural gas liquids as of December 31, 2012

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	15 487	2 298	1 215	2 558	6 071
Ante Creek North	1 485	285	155	502	943
Brazeau River	8 572	1 143	700	1 604	3 447
Caroline	5 464	950	589	1 068	2 607
Cecilia	5 744	442	185	650	1 277
Dunvegan	6 168	514	298	504	1 317
Edson	6 517	771	339	325	1 434
Elmworth	20 903	1 562	717	778	3 057
Fenn-Big Valley	2 399	921	400	109	1 430
Ferrier	8 338	1 333	662	600	2 596
Fir	12 238	1 013	490	680	2 183
Garrington	3 474	491	253	365	1 109
Gilby	4 007	564	287	309	1 160
Golden Spike	2 221	1 212	160	563	1 935
Harmattan East	7 379	1 004	597	945	2 546
Hussar	8 426	386	209	230	824
Judy Creek	3 515	1 660	684	389	2 733
Kakwa	9 361	1 280	595	627	2 502
Kaybob	3 297	631	309	347	1 286
Kaybob South	15 229	1 949	1 010	1 270	4 229
Leduc-Woodbend	2 903	1 481	853	481	2 815
Medicine River	2 971	472	230	228	930
Pembina	24 021	6 123	3 106	2 186	11 414
Pine Creek	7 727	985	467	513	1 965
Pouce Coupe South	7 693	530	288	294	1 112
Provost	8 852	563	365	265	1 192
Rainbow	8 959	1 828	1 010	1 041	3 879
Rainbow South	2 679	734	340	409	1 482
Redwater	3 629	1 248	782	311	2 342
Ricinus	4 119	522	262	477	1 260
Simonette	2 550	574	332	341	1 247
Sinclair	8 556	585	248	254	1 087
Sundance	10 827	1 074	466	419	1 959
Swan Hills South	3 297	1 956	898	384	3 238

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Table B.7 (*continued*)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Sylvan Lake	3 682	486	236	220	941
Valhalla	6 874	942	513	790	2 245
Virginia Hills	1 246	662	216	83	961
Wapiti	29 225	1 754	716	687	3 157
Waterton	5 132	251	221	1 396	1 868
Wayne-Rosedale	6 285	449	242	287	978
Wembley	2 642	579	340	762	1 681
Westerose South	5 536	973	469	465	1 907
Westpem	3 166	559	269	242	1 069
Wild River	18 744	1 700	703	1 041	3 444
Willesden Green	19 511	4 021	1 838	1 635	7 493
Wilson Creek	4 088	560	306	389	1 255
Subtotal	**355 138**	**52 017**	**25 568**	**30 019**	**107 604**
All other fields	**560 545**	**23 027**	**12 968**	**15 483**	**51 478**
Total	**915 683**	**75 044**	**38 536**	**45 502**	**159 082**

Appendix C CD – Basic Data Tables

ERCB staff developed the databases used to prepare this reserves report and CD. Input was also obtained from the National Energy Board (NEB) through an ongoing process of crude oil, natural gas, and crude bitumen studies. The crude oil and natural gas reserves data tables present the official reserve estimates of both the ERCB and NEB for the province of Alberta.

C.1 Basic Data Tables

The conventional oil and conventional natural gas reserves and their respective basic data tables are included as Microsoft Excel spreadsheets for 2012 on the CD that accompanies this report (available for $546 from ERCB Information Services). The individual oil and gas pool values are presented on the first worksheet of each spreadsheet. Oilfield and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place to allow for easy scrolling. All crude oil and natural gas pools are listed first alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data presented in **Tables B.1 and B.2** are included in Excel format on the CD.

C.2 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.

C.3 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.

C.4 Crude Bitumen Resources and Basic Data

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

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ADMIN 2	Administrative Area No. 2
ASSOC	associated gas
BDY	boundary
BELL	Belloy
BER	beyond economic reach
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
COMP	compressibility
DBLT	Debolt
DETR	Detrital
DISC YEAR	discovery year
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton
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
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NO.	number
NON-ASSOC	nonassociated gas
NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
PM-PN SYS	Permo-Penn System
RF	recovery factor
RK CK	Rock Creek
RUND or RUN	Rundle
SA	strike area
SATN	saturation
SD	sandstone

SE ALTA GAS SYS (MU)	Southeastern Alberta Gas System - commingled
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1 Development and exploratory wells, pre-1972–2012; number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Pre-1972	11 873	*	**	7 869	24 325	1 624	**	3 619	31 639	13 497	**	11 488	55 964
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897

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Table D.1 (*continued*)

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980
2010	1 979	1 336	0	3 408	7 103	280	1 331	391	2 130	2 259	2 697	3 799	9 233
2011	2 748	1 748	0	1 857	6 820	367	2 372	228	3 074	3 115	4 121	2 085	9 894
2012	2 534	1 787	0	841	5 860	283	2 050	142	2 562	2 817	3 837	983	8 422
Total	**73 980**	**23 605**	**615**	**137 147**	**261 219**	**17 594**	**27 135**	**48 139**	**149 136**	**91 574**	**51 356**	**185 286**	**410 355**

Source: pre-1972—ERCB corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2012—*Alberta Drilling Activity Monthly Statistics (ST59)*.

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

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

* Included in oil.

**Not available.

Table D.2 Development and exploratory wells, pre-1972–2012; kilometres drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Pre-1972	18 843	*	**	11 640	36 991	2 611	**	4 059	26 556	21 459	**	15 699	63 547
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435

(continued on next page)

Table D.2 (*continued*)

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	10 840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087
2010	3 809	1 336	0	5 134	10 653	514	461	848	1 965	4 323	1 797	5 982	12 618
2011	6 106	1 720	0	4 071	12 425	676	870	594	2 373	6 782	2 590	4 665	14 798
2012	6 218	2 179	0	2 536	11 630	591	782	435	2 018	6 809	2 961	2 971	13 648
Total	**109 053**	**22 698**	**373**	**144 956**	**315 273**	**24 905**	**7 272**	**60 152**	**147 557**	**133 963**	**30 343**	**205 109**	**462 830**

Source: pre-1972—ERCB corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2012—*Alberta Drilling Activity Monthly Statistics (ST59)*.

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

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

* Included in oil.

**Not available.

Appendix E Crude Bitumen Pay Thickness and Geological Structure Contour Maps

This appendix contains geological maps from the Crude Bitumen section that have appeared in previous *ST98* reports. These are the maps that the most recent determinations of in-place resources are based on. Any new mapping will be described in the main body of *ST98* in the first year of reporting.

E.1 Regional Map

E.1.1 Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity is the stratigraphic surface that forms the base on which the bitumen-bearing Cretaceous sediments were deposited. **Figure AE.1** is a structure contour map of that surface as it would have appeared at the end of Bluesky/Wabiskaw time. The parts of the Nisku and Grosmont formations that are bitumen bearing are outlined on this map. These Devonian carbonate formations subcrop along the sub-Cretaceous surface and contain bitumen in an updip location along the subcrop edge. Of particular note are the areas on this map identified as having a relative subsea elevation of greater than zero. These areas were still emergent at the end of Bluesky/Wabiskaw time and would have existed as islands within the transgressing northern Boreal Sea.

E.2 Peace River Oil Sands Area

E.2.1 Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. **Figure AE.2** is the bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 metres (m) thickness. The Bluesky-Gething is mapped as a single bitumen zone so that the full extent of the deposit at 6 mass per cent can be shown. Also shown on **Figure AE.2** are the paleotopographic highlands as they would have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. Oil migrated updip became trapped beneath the overlying Wilrich shales and against the highlands, where it was eventually biodegraded into bitumen.

E.3 Athabasca Oil Sands Area

E.3.1 Athabasca Grosmont Deposit

In 2009, the ERCB updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Township 62 to 103 and Range 13, West of the 4th Meridian, to Range 6, West of the 5th Meridian. In its resource assessment, the ERCB included the bitumen from the Upper Ireton Formation. The Grosmont and the Ireton formations are considered to be in hydraulic communication.

The Grosmont Formation is a late-Devonian shallow-marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying Clearwater Formation. **Figure AE.3** is the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

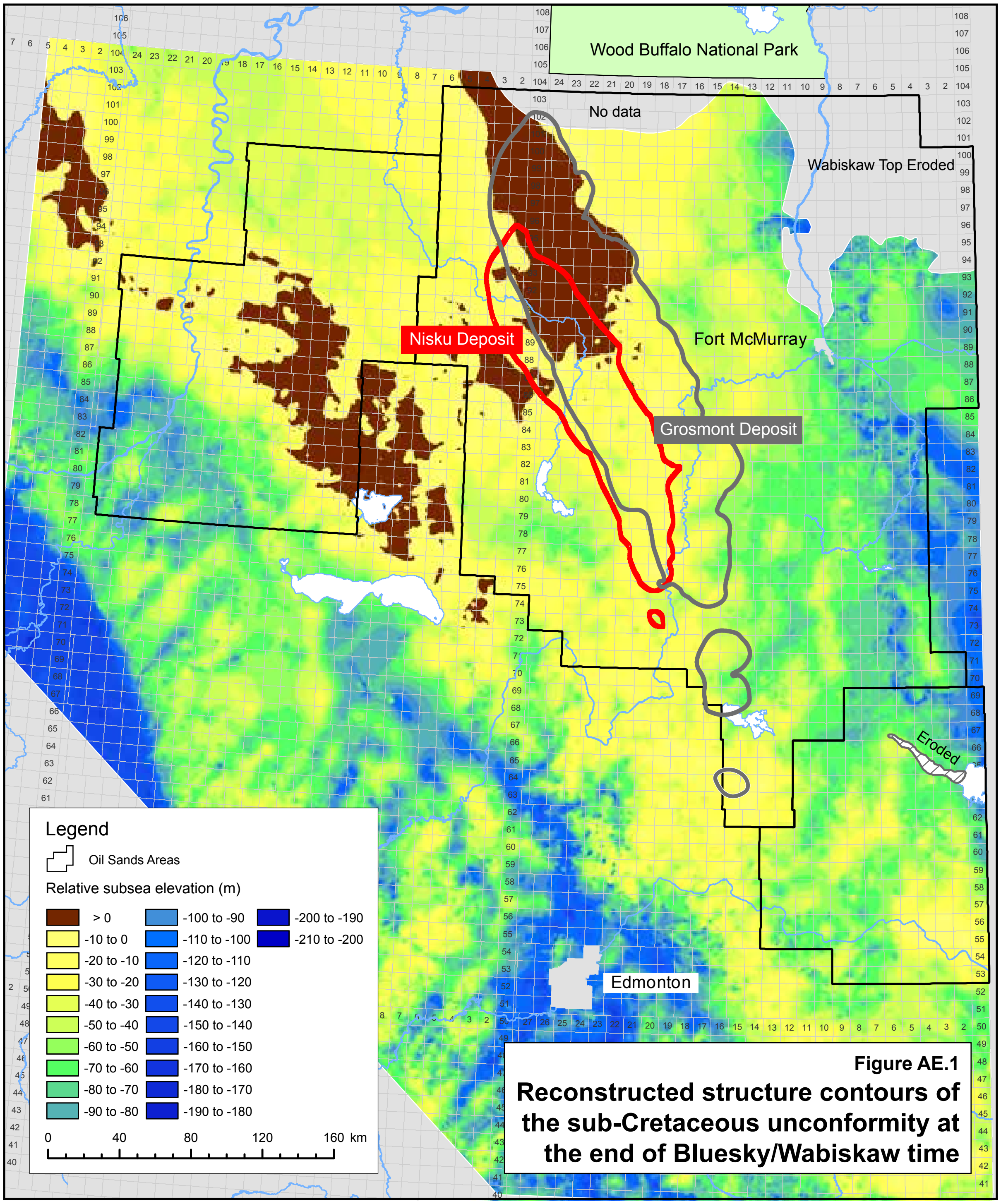


Figure AE.1
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

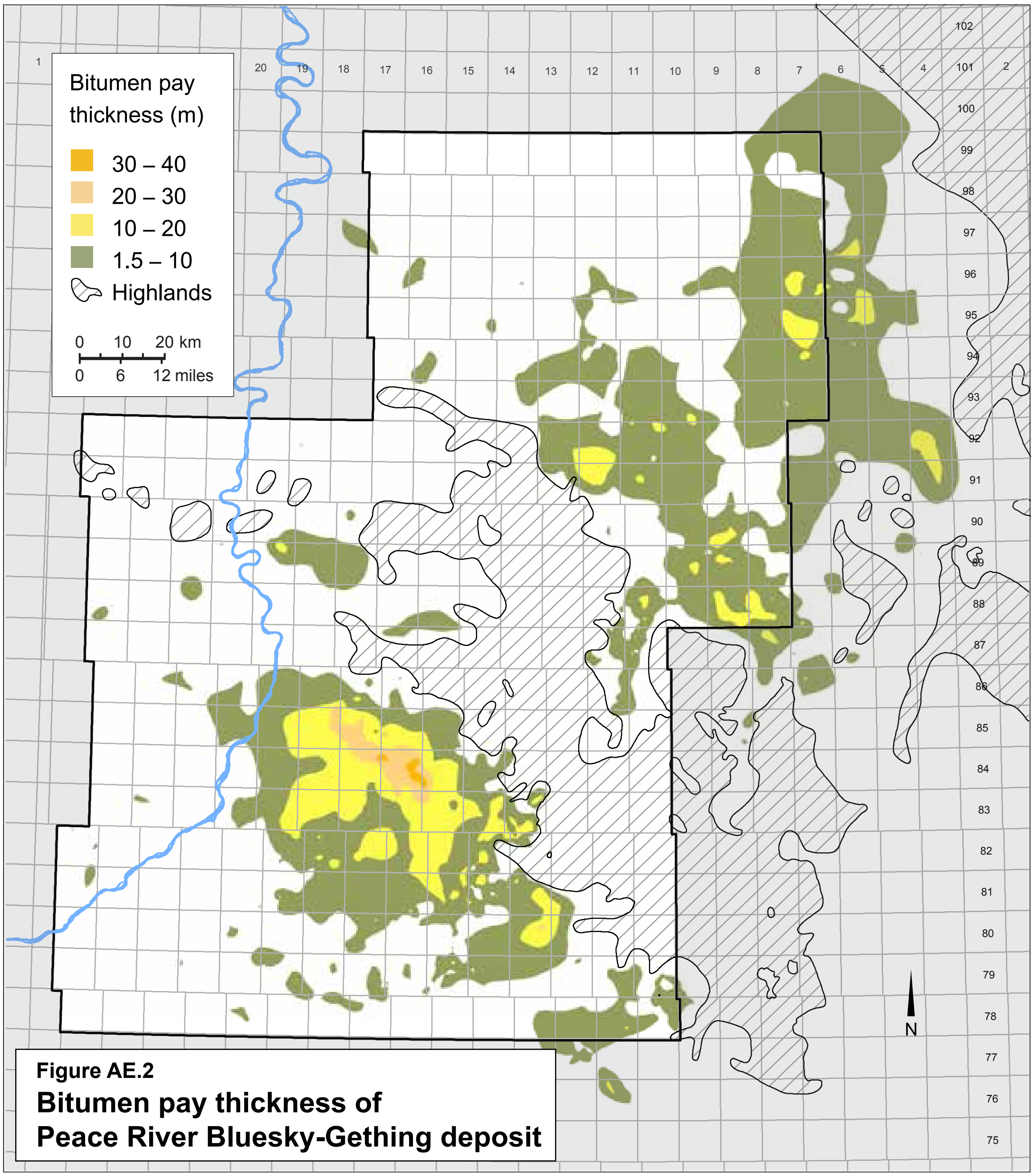


Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

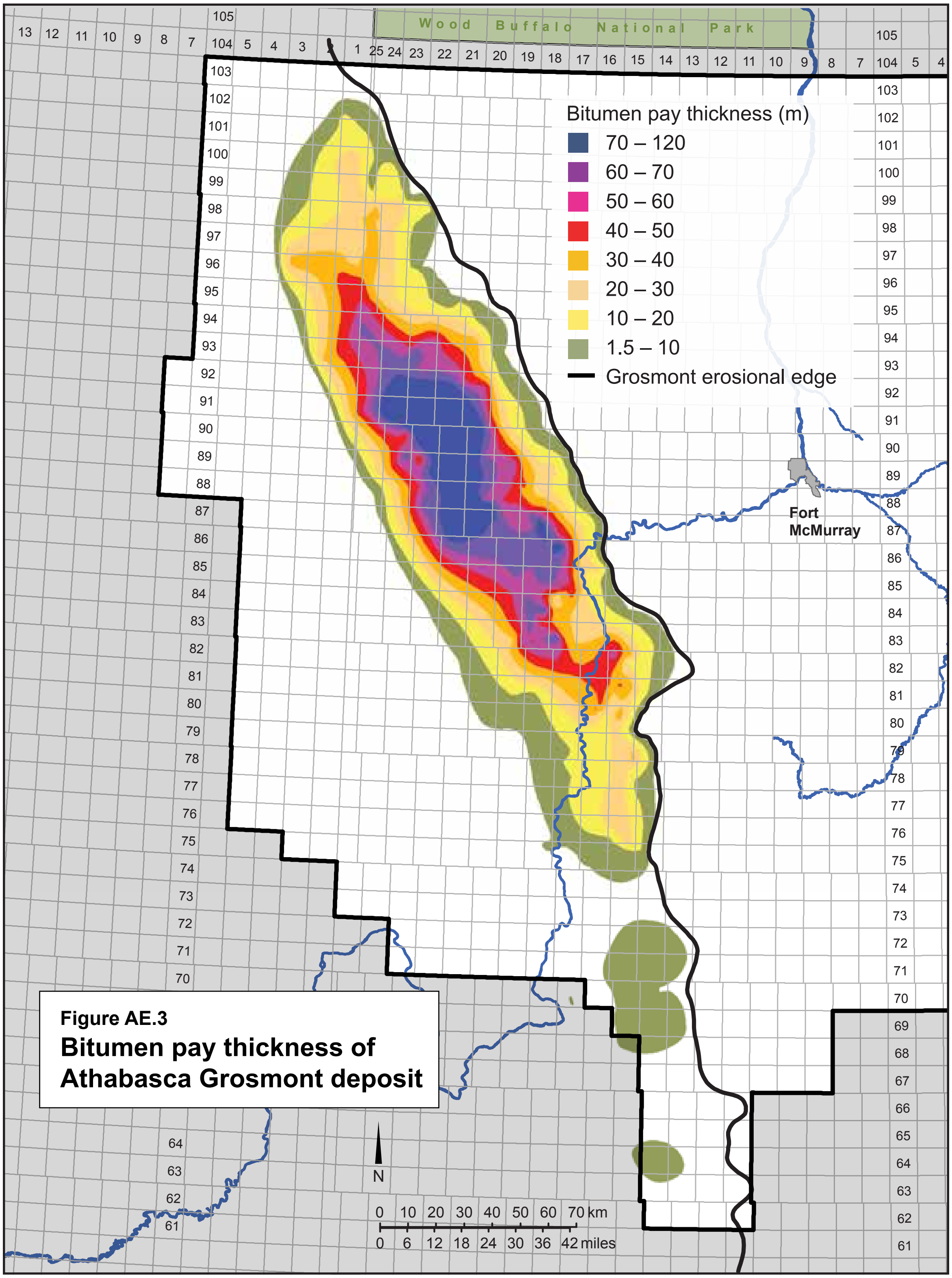


Figure AE.3
Bitumen pay thickness of Athabasca Grosmont deposit

E.3.2 Athabasca Wabiskaw-McMurray Deposit

In 2003, the ERCB completed a reassessment of the Wabiskaw-McMurray using geological information from over 13 000 wells and bitumen content evaluations from over 9000 wells to augment the over 7000 boreholes already assessed within the surface mineable area (SMA; see below for details). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added.

Figure AE.4 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval. Also shown is the extent of the SMA, an ERCB-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. This designation is for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside the area's boundaries, while in situ activities may occur within the SMA. Because the extent of the SMA is defined using township boundaries, it incorporates a few areas containing deeper bitumen resources that are more amenable to in situ recovery. The ERCB has generated a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is shown in **Figure AE.4**.

E.3.3 Athabasca Upper, Middle, and Lower Grand Rapids Deposits

The 2011 year-end review for the three Athabasca Grand Rapids deposits (Upper, Middle, and Lower), **Figures AE.5, AE.6**, and **AE.7**, included an evaluation of 3575 wells for stratigraphic tops and 1887 for reservoir parameters. The study area covered Townships 73 to 87 within Range 17, West of the 4th Meridian, to Range 1, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 8678 10^6 m^3 to 9274 10^6 m^3 for the Grand Rapids deposits. This represents a 7 per cent increase, which is attributed to an increased number of wells drilled in the area.

The Grand Rapids Formation is interpreted as a series of prograding sequences of shoreface sands and shales. Informally the formation has been divided into Upper, Middle, and Lower sequences, with the boundaries defined by laterally extensive marine shales (maximum flooding surfaces). The Athabasca Upper Grand Rapids accounts for the majority (approximately 60 per cent) of the bitumen-bearing sand within this formation (**Table 3.3**). The Grand Rapids Formation is bounded above and below by the marine shales of the Joli Fou and Clearwater formations, respectively.

E.3.4 Athabasca Nisku Deposit

The 2011 year-end review of the Athabasca Nisku Formation, **Figure AE.8**, included an evaluation of 560 wells for stratigraphic tops and 130 wells for reservoir parameters. The ERCB, in its evaluation of the Nisku Formation, included bitumen from the Blueridge Formation. The Calmar Formation is a shale within this deposit. Information to date indicates that the Calmar Formation is a potential baffle. The study area covered Townships 75 to 96

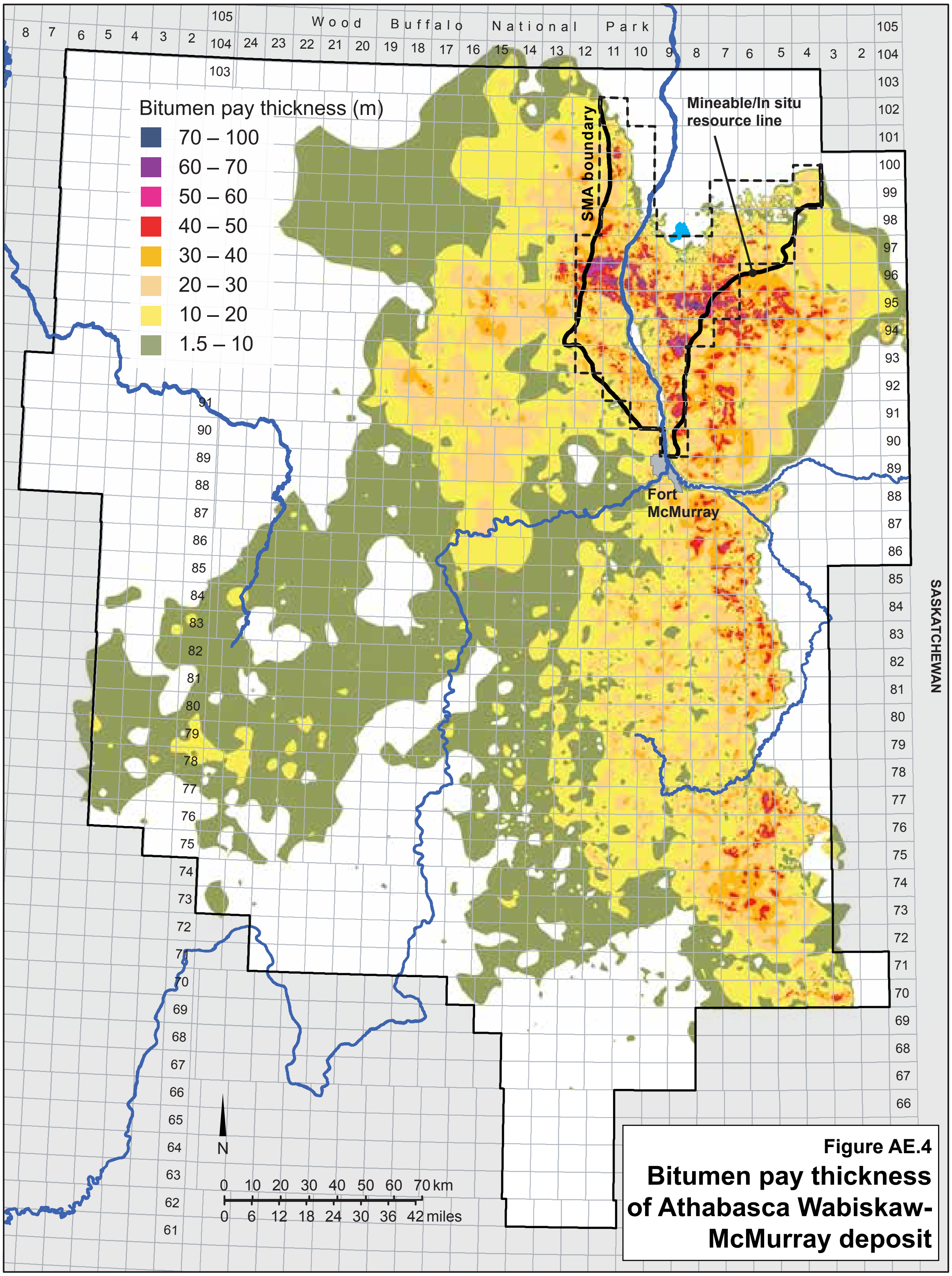


Figure AE.4
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

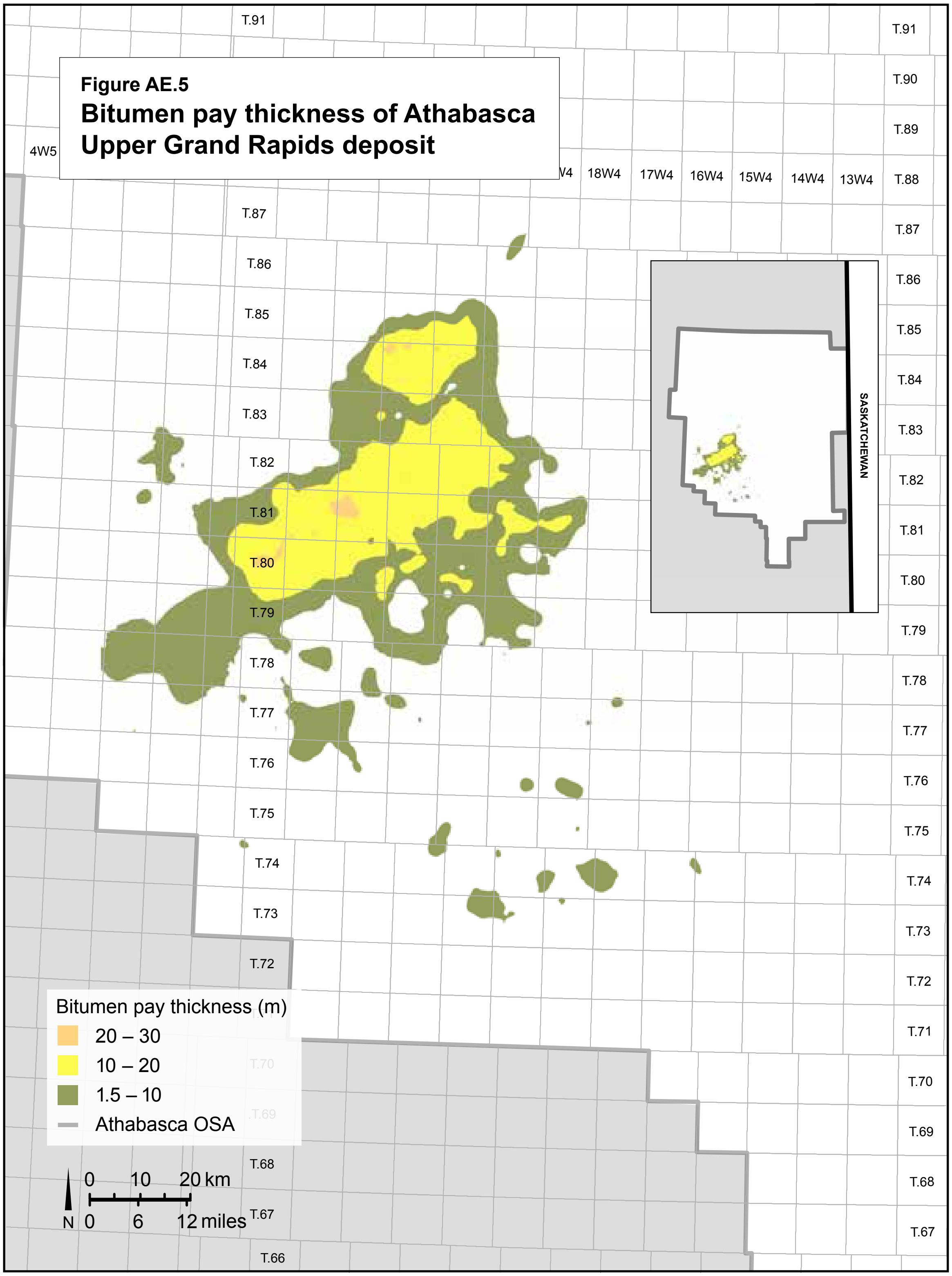


Figure AE.5
Bitumen pay thickness of Athabasca Upper Grand Rapids deposit
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
4W5
18W4
17W4
16W4
15W4
14W4
13W4
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66

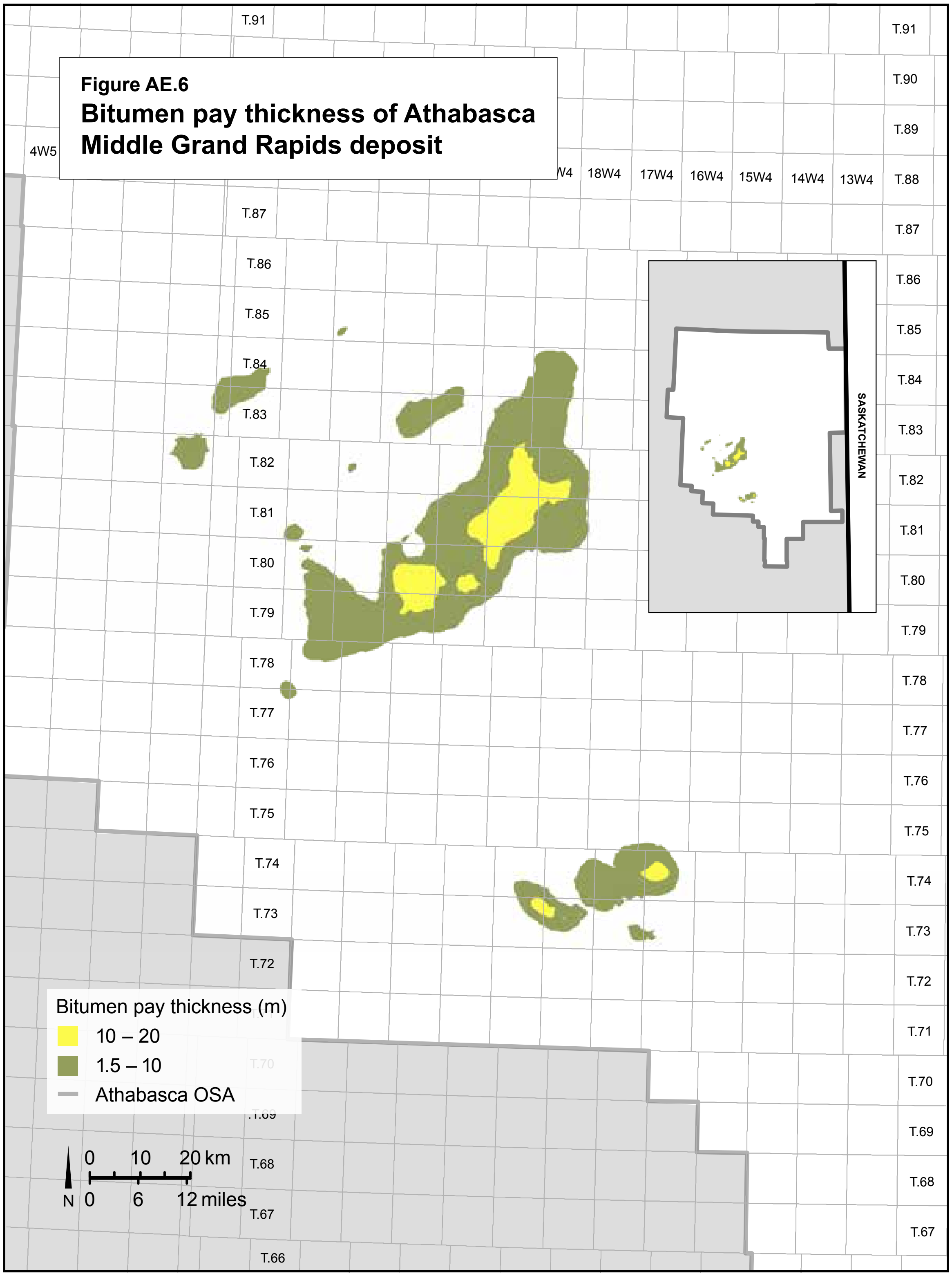
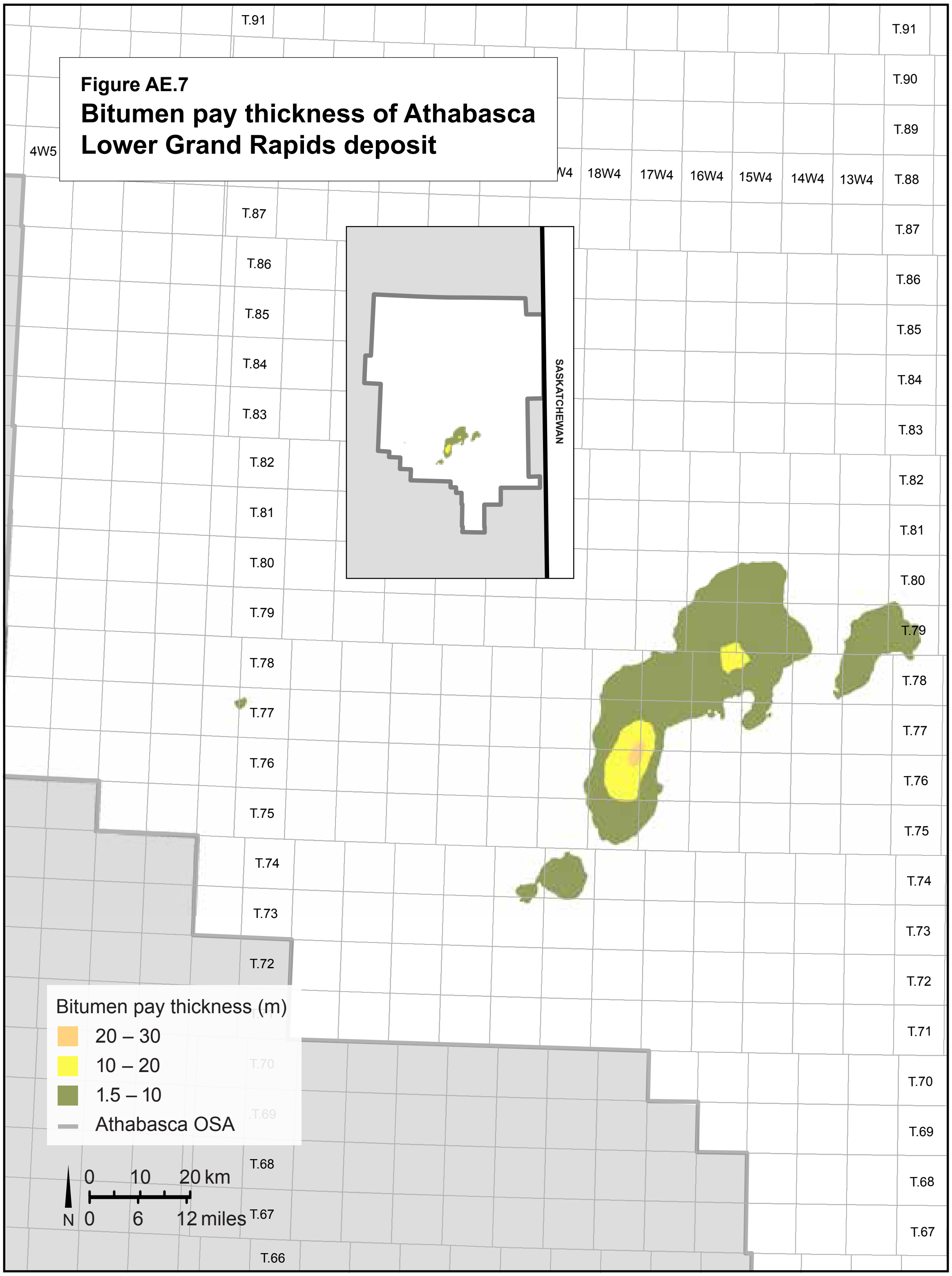


Figure AE.6
Bitumen pay thickness of Athabasca Middle Grand Rapids deposit
Bitumen pay thickness (m)
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
4W5
18W4
17W4
16W4
15W4
14W4
13W4
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66

Figure AE.7
Bitumen pay thickness of Athabasca Lower Grand Rapids deposit



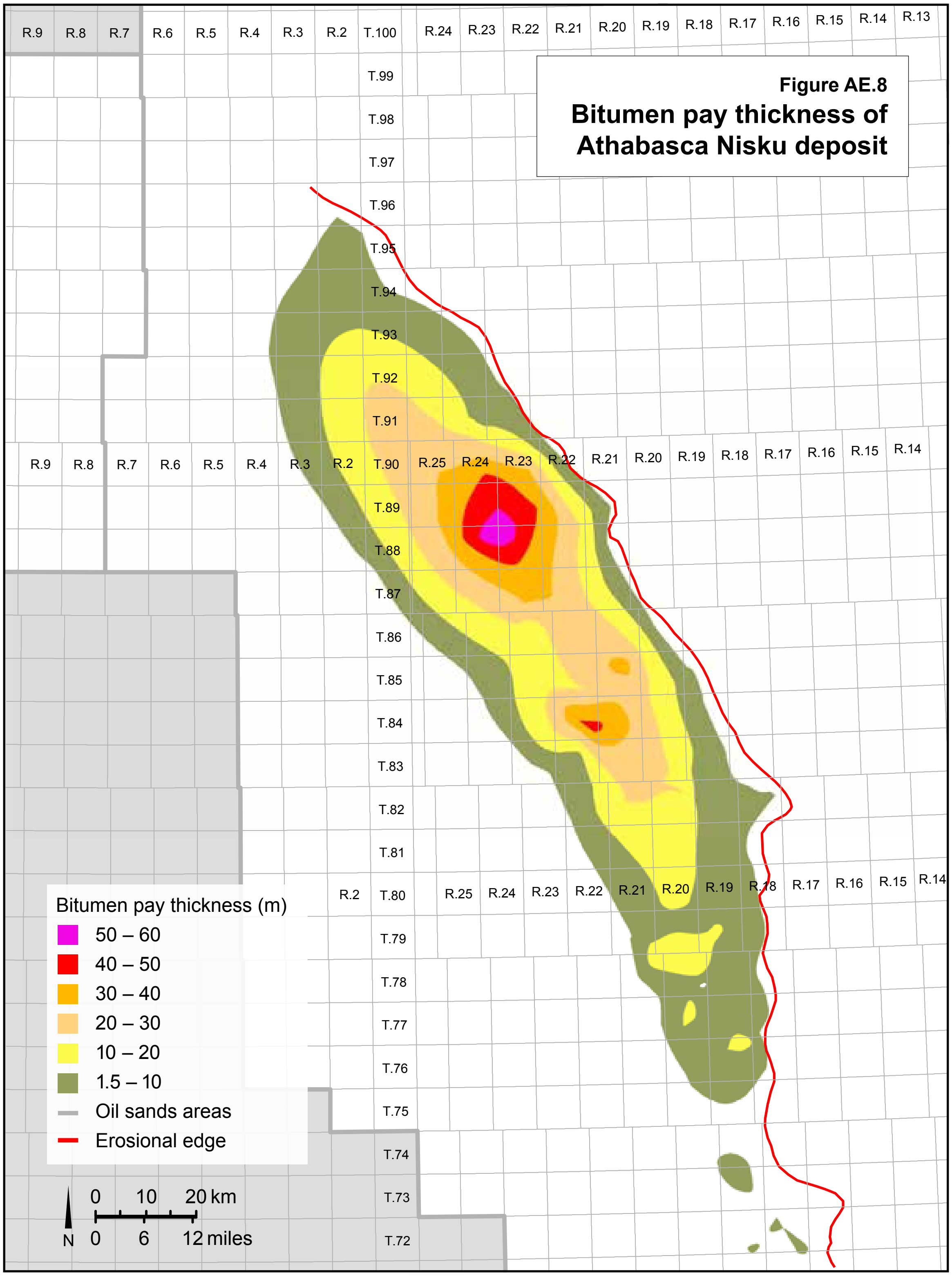


Figure AE.8
Bitumen pay thickness of Athabasca Nisku deposit
Bitumen pay thickness (m)
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Oil sands areas
Erosional edge
0 10 20 km
0 6 12 miles
N
R.9 R.8 R.7 R.6 R.5 R.4 R.3 R.2 T.100 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14 R.13
T.99
T.98
T.97
T.96
T.95
T.94
T.93
T.92
T.91
R.9 R.8 R.7 R.6 R.5 R.4 R.3 R.2 T.90 R.25 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
R.2 T.80 R.25 R.24 R.23 R.22 R.21 R.20 R.19 R.18 R.17 R.16 R.15 R.14
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72

within Range 18, West of the 4th Meridian, to Range 4, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 10 330 10^6 m^3 to 16 232 10^6 m^3. This represents a 57 per cent increase, which is attributed to an increase in well data and the expansion of the delineated resource area.

The Nisku Formation is a late-Devonian shelf carbonate. Early dolomitization and subsequent leaching of meteoric waters led to karsting and the creation of vugs and caves. The Nisku is a naturally fractured reservoir. Similar to the Grosmont Formation, the bitumen in the Nisku is contained in a triple porosity system within the vugs, the fractures, and the rock matrix. Hydrocarbons were probably trapped structurally along the updip erosional edge before degradation to bitumen.

E.4 Cold Lake Oil Sands Area

E.4.1 Sub-Cretaceous Unconformity

Figure AE.9 is a map of the reconstructed structure contours for the sub-Cretaceous unconformity in the northern part of the Cold Lake Oil Sands Area as they would have been at the beginning of deposition of the Mannville Clearwater Formation.

E.4.2 Cold Lake Wabiskaw-McMurray Deposit

For year-end 2005, the ERCB reassessed the northern portion of the Cold Lake Wabiskaw-McMurray deposit. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure AE.10** is the bitumen pay thickness map for the Cold Lake Wabiskaw-McMurray deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Although the Wabiskaw-McMurray contains some regionally mappable internal seals, and therefore several bitumen zones, this map was produced as a single bitumen zone to provide a regional overview of the distribution of the bitumen-saturated sands. A cutoff of 6 mass per cent bitumen was used.

E.4.3 Cold Lake Clearwater Deposit

For year-end 2005, the ERCB completed a reassessment of the Clearwater deposit. **Figure AE.11** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

E.4.4 Cold Lake Upper and Lower Grand Rapids Deposits

A reassessment for year-end 2009 of the Upper and Lower Grand Rapids deposits included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Township 52 to 66 replaced the area used in the previous assessment. Stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster.

Although crude bitumen within both Grand Rapids deposits is pervasive through much of the Cold Lake Oil Sands Area, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figures AE.12** and **AE.13** are maps of the cumulative net pay isopachs for the Upper Grand Rapids deposit and the Lower Grand Rapids deposit respectively. The net pay interpretations and volumetric calculations were completed for each zone and were then summed for the relevant deposit. The Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids.

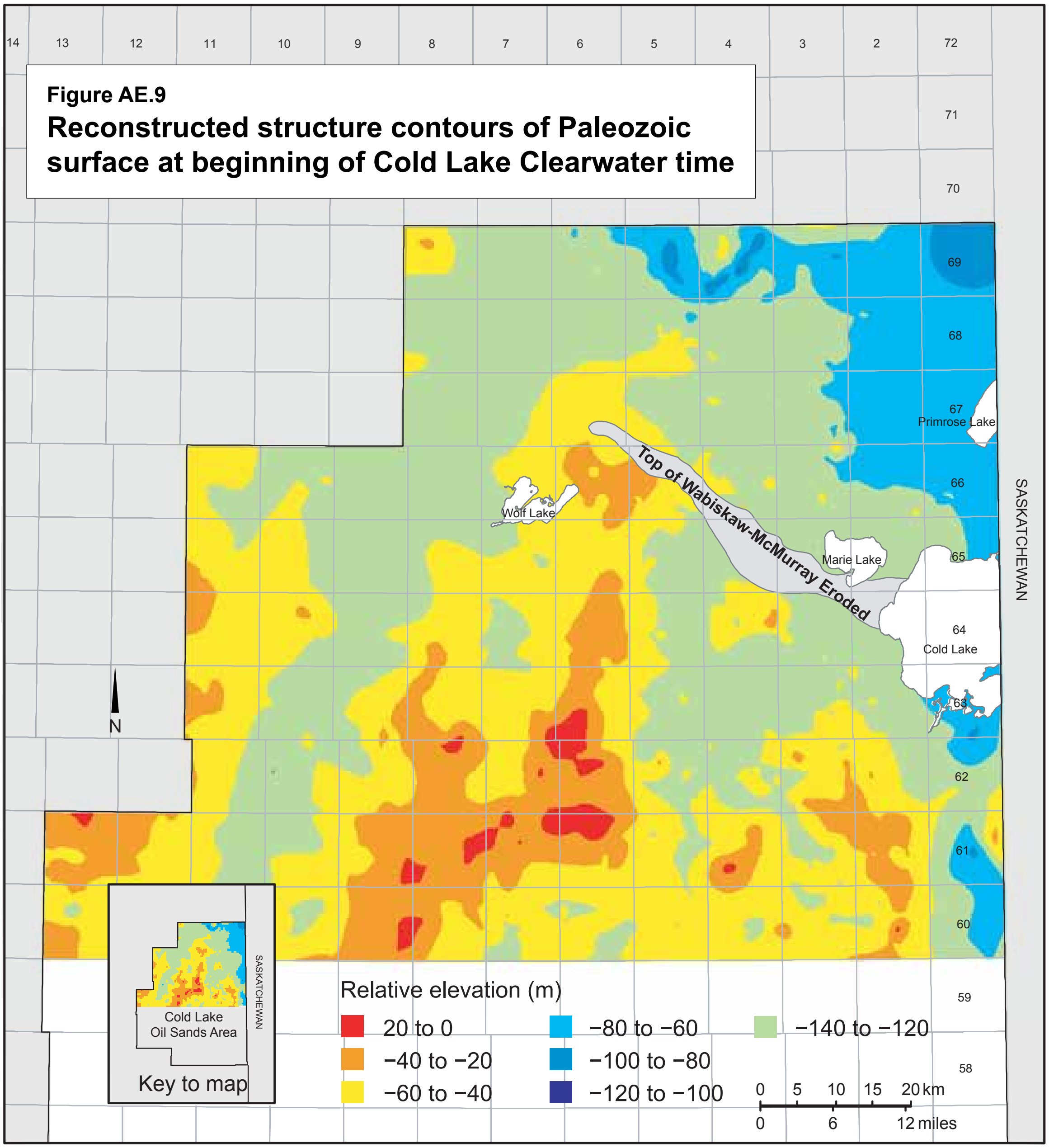


Figure AE.9
Reconstructed structure contours of Paleozoic surface at beginning of Cold Lake Clearwater time

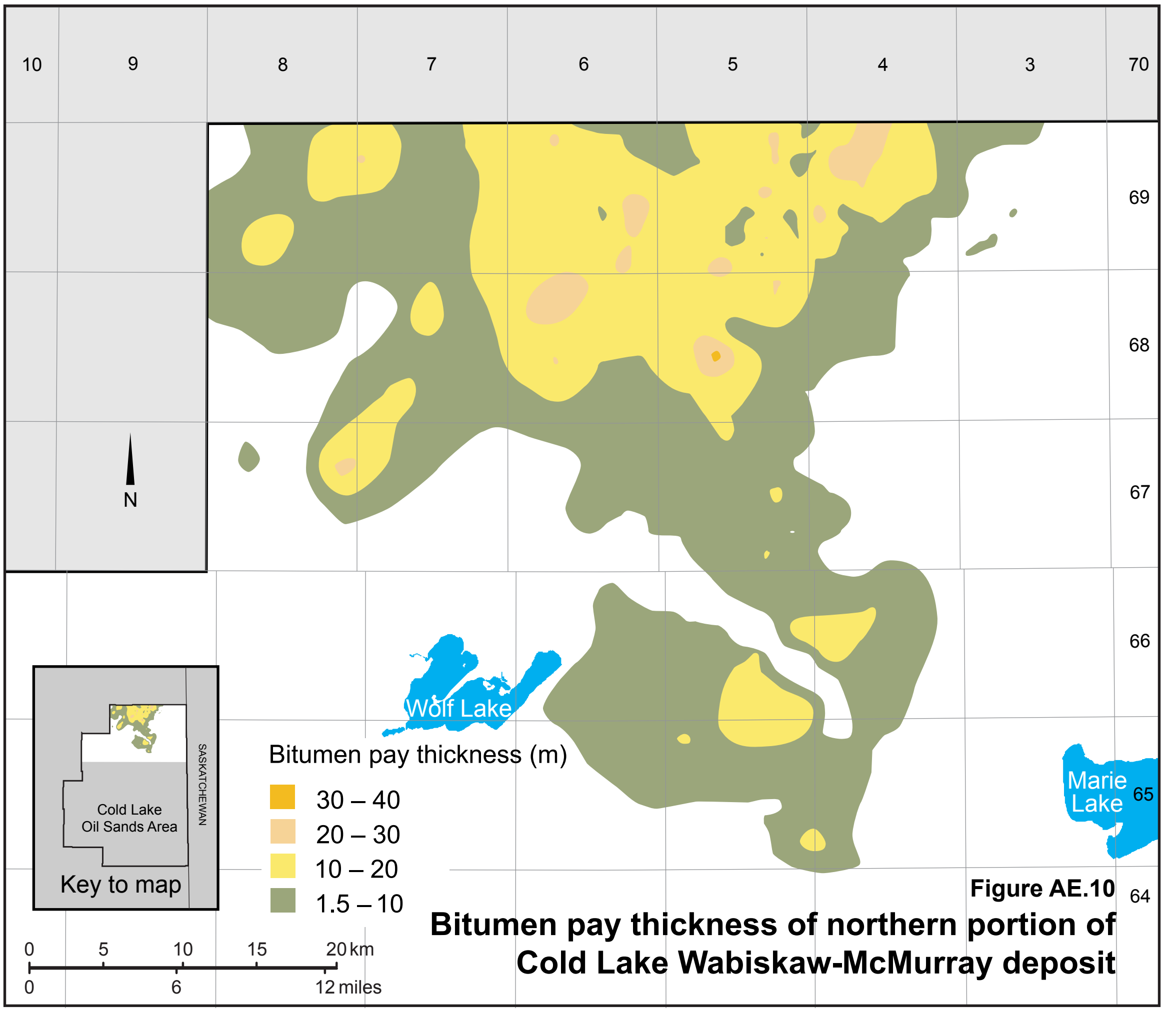


Figure AE.10
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

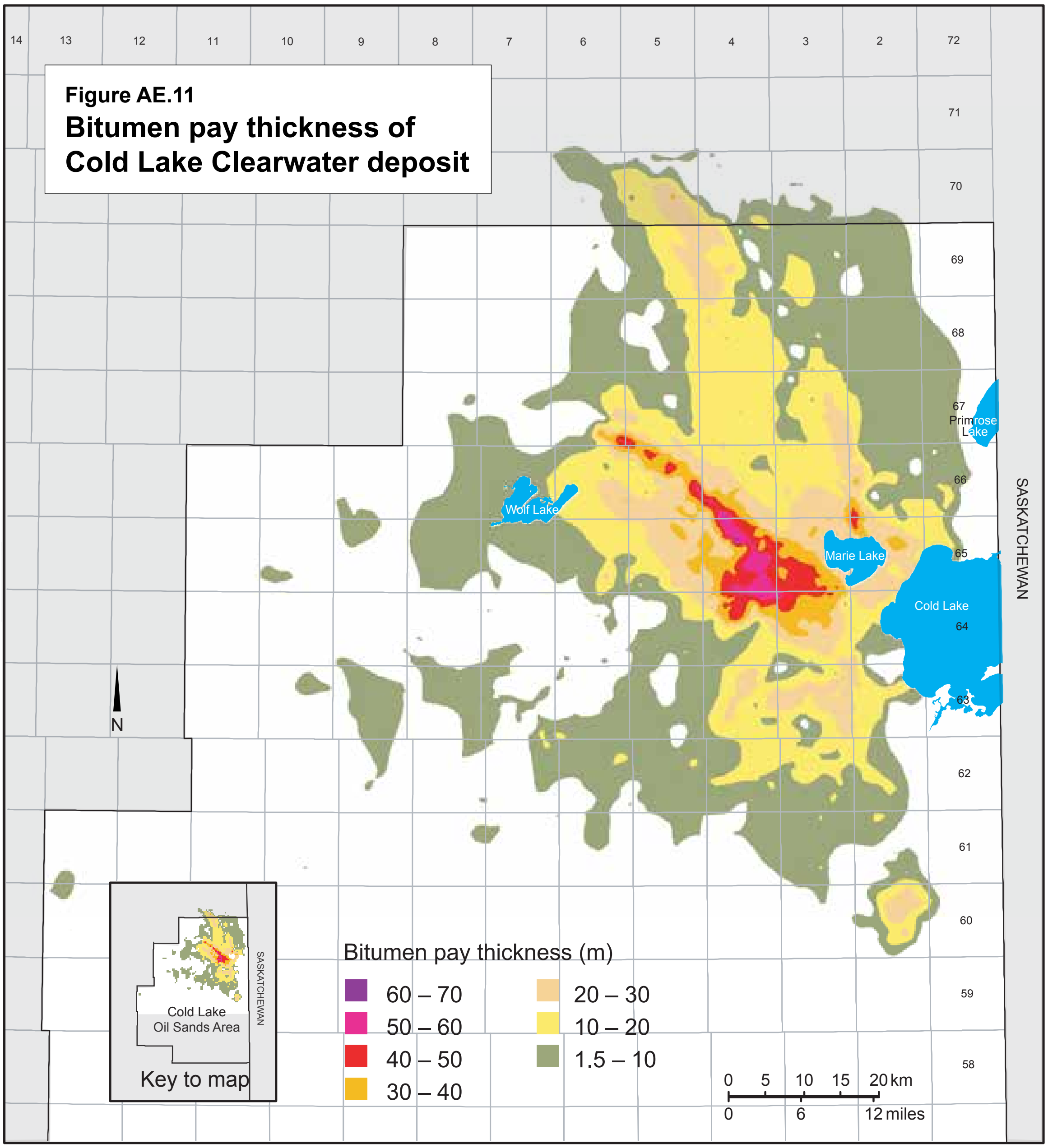
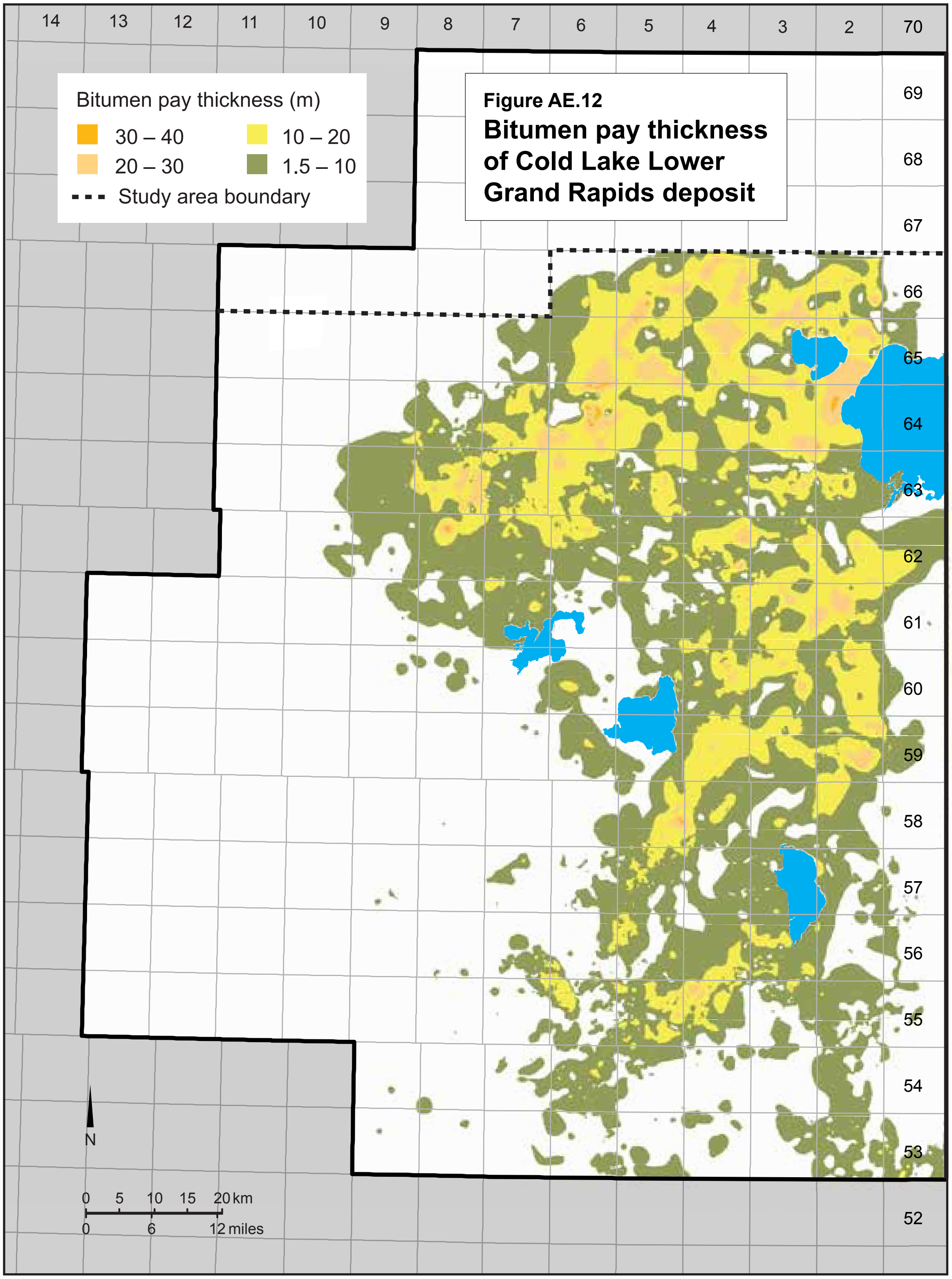


Figure AE.11
Bitumen pay thickness of Cold Lake Clearwater deposit


Bitumen pay thickness (m)
30 – 40
20 – 30
10 – 20
1.5 – 10
Study area boundary
Figure AE.12
Bitumen pay thickness of Cold Lake Lower Grand Rapids deposit
14 13 12 11 10 9 8 7 6 5 4 3 2
70 69 68 67 66 65 64 63 62 61 60 59 58 57 56 55 54 53 52
N
0 5 10 15 20 km
0 6 12 miles

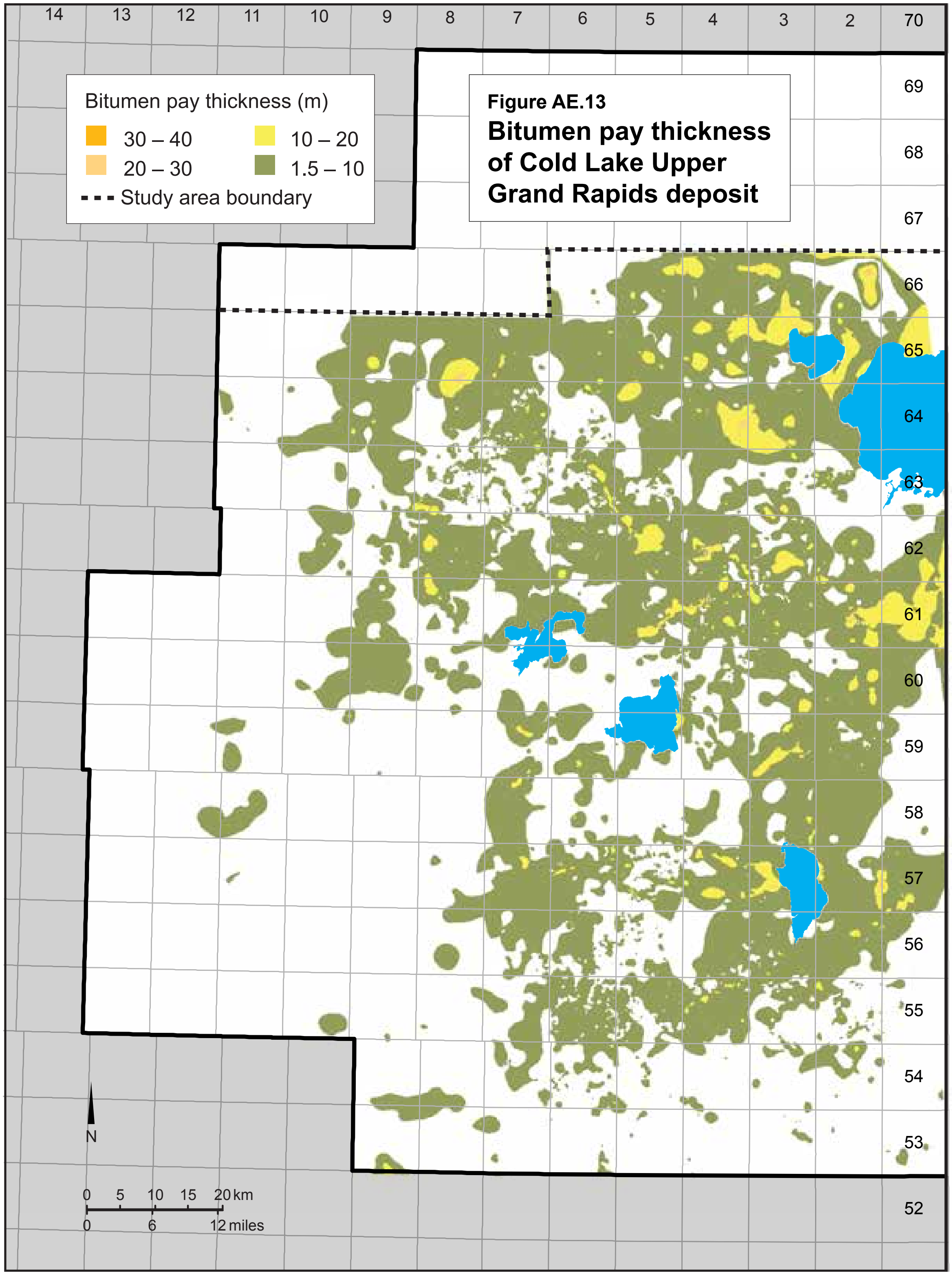


Figure AE.13
Bitumen pay thickness of Cold Lake Upper Grand Rapids deposit

Appendix F Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential

In 2012, the Energy Resources Appraisal Group of the ERCB completed a study entitled *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential* (ERCB/AGS Open File Report 2012-06).[1] The results of that study have been incorporated into this report, and the figures showing the medium (P_{50}) in-place resource values of natural gas, natural gas liquids, and crude oil for each of the six formations detailed in that study are shown in the six figures in this appendix.

[1] The study is available at the ERCB/Alberta Geological Survey's website at http://www.ags.gov.ab.ca/publications/abstracts/OFR_2012_06.html.

Figure AF.1

P50 gas, oil, and liquids initial in-place for the Duvernay Formation

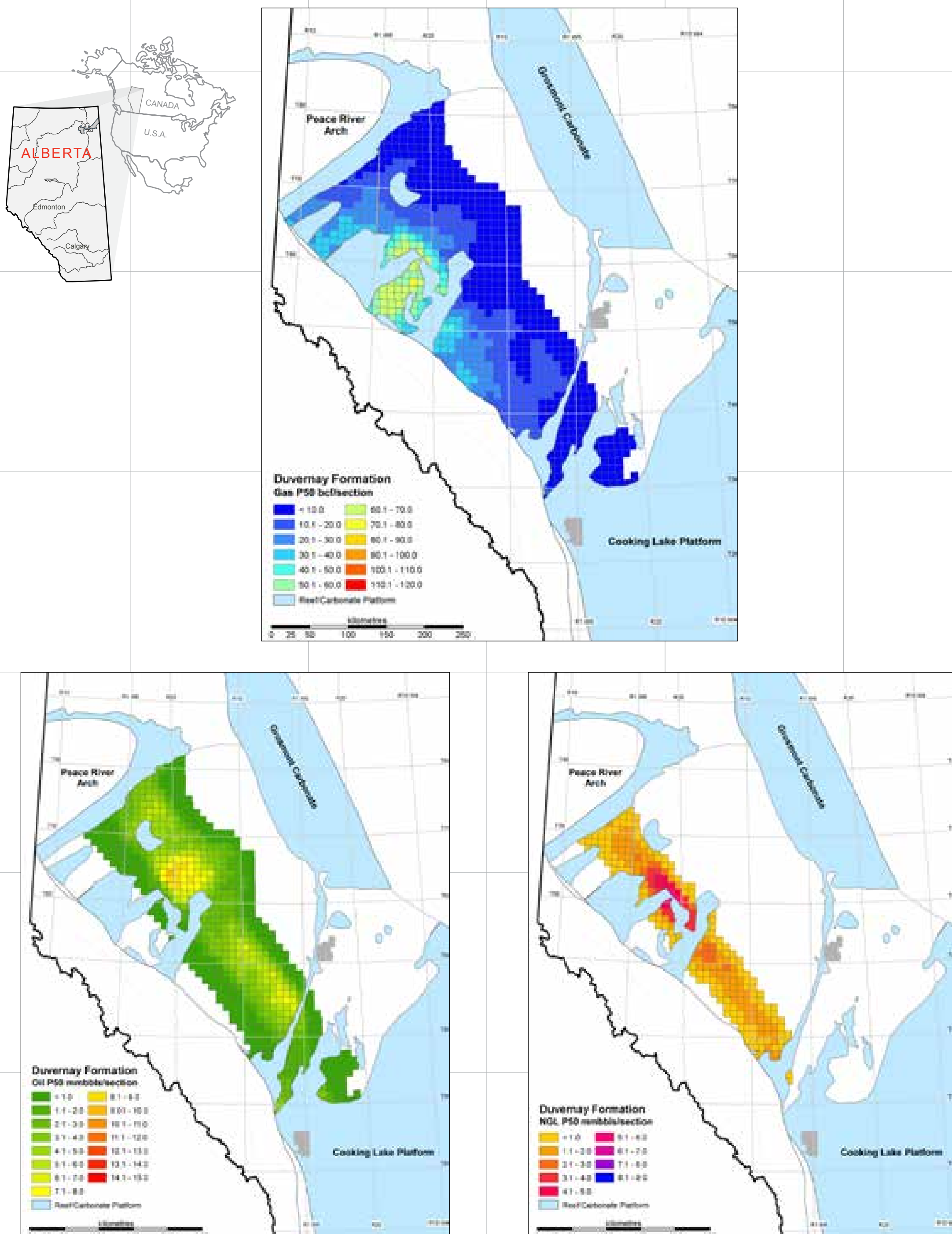


Figure AF.2

P50 gas, oil, and liquids initial in-place for the Muskwa Formation

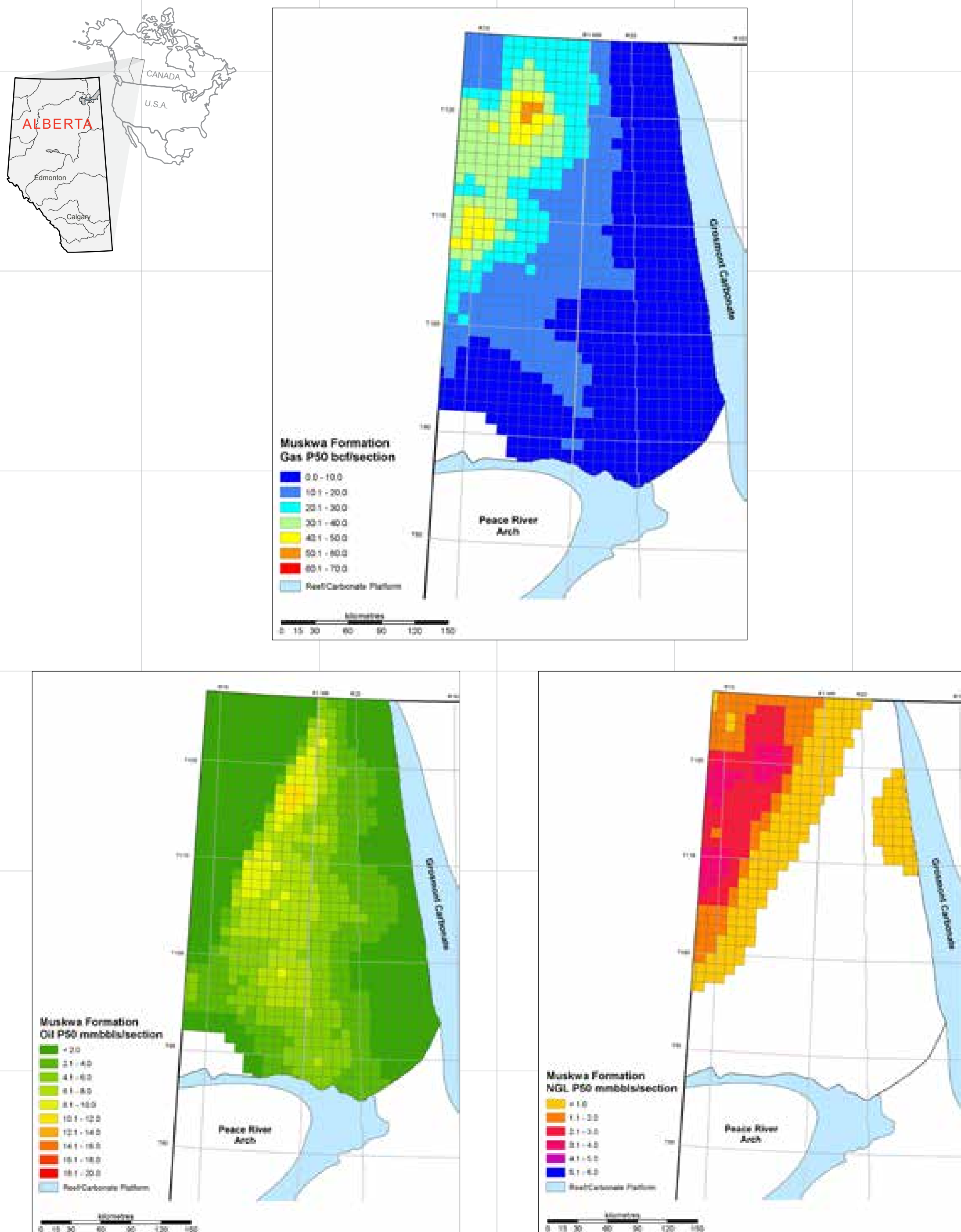


Figure AF.3

P50 gas, oil, and liquids initial in-place for the Montney Formation

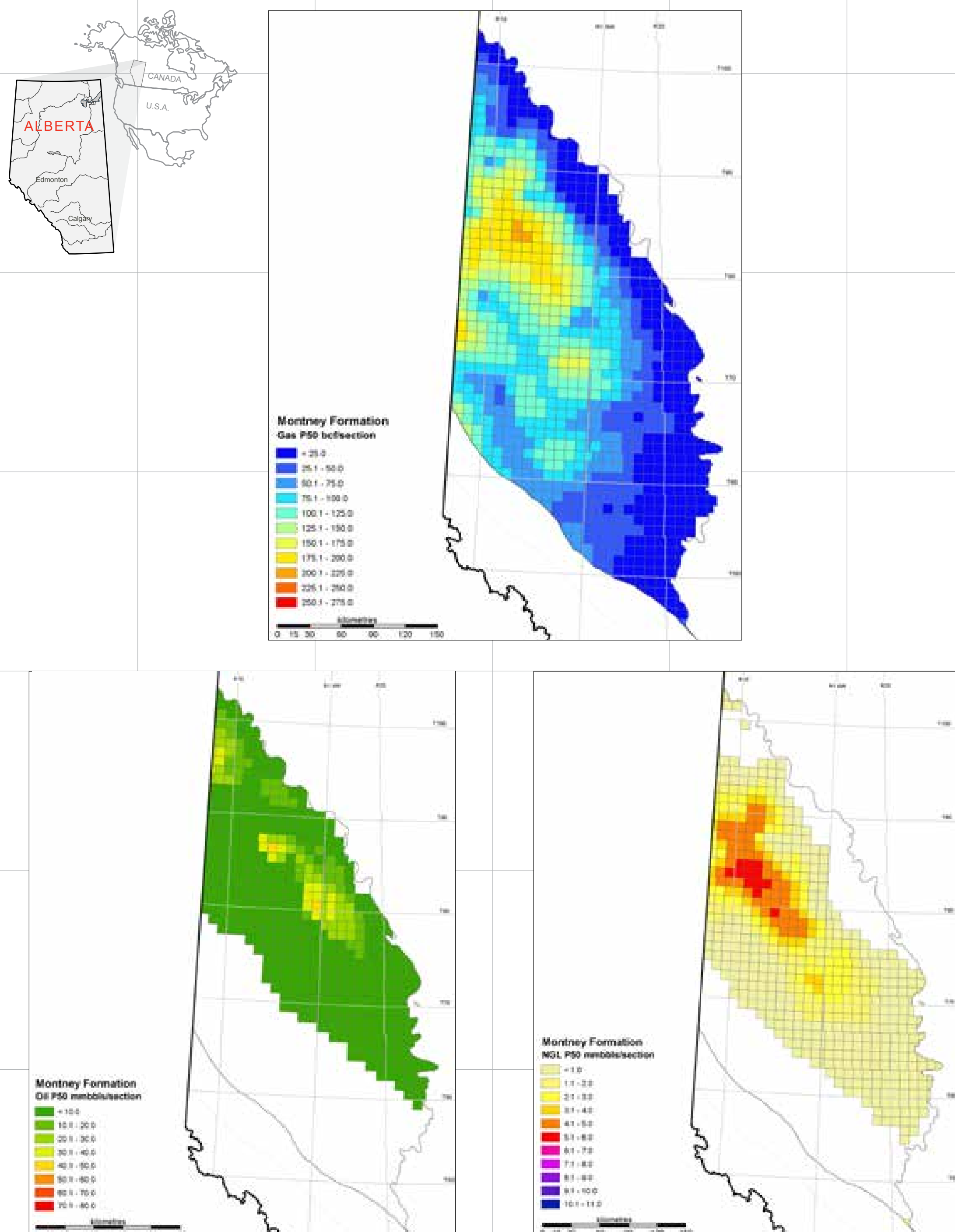


Figure AF.4

P50 gas, oil, and liquids initial in-place for the Banff/Exshaw Formation

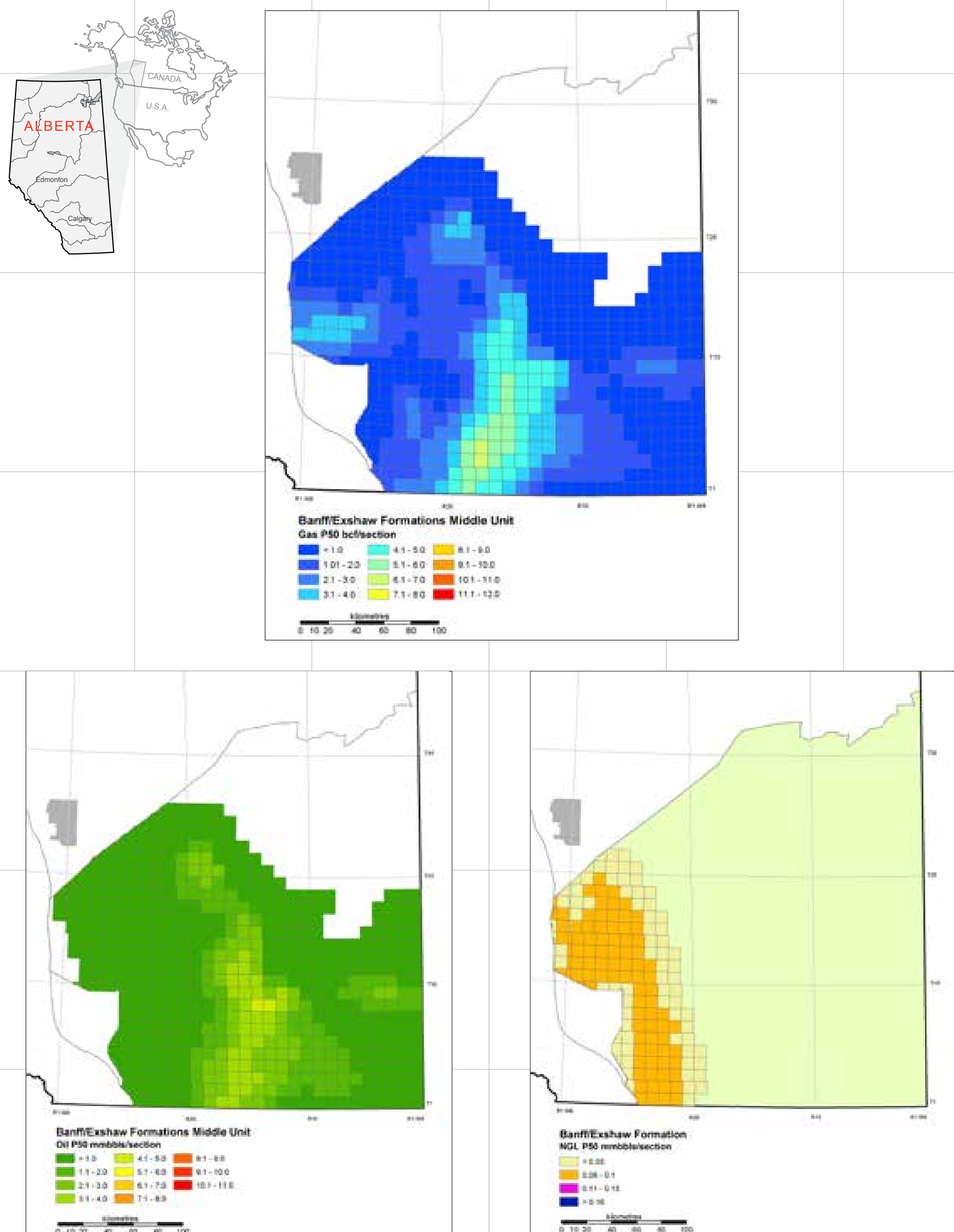


Figure AF.5

P50 gas, oil, and liquids initial in-place for the Nordegg Formation

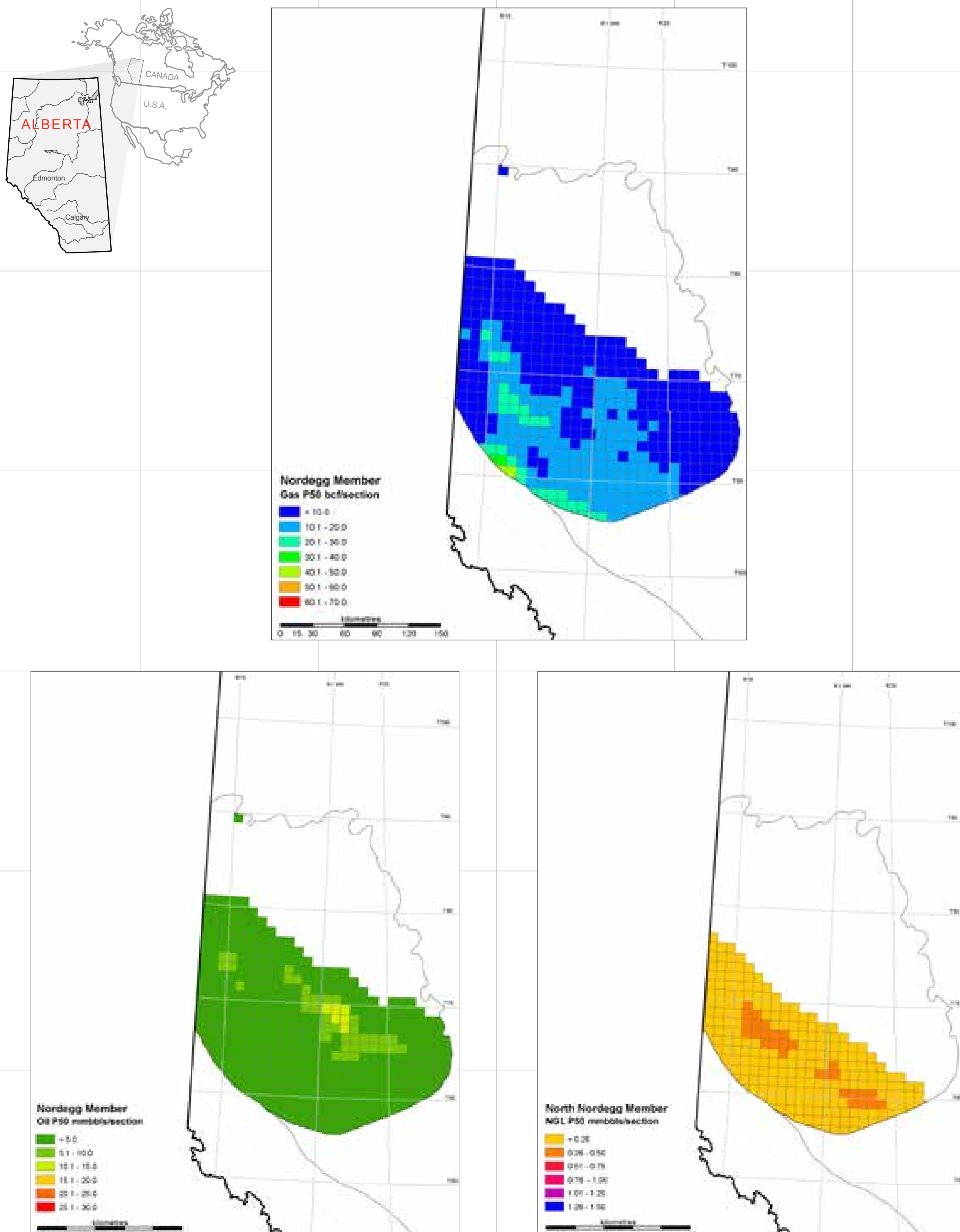
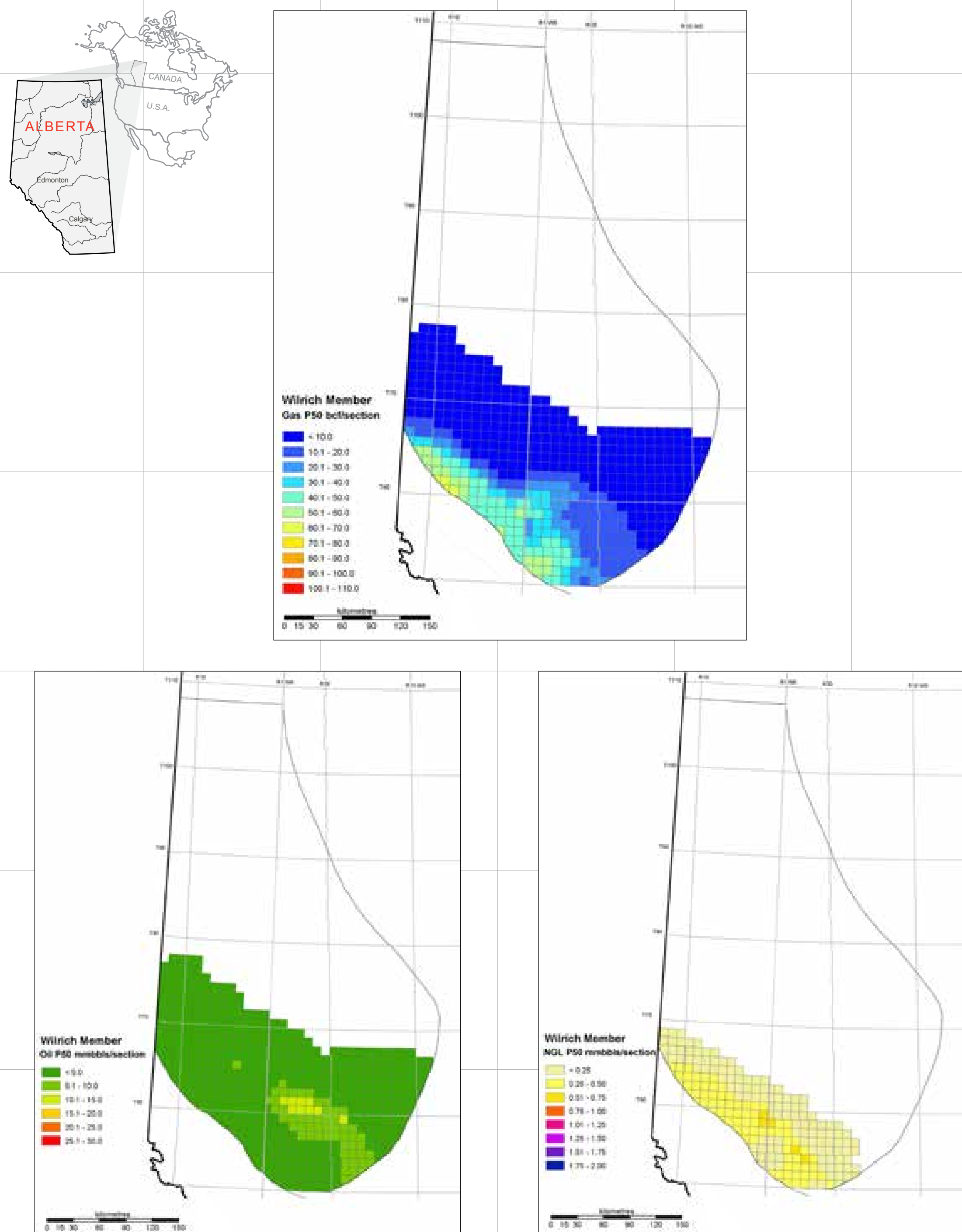


Figure AF.6

P50 gas, oil, and liquids initial in-place for the Wilrich Formation



Attachment 27

Attachment __. Valero Report to Investors; excerpts. Downloaded from:
http://www.sec.gov/Archives/edgar/containers/fix034/1035002/000119312513439300/d627324dex9901.htm

Attachment __. Valero Report to Investors; excerpts. Downloaded from:
http://www.sec.gov/Archives/edgar/containers/fix034/1035002/000119312513439300/d627324dex9901.htm

VALERO

Valero's Strategy to Supply Incremental Volumes of Cost-Advantaged Crude Oil

Gulf Coast Region

- Refineries mainly linked to cost-efficient pipelines
- Expect benefit as pipeline flows increase
- St. Charles refinery: expect to rail 20 MBPD of Canadian heavy crude by 1Q14 using Valero-owned rail cars and unloading terminal
  - Also, barge delivery capacity of 35 MBPD

West Coast Region

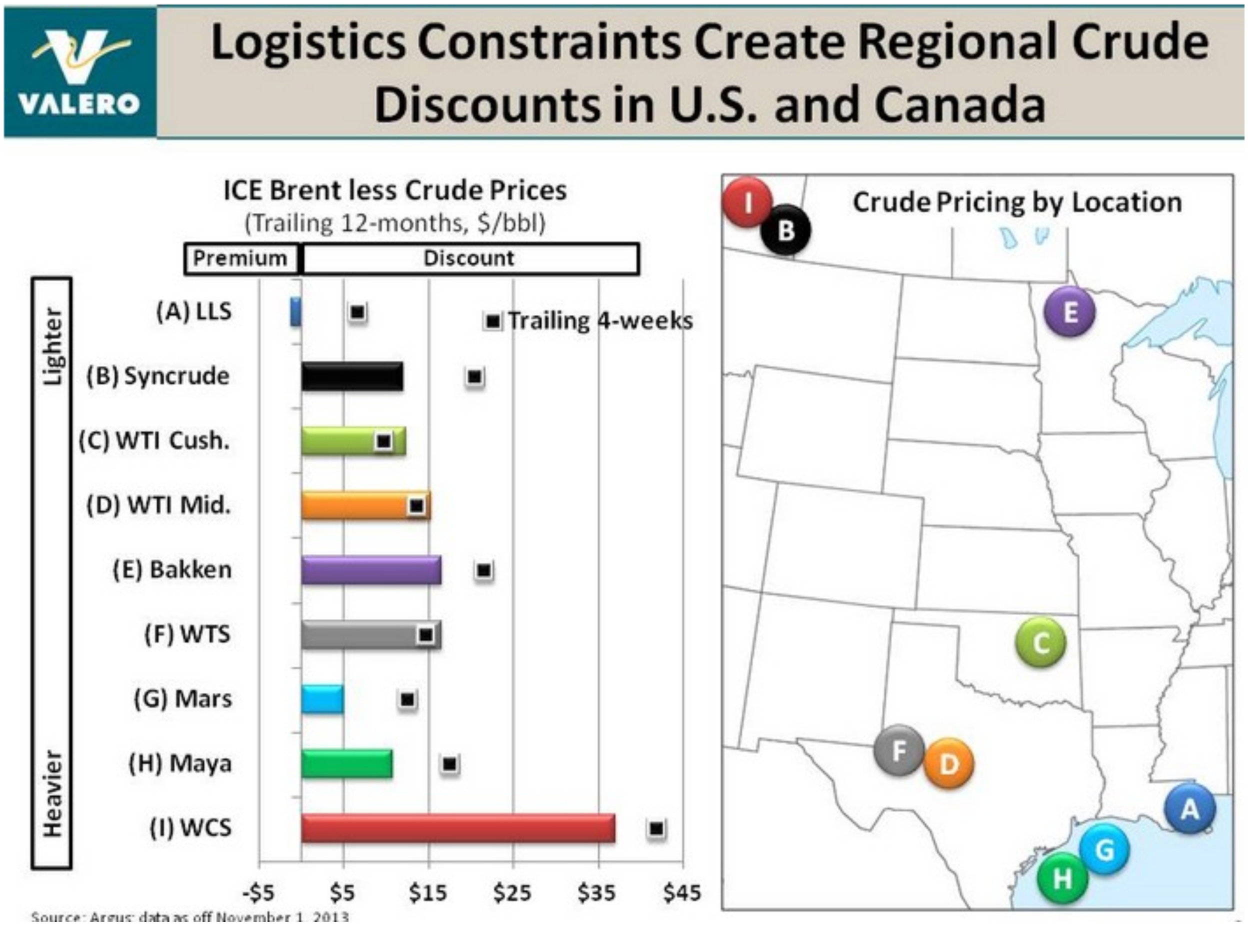
- Benicia refinery: Plan to rail a range of 30 to 50 MBPD of crude in 1Q15

North Atlantic Region

- Expect Quebec refinery to benefit and become supplied by U.S. and Canadian crude in three ways: rail, ship, and pipeline
  - Railing up to 30 MBPD of light crude started in August 2013, expect increase to 50 MBPD in 4Q13
  - Shipping Eagle Ford crude from Texas via lower-cost foreign-flagged vessels
  - Committed to receive substantial volume of light crude via Enbridge pipeline 9B and shuttled from Montreal by ship in 1Q15, based on Enbridge's revised timing

9

Attachment __. Valero Report to Investors; excerpts. Downloaded from:
http://www.sec.gov/Archives/edgar/containers/fix034/1035002/000119312513439300/d627324dex9901.htm



Attachment 28

Phillips 66
2013 Barclays CEO Energy-Power Conference
Greg Garland, Chairman and CEO, Phillips 66

Sept. 12, 2013
11:05 a.m. ET

Paul Cheng: Good morning. Our next presentation is Phillips 66, one of the largest and also most diversified downstream companies in the country. We are extremely happy to have their senior management team here. The speaker is Chairman and CEO, Greg Garland. Without further delay, let me welcome Greg.

Greg Garland: Good morning, everyone. It's a pleasure to be with you here today. Paul thanks for being a great host for us. We're glad to be back at Barclays and for the people in the room, thank you for the interest in our Company.

This is the obligatory Safe Harbor statement. We may make forward-looking statements today during the presentation and in the course of the question-and-answer session later today. Actual results could differ materially. The sources of those differences are right here on this slide and with our filings with the SEC.

So, I've been in the energy business for 33 years and I can't think of a more exciting time to be in this business. Think of what's happening in the changing American energy landscape, technology-driven access to shale and we look at the natural gas, the crudes and the natural gas liquids expansions coming at us and we look at where the assets at PSX sit, we think we're uniquely positioned to participate in this American energy landscape and the revolution in energy that's going on in our country today.

And so our question is- how do we take advantage of that and how do we lever that and capitalize on that as Phillips 66? And as we look at our strategy, it hasn't changed since I talked to you last year. We still think this is the right strategy for our Company and it starts with operating excellence and for us, that's to be one of the safest companies in the industry. Every employee, every contractor goes home safe every day. We manage our environmental footprint, we manage our costs; we run reliably.

We believe that is essential to sustainable value creation at Phillips 66. So you'll hear us talk a lot about this because this is job one and you pay us to do this job very well every day.

Secondly, I think the infrastructure development around the shales, the opportunity for the chemical is clearly our growth avenues for our Company. We have opportunities to improve returns in the base business in refining. Also, as we shift investment into higher-returning, higher multiple-valued businesses, then we can create total shareholder return value, too.

Distributions are fundamental to who we are. We've raised the dividend 56% since we formed the Company. We've got a $3 billion share repurchase program underway. And then finally, just in terms of strategy, high-performing organization; a high-performing organization is an organization that knows how to win. It's an organization that knows how to capture value from existing assets and create value from new assets, and simply put is an organization that is inspired to do their very best and achieve their very best every day. And so our 13,500 employees are well engaged and well committed to doing that every day.

Let me just talk about operating excellence for just a minute. We have a strong history and legacy of great operations at Phillips 66 Company. You can look at the results across our three major business platforms in 2012. Each segment was among the very best in its respective industry segment. We've continued that trend into 2013.

The other thing I would say is the industry and also our Company has done a really good job managing our environmental footprint. We've got a great story to tell here. We need to do a better job of telling it. But you can see the chart on the right, which is SOx, NOx and particulate emissions. We've made great progress in terms of reducing that footprint.

So this is a four box on strategy; the units across the top are our growth areas in Midstream and Chemicals. As we think about Midstream, we think $100 billion of industry investment in infrastructure and logistics. And we want to build on our integrated transportation system. We want to use the Phillips 66 Master Limited Partnership as a vehicle to help fund that growth. We'll continue an aggressive program of growth at DCP.

As we think about Chemicals, we've got great organic growth opportunities in North America in the Chemicals business. CPChem has a great platform of proprietary technology, great marketing, global reach in terms of their marketing ability and so you think about access to low-cost feedstocks- the Middle East and North America extremely well positioned.

As you look to the bottom chart, our Refining strategy is to improve returns across that. We're focused not on growing capacity in refining; in fact, you're going to see us be very disciplined about the investments that we make in the refining business. Our view is that our North American assets and our European assets; the markets are flat to declining and we won't invest in capacity additions. We will invest in infrastructure on the front end to capture advantaged crudes, on export infrastructure on the back end; we will invest in quick-hit 40%-type return projects, which we'll talk more about today.

But this is an area of ROCE improvement for us and we have programs in place to improve our base return on a price-normalized basis.

Our Marketing and Specialties business is a great business. It generates about $1 billion a year of EBITDA. We like these businesses. When we look at our retail businesses in Europe, we look at our wholesale business in the U.S.; that we have a lubes business that is a very good business and we'll seek to grow that business and grow our other specialty businesses, including our flow improvers business.

Historically, Refining represented about 50% of our earnings. As we move forward into the future, we want a company that you look at and you see a company that is more marketing and specialties, more midstream logistics, transportation and more chemicals. So five years from today, Refining will be less than 50% of our income and it's not necessarily that it's going be so much smaller, but these other businesses are going to get larger and we think we create shareholder value by shifting the overall portfolio into higher-returning, higher EV-type businesses.

So we like our assets. We like all the platforms we have. We look at the Midstream and we look at the Chemicals; you look at our Refining and Marketing and as we benchmark that, we still think return on capital employed is a good benchmark. We use it as we allocate capital. We use it as we look at the portfolio and the changes we want to make in the portfolio. And these are some of the best assets out there today in terms of return on capital employed.

Just a couple comments about the macro environment, and this gets back to our strategy. As we look at what's happening in the North American energy landscape, we think natural gas is going to go from about 65 billion cubic feet a day, to about 78 billion cubic feet a day in 2020, 3 million barrels a day of new light sweet crude coming on in North America coming at us, natural gas liquids growing from 2.5 million barrels a day to over 3.5 million barrels a day. So this growing domestic crude supply, natural gas and NGLs is creating opportunities; creating opportunity for infrastructure investments, it's creating opportunity to capture advantaged crudes and get them to the front of our refineries, it's going to create opportunities for us to grow our Chemicals business long term.

We think over $100 billion of industry investment in infrastructure is going to be made over this period of time to gather the gas, process it, get the NGLs to the market centers, move the crude to where it needs to be to the liquid markets.

A word about the macro environment for our Chemicals business; you know, you look at the forecasts for ethane supply growth anywhere from 600,000 to over a million barrels a day of new ethane supply that are coming on. You look at the cost curve on the right-hand side of that chart and it tells you that the Middle East and North America are the two best places to make petrochemicals today. And fundamentally, as we look at the olefins, polyolefins business and petrochemicals business, we think it remains a very attractive place to invest. We think we have a good platform to invest through our CPChem business and really it's based upon growing demand for the products. So the products are growing at some multiple of GDP and then access to affordable, reliable, secure feedstocks.

Looking at Refining, I always say this. This is business always has been, it is today and I can almost assure you with absolute certainly, it's going to be a volatile business in the future. And it's difficult to predict these dips and these spreads day to day, quarterly; but if we back-up and think over longer periods of time, we think that we've got crude coming at us, we've got NGLs coming at us and you think about 3 million barrels a day coming on in the Midcon area of the U.S.

We think transportation infrastructure ultimately gets built. It clears north and south. So as we think about what happens, we go back to the marginal cost of transportation to move these crudes east and west as they clear. And so we tend to think of WTI to Brent in a range of $6 to $10. We tend to think of LLS discounting to Brent in a range of $2 to $4.

You think about, as that crude shows up on the U.S. Gulf Coast; and what's the impact? So all that light sweet crude shows up; ultimately you satiate the demand or the ability of the industry to consume the light sweet crude. And then you have to start incenting the refiners- just go to the light sours or even the medium crudes or you start moving to the East and the West Coast.

So we think, by the end of next year, that North American sweet production will be displaced; all the imports of light sweet crude in the U.S., certainly in the Gulf Coast. And then this is kind of our idea of the timeline as you move across from left to right.

So let me talk about each segment if I can, and I'm going to start with Midstream. The strategy is growth for our Midstream businesses. And what we want to do is build on our integrated transportation system at Phillips 66. We do intend to leverage Phillips 66 Partners as one of the primary vehicles or tools that we use to accelerate investment in our own infrastructure in midstream businesses. There's no question that we'll continue the aggressive growth program at DCP and we'll talk about DCP in just a minute; but we'll continue to use the MLP at DCP to fund growth at the DCP level.

On Transportation we've talked a lot in the past about the rail cars, the acquiring of 2,000 rails cars, the two Jones Act ships, the unit train unloading facility; so we're looking at unloading facilities at Bayway is under construction, at Ferndale is under construction. We're looking a new 17,000 to 20,000 barrel-a-day unloading facility at Santa Maria in California.

One thing I would say to you today that- one of the things MLP has done for us; it has reoriented our thinking. As we've looked at our Transportation historically, we treat it as a cost center, we treat is as a service center to really service the refineries and the marketing folks. We're starting to think about this-- this is a business and we have opportunities to expand and grow this business. We're looking at idle pipes that we've had that may have been in NGL service. Now we can convert those to crude service, put third-party volumes through those pipes.

We're looking at new storage facilities at our refineries. We're going to build a 500,000 barrel-a-day tank at Los Angeles so that we import crude and advantaged crudes into California for our Los Angeles area refineries.

We talked about PSXP- has a piece of pipe that runs between Sweeny under the Houston Ship Channel and can connect to the Magellan and Kinder Morgan systems. And so we'll be reactivating that line for PSXP.

So it's a change in mindset for us. It's a good change for us. It's a change that needed to happen and it's been liberated by our new MLP. So lots going on in the transportation area; and as you know, we have a significant amount of assets in this space and there's optimization to occur here.

So we announced PSXP partners and got the IPO out in July, ahead of our original schedule. I would say we're very pleased with the IPO to this point. The MLP PSXP will own, it will develop and it will acquire primarily fee-based assets in transportation and midstream. We look at it as a low-cost source of capital. We look at it as a tool in our toolbox that we can grow our midstream and transportation infrastructure faster than we might normally otherwise would have.

It's an opportunity for the PSXP to purchase assets from Phillips 66 in the transportation space. We have a large portfolio or inventory of assets that can be dropped into the MLP. Certainly at some point in time, PSXP achieves the scale that it can step out and do its own projects. We do envision that we will make investments at the PSX level. We'll incubate those and we'll drop those into the MLP with time.

As we think about the MLP itself, we're going to target the top quartile of distribution growth for Phillips 66 Partners and I would say in the early years you expect it might actually be above top quartile, because we're growing from a relatively small base.

Moving on to DCP Midstream; this is our joint venture with Spectra. This is a great joint venture. It's 50/50. It's 13-14 years of relationship. It's been a significant source of growth for us in the midstream. The big pipes- Sand Hills and Southern Hills are completed. They're in service. Volumes are ramping up over the next two to three years on these projects. We're completing the gathering systems, the gas plants; you can see them all listed here, including completing Front Range in Texas Express pipelines.

So when you look at the DCP footprint, it's a great footprint. The legacy assets set over some of the best plays from the Permian down to the Eagle Ford to the Gulf Coast, up to the Midcon, up to the DJ in Colorado. We have about $2 billion to $4 billion of projects in flight at DCP over the next couple of years that we will execute. We will use partners, DPM, to fund a lot of this growth that we have at DCP Midstream. That's consistent with what we've been saying of DCP. So DCP is executing well. Their growth projects are on track and executing a large program very good.

As we look at our Midstream business at Phillips 66, of course we took a one-third interest in Sand Hills and Southern Hills; so the EBITDA is starting to flow through those. I think one of the things that we're looking at accelerating is our own frac and export facility. So we're looking at a world-scale, 100,000-barrel-a-day frac at our Sweeny complex, all the associated pipelines and cavern storage at Clemens and then ultimately connecting that with an export facility at Freeport which would be propane, butane and condensate.

This is a $2 billion to $3 billion investment. Ultimately, we expect this would generate $400 million to $500 million of EBITDA, and this would be an asset that would be destined for the Master Limited Partnership. I would say there's a lot of interest in this facility; so our idea is we create a new hub outside of Mont Belvieu, so a lot of interest from international and national, in terms of having ability to export condensate material, ability of the petchems, as you think kind of west of the Houston Ship Channel; for feedstocks for the next round of crackers that people are thinking about and looking at.

So we would expect that the frac would up in the 2015 timeframe and that the export facility would follow closely behind in early 2016.

So good growth here, a reorientation for us is we're thinking what the MLP gives us the opportunity and the toolset to do in growing this part of the business quicker.

So this is the rack up of the midstream in terms of the projects and the capital spend. You can see that we've aggressively grown the capital spend. The DCP portion is the equity share of our investment at DCP and then the transportation and NGL operations piece is the 100% piece of PSX's investment. So a growth rate of over 40% in this business. As we look out into the future we see similar type spins as we start executing the frac and the export facilities at PSX.

Let's move on and talk about Chemicals. As we look at our Chemicals business, its organic growth; lots of opportunity to grow the chemicals organically. Without question, CPChem has great global market positions in the products that they serve. Most of CPChem's positions are built upon proprietary technology. CPChem has done a nice job over the last decade executing five megaprojects in the Middle East- in Saudi Arabia and in Qatar. And our attention is now really turning to the U.S. Gulf Coast, because that's the next area of opportunity.

And if you're going to play in this business, having access to advantaged feedstocks is a sustainable source of value creation. If you think about feedstocks and you think about energy; it's 85% of your cost structure in this business. And so being able to win is being able to access these attractively-prices feedstocks.

Just a little bit more on the portfolio; on the right, we've shown you CPChem's portfolio by region. You can see that our assets are primarily concentrated in North America and the Middle East. Those are the two best regions to be in now and into the future, we believe. You know, we can run up to 100% light feedstock at CPChem, given our facilities in the Middle East and in North America.

We intentionally pick these regions for growth for access to advantaged feedstocks. Without question, the Middle East has improved CPChem's competitive position and these projects that we have underway in North America will continue to do that.

We're a first mover. We believe in terms of building new capacity on the U.S. Gulf Coast. This is a rack up of the projects that we have, all centered around U.S. Gulf Coast expansion. So as you look at CPChem over the next couple years to 2017, we're going to add about 30% capacity to CPChem. We're going to spend between $6 billion and $7 billion of capital between now and 2017 and we're going to add between $1.3 billion and $1.6 billion a year of EBITDA, plus 2017 as these projects come up.

So this is going to be a great source of top-line growth for our Company. These are good, solid-return projects for CPChem and also for Phillips 66. So good growth in CPChem; CPChem has great experience in executing megaprojects. We've done five of these projects over the last 10 to 12 years in the Middle East, so we're taking that knowledge that we acquired by executing those projects, the project management skills, building very similar type assets and we're leveraging that knowledge as now we impart on building on the U.S. Gulf Coast.

I would also say that one thing that we think differentiates us as a first mover here is we have all the permits in hand to start construction. So we have a greenhouse gas permit for the new cracker; the only one in the industry. We have all the other construction permits we need from the state of Texas so you should expect that imminently, we'll take FID for this project. We go to our Board in the next couple weeks for approval. We've been doing the early engineering on the big project, long-lead items are underway, contractors have been selected, contracts negotiated; so we know what it's going to cost and we're ready to get started on this project.

So here's the rack up of projects and capital program; very similar to Midstream; you can see our steady progress in terms of shifting investment into the Chemicals business. You can see the timeline. The other thing I would say that we would expect both DCP and CPChem to be self-funding over this period of time. Peak spend on the cracker project, derivator (ph) project, will be around 2015. As you think about CPChem last year, it threw off about $3 billion of EBITDA. Peak spend is going to be somewhere between $1.8 billion and $2 billion at CPChem level. So we have an expectation we will fund capital through the cycle and return cash back to the owners of CPChem during this cycle.

So we'll move on and talk about one of our core businesses. It's our Refining business. As you think about the Refining business, we have the opportunity to improve returns in this business. It's not a growth business for us. It's run-well and optimized business for us. We have five things we're doing to improve returns here. Ultimately, cumulatively we think this is about a 400 basis point improvement in a price-neutral environment in terms of our Refining business.

So first thing, and one of the big levers, is getting more advantaged crude to the front end of the refineries. We continue to work yields. Clean product yield, a 1% change is worth north of $100 million to us. We've improved clean product yields about 2% over the last couple of years. We think we may have another 1% to 2% improvement left without a lot of capital or hardly any capital investment.

We're also preferentially trying to make diesel versus gasoline. Diesel demand is going to grow two and a half times what gasoline demand is going to grow globally. So we think there's an opportunity. We already have an industry-leading distillate yield at about 40%. We think we have another 1% or 2% that we can move that yield.

We're working on the back end of the refineries to increase our export capability because we want to be able to run these facilities at rate. We're working on the operating cost side of our business and then we have continued portfolio optimization work. So we have a sales process underway for our Whitegate, Ireland facility. I really can't comment much because it's underway but you can expect we'll give you some updates. We do have people interested. That's the good news, in this facility; so hopefully early next year we can give you an update of what's going on with that.

Long-term Asia also is really not core to our portfolio. So you should expect that we would do something with that facility with time.

So you look at our refining portfolio; 15 refineries worldwide, 11 in the U.S.; 2.2 million barrels a day of capacity. 55% of our capacity is either in the Midcon or Gulf Coast. We like that footprint that we have. 65% light, 35% heavy; 50% sweet, 50% sour; and so when we look at the crude slate that is coming to us, we think our refining portfolio is positioned about right.

And so integrating our transportation system and our infrastructure to make sure we get the right crudes into these facilities and using the MLP to help us do that is key to what we're going to be doing in Refining in terms of putting those advantaged crudes to the front of the refinery. We ran in the second quarter about 68% advantage crudes; that's 10% more than we ran last year. Ultimately, we want to get to 100% advantaged crudes.

So I think between what we're doing, Tesoro, Valero is doing on the West Coast; I think ANS actually becomes an advantaged crude at some point in time. As these crudes show up on the Gulf Coast, I think LLS will become an advantaged crude. Our real challenge that we have or opportunity that we have is to get advantaged crudes to the East Coast and West Coast. So we're working that in terms of moving Canadian crudes down into California or building rail facilities. We're looking at rail to barge to ship, down to the West Coast refineries. We've taken the Jones Act vessels to run Eagle Ford from Corpus around to the Alliance Refinery and also around to the Bayway Refinery. Ultimately, Bayway will be on a diet of Bakken and Eagle Ford crudes which we think will be advantaged.

So I think I'd say is we have a sophisticated commercial organization that's out in the field, buying at the field. It allows us to take advantage of opportunities. It allows us hopefully to anticipate changes in the market, but certainly be able to respond quickly when changes in the market do occur. And that's part of the overall optimization that this commercial group helps us achieve.

Increasing exports we believe is going to be important. We have seven coastal refineries; three on the West Coast, one on the East Coast and of course we have our refineries on the U.S. Gulf Coast, three of those refineries. Today we have the capability to export about 320,000 barrels a day. In the second quarter we actually exported 180,000 barrels a day and you can see about 80% was distillate and 20% was gasoline.

As we look to the future and we think gasoline demand declines in the U.S., we're going to need to export more gasoline to run our facilities at rate. So we think gasoline demand over the next five to seven years is going to decline on the order of 200,000 to 400,000 barrels a day. We look at the geographic close markets in Latin America and South America. We think gasoline demand in that area grows by about that same amount. So we think that we can offset that decline in the U.S. with exports out of the U.S. into those close areas.

When you look at U.S. refiners in general, they have an energy cost advantage over European and Asian refiners of $1 to $3 a barrel. I think we're going have some advantaged crude. We have the close geography. So I think that not only can we take the growth, we can compete and win in displacing others that are exporting into those markets today.

So I said we kind of have an agenda, a plan to increase by 400 basis points on a price-neutral basis, our returns in Refining. You're going to see us be very disciplined in our investments in Refining. We need about $700 million annually of maintenance capital and we will keep our refineries in great shape. You need to be able to run refineries every day in this business to take advantage of opportunities and you do that by taking good care of your facilities. So we will take the very best care of our facilities. We'll make the investments to keep them reliable, to make them environmentally friendly.

But not a lot of growth capital is going to go in our refining business. I told the guys in refining that we'll fund every 40% return project you bring us. And as shareholders, you want us to fund all of those 40% return projects. The issue that I see is there's not a lot of 40% return projects in refining today. Certainly we have some energy-efficiency projects. We're looking at small, quick hit, quick turn investments. We're looking at some pre-flash capability in some of our Gulf Coast refineries where we can incrementally run some more barrels of light sweet crude. We may not increase overall capacity, but just the ability to get more light sweet crude through the facilities without taking a rate reduction of running it through.

So those are some of the projects that we would be considering. But you can see a very disciplined capital in terms of our Refining business.

Moving on to Marketing and Specialties; it's selective growth. Again, this is about $1 billion a year EBITDA business. It's very stable income. This is high-return business for us. Our U.S. wholesale business has about 7,000 sites. These are designed. We have great relationships with our customers, long-term contracts; but it is really to ensure a low-cost way, a pull-through to the refineries to run the refineries at rate.

We like our retail presence in Europe; just over 1,000 sites in Europe. We think over the next five years, we're going to add about 150 sites in Europe. But we draw a ring around our European assets, the MiRO plus European retail is 25% plus return on capital employed business for us. We have a great position in lubricants. We'll-- look to us that we will grow that position. We have a great flow improvers business and we'll grow that business also.

But the capital spend here is going to be relatively modest. It's going to be on the order of $100 million to $150 million a year; so great business, but selective growth in this business.

Starting to wrap things up here, on the financial summary; so you can see the volatility here; we want to be very thoughtful about how we allocate capital at Phillips 66. We're going to take a very disciplined approach and when we look at investment in the business versus returning capital to our shareholders. We have objectives around earnings growth but also objectives around growing shareholder distributions.

We will commit the funds if necessary to maintain all of our assets at the very best level, but we also think it's important to have a strong balance sheet and financial flexibility.

And so we've paid $1.5 billion of debt so we've gone—essentially from $8 billion to $6.5 billion. You should expect we'll pay another $500 million of debt down this year. That takes us to $6 billion of debt. We'll hold at that level. We have no plans to reduce below the $6 billion level. That would put us at a 20% debt-to-cap ratio and that's kind of in the low end of our range of 20% to30%.

What does that do for us? That gives us capability at all points in the cycle, even with the volatility in this business, to continue our investments in growth, continue our investments in distributions to our shareholders.

Just guidance a little bit on 2013 CapEx. We're right on top of the previous guidance at $3.7 billion total. So this is our share plus our equity share of our affiliates. About $1 billion of maintenance capital at PSX; we have about another $900 million of growth capital this year, a big portion of that was completion of our interest in finishing up the Sand Hills and Southern Hills pipelines. The rest of it around infrastructure; tank storage, rail loading, unloading facilities, etc; at our joint venture, it's $1.8 billion and so we're on track for about $3.7 billion total this year.

Moving on to distributions; we believe that growing shareholder distributions create total shareholder return for our Company. We think that dividends need to be bulletproof. You need to know that they're secure. You need to be able to see the runway that we have to increase that dividend with time. We've always said- in ten years we want to look back and say we increased the dividend every year. You should expect that we will increase the dividend in 2013.

Our Board has authorized $3 billion of share repurchases. We're well on our way to completing the first $2 billion tranche and we will start the last $1 billion tranche the third billion dollars, this year.

So when you look, since formation you look at our dividends and you look at our share repurchase program; we've returned about $2 billion of cash back to shareholders. We've paid $1.5 billion of debt down.

So I'm going to wrap up. I see my clock- I have one minute and twelve seconds left. So, I started today saying that I can't think of a more exciting time to be in this energy business and I meant that. I haven't seen the opportunities that I see today for-- really for our country, for our industry, but also for Phillips 66 Company. I think we're at the beginning of a new American century in terms of energy development in the U.S.

It's going to be an energy century as you think about it; it's going to be a century of opportunity. We're very optimistic about the growth in U.S. manufacturing as people see $3.50 natural gas; they're looking at 8% unemployment. They see the investment that the industry is making in infrastructure and petrochemical facilities and etc. And we think at Phillips 66 we're extremely well-positioned to play our part in this changing American energy landscape and that we can be one of the premier companies in this space in terms of creating jobs, capturing value, providing energy and improving lives.

Paul Cheng: So thanks for being here today. I appreciate your attention.
That's perfect timing. We will move directly to the breakout session; Liberty one and two for additional discussions. Thank you.

Attachment 29

03-Sep-2014

Phillips 66 (PSX)

Barclays CEO Energy-Power Conference

CORPORATE PARTICIPANTS

Greg C. Garland
Chairman & Chief Executive Officer, Phillips 66

OTHER PARTICIPANTS

Paul Cheng
Analyst, Barclays Capital, Inc.

MANAGEMENT DISCUSSION SECTION

Paul Cheng

Analyst, Barclays Capital, Inc.

Good morning. Our next presentation is Phillips 66. With great pleasure, we have the CEO and Chairman, Greg Garland with us. The last two years since the spin-off from Conoco, Greg with his leadership and the rest of his team has done phenomenally in the company and being considered one of the best operating team and also then one of the most financial savvy.

So without further delay, let me welcome Greg and share with us all the exciting developments.

Greg C. Garland

Chairman & Chief Executive Officer, Phillips 66

Thanks, Paul. Hey, good morning, everyone. Pleasure to be with you here at the Barclays Energy Conference. I told Paul, I said, you're getting reputation. You're the guy that ruined summer because this is the end of summer for us all as we get back from summer vacations, get started with the Barclays conference, but we were really pleased to be here, Paul. Thank you and to your team, you do a great job with this conference.

So let's get started. Safe Harbor statement, during the course of the presentation today and during the Q&A later, we could make forward-looking statements. Material results could be different, the actual results could be different and the source is different since we're here, our filings with the SEC.

So here is our strategy, growth, returns, distributions. We have an unyielding commitment to operational excellence, which for us is personal safety, process safety, environmental excellence reliability, cost management and a commitment to have a high performing organization. So right people, at the right place, at the right time to execute the plan, and having people that know how to win and are committed to differentiating shareholder value. So that's kind of the strategy.

As we look at our refining business, it's run well, it's optimized, it's minimized capital investments. We won't invest in advantaged crude at the front end, exports on the backend, yield capture, energy efficiency, but really very disciplined capital investment in our refining business. Midstream business, aggressive growth and we'll go through that today as we move into the presentation.

Chemicals, aggressive growth; selective growth in our marketing and specialties businesses. We're executing well. We've identified lot of growth opportunities in the company, we'll talk about today. A lot of them around midstream and logistics, ultimately destined for our master limited partnership. We've raised the dividend 28% in May and June. The board approved additional $2 billion share repurchase, so we're at $7 billion total authorization on share repurchases.

We strengthened the balance sheet, so we're at the low end of our 20% to 30% debt-to-cap ratio, and our strategy is about transformational change. As you think about moving from essentially a refining company, where most of the income is refining, to go into about a third refining, we plan to double the enterprise value of our company by 2018 compared to the historical mid-cycle average.

Just a word about operational excellence, we have the energy to lead our industry in this space. We're performing well, executing well and that's continued into 2014. Look at Phillips 66, our total recordable incident rate is 0.18, which is about 18% better than 2013. So, we continue to do really well in this space.

If we turn to our internal refining metrics, by any measure on our refining side, we continue to improve our environmental footprint. In the last 10 years, we've invested more than $1.5 billion in process control and in systems that have allowed us to reduce our environmental footprint. That's a very important thing for us as we move forward. So, we want to lead our industry in operational excellence.

So thinking about our plans, our plan promises continued growth in energy availability and supplies in North America. Thinking about crude production in the U.S., starting to push 10 million barrels a day by the end of this decade, natural gas liquids going from somewhere just over 2 million barrels a day to 3.5 million barrels a day to 4.5 million barrels a day, natural gas production to 80 billion cubic feet a day by the end of the decade, so significant growth.

This is creating opportunities for infrastructure investment. So in our midstream business, it's gas gathering and gas processing, crude pipelines, crude gathering systems, terminals, NGL fracs, export facilities, just billions of dollars of investment there.

And then this big increase in natural gas liquids from 2 million to 3.5 million to 4.5 million barrels a day is creating opportunities, obviously, for exports of natural gas like the propane and butane, but also feedstocks for petrochemicals, and so significant growth opportunities for our company and for our industry in terms of petrochemicals. Our view is, over the next decade, the best place to make petrochemicals is going to be in the Middle East and in the U.S. Gulf Coast.

So as we consider the energy landscape, we think about the value chain and the value capture opportunities this way. We think that the value capture between NGLs and crude is more sustainable and is more durable than the value capture opportunity between crude and refined products and, hence, that's why we're investing more in midstream and logistics and petrochemicals preferentially as we try to make the transformational change of our company.

We understand that demand for refined products in the U.S. is going to be probably flat to declining and so access to export markets for refined products is going to be important. So we'll show you our plans around that today.

Our capital plans do include the required funds to make the builds for regulatory mandates whether it's Tier 3 gasoline requirements, the flare controls, coker vents, et cetera, but we've got that built into the plant. This is a business that has inherent risk.

We have a management team that is highly experienced at managing risk, whether it's commodity risk and the day-to-day risk, or it's a risk of managing hydrocarbons on a day-to-day, whether it's executing large complex mega billion dollar projects. We have a very well seasoned, well fully capable management team to do that.

So, when you look across our business platform, either in the midstream business or refining marketing, specialties or chemicals, we think that we have the human resource potential that we need to execute our plans.

So, let me move on and talk about our capital program. Our total capital program for 2014 is $5.8 billion. That includes $1.9 billion of our proportional share of the equity share joint venture, so WRB, ECP and CPChem.

Our regional budget at Phillips 66 was $2.7 billion. So, that excludes the equity JVs. In July, our board approved a $1.2 billion increase to that, really in two pieces. $900 million was around a list of acquisitions, which we'll go through some of those today during the presentation. $300 million of that was really for acceleration of workaround the Sweeny Frac and the Freeport LPG facility.

So, I'll talk about Beaumont spectrum, Sweeny Cogen. We took out our other equity owner, 50% owner of the 440 megawatt Cogen facility at Sweeny. When you think about the existing investment we have, the new investment going in at Sweeny, both from PSX and also CPChem, we want to make sure we harden that electrical infrastructure.

You remember in the first quarter and second quarter of last year, we had some issues, mostly related to our third-party providers. We want to ensure that we've got that well in hand and we don't have that ever happen to us again and so that was part of the reason for that. Explorer, we had the opportunity to pick up additional 5.8% interest, bringing our interest to 19.5% on Explorer Pipeline.

So, if you look at our investments over the next few years 2014, 2015, 2016 actually into 2017 as these projects start coming online, on a price neutral basis, we expect EBITDA will grow by $2.5 billion at PSX.

So, here's some new information versus the Analyst Meeting in April. We showed you $1.5 billion of MLP-able EBITDA at PSX Midstream. What we've done is we extended out 2017 to 2018 to get a full year. We've shown the impact of a second frac and also the Beaumont terminal, but we're showing $2.3 billion of EBITDA, total MLP-able EBITDA in our midstream segment.

As you start, today, we have about $500 million in midstream and that excludes the EBITDA from DCP, about $250 million of EBITDA that's embedded in our refining business today. So, you have roughly $1.6 billion of growth, mostly around NGL and transportation and logistics. I would say the majority of this EBITDA is fee-based.

So, I'm going to talk about the NGL opportunities on the Gulf Coast. Obviously, we have the one-third interest in Sand Hills and Southern Hills, so those are in service, ramping up as per schedule. We talked about our Sweeny project on the frac. We're going to build a 100,000 barrel a day frac at Sweeny, 150,000 barrel a day export facility at Freeport, about 250 miles of pipelines that connect Belvieu and those areas.

We're going to build a 450,000 barrels of natural gasoline storage and about 550,000 barrels of propane storage. So, a significant project, all in $3 billion to $3.5 billion. We expect $400 million to $500 million of EBITDA associated with this project.

We also, as we evaluate the opportunity, see the need for a second fractionator. We're going to FID that in 2015. We expected that that will be up in 2017. Estimated EBITDA from that will be $300 million to $400 million.

So, the Midcontinent is an important area for our company, three refineries or interest in three refiners, 485,000 barrels a day of capacity, about 22% of our global refining capacity, over 3,000 miles of pipes, 20 terminals. As we think about the opportunity, to just give you an example of what we're doing in the Mid-Con around crude acquisition, Ponca City, we've invested in truck loading, unloading capabilities of 70,000 barrels a day. By midpoint of next year, 100,000 barrels a day, the Magellan pipe to another 20,000 a day going in Ponca City.

So, we're buying indigenous Oklahoma crudes at the wellhead, very consistent product, we know what we're getting and that's translating into better yields at the refinery, good throughputs. And so, as we go to wellhead and buy, we know the crude, the quality of the crude that's coming in, and another opportunity to leverage our expertise in our commercial business into our refining business.

We'll then talk about the East Coast and West Coast. So, when you think about 55% of our capacity in the Gulf Coast, is in the Mid Con, the real opportunity to put advantaged crude left to us is on our East Coast and West Coast.

So let me start on the East Coast at Bayway. We've built the 70,000 barrel a day rail rack. It's operational. We unloaded our first unit train in August, August 5. We can do one unit train a day there at Bayway. That was a global deal. We can do 50,000 to 75,000 a day in the global deal. And then we have our Jones Act vessels also to move crude around from the Texas Gulf Coast to Bayway.

Thinking about California, work in process, I would say, in terms of putting advantaged crude into California. Ferndale, we have a rail rack under construction, 30,000 barrels a day. It will be ready by the fourth quarter of this year. We're disappointed in the progress to permit our Santa Maria rail rack 40,000 a day, but we have – we're optimistic that we'll get that done. It just takes time in California to get these things permitted.

We signed a deal with Plains in Bakersfield to do 20,000 a day into that terminal. On the loading side, another 20,000 a day at Hardisty,10,000 a day at Cogen at Casper in Wyoming. So we're making progress in terms of put advantaged crude to the front of our refineries in California.

The thing I would say is in terms of North Dakota, we acquired 700 acres of land. We have permits in hand and engineering to construct a new rail loading facility. This is permitted up to 200,000 barrels a day. We'll probably do about a 160,000 barrels a day, about 300,000 barrels of storage there.

When you look at the rail fleet that we have, we acquired the first 2,000 cars. We said we're going to acquire another 1,200 and we're actually acquiring another 500 on top of that. So we're going to have 3,700 cars in total and we'll be able to move about a 185,000 barrels a day out of Bakken essentially East and West to these refineries. So we made a lot of progress in 2014 around putting advantaged crude both East and West.

Moving on and looking at the Gulf Coast, very important area for us. 33% of our capacity, refunding capacity is on the U.S. Gulf Coast. A large portion of our transportation assets are there. Well, I'll talk about the Beaumont Terminal acquisition on a subsequent slide. But certainly when you think about the crudes coming out of the Permian, the Eagle Ford and coming down from Cushing, the U.S. Gulf Coast is going to be an important place.

And logistics around the Gulf Coast are going to be important and an opportunity to create a lot of value. We currently have two Jones Act vessels that we use. Starting in January, we're adding a third Jones Act to the fleet. So we've added capability there coming up this January.

Working on expanding our dock capacity, we're about 440 today. Beaumont gives us 600,000 barrels a day of exports. We're up over 1 million barrels a day of export capability today and ultimately we get to one-one, one-two, so very important for our future.

The other thing I would say is that condensate, there's a lot of conversation around condensate today. Our definition is anything 45 or greater on API gravity and it could be anywhere from simple splitting to very complex splitters, but the infrastructure to gather then split and then the dock to export or to make the products go to the right markets with the highest value, we see a lot of opportunity around that. A lot of engineering work going on around infrastructure together, splitting et cetera, more to come on that in the future.

Talking about Beaumont, I will tell you we're really pleased with this asset. It's a great asset. It's in the right zip code. The employees we've got are just fantastic employees associated with this facility. 7 million barrels of storage capability, 5 crude, 2 million of products. We see the opportunity to expand this from 7 million barrels a day to 12 million barrels a day.

We see the ability to tie this into some of the pipelines that are getting built, that will show up in the Nederland area, and ultimately, part of our plan to make our Louisiana refineries look a lot more like a Texas refinery in terms of their access to crude and the ability to put more advantaged crude into our Louisiana refineries. So we think, it's a great asset. We didn't buy it exactly for what it is today but for what it can be. So we're excited about the opportunity that this terminal provides for us.

A word about Phillips 66 partners, we look at the PSXP as a tool and our toolbox is certainly a key vehicle that we're going to use to grow our midstream business faster. Without question, create significant value for the unitholders of PSXP but also for the shareholders of Phillips 66. Since the IPO just over a year ago, we've doubled the EBITDA at PSXP.

We've shown you the MLP math on the right, where there's $145 million of EBITDA embedded in PSX, was probably valued at about $1 billion and then, when we did this slide, it was about $6 billion of value. So clearly that incents us to keep our foot on the accelerator versus hitting the break in terms of the master limited partnership and how we use that master limited partnership.

The thing I would say is that until the MLP gets to scale, it does incent Phillips 66 to use our cash, to use our balance sheet, to build out the midstream and we're willing to do that, incubate projects at PSX and then drop those projects in to PSXP. So clearly, a big element of our growth profile and our capital spend is directed towards these kind of projects. But clearly pleased with the performance of PSXP at this point.

The other part of our midstream program is around DCP. DCP is our 50-50 joint venture with Spectra Energy. This joint venture has a 14-year history of creating value for its owners. DCP is one of the largest gas gatherers, processors, NGL producers, NGL pipeline operators in North America today.

We have an expectation, our plan is that the DCP EBITDA growth at 11% compounded growth rate, 2014, 2015 and 2016. Growth is being driven by – the big pipes are in service. We're ramping those up. But it's increased gathering capabilities, gas processing plants. DCP has about $2 billion of projects in flight and execution today between now and 2016, $4 billion to $6 billion worth of projects. Our view is that that DCP is on a self-funded basis, so they use their cash, their balance sheet and dropping assets into their MLP to fund this growth into the future.

So thinking about the chemicals portfolio, we own a half of a world-class chemical company. Chevron owns the other half at CPChem. Clearly, CPChem is a global company. We like the asset footprint that CPChem has. You look at their olefins and polyolefins business, about three quarters of it is in the U.S. and North America, about 25% in the Middle East. And those are the two best places to make petrochemicals today and what we think out into the next decade.

So we think the value capture opportunity is significant at our chemicals company. Over the next two years, growth is going to come from additions in 1-hexene, so that unit is operational, started up in June. And then, we're adding an additional furnace at Sweeny. But the real mover for CPChem is really the Gulf Coast petrochemicals project, which starts up in mid-2017, circa $6 billion project, adding 1.5 million tons of ethylene capacity and associated polyethylene capacity. Ethylene unit will be at Baytown. The derivatives, the polyethylene will be at our Sweeny complex.

So, I think as you work at the capacity increase, we got 36% O&P capacity increase, significant increase. And when you think about how does that translate into EBITDA, you can see – by the way, I should tell you, this is a look-through EBITDA. So, this includes the embedded D&A and interest and taxes of the joint ventures within CPChem themselves.

So, you can see $3.4 billion of EBITDA kind of on 2012 and 2013, good first half of the year this year. But we expect that these new projects as they come on, they get loaded up in 2017 increase the EBITDA by $1.3 billion to $1.6 billion on a price neutral basis for CPChem.

We will move on and talk about our refining business. Again, this business for us is run well, optimized business. We have 15 refineries or interest in 15 refineries, 11 in the U.S., 7 are coastal. Operating excellence is key. Putting advantaged crude to the front of refineries, working our yields, improving our yields at our refineries and working on our cost structure is the key of what we're trying to accomplish here.

$13 billion of capital employed in this business, it's a huge base. And when you think about 400 basis points of improvement in a business of this scale, that's huge. It's about $600 million of net income improvement. $400 million of that comes from advantaged crude capture, $200 million is around yields and cost reduction. So significant improvement in our base refining business. We view this as moving from a 10% to a 14% return on capital employed business.

A word about our specialties businesses in our marketing, so this is divided into U.S. marketing, our international marketing and then specialties. I think it's probably the first time we've shown you the pie chart. On average over the last five years, this is $1 billion of EBITDA in this segment.

You look at our U.S. marketing business, it's essentially a wholesale business, really around pull-through from the refineries. So you think about our inland refineries and think about our West Coast refineries, we think that pull-through is valuable today and we think it becomes more valuable in the future.

So you think about our European marketing, Central Europe, high return business, we have 1,200 sites. We're going to modestly grow this business over the next few years, add 200 sites between now and 2018. But again, selling under the Jet brand, high value, greater than 30% returns in this portion of the business.

Our specialties business consists of our finished lubes business. Our joint venture Excel Paralubes and base oil and then our specialty needle, anode-grade coke businesses. They're all very profitable. They all have high returns.

Our finished lubes business is the third largest in the U.S. It's a good return business. It's a business we want to grow selectively. The Spectrum acquisition was essentially a bolt-on acquisition. It increases our specialties EBITDA by about 10%. It really filled in some gaps that we had in our portfolio in terms of two cycle, four cycle. It filled in some international packaging gaps that we had. So just a nice bolt-on acquisition that we made. So it allowed us to extend our reach and to grow this business.

Okay, talk about capital allocation. I think at the April Analyst Meeting, we used this same slide and nothing's changed. As we said in April, as we consider cash from all sources, that could be funds from operations, it could be our balance sheet, it could be cash on hand, it could be cash generated from master limited partnership. 60% of that we're going to reinvest in the business. 40% of that we're going to distribute back to the owners of Phillips 66 Company in the form of dividends, secured growing, and then also share repurchases. So our view around that hasn't changed.

In terms of our distributions and dividends, the guidance we gave 2014, 2015, 2016, expect double-digit increases in the dividends. We think dividends need to be secure and growing and competitive. I think we're off to a good start this year in 2014, with a 28% increase in the dividend. And then, as long as the shares trade below intrinsic value, we're going to be buyers of our shares. And we think that creates value for the shareholders of Phillips 66 Company.

In terms of our capital structure, 20% to 30%, we're certainly at the low end of that. We wouldn't hesitate to go to our balance sheet to continue to fund a fairly aggressive growth program and also to fund our distributions. And, so let me kind of talk to that point if I can on this slide.

We said many times that mid cycle cash flow is between $4 billion and $5 billion for Phillips 66. And I know you guys like to do the math, and so if you start with a $1 billion dividend and $1 billion of sustaining capital and $3 billion of growth, that kind of get you to the $5 billion.

And one of the things that we want to make sure is that we completely feel comfortable that we have the capacity to execute a very aggressive capital program and a very aggressive distribution program. And that we have sources of cash, whether it's coming from funds of operations, whether it's coming from cash on hand, we have $5 billion cash on the balance sheet, $5 billion in capacity under the revolver. We have $4 billion to $5 billion capacity of debt and then we have billions of dollars of capacity with the MLP.

So, you think about that holistically. You think about our desire to grow our midstream business and incubate projects for the next two years to three years that ultimately are destined for the MLP. That's really the strategy. What I would say is that we're not going to jeopardize our balance sheet. We're not going to jeopardize our ability to continue to grow our distributions in terms of our dividend or it makes significant share repurchases over the next three years while we execute this strategy.

Talk about returns, we generally show you our returns versus our competitors and you can go back from [indiscernible] (26:25) through today, we're still leaders in our peer group in terms of returns. Every once in a while, I like to look at it this way. It reminds me of why we're investing in marketing and specialties and chemicals and in midstream.

You can see refining is 10% return. We do have a broad base of capital employed in our refining business, but clearly, as we shift the portfolio to higher returning, more stable, more highly valued businesses, that's where we're going to get the enterprise value enhancement at Philips 66. So, returns matter. We watch them and we watch them very closely.

Distributions, just an update on distributions. Between share repurchases and exchanges, we've taken in 66 million shares, kind of has a nice ring to it, doesn't it, 66, Phillips 66. It just kind of worked out that way. The dividend growth has been aggressive, 150%, we've gone from $0.20 to $0.50 a quarter in terms of the dividend.

In April, we kind of laid out what we wanted to accomplish in 2014. I know the year's not over yet, but we've accomplished most of what we wanted to accomplish this year. As you think about the growth $4.2 billion growth program, the acquisitions that we've made, we've doubled the EBITDA at the MLP level.

In terms of returns, we approved an advantaged crude capture from 91% to 93%. We've exported record volumes 180,000 barrels a day in the second quarter. So we're on track in terms of our return improvement. And then in terms of distributions, we've talked about 28% increase in dividend this year and additional $2 billion share repurchase. So $7 billion total authorized now, through the second quarter, $3.9 billion actually executed, so $3.1 billion to go under that authorization in that program.

So, when we think about Phillips 66 Company, we think it's a compelling investment story. Certainly, I think we're executing successfully of our strategy of growth, returns and distributions, set upon a strong foundation of operational excellence and having a high performing organization that knows how to win, and knows how to deliver differentiated value for our shareholders.

Given the uniqueness of our portfolio, we think that we offer investors a singular opportunity to participate in the value upgrade capture opportunity that North American energy is providing everyone. And so we are certainly all around that.

We have a leadership team that's experienced. They're experienced at managing commodity businesses, volatile businesses. They're experienced at mega project execution, and they're experienced at delivering operational excellence and provides personnel safety, process safety environmental excellence, reliability and cost management. So the blocking and tackling is there every day so that your investment is in safe hands with the Phillips 66 management team.

I would say that we do expect that we're going to see multiple expansion and that's going to translate into increased economic value or enterprise value for PSX shareholders. As we move our business to more stable, less volatile, more highly valued businesses, we expect that's going to show up in the share price for PSX. And then finally I'll just say that we're confident about the opportunity set that we have in front of us for Phillips 66 and our ability to execute on that.

So thank you for being here today, thank you for the interest in our company and I'll turn it back over to Paul.

Paul Cheng
Analyst, Barclays Capital, Inc.

Thank you, Greg. I think we have time for maybe one or two and mostly two questions and then we will move to the breakout session. There's a question here.

QUESTION AND ANSWER SECTION

Q

Greg, congratulations on the progress you've made since the spin.

Greg C. Garland
Chairman & Chief Executive Officer, Phillips 66

A

Thanks, [ph] George. (30:26)

Q

A quick comment, you're the only CEO that we've seen who emphasizes operational excellence throughout your presentation, so nice job on that. Quick question, what's your philosophy on major acquisitions either buying out your JV partners or a major acquisition in the midstream?

Greg C. Garland
Chairman & Chief Executive Officer, Phillips 66

A

So, I wouldn't rule out an acquisition. We've learned to say that. But as I evaluate the landscape and we look at the landscape every day, things look pretty fully valued to us in midstream and chemicals, where we want to make an acquisition and we look at the organic opportunities.

The issue with organic opportunity is it takes two years to three years before you start seeing and you have some execution risk on the organic, but certainly we think that we have a stable portfolio of opportunities to invest in, that we like and that we can create tremendous value for shareholders of PSX over the long-term.

So, we do look at that universe. I would say that we're never going to overpay for anything. I mean, buy high, sell low is a terrible strategy and a lot of people get caught up in that over the course of their careers, but I guess I'd tell you, we don't need to do that. And we're blessed in many ways and I'm thankful in many ways that we have this large organic portfolio in front of us that we have to invest in.

Operational excellence is critical. As you know, we have a legacy of great performance there. We think about it every day, and I would just tell you, I am convinced that we protect and we enhance shareholder value by getting that part of our jobs right every day.

Paul Cheng
Analyst, Barclays Capital, Inc.

Thank you, Greg. I think we will move to the breakout session for additional Q&A. Thank you. It's going to on the Liberty 3.

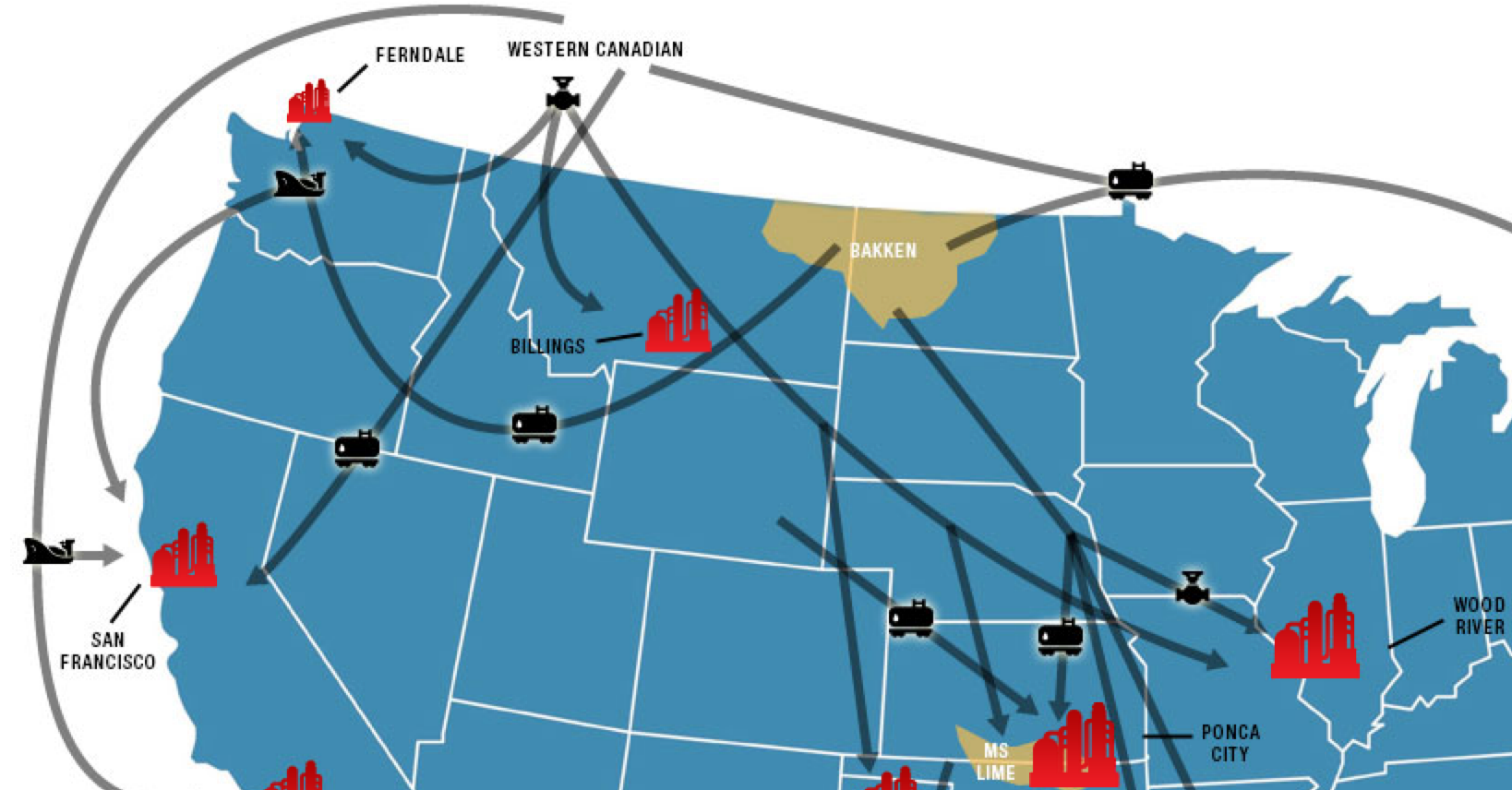
Greg C. Garland
Chairman & Chief Executive Officer, Phillips 66

Great, thank you.

Attachment 30

PHILLIPS 66 ADVANTAGED CRUDE ACTIVITIES

UPDATED MAY 2013



Attachment 31

TESORO

Transformation through Distinctive Performance

Simmons Energy Conference

February 27, 2014

Forward Looking Statements

- This Presentation includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements relate to, among other things:
  - The execution and effects of our strategic priorities, including achieving improvements in operational efficiency and effectiveness including safety performance, developing commercial excellence, and maintaining financial discipline and a high performing culture;
  - The market outlook, including expectations regarding crude oil production growth, feedstock costs, differentials, spreads, import and export opportunities, the Tesoro index and the anticipated costs of crude movements;
  - The timing, value and type of expected synergies from our acquisition of BP's Southern California refining and marketing business in June 2013 and the capital expenditures needed to realize such synergies, as well as our California emissions and the impact of the California regulatory environment;
  - Tesoro's competitive position and competitive advantages, including its advantaged feedstock position, the costs, benefits and timing of projects designed to enhance gross margin capture, earnings diversification and marking optimization through brand expansion and growth;
  - West Coast logistics development, transportation advantages and refining system opportunities;
  - The timing and results of Tesoro's disciplined improvement program;
  - The results of Tesoro's logistics growth strategy, including plans for Tesoro Logistics LP ("TLLP"), the potential value of possible future asset sales to TLLP, TLLP's organic growth opportunities, the value to Tesoro of distributions from TLLP, the implied enterprise value of TLLP and the value of Tesoro's stake in TLLP;
  - Maintenance of Tesoro's financial priorities, including balance sheet strength, Tesoro's target debt capitalization, and TLLP's target debt to EBITDA level;
  - Capital expenditures, turnaround spending, and the cost, timing and return on capital projects, including expectations regarding incremental EBITDA improvements;
  - Expectations regarding free cash flow, the implementation of Tesoro's cash strategy and the return of excess cash flow to shareholders through dividends and share repurchases; and
  - Growth opportunities for both Tesoro and TLLP.
- We have used the words "anticipate", "believe", "could", "estimate", "expect", "intend", "may", "plan", "predict", "project", "should", "will" and similar terms and phrases to identify forward-looking statements in this Presentation.
- Although we believe the assumptions upon which these forward-looking statements are based are reasonable, any of these assumptions could prove to be inaccurate and the forward-looking statements based on these assumptions could be incorrect. Our operations and anticipated transactions involve risks and uncertainties, many of which are outside our control, and any one of which, or a combination of which, could materially affect our results of operations and whether the forward-looking statements ultimately prove to be correct.
- Actual results and trends in the future may differ materially from those suggested or implied by the forward-looking statements depending on a variety of factors which are described in greater detail in our filings with the SEC. All future written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the previous statements. We undertake no obligation to update any information contained herein or to publicly release the results of any revisions to any forward-looking statements that may be made to reflect events or circumstances that occur, or that we become aware of, after the date of this Presentation.
- We have included various estimates of EBITDA and free cash flow, each of which are non-GAAP financial measures, throughout the presentation. Please see Appendix for the definition and reconciliation of these EBITDA and free cash flow estimates.

Tesoro

Key Metrics	2010	2013
Enterprise Value ($ billions)	3.5	10.5
Market Cap ($ billions)	2.0	7.7
Refining Capacity (MBD)	665	850
Refining Complexity	9.8	11.5
Branded Retail Stations	880	2,264
Marketing Integration (%)	53	87
Employees	5,300	7,000
Retail Sales (4Q13 MBD)	87	266

As of 3/31/10 and 12/31/2013

Tesoro Logistics LP

	Key Metrics
Enterprise Value ($ billions)	4.0
Market Cap ($ billions)	2.9
Crude Oil and Refined Product Pipelines	1,570 miles
High Plains Pipeline Throughput	90+ MBD
High Plains Trucking Volume	45 MBD
Marketing Terminal Capacity	636 MBD
Marine Terminal Capacity	795 MBD
Rail Terminal Capacity	50 MBD
Dedicated Storage Capacity	7,700 MBBLS

As of 12/31/2013

TLLP growing rapidly into a premier Western US logistics provider

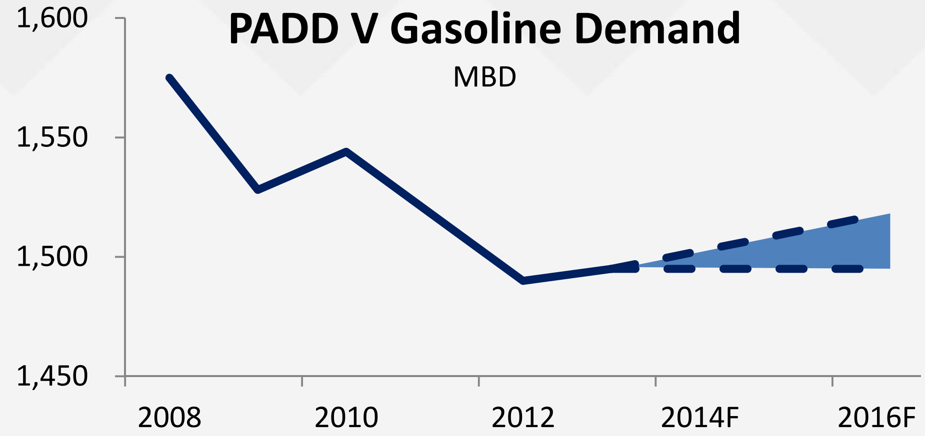
Market Outlook - Overview

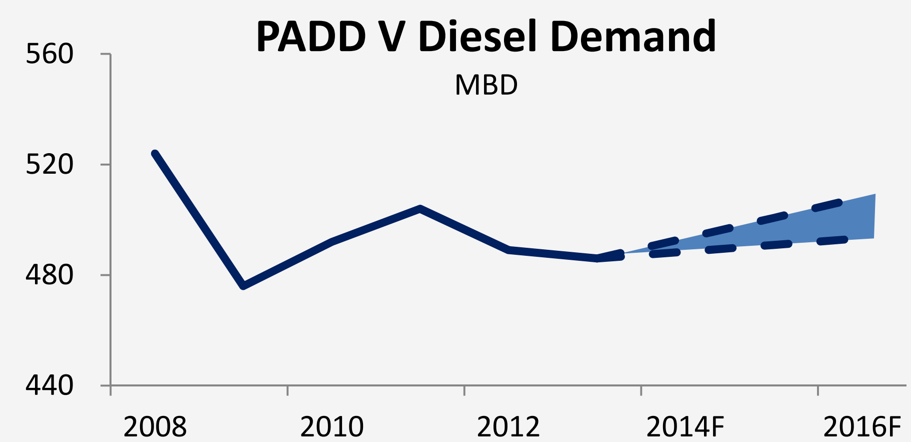
Key Drivers	Tesoro's View
Global Economic Outlook	Moderate growth
U.S. Economic Outlook	2 – 2.5% GDP growth
Global Refining Capacity	Capacity exceeds demand
U.S. Refining Utilization	High due to low feedstock and natural gas prices
U.S. Crude Oil Supply	Strong growth in North American crude oil production
World Product Demand Growth	Gasoline ~1%; diesel ~2% per year
U.S. Product Demand Growth	Gasoline flat; diesel ~1% per year
U.S. Product Exports	Strong and growing supported by U.S. competitive position
Renewable Fuel Growth	Delays in development of advanced fuels
Regulatory Environment	Challenges and uncertainty

Source: Internal Tesoro estimates.

PADD V Fundamentals

- Gasoline demand expected to grow 0 to 0.5% annually through 2016
- Diesel demand expected to grow 1.0% annually
- Net clean product exports expected to remain 100-150 MBD
- California unemployment 8.7%, down from over 10% last year
- Tesoro's gasoline refining production is highly integrated with marketing





West Coast economy improved and demand stabilizing

Source: EIA monthly data, forecast based on internal Tesoro forecasts.

Keys to Distinction on the West Coast

TESORO

- Operating cost advantage
- Flexible yield structure
- Access to cost-advantaged crude oil
- Integrated logistics infrastructure
- Secure and ratable refinery off-take
- Cost-advantaged regulatory compliance

Los Angeles acquisition transforms our capabilities

Strategic Priorities

- Operational efficiency and effectiveness
  - Safety and reliability
  - Cost leadership
  - System improvements
- Commercial excellence
- Financial discipline
- Value-driven growth
- High performing culture

Enduring commitment to execution

Execution of Strategic Priorities

TESORO

Distinctive Performance: 2014 and 2015

- Deliver California synergies
- Enhance gross margin
- Improve the base
- Grow logistics
- Maintain financial discipline

Targeting $370 to $430 million of EBITDA improvements in 2014

Distinctive Performance Objectives

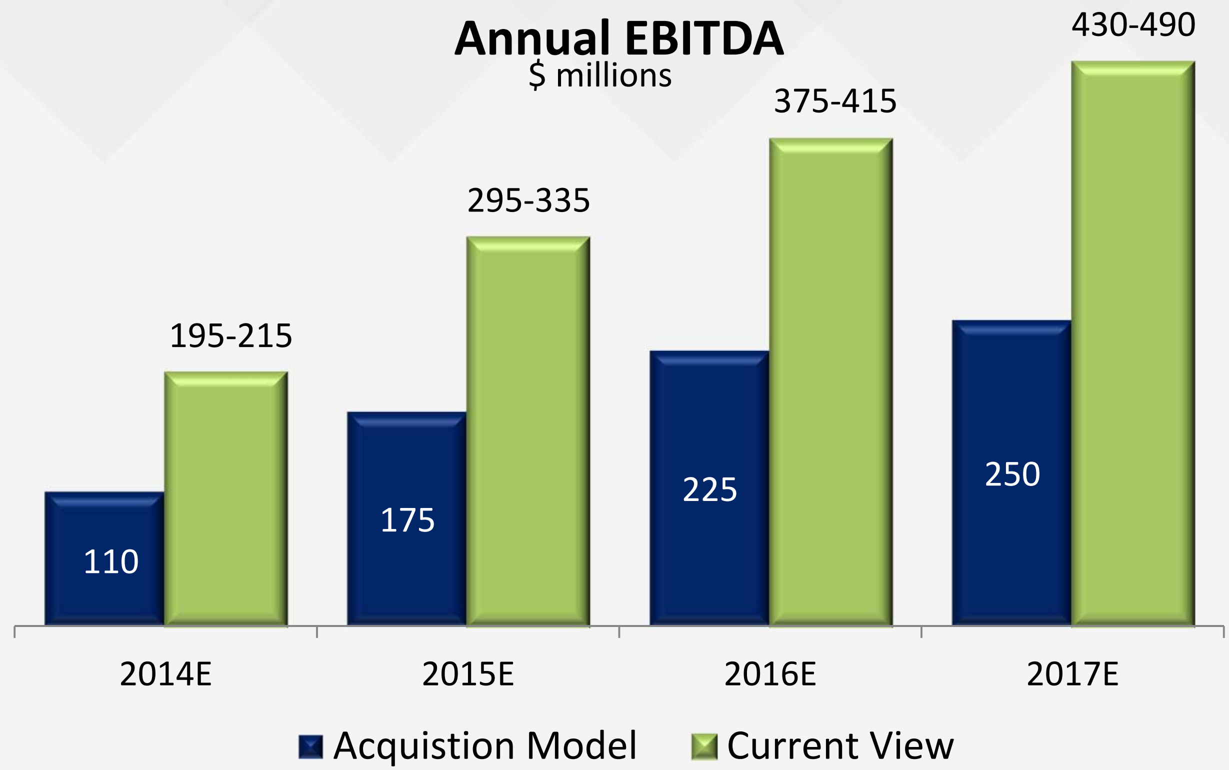
- Distinctive Performance Objectives

$ million	2014	2015
Deliver California Synergies	160 – 180	260 – 300
Enhance gross margin	140 – 160	250 – 290
Improve the base	70 – 90	80 – 120
Annual EBITDA Improvement[1]	**370 – 430**	**590 – 710**

- Grow logistics
  - Grow EBITDA by $200 million by 2015
  - Deliver incremental Tesoro shareholder value of $1 billion
- Maintain financial discipline
  - Maintain balance sheet strength, drive toward investment grade
  - Invest free cash flow in high-return capital projects
  - Return excess cash to shareholders

1) Improvements over 2013 results.

California Synergy EBITDA

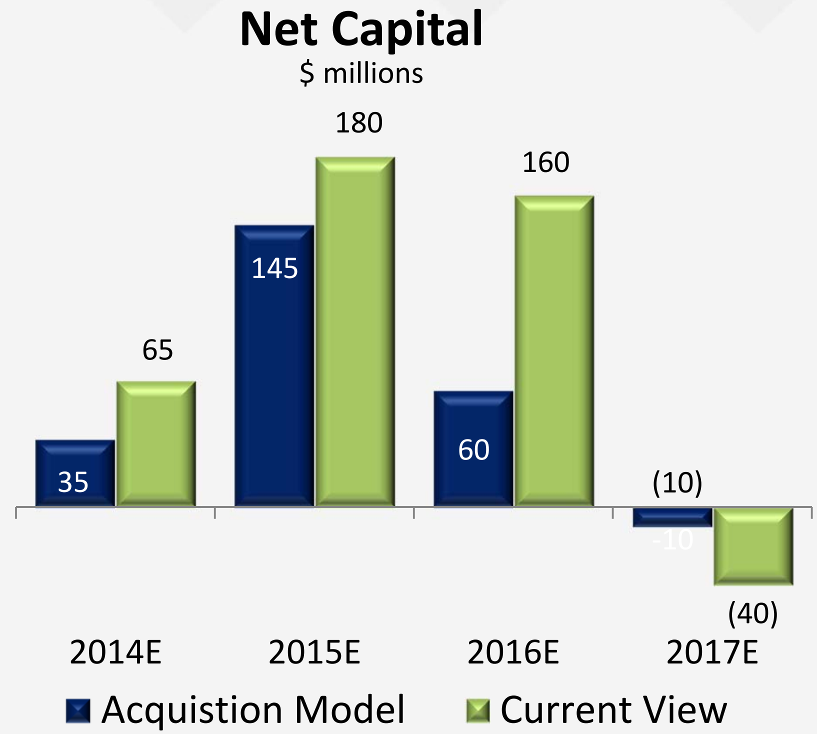


- Feedstock Advantage
- Logistics Optimization
- Production Optimization
- Operating Cost Improvements

Synergy value and pace of capture significantly improved

California Synergy Capital Expenditures

- **Los Angeles Refinery Integration Project**
  - Optimizes processing capability
  - Provides 30-40 MBD product flexibility
  - Reduces CO_2 emission 500,000 tons per year
- **Logistics Projects**
  - Link logistics assets
  - Reduce third party fees
  - Provides feedstock and product optionality
- **Processing Projects**
  - Strengthen conversion capability
  - Provides feedstock flexibility
  - Improves product yields



Disciplined delivery of high return capital investments

Note: Net synergy capital of ~$375 MM (including savings beyond 2017, which are reflected in 2017E), capital plan net of capital avoidance, 2017 emissions estimate is subject to final project scope and detailed engineering.

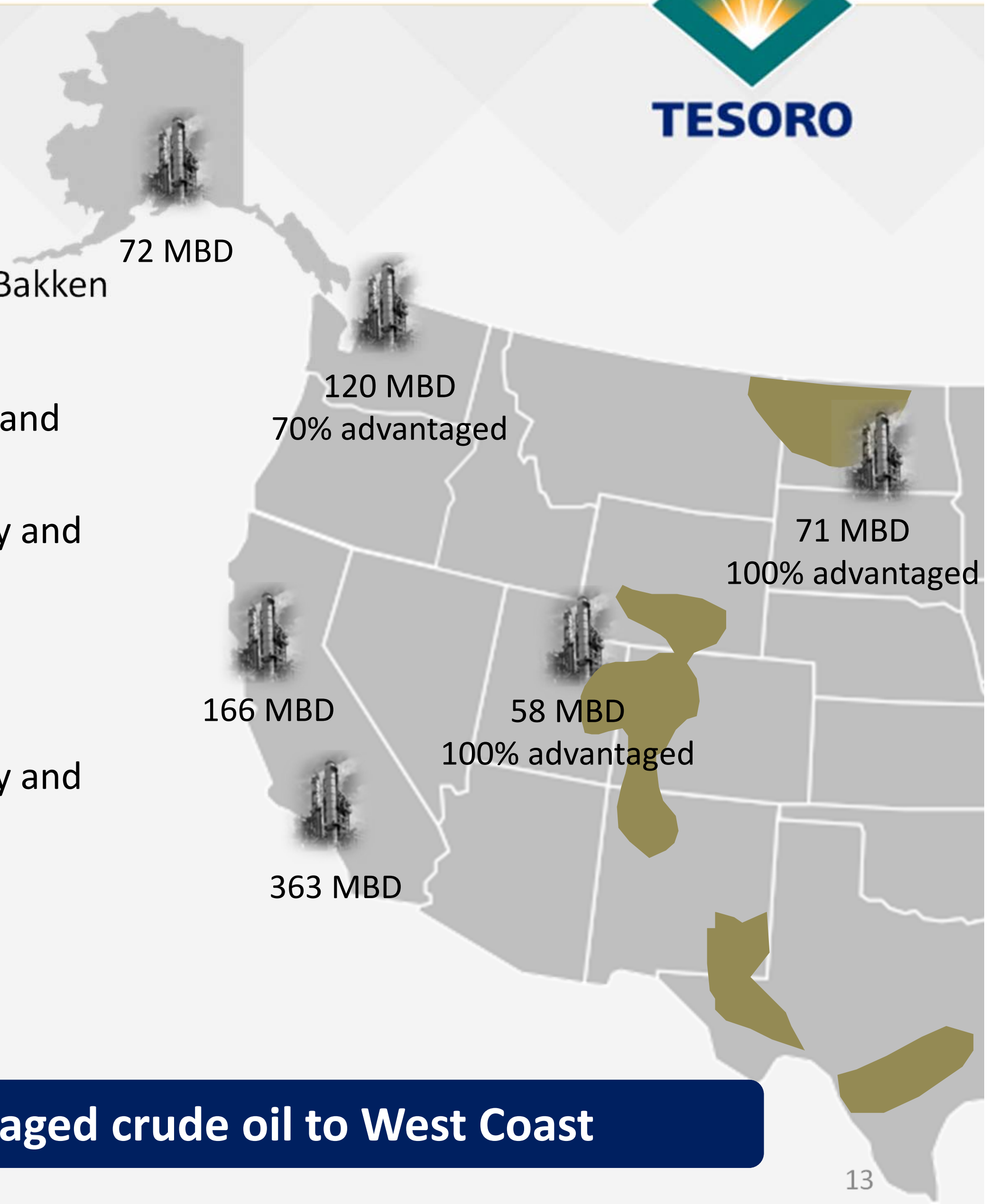
Tesoro's Advantaged Feedstock Opportunity

Opportunities by Refinery

- **Kenai**
  - Currently up to 25% Cook Inlet
  - Potentially up to 67% Cook Inlet and Bakken
- **Martinez**
  - Currently up to 45% California Heavy and Bakken
  - Potentially up to 67% California Heavy and Bakken
- **Los Angeles**
  - Currently up to 15% California Heavy
  - Potentially up to 50% California Heavy and Bakken

Potential impact on ANS crude oil

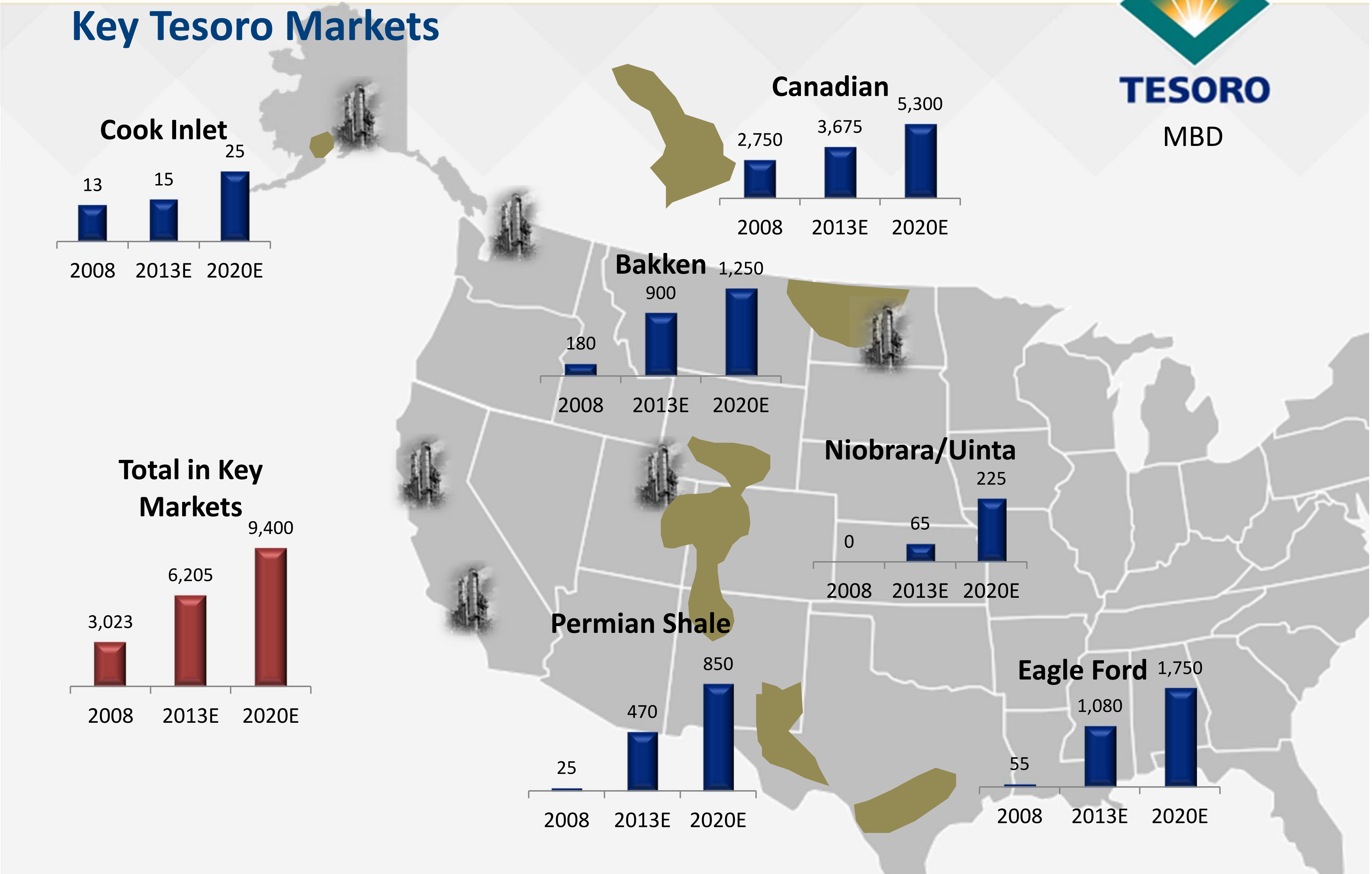
- Competitive pricing
- Relative refining value



Extending the advantaged crude oil to West Coast

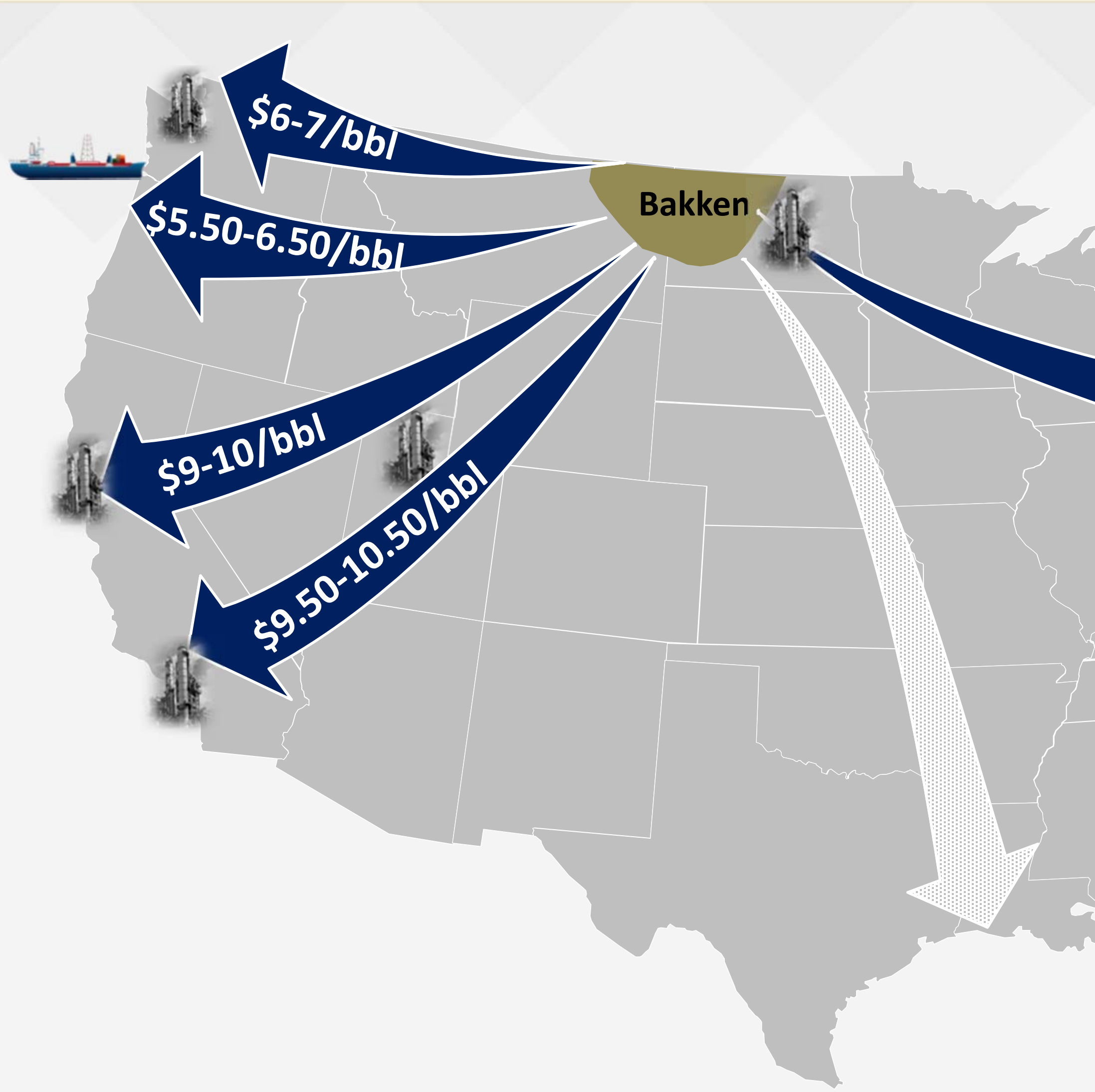
Crude Oil Production Growth

Key Tesoro Markets



Source: 2008 EIA and Canadian NEB, 2013E and 2020E estimates based on Independent consultants/TSO Analysis.

Rail Costs to Clear Bakken



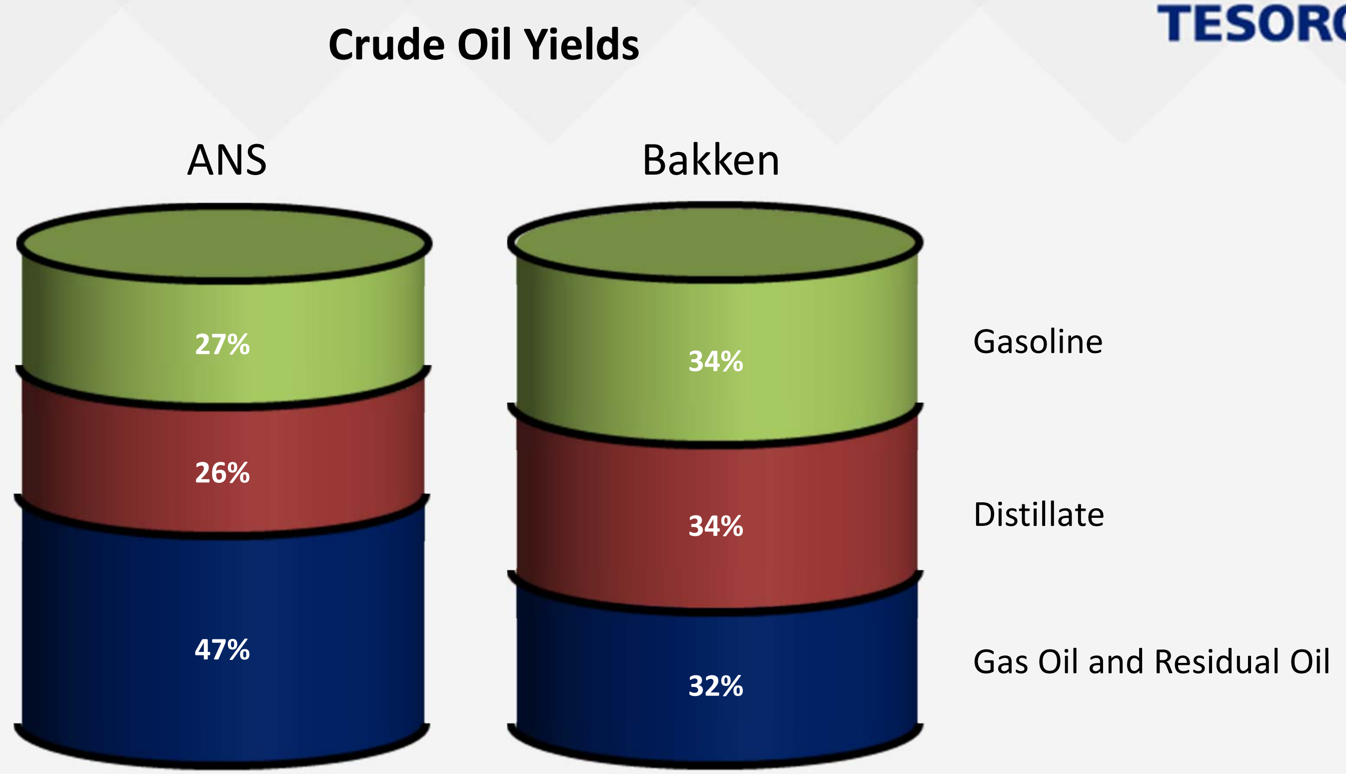
Bakken Crude Oil Supply and Logistics			
MBD	**2013**	**2014E**	**2015E**
Crude Oil Production[1]	865	1,000	1,200
Pipeline Export Capacity	635	685	685
Rail Export Capacity	865	1,015	1,015
West Coast Unloading Capacity	218	395	910
East Coast Unloading Capacity	700	780	780

West and East Coasts clearing destinations for Bakken crude oil

Note: Rail cost estimates include only the railroad tariff.

1) Average annual crude oil production, export capacity and price discount estimates based on industry consultant and Tesoro market outlook.

Anacortes Yield Comparison



Bakken crude oil yields 14% to 16% more gasoline and distillate than ANS

Port of Vancouver

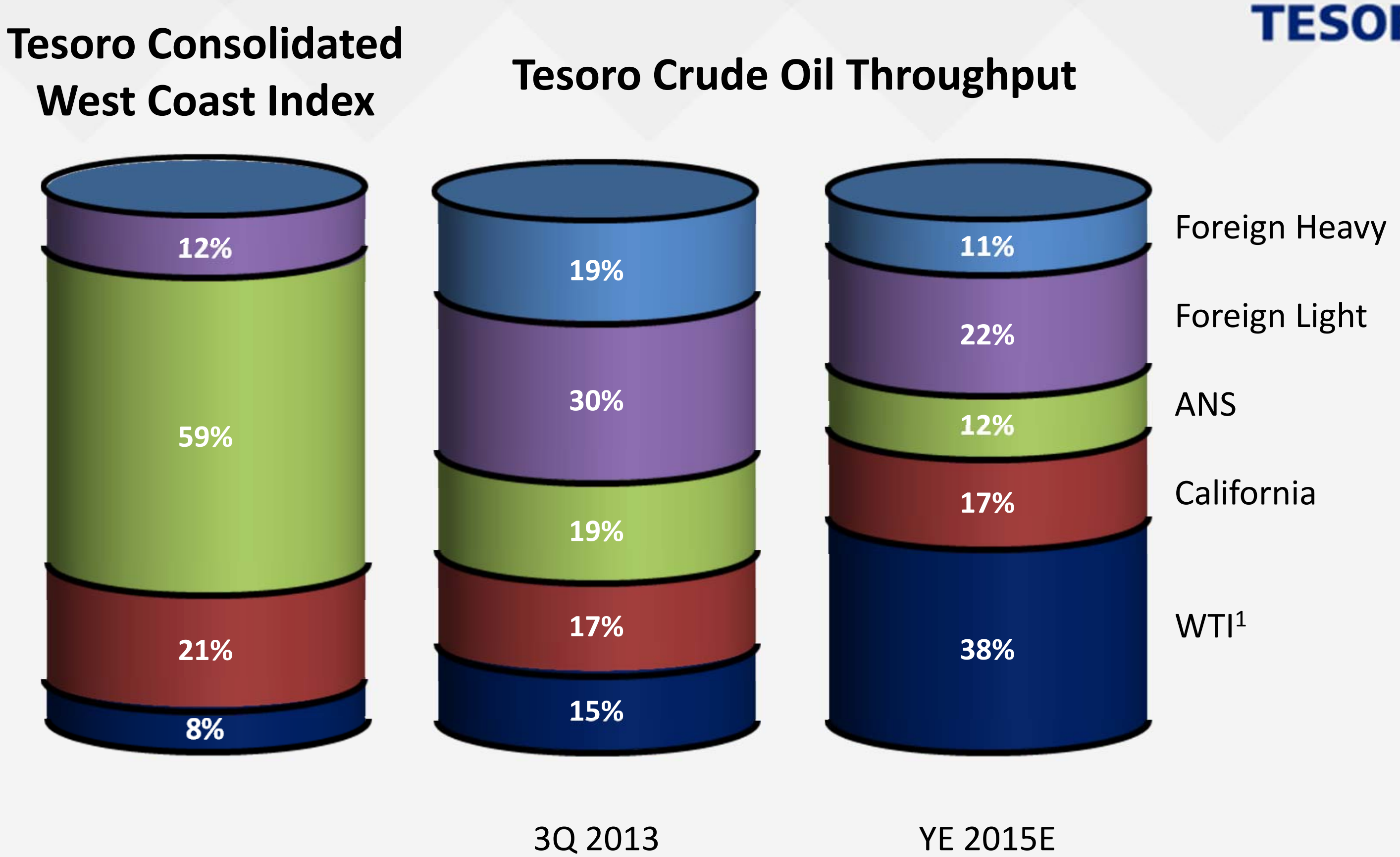
TESORO

- Up to 300 MBD Rail-to-Marine Terminal
  - Joint venture with Savage Companies
- Port of Vancouver advantages
  - Flexibility to deliver to all West Coast refineries
  - Competitive with direct rail cost to California
  - Existing rail and marine infrastructure
- Port of Vancouver granted lease 3Q13

	Completed Facility
Capacity	Up to 300 MBD
Estimated Completion	4Q14 – 4Q15
Tesoro Initial Committed Capacity	60 MBD

A premier advantaged crude oil facility for the West Coast

West Coast Refining System Opportunity

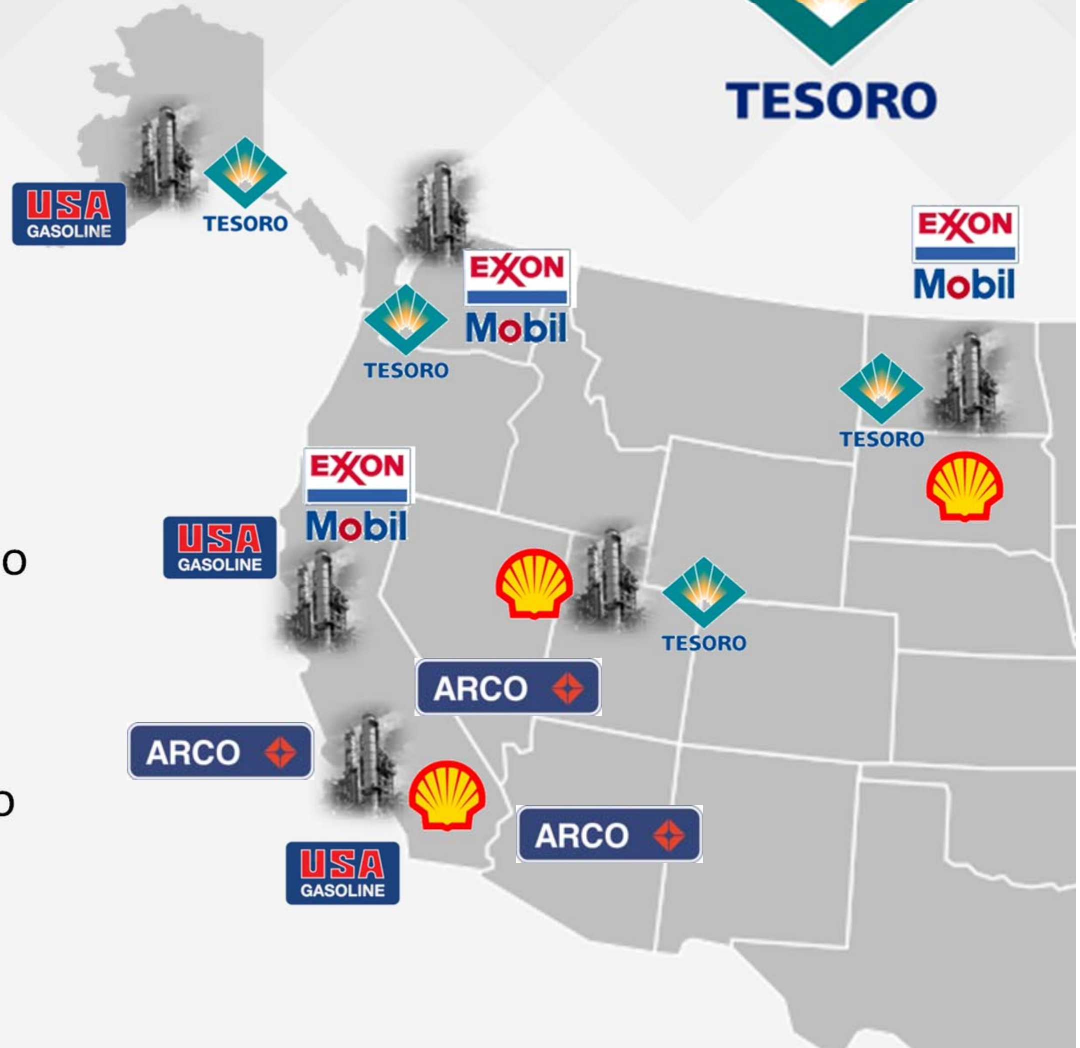


Advantage crude oil strategy enhances realized margins

1) WTI crude oil includes all grades of N. American crude oil other than those stated in other categories.

Marketing Brands

- Deploy a premium and value branding strategy within each region
- New brands allow for site optimization and conversion
- Leverage Shell®, Exxon® and Mobil® premium brand value to improve marketing channels
- Leverage ARCO®, Tesoro and USA value brand proposition to drive high utilization



Emphasis on growing ARCO®, Shell®, Exxon® and Mobil® outlets

Solomon Based Cost Reductions

TESORO

Total Operating Expense Gap (Non-energy)[1]

$/bbl	2010	2011	2012
California	1.70	1.10	0.85
Pacific Northwest	NA	0.05	0.30
Mid-Continent	0.30	0.15	1.10
Weighted Average	**1.15**	**0.55**	**0.75**

- Captured cost improvements in California, opportunities remain
- Mid-Continent performance reflects increased spending to strengthen long-term reliability
- Maintenance, personnel efficiency and improved reliability driving per barrel operating cost improvement

Targeting first tercile cost position in California

1) Versus Solomon Refinery Supply Corridor (RSC) 1st tercile, Pacific Northwest adjusted in 2010 and 2011 to exclude the impact of the Anacortes incident.

TLLP Strategic Drivers

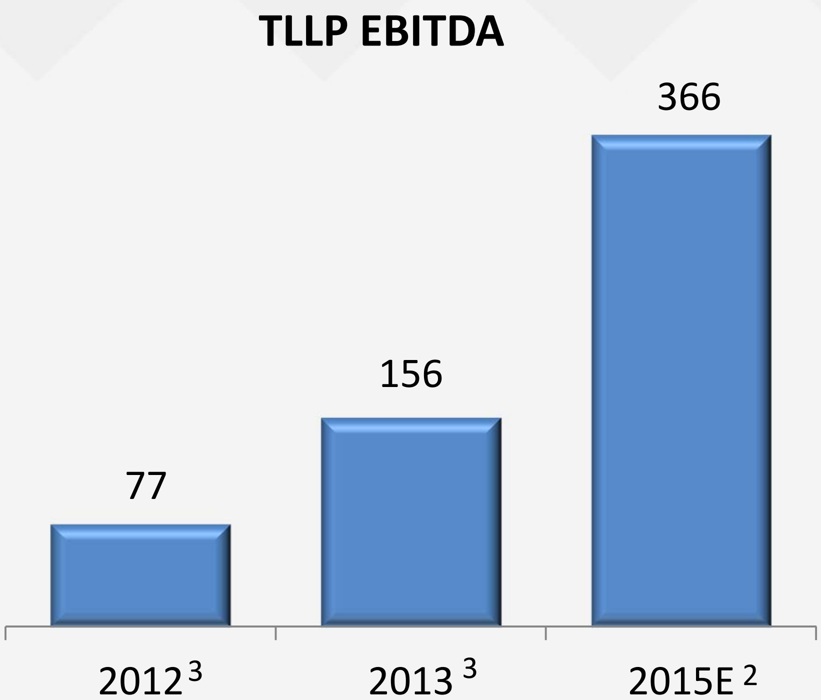
TESORO

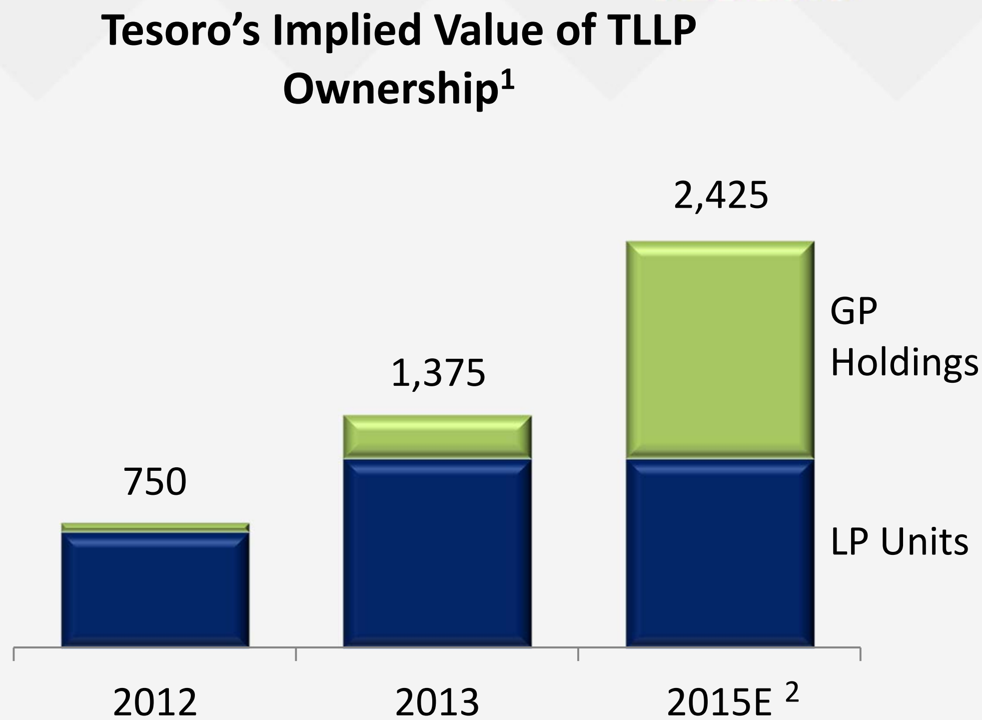
Focus on Stable, Fee-Based Business	▪ Fee-based committed businesses ▪ Maintain stable cash flow
Optimize Existing Asset Base	▪ Increase third-party volumes ▪ Consolidate Tesoro business into TLLP terminals
Pursue Organic Expansion Opportunities	▪ Execute growth projects ▪ Leverage low cost of capital
Grow Through Strategic Acquisitions	▪ Pursue acquisitions that fit Western-US footprint ▪ Strategic partner in Tesoro's growth plan

Increase EBITDA and cash distributions through fee-based logistics business model

TLLP Value Proposition to Tesoro

$ millions





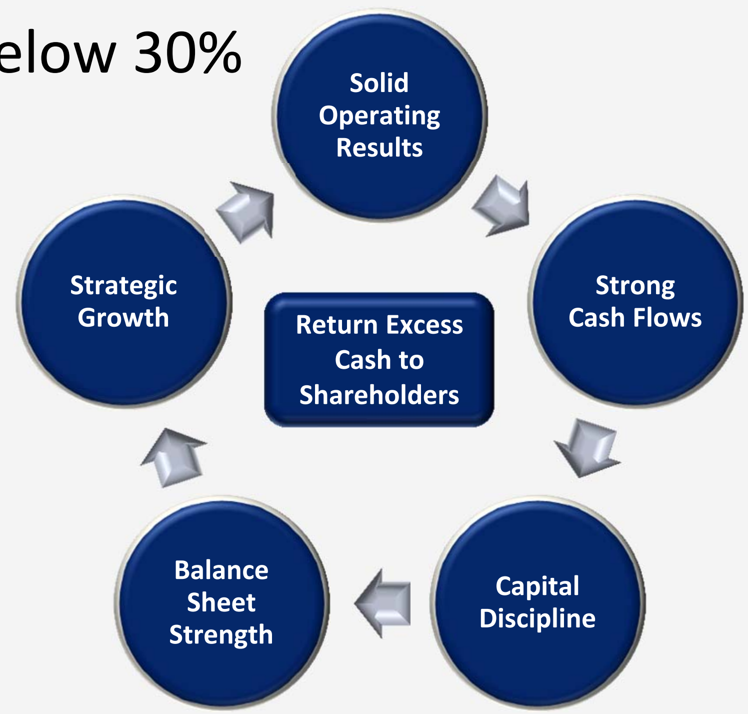
	2012	2013	2015E[2]
Implied value per Tesoro share	$5.50	$10.47	$17.20

TLLP's growth drives significant Tesoro shareholder value creation

1) TSO Market Cap as of 2/19/14, LP value based on market price, GP value based on 20X distributions.
2) Estimates based on TLLP first call consensus EBITDA figures as of 12/31/13.
3) Adjusted EBITDA, excludes predecessor results

Financial Priorities

- Maintain a minimum cash balance of $600 to $800 million
- Target TSO debt to capitalization[1] below 30%
- Target TLLP debt at 3x to 4x EBITDA
- Invest in growth opportunities to drive further value creation
- Return excess cash to shareholders
- Drive towards investment-grade credit rating



1) Excluding TLLP debt and equity.

Appropriate Leverage for Growth

TESORO

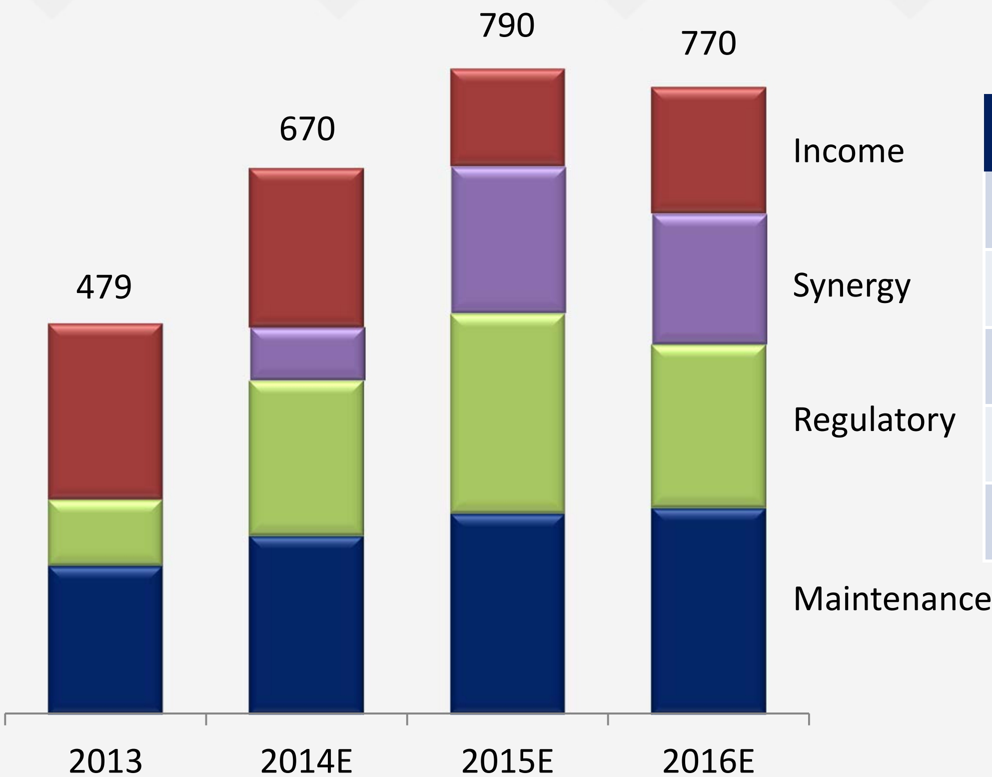
$ millions	TSO[1]	TLLP[1]	Consolidated
Total Debt	1,665	1,164	2,829
Total Equity	4,302	1,183[3]	5,485
Debt to Total Capitalization	**28%**	50%	34%
Total Debt to EBITDA[2]	0.8x	**4.1x**	1.4x

Tesoro leverage in target range less than 8 months after Los Angeles acquisition

1) As of December 31, 2013
2) EBITDA forecast based on latest 2014 consensus analyst research estimates of $2.0 billion for TSO and $287 million for TLLP
3) Represents non-controlling interest as of December 31, 2013

Summary Capital Spending

Tesoro Capital Spending[1]
$ in millions



Summary Capital Expenditures

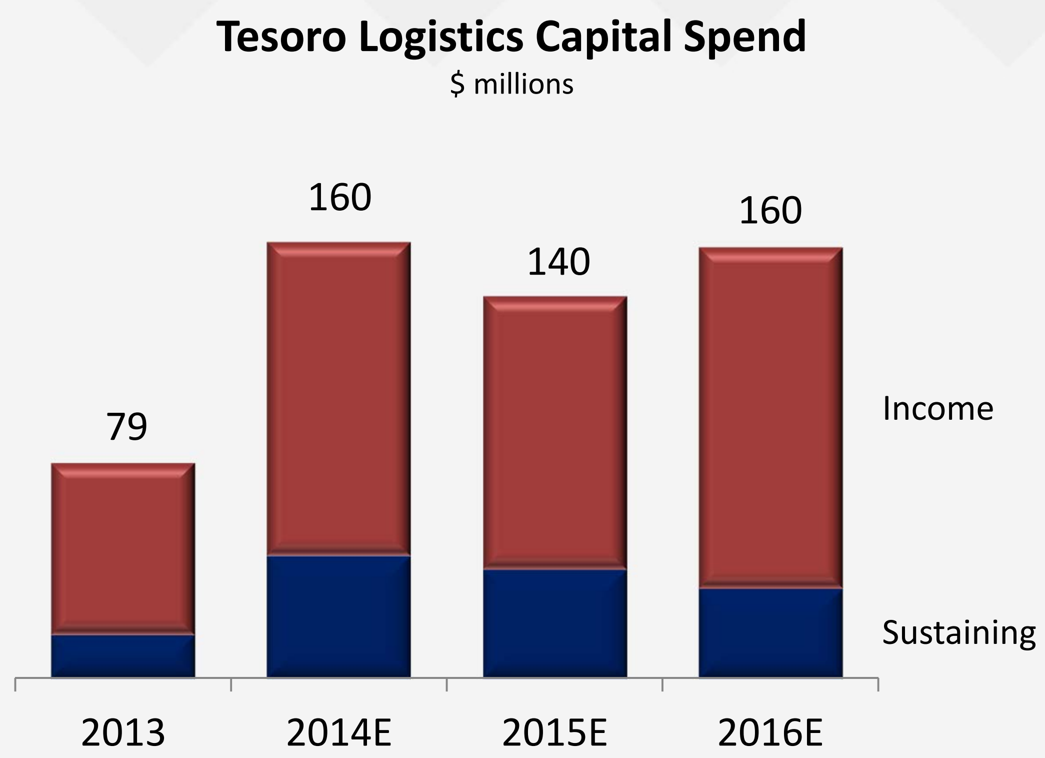
$ millions	2013	2014E	2015E	2016E
Maintenance	182	220	245	255
Regulatory	81	190	245	200
Synergy[2]	0	65	180	160
Income	216	195	120	155
Total	**479**	**670**	**790**	**770**

Capital spending plans well supported by strong and growing EBITDA

1) Excludes self-funded TLLP capital expenditures. All references to capital spending on this page are estimated.
2) Net synergy capital.

TLLP Capital Spending

- TLLP plans to spend about $100 million per year on income projects
- Typical project return of 15-25%
- Pursing opportunities to expand gathering system
- TLLP self funds capital

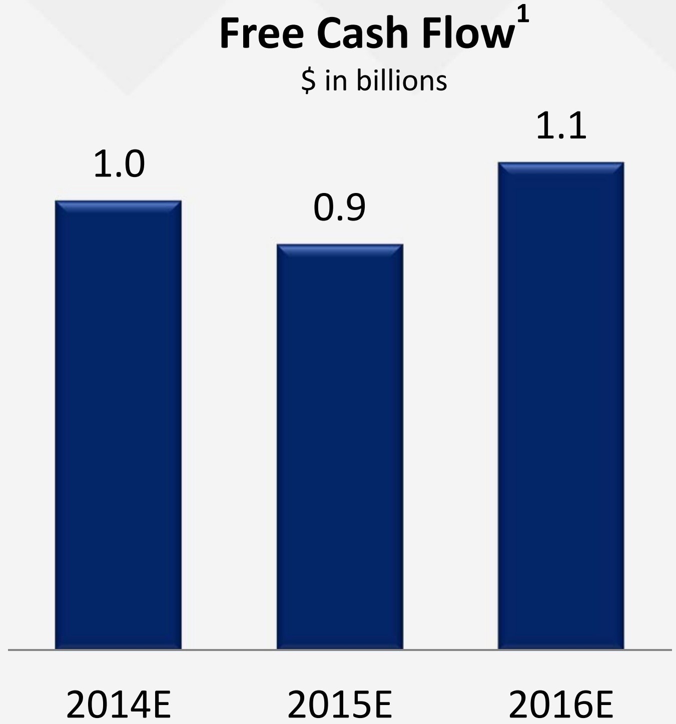


Income capital expected to support significant organic growth

Note: Maintenance and regulatory capital before reimbursements. All references to capital spending on this page are estimated.

Delivering Free Cash Flow

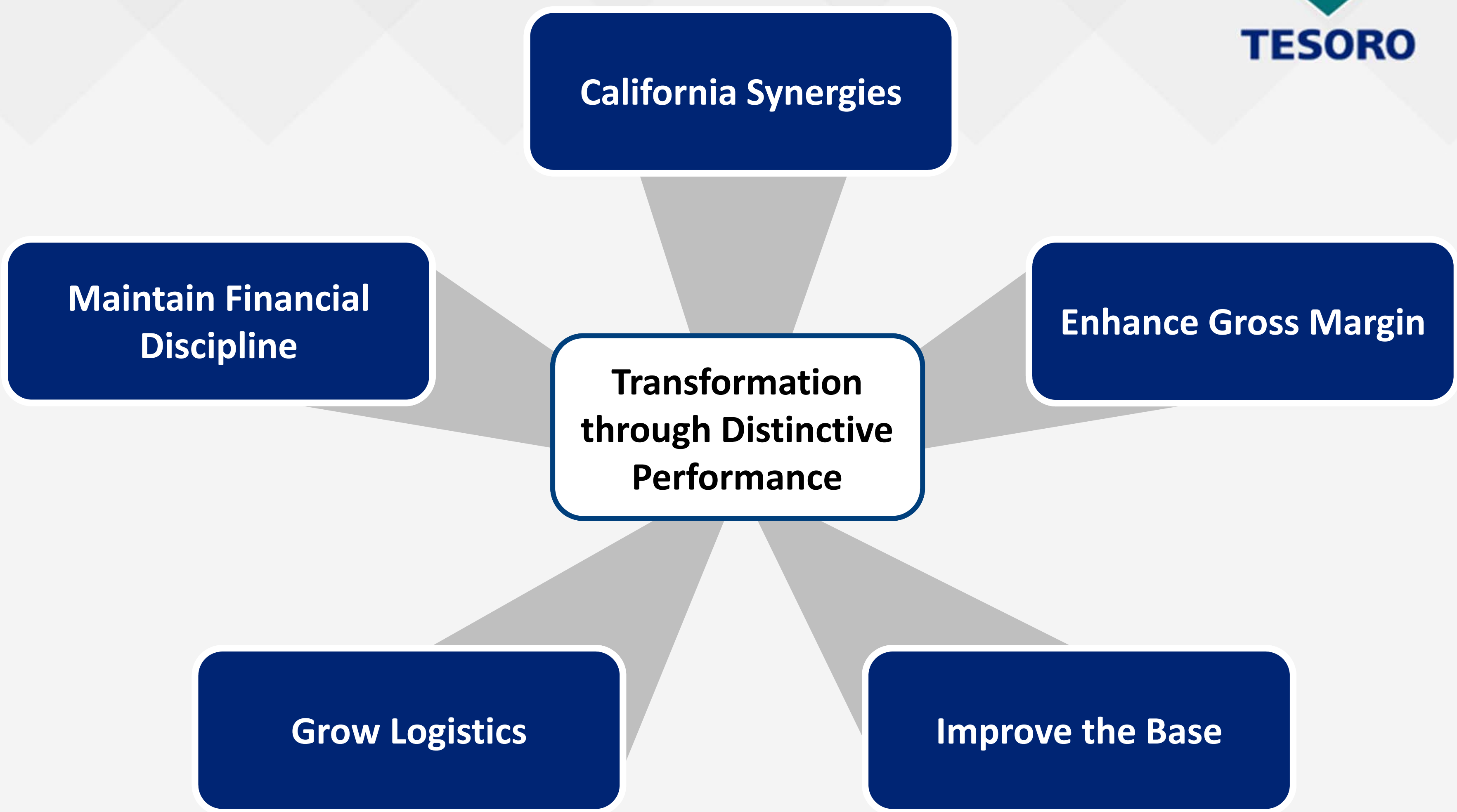
- Expect to generate approximately $3.0 billion in free cash flow over next three years
- Before potential $1.5 billion of further logistics asset sales to TLLP
- Plan to spend less than a third on high-return income capital projects
- Tesoro well positioned for further growth and returning cash to shareholders



Strong financial position and significant free cash flow in 2014 and beyond

(1) Defined as EBITDA less cash interest and taxes, sustaining capital, turnaround spending and TLLP distributions. EBITDA estimates based on consensus analyst research estimates as of November 19, 2013 and incremental improvements in this presentation above base Los Angeles synergies announced at time of acquisition. Interest, taxes, sustaining capital, turnaround spending and TLLP distributions based on Tesoro's 2014 Business Plan.

Delivering Shareholder Value



Non-GAAP Financial Measures

EBITDA represents earnings before interest and financing costs, net, interest income, income taxes, and depreciation and amortization expense. We present EBITDA because we believe some investors and analysts use EBITDA to help analyze our cash flows including our ability to satisfy principal and interest obligations with respect to our indebtedness and to use cash for other purposes, including capital expenditures. EBITDA is also used by some investors and analysts to analyze and compare companies on the basis of operating performance and by management for internal analysis. EBITDA should not be considered as an alternative to net earnings, earnings before income taxes, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America. EBITDA may not be comparable to similarly titled measures used by other entities.

(In millions) Unaudited	California Synergy EBITDA - Acquisition Model			
	2014E	2015E	2016E	2017E
Projected net earnings	$ 67	$ 104	$ 133	$ 149
Add income tax expense	41	63	82	91
Add depreciation and amortization expense	2	8	10	10
EBITDA (1)	$ 110	$ 175	$ 225	$ 250

(In millions) Unaudited	California Synergy EBITDA - Current View			
	2014E	2015E	2016E	2017E
Projected net earnings	$ 127	$ 193	$ 239	$ 280
Add income tax expense	75	113	141	165
Add depreciation and amortization expense	3	9	15	15
EBITDA (1)	$ 205	$ 315	$ 395	$ 460

(1) When a range of estimated EBITDA has been disclosed and/or previously disclosed, we have included the EBITDA reconciliation for the mid-point range.

Non-GAAP Financial Measures

(In millions) Unaudited	Gross Margin Capture Improvements EBITDA			
		2014E		2015E
Projected net earnings	$	88	$	163
Add income tax expense		51		96
Add depreciation and amortization expense		11		11
EBITDA (1)	$	150	$	270

(In millions) Unaudited	Improve the Base EBITDA			
		2014E		2015E
Projected net earnings	$	50	$	63
Add income tax expense		30		37
Add depreciation and amortization expense		0		0
EBITDA (1)	$	80	$	100

(In billions) Unaudited	Free Cash Flow Reconciliation					
		2014E		2015E		2016E
Net Cash Flow from Operating Activities	$	1.5	$	1.5	$	1.8
Less Sustaining Capital		0.4		0.5		0.5
Less TLLP Distributions		0.1		0.1		0.2
Free Cash Flow	$	1.0	$	0.9	$	1.1

(1) When a range of estimated EBITDA has been disclosed and/or previously disclosed, we have included the EBITDA reconciliation for the mid-point range.
(2) TLLP EBITDA is not representative of Tesoro consolidated EBITDA as intercompany transactions between TLLP and Tesoro are eliminated upon consolidation.

Non-GAAP Financial Measures

TESORO

(In millions) Unaudited	TLLP EBITDA December 31, 2012 [2]		
	Tesoro Logistics LP (Partnership)	Predecessor	Total Tesoro Logistics LP
Net earnings	$ 57	$ (1)	$ 56
Add interest and financing costs, net	9	0	9
Add depreciation and amortization expense	11	2	13
EBITDA	$ 77	$ 1	$ 78

(In millions) Unaudited	TLLP EBITDA December 31, 2013 [2]		
	Tesoro Logistics LP (Partnership)	Predecessor	Total Tesoro Logistics LP
Net earnings	$ 80	$ (38)	$ 42
Add interest and financing costs, net	40	-	40
Add depreciation and amortization expense	37	6	43
Less interest income	(1)	-	(1)
EBITDA	$ 156	$ (32)	$ 124

(In millions) Unaudited	TLLP Projected EBITDA [2]
	2015E
Net earnings	$ 215
Add interest and financing costs, net	75
Add depreciation and amortization expense	76
EBITDA	$ 366

(1) When a range of estimated EBITDA has been disclosed and/or previously disclosed, we have included the EBITDA reconciliation for the mid-point range.
(2) TLLP EBITDA is not representative of Tesoro consolidated EBITDA as intercompany transactions between TLLP and Tesoro are eliminated upon consolidation.

Attachment 32

CAPP

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

Crude Oil

Forecast, Markets & Transportation

June 2015

On Cover:
Top Left: Crude by Rail tank car- photo courtesy of Altex Energy
Middle Left: NCRA refinery at McPherson, KS - photo courtesy of NCRA
Middle Right: Seaway Pipeline construction - photo courtesy of Enbridge
Bottom: Kinosis *in situ* project - photo courtesy of Nexen

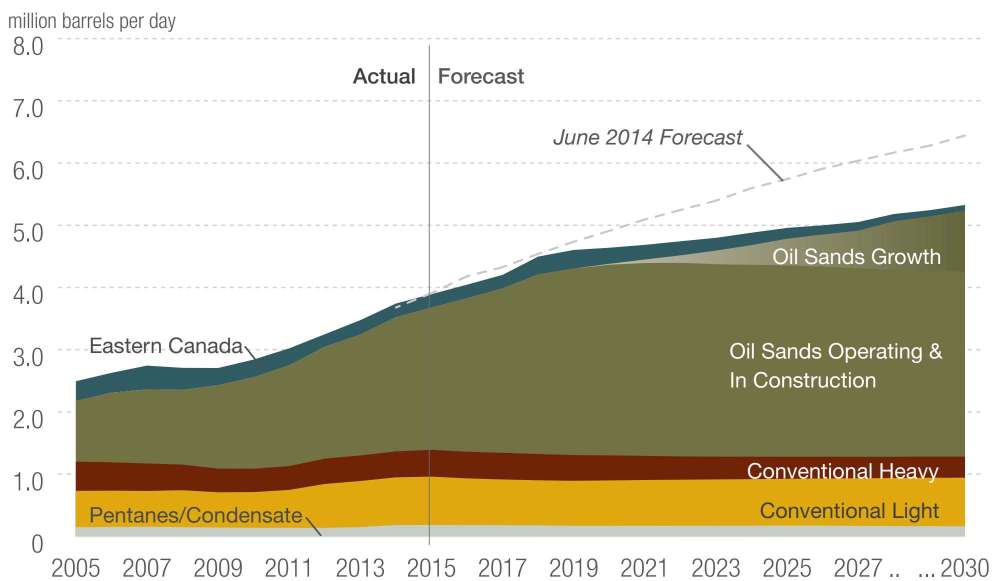
Back Cover: Long Lake - photo courtesy of Nexen

EXECUTIVE SUMMARY

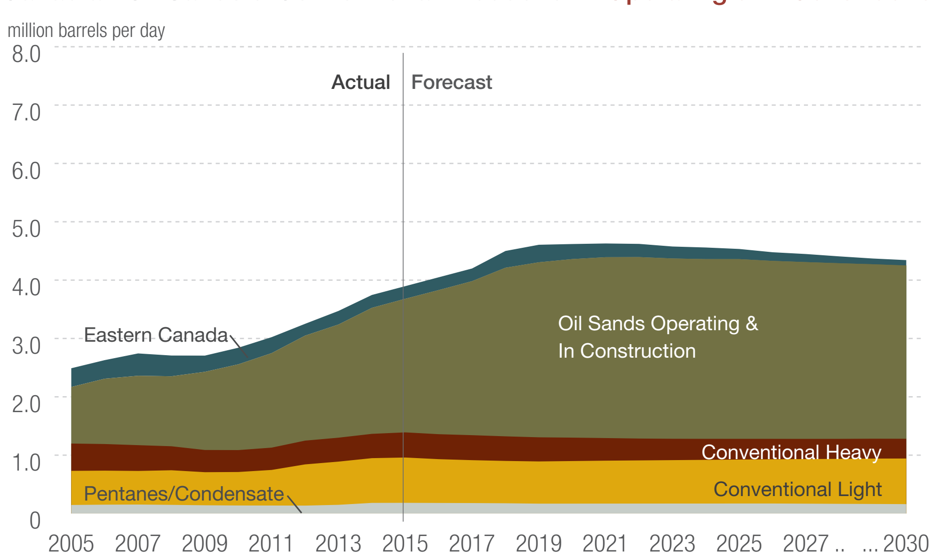
The Canadian crude oil industry is facing risks on multiple fronts in a market transformed by increased global crude oil supplies resulting in lower oil prices. These market forces are the primary driver of our revised outlook. Lower oil prices have challenged project economics and reduced capital spending intentions. These constraints have dampened the outlook for future production growth. Against this changed backdrop, highlights of this year's outlook are:

- Total oil production continues to grow but at a slower pace than previously anticipated.
- Total Canadian production grows from 3.7 million b/d in 2014 up to 5.3 million b/d in 2030, which is 1.1 million b/d lower than last year's forecast.
- Market diversity and access is still required to the U.S. Gulf Coast, the U.S. Midwest and Eastern Canada in North America. International interest in accessing Canadian crude oil is also increasing as several test cargoes were shipped to global markets in both Asia and Europe in 2014.
- The timely development of infrastructure to obtain market access is a continuing concern. The in-service dates for many of the pipeline projects have already been delayed and could be even further delayed due to extended regulatory processes. Transport of crude by rail has been growing in importance. The growth of rail beyond 2018 will primarily depend on the availability of pipeline capacity.

Canadian Oil Sands & Conventional Production - Operating & In Construction + Growth



Canadian Oil Sands & Conventional Production - Operating & In Construction ONLY



Crude Oil Production and Supply

Total production continues to grow but at a slower pace. Conventional crude oil production declines slightly over the forecast period and with 1.8 million b/d in oil sands growth, total Canadian crude oil production grows to 5.3 million b/d in 2030.

Given the challenge of developing a forecast in the current low oil price environment, a range is presented. Total oil production continues to grow but at a slower pace than previously anticipated and is 1.1 million b/d lower by 2030 than the June 2014 forecast. This is due to:

- Lower oil sands *in situ* ~835,000 b/d
- Lower oil sands mining ~33,000 b/d
- Lower conventional oil ~260,000 b/d

The oil sands production outlook that includes only projects that are currently operating or in construction represents the lower range outlook from the oil sands.

In the lower range outlook, total oil production grows from 3.7 million b/d in 2014 to 4.3 million b/d in 2030.

In the current uncertain global price environment companies continue to evaluate their growth plans. The difference in production from incorporating only the operating and in construction projects compared to the inclusion of additional production from projects currently at earlier development stages widens after 2020 and reaches almost 1 million b/d by 2030.

Conventional Oil

Conventional production in Western Canada is currently 1.4 million b/d and is expected to decline slightly to 1.3 million b/d by 2020. Of these volumes, condensate and pentanes production comprise 182,000 b/d and are expected to decline to 161,000 b/d by 2030.

Conventional oil well drilling activity is expected to decline substantially in the near-term in 2015 and 2016. Although some recovery in drilling activity has been incorporated in the latter years, there is significant uncertainty surrounding the timing.

Oil Sands

The vast majority of Canada's crude oil reserves reside in the oil sands so it is natural for this resource to be the primary driver for future overall growth. The 2015 outlook for oil sands reflects an average annual growth of 168,000 b/d through to 2019. During the last decade of the outlook, the average annual pace from 2020 to 2030 declines to approximately 86,000 b/d.

In 2014, 2.2 million b/d were produced from the oil sands of which 912,000 b/d was from mining and 1.2 million b/d from *in situ* projects. Looking ahead to 2030, mining production is forecast to reach at least 1.4 million b/d in 2030 from projects that are operating or in construction and up to 1.6 million b/d with the additional growth forecast. *In situ* production is forecast to reach at least 1.6 million b/d from the lower range and up to 2.4 million b/d with the forecast growth.

Eastern Canada

In 2014, Eastern Canada accounted for about 6 per cent, or 220,000 b/d of total Canadian crude oil production. The Hebron project is scheduled to start operations in 2017 and provide new volumes. By 2030, production is forecast to gradually decline to around 92,000 b/d but this could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable crude oil.

Canadian Crude Oil Production

million b/d	2014	2015	2020	2025	2030
Total* Canada	3.74	3.89	4.64	4.96	5.33
Eastern Canada	0.22	0.22	0.26	0.17	0.09
Western Canada Conventional (including condensate)	1.37	1.39	1.30	1.28	1.28
Oil Sands					
Oil Sands Operating & In Construction	2.16	2.29	3.07	3.08	2.97
+ Oil Sands Additional Growth	-	-	+0.01	+0.43	+0.98
Oil Sands Operating & In Construction with Growth	2.16	2.29	3.08	3.51	3.95
Western Canada	3.52	3.68	4.38	4.78	5.23

*Totals may not add up due to rounding.

Crude Oil Markets

International markets are showing interest in growing Canadian supplies.

Market diversity and corresponding expanded transportation capacity remain key issues associated with this latest outlook. Canadian production requires additional tidewater access in order to reach global markets and even some prospective North American markets, including California.

Eastern Canada and the Gulf Coast represent the greatest opportunity for expanded markets in North America for Canadian crude oil production. The U.S. East Coast holds limited expansion opportunities due to their primarily light crude oil requirements that will likely be increasingly satisfied through growing U.S. domestic production. The larger U.S. Midwest market is already well supplied with western Canadian and domestic U.S. supplies.

Growing supplies of western Canadian production must be transported to tidewater if it is to ultimately reach international markets.

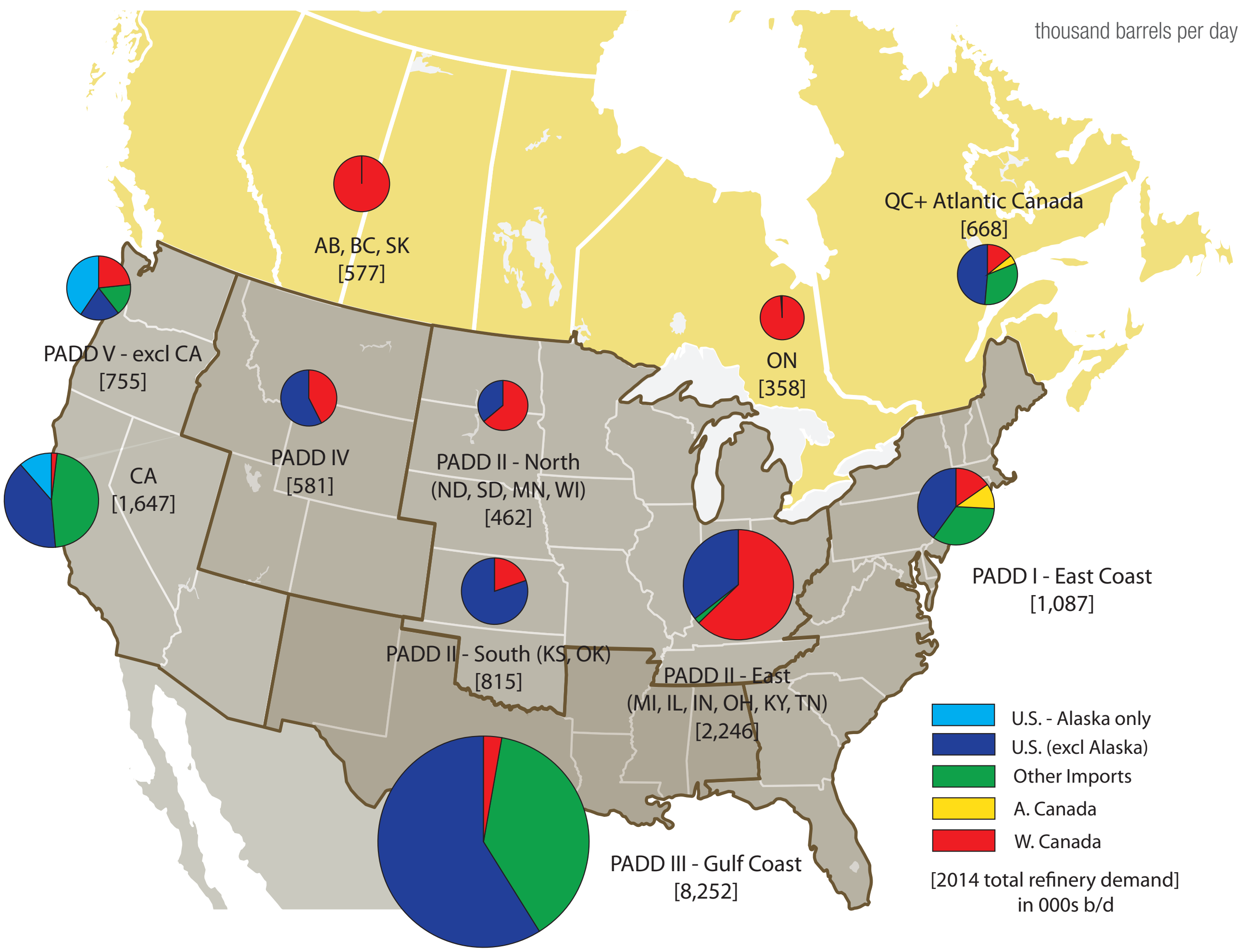
Eastern Canada

Refineries in Québec and Atlantic Canada currently import 77 per cent of their crude oil feedstock requirements. This translates to a potential 500,000 b/d domestic market opportunity for Canadian supplies, particularly conventional light and upgraded light crude oil. However, in 2014, imports from the U.S. more than doubled and accounted for 60 per cent of Canada's foreign imports. These volumes were transported by rail and tanker. Refineries in Ontario have already shifted their main source of crude oil feedstock to Western Canada.

United States

Refineries in the U.S. Gulf Coast processed over 8 million b/d of crude oil in 2014, including over 2 million b/d of foreign heavy oil imports. Canadian producers are displacing some of these imported volumes and are forecast to supply at least 468,000 b/d to this market by 2020. This is about double the 235,000 b/d that is currently supplied.

2014 Canada and U.S. Crude Oil Demand by Market Region



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

The U.S. Midwest will remain Canada's largest export market. In 2014, Canadian producers supplied 1.9 million b/d to this market. A number of refinery conversion projects for processing heavy crude oil have been completed in the last two years and are anticipated to increase demand in the region by 190,000 b/d to reach 2.1 million b/d by 2020.

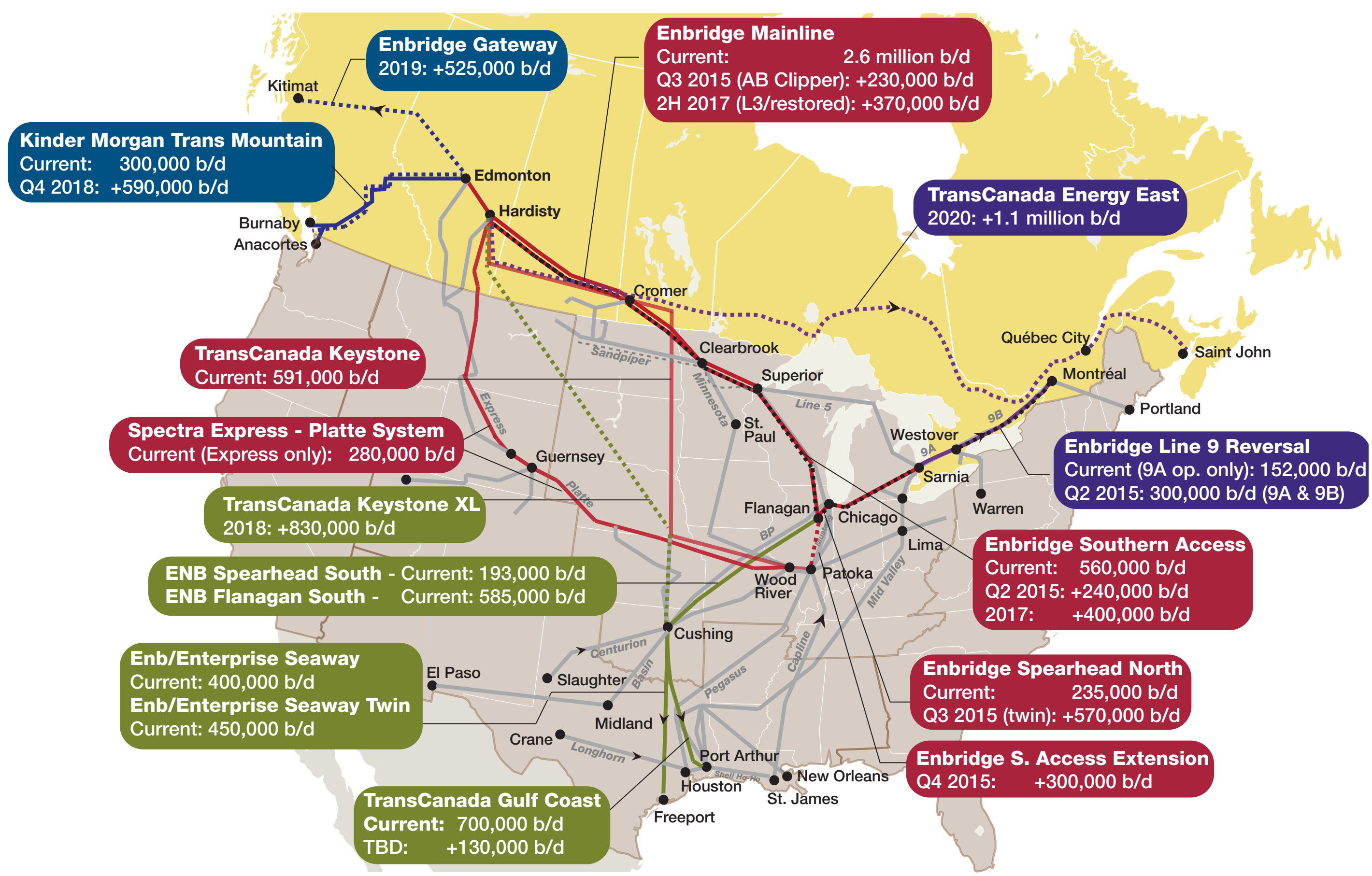
Refineries in Washington and California need to replace their declining traditional sources of supply from Alaska. These refineries are expected to increase current demand for western Canadian crude oil from 211,000 b/d to 391,000 b/d. Demand for western Canadian crude oil from U.S. East Coast refineries is not expected to grow given 2014 demand of 167,000 b/d and the survey indicating 2020 demand will fall to 133,000 b/d.

World

Currently crude oil from Western Canada has limited access to tidewater and hence to global crude oil markets. However, there is growing interest in Canada's crude oil supply in both Asia and Europe. In 2014, Statistics Canada reported shipments of Canadian crude oil destined for Italy, United, Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India. China and India have huge potential as markets for Canadian crude oil as they currently have the fastest growing demand for crude oil in the world.

According to the U.S. Energy Information Administration (EIA), combined oil imports from China and India are forecast to increase by 6.6 million b/d; going from 10.3 million b/d in 2014 to 16.9 million b/d by 2030.

Canadian & U.S. Crude Oil Pipelines and Proposals



Crude Oil Transportation

Pipeline projects to the East, West and South are being developed and are all needed to provide sufficient market diversification to western Canadian producers.

Even with this lower growth forecast, an expansion of the existing transportation infrastructure is needed to connect growing crude oil supply from Western Canada to new markets. Pipelines are the primary mode of transportation for long term movements of crude oil but the protracted regulatory processes continues to present a number of challenges. Delays in startup timing are providing the impetus for additional capacity from railways in the transport mix to complement pipelines transport.

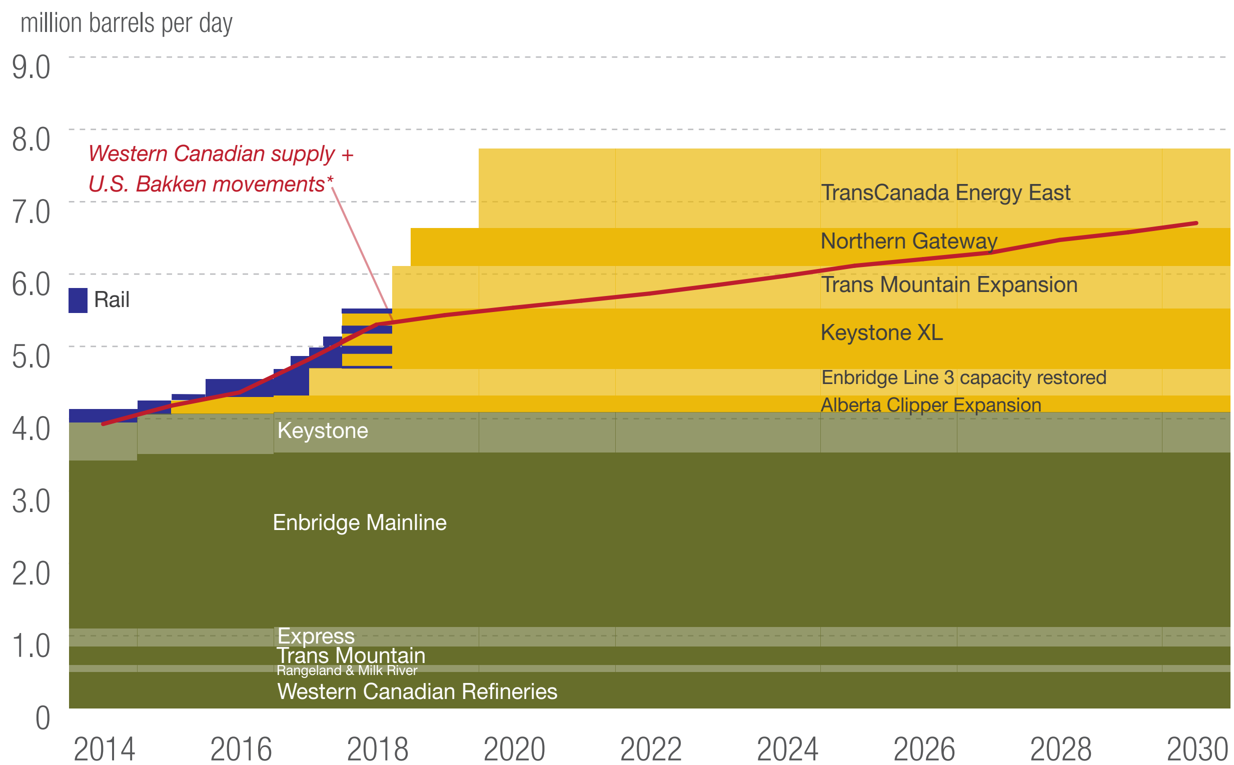
The graph below shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted crude oil supply movements. Rail has been supplying increased transportation capacity. The purple represents the current and growing rail throughput that could occur until 2018. The forecasted supply movements was developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that would utilize a portion of the pipeline capacity that exits Western Canada.

The proposed pipeline projects are stacked in order of the reported timing of the various individual projects. It should not be interpreted as CAPP's view of the likelihood of one project proceeding faster than another. The Keystone XL project would offer connections to the U.S. Gulf Coast refineries. The Trans Mountain Expansion and Northern Gateway projects would provide access to the West Coast and allow deliveries to Asian markets while TransCanada Energy East would provide access the East Coast markets in Canada and the U.S. and allow deliveries to be made to European markets.

These projects target three different markets and as such, all will be needed to provide western Canadian producers with a level of market diversification that would allow Canada to achieve the maximum value for its resources. Increasing market optionality is of vital importance to companies considering investing large amounts of capital in order to realize the enormous resource potential that Western Canada holds. It should be noted that the announced timing for all of the pipeline proposals have been delayed by the proponents from the dates reported last year. This reflects the challenges associated with large linear infrastructure projects.

In 2014, crude by rail volumes averaged 185,000 b/d. Crude by rail continues to be used as a complement to pipeline transportation with volumes moving by rail anticipated to continue to grow through to 2018. Beyond that rail use will be impacted by the timing of proposed pipeline projects.

WCSB Takeaway Capacity vs. Supply Forecast



*Refers to the portion of U.S. Bakken production that is also transported on the Canadian pipeline network.
Capacity shown can be reduced by temporary operating and physical constraints.

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1 | INTRODUCTION

CAPP's *Crude Oil Forecast, Markets & Transportation* report is typically published around the middle of each year. The crude oil supply outlook for Canada is provided in conjunction with an examination of the potential demand for this production in various markets. There is also an update on the existing transportation infrastructure and proposed transportation projects to serve these markets. As such, the report endeavors to meet the growing need for a timely reference document that can be used by industry, government, media, the financial community, environmental groups and the general public alike.

The 2015 CAPP crude oil forecast provides the outlook for Canadian production from 2015 to 2030. It covers conventional oil, oil sands and offshore production. The oil sands forecast is based on the amalgamated results of the producers' latest reported data on their individual oil sands projects. The market demand forecast reflects an unadjusted survey of North American refiners' future demand for western Canadian crude oil until 2020.

The Canadian crude oil industry is managing risks on multiple fronts in an environment transformed by lower oil prices. During the latter part of 2014, the industry witnessed a rapid drop in oil prices. The benchmark WTI crude oil spot price dropped from a peak of over US$100 per barrel in June 2014 to below US$55 per barrel in December. From January to April 2015, the oil price averaged around $50 per barrel. Lower oil prices are challenging project economics. Against this changed backdrop, CAPP's latest Canadian oil production outlook anticipates that total oil production continues to grow but at a slower pace and is 1.1 million b/d lower by 2030 than was forecast a year ago.

Canadian crude oil production growth remains driven primarily by production from oil sands resources, which comprise over 97 per cent of Canada's crude oil reserves. CAPP's estimate of industry capital spending for oil sands development is C$23 billion for 2015, which is C$10 billion lower from the estimated expenditure in 2014. Conventional production declines slightly through the forecast, whereas the declines in production from offshore Eastern Canada commence in 2020.

1.1 Production and Supply Forecast Methodology

The oil sands component of the forecast is based on CAPP's survey of all oil sands producers and as such, reflects the latest industry insight on factors such as production capability from individual projects and general market opportunities.

CAPP does not forecast crude oil prices. Producers responded to the survey using their own internal view of the long-term oil price. In this manner, CAPP is assuming that the oil price will be sufficient to make these projects economic so that this production will be available to the market.

Producers were surveyed for the following data:

a) expected production for each project by phase;

b) upgraded light crude oil production; and

c) volumes of synthetic crude oil and condensate used as diluent required to move the volumes to market.

The survey results were then adjusted or "risked" accordingly based on each project's stage of development. Past performance was considered in determining the pace of development in future project stages. The overall forecast was then verified for reasonableness against historical trends. No constraints were put on the forecast due to availability of condensate for blending purposes or transportation infrastructure.

The conventional component of the forecast is undertaken at a provincial level and was developed through CAPP's internal analysis of historical trends, expected drilling activity, recent announcements, as well as discussions with industry stakeholders and government agencies.

The Saskatchewan forecast is further supported by the data from CAPP's survey of the oil producers in the province regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production and decline rates.

1.2 Market Demand Outlook Methodology

As in the past, CAPP did not make any adjustments to the data submitted by refiners regarding their expectation of future demand for Canadian crude oil beyond checking for potential errors. Where possible, EIA data was used or adjusted to complete gaps in the survey data for actual demand in 2014 for each region of the U.S.

The CAPP survey categorizes western Canadian crude oil into four main types as follows:

1. Conventional Light Sweet (greater than 27° API and less than or equal to 0.5% sulphur) including condensates and pentanes plus
2. Heavy (equal to or less than 27° API) including conventional heavy, synthetic sour and crude oil blends such as DilBit, SynBit and DilSynBit
3. Conventional Medium Sour (greater than 27° API and greater than 0.5% sulphur)
4. Light Sweet Synthetic (Upgraded Light)

The following crude types and definitions apply to the historical data of foreign imports presented in the source of supply pie charts in this section of the report:

- Sweet: crude oil with a sulphur content of less than or equal to 0.5%
- Sour: crude oil with a sulphur content of greater than 0.5%
- Light: crude oil with an API of at least 30°
- Medium: crude oil with an API of greater than 27° but less than 30°
- Heavy: crude oil with an API of 27° or less

No differentiation is made between sweet and sour crude oil that falls into the heavy category because heavy crude oil is generally assumed to be sour.

1.3 Transportation Outlook Methodology

In this publication, CAPP reports the timing of the proposed pipeline and rail projects based on information released by the project proponents. The project-review timelines within the regulatory process can be lengthier than originally anticipated and represents a significant factor that impacts the final in-service date of these projects.

CAPP's production forecast is not constrained by a lack of any transportation infrastructure. However, the report does compare the supply that the analysis produces against the current and proposed pipeline and rail projects to determine where bottlenecks may occur if these transportation projects fail to materialize in the time frame they are currently envisaged.

2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST

Oil is one of the most important sources of energy in the world, accounting for over 30 per cent of the total primary energy consumption. Globally, Canada is the 5th largest producer of oil, according to the U.S. Department of Energy, Energy Information Administration (EIA). The Oil & Gas Journal reports Canada's proven oil reserves at 173 billion barrels; the world's third largest reserves after Venezuela and Saudi Arabia. Notably, the oil sands that are located in the province of Alberta hold 167 billion barrels of these reserves.

The strategic development of these resources is important to both industry and the Canadian economy. In the current low oil price environment, it is vitally important to encourage investment in the oil industry. It provides the foundation for security of supply and jobs. The impact of the lower world oil prices on the Canadian industry has been mitigated somewhat by the lower Canadian dollar and lower discounts for Canadian crude oil. However, the industry continues to manage long term challenges including volatile price differentials and increasing costs related to operations and improving market access.

2.1 Canadian Crude Oil Production

In 2014, Canada produced 3.7 million b/d of crude oil, an increase of 267,000 b/d or 8 per cent over 2013 levels. Production is expected to continue to grow throughout the forecast period. Western Canada produced 3.5 million b/d, of which 2.2 million b/d came from the oil sands and 1.4 million b/d came from conventional resources. About 220,000 b/d originated in Eastern Canada.

This year, we have provided additional detail underlying our forecast by breaking out the component of the forecast for oil sands production that includes only projects currently "Operating" or "In Construction". In the current uncertain global price environment companies continue to evaluate their growth plans. Table 2.1 shows the forecast for total Canadian production and its breakdown between Eastern and Western Canada.

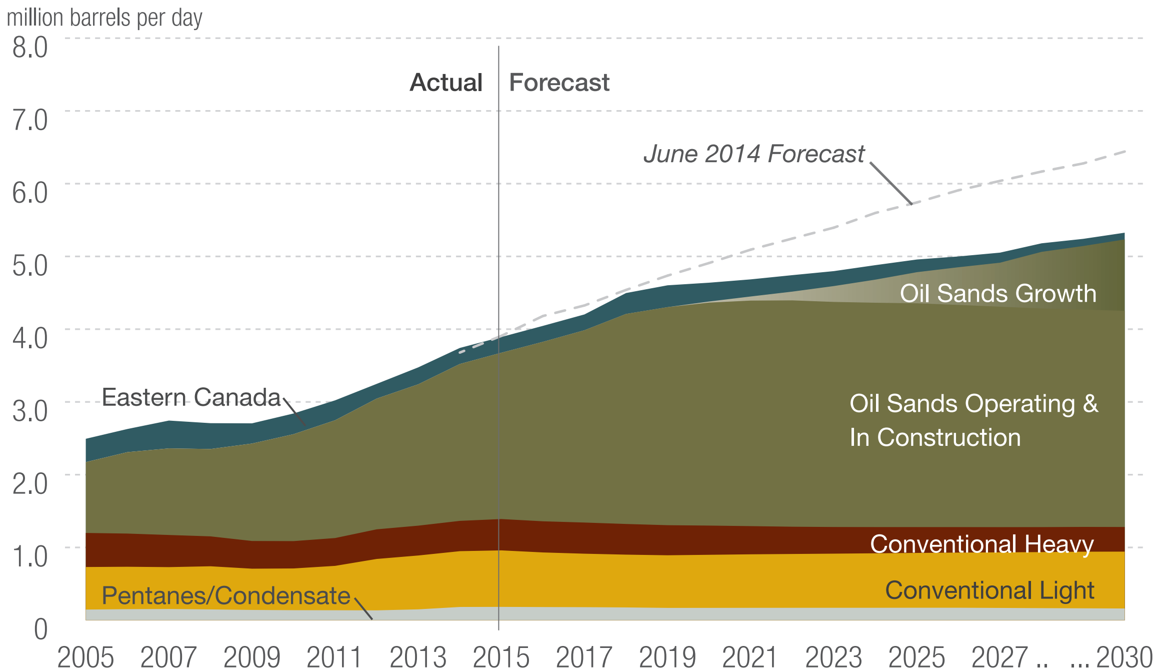
Table 2.1 Canadian Crude Oil Production

million b/d	2014	2015	2020	2025	2030
Total* Canada	3.74	3.89	4.64	4.96	5.33
Eastern Canada	0.22	0.22	0.26	0.17	0.09
Western Canada Operating & In Construction	3.52	3.68	4.37	4.36	4.25
+ Western Canada Growth	-	-	+0.01	+0.43	+0.98
Western Canada	3.52	3.68	4.38	4.78	5.23

*Totals may not add up due to rounding.

Figure 2.1 shows the total Canadian production forecast. Conventional production from Western Canada is expected to decline slightly throughout the forecast and falls to 1.3 million b/d by 2030. Oil sands production will drive the overall increase in production, which is expected to grow on average by 168,000 b/d for the next 5 years. This rate of growth is similar to that exhibited in the past 5 years. However, this rate of growth slows by almost a half for the last decade of the forecast as oil sands production is anticipated to reach almost 4.0 million b/d by the end of the forecast period in 2030.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.2 Eastern Canadian Crude Oil Production

There are small volumes of crude oil produced in Ontario and New Brunswick. In terms of development in other provinces, the Québec government supported preliminary oil exploration work on Anticosti Island in 2014. It was recently reported that oil was discovered in the Gaspé region of Québec.

However, the primary source of Eastern Canada's crude oil production is from projects located offshore of Newfoundland and Labrador. The three offshore oil fields currently in production are: Hibernia, Terra Nova and White Rose. The overall rate of decline from these facilities has slowed as a result of continued drilling at satellite fields associated with these projects (e.g. Hibernia South Extension, North Amethyst and White Rose Extensions).

Development drilling continued on the first production wells for the South White Rose Extension with first oil anticipated in mid-2015. The final investment decision for the West White Rose Extension project was deferred by the operator in December 2014 as part of the overall reduction in captital investment and is not included in CAPP's forecast.

Drilling of the Hibernia-formation well at the North Amethyst field is scheduled to resume after the first two South White Rose production wells have been brought online in mid-year. First production from the well is expected in the third quarter of 2015. A planned sidetrack of the first appraisal well was completed and drilling of the second well began in the first quarter of 2015. First oil from Hebron, the fourth major project, is expected around the end of 2017.

In 2014, eastern Canadian production declined to 220,000 b/d, which translates to a 5 per cent decrease from the previous year. At the end of the forecast period, production is expected to decline to 92,000 b/d by 2030. Overall, there is little change compared to CAPP's 2014 forecast.

Future production could be higher than forecast as potential production from the Flemish Pass Basin have not yet been incorporated in CAPP's forecast due to the early stage of evaluation. The Bay du Nord discovery area is estimated to hold between 300 and 600 million barrels of recoverable oil. The Mizzen discovery is estimated to hold 100 to 200 million barrels while the Harpoon discovery is still under evaluation.

2.3 Western Canadian Crude Oil Production

Western Canadian crude oil production originates from both conventional and oil sands sources (Table 2.2). The oil sands are essentially found in the province of Alberta, while conventional resources underlie Alberta, northeast British Columbia, Saskatchewan and parts of Manitoba and the Northwest Territories.

Similar to CAPP's 2014 report, production is expected to grow by 156,000 b/d until 2020, which effectively maintains a similar growth rate that has been exhibited for the past five years. This is primarily due to commitments to capital investments already underway for upcoming oil sands projects. From 2020 to 2030, however, this rate of growth is expected to slow to 85,000 b/d year-over year until 2030. At the end of the outlook period, western Canadian oil production is 1.1 million b/d lower than forecast last year but still reaches 5.2 million b/d in 2030.

Conventional production is forecast to contribute 1.3 million b/d to the total output on average over the forecast period. Compared to last year's forecast, conventional production is 260,000 b/d lower by 2030; the majority of this decline reflects the significant drop in the number of wells drilled in the short-term given the low oil price environment.

Table 2.2 Western Canadian Crude Oil Production

million b/d	2014	2015	2020	2025	2030
Western Canada	3.52	3.68	4.38	4.78	5.23
Conventional (including pentanes/ condensate)	1.37	1.39	1.30	1.28	1.28
Oil Sands Operating & In Construction	2.16	2.29	3.07	3.08	2.97
+ Oil Sands Growth	-	-	+0.01	+0.43	+0.98
Oil sands (bitumen & upgraded)	2.16	2.29	3.08	3.50	3.95

*Totals may not add up due to rounding.

2.3.1 Conventional Crude Oil Production

In 2014, conventional production, including condensates, increased by 66,000 b/d to 1.4 million b/d. Although there has been a year-over-year upward trend in conventional production since 2010, it is expected to return to a slow decline starting in 2016. Most of the conventional production comes from Alberta and Saskatchewan, of which over 60 per cent is light crude oil. By 2030, the light portion, including condensates, is forecast to comprise 74 per cent of total conventional production.

Most of the condensate production in Canada comes from Alberta and British Columbia and is primarily recovered from natural gas wells. Notably, condensate production, a subset of total conventional production, increased by 33,000 b/d in 2014 or 22 per cent, growing from 149,000 b/d to 182,000 b/d. Condensate production from the liquids-rich Montney play and emerging Duvernay play rose with higher drilling activity but due to lower oil and gas prices, drilling activity is expected to decline in the near term. However, overall condensate production is forecast to only decline slightly to 161,000 by 2030.

Alberta

Alberta is well-known for its oil sands resources but it also accounts for about half of Western Canada's conventional oil production, excluding condensates. In addition, the province is the source of 84 per cent of the condensate production in Western Canada. In 2014, Alberta's conventional light crude oil production, increased by 2 per cent compared to 2013, to 440,000 b/d. In contrast, conventional heavy crude oil production, decreased by 2 per cent to 150,000 b/d. Overall, total conventional production increased by 1 per cent to 590,000 b/d. The outlook calls for a slight decline throughout the forecast to 524,000 b/d by 2030. The province's condensate/pentanes plus production increased by 21 per cent to 153,000 b/d in 2014.

Saskatchewan

Saskatchewan is the second largest oil producing province in Canada. A growth in conventional light oil production over the past three years, continued with an 8 per cent increase in 2014 with production reaching 248,000 b/d. There was also a 4 per cent growth in conventional heavy oil production so that this production rose to 267,000 b/d. The total conventional production in Saskatchewan grew by 6 per cent or 28,000 b/d to reach 514,000 b/d. On average, Saskatchewan conventional production is expected to contribute 536,000 b/d during the outlook.

Manitoba, British Columbia, NWT

Manitoba accounts for 4 per cent of the total conventional production from Western Canada excluding condensates. Current production of 47,000 b/d is forecast to decline gradually through the outlook to 27,000 b/d by 2030.

British Columbia is the second largest provincial source of condensate production after Alberta, accounting for 15 per cent of total condensate production in Western Canada. The province also accounts for 2 per cent of total western Canadian conventional production.

Little production currently comes from the Northwest Territories (NWT); however, there has been some investment attracted to the Sahtu region, one of North America's oldest fields. The NEB and the Northwest Territories Geological Survey released its first publicly available assessment of the unconventional oil-in-place resources for the Bluefish Shale and Canol Shale in the NWT, in May 2015. The report stated that if only 1 per cent of the oil-in-place assessed for Canol Shale could be recovered, it would represent a marketable resource of 1.45 billion barrels.

2.3.2 Oil Sands

Three designated oil sands areas in Northern Alberta have been established in order to differentiate the extra heavy crude oil produced from these regions, termed bitumen, from conventional crude oil production. The regions are referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3).

Figure 2.2 Western Canada Conventional Production

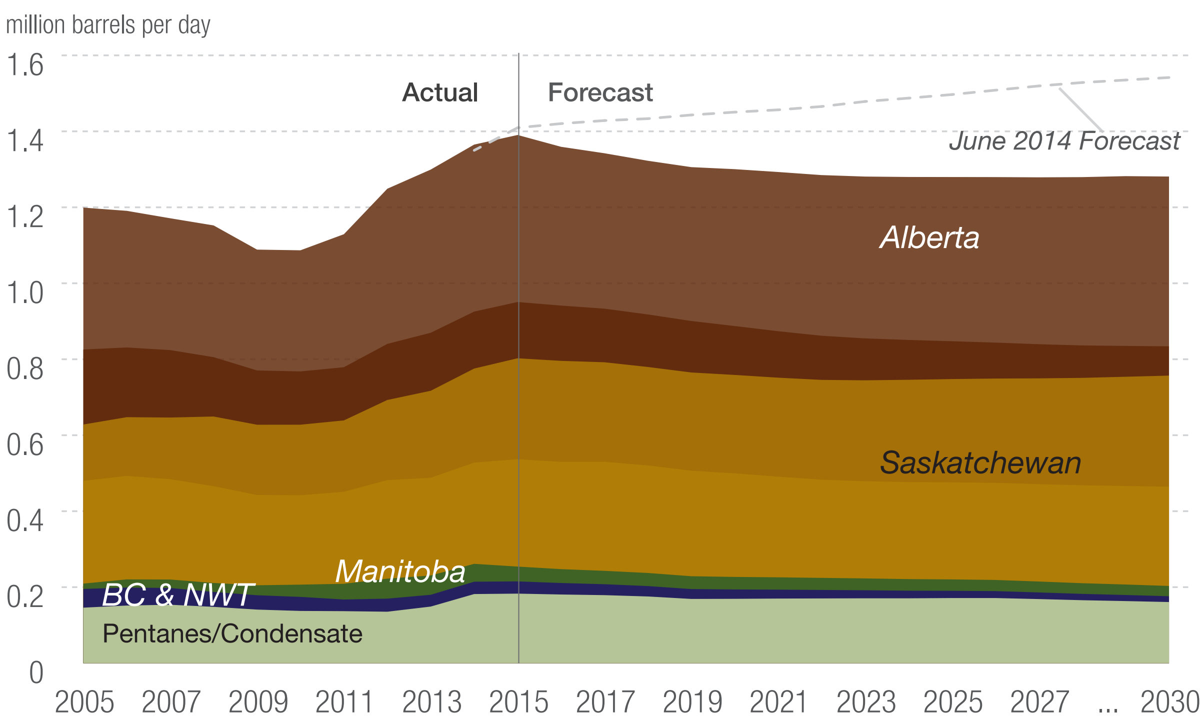


Figure 2.3 Oil Sands Regions

The AER estimated at year-end 2013, that these areas contain remaining established reserves of 167 billion barrels. Depending on the depth of the deposit, one of two methods is used to recover the bitumen. Surface or open pit mining can be used to recover bitumen that occurs near the surface.

At greater depths, *in situ* (Latin for "in-place") techniques are employed. The term is used in reference to both primary development, which uses methods similar to conventional crude oil production, and enhanced recovery techniques - the main methods being cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). As such the resources are accessed via a combination of steam injection wells to reduce the viscosity of the bitumen and recovery or production wells. Of the remaining established oil sands reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 135 billion barrels or 80 per cent can be recovered using *in situ* techniques.

The growth reflected in this latest oil sands forecast from 2015 to 2019 is relatively unchanged from CAPP's 2014 forecast as it is mostly comprised of the production from phases of the oil sands projects that are either already operating or are in the process of being constructed. During the latter part of the forecast from 2020 to 2030, oil sands production is lower by 117,000 b/d in 2020 and up to 857,000 b/d lower by 2030 than the previous year forecast due to a lower outlook for *in situ* production.

In 2014, oil sands production totaled 2.2 million b/d. Of these volumes, 1.2 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow up to 1.6 million b/d by 2030. Most of the growth is expected from *in situ* production, which is forecast to grow to 2.4 million b/d by 2030 (Table 2.3).

Figure 2.4 Western Canada Oil Sands **(Operating & In Construction)** & Conventional Production

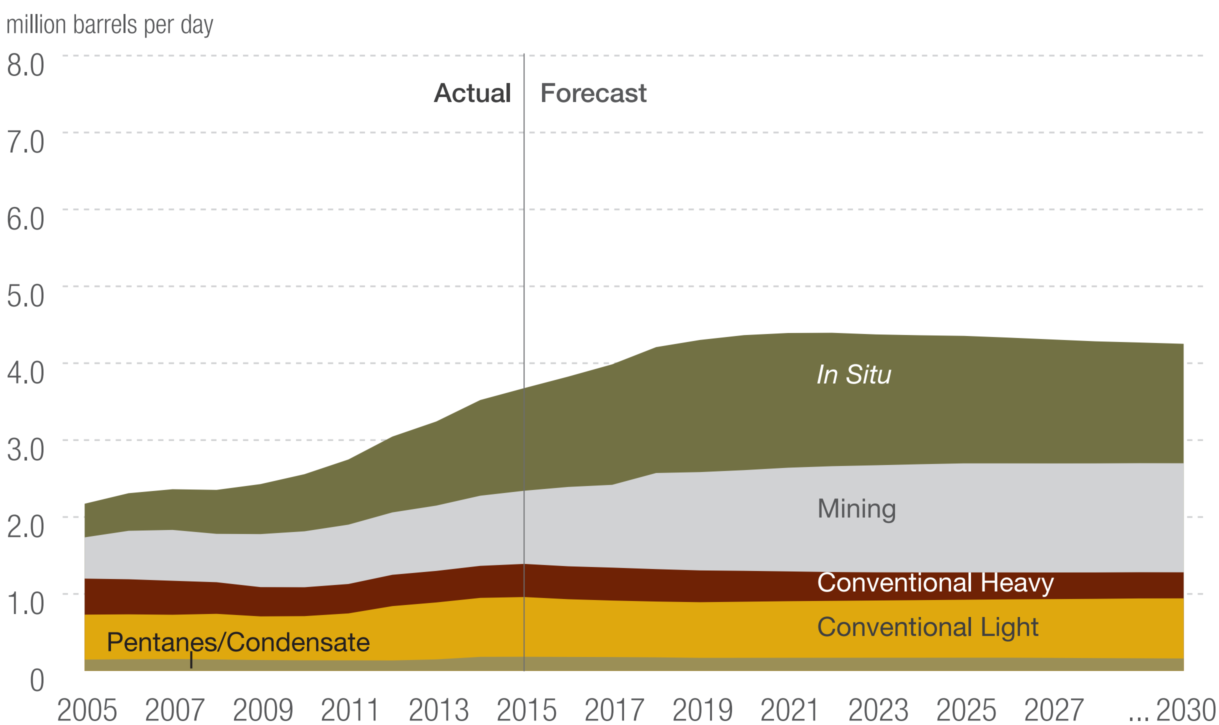


Table 2.3 Oil Sands Production

million b/d	2014	2015	2020	2025	2030
Total*	2.16	2.29	3.08	3.50	3.95
Mining (Operating & In Construction)	0.91	0.95	1.31	1.42	1.42
+ Mining Growth	-	-	-	-	+0.16
Mining	0.91	0.95	1.31	1.42	1.58
In Situ (Operating & In Construction)	1.24	1.33	1.76	1.66	1.55
+ *In Situ* Growth	-	-	+.01	+0.43	+0.82
In Situ	1.24	1.33	1.77	2.09	2.38

*Total may not add up due to rounding.

Production volumes from oil sands are typically reported using the upgraded crude oil volumes from integrated projects instead of the raw bitumen volumes processed by these projects. The yield losses associated with upgraded bitumen volumes from non-integrated producers have been accounted for in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 61 per cent of Western Canada's total crude oil production. In this forecast, oil sands production of 2.2 million b/d in 2014 increases by 1 million b/d in eight years and reaches 3.9 million b/d by 2030 (Figure 2.4). The oil sands forecast in 2030, is approximately 857,000 b/d lower than forecast in the last report.

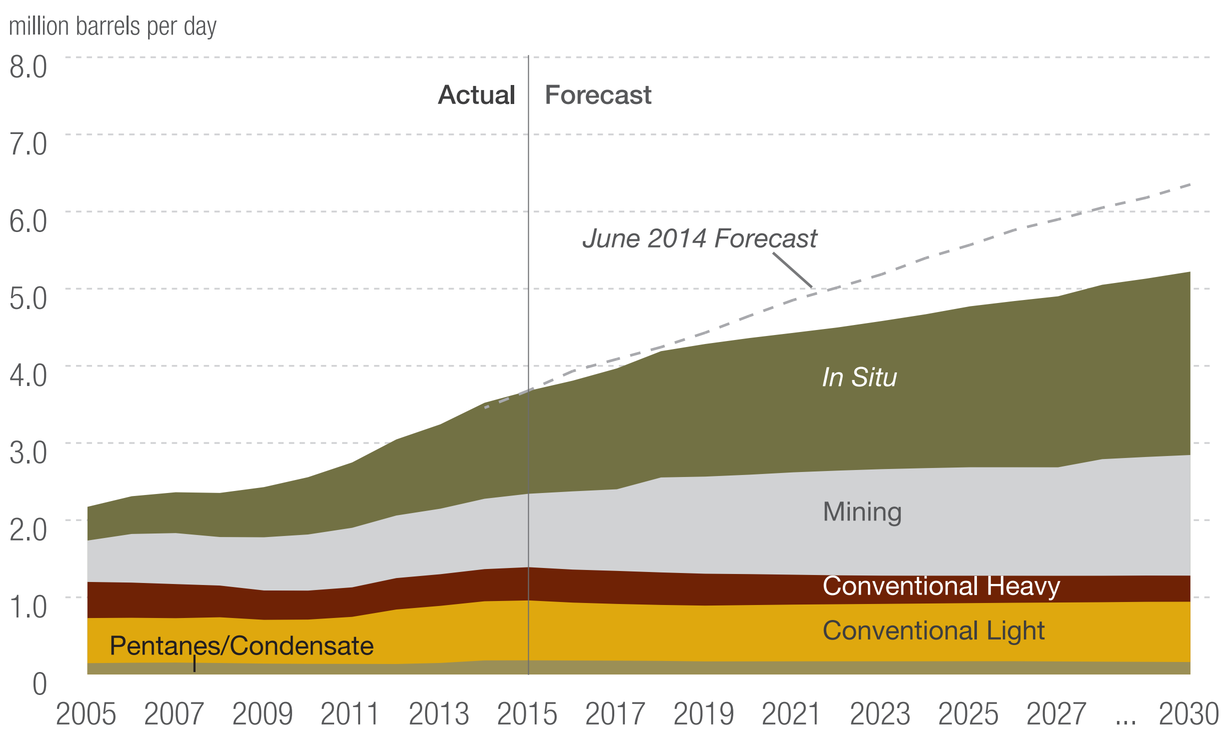
Refer to Appendix A.1 for detailed production data.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities. All mined bitumen projects, with the exception of the Imperial's Kearl mining project, have an affiliated upgrader that transforms the mined bitumen production into upgraded light crude oil. The Kearl project delivers diluted bitumen to the market. Some *in situ* volumes from Suncor's Firebag and MacKay River projects are upgraded at the Suncor upgrader.

Existing integrated mining and upgrading projects are listed below:

- Athabasca Oil Sands Project (AOSP) and Shell Jackpine Mine;
- Canadian Natural Horizon Project;
- Suncor Steepbank and Millennium Mine; and
- Syncrude Mildred Lake Mine and Aurora Mine.

Figure 2.5 Western Canada Oil Sands (Operating & In Construction + Growth) & Conventional Production



2.4 Western Canadian Crude Oil Supply

The composition of the various crude types available in the market typically differs from crude oil at the production level. Both conventional heavy crude oil and bitumen from oil sands are either upgraded or blended in order to be transported or to meet optimal refinery specifications. In any event, it is these crude oil supplies that are ultimately delivered to the end-use markets and therefore most relevant to market observers.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into the following main categories: Conventional Light; Conventional Heavy; Upgraded Light; and Oil Sands Heavy. Oil Sands Heavy includes upgraded heavy sour crude oil, bitumen diluted with upgraded light crude oil (also known as "SynBit") and bitumen diluted with condensate (also known as "DilBit"). Blending for DilBit differs by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50. Bitumen volumes transported by rail are currently relatively small. These railed volumes may be transported as raw bitumen or could use less diluent for blending (also known as "RailBit") versus moving by pipeline.

In 2014, about 1.1 million b/d or 52 per cent of the total bitumen produced in Canada was upgraded, including volumes of bitumen that were processed at the Suncor refinery in Edmonton. This refinery intake was included since it can process oil sands feedstock exclusively.

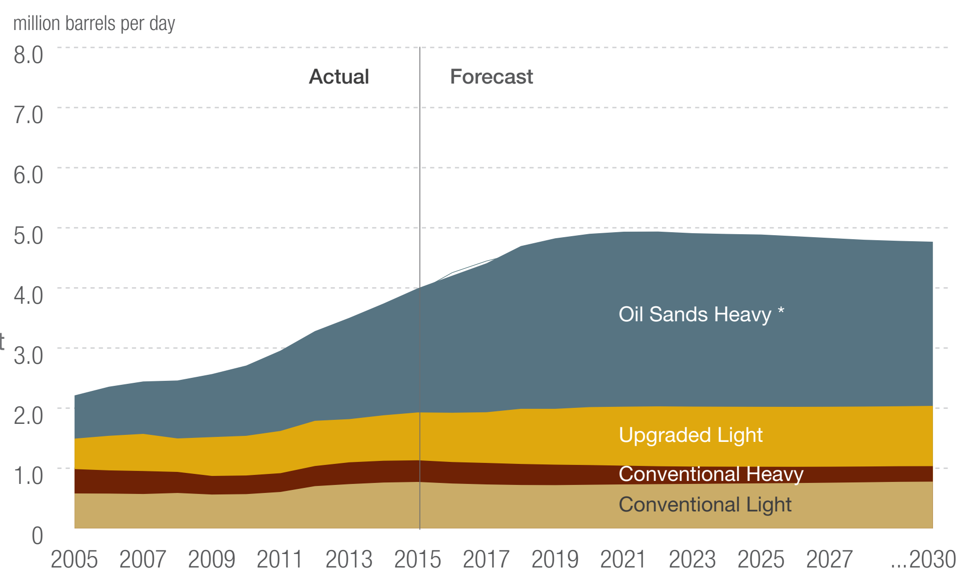
Upgraded volumes are forecast to rise to 1.6 million b/d by 2030. The bitumen upgraders located in Alberta produce a variety of upgraded products. Suncor produces synthetic light sweet crude and medium sour crudes, including diesel; Syncrude, Canadian Natural Horizon, and Nexen Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as sweet and heavy synthetic crude.

Canada's upgrading capacity is not expected to rise commensurately with bitumen production growth due to a number of economic challenges. These include the high capital costs incurred with upgrading and the need for a sustained differential between light and heavy crude oil of at least $25 per barrel. It is difficult for a new upgrader to compete with the option of transporting heavy crude oil to existing refineries located throughout North America that have spare coking capacity and are able to refine the heavy crude slates produced in Western Canada.

If it is not upgraded, bitumen is so viscous at its production stage that it needs to be diluted with a lighter hydrocarbon or diluent to create a type of crude that meets pipeline specifications for density and viscosity. Unblended bitumen generally cannot be moved by pipeline. Less diluent could be required when bitumen is moved by rail if it is transported in heated rail cars that lower the viscosity of the bitumen. The main source of diluent is condensate that is recovered from processing natural gas in Western Canada. This source of condensate will be insufficient to meet the blending needs associated with growing bitumen production.

In 2014, around 250,000 b/d of imported condensates, diluents from upgraders, as well as quantities of butane were needed to supplement the condensate supply from indigenous natural gas wells. CAPP's forecast is not constrained by the availability of condensate imports as new sources of condensate are assumed to be available to meet market requirements. Refer to Section 4.7 for details on existing and proposed diluent import pipeline projects.

Figure 2.6 Western Canada Oil Sands (Operating & In Construction) & Conventional Supply



* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or upgraded crude oil.

The potential for bitumen to travel by rail with reduced diluent requirement has not been factored into the analysis of condensate demand. Should rail become a more significant delivery system, its corresponding impact on the required diluent volumes will be reflected in future survey results and in turn, incorporated in CAPP's future forecasts.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2014	2015	2020	2025	2030
Operating & In Construction Total*	3.74	4.00	4.90	4.89	4.77
Light	1.52	1.57	1.69	1.75	1.78
Heavy	2.22	2.43	3.21	3.14	2.99
Growth Total*	3.74	4.00	4.92	5.47	6.06
Light	1.52	1.57	1.69	1.68	1.85
Heavy	2.22	2.43	3.23	3.79	4.21

*Total may not add up due to rounding.

Table 2.4 shows the projections for total western Canadian crude oil supply. Refer to Appendix A.2 for detailed data. Light crude oil supply is projected to be relatively stable at around 1.7 million b/d on average for the outlook. Heavy crude oil supply is projected to grow from 2.2 million b/d in 2014 to almost double this at 4.2 million b/d in 2030.

The Upgraded Light crude oil supply includes the light crude oil volumes produced from:

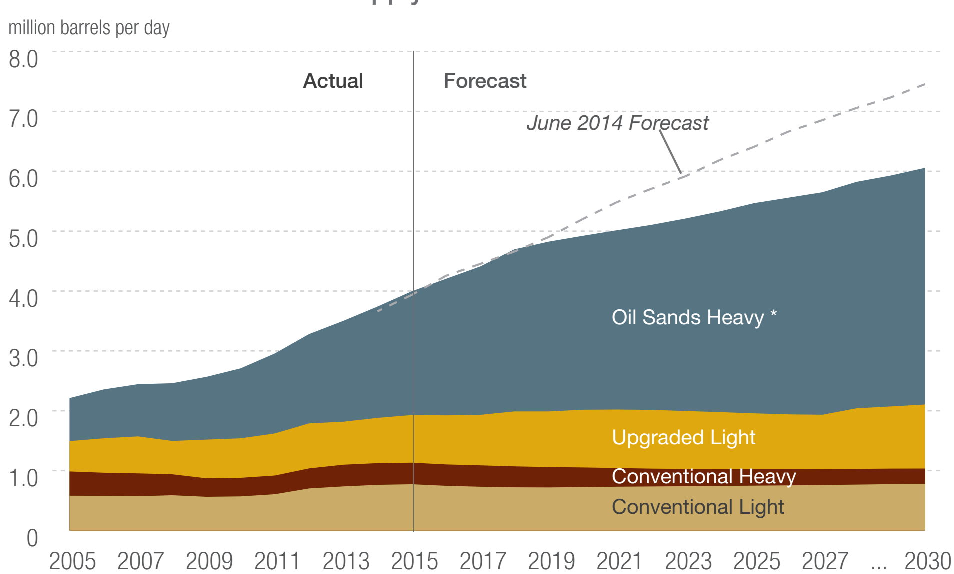
- Upgraders that process conventional heavy oil;
- Integrated mining and upgrading projects;
- Integrated *in situ* projects; and
- Off site upgraders.

Compared to the 2014 forecast, the upgraded light crude oil supply is relatively unchanged. The Oil Sands Heavy category is forecast to double from 1.9 million b/d in 2014 to 4.0 million b/d by 2030 (Figure 2.7), which is 1.4 million b/d lower than was forecasted last year.

2.5 Crude Oil Production and Supply Summary

Overall, total Canadian production is anticipated to grow from 3.7 million b/d in 2014 to 5.3 million b/d in 2030 which is 1.1 million b/d lower by 2030 than CAPP's June 2014 forecast. It reflects continued growth but at a slower pace. This reduction in future production is the combined effect of a 835,000 b/d lower forecast from *in situ* oil sands; a 21,000 b/d lower forecast from mining and a 260,000 b/d lower forecast from conventional oil. In this latest forecast, the growth in oil sands production is relatively unchanged until 2020. The existing oil sands projects and those under construction will continue to proceed but there is some uncertainty surrounding future projects. In contrast, conventional production is more sensitive to short term fluctuations in oil prices.

Figure 2.7 Western Canada Oil Sands (Operating & In Construction + Growth) & Conventional Supply



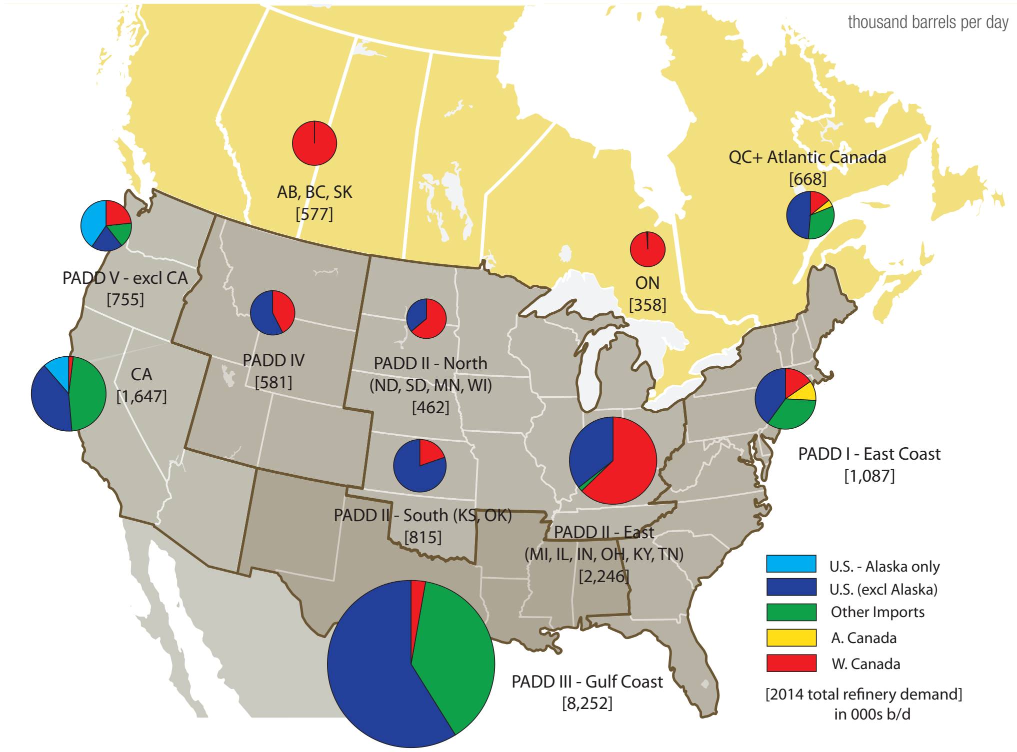
* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or upgraded crude oil.

The production outlook from offshore Atlantic Canada is unchanged with stable production levels anticipated in the near-term. Long-term declines are offset by production from satellite fields. The Hebron project, expected to start in 2017 will contribute additional production. By 2030, however, production is forecast to decline to 92,000 b/d.

3 | CRUDE OIL MARKETS

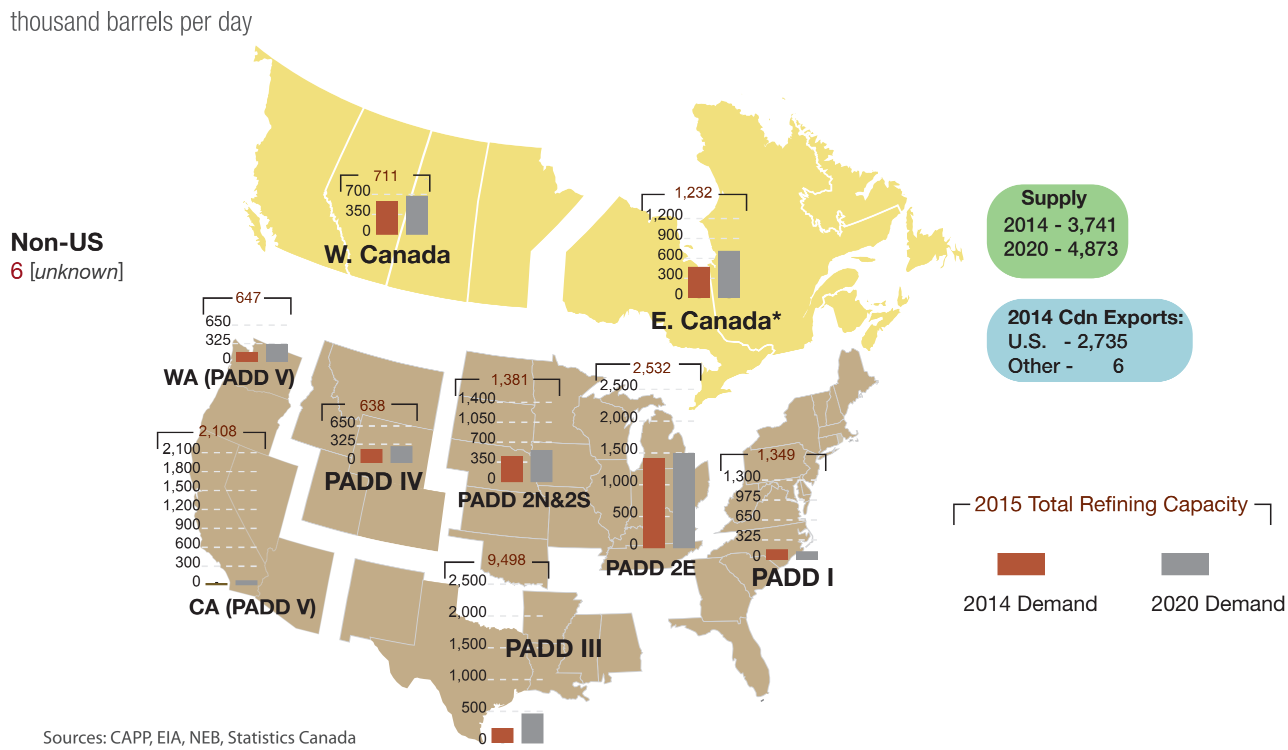
Crude oil supply from Western Canada by 2020 is forecast to increase by 1.1 million b/d from current levels. This chapter investigates which markets could be served by growing Canadian crude oil supplies. Figure 3.1 shows the size of and the sources of supply for refining markets in Canada and the United States (U.S.). The area in red shows the share of a given market taken up by western Canadian crude oil. The U.S. Gulf Coast has significant heavy oil processing capacity and as such, is an ideal target market for growing supplies of western Canadian heavy crude oil supplies. In order to increase its market share in these markets, Canadian production will have to displace other sources of crude oil. Access to tidewater is needed in order for Canadian producers to serve global markets that lie beyond North America, such as Asia and Europe.

Figure 3.1 **Canada and U.S. Market Demand for Crude Oil in 2014 by Source**



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

Figure 3.2 Market Demand for Western Canadian Crude Oil: Actual 2014 and 2020



Sources: CAPP, EIA, NEB, Statistics Canada

* E.Canada demand for W. Canadian crude oil in 2014 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2014 demand does not equal available supply due to factors including inventory adjustment, timing differences, and the potential for U.S. production transiting in Canada before being refined in the U.S. being reported as Canadian exports.

About 30 per cent of the total western Canadian crude oil supply available is processed at Canadian refineries. In 2014, this was equivalent to 1.1 million b/d that was refined domestically with the remaining 70 per cent exported. Data collected by the EIA indicated that U.S. imports from Western Canada totaled 2.7 million b/d. CAPP's refiner survey results indicate that Eastern Canada, PADD III, PADD II and PADD IV could potentially absorb the forecasted growth in western Canadian supply by 2020 (Figure 3.2).

The oil pipeline network exiting Western Canada currently connects to refineries in Western Canada and Ontario. Some Canadian refineries located further east that currently lack pipeline access to continental production started using rail and/or trucks to benefit from growing North American sources of supply. The Canadian demand for western Canadian crude oil is expected to increase to 1.5 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1 Canada

Canadian refineries have the capacity to process 1.9 million b/d of crude oil. About two-thirds of the crude oil processed in Canada is sourced from domestic production but this share is expected to increase as refineries in Eastern Canada gain additional access to western Canadian crude oil supplies. In 2014, Canadian refineries processed 1.0 million b/d of western Canadian crude oil and 34,000 b/d of crude oil produced in Eastern Canada. About 542,000 b/d of foreign crude oil was imported, of which, 324,000 b/d was sourced from the U.S.

3.1.1 Western Canada

Western Canada has a total refining capacity of 711,000 b/d from eight refineries. In 2014, these refineries processed 577,000 b/d of crude oil that was sourced exclusively from Western Canada. By 2020, western Canadian crude oil will remain the sole diet for these refineries and demand is expected to increase by 96,000 b/d to 673,000 b/d (Figure 3.3). The additional crude oil receipts in the future are related to a debottleneck project at the Moose Jaw plant, expansion plans at the Co-op refinery complex, which are both located in Saskatchewan, and the startup of the North West Redwater Partnership's refinery near Redwater in Sturgeon County, located about 45 km northeast of Edmonton, Alberta.

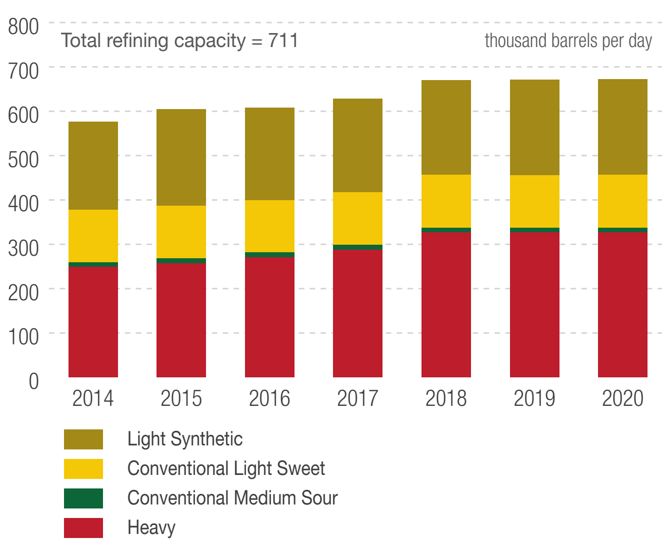
The Co-op Refinery Complex owned by Federated Co-operatives Limited (FCL) experienced a fire in December 2013 which affected the heavy feedstock demand for a significant portion of 2014. The anticipated increase in demand in 2015 relative to 2014 relates to the facility returning to normal operations.

The $8.5 billion Sturgeon refinery is designed to process 50,000 b/d of raw bitumen feedstock under 30 year fee-for-service Processing Agreements. The Alberta Petroleum Marketing Commission, an agent of the Alberta provincial government, will supply 75 per cent of the feedstock and Canadian Natural Resources Limited will supply the rest. The project broke ground on September 20, 2013 and is scheduled to be operating by September 2017.

Gibson Energy has also announced an expansion to its Moose Jaw plant that is scheduled to be completed by November 2015.

Two new export refinery concepts in British Columbia (BC) are being developed. Kitimat Clean's refinery is proposed by newspaper publisher David Black and would be located near Kitimat, BC. The refinery would be designed to process 550,000 b/d of bitumen into 460,000 b/d of gasoline, jet fuel and diesel for transportation to Asian markets. The second refinery is being proposed by Pacific Future Energy Corp. with former politician, Stockwell Day, promoting the project. A site location decision has not been finalized. The refinery would be designed to be built in modules with the first phase able to process 200,000 b/d of bitumen.

Figure 3.3 Western Canada: Crude Oil Receipts from Western Canada



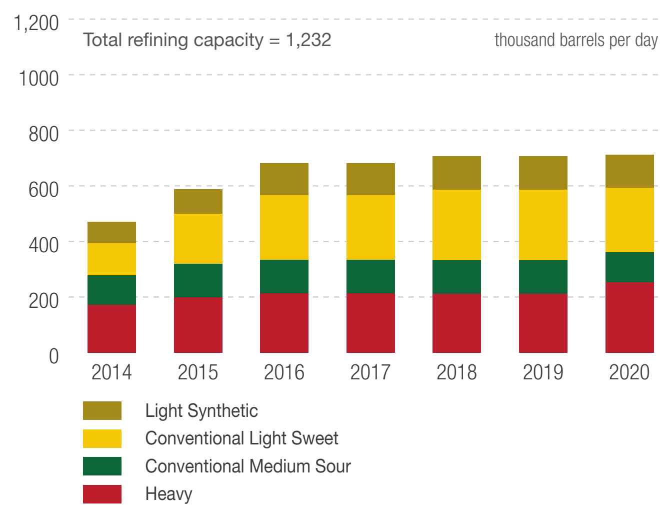
Source: 2015 CAPP Refinery Survey

3.1.2 Eastern Canada

A total of eight refineries are located in Ontario, Québec and Atlantic Canada. These eastern Canadian refineries have a combined capacity of about 1.2 million b/d. In 2014, Western Canada supplied 472,000 b/d to this market, which was over 100,000 b/d more than that supplied in 2013. These deliveries were facilitated through the increased use of rail transportation.

Most of this production was delivered to Ontario. By 2020, overall demand for western Canadian crude oil is expected to increase by 240,000 b/d. The upcoming reversal of the Enbridge Line 9 to Montréal will provide this market with pipeline access to western Canadian crude oil. The TransCanada Energy East project also proposes to provide Canadian crude oil access to this market in 2020. (Figure 3.4).

Figure 3.4 Eastern Canada: Crude Oil Receipts from Western Canada



Source: 2015 CAPP Refinery Survey

Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. Most of the crude processed at the Ontario refineries is sourced from Western Canada but they also refine some foreign crude oil and crude oil transported from Atlantic Canada. In 2014, Ontario refineries processed 379,000 b/d of crude oil, which was comprised of 356,000 b/d from domestic supplies and the remainder from foreign imports.

Québec & Atlantic Provinces

The four refineries in Québec and Atlantic Canada have a combined capacity of 837,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Crude oil imports sourced from the U.S. have more than doubled in the last year and accounted for 60 per cent of Canada's foreign imports in 2014. Crude oil originating from the U.S. Bakken in Montana and North Dakota has been transported by rail to the Québec refineries and the refinery in Saint John, New Brunswick. The North Atlantic refinery has also been receiving crude oil shipped from Texas via tanker. After the U.S., the top five sources for Canadian crude imports are Saudi Arabia, Iraq, Norway, Algeria and Angola.

Both regions are expected to increase receipts of western Canadian crude oil once Enbridge's Line 9 reversal is in service, which will deliver crude oil all the way to Montréal.

3.2 United States

Canada has been the top foreign supplier of crude oil to the U.S. since 2004 and is likely to remain as such for the foreseeable future. According to data from the EIA, Canada's exports to the U.S. increased by 306,000 b/d or 12 per cent in 2014 despite a 393,000 b/d or 5 per cent decline in total foreign imports. Canada exported 2.9 million b/d, with nearly all of these volumes being exported to the U.S.

Rising U.S. domestic production in recent years has been driven by drilling in the shale and tight oil plays in the Eagle Ford in Texas and Bakken in North Dakota. In 2014, U.S. production of crude oil exceeded the level of U.S. imports for the first time in 20 years. Annual production in the U.S. in 2014 grew by 1.2 million b/d from 2013, which is the highest growth recorded since 1990. This growth is expected to be more moderate in the next two years due to the impact of lower oil prices slowing production in more marginal drilling areas.

To date, increased light domestic production has displaced light crude oil imports, particularly at refineries on the U.S. Gulf Coast and the East Coast. The projected growth of western Canadian crude oil supplies are predominately heavy crude oil, therefore the U.S. Gulf Coast refineries, with their substantial heavy oil processing capabilities, remain a key target market. However, some imports of heavier crude types have also been displaced in the other U.S. regions.

The U.S. Department of Energy divides the 50 states into five market regions termed the Petroleum Administration of Defense Districts or PADDs. These PADDs were originally created during World War II to help allocate fuels derived from petroleum products. Today, this delineation continues to be used when reporting data to describe the U.S. crude oil market regions.

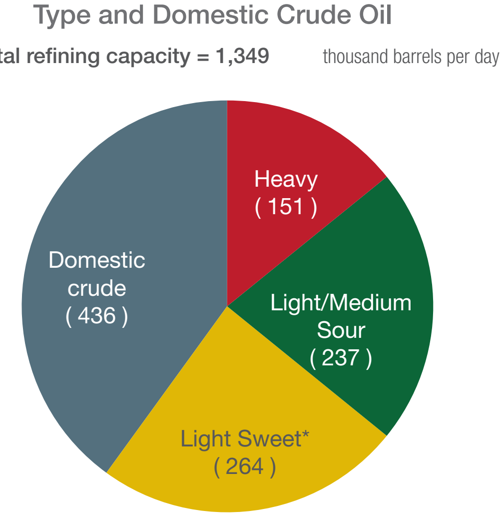
3.2.1 PADD I (East Coast)

The 1.3 million b/d refining capacity in the U.S. East Coast is comprised of nine refineries located in the states of Delaware, New Jersey, Pennsylvania and West Virginia. These refineries primarily process light crude oil (Figure 3.5). In 2014, these refineries processed 1.1 million b/d of crude oil, of which 651,000 b/d or 60 per cent was sourced from foreign sources.

The U.S. domestic portion of feedstock slate increased by 70 per cent from 254,000 b/d in 2013 to 436,000 b/d as a result of the growth of light U.S. Bakken production in North Dakota along with the development of rail facilities to the East Coast in 2013 and 2014 (Table 3.1).

Foreign imports to the region declined by 17 per cent, most of which was displaced by U.S. domestic production. However, imports of heavy crude oil from Canada increased as the new rail facilities provided the East Coast refineries new access to this supply source. PADD I refineries imported 282,900 b/d of crude oil from Canada. About 166,600 b/d was sourced from Western Canada in 2014 compared to 104,000 b/d in 2013. Of these imports, about 100,000 b/d arrived by rail.

Figure 3.5 2014 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

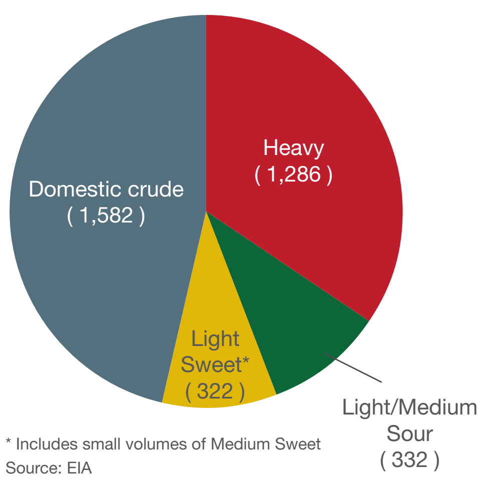
Table 3.1 Rail Offloading Terminals in PADD I

Operator	Location	Capacity (thousand b/d)	Scheduled In-Service	Description
PBF Energy (refinery)	Delaware City, DE	170 (130 light/40 heavy)	Operating since Feb 2013; expanded Aug 2014	Both light and heavy crude oil unloading capacity. Light oil double loop track for two 100-car unit trains
Axeon Specialty Partners (refinery)	Savannah, GA	9* *16 tank cars per day of heavy crude; expandable up to 32)	Operating since Jan 2014	Crude oil that is shipped by rail to Savannah could move to Paulsboro via backhauls on waterborne vessels
Westville	Eagle Point (near Paulsboro), NJ	44* *66 cars / day	Operating since Jan 2012	Can unload 66 cars / day using 22 offload spots or a unit train every 2 days.
Axeon Specialty Partners (refinery)	Paulsboro, NJ	small volumes Unit train capable	Operating 2014?	Unit train capability is being contemplated
Buckeye Partners, L.P.	Perth Amboy, NJ	60-80 104-car unit train/ day	Operating since Q3 2014	Light crude; possibly handle heavy in the future
Buckeye Partners, L.P.	Albany, NY	135	Operating since Nov 2012	Multi-year agreement with Irving refinery
Global Partners	Albany, NY	160 (estimated to be operating at 100)	Operating since 2011	Light crude oil receipts; seeking permit for facility to heat crude oil. Phillips 66 has a 5 year contract for 50,000 b/d
Eddystone Rail Company (Enbridge JV)	Philadelphia, PA	80* *one 118-car unit train; expandable to 2 unit trains (160,000+ b/d)	Operating since April 2014	A crude-by-rail-to-barge facility. First train received on May 3, 2014. Exclusive long-term contract with Bridger Logistics for existing capacity. Transport Bakken crude.
Philadelphia Energy Solutions (refinery)	Philadelphia, PA	280 four 104-car unit trains / day	Operating since Oct 2013; expanded Oct 2014	A crude-by-rail-to-barge facility. Terminal started operation on October 23, 2013 and was expanded from 2 unit trains to 4 on October 28, 2014
Plains All American Pipeline (PAAP)	Yorktown, VA	60	Operating since Dec 2013	First 98-car unit train received on Dec. 30, 2013. Up to 800 trains per year can be unloaded with up to 104 rail cars per train.
Total Existing Capacity		**998,000 b/d**		

3.2.2 PADD II (Midwest)

Over 3.9 million b/d of refining capacity is located in PADD II. In 2014, these refineries received 1.9 million b/d of foreign sourced crude oil, almost all of which was from Western Canada and were predominantly heavy supplies (Figure 3.6).

Figure 3.6 2014 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

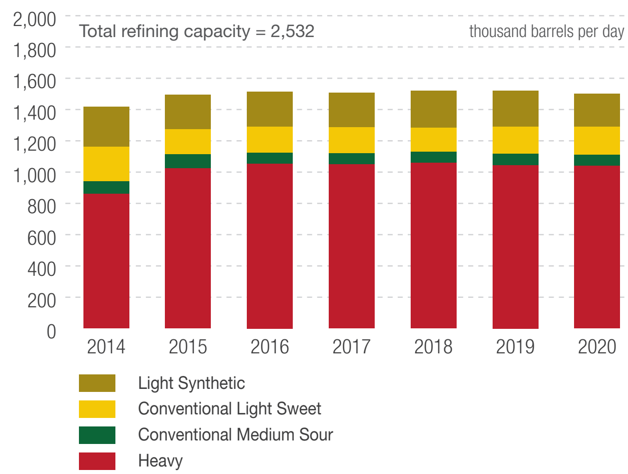
PADD II can be further divided into the Northern, Eastern, and Southern PADD II states. The primary market hubs within PADD II are located at Clearbrook, Minnesota for the Northern PADD II states; Wood River-Patoka, Illinois area for the Eastern PADD II states; and Cushing, Oklahoma for the Southern PADD II states.

The Midwest region is currently Canada's largest market due to its close proximity, large size and established pipeline network. However, this traditional market is becoming saturated as evidenced by the high level of inventories from growing domestic production and imports from Western Canada. Nonetheless, deliveries of western Canadian crude oil to this market are expected to increase by 190,000 b/d from 2014 levels by 2020.

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 14 refineries located throughout Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2014, this market collectively imported over 1.4 million b/d of crude oil supplies, of which 98 per cent were sourced from Western Canada. Imports of western Canadian heavy crude oil are estimated to increase slightly from current levels by 180,000 b/d in 2020 (Figure 3.7). In early 2015, Husky announced a postponement of its crude flexibility project by two years. The project was designed to allow the processing of up to 40,000 b/d of heavy crude oil from Western Canada and was originally scheduled to start in 2017 (Table 3.3).

Figure 3.7 PADD II (East): Crude Oil Receipts from Western Canada



Source: 2015 CAPP Refinery Survey

Table 3.2 Proposed Refinery Upgrade Projects in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost ($ million)	Description
Husky	Lima, OH	160	2019 (originally 2017)	300	Modifications to coker and other processing units to increase ability to process heavy crude oil by up to 40,000 b/d.

Northern and Southern PADD II

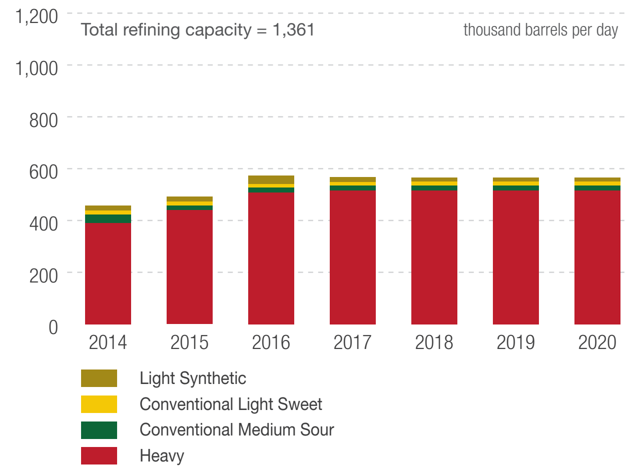
In Northern PADD II, there are two refineries located in Minnesota, a refinery in Wisconsin and two refineries in North Dakota. These five refineries have a combined capacity of 564,500 b/d. The Dakota Prairie refinery project was recently completed in April 2015. The refinery has a capacity of 20,000 b/d and is a joint venture between MDU Resources Group and Calumet Specialty Products. It will process Bakken crude oil to primarily make diesel fuel. Despite its small size, the refinery is significant as it is the first new U.S. refinery built since 1976. Additional similarly-sized refinery projects in North Dakota are currently being assessed.

There are seven refineries in Southern PADD II that account for a combined capacity of 816,000 b/d. These refineries are either located in Kansas or Oklahoma. U.S. domestic production satisfies 64 per cent of the combined refinery feedstock demand in these two regions. All of the foreign imports are sourced from Western Canada. Most, or 85 per cent, of the 457,000 b/d of imports was heavy crude oil.

Given the small relative size of these two markets and competition with U.S. domestic production for light crude oil demand, the growth in demand for western Canadian crude oil is limited. It is forecast to reach an additional 108,000 b/d from today's levels by 2020 (Figure 3.8).

The addition of a new coking facility at the National Cooperative Refinery Association (NCRA) McPherson refinery is scheduled to start up in late September 2015 (Table 3.2).

Figure 3.8 PADD II (North & South): Crude Oil Receipts from Western Canada



Source: 2015 CAPP Refinery Survey

Table 3.3 Recent and Proposed Refinery Upgrades in Northern & Southern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost ($ million)	Description
Dakota Prairie LLC	Dickinson, ND	20	Completed April 2015	400	New refinery processing Bakken crude oil to produce primarily diesel.
NCRA	McPherson, KS	85	Q4 2015	555	Plan to expand capacity to 100,000 b/d and increase heavy crude oil processing capacity to 50% with installation of new delayed coker.

3.2.3 PADD III (Gulf Coast)

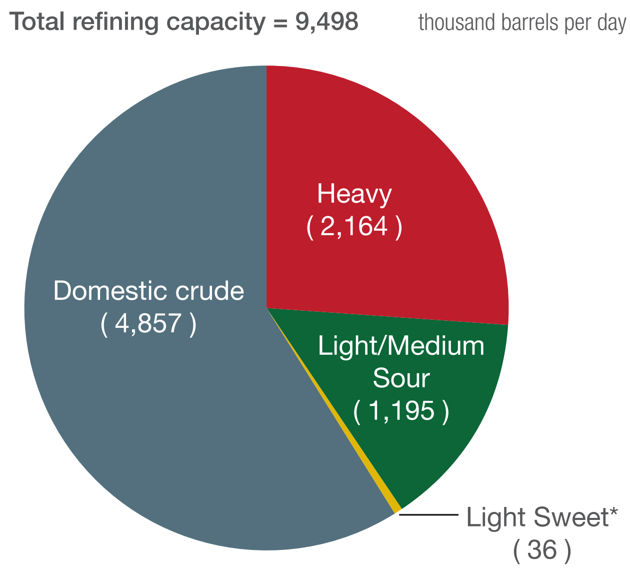
There are 50 refineries located on the Gulf Coast with a combined refining capacity of 9.5 million b/d or more than half of the total refining capacity in the U.S. The vast majority of this capacity is located in two states: Louisiana and Texas. The remaining refineries are located in Alabama, Arkansas, Mississippi, and New Mexico.

Greater access to this market would allow production from Canada to significantly expand its reach into the United States. Most of the Gulf Coast refineries have the capacity to process heavy, high sulphur crude oil, which is similar to the growing supplies expected to be produced from Western Canada.

Foreign imports of crude oil totaled 3.2 million b/d in 2014, which was a decline of 13 per cent from 2013. Growing production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, has almost completely displaced light-sweet crude oil imports from refineries along the U.S. Gulf Coast (Figure 3.9).

The supplemental use of rail has almost doubled the volumes of western Canadian crude oil destined for the U.S. Gulf Coast region from only 118,000 b/d in 2013 to 235,000 b/d in 2014. However, limited pipeline connection between western Canadian production and the Gulf Coast is still a major barrier to increased access to this market. CAPP's 2015 refinery survey indicates that western Canadian crude oil supplied to this market could reach 468,000 b/d in 2020. Note that these volumes are likely understated as only seven refineries in this region provided responses to the survey. Some refinery upgrades have been announced that could increase the size of this market or its ability to process heavy crude oil in the near future (Table 3.4).

Figure 3.9 2014 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

Saudi Arabia, Mexico, and Venezuela are the top three suppliers of foreign sourced crude oil to PADD III. With roughly an equal share, these countries combined account for 65 per cent of total imports. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oils. Venezuela and Mexico supply the majority of all heavy imports. The opportunity for growing supplies from Western Canada to gain a presence in this market lies in the displacement of heavy imports and not competition with U.S. domestic production, which is primarily light crude oil.

Table 3.4 Recent and Proposed Refinery Upgrades in PADD III

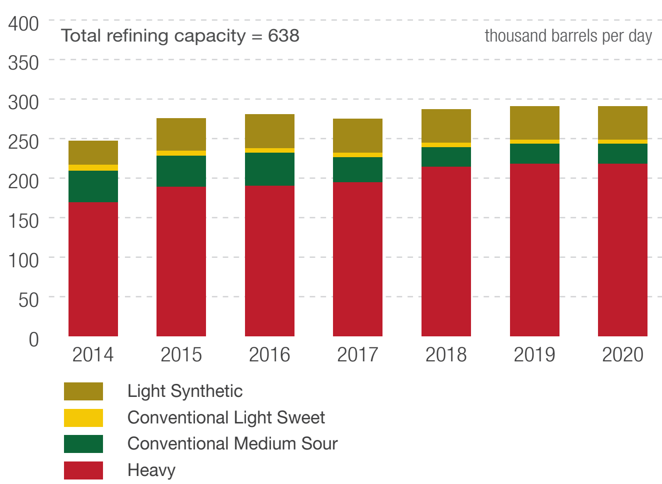
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Delek	Tyler, TX	75	Completed Mar 2015	Expansion from 60,000 b/d capacity
Marathon	Garyville, LA	522	2018 (decision in early 2015)	Installation of hydrotreating, hydrocracking, & desulphurization equipment.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.
LyondellBasell Industries NV	Houston, TX	268	2015	Increase ability to process heavy crude oil from 60,000 b/d to 175,000 b/d.

3.2.4 PADD IV (Rockies)

There are 14 refineries in PADD IV located in Colorado, Montana, Utah, and Wyoming with a combined refining capacity of 638,000 b/d. The refineries in this market process U.S. domestic crude oil supplies from the Bakken oil play and source all foreign imports from Western Canada.

In 2014, PADD IV refineries processed 247,000 b/d of Canadian crude oil, representing, 43 per cent of total feedstock requirements in the region. Receipts of heavy western Canadian supply are forecast to increase slightly from current levels (Figure 3.10). One refinery expansion has been announced that will occur within the forecast period (Table 3.5).

Figure 3.10 PADD IV: Crude Oil Receipts from Western Canada

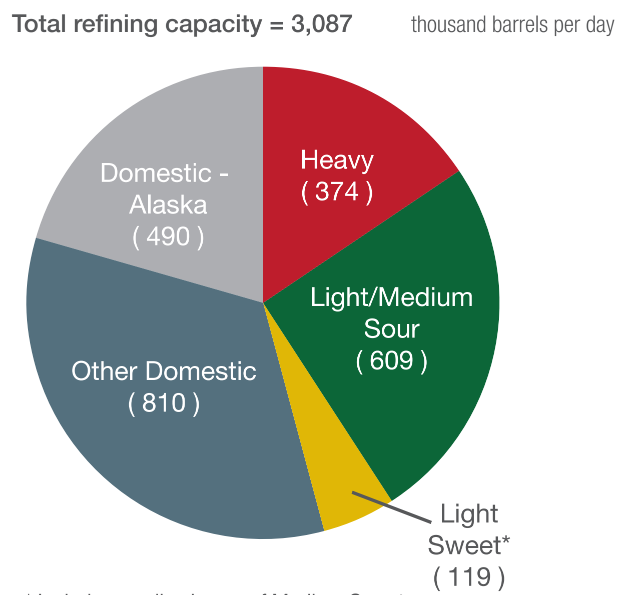


Source: 2015 CAPP Refinery Survey

3.2.5 PADD V (West Coast)

PADD V is divided from the rest of the U.S. by the Rocky Mountains and this geographical isolation has affected the development of crude supply sources to the region. The states in PADD V that have refineries are Alaska, California, Hawaii, and Washington. These refineries take production from California and Alaska and also have good access to tankers that can import crude from more distant regions. There is over 3.1 million b/d of refining capacity in the region. Foreign imports typically supply almost 50 per cent of the crude oil feedstock demand (Figure 3.11) and this share is expected to supplement the declining production from Alaska.

Figure 3.11 2014 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

The following discussion focuses only on Washington and California as the demand from refiners located in these two states account for both the current and future prospects for western Canadian crude oil in this region.

Table 3.5 Proposed Refinery Upgrade Projects in PADD IV

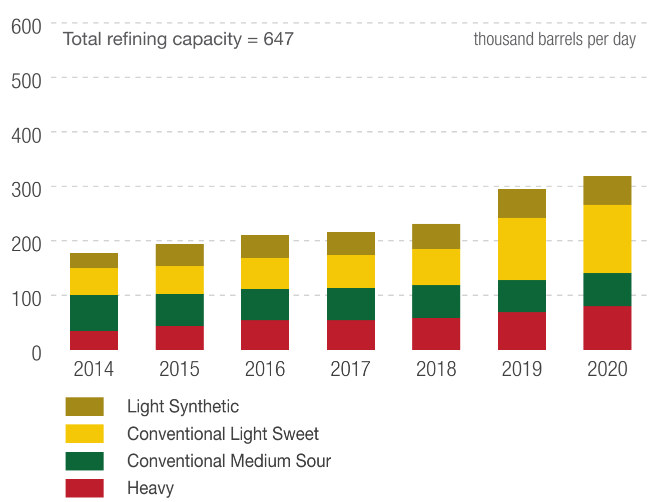
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost ($ million)	Description
Calumet Montana Refining	Great Falls Montana	10 (20 after expansion)	Q1 2016	400	Installation of new crude unit, mild pressure hydrocracker and tankage

Washington

Refining capacity in Washington totals 647,000 b/d. The state's five refineries have been primarily supplied with Alaskan production delivered by tanker but production from this source continues to decline. At 497,000 b/d in 2014, Alaskan production is only about a quarter of the peak levels achieved in 1988. Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to access part of the North Dakota's growing crude oil production supply through the use of rail.

In 2014, Washington refineries received 223,000 b/d of foreign imports of which 77 per cent was supplied by Canada. Results from CAPP's refinery survey indicate that demand for crude oil from Western Canada will increase by 141,000 b/d from current levels, which translates to an 80 per cent increase (Figure 3.12). This growth in demand relies on the successful construction of proposed rail or pipeline projects that would reach the West Coast. Refer to Section 4.5 for details on the Pipelines to the West Coast.

Figure 3.12 PADD V (Washington): Crude Oil Receipts from Western Canada



Source: 2015 CAPP Refinery Survey

A few refineries began investing in rail offloading facilities in recent years in order to access growing supplies of crude oil from North Dakota and Western Canada. All the refineries in Washington are either already receiving some crude shipments by rail or have plans to do so by the end of the year.

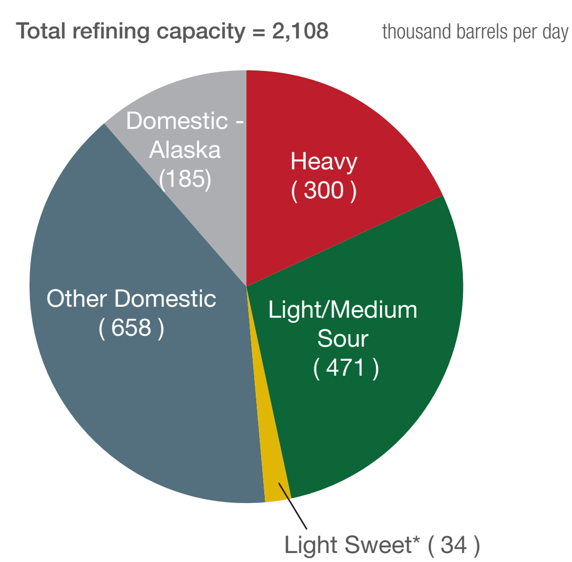
California

California dominates PADD V in terms of state oil production and refining capacity. There are 16 refineries located in California that contribute to a total refining capacity of 2.1 million b/d. Almost all of the refineries are located near the coast in the Los Angeles and the San Francisco Bay areas. There is no direct pipeline to California from producing regions outside of California. Therefore, as Alaskan crude oil declines an opportunity arises to process more crude oil from the Bakken area of North Dakota and potentially from Canada. Refer to Section 4.5 for pipeline proposal projects connecting western Canadian crude oil to the west coast where the crude oil could then be loaded on to tankers to serve these refineries.

Direct pipeline access to this market is unlikely due to the limited size of the market but a number of rail unloading projects are being pursued that would increase access. Four major projects are currently planned that have a combined capacity of 326,000 b/d by early 2016 (Table 3.6).

In 2014, California refineries imported 805,000 b/d of crude oil from foreign sources, which is equivalent to almost half of the total feedstock demand (Figure 3.13).

Figure 3.13 2014 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA and California Energy Commission

Table 3.6 Rail Offloading Terminals in Western Canada and PADD V

Company	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Western Canada				
Chevron (refinery)	Burnaby, B.C.	8	Operating since 2013	
Western Canada capacity subtotal		**8,000 b/d**		
Washington				
Shell (refinery)	Anacortes, WA	50	?	Applied for permits
Tesoro (refinery)	Anacortes, WA	50	Operating since 2012	
BP (refinery)	Cherry Point/Blaine, WA	60	Operating since Dec 2013	
Phillips 66 (refinery)	Ferndale, WA	small volumes Expansion to 30	Operating Dec 2014	Currently receiving manifest trains; applied for permits for expansion
US Oil (refinery)	Tacoma, WA	30	Operating since 2012	Unit train capable
US Development Group	Grays Harbour, WA	50	2016	Applied for permits
Westway	Grays Harbour, WA	27	Q1 2015	Applied for permits
Imperium Renewables	Grays Harbour, WA	?	?	Applied for permits; would accept other products besides crude oil
Tesoro/Savage	Port of Vancouver, WA	120 (expandable to 280)	2017	Applied for permits
Global Partners of Massachusetts	Port Westward/ Calskanie, WA	65 (expandable to 130)	Operating since Q4 2012	24 trains per month; expandable to 50
Washington capacity subtotal		**145,000 b/d; potential for additional 337,000 b/d**		
California				
Alon USA	Bakersfield, CA	manifest; Expansion to 150	Operating 2016	Heavy and light crude oil capacity
Plains All American	Bakersfield, CA	65	Q1 2015	
Valero (refinery)	Benicia, CA	70	Q1 2015	western Cdn crude + US
Phillips 66 (refinery)	Santa Maria, CA	41	Q1 2016	
California capacity subtotal		**manifest trains; potential for additional 326,000 b/d**		
TOTAL		**153,000 b/d; potential for additional 663,000 b/d**		

3.3 International

There is growing interest in Canada's crude oil supply in both Europe and Asia. In 2014, Statistics Canada reported shipments of Canadian crude oil destined to Italy, United Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India.

The European Union Parliament's original fuel quality directive (FQD) proposal discriminated against Canadian oil sands crude as the only more carbon intensive crude oil. The Canadian government and industry objected, noting that Canadian crude was less carbon intensive than some other sources of crude and that other jurisdictions were less transparent in their reporting. Late in 2014, the FQD was revised to avoid discrimination against Canadian oil sands crude. Exports of Canadian crude oil to Europe have begun to occur and expanded transportation infrastructure in Canada with proposed pipelines to the coast will lead to increased exports in the future.

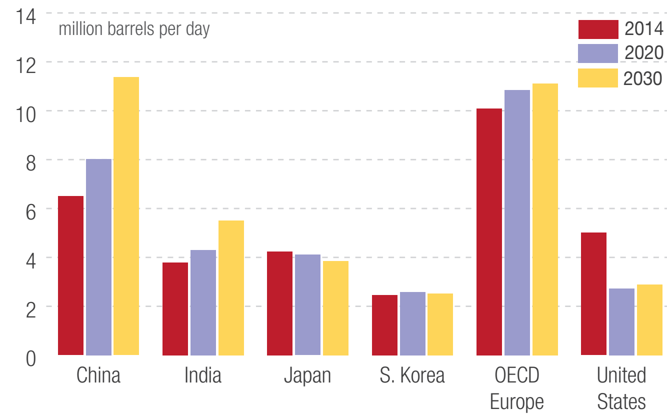
Demand for petroleum liquids in China and India combined are expected to account for close to half the projected world demand increase in 2030 compared 2014 levels. The International Energy Agency in its World Energy Outlook 2014, which was released in November 2014, predicts that China will become the largest consumer of oil in the world, overtaking the United States in the early 2030s. Table 3.7 shows forecasted oil demand in major Asian markets. Figure 3.14 shows the changing global import needs. Not surprisingly, imports of petroleum from China and India are expected to grow. Slight growth is expected in OECD Europe but demand is expected to drop in the U.S., which is currently the market for almost all of Western Canada's crude oil exports.

Table 3.7 Total Oil Demand in Major Asian Countries

million b/d	2013	2020	2025	2030
China	9.8	12.0	13.9	15.1
India	3.7	4.9	5.8	7.0
Japan	4.4	3.7	3.3	3.0

Source: IEA World Energy Outlook 2014, New Policies Scenario

Figure 3.14 Global Net Oil Imports: 2014 to 2030



Source: EIA Annual Energy Outlook 2015

3.4 Markets Summary

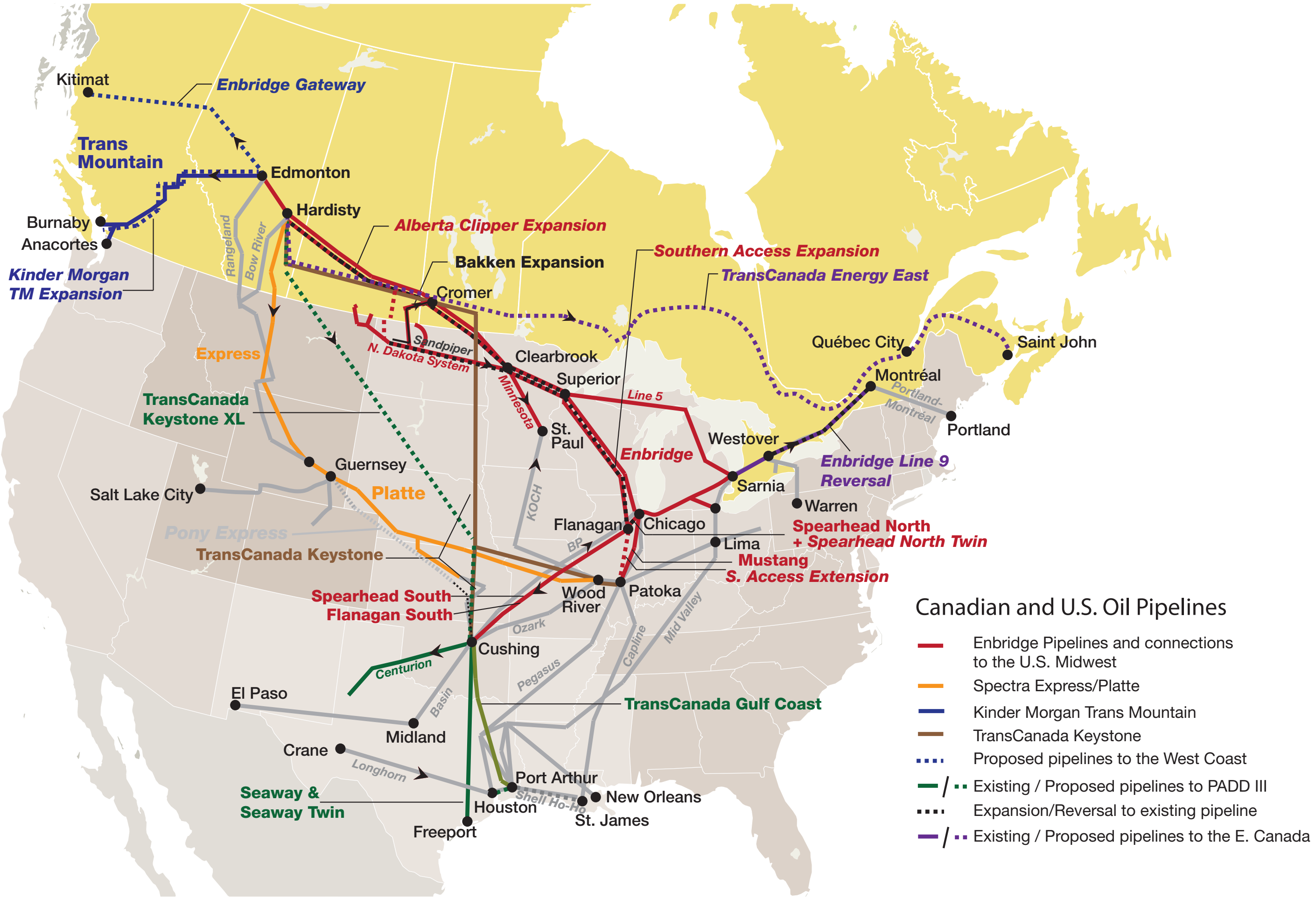
Market diversity and corresponding expanded transportation capacity remain key features of this latest outlook. Canadian production requires tidewater access in order to reach global markets and even some prospective North American markets, including California. Eastern Canada and the U.S. Gulf Coast represent the greatest opportunity for expanded markets in North America for Canadian crude oil production.

PADD I holds limited expansion opportunities due to its size, and primarily light crude oil requirements that will likely be increasingly satisfied through growing U.S. domestic production. The larger PADD II market is essentially saturated with western Canadian and domestic U.S. supplies. Growing supplies of western Canadian production must be transported to tidewater if it is to ultimately reach international markets. Recent test cargoes of Canadian crude oil destined for Italy, United Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India show there is growing interest from European and Asian markets for Canadian production.

4 | TRANSPORTATION

The growing supply of western Canadian crude oil relies on the availability of a strong transportation infrastructure network to connect to refining markets. This transportation network involves all modes of transportation that includes pipelines, rail, marine and trucks. However, the existing pipeline infrastructure and proposed pipeline projects provide the most efficient means of transporting large quantities of crude oil. Figure 4.1 shows both the existing and proposed pipeline projects that could deliver large volumes of western Canadian crude oil to the East Coast, West Coast, U.S. Gulf Coast and offshore markets.

Figure 4.1 Existing and Proposed Canadian & U.S. Crude Oil Pipelines



4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines which move western Canadian crude out of the WCSB. Of these pipelines, both the Enbridge Mainline pipeline and the Kinder Morgan Trans Mountain pipeline originate at Edmonton, Alberta. The Spectra Express pipeline and the TransCanada Keystone pipeline originate at Hardisty, Alberta. Together, these pipelines provide about 3.8 million b/d of capacity out of Western Canada. In addition, a number of proposals have been announced that could increase this capacity during the next five years (Table 4.1). Pipeline capacity continues to be tight with strong growth in production volumes forecast until 2020. In addition, operational constraints can and have, at times, reduced the available capacity to below nameplate capacity.

Table 4.1 **Major Existing & Proposed Crude Oil Pipelines Exiting the WCSB**

Pipeline	Capacity (thousand b/d)	Target In-Service
Enbridge Mainline	2,621	Operating since 1950
Enbridge Alberta Clipper Expansion	+230	Q3 2015
Enbridge Line 3 Restored	+370	2H 2017
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2018
Spectra Express *downstream Platte operating since 1952	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL **assuming approval obtained by end 2015	+830	2018**
Enbridge Northern Gateway	+525	2019
TransCanada Energy East	+1,100	2020
Total Existing Capacity		**3,792**
Total Proposed Additional Capacity		**+3,645**

The next sections describe the existing pipeline projects. The proposed projects are discussed in the subsequent sections and are categorized by their destination markets.

4.1.1 Enbridge Mainline

The Enbridge Mainline consists of numerous lines which deliver light and heavy crude oil as well as refined products from Western Canada, Montana and North Dakota to markets in Western Canada, the U.S. Midwest and Ontario. The Mainline connects with several pipelines: Line 9 at Sarnia, Ontario; the Minnesota Pipeline at Clearbrook, Minnesota; Spearhead South and Flanagan South at Flanagan, Illinois; Chicap at Patoka, Illinois; Mustang at Chicago, Illinois and Toledo at Stockbridge, Michigan. The annual average receipt capacity from Western Canada into the Mainline system is about 2.6 million b/d. However, the effective capacity is slightly less due to operational pressure restrictions on certain lines and physical constraints at terminals on the system.

There is also some U.S. production which enters the Enbridge Mainline and competes for space on the pipeline and in turn reduces the available capacity to transport crude oil from Western Canada. The Enbridge North Dakota pipeline originates at Plentywood, Montana and ends at Clearbrook, Minnesota. It has a current capacity of 210,000 b/d which serves local markets and markets further east. Some U.S. crude oil production from the Bakken formation currently enters the Enbridge Mainline system at Clearbrook, Minnesota.

In response to significant growth in North Dakota and Montana, Enbridge is proposing an expansion of its North Dakota system. The project known as Sandpiper would include: a new 24-inch diameter pipeline from Beaver Lodge, North Dakota to Clearbrook, Minnesota with an incremental capacity of 225,000 b/d and a new 30-inch diameter pipeline from Clearbrook, Minnesota to Superior, Wisconsin with an initial capacity of 375,000 b/d. As part of the project scope, Enbridge would relocate the interconnection of the Enbridge North Dakota pipeline to the Lakehead System from Clearbrook, Minnesota. As a result, about 375,000 b/d of Bakken crude would enter the Enbridge Mainline at Superior, Wisconsin instead. The target in-service date for this project is 2017.

The Enbridge Bakken Expansion project from Berthold, North Dakota to Cromer, Manitoba was put in service in March 2013. It provides 145,000 b/d of capacity to move U.S. Bakken crude into the Mainline destined for markets in the U.S. Midwest, Midcontinent and Eastern Canada.

Enbridge Mainline Expansion Projects

The current capacity on the Enbridge Mainline System between Edmonton, Alberta and Superior, Wisconsin is approximately 2.6 million b/d and is comprised of the capacity from a number of pipelines. These pipelines include Line 1, Line 2, Line 3, Line 4, Line 65 and the Alberta Clipper, which is also identified as Line 67.

Enbridge recently completed a number of expansions and is also planning further expansions that will allow western Canadian crude to reach existing markets in the Midwest and Ontario and new markets in the U.S. Gulf Coast. Enbridge is undertaking a $7 billion project to replace its Line 3 pipeline. The new pipeline is scheduled to be in service in the second half of 2017 and will restore Line 3 to its original capacity of 760,000 b/d.

The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin. Enbridge completed the Phase 1 Expansion of this pipeline in the fall of 2014, which increased its original capacity by 120,000 b/d from 450,000 b/d to its current capacity of 570,000 b/d. The Phase 2 Expansion, scheduled to be in service in Q3 2015 would provide an additional 230,000 b/d and bring the Alberta Clipper pipeline up to its ultimate designed capacity of 800,000 b/d. The Alberta Clipper pipeline will be expanded through the addition of new pumps and station upgrades.

Enbridge's Light Oil Market Access Program (LOMAP) is directed at expanding market access for light crude oil production from North Dakota and Western Canada. The Southern Access Pipeline is part of the Lakehead System (Enbridge U.S. Mainline) and runs from Superior, Wisconsin to Flanagan, Illinois. The current capacity is 560,000 b/d. As part of its LOMAP, Enbridge completed an initial expansion of the pipeline by 160,000 b/d from its original capacity of 400,000 b/d in August 2014. The next step in the plan will be to further increase capacity on the pipeline by 240,000 b/d in Q2 2015 through the addition of pumping stations. Enbridge has delayed the last expansion phase of an additional 400,000 b/d until 2017, which would bring the Southern Access pipeline to its ultimate designed capacity of 1.2 million b/d.

4.1.2 Kinder Morgan Trans Mountain

The Trans Mountain system is currently the only crude oil pipeline serving Canada's west coast. It originates at Edmonton, Alberta, delivering both crude oil and petroleum products, to points in British Columbia, Washington, and the Westridge marine terminal. From this marine terminal located at Burnaby, British Columbia, crude oil is loaded onto vessels for offshore exports destined for California, the U.S. Gulf Coast and Asia.

The current capacity on the pipeline system is 300,000 b/d (assuming 20 per cent of the volumes being transported are heavy crude oil). Of the total capacity, 221,000 b/d is allocated to refineries with connections in British Columbia and Washington State and 79,000 b/d is allocated to the Westridge terminal for marine exports. Of the capacity designated to the marine terminal, 54,000 b/d or 68 per cent is underpinned by firm contracts and the remainder is available for spot shipments. Demand for access to this pipeline has been high and as such the nominations for service on this pipeline have been in apportionment since late 2010. See Section 4.5.2 for details on the Trans Mountain Expansion Project.

4.1.3 Spectra Express-Platte

The Express Pipeline is a 24-inch diameter pipeline that originates at Hardisty, Alberta and terminates at the Casper, Wyoming facilities on the Platte Pipeline. The designed capacity on Express is 280,000 b/d. The ability to move crude on the Express pipeline is limited due to insufficient downstream capacity on the Platte pipeline but rail connections have helped to increase throughput capacity. About 225,000 b/d of the capacity on Express is contracted. Spectra held an open season from December 10, 2014 to January 30, 2015 that offered 19,000 b/d of capacity for committed service that could be available through debottleneck work that would optimize use of Express's design capacity. These contracts would be effective by late 2016.

The Platte Pipeline which is a 20-inch diameter pipeline moves crude oil from Western Canada, the Rockies (PADD IV), including the Bakken play area to refineries in the Midwest (PADD II). It runs from Casper, Wyoming to Wood River, Illinois. The capacity on the pipeline ranges from 164,000 b/d in Wyoming to 145,000b/d in Illinois.

4.1.4 TransCanada Keystone

The Keystone pipeline system originates at Hardisty, Alberta and connects to Steele City, Nebraska. From this juncture crude oil can be transported east to terminals in Wood River and Patoka, Illinois or south to Cushing, Oklahoma. The pipeline system can deliver a total of 590,000 b/d with each destination capable of taking this maximum capacity if shippers so elect. The pipeline started operations in June 2010 to serve the Wood River/ Patoka markets while the Cushing extension came online in February 2011. About 530,000 b/d of capacity is contracted for an average of 18 years.

4.2 New Regional Infrastructure Projects in Western Canada

The companies which own the pipelines that move western Canadian crude out of the basin are investing significant capital in regional pipeline infrastructure to move incremental production to markets. The upstream expansions into Hardisty, Alberta could feed the Enbridge Mainline, Keystone, and the proposed TransCanada Energy East Pipeline into Eastern Canada and Keystone XL.

4.2.1 Enbridge - Alberta Regional Pipeline

Enbridge - Edmonton to Hardisty

Enbridge's new 36-inch diameter pipeline from Edmonton to Hardisty was placed into service in May 2015. The pipeline has an initial capacity of 570,000 b/d and will reach its full designed capacity of 800,000 b/d in Q3 2015 once all tanks are in place.

4.2.2 TransCanada - Alberta Regional Pipelines

Heartland Pipeline and Terminal

TransCanada is proposing a 36-inch diameter pipeline from the Heartland region to Hardisty, Alberta, which is the starting point of its Keystone pipeline system. Heartland is an industrial area north of Edmonton, Alberta. The initial capacity would be 500,000 b/d but the pipeline could be expanded to 900,000 b/d. At Hardisty, Alberta the pipeline would have connections to Keystone, Keystone XL and Energy East. In the Heartland region, there will be up to 1.9 million barrels of tank capacity available. Pending regulatory approvals, the target in-service date for the Heartland pipeline is late 2016.

Grand Rapids Pipeline Project

TransCanada in partnership with Brion Energy Corporation (formerly Phoenix Energy Holdings Limited) is proposing to develop the Grand Rapids Pipeline in Northern Alberta. Each party will own 50 per cent of the proposed pipeline system. The project is a 460 km long dual pipeline system between the producing area northwest of Fort McMurray and Heartland. It includes a pipeline that could transport up to 900,000 b/d of crude oil and another pipeline that could transport up to 330,000 b/d of diluent. The pipeline in crude oil service is targeted to be in service by mid-2016. TransCanada will operate the pipeline and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the pipeline system. Following a hearing in June and July 2014, regulatory approval from the Alberta Energy Regulator for the pipeline was received in October 2014 with certain conditions.

4.3 Oil Pipelines to the U.S. Midwest

The U.S. Midwest is the largest market for western Canadian crude oil. The key market hubs in this region are located at Wood River and Patoka in Illinois and at Cushing, Oklahoma. Table 4.2 summarizes the pipelines which deliver Canadian crude oil to the Midwest.

4.3.1 Spectra Express-Platte

See Section 4.1.3.

4.3.2 TransCanada Keystone

See Section 4.1.4.

4.3.3 Southern Access Extension

Construction of an extension to Enbridge's Southern Access pipeline is underway. The proposed extension would be a 24-inch diameter pipeline that would run from Flanagan, Illinois to Patoka, Illinois. The pipeline would have an initial capacity of 300,000 b/d and is targeted to be in-service in Q4 2015.

4.3.4 Enbridge Line 6B

As part of its Eastern Access program, Enbridge has fully completed replacement of Line 6B. The new segment from Griffith, Indiana to Stockbridge, Michigan was put in service in Q2 2014. The segment from Stockbridge to the Canadian border was put in service in October 2014. As a result, capacity on Line 6B increased from 240,000 b/d to its current capacity of 500,000 b/d.

As part of its Light Oil market access program, Enbridge is proposing to increase capacity of the Line 6B between Griffith, Illinois and Stockbridge, Michigan from 500,000 b/d to 570,000 b/d. The target in-service date is Q1 2016.

4.3.5 Minnesota Pipeline System

The Minnesota Pipeline system runs from Clearbrook, Minnesota to the Twin Cities. It is operated by Koch Pipeline Company. The pipeline delivers crude to the Northern Tier refinery in St. Paul Park and the Pine Bend refinery owned by Flint Hills in Rosemont. The system has a current capacity of 465,000 b/d that can be expanded to 650,000 b/d.

4.3.6 Spearhead

The Spearhead Pipeline system originates at Flanagan, Illinois and receives crude oil from the Enbridge Mainline. From there, crude oil can be transported to Griffith, Indiana via Spearhead North or to Cushing, Oklahoma on Spearhead South.

As part of its Light Oil Market Access project, Enbridge is twinning the Spearhead North (Line 62) pipeline by constructing a new pipeline that would be located parallel to the existing pipeline. This new pipeline would provide an incremental capacity of 570,000 b/d and is targeted to be in service at the end of Q3 2015.

4.3.7 Enbridge Flanagan South

Enbridge's newly operating 36-inch diameter Flanagan South Pipeline has a capacity of 585,000 b/d and an ultimate design capacity of 880,000 b/d after pump station enhancements. It originates in Pontiac, Illinois. and terminates in Cushing, Oklahoma. It traverses Illinois, Missouri, Kansas, and Oklahoma. The majority of the pipeline runs parallel to Enbridge's Spearhead South pipeline's right-of-way. Enbridge shippers that contract for capacity on Flanagan South are able to nominate crude volumes originating in Western Canada for delivery to U.S. Gulf Coast markets. In order to provide this service, Enbridge utilizes its mainline facilities and capacity has been reserved on the downstream Seaway pipeline that delivers crude from Cushing to the US Gulf Coast.

4.3.8 Enbridge Toledo Pipeline Expansion

Enbridge operates a pipeline which connects with the Mainline near Stockbridge, Michigan and extends east and south, terminating near Romulus, Michigan. This 20-inch diameter pipeline, known as Line 79, has been operating since May 2013 and has a capacity of 80,000 b/d. The Line 17 is a 16-inch diameter pipeline that pre-existed Line 79 and extends from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. These two pipelines combined, provide a total capacity of 180,000 b/d to serve refineries in Toledo, Ohio and Detroit, Michigan.

Table 4.2 Summary of Crude Oil Pipelines to the U.S. Midwest

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Minnesota Pipeline	Clearbrook, MN	Minnesota refineries	Operating	465
Enbridge Mainline	Superior, WI	various delivery points via L5, L6, L14/64,	Operating	1,525
Southern Access Southern Access Expansion Southern Access Expansion	Superior, WI	Flanagan, IL	Operating Proposed - Q2 2015 Proposed - 2017	560 +240 +400
Enbridge Spearhead North	Flanagan, IL	Chicago, IL	Operating	235
Enbridge Spearhead North Twin	Flanagan, IL	Chicago, IL	Proposed - Q3 2015	+570
Enbridge Spearhead South	Flanagan, IL	Cushing, OK	Operating	193
Enbridge Flanagan South	Flanagan, IL	Cushing, OK	Operating since Dec 2014	585
Enbridge Mustang	Lockport, IL	Patoka, IL	Operating	100
Spectra Express-Platte	Guernsey, WY	Wood River, IL	Operating	145
TransCanada Keystone	Hardisty, AB to Steel City, NE	east to Patoka, IL / Wood River, IL or south to Cushing, OK	Operating	591
PAAP Diamond	Cushing, OK	Memphis, TX	Proposed - Q4 2016	+200

4.3.9 Plains All American Diamond Pipeline

Plains All American announced plans to build a new 200,000 b/d crude oil pipeline from Cushing, Oklahoma to Valero's refinery in Memphis, Tennesse by early 2017. The pipeline is estimated to cost $900 million. Valero also holds the option until January 2016 to purchase 50 per cent interest of the pipeline.

4.4 Oil Pipelines to the U.S. Gulf Coast

The Gulf Coast represents the most significant opportunity for market growth for heavy Canadian crude oil supplies in North America. Refineries in the region rely on domestic supply and imports primarily from Mexico, Saudi Arabia, and Venezuela to meet their requirements.

Western Canadian and Bakken production historically had limited access to this market but two pipeline projects began operating in 2014 that connected supply from the Midwest to the U.S. Gulf Coast (Table 4.3).

4.4.1 Enbridge/Enterprise Seaway

The Seaway Pipeline system is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. Seaway is comprised of two parallel 30-inch diameter pipelines. The total current capacity is 850,000 b/d with 400,000 b/d contributed by the legacy pipeline between Cushing, Oklahoma and the Freeport, Texas area and 450,000 b/d contributed by the Seaway Twin pipeline from the ECHO terminal to Beaumont, Port Arthur, which was recently brought into service on December 1, 2014.

The system can deliver to Jones Creek, Freeport, ECHO terminal, Texas City & Port Arthur. The Jones Creek to ECHO terminal lateral is a 36-inch diameter pipeline with a capacity of 850,000 b/d while the ECHO terminal to Beaumont/Port Arthur lateral is a 30-inch diameter pipeline with a capacity of 650,000 b/d. As mentioned previously in Section 4.3.7, a portion of the Seaway pipeline has been reserved to take deliveries from the Flanagan South pipeline for those shippers that have nominated deliveries to Gulf Coast.

U.S. Gulf Coast market access for western Canadian crude oil has only started to emerge in recent years. The direction of flow on the legacy Seaway pipeline was reversed on May 17, 2012 in order to allow crude oil to be transported from the bottlenecked Cushing, Oklahoma hub to the Gulf Coast refineries near Houston. The first volumes arrived at the Jones Creek terminal, just north of Freeport, on June 6, 2012. The original capacity of the reversed pipeline was only 150,000 b/d but since January 2013, its capacity was increased to 400,000 b/d through pump station modifications and additions. On average, 290,000 b/d was transported in 2014 on the Seaway system.

4.4.2 TransCanada Keystone XL

The Keystone XL Pipeline is a 36-inch-diameter crude oil pipeline proposed by TransCanada that originates in Hardisty, Alberta, and extends south to Steele City, Nebraska. The project was originally proposed in 2005. TransCanada applied for a Presidential Permit with the U.S. Department of State to build this cross-border pipeline in September 2008; the long awaited decision on the project is assumed to occur before the end of 2015.

The Bakken Marketlink project from Baker, Montana, to Cushing, Oklahoma is designed to allow receipts of up to 100,000 b/d of crude oil from the Williston Basin, using capacity on the northern leg of Keystone XL. The Bakken Marketlink project is underpinned by 65,000 b/d of firm commitments.

Keystone XL and the Bakken Marketlink are expected to be in service two years following the receipt of a Presidential Permit.

4.4.3 TransCanada Gulf Coast

TransCanada's Gulf Coast Project started delivering crude oil on January 22, 2014. The 36-inch diameter pipeline is part of the Keystone Pipeline system and provides capacity from Cushing, Oklahoma to Port Arthur and Houston, Texas. During the first year of operations, the capacity is expected to average 520,000 b/d before ramping up to 700,000 b/d.

The Keystone Pipeline System which includes Keystone, the Gulf Coast Project and the proposed Keystone XL would provide 1.4 million b/d of capacity of which 1.1 million b/d is underpinned by long term contracts.

4.4.4 Capline Reversal

The Capline pipeline currently transports crude oil northbound from St. James, Louisiana to Patoka, Illinois. It is a 40-inch diameter pipeline system with a capacity of 1.2 million b/d of capacity. If reversed, the pipeline could move western Canadian crude to refineries in Lousiana but infrastructure upstream of the origination point would be required to connect to sources of supply. Marathon operates the pipeline while Plains All American Pipeline is the majority owner; the other part owner is BP. The owners have indicated that they would consider connecting Capline to the Diamond pipeline (See Section 4.3.9).

4.5 Oil Pipelines to the West Coast of Canada

The Kinder Morgan Trans Mountain pipeline is currently the only pipeline transporting crude oil from Alberta to the west coast. There is significant interest in building new pipeline capacity to the west coast. Once crude oil reaches the coast, it can be offloaded onto crude carriers to reach markets such as California, the U.S. Gulf Coast and Asia.

Table 4.3 Summary of Crude Oil Pipelines to the U.S. Gulf Coast

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Seaway	Cushing, OK	Freeport, TX	Operating	400
Seaway Twin Line			Operating since Dec 2014	450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2018	+830
TransCanada Cushing Extension	*Steele City, NE*	*Cushing, OK*	*Operating since Feb 2011*	
TransCanada Gulf Coast	*Cushing, OK*	*Nederland, TX*	*Operating since Jan 2014*	700
			Proposed - TBD	+130
Capline Reversal	Patoka,IL	St, James, LA	Proposed – TBD	+1,200

Table 4.4 summarizes the Enbridge Northern Gateway and Kinder Morgan's pipeline proposals to the West Coast.

4.5.1 Enbridge Northern Gateway

The Northern Gateway Project includes a new 36-inch diameter crude oil pipeline with an initial capacity of 525,000 b/d from Bruderheim, Alberta (near Edmonton, Alberta) to Kitimat, British Columbia. In June 2014, the project was approved by the Governor in Council subject to 209 conditions and further discussions with Aboriginal communities. The target in-service date for the project is 2019.

4.5.2 Kinder Morgan Trans Mountain Expansion

On December 16, 2013, Kinder Morgan submitted an application to the National Energy Board (NEB) for an expansion to its existing Trans Mountain pipeline (see Section 4.1.2). The capital cost for the Trans Mountain Pipeline Expansion project is estimated at $5.5 billion. If approved and constructed, the expanded system would be comprised of two parallel pipelines. Line 1 would consist of existing pipeline segments and could transport 350,000 b/d of refined petroleum products and light crude or potentially heavy crude oil depending on demand. The proposed Line 2 would have a capacity of 540,000 b/d and would be allocated to the transportation of heavy crude oil. This new pipeline and revamped configuration would, in effect, add 590,000 b/d of capacity to the existing system for a total capacity of 890,000 b/d.

The expansion is underpinned by contracts totaling 707,500 b/d under 15 and 20-year commitments from 13 shippers. If construction starts in 2016, the expanded pipeline would be operational in late 2018.

4.6 Oil Pipelines to Eastern Canada

In 2014, refineries in Eastern Canada processed almost 1.2 million b/d of crude oil, of which 542,000 b/d originated from foreign sources. There is currently no pipeline infrastructure that connects western Canadian crude oil supply to markets in Atlantic Canada. This market represents a significant opportunity for western Canadian producers. Table 4.5 lists the pipeline proposals that could be conduits to this market.

4.6.1 Enbridge Line 9 Reversal

The Enbridge Line 9 Reversal project is a 30-inch diameter pipeline that will transport crude oil from Sarnia, Ontario to Montréal, Québec. The 9A portion has been flowing crude oil from the Sarnia, Ontario to North Westover, Ontario since August 2013. The current capacity is 152,000 b/d.

Reversal of the remaining portion, Line 9B, to flow crude oil from North Westover, Ontario to Montréal, Québec and expansion of the completed pipeline to 300,000 b/d is targeted for in service in Q2 2015. Line 9B awaiting the final leave to open from the NEB which was filed in February 2015.

4.6.2 TransCanada Energy East

TransCanada Energy East is a proposed pipeline system that would provide transportation service from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Québec and New Brunswick. The major components of the project includes the conversion of a natural gas pipeline to oil service and constructing new pipeline segments in Alberta, Saskatchewan, Manitoba, Eastern Ontario, Québec and New Brunswick. Construction of associated facilities, pump stations and tank terminals, including marine facilities would also be required. The 4,600 km long pipeline is estimated to cost $12 billion and would have a capacity of 1.1 million b/d, of which 900,000 b/d is underpinned by firm contracts.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast of Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Kinder Morgan Trans Mountain	Edmonton , AB	Burnaby, BC	Operating	300
Kinder Morgan Trans Mountain Expansion			Proposed - Q4 2018	+590
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed - 2019	+525

Table 4.5 Summary of Crude Oil Pipelines to Eastern Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Line 9 Reversal	Sarnia, ON	Montréal, QC	Proposed	+300
9A	Sarnia, ON	North Westover, ON	Operating since Aug 2013	152
9B	North Westover, ON	Montréal, QC	Q2 2015	
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - 2020	+1,100

In TransCanada's original application to the NEB filed on October 30, 2014, the project included delivery points to three refineries in Eastern Canada and two marine terminals, one at Gros Cacouna, Québec and one at Saint John, New Brunswick to allow for exports to international markets.

Waters surrounding Gros Cacouna are included within the designated critical habitat for the St. Lawrence Estuary population of beluga whales. In November 2014, the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) recommended the re-designation of this whale population from a threatened to an endangered species. In April 2015, TransCanada announced that it will not be building the marine terminal and oil storage facility at Gros Cacouna, Québec and will be relocating the marine terminal to a different site that would not affect the beluga whale population. TransCanada intends to file an amendment to its regulatory filing in Q4 2015. The revised targeted in-service date for the project is 2020.

The TransCanada Energy East Pipeline Project includes the conversion of a natural gas pipeline to oil service and new pipeline segments to provide transportation service from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Québec and New Brunswick. The delivery points include three existing refineries in Eastern Canada and two marine terminals, one at Cacouna, Québec and one at Saint John, New Brunswick to allow for exports to international markets. The proposed pipeline would have a capacity of 1.1 million b/d, of which 900,000 b/d is underpinned by firm contracts. The scheduled in-service date for the project is Q4 2018.

4.7 Diluent Pipelines

Table 4.6 provides a summary of projects which aim to bring diluent supply which may be required to satisfying growing supply of heavy oil from Western Canada.

4.7.1 Enbridge Southern Lights

The Southern Lights pipeline which runs from Manhattan, Illinois (near Chicago) to Edmonton, Alberta has been moving diluent since 2010. The current capacity of the pipeline is 180,000 b/d. Of this initial capacity, 162,000 b/d is secured by long-term contracts. Enbridge is evaluating a future expansion of the Southern Lights system to increase capacity to 275,000 b/d by 2025 through the use of additional horse power and drag reducing agents.

4.7.2 Enbridge Northern Gateway Diluent

As part of its Northern Gateway Project, Enbridge is proposing a diluent pipeline that would run from Kitimat, British Columbia to Bruderheim, Alberta. The proposed capacity of the pipeline is 193,000 b/d. The project has been approved with numerous conditions. The updated target in-service date for the project is 2019.

4.7.3 TransCanada Grand Rapids Diluent

As part of its Grand Rapids Pipeline project, which was approved in October 2014, TransCanada plans to build a diluent line from the Heartland region to Fort McMurray, Alberta. The diluent pipeline would have a capacity of 330,000 b/d and is expected to be operating in 2017. Anchor shipper commitments have been obtained.

4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan's Cochin system is a 12-inch diameter multi-product pipeline. In April 2014, the pipeline was removed from ethane-propane service. Since July 2014, the pipeline has been shipping condensate from Kankakee County, Illinois to Fort Saskatchewan, Alberta. The pipeline's estimated capacity is 95,000 b/d.

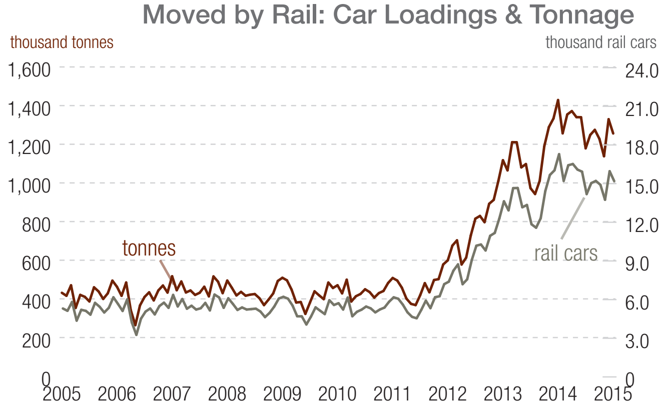
Table 4.6 Summary of Diluent Pipelines

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Southern Lights Southern Lights Expansion	Flanagan, IL	Edmonton, AB	Operating Proposed - 2025	180 +95
Enbridge Northern Gateway	Kitimat, BC	Bruderheim, AB	Proposed - 2019	+193
Kinder Morgan Cochin Conversion	Kankakee County, IL	Fort Saskatchewan, AB	Operating since July 2014	95
TransCanada Grand Rapids	Heartland, AB	Fort McMurray, AB	Proposed - 2017	+330

4.8 Crude Oil by Rail

In recent years, rail transport of crude oil has grown as an alternative mode of transport to accommodate the rapid growth from new supply regions that quickly exceeded the available pipeline capacity. Rail transport is expected to continue to rise due to the protracted regulatory processes for new pipelines. The number of Canadian rail car loadings of crude oil and petroleum products in 2014 increased by 14 per cent over 2013. Monthly loadings ranged between 13,745 car loads and 17,288 car loads throughout the year (Figure 4.2).

Figure 4.2 Canadian Fuel Oil and Crude Petroleum Moved by Rail: Car Loadings & Tonnage



Source: Statistics Canada

Pipelines are the most efficient means of connecting large supply basins to large market areas. However, in the absence of adequate pipeline capacity exiting Western Canada, rail transport will continue to rise due to the protracted regulatory processes for new pipelines and growing production and the startup of new terminals. There is a long-term future for this mode of transportation serving small producers without pipeline connections but also providing all producers with the flexibility to move to different markets in response to demand opportunities.

Producer Benefits of Rail

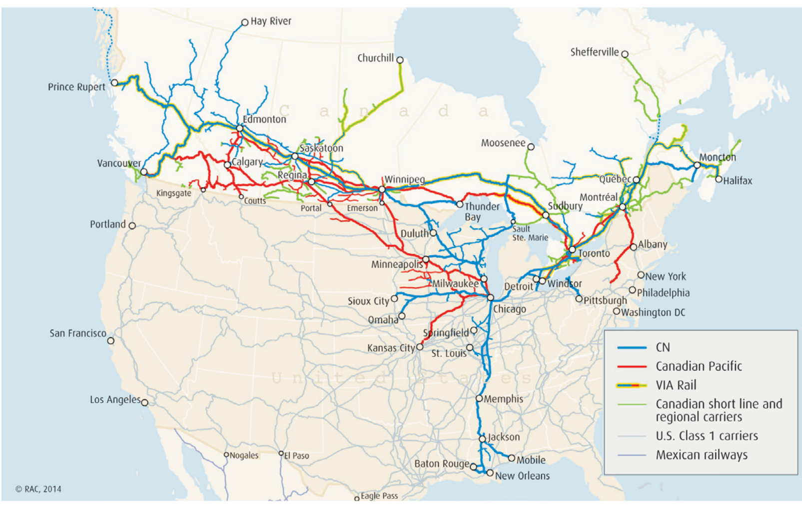
- ***Speed to Market***: *A unit train averages 28 km/hr. Getting oil to the refinery quickly means producers are paid sooner and refiners receive feedstock sooner.*
- ***Optionality/Flexibility:*** *There are existing rail tracks in place to reach the East Coast, West Coast and Gulf Coast markets in the U.S. Once on a rail tank car, crude oil can be delivered anywhere with an unloading facility.*
- ***Diluent:*** *Less or no diluent is required when transporting bitumen in rail tank cars, representing a significant cost savings. However, producers have continued to transport DilBit because raw bitumen can become too viscous as a result of cold temperatures en route. This can lead to longer unloading times as the bitumen would then need to be heated to flowing temperatures.*
- ***Scalability:*** *Producers have the flexibility to adjust the volumes being shipped with manifest trains. Unit trains provide economies of scale but require larger volumes to be shipped.*
- ***Product integrity:*** *Commodity isolation in separate rail tank cars results in no loss of quality during transportation.*
- ***Low Capital requirements:*** *Typical costs to build unit train terminals range between $30 to $50 million with a capital payout of 5 years or less. A unit train loading terminal can be constructed in about 12 months.*

In 2014, industry data indicated that about 185,000 b/d of western Canadian crude oil was transported to market by rail. In 2015, rail movements is expected to grow slightly to 200,000 b/d. In 2016, CAPP estimates the annual crude movement by rail could rise to 250,000 b/d. In 2017, it could reach 350,000 b/d. In 2018, rail volumes are estimated at around 500,000 b/d to 600,000 b/d if Keystone XL is not available but if the pipeline is in place, volumes might decrease significantly. Beyond 2018, as new pipeline projects become available, the crude volumes transported by rail could be be reduced.

Rail Quick Facts

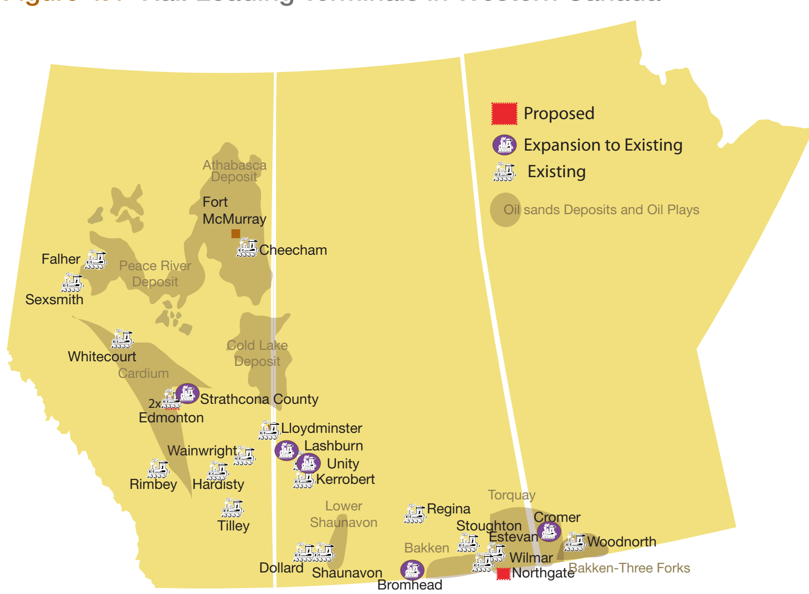
- Rail tank car capacity carrying light oil: 600 to 700 bbls
- Rail tank car capacity carrying heavy oil: 500 to 525 bbls
- RailBit and raw bitumen is transported in coiled and insulated rail tank cars to prevent solidifying in cold weather
- Unit train: 70 to 120 cars carrying only crude oil
- Manifest trains are mixed cargo trains delivering to different destinations
- Unit trains are used to carry one type of cargo from one location to another
- Economics for transport by rail improves with unit trains

Figure 4.3 North American Rail Network



Source: Rail Association of Canada

Figure 4.4 Rail Loading Terminals in Western Canada



The current rail loading capacity originating in Western Canada is 776,000 b/d. Some new facilities and expansion projects that were originally proposed to be in service by the end of 2015 have been deferred with unknown new timing. Figure 4.4 shows all the major existing and proposed rail terminals for uploading crude oil in Western Canada.

Transport Canada and the U.S. Department of Transportation announced new harmonized tank car standards in May 2015 in response to increased crude oil moved by rail and to address growing concerns around safety.

Major* Announced Rail Uploading Terminals in Western Canada

Operator	**Location**	**Expanded / Proposed Capacity**** ('000 b/d)	**Scheduled Startup**
	ALBERTA		
Keyera/ Enbridge	*Cheecham*	*32*	*Operating since Oct 2013*
Grizzly	*Conklin*	*10*	*Operating since Mar 2014; expansion potential*
Canexus	*Bruderheim (near Edmonton)*	*100*	*Operating; Expandable*
Gibson	*Edmonton*	*20 (expandable to 40)*	*Q3 2015*
Keyera/Kinder Morgan	*Edmonton*	*30 to 40*	*Operating since September 2014*
Pembina	*Edmonton*	*40*	*Operating*
Gibson/USDG	*Hardisty*	*120 (expandable to 240)*	*Operating since July 2014; expansion 18 months from decision*
Altex	*Lynton (Ft. McMurray*	*15*	*Operating*
Kinder Morgan /Imperial	*Strathcona County*	*210 to 250*	*Operating since April 2015*
	SASKATCHEWAN		
TORQ Transloading	*Bromhead*	*20 +58*	*Operating; Expansion planned*
Crescent Point	*Dollard*	*27*	*Operating; Expansion Q2 2014*
Altex	*Lashburn*	*35 +25*	*Operating; Expansion underway*
TORQ Transloading	*Lloydminster*	*25*	*Operating; Expandable to 88*
Ceres Global	*Northgate*	*35*	*Construction on hold: Expandable to (70,000)*
Crescent Point	*Stoughton*	*45*	*Operating*
Altex	*Unity*	*15*	*Operating*
TORQ Transloading	*Unity*	*22 +44*	*Operating; Expansion underway*
	MANITOBA		
Tundra	*Cromer*	*30 +30*	*Operating; + ultimate expansion*
TOTAL	*776,000 b/d + potential expansions*		

*Facilities with less than 15,000 b/d are not shown
**Capacities of facilities are not exactly comparable due to differences within factors used to determine capacity such as operating hours, available car spots and contracts in place.

4.9 Transportation Summary

An expansion of the existing transportation infrastructure is needed to connect growing crude oil supply from Western Canada to new markets. Pipelines are the preferred mode of transportation to move crude oil but the protracted regulatory processes continues to present a number of challenges. At least one new pipeline project is needed in the very near term to accommodate growing supplies.

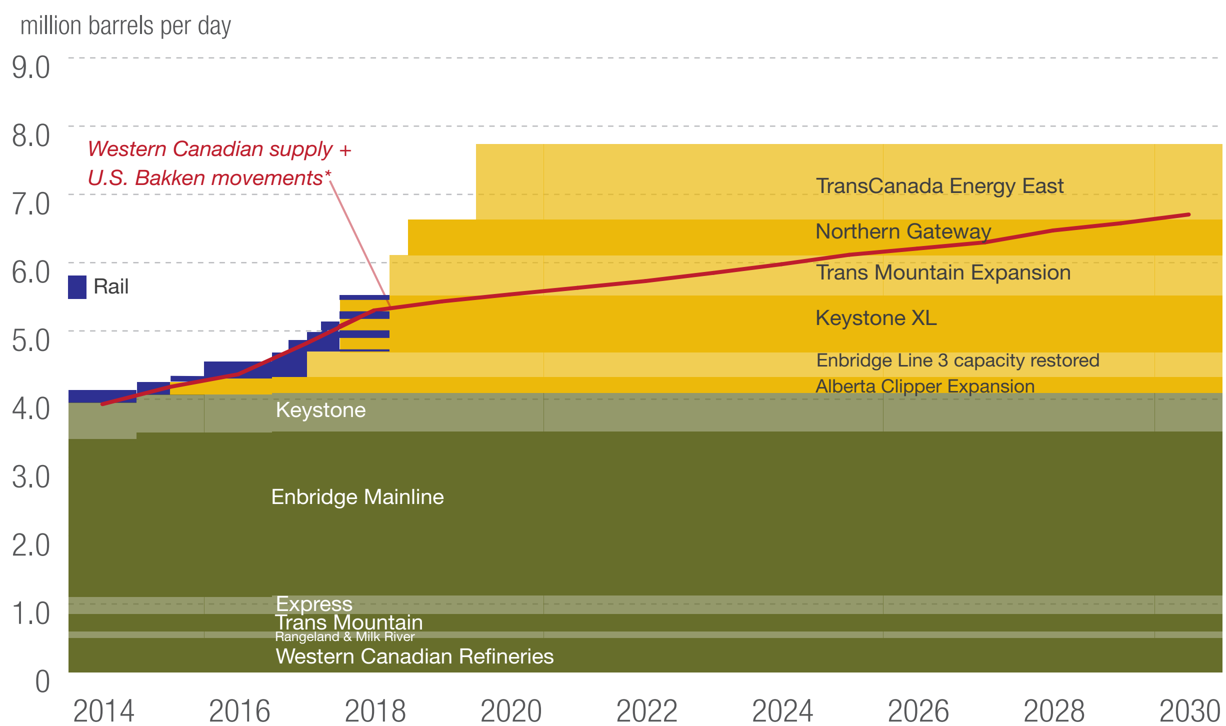
Figure 4.5 shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted crude oil supply movements. The purple represents the growing rail throughput that could occur until 2018. The forecasted supply movements was developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that would utilize a portion of the pipeline capacity that exits Western Canada.

The proposed pipeline projects are stacked in order of the reported timing of the various individual projects. It should not be interpreted as CAPP's view of the likelihood of one project proceeding faster than another.

The Keystone XL project would offer connections to the U.S. Gulf Coast refineries. The Trans Mountain Expansion and Northern Gateway projects would provide access to the West Coast and allow deliveries to Asian and Californian markets while TransCanada Energy East would provide access to the East Coast and allow deliveries to be made to European markets. These projects target three different markets and as such all will be needed to provide western Canadian producers with a level of market diversification that would allow the industry to flourish and grow. Increasing market optionality is of vital importance to companies considering investing large amounts of capital in order to realize the enormous resource potential that Western Canada holds. It should be noted that the startup timing for all of the pipeline proposals have been delayed from the dates reported last year, which reflects the difficulties industry is facing in putting into place large linear infrastructure projects.

In 2014, crude by rail volumes averaged 185,000 b/d. Crude by rail continues to be used as a complement to pipelines with volumes moving by rail growing to 2018. Beyond that rail use will be primarily impacted by the timing of proposed pipeline projects.

Figure 4.5 **WCSB Takeaway Capacity vs. Supply Forecast**



*Refers to the portion of U.S. Bakken production that is also transported on the Canadian pipeline network.
Capacity shown can be reduced by temporary operating and physical constraints.

GLOSSARY

Asphalt plant	A facility that processes crude oil into various types and grades of asphalt, ranging from dust-abatement road oils to highway-grade asphalt, to roofing tar.
API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volumes is measured or estimated. US condensate is arbitrarily divided into two broad categories. The first is lease condensate produced at or near the wellhead (either natural gas or crude oil). The second category is plant condensate, also known as NGL's, natural gasoline, pentanes plus or C5+, that remains suspended in natural gas at the wellhead and is removed at a gas processing plant. For purposes of this report, both categories are included in the termc"condensate.". Both categories of condensate are substantially similar in composition but the US EIA arbitrarily defines lease condensate as crude oil and plant condensate as an NGL (pentanes plus). Furthermore, Department of Commerce - Bureau of Industry and Security (BIS) regulations also define lease condensate as crude oil.
Crude oil (Conventional)	A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volumes is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or bitumen.
Crude oil (heavy)	Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27° or less. No differentiation is made between sweet and sour crude oil that falls in the heavy category because heavy crude oil is generally sour.
Crude oil (medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27° but less than 30°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude oil (synthetic)	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).

Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.
Integrated mining project	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
***In Situ* recovery**	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.
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 sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
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. The AER has designated three areas in Alberta as oil sands areas.
Oil Sands Heavy	In this report, Oil Sands Heavy includes upgraded heavy sour crude oil, and bitumen to which light oil fractions (i.e. diluent or upgraded crude oil) have been added in order to reduce its viscosity and density to meet pipeline specifications.
Open Season	A period of time designated by a pipeline company to determine shipper interest on a proposed project. Potential customers can indicate their interest/support by signing a transportation services agreement for capacity on the pipeline.
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.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Refined Petroleum Products	End products in the refining process (e.g. gasoline).
Specification	Defined properties of a crude oil or refined petroleum product.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.
Train (Manifest)	Manifest trains carry multiple cargoes and make multiple stops. These are small group or single car load.
Train (Unit)	Unit trains carry a single cargo and deliver a single shipment to one destination, lowering the cost and shortening the trip.
Upgrading	The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

APPENDIX A.1

CAPP Canadian Crude Oil Production Forecast 2015 – 2030

thousand barrels per day	Actual	*Forecast*															
EASTERN CANADA	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Ontario	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Atlantic Provinces[1]	219	215	218	216	286	299	257	234	225	204	198	173	147	137	116	97	91
E. Canada Conventional	**220**	**216**	**219**	**217**	**287**	**300**	**258**	**235**	**226**	**205**	**199**	**174**	**148**	**138**	**117**	**98**	**92**

WESTERN CANADA CONVENTIONAL	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Conventional Light & Medium																	
Alberta	440	440	418	409	405	405	413	419	423	426	429	432	436	439	443	447	447
B.C.	21	22	21	20	19	18	17	16	15	15	14	13	13	12	11	11	10
Saskatchewan [1,2]	248	266	266	262	259	258	259	260	263	266	269	272	275	278	283	287	292
Manitoba	47	39	37	35	34	34	33	32	32	31	30	30	29	29	28	28	27
N.W.T.	11	10	9	9	8	8	8	7	7	6	6	6	6	5	5	5	5
W. Canada Light & Medium	**767**	**777**	**751**	**735**	**726**	**723**	**730**	**736**	**740**	**744**	**749**	**753**	**758**	**764**	**771**	**778**	**782**
Conventional Heavy																	
Alberta Conv. Heavy	150	148	146	141	138	135	129	122	116	110	105	100	95	90	85	81	77
Saskatchewan Conv. Heavy [2,]	267	283	282	287	283	278	273	265	259	256	255	256	256	256	258	259	261
W. Canada Heavy	**416**	**431**	**428**	**428**	**421**	**413**	**401**	**387**	**375**	**366**	**360**	**355**	**350**	**346**	**343**	**341**	**339**
PENTANES/CONDENSATE	**182**	**183**	**181**	**179**	**176**	**169**	**169**	**170**	**170**	**171**	**171**	**171**	**171**	**169**	**166**	**163**	**161**
W. Canada Conventional (incl. condensates)	**1,365**	**1,390**	**1,359**	**1,342**	**1,322**	**1,306**	**1,300**	**1,293**	**1,285**	**1,281**	**1,280**	**1,280**	**1,280**	**1,279**	**1,279**	**1,282**	**1,281**

Notes:

1. *Atlantic Canada production includes Newfoundland & Labrador production and negligible volumes from New Brunswick. Condensates/pentanes from Nova Scotia and New Brunswick are also added.*
2. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m^3.*

WESTERN CANADA OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Sands Mining Operating & In Construction	912	951	1,032	1,076	1,250	1,279	1,309	1,348	1,376	1,392	1,407	1,418	1,418	1,418	1,418	1,418	1,418
+ additional growth		-	-	-	-	-	-	-	-	-	-	-	-	-	+105	+131	+158
Oil Sands Mining	912	951	1,032	1,076	1,250	1,279	1,309	1,348	1,376	1,392	1,407	1,418	1,418	1,418	1,523	1,549	1,576
Oil Sands *In situ* Operating & In Construction	1,244	1,334	1,435	1,567	1,637	1,719	1,755	1,752	1,735	1,701	1,677	1,658	1,636	1,612	1,587	1,569	1,553
+ additional growth		-	-	-	-	-	+15	+57	+120	+218	+318	+428	+518	+605	+673	+743	+824
Oil Sands *In situ*	1,244	1,334	1,435	1,567	1,637	1,719	1,771	1,808	1,855	1,920	1,995	2,086	2,154	2,217	2,260	2,312	2,377
Oil Sands Operating & In Construction	**2,157**	**2,286**	**2,467**	**2,643**	**2,887**	**2,997**	**3,065**	**3,100**	**3,111**	**3,094**	**3,083**	**3,076**	**3,054**	**3,030**	**3,005**	**2,987**	**2,971**
+ additional Growth		-	-	-	-	-	+15	+57	+120	+218	+318	+428	+518	+605	+778	+874	+981
TOTAL OIL SANDS	**2,157**	**2,286**	**2,467**	**2,643**	**2,887**	**2,997**	**3,080**	**3,157**	**3,232**	**3,312**	**3,401**	**3,504**	**3,572**	**3,635**	**3,784**	**3,861**	**3,953**
W. Canada Oil Production	*3,522*	*3,676*	*3,826*	*3,986*	*4,209*	*4,303*	*4,381*	*4,449*	*4,516*	*4,593*	*4,681*	*4,784*	*4,851*	*4,914*	*5,063*	*5,143*	*5,234*
E. Canada Oil Production	*220*	*216*	*219*	*217*	*287*	*300*	*258*	*235*	*226*	*205*	*199*	*174*	*148*	*138*	*117*	*98*	*92*
TOTAL CANADIAN OIL PRODUCTION	**3,742**	**3,893**	**4,045**	**4,203**	**4,497**	**4,603**	**4,639**	**4,685**	**4,743**	**4,798**	**4,880**	**4,958**	**5,000**	**5,052**	**5,180**	**5,241**	**5,326**

OIL SANDS RAW BITUMEN**	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Sands Mining Operating & In Construction	1,038	1,083	1,168	1,218	1,404	1,435	1,468	1,510	1,539	1,555	1,570	1,581	1,581	1,581	1,581	1,581	1,581
+ additional Growth		-	-	-	-	-	-	-	-	-	-	-	-	-	+123	+153	+184
Oil Sands Mining	1,038	1,083	1,168	1,218	1,404	1,435	1,468	1,510	1,539	1,555	1,570	1,581	1,581	1,581	1,704	1,735	1,765
Oil Sands *In Situ* Operating & In Construction	1,266	1,354	1,455	1,587	1,657	1,740	1,778	1,775	1,759	1,726	1,702	1,682	1,660	1,637	1,612	1,594	1,578
+ additional Growth		-	-	-	-	-	+15	+57	+120	+218	+324	+442	+533	+620	+689	+771	+865
Oil Sands *In Situ*	1,266	1,354	1,455	1,587	1,657	1,740	1,793	1,831	1,880	1,944	2,025	2,125	2,194	2,257	2,301	2,365	2,443
OIL SANDS Operating & In Construction	**2,305**	**2,437**	**2,623**	**2,805**	**3,061**	**3,175**	**3,246**	**3,284**	**3,299**	**3,281**	**3,271**	**3,264**	**3,242**	**3,218**	**3,193**	**3,175**	**3,159**
+ additional Growth		**-**	**-**	**-**	**-**	**-**	**+15**	**+57**	**+120**	**+218**	**+324**	**+442**	**+533**	**+620**	**+812**	**+925**	**+1,050**
TOTAL OIL SANDS	**2,305**	**2,437**	**2,623**	**2,805**	**3,061**	**3,175**	**3,261**	**3,341**	**3,419**	**3,499**	**3,595**	**3,706**	**3,775**	**3,838**	**4,005**	**4,100**	**4,209**

Totals may not add up due to rounding.

Notes:

*** Raw bitumen numbers are provided at the bottom of the table. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

APPENDIX A.2 CAPP Western Canadian Crude Oil Supply Forecast 2015-2030

Blended Supply to Trunk Pipelines and Markets *thousand barrels per day*

	Actual	*Forecast*															
CONVENTIONAL	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Light and Medium	763	773	747	731	722	719	726	732	736	740	745	749	754	760	767	774	778
Net Conventional Heavy to Market	362	360	357	357	350	341	327	312	298	288	282	276	271	266	263	260	257
TOTAL CONVENTIONAL	**1,125**	**1,133**	**1,104**	**1,088**	**1,071**	**1,060**	**1,053**	**1,043**	**1,033**	**1,028**	**1,027**	**1,025**	**1,024**	**1,026**	**1,029**	**1,034**	**1,035**
OIL SANDS																	
Upgraded Light (Synthetic)[1]	756	796	820	844	918	929	964	977	982	968	951	932	916	908	1,012	1,038	1,070
Oil Sands Heavy [2]	1,859	2,066	2,280	2,478	2,707	2,836	2,905	2,995	3,090	3,215	3,352	3,510	3,618	3,716	3,783	3,857	3,953
TOTAL OIL SANDS AND UPGRADERS	**2,616**	**2,862**	**3,100**	**3,322**	**3,625**	**3,765**	**3,869**	**3,972**	**4,072**	**4,183**	**4,303**	**4,442**	**4,534**	**4,624**	**4,795**	**4,895**	**5,022**
Total Light Supply	1,519	1,569	1,566	1,575	1,639	1,648	1,690	1,709	1,717	1,708	1,696	1,681	1,669	1,668	1,779	1,812	1,847
Total Heavy Supply	2,222	2,426	2,637	2,835	3,057	3,177	3,233	3,306	3,388	3,503	3,633	3,786	3,889	3,982	4,045	4,117	4,210
WESTERN CANADA OIL SUPPLY	**3,741**	**3,995**	**4,204**	**4,410**	**4,696**	**4,825**	**4,922**	**5,015**	**5,105**	**5,211**	**5,329**	**5,467**	**5,558**	**5,650**	**5,824**	**5,929**	**6,058**

Notes:

1. Includes upgraded conventional.

2. Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders.

Supply numbers from operating and in construction projects only are not provided due to confidentiality concerns.

APPENDIX B ACRONYMS, ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Acronyms

API	American Petroleum Institute
AER	Alberta Energy Regulator
CAPP	Canadian Association of Petroleum Producers
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
IEA	International Energy Agency
NEB	National Energy Board
OECD	Organization for Economic Co-operation and Development
PADD	Petroleum Administration for Defense District
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Canadian Provincial Abbreviations

AB	Alberta
BC	British Columbia
MB	Manitoba
NB	New Brunswick
NL	Newfoundland & Labrador
NWT	Northwest Territories
ON	Ontario
QC	Québec
SK	Saskatchewan

Units

b/d barrels per day

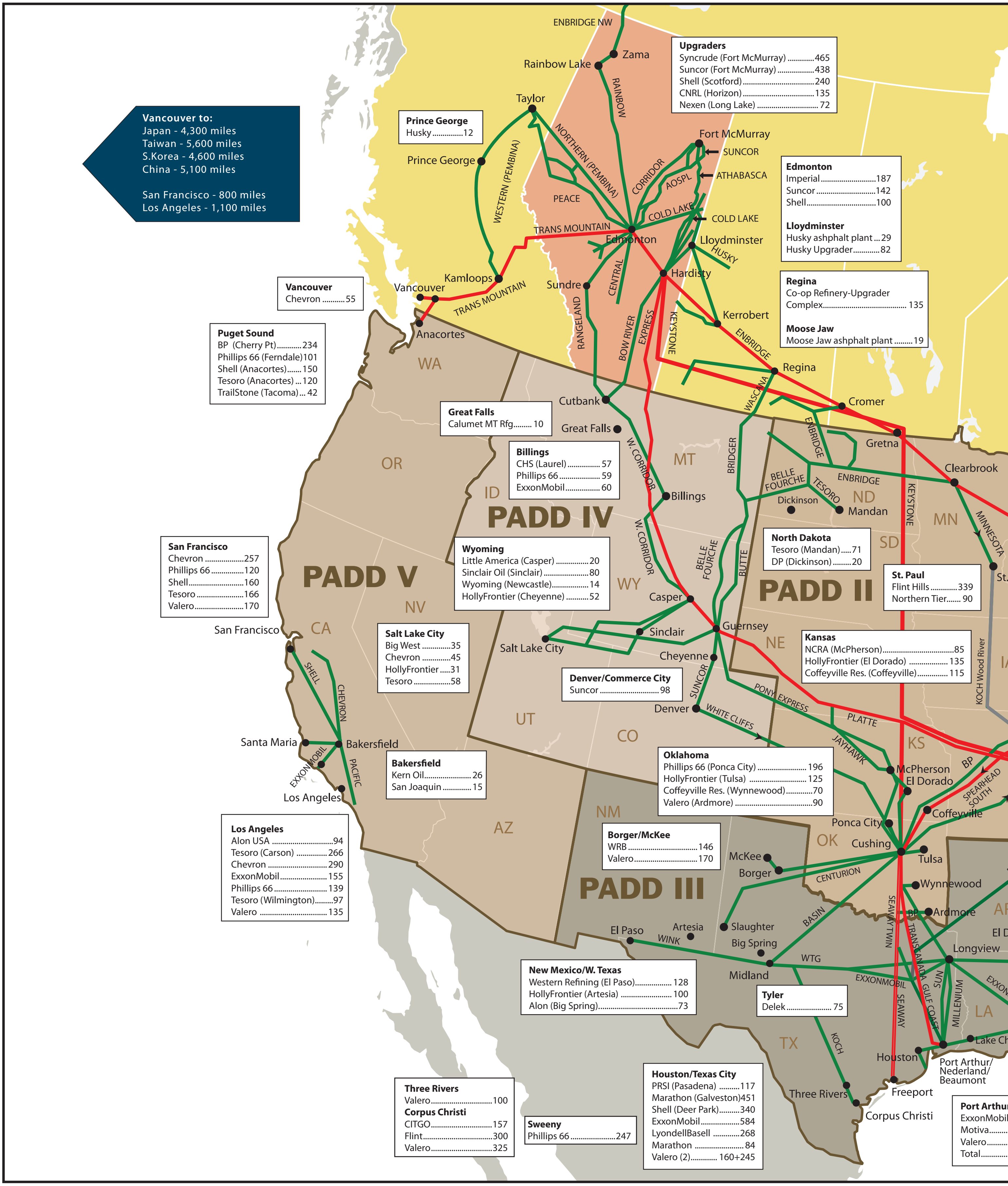
Conversion Factor

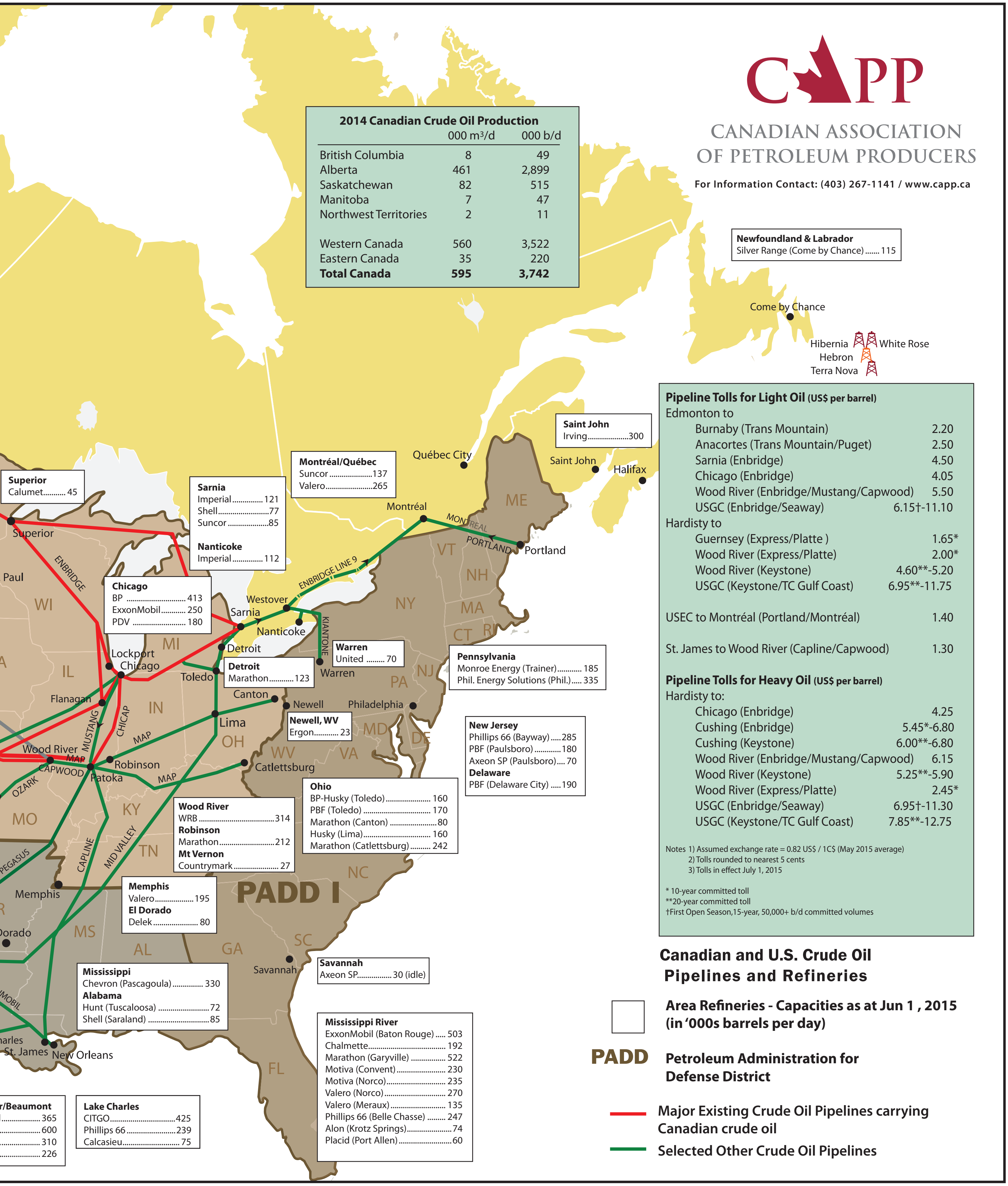
1 cubic metre = 6.293 barrels (oil)

U.S. State Abbreviations

AL	Alabama
AK	Alaska
AZ	Arizona
AR	Arkansas
CA	California
CO	Colorado
CT	Connecticut
DE	Delaware
FL	Florida
GA	Georgia
ID	Idaho
IL	Illinois
IN	Indiana
IA	Iowa
KS	Kansas
KY	Kentucky
LA	Louisiana
ME	Maine
MD	Maryland
MA	Massachusetts
MI	Michigan
MN	Minnesota
MS	Mississippi
MO	Missouri
MT	Montana
NE	Nebraska
NV	Nevada
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NY	New York
NC	North Carolina
ND	North Dakota
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VT	Vermont
VA	Virginia
VI	Virgin Islands
WA	Washington
WV	West Virginia
WI	Wisconsin
WY	Wyoming

APPENDIX C
Crude Oil Pipelines and Refineries





2014 Canadian Crude Oil Production

	000 m³/d	000 b/d
British Columbia	8	49
Alberta	461	2,899
Saskatchewan	82	515
Manitoba	7	47
Northwest Territories	2	11
Western Canada	560	3,522
Eastern Canada	35	220
Total Canada	**595**	**3,742**

Pipeline Tolls for Light Oil (US$ per barrel)

Edmonton to	
Burnaby (Trans Mountain)	2.20
Anacortes (Trans Mountain/Puget)	2.50
Sarnia (Enbridge)	4.50
Chicago (Enbridge)	4.05
Wood River (Enbridge/Mustang/Capwood)	5.50
USGC (Enbridge/Seaway)	6.15†-11.10
Hardisty to	
Guernsey (Express/Platte)	1.65*
Wood River (Express/Platte)	2.00*
Wood River (Keystone)	4.60**-5.20
USGC (Keystone/TC Gulf Coast)	6.95**-11.75
USEC to Montréal (Portland/Montréal)	1.40
St. James to Wood River (Capline/Capwood)	1.30

Pipeline Tolls for Heavy Oil (US$ per barrel)

Hardisty to:	
Chicago (Enbridge)	4.25
Cushing (Enbridge)	5.45*-6.80
Cushing (Keystone)	6.00**-6.80
Wood River (Enbridge/Mustang/Capwood)	6.15
Wood River (Keystone)	5.25**-5.90
Wood River (Express/Platte)	2.45*
USGC (Enbridge/Seaway)	6.95†-11.30
USGC (Keystone/TC Gulf Coast)	7.85**-12.75

Notes 1) Assumed exchange rate = 0.82 US$ / 1C$ (May 2015 average)
2) Tolls rounded to nearest 5 cents
3) Tolls in effect July 1, 2015

* 10-year committed toll
**20-year committed toll
†First Open Season,15-year, 50,000+ b/d committed volumes

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about $120 billion a year. CAPP's mission, on behalf of the Canadian upstream oil and gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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