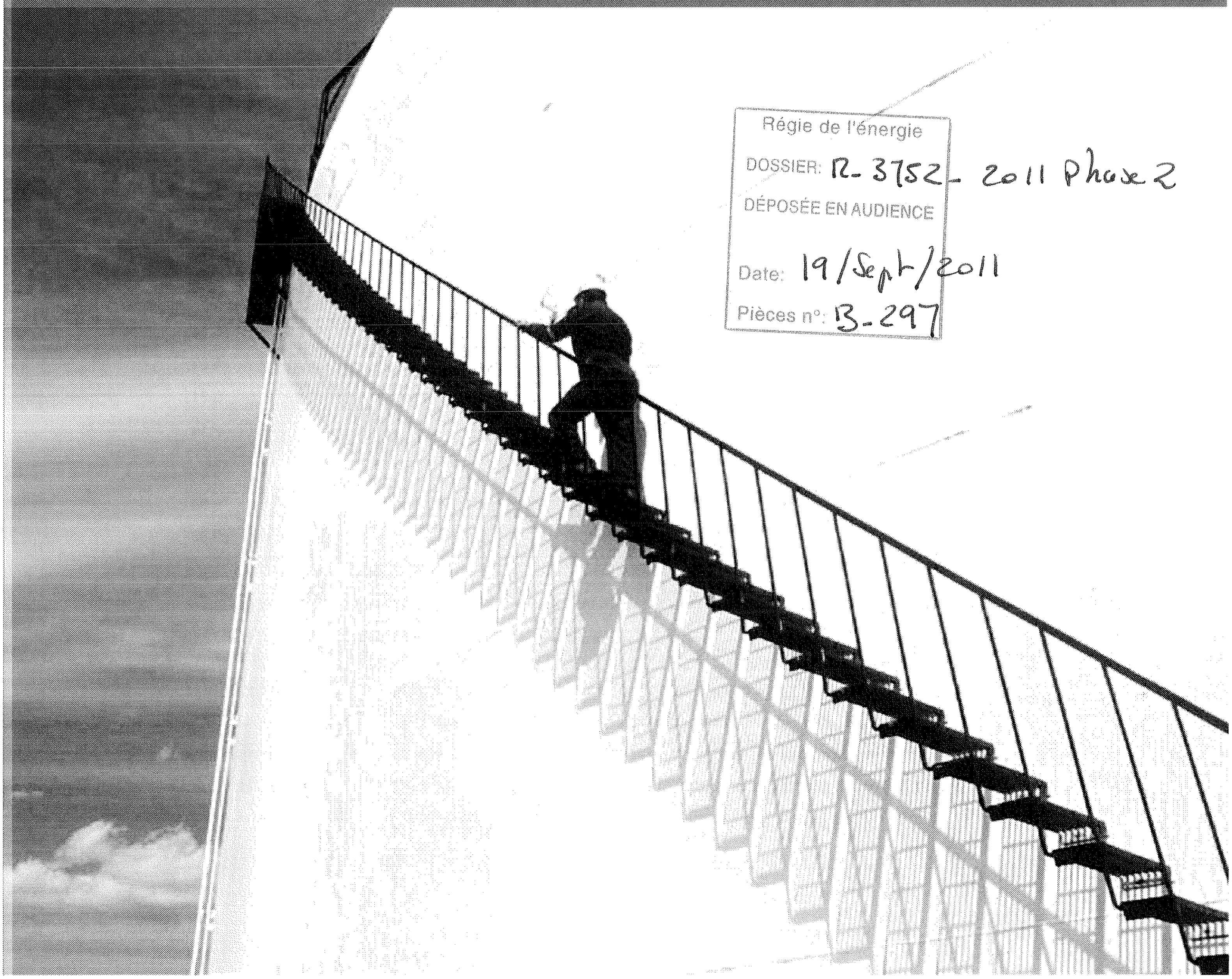
ERCB Energy Resources Conservation Board

ST98-2011

Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020



In 2010, about 11.7 10^6 m^3/d of process gas was generated at oil sands upgrading facilities and used as fuel. This number is expected to reach 21.0 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells was 4.3 10^6 m^3/d in 2010 and is forecast to increase to 6.3 10^6 m^3/d by 2020. 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.

5.2.6 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, and earn a 10 per cent specified return on investment.

The following table summarizes estimated costs of conventional gas supplies from selected areas in Alberta based on 2009 drilling and operating costs and production rates. Supply costs for different geological plays within the province can vary significantly because of differing discovered reserves and resulting production rates and drilling and operating costs. Some selected results for Alberta are displayed below in **Table 5.16**.

Table 5.16 Supply costs for gas wells in Alberta

Area of Alberta	Resource type	Resource group	Supply cost ($C/GJ)
Central	Tight	Mannville	3.23
West Central	Conventional	Upper Cretaceous; Upper Colorado	3.68
Southwest	Conventional	Middle and Lower Manville	4.45
Kaybob	Conventional	Triassic	4.76
Southern	Conventional	Mannville	5.44
Deep Basin	Tight	Mannville; Jurassic	5.62
CBM deposit play area	Coalbed methane	Mannville	6.31
Southern Foothills	Conventional	Mississipian; Upper Devonian	7.14
Northeast Alberta	Conventional	Manville; Upper Devonian	8.54
Central Foothills	Conventional	Mississippi	9.04
Eastern	Conventional	Colorado; Manville	9.83

Source: National Energy Board (NEB), November 2010, *Supply Costs in Western Canada in 2009*.

5.2.7 Natural Gas Storage

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

In summer, 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 5.17**.

In 2010, natural gas withdrawals for all storage schemes exceeded injections by 277 10^6 m^3. Marketable gas production volumes determined for 2010 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.

Table 5.17 Commercial natural gas storage pools as of December 31, 2010

Pool	Operator	Storage capacity (10^6 m^3)	Maximum deliverability (10^3 m^3/d)	Injection volumes, 2010 (10^6 m^3)	Withdrawal volumes, 2010 (10^6 m^3)
Carbon Glauconitic	ATCO Midstream	1 127	15 500	644	861
Countess Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	35 217	1 130	1 070
Crossfield East Elkton A & D	CrossAlta Gas Storage	1 197	14 790	858	995
Edson Viking D	TransCanada Pipelines Ltd.	1 775	25 740	591	721
Hussar Glauconitic R	Husky Oil Operations Limited	423	5 635	199	206
McLeod Cardium A	Iberdrola Canada Energy Services Ltd.	986	16 900	343	287
McLeod Cardium D	Iberdrola Canada Energy Services Ltd.	282	4 230	152	274
Suffield Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	50 713	1 435	1 633
Warwick Glauconitic-Nisku A	Warwick Gas Storage Inc. (WGSI)	881	3 300	434	17
Total				**5 787**	**6 064**
Difference					**277**

Figure S5.24 shows the location of existing gas storage facilities at the Alberta pipeline systems.

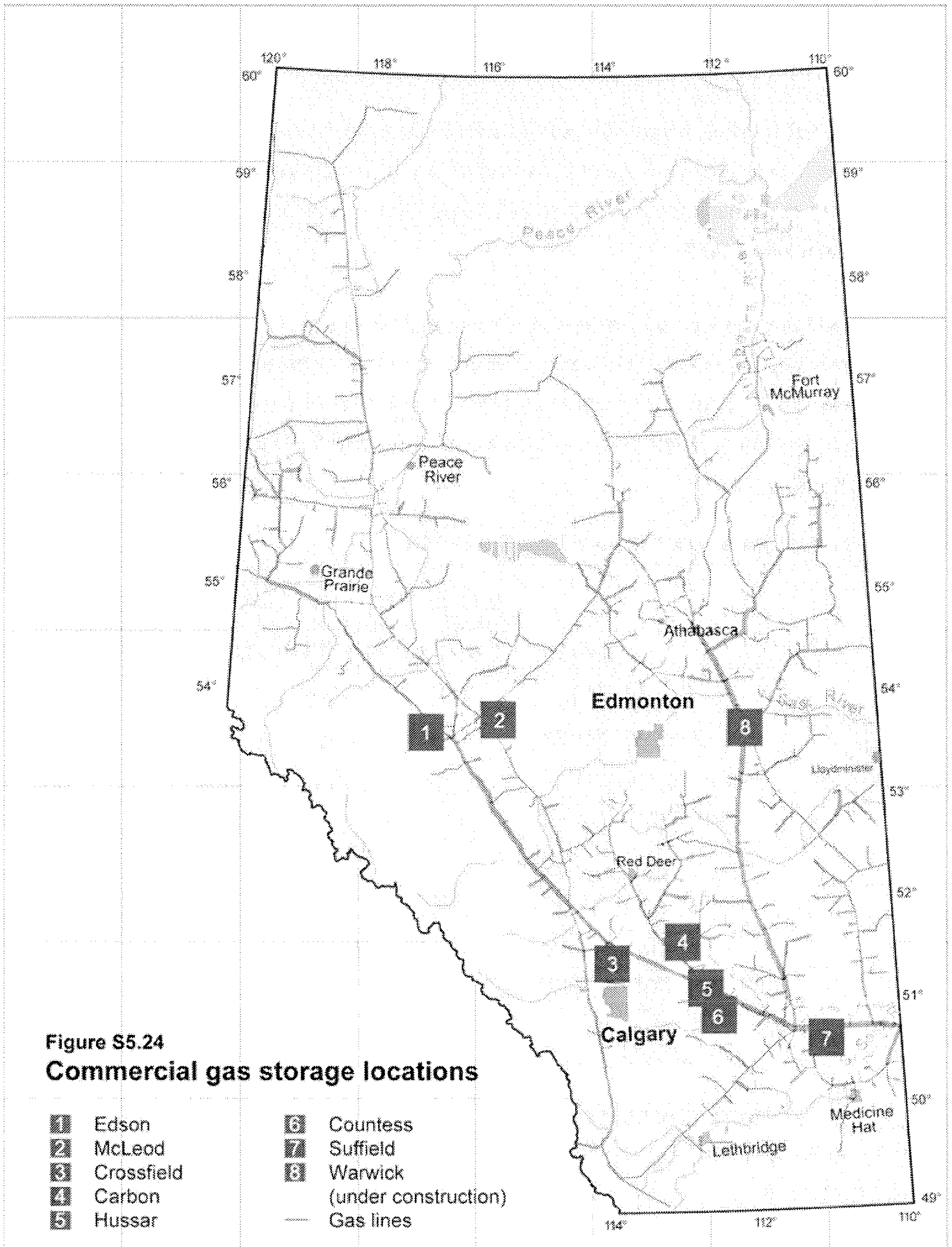


Figure S5.24
Commercial gas storage locations

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. Exports of gas from Alberta are only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.

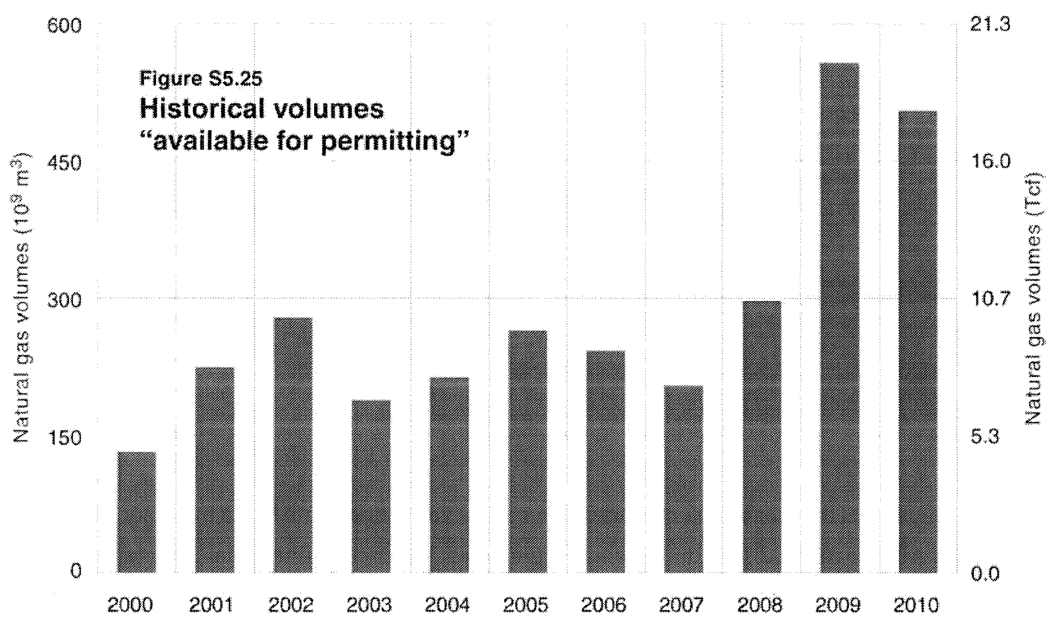
The calculation in **Table 5.18** is done annually to determine what volume of gas is available for removals from Alberta after accounting for Alberta's future requirements. Using the 2010 remaining established reserves number, surplus natural gas is currently calculated to be 505 10^9 m^3. **Figure S5.25** illustrates historical "available for permitting" volumes.

Table 5.18 Estimate of gas reserves available for inclusion in permits as of December 31, 2010

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2010)	
1. Total remaining established reserves	1 066
Alberta requirements	
2. Core market requirements	114
3. Contracted for non-core markets[a]	131
4. Permit-related fuel and shrinkage	29
Permit requirements	
5. Remaining permit commitments[b]	287
6. Total requirements	561
Available	
7. Available for permits	505

[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 90 per cent under short-term permits and 10 per cent under long-term permits.



Gas removals from Alberta have declined since 2001, from 315.5 10^6 m^3/d in 2001 to 196.5 10^6 m^3/d in 2010. Based on the ERCB's projection of gas production, this rate is forecast to drop to 50.8 10^6 m^3/d by 2020.

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.

Forecasting demand for Alberta natural gas in markets outside the province is done less rigorously. For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on export pipeline capacity available to serve such markets, and on the recent historical trends in meeting that demand. Excess pipeline capacity to the U.S. allows gas to move to areas of the U.S. that provide for the highest netback to the producer. The major natural gas pipelines in Canada that move Alberta gas to market are illustrated in **Figure S5.26**, with removal points identified.

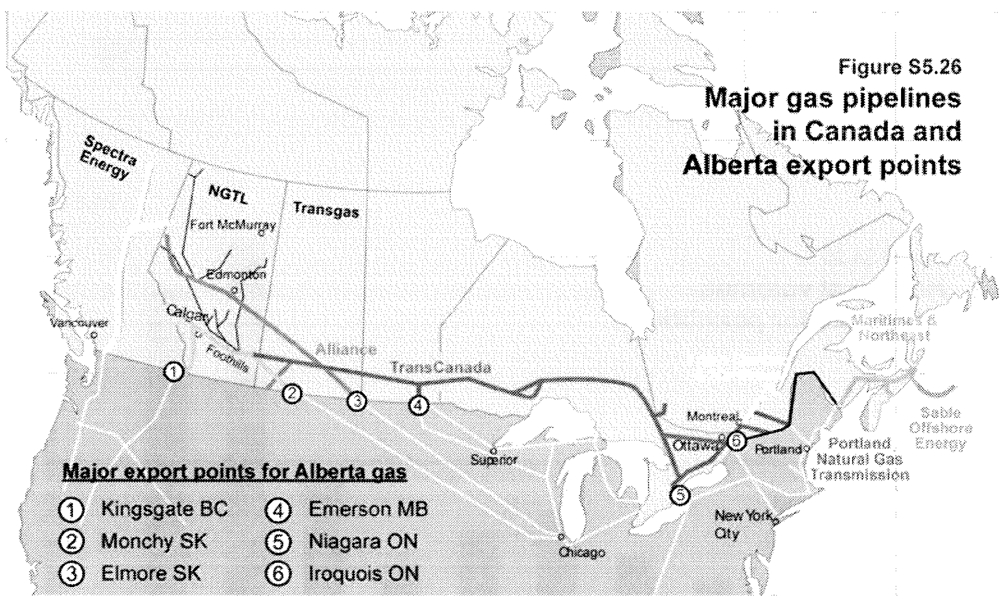


Figure S5.27 illustrates the breakdown of marketable natural gas demand in Alberta by sector. In 2010, demand within Alberta was 122.1 10^6 m^3/d, which represented 38 per cent of the total Alberta natural gas production. By the end of the forecast period, demand is estimated to reach 166.4 10^6 m^3/d, or 77 per cent of total production.

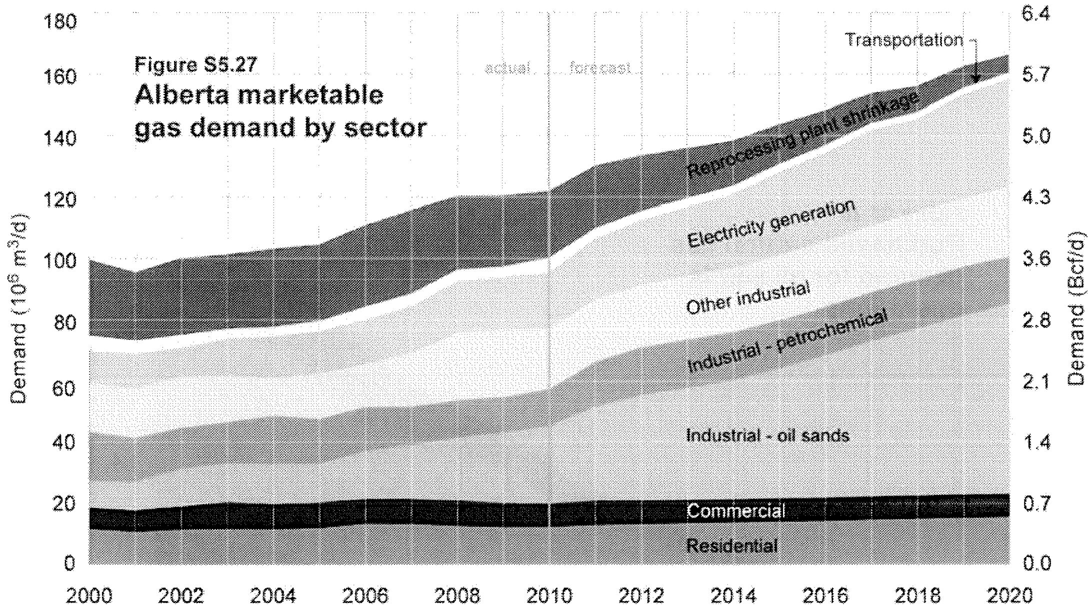


Figure S5.27
Alberta marketable gas demand by sector

Residential gas requirements are expected to grow moderately at an average annual rate of 2 per cent over the forecast period. The key variables that affect residential gas demand are natural gas prices, population, the number of households, energy efficiencies, and the weather. Energy efficiency improvements prevent 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 efficiencies and a shift towards electricity.

The electricity generating industry will require increased volumes of natural gas to fuel the new industrial on-site and peaking plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 18.3 10^6 m^3/d in 2010 to 35.1 10^6 m^3/d by 2020. 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. See Section 9 for details on the new gas-fired plants projected to come on stream over the forecast period.

Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations will increase from 25.1 10^6 m^3/d in 2010 to 62.0 10^6 m^3/d by 2020. The purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil (SCO), including gas used by the electricity cogeneration units on site at the oil sands operations, shown in **Figure S5.28**, are expected to increase from 35.8 10^6 m^3/d in 2010 to 83.4 10^6 m^3/d by 2020. All purchased gas use for upgrading operations, including the gas used by Nexen/OPTI to upgrade in situ bitumen, is included in the mining and upgrading category shown in the Figure. **Table 5.19** outlines the average purchased gas use rates for oil sands operations.

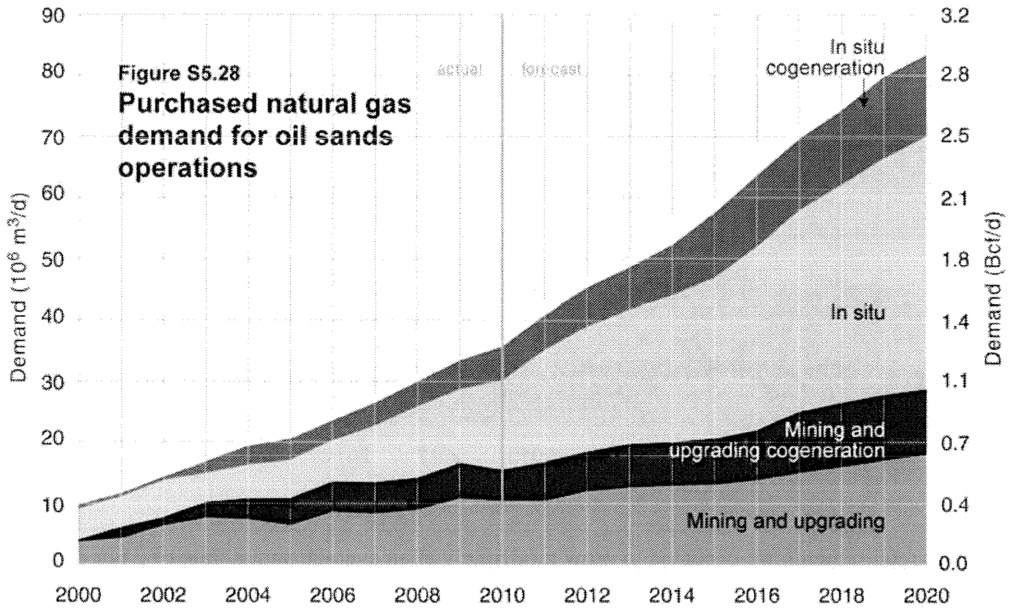


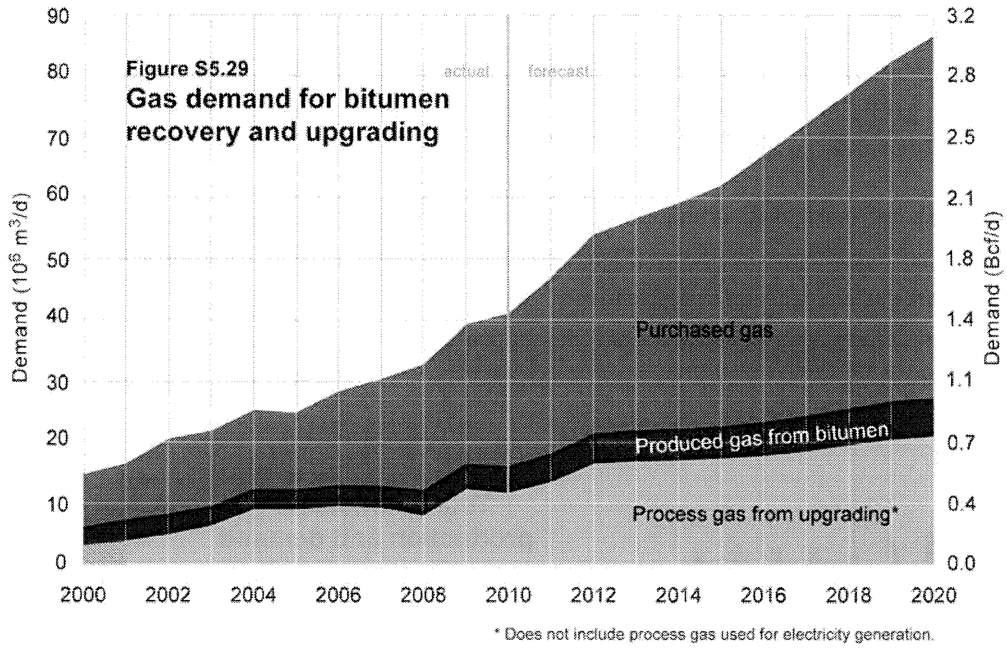
Table 5.19 2010 oil sands average purchased gas use rates*

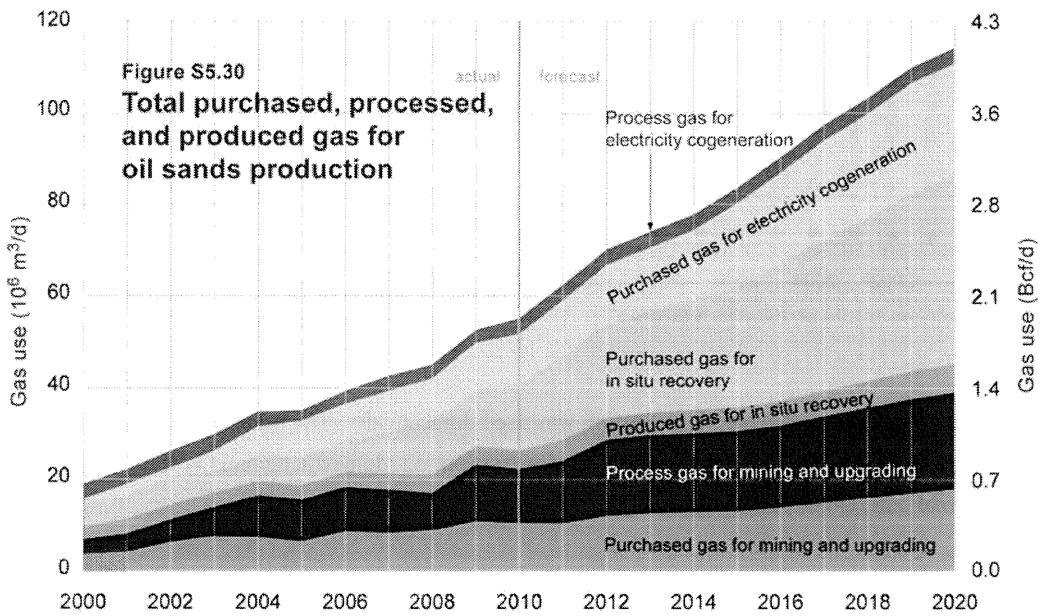
Extraction method	Excluding purchased gas for cogeneration (m^3/m^3)	(mcf/bbl)	Including purchased gas for cogeneration (m^3/m^3)	(mcf/bbl)
In situ				
SAGD	167	0.94	241	1.36
CSS	189	1.06	237	1.33
Mining with upgrading	83	0.47	124	0.70

* Expressed as cubic metres of natural gas per cubic metre of bitumen/synthetic crude oil production. Rates are an average of typical schemes with sustained production.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.29** illustrates the sector's total gas demand, which is the sum of purchased gas, process gas, and solution gas produced at bitumen wells. This demand is expected to nearly double from 41.1 10^6 m^3/d in 2010 to 86.6 10^6 m^3/d by 2020.

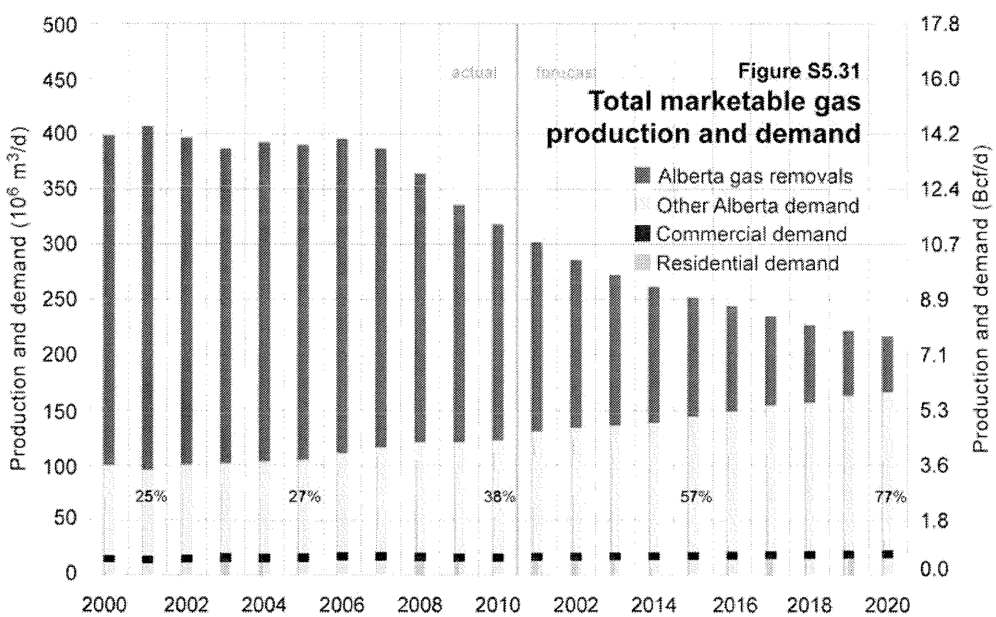
Gas use by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, as shown in **Figure S5.30**, was 55.3 10^6 m^3/d in 2010 and is forecast to increase to 114.2 10^6 m^3/d by 2020.





The potential high use of natural gas in bitumen production and upgrading has exposed the companies involved in the business to risk caused by volatile gas prices. The Nexen/OPTI Long Lake Project began commercial operations in January 2009, employing technology that produces synthetic gas by burning ashphaltines in its new bitumen upgrader. In previous years when the price of natural gas was relatively high, companies were exploring the option of self-sufficiency for their gas requirements. The existing bitumen gasification technology was one attractive alternative being pursued. If gas prices increase to levels at which gasification at upgrading operations is again considered economic, natural gas requirements could decrease substantially.

Figure S5.31 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading (**Figure S5.27**) 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 only, minus Alberta demand.



2010 volumes for shale gas production is included in the chart; shale gas production has not been forecast.

In 2010, about 38 per cent of Alberta production was used domestically. The remainder was sent to other Canadian provinces and the U.S. By the end of the forecast period, domestic demand will represent 77 per cent of total natural gas production.