aeso
ALBERTA
ELECTRIC
SYSTEM
OPERATOR

Future Demand and Energy Outlook (2008 – 2028)

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Executive Summary

The *Future Demand and Energy Outlook, 2008-2028* (FC2008) is the Alberta Electric System Operator's (AESO) long-term load forecast. FC2008 describes the assumptions, methodology, and processes that the AESO uses to assess Alberta's future demand and energy requirements.

This report is prepared annually in accordance with the duties of the AESO as outlined in Alberta's *Electric Utilities Act* (EUA) and the *Transmission Regulation* (AR 86/2007) and will be used to support filings that may be submitted to the Alberta Utilities Commission (AUC).

FC2008 includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (GDP), oilsands production forecast, population projections by select customer sectors, with regional adjustments based on historical results and customer-driven growth expectations.

In the past five years (2003 – 2007), Alberta's Internal Load (AIL) peak demand has grown by an average of 228 megawatts (MW) (2.5 per cent) per year from 8,570 MW to 9,710 MW (an overall increase of 13.3 per cent). Electricity consumption has grown by an average of 3.2 per cent per year from 59,437 gigawatt hours (GWh) to 69,660 GWh.

The AESO forecasts the peak AIL demand to grow by an average 3.4 per cent per year for the next 20 years. Electricity consumption is expected to grow by 3.5 per cent per year.

In addition to reporting the detailed forecast results, this report includes a review of the AESO's load forecasting methodology and a brief statement on the potential impact of this past fall's economic turmoil. The energy and demand forecast is prepared based on an examination of five sectors: industrial without oilsands, oilsands, commercial, residential and farm. The results are organized by the AESO's five bulk transmission planning regions and six regional planning regions.

The FC2008 concludes with a brief discussion of the challenges faced in preparing a load forecast for Alberta.

1.0 Introduction

The AESO's long-term load forecast is a study of past energy use patterns and future economic indicators, that are, in simple terms, combined to produce a future energy forecast. The AESO annually updates this energy forecast with a 20-year outlook of Alberta's electric energy consumption and peak load demand. The estimates of future electricity market needs are one of the drivers the AESO uses in analyzing and planning the timely development of the transmission system. The annual forecast is based on economic, demographic and customer information collected from January through June of 2008.

Completed in the third quarter of 2008, the AESO's *Future Demand and Energy Outlook (2008-2028)* or "FC2008", describes the assumptions, methodology and processes that the AESO employs to assess Alberta's future demand and energy requirements.

The FC2008 recognizes some future project uncertainty in regards to timing, size and number of large oilsands extraction facilities and upgraders in the northeast of the province. This uncertainty is reflected in the FC2008 demand and shows a drop in demand from the FC2007 in the first 10-year period.

1.1 Economic Update November 2008

The AESO has performed a preliminary assessment to measure the impact of recent global economic events on the future demand for electricity in Alberta. Preliminary estimates show a short-term slowdown in economic growth could result in a reduction in peak demand of about 200 - 400 MW in the 10-year horizon and 500 - 600 MW in the 20-year horizon in relation to the forecast contained in this report. This assessment further indicates that the recent global economic turmoil should not affect electricity growth in the province to a large degree in the long-term.

Table 1.1-1: Alberta GDP Growth Comparison

Year	Conference Board of Canada Provincial Outlook 2008 Released: March 2008	Conference Board of Canada Provincial Outlook Autumn 2008 Released: November 2008
2007	*3.4% (not final)*	3.1%
2008	3.6%	1.2%
2009	3.6%	2.6%
2010	3.7%	3.8%

2.0 Economic Outlook

The foundation for the AESO's electricity demand and energy forecast is Alberta's economic outlook, which continues to be strong according to the Conference Board of Canada's long-term economic forecast (*Provincial Outlook Long-term Forecast 2008* published in March 28, 2008).

Economic growth, as measured by the provincial gross domestic product (GDP), is expected to be strong in the coming decade, ranging from 2.6 per cent to 3.7 per cent. According to the Conference Board of Canada, GDP is forecast to be 3.6 per cent in 2008 and 3.6 per cent in 2009. Over the last two decades, Alberta had the highest rate of GDP growth in Canada, averaging 3.8 per cent per year.

The AESO's economic outlook is developed using information and analysis from the Conference Board of Canada, Statistics Canada and other independent subject matter experts.

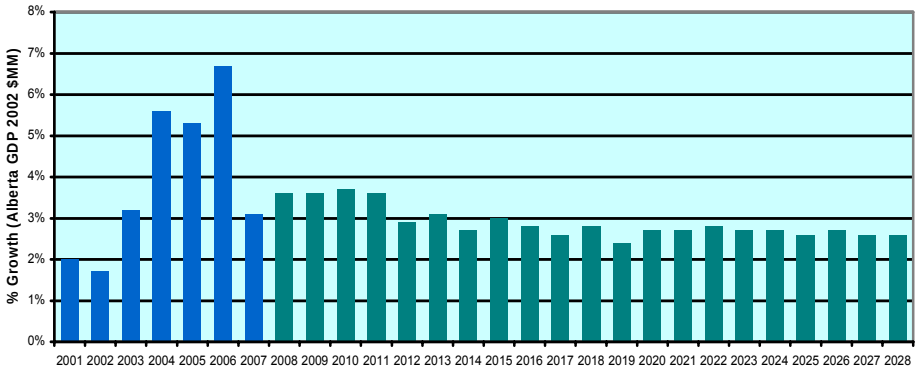
The key factor driving the Alberta economy continues to be investment in the development of oilsands, which is largely driven by oil demand and oil prices on the world market. This investment – direct, indirect and tertiary – creates jobs that ensure a continuation of large annual increases in retail sales. Economic growth in Alberta will be somewhat tempered by an increasing cost of living and under-developed infrastructure which has caused a slow-down of net migration and immigration.

2.1 Alberta's GDP Growth

GDP is a function of consumer spending, private and public investment, exports and imports. In Alberta, these fundamental economic characteristics continue to be strong:

- **Consumer Spending:** From 2004 to 2007, retail sales grew over 10 per cent per year. The forecasted growth for 2008 is 7.5 per cent, but more recent figures in October 2008 indicate retail sales growth will drop to approximately 4.1 per cent.
- **Investment:** Capital investment in 2006 was $75 billion. This grew by five per cent to $80 billion in 2007. Recent indicators suggest capital investment will reach $83 billion in 2008. Between 2006 and 2011, over $50 billion is expected to be invested in the oilsands. At $23,230 in 2007, Alberta had the highest investment per capita in Canada. Also in 2007, the Alberta Government announced a three year, $18.2 billion infrastructure development program.
- **Exports and Imports:** Net exports continue to increase, with natural gas and crude oil production leading the way, followed by industrial goods and agricultural products.

Figure 2.1-1: Changes in GDP



Source: Conference Board of Canada

As shown in Figure 2.1-1, Change in Alberta's GDP, the real economic growth (per cent change in real GDP) in 2007 was 3.1 per cent

Alberta's GDP is influenced by:

- energy prices
- immense non-conventional oil reserves (oilsands)
- declining natural gas production
- fluctuating productivity as the aging workforce is revitalized with migration, and immigration as the province continues to attract businesses and job seekers

The overarching strength of the Alberta economy does not preclude the existence of economic difficulties in some sectors. In 2007, the most noticeable of these was the chemical sector. In 2008, the indicators suggest that the forestry sector will be adversely affected by the virtual disappearance of the United States (U.S.) housing construction market. By the end of the first quarter, two mills had closed indefinitely. With respect to electricity demand, this represents a loss of approximately 15 MW. Reduced wood product sales, with the possibility of further mill closures, are expected to affect the industry for the next 12 to 24 months.

The electricity energy growth forecast is based in part on a GDP forecast, which has since been impacted by the following:

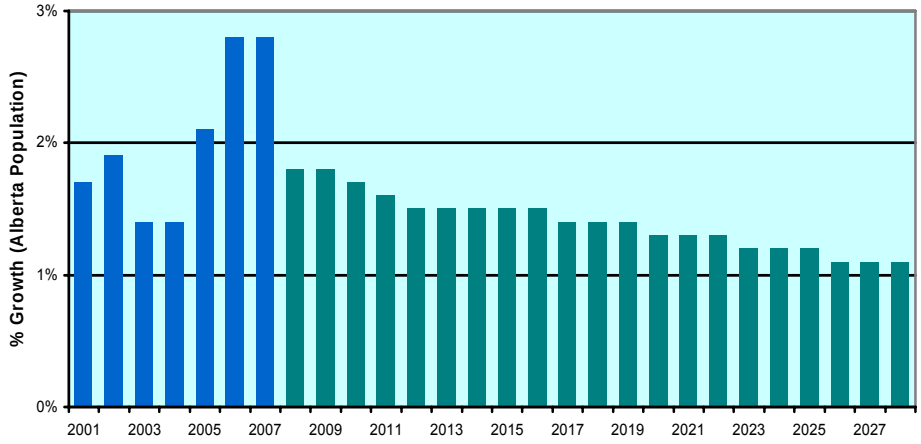
- labour shortages
- low natural gas prices
- volatile oil prices
- the strength of the Canadian dollar
- health of U.S. economy
- escalating construction and housing costs

In summary, in the short to medium term, the energy sector will continue to be Alberta's primary economic driver contributing to the continued growth in electricity consumption. This is based on energy prices, a very significant non-conventional oil supply and extraction technology improvements. Over the 20-year forecast horizon, Alberta's economy is expected to exhibit solid GDP growth, expanding at an average annual rate of three per cent.

2.2 Alberta's Population Growth

In 2007, Alberta's population grew by approximately 100,000 people (three per cent) to 3.47 million. As depicted in Figure 2.1-1, the forecast for population growth is expected to remain steady. This is largely due to the steady demand for skilled labour.

Figure 2.2-1: Population Growth in Alberta (per cent)



Source: Conference Board of Canada

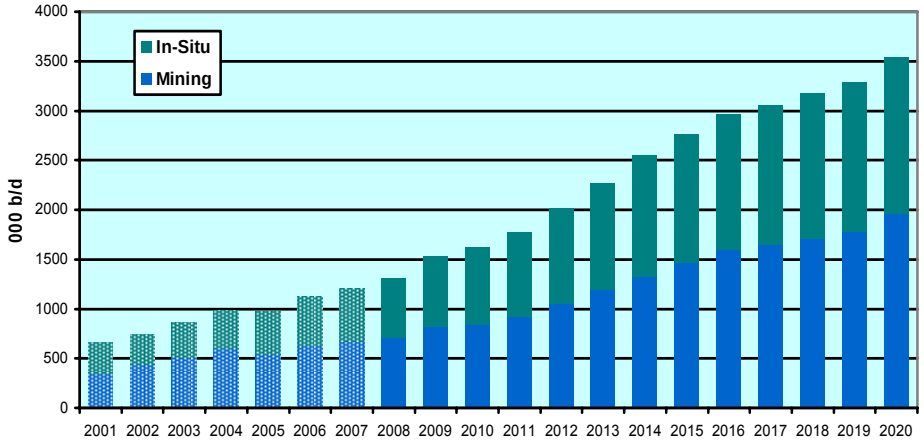
The prospect of employment will continue to attract workers from across Canada and around the world. Since 2004, the unemployment rate has steadily fallen from 4.6 per cent to 3.5 per cent.

2.3 Oilsands Production Growth

Due to the strong dependency of the Alberta economy on oilsands activity, the AESO has added a separate customer sector for the energy consumed by oilsands sites in the 2008 methodology. The oilsands sector is located in the Cold Lake, Athabasca/Lac La Biche and Fort McMurray transmission planning areas. The energy consumption to produce a barrel of synthetic crude oil from bitumen can be measured fairly easily and therefore, energy consumption by this sector can be forecasted with assumptions of kWh/barrel multiplied by an oilsands production forecast.

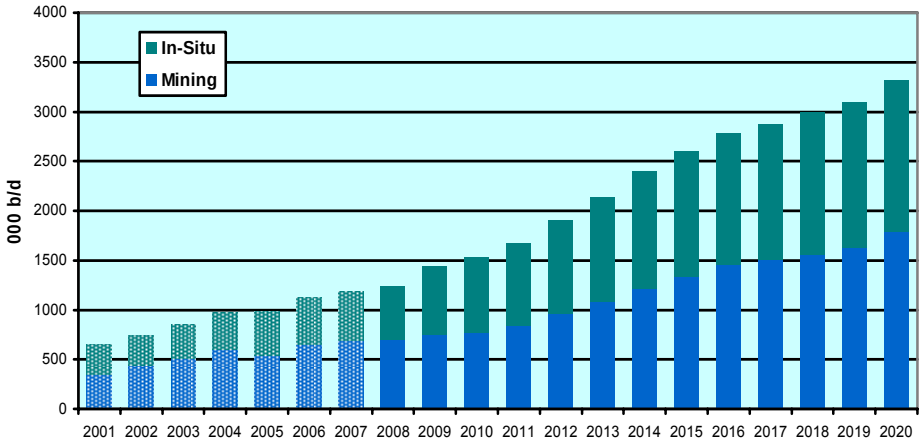
For the FC2008, the AESO used the Canadian Association of Petroleum Producers (CAPP) *Crude Oil Forecast, Markets & Pipeline Expansions – June 2008* production forecast of 'Oil Sands Mining' and 'In-Situ Moderate Growth' as a starting point. After evaluating past CAPP forecasts compared to actual production figures, the AESO added an adjustment factor to CAPP's 2008 forecast. The Mining production forecast was adjusted by minus nine per cent and In-Situ was adjusted by minus three per cent each from 2008 until 2020. Years 2021 through to 2028 were extrapolated using the CAPP's 2015-2020 growth rate (3.3 per cent). In the short-term this forecast will be impacted by project deferrals, but in the long-term it is still appropriate as an indicator of the future energy and demand outlook for Alberta.

Figure 2.3-1: Oilsands Production Forecast



Source: CAPP – Crude Oil Forecast, Market & Pipeline Expansions – June 2008 – Moderate Growth

Figure 2.3-2: AESO Adjusted Oilsands Production Forecast



Source: AESO adjusted CAPP

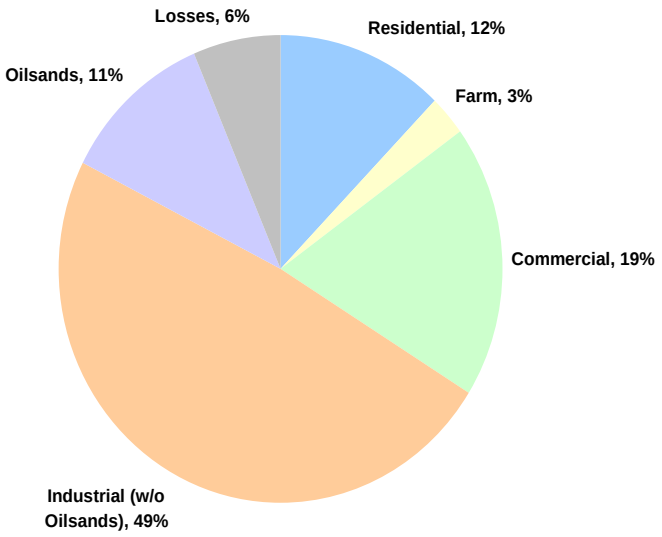
3.0 Methodology

The AESO uses a standard econometric approach to estimating future demand and electricity usage. This methodology provides a consistent approach to load forecasting through the use of a combination of fitted statistical models, historical data, third-party economic forecasts and customer-specific information.

The long-term load forecast is developed in five categories:

- Industrial without Oilsands
- Oilsands
- Commercial
- Residential
- Farm

Figure 3.0-1: Customer Sector as Percentage of Total Energy (2007)

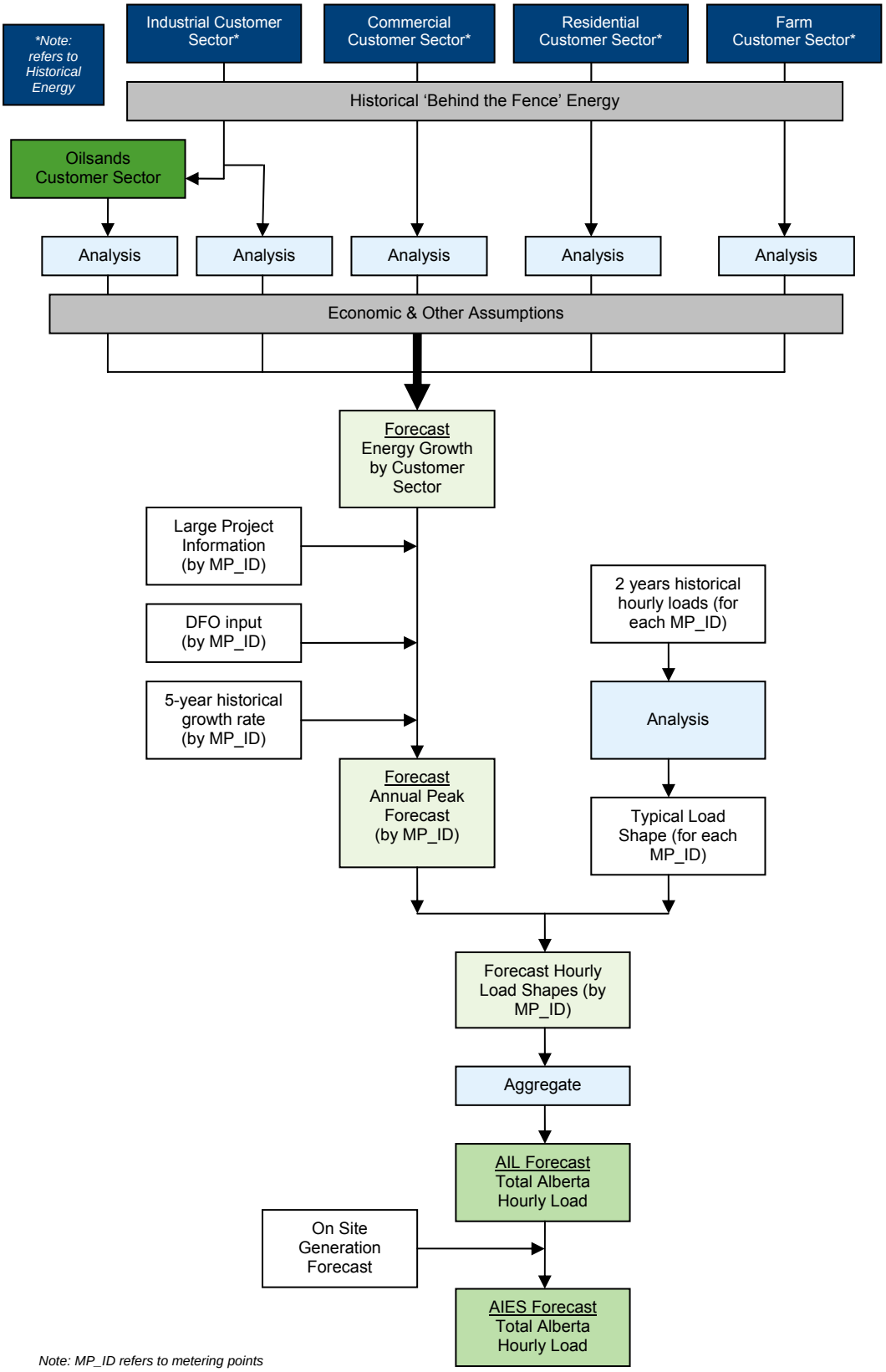


Source: AESO and ERCB

A high-level overview of the AESO's long-term load forecasting methodology is found in Figure 3.1-2 and the details for each sector are discussed in the following sections.

3.1 AESO Methodology Diagram

Figure 3.1-1: AESO Load Forecast Methodology Flow Diagram



Note: MP_ID refers to metering points

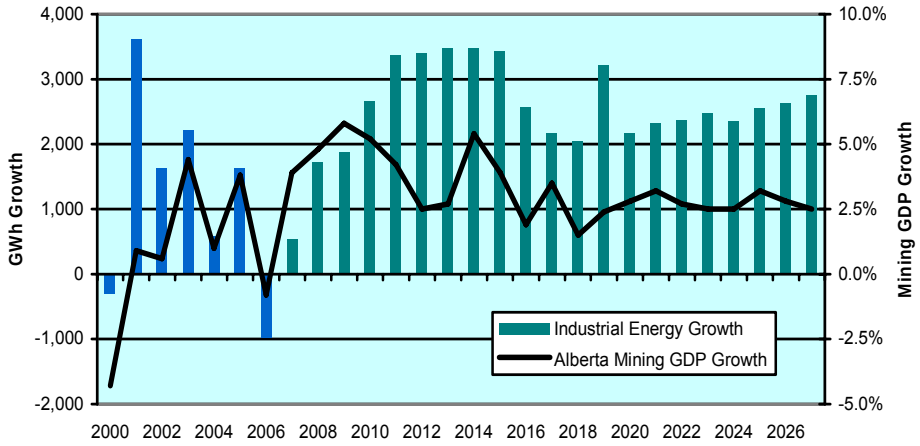
3.2 Industrial (without Oilsands) Customer Sector

The Industrial sector is the largest sector in terms of load and energy consumption, comprising roughly 49 per cent of total AIL energy use. The forecast for this sector is a function of real economic growth and historical usage.

The AESO's industrial energy forecast relies on the historical relationship between Alberta's economic growth and electricity energy growth. This relationship (Figure 3.2-1) is analyzed and along with a forecast of Alberta's future economic growth, is used to determine the future electricity energy growth.

In designing the economic models for the 2008-2028 forecast, the AESO looked at various economic indicators that should be used to best predict the future demand of this sector. In the AESO's studies, the best fit was found between Alberta mining GDP and this sector. The Alberta Mining category used by Statistics Canada measures the value of output of all industries engaged in extracting naturally occurring minerals. The term *mining* is used in the broad sense to include quarrying, well operations, milling and other preparation customarily done at site. This includes oil and gas exploration and development. With the dependency of Alberta's economy on the energy sector, it is intuitive that the Industrial sector is highly dependent on the health of energy exploration and development.

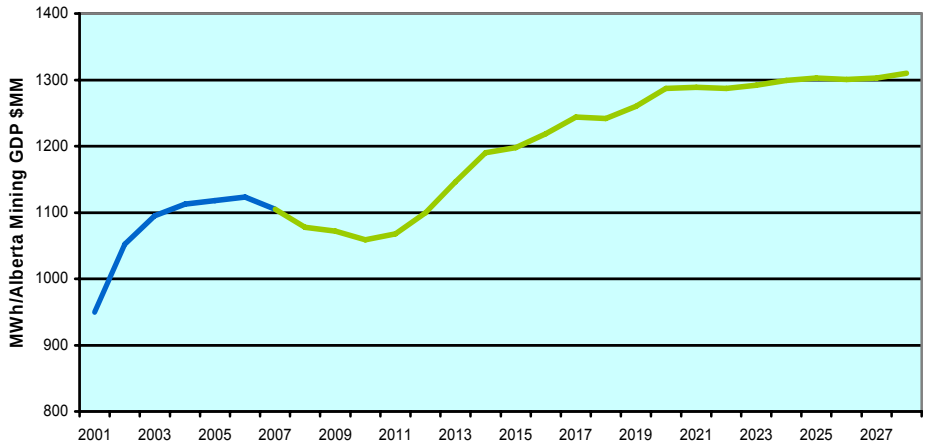
Figure 3.2-1: Industrial (without Oilsands) Energy Growth & Alberta Mining GDP Growth



Source: AESO, ERCB and Statistics Canada

Regression analysis is used to determine the relationship of Alberta Mining GDP to Industrial without oilsands energy. The relationship between megawatt hours (MWh) and real GDP growth ($ million) is plotted in Figure 3.2-2.

Figure 3.2-2: Industrial (without Oilsands) Energy Intensity



Source: AESO, ERCB and Statistics Canada

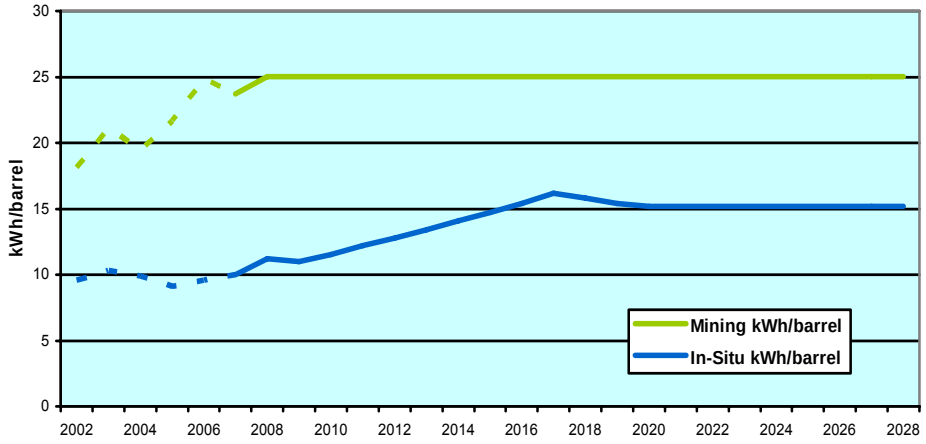
3.3 Oilsands Customer Sector

The Oilsands sector is comprised of sites using mining and In-Situ extraction techniques to remove bitumen from the ground. These sites make up approximately 11 per cent of total AIL consumption and do not include product upgrading. Each of these technologies use vastly different amounts of electricity to extract bitumen. Due to this factor, the AESO used an industry forecast of oilsands that includes a break-out of these two technologies. No other large scale extraction technologies are being utilized and therefore have not been examined.

Since 2002, the average kWh/barrel required for In-Situ production has been 9.8 kWh. With the possibility of higher electric intensity processes being considered by some sites, such as gasifying upgrading by-products, the AESO included an increasing mix of higher intensity sites. The AESO's forecast includes an increasing electric intensity by the In-Situ operators to 15.2 kWh/barrel by 2020.

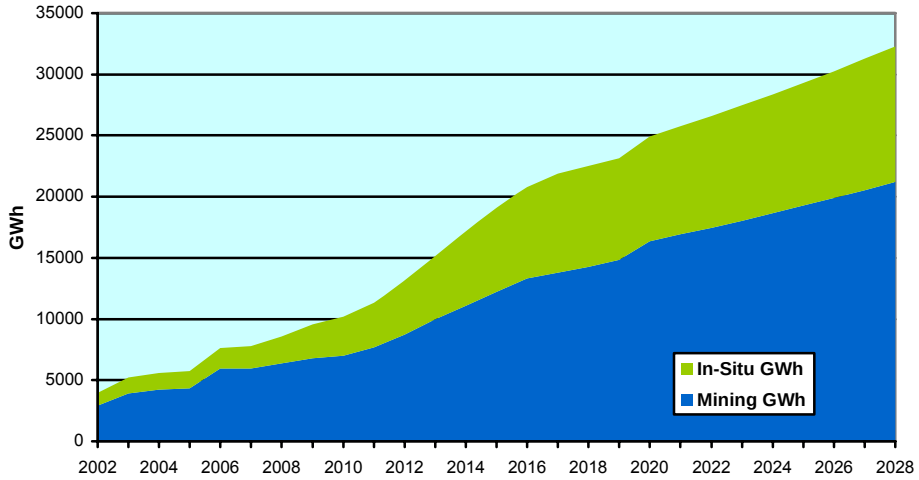
The kWh/barrel for mining operations has steadily increased since 2002 from 18.1 kWh to 24.8 kWh in 2006, dropping slightly in 2007 to 23.7 kWh. The AESO used a value of 25.2 kWh in the FC2008 to estimate for the electric intensity by mining operators for the period 2008 to 2028.

Figure 3.3-1: Oilsands Energy Intensity



Source: AESO, ERCB and Statistics Canada

Figure 3.3-2: Oilsands Energy



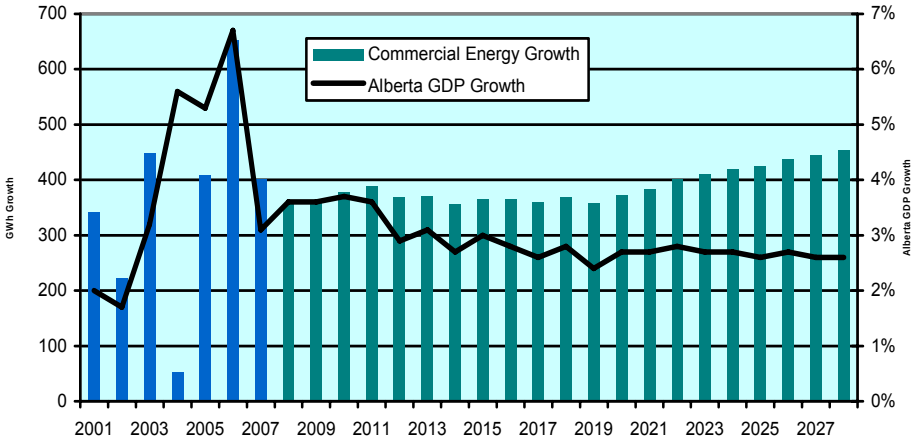
Source: AESO

3.4 Commercial Customer Sector

The Commercial sector is the second largest sector in terms of energy consumption, accounting for roughly 19 per cent of total AIL energy use. The forecast for this sector is a function of real economic growth and historical usage.

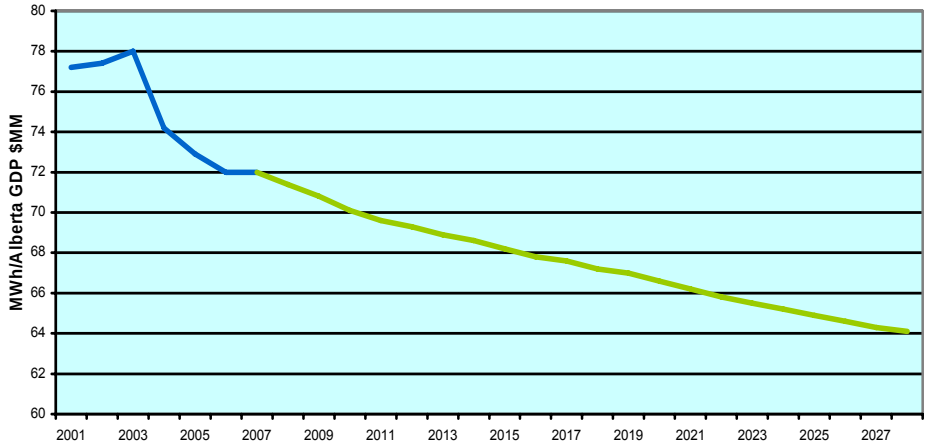
The AESO's commercial energy forecast relies on the historical relationship between Alberta's economic growth and electricity energy growth. This relationship (Figure 3.4-1) is analyzed and along with a forecast of Alberta's future economic growth, is used to determine the future electricity energy growth.

Figure 3.4-1: Commercial Energy Growth and Alberta GDP Growth



Source: AESO, ERCB and Statistics Canada

Figure 3.4-2: Commercial Energy Intensity



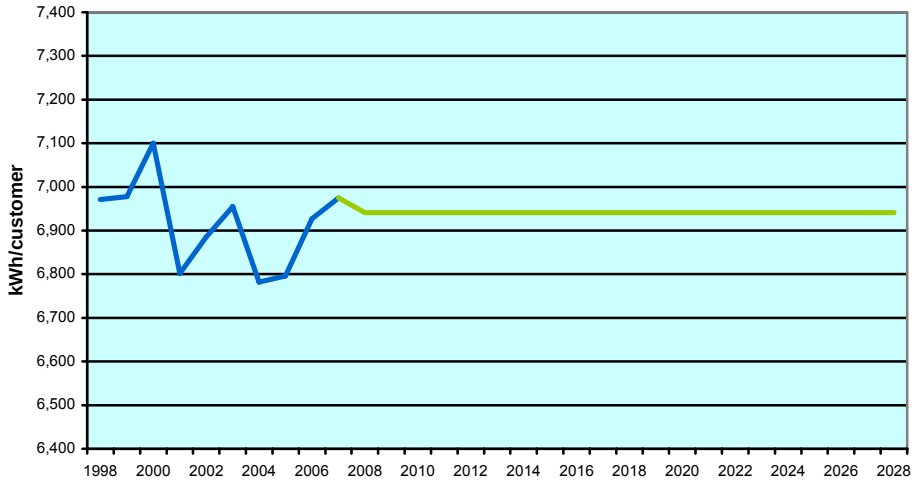
Source: AESO, ERCB and Statistics Canada

3.5 Residential Customer Sector

Future energy requirements for the Residential sector are calculated by multiplying the forecast number of customers in the province by the historical 10-year average use by customers (approximately 6,941kWh per customer). The Residential sector is roughly 12 per cent of total AIL consumption.

In general, residential electricity consumption (kWh per customer) has seen little change over the past decade (Figure 3.5-1).

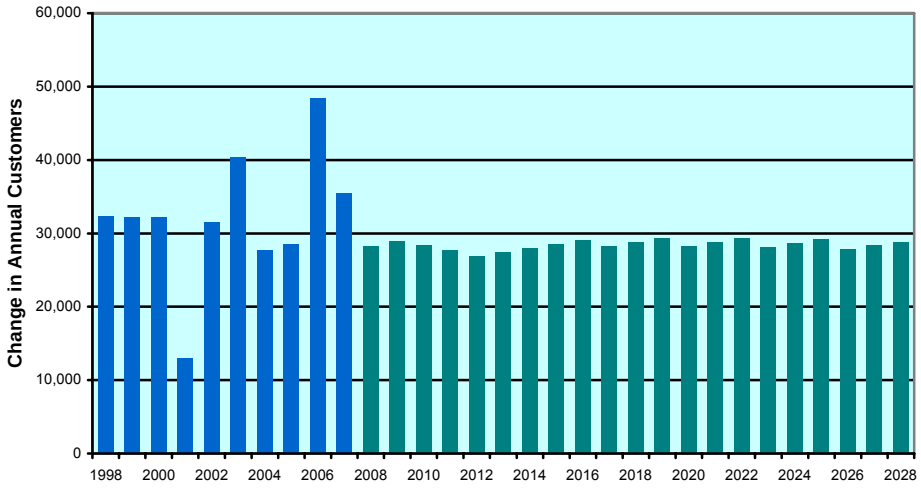
Figure 3.5-1: Average Residential Use



Source: AESO and ERCB

The AESO's residential customer forecast (Figure 3.5-2) is driven by the Conference Board of Canada's population forecast.

Figure 3.5-2: Annual Change in the Number of Residential Customers

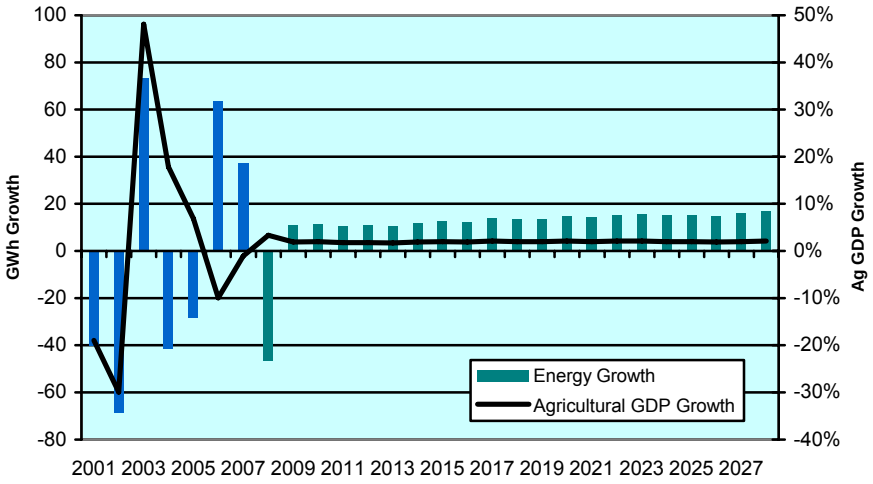


Source: AESO and ERCB

3.6 Farm Customer Sector

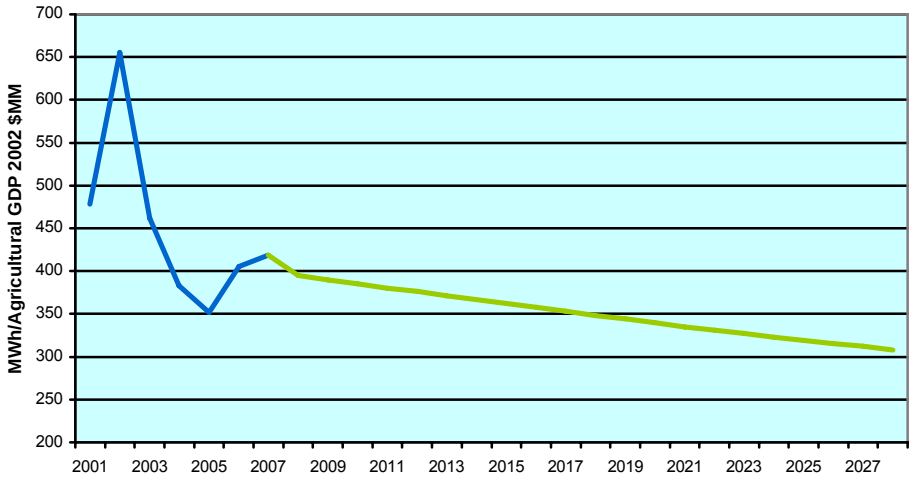
The Farm sector is the smallest of all the sectors to be analyzed by the AESO and is roughly three per cent of total AIL energy consumption. The relationship between energy and the Agriculture portion of the Alberta GDP is studied through the use of regression analysis to predict the farm energy component. This relationship is found in Figure 3.6-1.

Figure 3.6-1: Farm Energy Growth and Agricultural GDP Growth



Source: AESO, ERCB and Statistics Canada

Figure 3.6-2: Farm Energy Intensity



Source: AESO, ERCB and Statistics Canada

Since 1992, electricity usage as a function of Agricultural GDP has been declining. The notable exception was in 2002. At that time, Agricultural GDP dropped sharply due to export restrictions and soft commodity prices. This resulted in a large increase in the relationship with energy since the amount of electricity consumed on farms did not change significantly.

In 2006, Agricultural GDP grew sharply by almost 16 per cent. For the period from 2008 to 2028, the average increase is expected to be two per cent.

4.0 Forecast Results

This section provides detailed forecast results for the period from 2008 to 2028 for the Alberta Internal Load (AIL) and Alberta Interconnected Electric System (AIES).

4.1 Provincial Results – AIL Forecast

AIL is the sum of all electricity sales (residential, commercial, industrial and farm), losses (both transmission and distribution) and behind-the-fence load (BTF). BTF is any industrial load that is characterized by being served in whole, or in part, by on-site generation.

Tables 4.1-1 through 4.1-3 compare the growth in AIL demand and energy from the FC2008 with last year's forecast, the FC2007. In the last five years, AIL demand has grown by 2.5 per cent per year and AIL energy has grown by 3.2 per cent per year. For the next five years, average annual demand is forecasted to grow by 4.2 per cent and energy is expected to grow by 4.5 per cent. FC2008 shows an annual average growth rate of 3.4 per cent for AIL load and a growth rate for energy of 3.5 per cent for the period 2008 to 2028.

Table 4.1-1: Alberta Internal Load (AIL) Winter Peak Demand

	FC2007 (MW)	FC2008 (MW)	FC2008 growth	Forecasts Diff (MW)
2000/01	–	7,785*	–	–
2001/02	–	7,934	1.9%	–
2002/03	–	8,570	8.0%	–
2003/04	–	8,967	4.6%	–
2004/05	–	9,236	7.8%	–
2005/06	–	9,580	6.8%	–
2006/07	–	9,661	0.8%	–
2007/08	10,028	9,710	0.5%	-318
2008/09	10,467	9,833	1.3%	-633
2009/10	10,793	10,202	3.7%	-591
2010/11	11,212	10,650	4.4%	-561
2011/12	11,662	11,217	5.3%	-445
2012/13	12,062	11,737	4.6%	-325
2013/14	12,519	12,357	5.3%	-162
2014/15	12,929	12,897	4.4%	-33
2015/16	13,312	13,401	3.9%	+89
2016/17	13,711	13,899	3.7%	+187
2017/18	14,155	14,290	2.8%	+135
2018/19	14,566	14,659	2.6%	+92
2019/20	14,971	15,117	3.1%	+146
2020/21	15,355	15,573	3.0%	+218
2021/22	15,852	15,987	2.7%	+135
2022/23	16,323	16,431	2.8%	+107
2023/24	16,808	16,860	2.6%	+52
2024/25	17,241	17,312	2.7%	+72
2025/26	17,796	17,798	2.8%	+3
2026/27	18,304	18,298	2.8%	-7
2027/28	18,824	18,781	2.6%	-43
2028/29	19,303	19,271	2.6%	-32

Table 4.1-2: Alberta Internal Load (AIL) Summer Peak Demand

	FC2007 (MW)	FC2008 (MW)	FC2008 growth	Forecasts Diff (MW)
2000	–	7,150*	–	–
2001	–	7,266	1.6%	–
2002	–	8,217	13.1%	–
2003	–	8.295	0.9%	–
2004	–	8,578	4.4%	–
2005	–	8,766	5.7%	–
2006	–	9,050	3.2%	–
2007	9,225	9,321	3.0%	+96
2008	9,515	9,541	2.4%	+26
2009	9,996	9,685	1.5%	-311
2010	10,314	10,037	3.6%	-277
2011	10,820	10,487	4.5%	-333
2012	11,204	10,976	4.7%	-228
2013	11,618	11,559	5.3%	-59
2014	11,899	12,112	4.8%	+213
2015	12,358	12,651	4.4%	+293
2016	12,823	13,111	3.6%	+288
2017	13,260	13,554	3.4%	+293
2018	13,655	13,927	2.8%	+272
2019	13,983	14,293	2.6%	+311
2020	14,230	14,785	3.4%	+555
2021	14,662	15,197	2.8%	+535
2022	15,295	15,625	2.8%	+330
2023	15,740	16,039	2.6%	+299
2024	16,102	16,448	2.6%	+347
2025	16,326	16,905	2.8%	+579
2026	16,762	17,366	2.7%	+604
2027	17,207	17,812	2.6%	+605
2028	18,059	18,262	2.5%	+203

**** denotes actuals***

Note : 2002 includes a redefinition of BTF load, approximately 400MW

Table 4.1-3: Alberta Internal Load (AIL) - Annual Energy

	FC2007 (GWh)	FC2008 (GWh)	FC2008 growth	Forecasts Diff (GWh)	Load Factor
2000	–	54,054*	–	–	79.0%
2001	–	54,467	0.8%	–	78.4%
2002	–	59,437	9.1%	–	79.2%
2003	–	62,716	5.5%	–	79.8%
2004	–	65,259	9.8%	–	82.9%
2005	–	66,268	5.7%	–	81.9%
2006	–	69,371	4.7%	–	82.7%
2007	70,481	69,660	0.4%	-821	82.3%
2008	73,696	70,511	1.2%	-3,185	81.6%
2009	76,792	73,062	3.6%	-3,730	81.8%
2010	79,478	75,727	3.6%	-3,751	81.2%
2011	82,710	79,146	4.5%	-3,564	80.5%
2012	85,978	83,485	5.5%	-2,493	81.0%
2013	89,205	87,678	5.0%	-1,527	81.0%
2014	92,312	92,106	5.0%	-206	81.5%
2015	95,420	96,448	4.7%	+1,028	82.2%
2016	98,629	100,487	4.2%	+1,857	82.3%
2017	101,715	103,841	3.3%	+2,126	83.0%
2018	104,706	106,775	2.8%	+2,069	83.2%
2019	107,645	109,562	2.6%	+1,917	82.7%
2020	110,692	113,652	3.7%	+2,961	83.1%
2021	113,744	116,626	2.6%	+2,882	83.3%
2022	116,836	119,804	2.7%	+2,968	83.2%
2023	119,980	123,028	2.7%	+3,048	83.3%
2024	123,176	126,376	2.7%	+3,200	83.1%
2025	126,436	129,601	2.6%	+3,165	83.1%
2026	129,759	133,049	2.7%	+3,290	83.0%
2027	133,158	136,584	2.7%	+3,426	83.0%
2028	136,616	140,265	2.7%	+3,649	82.9%

**** denotes actuals***
Note : 2002 includes a redefinition of BTF load, approximately 400MW

4.2 Provincial Results - AIES Forecast with Behind-the-Fence (BTF) Load Estimation

The AESO forecasts these changes in the amount of on-site generation. In order to calculate the AIES demand and energy, the AESO forecasts the amount of AIL served based on historical on-site generation or any subsequent changes. The results from this work are presented in the following three tables.

Table 4.2-1: Alberta Interconnected Electric System (AIES) - Winter Peak Demand

	FC2007 (MW)	FC2008 (MW)	FC2008 growth	Forecasts Diff (MW)
2000/01	–	7,666*	–	–
2001/02	–	7,527	-1.8%	–
2002/03	–	7,552	0.3%	–
2003/04	–	7,650	1.3%	–
2004/05	–	7,910	4.7%	–
2005/06	–	8,066	5.4%	–
2006/07	–	8,177	1.4%	–
2007/08	8,625	8,228	0.6%	-398
2008/09	8,983	8,358	1.6%	-625
2009/10	9,148	8,650	3.5%	-498
2010/11	9,456	8,994	4.0%	-462
2011/12	9,750	9,498	5.6%	-251
2012/13	10,064	9,943	4.7%	-121
2013/14	10,425	10,436	5.0%	+12
2014/15	10,719	10,866	4.1%	+148
2015/16	11,005	11,329	4..3%	+324
2016/17	11,328	11,780	4.0%	+451
2017/18	11,647	12,140	3.1%	+493
2018/19	11,909	12,493	2.9%	+584
2019/20	12,188	12,828	2.7%	+639
2020/21	12,560	13,213	3.0%	+654
2021/22	13,000	13,640	3.2%	+639
2022/23	13,422	14,095	3.3%	+673
2023/24	13,856	14,540	3.2%	+683
2024/25	14,250	14,981	3.0%	+731
2025/26	14,758	15,478	3.3%	+719
2026/27	15,223	15,977	3.2%	+754
2027/28	15,703	16,461	3.0%	+758
2028/29	16,148	16,951	3.0%	+803

Table 4.2-2: Alberta Interconnected Electric System (AIES) - Summer Peak Demand

	FC2007 (MW)	FC2008 (MW)	FC2008 growth	Forecasts Diff (MW)
2000	–	6,998*	–	–
2001	–	7,026	0.4%	–
2002	–	7,312	4.1%	–
2003	–	7,012	-4.1%	–
2004	–	7,184	-1.7%	–
2005	–	7,268	3.7%	–
2006	–	7,573	4.2%	–
2007	7,728	7,900	4.3%	+172
2008	8,045	8,050	1.9%	+5
2009	8,344	8,107	0.8%	-238
2010	8,546	8,437	4.1%	-109
2011	8,805	8,831	4.7%	+26
2012	9,102	9,241	4.6%	+138
2013	9,452	9,687	4.8%	+235
2014	9,693	10,113	4.4%	+421
2015	10,057	10,622	5.0%	+565
2016	10,349	11,048	4.0%	+699
2017	10,657	11,375	3.0%	+718
2018	10,888	11,699	2.8%	+811
2019	11,144	12,004	2.6%	+860
2020	11,464	12,396	3.3%	+931
2021	11,842	12,808	3.3%	+966
2022	12,253	13,235	3.3%	+982
2023	12,684	13,653	3.2%	+968
2024	13,051	14,057	3.0%	+1,006
2025	13,330	14,506	3.2%	+1,176
2026	13,724	14,969	3.2%	+1,246
2027	14,130	15,415	3.0%	+1,285
2028	14,827	15,866	2.9%	+1,039

**** denotes actuals***

Table 4.2-3: Alberta Interconnected Electric System (AIES) - Annual Energy

	FC2007 (GWh)	FC2008 (GWh)	FC2008 growth	Forecasts Diff (GWh)	Load Factor
2000	–	52,914*	–	–	78.6%
2001	–	52,480	-0.8%	–	79.6%
2002	–	53,673	2.3%	–	81.1%
2003	–	53,169	-0.9%	–	79.3%
2004	–	54,669	1.9%	–	78.7%
2005	–	55,697	4.8%	–	78.8%
2006	–	57,433	3.1%	–	80.2%
2007	58,615	57,701	0.5%	-914	80.1%
2008	61,461	58,327	1.1%	-3,133	79.4%
2009	63,054	60,105	3.0%	-2,949	79.3%
2010	64,766	62,364	3.8%	-2,403	79.2%
2011	66,737	65,368	4.8%	-1,369	78.6%
2012	69,271	69,139	5.8%	-133	79.2%
2013	71,787	72,648	5.1%	+861	79.5%
2014	73,940	76,020	4.6%	+2,079	79.9%
2015	76,278	79,833	5.0%	+3,556	80.4%
2016	78,841	83,521	4.6%	+4,680	80.7%
2017	80,962	86,293	3.3%	+5,331	81.1%
2018	82,784	88,531	2.6%	+5,747	80.9%
2019	84,737	90,809	2.6%	+6,072	80.8%
2020	87,614	93,794	3.3%	+6,181	80.8%
2021	90,264	96,722	3.1%	+6,458	81.0%
2022	92,948	99,830	3.2%	+6,882	80.9%
2023	95,695	103,009	3.2%	+7,315	80.9%
2024	98,517	106,226	3.1%	+7,709	80.7%
2025	101,461	109,462	3.0%	+8,001	80.7%
2026	104,424	112,916	3.2%	+8,492	80.7%
2027	107,501	116,447	3.1%	+8,945	80.8%
2028	110,624	120,051	3.1%	+9,427	80.6%

**** denotes actuals***

4.3 Forecast Results for Bulk Planning Purposes

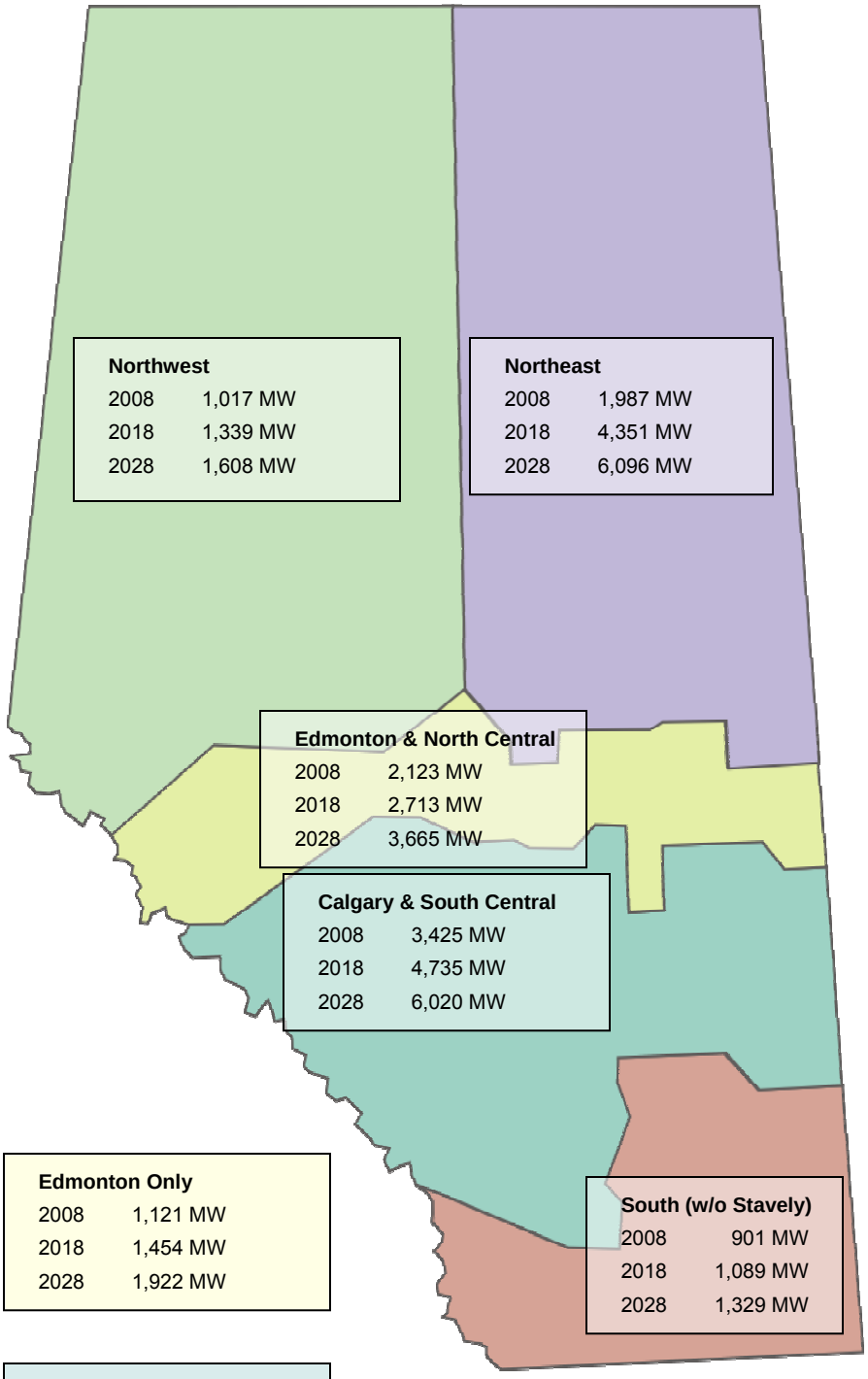
Together with the AESO'S generation scenarios, the long-term load forecast serves as a tool to aid in transmission planning. Bulk transmission planners (i.e. the planning on the 240 kV and 500 kV system) use the forecast to determine where future load growth and demand is expected. They can also use the forecast to study the flow of electric power for up to 20 years in the future from region to region. It is for this purpose that the provincial forecast, including demand peaks, is produced. The 20-year forecast also provides a transparent input to the AESO's plans for the industry.

In order to study the bulk electric flows, bulk transmission system planners examine the region peaks at the time when the provincial peak is occurring (i.e. a province-wide coincident peak). FC2008 results are presented in a format that is applicable for bulk planning purposes. It should be noted that the bulk regional peak numbers will differ from the peak numbers studied by the regional transmission planners (i.e. planning performed within specific regions), as the regional planners are interested in demand at the time of region peak (a coincident peak among all the areas that fall under the region they are studying). The regional coincident peak forecasts are examined further in Section 4.4.

From a bulk transmission planning perspective, the AESO has defined five primary regions in Alberta. There are also two large urban centers: Calgary and Edmonton.

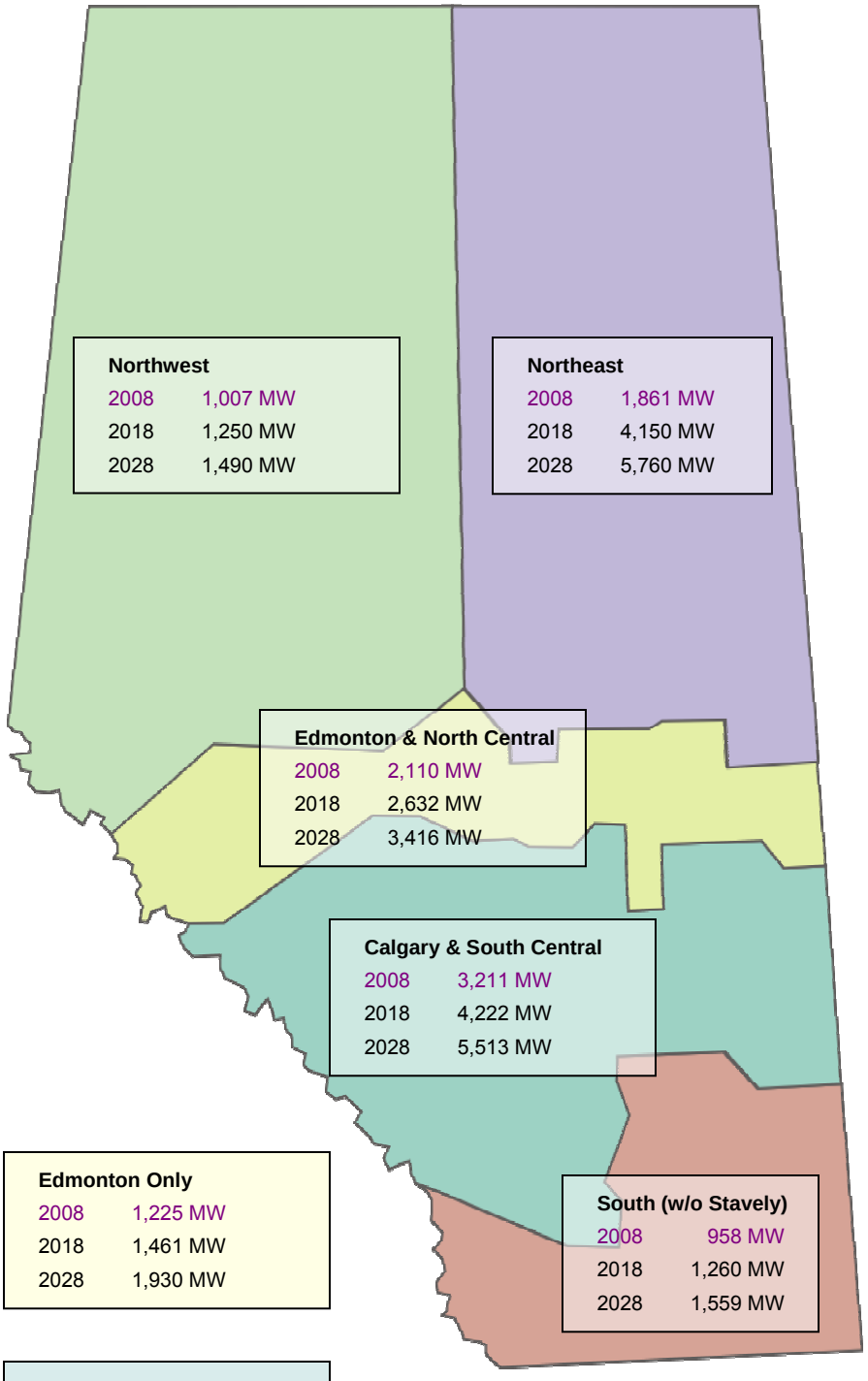
Figure 4.3-1 shows the forecasted regional winter peaks for 2008, 2018 and 2028. Figure 4.3-2 shows the regional summer peaks for the same periods. In this case, the winter season is the period from November 1st to April 30th and the summer season is from May 1st to October 31st.

Figure 4.3-1: Region Demand at Time of Winter AIL Peak



2008 winter peak is not final at date of publication, therefore forecast winter demands are shown in this figure.

Figure 4.3-2: Region Demand at Time of Summer AIL Peak



** denotes actuals*

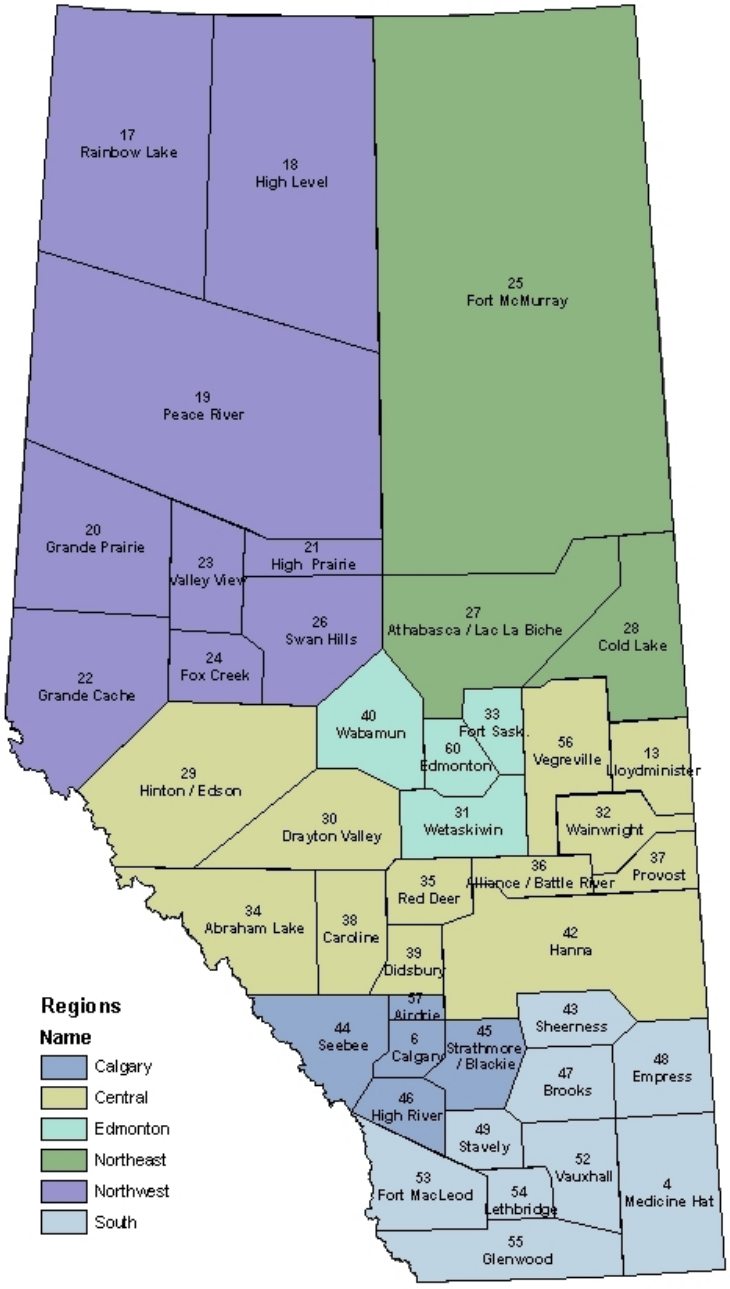
4.4 Forecast Results for Regional Planning Purposes

The province of Alberta covers over 661,100 square kilometres (km^2). This represents approximately seven per cent of Canada's total land mass. Given the considerable size of the province, it is reasonable to expect that the geography, economics and climate will vary from one region to another. This geographical diversity is apparent in the AESO's load forecast as seen in the tables below. Figure 4.4-1 shows the province of Alberta divided into areas. These areas can be added together to explore the electric power needs unique to that particular region.

For Regional planning purposes, the areas have been grouped together to represent six regions: South, Calgary, Central, Edmonton, Northeast and Northwest regions.

The following tables show regional peak coincident for both the summer and winter seasons. FC2008 results are compared to the forecast numbers for 2013, 2018 and 2028.

Figure 4.4-1: Grouping of Areas for Regional Planning Purposes



South Region

The South Region includes the Medicine Hat, Sheerness, Brooks, Empress, Stavely, Vauxhall, Fort MacLeod, Lethbridge and Glenwood planning areas.

Table 4.4-1: Coincident Peak (MW) for South Region

South	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter	954	1,039	1.7%	1,136	1.8%	1,399	1.9%
Summer	1,084	1174	1.6%	1,292	1.8%	1,601	2.7%

Calgary Region

Included in this region are the Calgary, Strathmore/Blackie, Seebe, High River and Airdrie planning areas. A look at all the ENMAX metering points – as supplied by ENMAX – also provides a forecast for the City of Calgary.

Table 4.4-2: Coincident Peak (MW) for Calgary Region

Calgary	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter							
Calgary Area	2,034	2,480	4.0%	2,818	3.3%	3,653	3.0%
City of Calgary (ENMAX)	1,527	1,881	4.3%	2,149	3.5%	2,783	3.0%
Summer							
Calgary Area	1,900	2,334	4.2%	2,663	3.4%	3,405	3.0%
City of Calgary (ENMAX)	1,472	1,844	4.6%	2,116	3.7%	2,696	2.7%

Central Region

The Central Region is considered to be between Edmonton and Calgary. Included are the Lloydminster, Hinton/Edson, Drayton Valley, Wainwright, Abraham Lake, Red Deer, Alliance/Battle River, Provost, Caroline, Didsbury, Hanna and Vegreville planning areas.

Table 4.4-3: Coincident Peak (MW) for Central Region

Central	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter	1,561	1.742	2.2%	1.975	2.4%	2,604	2.6%
Summer	1,387	1,570	2.5%	1,810	2.7%	2,356	2.7%

Edmonton Region

Acting as a transmission "hub", the Edmonton Region includes the Wetaskiwin, Fort Saskatchewan, Wabamun and Edmonton planning areas.

A look at all the EPCOR metering points – as supplied by EPCOR – also provides a forecast for the City of Edmonton.

Table 4.4-4: Coincident Peak (MW) for Edmonton Region

Edmonton	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter							
Edmonton Area	2,517	3,027	3.8%	3,654	3.8%	4,792	3.3%
City of Edmonton (EPCOR)	1,127	1,305	3.0%	1,461	2.6%	1,929	2.7%
Summer							
Edmonton Area	2,450	2,938	3.7%	3,553	3.8%	4,647	3.3%
City of Edmonton (EPCOR)	1,139	1,320	3.0%	1,481	2.7%	1,955	2.7%

Northeast Region

The Northeast Region is forecasted to experience the greatest load growth over the next 10 years. This is due in large part to the oilsands, forestry industries and related secondary service industries in the municipalities. The Northeast Region includes the Fort McMurray, Athabasca/Lac La Biche and Cold Lake planning areas.

Table 4.4-5: Coincident Peak (MW) for Northeast Region

Northeast	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter	1,567	2,666	11.2%	3,550	8.5%	5,052	6.0%
Summer	1,468	2,351	9.9%	3,338	8.6%	4,712	6.0%

Northwest Region

The Northwest Region includes the Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grand Cache, Valleyview, Fox Creek and Swan Hills planning areas.

Table 4.4-6: Coincident Peak (MW) for Northwest Region

Northwest	FC2008 2008	FC2008 2013	Average annual growth	FC2008 2018	Average annual growth	FC2008 2028	Average annual growth
Winter	1,109	1,258	2.6%	1,391	2.3%	1,687	2.1%
Summer	1,078	1,220	2.5%	1,341	2.2%	1,594	2.0%

5.0 Other Load Forecasting Considerations

In addition to the uncertainty associated with the economic and demographic variables, there are other significant challenges in developing a long-term load forecast for Alberta. Many of these are addressed implicitly by the AESO's load forecasting models. Although the factors discussed below are not explicitly included in the load forecasting models, they are examined by the AESO on a regular basis, so as to inform the load forecasting process.

5.1 Demand Responsive Load and Conservation

The potential impact of conservation and efficiency (which will drive the advancement of new technologies), and demand responsive load programs represents an additional source of uncertainty and challenge for the AESO's load forecast. In general, these can be programs that encourage conservation and efficiency, or programs that allow consumers to respond to market signals and voluntarily reduce consumption based on market prices. Another change affecting the forecast relates to the system controller and the direction to facility owners during supply shortfall in the form of Operational Policy and Procedures. Therefore, with such programs there is the potential to reduce or shift the timing of Alberta system peaks and energy requirements.

The current Alberta market design relies primarily on price signals to provide consumer incentives for economically efficient energy consumption and production decisions. Price responsive load has been seen primarily from industrial customers that have flexible production such that they can "turn down" operations and respond to high market prices. Depending on the market price, the amount of price responsive load has ranged from 175 MW to 300 MW.

The AESO has implemented a combination of demand response programs to assist in managing or preventing emergency system operating conditions. These include:

- Voluntary load curtailment protocol (VLCP) – a demand response program based on a pre-arranged contract.
- Demand opportunity service (DOS) – an opportunity transmission service with regulated rates for each level of interruption (seven minute and one hour).
- Frequency Load Shed Service (FLSS) – load shed instantaneously during system events.
- Supplemental Operating Reserves (SUP) – Ancillary service available to arrest frequency decline but not required to respond directly to frequency deviations. This can be a load or generator service.

The net impact of these programs is captured in the AESO's long-term load forecast modeling processes.

There is a major emphasis on energy efficiency and conservation programs in various North American jurisdictions, which are encompassed by the term demand side management (DSM). DSM generally refers to activities that occur on the demand side of the meter, and are implemented by the customer directly or by load serving entities. DSM initiatives are aimed at achieving energy savings as a result of conservation, energy efficiency and load displacement programs. A substantial portion of these energy savings have resulted from appliance and building standards. Another major portion of savings have been the utility programs mandated by governments and regulators, including efficiency services in the form of energy audits, financial incentive, load-shifting activities and rate design.

Several jurisdictions including California, the U.S. Pacific Northwest and B.C. are implementing very aggressive DSM programs. For example, BC Hydro is required to acquire 50 per cent of its incremental resource needs through conservation (DSM) by 2020. The approach adopted to load forecasting in these jurisdictions typically involves a detailed assessment of the impact of DSM programs and price effects on electricity demand. These analytical requirements characteristically necessitate an extremely detailed end-use approach to demand forecasting. To date, load-serving entities or retailers in Alberta have not developed price responsive, efficiency or conservation programs in the same way as other jurisdictions, especially those that rely on the traditional integrated utility model. Consequently, opportunities from this sector to date have been negligible. The potential impacts of demand response and DSM type programs are not explicitly included in the AESO's load-forecasting models, given that such programs are not widespread and that any future programs are unknown at this time. The AESO will continue to work collaboratively with stakeholders to evaluate appropriate programs related to DSM.

5.2 Alberta Market Structure

The unique structure of the Alberta market contributes to the uncertainty associated with the load forecast. The competitive Alberta generation market and the power pool based pricing structure involve greater load forecast uncertainty than is associated with more traditional regulated markets. In part, this is because of the expectation of greater volatility in wholesale power prices in Alberta, which in turn can be expected to have an impact on the demand (i.e. cause a price response) for electricity, on a short-term and longer-term basis. Therefore, similar and related to the impact of DSM, the potential impact of the future level and volatility of prices is not specifically modeled, but it is captured in the long-term load forecast through the econometric modeling of electricity consumption by sector.

5.3 Composition of Load

Industrial load represents a very high percentage of the total load in Alberta and this can be expected to contribute to greater uncertainty in the load forecast.

Unlike the residential and commercial sectors, where the uses of electricity are relatively similar in different houses or buildings, the industrial uses of electricity are very diverse. It is difficult to generalize about the uses of electricity in a "typical" industrial plant. Electricity consumption is typically greater in this sector than other sectors. Alberta's industrial electricity consumption is tied closely to the level of economic activity and to world oil and gas market conditions. Beyond the general risk of higher or lower than expected economic growth materializing, a significant risk to the industrial load forecast pertains to discrete one time, unforeseen changes in load that are the result of corporate decisions that impact the opening, timing, restarting or closing of major facilities.

The oilsands industry in particular, which is driving the behind-the-fence (BTF) load in Alberta, is very dynamic. These projects have unique attributes in terms of the size, cost, location, labour, and electricity requirements. Since oilsands producers are expected to behave differently from the rest of the Industrial sector, they are a potential source of significant uncertainty in the long-term load forecast. This includes the development of specific major oilsands projects, which have announced onsite generation, and projects that are likely to do so. Given the many options available to developers, the volatility of oil prices, and the shortage of labour and material for constructing new projects, the load growth in the oilsands industry is not expected to occur in a smooth, easily foreseeable or predictable manner.

5.4 Distributed Generation

Distributed generation involves the installation of small-scale power sources (typically in the range of three kilowatts kW to 10 MW) at or near a customer's site, to provide an alternative to or an enhancement of the traditional electric power system.

For generation smaller than 150 kW, modeling and forecasting of this generation and the load that it offsets is not specifically tracked. The "smart grid" could facilitate specific tracking of micro and other generation. It is assumed that the impact of any potential drop in load caused by distributed generation will be captured through trends seen in the econometric modeling of energy consumption by sector. Major shifts can be addressed as they are identified.

5.5 Environmental Costs

The costs of meeting environmental requirements are expected to rise across North America, particularly for large greenhouse gas (GHG) emitters. While this may have an impact on the in-service dates for some oilsands and upgrader projects, at this time there is no basis for assuming that these costs will significantly slow expansion in Alberta's energy producing sectors. Because it is unlikely that reduction in GHG emissions will occur without cost, future climate control policy is a risk of uncertain magnitude and timing to the load forecast. Load forecasting models used in other jurisdictions generally tend to use a fuel carbon content tax as a proxy for the cost of mandated greenhouse gas (GHG) reductions, whatever the means of implementation.

It can be expected that any costs associated with meeting environmental requirements for electricity generation facilities in the future will ultimately be reflected in electricity prices. As previously discussed, the AESO's load-forecasting models do not explicitly include the influence of electricity prices on electricity demand. However, any changes in demand patterns are captured through the modeling process that accounts for historic trends that capture various econometric drivers.

5.6 Challenges on the Horizon

In the process of developing the load forecast each year, there are internal discussions about changes on the Alberta's horizon that may have a material impact on the future load and energy requirements.

This year a number of future challenges have been identified:

- New demand side management initiatives, including demand response programs
- New technology, with different electricity intensities
- New environmental regulations around greenhouse gases
- New vehicle technology, including plug-in electric cars
- Global economic turmoil

Each of these challenges will be explored in the coming year to determine their significance with respect to the fundamental relationships that form the basis of the AESO's *Future Demand and Energy Outlook (2008 – 2028)*.

6.0 Historical and Past Forecast Results

In the process of preparing the long-term load forecast, the AESO assesses past forecasts along with Alberta's actual demand and electricity usage, in order to verify the methodology and to identify variances that could impact the current forecast.

6.1 Past Forecast Variances

Table 6.1-1: Energy Forecast Variance History

Year	Actuals (GWh)	Year over Year Change	FC2005	FC2006	FC2007	FC2008
2006	69,370	–	-1.6%	+1.2%	–	–
2007	69,660	+290	-3.4%	-1.5%	-1.2%	–
2008	69,946	+286	-7.7%	-4.9%	-4.8%	-1.3%

Table 6.1-2 examines the variance between the actual peak load and the forecasted peak load. This table also highlights the convergence of summer and winter peaks since 2005. The winter peak in 2005/06 was higher than forecast, while the winter peak for both 2006/07 and 2007/08 were lower than forecast.

Table 6.1-2: Peak Forecast Variance History

Year/Season	Actuals (MW)	Year over Year Change	Season over Season	FC2005	FC2006	FC2007	FC2008
2005/06 Winter	9,580	–	–	+0.5%	–	–	–
2006 Summer	9,050	–	-530	-2.4%	+2.3%	–	–
2006/07 Winter	9,661	+81	+611	-4.0%	-3.8%	–	–
2007 Summer	9,321	+271	-340	-2.6%	+2.4%	+1.0%	–
2007/08 Winter	9,710	+49	+389	-5.6%	-5.4%	-3.2%	–
2008 Summer	9,541	+220	-169	-4.0%	+1.2%	+0.3%	+1.0%

List of Reference Documents

Alberta Employment, Immigration and Industry (December, 2008) *Monthly Economic Review*.

Energy Resources and Conservation Board *Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017* (ST98-2008).

Energy Resources and Conservation Board *Table 11: ELECTRIC ENERGY DISTRIBUTION SALES AND NUMBER OF CUSTOMERS*

Canadian Association of Petroleum Producers (June, 2008) *Crude oil Forecast, Markets and Pipeline Expansions*.

Conference Board of Canada (2008) *Provincial Outlook Long-Term Economic Forecast: 2008*.

Conference Board of Canada (2008) *Provincial Outlook Autumn 2008*

National Energy Board (June 2006) *Canada's Oil Sands - Opportunities and Challenges to 2015: An Update*. (Review only)

Statistics Canada (December 2008) *Retail Sales by industry (monthly)*

Statistics Canada (March 2008) *Alberta Gross Domestic Product at Basic Prices by industry (annual)*

Statistics Canada (March 2008) *Alberta Population (annual)*

Glossary

Alberta Interconnected Electric System (AIES): is the system of interconnected transmission power lines and generators that is managed so generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. The power flowing through this system includes the sum of all electricity sales and losses (both transmission and distribution).

Alberta Internal Load (AIL): is the total electricity consumption including behind-the-fence (BTF), the City of Medicine Hat and losses (transmission and distribution).

Behind-the-fence load (BTF): is industrial load that is characterized by being served in whole, or in part, by on-site generation, in other words, plants that are built on the industrial host's site. When these plants have excess power available they sell it into the competitive wholesale marketplace.

Bulk transmission system: is the integrated system of transmission lines and substations that delivers electric power from major generating stations to load centers. The bulk system, which generally includes the 240 kV and 500 kV transmission lines and substations, also delivers/receives power to and from adjacent power systems.

Customer Sectors: are used to classify types of load. For the purposes of this report, five sectors are used: Industrial (without Oilsands), Oilsands, Residential, Commercial and Farm.

Demand: (or coincident demand) commonly and for the purpose of this report, refers to a maximum electricity load in a given period of time for a defined area expressed in units of kW (kilowatt) or MW (megawatt)

Demand responsive load or price responsive load: are generally large commercial and industrial customers who have flexibility in their operations to enable them to reduce their load or demand in response to market price signals or other directions from a system controller.

Demand side management (DSM): generally refers to activities that occur on the demand side of the meter and are implemented by the customer directly or by load serving entities. DSM initiatives are aimed at achieving energy savings as a result of conservation, energy efficiency and load displacement programs.

Energy: commonly and for the purpose of this report, refers to electricity consumption over a given period of time for a defined area expressed in units of kWh (kilowatt hour), MWh (megawatt hour) or GWh (gigawatt hour)

Gigawatt hour (GWh): One billion watt hours.

Gross domestic product: is one of the measures of national income and output for a given country's economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered the sum of a value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time, and it is given a money value.

Load factor: is the ratio of average load to the peak load during a specified period of time; expressed in per cent.

Megawatt (MW): One million watts.

Metering Point Identifier (MP_ID): Defined point of connection on the Transmission Provider's System where capacity and/or energy are made available to the end user.

Seasonal coincident peak: is a coincident peak measured within a specific period of time defined as a season. Typically Summer and Winter are used but Fall and Spring can be included as well.

Substation: is a facility used for switching and/or changing or regulating the voltage of electricity.

Transmission Losses: are made up of physical conductors. As a result of this, loss of electrical power occurs on transmission lines.

Transmission System (Electric): is an interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

For further information:

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