aeso
ALBERTA
ELECTRIC
SYSTEM
OPERATOR

2013 Annual Market Statistics

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Executive Summary

The Alberta Electric System Operator (AESO) leads the safe, reliable, and economic planning and operation of the Alberta Interconnected Electric System (AIES), and facilitates the fair, efficient, and openly competitive operation of the wholesale electricity market. The Annual Market Statistics report provides a summary of key market information over the past year, and describes historical market trends. The accompanying **data file** provides stakeholders with the data that underlies the tables and figures in this report.

In 2013, 176 participants in the Alberta wholesale electricity market transacted approximately $8 billion of energy. The annual average pool price for wholesale electricity rose 24.7 per cent from its previous year value to $80.19/MWh. The average AECO/NIT natural gas price increased 32.7 per cent, averaging $3.01/GJ. The average market heat rate fell 2.1 per cent to 27.5 GJ/MWh.

Alberta load growth remained strong in 2013. The average Alberta Internal Load (AIL) increased by 2.8 per cent over 2012 values and hourly load set new seasonal and overall peak records.

Price	2013	Year/Year Change
Pool price	$80.19/MWh	+24.7%
Gas price	$3.01/GJ	+32.7%
Heat rate	27.5 GJ/MWh	-2.1%

Load	2013	Year/Year Change
Average AIL	8,841 MW	+2.8%
Winter peak	11,139 MW	+5.0%
Summer peak	10,063 MW	+1.8%

In 2013, energy produced through coal generation continued to serve most Alberta system demand. Installed generation increased 1.1 per cent to 14,568 MW, buoyed by increased cogeneration capacity. Supply adequacy in early 2013 fell as load growth outpaced growth in generation capacity, but rebounded in late 2013 with the return of the Sundance and Keephills coal units to service.

Net imports to Alberta in 2013 decreased 34.5 per cent from 2012 volumes as low precipitation limited hydro generation in the Pacific Northwest. The Montana-Alberta Tie Line (MATL) started commercial operation in September 2013. This new interconnection diversified the sources of imported energy, but did not increase the total transfer capability of the AIES. The AESO is exploring initiatives to restore intertie capability.

The cost of operating reserve rose 13.2 per cent to $369 million due to the increased pool price in 2013. The cost of Dispatch Down Service (DDS) fell 67.1 per cent to $575 thousand due to decreased volumes of transmission must-run (TMR) service. The cost of payments to suppliers on the margin (PSM) increased 15.8 per cent to $2.6 million.

Pool Price Review

Pool price averaged $80.19/MWh in 2013—an increase of 24.7 per cent from 2012. The on-peak average price increased 25.3 per cent to $106.13/MWh, and the off-peak average price rose 20.3 per cent to $28.29/MWh. Table 1 summarizes the historical price statistics from 2004 to 2013.

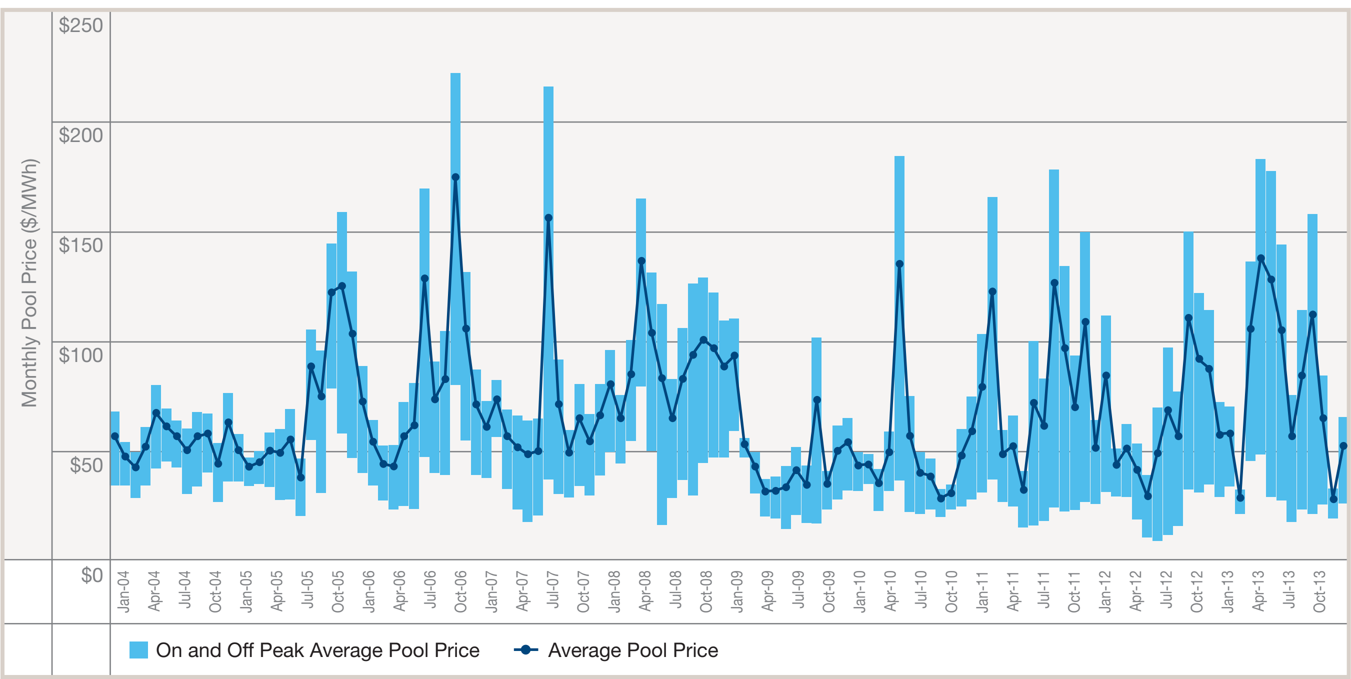
TABLE 1
Annual Pool Price Statistics

Pool Price *($/MWh)*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Average pool price	54.59	70.36	80.79	66.95	89.95	47.81	50.88	76.22	64.32	**80.19**
On-peak average pool price	64.03	85.35	101.41	84.37	112.97	58.04	62.99	102.22	84.72	**106.13**
Off-peak average pool price	35.72	40.37	39.54	32.11	43.92	27.36	26.67	24.22	23.51	**28.29**
Maximum pool price	998.01	999.99	999.99	999.99	999.99	999.99	999.99	999.99	1,000.00	**1,000.00**
Minimum pool price	0.00	4.66	5.42	0.00	0.00	0.10	0.00	0.00	0.00	**0.00**

Note: The on-peak period starts at 7:00 am and ends at 11:00 pm, Monday through Sunday inclusive. The off-peak period includes all other hours.

Over the year, the hourly pool price ranged between the offer floor of $0.00/MWh and the administrative price cap of $1,000/MWh. The monthly average pool price ranged from a low of $28.34/MWh in November to a high of $137.66/MWh in April. Figure 1 shows the monthly distribution of prices over the past ten years.

FIGURE 1
Monthly Average Pool Price



The wholesale price of electricity in Alberta is determined according to the principles of supply and demand. Generators submit offers specifying the amount of power that they will provide in a one hour settlement period and the price at which they are willing to supply it. This offer price can range from a low of $0/MWh to a maximum of $999.99/MWh. The automated Energy Trading System arranges offers from lowest to highest price. This sorted list of energy offers is called the energy market merit order.

The system controller dispatches generating units from the merit order in ascending order of price until supply satisfies demand. The highest priced unit dispatched is called the marginal unit and its offer price sets the system marginal price (SMP) for a one minute period. The pool price is the simple average of the sixty system marginal prices in the hour. All energy generated in the hour receives a uniform clearing price—the pool price—regardless of its offer price.

The offer price of energy differs between assets based on the operational characteristics of the unit, the price of fuel, and other cost considerations of the unit operator. Baseload generation technologies typically adopt a price-taker strategy—they offer energy to the market at a low price and produce energy in the majority of hours. Peaking generation technologies adopt a scarcity-pricing strategy—they offer energy at a higher price and only produce energy when demand is high. The combination of offer strategy and operational characteristics determines the average revenue that each asset type receives.

Baseload generation technologies optimally operate throughout the entire day. These baseload technologies include coal, gas cogeneration and run-of-river hydroelectric. The low cost of coal generation means that it is more economical to continue operating through low-priced hours than to incur the high costs associated with halting and restarting generation. Most cogeneration facilities generate electricity as a by-product of industrial processes that operate around the clock independent of the price of electricity. Run-of-river hydroelectric generates electricity as water flows through streams and rivers. Baseload generation generally offers its energy into the market at low prices. This price-taker strategy ensures that baseload generation is usually dispatched to run and receives an average revenue close to the average pool price.

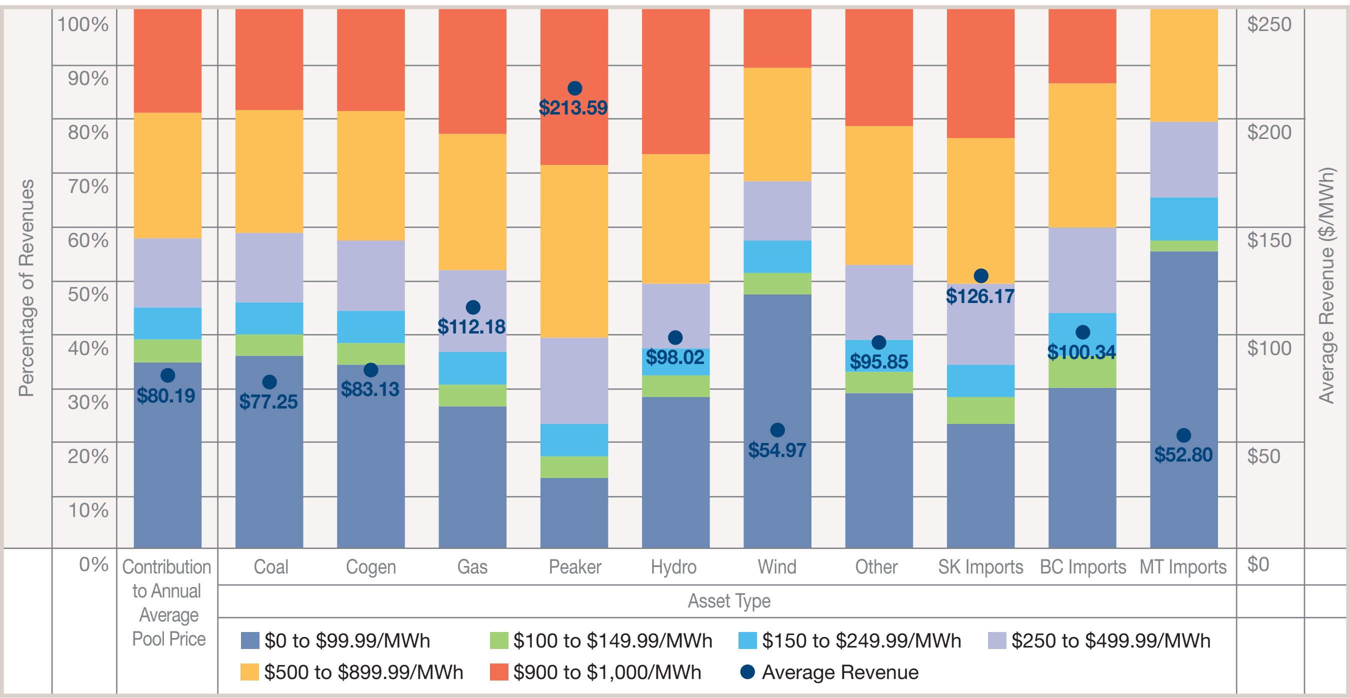
Peaking generation technologies achieve greater operational flexibility than baseload generation, but at higher cost. The gas-fired combustion turbines used in peaking generation can halt and restart operation without incurring high costs, but cost more to operate. This higher cost of generation is reflected in higher offer prices. High-priced peaking generation will only be dispatched to run during periods of high demand, after lower-priced generation has been completely dispatched. Peaking generation operates in fewer hours than baseload generation but achieves higher average revenue.

Although wind generation and importers are both price-takers, the average revenue received by each asset type differs dramatically due to operational differences. Wind generation cannot control its operational schedule. Wind facilities generate electricity according to local weather systems. Wind generation displaces marginal units from the merit order and lowers the SMP. Because strong wind generation generally depresses the SMP, wind generation usually receives lower average revenue than other asset types.

Imported energy displaces marginal units from the merit order and drives prices lower. Unlike wind, importers can choose when to operate. Importers transfer energy into Alberta only during favorable economic conditions, and this operational flexibility is reflected in higher average revenues. Alberta can import energy across interties to three neighbouring jurisdictions: British Columbia, Saskatchewan and Montana. In 2013, imports from both B.C. and Saskatchewan achieved high average revenue. Imports from Montana achieved lower average revenue because the interconnection operated only during the low-priced hours at the end of 2013.

Figure 2 illustrates the average hourly revenue collected by different asset types. The leftmost bar in Figure 2 represents the pool price, which is provided as comparison for a hypothetical unit that produces the same amount of energy in each hour of the year.

FIGURE 2
Average Revenue by Asset Type

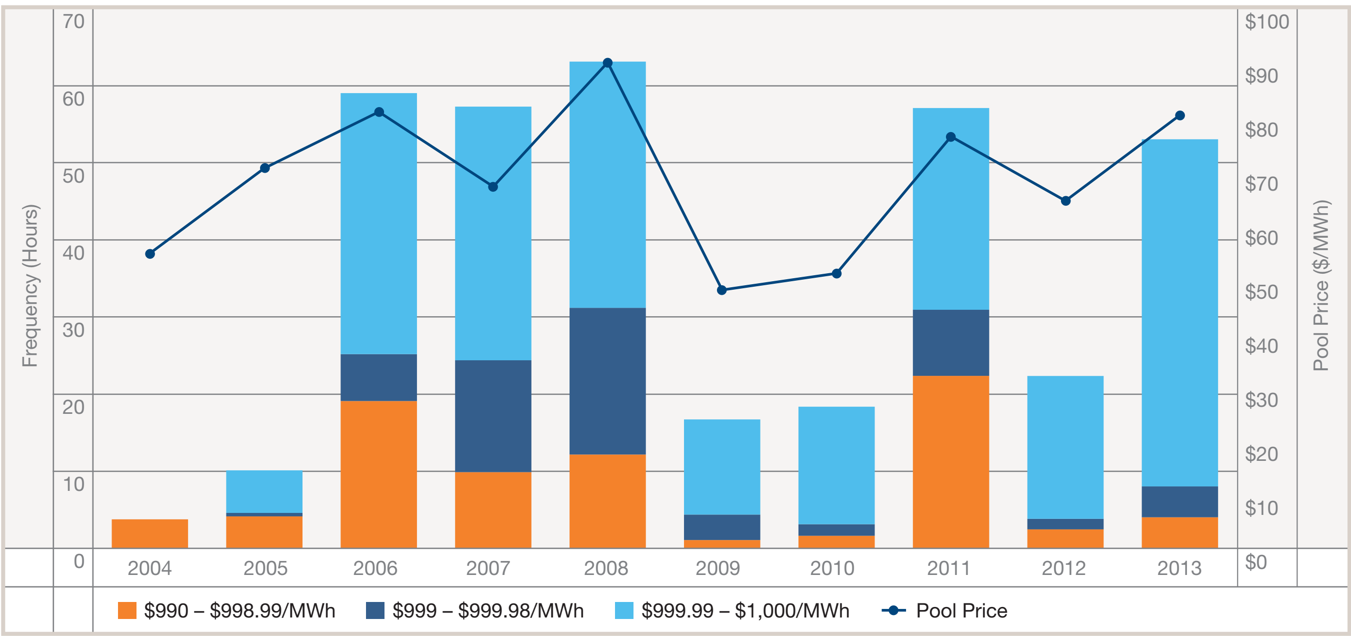


AESO system controllers dispatch generation from the merit order to serve demand on the AIES. High system demand requires system controllers to dispatch more generation, increasing the system marginal price. Figure 3 shows that generation priced above $990/MWh set SMP more frequently in 2013 than it did in 2012. In 2013, pool price settled at the offer cap of $999.99/MWh in 35 of the 8,760 hours. These high-priced hours occurred more frequently than in 2012, when pool price settled at the offer cap in only six hours.

Supply shortfall conditions occur when system demand exceeds the total generation in the energy market merit order that is available for dispatch. Supply shortfall conditions do not necessarily imply that firm load must be curtailed. System controllers manage supply shortfall events according to a prescribed mitigation procedure. The final step in this procedure requires the system controller to shed firm load when supply shortfall conditions threaten system stability. When the system controller is forced to curtail load, the SMP is set to the administrative price cap of $1,000/MWh.

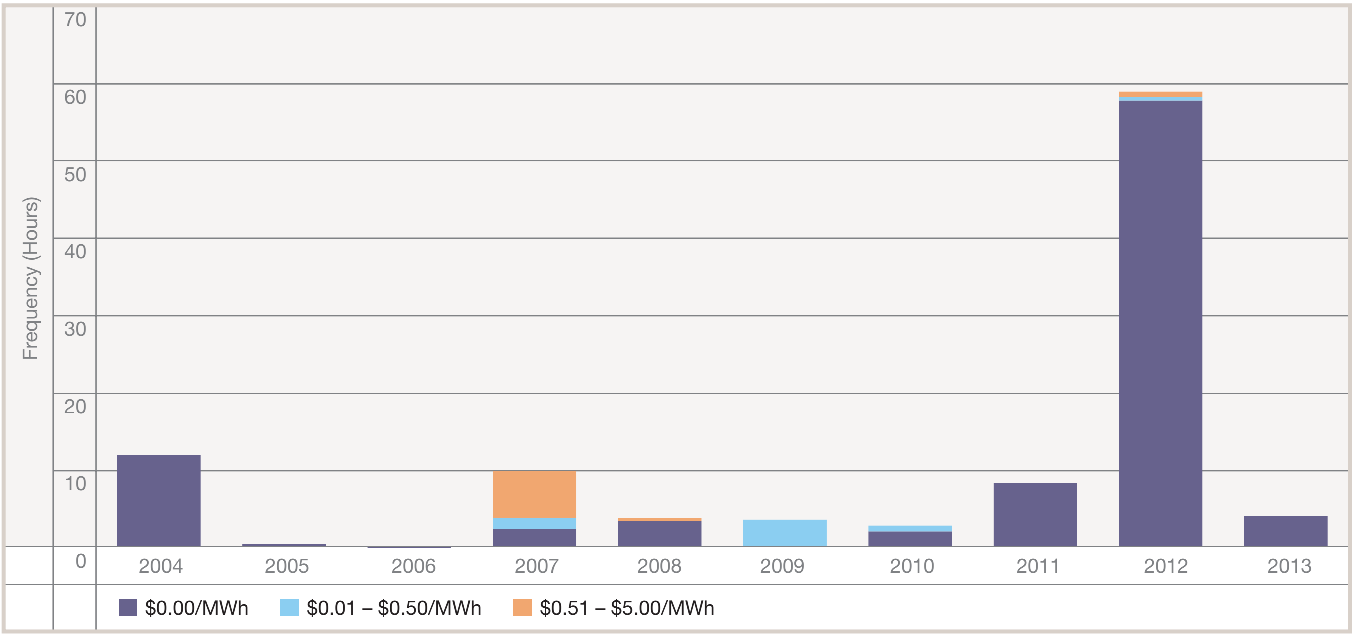
The system controller curtailed load only once in 2013. On the morning of July 2, 2013, high temperatures across Alberta reduced generation capability and drove electricity demand to a new summer peak. The combination of reduced generation capability and high system load pushed the system into a state of energy supply shortfall. While the system remained in this state of emergency, a transformer outage at the Ellerslie substation further reduced the energy supply and forced the AESO to curtail firm load. The firm load shed event of July 2, 2013, set SMP for one hour. The previous load shed event occurred one year earlier, on July 9, 2012, and set price for three hours.

FIGURE 3
Total Time Where SMP Exceeded $990.00/MWh



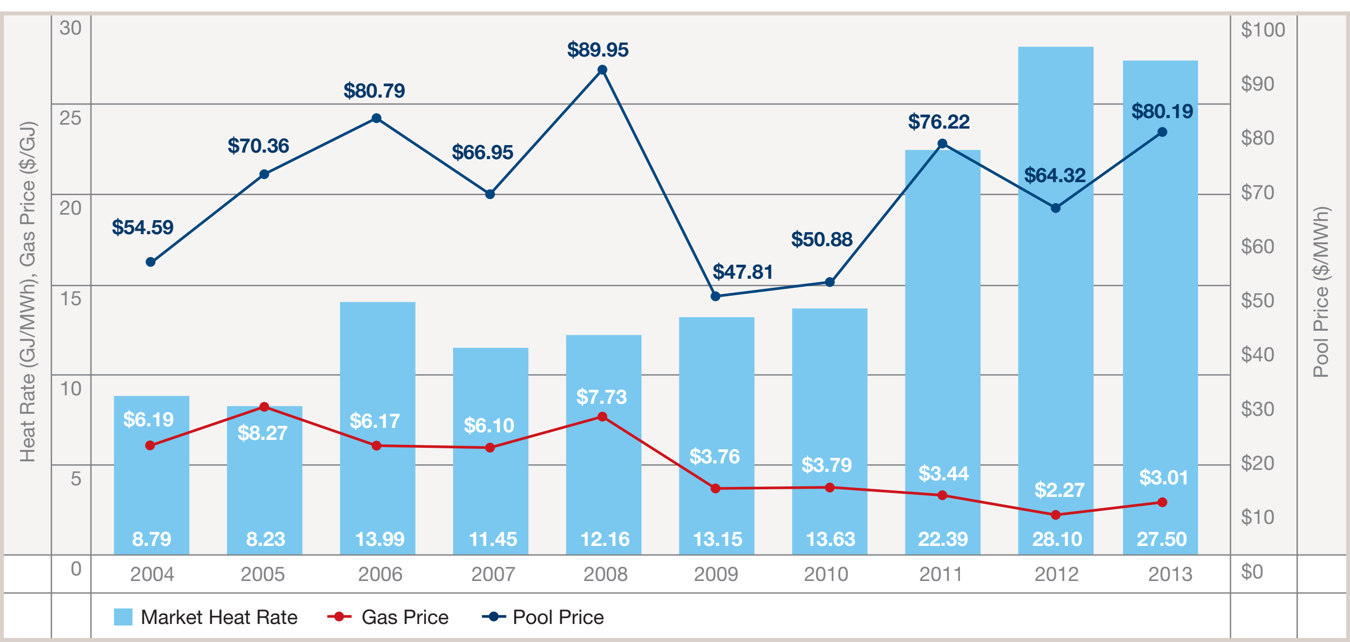
Supply surplus events occur when the supply of energy offered to the market at $0/MWh exceeds system demand. During a supply surplus event, generation must be curtailed to preserve system stability. The frequency of supply surplus events in 2013 declined from its peak in 2012 to a level consistent with the long-term average. In 2013, pool price settled at $0/MWh for three consecutive hours in the morning of July 7, 2013. This supply surplus event was caused by low demand, high imports and higher baseload generation. Figure 4 illustrates the frequency of supply surplus events over the past ten years.

FIGURE 4
Total Time Where SMP Settled Below $5.00/MWh



The market heat rate expresses the average price of electricity in units of natural gas. It is calculated as the ratio of the annual average pool price to the annual average natural gas price. In 2013, natural gas prices averaged $3.01/GJ, an increase of 32.7 per cent from the 2012 average of $2.27/GJ. The annual market heat rate decreased from 28.1 GJ/MWh in 2012 to 27.5 GJ/MWh in 2013 as natural gas prices increased at a greater rate than pool prices. Figure 5 shows the historic relationship between natural gas prices and the pool price over the past ten years.

FIGURE 5
Annual Average Pool Price, AECO Natural Gas Price and Market Heat Rate



Alberta Internal Load

Average Load Grew Three Per Cent

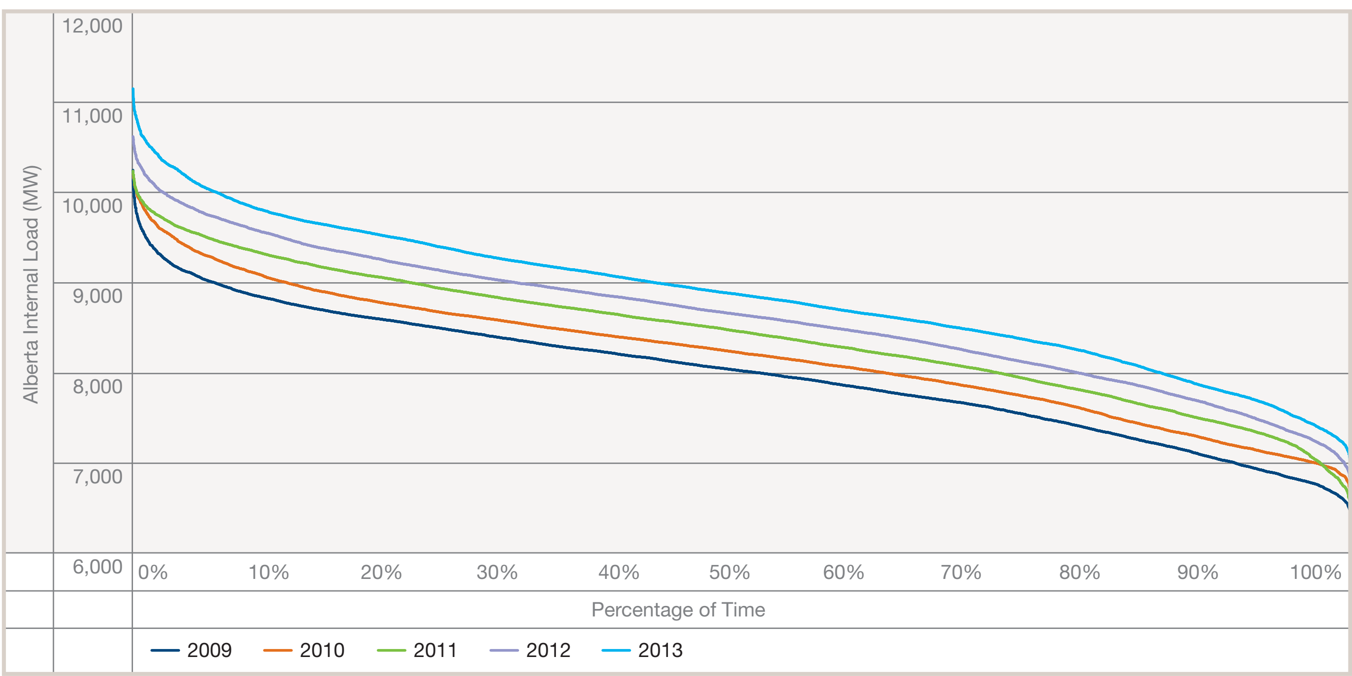
In 2013, the average hourly AIL grew 2.8 per cent to 8,841 MW and peak load increased five per cent to a new record of 11,139 MW. This load growth was driven primarily by increased oilsands demand in northeastern Alberta and, to a lesser extent, by increased commercial and residential demand in urban areas and industrial demand throughout the province. Table 2 summarizes annual demand statistics over the past ten years.

TABLE 2
Annual AIL Statistics

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total AIL *(GWh)*	65,260	66,267	69,371	69,661	69,947	69,914	71,723	73,600	75,574	**77,451**
Average load *(MW)*	7,429	7,565	7,919	7,952	7,963	7,981	8,188	8,402	8,604	**8,841**
Maximum load *(MW)*	9,236	9,580	9,661	9,701	9,806	10,236	10,196	10,226	10,609	**11,139**
Minimum load *(MW)*	6,017	6,104	6,351	6,440	6,411	6,454	6,641	6,459	6,828	**6,991**
Annual growth in total AIL *(%)*	+4.1	+1.5	+4.7	+0.4	+0.4	-0.0	+2.6	+2.6	+2.7	**+2.5**
Annual growth in average load *(%)*	+3.8	+1.8	+4.7	+0.4	+0.1	+0.2	+2.6	+2.6	+2.4	**+2.8**
Load factor *(%)*	80.4	79.0	82.0	82.0	81.2	78.0	80.3	82.2	81.1	**79.4**

Load growth in 2013 represented a consistent and largely uniform increase from 2012. Load duration represents the percentage of time that the load was greater than or equal to the specified load. Figure 6 shows that the load duration in 2013 exceeded 2012 at every value. Load in 2013 equaled or exceeded 2012 peak demand in 73 hours.

FIGURE 6
Annual Load Duration Curves

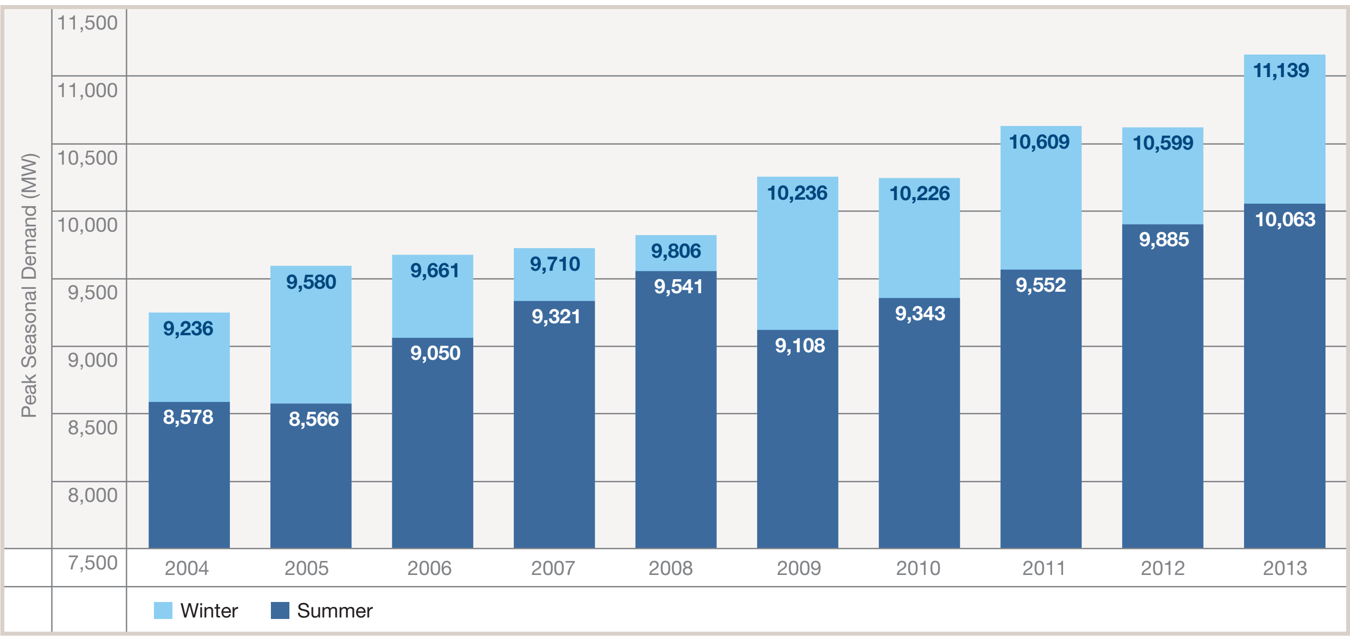


Summer and Winter Demand Set Peak Records

Demand in 2013 set new records for peak load in both the summer and winter seasons. Alberta peak demand is usually set during periods of extreme temperatures: summer peaks are driven by heat while winter peaks are driven by cold. The summer season starts on May 1 and ends on October 31. On July 2, 2013, high temperatures drove system load to a new summer peak of 10,063 MW. The previous summer peak was set one year earlier, in summer 2012, at 9,885 MW.

The winter season starts on November 1 and ends on April 30 of the following year.[1] On December 2, 2013, cold temperatures drove Alberta load to a new winter and overall peak record of 11,139 MW. The previous highest winter and system peak was set in winter 2011 when AIL reached 10,609 MW. Figure 7 illustrates the winter and summer peak demand over the past ten years.

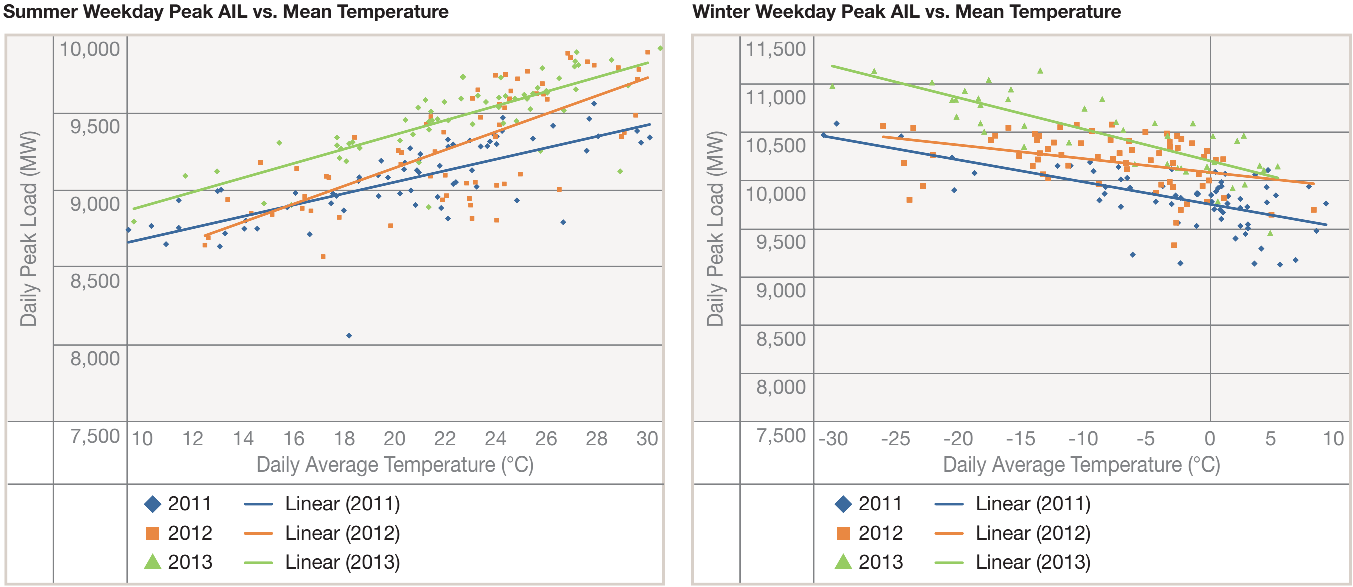
FIGURE 7
Seasonal Peak Load



Even within the same season, temperature influences demand. AIL tends to increase as the temperature becomes more extreme. Summer load is more sensitive to extreme temperatures than winter because air conditioning tends to draw more electrical load than the gas-fired heating that is common in Alberta. During summer weekdays in 2013, an increase of one degree Celsius increased peak AIL by an average of 49 MW. On winter weekdays in 2013, a decrease of one degree Celsius increased peak AIL by an average of 35 MW. Figure 8 illustrates the relationship between temperature and daily peak demand in summer and winter.

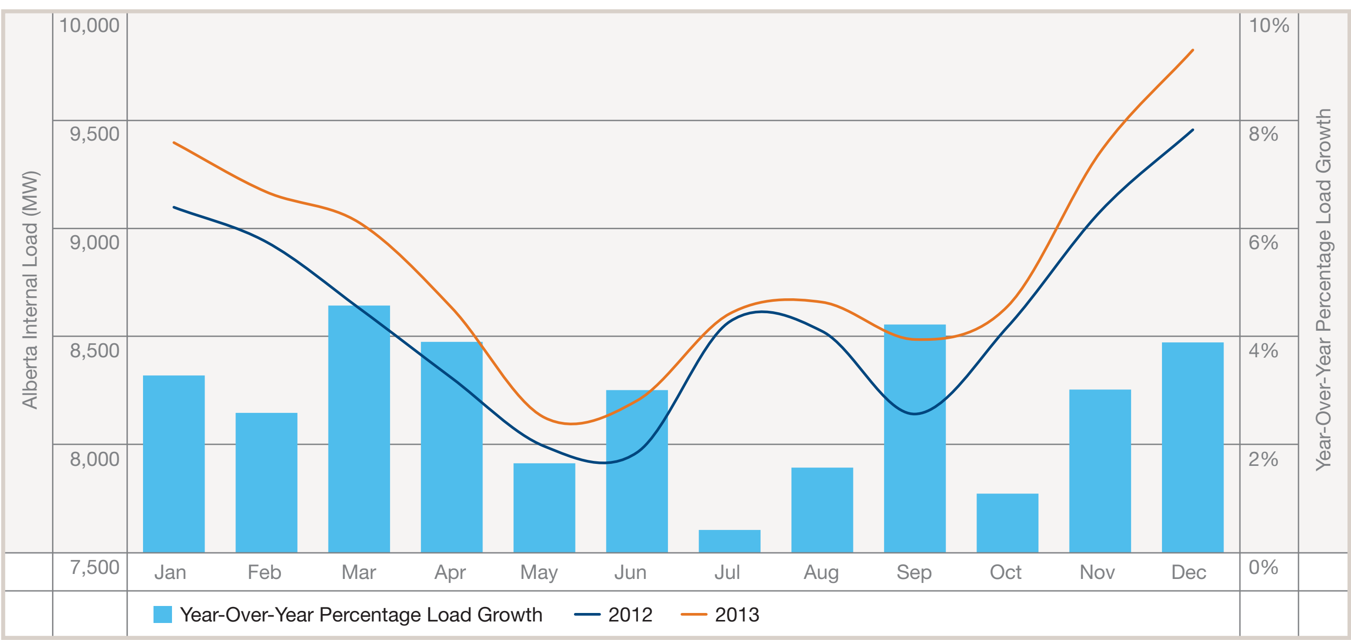
[1] *Winter 2013 data is limited to observations between November 2013 and December 2013.*

FIGURE 8
Summer and Winter Peak Demand and Temperature



In every month of 2013, monthly average demand increased from 2012 levels. The highest load growth occurred in March due to strong oilsands demand. The lowest load growth occurred in July due to lower temperatures following the Alberta floods. Figure 9 shows the monthly load growth between 2012 and 2013.

FIGURE 9
Monthly Average AIL and Load Growth

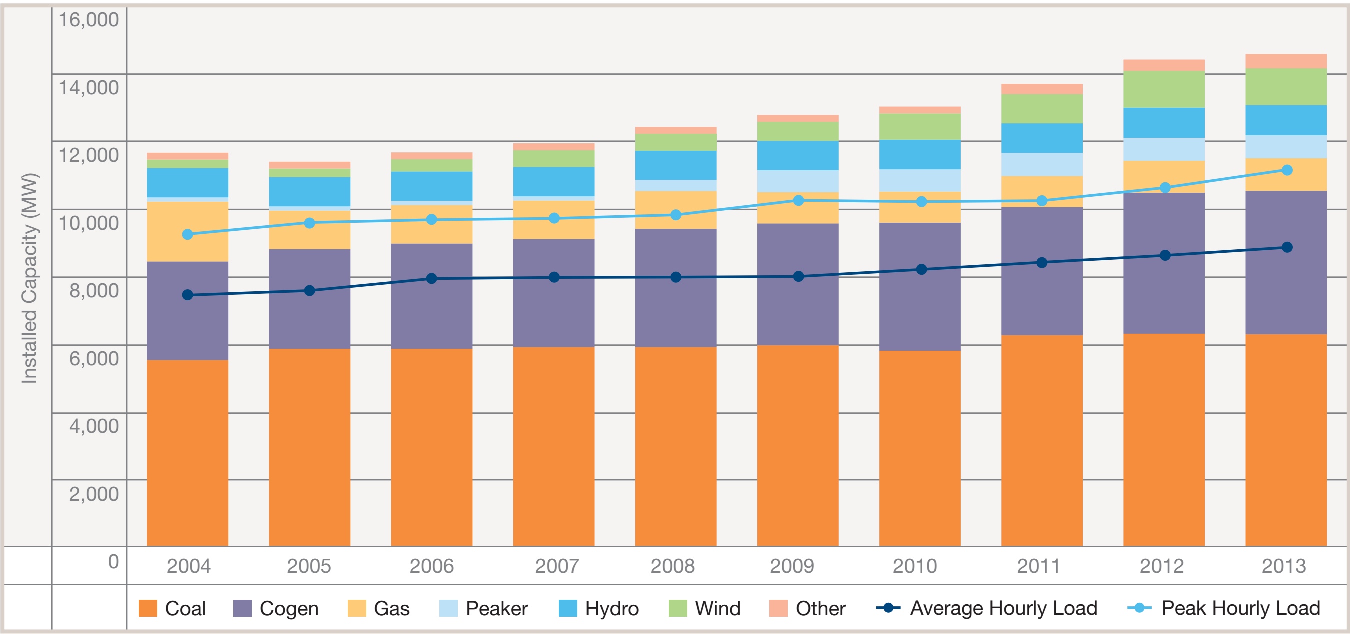


Installed Generation

Generation Capacity Increased 163 MW

The total installed generation capacity in Alberta increased 1.1 per cent to 14,568 MW in 2013. Figure 10 shows the annual installed capacity at the end of each year for the past ten years.

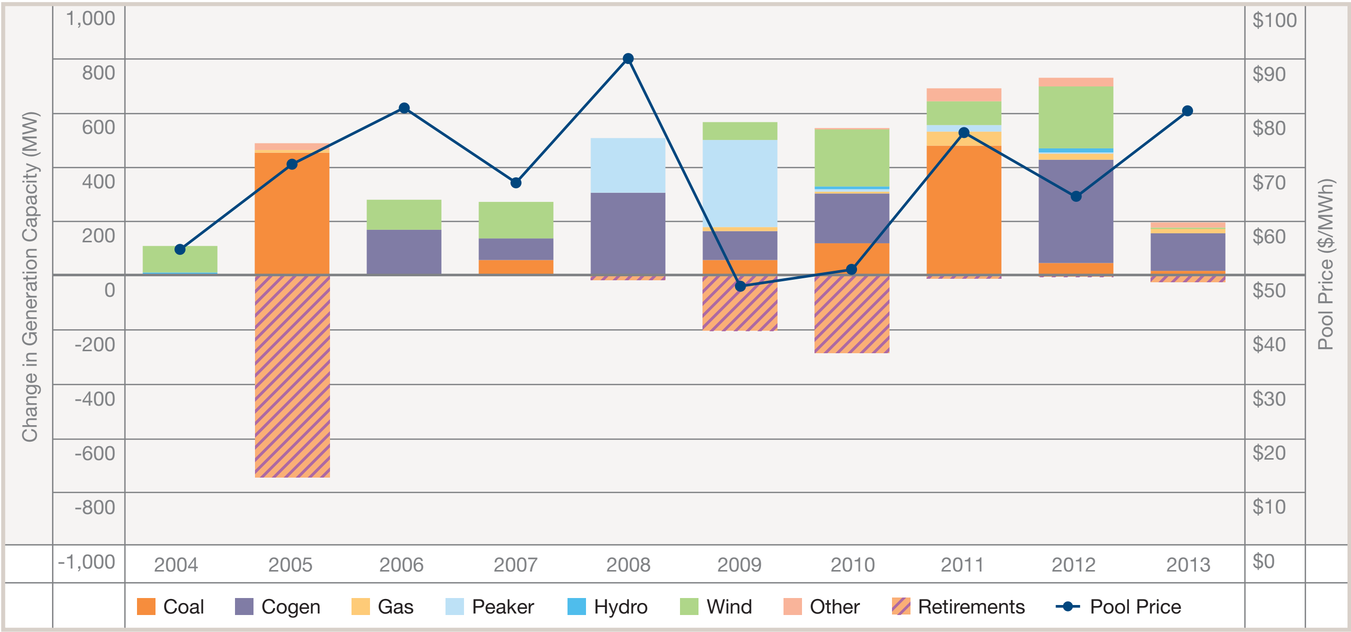
FIGURE 10
Installed Generation Capacity



The change in installed capacity was driven by increased gas-fired cogeneration and waste heat generation and decreased coal generation. MEG Energy Corp. expanded its cogeneration project in Christina Lake, Alberta, increasing the maximum capability of the unit from 92 MW to 202 MW. NRGreen Power Ltd. installed a new 19 MW waste heat generation unit near Whitecourt, Alberta; however, while this unit increased system capacity, it is not expected to start operation until early 2014. Reductions in the maximum capability of coal units lowered total system generation capability by 28 MW.

Figure 11 shows the annual generation additions and retirements over the past 10 years. Although capacity growth was markedly lower in 2013 than in previous years, more than 1,500 MW of additional generation capability currently under construction in Alberta is scheduled to start operation in 2014 and 2015.

FIGURE 11
Generation Additions and Retirements



In 2013, three biomass cogeneration units totaling 69 MW in capacity were reclassified from cogeneration to other generation. The revised asset classification is reflected in the installed capacity for 2013 in Figure 10. Installed capacity in previous years remains unchanged. Since this change is neither an addition nor a retirement, it is excluded from Figure 11.

Generation Outages Decreased as Coal Units Returned to Service

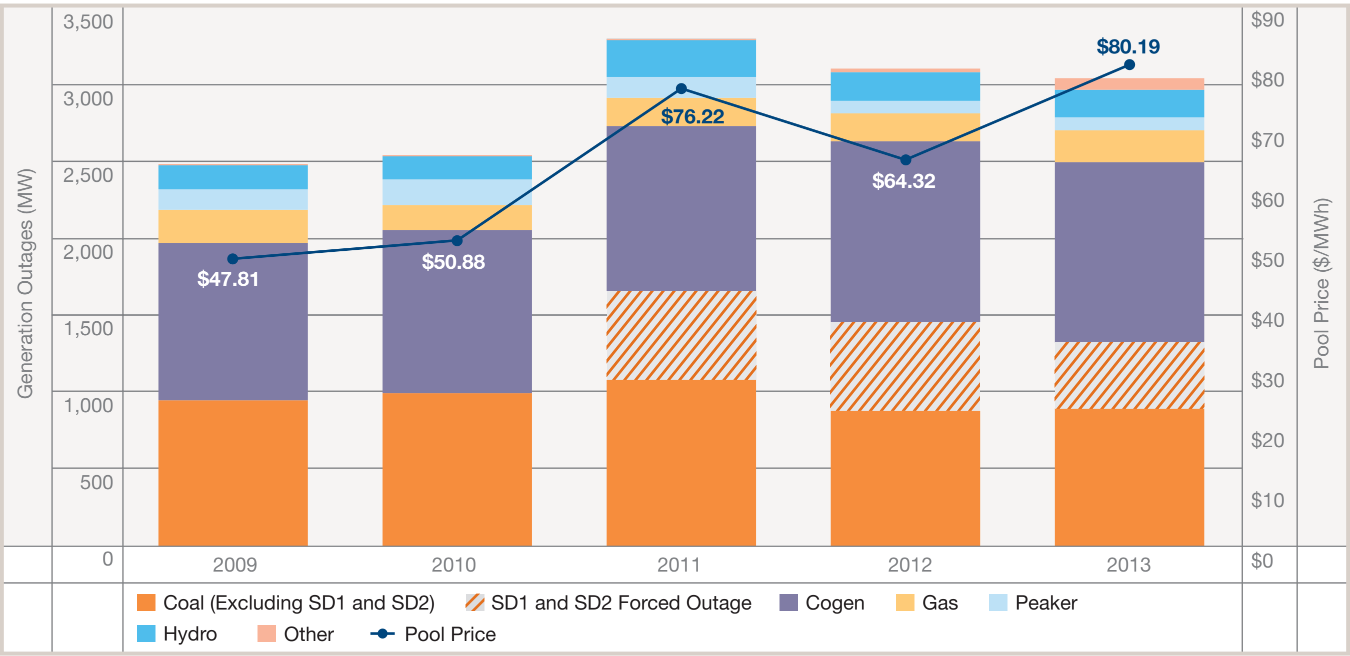
Operational issues at generating units often limit the generation capability of the system. The maximum capability (MC) of a unit represents the power that an asset can generate under optimal operating conditions. The available capability (AC) represents the power that an asset is actually capable of generating. Generally, the AC equals the MC; however, when operational issues cause lower AC, the difference between MC and AC is called the generation outage. Unit operators must provide an acceptable operating reason (AOR) to justify an outage.

Each asset must offer its AC into the energy market. When low-priced baseload generation is unavailable due to planned or forced outages, system controllers must dispatch higher-priced offers from the energy market merit order to serve demand. The replacement of low-priced baseload generation with higher-priced generation increases system prices. In 2013, extended outages at three coal assets contributed to raised pool prices.

In December 2010, operational issues at Sundance 1 (SD1) and Sundance 2 (SD2) forced TransAlta Corp. to remove the coal units from service. The removal of 576 MW of baseload generation capability from the system exerted upward pressure on pool prices in 2011 and 2012. In March 2013, TransAlta Corp. was forced to remove an additional 395 MW of generation capability from service due to technical issues at Keephills 1. Sundance 1 returned to service in September 2013; Sundance 2 and Keephills 1 returned in October 2013. The return of baseload capability contributed to lower pool prices in late 2013.

Figure 12 illustrates average outages by asset type over the past five years.

FIGURE 12
Annual Average Generation Outages Versus the Pool Price



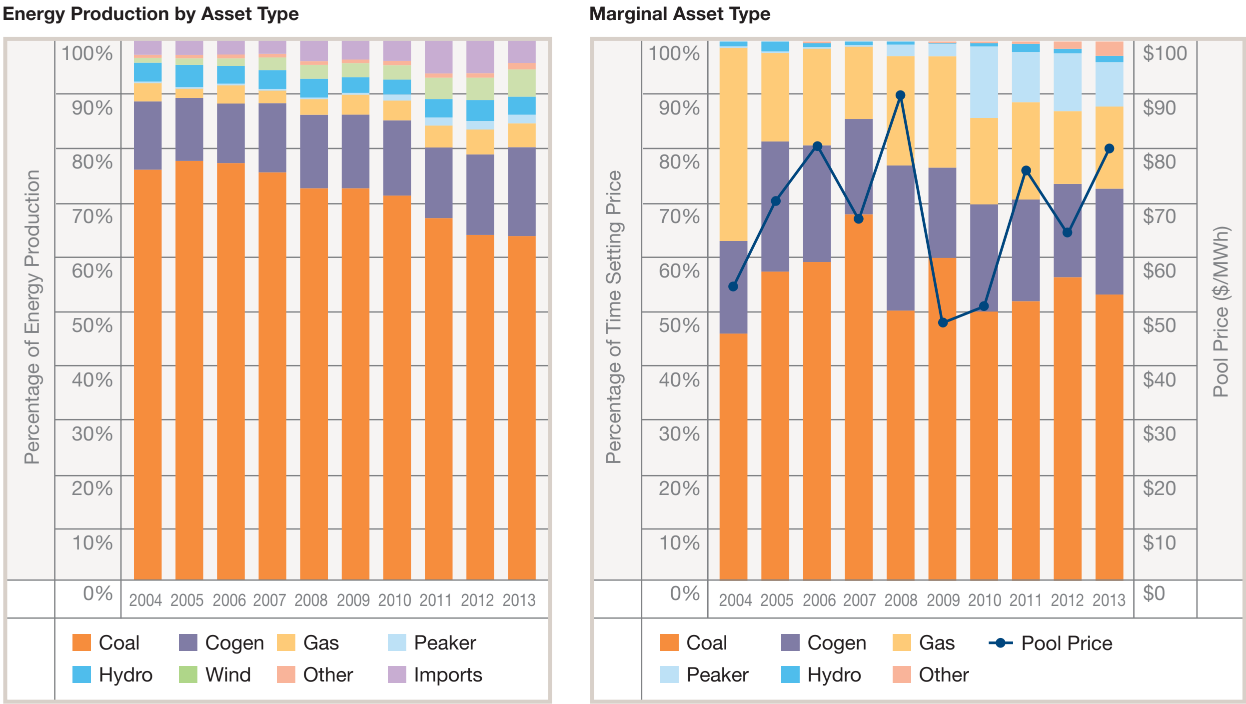
Energy Production and Marginal Asset Type

Coal generation produces the majority of energy used in the province. Although the percentage of total energy produced by coal generation has declined over the past ten years, coal generation continues to produce more energy than all other asset types combined.

Energy production does not translate to price setting frequency. The marginal asset type identifies the generation technology in use at the marginal unit. Low-priced baseload generation technologies most frequently set price in hours when demand is low. As demand increases, higher-priced generation sets the system marginal price.

The percentages of energy production and marginal asset types in 2013 remained largely consistent with 2012 levels. Figure 13 shows the annual energy production and price-setting share by asset type over the last ten years. The one hour supply shortfall period during which the administrative price cap set the SMP is grouped with other generation.

FIGURE 13
Energy Production and Marginal Asset Type



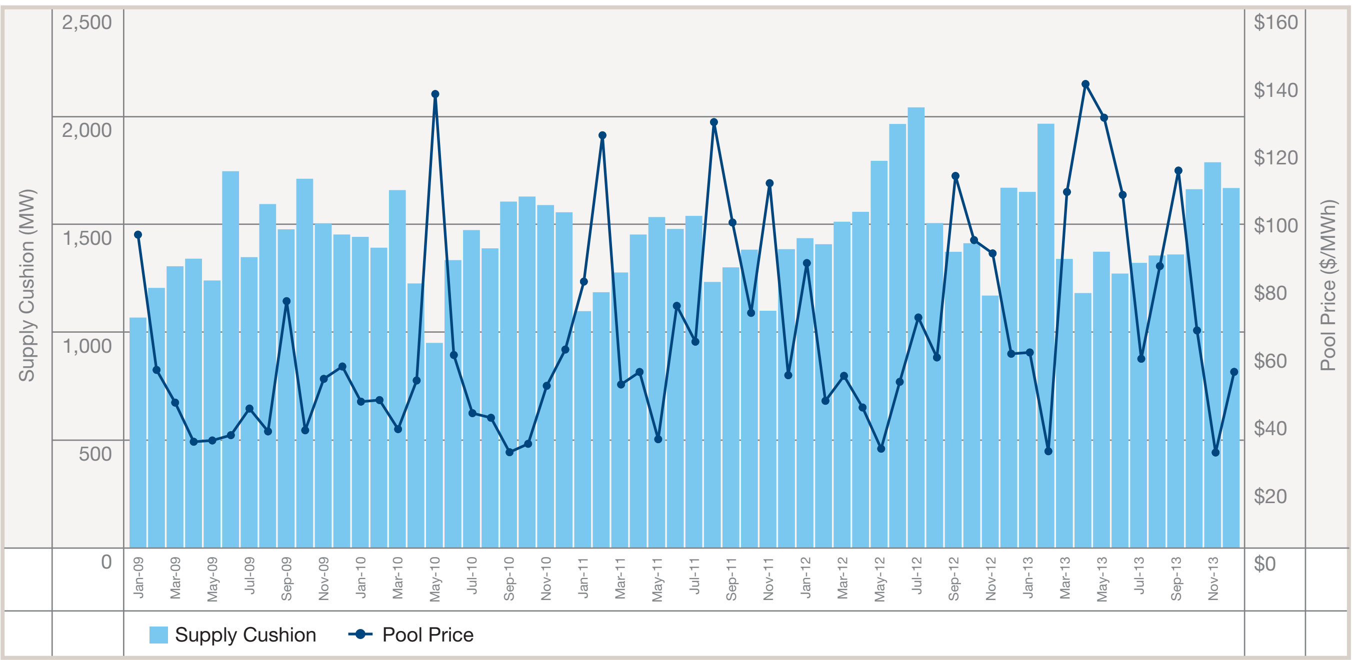
Supply Adequacy

Supply adequacy expresses the ability of the system to serve demand. Supply adequacy increases when generation capability increases and decreases as system load increases. Higher supply adequacy indicates greater system reliability and lower supply adequacy indicates lower system reliability. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin.

Average Supply Cushion

The hourly supply cushion indicates the additional generation capability that remained available for dispatch after all existing demand had been served. In 2013, the hourly supply cushion averaged 1,493 MW—slightly larger than average demand in the City of Edmonton—but over the year, ranged from a low of 0 MW during supply shortfall conditions to a peak of 3,598 MW. The average supply cushion fell 5.1 per cent from 2012 as load growth outpaced increases in generation capability. Figure 14 shows the monthly average supply cushion over the past ten years.

FIGURE 14
Monthly Average Supply Cushion

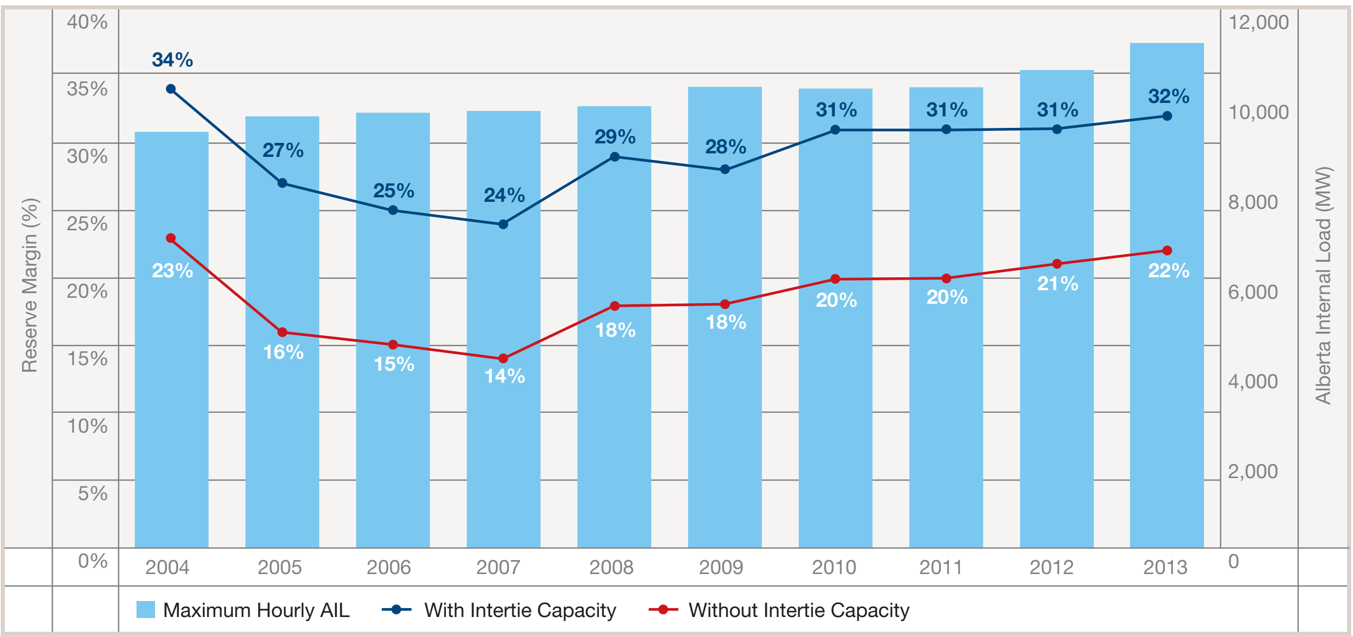


Reserve Margin Remained Constant

The reserve margin expresses the system generation capability in excess of that required to serve peak system load. In this calculation, generation capability excludes wind generation, which may be unavailable, and reduces hydro generation to reflect seasonal variability. The reserve margin is calculated both including and excluding the combined import capacity of interties in order to evaluate system reliance on generation outside Alberta.

The reserve margin increased slightly in 2013, reflecting the return of Sundance 1 and 2 to service. The reserve margin calculations in 2011 and 2012 excluded the generation capability of the two Sundance coal units. Figure 15 shows the annual reserve margin over the past ten years[2].

FIGURE 15
Annual Reserve Margin and Peak Alberta Internal Load (AIL)



2 *Reserve margin is calculated using the methodology defined in the quarterly* **Long Term Adequacy (LTA) Metrics** *report.*

Imports and Exports

Montana-Alberta Tie Line Started Operation

Alberta imports and exports energy across electrical interconnections with neighbouring control areas. Before 2013, imports and exports flowed between Alberta and its two provincial neighbours, British Columbia and Saskatchewan. In September 2013, MATL started commercial operation. This new interconnection permits Alberta to import up to 300 MW and export up to 325 MW of energy across the border with Montana.

Although the addition of MATL diversified the sources of imported energy, it did not increase the total import and export capability of the AIES. Reliability criteria currently limit the total energy that can be transferred between Alberta and the rest of the Western Electricity Coordinating Council (WECC) region. The total energy transferred between Alberta and B.C. and between Alberta and Montana cannot exceed the transfer capability limit between Alberta and the WECC region. When the combined offers from B.C. and Montana exceed this transfer capability limit, transfer capability between Alberta and the WECC region must be allocated between MATL and the interconnection to British Columbia. The AESO is exploring initiatives to restore intertie transfer capability.

Imports Served Three Per Cent of Load

Alberta has been a net importer of electricity for the last 11 years, and in 17 of the 18 years since 1995. In 2013, net imports totaled 2,289 GWh and served three per cent of total AIL. Total net imports in 2013 fell 34.5 per cent from 2012 as low precipitation in the Pacific Northwest limited hydro generation. This decline averaged 138 MW in every hour—equivalent to 40 per cent of the capability of the average coal unit in Alberta. Because imported energy must be offered to the energy market at $0/MWh, this reduction in imported energy exerted an upward influence on the average pool price.

Table 3 shows the annual import statistics over the last ten years.

TABLE 3
Annual Intertie Statistics

Intertie Statistics *(GWh)*	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Total Scheduled Imports										
Imports on B.C. intertie	1,073	1,071	1,101	927	1,574	1,344	1,847	3,047	3,067	**1,902**
Imports on Saskatchewan intertie	418	464	416	540	674	675	358	544	515	**518**
Imports on MT intertie	0	0	0	0	0	0	0	0	0	**126**
Total imports	1,492	1,535	1,517	1,467	2,248	2,019	2,205	3,591	3,582	**2,546**
Total imports as a per cent of total AIL *(%)*	2.3	2.3	2.2	2.1	3.2	2.9	3.1	4.9	4.7	**3.3**
Total Scheduled Exports										
Exports on B.C. intertie	968	988	460	886	518	488	422	71	62	**223**
Exports on Saskatchewan intertie	93	50	29	88	40	25	48	48	23	**32**
Exports on MT intertie	0	0	0	0	0	0	0	0	0	**2**
Total exports	1,061	1,038	489	973	559	513	470	119	85	**257**
Total exports as a per cent of total AIL *(%)*	1.6	1.6	0.7	1.4	0.8	0.7	0.7	0.2	0.1	**0.3**
Net Imports (Imports Minus Exports)										
Net B.C. imports	105	83	641	42	1,056	856	1,425	2,976	3,005	**1,679**
Net Saskatchewan imports	325	413	386	452	633	649	310	496	492	**486**
Net MT imports	0	0	0	0	0	0	0	0	0	**124**
Total net imports	430	497	1,028	494	1,689	1,505	1,735	3,473	3,497	**2,289**
Total net imports as a per cent of total AIL *(%)*	0.7	0.7	1.5	0.7	2.4	2.2	2.4	4.7	4.6	**3.0**
Market Size (Total Demand)										
Alberta Internal Load (AIL)	65,260	66,267	69,371	69,661	69,947	69,914	71,723	73,600	75,574	**77,451**

The maximum transfer capabilities for all interconnections remained unchanged from 2012. The average import transfer capability of the interconnection between Alberta and the WECC region in 2013 fell by 3.6 per cent from its 2012 value. This decrease in transfer capability was largely due to more frequent outages on the transmission line linking Alberta and British Columbia. The average transfer capability of the interconnection between Alberta and Saskatchewan remained stable between 2012 and 2013. Table 4 shows the annual intertie transfer capability statistics over the past five years.

TABLE 4
Annual Intertie Transfer Capability Statistics

	WECC Export Transfer Capability *(MW)*		WECC Import Transfer Capability *(MW)*		Saskatchewan Export Transfer Capability *(MW)*		Saskatchewan Import Transfer Capability *(MW)*	
Year	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average
2009	735	322	600	449	61	37	153	146
2010	735	389	650	507	153	88	153	114
2011	735	421	625	525	153	134	153	137
2012	735	313	700	528	153	145	153	143
2013	**735**	**253**	**700**	**509**	**153**	**146**	**153**	**146**

Note: Before MATL started operation, WECC export and import transfer capabilities only reflected the interconnection between Alberta and B.C. After MATL started operation, WECC transfer capabilities reflect the combined transfer capabilities across the interconnections with B.C. and Montana.

Interchange utilization represents the ratio of net imports between control areas to the maximum transfer capability of the interconnection. The calculation of net imports includes the volume of operating reserve scheduled through the interties. The maximum transfer capability of the interconnection between Alberta and the WECC region reflects the limit of the interconnection with B.C., the limit of MATL, and the system operating limit on the combined flow across the two interconnections.

During 21 per cent of hours in 2013, Alberta imported energy from the WECC region at the transfer capability of the interconnection. Imports from the WECC region occurred 74 per cent of the time. Exports to the WECC region occurred 12 per cent of the time and the export transfer capability to WECC was fully utilized for 41 hours. The Saskatchewan intertie was fully utilized 13 per cent of the time and imports occurred 62 per cent of the time. Exports on the Saskatchewan intertie occurred five per cent of the time.

Figure 16 illustrates the annual interchange utilization between Alberta and the WECC region over the past five years.

FIGURE 16
Interchange Utilization with WECC Region

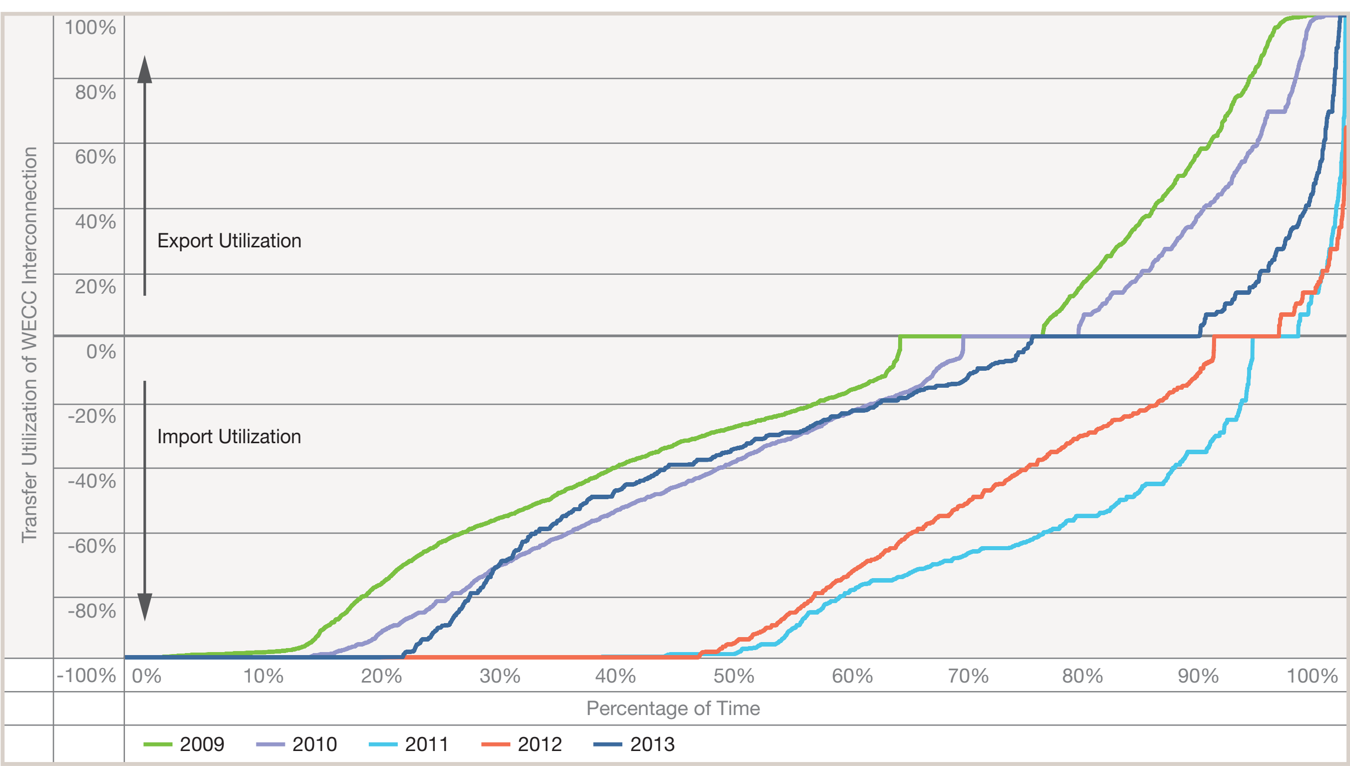
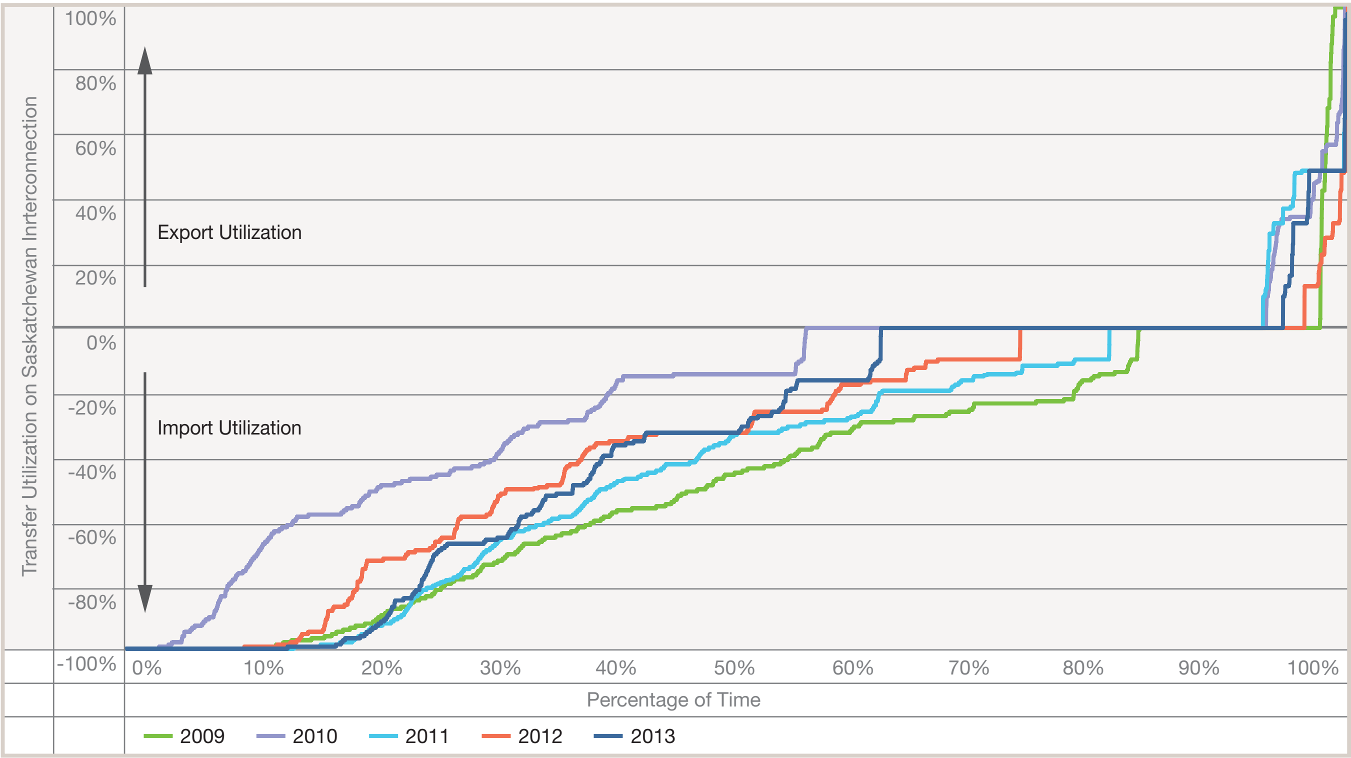


Figure 17 illustrates the annual interchange utilization between Alberta and Saskatchewan over the same period.

FIGURE 17
Interchange Utilization with Saskatchewan



Wind Served Four Per Cent of Load

At the end of 2013, generation capacity from wind power totaled 1,088 MW, making up 7.5 per cent of the total installed generation capacity in Alberta. Wind generation over the year totaled three TWh and served 3.9 per cent of the total annual AIL. Table 5 summarizes the annual performance statistics for wind generation.

TABLE 5
Wind Generation Statistics

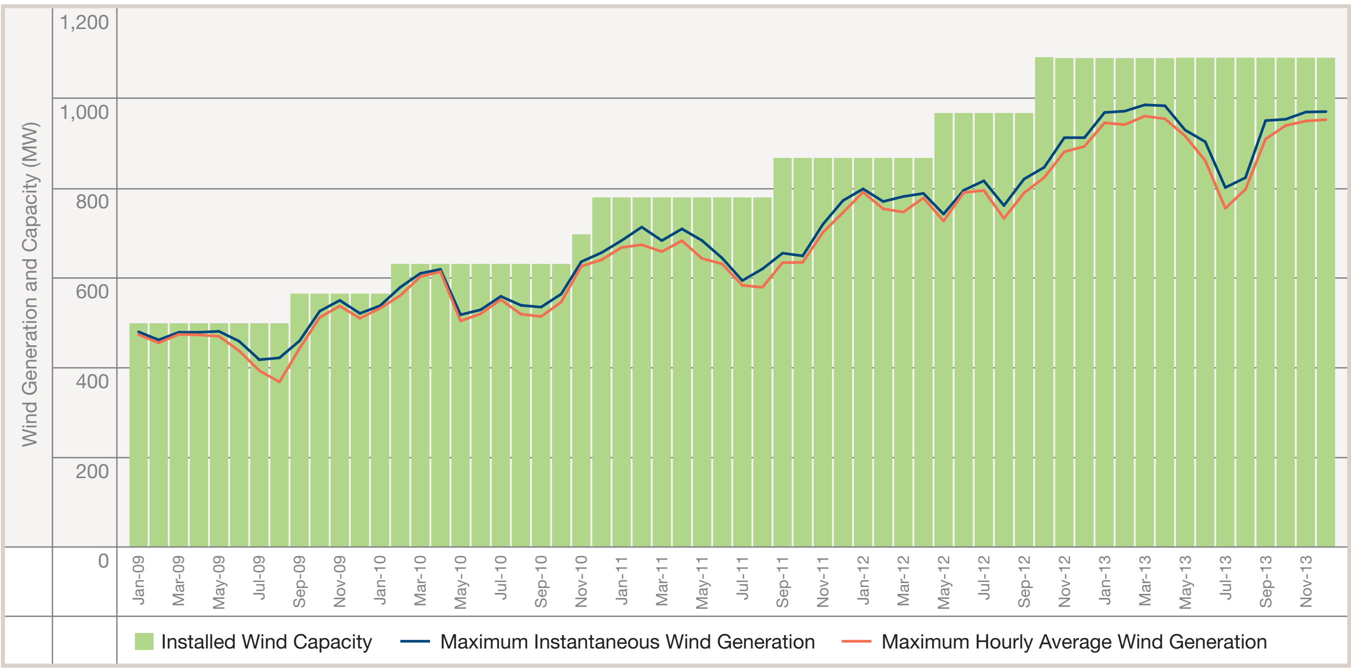
Year	2009	2010	2011	2012	2013
Installed wind capacity at year end *(MW)*	563	777	865	1,087	**1,088**
Total wind generation *(GWh)*	1,503	1,552	2,323	2,574	**3,013**
Wind generation as a percentage of total AIL *(%)*	2.2	2.2	3.2	3.4	**3.9**
Average hourly capacity factor *(%)*	32.9	27.9	33.0	31.2	**31.6**
Maximum hourly capacity factor *(%)*	95.1	97.3	87.6	91.2	**88.1**
Wind capacity factor during annual peak demand *(%)*	2.7	0.0	13.4	4.8	**53.3**

At the end of 2013, wind generation capacity totaled 768 MW in southern Alberta and 320 MW in central Alberta. Though the installed wind generation capacity in 2013 remained largely unchanged from 2012, an additional 350 MW of wind generation is currently under construction and is expected to enter service in 2014.

When wind generation is strongly concentrated in a limited geographic region, price can be highly volatile. Wind power facilities do not specify an offer price for the energy that it generates. Instead, wind power displaces higher-priced generation from the energy market merit order. When wind generation decreases, system controllers must quickly dispatch generation to supply demand and price rises.

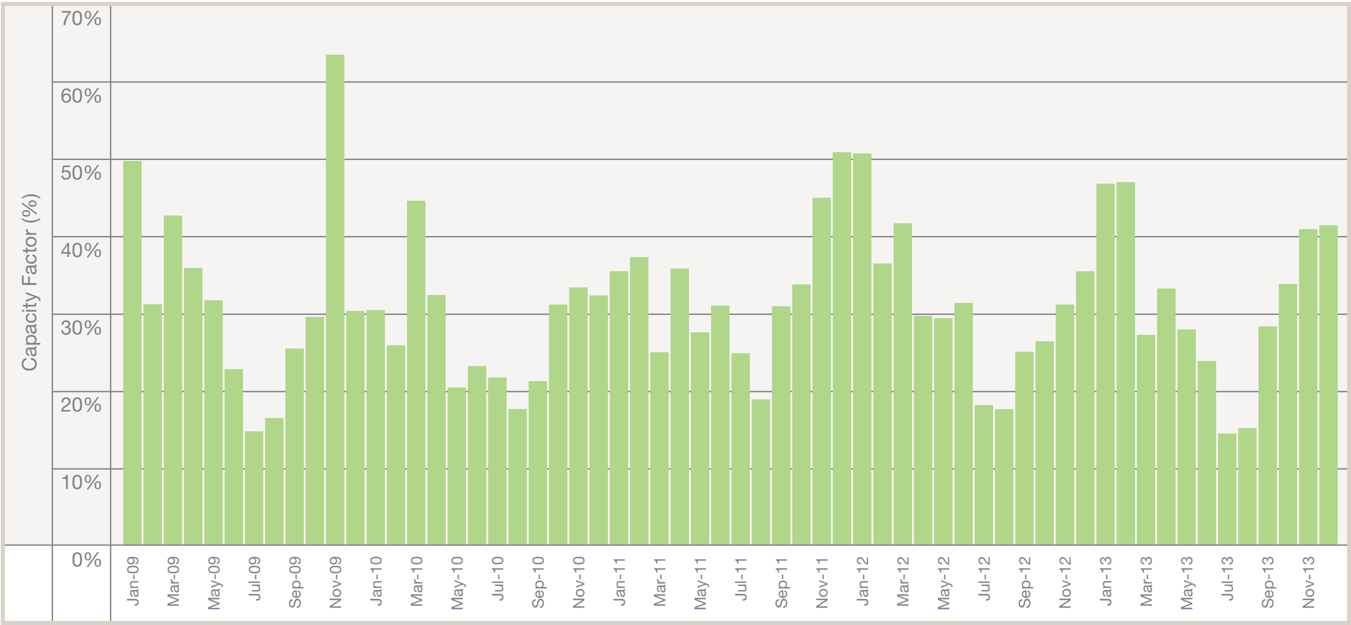
Wind generation in the province was concentrated in southern Alberta until early 2011. Since 2011, the addition of three wind facilities in central Alberta increased the geographic diversification of wind generation across the province. Increased geographic diversification of wind assets minimizes the variability of total wind generation, which reduces the volatility of pool price. Figure 18 shows the installed wind capacity and the maximum instantaneous and hourly wind generation levels in each month.

FIGURE 18
Monthly Installed Wind Capacity



The capacity factor expresses the ratio of the actual energy production to the theoretical maximum energy production. The annual average capacity factor for wind generation in Alberta increased slightly from 31.2 per cent in 2012 to 31.6 per cent in 2013. The wind capacity factor exhibits a seasonal pattern, peaking in winter months and falling in summer months. Over 2013, the monthly average wind capacity factor ranged from a low of 14.5 per cent in July to a high of 47.1 per cent in February. Figure 19 illustrates the monthly average wind capacity factor over the past five years.

FIGURE 19
Monthly Average Hourly Wind Capacity Factor



The wind capacity factor during the 2013 demand peak was higher than average. Wind exercises a moderating effect on temperature: wind generation is usually low during the extremely cold periods that drive peak load. When system demand peaked on December 2, 2013, the hourly wind capacity factor averaged 53.3 per cent. This high wind generation contributed to lower pool prices during the demand peak.

Operating Reserve Costs Rose 13 Per Cent

Operating reserve manages fluctuations in supply or demand on the AIES. Operating reserve is separated into regulating reserve and contingency reserve. Regulating reserve uses automatic generation control to match supply and demand in real time. Contingency reserve maintains the balance of supply and demand when an unexpected system event occurs. Contingency reserve is divided into two products: spinning reserve and supplemental reserve. Spinning reserve must be synchronized to the grid while supplemental reserve does not. Alberta reliability criteria require that spinning reserve provides at least half of the total contingency reserve.

Operating reserve is traded through the Watt-Ex trading system on NGX. For each of the three products of operating reserve—regulating, spinning and supplemental reserve—the AESO must procure both active and standby reserve. Active reserve is used to maintain system reliability under normal operating conditions. Standby reserve provides additional reserve capability for use when active reserve is insufficient. Standby reserve is dispatched after all active reserve has been dispatched, or when procured active reserve cannot be provided due to generator outage or transmission constraint.

The price of operating reserve depends on the commodity. The active reserve market specifies the price of operating reserve as a premium or discount to the pool price. The clearing price of active reserve is the sum of the market price of active reserve and the hourly pool price. The standby reserve market involves two prices: the option premium and the activation price. The premium grants the option to activate standby reserve. If the AESO exercises this option and activates the standby reserve, the provider also receives the activation price.

In 2013, the total cost of operating reserve increased 13.2 per cent to $369 million. Active reserve represents most of the total cost of operating reserve. The AESO requires more active reserve than it does standby reserve and the price of active reserve is indexed to the market pool price. The higher pool price in 2013 raised the clearing price of active reserve and increased the total cost of operating reserve. Table 6 summarizes the total cost of operating reserve over the past five years.

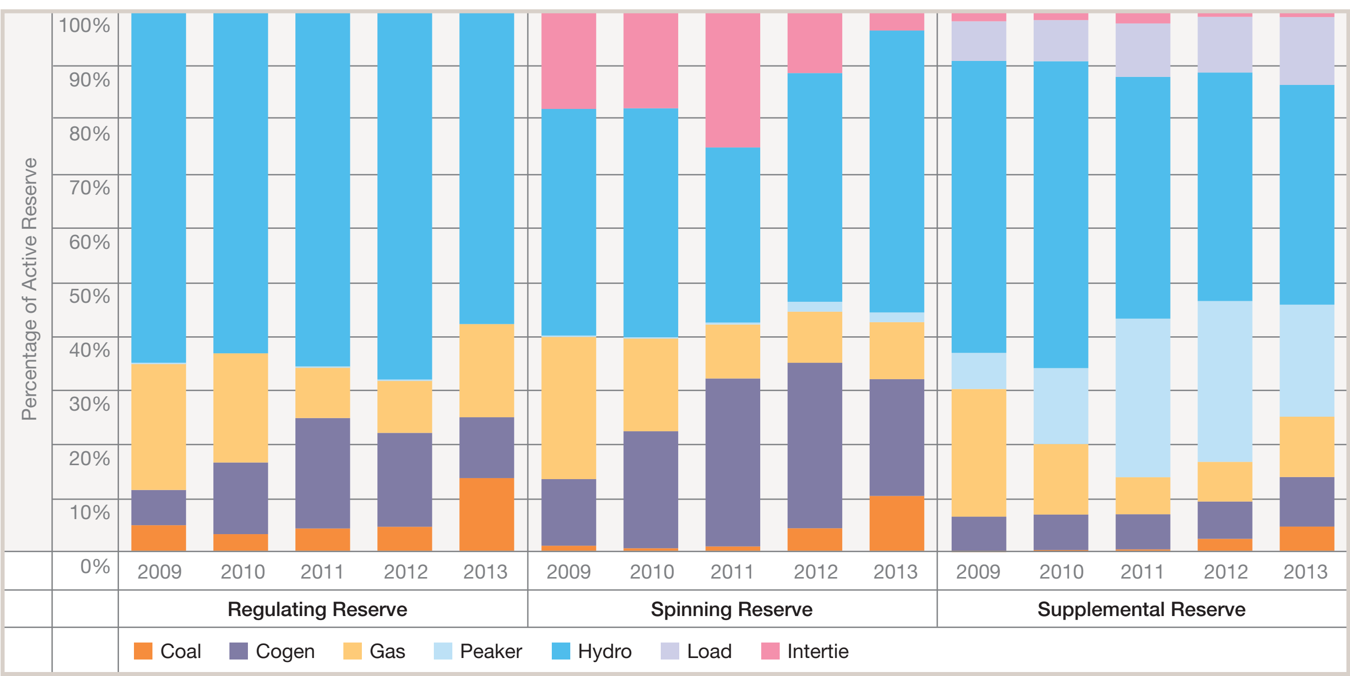
TABLE 6
Annual Cost of Operating Reserve

	Volume *(GWh)*			**Cost** *($ millions)*			
Year	**Active Procured**	**Standby Procured**	**Standby Activated**	**Active Procured**	**Standby Procured**	**Standby Activated**	**Total**
2009	5,660	2,398	59	$89	$10	$5	$104
2010	5,673	2,412	68	$117	$13	$7	$137
2011	5,705	2,311	51	$307	$16	$6	$329
2012	5,901	2,133	58	$296	$26	$5	$326
2013	**6,019**	**2,144**	**77**	**$341**	**$19**	**$10**	**$369**

The technical requirements of operating reserve differ between products. Currently, regulating reserve must be supplied by generation located within the province of Alberta. Neither imports nor load can provide regulating reserve. Imports can provide contingency reserve, but load can only provide supplemental reserve.

In each of the past five years, hydroelectric generation supplied more active reserve than any other asset type. Hydroelectric generation is well suited to providing active reserve due to its fast response to system dispatches and its low marginal cost of generation. Figure 20 illustrates the annual market share of active reserve by asset type.

FIGURE 20
Market Share of Active Reserve by Asset Type



Cost of Dispatch Down Service Fell 67 Per Cent

The system controller issues transmission must-run (TMR) dispatches when transmission capacity is insufficient to support local demand or guarantee system reliability within a specific area in Alberta. TMR dispatches command a generator in or near the affected area to operate at a specified generation level in order to maintain system stability. By dispatching location-specific generation, the system controller averts potential supply shortages or frequency events.

TMR dispatches effectively resolve certain transmission constraints, but also exert an undesired secondary effect on the energy market. Energy dispatched under TMR service displaces higher-priced energy from the merit order and lowers the pool price. This secondary effect interferes with the efficient operation of the electricity market. In December 2007, the AESO introduced the Dispatch Down Service (DDS) to negate the downward effect of dispatched TMR energy and reconstitute the pool price.

DDS offsets the price effect of TMR dispatches by removing dispatched in-merit energy from the merit order. DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2013, DDS offset 45 per cent of dispatched TMR volume. The annual cost of DDS in 2013 totaled $575 thousand. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. In 2013, the average DDS charge was $0.01/MWh, down two cents from its 2012 value.

Over the past two years, transmission reinforcement significantly reduced the operational constraints in northwest Alberta. As a result, dispatched TMR volumes decreased 91 per cent from 2011 and DDS volumes decreased 94 per cent. The annual cost of DDS in 2013 declined 91 per cent from 2011.

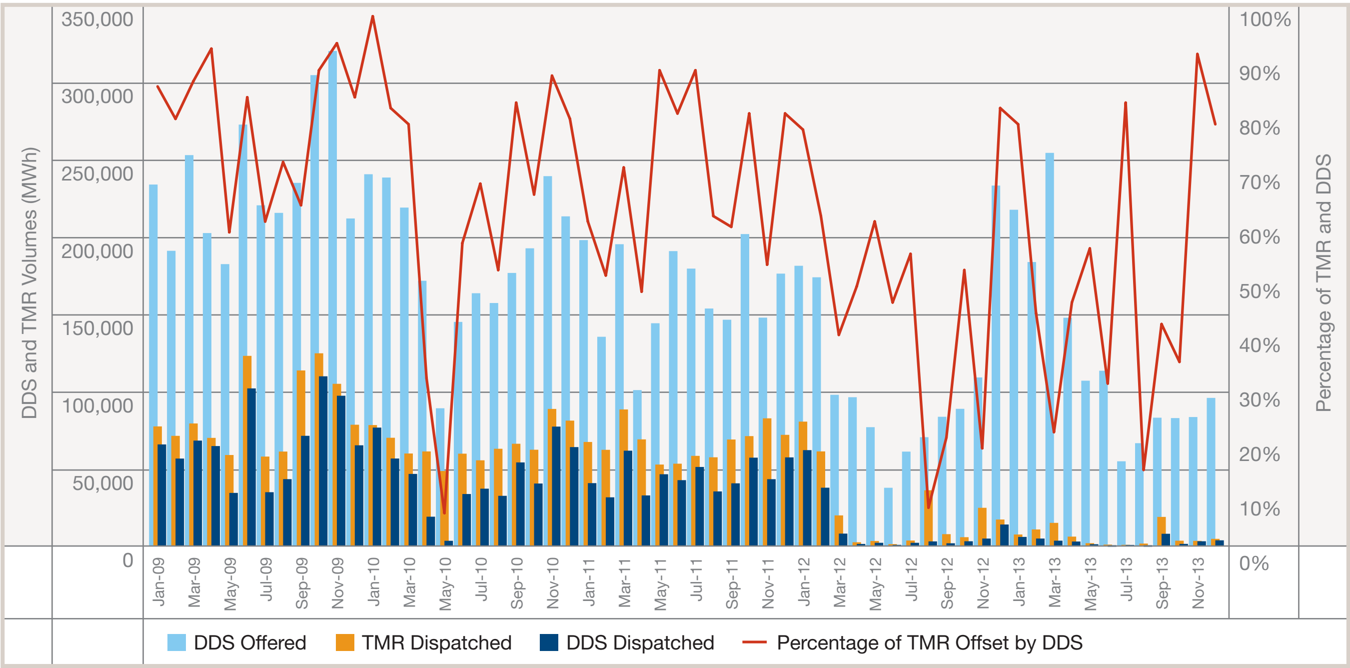
Table 7 summarizes the annual TMR and DDS statistics over the past five years.

TABLE 7
Annual Dispatch Down Service (DDS) Statistics

Year	TMR Dispatched *(GWh)*	DDS Dispatched *(GWh)*	Total DDS Payments *($ millions)*	Average DDS Charge *($/MWh)*
2009	1,018	810	$13.29	$0.23
2010	792	538	$7.71	$0.13
2011	801	537	$6.48	$0.11
2012	260	137	$1.75	$0.03
2013	**71**	**32**	**$0.57**	**$0.01**

Figure 21 shows the monthly volumes of TMR and DDS dispatched over the past five years.

FIGURE 21
Monthly TMR and DDS Dispatched Volumes



Payments to Suppliers on the Margin Increased 16 Per Cent

Payment to suppliers on the margin (PSM) is a settlement rule intended to address price discrepancies between dispatch and settlement intervals. System controllers dispatch offer blocks from the energy market merit order to supply system load. The highest priced offer block dispatched in each minute sets the SMP. At settlement, the hourly pool price is calculated as the simple average of SMP. When system controllers dispatched an offer block that was priced above the settled pool price, that offer block may qualify for compensation under the PSM rule.

The cost of PSM represents a small fraction of the overall market value. In 2013, PSM totaled $2.6 million, or 0.05 per cent of the total market value. Table 8 summarizes the cost of PSM over the past five years.

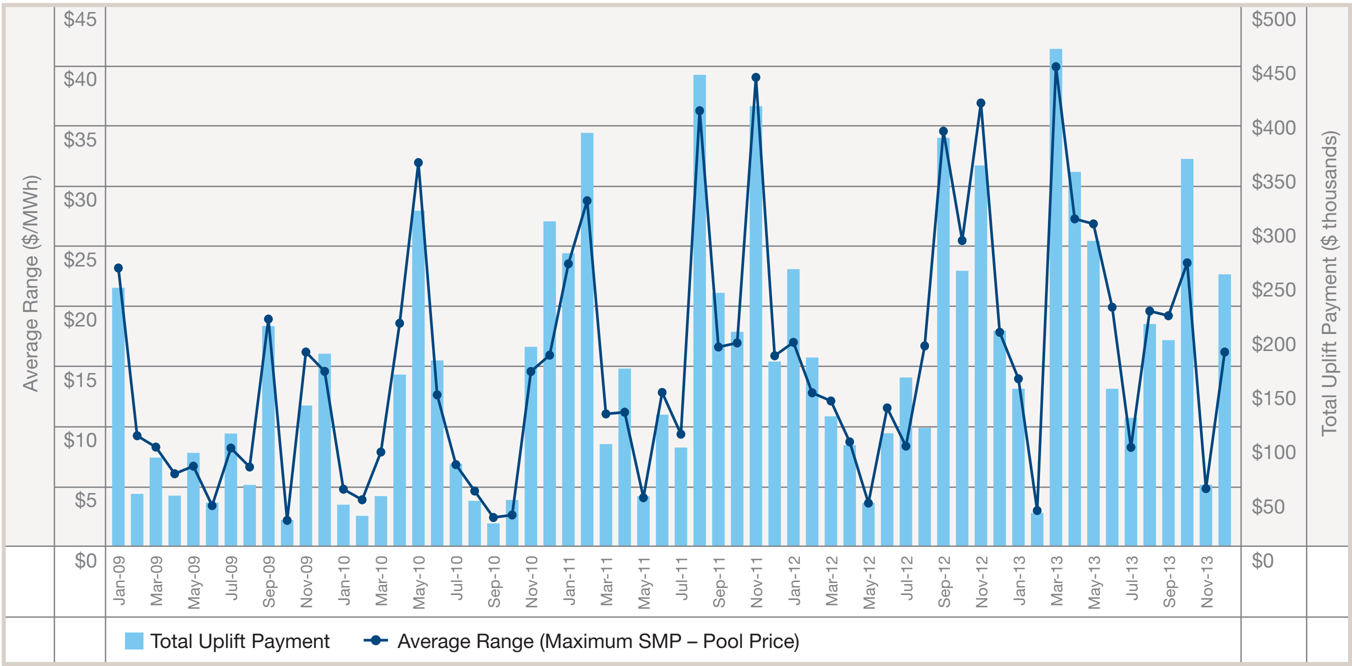
TABLE 8
Annual Payments to Suppliers on the Margin Statistics

Year	Total PSM *($ millions)*	Average Range between the Maximum SMP and the Pool Price *($/MWh)*	Average Charge *($/MWh)*	Market Value *($ millions)*	Percentage of Market Value
2009	1.2	10.29	0.02	2,734	0.05
2010	1.4	10.60	0.02	2,896	0.05
2011	2.6	18.72	0.04	4,580	0.06
2012	2.2	17.11	0.04	3,903	0.06
2013	**2.6**	**18.70**	**0.04**	**4,862**	**0.05**

Note: Market value is determined by the pool price multiplied by the AIES load in the hour

The increased cost of PSM reflects increased volatility in the system marginal prices within each settlement period. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price. The annual average price range increased from $17.11/MWh in 2012 to $18.70/MWh in 2013. Figure 22 shows the monthly average price range over the past five years.

FIGURE 22
Monthly Payments to Suppliers on the Margin



Final Notes

As the market evolves throughout 2014 and into the future, the AESO will continue to monitor, analyze and report on market outcomes. As part of this monitoring process, the AESO provides real-time, historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. Reports are produced with the best information available at the time and will change as better information becomes available. The AESO encourages stakeholders to send any comments or questions on this report, or any other market analysis questions to **market.analysis@aeso.ca**
We appreciate your input.

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