aeso
ALBERTA
ELECTRIC
SYSTEM
OPERATOR

2014 Annual Market Statistics

Contents

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 2014, 196 participants in the Alberta wholesale electricity market transacted approximately $5 billion of energy. The annual average pool price for wholesale electricity fell 38 per cent from its previous-year value to $49.42/MWh. The average natural gas price increased 41 per cent, averaging $4.24/GJ. The combination of falling energy prices and rising gas prices depressed the average market heat rate by 58 per cent to 11.5 GJ/MWh.

Alberta load growth remained strong in 2014. The average Alberta Internal Load increased by three per cent over 2013 values, and hourly load set new seasonal and overall peak records.

Price	2014	Year/Year Change
Pool price	$49.42/MWh	-39%
Gas price	$4.24/GJ	+41%
Heat rate	11.5 GJ/MWh	-58%

Load	2014	Year/Year Change
Average AIL	9,127 MW	+3%
Winter peak	11,169 MW	+0%
Summer peak	10,419 MW	+4%

In 2014, installed generation capacity increased 11 per cent to 16,151 MW, buoyed by new gas and wind generation facilities; however, most of this capacity increase represented generation that was not yet operational. Energy produced through coal generation continued to serve most Alberta system demand. Supply adequacy measures indicate that the Alberta electric system continues to operate reliably, and that the Alberta wholesale market continues to function efficiently.

Net imports to Alberta in 2014 decreased 35 per cent from 2013 volumes. An operational outage on the Saskatchewan intertie limited imports, and prices in Alberta encouraged exports to neighbouring jurisdictions. Imports from the Western Electricity Coordinating Council (WECC) region fell two per cent from 2013 levels. British Columbia supplied two-thirds of imports from the WECC region.

Lower pool prices in 2014 reduced the cost of operating reserve by 50 per cent to $185 million. The cost of Dispatch Down Service increased 109 per cent to $1.2 million due to increased usage. The cost of payments to suppliers on the margin decreased 56 per cent to $1.2 million.

Price of Electricity

Pool Price Fell 38 Per Cent

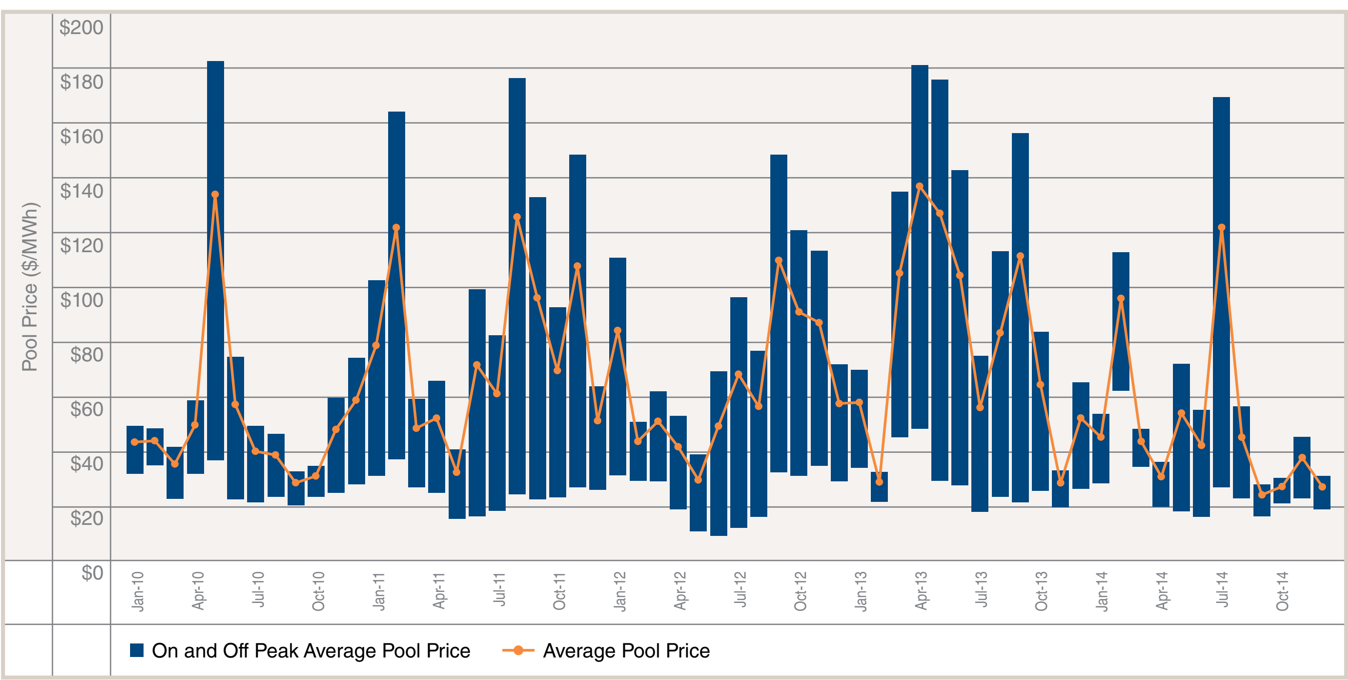
Pool price averaged $49.42/MWh over 2014—a decrease of 38 per cent from 2013. The AESO separates each day into on-peak and off-peak periods: on-peak periods start at 7:00 am and end at 11:00 pm; the remaining eight hours in each day make up the off-peak period. In 2014, the average pool price during the on-peak period fell 42 per cent to $61.48/MWh, and the off-peak average pool price fell 11 per cent to $25.28/MWh. Table 1 summarizes historical price statistics over the ten-year period between 2005 and 2014.

TABLE 1
Annual Pool Price Statistics

Pool Price *($/MWh)*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Average pool price	70.36	80.79	66.95	89.95	47.81	50.88	76.22	64.32	80.19	**49.42**
On-peak average pool price	85.35	101.41	84.37	112.97	58.04	62.99	102.22	84.72	106.13	**61.48**
Off-peak average pool price	40.37	39.54	32.11	43.92	27.36	26.67	24.22	23.51	28.29	**25.28**
Maximum pool price	999.99	999.99	999.99	999.99	999.99	999.99	999.99	1,000.00	1,000.00	**999.99**
Minimum pool price	4.66	5.42	0.00	0.00	0.10	0.00	0.00	0.00	0.00	**7.88**

The pool price sets the wholesale price of electricity, and influences the cost of electricity for retail customers on flow-through contracts. Figure 1 shows the monthly distribution of prices over the past five years. Over 2014, the monthly average pool price ranged from a low of $23.98/MWh in September to a high of $122.54/MWh in July.

FIGURE 1
Monthly Average Pool Price

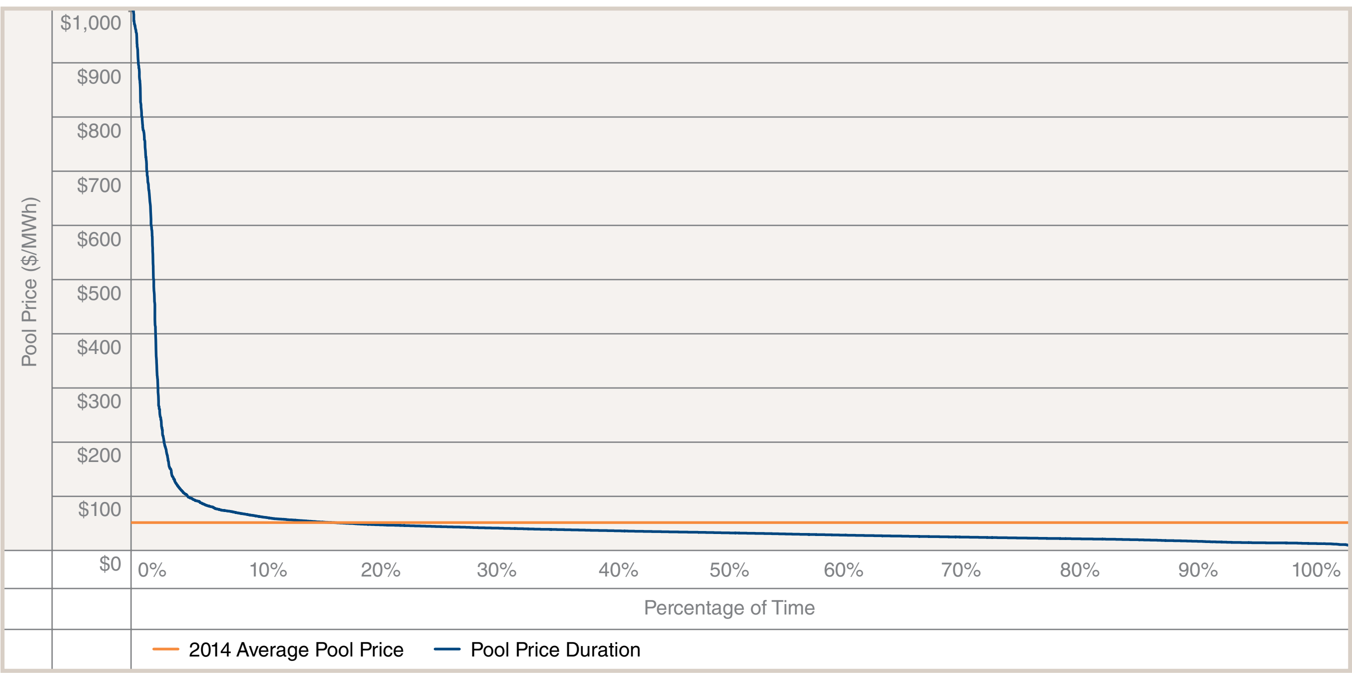


The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. Generators submit offers specifying the amount of power that they will provide in a one hour settlement period and the price at which they are willing to supply it. This offer price can 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 merit order.

The system controller dispatches generating units from the merit order in ascending order of price until supply satisfies demand. Dispatched units are said to be in merit; units that are not dispatched are out of merit. The highest priced in-merit unit is called the marginal unit, and its offer price sets the system marginal price for one minute. The pool price is the simple average of the sixty system marginal prices in the one-hour settlement interval. All energy generated in the hour receives a uniform clearing price—the pool price—regardless of its offer price.

Price duration represents the percentage of hours in which pool price equaled or exceeded a specified level. Figure 2 shows pool price duration over the 2014 year. As usual, the annual average price of electricity was heavily influenced by infrequent high-priced hours. The hourly price of electricity exceeded the annual average in only 17 per cent of hours, or approximately one hour of every six; however, because electricity was significantly more expensive in these hours, they exert strong upward influence on the average price.

FIGURE 2
2014 Pool Price Duration Curve



Supply shortfall conditions occur when system demand exceeds the total generation in the merit order that is available for dispatch. Supply shortfall conditions can threaten the stability of the AIES. To preserve system reliability, system controllers manage supply shortfall events according to a prescribed mitigation procedure. The final step in this procedure requires the system operator to curtail firm load. When the system operator is forced to curtail load, the system marginal price is set to the administrative price cap of $1000.00/MWh. There were no load-curtailment events in 2014. System controllers last curtailed firm load on July 2, 2013.

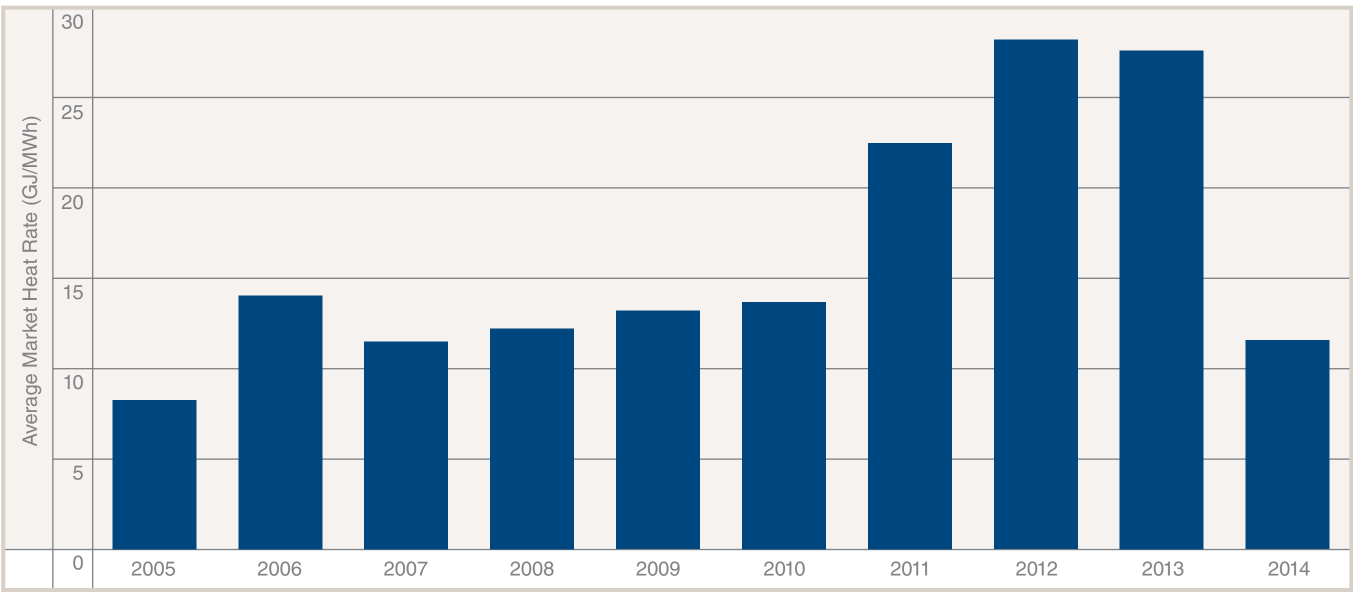
Supply surplus events occur when the supply of energy offered to the market at $0/MWh exceeds system demand. During a supply surplus event, in-merit generation must be curtailed to preserve system stability. The Alberta electric system was in supply surplus conditions for eleven minutes in May 28, 2014. The previous supply surplus event occurred on July 7, 2013.

Heat Rate Fell 58 Per Cent

The market heat rate expresses the price of electricity in units of natural gas instead of dollars. This measure represents an economic threshold for gas-fired generation. When the market heat rate exceeds the operational heat rate of a gas-fired generation facility, the plant earns money by operating; otherwise, it is cheaper to procure energy from the market.

The hourly market heat rate is the ratio of the pool price to the daily price of natural gas. The annual market heat rate is the simple average of all hourly heat rates over the year. In 2014, natural gas prices increased 41 per cent to $4.24/GJ due largely to strong demand for heating fuel during the polar vortex. The combination of declining electricity prices and rising gas prices forced the annual market heat rate down 58 per cent to 11.5 GJ/MWh. Figure 3 shows the market heat rate over the past ten years.

FIGURE 3
Annual Market Heat Rate



Alberta Internal Load

Average Load Grew Three Per Cent

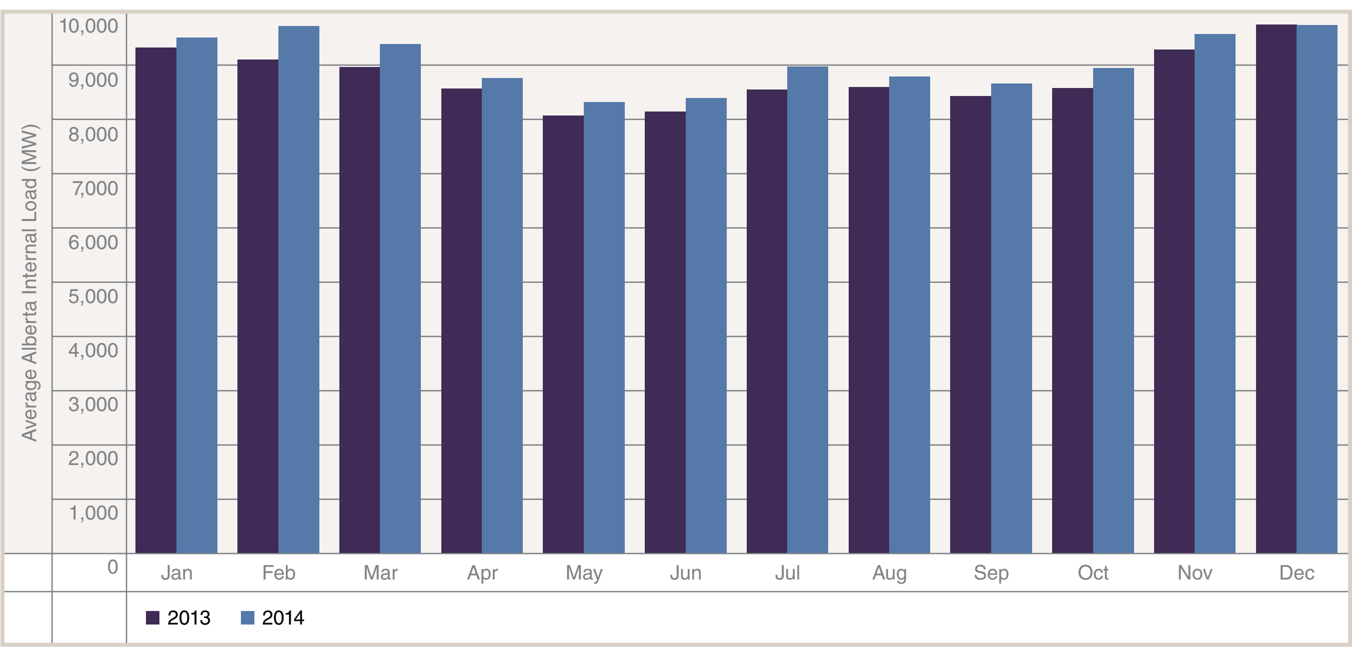
In 2014, the average hourly Alberta Internal Load (AIL) grew three per cent to 9,127 MW, and peak load increased 0.3 per cent to a new record of 11,169 MW. This load growth was driven by increased oilsands demand in northeastern Alberta and increased commercial and residential demand in urban areas. Table 2 summarizes annual demand statistics over the past ten years.

TABLE 2
Annual System Demand Statistics

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total AIL (GWh)	66,267	69,371	69,661	69,947	69,914	71,723	73,600	75,574	77,451	**79,949**
Average load (MW)	7,565	7,919	7,952	7,963	7,981	8,188	8,402	8,604	8,841	**9,127**
Maximum load (MW)	9,580	9,661	9,701	9,806	10,236	10,196	10,226	10,609	11,139	**11,169**
Minimum load (MW)	6,104	6,351	6,440	6,411	6,454	6,641	6,459	6,828	6,991	**7,162**
Annual growth in average load (%)	1.8	4.7	0.4	0.1	0.2	2.6	2.6	2.4	2.8	**3.2**
Load factor (%)	79.0	82.0	82.0	81.2	78.0	80.3	82.2	81.1	79.4	**81.7**

Monthly average load increased from 2013 levels in every month except December. Monthly average load grew by a maximum of seven per cent in February due to cold temperatures across Alberta. An extended period of mild winter temperatures reduced average load in December by 0.1 per cent. Figure 4 shows the monthly load growth between 2013 and 2014.

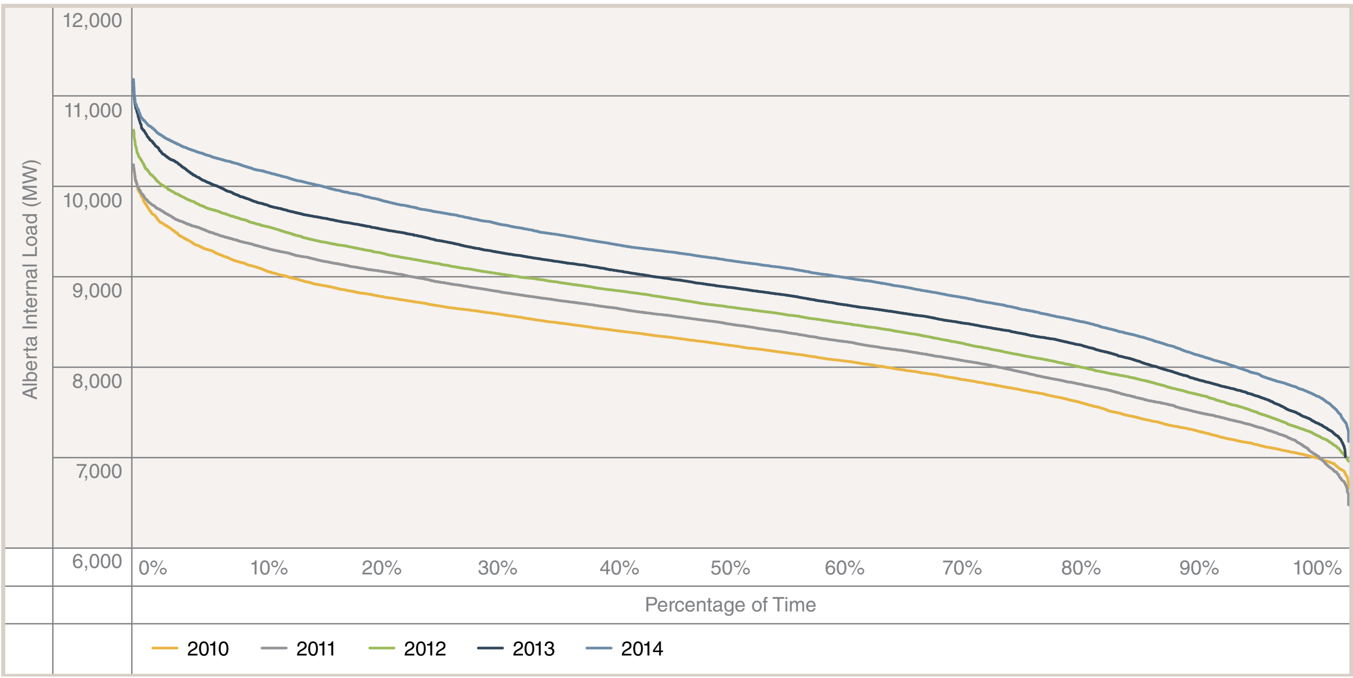
FIGURE 4
Monthly Average Load



Load duration represents the percentage of time that the load was greater than or equal to the specified load. Figure 5 plots the annual load duration curve for each of the last five years. Load growth in 2014 represented a consistent and largely uniform increase from 2013 load; however, peak loads increased only slightly due to milder winter temperatures in late 2014 compared to those in 2013.

FIGURE 5

Annual Load Duration Curves

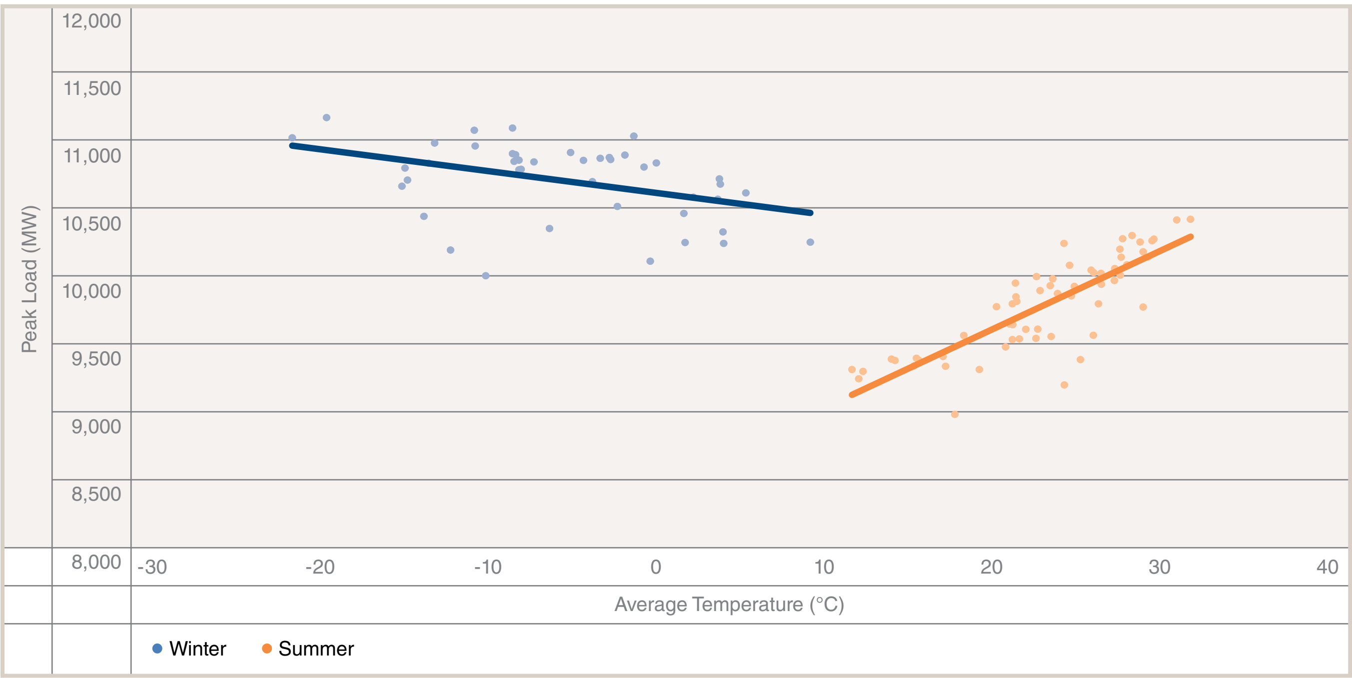


Seasonal Demand Sets Peak Records

Temperature exerts a strong influence on system load. The Alberta Internal Load tends to increase as the temperature becomes more extreme. Figure 6 illustrates the relationship between temperature and daily peak demand in weekdays over 2014. On winter weekdays, a decrease of one degree Celsius increased peak load by an average of 17 MW. During summer weekdays, an increase of one degree Celsius increased peak load by an average of 59 MW. 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.

FIGURE 6

Daily Peak Load and Average Temperature

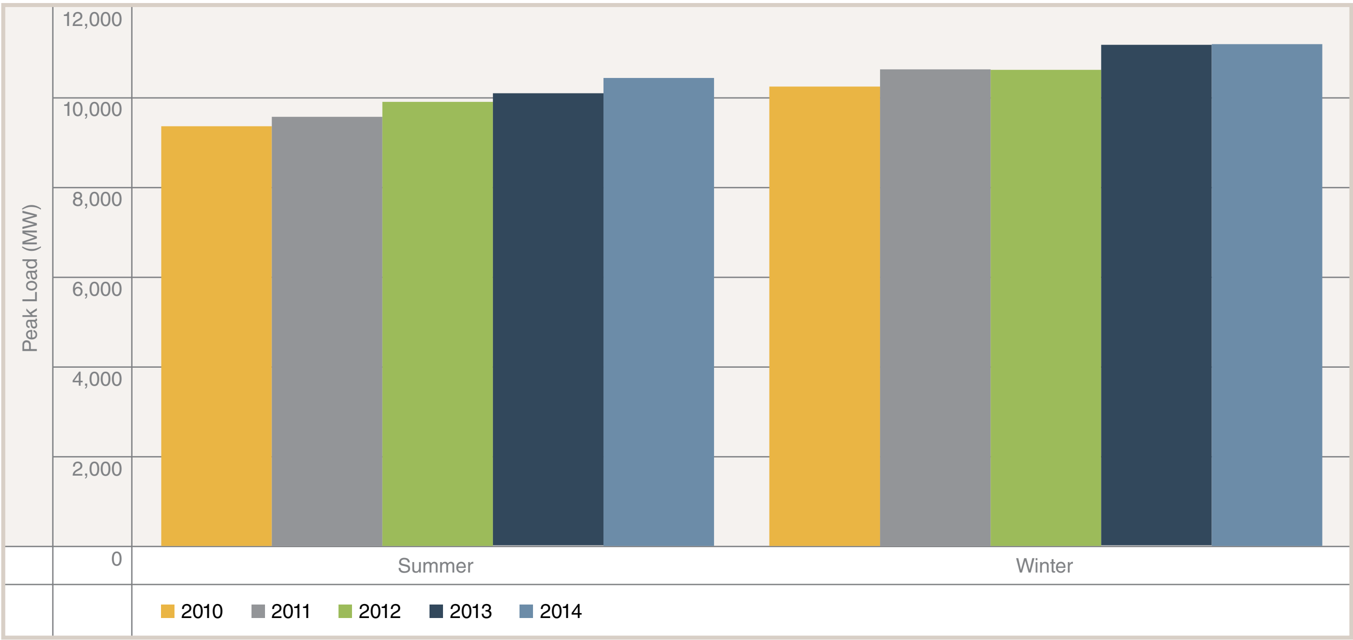


Alberta peak demand is usually set during periods of extreme temperatures: summer peaks are usually driven by heat; winter peaks are usually driven by cold. Demand in 2014 set new records for peak load in both the summer and winter seasons. The summer season starts on May 1 and ends on October 31. On July 30, 2014, high temperatures drove system load to a new summer peak of 10,419 MW. The previous summer peak was set one year earlier, on July 2, 2013, at 10,063 MW.

The winter season starts on November 1 and ends on April 30 of the following year[1]. On December 29, 2014, cold temperatures drove Alberta load to a new winter and overall peak record of 11,169 MW. The previous highest winter and system peak was set on December 2, 2013, when system load reached 11,139 MW. Figure 7 illustrates the winter and summer peak demand over the past five years.

[1] Winter 2014 data in this report is limited to observations between November 2014 and December 2014.

FIGURE 7
Seasonal Peak Load



Installed Generation

Total Generation Capacity Increased 11 Per Cent

The total installed generation capacity in Alberta increased 11 per cent to 16,151 MW in 2014. Figure 8 shows the annual installed capacity at the end of each year for the past five years. The increase in installed capacity over the past year was mostly driven by new gas and wind generation plants. ENMAX added 873 MW of generation capacity with its new Shepard combined-cycle gas plant. Imperial Oil increased generation capacity by an additional 254 MW from new cogeneration facilities at its Kearl and Nabiye oilsands projects. New wind generation in southern Alberta increased installed capacity by 346 MW: 300 MW at the Blackspring Ridge wind farm, and 46 MW at Oldman 2. A number of smaller facilities also connected to the grid.

Although capacity growth was higher in 2014 than in any other year over the past decade, most of the increase did not immediately translate into additional energy generation: the Shepard, Kearl, and Nabiye facilities are not expected to start commercial operation until 2015.

FIGURE 8
Annual System Generation Capacity

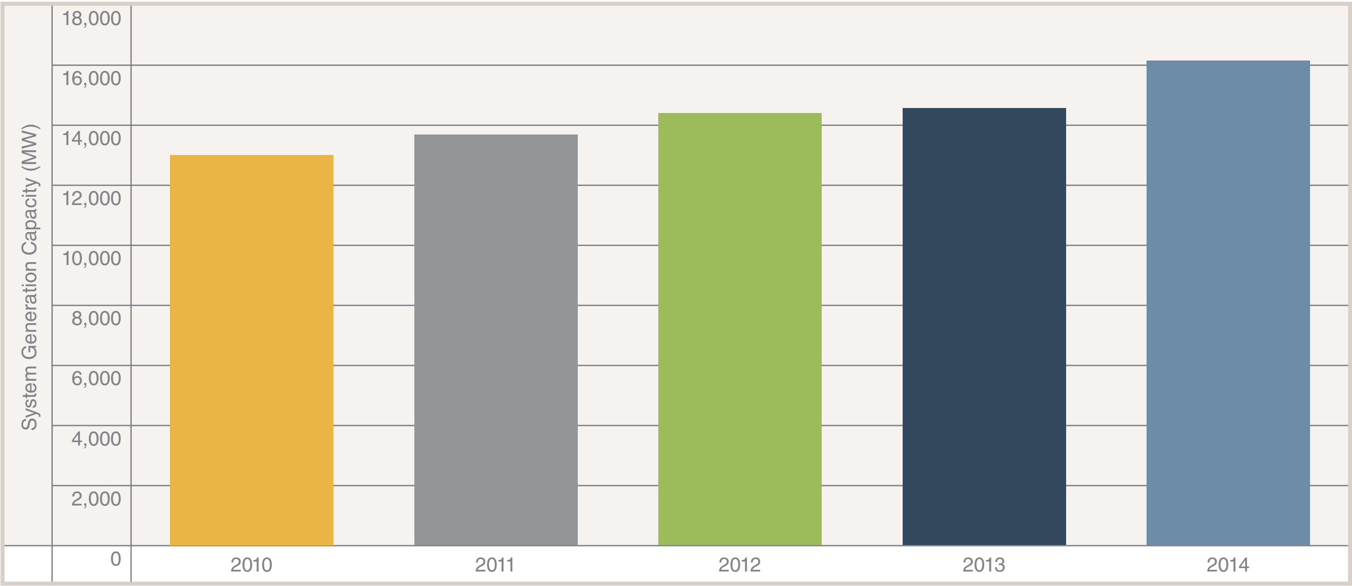
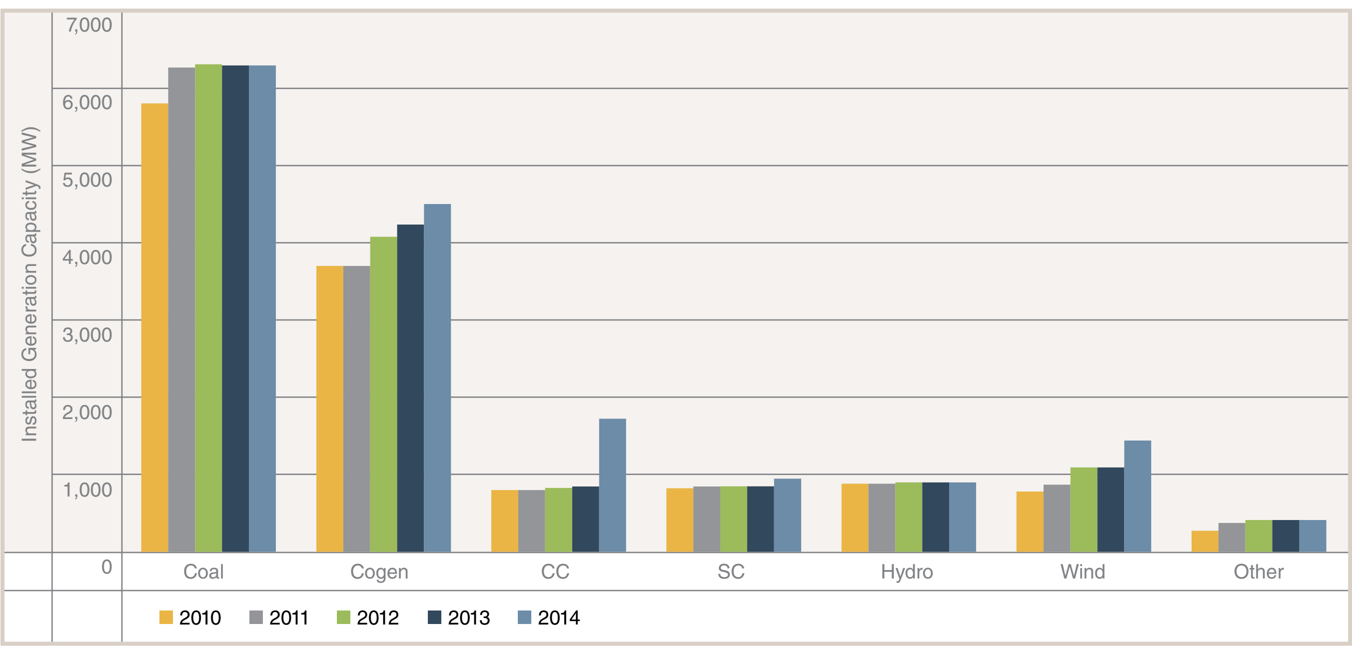


Figure 9 shows annual installed capacity by generation technology over the past five years. In 2014, the total installed capacity of gas-fired generation—which includes cogeneration, combined-cycle (CC), and simple-cycle (SC) technologies—exceeded that of coal generation for the first time.

FIGURE 9
Annual Installed Capacity by Generation Technology



Coal Fleet Back to Full Operation

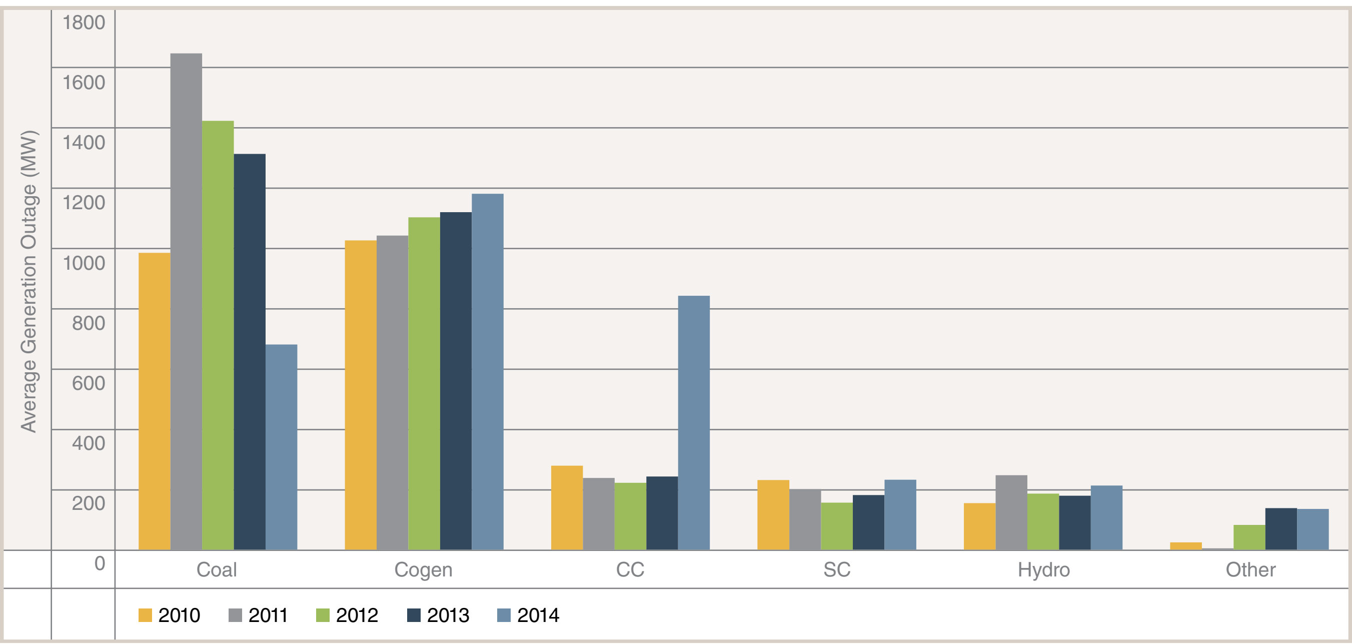
Operational issues at generating units can limit the generation capability of the system. The maximum capability (MC) of a unit represents the power that an asset can generate under optimal conditions. The available capability (AC) represents the power that an asset can generate under operational conditions. When operational issues reduce AC below MC, the difference is called the generation outage. Generation outages can be either partial (when AC is non-zero) or total (when AC falls to zero). Unit operators must provide an acceptable operational reason to system controllers in order to justify any unit outage.

Each asset must offer its AC into the energy market. Baseload generation technologies, including coal generation, tend to supply energy to the market at low prices. When baseload generation is unavailable, 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.

Figure 10 illustrates average outages by asset type over the past five years.

FIGURE 10

Annual Average Generation Outages



Coal outages fell in 2014 due to the return of generation assets from extended operational outages. In late 2013, three coal generation facilities returned to service: Sundance 1 resumed commercial operation in September, and both Sundance 2 and Keephills 1 returned in October. The return of baseload generation displaced the higher-priced energy that served load during the operational outages, and contributed to lower pool prices in 2014.

The spike in combined-cycle gas outages in 2014 is mainly attributable to the addition of the Shepard plant. The Shepard plant added capacity in late April 2014; however, it is not expected to start commercial operation until 2015. During the commissioning period over the last eight months of 2014, the unit reported total or near-total partial outages. This reporting convention increased the outage calculation by 586 MW. Excluding Shepard from the calculation reduces combined-cycle gas outages over 2014 to 258 MW.

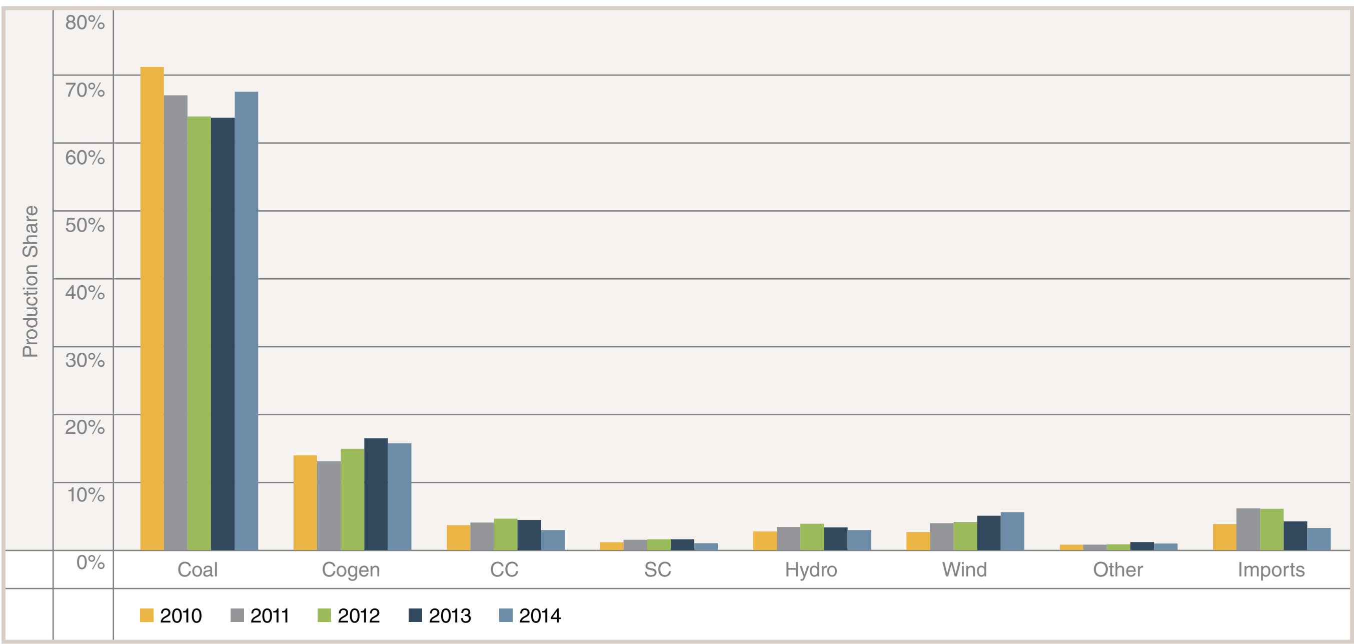
Coal Generation Serves Most Alberta Demand

Production share represents the percentage of total energy delivered to the Alberta electric system by each generation technology, including imports. Coal generation produces the majority of energy used on the system; coal facilities produce more energy than all other technologies combined. Although the production share of coal generation has declined over the past five years, increased coal availability in 2014 temporarily reversed the long-term trend of decreasing production share.

Production share is calculated from the energy delivered to the interconnected electric system. This methodology does not include energy that serves behind-the-fence load at the generating facility. Cogeneration gas accounts for a much smaller percentage of production than its installed capacity would imply because many cogeneration gas facilities serve behind-the-fence load at large industrial sites. Figure 11 shows production share by generation technology over the last five years. Percentages in each year sum to 100 per cent.

FIGURE 11

Annual Production Share

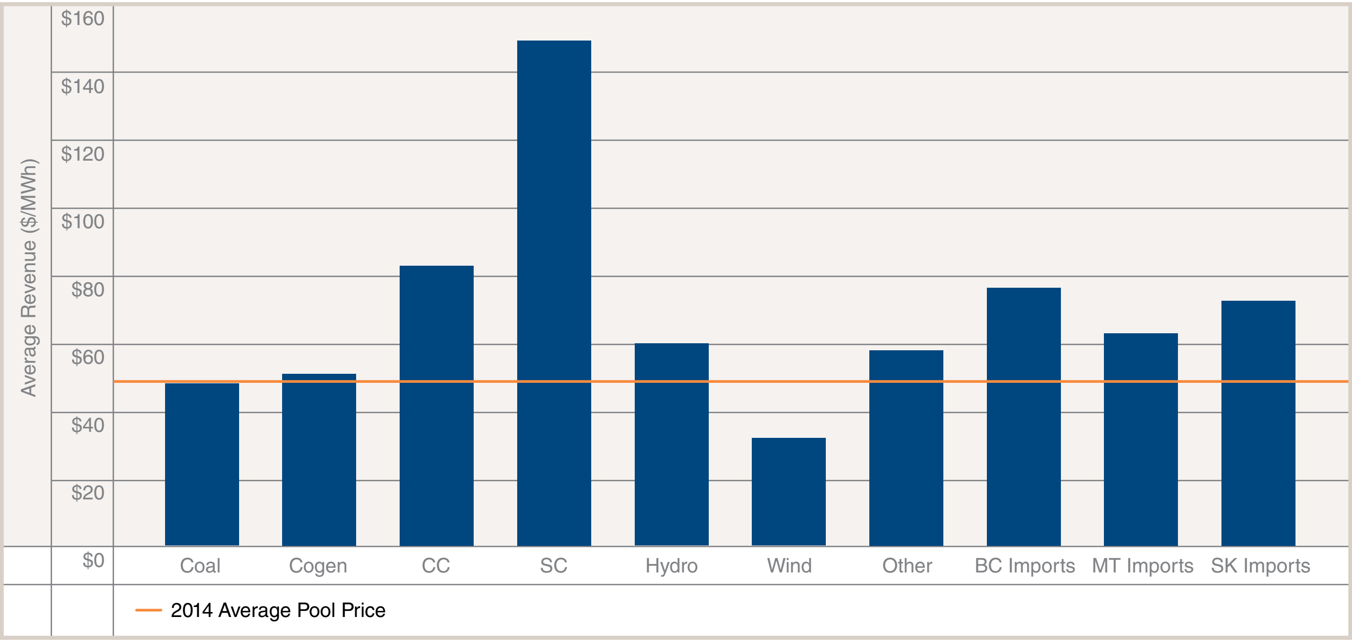


Simple-Cycle Gas Realizes Highest Average Revenue; Wind, the Lowest

Average revenue represents the average pool price realized in the wholesale market for energy delivered to the grid. Figure 12 illustrates the average revenue realized by different generation technologies over the 2014 year. The red line represents the annual average pool price.

FIGURE 12

2014 Average Revenue by Generation Technology



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 strong demand drives pool price higher. The combination of offer strategy and market conditions determines the average revenue that each asset type receives.

Baseload generation technologies optimally operate throughout the entire day. These baseload technologies include coal and cogeneration gas. 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. 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. In 2014, coal generation received a one per cent discount to pool price, and cogeneration gas realized a five per cent premium.

Peaking generation technologies achieve greater operational flexibility than baseload generation, but at higher cost. The combustion turbines used in simple-cycle gas 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. In 2014, simple-cycle gas received a 208 per cent premium to pool price.

Although both wind generation and importers are price-takers, the average revenue received by each technology differs dramatically. Wind generation cannot control its operational schedule. Wind facilities generate electricity according to local weather systems. Wind generation displaces marginal units from the energy market merit order, reducing SMP and lowering its average revenue. In 2014, wind generation received a 35 per cent discount to pool price.

Like wind, imported energy displaces marginal units from the merit order, and drives prices lower; however, unlike wind, importers can choose when to operate. Importers transfer energy into Alberta only during favourable economic conditions. This operational flexibility is reflected in higher average revenues. In 2014, the premium to pool price on imported energy ranged between 30 and 57 per cent.

Supply Adequacy

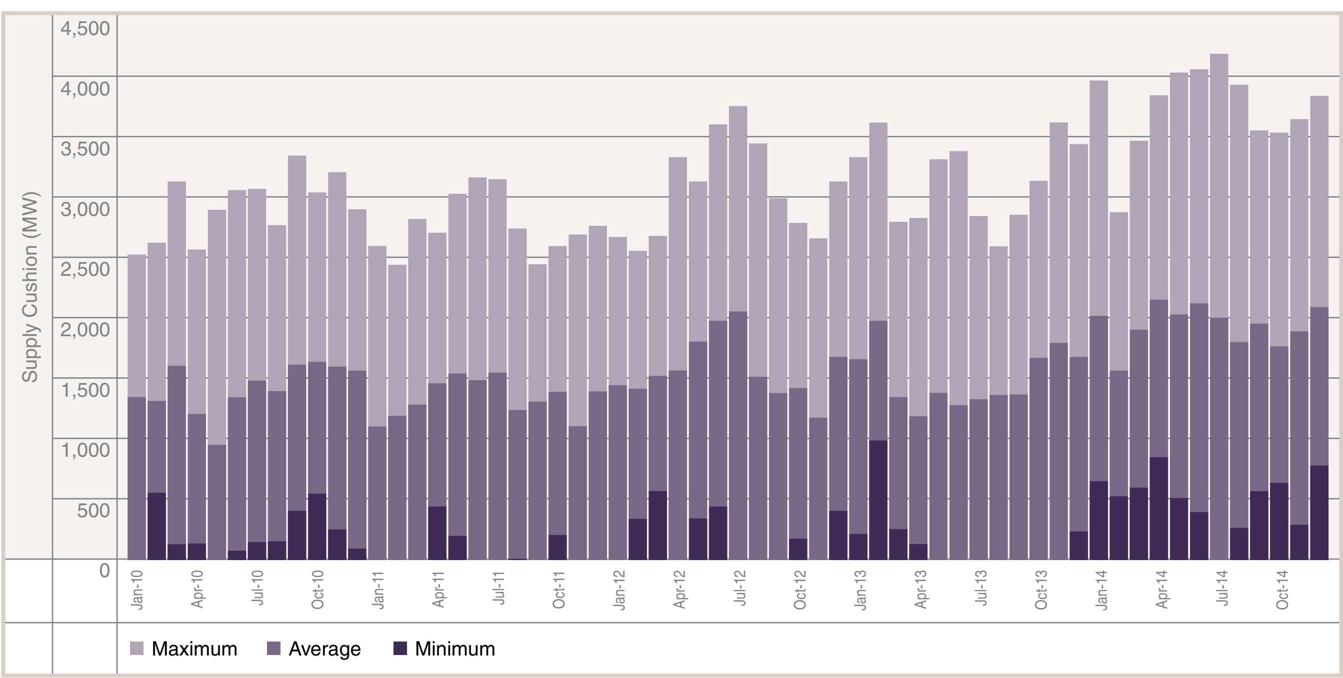
Supply adequacy expresses the ability of the system to serve demand. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin.

Supply Cushion Indicates Greater System Reliability

The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after system demand is served. Large supply cushions indicate greater reliability because more energy is available to respond to unplanned outages. Over 2014, the average supply cushion increased 29 per cent to 1,933 MW due to the return of coal-fired generation capability in late 2013.

Supply-shortfall conditions indicate that the supply cushion is zero. When the supply cushion falls to zero, system controllers may be required to take action to resolve supply shortfall conditions. Over 2014, the only supply shortfall event occurred on July 30, 2014, when the AESO declared an Energy Emergency Alert for a six-hour period. Supply shortfall conditions do not necessarily require system controllers to curtail firm load. System controllers were able to resolve the 2014 supply shortfall event without curtailing firm load. Figure 13 shows the monthly supply cushion over the past five years.

FIGURE 13
Monthly Supply Cushion



Reserve Margin Indicates Efficient Wholesale Market

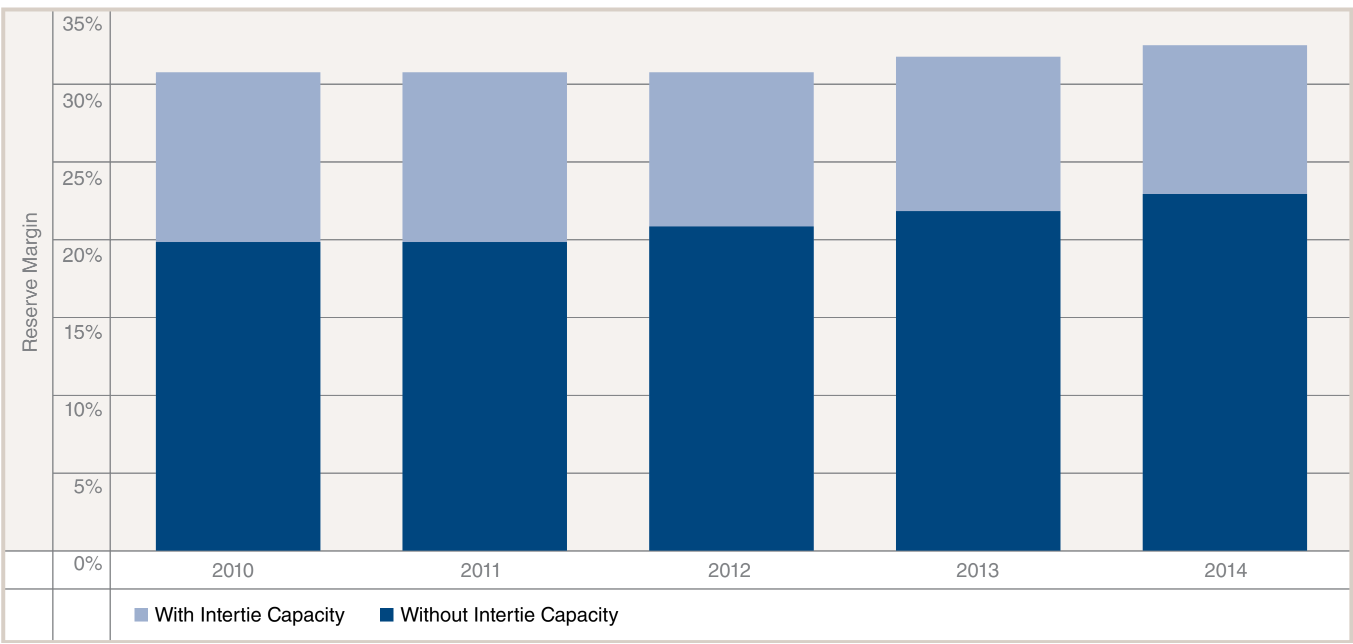
Reserve margin represents the system generation capability in excess of that required to serve peak system load. The annual reserve margin is calculated both including and excluding the combined import capacity of interties in order to evaluate system reliance on generation outside Alberta. In this calculation,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

Generation capability reflects extended unit outages and the commissioning dates of new generation. Reserve margin calculations in 2011 and 2012 exclude the generation capability of the two Sundance coal units to reflect the extended forced outage. Reserve margin calculations in 2014 exclude the Shepard combined-cycle gas generation plant and the cogeneration plants at Nabiye and Kearl, which did not start commercial operations in 2014.

Figure 14 shows the annual reserve margin over the past five years.[2] In 2014, the reserve margin remained reasonably constant from 2013 levels, indicating that excess generation capability increased at the same rate as peak system load. The stability of the reserve margin over time indicates that the Alberta wholesale market is functioning efficiently, as the market has encouraged developers to build new generation to serve increasing system load.

FIGURE 14

Annual Reserve Margin



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

Imports and Exports

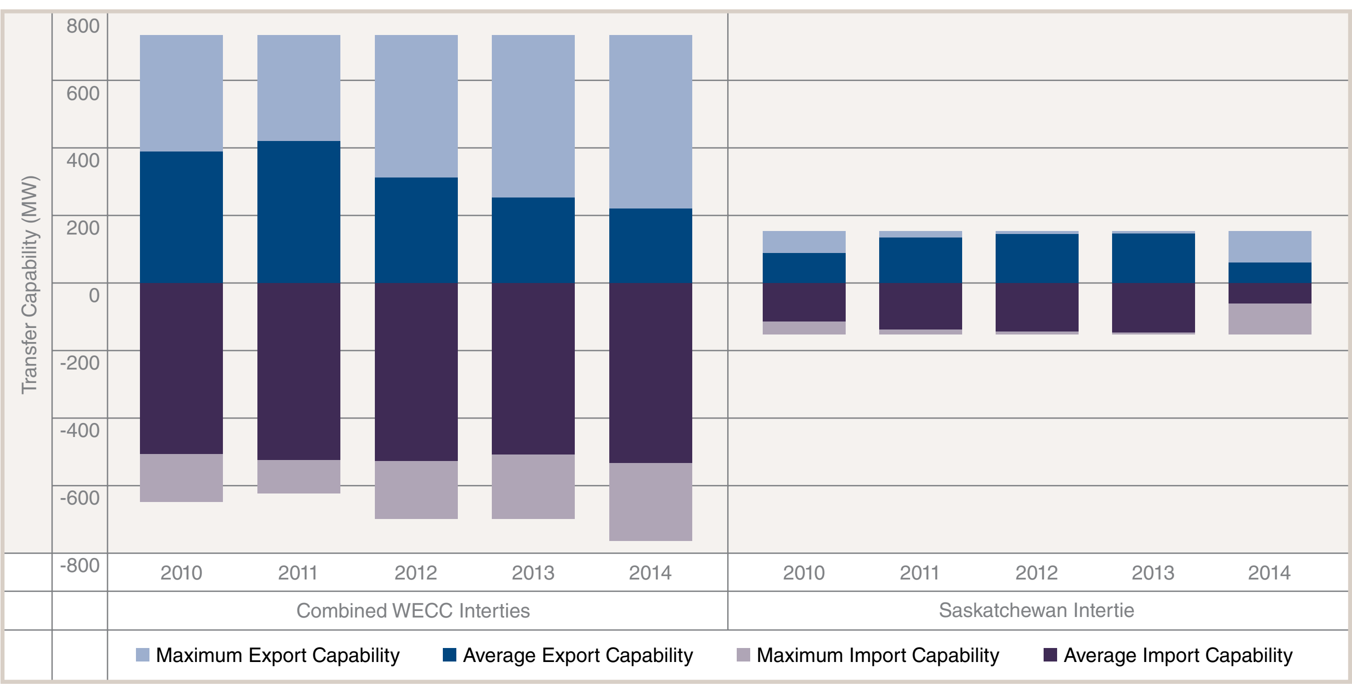
Alberta has been a net importer of electricity for the last 12 years, and in 18 of the 19 years since 1995. Before 2013, imports and exports flowed between Alberta and its two provincial neighbours: British Columbia and Saskatchewan. In September 2013, the Montana-Alberta Tie Line (MATL) started commercial operation. This new intertie permitted Alberta to transfer energy directly across the border with the United States.

System reliability standards determine the total energy that can be transferred between jurisdictions. The available transfer capability (ATC) specifies the maximum imports and exports on an intertie. The combined operating limit sets the maximum net import capability between Alberta and the rest of the Western Electricity Coordinating Council (WECC) region–which includes BC and Montana, but excludes Saskatchewan. The Alberta system operating limit specifies the maximum net import capability between Alberta and all neighbouring jurisdictions.

Updated System Studies Increase Transfer Capability

Figure 15 shows the import and export transfer capabilities over the past five years. In 2014, the combined operating limit on imports from the WECC region increased to 765 MW based on updated system studies. The average import transfer capability between Alberta and the rest of the WECC region increased five per cent from its 2013 value, and the average export transfer capability declined 13 per cent. An extended operational outage on the intertie between Alberta and Saskatchewan reduced its average import and export transfer capabilities by 60 per cent.

FIGURE 15
Annual Intertie Transfer Capability

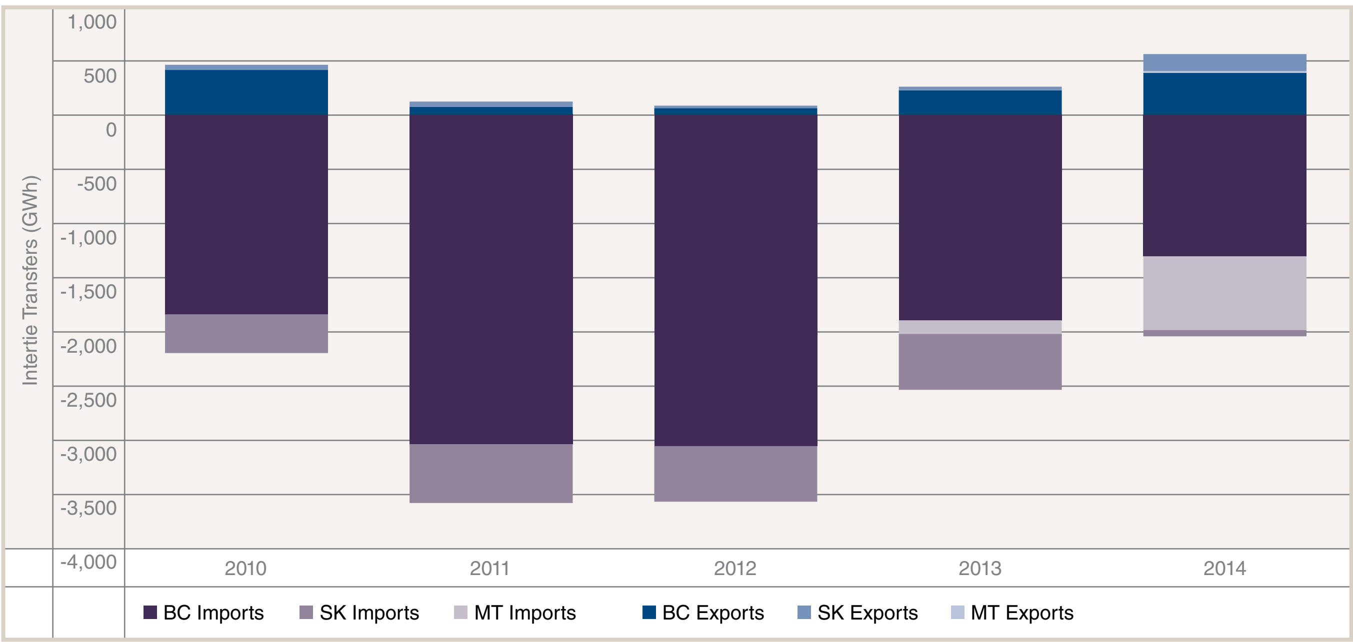


Net Imports Down From Previous Year

Net imports to Alberta over 2014 totaled 1,493 GWh and served almost two per cent of Alberta internal load. Figure 16 shows the annual import and export volumes across each intertie over the past five years. Imports to Alberta fell to 2,050 GWh, largely due to the extended operational outage on the Saskatchewan intertie. Exports from Alberta rose to 557 GWh, realigning with levels seen prior to 2011, largely due to lower pool prices compared to 2013. The combination of decreasing imports and increasing exports forced net imports down 35 per cent.

FIGURE 16

Annual Intertie Transfers



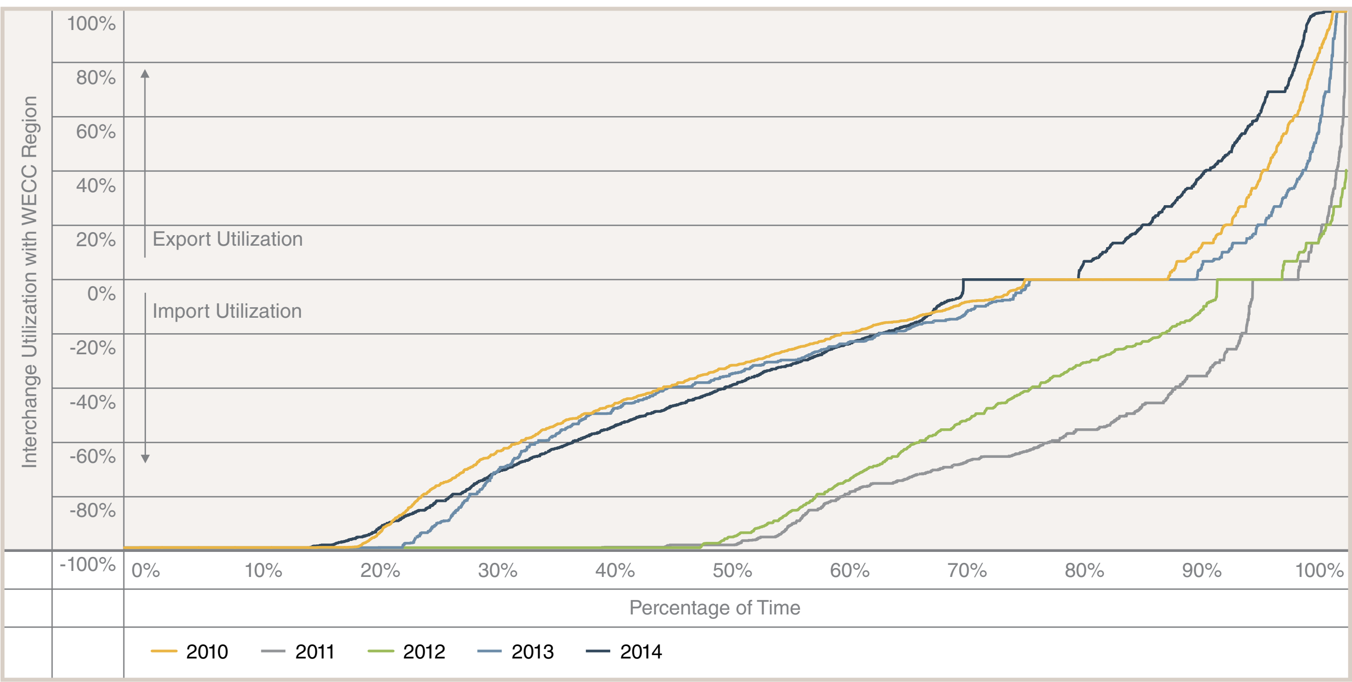
Imports from WECC Region Constant

Although the addition of MATL in September 2013 diversified the sources of imported energy, it did not increase the total import and export capability of the system. The combined operating limit sets a ceiling on the total energy that may be transferred from BC and Montana. When offered energy exceeds this combined operating limit, the transfer capability is proportionally allocated between the BC and Montana interties. The AESO continues to explore initiatives to restore intertie transfer capability.

Despite low electricity prices in Alberta, imports from the WECC region fell only two per cent to 1,992 GWh. British Columbia provided 66 per cent of these imports. Figure 17 shows the annual interchange utilization between Alberta and the WECC region over the past five years. Interchange utilization represents the ratio of net imports across the intertie to its transfer capability. Net imports include the volume of operating reserve procured on the intertie. The utilization calculation reflects the limits of the interties with BC and Montana, the combined operating limit, and the Alberta system operating limit. Over 2014, Alberta imported energy from the WECC region in 74 per cent of hours, and exported energy in 15 per cent of hours.

FIGURE 17

Annual Interchange Utilization with WECC Region

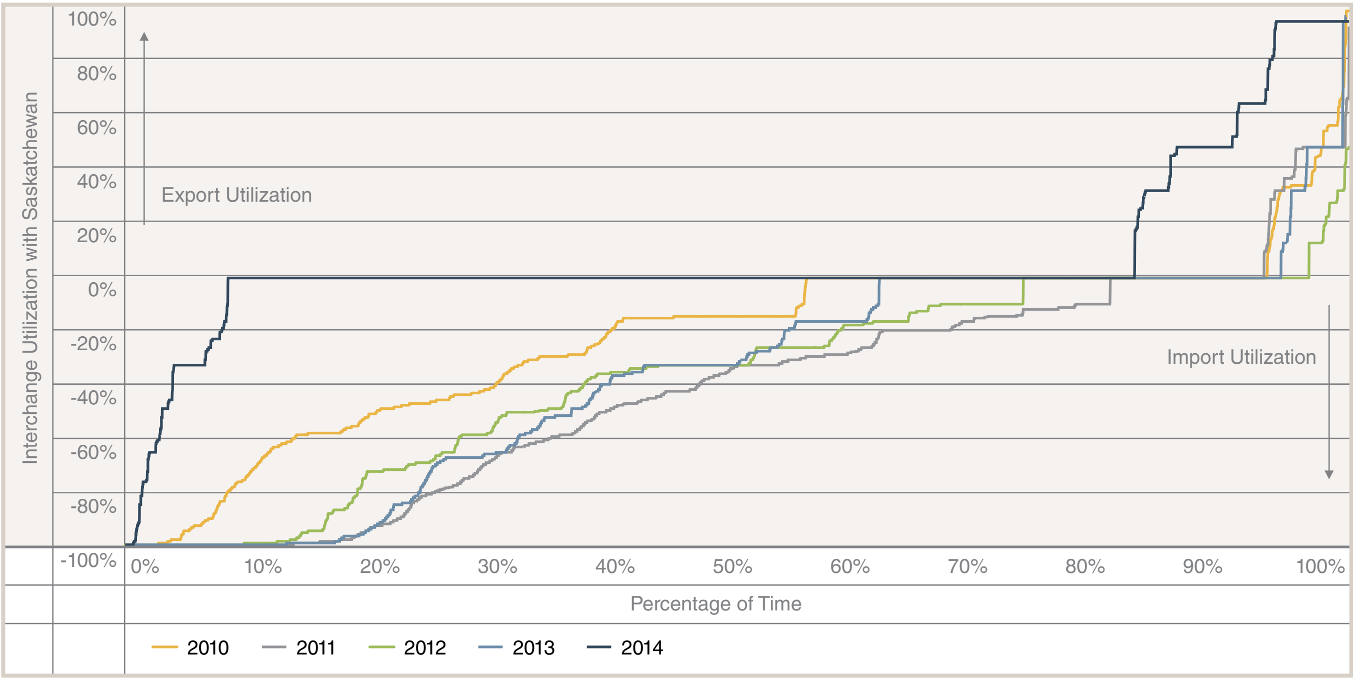


Exports to Saskatchewan Exceeded Imports

An extended outage on the intertie with Saskatchewan reduced total imports to Alberta in 2014. Although maintenance was scheduled to occur in June 2014, an unexpected operational outage in late May forced the tie line out of commercial operation for the rest of the year. This outage reduced imports across the intertie by 89 per cent to 58 GWh in 2014.

Figure 18 illustrates the annual interchange utilization between Alberta and Saskatchewan over 2014. Alberta imported energy from Saskatchewan in eight per cent of hours, and exported energy in 18 per cent of hours.

FIGURE 18
Annual Interchange Utilization with Saskatchewan



Wind Generation

Wind Served Four Per Cent of Load

Table 3 summarizes the annual statistics for wind generation. At the end of 2014, wind generation comprised nine per cent of the total installed generation capacity in Alberta. Over the year, installed wind generation capability grew by 32 per cent to 1,434 MW. Most of this capacity addition was due to the new 300 MW wind farm at Blackspring Ridge. Wind generation over 2014 totaled 3.5 TWh, and served more than four per cent of the annual Alberta Internal Load.

TABLE 3
Annual Wind Generation Statistics

Year	2010	2011	2012	2013	2014
Installed wind capacity at year end (MW)	777	865	1,087	1,088	**1,434**
Total wind generation (GWh)	1,552	2,323	2,574	3,013	**3,519**
Wind generation as a percentage of total AIL (%)	2.2	3.2	3.4	3.9	**4.4**
Average Hourly Capacity Factor (%)	28.2	33.8	31.9	32.1	**29.7**
Maximum Hourly Capacity Factor (%)	97.7	89.0	91.7	89.0	**88.4**
Wind Capacity Factor during Annual Peak Demand (%)	0.0	13.7	5.1	50.0	**3.5**

Figure 19 shows the monthly wind capacity and the average and maximum wind generation in each month.
Capacity factor expresses the ratio of the net-to-grid energy production to the theoretical maximum energy production. The monthly average capacity factor exhibits a seasonal pattern, peaking in winter and falling in summer. The monthly maximum capacity factor exhibits a less pronounced seasonal pattern. Strong winds may occur in any month, though they are most likely to occur in winter.

FIGURE 19

Monthly Wind Capacity and Generation

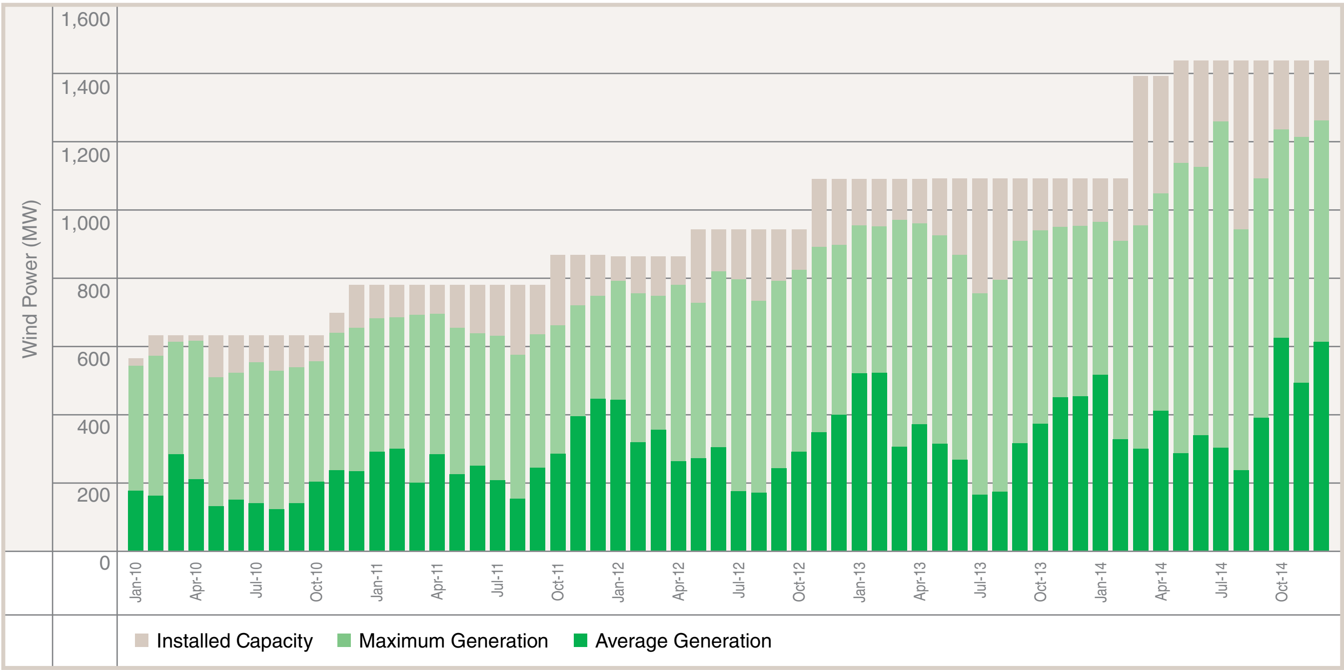
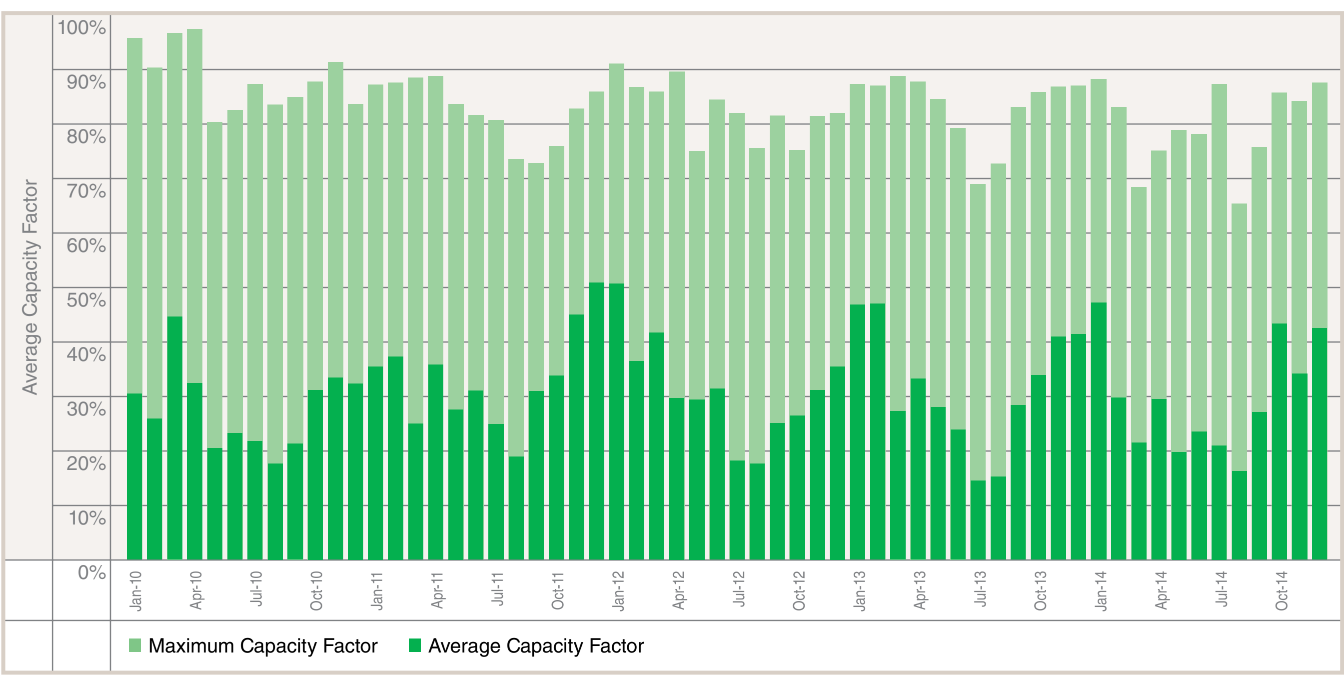


Figure 20 illustrates the monthly average and maximum capacity factors for wind generation over the past five years. The annual average capacity factor for wind generation in Alberta fell from 32 per cent in 2013 to 30 per cent in 2014. The annual maximum capacity factor fell from 89 per cent to 88 per cent. Over 2014, the monthly average wind capacity factor ranged from a low of 16 per cent in August to a high of 47 per cent in January.

FIGURE 20

Monthly Average and Maximum Wind Capacity Factors



Wind Achieved Higher Capacity Factor in Central Region

Pool price can be volatile when wind generation is strongly concentrated in a limited geographic region. Unlike other generation technologies, wind generation facilities do not currently specify an offer price. Instead, wind power is delivered to the Alberta electric system as it is generated. When wind power facilities are concentrated in a geographic area, large volumes of wind generation displace marginal generation from the merit order, and drive the system marginal price downward. When wind generation falls, system controllers must quickly dispatch generation to fulfill demand, increasing the marginal price of electricity.

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. At the end of 2014, wind generation capacity totaled 1,114 MW in southern Alberta, and 320 MW in central Alberta. Increased geographic diversification of wind assets minimized the variability of total wind generation, which reduces the volatility of pool price.

Over the past year, wind facilities in central Alberta outperformed those in southern Alberta. Table 4 tabulates regional wind generation statistics over 2014. The average capacity factor for central wind exceeded that for southern wind. For each megawatt of installed capacity, a wind farm in central Alberta produced more energy than a wind farm in southern Alberta. The average revenue for central wind was also higher than that for southern wind. For each megawatt hour of energy generated, a central wind farm earned more money than a southern wind farm.

TABLE 4
2014 Regional Wind Statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,114	320	**1,434**
Total wind generation (GWh)	2,590	929	**3,519**
Average wind capacity factor (%)	28.5	33.1	**29.7**
Average revenue ($/MWh)	31.10	35.92	**32.37**

Operating Reserve Costs Fell by Half

Operating reserve manages fluctuations in supply or demand on the AIES. Operating reserve is separated into two products: 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 further divided into two products: spinning reserve and supplemental reserve. Spinning reserve must be synchronized to the grid; supplemental reserve does not need to be. 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, the AESO must procure two commodities: active and standby. 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 is determined differently in the active and standby reserve markets. Participants in the active reserve market specify offer prices as premiums or discounts to the pool price. Systems controllers procure active operating reserve in ascending order of offer price until active operating reserve levels satisfy system reliability criteria. The equilibrium price of active reserve is the average of the marginal offer price and the bid ceiling submitted by the AESO. The clearing price of active reserve, paid to all dispatched active reserve, is the sum of this equilibrium price 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. The standby market clears based on a blended price formula that takes into consideration the premium and activation price offered by each potential supplier. However, payment for cleared offers in the standby market is a pay-as-bid mechanism. The cleared offers are paid their specified premium price for the option, and if the AESO exercises this option and activates the standby reserve, the provider also receives the activation price.

In 2014, the total cost of operating reserve decreased 50 per cent to $185 million due mostly to the fall in pool price. 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 lower pool price in 2014 reduced the price of active reserve, and nearly halved the total cost of operating reserve. Table 5 summarizes the total cost of operating reserve over the past five years.

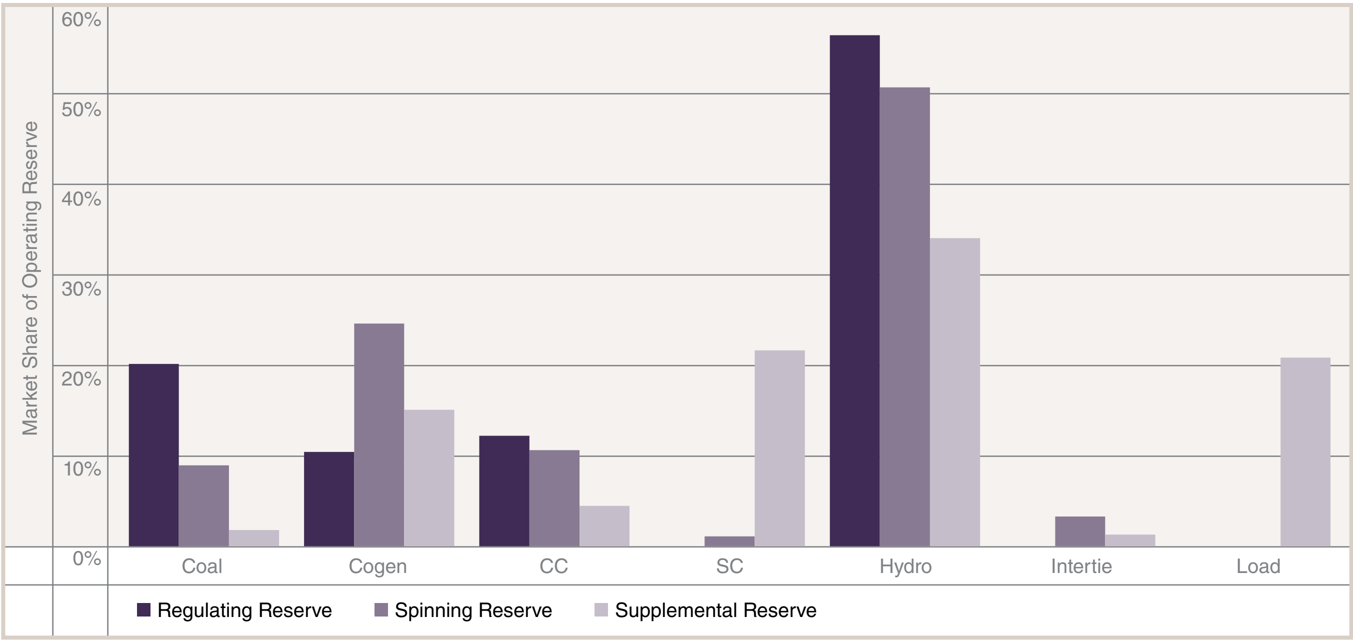
TABLE 5
Annual Cost of Operating Reserve

	Volume *(GWh)*			**Cost** *($-millions)*			
Year	**Active Procured**	**Standby Procured**	**Standby Activated**	**Active Procured**	**Standby Procured**	**Standby Activated**	**Total**
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
2014	**6,006**	**2,142**	**65**	**$168**	**$14**	**$3**	**$185**

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; however, load can only provide supplemental reserve.

Market share represents the percentage of total procured energy that is provided by each generation technology. Figure 21 illustrates the annual market share of active operating reserve. Hydroelectric generation is well suited to providing active reserve due to its fast response to system dispatches and its low marginal cost of generation.
In 2014, hydroelectric generation procured a greater market share of all active operating reserve products than any other asset type.

FIGURE 21
2014 Market Share of Active Operating Reserve



Transmission Must-Run Volumes Remained Low

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 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 fair, efficient, and openly competitive 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 2014, DDS offset 67 per cent of dispatched TMR volume. Table 6 summarizes the annual TMR and DDS statistics over the past five years. The annual cost of DDS in 2014 totaled $1.2 million. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported.

TABLE 6

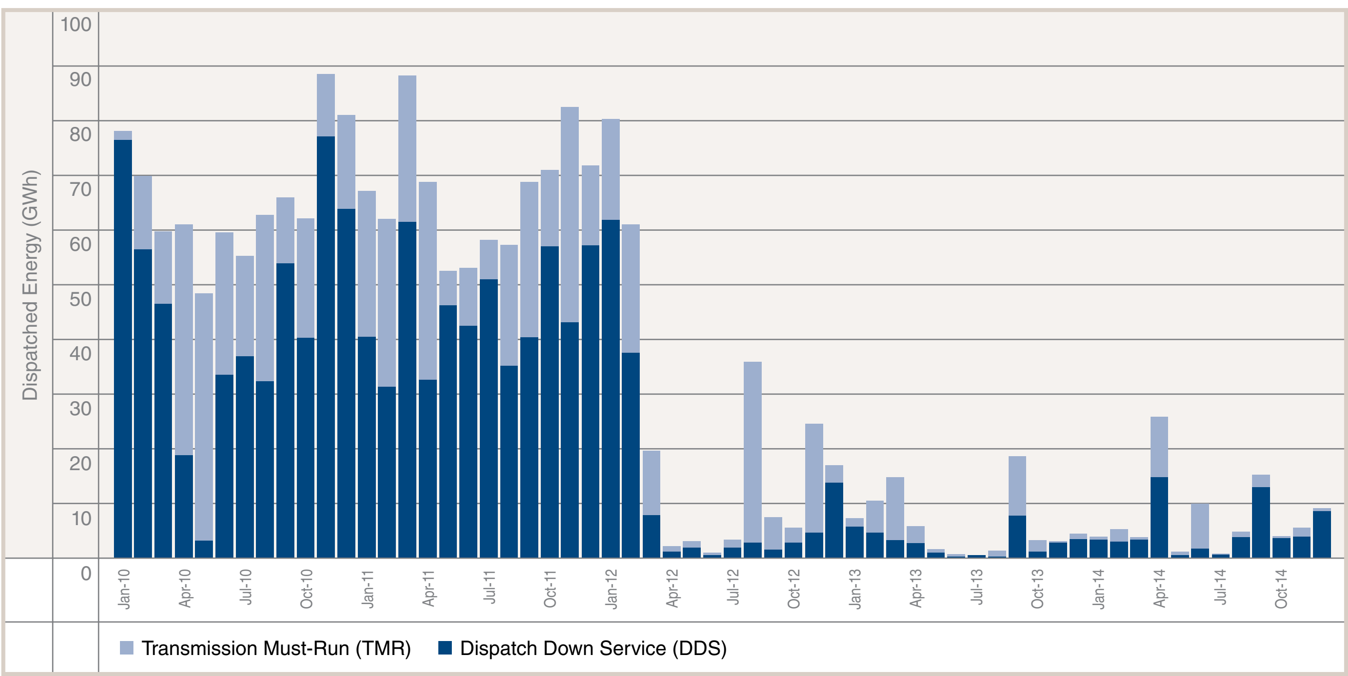
Annual Dispatch Down Service (DDS) Statistics

Year	TMR Dispatched *(GWh)*	DDS Dispatched *(GWh)*	Total DDS Payments *($-millions)*	Average DDS Charge per MWh *($/MWh)*
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**
2014	88	59	$1.19	**$0.02**

TMR service and DDS reflect transmission constraints on the AIES. Transmission reinforcement projects in 2011 and 2012 significantly reduced the operational constraints in northwest Alberta. As a result, both TMR and DDS volumes in 2014 decreased 89 per cent from 2010 levels. The annual cost of DDS in 2014 declined 85 per cent from its 2010 total. Figure 22 shows the monthly volumes of TMR and DDS dispatched over the past five years.

FIGURE 22

Monthly TMR and DDS Dispatched Energy



Payments to Suppliers on the Margin Declined 54 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 merit order to supply system load. The highest priced offer block dispatched in each minute sets the system marginal price (SMP). At settlement, the hourly pool price is calculated as the simple average of SMP. When system controllers dispatch an offer block that is priced above the settled pool price, that offer block may qualify for compensation under the PSM rule.
Table 7 summarizes the cost of PSM over the past five years.

TABLE 7
Annual Payments to Suppliers on the Margin Statistics

Year	Total Payments to Suppliers on the Margin *($-millions)*	Average Range between Maximum SMP and Pool Price *($)*	Average Charge *($)*
2010	$1.40	$10.60	$0.02
2011	$2.60	$18.72	$0.04
2012	$2.24	$17.11	$0.04
2013	$2.60	$18.70	$0.04
2014	**$1.16**	**$7.54**	**$0.02**

The annual cost of PSM declined 56 per cent to $1.2 million in 2014. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price. The annual average price range decreased 60 per cent to $7.54/MWh in 2014. The decreased volatility in the system marginal prices reduced the cost of PSM in each settlement period.

Final Notes

As the market evolves throughout 2015 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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