

AESO 2015 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 *2015 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 2015, 201 participants in the Alberta wholesale electricity market transacted approximately \$4 billion of energy. The annual average pool price for wholesale electricity fell 33 per cent from its previous-year value to \$33.34/MWh. The average natural gas price fell 40 per cent, averaging \$2.56/GJ. The average market heat rate increased by 13 per cent to 13.07 GJ/MWh, as falling gas prices outpaced falling pool price.

Alberta load leveled off in 2015 due to mild weather and reduced economic activity. The average Alberta Internal Load increased only slightly from 2014 levels. Hourly load set a new seasonal peak in the summer, but peak load in the winter season fell below previous records.

Price	2015	Year/Year Change	Load	2015	Year/Year Change
Pool price	\$33.34/MWh	-33%	Average AIL	9,162 MW	+0%
Gas price	\$2.56/GJ	-40%	Winter peak	10,982 MW	-1%
Heat rate	13.07 GJ/MWh	+13%	Summer peak	10,520 MW	+1%

In 2015, new simple-cycle gas and wind generation facilities increased the installed generation capacity by one per cent to 16,288 MW. Energy produced through coal generation continued to serve most Alberta load. Supply adequacy measures indicate that the AIES continues to operate reliably, and that the Alberta wholesale market continues to function efficiently.

Alberta remained a net importer of electricity for the thirteenth consecutive year; however, net imports to the province fell 71 per cent from 2014 volumes as low pool prices discouraged imports and encouraged exports. For the second year, exports to Saskatchewan exceeded imports from Saskatchewan.

Price of Electricity

Pool Price Fell 33 Per Cent

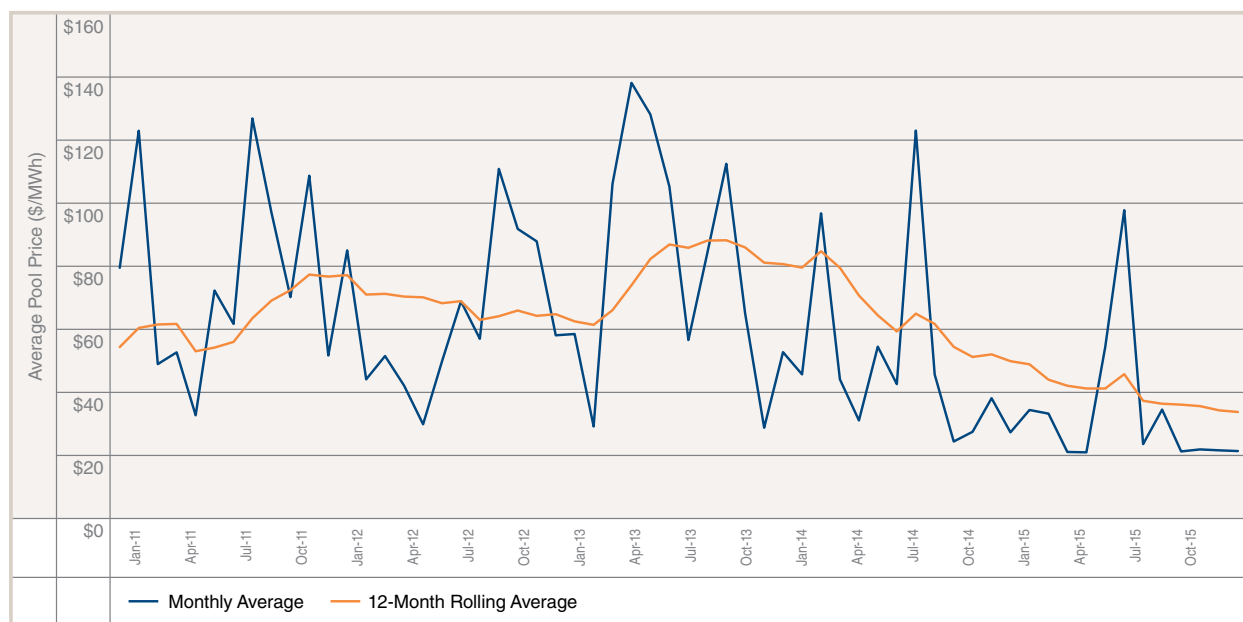
Pool price averaged \$33.34/MWh over 2015—a decrease of 33 per cent from 2014. The AESO separates each day into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m.; the remaining eight hours in each day make up the off-peak period. In 2015, the average pool price during the on-peak period fell 34 per cent to \$40.73/MWh, and the off-peak average pool price fell 27 per cent to \$18.55/MWh. Table 1 summarizes historical price statistics over the ten-year period between 2006 and 2015.

TABLE 1: Annual Market Price Statistics

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average pool price (\$/MWh)	80.79	66.95	89.95	47.81	50.88	76.22	64.32	80.19	49.42	33.34
On-peak average price (\$/MWh)	101.41	84.37	112.97	58.04	62.99	102.22	84.72	106.13	61.48	40.73
Off-peak average price (\$/MWh)	39.54	32.11	43.92	27.36	26.67	24.22	23.51	28.29	25.28	18.55
Average heat rate (GJ/MWh)	13.99	11.45	12.16	13.15	13.63	22.40	28.10	27.49	11.53	13.07

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 2015, the monthly average pool price ranged from a low of \$20.52/MWh in April to a high of \$97.31/MWh in June. The twelve-month rolling average shows that pool prices have decreased steadily since reaching a multi-year high in September 2013.

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 offer 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 operating unit. Before the revised Transmission Constraints Management (TCM) Rule became effective in November 2015, this marginal operating unit always set the system marginal price.

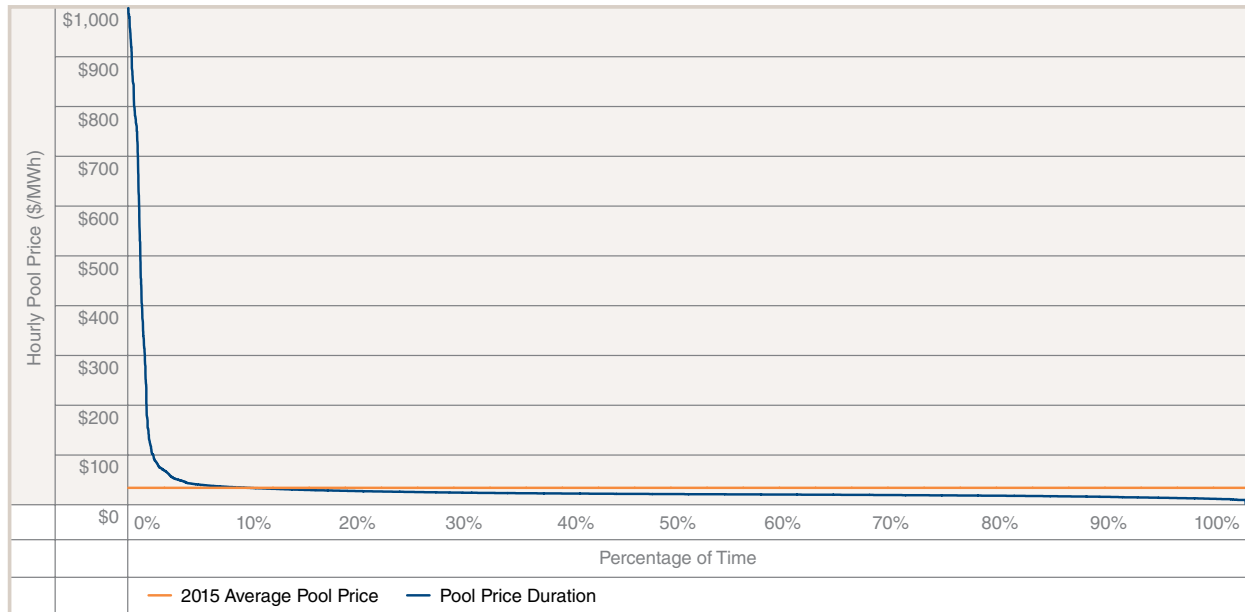
The revised TCM Rule introduced a new pricing mechanism to mitigate the effects of transmission constraints on pool price. When constraints on the transmission system prevent in-merit generation from supplying energy to the AIES, system controllers may dispatch generators that would otherwise fall out of merit. Until November 2015, this out-of-merit generation dispatched by system controllers—including the marginal operating unit—could set the system marginal price.

After the revised TCM Rule became effective, only generation that would be in merit in an unconstrained transmission system sets system marginal price. If a transmission constraint requires system controllers to constrain in-merit generation, the replacement energy does not influence system marginal price. Instead, this replacement energy receives an uplift payment, referred to as transmission constraint rebalancing. No transmission constraint events that required transmission constraint rebalancing occurred between the project implementation and the end of the year.

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 2015 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 fewer than 11 per cent of hours, or approximately one hour of every nine; however, because electricity was significantly more expensive in these hours, they exerted strong upward influence on the average price.

FIGURE 2: 2015 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. No load-curtailement events have occurred since 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 AIES was in supply surplus conditions for 303 minutes in 2015: 232 minutes on February 19, 70 minutes on October 11, and one minute on August 5. The previous supply surplus event occurred on May 28, 2014.

Heat Rate Rose 13 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 may earn 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 average of all hourly heat rates over the year. In 2015, the average natural gas price fell 40 per cent to \$2.56/GJ. Because gas prices fell more dramatically than electricity prices, the annual market heat rate increased 13 per cent to 13.07 GJ/MWh.

Alberta Internal Load

Average Load Remained Stable

Table 2 summarizes annual demand statistics over the past ten years. In 2015, the Alberta Internal Load (AIL) increased only slightly from 2014 levels. Average load grew to 9,162 MW, and peak load set a new record at 11,229 MW. Slowing load growth can be attributed to mild winter weather and decreased economic activity throughout Alberta.

TABLE 2: Annual Load Statistics

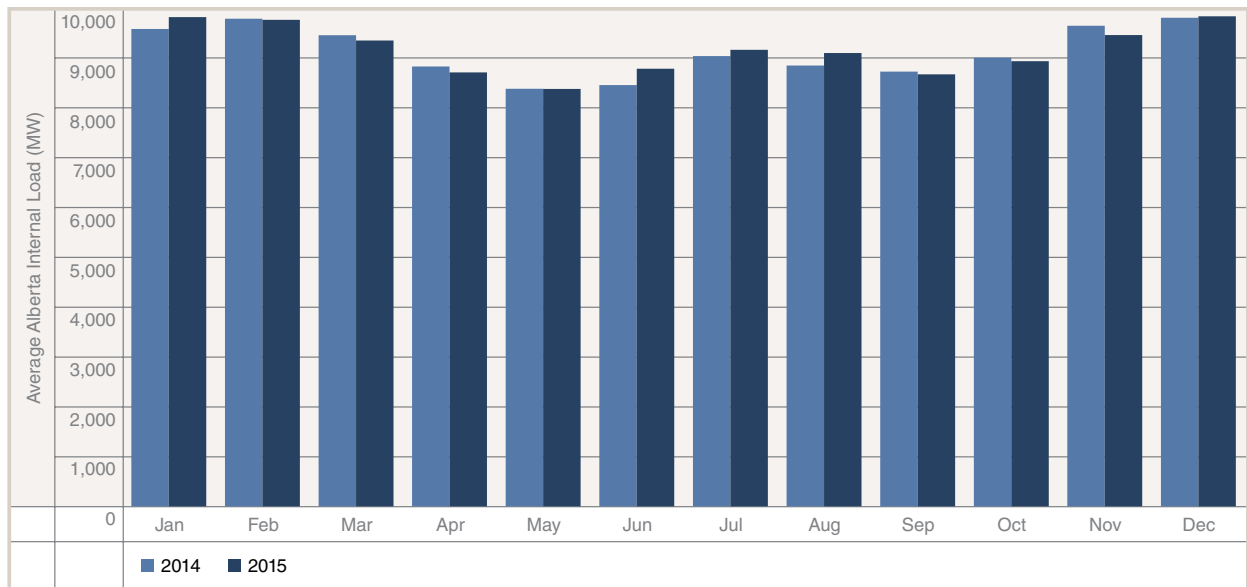
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total AIL (GWh)	69,371	69,661	69,947	69,914	71,723	73,600	75,574	77,451	79,949	80,257
Average AIL (MW)	7,919	7,952	7,963	7,981	8,188	8,402	8,604	8,841	9,127	9,162
Maximum AIL (MW)	9,661	9,701	9,806	10,236	10,196	10,226	10,609	11,139	11,169	11,229
Minimum AIL (MW)	6,351	6,440	6,411	6,454	6,641	6,459	6,828	6,991	7,162	7,203
Average system load (MW)	6,556	6,587	6,595	6,434	6,550	6,699	6,791	6,903	7,132	7,110
Growth in average AIL (%)	+4.7%	+0.4%	+0.1%	+0.2%	+2.6%	+2.6%	+2.4%	+2.8%	+3.2%	+0.4%
Load factor (%)	82%	82%	81%	78%	80%	82%	81%	79%	82%	82%

Alberta Internal Load is the sum of system load and behind-the-fence load. System load represents the total electric energy delivered to consumers in Alberta through the AIES, including transmission losses. Behind-the-fence load represents the total electric demand in Alberta that is served by on-site generation. Behind-the-fence load usually occurs at industrial sites, and is typically served by cogeneration gas facilities.

The load factor represents the ratio of the average AIL to the maximum AIL in each year. A low load factor indicates that load is highly volatile: peak hourly load significantly exceeds the average load over the year. A high load factor indicates that load is relatively stable: the peak hourly load is not significantly higher than the average load. The high load factor in Alberta indicates stable load, due largely to strong industrial demand.

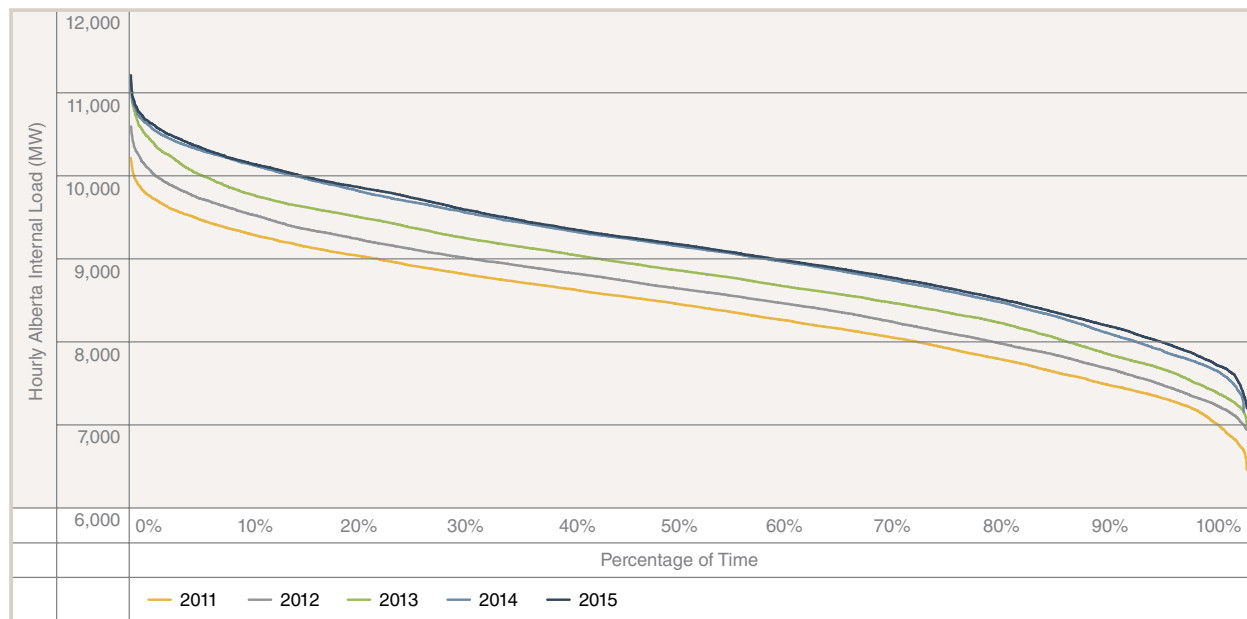
Although the annual average load remained reasonably constant between years, the monthly average load in 2015 differed significantly from 2014 levels. Load reached a new peak in January due to extremely cold winter temperatures; however, Alberta temperatures over the rest of year were higher than usual. Warm summer weather pushed the average load in June up by four per cent—the largest increase in monthly load observed in 2015. Winter temperatures in late 2015 were unseasonably temperate. These mild winter temperatures reduced the average load in November by two per cent—the greatest decline in monthly load. Figure 3 shows the monthly average load in 2014 and 2015.

FIGURE 3: Monthly Average Load



Load duration represents the percentage of time that AIL was greater than or equal to the specified load. Figure 4 plots the annual load duration curve for each of the last five years. Unlike the steady increases in load observed in previous years, hourly load in 2015 increased only slightly from 2014 levels.

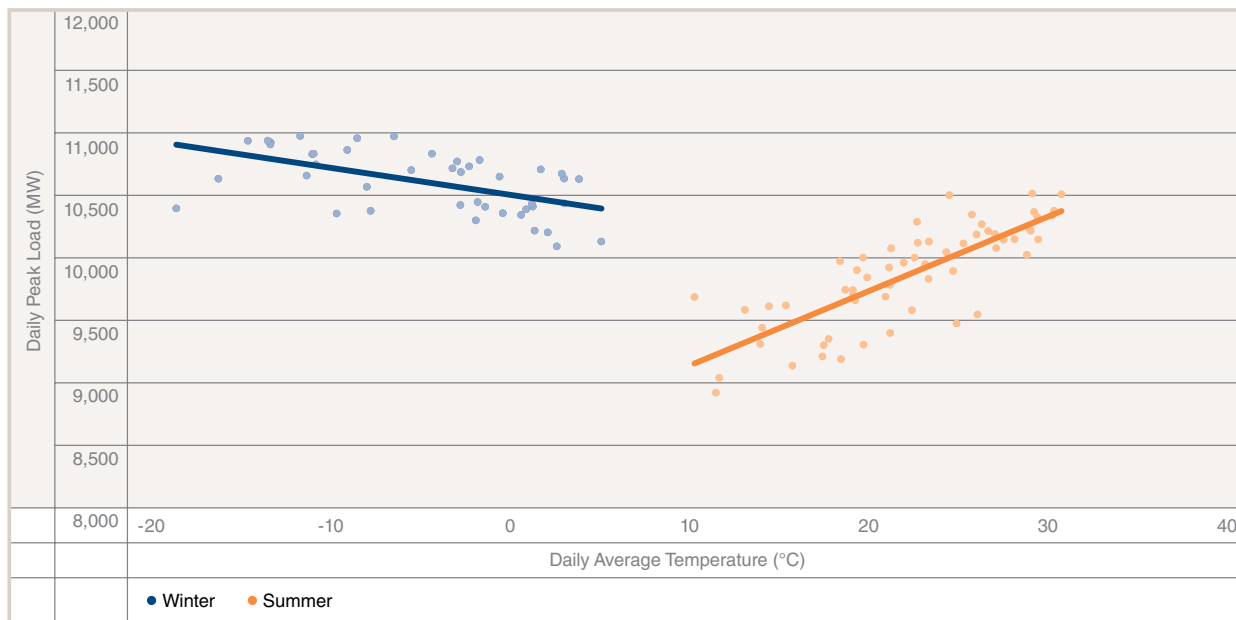
FIGURE 4: Annual Load Duration Curves



Seasonal Load

Temperature exerts a strong influence on load. Alberta Internal Load (AIL) tends to increase as the temperature becomes more extreme. Figure 5 illustrates the relationship between temperature and daily peak demand in weekdays over 2015. On winter weekdays, a decrease of one degree Celsius increased peak load by an average of 23 MW. During summer weekdays, an increase of one degree Celsius increased peak load by an average of 62 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.

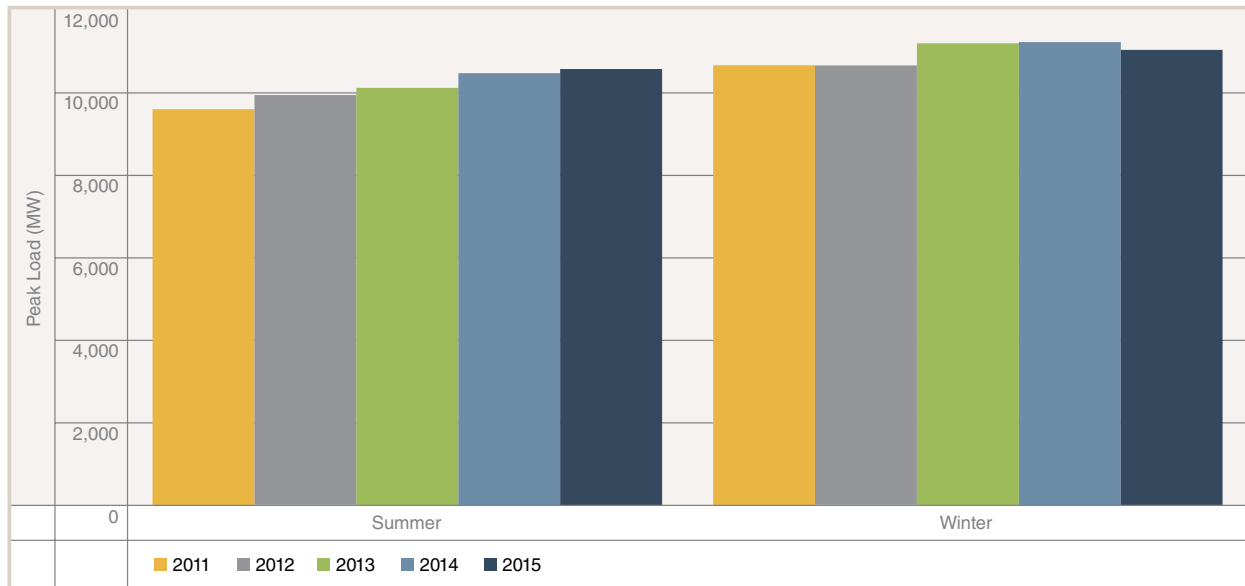
FIGURE 5: Daily Peak Load and Average Temperature



Seasonal peaks in Alberta load are usually set during periods of extreme temperatures: summer peaks are usually driven by heat; winter peaks are usually driven by cold. The summer season starts on May 1 and ends on October 31. On July 9, 2015, high temperatures drove AIL to a new summer peak of 10,520 MW. The previous summer peak was set one year earlier, on July 30, 2014, at 10,419 MW.

The effect of temperature on load is clearly evident in the difference between the two winters that fell in the 2015 calendar year. The winter season starts on November 1 and ends on April 30 of the following year. Extremely cold temperatures in winter 2014 spurred heating demand, and pushed the seasonal load to a new winter and overall peak: on January 5, 2015, Alberta internal load reached 11,229 MW. Milder temperatures in winter 2015 limited Alberta load: load peaked at 10,982 MW on December 22, 2015. Figure 6 illustrates the winter and summer peak demand over the past five years.

FIGURE 6: Seasonal Peak Load

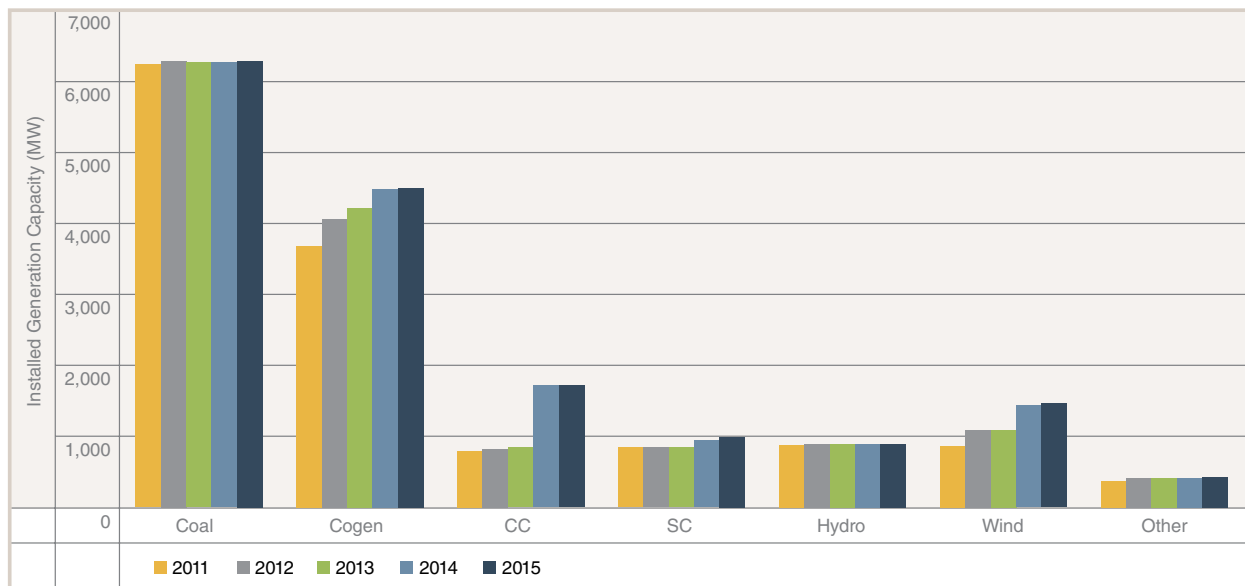


Installed Generation

Total Generation Capacity Increased One Per Cent

The total installed generation capacity in Alberta increased one per cent to 16,288 MW in 2015. Figure 7 shows the annual installed capacity at the end of each calendar year. Most of the increase in installed capacity over the past year occurred due to the addition of 41 MW of new simple-cycle gas generation and 29 MW of new wind generation.

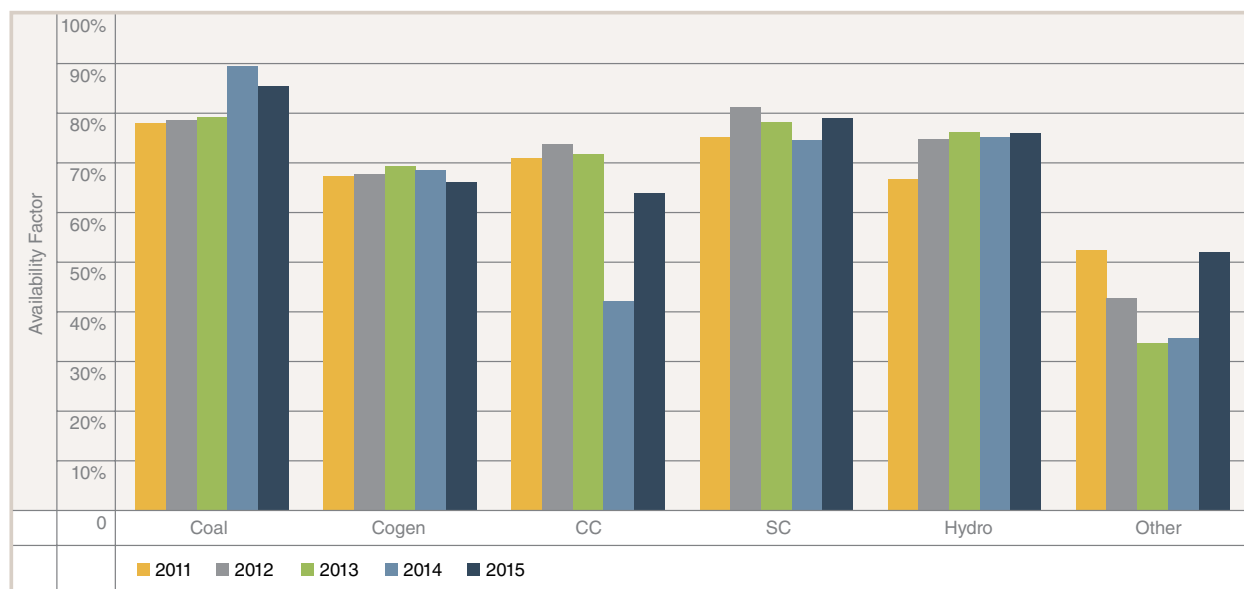
FIGURE 7: Annual Generation Capacity by Technology



Generation Availability Stable Across Technologies

The availability factor represents the percentage of the installed generation capacity that was available for dispatch into the energy or ancillary services markets. The availability factor is calculated as the ratio of the available capability to the installed generation capacity. Wind generation is excluded from this calculation since the availability of wind power depends on environmental factors. Figure 8 illustrates the annual availability factor by generation technology.

FIGURE 8: Annual Availability Factor by Technology



Most Available Coal Power Dispatched

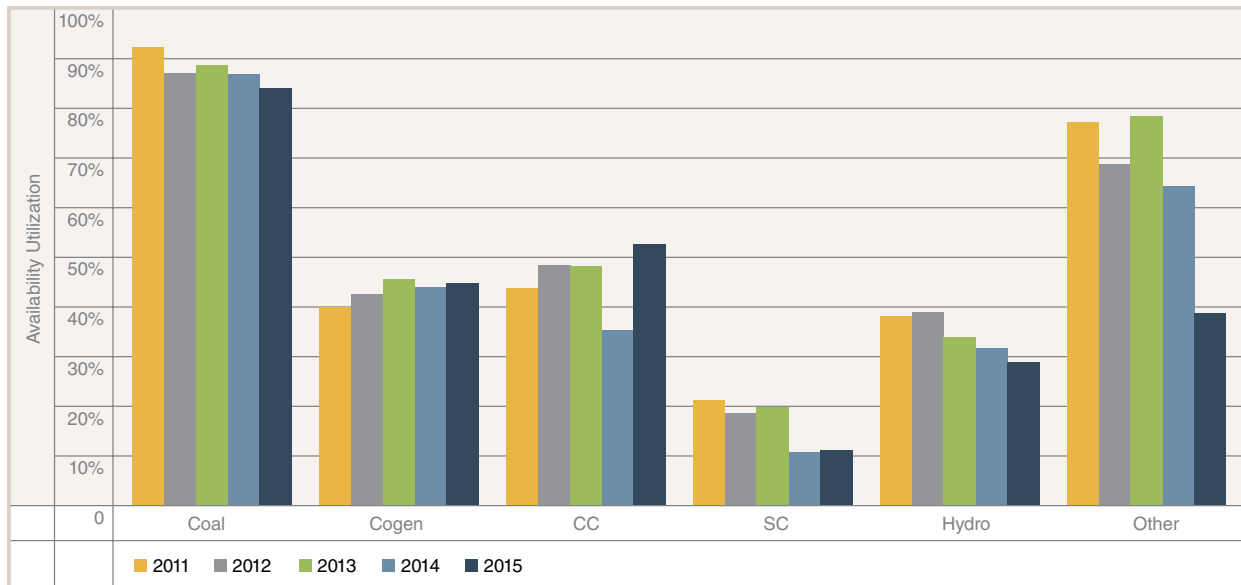
Availability utilization represents the percentage of the available power that was dispatched to serve system load. Availability utilization is calculated as the ratio of net-to-grid generation to the available capability. Wind generation is excluded from this calculation since all available wind power was fully utilized. Figure 9 illustrates the annual availability utilization by generation technology.

Over the five-year period between 2011 and 2015, the availability utilization of coal generation was consistently highest among dispatchable generation technologies. Over the last five years, the availability utilization of coal generation never dropped below 80 per cent. This relationship occurs because coal generation tends to offer its energy to the market at low prices. As a result, coal generation is usually dispatched before any higher priced generation technology, and provides a stable baseload of energy.

Although both coal generation and cogeneration gas are baseload technologies, the availability utilization of coal generation significantly exceeds the availability utilization of cogeneration gas. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve behind-the-fence load. The power used to serve behind-the-fence load is excluded from the calculation of availability utilization. This quantity includes only the energy delivered to the AIES.

Over the last five years, the availability utilization of simple-cycle gas was consistently the lowest across dispatchable generation technologies. This relationship occurs because simple-cycle gas tends to offer its energy to the market at higher prices. As a result, simple-cycle gas generation is dispatched to run only after all lower priced generation has already been dispatched from the merit order. This offer behaviour tends to limit dispatch of simple-cycle gas generation to peak system loads when pool prices are high.

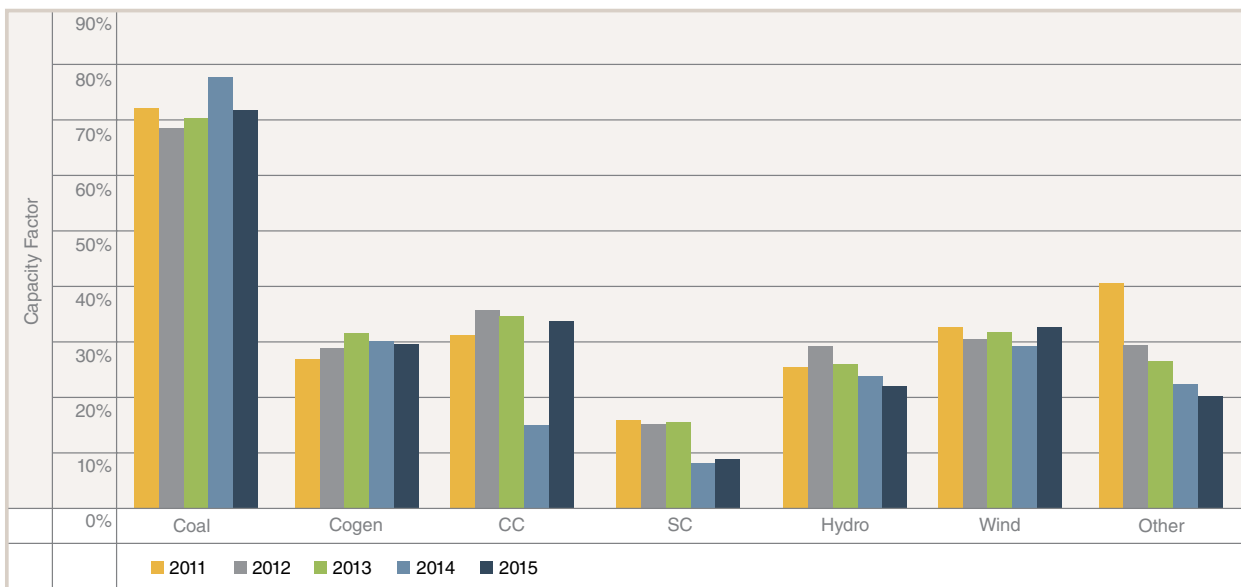
FIGURE 9: Annual Availability Utilization Factor by Technology



Coal Generation Capacity Most Utilized

Capacity factor represents the percentage of installed capacity used to serve system load. Capacity factor is calculated as the ratio of net-to-grid generation to the maximum capability. This calculation is equivalent to the product of the availability factor and availability utilization for dispatchable generation technologies; however, capacity factor can also be calculated for wind generation. Figure 10 illustrates the annual capacity factor by generation technology.

FIGURE 10: Annual Capacity Factor by Technology



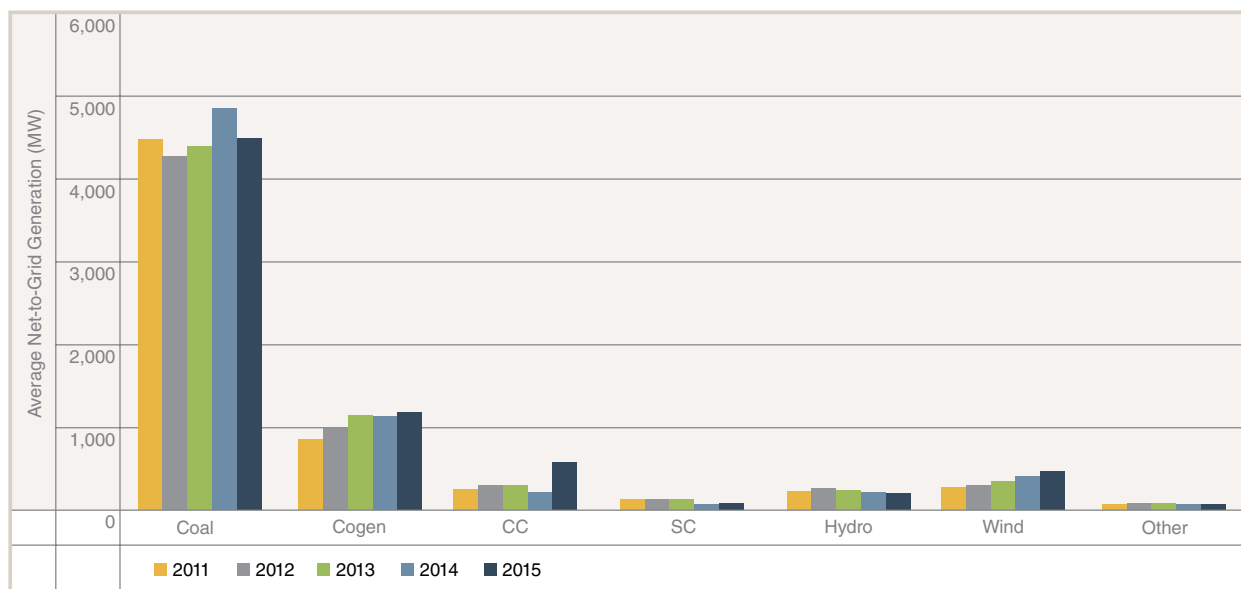
Over the five year period between 2011 and 2015, the capacity factor of coal generation was consistently higher than the capacity factor of any other generation technology. In 2015, the capacity factor of coal reached 72 per cent—on average, for every 100 MW of installed capacity, coal generation delivered 72 MWh to the AIES each hour. This result is consistent with the baseload operation of coal generation technology.

Over the same period, the capacity factor of simple-cycle gas generation was consistently lowest among generation technologies. In 2015, the capacity factor of simple-cycle gas generation was only nine per cent. This result is consistent with the peaking operation of simple-cycle gas generation.

Coal Generation Served 64 Per Cent of System Load

Figure 11 illustrates the total net-to-grid generation from each generation technology over the last five years. In 2015, coal generation supplied almost two-thirds of energy used to serve system load. Gas generation technologies served 26 per cent of system load. Renewable generation served the remaining ten per cent of system load. Seven per cent of system load was served by wind power alone.

FIGURE 11: Annual Average Net-to-Grid Generation by Technology



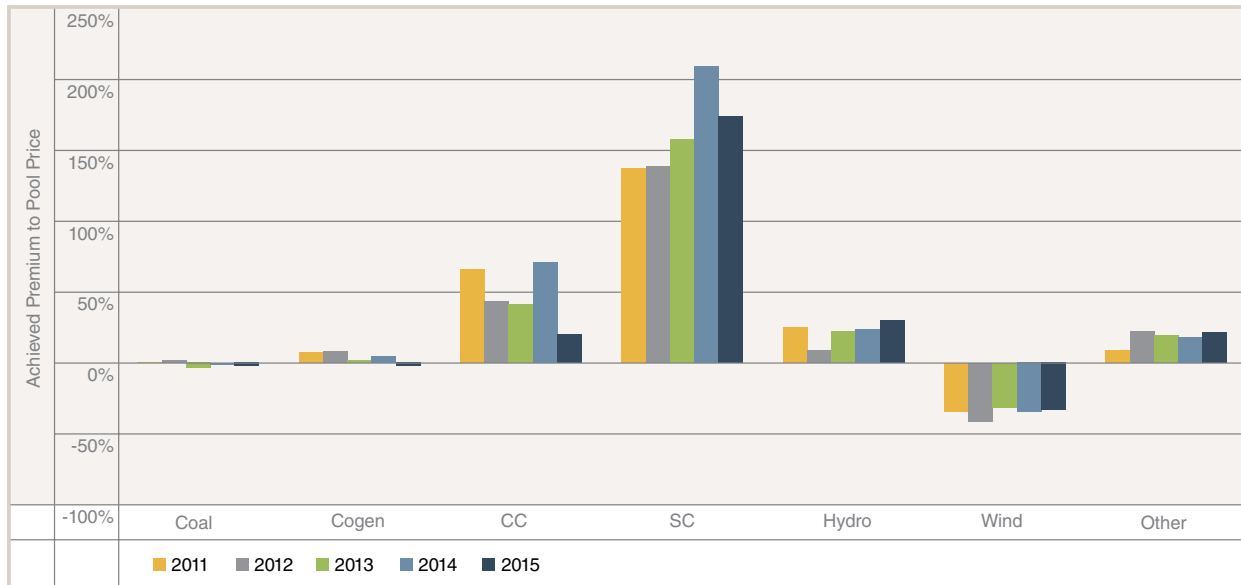
Simple-Cycle Gas Realizes Highest Achieved Premium to Pool Price

Achieved price represents the average price realized in the wholesale energy market for electricity delivered to the grid. Achieved price is calculated as the weighted average of hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation. The achieved margin represents the difference between the achieved price and the average pool price. The achieved premium to pool price is calculated as the ratio of the achieved margin to the average pool price.

The achieved premium to pool price indicates the profitability of generation relative to baseload operation. An achieved premium of zero indicates that the achieved price is equal to the average pool price. An achieved premium of 100 per cent indicates that the achieved price is double the average pool price. An achieved premium of 50 per cent indicates that the achieved price is half the average pool price.

Figure 12 illustrates the achieved premium to pool price realized by each generation technology over the past five years.

FIGURE 12: Annual Achieved Premium to Pool Price by Generation Technology



The offer price of power dictates its position in the merit order, which determines whether system controllers will dispatch the unit to run. Market participants choose offer prices 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 achieved price that each asset type receives.

Optimally, baseload generation technologies 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 at a relatively constant level over time, and realizes an achieved price close to the average pool price. In 2015, both coal and cogeneration gas technologies realized a two per cent discount to pool price.

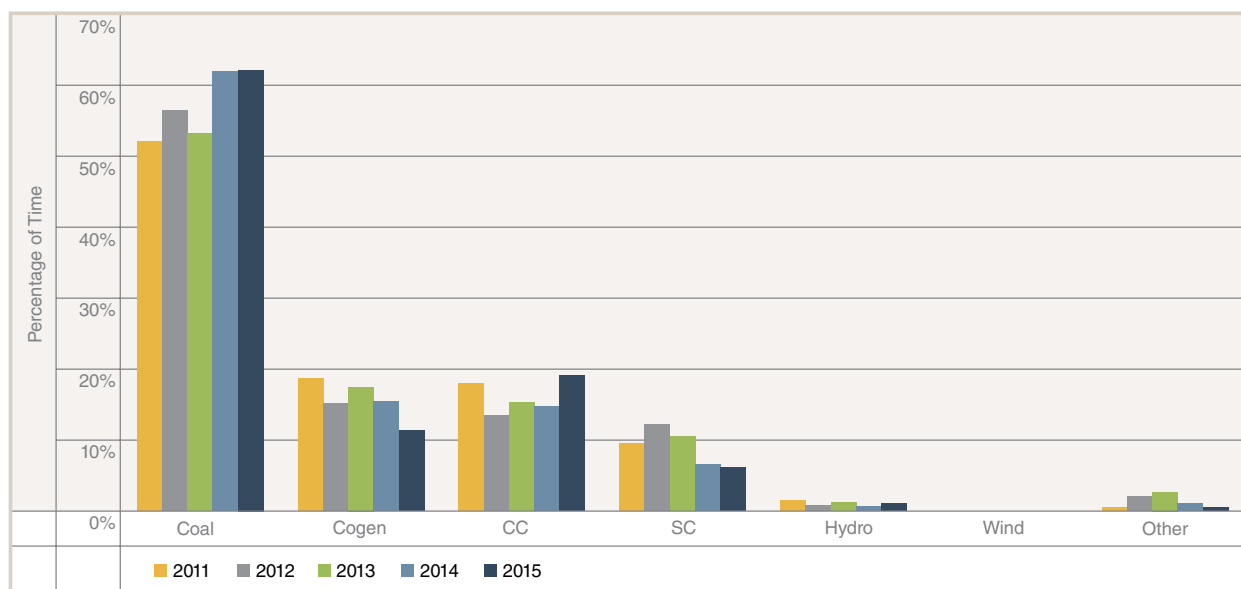
Peaking generation technologies achieve greater operational flexibility than baseload generation, but at higher cost. The combustion turbines used in simple-cycle gas generation can halt and restart operation without incurring high costs, but cost more to operate. These higher costs are reflected in higher offer prices, which positions peaking generation capacity high in the merit order. 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. Over the last five years, the achieved price of simple-cycle gas generation was consistently more than double the average pool price. In 2015, simple-cycle gas received a 173 per cent premium to pool price.

Wind generation is the only technology that consistently achieves a discount to pool price—that is, the achieved premium is consistently negative. This discount occurs due to technological limitations and geographic concentration. Wind power cannot control its operational schedule: the availability of wind power varies according to environmental conditions that are largely beyond human control. When wind blows in a region, all in-merit wind generation in that region is delivered to the AIES. Wind generation in Alberta remains heavily concentrated in the southern region. When wind blows in southern Alberta, wind energy displaces a significant quantity of power from the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2015, wind generation received a 33 per cent discount to pool price.

Coal Generation Sets Marginal Price In 62 Per Cent of Hours

Figure 13 illustrates how frequently each generation technology set the system marginal price. Over each of the last five years, coal generation was the most common marginal price-setting technology. This prominence is consistent with the baseload operation of coal generation technology. Because coal assets would incur high costs by halting and restarting operation, they tend to operate in both on- and off-peak hours. Coal generation disproportionately set the system marginal price during off-peak hours when load was low; however, coal assets also set the marginal price in more than half of the on-peak hours in 2015. The high frequency where low-priced coal generation set price contributed to the low average pool price in 2015.

FIGURE 13: Annual Marginal Price-Setting Technology



Supply Adequacy

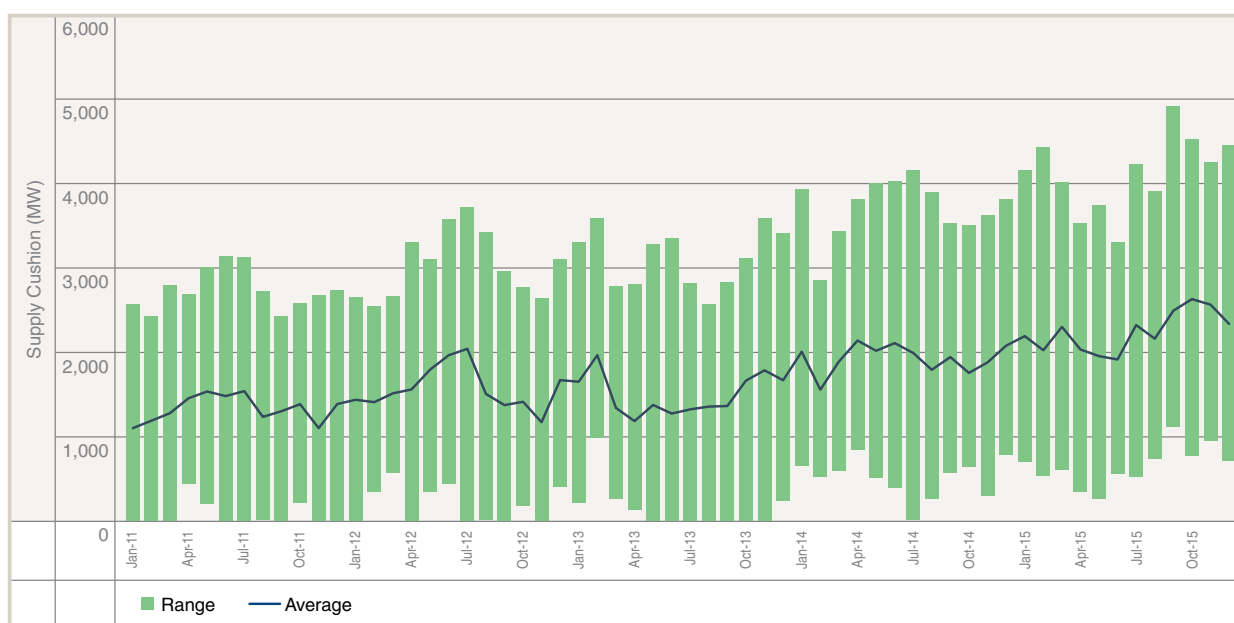
Supply adequacy expresses the ability of the system to serve demand. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. The *2015 Annual Market Statistics* report evaluates supply adequacy using two common measures: supply cushion and reserve 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 load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages. Over 2015, the average supply cushion increased 16 per cent to 2,255 MW due largely to the start of commercial operations at the Shepard combined-cycle gas generation plant.

Supply shortfall conditions indicate that the supply cushion is zero. When the supply cushion falls to zero, all available power in the merit order has been dispatched to run, and system controllers may be required to take emergency action to ensure system stability. No supply shortfall events occurred in 2015. Supply shortfall conditions last occurred on July 30, 2014. Figure 14 shows the monthly supply cushion over the past five years. The increasing trend in the supply cushion reflects additional installed generation capacity and slowing load growth.

FIGURE 14: Monthly Supply Cushion



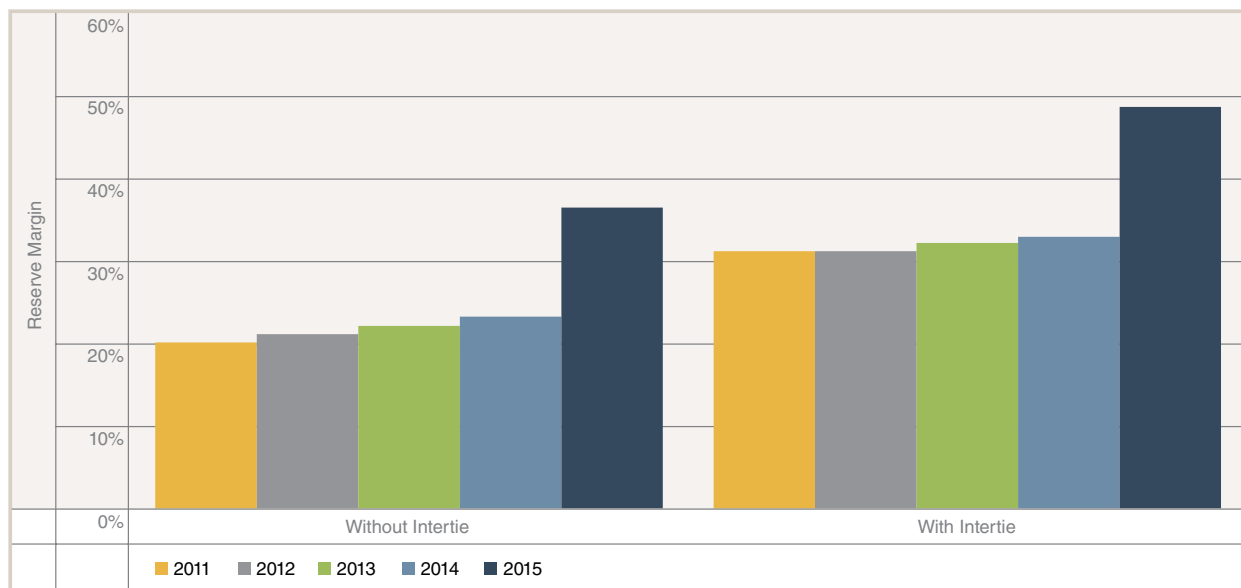
Reserve Margin Indicates Adequate Supply

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 2012 excluded the generation capability of the two Sundance coal units to reflect the extended forced outage. Reserve margin calculations in 2014 excluded the Shepard combined-cycle gas generation plant and the cogeneration plants at Nabiye and Kearl, which started commercial operations in 2015.

Figure 15 shows the annual reserve margin over the past five years. In 2015, the reserve margin rose significantly from 2014 levels, indicating that increases in excess generation capability outpaced system load. The high reserve margin indicates that the Alberta wholesale market is adequately supplied, as the market has encouraged developers to build new generation to serve increasing system load.

FIGURE 15: Annual Reserve Margin



Imports and Exports

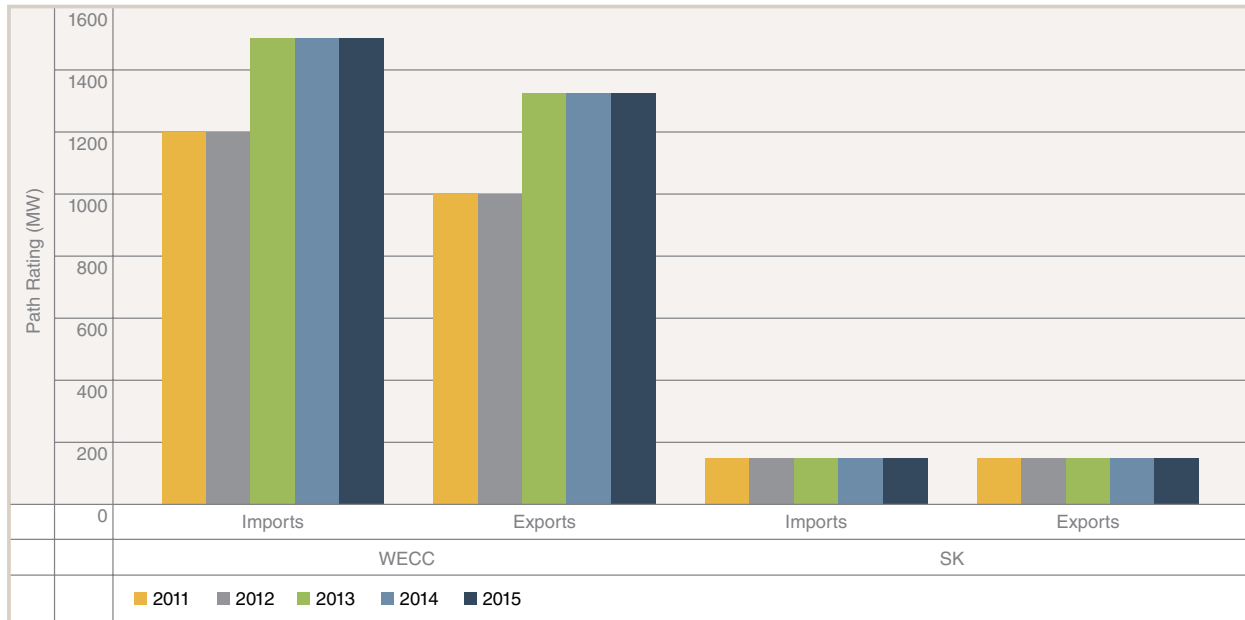
Alberta has been a net importer of electricity for the last 13 years, and in 19 of the 20 years since 1995. Before 2013, imports and exports flowed between Alberta and its two provincial neighbours: British Columbia and Saskatchewan. In September 2013, the Montana-Alberta Tie Line (MATL) started commercial operation. This new intertie permitted Alberta to transfer energy directly across the border with the United States.

Transfer Path Rating Remained Stable

The transfer path rating establishes the limits of power flow across defined paths between control areas. Alberta is connected to three neighbouring control areas: British Columbia, Montana, and Saskatchewan. Alberta, British Columbia, and Montana are members of the Western Electricity Coordinating Council (WECC) region—Saskatchewan is not.

The maximum power that could flow between Alberta and other members of the WECC region is the sum of the path ratings for the individual interties. Figure 16 shows the maximum power flow at the end of each calendar year between Alberta and other WECC members, and between Alberta and Saskatchewan.

FIGURE 16: Annual Path Rating by Transfer Path

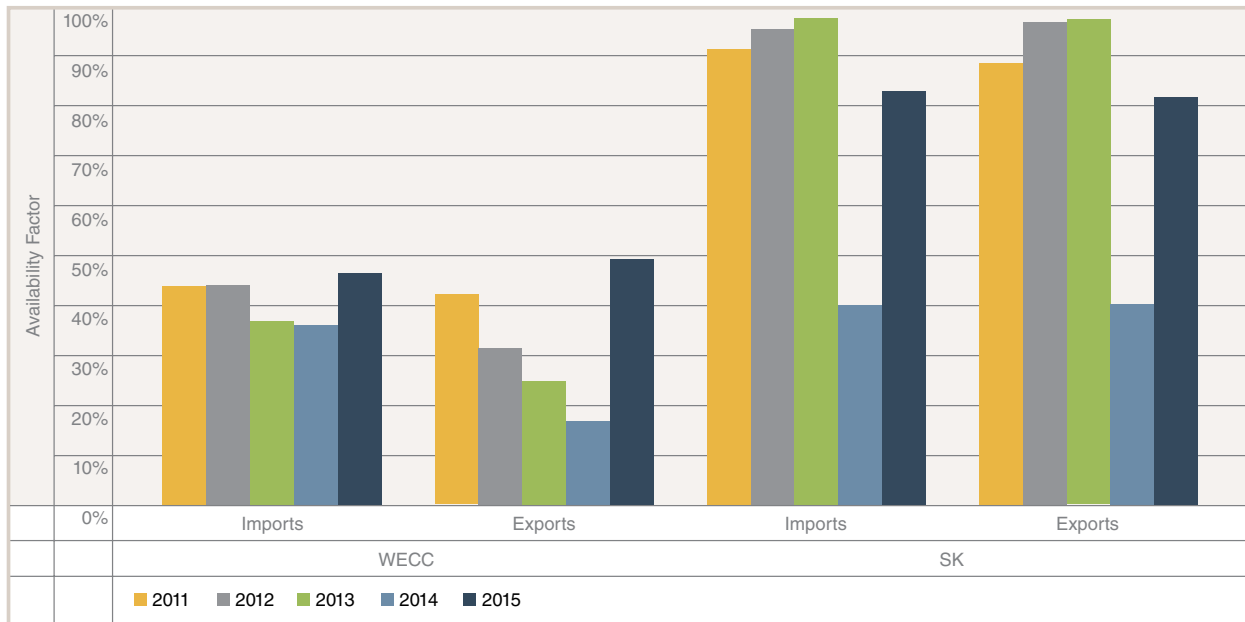


Transfer Path Availability Increased

System reliability standards define the criteria that determine the energy that can be transferred between jurisdictions. These standards impose three limits on transfers between control areas. The available transfer capability (ATC) limits imports and exports on an individual transfer path to reflect operational conditions and maintain the transmission reliability margin. The combined operating limit further restricts the transfer capability of total energy transfers between Alberta and other WECC members. The system operating limit specifies the maximum import and export capability between Alberta and all neighbouring jurisdictions.

The availability factor represents the percentage of the maximum power flow that was available to transfer energy between jurisdictions. The availability factor is calculated as the ratio of the ATC to the sum of path ratings. Figure 17 illustrates the annual availability factor for transfers between Alberta and other regions. In 2015, updated system studies increased the combined operating limit that governed energy transfers between Alberta and other WECC members. The increased availability of the individual Saskatchewan transfer path reflects its return to operation from a long-term outage between May 2014 and February 2015. The AESO continues to explore initiatives to restore inertia transfer capability.

FIGURE 17: Annual Availability Factor by Transfer Path



Intertie Transfer Activity Falls

Availability utilization represents the percentage of available transfer capability that was used to transfer energy between jurisdictions. Availability utilization is calculated as the ratio of transferred energy to the ATC of the transfer path. Figure 18 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members and between Alberta and Saskatchewan. In 2015, the availability utilization of all transfer paths declined from 2014 levels.

FIGURE 18: Annual Availability Utilization by Transfer Path

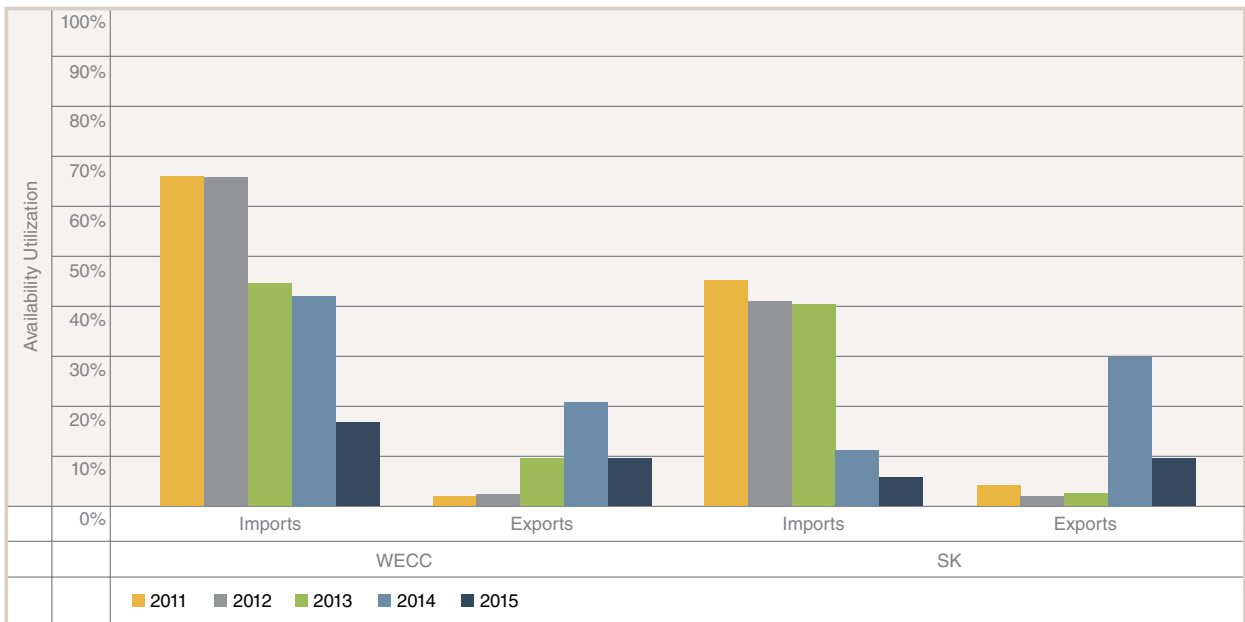


Figure 19 shows the annual interchange utilization between Alberta and the WECC regions over the past five years.

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 limits, and the Alberta system operating limit. Over 2015, Alberta imported energy from the WECC region in 49 per cent of hours, and exported energy in 29 per cent of hours.

FIGURE 19: Annual Interchange Utilization with WECC Region

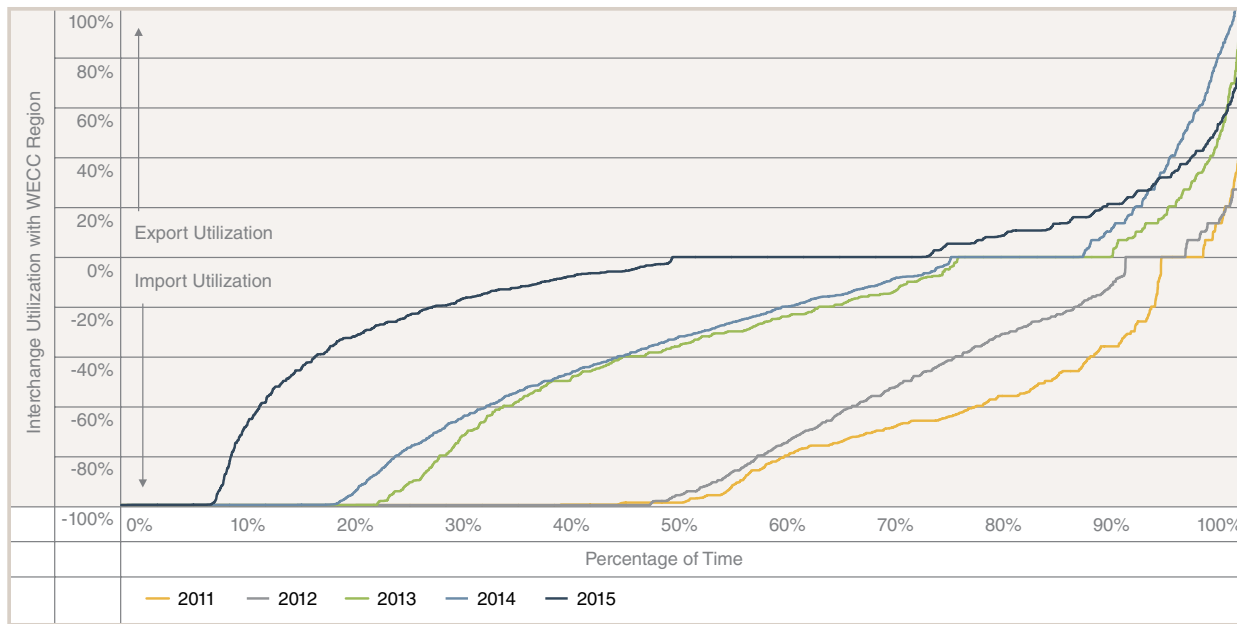
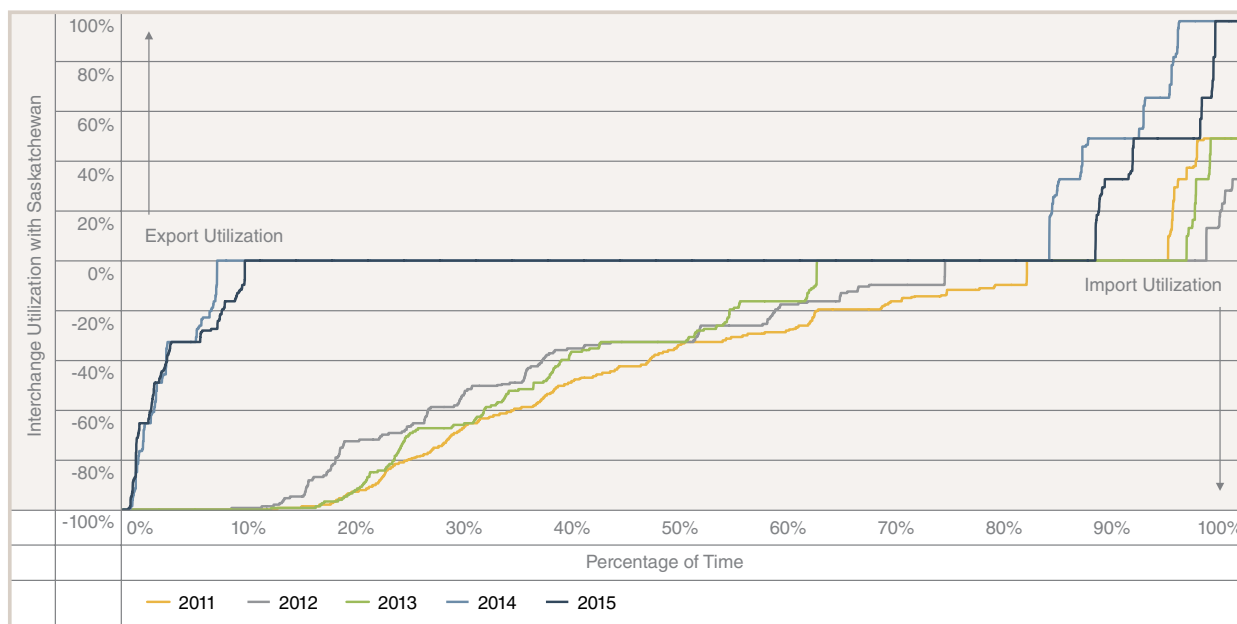


Figure 20 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2015, Alberta imported energy from Saskatchewan in 11 per cent of hours, and exported energy in 13 per cent of hours.

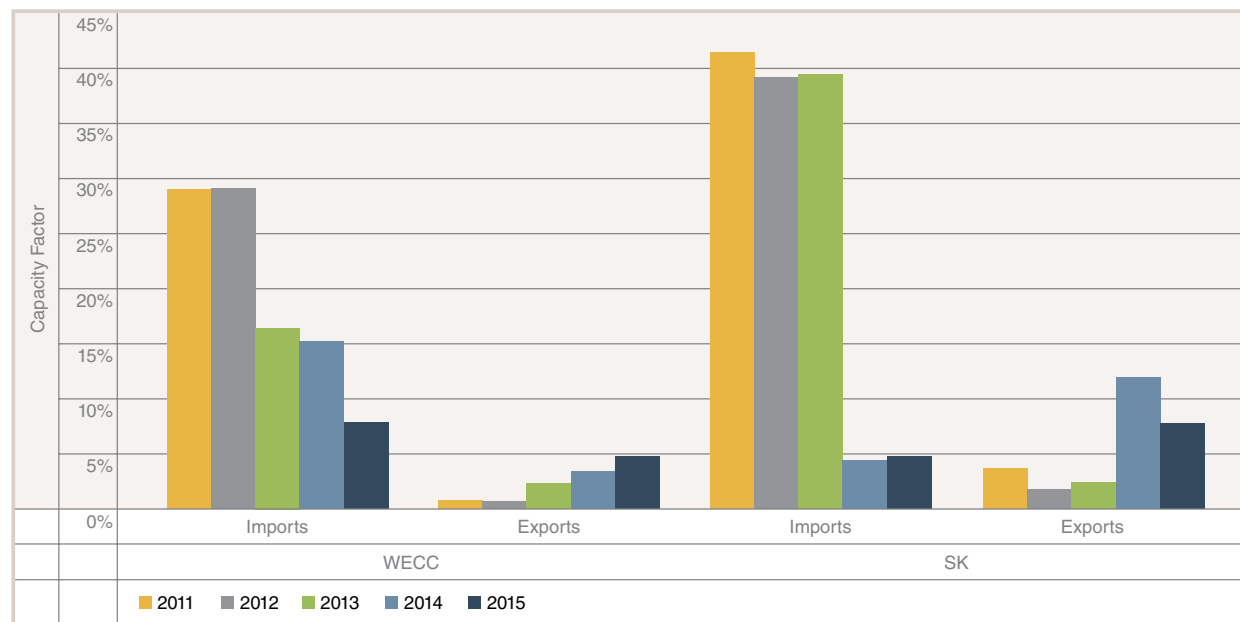
FIGURE 20: Annual Interchange Utilization with Saskatchewan



Capacity Factor Reflects Fall in Net Imports

Capacity factor represents the percentage of the physical transfer capacity that was used to transfer energy between jurisdictions. The capacity factor is calculated as the ratio of total transferred energy to the path rating. This calculation is equivalent to the product of the availability factor and the availability utilization. Figure 21 illustrates the annual capacity factor for transfers between Alberta and other WECC members and between Alberta and Saskatchewan.

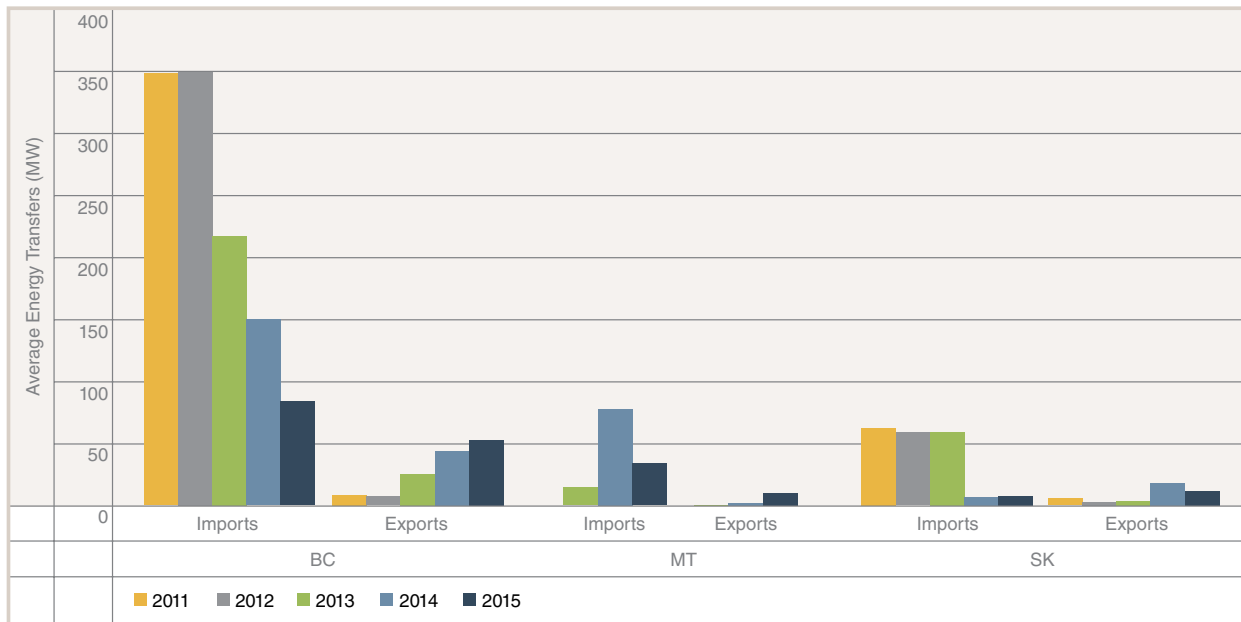
FIGURE 21: Annual Capacity Factor by Transfer Path



Alberta Remained Net Importer

Figure 22 illustrates the annual average energy transferred from each province or state. Alberta remained a net importer in 2015 for the thirteenth consecutive year. Net imports from BC and Montana decreased from 2014 levels as imports fell and exports rose. For the second consecutive year, Alberta exported more energy to Saskatchewan than it imported; however, the net exported energy decreased from the previous year as imports remained constant and exports fell. In total, net imports from British Columbia and Montana outweighed net exports to Saskatchewan.

FIGURE 22: Annual Intertie Transfers by Province or State

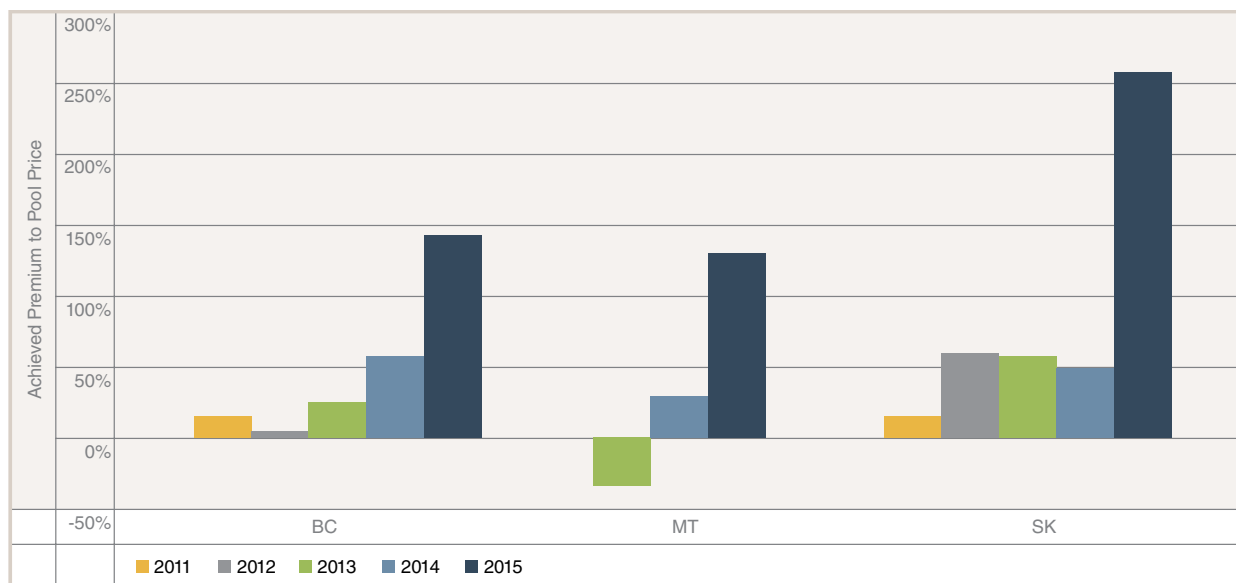


Achieved Premium to Pool Price for Imports Rises to Multi-Year High

Figure 23 illustrates the achieved premium to pool price on imported energy by province or state. Imported energy exerts downward pressure on pool price. Market participants cannot specify an offer price for imported energy: all imported energy is priced at \$0/MWh. As a result, imported energy displaces power from the merit order, and reduces the system marginal price. Importers transfer energy into Alberta only during favourable economic conditions.

In 2015, the achieved premium to pool price on imported energy ranged between 130 and 258 per cent. This premium exceeded the achieved premium for every generation technology except simple-cycle gas generation. This outcome is consistent with the reduced energy transfers observed previously. Market participants limited import activity in 2015 to high-priced hours.

FIGURE 23: Achieved Premium to Pool Price by Province or State



Wind Generation

Wind Generation Served Five Per Cent of Alberta Internal Load

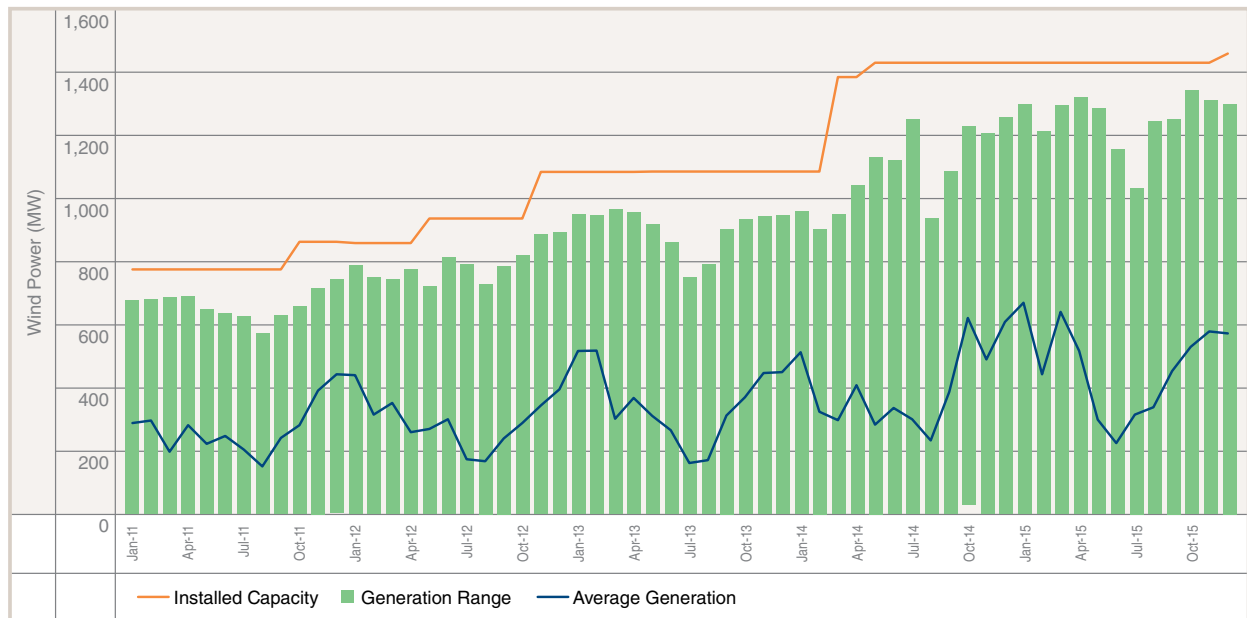
Table 3 summarizes the annual statistics for wind generation. At the end of 2015, wind generation made up nine per cent of the total installed generation capacity in Alberta. Over the year, installed wind generation capability grew by two per cent to 1,463 MW due to the addition of two wind farms at Bull Creek in central Alberta. Wind energy served five per cent of total load in 2015.

TABLE 3: Annual Wind Generation Statistics

Year	2011	2012	2013	2014	2015
Installed wind capacity at year end (MW)	865	1,087	1,088	1,434	1,463
Total wind generation (GWh)	2,323	2,574	3,013	3,519	4,089
Wind generation as a percentage of total AIL	3%	3%	4%	4%	5%
Average hourly capacity factor	34%	32%	32%	30%	33%
Maximum hourly capacity factor	89%	92%	89%	88%	94%
Wind capacity factor during annual peak AIL	14%	5%	50%	3%	7%

Figure 24 shows the installed wind generation capacity and the average and maximum wind generation in each month. The monthly average of wind generation exhibits a pronounced seasonal pattern, peaking in winter and falling in summer. The maximum of wind generation exhibits a weaker seasonal pattern. Strong winds may occur in any month, though they occur more frequently in winter.

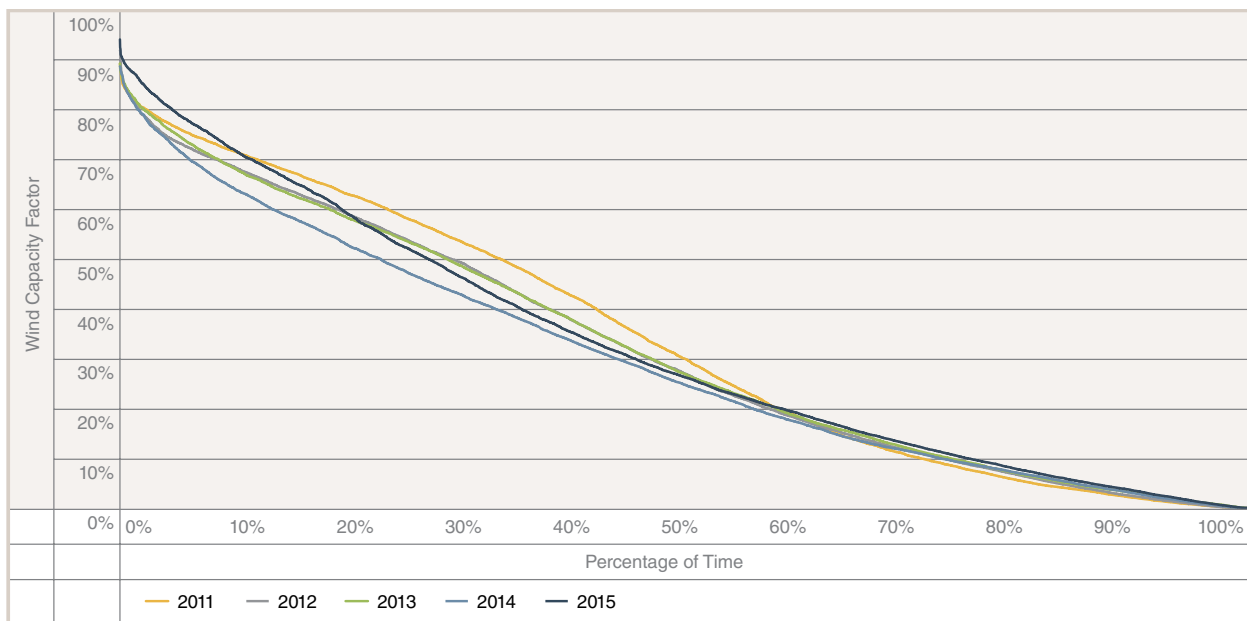
FIGURE 24: Monthly Wind Capacity and Generation



Wind Capacity Factor

Figure 25 illustrates annual duration curves for the hourly capacity factor for Alberta wind generation. Capacity factor represents the percentage of installed capacity used to generate energy that is delivered to the AIES. The duration represents the percentage of time that capacity factor of wind generation equals or exceeds a specific value.

FIGURE 25: Annual Wind Capacity Factor Duration Curves



The duration curves for the capacity factor of wind generation remained relatively constant over the last five years. The capacity factor of wind generation averaged 33 per cent over 2015—for every 100 MW of installed wind capacity, wind power generated 33 MWh of energy. This capacity factor is comparable to cogeneration and combined-cycle gas generation; however, unlike these technologies, wind generation depends largely on environmental factors—it cannot be dispatched to run when wind is unavailable.

Wind Integration Project Completed in April 2015

Before April 2015, wind power was unable to specify an offer price for generated energy. Wind energy was delivered to the AIES as it was generated, and displaced offers from the merit order. High levels of wind generation displaced marginal generation from the merit order, and drove the system marginal price downward. When wind generation fell, system controllers quickly dispatched generation to fulfill demand, and increased the marginal price of electricity.

The wind integration project allowed market participants to specify offer prices for wind generation. If a wind asset falls out of merit due to high offer pricing, the energy that it generates is not delivered to the Alberta energy system. This offer strategy could exercise upward pressure on pool price. When market participants offer wind energy at zero dollars, however, the changes introduced by the wind integration project have no effect on price.

The wind integration project had no effect on wind generation in 2015. Over the year, one wind asset offered power at non-zero prices in one hour—and it remained in merit.

Regional Wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. This concentration of wind generation contributed to high pool price volatility. Since 2011, the addition of five wind facilities in central Alberta increased the geographic diversification of wind generation across the province. At the end of 2015, wind generation capacity totaled 1,114 MW in southern Alberta, and 349 MW in central Alberta. Increased geographic diversification of wind assets reduced the variability of total wind generation in the province, and lowered the volatility of pool price.

In 2015, wind facilities in central Alberta continued to outperform those in southern Alberta. Table 4 tabulates regional wind generation statistics over 2015. The average capacity factor for central wind slightly exceeded that for southern wind—in part, due to the newer generation technology in operation at central wind farms. For each megawatt of installed capacity, a wind farm in central Alberta produced more energy than a wind farm in southern Alberta. The achieved price 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: 2015 Regional Wind Statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,114	349	1,463
Total wind generation (GWh)	3,161	928	4,089
Average wind capacity factor	32%	33%	33%
Achieved price (\$/MWh)	\$21.56	\$24.93	\$22.33

Ancillary Services

Cost of Operating Reserve Fell 25 Per Cent

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 procured by the AESO on a day-ahead basis using the Watt-Ex trading system. 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. The AESO procures 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.

The total cost of operating reserve in 2015 decreased 25 per cent to \$138 million due to the falling cost of active reserve. Table 5 summarizes the total cost of operating reserve over the past five years. Active reserve represented most of the total cost of operating reserve. The decreased pool price, combined with reduced procurement volumes, decreased the cost of active reserve. This decrease was slightly offset by the increased cost of standby activations. Both the volume and price of activating standby reserve increased from the previous year.

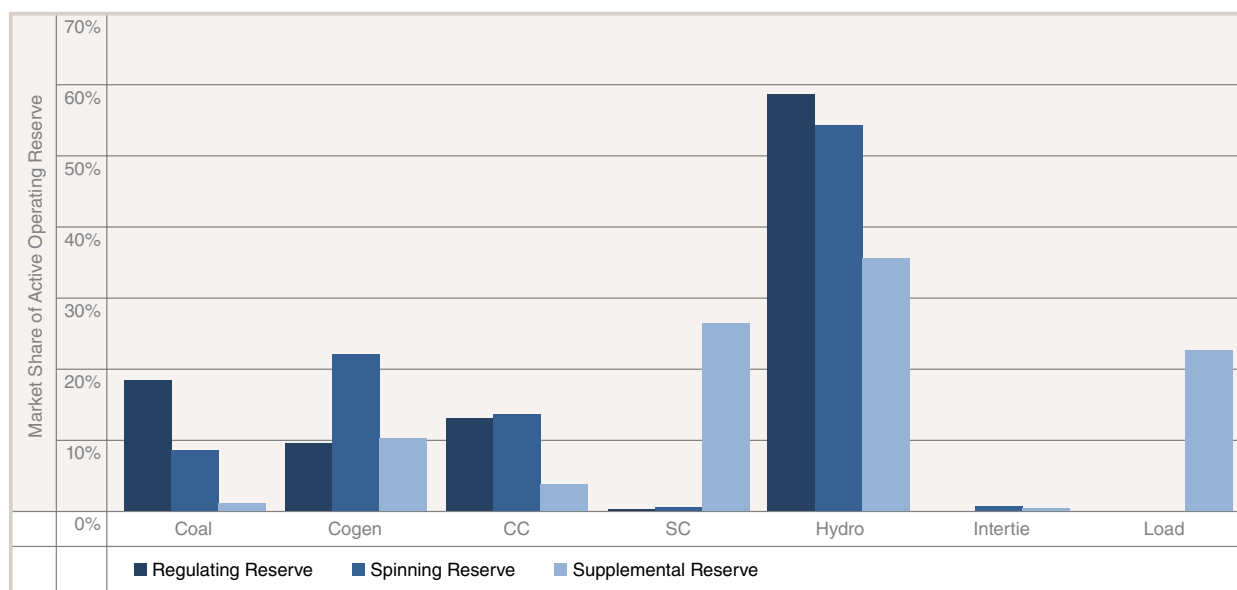
TABLE 5: Annual Operating Reserve Statistics

Year	2011	2012	2013	2014	2015
Volume (GWh)					
Active Procured	5,705	5,901	6,019	6,006	5,333
Standby Procured	2,311	2,133	2,144	2,142	2,140
Standby Activated	51	58	77	65	136
Cost (\$-millions)					
Active Procured	\$307	\$296	\$341	\$168	\$105
Standby Procured	\$16	\$26	\$19	\$14	\$13
Standby Activated	\$6	\$5	\$10	\$3	\$20
Total	\$329	\$326	\$369	\$185	\$138

The technical requirements of operating reserve differ between products. Currently, regulating reserve must be supplied by generation located within the province of Alberta. Contingency reserve—both spinning and supplemental reserve—may be supplied by generation, imports, or load.

Market share represents the percentage of total procured energy that is provided as operating reserve by each generation technology. Figure 26 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 2015, hydroelectric generation obtained a greater market share of all active operating reserve products than any other technology.

FIGURE 26: 2015 Market Share of Active Operating Reserve



Transmission Must-Run and Dispatch Down Service

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 a 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.

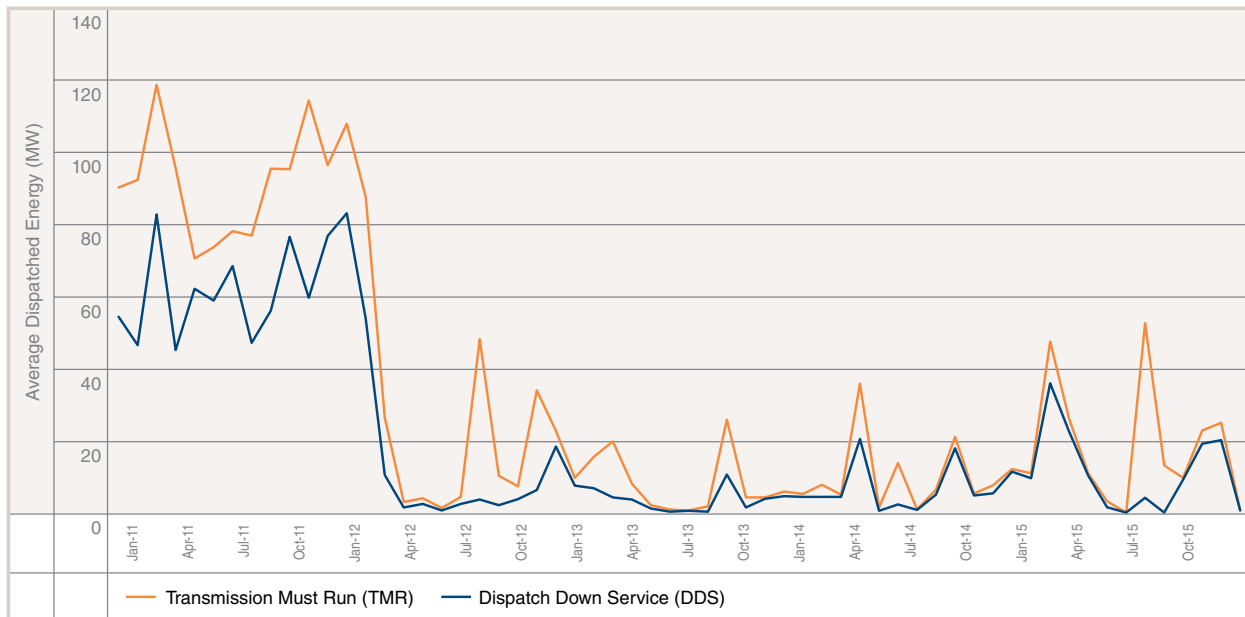
DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2014, DDS offset 59 per cent of dispatched TMR volume. Table 6 summarizes the annual TMR and DDS statistics over the past five years. The annual cost of DDS in 2015 totaled \$1.6 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 TMR and DDS Statistics

Year	2011	2012	2013	2014	2015
TMR dispatched (GWh)	801	260	71	88	161
DDS dispatched (GWh)	537	137	32	59	95
Total DDS payments (\$-millions)	\$6.5	\$1.7	\$0.6	\$1.2	\$1.6
Average DDS charge (\$/MWh)	\$0.11	\$0.03	\$0.01	\$0.02	\$0.02

Figure 27 shows the monthly volumes of TMR and DDS dispatched over the past five years. System controllers issue TMR dispatches in response to transmission constraints on the AIES. Transmission reinforcement projects in 2011 and 2012 significantly reduced the operational constraints in northwest Alberta. As the frequency and severity of transmission constraints declined, the need for TMR service fell.

FIGURE 27: Monthly TMR and DDS Dispatched Energy



Payments to Suppliers on the Margin

Payments 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.

Annual PSM

TABLE 7: Annual Payments to Suppliers on the Margin Statistics

Year	Total Payments (\$-millions)	Average Range between Maximum SMP and Pool Price (\$/MWh)	Average Charge (\$)
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
2015	\$1.25	\$5.99	\$0.02

The annual cost of PSM increased eight per cent to \$1.25 million in 2015. 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 21 per cent to \$5.99/MWh in 2015.

Final Notes

As the market evolves throughout 2016 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. This information is available to all market participants on the AESO's [Market & System Reporting webpage](#). Reports are produced with the best information available at the time, and will change as more information becomes available.

Stakeholders can obtain the data file that underlies the tables and figures in this report [here](#).

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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