AESO 2016
Annual Market Statistics

FEBRUARY 2017

Contents

Executive summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient and openly competitive market for electricity and provides for the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES). 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 2016, 188 participants in the Alberta wholesale electricity market transacted approximately $2 billion of energy. The annual average pool price for wholesale electricity fell 45 per cent from its previous-year value to $18.28/MWh. The average natural gas price fell 20 per cent, averaging $2.06/GJ. The average market heat rate decreased by 25 per cent to 9.9 GJ/MWh, as falling pool prices outpaced the falling gas price.

The average Alberta load in 2016 decreased one per cent from 2015 levels due to mild spring weather and the Fort McMurray fires in May and June. Despite reduced spring and summer load, Alberta set a new winter peak load in December due to inclement weather conditions.

Price	2016	Year/Year Change
Pool price	$18.28/MWh	-45%
Gas price	$2.06/GJ	-20%
Heat rate	9.9 GJ/MWh	-25%

Load	2016	Year/Year Change
Average AIL	9,057 MW	-1%
Winter peak	11,458 MW	+4%
Summer peak	10,244 MW	-3%

In 2016, new cogeneration gas and expansions at existing cogeneration gas facilities increased the installed generation capacity by one per cent to 16,423 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.

For the first time in 14 years, Alberta was a net exporter of electricity in 2016. Low pool prices reduced imports to the province 60 per cent from 2015 levels, and increased exports by 34 per cent. Exports exceeded imports across interties to both British Columbia and Saskatchewan; however, Alberta remained a net importer across the Montana-Alberta Tie Line.

Price of electricity

Pool price fell 45 per cent

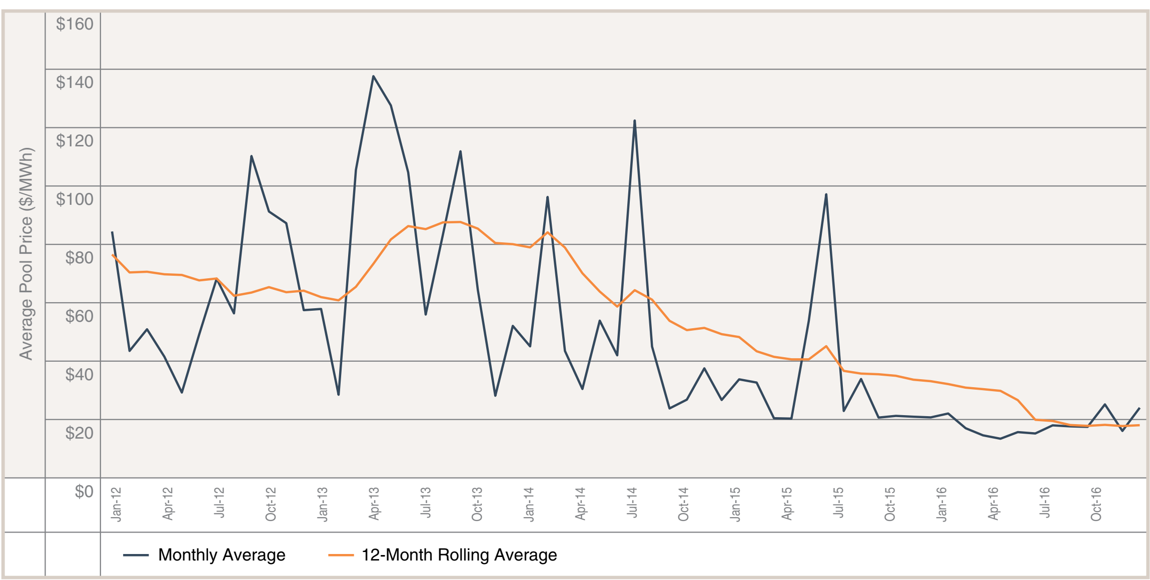
Pool price averaged $18.28/MWh over 2016—a decrease of 45 per cent from 2015. The AESO separates each day into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m.; the remaining hours of the day make up the off-peak period. In 2016, the average pool price during the on-peak period fell 52 per cent to $19.73/MWh, and the off-peak average pool price fell 17 per cent to $15.37/MWh. Table 1 summarizes historical price statistics over the 10-year period between 2007 and 2016.

TABLE 1: Annual pool price statistics

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Pool price ($/MWh)										
Average	66.95	89.95	47.81	50.88	76.22	64.32	80.19	49.42	33.34	**18.28**
On-peak average	84.37	112.97	58.04	62.99	102.22	84.72	106.13	61.48	40.73	**19.73**
Off-peak average	32.11	43.92	27.36	26.67	24.22	23.51	28.29	25.28	18.55	**15.37**
Market heat rate (GJ/MWh)										
Average	11.5	12.2	13.1	13.6	22.4	28.1	27.5	11.5	13.1	**9.9**

The pool price sets the wholesale price of electricity—the settlement price for all transactions in the energy market. Figure 1 shows the monthly distribution of prices over the past five years. Over 2016, the monthly average pool price ranged from a low of $13.63/MWh in April to a high of $25.37/MWh in October. The 12-month rolling average shows that pool prices have trended steadily lower since reaching a multi-year high in September 2013.

FIGURE 1: Monthly average pool price



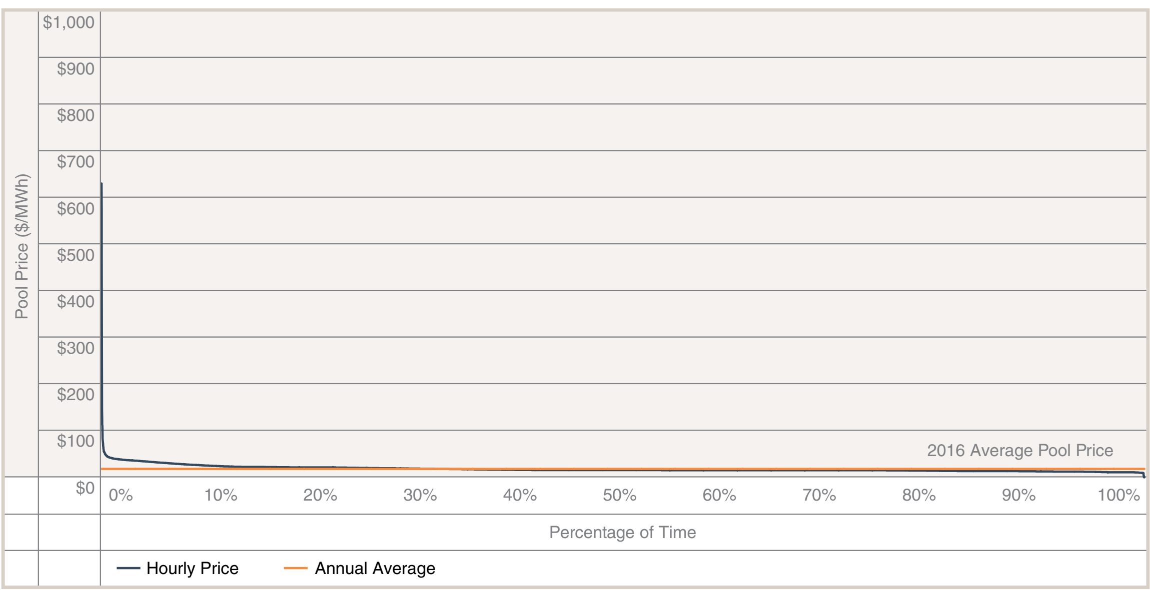
The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. Generators submit offers specifying the amount of power that they will provide in a one hour settlement period and the price at which they are willing to supply it. This offer price can 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. The 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 in each minute is called the marginal operating unit, and under normal operating conditions, sets the system marginal price for that one-minute period.

The pool price is the simple average of the 60 system marginal prices in the one-hour settlement interval. All energy generated in the hour and delivered to the AIES receives a uniform clearing price—the pool price—regardless of its offer price. System load draws energy from the grid, and pays the uniform clearing price.

The price duration curve represents the percentage of hours in which pool price equaled or exceeded a specified level. Figure 2 shows pool price duration over the 2016 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 32 per cent of hours, or approximately one hour of every three; however, because electricity was more expensive in these hours, they exerted upward influence on the average price.

FIGURE 2: 2016 pool price duration curve



The reliability of the AIES depends on the ability of System Controllers to dispatch supply to serve system load. During supply shortfall and supply surplus conditions, generation may be unavailable for dispatch. Left unaddressed, these system conditions could threaten the stability of the AIES. In order to preserve system stability, System Controllers must follow prescribed mitigation procedures to restore the balance between supply and demand.

Supply shortfall conditions occur when Alberta load exceeds the total energy available for dispatch from the merit order. When system shortfall conditions occur, according to the mitigation procedure, System Controllers may halt exports, re-dispatch imports and ancillary services, and finally, curtail firm load. When the system operator is forced to curtail load, the system marginal price is set to the administrative price cap of $1,000/MWh. The last load curtailment event occurred on July 2, 2013.

Supply surplus events occur when the supply of energy offered to the market at $0/MWh exceeds system demand. The mitigation procedure for supply surplus events authorizes System Controllers to halt imports, re-schedule exports, and curtail or cut in-merit generation. The AIES was in supply surplus conditions for 362 minutes in 2016: 264 minutes on June 19, and 98 minutes on April 13. Both of these events were successfully resolved by curtailing in-merit generation. The previous supply surplus event occurred on Oct. 11, 2015.

Heat rate fell 25 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 2016, the average natural gas price fell 20 per cent to $2.06/GJ. Because electricity prices fell more dramatically than gas prices, the annual market heat rate decreased 25 per cent to 9.9 GJ/MWh.

Alberta Internal Load

Average load fell one per cent while winter peak grew four per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2016, average Alberta Internal Load (AIL) decreased one per cent to 9,057 MW, but peak load set a new record at 11,458 MW. Slowing load growth since 2014 can be attributed to mild winter weather and decreased industrial activity throughout Alberta. The drop in average load in 2016 can be attributed largely to the reduction in operations at oilsands facilities during the devastating Fort McMurray wildfire in May.

TABLE 2: Annual load statistics

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Alberta Internal Load										
Total (GWh)	69,661	69,947	69,914	71,723	73,600	75,574	77,451	79,949	80,257	**79,560**
Average (MW)	7,952	7,963	7,981	8,188	8,402	8,604	8,841	9,127	9,162	**9,057**
Maximum (MW)	9,701	9,806	10,236	10,196	10,226	10,609	11,139	11,169	11,229	**11,458**
Minimum (MW)	6,440	6,411	6,454	6,641	6,459	6,828	6,991	7,162	7,203	**6,595**
Average growth	+0.4%	+0.1%	+0.2%	+2.6%	+2.6%	+2.4%	+2.8%	+3.2%	+0.4%	**-0.9%**
Load factor	82%	81%	78%	80%	82%	81%	79%	82%	82%	79%
System load										
Average (MW)	6,587	6,595	6,434	6,550	6,699	6,791	6,903	7,132	7,110	**7,070**

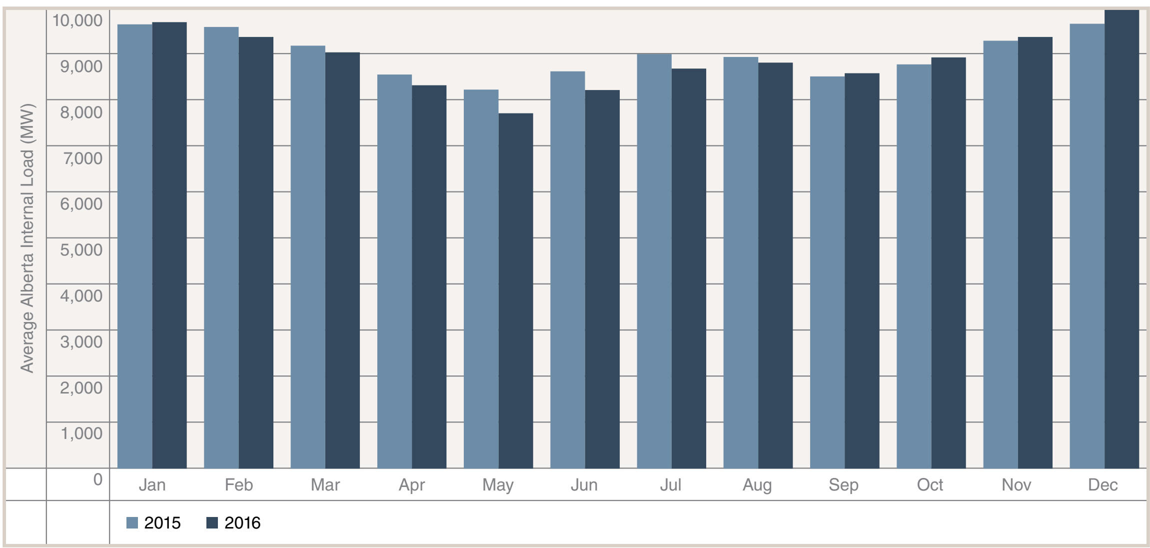
AIL is the sum of system load and behind-the-fence load. System load represents the total electric energy delivered to consumers in Alberta through the AIES, including transmission losses. Behind-the-fence load represents the total electric demand in Alberta that is served by on-site generation. Behind-the-fence 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.

Figure 3 shows the monthly average load in 2015 and 2016. Cold winter temperatures in January 2016 drove monthly load above the previous-year level, but milder weather starting in February reversed this trend. In May 2016, the Government of Alberta declared a provincial state of emergency in response to fires in northeastern Alberta that forced the evacuation of Fort McMurray and nearby communities.

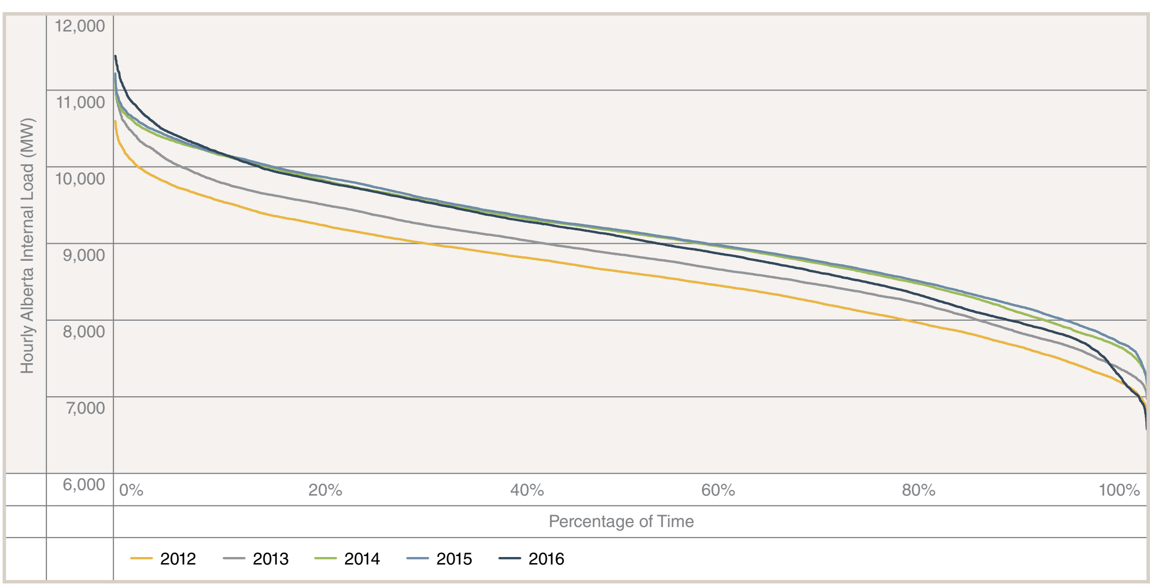
The destruction of residential and commercial properties and the interruption to oilsands and industrial operations reduced May load by six per cent over previous-year levels. Cold weather across Alberta increased the average load in December by three per cent over 2015 levels to set a new peak record in Alberta. Due to the fire effects and the very cold winter, the range between the minimum and maximum load in 2016 was largest in the history of Alberta.

FIGURE 3: Monthly average load



The load duration curve 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. The wide range of hourly loads observed in 2016 is clearly evident in this figure: AIL reached a higher peak and a lower point in 2016 than in any other year.

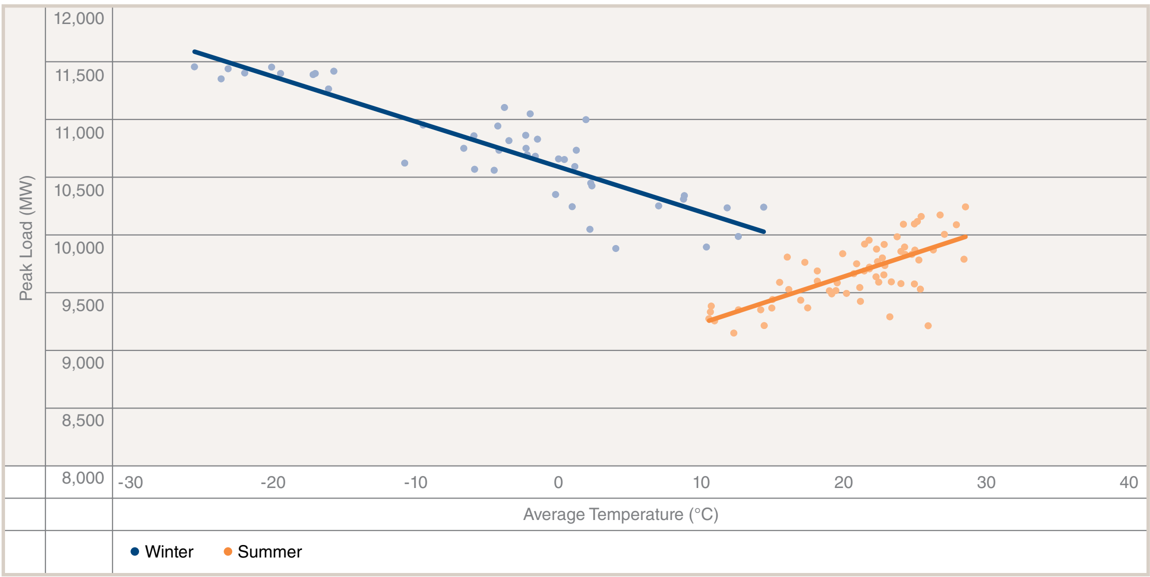
FIGURE 4: Annual load duration curves



Seasonal load

Temperature exerts a strong influence on 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 2016. On winter weekdays, a decrease of one degree Celsius increased peak load by an average of 41 MW. During summer weekdays, an increase of one degree Celsius increased peak load by an average of 42 MW.

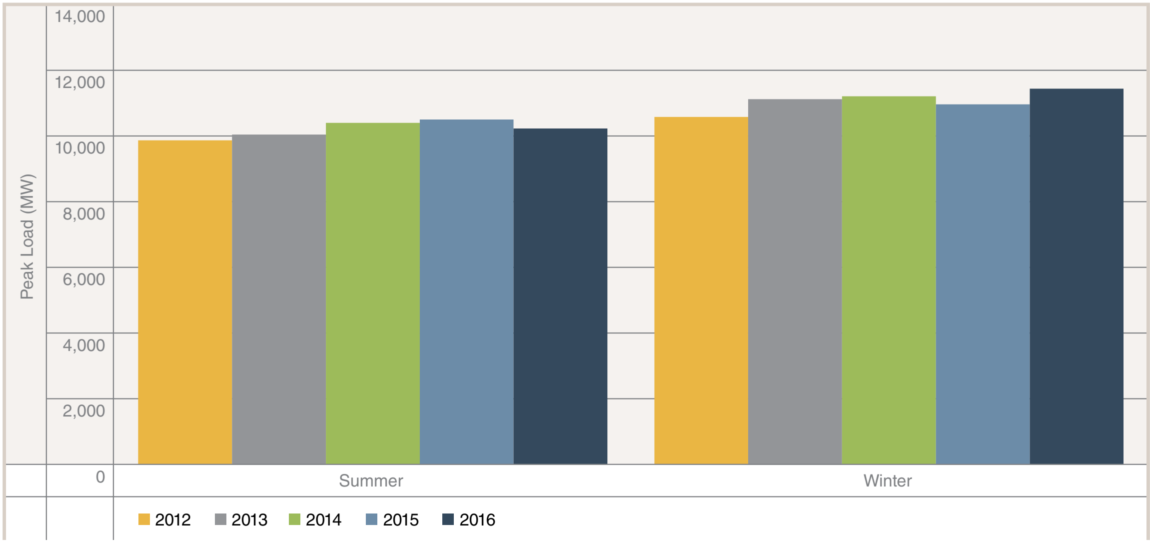
FIGURE 5: Daily peak demand and average temperature



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. Moderate summer temperatures in Alberta slowed load growth in 2016: summer load peaked at 10,244 MW on August 16, three per cent below the 2015 summer peak of 10,520 MW.

The effect of temperature on load is clearly evident in the difference between the two winters that fell in the 2016 calendar year. The winter season starts on November 1 and ends on April 30 of the following year. Mild temperatures in winter 2015 limited Alberta load: load peaked at 10,982 MW on Dec. 22, 2015. Significantly colder temperatures in 2016 drove winter load to a new record high: winter load peaked at 11,458 MW on Dec. 16, 2016. Figure 6 illustrates the winter and summer peak demand over the past five years.

FIGURE 6: Seasonal peak load

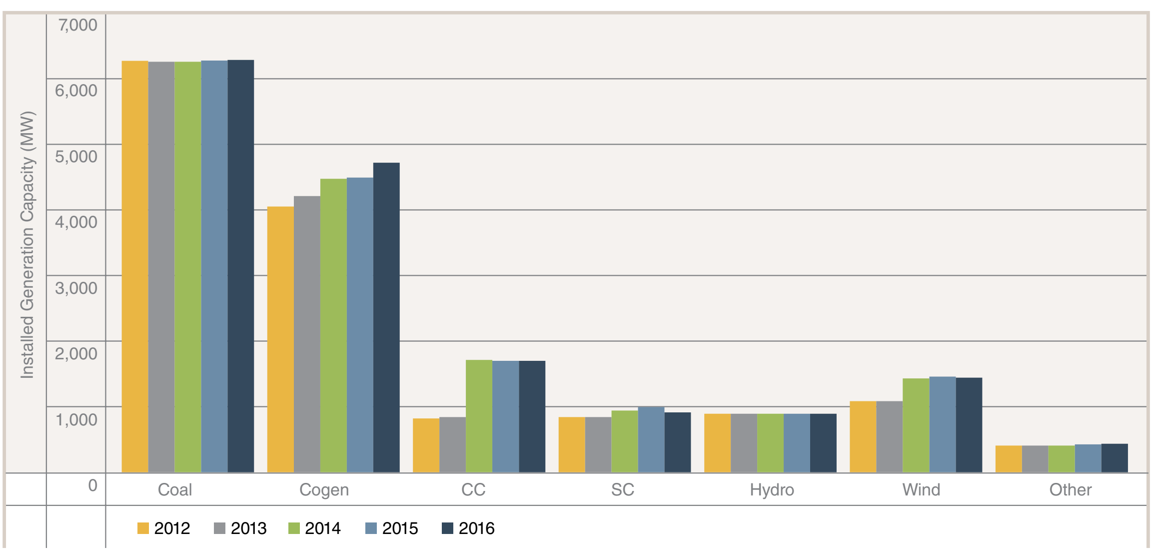


Installed generation

Total generation capacity increased one per cent

The total installed generation capacity in Alberta increased one per cent to 16,423 MW in 2016. 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 227 MW of new cogeneration gas capacity: 101 MW of new capacity at Christina Lake, 100 MW of additional capacity at CNRL Horizon, and two new cogeneration gas units at Lindbergh and Camrose totaling 26 MW in capacity.

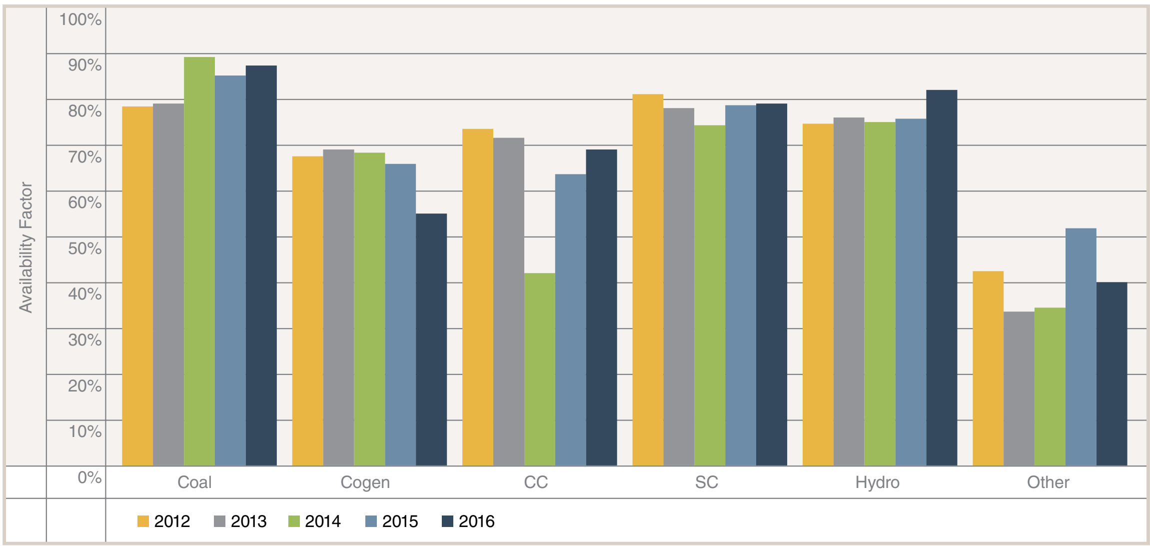
FIGURE 7: Annual generation capacity by technology



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.

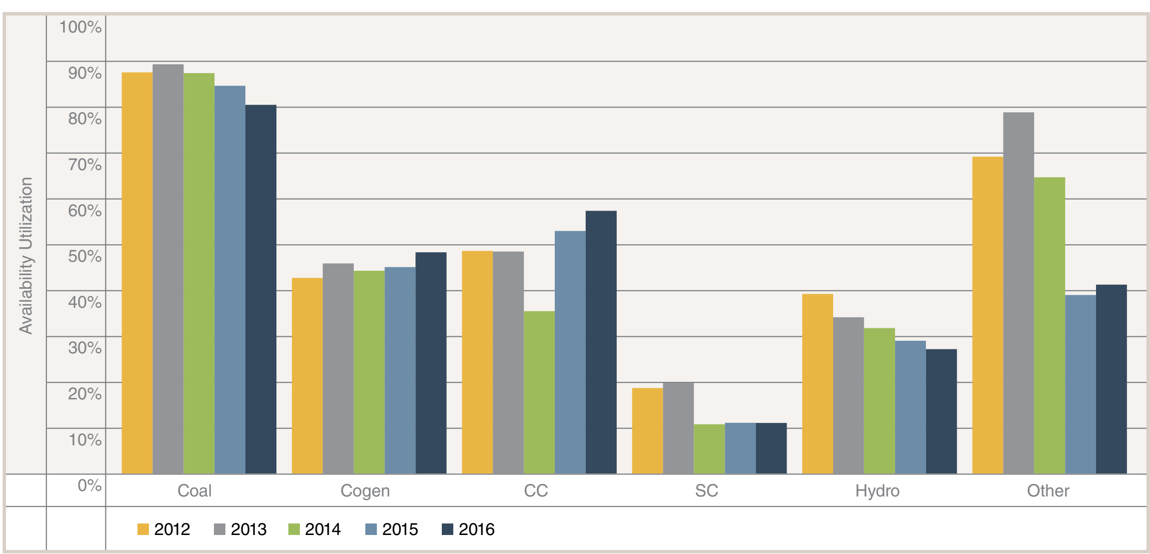
FIGURE 8: Annual availability factor by technology



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.

FIGURE 9: Annual availability utilization by technology



Over the five-year period between 2012 and 2016, the availability utilization of coal generation was consistently highest among dispatchable generation technologies. This relationship persists 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 supply of energy. Despite this behaviour, coal utilization has steadily declined since 2013 due to the return of coal assets from long-term outages and to competition from baseload combined-cycle gas generation.

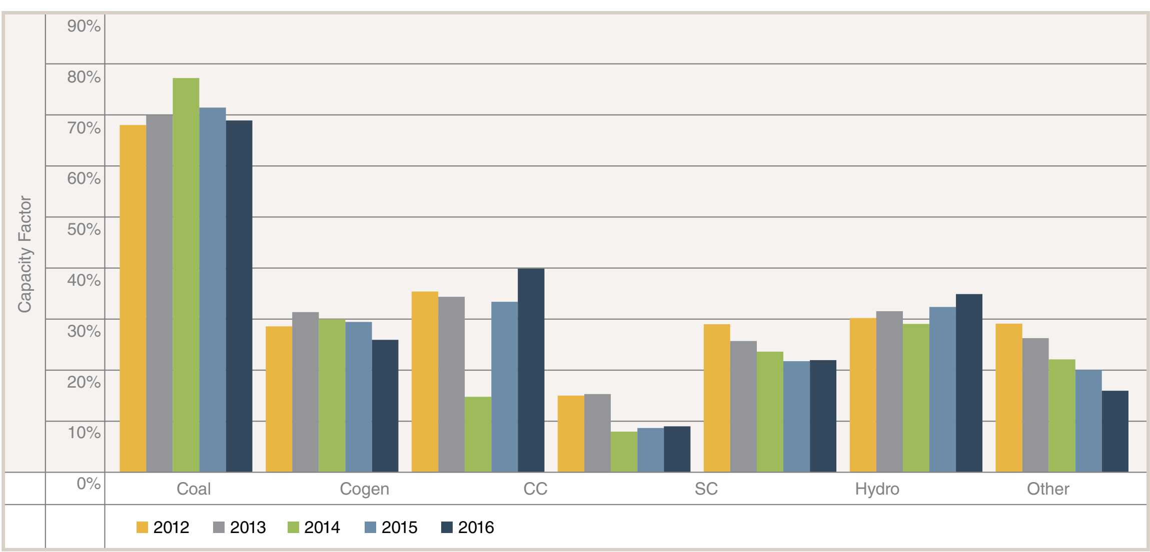
Although both coal generation and cogeneration gas are baseload technologies, the availability utilization of coal generation significantly exceeds that of cogeneration gas. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve behind-the-fence 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.

The availability utilization of simple-cycle gas is consistently lowest across dispatchable generation technologies. Simple-cycle gas generation tends to offer its energy to the market at higher prices than competing generation technologies. This offer behaviour tends to limit simple-cycle gas generation to peak system loads when pool prices are high and all lower priced generation in the merit order has already been dispatched. The increase in baseload generation capacity since 2013 reduced the frequency of high pool price hours, lowering pool price, and with it, simple-cycle gas utilization.

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



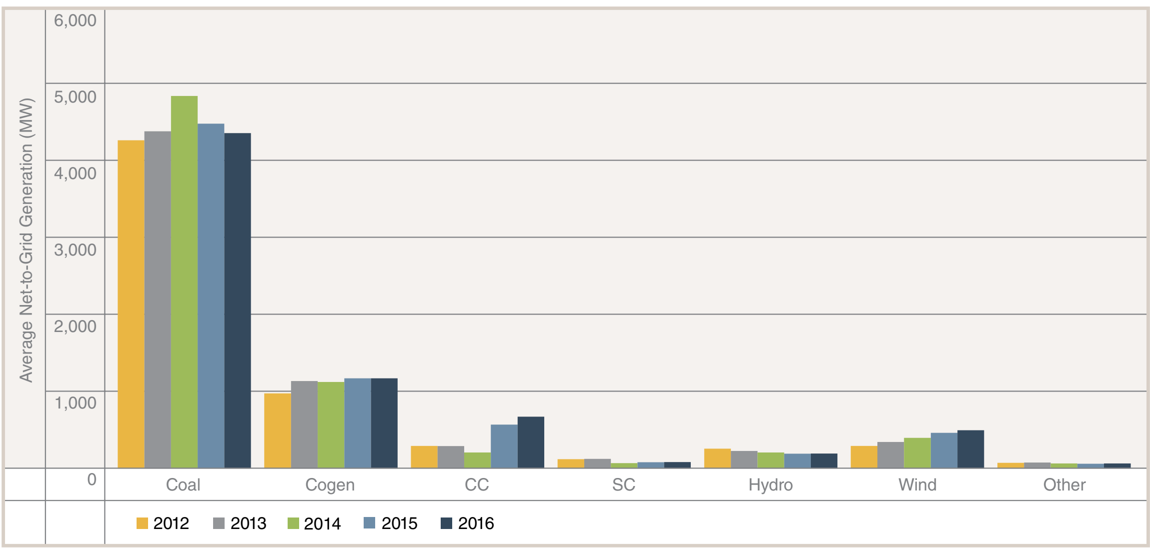
Over the five-year period between 2012 and 2016, the capacity factor of coal generation was consistently higher than the capacity factor of any other generation technology. In 2016, the capacity factor of coal reached 69 per cent—on average, for every 100 MW of installed capacity, coal generation delivered 69 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 2016, 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 supplied 62 per cent of net-to-grid energy

Figure 11 illustrates the total net-to-grid generation from each generation technology over the last five years. In 2016, coal generation supplied almost two-thirds of energy delivered to the AIES. Gas generation technologies delivered 27 per cent of net-to-grid generation. Renewable generation provided the remaining 11 per cent. Wind generation provided the majority of energy from renewable sources: seven per cent of total net-to-grid generation was provided by wind power alone.

FIGURE 11: Annual average net-to-grid generation by technology



Simple-cycle gas realizes highest achieved premium to pool price

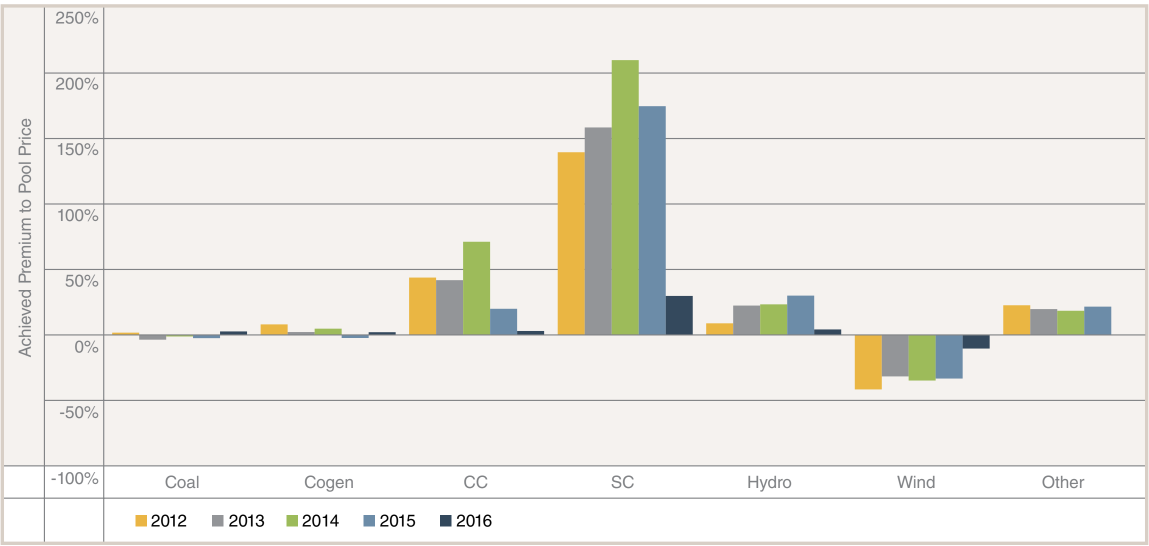
Achieved price represents the average price realized in the wholesale energy market for electricity delivered to the grid. Achieved price is calculated as the weighted average of hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation. The achieved margin 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. 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 discount of 50 per cent (that is, an achieved premium of negative 50 per cent) indicates that the achieved price is half the average pool price.

The achieved premium to pool price reflects the effect of offer behaviour on the average revenue per unit of energy delivered to the grid. Generation technologies that operate at a constant level regardless of pool price would realize achieved premiums around zero. Generation technologies that restrict operation to higher priced hours would realize positive achieved premiums to pool price. Generation technologies that operate in lower priced hours would realize negative achieved premiums to pool price.

Figure 12 illustrates the achieved premium to pool price realized by each generation technology over the past five years. Note that both premiums and discounts to pool price in 2016 were significantly muted from those in previous years. Operational characteristics of generation technologies inform offer behaviour, which influences the achieved price; however, the low price volatility in 2016 limited the effect of offer behaviour on achieved price. As a result, the differences between the achieved premiums realized by different generation technologies were less pronounced than those observed in previous years.

FIGURE 12: Annual average achieved premium to pool price by 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 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 along with its operational considerations 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 2016, coal and cogeneration gas technologies realized premiums to pool price between two and three per cent.

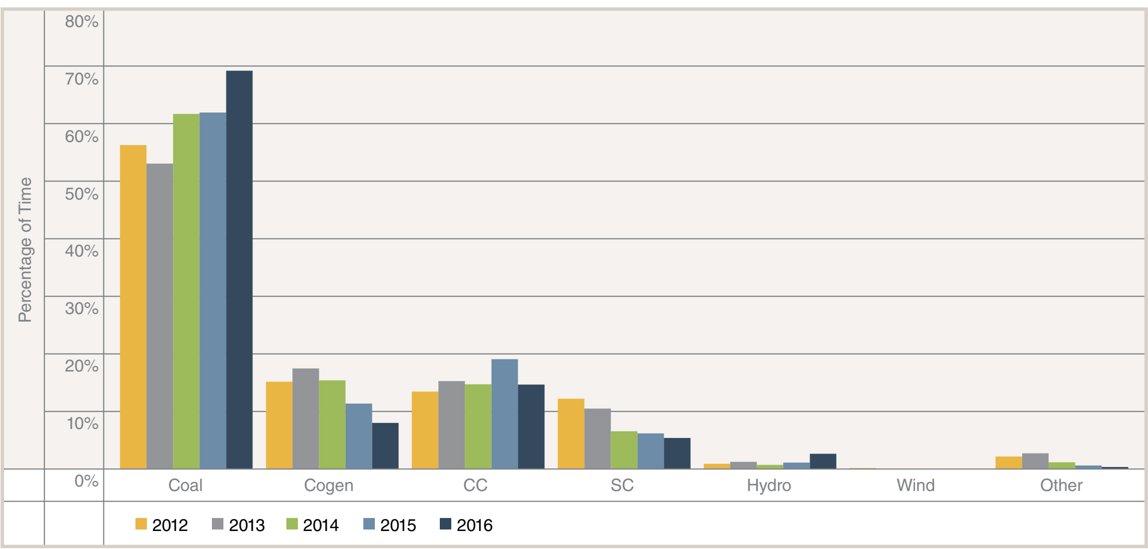
Peaking generation technologies achieve greater operational flexibility than baseload generation, but at higher cost. The combustion turbines used in simple-cycle gas generation can halt and restart operation without incurring high costs, but cost more to operate. These higher costs are reflected in higher offer prices, which positions peaking generation capacity late 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, simple-cycle gas generation achieved the highest premium across all generation technologies in Alberta. In 2016, simple-cycle gas received only a 30 per cent premium to pool price—much lower than historical achieved premiums.

Wind generation is the only technology that consistently achieved 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 2016, wind generation received a 10 per cent discount to pool price.

Coal generation sets marginal price in 69 per cent of hours

Figure 13 illustrates how frequently each generation technology sets 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 2016. The high frequency where low-priced coal generation set the price contributed to the low average pool price in 2016.

FIGURE 13: Annual marginal price-setting technology



Supply adequacy

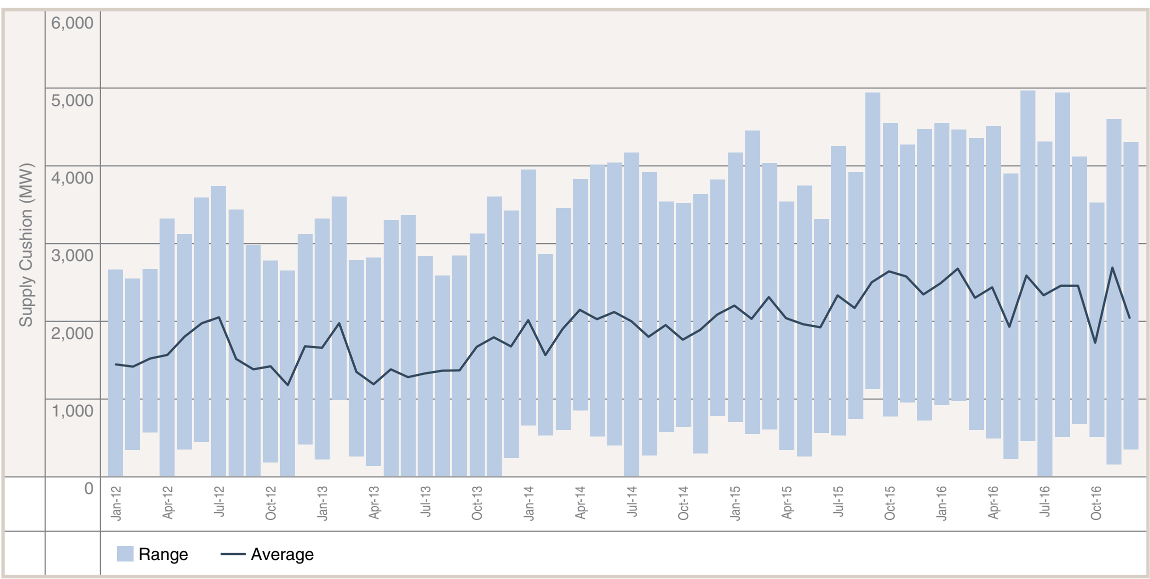
Supply adequacy expresses the ability of the system to serve demand. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin. An in-depth analysis of future supply adequacy is provided on the AESO website in the quarterly *Long-Term Adequacy Metrics* report.

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 remained available to respond to unplanned outages. Over 2016, the average supply cushion increased four per cent to 2,333 MW due mostly to the fall in system load.

Supply shortfall conditions arise when 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. In 2016, supply shortfall conditions occurred only once: over a 15-minute interval on July 26. 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



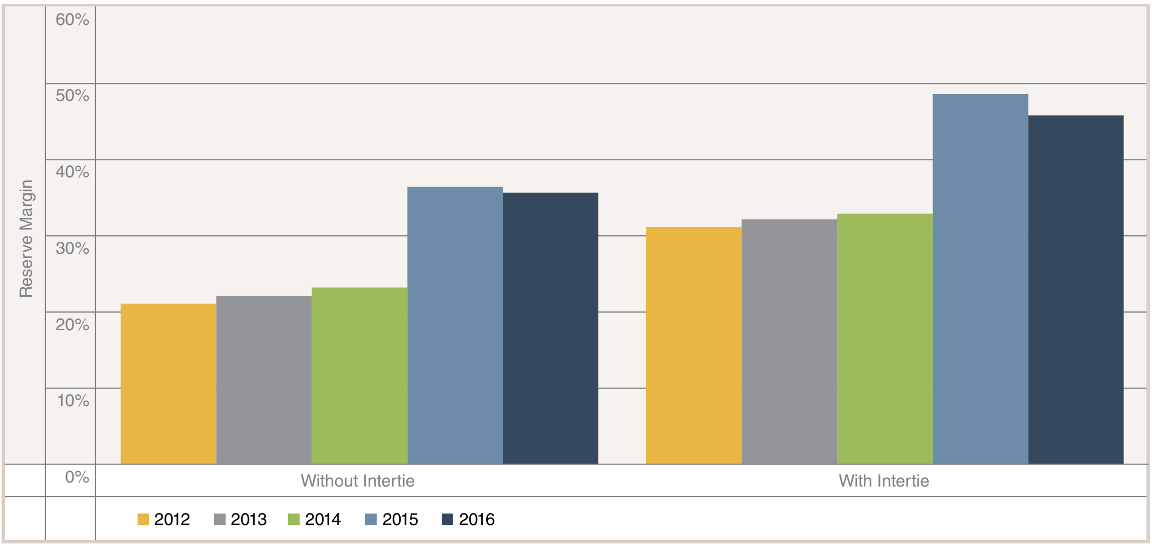
Reserve margin indicates adequate supply

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. The slight decrease in the reserve margin from 2015 to 2016 indicates that excess generation capability declined more rapidly than peak system load; however, the high reserve margin in 2016 relative to previous years indicates that the Alberta wholesale market remained adequately supplied with generation capacity in 2016.

FIGURE 15: Annual reserve margin



Imports and exports

Alberta transfers electricity across interties with three neighbouring control areas: British Columbia, Montana, and Saskatchewan. Before 2013, imports and exports only flowed between Alberta and the two neighbouring Canadian provinces. The Montana-Alberta Tie Line (MATL) started commercial operation in September 2013.
This new intertie permitted Alberta to transfer energy directly across the border with the United States.

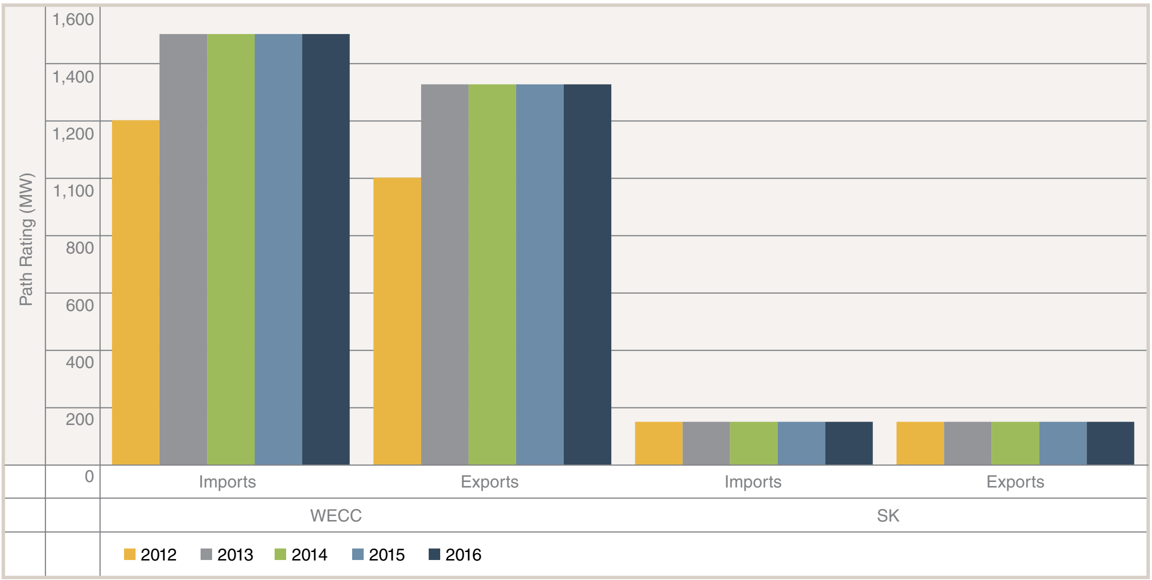
Transfer path rating remained stable

The transfer path rating establishes the limits of power flow across defined paths between control areas. The maximum power that can flow between control areas is governed by the path rating of the individual intertie.

Alberta, British Columbia, and Montana are members of the Western Electricity Coordinating Council (WECC) region—Saskatchewan is not. The total power that can flow between Alberta and other members of the WECC region is expressed as the combined path rating, calculated as the sum of the path ratings of the two 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. Path ratings remained unchanged between 2015 and 2016.

FIGURE 16: Annual path rating by transfer path

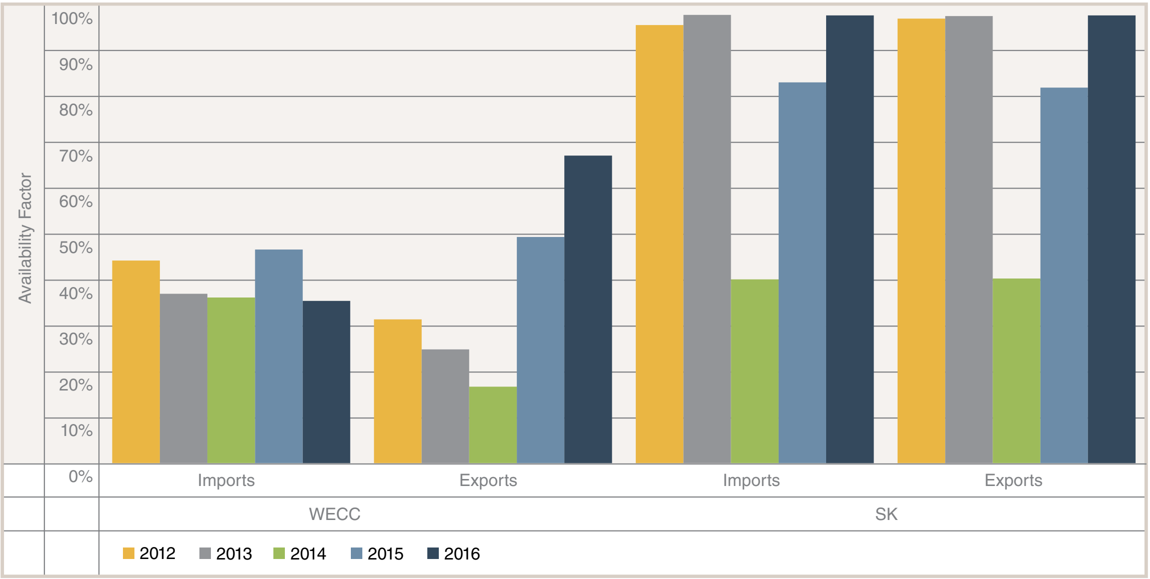


Export availability increased

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, and is calculated as the ratio of the ATC to the path rating. 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 decrease in import availability on the combined BC-MATL transfer path reflects more accurate reporting on constraints that limit import ATC. The AESO is currently working to restore intertie transfer capability.

FIGURE 17: Annual availability factor by transfer path



Import 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 2016, import utilization declined from 2015 levels while export utilization increased or held steady.

FIGURE 18: Annual availability utilization by transfer path

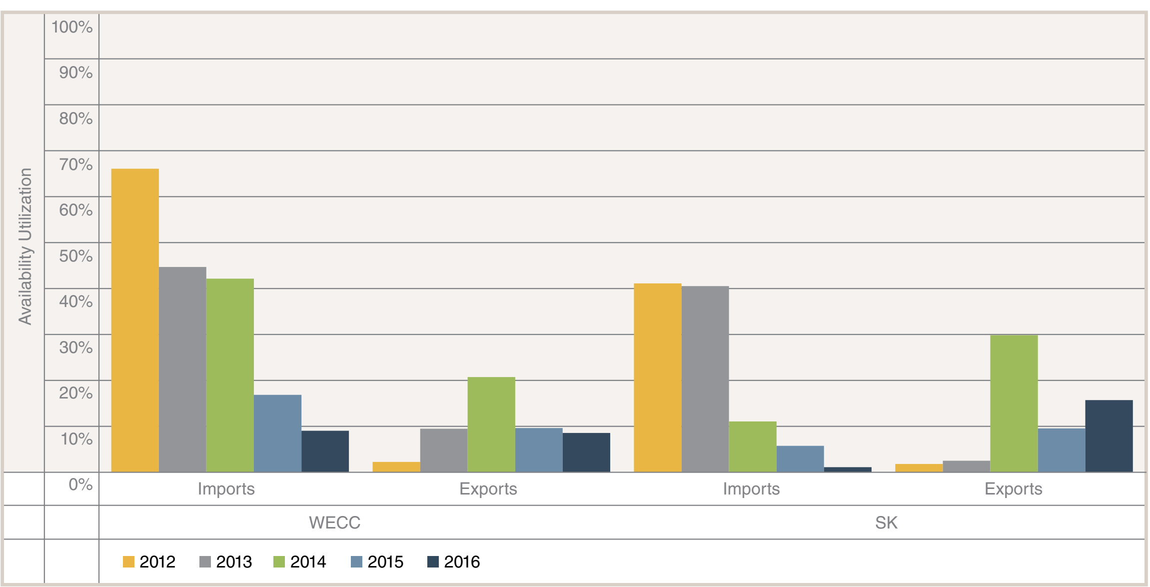


Figure 19 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. Interchange utilization represents the ratio of net imports across the intertie to its transfer capability. Net imports include the volume of operating reserve procured on the intertie. The utilization calculation reflects the limits of the interties with BC and Montana, the combined operating limits, and the Alberta system operating limit. Over 2016, Alberta imported energy from the WECC region in 31 per cent of hours, and exported energy in 36 per cent of hours.

FIGURE 19: Annual intertie utilization with WECC region

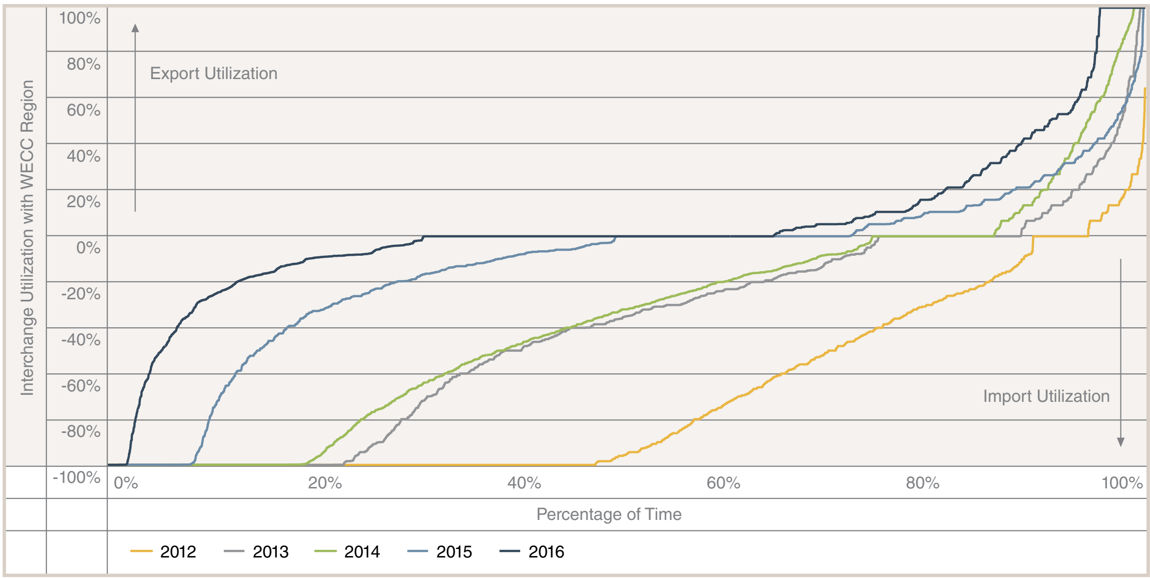
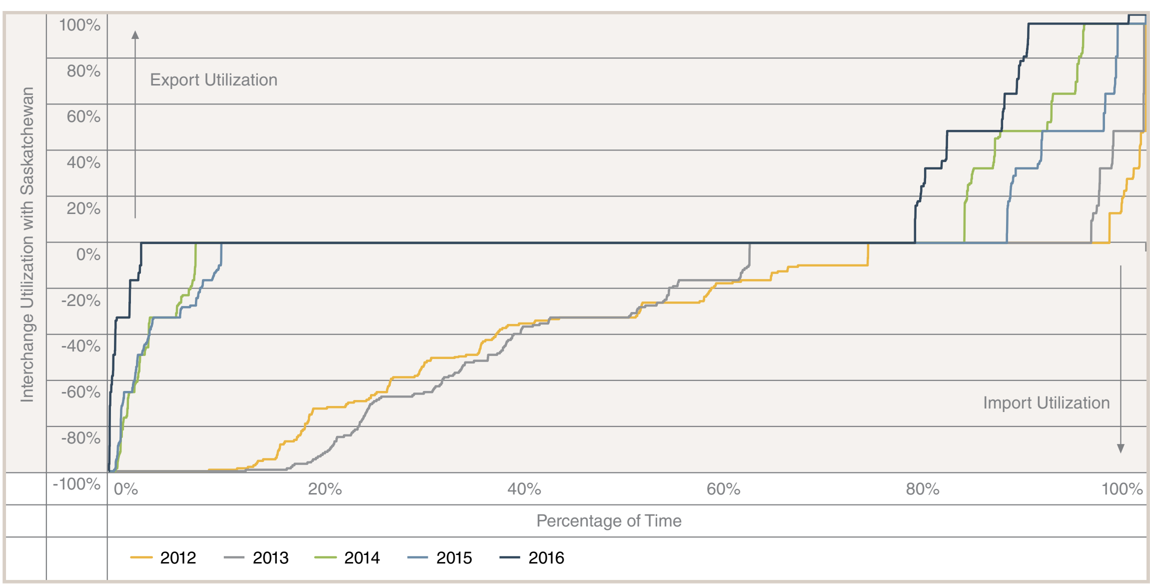


Figure 20 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2016, Alberta imported energy from Saskatchewan in three per cent of hours, and exported energy in 21 per cent of hours.

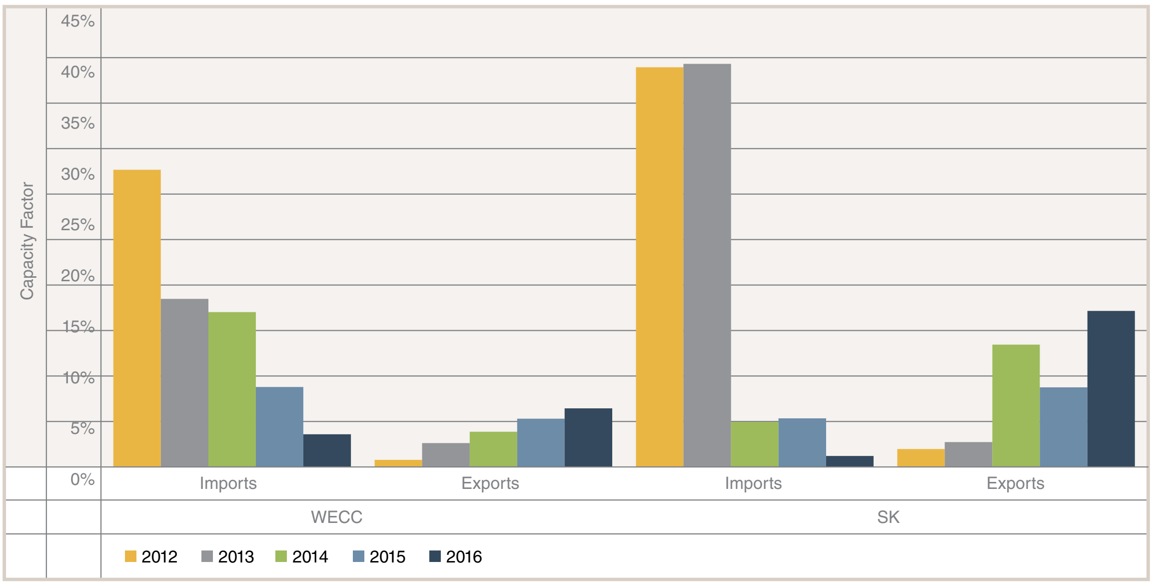
FIGURE 20: Annual intertie utilization with Saskatchewan



Capacity factor reflects increase in net exports

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.

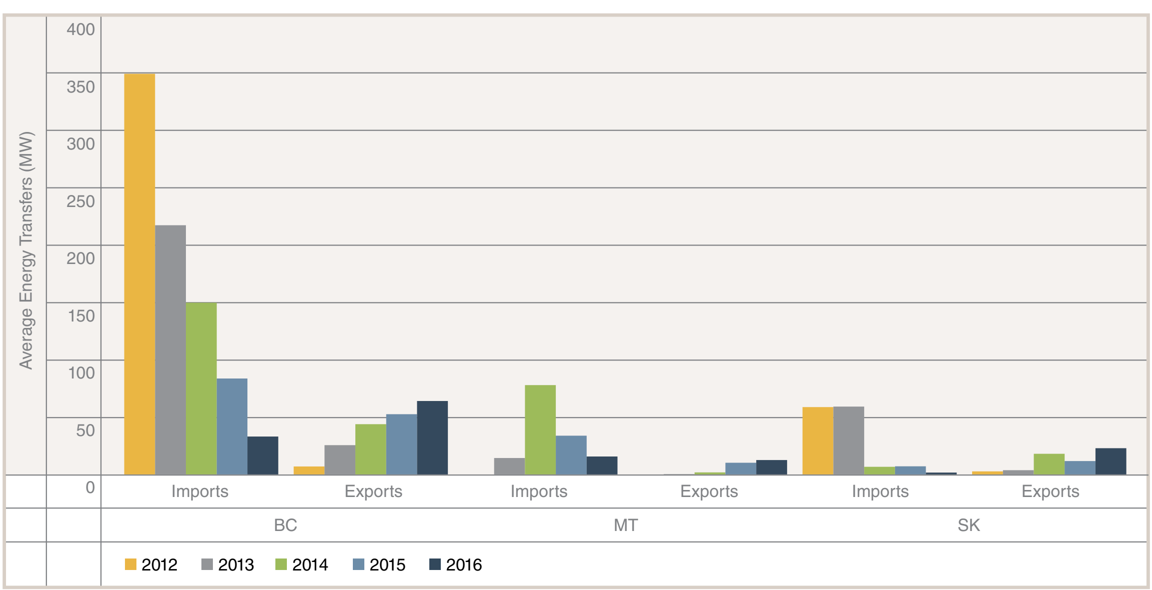
FIGURE 21: Annual capacity factor by transfer path



Exports from Alberta exceeded imports

Figure 22 illustrates the annual average energy transferred from each province or state. In 2016, Alberta was a net exporter for the first time in 14 years, and only the second time since 1995. Net imports from all jurisdictions fell as low pool prices in Alberta discouraged imports and encouraged exports. Alberta exported more electricity to British Columbia and Saskatchewan than it imported; however, Alberta imported more electricity from Montana than it exported. In total, net exports to British Columbia and Saskatchewan outweighed net imports from Montana.

FIGURE 22: Annual intertie transfers by province or state

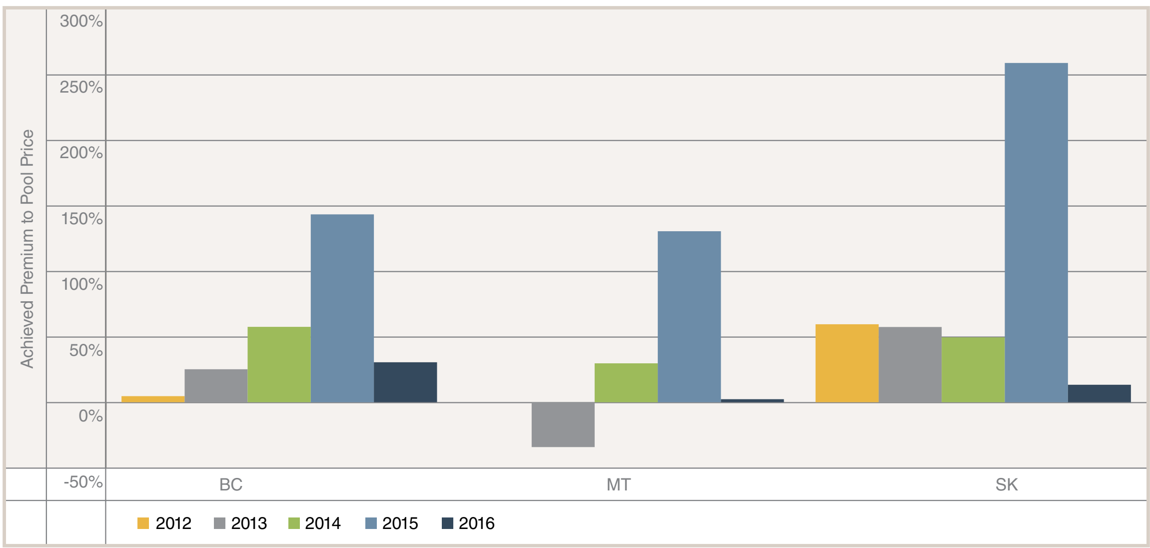


Achieved premium to pool price for imports tumbles

Figure 23 illustrates the achieved premium to pool price on imported energy by province or state. Imported energy exerts downward pressure on pool price. All imports are priced at $0/MWh. As a result, imported energy displaces power from the merit order, and reduces the system marginal price. Market participants earn a profit by importing energy into Alberta only when the pool price—after the effect of imports—exceeds their costs.

Although low pool price volatility in 2016 limited profit opportunities for importers, the achieved premium to pool price on imported energy remained positive: the achieved premium ranged between two per cent and 31 per cent. The achieved premium for imported energy was comparable or superior to the achieved premium for every generation technology except simple-cycle gas generation. This outcome is consistent with the reduced energy transfers observed previously: fewer opportunities for profit reduced energy imports to Alberta.

FIGURE 23: Annual achieved premium to pool price by province or state



Wind generation

Wind generation served six per cent of Alberta Internal Load

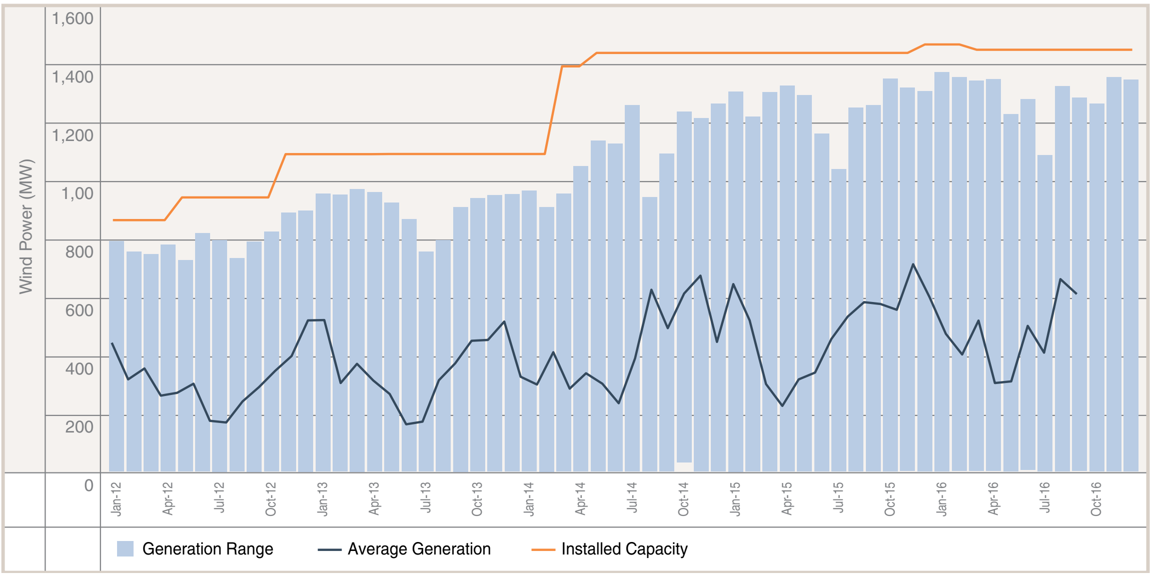
Table 3 summarizes the annual statistics for wind generation. Over 2016, installed wind generation capability declined by one per cent to 1,445 MW due to the retirement of 18 MW of generation capacity at Cowley Ridge in southern Alberta. At the end of the year, wind farms made up nine per cent of the total installed generation capacity in Alberta. Energy produced by wind generation served six per cent of total load in 2016.

TABLE 3: Annual wind generation statistics

Year	2012	2013	2014	2015	2016
Installed wind capacity at year end (MW)	1,087	1,088	1,434	1,463	**1,445**
Total wind generation (GWh)	2,574	3,013	3,519	4,089	**4,402**
Wind generation as a percentage of total AIL	3%	4%	4%	5%	**6%**
Average hourly capacity factor	32%	32%	30%	33%	**35%**
Maximum hourly capacity factor	92%	89%	88%	94%	**93%**
Wind capacity factor during annual peak AIL	5%	50%	3%	7%	**15%**

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.

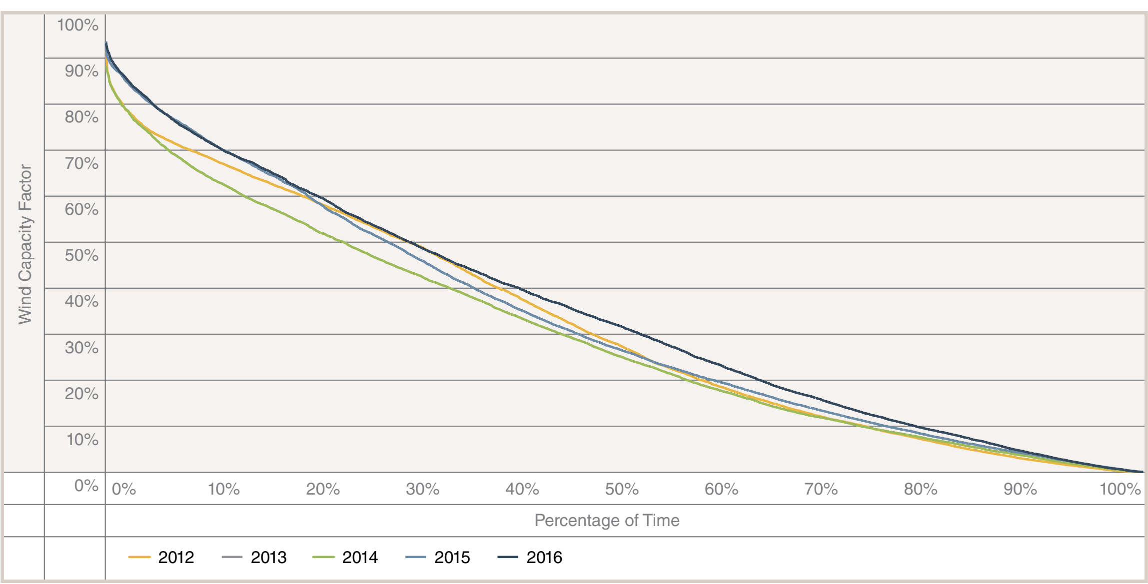
FIGURE 24: Monthly wind capacity and generation



Wind capacity factor remains constant

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 35 per cent over 2016: for every 100 MW of installed wind capacity, wind power generated an average of 35 MWh of energy each hour. The capacity factor—that is, the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of 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 generation acts as price-taker

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 AIES. 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 market effect in 2016. Over the year, no wind assets offered power at non-zero prices.

Regional wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. This concentration of wind generation contributed to 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 2016, wind generation capacity totaled 1,096 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.

Table 4 tabulates regional wind generation statistics over 2016. The average capacity factor for southern wind slightly exceeded that for central wind; however, the achieved price for central wind was slightly higher than that for southern wind. For each megawatt of installed capacity, a wind farm in southern Alberta generated more energy than a wind farm in central Alberta, but for each unit of energy generated, a central wind farm earned more money than a southern wind farm.

TABLE 4: 2016 Regional wind statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,096	349	**1,445**
Total wind generation (GWh)	3,377	1,028	**4,405**
Average wind capacity factor	35%	34%	**35%**
Achieved price ($/MWh)	$16.27	$16.79	**$16.40**

Ancillary services

Cost of operating reserve fell 51 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 Standards 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 as required 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 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.

Table 5 summarizes the total cost of operating reserve over the past five years. The total cost of operating reserve in 2016 decreased 51 per cent to $67 million, driven by the effect of lower pool prices on the cost of active reserves. Reduced procurement and activation of standby reserves further reduced the total cost of operating reserves.

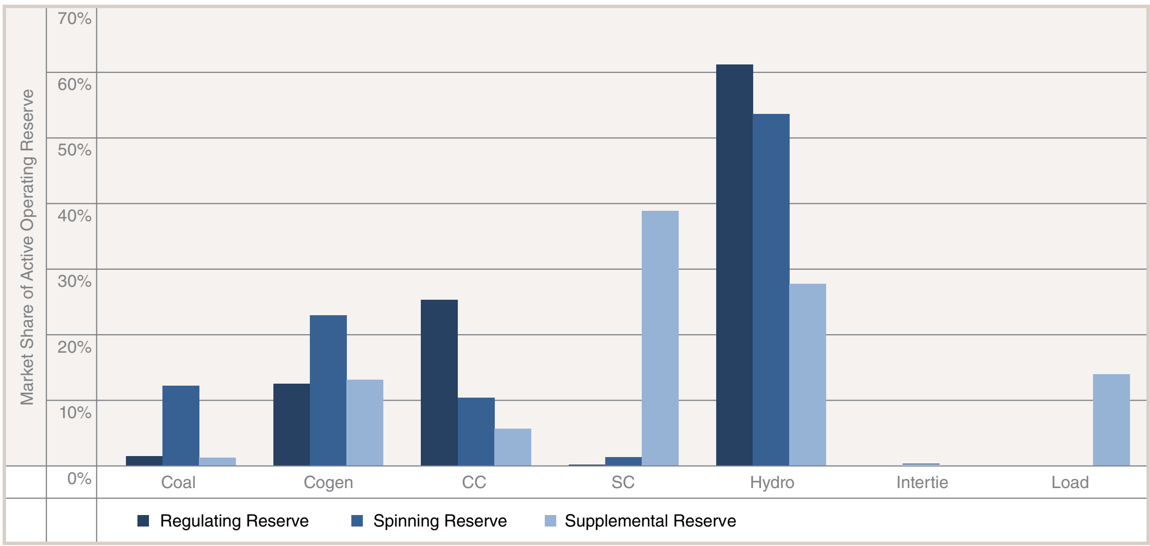
TABLE 5: Annual operating reserve statistics

Year	2012	2013	2014	2015	2016
Volume *(GWh)*					
Active procured	5,901	6,019	6,006	5,333	**5,262**
Standby procured	2,133	2,144	2,142	2,140	**2,049**
Standby activated	58	77	65	136	**85**
Cost *($-millions)*					
Active procured	$296	$341	$168	$105	**$53**
Standby procured	$26	$19	$14	$13	**$12**
Standby activated	$5	$10	$3	$20	**$2**
Total	$326	$369	$185	$138	**$67**

The technical requirements of operating reserve differ between products. Currently, regulating reserve can only 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. In 2016, hydroelectric generation obtained a greater market share of all active operating reserve products than any other technology.

FIGURE 26: 2016 Market share of active operating reserves



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 downward influence of TMR dispatches on pool price by removing dispatched in-merit energy from the merit order.

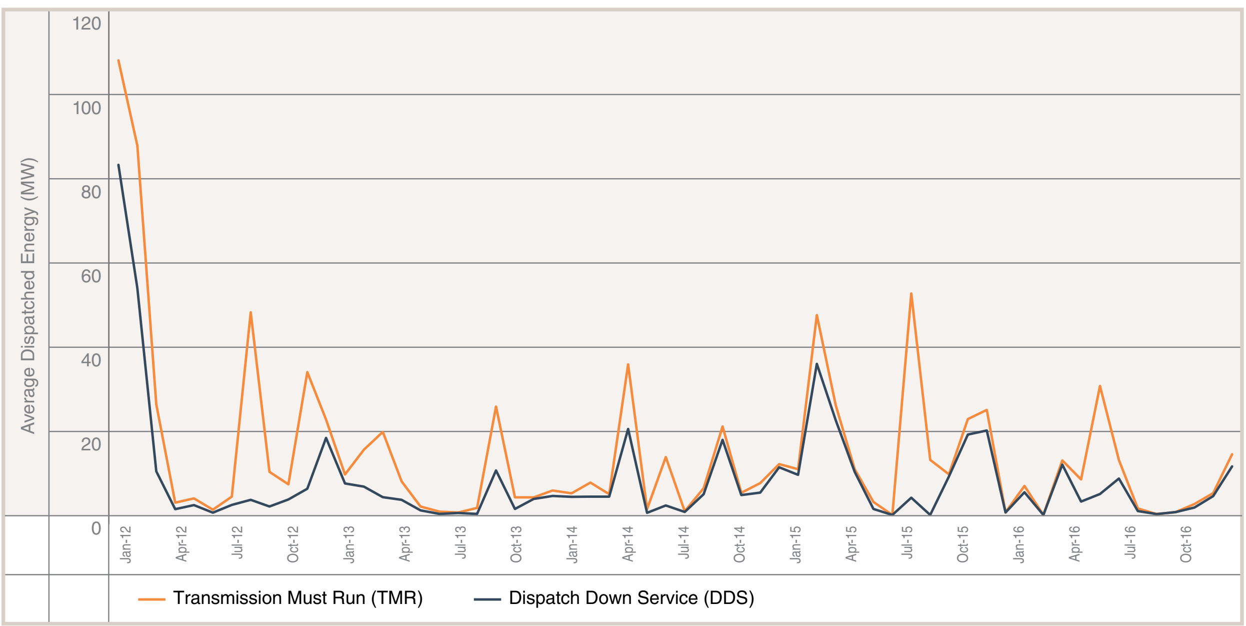
DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2016, DDS offset 55 per cent of dispatched TMR volume. Table 6 summarizes the annual TMR and DDS statistics over the past five years. The annual cost of DDS in 2016 totaled $0.5 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	2012	2013	2014	2015	2016
Transmission Must-Run					
Dispatched energy (GWh)	260	71	88	161	71
Dispatch Down Service					
Total payments ($-millions)	$1.7	$0.6	$1.2	$1.6	$0.5
Dispatched energy (GWh)	137	32	59	95	39
Average charge ($/MWh)	$0.03	$0.01	$0.02	$0.02	$0.01

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



Uplift payments

All energy delivered to the Alberta interconnected energy system receives the same price, called the pool price. Uplift payments represent additional compensation paid to market participants for dispatched generation that was offered at a higher price than the pool price. Table 7 summarizes the cost of uplift payments over the past five years.

TABLE 7: Annual uplift payment statistics

Year	2012	2013	2014	2015	2016
Payments to suppliers on the margin					
Average range ($/MWh)	17.11	18.7	7.54	5.99	**1.08**
Total payments ($-millions)	2.24	2.60	1.16	1.25	**0.16**
Transmission constraint rebalancing					
Price effect ($/MWh)				0	**-0.01**
Constrained-down generation (GWh)				0	**2**
Total payments ($-millions)				0	**0.01**

Payments to suppliers on the margin decrease 87 per cent

Payment to suppliers on the margin (PSM) is a settlement rule intended to address price discrepancies between dispatch and settlement intervals. 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.

The annual cost of PSM decreased 87 per cent to $0.16 million in 2016. 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 82 per cent to $1.08/MWh in 2016.

Transmission constraint rebalancing

The revised transmission constraint management (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 must dispatch generators that would otherwise fall out of merit. Until November 2015, this normally out-of-merit generation could set the system marginal price.

After the revised TCM rule became effective in November 2015, only generation that would be in merit in an unconstrained transmission system can set system marginal price. If a transmission constraint requires System Controllers to constrain in-merit generation, the energy dispatched to replace the constrained-down generation (CDG) does not influence system marginal price. Instead, this replacement energy receives an additional uplift payment, referred to as transmission constraint rebalancing (TCR).

In 2016, the implementation of the revised TCM rule reduced the average pool price by $0.01/MWh from the value that would have been calculated under the previous methodology. Constraints on the transmission system required System Controllers to curtail 2 GWh of in-merit energy and additional TCR payments to market participants totaled approximately $10,000.

Final notes

As the market evolves throughout 2017 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.

Alberta Electric System Operator
2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
Fax: 403-539-2949
www.aeso.ca
@theaeso