AESO 2019 Annual Market Statistics

MARCH 2020

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 *AESO 2019 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 information that underlies the tables and figures in this report.

In 2019, 194 participants in the Alberta wholesale electricity market transacted approximately $7 billion of energy. The annual average pool price for wholesale electricity increased nine per cent from its previous-year value to $54.88/megawatt hour (MWh). The average natural gas price increased 17 per cent, averaging $1.69/gigajoule (GJ). The average spark spread based on a 7.5 GJ/MWh heat rate increased six per cent to $42.21/MWh from its previous-year value.

The average Alberta Internal Load (AIL) decreased by half a per cent over 2018 values.

Price	2018	2019	Year/Year Change
Pool price	$50.35/MWh	$54.88/MWh	+9%
Gas price	$1.44/GJ	$ 1.69/GJ	+17%
Spark spread at 7.5 GJ/MWh	$39.68/MWh	$42.21/MWh	+6%

Load	2018	2019	Year/Year Change
Average AIL	9,741 MW	9,695 MW	-0.5 %
Winter peak	11,471 MW	11,698 MW	+2 %
Summer peak	11,169 MW	10,822 MW	-3 %

The installed generation capacity increased three per cent in 2019, mostly due to the addition of new wind generation. Coal-fired generation[1] continued to provide more energy than any other sources in 2019.

Gas-fired generation continued to provide a large share of generated energy in 2019, supplying 43 per cent of Alberta's net-to-grid energy, a one percent increase from 2018.

Alberta was a net importer of electricity along all interties in 2019. Imports to the province decreased 37 per cent from 2018 levels. Exports decreased by 16 per cent.

[1] Several coal-fired facilities in Alberta have converted to "dual fuel" or "co-fired" capability, allowing them to operate as either natural gas- or coal-fired, or both. The AESO is presently unable to discern which fuel is being utilized at any given time and, therefore, references in this report to coal-fired generation may also reflect natural gas firing at these facilities.

Price of electricity

Pool price increased nine per cent

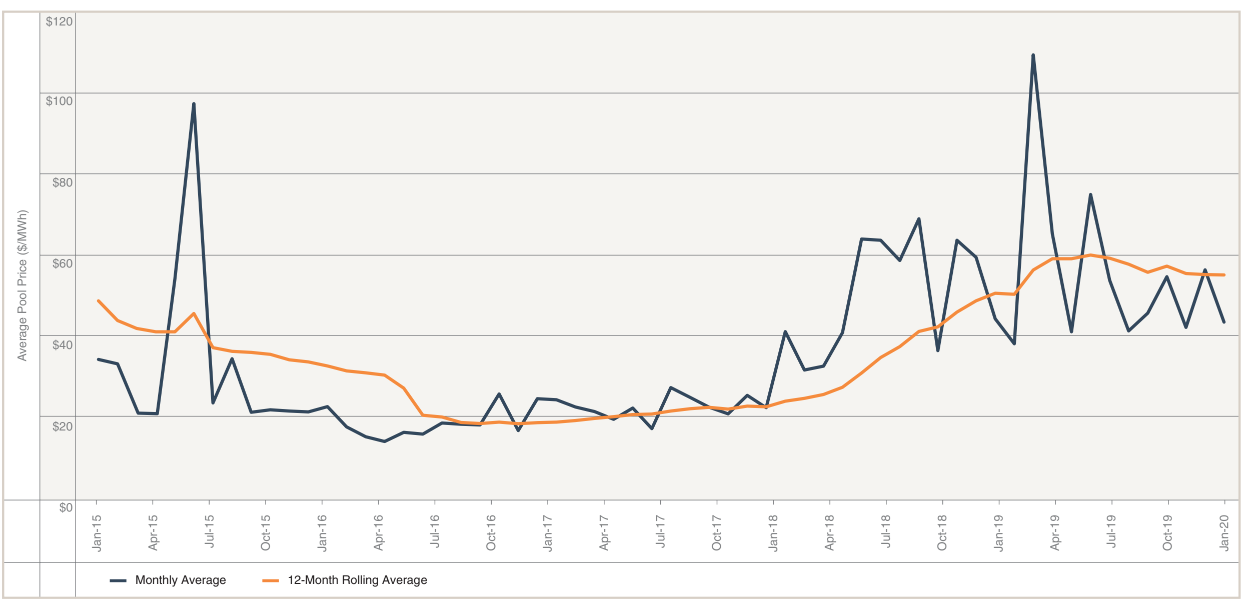
The pool price averaged $54.88/MWh over 2019—an increase of nine per cent from 2018. In this report, each day is separated into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m.; the remaining hours of the day make up the off-peak period. In 2019, the average pool price during the on-peak period increased eight per cent to $64.12/MWh, and the off-peak average pool price increased 12 per cent to $36.40/MWh. Table 1 summarizes historical price statistics over the 10-year period between 2010 and 2019. The average pool price in 2019 was the highest since 2013.

TABLE 1: Annual market price statistics

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Pool price ($/MWh)										
Average	50.88	76.22	64.32	80.19	49.42	33.34	18.28	22.19	50.35	**54.88**
On-peak average	62.99	102.22	84.72	106.13	61.48	40.73	19.73	24.46	59.28	**64.12**
Off-peak average	26.67	24.22	23.51	28.29	25.28	18.55	15.37	17.64	32.47	**36.40**
Spark spread at 7.5 (GJ/MWh)										
Average	22.5	50.4	47.3	57.6	17.6	14.1	2.8	6.8	39.7	**42.2**

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. Through 2019, the monthly average pool price ranged from a low of $37.83/MWh in January to a high of $109.36/MWh in February.

FIGURE 1: Monthly average pool price



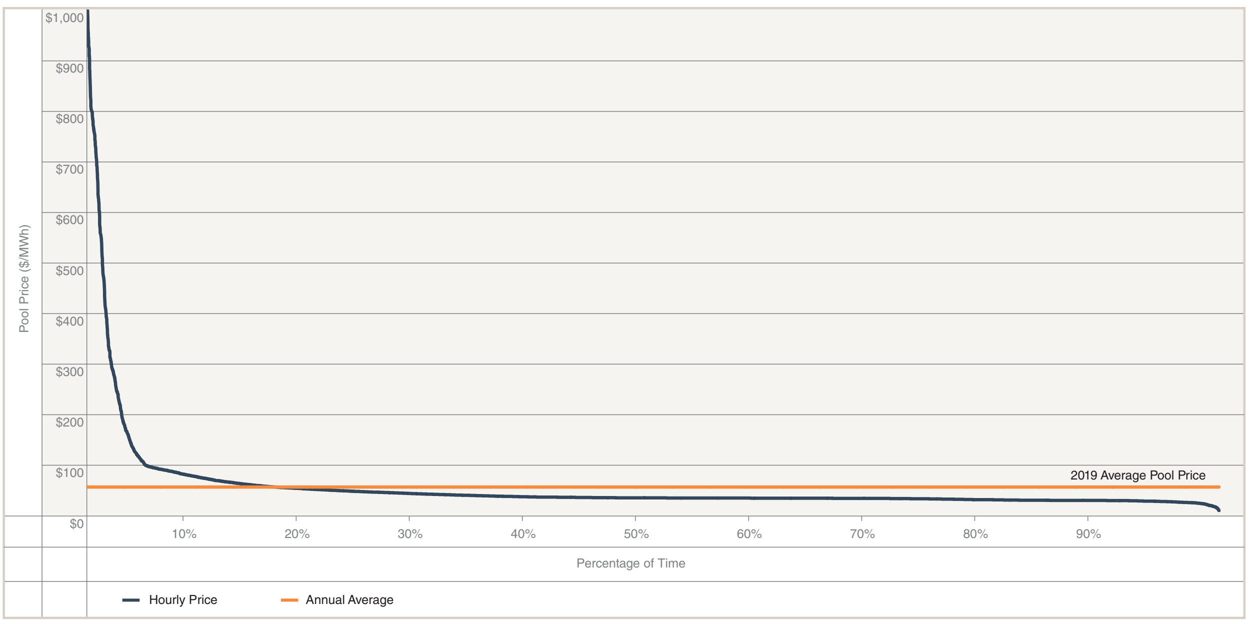
The hourly price of electricity in Alberta is determined according to the economic principles of supply and demand. For any given hour, generators submit offers specifying the amount of power that they will provide and the price at which they are willing to supply it. This offer price can range from a low of $0/MWh to a maximum of $999.99/MWh. The offers are arranged from lowest to highest price to create the energy market 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 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 2019. The hourly price of electricity exceeded the annual average in 17 per cent of hours, or approximately one hour of every six.

FIGURE 2: 2019 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, mitigation procedures are deployed under which system controllers may halt exports, re-dispatch imports and ancillary services, and finally, curtail firm load. When the system operator is forced to curtail firm load, the system marginal price is set to the administrative price cap of $1,000/MWh. The last firm 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 not in any supply surplus conditions in 2019. System marginal price was constantly above zero $/MWh in 2019. The last supply surplus event occurred on June 4, 2018.

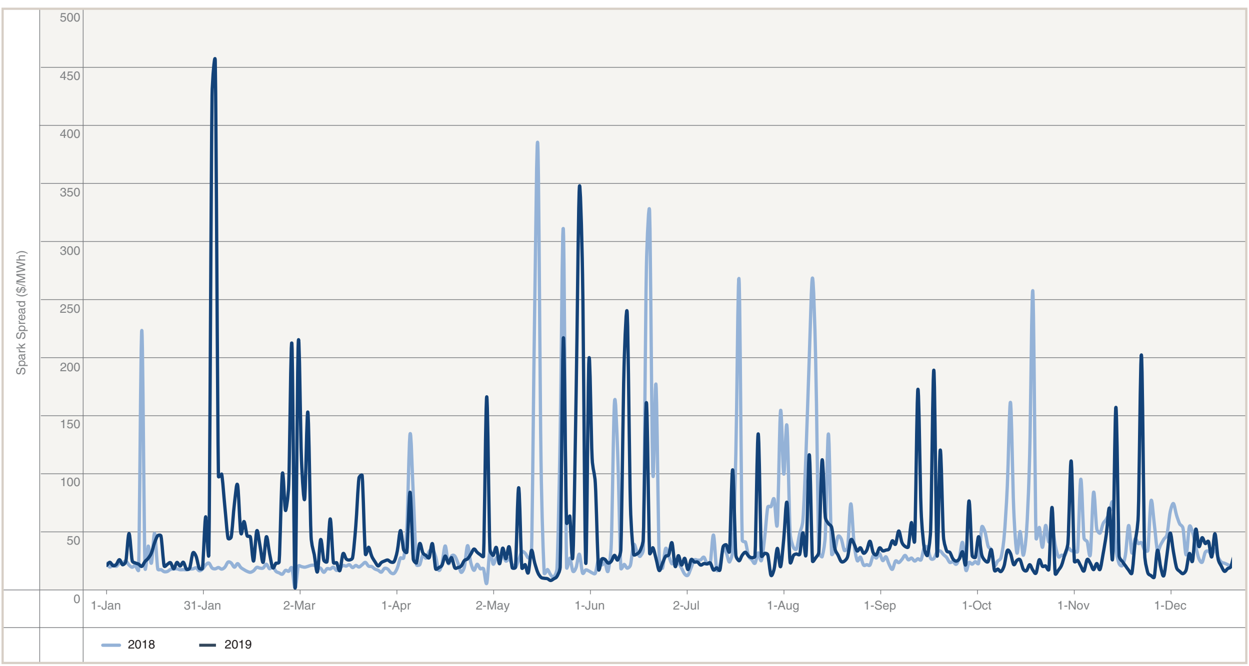
Spark spread increased six per cent

The spark spread is a high-level measurement that approximates the profitability of operations of a generic combined-cycle natural gas baseload generation asset in the energy market. The hourly spark spread is the difference between the wholesale price of electricity and the cost of natural gas required to generate that electricity. The cost of fuel is calculated as the product of the operating heat rate and the unit cost of natural gas. The operating heat rate measures the efficiency of the generation asset. It represents the amount of fuel energy required to produce one unit of electrical energy. Operating heat rates vary between generating units. This report uses an operating heat rate of 7.5 GJ/MWh in order to assess market conditions for a reasonably efficient combined-cycle gas generation asset.

A positive spark spread implies that baseload operation would be profitable for gas-fired generators; a negative spark spread implies that baseload operation would be unprofitable. The spark spread is indicative and does not include costs such as variable operations, maintenance or the cost of carbon.

Figure 3 shows the daily average spark spread for 2018 and 2019. In 2019, the average spark spread increased six per cent to $42.21/MWh; this can primarily be attributed to higher pool prices in 2019.

FIGURE 3: 2018 and 2019 daily average spark spread



Alberta Internal Load

In this report, all annual load statistics are reported based on the calendar year that starts January 1 and ends December 31 of the same year. However, the seasonal load statistics are reported based on a seasonal year. The winter season starts on November 1 and ends on April 30 of the following year, and the summer season starts on May 1 and ends on October 31. In the seasonal load discussions in this report, the terms winter and summer refer to these seasonal definitions.

Average load decreased half a per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2019, average AIL decreased half a per cent to 9,695 MW, and annual peak load of 11,471 MW occurred on February 12, 2019. The decrease in AIL from 2018 to 2019 was primarily driven by milder weather in 2019 compared to 2018, and decreases in industrial load in some parts of the province.

TABLE 2: Annual load statistics

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Alberta Internal Load										
Total (GWh)	71,723	73,600	75,574	77,451	79,949	80,257	79,560	82,572	85,330	**84,925**
Average (MW)	8,188	8,402	8,604	8,841	9,127	9,162	9,057	9,426	9,741	**9,695**
Maximum (MW)	10,196	10,226	10,609	11,139	11,169	11,229	11,458	11,473	11,697	**11,471**
Minimum (MW)	6,641	6,459	6,828	6,991	7,162	7,203	6,595	7,600	7,819	**8,024**
Average growth	2.6%	2.6%	2.4%	2.8%	3.2%	0.4%	-1.1%	4.1%	3.3%	**-0.5%**
Load factor	80%	82%	81%	79%	82%	82%	79%	82%	83%	**85%**
System load										
Average (MW)	6,450	6,593	6,620	6,778	7,024	6,998	6,919	7,121	7,183	**7,027**

AIL represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat. It is consistent with the generation and load represented on the AESO's Current Supply and Demand page[2] and it is the main load measure used by the AESO to denote total load within the province. System load represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson, British Columbia (B.C.), Demand Opportunity Service (DOS)[3], plus transmission losses.

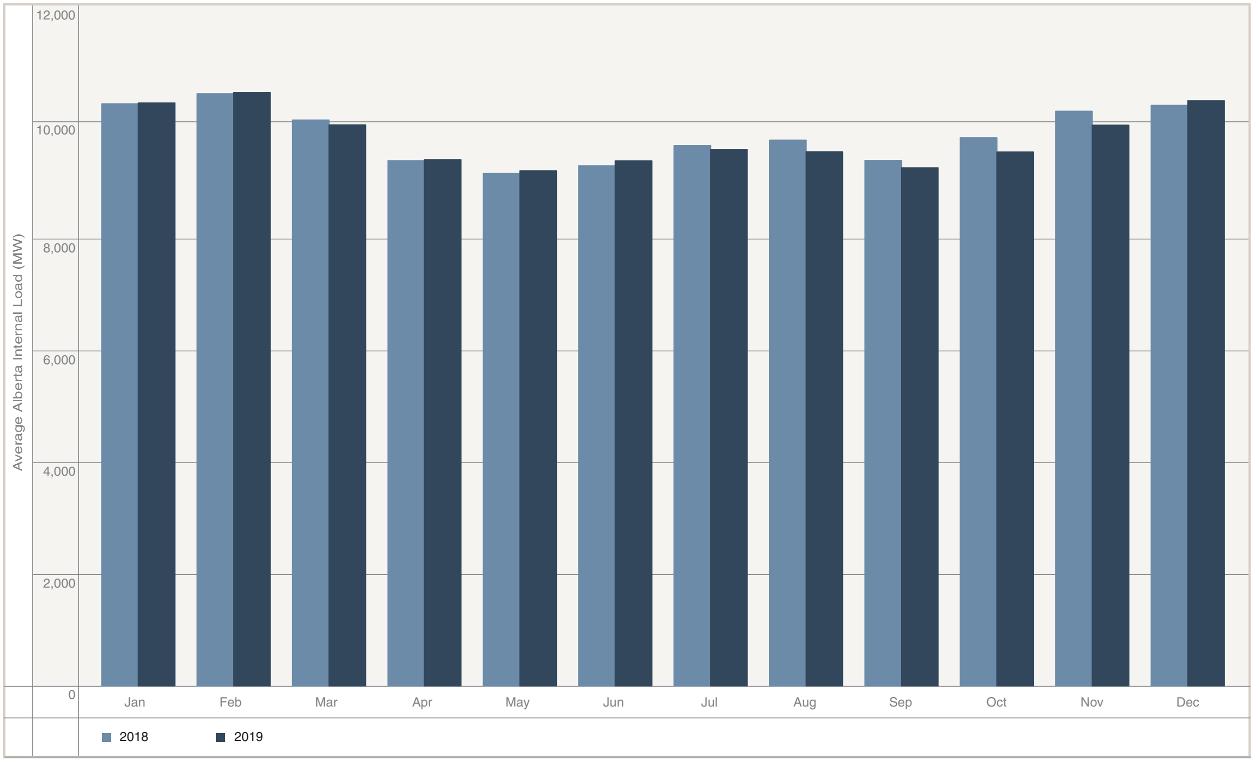
The load factor represents the ratio of the average AIL to the maximum AIL in each year. A low load factor indicates that load is highly volatile: peak hourly load significantly exceeds the average load over the year. A high load factor indicates that load is relatively stable: the peak hourly load is not significantly higher than the average load. The high load factor in Alberta indicates stable load, due largely to strong industrial demand. In 2019, the load factor was 85 per cent which is the highest on record.

Figure 4 shows the monthly average load in 2018 and 2019. The monthly average load in 2019 was below monthly 2018 levels from July through November. Summer 2018 was relatively warm and load reached a new all-time summer peak load in August 2018. The monthly average load for the rest of 2019 was similar to 2018 levels.

2 http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

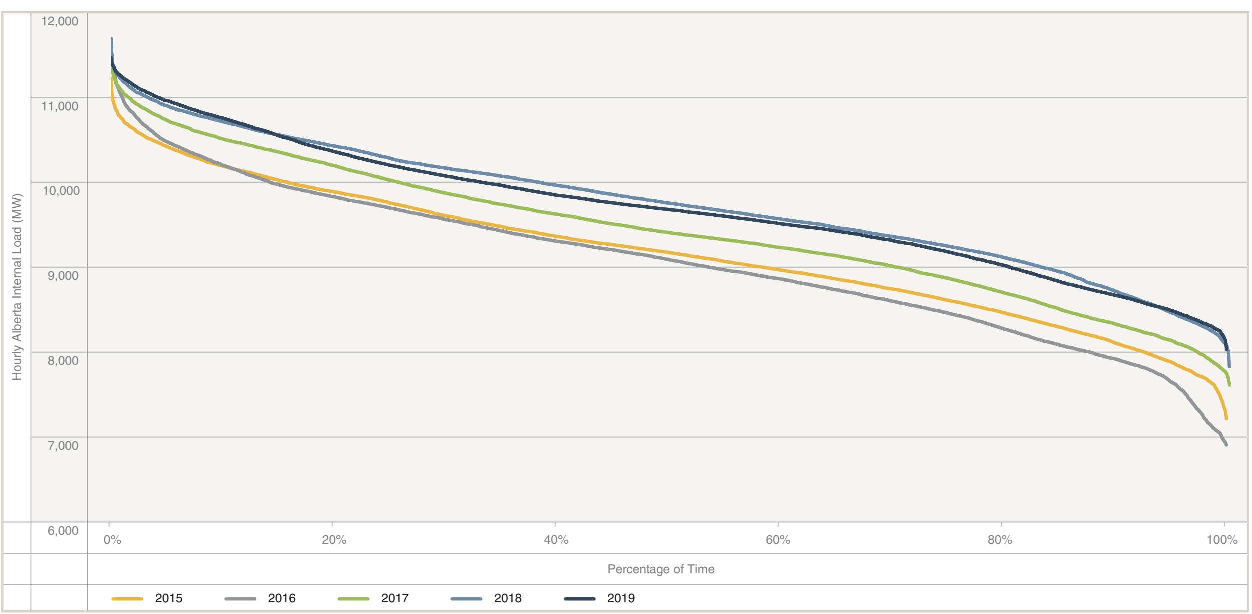
3 Demand Opportunity Service (DOS) allows customers connected to the grid to draw additional power over and above the amount they are contracted for.

FIGURE 4: 2018 and 2019 monthly average load



The load duration curve represents the percentage of time that AIL was greater than or equal to the specified load. Figure 5 plots the annual load duration curve for each of the past five years. This figure shows that both peak load and hourly load in 2019 decreased slightly from its previous-year value. Hourly load and peak load in 2018 remain the highest in the previous years.

FIGURE 5: Annual load duration curves



Seasonal load

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 2019 winter peak load occurred in January 2020[4]. On January 14, 2020, hour ending 18, Alberta internal load reached 11,698 MW which set an all-time peak load record. This record was only one MW higher than the previous record that occurred in January 2018.

TABLE 3: Seasonal peak load

Season	Peak AIL (MW)	Date	Calendar Year
Summer 2015	10,520	2015-07-09	2015
Winter 2015	10,982	2015-12-22	2015
Summer 2016	10,244	2016-08-16	2016
Winter 2016	11,458	2016-12-16	2016
Summer 2017	10,852	2017-07-27	2017
Winter 2017	11,697	2018-01-11	2018
Summer 2018	11,169	2018-08-10	2018
Winter 2018	11,471	2019-02-12	2019
Summer 2019	10,822	2019-08-02	2019
Winter 2019	11,698	2020-01-14	2020

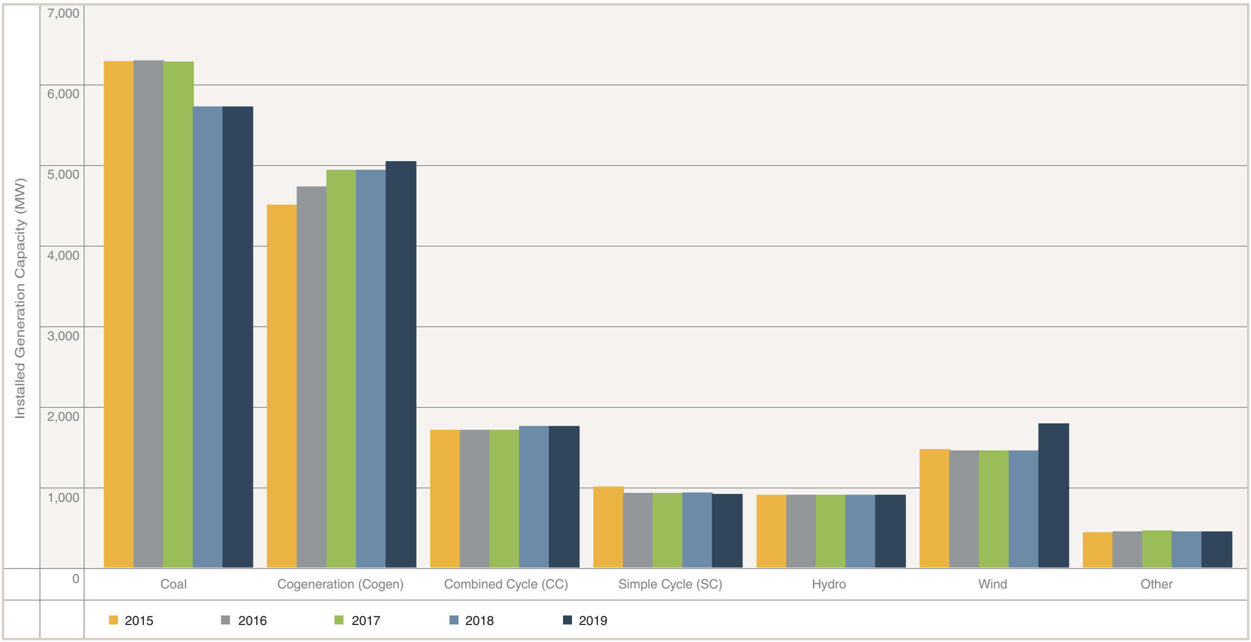
Installed generation

Total generation capacity increased three per cent

By the end of 2019, the total installed generation capacity in Alberta increased three per cent to 16,532 MW. Most of the increase in installed capacity over the past year occurred due to the addition of 336 MW of new wind capacity and 106 MW of cogeneration. The largest addition was Whitla Wind 1 with a capacity of 202 MW. The Riverview Wind Power Plant added another 105 MW and Castle Rock Ridge 2 added 29 MW of wind capacity. The increase in cogeneration capacity mostly occurred at existing assets with the addition of multiple relatively small assets. The retirement of High River (MFG1) reduced capacity from the simple cycle fleet by 16 MW. Figure 6 shows the annual installed capacity at the end of each calendar year.

[4] At the time of publication winter season is not over for 2019. However, the winter peak load has most likely occurred already.

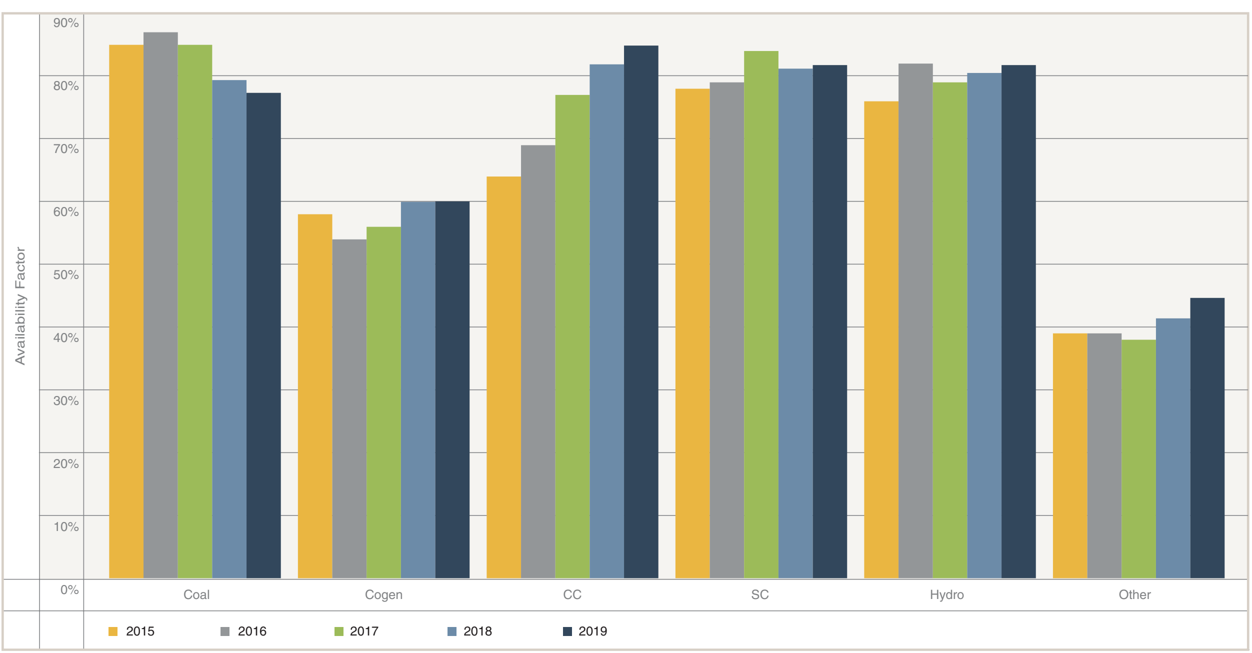
FIGURE 6: Annual generation capacity by technology



Generation availability

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 and solar are excluded from this calculation since the availability of wind and solar power depend on environmental factors. Figure 7 illustrates the annual availability factor by generation technology. Availability of coal-fired generation has been continuously decreasing in recent years and the availability of combined-cycle generation has been consistently increasing. Most of the decrease in availability factor of coal-fired generation in 2018 and 2019 was a result of mothball outage of the coal units.

FIGURE 7: Annual availability factor by technology



Most available combined-cycle power dispatched

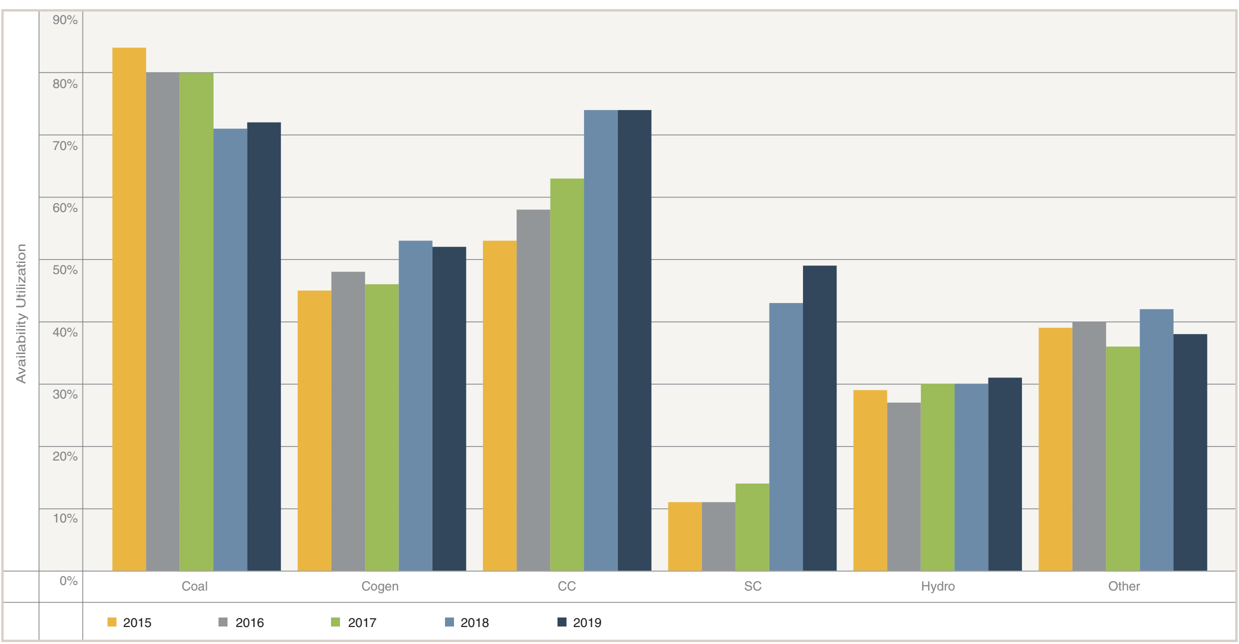
Availability utilization represents the percentage of the available power that was dispatched to serve load. Availability utilization is calculated as the ratio of net-to-grid generation to the available capability. Wind and solar generation are excluded from this calculation since all available wind and solar power were fully utilized. Figure 8 illustrates the annual availability utilization by generation technology.

Over the period between 2015 and 2017, the availability utilization of coal-fired generation was consistently highest among dispatchable generation technologies[5]. In 2018, combined-cycle gas generation replaced coal-fired generation as the most utilized generation technology. In 2019, combined-cycle generation continued to be the most utilized generation technology. This can be attributed to a combination of relatively inexpensive gas and carbon costs.

The availability utilization of cogeneration gas is less than that of other thermal generation. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve on-site load. The power used to serve on-site load is excluded from the calculation of availability utilization. This quantity includes only the energy delivered to the AIES; as a result, the availability utilization measure may underestimate the reliability of cogeneration gas technology.

Over the period of 2015 to 2017, the availability utilization of simple-cycle gas was 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 tends to limit the dispatch of simple-cycle gas generation to higher system loads when pool prices are high and all lower-priced generation in the merit order has already been dispatched. However, since 2018 the availability utilization of simple-cycle gas generation increased. Since 2018, the cost of carbon on coal-fired plants combined with low gas prices has made gas-fired generation less expensive relative to coal-fired generation and its utilization rate has increased.

FIGURE 8: Annual availability utilization factor by technology

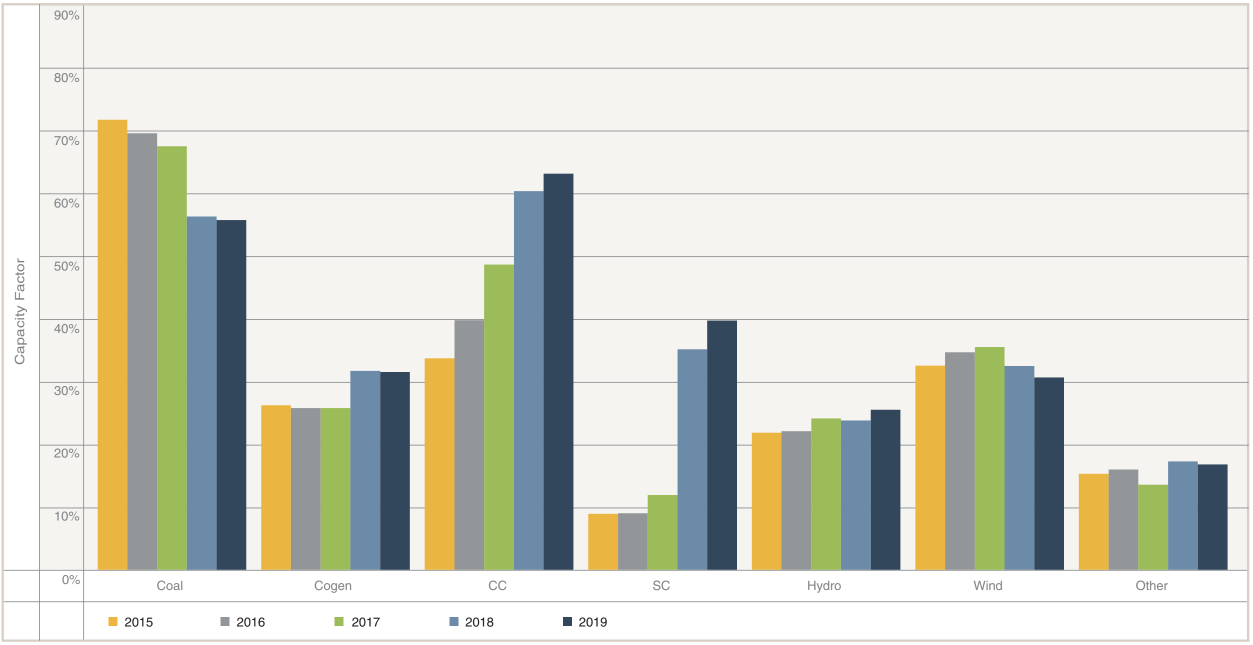


5 Dispatchable technologies refer to non-variable generation resources which can be dispatched up or down to follow load regardless of environmental conditions.

Combined-cycle generation capacity factor remains the highest

Capacity factor represents the percentage of installed capacity used to generate electricity that was delivered to the grid. For a given period of time, capacity factor is calculated as the ratio of average net-to-grid generation to the maximum capability within that period. Figure 9 illustrates the annual capacity factor by generation technology.

FIGURE 9: Annual capacity factor by technology



Prior to 2018, the capacity factor of coal-fired generation was consistently higher than the capacity factor of any other generation technology. However, the capacity factor of combined-cycle has been increasing in recent years and exceeded that of coal-fired generation in 2018. The capacity factor of combined-cycle generation remained highest among all generation technologies in 2019 with an increase of three percent. The capacity factor of combined-cycle was 63 per cent—on average, for every 100 MW of installed capacity, combined-cycle generation delivered 63 MWh to the AIES each hour. This result is consistent with the baseload operation of combined-cycle generation technology and implies an increase in combined-cycle share in baseload generation.

The capacity factor of simple-cycle gas generation has also been consistently increasing in recent years. In 2019, the capacity factor of simple-cycle gas generation increased five per cent. As gas-fired generation continued to have favorable costs compared to coal-fired generation. In addition, increased scarcity in the market lead to an increase in simple cycle units being in merit and hence dispatched.

Gas generation supplied 43 per cent of net-to-grid energy

Figure 10 illustrates the average net-to-grid generation from each generation technology over the past five years. In 2019, coal-fired generation supplied 46 per cent of the energy delivered to the AIES. Gas generation technologies delivered 43 per cent of net-to-grid generation, a one per cent increase from 2018. Renewable generation provided the remaining 11 per cent, on par with 2018. Also the same as 2018, wind generation provided the majority of energy from renewable sources. In 2019, seven per cent of total net-to-grid generation was provided by wind power alone. The remaining four percent was provided by a combination of hydro and other renewables generation.

FIGURE 10: Annual average net-to-grid generation by technology

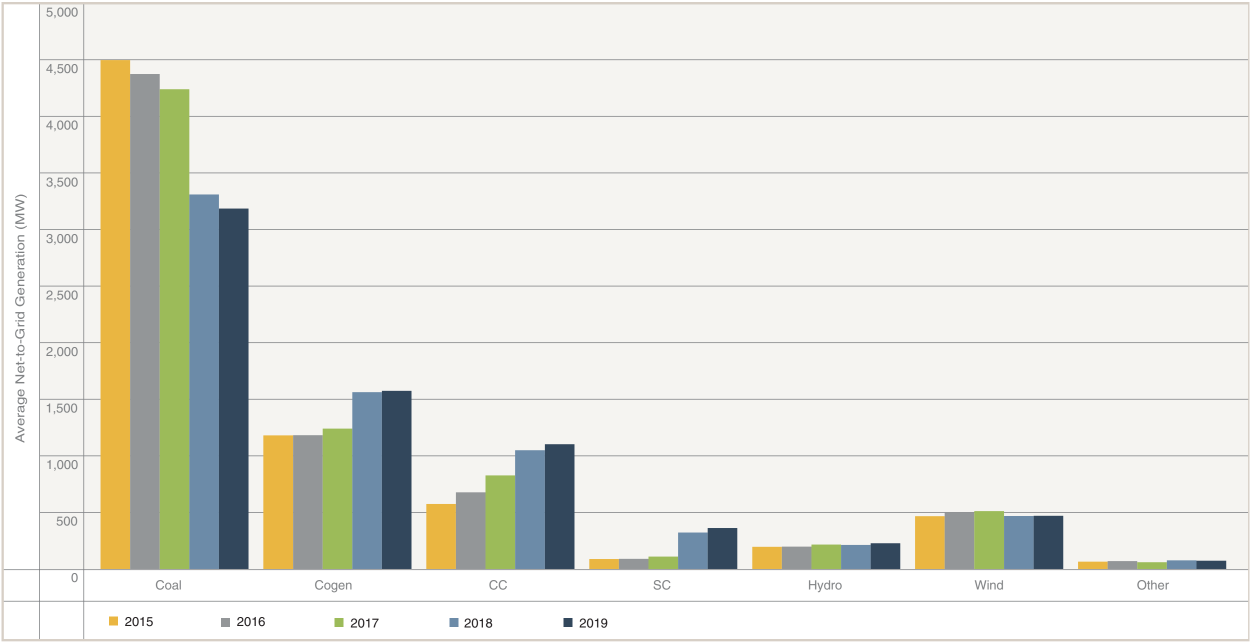
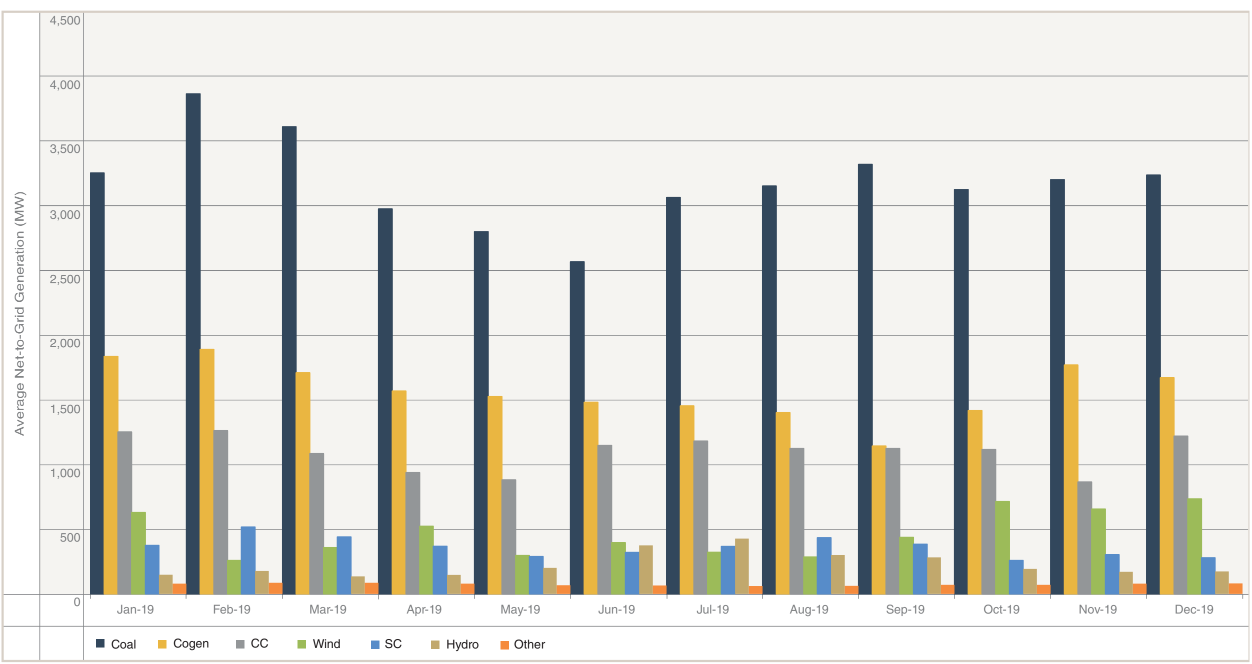


Figure 11 illustrates the monthly average net-to-grid generation from each generation technology over the past year. Seasonal patterns in generation are evident in this figure. Hydro generates more energy during spring-summer time and wind has higher output during winter months. Coal-fired generation declines during spring time. This is primarily due to maintenance outages of coal-fired units that are usually scheduled during this time of the year. In addition, load is relatively lower in spring and since gas generation is cost competitive, there is less need to dispatch coal energy in the merit order.

FIGURE 11: 2019 monthly average net-to-grid generation by technology



Simple-cycle gas realized 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.

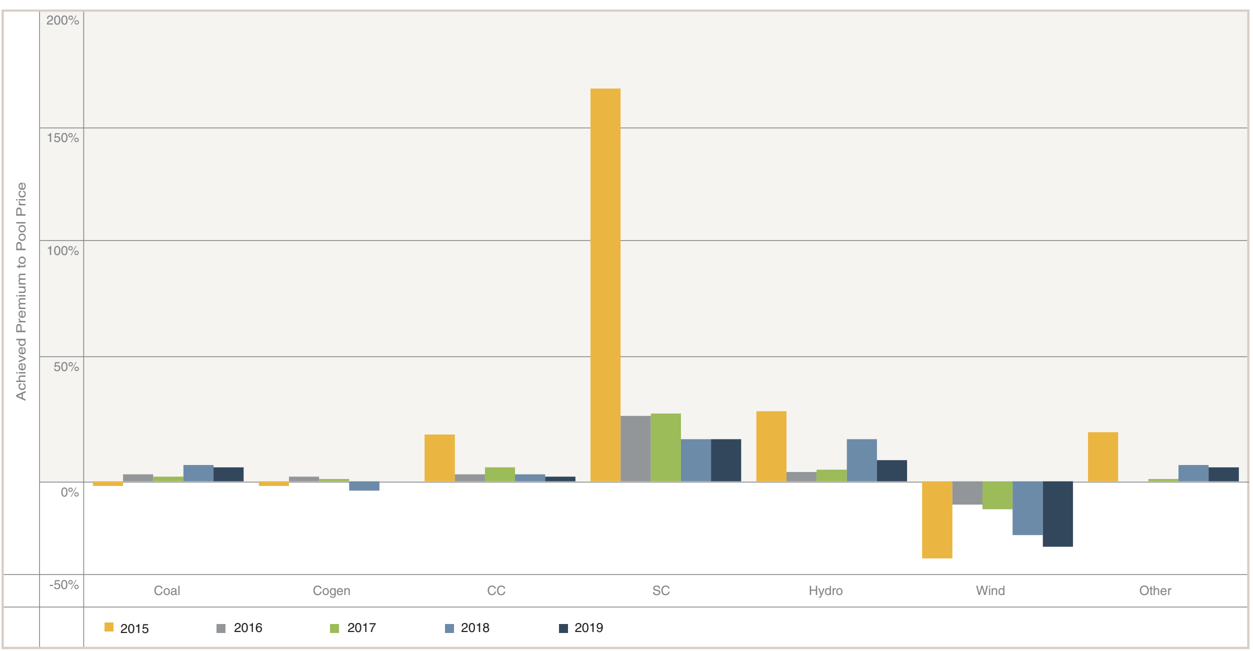
The achieved premium to pool price is calculated as the ratio of the achieved margin to the average pool price. An achieved premium of zero indicates that the achieved price is equal to the average pool price. An achieved premium of 100 per cent indicates that the achieved price is double the average pool price. An achieved discount of 50 per cent, i.e., 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 and availability 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 operate primarily in higher-priced hours would realize positive achieved premiums to pool price, while those that are available or 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 starting in 2016 both premiums and discounts to pool price were significantly muted from those in years before 2016 as a result of reduced price volatility.

Simple-cycle units have been running in a higher proportion of hours since the beginning of 2018, and this has led to a decrease in their achieved premium to pool price relative to historical values. However, at an 18 per cent achieved premium, simple-cycle units continued to have the highest achieved premium to pool price in 2019.

FIGURE 12: Annual achieved premium to pool price on generated energy



The offered price of power dictates a unit's position in the merit order which, in turn, 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 economic considerations of the unit operator. Low-cost baseload generation technologies typically adopt a price-taker strategy: they offer energy to the market at a low price (usually $0/MWh) to ensure dispatch, and produce energy in the majority of hours. Higher-cost peaking generation or fuel-limited technologies typically offer energy at a higher price and only produce energy when strong demand drives pool price higher. In the Alberta market, a range of technologies also employ a scarcity pricing approach for all or a portion of the unit to reflect higher value for energy during tighter supply demand balance conditions. The combination of offer strategy, market conditions and dispatched volumes determines the achieved price that each asset type receives.

Optimally, baseload generation technologies operate throughout the entire day. These baseload technologies include coal-fired, cogeneration and combined-cycle. For combined-cycle and coal-fired generation it is more economical to continue operating through low-priced hours than to incur the high cycling costs associated with halting and restarting generation. Most cogeneration facilities generate electricity as a byproduct 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 2019, combined-cycle and coal-fired technologies realized two and six per cent premium to pool price, and cogeneration gas technology achieved zero per cent.

Peaking generation technologies achieve greater operational flexibility than baseload generation. 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 higher in the merit order.

Peaking generation will typically 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 period of 2014 to 2017, simple-cycle gas generation achieved the highest premium across all generation technologies in Alberta. In 2019, simple-cycle units received an 18 per cent premium to pool price, the same as achieved in 2018. Hydro received a nine per cent premium to pool price, which was nine per cent lower than its value in 2018.

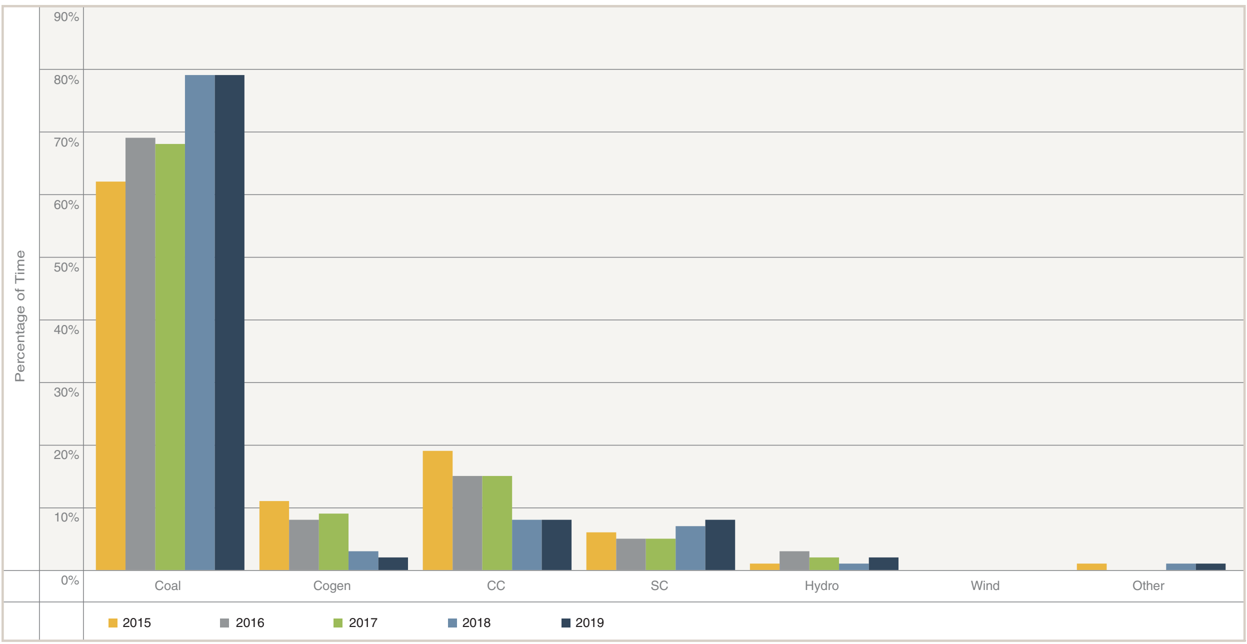
Wind generation is the only technology that consistently received a discount to pool price, i.e., the achieved premium is consistently negative. This discount occurs due to technological limitations and geographic concentration. Wind power cannot control its operational schedule with the output of wind power varying according to environmental conditions.

When wind blows in a region, all available 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 replaces some quantity of power from the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2019, wind generation received a 28 per cent discount to pool price.

Coal-fired generation sets marginal price in 79 per cent of hours

Figure 13 illustrates how frequently each generation technology sets the system marginal price. Over each of the past five years, coal-fired generation was the most common marginal price-setting technology. This prominence is consistent with the baseload operation of coal-fired generation technology. Because coal-fired assets would incur high costs by halting and restarting operation, they tend to operate in both on- and off-peak hours. In 2019, coal-fired generation set the system marginal price 78 per cent of the on-peak hours and 81 per cent of the off-peak hours. The high costs of coal-fired generation, driven in part by a shift in carbon pricing, contributed to the relatively high average pool prices in 2018 and 2019.

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[6].

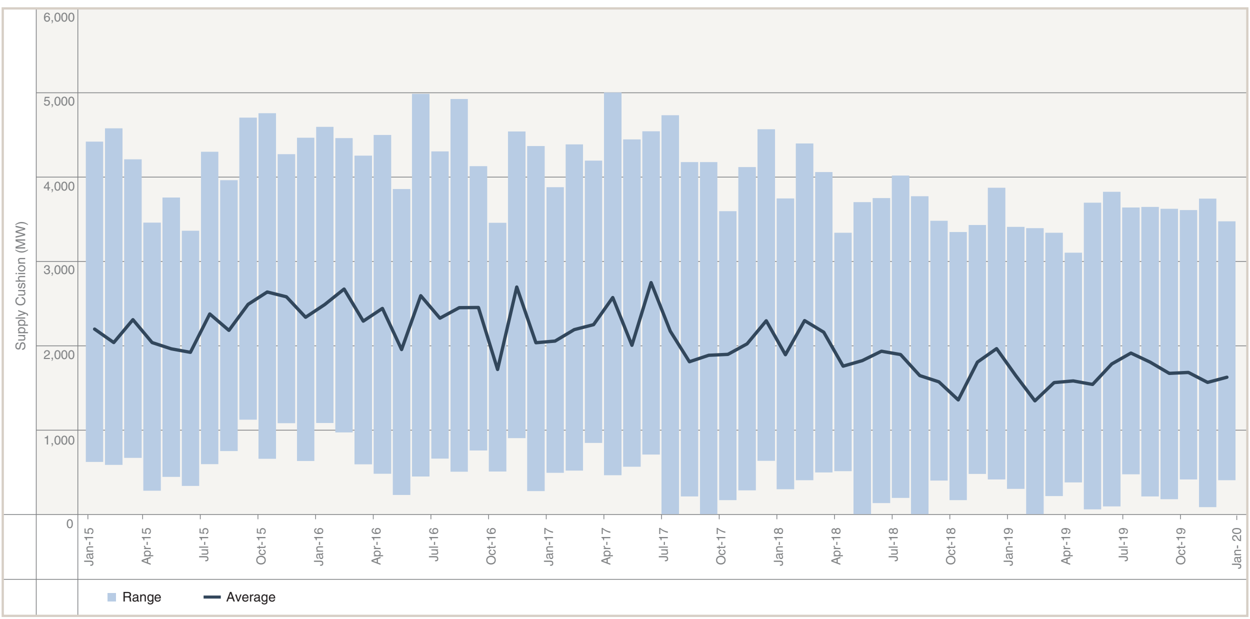
[6] https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

Supply cushion decreased 11 per cent

The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages or unexpected increases in demand. Over 2019, the average supply cushion decreased 11 per cent to 1,645 MW from its previous-year value. Tight supply periods during February and March reduced the average supply cushion in 2019. Figure 14 shows the monthly supply cushion over the past five years.

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. During a supply shortfall event, the AESO must declare an Energy Emergency Alert (EEA)[7] if dispatches have been issued for all operating blocks in the energy market merit order, operating reserves requirements are being met and the AESO is concerned about sustaining its operating reserves. An EEA2 must be declared when operating reserves are committed to maintain the supply-demand balance, ensuring that regulating reserve margin is maintained. An EEA3 must be declared if the AESO foresees or has implemented curtailment of firm load. In 2019, supply shortfall conditions occurred twice. The first event was a 110-minute interval on February 3 which resulted in declaring an EEA1. The second one was a 70-minute interval on February 4 that led to declaration of an EEA2. Coal- and gas-fired generation outages, as well as low wind generation were the main drivers of these events.

FIGURE 14: Monthly supply cushion



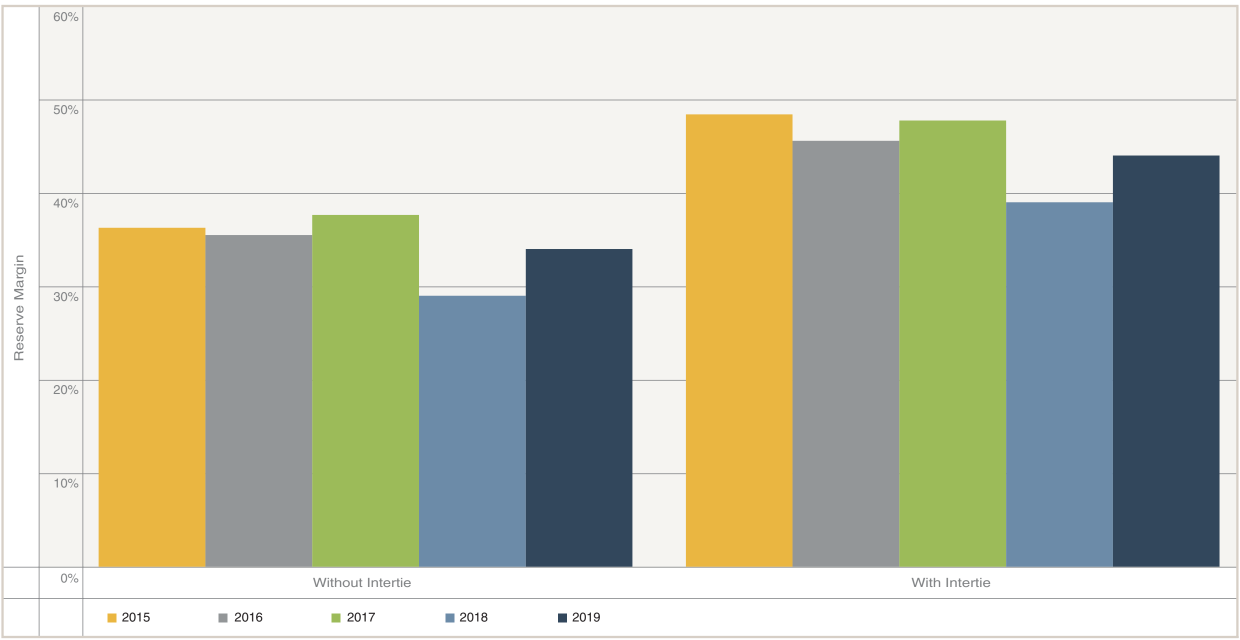
Reserve margin increased five per cent

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 the commissioning dates of new generation.

7 https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-305-1-energy-emergency-alerts/

Figure 15 shows the annual reserve margin over the past five years. The increase in the reserve margin from 2018 to 2019 is due to the decrease in the peak system load from 2018 and a slight increase in installed cogeneration. Alberta experienced higher system load peak in 2018 due to cold temperatures, which resulted in a relatively lower reserve margin in 2018.

FIGURE 15: Annual reserve margin



Imports and exports

Alberta transfers electric energy across interties with three neighbouring jurisdictions: B.C., Montana and Saskatchewan.

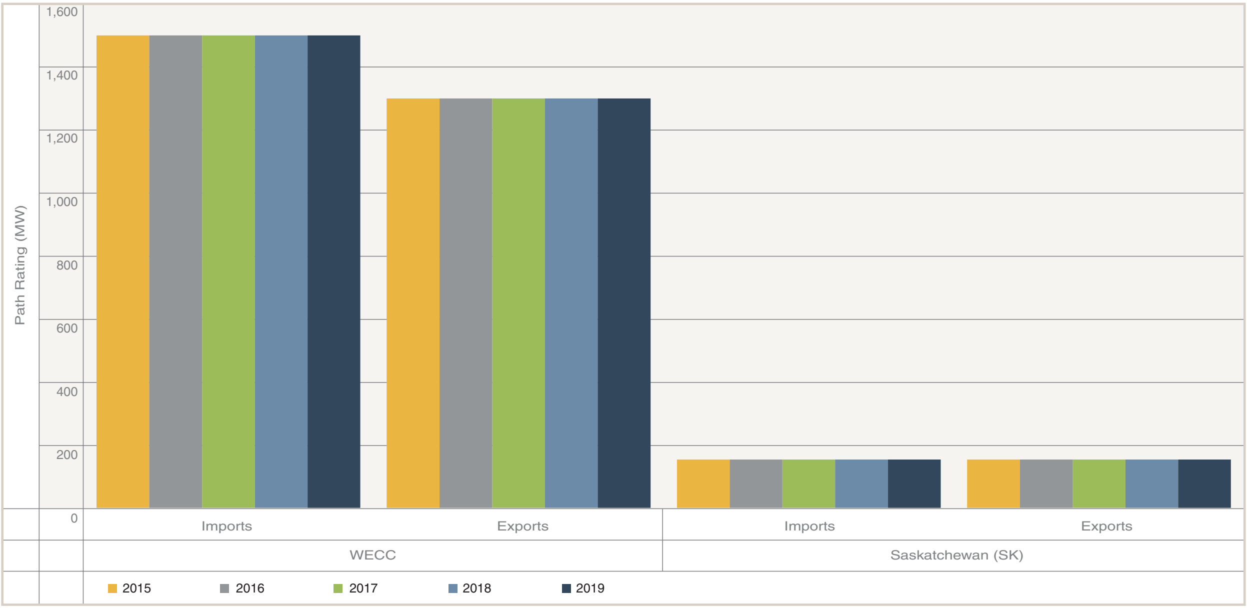
Transfer path rating remained stable

The transfer path rating establishes the physical capacity for the power that can flow across defined paths, and is estimated based on the physical properties of the interties.

Alberta, B.C. and Montana are members of the Western Electricity Coordinating Council (WECC) region while Saskatchewan is not. The total power that can flow between Alberta and other members of the WECC region is expressed as a combined path rating, calculated as the sum of the path ratings of the two individual interties which connect Alberta to B.C. and Montana.

Figure 16 shows the path rating at the end of each calendar year between Alberta and other WECC members, and between Alberta and Saskatchewan. Path ratings remained unchanged between 2018 and 2019.

FIGURE 16: Annual path rating by transfer path

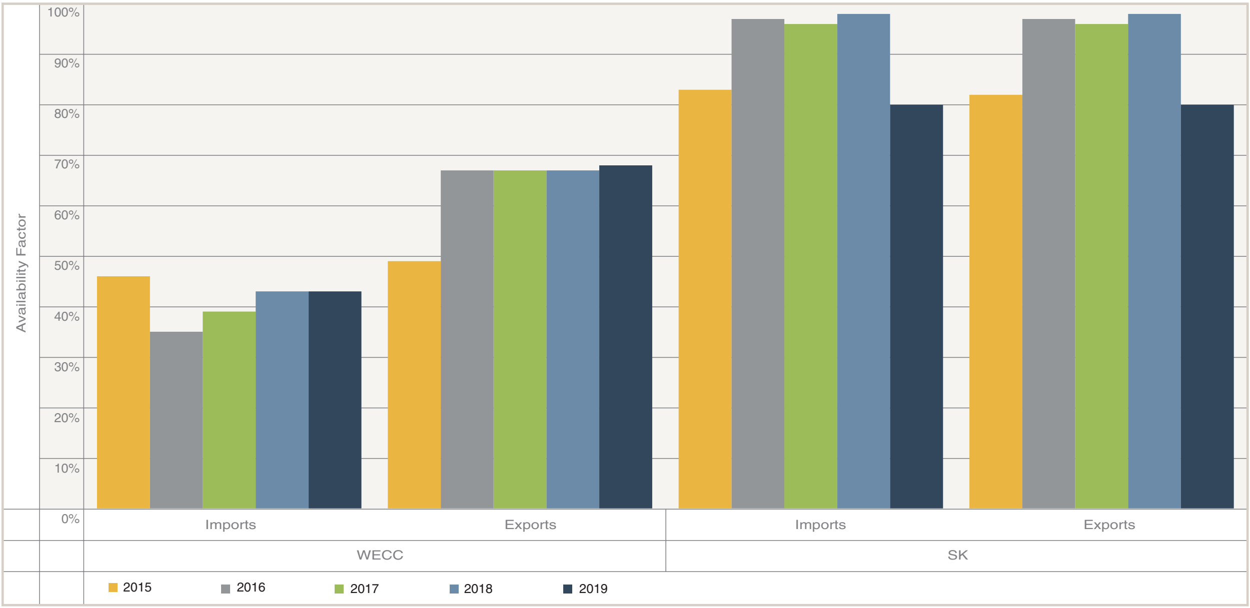


Intertie availability factor

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 (TRM). 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 physical limit 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 2019, the availability of Saskatchewan decreased for both imports and exports due to a planned maintenance outage during June and July.

FIGURE 17: Annual availability factor by transfer path



Availability utilization

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 2019, import utilization decreased 22 per cent from 2018 levels between Alberta and WECC, and increased four per cent on the Saskatchewan transfer path. The export utilization decreased along Saskatchewan transfer path.

FIGURE 18: Annual availability utilization by transfer path

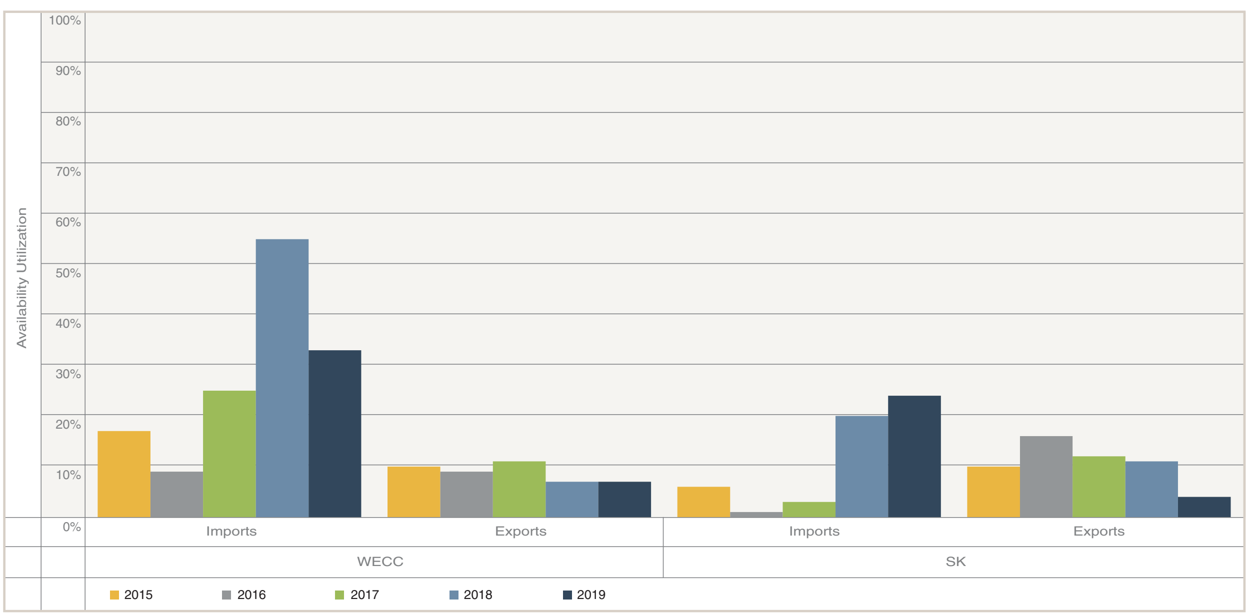


Figure 19 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. Interchange utilization represents the ratio of net imports across the intertie to its transfer capability. Net imports include the volume of operating reserve procured on the intertie. The utilization calculation reflects the limits of the interties with B.C. and Montana, the combined operating limits, and the Alberta system operating limit. Over 2019, Alberta imported energy from the WECC region in 69 per cent of hours, and exported energy in 20 per cent of the hours.

FIGURE 19: Annual interchange utilization with WECC region

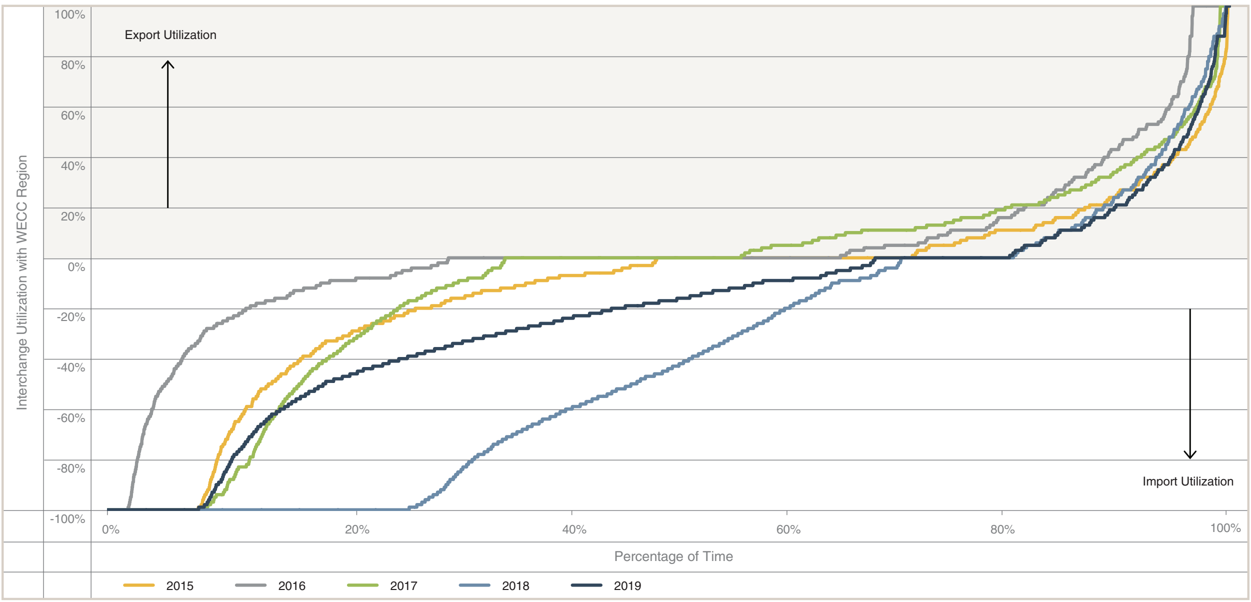
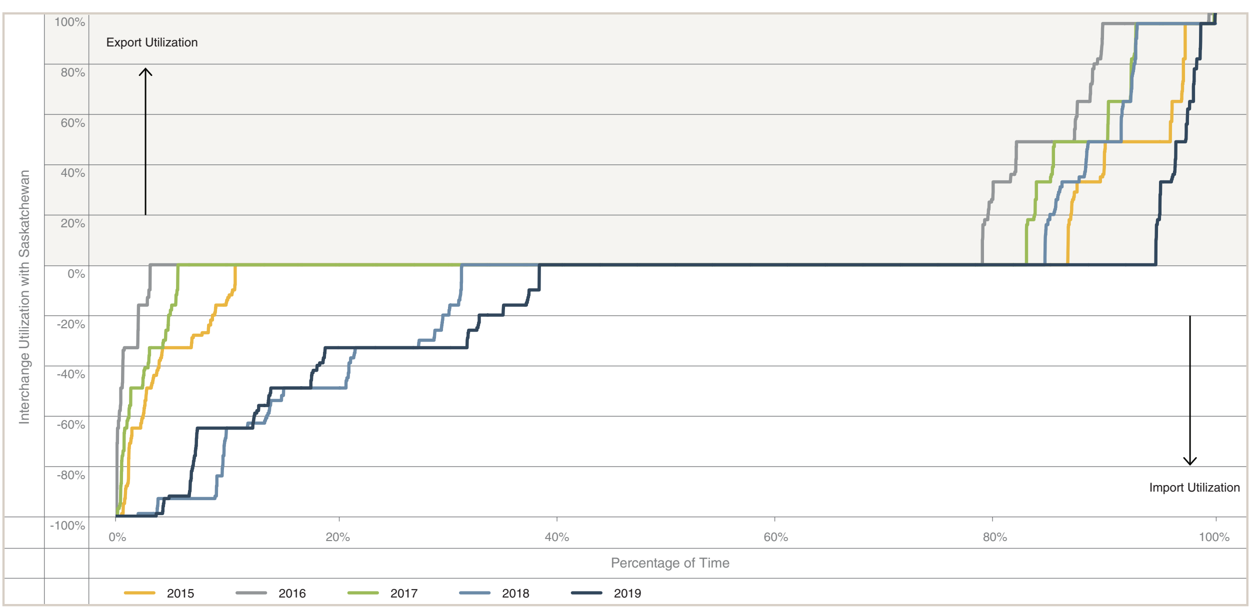


Figure 20 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2019, Alberta imported energy from Saskatchewan in 39 per cent of hours, and exported energy in five per cent of hours.

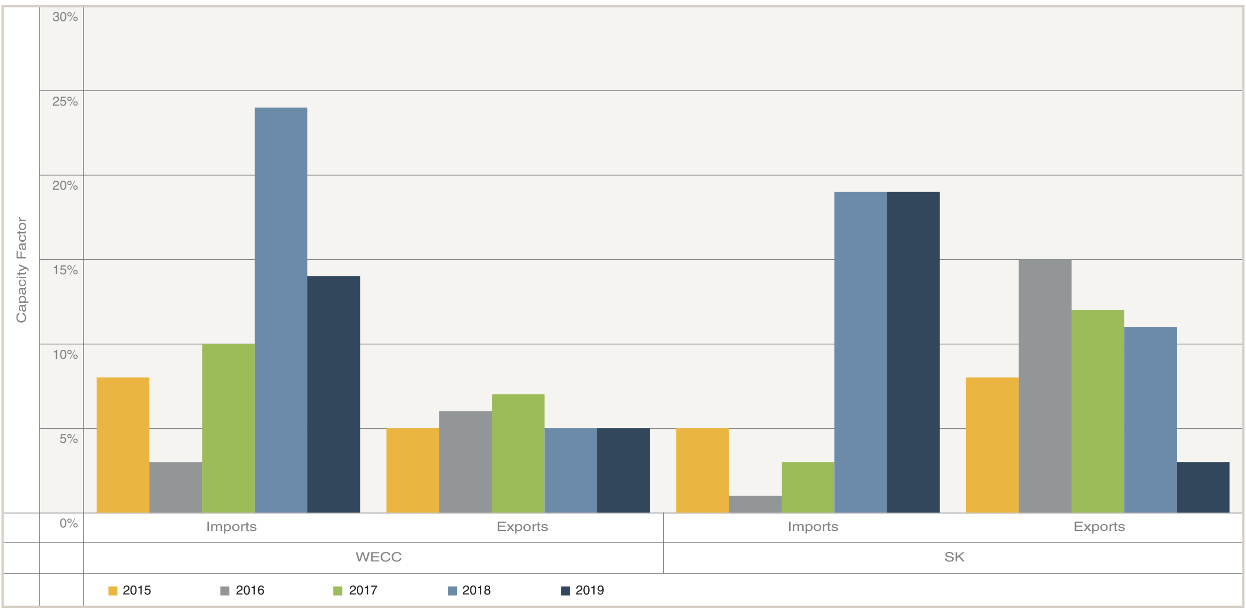
FIGURE 20: Annual interchange utilization with Saskatchewan



Capacity factor reflects fall in 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 remains a net importer

Figure 22 illustrates the annual average energy transferred from each province or state. In 2019, Alberta was a net importer. Relatively high electricity prices in Alberta encouraged imports into Alberta and consequently net imports remained relatively high compared to historical levels. However, lower water supplies in the Pacific Northwest in 2019 resulted in a 37 per cent decrease in imports from 2018.

FIGURE 22: Annual intertie transfers by province or state

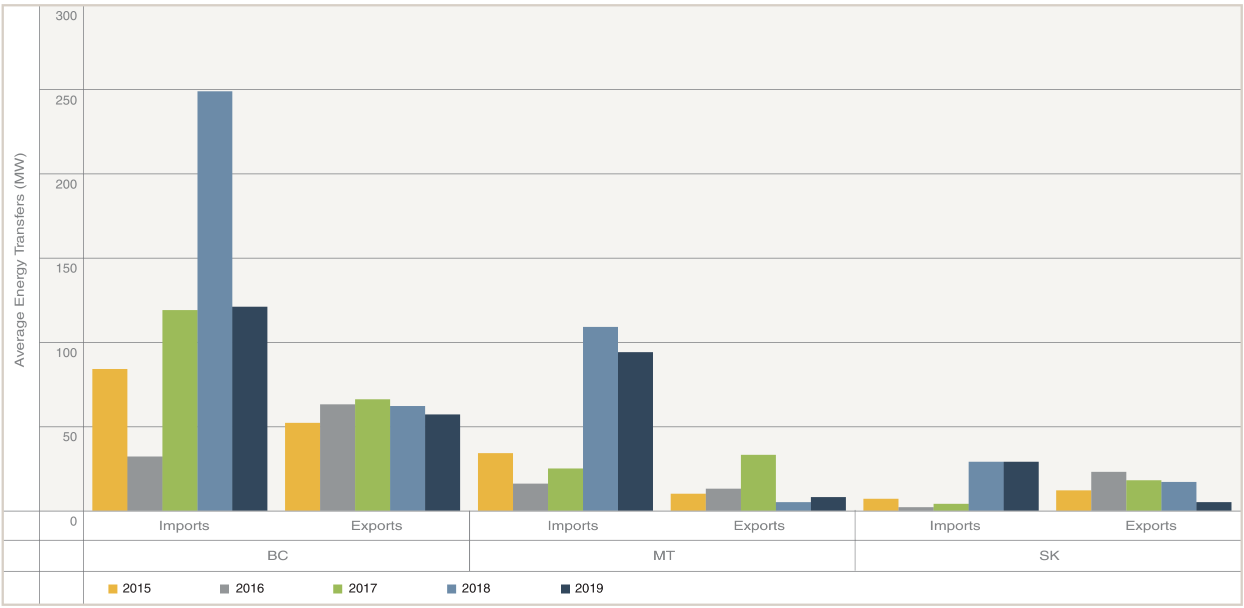
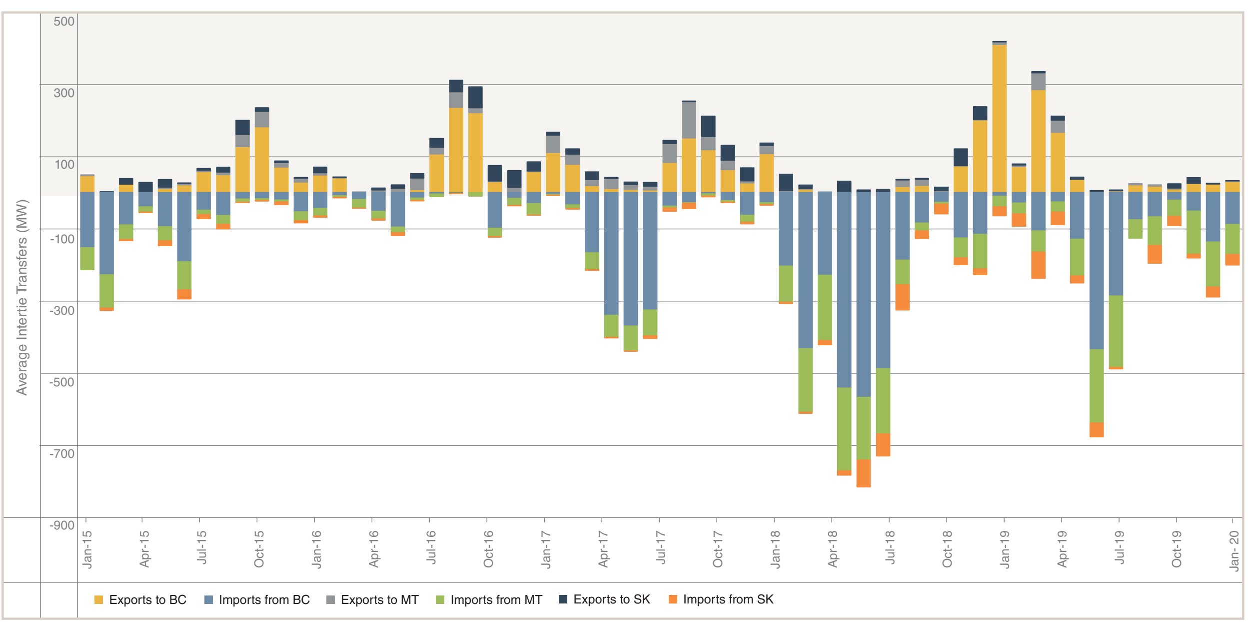


Figure 23 illustrates the monthly average energy transferred from each province or state. Negative values represent imports to the province and positive values represent exports to other jurisdictions. In 2019, the highest level of imports occurred in May and most energy was exported out of province in February.

FIGURE 23: Monthly average intertie transfers

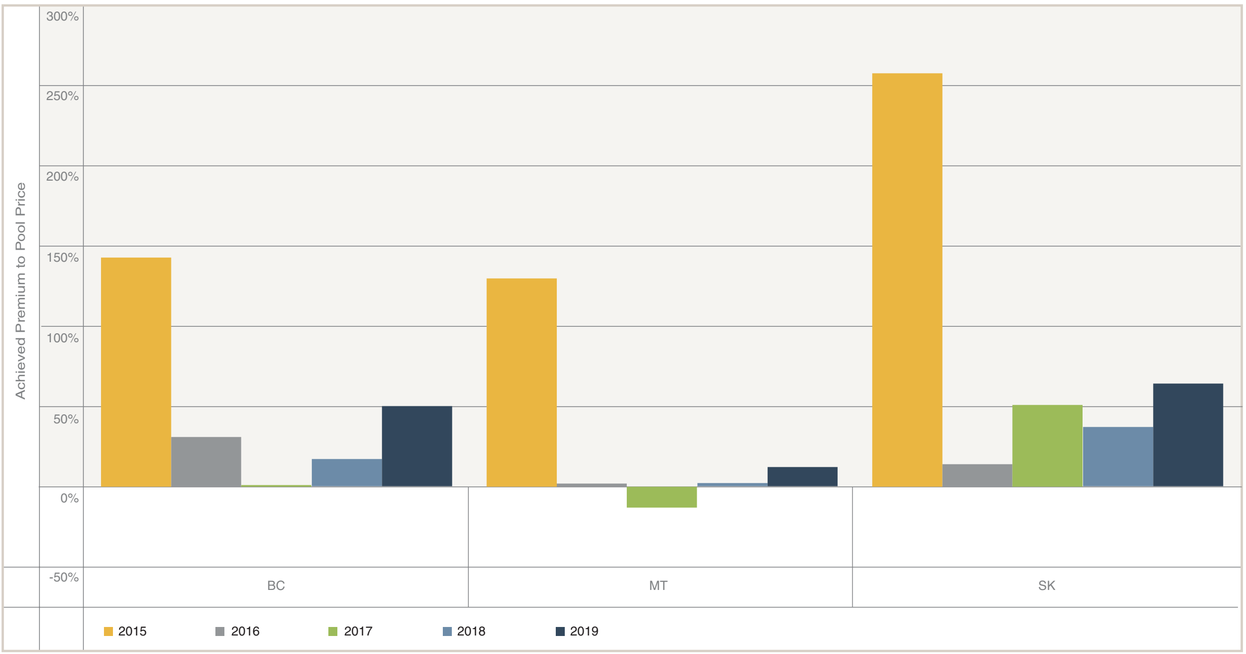


Achieved premium to pool price increased

Figure 24 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 other energy in 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 considering the price impact from the imported volume—exceeds their costs.

High pool prices in 2019 provided profit opportunities for importers and the achieved premium to pool price on imported energy increased for all interties: the achieved premium ranged between 12 to 64 per cent.

FIGURE 24: Annual achieved premium to pool price on imported energy



Wind generation

Wind generation served five per cent of Alberta internal load

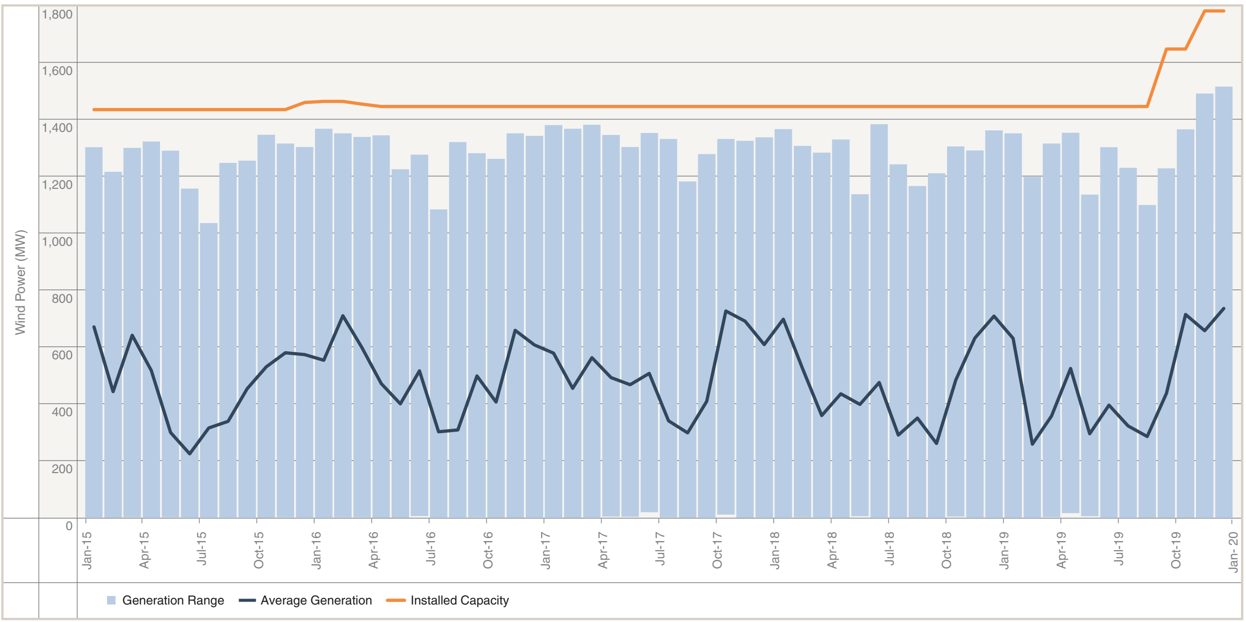
Table 4 summarizes the annual statistics for wind generation. Over 2019, installed wind generation capability increased 336 MW as new wind facilities were added to the fleet. At the end of the year, wind farms made up 11 per cent of the total installed generation capacity in Alberta. Wind generation produced seven per cent of Alberta's net to grid generation and served five per cent of total AIL in 2019.

TABLE 4: Annual wind generation statistics

Year	2015	2016	2017	2018	2019
Installed wind capacity at year end (MW)	1,463	1,445	1,445	1,445	**1,781**
Total wind generation (GWh)	4,089	4,402	4,486	4,100	**4,116**
Wind generation as a percentage of total AIL	5%	6%	5%	5%	**5%**
Average hourly capacity factor	33%	35%	35%	32%	**31%**
Maximum hourly capacity factor	94%	93%	96%	96%	**94%**
Wind capacity factor during annual peak AIL	7%	15%	6%	9%	**0%**

Figure 25 shows the installed wind generation capacity and monthly wind generation ranges. 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. The increased installed capacity is due to the addition of 202 MW by Whitla Wind 1 in September and a combined 134 MW by Castle Rock Ridge 2 and Riverview in November.

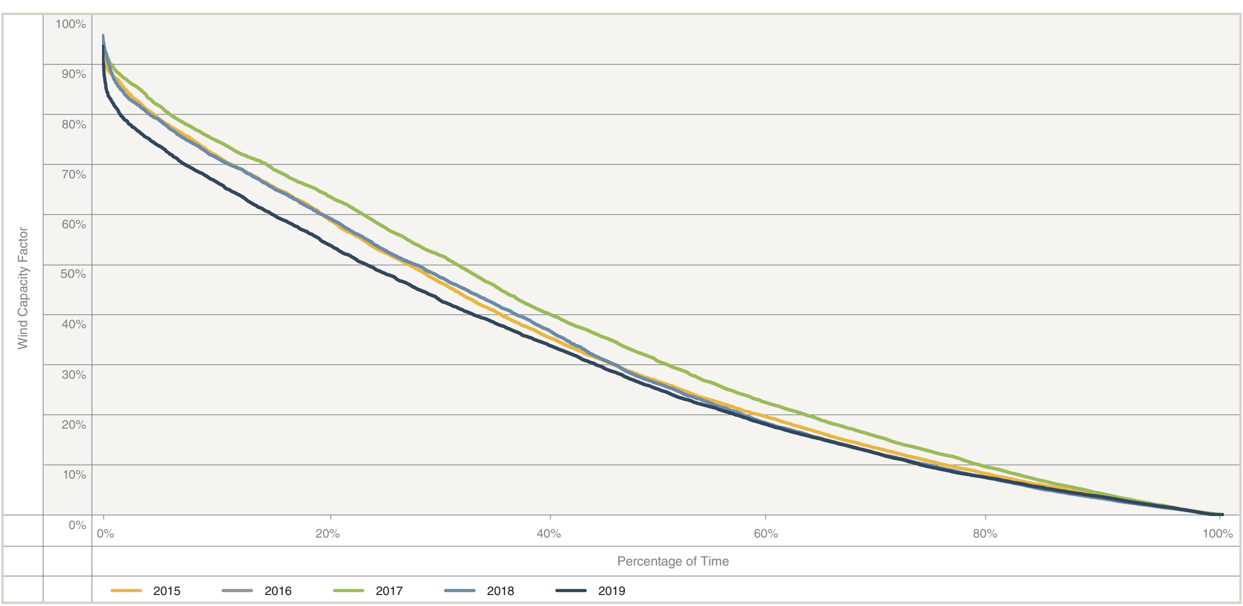
FIGURE 25: Monthly wind capacity and generation



Wind capacity factor decreased

Figure 26 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 26: Annual wind capacity factor duration curves



The duration curve for the capacity factor of wind generation decreased in 2019 and was lowest in the past five years. The capacity factor of wind generation averaged 31 per cent over 2019 showing a one percent decrease from 2018. For every 100 MW of installed wind capacity, wind power generated an average of 31 MW of energy each hour in 2019. The capacity factor—the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of cogeneration and simple-cycle gas generation; however, unlike these technologies, wind generation depends on environmental factors and cannot be dispatched to run when wind is unavailable.

Regional wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. Since 2011, the addition of five wind facilities in central Alberta has increased the geographic diversification of wind generation across the province. At the end of 2019, wind generation capacity totaled 1,432 MW in southern Alberta, and 349 MW in central Alberta.

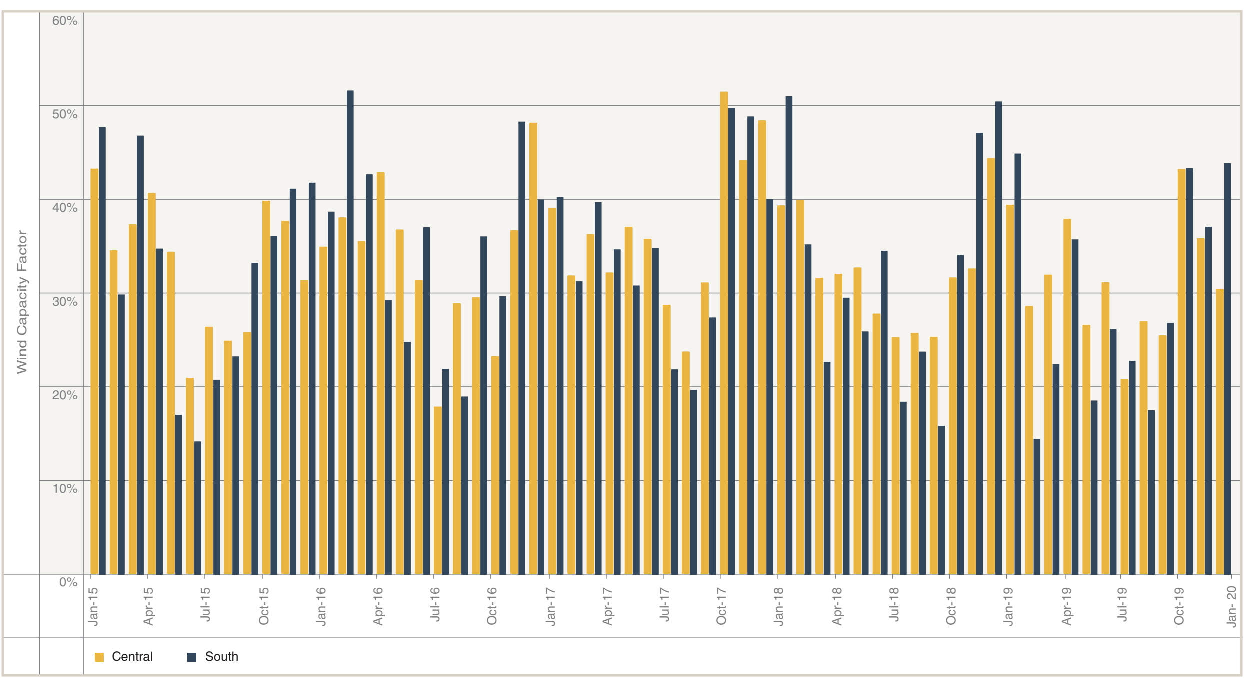
Table 5 shows regional wind generation statistics over 2019. The average capacity factor and the achieved price for central wind exceeded those for southern wind. For each megawatt of installed capacity, a wind farm in central Alberta generated more energy than a wind farm in southern Alberta, and for each unit of energy generated, a central wind farm earned more revenue than a southern wind farm.

TABLE 5: 2019 regional wind statistics

Region	South	Central	Total
Installed wind capacity at year end (MW)	1,432	349	**1,781**
Total wind generation (GWh)	3,154	962	**4,116**
Average wind capacity factor	30%	31%	**30%**
Achieved price ($/MWh)	$38.00	$44.00	**$39.43**

Figure 27 shows the monthly average capacity factor by region in the past five years. In 2019, southern wind generated the most energy in January with a capacity factor of 45 per cent, and central wind generated the most energy in October with a capacity factor of 43 per cent.

FIGURE 27: Monthly wind capacity factor by region



Solar generation

As of December 31, 2019, the Brooks Solar Project was the only utility-scale solar generation in Alberta. This facility has a maximum capability of 15 MW and started operating in December 2017. Figure 28 illustrates the monthly total generation of Brooks Solar for the years 2018 and 2019. In 2019, the highest output from this facility occurred in June and the least output occurred in February.

FIGURE 28: Total monthly output of Brooks Solar

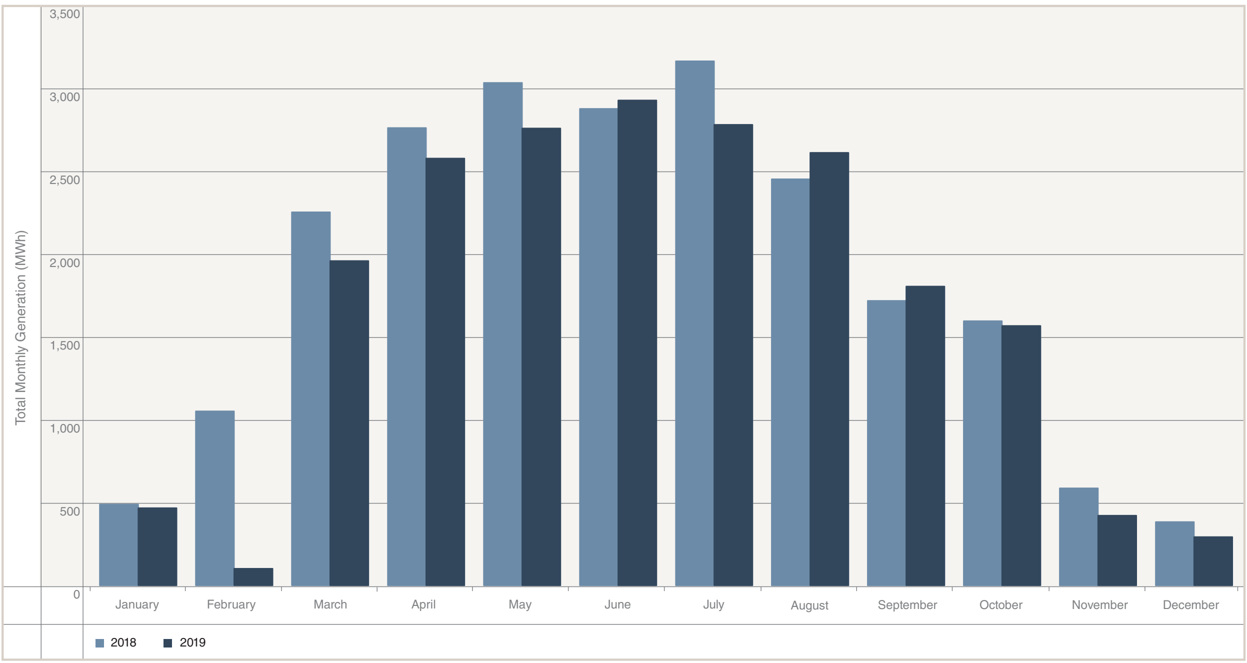
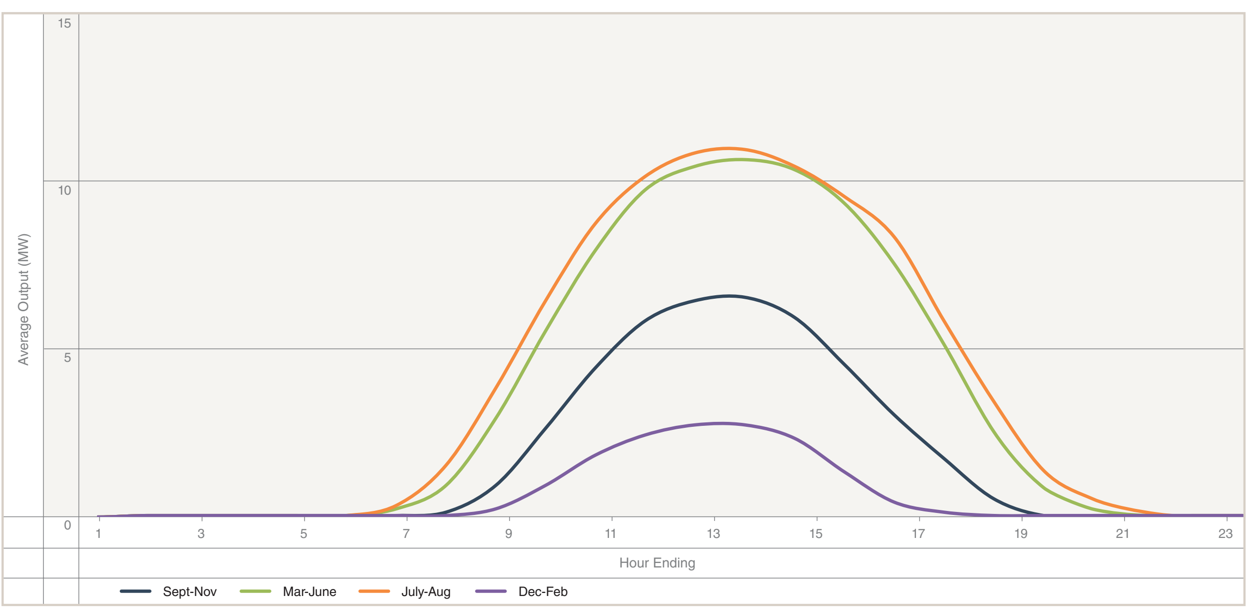


Figure 29 shows average hourly output of Brooks Solar in different periods of the year in 2018 and 2019. This facility has its most output in hour endings 13 and 14 from July through August.

FIGURE 29: 2018 and 2019 seasonal average hourly output of Brooks Solar



Ancillary services

Cost of operating reserves decreased

Operating reserves are used to manage second-to-second fluctuations in supply or demand on the AIES and ensure the system has adequate supply to respond to supply contingencies. Operating reserves are 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. 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 established 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.

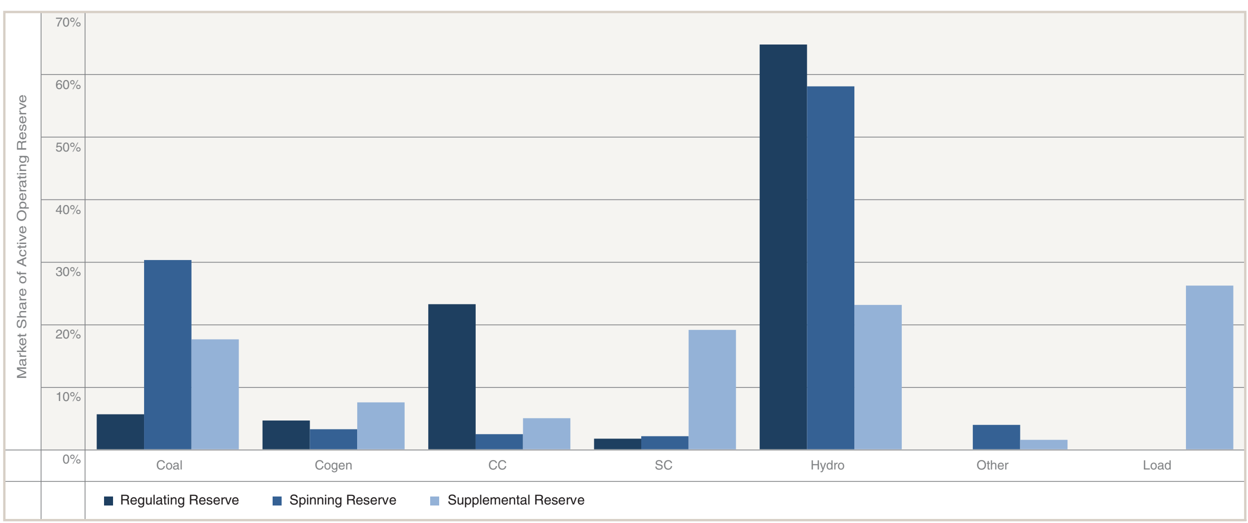
Table 6 summarizes the total cost of operating reserve over the past five years. The total cost of operating reserve in 2019 decreased 20 per cent from 2018 to $193 million, mostly driven by lower activation price of standby reserves and a reduction in the procured volumes of contingency reserves.

TABLE 6: Annual operating reserve statistics

Year	2015	2016	2017	2018	2019
Volume (GWh)					
Active procured	5,333	5,262	5,449	5,802	**5,640**
Standby procured	2,140	2,049	2,058	1,971	**2,124**
Standby activated	136	85	236	343	**180**
Cost ($-millions)					
Active procured	$105	$53	$67	$195	**$172**
Standby procured	$13	$12	$8	$8	**$6**
Standby activated	$20	$2	$6	$36	**$14**
Total	$138	$67	$81	$240	**$193**

Market share represents the percentage of total procured capacity that is provided as operating reserve by each generation technology. Figure 30 illustrates the annual market share of active operating reserve. In 2019, hydroelectric generation continued to have the largest market share of all active operating reserve products than any other technology.

FIGURE 30: 2019 market share of active operating reserve



Transmission must-run and dispatch down service

The system controller issues TMR dispatches in parts of the province's electricity system when transmission capacity is insufficient to support local demand. TMR dispatches command a generator in or near the affected area to operate out of merit at a specified generation level in order to maintain system reliability.

TMR dispatches effectively resolve transmission constraints, but also exert a secondary effect on the energy market. Energy dispatched under TMR service displaces marginal operating units 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.

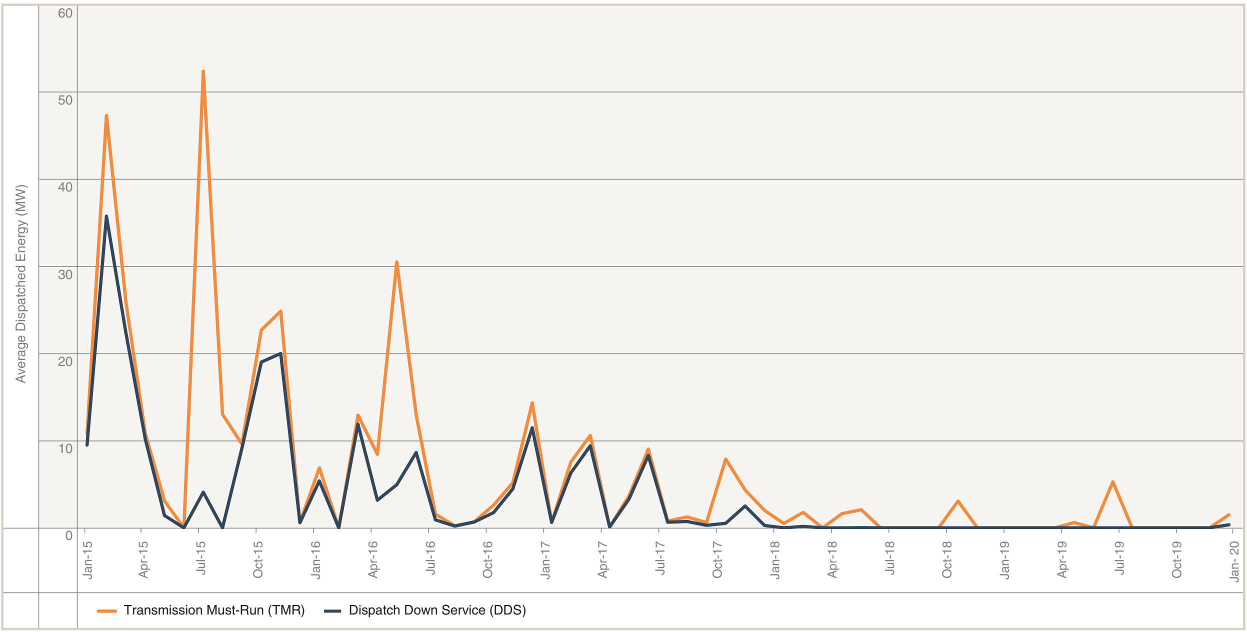
DDS requirements are limited to the amount of dispatched TMR. DDS cannot offset more energy than is dispatched under TMR service. In 2019, DDS offset five per cent of dispatched TMR volume. Table 7 summarizes the annual TMR and DDS statistics over the past five years. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. Both dispatched TMR and DDS volumes have shown a significant decrease compared to historical values as generation dispatch patterns have changed with natural gas units being dispatched in merit more frequently.

TABLE 7: Annual TMR and DDS statistics

Year	2015	2016	2017	2018	2019
Transmission Must-Run					
Dispatched energy (GWh)	161	71	35	7	**5**
Dispatch Down Service					
Total payments ($-millions)	$1.51	$0.51	0.11	0.00	**0.01**
Dispatched energy (GWh)	95,022	39,489	23,875	107	**256**
Average charge ($/MWh)	$0.02	$0.01	$0.00	$0.02	**$0.00**

Figure 31 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.

FIGURE 31: Monthly TMR and DDS dispatched energy



Uplift payments

All energy delivered to the AIES 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 realized pool price for the hour. Table 8 summarizes the cost of uplift payments over the past five years.

TABLE 8: Annual uplift payments

Year	2015	2016	2017	2018	2019
Payments to Suppliers on the Margin					
Average range ($/MWh)	5.99	1.08	2.35	8.15	**12.99**
Total payments ($-millions)	1.23	0.15	0.21	1.31	**1.58**
Transmission Constraint Rebalancing					
Constrained-down generation (GWh)		2.4	1.4	3.0	**3.3**
Total payments ($-millions)		0.01	0.02	0.04	**0.27**

Payments to suppliers on the margin

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 for an hour, that offer block may qualify for compensation under the PSM rule.

The annual cost of PSM increased to $1.58 million in 2019 from $1.31 million in 2018. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price. The annual average price range increased 59 per cent to $12.99/MWh in 2019.

Transmission Constraint Rebalancing payments

When the AESO dispatches up the energy market merit order in order to replace in-merit generation that has been curtailed due to a constraint, those generators with offers located above the unconstrained price are eligible to receive a Transmission Constraint Rebalancing (TCR) payment. The AESO determines the energy production volume of each block of energy priced between the constrained system marginal price and the unconstrained system marginal price and multiplies that volume by the difference between the unconstrained pool price and the offer price associated with the MW level of energy provided by that eligible offer block in order to determine the amount of the transmission constraint rebalancing payment. In 2019, constraints on the transmission system required system controllers to curtail 3.3 GWh of in-merit energy and the TCR payments to market participants totaled approximately $270,000.

Flexibility

In the AESO's *Dispatchable Renewables and Energy Storage Report*[8], the AESO assessed the challenges for renewable energy integration in Alberta, and whether Alberta has sufficient flexibility in dispatchable resources to be capable of matching the net-demand[9] changes and to reduce curtailment of generation surpluses. The report concluded that there were no immediate concerns regarding sufficient dispatch flexibility in the Alberta system but that ongoing monitoring was required to proactively identify and address any emerging issues. As a result of the report, the AESO has commenced a flexibility roadmap to sustainably monitor and forecast flexibility capabilities and needs and proactively plan to enhance system flexibility through tools, processes, standards, rules, etc. as appropriate.[10]

The AESO is including monitoring of historical flexibility parameters regarding market and system operation in the Annual Market Statistics report. In this section these parameters are introduced and reported for the past year.

[8] https://www.aeso.ca/assets/Uploads/AESO-Dispatchable-Renewables-Storage-Report-May2018.pdf

[9] Net demand is the overall customer demand, less the overall variable generation on the system at every moment. Customer demand is AIL and variable generation is a combination of wind and solar generation.

[10] For further detail see https://www.aeso.ca/assets/Uploads/Energy-Storage-Session-Aug-7-8.7.19-Final.pptx

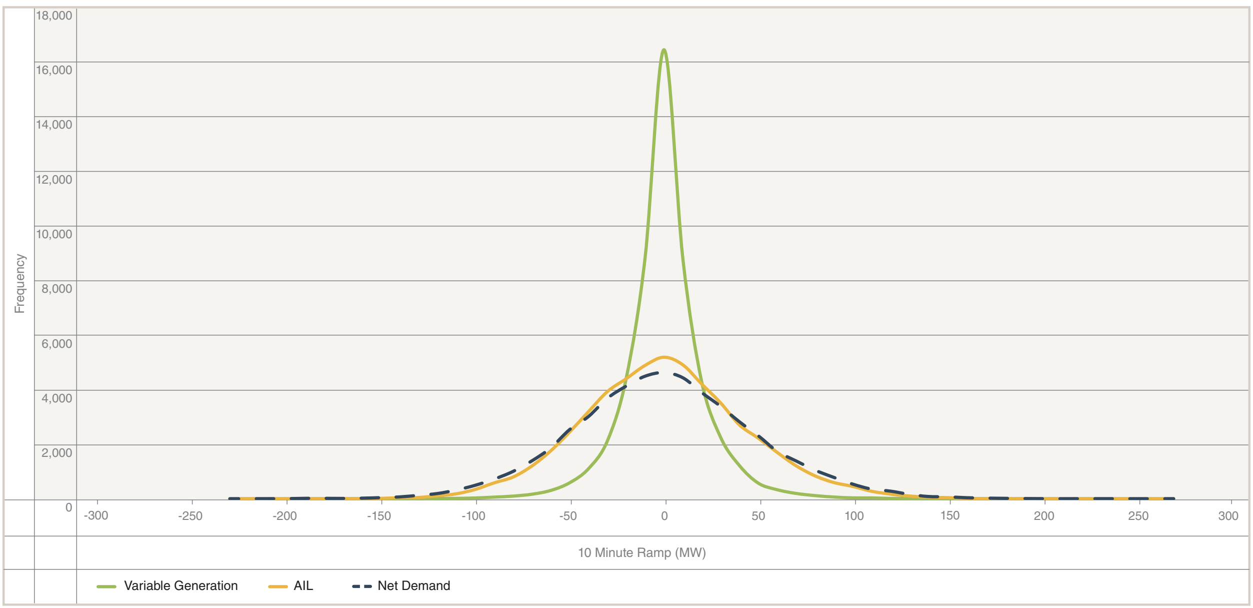
Net demand variability

The size and frequency of net-demand ramps on the grid are one of the common challenges experienced with higher variable renewable generation penetration. Dispatchable resources need to be able to match the size, speed and frequency of the net demand ramps in order to reliably supply customers as additional variable renewable generation is added to the grid.

Figure 32 provides the frequency and size of 10-minute ramps of variable generation, AIL, and net-demand in 2019. The 10-minute ramp size for each parameter is the amount of change within a given 10-minute period and can be negative or positive. This was measured for every 10-minute period in 2019. Variable generation includes all wind assets in Alberta plus Brooks Solar generation. As of the end of 2019, the AESO only had visibility on Brooks Solar generation which has a capacity of 15 MW. Other small-scale solar generators within the province are connected to the distribution system at customer locations and their variability would be reflected in the AIL.

In 2019, 10-minute net-demand ramp sizes were mostly in the plus/minus 150 MW range. Given the current variable generation volumes, changes in load remain the strongest driver of net-demand ramps. As more variable renewable generation is added to the grid, the frequency of larger net-demand ramps may increase.

FIGURE 32: Distribution of 10-minute ramps for variable generation, load and net demand in 2019



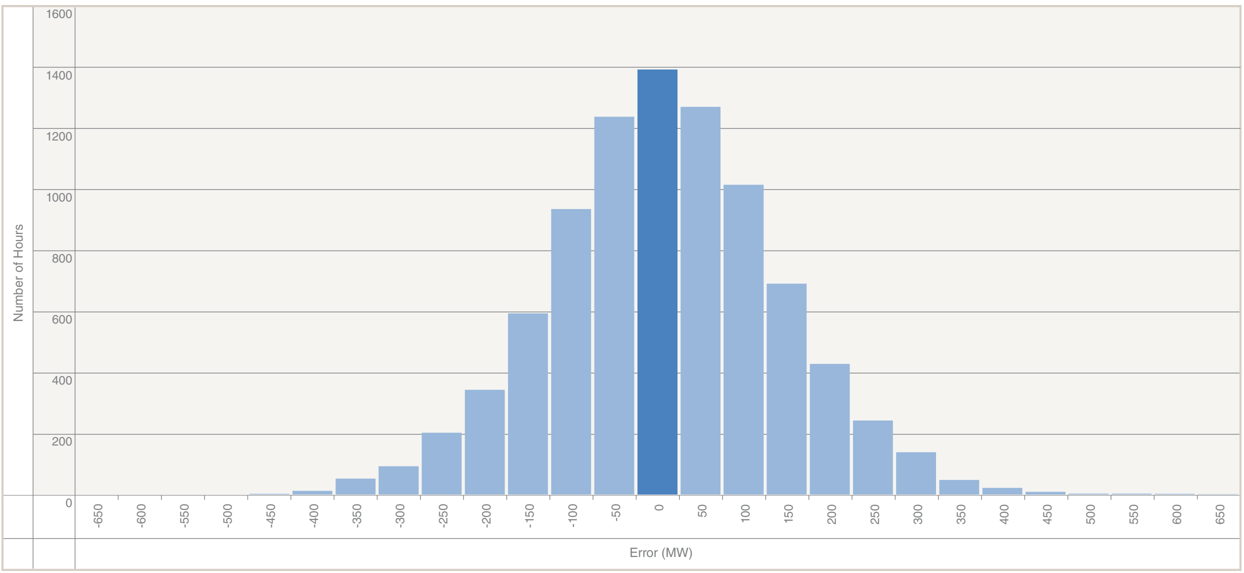
Forecast uncertainty

In Alberta, real-time energy market dispatch is performed by a system controller through the manual process of dispatching energy in the merit order. Continuous real-time system controller dispatch decisions maintain the balance between changing supply and changing demand. Every minute, system controllers face uncertainty as to what the next minute, 10 minutes, 20 minutes, etc. of net demand will be and how to match demand with dispatchable resources. The accuracy of real-time forecasts is not perfect; therefore, issues can arise because of uncertainty or forecast error. Accurate forecasting is important to ensure the AESO has the information to manage the variability of the net-demand. This includes the accuracy of short-term load forecasts, as well as variable generation forecasts. In this report the variable generation forecast only covers the wind forecast. Forecasting solar output is a new capability for the AESO that became available starting in 2020.

Short-term load forecast uncertainty

Figure 33 illustrates the distribution of the day-ahead load forecast error for all hours in 2019. The error at a given hour is defined as the day-ahead forecast of AIL minus the actual AIL for that hour. The distribution is slightly skewed towards the right, indicating that the number of hours that were over-forecast were more frequent than the number of hours that were under-forecast. In 2019, the forecast error was in the plus/minus 265 MW range 95 per cent of the time, equivalent to plus/minus three per cent of average 2019 AIL.

FIGURE 33: Distribution of day-ahead load forecast error in 2019



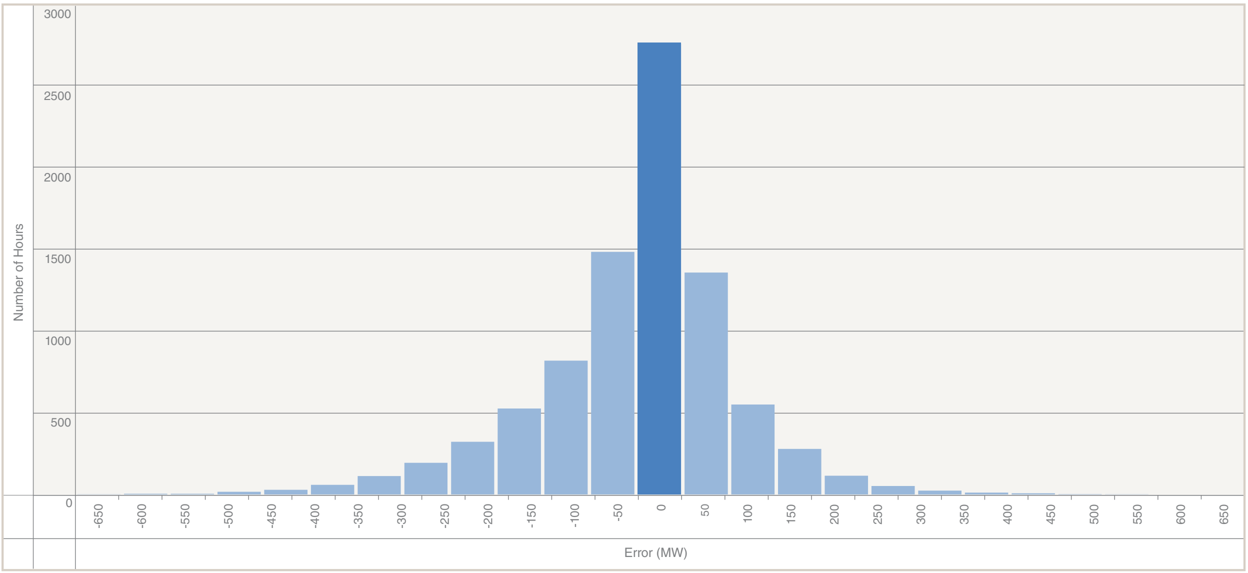
Wind power forecast uncertainty

The AESO's wind power forecast uses near real-time meteorological data to indicate the amount of wind power available to the Alberta grid on a seven days ahead (long-term) and a 12 hour ahead (short-term) basis[11]. The short-term forecast is updated every ten minutes and the long-term forecast is updated every six hours. For the purpose of this report, the error of the hour-ahead short-term forecast is used to measure the uncertainty of the wind forecast because AESO system operators require accurate near-term wind power forecasts to manage net demand variability.

At a given hour, the forecast error is calculated as the hour-ahead forecasted volume minus the actual wind generation. Figure 34 shows the distribution of the calculated errors for 2019. The distribution is skewed to the left which indicates wind was under-forecast more than it was over-forecast; 53 per cent of the time the hour-ahead forecast was lower than the actual wind generation. The introduction of the Whitla Wind facility in November 2019 decreased accuracy of the forecast during the testing period of the facility. The AESO has also recently procured a new wind power forecast vendor and 2019 accuracy results may not be indicative of future performance.

[11] https://www.aeso.ca/grid/forecasting/wind-power-forecasting/

FIGURE 34: Distribution of hour-ahead wind forecast error in 2019



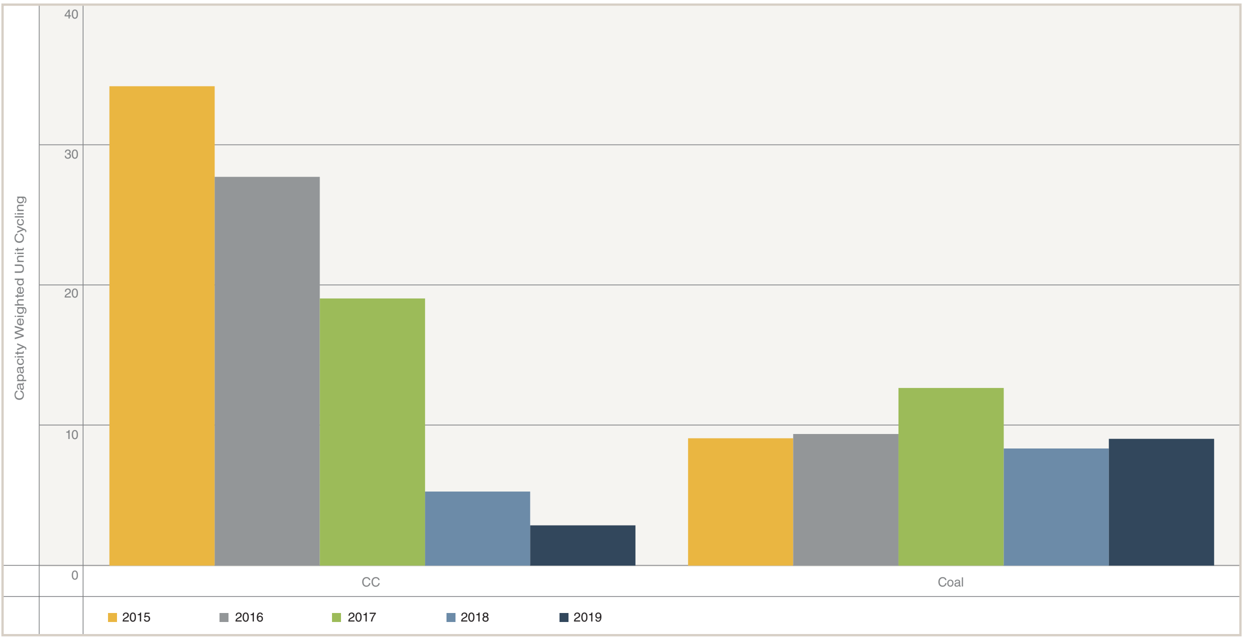
Unit on/off cycling

On/off cycling refers to starting up from a non-operational state, operating at any level for any duration, and then shutting down to return to a non-operational state. On/off cycling typically increases the operational costs for baseload generation such as combined-cycle and coal-fired generation units and may reduce the expected life of the generating unit. This section presents the average on/off cycles for baseload generating units weighted by maximum capability, over the past five years.

The number of on/off cycles for each unit was first counted for each year from 2015 to 2019. For each technology type and year, the average of the on/off cycles was calculated, weighted by the maximum capability of each generating unit. All combined-cycle and coal-fired generation were included in the calculation, except for any units within the City of Medicine Hat.

Figure 34 illustrates a trend of decreasing average on/off cycles for combined cycle generating units over 2015 to 2019. The average on/off cycles for coal-fired generating units has remained relatively stable over the same years.

FIGURE 35: Average number of on/off cycles per generating unit, by technology and year



Many factors impact the number of on/off cycles experienced by an individual generating unit, including factors that affect generating unit offers (such as natural gas prices, carbon costs and other economic drivers), planned and forced outages of transmission facilities, and planned and forced outages of the generating unit itself. For example, in 2018 and 2019 low gas prices and high pool prices made gas-fired generation more competitive, with the result that combined-cycle generating units generated more continuously and experienced fewer on/off cycles compare to previous years.

The AESO will continue to monitor these metrics and others as applicable, to understand the changing flexibility needs of the system as variable generation increases. The AESO is also currently undertaking a forward-looking study on flexibility needs for Alberta which is expected to be released in 2020.

Final notes

As the market evolves throughout 2020 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 reserves market statistics and a broad selection of historical datasets. The AESO continues to explore additional flexibility parameters and metrics which may be added to the annual market statistics report in the future.

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