AESO 2020 Annual Market Statistics

MARCH 2021

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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 2020 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 2020, 208 participants in the Alberta wholesale electricity market transacted approximately $5.7 billion of energy. The annual average pool price for wholesale electricity decreased 15 per cent from its previous-year value to $46.72/megawatt hour (MWh). The average natural gas price increased 25 per cent, averaging $2.12/gigajoule (GJ). The average spark spread based on a 7.5 GJ/MWh heat rate decreased 27 per cent to $30.81/MWh from its previous-year value.

The average Alberta Internal Load (AIL) decreased by 2.4 per cent over 2019 values.

Price	2019	2020	Year/Year Change
Pool price	$54.88/MWh	$46.72/MWh	-15%
Gas price	$1.69/GJ	$2.12/GJ	+25%
Spark spread at 7.5 GJ/MWh	$42.21/MWh	$30.81/MWh	-27%

Load	2019	2020	Year/Year Change
Average AIL	9,695 MW	9,462 MW	-2.4%
Winter peak	11,698 MW[1]	11,729 MW[2]	+0.2%
Summer peak	10,822 MW	10,532 MW	-2.7%

Demand from April through October was much lower than 2019 due to impacts of the COVID-19 pandemic, leading to a decrease in average AIL of 2.4 per cent and a decrease in the summer peak of 2.7 per cent.

Installed generation capacity at the end of 2020 decreased 1.5 per cent from the end of 2019, due to the retirement of just over 500 MW of coal-fired units. In 2020, for the first time, natural gas generation overtook coal-fired generation[3] as the primary source of electricity provided to the AESO grid. Gas-fired generation supplied 46 per cent of Alberta's net-to-grid energy.

Alberta was a net importer of electricity along all interties in 2020. Imports to the province increased 85 per cent from 2019 levels. Exports decreased by 84 per cent.

1 Winter 2019/20 seasonal peak was set January 14, 2020

2 Winter 2020/21 seasonal peak was set February 9, 2021

3 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 also reflect natural gas firing at these facilities.

Price of electricity

Pool price decreased 15 per cent

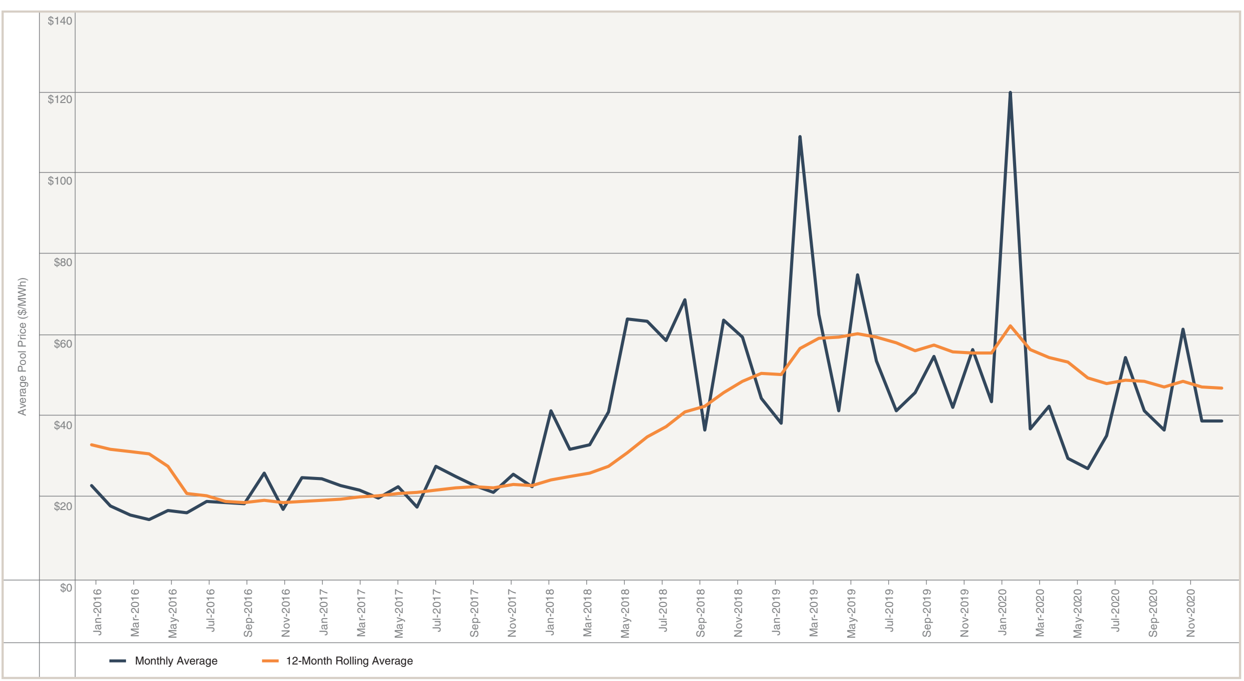
The pool price during 2020 averaged $46.72/MWh—a decrease of 15 per cent from 2019. In addition, each day is separated into on-peak and off-peak periods: on-peak periods start at 7 a.m. and end at 11 p.m. every day; the remaining hours of the day make up the off-peak period. In 2020, the average pool price during the on-peak period decreased 15 per cent to $54.72/MWh, and the off-peak average pool price decreased 16 per cent to $30.71/MWh. The spark spread is a high-level measurement that estimates the profitability of operating a generic combined-cycle natural gas baseload generation asset in the energy market. In 2020, the spark spread fell 27 per cent to $30.81/ MWh. Table 1 summarizes historical price statistics over the 10-year period between 2011 and 2020.

TABLE 1: Annual market price statistics

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Pool price ($/MWh)										
Average	76.22	64.32	80.19	49.42	33.34	18.28	22.19	50.35	54.88	**46.72**
On-peak average	102.22	84.72	106.13	61.48	40.73	19.73	24.46	59.28	64.12	**54.72**
Off-peak average	24.22	23.51	28.29	25.28	18.55	15.37	17.64	32.47	36.40	**30.71**
Spark spread at 7.5 (GJ/MWh)										
Average	50.46	47.28	57.58	17.56	14.12	2.77	6.70	39.54	42.21	**30.81**

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. For 2020, the monthly average pool price ranged from a low of $26.36/MWh in May to a high of $120.67/MWh in January.

FIGURE 1: Monthly average pool price



The hourly price of electricity in Alberta reflects 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 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 on-peak pool price duration curves for the last five years. The major difference between the average prices for 2016-2017 and 2018-2020 was the higher duration of high prices in the latter years. A combination of higher demand and less supply in the 2018-2020 period is the main reason for this difference.

FIGURE 2: On-peak pool price duration curve

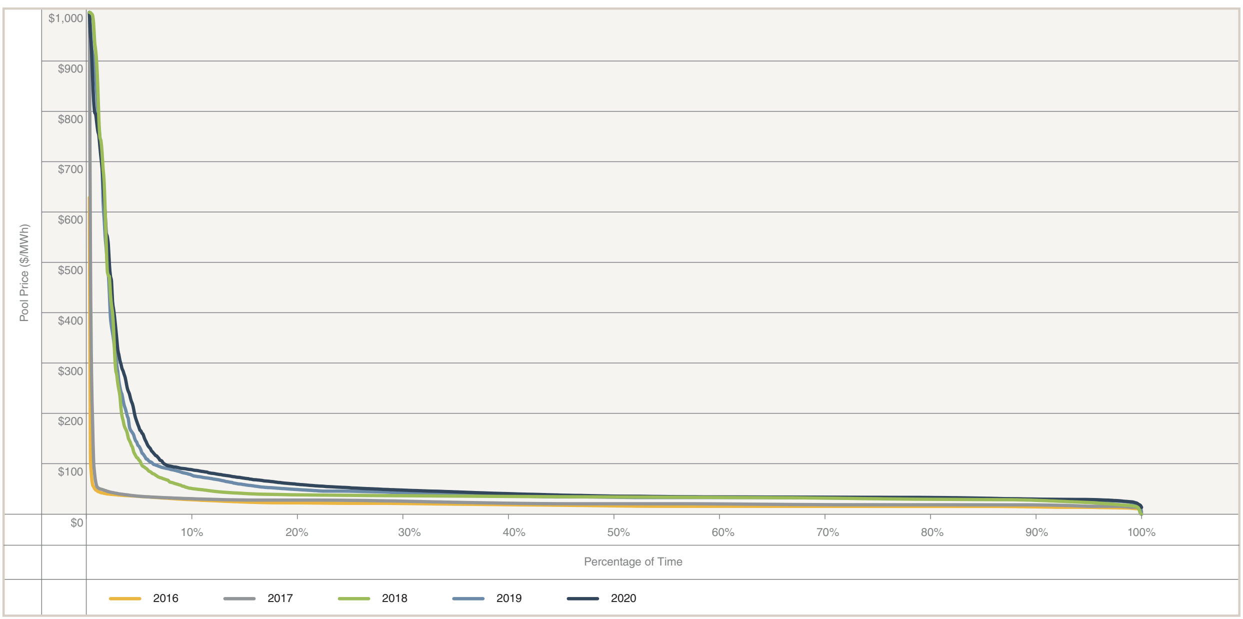
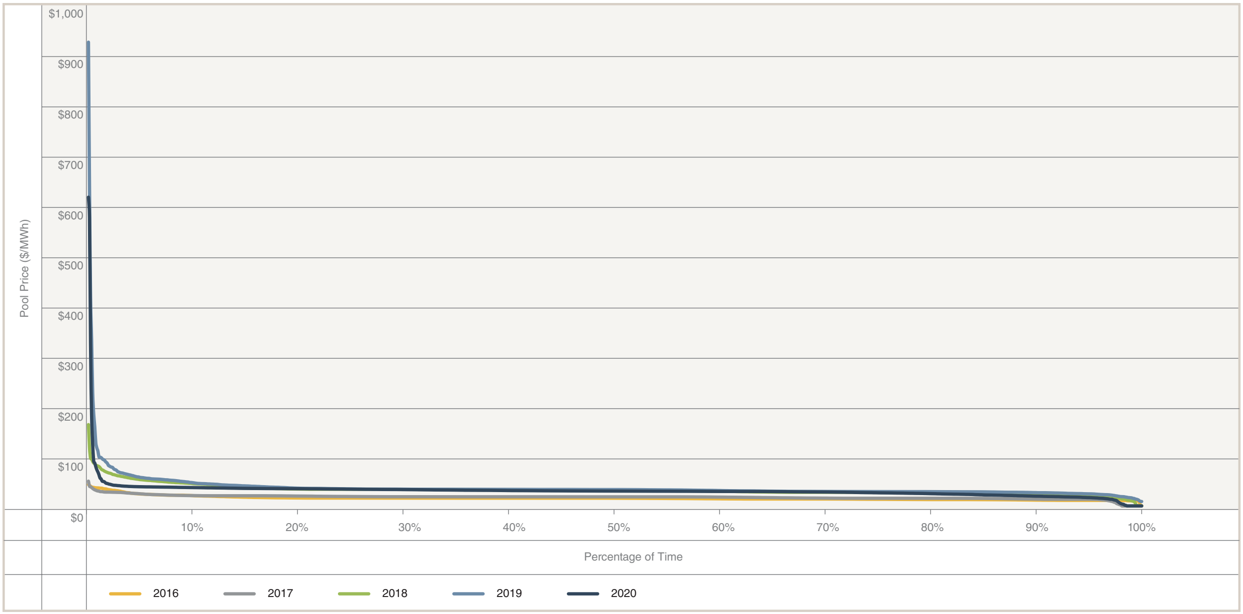


Figure 3 shows off-peak pool price duration curves for the last five years. While not as pronounced as the on-peak duration curves, the same contrast in durations of high prices is the major differentiator between the average prices for the 2016-2017 period and the 2018-2020 period.

FIGURE 3: Off-peak pool price duration curve



The reliability of the AIES depends on the ability of system controllers to dispatch supply to satisfy demand. During supply shortfall conditions and supply surplus conditions, electricity supply is mismatched with demand requirements. Left unaddressed, these system conditions could threaten the stability of the AIES. To preserve system stability, system controllers must follow prescribed mitigation procedures to maintain the balance between supply and demand.

Supply shortfall conditions occur when Alberta load exceeds the total supply available for dispatch from the merit order. When supply 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.

On June 7, 2020, a lightning strike on the B.C.–Alberta intertie caused the loss of approximately 900 MW of imports, leading to an under-frequency event. While not technically a supply shortfall event, the AESO was forced to shed firm load during this event. The available supply could not respond fast enough to cover the amount of lost imports. This was the first firm load curtailment since July 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. From April through September 2020, there were 68 hours of supply surplus. This was due to a combination of low load from COVID-19 restrictions, lower oilsands production due to low oil prices and higher than average supply from wind generation and imports.

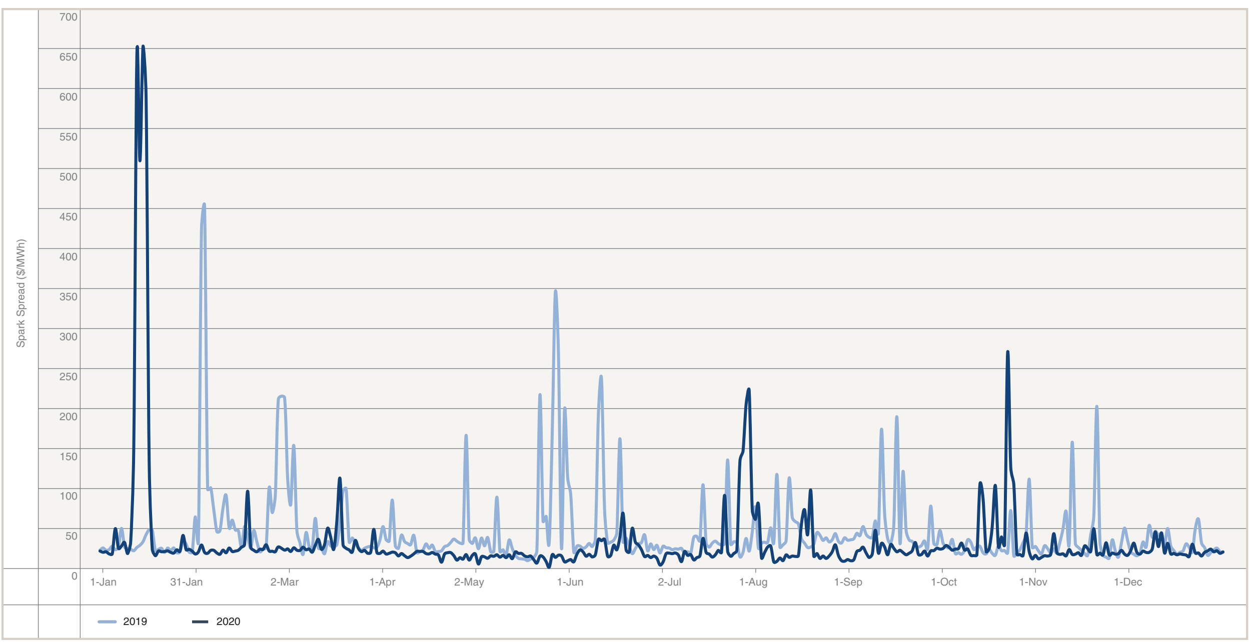
Spark spread decreased 27 per cent

As mentioned above, the spark spread is a high-level measurement that estimates the profitability of operating 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, which measures the efficiency of the generation asset, and the unit cost of natural gas. The operating heat rate represents the amount of fuel energy required to produce one unit of electrical energy and varies 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 the generic gas-fired generator; 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 4 shows the daily average spark spread for 2019 and 2020. In 2020, the average spark spread decreased 27 per cent to $30.80/MWh. This was due to a fall in the pool price of 15 per cent and increase in the average gas price of 26 per cent.

FIGURE 4: 2019 and 2020 daily average spark spread



Alberta 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 2.4 per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2020, average AIL decreased by 2.4 per cent to 9,462 MW, and annual peak load of 11,698 MW occurred on Jan. 14, 2020. The decrease in AIL from 2019 to 2020 was primarily driven by changes in energy consumption caused by the COVID-19 pandemic and a reduction in oil and gas production and servicing industries resulting from the decline in oil prices.[4]

TABLE 2: Annual load statistics

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Alberta Internal Load (AIL)										
Total (GWh)	73,600	75,574	77,451	79,949	80,257	79,560	82,572	85,330	84,925	**83,115**
Average (MW)	8,402	8,604	8,841	9,127	9,162	9,057	9,426	9,741	9,695	**9,462**
Maximum (MW)	10,226	10,609	11,139	11,169	11,229	11,458	11,473	11,697	11,471	**11,698**
Minimum (MW)	6,459	6,828	6,991	7,162	7,203	6,595	7,600	7,819	8,024	**7,579**
Average growth	2.6%	2.4%	2.8%	3.2%	0.4%	-1.1%	4.1%	3.3%	-0.5%	**-2.4%**
Load factor	82%	81%	79%	82%	82%	79%	82%	83%	85%	**81%**
System load										
Average (MW)	6,593	6,620	6,778	7,024	6,998	6,919	7,121	7,183	7,030	**6844**
System-to-AIL ratio	78%	77%	77%	77%	76%	76%	76%	74%	72%	**72%**
Implied BTF load	1809	1984	2063	2103	2164	2139	2305	2558	2664	**2618**

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[5] and 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.)[6], plus transmission losses.

The load factor represents the ratio of the average AIL to the peak 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 decrease in the load factor for 2020 is due to the peak load being set early in the year, then load dropping significantly due to the COVID-19 pandemic and declining industrial load in response to low oil prices. These impacts started in spring and remained in effect for most of the rest of the year.

4 Throughout 2020, the AESO published several detailed analyses on the impact of COVID-19 and low oil prices on Alberta's power system. See https://www.aeso.ca/stakeholder-engagement/covid-19/

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

6 For system access service provided in accordance with the ISO tariff under Rates DTS, FTS, and DOS.

The system load to AIL ratio describes how much of total load on Alberta is served using the transmission system. In 2020, 72 per cent of Alberta's load was served using the transmission system - the same as 2019. The difference between AIL and system load represents load that is not served by utilizing the transmission system, commonly referred to as "behind the fence" (BTF) load. BTF load is self-supplied generation as large as on-site cogeneration plants or as small as small roof-top solar panels. The implied average hourly BTF load is 2,618 MW for 2020. This is down two per cent from 2019, likely due to impacts from the COVID-19 pandemic. However, over the last decade, this volume has increased 44 per cent.

Figure 5 shows the monthly average load in 2019 and 2020. The average load in 2020 started the year higher than 2019 due to a non-weather-related increase in load. Differences in February and March were primarily due to weather. Load was lower for April through October of 2020 primarily due to COVID-19 restrictions. Low oil prices had the biggest negative impact on demand for April through June. Demand fully recovered in November and was about 200 MW higher than 2019 for the month. Increased COVID-19 restrictions in December caused load to fall below 2019 levels again. Absent impacts from the pandemic, it is estimated 2020 demand would have been 200-300 MW higher when compared to 2019.

FIGURE 5: 2019 and 2020 monthly average load

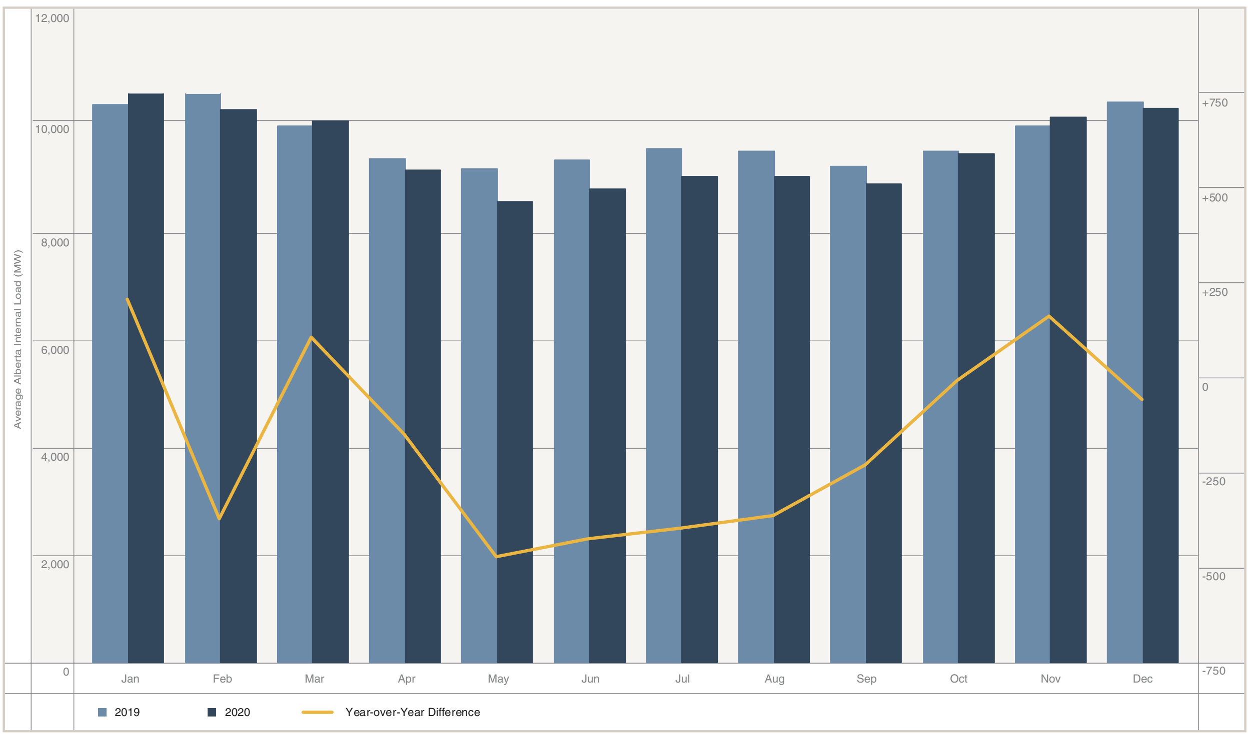
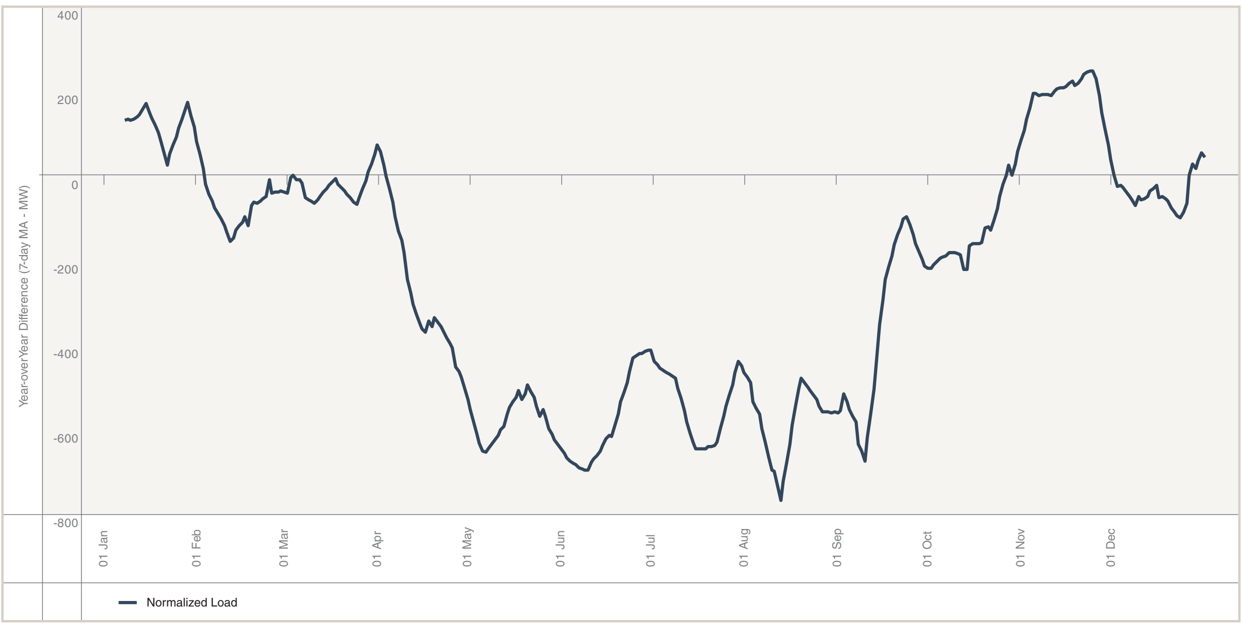


Figure 6 shows the weekly average weather-normalized load in 2020 as a difference to the weather-normalized load in 2019. Weather-normalization is the process of using a model to estimate what load would have been in multiple years if they had the same temperatures. This reduces the impact that temperatures have on load, allowing for the observation of structural changes. In 2020, weather-normalized load started the year slightly higher than 2019 before levelling off. Starting in April and lasting through most of the summer, load dropped between five and 8 per cent (400 MW to 800 MW) from 2019 load, due to the economic impact of COVID-19 and low oil prices curbing domestic oil sands production. Load began to rebound in mid-September and exceeded 2019 load for most of November. In December, COVID-19 restrictions were again increased, causing load to decline to 2019 levels. Overall, weather-normalized load was down 239 MW in 2020, as compared to 2019.

FIGURE 6: 2020 weekly average weather-normalized load vs. 2019



The load duration curve represents the percentage of time that AIL was greater than or equal to the specified load. Figure 7 plots the annual load duration curve for on-peak hours (HE8-23 for all days), while Figure 8 plots the same thing, but for off-peak hours (HE1-7,24). Both look at the past five years. Both figures show that 2020 was a bifurcated year. During higher load periods (i.e. winter months of January – March and October – December), load was slightly lower, yet comparable to 2018 and 2019. However, it was the summer months (April – September), when loads are generally below 10,000 MW, that were most impacted by the COVID-19 pandemic. During those months, load was lower than 2017 levels in close to 50 per cent of the hours.

FIGURE 7: Annual load duration curves – on-peak hours

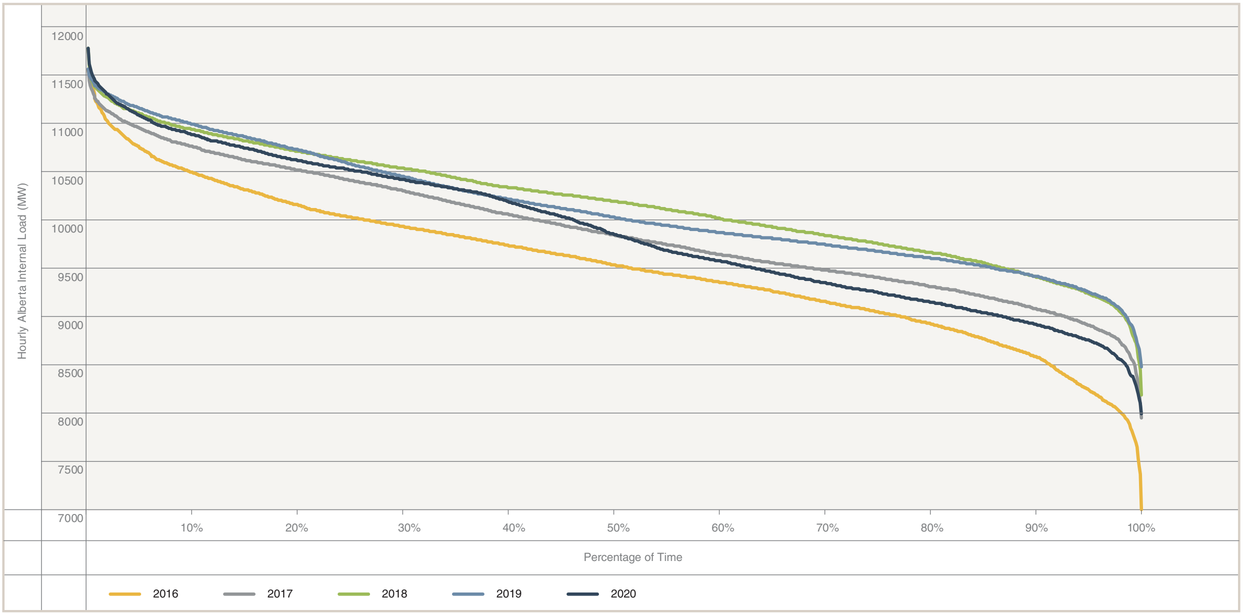
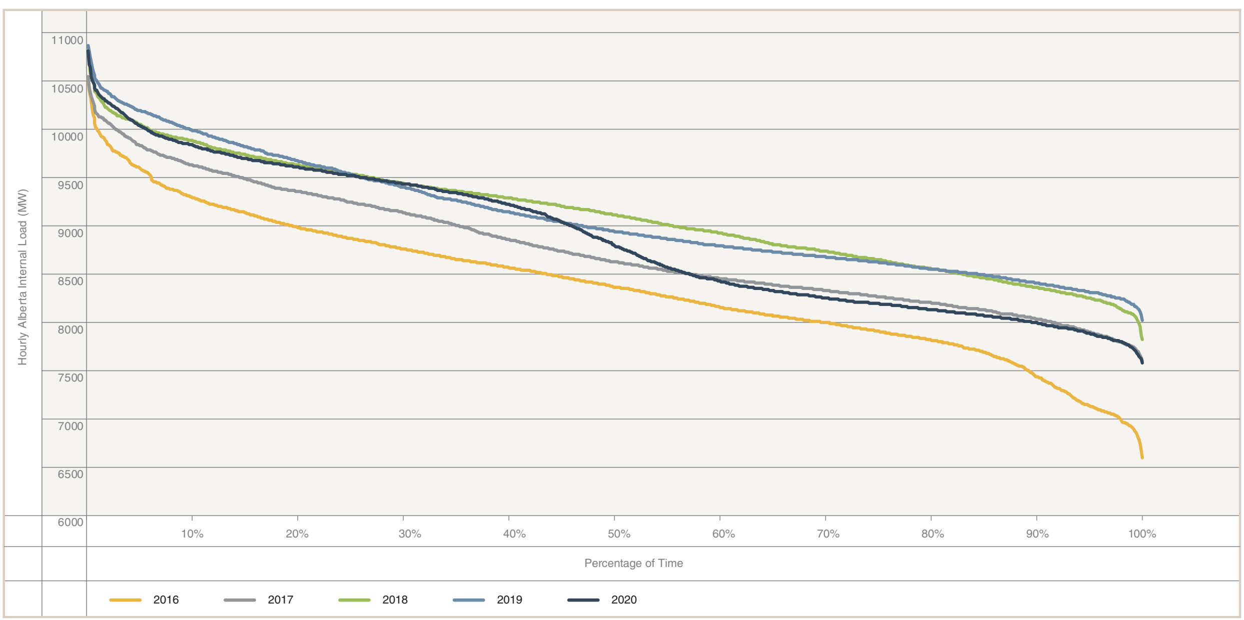


FIGURE 8: Annual load duration curves – off-peak hours



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. Alberta is a winter-peaking region, with a difference of around 1,000 MW between the summer and winter peaks. At the time of writing, the all-time peak load was set at 11,729 MW late in the Winter 2020 on Feb. 9, 2021.

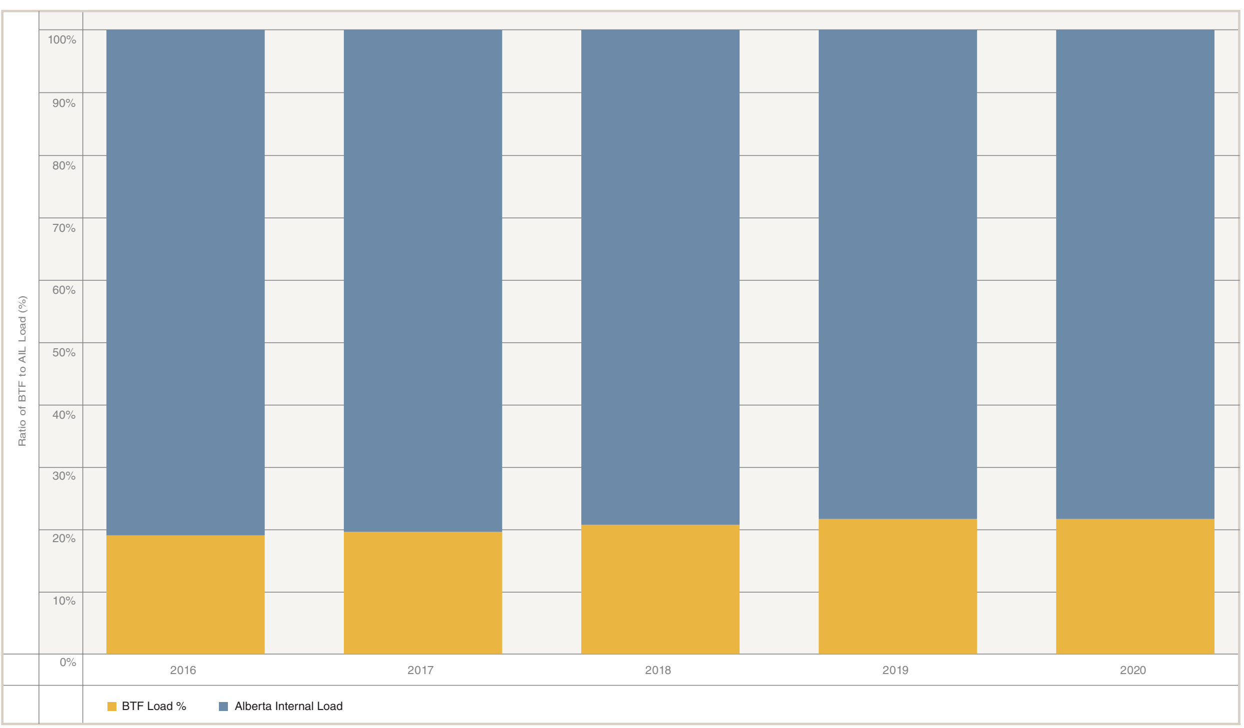
TABLE 3: Seasonal peak load

Season	Peak AIL (MW)	Date	Calendar Year
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
Summer 2020	10,532	2020-10-26	2020
Winter 2020 (to Feb 2021)	11,729	2021-02-09	2021

Behind-the-Fence load

In Alberta, AIL represents overall load within the province. System load is the load total of AESO-metered demand plus transmission system losses. BTF is the difference between AIL and system load. It is the estimated amount of load that is self-supplied with on-site generation. Since 2016, the percentage of AIL comprising BTF load has increased from 24 per cent to 28 per cent. In absolute terms, this is an increase of just under 500 MW over the last five years. Figure 9 shows the ratio of BTF load to AIL over the last five years.

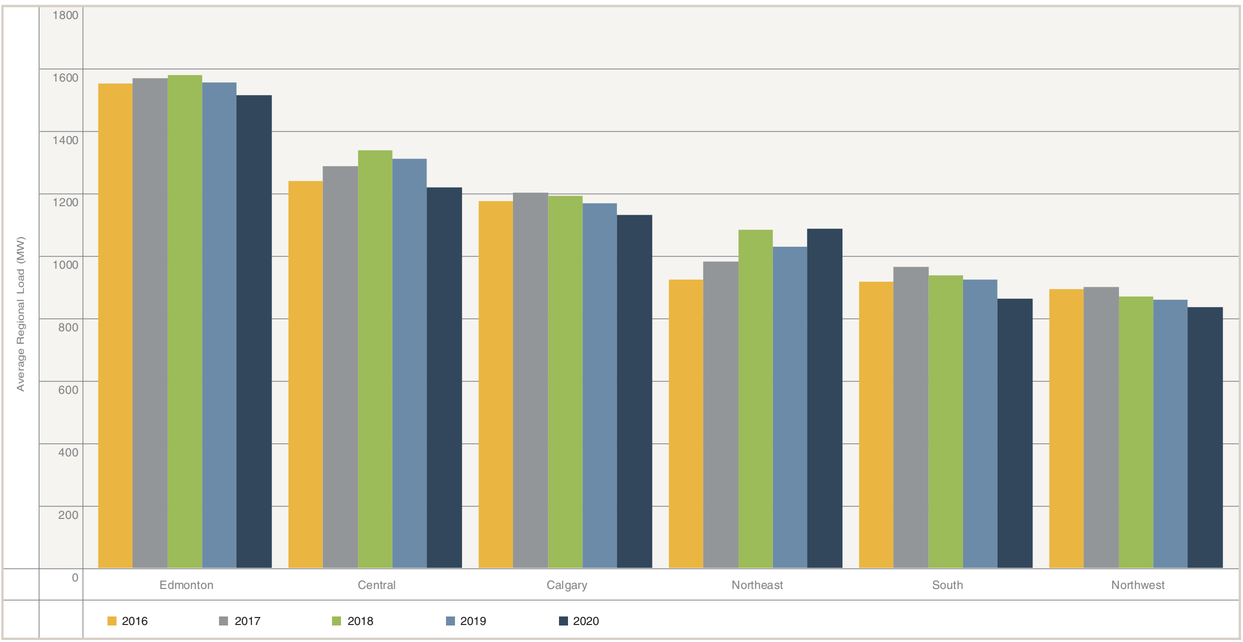
FIGURE 9: Behind-the-Fence load as percentage of AIL



Regional load

Figure 10 shows the average regional system[7] load (i.e. excluding BTF load) over the last five years. Except for the Northeast, all regions are showing a drop in load for 2020. Since the Northeast is primarily an industrial region, the implication is that COVID-19 restrictions are primarily impacting residential and commercial loads. The Central and South regions lost the most load year-over-year, down roughly 6.8 per cent. The Edmonton, Calgary and Northwest regions were down about 2.7 per cent. Only the Northeast gained load compared to 2019, up 5.6 per cent. For reference, AIL was down 2.4 per cent year-over-year and overall system load was down 2.6 per cent.

FIGURE 10: Regional average load



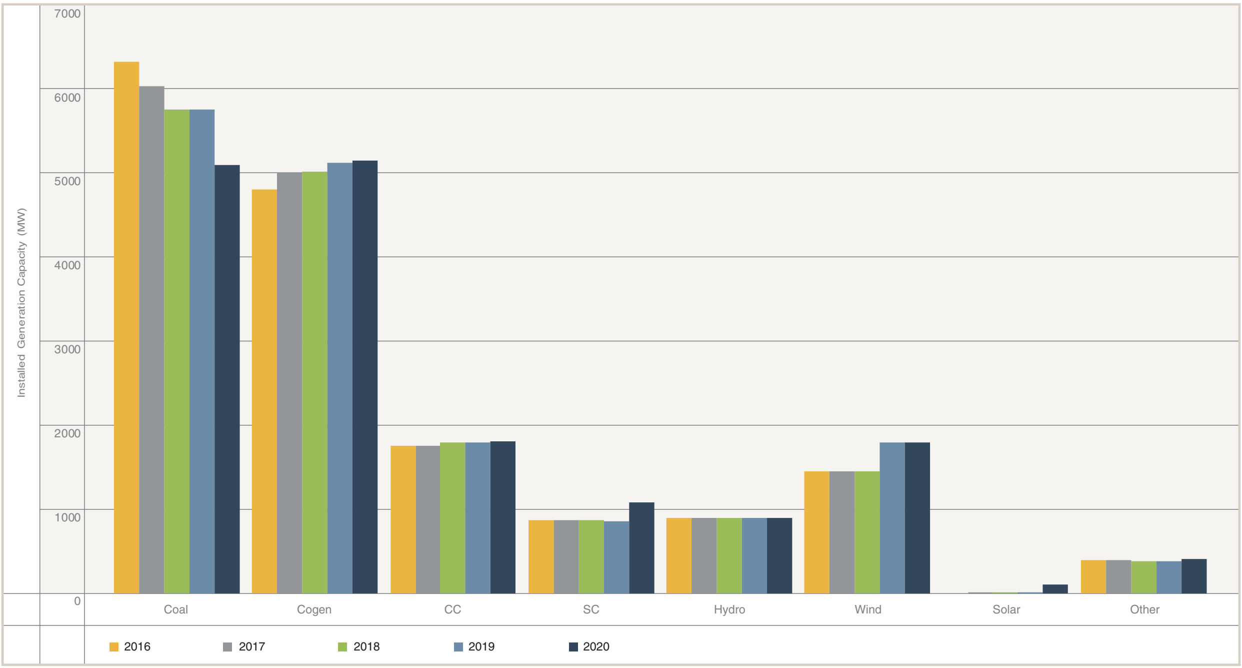
Installed generation

Year-end generation capacity decreased 1.5 per cent

At year-end 2020, the installed generation capacity was 16,270 MW, down from 16,532 MW at year-end 2019, a decrease of 1.5 per cent. The retirements of the Sundance 3 (368 MW) and Battle River 3 (149 MW) coal units during the year were the primary reason for the decrease in capacity. Offsetting these retirements were the addition of a number of new units throughout 2020: eReserve1 Rycroft (Storage – 20 MW, in Other technology type); Hull (Solar – 25 MW); Innisfail (Solar – 22 MW); Strathcona (Cogeneration – 43 MW); Pembina (Simple Cycle – 13 MW); Suffield (Solar – 23 MW); Summerview (Storage – 10 MW); and Vauxhall (Solar – 22 MW). In addition, simple-cycle units increased capacity and coal capacity fell due to the conversion from coal to gas of H.R. Milner. Milner's conversion also included an increase of 64 MW in its capacity, from 144 MW of coal to 208 MW of gas. Note that installed capacity includes mothballed but not retired units. Also, the Coal technology group includes a number of units that are capable of dual firing on both coal and gas. The AESO is investigating separating these units into a separate technology group in the future. Figure 10 shows the installed capacity at the end of each of the last five years.

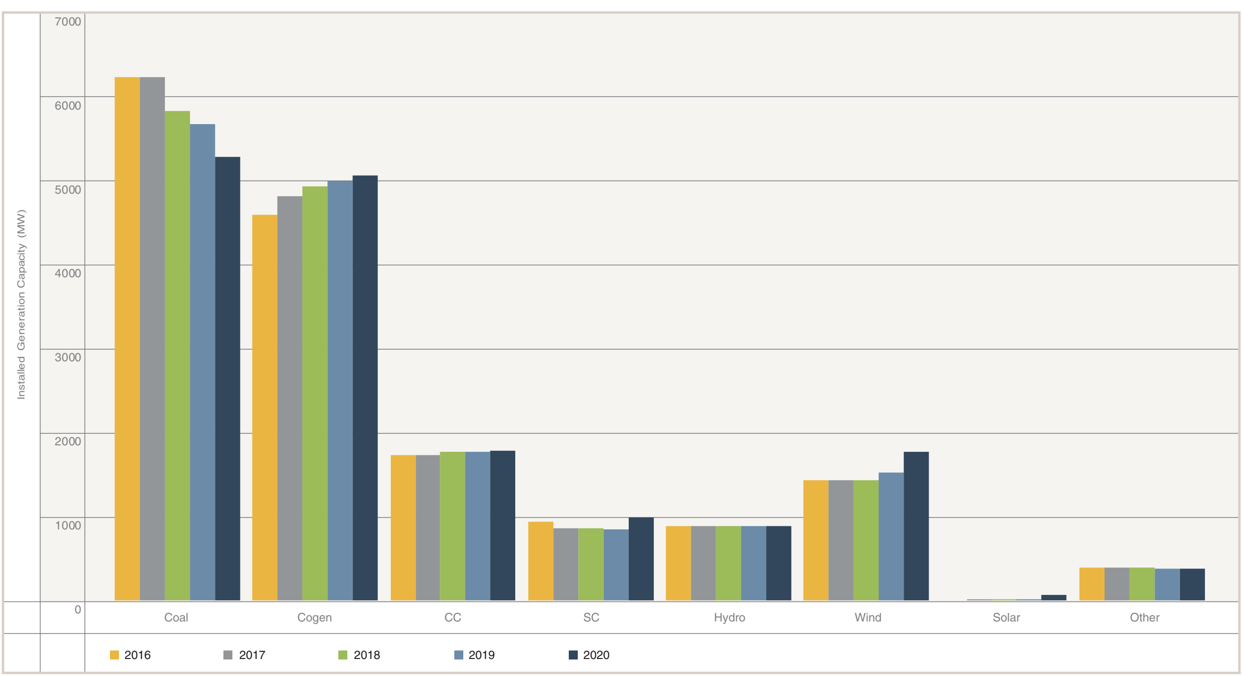
[7] The definition of the regions can be found in the document at this link: https://www.aeso.ca/assets/Uploads/Planning-Regions.pdf

FIGURE 11: Year-end generation capacity by technology



Despite the fall in year-end capacity, 2020 had an increase in the average annual installed generation capacity. During 2020, installed capacity averaged 16,362 MW, compared to 16,247 MW in 2019, for an increase of 0.7 per cent. This was attributable to a full year of wind generation that was installed in 2019 and the retirement of Sundance in late 2020. Figure 12 shows the changes in the average annual capacity of each technology type.

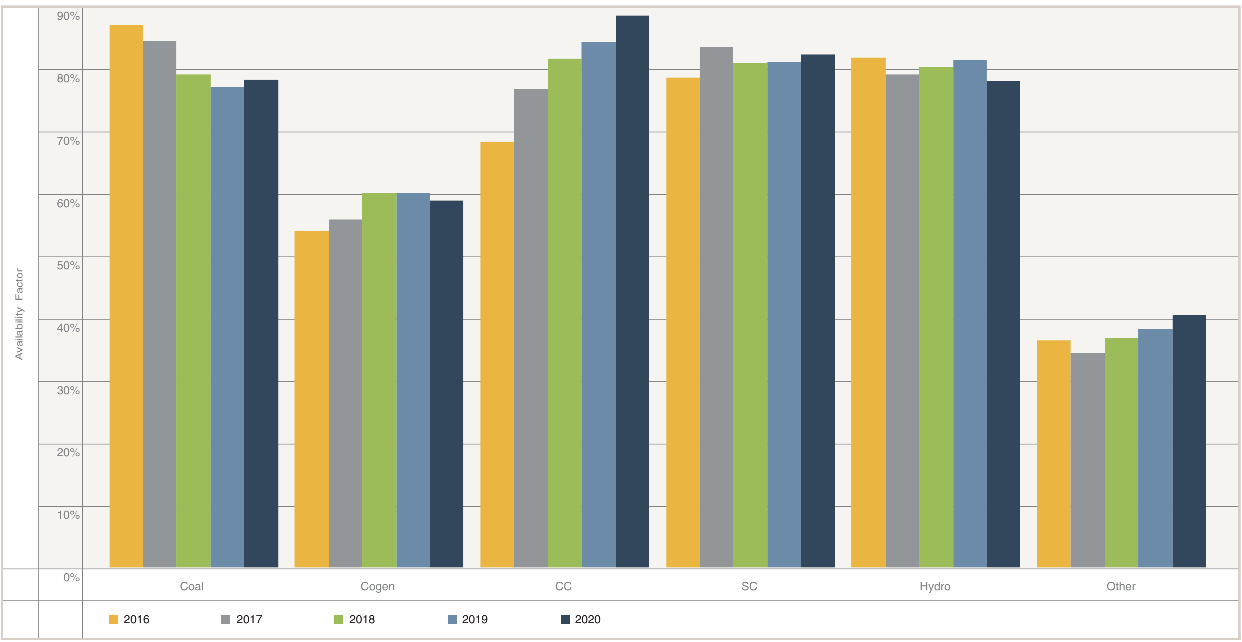
FIGURE 12: Average annual generation capacity by technology



Generation availability

The availability factor is the average percentage of installed generation capacity 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 and solar generation are excluded from this calculation as their available capability is dependent on environmental factors. All available wind and solar generation is used to supply demand, which is not true of other technologies. Also, any generation used to self-supply BTF load is excluded. Figure 13 illustrates the annual average availability factor by generation technology. Availability of coal-fired generation increased slightly in 2020 due to the retirement of some low availability units. The availability of combined-cycle generation continued to increase.

FIGURE 13: Annual availability factor by technology



Combined-cycle power is highest utilized technology

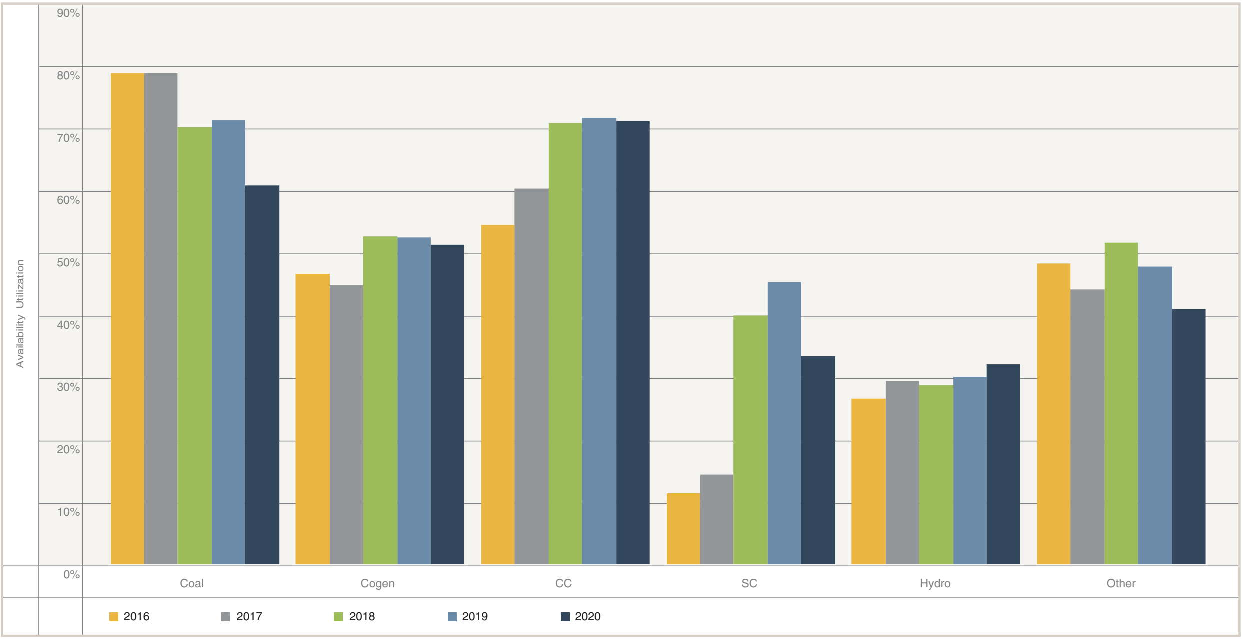
Availability utilization represents the percentage of the available power that was dispatched to serve load. Availability utilization is calculated as the ratio of net-to-grid generation to the net-to-grid available capability. Any capacity and generation used to supply BTF load has been excluded from the availability utilization calculation. Wind and solar generation are excluded from this calculation since all available wind and solar power is fully utilized, except in rare circumstances. Figure 14 illustrates the annual availability utilization by generation technology.

Prior to 2018, the availability utilization of coal-fired generation was consistently highest among dispatchable generation technologies[8]. Starting in 2018, the combination of lower gas prices and higher carbon costs, which had a bigger impact on coal-fired generation, led to combined-cycle gas generation replacing coal-fired generation as the lowest cost—and therefore the most utilized—generation technology. In 2020, combined-cycle generation continued to be the most utilized generation technology. Lower gas prices, combined with generally higher pool prices, have allowed the less efficient simple-cycle units to run more frequently. Previously, these units only ran during very high-priced periods. Starting in 2018, simple-cycle units tripled their availability utilization when compared to previous years.

Despite being a relatively low-cost option, the availability utilization of cogeneration gas is less than that of other thermal generation. This is primarily because reported capacity is the gross capacity while the reported availability is the net-to-grid availability. In addition, cogeneration gas is used mainly to provide on-site steam or electricity at industrial facilities, thus is less responsive to gas and power prices.

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

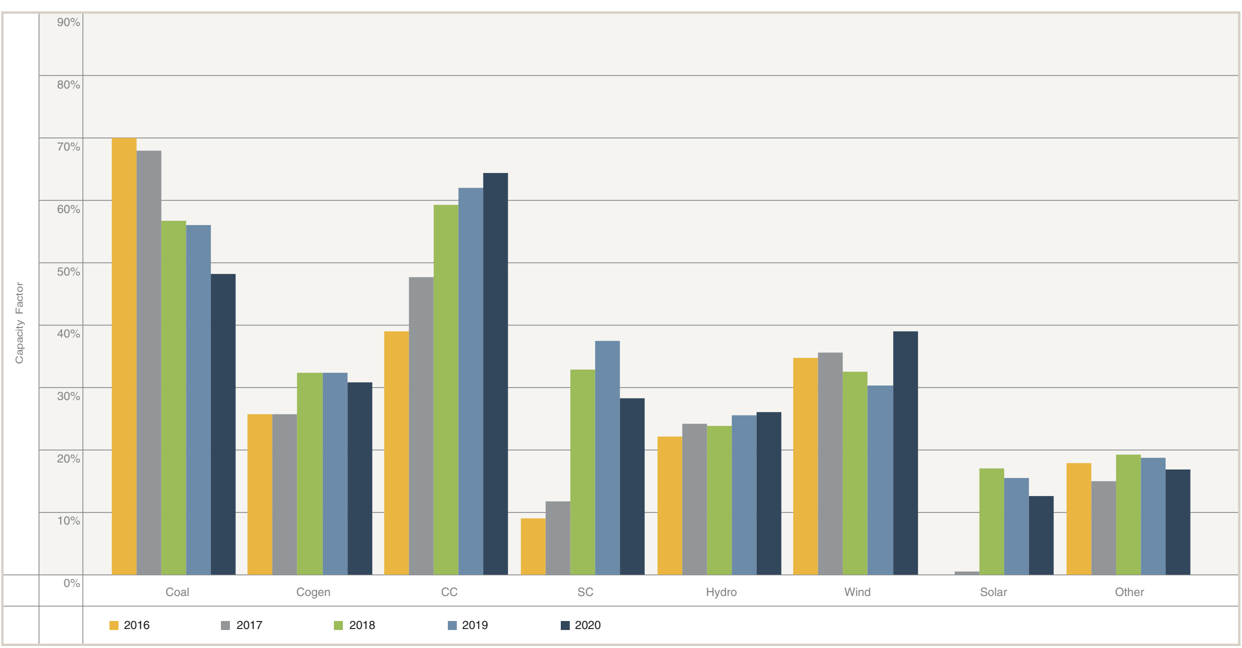
FIGURE 14: Annual availability utilization factor by technology



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. Capacity factor is calculated as the ratio of average net-to-grid generation to the maximum capability over the given year. The power used to serve on-site load is excluded from the calculation of the capacity factor. As a result, the capacity factor measure under-reports the total output of cogeneration gas technology. Figure 15 illustrates the annual capacity factor by generation technology.

FIGURE 15: Annual capacity factor by technology



Similar to comments in the above sections, the combination of higher carbon costs and lower gas prices has led to a change in the capacity factors of various technologies starting in 2018. The capacity factor of coal-fired generation has fallen from just under 70 per cent to below 50 per cent, as higher carbon costs increased the technology's prices. In contrast, lower gas prices led to increased capacity factors of both combined-cycle and simple-cycle gas units. Combined cycle units have replaced coal-fired units as the technology with the highest capacity factors, reflecting the lower cost of combined-cycle generation in 2020. The capacity factor of combined-cycle was 64 per cent; on average, for every 100 MW of installed capacity, combined-cycle generation delivered 64 MWh to the AIES each hour.

Gas generation supplied 46 per cent of net-to-grid energy

Figure 16 illustrates the average net-to-grid generation from each generation technology over the past five years. In 2020, coal-fired generation supplied 39 per cent of the energy delivered to the AIES, down from 62 per cent in 2016. Gas generation technologies delivered 46 per cent of net-to-grid generation, up from 28 per cent in 2016. It's important to note that gas-fired generation is under-reported due to the conversion of some coal units to dual-fired gas and coal units. Unfortunately, the AESO does not have access to a breakdown of each fuel type being used at these dual-fired units and is unable to estimate the amount of gas being used. Renewable generation (hydro, wind and solar) provided 14 per cent, up from 10 per cent in each of the last four years. Wind generation provided the majority of energy from renewable sources. In 2020, 11 per cent of total net-to-grid generation was provided by wind power, up from the average of seven per cent for 2016-2019.

FIGURE 16: Annual average net-to-grid generation by technology

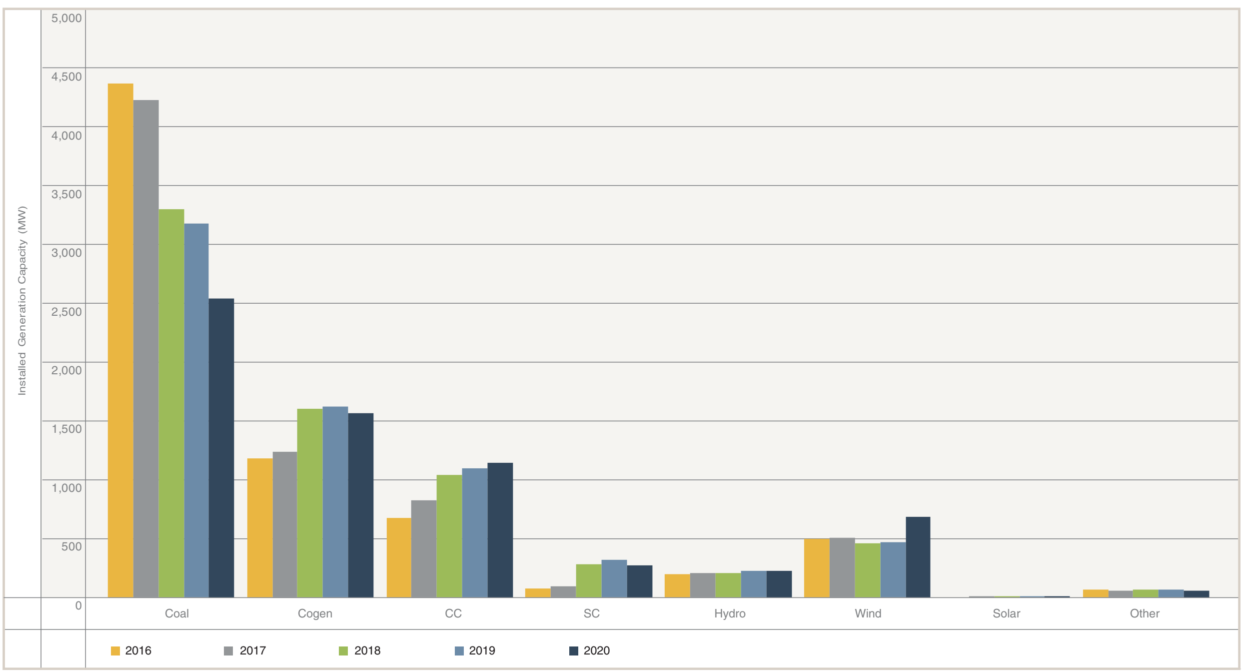
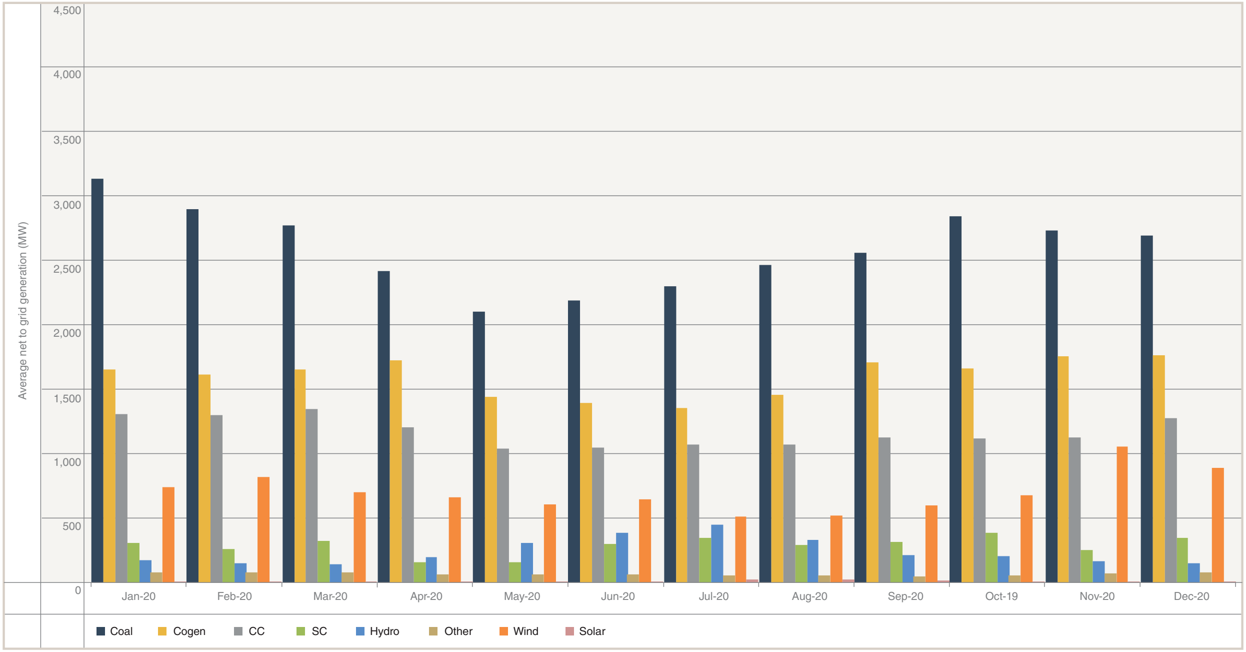


Figure 17 illustrates the monthly average net-to-grid generation from each generation technology over the past year. Seasonal patterns in generation are evident in this figure. Hydro generates more energy during spring and summer, while wind has higher output during winter months. During the spring, coal-fired generation generally declines due to maintenance outages. These outages are timed for periods of lower power prices when there is less need to dispatch coal energy in the merit order. The solar net-to-grid generation was distorted in 2020 due to the large increase in capacity throughout the year.

FIGURE 17: 2020 monthly average net-to-grid generation by technology



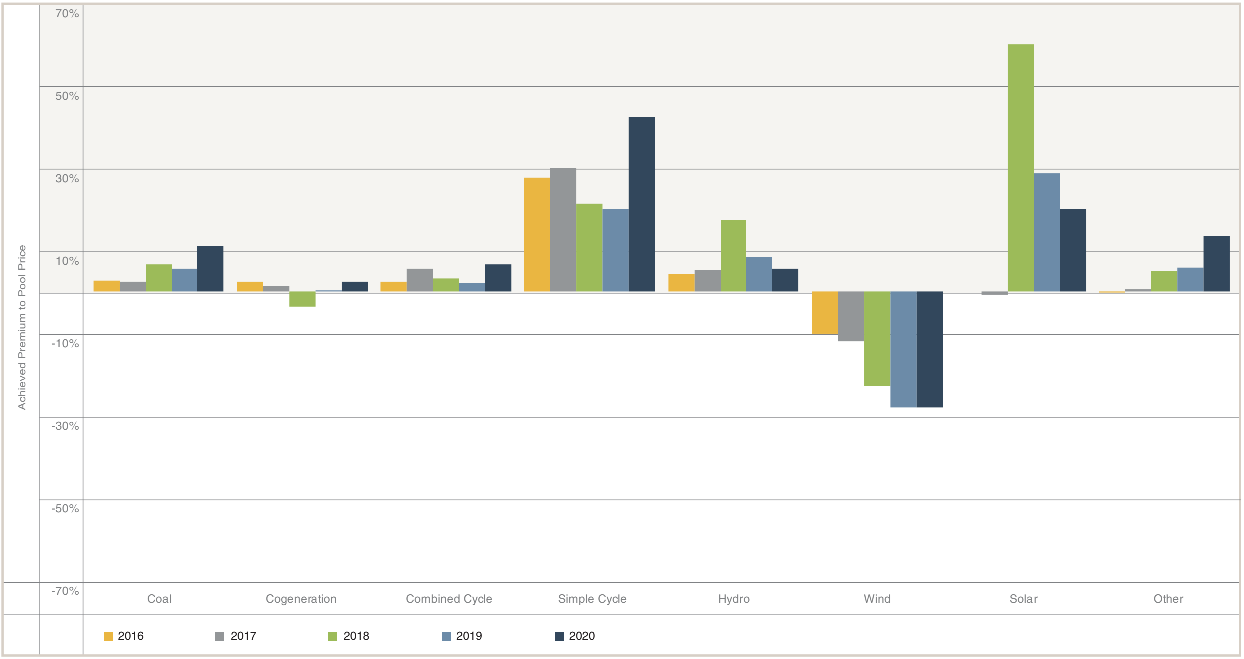
Simple-cycle gas realized highest achieved premium to pool price

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 in that interval. The achieved margin represents the difference between the achieved price and the average pool price over the year.

The achieved premium to pool price is calculated as the ratio of the achieved margin to the average pool price for each year. 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. Figure 18 illustrates the achieved premium to pool price realized by each generation technology in each of the past five years.

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 achieved discounts (or negative achieved premiums) to pool price.

FIGURE 18: Annual achieved premium to pool price



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 will produce energy in a 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 the 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 include coal-fired, cogeneration and combined-cycle baseload technologies. For combined-cycle and coal-fired generation, it is generally 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 2020, combined-cycle and coal-fired technologies realized 11 and seven per cent premiums to pool price, respectively. Cogeneration gas technology achieved a two per cent premium. Because of higher carbon costs, inefficient coal units are running more selectively than in past years. Going forward, this may result in higher achieved prices for the technology.

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 start-up costs but are less efficient and 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 for fewer hours than baseload generation but achieves a higher average price. Typically, simple-cycle gas generation achieves the highest premium across all generation technologies in Alberta. In 2020, simple-cycle units received a 42 per cent premium to pool price, more than double the premium from 2019. Hydro received a six per cent premium to pool price in 2020, down from an eight per cent premium in 2019.

Wind generation is the only technology that consistently receives 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, with the output of wind power varying according to environmental conditions. In addition, the strongest winds typically occur in the overnight hours, leading to the highest wind production during the lowest-priced hours.

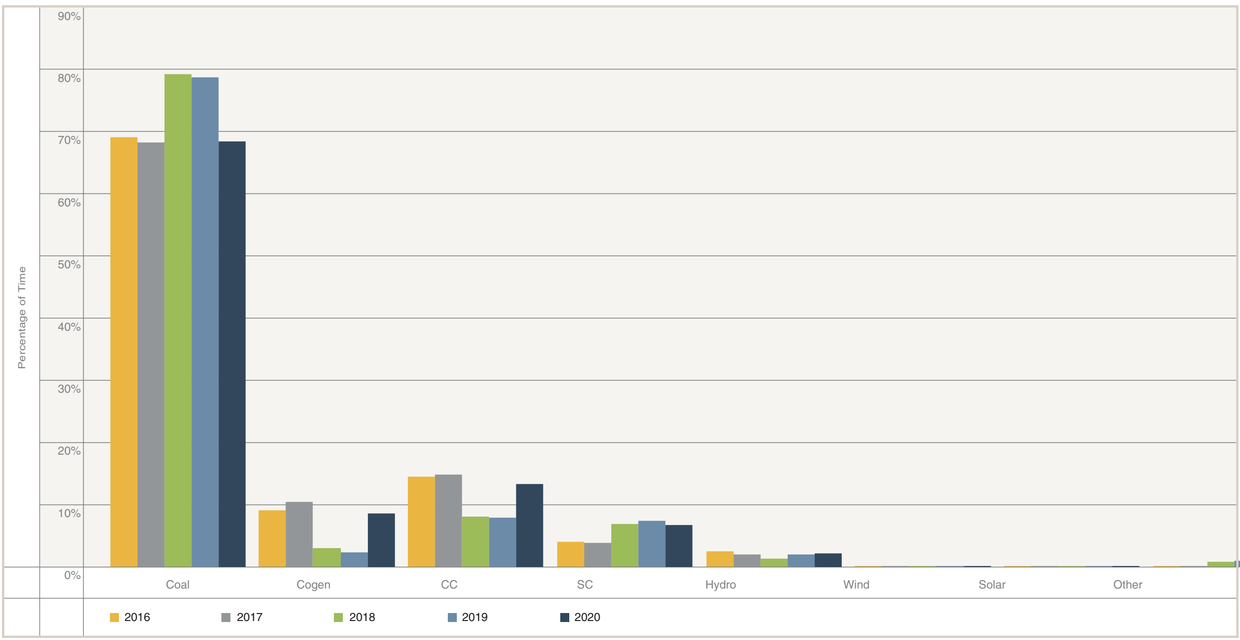
When wind blows in a region, all available wind generation in that region is delivered to the AIES. Wind generation in Alberta remains heavily concentrated in the southern region. When wind blows in southern Alberta, wind energy replaces some quantity of power from higher-priced generating units in the energy market merit order. Wind generation tends to reduce the system marginal price, which lowers its achieved price. In 2020, wind generation received a 28 per cent discount to pool price.

Solar power is like wind power, in that it cannot control its operational schedule because it is dependent on environmental conditions. However, since the highest priced hours are typically when the sun is shining during on-peak hours, solar power gets an achieved price premium. In 2020, this premium was 20 per cent.

Coal-fired generation sets marginal price in 69 per cent of hours

Figure 19 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 during on and off-peak hours. In 2020, coal-fired generation was the system marginal unit in 69 per cent of the hours, a drop from 79 per cent of the hours in 2019. Lower demand during part of the year and higher carbon prices meant that cogeneration and combined-cycle units were able to increase the number of hours they set the system marginal price.

FIGURE 19: Annual marginal price-setting technology



Supply adequacy

Supply adequacy expresses the ability of the system to serve load. 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.*[9]

Supply cushion increased 17 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. In 2020, the average supply cushion increased 17 per cent (286 MW) to 1,929 MW from its 2019 value. From January to March, the supply cushion was very similar to 2019. Lower demand from April through September, brought on by COVID-19 restrictions and low oil prices, caused the supply cushion to increase relative to 2019. From October to the end of the 2020, while load returned to 2019 levels, the supply cushion was 288 MW higher than 2019. The retirement of the two coal units did not impact the supply cushion during 2020, as they were not in the merit order at all during the year. Sundance 3 was

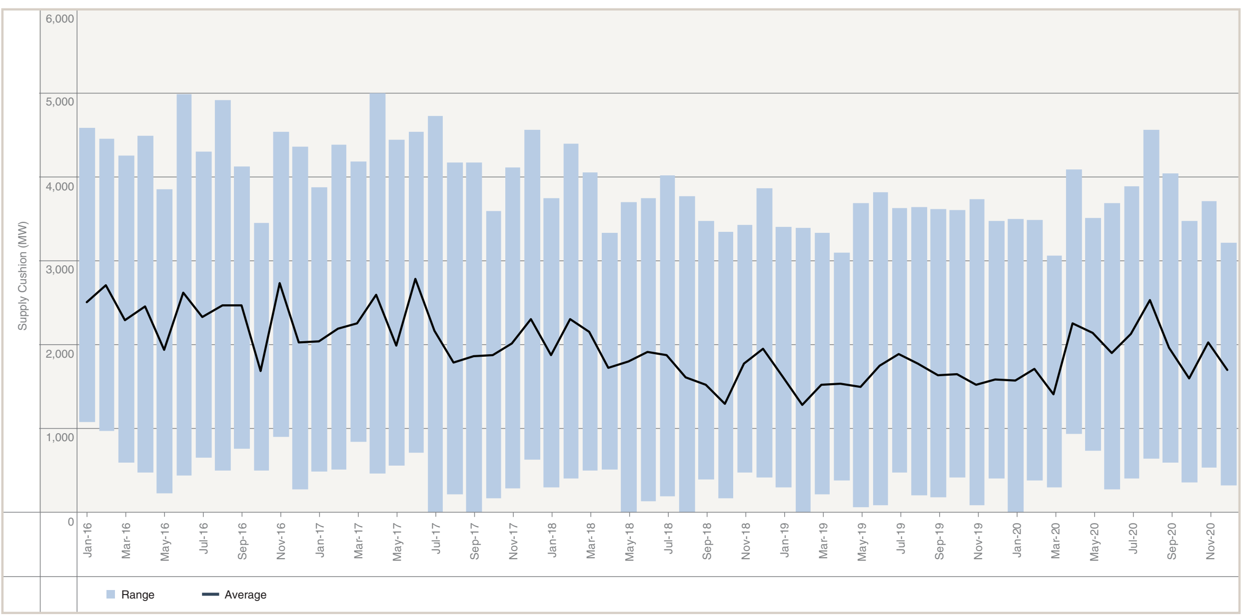
[9] https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

in mothball state and Battle River 3 retired on January 1, 2020. However, the retirement of Battle River 3 lowered the supply cushion by 149 MW when compared to 2019. This loss was offset by the addition of new supply brought online throughout the year.

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 Energy Emergency Alert Level 1 (EEA1)[10] 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. EEA2 must be declared when operating reserves are committed to maintain the supply-demand balance ensuring that regulating reserve margin is maintained. EEA3 must be declared if the AESO foresees or has implemented curtailment of firm load. In 2020, supply shortfall conditions occurred twice. The first event was a 250-minute event that occurred on January 14, in which both EEA1 and EEA2 were declared. The second was a 181-minute event on January 16, in which only EEA1 was declared. In each case, extreme cold weather and the loss of some generation led to the supply shortfall.

Figure 20 shows the monthly average of the supply cushion over the last five years. It also has the range of the supply cushion throughout each month.

FIGURE 20: Monthly supply cushion



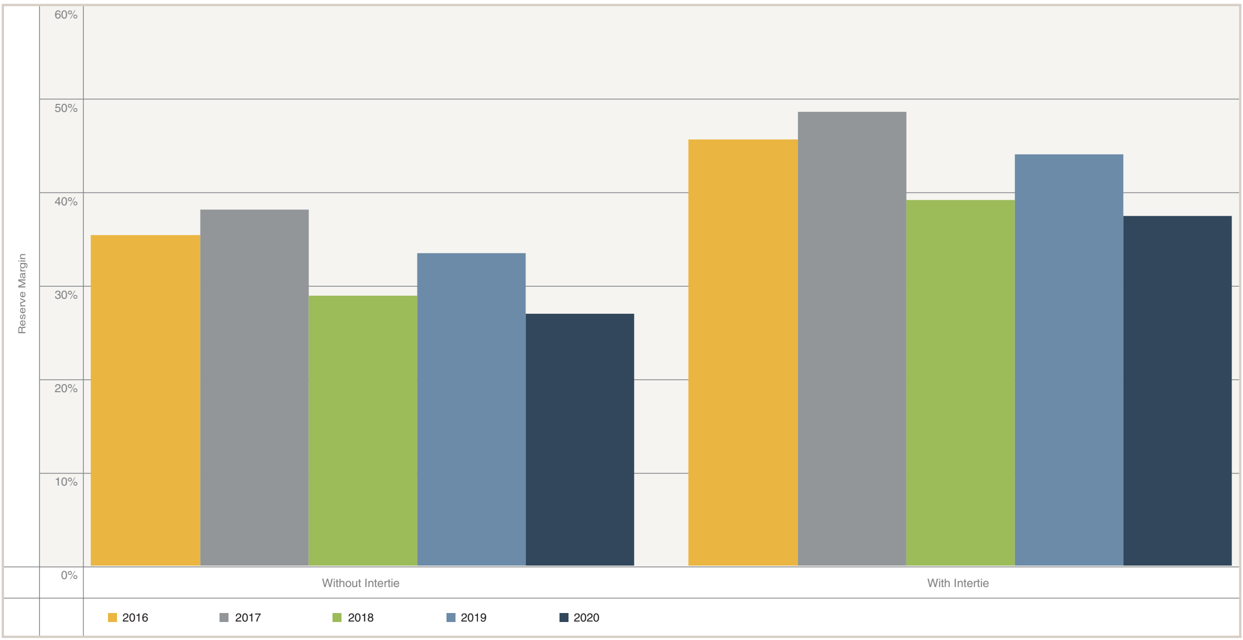
Reserve margin decreased nine per cent

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 and solar generation, which may be unavailable, and reduces hydro generation to reflect seasonal variability. Generation capability reflects the commissioning dates of new generation.

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

Figure 21 shows the annual reserve margin over the past five years. The decrease in the reserve margin from 2019 to 2020 is due to the retirement of just over 500 MW of coal units, in addition to a higher peak load in 2020.

FIGURE 21: Annual reserve margin



Wind generation

Wind generation served 7 per cent of Alberta internal load

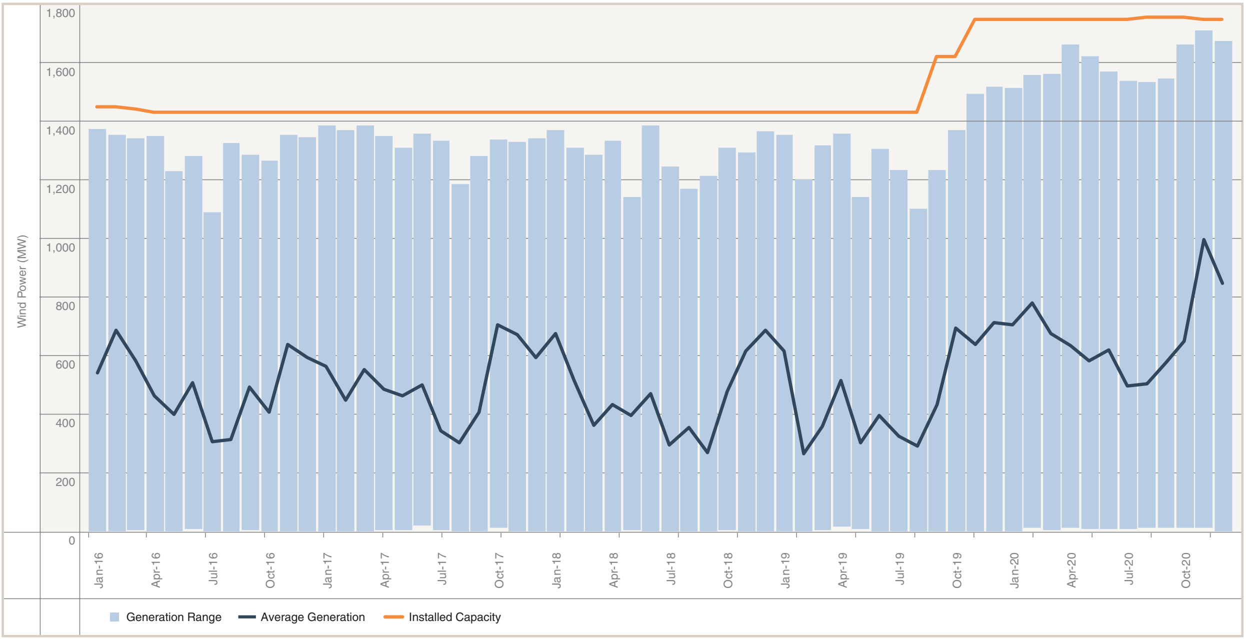
Table 4 summarizes the annual statistics for wind generation. No new wind facilities were installed in 2020, so the installed capacity at the end of the year remained at 1,781 MW. This represented 11 per cent of the total installed generation capacity in Alberta. Wind generation produced seven per cent of total AIL in 2020. Wind generation was stronger in 2020, as the technology's capacity factor increased from 30 per cent in 2019 to 39 per cent in 2020. This is the highest in the last five years. This increase was primarily due to better wind conditions, especially in November and December. More efficient wind turbines that have come on recently also helped increase the capacity factor.

TABLE 4: Annual wind generation statistics

Year	2016	2017	2018	2019	2020
Installed wind capacity at year end (MW)	1,445	1,445	1,445	1,781	**1,781**
Total wind generation (GWh)	4,405	4,486	4,104	4,116	**6,079**
Wind generation as a percentage of total AIL	6%	5%	5%	5%	**7%**
Average hourly capacity factor	35%	35%	32%	30%	**39%**
Maximum hourly capacity factor	93%	96%	96%	94%	**96%**
Wind capacity factor during annual peak AIL	15%	6%	9%	0%	**8%**

Figure 22 shows the installed wind generation capacity and range of hourly wind generation over each month. The monthly average of wind generation usually exhibits a seasonal pattern, generally peaking in winter and falling in summer. The maximum of hourly wind generation exhibits a weaker seasonal pattern. Strong winds may occur in any month, though they occur more frequently in winter. However, when the weather gets extremely cold, wind tends to be very weak, leading to low capacity factors during the annual peaks. From October 2020 to the end of 2020, wind generation in Alberta was the highest on record.

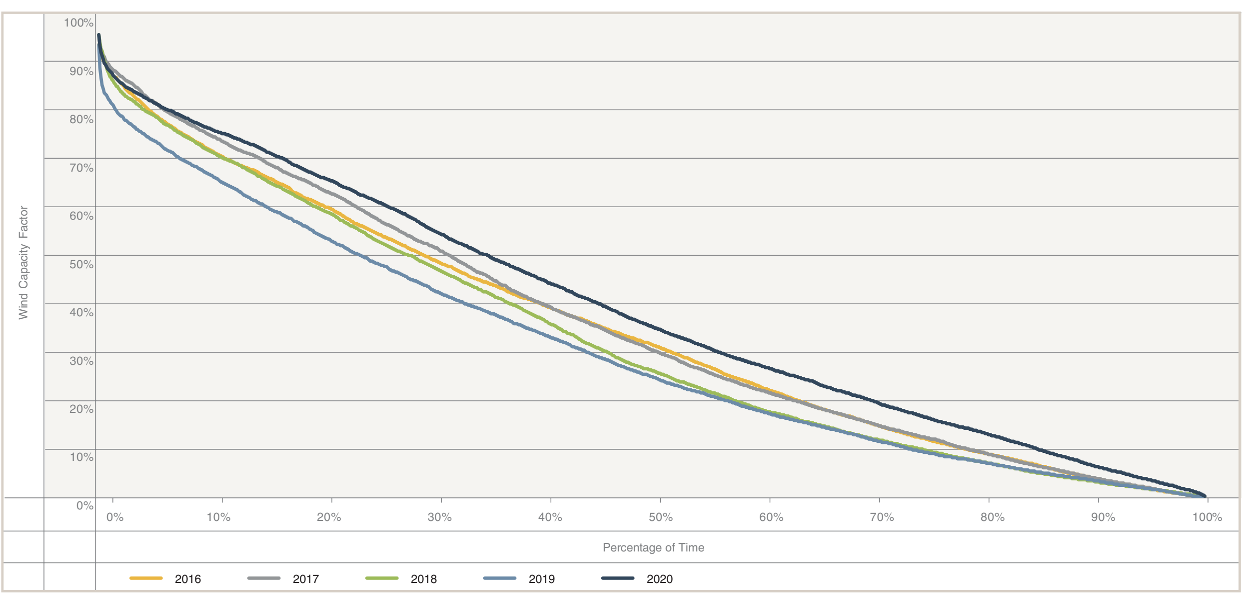
FIGURE 22: Monthly wind capacity and generation



Wind capacity factor increased

Figure 23 illustrates annual duration curves for the hourly capacity factor for Alberta wind generation. Capacity factor represents the percentage of installed capacity used to generate electricity that was delivered to the grid. The duration curve represents the percentage of time that capacity factor of wind generation equals or exceeds a specific value.

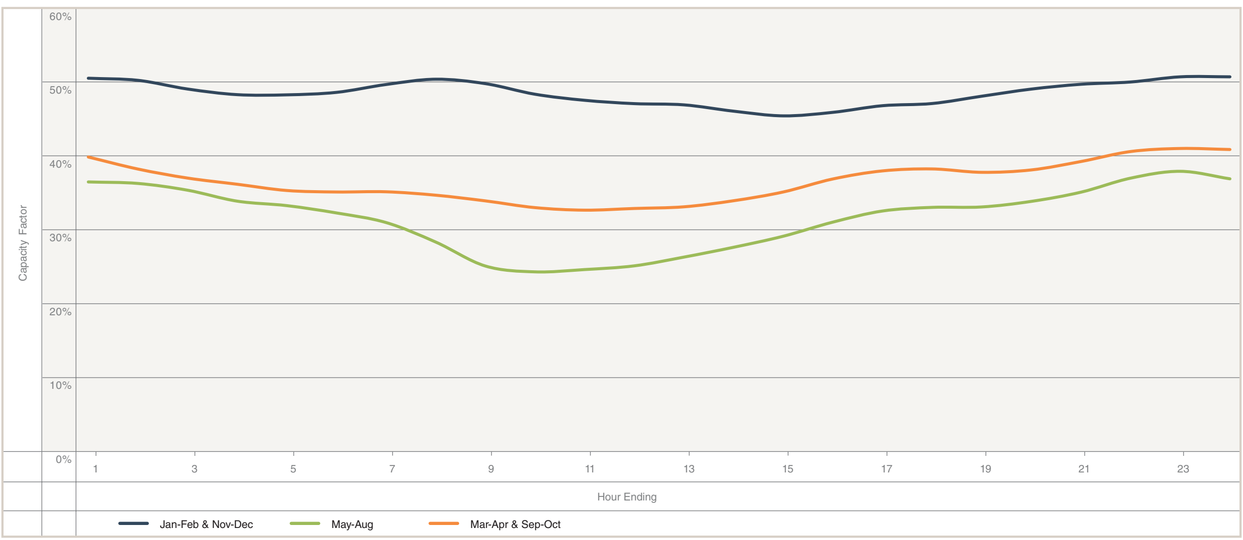
FIGURE 23: Annual wind capacity factor duration curves



The duration curve for the capacity factor of wind generation increased in 2020 and was the highest in the past five years. The capacity factor of wind generation averaged 39 per cent over 2020, which is a nine per cent increase from 2019. For every 100 MW of installed wind capacity, wind power generated an average of 39 MW of energy each hour in 2020. The capacity factor—the ratio of net-to-grid generation to installed capacity—for wind generation is comparable to that of simple-cycle gas generation; however, unlike gas generation, wind generation depends on environmental factors and cannot be dispatched to run when wind is unavailable.

Figure 24 shows average hourly capacity factor of wind generation for different seasons of the year during 2020. It shows that wind generation is typically highest in the overnight hours and lowest during the day, with this phenomenon more pronounced in the summer than the winter. The capacity factor of wind is 15-20 per cent higher in the winter than the summer. Not shown in this chart is the tendency of wind generation to be at its lowest during extreme weather events, such as a polar vortex in the winter or a heat wave in the summer. This is due to the presence of strong high-pressure weather systems in the wind generation regions of the province, which produce low wind conditions.

FIGURE 24: 2020 Wind generation seasonal average hourly output



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 outside of southern Alberta. At the end of 2020, wind generation capacity totaled 1,432 MW in southern Alberta, and 349 MW in central Alberta.

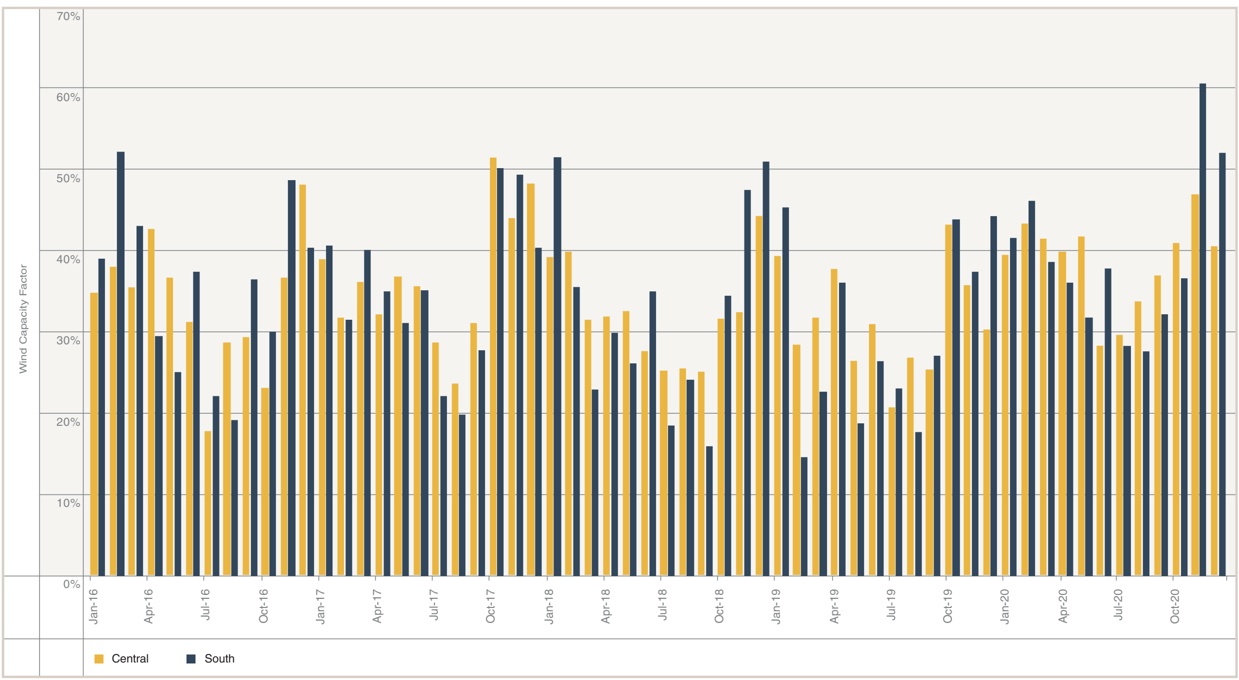
Table 5 shows regional wind generation statistics over 2020. The average capacity factor was the same for both regions, but the achieved price for Central wind exceeded those facilities in the South region. For each megawatt of installed capacity, a wind farm in central Alberta generated the same energy as a wind farm in southern Alberta, and for each unit of energy generated, Central wind generation earned more revenue than South wind generation.

TABLE 5: 2020 regional wind statistics

Region	Central	South	Total
Installed wind capacity at year end (MW)	349	1432	**1781**
Total wind generation (GWh)	1183	4896	**6079**
Average wind capacity factor	39%	39%	**39%**
Achieved price ($/MWh)	$35.55	$33.14	**$33.61**

Figure 25 shows the monthly average capacity factor by region in the past five years. In November, the South region had an average capacity factor nearing 60 per cent and was the highest average capacity factor over the last five years. As can be seen in the monthly profiles, wind tends to be most productive from October through April and the least productive in the summer months.

FIGURE 25: Monthly wind capacity factor by region



Solar generation

Throughout 2020, four new solar farms joined the Brooks Solar Project in the generation fleet, adding 92 MW of new capacity. Vauxhall (22 MW) started production in April; Hull (25 MW) and Innisfail (22 MW) came online during June; and Suffield (23 MW) started in September. Figure 26 illustrates the monthly total generation of the solar fleet for 2020 and 2019. Typically, May through July are the months with the highest output. However, in 2020, the addition of the new units has distorted the typical profile.

FIGURE 26: Solar generation total monthly output

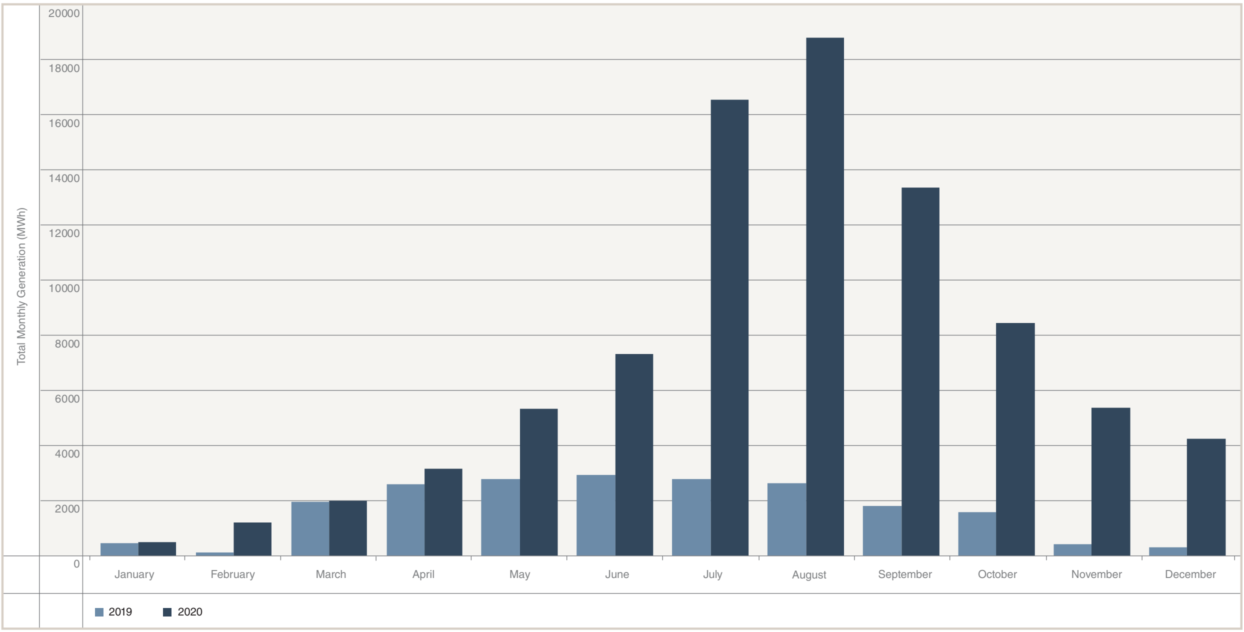
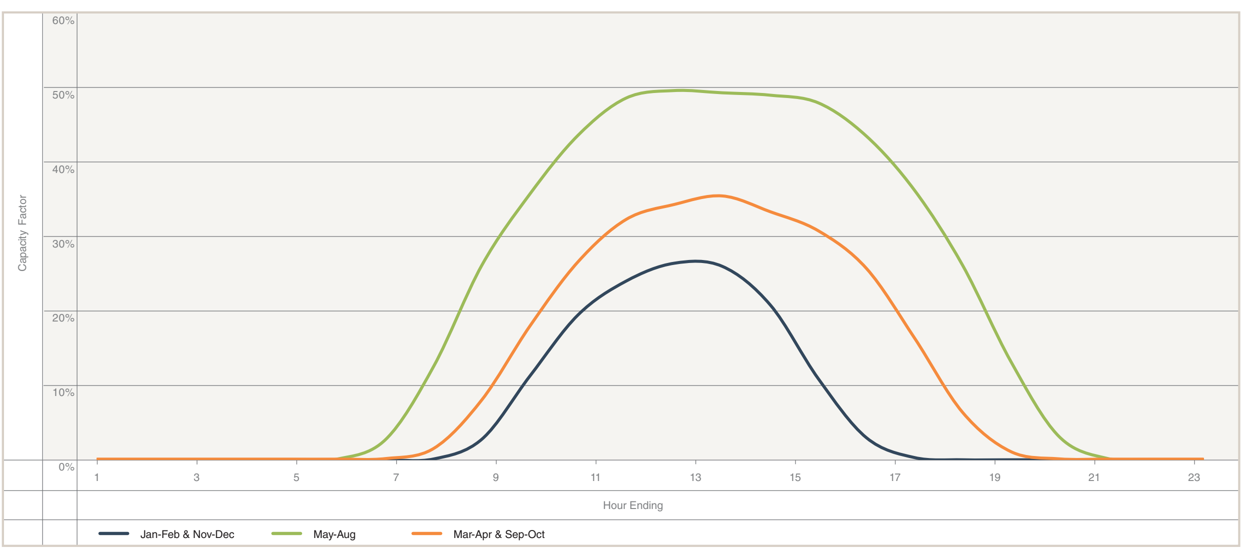


Figure 27 shows average hourly capacity factor of solar generation for different seasons of the year during 2020. Throughout the year, solar generation peaks in the early afternoon, around hour-ending 14. However, output in the summer months peaks at about twice that seen in the winter. In addition, the number of hours near the peak output is roughly double in the summer as in the winter. The profile of solar generation is a good complement to that of wind generation, which tends to have its highest generation in the overnight hours and lowest during the day.

FIGURE 27: 2020 Solar generation seasonal average hourly output



Imports and exports

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

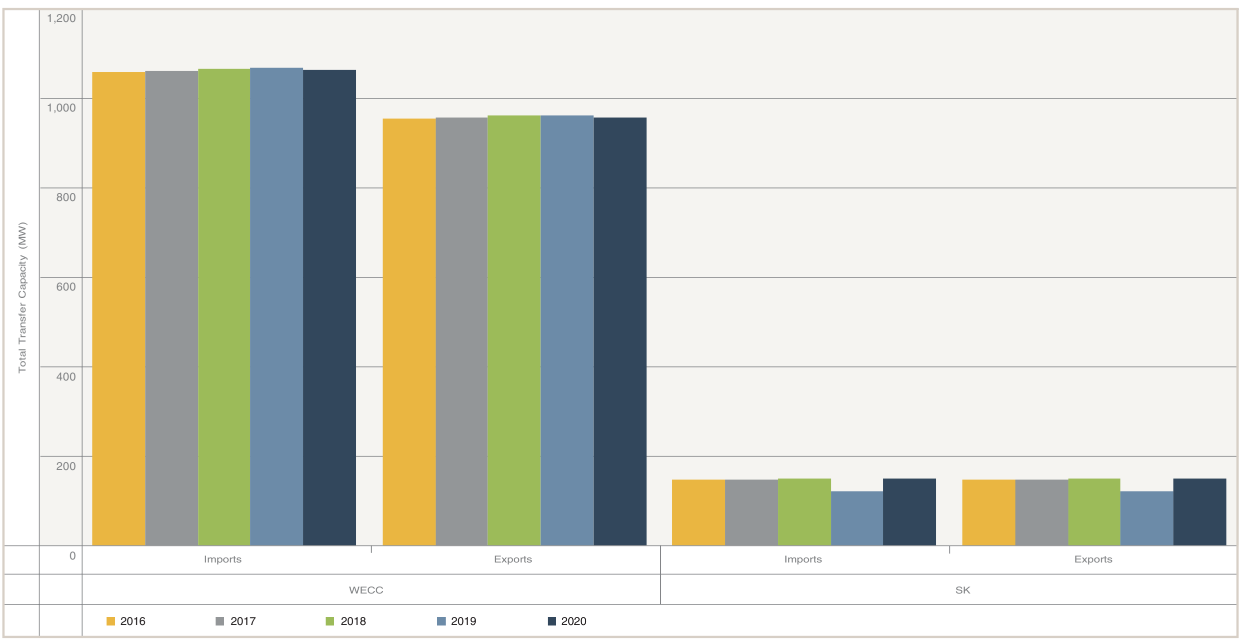
Total transfer capability rating remained stable

The total transfer capability (TTC) rating is the amount of physical power that can reliably flow across defined paths under specified system conditions. It is estimated based on the physical properties of the interties at the time power is to be flowed. Generally, the TTC is stable over time. However, yearly averages can vary slightly due to the amount of outages that occur.

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 TTC, calculated as the sum of the TTC of the two individual interties which connect Alberta to B.C. and Montana.

Figure 28 shows the average TTC in each year between Alberta and other WECC members, and between Alberta and Saskatchewan. The lower TTC in both directions to Saskatchewan in 2019 was due to planned maintenance that occurred in June and July of that year.

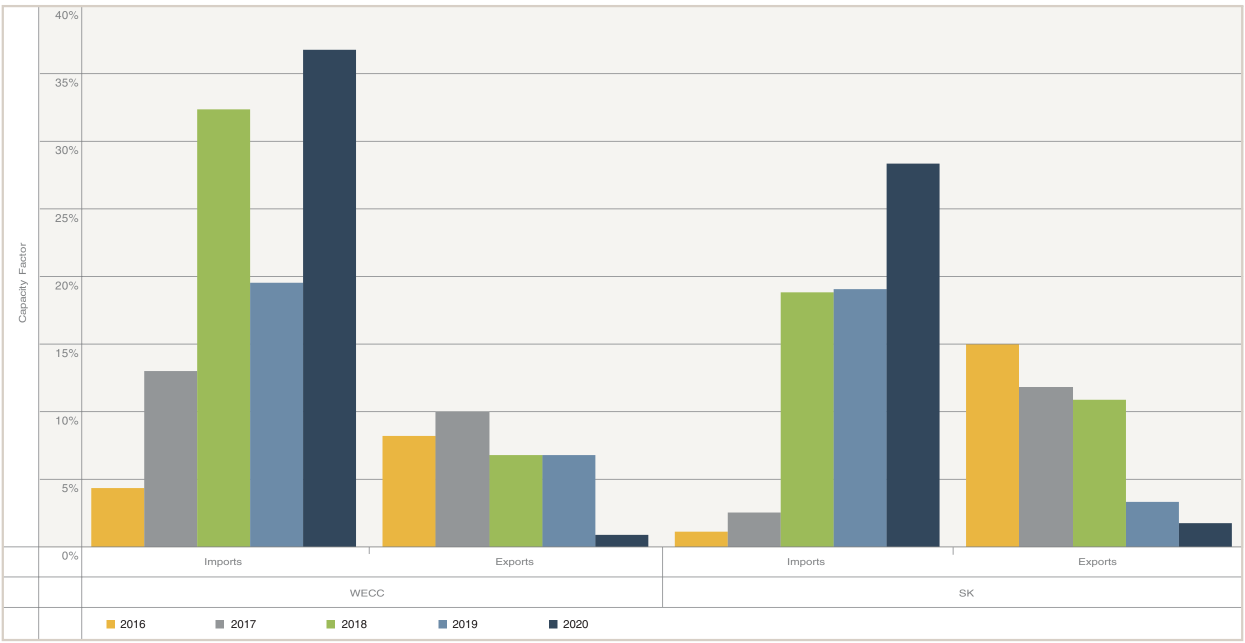
FIGURE 28: Annual total transfer capacity by transfer path



Capacity factor reflects increase in imports

Capacity factor represents the percentage of the TTC that was used to transfer energy between jurisdictions. The capacity factor is calculated as the ratio of total scheduled energy to the TTC. In 2020, imports from both WECC and Saskatchewan increased relative to 2019, resulting in a higher capacity factor. On the other hand, exports to the WECC region fell significantly in 2020 in comparison to the previous four years. It is thought that lower demand in surrounding jurisdictions, due to the impact of the COVID-19 pandemic, led them to increase imports into Alberta and decrease exports. Figure 29 illustrates the annual capacity factor for transfers between Alberta and other WECC members and between Alberta and Saskatchewan.

FIGURE 29: Annual capacity factor by transfer path

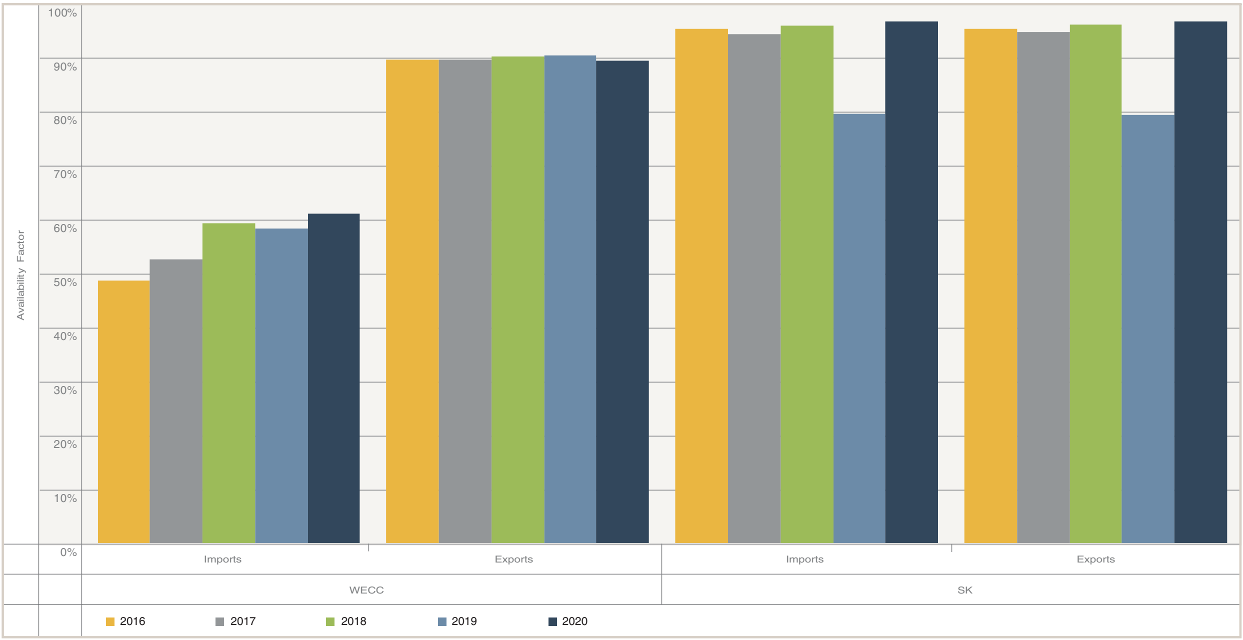


Intertie availability factor

Alberta reliability standards define the criteria that determine the energy that can be transferred between Alberta and other 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 TTC. Figure 30 illustrates the annual availability factor for transfers between Alberta and other regions. In 2020, the availability of the Saskatchewan intertie increased to normal levels for both imports and exports, after planned maintenance occurred in summer of 2019.

FIGURE 30: 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 annual average of the hourly ratio of transferred energy to the ATC of the transfer path. Figure 31 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. In 2020, import utilization increased 28 per cent from 2019 levels between Alberta and WECC, and increased nine per cent on the Saskatchewan transfer path. The export utilization decreased along both the Saskatchewan and WECC transfer paths.

FIGURE 31: Annual availability utilization by transfer path

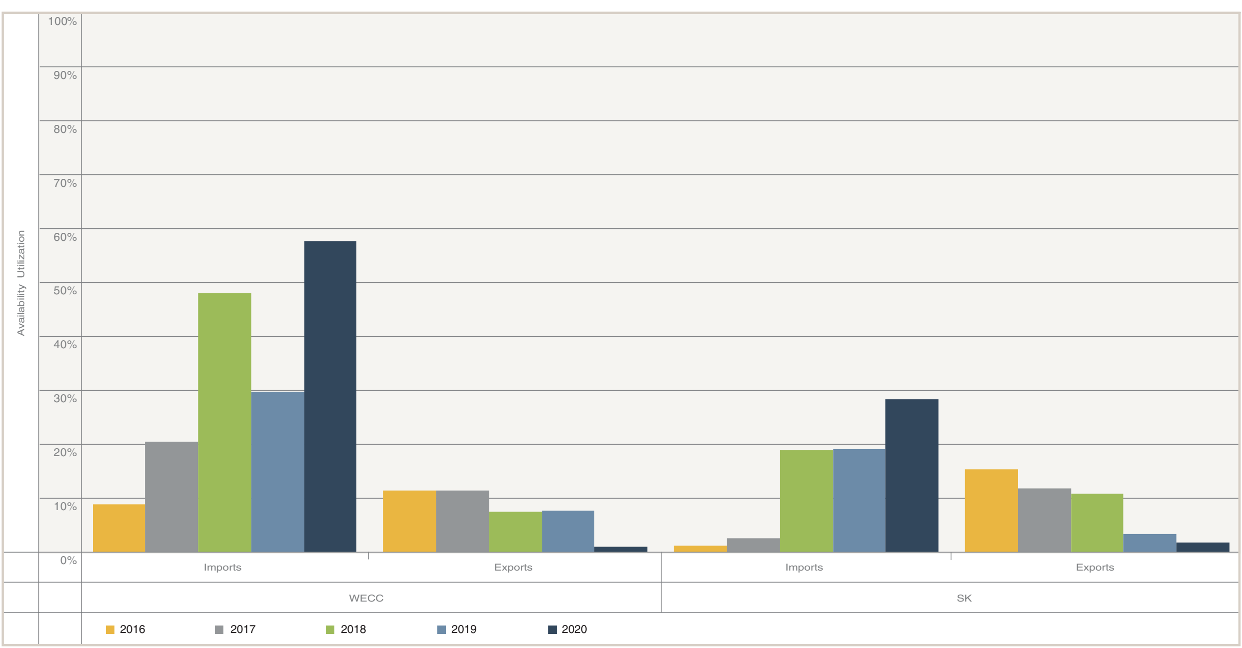


Figure 32 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. In this chart, the interchange utilization represents the ratio of net imports or exports across the intertie to its ATC. Imports include the volume of operating reserve procured on the intertie. 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 2020, Alberta had net imports from the WECC region in 93 per cent of hours and was a net exporter in just one per cent of the hours.

FIGURE 32: Annual interchange utilization with WECC region

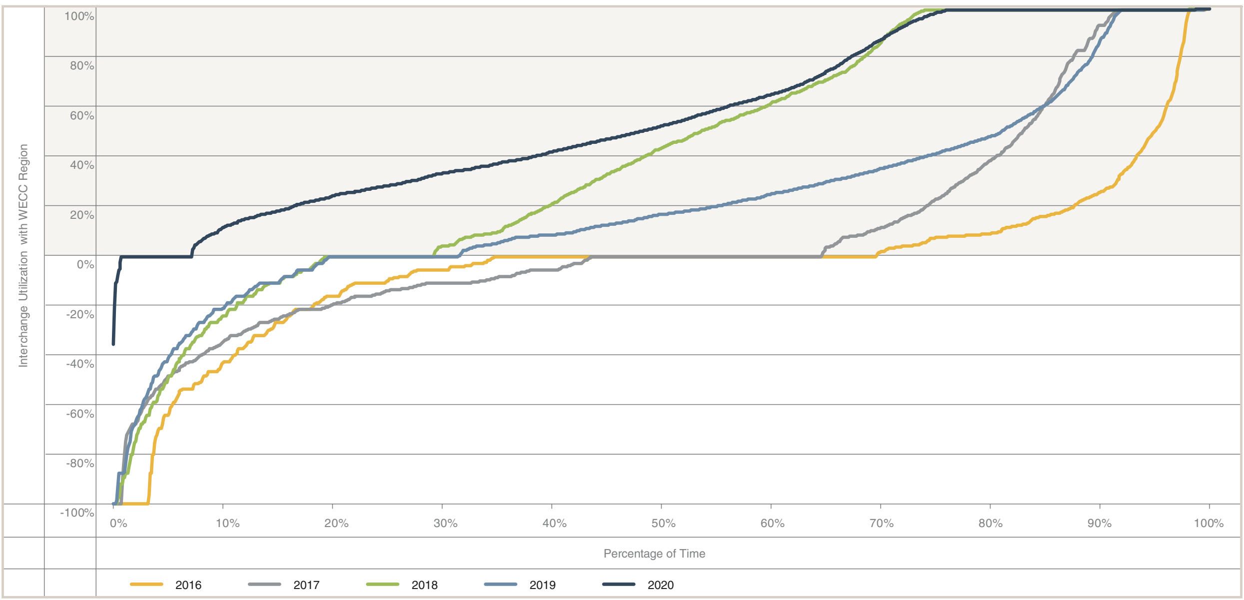
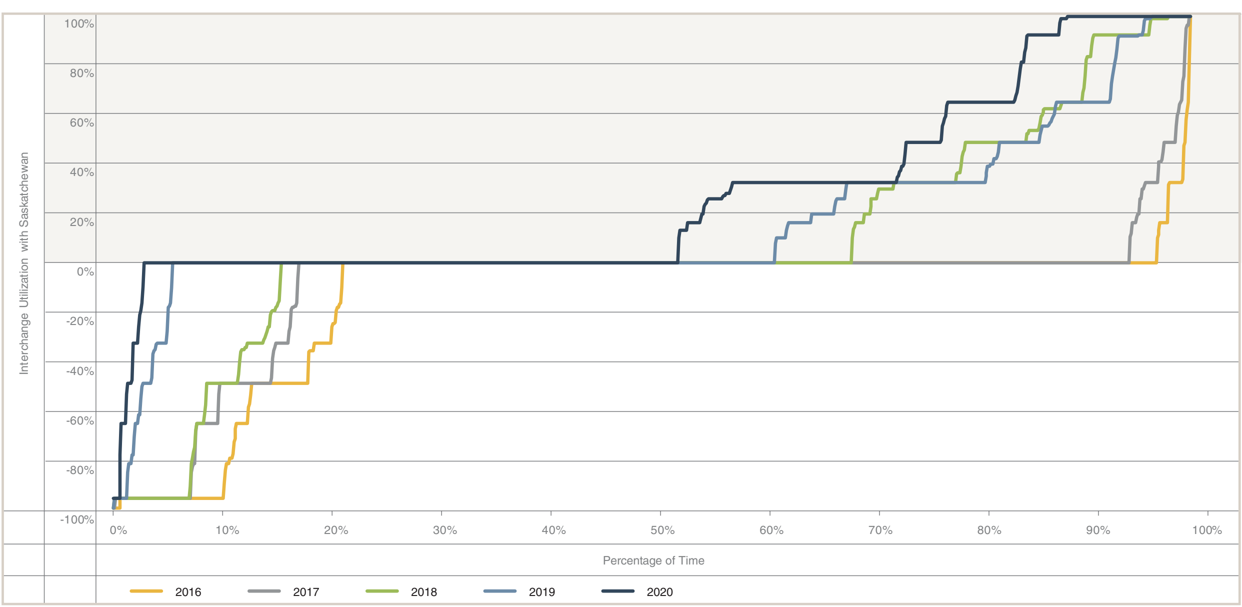


Figure 33 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2020, Alberta had net imports from Saskatchewan in 48 per cent of hours and was a net exporter in three per cent of hours.

FIGURE 33: Annual interchange utilization with Saskatchewan



Imports into Alberta increased in 2020

Figure 34 illustrates the annual average energy transferred from each province or state. Alberta has been a net importer since 2017, with 2020 having the highest amount of net imports since then. In 2020, relatively higher electricity prices in Alberta plus lower demand in both B.C. and Montana, due to the impact of COVID-19, encouraged more imports into Alberta when compared with 2019.

FIGURE 34: Annual intertie transfers by province or state

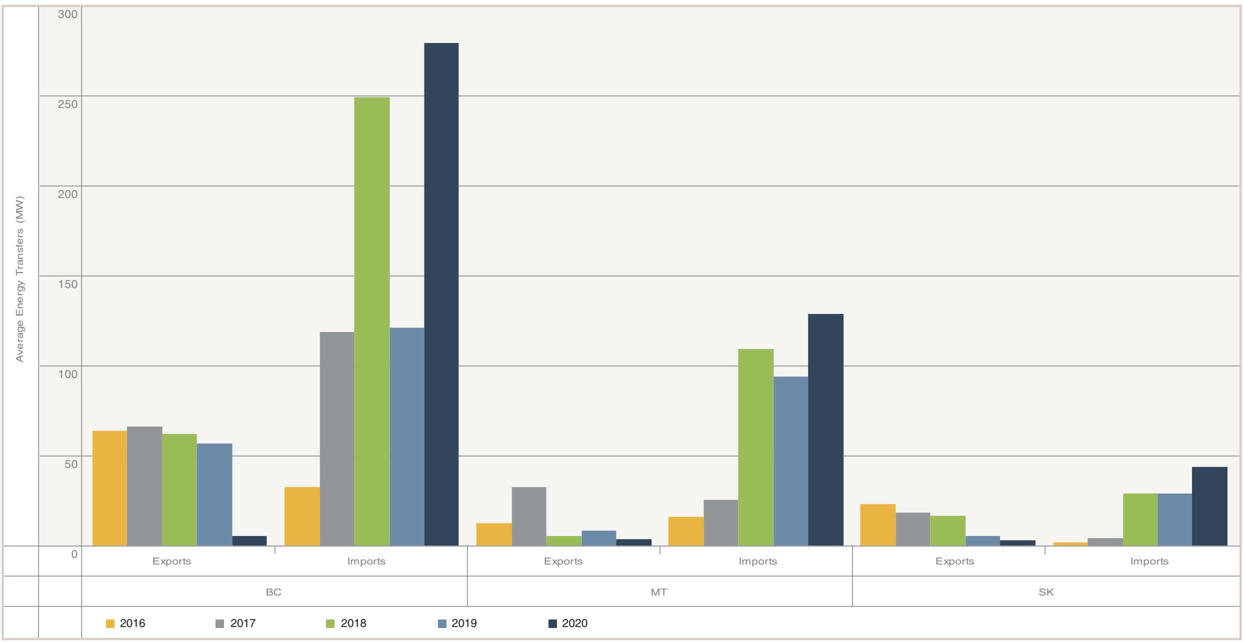
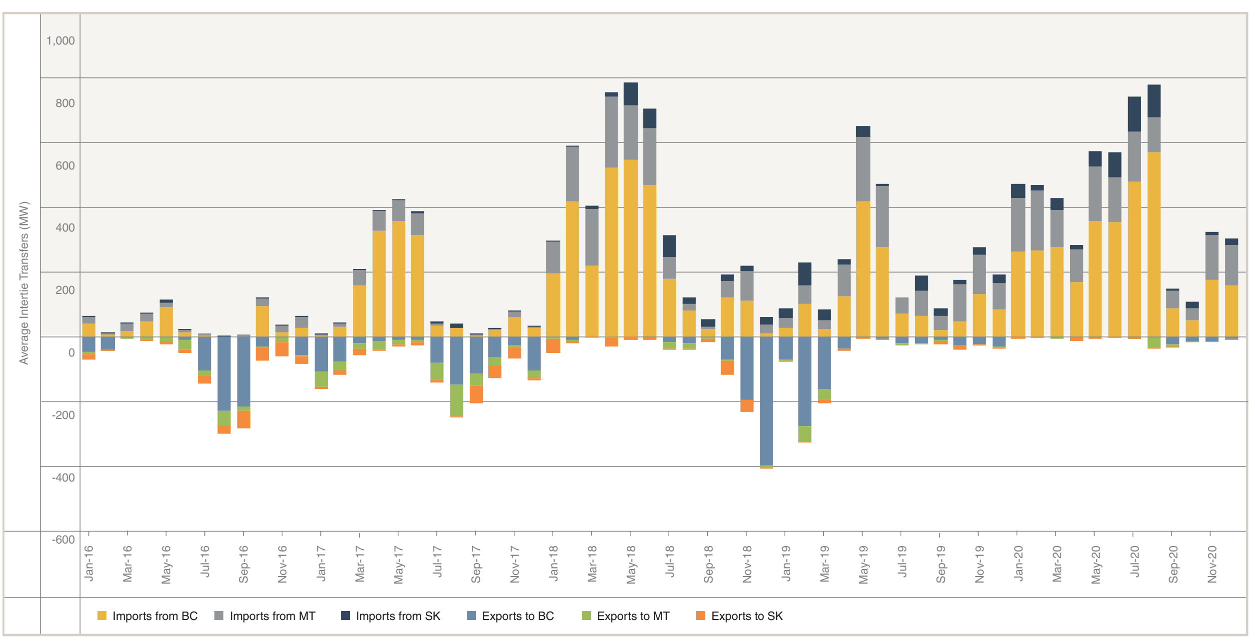


Figure 35 illustrates the monthly average energy transferred from each province or state. Positive values represent imports to the province and negative values represent exports to other jurisdictions. Typically, May and June see the highest amount of imports into Alberta, usually due to high hydro flows in both B.C. and the Pacific Northwest. In 2020, the winter months also saw a large volume of imports when compared to previous years.

FIGURE 35: Monthly average intertie transfers

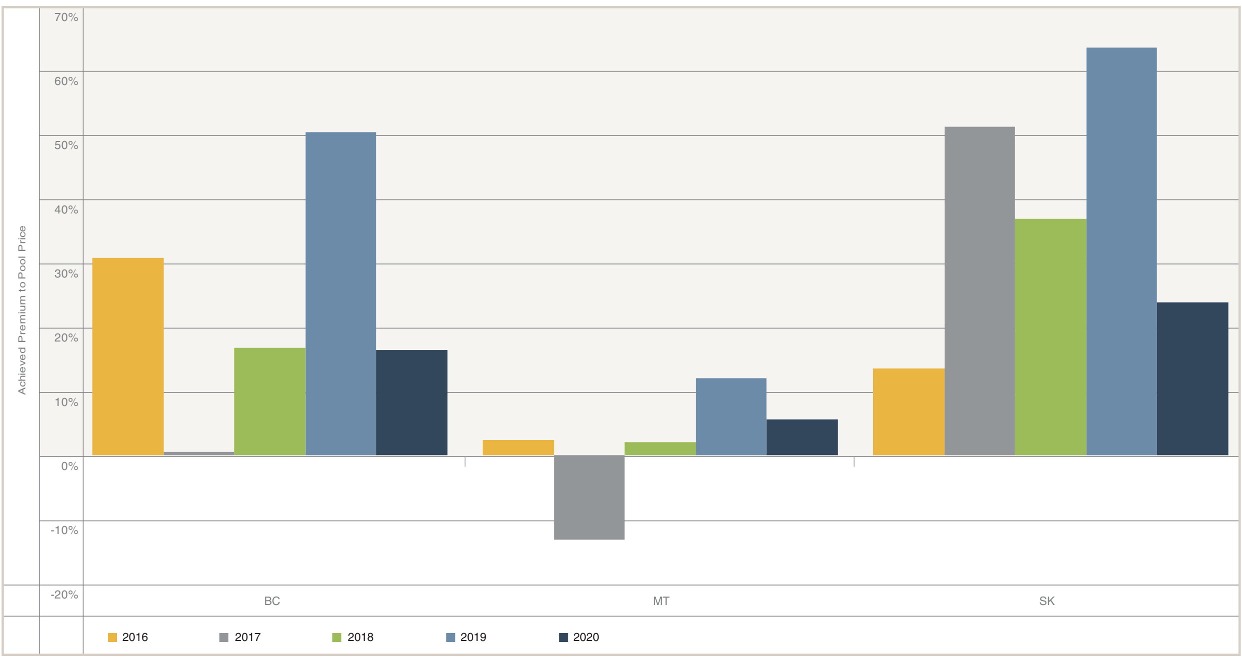


Achieved premium-to-pool price decreased in 2020

Figure 36 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.

An increased amount of imports led to a lower premium-to-pool price in 2020. For B.C. and Montana, the price premium was similar to that seen in 2018, another high import year. A surplus of energy in those two jurisdictions led them to increase the size of their imports and the amount of hours in which they imported. This, in turn, lowered their price premium. The same is true of Saskatchewan but on a smaller scale.

FIGURE 36: Annual achieved premium-to-pool price on imported energy



Ancillary services

Cost of operating reserves decreased

Operating reserves are used to manage real-time 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 while supplemental reserve does not. 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 procures 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 (or zero, as there are no negative clearing prices).

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.

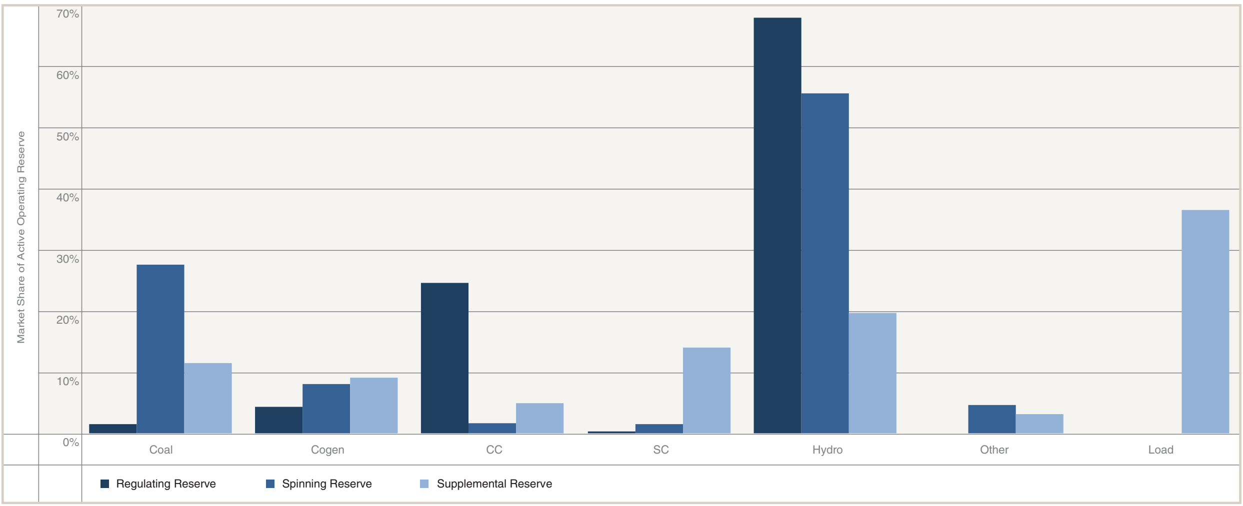
Table 6 summarizes the total cost of operating reserve over the past five years. The total cost of operating reserve in 2020 decreased 23 per cent from 2019 to $148 million. Lower operating reserve costs were primarily a result of lower active and standby procurement prices, which offset an increase in the volume and prices of standby activations.

TABLE 6: Annual operating reserve statistics

Year	2016	2017	2018	2019	2020
Volume (GWh)					
Active procured	5,262	5,449	5,802	5,640	**5,561**
Standby procured	2,049	2,058	1,971	2,124	**1,940**
Standby activated	85	236	343	180	**348**
Cost ($-millions)					
Active procured	$53	$67	$195	$172	**$122**
Standby procured	$12	$8	$8	$6	**$3**
Standby activated	$2	$6	$36	$14	**$23**
Total	$67	$81	$240	$193	**$148**

Market share represents the percentage of total procured capacity that is provided as operating reserve by each generation technology. Figure 37 illustrates the annual market share of active operating reserve. In 2020, hydroelectric generation continued to have the largest market share in active regulating and spinning reserves. Load has the highest share of procured active supplemental reserves.

FIGURE 37: 2020 market share of active operating reserve



Transmission must-run, transmission constraint rebalancing, and dispatch down service

The system controller issues transmission-must-run (TMR) dispatches in parts of the province's electricity system when regional transmission capacity is insufficient to provide enough imports to support local demand. A TMR dispatch directs a generator, in or near the affected area, to operate out of merit at a specified generation level 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 2020, dispatched TMR energy was 43 GW greater and costs were $666,173. This was higher than 2019 due to changed generation patterns and increased constraints in the transmission system.

When the AESO dispatches the energy market merit order, replacing in-merit generation that has been curtailed due to a constraint, dispatched generators with offers higher than 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 2020, constraints on the transmission system required system controllers to curtail 72 GWh of in-merit energy, and the TCR payments to market participants totaled approximately $520,000.

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 2020, DDS offset 14 per cent of dispatched TMR volume. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. While both dispatched TMR and DDS volumes were higher when compared to 2019, they are still significantly lower when compared to pre-2018 values. This is partly due to changed generation dispatch patterns, with natural gas units being dispatched in merit more frequently.

Table 7 summarizes the annual TMR, TCR and DDS statistics over the past five years. The total annual cost of Transmission Constraint Management (TCM), is the sum of the TMR and TCR costs.[11]

TABLE 7: Annual TMR and DDS statistics

Year	2016	2017	2018	2019	2020[12]
Transmission must-run					
Dispatched energy (GWh)	71	35	7	5	**48**
Contracted TMR costs ($ millions)	$0.30	$0.36	$0.01	$0.04	**$0.67**
Conscripted TMR costs ($ millions)	$1.21	$0.50	$0.43	$0.26[13]	**$0.73**
Transmission constraint rebalancing					
Constrained-down generation (GWh)	2.4	1.4	3.0	3.8	**72.0**
Number of days with TCR payment	5	10	7	14	**67**
Total TCR payments ($-millions)	0.01	0.02	0.04	0.27	**0.52**
Total annual TCM costs					
Annual TCM cost ($ millions)	$1.52	$0.88	$0.47	$0.56	**$1.92**
Dispatch down service					
Total payments ($-millions)	$0.51	0.11	0.00	0.01	**0.16**
Dispatched energy (GWh)	39,489	23,875	107	256	**6,919**
Average charge ($/MWh)	$13.04	$4.62	$13.10	$25.41	**$23.12**

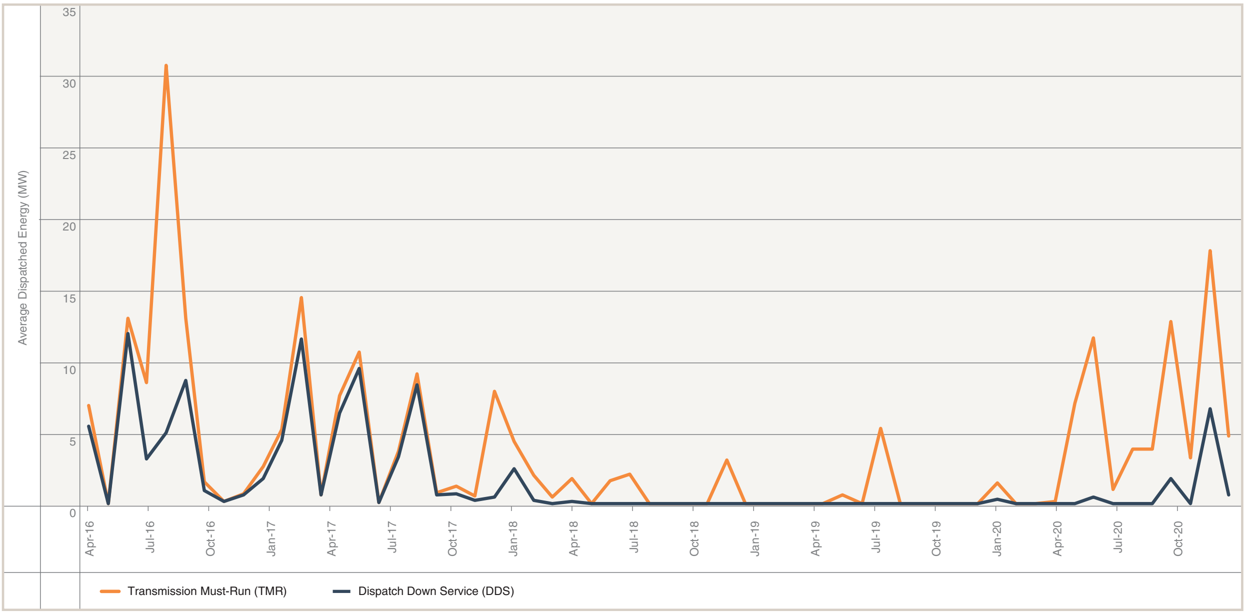
[11] The TCM data has been prepared pursuant to subsection 4(2) of Section 302.1 of the ISO rules, Real Time Transmission Constraint Management (Section 302.1), which requires the Alberta Electric System Operator (AESO) to: “monitor and publicly report on the costs incurred as a result of mitigating transmission constraints on an annual basis.”

[12] 2020 data is preliminary.

[13] The cost of conscripted TMR for 2019 has been adjusted since the June 2020 TCM report from $362,984 to $256,663.

Figure 38 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 38: 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	2016	2017	2018	2019	2020
Payments to suppliers on the margin					
Average range ($/MWh)	1.08	2.35	8.15	12.01	**5.21**
Total payments ($-millions)	0.15	0.21	1.32	1.58	**0.75**

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 decreased to $0.75 million in 2020 from $1.58 million in 2019. 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 57 per cent to $5.21/MWh in 2020.

System flexibility

In the AESO's *Dispatchable Renewables and Energy Storage Report*[14], the AESO assessed the ability of the electric system to adapt to dynamic and changing conditions, including continuously balancing supply and demand under different scenarios. As more variable generation is integrated into the electric system, additional balancing capability may be required to respond to the combined variability of demand and variable generation, which is referred to as net demand variability. Although the flexibility assessment did not identify any emerging needs for immediate system flexibility enhancements, the results support continued monitoring and periodic assessments of system flexibility to proactively identify when system flexibility may need to be enhanced.

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 reported for the past year.

Net demand variability

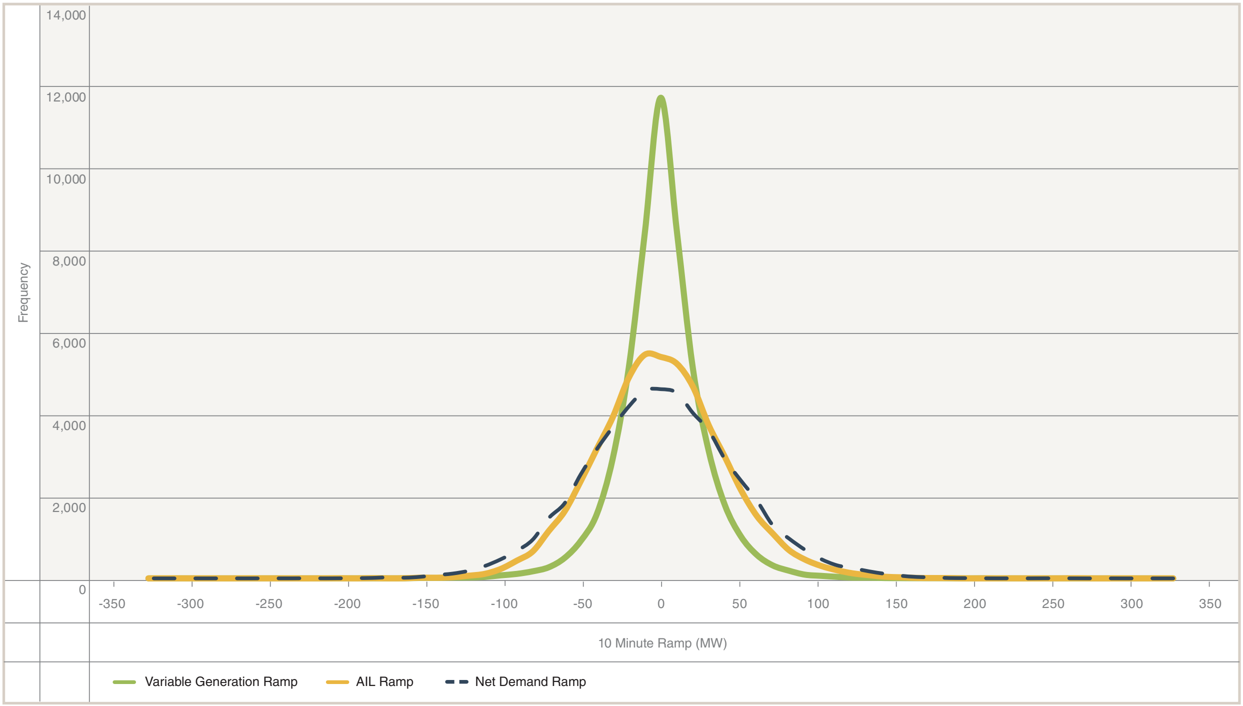
The size and frequency of net-demand ramps on the grid are one of the common challenges experienced with higher variable renewable generation. Dispatchable resources need to be able to match the size, speed, and frequency of the net-demand ramps to reliably supply customers as additional variable renewable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

Figure 39 provides the frequency and size of 10-minute ramps of variable generation, AIL, and net demand in 2020. 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 2020. Variable generation includes all five MW or larger wind and solar assets in Alberta. Small-scale wind and solar generators (i.e. less than five MW) within the province are generally connected to the distribution system and their variability is captured in AIL.

In 2020, 10-minute net-demand ramp sizes were mostly in the plus/minus 150 MW range, like that in 2019. 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. The chart below excludes a significant outlier in net demand variability. On June 7, 2020, a lightning strike on the B.C.–Alberta intertie resulted in the loss of close to 900 MW of imports. That led to load being shed to compensate, resulting in a 10-minute net-demand loss of just over 800 MW.

[14] https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf

FIGURE 39: Distribution of 10-minute ramps for variable generation, load and net demand in 2020



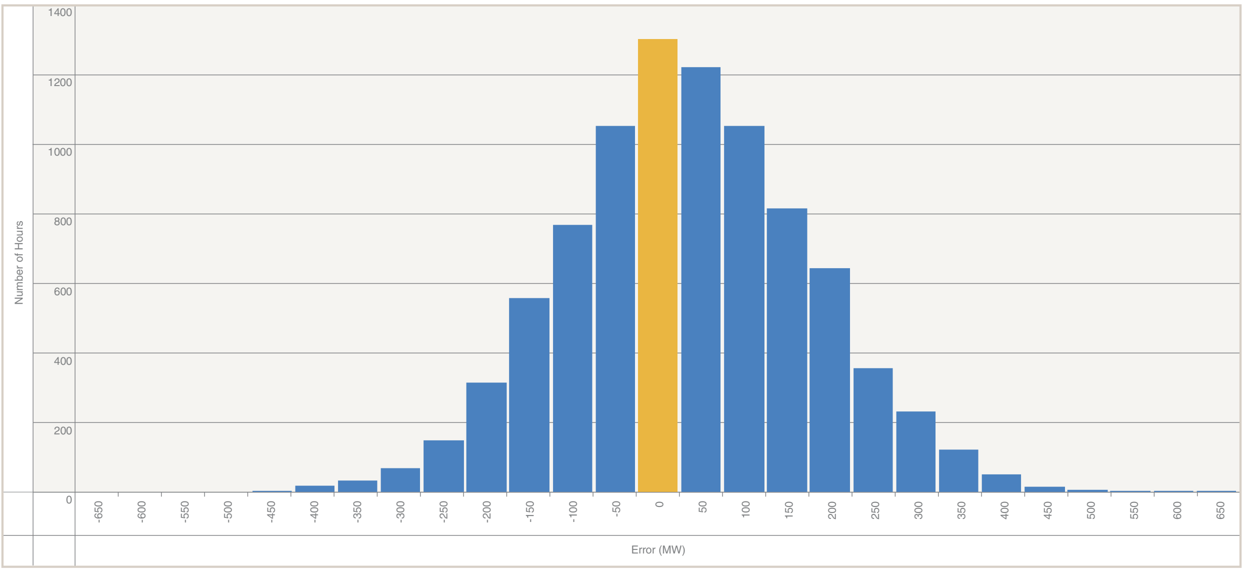
Forecast uncertainty

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 best information possible to manage the variability of net demand. This includes the accuracy of short-term load forecasts, as well as variable generation forecasts.

Short-term load forecast uncertainty

Figure 40 illustrates the distribution of the day-ahead load forecast error for all hours in 2020. 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 2020, the forecast error was in the plus/minus 275 MW range 95 per cent of the time, equivalent to plus/minus 2.9 per cent of average 2020 AIL. This was similar to 2019's error range.

FIGURE 40: Distribution of day-ahead load forecast error in 2020



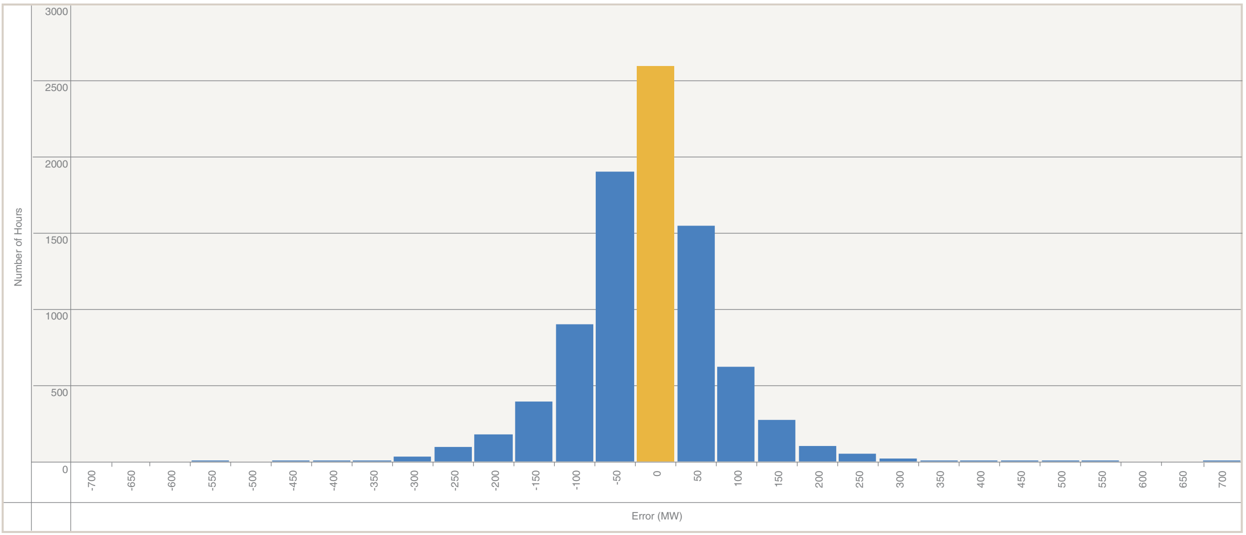
Wind and solar power forecast uncertainty

The AESO's wind and solar power forecast uses near real-time meteorological data to indicate the amount of wind and solar power available to the Alberta grid on a seven-day-ahead (long-term) and a 12-hour-ahead (short-term) basis.[15] The long-term forecast is updated every six hours and the short-term forecast is updated every 10 minutes. For the purposes of this report, the error of the short-term forecast is used to measure the uncertainty of the wind forecast because AESO system operators require accurate short-term wind power forecasts to manage net demand variability.

For a given hour, the forecast error is calculated as the hour-ahead forecasted volume minus the actual wind and solar generation. Figure 41 shows the distribution of the calculated errors of the combined wind and solar forecasts for 2020. The distribution is skewed to the left which indicates wind was under-forecast more than it was over-forecast. Overall, the average forecast error improved by 14 per cent, decreasing to 64 MW from 74 MW in 2019.

[15] https://www.aeso.ca/grid/forecasting/wind-and-solar-power-forecasting/

FIGURE 41: Distribution of hour-ahead wind forecast error in 2020



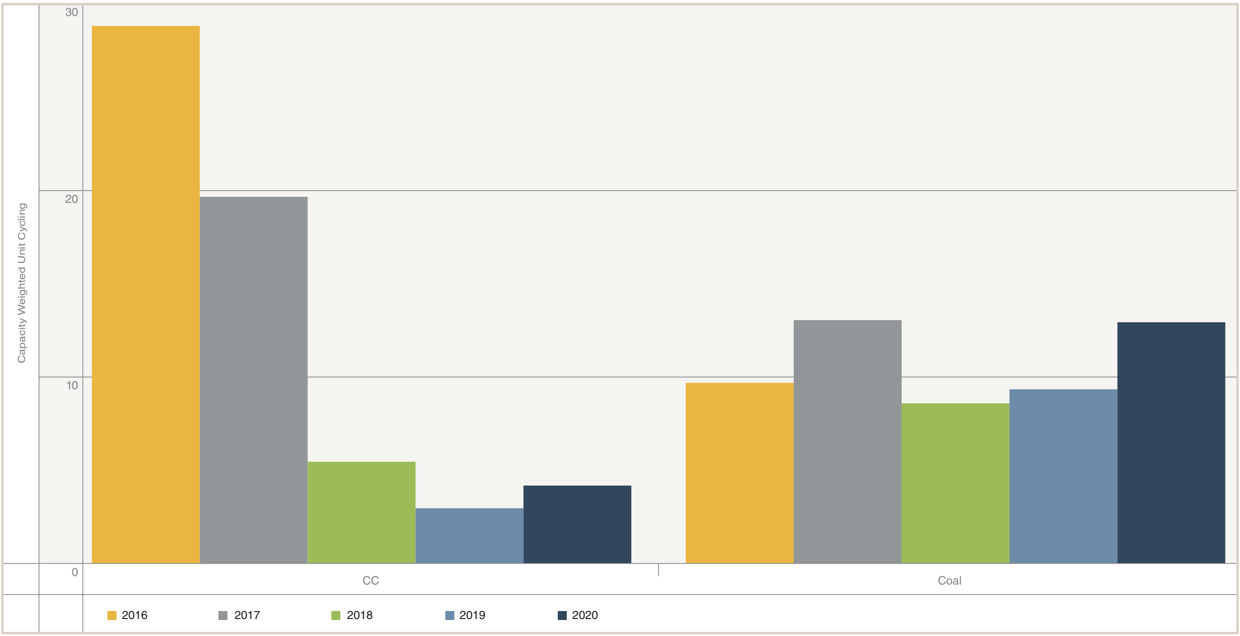
Unit on/off cycling

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 generating 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 2016 to 2020. 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 42 illustrates a trend of decreasing average on/off cycles for combined-cycle generating units over 2016 to 2020. The average on/off cycles for coal-fired generating units has remained relatively stable over the same years.

FIGURE 42: 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 compared to previous years. In 2020, lower power prices combined with higher gas prices led to slightly higher cycling rates for the combined-cycle units. With respect to the higher coal unit cycling in 2020, it's speculated that because of the increase in the number of dual-fuel fired units, they experienced more cycling when using gas as the main fuel. However, the AESO does not have visibility into the mix of fuel used at these dual-fired units, so this couldn't be confirmed.

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. As well, the system flexibility assessment on the AESO's website[16] will be periodically updated to reflect the evolution of the transmission system, changes in generation and loads, and the adoption of new technologies.

Final notes

As the market evolves throughout 2021 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 ad-hoc, 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.

[16] https://www.aeso.ca/market/market-and-system-reporting/system-flexibility-assessment/

Alberta Electric System Operator

2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
www.aeso.ca