aeso

AESO 2023
Annual Market Statistics

MARCH 2024

Contents

Executive Summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient, and openly competitive (FEOC) market for electricity and provides for the safe, reliable, and economic operation of the Alberta Interconnected Electric System (AIES). The AESO 2023 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.[1]

In 2023, 276 participants in the Alberta wholesale electricity market transacted approximately $15.8 billion of energy. The annual average pool price for wholesale electricity fell 18 per cent from 2022 to $133.63/megawatt hour (MWh). The average natural gas price fell almost 50 per cent, averaging $2.55/gigajoule (GJ). The average spark spread, based on a 7.5 GJ/MWh heat rate, fell 8 per cent to $114.52/MWh. The main reasons for the fall in the average pool price were less-extreme temperatures, lower natural gas prices, and increased competition.

Price	2022	2023	Year/Year Change
Pool price	$162.46/MWh	$133.63/MWh	-17.7%
Gas price	$5.07/GJ	$2.55/GJ	-49.7%
Spark spread @ 7.5 GJ/MWh	$124.46/MWh	$114.52/MWh	-8.0%

Load	2022	2023	Year/Year Change
Average Alberta Internal Load	9,883 MW	9,851 MW	-0.3%
Winter seasonal peak	12,193 MW	12,384 MW	+1.6%
Summer seasonal peak	11,381 MW	11,522 MW	+1.2%

The average Alberta Internal Load (AIL) fell by 0.3 per cent over 2022 values due to less extreme temperatures, especially in the winter months and, to a lesser extent, the high-volume but short-term impact of wildfires. Extreme temperatures in January 2024 resulted in the 2023 seasonal winter peak of 12,384 MW, which was also a new AIL peak record. For calendar year 2023, the AIL peak was 11,572 MW, down from 12,193 MW in 2022.

Installed generation capacity at the end of 2023 was 20,777 MW, up 13.3 per cent from 2022. Renewables capacity increased by 1,375 MW and natural gas capacity increased by 938 MW. It is important to note that 900 MW of this capacity did not produce any energy in 2023. Gas-fired generation provided 68.5 per cent of total generation, coal generation provided 12.2 per cent and renewables generation provided 16.5 per cent.

The total cost of operating reserve (OR) fell 25 per cent, to $378 million. This was primarily due to the lower pool prices. Despite the overall fall in OR costs, standby OR costs increased due to higher net-demand variability.

Other notable Alberta market and grid insights from 2023 include: net-demand variability continued to increase as more wind and solar generation was added to the grid; net imports and exports were basically equal in 2023, and average intertie flows with British Columbia (B.C.) were net exports.

[1] The link to the datafile can be found here: https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/.

Price of Electricity

Pool price fell 18 per cent

The pool price averaged $133.63/MWh for 2023—a decrease of 18 per cent from 2022. 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. daily; the remaining hours of the day make up the off-peak period. In 2023, the average pool price during the on-peak period decreased 19 per cent to $156.15/MWh, and the off-peak average pool price decreased 14 per cent to $88.59/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 2023, the spark spread decreased 8 per cent from a year earlier to $114.52/MWh.

The average pool price in 2023 was lower than 2022. The main drivers were slightly lower and less volatile demand, due to less extreme temperatures, lower gas prices, and increased competition in the energy market. Competition increased in the latter half of the year with increased supply from new wind and solar generation plus a large thermal asset returned from a year-long outage. As a result, there were less hours where generation offered at very high prices could set price.

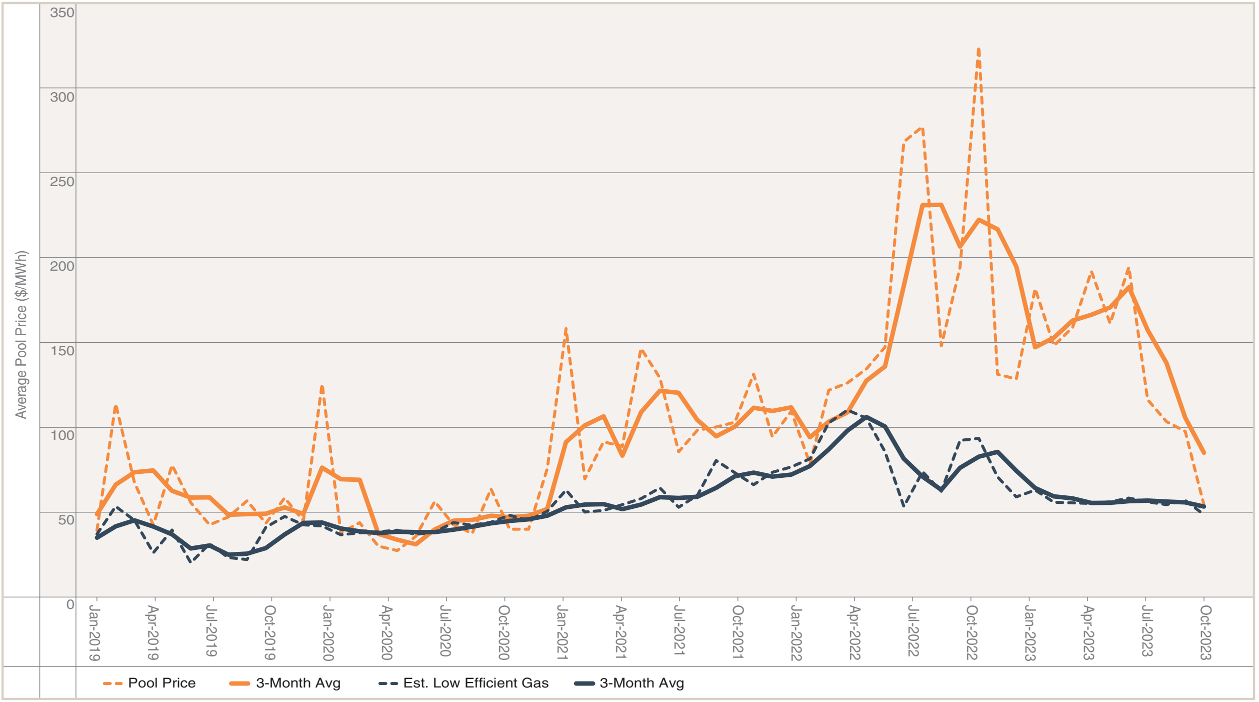
Table 1 summarizes historical price statistics over the 10-year period between 2014 and 2023.

TABLE 1: Annual market price statistics

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Pool price ($/MWh)										
Average	49.42	33.34	18.28	22.19	50.35	54.88	46.72	101.93	162.46	133.63
On-peak average	61.48	40.73	19.73	24.46	59.28	64.12	54.72	122.61	192.13	156.15
Off-peak average	25.28	18.55	15.37	17.64	32.47	36.40	30.71	60.58	103.14	88.59
Spark Spread at 7.5 GJ/MWh ($/MWh)										
Average	17.56	14.12	2.77	6.70	39.54	42.21	30.81	76.39	124.46	114.52

The pool price is the wholesale price of electricity, used as the settlement price for all transactions in the energy market. Figure 1 shows the monthly average pool price over the past five years. For 2023, the monthly average pool price ranged from a high of $186.80/MWh in August to a low of $52.05/MWh in December. Figure 1 also includes the estimated marginal cost of a theoretical low-efficiency simple-cycle natural gas unit. This estimated cost is for a 12 GJ/MWh heat rate unit and includes $5 for operating and maintenance costs, as well as the estimated carbon costs. For this theoretical unit, the carbon costs were $19.71/MWh in 2023 and $15.16/MWh in 2022. For comparison, a high-efficiency gas unit with a 7 GJ/MWh heat rate had an estimated carbon cost of $1.48/MWh in 2023, compared to $1.14/MWh in 2022.

FIGURE 1: Monthly average pool price



In 2019, the difference between pool price and the theoretical gas unit marginal cost averaged approximately $20. In 2020, the spread between these two prices fell to approximately $6, primarily due to a collapse in demand due to the impacts of COVID-19 restrictions. In 2021, with the expiration of the Power Purchase Agreements (PPA), offer control of many units returned to the original owners from the Balancing Pool. This concentrated offer control of the assets and some market participants began to offer power to the energy market at higher prices. As a result, the spread increased to approximately $44. Between Q3 2020 and Q2 2022, almost 1,300 MW of coal generation, no longer bound by PPAs, retired. This reduced generation supply, which allowed the spread to increase again in 2022. It almost doubled, averaging just over $81, as some market participants took advantage of the low supply situation to offer power at even higher prices.[2] In 2023, this dynamic continued, as the spread average was $78 for the year. However, moderate demand, significantly increased wind generation and the mid-year return of a large thermal unit helped bring the spread down in Q4. The spread averaged $94 from January to September and $30 from October to December. It is important to note that prices above the marginal unit cost go towards recovering fixed and/or investment costs in Alberta's energy-only market.

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.

[2] Section 1.3–Market Power: https://www.albertamsa.ca/assets/Documents/Q3-2022-Quarterly-Report.pdf.

Figure 2 shows the frequency of high-priced hours over the past five years. In 2021, the expiry of the PPAs led to increased offer prices, thus higher settled prices. In 2022, the number of high-priced hours almost doubled due to higher demand, lower supply, and continued high offer prices from some market participants. In 2023, high-priced hours were slightly lower, primarily due to more competition in the energy market from the addition of more renewable energy, as well as the return of a large thermal unit.

FIGURE 2: Frequency of high-priced hours

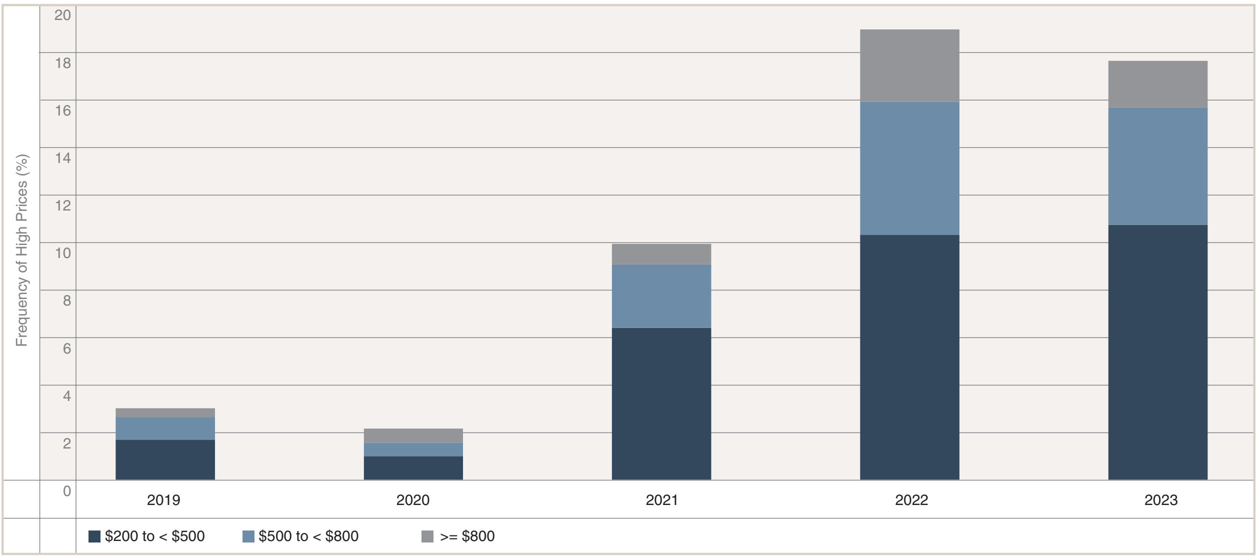
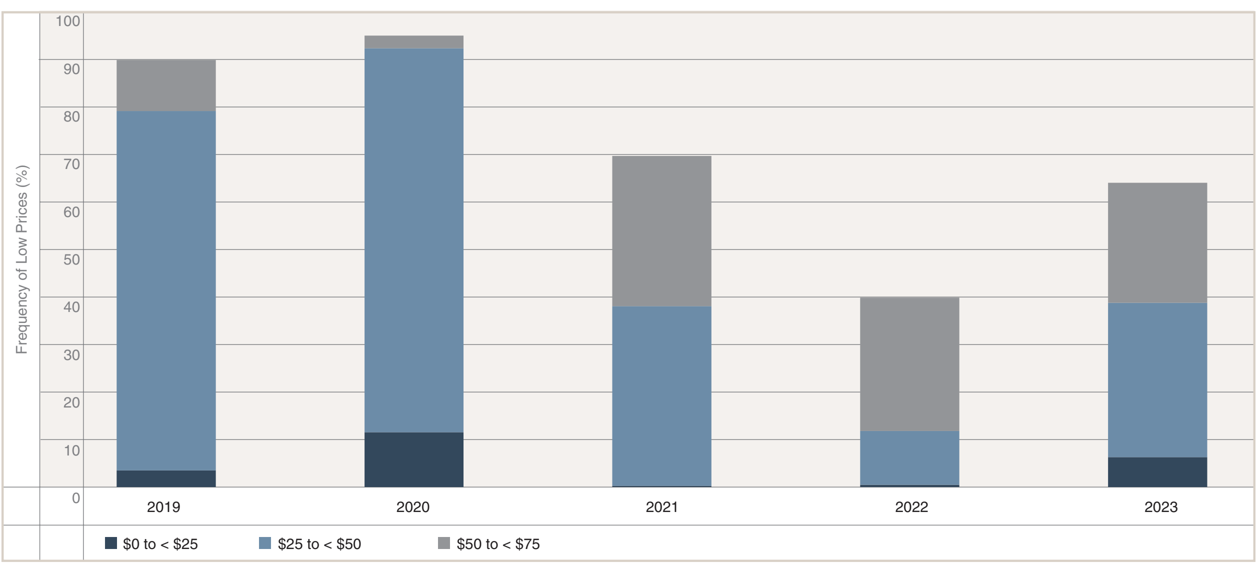


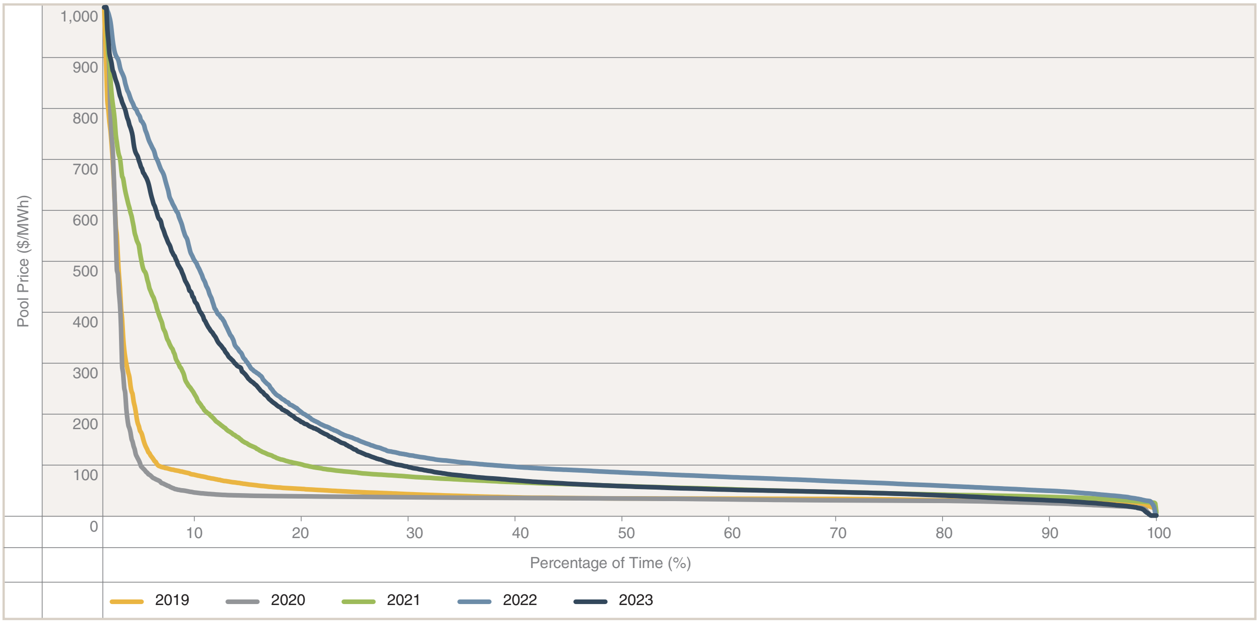
Figure 3 shows the frequency of low-priced hours over the past five years. The reasons previously mentioned for the changes in high-priced hours are generally the same for the smaller number of low-priced hours. Of note is the number of hours with prices below $25. In 2019 and 2020, this was due to low demand, with 2020 seeing a large impact of the COVID restrictions. However, in 2023, the increase in these hours was due to the addition of more wind and solar generation. Because wind and solar generation is generally offered at $0, it can lower the pool price when it is available in the merit order. The year-over-year change in the frequency of $25 to $50 prices was likely due to lower natural gas prices.

FIGURE 3: Frequency of low-priced hours



The price duration curve represents another view into the frequency of hourly pool prices. Figure 4 depicts the price duration curves for 2019 to 2023. It shows that 2023 was more like 2021 for prices under $100. For prices above $100, the frequency was similar to 2022, albeit with slightly lower prices.

FIGURE 4: Pool price duration curve

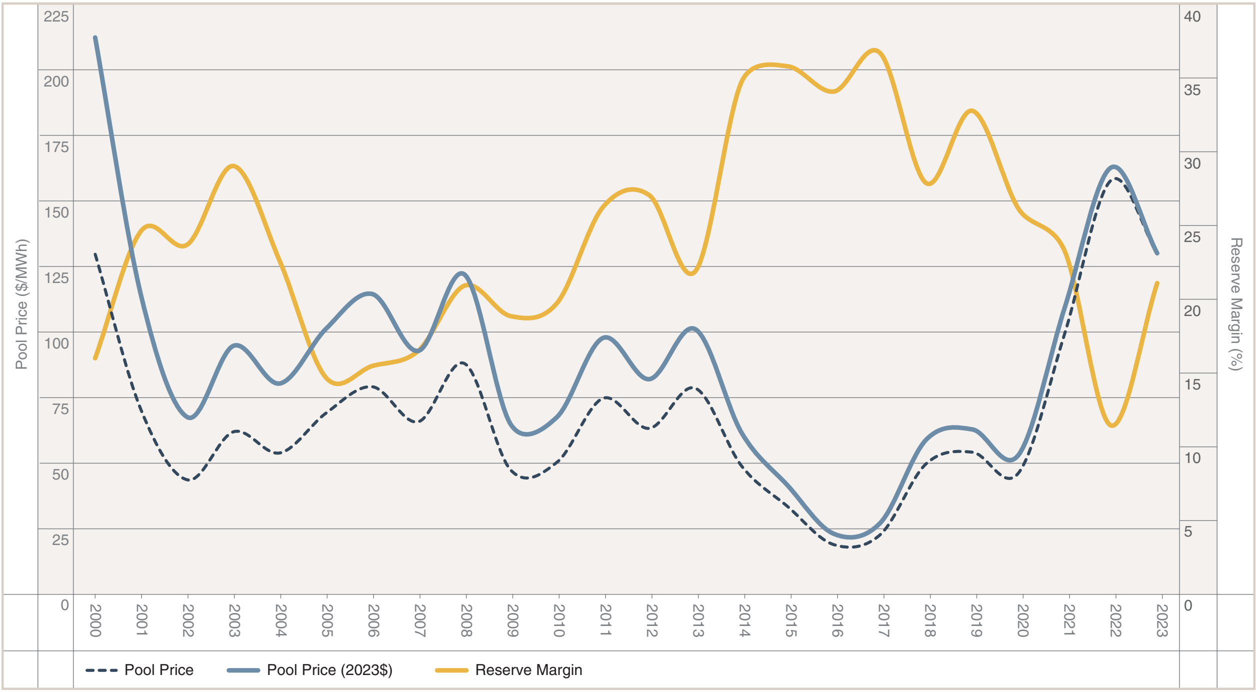


Historical pool price and reserve margin

Three of the four highest-priced years, in nominal terms, in the AESO's history occurred from 2021 to 2023. However, when put in context of the supply and demand cycles inherent in an energy-only market, prices over the past decade have been modest compared to previous periods in the AESO's history. This is due to the past decade also including the five lowest-priced years that the AESO has recorded. The inflation-adjusted 10-year average pool price for 2014-2023 was $74, compared to $109 for the 2000-2009 period.

It can take time for market participants to react to changing supply and demand patterns, which can result in price volatility. High prices incent participants to build new generation assets, while low prices will lead to participants removing generation if they do not feel they can adequately recover costs. In addition, changing demand patterns can heavily influence prices. For example, in 2014 there was a large increase in generation supply. However, this occurred just before oil prices were severely depressed, which lowered demand in Alberta. This resulted in several years of high reserve margins (a measure of the supply/demand dynamic) and low pool prices. Supply was then taken out of the market at the same time as demand increased. This led to 2022 having the lowest reserve margin in the AESO's history. See Figure 5 for the yearly real (i.e., inflation-adjusted) and nominal average pool prices, along with the AESO's reserve margin.

FIGURE 5: Yearly pool price and reserve margin



Supply shortfall and surplus

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 Controller is forced to curtail firm load, the system marginal price is set to the administrative price cap of $1,000/MWh.

In 2023, there were three supply shortfall events that required a Grid Alert,[3] compared to eight in 2022. When a Grid Alert is declared, the AESO is unable to meet minimum contingency reserve requirements and firm load interruption is imminent. During both 2022 and 2023, the AESO was able to manage the Grid Alerts such that no firm load was involuntarily shed. In 2023, one event occurred in June and two occurred in August. Each event occurred during a period of extreme seasonal demand and were accompanied by other precipitating factors including: intertie maintenance; low scheduled imports; unplanned thermal unit outages; thermal unit derates; and, low wind and solar generation. One or more of these reasons led to each of the Grid Alert events.

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

Supply surplus events occur when the supply of energy offered to the market at $0/MWh exceeds system demand and System Controllers are required to reduce supply using out-of-market actions. The mitigation procedure for supply surplus events authorizes System Controllers to halt imports, reschedule exports, and curtail or cut in-merit generation. In 2023, there were roughly 30 hours with at least a portion of the hour where the system marginal price was $0/MWh and System Controllers were forced to curtail supply. Supply surplus events occur when supply from wind, solar and baseload dispatchable assets, which typically offer into the market at $0/MWh, is greater than demand. In addition, there were roughly 54 hours with at least a portion of the hour where the system marginal price was $0/MW, but no supply was forced to curtail due to the supply surplus. In these latter instances, there was generation curtailed due to transmission constraints. This required other generation, offered in at higher prices, to be dispatched to cover the lost generation and the unconstrained system marginal price was reconstituted, as per AESO rules, to $0/MWh. During the year, there were a total of 49 hours where the hourly pool price was $0/MWh.

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 fell 0.3 per cent

Table 2 summarizes annual demand statistics over the past 10 years. In 2023, average AIL fell by 0.3 per cent to 9,851 MW. The loss in load can primarily be attributed to milder weather in 2023 as compared to 2022. When the effects of year-over-year temperature differences are accounted for, there is virtually no difference in load between the two years. However, this masks some underlying changes, which will be discussed in the regional load section.

TABLE 2: Annual load statistics

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Alberta Internal Load										
Total (GWh)	79,949	80,257	79,560	82,572	85,330	84,925	83,115	85,214	86,572	86,293
Average (MW)	9,127	9,162	9,055	9,426	9,741	9,695	9,460	9,728	9,883	9,851
Maximum (MW)	11,169	11,229	11,458	11,473	11,697	11,471	11,698	11,729	12,193	11,572
Minimum (MW)	7,162	7,203	6,595	7,600	7,819	8,024	7,579	7,976	8,110	7,873
Average change	3.2%	0.4%	-1.1%	4.1%	3.3%	-0.5%	-2.4%	2.8%	1.6%	-0.3%
Load factor	81.7%	81.6%	79.0%	82.2%	83.3%	84.5%	80.9%	82.9%	81.1%	85.1%
System Load										
Total (GWh)	61,530	61,299	60,773	62,393	62,942	61,626	60,201	60,985	61,873	60,893
Average (MW)	7,024	6,998	6,919	7,123	7,185	7,035	6,854	6,962	7,063	6,951
Average Change	3.6%	-0.4%	-1.1%	2.9%	0.9%	-2.1%	-2.6%	1.6%	1.5%	-1.6%
System Load-to-AIL Ratio	77.0%	76.4%	76.4%	75.6%	73.8%	72.6%	72.4%	71.6%	71.5%	70.6%
Implied BTF Load (MW)	2,103	2,164	2,139	2,304	2,556	2,660	2,609	2,766	2,819	2,900

AIL represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system designation, as well as the City of Medicine Hat. It is consistent with the generation and load represented on the AESO's Current Supply and Demand page[4] 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, B.C.,[5] plus transmission losses.

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

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

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. In 2023, the load factor increased four percentage points, indicating lower variability in load. Again, this is likely due to relatively few weather events that were significantly outside normal levels.

The system-load-to-AIL-ratio describes how much of total load in Alberta is using the bulk transmission system. The difference between AIL and system load represents load that does not use the bulk transmission system, commonly referred to as behind-the-fence (BTF) load. Normally, BTF load includes industrial load self-supplied by large on-site cogeneration plants, as well as all load on distribution networks that can be served by small rooftop solar panels. However, for the purposes of this BTF calculation, only load self-supplied by large generators (i.e., greater than 5 MW) is captured. Gross load on distribution facility owner (DFO) transmission networks is not readily available to the AESO, only the net metered load. In 2023, 70.6 per cent of Alberta's load was using the bulk transmission system, down almost one per cent or roughly 80 MW.

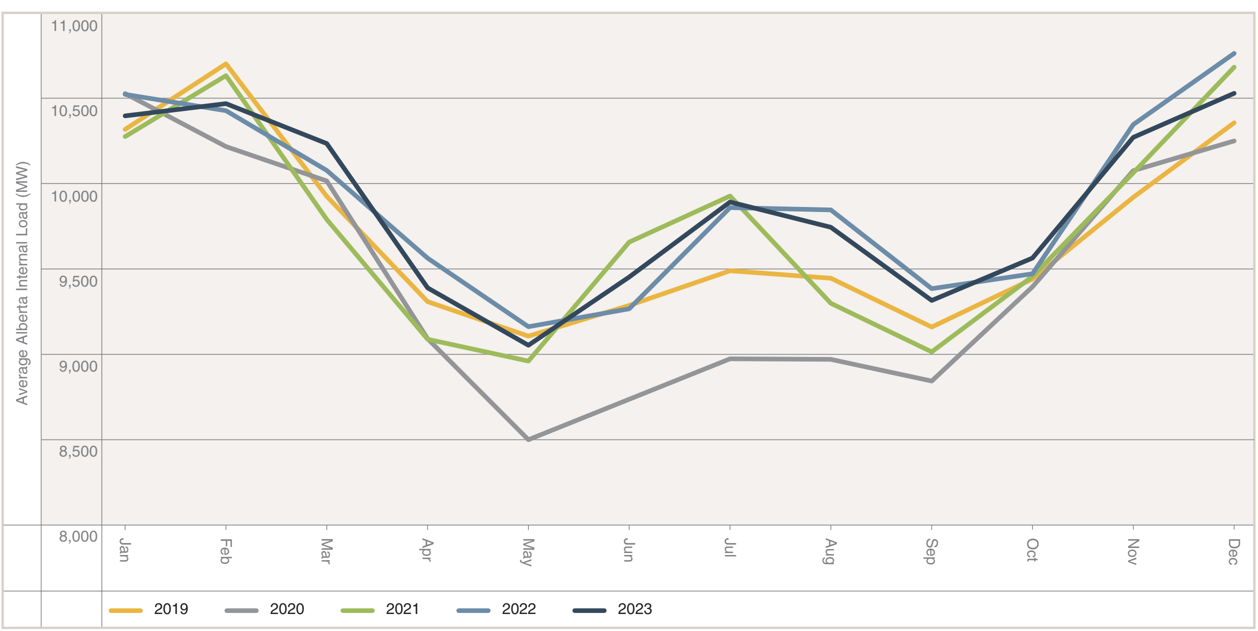
The implied average hourly BTF load was 2,900 MW for 2023, up 2.9 per cent from an implied 2,819 MW of BTF load in 2022. BTF load is primarily driven by industrial load, especially oil sands sites, while system load is roughly half residential plus commercial and half industrial. Therefore, a larger increase in BTF load compared to system load is indicative of AIL growth being driven primarily by industrial load. The gain in BTF load was primarily due to a few new generation assets built to self-supply industrial load, as well as some large-scale distribution-connected solar farms coming online.

Since 2014, the percentage of AIL from BTF load has increased from 23.0 per cent to 29.1 per cent. In absolute terms, this is an hourly average increase of 797 MW since 2014. In 2023, there was an increase in the hourly average BTF load of just under 80 MW. As the amount of BTF load increases, there is less load available to pay for bulk transmission costs.

Monthly average Alberta Internal Load

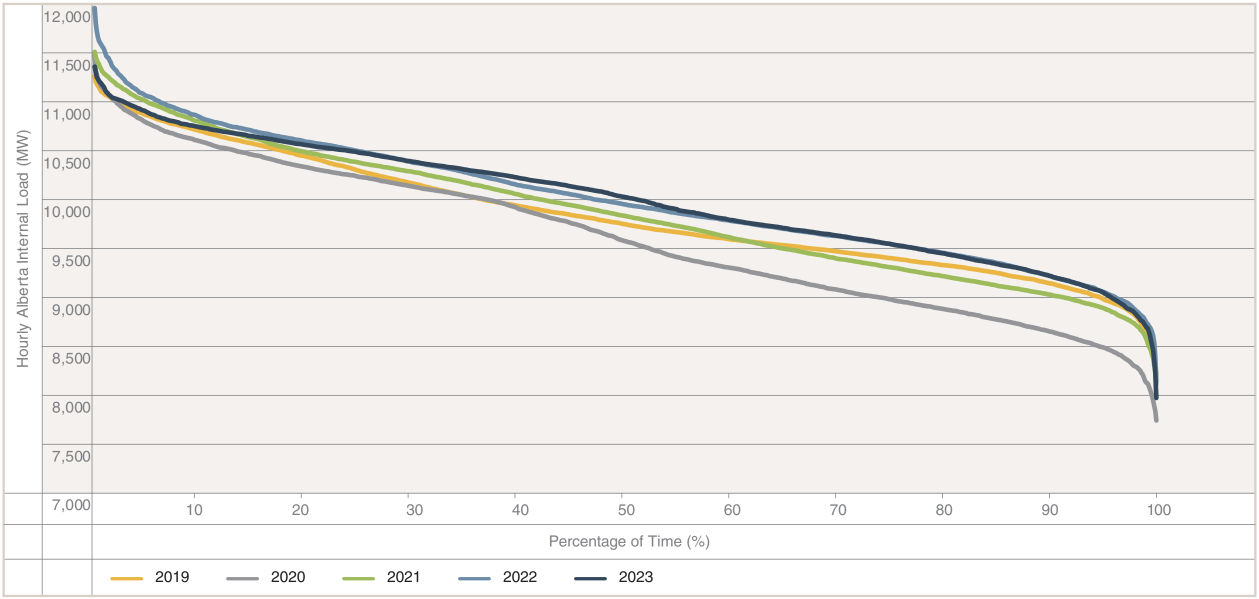
Figure 6 shows the monthly average AIL over the past five years. Typically, the year-over-year differences in AIL are primarily due to differences in temperatures between the two years. However, in 2023, wildfires had an impact on load, especially during May and June. It is estimated the impact in May and June was 100 – 150 MW, with diminishing impacts over the rest of the summer and early fall. The impacts of COVID-19 restrictions can clearly be seen in the May through September period of 2020.

FIGURE 6: Monthly average Alberta Internal Load



The load duration curve represents the percentage of time that AIL was greater than or equal to the specified AIL volume. Figure 7 plots the annual load duration curve over the past five years. In 2023, just under 75 per cent of the most frequent AIL volumes were the same or higher than those in 2022 (i.e., represented by 25 to 100 per cent on the horizontal axis). However, the highest AIL volumes were markedly higher in 2022 than in 2023. This shows the impact of the less extreme temperatures experienced in 2023. The very low volumes shown in 2020 are a result of the impacts brought on by the COVID-19 pandemic.

FIGURE 7: Annual AIL duration curves



Seasonal load

Seasonal peaks in Alberta load are usually set during periods of extreme temperatures: summer peaks are driven by heat; winter peaks are driven by cold. Alberta has always been a winter-peaking region, meaning that the highest yearly peak occurs in the winter season. In 2023, the summer peak of 11,522 MW was set in late July and the winter peak of 12,384 MW was set in January 2024 (a new AIL peak load record). Interestingly, the 2023 calendar peak of 11,572, which occurred in February, was only 50 MW higher than the summer peak. This was second only to the nine-MW difference that occurred in 2021. The seasonal system load numbers are not presented here, but they show that summer loads, unlike AIL, have not set new highs in the past three years. This implies that it is BTF load at industrial sites that is primarily driving increased summer AIL values.

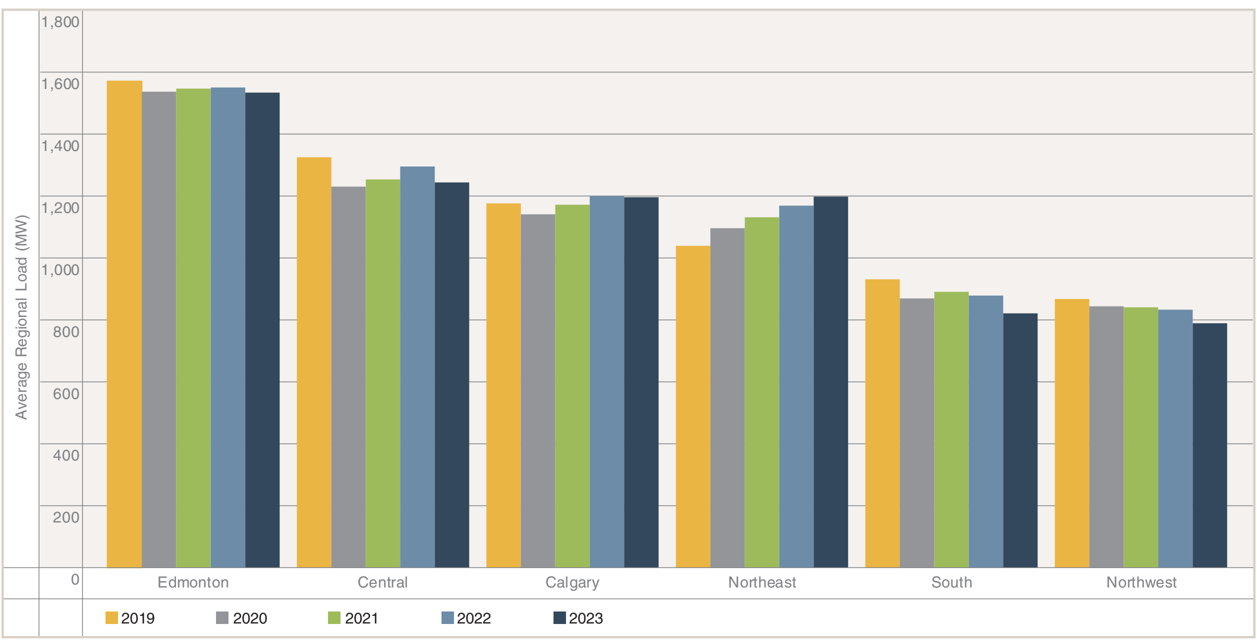
TABLE 3: Seasonal peak load

Season	Peak AIL (MW)	Date
Summer 2019	10,822	2019-08-02
Winter 2019	11,698	2020-01-14
Summer 2020	10,532	2020-10-26
Winter 2020	11,729	2021-02-09
Summer 2021	11,721	2021-06-29
Winter 2021	11,939	2022-01-03
Summer 2022	11,381	2022-07-28
Winter 2022	12,193	2022-12-21
Summer 2023	11,522	2023-07-24
Winter 2023 (to Feb 2024)	12,384	2024-01-11

Regional load

Figure 8 shows the average regional system load (i.e., excluding losses and BTF load) over the past five years.[6] As mentioned in the discussion on AIL, the small loss in year-over-year demand hides some significant changes at the regional level. Milder temperatures lowered year-over-year load in all regions, but to differing degrees. However, the individual regions also had some unique impacts to their load changes.

FIGURE 8: Regional average load



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

In Calgary and Edmonton, which are primarily residential and commercial load, system load fell 0.3 and 1.1 per cent respectively. The Edmonton region also includes some large industrial sites and the larger fall in system load was due to a small increase in BTF generation. Increased installation of small-scale solar panels, such as rooftop solar, likely offset underlying load growth from increased population. The Northeast region saw a 2.5 per cent increase in load, driven by increased oil sands production. The Northwest and Central regions saw system load fall by 5.2 and 4.0 per cent. Wildfires caused mostly temporary load reductions in both regions, although the Northwest was more impacted. In addition, both regions saw some long-term load loss in a variety of industries, including forestry, chemicals, and cryptocurrency mining. The South's system load fell 6.5 per cent, but this was primarily due to the addition of BTF generation rather than actual load being lost. The actual load lost was closer to 0.5 per cent and was likely temperature related.

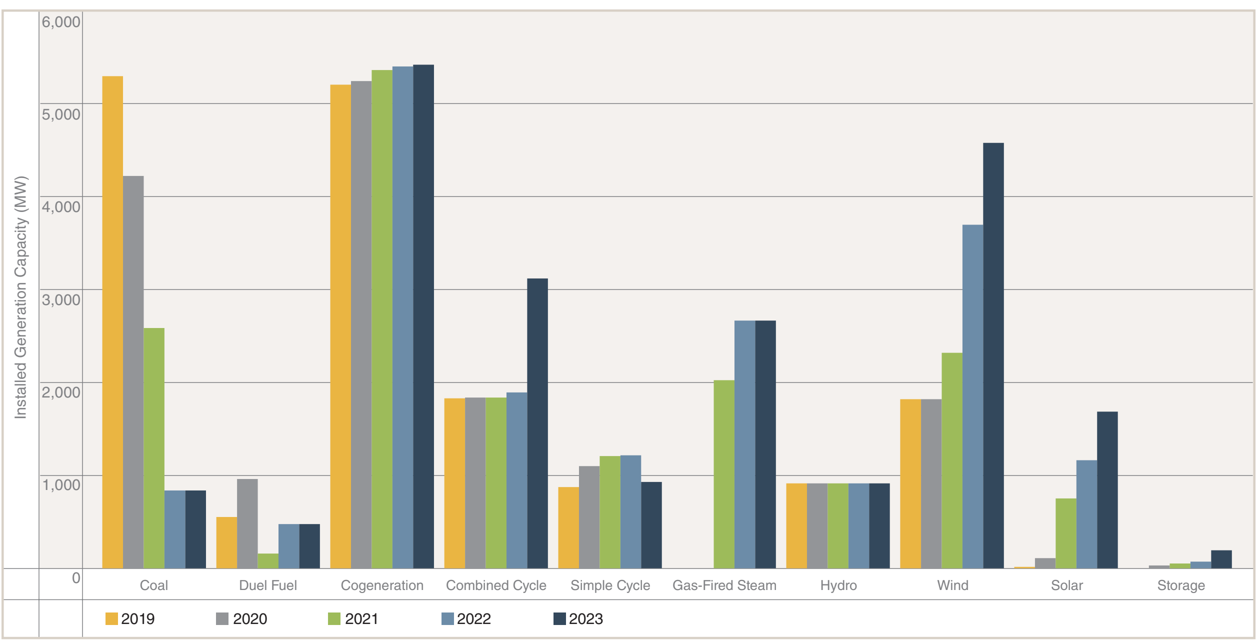
Alberta Generation

Year-end generation capacity increased by 13.3 per cent

At the end of 2023, installed generation capacity[7] in Alberta had increased to 20,777 MW, an increase of 2,433 MW or 13.3 per cent over the 18,344 MW installed at the end of 2022. All the total capacity change was from new generation installed during 2023, including 863 MW of wind, 512 MW of solar, 120 MW of battery storage, and 938 MW of gas generation. Within the category of gas generation, 19 MW of simple-cycle and 19 MW of cogeneration were added. The addition of Cascade 1 and 2 increased combined-cycle capacity by 900 MW, but Cascade was still in its commissioning phase and did not produce electricity in 2023. In addition, the 300 MW H.R. Milner facility completed its conversion from simple-cycle to combined-cycle. It returned to operation in October 2023 after being on an unexpected outage for over a year. No generation facilities were retired in 2023. In 2024, it is expected that the remaining coal assets will be converted to natural gas, while an additional several hundred MW each of gas, wind, and solar generation will be added.

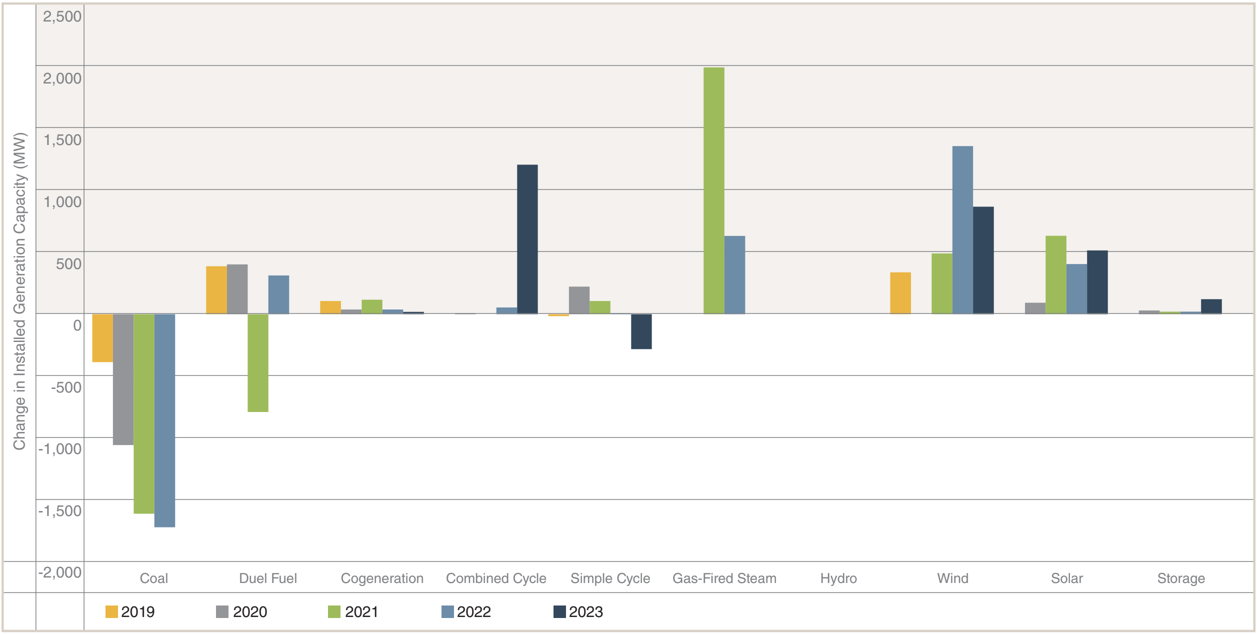
At year-end, purely gas-fired generation represented 57 per cent of total installed generation capacity. Coal and dual-fuel (using both coal and natural gas) generation capacity represented six per cent of the total. Wind generation capacity increased to 22 per cent in 2023 from 20 per cent in 2022, and solar increased to eight per cent in 2023 from six per cent in 2022. Total renewable capacity, including hydro, increased to 34 per cent of total capacity, up from 31 per cent in 2022 and 16 per cent in 2018. Figure 9 shows the installed capacity of each fuel type at the end of each of the past five years, while Figure 10 highlights the year-over-year change.

FIGURE 9: Year-end gross generation capacity by technology



[7] From the AESO's perspective, a unit's capacity is considered installed when its transmission connection becomes active. The active operation of the unit may lag the connection date by a significant period of time.

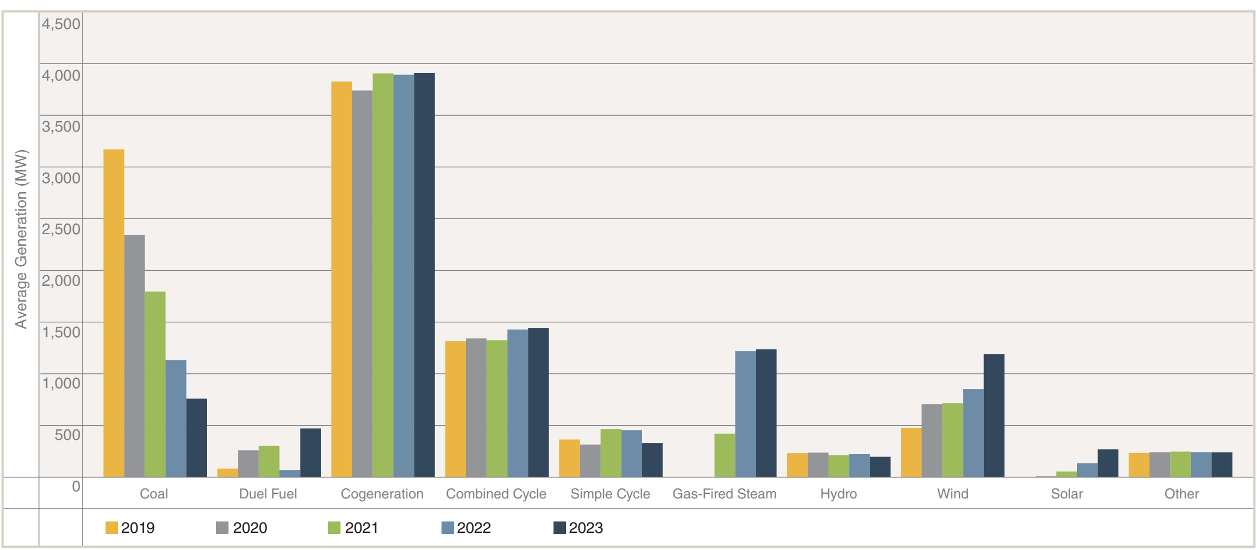
FIGURE 10: Year-over-year change in year-end generation capacity by technology



Gas generation supplied 69 per cent of all electricity

Figure 11 illustrates the average hourly overall generation from each technology over the past five years. This figure includes all assets with a capacity greater than five MW, including those self-supplying loads (BTF generation).

FIGURE 11: Annual average overall generation by technology



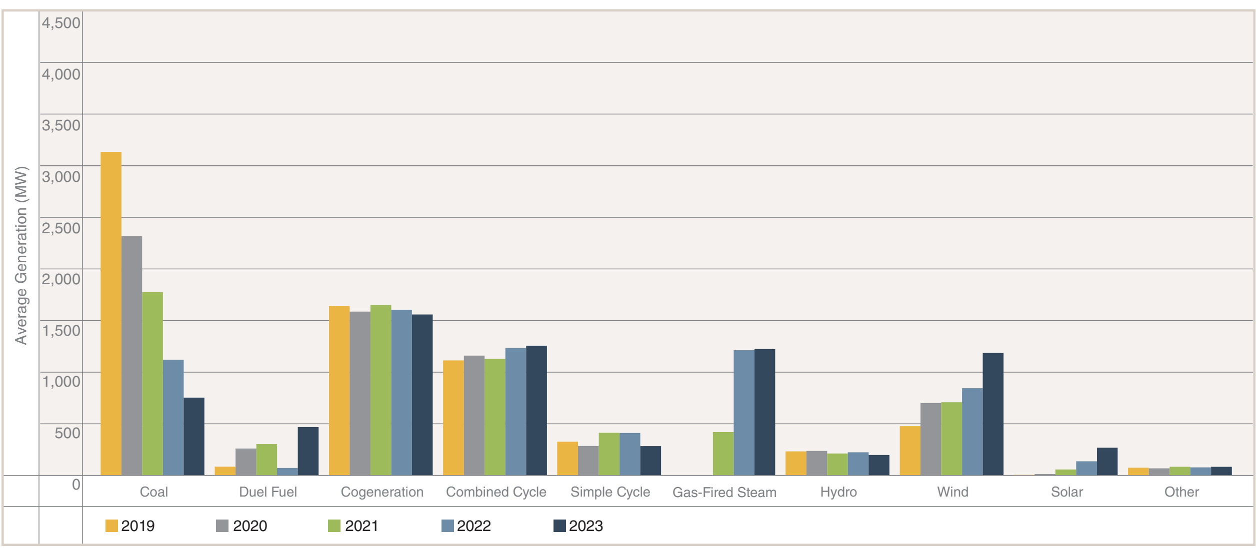
In 2023, pure gas-generation technologies delivered 68.9 per cent of all generation in Alberta, up from 56.7 per cent in 2019. Coal and dual-fuel generation provided 12.2 per cent, down from 33.5 per cent in 2019. Finally, renewables generation provided 16.5 per cent of Alberta's generation, up from 7.3 per cent in 2019. The interim targets for renewables generation related to *Alberta's Renewable Electricity Act* include a 15 per cent target for 2022 and 20 per cent for 2025. A linear trajectory between these targets implies renewables generation should make up 16.7 per cent of all generation in 2023. Renewables generation appears to be on track in relation to the interim targets, with 16.5 per cent of generation coming from large-scale hydro, wind and solar. There is additional renewables generation from the biomass portion of the "Other" large-scale generation category and output from small-scale renewables generation (< 5 MW), including micro-generation, which is not included in these statistics.

With respect to renewables generation, wind generation provided 11.9 per cent of the electricity generated in Alberta in 2023, compared to 8.8 per cent in 2022 and 4.9 per cent in 2019. Solar electricity was 2.7 per cent, up from 1.4 per cent in 2022 and close to zero in 2019. Facing Alberta's dry weather conditions in 2023, hydro provided 2.0 per cent of total generation, compared to 2.3 per cent in 2022.

Gas generation supplied 59 per cent of net-to-grid electricity

Figure 12 illustrates the average hourly volume of net-to-grid generation, meaning generation that was dispatched to serve system load, from each technology over the past five years. Net-to-grid generation differs from overall generation in that it excludes generation that serves BTF load rather than entering the bulk transmission system. Since cogeneration frequently serves BTF load rather than system load, net-to-grid generation from cogeneration assets is much smaller than overall generation. Combined-cycle, simple-cycle, and "other" assets also have lower net-to-grid generation, but to a lesser extent.

FIGURE 12: Annual average net-to-grid generation by technology



In 2023, pure gas-generation technologies delivered 59.4 per cent of net-to-grid generation in Alberta, up from 43.5 per cent in 2019, but down from 64.4 per cent in 2022. Coal generation provided 10 per cent, down from 44 per cent in 2019. Finally, renewables generation provided 22.7 per cent of Alberta's net-to-grid generation, up from 10.0 per cent in 2019. After surpassing coal generation for the first time in 2022, renewables net-to-grid generation more than doubled purely coal-fired generation in 2023 (excluding dual fuel).

Within renewables generation, net-to-grid generation from wind and solar both increased significantly. In 2023, wind generation provided 16.3 per cent of the total, compared to 12.2 per cent in 2022. Solar generation provided 3.7 per cent in 2023, compared to 1.9 per cent in 2022. Facing Alberta's dry weather conditions in 2023, hydro provided 2.7 per cent of net-to-grid electricity, compared to 3.2 per cent in 2022.

Monthly average overall generation

Average generation varies by month, corresponding to the higher demand experienced in the coldest and warmest months of the year. Figures 13 and 14 illustrate the monthly average overall generation and share of the total for each technology in 2023.

FIGURE 13: Average generation by technology by month (2023)

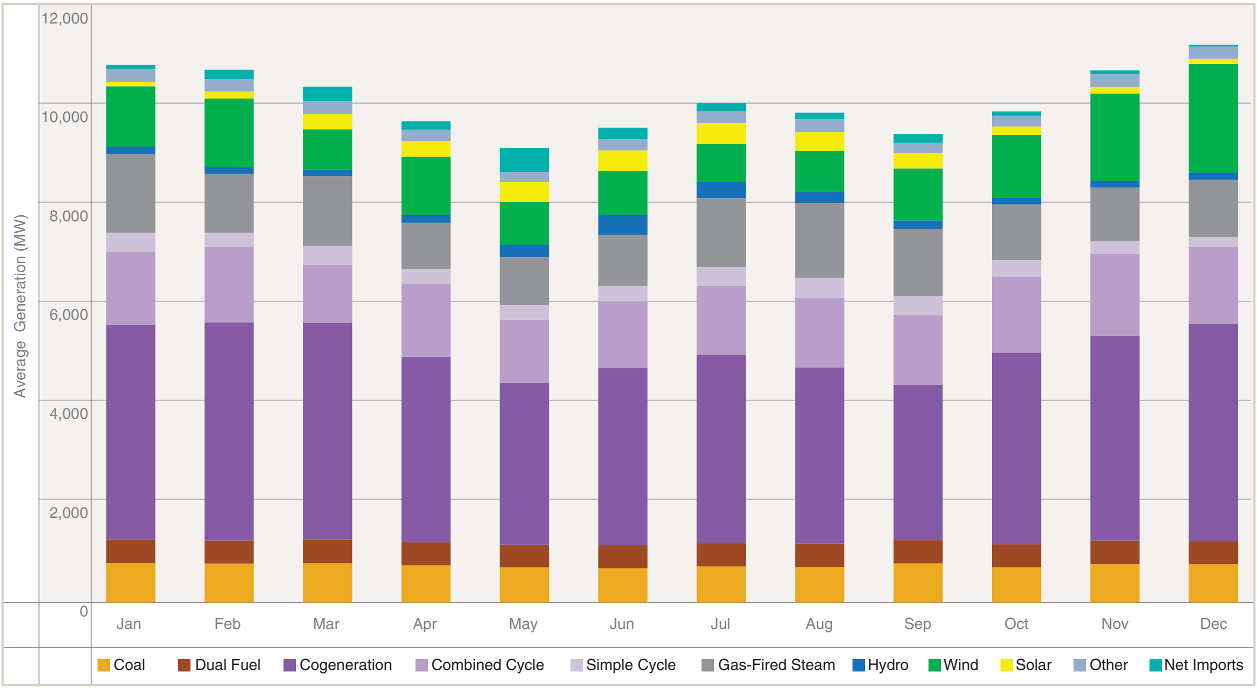
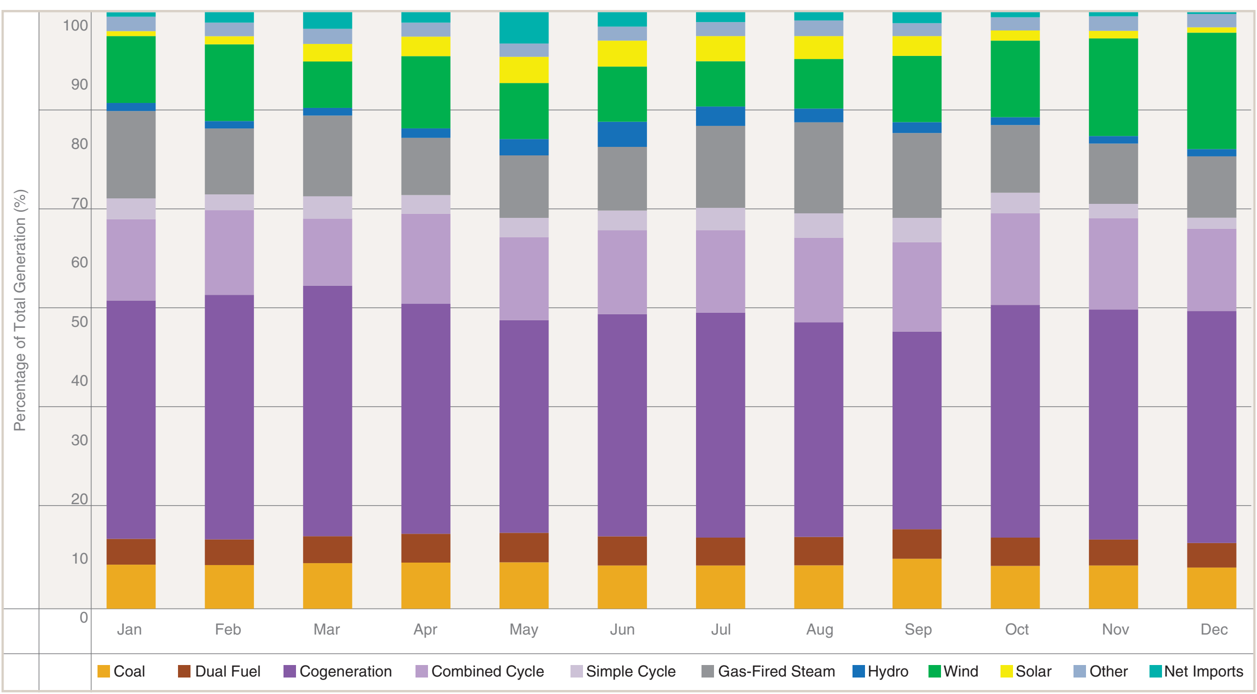


FIGURE 14: Percentage of total generation by technology by month (2023)



In 2023, coal and dual fuel generation were the most stable over the course of the year, with their combined generation ranging from a monthly average of 1,147 MW in June to 1,255 MW in January, for a nine per cent spread. Monthly average gas generation ranged from 5,727 MW (May) to 7,679 MW (January) for a 34 per cent spread. Unlike thermal generation, hydro generation was highest in June (398 MW) due to spring runoff, more than triple its output in October (127 MW). Wind varied from 757 MW in July to 2,168 MW in December, with much of this 186 per cent increase due to new wind generation coming online towards the end of the year. Solar generation, which is the most impacted by seasonal changes, varied from 88 MW in January to 418 MW in July (over four times higher).

The contribution of net imports in a month is calculated based on hours when Alberta is in a net import position. For this calculation, net imports are considered to be zero in hours when Alberta is in a net export position overall. Compared to previous years, net imports were relatively small in 2023 (see the Imports and Exports section of this report). Net imports were most significant in May at an average of 476 MW but averaged as low as 33 MW in December.

Hourly average overall generation

Alberta's generation mix also changes throughout the day due to the daily load profile and patterns of wind and solar generation. Figures 15 and 16 illustrate the average overall generation for each hour of the day and share of the total for each technology in 2023.

In 2023, thermal generation (including coal, dual fuel, gas, and other) ranged from an average of 7,820 MW in Hour Ending (HE)4, when demand is typically low, to 8,531 MW in HE21, when demand is relatively high but solar generation is unavailable.

Wind and solar generation follow a daily pattern dictated by environmental factors. Wind generation is typically highest at night. In 2023, wind generation averaged 1,319 MW in HE24, compared to 997 MW in HE12. Solar generation is zero at night but reached an average of 705 MW in HE14 during 2023.

FIGURE 15: Average generation by technology by hour (2023)

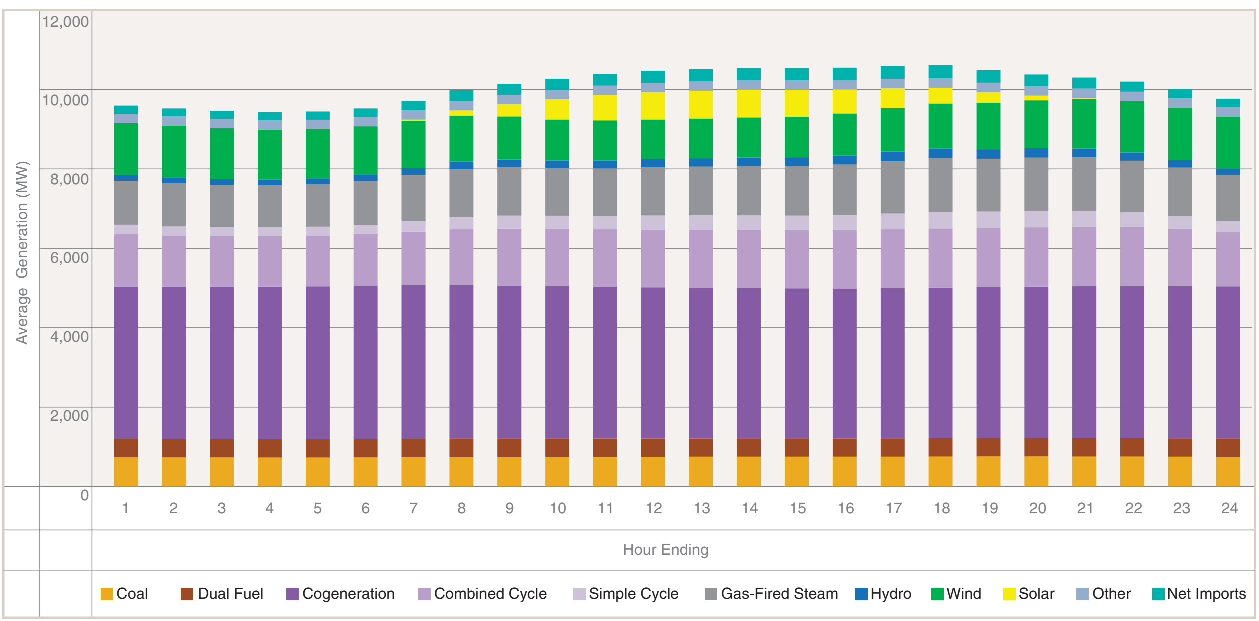
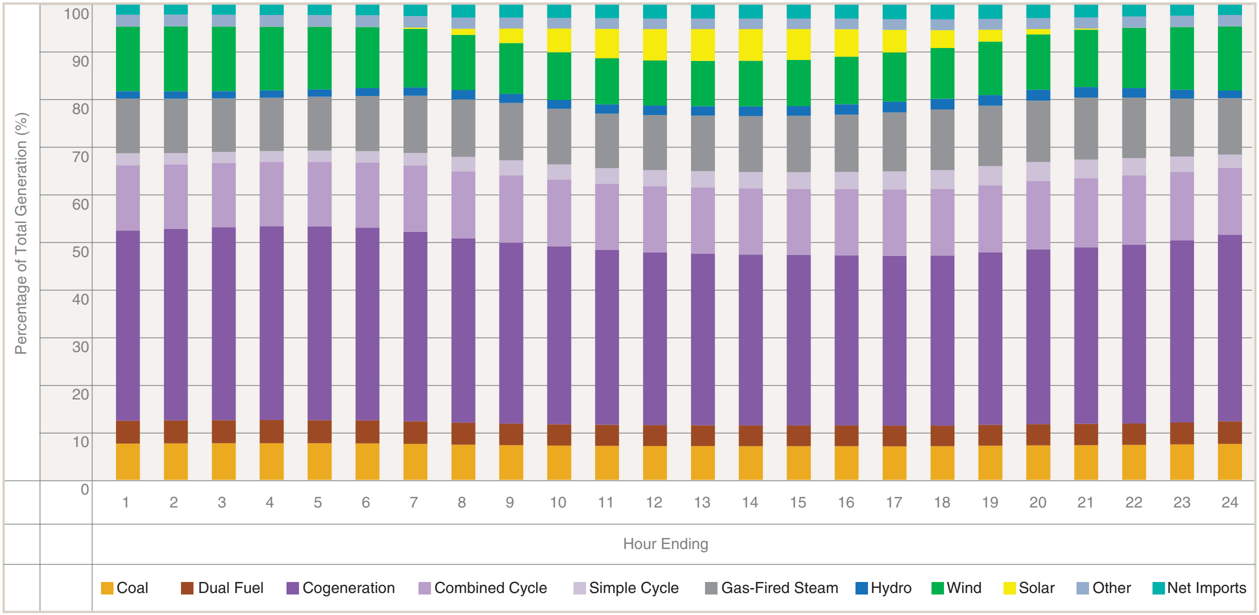


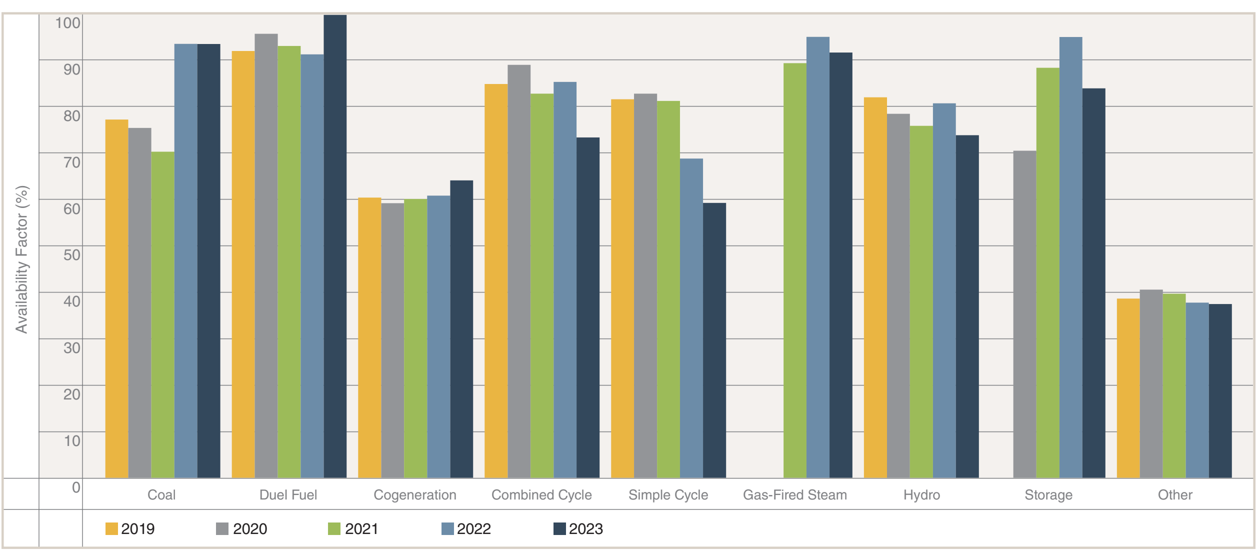
FIGURE 16: Percentage of total generation by technology by hour (2023)



Coal and dual-fuel technologies had the highest availability factors

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 capacity to the installed generation capacity. Wind and solar generation are excluded from this calculation as their available capacity is dependent on environmental factors. All available generation from wind and solar is used to supply demand, which is not true of other technologies. Since it is not available to the energy or ancillary services markets, any generation used to self-supply BTF load is excluded from the available energy volume part of the calculation, but the installed capacity is included in the generation capacity volume. Because it is used mainly for BTF generation, cogeneration assets tend to have low generation availability. Figure 17 illustrates the annual average availability factor by generation technology.

FIGURE 17: Annual net-to-grid availability factor by technology

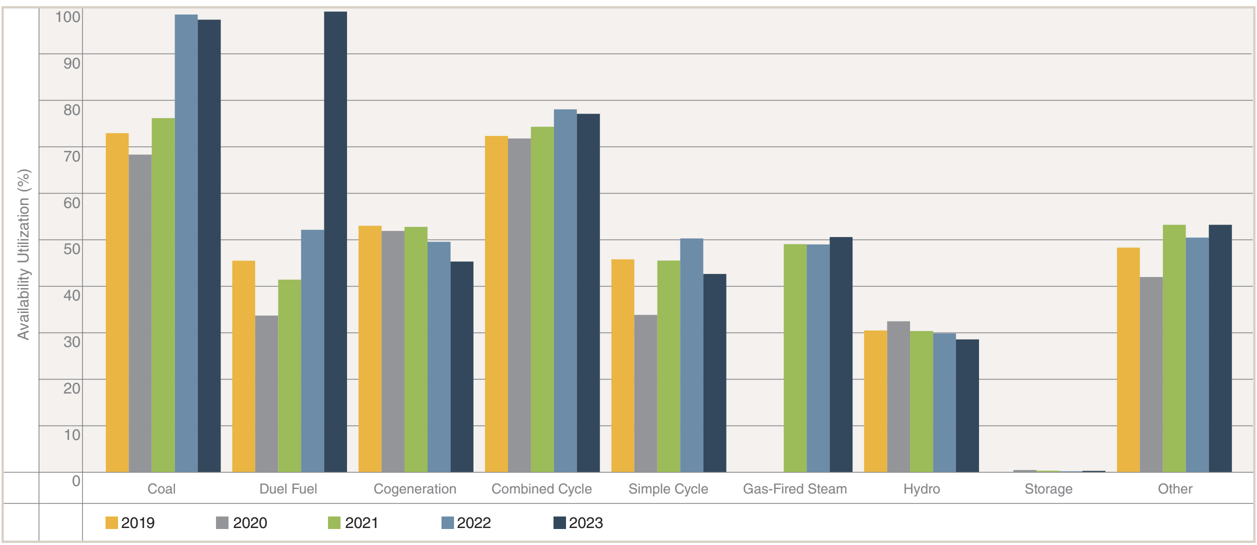


The long-term outage at H.R. Milner during its conversion lowered simple-cycle generation availability. The addition of Cascade 1 and 2 to installed capacity while these units were still commissioning and not available to generate electricity reduced combined-cycle generation availability. If Cascade is excluded from the calculation of generation availability, the combined-cycle availability factor for 2023 becomes 83 per cent rather than 73 per cent, only a small change from the 2022 combined-cycle availability factor of 85 per cent.

Coal and dual-fuel technologies had the highest utilization factors

Availability utilization represents the percentage of the available power that was dispatched to serve system load. Net-to-grid generation is the generation dispatched to meet system load. Availability utilization is calculated as the ratio of net-to-grid generation to net-to-grid available capacity. Capacity and generation used to supply BTF load has been excluded from the availability utilization calculation. Wind and solar generation are also excluded from this calculation since available wind and solar power is expected to be fully utilized. Figure 18 illustrates the annual availability utilization by generation technology.

FIGURE 18: Annual net-to-grid availability utilization factor by 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 led to combined-cycle gas generation replacing coal-fired generation as the lowest cost — and therefore the most utilized—generation technology. In 2021, due to high gas prices and the retirement and/or conversion to gas of less efficient coal units, coal-fired generation began to have the highest utilization factor again. In 2022, with the retirement of two more coal units, the remaining assets were the most efficient and lowest cost. In 2023, the pattern continued, as coal continued to be offered in the market typically as a price taker. Dual-fuel generation also began to follow this behaviour in 2023, leading to a 99 per cent utilization factor for dual-fuel and 98 per cent for coal.

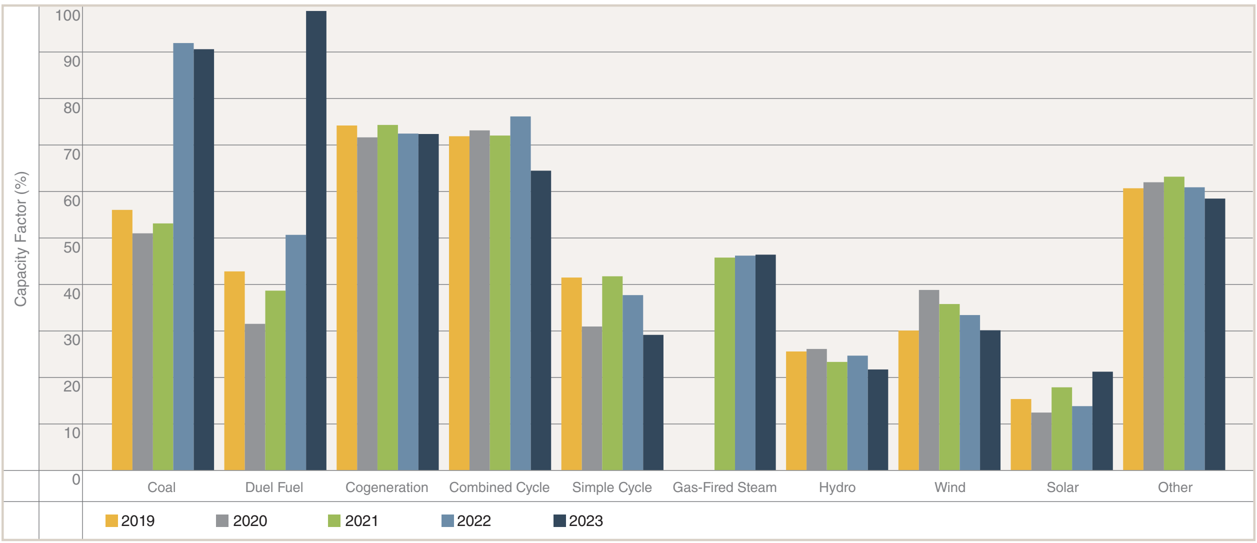
Despite being a relatively low-cost option, the availability utilization of cogeneration gas is less than that of other thermal generation. This relationship exists because cogeneration gas is used mainly as on-site generation at industrial facilities to serve on-site load, thus is less available to the grid.

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

Coal and dual-fuel assets had the highest capacity factors

Capacity factor represents the percentage of installed capacity used to generate electricity. Capacity factor is calculated as the ratio of average generation to the maximum capability over the given year. It is calculated using total generation (not net-to-grid generation) of all assets with an installed capacity of greater than 5 MW and does not include smaller, distributed generation. Energy storage is excluded from this chart, as those assets do not have the ability to provide continuous generation over long periods of time. Figure 19 illustrates the annual capacity factor by generation technology.

FIGURE 19: Annual capacity factor by technology



In 2023, dual-fuel assets had a capacity factor of 99 per cent—meaning for every 100 MW of installed capacity, dual-fuel assets generated 99 MW on average each hour. Coal generation also had a large capacity factor, at 91 per cent. The increase in the capacity factor for dual fuel in 2023 is related to two changes that took place during 2022: the conversion of a less efficient dual-fuel unit to gas and the conversion of a coal unit to a more efficient dual-fuel unit.

The addition of Cascade 1 and 2 to installed capacity while these units were still commissioning and not available to generate reduced the combined-cycle capacity factor. If Cascade is excluded from the calculation of generation availability, the combined-cycle capacity factor for 2023 becomes 73 per cent rather than 65 per cent, only a small change from the 2022 combined-cycle capacity factor of 76 per cent.

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, as well as 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 most 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.

Achieved price, as illustrated in Figure 20, represents the average price realized in the wholesale energy market for electricity delivered to the grid and is calculated as the volume-weighted average of the hourly pool price, where the price in each settlement interval is weighted by the net-to-grid generation volume in that interval.

A combination of offer strategy, market conditions and dispatched volumes determines the achieved price that each asset type receives. The achieved margin represents the difference between the achieved price and the average pool price over the year.

FIGURE 20: Annual achieved price by technology

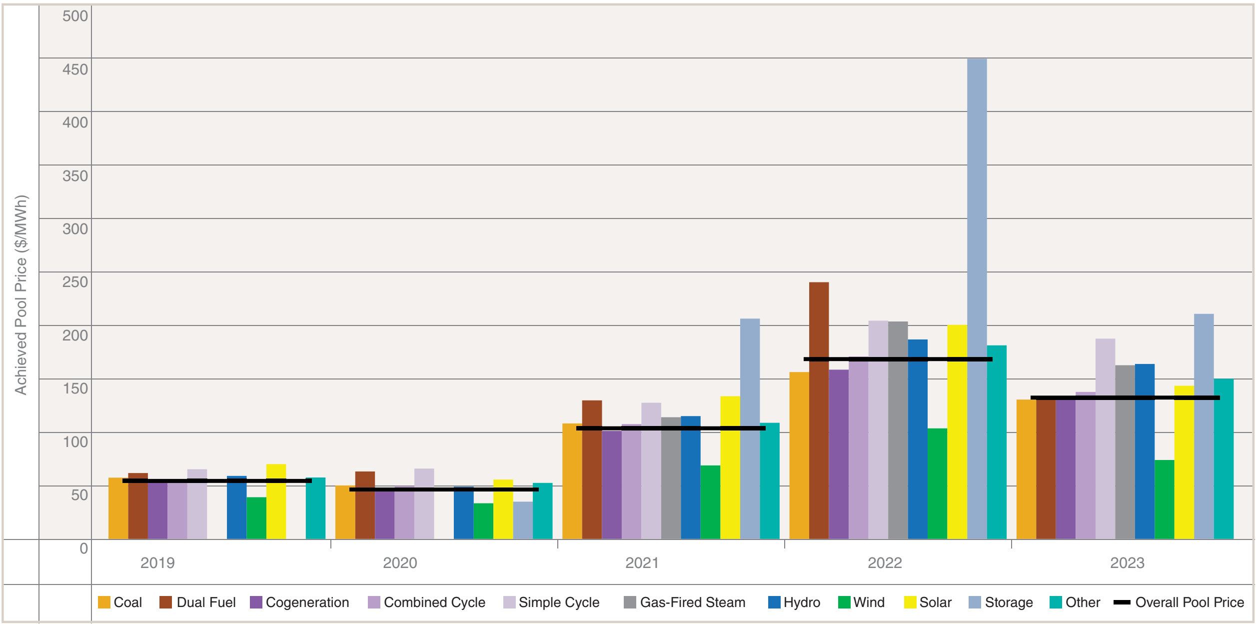
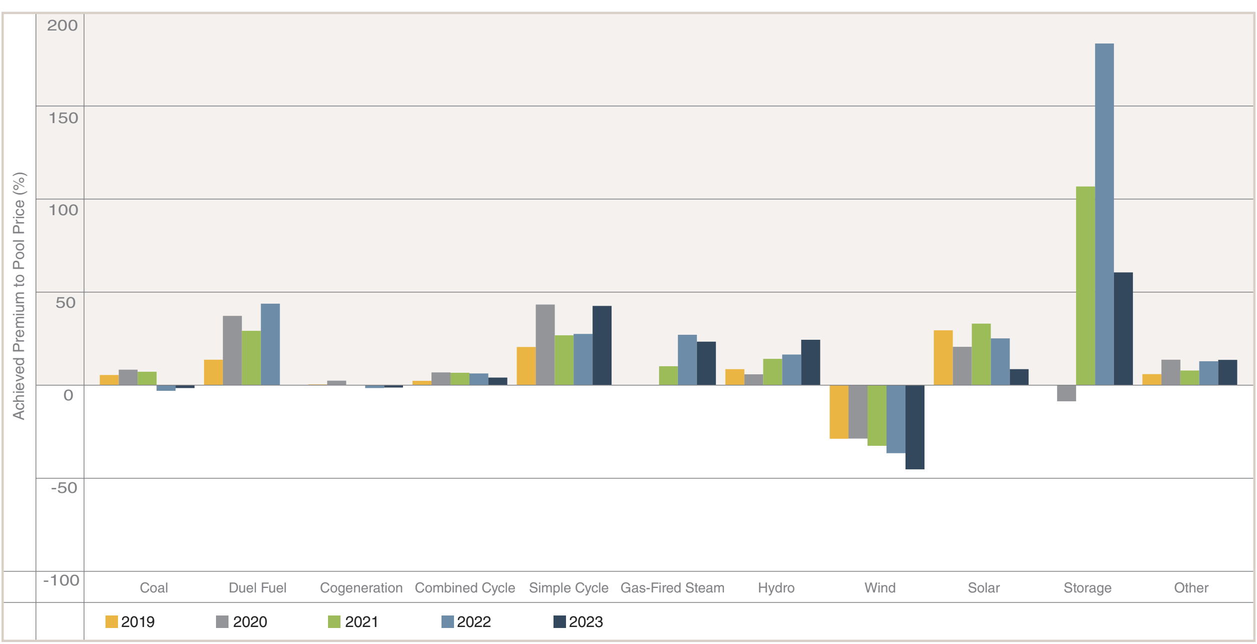


Figure 21 illustrates the achieved premium-to-pool price realized by each generation technology over the past five years. The achieved premium-to-pool price is calculated as the ratio of the achieved margin to the average pool price for each year. An achieved premium of zero indicates that the achieved 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 21: Annual achieved premium-to-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, such as coal and cogeneration, realize achieved premiums near zero. Generation technologies that operate primarily in higher-priced hours—for example, simple-cycle or storage—realize positive achieved premiums-to-pool price, while those that tend to operate in lower-priced hours, such as wind, realize achieved discounts- (or negative achieved premiums) to-pool price. Since the generation of a wind asset tends to be correlated with the generation of other wind assets, the increased supply when wind assets are generating results in reduced prices. A similar effect applies to solar assets, though to a lesser extent due to the smaller size of the solar fleet.

Optimally, baseload generation technologies operate constantly 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 2023, cogeneration and coal-fired technologies realized one and two-per cent deficits to pool price, respectively, as their energy was offered as baseload. Combined-cycle realized a four per cent premium-to-pool price. A majority of energy for this type of unit is economic at low prices, while a smaller portion requires higher prices to be economic. Dual-fuel generation ran as baseload in 2023 and achieved a zero percent premium.

Peaking-generation technologies achieve greater operational flexibility than baseload generation. The combustion turbines used in simple-cycle or gas-fire steam 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 in fewer hours than baseload generation but achieves a higher average price. Typically, simple-cycle gas and gas-fired steam generation achieve some of the highest premiums across all generation technologies in Alberta. In 2023, simple-cycle units received a 42 per cent premium-to-pool price, while gas-fired steam achieved a 23 per cent premium. Battery storage units run in even fewer hours than simple-cycle units. Since they are much more selective of the hours they provide energy, they obtain a higher premium. In 2023, storage units achieved a 59 per cent premium-to-pool price.

Wind generation is the only technology that consistently received a discount-to-pool price over the past five years; 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, as the output of wind power varies according to environmental conditions. In addition, the strongest winds typically occur in the overnight hours, leading to the highest wind production occurring during the lowest-priced hours.

When wind blows in a particular 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, it replaces some quantity of power from higher-priced generating units in the energy market merit order, and thus tends to reduce the system marginal price. This, in turn, lowers its achieved price. As the total amount of wind capacity has increased over the past three years, this effect has grown increasingly strong. In 2023, wind generation received a 44 per cent discount-to-the-pool price.

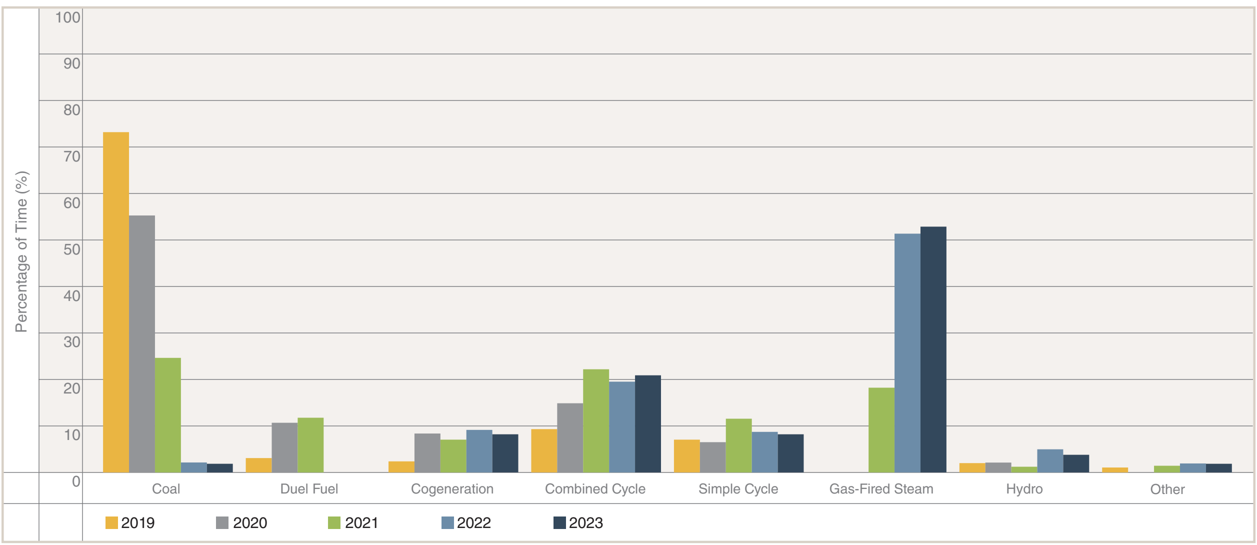
Solar power is like wind power in that the timing of generation is dependent on environmental conditions. The generation of solar assets is also typically correlated. However, since the highest-priced hours are typically during on-peak hours when the sun is shining, solar power tends to receive an achieved price premium. This premium has declined as more solar generation has come online, lowering the pool price in the sunniest hours. In 2023, the premium was eight per cent, down from 25 per cent in 2022.

Hydro units have a mix of offering strategies. Many hydro units are run-of-river and provide generation regardless of the pool price. Other units have a reservoir, allowing some generation to be timed with higher-priced hours. Additionally, environmental conditions, such as spring runoff or low water, may impact the amount of generation at hydro units. In 2023, hydro received a 24 per cent premium-to-pool price.

Gas-fired steam generation set marginal price in 54 per cent of hours

Figure 22 illustrates how frequently each generation technology set the system marginal price in each of the last five years. In 2023, pure gas-fired generation, which includes combined-cycle, cogeneration, simple-cycle, and gas-fired steam, was on the margin 92 per cent of the time, compared to only 19 per cent in 2019. Coal generation, including dual fuel, was only on the margin two per cent of the time in 2023. In 2019, it was on the margin 78 per cent of the time. The decline in coal-fired generation on the margin in 2023 is due to the remaining coal units being primarily price-takers. The specific gas generation technology that was on the margin the most was gas-fired steam, at 54 per cent of 2023 hours.

FIGURE 22: Annual marginal price-setting technology



Supply Adequacy

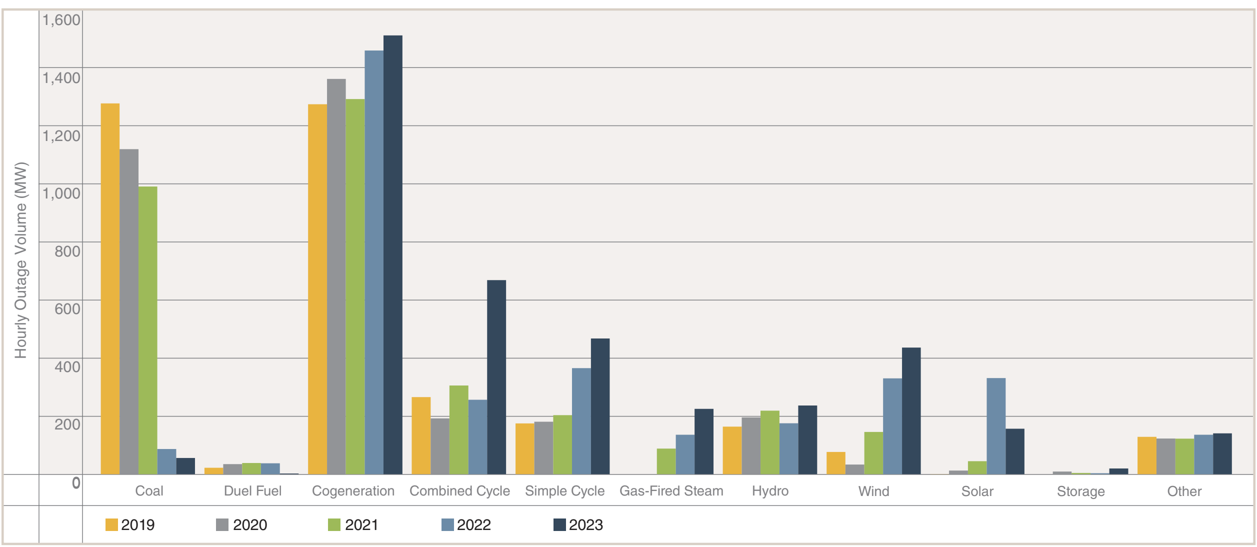
Supply adequacy expresses the ability of the system to serve load and system losses. In general, supply adequacy increases as generation capability increases, and decreases as system load increases. This report evaluates supply adequacy using two common measures: supply cushion and reserve margin. An in-depth analysis of future supply adequacy is provided on the AESO website in the quarterly Long-Term Adequacy Metrics report.[9]

Generation outages were 18 per cent higher due to commissioning

The volume of generation outages is a primary driver of the supply cushion, as outages reduce the amount of supply available. Outages are either planned, such as for maintenance, or they can be unexpected, such as a tube leak that forces a generator offline. The volume of an outage is the result of subtracting a unit's available capacity from its maximum capacity available to the bulk transmission system. Assets that are completely BTF at a self-supplied site, and do not offer into the electricity market, are not included in the calculation.

For the purposes of this calculation, mothballed units are considered on outage. Two units, Sundance 3 and 5, were mothballed in April 2018. This added 368 MW and 406 MW, respectively, to the coal outage totals, until Sundance 3 retired in 2020 and Sundance 5 retired in 2021. Figure 23 shows the average hourly outage volume by technology for the past five years.

FIGURE 23: Annual hourly average generation outages by fuel type

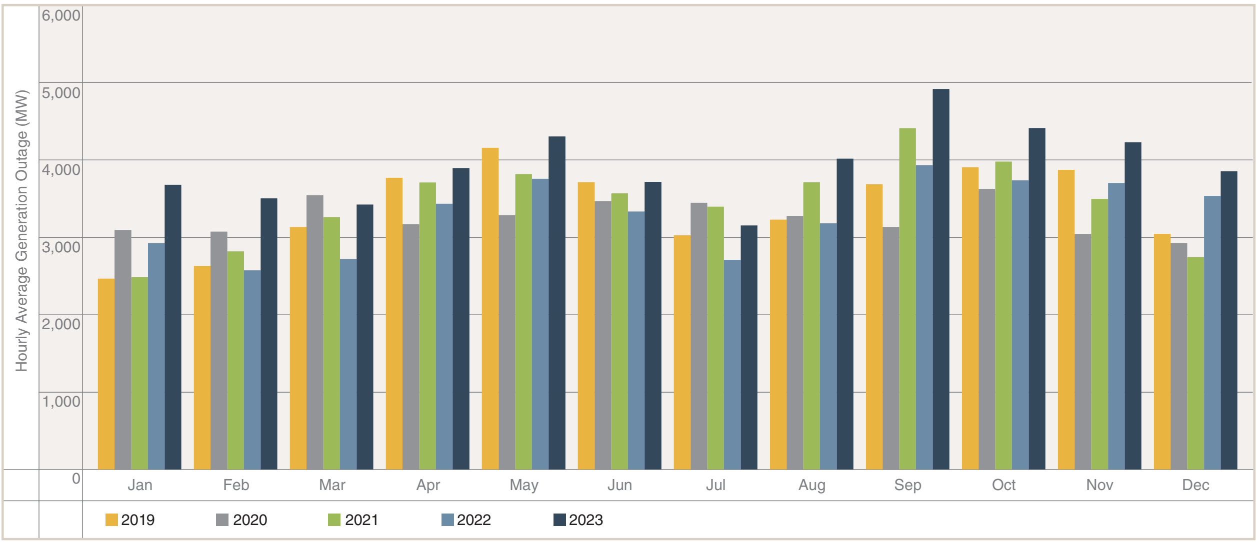


In 2023, the overall average hourly outage volume increased by just over 600 MW, or 18 per cent, compared to 2022. In the outage calculation, assets that have energized their connection to the grid, but have not completed their commissioning, are still considered online. If the asset is not generating power because it is not fully commissioned, that capacity is still counted as an outage. The overall increase in outages in 2023 was largely due to commissioning-related outages from the newly added Cascade combined-cycle facility and new wind units, rather than actual maintenance or unexpected outages.

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

Expected generation outages are usually seasonal. The highest outages typically occur during the shoulder period from mid-April to mid-June and late-September to early-November. This is usually when load is the lowest and any outages have the least impact. In 2023, the connection of new capacity to the grid that was not yet generating increased the calculated outages from August to December. Figure 24 shows the hourly average generation outage volume by month for the past five years.

FIGURE 24: Generation outages by month



Supply cushion increased by 2 per cent

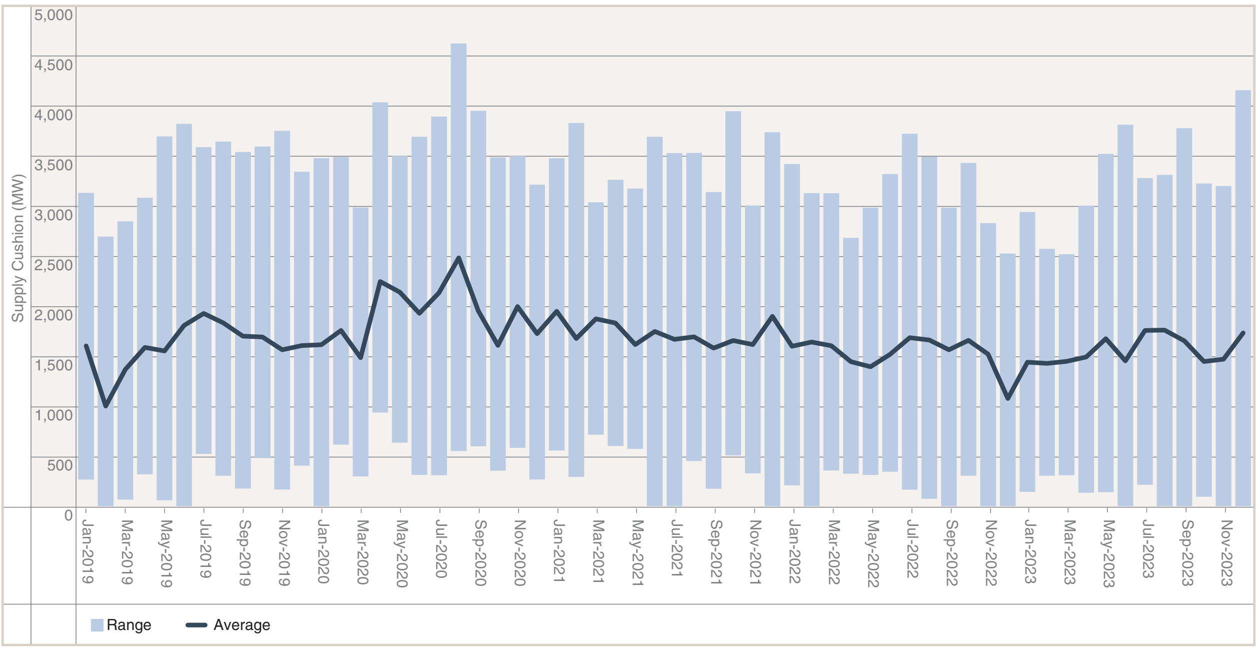
The hourly supply cushion represents the additional energy in the merit order that remains available for dispatch after load is served. Large supply cushions indicate greater reliability because more energy remains available to respond to unplanned outages or unexpected increases in demand. In 2023, the average supply cushion increased 34 MW (2.3 per cent) from its 2022 value to 1,565 MW. The more comfortable average supply cushion was the result of lower average demand in 2023 compared to 2022 and the addition of new wind and solar generation capacity. In December 2023, with above-average temperatures resulting in reduced load, the average supply cushion was over 650 MW larger than in the frigid December 2022.

Supply shortfall conditions arise when the supply cushion is zero. At that point, 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 a Grid Alert if it is unable to meet minimum contingency reserve requirements as some or all of the needed reserve capacity is used to serve load instead.

In 2023, Grid Alerts were declared three times: once in June and twice in August. Despite Alberta being a winter-peaking region for electricity usage, amid the relatively warm weather in the winter months in early and late 2023, the AESO faced no cold-weather Grid Alerts in 2023. The contributing factors to the Grid Alert events in June and August 2023 included thermal generation outages and derates plus limited import capacity. During the August events, intertie maintenance reduced imports from B.C. and Montana to near zero. In addition, the supply challenges during these events coincided with above-average demand due to high temperatures and low wind generation. No load shedding was required during any of the three events.

Figure 25 shows the monthly average of the supply cushion over the past five years. It also has the range of the supply cushion throughout each month.

FIGURE 25: Monthly supply cushion

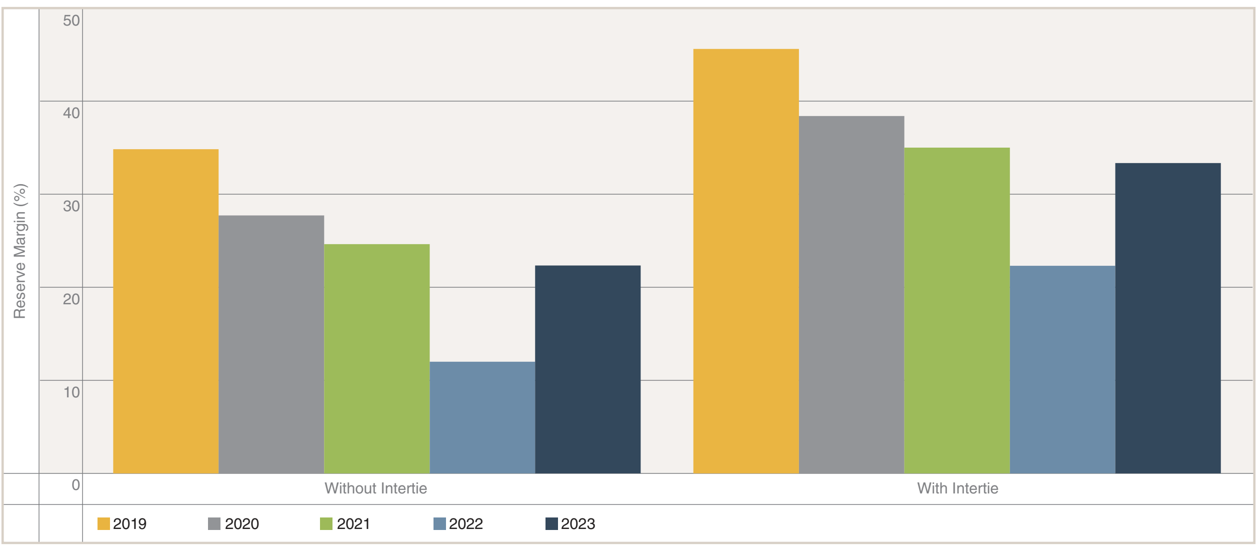


Reserve margin increased by 10 percentage points

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 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 installed capacity volumes at the end of the year. For 2023, Cascade 1 and 2 have been excluded from the calculation of the reserve margin as those units were still commissioning and not yet producing electricity at the end of 2023.

Figure 26 shows the annual reserve margin over the past five years. In 2023, the annual reserve margin was 22 per cent without the intertie and 32 per cent with the intertie. Both metrics were up by over 10 percentage points compared to 2022. The year-over-year increase in the reserve margin was primarily due to the fact that peak load happened to be 621 MW lower in 2023 than in 2022. Over eight percentage points of the increase can be attributed to the smaller peak load used in the calculation. The remainder of the increase came from a small 158 MW increase in dispatchable generation (including 120 MW of battery storage).

FIGURE 26: Annual reserve margin



Wind Generation

Wind generation served 12 per cent of Alberta Internal Load

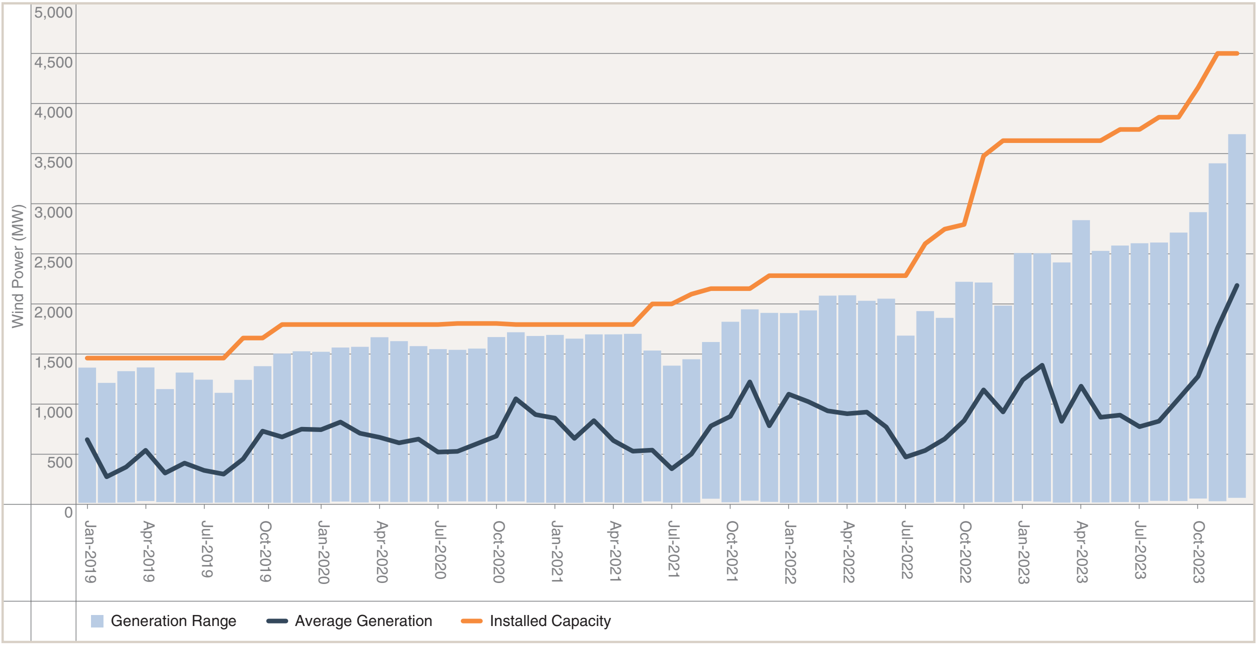
Wind generation has been one of the fuel types with the most rapid increase in new generation capacity over the past three years. Table 4 summarizes the annual statistics for wind generation over the past five years and shows this rapid change. A total of nine new wind facilities, with a combined capacity of 863 MW, came online in 2023. This increased the total capacity for wind to 4,481 MW at the end of the year. Over the past three years, wind capacity has increased more than 150 per cent. At the end of 2023, wind capacity represented almost 22 per cent of the total installed generation capacity in Alberta. Wind generation produced over 12 per cent of total AIL in 2023, up from eight per cent in 2022. The capacity factor of wind generation fell to 30 per cent, down from 33 per cent in 2022, primarily due to many units that connected to the grid but did not immediately start generating.

TABLE 4: Annual wind generation statistics

	2019	2020	2021	2022	2023
Installed wind capacity at year end (MW)	1,781	1,781	2,269	3,618	4,481
Total wind generation (GWh)	4,116	6,079	6,133	7,314	10,283
Wind generation as a percentage of total AIL	5%	7%	7%	8%	12%
Average hourly capacity factor	30%	39%	36%	33%	30%
Maximum hourly capacity factor	94%	96%	95%	91%	82%
Wind capacity factor during annual peak AIL	0%	8%	16%	17%	18%

Figure 27 shows the installed wind generation capacity and range of hourly wind generation over each month. As can be seen by the increase in capacity, a significant number of new wind projects connected in the second half of 2022, and again in late 2023. Prior to these new connections, the maximum generation, represented by the top of the blue bars, was roughly 85 to 90 per cent of installed capacity. From July 2022 to October 2023, this ratio was usually in the 65 to 70 per cent range. This was due to new wind generation capacity taking time to finish commissioning. Based on the observed maximum generation levels, the effective capacity of wind through October was roughly 2,650 MW. But in November, actual generation, relative to capacity, began to increase. By December, the maximum output to capacity ratio was back up to 82 per cent. A new record for wind generation was set on December 26, 2023, at 3,672 MW, and the record for monthly average generation was set at 2,172 MW.

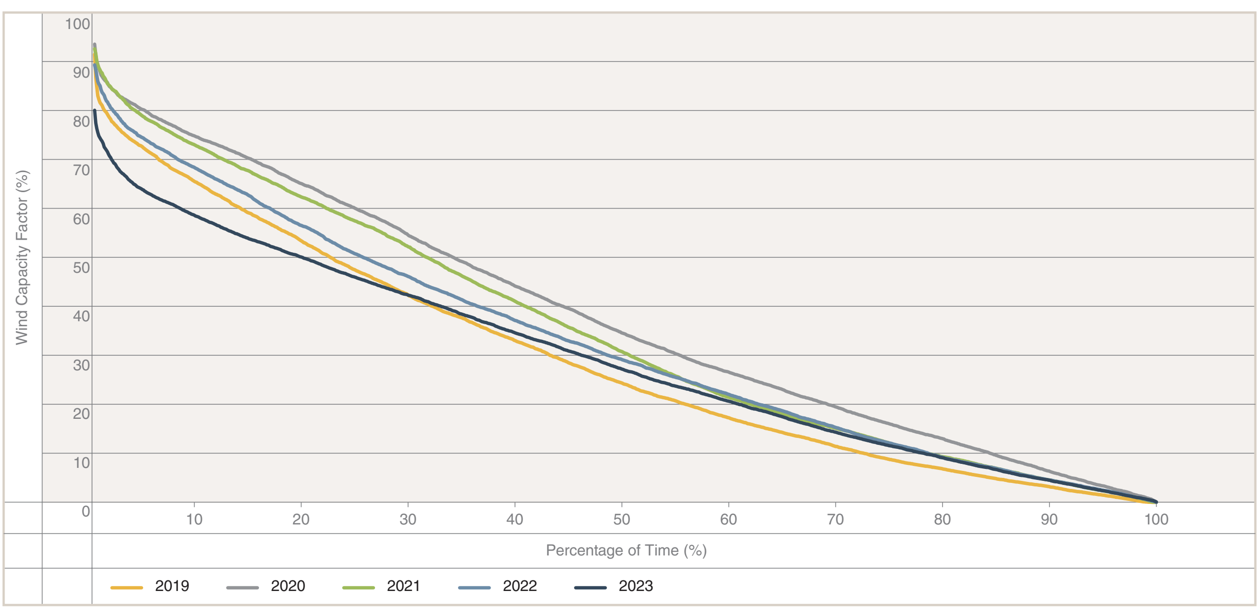
FIGURE 27: Monthly average wind capacity and generation



Wind capacity factor decreased due to commissioning activities

Figure 28 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 represents the percentage of time that the capacity factor of wind generation equals or exceeds a specific value.

FIGURE 28: Annual wind capacity factor duration curves

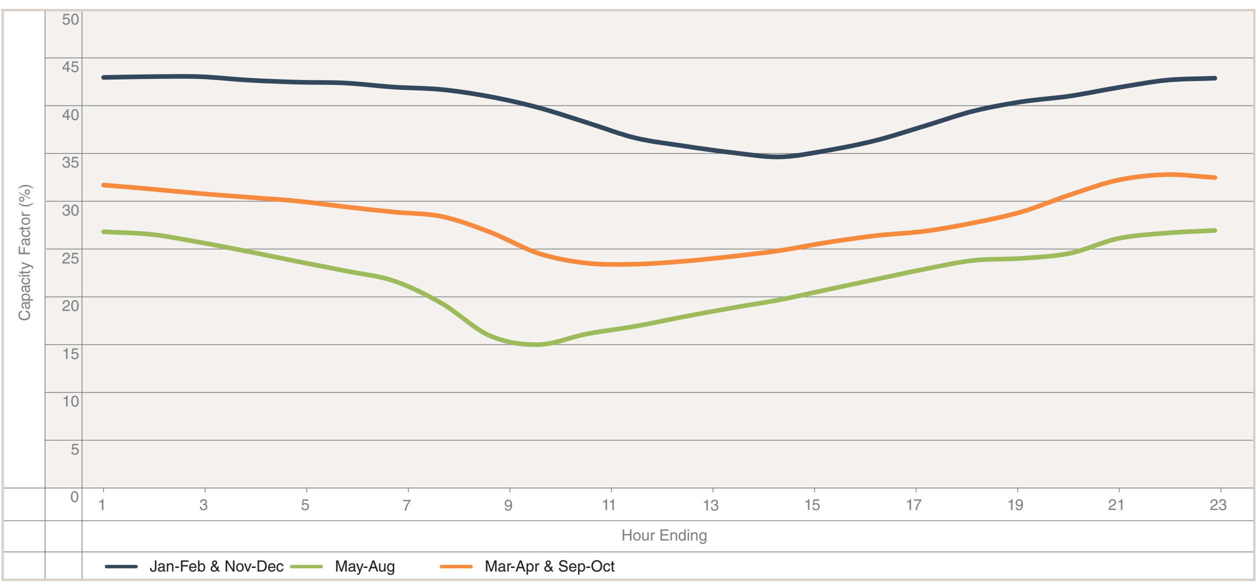


The duration curve for the capacity factor of wind generation decreased again in 2023, averaging 30 per cent compared to 33 per cent in 2022. A key reason for the lower capacity factor can be attributed to minimal output from the new wind farms for several months after they were declared in-service. Combined, the new projects that came online in late 2022 and 2023 had an average capacity factor of just under 25 per cent and an average availability factor of 73 per cent. Collectively, these new assets have a combined capacity of just over 1,700 MW.

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. In addition, wind generation usually exhibits a seasonal pattern, peaking in winter and falling in summer. The maximum hourly wind generation exhibits a weaker seasonal pattern. Strong winds may occur in any month, though they occur more frequently in winter. During extreme weather events, such as a polar vortex in the winter or a heat wave in the summer, wind generation tends to be very weak. This is due to the presence of strong high-pressure weather systems in the wind-generating regions of the province. This results in lower capacity factors during peak-demand periods. Because wind is not dispatchable and, instead, is dependent on environmental conditions, it is excluded from long-term reserve margin forecasts.

Figure 29 shows the average hourly capacity factor of wind generation for different seasons of the year during 2023. It shows that wind generation is typically highest in the overnight hours and lowest during the middle of the day, with this phenomenon more pronounced in the summer than the winter. The capacity factor of wind ranged from 16 to 25 per cent higher in the winter than the summer, although part of this discrepancy is due to the previously mentioned timing of commissioning.

FIGURE 29: Wind generation seasonal average hourly output (2023)



Regional wind

Wind generation in the province was located exclusively in southern Alberta until early 2011. Since 2011, the addition of wind facilities in central Alberta has increased the geographic diversification of wind generation. In 2023, there were two new facilities connected in central Alberta, bringing the total to 10. At the end of 2023, wind generation capacity totaled 3,147 MW in southern Alberta and 1,334 MW in central Alberta.

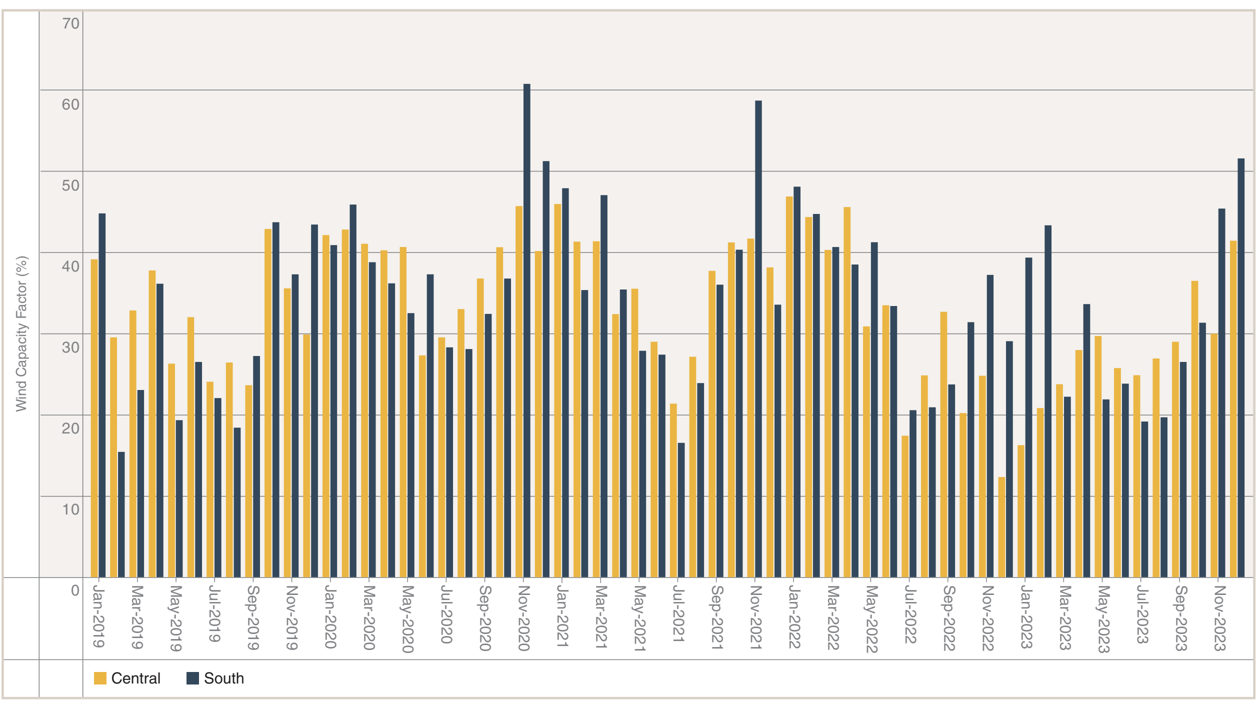
Table 5 shows regional wind generation statistics for 2023. The average capacity factor was lower for assets in the Central region, but the achieved price for their output was higher. Wind facilities in the Central region tended to earn more per megawatt of capacity than those in the South region.

TABLE 5: Regional wind statistics (2023)

	Central	South	Total
Installed wind capacity at year end (MW)	1,334	3,147	**4,481**
Total wind generation (GWh)	2,289	7,995	**10,283**
Average wind capacity factor	27.7%	31.3%	**30.5%**
Achieved price ($/MWh)	$82.07	$72.39	**$74.54**

Figure 30 shows the monthly average capacity factor by region in the past five years. The capacity factors in November and December 2023 are lower in the Central region due to the addition of new capacity that took some time to commission. As can be seen in the monthly profiles, wind tends to be most productive from October through April and least productive in the summer months.

FIGURE 30: Monthly wind capacity factor by region



Solar Generation

Solar generation served 3 per cent of Alberta Internal Load

Solar generation capacity is the other fuel type that saw a rapid increase in new generation capacity over the past three years. Table 6 summarizes the annual statistics for solar generation over the past five years. A total of 14 new solar facilities, with a combined capacity of 512 MW, came online in 2023. This increased the total capacity for solar to 1,650 MW at the end of the year. Since 2021, solar capacity has more than doubled. At the end of 2023, solar capacity represented almost eight per cent of the total installed generation capacity in Alberta. During the year, solar produced roughly three per cent of total AIL, up from one per cent in 2022. The capacity factor of solar increased to 21 per cent, up from 14 per cent in 2022. This was due to a combination of units that came on in 2021 and 2022 getting to full capacity and the fact that many assets connected late in 2023, so the impacts of their commissioning on the capacity factor were relatively small. This data does not include the roughly 200 MW of solar generation that has been installed under the *Micro-generation Regulation*.[10] These micro-generation sites, which includes rooftop solar, are installed on distribution systems and do not provide actual generation values to the AESO. More details on micro-generation assets can be found at the Micro- and Small Distributed Generation Reporting webpage.[11]

TABLE 6: Annual solar generation statistics

	2019	2020	2021	2022	2023
Installed solar capacity at year end (MW)	15	107	736	1,138	1,650
Total solar generation (GWh)	20	86	477	1,164	2,311
Solar generation as a percentage of total AIL	0%	0%	1%	1%	3%
Average hourly capacity factor	15%	12%	18%	14%	21%
Maximum hourly capacity factor	100%	93%	98%	78%	93%
Solar capacity factor during annual peak AIL	0%	0%	0%	0%	1%

During 2023, 14 new solar farms joined the generation fleet, adding 512 MW of new capacity. The new assets were added throughout the year and took varying amounts of time to begin generating electricity. Like the wind assets, it can take up to a couple of months after the transmission connection being declared active before there is any consistent output from new solar assets. The highest hourly generation for solar occurred on September 10, 2023, at 1,162 MW.

Figure 31 illustrates the monthly average generation of the solar fleet for the past five years. Overnight hours, when the sun is down and solar generation is not possible, have been excluded from these calculations. In the chart, one can see the rapid increase in capacity at the end 2021, with the addition of the Travers Solar Project. Throughout 2022, actual generation did not reflect the capacity level due to commissioning activities. During the summer of 2022, effective capacity, represented by the maximum generation level (i.e., the top of the blue bars in the below chart), was just over 700 MW versus an average installed capacity of 1,000 MW. It was not until March 2023 that the generation installed in 2022 was able to generate near actual capacity levels. During the summer of 2023, effective capacity was roughly 1,100 MW versus an average installed capacity of 1,280 MW. In Q4 2023, roughly another 350 MW of capacity was connected and is not expected to get to full capacity until early 2024.

[10] https://www.alberta.ca/micro-generation.

[11] https://www.aeso.ca/market/market-and-system-reporting/micro-and-small-distributed-generation-reporting/.

FIGURE 31: Monthly average on-peak solar capacity and generation

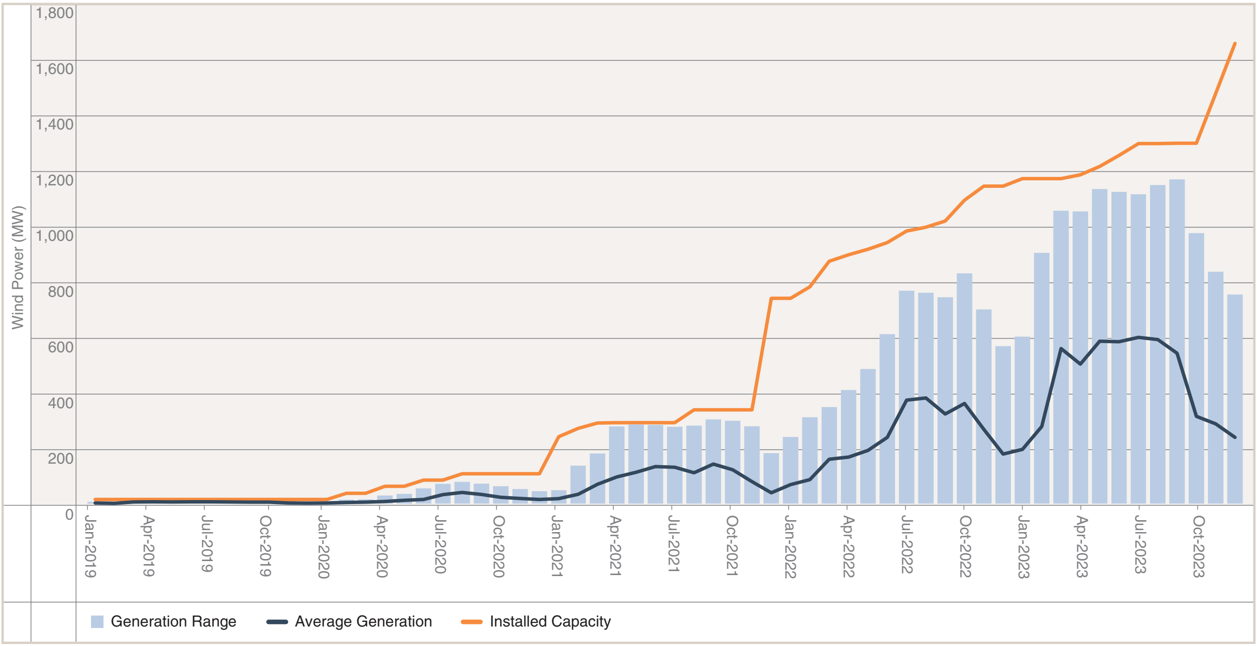
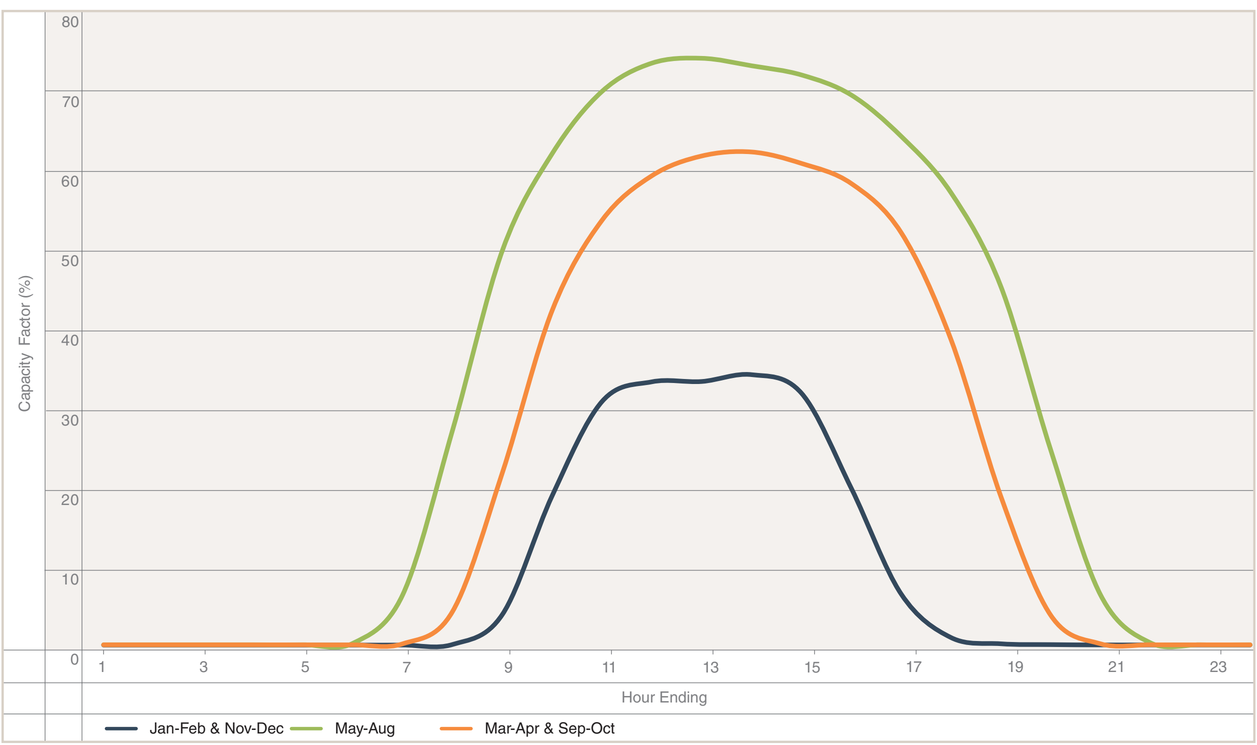


Figure 32 shows the average hourly output of solar generation for different periods of the year during 2023. Peak generation occurs between 10 a.m. to 3 p.m., with the summer and shoulder months seeing a couple of extra hours of peak generation in the morning and early evening. The average capacity factors are lower than normal due to assets connecting to the grid but not being able to generate immediately.

FIGURE 32: Seasonal average hourly output of solar fleet (2023)



Imports and Exports

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

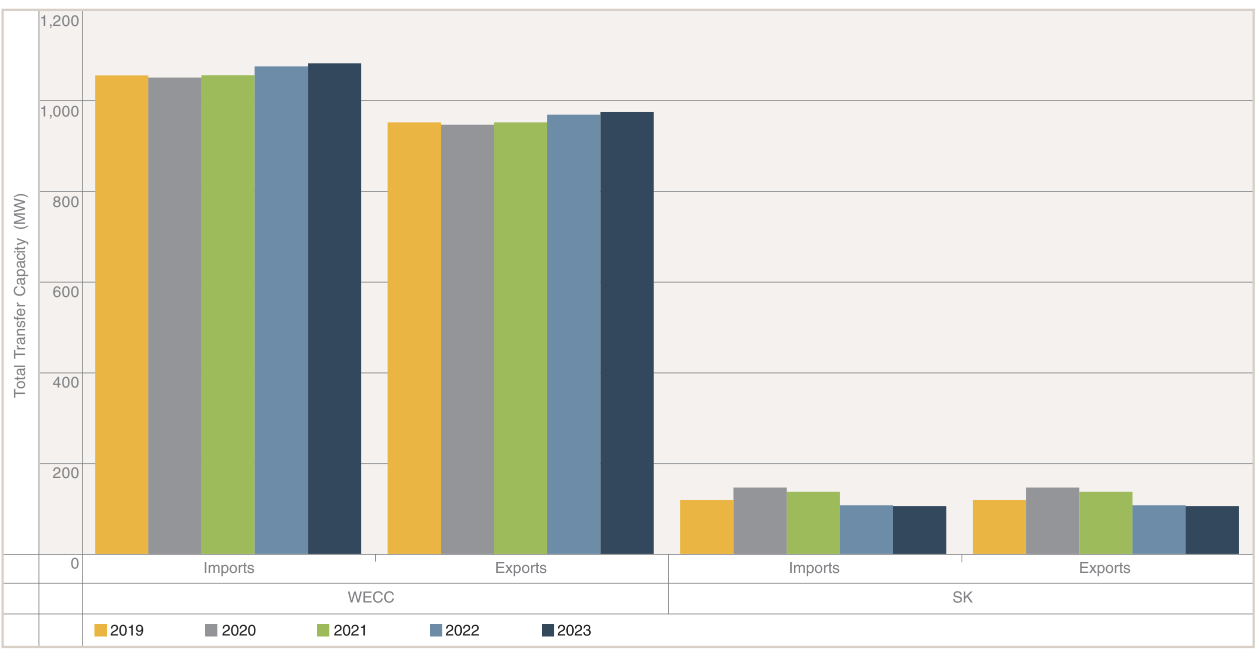
Transfer path rating remained stable

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 duration of outages that occur.

Alberta, B.C., and Montana are members of the Western Electricity Coordinating Council (WECC) region while Saskatchewan is part of the Midwest Reliability Organization (MRO) region. 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 that connect Alberta to B.C. and Montana.

Figure 33 shows the average TTC in each year between Alberta and other WECC members, and between Alberta and Saskatchewan. The TTC rating for WECC members increased by one per cent, while the Saskatchewan TTC decreased by two per cent relative to 2022. Outages that left the Saskatchewan intertie partially derated for significant periods of both 2022 and 2023 meant that average TTC in 2023 was similar to 2022, but 23 per cent lower than in 2021.

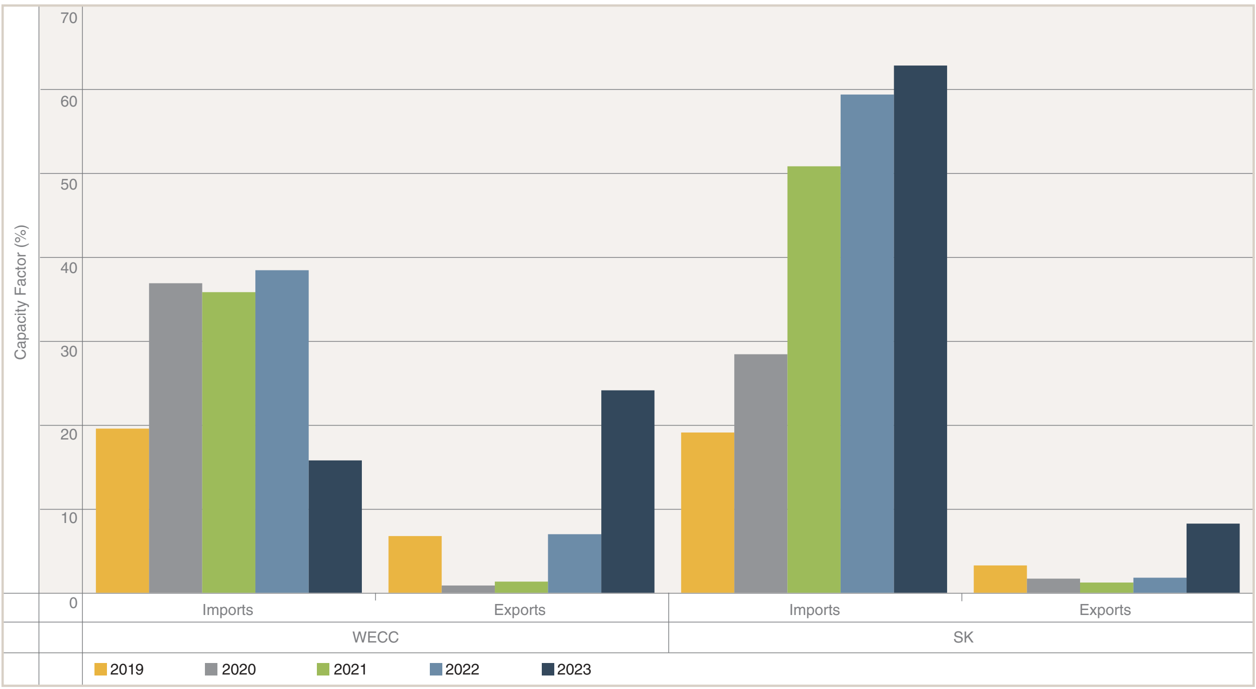
FIGURE 33: Average annual path rating by transfer path



Capacity factors for exports increased

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. Figure 34 shows the annual capacity factor for transfers between Alberta and other WECC members, and between Alberta and Saskatchewan. The capacity factor is affected by market conditions between jurisdictions that affect offers for imports and exports as well as the availability factor of the intertie, which may restrict import or export offers (as described in the next section).

FIGURE 34: Annual capacity factor by transfer path



The capacity factor for imports from WECC decreased to 16 per cent in 2023 from 38 per cent in 2022, while the capacity factor for WECC exports rose to 24 per cent from seven per cent. Dry conditions resulted in lower hydro output in B.C. and affected the shift towards WECC exports rather than imports. Lower availability for WECC imports, as described in the next section, also affected the WECC imports capacity factor.

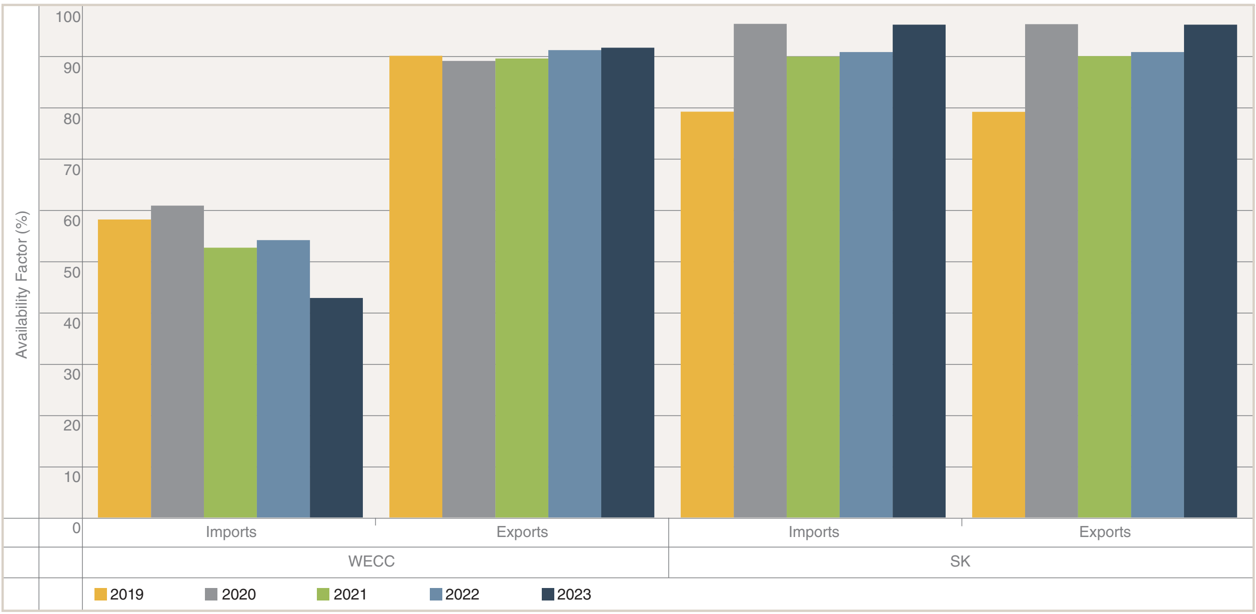
Capacity factors for both imports and exports on the Saskatchewan intertie increased slightly, thanks to fewer full intertie outages in 2023 compared to 2022. The capacity factor for imports from Saskatchewan increased to 63 per cent in 2023 from 59 per cent in 2022, while the export capacity factor for Saskatchewan increased to eight per cent in 2023 from two per cent in 2022.

Availability factor for WECC imports decreased by 9 percentage points

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 ATC limits imports and exports on an individual transfer path to reflect operational conditions and maintain the transmission reliability margin (TRM). The system operating limit specifies the maximum import and export capability between Alberta and all neighbouring jurisdictions. A combined operating limit on the B.C. and Montana interties further restricts the transfer capability of total energy transfers between Alberta and other WECC members.

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 35 illustrates the annual availability factor for transfers between Alberta and other regions. In 2023, the WECC transfer path had a reduced import availability factor compared to 2022 primarily due to updated reliability requirements in Alberta that increased the volume of Load Shed Service for imports (LSSi) needed.[12] The availability factor for WECC imports decreased from 54 per cent in 2022 to 43 per cent in 2023.

FIGURE 35: Annual availability factor by transfer path



Fewer full outages on the Saskatchewan intertie increased its availability factor in both directions from 91 per cent in 2022 to 96 per cent in 2023.

Availability utilization

Availability utilization is the percentage of ATC used to transfer energy between jurisdictions. Availability utilization is calculated as the ratio of transferred energy to the ATC of the transfer path. Figure 36 illustrates the annual availability utilization for energy transfers between Alberta and other WECC members, and between Alberta and Saskatchewan.

In 2023, imports to Alberta from WECC decreased significantly while exports increased. Drought conditions in British Columbia and the Pacific Northwest which limited hydro generation was the primary reason for this change in dynamics, while an increase in Alberta's renewables generation and lower average prices also contributed to the shift from imports towards exports. WECC import utilization fell from 68 per cent in 2022 to 39 per cent in 2023, despite the lower ATC in 2023. WECC export utilization, on the other hand, increased to 26 per cent from seven per cent.

[12] Load Shed Service for imports (LSSi) is a transmission system reliability product. See https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/ for details.

FIGURE 36: Annual availability utilization by transfer path

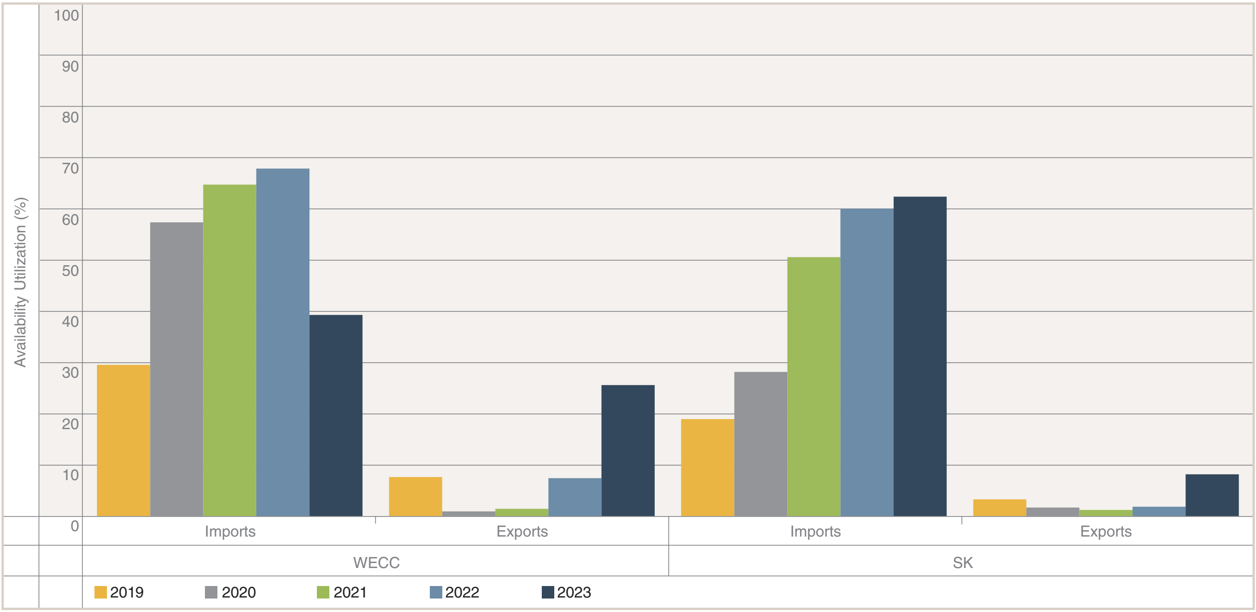
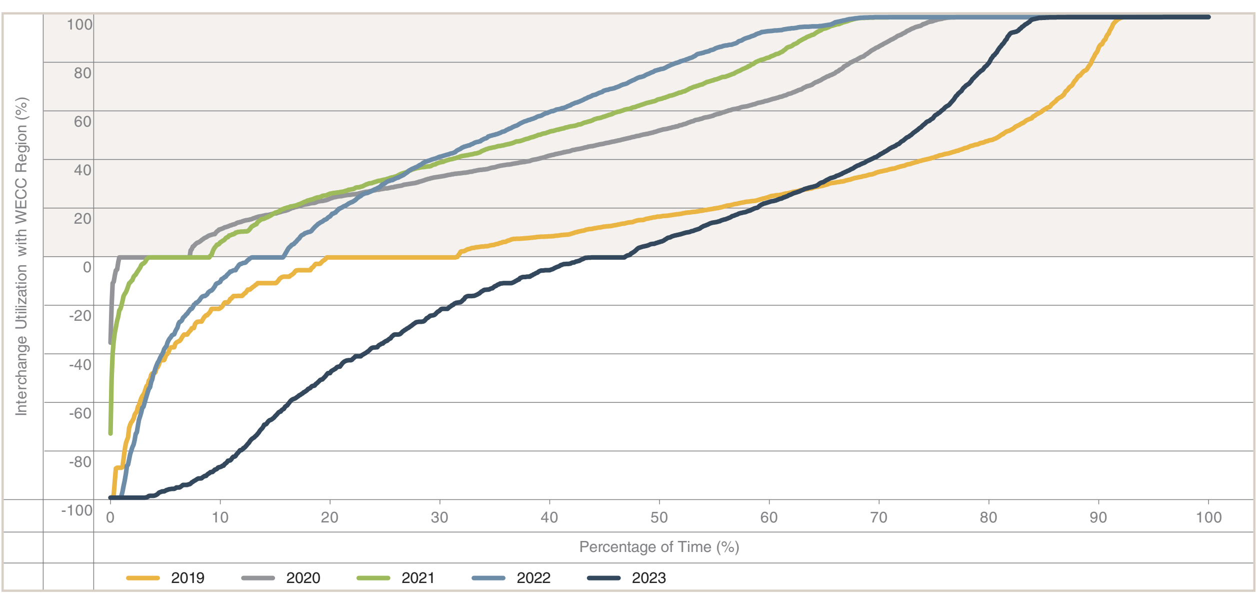


Figure 37 shows the annual interchange utilization between Alberta and the WECC regions over the past five years. In this chart, the interchange utilization represents the ratio of net imports or exports to the intertie's ATC. Imports include any volume of operating reserve procured on the intertie. The utilization calculation reflects the combined operating limit of the B.C. and Montana interties and the Alberta system operating limit. In 2023, Alberta had net imports from the WECC region in approximately 53 per cent of the hours, a significant change from 85 per cent of the hours in 2022. Alberta was a net exporter in 44 per cent of the hours in 2023, up from 13 per cent in 2022. Alberta was exporting to the WECC region at within one per cent of maximum availability for four per cent of the hours in 2023 and importing from the WECC region within one per cent of maximum availability for 16 per cent of the hours.

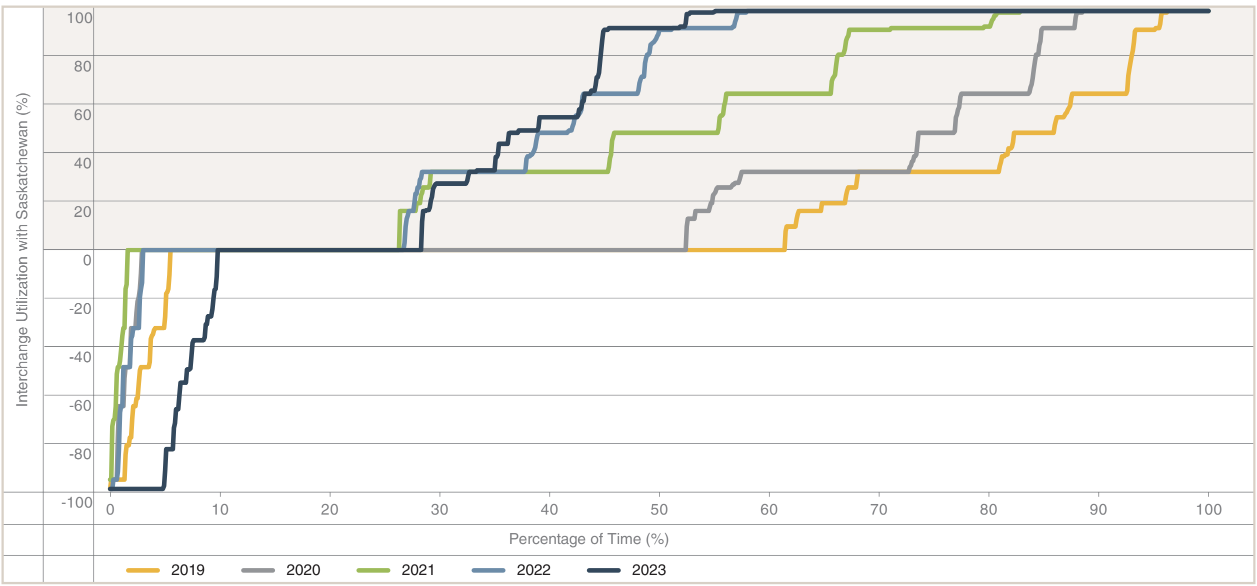
FIGURE 37: Annual interchange utilization with WECC region



Availability utilization increased in both directions on the Saskatchewan intertie. Import utilization increased from 60 per cent in 2022 to 63 per cent in 2023, while export utilization increased from two per cent in 2022 to eight per cent in 2023. Fewer maintenance outages on the intertie increased the utilization in both directions, while a higher frequency of low-priced hours in Alberta in 2023 resulted in higher exports to Saskatchewan.

Figure 38 shows the annual interchange utilization between Alberta and Saskatchewan over the past five years. In 2023, Alberta imported energy from Saskatchewan in 72 per cent of the hours and exported energy in just under 10 per cent of the hours. Alberta was exporting to Saskatchewan at within one per cent of maximum availability for just under five per cent of the hours in 2023 and importing from Saskatchewan within one per cent of maximum availability for over 47 per cent of the hours.

FIGURE 38: Annual interchange utilization with Saskatchewan



Total imports and exports roughly equal in 2023

Figure 39 illustrates the annual average energy transferred from each province or state. Alberta has been a net importer since 2017, but in 2023, average total imports exceeded average total exports by less than one MW. Alberta was a net importer on the Saskatchewan and Montana interties, as usual, but in 2023 these imports were offset by exports over the B.C. intertie. Imports from B.C. decreased from an average of 282 MW in 2022 to 83 MW in 2023, while exports increased from 54 MW in 2022 to 224 MW in 2023.

FIGURE 39: Annual intertie transfers by province or state

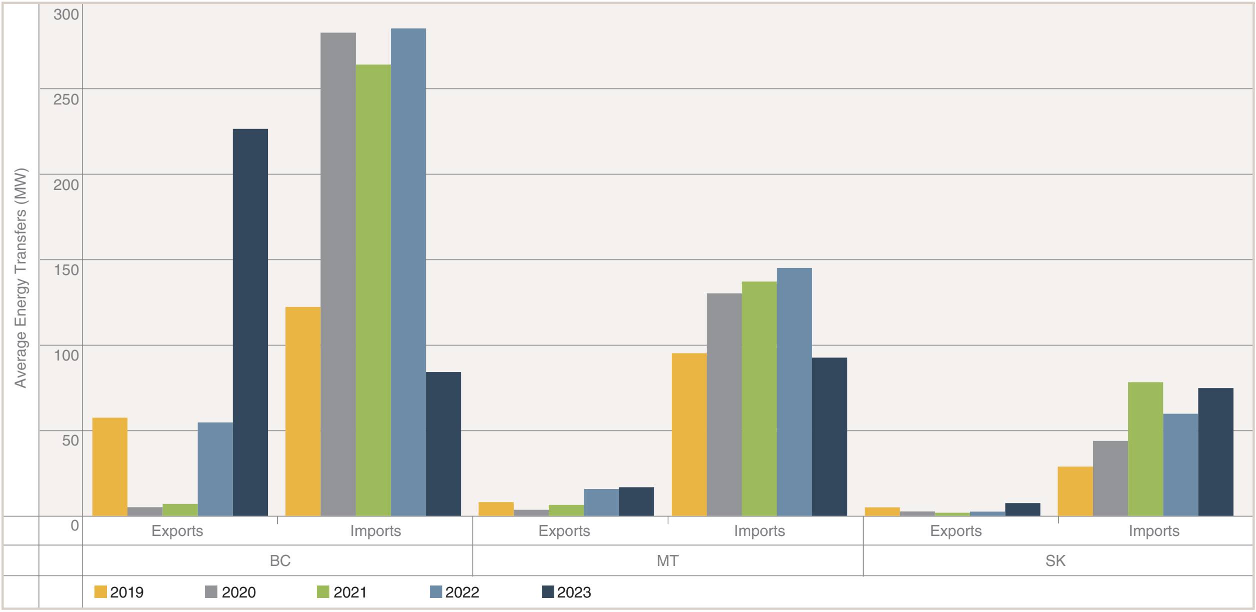
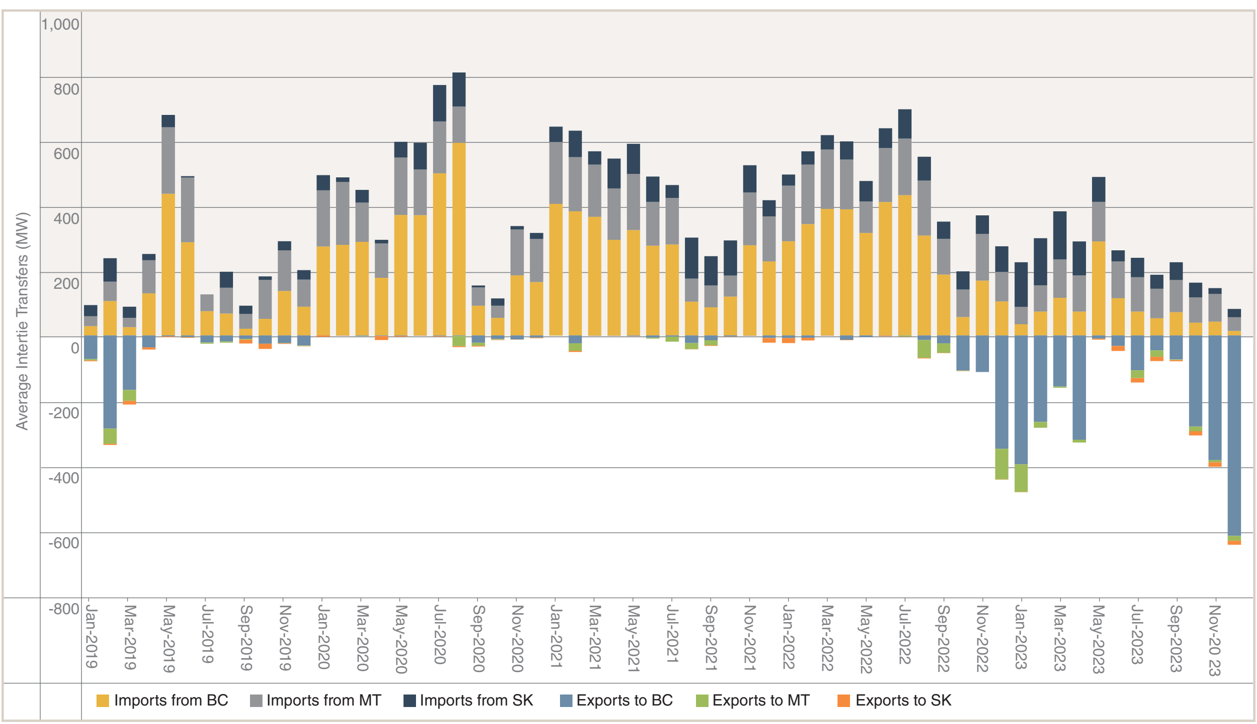


Figure 40 illustrates the monthly average energy transferred from each province or state. Positive values represent imports to the province and negative values represent exports to other jurisdictions. Dry conditions in B.C., particularly in the winter months at the beginning and end of 2023, led to reduced hydro generation and a shift towards exports to B.C. rather than imports.

FIGURE 40: Monthly average intertie transfers

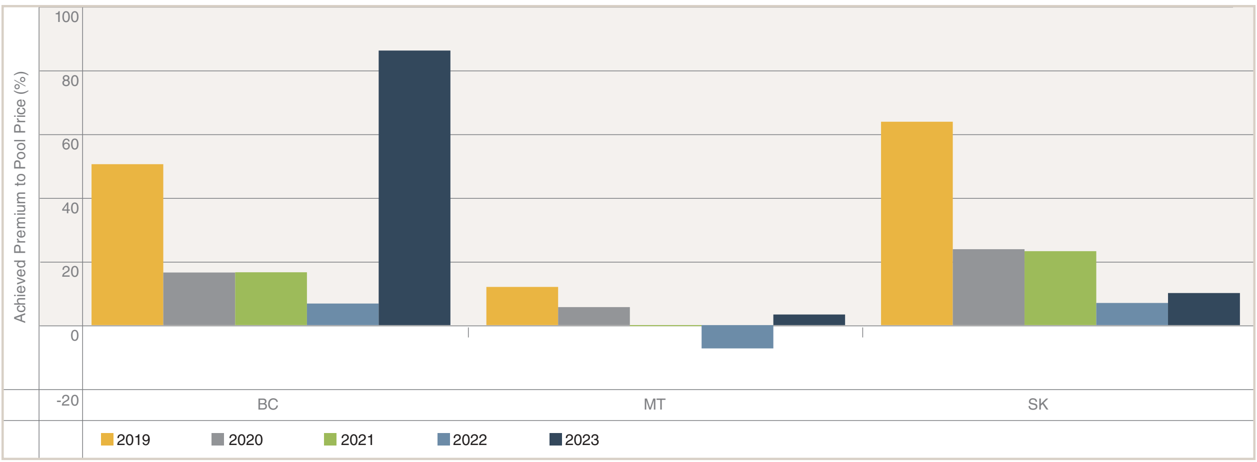


Imports from B.C. stood out in May 2023, averaging at 289 MW, as an early spring runoff led to increased hydro generation. However, imports from B.C. only exceeded exports from B.C. in the months of May, June and August, with Alberta being a net exporter to B.C. in all other months. Exports to B.C. were the largest in December 2023, reaching an average of 616 MW.

Achieved premium-to-pool price on imports from B.C. surged to 86 per cent

Figure 41 illustrates the achieved premium-to-pool price on imported energy by province or state. This measure compares the average cost of imported energy versus the yearly average pool price. Imported energy exerts downward pressure on the 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.

FIGURE 41: Annual achieved premium to pool price on imported energy



Imports from B.C. were much lower in 2023 compared to 2022, as the drought conditions in B.C. and the Pacific Northwest increased the value of exporting to B.C. instead of importing. The result was that when imports did occur in 2023, it was typically during hours of relatively high prices. Thus, imports from B.C. achieved a premium of 86 per cent over the average pool price in 2023, compared to a seven-per-cent premium in 2022.

Imports from Montana received a relatively small premium to the pool price of three per cent in 2023, after receiving a discount of seven per cent in 2022. Montana is impacted by a correlation to the wind profile in the southern region of Alberta. Since most power imports from Montana are wind-generated, strong imports from that jurisdiction tend to coincide with periods of higher wind generation in Alberta, which keeps the premium for Montana imports low.

Imports from Saskatchewan received a 10 per cent premium over the pool price, slightly higher than the seven per cent premium received in 2022.

Ancillary Services

Cost of operating reserve decreased

Operating reserve (OR) is 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. OR is separated into two products: regulating reserve and contingency reserve (CR). Regulating reserve uses automatic generation control to match supply and demand in real time. CR maintains the balance of supply and demand when an unexpected system event occurs. CR is further divided into two products: spinning reserve and supplemental reserve. Spinning reserve must be synchronized to the grid while supplemental reserve is not required to be synchronized. Alberta reliability standards require spinning reserve to provide 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 OR, 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 a generator outage or transmission constraint.

The price of OR 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 the offer price until active OR 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 price 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 7 summarizes the total cost of OR over the past five years. The total cost of OR in 2023 was $378 million, a 25 per cent decrease from 2022. As explained above, active OR products are directly indexed to the pool price. While not directly indexed to the pool price, standby OR product prices are influenced by it. Therefore, the 18 per cent year-over-year decrease in the pool price was a key driver in the decrease of OR costs. Declining prices of spinning reserve caused by competition between newer storage assets and incumbent hydroelectric generation assets also contributed to the fall in OR costs. By August 2023, 60 MW of battery storage capacity was energized that met the technical requirements to participate in the spinning reserve market. This introduction of new capacity increased energy supply and competition between generators in the spinning reserve market, which in turn drove down the price and cost in the latter half of 2023.

Volumes of CR procured declined in 2023 in part due to the implementation of the new LSSi Table on March 16, 2023, which increased the LSSi armed requirements and in turn decreased the active contingency reserve required. On the other hand, the volume of on-peak regulating reserve procured increased from 130 MW to 170 MW in late August, and then again from 170 MW to 210 MW in early October. This growth in regulating reserve procurement was required to balance net-demand variability caused by intermittent generation, which is discussed in further detail in the following Flexibility section.

TABLE 7: Annual operating reserve statistics

	2019	2020	2021	2022	2023
Volume (GWh)					
Active procured	5,640	5,561	5,624	5,719	5,360
Standby procured	2,124	1,940	1,191	994	954
Standby activated	180	348	156	179	215
Cost ($ millions)					
Active procured	$172	$122	$314	$466	$334
Standby procured	$6	$3	$4	$2	$4
Standby activated	$14	$23	$20	$33	$41
Total ($ millions)	**$193**	**$148**	**$339**	**$501**	**$378**

Market share represents the percentage of total procured OR capacity provided by each generation technology. Figure 42 illustrates the annual market share of active OR by fuel type. In 2023, hydroelectric generation had the largest market share in the regulating and spinning products at 59 per cent and 39 per cent, respectively. Storage assets had the second largest market share of active spinning at 33 per cent, which was up significantly from 17 per cent in 2022. The jump in storage can be attributed to new battery storage assets that were energized in 2023. Finally, hydro had the largest market share of supplemental product at 46 per cent followed by load at 38 per cent.

FIGURE 42: Market share of active operating reserve (2023)

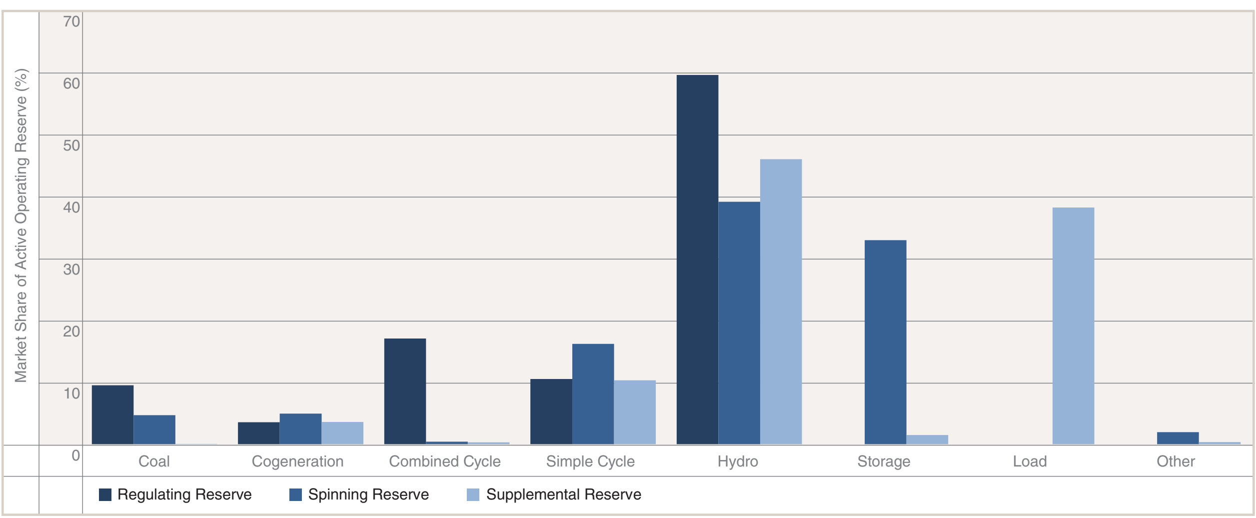
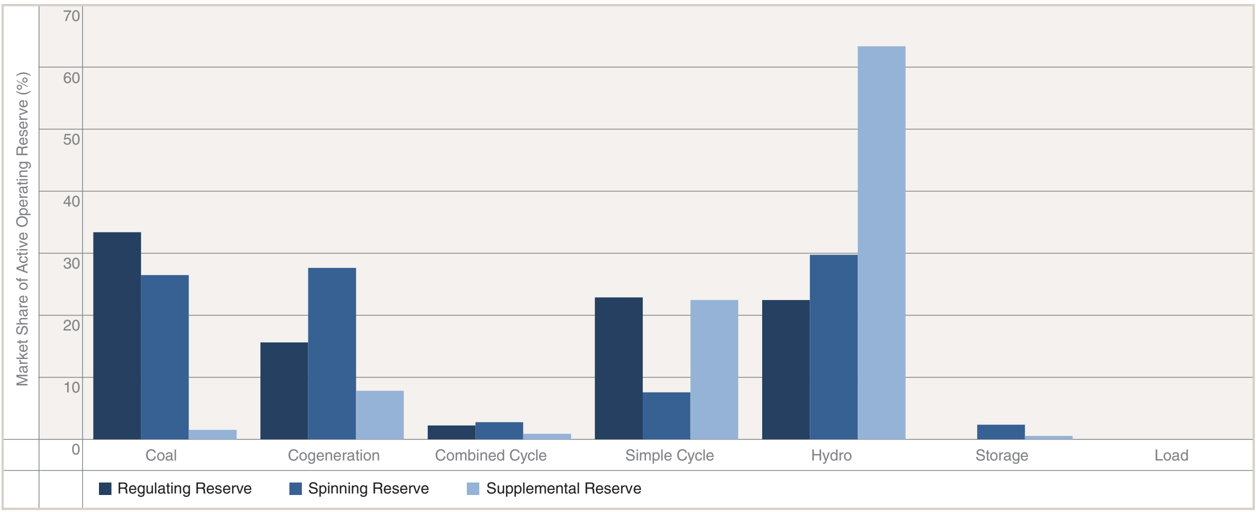


Figure 43 shows the annual market share in the standby OR market by fuel type. Market share is more evenly distributed among the fuel types in standby, with cogeneration generation providing 16 per cent of the standby regulating and 29 per cent of the spinning reserve markets. Simple cycle has the biggest share of the standby supplemental market at 66 per cent, followed by hydro at 23 per cent. In these charts, dual-fuel assets are included with coal assets and gas-fired steam assets are included with simple-cycle assets.

FIGURE 43: Market share of standby operating reserve (2023)



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. The pool price must be mitigated, otherwise this secondary effect interferes with the fair, efficient and openly competitive operation of the electricity market. In 2023, dispatched TMR energy was 55 GWh and costs were $3.59 million. A significant share of the TMR dispatched in 2023 occurred during May. This was primarily in response to transmission constraints caused by the wildfires in the Northwest region.

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 hourly pool 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 megawatt level of energy provided by that eligible offer block to determine the amount of the transmission constraint rebalancing payment. In 2023, constraints on the transmission system required System Controllers to curtail 305 GWh of in-merit energy, and the TCR payments to market participants totaled approximately $5.4 million which represents a significant increase from 89 GWh of in-merit energy curtailed and $1.8 million in TCR payments in 2022. Higher instances of curtailment in 2023 can be attributed to more congestion on the grid during hours with high variable generation.

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 and cannot offset more energy than is dispatched under the TMR service. The total cost of DDS is allocated between energy suppliers in proportion to the volume of energy that they generated or imported. In 2023, DDS offset none of the dispatched TMR volume. DDS is a voluntary program and, in 2023, market participants chose not to participate as much as they had in previous years. Furthermore, there was little need for DDS as the pool price was above the TMR reference price for most hours, as such, dispatching TMR would not have the downward effect on pool price that DDS was created to address.

Table 8 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.[13]

TABLE 8: Annual TMR and DDS statistics

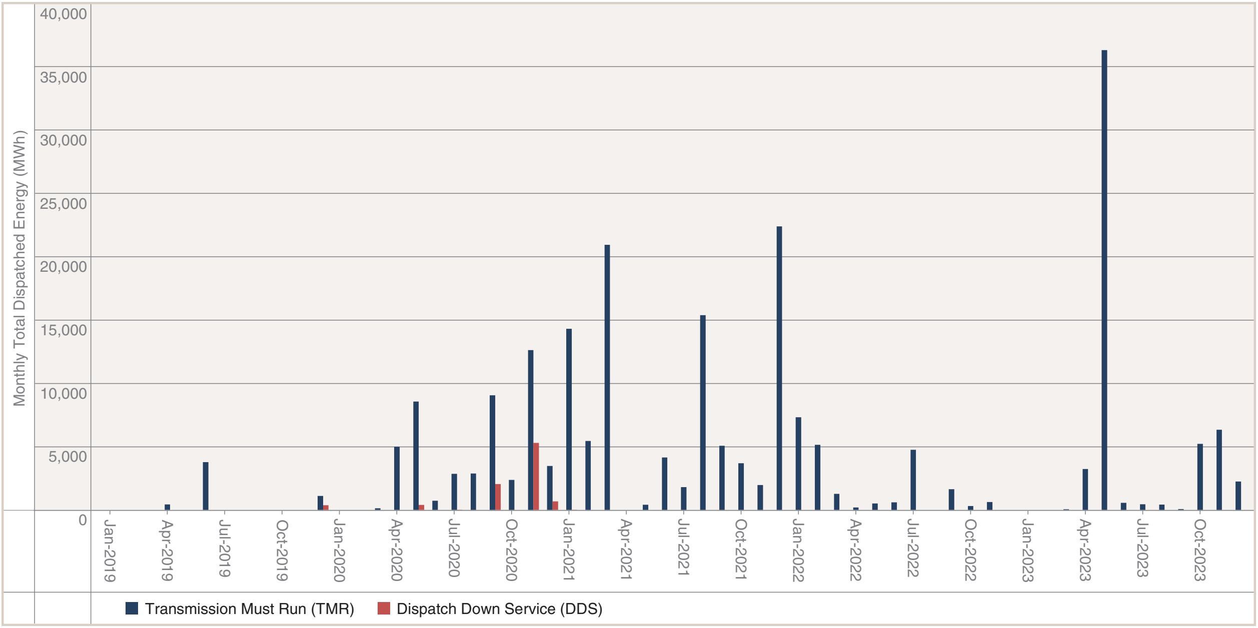
	2019	2020	2021	2022	2023[14]
Transmission must-run					
Dispatched energy (GWh)	5	48	96	23	55
Contracted TMR costs ($ millions)	$0.04	$0.67	$0.01	$0.02	$0.12
Conscripted TMR costs ($ millions)	$0.26	$1.93	$5.69	$2.51	$3.47
Transmission constraint rebalancing					
Constrained-down generation (GWh)	4	73	69	89	305
Number of days with TCR payment	14	67	89	207	291
Total TCR payments ($ millions)	$0.27	$0.52	$2.65	$1.80	$5.37
Total annual TCM costs					
Annual TCM cost ($ millions)	$0.56	$3.12	$8.35	$4.33	$8.97
Dispatch down service					
Total payments ($ millions)	$0.01	$0.16	$0.00	$0.00	$0.00
Dispatched energy (MWh)	377	8,492	11	0	0
Average charge ($/MWh)	$17.24	$18.84	$19.58	$0.00	$0.00

[13] 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.”

[14] Preliminary data.

Figure 44 shows the monthly volumes of TMR and DDS dispatched over the past five years. The System Controller issues TMR dispatches when needed to respond to transmission constraints on the AIES.

FIGURE 44: Monthly TMR and DDS dispatched energy



Payments to suppliers on the margin

All energy delivered to the AIES receives the same price, called the pool price. Payments to suppliers on the margin (PSM), otherwise known as uplift payments, follow from 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 the System Controller dispatches 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. Table 9 summarizes the cost of PSM payments over the past five years.

TABLE 9: Annual uplift payments

	2019	2020	2021	2022	2023
Payments to suppliers on the margin					
Average range ($/MWh)	$12.36	$5.89	$24.99	$38.08	$48.18
Total PSM payments ($ millions)	$1.58	$0.75	$2.89	$4.57	$5.89

In 2023, the total cost of PSM was $5.89 million, up from $4.57 million in 2022. 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 27 per cent to $48.18/MWh in 2023 due to higher volatility in the merit order offers, especially in the first three quarters of the year.

Flexibility

There are two types of generation on Alberta's electric system, dispatchable and variable (or intermittent). Dispatchable generation can be controlled by operators, while variable generation (i.e., wind and solar) is dependent on environmental conditions. In the *AESO 2023 Reliability Requirements Roadmap* (Reliability Roadmap),[15] the AESO assessed the ability of the electric system to adapt to increasing amounts of variable generation, including the need to continuously balance supply and demand under different scenarios. As more wind and solar generation is integrated into the electric system, fluctuations in demand and variable generation, which is referred to as net-demand variability, are expected to increase. To respond to the increased net-demand variability, additional balancing capability, as outlined in the Reliability Roadmap,[16] will be required.

Historical flexibility parameters for market and system operations are included in the Annual Market Statistics report. In this section, these parameters are reported for the past year.

Net-demand variability

A net-demand ramp is the difference in the period-to-period change of AIL and variable generation. For example, if in a 10-minute period, AIL increases 10 MW and variable generation falls 10 MW, the 10-minutes net-demand ramp is +20 MW. The increasing size and frequency of net-demand ramps, both up and down, on the transmission system is a challenge associated with higher variable wind and solar generation volumes. Dispatchable resources need to be able to match the size, speed, and frequency of the net-demand ramps to reliably supply load customers as additional variable wind and solar generation is added to the grid.

Figure 45 shows the frequency and size of 10-minute ramps of variable generation, AIL, and net demand in 2023. 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 the given year. Variable generation includes all five megawatt or larger wind and solar assets in Alberta. Small-scale wind and solar generators (i.e., less than five megawatts) within the province are generally connected to the distribution system and their variability is captured in AIL.

In 2023, 27.0 per cent of all 10-minute net-demand ramps were greater than plus/minus 50 MW, up from 20.9 per cent of ramp periods in 2022. This is almost at the 27.8 per cent frequency forecast in the Reliability Roadmap for the 2026 Reference Case.[17] This indicates that the frequency of larger net-demand ramps has increased more quickly than expected. In fact, this result tracked closer to Clean-Tech scenario. Figure 46 shows the year-over-year change in the frequency of ramps of different sizes. As can be seen, the number of ramps plus/minus 30 MW decreased, while there was a corresponding increase of ramps greater than 30 MW. In addition, the change in the variable generation ramp size is skewed. Ramp-downs tend to be larger than ramp-ups. This is because the variable generation ramp-downs are dependent on environmental conditions, while during some ramp ups the variable assets have to be constrained to match the slower ramping characteristics of dispatchable assets.

15 https://www.aesoengage.aeso.ca/reliability-requirements-roadmap.

16 Ibid., page 101.

17 Ibid., page 99, Table 9.

FIGURE 45: Distribution of 10-minute ramps for wind and solar generation, load, and net demand in 2023

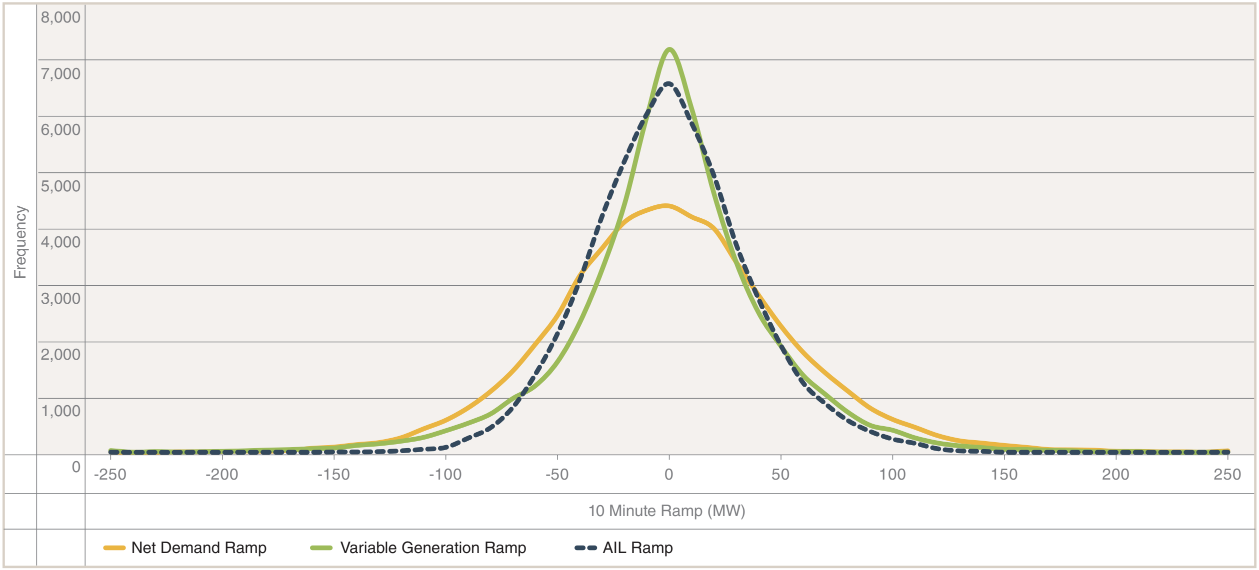
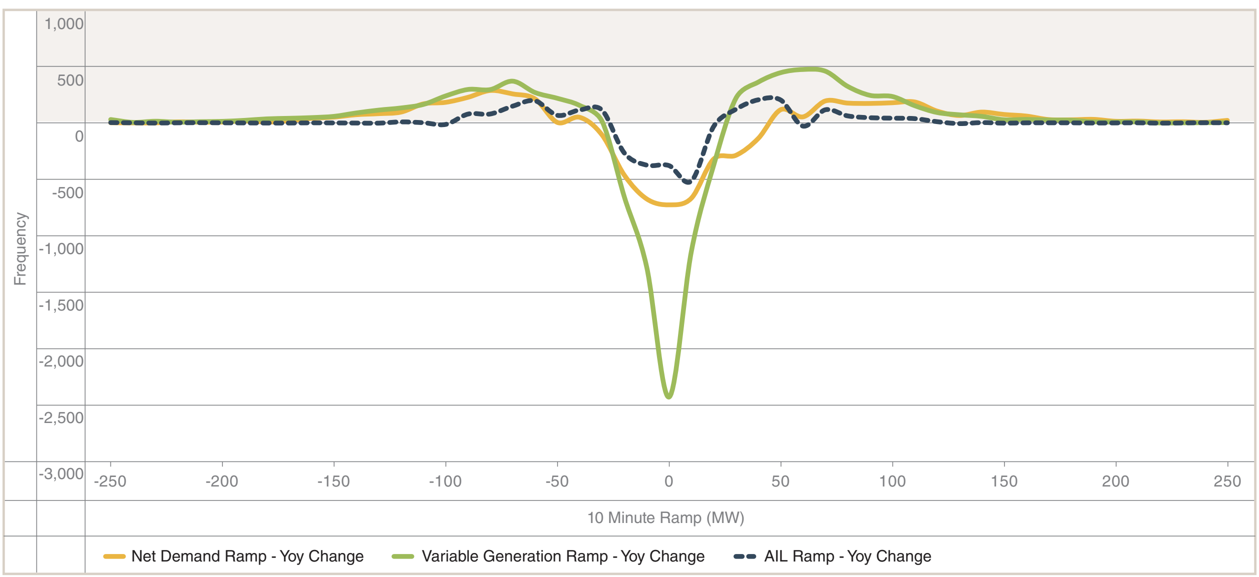


FIGURE 46: Distribution of 2023 year-over-year change in 10-minute ramps for wind and solar generation, load, and net demand

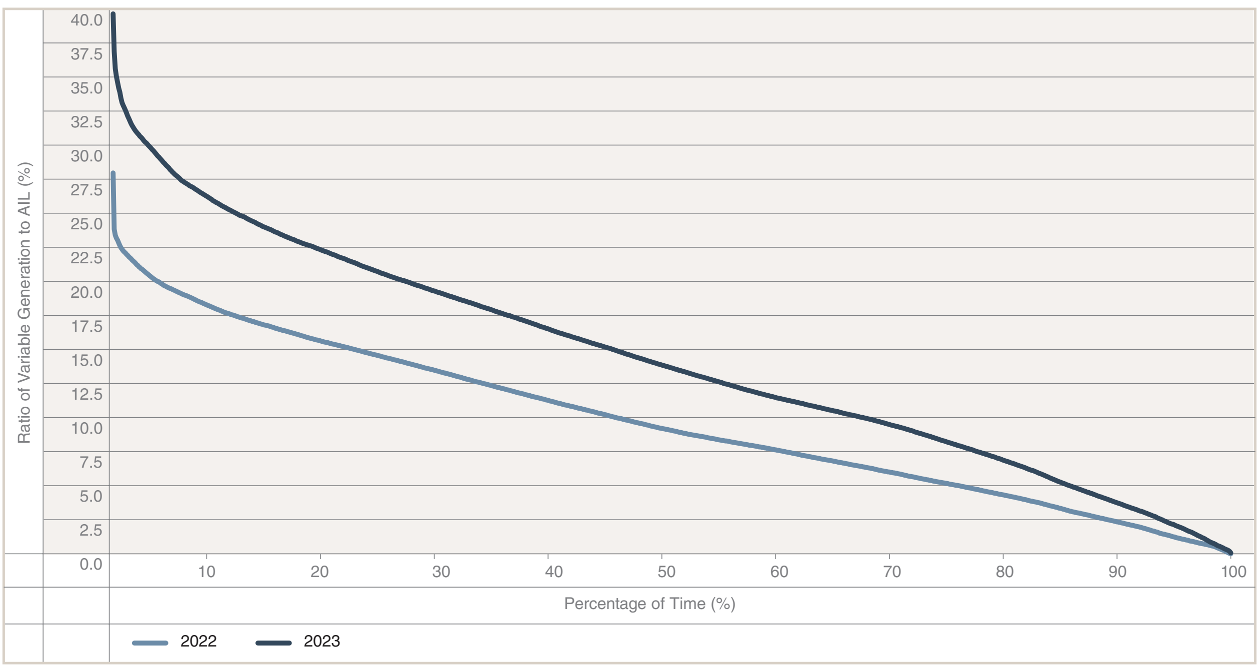


While the increase in the number of large net-demand ramps can be attributed to the increased capacity of both wind and solar generation, solar appears to be the primary driver. In 2023, solar ramps of 50 MW or more increased to 11.0 per cent of all 10-minute periods from 3.3 per cent in 2022. Large wind ramps increased at a slower rate, from 9.0 per cent to 13.9 per cent. In addition, in 2023, solar generation saw 68 10-minute periods with ramps of 200 MW or larger, while wind generation only saw 25 such ramps. This occurred even though solar capacity is roughly one-third that of wind capacity. As a result of this significant increase in net-demand variability, the AESO increased the amount of regulating reserve it procured to help balance the electric system.

Variable generation-to-Alberta Internal Load ratio

As more variable wind and solar generation connects to the transmission system, it contributes a higher proportion of the overall generation production. This, in turn, is expected to create a need for greater system flexibility to respond to higher net-demand variability. Figure 47 shows a duration curve of the ratio of variable generation to AIL, using the same 10-minute intervals as used in the net-demand variability data. With the increased wind and solar capacity in 2023, the highest ratio of variable generation to AIL grew to 39.9 per cent, compared to 28.1 per cent in 2022. The median ratio in 2023 was 13.7 per cent versus 9.1 per cent in 2022.

FIGURE 47: Ratio of variable generation to AIL



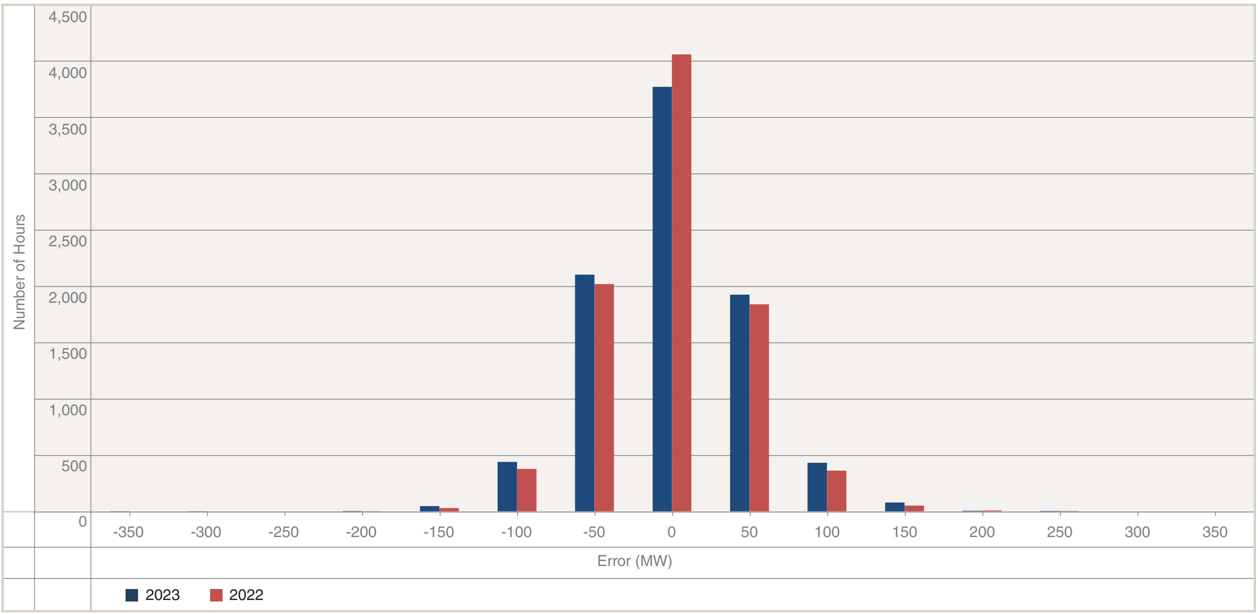
Forecast uncertainty

In Alberta, real-time energy market dispatch is performed by the 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 available 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 48 illustrates the distribution of the day-ahead load forecast error for all hours in 2023 compared to 2022. The error at a given hour is defined as the day-ahead forecast of AIL minus the actual AIL for that hour. In 2023, the mean absolute per cent error (MAPE) was 0.38 per cent, a slight degradation from 0.35 per cent in 2023, but still very low.

FIGURE 48: Distribution of day-ahead load forecast error in 2023 and 2022



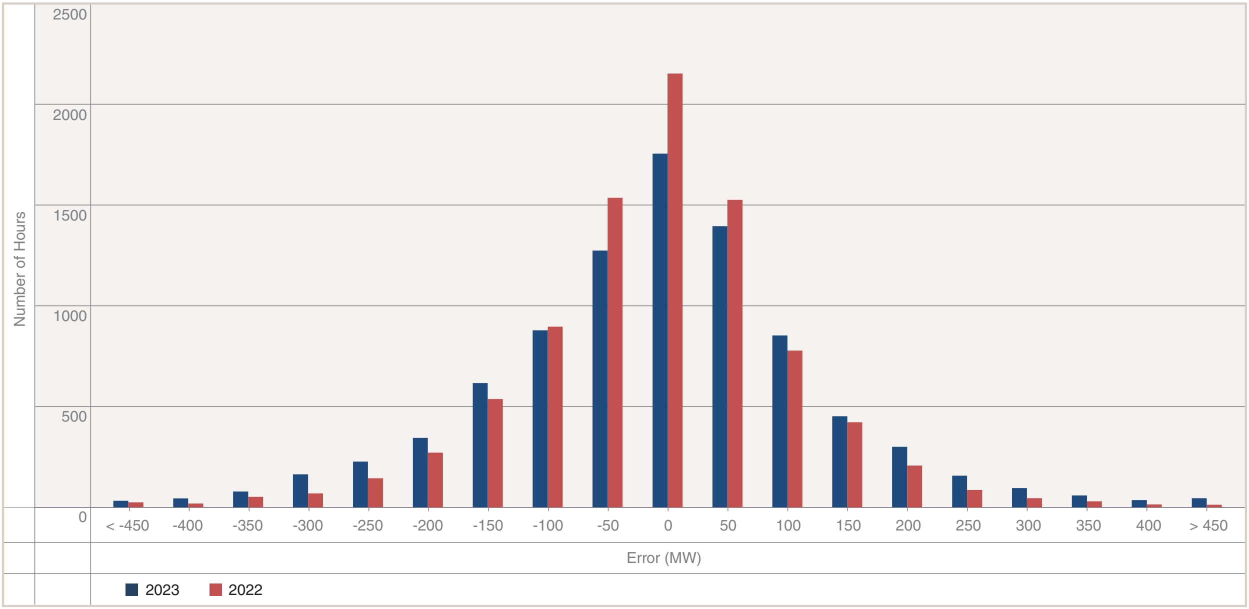
Wind power forecast uncertainty

The AESO's wind and solar power forecast uses near real-time meteorological data to predict the amount of wind and solar power that will be supplied to the Alberta system on a seven-day-ahead (long-term) and a 12-hour-ahead (short-term) basis.[18] The long-term forecast is updated every six hours and the short-term forecast is updated every 10 minutes. AESO System Controllers require accurate short-term wind and solar power forecasts to manage net-demand variability. Therefore, the error of the short-term forecast is used to measure the uncertainty of the wind and solar forecasts.

For a given hour, the wind power forecast error is calculated as the hour-ahead forecasted wind volume minus the actual wind generation. Figure 49 shows the distribution of the calculated errors for the wind power forecast in 2022 and 2023. Overall, the average wind forecast error increased to 102 MW from 82 MW in 2022. However, as a percentage of installed and available wind capacity, the error improved to 2.6 per cent from 3.2 per cent in 2022. As more wind capacity is installed, it is expected that the raw forecast error will increase, but the error as a percentage of capacity will stay the same or improve.

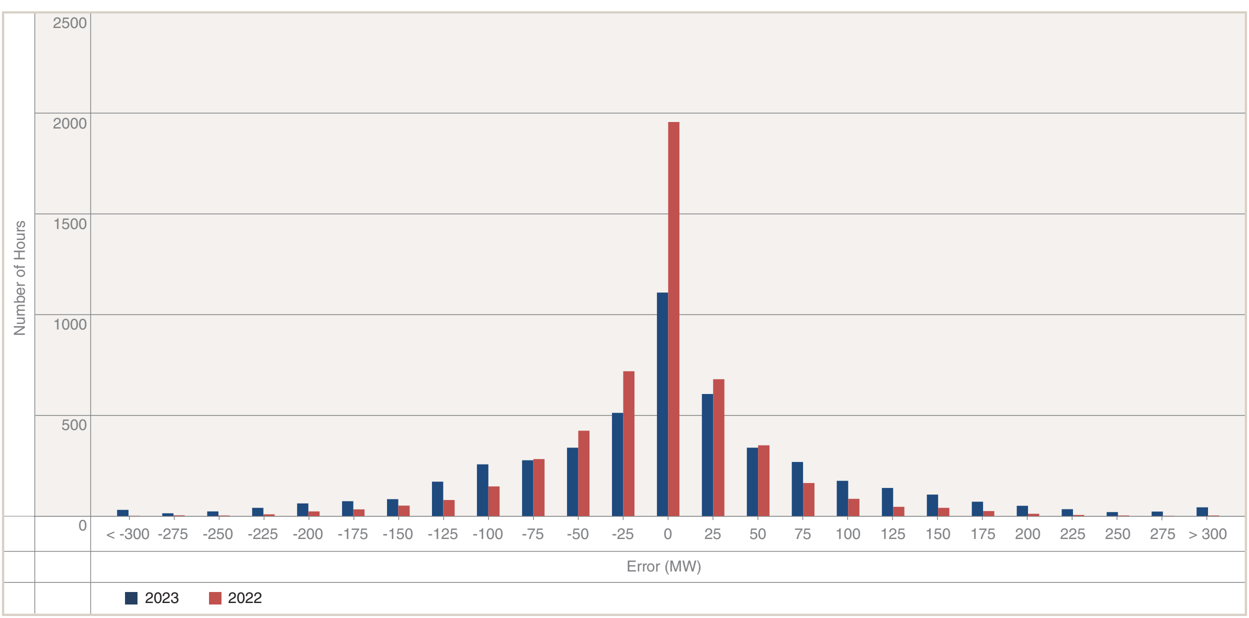
[18] https://www.aeso.ca/grid/forecasting/wind-and-solar-power-forecasting/.

FIGURE 49: Distribution of hour-ahead wind power forecast error in 2023 and 2022



Like the wind power forecast, the forecast error for solar power is calculated as the hour-ahead forecasted volume minus the actual volume. Figure 50 shows the distribution of the calculated errors for the solar forecast in 2023 and 2022. This data excludes any non-daylight hours, where the forecast and actual generation was zero. Overall, the average forecast error increased to 67 MW from 37 MW in 2022. As a percentage of installed solar power capacity, the error increased to 5.9 per cent from 5.0 per cent in 2022. There were two main reasons for the increased error percentage. First, some solar assets provided an incorrect maximum capacity during commissioning, which led to a higher forecast output than was possible. Second, higher levels of transmission congestion limited actual output below what was theoretically possible.

FIGURE 50: Distribution of hour-ahead solar forecast error in 2023 and 2022



Unit on/off cycling

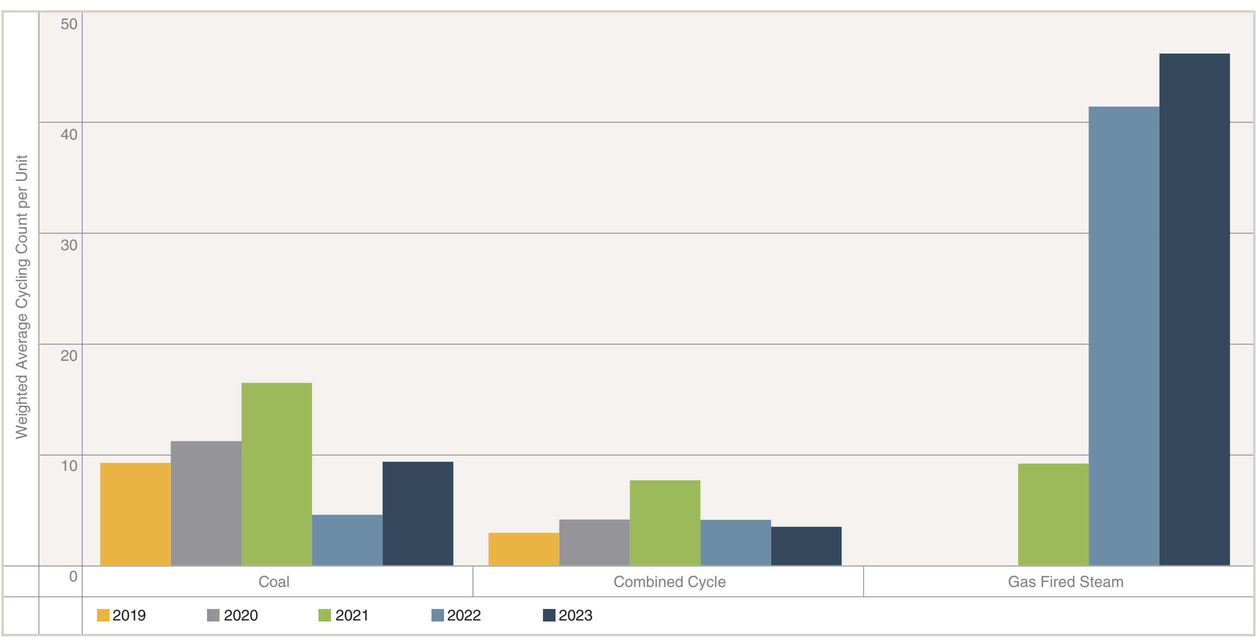
On/off cycling refers to starting up from a non-operational state, operating at any level for any duration, and then shutting down to return to a non-operational state. On/off cycling typically increases the operational costs for baseload generation, such as combined-cycle and coal-fired generating units 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. This section also contains former coal-fired generating units that have been converted to gas-fired steam generating units. The AESO will continue to monitor such units to identify whether there are changes to cycling behavior in the future.

The number of on/off cycles for each unit was first counted for each year from 2019 to 2023. For each technology type and year, the average of the on/off cycles was calculated, weighted by the maximum capability of each generating unit. For units that only were available for a portion of a year, such as units that retired or converted to another fuel type, the number of on/off cycles was increased proportionately to a yearly total. All combined-cycle, gas-fired steam and coal-fired (including units capable of operating as dual-fuel) units were included in the calculation, except for units within the City of Medicine Hat.

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.

Figure 51 illustrates the average number of on/off cycles over the past five years. By 2022, most coal units had converted to other fuel types including gas-fired steam. The conversion from coal to gas-fired steam capacity is part of the reason for the increase in gas-fired steam cycling, as there was significantly more gas-fired steam capacity in 2023 than in 2019. In addition, gas-fired steam assets have been the marginal unit much of 2022 and 2023. This led market participants to take gas-fired steam assets offline more frequently, likely at times the participants felt it was less economic to run them.

FIGURE 51: Average number of on/off cycles per generating unit, by technology and year



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.

Conclusion

As the market evolves throughout 2024 and into the future, the AESO will continue to monitor, analyze, and report on market outcomes. As part of this monitoring process, the AESO provides real-time historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. In addition, there are multi-year forward-looking reports, such as the Long-Term Outlook and the Long-Term Adequacy reports. Finally, the AESO continues to explore additional reliability and flexibility metrics which may be added to future Annual Market Statistics reports.

Much of the report data is available for download via a Tableau site and is updated monthly. The site is accessible from the Annual Market Statistics report page.[19] If there are any questions, please email market.analysis@aeso.ca.

[19] https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/.

Alberta Electric System Operator

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