aeso

AESO 2025
Annual Market Statistics

MARCH 2026

Executive Summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient and openly competitive (FEOC) electricity market while maintaining the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES).

The AESO 2025 Annual Market Statistics Report provides a comprehensive overview of key market trends and data from the past year. The interactive data file that accompanies this report enables a deeper analysis of the data presented.

Price	2024	2025	Year/Year Change
Pool price	$62.78/MWh	$43.68/MWh	-30%
Gas price	$1.30/GJ	$1.61/GJ	+24%
Spark spread @ 7.5 GJ/MWh	$53.07/MWh	$31.58/MWh	-40%

Load	2024	2025	Year/Year Change
Average Alberta Internal Load (AIL)	10,112 MW	10,316 MW	+2.0%
Winter seasonal peak	12,241 MW	12,785 MW	+4.4%
Summer seasonal peak	12,221 MW	12,005 MW	-1.8%

Installed Capacity	2024	2025	Year/Year Change
Total	23,122 MW	23,242 MW	+0.5%
Gas	14,136 MW	14,182 MW	+0.3%
Wind	5,688 MW	5,684 MW	-0.1%
Solar	1,812 MW	1,850 MW	+2.1%

Supply Trends	2024	2025	Year/Year Change
Average Supply Cushion	1,794 MW	1,960 MW	+9.3%
Supply Surplus Hours	290	298	+2.8%

Net Intertie Flows (Imports = +)	2024	2025	Year/Year Change
British Columbia	-253 MW	-323 MW	-70 MW
Montana	21 MW	-27 MW	-48 MW
Saskatchewan	21 MW	1 MW	-20 MW

During 2025, 409 participants transacted approximately $5.3 billion of energy in the Alberta wholesale electricity market.

Energy Prices Lowest in Eight years

Increased Supply Competition

The average pool price fell 30.4 per cent in 2025 to $43.68/MWh - the lowest level in eight years. The primary driver was the full-year impact of highly efficient gas-fired generation commissioned in late 2024, along with additional output from recently built wind and solar facilities. The decline occurred despite record-setting load levels and a 23.8 per cent increase in average gas prices.

Pricing Context for Stakeholders

The 2025 average pool price was well below the 10-year average, offering a more cost-effective environment for consumers and industries reliant on electricity.

Demand Growth and Peak Record

Demand Growth Trends

Average Alberta Internal Load (AIL) increased 2.0 per cent to 10,316 MW in 2025. Over the past five years, average annual growth has been 1.5 per cent. Growth was broad-based, with particularly strong industrial demand and continued population growth in Alberta's major cities.

Record-Setting Peaks

A new all-time winter peak of 12,785 MW was set in December 2025, 3.2 per cent higher than the previous record. Notably, this occurred despite temperatures being more than 10 degrees warmer than during the prior record peak, underscoring the structural nature of load growth.

Increased Use of Bulk Transmission System

System load rose 4.0 per cent year-over-year, driven by: higher overall demand, reduced behind-the-fence (BTF) generation, and increased system losses.

Impacts of Prior Capacity Expansions

Minimal Generation Capacity Additions

After Alberta experienced rapid additions of gas, wind and solar generation between 2021 and 2024, 2025 saw minimal new capacity additions. The surge in capacity led to the continued trend of lower pool prices and reduced the immediate need for further generation development.

Increased Average Supply Cushion

The additional capacity brought online in 2024 increased the average supply cushion by 9.3 per cent in 2025. Supply surplus conditions occurred in 298 hours, which was slightly higher than 2024. One Grid Alert was issued during 2025.

Continued Renewables Rise and System Variability

Wind, solar and hydro accounted for approximately 21.0 per cent of total generation in 2025, up from 19.0 per cent in 2024. While renewable output increased, rapid wind and solar growth continued to drive net demand variability (NDV) beyond earlier projections, increasing operational complexity.

Increased Transmission Congestion

Transmission congested volumes increased to an hourly average of 146 MW in 2025 from 48 MW in 2024. This was primarily driven by two significant transmission outages during the year, as well as higher wind generation capacity added in late 2024.

Changing Intertie Trend

Rising Exports and Falling Imports

Since 2022, Alberta has seen a transition toward lower imports and higher exports. In 2025, exports were six times greater than imports, supported by lower Alberta pool prices and increased generation capacity. ATC on the BC/MATL interties only limited imports in 5.0 per cent of hours in 2025.

Operating Reserve Insights

Total operating reserve (OR) costs declined 19.6 per cent to $218 million driven mainly by the fall in pool prices.

Contents

Electricity Prices

Pool Prices Dropped 30.4 Per Cent

Table 1 summarizes historical pool price statistics over the 10-year period between 2016 and 2025, along with other price-related metrics.

TABLE 1: Annual Market Price Statistics

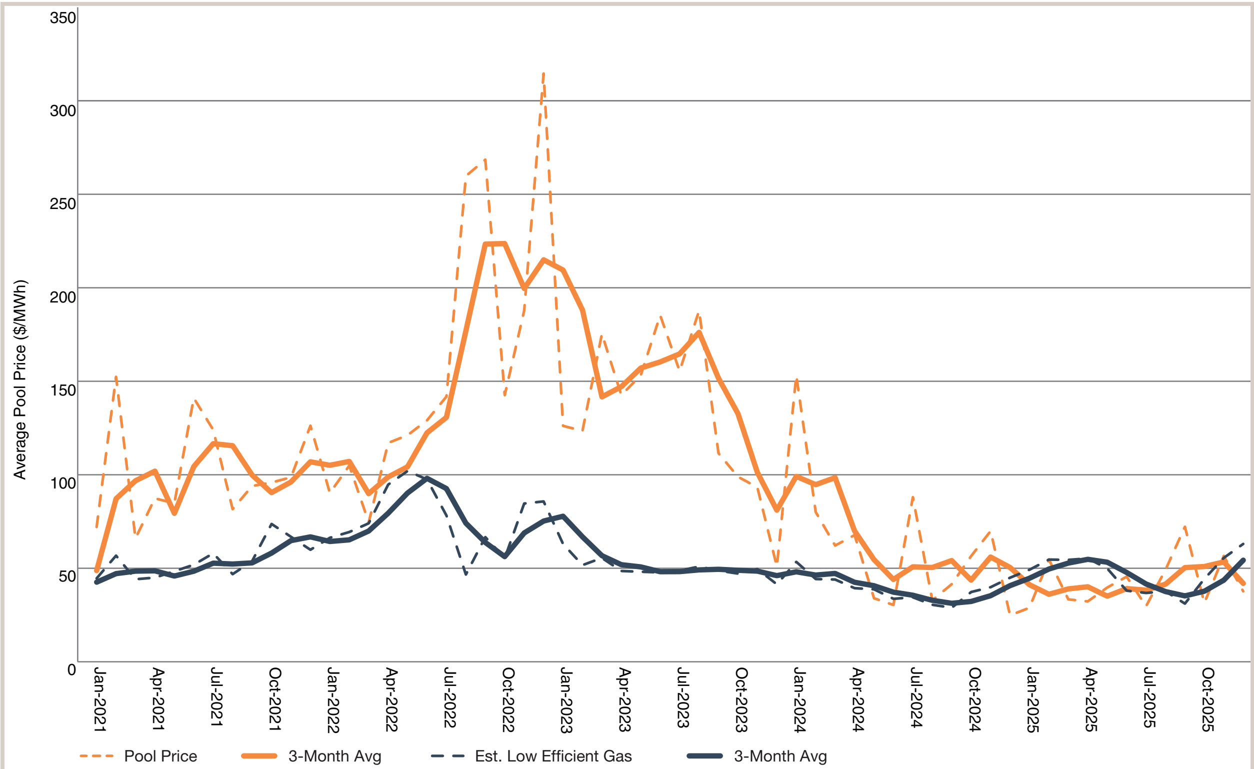
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pool price ($/MWh)										
Daily Average	18.28	22.19	50.35	54.88	46.72	101.93	162.46	133.63	62.78	43.68
On-peak average	19.73	24.46	59.28	64.12	54.72	122.61	192.13	156.15	74.46	52.15
Off-peak average	15.37	17.64	32.47	36.40	30.71	60.58	103.14	88.59	39.43	26.74
Spark Spread at 7.5 GJ/MWh ($/MWh)										
Daily Average	2.77	6.70	39.54	42.21	30.81	76.39	124.46	114.52	53.06	31.58
Estimated Gas Unit Marginal Cost ($/MWh)[1]										
High Efficiency (7HR)	19.82	19.91	15.77	17.51	20.53	29.75	41.60	24.31	15.89	16.71
Low Efficiency (12HR)	34.37	35.84	31.39	34.37	39.55	58.00	80.96	55.29	44.82	48.68
Estimated Carbon Cost ($/MWh)										
High Efficiency (7HR)	0.79	1.41	-0.53	-0.53	-0.53	-0.71	-0.89	-0.67	-0.24	0.42
Low Efficiency (12HR)	1.36	2.42	7.02	7.02	7.02	9.35	11.69	15.68	19.89	24.32
Gas Price ($/GJ)										
Daily Average	2.07	2.06	1.44	1.69	2.12	3.41	5.07	2.55	1.30	1.61

- The 2025 daily average pool price ($43.68) fell by 30.4 per cent compared to 2024 ($62.78).
  - Lower prices were primarily due to new efficient gas-fired capacity, that came online in stages during 2024, and additional output from recently built wind and solar assets.
  - This was despite higher overall demand and a higher average gas price.

[1] The estimated gas unit marginal costs include the fuel cost (HR times gas price), the estimated carbon cost and an assumed $5/MWh for operating and maintenance. The gas price is the day-ahead AECO spot price.

Figure 1 compares the monthly average pool price over five years to the estimated cost of a theoretical low-efficiency simple-cycle natural gas unit. This estimated cost is for a 12-gigajoule (GJ) per megawatt-hour (MWh) unit, including $5 for operation and maintenance costs as well as the estimated carbon costs. Monthly pool prices tend to be volatile, so a 3-month moving average of the monthly prices has been added to smooth out the price trends.

FIGURE 1: Monthly Average Pool Price



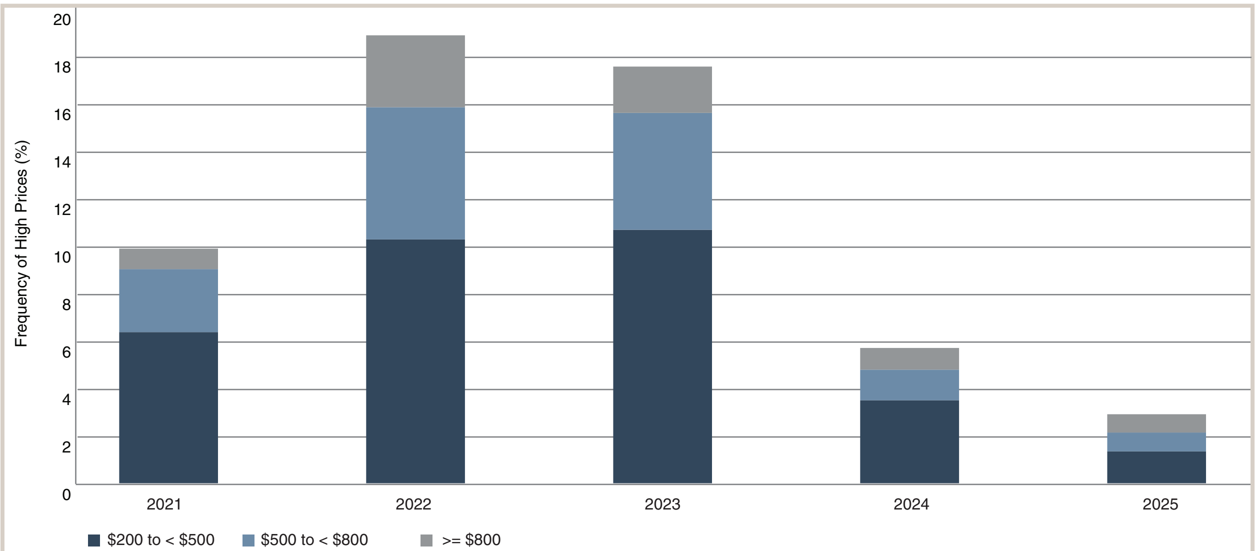
Key Observations:

- The expiry of Power Purchase Agreements (PPAs) in 2021, shifted offer control back to asset owners from the Balancing Pool. The asset owners tended to offer their energy at higher prices, resulting in higher energy market prices than seen in previous years.
- Between Q3 2020 and Q2 2022, approximately 1,300 MW of coal retired. The resulting supply reduction contributed to sustained price strength, with the pool price exceeding the theoretical low-efficiency gas unit cost by more than $32.
- Pool prices hit a peak between Q2 2022 and Q2 2023, where the pool price / gas unit spread averaged $103.
- Pool prices trended lower starting in Q3 2023, as new wind and solar projects entered service and the 300 MW H.R. Milner gas unit returned from outage. The last half of 2023 saw the spread average fall to $68.
- The commissioning of two large, efficient gas plants in 2024 further increased competition and reduced scarcity pricing. This lowered pool prices and shrank the pool / gas unit spread from $30 in Q4 2023 to under $10 in Q4 2024. For the full year, the average was $22.
- In 2025, after a full year of the two new gas plants, plus additional wind and solar generation from units commissioned during 2024, pool prices stayed below the 2024 average pool price in 11 of 12 months. The pool price / gas unit spread averaged just over -$5 for the year.

Alberta's hourly electricity price is based on 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. These offers make up the Energy Market Merit Order (EMMO), which is used to set prices based on the amount of supply needed to serve load.

Figure 2 shows how often high-priced hours occurred over the last five years. High-priced hours reflect a scarcity of generation capacity remaining in the EMMO to serve additional load.

FIGURE 2: Frequency of High-Priced Hours

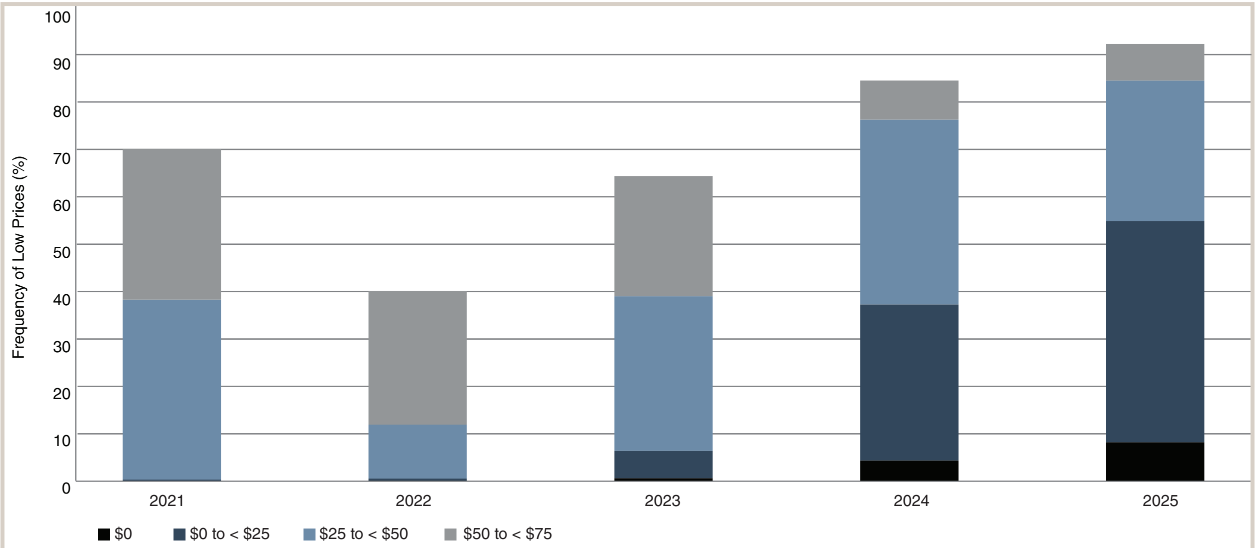


Key Observations:

- The expiry of PPAs in 2021 led to higher offer and settled prices when compared to the previous few years.
- High-priced hours doubled in 2022 and 2023 due to higher demand, lower supply, and high offer prices from some participants.
- Starting in late 2023 and throughout 2024, high-priced hours dropped significantly due to completion of new baseload thermal generation and new wind and solar projects, which increased competition. In addition, a major thermal unit returned from a year-long unplanned outage.
- In 2025, the thermal, wind, and solar projects that came online throughout 2024 were available for the full year, which further reduced the high-priced hours.

Figure 3 shows how often electricity prices fell below $75 per hour over the last five years, with a focus on sub-$25 hours. For reference, most of the gas fleet in Alberta had an estimated average marginal cost of between $17 and $49 in 2025.

FIGURE 3: Frequency of Low-Priced Hours

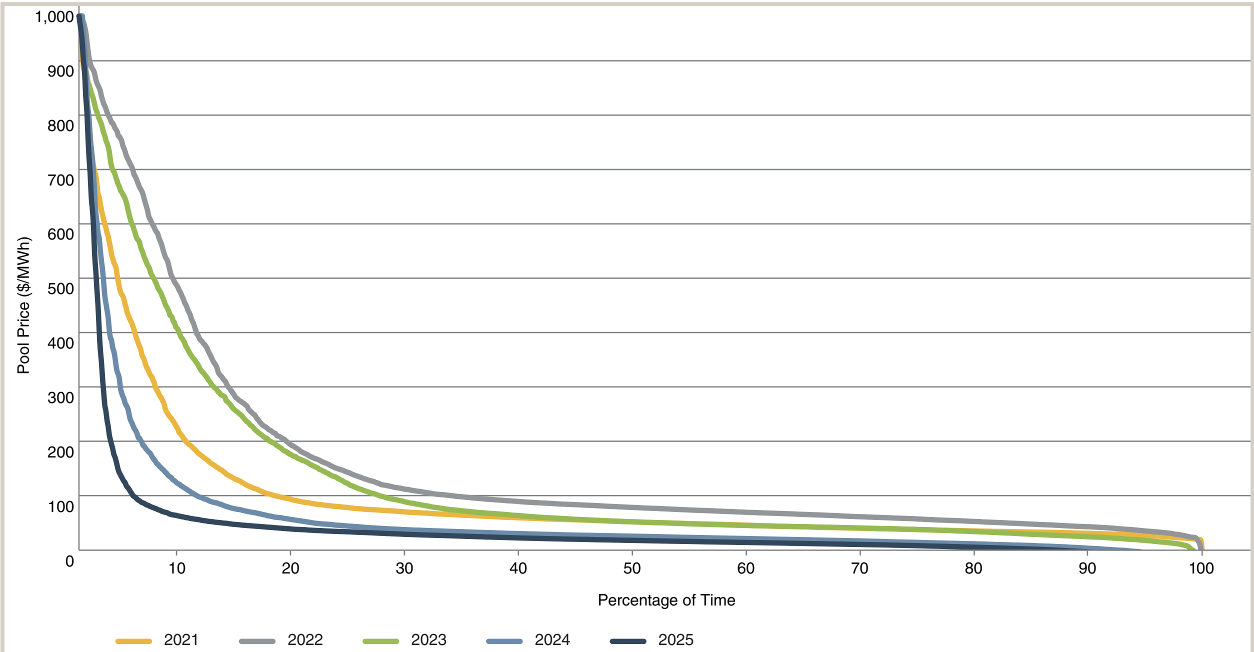


Key Observations:

- High gas prices and limited supply in 2021 and 2022 virtually eliminated sub-$25 hours.
- By 2023, declining gas prices and growing renewable output modestly increased sub-$25 hours. Wind and solar, typically offered at $0, lowered pool prices when available.
- In 2024, new baseload thermal generation, with marginal costs estimated in the $15 - $20 range, significantly boosted sub-$25 hours, primarily in the latter half of the year.
- In 2025, a full year of incremental gas, wind and solar generation further expanded sub-$25 hours.
  - Hours that settled at $0 were 8.1 per cent of hours in 2025, compared to 4.2 per cent in 2024.

Figure 4 shows the price duration curve for how often hourly pool prices occurred over the previous five years.

FIGURE 4: Pool Price Duration Curve



Key Observations:

- The chart shows how 2024 and 2025 are more alike than the previous two years. This is due to the new generation that came online in mid-2024.
  - In 2024, there was a higher percentage of time with prices higher than $100. These times occurred mostly in the first half of the year, before the new generation came online.
- The median pool price in 2025 was $23. For comparison:
  - In 2024, it was $31.
  - Both 2021 and 2023 saw a median price near $57.
  - The highest median price of the last five years was in 2022 at $84.
- Prices were above $100 in about 5.1 per cent of hours in 2025 and 11.2 per cent in 2024
  - In 2022, 36.2 per cent of the hours were above $100.

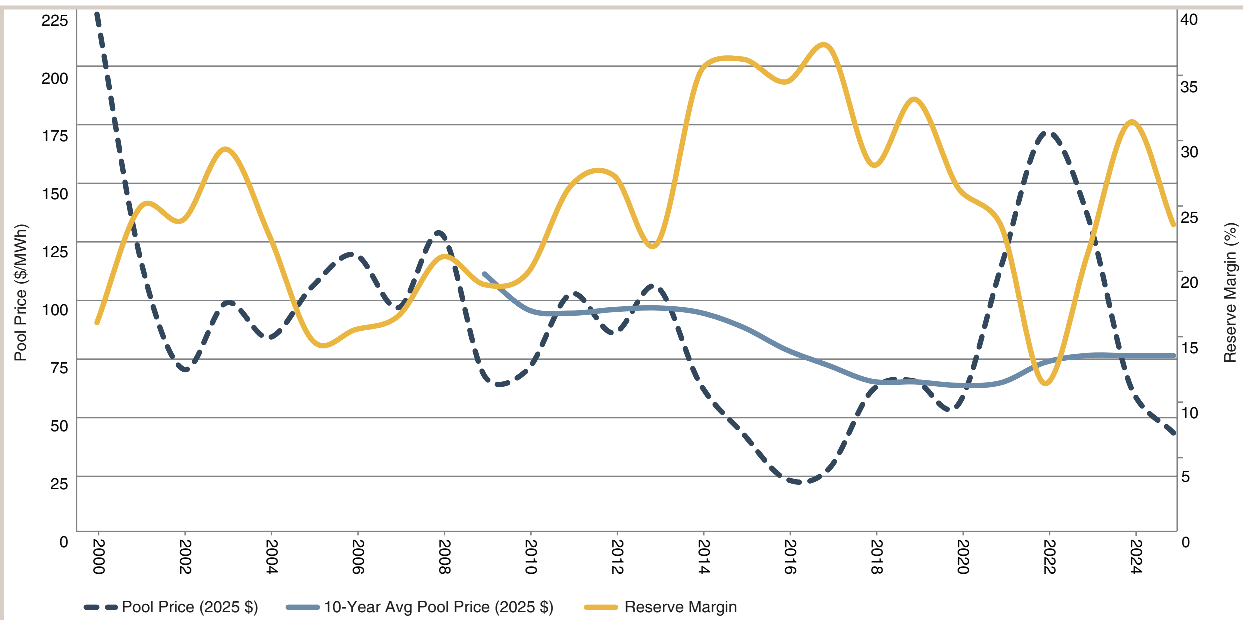
Historical Pool Price and Reserve Margin

Over the past decade, the Alberta electricity market has experienced notable fluctuations in pool prices, shaped significantly by shifts in supply, demand, and external factors.

Figure 5 highlights these trends with inflation-adjusted yearly pool prices (in 2025 dollars), the 10-year rolling average of the inflation-adjusted prices, and AESO's annual reserve margin.

- Between 2016 and 2025, the inflation-adjusted 10-year pool price average stood at $78, significantly lower than the $113 average recorded during 2000–2009.
- Included in the most recent 10-year average pool price are years with two of the three highest inflation-adjusted pool prices in AESO's history (2022 and 2023).

FIGURE 5: Inflation-adjusted Yearly Pool Price and Reserve Margin



Key Observations:

- High reserve margins from 2014 to 2020 sustained a prolonged period of low prices.
  - New thermal generation and reduced demand, caused by declining oil prices, created high reserve margins.
- Coal retirements, generation project delays, and rising demand compressed reserve margins in 2021 to 2022, contributing to sharp price increases.
- Additional thermal, wind, and solar capacity led to lower prices in 2023 as compared to 2022.
- In 2024, a significant volume of thermal capacity came online. This, plus some additional wind and solar capacity, resulted in an average price below the 10-year average.
- In 2025, the reserve margin fell to 24.1 per cent from 32.6 per cent in 2024. This was due to the mothballing of Sundance 6 and a 400 MW increase in the peak load year-over-year. However, despite the fall in the reserve margin, the average 2025 pool price was the lowest in eight years.

These observations highlight the sensitivity of Alberta's electricity market to demand fluctuations, supply economics, and external factors. High prices tend to drive investments in new generation, while low prices prompt generator retirements, underscoring the cyclical nature of supply and demand.

Alberta Load

All annual load statistics in this report are based on the calendar year from January 1 to December 31.

Average Load Grew 2.0 Per Cent

Table 2 summarizes the annual demand statistics over the past 10 years.

TABLE 2: Annual Load Statistics

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Alberta Internal Load										
Total (GWh)	79,560	82,572	85,330	84,925	83,115	85,214	86,572	86,293	88,827	90,371
Average (MW)	9,055	9,426	9,741	9,695	9,460	9,728	9,883	9,851	10,112	10,316
Maximum (MW)	11,458	11,473	11,697	11,471	11,698	11,729	12,193	11,572	12,384	12,785
Minimum (MW)	6,595	7,600	7,819	8,024	7,579	7,976	8,110	7,873	8,166	8,295
Average change	-1.1%	4.1%	3.3%	-0.5%	-2.4%	2.8%	1.6%	-0.3%	2.6%	2.0%
Load factor	79%	82.2%	83.3%	84.5%	80.9%	82.9%	81.1%	85.1%	81.7%	80.7%
System Load										
Total (GWh)	60,773	62,393	62,942	61,626	60,201	60,985	61,873	60,929	63,054	65,372
Average (MW)	6,919	7,123	7,185	7,035	6,854	6,962	7,063	6,955	7,178	7,463
Average Change	-1.1%	2.9%	0.9%	-2.1%	-2.6%	1.6%	1.5%	-1.5%	3.2%	4.0%
System Load-to-AIL Ratio	76.4%	75.6%	73.8%	72.6%	72.4%	71.6%	71.5%	70.6%	71%	72.3%
Losses (MW)	245	253	213	214	222	215	226	255	281	315
Estimated BTF Load (MW)	2,139	2,304	2,556	2,660	2,609	2,766	2,819	2,895	2,934	2,853

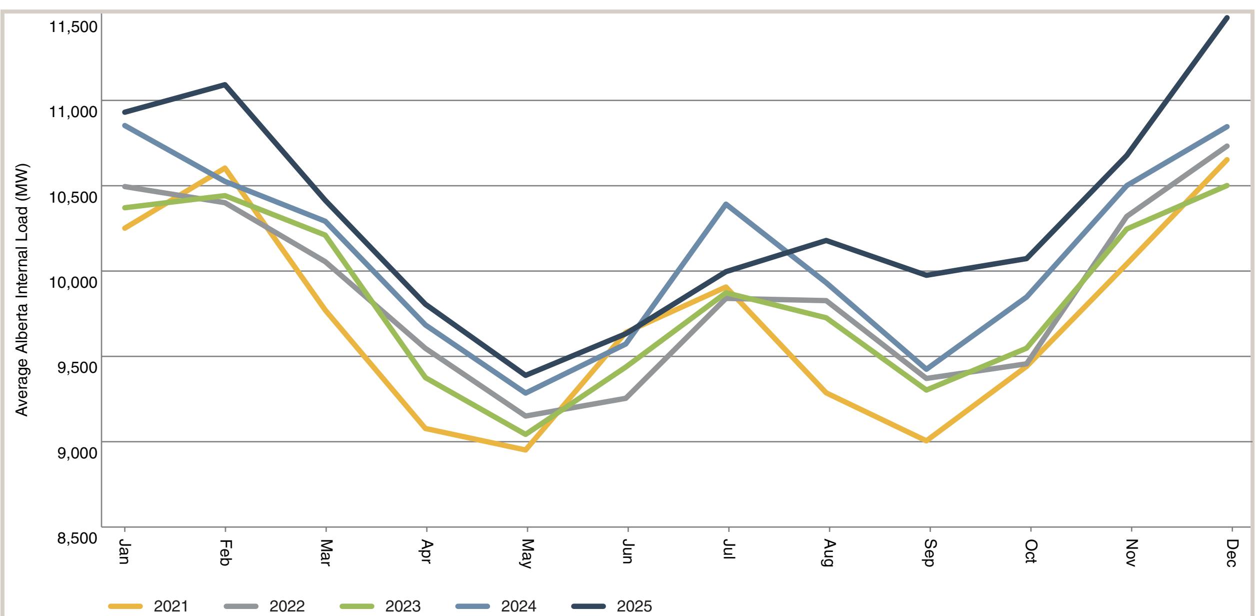
Key Observations:

- In 2025, the average Alberta Internal Load (AIL) grew by 2.0 per cent. The growth was broad based, but industrial load growth was higher than residential and commercial load growth.
  - Over the last five years, AIL has averaged 1.5 per cent growth.
  - The year-over-year increase in losses was 0.3 per cent of the 2.0 per cent load growth. Over the last five years, losses have grown an average of 10.0 per cent per year.
- After adjusting for year-over-year temperature differences, most of the growth was structural rather than weather-related.
- A decrease in the AIL load factor shows that high load periods in 2025 were more extreme than in 2024.
- Total AIL rose by 1.7 per cent which was lower than the average AIL increase of 2.0 per cent. This was because of the additional leap day in 2024.
- Average system load was higher year-over-year by 4.0 per cent due to increased usage of the bulk transmission system caused by higher overall demand, lower behind-the-fence (BTF) load, and an increase in system losses.
  - BTF load was lower by 2.7 per cent (80 MW) year-over-year likely due to lower pool prices, making it cheaper to use power from the bulk transmission system instead of BTF generation.
  - System losses were 12.1 per cent (34 MW) higher driven by more generation being provided by generators that are further from load than in previous years.

Monthly Average AIL

Figure 6 shows the monthly average AIL over the last five years. Typically, large year-over-year differences in AIL are primarily due to temperature variations between the years.

FIGURE 6: Monthly Average AIL

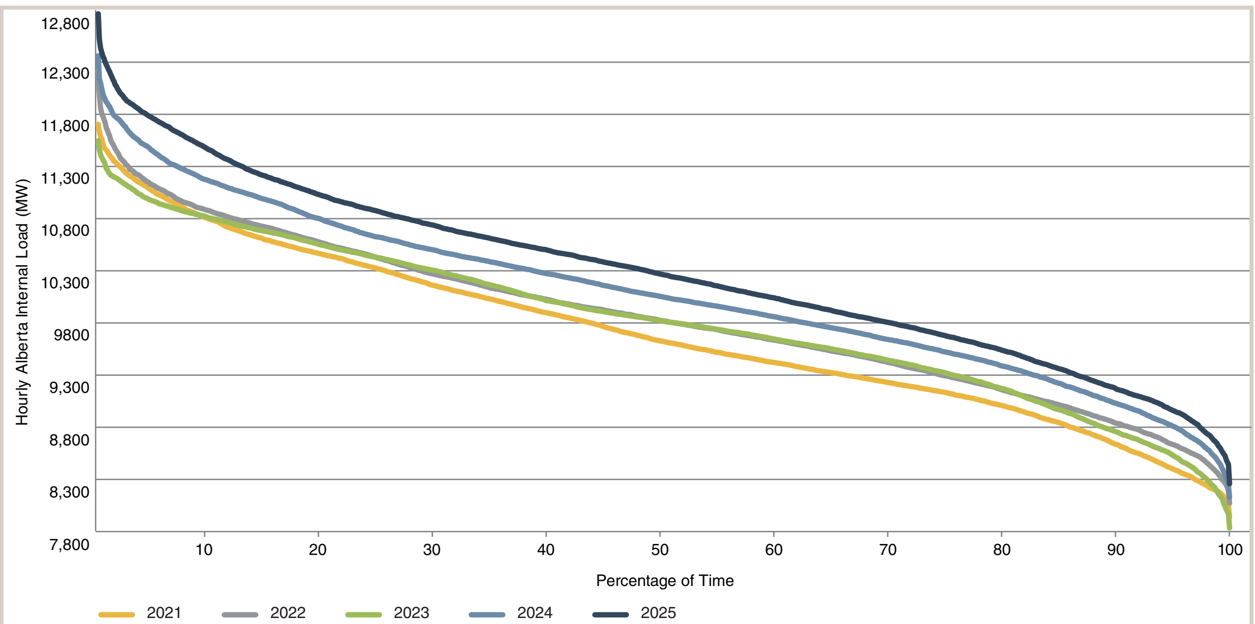


Key Observations:

- **2025:**
  - The extreme load growth observed in February and December were primarily a result of colder year-over-year temperatures, in addition to the underlying structural growth.
  - From August through November, growth was primarily structural rather than temperature-driven.
  - The AESO does not have access to data pertaining to the output of small generators, such as rooftop solar. However, the capacity of these assets is close to 200 MW higher since the end of 2023, and it is believed their output is masking some increased load related to population growth.
- **2024:** There was significant load growth observed in January and July caused by extreme cold and heat, respectively.
- **2023:** Wildfires led to load reductions of 100–150 MW during May and June, with smaller impacts through the summer and early fall.

Figure 7 plots the annual load duration curve over the last five years. The load duration curve shows the percentage of time AIL met or exceeded a specific volume.

FIGURE 7: Annual AIL Duration Curves



Key Observations:

- **2025:** Despite 2024 having more extreme weather periods, year-over-year load growth can be seen across all points of the duration curve. This is another indication that the load growth was primarily structural, rather than driven by weather.
- **2024:** Load growth compared to 2023 can be seen across all hours.
- **2022 to 2023:** Minimal changes occurred as compared to 2021, except for the highest and lowest 15 per cent of hours, which were driven by more extreme temperatures occurring in 2022.

Seasonal Load

Seasonal load statistics are based on the following periods:

- Winter: November 1 to April 30
- Summer: May 1 to October 31

Seasonal peaks in Alberta load typically align with periods of extreme temperatures: summer peaks are driven by heat and winter peaks by cold. Here are the current records for seasonal peaks:

- **July 22, 2024:** The summer peak electricity demand record of 12,221 MW was set during a period where Calgary and Edmonton experienced temperatures at least seven degrees above normal.
- **December 11, 2025:** A new winter and overall peak AIL of 12,785 MW occurred, 3.2 per cent higher than the previous record set in January 2024. The current record was set despite temperatures that were over 10 degrees Celsius warmer than during the previous record.

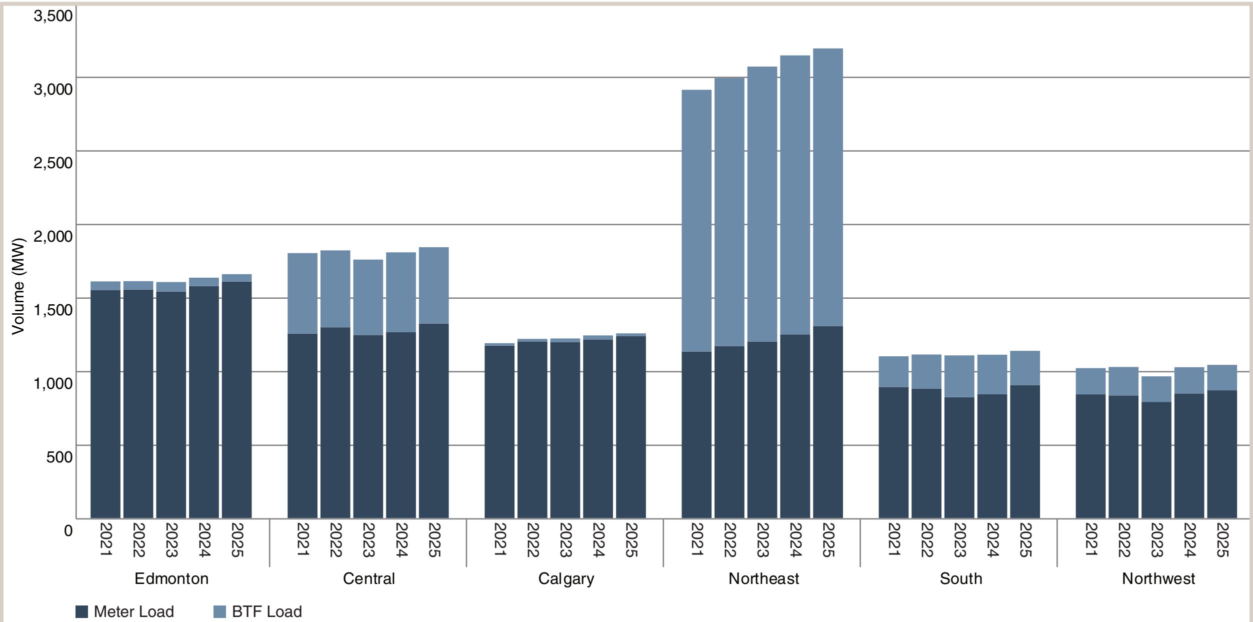
TABLE 3: Seasonal Peak Load

Season	PEAK AIL (MW)	Date	Calendar Year
Summer 2021	11,721	2021-06-29	2021
Winter 2021	11,939	2022-01-03	2022
Summer 2022	11,381	2022-07-28	2022
Winter 2022	12,193	2022-12-21	2022
Summer 2023	11,522	2023-07-24	2023
Winter 2023	12,384	2024-01-11	2024
Summer 2024	12,221	2024-07-22	2024
Winter 2024	12,241	2024-12-18	2024
Summer 2025	12,005	2025-08-27	2025
Winter 2025 (thru Feb 2026)	12,785	2025-12-11	2025

Regional Load

Figure 8 shows the average regional meter and BTF load over the last five years. The sum of the two loads is the average regional actual load. While AIL[2] increased 2.0 per cent in 2025, the regional growth rates were varied. Only the Central and Northwest regions did not set new annual average actual load records.

FIGURE 8: Regional Load



Key Observations:

- **Edmonton and Calgary:**
  - Average actual load increased by 1.5 per cent in Edmonton to (1,636 MW) and 1.2 per cent in Calgary to (1,239 MW). Both were new records.
  - The increase in load was most noticeable in the winter and shoulder months. Average summer load was a little higher, except for mid-July, when 2024 had some extreme temperatures.
  - The effect of population growth has been partly offset by increased rooftop solar capacity.
  - Over the last 5 years, Calgary load has grown an average of 1.4 per cent per year, while Edmonton has grown 0.8 per cent per year.
- **Central:**
  - Average actual load increased by 1.9 per cent to 1,817 MW, primarily due to growth at a variety of industrial sites.
    - Metered load was up 4.7 per cent (+59 MW), while BTF load was down 4.5 per cent (-24 MW).
  - Load growth was highest in the winter and summer months, while the shoulder months grew a little less than in 2024.

[2] The sum of the six regional average loads and losses is roughly equivalent to AIL. However, AIL is measured using SCADA data, while regional meter load uses revenue meter data. The two types of data are not exactly the same and the revenue meter data is subject to change up to 5 months after the flow month.

- Over the last 5 years, load growth has averaged 0.5 per cent.
- The highest average annual demand was set in 2018, at 1,852 MW.

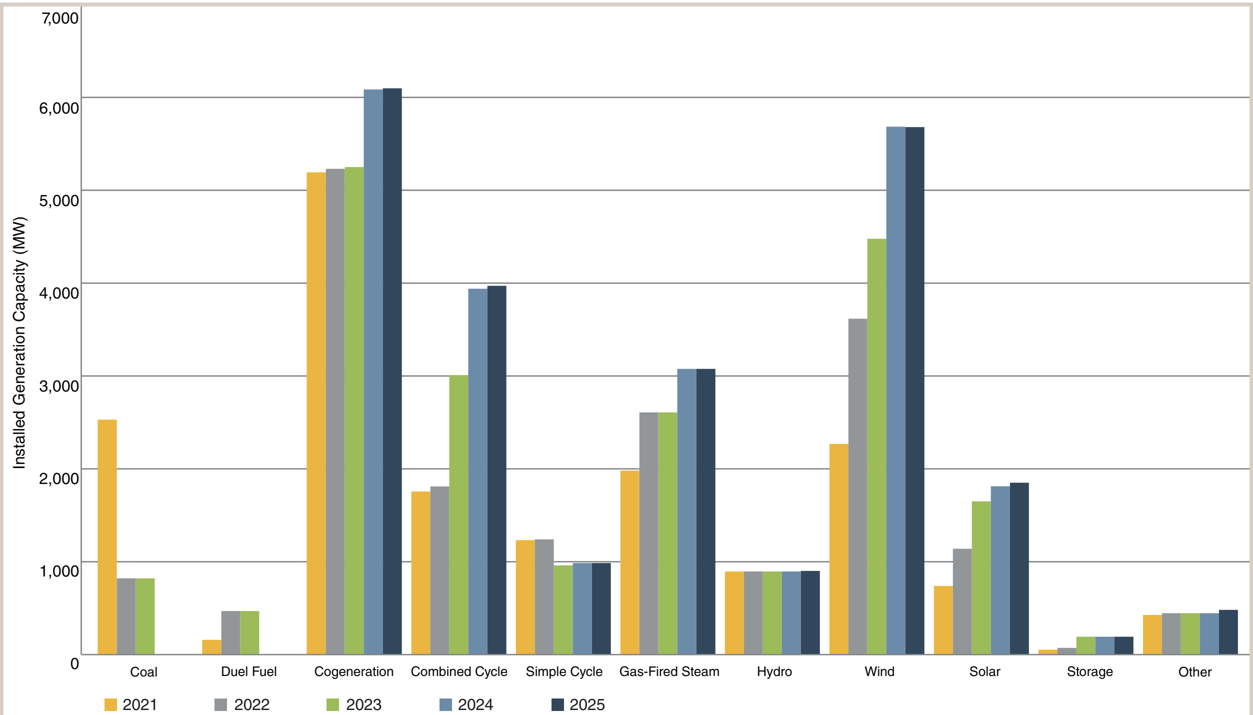
- **Northeast:**
  - Average actual load grew 1.5 per cent year-over-year to a new record average high of 3,150 MW.
    - This was primarily due to load growth at multiple oil sands sites.
    - Metered load was up 4.6 per cent (57 MW), while BTF load was down 0.5 per cent (-10 MW).
- **South:**
  - Average actual load increased by 2.4 per cent to 1,122 MW. The load growth was most noticeable in the shoulder seasons and December.
    - The increase was due to broad-based load growth in industrial and residential/ commercial consumers.
    - Metered load was up 7.5 per cent (62 MW), while BTF load was down 13.7 per cent (-36 MW).
  - Over the last 5 years, load growth has averaged 0.8 per cent.
- **Northwest:**
  - Load increased by 1.6 per cent to 1,028 MW, primarily due to new oil and gas activity, but offset by the loss of some pulp and paper load.
  - Over the last five years, load growth has averaged 0.5 per cent.
    - Load growth has been volatile, reacting to changing prices, as well as some load loss during the 2023 wildfires.
    - Load remains below the record set in 2018 at 1,045 MW.

Alberta Generation

Generation Capacity Increased by 0.5 per cent in 2025

Generation capacity in Alberta grew rapidly from 2021 to 2024, led by increases in wind and solar capacity. Several coal assets also converted to natural gas during this period. This pace of growth finally plateaued in 2025, with only minor capacity additions and changes during the year.

FIGURE 9: Year-End Gross Generation Capacity by Technology



Key Observations:

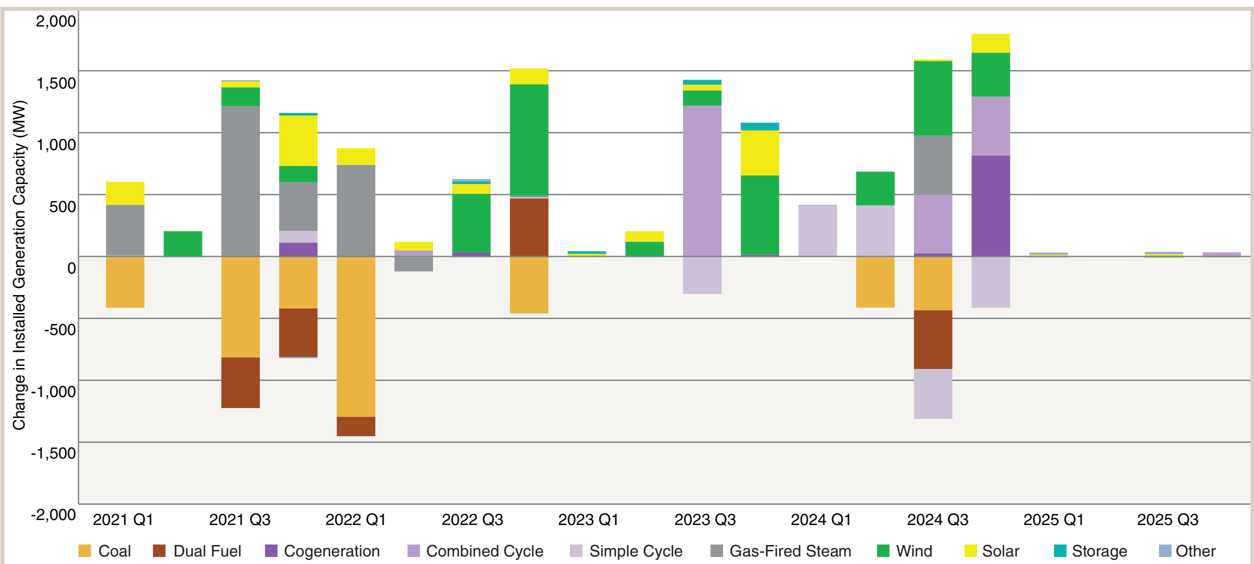
- Despite the retirement of coal assets, dispatchable installed capacity (excludes wind and solar) increased by 1,489 MW between 2021 and 2025.
- Wind and solar installed capacity increased by 4,529 MW between 2021 and 2025, but 2025's contribution to that growth was minimal.

TABLE 4: 2024-2025 Installed Generation Capacity by Fuel Type

Fuel Type	2024 No. of Assets	2024 Year End Capacity (MW)	2025 No. of Assets	2025 Year End Capacity (MW)	Change in No. of Assets	Change in Capacity (MW)
Cogeneration	41	6,090	41	6,104	0	14
Combined Cycle	11	3,942	11	3,974	0	32
Simple Cycle	35	984	35	984	0	0
Gas-Fired Steam	8	3,078	8	3,078	0	0
Hydro	9	894	9	899	0	5
Wind	50	5,688	50	5,684	0	-4
Solar	45	1,812	47	1,850	2	38
Storage[3]	10	190	10	190	0	0
Other	13	444	14	479	1	35
Total	**222**	**23,122**	**225**	**23,242**	**3**	**120**

Figure 10 shows quarterly capacity additions and retirements over the past five years, highlighting the transition from coal to natural gas and the growth in renewable generation types.

FIGURE 10: Quarterly Capacity Additions and Retirements by Technology



Key Observations:

- From 2021 to 2024, there was a prominent transition from coal to natural gas, including coal-to-gas conversions and new gas assets. At the same time, there was a significant buildout of wind and solar generating capacity.
- In 2025, growth of installed capacity of all types plateaued. The drivers behind this shift include:

[3] At the end of 2025, there was an additional 70 MW of storage capacity located within hybrid solar or hydro assets, which is not included in the count of storage capacity in this table.

- The increase in supply of wind, solar, and gas generation during 2021-2024 led to a significant fall in pool prices by 2025. The increased size of the wind and solar fleet led to even lower achieved prices for these intermittent assets (see the section on achieved prices).
  - Wind and solar assets also faced curtailments during times of supply surplus or transmission congestion due to the increased supply.
- The last remaining coal assets in Alberta were converted to gas in 2024, completing the transition away from coal and replacement with gas generation.

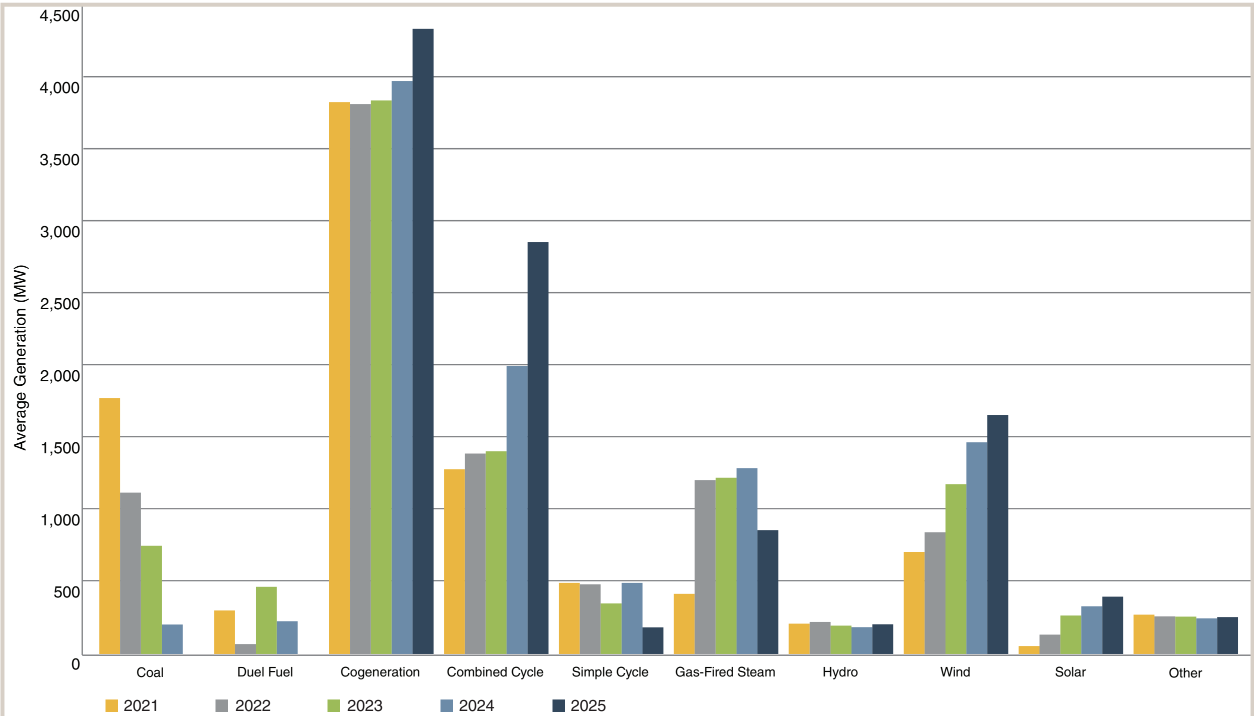
TABLE 5: 2025 Actual Gas, Wind, and Solar Capacity and 2024 LTO Projected Capacity

	2025 Actual	2025 Projection from 2024 LTO Reference Case
Year-end gas capacity (MW)	14,140	13,842
Year-end wind capacity (MW)	5,684	5,862
Year-end solar capacity (MW)	1,850	3,465

Gas Generation Supplied 76.8 per cent of all Electricity

With coal generation completely phased out since mid-2024, natural gas has become the dominant fuel type.

FIGURE 11: Annual Average Overall Generation by Technology[4]

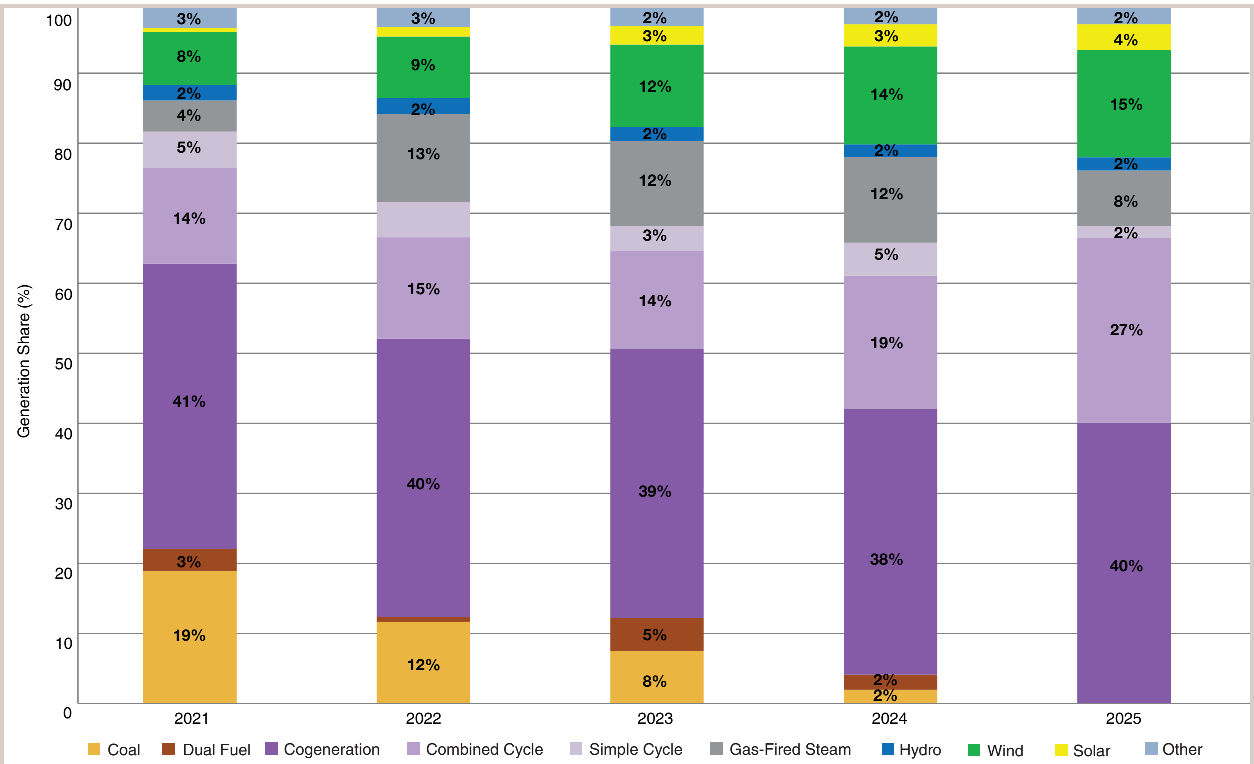


Key Observations:

- In 2025, gas-fired generation accounted for 76.8 per cent of Alberta's total generation, up from 74.7 per cent in 2024.
- Wind, solar and hydro generation provided 21.0 per cent of Alberta's generation in 2025, up from 19.0 per cent in 2024.
- The interim target of 20.0 per cent renewable generation by 2025, set under Alberta's Renewable Electricity Act, was achieved.
  - Under the Act, biomass and rooftop solar generation are included in the target. However, due to the difficulty calculating the actual output from this capacity, they are excluded from the AESO's renewable calculation. It's estimated that biomass and rooftop solar provided between 0.5 and 1.0 per cent of Alberta's generation.

[4] Generation calculated from all assets with a capacity greater than five MW.

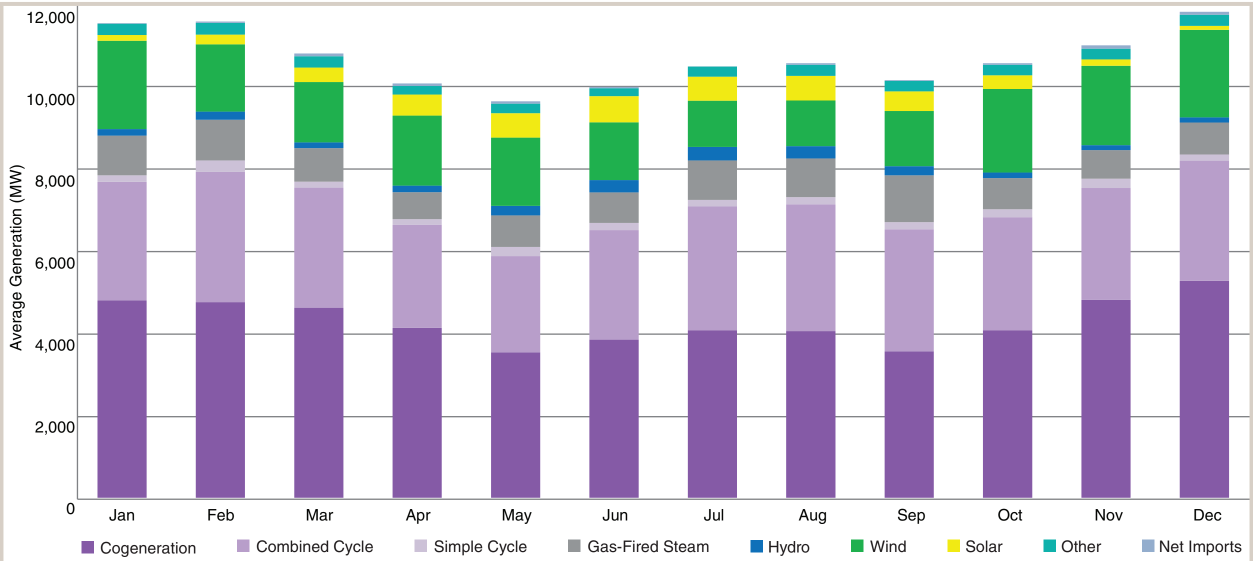
FIGURE 12: Share of Total Generation by Technology



Monthly Average Overall Generation

Average generation varies by month, aligning with higher demand during the coldest and warmest months.

FIGURE 13: Average Generation by Technology by Month (2025)



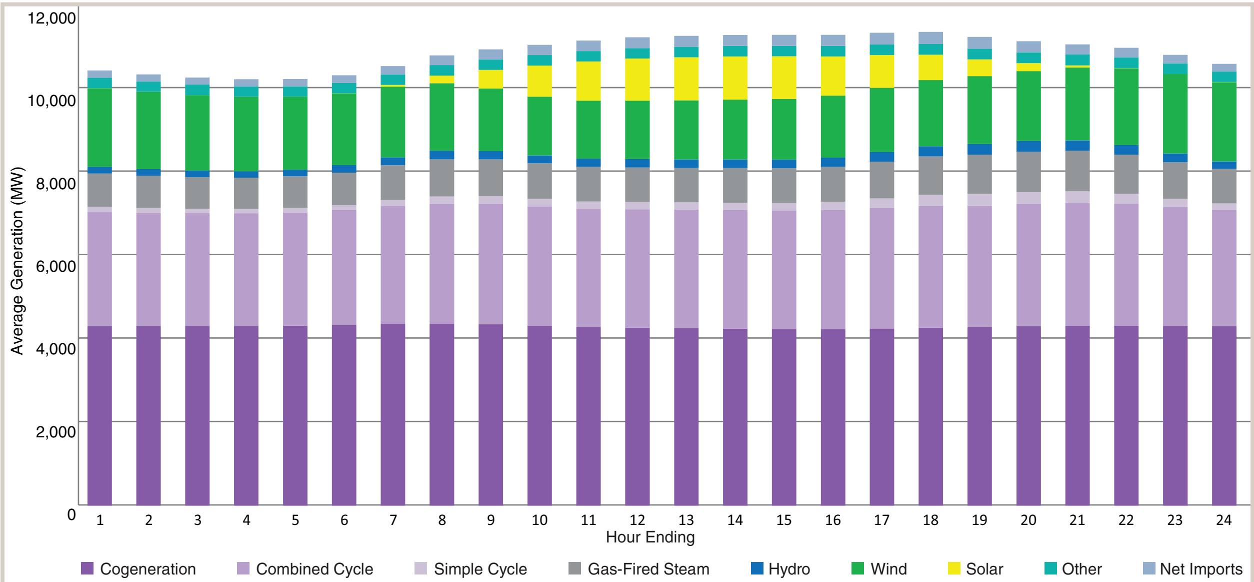
Key Observations:

- February and December recorded the highest average hourly generation, while May had the lowest. Load tends to be higher when temperatures are very cold or very warm.
- Wind generation was highest in January and October through December, while solar generation is highest during the long days of April through September.

Hourly Average Generation

Alberta's generation mix varies throughout the day due to the daily load patterns and the characteristics of wind and solar generation.

FIGURE 14: Average Generation by Technology by Hour (2025)

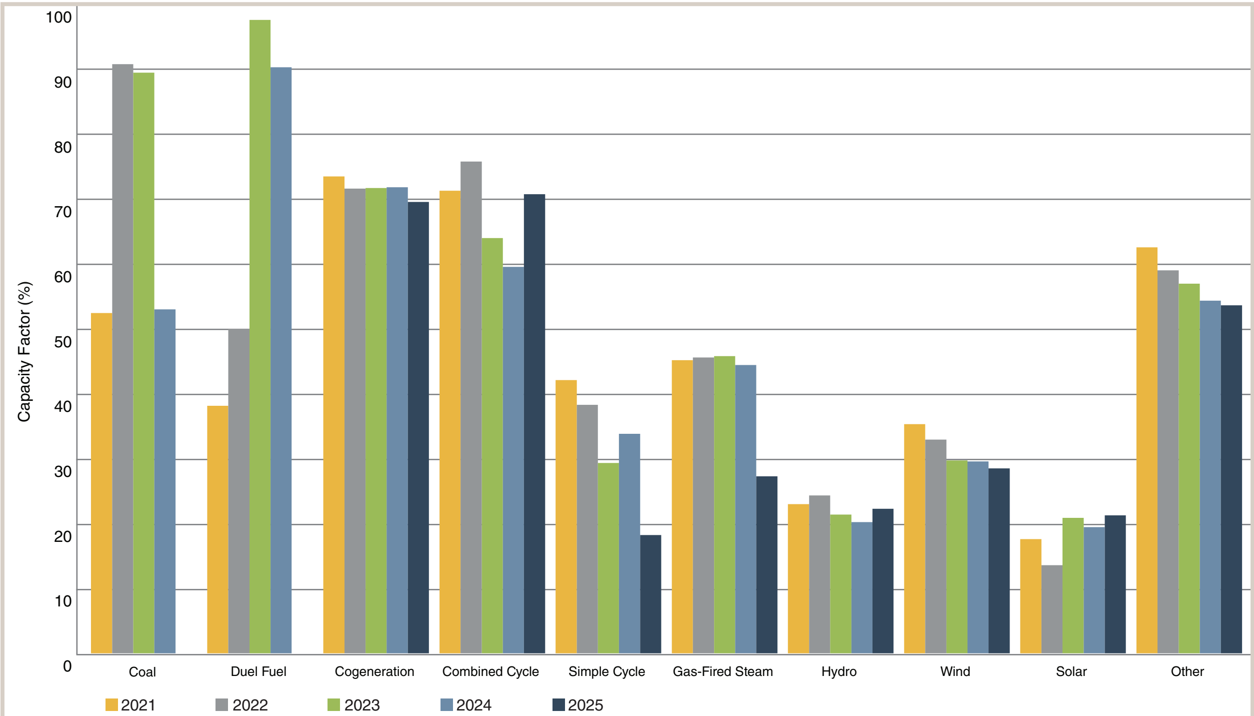


Key Observations:

- Wind generation tends to be slightly higher at night, while solar generation is only available during the day.
- Dispatchable thermal generation is at its highest during the evening peak hours when demand is highest and solar generation is dropping.
- Baseload thermal generation, such as cogeneration and combined-cycle gas units are steady throughout the day, while simple-cycle, gas-fired steam, and hydro assets fill in most daily variations.

Capacity Factors for Simple Cycle and Gas-Fired Steam Fell in 2025

FIGURE 15: Annual Capacity Factor by Technology [5]



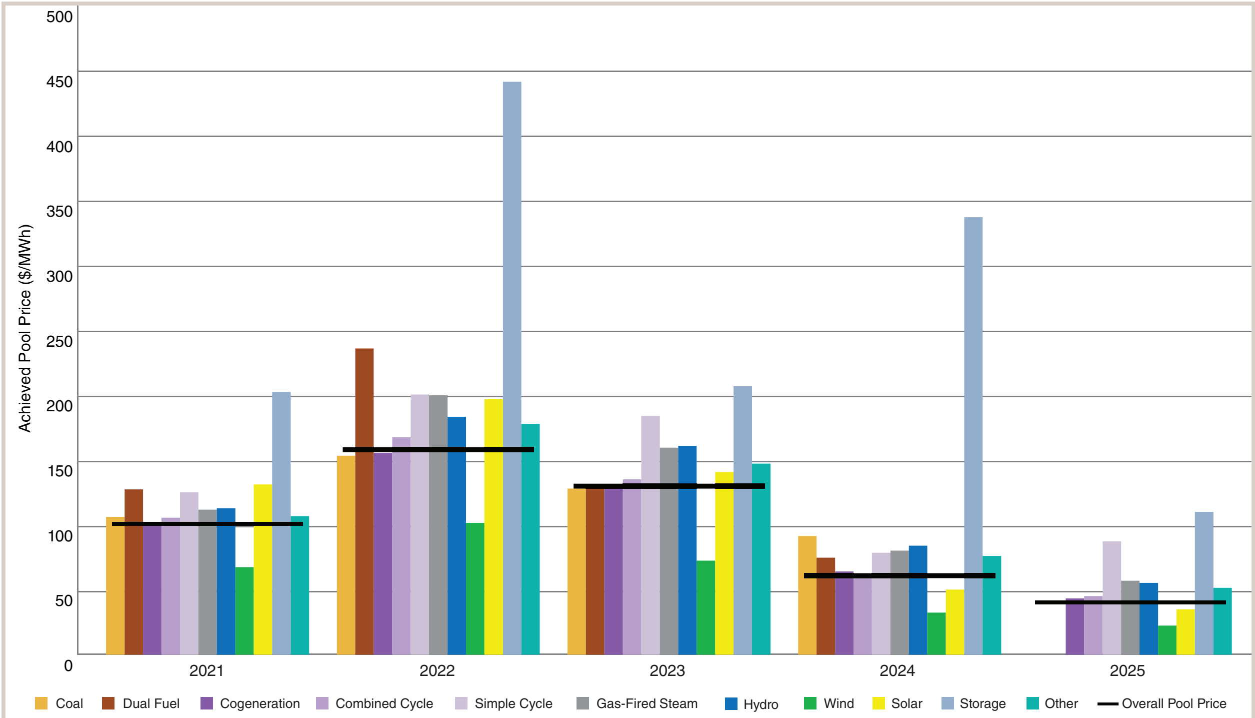
Key Observations:

- Fuel types providing baseload energy, including cogeneration and combined cycle, had the highest capacity factors. New combined cycle assets that were added in 2024 had completed commissioning by 2025, leading to an increase in the combined cycle capacity factor in 2025. Commissioning continued in 2025 for the new cogeneration capacity added in 2024, leading to a small decrease in the cogeneration capacity factor.
- With the addition of new baseload capacity in 2024, fuel types such as gas-fired steam and simple cycle were displaced and had a lower capacity factor in 2025.
- Gas-fired steam assets, all of which were long lead time assets, were commercially offline more in 2025 than 2024. In 2024, on average, 19.2 per cent of gas-fired steam capacity was commercially offline. In 2025, this rose to 29.1 per cent.

[5] Energy storage is excluded from this chart, as those assets do not have the ability to provide continuous generation over long periods of time.

Achieved Prices Drop for Most Fuel Types in 2025

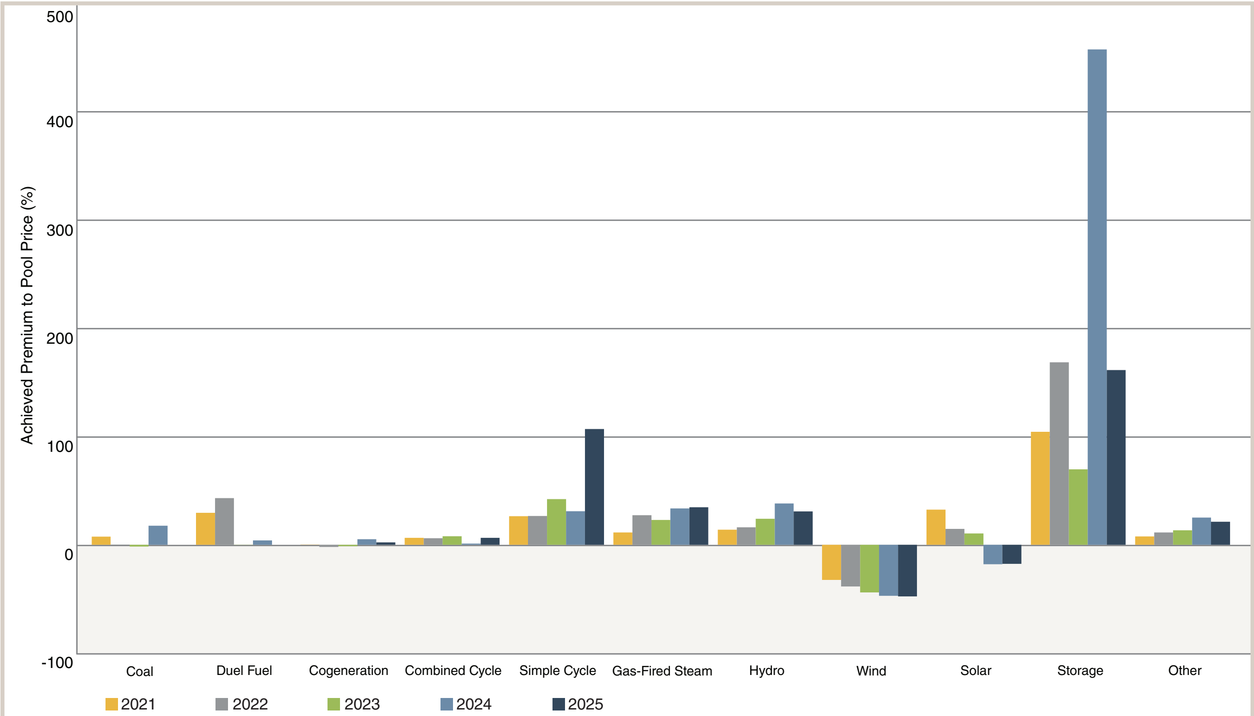
FIGURE 16: Annual Achieved Price by Technology



Key Observations:

- Lower average pool prices in 2025 resulted in a decline in the achieved price for most asset types compared to 2024.
- Simple-cycle assets generated less in 2025, but were more concentrated in higher priced hours, leading to an increase in achieved price compared to 2024.

FIGURE 17: Annual Achieved Premium-to-Pool Price

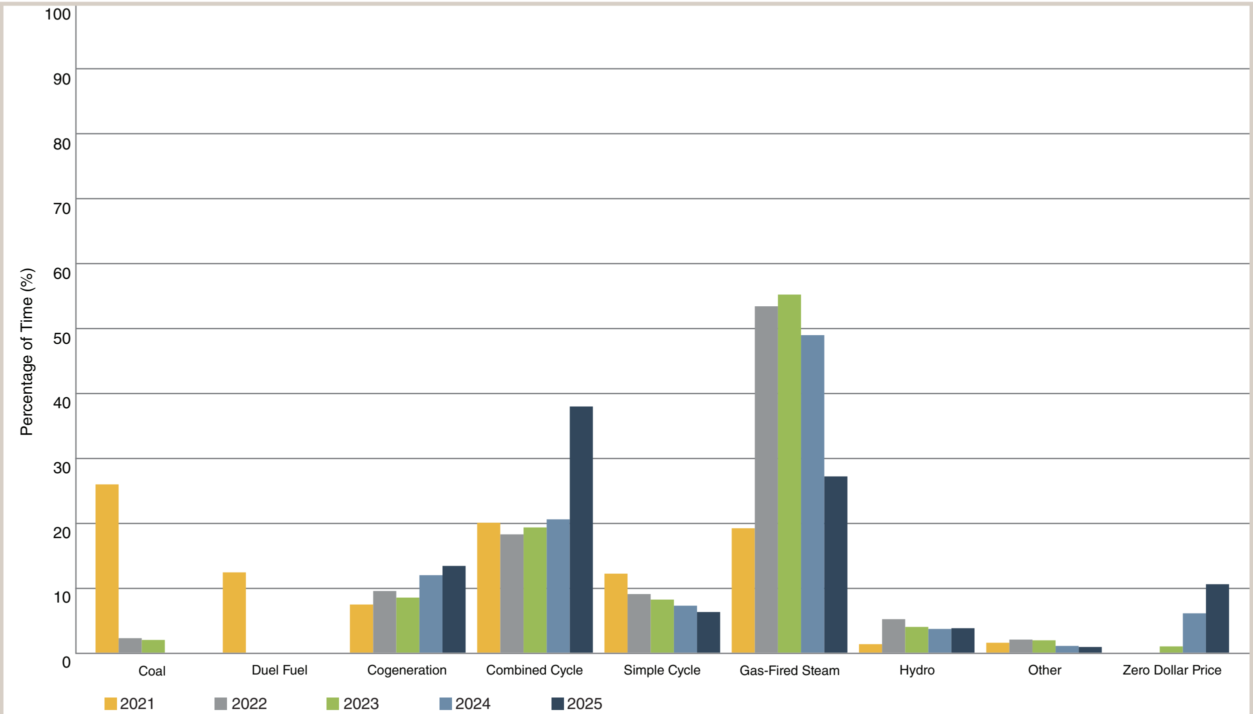


Key Observations:

- Combined cycle and cogeneration assets operated at baseload in 2025 and achieved prices near the average pool price.
- Simple-cycle, gas-fired steam, hydro, and energy storage units were more often dispatched during high-priced hours because they were offered higher in the merit order.
- Wind (-46.9 per cent) and solar (-17.4 per cent) were the only asset types to achieve a discount to average pool price.
  - The discount is a result of the fact that these assets are offered at $0 in the energy market and the highly correlated nature of their generation output.
  - Due to the lack of major additions to wind and solar capacity, there was minimal change to the discount when compared to 2024.

Combined Cycle Assets More Frequently Set Marginal Price in 2025

FIGURE 18: Annual Marginal Price-Setting Technology



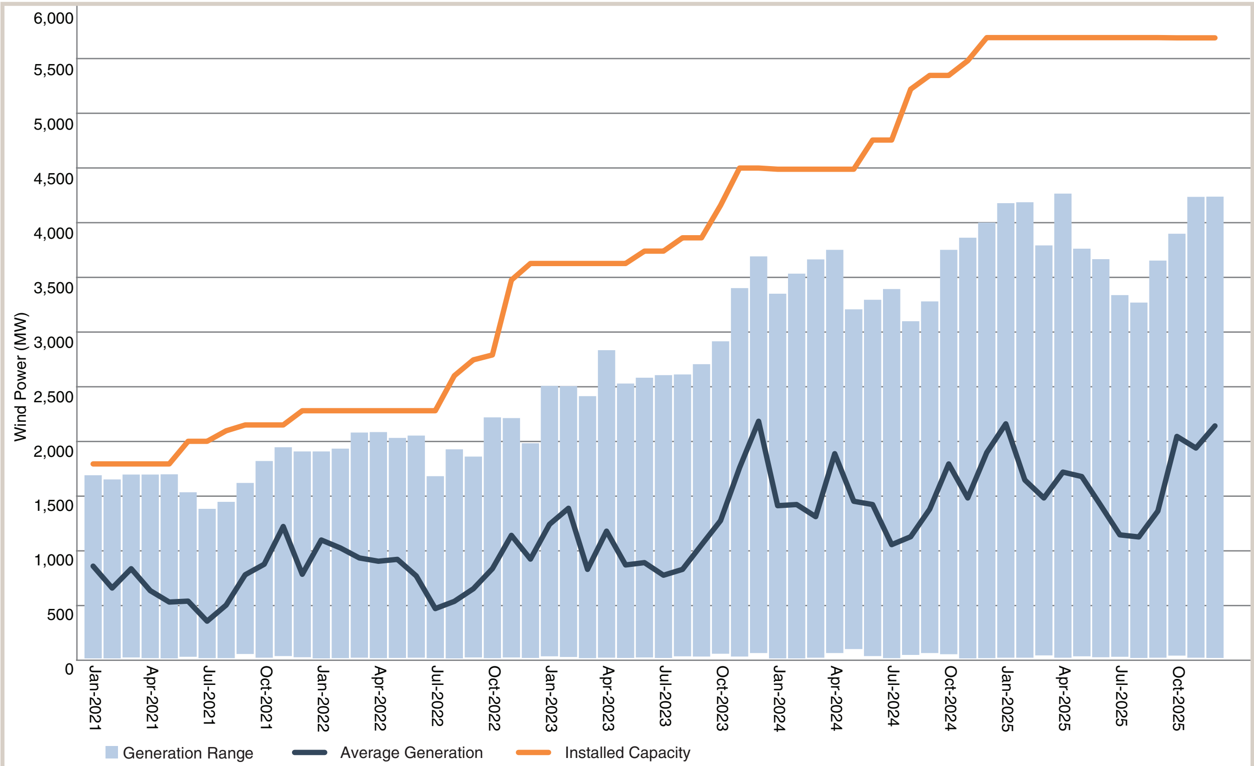
Key Observations:

- New combined cycle, cogeneration, wind, and solar capacity added throughout 2024 led to lower prices and a shift in marginal price-setting technologies in 2025.
  - Combined cycle generation was on the margin 38.0 per cent of the time--more frequently than gas-fired steam, simple cycle, and hydro assets, which are typically offered at higher prices.
  - A zero-dollar system marginal price (SMP) was observed 10.6 per cent of the time in 2025.[6]

[6] When the marginal price is $0, a supply surplus may be called if the amount of supply offered at zero dollars exceeds the amount needed to meet demand. If this occurs, all flexible zero-dollar energy offers, regardless of type, are proportionally reduced, so no single type is on the margin.

Total Wind Generation up by 12.5 per cent

FIGURE 19: Monthly Average Wind Capacity and Generation



Key Observations:

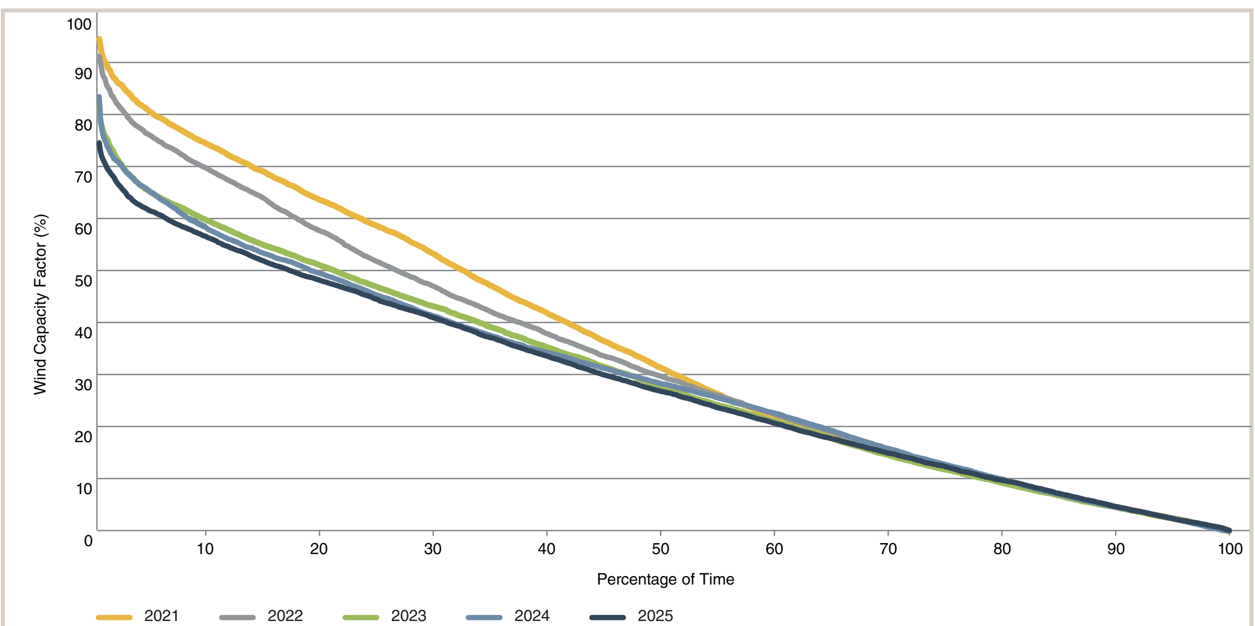
- In 2025, no new wind facilities connected to the grid. One wind asset decreased its installed capacity by 4 MW.
- Much of the new wind capacity added in 2024 did not reach full operation until 2025, so despite the lack of new capacity added in 2025, total wind generation increased by 12.5 per cent in 2025.
- During periods of high wind, wind generation was frequently impacted by transmission congestion constraints in 2025, limiting the increase in total generation. (See the Transmission Congestion section later in this report.)
- Since 2021, total wind capacity has increased by 150.5 per cent, while total output has increased by 134.2 per cent.
- Wind farms connected to the grid since late 2022 have taken up to 12 months to reach operation levels near maximum capacity.
  - Capacity added in 2024 began to increase output in 2025, but the potential increase, especially in late 2025, was curbed by transmission constraints.

TABLE 6: Annual Wind Generation Statistics

Year	2021	2022	2023	2024	2025
Installed wind capacity at year end (MW)	2,269	3,618	4,481	5,688	5,684
Maximum Hourly Generation (MWh)	1,933	2,208	3,683	3,993	4,258
Total wind generation (GWh)	6,133	7,314	10,283	12,797	14,393
Wind generation as a percentage of total AIL (Average)	7%	8%	12%	14%	16%
Wind generation as a percentage of total AIL (Maximum)	20%	24%	37%	42%	45%
Average hourly capacity factor	36%	33%	30%	30%	29%
Maximum hourly capacity factor	95%	91%	82%	84%	75%
Wind capacity factor during annual peak AIL	16%	17%	18%	24%	36%

Figure 20 shows annual duration curves for Alberta's wind generation capacity factors. The duration represents the percentage of time wind generation met or exceeded specific capacity factor values.

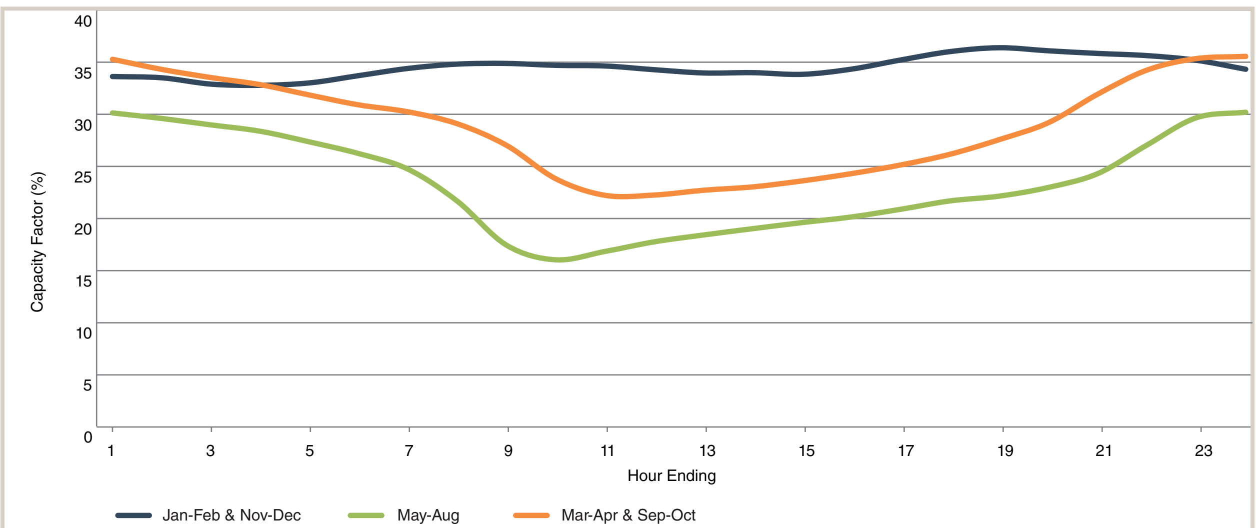
FIGURE 20: Annual Wind Capacity Factor Duration Curves



Key Observations:

- In 2025, the average wind capacity factor fell to 29.2 per cent from 30.2 per cent in 2024.
- The wind capacity factor was below 10.0 per cent for 20.7 per cent of hours in 2025. (For 2025, this means wind generation less than approximately 569 MW.)
- There were 102 periods of more than six consecutive hours with the wind capacity factor less than 10.0 per cent.
  - The average period length was 15 hours.
  - The longest period length was 62 hours.
  - These periods were 17.5 per cent of hours in 2025, which was the majority of the 20.7 per cent of hours with less than 10.0 per cent capacity factor.
- The wind capacity factor reached a maximum of 75.0 per cent in 2025, and the capacity factor was above 50.0 per cent for only 17.1 per cent of hours.
  - Transmission constraints and supply surplus conditions often result during periods of high wind, effectively capping the maximum total wind generation in many hours.

FIGURE 21: 2025 Wind Generation Seasonal Average Hourly Capacity Factor



Key Observations:

- Wind generation is highest in winter and drops in summer, following a seasonal pattern. Strong winds are more common in winter.
- Extreme weather, like polar vortexes or heat waves, includes conditions that lead to low wind output during high-demand periods.
- Wind generation generally peaks overnight and drops at midday, a trend seen more strongly in summer than in winter.

Stronger Wind Generation Growth in South Region

Wind generation facilities are spread across the South and Central regions.

TABLE 7: 2025 Regional Wind Statistics

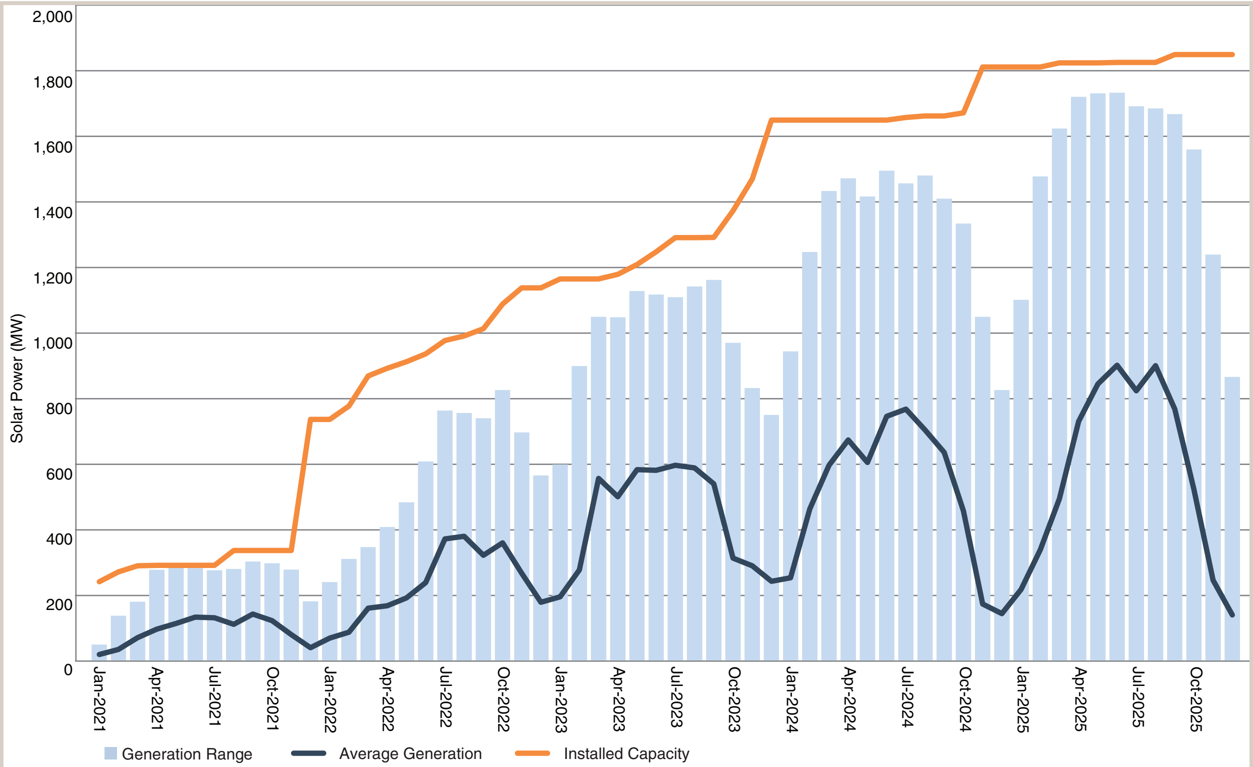
Region	Central	South	Total
Installed wind capacity at year end (y/y change) (MW)	1,456 (-4)	4,228 (+0)	5,684 (-4)
Total wind generation (y/y change) (GWh)	4,103 (+266)	10,290 (+1,331)	14,393 (+1,596)
Average wind capacity factor (y/y change)	32.1% (+0.2%)	27.8% (-1.5%)	29.0% (-1.0%)
Achieved price ($/MWh)	$24.39	$22.70	$23.18

Key Observations:

- **South**: 1,207 MW of new capacity was installed in the South in 2024, but primarily during the latter half of the year. Additionally, due to time spent commissioning, much of the generation installed in 2024 did not provide energy until later in 2024. Thus, total wind generation increased by 1,331 MW (14.9 per cent) in the South in 2025. However, the average capacity factor fell due to significant transmission congestion in 2025.
- **Central**: Only one new facility started operating in the Central region in 2024, so there was only a small increase in total generation in 2025. Since the smaller wind fleet in this region can sometimes generate asynchronously with the larger fleet in the South, it typically achieves higher prices.

Total Solar Generation up by 20.2 per cent

FIGURE 22: Monthly Average On-Peak Solar Capacity and Generation[7]



Key Observations

- Two new solar facilities with a combined capacity of 38 MW were added to the grid in 2025.
- Thanks to capacity added in late 2024, total solar generation increased by 20.2 per cent in 2025.
- Over 400 MW of solar generation installed under the Micro-generation Regulation is not included in these figures. These sites, which include rooftop solar, connect to distribution networks and don't report actual generation values to the AESO. More details on micro-generation assets can be found here: Micro- and Small Distributed Generation Reporting.
- Solar facilities, apart from the 465 MW Travers solar asset launched in 2022, typically reach commercial operation faster than wind facilities due to their smaller size.

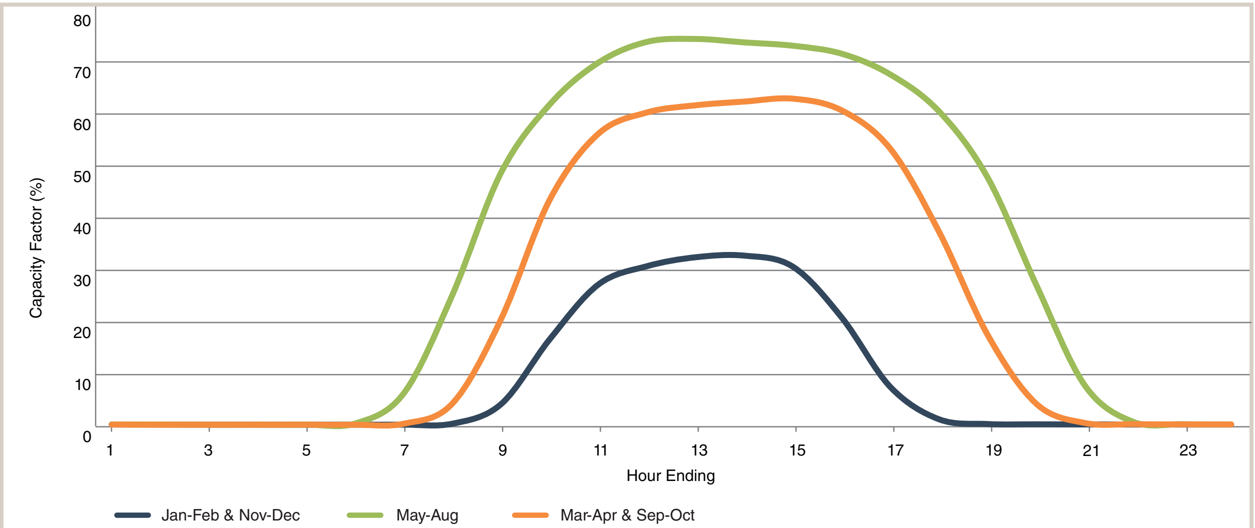
TABLE 8: Annual Solar Generation Statistics

Year	2021	2022	2023	2024	2025
Installed solar capacity at year end (MW)	736	1,138	1,650	1,812	1,850
Maximum Hourly Generation (MWh)	302	819	1,157	1,502	1,735
Total solar generation (GWh)	86	477	1,164	2,882	3,464
Solar generation as a percentage of total AIL (Average)	1%	1%	3%	3%	4%
Solar generation as a percentage of total AIL (Maximum)	3%	8%	12%	15%	18%

[7] Overnight hours, when there is no solar generation, are excluded.

Year	2021	2022	2023	2024	2025
Average hourly capacity factor	18%	14%	21%	20%	22%
Maximum hourly capacity factor	98%	78%	93%	91%	95%
Solar capacity factor during annual peak AIL	0%	0%	1%	0%	0%

FIGURE 23: 2025 Solar Generation Seasonal Average Hourly Capacity Factor



Key Observations

- Peak generation occurs between 10:00 a.m. to 3:00 p.m., with summer and shoulder months extending peak hours into the morning and early evening.

Interim Market Power Mitigation Rules

In March 2024, the Alberta government announced regulatory changes regarding economic withholding in the energy market and enacted two new regulations, the Market Power Mitigation Regulation (MPMR) and the Supply Cushion Regulation (SCR), collectively known as the Interim Market Power Mitigation Rules.

- The MPMR implements a secondary offer price limit once a certain net revenue threshold has been reached in a month.
- The SCR requires the AESO to direct long lead time assets online when the AESO's supply cushion is forecasted to be below a 932 MW specified threshold.
- The MPMR and SCR are implemented through Section 206.1 and Section 206.2 of the ISO rules, respectively, which came in effect July 1, 2024.

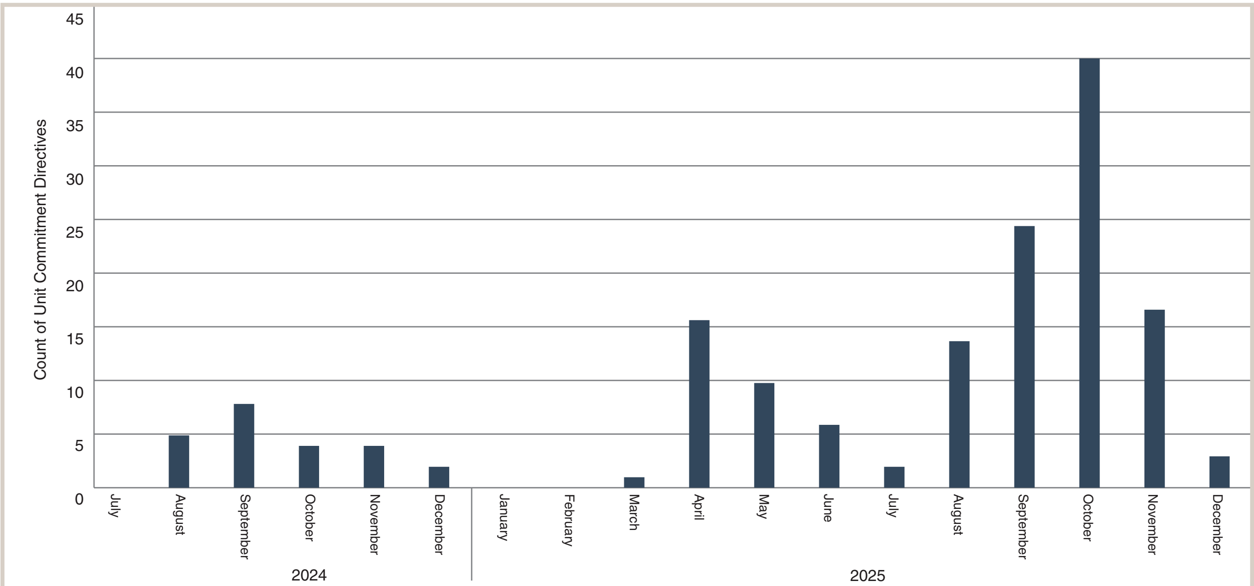
Secondary Offer Price Limit Not Triggered in 2025

After implementation, the secondary offer price limit was in effect for only one period, from hour-ending 02:00 on July 23, 2024, through the end of July 2024. It did not come into effect in 2025.

135 Unit Commitment Directives Issued

The AESO issued a total of 135 Unit Commitment Directives (UCD) to six separate eligible long lead time (LLT) assets in 2025.

FIGURE 24: Count of Unit Commitment Events by Month



Key Observations:

- There were a large number of UCD events in October 2025 due to significant transmission congestion. This led to a situation with low pool prices after price reconstitution, but also low supply cushion. The low prices meant LLT assets were unprofitable, but the low supply cushion required them online.

Imports and Exports

Alberta exchanges electricity with other jurisdictions through interties with British Columbia (B.C.), Montana (MATL), and Saskatchewan (SK). In 2025, the shift in intertie usage from imports to exports continued, driven by Alberta's growing capacity of low-cost generation.

Market Conditions and Outages Lead to Lower ATC in 2025

Figure 25 shows the average Total Transmission Capability (TTC) between Alberta, other Western Electricity Coordinating Council (WECC) members[8] and Saskatchewan. The average Available Transfer Capability (ATC) is shown for comparison. Table 9 compares the overall average WECC ATC to the average during import hours only.

FIGURE 25: Average Annual Path Rating by Transfer Path

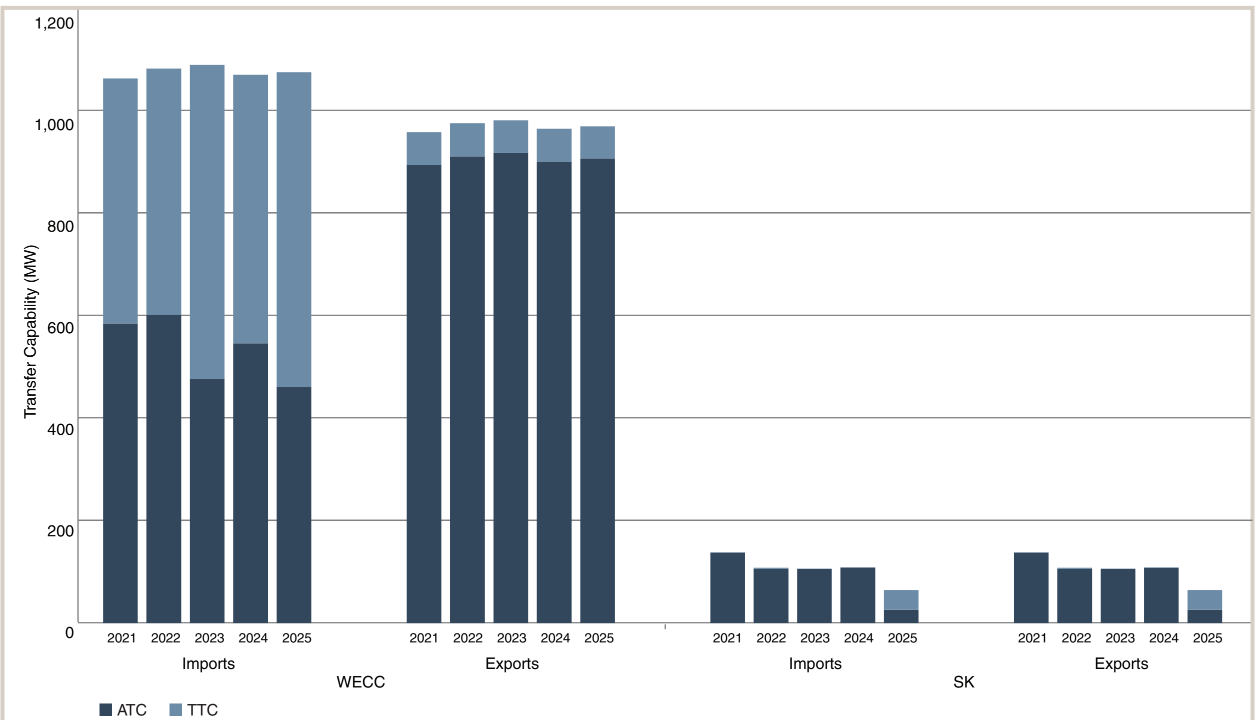


TABLE 9: Average WECC Import ATC during Net Import Hours

Year	2021	2022	2023	2024	2025
Average WECC Import ATC in all hours (MW)	586	602	477	547	**461**
Count of hours with scheduled net imports	8063	7395	4712	2586	**1768**
Average WECC Import ATC during net import hours (MW)	609	623	453	525	**446**

[8] Alberta, B.C., and Montana are members of the WECC region while Saskatchewan is part of the Midwest Reliability Organization (MRO). 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.

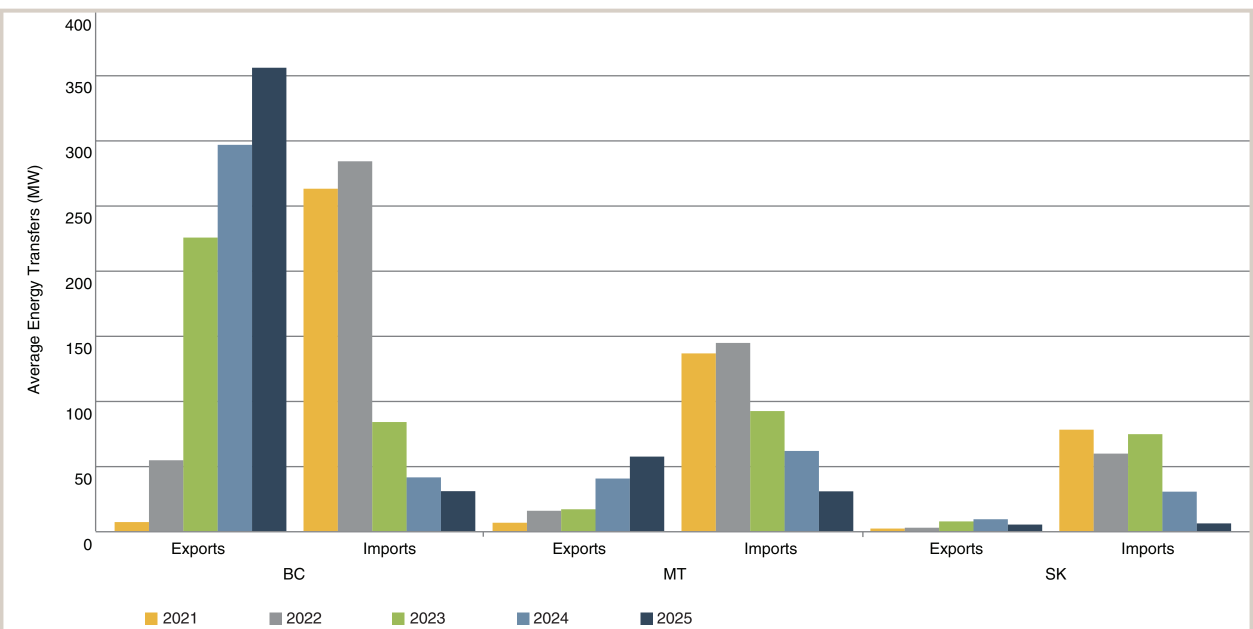
Key Observations:

- In 2023, the average WECC import ATC declined due to updated reliability requirements that increased the amount of Load Shed Service for imports (LSSi) or Fast Frequency Response (FFR)[9] needed to support imports.
- When looking at all hours, average import ATC for the WECC interties (B.C. and MATL) decreased by 85 MW in 2025 compared to 2024.
  - Likely because of the infrequency of import hours in 2025, some generation assets capable of providing FFR chose to participate in other markets for much of the year. This led to lower FFR volumes and a lower average ATC in both export hours and import hours.
  - Only 20 per cent of hours had imports in 2025, compared to 30 per cent in 2024.
- Since 2023, the average import ATC during net import hours has been lower than the overall average. This is because some loads that provide FFR are also price responsive. Since import hours often occur during periods of higher pool prices, the reduction in load from price responsive loads can lead to lower FFR availability in those hours.
- Outages on the SK intertie, both partial and full, reduced its average capacity during 2022, 2023, and 2024. TTC on the SK intertie was at zero due to an outage from late-2024 until mid-June 2025. At that point, TTC was raised to 153 MW, but ATC remained at zero and the intertie remained available for emergency power only until the end of October, when the intertie returned to full service.

Exports Up and Imports Down in 2025

Alberta crossed the threshold from net importer to net exporter in 2024. In 2025, the trend continued, with Alberta exporting over six times more power than it imported. This was primarily the result of lower pool prices in Alberta due to increased generation capacity.

FIGURE 26: Annual Intertie Transfers by Province or State

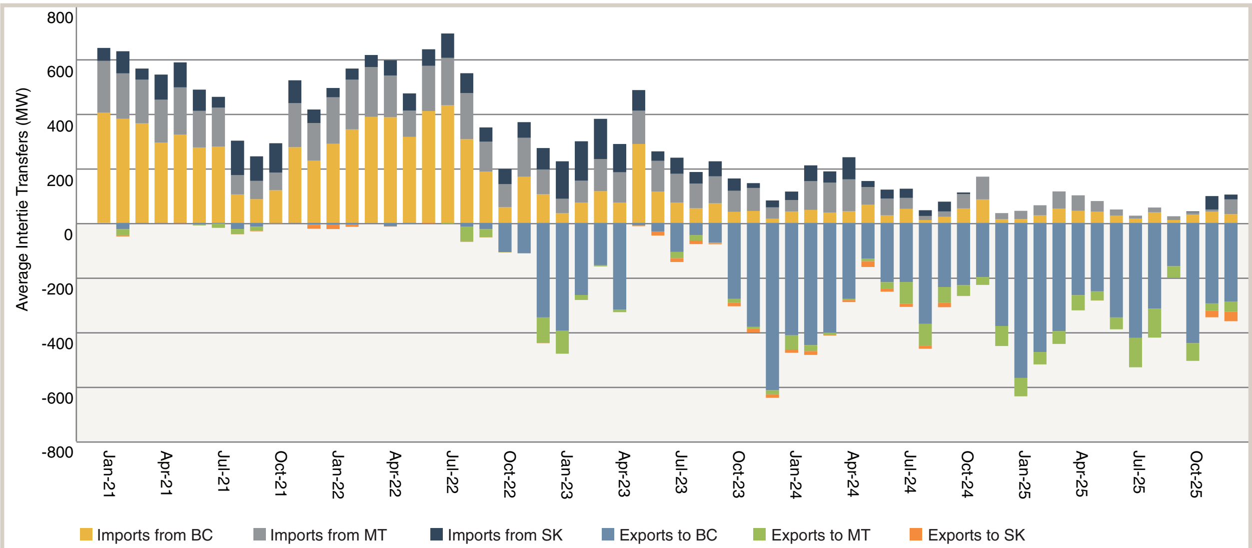


[9] FFR replaced LSSi in 2024. Both products provide a similar service, but LSSi is for load assets only, while FFR can also be provided by generation assets.

Key Observations:

- The average total scheduled flow was 348 MW in the net export direction in 2025, compared to 212 MW of net exports in 2024.
  - Average exports were 415 MW in 2025, while average imports were 66 MW.
- Most exports flowed into B.C., with average exports of 353 MW.
- Exports exceeded imports on MATL for the first time since 2017.
- Transfers on the Saskatchewan intertie were minimal due to a prolonged outage, but imports were slightly higher than exports.

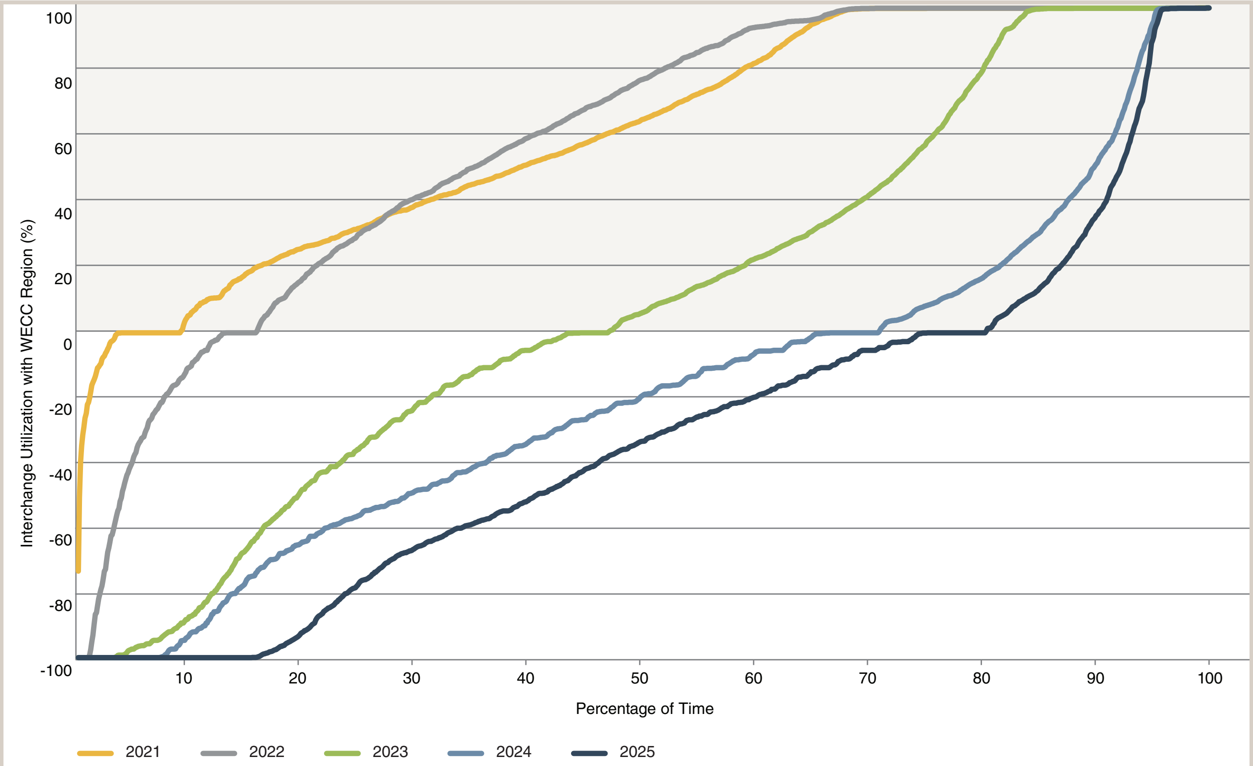
FIGURE 27: Monthly Average Intertie Transfers



Key Observations:

- Alberta's total monthly exports exceeded imports in every month of 2025.
- Net-exports were highest in January 2025, due to plentiful wind and thermal generation and seasonally mild temperatures.
- Since late 2022, dry conditions in B.C. and the Pacific Northwest, plus increased supply in Alberta, have structurally shifted trade flows from imports to exports to both B.C. and Montana.

FIGURE 28: Annual Interchange Utilization with WECC Region[10]



Key Observations:

- Alberta was a net exporter to WECC in 75.0 per cent of the hours in 2025.

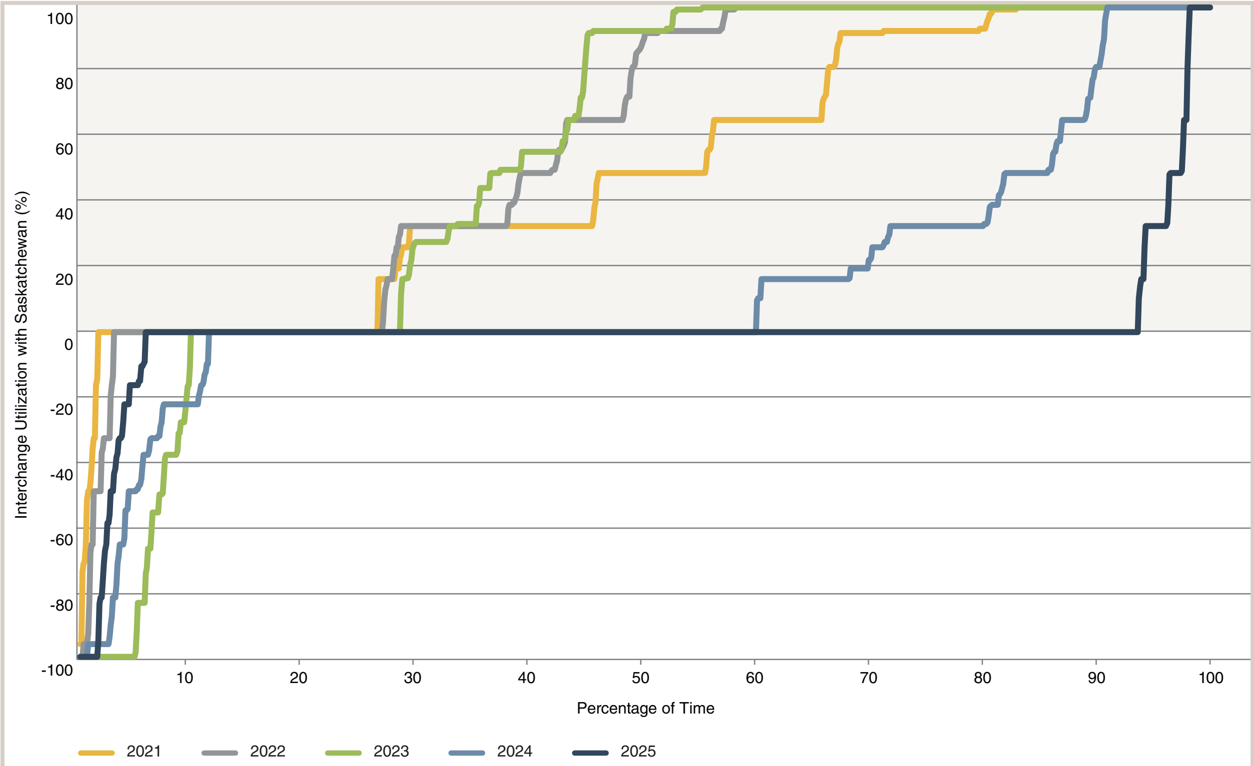
Table 10 shows how frequently the ATC limit was reached on the WECC interties each year. The ATC is considered binding in an hour if ATC is greater than zero and net offers exceed the ATC.

TABLE 10: Per cent of Hours with WECC ATC Binding

Year	2021	2022	2023	2024	2025
Hours with WECC Import ATC Binding (%)	38%	46%	20%	6%	5%
Hours with WECC Export ATC Binding (%)	0%	1%	5%	8%	19%

[10] Interchange utilization is the percentage of available transfer capability (ATC) used to transfer energy between jurisdictions. This chart displays actual flows, not scheduled flows based on offers.

FIGURE 29: Annual Interchange Utilization with Saskatchewan

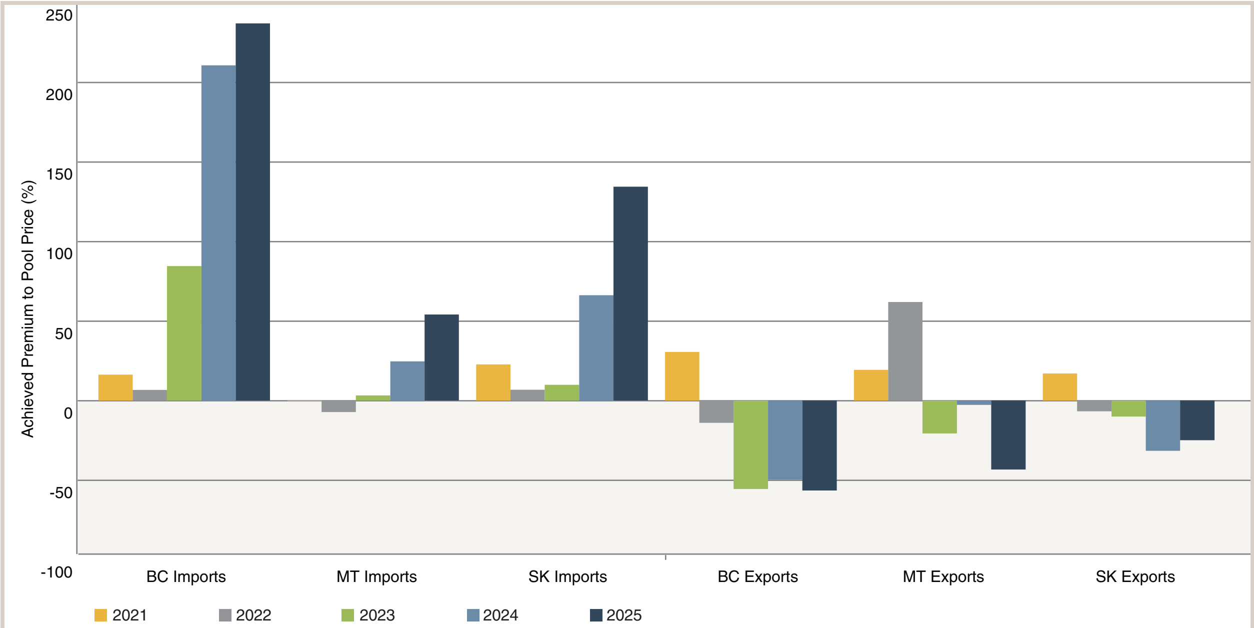


Key Observations:

- Alberta was marginally a net importer from Saskatchewan in 2025. However, transfers were at zero for 87.2 per cent of the year, due to an extended outage in place from before the start of the year until October 29.

Imports Received High Premium to Pool Price

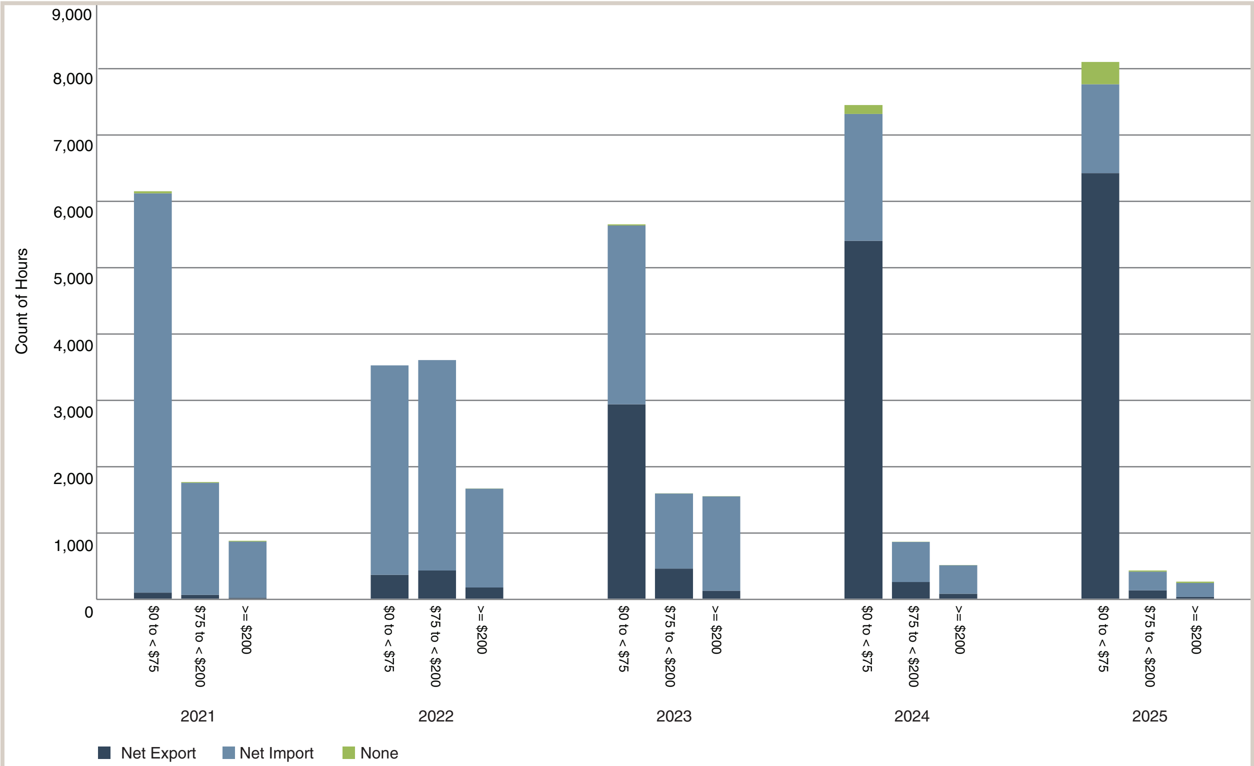
FIGURE 30: Annual Achieved Premium to Pool Price on Imported and Exported Energy



Key Observations:

- In 2025, imported electricity consistently cleared at prices above Alberta's average pool price, while exports cleared at a discount.
- Import premiums increased across all interties and export discounts were higher on the B.C. and MATL interties.
  - Imports from B.C. achieved prices 240.9 per cent higher than the overall average pool price. The limited volume of imports occurred almost exclusively during the highest-priced hours.
- The increase in both the import premium and export discount on MATL suggests greater flexibility for arbitrage opportunities with non-Alberta jurisdictions than observed in the past.

FIGURE 31: Yearly Count of Hours by Price and Net Import/Export Status



Key Observations:

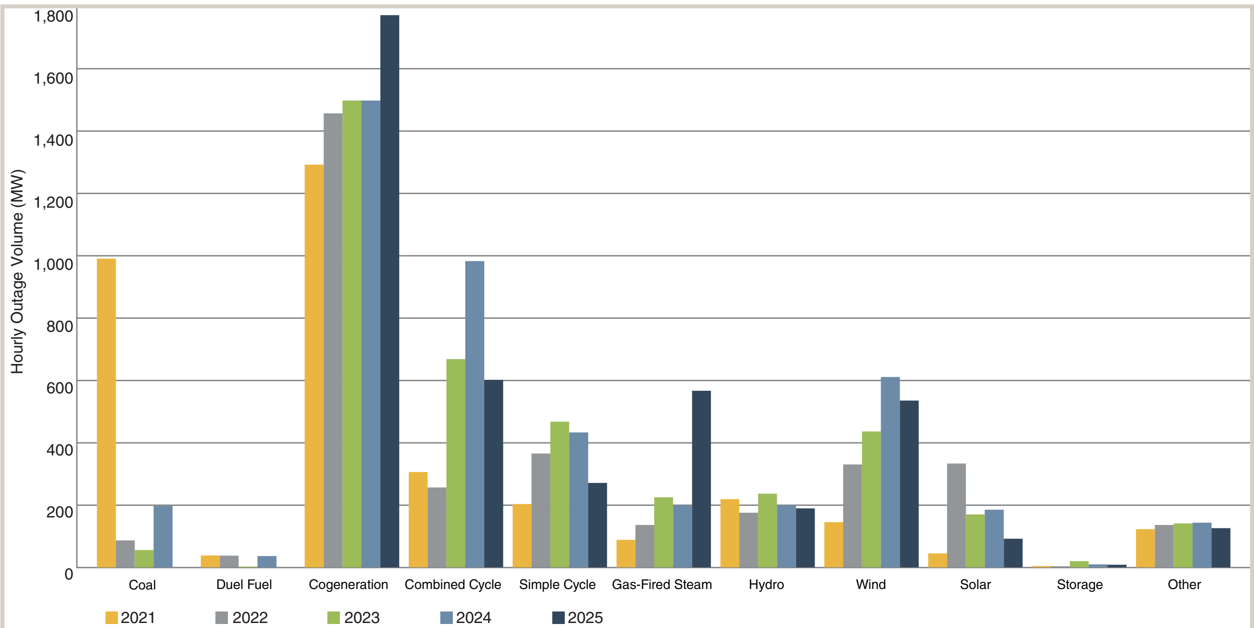
- In 2021-2022, net imports (across all interties combined) occurred more often than net exports across all price categories.
- In 2023 through 2025, low-priced hours became more increasingly more frequent compared to 2022. Exports during those low-priced hours also increased each year.
- In 2025, imports were still more common than exports during hours when prices exceeded $75.

Supply Adequacy

Supply adequacy measures the system's ability to meet electricity demand. While this section reviews past performance, a detailed analysis of future supply adequacy is available in the AESO's quarterly Long-Term Adequacy Metrics report.

Generation Outages Lower Overall in 2025 as Commissioning Completed

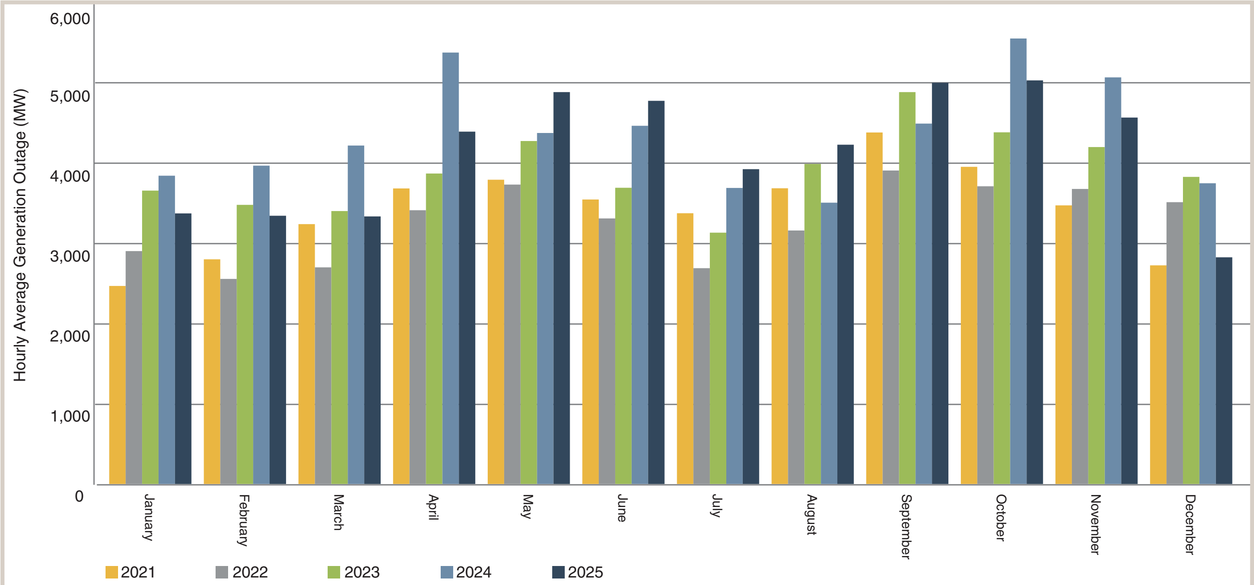
FIGURE 32: Annual Hourly Average Generation Outages by Fuel Type



Key Observations:

- Total average generation outages fell from 4,484 MW in 2024 to 4,153 MW in 2025. The decline reflects the high outages related to the commissioning of new assets in 2024.
- The addition of 806 MW of cogeneration capacity at Base Plant (SCR1) in Q4 2024 increased average cogeneration outages while commissioning continued through much of 2025.
- Sundance 6, a gas-fired steam unit, entered mothball status in April 2025, contributing to higher gas-fired steam outage volumes.

FIGURE 33: Generation Outages by Month



Key Observations:

- As is typical, outages in 2025 were highest during the months of April-June and September-November. Planned outages are often scheduled during these times because expected load is typically lower than other months.

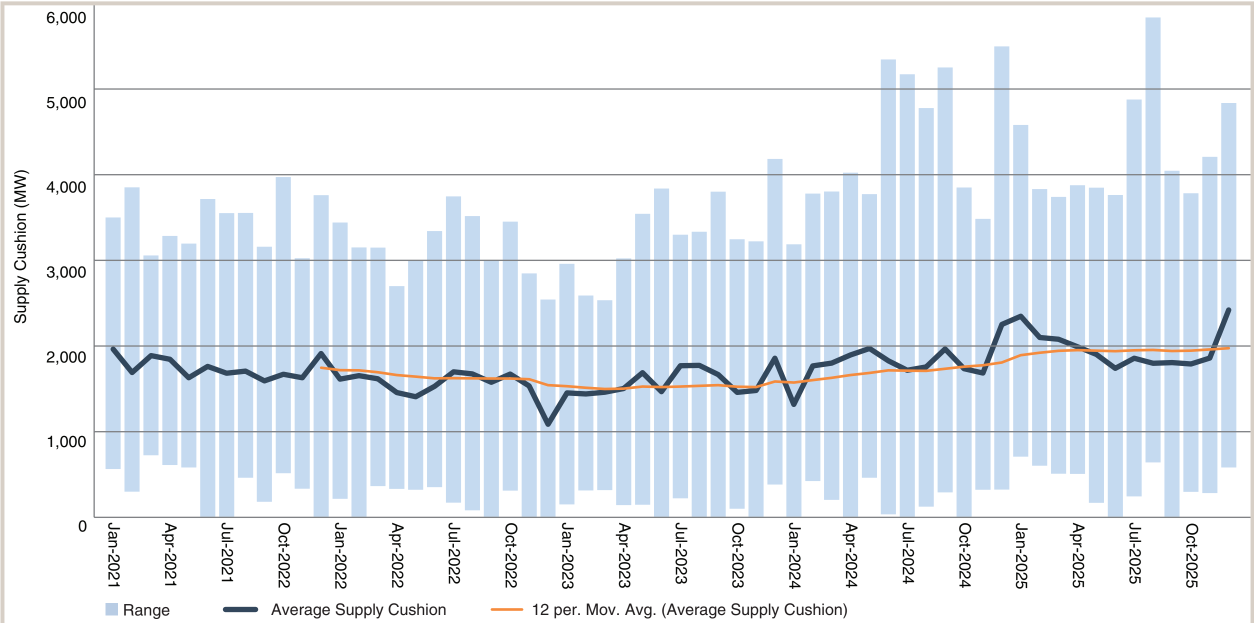
Average Supply Cushion Increased 9.3 per cent

The hourly supply cushion represents the extra energy in the merit order available for dispatch after meeting demand.

TABLE 11: Supply Cushion Summary by Year

Year	2021	2022	2023	2024	2025
Minimum Supply Cushion (MW)	0	0	0	0	0
Average Supply Cushion (MW)	1,735	1,530	1,574	1,794	1,960
Maximum Supply Cushion (MW)	3,950	3,725	4,161	5,471	5,807

FIGURE 34: Monthly Supply Cushion



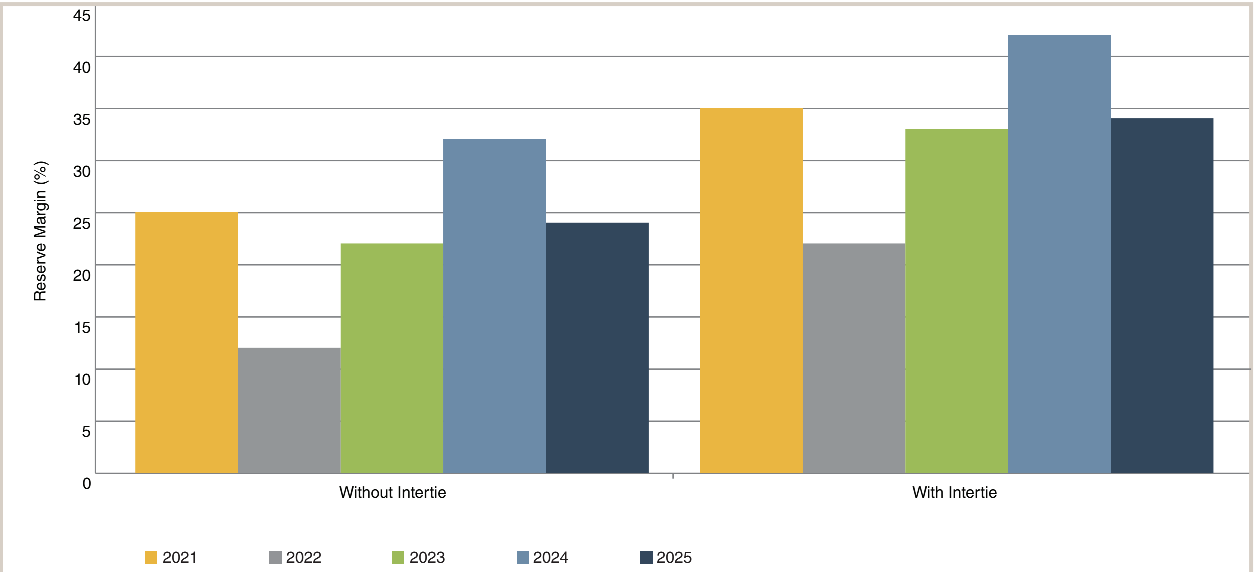
Key Observations:

- In 2025, the average supply cushion increased by 9.3 per cent compared to 2024, driven by the additions of new supply during 2024.

Reserve Margin Fell 8.5 Per Cent

Reserve margin measures the system generation capability above what is needed to meet peak system load.[11]

FIGURE 35: Annual Reserve Margin



Key Observations:

- In 2025, the reserve margin without intertie fell from 32.6 to 24.1 per cent.
  - Peak load increased by 401 MW and the Sundance 6 mothballing reduced usable capacity by 400 MW compared to 2024.

One Grid Alert Issued in 2025

The AESO declared a grid alert from 18:54-20:09 on Sep 8, 2025. All available energy in the merit order and some contingency reserves were required to meet demand. In the end, all demand was served; no load shed was required. Contributing factors that led to the event included:

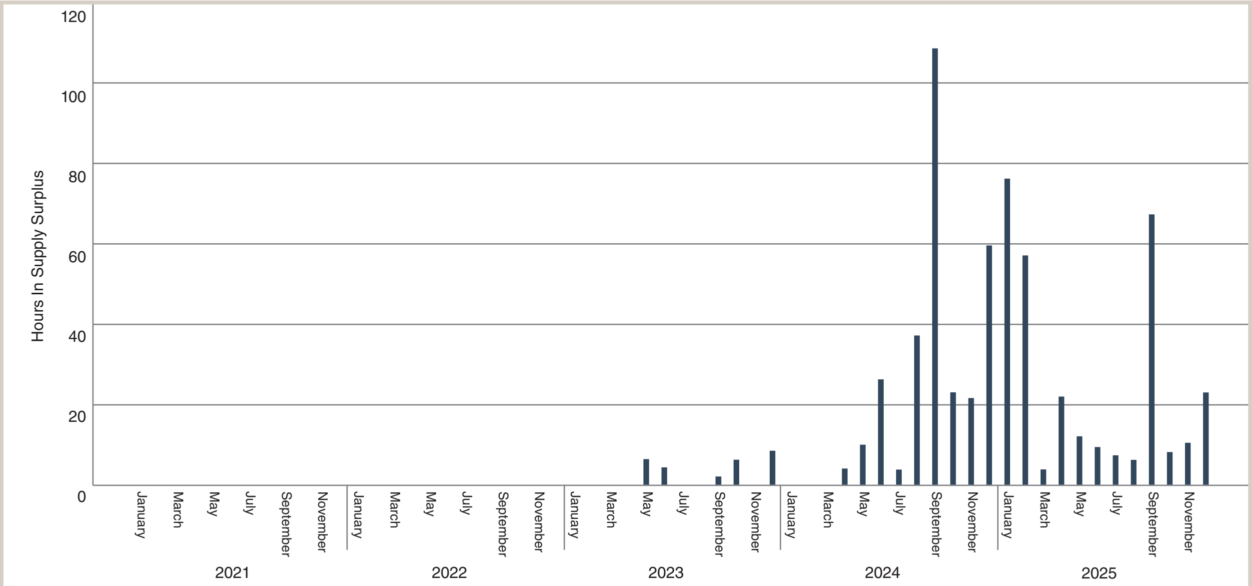
- An outage on the B.C. side of the intertie that severely limited available imports
- Low wind and solar output
- Outages and derates (both forced and unforced) of some dispatchable generation assets

Supply Surplus Events Called 99 Times in 2025

Supply Surplus events occur when the total amount of energy offered into the merit order at zero dollars exceeds the total energy required to be dispatched.

[11] 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.

FIGURE 36: Monthly Total Duration of Supply Surplus Events



Key Observations:

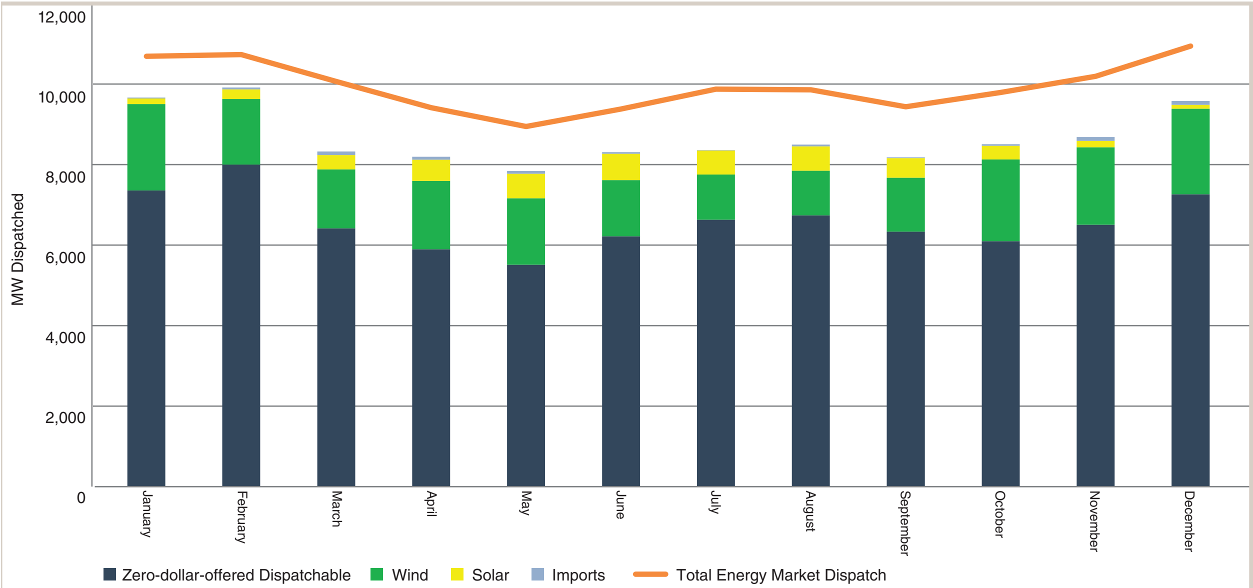
- Supply surplus events totaled 298 hours, or 3.4 per cent of the year, in 2025. This was up slightly from 290 hours in 2024.
- Most events in 2025 occurred during:
  - Parts of the winter months when temperatures were moderate, generation outages were low, and wind generation was very high.
  - The September BC/MATL intertie outage that prevented exports.
- Some market participants changed their behaviour to reduce the supply surplus hours outside of the above conditions in 2025.

Even outside of supply surplus periods, most dispatched energy is offered into the merit order at zero dollars. These offers exhibit “price-taking” behaviour, indicating a willingness to be dispatched at any price. There are a number of reasons for these zero-dollar offers:

- Thermal assets, such as combined cycle assets, that want to stay online over multiple hours will offer their minimum stable generation volume at zero dollars.
- Cogeneration assets have a volume of energy that is required to maintain industrial processes.
- Hydro assets have a minimum must-run volume to ensure their river flows are maintained.
- Wind, solar, and import offers are all price takers.

Figure 37 illustrates the average energy dispatched in the merit order each month as well as a breakdown of the portion of that dispatched energy that was offered at zero dollars.

FIGURE 37: Average Zero-dollar-offered Dispatched Energy vs Total Energy Market Dispatch by Month in 2025



Key Observations:

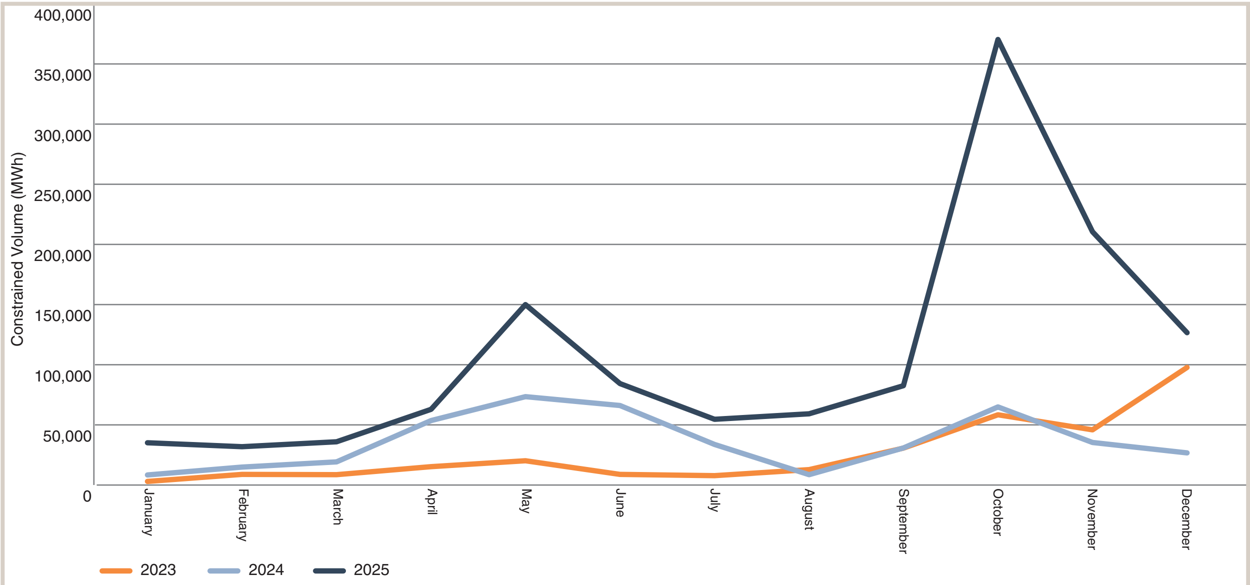
- Zero-dollar offer volumes accounted for about 87.2 per cent of total dispatched energy in 2025.
- Of this roughly 75.9 per cent was from dispatchable (gas, hydro, storage, or other) assets, with the rest coming from wind, solar, and imports.
- All else being equal, higher output from wind and solar assets increases the likelihood of a supply surplus condition occurring.

Transmission Constrained Volume Increased

When power flows on one or more transmission lines are near their physical limits, system controllers direct effective generators to modify their generation in such a way that eases the congestion on those lines. They take this action to prevent overheating or stability problems. By limiting the flows, they protect the lines from failure, which would cause far greater damage to overall grid operations.

The main reasons that transmission lines can be near their physical limits are: planned or unplanned outages on other transmission lines that change the normal flow of electricity; assets are generating more electricity than can be handled by an area’s transmission lines; or, less frequently, an area’s load is higher than the grid’s transmission lines can support.

FIGURE 38: Monthly Congestion Volumes

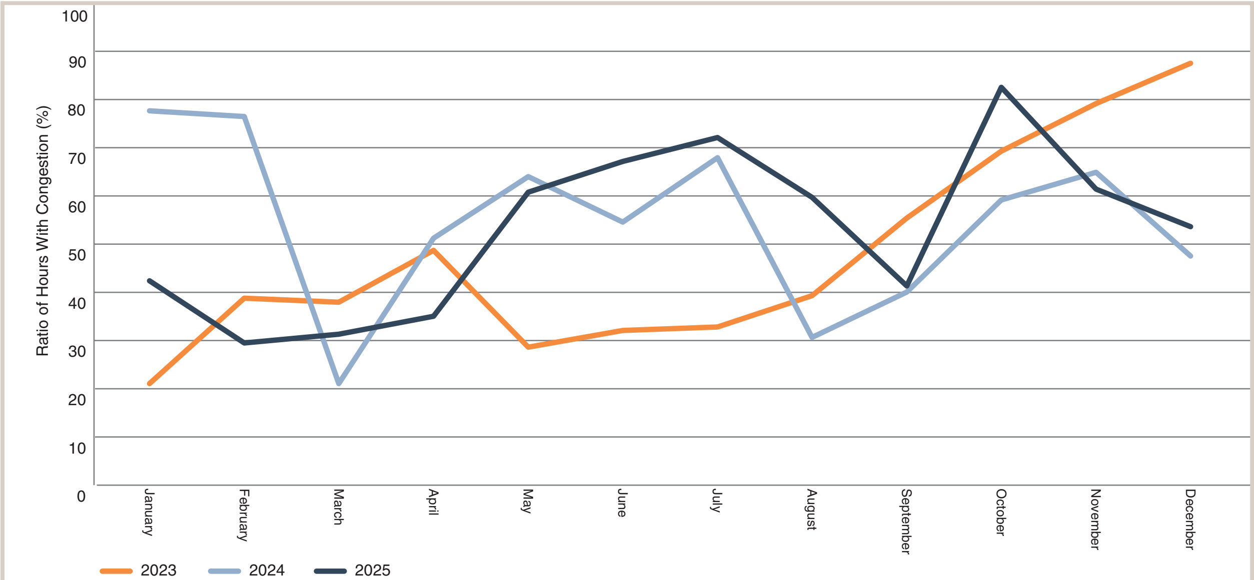


Key Observations:

- In 2025, estimated total congested volumes were 1,277 GWh compared to 424 GWh in 2024.
  - These volumes are a small fraction of overall AIL, which was 90,371 GWh in 2025.
- Seasonality affects the volume of congestion. The shoulder months of spring and fall tend to have a higher volume of congestion, due to more wind generation.
- Over the last three years, the volume of congestion has increased primarily due to the increase in wind capacity and, to a lesser extent, solar generation capacity.
- In 2025, two significant outages caused higher-than-normal congestion on the grid.
  - In May, bi-annual maintenance on the 500 kV Eastern Alberta Transmission Line (EATL) was the main driver of congestion. This congestion may occur the next time EATL maintenance work occurs, which is currently planned for 2027.
  - There were two planned outages that were the primary drivers of the congestion in late October and early November. One of the outages was deferred from August because of emergency work on transmission lines damaged by major windstorms near Brooks. This level of congestion is not expected to be a regular occurrence in the future.

Figure 39 shows the percentage of hours with any volume of congestion due to transmission constraints.

FIGURE 39: Hours with Congestion by Month



Key Observations:

- Seasonality influences not only the volume of congestion, but also how often it occurs. Congestion events are most frequent during the summer months, driven by elevated levels of solar generation. However, while congestion happens more often in summer, the magnitude of these events is typically lower.
- A primary driver of congestion is planned or unplanned transmission outages, which can cause frequent, but low volume congestion.
  - For example, the high frequency of congestion in Q4 2023 to Q1 2024 was due to the lingering impacts of wildfires in the Northwest region.

FIGURE 40: Ratio of Congestion Volume by Region

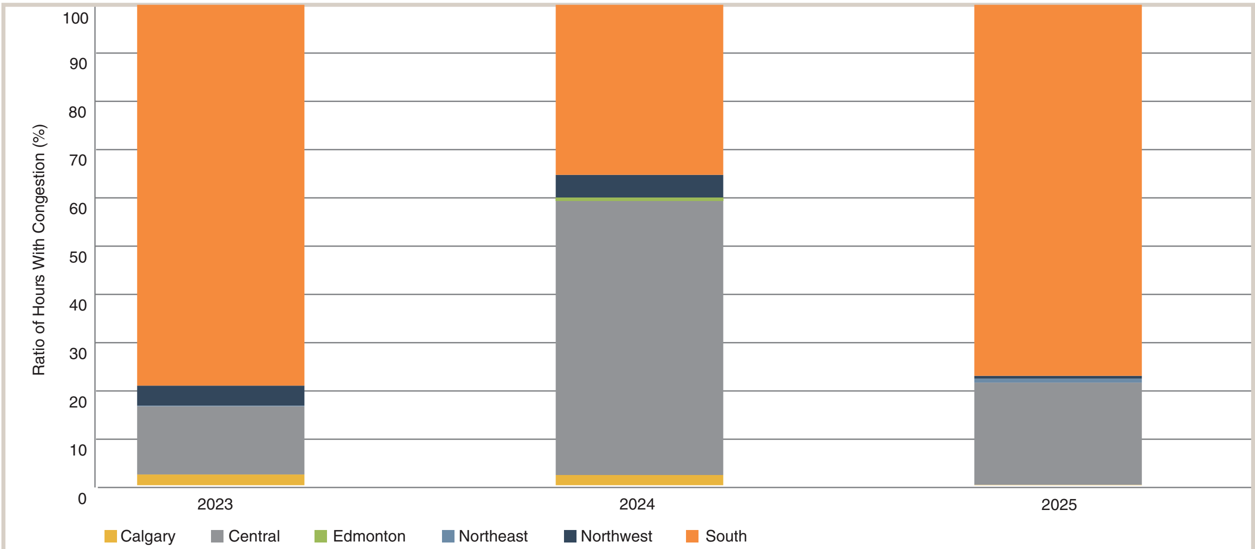
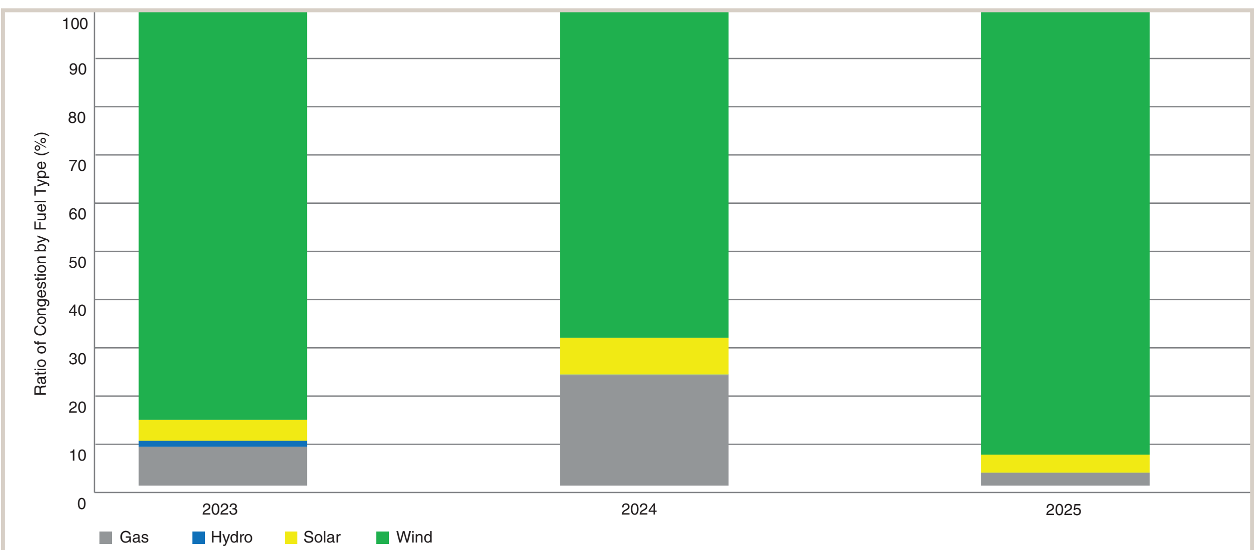


FIGURE 41: Ratio of Congestion Volume by Fuel Type



Key Observations:

- Most congestion volume is related to the large capacity of wind and solar installed in the South and Central regions.
- The rising frequency of congestion is largely the result of wind and solar generation capacity being added more quickly than the transmission infrastructure needed to deliver it. In several regions, grid expansion has not kept pace with capacity growth. In addition, transmission outages can sharply amplify congestion. When outages persist for extended periods, they constrain available pathways and drive overall congestion higher.
- As new transmission lines are built, some of the congestion is relieved. The fall in congested volumes for gas and solar generation between 2024 and 2025 was a result of upgrades or repairs to transmission lines that relieved some of the congestion issues.

Flexibility

The electric system includes two types of generation: dispatchable and intermittent. Dispatchable generation, including thermal, hydro and battery storage, can be controlled by operators. Intermittent generation, such as wind and solar, depends on environmental conditions.

The AESO's 2025 Reliability Requirements Roadmap (R3) assessed the system's ability to adapt to handle increasing amounts of intermittent generation, including the need to continuously balance supply and demand under different scenarios. It also described some activities the AESO has undertaken since the 2023 R3 report to maintain operational reliability of the transmission system.

As wind and solar capacity continued to increase, demand and intermittent generation fluctuations—known as net demand variability—grew. To manage this variability, the AESO added additional balancing measures, such as more regulating reserves and fast-frequency response (FFR) and introduced some operational limits to maintain reliability in weaker parts of the transmission system.

Historical data on market and system flexibility are covered in this section.

Intermittent Generation-to-AIL Ratio

In 2025, wind and solar continued to increase their share of total generation on the grid. This growth has increased the need for greater system flexibility to handle higher volumes of net-demand variability.

Figure 42 shows a duration curve of the ratio of intermittent generation to AIL in 2024 and 2025.

FIGURE 42: Ratio of Intermittent Generation to AIL

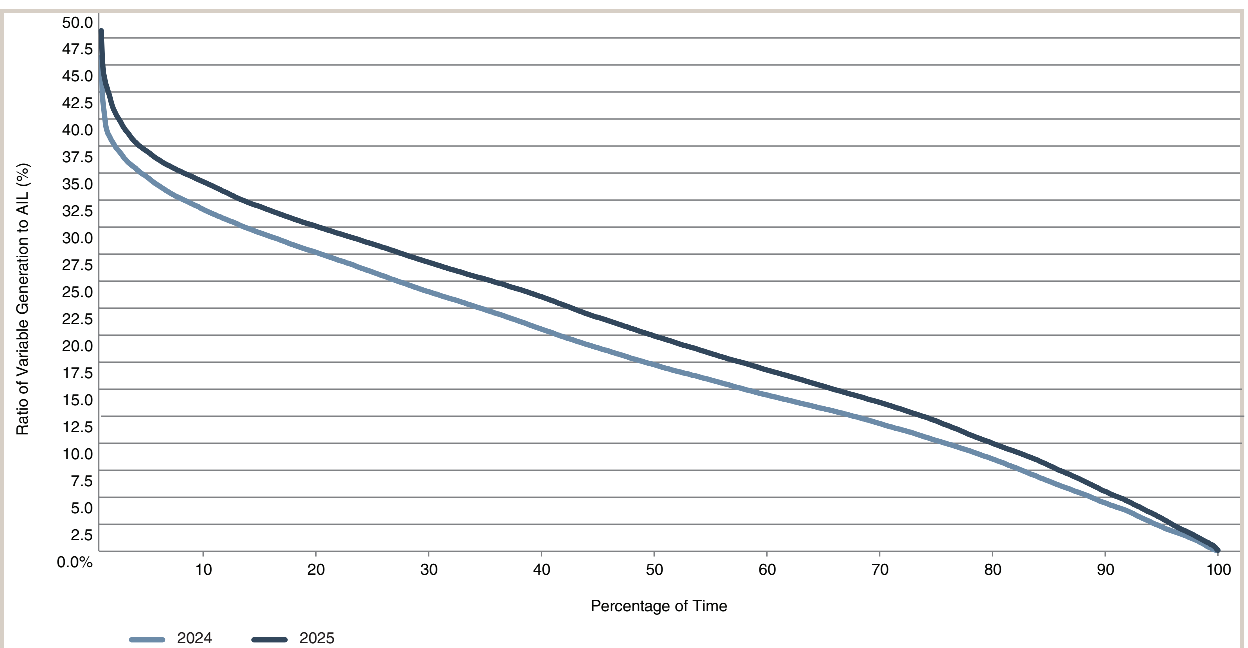


Table 12 shows the median and maximum ratio of intermittent generation volume to total AIL in 2024 and 2025. The solar values exclude overnight hours with no generation.

TABLE 12: Ratio of Wind and Solar to AIL

		2024	2025
Combined	Median	17.0%	19.7%
	Max	45.6%	48.0%
Wind	Median	13.4%	14.7%
	Max	41.8%	45.4%
Solar	Median	5.0%	5.5%
	Max	15.6%	18.4%

Key Observations:

- The ratio of intermittent generation to AIL continued to increase in 2025 with the addition of new capacity, although the growth in the ratio slowed due to less capacity coming online compared to previous years.
- Wind and solar made up at least 30.0 per cent of AIL in almost 19.0 per cent of hours.

Net Demand Variability

Net demand ramps show the change in AIL and intermittent generation over a set period. For example, during a 10-minute period, if AIL increases by 10 MW and intermittent generation drops by 10 MW, the net demand ramp is +20 MW, meaning dispatchable generation must cover the 20-MW gap.

The increasing size and frequency of net demand ramps, both up and down, is a challenge due to increased intermittent wind and solar generation volumes. Dispatchable resources must be able to match the size, speed and frequency of the net demand ramps to reliably supply load customers.

Figure 43 shows the frequency and size of 10-minute ramps of intermittent generation, AIL, and net demand in 2025. Figure 44 shows the year-over-year differences in the frequency and size of the ramps.

These figures use data from every 10-minute period in the given year. Intermittent generation includes all five MW-or-larger wind and solar assets in Alberta. Small-scale wind and solar generators that produce less than five megawatts are generally connected to the distribution system and their variability is captured in AIL.

FIGURE 43: Distribution of 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand in 2025

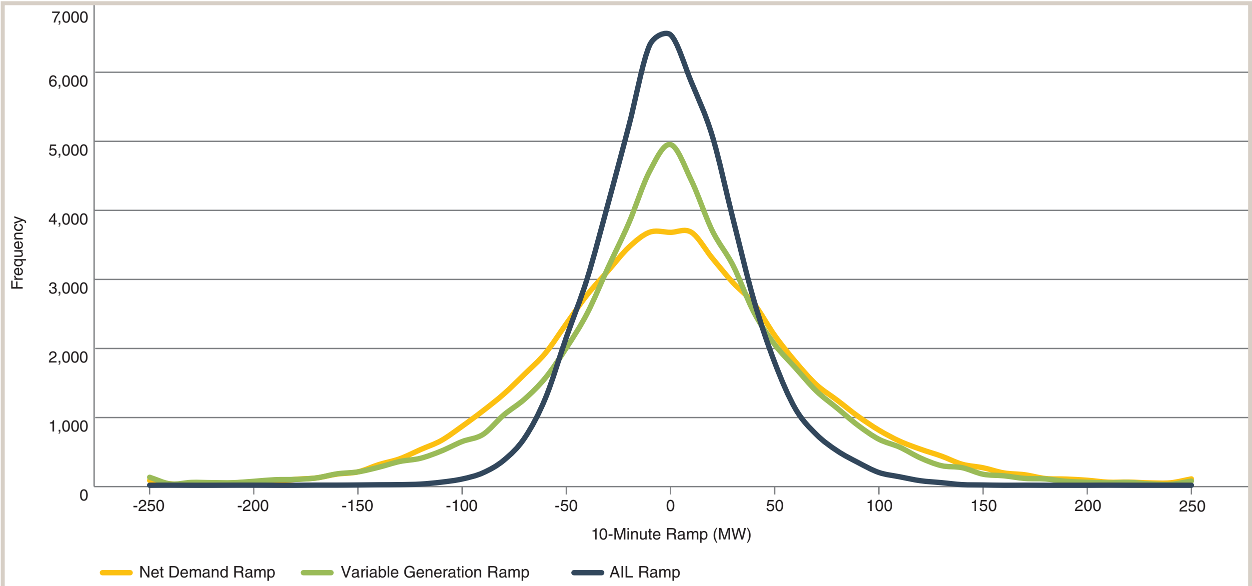
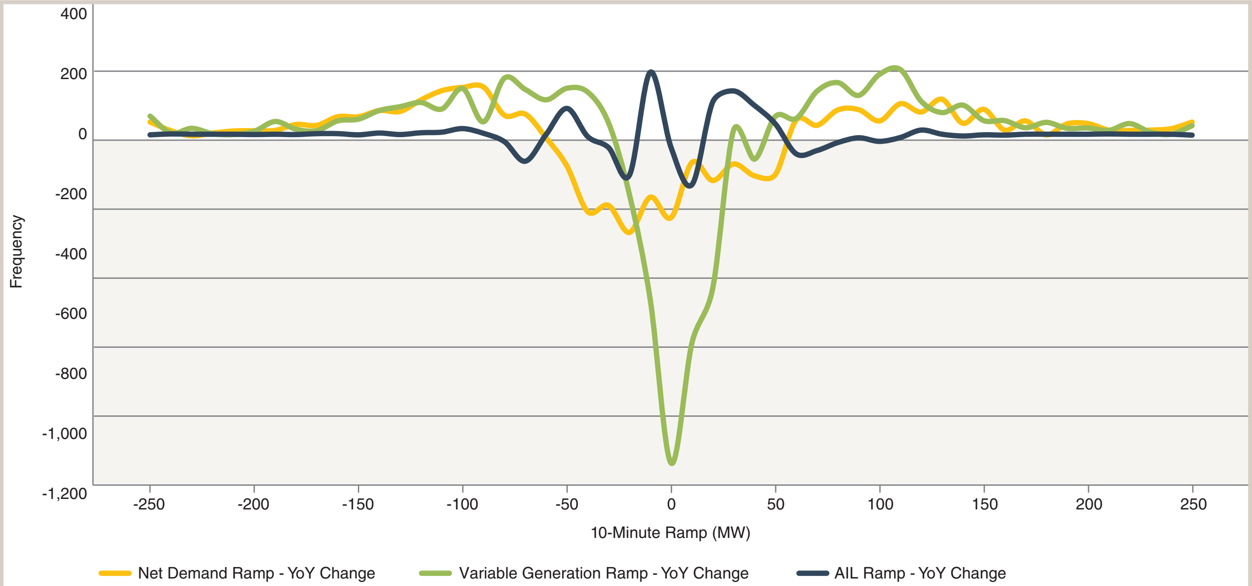


FIGURE 44: Distribution of Year-Over-Year Change for 2025 in 10-Minute Ramps for Wind and Solar Generation, Load, and Net Demand



Key Observations:

- The ratio of large (+/- 50 MW) to all net-demand ramps was 35.6 per cent in 2025, up from 31.7 per cent in 2024.
- Large ramps (+/-50 MW over 10 minutes) are growing faster than predicted. The frequency in the 2023 R3 for the 2026 Reference Case[12] was 27.8 per cent.
- The 2025 frequency (35.6 per cent) is higher than forecasted in the 2023 R3 Clean-Tech scenario for 2026 forecast (31.8 per cent).
- This increase is mainly driven by wind generation.
- To handle this increased variability and to help maintain grid reliability, the AESO increased its regulating reserve procurement in late 2023.

Forecast Uncertainty

AESO System Controllers maintain real-time system balance by dispatching energy according to the market merit order. They make continuous, split-second decisions to align supply with demand as conditions shift—often without certainty about how net demand will change in the minutes ahead.

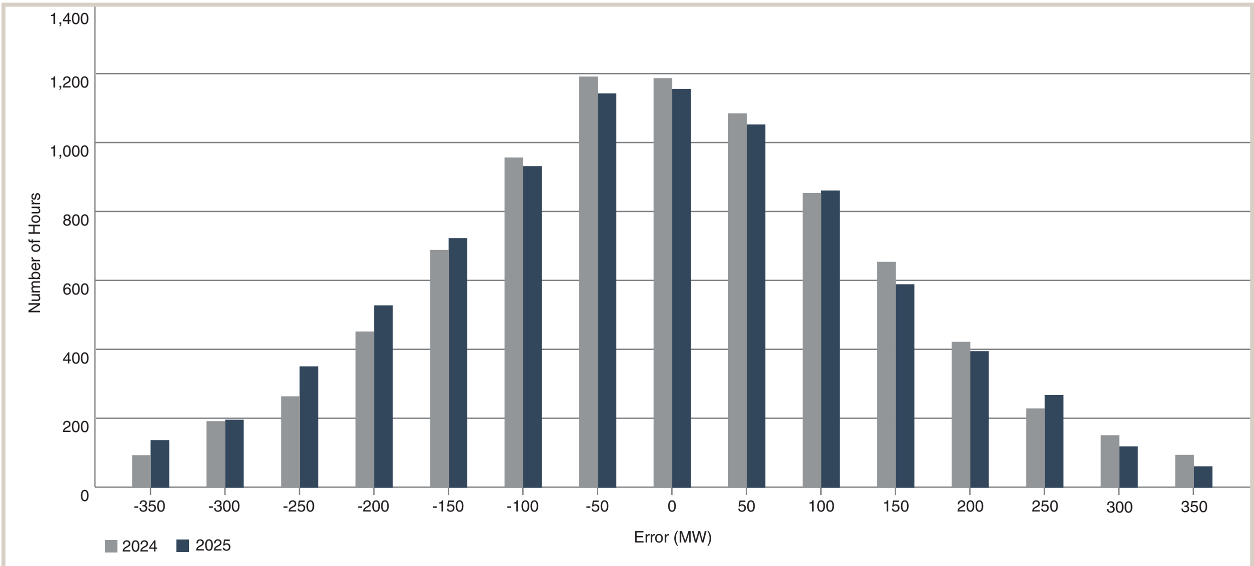
Load forecasts and intermittent generation are inherently imperfect; therefore uncertainty is unavoidable. Improving short-term forecasting for both demand and variable resources is therefore critical to managing volatility and ensuring reliable system operations.

Short-Term Load Forecast Uncertainty

Figure 45 shows the distribution of the day-ahead load forecast error for all hours in 2025 and 2024. The error is calculated as the AIL day ahead forecast minus the actual AIL for a given hour.

[12] See Table 9 on page 107 of the 2023 Reliability Requirements Roadmap.

FIGURE 45: Distribution of Day Ahead Load Forecast in 2025 and 2024



Key Observations:

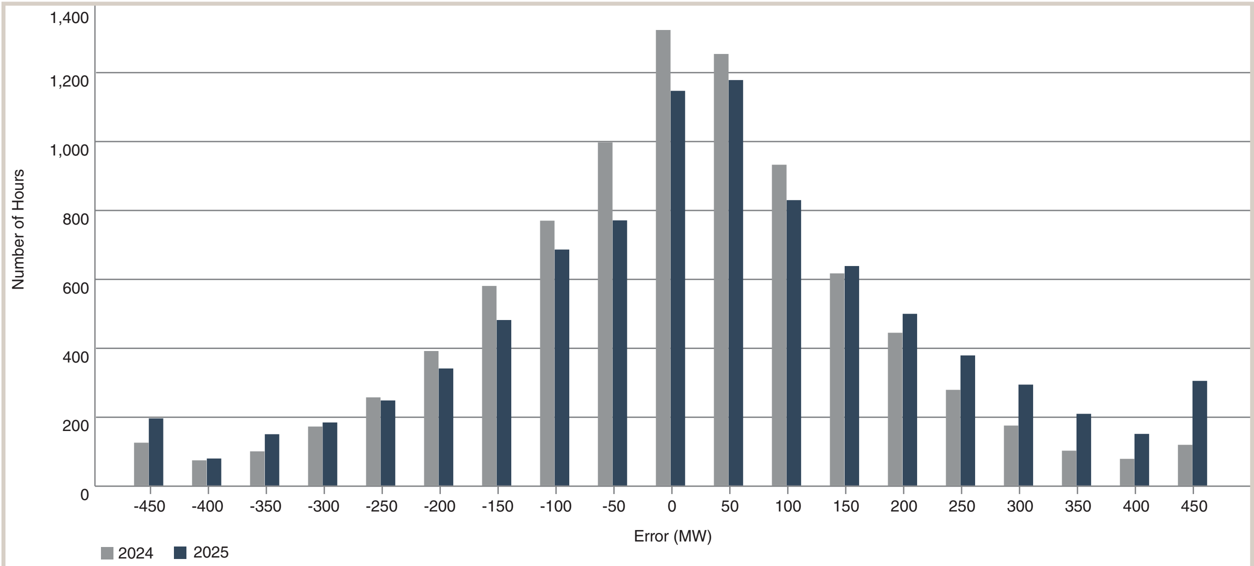
- The median absolute per cent error (APE) was 1.0 per cent, slightly worse than the 0.99 seen in 2024.
- The 95th percentile of median APE was 3.0 per cent (down from 3.2 per cent in 2024), equivalent to approximately +/- 300 MW. This indicates that the AIL forecast model reduced the amount of significant errors in 2025.
- The error in 2025 was more negatively skewed than 2024, meaning the forecast more often underestimated the AIL. It is likely because of record load in 2025 that was from structural changes rather than weather-related load.

Wind Power Forecast Uncertainty

The AESO uses meteorological data to forecast wind and solar power supply for Alberta on both a seven-day-ahead (long-term) and a 12-hour-ahead (short-term) basis. Long-term forecasts update every six hours, while short-term forecasts update every 10 minutes.

Figure 46 shows the wind forecast error distribution for 2024 and 2025. The wind generation forecast error for a given hour is the difference between the hour-ahead forecasted output volume and the actual output volume.

FIGURE 46: Distribution of Hour-Ahead Wind Power Forecast Error in 2025 and 2024



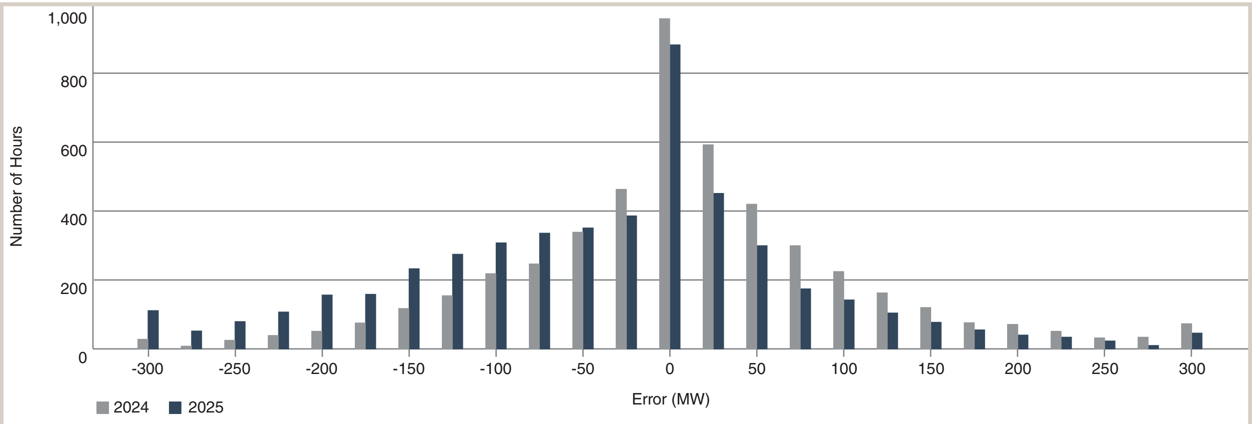
Key Observations:

- The median wind forecast error increased to 116 MW in 2025, up from 96 MW in 2024.
- This error equaled 2.0 per cent of commissioned wind capacity in 2025 compared to 1.7 per cent of 2024 capacity.
- Forecast error is more skewed toward over-forecasted wind generation. This is primarily because of unpredicted curtailments, such as supply surplus events or transmission constraints, which inflates the overall error.

Solar Power Forecast Uncertainty

Figure 47 shows the solar forecast error distribution for 2024 and 2025, excluding non-daylight hours where generation was zero.

FIGURE 47: Distribution of Hour-Ahead Solar Forecast Error in 2025 and 2024



Key Observations:

- The median forecast error increased to 67 MW in 2025, up from 51 MW in 2024.
- As a percentage of commissioned solar capacity, the median error was 3.6 per cent in 2025, up from 2.8 per cent in 2024.
- The solar forecast tended to underestimate solar generation in 2025.
  - In October 2025, an error in the solar forecast methodology was observed that caused the majority of underestimation. The error has been fixed and, as a result, it is expected that solar forecast errors in 2026 will be lower.

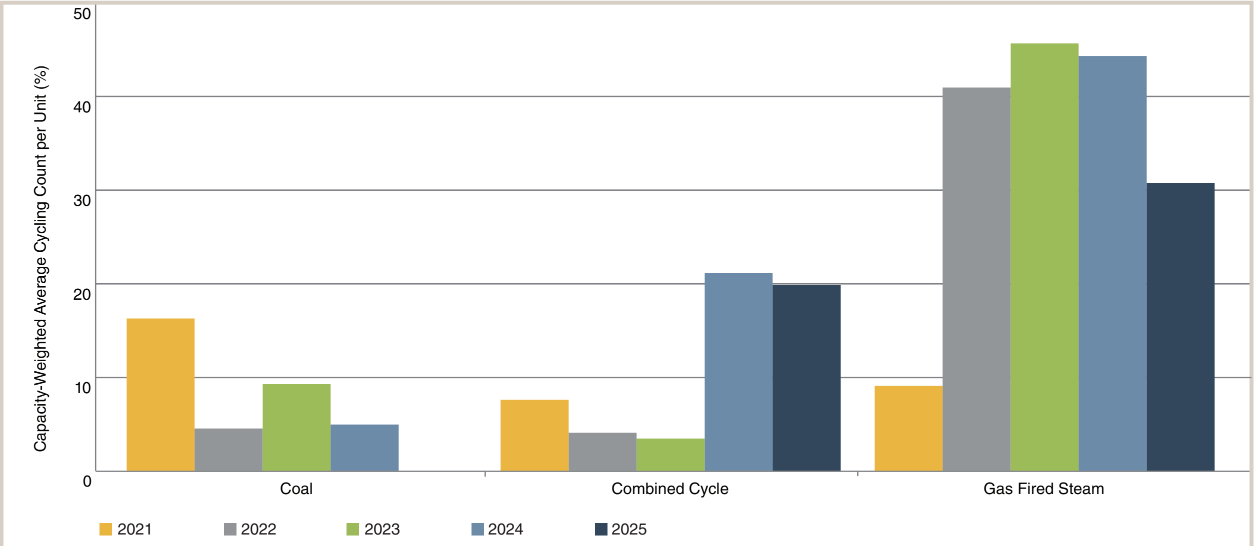
Unit On/Off Cycling

Figure 48 shows the average number of on/off cycles[13] for baseload generating units, weighted by maximum capability, over the past five years.

Several factors impact the number of on/off cycles of individual units, including economic drivers like natural gas prices and carbon costs, as well as planned and forced outages of the units or related transmission facilities connected to the generating unit.

[13] 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 gas-fired steam generating units and may reduce the expected life of the generating unit.

FIGURE 48: Average Number of On/Off Cycles Per Generating Unit, by Technology and Year



Key Observations:

- By 2022, most coal units had converted to other fuel types including gas-fired steam, with primarily baseload units left behind. As of mid-2024, there is no coal generation in the AIES.
- Due to their high operating costs, gas-fired steam assets are often taken offline during periods of high supply.
  - Because of the addition of a large capacity of new, low-priced generation throughout 2024, there were more periods of high supply and less need to cycle the gas-fired steam.
- The increased combined-cycle cycling in 2024 was primarily due to the testing behavior of newly commissioned assets.
- In 2025, the continued high number of cycling of combined-cycle assets was primarily due to testing issues during major maintenance that caused units to trip offline repeatedly.

Ancillary Services

Cost of Operating Reserves Decreased

Operating reserves (OR) help manage real-time fluctuations in supply or demand on the AIES, ensuring the system has adequate supply to respond to supply contingencies. OR consists of two products:

- Regulating Reserve (RR): Uses automatic generation control to balance supply and demand in real time.
- Contingency Reserve (CR): Ensures supply and demand remained balanced during unexpected system events. CR is further divided into:
  - Spinning Reserve: Connected and synchronized to the grid.
  - Supplemental Reserve: Not synchronized with the grid.

Table 13 summarizes the total cost of OR over the past five years.

TABLE 13: Annual Operating Reserve Statistics

Year	2021	2022	2023	2024	2025
Volume (GWh)					
Active procured	5,624	5,719	5,360	5,834	5,928
Standby procured	1,191	994	954	713	709
Standby activated	156	179	215	87	110
Cost ($-millions)					
Active procured	$314	$466	$334	$255	$206
Standby procured	$4	$2	$4	$10	$8
Standby activated	$20	$33	$41	$6	$4
Total ($-millions)	**$339**	**$501**	**$378**	**$271**	**$218**

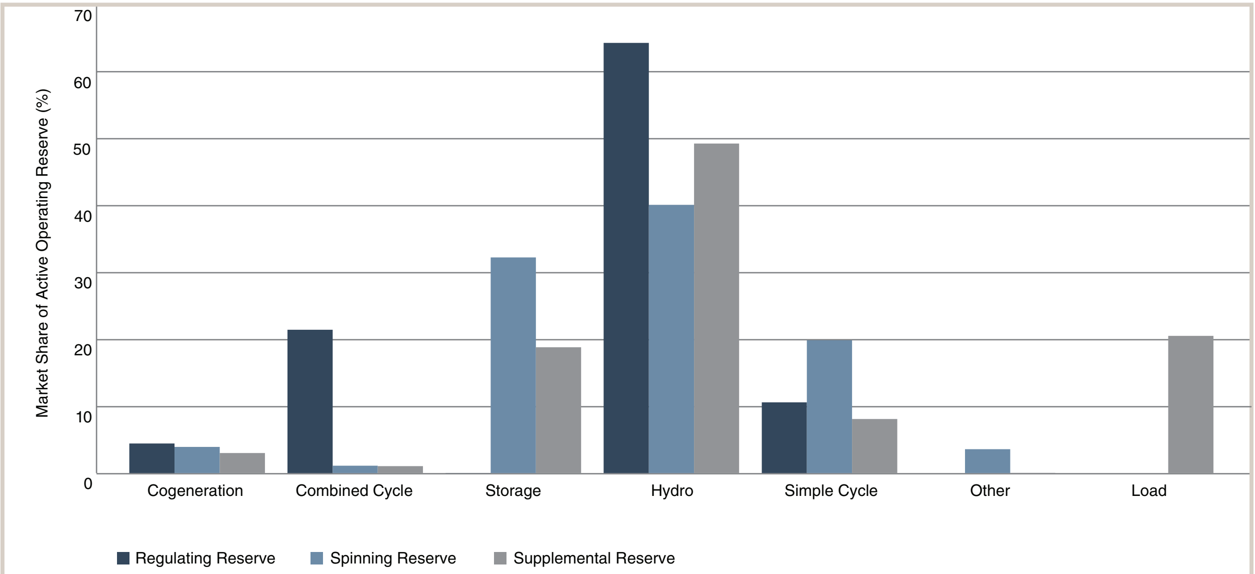
Key Observations:

- OR costs dropped by 19.6 per cent in 2025 compared to 2024, marking the third consecutive year of declining costs.
- A 30.4 per cent drop in pool prices was a key driver for lower OR costs.
- The volume of active reserves procured increased by 2.0 per cent (94 GWh), marking the second annual consecutive increase, following the rise in on-peak regulating reserve (RR) requirements from 170 MW to 210 MW in early October 2023. Standby reserve procurement and activation remains below historical levels following this change.
- Changes to operating reserve (OR) market pricing implemented on April 15, 2024, also reduced standby reserve costs, with the cost of activated standby reserves declining to $4 million in 2025, compared to $41 million in 2023. The adjustments in the standby market's activation price calculations in 2024 reduced the selection of offers with higher activation prices.

Market share represents the percentage of total procured OR capacity provided by each technology of generation.

Figure 49 shows the annual market share of active OR by fuel type in 2025.

FIGURE 49: 2025 Market Share of Active Operating Reserve

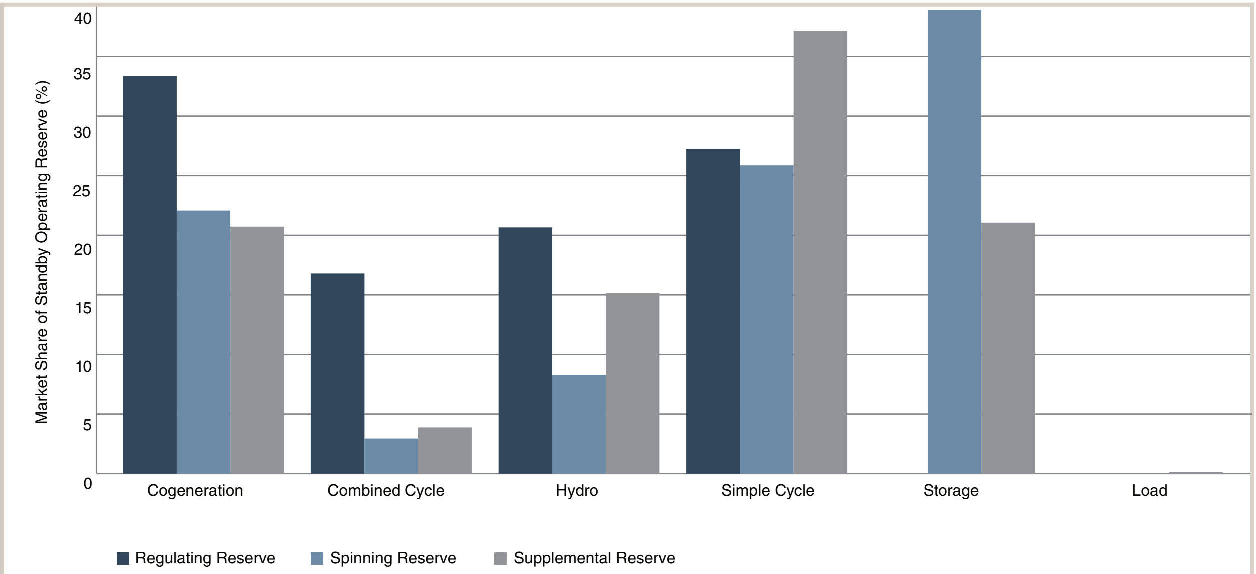


Key Observations:

- Hydroelectric generation had the largest market share in the regulating (63.8 per cent) and spinning (39.8 per cent) reserves.
- Storage assets supplied a larger share of operating reserves, accounting for 32.0 per cent of spinning reserves and 18.7 per cent of supplemental reserves, compared with 25.8 per cent and 9.1 per cent, respectively, in 2024.
- Hydroelectric generation also had the largest market share of supplemental product at 48.9 per cent, followed by load at 20.4 per cent.

Figure 50 shows the annual market share in the standby OR market by fuel type. Gas-fired steam assets are included with simple-cycle assets.

FIGURE 50: 2025 Market Share of Standby Operating Reserve



Key Observations:

- Market share within standby regulating reserves is distributed more evenly, with cogeneration accounting at 34.0 per cent and simple-cycle generation at 27.8 per cent.
  - Following the retirement of coal-fired generation in 2024, the simple-cycle assets became more prominent contributors to the standby reserve market.
- In 2025, storage's share of standby reserves rose significantly, reaching 39.7 per cent of the standby spinning reserve market and 21.5 per cent of the standby supplemental market, up from 8.3 per cent and 6.6 per cent, respectively, in 2024.
  - Simple cycle assets provide the second most standby spinning reserve volumes at 26.4 per cent, down from 32.5 per cent in 2024.
- For standby supplemental reserves, simple cycle holds the largest share at 37.9 per cent, followed by cogeneration and storage both at 21.1 per cent.

Transmission Must-Run, Transmission Constraint Rebalancing, and Dispatch Down Service

AESO System Controllers issue transmission-must-run (TMR) dispatches to ensure system reliability when regional transmission capacity cannot provide enough imports to support local demand. TMR dispatches direct generators in or near the affected area to operate out-of-merit at a specified generation level.

Table 14 summarizes the annual TMR, Transmission Constraint Rebalancing (TCR) and Dispatch Down Service (DDS) statistics over the past five years. TMR and TCR combined represent the total annual cost of Transmission Constraint Management (TCM).[14]

TABLE 14: Annual TMR and DDS Statistics

Year	2021	2022	2023	2024	2025[15]
Transmission Must-run					
Dispatched energy (GWh)	95	31	55	80	340
Contracted TMR costs ($-millions)[16]	$0	$1.2	$1.9	$2.8	$5.6
Conscripted TMR costs ($-millions)	$5.5	$3.0	$3.0	$3.4	$16.7
Transmission Constraint Rebalancing					
TCR Volume (GWh)[17]	69	89	305	409	1,065
Number of days with TCR payment	89	207	291	292	304
Total TCR payments ($-millions)	$2.7	$1.8	$5.4	$3.8	$14.4
Total Annual TCM Costs					
Annual TCM cost ($-millions)	$8.2	$6.0	$10.3	$10.0	$36.7
Dispatch Down Service					
Total payments ($-millions)	$0	$0	$0	$0	$0.02
Dispatched energy (MWh)	11	0	0	0	907
Average charge ($/MWh)	$19.58	$0	$0	$0	$18.73

Key Observations:

- In 2025, 340 GWh of TMR energy was dispatched, costing $16.7 million.
  - This was a 325 per cent increase over 2024.
  - Primary causes were more planned transmission outages in the Northwest region, unplanned outages in both the Northwest and South regions, and increased load in transmission-constrained areas of the Northwest region.

When transmission constraints force in-merit generation to be curtailed and replaced with higher-cost alternatives, the dispatched generators may be eligible for Transmission Constraint Rebalancing (TCR) payments.

- TCR payments to market participants totaled approximately $14.4 million in 2025.

[14] 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."

[15] Preliminary data. Some costs included estimated values, which may change once the costs are actualized.

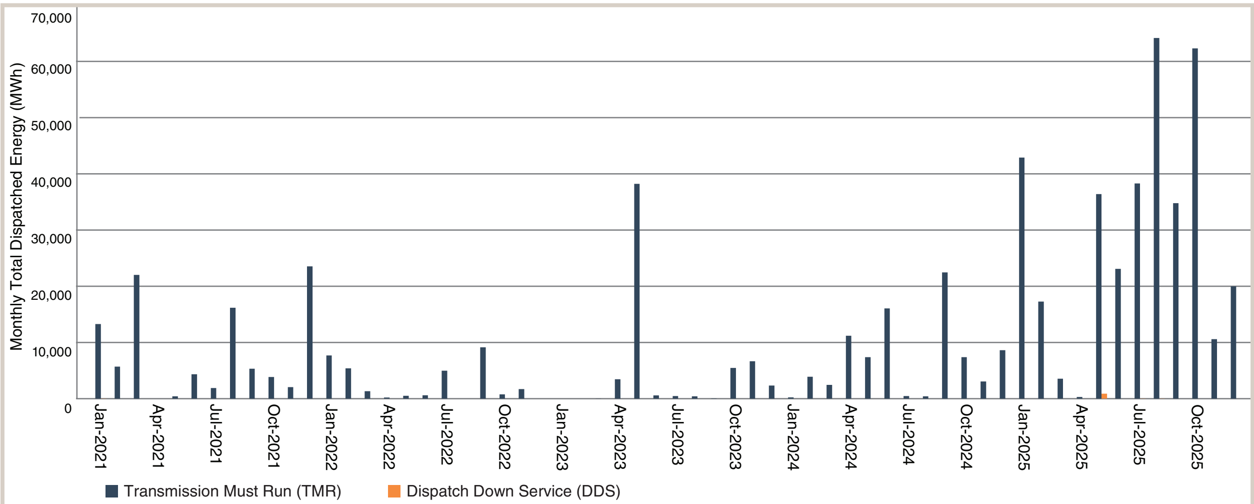
[16] An error in the calculation of conscripted TMR was discovered in previous Annual Statistics reports and has been corrected for 2025.

[17] Volume of generation that received a TCR payment. Does not include constrained-up BTF generation, as TCR payments only apply to metered generation.

- This was a 278.9 per cent increase from 2024, driven by higher transmission congestion throughout the year.
  - The volume of generation receiving TCR payments was 1,065 GWh.
  - Over half of the TCR payments occurred in October due to congestion related to planned transmission maintenance.

Figure 51 shows the monthly volumes of TMR and DDS dispatched over the past five years. AESO System Controllers issue TMR dispatches in response to transmission constraints on the AIES.

FIGURE 51: Monthly TMR and DDS Dispatched Energy



Payments to Suppliers on the Margin

Payments to Suppliers on the Margin (PSM) compensate generators when their dispatched offer blocks are priced higher than the settled pool price, covering the gap between dispatch and settlement intervals.

Table 15 summarizes the cost of PSM payments over the past five years.

TABLE 15: Annual Uplift Payments

Year	2021	2022	2023	2024	2025
Payments to Suppliers on the Margin					
Average range ($/MWh)	$24.99	$38.08	$48.18	$21.06	$23.39
Total PSM payments ($-millions)	$2.89	$4.57	$5.89	$2.01	$2.29

- The total cost of PSM was $2.29 million in 2025, up from $2.01 million in 2024.
- The annual average price range increased 11.1 per cent to $23.39 MWh in 2025 due to increased price volatility.

Glossary

- **Achieved Premium-to-Pool Price:** 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.
- **Achieved Price:** 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. The achieved margin represents the difference between the achieved price and the average pool price over the year.
- **Active Reserve:** An operating reserve that is deployed immediately to maintain system reliability under normal conditions. It is procured day-ahead, with offers submitted as premiums or discounts to the pool price. The AESO procures Active Reserve in ascending order of offer price, setting the clearing price as the sum of the equilibrium price (average of the marginal offer and bid ceiling) and the hourly pool price.
- **Alberta Internal Load (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 and it is the main load measure used by the AESO to denote total load within the province.
- **Availability Factor:** 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.
- **Available Transfer Capability (ATC):** Limits imports and exports on an individual transfer path to reflect operational conditions and maintain the transmission reliability margin (TRM). The system operating limit specifies the maximum import and export capability between Alberta and all neighboring 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.
- **Behind-the-Fence (BTF) Load:** Load that is self-supplied and does not rely on the bulk transmission system. It 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 roof-top solar panels. For the purposes of BTF calculations in this document, only load self-supplied by large generators (i.e., greater than five MW) is captured, thus is almost all industrial load.
  - Gross load on distribution facility owner (DFO) transmission networks is not readily available to the AESO, only the net metered load.
- **Capacity factor:** Represents the percentage of installed capacity used to generate electricity that was delivered to the grid. Capacity factor is calculated as the ratio of average 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 five MW and does not include smaller, distributed generation.
- **Cogeneration:** A gas-fired generation capacity type that produces electricity concurrently with heat needed for industrial processes.

- **Combined Cycle:** A gas-fired generation capacity type. A combined cycle asset contains one or more gas turbines with waste heat being used to power a steam turbine.
- **Dispatch Down Service (DDS):** A voluntary service designed to counteract the downward price impact of TMR dispatches. 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.
- **Dual Fuel:** Refers to assets that use both coal and natural gas as fuel sources.
- **Energy Market Merit Order (EMMO):** A list of price and volume quantity pairs the ISO allocates to a pool asset within a settlement interval for the purposes of submitting bids and offers. These price/quantity pairs are called operating blocks. Generation assets have 7 different blocks, while dispatchable loads, imports and export assets have 1 block. The blocks are sorted from lowest to highest price to form the EMMO. The EMMO is the order in which assets are dispatched to serve load.
- **Fast Frequency Response (FFR)** is a technology-neutral ancillary service (replacing Load Shed Service for imports (LSSi)), which supplements the frequency response available from generators and load, and allows for higher intertie transfers (when interconnected) and generator contingencies (when islanded)
- **Gas-Fired Steam:** A gas-fired generation capacity type consisting of former coal generators that were converted to use natural gas rather than coal as a fuel source for a steam turbine.
- **Grid Alert:** Occurs when the supply cushion is zero and emergency action is taken to ensure system stability. The AESO must declare a Grid Alert if it is unable to meet minimum contingency reserve requirements as some or all the needed reserve capacity is used to serve load instead.
- **Intermittent Renewable Energy Sources (IRES) or Intermittent Generation:** Renewable generation that is not dispatchable and subject to changing weather conditions, such as wind and solar generation.
- **Inverter-Based Resource (IBR):** A source of electricity that is asynchronously connected to the grid via an inverter. This includes wind and solar assets, as well as battery storage.
- **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.
- **Long Lead Time Asset:** A generation asset with a start-up time greater than one hour is considered a long lead time asset. If these assets are offline but not on outage, meaning that they have a positive available capacity but zero generation, they will not be available to the energy market in the short term due to the long start-up time.
- **Losses:** The difference between the total electrical energy generated and the energy actually consumed by end-users, as measured by revenue meters. It is primarily energy dissipated during transmission and distribution, lost as heat due to the electrical resistance of transmission lines and equipment. Generally, the further electricity has to travel from generator to load, the more is lost.
- **Metered Load / Generation:** Electricity that passes from a generator to or consumed by load off the transmission backbone, as measured by revenue meters. The metered volumes are used for settlement billing with market participants.

- **On-Peak and Off-Peak:** Each day is separated into on-peak and off-peak periods: on-peak periods start at 7:00 a.m. and end at 11:00 p.m. daily; the remaining hours of the day make up the off-peak period.
- **On/off cycle average - Methodology for calculating:** The number of on/off cycles for each unit was counted for each year in the study period. Then, 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.
- **Operating Reserve (OR):** A service used to manage real-time fluctuations in supply and demand, ensuring the system has sufficient supply to respond to contingencies. OR is divided into:
  - **Regulating Reserve (RR):** Uses automatic generation control to continuously match supply and demand in real-time.
  - **Contingency Reserve (CR):** Maintains the balance of supply and demand when an unexpected system event occurs.
    - **Spinning Reserve:** Synchronized to the grid and ready to respond immediately. Alberta reliability standards require spinning reserves to provide at least half of the total contingency reserve.
    - **Supplemental Reserve:** Available but not required for synchronizing.
- **Other** fuel types contain thermal assets with fuel sources such as biomass, waste heat, or geothermal energy, often in combination with natural gas.
- **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. Hourly PSM is determined by the difference between the maximum SMP in a settlement period and the pool price.
- **Pool Price:** The simple average of the 60 system marginal prices (see system marginal price definition) 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.
- **Power Purchase Agreements (PPA):** Agreements developed by the Province of Alberta as part of the transition to a fully deregulated electricity market, starting in 2000. Under the agreements, PPA buyers compensated the owner of the generation facility for fixed and variable costs in exchange for the right to a specified generation capacity generated at the facility. After 20 years, these agreements expired and the rights to the generation capacity reverted by to the facility owners.
- **Renewable Generation:** Defined to include wind, solar, and hydro generation.
- **Reserve Margin:** Represents the amount of firm generation capacity more than the annual system peak load expressed as a percentage of the system peak load. Firm generation is defined as installed and future generation capacity, adjusting for seasonal hydro capacity and behind-the-fence demand and generation, and excludes wind and solar capacity.

- **Simple Cycle:** A gas-fired generation capacity type including gas turbines and reciprocating engines. These differ from combined cycle assets in that they do not recover waste heat. They are generally smaller and more flexible but less efficient than combined cycle assets.
- **Spark Spread:** A high-level estimate of the profitability of operating a generic combined-cycle natural gas baseload generation asset, with a heat-rate (HR) of 7.5 GJ/MWh, in the energy market.
- **Standby Reserve:** An additional reserve procured to be available if active reserve is insufficient. It is dispatched when required or if active reserve cannot be provided due to outages or transmission constraints. It operates with two price components: the premium price, paid for availability, and the activation price, paid if dispatched. The standby market clears based on a blended price formula that takes into consideration the premium and activation price offered by each potential supplier.
- **Supply Cushion:** Represents the amount of unused but available capacity remaining in the merit order at a given moment. If the supply cushion reaches zero, a Grid Alert may be called if additional resources are needed (such as the use of contingency reserves) to balance supply and demand.
- **Supply Surplus Event:** Occurs when the amount of generation offered into the market at a price of zero dollars exceeds the amount needed to meet demand. The AESO takes actions such as curtailing import volumes and zero-dollar generation to respond to these circumstances.
- **System Load:** Represents the total electric energy billed to transmission consumers in Alberta and Fort Nelson, British Columbia (B.C.),[18] plus transmission losses. System load is roughly comprised of half residential plus commercial loads and half industrial loads. It is equal to all metered load plus calculated losses.
- **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.
- **System Marginal Price (SMP):** Represents the price of electric energy in each minute. During normal operating conditions, SMP is defined as the offer price of the most expensive offer block in the Energy Market Merit order that needed to be dispatched to meet 1 additional MW of demand, excluding imports and exports, in each minute. The simple average of the SMP over the sixty minutes in a settlement interval is the Pool Price.
- **Total Transfer Capability (TTC) rating:** 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.
- **Transmission Constraint Rebalancing (TCR):** Represents a mechanism to compensate generators when system constraints force a change in the merit order, affecting their dispatch position. 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.
- **Transmission Must-Run (TMR):** A service where generators in constrained regions are directed to operate out of merit to maintain system reliability when transmission capacity is insufficient to support local demand.

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

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