# Annual Planning Outlook

## Supply, Adequacy and Energy Outlook Module

March 2024

Connecting Today.
Powering Tomorrow.

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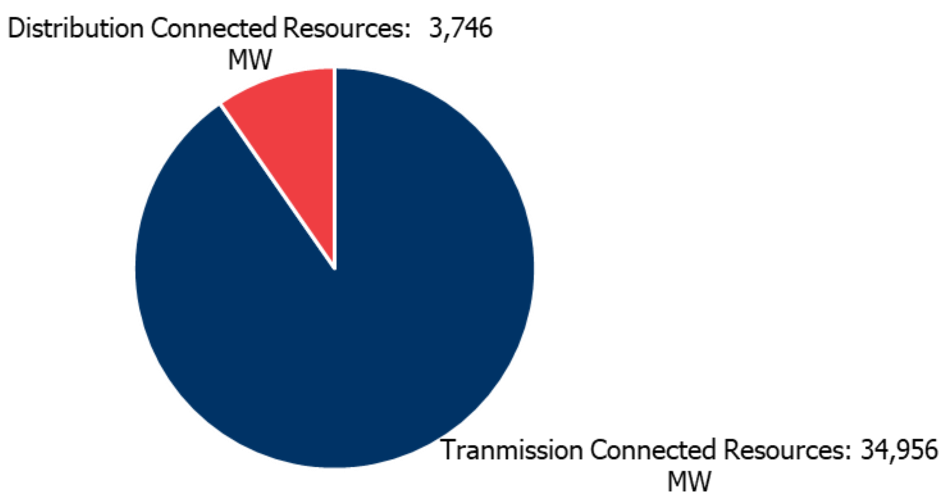
# 1. Supply Outlook

## 1.1 2024 Transmission and Distribution Connected Installed Capacity

Of the 38,702 MW of installed capacity that exists in the system today, about 90% is connected to the transmission system whereas the remaining 10% is connected to the distribution system. The transmission-connected resources are generally connected to the IESO controlled grid and are mostly market participants. However, the distribution-connected resources tend to be embedded resources consisting of either contracted or rate-regulated resources, and are mostly non-market participants. The distribution-connected resources exclude behind the meter resources that do not have a contract with the IESO, as the IESO has limited visibility of these resources. In 2024, there are about 34,956 MW installed capacity of transmission-connected resources and about 3,746 MW installed capacity of distribution-connected resources.

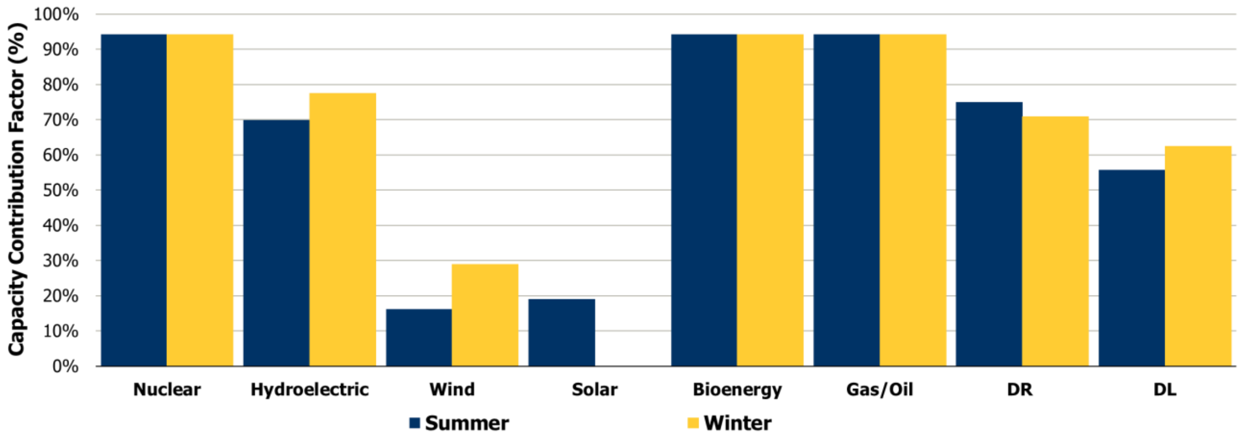
**Figure 1| 2024 Installed Capacity**



## 1.2 Summer and Winter Capacity Contribution

Figure 2 represents the summer and winter peak capacity contribution by fuel type. As shown below, these values are generally higher in the winter than summer except for solar.

**Figure 2| 2024 Summer and Winter Peak Capacity Contribution**




Capacity contribution factors reflect forced outages as well as reductions due to ambient conditions. The reasons for the differences in contribution by season are as follows:

- Nuclear units, Bioenergy, and Gas/Oil resources do not exhibit much variation between summer and winter capacity contributions.
- Hydroelectric capacity contribution factors are higher in the winter due to increased water availability.
- Wind capacity contribution factors vary throughout the year because of seasonal wind patterns. Wind speeds are typically higher in winter causing increased average production compared to summer resulting in higher contribution factors in winter.
- Solar contribution factors vary throughout the day, with the highest from noon to mid-afternoon. Since demand peaks are later in the evening in the winter, solar factors are negligible in the winter and higher in the summer.
- Demand response and dispatchable loads peak capacity contribution varies as it depends on their bid values by season.

# 2. Capacity Adequacy Outlook

## 2.1 Nuclear Refurbishment Reserve

Resource adequacy assessments reflect additional planning reserve to manage the risk of nuclear refurbishment project delays. The contribution of this additional planning reserve on summer and winter adequacy needs is shown in Figure 3 and Figure 4 respectively.

**Figure 3 | Planning Reserve for Nuclear Refurbishment, Summer**

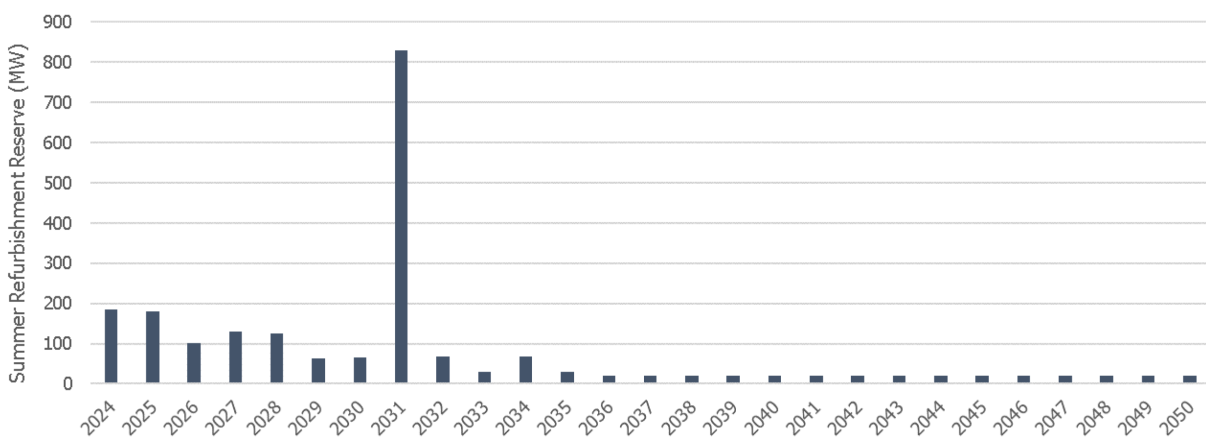
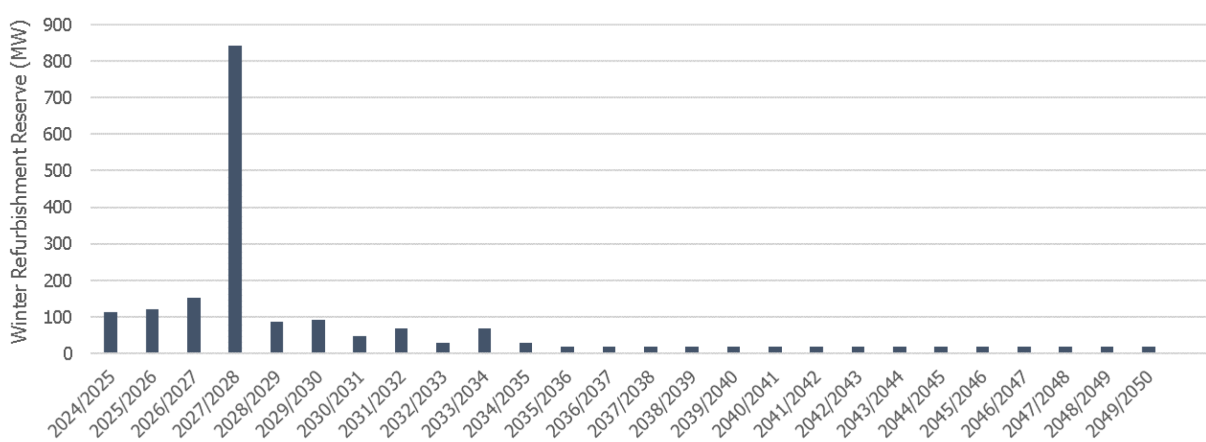



**Figure 4 | Planning Reserve for Nuclear Refurbishment, Winter**



## 2.2 Seasonal LOLE Allocation

The IESO's resource adequacy criteria require an annual loss-of-load expectation (LOLE) of 0.1 days/year. The criteria do not provide guidance on how the LOLE should be allocated across seasons. The IESO allocates LOLE across seasons to minimize capacity needs, based on the prevailing supply and demand conditions within a given year.

In the long-run, internal studies have shown that annual average resource requirements are minimized when the LOLE is split 0.06 days/year in summer and 0.04 days/year in winter. In the near-term, different allocations minimize the resource requirements. The 2024 APO LOLE allocation is shown in Table 1 and Table 2.

**Table 1 | Summer LOLE Allocation**

| Season | 2025 | 2026 | 2027-2050 |
|---|---|---|---|
| Target LOLE (days/year) | 0.09 | 0.09 | 0.06 |

**Table 2 | Winter LOLE Allocation**

| Season | 2025/26 | 2026/27 | 2027/28-2049/50 |
|---|---|---|---|
| Target LOLE (days/year) | 0.01 | 0.01 | 0.04 |

The impact of the 2024 APO LOLE allocation, described in the previous paragraph, compared to the long-run 60/40 assumption is shown in Figure 5 and Figure 6 for summer and winter, respectively. This LOLE allocation has the effect of reducing summer and winter needs.

**Figure 5 | Impact of 2024 APO LOLE Allocation vs. Long-Run Assumption, Summer (High Nuclear Case)**

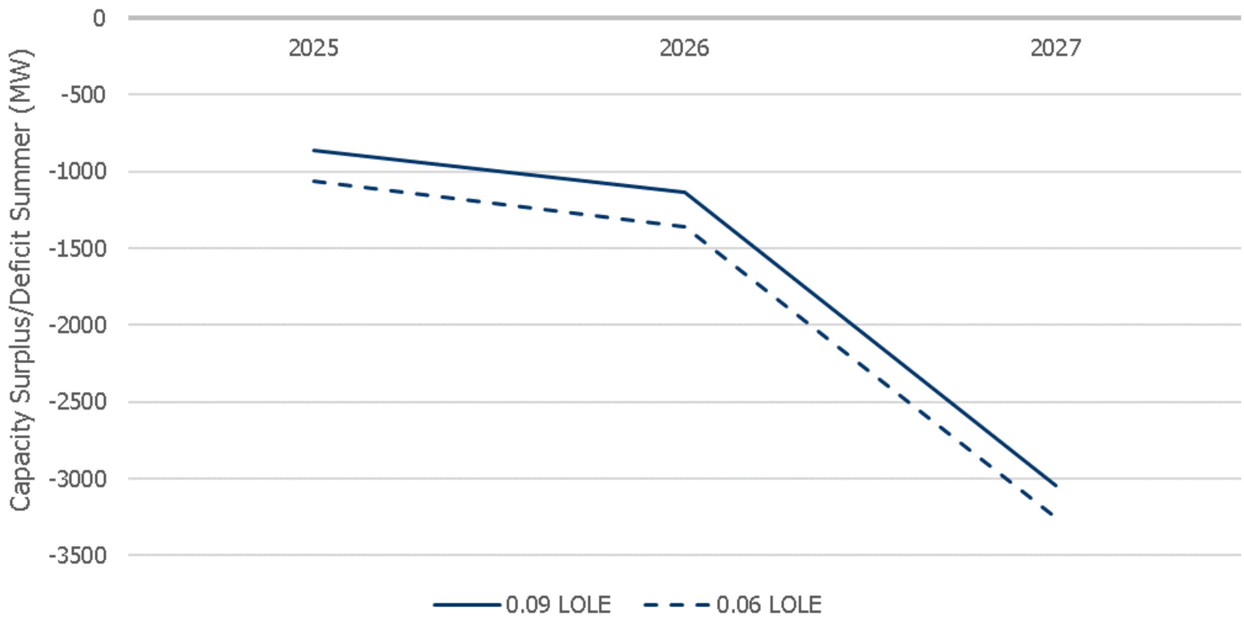
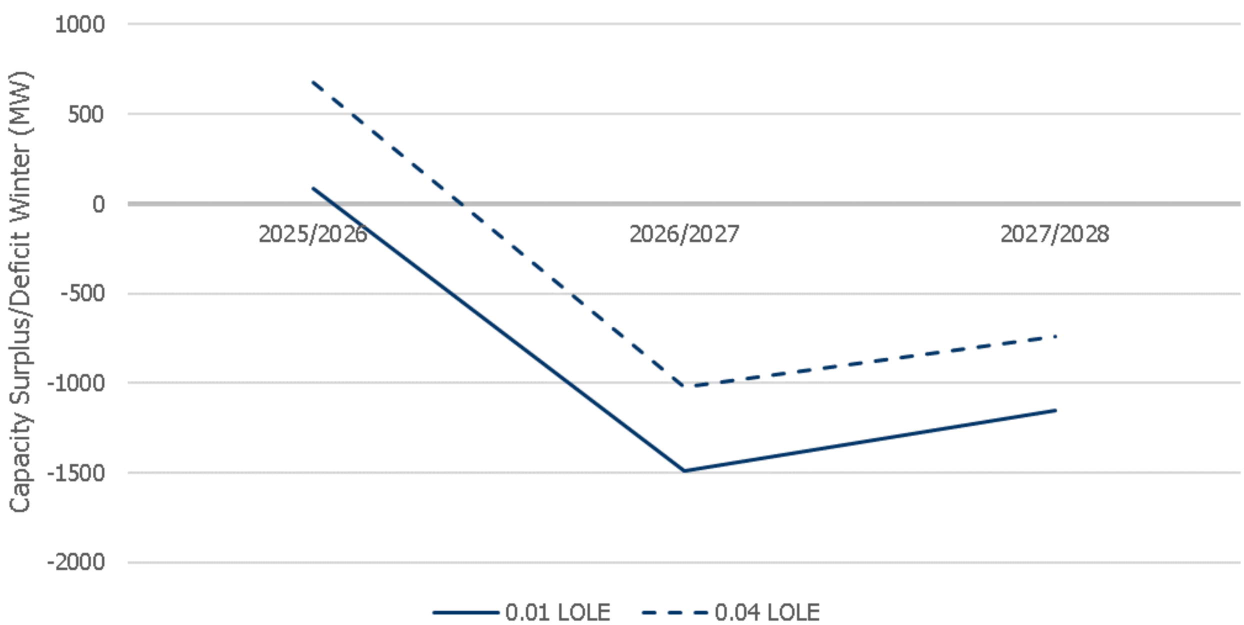



**Figure 6 | Impact of 2024 APO LOLE Allocation vs. Long-Run Assumption, Winter (High Nuclear Case)**



## 2.3 Ontario's Trading with Quebec

The 2015 capacity sharing agreement saw Ontario provide 500 MW of capacity to Hydro-Québec (HQ) during Quebec's winter peak periods. This agreement was in place until winter 2022/23. The winter capacity adequacy assessments shown in the APO no longer reflect this amount as the start of the study year is 2025.

The IESO has the option to call on 500 MW of import capacity from HQ to contribute towards resource adequacy. This option is available in any summer prior to 2030. It would reduce the need to acquire capacity in the amount/year exercised. Ontario expects to call on that option in the summer 2027. This is considered in the Integrated Reliability Needs assessment of the 2024 APO

In 2023, IESO and HQ set out their intentions to negotiate a new capacity sharing agreement in a Memorandum of Understanding that will see a swap of a minimum of 600 MW of capacity per season. This is also considered in the Integrated Reliability Needs assessment of the 2024 APO.

## 2.4 Zonal Constraints

Locational requirements exist due to limitations on the transmission system, typically specified through "transmission transfer capability limits" over transmission interfaces.

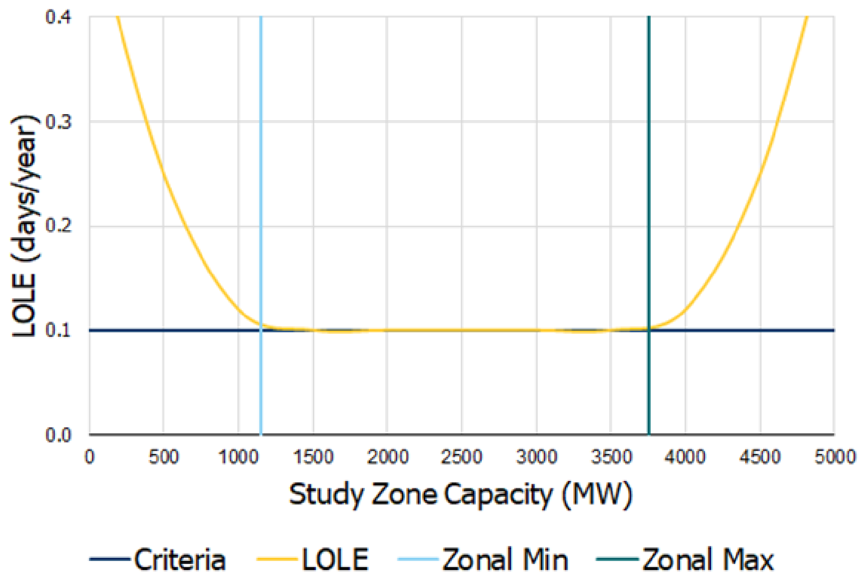
To account for transmission transfer capabilities across Ontario's interfaces, the IESO specifies the minimum and maximum incremental capacity amounts required in certain regions of the province. These minima and maxima are typically presented at the zonal level, and in some cases are reported for groups of zones that share a common limiting interface. The zonal constraints calculation methodology described in this section is used to inform the annual Capacity Auction targets.

A zonal minimum represents the minimum required capacity necessary to meet the provincial resource adequacy criterion. A zonal maximum represents the maximum amount of capacity in a zone that can contribute to provincial resource adequacy. In other words, the zonal minimum is a capacity requirement; capacity exceeding the zonal maximum does not provide further value from a resource adequacy perspective (e.g. transmission deliverability assessments may further reduce the maximum in some areas).

The methodology for establishing the transmission transfer capabilities is provided in the Ontario Transmission Interfaces and Interties Overview. These capabilities can have an impact on the extent to which a resource can contribute towards adequacy. The 0.1 days/year LOLE criteria is not set at a zonal level – it is an adequacy target for the province as a whole. The same LOLE can be achieved by placing resources in different locations. However, some locations may be better than others as a result of interface limits.

Zonal minimum and maximum capacity values are calculated using zonal constraint curves. Zonal constraint curves are developed by adding or removing capacity in a zone and removing or adding a corresponding amount of capacity in the rest of the system, such that the total incremental capacity is constant. The zonal constraint curve is developed using a "two-zone" representation of the transmission system. The only interfaces that are represented in the capacity adequacy tool should be those that are connected to the study zone; the remainder are removed or set to a non-limiting value. The resulting system LOLE across a range of study zone capacities creates the zonal constraint curve, as shown in Figure 7.

**Figure 7| General Shape of Zonal Constraint Curve**




The flat portion of the curve represents the range of study zone capacity where the system LOLE will remain approximately unchanged for an equal and offsetting amount of capacity in the rest of the system. Where the curve slopes upwards to the right, LOLE is increasing as study zone MWs are added and an equal amount of MWs are removed from the rest of the system. This indicates that additional MWs in the study zone cannot be fully utilized to offset capacity in the rest of the system and a zonal maximum can be established where the LOLE is greater than the LOLE threshold[1].

Similarly, where the curve slopes upward to the left, LOLE is increasing as study zone incremental capacity is reduced and an equal amount of MWs are added in the rest of the system. This indicates that additional MWs in the rest of the system cannot be fully utilized to offset capacity in the study zone and a zonal minimum can be established where the LOLE is greater than the LOLE threshold.

Zonal adequacy constraints help identify where adequacy needs exist across the system and where they can most effectively contribute towards meeting resource adequacy needs. The zonal constraint curves described only reflect adequacy needs and not security needs. Security needs are considered as part of a transmission assessment and may lead to additional constraints on the amount of capacity acquired in a zone.

For the zones without minimums, the assumption is the zone's adequacy needs would be satisfied by acquiring the system's capacity need while not violating the zonal maximums. For zones without maximums, it implies that the true maximum is outside the scope/upper bound of the model and any capacity acquired would be capped at the provincial capacity need. Although zonal maximums limit

[1] LOLE threshold = System LOLE using target capacity requirement (per seasonal allocation) + 0.001 days/year

the amount of capacity that can be added to a zone, the total amount of capacity added to all zones is limited by the global resource adequacy (capacity) need.

Table 3 and Table 4 provide a summary of the zones and their defining interfaces considered in the zonal adequacy assessment along with the assumed transmission transfer capability across each interface.

**Table 3 | Zones and Defining Interfaces**

| Area | Interface |
|---|---|
| Bruce | FABC |
| Niagara | QFW |
| Northwest | E-W |
| West | BLIP |
| Toronto+Essa+East+Ottawa | FETT, FN/FS |
| Northeast+Northwest | E-W, FN/FS |

**Table 4 | Transmission Transfer Capabilities (2025-2050)**

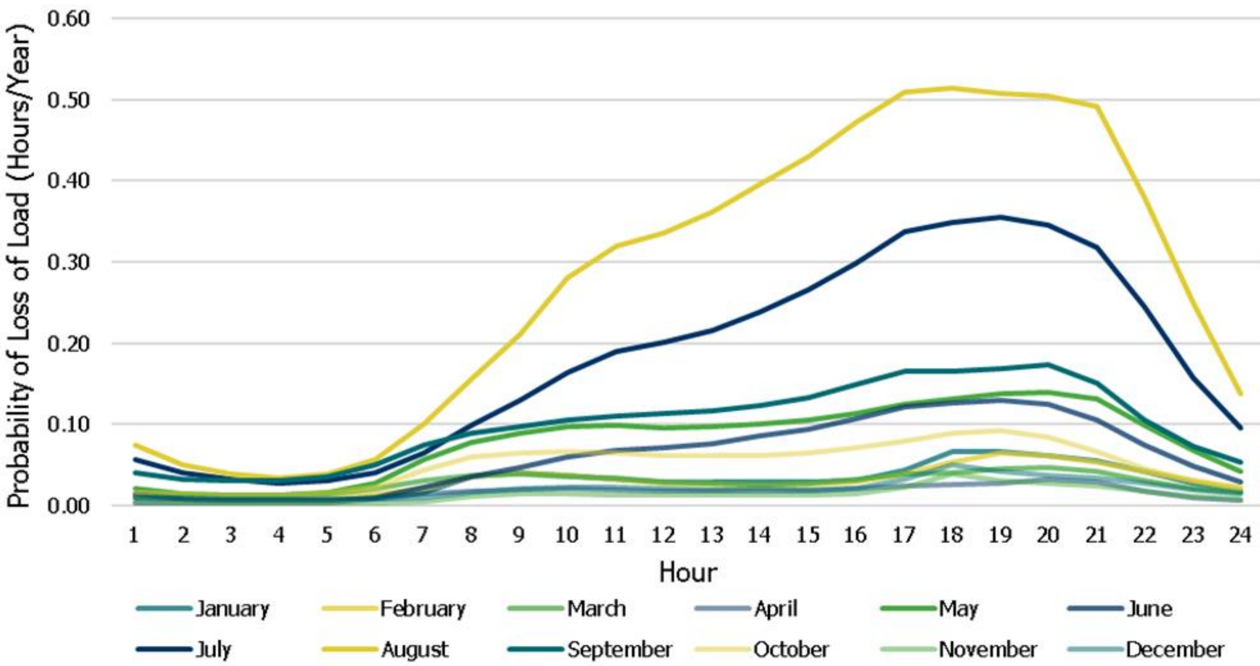
| Interface | Positive Direction Interface Transfer Capability (MW) | Negative Direction Interface Transfer Capability (MW) |
|---|---|---|
| E-W | Ranges from 490 to 830 | Ranges from 420 to 700 |
| FABC | 9,999 | 9,999 |
| BLIP | Ranges from 2,460 to 3,775 | Ranges from 1,510 to 1,625 |
| QFW | Ranges from 2,025 to 2,110 | 9,999 |
| FETT | Ranges from 4,700 to 7,350 | 9,999 |
| TEC | 9,999 | 9,999 |
| FIO | 2,950 | 9,999 |
| FN/FS | Ranges from 1,865 to 1,979 | Ranges from 1,750 to 2,270 |
| CLAN | 9,999 | 9,999 |

## 2.5 Hourly Probability of Loss of Load

To further understand the characteristics of system needs and the types of resources that can meet these needs, the hourly probability of loss of load was analyzed for the year 2029, against the resource adequacy outlook in Section 8 of the 2024 Annual Planning Outlook, and does not consider the previous and underway actions, and risks identified in Section 12. Given the hourly load forecast and the available resources at each hour, the probability of loss of load is different for every hour. If the system's reserve margin falls below zero in a particular hour, then loss of load is certain.

In its probabilistic assessment, the IESO has analyzed hundreds of simulations at different load levels to determine a metric that best represents the probability of loss of load at every hour of the year. Figure 8 outlines the described metric at every hour of the day for each month in 2029 against the reference demand forecast and the High Nuclear case supply outlook. The contract expiry of the Lennox generating station in 2029 causes a significant increase in need. Summer months such as July and August exhibit a higher probability of need during hours 16-22, while in winter, there is a small spike around hours 9-10 and then a larger need during hours 17-23. In Ontario, summer months constitute most of the hourly needs given that the system is currently summer peaking; however, the shape of the hourly profiles changes from year to year and is impacted by factors such as the demand forecast, load forecast uncertainty, supply forecast, outages and transmission constraints.

**Figure 8 | Hourly Probability of Loss of Load, 2029 (High Nuclear Case)**




## 2.6 Duration of Loss of Load

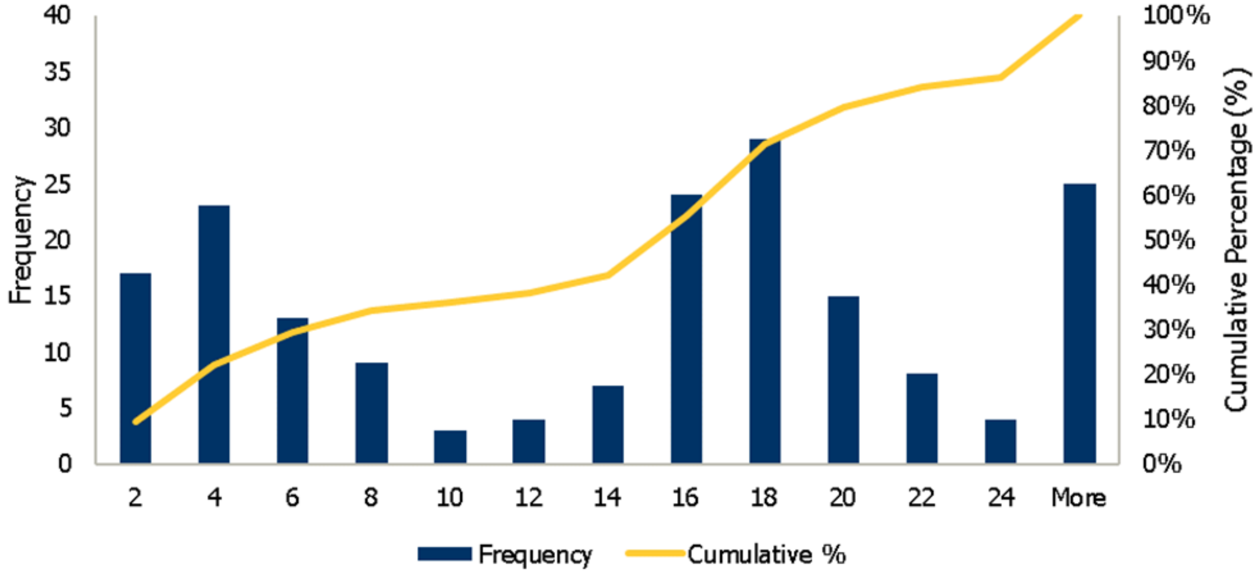
The periods of resource adequacy risk identified in this report tend to be sustained for multiple, consecutive hours. Figure 9 shows the duration of risk periods in 2029. This assessment shows that the length of risk periods can vary greatly.

Looking at the entire range of outcomes observed in the IESO's probabilistic assessments can inform future procurements on the value of resources that are capable of providing energy for a sustained period of time, particularly in preparation for the potential for severe weather conditions:

- 20 per cent of events persist for up to four hours;
- 15 per cent of events persist for more than 4 and up to 8 hours;
- 20 per cent of events persist for more than 8 and up to 16 hours; and
- 45 per cent of events persist for more than 16 hours.

The same technology upgrades, expedited LT1 and LT1 RFPs are designed to run for a minimum of four continuous hours, and are encouraged to generate for longer durations, to address these needs.

**Figure 9| Duration of Resource Adequacy Risk Periods, 2029 (High Nuclear Case)**



# 3. Energy Adequacy Outlook

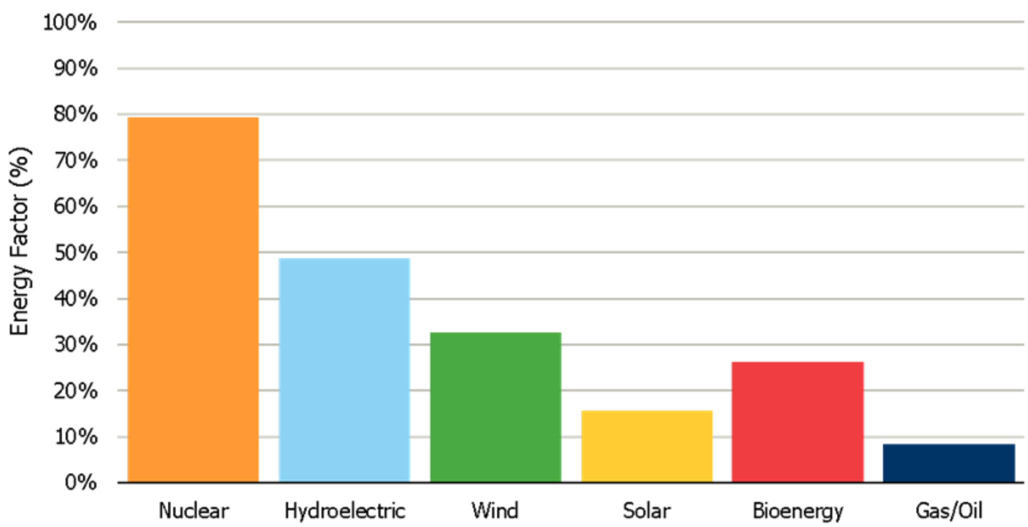
## 3.1 Exchange Rate and Ontario Natural Gas Price Forecast

The annual exchange rate and natural gas fuel forecast assumption is from the Sproule Price Outlook, released March 30, 2023. These assumptions can be found in Table 2: Sproule Forecast – Henry Hub, Dawn, USD/CAD Exchange Rate, in the Fuel Cost APO Data Table.

## 3.2 Annual Energy Contribution Factors

Figure 10 represents the annual energy contribution factors by fuel type, based on average hourly production for the year 2024.

**Figure 10 | Annual Energy Contribution Factors**




Energy contribution factors reflect outages as well as reductions due to ambient conditions. The reasons for the differences in contribution by fuel type are as follows:

- Nuclear units are must-run resources that have minimal weather and fuel limitations, so their production is high throughout the year. Their energy production is mainly limited by planned and forced outages.
- Hydroelectric energy contribution varies with season; it is highly dependent on the precipitation, and stochastic in nature. Therefore, the average production over the year is lower than the capacity contributions during peak hours in Figure 2.
- Wind energy production is dependent on seasonal wind patterns, which is also stochastic in nature. Wind energy generation is higher in the winter compared to the summer.

- Solar energy production is dependent on time of day and season. It is greatest during noon to mid-afternoon in the summer and lower in winter. Due to these varying hourly and seasonal contributions, solar exhibits a low energy contribution.
- Bioenergy is an energy-limited resource. Its energy contribution is limited by its fuel availability throughout the year.
- Gas/oil resources are only dispatched as needed by the system and hence their energy production is significantly lower compared to peak capacity factors in Figure 2.

## 3.3 Unserved Energy Description

Figure 12 to Figure 17 separate the annual unserved energy as described in Section 8 of the 2024 Annual Planning Outlook into winter, summer and shoulder periods. These figures do not consider the previous and underway actions, and risks, identified in Section 12 of the 2024 Annual Planning Outlook.

Defining the characteristics of the unserved energy, for example, by the timing and magnitude, is important to better understand what resource can meet these needs and provide value. That is because different resource types provide differently across seasons (e.g. if the unserved energy is greater in the winter than in the summer, some resources such as solar and/or hydroelectric, may be less dependable as they produce less energy during the winter).

The heat maps below illustrate the total unserved energy, average unserved energy and maximum unserved energy during the winter, summer and shoulder seasons, over time of use (TOU) periods, across the study horizon, for the As Is and High Nuclear Case. The time of use period definitions are described in Figure 11. It is important to note that the time of use periods are not of equal size in that they do not contain the same number of hours.

**Figure 11 | Time-Of-Use Period Definitions**

| Winter | | | Summer | | | Shoulder | |
|---|---|---|---|---|---|---|---|
| On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak |
| December - March | | | June - September | | | April, May, October, November | |
| 7 AM - 11 AM; 5 PM - 8 PM | 11 AM - 5 PM; 8 PM - 11 PM | 11 PM - 7 AM | 11 AM - 5 PM | 7 AM - 11 AM; 5 PM - 11 PM | 11 PM - 7 AM | 7 AM - 11 PM | 11 PM - 7 AM |

In both the As Is and High Nuclear cases, the unserved energy begins to grow around 2030. It is observed across all seasons, with most of the time occurring in the winter.

**Figure 12 | Total GWh Unserved Energy by TOU periods (As Is Case)**

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Total |
| 2025 | 2 | 2 | 2 | 1 | 2 | 5 | 45 | 16 | 74 |
| 2030 | 1,058 | 1,065 | 1,025 | 907 | 1,186 | 357 | 792 | 170 | 6,561 |
| 2035 | 3,986 | 4,967 | 7,845 | 4,203 | 6,140 | 7,448 | 8,488 | 6,220 | 49,297 |
| 2040 | 7,983 | 10,226 | 18,282 | 6,025 | 9,078 | 13,001 | 14,703 | 12,864 | 92,161 |
| 2045 | 9,651 | 12,406 | 22,385 | 7,535 | 11,532 | 17,202 | 17,771 | 16,966 | 115,448 |
| 2050 | 10,862 | 13,951 | 25,261 | 8,548 | 13,165 | 19,803 | 20,398 | 20,357 | 132,344 |

### Figure 13 | Total GWh Unserved Energy by TOU periods (High Nuclear Case)

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Total |
| 2025 | 2 | 2 | 2 | 1 | 2 | 5 | 45 | 16 | 74 |
| 2030 | 1,016 | 1,025 | 987 | 856 | 1,106 | 289 | 585 | 118 | 5,981 |
| 2035 | 2,799 | 3,441 | 4,841 | 3,209 | 4,480 | 4,497 | 5,610 | 3,356 | 32,233 |
| 2040 | 6,031 | 7,714 | 13,261 | 4,399 | 6,366 | 8,113 | 10,200 | 8,080 | 64,164 |
| 2045 | 6,303 | 8,102 | 13,951 | 4,705 | 6,813 | 8,908 | 10,162 | 8,542 | 67,486 |
| 2050 | 6,799 | 8,731 | 15,031 | 5,103 | 7,425 | 9,829 | 11,306 | 10,130 | 74,354 |

### Figure 14 | Average MWh Unserved Energy by TOU periods (As Is Case)

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Average |
| 2025 | 255 | 435 | 233 | 309 | 211 | 505 | 981 | 855 | 710 |
| 2030 | 2,177 | 1,955 | 1,415 | 2,369 | 2,066 | 1,060 | 1,168 | 786 | 1,663 |
| 2035 | 6,621 | 6,418 | 5,134 | 8,145 | 7,139 | 4,799 | 5,960 | 4,169 | 5,635 |
| 2040 | 13,261 | 13,211 | 11,779 | 11,675 | 10,556 | 8,377 | 10,325 | 8,553 | 10,492 |
| 2045 | 16,032 | 16,028 | 14,650 | 14,435 | 13,255 | 11,199 | 12,766 | 11,046 | 13,179 |
| 2050 | 18,043 | 18,025 | 16,532 | 16,189 | 14,960 | 13,028 | 14,824 | 13,116 | 15,108 |

### Figure 15 | Average MWh Unserved Energy by TOU periods (High Nuclear Case)

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Average |
| 2025 | 255 | 435 | 233 | 309 | 211 | 505 | 981 | 855 | 710 |
| 2030 | 2,273 | 1,975 | 1,412 | 2,259 | 1,964 | 960 | 987 | 907 | 1,648 |
| 2035 | 4,705 | 4,498 | 3,267 | 6,219 | 5,210 | 3,055 | 3,970 | 2,644 | 3,850 |
| 2040 | 10,018 | 9,967 | 8,544 | 8,525 | 7,403 | 5,227 | 7,163 | 5,394 | 7,310 |
| 2045 | 10,471 | 10,468 | 9,130 | 9,014 | 7,831 | 5,800 | 7,300 | 5,598 | 7,713 |
| 2050 | 11,295 | 11,281 | 9,837 | 9,665 | 8,438 | 6,466 | 8,216 | 6,527 | 8,488 |

### Figure 16 | Max MWh Unserved Energy by TOU periods (As Is Case)

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Max |
| 2025 | 809 | 935 | 407 | 405 | 537 | 2,087 | 3,358 | 3,098 | 3,358 |
| 2030 | 5,348 | 5,587 | 5,359 | 6,981 | 6,744 | 3,751 | 4,535 | 3,747 | 6,981 |
| 2035 | 9,635 | 9,430 | 9,705 | 13,671 | 12,832 | 10,673 | 9,239 | 8,636 | 13,671 |
| 2040 | 18,303 | 18,318 | 18,450 | 16,701 | 15,735 | 14,067 | 15,753 | 15,640 | 18,450 |
| 2045 | 19,938 | 19,947 | 19,593 | 20,203 | 18,885 | 17,130 | 17,703 | 17,286 | 20,203 |
| 2050 | 21,905 | 22,049 | 21,754 | 21,854 | 20,570 | 18,536 | 19,548 | 19,538 | 22,049 |

**Figure 17 | Max MWh Unserved Energy by TOU periods (High Nuclear Case)**

| | Winter | | | Summer | | | Shoulder | | Annual |
|---|---|---|---|---|---|---|---|---|---|
| Year | On-Peak | Mid-Peak | Off-Peak | On-Peak | Mid-Peak | Off-Peak | Mid-Peak | Off-Peak | Max |
| 2025 | 809 | 935 | 407 | 405 | 537 | 2,087 | 3,358 | 3,098 | 3,358 |
| 2030 | 5,348 | 5,587 | 5,359 | 6,771 | 6,684 | 3,751 | 4,535 | 3,747 | 6,771 |
| 2035 | 7,655 | 7,295 | 7,570 | 11,534 | 10,695 | 8,536 | 7,103 | 6,501 | 11,534 |
| 2040 | 15,261 | 15,462 | 15,042 | 13,839 | 13,606 | 10,659 | 12,345 | 12,232 | 15,462 |
| 2045 | 14,566 | 14,343 | 14,445 | 14,525 | 14,330 | 11,322 | 11,895 | 11,478 | 14,566 |
| 2050 | 15,661 | 15,878 | 15,298 | 14,846 | 14,556 | 12,080 | 13,063 | 12,530 | 15,878 |

Duration curves can also provide insights at the extremes (e.g. baseload and peaking requirements). Similar to the figures above, these duration curves represent the unserved energy described in Section 8 of the 2024 Annual Planning Outlook. They do not consider the previous and underway actions, and risks, identified in Section 12 of the 2024 Annual Planning Outlook.

Figure 18 and Figure 19 separate the annual unserved energy by season for the As Is and High Nuclear cases respectively, and demonstrate that the unserved energy is greater in the winter than in the summer, illustrating that some resources (e.g. solar) may be less dependable as they produce less energy during the winter.

For this analysis, summer months are assumed to be May to October; winter months are November to April.

**Figure 18 | Unserved Energy by Season (As Is Case)**

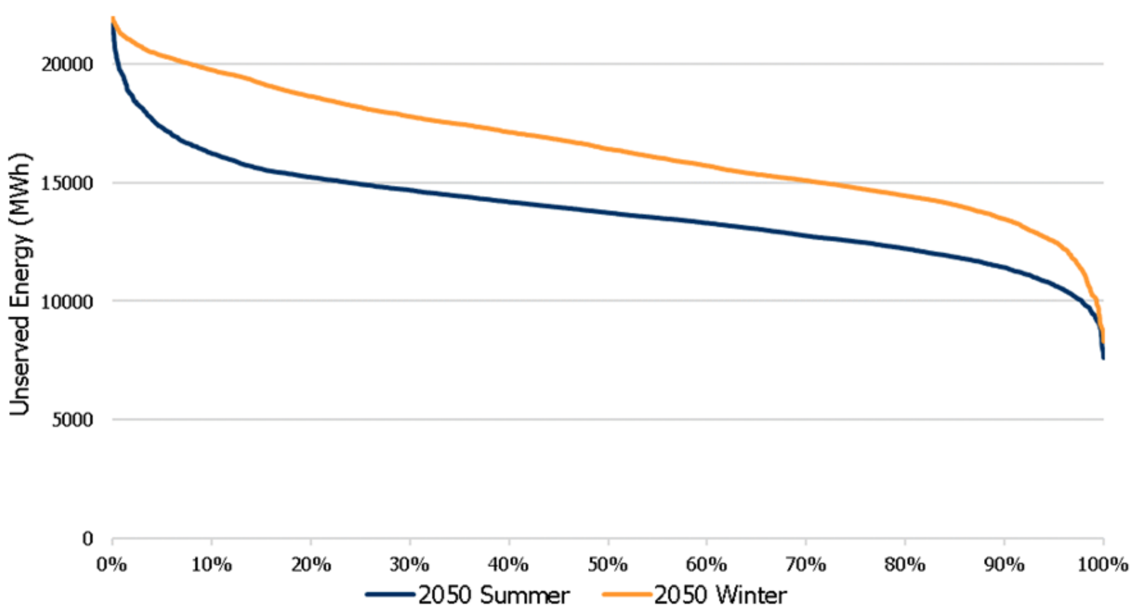


**Figure 19 | Unserved Energy by Season (High Nuclear Case)**

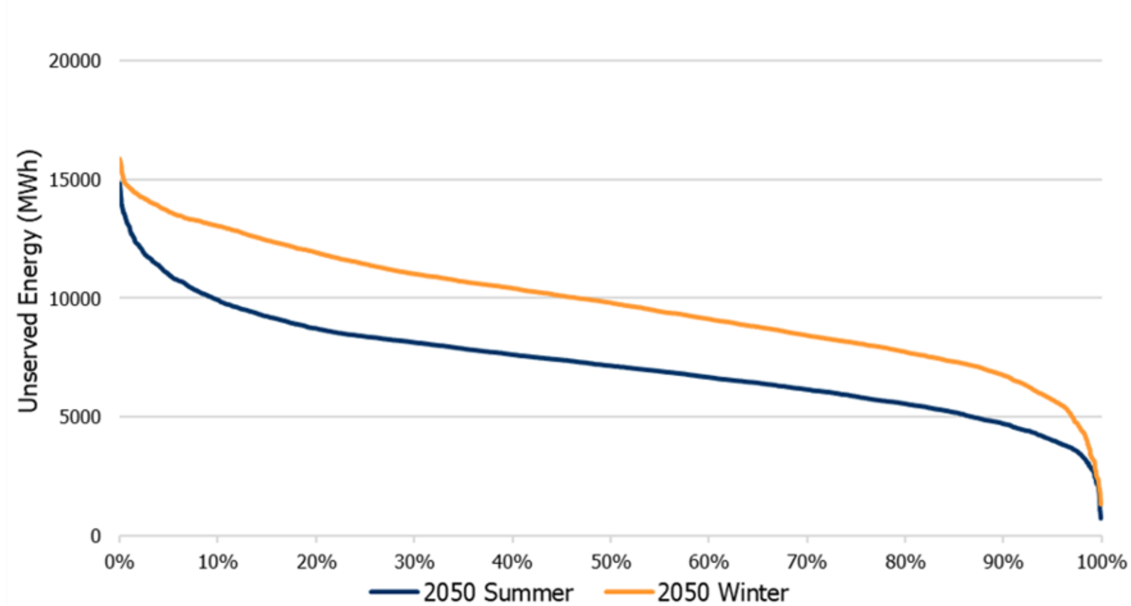



Figure 20 and Figure 21 show duration curves of the unserved energy need for years 2025, 2030 and 2050. These duration curves are used to illustrate the relationship between capacity requirement and utilization.

**Figure 20 | Unserved Energy Duration Curve (As Is Case)**

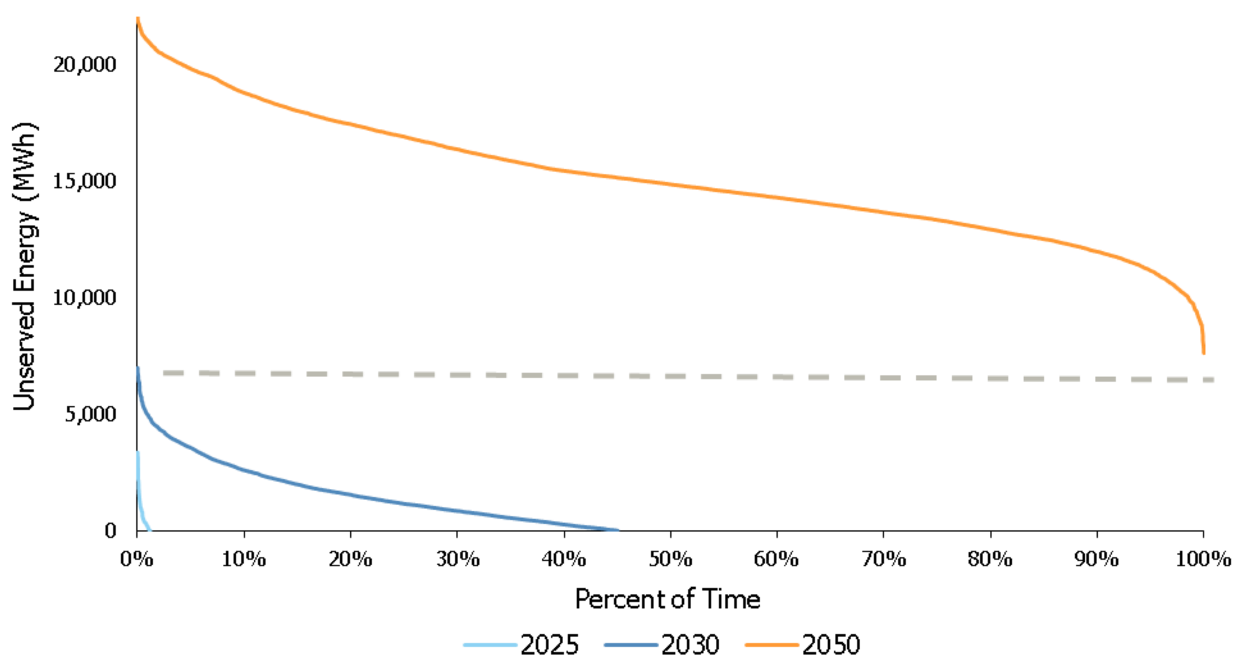
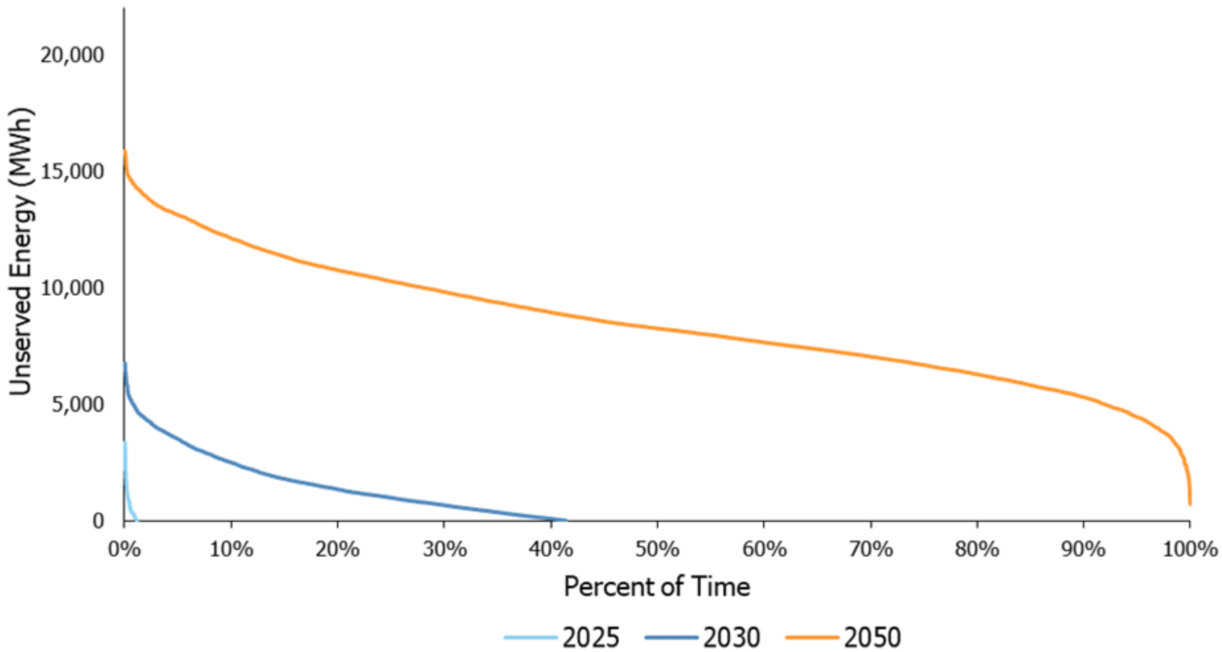


**Figure 21 | Unserved Energy Duration Curve (High Nuclear Case)**




In the As Is Case, in 2030, a portion of the total energy need is not served (unserved energy) for about 40% of the year, as illustrated in Figure 20. By 2050, the energy not served occurs in all hours of the year; with a sizeable baseload amount that will be required at all times, as estimated by the grey line.

In the High Nuclear Case, in 2050, unserved energy continues to occur at all hours, though at lower volumes than in the As Is case due to the additional baseload nuclear resources in the High Nuclear case as shown in Figure 21.

The need for baseload resources is not significant in the near term. However, it is expected to increase over the planning horizon. The peaking portion of the duration curve could be met by capacity products.

## 3.4 Discussion

Overall, the trends in the energy outlook in the 2024 APO are consistent with previous outlooks. The surplus baseload generation (SBG) is no longer an issue in 2024 APO. The growth in demand in the longer term increases capacity and energy requirements. Nuclear generation continues to be a major source of generation in Ontario. Energy from non-hydroelectric renewables has not changed materially while hydroelectric production is expected to be lower marginally due to lowered OPG hydroelectric production in line with OPG 2023 Business Plan energy forecast. The extent to which existing resources remain in the market will dictate whether the need for future supply is primarily capacity or energy driven.

Energy results are shown for normal or median conditions. Weather conditions can have a substantial effect on energy demand and production from wind, hydroelectric, and solar resources. When interpreting energy outlooks, focus should be on trends, order of magnitude, and relative direction.

Updated on March 28, 2024: A previous version of this report misstated the forecasted energy production of natural gas resources from 2035-2042. Values in the corresponding energy figures and data tables have been corrected.

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