Annual Planning Outlook

Resource Adequacy and Energy Assessments Methodology

March 2026

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1. Introduction

This document describes the data sources and methodologies used to perform the resource adequacy and energy assessments included in the Annual Planning Outlook (APO).

1.1 Resource Adequacy Assessments

Resource adequacy assessments are a way to assess the ability of electricity resources to meet electricity demand, taking into consideration the demand forecast, generator availability, and transmission constraints.

Adequacy studies are performed to:

- Determine the supply/demand balance
- Identify the amount, timing, location, and duration of system needs
- Assess the ability of different resource types to meet system needs
- Provide guidance on the scope and timing for resource acquisition and investment decisions
- Provide recommendations on outage management and inform capacity import and export decisions

From a long-term planning perspective, a capacity need (or capacity deficit) occurs when there is a risk of using emergency operating procedures, such as public appeals, voltage reductions, or disconnecting firm load due to resource deficiencies. Resource adequacy criteria define which sources of risk to consider and what level of risk the electricity system should be prepared to meet.

1.1.1 Resource Adequacy Criteria

The Independent Electricity System Operator (IESO) is the Planning Coordinator and Resource Planner for Ontario, as defined by the North American Electric Reliability Corporation (NERC).[1] As detailed in the Ontario Resource and Transmission Assessment Criteria (ORTAC),[2] the IESO follows the Northeast Power Coordinating Council (NPCC) resource adequacy criterion, as outlined in NPCC "Directory #1: Design and Operation of the Bulk Power System:"[3]

"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."

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[1] For more information, refer to the NERC Reliability Functional Model, Dec 2018

[2] For more information, refer to the Ontario Resource and Transmission Assessment Criteria, September 2025

[3] For more information, refer to the NPCC Regional Reliability Reference Directory #1

Directory #1 further requires applicable entities to "make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighbouring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

The ORTAC states that the IESO will not consider emergency operating procedures for long-term capacity planning.

1.2 Energy Assessments

Energy assessments give insight into how the electricity system will operate under expected future conditions. Energy adequacy assessments indicate Ontario's ability to meet its own electricity needs and better characterize the nature of future needs. The assessment does not include any economic imports or exports across Ontario's interconnections. These types of assessments are used as a deterministic supplement to resource adequacy assessments in evaluating both the ability of Ontario's resources to meet system load, and the potential for unserved energy or surplus baseload generation in Ontario under normal system conditions.

2. Demand Forecast

The long-term demand forecast is a key input into the APO's resource adequacy and energy assessments. The demand forecast is an hourly forecast of the demand for electricity in each of Ontario's 10 electrical zones. The methodology to produce the long-term demand forecast is described in the 2026 APO Demand Forecast Methodology.

3. Supply Outlook

The supply outlook is the starting point for modelling electricity resources in both resource adequacy and energy assessments. An up-to-date overview of the resources expected to be available over the planning horizon is required to project adequacy needs and evaluate system performance.

To create the supply outlook, information about each supply resource in Ontario is gathered from various datasets and assembled into a single database. Supply resources modelled in the APO include market participants (generally connected to the IESO-controlled grid) and non-market participants resources (generally connected to the distribution system). Generators that are behind a customer's electricity meter are not considered as a supply resource, but as a demand modifier in the demand forecast.

Data sources for creating the supply outlook include information collected directly from market participants through the Customer Data Management System (CDMS) and through Form 1230 Reliability Assessment submissions, as well as information from IESO-held contracts, the Ontario Electricity Financial Corporation (OEFC) for non-utility generators (NUGs), and from the Ontario Energy Board (OEB) for rate-regulated resources.

From these data sources, the IESO creates a common resource database that has the most up-to-date information for each resource, including:

- Resource name
- Installed capacity
- Fuel type
- IESO zone
- In-service date
- Out-of-service date
- Status

The installed capacity in megawatts (MW) for thermal resources represents the maximum active power capability, minus station service load collected through the CDMS. For non-thermal resources, installed capacity is the maximum active power capability collected through the CDMS. For non-market participants, installed capacity is assumed as their contract capacity. The in-service date for new resources is the expected start date of commercial operation, and the out-of-service date is the end of a resource's contract/commitment or the retirement date (not the date of market de-registration).

There are three types of resource status: existing, committed and merchant. Existing resources have a contract/commitment or are rate-regulated and are currently in operation. Committed resources have a contract, but are still in the construction/commissioning phase, or do not have a contract but are expected be available during the study horizon. Merchant resources are resources that operate in the IESO electricity market without a contract.

One supply case is presented in the 2026 APO and consists of existing, committed and merchant resources, including resources committed through actions undertaken by the IESO and/or informed by government policy, until their contract or commitment period ends.

After the supply outlook database is created, it is supplemented with information required to properly model the performance of each resource. Some of this supplemental information is common between resource adequacy and energy assessments, while other information is assessment specific.

3.1 Installed Capacity Ratings (ICAP)

For resource adequacy modelling, the ICAP rating represents the available capacity at a given point in time. The maximum capability for most thermal generating resources, such as nuclear, biofuel and gas-fired generators, is affected by external factors, such as ambient temperature and humidity or cooling water temperature. To capture those variables, the ICAP value for each thermal generator is modelled on a monthly basis.

For thermal resources, see Section 4.5.1 of the Methodology to Perform the Reliability Outlook document.

For hydroelectric, wind, and solar resources, monthly ICAP ratings are equal to the installed capacity.

3.2 Hydroelectric, Wind, Solar, Storage and Demand Response

Hydroelectric, wind, and solar resource performance is captured through measures other than ICAP ratings. To inform the modelling of hydroelectric, wind, and solar resources, historical and simulated hourly profiles are used for each generator.

Hourly historical data is plant-specific and includes historical production, scheduled operating reserve and market offer data. Hourly simulated production data is specific to a certain site; resources are mapped to the closest appropriate simulated site, depending on technology type.

To assess capacity contribution factors, solar and wind generation uses Allocated Quantity of Energy Injected (AQEI) and foregone energy that coincides with the top 200 hours of highest Ontario demand per season, over the most recent five years on a zonal fleet wide basis.

For hydroelectric resources, hydroelectric performance modeling is based on a combination of historical production, historical offer data and incorporating multiple water years.

Demand Response (DR) capacity contribution factors are based on the DR historical performance from past DR activations and DR test results. Dispatchable Load (DL) capacity contribution factors are based on the median of hourly bids quantity over the maximum seasonal energy bid in the top 200 hours of Ontario Demand per obligation period from the most recent complete obligation period.

The capacity contribution of storage depends on the type, size, duration as well as the conditions of the underlying system. The capacity value for storage is expected to evolve over time.

3.3 Forced Outage Rates

For thermal resources, performance is measured with Equivalent Forced Outage Rate on Demand ($EFOR_d$). $EFOR_d$ is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.[4] A generator is subject to failure when it is online (requested by the system) or offline due to economics (not requested by the system). EFOR is a measure of the probability that a generating unit will not be available regardless of the system needs.

The $EFOR_d$ is currently defined in the Institute of Electrical and Electronics Engineers (IEEE) Std 762-2006 as following:

$$EFOR_d = \left(\frac{FOH_d + EFDH_d}{SH + FOH_d}\right) \times 100$$

where:

SH — Service Hours

FOHd — Forced Outage Hours on demand

EFDHd — Equivalent Forced Derated Outage Hours on demand

The IESO determines an $EFOR_d$ of a generator based on a five-year dataset. The dataset is based on a rolling window of five years of historical AQEI (Allocated Quantity of Energy Injected is megawatt-hour (MWh) received from meter data that accounts for losses and totalization) and outage data from Control Room Operators Window (CROW). Every year, a new year of the AQEI and outage data is added to the dataset, and the oldest year is discarded from the $EFOR_d$ calculation.

To ensure the accuracy of calculated $EFOR_d$ percentage, the $EFOR_d$ analysis excluded certain types of outages. These include:

- Curtailment outages
- Cross-over hold outages: outages where a generator is derated and a technical threshold is put on hold during operation
- Contract termination: outages were requested where the generator's contract ended

3.3.1 Generator Chronology

To calculate $EFOR_d$, a chronology is developed for each generator covering the five-year window. The chronology describes, for the entire five years, the state that the generator was in. The seven possible states, and its definition, are outlined in Table 1.

Table 1 | Seven Possible States

[4] IEEE Power Engineering Society. (2007). IEEE 762 Standard Definitions for Use in Reporting Electric Generating Unit Reliability Availability and Productivity. *Definitions*, 3.

No.	Grouping	State	Description
1	Available	I/S [In-Service]	The unit is fully available and operating
2	Available	RS [Reserve Shutdown]	The unit is available (i.e., has no outages) but not required for service[5] (i.e., AQEI ≤ 1 per cent MCR[6], Maximum Continuous Rating)
3	Available	F-derate1 [Forced Derating1]	A forced derating D1 which occurred during the period of demand (i.e., AQEI > 1 per cent MCR) and is mapped to the first derate level
4	Available	F-derate2 [Forced Derating2]	A forced derating D2 which occurred during the period of demand (i.e., AQEI > 1 per cent MCR) and is mapped to the second derate level
5	Unavailable	F [Forced Outage]	A full forced outage
6	Unavailable	P [Planned Outage]	A full planned outage
7	Available	P-derate [Planned Derating]	A portion of the planned derating which occurred during the period of demand (i.e., AQEI > 1 per cent MCR)

States are defined in Table 2 below. Notably, if the outage data indicates that a generator should not be running (F or P) and AQEI indicates that it was running, the AQEI data overrides . data and the I/S state is assigned.

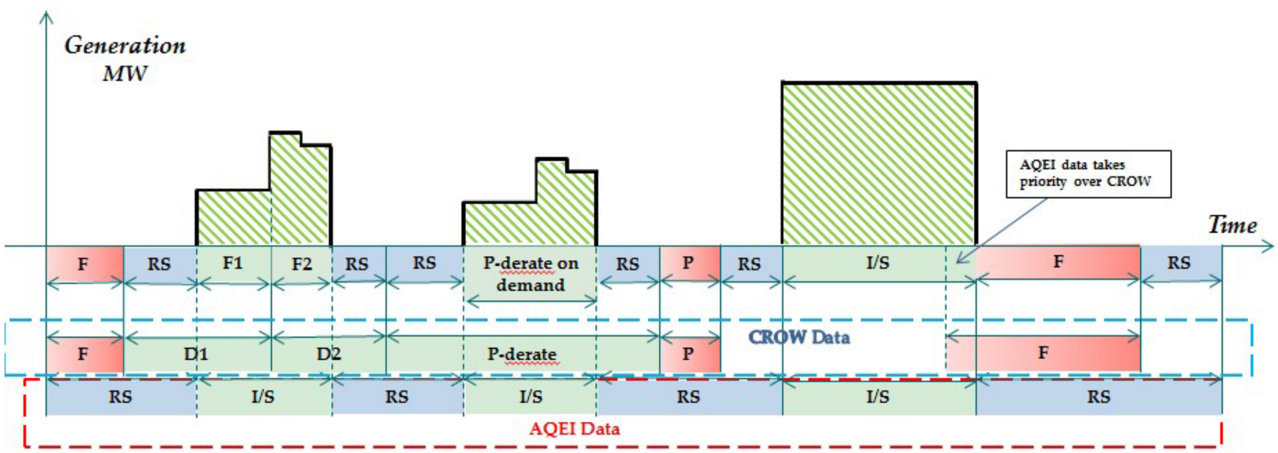
[5] IEEE Power Engineering Society. (2007). IEEE 762 Standard Definitions for Use in Reporting Electric Generating Unit Reliability Availability and Productivity. *Unit States*, 9.

[6] AQEI ≤ 1 per cent MCR: AQEI in represented in MWh where MCR is represented in hour. MWh divided by hour yields MW, and if the MW value is less than 0.01 then the generator is assumed to be in reserve shutdown.

Table 2 | EFORd States

Outage Info	AQEI < 1% of MCR	1% < AQEI < 99%	AQEI > 99% of MCR
No Outages	RS	I/S	I/S
Forced Out	F	I/S	I/S
Forced Derate	RS	F-derate	I/S
Planned Out	P	I/S	I/S
Planned Derate	RS	P-derate	I/S

Figure 1 | Chronology of Operating States



3.3.2 EFORd Calculation

To calculate the $EFOR_d$, the number of hours in each of the seven states and the number of transitions between each state is needed. An example is shown in the two tables below.

Table 3 | Hours in State

State	Hours
I/S	5,209
F - Derate 2	743
F - Derate 1	139
F	1,191
RS	22,108
P	9,755
P - Derate	4,679

Table 4 | Number of Transitions

	Number of Transitions:				To:			
		I/S	F-Derate 2	F-Derate 1	F	RS	P	P-Derate
	I/S	0	5	6	13	259	2	17
	F-Derate 2	4	0	2	0	49	0	9
From:	F-Derate 1	11	2	0	0	4	0	17
	F	4	0	1	0	24	3	0
	RS	255	46	8	15	0	38	292
	P	1	0	0	4	38	0	0
	P-Derate	27	11	17	0	280	0	0

Three intermediate quantities are needed for the EFORd formula:

1. **Service hours (SH)** is the sum of hours in the states I/S, F – Derate 2, F – Derate 1, and P – Derate. In other words, all hours where AQEI >= 1% of MCR.
2. **FOHd** is calculated using the demand factor f as outlined in IEEE Std 762-2006 section 6.10.1, where FOH is the number of hours in state F, state F-Derate 2, and state F-Derate 1:

$$FOHd = f \text{ x } FOH$$

where

$$f = \left\{ \frac{\left\{\frac{1}{r} + \frac{1}{T}\right\}}{\left\{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right\}} \right\}$$

Calculating the demand factor requires looking at the number of transitions and the number of hours in each state:

- The variable r is the average duration of a forced outage. It is the total hours in state F (FOH) divided by the number of transitions to F. 1/r is the repair rate.
- The variable T is the average duration of a reserve shutdown. It is the total hours in state RS divided by the number of transitions from RS to a state other than P. Transitions from RS to P are excluded because a long shutdown interrupted by a planned outage is counted as a single reserve shutdown.
- The variable D is the average demand time (duty cycle time). It is the total SH divided by the number of transitions from the F or RS state to one of the states that define SH.

3. **EFDHd** accounts for forced derates during service hours. It is calculated as:

$$EFDH_d = EFDH - ERSFDH$$

where

EFDH — Equivalent Forced Derated Outage Hours

ERSFDH — Equivalent Reserve Shutdown Forced Derated Hours

   a. **EFDH** — Equivalent Forced Derated Outage Hours

$$EFDH = \frac{\sum_{i=1}^{n} FD_i \times T_i}{MC}$$

where

FDi – is Forced Derated states

Ti – is the number of hours accumulated in the time category of interest between the i and the (i + 1) change in capacity

MC – is the Maximum Capacity

b. **ERSFDH** — Equivalent Reserve Shutdown Forced Derated Hours

$$ERSFDH = \frac{\sum_{i=1}^{n} RSFD_i \times T_i}{MC}$$

where

RSFDi – is Reserve Shutdown Forced Derated states

Ti – is the number of hours accumulated in the time category of interest between the i and the (i + 1) change in capacity

MC – is the Maximum Capacity

3.4 Planned Outages

Planned outage information is received from market participants and used to develop planned outage schedules for each generator over the planning horizon. Data from the CROW takes precedence, followed by data submitted through Form 1230s or submitted directly by market participants. For years and/or generators for which no planned outage information has been submitted, the IESO uses a combination of available submitted information and historical planned outage rates to make assumptions about future planned outages.

Some resource types require resource-specific inputs for planned outages:

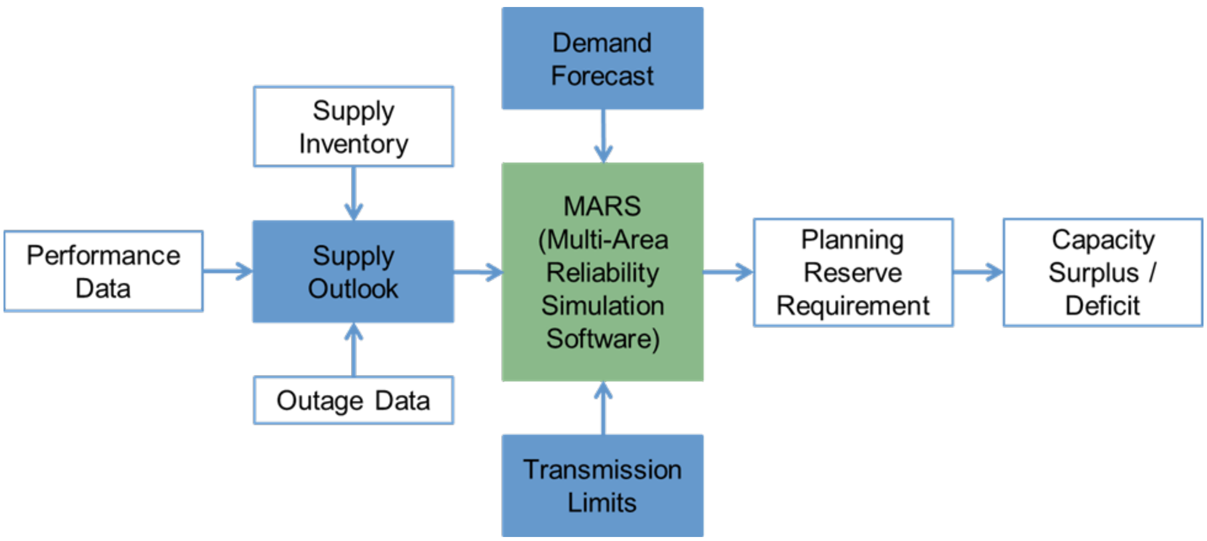
- Hydroelectric planned outages are generally not modelled explicitly, as outages are embedded within the historical profiles. When significant outages of sufficient duration are planned, these outages are modelled.
- Wind and solar planned outages are not modelled explicitly as they are embedded within the simulated profiles.
- DR is assumed to have no planned outages.

For the APO, capacity needs are displayed after some outages have been rescheduled. To comply with the ORTAC/NPCC resource adequacy criteria, and for the purpose of the adequacy assessment, non-critical outages may be moved from critical periods. This minimizes system costs as it is more efficient to move an outage than purchase new capacity. Typically, major outages (including nuclear refurbishment outages and regulatory-driven outages) are not moved in the APO resource adequacy assessment. However, opportunities to reschedule these particular outages are considered in other near-term adequacy assessments, such as the Reliability Outlook.

4. Resource Adequacy Assessment

The capacity adequacy assessment takes the demand forecast and supply outlook as a starting point, then introduces probabilistic risks to determine the loss of load expectation (LOLE). The assessment is performed using General Electric's Multi-Area Reliability Simulation (MARS) model, as detailed in Figure 2.

Figure 2 | Overview of Inputs and Process for MARS Model and Resource Adequacy Assessment



4.1 MARS Model Overview

A sequential Monte Carlo simulation forms the basis for the MARS calculating algorithm. The sequential simulation steps through the study period chronologically, enabling MARS to model time-correlated events and calculate various measures of reliability, including LOLE in days/year.

MARS is capable of probabilistically modelling uncertainty in forecast load and generating unit availability due to forced outages. Furthermore, MARS can determine the expected number of times various emergency operating procedures (EOPs) will be used in each zone.

In MARS, system reliability is determined by combining the following:

- Randomly generated forced outage patterns of thermal units
- Planned outage schedules of thermal units
- Capacity and/or energy limitations of both thermal and non-thermal units
- Transfer limits of interfaces between interconnected zones
- Hourly chronological load and load forecast uncertainty

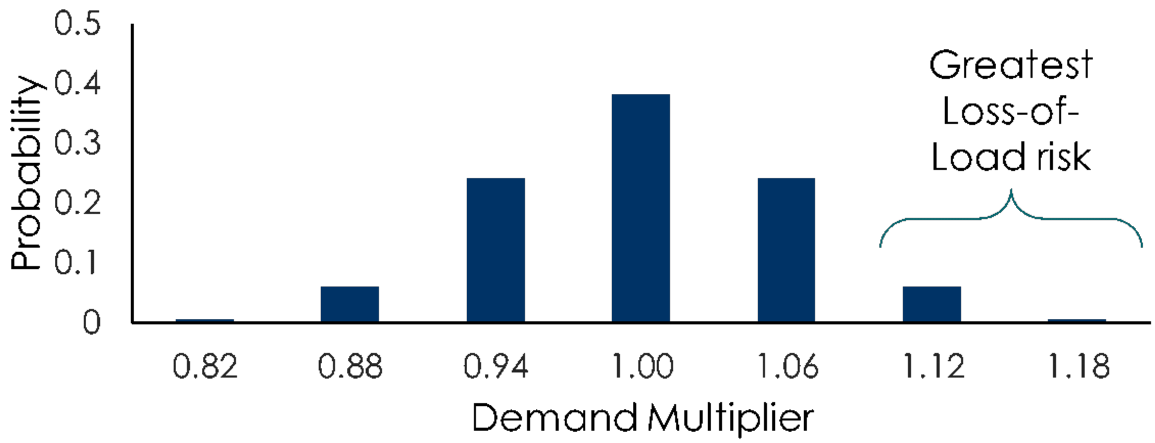
The system can be modelled with recognition of random events, such as equipment failures and load uncertainties, as well as deterministic rules that govern system operation. For each yearly system simulation, the model is run between 500 and 2,000 random iterations.

4.2 Demand and Load Forecast Uncertainty

Each zone has an hourly load from the demand forecast, as well as a monthly load forecast uncertainty (LFU) distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution, as demonstrated in Figure 3. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability.

Figure 3 | Illustrative Example of Load Forecast Uncertainty Distribution



4.3 Thermal Generators

The MARS model does not include dispatch-related constraints, such as minimum run time, variable costs, or ramp rates; it assumes any available thermal resources will be scheduled appropriately in the operational planning time frame to satisfy system needs.

All thermal generators use the following inputs described in the Section 3:

- In-service and out-of-service dates
- Monthly ICAP ratings
- IESO zone
- Planned outages

For non-nuclear thermal generators, the input planned outage schedule is converted into an annual planned outage rate for each model year. The MARS model creates an optimized outage schedule that minimizes LOLE, while respecting the outage rates provided. For nuclear generators, the input planned outages schedule is input directly into the model.

The forced outage rates ($EFOR_d$) described in the Section 3 are converted to state transition matrices for input into MARS. A probability of moving from one state to another is assigned to each generator, such that the calculated $EFOR_d$ is replicated in the model. In each iteration of the MARS model, a random pattern of forced outages is produced, governed by the state transition matrices.

Some thermal generators have limited fuel supply, requiring a modified modelling approach. For these units, a monthly energy limit is given to the model which can be used as needed to shave system peaks; any unused energy may be carried over into the next month. Forced outages cannot be modelled using a state transition matrix for energy-limited resources; instead, the maximum capacity of these units is reduced such that the effective capacity is equivalent to a thermal generator with forced outages.

4.4 Hydroelectric Generators

Hydroelectric generators are modeled as either run-of-river or peaking plants. The modeling approach is different depending on the type of plant.

Run-of-river plants are modeled using hourly profiles. In the Monte Carlo analysis, each iteration of the model randomly selects a different yearly run-of-river profile from the previous thirty years of data. Annual hourly run-of-river profiles are either actual hourly historical production or simulated production profiles. Actual historical hourly production is used for years where the data is available, and the generator was operating at its current installed capacity. Simulated production profiles are used for years where actual historical production is unavailable or the generator was operating at a different installed capacity than its current configuration. Simulated hourly production profiles are created by taking historical daily flow data and converting it into an hourly production profile.

Peaking plants are treated as dispatchable energy-limited resources. These generators can be dispatched as needed to meet system conditions, up to the maximum dispatchable capacity, provided there is sufficient dispatchable energy remaining in the month. Inputs for the peaking plants are calculated on a monthly basis, using the last five years of operational data as this best reflects current operations. There is a minimum output, which is the average daily minimum flow for the month. The maximum output is the 90th percentile of daily maximum offers, which accounts for some forced and planned outages. The monthly energy is the average monthly energy production.

4.5 Wind Generators

Wind generation is aggregated by IESO zone. For the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

For resource adequacy assessments, wind generation uses 30 years of simulated hourly profiles. Wind generators are matched to the closest simulated site, and then output is scaled relative to installed capacity.

4.6 Solar Generators

Solar generation is aggregated by IESO zone. In the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

Solar generation uses 10 years of simulated hourly profiles. Solar generators are matched to the closest simulated site and technology type (ground-mount or rooftop), and then output is scaled relative to installed capacity.

4.7 Demand-Side Resources

The IESO models two demand-side resources as a supply resource: DR and DL. Both measures are modelled on an as-needed basis in MARS and will only be used when all other supply-side resources are insufficient to meet demand. DR and DL capacity is aggregated by IESO zone.

Monthly demand-response capacity is equal to the capacity obligation from the most recent auction, de-rated by historical performance during testing. Effective capacity available from dispatchable loads is determined based on historical bids, using the last five years of history, by the DL participants during peak demand hours. The effective dispatchable load capacity for the summer (June to August) is based on bids during critical peak pricing periods.

4.8 Energy Storage

The largest energy storage facility in Ontario is the Sir Adam Beck Pump Generating Station. It is modelled in aggregate with the rest of the hydroelectric capacity at the Sir Adam Beck complex on the Niagara River. The remaining energy storage facilities in the IESO-administered markets can be used to represent resources that are operated by filling or charging energy into a reservoir and drawing from that energy when there are shortages in the system. This model can be used to represent units such as batteries or pumped-hydro storage.

The parameters that define a storage unit include the following:

- Storage size: Maximum amount of energy (in MWh) that can be stored
- Generation rating: Maximum capacity (in MW) that the unit can generate in an hour

In MARS, storage units are modeled as units that hold a certain amount of energy reserves that get deployed on an as needed basis (i.e., their capacity is used if there is a shortage in the system). Each replication may result in a different dispatch of the unit. The unit is limited by the amount of energy stored, its generating rating and the ability of providing power to the areas with shortages through interfaces.

If there is a surplus of capacity in the system, storage units will attempt to fill (or charge) their energy reservoirs without causing shortfalls in the system. The charging of storage units is limited to its charging capacity, the amount of room in the reservoir and the ability of the system to deliver excess capacity to the areas where storage units are located. Additionally, a roundtrip efficiency is assumed based on technology type for non-hydro storage resources.

4.9 Transmission Transfer Capabilities

The IESO-controlled grid is modelled using 10 electrical zones with connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in the IESO's Transfer Capability Assessment Methodology: For Transmission Planning Studies. The transmission limits between zones show "all-in" service limits reflecting the next contingency. Forced outages are not considered as they are captured in the transmission security assessments that complement the resource adequacy assessment.

4.10 External Jurisdictions

Ontario's neighbouring jurisdictions are not explicitly modelled. Firm export contracts are represented by a firm load that is added to the zone which is connected to the export market. Firm imports are represented as a firm generator added to the zone connected to the jurisdiction providing the import.

Non-firm imports are included in the IESO's resource adequacy assessments. The seasonal non-firm import capacity assumption is based on the minimum value from six non-firm import capacity considerations, shown in Table 5. The most limiting value was determined to be imports that are likely to flow under tight supply conditions and prices, which yields seasonal values of 302 MW for summer and 59 MW for winter; these values were assumed for the 2026 APO.

Table 5 | Non-firm import capacity considerations

Consideration	Data Source
Excess capacity available in neighbouring areas (planning criteria)	NPCC "Review of Interconnection Assistance Reliability Benefits" report
Excess supply available in neighbouring areas in real-time	90th percentile dependable import offer in top 5 per cent of hourly Ontario energy price (HOEP) hours, last four years
Sufficient intertie capability	Interconnection capacity with one element out of service at each intertie
Deliverable within Ontario	Coincident import capability with internal constraints
Ability to manage non-discretionary outages (regulatory requirements)	Minimum Resources Above Requirements from Reliability Outlook, assuming no outages or de-rates, last four years
Imports likely to flow under tight supply conditions/prices	90th percentile dependable import flow in top 17per cent of HOEP hours, last four years

4.11 Emergency Operating Procedures

Emergency operating procedures, such as voltage reduction and public appeals, are not considered in the resource adequacy assessment for the APO. These measures are occasionally used in submissions to NPCC.

4.12 Determining the Resource Adequacy Requirement

The MARS model calculates the system LOLE based on the demand forecast and supply outlook, with associated risks and uncertainties. The capacity requirement is the amount of capacity that must be added to the system to satisfy the LOLE criterion.

Generally, the demand forecast and supply outlook do not produce a LOLE at criteria; the model must be adjusted to determine the amount of capacity that must be added (or removed) to meet the LOLE criteria. A standard "perfect capacity," a resource which is available in all hours of the study period, is used to adjust the capacity in the model. When the perfect capacity has a negative value, it represents the amount of supply reduction that could be accepted and still satisfy the resource adequacy criteria.

To satisfy the LOLE criteria, the MARS model is run iteratively with different amounts of perfect capacity for each season. When enough data points have been found in the neighbourhood of 0.1 days/year LOLE, a best-fit curve is created.

4.12.1 Reserve Margin

The reserve margin is expressed as a percentage of demand at the time of the annual peak where the LOLE is at or just below 0.1 days per year. At least once per year, IESO will calculate the required reserve margin at the time of annual peak for the next five years and will publish this value. Below is a breakdown of IESO's reserve margin calculation:

- Total Resource Requirement (MW) = Effective Capacity at Time of Peak Demand – Capacity Surplus/Deficit at Time of Peak Demand
- Reserve Margin Available (MW) = Effective Capacity at Time of Peak Demand – Annual Peak Demand
- Reserve Margin Available (%) = Reserve Margin Available / Annual Peak Demand
- Reserve Margin Requirement (%) = (Total Resource Requirement – Annual Peak Demand)/ Annual Peak Demand

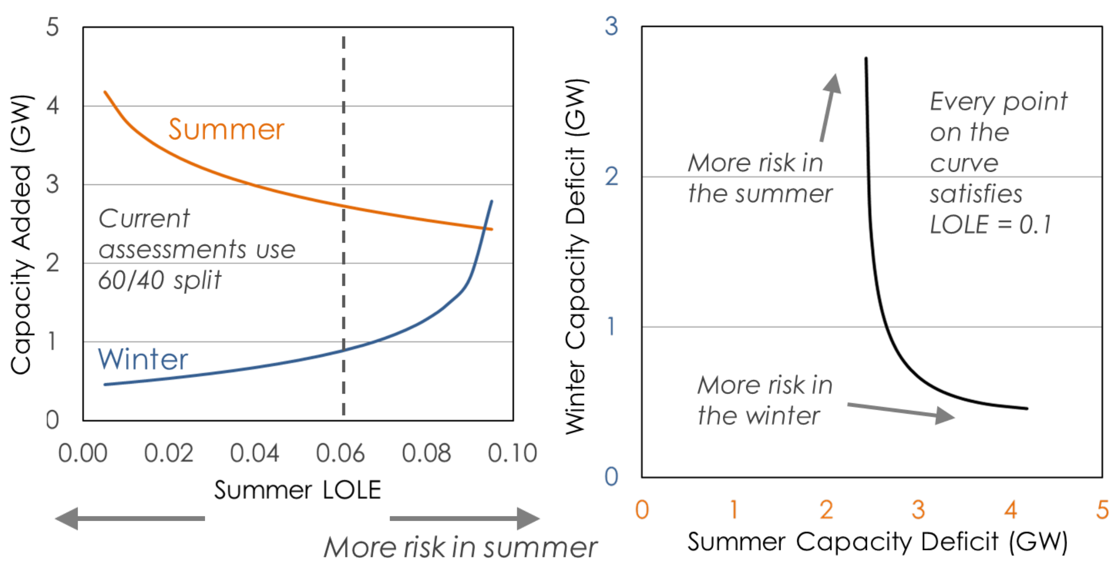
Given the uncertainty of the future supply mix, the reserve margin was further post processed for years 2030 onwards. First, the average of each year's reserve margin requirement percentage was taken for years 2030 through to 2050. Then, this average reserve margin requirement percentage was applied to the peak demand forecasted in each year to determine the reserve margin required in each year. This annual reserve margin required was then added to the annual peak demand to determine the total resource requirement for each year. This is presented in Figure 18 in the 2026 APO.

4.12.2 Seasonal Considerations

Seasonal LOLE targets are required to develop seasonal capacity requirements. The IESO may select any allocation of LOLE between summer and winter seasons,[7] provided that the sum of the two seasonal targets over a given year is no more than 0.1 days/year.

The IESO has determined that in the long run, an allocation of 0.06 days/year in summer and 0.04 days/year in winter minimizes total annual capacity requirements. An allocation of 0.09 days/year in summer and 0.01 days/year in winter may minimize capacity costs, if summer capacity is assumed to have a higher price than winter capacity.

Figure 4 | Overview of Seasonal Considerations and Optimal LOLE Allocation



As shown in Figure 4 the choice of seasonal LOLE allocation can change the seasonal capacity requirement by several hundred MW. For example, moving from 0.06 days/year in summer to 0.09 days/year would reduce the summer requirement by roughly 250 MW and increase the winter requirement by roughly 550 MW. In performing resource adequacy assessments, the IESO allocates LOLE across the summer and winter periods in a manner that minimizes the amount of capacity required to satisfy the resource adequacy criteria of 0.1 days/year.

4.13 Nuclear Reserve

Ontario currently has 16 nuclear units. As of 2025, six of those units have completed a mid-life refurbishment, three units are currently being refurbished, and the other seven are scheduled to be refurbished over the next decade. Given the size of each unit, there is a significant risk to resource adequacy if the return of units is delayed due to unforeseen circumstances. There is also some risk of increased forced outage rates pre- and post-refurbishment. These risks and their associated impact on LOLE are assessed outside of MARS due to limitations in the model.

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[7] Summer: May-October, Winter: November-April

Based on information provided by nuclear operators, a return-to-service distribution is used to capture the likelihood of refurbishment delay. Nuclear plant outage rates typically increase as the units approach refurbishment, return to service from refurbishment and approach end-of-life. Performance risk is captured by creating distributions of projected $EFOR_d$ change, based on the actual submissions by generators.

By probabilistically assessing the delays in return to service and forced outage rates, a spreadsheet-based Monte Carlo analysis tool is used to first calculate the average change in available capacity. With an updated available capacity, a risk-adjusted LOLE-MW curve is created, which is used to determine the amount of additional reserve required to maintain a yearly LOLE of 0.1 days/year.

5. Energy Assessments

Energy adequacy assessments are performed using the PLEXOS model.

5.1 PLEXOS Model Overview

PLEXOS is an economic dispatch model that simulates the dispatch of electricity resources based on the variable cost of energy production on an hourly basis over the planning time frame. The model takes into account the operating characteristics of each generator and their cost of dispatch. For each hour, generator offers are simulated based on their expected dispatch costs. The clearing price is the dispatch cost of the last unit that clears in each hour. This is accomplished using linear programming (LP) with DC Optimal Power Flow (OPF) for both unit commitment and economic dispatch while respecting system constraints.

PLEXOS commits available generators in Ontario and its neighbouring jurisdictions in the Eastern Interconnection to meet the load and ancillary service requirements at each load bus. The model minimizes the cost of dispatch across the Eastern Interconnection, taking into account electricity import and export opportunities.

5.2 Demand Forecast

Each of the IESO's 10 zones has an hourly load from the demand forecast consistent with the resource adequacy assessment. PLEXOS is a deterministic model; there is no load forecast uncertainty applied.

5.3 Nuclear Generators

Nuclear generators are considered to be base generation and are characterized with price-quantity pairs, with offer prices ranging between -$350 to -$200.

5.4 Thermal Generators

Thermal generators create heat using an input fuel that is converted to electricity; fuel types include natural gas and fuel oil. Along with the model inputs used for the resource adequacy assessment, each dispatchable thermal generator has the following additional inputs for PLEXOS:

- Heat rate
- Variable operations & maintenance (VO&M) cost
- Fuel price
- Carbon price
- Start-up costs
- Minimum up time and down time

- Ramp-up rate

Fossil fuels are subject to a carbon price, consistent with the most recent applicable carbon price policies. For each facility, the heat rate is combined with a projection of fuel price and carbon price to determine the total fuel cost, in dollars per megawatt-hour, for each hour. The dispatch cost is the combination of total fuel cost, carbon price, and VO&M cost.

5.4.1 Combined Heat and Power Generators

Combined heat and power (CHP) generators are cogeneration units that provide both thermal and electrical output. CHP generators can be either self-scheduling or dispatchable. If the heat rate of a CHP generator is known, it is used in PLEXOS and the generator is treated as a dispatchable unit. The capacity factors for embedded CHP generators with metered data are well below 20 per cent.

5.4.2 Dual-Fuel and Energy-Limited Thermal Generators

Some thermal generators have unique operational characteristics that require specialized model inputs. Operating characteristic data for these types of units are generally provided directly by the asset owner.

5.4.3 Bioenergy Generators

Most bioenergy facilities, excluding those with unique operational characteristics, are considered to be "must-run" resources and are assigned predefined profiles. For embedded bioenergy facilities with metered data, the profiles are based on the median year of energy production. For other embedded bioenergy facilities without metered data, the profiles are derived from the capacity factors of facilities with metered data. Embedded bioenergy resources are then lumped together based on zones and each zone has one bioenergy profile.

5.5 Hydroelectric Generators

Hourly hydroelectric generation profiles are created external to PLEXOS and entered into the model as a must-run resource. The production profiles for generators with metered data are based on historical energy production, while production profiles for generators without metered data (149 MW out of a total 9,265 MW of hydro resources) are derived based on capacity factors of generators with metered data. For generators in the same region, the same year of hourly production profiles are applied.

The hydroelectric generation profile is split into a must-run component and a dispatchable component, differentiated by price-quantity pairs. The must-run components are priced between $200 and -$20, and the dispatchable component is priced at gross revenue charges.

All transmission-connected hydroelectric stations are modelled individually. The exception is Espanola Mill GS, which has no metered data and is lumped in with embedded hydroelectric stations into the Northeast zone profile. The embedded hydroelectric stations are grouped into zonal profiles. For all Ontario Power Generation (OPG) transmission-connected units (except for Beck and Peter Sutherland Sr), the hourly profiles are rearranged to follow modified load profiles on a daily basis without changes to the daily energy. To accomplish this process, the demand forecast is adjusted to account for other must-run resources (wind, solar, nuclear, must-run bios, and run-of-river hydro). The rearrangement follows the order of Decew, Saunders, and stations in Northwest, Northeast and Ottawa.

5.6 Wind Generators

For transmission-connected wind generators, historic hourly production from 2024 is used to generate input profiles. Transmission-connected wind farms are then grouped into zonal profiles. Each transmission-connected zonal wind profile is further separated into two series; the first series is 10 per cent of the original zonal profile, priced at -$100 as must-run units, and the second series is 90 per cent of the original zonal profile, priced at $0 and subject to curtailment. For embedded wind generation, hourly profiles are provided by demand forecast group based on nodal representations and grouped into zonal profiles for input into PLEXOS.

5.7 Solar Generators

For transmission-connected solar generators, historic hourly production from 2024 is used to generate input profiles. Transmission-connected solar farms are then grouped into zonal profiles. For embedded solar generation, hourly profiles are based on nodal representation and are grouped into zonal profiles for input into PLEXOS.

5.8 Demand-Side Resources

Demand response and dispatchable loads are not currently simulated in PLEXOS, as these resources supply very little energy and are modelled for resource capacity adequacy only.

5.9 Storage Resources

Storage resources are modelled in PLEXOS using assumptions for charging and discharging efficiency, bid and offer prices, and seasonal firm capacity for the winter and summer periods. Within the economic dispatch model, storage resources can charge by bidding for load and can discharge by offering energy back to the system, with their operation determined based on system conditions and the modeled bid-offer spread. This approach captures both the contribution of storage to resource adequacy and its operational role in shifting energy across hours. Historical battery dispatch patterns and market participation are currently being assessed to refine storage modeling assumptions and support further improvements to the methodology.

5.10 Transmission System

For energy assessments, internal transmission transfer capabilities are not explicitly modelled except for the East-West Tie, Flow North/South, and Flow Into Ottawa interfaces. External transmission transfer capabilities between Ontario and neighbouring jurisdictions are included in the model. Planned and unplanned outages of transmission elements are not considered. Transmission upgrades expected over the assessment horizon are incorporated into the energy model with their respective planned in-service dates.

5.11 Neighbouring Jurisdictions

Ontario's neighbouring jurisdictions are modelled using the same methods as for Ontario. Model input data on demand, supply, and transmission are obtained from the PLEXOS vendor.

5.12 Unserved Energy

Unserved energy in the APO represents the amount of load, in a normal weather scenario, that a resource mix is unable to meet, without consideration of energy from imports. In hours where there is insufficient energy production, the difference between energy demand and energy supply is the unserved energy. The unserved energy reported in the APO are the annual sums of all hourly unserved energy values.

5.13 Marginal Costs

The dispatch of generation in PLEXOS is based on the hourly dispatch cost. The marginal cost for each hour is the clearing price, which is the dispatch cost of the last unit that clears in that hour.

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