Annual Planning Outlook

Resource Adequacy and Energy Assessments Methodology

December 2021

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Powering Tomorrow.

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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 capacity needs
- Assess the ability of different resource types to meet capacity needs
- Provide guidance on the scope and timing for resource acquisition and investment decisions
- Provide recommendations on outage management and capacity export decisions

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 IESO is the Planning Coordinator and Resource Planner for Ontario, as defined by the North American Electric Reliability Corporation (NERC).[1] As detailed in Section 8 of 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."

[1]For more information, refer to the NERC Reliability Functional Model, June 2016

[2]For more information, refer to the Ontario Resource and Transmission Assessment Criteria, August 2007

[3]For more information, refer to the NPCC Directory #1, September 2015

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."

ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighbouring Planning Coordinator Areas as contributing to resource adequacy needs in the APO resource adequacy assessments.

1.2 Energy Assessments

Energy assessments give insight into how the electricity system will operate under expected future conditions. There are two main types of energy assessments: energy adequacy and energy production.

Energy adequacy assessments assess 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 and surplus baseload generation (SBG) in Ontario under normal system conditions.

Energy production assessments include economic imports and exports between Ontario and its neighbours. These assessments are used to simulate Ontario's electricity market by informing system economics (e.g. system costs, marginal costs) and system performance (e.g. electricity sector emissions).

2. Demand Forecast

The long-term demand forecast is a key input into the Annual Planning Outlook'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 2021 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 that are 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 (connected to the IESO-controlled grid) and embedded resources (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 MWs for thermal resources represent the maximum active power capability less station service load collected through the CDMS. For non-thermal resources, the installed capacity is the maximum active power capability collected through the CDMS. For non-market participants, the installed capacity is assumed as their contract capacity. The in-service date for new resources is the expected start date of commercial operation. 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. Merchant resources are resources that operate in the IESO electricity market without a contract.

The IESO generally considers two supply scenarios. In the first, resources are assumed to be unavailable beyond their contract expiry; this informs the need for resource acquisitions, which could include reacquiring existing resource or acquiring new resources. The second scenario assumes merchant resources and resources beyond their contract expiry are available; this gives insight into the amount of incremental new capacity that may be required in the future over and above what existing resources can provide.

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 ICAP Ratings

For resource adequacy modelling, ICAP 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, and Solar

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.

Wind generation currently uses 28 years of simulated hourly profiles. Wind generators are matched to the closest simulated site, and then output is scaled relative to installed capacity.

Solar generation currently 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.

3.3 Forced Outage Rates

For thermal resources, performance is measured with Equivalent Forced Outage Rate on Demand ($EFOR_d$). An industry metric defined by the IEEE,[4] $EFOR_d$ is the probability that a generating unit will not be available (completely or in part) during hours the unit is called upon to generate (i.e., during on-demand hours) due to forced outages and forced de-ratings. $EFOR_d$ is calculated using the following formula, where FOH_d is Forced Outage Hours on Demand, $EFDH_d$ is Equivalent Forced De-Rated Outage Hours on Demand, and SH is Service Hours:

$$EFOR_d = \frac{FOH_d + EFDH_d}{SH + FOH_d} \times 100$$

$EFOR_d$ is calculated for each thermal generator on a rolling five-year basis using a combination of data submitted by market participants, data collected using IESO's outage management system, and historical production data.

For non-thermal generators, forced outages are embedded within the historical and/or simulated production profiles described previously.

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 Control Room Operations Window (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.
- Demand response is assumed to have no planned outages.

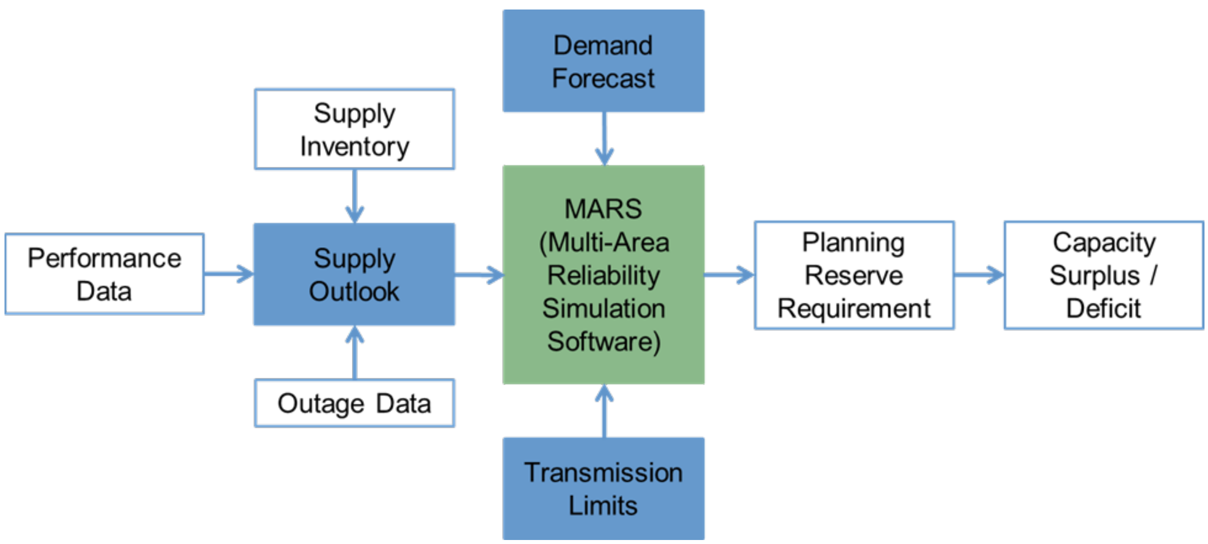
For the APO, capacity needs are displayed after some outages have been rescheduled. To comply with the ORTAC/NPCC resource adequacy criteria, non-critical outages may be moved from critical periods. This minimizes system costs as it is more efficient to move an outage than purchase new capacity. Usually, 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] For more information, refer to the IEEE Std 762-2006: IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.

4. Resource Adequacy Assessment

The resource 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 1.

Figure 1 | 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

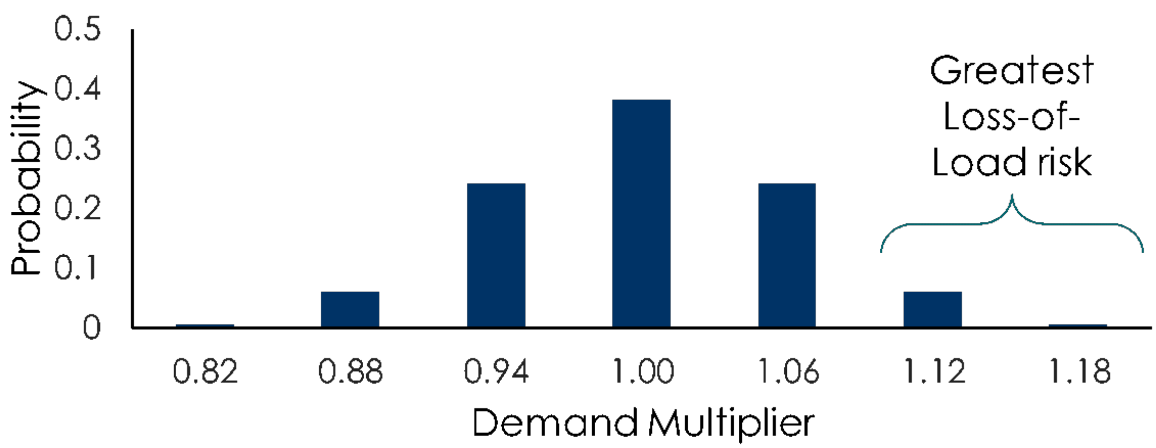
The system can be modelled with recognition of random events, such as equipment failures and load uncertainties, as well as deterministic rules that govern system operation. For each yearly system simulation, the model is run between 500 and 2,000 random iterations.

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 2. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability.

Figure 2 | 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 Supply Outlook:

- 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 Supply Outlook are converted to state transition matrices for input into MARS. Each generator can be in four possible states: fully in-service, fully out of service, and two possible levels of forced de-rate. The two de-rated states are chosen to most closely match observed de-rates over the last five years of historical data. 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

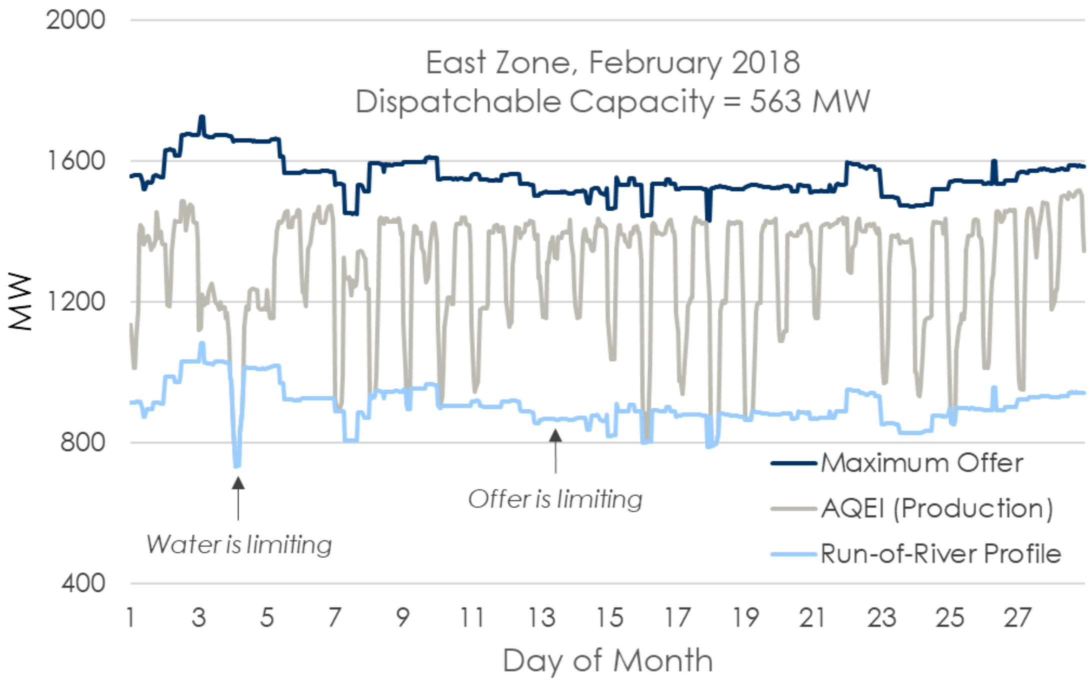
Hydroelectric generation is modelled using three inputs: a run-of-river component, which simulates the range of historical water availability, a maximum dispatchable capacity, and a dispatchable energy. Input values are calculated using a combination of historic hourly maximum offer data and historic hourly production data, aggregated on a zonal level. The three inputs work together to simulate the range of historical water conditions experienced since market opening in 2002.

Dispatchable capacity is input on a monthly basis, and calculated by comparing hourly maximum offers during weekday demand peaks to the corresponding historical production. The largest difference between weekday peak maximum offer and weekday peak production is the peaking capacity for that month. The reason for selecting the maximum is to ensure that, whatever the flow conditions for the run-of-river component, the model will be able to dispatch to the corresponding maximum historical offer.

Hourly run-of-river profiles are developed using historical hourly energy production and the calculated monthly peak dispatchable capacity. The hourly run-of-river value is the lesser of the actual production during that hour or the maximum offer minus the calculated monthly peak dispatchable capacity (see Figure 3). This approach ensures that the model cannot produce more than the maximum offer in a given hour. In the Monte Carlo analysis, each iteration of the model randomly selects a different yearly run-of-river profile.

In the model, the dispatchable component of hydroelectric generation is treated as an energy-limited resource. It 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. The monthly dispatchable energy is calculated by comparing the actual historical production in a year to the run-of-river profiles, calculated above; it is the monthly difference between actual energy production and the run-of-river energy, averaged for all years in the dataset.

Figure 3 | Determining Run-of-River Component for Hydroelectric Generation



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.

4.6 Solar Generators

Solar generation is aggregated by IESO zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production.

4.7 Demand-Side Resources

The IESO models two demand-side resources as a supply resource: demand response (DR) and dispatchable loads (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 are pilot projects and as such, they are not modelled in resource adequacy assessments.

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 Neighbouring 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 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 1. The most limiting value was imports that are likely to flow under tight supply conditions/prices, which yields seasonal values of 251 MW for summer and 243 MW for winter, is assumed for the APO.

Table 1 | 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 a areas in real-time	90^{th} percentile dependable import offer in top 5% of HOEP hours, last 4 years
Sufficient intertie capability	Interconnection capacity with one element out of service at each intertie

Consideration	Data Source
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 4 years
Imports likely to flow under tight supply conditions/prices	90^{th} percentile dependable import flow in top 5% of HOEP hours, last 4 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 an 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) = Summer Effective Capacity – Summer Capacity Surplus/Deficit
- Reserve Margin Available (MW) = Summer Effective Capacity – Summer Peak Demand

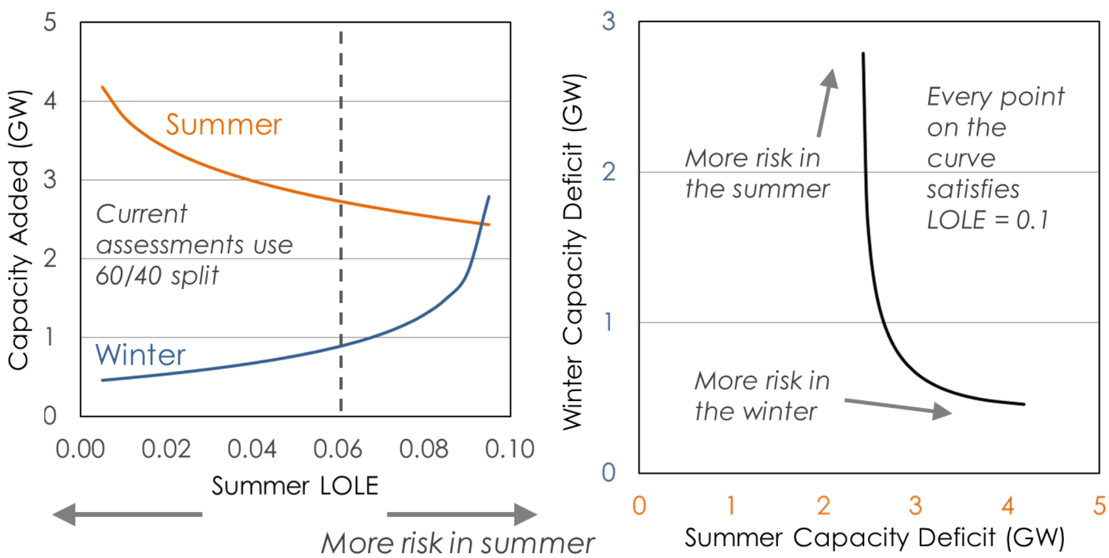
- Reserve Margin Available (%) = Reserve Margin Available (MW)/ Summer Peak Demand
- Reserve Margin Requirement (%) = (Total Resource Requirement – Summer Peak Demand)/ Summer Peak Demand

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,[5] 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.

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

4.12.3 Zonal Adequacy Constraints

The provincial capacity requirement is intended to be the lowest amount of capacity needed to meet the LOLE criteria. Under certain conditions, some capacity must be added to specific zones to satisfy that criteria. There may also be limits on how much capacity can be added to any given zone.

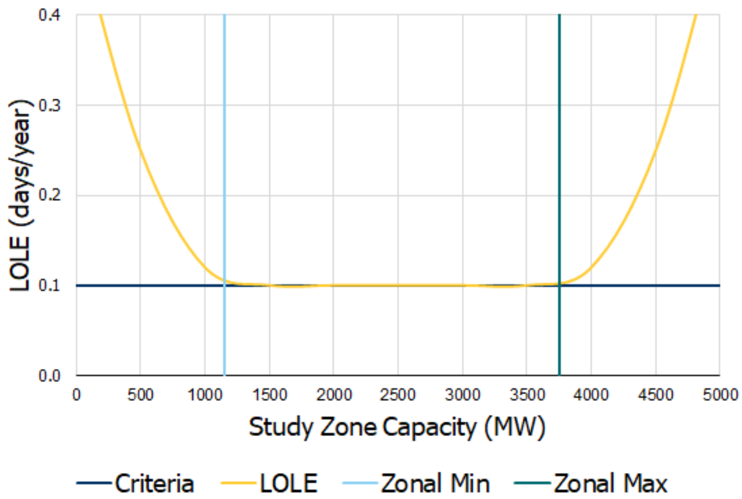
Zonal constraints are limits on zonal incremental capacity due to transmission constraints between zones. The IESO can produce the following zonal constraints:

- A zonal ***maximum*** incremental capacity limit for all individual zones that have a limited transfer capability ***out*** of the zone
- A zonal ***minimum*** incremental capacity limit for all individual zones that have a limited transfer capability ***into*** the zone
- A multi-zone group ***maximum*** incremental capacity limit for selected combinations of zones where it is clear that a common grid constraint(s) restricts the combined maximum capacity for the selected group of zones[6]
- A multi-zone group ***minimum*** incremental capacity limit for selected combinations of zones where it is clear that a common grid constraint(s) restricts the combined minimum capacity for the selected zones

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 MARS 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 5.

[6] The multi-zone groupings are reviewed on an annual basis and are not binding.

Figure 5 | 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.[7]

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.

For the annual planning outlook, the zonal constraints are determined to reflect the resource adequacy needs of each zone, as well as the province's transmission security requirements. While the curves are based on reliability only, there are other considerations that could impact the zonal constraints, such as procurement targets, creating sustainable MWs to avoid volatility of constraints, etc.

4.13 Nuclear Refurbishment Reserve

Ontario currently has 18 nuclear units, six of which are expected to retire by 2024/2025. As of 2016, 10 of the remaining 12 units are undergoing mid-life refurbishment over the next 15 years. 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] LOLE threshold = System LOLE using target capacity requirement (per seasonal allocation) + 0.001 days/year

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 have generally increased as the units approach refurbishment, as they return to service from refurbishment and as the units 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 to service and forced outage rates, a spreadsheet-based Monte Carlo analysis tool is used to first calculate the average change in available capacity. Then with an updated available nuclear 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

Both energy adequacy and energy production assessments are performed using the UPLAN model.

5.1 UPLAN Model Overview

UPLAN 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.

UPLAN 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. UPLAN is a deterministic model; there is no load forecast uncertainty applied.

5.3 Thermal Generators

Thermal generators include a number of different fuel types (nuclear, natural gas, fuel oil, or biofuel) that create heat using an input fuel that is converted to electricity. Along with the model inputs used for the resource adequacy assessment, each dispatchable thermal generator has the following additional inputs for UPLAN:

- 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.

5.3.1 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. In UPLAN, CHP self-scheduling facilities are assumed to run on weekdays for 16 hours a day (7 a.m. to 11 p.m.). If available for a self-scheduling CHP generator, a historical profile is used in place of the generic profile. If the heat rate of a CHP generator is known, it is used in UPLAN and the generator is treated as a dispatchable unit.

5.3.2 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.

5.3.3 Bioenergy Generators

Most bioenergy facilities, excluding those with unique operational characteristics, are considered to be "must-run" resources. The assumed capacity factor for these generators ranges from 40-80 per cent, depending on the technology type and fuel availability.

5.4 Hydroelectric Generators

Hourly hydroelectric generation profiles are created external to UPLAN, and then entered into the model as a must-run resource. The production profiles for each generator are based on the historical flow of water and energy production, with the goal of optimizing production based on water conditions, operational capabilities, and market opportunities.

The hydroelectric generation profile is split into a must-run component and a dispatchable component. The dispatchable component is optimized to ensure the most efficient resource is relied upon to meet peak-demand requirements, which means that dispatchable hydroelectric generation is being dispatched prior to the operation of natural gas generation.

To accomplish this optimization, the demand forecast is adjusted to account for other must-run resources (wind, solar, nuclear, and run-of-river hydro). The remaining hydroelectric units are then dispatched to peak shave in the order from least flexible to most flexible, in terms of operational characteristics. Geographically, this tends to be from the northwestern Ontario, to the northeast, and then to the south.

The optimization process accounts for the run-of-river flows that are subject to cascading impacts based on the given river system, as is the case for the Mississagi and Madawaska River systems. For these river systems, a correlation of the flow between stations incorporates the time lag experienced for peaks in flow between stations from upstream to downstream.

5.5 Wind Generators

Wind generation is modelled using the median production year of 31 historical simulated profiles which were provided by AWS Truepower. Wind generation is geographically aggregated at bus level and treated as a must-run resource.

5.6 Solar Generators

Solar generation is modelled using the median production year of the historical simulated profiles provided by AWS TruePower. Solar generation is geographically aggregated at bus level and treated as a must-run resource.

5.7 Demand-Side Resources

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

5.8 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.

5.9 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 UPLAN vendor.

5.10 Unserved Energy

Unserved energy in the APO represents the amount of load, in a median weather year, 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.

5.11 Surplus Baseload Generation

There may be periods when the amount of must-run generation within Ontario is greater than demand. This extra supply is called surplus baseload generation (SBG). When Ontario is modelled with interconnections to its neighbouring jurisdictions, the low dispatch cost of these must-run resources means their production is generally exported.

When Ontario is modelled without interconnections, some must-run generation must be curtailed. The curtailment is done in accordance with SE-91.[8] Must-run resources are curtailed in the following order: dispatchable hydroelectric, CHP, wind generators with a nameplate capacity greater than 5 MW, solar, wind generators with a nameplate capacity less than 5 MW, bioenergy, run-of-river hydroelectric, and nuclear. The surplus baseload generation values reported in the APO are the annual sums of all curtailed energy.

5.12 Marginal Costs

The dispatch of generation in UPLAN 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. In the APO, the reported marginal cost is the annual average hourly marginal cost.

5.13 Greenhouse Gas Emissions

The APO presents a graph showing historical and forecast greenhouse gas emissions. Historical emissions data are from the National Inventory Report[9] up to 2019 as there is a two-year lag time in the data. Estimates of historical emissions in years for which data are unavailable (2020, 2021) are created using actual generation and emission factors calculated based on historical data. Forecast emissions are an output of the UPLAN model and are calculated as the product of each unit's forecast generation and associated emission factor.

[8] For more information, refer to the Renewable Integration (SE-91) Engagement

[9] For more information, refer to the National Inventory Report

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