# Methodology to Perform Long Term Assessments

Power to Ontario. On Demand.

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# 1.0 Introduction

This document describes the methodology used to perform the Ontario Demand forecast, and the associated resource and transmission adequacy assessments for the 18-Month Outlook and the Ontario Reliabilty Outlook. Over time, the methodology may change to reflect the most appropriate approach to complete the Outlook process.

- End of Section -

# 2.0 Demand Forecasting Methodology

The demand forecasts presented in the Outlook documents are generated to meet to two main requirements; the market rules and regulatory obligations. The Ontario Electricity Market Rules (Chapter 5 Section 7.1) require that a demand forecast for the next 18 months be produced and published on a quarterly basis by a set date. The IESO is also required to file both actual and forecast demand related information with the Ontario Energy Board, the Northeast Power Coordinating Council and the North American Electricity Reliability Corporation. These requirements include obligations to provide a long-term forecast which is produced in conjunction with the Ontario Power Authority who has responsibility for long-term planning for the Ontario electricity market. These regulatory obligations have specific needs and timelines and the IESO's forecast production schedule has been designed to satisfy those requirements.

## 2.1 Demand Forecasting System

Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by generation not participating in the market (embedded generation).

The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic and demographic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, and zonal and system wide projections.

We produce a forecast of hourly demand by zone. From this forecast the following information is available:

- hourly peak demand;
- hourly minimum demand;
- hourly coincident and non-coincident peak demand by zone;
- energy demand by zone.

These forecasts are generated based on a set of weather and economic assumptions. We use a number of different weather scenarios to forecast demand. The appropriate weather scenarios are determined by the purpose and underlying assumptions of the analysis. An explanation of the weather scenarios follows in Section 2.3: Weather Scenarios.

The impacts of conservation and demand management are treated differently. Demand management is treated as a resource and is based on market participant information and actual market experience. In the Outlook documents these programs are referred to as demand response. Conservation projections are decremented from the demand forecast. A similar approach is used to quantify the impact of embedded generation. A further discussion on this topic can be found in Section 2.4.

## 2.2 Demand Forecast Drivers

Consumption of electricity is modeled using three sets of forecast drivers: calendar variables, weather effects and economic conditions. Each of these drivers plays a role in shaping the results. The impacts of conservation and embedded generation are layered onto the model results

**Calendar** variables include the day of the week and holidays, both of which impact energy consumption. Electricity consumption is higher during the week than on weekends and there is a pattern determined by the day of the week. Much like weekends, holidays have lower energy consumption as fewer businesses and facilities are operating.

Hours of daylight are instrumental in shaping the demand profile through lighting load. This is particularly important in the winter when sunset coincides with increases in load associated with cooking load and return to home activities. Hours of daylight are included with calendar variables.

**Weather** effects include temperature, cloud cover, wind speed and dew point (humidity). Both energy and peak demand are weather sensitive. The length and severity of a season's weather contributes to the level of energy consumed. Weather effects over a longer time frame tend to be offsetting resulting in a muted impact. Acute weather conditions underpin peak demands.

For the Ontario Demand forecast, weather is not forecasted but weather scenarios based on historical data are used in place of a weather forecast. Load Forecast Uncertainty (LFU) is used as a measure of the variation in demand due to weather volatility. For resource adequacy assessments a Monthly Normal weather forecast is used in conjunction with LFU to consider a full range of peak demands that can occur under various weather conditions with a varying probability of occurrence.

**Economic** conditions contribute to growth in both peak and energy demand. An economic forecast is required to produce the demand forecast. We use a consensus of four major, publicly available provincial forecasts to generate the economic drivers used in the model. Additionally, we purchase forecast data from a service provider to enable further analysis and insight. Population projections, labour market drivers and industrial indicators are utilized to generate the forecast of demand.

Population projections are based on the Ministry of Finance's Ontario Population Projections.

## 2.3 Weather Scenarios

Since weather has a tremendous impact on demand, we use a variety of weather scenarios in order to capture the variability in both demand and weather. The weather scenarios are defined by:

- the normalization period – daily, weekly, monthly or seasonal
- the weather selected – mild, normal or extreme

The normalization period refers to the time span over which the weather data is grouped. We use weekly and monthly normalized weather. The weather selection method determines how you select the scenario from the data for the normalization period. We select data based on minimum values (mild scenarios) median values (normal scenarios) or maximum values (extreme scenarios). Based on these two parameters, we could conceivably have six different weather scenarios Table 2.1 shows the weather scenarios from the various combinations.

**Table 2.1 Weather Scenarios**

| Weather Scenarios | | Normalization Period | |
|---|---|---|---|
| | | Weekly | Monthly |
| Weather Selection | Mild | Weekly Mild | Monthly Mild |
| | Normal | Weekly Normal | Monthly Normal |
| | Extreme | Weekly Extreme | Monthly Extreme |

Here are some key notes on the weather scenarios:

- We use monthly normalization for the winter and summer seasons as we feel it better captures the elements that are needed in our analysis.
- Monthly normalization results in higher peak demands and lower minimums as compared to daily or weekly normalization. This is due to the large set of sorted and grouped data that allows for more differentiation between the weather that is most influential and the weather that is least influential.
- The Mild scenarios are used least. Some financial analysis and minimum demand analysis use these scenarios.
- The Normal scenarios are used for reliability analysis for both energy and peak demand.
- The Extreme weather scenarios are used to study the system under duress. They are not used for energy analysis as sustained Extreme weather is highly unlikely.

Each of the scenarios has an associated Load Forecast Uncertainty (LFU) that captures the variability of the weather scenario. For a Mild weather scenario the LFU would be very large as the potential for colder or hotter weather is significant. Conversely, the LFU for an Extreme weather scenario will be quite small as the possibility of exceeding those values is slim. Usually the weather scenario and its LFU are used in a probabilistic approach to generate a distribution of potential outcomes acknowledging the variability of weather and its impact on demand.

As stated earlier, the purpose and assumptions underlying each analysis will help determine the appropriate weather scenario to use. In conducting energy analysis it would be inappropriate to use Extreme weather as the likelihood of observing sustained extreme weather is highly unlikely. However, in assessing the system's capability to meet a one hour summer peak, a Monthly Extreme peak demand forecast would be more appropriate.

The weekly resource adequacy assessments in the 18-Month Outlook documents use demand forecasts based on Monthly Normal weather and their associated LFU. Unlike the weather scenarios, which are derived to provide point forecasts under different weather conditions, LFU is used to develop distributions of possible outcomes around those point forecasts. For the summer and winter, Monthly Normal weather is used and Weekly Normal weather is used for the spring and fall. The Normal weather and the associated LFU are therefore used on a probabilistic basis over the study period.

The Extreme weather scenario does not directly translate into probabilistic terms since it is based on severe historic weather conditions. The exact probability associated with the Extreme weather scenario varies by week, month or season. In some instances the Extreme weather value lies outside of two standard deviations and in other cases it lies within two standard deviations. This is not illogical for any given week as history may have provided an unusual weather episode that will not be surpassed for many years, whereas another week may not have encountered an unusual weather episode.

In addition to these weather scenarios, historic weather years are used in certain studies. The years that are typically used are: 1976-77 (typical winter), 1990 (typical summer), 1993-94 (extreme winter), 1995 (extreme summer and winter), 2002 (extreme summer) and 2005 (hot summer). These studies are of particular value when looking at specific events in those years – be it in Ontario or surrounding jurisdictions.

An additional weather scenario was created to analyze the hourly allocation of resources. The purpose of this analysis was to evaluate the allocation of resources under sustained high levels of demand. In order to generate this hourly demand profile, a “challenging” weather week was selected from history. The weather was deemed challenging if it led to both a high peak demand and sustained energy demand. A study of the history (1970-2005) led to the selection of a week from January, 1982 and a week from August 1973 as challenging winter and summer weather weeks. This weather data was used to generate an hourly demand forecast that was, in turn used to evaluate the resource allocation.

To better illustrate the weather scenarios, let’s look at how a scenario is developed. For this example we will look at the Monthly Normal weather for January.

We use a rolling 31 years of weather data to generate Normal and Extreme weather scenarios. For each historical day, the daily weather can be converted into a "weather factor" based on wind, cloud, temperature and humidity conditions for that day. This weather factor represents that days’ weather in a MW demand impact. Therefore, each day in January from 1975 to 2005 is converted into a number based on that day's weather. Then, within each month, the 31 days are ranked from highest to lowest weather impact. Next, the median value of the highest ranked days becomes the highest ranked day in the Normal month. The median value of the second highest ranked days becomes the second highest ranked day in the Normal weather. This is repeated until 31 Normal days are generated for January. This is depicted in Figure 2.1

| | | | | | Year | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Rank** | **1973** | **1974** | **1975** | **1976** | **2001** | **2002** | **2003** | **2004** | **Median** |
| 1 | 4,791 | 4,427 | 5,569 | **4,921** | 5,219 | 4,985 | 5,321 | 4,857 | 4,921 |
| 2 | 4,395 | 4,393 | 5,482 | 4,705 | 4,989 | 4,822 | 5,317 | 4,522 | 4,764 |
| 3 | 4,373 | 4,310 | 5,201 | 4,517 | 4,850 | 4,285 | 4,845 | 4,383 | 4,450 |
| 4 | 4,272 | 4,057 | 4,912 | 3,994 | 4,799 | 4,255 | 4,292 | 4,081 | 4,264 |
| 5 | 4,042 | 4,002 | 4,703 | 3,971 | 4,630 | 4,126 | 4,291 | 3,847 | 4,084 |
| 26 | 2,179 | 2,413 | 2,987 | 2,206 | 2,457 | 2,685 | 2,068 | 2,451 | 2,432 |
| 27 | 2,168 | 2,099 | 2,892 | 2,174 | 2,348 | 2,441 | 1,934 | 2,447 | 2,261 |
| 28 | 1,807 | 1,954 | 2,821 | 1,840 | 2,344 | 1,797 | 1,680 | 2,173 | 2,344 |
| 29 | 1,770 | 1,952 | 2,644 | 1,775 | 2,330 | 1,756 | 1,366 | 2,125 | 1,863 |
| 30 | 1,692 | 1,902 | 2,345 | 1,402 | 2,180 | 1,558 | 1,185 | 1,803 | 1,747 |
| 31 | 1,394 | 1,788 | 2,009 | 1,202 | 1,893 | **1,452** | 1,111 | 1,692 | 1,452 |

**Figure 2.1 Creating Monthly Normal Weather - January**

The median number 4,921 corresponds to January 21st, 1976. Therefore, the "coldest" day for January in the Monthly Normal weather scenario is represented by that day's weather. Similarly, the mildest day (1,452) in the Monthly Normal weather scenario for January is represented by January 4th, 2002.

This process is repeated for all the months of the year to finish generating the Monthly Normal weather scenario. The process is the same for Seasonal and Weekly Normal weather. In order to generate the Extreme weather scenarios, the maximum value is taken rather than the median in the above example. Likewise, the Mild scenario is based on minimum values. The LFU is calculated based on the distribution of weather factors within the weather scenario.

The demand values presented in the Outlook documents are based on Normal weather unless otherwise specified.

After the representative days are selected for the weather scenarios, they need to be mapped to the dates to be forecasted. They are mapped in a conservative approach ensuring that peak-maximizing-weather will not land on a weekend or holiday. This allows for consistent inter-week comparison and a smoother weekly profile. The monthly and seasonal weather scenarios are mapped to the calendar based on the profile of the weekly scenarios

## 2.4 Conservation and Demand Management

For the purposes of our analysis, we include the impacts of embedded generation with those of conservation and demand management. This is due to the fact that the information comes to the IESO from many of the same sources.

The IESO includes demand reductions due to energy efficiency, fuel switching and conservation behavior (this includes the impact smart meters) under the category of conservation. Information on program's targets is provided by the Ontario Power Authority (OPA) and form the basis of the conservation numbers. These impacts are decremented from the demand forecast.

Demand management includes a number of demand response programs. These programs include the OPA's Demand Response programs and the IESO's dispatchable loads program. Based on information from the OPA and the IESO we determine an amount of total capacity. Using historical data we determine the quantity of reliably available capacity for each zone. Since demand management programs act like resources that are available to be dispatched, we treat this derived capacity as a resource in our assessments.

The last segment that we include in this area is the impact of embedded generation. We include it in this section as increases in embedded generation lead to a reduction in demand on the grid. Also, much of the growth in embedded generation originally stemmed from the OPA's Renewable Energy Standard Offer Program (RESOP) and continues under the Feed in Tariff (FIT) program. The OPA provides projections to the IESO on embedded generation. This information is used to derive the expected reductions in "on-grid" demand. These figures are then decremented from demand.

## 2.5 Updating the Demand Forecasting System

There are several tasks that are carried out on a regular basis as part of the Outlook process.

- The models are updated for actual data prior to each forecast and the equations are re-estimated. This enables the system to consistently "learn" from new data.
- The weather scenarios are updated to include the most recent weather data.

- A new economic forecast is generated for the economic drivers in the model
- Updated conservation and demand response numbers are obtained and calculated

The system will therefore include recent experience and the forecast will be based on the most recent weather scenarios and economic outlooks.

- End of Section -

# 3.0 Resource Adequacy Assessment Methodology

This section describes the criteria, tools and methodology the IESO uses to perform resource adequacy assessments. In Section 3.1 the NPCC resource adequacy criteria are described, as provided in the NPCC "Directory #1: Design and Operation of the Bulk Power System". Sections 3.2 and 3.3 briefly describe the Load and Capacity (L&C) and Multi Area Reliability Simulation (MARS) software tools, and the way they are used in the resource adequacy assessment process. Section 3.4 explains how the Reserve Above Requirement values are derived. Section 3.5 describes the methodology used to forecast the energy production capability.

## 3.1 Resource Adequacy Criteria

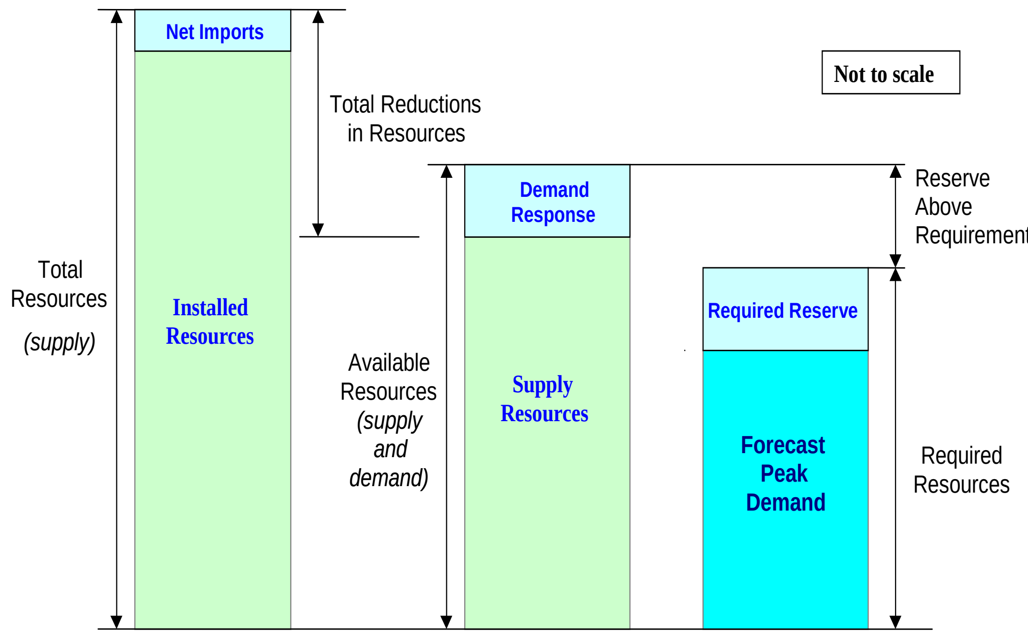
The IESO uses the following NPCC resource adequacy design criteria to assess the adequacy of resources in the Ontario control area:

"The probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas', transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

## 3.2 Required Reserves

Reserves are required to ensure that the forecast Ontario Demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve to meet the NPCC resource adequacy criterion is calculated on a week-by-week basis, as described in Section 3.2.1.

**Figure 3.1 Reserve Above Requirement**




The Required Resources are the amount of resources needed to supply the peak Ontario Demand and meet the Required Reserve. As shown in Figure 3.1, the Reserve Above Requirement is the difference between Available Resources and Required Resources.

The Required Reserve is a planning parameter that is at least as large as the amount required to meet the NPCC resource adequacy standard. In the mid-term planning horizon (beyond the next 33 days), a probabilistic approach is used, which considers the uncertainty associated with demand forecasts and generator forced outages. The value for Required Reserve from this approach is then compared with results from a deterministic calculation used for near-term planning (within the next 33 days). The Required Reserve reported for each period in the Outlook tables is the greater of the probabilistic or the deterministic values. These requirements are described in more detail in Section 3.2.1.

### 3.2.1 Load and Capacity Model

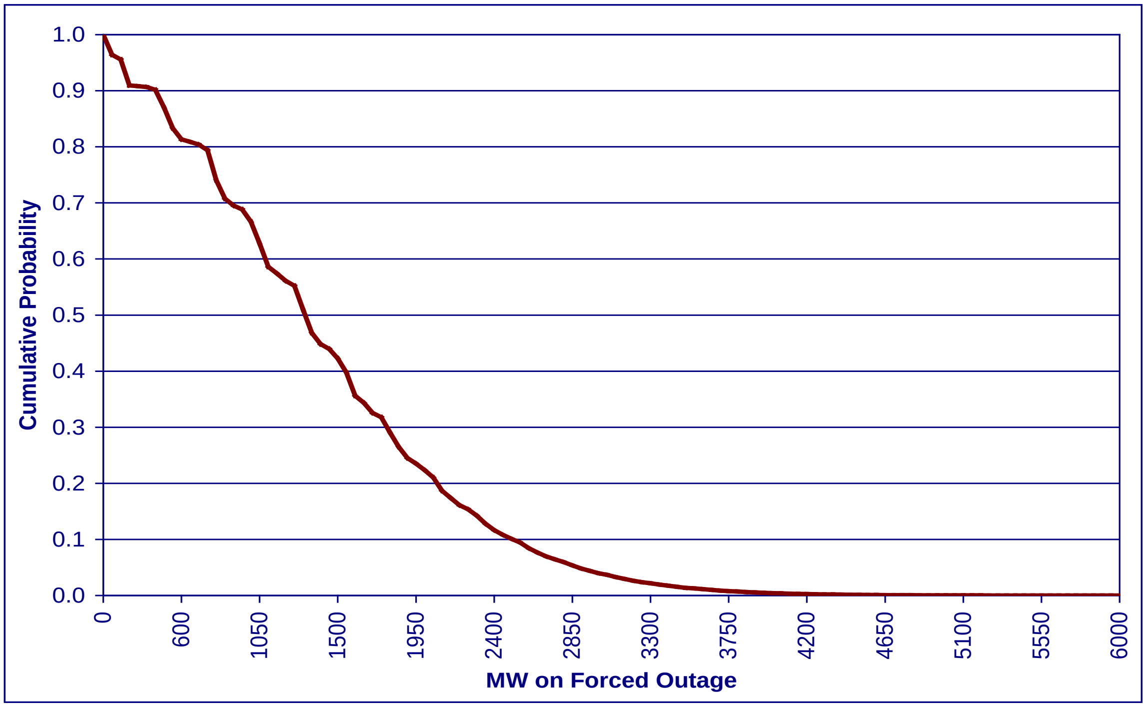
The IESO uses the Load and Capacity (L&C) model to determine the Required Reserve for each week in the study period. Each thermal generating unit's maximum continuous rating (MCR) and its planned outages, deratings, and forced outage rates, hydroelectric dependable capacity, wind capacity contribution (WCC) values as well as the demand forecast and its uncertainty are inputs to the model.

The weekly Required Reserve is the maximum of a deterministically and a probabilistically calculated reserve requirement.

A resource adequacy criterion equivalent to an annual loss of load expectation (LOLE) of 0.1 days per year is used to determine the probabilistic reserve requirement for each week of the planning year. The program uses the 'direct convolution' method to calculate the weekly probabilistic reserve requirement. Based on the generating units MCR and forced outage rates, a Capacity on Outage Probability Table

(COPT) is built, in which the cumulative probabilities of having various amounts of generating capacity on forced outage are determined and stored. A graphical example is shown in Figure 3.2.

**Figure 3.2 Capacity on Outage Probability Table – Graphical Example**




In the L&C model, a normal distribution of demand values around the mean demand value is assumed, as described in Section 3.2.2. The probabilistic reserve requirement calculation is executed in an iterative manner. In each iteration, an amount of Generation Reserve is assumed and an associated LOLE is calculated by convolving the load forecast uncertainty (LFU) corresponding to the peak demand value with the COPT. The iterative process is repeated with small changes to the assumed Generation Reserve until the calculated LOLE becomes equal to or less than the target. When this condition becomes true, the assumed level of Generation Reserve equals the probabilistic required reserve necessary to meet the reliability target.

The deterministic reserve requirement for each summer week is equal to the Operating Reserve (approximately 1,620 MW, depending on the size of the single largest contingency plus half the MCR of the next largest available generating unit) plus the absolute value of the LFU. The deterministic reserve requirement for each winter week is equal to the Operating Reserve (approximately 1,620 MW, depending on the size of the single largest contingency) plus the MCR of the largest available generating unit plus the absolute value of the LFU.

The adequacy of the available resources to meet the demand over the study period can then be assessed, in an arithmetic calculation illustrated in Figure 3.1. For each planning week, the expected level of Available Resources is determined, considering:

- the amount of generator deratings,
- planned and long term unplanned generator outages,

- generation constrained off due to transmission interface limitations,
- any imports or exports into or out of Ontario (as identified by market participants to the IESO),
- and an assumed amount of price responsive demand.

Under the present procedures in the Ontario market, there are no exports that are considered to continue if the Ontario non-dispatchable demand is not served. Therefore, the current Outlook does not include any exports from Ontario in the assessment of overall resource adequacy.

In the 18-Month Outlook report, reserve levels are presented without any imports assumed to be reliably available. For a specific outage assessment in the 18-month timeframe, the current procedures will consider imports up to 700 MW may be available plus any imports that generators have confirmed they will make to support a planned outage request, according to the applicable market manuals.

The expected level of Available Resources is calculated on the "maximum outage day", which is the day with the maximum amount of unavailable generating capacity in that planning week. Although the weekly peak does not always occur on the maximum outage day, such coincidence is assumed for the determination of Available Resources. The Reserve Above Requirement is then obtained by subtracting the Required Resources (equal to the peak demand plus Required Reserve) from the Available Resources.

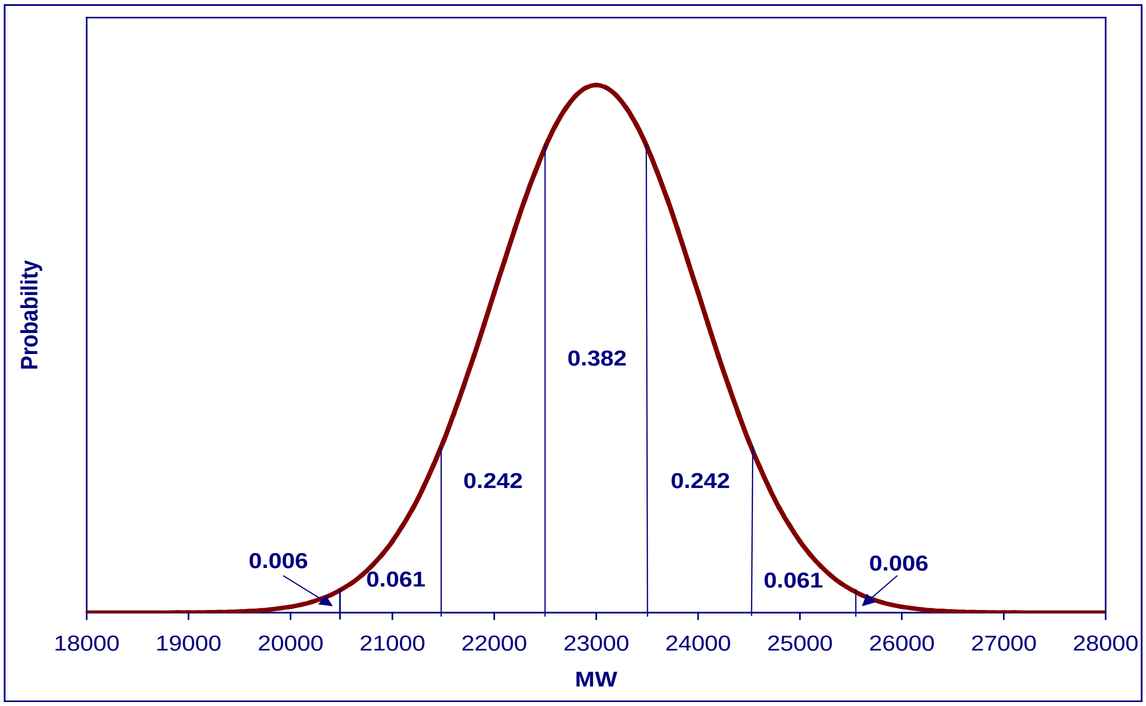
It should be noted that negative Reserve Above Requirement values in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. This may only mean higher risk levels for the respective weeks. Whenever negative Reserve Above Requirement values are identified, the possible control actions to restore the reserves to required levels are considered and assessed.

### 3.2.2 Representation of Demand and Its Uncertainty Due to Weather

The L&C program requires weekly peak demands for the study period. These peak demand values include loads that may be dispatched off during high price periods, loads that may simply reduce in response to high prices, and loads that may otherwise be reduced in the case of a shortfall in reserves. For modeling purposes, the total demand is assumed to be supplied, and is included in the peak demand forecast when the probabilistic reserve requirement is calculated. To meet the Required Reserve, the assessment allows that some of the reserve may be comprised of a quantity of demand that can decrease in response to market signals. The IESO forecasts the future price responsive demand levels based on Market Participant registered data and consideration of actual market experience.

The LFU for each week, due mostly to weather swings, is represented by the associated standard deviation, assuming a normal probability distribution. This data is obtained from 30-year weather statistics and is updated annually. The weather-related standard deviations vary between about 2% and 7% of their associated mean demand values through the year. Each week's peak demand is modeled by a multi-step approximation of a normal distribution whose mean is equal to the forecast weekly peak and whose standard deviation is equal to the LFU. Subsequently, in the probabilistic reserve requirement calculation for each planning week, not only the mean value of the peak demand is included, but also a range of peak demand values, ranging from mild to extreme demand values. Figure 3.3 illustrates a seven-step example of such an approximation, using a weekly peak value of 23,000 MW and an associated LFU value of 1,000 MW. In this example, the peak values considered in the probabilistic reserve requirement calculation would range from 20,000 MW to as high as 26,000 MW. Consequently, the calculated probabilistic reserve requirement reflects not only the impact of the generation mix (generator sizes and failure rates) but also the impact of uncertainties in demand related to weather, by averaging the impact of the peak demand values around the forecast mean value, weighted by their associated probabilities of occurrence (shown in Figure 3.3 under the curve).

**Figure 3.3 Seven-Step Approximation of Normal Distribution - Example**




### 3.2.3 Representation of Generation Resources

**Capacity Ratings**

Thermal generating units are assumed to be capable of operating at a level equal to their normal MCR or as otherwise identified to the IESO. The peak and energy output of all combustion turbines vary considerably with changes in ambient air temperature, and hence, both summer and winter capacity values are included.

Hydroelectric generation output forecast is based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Market data, starting from May 2002, is used, with new values calculated annually as additional years of market experience are acquired. The table below shows the historical hydroelectric median values calculated with the data from May 2002 to March 2013. These values are updated annually to coincide with the release of summer 18-Month Outlook.

**Table 3.1 Monthly Historical Hydroelectric Median Values**

| Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Historical Hydroelectric Median Values (MW)** | 6,089 | 6,097 | 5,923 | 5,878 | 5,911 | 5,788 | 5,718 | 5,403 | 4,980 | 5,390 | 5,762 | 6,158 |

The forecast may be adjusted to account for the impact of project related long-duration outages[1] that occur less frequently than regular maintenance. The hydroelectric performance is monitored on a monthly basis and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months.

Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (% of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data, and the simulated 10-year historic wind data will continue until 10-years of actual wind data is accumulated; at which point the simulated wind data will be phased out of the WCC calculation. The table below shows the monthly WCC values (with actual historic wind output up to February 28, 2013). These values are updated annually to coincide with the release of summer 18-Month Outlook.

**Table 3.2 Monthly Wind Capacity Contribution Values**

| Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WCC (% of Installed Capacity) | 33.4% | 33.4% | 26.0% | 21.1% | 20.4% | 13.6% | 13.6% | 13.6% | 15.9% | 21.6% | 28.9% | 33.4% |

Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values (% of installed capacity) are determined by calculating the simulated 10-year solar historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process of picking the lower value between actual historic solar data, and the simulated 10-year historic solar data will be incorporated into the SCC methodology until 10-years of actual solar data is accumulated, at which point the simulated solar data will be phased out of the SCC calculation. The table below shows the monthly SCC values. These values are updated annually to coincide with the release of summer 18-Month Outlook.

| Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCC (% of Installed Capacity) | 0.0% | 0.0% | 0.0% | 28.0% | 54.0% | 34.0% | 34.0% | 34.0% | 6.0% | 1.0% | 0.0% | 0.0% |

In addition to determining the historic median solar capacity contribution values, the simulated 10-year solar historic average contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month were also calculated. The results of this calculation are presented in the table below for information purposes.

[1] Project related long duration outages may occur due to causes including hydro facility expansions and major equipment replacements and/or repairs.

| Month | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **SCC (% of Installed Capacity)** | 1.0% | 1.0% | 5.0% | 37.0% | 52.0% | 40.0% | 40.0% | 40.0% | 13.0% | 8.0% | 1.0% | 1.0% |

**Forced Outage Rates of Generating Units**
Derating-Adjusted Forced outage rates that are used for each unit reflect both forced outages and periods of derated output. The values are provided by the generation plant owners, based on past experience modified to reflect forecast improvements from maintenance activities or declines due to age or need for repair. When forecast forced outage rates are not available, forced outage rates compiled from generating units past performance information are used.

### 3.2.4 Representation of Interconnected Systems

There are five interconnected systems that could provide additional resources to supply Ontario, namely, New York, Michigan, Quebec, Minnesota and Manitoba.

In the probabilistic calculation of reserve requirements, the interconnected systems are modeled as fictitious generators having forced outage rates assigned. Therefore, the calculated Required Reserve levels take into account the potential need for external generating capacity.

At the deterministic calculation stage, Available Resource values include external purchases that are backed by firm contracts. The inclusion of only firm purchases in the assessment represents a conservative assumption. Therefore, whenever reserves are lower than required, the necessary level of assistance from neighboring systems is considered as a possible control action. The confidence level in the availability of such an assistance level is also assessed, using past operational information, as well as latest load and capacity reports issued by the neighboring jurisdictions, in which forecast levels of spare capacity are included.

### 3.2.5 Representation of the Transmission System

The IESO-controlled grid consists of a robust southern grid and a sparse northern grid. The northern grid has limitations, which potentially constrain the use of some generation capacity. As new generation projects materialize, the relatively large generation capacity additions in the Bruce and West zones of the system cause the operation of some generation to be constrained at times, because of the transmission interface limitations. The amount of generation constrained varies with the demand level and the amount of total generating capacity in a zone. All transmission constrained generation and the reserve carried for that constrained generation are subtracted from the Available Resources when calculating the Reserve Above Requirement.

## 3.3 Multi-Area Reliability Simulation (MARS) Approach

The MARS program allows the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools. The IESO-controlled grid has been modeled as a pool composed of ten zones. Figure 4.1.1 provides a pictorial representation of Ontario's ten zones.

### 3.3.1 Multi-Area Reliability Simulation (MARS) Model

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, chronological system histories are developed by combining randomly generated operating histories for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation.

Various measures of reliability can be reported using MARS, including the LOLE for various time frames.

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without LFU. The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures will be implemented in each zone and pool.

The first step in calculating the reliability indices is to compute the zone margins on an isolated basis for each hour, by subtracting the load for the hour from the total available capacity in the hour. If a zone has a positive or a zero margin, then it has sufficient capacity to meet its load. If the zone margin is negative, the load exceeds the capacity available to serve it, and the zone is in a potential loss-of-load situation. If there are any zones that have negative margins after the isolated zone margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from zones that have positive margins. There are two ways for determining how the reserves from zones with excess capacity are allocated among the zones that are deficient. In the first approach, the user specifies the priority order in which deficient zones receive assistance from zones with excess resources. The second method shares the available excess resources among deficient zones in proportion to the size of their shortfalls. Priorities within pools, as well as among pools, can also be modeled.

### 3.3.2 Representation of Demand and Its Uncertainty Due to Weather

The MARS program requires mean hourly load data, as well as a monthly standard deviation (SD), for each zone modeled. The reliability indices are calculated at each load level around the mean value (mean, mean $\pm$ SD, mean $\pm$ 2SD, mean $\pm$ 3SD), as well as the average indices.

Hourly loads for each of the ten Ontario zones are modeled, for the study period, and a seven-step normal distribution is calculated for each of the ten zone loads. A graphical example is provided in Figure 3.3, in Section 3.2.2.

### 3.3.3 Representation of Generation Resources

MARS has the capability to model the following types of generation resources:

- Thermal.
- Energy-limited.
- Cogeneration.
- Energy-storage.
- Demand-side management.

An energy-limited unit can be modeled probabilistically as a thermal unit with an energy probability distribution, or deterministically as a load modifier. Cogeneration units can be modeled as thermal units with an associated hourly load. Energy-storage and demand-side management impacts can be modeled as load modifiers. For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads depend on the unit type. The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis.

All thermal generators in Ontario, for each of the ten zones, are modeled on an individual unit basis. The available capacity states, state transition rates, and planned outage information are input for each thermal unit. Hydroelectric generators are modeled as energy-limited resources. Minimum ratings, median historic values and energy production capabilities are input on a monthly basis for the hydroelectric generators. Wind capacity contributions are modeled as monthly cumulative probability density functions from which stochastic selections are made by the program.

### 3.3.4 Representation of Interconnected Systems

The five interconnected systems that can provide assistance to the Ontario system are modeled as areas external to the Ontario pool (composed of the ten zones).

Neighboring systems are modeled as external areas with constant hourly loads of 1 MW. In each of these external areas a dummy generator is modeled, which has a variable capacity up to the amounts expected to be offered into the Ontario market. The expected capacity values are based on past operational experience and latest load and capacity reports issued by the respective system operators, with the limitations outlined in Section 3.3.5.

### 3.3.5 Representation of the Transmission System

The transmission system between interconnected zones can be modeled through transfer limits on the interfaces between pairs of zones. Also, transfer limits on groups of interfaces can be defined. The transfer limits are specified for each direction (positive and negative) of the interface and are changed monthly if necessary. Random forced outage rates are modeled on the interfaces in the same manner as the outages on thermal units, through the use of state transition rates. The amount of assistance deficient zones will receive from zones with excess resources is limited by the transfer limits on the interfaces.

All transmission interfaces between the ten zones within Ontario pool are modeled as they are defined in System Control Orders (SCO). Seasonal base limits are implemented for each interface. The tie lines with the neighboring systems are modeled, along with their seasonal transfer limits, taking into account the total Ontario import capability. Therefore, the amount of external capacity available to Ontario at any moment will not exceed the total tie lines transfer capability. No random outages are modeled on the interfaces.

## 3.4 Resource Adequacy Risks

The 18-Month Outlook considers two scenarios, the Firm and the Planned Scenario. The forecast reserve levels for both the scenarios should be assessed bearing in mind the risks discussed below.

### 3.4.1 Extreme Weather

Peak demands in both summer and winter typically occur during periods of extreme weather. Unfortunately, the occurrence and timing of extreme weather is impossible to accurately forecast far in advance. The impact of extreme weather was demonstrated in the first week of August 2006, when Ontario established an all-time record demand of 27,005 MW. Over 3,000 MW of this demand was due to the higher than average heat and humidity.

In order to illustrate the impact of extreme weather on forecast reserve levels during the Outlook period, both scenarios were re-calculated assuming extreme weather in each week in place of normal (average) weather. The probability of this occurring in every week is very small; however the probability of an occurrence in any given week is greater (about 2.5 percent). When one looks at the entire summer or winter periods, the expectation of at least one period of extreme weather becomes very likely.

The lower reserve levels, under extreme weather illustrates circumstances could arise under which reliance on a combination of interconnected supply, rejection of planned generator maintenance or emergency actions may be required.

### 3.4.2 New Facilities

The improved reserve levels, seen in the Planned Scenario, is dependent on the additional generation and demand measures coming into service as forecast.

The OPA monitors and reports on the progress of the electricity supply contract projects on a quarterly basis at their web site found below:

http://www.powerauthority.on.ca/news/publications

### 3.4.3 Generator Planned Outages

A number of large generating units perform their maintenance in the spring and are scheduled to return to service from outage prior to summer peak. Meeting these schedules is critical to maintaining adequate reserve levels. Delays in returning generators to service from maintenance outages could lead to reliance on imports and/or cancellation of other planned generator outages.

Historically a number of generator outages had to be scheduled during the spring and fall “shoulder months” due to the dual peaking nature of the Ontario system. The system is, now, transitioning from dual peaking into summer peaking. This phenomenon together with more new resources creates some opportunities for generators to schedule their outages in winter months as well. These opportunities should provide generators with more flexibility to schedule their maintenance outages which should in turn provide greater assurances going forward that Ontario’s generation fleet will be well prepared for the high demand summer months.

### 3.4.4 Lower than Forecast Generator Availability

IESO resource adequacy assessments include a probabilistic allowance for random generator forced outages based on generator reliability information provided by market participants, or on industry-wide data for similar facilities. Along with weather-related demand impacts, the impact of generator forced outages is included in the determination of required resources.

### 3.4.5 Lower than Forecast Hydroelectric Resources

IESO resource adequacy assessments include hydroelectric generation outputs based on median historical values of hydroelectric production plus operating reserve during weekday peak demand hours and energy capability provided by market participants. The amount of available hydroelectric generation is greatly influenced both by water-flow conditions on the respective river systems and by the way in which water is utilized.

It is not possible to accurately forecast precipitation amounts far in advance. Drought conditions over some or all of the study period would lower the amount of generation available from hydroelectric resources. Low water conditions can result in significant challenges to maintaining reliability, as was experienced in the summer of 2005.

### 3.4.6 Wind Resource Risks

The Outlook assumes monthly WCC values to forecast the capacity contribution from wind generators. There is a risk that wind power output could be less than the forecasted values.

### 3.4.7 Capacity Limitations

There is a risk that any given generator may not be capable of producing the maximum capacity that the market participant has forecast to be available at the time of peak demand. There may be several reasons for these differences. Independent of the best efforts of generator owners to maintain generator capability, there are sometimes external factors which may impact the capability to produce.

Some outages and deratings, such as environmental limitations and high ambient temperature deratings, may be more likely to occur at roughly the same time as the extreme weather conditions that drive peaks in demand.

For example, there are risks that gas-fired generators may not be capable of producing the maximum capacity that the market participant has forecast to be available at the time of peak. The natural gas and electricity sectors are converging as natural gas becomes one of the more common fuels in North America for electric power generation. The IESO is jointly working with the Ontario gas transportation industry to identify and address issues.

### 3.4.8 Transmission Constrained Resource Utilization

Transmission constraints may occur more often than expected due to multiple unplanned outages and may also have greater impact than expected on the ability to deliver generation to load centres. This is particularly true for large transformers whose repair or replacement time can be much longer than for transmission lines. Although many transmission limitations are modeled in accordance with recognized reliability standards, limitations resulting from multiple forced transmission outages can have significant impacts on resource availability.

Constraints may also occur due to weather conditions that result in both high demands and higher than normal equipment limitations. For example periods of low wind combined with hot weather not only cause higher demands but also result in lower transmission capability. This can affect the utilization of internal generation and imports from neighbouring systems at critical times. Transmission constraints that result from loop flows can be particularly hard to predict because they result not only from the conditions within Ontario but from the dynamic patterns that are taking place within and between other areas. Depending on the direction of prevailing loop flows, this may improve or aggravate the ability to maintain reliability.

During high demand periods, the availability of high-voltage capacitors and the capability of generators to deliver their full reactive capability also become critically important for controlling voltage to permit the higher power transfers that are required. Outages or de-ratings to these reactive resources can restrict power transfer from generators and imports, and make it difficult to satisfy the peak demands.

The calculated values at the time of weekly peak for transmission constrained generation presented in the 18-Month Outlook Tables correspond to a generation dispatch that would maximize the possible reserve above requirements in Ontario. However, in real time operation, the actual amount of bottled generation will depend on many conditions prevailing at the time, including the local generation levels, overall generation dispatch and the direction and levels of flows into and out of Ontario. Electricity supply from some base load generation sources may be required to decrease during period of times when transmission constraints and tight supply conditions prevail.

### 3.5 Surplus Baseload Generation (SBG)

SBG occurs when the baseload generation is higher than the Ontario demand plus net exports. It typically happens during low demand periods. To calculate the SBG, IESO compares the minimum demand forecast to the expected baseload generation level, minus assumed exports. The expected generation level includes:

- Nuclear generation
- Baseload hydroelectric generation
- Wind generation
- Expected self-scheduling and intermittent generation

### 3.6 Forecast of Energy Production Capability

The forecast energy production capability of the Ontario generators is calculated on a month-by-month basis, for 18-Month Outlooks. Monthly energy production capabilities for the Ontario generators are provided by market participants or calculated by the IESO. They account for fuel supply limitations, scheduled and forced outages and deratings, environmental, regulatory and citizenship restrictions.

- End of Section -

# 4.0 Transmission Adequacy Assessment Methodology

## 4.1 Assessment Methodology for the 18-Month Outlook

For the 18-Month Outlook, the principal purpose of the transmission adequacy assessment is to forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in the base flow limit associated with the interface or interconnection. Another purpose of the transmission adequacy is to identify the possibility of any security-related events on the IESO controlled grid that could require contingency planning by Market Participants or by the IESO. As a result, transmission outages for the period of the 18-Month Outlook are reviewed to identify transmission system reliability concerns and to highlight those outages that could be rescheduled.

The assessment of transmission outages will also identify any resources that may potentially be constrained off due to the transmission outage conditions. Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO controlled-grid should be coordinated with the generator owners involved, especially at times when generation Reserve Above Requirement values are below required levels. The IESO reviews the integrated plans of generators and transmitters to identify situations that may adversely impact the reliability of the system and to notify the affected participants of these impacts.

The transmission outage plan for the 18-month period under study is extracted from the IESO Integrated Outage Management System (IOMS). Section 4.1.1 describes the methodology used to assess the transmission outage plan.

### 4.1.1 Transmission Outage Plan Assessment Methodology

The outage plan is filtered to contain only outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than five days. The outage plan is also filtered to include those outages associated with a major project. These outages are then sorted and grouped into tables, one table for each zone. The following items are listed for each outage, with items one to four having been provided by transmitters:

1) Start and finish dates,
2) Description of outaged transmission element or elements,
3) Outage type (DNW - Daily Not Weekends; DWW - Daily With Weekends; CNW - Continuous Not Weekends; CWW - Continuous With Weekends),
4) Recall time,
5) Description of outage impact to IESO-controlled grid, and
6) Reduction in the interconnection flow limits and/or major interface base limits (expressed in Megawatts).

Items 5 and 6 are only provided if the outage affects an interconnection and/or major interface. For these outages, if the recall time is greater than 36 hours and if the limit is penalized greater than 10%, there is an additional assessment, as required, to indicate the potential for constrained generation, the impact on generation reserve requirements and any local minimum generation requirements.

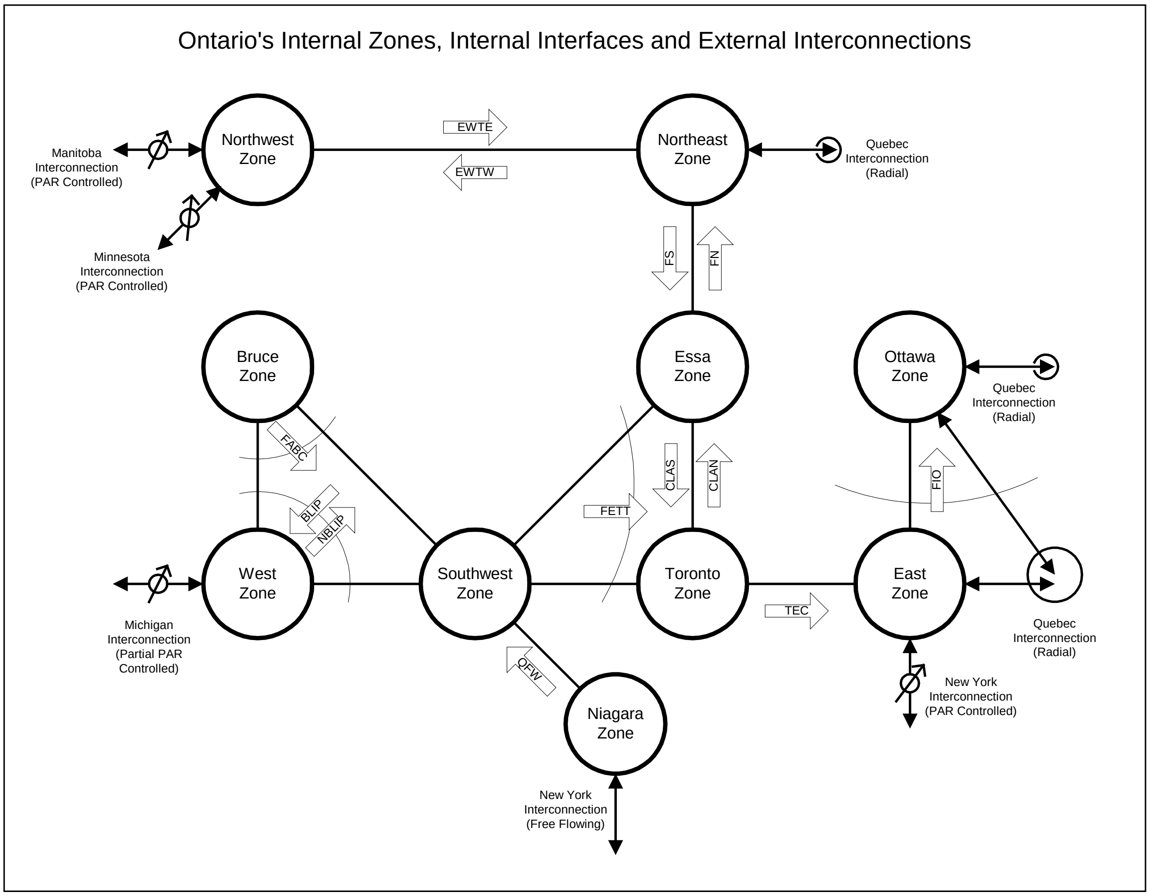
The planned transmission outages are reviewed in correlation with major planned resource outages and scheduled completion dates of new generation and transmission projects. This allows the IESO to identify transmission system reliability concerns and to highlight those outage plans that need to be adjusted. A change to an outage may include rescheduling the outage, reducing the scheduled duration or reducing the recall time as per the processes described in Market Manual 7: System Operations, Part 7.3: Outage Management.

This assessment will also identify any resources that have potential or are forecast to be constrained due to transmission outage conditions. Transmitters and generators are expected to develop ongoing arrangements and processes to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO-controlled grid should be coordinated with the generator operators involved, especially at times when a deficiency in reserve is forecast. Under the Market Rules, when the scheduling of planned outages by different market participants conflicts such that both or all outages cannot be approved by the IESO, the IESO will inform the affected market participants and request that they resolve the conflict. If the conflict remains unresolved, the IESO will determine which of the planned outages can be approved according to the priority of each planned outage as determined by the Market Rules detailed in Chapter 5, Sections 6.4.13 to 6.4.18.

The IESO assigns confidentiality classification to all the elements associated with an outage based on confidentiality requirements of Market Participants' data. The outages that have one or more transmission elements classified as confidential are excluded from the published tables. However, the reliability impact assessment of these outages is communicated confidentially to the transmission owner/operator.

Figure 4.1.1 provides a pictorial representation of Ontario's ten zones, major transmission interfaces and interconnections with neighboring jurisdictions.

**Figure 4.1.1 Ontario's Zones, Interfaces, and Interconnections**




Generally, IESO Outlooks identify the areas of the IESO-controlled grid where the projected extreme weather loading is expected to approach or exceed the capability of the transmission facilities for the conditions forecast in the planning period. In these situations there can also be an increased risk of load interruptions.

The IESO works with Hydro One and other Ontario transmitters to identify the highest priority transmission needs, and to ensure that those projects whose in-service dates are at risk are given as much priority as practical, especially those addressing reliability needs for peak demand periods of this Outlook. We have also been working closely with the OPA on identifying the transmission enhancements' location, timing and requirements to satisfy reliability standards.

## 4.2 Assessment Methodolgy for the Ontario Reliability Outlook

A transmission adequacy assessment is undertaken as part of the Ontario Reliability Outlook process.

The overall assessment provides input to market participants and connection applicants with respect to long term planning. The assessment may also identify the potential need for IESO-controlled grid investments or other actions by market participants to maintain reliability of the IESO-controlled grid and to permit the IESO-administered markets to function efficiently. The assessment also provides input to the IESO Board, the OEB and the Ontario Government regarding projected transmission adequacy. The conclusions and recommendations contained in the Ontario Reliability Outlook are available for use in proceedings before the OEB or other governmental or regulatory authorities with responsibilities for reviewing proposals to construct generating or transmission facilities.

Changes to transmission adequacy may occur over time, due to a combination of factors such as load growth, changes to generation capability, transmission equipment reliability, and the overall transmission facility configuration and operation.

To perform the overall assessment of transmission adequacy, there are a number of assessments, with narrower focus, that can be considered. Assessments of contingency-based supply reliability, voltage level adequacy and congestion, all contribute to the overall transmission adequacy assessment. In addition, a summary of the impact of proposed generation and transmission projects is provided where applicable.

Contingency-based supply reliability assesses the extent to which load pockets in Ontario can be supplied reliably, under various scenarios with existing and planned facilities.

Voltage level adequacy assesses the extent to which voltage levels on the IESO-controlled grid are expected to be maintained within acceptable ranges.

Congestion studies assess the extent to which major transmission interfaces have the potential to become congested and thus reduce market efficiency.

The present Outlook does not completely assess the adequacy of all of the 115 kV transmission supply on the IESO-controlled grid, nor does it completely address the adequacy of transmission supply to all local areas in the province. The absence of these assessments in this Outlook does not imply that deficiencies in these areas do not exist. Future Ontario Reliability Outlooks will attempt to more fully assess all significant areas of the province.

### 4.2.1 Models for Transmission Adequacy Assessment

The zones within Ontario that are specifically modeled in the Outlook studies are shown in Figure 4.1.1. These zones are defined in an attempt to specifically model the interfaces that are most likely to be limiting for an enduring period of time. As time progresses, some new interfaces may become more limiting, while other interfaces may become less limiting. However, changes to the interfaces that are modeled must be carefully considered.

Load flow studies, where appropriate, with various assumptions related to the level of imports or exports, are completed for selected years of the Outlook period. The specific years that are studied are selected to try to identify when there may be potential voltage problems and where there is a possible risk of violation of existing operating security limits. In addition, the specific years that are studied also capture planned transmission facilities that significantly change the overall configuration of the transmission network. The conditions under study are intended to stress the power system.

Transmission adequacy can be assessed assuming various transmission network scenarios and resource availability scenarios. The various resource availability scenarios may consider both existing operable generation and new generation projects that have been identified to the IESO under the Connection Assessment and Approval (CAA) Process. Likewise, the various transmission network scenarios may consider both existing transmission facilities and new transmission projects that have been identified to the IESO under the CAA Process.

The transmission adequacy assessment assumes that all transmission facilities are in-service, and assumes the continued use of Special Protection Systems such as generation rejection and load rejection in the determination of sufficiency.

### 4.2.3 Contingency-Based Supply Reliability Assessments

**Supply Deliverability Assessment**
The supply deliverability of certain transmission facilities of the IESO-controlled grid is evaluated by considering the impact of a specific contingency on the load supplied.

Specifically, those load pockets on the IESO-controlled grid that are 250 MW or higher are evaluated. The load pockets are determined by aggregating the forecast load supplied by certain transmission facilities on a double circuit line. The contingency that is assessed is a fault or outage to the double circuit line. Based on this contingency the resulting impact on load levels is estimated by considering the extent to which load is interrupted, and the duration of such interruption. In general, the greater the load affected, the shorter the duration of the interruption is desired. The most reliable area supply is one in which continuous supply to the load is ensured, despite the contingency. For other contingencies, it is recognized that load may be restored after a period of time to allow for switching operations to occur. Depending on the size of the load affected by the contingency, and on what type of contingency has occurred, various switching times can be expected.

Using extreme weather demand at summer peak conditions, this Supply Deliverability Assessment is completed in accordance with the IESO Supply Deliverability Guidelines.

**Thermal Rating Assessment**
The thermal overload capability of autotransformers and transmission circuits of the IESO-controlled grid is evaluated by considering the impact of specific contingencies and the resulting post-contingency flow on the facilities remaining in-service.

For 500 kV and 230 kV autotransformers, the loss of one autotransformer at the various transformation points on the IESO-controlled grid is evaluated to determine if the post-contingency flows on the remaining autotransformers are above their 10-Day Limited Time Ratings (LTRs).

For 500 kV, 230 kV and 115 kV transmission circuits, the loss of one circuit is studied to determine if any of the resulting post-contingency flows on the remaining transmission circuits are above their continuous ratings.

In addition, for autotransformers and transmission circuits, the loss of a double circuit line and a circuit plus a breaker-fail operation is studied to determine if any of the resulting post-contingency flows on the remaining autotransformers and circuits are above their 15-Minute LTRs.

Using extreme weather demand at summer peak conditions, the Contingency-Based Supply Reliability assessment is completed in accordance with Section 4.7 of the IESO Transmission Assessment Criteria Document.

### 4.2.4 Voltage Level Adequacy

Voltage level adequacy assesses the extent to which pre-contingency steady state voltage levels on the IESO-controlled grid are expected to be maintained within acceptable ranges.

For those selected years of study in the near-term of the Outlook period, a billing power factor is assumed. The billing power factor will be determined by the load power factor in the 'base case' load flow and having all low voltage shunt capacitor banks in-service.

For those selected years of study later in the Outlook period, a 0.9 lagging power factor is assumed for each transformer station defined meter point within a zone. Appendix 4.3, Reference #1 of the Ontario Market Rules require that "connected wholesale customers and distributors connected to the IESO-controlled grid shall operate at a power factor within the range of 0.9 lagging to 0.9 leading as measured at the defined meter point". However, it may be necessary to dispatch the power system such that some defined meter points will be operated at a power factor greater than 0.9 lagging in order to satisfy the minimum continuous voltage requirements as identified in Appendix 4.1, Reference #2 of the Market Rules.

In all studies, if the minimum System Control Order or market rule voltage requirements at a station cannot be met under the power factor assumptions, the station is identified in the assessment. The extent to which the problems will arise will depend on the amount of time such conditions will occur in the future.

Using extreme weather demand at summer peak conditions, the voltage level adequacy assessment is completed in accordance with Section 4.2 of the IESO Transmission Assessment Criteria Document.

### 4.2.5 Congestion Assessment

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. Each of these factors is inherently somewhat unpredictable due to the effect of random forced outages on generation and transmission facilities and the effect of weather on load levels. With the opening of the Ontario Electricity Market, an additional level of uncertainty is added because bid and offer prices, rather than traditional economic dispatch principles, will determine the dispatch of generation. With little history of market operation, congestion on the Ontario transmission system is difficult to forecast with any degree of accuracy. If generation is added to appropriate points on the system in future years, the level of system flows would generally be expected to reduce and congestion would tend to be relieved. Conversely, if too much generation is added to a transmission zone, it could increase the level of system flows on the connecting transmission transfer interface, thereby, creating congestion. The incorporation of additional transmission capacity on the interface would alleviate this problem.

The conditions under which congestion is expected are identified, with an assessment of the percentage of time such conditions are expected to occur. In general, the amount of congestion, the frequency, and the duration will depend on specific bid and offer conditions within Ontario, and the level of transactions between Ontario and the surrounding jurisdictions. For various scenarios, various levels of congestion occur. Various changes to generation, demand, or transmission can change the frequency, duration and/or magnitude of congestion.

### 4.2.6 Zone Assessments

General assessments relating to current and future concerns are provided for specific transmission zones.

### 4.2.7 Impact of Proposed New Generation and Transmission Projects

Planned and proposed generation and transmission projects are listed and discussed in the Ontario Reliability Outlook. The impact to the IESO-controlled grid for projects that are identified in the

Connection Assessment and Approval (CAA) process is available at the IESO web site at the following link.

http://www.ieso.ca/imoweb/connAssess/ca_projectlists.asp

- End of Section -

# 5.0 Comparison Between 18-Month Outlook and Ontario Reliability Outlook

The following table provides a comparison between the 18-Month Outlook used for operational planning purposes and the Ontario Reliability Outlook used for capacity planning purposes.

| Assumption Regarding | 18-Month Outlook | Ontario Reliability Outlook |
|---|---|---|
| Demand Forecast | Monthly Normalization for most months, Weekly Normalization for spring and fall months. | Seasonal Normalization.<br>Monthly or Weekly Normalization for the overlap period with the 18-Month Outlook. |
| Hydro Modeling | Historical median since market opening (May 2002) for energy and operating reserve contributions at the hour of peak week-day demand. Market participant submitted information for monthly energy production capability. | Same as for the 18-Month Outlook. |
| Wind Modeling | Wind Capacity Contribution (WCC) value that is lesser of actual historic median wind output or simulated 10-year historic median wind data for the month, during the top 5 contiguous demand hours for each month; and 29% energy contribution. | Same as for the 18-Month Outlook. |
| Solar Modeling | Solar Capacity Contribution (SCC) value is the simulated 10-year historic median of solar data for the month, during the top 5 contiguous demand hours for each month; and 14% energy contribution. | Same as for the 18-Month Outlook. |
| Resources Included | Resources under construction or identified as committed by the OPA. | Same as for the 18-Month Outlook. |
| Resource Adequacy Model | L&C | MARS |
| Imports | 0 MW | Equal to generator planned outage capacity, up to a 500 MW maximum, when required for resource adequacy. |
| Generator Planned Outages | As submitted by market participants. | Typical generic outage plan and/or forecast Planned Outage Factors (POF) submitted by market participants, except the overlap period with the 18-Month Outlook study timeframe, |

| | | |
|---|---|---|
| | | which uses outages as submitted by market participants. |

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