Independent Electricity Market Operator

Methodology to Perform Resource and Transmission Adequacy Assessments

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1.0 Introduction

This document describes the methododlogy used to perform the resource and transmission adequacy assessments. The resource adequacy assessment is intended to apply to both the 18-Month Outlook and the 10-Year Outlook. The transmission adequacy assesements methods are intended to be different for the 18-Month Outlook and 10-Year Outlooks.

The methodology for performing the transmission assessment for the 10-Year Outlook is presently described in the document titled, "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2002 to December 2011", dated June 28, 2001. In future it is expected that the 10-Year Outlook assessment methodology will be updated and described in this document.

2.0 Resource Adequacy Assessment Methodology

This section describes the criterion, tools, and methodology the IMO uses to perform the resource adequacy assessments. In Section 2.1 the NPCC resource adequacy criterion is described, as provided in the NPCC "Document A-2 Basic Criteria for Design and Operation of Interconnected Power Systems". Sections 2.2 and 2.3 briefly describe the L&C and MARS software tools, and the way they are used in the resource adequacy assessment process. Section 2.4 describes the methodology used to assess energy production adequacy.

2.1 Resource Adequacy Criterion

The IMO uses the following NPCC resource adequacy criterion to assess the adequacy of resources in the Ontario control area:

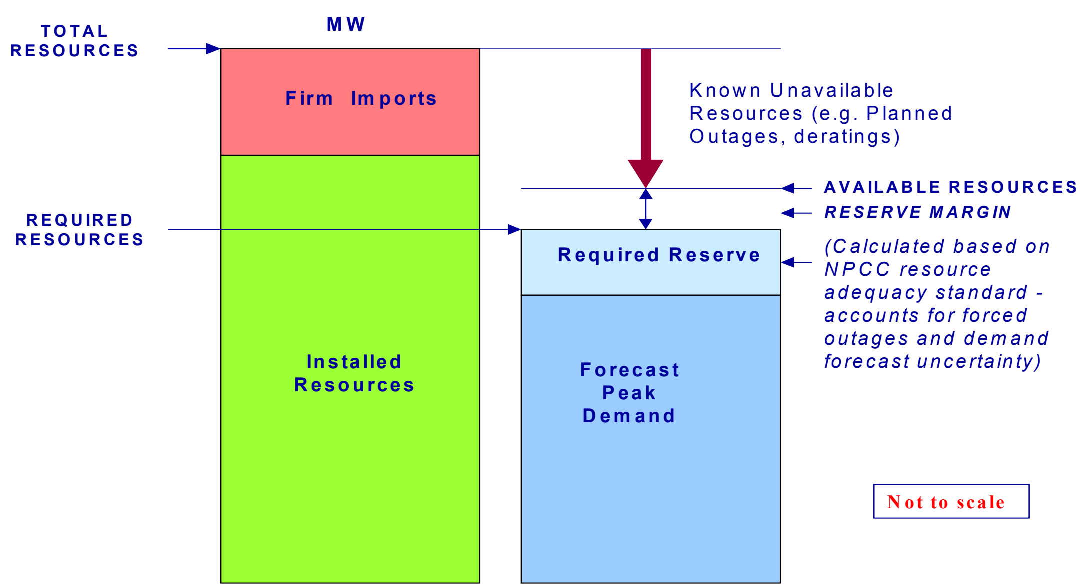
"… resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years ".

The IMO reports on resource adequacy relative to an NPCC-accepted variation of this criterion, which considers a Loss of Load Expectation of not more than 0.1 days per year.

2.2 Required Reserves

Reserves are required to ensure that the forecast demand can be supplied with a sufficiently high level of reliability. The amount of Required Reserve to meet the requirements of the NPCC resource adequacy criterion is calculated on a week-by-week basis, as described in Section 2.2.1.

Figure 2.1 Reserve Margin



The Required Resources are the amount of resources needed to supply the peak demand and meet the Required Reserve, as shown in Figure 2.1, and the Reserve Margin is the difference between Available Resources and Required Resources.

It should be noted that the Required Reserve is a planning parameter. In day to day operation the available resources must cover the demand plus the Operating Reserve, which for Ontario is about 1,350 MW, depending on the size of the largest generating units in service.

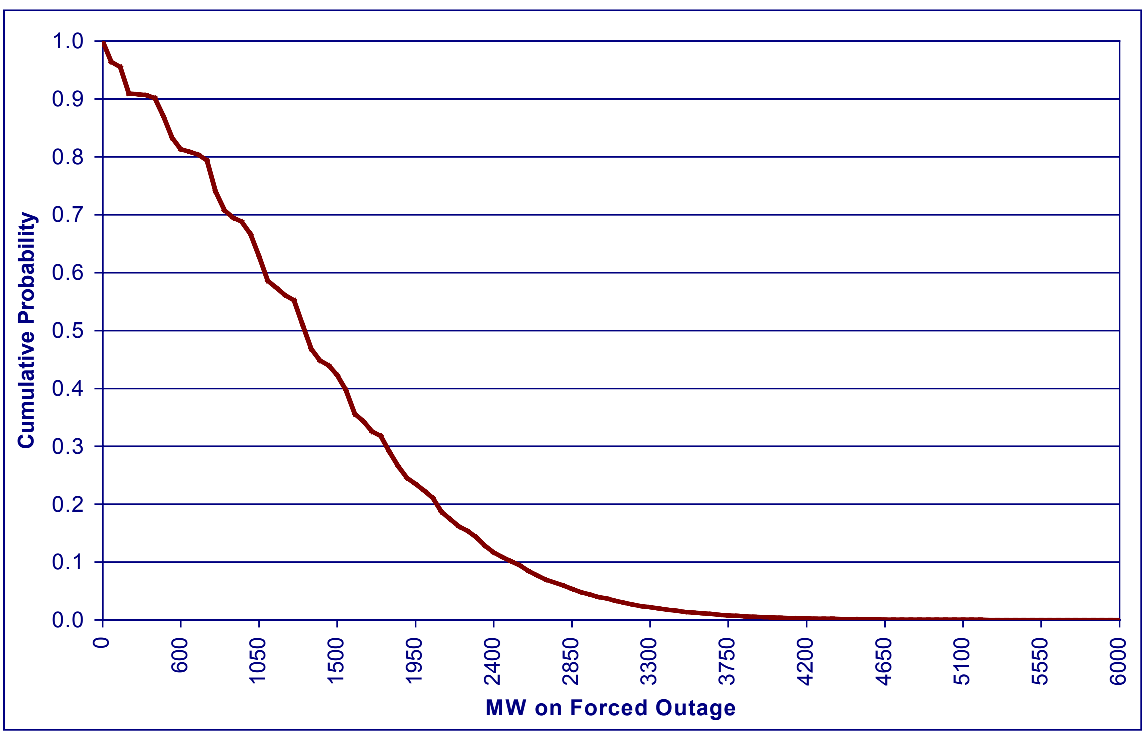
2.2.1 Load and Capacity Model

The IMO uses the Load and Capacity (L&C) model to determine the Required Reserves from week to week. Each thermal generating unit's maximum continuous rating (MCR), planned outages, deratings, and forced outage rates, as well as the demand forecast and its uncertainty are inputs to the model. A resource adequacy criterion equivalent to an annual loss of load probability (LOLP) of 0.1 is used to determine the Reserve Requirement for each week of the planning year. The program uses the 'direct convolution' method to calculate the weekly Reserve Requirement.

The probabilistic calculation of the Required Reserve for each planning week is performed as follows:

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 2.2.

Figure 2.2 Capacity on Outage Probability Table – Graphical Example



In the Load and Capacity model, a normal distribution of demand values around the mean demand value is assumed, as described in Section 2.2.2. The Required Reserve calculation is executed in an iterative manner. In each iteration, an amount of Generation Reserve is assumed and an associated $LOLP_{CALC}$ is derived, convolving the LFU corresponding to the 20-minute peak demand value with the Capacity on Outage Probability Table. The iterative process is repeated with small changes to the assumed Generation Reserve until the $LOLP_{CALC}$ becomes equal or less than the target. When this condition becomes true, the assumed level of Generation Reserve equals the Required Reserve necessary to meet the reliability target.

The adequacy of the available resources to meet the demand over the study period can then be assessed, in a deterministic calculation, as shown in Figure 2.1. For each planning week, the minimum level of Available Resources is determined, starting with the total resources then subtracting generator deratings, planned and long term unplanned generator outages, generation constrained off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity. The minimum 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 20-minute peak does not always occur on the same day. The Reserve Margin is then obtained by subtracting the Required Resources (equal to 20-minute peak demand plus the Required Reserve) from the Available Resources.

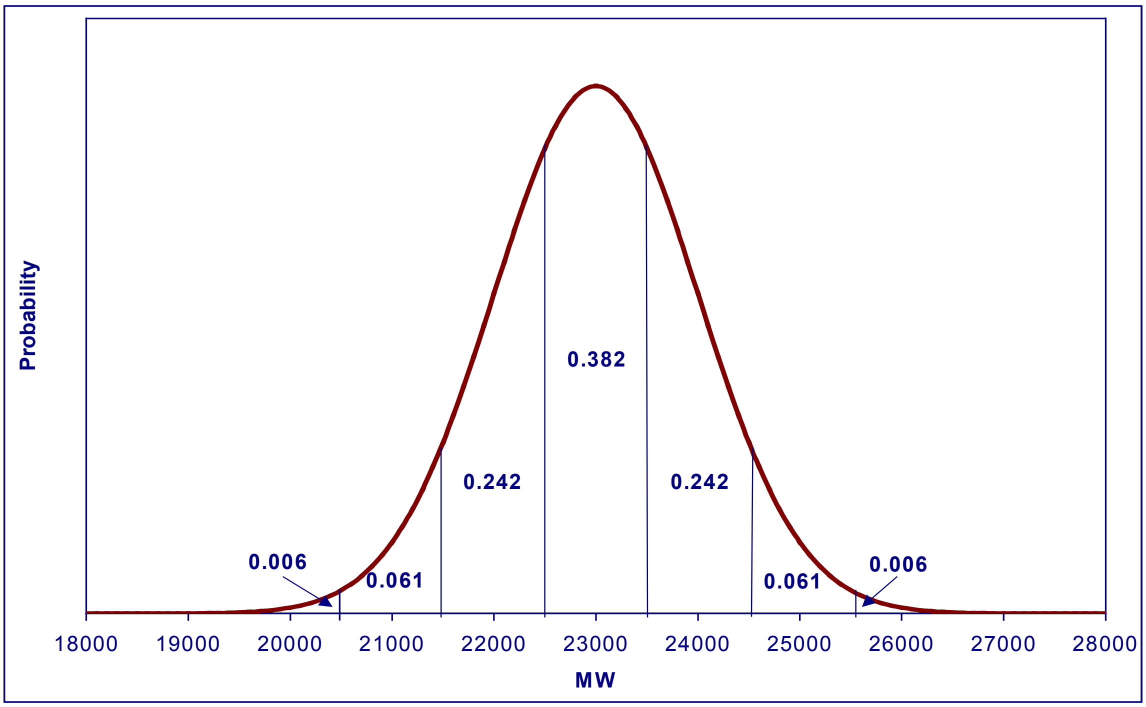
It should be noted that negative Reserve Margins in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. They only mean possible higher risk levels for the respective weeks. Whenever negative Reserve Margins are identified, the possible control actions to restore the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

2.2.2 Representation of Demand and Its Uncertainty Due to Weather

The L&C program requires weekly 20-minute 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 Required Reserve is probabilistically 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. A value of 300 MW is estimated, based on past operational experience. The IMO expects to be in a better position to forecast the future price responsive demand levels as Market Participant registration progresses and market experience is gained.

The Load Forecast Uncertainty (LFU), due mostly to weather swings, for each week, 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 deviation varies between about 2% and 7% through the year. For each weekly 20-minute peak demand, as the mean value, and its LFU, as the standard deviation, the model builds a multi-step approximation of the normal distribution. Subsequently, in the Required Reserve 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 2.3 illustrates a seven-step example of such an approximation, using a weekly 20-minute peak value of 23,000 MW and an associated LFU value of 1,000 MW. In this example, the peak values considered in the Required Reserve calculation would range from 20,000 MW to as high as 26,000 MW. Consequently, the calculated Required Reserve 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 2.3 under the curve).

Figure 2.3 Seven-Step Approximation of Normal Distribution - Example



2.2.3 Representation of Generation Resources

Unit Ratings

Thermal generating units are assumed to be capable of operating at a level equal to their normal Maximum Continuous Rating (MCR) or as otherwise identified to the IMO. Hydroelectric station peak outputs are based on one hour sustainable capability determined from about 30 years of record; these values are provided by the generation plant owners. The peak and energy output of all combustion turbines varies considerably with changes in ambient air temperature and, hence, both summer and winter capacity values are included.

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.

2.2.4 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. The Ontario total coincident import capability is approximately 3,900 MW.

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 neighbouring systems is estimated 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 neighbouring jurisdictions, in which forecast levels of spare capacity are included.

2.2.5 Representation of the Transmission System

The IMO-controlled grid consists of a robust southern grid and a sparse northern grid. The northwestern part of the northern grid has limitations, which potentially limit the use of generation capacity. The operation of some 25-hz generation in Niagara zone is limited by frequency changer capability. The total amount of the generation limitations varies between 0 and about 350 MW, depending on the load and resource levels, especially in the Northwest zone. Generation limitations are subtracted from the Available Resources when calculating the Reserve Margins.

2.3 Multi-Area Reliability Simulation (MARS) Approach

The GE Multi-Area Reliability Simulation (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 Ontario electricity system has been modeled as a pool composed of ten zones. Figure 3.1.1 provides a pictorial depiction of Ontario's ten zones.

2.3.1 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 Loss of Load Expectation (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 load forecast uncertainty (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 positive or 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.

2.3.2 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 2.3, in Section 2.2.2.

2.3.3 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 stochastically 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 and maximum ratings and monthly energy production capabilities are input on a monthly basis for the hydroelectric generators.

2.3.4 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).

As no information related to the neighbouring systems is available with the necessary level of detail required by MARS, they 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 2.3.5.

2.3.5 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 neighbouring 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.

2.4 Adequacy Assessment of Energy Production Capability

The adequacy of the energy production capability is assessed on a month-by-month basis. For each month in the study period, the forecast energy demand is compared with the energy production capability of the generators in Ontario and the energy-backed, firm purchase contracts with external jurisdictions. Monthly energy production capability values for the Ontario generators are provided by their owners or operators. They account for fuel supply limitations, scheduled and forced outages and deratings, environmental, regulatory and citizenship restrictions.

The monthly amount of generation limitations due to transmission constraints in the Northwest zone is subtracted from the total monthly available energy.

The need for additional energy, from outside Ontario, is assessed if the energy demand in a month exceeds the energy production capability of the above mentioned resources.

3.0 Transmission Adequacy Assessment Methodology

3.1 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 IMO controlled grid that could require contingency planning by Market Participants or by the IMO. 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.

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 IMO controlled-grid should be coordinated with the generator owners involved, especially at times when generation reserve margins are below required levels. The IMO 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.

During the transitional period prior to Market opening, an 18-Month rolling outage plan is submitted by Hydro One Networks to the IMO on a monthly basis. Section 3.1.1 describes the methodology used to assess the transmission outage plan.

3.1.1 Transmission Outage Plan Assessment Methodology

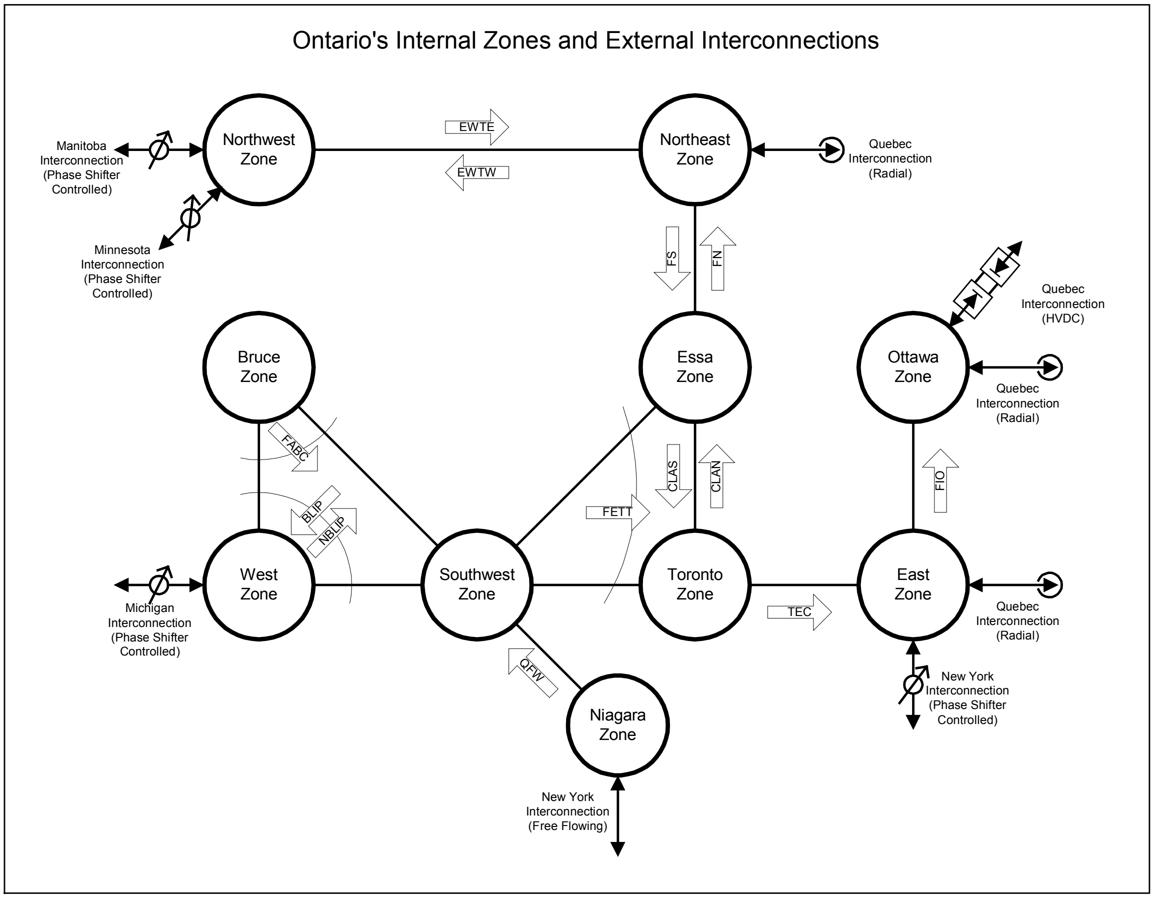
The outage plan is filtered to contain only outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than five days. These outages are then sorted and grouped into tables, one table for each zone. The following items are listed for each outage, with items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

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 IMO-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 to 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.

Figure 3.1.1 provides a pictorial depiction of Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions.

Figure 3.1.1 Ontario's Internal Zones and Interfaces, and External Interconnections



3.2 Assessment Methodology for the 10-Year Outlook

The methodology for performing the transmission assessment for the 10-Year Outlook is presently described in the document titled, "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2002 to December 2011", dated June 28, 2001. In future it is expected that the 10-Year Outlook assessment methodology will be updated and described in this document.