Methodology to Perform Long Term Assessments

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1.0 Introduction

This document describes the methodology used to perform the Ontario Demand forecast, the associated resource and transmission adequacy assessments, and operability assessments for the 18-Month 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

The demand forecasts presented in the Outlook documents are generated to meet 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 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, calendar variables, conservation and embedded generation. 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 assumptions for the various model drivers. 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.

Though conservation and demand management are often discussed together, for the purposes of forecasting, they are handled differently. Demand management is treated as a resource and is based on market participant information and actual market experience. Conservation projections are incorporated into the demand forecast. A similar approach is used to quantify the impact of embedded generation. A further discussion on demand management can be found in section 2.4.

2.2 Demand Forecast Drivers

Consumption of electricity is modelled using six sets of forecast drivers: calendar variables, weather effects, economic and demographic conditions, load modifiers (time of use and critical peak pricing), conservation impacts and embedded generation output. Each of these drivers plays a role in shaping the 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 forecast 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. This is discussed further in Section 2.3.

Economic and demographic 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 several service providers to enable further analysis and provide 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.

Conservation acts to reduce the need for electricity at the end-user. The IESO includes demand reductions due to energy efficiency, fuel switching and conservation behaviour under the category of conservation. Information on program targets and impacts, both past and future, are incorporated into the demand forecast.

Embedded generation reduces the need for grid supplied electricity by generating electricity on the distribution system. Since the majority of embedded generation is solar powered, embedded generation is divided into two separate components – solar and non-solar. Non-solar embedded generation includes generation fuelled by biogas and natural gas, water and wind. Contract information is used to estimate both the historical and future output of embedded generation. This information is incorporated into the demand model.

Load modifiers account for the impact of prices. The Industrial Conservation Initiative (ICI) and time of use prices (TOU) put downward pressure on demand during peak demand periods. These impacts are incorporated into the model.

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 deem 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 in extremis. They are not used for energy analysis as sustained Extreme weather is highly unlikely.

Each of the scenarios has an associated 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 the 31 year history 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.

Figure 2.1 Creating Monthly Normal Weather – January

	Year										
Rank	1985	1986	1987	1988	- - - - -	2012	2013	2014	2015		Median
1	4,791	4,427	5,569	**4,921**	- - - - -	5,219	4,985	5,321	4,875	→	4,921
2	4,395	4,393	5,482	4,517	- - - - -	4,989	4,820	5,317	4,522		4,764
3	4,373	4,310	5,201	3,994	- - - - -	4,850	4,285	4,845	4,383		4,450
4	4,272	4,057	4,912	3,971	- - - - -	4,799	4,255	4,292	4,081		4,264
5	4,024	4,002	4,703	3,877	- - - - -	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	2,441		2,261
28	1,807	1,954	2,821	1,840	- - - - -	2,330	1,979	1,680	2,173		2,344
29	1,770	1,952	2,644	1,775	- - - - -	2,180	1,756	1,366	2,125		1,963
30	1,692	1,902	2,345	1,402	- - - - -	1,893	1,558	1,185	1,804		1,747
31	1,394	1,788	2,009	1,202	- - - - -	1,830	**1,452**	1,111	1,692	→	1,452

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 forecast. 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 Demand Measures

The demand measures, which are dispatchable loads, Capacity Based Demand Response (CBDR) and resources secured under the DR Auction, are treated as resources in the assessment. As such, the reductions due to these programs are added back to the historical hourly demand. This ensures that the impacts are not counted twice – as a resource capacity and as lower demand.

These programs are summed to determine a total capacity number. 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.

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 data and the performance of demand measures are obtained and processed.

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

This section describes the criteria, tools and methodology the IESO uses to perform resource adequacy assessments. In Section 3.1, the resource adequacy criterion is described. Sections 3.2, 3.3 and 3.4 briefly describe the Load and Capacity (L&C), Multi Area Reliability Simulation (MARS) and the energy modelling software tools, and the way they are used in the resource adequacy assessment process. Section 3.5 presents the risk factors to the resource adequacy assessments.

3.1 Resource Adequacy Criteria

The IESO uses the NPCC resource adequacy design criteria as provided in the NPCC "Directory #1: Design and Operation of the Bulk Power System" to assess the adequacy of resources in the Ontario Area. The NPCC resource adequacy criterion states:

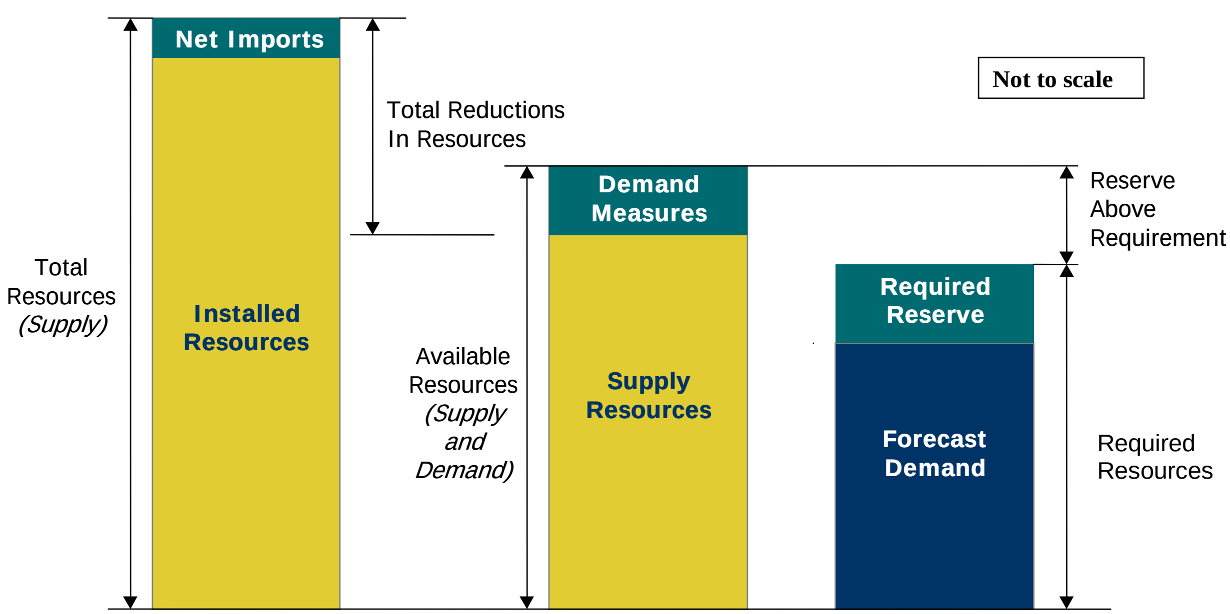
"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than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

Directory #1 further states that the applicable entities shall "Make due allowances 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."

Required Reserves

Reserves are required to ensure that the forecast Ontario Demand can be supplied with a sufficiently high level of reliability.

Figure 3.1 Reserve Above Requirement



The Required Resources are the amount of resources needed to supply the 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, depending on the type of assessment, takes into account the uncertainty associated with demand forecasts or generator forced outages in a probabilistic or deterministic approach.

3.2 Load and Capacity Model

The IESO uses the L&C model to determine the Required Reserve for capacity assessments for each week in the study period.

The following are inputs to the L&C model:

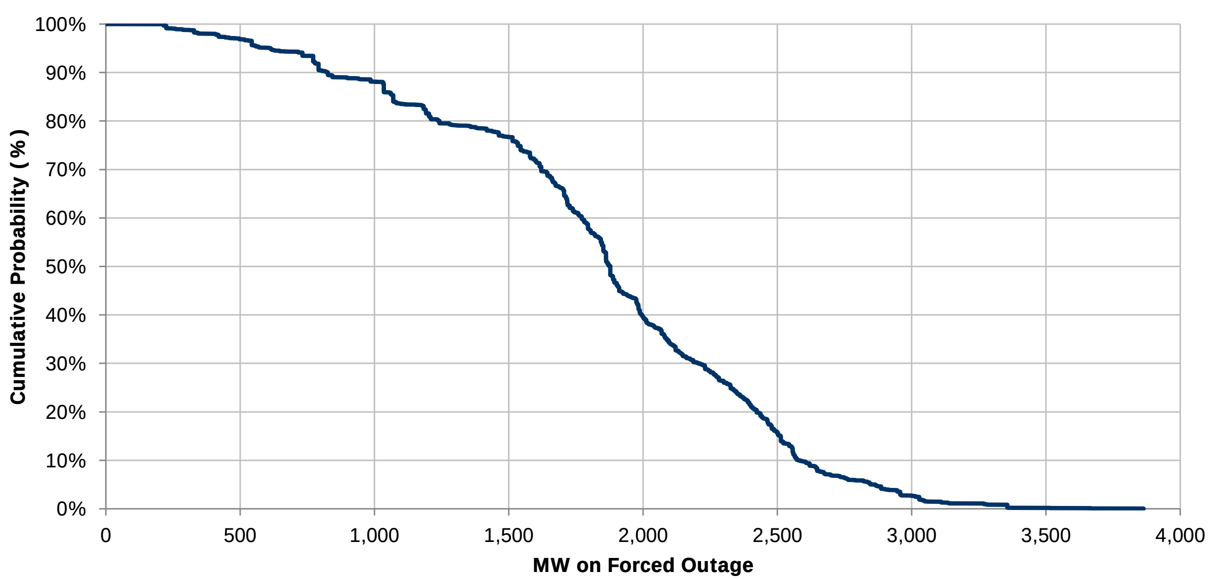
- Thermal generating units' net maximum continuous rating (MCR),
- Thermal generating units' planned outages, deratings, and forced outage rates on demand,
- Hydroelectric generating units' dependable capacity,
- Wind capacity contribution (WCC) values for wind generators,
- Solar capacity contribution (SCC) values for solar generators, and
- Demand forecast and its uncertainty.

The amount of Required Reserve to meet the resource adequacy criterion is calculated on a week-by-week basis as the maximum of a deterministically and a probabilistically calculated reserve requirement.

Probabilistic Reserve Requirement

A resource adequacy criterion equivalent to an 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. The MCRs and forced outage rates on demand of thermal generation units are used to build a Capacity on Outage Probability Table (COPT) which contains the cumulative probabilities of having various amounts of generating capacity or more on forced outage. 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 3.2.1. 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 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.

Deterministic reserve requirement

The deterministic reserve requirement for each winter week in December, January and February is equal to the Operating Reserve (equal to the first single largest contingency plus half the size of the next largest contingency), plus half the size of the second largest contingency, plus half the size of the third largest contingency, plus the absolute value of the LFU. For all remaining weeks of the year, the deterministic reserve requirement is equal to the Operating Reserve, plus half the size of the second largest contingency plus the absolute value of the LFU.

Available Resources

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 capacity imports or exports backed by firm contracts;
- Any imports identified by market participants to support planned outage requests to the IESO; and
- The assumed amount of price responsive demand.

The expected level of Available Resources is calculated using the outage profile associated with the "maximum outage day" in each planning week, i. e. the day with the maximum amount of unavailable generating capacity in that week. Although the weekly peak does not always occur on the maximum outage day, such coincidence is assumed for the determination of Available Resources.

For a specific outage assessment in the 18-month timeframe, imports of up to 700 MW may be considered as available plus any imports that generators have confirmed they will make to support a planned outage request, according to the applicable market manuals.

Reserve Above Requirement

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. The Reserve Above Requirement is obtained by subtracting the Required Resources (equal to the peak demand plus Required Reserve) from the Available Resources.

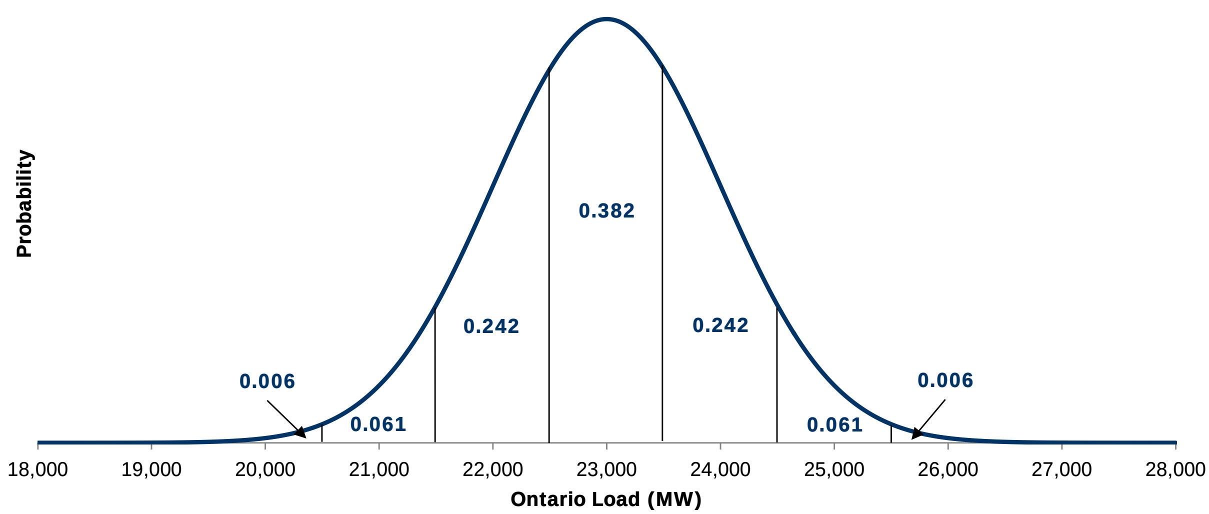
It should be noted that negative Reserve Above Requirement values in some weeks do not necessarily mean a violation of the NPCC resource adequacy criterion. This may only mean higher risk levels for the respective weeks. Whenever negative Reserve Above Requirement values are identified, the possible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

3.2.1 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 modelling 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 weather statistics going back to 1984, 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 modelled 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. This is achieved by weighting the impact of each of the seven peak demand values by its associated probability of occurrence (shown in Figure 3.3 under the curve).

Figure 3.3 Seven-Step Approximation of Normal Distribution - Example



3.2.2 Representation of Generation Resources

Capacity Ratings

Most of thermal generating units have their maximum capability varying with external factors, such as ambient temperature and humidity or cooling water temperature. To capture those variables, the MCRs for thermal generators are modelled on a monthly granularity.

Nuclear generators and the like whose MCR is not ambient temperature sensitive provide monthly gross MCR and their station service load.

Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide gross MCR at five different temperatures specified by the IESO which are used to construct a temperature derating curve. For each such generator, two monthly gross MCR values - one for the normal weather scenario and the second for the extreme weather scenario - are calculated at representative monthly temperatures using the derating curve.

Each zone's two monthly representative temperatures are determined from historical data collected from the weather station assigned to that zone based on proximity. For normal weather scenario, the zonal representative temperature is the median of the daily peak temperatures in the month in the zone. The zonal representative temperature for the extreme weather scenario is the maximum of the daily peak temperatures in the month in that zone for the months from April to October. For the months from November to March, the temperature for the extreme weather scenario is the minimum daily temperature in the month in each zone; the cold temperature is capped at -10°C.

Generators also provide their station service load annually which is allocated in proportion to the size of each unit at the station to calculate net MCR values for each unit.

The IESO updates the net MCR values annually in the second quarter using the data generators submit on form 1230 by April 1.

Non-Utility Generators (NUGs) whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. If the NUGs continue to provide forecast data, they are included in the planned scenario for the rest of the outlook period, too.

Monthly hydroelectric generation output forecast is calculated 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 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.

A recent review of historical hydroelectric production data during extreme summer period showed that forecasts based on median values for all years in the sample overstates the availability of hydroelectric

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

production during the summer extremes. To more accurately reflect hydroelectric production in the extreme weather scenario, the median contribution of the hydroelectric fleet at the time of peak for summer months (June to September) is based on 2012 – the driest year in the sample. This is estimated to be about 800 MW lower than the values for normal weather conditions. As additional years of market experience are acquired, the driest year will be determined to calculate the impact. The methodology to calculate the hydroelectric contribution at varying conditions is continuing to evolve to reflect the actual experience.

Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values in percentage of installed capacity are determined from actual historic median wind generator contribution over the last 10 years at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months.

Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the median contribution during the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. A dataset comprising ten years of simulated solar production history is used for this purpose. As for wind, the top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. As actual solar production data becomes available in future, the process of combining historical solar data and the simulated 10-year historical solar data will be incorporated into the SCC methodology, until sufficient actual solar production history has been accumulated, at which point the use of simulated data will be discontinued.

Forced Outage Rates on Demand of Generating Units

Equivalent forced outage rates on demand (EFORd) are used for each thermal generation unit as a measure of the probability that the unit will not be available due to forced outages and forced deratings when there is a demand for the unit to generate. The values are calculated by the IESO using a rolling five years of generator outage and operations data, consistent with IEEE Std 762[2]. EFOR data supplied by market participants will continue to be used for comparison purposes.

3.2.3 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 well, southern zones of the system could have some generation constrained at times, especially during outage conditions, 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 is subtracted from the Available Resources when calculating the Reserve Above Requirement.

3.3 General Electric's Multi-Area Reliability Simulation (MARS) Model

The General Electric's 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 is modelled as a pool composed of ten zones. Figure 4.1 provides a pictorial representation of Ontario's 10-zone model.

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[2] IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity, IEEE Std 762-2006,

3.3.1 Multi-Area Reliability Simulation (MARS) Model

A sequential Monte Carlo simulation forms the basis for the MARS calculating algorithm. The sequential simulation steps through the study horizon chronologically, enabling MARS to model time correlated events and calculate various measures of reliability, including loss of load expectation (LOLE) in days/year or hours/year. The use of Monte Carlo simulation allows MARS to compute the probability distributions of reported reliability statistics in addition to their expected values for the study period. MARS is capable of probabilistically modelling uncertainty in forecast load and generating unit availability due to unplanned outages. Furthermore, MARS can determine the expected number of times various emergency operating procedures (EOPs) will be utilized in each zone and pool.

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

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

Consequently, the system can be modelled in great detail with accurate recognition of random events, such as equipment failures and load uncertainties, as well as deterministic rules that govern system operation.

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, a user defined priority order is implemented to specify the priority in which deficient zones will receive assistance from zones with excess resources. The second method allows sharing the available excess resources among deficient zones in proportion to the size of their respective shortfalls. Priorities within pools, as well as among pools, can also be modelled. For purposes of IESO reliability assessments conducted using MARS, the former approach is applied by defining the priority order for allocating assistance among deficient zones.

3.3.2 Representation of Demand and Its Uncertainty Due to Weather

Load Forecast Uncertainty (LFU) curve is a probabilistic model representing probability of occurrence of various peak demands. The uncertainty in peak demand is considered to be mainly due to random weather fluctuations, and does not include any long-term economic influence. The temperature combined with the other load-contributing weather factors is denoted as Temperature Variable (TV). THI – temperature-humidity index, one of the variants of TV, is used for the study. Historical weather is used to simulate a set of peak loads with all other variables being equal. Poisson distribution is used to deduce the expected peak loads for 7 probability bins from the expected rates of occurrence of peak loads belonging to each bin.

A zonal LFU curve is developed for every month of the year and applied to each transmission zone.

A graphical example is provided in Figure 3.3 of Section 3.2.1.

3.3.3 Representation of Generation Resources

MARS has the capability to model the various types of generation resources including thermal, energy-limited, cogeneration, energy storage and demand-side management.

For each generation unit modelled, the installation and retirement dates are specified. Other data such as minimum and maximum ratings, energy limits, available capacity states, state transition rates, planned maintenance requirements, and net modification of the hourly loads are included depending on the generation type. More details of how different generation types are represented in MARS are described below.

Wind

Capacity limitations due to variability of wind generators are captured by providing probability density functions from which stochastic selections are made by the MARS software. Wind generation is aggregated on a zonal basis and modelled as an energy-limited resource with a cumulative probability density function (CPDF) which represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs vary by month and season.

The CPDFs are constructed based on the contribution of wind resources during a 5-hour window that represents the highest contiguous average demand hours for the summer and winter seasons, and for each month of spring and fall. Historical wind production data over the last 10 years are utilized for developing the CPDFs.

In the analysis referred to above, the top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months.

Solar

Solar generation is aggregated on a zonal basis and is modelled as load modifiers in MARS. The contribution of solar resources is modelled as fixed hourly profiles that vary by month and season. The MW production is calculated from projected installed capacities and hourly solar capacity factors (SCF) applicable to each month or season. Hourly SCFs are in turn determined from an analysis of ten years of simulated historical data and available actual historical production data by calculating the median solar contribution for each hour of the day of each applicable month and season.

Hydroelectric

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each zone. Maximum capacity values are based on historical median monthly production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the bottom 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value is derived based on the average monthly capacity factor at the time of system peak in the zone where the new project is located. The minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of a similar sized generator in the zone where the new project is located.

Furthermore, since the routine maintenance and actual forced outages are implicitly accounted for in the historical data that is used to derive capacity and energy limitations, no additional constraints are normally required to capture the impact of generation unavailability due to maintenance and unplanned events. However, for unusual outages in which significant amounts of generation are expected to be unavailable, appropriate adjustments are made to capacity and energy limitations.

Thermal Resources

Four resource types are modelled as thermal resources: nuclear, gas, oil and biofuel. All thermal generators in Ontario, for each of the ten zones, are modelled on an individual unit basis.

The monthly MCR values are consistent with those used in the L&C model. The planned outage schedules are based on information submitted by market participants. However, the available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling 5-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units of similar size and technical characteristics are applied.

For certain energy limited thermal units, minimum capacity, maximum capacity and monthly energy values are modelled to accurately capture the limitations of these units.

Demand Measures

The dependable contribution of each of the four components comprising demand measures (see Section 2.4) is modelled in the study as a resource as described below.

The effective capacity available from dispatchable loads is determined based on an analysis of historical bid-quantity data for peak demand hours and is modelled in MARS as monthly capacity that is aggregated for each transmission zone.

CBDR resources are separately represented as monthly values aggregated on a transmission zone basis. The effective capacity of these resources is determined based on an analysis of the historical performance of the participants in these programs. In MARS, CBDR is modelled as capacity that is available at all times Demand response procured through the Demand Response Auction process is modelled as aggregated zonal resources with a monthly capacity based on the capacity contracted. The effective capacity of these resources will, over time, be reflected in the models as operating experience with these new resources is accumulated.

3.3.4 Representation of Interconnected Systems

The five interconnected systems that can provide assistance to the Ontario system can be modelled as areas external to the Ontario pool. However, for purposes of IESO reliability assessments, any support from neighboring Planning Coordinator areas beyond the firm contracts is not relied upon currently to meet demand in the planning timeframe, but rather left as an additional resource to be used in real-time operations as required. Firm imports and exports are represented in MARS as a firm demand, which is based on the capacity procured from or committed to an external jurisdiction. Firm demand is only modelled for the hours when the firm transaction is eligible to flow.

3.3.5 Representation of the Transmission System within Ontario

The transmission system between interconnected zones can be modelled 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. The amount of assistance that deficient zones could receive from zones with excess resources is limited by the transfer limits on the interfaces.

All transmission interfaces between the ten zones within Ontario are modelled to reflect operational security limits. Seasonal base limits are implemented for each interface. In cases where external systems are modelled, the tie lines between Ontario and neighbouring systems are also modelled, 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 modelled on the interfaces.

3.4 Energy Adequacy Assessments

The changing resource mix in Ontario, including the increasing penetration of variable energy resources coupled with evolving demand profiles influenced by conservation and embedded generation have created the need for the IESO to assess Ontario's energy sufficiency in addition to the capacity adequacy. The Energy Adequacy Assessment (EAA) described in the following sections meets that need to assess whether the resources available over a specific assessment horizon will be sufficient to supply the forecast energy demand. Additionally, the EAA estimates the production by each resource over the assessment period to meet the projected demand based on expected resource availability.

3.4.1 EAA Overview

To perform the EAA, the IESO uses PLEXOS® Integrated Energy Model (Plexos) software to model and simulate the dispatch of Ontario's resources. Plexos calculates the optimal solution to the unit commitment problem by determining the commitment status (i. e. whether on or off) and production schedule of each resource in the system that minimizes total production cost subject to a set of operating constraints. .

The IESO's energy model currently comprises:

- All grid-connected resources, their operating characteristics and limitations;
- Random forced outages of thermal resources;
- Planned outages of thermal resources;
- Zonal demand forecasts on an hourly granularity;
- A representation of the Ontario transmission system that may be a either on a detailed nodal level, or on a zonal level as depicted in Figure 4.1; and
- Transmission element ratings and the limits of interfaces between interconnected zones;

In general, neighbouring jurisdictions are not modelled since the focus of the EAA is to determine Ontario's energy self-sufficiency. However, where firm contracts for sales or purchases exist, these are modeled as exports from or imports to a particular zone or intertie point. The energy model conducts a least-cost optimization to determine energy production over a 1-day optimization window, while respecting the thermal limits of transmission lines and transformers, the power flow limits of interfaces between transmission zones, technical limitations of each resource, and other imposed system limitations.

3.4.2 EAA Generation Methodology

In this section, the modelling of resources by fuel type in the EAA will be described in detail. These properties are updated annually unless otherwise specified. For each generation unit modelled, the installation and retirement dates are specified. Other data such as operational constraints, energy limitations, EFORd of thermal units and planned maintenance requirements, determined based on historical and/or market participant submitted information, are included depending on the generation type.

When modelling generator forced outages, a single pattern of forced outages for each thermal unit covering the entire Outlook period is selected from among a large number of candidates using a convergent Monte Carlo technique that pre-filters statistically unlikely outage patterns.

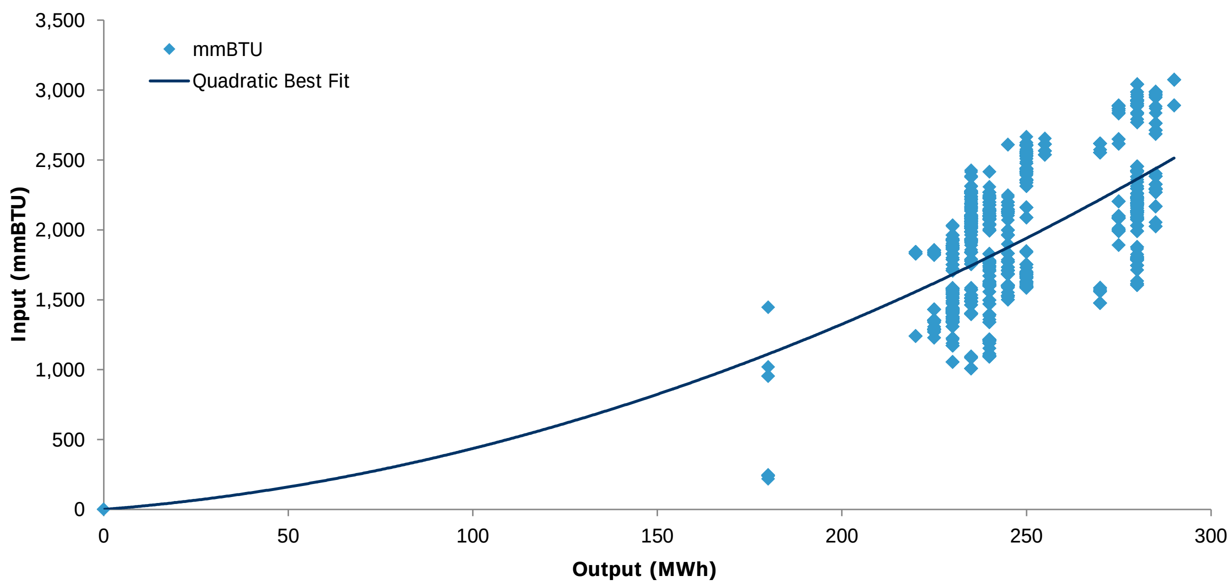
Combustion and Steam Units

The dispatchable gas, and oil generators, whether combustion or steam units, are modelled using a set of capacity and ramping properties, as well as heat rate equations. Capacity properties establish the bounds of the dispatch whereas the heat rate equations determine generator production cost.

The capacity properties are consistent with those used in capacity assessments. The Minimum Run Time (MRT), Minimum Loading Point (MLP) and ramping properties were created from market participant submitted data. Given that the IESO's energy model currently uses a 1-hour dispatch interval, the ramp rates do not limit the generator dispatch.

The dependencies between gas and steam units for CCGT (Combined Cycle Gas Turbine) are also modelled. The relationship between fuel input and generation output is illustrated in Figure 3.4 for a particular generator. The seasonal generation cost curve for each generator is calculated by combining the function that best represents the input and output (I-O) data with the forecast gas price.

Figure 3.4 Quadratic Best Fit I-O Equation for a Particular Combustion Generator



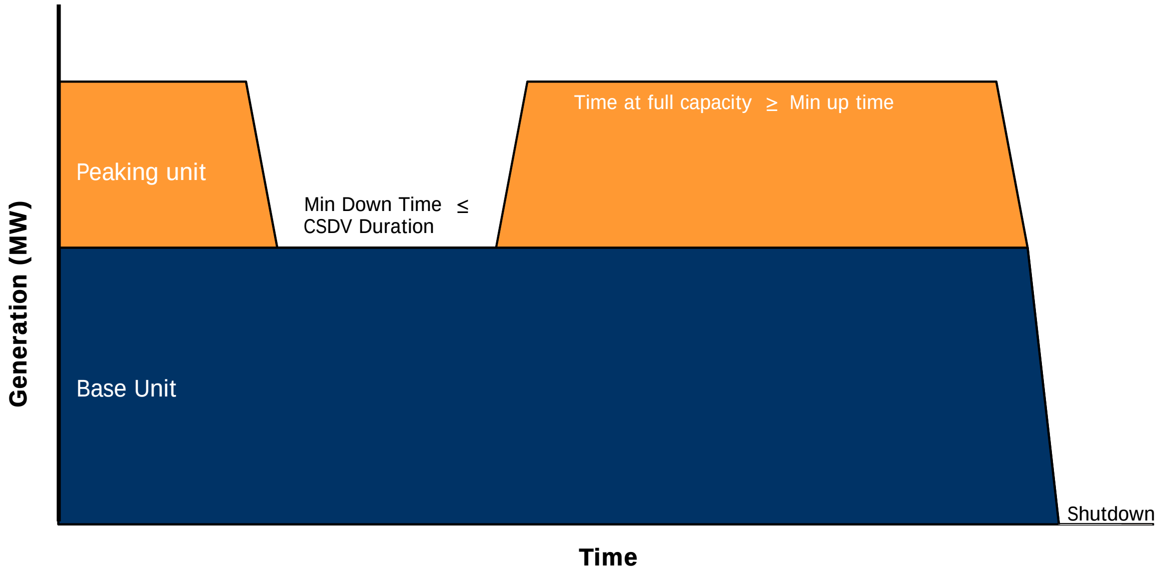
Non-dispatchable generators are modelled using a unit rating based on market participant submitted data.

Nuclear

Nuclear units are modelled using a set of capacity and ramping properties. Additionally, flexible nuclear generation is modelled with a set of constraints that reflect the capability to manoeuver (i. e. reduce its output by a prescribed amount) under normal operations without requiring a unit to shut down. The capacity properties are consistent with those used in capacity assessments. Ramping limits are based on market participant information as well as empirical data.

In order to model manoeuvering capability, the nuclear units are modelled as two joint units (base and peaking) with distinct floor prices as provided for in the Market Manual 4.2. Constraints ensure that a peaking unit is online only when the corresponding base unit is online. See Figure 3.5 for an illustration on how the base and peaking units interact.

Figure 3.5 Nuclear Manoeuvering Unit Dispatch Illustration



Biofuel

Biofuel units are modelled using a unit rating and either a fixed profile or a set of price-quantity pairs: non-dispatchable units are assigned a fixed monthly or hourly production schedule based on historical market data, while dispatchable units are assigned hourly price/quantity pairs derived from historical market data.

Hydroelectric

Hydroelectric generators are modelled as energy-limited resources since the hydroelectric production is limited by the amount of water available. There are two key components of modelling hydroelectric generators as energy-limited resources in the model: physical characteristics of individual units and capacity and energy limitations of each unit or groups of units that belong to a region (Ontario wide) or zone (such as Northwest). These limitations (constraints) exist in the hourly, daily and monthly timeframes.

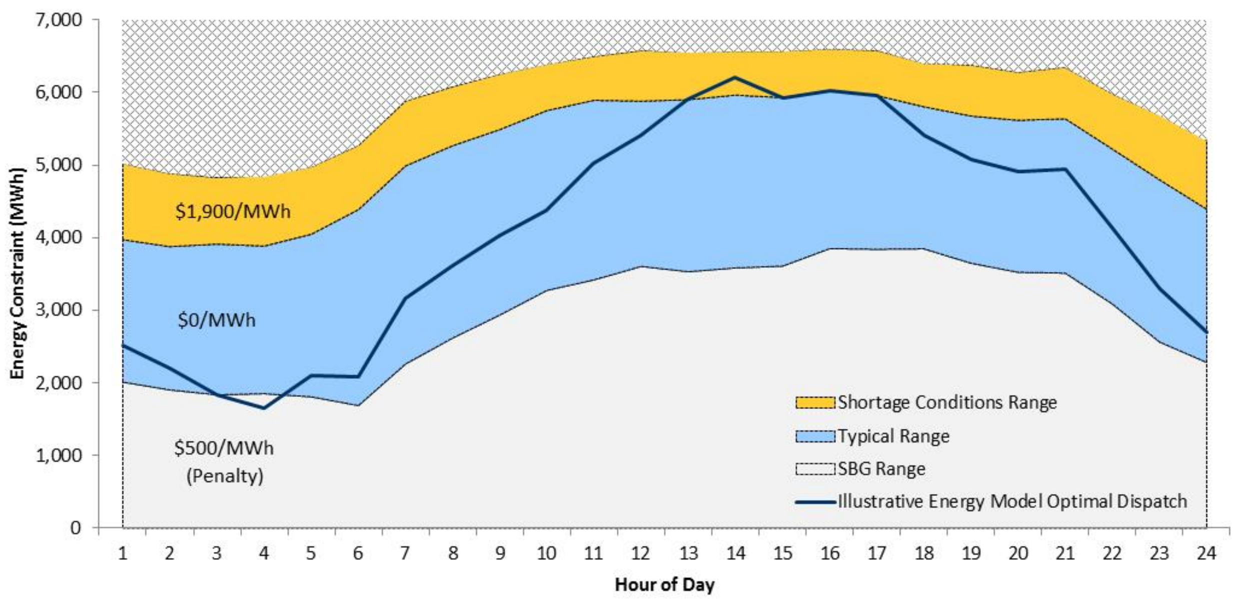
The hydroelectric run-of-the-river component for baseload units is must-run to ensure the energy model schedules this element. The dispatchable component of each unit is dispatched based on system needs and hydroelectric zonal or regional constraints.

In order to create the required unit capacity properties, historical production and operating reserve data from market opening to current is utilized. These properties are created to model seasonal, monthly and hourly trends.

Within a region or zone, hydroelectric generators do not all simultaneously peak to full capacity even when the need arises, therefore constraints are established for groups of generators to create a realistic dispatch. These constraints are created to simulate hydroelectric production during different system conditions and are based on observed hourly and daily energy upper and lower limits as well as monthly historical median hydroelectric production data from market opening to present. If future system configurations are not reflected in the historical dataset, changes to these constraints can be made in order to correctly forecast hydroelectric capability.

Figure 3.6 shows an illustrative energy modelling solution for the entire hydroelectric fleet (Ontario wide) within the established hourly constraints. In this example, the total hydroelectric production in hour ending 4 is constrained by the hourly minimum and penalized at $500/MWh for each MW below the threshold. In hour ending 14, the dispatch is constrained by the upper limit and costs $1,900/MWh yet cannot ever exceed the orange band, as that is a hard constraint. Although not visible in Figure 3.6, the total hydroelectric production in that day is also constrained by a daily energy limit, preventing the model from scheduling up to the maximum hourly capacity in all hours of the day, which would create an unrealistic dispatch. Finally, the total monthly production on the unit and fleet wide level cannot exceed a preset maximum based on historical trends.

Figure 3.6 Hydroelectric Solution for a Particular Weekday vs. Hourly and Daily Energy Constraints



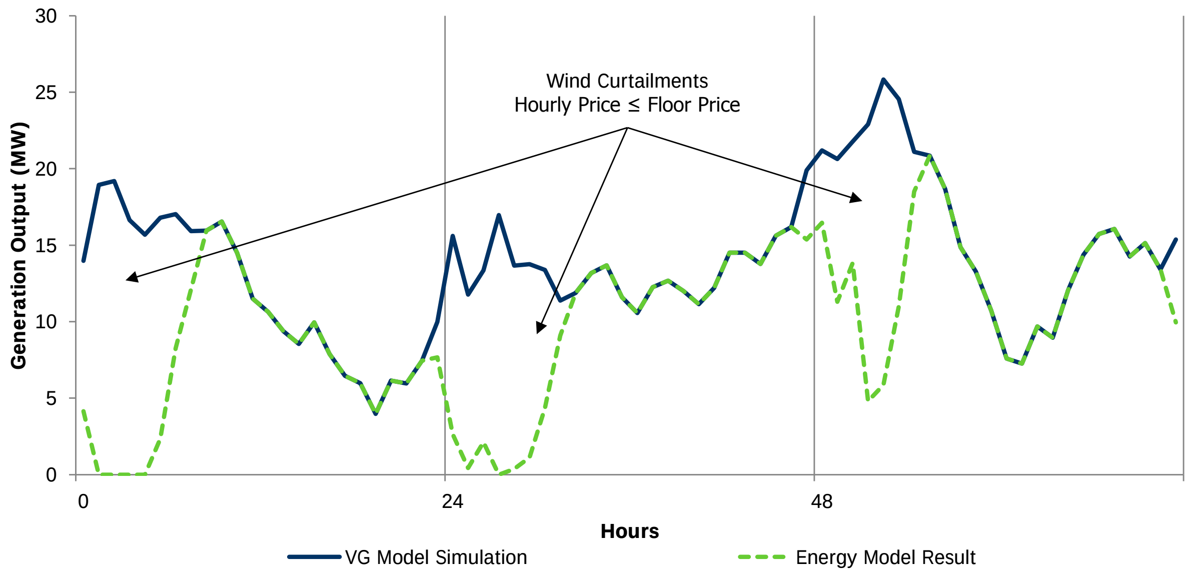
Wind

Wind resource output is highly random in nature and is therefore difficult to forecast beyond 48 to 72 hours. Therefore, in order to model wind generation, production profiles are simulated for Ontario's wind resources using IESO's Variable Generation Modelling tool (VG tool). The VG tool utilizes 10 years of simulated historical wind production data for geographically dispersed sites throughout Ontario to produce a time series profile for each wind site while retaining the statistical properties of simulated historical production data. Further, in order to sufficiently capture the potential impacts of variations in wind production for any specific hour or period, multiple site-specific production profiles are developed for each wind resource and the simulation is re-run for each set of wind profiles.

The derived wind production profiles represent the available wind energy at each site and wind dispatch in the energy model is constrained to match the simulated production profile unless the particular wind facility is dispatched down or off in accordance with the applicable floor price as per Market Manual 4.2.

See Figure 3.7 for an illustrative example.

Figure 3.7 Wind Simulation versus Energy Model Dispatch for a Particular Unit



Solar

Similar to wind resource modelling, a production profile is simulated using the Variable Generation Modelling tool (VG tool) to model solar production. The VG tool utilizes 10 years of simulated historical solar production data for geographically dispersed sites throughout Ontario to produce a time series profile for each solar site while retaining the statistical properties of simulated historical production data. A site-specific production profile is developed for each solar resource.

The derived solar production profiles represent the available solar energy at each site and solar dispatch in the energy model is constrained to match the simulated production profile unless the particular solar facility is dispatched-off in accordance with the applicable floor price as per Market Manual 4.2.

Demand Measures

In addition to the capacity considerations previously described in Section 3. 3 for modelling demand measures, the energy model more precisely represents the availability window of each of the demand measures.

The energy model also includes bid prices for demand response, CBDR and dispatchable loads. This additional information is used by the simulation software to “activate” these resources as required in a manner approximating program rules.

3.4.3 EAA Demand Forecast Methodology

The hourly normal weather demand forecast described in Section 2.3 is used for the energy adequacy assessment. This demand forecast includes transmission losses and incorporates the impacts of embedded generation and conservation (see Section 2.2). The LFU is not explicitly modelled as part of the EAA.

3.4.4 EAA Network Model

In assessments where a detailed nodal representation of Ontario's transmission system is required, a PSS/E[3] basecase is imported into the energy model to appropriately capture the properties and limitations of transmission elements. Specifically, using the imported PSS/E basecase, the thermal ratings of individual lines and transformers and other electrical parameters (such as resistance and reactance) are modelled. Furthermore, transmission upgrades expected over the assessment horizon are incorporated into the energy model with their respective planned in-service dates. The network model is updated periodically as required.

An optimal power flow (OPF) is performed on an hourly granularity as part of the energy simulation with the resultant dispatch subject to the operating security limits (OSL) of the network as well as the physical and operational limits of resources.

Key assumptions incorporated into the development of the transmission model are:

- Thermal limits of all transmission elements operated at 50 kV level and higher are utilized;
- Planned transmission outages are modelled based on Market Participant submitted information. Only outages for lines at a voltage level of 115 kV and higher and with duration five days or longer are considered;
- Operating security limits[4] of all major internal interfaces are explicitly modelled. Appropriate reductions to OSLs of major interface brought about by specific transmission outage are captured;
- Interconnection transfer capability between Ontario and neighbouring jurisdictions is assumed to be zero except when firm purchases and sales are modelled or when the benefits of non-firm transfers are being assessed;
- Transmission losses are not explicitly modelled, as losses are already accounted for in the demand forecast; and
- Unplanned outages of transmission element are not modelled.

In assessments where a zonal representation of Ontario's transmission system is used, the transmission network is modelled as shown in Figure 4.1 with all resources within a zone connected to a single node within that zone. Interface limits between zones are also modelled and these limits are adjusted as required to account for the impacts of planned outages on the transmission network or future system upgrades within the assessment period.

3.4.5 Forecast of Energy Production Capability

In addition to the energy modelling results, the forecast energy production capability of Ontario generators is calculated on a month-by-month basis for 18-Month Outlooks. Monthly energy production capabilities for the Ontario generators are either provided by market participants or calculated by the

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[3] Power System Simulator for Engineering (PSS/E) is a software tool used for simulating, analyzing, and optimizing power system performance.

[4] Operating security limit are used to ensure system stability, acceptable pre-contingency and post contingency voltage levels and acceptable thermal loading levels.

IESO. They account for fuel supply limitations, scheduled and forced outages and deratings, and environmental and regulatory restrictions.

3.5 Resource Adequacy Risks

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

3.5.1 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. While the probability of this occurring in every week is very small, 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 non-firm imports, rejection of planned generator maintenance or emergency actions may be required.

3.5.2 New Facilities

The risk of new facilities having a delayed connection to the system is accounted for in the 18-Month Outlook by considering two resource scenarios: a Firm Scenario and a Planned Scenario.

The Firm Scenario considers the existing installed resources, their status change such as retirements and shutdowns over the Outlook period and resources that reached commercial operation. On top of this, the Planned Scenario assumes that all new resources are available as scheduled.

3.5.3 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 has transitioned 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.

3.5.4 Lower than Forecast Generator Availability

IESO resource adequacy assessments include a probabilistic allowance for random generator forced outages of thermal generators. Along with weather-related demand uncertainty, the impact of random generator forced outages is included in the determination of required resources.

3.5.5 Lower than Forecast Hydroelectric Resources

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 2012. As such, in the extreme weather scenario of the 18-Month Outlook, the hydroelectric conditions are based on the median production at peak in the summer of 2012.

3.5.6 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 forecast values.

3.5.7 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.

3.5.8 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 modelled 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 baseload generation sources may have to be decreased during times when transmission constraints and tight supply conditions prevail.

- End of Section –

4.0 Transmission Adequacy Assessment

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's outage management system. 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. These outages are then sorted and grouped into tables, one table for each zone and one table for external interties. The following items are listed for each outage, with the first three items having been provided by transmitters:

- Start and finish dates;
- Outage transmission station element or elements;
- Recall time;
- Description of outage impact to IESO-controlled grid; and
- Reduction in the interconnection flow limits and/or major interface base limits (expressed in Megawatts).

The last two items are only provided if the outage affects an interconnection and/or major interface.

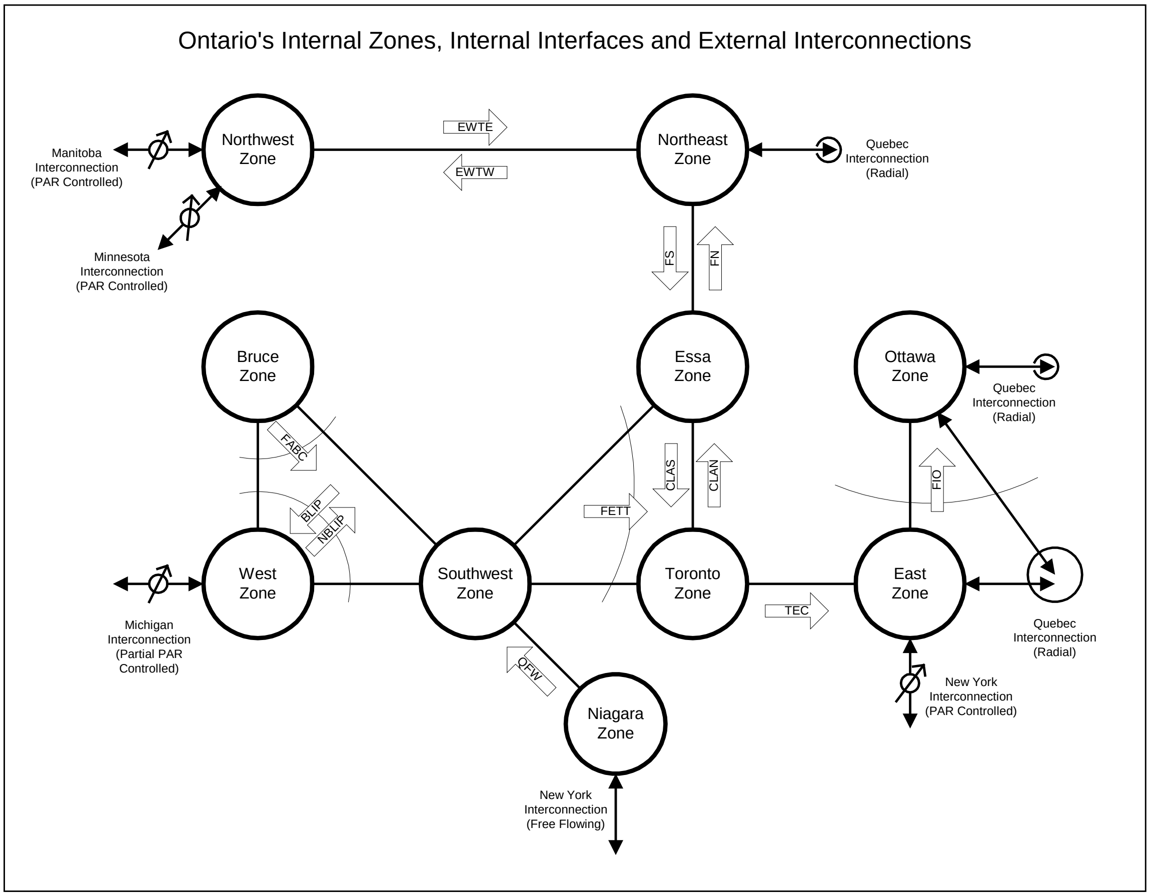
The planned transmission outages are reviewed in correlation with major planned resource outages and scheduled completion dates of new generation and transmission projects. This allows the IESO to identify transmission system reliability concerns and to highlight those outage plans that need to be adjusted. 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.

Figure 4.1 provides a pictorial representation of Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions.

Figure 4.1 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. The IESO's planning group identifies the transmission enhancements' location, timing and requirements to satisfy reliability standards.

4.2 Assessment Methodology 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 modelled in the Outlook studies are shown in Figure 4.1. 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 modelled 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.

4.2.2 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 Long Term Emergency (LTE) 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 Short Term Emergency ratings.

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.

4.2.3 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.

4.2.4 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.

4.2.5 Zone Assessments

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

4.2.6 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/Pages/Participate/Connection-Assessments/Application-Status. aspx

- End of Section –

5.0 Operability Assessments

5.1 Surplus Baseload Generation (SBG)

SBG occurs when the baseload generation is higher than the Ontario Demand plus net exports. SBG typically occurs during low demand periods. To calculate the SBG in the 18-Month Outlook, the minimum demand forecast is compared against the expected baseload generation level minus assumed net exports. The baseload generation assumptions are based on market participant-submitted minimum production data and historical minimum production observed by the IESO, planned outage information and in-service dates for new or refurbished generation. All generators expected to come into service over the outlook period are considered in the calculation.

The expected baseload generation includes nuclear generation, baseload hydroelectric generation, wind generation and self-scheduling and intermittent generation. Solar generation is not included in this SBG assessment, as this assessment describes periods with the largest magnitude of SBG. These periods typically occur overnight, when there is no output from solar generation.

Nuclear Generation Capability

Nuclear generation capability is calculated by adding the MCR for all nuclear units, decrementing any planned outages or deratings.

In order to reflect the floor prices for flexible nuclear generation, the SBG assessment includes the expected available nuclear curtailment. This value shows the sum of flexible nuclear capacity, decrementing any planned outages or deratings. The flexible nuclear capacity is capped due to environmental limitations. An extra seasonal buffer is added to the available nuclear curtailment. This buffer amounts to one flexible nuclear unit unavailable in the winter and two units unavailable in the summer.

Baseload Hydroelectric Generation

Baseload hydroelectric generation is based on the bottom 25th percentile of historical production during hours ending one through five for each month.

Wind Generation

Monthly Off-Peak Wind Capacity Contribution (WCC) values are used to forecast the contribution from existing and planned wind generators. Off-Peak WCC values in percentage of installed capacity are determined by calculating the historic median contribution during hours ending one through five for each winter and summer season, or shoulder period month.

Because the IESO can dispatch wind generation, the SBG assessment also includes the available wind curtailment. The value used in the 18-Month Outlook is 90% of the wind generation described above. This corresponds to the first set of floor prices for wind generation.

Self-Scheduling and Intermittent Generation

Monthly off-peak self-scheduling contribution values are used to forecast the contribution from self-scheduling generation. These values are determined by historical output from self-scheduling generators during weekend off-peak hours for each month. This contribution value is multiplied by the generation capability of self-scheduling generators (the total MCR for all generators decrementing planned outages or deratings).

Expected intermittent generation is the sum of the MCR for all intermittent generators decrementing any planned outages or deratings.

Assumed Net Exports

Assumed net exports are based on historical net exports during hours ending 1 through 5 over a rolling 12-month time frame. Assumed net exports are calculated with a monthly granularity and updated quarterly.

Forecast Minimum Demands

Minimum demand levels are forecast as described in section 2.1 using the Normal weather scenario.

- End of Document -

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