Methodology to Perform the Reliability Outlook

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1. 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 IESO Reliability Outlook. Over time, the methodology may change to reflect the most appropriate approach to complete the Outlook process

2. 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.

The demand forecasting methodology described in this section is applicable across the entire timeframe of the Outlook (i.e. it is the same for both the first 18 month period and the 42 month period).

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 fueled 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	Weekly Normalization Period	Monthly Normalization Period
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 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.

3. Resource Adequacy Risks

In the first 18 month horizon, the Outlook considers two scenarios, Firm and Planned, whereas the next 42 month horizon considers two scenarios: Planned and Delayed. The forecast reserve levels for the scenarios should be assessed bearing in mind the risks discussed below.

3.1 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 first 18 month, reserves were re calculated assuming extreme weather in each week in place of normal (median) 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.

3.2 New Facilities

The risk of new facilities having a delayed connection to the system is accounted for in the 18 month horizon 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. The capacity assumed for new resources is the greater of the contracted capacity, or where facilities have begun the market registration process, the capacity submitted to the IESO as part of their registration.

The risk of new facilities having a delayed connection to the system is accounted for in the 42 month horizon by considering two resource scenarios: a Planned Scenario and a Delayed Scenario. In the delayed scenario, it is expected that all resources will eventually come to service but are delayed by six months.

3.3 End of Life of Generation Facilities

Generation retirement risks are accounted for in the 18 month horizon in the two resource scenarios. In the Firm Scenario, all resources are removed at end of their contract term. Resources that forecast (via their Form 1230 submission) continued operations are included in the Planned Scenario.

In the 42 month horizon, only resources that have a publically confirmed retirement date are removed from the assessment in both scenarios.

3.4 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.

Information from the 18-Month Outlook report directly feeds into the IESO's Outage Management process. Outages are assessed against the firm resource, extreme weather conditions from a resource adequacy standpoint. Up to 2,000MW of import capability may be relied upon in extreme weather conditions, and therefore outages on resources (both transmission and generation) that affect resource availability beyond -2,000MW of Reserve Above Requirement (RAR) are at risk of being rejected, revoked or recalled. Events that reduce Ontario's ability to import power such as outages on interties, internal system constraints, and conditions of neighbouring jurisdictions will be considered, and the import assumption is adjusted accordingly between zero and two thousand megawatts.

3.5 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.

3.6 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.

3.7 Wind and Solar Resource Risks

The Outlook assumes monthly Wind Capacity Contribution Solar Capacity Contribution values to forecast the capacity contribution from wind and solar generators, respectively. There is a risk that wind power output could be less than the forecast values.

3.8 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.

3.9 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 IESO Reliability 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.

4. Capacity Adequacy Assessment

This section describes the criteria, tools and methodology the IESO uses to perform resource adequacy assessments. In Section 4.1, the resource adequacy criterion is described. Section 4.2 describes the Load and Capacity (L&C) software tool used in the resource adequacy assessment process. Section 4.5 presents the inputs used in the capacity adequacy assessment.

4.1 Resource Adequacy Criterion

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 (Requirement 4 in Directory #1) states:

> R4: 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.
>
> R4.1 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.

4.2 Load and Capacity Model

The IESO uses the Load and Capacity (L&C) model to evaluate the resource adequacy for each week in the study period consistent with the NPCC resource adequacy criterion.

Figure 4-1 describes, visually, the interaction between the inputs into and outputs from L&C. The Total Resources, shown in the far left, are values used for reporting purposes and are not part of the analysis. This indicates the total resources in Ontario, without prejudice to their availability or capability to serve Ontario's load. The Available Resources, shown in the centre, are the inputs relating to generation or demand measures that can be expected to serve Ontario's load. The assumptions used to develop these inputs are described in Section 4.5. At a high level, the key inputs to determine Available Resources are:

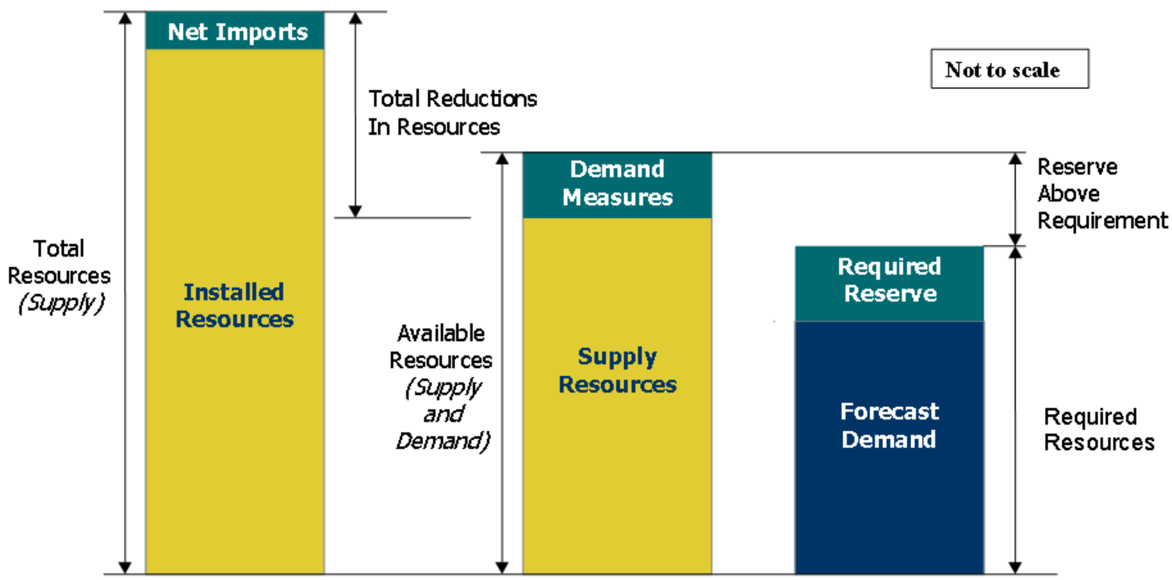
- Thermal generating units' net maximum continuous rating (MCR),
- Thermal generating units' planned outages and deratings,
- Forecast hydroelectric generation output
- Wind capacity contribution (WCC) values
- Solar capacity contribution (SCC) values for, and

- The forecast demand, whose methodology was described in Section 2.

The output of the L&C model is the required reserve (described in Section 4.4) to ensure that the resource adequacy criterion is met. The inputs that are used to determine the probabilistic required reserve are:

- Demand forecast and its uncertainty and
- Thermal generating units' forced outage rates on demand.

Figure 4-1 | Summary of Inputs and Outputs of L&C



4.3 Data Reported in the Reliability Outlook

The following section describes data that is reported in the Reliability Outlook but is not used in the L&C tool to determine required reserve.

4.3.1 Installed Resources/Total Internal Resources

The Installed Resources (also called Total Internal Resources) is not used in the L&C tool, but rather is a value used to report the total installed capacity of resources connected to and participating in the IESO Administered Energy Market. It is made up of two components; the first is the existing supply (generation) resources, which are presented in Table 4.1. For the existing supply, only resources that have completed the final milestone in the Market Registration timeline are included as existing resources. The capacities of these resources (referred to here as *Installed Capacity* of each resource) are determined by referring to two sources of data:

- Data provided by Market Participants via Online IESO, as part of the Market Registration process: the *Maximum Active Power Capability* (the maximum active power capability under any conditions without station service being supplied by the unit. This value will be used to calculate the energy resource's maximum offer capability), is retrieved from the IESO's Customer Data Management System for all facilities that have completed Market Registration.

- For some resources, there may be additional restrictions on their maximum capability, as determined during commissioning. In these cases, the IESO may further reduce their *Installed Capacity* using information provided in their Commissioning report.

To estimate future Installed Resources on a weekly basis (as shown in Table A1 of the IESO Reliability Outlook), expected changes shown in Table 4-1 as Firm Capacity are added or subtracted from the existing supply in the 18 month horizon or Table 7-7 in the 42 month horizon.

4.3.2 Total Resources

The Total Resources are the summation of the *Installed Resources* and the *Firm Net Imports*.

4.3.3 Total Reductions in Resources

Where any tables in the IESO Reliability Outlook reference *Reductions to Total Resources*, these reductions are relative to the Total Resources described above. Reductions are made up of differences between the *Total Resources* and the:

- Available Capacity of Thermal Resources;
- Forecast Hydroelectric Generation Output;
- Capacity Ratings for Wind Resources;
- Capacity Ratings for Solar Resources;
- Available Demand Measures; and
- Transmission Limitations.

4.4 Outputs of the Resource Adequacy Assessment

4.4.1 Required Reserve

Reserves are required to ensure that the forecast Ontario Demand can be supplied with a sufficiently high level of reliability. The Required Resources is the amount of resources needed to supply the Ontario Demand and meet the Required Reserve as shown in Figure 4-1. The Reserve Above Requirement is the difference between Available Resources and Required Resources.

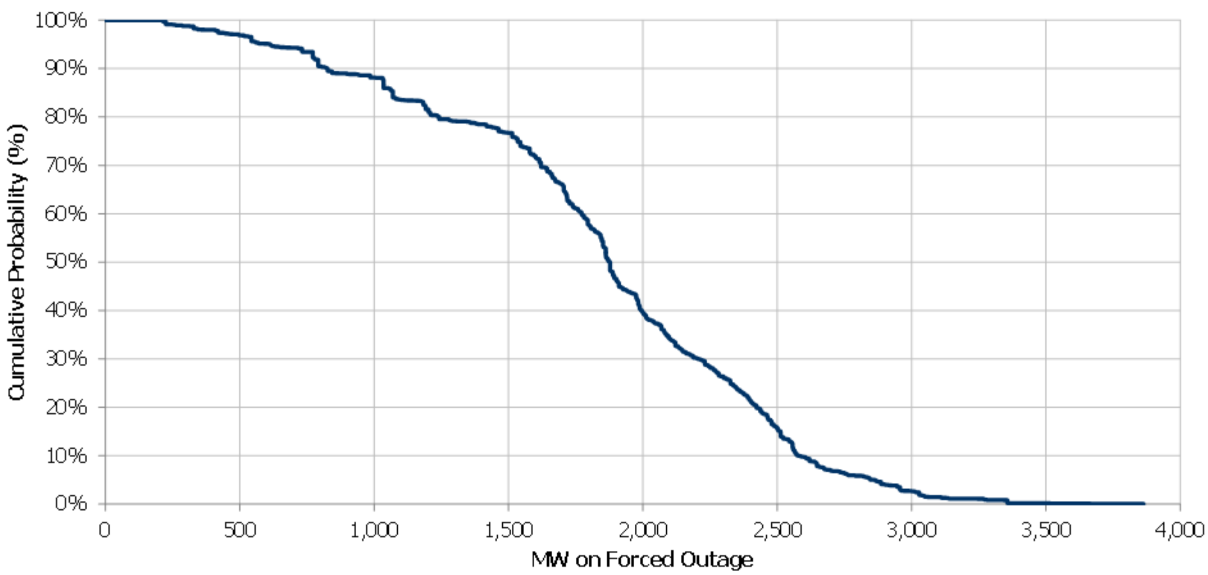
The Required Reserve is a planning parameter that, depending on the type of assessment, takes into account the uncertainty associated with demand forecasts or generator forced outages in a probabilistic or deterministic approach. The output of L&C is the amount of Required Reserve, in MW and as a percentage of forecast demand, for each week in the study period.

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. These two reserve requirements are described in this section.

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 probabilistic reserve requirement consider two inputs in a probabilistic manner: demand uncertainty and forced outages and deratings of thermal units. The inputs for these are described in Section 4.4. The available capacity 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 4-2.

Figure 4-2 | 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 4.1.5. 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.

4.4.2 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 4-1. 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.

4.5 Inputs to the Resource Adequacy Assessment

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*.

4.5.1 Weekly Available Capacity for Thermal Generating Resources

The maximum capability for most thermal generating resources, such as nuclear, biofuel and gas fired generators, is affected by external factors, such as ambient temperature and humidity or cooling water temperature. To capture those variables, the *Maximum Continuous Rating* (or "MCR") for each thermal generator is modelled on a monthly basis.

Nuclear generators and the like whose MCR is not ambient temperature sensitive provide monthly gross MCR and their station service load in their annual Form 1230 submission and this MCR is entered as a direct input in the L&C tool.

Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide, through their annual Form 1230 submission, 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.

If an existing generator is expected to shut down during the study timeframe, then the MCR is set to 0 MW beginning the week it is expected to expire. For example, for NUG whose contract expires during the Outlook period, its installed capacity and its rating are both set to zero beginning in the week of its contract expiry in the firm scenario.

Planned outages and deratings, as well as any forced outages that extend into the horizon of the 18 Month Outlook, are extracted from the IESO's outage management system. An outage profile for all thermal generators is calculated as an input into L&C using two steps:

1. Determine the *maximum outage day* (MOD) in each planning week. This is the day with the maximum amount of unavailable generating capacity in that week.
2. For the MOD selected, sum up the outages that occur during the daily peak window (currently hour ending 15 to 22). This is the window where the weekly peak demand is expected to occur. This ensures that outages covering the overnight off-peak hours do not affect the generation unavailability total of the MOD and consequently do not affect the *Reserve Above Requirement*.

Although the weekly peak does not always occur on the maximum outage day, such coincidence is assumed for the determination of Available Resources.

4.5.2 Forecast Hydroelectric Generation Output

The forecast hydroelectric generation output is calculated using median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours to create a dataset of historic production. The details for developing the generation output forecast are described in this subsection.

First, data of historical hydro production at the time of every non-holiday weekday are collected. For every non-holiday weekday since market open, the IESO selects the one individual hour that the daily peak demand occurred. The selection of the weekday peak demand hour may differ from day-to-day in the same month and can vary for the same month in different years as the demand profile changes from year-to-year. Once the daily peak is selected, the following pieces of data coincident to the peak are extracted:

- Hydro production (Allocated Quantity of Energy Injected or AQEI)
- Scheduled operating reserve in the constrained schedule
- Installed capacity
- Effects of historical outages on capability across the fleet

Since a large number of Ontario's hydroelectric generators are not run of river, this method assumes that regardless of what hour the peak may occur, the hydroelectric fleet would be scheduled in a manner that allows its output to peak coincident to when the Ontario demand peaks.

This new data set is then used to determine, on a monthly basis, the hydroelectric generation output forecast, which is shown in Table 4.3 of the Reliability Outlook. The "*Historical Hydroelectric Median Contribution*" is determined by:

1. For each hour in the data set, summing the hydro production and scheduled OR together ("generation output")
2. Grouping the generation output by month
3. Normalizing the generation output by the installed capacity of hydro generation. This normalization converts the generation output into a ratio of generation output to installed capacity.
4. Calculating the median for each month.
5. Multiplying each monthly capacity factor by the current hydroelectric Installed Capacity (all units currently in-service).

This calculation includes the impacts of hydroelectric outages. The expected capability of individual hydroelectric resources that were on planned outage and not injecting into the IESO grid is then estimated and added back into the historic production data. This allows the IESO to estimate the capability of the hydroelectric fleet if there were no outages. The following steps are used to "add back" the impacts of outages from the historic data. The end result of this calculation is presented in the Reliability Outlook as "*Historical Hydroelectric Median Contribution without Outages.*"

1. For each hour since market open, the IESO retrieves the hydro capacity that was on a planned outage. This creates an hourly profile of the capacity unavailable due to outages, but it overestimates the impact, as not all of a generator would have been available as fuel limitations impact hydro output. Because of this, the hourly unavailable capacity as a result of planned

outage is multiplied by a capacity factor that changes by month and zone. This capacity factor is calculated from historical norms. This creates an effective loss of capability due planned outages.

2. The amount of effective hydroelectric capability loss during the historical daily peak hour is added back to the historical contribution. This final value is the hydroelectric capability estimate assuming all units in-service. This is done so that we may discount hydroelectric capability by the effects of future planned outages over the planning timeframe. This step is necessary to ensure we are able to assess hydroelectric outages and its impact on resource adequacy.

The *Forecast Hydroelectric Generation Output*, which is ultimately input into L&C, takes into account the impacts of planned outages and deratings on a weekly basis. The IESO performs the following steps to create this estimate:

1. Planned outages and deratings that extend into the horizon of the outlook are extracted from the outage management system. The outages considered are only those that occur on the Maximum Outage Day of the week within the daily peak period.
2. The total reduction in the outage management system for each hydroelectric outage/derate is multiplied by a zonal capacity factor for the full duration of the outage. This capacity factor, which varies by month and zone, is derived from historical analysis of hydro. This is deemed the loss of capacity due to outages,
3. The loss of capacity from each outage/derate is summed up to determine the total loss of capacity for each week.
4. The weekly loss of capacity is subtracted for each week from the Historical Hydroelectric Median Contribution without Outages. This new value is the Forecast Hydroelectric Generation Output.

A 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 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.

4.5.3 Capacity Ratings for Wind Generation

Monthly *Wind Capacity Contribution* (WCC) values are used to forecast the contribution from wind generators as a percentage of installed capacity. To calculate the WCC the IESO performs the following steps:

- Actual historic median wind generation contribution over the last ten years is compiled. If a wind facility was curtailed, the impacts of this foregone energy are added back to the production numbers, to estimate what the wind generator was capable of producing at the time. The foregone energy is estimated from the 5 minute ahead wind forecast for that wind facility.

- The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. The demand hours are calculated for the winter and summer season, or shoulder period month.
- The dataset in step one is filtered for just the top 5 contiguous demand hours.
- The wind contribution across Ontario coincident to the demand hours previously estimated is summed together.
- The wind contribution each hour is normalized against the installed capacity of wind at the time of production.
- The median is then selected for each winter and summer season, or shoulder period month. For example, the wind generation contribution for summer is made the median generation contribution in the demand hours for June, July and August combined.
- For each week in the Reliability Outlook, the WCC is multiplied against the expected wind installed resources (this includes both existing and future wind generators).

4.5.4 Capacity Ratings for Solar Generation

Monthly *Solar Capacity Contribution* (SCC) values are used to forecast the contribution from solar generators as a percentage of installed capacity. 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.

The SCC is calculated by performing the following steps:

1. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. The demand hours are calculated for the winter and summer season, or shoulder period month. These hours are the same as those used for the WCC.
2. The IESO uses a dataset comprising ten years of simulated solar production history. This dataset is filtered for just the top 5 contiguous demand hours.
3. The dataset is further filtered to include only the data that represent solar output at a simulated site closest to where solar generation farms are actually installed in Ontario.
4. The solar contribution across Ontario coincident to the demand hours previously estimated is summed together. The summation is normalized against the installed capacity of solar.
5. The median is then selected for each winter and summer season, or shoulder period month.
6. For each week in the Reliability Outlook, the SCC is multiplied against the expected solar installed resources (this includes both existing and future wind generators).

4.5.5 Available Demand Measures

It is important to distinguish between demand measures and load modifiers. Demand measures include dispatchable loads and capacity secured through the Demand Response Auction. Demand measures are treated as a resource. Load modifiers include embedded generation output, Time of Use Rates and the Industrial Conservation Initiative (ICI). These are incorporated into the demand forecast.

The available capacity of dispatchable loads is based on historical offers into the market. For most weeks, the average bid at weekday peak in the last twelve months is used as the available capacity. For weeks that are likely the annual peak, the IESO determines the available capacity from the offers during the top 5 demand hours of the past year. This ensures that the impacts of the ICI program are not double counted, as many dispatchable loads also participate in ICI.

The capacity secured through the DR auction is discounted to 90% of what was procured for the obligation period to account for the fact that participants may not always be available.

4.5.6 Net Imports

The purpose of the IESO Reliability Outlook is to determine a required reserve for Ontario to be self-sufficient. Therefore, the only imports or exports considered are those backed by firm contracts. Where a contract exists, the capacity associated with it is calculated for each week of its stated deliverability period. The Net Imports are the Firm Imports less any Firm Exports. For example, if there are no Firm Imports in a given week but there is a Firm Export, then the Net Imports will be a negative number.

4.5.7 Transmission Limitations

The available capacity of thermal, hydroelectric, wind and solar resources may be subject to further reductions due to limitations 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. This becomes the final value used in calculating the Reserve Above Requirement.

4.5.8 Forced Outage Rates on Demand of Generating Units Used to Determine the Probabilistic Reserve Requirement

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[1]. EFOR data supplied by market participants will continue to be used for comparison purposes. EFORd impacts Required Reserve and does not impact the Total Reductions in Resources.

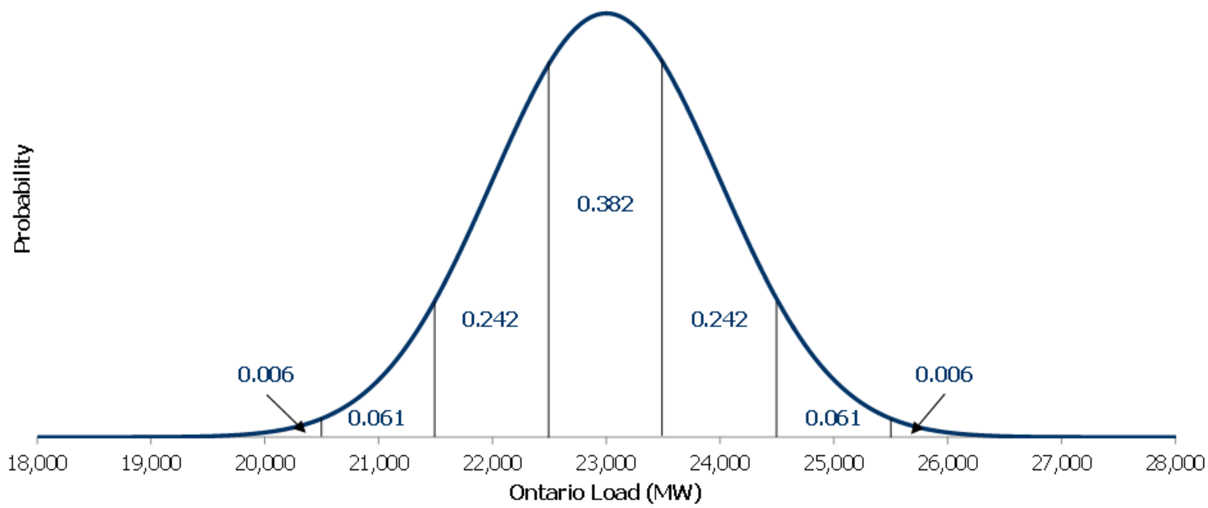
4.5.9 Demand Uncertainty Due to Weather to Determine the Probabilistic Reserve Requirement

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 4.3 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 4-3 under the curve).

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

Figure 4-3 | Seven-Step Approximation of Normal Distribution – Example



5. Additional Considerations in the 42 Month Horizon

The approach used for completing the capacity adequacy assessment in months 19 through 60 ("42 month horizon") is similar to the approach used for assessing the first 18 months of the outlook. The L&C tool and reserve requirement assessment are identical, including the EFORd and representation of load forecast uncertainty. The section below describes the different assumptions that are used in the 42 month horizon in the determination of installed resources, and therefore, Available Resources.

Treatment of New Resources

In the 42 month horizon, the capacity of new planned generator resources is assumed to be equal to their contracted capacity (whereas in the 18 month horizon, some facilities have begun the market registration process and may submit information to the IESO that indicates a higher capacity).

The in service dates for new generator resources are also treated differently in the 42 month horizon. In the planned scenario, just like in the first 18 months, all resources are anticipated to come into service on time. The delay scenario is intended to address project risks that are possible in the 42 month horizon, similar to how the firm scenario in the first 18 months addresses project risks for generation projects. The delay scenario groups several project risks together by delaying:

- new generation schedules by six months
- the completion date of nuclear refurbishment outages by twelve months; and
- new transmission equipment by one year.

Extraction of Planned Outages

In the 42 month horizon, not all outages have been submitted to the outage management system. To recognize the uncertainty in outage plans, two outage profiles are developed. The first, called the "All Scheduled Outages", are only outages submitted in the outage management system. This is no different than the outages that are extracted in the 18 Month horizon. A second scenario, called the "All Anticipated Outages" adds in additional outages that have been disclosed to the IESO in the annual Form 1230 submissions.

Treatment of Resources at End of Contract Term

Only resources that have a publically confirmed retirement date are removed from the assessment in all scenarios. For resources that reach contract expiry, these are assumed to continue.

Inputs that are Treated the Same in Both Time Frames

The inputs below are treated the same in both time frames:

- *Demand Forecast:* Uses the same methodology and tools to develop the demand forecast. Efforts are made to ensure annual peaks and energy under normal weather align with other IESO produced outlooks, including those developed for longer term planning.

- *Demand Uncertainty:* The same demand uncertainty is used across both time frames
- *Installed Resources:* The existing installed resources, the starting point of all supply side calculations, are the same for both scenarios. Changes differ only in the treatment of new resources or in treatment of resources at end of contract term, as previously discussed.
- *Generator Planned Outages*: The planned generator outage schedule in the 18 month time frame is queried from the IESO's outage management system. Similarly, the All Scheduled Outages scenario also includes planned generator outages, queried at the same time, from IESO's outage management system.
- *Forced Outage Rates on Demand for Generators:* The same forced outage rates are used across both time frames.
- *Forecast Hydro Production:* The same techniques are used to forecast hydro production across both time frames
- *Wind and Solar Capacity Contributions*: The same contributions are made across both time frames. No consideration is given to changing contributions due to changing time of peak demand nor increased penetration of wind or solar generation.

6. 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.

6.1 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; 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.

6.1.1 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.

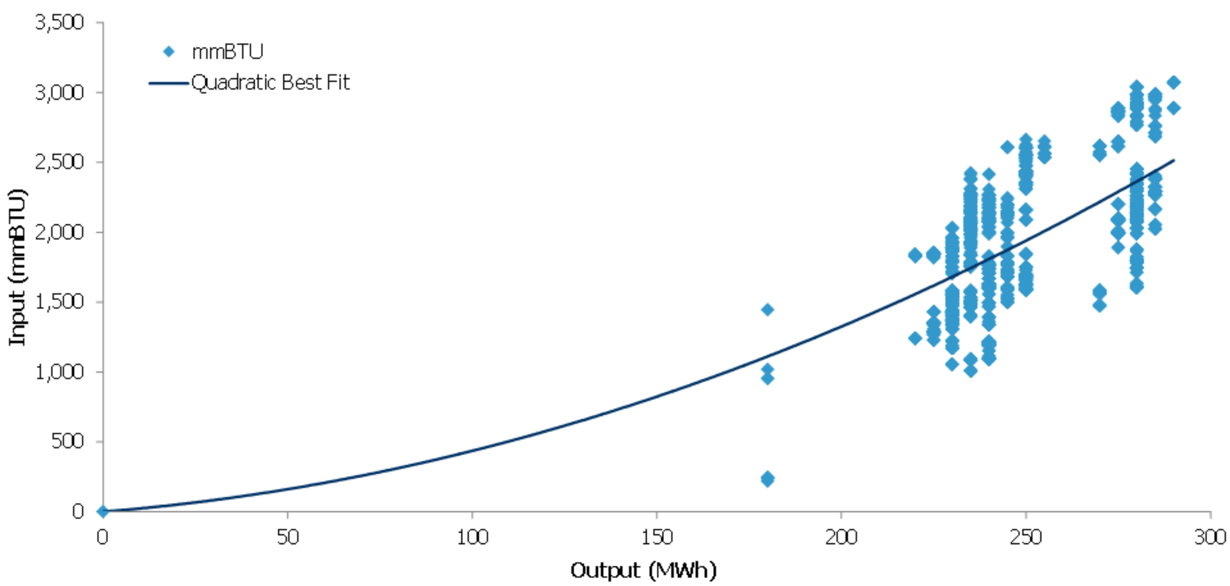
6.1.2 Combustion and Steam Units

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 or PQ pairs derived from historical offer data. Capacity properties establish the bounds of the dispatch whereas the heat rate equations or PQ pairs 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.

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 6-1 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 6-1 | Quadratic Best Fit I-O Equation for a Particular Combustion Generator



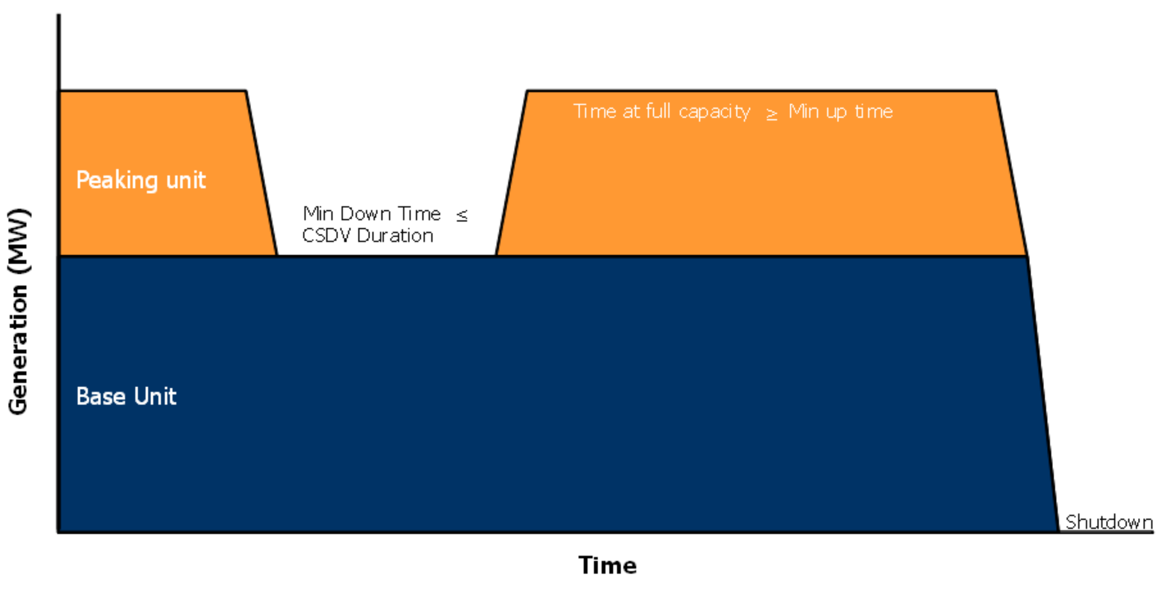
Non-dispatchable generators are modelled using a unit rating based on market participant submitted data.

6.1.3 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 6-2 for an illustration on how the base and peaking units interact.

Figure 6-2 | Nuclear Manoeuvering Unit Dispatch Illustration



6.1.4 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.

6.1.5 Hydroelectric

Hydroelectric generators are modelled as energy-limited resources, since the hydroelectric production is limited by the amount of water available, and through the use of Price-Quantity (P-Q) pairs derived from historical market offer datasets. 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.

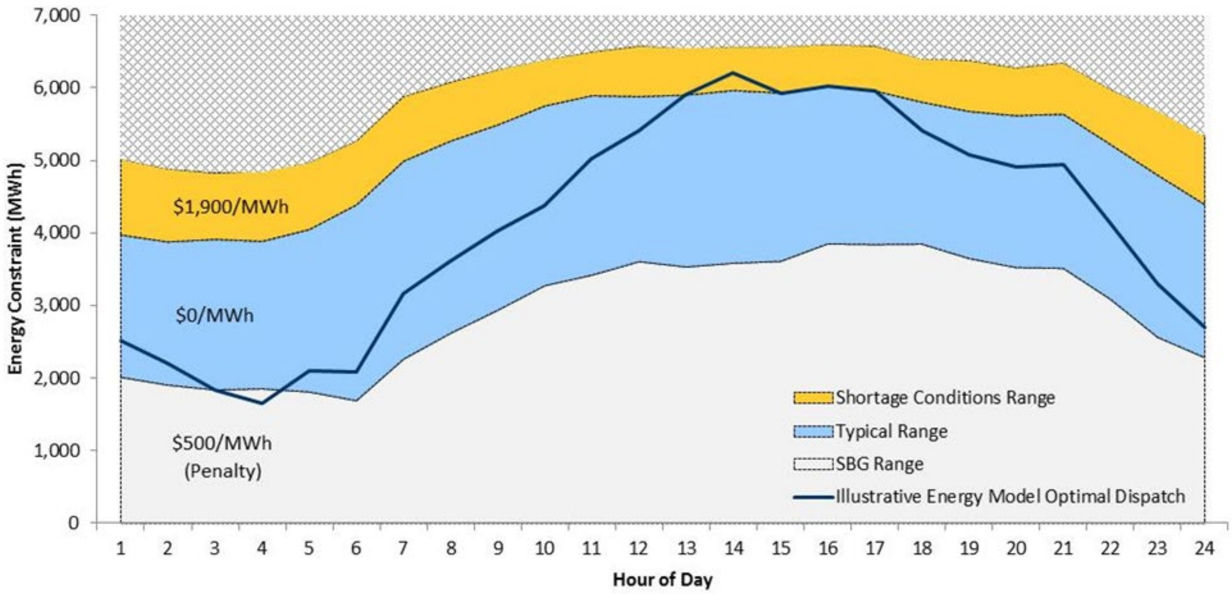
The hydroelectric run-of-the-river component for baseload units is must-run to ensure the energy model schedules this element. The dispatchable component of each unit is dispatched based on system needs and hydroelectric zonal or regional constraints.

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 6-3 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 6-3, 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 6-3 | Hydroelectric Solution for a Particular Weekday vs. Hourly and Daily Energy Constraints



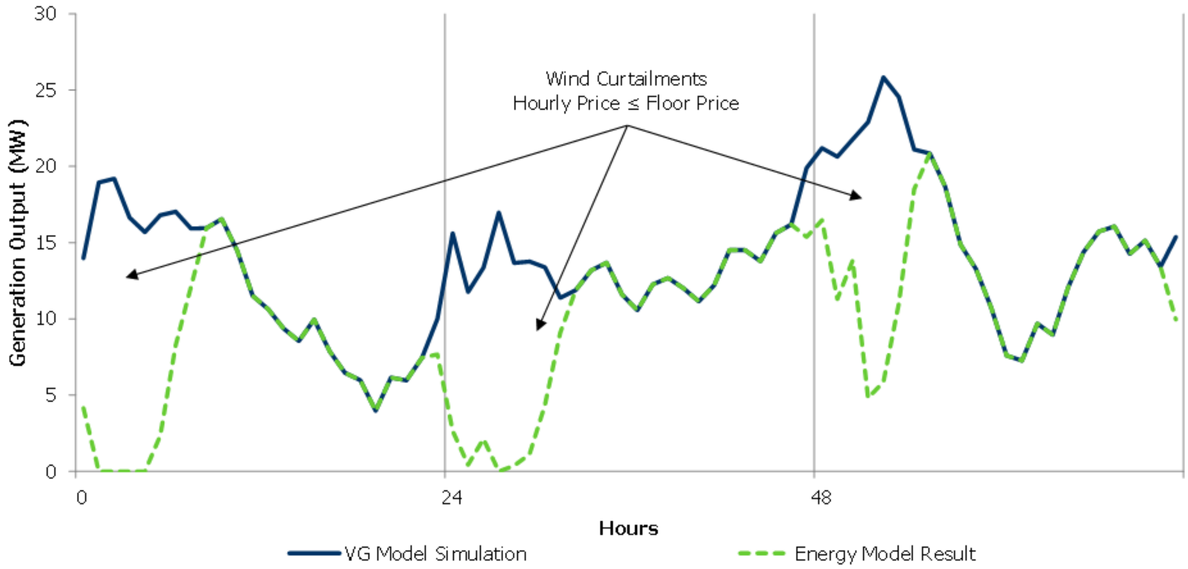
6.1.6 Wind

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 6-4 for an illustrative example.

Figure 6-4 | Wind Simulation versus Energy Model Dispatch for a Particular Unit



6.1.7 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.

6.1.8 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 and dispatchable loads. This additional information is used by the simulation software to "activate" these resources as required in a manner approximating program rules.

6.1.9 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.

6.1.10 EAA Network Model

In assessments where a detailed nodal representation of Ontario's transmission system is required, a PSS/E[2] 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 a duration of five days and longer are considered;
- Operating security limits[3] 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 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.

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

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

6.1.11 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 IESO Reliability Outlook. Monthly energy production capabilities for the Ontario generators are either provided by market participants or calculated by the IESO. They account for fuel supply limitations, scheduled and forced outages and deratings, and environmental or regulatory restrictions.

7. Transmission Adequacy Assessment

For the IESO Reliability 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 assessment 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 IESO Reliability 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 outage 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 period under study is extracted from the IESO's outage management system.

Ultimately, the focus of the transmission adequacy assessment for the IESO Reliability Outlook is to determine any reductions in transmission interface or interconnection capacity due to outages, and determine the impact of those reductions on reliability.

This chapter describes the methodology used to assess the transmission outage plan. The zones, interfaces and interconnections are described in the Transfer Capability Methodology document.

7.1 Assessment Methodology for the 18-Month Period

7.1.1 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 of five days and longer. 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. More information on Ontario's ten zones, major transmission interfaces and interconnections with neighbouring jurisdictions are available in the Transfer Capability Assessment Methodology document.

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 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.

7.2 Assessment Methodology for 42 month horizon

Transmission Adequacy is assessed within the 42-month horizon based on the ability of the IESO's major internal transmission interfaces and interconnections to transport bulk quantities of power to and from the 10 IESO Transmission Zones and neighbouring jurisdictions.

In order to conduct this Transmission Adequacy assessment, the IESO employs the "Transfer Capability Assessment Methodology". This methodology assesses the Transfer Capability of the IESO-Controlled Grid's major internal interfaces and interconnections with respect to the North American Electric Corporation Standard Requirements for determining the Transfer Capability within the near-term transmission planning horizon (i.e. up to 5-years out).

The Transfer Capability Assessment considers the generation and transmission outages that have been submitted within the 42-month horizon, as well as anticipated transmission expansion projects that are expected to come into service within the 42-month horizon. The resulting Transfer Capabilities for the major internal transmission interfaces and interconnections serve as inputs to the 42-month horizon Resource Adequacy Assessment to determine if generated energy may be bottled in over-generated zones such that it is unable to supply under-generated zones.

It should be noted that the Transmission Adequacy assessment employed for the 42-month horizon utilizes Transmission Planning Criteria, and the resulting Transfer Capabilities are therefore not the same as System operating limits which are determined based on Operating Standards and Policies.

8. Operability Assessments

8.1 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 IESO Reliability 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.

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