IESO 2014 Interim Review of Resource Adequacy

Covering the Ontario Area for the period 2015 to 2017

Approved by the RCC
December 2, 2014

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Document Change History

Issue	Reason for Issue	Date
1.0	Released for CP-8 review	October 30, 2014
2.0	Released for TFCP review	November 12, 2014
3.0	Released for RCC approval	November 24, 2014

1 EXECUTIVE SUMMARY

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). This 2014 Interim Review of Resource Adequacy (Interim Review) covers the study period from 2015 through 2017, and highlights changes since the 2012 Comprehensive Review of Resource Adequacy (Comprehensive Review).

The IESO determines Ontario's level of reliability using the General Electric Multi-Area Reliability Simulation (GE-MARS) program that is capable of performing probabilistic resource adequacy assessments.

This Interim Review identifies changes in assumptions from the 2012 Comprehensive Review, including changes to facilities and system conditions, generation resources' availability, load forecast, and the impact of these changes on the overall reliability of the Ontario electricity system. The report also presents a comparison with the 2012 Comprehensive Review.

This 2014 Interim Review concludes that Ontario will be able to meet the NPCC resource adequacy criterion that limits the loss of load expectation (LOLE) to no more than 0.1 days/year for all years within the study period (2015 to 2017).

Under median demand growth, for 2015 forecast year, both Emergency Operating Procedures (EOPs) and tie-benefits are utilized in addition to existing and planned resources to meet the NPCC criterion. For 2016 and 2017 forecast years, existing and planned resources are sufficient to satisfy the NPCC criterion.

Under the high demand growth scenario, for 2015 forecast year, both EOPs and tie-benefits are utilized in addition to existing and planned resources to meet the NPCC criterion. For 2016 and 2017 forecast years, the NPCC criterion is satisfied using EOPs in addition to existing and planned resources.

2 INTRODUCTION

The information presented in this 2014 Interim Review of resource adequacy covers the forecast period from 2015 through 2017.

The previous Comprehensive Review was submitted at the November 2012 meeting of the Reliability Coordinating Committee (RCC). Comparisons between this Interim Review and the IESO's 2012 Comprehensive Review are included in this report.

The guidelines for the review are specified in Appendix D of the NPCC Regional Reliability Reference Directory #1, Guidelines for Area Review of Resource Adequacy (Original document: December 1, 2009).

3 ASSUMPTION CHANGES

3.1 Demand Forecast

Tables 3.1 and 3.2 show a comparison between the peak demand forecasts for the 2012 Comprehensive Review and the 2014 Interim Review under median and high demand growth scenarios respectively.

The 2014 median growth peak demand forecast is similar to the 2012 forecast, but with slightly lower peaks over the forecast horizon. The 2014 forecast is based on the most recent inputs; updated economic and demographic projections, the most recent embedded generation figures and the inclusion of 2012 and 2013 actuals. The similarity between the most recent forecasts and the Comprehensive Review demonstrates that the underlying drivers and themes have remained fairly consistent.

Peak demands at the grid level continue to be shaped by a number of off-setting factors. Increase in demand as a result of modest economic and population growth is outstripped by demand reduction caused by conservation savings, inclusion of price responsive demand and increases in embedded generation. The overall impact will result in declining peaks over the forecast period.

Table 3.1 Demand Forecast Comparison – Median Demand Growth

Year	Normal Weather Annual Peak Median Demand Growth [MW]		
	2012 Comp. Review	2014 Interim Review	Difference
2015	22,859	22,726	-133
2016	22,640	22,535	-105
2017	22,471	22,344	-127
Growth Rate (%)	-0.6%	-0.6%	

The 2014 high demand growth scenario projects a much higher growth rate compared to the 2012 high demand growth forecast. Both forecasts end up with similar peaks in 2017 but have very different growth profiles getting there.

The current forecast is much lower in the near term as actuals for 2012 and 2013 have been incorporated into the forecast. The actuals for 2012 and 2013 were in line with the median demand growth forecast. Therefore, the high demand growth forecast is not consistent with that data and needed to be rebased starting in 2014. This approach changes the growth profile and accounts for the main differences between the two high demand growth scenarios.

Table 3.2 Demand Forecast Comparison – High Demand Growth

Year	Normal Weather Annual Peak High Demand Growth [MW]		
	2012 Comp. Review	2014 Interim Review	Difference
2015	24,395	22,953	-1,442
2016	24,614	23,436	-1,178
2017	23,980	23,953	-27
Growth Rate (%)	-0.57%	1.43%	

3.2 Resources Forecast

Table 3.3 compares the available capacity of supply resources at the time of the summer peaks for the current 2014 Interim Review with the 2012 Comprehensive Review. This 2014 review assumes resource availability based on the latest information regarding existing and planned resources. Resources considered in this review include all existing and planned resources.

Planned resources include all committed projects that have already been contracted by the Ontario Power Authority (OPA), along with the capacity to be contracted by the OPA, as directed by the Ontario Ministry of Energy, expected to be in service during the review period. Assumptions related to amounts and types of planned resources used in this review are provided by the OPA[1].

Available resources, effective capacity available at the time of summer peak, considered for 2014 Interim Review is provided in Appendix A.

Available resources at the time of summer peak, included in table 3.3, are determined based on the following:

1) historical median contribution of hydro resources during peak demand hours;
2) total capacity available from thermal units (nuclear, gas, oil and biomass) after discounting major nuclear refurbishment outages that extend over multiple years;
3) historical median contribution of wind resources during top 5 peak demand hours;
4) historical hourly median contribution of solar resources during peak demand hour; and
5) effective capacity of projected demand response (DR) resources.

Table 3.3 Comparison of Available Resources Forecasts

Year	Available Resources [MW] at Time of Summer Peak (July)		
	2012 Comp. Review	2014 Interim Review	Difference
2015	30,385	28,804	-1,580
2016	29,858	28,451	-1,407
2017	28,087	27,741	-346

The difference in available resources between 2012 Comprehensive Review and 2014 Interim Review is primarily a result of different planning assumptions used for demand response resources, as well as updated nuclear refurbishment schedule for 2017. The reasons for the differences are described in detail below.

- Approximately 350 MW of price responsive demand is now captured in the demand forecast as a load modifier rather than in the available resources forecast.
- In 2012 there were proposals to increase demand response programs. For 2015-2017, Ontario Long Term Energy Plan projects that the current level DR capacity will be maintained. This accounts for a difference in the projections of approximately 750 MW.

[1] The OPA is the provincial agency responsible for long term planning of the electricity system and for contracting electricity resources.

- A revised in-service date of one gas-fired generation project with a capacity of about 300 MW originally schedule for 2015 onwards. This project is assumed to be in service by January 2016 for this review.
- Removal of a government directed 245 MW CHP (combined heat and power) resource scheduled for January 2015, assumed in the 2012 Comprehensive Review.
- Only two nuclear units (one unit each at Bruce and Darlington GS) are expected to be on a refurbishment outage in summer 2017. However, in the 2012 Comprehensive Review, three nuclear units (two units at Bruce GS and one unit at Darlington GS)) were scheduled to undergo refurbishment outage in summer 2017.
- The remaining differences in resources are from small updates to hydroelectric, wind, solar and biomass resource contributions. In addition, project attrition and updates to in-service dates of future wind and solar resources also contributed to the difference.

3.3 Ontario Electricity Sector Changes

In fall of 2013, the provincial government released the updated Ontario LTEP specifying the target for large scale development of renewable energy projects, the nuclear refurbishment plan and plans for implementation of conservation. Some of the key targets that the 2013 LTEP specifies are:

- demand response is estimated to meet 10 percent of net peak demand by 2025, equivalent to approximately 2,400 MW under forecast conditions;
- conservation is expected to yield incremental peak savings of more than 3,000 MW by 2024;
- nuclear refurbishment is planned to begin at both Darlington and Bruce generating stations in 2016;
- hydroelectric generation target is increased to include 9,300 MW by 2025; and
- non-hydroelectric renewable resources target, which includes wind, solar and bioenergy resources, is set at 10,700 MW by 2021
- The Feed-in-Tariff (FIT) program is expected to result in a significant amount of renewable generation capacity to come online over the 2015-2017 timeframe. Wind and solar generation is expected to comprise the bulk of this new renewable capacity, with substantial amount expected to connect directly to the distribution system.

To complete its off-coal policy, in April 2014, Ontario retired its last operational coal unit. Thunder Bay GS is now expected to have one of its two coal units converted to biomass (142 MW) before summer of 2015. Earlier in the third quarter of 2014, Atikokan GS was converted to biomass (205 MW).

Effective January 1, 2015, as legislated by Ontario's provincial government, the IESO and the OPA will be merged into a single organization with an objective to increase efficiencies and contain costs between the two entities. The new organization - under the name IESO - will be responsible for both long-term planning and coordination of system operations to maintain electricity supply and demand balance.

3.4 Transfer Capabilities

In July 2014, the transfer limit of the interface between Northeast and Essa zones was increased from 1,550 MW to 2,100 MW. This expansion in the limit was a result of transmission reinforcements (voltage compensation) that were added to accommodate the new generation capacity connecting in the Northeast zone.

3.5 Emergency Operating Procedures

Emergency operating procedures (EOPs) are considered in the resource adequacy assessment if the existing and planned resources are not sufficient to meet the Loss of Load Expectation (LOLE) criterion. Table 3.4 summarizes the assumptions regarding the load relief and supply available from EOPs.

Table 3.4 Emergency Operating Procedures Assumptions and their Aggregate Impact[2]

EOP Measure	EOP Impact	
	% of Demand	MW
Public Appeals	1.0	
No 30-minute OR		473
Generator Stretch Capability		148
No 10-minute OR		945
Voltage Reductions	2.1	
Total Impact	3.1	1,566
Less OR Requirement		-1,418
Net Impact (% of Demand)	3.1	
Net Impact (MW)		148
Aggregated Net Impact	3.1% Reduction in Demand + 148 MW	

3.6 Fuel Supply Diversity

A diverse generation mix is important for resource adequacy and market efficiency, because it provides dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations.

With the addition of approximately 3,000 MW of gas-fired generation since 2009, the volume of gas consumed for electricity generation in Ontario is increasing. Ontario is well situated with respect to natural gas transmission and storage. Based on the input received from

[2] Although 30-minute and 10-minute OR are included in this list of EOPs, the analysis does not impose a requirement to provide for OR since only loss of load events are being considered. Therefore, the net benefit of applying EOPs in the analysis excludes relaxation of OR requirements.

stakeholders, the review of the winter operations conducted by the IESO as part of the Ontario's Gas-Electric coordination initiative and the assessment of initial results of the EIPC's (Eastern Interconnection Planning Collaborative) Gas-Electric System Interface Study, the IESO has concluded that Ontario's ability to meet the additional gas supply requirements in the period covered by this review is adequate and that risk of interruption of gas supply is within acceptable risk tolerance.

To meet the challenge of rapid deployment of renewables across the province and help capture the benefits of Ontario's investment in variable generation (wind and solar), the IESO has adapted operations as well as its markets to accommodate the influx of variable generation. In order to effectively integrate up to 10,700 MW of renewable generation by 2021, the IESO's Renewables Integration Initiative (RII) was implemented in 2013. RII involved integration of the hourly centralized variable generation forecast[3] into IESO scheduling tools, enhanced visibility of output of distributed-connected variable generation facilities 5 MW or greater, and dispatch of grid-connected variable resources. The new tool set provides system operators with greater levels of awareness of system conditions; improved variable generation forecast and increased operational flexibility from variable generation resources.

4 RESOURCE ADEQUACY ASSESSMENT

4.1 Loss of Load Expectation (LOLE) Results

The resource adequacy probabilistic assessment was performed using GE-MARS. The following inputs were used:

- median and high demand growth forecast and associated load forecast uncertainty (LFU);
- forecast of available resources and existing EOPs;
- planned outage schedule submitted by Market Participants;
- equivalent forced outage rates (EFORS) for thermal units derived using historical generator performance data; and
- transmission limits of major interfaces connecting different zones.

The above inputs are described in greater detail in *Appendix B – Resource Modeling Methodology* section of this report.

Table 4.1 provides a summary of the LOLE results from these MARS runs for the different scenarios.

[3] Centralized forecast is available for all wind and solar resources with an installed capacity of 5MW or greater and all wind and solar resources directly connected to the IESO-controlled grid.

Table 4.1 LOLE Results from MARS Runs

Scenario	Demand Growth	EOPs	Tie-Benefits	LOLE		
				2015	2016	2017
1	Median	No	0 MW	0.476	0.065	0.025
		Yes	0 MW	0.162	-	-
		Yes	175 MW only for 2015	0.096	-	-
2	High	No	0 MW	0.651	0.253	0.318
		Yes	0 MW	0.228	0.081	0.099
		Yes	375 MW only for 2015	0.099	-	-

Under median demand growth scenario, the NPCC criterion of LOLE no more than 0.1days/year is satisfied for the 2016 and 2017 forecast years without the use of EOPs or tie-benefits. However, for the 2015 forecast year, EOPs and tie-benefits are needed to satisfy the NPCC criterion. The critical period is in the spring of 2015, when overlapping nuclear station outages tighten the supply situation. Tie-benefits[4] of up to 175 MW, along with EOPs, were found to satisfy the NPCC criterion in 2015. This level of tie-benefits is well within the level of imports offered into the Ontario market. Also, the level of tie-benefits required falls within the range of tie-benefits assessed by the NPCC in its 'Review of Interconnection Assistance Reliability Benefits' study[5].

Under the high demand growth scenario, for 2015 forecast year the overlapping station outages in spring resulted in need to invoke EOPs and tie-benefits of up to 375 MW MWs to satisfy the NPCC criterion. The support provided by tie-benefits is primarily relied upon only during the shoulder period months when overlapping station outages occur. This amount of tie-benefits is also within the level of imports offered into the Ontario market and is well within the range of tie-benefits assessed by the NPCC in its 'Review of Interconnection Assistance Reliability Benefits' study. For 2016 and 2017 forecast years, EOPs are required in addition to existing and planned resources to satisfy the NPCC criterion.

The IESO facilitated the coordination of the 2015 nuclear outages, resulting in the outages being rescheduled by the market participants to the most appropriate period feasible for achieving both the regulatory requirements of the plants while meeting IESO reliability requirements for the power system. EOPs, increased reliance on the interties and flexibility to re-schedule other planned outages will be among the actions available to manage reserves in the event of extreme scenarios during the scheduled nuclear outages period in 2015.

The results above demonstrate that Ontario is expected to be compliant with the target LOLE of 0.1 days per year over the next three years.

[4] Capacity utilized through tie-benefits does not reflect firm imports. Ontario does not have any firm import capacity contracted.

[5] https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/RCC_Approved_CP-8_Tie_Benefit_Report_June_1_2011.pdf

4.2 Median Demand Growth LOLE Comparison – 2013 Interim vs. 2012 Comprehensive

Table 4.2 compares the LOLE results for the 2012 Comprehensive and 2014 Interim Reviews under the median demand growth scenario for 2015 to 2017. In general, LOLE values have increased in all three years of study, as a result of lower available resources as described in section 3.2 and updates to planned outages schedules of thermal units.

Highest change in LOLE between 2012 Comprehensive Review and 2014 Interim Review occurred in 2015, which is primarily driven by overlapping nuclear station outages in the spring that were included in 2014 Interim Review but not the 2012 review.

Table 4.2 2012 Comprehensive vs. 2014 Interim LOLE Results

NPCC Review	Demand Growth	EOPs	Tie-Benefits	LOLE		
				2015	2016	2017
2012 Comprehensive	Median	No	0 MW	0.041	0.001	0.001
2014 Interim	Median	No	0 MW	0.476	0.065	0.025
2014 Interim	Median	Yes	0 MW	0.162	-	-
2014 Interim	Median	Yes	175 MW only for 2015	0.096	-	-

4.3 Alleviating Factors and Contingency Mechanisms

There are several study assumptions which may change in such a way that reserve levels in Ontario could be different than presented in this 2014 Interim Review, including the amount of conservation and demand response, amount of tie-benefits available and the amount of generation that may be on planned outage.

Every quarter, looking out nine months into the future, the IESO assesses the integrated generator and transmission outage plans of market participants. Periods where outages result in inadequate resource levels are identified to generators and transmitters. If market participants fail to proactively reschedule outages to mitigate concerns, the IESO may reject outages to ensure sufficient capacity is available to meet non-dispatchable demand.

Deviations from initial generator outage plans through outage rescheduling and rejection are not always desirable. This could stretch the ability of generator owners/operators to accommodate larger amounts of outages over shorter time periods and may increase forced outage occurrences. Operational experience so far indicates generator owners are usually able to adapt their outage plans.

5 CONCLUSIONS

This 2014 Interim Review demonstrates that Ontario will be able to meet the NPCC resource adequacy criterion that limits the LOLE value to no more than 0.1 days/year for all years from 2015 to 2017.

Under median demand growth scenario, both EOPs and tie-benefits are utilized in addition to existing and planned resources to satisfy the NPCC criterion for 2015. For 2016 and 2017 forecast years, the NPCC criterion is achieved using only existing and planned resources.

Under the high demand growth scenario, for 2015, both EOPs and tie-benefits are required in addition to existing and planned resources to satisfy the NPCC criterion. For 2016 and 2017 forecast years, EOPs are utilized in addition to existing and planned resources to satisfy the NPCC criterion.

APPENDIX A: RESOURCE TALLY

Summary of Existing and Planned Resources

Table A.1 summarizes the total effective capacity of existing and planned resources available during summer peak by individual fuel type.

Planned resources include all committed projects under contract with the Ontario Power Authority (OPA), and capacity to be contracted by the OPA as directed by the Ontario's Ministry of Energy that are expected to be in service during the reviewed period.

Table A.1 Effective Existing and Planned Resources Available during Summer Peak

	2015 Existing and Planned Resources (MW)			2016 Existing and Planned Resources (MW)			2017 Existing and Planned Resources (MW)		
Resource Type	**Existing**	**Committed**	**Directed**	**Existing**	**Committed**	**Directed**	**Existing**	**Committed**	**Directed**
Nuclear	12,893.0	0.0	0.0	12,174.0	0.0	0.0	11,309.0	0.0	0.0
Wind	251.2	291.0	0.0	251.2	310.1	0.0	251.2	378.0	0.0
Solar	132.6	80.0	0.0	132.6	80.0	0.0	132.6	110.0	150.5
Biomass	112.4	185.5	127.8	112.4	185.5	127.8	112.4	185.5	127.8
Hydro	5,724.0	4.0	1.0	5,724.0	273.0	5.0	5,724.0	285.0	8.0
Gas & Oil	8,434.9	0.0	0.0	8,212.9	242.0	0.0	8,029.9	242.0	0.0
DR	502.6	0.0	64.8	502.6	0.0	118.1	502.6	0.0	192.6
Total	**28,050.7**	**560.5**	**193.6**	**27,109.7**	**1,090.6**	**250.9**	**26,061.7**	**1,200.5**	**478.9**

APPENDIX B – MARS MODELING METHODOLOGY

Wind

Wind resources are modeled probabilistically on a zonal basis as Type 1 Energy-Limited Resources with a cumulative probability density function (CPDF). In order to derive the CPDFs, first, the top 5 demand hour window by month for each shoulder period month and by season for summer and winter periods are determined based on 5-year historical demand data. Historical wind production during these top 5 demand hours is then extracted to determine the median contribution using both simulated and actual wind output data independently. A conservative approach of determining the lower median contribution during top 5 demand hours is applied to select historical simulated or actual wind output based CPDF for each month or season. Seasonal CPDFs for the summer and winter, and separate monthly CPDFs for the shoulder months are modeled in MARS to represent the capacity contribution of wind resources to the system

Solar

Solar resources are modeled as load modifiers in MARS with production (MW contribution) calculated from projected installed capacities and hourly solar contribution factors. Hourly solar contribution factors are determined using 10 years of historical simulated data by calculating the hourly median solar contribution by month for each shoulder period month and by season for summer and winter periods. This methodology results in 24-hour capacity factor that is used to create an hourly solar profile to modify load.

Hydroelectric

Hydroelectric resources are modeled 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 transmission 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.

Thermal Resources

Four resource types are modeled as thermal resources, viz. nuclear, gas, oil and biomass. The capacity values for each unit are based on monthly maximum capacity ratings contained in Market Participant submissions.

Equivalent Forced Outage Rates (EFOR) for existing units are derived using rolling five-year history of actual forced outages. The derived EFORs are then converted to capacity state and transition rate matrices for MARS. For units with insufficient historical data, and for new units, EFOR of existing unit with similar size and technical characteristics is utilized to model the forced outage rates. The projected EFOR values in the form of weighted average and range by fuel type is provided in table A.2 below.

Table A.2 Ontario's Projected Equivalent Forced Outage Rates

Fuel Type	Weighted Average EFOR	Range of EFOR
Nuclear	8.36%	3 - 22 %
Gas	6.26%	2 - 14%
Oil	5.22%	4 - 50 %
Biomass	6.20%	4 - 7 %

Planned Outages

Planned outages are in general based on outage submissions from Market Participants. For first year of the study, the planned outages are extracted from the Integrated Outage Management System (IOMS), and for later years the information submitted as part of 10 year outlook form submissions by market participants are utilized.

For those generating units with no specified outages over the planning period, the planned outages are based on forecast Planned Outage Factors (POFs) submitted by Market Participants and/or a generic outage plan derived from historic outage patterns of existing units. Planned and forced outage impacts for hydro, wind and solar are assumed to be already accommodated in the capacity assumptions used.

Transmission Limits (Interface and Zonal)

The Ontario transmission system is represented by ten interconnected zones with transmission limits between the zones explicitly modeled. The limits modeled are the operating security limits (OSL) specified for each interface and any projected limit increase due to future transmission system enhancements is appropriately represented.

Demand Forecast

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its ten zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. The forecast also accounts for conservation, price impacts, demand response and embedded generation.

Conservation impacts are provided by the agency responsible for conservation planning and savings verification. The impacts are incorporated into both the demand history and forecast where the final demand forecast is reduced for those conservation savings.

The demand forecast accounts for the impacts of embedded generation. Capacity projections based on projected generation are combined with historical production functions to generate estimated hourly output. This information is then applied to the demand forecast to determine the need for grid supplied electricity.

The IESO treats demand response as a resource. As such, to maintain consistency the impacts of demand response programs are added back to the historical data.

Price impacts from time of use rates and critical peak pricing programs are treated as load modifiers and decremented from the forecast. In Ontario, the participants of demand measure program also participate in a critical peak pricing program. Therefore, at the time of the annual peak, the demand forecast is reduced for the peak pricing impacts but, concurrently, the available demand response capacity is decremented to ensure that the contribution of these resources is not counted twice.

Weather is represented by a Monthly Normal weather scenario which uses last 31 years of historical weather data to generate typical or average monthly weather. This approach results in a monthly peak demand with a 50/50 probability of being exceeded. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario’s Ministry of Finance.

In the MARS program, demand is modeled as an hourly profile for each day of each year of the study period. The assumptions are consistent with those applied in preparing the forecast for the 18-Month Outlook. An allowance for load forecast uncertainty is also modeled as described below.

Demand Response

Under demand response category, contribution of Demand Response 3 (DR3), Dispatchable Loads (DL) and Peaksaver programs is captured.

Effective capacity available from dispatchable loads is determined based on historical capacity offered, using 5-year history, by the participants during peak demand hours. In MARS, dispatchable loads are modeled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

Effective capacity for DR3 and Peaksaver are determined based on historical performance of the participants of individual programs. In MARS, both programs are modeled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone. However, unlike DL, a monthly limit on number of activations is specified to restrict the number of activations for a month.

Load Forecast Uncertainty (LFU)

Load forecast uncertainty (LFU) arises due to variability in the weather conditions that drive future demand levels. LFU is modeled in MARS through the use of probability distributions. These distributions are derived from observed historical variation in weather conditions that are known to effect demand, viz. temperature, humidity, wind speed and cloud cover. Provincial-wide LFU distributions are developed for every month of the year and applied to all ten transmission zones.

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