NERC RAS Probabilistic Assessment

NPCC Region

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Conducted by the

NPCC CP-8 Working Group

NPCC CP-8 WORKING GROUP

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Introduction

Geographically, the NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states (New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, & Maine) and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

At the December 2008 NERC Planning Committee (PC) meeting, the PC approved the formation of a Generation & Transmission Reliability Planning Models Task Force (G&TRPMTF) with two main deliverables in the scope:

- ✓ to evaluate approaches and models for composite generation and transmission (G&T) reliability assessment; and,
- ✓ provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC's long term reliability assessments.

At the September 2010 PC meeting, the G&TRPMTF Final Report on Methodology and Metrics was approved. [1] The metrics recommended in the Final Report included the : (i) annual Loss-of Load Hours (LOLH), (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common NERC Long Term Reliability Assessment forecasted years.

The *2012 Pilot Probabilistic Assessment* [2] conducted with the recommended metrics was approved by the NERC PC at their June 2012 meeting; the pilot assessment recommended that:

- ✓ the format of assessment results for future years; and,
- ✓ the assessment be conducted on a biennial basis.

The *2013 Probabilistic Assessment* (based on the *NPCC 2012 Long Range Adequacy Overview*[3]) used the NERC *2012 Long-Term Reliability Assessment* reference case data. This assessment provides the required reliability indices for study the years of 2014 and 2016, and includes complete coverage of all NERC assessment areas.

This 2014 Probabilistic Assessment (based on the NPCC *2014 Long Range Adequacy Overview*) used the NERC 2014 *Long-Term Reliability Assessment*. [4] This assessment provides the required reliability indices for study the years of 2016 and 2018, and includes complete coverage of all NERC assessment areas. In addition, a No Emergency Operating Procedures Scenario case was added to estimate Loss of Load Hours (LOLH) and Expected unserved Energy (EUE) while still

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[1] See: http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF%20Meth%20&%20Metrics%20Report%20final%20w.%20PC%20approvals,%20revisions.pdf

[2] See: http://www.nerc.com/files/2012_ProbA.pdf

[3] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[4] See: https://www.npcc.org/Library/Resource%20Adequacy/2014LongRangeOverview(RCC%20Approved%20Dec%202%201014).pdf

maintaining Spinning & Non-Spinning (10 & 30 min.) Operating Reserve requirements. Other Operating Procedures may still be used in the calculation.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [5] was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. MARS version 3.18 was used for the assessment.

[5] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

Summary

The estimated Expected Unserved Energy (EUE) and the estimated Loss-of-load hours (LOLH) shown in Table 1 (a-e) are based on the results of NPCC's *2014 Long-Range Adequacy Overview*, [6] with assumptions consistent with those used for NPCC in the NERC *2014 Long-Term Reliability Assessment*. [7] The two years reported in this assessment are the years 2016 and 2018.

Appendices A-E shows the seasonal capacity totals (summer and winter) – by subcategory, for the assessment years, with totals provided for:

- ✓ Controllable capacity demand response;
- ✓ Intermittent and energy-limited variable resources;
- ✓ Traditional dispatchable capacity;
- ✓ Sales;
- ✓ Purchases; and,
- ✓ Coincident forecast 50/50 peak seasonal demands (summer and winter) as reported in the NERC *2014 Long-Term Reliability Assessment*.

In Table 1(a-e), the Forecast Capacity Resources shown equals the total installed capacity, minus capacity derates, plus net firm transactions; the Forecast Operable Capacity Resources equals Forecast Capacity Resources minus the assumed generator forced outage rates. Definitions used in the calculations are shown in Appendix F.

Table – 1a: Annual Peak Demand and Capacity Resources – Quebec

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2016	191,408	38,137	40,803	40,177	0.000	0.000	12.0%	10.3%
2018	192,576	38,658	41,917	41,267	0.000	0.000	14.0%	12.3%

Table -1b: Annual Peak Demand and Capacity Resources – Maritimes

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2016	27,682	5,308	6,820	6,541	0.000	0.001	35.3%	29.8%
2018	27,654	5,322	6,635	6,360	0.000	0.000	32.4%	26.9%

[6] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

[7] See: http://www.nerc.com/page.php?cid=4|61

Table - 1c: Annual Peak Demand and Capacity Resources – New England [8]								
Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh – ppm [9])	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2016	145,332	27,291	33,052	30,773	44.6 - 0.307	0.067	25.5%	16.8%
2018	146,114	27,677	31,519	29,493	253.8 - 1.737	0.288	18.2%	10.5%

Table - 1d: Annual Peak Demand and Capacity Resources – New York								
Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh – ppm [10])	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2016	163,907	34,412	38,314	35,318	1.9 - 0.010	0.009	15.3%	6.3%
2018	163,753	35,111	38,103	35,131	9.3 - 0.057	0.032	12.3%	3.6%

Table - 1e: Annual Peak Demand and Capacity Resources – Ontario [11]								
Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
2016	140,235	22,535	27,565	25,935	0.000	0.000	22.3%	15.1%
2018	138,227	22,301	28,202	26,526	0.000	0.000	26.5%	18.9%

Table 2 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount reported in the *NERC 2014 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS estimate for the total estimated NPCC annual energy is within approximately 1.0% of the corresponding sum of the NPCC Areas annual energy forecasts.[12]

[8] The Total Internal Demand reported is higher than reported in the NERC LTRA due to the treatment of passive demand response; in order to provide a proper comparison with the NERC LTRA, the data in Appendix B was adjusted to report the load demand response the same way as reported in the LTRA.
[9] MWh of EUE per Million MWh of Annual Load Energy
[10] MWh of EUE per Million MWh of Annual Load Energy
[11] The same resources are used as in the LTRA; the capacity reported for nuclear generation is not reduced for long-term refurbishment outages but instead is captured as a scheduled unavailability in the model.
[12] The simulated Net Energy of Load may differ from the Net Energy for Load as reported in the LTRA, due to the assumptions used the development of a chronological area load model from the area load forecasts.

Table 2 - Comparison of Energies Modeled (Annual MWhs)

Year	2016	2018
Quebec		
MARS	191,407,632	192,575,584
2014 LTRA	188,769,965	190,067,433
(MARS-LTRA)	2,637,667	2,508,151
% (MARS-LTRA)/LTRA	1.40	1.32
Maritimes		
MARS	27,682,142	27,653,688
2014 LTRA	27,474,836	27,624,243
(MARS-LTRA)	207,306	29,445
% (MARS-LTRA)/LTRA	0.75	0.11
New England		
MARS	145,331,856	146,114,064
2014 LTRA	14,233,500	14,538,500
(MARS-LTRA)	2,996,856	729,064
% (MARS-LTRA)/LTRA	2.1	0.5
New York		
MARS	163,907,008	163,753,008
2014 LTRA	163,907,000	163,753,000
(MARS-LTRA)	8	8
% (MARS-LTRA)/LTRA	0.00	0.00
Ontario		
MARS	140,234,784	138,227,168
2014 LTRA	136,513,075	133,445,341
(MARS-LTRA)	3,721,709	4,781,827
% (MARS-LTRA)/LTRA	2.73	3.58
NPCC		
MARS	668,568,328	668,323,520
2014 LTRA	658,999,876	660,275,017
(MARS-LTRA)	9,563,452	8,048,503
% (MARS-LTRA)/LTRA	1.45%	1.22%

Software Model Description

Multi-Area Reliability Simulation Program Description

General Electric's Multi-Area Reliability Simulation (MARS) program [13] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

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

Reliability Indices

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- ✓ Daily Loss of Load Expectation (LOLE - days/year);
- ✓ Hourly LOLE (hours/year);
- ✓ Loss of Energy Expectation (LOEE -MWh/year);
- ✓ Frequency of outage (outages/year);
- ✓ Duration of outage (hours/outage); and,
- ✓ Need for initiating Operating Procedures (days/year or days/period).

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. For each hour, the total available capacity in the area is subtracted from the load demand. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how

[13] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The second method was used in this assessment. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation

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

- ✓ Thermal;
- ✓ Energy-limited;
- ✓ Cogeneration;
- ✓ Energy-storage; and,
- ✓ Demand-side management.

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs. User specified maintenance was used in the assessment.

<u>Thermal Units</u>

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

<u>Energy-Limited Units</u>

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar where the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

<u>Cogeneration</u>

MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

<u>Energy-Storage and DSM</u>

Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts

Contracts are used to model firm scheduled interchanges of capacity between areas in the system. In addition, the program schedules any excess capacity in an area in a given hour to provide emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be only to the extent that the exporting Area has the necessary resources on its own or can obtain them as emergency assistance from other areas. Firm contracts and emergency assistance were modeled in this assessment.

Demand Modeling

The loads for each area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies.

Load Shape

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the 2003 – 2004 load shape has been used for the winter assessments. The selection of these load shapes was confirmed earlier this year based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008.

For a study such as this that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2002, 2003, and 2004. January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2003 and 2004 were adjusted by the ratios of their annual energy to the annual energy for 2002. This adjustment removed the load growth that had occurred from 2002, from the 2003 and 2004 loads, so as to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match the monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

Load Forecast Uncertainty

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

The per unit variations in Area and sub-Area load can vary on a monthly and annual basis. For example, Table 3(a) shows the values assumed for January 2015, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape). Table 3(a) also shows the probability of occurrence assumed for each of the seven load levels modeled. Similarly, Table 3(b) shows the corresponding values for July 2015.

In computing the reliability indices, all of the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, the reliability indices were calculated for the expected load conditions, derived from computing the reliability at each of the seven load levels modeled, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Table 3(a)
Per Unit Variation in Load Assumed (Month of January 2015)

Area	Per-Unit Variation in Load						
MT	1.1380	1.0920	1.0460	1.0000	0.9540	0.9080	0.8620
NE	1.0934	1.0383	0.9971	0.9635	0.9402	0.8500	0.8000
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0885	1.0590	1.0295	1.0000	0.9705	0.9410	0.9115
QC	1.0870	1.0860	1.0400	0.9991	0.9613	0.9230	0.9130
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 3(b)
Per Unit Variation in Load Assumed (Month of July 2015)

Area	Per-Unit Variation in Load						
MT	1.1380	1.0920	1.0460	1.0000	0.9540	0.9080	0.8620
NE	1.2480	1.1187	1.0047	0.9936	0.8970	0.8864	0.8513
NY	1.1173	1.0857	1.0459	0.9930	0.9371	0.8800	0.8283
ON	1.1296	1.0864	1.0432	1.0000	0.9568	0.9136	0.8704
QC	1.0542	1.0542	1.0247	1.0010	0.9753	0.9470	0.9458
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Behind-the-meter generation was modeled as netted from load.

Demand Response

New England: Passive and active demand resources participate in the New England Forward Capacity Market (FCM), and are represented as supply-side resources in this study. The Qualified Capacity of passive demand resources under the FCM are used for the years 2015 to 2017, and a forecast amount is used for 2018 and 2019. For the active demand resources, the study assumes the actual amount procured under FCM for 2015 to 2017. As there are no auction results for 2018 and 2019, the values are assumed to remain at the 2017 level through 2019.

Ontario: Ontario IESO treats Demand Response as a resource, instead of as a load-modifier.

Controllable Capacity Demand Response Modeling

Each area takes defined steps as their reserve levels approach critical levels. Table 4 shows these steps, consisting of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

The need for an area to begin these operating procedures is modeled in MARS by evaluating the daily probabilistic expectation at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

Table 4
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2015 Load Relief Assumptions - MW

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (July)	QC (Jan)
1. Curtail Load / Utility Surplus	-	-	-	228	1,277
Appeals	-	-	-	1% of load	-
RT-DR/SCR/EDRP	-	738[14]	738[15]	-	-
SCR Load /Man. Volt. Red.	-		0.17% of load	-	-
2. No 30-min Reserves	233	625	655	473	500
3. Voltage Reduction	-	422	1.28% of load	1.40% of load-	250
Interruptible Loads	250	-	-	528	-
4. No 10-min Reserves	505	-	-	945	750
			-		
RT-EG	-	294 [16]	-	-	-
General Public Appeals	-	-	204	-	-
5. 5% Voltage Reduction	-	-	-	0.70% of load	-
No 10-min Reserves	-	1,550	1,310	-	-
Appeals/Curtailments	-	-	-	40	-

[14] Derated value shown accounts for assumed availability.
[15] Derated value shown accounts for assumed availability.
[16] Derated value shown accounts for assumed availability.

Capacity Modeling

Generator Unit Availability

Details regarding the NPCC area's assumptions for generator unit availability are described in the latest NPCC Seasonal Multi-Area Probabilistic Assessment. [17]

Wind Resource Modeling

Each area provides the modeling details for their wind resources consistent with their internal studies. The details of each area's modeling, as well as a comparison to how wind is reported in the LTRA follows.

Maritimes: The Maritimes provides an hourly historical wind output for each sub-area. This profile is then scaled according to the wind online at the time of the regional peak. The LTRA reports de-rated nameplate values.

New England: New England utilizes units of a fixed capacity (that varies seasonally) representing the Seasonal Claimed Capability to represent their wind resources. In the LTRA, both nameplate ratings and Seasonal Claimed Capabilities for wind units are reported. The Seasonal Claimed Capabilities in the Probabilistic assessment are consistent with the LTRA.

New York: New York provides an hourly historical wind profile for each wind plant, based on the 2013 wind production data. The full wind nameplate capacity is used for margin calculations. In the LTRA, wind is reported as the expected (Existing-Certain) on-peak capacity (nominally 17% of nameplate capacity), and the remaining capacity is reported as Existing-Other.

Ontario: Ontario aggregates wind on a sub-area basis and models as an energy limited unit, utilizing a cumulative probability density function (CPDF). This CPDF, which can vary by month and season, represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs are constructed based on the contribution of wind resources during a 5-hour window that represents the highest contiguous average demand hours for the summer and winter seasons, and for each month of spring and fall. In the absence of sufficient historical (actual) wind production data to confidently estimate expected wind contribution during peak demand hours, both historical and simulated wind production data are utilized for developing the CPDFs. The capacity reported in the LTRA is calculated using Wind Capacity Contribution (WCC) factors. WCC values in percentage of installed capacity are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data and the simulated 10-year historic wind data will continue until 10-years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation.

Quebec: Quebec utilizes units of a fixed capacity (that varies seasonally) to represent the expected capacity. The expected capacity at peak is 30% of the Installed (Nameplate) capacity, with the exception of a small amount (roughly 3%) which is derated for all years of the study. This method was also used in the LTRA.

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[17] See: http://www.npcc.org/adequacy.cfm

Capacity and Load Summary

Figures 1 through 6 summarize area capacity and load assumed in this Overview at the time of area peak for the period 2015 to 2019. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance. Details regarding area capacity and load assumptions can be found in Appendices A-E.

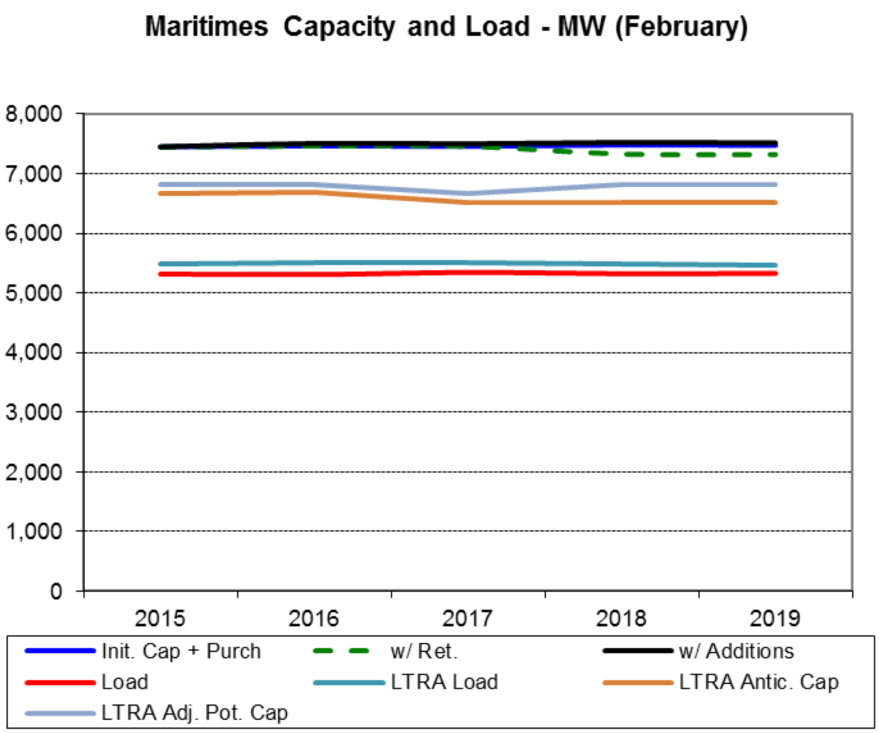


Figure 1 – Maritimes Area Capacity and Load

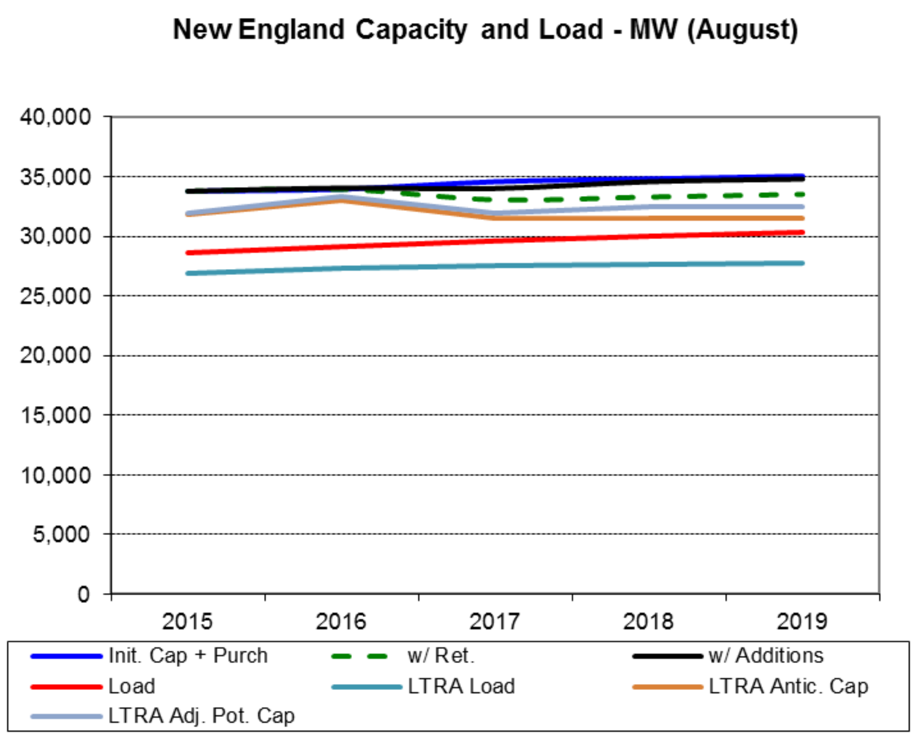


Figure 2 – New England Capacity and Load

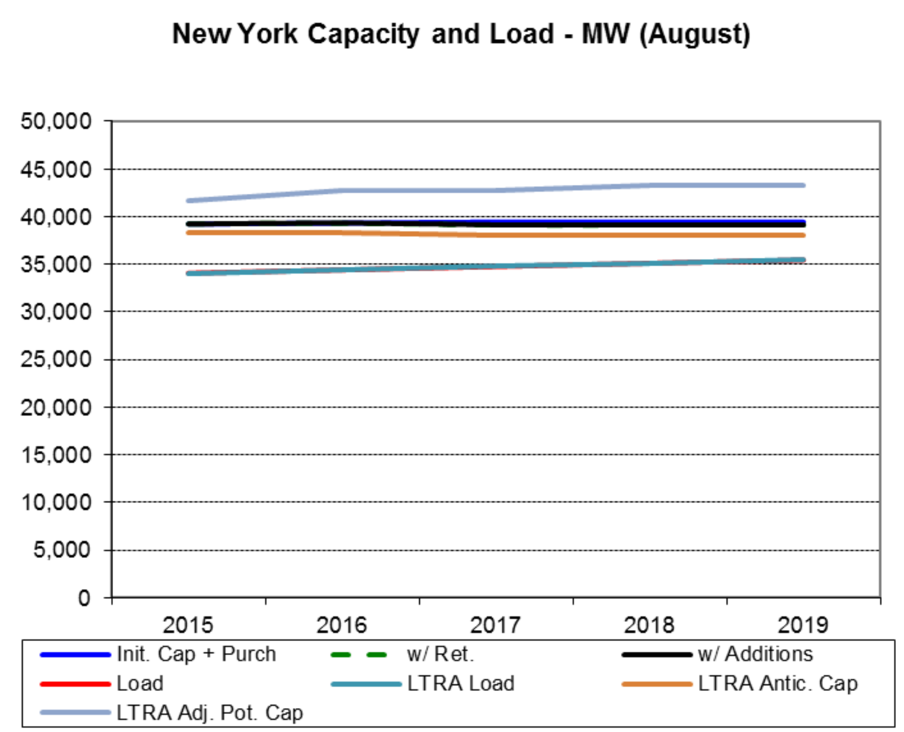


Figure 3 – New York Area Capacity and Load

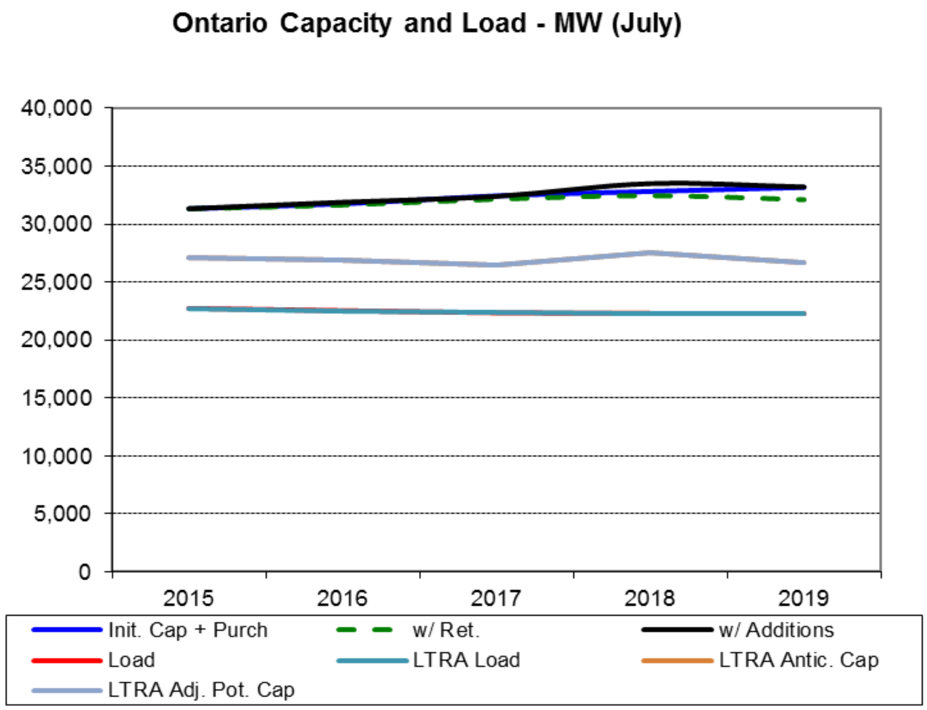


Figure 4 – Ontario Capacity and Load

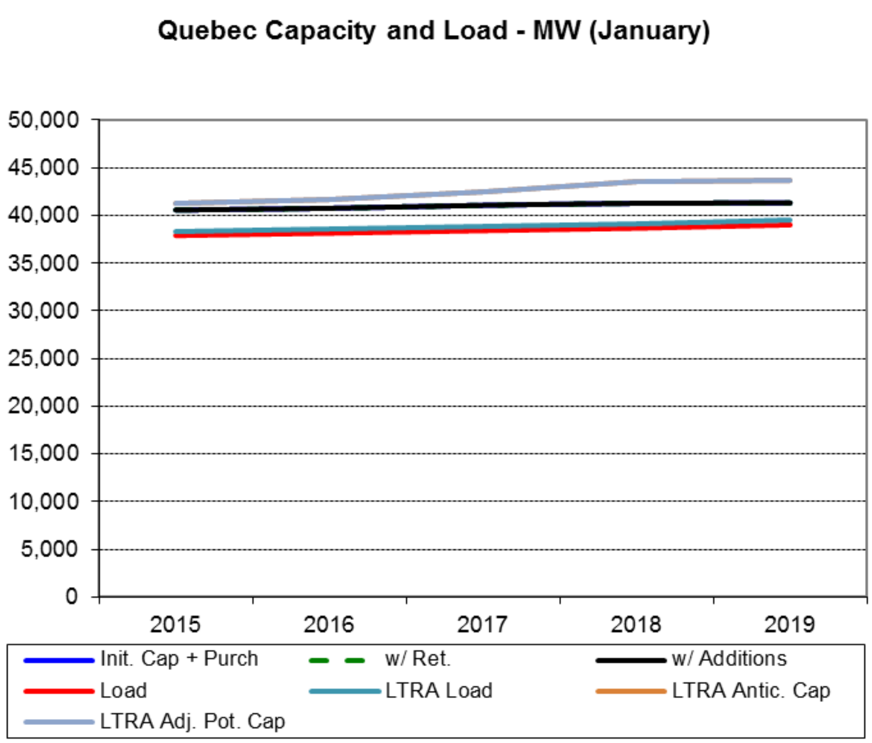


Figure 5 – Québec Capacity and Load

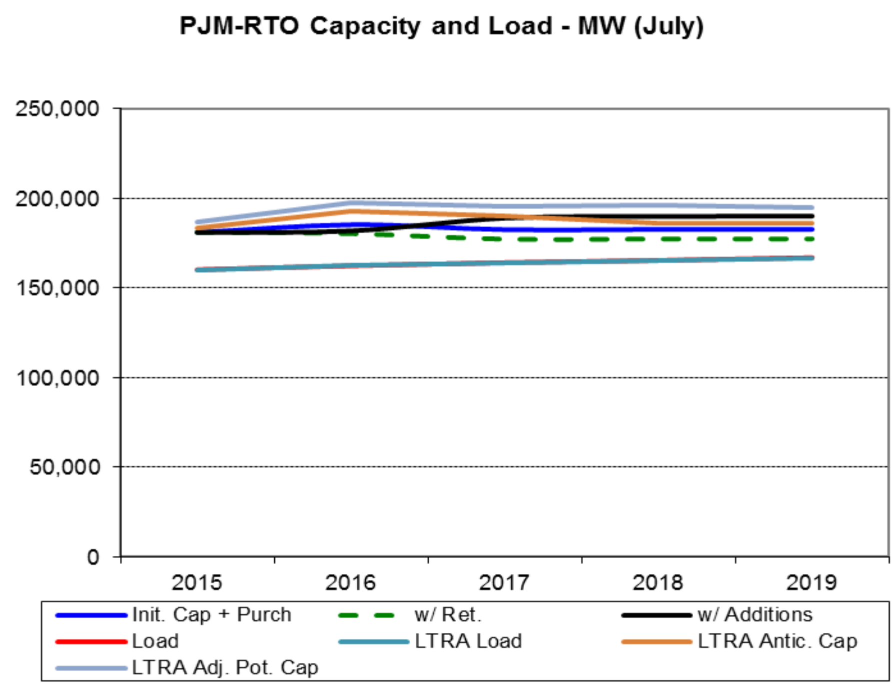


Figure 6 – PJM-RTO Capacity and Load

Transmission

Transmission additions and retirements assumed in the modeling was consistent with the data provided for the NERC *2014 Long-Term Reliability Assessment*. Figure 7 stylistically summaries the transmission system that was assumed, showing area and assumed transfer limits.

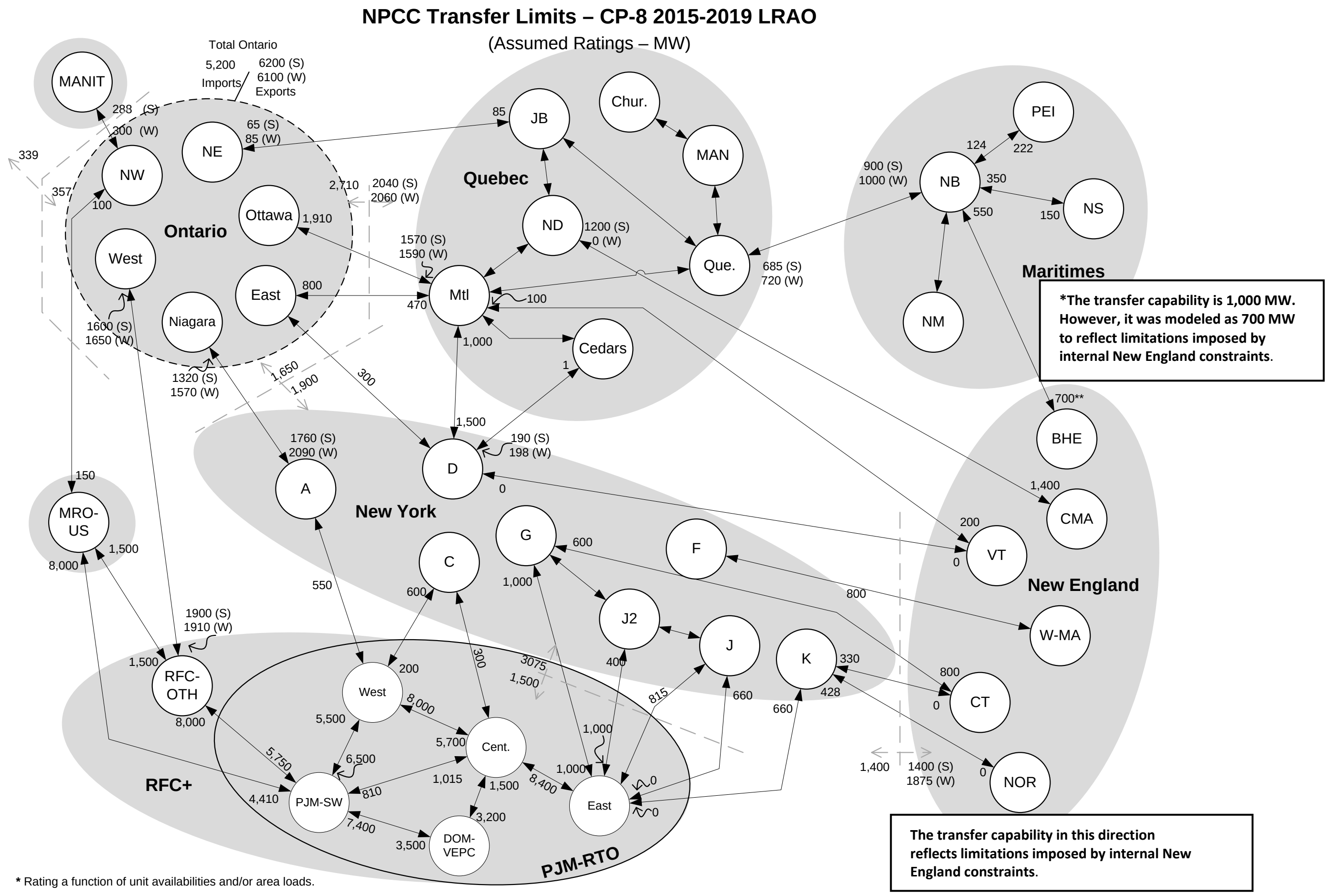


Figure 7 - Assumed Transfer Limits

Transfer limits between and within some areas are indicated in Figure 7 with seasonal ratings (S-summer, W- winter). The acronyms and notes used are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- Reliability*First*
MRO	- Midwest Reliability Organization	Que Centre	- Québec Centre	MT	- Maritimes Area

The modeling of the Maritimes shown in Figure 7 is consistent with its 2013 NPCC Comprehensive Review of Resource Adequacy. [18]

Details regarding the development of the transmission representation for New York shown in Figure 7(a) and 7(b) are consistent with the New York State Reliability Council “New York Control Area Installed Capacity Requirements for the Period May 2014 through April 2015” Technical Study Report, December 6, 2013. [19]

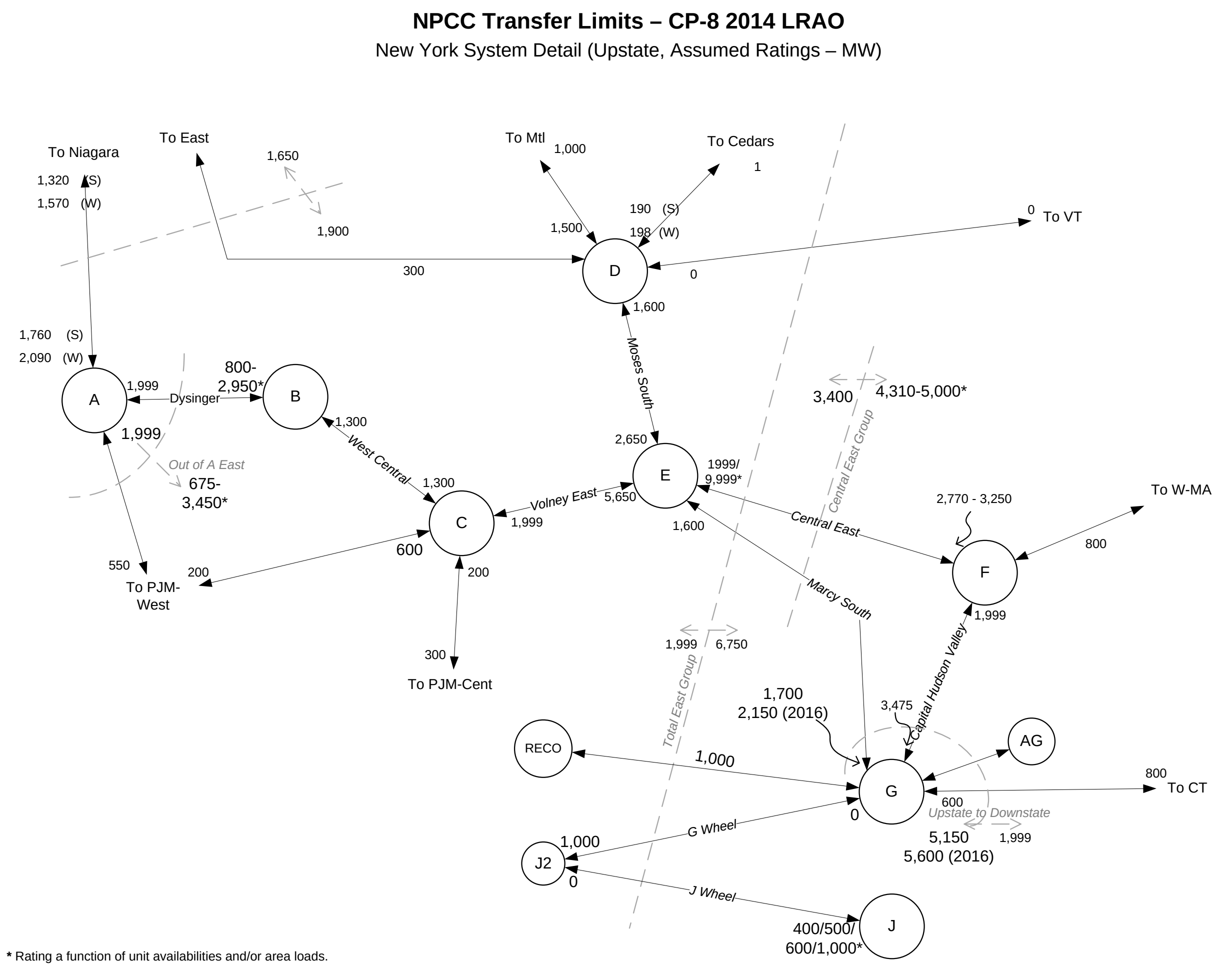
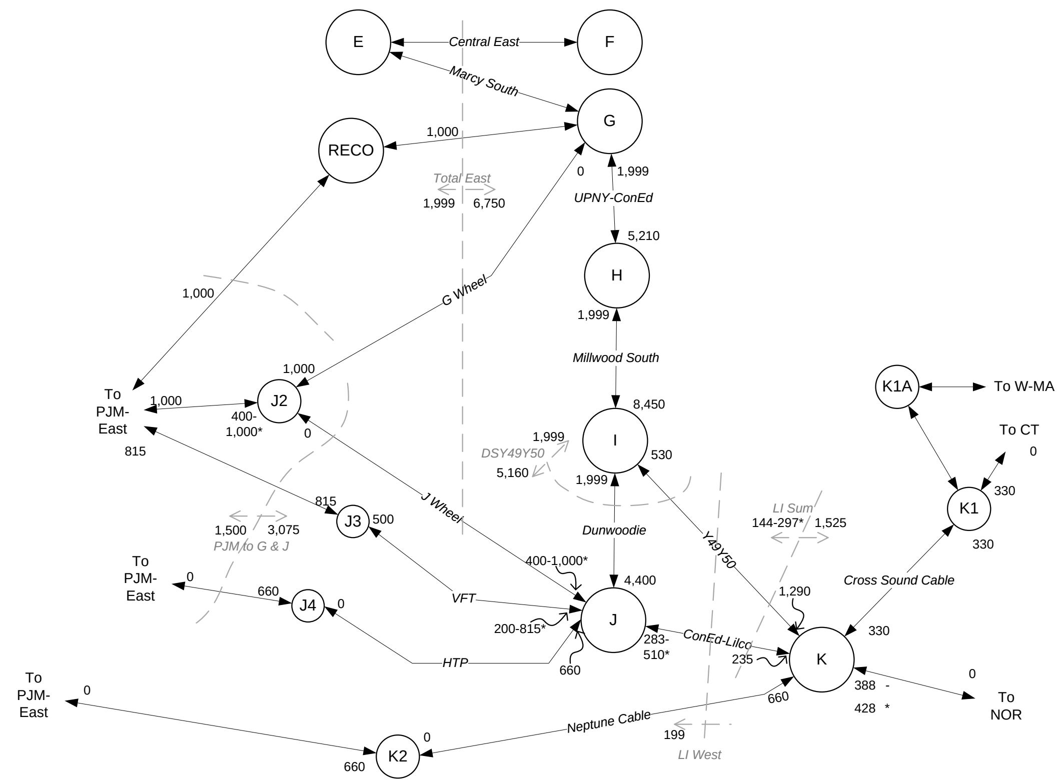


Figure 7(a) Assumed Northern New York Transmission Limits

[18] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[19] See: http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

NPCC Transfer Limits – CP-8 2014 LRAO

New York System Detail (Downstate, Assumed Ratings – MW)



* Rating a function of unit availabilities and/or area loads.

Figure 7(b) Assumed Southern New York Transmission Limits

Details regarding the development of the transmission representation for New England shown in Figure 7(c) can be found in the New England Regional System Plan 2014. [20]

[20] See: http://www.iso-ne.com/trans/rsp/index.html

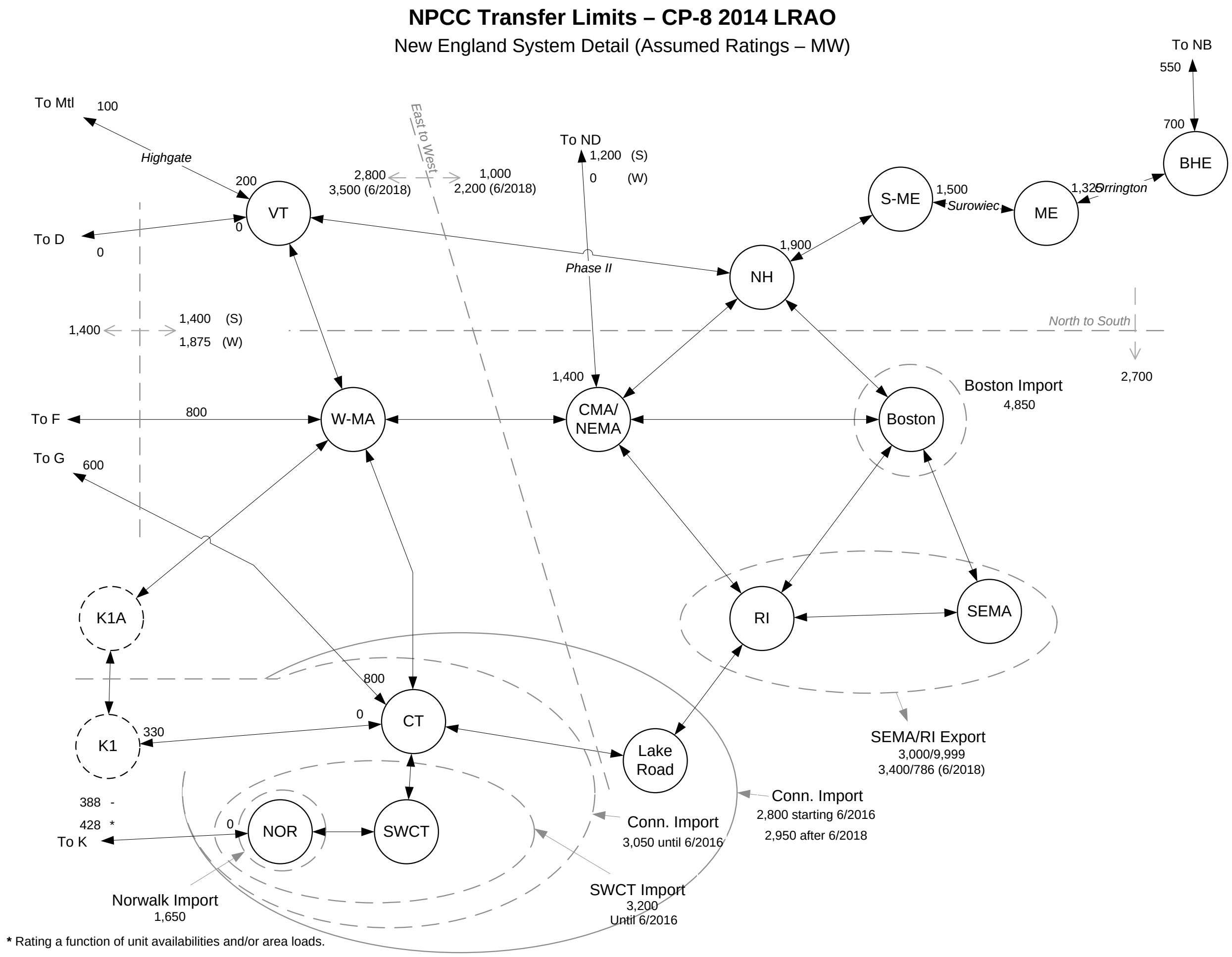


Figure 7(c) New England Transmission Limits

Details regarding the development of the transmission representation for Ontario shown in Figure 7(d) can be found in the "Ontario Transmission System," June 2014. [21]

[21] See: http://www.ieso.ca/Documents/marketReports/OntTxSystem_2014jun.pdf

NPCC Transfer Limits – CP-8 2014 LRAO
Ontario System Detail (Assumed Ratings – MW)

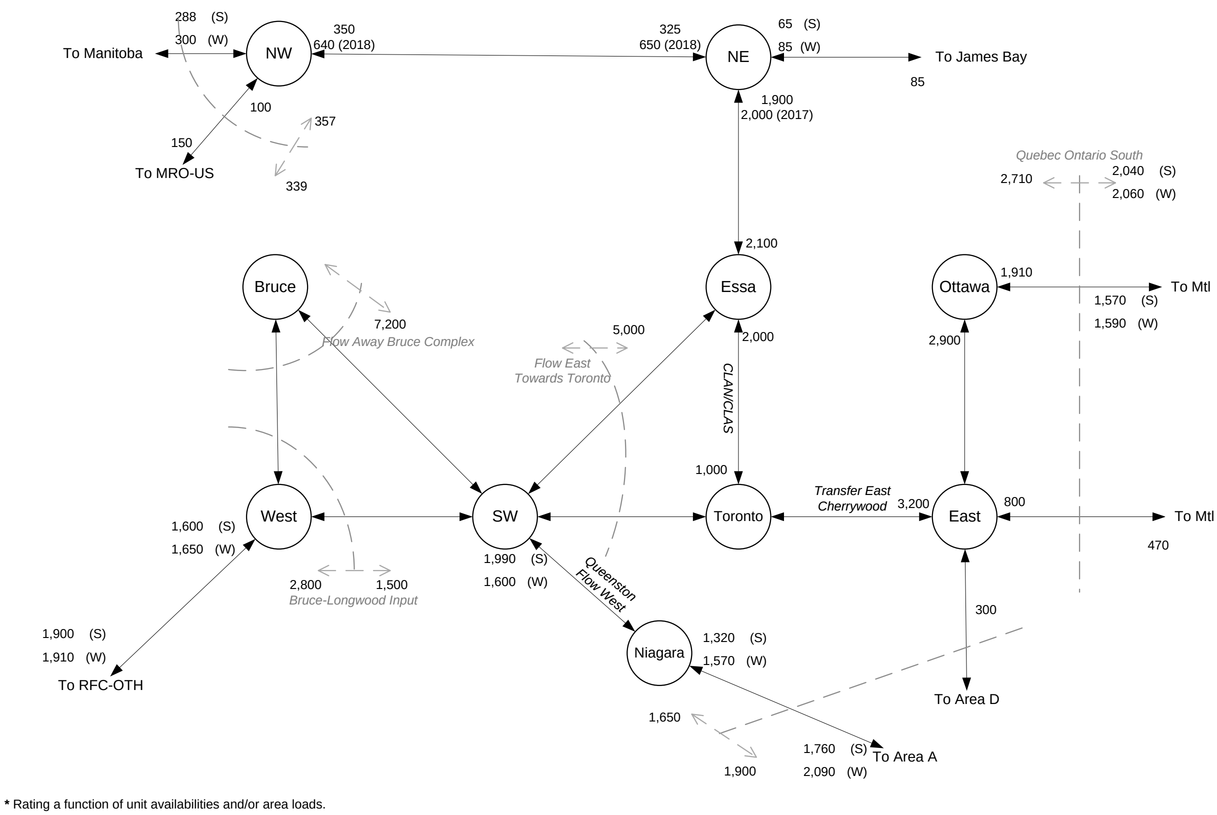


Figure 7(d) Ontario Transmission Limits

The modeling of Quebec shown in Figure 7(e) is consistent with its 2013 NPCC Interim Review of Resource Adequacy. [22]

[22] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

NPCC Transfer Limits – CP-8 2015-2019 LRAO

Quebec System Detail (Assumed Ratings – MW)

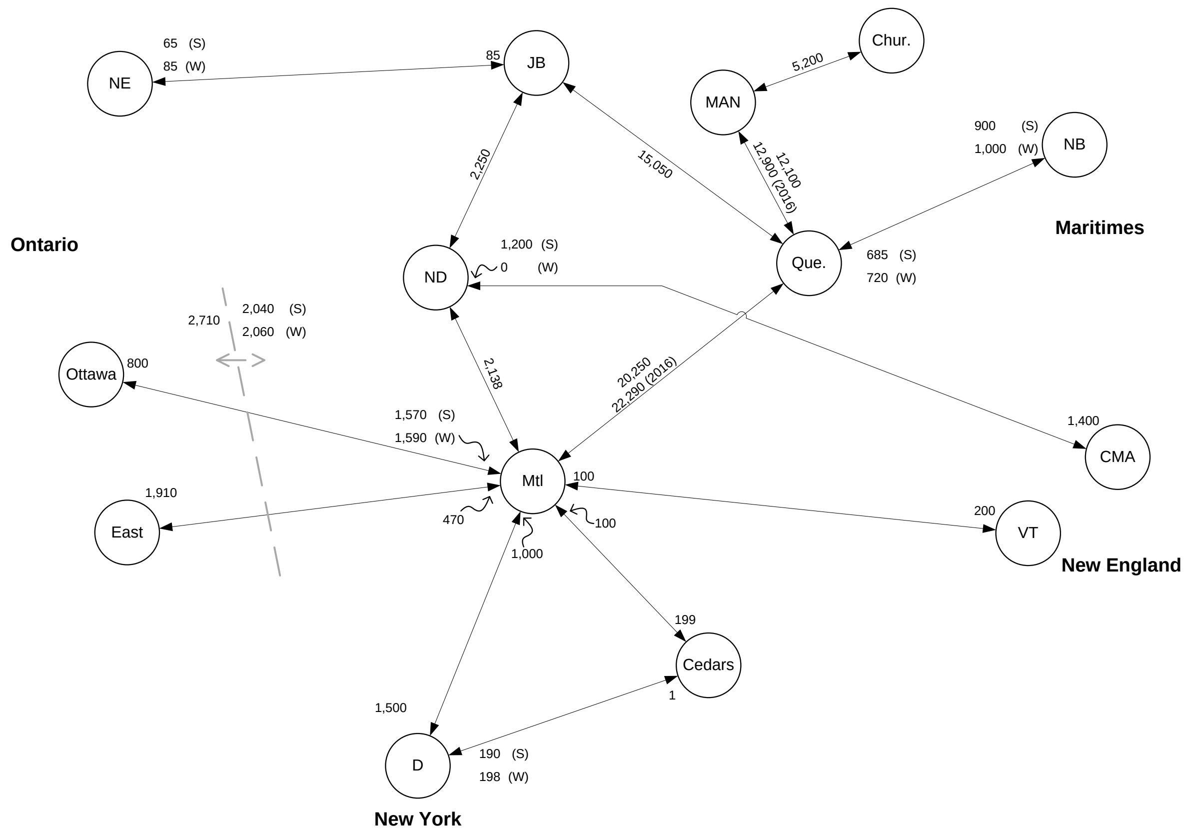


Figure 7(e) Quebec Transmission Limits

The modeling of the PJM-RTO shown in Figure 7 was divided into five distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, PJM West, and PJM South. This represents a slight departure from modeling practices prior to this year in which PJM West and PJM South were combined into one region (PJM Rest). This modeling change is justified on grounds that the PJM South area (Dominion Virginia Power) is a member of SERC while practically all the PJM West area is a member of RFC. Furthermore, PJM West and PJM South are two separate areas in the PJM Capacity Market framework (PJM's Reliability Pricing Model).

The modeling follows known operational models and constraints while recognizing that areas with high reserves have few events invoking emergency operating procedures. The model in this study used many of the same modeling assumptions used in the PJM 2014 reserve requirement study. [23]

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[23] See: http://www.pjm.com/~/media/committees-groups/committees/mc/20141120/20141120-item-02c-2014-reserve-requirement-study.ashx

Assistance from External Resources

All Areas received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.

A detailed representation of the neighboring regions of RFC (Reliability*First* Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 5 and Figure 8.

Table 5
PJM, RFC-Other and MRO-US 2015 Assumptions [24]

	PJM	RFC-Other	MRO-US
Peak Load (MW)	160,257	44,209	32,221
Peak Month	July	July	July
Assumed Capacity (MW)	179,287	49,308	36,340
Purchase/Sale (MW)	3,263	-2,067	-1,589
Reserve (%)	23	15	16
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	14,815	3,694	2,692
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	1,100	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	200	200
Load Forecast Uncertainty	+/- 12.58%, 8.39%, 4.20%	+/- 11.77%, 7.85%, 3.92%	+/- 11.77%, 7.85%, 3.92%

[24] Load and capacity assumptions for RFC-Other and MRO-US based on NERC's Electricity, Supply and Demand Database (ES&D) available at: http://www.nerc.com/~esd/

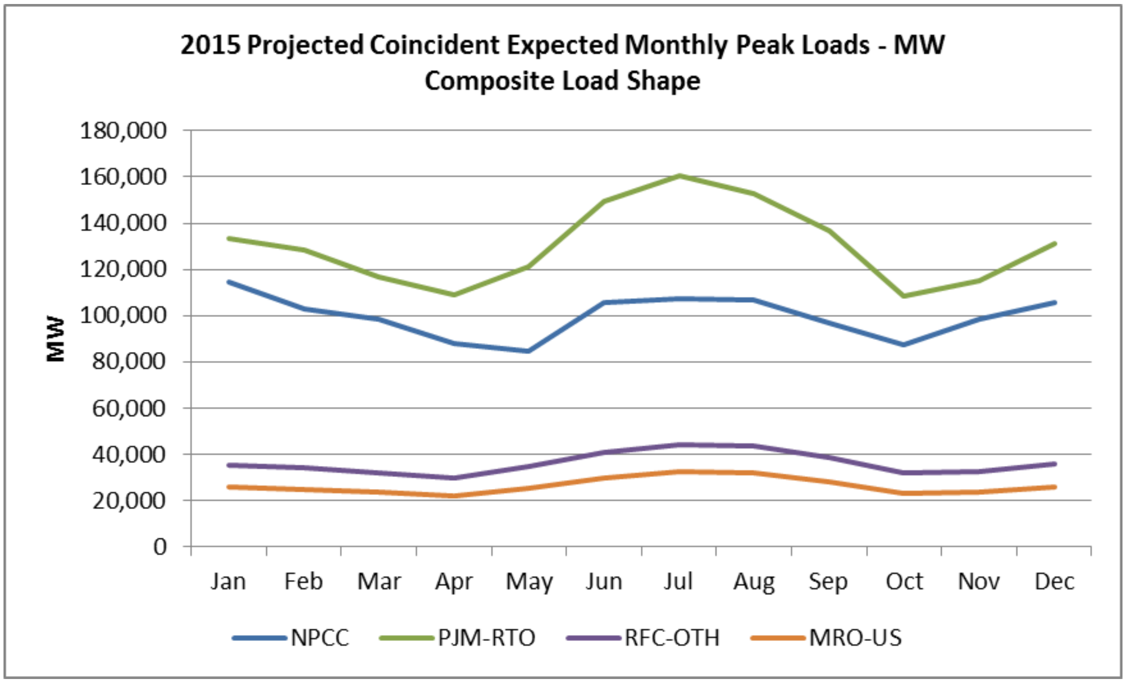

Figure 8 - 2015 Projected Monthly Expected Peak Loads for NPCC, RFC, PJM and the MRO

Reliability*First*

Reliability*First* is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.

Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations. The year 2006 is a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities were transferred to Reliability*First*.

The Bulk Power System within the Reliability*First* footprint consists of an extensive 115 kV to 765 kV network. Systems within Reliability*First* interconnect with systems in the Midwest Reliability Organization (MRO), NPCC, and the Southeastern Reliability Corporation (SERC).

MRO

The Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability of the bulk power system in the North Central part of North America. The primary focus of the MRO is ensuring compliance with regional and international reliability standards and criteria utilizing open, fair processes in the public interest.

Formation of the MRO was approved by the Mid-Continent Area Power Pool (MAPP) Executive Committee in November 2002. In 2005, this organization became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council.

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. Each individual unit represented in the MRO-US region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2014 RRS Report).

PJM-RTO

Load Model

PJM's Load Forecast issued in January 2014 [25] was used in this study. The methods and techniques used in the load forecasting process are documented in Manual 19 [26] (Load Forecasting and Analysis) and Manual 20 [27] (PJM Resource Adequacy Analysis.) The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the 2014 PJM Load Forecast Report on a monthly basis. The load forecast uncertainty considered in this study is consistent with other recent probabilistic PJM models (the PJM Reserve Requirement Study, specifically). This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, and the forecast horizon.

Generation Model

Performance statistics such as outage rates and planned outages for generation units considered in the study are based on 5-year (2009-13) GADS data. This is consistent with modeling practices in the 2014 PJM Reserve Requirement Study. Wind and solar units are assigned a forced outage rate of 0 and a capacity credit factor computed based on generating output on peak hours (hours ending 3, 4, 5, and 6 PM Local Prevailing Time) during the past 3 summer periods.

[25] Please see http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx
[26] http://www.pjm.com/~/media/documents/manuals/m19.ashx
[27] http://www.pjm.com/~/media/documents/manuals/m20.ashx

Definition of Loss-of-Load Event

NPCC Regional Reliability Reference Directory No. 1 "Design and Operation of the Bulk Power System" Section 5.2 Resource Adequacy – Design Criteria states: [28]

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

Area operators may invoke their available operating procedures in any order, depending on the situation faced at the time; for this analysis, the reliability indices were calculated following the sequential order shown in the tables below; the CP-8 Working Group agreed that modeling the actions this way was a reasonable approximation for this analysis.

It should be recognized that changing the assumed order of the operating procedures in the analysis will change the magnitude of the calculated indices. The highlighted values for the metrics in the Tables 6 and 7 estimates below are consistent with NPCC's Resource Adequacy – Design Criteria; i.e., they are calculated following all possible allowable "load relief from available operating procedures."

[28] See: http://www.npcc.org/documents/regStandards/Directories.aspx

Base Case Results

Table 6(a) Base Case Results for 2016 – LOLH (hours/year)

	Expected Load				
	Q	**MT**	**NE**	**NY**	**ON**
Curtail Load / Utility Surplus	0.040	0.488	2.112	2.203	0.667
No 30-min Reserves	0.001	0.462	1.061	0.869	0.024
Volt. Red. or Inter. Loads	0.000	0.177	0.582	0.226	0.003
No 10-min Reserves (NY - Public Appeals)	0.000	0.015	0.413	0.126	0.000
General Public Appeals (NY - No 10-min.)	0.000	0.001	0.340	0.075	0.000
Disconnect Load	0.000	0.001	0.067	0.009	0.000

Table 6(b) Base Case Results for 2016 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	Expected Load				
	Q	**MT**	**NE**	**NY**	**ON**
Curtail Load / Utility Surplus	0.056	0.928	14.151	12.193	2.719
No 30-min Reserves	0.000	0.871	7.631	2.055	0.064
Volt. Red. or Inter. Loads	0.000	0.871	7.631	2.055	0.064
No 10-min Reserves (NY - Public Appeals)	0.000	0.347	4.171	0.643	0.006
General Public Appeals (NY - No 10-min.)	0.000	0.029	2.772	0.300	0.000
Disconnect Load	0.000	0.000	0.307	0.010	0.000

Table 6(c) Base Case Results for 2016 – EUE (MWh of Unserved Energy)

	Expected Load				
	Q	**MT**	**NE**	**NY**	**ON**
Curtail Load / Utility Surplus	10.8	25.7	2,056.6	1,998.6	381.3
No 30-min Reserves	0.1	24.1	1,109.0	336.8	9.0
Volt. Red. or Inter. Loads	0.0	9.6	606.2	105.4	0.8
No 10-min Reserves (NY - Public Appeals)	0.0	0.8	402.9	49.2	0.0
General Public Appeals (NY - No 10-min.)	0.0	0.0	318.3	30.1	0.0
Disconnect Load	0.0	0.0	44.6	1.9	0.0

Table 7(a) Base Case Results for 2018 – LOLH (hours/year)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.035	0.525	4.287	4.470	0.471
No 30-min Reserves	0.001	0.498	3.068	1.886	0.048
Volt. Red. or Inter. Loads	0.000	0.183	1.688	0.731	0.007
No 10-min Reserves (NY - Public Appeals)	0.000	0.018	1.172	0.397	0.000
General Public Appeals (NY - No 10-min.)	0.000	0.000	0.962	0.268	0.000
Disconnect Load	0.000	0.000	0.288	0.032	0.000

Table 7(b) Base Case Results for 2018 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.054	0.839	30.057	34.305	1.457
No 30-min Reserves	0.000	0.727	23.306	6.304	0.118
Volt. Red. or Inter. Loads	0.000	0.278	13.184	2.523	0.011
No 10-min Reserves (NY - Public Appeals)	0.000	0.022	9.174	1.214	0.000
General Public Appeals (NY - No 10-min.)	0.000	0.000	7.490	0.804	0.000
Disconnect Load	0.000	0.000	1.737	0.057	0.000

Table 7(c) Base Case Results for 2018 – EUE (MWh of Unserved Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	10.4	23.2	4,391.7	5,617.6	201.4
No 30-min Reserves	0.1	20.1	3,405.4	1,032.3	16.3
Volt. Red. or Inter. Loads	0.0	7.7	1,926.3	413.1	1.5
No 10-min Reserves (NY - Public Appeals)	0.0	0.6	1,340.5	198.8	0.0
General Public Appeals (NY - No 10-min.)	0.0	0.0	1,094.4	131.7	0.0
Disconnect Load	0.0	0.0	253.8	9.3	0.0

Scenario Results

The scenario estimated the Loss of Load Hours (LOLH) while still maintaining non-spinning and spinning operating reserves. The benefits of 30 and 10 minute reserve EOPs were set to 0. Tables 8 and 9 show the results after allowing "load relief from available from other operating procedures."

Table 8(a) Scenario Case Results for 2016 – LOLH (hours/year)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.040	0.488	2.112	2.203	0.667
No 30-min Reserves	0.001	0.462	1.061	0.869	0.024
Volt. Red. or Inter. Loads	0.001	0.462	1.061	0.869	0.024
No 10-min Reserves (NY - Public Appeals)	0.000	0.037	0.727	0.591	0.001
General Public Appeals (NY - No 10-min.)	0.000	0.037	0.595	0.367	0.001
Disconnect Load	0.000	0.037	0.595	0.366	0.000

Table 8(b) Scenario Case Results for 2016 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.056	0.926	13.809	12.164	2.789
No 30-min Reserves	0.000	0.869	7.446	2.050	0.066
Volt. Red. or Inter. Loads	0.000	0.869	7.449	2.050	0.066
No 10-min Reserves (NY - Public Appeals)	0.000	0.076	5.060	1.152	0.002
General Public Appeals (NY - No 10-min.)	0.000	0.076	4.077	0.716	0.002
Disconnect Load	0.000	0.076	4.007	0.714	0.000

Table 8(c) Scenario Case Results for 2016 – EUE (MWh of Unserved Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	10.8	25.7	2,056.6	1,998.6	381.3
No 30-min Reserves	0.1	24.1	1,109.0	336.8	9.0
Volt. Red. or Inter. Loads	0.1	24.1	1,109.0	336.8	9.0
No 10-min Reserves (NY - Public Appeals)	0.0	2.1	753.6	189.3	0.3
General Public Appeals (NY - No 10-min.)	0.0	2.1	607.2	117.6	0.3
Disconnect Load	0.0	2.1	607.2	117.3	0.1

Table 9(a) Scenario Case Results for 2018 – LOLH (hours/year)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.035	0.525	4.287	4.470	0.471
No 30-min Reserves	0.001	0.498	3.068	1.886	0.048
Volt. Red. or Inter. Loads	0.001	0.498	3.068	1.886	0.048
No 10-min Reserves (NY - Public Appeals)	0.000	0.061	2.115	1.229	0.002
General Public Appeals (NY - No 10-min.)	0.000	0.061	1.711	0.822	0.002
Disconnect Load	0.000	0.061	1.711	0.821	0.001

Table 9(b) Base Case Results for 2018 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	0.054	0.836	29.488	34.190	1.473
No 30-min Reserves	0.000	0.725	22.865	6.283	0.119
Volt. Red. or Inter. Loads	0.000	0.725	22.865	6.283	0.119
No 10-min Reserves (NY - Public Appeals)	0.000	0.068	15.849	3.354	0.004
General Public Appeals (NY - No 10-min.)	0.000	0.068	12.892	2.286	0.004
Disconnect Load	0.000	0.068	12.889	2.257	0.000

Table 9(c) Scenario Case Results for 2018 – EUE (MWh of Unserved Energy)

	Expected Load				
	Q	MT	NE	NY	ON
Curtail Load / Utility Surplus	10.4	23.2	4,391.7	5,617.6	201.4
No 30-min Reserves	0.1	20.1	3,405.4	1,032.3	16.3
Volt. Red. or Inter. Loads	0.1	20.1	3,405.4	1,032.3	16.3
No 10-min Reserves (NY - Public Appeals)	0.0	1.9	2,360.4	551.1	0.5
General Public Appeals (NY - No 10-min.)	0.0	1.9	1,920.0	375.6	0.5
Disconnect Load	0.0	1.9	1,919.6	370.8	0.1

Comparison with the 2012 Assessment

Table 10(a) - New England 2012 assessment comparison for the year 2016

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh – ppm [29])	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
*2016**	*149,564*	*29,400*	*33,260*	*31,744*	*6.700 - 0.045*	*0.014*	*13.1%*	*8.0%*
2016	145,332	27,291	33,052	30,773	44.6 - 0.307	0.067	25.5%	16.8%

** Results from the 2012 Probabilistic Assessment*

For the year 2016, the estimates for New England's LOLH and EUE are higher in the 2014 Probabilistic Assessment as compared to the 2012 Probabilistic Assessment. The 2014 Probabilistic Assessment assumed a Forecast Peak Demand for 2016 that was lower than the corresponding value forecast in the 2012 study (column 3 of Table 10(a)), with less Forecast Capacity and Operable Capacity Resources (columns 4-5 of Table 10(a)) that contribute to this result.

Table 10(b) - New York 2012 assessment comparison for the year 2016

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh – ppm [30])	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
*2016**	*171,282*	*33,598*	*40,730*	*37,953*	*3.000 – 0.018*	*0.012*	*21.2%*	*13.0%*
2016	163,907	34,412	38,314	35,318	1.900 - 0.010	0.009	15.3%	6.3%

** Results from the 2012 Probabilistic Assessment*

For the year 2016, the estimates for New York's LOLH and EUE are lower in the 2014 Probabilistic Assessment as compared to the 2012 Probabilistic Assessment. The 2014 Probabilistic Assessment assumed a Forecast Peak Demand for 2016 that was higher than the corresponding value assumed in the 2012 study (column 3 of Table 10(b)), with less Forecast and Operable Capacity Resources (columns 4-5 of Table 10(b); reliance on demand response, operating procedures and tie benefits contribute to this result.

[29] MWh of EUE per Million MWh of Annual Load Energy
[30] MWh of EUE per Million MWh of Annual Load Energy

Table 10(c) - Ontario 2012 assessment comparison for the year 2016

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
*2016**	*131,834*	*22,436*	*27,384*	*26,487*	*0.000*	*0.000*	*22.1%*	*18.1%*
2016	140,235	22,535	27,565	25,935	0.000	0.000	22.3%	15.1%

** Results from the 2012 Probabilistic Assessment*

Due to essentially the same Forecast Planning Reserve Margin (column 8 in Table 10(c)) the estimates for Ontario's EUE and LOLE for 2016 are the same in the 2014 Probabilistic Assessment, as compared to the 2012 Probabilistic Assessment.

Table 10(d) - Quebec 2012 assessment comparison for the year 2016

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
*2016**	*193,728*	*38,448*	*41,968*	*41,399*	*0.000*	*0.000*	*9.2%*	*7.7%*
2016	191,408	38,137	40,803	40,177	0.000	0.000	12.0%	10.3%

** Results from the 2012 Probabilistic Assessment*

For the year 2016, the estimates for Quebec's LOLH and EUE are the same in the 2014 Probabilistic Assessment, as compared to the 2012 Probabilistic Assessment. The 2014 Probabilistic Assessment assumed a Forecast Peak Demand for 2016 that was lower than the corresponding value assumed in the 2014 study, resulting in higher estimated Planning and Operable Reserve Margins (columns 8-9 in Table 10(d)).

Table 10(e) - Maritimes 2012 assessment comparison for the year 2016

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Forecast Operable Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh – ppm [31])	Loss of Load Hours (LOLH) (hours/yr)	Forecast Planning Reserve Margin (%)	Forecast Operable Reserve Margin (%)
*2016**	*27,079*	*5,206*	*6,893*	*6,670*	*0.200 - .0070*	*0.005*	*32.4%*	*28.1%*
2016	27,682	5,308	6,820	6,541	0.000 - 0.000	0.001	35.3%	29.8%

** Results from the 2012 Probabilistic Assessment*

Due to the higher estimated Planning and Operable Reserve Margins (columns 8-9 in Table 10(e)); the estimates of the Maritime's LOLH and EUE for 2016 are smaller in the 2014 Probabilistic Assessment as compared to the 2012 Probabilistic Assessment.

[31] MWh of EUE per Million MWh of Annual Load Energy

APPENDIX A
Demand and Capacity – Maritimes

	2016	2018
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	27682	27654

	2016		2018	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	5308	3669	5322	3612
Low Forecast Cumulative Probability	7%	7%	7%	7%
Low Forecast Demand	4737	3298	4831	3262
High Forecast Cumulative Probability	93%	93%	93%	93%
High Forecast Demand	5697	3967	5810	3923
Demand-Side Management - Program Total	**267**	**342**	**312**	**342**
Direct Control Load Management (DCLM)	20	0	60	0
Interruptible Load	247	342	252	342
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Demand-Side Management - Available	**267**	**342**	**312**	**342**
Direct Control Load Management (DCLM)	20	0	60	0
Interruptible Load	247	342	252	342
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Net Internal Demand	**5041**	**3327**	**5010**	**3270**

	2016		2018	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**7916**	**7916**	**7793**	**7793**
Coal	1762	1762	1607	1607
Petroleum	1964	1964	1964	1964
Gas	844	844	844	844
Nuclear	705	705	705	705
Other/Unknown	0	0	0	0
Renewable – Hydro	1321	1321	1321	1321
Renewable - Pumped Storage	0	0	0	0
Renewable – Geothermal	0	0	0	0
Renewable – Biomass	223	223	223	223
Renewable – Wind	1069	1069	1101	1101
Renewable – Solar	0	0	0	0
Renewable – Other	28	28	28	28

Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**6381**	**6614**	**6681**	**6465**
Coal	1709	1694	1556	1541
Petroleum	1893	1787	1893	1787
Gas	848	838	848	838
Nuclear	660	660	660	660
Other/Unknown	0	0	0	0
Renewable – Hydro	1320	1320	1320	1320
Renewable - Pumped Storage	0	0	0	0
Renewable – Geothermal	0	0	0	0
Renewable – Biomass	130	130	130	130
Renewable – Wind	271	185	275	189
Renewable – Solar	0	0	0	0
Renewable – Other	0	0	0	0
Capacity Adjustments On-Peak	**10**	**991**	**47**	**258**
Scheduled Outages	10	991	47	258
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	4.4%	4.3%	4.6%	4.4%
Petroleum	2.7%	2.5%	2.7%	2.5%
Gas	3.7%	3.7%	3.7%	3.7%
Nuclear	15.5%	15.5%	15.5%	15.5%
Other/Unknown	0.0%	0.0%	0.0%	0.0%
Renewable – Hydro	1.0%	1.0%	1.0%	1.0%
Renewable - Pumped Storage	0.0%	0.0%	0.0%	0.0%
Renewable – Geothermal	0.0%	0.0%	0.0%	0.0%
Renewable – Biomass	4.3%	4.3%	4.3%	4.3%
Renewable – Wind	0.0%	0.0%	0.0%	0.0%
Renewable – Solar	0.0%	0.0%	0.0%	0.0%
Renewable – Other	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	**6551**	**6343**	**6407**	**6199**

	2016		**2018**	
CAPACITY TRANSFERS	**Winter**	**Summer**	**Winter**	**Summer**
Imports				
Firm	0	0	0	0
Expected	0	0	0	153
Exports				
Firm	0	0	0	0
Expected	0	0	0	0

	2016		**2018**	
CAPACITY OBLIGATIONS & OPERATING PROCEDURES	**Winter**	**Summer**	**Winter**	**Summer**

Other Obligations from Resources	**738**	**738**	**738**	**738**
Non-Spinning Reserves	738	738	738	738
Spinning Reserves				
Other Obligations				
Operating Procedures (Before Loss-of-Load)	**1403**	**1415**	**1402**	**1414**
Additional Demand Response	333	338	332	338
Non-Spinning Reserves (Forgone)	233	233	233	233
Spinning Reserves (Forgone)	505	505	505	505
Other Obligations (Forgone)	0	0	0	0
Interruptible Load	333	338	332	338
Voltage Reductions	0	0	0	0
Public Appeals	0	0	0	0
Other	0	0	0	0

	2016	**2018**
PROBABILISTIC STATISTICS	**Annual**	**Annual**
Expected Unsupplied Energy (EUE) (MWh)	0.000000	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.001000	0.000000

APPENDIX B

Demand and Capacity - New England

	2016	2018
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	145332	146114

	2016		2018	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	22755	27291	21238	27677
Low Forecast Cumulative Probability	7%	7%	7%	7%
Low Forecast Demand	19212	25725	19438	26498
High Forecast Cumulative Probability	93%	93%	93%	93%
High Forecast Demand	23468	32467	23744	33442
Demand-Side Management - Program Total	**1129**	**944**	**978**	**994**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	1129	944	978	994
Demand-Side Management - Available	**1129**	**944**	**978**	**994**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	1129	944	978	994
Net Internal Demand	**21626**	**26347**	**20260**	**26683**

	2016		2018	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**37531**	**38847**	**37214**	**37583**
Coal	2488	2488	1364	1364
Petroleum	8596	8596	7751	8105
Gas	15720	16436	16768	16768
Nuclear	4638	4638	4638	4638
Other/Unknown	31	31	31	31
Renewable - Hydro	1710	1712	1696	1712
Renewable - Pumped Storage	1571	1621	1621	1621
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	1257	1326	1326	1326
Renewable - Wind	1200	1678	1698	1698
Renewable - Solar	125	125	125	125

Renewable - Other	194	194	194	194
Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**33709**	**31545**	**33361**	**30362**
Coal	2300	2116	1194	1042
Petroleum	7582	6560	7124	6113
Gas	15218	14161	16224	14493
Nuclear	4041	4022	4041	4022
Other/Unknown	16	20	16	20
Renewable - Hydro	1574	1492	1568	1492
Renewable - Pumped Storage	1730	1769	1679	1769
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	922	1029	992	1029
Renewable - Wind	300	281	496	287
Renewable - Solar	27	97	27	97
Renewable - Other	0	0	0	0
Capacity Adjustments On-Peak	**2576**	**0**	**2764**	**0**
Scheduled Outages	2576	0	2764	0
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	11.8%	12.1%	9.6%	9.8%
Petroleum	17.2%	16.6%	16.9%	16.2%
Gas	3.9%	3.9%	3.9%	3.9%
Nuclear	3.1%	3.1%	3.1%	3.1%
Other/Unknown	14.2%	14.2%	14.2%	14.2%
Renewable - Hydro	2.2%	2.0%	2.2%	2.0%
Renewable - Pumped Storage	7.3%	7.1%	7.4%	7.1%
Renewable - Geothermal	0.0%	0.0%	0.0%	0.0%
Renewable - Biomass	5.5%	6.1%	5.5%	6.1%
Renewable - Wind	7.8%	7.8%	7.8%	7.8%
Renewable - Solar	7.8%	7.8%	7.8%	7.8%
Renewable - Other	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	**31175**	**29266**	**31035**	**28326**

	2016		**2018**	
CAPACITY TRANSFERS	**Winter**	**Summer**	**Winter**	**Summer**
Imports				
Firm	1631	1607	1267	1267
Expected	0	0	0	0
Exports				
Firm	100	100	100	100
Expected	0	0	0	0

	2016		**2018**	

CAPACITY OBLIGATIONS & OPERATING PROCEDURES	Winter	Summer	Winter	Summer
Other Obligations from Resources	**2375**	**2375**	**2375**	**2375**
Non-Spinning Reserves	2375	2375	2375	2375
Spinning Reserves				
Other Obligations				
Operating Procedures (Before Loss-of-Load)	**3446**	**3319**	**2848**	**2717**
Additional Demand Response	840	827	237	228
Non-Spinning Reserves (Forgone)	625	625	625	625
Spinning Reserves (Forgone)	1550	1550	1550	1550
Other Obligations (Forgone)				
Interruptible Load	0	0	0	0
Voltage Reductions	431	316	437	314
Public Appeals	0	0	0	0
Other	0	0	0	0

	2016	2018
PROBABILISTIC STATISTICS	**Annual**	**Annual**
Expected Unsupplied Energy (EUE) (ppm) [32]	0.306884	1.736999
Expected Unsupplied Energy (EUE) (MWh)	44.6	253.8
Loss of Load Hours (LOLH) (hours/year)	0.067000	0.288000

[32] MWh of EUE per Million MWh of Annual Load Energy

APPENDIX C

Demand and Capacity - New York

	2016	2018
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	163907	163753

	2016		2018	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	27496	34412	28041	35111
Low Forecast Cumulative Probability	7%	7%	7%	7%
Low Forecast Demand	25394	30299	25897	30918
High Forecast Cumulative Probability	93%	93%	93%	93%
High Forecast Demand	27734	37364	28284	38116
Demand-Side Management - Program Total	**843**	**1189**	**843**	**1189**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	843	1189	843	1189
Demand-Side Management - Available	**843**	**1189**	**843**	**1189**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	843	1189	843	1189
Net Internal Demand	**26653**	**33223**	**27198**	**33922**

	2016		2018	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**43557**	**43557**	**43235**	**43171**
Coal	1567	1567	1245	1245
Petroleum	9926	9926	9926	9862
Gas	17697	17697	17697	17697
Nuclear	5708	5708	5708	5708
Other/Unknown	0	0	0	0
Renewable - Hydro	4949	4949	4949	4949
Renewable - Pumped Storage	1400	1400	1400	1400
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	463	463	463	463
Renewable - Wind	1708	1708	1708	1708
Renewable - Solar	32	32	32	32

Renewable - Other	109	109	109	109
Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**39295**	**36878**	**39422**	**36569**
Coal	1410	1408	1102	1099
Petroleum	2958	2475	2958	2475
Gas	23225	21832	23660	21832
Nuclear	5449	5371	5449	5371
Other/Unknown	0	0	0	0
Renewable - Hydro	3835	3807	3835	3807
Renewable - Pumped Storage	1409	1404	1409	1404
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	498	490	498	490
Renewable - Wind	512	82	512	82
Renewable - Solar	0	9	0	9
Renewable - Other	0	0	0	0
Capacity Adjustments On-Peak	**2484**	**291**	**2506**	**291**
Scheduled Outages	2484	291	2506	291
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	5.5%	5.5%	4.9%	4.9%
Petroleum	25.3%	24.7%	25.3%	24.7%
Gas	9.2%	9.3%	9.2%	9.3%
Nuclear	3.0%	3.0%	3.0%	3.0%
Other/Unknown	0.0%	0.0%	0.0%	0.0%
Renewable – Hydro	0.0%	0.0%	0.0%	0.0%
Renewable - Pumped Storage	3.2%	3.2%	3.2%	3.2%
Renewable – Geothermal	0.0%	0.0%	0.0%	0.0%
Renewable – Biomass	14.8%	14.3%	14.3%	14.3%
Renewable – Wind	0.0%	0.0%	0.0%	0.0%
Renewable – Solar	0.0%	0.0%	0.0%	0.0%
Renewable – Other	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	**33565**	**33591**	**33658**	**33306**

	2016		**2018**	
CAPACITY TRANSFERS	**Winter**	**Summer**	**Winter**	**Summer**
Imports				
Firm	1428	2518	1428	2518
Expected				
Exports				
Firm	1921	791	1731	693
Expected				

	2016	**2018**

CAPACITY OBLIGATIONS & OPERATING PROCEDURES	Winter	Summer	Winter	Summer
Other Obligations from Resources	**1965**	**1965**	**1965**	**1965**
Non-Spinning Reserves	1965	1965	1965	1965
Spinning Reserves				
Other Obligations				
Operating Procedures (Before Loss-of-Load)	**3104**	**3217**	**3112**	**3228**
Additional Demand Response	806	810	807	811
Non-Spinning Reserves (Forgone)	655	655	655	655
Spinning Reserves (Forgone)	1310	1310	1310	1310
Other Obligations (Forgone)	0	0	0	0
Interruptible Load	0	0	0	0
Voltage Reductions	333	442	340	452
Public Appeals	0	0	0	0
Other	0	0	0	0

	2016	**2018**
PROBABILISTIC STATISTICS	**Annual**	**Annual**
Expected Unsupplied Energy (EUE) (ppm) [33]	0.010	0.057
Expected Unsupplied Energy (EUE) (MWh)	1.9	9.3
Loss of Load Hours (LOLH) (hours/year)	0.009000	0.032000

[33] MWh of EUE per Million MWh of Annual Load Energy

Appendix D

Demand and Capacity – Ontario

	2016	2018
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	140235	138227

	2016		2018	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	21878	22535	21582	22301
Low Forecast Cumulative Probability	7%	7%	7%	7%
Low Forecast Demand	20507	19803	20234	19593
High Forecast Cumulative Probability	93%	93%	93%	93%
High Forecast Demand	22752	25097	22449	24830
Demand-Side Management - Program Total	**0**	**0**	**0**	**0**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Demand-Side Management - Available	**0**	**0**	**0**	**0**
Direct Control Load Management (DCLM)	0	0	0	0
Interruptible Load	0	0	0	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Net Internal Demand	**21878**	**22535**	**21582**	**22301**

	2016		2018	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**35738**	**34770**	**36122**	**36293**
Coal	0	0	0	0
Petroleum	2139	2139	2139	2139
Gas	7781	7504	8493	8344
Nuclear	12388	11664	11280	11299
Other/Unknown	0	0	0	0
Renewable - Hydro	8513	8546	8584	8584
Renewable - Pumped Storage	0	0	0	0
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	502	502	550	550
Renewable - Wind	4127	4127	4426	4726
Renewable - Solar	280	280	642	642

Renewable - Other	9	9	9	9
Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**30658**	**28845**	**31500**	**29838**
Coal	0	0	0	0
Petroleum	2146	2146	2146	2146
Gas	6938	6309	7353	6798
Nuclear	12929	12929	12925	12925
Other/Unknown	0	0	0	0
Renewable - Hydro	6351	6002	6407	6029
Renewable - Pumped Storage	0	0	0	0
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	426	426	473	473
Renewable - Wind	1783	821	1998	980
Renewable - Solar	86	213	198	487
Renewable - Other	0	0	0	0
Capacity Adjustments On-Peak	**1554**	**1280**	**2924**	**1636**
Scheduled Outages	1554	1280	2924	1636
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	0.0%	0.0%	0.0%	0.0%
Petroleum	5.1%	5.1%	5.1%	5.1%
Gas	6.3%	6.4%	6.5%	6.5%
Nuclear	8.5%	8.5%	8.5%	8.5%
Other/Unknown	0.0%	0.0%	0.0%	0.0%
Renewable - Hydro	0.0%	0.0%	0.0%	0.0%
Renewable - Pumped Storage	0.0%	0.0%	0.0%	0.0%
Renewable - Geothermal	0.0%	0.0%	0.0%	0.0%
Renewable - Biomass	5.5%	5.5%	5.5%	5.9%
Renewable - Wind	0.0%	0.0%	0.0%	0.0%
Renewable - Solar	0.0%	0.0%	0.0%	0.0%
Renewable - Other	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	**28995**	**27215**	**29790**	**28162**

	2016		**2018**	
CAPACITY TRANSFERS	**Winter**	**Summer**	**Winter**	**Summer**
Imports				
Firm	0	0	0	0
Expected	0	0	0	0
Exports				
Firm	0	0	0	0
Expected	0	0	0	0

	2016		**2018**	

CAPACITY OBLIGATIONS & OPERATING PROCEDURES	Winter	Summer	Winter	Summer
Other Obligations from Resources	**1418.1**	**1418.1**	**1418.1**	**1418.1**
Non-Spinning Reserves	1418	1418	1418	1418
Spinning Reserves				
Other Obligations				
Operating Procedures (Before Loss-of-Load)	**3807**	**3833**	**3946**	**3974**
Additional Demand Response	909	909	984	984
Non-Spinning Reserves (Forgone)	473	473	473	473
Spinning Reserves (Forgone)	945	945	945	945
Other Obligations (Forgone)	0	0	0	0
Interruptible Load	809	809	884	884
Voltage Reductions	454	472	448	467
Public Appeals	216	225	213	222
Other	0	0	0	0

	2016	2018
PROBABILISTIC STATISTICS	**Annual**	**Annual**
Expected Unsupplied Energy (EUE) (MWh)	0.000000	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.000000	0.000000

Appendix E
Demand and Capacity - Quebec

	2016	2018
ENERGY	**Annual**	**Annual**
Net Energy for Load - Annual (GWh)	191408	192576

	2016		2018	
DEMAND	**Winter**	**Summer**	**Winter**	**Summer**
Total Internal Demand				
Expected Demand (50/50)	38137	21867	38658	21942
Low Forecast Cumulative Probability	7%	7%	7%	7%
Low Forecast Demand	35030	20258	35240	19770
High Forecast Cumulative Probability	93%	93%	93%	93%
High Forecast Demand	41413	23952	42237	23789
Demand-Side Management - Program Total	**1708**	**0**	**1902**	**0**
Direct Control Load Management (DCLM)	250	0	350	0
Interruptible Load	1458	0	1552	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Demand-Side Management - Available	**1708**	**0**	**1902**	**0**
Direct Control Load Management (DCLM)	250	0	350	0
Interruptible Load	1458	0	1552	0
Critical Peak-Pricing (CPP) with Control	0	0	0	0
Load as a Capacity Resource	0	0	0	0
Net Internal Demand	**36429**	**21867**	**36756**	**21942**

	2016		2018	
CAPACITY	**Winter**	**Summer**	**Winter**	**Summer**
Capacity Installed (Nameplate)	**45397**	**46466**	**46757**	**46957**
Coal	0	0	0	0
Petroleum	436	436	436	436
Gas	507	507	507	507
Nuclear	0	0	0	0
Other/Unknown	0	0	0	0
Renewable - Hydro	40696	40956	41406	41406
Renewable - Pumped Storage	0	0	0	0
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	411	420	461	461
Renewable - Wind	3328	4128	3928	4128
Renewable - Solar	0	0	0	0

Renewable - Other	19	19	19	19
Capacity Expected On-Peak (Summer/Winter Certain/Planned)	**40818**	**35007**	**41729**	**35769**
Coal	0	0	0	0
Petroleum	436	383	436	383
Gas	0	0	0	0
Nuclear	0	0	0	0
Other/Unknown	0	0	0	0
Renewable - Hydro	39024	34268	39710	34956
Renewable - Pumped Storage	0	0	0	0
Renewable - Geothermal	0	0	0	0
Renewable - Biomass	385	356	430	430
Renewable - Wind	973	0	1153	0
Renewable - Solar	0	0	0	0
Renewable - Other	0	0	0	0
Capacity Adjustments On-Peak	**0**	**0**	**0**	**0**
Scheduled Outages	0	0	0	0
Transmission Limitations	0	0	0	0
Other	0	0	0	0
Weighted Average Forced Outage Rate On-Peak				
Coal	0.0%	0.0%	0.0%	0.0%
Petroleum	4.5%	4.5%	4.5%	4.5%
Gas	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Other/Unknown	0.0%	0.0%	0.0%	0.0%
Renewable - Hydro	1.6%	1.6%	1.6%	1.6%
Renewable - Pumped Storage	0.0%	0.0%	0.0%	0.0%
Renewable - Geothermal	0.0%	0.0%	0.0%	0.0%
Renewable - Biomass	0.0%	0.0%	0.0%	0.0%
Renewable - Wind	0.0%	0.0%	0.0%	0.0%
Renewable - Solar	0.0%	0.0%	0.0%	0.0%
Renewable - Other	0.0%	0.0%	0.0%	0.0%
Operable Capacity Resources	**40191**	**34452**	**41079**	**35185**

	2016		**2018**	
CAPACITY TRANSFERS	**Winter**	**Summer**	**Winter**	**Summer**
Imports				
Firm	1299	191	1299	191
Expected	0	0	0	0
Exports				
Firm	1314	2464	1111	2193
Expected				

	2016	**2018**

CAPACITY OBLIGATIONS & OPERATING PROCEDURES	Winter	Summer	Winter	Summer
Other Obligations from Resources	**1500**	**1500**	**1500**	**1500**
Non-Spinning Reserves	1500	1500	1500	1500
Spinning Reserves				
Other Obligations				
Operating Procedures (Before Loss-of-Load)	**1466**	**2791**	**1566**	**2895**
Additional Demand Response	1240	0	1245	0
Non-Spinning Reserves (Forgone)	500	500	500	500
Spinning Reserves (Forgone)	750	750	750	750
Other Obligations (Forgone)	0	0	0	0
Interruptible Load	0	0	0	0
Voltage Reductions	300	216	400	316
Public Appeals	0	0	0	0
Other	0	0	0	0

	2016	2018
PROBABILISTIC STATISTICS	**Annual**	**Annual**
Expected Unsupplied Energy (EUE) (MWh)	0.000000	0.000000
Loss of Load Hours (LOLH) (hours/year)	0.000000	0.000000

Appendix F

Definitions

Net Energy for Load (GWh)	*Energy Modeled (Input)*
Total Internal Demand (MW)	*Peak Load (Input)*
Demand-Side Management – Available	Sum of DCLM, Interruptible Load, CPP, Load as Cap (from Form A) (Not probabilistic data)
Net Internal Demand (MW)	Peak Load - Demand-Side Management – Available
Capacity Expected on Peak	*Sum of capacity by type modeled in probabilistic (Input)*
Net Firm Import/Exports	*Input*
Forecast Capacity Resources (MW)	Capacity Expected on Peak + Net Firm Import/Exports - Capacity Adjustments
Weighted average forced outage	*Input based on weighted EFOR by Area*
Operable Capacity Resources	Sum of capacity expected on peak * weighted average forced outage rate by type
Forecast Operable Capacity Resources (MW)	Operable Capacity Resources + Net Firm Import/Exports - Capacity Adjustments
Expected Unsupplied Energy (EUE) (MWh)	*Result (Input)*
Loss of Load Hours (LOLH) (hours/year)	*Result (Input)*
Forecast Planning Reserve Margin (%)	Forecast Capacity Resources/Net Internal Demand - 1
Forecast Operable Reserve Margin (%)	Forecast Operable Capacity Resources / Net Internal Demand - 1

Appendix G

2014 LTRA Reference Case Data Summary

Projected Total Internal Demand by Assessment Area and Interconnection: 2015–2024 Summer [34]

Assessment Area / Interconnection	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-Year CAGR
FRCC	46,719	47,615	48,501	49,147	49,852	50,554	51,263	52,049	52,981	52,981	1.41%
MISO	128,571	130,101	131,242	132,376	133,470	134,509	135,526	136,460	137,377	138,433	0.82%
MRO-Manitoba Hydro	3,434	3,483	3,424	3,446	3,482	3,555	3,610	3,655	3,703	3,753	0.99%
MRO-MAPP	5,028	5,374	5,500	5,690	5,810	5,927	6,038	6,145	6,257	6,427	2.77%
MRO-SaskPower	3,208	3,289	3,357	3,469	3,569	3,593	3,634	3,677	3,712	3,735	1.70%
NPCC-Maritimes	3,420	3,529	3,497	3,481	3,455	3,444	3,425	3,421	3,418	3,421	0.00%
NPCC-New England	26,930	27,291	27,521	27,677	27,782	27,911	28,028	28,167	28,298	28,430	0.60%
NPCC-New York	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580	0.79%
NPCC-Ontario	22,726	22,535	22,344	22,301	22,272	22,170	22,479	22,609	22,616	22,541	-0.09%
NPCC-Québec	21,436	21,196	21,320	21,335	21,471	21,673	22,110	22,274	22,421	22,557	0.57%
PJM	160,259	162,470	164,195	165,479	166,900	168,593	170,027	171,217	172,542	173,729	0.90%
SERC-E	44,086	44,768	45,398	45,992	46,669	47,289	47,928	48,579	49,251	49,943	1.40%
SERC-N	42,100	42,571	42,917	43,298	43,677	44,018	44,470	44,908	45,359	45,797	0.94%
SERC-SE	47,116	48,137	48,931	49,427	50,124	51,135	51,563	52,292	53,046	53,844	1.49%
SPP	49,710	50,993	51,700	52,267	52,849	53,454	53,999	54,817	55,438	56,991	1.53%
TRE-ERCOT	69,057	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	1.29%
WECC-CAMX	57,606	56,767	57,004	57,245	57,580	58,003	58,257	58,542	58,742	58,930	0.25%
WECC-NWPP	66,283	67,733	69,233	70,674	71,799	72,745	73,586	74,390	75,364	76,652	1.63%
WECC-RMRG	9,899	10,100	10,239	10,410	10,558	10,709	10,843	10,901	11,046	11,249	1.43%
WECC-SWSG	22,635	22,760	23,282	23,762	24,335	24,707	25,113	25,694	26,193	26,709	1.86%
Eastern Interconnection	617,372	626,567	633,293	639,161	645,365	651,809	657,879	664,123	670,366	676,604	1.02%
Québec Interconnection	21,436	21,196	21,320	21,335	21,471	21,673	22,110	22,274	22,421	22,557	0.57%
ERCOT Interconnection	69,057	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	1.29%
Western Interconnection	156,423	157,360	159,758	162,092	164,272	166,165	167,798	169,527	171,345	173,540	1.16%
TOTAL-NERC	**864,288**	**875,137**	**885,242**	**894,393**	**903,967**	**913,430**	**922,497**	**931,555**	**940,682**	**950,171**	**1.06%**

[34] Appendix I – 2014 NERC Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

Projected Total Internal Demand by Assessment Area and Interconnection: 2015–2024 Winter

Assessment Area / Interconnection	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-Year CAGR
FRCC	45,668	46,415	47,165	47,692	48,241	48,769	49,323	49,934	50,584	50,584	1.14%
MISO	104,414	107,352	108,414	109,506	110,457	111,360	112,219	113,053	113,797	115,031	1.08%
MRO-Manitoba Hydro	4,652	4,713	4,663	4,705	4,761	4,854	4,931	4,997	5,066	5,136	1.11%
MRO-MAPP	5,457	5,818	5,949	6,176	6,311	6,440	6,572	6,702	6,832	7,009	2.82%
MRO-SaskPower	3,557	3,647	3,722	3,846	3,957	3,984	4,029	4,077	4,116	4,141	1.70%
NPCC-Maritimes	5,477	5,513	5,508	5,493	5,466	5,434	5,421	5,420	5,425	5,427	-0.10%
NPCC-New England	22,755	21,274	21,238	21,153	21,062	20,986	20,918	20,865	20,822	20,790	-1.00%
NPCC-New York	24,795	24,856	24,906	24,966	25,104	25,177	25,252	25,334	25,427	25,537	0.33%
NPCC-Ontario	21,901	21,901	21,529	21,592	21,578	21,535	21,646	21,541	21,508	21,628	-0.14%
NPCC-Québec	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373	0.86%
PJM	135,526	137,308	138,314	139,213	139,975	141,369	142,489	143,481	144,359	144,913	0.75%
SERC-E	42,466	42,560	42,907	43,476	44,186	44,858	45,603	46,300	46,847	47,557	1.27%
SERC-N	40,288	41,022	41,348	41,639	41,955	42,419	42,902	43,322	43,642	44,263	1.05%
SERC-SE	44,692	45,292	45,946	46,332	46,997	47,635	48,300	48,996	49,679	50,399	1.34%
SPP	36,702	38,123	38,549	39,181	39,546	40,062	40,664	41,141	41,639	42,064	1.53%
TRE-ERCOT	53,719	53,719	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	1.33%
WECC-CAMX	40,189	40,227	40,292	40,432	40,636	40,946	41,209	41,424	41,515	41,564	0.37%
WECC-NWPP	70,778	71,786	73,217	74,430	75,490	76,482	77,422	78,320	79,189	79,912	1.36%
WECC-RMRG	10,061	10,205	10,355	10,466	10,584	10,724	10,863	10,994	11,121	11,251	1.25%
WECC-SWSG	15,650	15,862	16,138	16,443	16,852	17,190	17,492	17,814	18,156	18,439	1.84%
Eastern Interconnection	538,350	545,794	550,157	554,970	559,596	564,883	570,270	575,163	579,742	584,478	0.92%
Québec Interconnection	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373	0.86%
ERCOT Interconnection	53,719	53,719	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	1.33%
Western Interconnection	136,678	138,080	140,002	141,771	143,562	145,341	146,986	148,551	149,981	151,166	1.13%
TOTAL-NERC	**767,063**	**776,205**	**783,586**	**791,350**	**799,005**	**807,558**	**815,776**	**823,381**	**830,486**	**837,497**	**0.98%**

NPCC-Maritimes

Assessment Area Overview [35]

The Maritimes Assessment Area is a winter-peaking NPCC subregion that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles, with a total population of 1.9 million people.

Summary of Methods and Assumptions

Reference Margin Level
20 percent

Load Forecast Method
Coincident; 50/50 forecast

Peak Season
Winter

Planning Considerations for Wind Resources
Estimated capacity is derived from a combination of mandated capacity factors and reliability impacts.

Planning Considerations for Solar Resources
N/A

Footprint Changes
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	5,477	5,513	5,508	5,493	5,466	5,434	5,421	5,420	5,425	5,427
Demand Response	247	252	252	252	251	251	251	251	251	251
Net Internal Demand	5,230	5,261	5,256	5,241	5,214	5,183	5,170	5,169	5,174	5,176
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	6,676	6,680	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527
Prospective	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Adjusted-Potential	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27.66%	26.97%	24.19%	24.53%	25.18%	25.93%	26.25%	26.28%	26.16%	26.11%
Prospective	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
Adjusted-Potential	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
Reference Margin Level	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	401	366	220	238	270	308	323	325	319	316
Prospective	545	511	364	535	567	605	620	622	616	613
Adjusted-Potential	545	511	364	535	567	605	620	622	616	613

[35] Page 55 - NERC 2014 Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

NPCC-New England

Assessment Area Overview [36]

ISO New England (ISO-NE) Inc. is a regional transmission organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

Summary of Methods and Assumptions

Reference Margin Level
The Installed Capacity Requirement (ICR) results in a Reference Margin Level of 15.7 percent in 2015, declining to 14.3 percent in 2017 and remaining at that level for the duration of the period.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
5 percent of the total

Planning Considerations for Solar Resources
Seasonal claimed capability

Footprint Changes
N/A

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	26,930	27,291	27,521	27,677	27,782	27,911	28,028	28,167	28,298	28,430
Demand Response	1,167	944	994	994	994	994	994	994	994	994
Net Internal Demand	25,763	26,347	26,527	26,683	26,788	26,917	27,034	27,173	27,304	27,436
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	31,880	33,052	31,529	31,529	31,529	31,529	31,529	31,529	31,529	31,529
Prospective	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Adjusted-Potential	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	23.75%	25.45%	18.85%	18.16%	17.70%	17.13%	16.63%	16.03%	15.47%	14.92%
Prospective	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Adjusted-Potential	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Reference Margin Level	15.70%	15.10%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Excess/Shortfall (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	2,073	2,727	1,208	1,030	910	762	629	470	320	169
Prospective	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103
Adjusted-Potential	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103

[36] Page 59 - NERC 2014 Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

NPCC-New York

Assessment Area Overview [37]

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). The NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. The NYISO manages the New York State transmission grid, encompassing approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

Summary of Methods and Assumptions

Reference Margin Level
The New York State Reliability Council (NYSRC) Installed Reserve Margin (IRM) of 17 percent extends through April 2015. Because this margin will be reassigned in 2015, NYISO will use the default Reference Margin Level of 15 percent.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled with a 17 percent capacity factor

Planning Considerations for Solar Resources
Modeled with a 65 percent capacity factor

Footprint Changes
N/A

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580
Demand Response	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189
Net Internal Demand	32,877	33,223	33,577	33,922	34,265	34,467	34,701	34,938	35,180	35,391
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	38,311	38,330	37,980	37,980	37,985	37,985	37,985	37,985	37,985	37,985
Prospective	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Adjusted-Potential	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	16.53%	15.37%	13.11%	11.96%	10.86%	10.21%	9.46%	8.72%	7.97%	7.33%
Prospective	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
Adjusted-Potential	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	502	123	(633)	(1,030)	(1,420)	(1,652)	(1,921)	(2,194)	(2,472)	(2,715)
Prospective	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528
Adjusted-Potential	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528

[37] Page 65 - NERC 2014 Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

NPCC-Ontario

Assessment Area Overview [38]

Ontario's electrical power system is geographically one of the largest in North America, covering an area of 415,000 square miles and serving the power needs of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established Reserve Margin Requirement is applied as the Reference Margin Level.[39]

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled, based on historic performance and historic weather data

Planning Considerations for Solar Resources
Modeled, based on historic weather data; 30 percent for summer

Footprint Changes
N/A

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	22,726	22,535	22,344	22,301	22,272	22,170	22,479	22,609	22,616	22,541
Demand Response	567	621	695	695	695	795	945	1,095	1,295	1,495
Net Internal Demand	22,158	21,914	21,649	21,606	21,576	21,375	21,534	21,514	21,321	21,046
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Prospective	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Adjusted-Potential	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Prospective	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Adjusted-Potential	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Reference Margin Level	19.50%	18.78%	19.86%	19.99%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	633	880	549	1,593	738	695	680	638	1,583	1,977
Prospective	633	880	549	1,593	738	695	680	638	1,583	1,977
Adjusted-Potential	633	880	549	1,593	738	695	680	638	1,583	1,977

[38] Page 69 - NERC 2014 Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf

[39] Ontario IESO, for its own assessments, treats Demand Response as a resource instead of as a load-modifier. As a consequence, the Net Internal Demand, Planning Reserve Margins and the Target Reserve Margin numbers differ in IESO reports when compared to NERC reports. The Ontario reports would report lower reserve margins.

NPCC-Québec

Assessment Area Overview [40]

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

Summary of Methods and Assumptions

Reference Margin Level
Reference Margin Levels are drawn from the Québec Area 2013 Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2013.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Winter

Planning Considerations for Wind Resources
On-peak contribution is approximately 30 percent of the total

Planning Considerations for Solar Resources
N/A

Footprint Changes
N/A

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373
Demand Response	1,708	1,852	1,902	1,952	2,002	2,202	2,252	2,252	2,252	2,252
Net Internal Demand	36,608	36,760	36,945	37,216	37,565	38,016	38,306	38,610	38,868	39,121
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Prospective	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Adjusted-Potential	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Prospective	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Adjusted-Potential	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Reference Margin Level	11.60%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Prospective	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Adjusted-Potential	476	384	968	1,845	1,489	1,374	1,071	765	511	226

[40] Page 74 - Page 69 - NERC 2014 Long-Term Reliability Assessment at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf