

Northeast Power Coordinating Council

2015 Long Range Adequacy Overview

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Conducted by the
NPCC CP-8 Working Group



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

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PREFACE

This assessment does not reflect the October 12, 2015 request, submitted by Entergy Nuclear Power Marketing, to retire the 680 MW Pilgrim nuclear unit by June 1, 2019. As required by its tariff, ISO New England will conduct a study to determine how the retirement will affect the overall reliability of the region's bulk power system. The retirement of this nuclear unit will be reflected in the 2016 NPCC Long Range Adequacy Overview.

On November 2, 2015 Entergy Nuclear Power Marketing announced their intention of retiring the 838 MW James A. Fitzpatrick nuclear unit at the end of its current fuel cycle by June 2017. The New York ISO will be conducting an assessment to determine how the retirement will affect the overall reliability of the region's bulk power system. The results of this assessment will be reflected in the 2016 NPCC Long Range Adequacy Overview.



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INTRODUCTION

This study evaluated, on a consistent basis, the long range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Regions' plans to meet their Loss of Load Expectation (LOLE) planning criteria ¹ through a multi-area probabilistic assessment for the period from 2016 to 2020, based on the reported NERC *2015 Long Term Reliability Assessment* ² data.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program ³ 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.

The database developed by the NPCC CP-8 Working Group's "*NPCC Reliability Assessment for Summer 2015*", April 30, 2015, ⁴ was used as the starting point for this Overview. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the 2016-2020 period, consistent with the information reported for the *NERC 2015 Long-Term Reliability Assessment*.

This report is organized in the following manner: after a brief Introduction, general modeling assumptions are presented followed by a summary provided by each Area describing their specific representation. The results and observations of the Overview are then presented.

The Overview's Objective and Scope of Work are shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis. NERC's 2015 Long-Term Reliability Assessment (LTRA) Narratives are provided (for reference) in Appendix C.

¹ See: <https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf> , Directory No. 1, Section 5.2

² See: <http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>

³ See: <http://geenergyconsulting.com/practice-area/software-products/mars>

⁴ See: <https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx> , Appendix VIII



MODEL ASSUMPTIONS

The assumptions used in NPCC's Long Range Adequacy Overview are consistent with the assumptions of the following recently completed Area studies:

Area Studies

New York

The Comprehensive System Planning Process⁵ (CSPP) is the NYISO's biennial ten-year planning process comprised of four components: 1) Local transmission Planning Process (LTPP); 2) Reliability Planning Process (RPP); 3) Congestion Assessment and Resource Integration Study (CARIS); and 4) Public Policy Transmission Planning Process. In addition, the CSPP provides for cost allocation and cost recovery in certain circumstances for regulated reliability and economic transmission projects, as well as the coordination of interregional planning activities.

The RPP consist of two studies:

- ✓ The Reliability Needs Assessment (RNA): The NYISO performs a biennial study in which it evaluates the resource adequacy and transmission system adequacy and security of the New York bulk power system over a ten year Study Period. Through this evaluation, the NYISO identifies Reliability Needs, if any, in compliance with applicable Reliability Criteria. The RNA report is reviewed by NYISO stakeholders and approved by the Board of Directors.
- ✓ The Comprehensive Reliability Plan (CRP): After the RNA is complete, the NYISO requests the submission of market-based solutions to satisfy the Reliability Need. The NYISO also identifies a Responsible TO and requests that the Responsible TO submit a regulated backstop solution, and provides that any interested entities may submit alternative regulated solutions to address the identified Reliability Needs. Prior to providing its response to the RNA, each Responsible TO will present any updates in its LTP that impact a Reliability Need identified in the RNA. If major system changes occur after the lock down date of the RNA base case, and these changes meet the base case inclusion rules, the NYISO next updates the CRP base case and determines whether the Reliability Needs identified in the RNA persist. The NYISO analyzes the viability and sufficiency of the proposed solutions to satisfy the identified Reliability Needs and evaluates and selects the more efficient or cost-effective transmission solution from among proposed transmission solutions to the identified Reliability Need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO triggers regulated solution(s) to satisfy the need. The NYISO develops the CRP for the ten year Study Period that sets forth its findings regarding the proposed solutions. The CRP is reviewed by NYISO stakeholders and approved by the Board of Directors.

Summary of 2014 RNA (September 2014)

Under base case assumptions, the 2014 RNA identified transmission system security violations beginning in 2015 and resource adequacy violations beginning in 2019 and increasing through 2024. For transmission security, there were four primary regions with Reliability Needs identified: Rochester, Western & Central New York, Capital Region, and the Lower Hudson Valley and New York City.

⁵ See Attachment Y of the NYISO Open Access Tariff (OATT)



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These Reliability Needs were generally driven by then-recent and proposed generator deactivations, combined with load growth. The New York transmission owners developed plans through their respective local transmission planning processes to construct transmission projects to meet not only the needs identified in the prior Reliability Planning Process, but also any additional needs occurring since then. Those transmission projects were included in the 2014 RNA base case. The NYISO identified the Reliability Needs in the 2014 RNA even with the inclusion of those transmission projects in the base case, or determined that the needs existed until the in-service date of certain projects.

New England

The 2015 Regional System Plan (RSP15) is the annual report prepared by ISO New England (ISO-NE) on the planning efforts to identify the region's electricity needs and actions for meeting these needs in order to maintain reliable and economic operation of New England's bulk power system over a ten-year horizon from 2015 to 2024. RSP15 and the ongoing system planning process comply with all applicable sections of the ISO's Transmission, Markets, and Services Tariff (ISO tariff), approved by FERC. The plan and planning process also satisfy the relevant standards, criteria, and other requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), participating transmission owners (PTOs), and the ISO. The study proposals, scopes of work, assumptions, study results, findings and recommendations presented in this report have been reviewed and discussed through the regional stakeholder process. The report was approved by the ISO-New England's Board of Directors on November 5, 2015.⁶

The RSP15 updates the system plans and analyses included in the 2014 Regional System Plan (RSP14). It provides updated information on electric power system needs; system improvements; and the results of newly completed load, resource, and transmission studies for reliably meeting demand throughout the region to 2024. It addresses stakeholder comments received throughout the planning process, and includes new information, such as the enhanced ISO forecast of photovoltaics (PV). RSP15 discusses ongoing and new analyses based on the current and planned system and describes new and planned infrastructure for all areas of New England. The report continues to address many of the challenges the region is facing and how the ISO and its stakeholders are addressing key strategic issues. Notably, the report addresses the major factors influencing resource development, the requirements for fuel certainty, and the development of the electric power system infrastructure for the 10-year planning period, such as existing and pending state and federal environmental and energy policies. As part of its compliance with Attachment K of the ISO's Open Access Transmission Tariff (OATT), RSP15 specifically provides information on the timing of system needs and the quantity, general locations, and characteristics of the generation and demand resources that could resolve these needs and defer or eliminate the need for transmission projects.

Major findings and observations of the RSP15 include:

Public policies are key drivers for the continuous growth of energy-efficiency resources and the development of photovoltaic facilities in the region. A 10-year PV forecast has been developed for the region based upon higher quality historical data of PV installations and production, and some key economic factors affecting future PV development. Regional passive demand resources and energy efficiency are expected to grow from 1,685 MW in 2015 to 3,579 MW in 2024, which drives the

⁶ See: http://www.iso-ne.com/static-assets/documents/2015/11/20151105_press_release_rsp15_final.pdf



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reduction of the growth rate of the 10-year gross winter peak demand from 0.7% to a net annual value of -0.1%. The 10-year growth rate of the net demand forecast is 0.6% per year for the summer peak demand, and 0.0% per year for the annual use of electric energy. Photovoltaic resources reached 908 MWac (nameplate rating) (i.e., the amount of electricity that PV could feed into the electrical system) by the end of 2014 and produced 864 GWh. These resources are expected to grow to 2,449 MWac nameplate rating by 2024 and are forecast to produce 2,593 GWh.

The region's net Installed Capacity Requirement is expected to grow from 33,391 MW in 2015 to a representative value of 36,000 MW by 2024. The net ICR increases approximately 290 MW per year, which is equivalent to 0.8% per year.

Transmission projects have improved regional reliability and continue to support the efficient operation of the markets. The Interstate Reliability Project, which is under construction, and the Greater Boston Reliability Project represent the most recent major 345 kV projects required to meet regional reliability. These projects will improve the ability to move power to all areas of the system. The interconnection process for elective transmission upgrades has been improved, and ETU projects are in various stages of development with the potential to provide access to renewable resources in remote areas of New England and neighboring regions, including Atlantic Canada and Québec'

The regional dependence on natural-gas-fired generation, coupled with natural gas pipeline constraints, pose reliability issues and can lead to price spikes in the wholesale electricity markets. Recent improvements to the wholesale markets have been designed to improve regional reliability and market efficiency and to decrease electricity price volatility. The region addressed the risks associated with fuel certainty in winter 2014/2015. As part of that winter's reliability program, payments to secure fuel inventory and fuel-switching capability were made to oil-fired and dual-fuel generators, units contracting with LNG supplies, and demand resources that elected to participate. The resources were compensated for unused fuel inventory and were subject to nonperformance charges. Similar winter reliability programs approved by FERC will be implemented between now and 2018 when FCM improvements are in effect.

Options for meeting or exceeding the regional Renewable Portfolio Standards (RPSs) include developing the renewable resources in the ISO queue, importing qualifying renewable resource energy from neighboring areas, building new renewable resources in New England not yet in the queue, developing behind-the-meter projects, and using eligible renewable fuels in existing generators. In addition, load-serving entities can make state-established alternative compliance payments if their qualified renewable resources fall short of providing sufficient Renewable Energy Certificates (RECs) to meet the RPSs. Alternative compliance payments also can serve as a price cap on the cost of RECs.

Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements are likely to impose operational limits on new and existing generators but pose only a limited retirement risk and lower reliability impacts compared to earlier assessments. The lowered retirement risk is due in large part to the flexibility that the EPA has provided in its cooling water rule and the Mercury & Air Toxics Standards (MATS), recognizing the reliability value that low capacity factor fossil steam generators provide in maintaining system fuel diversity.



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Ontario

The Ontario assumptions used in this study are consistent with the assumptions used in the latest 18-Month Outlook, the 2015 NERC Long-Term Reliability Assessment and the Ontario's 2015 Comprehensive Review of Resource Adequacy.

Over the assessment period (2016-2020), Ontario's energy demand is expected to decrease by about 1.2% annually, and both the summer and winter peaks are expected to decline. This is due to the fact that the downward pressure from price impacts, increased conservation savings and the growth in embedded generation output outstrips the underlying growth from economic expansion and population growth.

About 4,100 MW of generation additions and 481 MW of capacity retirements are expected by the end of 2020. Major nuclear refurbishments are scheduled during this period and treated as outages. As part of the IESO - Hydro Quebec seasonal firm capacity sharing agreement, Ontario will be supplying 500 MW of capacity to Quebec for the next two winter seasons. Ontario has the option to import up to 500 MW in summer months over the 10-year period of the agreement.

An annual Demand Response Auction is currently being developed by the IESO to procure DR capacity through a cost-competitive mechanism. The quantity of DR capacity that the auction will seek to procure will be equivalent to the quantity expiring from the transitional Capacity-Based Demand Response (CBDR). The combined total of DR capacity in the CBDR program and selected through the DR auction will remain approximately 500 MW, which is consistent with what was previously procured under DR2 and DR3 contracts. The first Demand Response Auction will be held in December 2015 for both a Summer (May 1, 2016 – October 31, 2016) and Winter (November 1, 2016 – April 30, 2017) commitment periods. The DR resources clearing the market will have the obligation and the incentives to be available when needed for reliability, and would also allow a higher frequency of deployment than the DR procured under previous programs

Québec

The Québec assumptions used in this study are consistent with the 2015 NERC Long-Term Reliability Assessment.⁷

The demand forecast average annual growth is 0.9 percent during the 5-year period. Energy efficiency and conservation programs are integrated in the demand forecasts and account for an average annual impact of 140 MW (at winter peak) over the 5-year period. Demand forecasts also take into account the load shaving resulting from the residential dual energy space heating program. The impact of this program on peak load demand is estimated to be around 600 MW during the assessment period.

Demand Response (DR) programs in the Québec Area are specifically designed for peak-load reduction during winter operating periods and are mostly interruptible demand programs for large industrial customers. The Québec Area is also currently developing new DR programs, including Direct Control Load Management (DCLM) and others. Total DR expected to be available during the peak for the 2019–

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



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2020 winter period is projected to be approximately 1,800 MW, including 250 MW of voltage reduction as an emergency operating procedure.

About 1,400 MW of new available capacity is expected to be in service between winter 2015-2016 and winter 2019-2020. There is no significant unit retirement planned during the assessment period.

Maritimes

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick (NB), Nova Scotia, Prince Edward Island (PEI), and Northern Maine. NB Power is the Reliability Coordinator for the Maritimes Area with its system operator functions performed by its Transmission and System Operator division under a regulator approved Standards of Conduct.

Growth in both demand and capacity resources will be essentially flat over the time frame of this review. Late in 2017, Nova Scotia will connect the Maritimes Link project, an HVDC link between Nova Scotia and the Canadian Province of Newfoundland and Labrador. Because the 153 MW of firm hydro resource additions associated with this interconnection will coincide with the retirement of the same amount of coal fired capacity, the impact on resource adequacy within the Maritimes Area will be minimal.

The assumptions used in this study are consistent with the 2013 NPCC Maritimes Area Comprehensive Review of Resource Adequacy;⁸ the results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

PJM-RTO

The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst Corporation (RFC) in compliance with Standard BAL-502-RFC-02. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load with sufficient reserves.

The results of the RRS provide key inputs to the PJM Reliability Pricing Model (RPM). The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process, pursuant to Schedule 6 of the PJM Operating Agreement, for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

⁸ See:

<https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%20202013%20Maritimes%20Area%20Comprehensive%20Resource%20Adequacy%20report.pdf>



Load Representation

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 were based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008.

- ✓ a 2002/03 load shape representative of a winter weather pattern with a typical expectation of cold days; and,
- ✓ a 2003/04 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

Review of the results for both load shape assumptions indicated only slight differences in the results. The Working Group agreed that the weather patterns associated with the 2003/04 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments. Upon review of subsequent winter weather experience, the Working Group agreed that the 2003/04 load shape assumption be again used for this analysis.

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.



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While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, Table 1 shows the values assumed for January 2014, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape). Table 1 also shows the probability of occurrence assumed for each of the seven load levels modeled.

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 1(a)
Per Unit Variation in Load Assumed (Month of January 2016)

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	1.0779	1.0519	1.0260	1.0000	0.9740	0.9481	0.9221
QC	1.0896	1.0896	1.0415	0.9991	0.9601	0.9207	0.9104
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 1(b)
Per Unit Variation in Load Assumed (Month of July 2016)

Area	Per-Unit Variation in Load						
MT	1.1380	1.0920	1.0460	1.0000	0.9540	0.9080	0.8620
NE	1.2548	1.1229	1.0047	0.9936	0.8970	0.8864	0.8513
NY	1.1171	1.0855	1.0457	0.9929	0.9370	0.8800	0.8282
ON	1.1769	1.1179	1.0590	1.0000	0.9410	0.8821	0.8231
QC	1.0562	1.0510	1.0260	1.0010	0.9740	0.9460	0.9210
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062



Generation

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.⁹

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 2016 to 2020. 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. Initial capacity for Ontario reflects certain units which are on extended maintenance. More details can be found in Appendix B.

Maritimes Capacity and Load - MW (February)

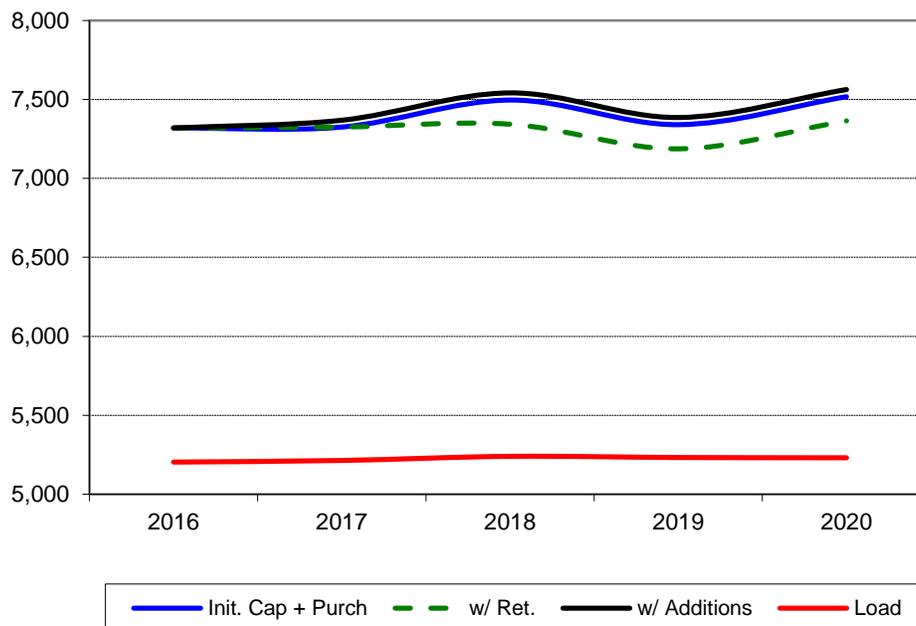


Figure 1 – Maritimes Area Capacity and Load

⁹ See: <https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx>



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New England Capacity and Load - MW (August)

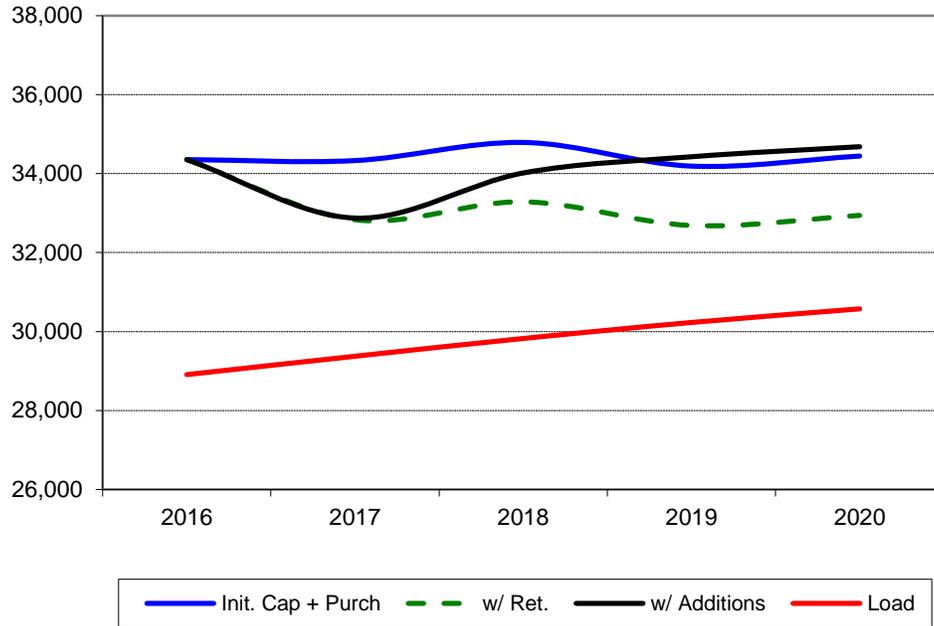


Figure 2 – New England Capacity and Load

New York Capacity and Load - MW (August)

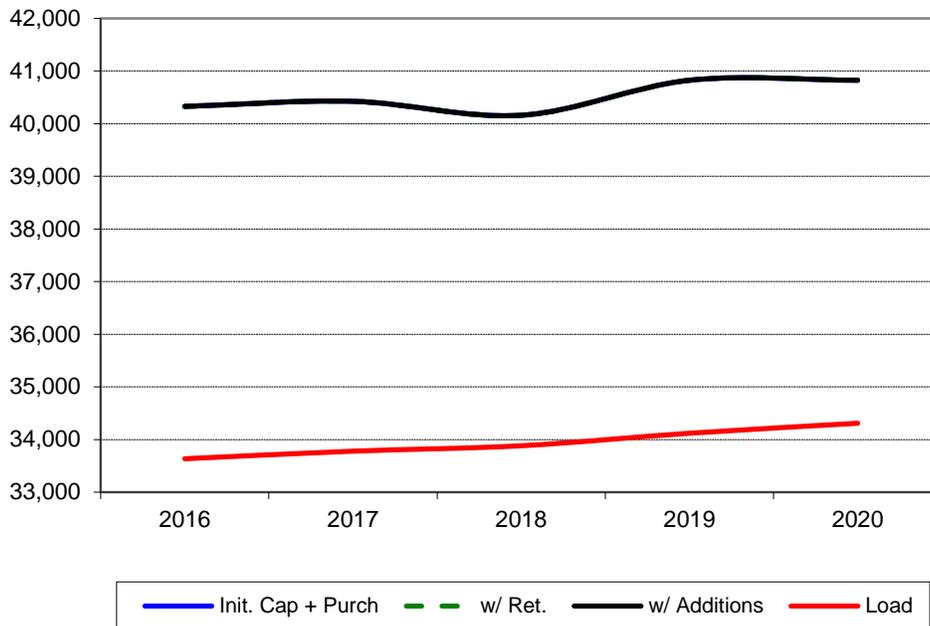


Figure 3 – New York Area Capacity and Load



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Ontario Capacity and Load - MW (July)

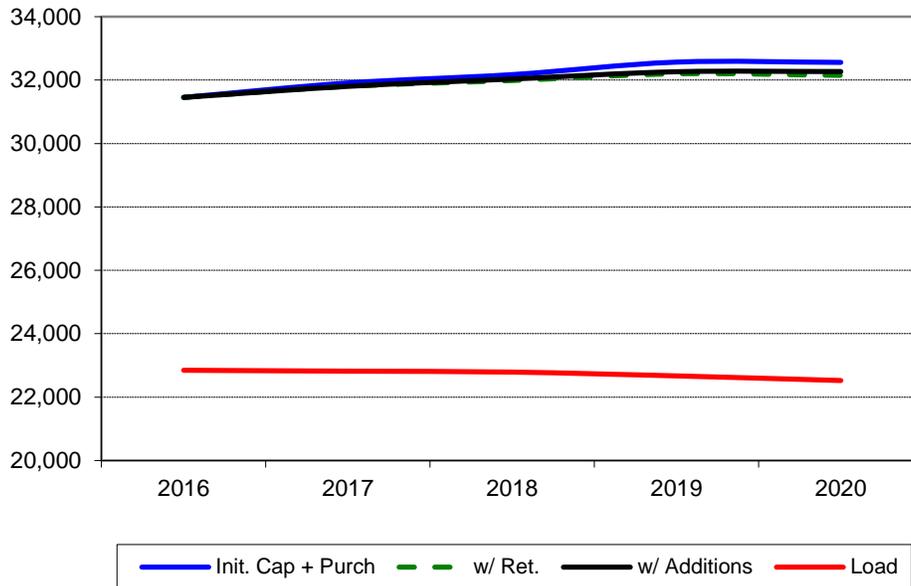


Figure 4 – Ontario Capacity and Load

Quebec Capacity and Load - MW (January)

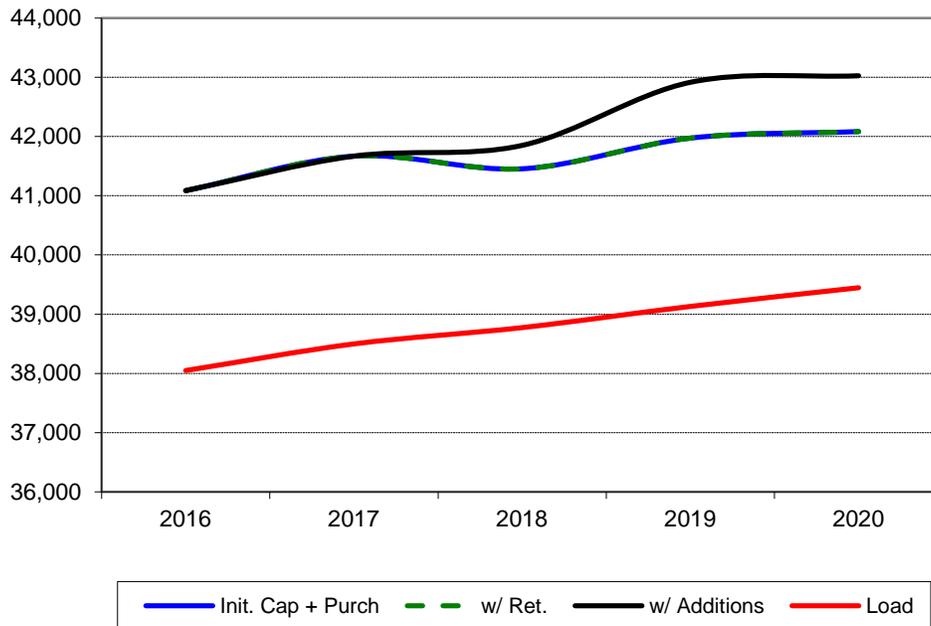


Figure 5 – Québec Capacity and Load



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PJM-RTO Capacity and Load - MW (July)

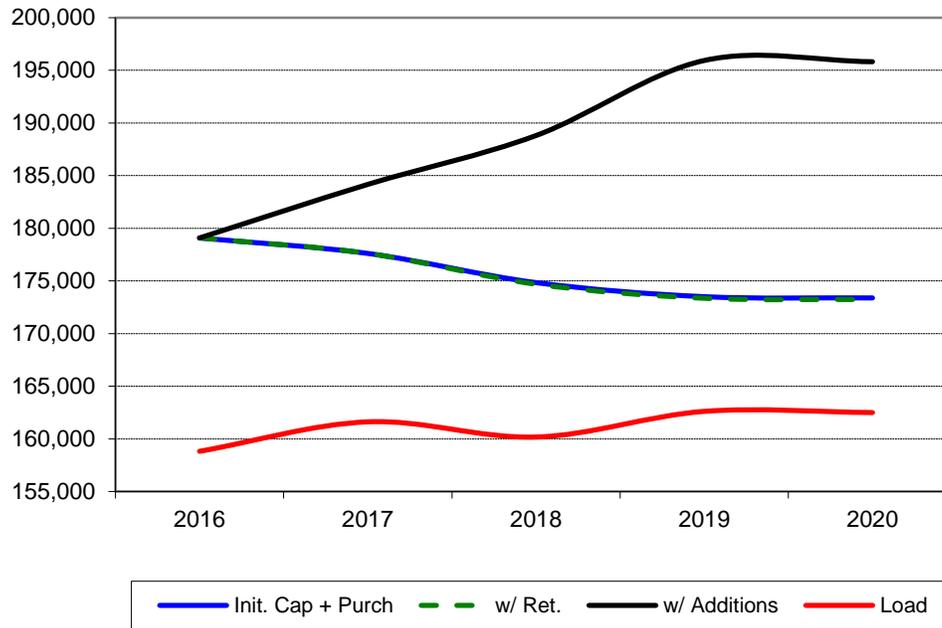
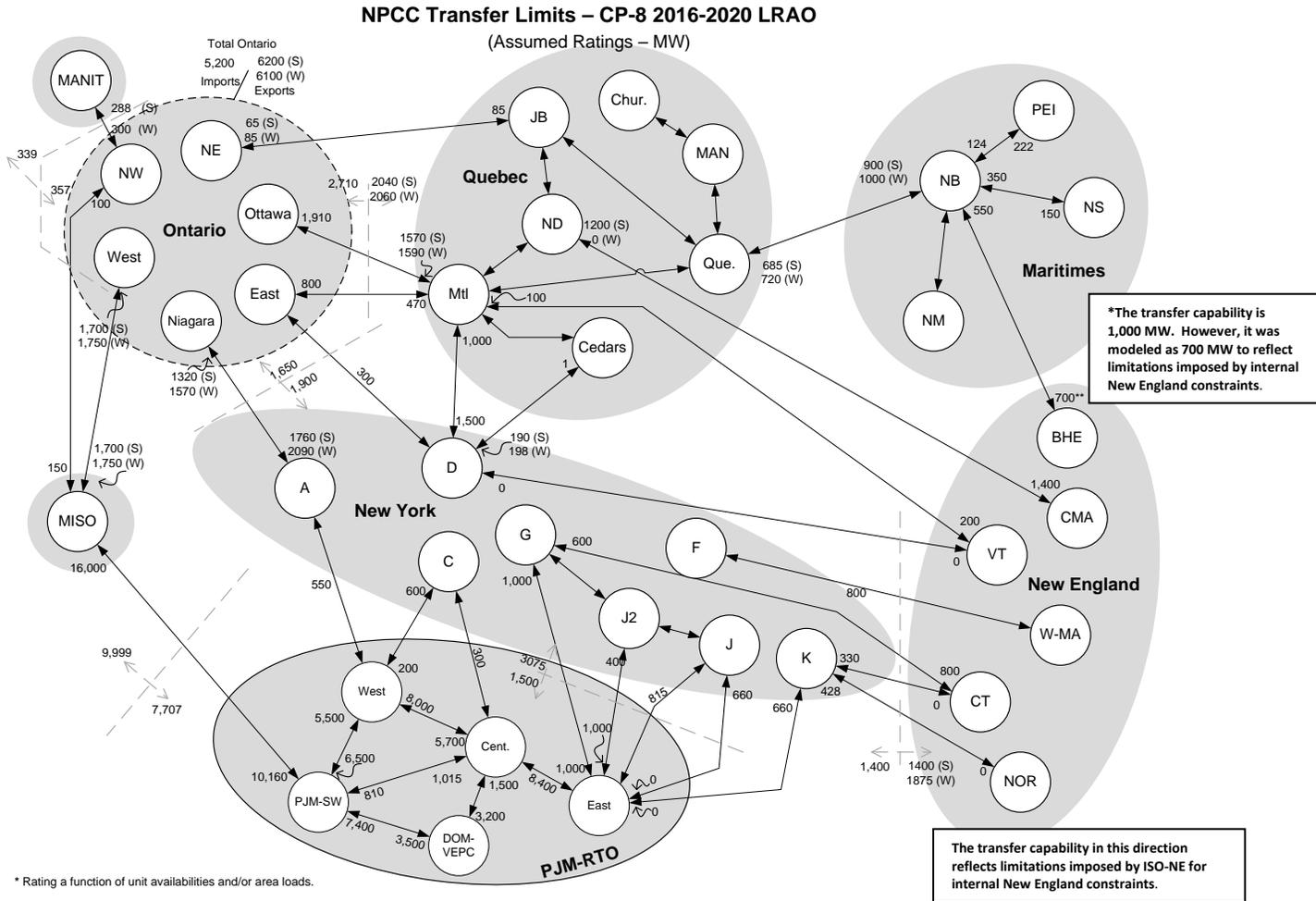


Figure 6 – PJM-RTO Capacity and Load

Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2016 to 2020.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York.¹⁰

Figure 7 - Assumed Transfer Limits

¹⁰ See: http://www.oasis.oati.com/HQT/HQTdocs/2014-04_DEN_et_CORN-version_finale_en.pdf



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Transfer limits between and within some areas are indicated in Figure 7 with seasonal ratings (S-summer, W- winter) where appropriate. The acronyms and notes used in Figure 7 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
W MA	- Western MA	NS	- Nova Scotia	Dom-VEPC	- Dominion Virginia Power
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	MT	- Maritimes Area
MISO	- Mid-Continent Independent System Operator		- Québec Centre Centre		



Operating Procedures to Mitigate Resource Shortages

Each area takes defined steps as their reserve levels approach critical levels. These steps consist 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. Table 2 summarizes the load relief assumptions modeled for each NPCC area.

**Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2016 Load Relief Assumptions - MW**

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (July)	QC (Jan)
1. Curtail Load / Utility Surplus	-	-	-	151	1,351
Appeals	-	-	-	1% of load	-
RT-DR/SCR/EDRP	-	609 ¹¹	891 ¹²	-	-
SCR Load /Man. Volt. Red.	-	-	0.20% of load	-	-
2. No 30-min Reserves	233	625	655	473	500
3. Voltage Reduction	-	424	1.11% of load	-	250
Interruptible Loads	250	-	141.49	576	-
4. No 10-min Reserves	505	-	-	945	750
RT-EG	-	218 ¹³	-	-	-
General Public Appeals	-	-	88	-	-
5. 5% Voltage Reduction	-	-	-	2.00% of load	-
No 10-min Reserves	-	1,550	1,310	-	-
Appeals/Curtailments	-	-	-	-	-

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.

¹¹ Derated value shown accounts for assumed availability.

¹² Derated value shown accounts for assumed availability.

¹³ Derated value shown accounts for assumed availability.



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The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 2 was a reasonable approximation for this analysis.

Assistance Priority

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.



Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of MISO (Midcontinent Independent System Operator) was assumed. The assumptions are summarized in Table 3 and Figure 8.

**Table 3
PJM and MISO 2016 Assumptions ¹⁴**

	PJM	MISO
Peak Load (MW)	158,819	94,714
Peak Month	July	July
Assumed Capacity (MW)	180,069	114,755
Purchase/Sale (MW)	5,571	-6,709
Reserve (%)	22	14
Operating Reserves (MW)	3,400	3,906
Curtable Load (MW)	7,907	3,791
No 30-min Reserves (MW)	2,765	2,670
Voltage Reduction (MW)	2,201	2,200
No 10-min Reserves (MW)	635	1,236
Appeals (MW)	400	400
Load Forecast Uncertainty	+/- 13.52%, 9.02%, 4.510%	+/- 11.17%, 7.45%, 3.72%

For the 2015 LRAO, the MISO region (minus the recently integrated Entergy region) was included in the analysis replacing the RFC-OTH and MRO-US regions. In previous versions of the LRAO, RFC-OTH and MRO-US were included to represent specific areas of MISO, however due to difficulties in gathering load and capacity data for these two regions (since most of the reporting is done at the MISO level), it was decided to start including the entirety of MISO in the model beginning this year. MISO was modeled in this study due to the strong transmission ties of the region with the rest of the study system.

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2008 NERC Electricity Supply & Demand (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the

¹⁴ 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/>



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR.

Unit data was from the publicly available NERC data. Each individual unit represented in the non-PJM RFC region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2014 RRS Report).

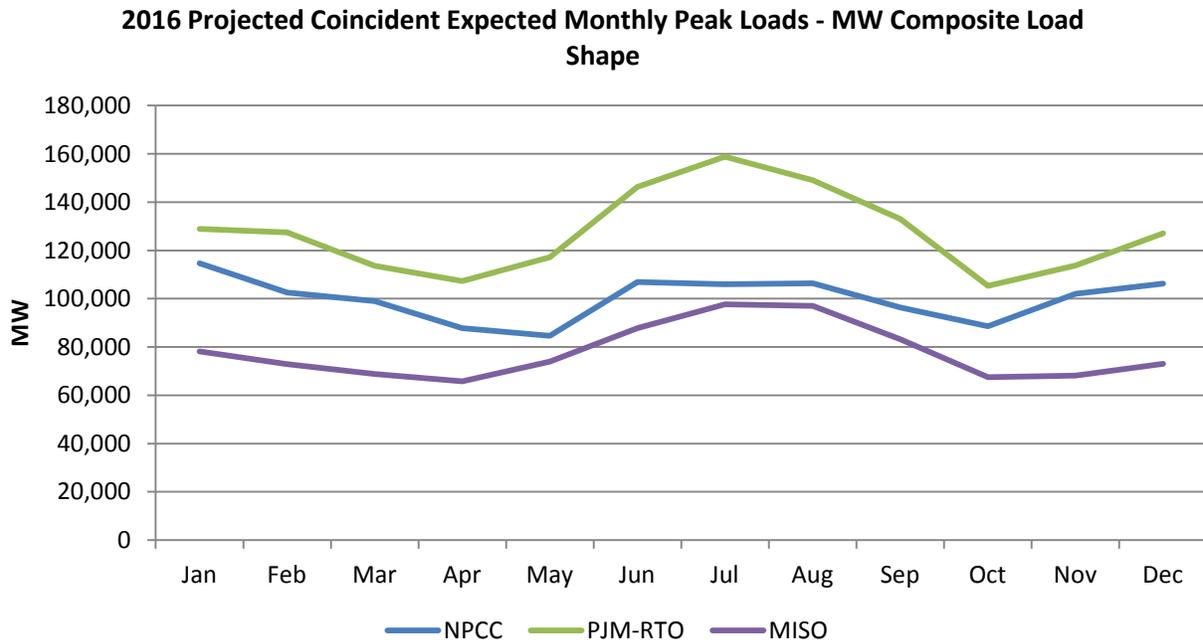


Figure 8 – 2016 Projected Monthly Expected Peak Loads for NPCC, PJM and MISO

MISO

The Mid-Continent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets in all or parts of 15 states in the US.

MISO unit data was obtained from the publicly available NERC datasets. Each individual unit represented in MISO was then assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2015 RRS Report).

MISO load data was obtained from publicly available sources, namely FERC Form 714 and the 2015-2016 MISO LOLE Study Report.¹⁵

PJM-RTO

Load Model

PJM's Load Forecast issued in January 2015¹⁶ was used in this study. The methods and techniques used in the load forecasting process are documented in Manual 19¹⁷ (Load Forecasting and Analysis) and

¹⁵ <https://www.misoenergy.org/Library/Repository/Study/LOLE/2015%20LOLE%20Study%20Report.pdf>

¹⁶ <https://www.pjm.com/~media/documents/reports/2015-load-forecast-report.ashx>



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Manual 20¹⁸ (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 2015 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.

Footprint Modeling

The PJM-RTO 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 2014 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).

Generation Model

Performance statistics such as outage rates and planned outages for generation units considered in the study are based on 5-year (2010-14) GADS data. This is consistent with modeling practices in the 2015 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 three summer periods.

¹⁷ <http://www.pjm.com/~media/documents/manuals/m19.ashx>

¹⁸ <http://www.pjm.com/~media/documents/manuals/m20.ashx>

RESULTS

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2016-2020 period.

Daily LOLE - Expected Load

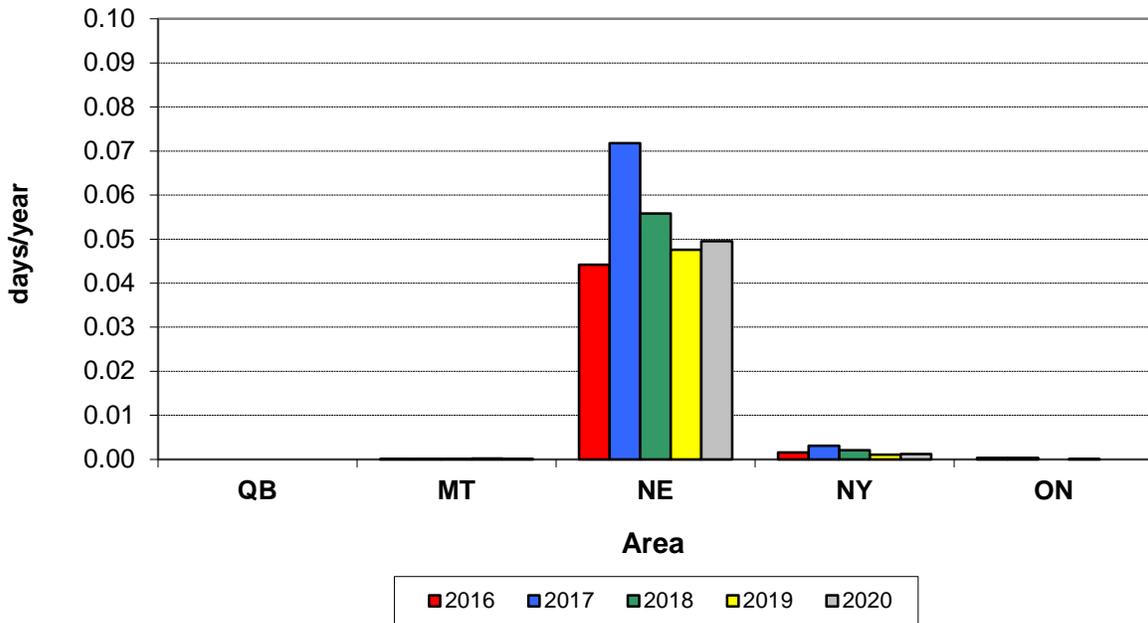


Figure 9(a) - Estimated Annual NPCC Area LOLE (2016 – 2020)

Daily LOLE - Expected Load

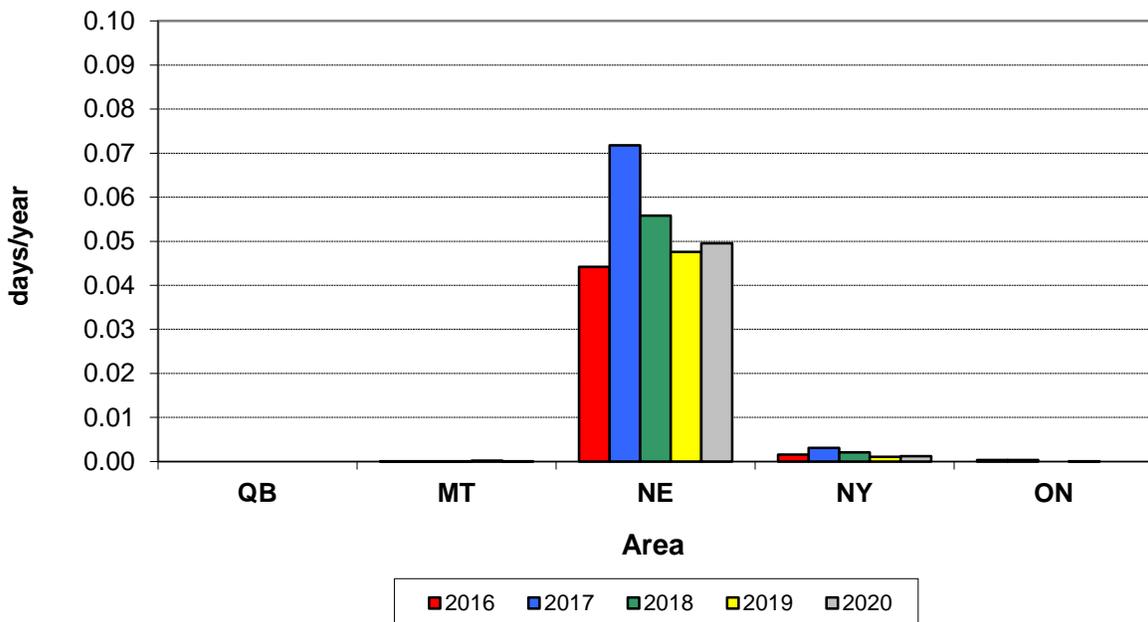


Figure 9(b) - Estimated Annual NPCC Area LOLE (2016– 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2016-2020 period.

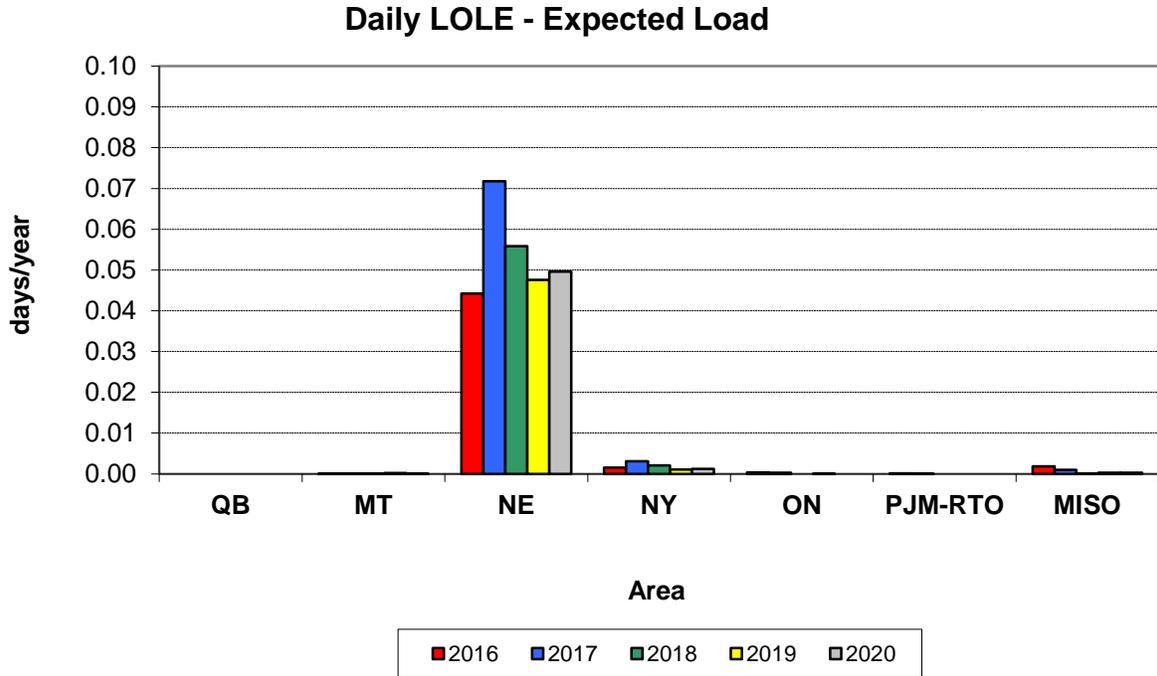


Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2016 – 2020)

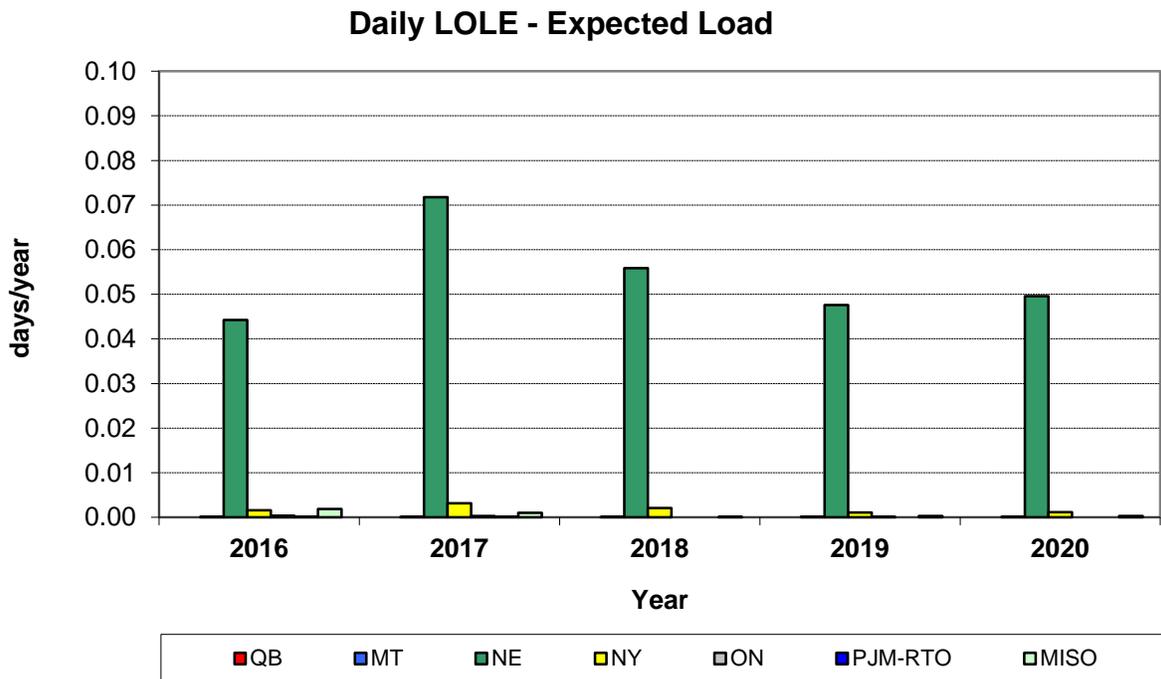


Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region's LOLE (2016 – 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2016-2020 period.

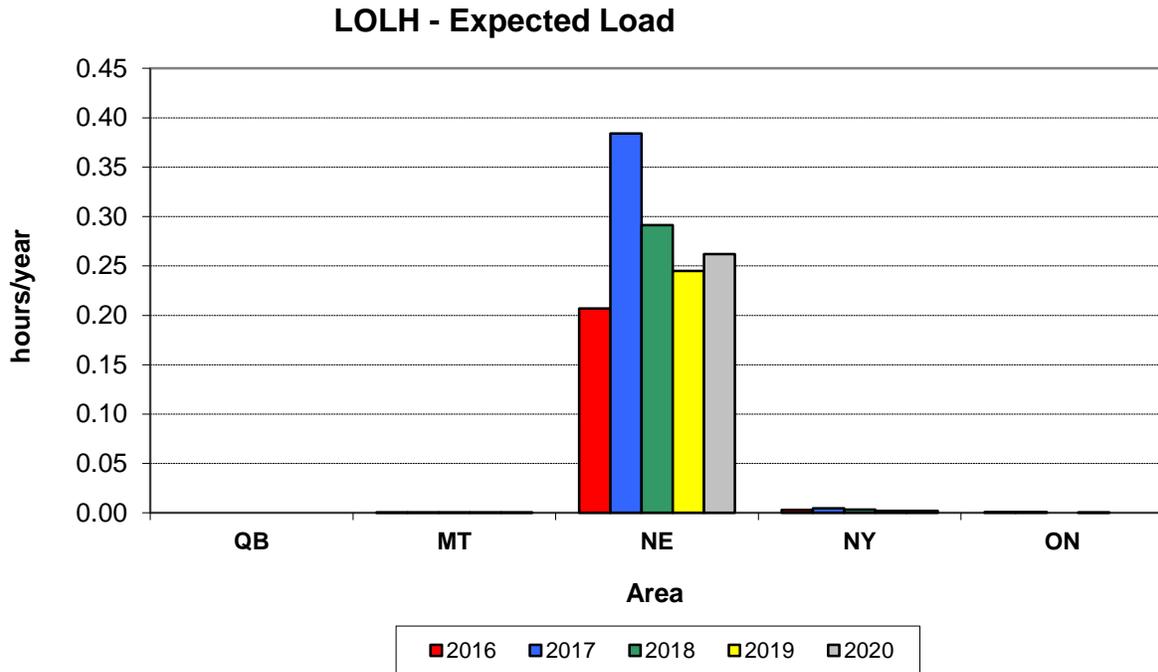


Figure 10(a) - Estimated Annual NPCC Area LOLH (2016 – 2020)

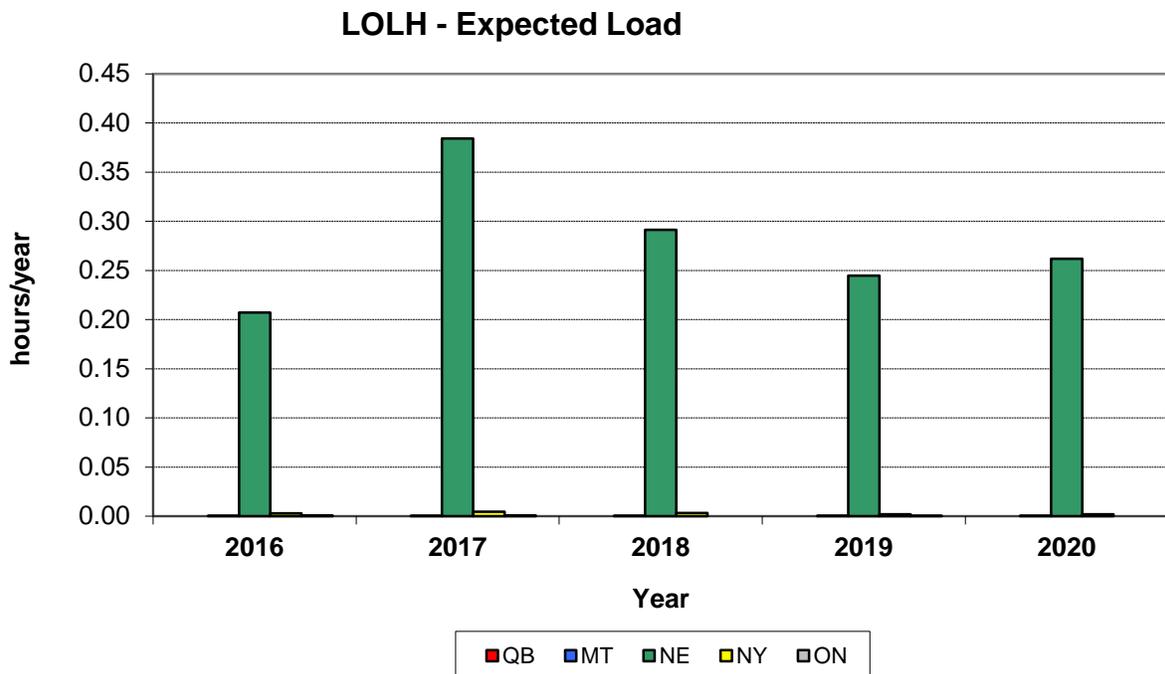


Figure 10(b) - Estimated Annual NPCC Area LOLH (2016 – 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2016-2020 period.

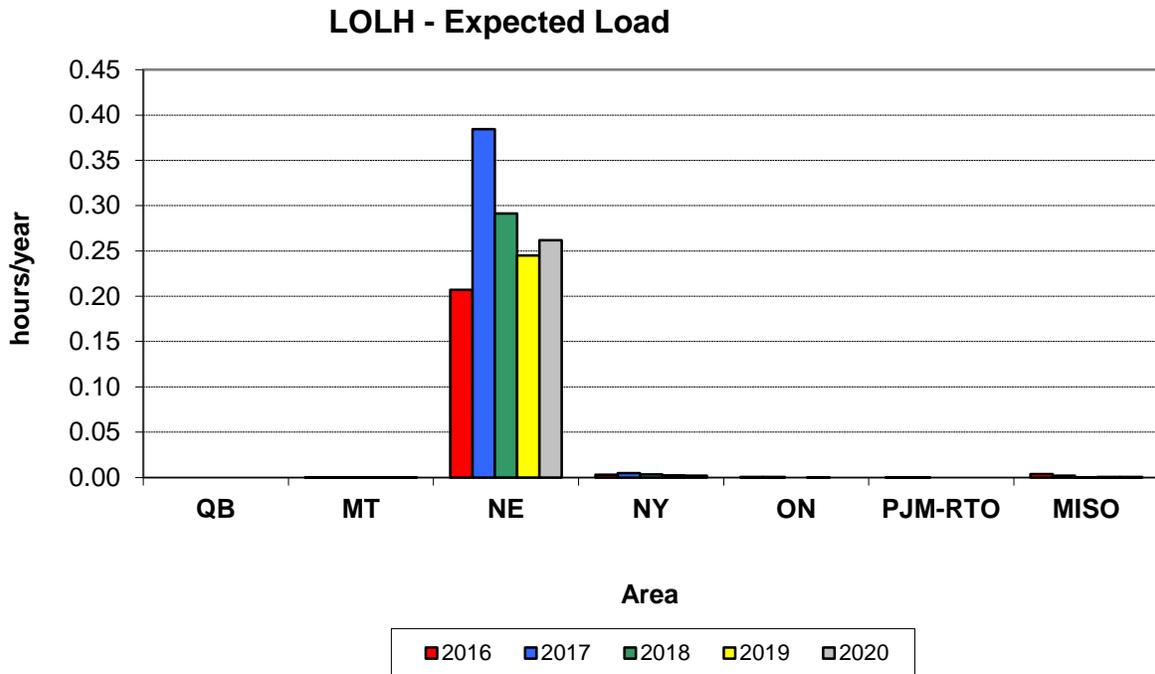


Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2016 – 2020)

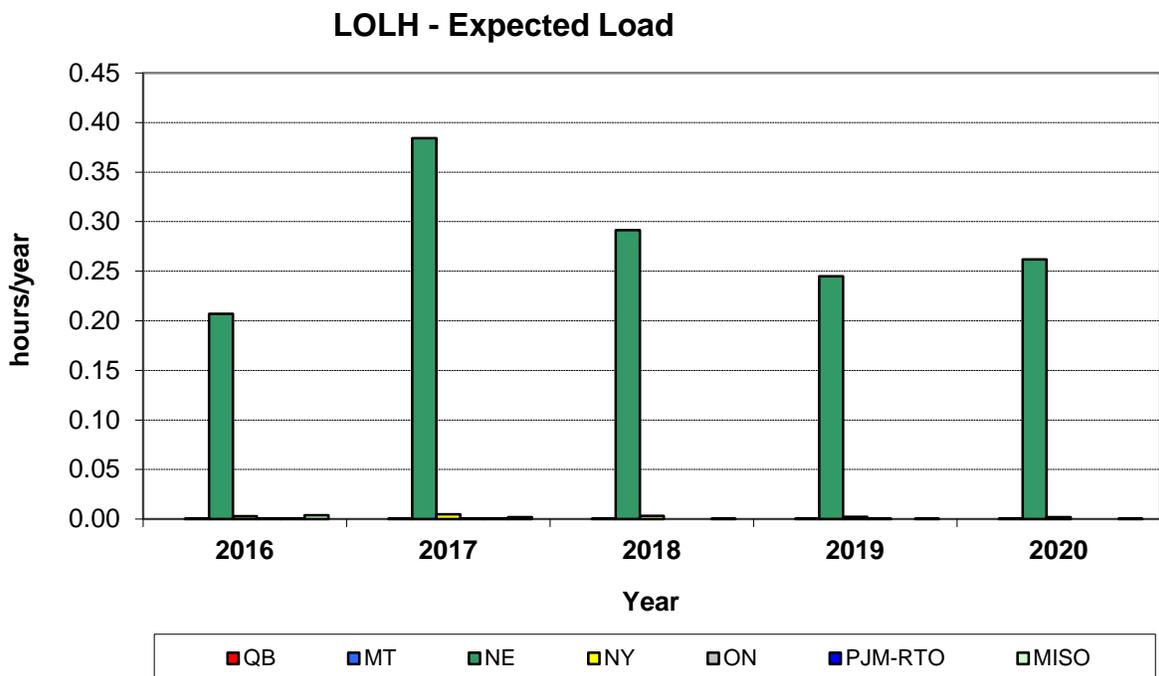


Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2016 – 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2016-2020 period.

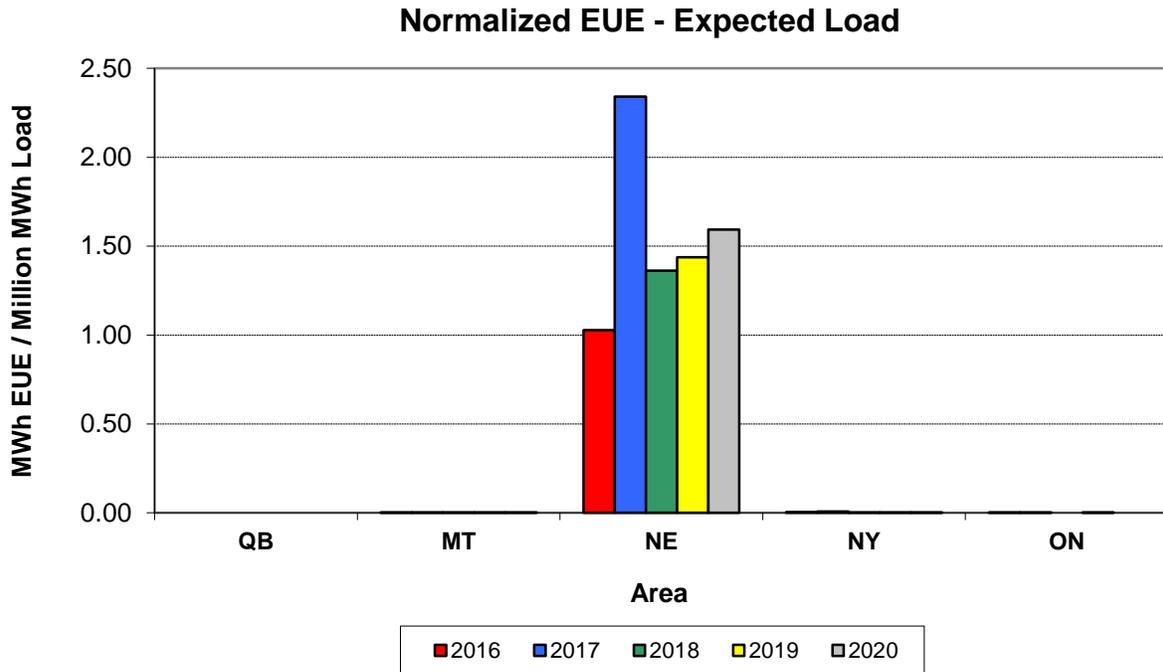


Figure 11(a) - Estimated Annual NPCC Area EUE (2016 – 2020)

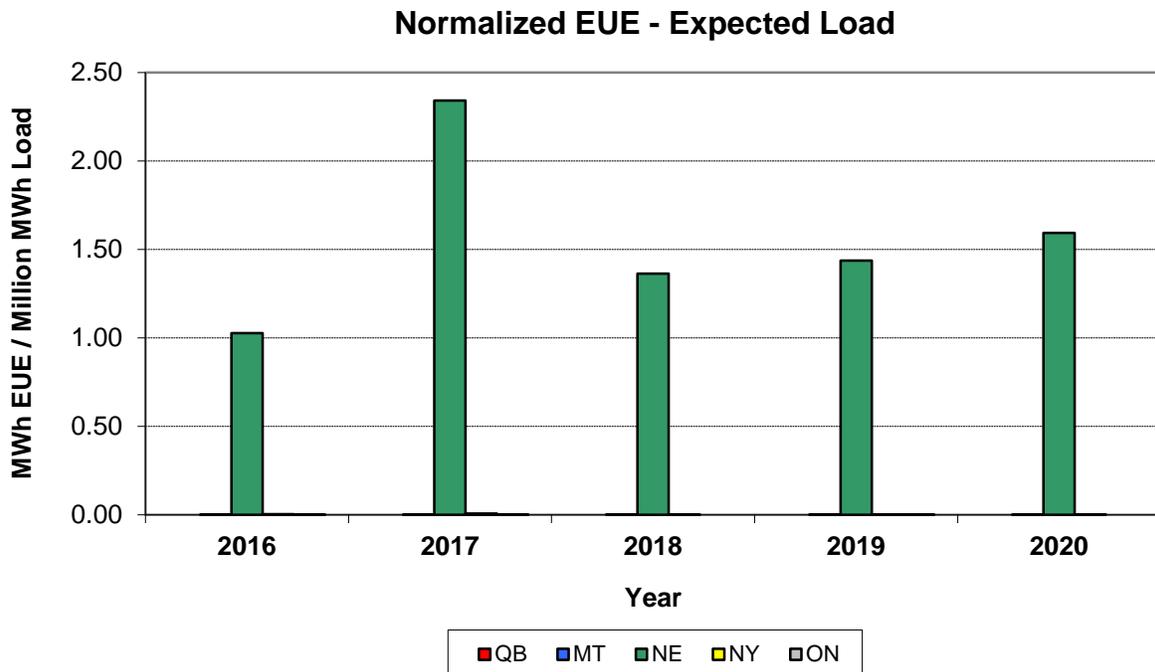


Figure 11(b) – Estimated Annual NPCC Area LOLH (2016 – 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2016-2020 period.

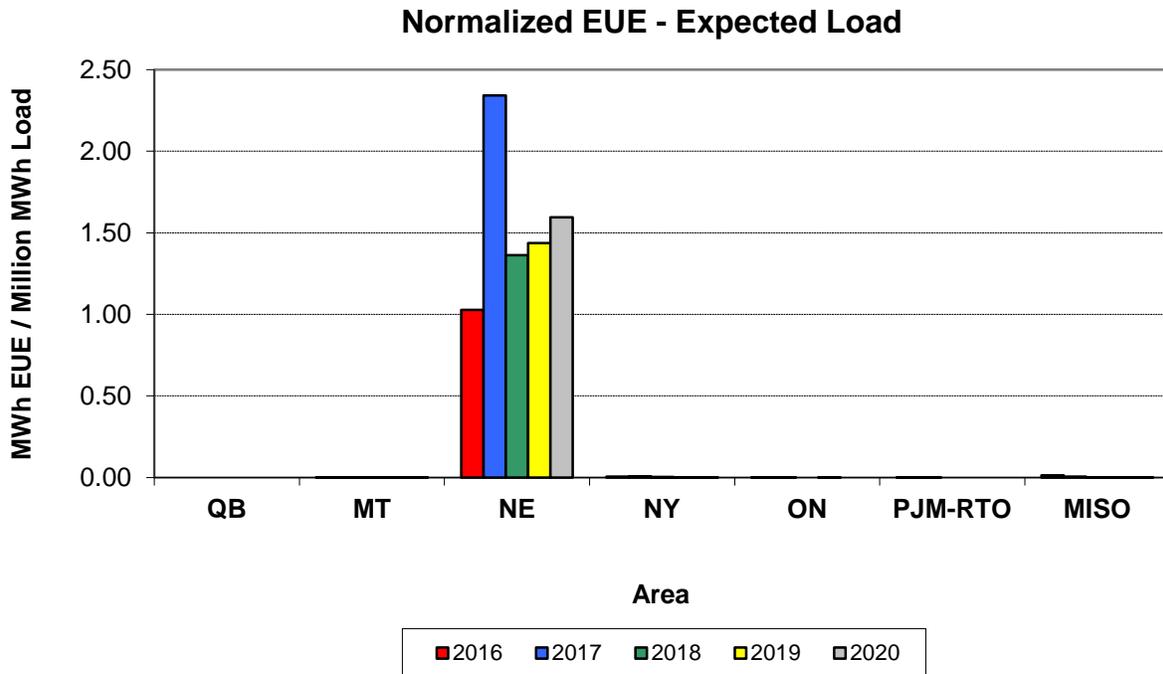


Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2016 – 2020)

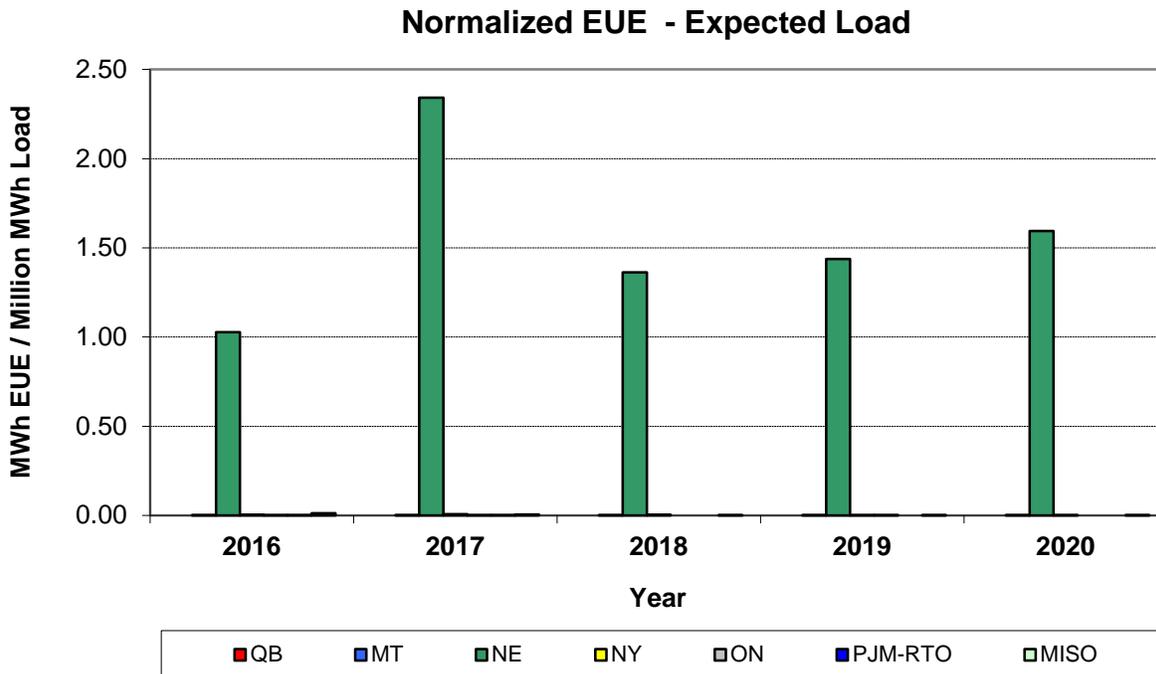


Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2016 – 2020)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Table 4 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 calculation for the total estimated NPCC annual energy is approximately within 3.6 percent of the corresponding sum of the NPCC Areas annual energy forecasts.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Table 4 – Comparison of Energies Modeled (Annual MWhrs)

Year	2016	2017	2018	2019	2020
Québec					
MARS	192,503,328	192,262,368	194,580,176	194,448,928	195,740,416
2015 LTRA	186,003,039	186,661,344	187,459,496	188,688,932	191,280,573
MARS - LTRA	6,500,289	5,601,024	7,120,680	5,759,996	4,459,843
%(MARS-LTRA)/LTRA	3.49%	3.00%	3.80%	3.05%	2.33%
Maritimes					
MARS	27,174,756	27,508,758	27,792,800	27,916,398	27,962,364
2015 LTRA	27,174,800	27,508,000	27,789,000	27,915,000	27,961,000
MARS - LTRA	-44	758	3,800	1,398	1,364
%(MARS-LTRA)/LTRA	0.00%	0.00%	0.01%	0.01%	0.00%
New England					
MARS	143,463,008	145,055,216	145,973,856	149,137,152	151,410,080
2015 LTRA	139,583,000	141,102,000	142,614,000	143,925,000	145,182,000
MARS - LTRA	3,880,008	3,953,216	3,359,856	5,212,152	6,228,080
%(MARS-LTRA)/LTRA	2.78%	2.80%	2.36%	3.62%	4.29%
New York					
MARS	159,970,000	158,980,000	158,280,000	158,797,008	159,584,992
2015 LTRA	159,970,000	158,980,000	158,280,000	158,797,000	159,585,000
MARS - LTRA	0	0	0	8	-8
%(MARS-LTRA)/LTRA	0.00%	0.00%	0.00%	0.00%	0.00%
Ontario					
MARS	139,741,408	136,974,768	134,208,080	133,349,104	133,148,704
2015 LTRA	139,741,323	136,974,750	134,208,177	133,348,998	133,148,679
MARS - LTRA	85	18	-97	106	25
%(MARS-LTRA)/LTRA	0.00%	0.00%	0.00%	0.00%	0.00%



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Year	2016	2017	2018	2019	2020
NPCC					
MARS	662,852,480	660,781,056	660,834,880	663,648,576	667,846,656
2014 LTRA	639,701,162	651,226,094	650,350,673	652,674,930	657,157,252
MARS - LTRA	23,151,318	9,554,962	10,484,207	10,973,646	10,689,404
%(MARS-LTRA)/LTRA	3.62%	1.47%	1.61%	1.68%	1.63%



OBSERVATIONS

Figures 12(a) and 12(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

Area LOLE - Expected Load

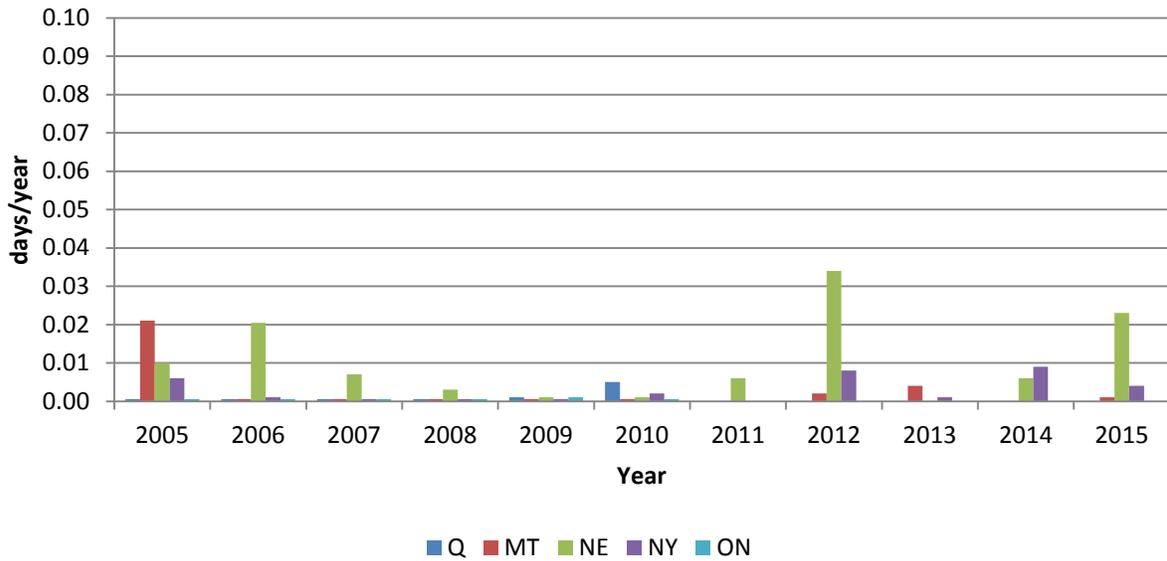
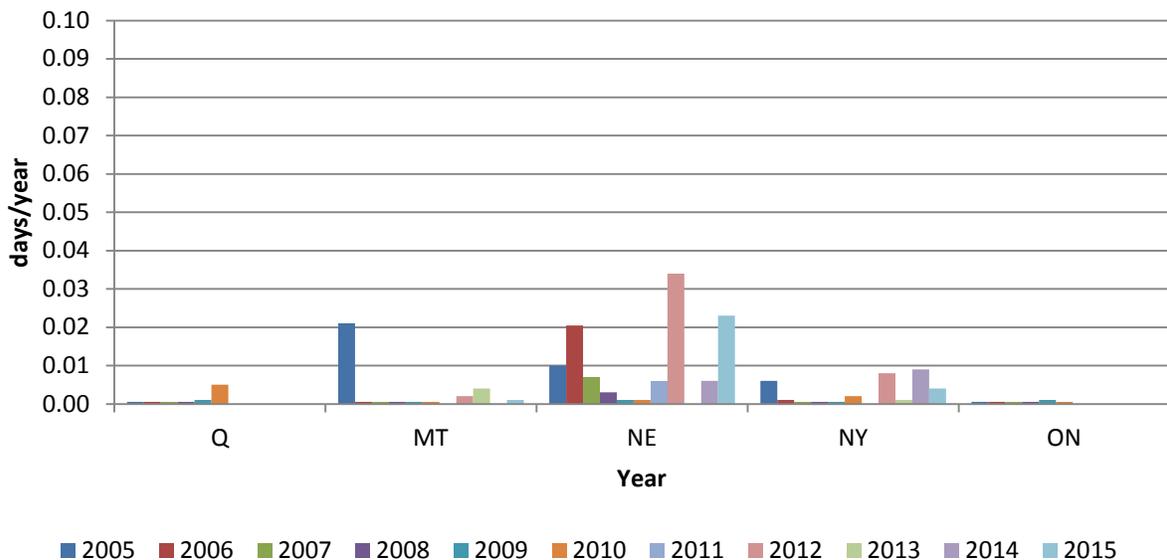


Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

Area LOLE - Expected Load





NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 13(a) and 13(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2016 – 2020.

Area LOLE - Expected Load

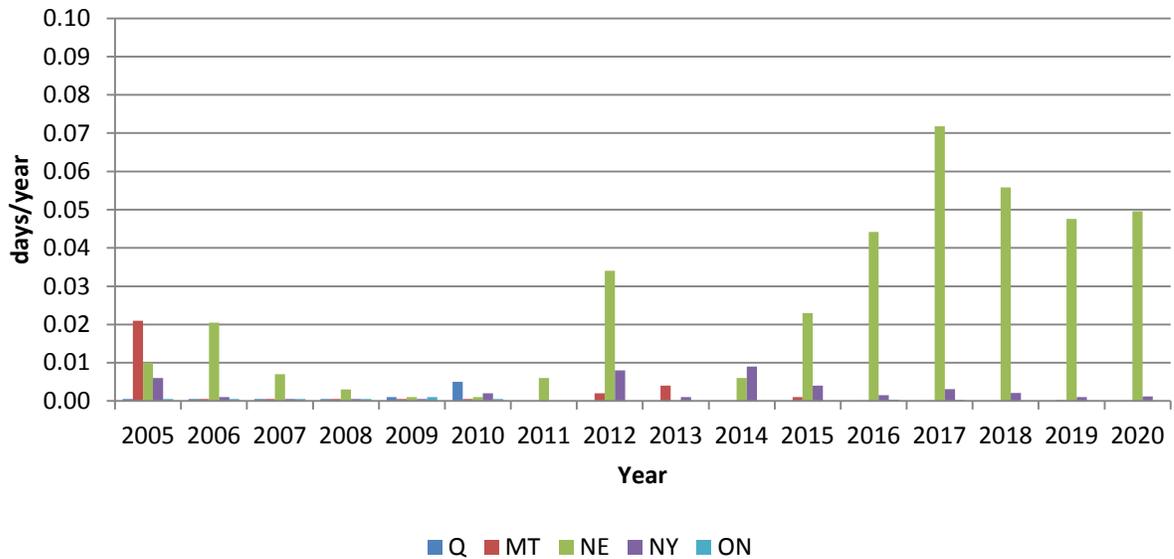


Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Area LOLE - Expected Load

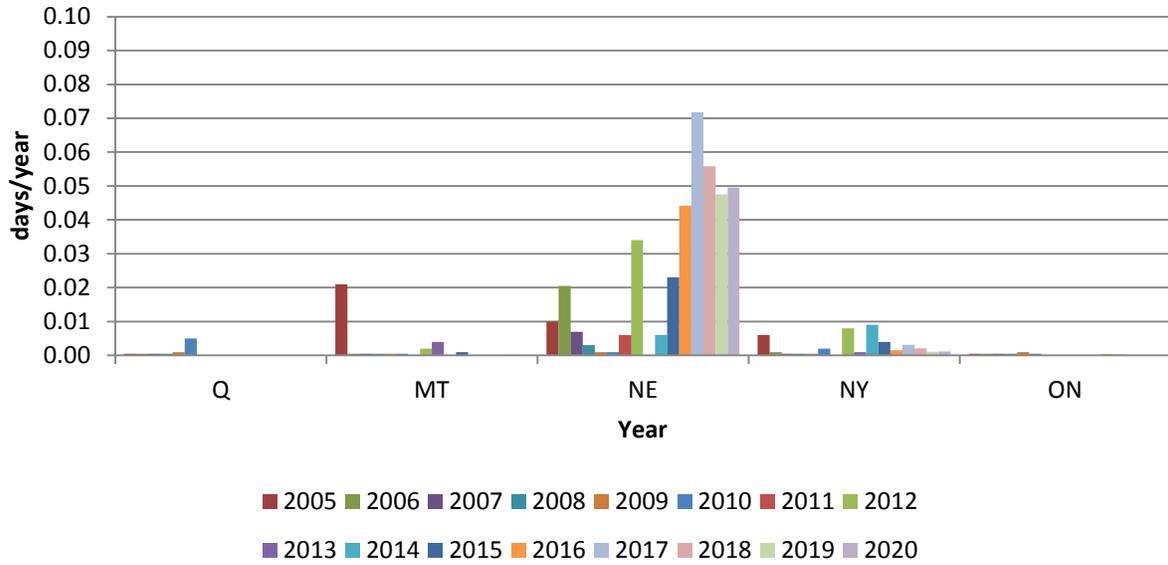


Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)



APPENDIX A

Objective and Scope of Work

1. Objective

On a consistent basis, evaluate the near term seasonal and long-range (five year) adequacy of NPCC Areas' and reflecting neighboring regional plans proposed to meet their respective resource adequacy planning criteria through multi-area probabilistic assessments. Monitor and include the potential effects of proposed market mechanisms in NPCC and neighboring regions expected to provide for future adequacy in the overview.

In meeting this objective, the CP-8 Working Group will use the G.E. Multi-Area Reliability Simulation (MARS) program, incorporating, to the extent possible, a detailed reliability representation for regions bordering NPCC for the 2015 - 2020 time period.

2. Scope

The near term seasonal analyses will use the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2015 - 2020 time period to consistently review the resource adequacy of NPCC Areas and reflecting neighboring Regions' assumptions under Base Case (likely available resources and transmission) and Severe Case assumptions for the May to September 2015 summer and November 2015 to March 2016 winter period, recognizing:

- ✓ uncertainty in forecasted demand,
- ✓ scheduled outages of transmission,
- ✓ forced and scheduled outages of generation facilities, including fuel supply disruptions,
- ✓ the impacts of Sub-Area transmission constraints,
- ✓ the impacts of proposed load response programs; and,
- ✓ as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

Reliability for the near term seasonal analyses (2015 - 2016) will be measured by estimating annual NPCC Area LOLE and use of NPCC Area operating procedures used to mitigate resource shortages.

The long-range analysis will extend the CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2016 - 2020 time period, to consistently review the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) assumptions, recognizing the above considerations.

Reliability for the long-range (2016 – 2020) analysis will be measured by calculating the annual Loss of Load Expectation (LOLE) for each NPCC Area and neighboring Regions for each calendar year. In addition, Loss of Load Hours (LOLH) and Expected Unserved Energy will also be similarly estimated for the NPCC Areas.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2015.

A report of the results of the winter assessment will be approved no later than September 30, 2015.

A report summarizing the results of the NPCC Long Range Adequacy Overview will be published no later than December 31, 2015.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

APPENDIX B

Modeled Capacity and Load at time of Area's Annual Peak, Based on Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2016	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	40,683	7,609	31,044	38,811	26,914	180,069	114,755
Purchase/Sale (MW)	266	-200	1,516	1,727	0	5,571	-6,709
Load (MW)	38,049	5,204	28,910	33,635	22,848	158,819	97,714
Nameplate Demand Response (MW) *****	1,351	252	2,664	958	576	7,907	3,791
Reserves (%)	11	47	22	23	20	22	14
Maintenance - Peak Week (MW)	**	0	0	363	1,178	0	0
Wind Output at time of Area Peak (MW)	974	645	182	82	825 ***	938	1,120
Wind Nameplate Capacity (MW)	3,246	1,101	1,081	1,457	4,148	938	1,120



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2017	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	40,910	7,678	30,306	38,811	26,547	187,867	114,013
Purchase/Sale (MW)	756	-200	1,167	1,825	0	3,289	-4,427
Load (MW)	38,498	5,214	29,375	33,779	22,819	161,618	98,876
Nameplate Demand Response (MW) *****	1,445	252	3,005	1,132	576	7,991	3,791
Reserves (%)	12	48	17	24	19	23	15
Maintenance - Peak Week (MW)	**	37	0	291	760	0	0
Wind Output at time of Area Peak (MW)	1,041	311	182	82	885 ***	929	1,158
Wind Nameplate Capacity (MW)	3,471	1,118	1,714	1,457	4,445	929	1,158



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2018	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	41,540	7,597	31,344	38,811	25,982	194,951	112,324
Purchase/Sale (MW)	308	-29	1,379	1,560	0	688	-1,826
Load (MW)	38,774	5,240	29,825	33,882	22,790	160,173	99,744
Nameplate Demand Response (MW) *****	1,445	252	3,033	1,132	576	8,053	3,791
Reserves (%)	12	49	20	22	17	27	15
Maintenance - Peak Week (MW)	**	47	0	291	1,337	0	0
Wind Output at time of Area Peak (MW)	1,153	668	182	123	935 ***	2,022	1,218
Wind Nameplate Capacity (MW)	3,842	1,143	1,734	1,457	4,700	2,022	1,218



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2019	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	42,062	7,622	31,371	38,811	26,686	195,157	113,314
Purchase/Sale (MW)	851	-177	-5	2,225	0	778	-1,916
Load (MW)	39,131	5,233	30,230	34,120	22,670	162,612	100,606
Nameplate Demand Response (MW) *****	1,470	251	3,322	1,132	576	8,119	3,791
Reserves (%)	13	47	15	24	20	25	14
Maintenance - Peak Week (MW)	**	47	0	291	601	0	0
Wind Output at time of Area Peak (MW)	1,153	1,168	182	82	995 ***	2,022	1,278
Wind Nameplate Capacity (MW)	3,842	529	1,734	1,457	5,000	2,022	1,278



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2020	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	42,092	7,622	31,395	38,811	27,531	195,039	114,269
Purchase/Sale (MW)	931	0	-5	2,225	0	778	-1,916
Load (MW)	39,447	5,231	30,575	34,310	22,524	162,498	101,437
Nameplate Demand Response (MW) *****	1,520	251	3,546	1,132	676	8,204	3,791
Reserves (%)	13	51	14	23	25	26	14
Maintenance - Peak Week (MW)	**	47	0	291	529	0	0
Wind Output at time of Area Peak (MW)	1,153	455	182	82	995 ***	2,022	1,328
Wind Nameplate Capacity (MW)	3,842	1,168	1,734	1,457	5,000	2,022	1,328

- * Wind capacity included at nameplate rating; demand response not included in capacity. Capacity for Ontario is available capacity and reflects maintenance; wind capacity included at 13.6%, the summer capacity contribution at the time of peak.
- ** Capacity for Quebec reflects scheduled maintenance and restrictions
- *** Random draws using a probability density function during the Monte Carlo simulation are used to simulate unit output. This value reflects an expected value of that function.
- ***** Demand Response values for Ontario represent the effective DR capacity at peak



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

APPENDIX C

Maritimes

Assessment Area Overview

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.

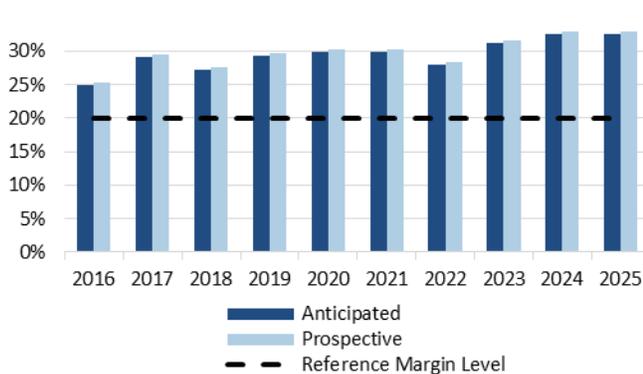
Assessment Area Footprint



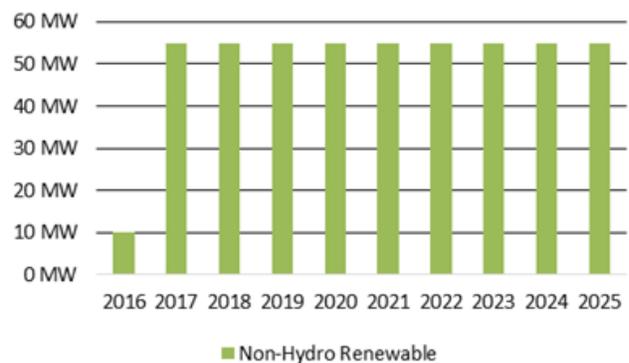
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	5,400	5,426	5,417	5,418	5,401	5,401	5,373	5,346	5,294	5,292
Demand Response	239	241	241	242	242	242	242	242	242	242
Net Internal Demand	5,162	5,185	5,176	5,176	5,159	5,159	5,131	5,105	5,052	5,051
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	6,453	6,698	6,584	6,698	6,698	6,698	6,571	6,698	6,698	6,698
Prospective	6,472	6,717	6,603	6,717	6,717	6,717	6,591	6,717	6,717	6,717
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	25.01%	29.18%	27.20%	29.41%	29.83%	29.83%	28.07%	31.21%	32.57%	32.60%
Prospective	25.39%	29.55%	27.58%	29.79%	30.21%	30.21%	28.45%	31.60%	32.96%	32.99%
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)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	259	476	373	487	507	507	414	572	635	637
Prospective	278	495	392	507	527	527	434	592	655	656

Peak Season Reserve Margins



10-Year Peak Cumulative Generation Mix Change





NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Demand, Resources, Reserve Margins, Transmission Outlook and System Enhancements

The Maritimes Area is comprised of four sub-areas: New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM).

During summer and winter peak load periods, the Existing Certain and Net Firm Transfers, Anticipated, Prospective, and Adjusted Potential Resources margins for the Maritimes Area do not fall below the target level at any time and exceed 86% and 26% during summer and winter periods, respectively, each year over this assessment's 10-year time frame. The Assessment Area does not anticipate any resource adequacy deficiencies during the assessment period.

The aggregated load growth rate for the combined sub-areas is practically unchanged for both the summer and winter seasonal peak load periods since last year's assessment. Overall, the Maritimes Area's 3,500 MW summer peak and 5,500 MW winter peak loads are both expected to decline slightly during the 10-year assessment period.

Current and projected energy efficiency effects are incorporated directly into the load forecast for each of the areas. Direct Control Load Management (DCLM) in New Brunswick (NB) is intended to shift load from peak periods into lower load periods, is embedded directly into the load forecast, and is included with energy efficiency. DCLM in NB is expected to rise from approximately 20 MW in 2015 to about 240 MW at the end of the assessment period. Interruptible load in 2015, projected at levels approximating 335 MW in the summer and 240 MW in the winter for the Maritimes Area, increases by about 10 MW for both seasons over the LTRA assessment period.

Additions of a total of 228 MW of wind generation capacity providing an expected 27 MW during the peak period and a 10 MW biomass plant, all in Nova Scotia (NS), are the new generation additions planned during the assessment period. Because of their small sizes, they will have virtually no impact on reliability. A 153 MW generator in NS is expected to be retired in October 2017. Its retirement depends on the planned construction of an undersea HVdc cable between NS and the Canadian Province of Newfoundland and Labrador as part of the Muskrat Falls hydroelectric generation development. NS plans to offset the retirement of the thermal unit with a 153 MW import of hydro capacity from Muskrat Falls.

During the winters of 2015–16 and 2016–17, the Maritimes will export 200 MW of capacity to a neighboring area. For a duration of one year, beginning in 2018 and ending in 2019, the Maritimes Area expects to export 114 MW of firm capacity to a neighboring area. In 2017, an expected import of 153 MW will be available from the Maritime Link project via Muskrat Falls hydro. This import will be timed simultaneously with the retirement of a similar amount of coal-fueled capacity in Nova Scotia. While the Maritimes Area includes 300 MW of tie benefits in its resource adequacy analyses, it is not dependent on these capacity transactions or emergency imports from neighboring areas to meet its Reserve Margin Reference targets. These tie benefits are not firm transactions and are not modeled in this LTRA analysis. Any such transactions are coordinated through the Northeast Power Coordinating Council (NPCC) working groups, which include members from all neighboring areas.

One major new transmission line addition in the Maritimes Area is planned for 2017. Development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador in 2017 will see the installation of an HVdc undersea cable link (Maritime Link) between that province and NS.

The construction periods for the planned projects mentioned above are all short and can be scheduled during times that will not significantly affect the reliability of the area. Capacity imports associated with the Maritime Link Project and the retirement of a comparable-sized unit will be timed to coincide so that the project will not have an impact on overall reliability.

The hydroelectric power supply system in the Maritimes Area with a capacity of approximately 1,330 MW is predominantly run of the river as opposed to storage based. Large quantities of energy cannot be held in reserve to stave off drought conditions. If such conditions occur, the hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems



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usable only for load following and/or peak supply. The Maritimes area is not overly reliant on wind capacity to meet resource adequacy requirements. The lack of wind during peaks or very high wind speeds and/or icing conditions that would cause wind farms to suddenly shut down should not affect the dependability of supply to the area as ample spinning reserve is available to cover the loss of the largest base-loaded generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the Assessment Area.

Renewable Portfolio Standards (RPSs) have led to the development of substantially more wind generation capacity than any other type of renewable generation. Reduced frequency response associated with wind generation may, with increasing levels of wind generation in the future, require displacement with conventional generation during light load periods. With the significant amount of large-scale wind energy currently being balanced on the NB system, the next phase of renewable energy development in NB will focus on smaller-scale projects with a particular emphasis on nonintermittent forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will provide renewable hydro resources that may otherwise have been provided by intermittent resources and would have further reduced frequency response capability. For the purposes of LTRA assessments, NB, NS, and PEI capacity credits for wind resources are estimated based on probabilistic assessments. NM credits are based on capacity factors for separate summer and winter periods.

The Maritimes Assessment Area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual-fuel oil/gas, tie benefits, and biomass with no one type feeding more than 26% of the total capacity in the area. There is not a high degree of reliance on any one type or source of fuel. The Maritimes Assessment Area does not anticipate fuel disruptions to pose significant challenges to resource adequacy in the area during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues such as potential restrictions to greenhouse gas emissions.

Load growth in the southeastern corner of the NB sub-area, though not specifically identified in the load projections, has outpaced the rest of that sub-area. Planners are monitoring transmission loads and voltages in the area to ensure reliability is not affected. No reinforcements have been planned at this time. Demand-side management programs aimed at reducing and shifting peak demands and any future potential imports to NB from NS could reduce transmission loads in the southeastern NB area. On the whole, the NB sub-area expects a slight decline in load during the LTRA 10-year assessment period. The impact on the resource adequacy loss-of-load expectancy (LOLE) value is captured by modeling a reduction in tie transfer capabilities between sub-areas. The 2013 Maritimes Area Comprehensive Review of Resource Adequacy for NPCC showed that after transfer levels are reduced from 300 MW to 150 MW, LOLE values do not exceed the NPCC target limit of 0.1 days per year of resource inadequacy. The LTRA Reserve Margin Reference levels will not be affected by this issue.

The addition of renewable resources particularly in NS is an emerging issue in the Maritimes area within the assessment period. Nova Scotia's Renewable Electricity Standard (RES) is seeking to displace significant amounts of fossil-fueled generation with renewable resources. By 2015, 25% of the province's electricity sales will be supplied by renewable energy sources, and by 2020, this number increases to 40%. Increasing amounts of renewable resources could affect BPS reliability if variable or low-mass slow-speed units are added without considering the reduction of frequency response after system contingencies or transmission enhancements to prevent voltage or overload problems. The process of completing system impact studies prior to interconnecting new generation should identify whether the emergence of any of these issues could limit operation of or the amount of new renewable generation added to the system on a case-by-case basis.

Because of the relative size of the Maritimes Assessment Area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the Maritimes Assessment Area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high-capacity transmission lines but is not dependent on these areas to supply area load. As a result, LOLE analysis suggests that even with reasonable foreseeable contingencies including load forecast uncertainty, extreme weather, fuel disruptions, and generator and transmission interruptions, the Maritimes Assessment Area load will be reliably supplied for the 10 years covered in this report.



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New England

Assessment Area Overview

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 15.9% in 2016, declining to 13.9% in 2018 and assumed to be 14.3% for the remainder of the period.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

5% of the total

Planning Considerations for Solar Resources

Seasonal claimed capability

Footprint Changes

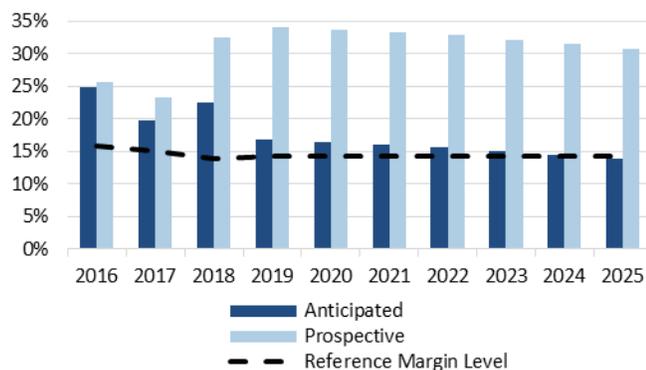
N/A

Assessment Area Footprint

Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	26,835	26,977	27,178	27,310	27,400	27,487	27,599	27,733	27,876	28,019
Demand Response	922	897	647	647	647	647	647	647	647	647
Net Internal Demand	25,913	26,080	26,531	26,663	26,753	26,840	26,952	27,086	27,229	27,372
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	32,378	31,262	32,498	31,133	31,150	31,156	31,164	31,172	31,179	31,179
Prospective	32,571	32,170	35,184	35,743	35,790	35,797	35,805	35,812	35,820	35,820
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	24.95%	19.87%	22.49%	16.76%	16.44%	16.08%	15.63%	15.09%	14.51%	13.91%
Prospective	25.69%	23.35%	32.61%	34.06%	33.78%	33.37%	32.85%	32.22%	31.55%	30.86%
Reference Margin Level	15.91%	15.03%	13.94%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,342	1,262	2,269	657	571	478	358	213	57	(107)
Prospective	2,535	2,170	4,954	5,267	5,212	5,119	4,999	4,853	4,697	4,534

Peak Season Reserve Margins



10=Year peak Season Cumulative Generation Mix Change





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Planning Reserve Margins

ISO-NE's Anticipated Reserve Margin will remain above its Reference Margin Levels throughout the study period except for the last year of this assessment. For 2025, New England will need an additional 107 MW of capacity resources to meet the 14.3% assumed Anticipated Reserve Margin for that year. Since ISO-NE has 4,600 MW of prospective capacity in its generator interconnection queue, and capacity needed to meet demand will be purchased through the Forward Capacity Market (FCM) three years in advance, the ISO will be able to secure enough capacity to meet reliability requirements through the assessment period.

Demand

The 2016 summer peak total internal demand (TID) of 26,835 MW takes into account 1,839 MW of energy efficiency as well as 237 MW of behind-the-meter photovoltaic resources. The demand forecast has decreased somewhat from the previous year's forecast, primarily due to ISO-NE's new forecast of behind-the-meter PV, which grows to 450 MW by 2024. This year's forecast of the 10-year summer TID compounded annual growth rate (CAGR) is 0.48%, as compared to the 2014 LTRA projection of 0.60%.

Demand-Side Management

Energy Efficiency and Conservation, which is secured by means of the FCM, includes installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. For the years beyond the FCM commitment periods, ISO-NE uses an energy efficiency forecasting methodology that takes into account the potential impact of growing energy efficiency and conservation initiatives in the Region. Energy efficiency has generally been increasing and is projected to continue growing throughout the study period. The amount of EE is projected to increase to over 3,500 MW by 2024.

Active demand resources, which are also procured through the FCM, consist of Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG), which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). Active demand resources are based on the Capacity Supply Obligations (CSOs) obtained through ISO-NE's FCM three years in advance. The CSOs decrease from 922 MW in 2016 to 647 MW in 2018. Since there are no further auction results, the ISO assumes that the CSOs will remain at the same level through the end of the reporting period.

The amount of Demand Response participating in ISO-NE's Forward Capacity Market has been decreasing since the start of FCM in 2010. Currently, the amount of dispatchable RTDR and RTEG demand resources is only about 2.4% of the summer TID. However, if in the future there is a substantial increase in the amount of these demand resources, there could be cause for concern. RTDR and RTEG can have significant variations in their availability and performance depending on several factors such as weather conditions, day of week, time of dispatch, and forced or planned facility or equipment shutdowns. While overall performance throughout the system has been high due to the large number and diversity of individual assets, ISO-NE has experienced relatively high variability of performance from one resource to another and from one dispatch zone to another.

Generation

A total of 104 MW (summer ratings) of new capacity consisting primarily of biomass and PV resources has been added in New England since the 2014LTRA. Anticipated capacity additions include 85 MW of new wind capacity (393 MW nameplate) and approximately 1,800 MW of natural-gas-fired power plants. Prospective capacity in ISO-NE's generator interconnection queue consists of 3,642 MW of nameplate wind capacity (256 MW on peak), 4,277 MW of natural-gas-fired capacity, and 70 MW of biomass facilities. Brayton Point station, a 1,535 MW coal, oil, and natural-gas-fired power plant, has announced that it will retire by June 1, 2017. Despite these retirements, ISO-NE's Reserve Margin is not expected to fall below the 13.9% Reference Margin Level until 2025. Furthermore, there is an additional 4,600 MW of potential replacement capacity in the interconnection queue.¹⁹

The retirement of the Brayton Point station could result in additional demand for natural gas to fuel the generating resources to replace the energy lost from the Brayton Point station. ISO-NE does not expect adverse reliability impacts during the summer peak load period due to this plant retirement. However, the retirement of the oil- and coal-fired units in this plant

¹⁹ On October 12, 2015, Entergy Nuclear Power Marketing announced their intention to retire the 680 MW Pilgrim nuclear unit by June 1, 2019. As required by its tariff, ISO New England will conduct a study to determine how the retirement will affect the overall reliability of the region's BPS. The results of this determination will be reflected in the 2016LTRA.



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could exacerbate the natural gas availability concerns during the winter months. ISO-NE has implemented various market rule changes to address these concerns.

PV resources constitute the largest segment of distributed generation resources throughout New England. The region has witnessed significant growth in the development of solar photovoltaic resources over the past few years, and continued growth of PV is anticipated. In order to determine what impacts future PV could have on the regional power grid, the ISO created a forecast of future PV. The total capability of all PV in New England, which is capacity rated at 40% of the nameplate, amounts to 494 MW in 2015 and is forecast to grow to 980 MW in 2024.

Regional PV installations are predominantly small (i.e., less than 5 MW) and state-jurisdictionally interconnected to the distribution system. States with policies more supportive of PV (e.g., Massachusetts, which had 73% of the total installed PV in New England as of the end of 2014) are experiencing the most growth of the resource. Existing amounts of PV have not caused noticeable effects on system operation, but as penetrations continue to grow and displace energy production from other resources, PV power production will introduce increased variability and uncertainty to the system, and eventually will have an impact on system operations (e.g., result in the need for increased reserve, regulation, and ramping).

The ISO is participating in projects with various organizations to prepare for integrating significant amounts of PV into its system. These include a project to improve the state of the science of solar forecasting, which will assist the ISO in developing ways of incorporating the load-reducing effects of PV into improved load-forecasting processes required to support the efficient and reliable integration of increasing amounts of PV; an evaluation of the potential reliability impacts of large amounts of distributed generation, such as PV; and a project to ensure that the future interconnection standards for PV (and other inverter-interfaced DG resources) better coordinate with broader system reliability requirements.

In January 2014, ISO-NE began incorporating wind forecasting into its processes, scheduling, and dispatch services. In addition to the ISO's use of the wind forecast, the lead market participant of a wind resource can download the forecast of expected output for their individual unit(s), which can help them build a strategy for bidding in the day-ahead energy market. As part of the first phase of this wind forecasting project, the ISO has also created real-time displays that improve the control room operators' situational awareness and is now maintaining historical wind data for future use by the forecast service. With the wind forecast integration project complete, the ISO will be working toward implementing the full economic dispatch of wind resources in phase 2 of this project, which is scheduled for implementation in 2016.

Although currently there are only 92 MW of on-peak wind capacity in New England, and only 84 MW (on-peak capacity) of future planned wind additions during the study period, an additional 3,642 MW of nameplate wind capacity is proposed within the ISO's interconnection queue. ISO New England is conducting transmission system reliability assessments to identify the nature of system reinforcements necessary to integrate significant amounts of wind resources into the system. The Strategic Transmission Analysis examined the integration of 1,113 MW of wind resources in Maine and 547 MW in Vermont. Of these amounts, all but 85 MW in Maine could be accommodated without major new transmission investment. The studies showed conceptual (non-major) transmission improvements, including static and reactive dynamic support to provide voltage control and thyristor-controlled series compensators, which would allow for the reliable integration of these proposed wind resources.

Capacity Transfers

Firm summer capacity imports are based on FCM CSOs, which amount to 1,616 MW in 2016 and decrease to 1,479 MW in 2018. The imports that are assumed for 2019–2025 are those based on long-term firm contracts, totaling approximately 90 MW. However, it is expected that imports during those years will remain at the level of the CSOs, which have been at least 1,200 MW over the past five years. In addition to firm imports, external transactions can participate in the day-ahead and real-time energy markets. In past years, actual imports during peak periods have been significantly higher than the CSOs. During the assessment period, a firm capacity sale to New York (Long Island) of 100 MW is anticipated to be delivered via the Cross-Sound Cable.

ISO-NE meets annually with its adjacent RCs to review applicable operating agreements and procedures and routinely evaluates changes to the transmission system that could have an impact on import and export capabilities. ISO-NE also coordinates all its study assumptions regarding capacity transactions and interregional transmission transfer capability of its external ties with neighboring BAs through the NPCC meetings that relate to various resource adequacy/reliability studies that are conducted annually. Regarding the internal and external transmission interface limits, ISO-NE conducts annual studies to update, if necessary, transfer capability of all the relevant transmission internal and external interfaces and publishes the resulting assumptions in its annual regional transmission plan. These transmission transfer capability assumptions are shared with and used by NPCC in its studies. In addition, as part of its FCM qualification process, new



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import resources must provide detailed information to confirm that the generator has the ability to deliver the specified capacity to New England.

Transmission and System Enhancements

Several transmission projects that are important to the continuation of or enhancement to system or sub-area reliability are projected to come on-line during the assessment period. These projects are the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England and developing and implementing solutions to address existing and projected transmission system needs. The major projects under development in New England include New England East–West Solution (NEEWS) and the greater Boston upgrades. NEEWS consists of a series of projects that will improve system reliability across southern New England, including helping to address concerns in Rhode Island that are exacerbated by upcoming resource retirements, and increasing total transfer capability across New England’s east-to-west and west-to-east interfaces. Some of the system upgrades were placed in service in early 2015, with the rest scheduled to be completed by end of 2015. The greater Boston upgrades are critical to improving the ability to move power into the greater Boston area and also in moving power from northern New England to southern New England. This set of upgrades includes a Static synchronous compensator (STATCOM) in Maine that will also help to address concerns with the potential for system separation due to significant contingencies in southern New England. The greater Boston upgrades have been certified to be in service by June 2019.

Long-Term Reliability Issues

Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements appear more likely to impose operational limits rather than a retirement risk on new and existing generators. The lower retirement risk is due in large part to exemptions offered under MATS for limited continued operation of certain (oil-fired) steam generators, recognizing the reliability value that low-capacity-factor fossil steam generators provide in maintaining system fuel diversity. Although approximately 6.3 GW of existing coal- or oil-fired capacity in the Region is subject to MATS, most affected generators in New England are already equipped with required air toxics control devices due to earlier compliance with state air toxics regulations in New England. In addition to MATS, 9.85 GW of generating capacity currently using once-through cooling will potentially be affected by the Clean Water Act 316(b) Cooling Water and may need to convert to closed-cycle cooling systems or retire. Other regulations that will likely affect existing and future fossil-generating capacity in New England include recent revisions to air quality standards limiting ambient concentrations of various air pollutants, as well as proposed federal carbon dioxide emission requirements beginning in 2020.

The continuing trend of retirement of non-natural gas capacity in New England is a cause for concern. Currently approximately 44% of the region’s capacity is natural-gas-fired generation. Based on the projects in the interconnection queue, that percentage is likely to increase significantly in the future, further straining regional fuel supplies. Serious reliability issues have emerged because of constraints on the regional natural gas delivery system as well as the cost and availability of imported liquefied natural gas (LNG). The existing natural gas pipeline system in New England is being operated at maximum capacity more often, especially in winter. The priority for a pipeline’s transmission capacity goes to customers who have signed long-term firm contracts, and in New England, these customers have been the local gas distribution companies. Most natural gas plants have interruptible fuel arrangements that procure pipeline supply and transportation that has been released by these LDCs. As more homes and businesses convert to natural gas for heating, LDCs have had less capacity to release to the secondary market. This means that the increasing numbers of gas-fired generators are competing for limited amounts of fuel supply. Imported LNG can be used to meet spikes in regional gas demand, but it is significantly more expensive than natural gas from the Marcellus shales.

Although Marcellus shale gas production holds the promise of plentiful and inexpensive natural gas supply for the foreseeable future, additional pipeline capacity to New England is required. Only eight of the 19 proposed pipeline-expansion projects across the Northeast would bring new or incremental pipeline capacity to New England. Although two pipeline expansion projects, Spectra Energy’s Algonquin Incremental Market (AIM) project and Tennessee Gas Pipeline’s Connecticut Expansion Project, are anticipated to be in service by winter 2016–17, these projects and their benefits will be more than offset by the retirement of Brayton Point Station. A study commissioned by the ISO highlights the problem; ICF International’s 2014 gas study report projects regional shortfalls of natural gas supply during winter periods through 2020, even with the addition of 421 million cubic feet per day of new pipeline capacity.

The ISO is increasingly concerned about its ability to maintain power grid reliability during the coldest days of winter due to fuel unavailability. In winter 2014–15, the ISO implemented for the second year a special reliability program to mitigate risks associated with the retirement of key nongas generators, gas pipeline constraints, and generators’ difficulties in replenishing oil supplies. As part of the 2014–15 winter program, oil-fired and dual-fuel generators, and generators that can access LNG were paid to secure fuel inventory and test fuel-switching capability; were compensated for any unused fuel inventory; and



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were also subject to nonperformance charges. The 2014–15 program also included permanent improvements such as the continued ability to test resources' fuel-switching ability and to compensate them for running the test. In addition, ISO-NE implemented a project that allowed generators to reflect fuel costs in their energy market offers as those costs change throughout the day, and changed the timing of the day-ahead energy market to better align with natural gas trading deadlines. The ISO has initiated a stakeholder process to explore proposals to address reliability concerns for winter 2015–16 and at least until 2018, when capacity market refinements to incentivize performance begin to take effect. Those refinements include Pay-for-Performance (PFP), which will strengthen availability incentives within the forward capacity market. Other efforts undertaken to shore up operations include the development of tools that help operations personnel more accurately predict the availability of natural gas supply for generators, improving unit commitment decisions; and increased communications with gas pipeline operators (assisted by FERC Order 787) to verify whether natural-gas-fired generators that are scheduled to run will be able to obtain fuel.

Pay-for-Performance, which will go into effect in June 2018, will create stronger financial incentives for generators to perform when called upon during periods of system stress: a resource that underperforms will effectively forfeit some or all capacity payments, and resources that perform in its place will get the payment instead. PFP will also create incentives to make investments to ensure performance, such as upgrading to dual-fuel capability, entering into firm gas-supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site oil or LNG fuel storage, or expanded gas pipeline infrastructure. However, PFP will not reach full effectiveness until the seven-year phase-in of the new performance rate is complete. Until that time, the region may be challenged to meet power demand at times when regional gas pipeline capacity is constrained. PFP may also hasten the retirement of inefficient resources with poor historical performance and the entrance of new, efficient, better-performing resources.



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New York

Assessment Area Overview

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 % extends through April 2016. New York's IRM is set annually, one year at a time, the NYISO will use the 2015 IRM of 17% throughout the assessment period

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

Modeled with a 17 % capacity factor

Planning Considerations for Solar Resources

Modeled with a 48 % capacity factor

Footprint Changes

N/A

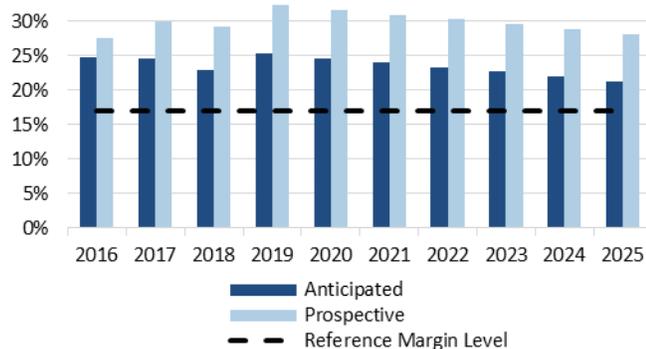
Assessment Area Footprint



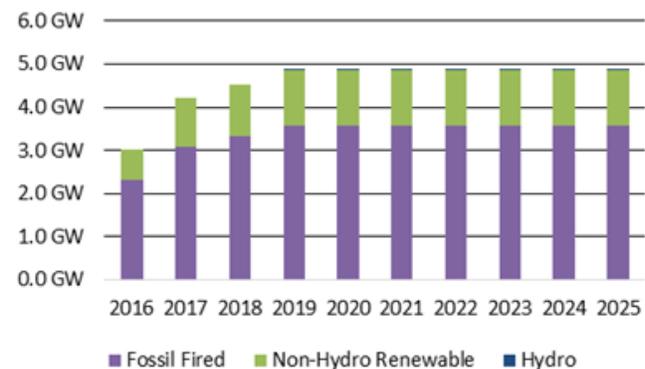
Peak Season Demand, Resources, and Reserve Margins²⁰

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	33,636	33,779	33,882	34,119	34,309	34,469	34,639	34,823	35,010	35,219
Demand Response	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124
Net Internal Demand	32,512	32,655	32,758	32,995	33,185	33,345	33,515	33,699	33,886	34,095
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	40,546	40,669	40,293	41,347	41,347	41,347	41,347	41,347	41,347	41,347
Prospective	41,488	42,454	42,340	43,650	43,650	43,650	43,650	43,650	43,650	43,650
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	24.71%	24.54%	23.00%	25.31%	24.60%	24.00%	23.37%	22.70%	22.02%	21.27%
Prospective	27.61%	30.01%	29.25%	32.29%	31.54%	30.91%	30.24%	29.53%	28.82%	28.03%
Reference Margin Level	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,508	2,463	1,967	2,743	2,521	2,334	2,135	1,920	1,701	1,456
Prospective	3,450	4,248	4,013	5,046	4,824	4,637	4,438	4,223	4,004	3,759

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



²⁰ Based on New York Installed Capacity (ICAP) values.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Planning Reserve Margins

For the LTRA Reference Margin, New York has agreed to using the current capability year 17% Installed Reserve Margin (IRM) value extended out for the entire 10-year window. New York has reported it that way in the past. The IRM value is determined and set each year by a study conducted by the New York State Reliability Council (NYSRC) and is based on wind and solar at full ICAP value modeled using an hourly supply shape for each wind and solar location. New York does not mix ICAP and UCAP in the IRM calculation. The data New York reported in the LTRA has wind and solar at full ICAP.

Demand

The energy forecast for the NYBA is lower than last year due to a change in the expected relationship of energy growth with the economy. Whereas economic growth (based on either employment or metro area GDP) continues to increase, the energy growth in most areas of the state is projected to be negative. Positive growth in summer and winter peak demand is expected. The decline in year-over-year energy usage is attributed to the continued impact of energy efficiency programs and additional incentives for customer-sited solar PV.

The average annual statewide energy growth is 0.00% for the period 2015 through 2025. In last year's forecast the annual average statewide energy growth was 0.16% for the period 2014 through 2024.

The average annual statewide summer peak demand growth is 0.48% for the period 2015 through 2025. In last year's forecast the annual average statewide energy growth was 0.83% for the period 2014 through 2024.

This difference between the energy growth and the summer peak demand growth from the 2014 forecast to the 2015 forecast indicates a continuation of the decoupling of the traditional relationship between growth patterns in annual energy consumption and summer peak demand.

Summer peak demand growth is expected to be slightly higher in the downstate region comprised of NYBA's Zones J and K (similar to New York City and Long Island), as compared to other areas of the state. This is expected to continue throughout the forecast horizon, but is not expected have any reliability impacts.

Demand-Side Management

Energy efficiency programs in the state are expected to continue to grow at the rate of about 200 MW (summer) per year, consistent with projections in prior years. In addition, NYISO expects summer peak reductions of about 80 MW per year due to customer-sited solar PV.

The Emergency Demand Response Program provides demand resources an opportunity to earn the greater of \$500/MWh or the prevailing locational-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on the resource. Resources must be enrolled through Curtailment Service Providers (CSPs), which serve as the interface between NYISO and the resources, in order to participate in EDRP. There are no obligations for enrolled EDRP resources to curtail their load during an EDRP event.

Demand Response is considered in the NYISO planning processes including load forecast and resource adequacy analysis. Demand Response enrollments are currently trending at approximately at 3.5% of the NYISO system peak load. In addition, NYISO does not anticipate a significant increase in Demand Response enrollments in the near future. Given these factors, NYISO does not anticipate significant long-term reliability impacts from a modest increase in the Demand Response enrollments from the current enrollment levels.

Generation

Since the 2014 LTRA, seven previously mothballed units were returned to service, representing a total capability of 749 MW. Over the current 2015 LTRA assessment period, Tier 1 resources are expected to add 753 MW. These include the repowering of two former mothballed coal plants (360 MW) to run on natural gas; three units were rerated, adding 393 MW. Tier 2 resources, if they come on-line, are expected to add 2,550 MW.

Approximately 125 MWdc equivalent of customer-sited solar PV facilities were added in the NYBA from May 2014 to May 2015.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Two units (304 MW) are planned to retire/mothball in summer 2017.²¹ When the NYISO receives a generator retirement/mothball notice, NYISO conducts an impact study to determine if a reliability need is created when the unit shuts down. If no reliability need is determined, then the unit may retire/mothball as planned. These units have completed the retired/mothball process and are now planned to retire/mothball in summer 2017.

No other large generators are expected to be unavailable over the assessment period.

The long-term forecast of annual energy and seasonal peak demands incorporates explicit adjustments for distributed energy resources, such as solar PV and distributed generation, along with energy efficiency. Based on approved funding levels, the expected on-peak impact of customer-sited solar PV is 799 MW by 2025. The expected impact of energy efficiency and other distributed energy resources is 1,939 MW by that year.

NYISO is currently conducting a Solar Integration Study with input of stakeholders and involved agencies to determine the impact of customer-sited solar PV on operational levels for regulation. It is also conducting a literature review, a solar forecasting evaluation, and a review of how solar PV is being accounted for by other ISOs/RTOs.

There have been no changes to the methods used to determine the on-peak capacity values for wind, solar, and hydro. Hourly unit output data for wind, run-of-river hydro, and solar units are collected for the summer peak hours (2:00 p.m. – 5:00 p.m. Eastern) from June 1 through August 31. The capacity on-peak for these resources is determined using an assumed capability for each resource class based on unit historic operating data and engineering judgment.

In addition, on-peak resources available from solar PV include a number of factors, such as inverter sizing and efficiency, the impact of cloud cover, other atmospheric conditions that attenuate solar irradiance, and the seasonal and diurnal variations in solar irradiance. These are compared to actual power production of solar PV systems to provide that the combined effect of all factors is consistent with current levels of technology.

Capacity Transfers

There are three classifications of capacity transfers. The first includes grandfathered contracts and external Capacity Resource Interconnection Service (CRIS) Rights. Grandfathered contracts predate the formation of NYISO and are honored at their capacity levels for their duration. External CRIS Rights authorize the owner to deliver capacity to New York from neighboring Balancing Authorities. These total 1,127 MW and cover the entire 2015LTRA assessment period. The second class is Unforced Deliverability Rights (UDRs). These are rights to deliver capacity over controllable tie lines. The total UDR capability is 1,965 MW across the four controllable ties. The owners of the UDRs notify NYISO each year of the amount of capacity that will be delivered; UDR election levels are treated by NYISO as confidential information. Any transfer capability not utilized is available to provide emergency assistance in both our planning studies and operationally, if the need arises. The third classification is Import Rights. Once the annual Installed Reserve Margin (IRM) study is completed, an Import Rights study is conducted to determine the transfer capability available over and above the IRM requirement. For 2015, these total 580 MW and are available month to month on a first-come first-served basis in the capacity auctions.

Capacity transactions modeled in NYISO's assessments have met the capacity resource requirements as defined in NYISO's tariffs. Both NYISO and its respective neighboring Assessment Areas have agreed on the terms of the capacity transaction including, for example, (1) the MW value, (2) the duration, (3) the contract path, (4) the source of capacity, and (5) the capacity rating of the resource.

Transmission and System Enhancements

The Transmission Owner Transmission Solutions (TOTS) consists of three transmission projects in central New York, downstate New York, and New York City. TOTS is part of the Con Edison and the New York Power Authority (NYPA) filing in response to a November 2012 order from the New York Public Service Commission (PSC) that recognized significant reliability needs would occur if the Indian Point Energy Center (IPEC) was retired upon the expiration of IPEC's existing licenses or became unavailable for any reason. The three TOTS transmission projects are described in the following paragraphs.

²¹ On November 2, 2015, Entergy Nuclear Power Marketing announced their intention of retiring the 838 MW James A. Fitzpatrick nuclear unit at the end of the current fuel cycle, by June 2017. NYISO will be conducting an assessment to determine how this retirement will affect the overall reliability of the region's bulk power system. The results of this assessment will be reflected in the 2016LTRA.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

The Ramapo-Rock Tavern project will establish a second 345 kV line from Con Edison's Ramapo 345 kV substation to Central Hudson Gas and Electric Corporation's (CHGE) Rock Tavern 345 kV substation. The project will increase the import capability into Southeastern New York (SENY), including New York City, during normal and emergency conditions and will provide a partial solution for system reliability should the IPEC retire. The project will be located in Orange and Rockland Counties in New York along the right-of-way for the existing Con Edison 345 kV Feeder 77 (Ramapo to Rock Tavern) and using existing transmission towers. The transmission line terminals are located in NYISO Zone G. This project involves work that will be performed by Orange & Rockland Utilities (O&R) and CHGE; as such, Con Edison has and will continue to coordinate this effort with both O&R and CHGE.

The Staten Island Unbottling project will unbottle generation and transmission resources on Staten Island. It is a new resource and will be located in NYISO Zone J. The initial option for this project was to install a new 345 kV feeder and the forced cooling of four existing 345 kV feeders. The new option, a 1.5 mile feeder interconnecting the Goethals substation to the Linden substation, would mitigate a contingency within New York City by installing a new double leg feeder into new positions at the Goethals and Linden substations. Based on additional preliminary engineering and design work, Con Edison made certain changes to the project design. Instead of a new feeder installation, splitting an existing feeder between Goethals and Linden Cogen substations will provide a similar solution at a lower cost and with lower environmental impacts. The forced cooling of the existing four 345 kV feeders remains in the project scope and will increase transmission capacity between the Goethals, Gowanus, and Farragut substations. This project is located in Staten Island and Brooklyn, New York, and Union County (Linden), New Jersey.

The Marcy South Series Compensation project is a transmission improvement project that adds switchable series compensation to increase power transfer by reducing series impedance over the existing 345 kV Marcy South lines. Specifically, the project adds 40% compensation to the Marcy-Coopers Corners 345 kV line, 25% compensation to the Edic-Fraser 345 kV line, and 25% compensation to the Fraser-Coopers Corners 345 kV line through installation of series capacitors. The project also involves upgrades at Marcy and Fraser 345 kV substations. The project includes reconductoring of approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345 kV line (FCC-33) with a higher thermal-rated conductor installed on existing wooden pole and steel tower structures. The project increases thermal transfer limits across the Total East Interface and the UPNY/SENY Interface.

The NYISO 2014 Reliability Needs Assessment identified thermal violations under N-1-1 post-contingency conditions (applying more stringent NPCC criteria) in the Rochester and Syracuse areas. The draft 2014 Comprehensive Reliability Plan states that these violations will be resolved with permanent solutions identified in the most recent Transmission Owner local transmission plans scheduled to be completed by summer 2017 in Rochester and the end of 2017 in the Syracuse area. In the interim, the local transmission owners will implement local operating procedures, if required, to prevent overloads, including the potential for limited load shedding in the Rochester and Syracuse areas.

Long-Term Reliability Issues

Recently agencies and generators have begun to examine or implement operational limits as an alternative means of achieving compliance with environmental regulations. Such limits may pose a risk to system reliability if generators exhaust their permitted emission limits and may not be in a position to operate for portions of the year when they are needed to maintain BPS reliability. The 2014 Reliability Needs Assessment (RNA) reviewed the impacts of federal and state environmental regulations on operation of the bulk power transmission facilities. The potential risks to system reliability posed by implementation of emission and operational limits to comply with pending environmental regulations are:

1. Phase I of CSAPR has begun replacing obligations under the Clean Air Interstate Rule (CAIR) for NO_x and SO₂ emissions. Allocations under Phase I to NYBA generators are approximately equivalent with reported emissions for 2014. In 2016, it is expected that the operation of installed control equipment will be optimized to achieve compliance. CSAPR Phase II begins in 2017. In this phase, the SO₂ allocations are reduced, interstate trading limits are imposed, and NYS is seeking to have allowances directed to the State instead of the generators. The CSAPR Phase II Cap will be binding nationally, which will likely result in increased allowance prices. Nevertheless, under most conditions it appears that sufficient allowances should be available to the NYBA generation fleet.
2. Compliance with MATS began on April 16, 2015, for new and existing coal- and oil-fired units. Some dual-fuel units have chosen to limit oil use to avoid more challenging emission requirements. Depending on system conditions, such operational limits could pose a risk to system reliability, as they have the potential to reduce the



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

effective aggregate dual-fuel capacity available to maintain the reliability of the New York Bulk Power Transmission Facilities (BPTF).

3. The draft EPA Clean Power Plan rules would require CO₂ emission reductions beginning in 2020. In comments on the proposal, the NYISO voiced concerns about the potential implications for electric system reliability and the lack of recognition of the progress New York has already made in achieving significant reductions in CO₂ emissions. NYISO stated in its comments to the EPA, “As proposed, the Clean Power Plan presents potentially serious reliability implications for New York. A majority of the electric capacity within New York City is dual-fuel oil/gas steam-fired electric generating units. These units are critically important, both due to their location within the transmission-constrained New York City area and because they possess dual-fuel capability that provides a needed measure of protection against disruptions in the natural gas supply system.” The comments questioned the EPA’s assumption that the output from vital dual-fuel units could be reduced by over 99% while maintaining reliable electric service to New York City.
4. EPA is currently in the process of revising the National Ambient Air Quality Standard (NAAQS) for Ozone. Depending upon the ultimate level selected, the Ozone NAAQS will likely require further Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) emission reductions from NYCA generators. Such reduction requirements are not anticipated prior to 2022.

The NYBA is reliant on natural gas as the primary fuel for electric generation. Ongoing studies and efforts focus on:

1. improving communication and coordination between the sectors
2. addressing market structure enhancements, such as the closing time of the natural gas markets
3. providing for back-up fuel (primarily distillate oil) assurance to generation
4. addressing the electric system reliability impact of the sudden catastrophic loss of gas

NYISO, in conjunction with its stakeholders, is exploring market rule changes to help assure fuel availability during cold weather conditions. Improvements will be considered in reporting seasonal fuel inventories and daily replenishment schedules. NYISO will work with New York State regulatory agencies to develop a formal process to identify reliability needs that would be mitigated by generator requests for certain waivers. FERC has issued a NOPR to gather public comments to propose rule modifications in the gas market to provide better coordination between the electric and gas markets.

Generator retirements also pose the potential for an emerging reliability issue. While NYISO concludes that long-term reliability needs have been satisfied in the draft 2014 Comprehensive Reliability Plan (CRP) report, the margin to maintain reliability narrows over the 10-year study period based on projected load growth and the assumption that there are no additional resources added after 2017. Potential risk factors, such as long-term generator unavailability or higher load levels in regions of upstate New York (including Rochester, Western and Central New York, and the Capital Region), could potentially lead to immediate and severe transmission security violations. The projected NYBA capacity margins are narrow in the later years of the study; therefore, a small decrease in their existing resource capacity or an increase in loads by 2024 would result in an LOLE (loss-of-load event) violation in that year



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Ontario

Assessment Area Overview

Ontario's electrical power system covers an area of 415,000 square miles and serves 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.²²

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;

Footprint Changes

N/A

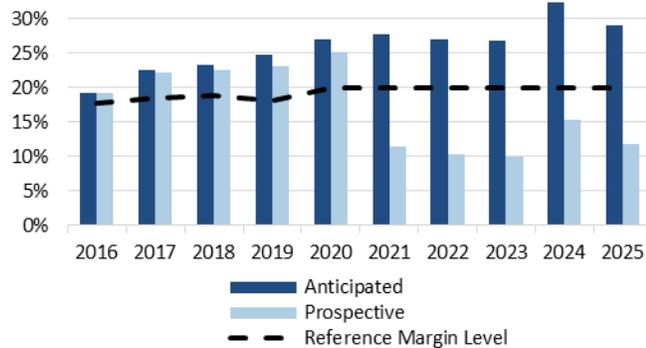
Assessment Area Footprint



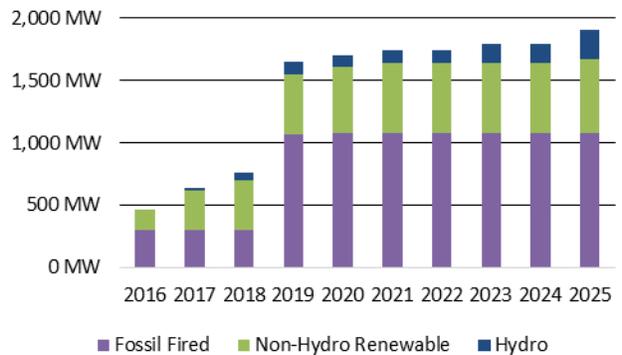
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	22,849	22,819	22,790	22,669	22,522	22,479	22,760	22,976	22,920	23,135
Demand Response	576	576	576	576	676	826	976	1,176	1,376	1,566
Net Internal Demand	22,273	22,243	22,214	22,093	21,846	21,653	21,784	21,801	21,544	21,569
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	26,548	27,274	27,406	27,545	27,748	27,659	27,659	27,653	28,531	27,827
Prospective	26,548	27,170	27,222	27,181	27,322	24,139	24,021	23,962	24,840	24,136
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	19.20%	22.61%	23.37%	24.68%	27.02%	27.74%	26.97%	26.84%	32.43%	29.01%
Prospective	19.20%	22.15%	22.55%	23.03%	25.07%	11.48%	10.27%	9.91%	15.30%	11.90%
Reference Margin Level	17.72%	18.40%	18.90%	18.02%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	329	937	994	1,471	1,533	1,675	1,518	1,492	2,678	1,944
Prospective	329	834	810	1,107	1,107	(1,845)	(2,120)	(2,199)	(1,013)	(1,747)

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



²² 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 Target Reserve Margin numbers differ in IESO reports when compared to NERC reports. The Ontario reports would report lower Reserve Margins.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Demand, Resources and Planning Reserve Margins

Ontario has invested heavily in electricity infrastructure over the past decade. Investments have enabled the phase-out of coal-fired generation in the province and have reduced the carbon intensity of Ontario's electricity supply mix. Growing net supply additions to manage the retirement of coal-fired generation and moderate demand resulted in substantial Reserve Margins in the recent past. With the recent phase-out of coal-fired generation in the province, Reserve Margins are reduced to levels that satisfy the reserve requirement.

Ontario is adequate for the entire duration of the assessment under the anticipated scenario. Under the prospective scenario, Ontario has enough confirmed planned resources (Tier 1) to meet its Reference Margin Levels for the first half of the assessment period and will rely on new resources (Tier 3) of up to 2,200 MW to meet the Reference Margin Level between 2022 and 2025. Ontario possesses a range of options to address these needs, including market-based mechanisms and capacity imports.

Over the 10-year period, Ontario expects increased demand for electricity, driven by modest economic expansion and population growth. However, these increases are being offset by three key factors:

1. The growth in embedded generation (behind-the-meter) capacity, which has a significant downward impact on grid-supplied electricity.
2. Conservation impacts that reduce the overall need for both end-use and grid-supplied electricity.
3. The increasing impact of price-sensitive demand through the implementation of time-of-use rates, as well as the Industrial Conservation Initiative.

Over the assessment period, the capacity of distribution-connected generation (DG) is expected to increase. As of December 31, 2014, more than 1,925 MW of variable generation was operating within distribution systems. Over the forecast period, about 1,900 MW of renewable capacity is projected to be added. Most of this embedded generation will be solar powered.

Overall growth in summer peak demand is modest due to the deployment of DG, especially the increased penetration of solar-powered DG. The summer peaks are also being influenced by efficiency changes to air conditioners. The winter peaks in Ontario occur after sunset so they are not significantly impacted by the mostly solar DG. However, the winter peak is seeing downward pressure from conservation savings due primarily to lighting efficiencies as end users move to compact fluorescent and LED technology.

There will be some variation in demand growth within Ontario. The greater Toronto area (GTA) has the largest share of the Ontario population and economy. The Essa zone, which lies just north of the GTA, will see positive growth resulting from ongoing expansion of the GTA. Primarily due to expected mining growth in the northern portions of the province, a rebound is expected during the later years of the forecast in the Northern Ontario zone.

The Demand Response programs during the summer are expected to increase from just over 500 MW at present to over 1,500 MW by the end of the forecast period. Ontario currently has three main Demand Response programs: Peaksaver PLUS® (primarily driven by air-conditioning load), dispatchable loads, and Capacity-Based Demand Response (CBDR), which is a new program for the previous Demand Response 3 (DR3) program participants. Future Demand Response may also participate in market-based mechanisms such as a Demand Response Auction. Participation in dispatchable load programs drops during the peak period as the loads take advantage of the Industrial Conservation Initiative.

Ontario is a strong proponent of conservation. The programs designed to achieve conservation targets are expected to deliver cumulative savings of 12.7 TWh over the forecast horizon. Those savings will be achieved through improved building codes, equipment standards, and incentive-based conservation programs. This includes time-of-use rates and the Industrial Conservation Initiative.

To meet the challenge of rapid deployment of renewables across the province and help capture the benefits of Ontario's investment in variable generation, the IESO implemented the Renewables Integration Initiative (RII) in 2013. RII has yielded results including the integration of the hourly centralized forecast into IESO scheduling tools, enhanced visibility of renewable output of distributed-connected variable generation facilities 5 MW or greater, and the dispatch of grid-connected variable generation. Frequency response, short-term inertial response, voltage ride-through capability, and voltage support are some of the performance requirements clearly identified during the connection process and validated through tests before the new grid-connected resources complete their facility registration with the IESO. Frequency response and voltage ride-through capability requirements also apply to distribution-connected resources larger than 10 MW.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

In May 2015, the IESO signed a 500 MW seasonal firm capacity sharing agreement with Hydro Quebec. This agreement takes advantage of the provinces' complementary seasonal peaks to support reliability and will be in effect for 10 years, starting from December of 2015. The capacity will be shared, allowing Quebec to import up to 500 MW in winter months, and Ontario to import up to 500 MW in summer months. The energy associated with the capacity agreement will be scheduled through existing market mechanisms.

Transmission Outlook and System Enhancements

Transmission planning to address changes to the supply mix and ensure reliability throughout the province is ongoing. System enhancement projects that are underway include a new 230 kV double-circuit East-West Tie line, and the addition of a new 500-to-230 kV transformer station (TS), Clarington TS, in the eastern portion of the GTA. The in-service date for the new East-West Tie line has been revised from 2018 to 2020 due to slower than anticipated near-term load growth in northwestern Ontario. The Clarington transformer station is scheduled to be in service in the first half of 2018.

Planning studies are being finalized to manage the loading on the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS, which are forecast to be exceeded by 2020. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station, with eight 230 kV circuit terminations and 12 km (7.5 miles) of new double-circuit line sections connecting the new Milton TS to Hurontario Switching Station.

Long-Term Reliability Issues

With the growth in the embedded variable generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected variable generation and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

All coal units in Ontario have been phased out as of April 2014, in accordance with Ontario government policy. In the years following the coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. Nuclear units at Pickering Generating Station will not be refurbished, and current plans are to operate these units through approximately 2020. The other two nuclear plants in the province, Darlington and Bruce, are scheduled for refurbishment between 2016 and 2031. These changes may lead to a supply gap starting in 2021. Flexibility, cost, and environmental performance have been incorporated in Ontario's energy plan to ensure that commitment decisions are made in a timely manner. If additional resources are needed, market-based mechanisms such as the Demand Response Auction or the Capacity Auction are planned to facilitate procuring new resources. Other options include recontracting Non-Utility Generator (NUG) facilities as their contracts reach maturity, new gas-fired generation, imports, energy storage, and additional conservation above current targets.

High voltages are experienced in southern Ontario during light load periods and, with the planned shutdown of Pickering GS and the removal of its reactive absorption capability, the situation is expected to persist. Planning work for the new installation of new voltage control devices has been initiated.



NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Québec

Assessment Area Overview

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 2014 Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2014.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Winter

Planning Considerations for Wind Resources

On-peak contribution is approximately 30 % of the total

Planning Considerations for Solar Resources

N/A

Footprint Changes

N/A

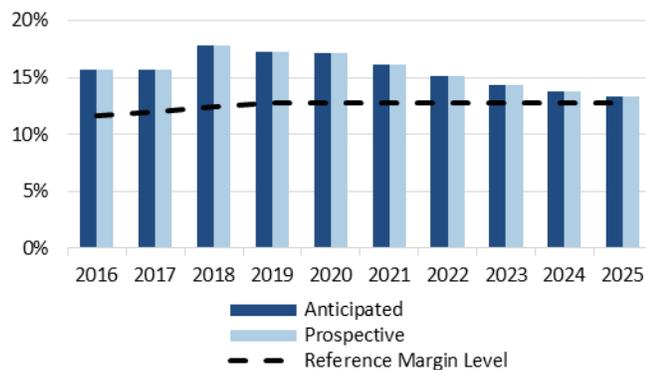
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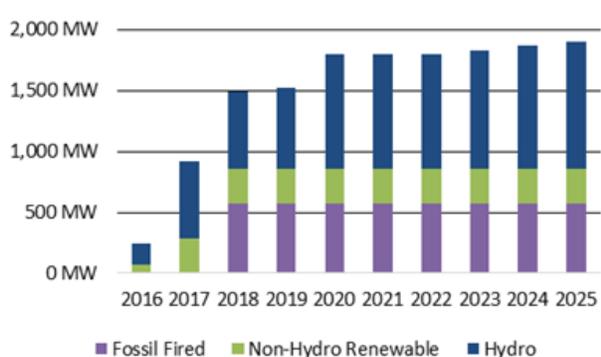
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	38,650	38,855	39,175	39,469	39,792	40,114	40,440	40,724	40,965	41,149
Demand Response	2,197	2,197	2,222	2,272	2,297	2,297	2,297	2,297	2,297	2,297
Net Internal Demand	36,453	36,658	36,953	37,197	37,495	37,817	38,143	38,427	38,668	38,852
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	42,179	42,421	43,544	43,624	43,905	43,905	43,905	43,940	43,975	44,010
Prospective	42,179	42,421	43,544	43,624	43,905	43,905	43,905	43,940	43,975	44,010
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	15.71%	15.72%	17.84%	17.28%	17.09%	16.10%	15.11%	14.35%	13.72%	13.28%
Prospective	15.71%	15.72%	17.84%	17.28%	17.09%	16.10%	15.11%	14.35%	13.72%	13.28%
Reference Margin Level	11.60%	12.00%	12.40%	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	1,497	1,363	2,009	1,665	1,610	1,247	880	594	358	185
Prospective	1,497	1,363	2,009	1,665	1,610	1,247	880	594	358	185

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change





NPCC 2015 LONG RANGE ADEQUACY OVERVIEW

Demand, Resources, and Planning Reserve Margins

The Anticipated Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period.

The Québec Area demand forecast average annual growth is 0.7% during the 10-year period, a decrease since the 2014LTRA report (0.9% average annual growth). This decrease in the demand forecast is mainly attributed to the industrial sector. Total Internal Demand is calculated for the Québec area as a single entity, and the area's peak demand forecast is coincident. Energy efficiency and conservation programs are integrated in the Assessment Area's demand forecasts and account for an average annual impact of 140 MW (at winter peak) over the 10-year period.

Demand Response (DR) programs in the Québec area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs (for large industrial customers), totaling 1,747 MW for the 2016–17 winter period. The area is developing some interventions in DR (direct control load management and others) to its customers, which would provide 300 MW by 2021–22. The total on-peak DR for the 2025–26 winter period is projected to be 2,297 MW.

In 2014, the generating station La Romaine-2 was integrated for a total of 640 MW of new added hydro capacity. Work is underway on the La Romaine-1 (270 MW) and La Romaine-3 (395 MW) developments, which will be fully operational in 2016 and 2017, respectively. Some preparatory work has also begun on the La Romaine-4 (245 MW) development, which will be fully operational by the end of 2020. The retrofitting of some hydro units should also add 219 MW of capacity over the assessment period. For other renewable resources, about 480 MW of wind capacity and 60 MW of biomass have been added to the system since the beginning of 2014. Additionally, about 1,040 MW of wind capacity and 120 MW of biomass are expected to be in service by the end of 2017.

The Québec area will support firm capacity sales totaling 1,017 MW during the 2016–17 winter peak period, declining to 145 MW for the 2020–21 winter period. Also, a total of 1,800 MW of firm capacity purchases are planned for winter 2016–17, declining to 1,100 MW for the subsequent nine winter periods.

Transmission Outlook and System Enhancements

Romaine River Hydro Complex Integration

Construction of the first phase of transmission for the Romaine River Hydro Complex project is presently underway. Total capacity will be 1,550 MW. Romaine-2 (640 MW), which was commissioned in December 2014, is integrated on a 735 kV infrastructure initially operated at 315 kV to Arnaud 735/315/161 kV substation. One 315/161 kV, 500 MVA transformer has also been installed at this substation for the need of the project. The next generating station to be commissioned will be Romaine-1 (270 MW) at the end of 2015 and the beginning of 2016. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated between 2017 and 2020 at Montagnais 735/315 kV substation.

Main system upgrades for this project require construction of a new 735 kV switching station to be named Aux Outardes, which will be located between existing Micoua and Manicouagan Transformer substations. Two 735 kV lines will be redirected into the new station, and one new 735 kV line (5 km, or 3.1 miles) will be built between Aux Outardes and Micoua. This project was initially planned to be commissioned in 2014 and has been delayed to 2015.

Chamouchouane – Judith-Jasmin 735 kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735 kV line in the near future in order to meet the Reliability Standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km, or 250 miles). The new 735 kV substation is required to fulfill two objectives: providing a new source of electricity supply on the north shore of Montreal, and connecting the new 735 kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses.

Planning, permitting, and construction delays are such that the line is scheduled for the 2018–19 winter peak period. Public information meetings have begun on this project.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England is currently under study. It involves the construction of a ± 320 kV dc transmission line about (75 km, or 47 miles) long from Des Cantons 735/230 kV substation to the Canada–U.S. border. This line will be extended into the United States to a substation built in Franklin, New Hampshire. The project in Québec also includes the construction of an HVdc converter at Des Cantons and a 320 kV dc switchyard. The planned in-service date is now 2019.



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The Champlain-Hudson Power Express Project

This project to increase transfer capability between Québec and New York by 1,000 MW is currently under study. The project involves construction of a ± 320 kV dc underground transmission line about (50 km, or 31 miles) long from Hertel 735/315 kV substation just south of Montréal to the Canada–U.S. border. This line will be extended underground and underwater (Lake Champlain and Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of one 1,000 MW converter at Hertel. The planned in-service date is 2018.

Wind Generation Integration Projects

Different calls for tenders for wind generation have been issued in the past years. About 3,950 MW (including wind generation already in service) is forecast to be on-line by the end of 2017. A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages to complete the integration of wind generation resulting from the past calls for tenders. These projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

Upcoming Regional Projects

Other regional substation and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas and another dozen in other areas with in-service dates from 2015 to 2020, consisting mostly of 315/25 kV and 230/25 kV distribution substations to replace 120 kV and 69 kV infrastructures.

Long-Term Reliability Issues

While technical developments in recent years have contributed to creating a more reliable system, sustainable system reliability may be challenged by several issues. For example, wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up, and the following are under study:

- Wind generation variability on system load and interconnection ramping
- Frequency and voltage regulation
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability
- Efficiency losses in generating units and/or reduction of low-load operation flexibility due to the low inertia response of wind generation coupled with must-run hydroelectric generation

In addition to these issues, there are occasions during recent summers when several 735 kV lines in the southern part of the system became heavily loaded due to the hot temperatures in southern Québec. Although this is a new issue for the Québec area, it is expected to occur again with increased air-conditioning loads and growing exports to other summer-peaking systems. More recently, studies have been performed and thermal limits have been optimized with other mitigating measures to address the potential for future line overloads following a contingency during periods of hot temperatures



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PJM

Assessment Area Overview

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM companies serve 61 million people and covers 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Summary of Methods and Assumptions

Reference Margin Level

The PJM RTO Reserve Requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

Initially 13% of nameplate replaced with historic information tracked over the peak period

Planning Considerations for Solar Resources

Initially 38% of nameplate replaced with historic information tracked over the peak period

Footprint Changes

The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

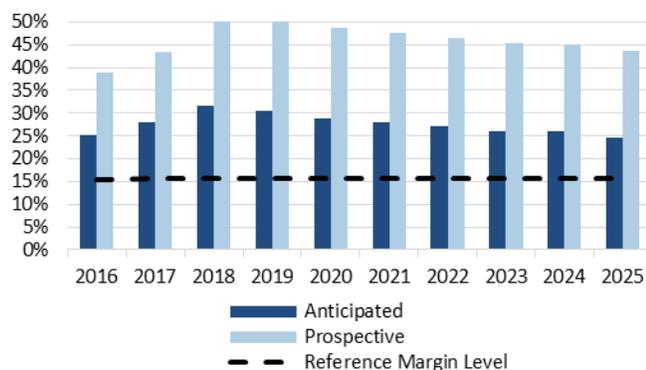
Assessment Area Footprint



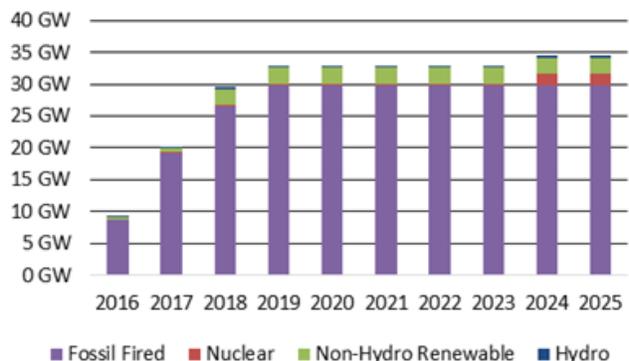
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	157,912	159,808	161,128	162,618	164,443	165,764	166,902	168,399	169,706	171,580
Demand Response	7,896	7,990	8,056	8,131	8,222	8,288	8,345	8,420	8,485	8,579
Net Internal Demand	150,016	151,818	153,072	154,487	156,221	157,476	158,557	159,979	161,221	163,001
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	187,811	194,181	201,330	201,538	201,420	201,420	201,420	201,420	202,990	202,990
Prospective	208,288	217,664	230,700	232,608	232,490	232,490	232,490	232,490	234,060	234,060
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	25.19%	27.90%	31.53%	30.46%	28.93%	27.91%	27.03%	25.90%	25.91%	24.53%
Prospective	38.84%	43.37%	50.71%	50.57%	48.82%	47.64%	46.63%	45.33%	45.18%	43.59%
Reference Margin Level	15.50%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	14,542	18,528	24,226	22,797	20,673	19,221	17,970	16,324	16,458	14,398
Prospective	35,019	42,011	53,596	53,867	51,743	50,291	49,040	47,394	47,528	45,468

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change





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PJM meets its Reference Margin Level using Anticipated Resources for the entire assessment period. The PJM Reserve Requirement is 15.6% in 2015, 15.5% in 2016, and 15.7% for the rest of the assessment period. Winter season Reserve Margins remain above the Reserve Margin requirement through the entire assessment period.

All load models were estimated with historical data from January 1998 through August 2014. There are 13 weather-variable rotations for each year. A scenario is created for the date in question plus one each for the six prior days and the six succeeding days. The models were simulated with weather data from years 1973 through 2013, generating 533 scenarios. The economic forecast used was Moody's Analytics' October 2014 release.

During 2014, amid growing evidence that the PJM load forecast model was persistently overforecasting, PJM investigated a more fundamental change to the load forecast model to account for missing factors that could be influencing recent electricity usage patterns. PJM acquired historical and forecast appliance saturation data as well as residential and commercial end-use data as drawn from the U.S. Energy Information Administration. From this data, PJM derived three additional variables for its energy (GWh) model:

1. A cooling equipment trend
2. A heating equipment trend
3. A trend for miscellaneous uses

Benchmarking tests demonstrated that this refined energy model provided a better estimate of the slowdown in energy usage in recent years and produced forecasts that tend to start lower than the current model, ultimately growing at a slightly faster rate. PJM reviewed the model and benchmark results with the PJM Load Analysis Subcommittee and PJM Planning Committee and has elected to publish the results of the new model as an alternative energy forecast. Going forward, PJM will attempt to extend the new model specification in order to apply it to peak load megawatt forecast.

For the 2015 Load Forecast, PJM adopted an interim improvement to the peak demand forecast model as a transitional mechanism until more permanent changes can be implemented based on more extensive and rigorous analysis and review. The interim improvement includes a binary variable in the model specification for the years 2013 and 2014 to account for factors such as changing energy usage trends not fully captured by the current model specification. This additional variable in the model results in a downward adjustment for the majority of PJM zonal forecasts. The forecast of the EKPC zone used historic load values that were recalculated to be consistent with load on that transmission system. This led to higher peak loads for both summer and winter forecasts. The forecast of the Dominion Virginia Power zone has been adjusted to account for substantial ongoing growth in data center construction, which adds 150–730 MW to the summer peak beginning in 2016.

Energy efficiency impacts have increased from approximately 900 MW to 1,200 MW. Assumptions for EE are based on PJM Reliability Pricing Model (RPM) auction results.

In 2014, PJM began to investigate potential changes in its planning assumptions to address concerns that the recent expected demand resource levels may be too high. The concern has arisen because providers have bought out a significant portion of their RPM auction's demand resource positions or replaced it with other capacity resources prior to the start of the delivery year. The impact has been that PJM has assumed the availability of more demand resources in its planning studies than actually is committed to PJM at the time the delivery year arrives. Planning assumption changes recognize such factors: existing uncleared generation and the average percentage of PJM demand resource net replacement (e.g., capacity) that has occurred in recent RPM auctions. The new method uses an average of the percent amount of DR that committed in the three most recent historical years. For the RTO, that number is pretty consistent at 5% of the unrestricted load each year, so it is assumed that ratio will be about the same in summer 2015 and in the future.

Another source of some uncertainty regarding future demand resource availability arises out of a recent federal appellate decision in *Electric Power Supply Associations vs. FERC*, 753 F.3d 216 (D.C. Circuit 2014), coupled with the pending Complaint of FirstEnergy Service Company at Docket EL14-55-00. These cases call into question demand resource eligibility to participate in any wholesale electricity market, including RPM auctions. Recently, demand resources totaling between 11,000 and 15,000 MW have cleared PJM auctions. The loss of these megawatts could have serious implications for PJM



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reliability. Given this uncertainty, PJM will need to adjust its planning procedures going forward to include scenarios in which all or a significant portion of cleared demand resources in future years is no longer committed to PJM.

PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have reliability concerns with DR expansion, but the additional operational information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions.

Tier 1 resources increase rapidly in 2019 to over 21,590 MW then level off in subsequent years before jumping again with the addition of a new nuclear unit in 2024. It is anticipated that approximately 35% of capacity will be moved from the prospective (Tier 2) category to the planned category (Tier 1) in the coming years. Almost all the significant development is natural gas powered. Minor amounts of biomass and landfill gas development are also augmented by new wind and solar resources.

PJM requested that all impacted Generator Owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates, and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short-term impacts and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners as required to address local reliability issues and is also communicating with neighboring Reliability Coordinators to compare reliability analyses and coordinate outages. The majority of retirements are coal powered, but some natural gas retirements are included. The loss of resources, no matter what the fuel, is the real concern.

The same imports and exports as the 2016–17 planning period are expected for the remaining years of the assessment. Each import transaction is accepted with the agreement that the specific units in question are no longer available to any other party but PJM. PJM treats exports in the same manner and does not consider units to be exported as PJM capacity. Transfer capability across PJM's border is also a requirement of accepting an import or export. PJM Balancing Authority operators confirm each transaction before they actually go into effect.

PJM's transmission expansion recommendation to the PJM Board in December 2014 encompassed a set of 22 projects to address 56 flowgate violations. They included several line reconductor projects, replacement of existing transformers with larger transformers, upgrades to terminal equipment on existing facilities, and circuit breaker replacements. All 22 recommended projects were upgrades to existing facilities.

PJM's transmission expansion recommendation to the PJM Board in February 2015 encompassed a set of 33 upgrades to address 132 flowgate violations. The recommendations included Greenfield solutions, reactor installations, capacitor installations, relay upgrades, line rebuilds, and new transformers.

Consistent with established practice, PJM's 15-year planning horizon encompassed both reliability and market efficiency analysis. PJM's planning horizon exceeds the scope of that specified by NERC and permits PJM to identify potential reliability criteria violations that may require larger-scale, longer-lead-time solutions. Results are reviewed to identify violations that occur across multiple deliverability areas or multiple violations clustered in a specific area. Long-term reliability analyses included the following test procedures for model year 2022: Generator Deliverability and Common Mode Outage Analysis, Load Deliverability Thermal and Voltage Analysis, and Specific Load Deliverability. These results were then extrapolated out through 2029 based on distribution factor calculations and applying incremental load increases based on PJM's 2014 Load Forecast Report. None of the identified reliability criteria violations suggested the need for a long-lead-time, larger-scope transmission solution. PJM communicated to stakeholders that while it intended to open a long-term RTEP proposal window, PJM did not believe that a transmission solution at this point was needed to resolve these specific violations. Rather, the major focus of the window would be to seek technical solution alternatives to relieve market efficiency congestion identified in related 2014 RTEP analyses.

PJM continually reviews its entire system for reactive concerns and initiates enhancements if necessary. Along with several dynamic reactive control devices, there are plans to install over 5,000 MVar of static capacitors.

No new SPSs are planned. Several existing SPSs will be removed from service over the assessment period.



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Extreme weather is part of the PJM normal planning process. Extreme weather is considered in line with the probability of its occurrence. Recent focus has been on the winter peak period of 2013–14 and 2014–15. New winter all-time peaks were experienced in early 2014 and then again in early 2015. Some investigation has been undertaken to determine if a winter reserve requirement is needed, but at this time no changes have been made to PJM's planning assumptions or methods due to extreme weather.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs versus the cost of constructing a new natural-gas-fired turbine. This at-risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint; however, there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generator Owners, PJM Transmission Owners, and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as reliability-must-run if their retirement date is targeted to be in advance of required system reinforcements.

At this point PJM has added the environmental retrofit outages to the extent provided by the Generator Owners to projections for maintenance outages from 2015 to 2018, and they are continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation, and transmission maintenance outages as well as transmission outages required to perform planning upgrades resulting from retiring generation. Generator Owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

Gas supply and transportation risks are captured in PJM resource planning studies to the extent they impact generator-forced outage rates. All forced outages, whether outside management control or not, are included in the calculations used in planning studies. PJM is investigating gas supply and transportation risk, considering the potential correlation with extreme cold weather (and high winter loads) and the potential for the loss of multiple units due to gas transportation disruption