Review of Interconnection Assistance Reliability Benefits

December 16, 2019

NPCC CP-8
Working Group

NORTHEAST POWER COORDINATING COUNCIL, Inc.

CP-8 WORKING GROUP

REVIEW OF INTERCONNECTION ASSISTANCE RELIABILITY BENEFITS

December 16, 2019

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EXECUTIVE SUMMARY

NPCC's CP-8 Working Group, under the auspices of the Task Force on Coordination of Planning was charged to estimate NPCC Area Annual Tie Benefits for a five-year period, assuming a hypothetically "At Criteria" and "As Is" system representation, applying consistent methodology and assumptions to all NPCC Areas, using the same multi-area reliability model.

For the purposes of this review, the Annual Tie Benefits includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas. Recognizing that different definitions may exist, both components will be reported.

In meeting this objective, the CP-8 Working Group analyzed the results of the simulations utilizing the General Electric (GE) Multi-Area Reliability Simulation (MARS) program to:

1. Estimate (on a consistent basis) the amount of interconnection benefits available to the NPCC Areas for the 2020 – 2024 period;
2. Review each NPCC Area's current estimates of interconnection benefits used to meet the NPCC Resource Adequacy Criteria; and,
3. Verify that the current levels of interconnection benefits assumed in each Area's resource adequacy are reasonable.

Table EX-1 shows the interconnection assistance reported in recent Area studies and the results from this Review. Although the data and assumptions used in recent Area studies may be different from those used in these studies and the underlying methodology varies for each NPCC Area. the results of this study estimate the range of the Annual Tie Benefits each Area will likely be able to rely on for planning purposes.

Table EX – 1
Comparison of Assumed and Estimated
ANNUAL INTERCONNECTION ASSISTANCE – MW

NPCC Area Comprehensive Reviews [1]	Assistance Reported in Recent NPCC Review of Resource Adequacy	Net Firm Imports assumed at time of Peak (2020/2024)	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2020	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2024
Québec (2017)	1,600 [2]	924/577	2,129 -2 ,633	2,648 - 2,702
Maritimes (2019)	300	-110/0	1,016 -1 ,623	1,016 - 1,504
New England (2017)	1,950 – 2,020 [3]	1,522/81	2,070 - 2,221	3,577 - 3,804
New York (2018)	3,500 [4]	1,783/1,939	4,665- 4,808	3,737 - 3,878
Ontario (2018)	501 - 2,707 [5]	0/0	3,535 - 3,702	3,663 - 3,789

After consistently applying the methodology and assumptions used in this Review to all NPCC Areas, using the same multi-Area reliability model, and after reviewing, on a consistent basis, the NPCC Area estimates of interconnection benefits used to meet the NPCC Resource Reliability Criteria, the CP-8 Working Group concluded that the interconnection assistance values assumed by NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

[1] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.
[2] The import capability of HVDC Sandy Pond – Nicolet interconnection has been excluded due to its unavailability during the peak period.
[3] These tie benefits values assumed by ISO New England for its resource adequacy studies are the non-firm emergency assistance from its directly interconnected external areas. The remaining transfer capabilities of the external ties can be used for capacity import purposes. See: https://www.iso-ne.com/static-assets/documents/2019/08/2019_08_29_a04_tie_benefits_analysis.pptx and https://www.iso-ne.com/static-assets/documents/2018/07/a41_pspc_propsd_tiebenfits_fca13_07262018.pdf.
[4] Implemented a statewide limit of 3500 MW.
[5] NPCC 2019 Ontario Area Interim Review of Resource Adequacy.

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The CP-8 Working Group acknowledges the efforts of Messrs. Eduardo Ibanez and Mitch Bringolf, GE Energy Consulting, and Patricio Rocha-Garrido, the PJM Interconnection, and thanks them for their assistance in this analysis.

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1.0 INTRODUCTION

The objective of the CP-8 Working Group's Review of Interconnection Assistance Reliability Benefits is to estimate (on a consistent basis) the amount of interconnection assistance available to NPCC Areas for today's system (2020) and the near term (2024), review each NPCC Area's current estimates of interconnection benefits and verify that the current levels of interconnection assistance assumed in each Area's resource adequacy assessments are reasonable and do not result in overstating any Area's reliability.

The *NPCC Regional Reliability Directory No. 1 - Design and Operation of the Bulk Power System*, R4 - Resource Adequacy [1] states:

"R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

R4.1 Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

This is commonly referred to as the "NPCC Resource Adequacy Criteria."

In meeting its objective, the CP-8 Working Group used General Electric's (GE) Multi-Area Reliability Simulation (MARS) program to examine interconnection assistance for each of the NPCC Areas. GE International, Inc. was retained by NPCC to conduct the simulations. The CP-8 Working Group:

1. Used the current NPCC CP-8 Working Group's GE MARS database to develop a model suitable for the 2020 and 2024 time periods;
2. Considered the impacts of Sub-Area transmission constraints; and,
3. Worked with neighboring Areas to develop a detailed near-term GE MARS reliability representation for regions bordering NPCC.

This evaluation utilized a common multi-area reliability program and a consistent set of assumptions and methodology to evaluate each NPCC Area's interconnection assistance, based on the assumptions used for the *2019 NERC Long-Term Reliability Assessment*. [2]

Area loads were correlated based on a composite load shape developed from the historical hourly loads for 2002, 2003, and 2004. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer period assessments. Likewise, the 2003 – 2004 load shape has been used for the winter period assessments.

[1] See: https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf.
[2] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

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.

Area load forecast uncertainties and emergency operating procedures [1] were modeled on a consistent basis. The study recognized that each of the Canadian utilities may have dispatchable loads [interruptible loads] which are operating procedures restricted for use solely by that utility.

While the amount of interconnection assistance that an Area receives from neighboring Areas will vary from hour to hour throughout the year, depending on its needs and availability of support, this study sought to determine an annual equivalent value of interconnection assistance that is available to each Area from its neighboring Areas.

2.0 AREA INTERCONNECTION ASSISTANCE

Each NPCC Area is responsible for demonstrating that sufficient resources are available to meet its load and operating reserve in accordance with the NPCC Criteria, taking into consideration the potential benefit arising from reserve sharing through interconnections with neighboring Areas. Each NPCC Area is required to comply with the requirements outlined in the "*NPCC Regional Reliability Directory No. 1 - Design and Operation of the Bulk Power System*" and report their findings in their respective Area's "*Interim/Comprehensive Review of Resource Adequacy.*" NPCC Areas currently measure Loss of Load Expectation (LOLE) when evaluating the resource adequacy of their systems. Table 1 provides a list of factors that affect interconnection assistance and how each Area has modeled them in their resource adequacy assessments.

The Annual Tie Benefit Potential determined in this review is the amount of "perfect capacity" (capacity with no planned or forced outages) which, when added to an Area that has been isolated from the remainder of NPCC, allows the Area to maintain the same level of reliability, in terms of LOLE (Loss of Load Expectation in days/year), as it had when interconnected. It is expressed as a single MW value. This single MW value for an Area will be referred to as its **Annual Tie Benefit**. The **Annual Tie Benefit** includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

In this review, the Annual Tie Benefit Potential includes both the non-firm emergency assistance into an Area, and the net Area import from firm scheduled transactions between Areas.

[1] See Section 5

Table 1
NPCC AREA INTERCONNECTION ASSISTANCE MODELING

FACTOR	Québec	Maritimes	New England	New York	Ontario
1. Capacity support from interconnection modeled	Yes	No	Yes	Yes	Yes
2. Reliability Index Calculated in Area Resource Adequacy Studies [1]	LOLE	LOLE	LOLE	LOLE	LOLE
3. Number of adjacent Areas/internal sub-Areas modeled	4/6	2/1	3/13	4/12	5/10
4. Interconnections explicitly modeled	No	No	Yes	Yes	No [3]
5. Load forecast uncertainty represented	Yes	Yes	Yes	Yes	Yes
6. Basis for installed reserve assumed for interconnected systems	N.A.	N.A.	Equal Risk	Equal Risk	N.A.
7. Internal Area transmission modeled for resource adequacy assessments	Yes	No	Yes	Yes	Yes
8. Interconnection outages modeled	No	No	Yes	Yes [2]	No
9. Year of Recently Approved NPCC Area Review of Resource Adequacy	2017	2019	2017	2018	2018

[1] Loss of Load Expectation equal to 0.1 days/year.

[2] Outages modeled on cables into New York City and Long Island.

[3] In Ontario, imports and exports are modeled as load modifiers

Table 2 shows the interconnected Areas that are considered when each Area performs its reliability studies. Table 2 is read from left to right (e.g. the New York Area considers interconnections with the Québec, New England, Ontario and PJM Areas).

Table 2
INTERCONNECTIONS CONSIDERED BY NPCC AREAS

Area Doing Study	Interconnections Considered in Area Studies						
	Québec	Maritimes	New England	New York	Ontario	RFC	PJM
Québec	-	X	X	X	X	-	-
Maritimes	X	-	X	-	-	-	-
New England	X	X	-	X	-	-	-
New York	X	-	X	-	X	-	X
Ontario[1]	X	-	-	X	-	X	-

[1] Ontario also models interconnections with Manitoba and the MRO.

3.0 MULTI-AREA RELIABILITY ANALYSIS

3.1 MULTI AREA RELIABILITY MODEL

(1) GE's MARS Program

General Electric's (GE) Multi-Area Reliability Simulation (MARS) Program [1] is a sequential Monte-Carlo simulator. It is capable of calculating on an Area and Sub-Area basis, the standard indices of daily Loss of Load Expectation (LOLE in days/year), hourly LOLE (hours/year) and a Loss of Energy Expectation (LOEE in MWh/year). In this study, the model was used to determine daily LOLE for each of the NPCC Areas and Sub-Areas based on all hours in the day.

In MARS, chronological system events are developed by combining randomly generated operating histories of the generating resources with inter-Area and intra-Area transfer limits and chronological hourly loads. The capacity margin is determined for each isolated Area at the time of its daily peak load. If an isolated Area has a negative capacity margin, the model seeks to initiate transfers from Areas with a positive capacity margin. Available reserves are allocated among all deficient Areas in proportion to their shortfalls. If a shortfall still exists after allocating the reserves that are available to flow across constrained interfaces, the model implements emergency operating procedures to avoid a loss of load to the extent possible. This process is repeated for each load forecast uncertainty level.

[1] See: https://www.geenergyconsulting.com/practice-area/software-products/mars

3.2 METHODOLOGY

The Tie Benefits Methodology used in this Review is a multi-step process that seeks to determine the amount of "perfect capacity" (capacity with no planned or forced outages) which, when added to an Area that has been isolated from the remainder of NPCC, allows the Area to maintain the same level of reliability, in terms of daily LOLE (loss-of-load expectation in days/year), as it had when interconnected.

While the amount of interconnection assistance that an Area receives from neighboring Areas will vary from hour to hour throughout the year, depending on its load, unit outages, etc., this study sought to determine an annual value of interconnection assistance which, if perfectly available for the entire year (in place of the actual interconnections with surrounding Areas) would enable the Area to maintain the same level of reliability, as measured in terms of daily LOLE as if the actual interconnections were present. This single MW value for an Area will be referred to as its **Annual Tie Benefit Potential.** In this review, the **Annual Tie Benefit Potential** includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

The specific Steps are summarized below:

> **Step 1 –** Isolate the "As Is" [1] Areas after scheduling firm contracts, remove any internal transmission constraints, and calculate the daily LOLE. Although this step is not required for the actual determination of the Annual Tie Benefit Potential, it does provide an indication of the reliability of each of the "As-Is" Areas which can be helpful in understanding the study results.
>
> **Step 2 –** Interconnect the Areas and restore internal transmission constraints in all Areas except for the Area of interest. Starting with the "As Is" capacity in each Area, adjust the capacity in the Area of interest (by adding or removing "perfect" capacity), based on the reserve margins relative to the sub-Area loads and subject to any locational requirements, until the Area is at approximately 0.1 days/year.
>
> **Step 3 –** Using the adjusted capacity for each Area from Step 2, isolate the Areas after scheduling firm contracts and removing internal transmission constraints. Add "perfect" capacity to each Area for the entire year until the Area LOLE returns to the LOLE calculated in Step 2 (approximately 0.1 days/year). The amount of perfect capacity added is the maximum amount of tie benefit available for each Area, excluding any firm contracts, assuming "As-Is" capacity for the neighboring Areas.

The reserve margin calculation used in Step 2 to determine the capacity adjustments to each sub-Area within an Area is a simple calculation that involves just the installed capacity and annual peak load of the sub-Areas. It does not consider purchases and sales, demand response, or any other adjustments that an Area may include in its own reserve margin calculations. The purpose of the reserve margin calculation as used here is to allocate the capacity adjustment in an Area between its sub-Areas. If we want to remove capacity from an Area (the usual situation), a target maximum reserve margin is determined that will result in the desired capacity adjustment to the Area. Perfect capacity is then removed from any sub-Areas that exceed the target maximum; sub-Areas below the target are left unchanged.

[1] The "As-Is" assumption refers to the modeling of systems with resources that are expected to be in-place for the years 2020 or 2024, as supplied by the CP-8 Working Group in August 2019.

While adjusting the sub-Area capacities based on reserve margins is a good approach in estimating the total capacity adjustment that an Area can accommodate through its interconnections with neighboring Areas, the presence of internal transmission constraints within an Area can limit the amount of capacity adjustment possible in the constrained sub-Areas, and consequently in the Area as a whole. For this reason, the methodology employed in this study ignores the internal transmission constraints in an Area when adjusting the sub-Area capacities to determine the amount of assistance (non-coincident) that the other Areas can provide (Step 2). This approach thus provides an estimate of the amount of assistance (non-coincident) that's available to an Area, regardless of whether or not an Area can make use of all of it due to internal constraints.

In Step 2, while the internal constraints were ignored in the Area of interest, the internal constraints in all of the other Areas were respected in case there was bottled generation that would limit the amount of assistance that an Area could provide. Failure to model the internal constraints in the Areas providing assistance could overstate the amount of assistance that they are actually able to deliver to their borders.

In Step 3, the Areas start with the adjusted capacities determined in Step 2 and are isolated from one another after scheduling the firm contracts and removing the internal constraints. Perfect capacity is then added to each Area until it returns to the target LOLE from Step 2, approximately 0.1 days/year. This then determines for each Area the single annual MW amount that is equivalent, on an annual basis, to the reliability benefits provided by the interconnections. This amount, when added to the next firm imports at time of Area peak, is **the “As-Is” Annual Tie Benefit** Potential.

The above methodology was used for both 2020 and 2024 and provided an estimate of the **“As Is” Annual Tie Benefit** assuming the “As Is” loads in each of the Areas providing assistance. Since it is optimistic for an Area to plan its system assuming that the neighboring systems are much more reliable than is required by the NPCC criteria, the methodology was refined by adding the following steps:

> **Step 4** - Bring each Area of the interconnected “As-Is” system (including outside regions), with internal transmission constraints, to approximately 0.1 days/year LOLE by adjusting the capacity in each Areas based on the reserve margins in the sub-Areas, subject to any locational requirements.
>
> **Step 5** - Starting with the adjusted capacities from Step 4, remove the internal transmission constraints in the Area of interest and adjust its sub-Area capacity, based on reserve margins and subject to any locational requirements, until it returns to the LOLE in Step 4. This step is the same as Step 2 except for the capacity in the Areas providing assistance.
>
> **Step 6 –** Using the adjusted capacity for each Area from Step 5, isolate the Areas after scheduling firm contracts and removing the internal transmission constraints. Add “perfect” (100% available) capacity to each Area for the entire year until the Area LOLE returns to the LOLE calculated in Step 5 (approximately 0.1 days/year). The amount of perfect capacity added is the maximum amount of tie benefit available for each Area, excluding any firm contracts, assuming “At-Criteria” capacity for the neighboring Areas. This amount, when added to the net firm imports at time of Area peak, is the “At-Criteria” Annual Tie Benefit Potential.

These additional Steps were applied for the years 2020 and 2024 to provide an estimate of the amount of **“At Criteria” Annual Tie Benefit** available if each Area just met criterion.

3.3 RESULTS

The **Annual Tie Benefits** are shown are shown in Table 3 (a) for the year 2020 and Table 3 (b) for the year 2024. These results indicate the range of the Tie Benefit potential, regardless of whether or not an Area can make use of it due to its internal constraints. For reference, also shown in Table 3(a) and Table 3(b) is the Area’s total import capability at time of their peak load.

For Areas where the **“At Criteria” Annual Tie Benefit** is nearly equal to the **“As Is” Annual Tie Benefit**, the **Annual Tie Benefit** is more limited by the area’s ability to import the assistance than it is by the ability of the other Areas to assist.

The larger difference between the **“As Is” and “At Criteria” Annual Tie Benefit** indicates the extent to which those Areas, with more than adequate import capabilities, could rely extensively on assistance from their neighbors.

Table 3 (a)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2020 - MW

Area	Total Tie Capacity at time of Area peak	Net Firm Imports assumed at time of Peak	Without Internal Constraints	
			“At Criteria” Annual Tie Benefit	“As Is” Annual Tie Benefit
HQ	4,123	924	2,129	2,633
MT	1,550	-110	1,106	1,623
NE	3,700	1,522	2,070	2,221
NY	10,305	1,783	4,665	4,808
ON	5,910	0	3,535	3,702

Table 3 (b)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2024 – MW

Area	Total Tie Capacity at time of Area peak	Net Firm Imports assumed at time of Peak	Without Internal Constraints	
			“At Criteria” Annual Tie Benefit	“As Is” Annual Tie Benefit
HQ	4,123	577	2,648	2,702
MT	1,550	0	1,016	1,504
NE	3,700	81	3,577	3,804
NY	10,455	1,939	3,737	3,878
ON	5,910	0	3,663	3,789

3.4 COMPARISON OF AREA INTERCONNECTION ASSISTANCE

Table 4 shows the interconnection assistance assumed in recent Area studies and the results from this Review. Although the data and assumptions used in recent Area studies may be different from those used in these studies and the underlying methodology varies for each NPCC Area.

the results of this study estimate the range of the Annual Tie Benefits each Area will likely be able to rely on for planning purposes.

Additional information follows for the five NPCC Areas that assume interconnection assistance in their resource adequacy assessments.

Table 4
COMPARISON OF ASSUMED AND ESTIMATED ANNUAL INTERCONNECTION ASSISTANCE – MW

NPCC Area (Year of Comprehensive Review)	Assistance Reported in Recent NPCC Reviews of Resource Adequacy	Net Firm Imports assumed at time of Peak (2020/2024)	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2020	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2024
Québec (2017)	1,600 [1]	924/577	2,129-2,633	2,648-2,702
Maritimes (2019)	300	-110/0	1,006-1,623	1,016-1,504
New England (2017)	1,950 – 2,020 [2]	1,522/81	2.070-2,221	3,577-3,804
New York (2018)	3,500 [3]	1,783/1,939	4,665-4,808	3,737-3,878
Ontario (2018)	501 - 2,707 [4]	0/0	3,535-3,702	3,663-3,789

New England

In setting its Installed Capacity Requirement (ICR) for its Forward Capacity Market, ISO New England includes the tie benefits (emergency assistance) from its directly interconnected neighboring bulk power systems of Quebec, Maritimes, and New York. The tie benefits are derived based on the results of studies conducted annually. In these tie benefit studies, all the interconnected Areas are assumed to be at the 0.1 days/year resource adequacy criterion simultaneously. The tie benefits assumed in the latest ICR calculations are 1,950 MW for 2020, 2,020 MW for 2021, 2,000 MW for 2022, and 1,940 MW for 2023 [5]

New York

The New York State Reliability Council (NYSRC) approved the 2019–2020 Installed Reserve Margin ("IRM") at 17.0% on December 7, 2018. The New York ISO then determined the Locational Minimum Installed Capacity Requirements ("LCRs") for the Localities of New York City (Load Zone J), Long Island (Load Zone K), and the G-J Locality (Load Zones G, H, I, and J) for the 2019–2020 Capability Year beginning May 1, 2019. [6]

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[1] The import capability of HVDC Sandy Pond – Nicolet interconnection has been excluded due to its unavailability.

[2] These tie benefits values assumed by ISO New England for its resource adequacy studies are the non-firm emergency assistance from its directly interconnected external areas. The remaining transfer capabilities of the external ties can be used for capacity import purposes. For the latest tie benefits study for the 2023-2024 capacity commitment period, please see: https://www.iso-ne.com/static-assets/documents/2019/07/pspc_a05_tiebenefitswithandwithoutmystic89.pptx.

[3] Implemented a statewide limit of 3,500 MW.

[4] NPCC 2019 Ontario Area Interim Review of Resource Adequacy.

[5] See: https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx . The value for 2023 assumes that the Mystic generating facility will be in-service. Without the Mystic facility, the tie benefits would be 1,910 MW.

[6] See: https://www.nyiso.com/documents/20142/3679493/LCR2019-Report2-clean.pdf/d6ffe9be-a058-7cde-4bd3-725cce0105ef.

The LCRs took into consideration changes that have occurred since the NYSRC approved the IRM base case. The changes include adjusting the IRM from its base case value (16.8%) [1] to its approved value (17.0%), the completion of the final 2019 ICAP/LCR load forecast, and the withdrawal of Selkirk 1 and Selkirk 2's Mothball Notice (i.e., continued operation of Selkirk 1 and Selkirk 2).

Based on the NYSRC IRM base case for the 2019–2020 Capability Year and the changes identified above, the NYISO's calculations result in effective New York City LCR of 82.8%, a Long Island LCR of 104.1%, and a G-J Locality LCR of 92.3%.

A study to examine issues related to the amount of emergency assistance that can be reasonably relied on was conducted by the New York ISO in 2016. Building on the results of this study that reviewed alternate models for representing emergency assistance, the NYSRC determined that limiting total emergency assistance to a maximum of 3,500 MW based on an analysis of total actual excess ten-minute operating reserves above required operating reserves in the four neighboring external areas, is appropriate. [2]

Ontario

The Ontario Independent Electricity System Operator (IESO) has reported that it expects to meet the NPCC resource adequacy criterion in its most recent NPCC Review of Resource Adequacy. [3]

For the median demand growth scenario, the NPCC criterion is satisfied for 2020 to 2022 forecast years with existing and planned resources. For the 2023 forecast year, the invoking of Emergency Operating Procedures (EOP) and 501 MW of tie benefits would be required to meet the LOLE criterion.

For the high demand growth scenario, the NPCC criterion is met for 2020 and 2021 forecast years with existing and planned resources. For the 2022 and 2023 forecast years, the invoking of EOP and the use of up to 2,707 MW of tie benefits would be required to meet the LOLE criterion.

Maritimes Area

In the *NPCC 2019 Maritimes Area Comprehensive Review of Resource Adequacy*, [4] 300 MW of interconnection tie benefits from New England are assumed. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007.

Québec

Results of the *NPCC 2019 Québec Interim Review of Resource Adequacy* [5] show that the loss of load expectation (LOLE) for the Québec area is below the NPCC reliability criterion of not more

[1] *New York Control Area Installed Capacity Requirements for the Period May 2019 Through April 2020*. See: http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Body-Final%20Report[6815].pdf.
[2] For more information see the NYSRC white paper, *MARS Emergency Assistance Modeling*, at http://www.nysrc.org/pdf/Reports/IRM%20White%20Papers/MARS%20Emergency%20Assistance%20Modeling%20Final%20Draft.pdf .
[3] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.
[4] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.
[5] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.

than 0.1 day per year under the base case scenario for winter 2019-2020. This was achieved with the inclusion of 1,100 MW of expected winter capacity purchases from New York ISO and 500 MW of firm capacity import from Ontario due to a new capacity sharing agreement between Hydro-Québec and the Ontario IESO.

In fact, Hydro-Québec Distribution (HQD), which is the Load Serving Entity responsible for resource adequacy in Québec, will only purchase the amount of capacity needed to meet its requirements every year. In order to secure the appropriate access to capacity located in neighboring areas, HQD has designated the Massena-Châteauguay (1,000 MW) and the Dennison-Langlois (100 MW) interconnections to meet its resource requirements during winter peak period. The Quebec area limits its planned capacity purchases to capacity accessible from summer peaking neighboring areas having an organized market structure.

Also, in May 2015, the Ontario IESO signed a 500 MW seasonal firm capacity sharing agreement with Hydro-Québec. This agreement takes advantage of the provinces' complementary seasonal peaks to support reliability. 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.

4.0 CONCLUSIONS

The CP-8 Working Group concluded that:

- the estimates of interconnection benefits used to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis;
- the interconnection assistance values reported by NPCC Areas in their recent resource adequacy methodology and assumptions used in this Review was consistently applied to all NPCC Areas, using the same multi-Area reliability model; and,
- NPCC Area assessments appear to be reasonable and do not overstate interconnection benefits.

5.0 MODEL ASSUMPTIONS

The assumptions are consistent with the assumptions of the following recently completed Area studies:

Area Studies

New York

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

The RPP consist of two evaluations:

1. The Reliability Needs Assessment (RNA). The NYISO performs a biennial study in which it evaluates the resource and transmission adequacy and transmission system security of the New York Bulk Power Transmission Facilities (BPTF) over a ten-year Study Period. Through this evaluation, the NYISO identifies Reliability Needs in accordance with applicable Reliability Criteria. This report is reviewed by the New York ISO stakeholders and approved by the Board of Directors.
2. The Comprehensive Reliability Plan (CRP). After the RNA is complete, the New York ISO requests the submission of market-based solutions to satisfy the Reliability Need. The New York ISO also identifies a Responsible TO and requests that the TO submit a regulated backstop solution and that any interested entities submit alternative regulated solutions to address the identified Reliability Needs. The New York ISO evaluates 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 to the identified need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the New York ISO 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 the New York ISO stakeholders and approved by the Board of Directors.

The 2018-2019 cycle of the Reliability Planning Process (RPP) has been completed. The RPP's first phase, the 2018 Reliability Needs Assessment (RNA), [1] was approved by the New York ISO Board of Directors on October 16, 2018. The 2018 RNA report identified no Reliability Needs for the 2019-2028 study period. The 2019-2028 Comprehensive Reliability Plan (CRP), [2] was approved by the New York ISO Board of Directors on July 2019 and re-iterated the RNA's conclusion that there are no Reliability Needs, along with identifying risk factors. As part of the CRP, a scenario was performed jointly by the New York ISO, Con Edison, and PSEG Long Island to assess potential reliability impacts from the draft DEC NOx emissions rule affecting

[1] See: https://www.nyiso.com/documents/20142/2248793/2018-Reliability-Needs-Assessment.pdf/c17f6a4a-6d22-26ee-9e28-4715af52d3c7.

[2] See: https://www.nyiso.com/documents/20142/2248481/2019-2028CRP-FinalReportJuly-2019.pdf/51b573b7-9edb-bbb9-8a87-742e9e7c3b7f.

simple cycle combustion turbines (the “peaker rule”). The scenario results show that both transmission security and resource adequacy needs would arise from the deactivation of the peakers.

New England

The assumptions used by ISO New England in this study for the period 2020-2024 are consistent with the assumptions published within the:

1. *2019-2028 Forecast Report of Capacity, Energy, Loads and Transmission* (2019 CELT Report);
2. *NERC 2019 Long-Term Reliability Assessment* (NERC 2019 LTRA); and,
3. *NPCC 2019 New England Interim Review of Resource Adequacy.*

Capacity

Sufficient resources are projected for New England through 2024 to meet the resource adequacy planning criterion, assuming no major retirements and the successful completion and operation of all new resources that have cleared the Forward Capacity Market (FCM). To date, resource-adequacy studies have shown that the most reliable and economic place for developing new resources is in the Northeastern Massachusetts (NEMA)/Boston and Southeastern Massachusetts/ Rhode Island (SEMA/RI) areas. This is due to recent and anticipated retirements of aging fossil generation and the projected load growth in these areas. Transmission improvements are also underway in these areas, and new fast-start generation is under construction. This will help meet the regional and local capacity needs and improve system reliability. However, delays in the construction or additional retirements would make meeting local resource-adequacy requirements less certain. Overall, the region is expected to experience more generating resource additions than retirements, and the ISO projects that adequate resources will be available to meet net ICR for the next 5-10 years.

Although New England has adequate installed capacity to meet the winter peak demands, which are 6,000 MW to 7,000 MW lower than the summer peak demands, emergency operating procedures (EOPs) may still be necessary during extreme cold weather. This is because the region relies on natural gas to fuel much of its generation, and sufficient fuel may not be readily available when the weather is extremely cold. ISO-New England accounts for these fuel-constrained reductions within its seasonal operable capacity projections.

As of April 1, 2019, the ISO’s Interconnection Request Queue (the queue) reflected 19,047 MW of proposed projects. This includes an additional 11,316 MW of wind resources, 3,070 MW of large-scale PV, and 1,381 MW of battery storage. Offshore resources are being proposed off the southeastern New England coast, and proposed onshore wind resources are predominantly in northern New England.

Peak Demand

The 5-year summer 50/50 net peak demand, accounting for both EE and PV, is projected to decrease from 25,025 MW in 2020 to 24,383 MW in 2024, which represents a decline of -642 MW or -2.56%. The 90/10 net summer peak demand forecast, accounting for both BTM PV & EE, which represents more extreme summer heat waves, is 26,167 MW for 2020 and decreases to 25,455 MW in 2024 which represents a decline of -712 MW or -2.72%.

The 5-year winter 50/50 net peak demand, accounting for both EE and PV, is projected to decrease from 20,215 MW in 2020 to 19,528 MW in 2024, which represents a decline of -687

MW or -3.4%. The 90/10 net winter peak demand forecast, accounting for both BTM PV & EE, which represents more extreme winter weather, is 20,920 MW for 2020 and decreases to 20,265 MW in 2024. which represents a decline of -655 MW or -3.13%. Only the EE forecast drives the reduction to the growth rate of the 5-year gross winter peak demand, which may help mitigate winter reliability concerns.

The 5-year net energy for load, accounting for both EE and PV, is projected to decrease from 123,560 GWh in 2020 to 120,544 GWh in 2024, which represents a decline of -3,016 GWH or -2.44%. The combined increase forecast for both BTM PV and EE energy reductions are a main driver to the overall reduction to the annual net energy for load projections. The federal residential and business Investment Tax Credit (ITC) is a key driver of PV development in New England. The EE forecast estimates reductions in energy and demand from state-sponsored EE programs in the New England control area by state (CT, MA, ME, NH, RI, VT).

Transmission

As a result of transmission expansion in New England, the region has maintained a high level of reliability and resiliency; the dispatch of more efficient generating units, which reduces the need for out-of-merit unit commitment; and lower wholesale market costs. The low growth of net peak demand and changes to the assumptions used in needs assessments has reduced the overall need for major additional reliability-based transmission projects over the planning horizon. The development of FCM resources in appropriate zones also has deferred the need for major new projects. Drivers of needed transmission improvements include the following:

- Resource retirements;
- Anticipation of light-load operating conditions;
- Integration of inverter-based technologies;
- Need to upgrade aging infrastructure; and,
- Compliance with evolving Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) requirements.

More sophisticated modeling is now under development by ISO-New England to better reflect the dynamic characteristics of generators and load and the expansion of distributed resources, which will inform future transmission needs.

ISO-New England has improved the interconnection process and now offers a cluster study approach, which provides the means for considering multiple requests in the same study and allocating the costs of significant upgrades among the cluster participants in the interconnection queue. To date, the ISO completed a cluster study for proposed resources in northern and western Maine. A second cluster study for resources in that same area is underway and anticipated to be completed by the fourth quarter of 2019. Even with the cluster approach, remote resources would require considerable transmission improvements, which may be costly to build, to be well integrated with the demand centers in southern New England.

Improvements have been identified for both SEMA/RI and Greater Boston, and their associated development and construction are underway. These reliability upgrade projects will bolster the 345 kV and 115 kV facilities of the New England transmission system. A needs assessment has been completed for Boston, which identifies time-sensitive concerns under minimum load and also non-time-sensitive thermal overloads and system restoration concerns due to the retirement of the Mystic generators. ISO-New England is updating the Maine, New Hampshire, Western and Central Massachusetts, and Eastern Connecticut area studies to reflect the revised study assumptions and processes.

Interconnections with neighboring systems provide access to capacity and energy and reduce emissions by generators within the New England area. The interconnections continue to support regional reliability and the economic operation of the system. The ISO fully reflects the energy and capacity import capabilities of the interconnections in its planning studies.

Assumed External Interface Import Capability

The Table 5 below summarizes ISO-New England's planning studies use of energy and capacity import capability assumptions of the 13 interconnections New England has with neighboring power systems in the United States and Eastern Canada.

Table 5
Summary of New England's Import Capability Assumptions

Interconnection	Import Type	Assumed Import Capability (MW)
New York–New England AC	Energy	1,400
	Capacity	1,400
Cross-Sound Cable	Energy	330
	Capacity	0
Maritimes–New England	Energy	1,000
	Capacity	700
Québec–New England (Highgate)[(e)]	Energy	217
	Capacity	200
Québec–New England (Phase II)	Energy	2,000
	Capacity	1,400

Ontario

The Ontario assumptions used in this study are consistent with the assumptions used in the *Reliability Outlook* [1] published on June 30, 2019, the *NERC 2019 Long-Term Reliability Assessment* [2] and the *Ontario 2019 Interim Review of Resource Adequacy*. [3]

Québec

The Québec assumptions used in this study are consistent with the *NERC 2019 Long-Term Reliability Assessment.* [4]

The demand forecast average annual growth is 1.3 percent during the five-year period. Energy efficiency and conservation programs are integrated in the demand forecasts. Demand forecasts also consider 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 440 MW by the end of the assessment period.

[1] See: to http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2019Jun.pdf?la=en .
[2] See: http://www.nerc.com/page.php?cid=4|61.
[3] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.
[4] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

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 continues to develop new DR programs, including Direct Control Load Management and others. Total DR expected to be available during the peak for the 2023-2024 winter period is projected to be approximately 2,741 MW, including 1,100 MW from an interruptible load program mainly for large industrial customers, 1,013 MW from interruptible programs for residential and commercial buildings, 725 MW from dynamic rates and from a program dedicated to data centers specialized in block chain applications, as well as 250 MW of voltage reduction as an emergency operating procedure.

About 400 MW of new available capacity is expected to be in service by 2024. Work is underway on the La Romaine-4 unit (245 MW), which is expected be fully operational in November 2021. No retrofitting of hydro units is considered over the assessment period. The integration of small hydro units also accounts for 19 MW of new capacity during the assessment period. Additionally, 48 MW (17 MW on-peak value) of wind capacity and 89 MW of biomass are expected to be in service by 2022. There is no 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 completed the Maritimes Link project, an undersea HVDC cable link between Nova Scotia and the Canadian Province of Newfoundland and Labrador. [1]

Associated energy from the Muskrat Falls Hydro Electric project is currently expected to begin to flow across the Maritimes Link starting mid-2020. 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 *2019 NPCC Maritimes Area Comprehensive Review of Resource Adequacy*; [2] the results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

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.

[1] See: http://www.emeranl.com/en/home/themaritimelink/infrastructure.aspx
[2] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

Load Shape

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the 2003 – 2004 load shape has been used for the winter assessments. The selection of these load shapes was 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.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, Table 6(a) shows the values assumed for January 2020, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape) and for August 2020, corresponding to the NPCC summer peak load. Table 6(b) 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 6(a)
Per Unit Variation in Load Assumed (Month of January 2020)

Area	**Per-Unit Variation in Load**						
HQ	1.084	1.084	1.042	1.000	0.959	0.916	0.911
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.093	1.038	0.997	0.963	0.940	0.850	0.800
NY	1.118	1.075	1.036	1.000	0.967	0.938	0.913
ON	1.057	1.041	1.021	1.000	0.975	0.948	0.919
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

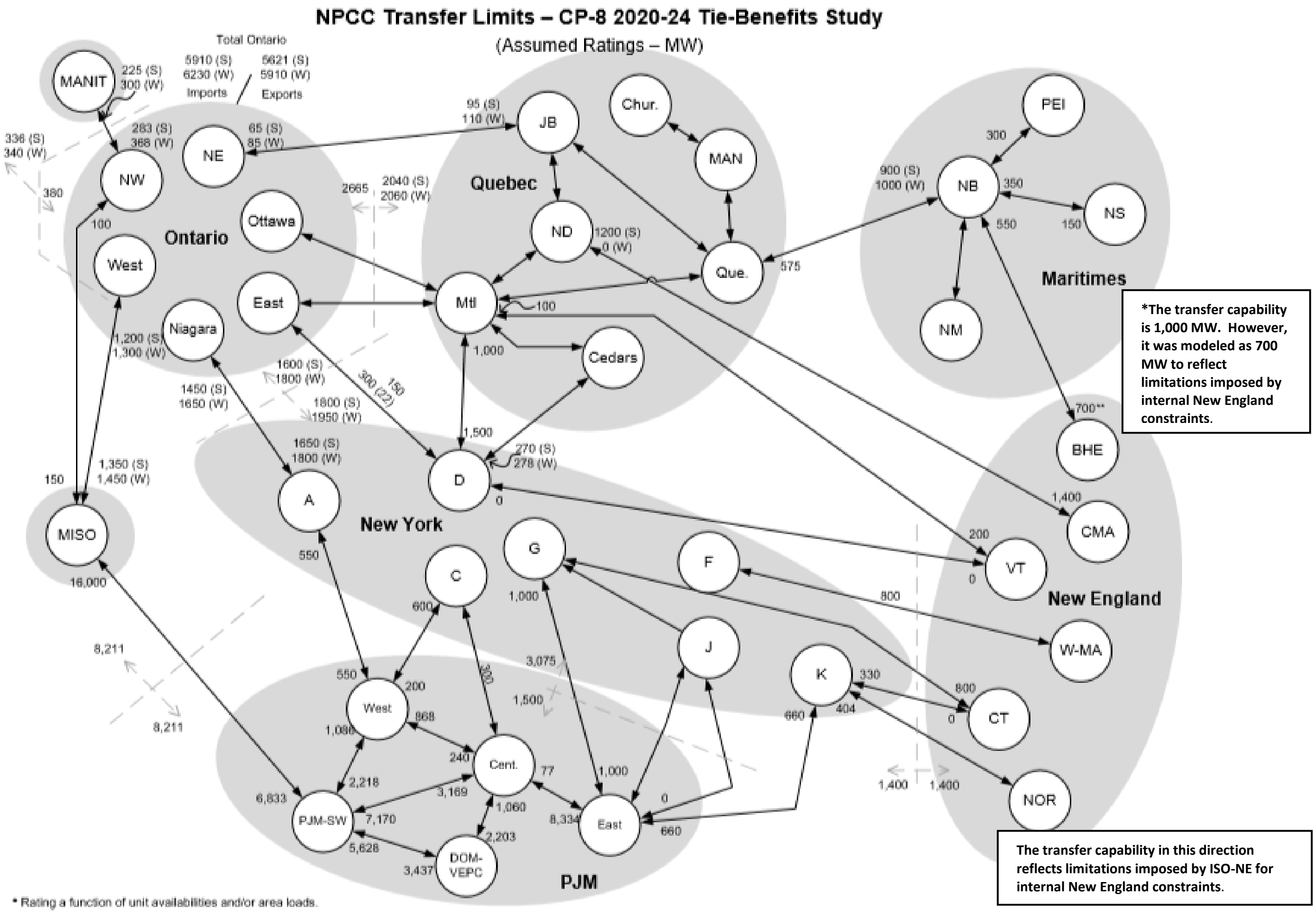
Table 6(b)
Per Unit Variation in Load Assumed (Month of August 2020)

Area	**Per-Unit Variation in Load**						
HQ	1.069	1.069	1.035	1.000	0.968	0.939	0.911
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.226	1.103	1.050	1.000	0.950	0.886	0.851
NY	1.137	1.094	1.045	0.991	0.933	0.875	0.819
ON	1.143	1.100	1.050	1.000	0.947	0.895	0.851
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Transfer Limits

Figure 1 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2020 to 2024. References for the transmission representation for Ontario [1], New York [2], and New England [3] are provided in the respective footnotes.

[1] See: http://www.ieso.ca/localContent/ontarioenergymap/index.html.
[2] See: http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Appendices%20-Final%20Report[6816].pdf.
[3] The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/index.html.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York. [1]

Figure 1 - Assumed Transfer Limits

Transfer limits between and within some areas are indicated in Figure 1 with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 1 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	Que	- Québec Centre		

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

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. [1]

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 7 summarizes the load relief assumptions modeled for each NPCC area.

Table 7
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2020 Load Relief Assumptions - MW

Actions	HQ (Jan)	MT (Jan)	NE (Aug)	NY (Aug)	ON (Aug)
1. Curtail Load	1,437	-	-	-	-
Appeals	-	-	-	-	1% of load
RT-DR/SCR/EDRP	-	-	-	857[2]	-
SCR Load /Man. Volt. Red.	-	-	-	0.21% of load	-
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction	250	-	265	1% of load	-
Interruptible Loads	-	270	-	207	877
4. No 10-min Reserves	750	505	-	-	945
General Public Appeals	-	-	-	80	-
5. 5% Voltage Reduction	-	-	-	-	2.2% of load
No 10-min Reserves	-	-	980	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.

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 7 was a reasonable approximation for this analysis.

[1] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx .

[2] Derated value shown accounts for assumed availability.

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 Areas

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 8 and Figure 2.

Table 8
PJM and MISO 2020 Assumptions [1]

	PJM	MISO
Peak Load (MW)	152,160	95,216
Peak Month	July	August
Assumed Capacity (MW)	196,209	109,061
Purchase/Sale (MW)	362	-1,497
Reserve (%)	35.2	17.8
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	9,127	4,553
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	+/- 13.5%, 9.0%, 4.5%	+/- 11.3%, 7.5%, 3.8%

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

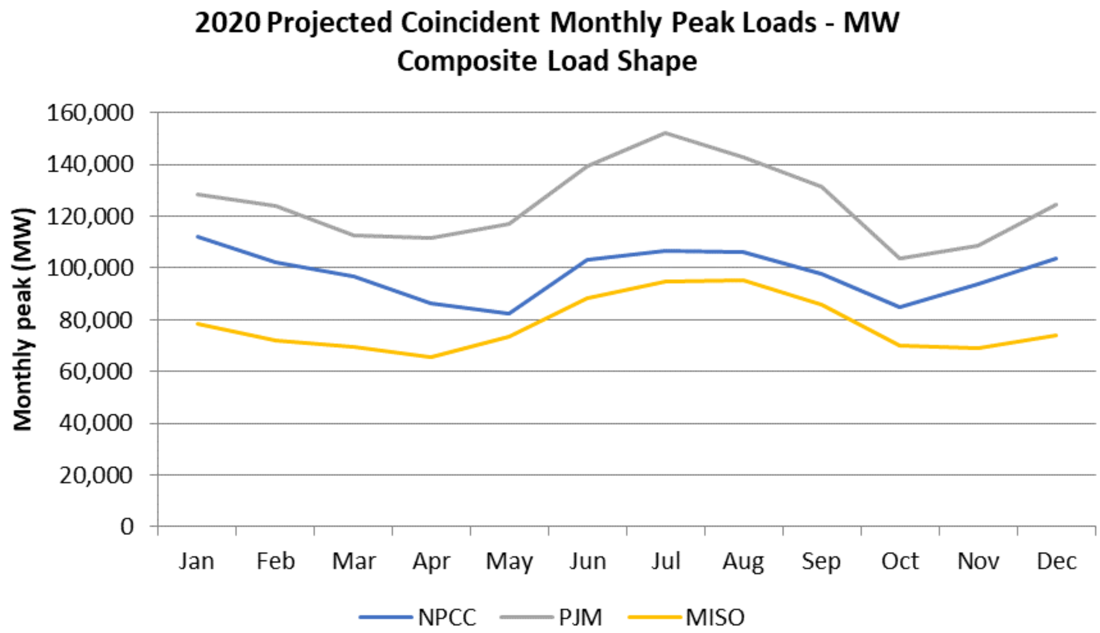


Figure 2 – 2020 Projected Monthly Expected Peak Loads for NPCC, PJM and MISO

MISO

The Mid-Continent Independent System Operator, Inc. (MISO) region (minus the integrated Entergy region) was included in the analysis replacing the RFC-OTH and MRO-US regions used in the previous analysis.

MISO was modeled in this study due to the strong transmission ties of the region with the rest of the study system.

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 2019 RRS Report).

MISO load data was obtained from publicly available sources, namely FERC Form 714 and the 2018-2019 MISO LOLE Study Report. [1]

PJM-RTO

Load Model

The load model used for the PJM-RTO in this study is consistent with the PJM Planning division's technical methods. [2] The hourly load shape is based on observed 2003/04 calendar year values, which reflects representative weather and economic conditions for a winter peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2019. [3] Load Forecast Uncertainty was modeled consistent with recent planning PJM models [4] considering seven load levels, each with an associated probability of occurrence. This load

[1] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016bIiAAI.

[2] Please refer to PJM Manuals 19 and 20 at http://www.pjm.com/~/media/documents/manuals/m19 redline.ashx and http://www.pjm.com/~/media/documents/manuals/m20-redline.ashx for technical specifics.

[3] See: http://www.pjm.com/~/media/library/reports-notices/load-forecast/2019-load-forecast-report.ashx.

[4] See: http://www.pjm.com/~/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx.

uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years the model is based on, sampling size, and how many years ahead in the future for which the load forecast is being derived.

Expected Resources

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Load Management (LM) is modeled as an Emergency Operating Procedure. The total available MW as LM is as per results from the PJM's capacity market.

Expected Transmission Projects

The transfer values shown in the study are reflective of peak emergency conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's regional Transmission Expansion Plan. [1]

AS-IS LOLE RESULTS

Figure 3 shows the estimated "As Is" annual NPCC Areas and neighboring Regions' Loss of Load Expectation (LOLE) for the 2020-2024 period.

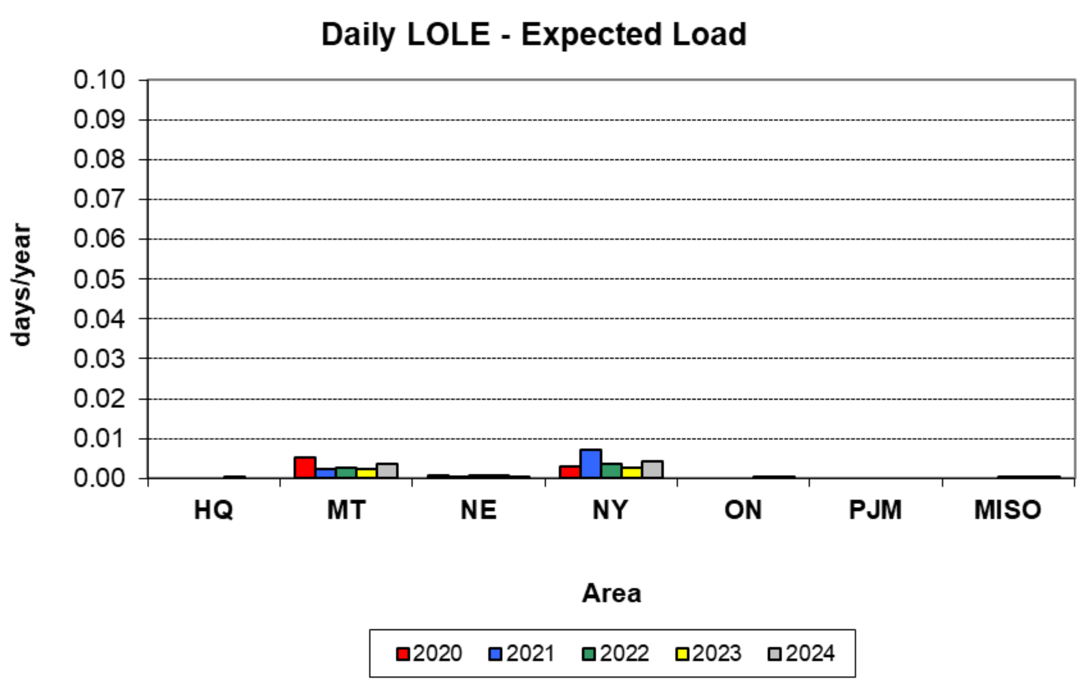


Figure 3 - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2020 – 2024)

[1] See: http://www.pjm.com/planning.aspx.

7.0 CAPACITY AND LOAD AT TIME OF AREA'S PEAK

Based on Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2020 (Peak Month)	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	44,295	7,669	32,188	39,825	30,313	196,209	109,061
Purchase/Sale (MW)	924	-110	1,522	1,783	0	362	-1,497
Load (MW)	38,783	5,466	26,937	32,202	22,095	152,160	95,216
Nameplate Demand Response [1] (MW)	1,437	270	3,327	873	877	9,127	4,553
Reserves (%)	20	43	38	32	41	35	18
Maintenance - Peak Week (MW)	**	110	0	50	525	0	0
Wind Output at time of Area Peak (MW) ***	1,3332	243	163	373	844	1,667	1,524
Wind Nameplate Capacity (MW)	3,700	1,149	1,081	1,998	4,946	1,667	1,524

* Wind capacity included at nameplate rating; demand response not included in capacity.

** Capacity for Quebec reflects scheduled maintenance and restrictions.

*** This value reflects the expected value during peak, although the modeling varies across areas: Quebec, New England, PJM and MISO model wind units as equivalent thermal units; the Maritimes, New York and Ontario use historical hourly profiles. [2]

[1] For Quebec, this value represents net DR, after reserve, excluding 250 MW of voltage reduction.

[2] The values shown represent the average wind generation in the top ten load hours, and does not represent the effective load carrying capability of the wind units or the firm capacity value.

Based on Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2024 (Peak Month)	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	44,647	7,564	31,538	38,941	28,885	193,603	110,076
Purchase/Sale (MW)	577	0	81	1,939	0	913	-2,048
Load (MW)	40,815	5,390	26,744	31,522	23,128	155,292	96,075
Nameplate Demand Response [1] (MW)	2,754	277	4,632	873	877	9,243	4,553
Reserves (%)	17	45	36	33	26	31	17
Maintenance - Peak Week (MW)	**	0	0	50	525	0	0
Wind Output at time of Area Peak (MW) ***	1,349	243	405	405	804	1,803	1,667
Wind Nameplate Capacity (MW)	3,748	1,229	1,081	2,124	4,946	1,803	1,667

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected value during peak, although the modeling varies across areas: Quebec, New England, PJM and MISO model wind units as equivalent thermal units; the Maritimes, New York and Ontario use historical hourly profiles. **[2]**

[1] For Quebec, this value represents net DR, after reserve, excluding 250 MW of voltage reduction.
[2] The values shown represent the average wind generation in the top ten load hours, and does not represent the effective load carrying capability of the wind units or the firm capacity value.