NORTHEAST POWER COORDINATING COUNCIL

Review of Interconnection Assistance Reliability Benefits

December 31, 2015

NPCC CP-8
Working Group

NORTHEAST POWER COORDINATING COUNCIL, Inc.

CP-8 WORKING GROUP

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December 31, 2015

Approved by the RCC
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PREFACE

On October 12, 2015 Entergy Nuclear Power Marketing announced their intention to retire the 680 MW Pilgrim nuclear unit by June 1, 2019. As stated in its tariff, ISO New England is required to determine how this retirement will affect the local reliability of the bulk power system in deciding whether to accept or reject the Pilgrim unit Non-Price Retirement Request.

In November 2015, Entergy Nuclear FitzPatrick, LLC provided a generator deactivation notice for the proposed retirement of the James A. FitzPatrick Nuclear Generating Facility to the New York Independent System Operator (NYISO). Entergy reported that the deactivation of the 882 MW facility is intended to occur at the end of the current fuel cycle (i.e., Quarter 4 of 2016 – Quarter 1 of 2017). On February 11, 2016, the NYISO identified a statewide resource deficiency that would occur starting in 2019. As required by its tariff, the NYISO will evaluate solutions through its reliability planning process.

Due to the timing of the announcements, these retirements were not reflected in this study; the impact of the retirements of these nuclear units will be reflected in the 2016 NPCC Long Range Adequacy Overview.

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 (years 2016 – 2020):

- assuming a hypothetically "At Criteria" and "As Is" system representation;
- applying consistent methodology and assumptions to all NPCC Areas; and
- using the same multi-Area reliability model.

For the purposes of this review, 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. Recognizing that different definitions may exist, both components are 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 five year (2016 – 2020) time period;
2. Review each NPCC Area's current assumed 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 studies are reasonable.

Table EX-1 shows the interconnection assistance reported in recent Area studies and the results from this Review. When interpreting these results, there are two important points to recognize; first, the data and assumptions used in recent Area studies may be different from those used in this study and second, the underlying methodology in Area studies varies for each Area.

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

NPCC Area (2015 Review)	Tie Assistance Reported in 2015 NPCC Area Review of Resource Adequacy [1]	Net Firm Imports assumed at time of Peak (MW) (2016/2020)	Available Estimated Annual Tie Benefit for 2016 At Criteria/As Is	Available Estimated Annual Tie Benefit for 2020 At Criteria/As Is
Québec	1,600 [2]	766/931	3,402/3,491	3,592/3,789
Maritimes	300 [3]	-200/0	423/702	523/1,012
New England	1,847 1,990 [4]	1,516/-5	3,454/3,485	3,214/3,487
New York	4,135 [5]	1,727/2,225	8,571/9,774	8,311/9,632
Ontario	300 1,350 [6]	0	3,852/4,094	4,414/4,703

The CP-8 Working concluded that:

- the estimates of interconnection benefits available to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis;
- a consistent methodology and assumptions were applied to all NPCC Areas, using the same multi-Area reliability model; and,
- the Tie Benefits assumed in NPCC Area Resource Adequacy Reviews were below the estimated available Tie Benefits calculated in this study, and do not overstate the available interconnection benefits.

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

[2] The NPCC 2014 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy reported 1,100 MW of winter capacity purchases from New York; the NPCC 2015 Quebec Balancing Authority Area Interim Review of Resource Adequacy assumed a higher firm capacity import due to a new capacity sharing agreement between Québec and Ontario (500 MW for winter 2015-2016 and 2016-2017) for the base case scenario.

[3] The NPCC 2015 Maritimes Area Interim Review of Resource Adequacy reported 300 MW of interconnection benefits from New England.

[4] 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.

[5] The New York 2015 Comprehensive Review of Resource Adequacy reported 2,170 MW of summer external capacity 1,080 MW from PJM and 1,090 from Hydro-Quebec. In addition, up to 1,965 MW of locational capacity benefits are available through Unforced Capacity Deliverability Rights (UDRs).

[6] The 2015 Ontario Comprehensive Review of Resource Adequacy reported for the high demand growth scenario for 2018, 2019, and 2020 forecast years, reported up to 1,350 MW of tie benefits; however, if planned outages were rescheduled, only 300 MW of tie benefits are required for 2019.

NPCC CP-8 WORKING GROUP

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The CP-8 Working Group acknowledges the efforts of Messrs. Mark Walling and Christopher Cox, 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 (2016) and the near term (2020), 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 do not result in overstating any Area's reliability.

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

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 the CP-8 Working Group 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 2016 and 2020 time periods;
2. Considered the impacts of Sub-Area transmission constraints;
3. Worked with neighboring Areas to develop a detailed near-term GE MARS reliability representation for regions bordering NPCC.

[1] See: https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

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 "*2015 NPCC Long Range Adequacy Overview*." [1]
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.

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 were modeled on a consistent basis as described in the *2015 NPCC Long Range Adequacy Overview*. [2] 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.

The **Annual Tie Benefit** 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. In this review, 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.

[1] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[2] See:
https://www.npcc.org/Library/Resource%20Adequacy/2015LongRangeOverviewRCCApprovedDecember1.pdf

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 Reference 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.

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. The interconnection assistance for an Area is calculated as perfect capacity (perfectly available for the entire year) that would enable the Area to maintain the same level of reliability in isolation, as measured in terms of daily Loss of Load Expectation (LOLE in days/year) as if the actual interconnections were present. 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.

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	2/4	3/13	4/12	5/10
4.	Interconnections explicitly modeled	No	No	Yes	Yes	No [9]
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	Yes	Yes	Yes	Yes
8.	Interconnection outages modeled	No	No	Yes [3]	Yes [2]	No
9.	Year of Recently Approved NPCC Area Review of Resource Adequacy	2015 [4]	2015 [5]	2015 [6]	2015 [7]	2015 [8]

1 Loss of Load Expectation equal to 0.1 days/year.
2 Outages modeled on cables into New York City and Long Island..
3 Outages modeled on Hydro-Quebec (Phase II and High gate) and New Brunswick interconnections.
4 2015 Interim Review of Québec Area Resource Adequacy approved December 1, 2015.
5 2015 Interim Review of Maritimes Area Resource Adequacy approved September 10, 2015.
6 2015 Interim Review of New England Area Resource Adequacy approved December 1, 2015.
7 2015 New York Area Comprehensive Review of Resource Adequacy approved December 1, 2015.
8 2015 Ontario Comprehensive Review of Resource Adequacy approved December 1, 2015.
9 In Ontario, interconnections are modeled as a load modifier in each zone that has an interconnection, proportional to its inter-tie capacity.

Table 2 shows the interconnected Areas that are considered when each Area performs its reliability studies. The following table 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.

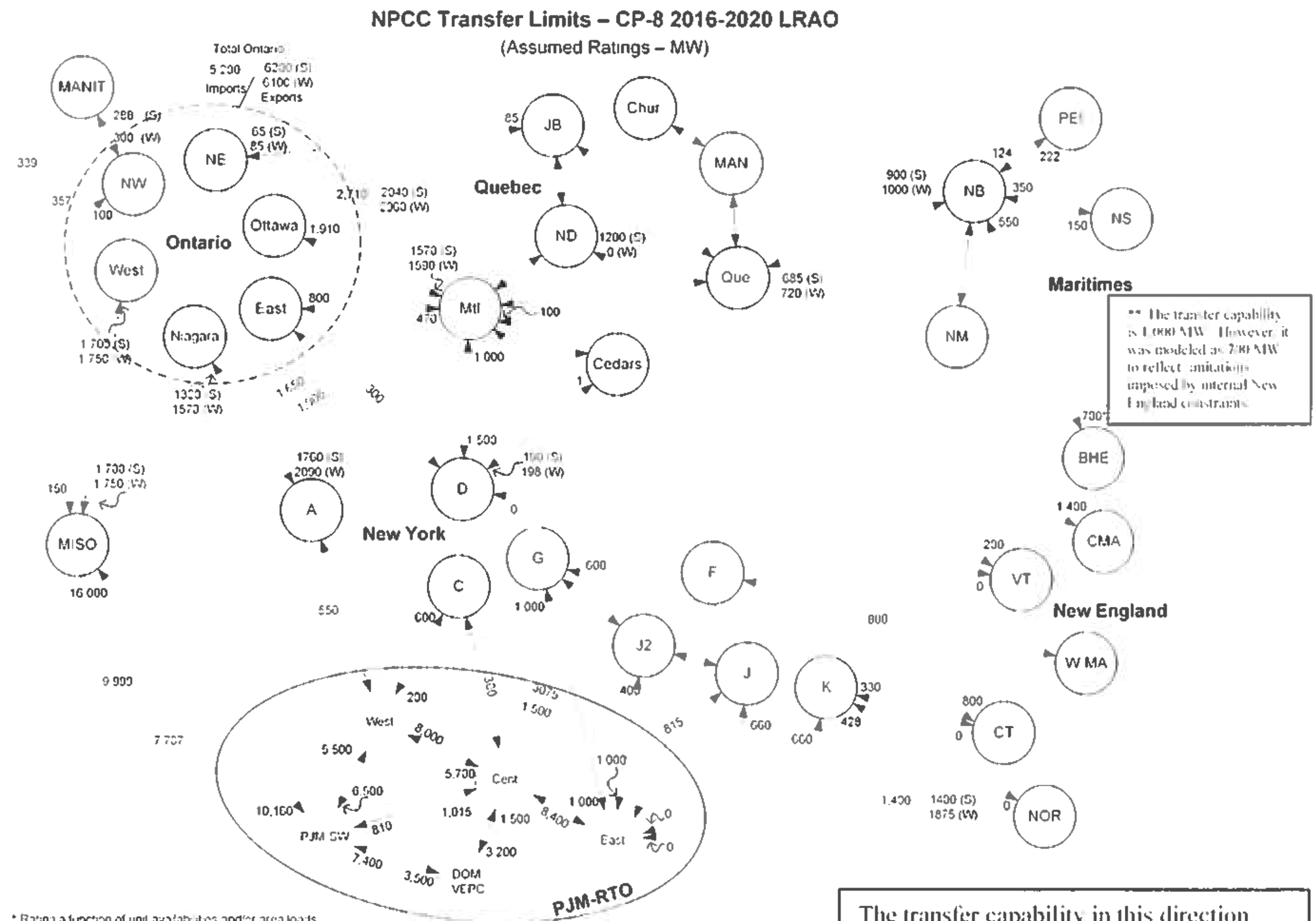
In MARS, chronological system events are developed by combining randomly generated operating histories of the generating resources with inter-Area and intra-Area transfer limits and chronological hourly loads. The capacity margin is determined for each isolated Area at the time of its daily peak load. 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: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

3.2 MODELING ASSUMPTIONS

(1) Transfer Limits

Figure 1 stylistically illustrates the Areas and transfer limits assumed for study years 2016 and 2020. Tie transfer limits between Areas are indicated with seasonal ratings as appropriate. Internal Area transmission constraints were represented in New York, New England, Ontario, and the Maritimes Areas, consistent with their respective modeling practices.



The transfer capability in this direction reflects limitations imposed by ISO-NE for internal New England constraints.

Transfer Limits have Annual Ratings unless noted:
S Summer Rating
W Winter Rating

Figure 1 - Assumed NPCC Transfer Limits (MW) – 2016 and 2020

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

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 7 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk Stamford	NM	- Northern Maine
MANI I	- 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	NW	- Northwest (Ontario)	NE	- Northeast (Ontario)
VT	- Vermont	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

Figures 2 (a) and 2 (b) shows the resulting diversity in load shapes between the NPCC Areas forecast for the years 2016 and 2020, respectively. The Quebec and Maritimes Areas are winter peaking while the New England, New York and Ontario Areas are summer peaking. This seasonal difference in the annual peak load contributes to the interconnection assistance available to each Area.

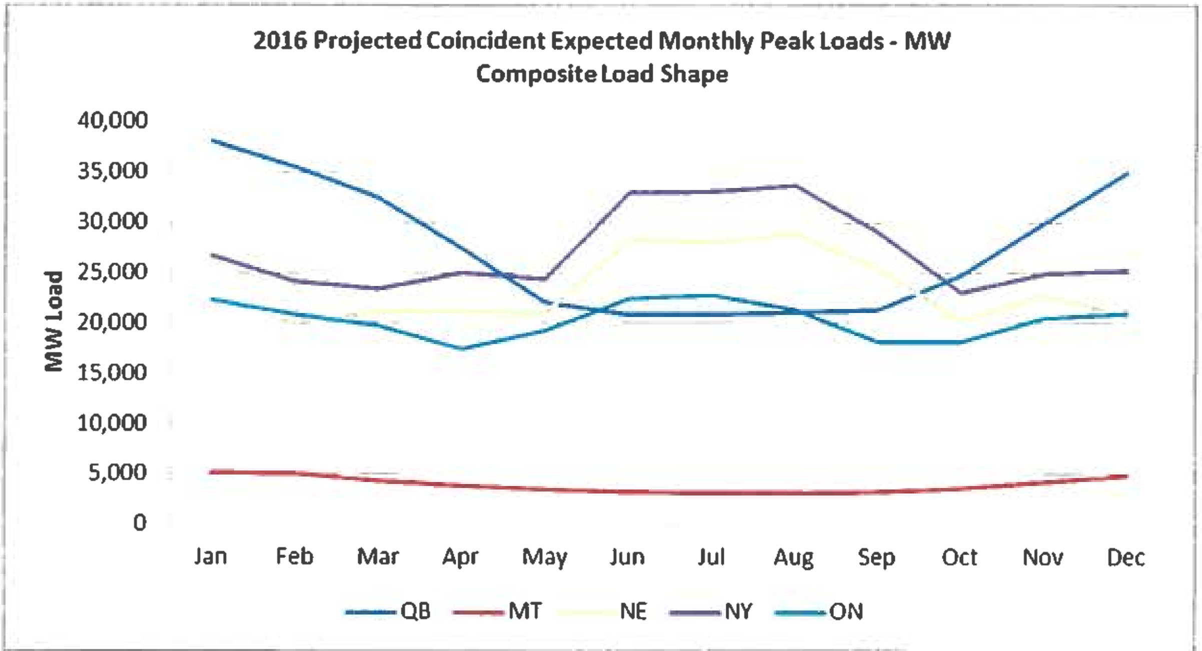


Figure 2 (a) - 2016 Forecast Monthly Peak Loads for NPCC Areas

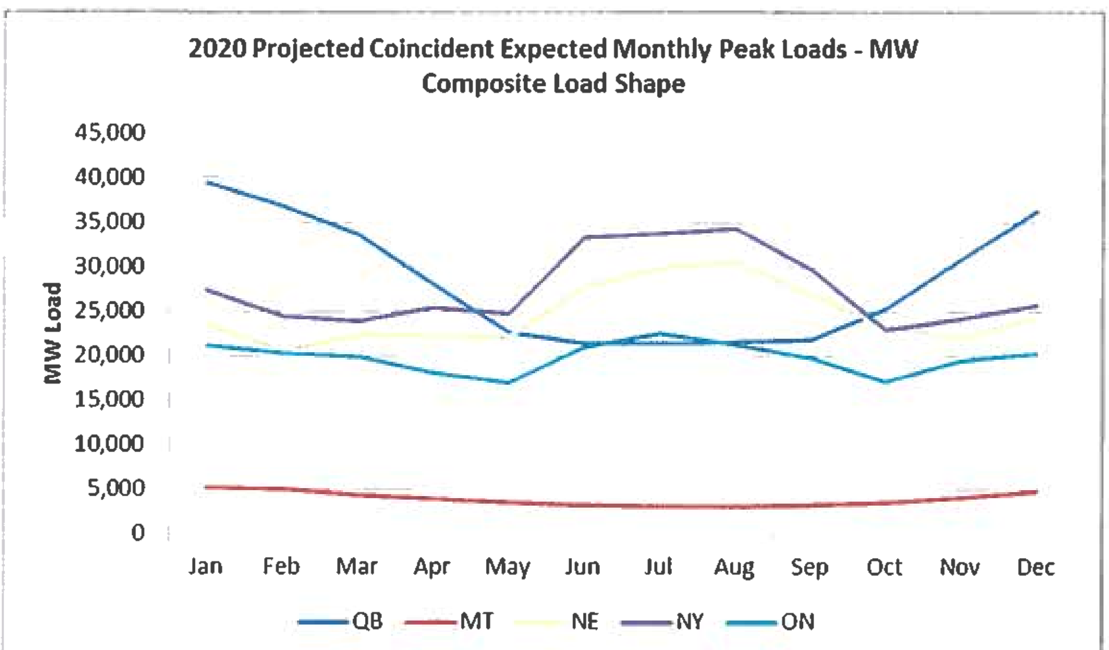


Figure 2 (b) - 2020 Forecast Monthly Peak Loads for NPCC Areas

(2) Generation Resources

Each Area provided its projections of "As Is" available resources consistent with their forecasts for the years 2016 (Table 3(a)) and 2020 (Table 3(b)), as of the Area's peak month. Firm purchases and sales were modeled as a shift in resources from the selling Area to the buying Area.

Table 3 (a)
NPCC Capacity and Load Assumptions for Peak Month 2016 - MW
"As Is"

	Q (Jan) [1]	MT (Jan)	NE (Aug)	NY (Aug)	ON (Jul)
Assumed Capacity	40,683	7,609	31,044	38,811	26,914
Purchase/Sale	266	-200	1,516	1,727	0
Peak Load	38,049	5,204	28,910	33,635	22,848
Reserve (%)	11	47	22	23	20
Scheduled Maintenance	(1)	0	0	363	1,178

Table 3 (b)
NPCC Capacity and Load Assumptions for Peak Month 2020 - MW
"As Is"

	Q (Jan) [1]	MT (Jan)	NE (Aug)	NY (Aug)	ON (Jul)
Assumed Capacity	42,092	7,622	31,395	38,811	27,531
Purchase/Sale	931	0	-5	2,225	0
Peak Load	39,447	5,231	30,575	34,310	22,524
Reserve (%)	13	51	14	23	25
Scheduled Maintenance	(1)	47	0	291	529

(3) Transition Rates

The MARS program uses transition rates to represent the random forced outages of thermal units. Most of the unit data was represented with two-state transition rates, where units are represented as being fully available or as on full forced outage. The Maritimes and New York Areas also modeled units with partial outage states. Partial outage rates represent a unit as fully available, as on full forced outage, and with partially available state(s).

[1] Capacity shown for Québec adjusted for scheduled maintenance.

(4) *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.

(5) *Operating Procedure Assumptions*

Table 4 indicates the amount of load relief assumed available from operating procedures for each NPCC Area. Each step was initiated simultaneously in all NPCC Areas and Sub-Areas. The amount of Area Interconnection Assistance was calculated following the utilization of these amounts.

Table 4
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[1]	891[2]	-	-
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 [3]	- -	-	-
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

[1] Derated value shown accounts for assumed availability.
[2] Derated value shown accounts for assumed availability.
[3] Derated value shown accounts for assumed availability.

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.

(6) Load Forecast Uncertainty

Tables 5a and 5b shows the uncertainty of the annual peak load forecast modeled. The effects on reliability of uncertainties in the peak 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 the load can vary on a monthly basis, Tables 5a and 5b shows the values assumed for the corresponding to the occurrence of the NPCC system peak load.

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.

Table 5(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 5(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

(7) 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.

3.3 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.** In this review, 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.

Two levels of Tie Benefits are estimated: "As Is" Tie Benefits and "At Criterion" Tie Benefits. The "As Is" Tie Benefits are the tie benefits available to an Area with resources that are expected to be in-place for the years 2016 or 2020, as supplied by the CP-8 Working Group in August 2015. The "At Criterion" Tie Benefits are the tie benefits available to an Area when the capacities of each of its neighboring Areas are adjusted to simultaneously meet the NPCC Criterion.

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

[1] The "As-Is" assumption refers to the modeling of systems with resources that are expected to be in-place for the years 2016 and 2020, as reported in the NPCC 2015 Long Range Adequacy Overview

capacity in the Area of interest (by adding or removing "perfect" capacity), based on the reserve margins in 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 the Area of interest from Step 2, isolate the Areas after scheduling firm contracts and removing internal transmission constraints. Add "perfect" capacity to the 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 the Area, excluding any firm contracts, assuming "As-Is" capacity for the neighboring Areas.

Steps 2 and 3 are repeated for all of the NPCC Areas to determine the "As Is" Tie Benefits for each Area.

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.

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 that the other Areas can provide (Step 2). This approach thus provides an estimate of the amount of assistance that's available to an Area, regardless of whether or not an Area can make use of all of it due to internal constraints.[1]

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 net firm imports at time of Area peak, is the **"As-Is" Annual Tie Benefit**.

The above methodology was used for both 2016 and 2020 and provided an estimate of the **"As Is" Annual Tie Benefit** assuming the "As Is" conditions in each of the Areas providing assistance.

Since an Area may assume that the neighboring systems are more reliable than is required by the NPCC criteria, the methodology was refined to calculate the "At Criteria" Tie Benefits by adding the following steps:

> **Step 4** - Bring each Area of the interconnected "As-Is" system (including outside regions), with internal transmission constraints, simultaneously 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. This process is performed iteratively, adjusting the Area with the LOLE furthest from the target LOLE by a small amount in proportion to its reserves, each iteration, until the entire system has reached the target criteria.
>
> **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

[1] The amount of assistance reported may not be available to all Areas simultaneously, but instead estimates the annual average of the amount of assistance that is available to an Area during the year.

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 next firm imports at time of Area peak, is the "At-Criteria" Annual Tie Benefit Potential.

These additional Steps were applied for the years 2016 and 2020 to provide an estimate of the amount of **"At Criteria" Annual Tie Benefit** available if each Area just met criterion.

During Step 4, any Areas without measurable LOLE in the "As Is" system will have the minimum amount of capacity required removed from them in order to achieve a measurable LOLE. Once all areas have a non-zero LOLE, the area with the largest absolute delta LOLE has a small amount of capacity removed or added, as appropriate. The amount of capacity changed in an Area is determined by adjusting the current target maximum reserve margin by 1%. A GE MARS simulation is performed to calculate the new LOLEs for all of the Areas, and the process is repeated until all Areas have simultaneously reached the criteria of 0.1 days per year. This methodology of making very small changes iteratively reduces the possibility of one area excessively relying on external assistance when it reaches criteria.

3.4 RESULTS

The **Annual Tie Benefits** are shown are shown in Table 6 (a) for the year 2016 and Table 6 (b) for the year 2020. 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 6 (a) and Table 6 (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 6 (a)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2016 - MW

Area	Total Tie Capacity assumed at time of Area peak [1]	Net Firm Imports assumed at time of Peak (MW)	Without Internal Constraints	
			"At Criteria" Annual Tie Benefit	"As Is" Annual Tie Benefit
QB	3,966	766	3,402	3,491
MT	1,550	-200	423	702
NE	3,700	1,516	3,454	3,485
NY	10,305	1,727	8,571	9,774
ON	6,195	0	3,852	4,094

Table 6 (b)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2020 – MW

Area	Total Tie Capacity assumed at time of Area peak [1]	Net Firm Imports assumed at time of Peak (MW)	Without Internal Constraints	
			"At Criteria" Annual Tie Benefit	"As Is" Annual Tie Benefit
QB	3,966	931	3,592	3,789
MT	1,550	0	523	1,012
NE	3,700	-5	3,214	3,487
NY	10,305	2,225	8,311	9,632
ON	6,195	0	4,414	4,703

[1] Based on the transfer limits shown in Figure 1, assumed in the *NPCC 2015 Long Range Adequacy Overview*.

3.5 COMPARISON OF AREA INTERCONNECTION ASSISTANCE

Table 7 shows the interconnection assistance assumed in recent Area studies and the results from this Review. When interpreting these results, there are two important points to recognize; first, the data used in recent Area studies may be different from that used in this study, and second, the underlying methodology in Area studies varies for each NPCC Area. Additional information follows for the five NPCC Areas (Quebec, Maritimes, New England, New York, and Ontario) that assume interconnection assistance in their resource adequacy assessments.

Table 7
COMPARISON OF ASSUMED AND ESTIMATED ANNUAL INTERCONNECTION ASSISTANCE – MW

NPCC Area (Year of Review)	Tie Assistance Reported in 2015 NPCC Review of Resource Adequacy [1]	Net Firm Imports assumed at time of Peak (MW) (2016/2020)	Available Estimated Annual Tie Benefit for 2016 At Criteria/As Is	Available Estimated Annual Tie Benefit for 2020 At Criteria/As Is
Québec	1,600 [2]	766/931	3,402/3,491	3,592-3,789
Maritimes	300 [3]	-200/0	423/702	523-1,012
New England	1,847 – 1,990 [4]	1,516/-5	3,454/3,485	3,214-3,487
New York	4,135 [5]	1,727/2,225	8,571/9,774	8,311-9,632
Ontario	300 – 1,350 [6]	0	3,852/4,094	4,414-4,703

[1] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[2] The NPCC 2014 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy reported 1,100 MW of winter capacity purchases from New York; the NPCC 2015 Quebec Balancing Authority Area Interim Review of Resource Adequacy assumed a higher firm capacity import due to a new capacity sharing agreement between Québec and Ontario (500 MW for winter 2015-2016 and 2016-2017) for the base case scenario.
[3] The NPCC 2015 Maritimes Area Interim Review of Resource Adequacy reported 300 MW of interconnection benefits from New England.
[4] 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.
[5] The New York 2015 Comprehensive Review of Resource Adequacy reported 2,170 MW of summer external capacity – 1,080 MW from PJM and 1,090 from Hydro-Quebec. In addition, up to 1,965 MW of locational capacity benefits are available through Unforced Capacity Deliverability Rights (UDRs)
[6] The 2015 Ontario Comprehensive Review of Resource Adequacy reported for the high demand growth scenario for 2018, 2019, and 2020 forecast years, reported up to 1,350 MW of tie benefits; however, if planned outages were rescheduled, only 300 MW of tie benefits are required for 2019.

Québec

Results of the 2015 Québec Interim Review of Resource Adequacy [1] show that the loss of load expectation (LOLE) for the Québec area is below the NPCC reliability criterion of not more than 0.1 day per year under the base case scenario for winter 2015-2016. This was achieved with the inclusion of 1,100 MW of expected winter capacity purchases from NYISO and 500 MW of firm capacity import from Ontario due to a new capacity sharing agreement between Hydro-Québec and the 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 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.

Maritimes Area

In the "*NPCC 2015 Maritimes Area Interim Review of Resource Adequacy*," [2] 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

[1] See: https://www.npcc.org/Library/Resource%20Adequacy/2015%20Québec%20Interim%20Review.pdf
[2] See:
https://www.npcc.org/Library/Resource%20Adequacy/2015%20Maritimes%20Area%20IRRA%20for%20RCC%20 20150805.pdf

peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. This was unchanged from the 2013 Comprehensive Review.

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 1,847 MW for 2016, 1,870 MW for 2017, 1,970 MW for 2018, and 1,990 MW for 2019. [1]

New York

The New York State Reliability Council established the annual statewide installed reserve margin for the New York Control Area for the May 2016 through April 2017 period at 17.5 percent. [2] This equates to an Installed Capacity Requirement of 1.175 times the forecasted New York Control Area 2016 peak load. The New York ISO determined the locational installed capacity requirements for the New York Control Area for the 2016 – 2017 Capability Year beginning May 1, 2016 [3] based on the installed reserve margin of 17.5 percent.

The study assumed a total of 2,170 MW of summer external capacity (1,090 MW grandfathered purchases from Hydro-Québec, and 1,080 MW from PJM). In addition, the external capacity representation also includes Unforced Capacity Deliverability Rights (UDRs). These rights

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[1] See: http://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements

[2] "*New York Control Area Installed Capacity Requirements for the Period May 2016 Through April 2017.*" See: http://www.nysrc.org/pdf/Reports/2016%20IRM%20Tech%20Study%20Report%20Final%2012-15-15.pdf

[3] Since the start of this study, several changes were noted in the New York State Reliability Committee (NYSRC) study assumptions. These changes resulted in the NYSRC imposing a PJM-SENY group limit to reflect internal constraints in both PJM and NY systems, and was restored to the topology and transfer limits of 2,000MW similar to 2014 IRM Study topology, which is different than the 3075MW used in this "Review of Interconnection Assistance Reliability Benefits". The changes were made to reflect: 1) the balance of the ConEd-PSEG wheel, and 2) the delay of the assumed Northern NJ transmission upgrades and the potential delay of the Phase II (additional cooling) of Staten Island Unbottling project Central East, Central East Group, and UPNY-SENY interface transfer limits were updated to reflect the additional transmission facilities. Portions of the Transmission Owner Transmission Solutions (TOTS) are expected to be in-service before summer 2016: Marcy South Series Compensation, an additional 345 kV circuit between Rock Tavern and Ramapo, and a 345/138 kV tap connecting to the existing Sugarloaf 138 kV station.

allow the owner of an incremental controllable transmission project to extract locational capacity benefit derived by the NYCA from the project. The owner of UDR facility rights designates how they will be treated by the NYISO in resource adequacy studies on an annual basis.

LIPA's 330 MW HVDC Cross Sound Cable, the 660 MW HVDC Neptune Cable, Con Ed's 315 MW Linden VFT, and the 660 HTP (Hudson Transmission Partners) cable are facilities that are represented as having UDR rights. Remaining transmission capacity beyond that identified by the owners as 'in use' for locational capacity benefit is modeled as available to support emergency assistance.

In a scenario where the NYCA system is isolated and receives no emergency assistance from neighboring control areas, (New England, Ontario, Quebec, and PJM), the installed reserve margin is estimated to be 8.5 percentage points higher than otherwise required.

Ontario

The Ontario Independent Electricity Market Operator (IESO) has reported that it expects to meet the NPCC resource adequacy criterion in its most recent Comprehensive Review of Resource Adequacy. [1] The IESO forecast considers the potential use of operating actions, including outage rescheduling and use of emergency operating procedures. In the high demand growth scenario, for the 2016, 2019 and 2020 forecast years, up to 1, 350 MW of reliance on interconnection benefits (in addition to EOPs) are required; however, if planned outages are rescheduled, then only 300 MW of reliance on interconnection benefits in conjunction with operating actions are required.

4.0 CONCLUSIONS

The CP-8 Working Group concluded that:

- the estimates of interconnection benefits available to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis;
- a consistent methodology and assumptions were applied to all NPCC Areas, using the same multi-Area reliability model; and,
- the Tie Benefits assumed in NPCC Area Resource Adequacy Reviews were below the estimated available Tie Benefits calculated in this study, and do not overstate the available interconnection benefits.

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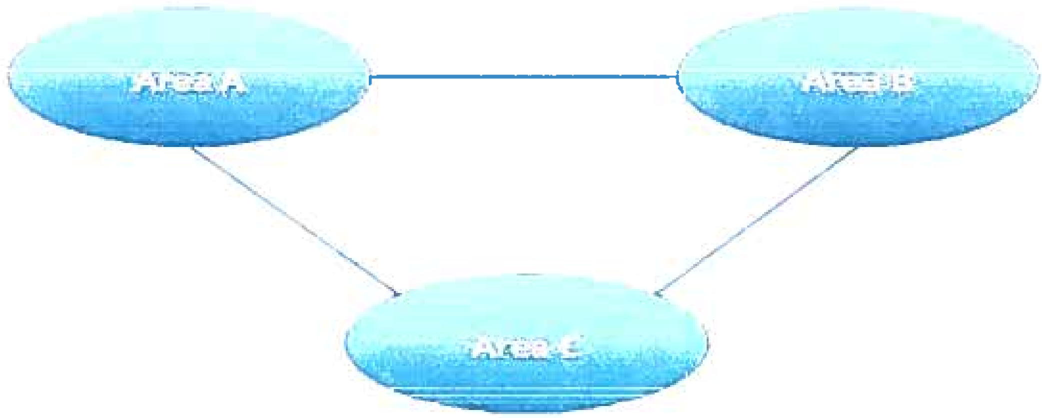
[1] See: https://www.npcc.org/Library/Resource%20Adequacy/IESO%202015%20Comprehensive%20Review%20Resource%20Adequacy%20Approved%20by%20the%20RCC.pdf

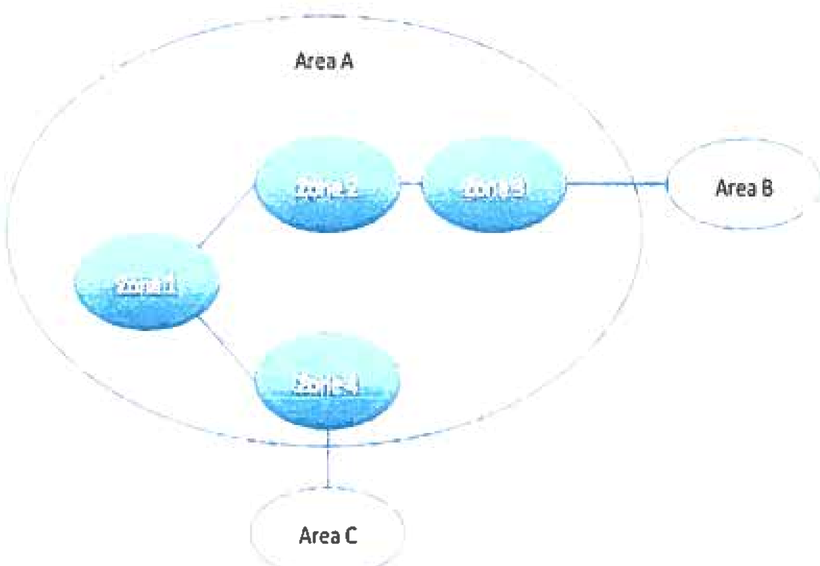
Appendix 1 – Methodology Overview

Consider the following example system:



Area	Capacity (MW)	Load (MW)	Reserve Margin (%)	"As Is" LOLE (days/yr)
Area A	2,400	2,000	20	0.005
Area B	4,050	3,000	35	0.000
Area C	1,725	1,500	15	0.038

Area A consists of the following sub-Areas, or Zones:



Zone	Capacity (MW)	Load (MW)	Reserve Margin (%)
Zone 1	800	1,000	-20
Zone 2	300	200	50
Zone 3	500	300	67
Zone 4	800	500	20

Other Areas have similar sub-Area configurations.

Step 1: Isolated Areas, no internal constraints

In Step 1, the ties between the three Areas are cut, and internal constraints are removed. The resulting LOLEs from this step are:

Area	LOLE (days/yr)
Area A	0.010
Area B	0.000
Area C	0.060

For Steps 2 and 3, Area A will be the Area of Interest. These steps would subsequently be repeated for Areas B and C as well, following the same methodology.

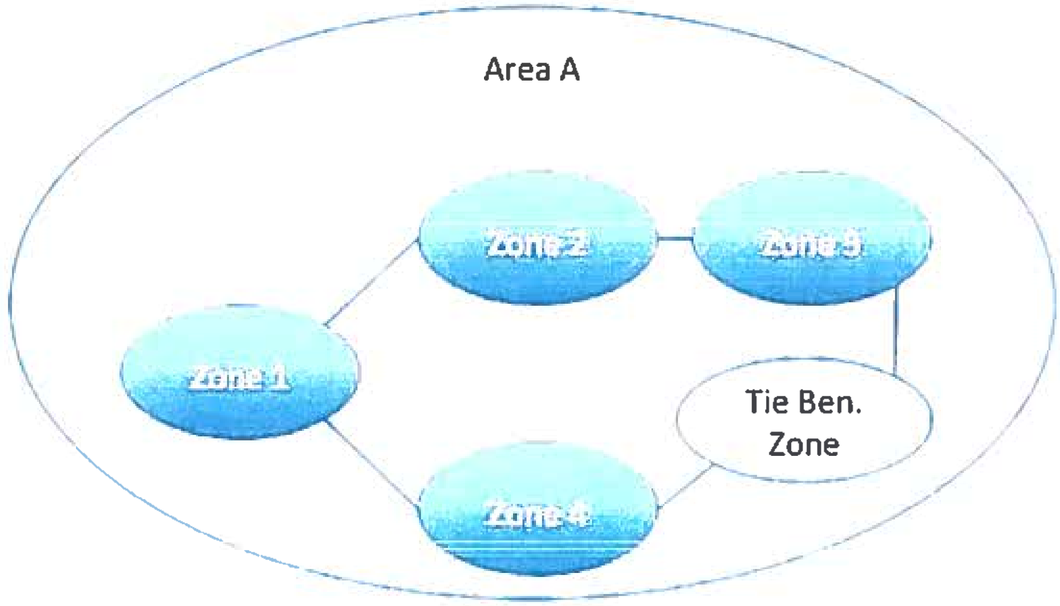
Step 2: Bring Area of Interest to criteria, interconnected

In Step 2, the ties between the Areas are restored, and internal constraints in the Area of Interest are removed. The Area of Interest is then driven to 0.1 days/year LOLE by adjusting capacity.

Iteration	Δ RM Change (%)	Target Max RM (%)	Zone 1 Cap/RM (MW/%)	Zone 2 Cap/RM (MW/%)	Zone 3 Cap/RM (MW/%)	Zone 4 Cap/RM (MW/%)	Area A Cap/RM (MW/%)	LOLE (days/year)
0	0	67	800/-20	300/50	500/67	800/60	2400/20	0.002
1	-5	63	800/-20	300/50	490/63	800/60	2390/20	0.010
2	-10	57	800/-20	300/50	471/57	785/57	2356/18	0.010
3	-15	48	800/-20	297/48	445/48	742/48	2285/14	0.070
4	-10	44	800/-20	287/44	431/44	718/44	2236/12	0.100

Step 3: Isolate Area, model Tie Benefits

With the Area of Interest at criteria, isolate it from the neighboring Areas, and continue with no internal constraints. A dummy zone is added to the Area, and is connected to the zones which have external ties, as shown below:



Capacity is added to this zone until the isolated Area returns to an LOLE of 0.1 days/year.

This capacity added, plus the net firm imports (of which there are none in this example), represents the "As Is" Annual Tie Benefit.

Step 4: Bring Region to Criteria

Starting from the "As Is" system, determine the minimum capacity removal required for all Areas to have a measurable LOLE (greater than 0.000). This capacity removal is done in the same way as Step 2.

Once all areas have a measurable LOLE, the capacity is adjusted in the Area with the greatest absolute delta LOLE from criteria. The target maximum reserve margin in an area is adjusted by 1%, and the LOLE is recalculated for each of the Areas. This process is repeated iteratively until the entire region is simultaneously at approximately 0.1 days/year.

	Area A		Area B		Area C	
Iteration	Target Max RM (%)	LOLE (days/year)	Target Max RM (%)	LOLE (days/year)	Target Max RM (%)	LOLE (days/year)
0	20.0	0.005	35.0	0.000	15.0	0.038
1	20.0	0.005	30.0	0.001	15.0	0.038
2	20.0	0.005	29.7	0.008	15.0	0.038
3	19.8	0.010	29.7	0.008	15.0	0.038
...						
X	14.7	0.100	16.9	0.100	13.1	0.100

Steps 5 and 6 then follow the same methodology as Steps 2 and 3, respectively, with the exception of being based on the system resulting from Step 4.