Approved by the RCC
November 27, 2007

NPCC, Inc.

Review of Interconnection Assistance Reliability Benefits

November 6, 2007

NPCC CP-8
Working Group

NORTHEAST POWER COORDINATING COUNCIL, Inc.

CP-8 WORKING GROUP

REVIEW OF INTERCONNECTION ASSISTANCE RELIABILITY BENEFITS

November 6, 2007

EXECUTIVE SUMMARY

NPCC's CP-8 Working Group, under the auspices of the Task Force on Coordination of Planning was charged to:

1. Estimate (on a consistent basis) the amount of interconnection assistance available to the NPCC Areas for today's system (2007) and the near term (2009);
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 assessments are reasonable and do not result in overstating any Area's reliability.

The General Electric (GE) Multi-Area Reliability Simulation (MARS) program was used to estimate NPCC Area Annual Tie Benefits for a hypothetically "At Criteria" and "As Is" year 2007 and year 2009 system representation. GE Energy was retained by the CP-8 Working Group to conduct the simulations.

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 that are critical to recognize; first, the data and assumptions used in recent Area studies may have been considerably different from that used in this Review, and second, the underlying methodology may vary for each NPCC Area. 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.

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

NPCC Area (Year of Review)	Tie Benefit Assumption Reported in Recent NPCC Review of Resource Adequacy	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2007	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2009
Québec (2006)	0	2,264 – 2,534	1,618– 2,440
Maritimes (2006)	0	1,026 - 1,200	1,291 – 1,491
New England (2006)	2,000	3,492 – 4,407	4,110 – 4,701
New York (2006)	2,300	5,418 – 7,015	3,698 – 6,203
Ontario (2006)	1,200	3,760 – 4,000	5,245 – 5,250

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 the current NPCC Area estimates of interconnection benefits used to meet the NPCC Resource Adequacy Criteria, the CP-8 Working Group concluded that the interconnection assistance values reported by NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

CP-8 WORKING GROUP

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The members of NPCC's CP-8 Working Group wish to acknowledge the contributions of Messrs. Glenn E. Haringa, GE Energy and Andy Ford, of PJM.

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1.0 INTRODUCTION

The objective of CP-8 Working Group's Review of Interconnection Assistance Reliability Benefits was to estimate (on a consistent basis) the amount of interconnection assistance available to NPCC Areas for today's system (2007) and the near term (2009), 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. NPCC Document A-02, Basic Criteria for Design and Operation of Interconnected Power Systems [1], Section 3.0 Resource Adequacy – Design Criteria states– "Each Area's probability (or risk) of disconnecting firm load due to resource deficiencies shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day/year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

In meeting this 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 Energy 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 2007 and 2009 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 the 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. Area loads were correlated based on the 2002 historical load period. Area load forecast uncertainties and emergency operating procedures were modeled on a consistent basis. The study recognized that each of the Canadian utilities have dispatchable loads [interruptible loads] which are operating procedures restricted for use solely by that utility.

[1] See: http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf.

2.0 AREA INTERCONNECTION ASSISTANCE

Each NPCC Area is responsible for demonstrating that sufficient resources are available to meet its firm load in accordance with the NPCC Resource Adequacy 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 NPCC Document B-08 [1] , "Guidelines for Area Review of Resource Adequacy" and report their findings in their respective Area's "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 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 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**. 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: http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/B-08.pdf.

Table 1
NPCC AREA INTERCONNECTION ASSISTANCE MODELING

FACTOR	Québec	Maritimes	New England	New York	Ontario
1. Tie Benefit support from interconnections 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	Yes
5. Load forecast uncertainty represented	Yes	Yes	Yes	Yes	Yes
6. Basis for installed reserve assumed for interconnected systems	Equal Risk	N.A.	Equal Risk	Equal Risk	Equal Risk
7. Internal Area transmission modeled for resource adequacy assessments	Yes	No	Yes	Yes	Yes
8. Interconnection outages modeled	No	No	Yes [2]	Yes [3]	No
9. Year of Recently Approved NPCC Area Review of Resource Adequacy	2006 [4]	2006 [5]	2006 [6]	2006 [7]	2006 [8]

[1] Loss of Load Expectation (days/year).

[2] Outages modeled on Hydro-Quebec and New Brunswick interconnections.

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

[4] 2006 Interim Review of Québec Area Resource Adequacy approved March 14, 2007.

[5] 2006 Interim Review of Maritimes Area Resource Adequacy approved March 14, 2007.

[6] New England 2006 Interim Review of New England Area Resource Adequacy approved November 28, 2006.

[7] 2006 Interim Review of New York Area Resource Adequacy approved November 28, 2006.

[8] IESO 2006 Comprehensive Review of Ontario Resource Adequacy approved November 28, 2006.

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 the CP-8 study, the model was used to determine daily LOLE for each of the NPCC Areas and Sub-Areas at the time of each NPCC Area's daily peak load.

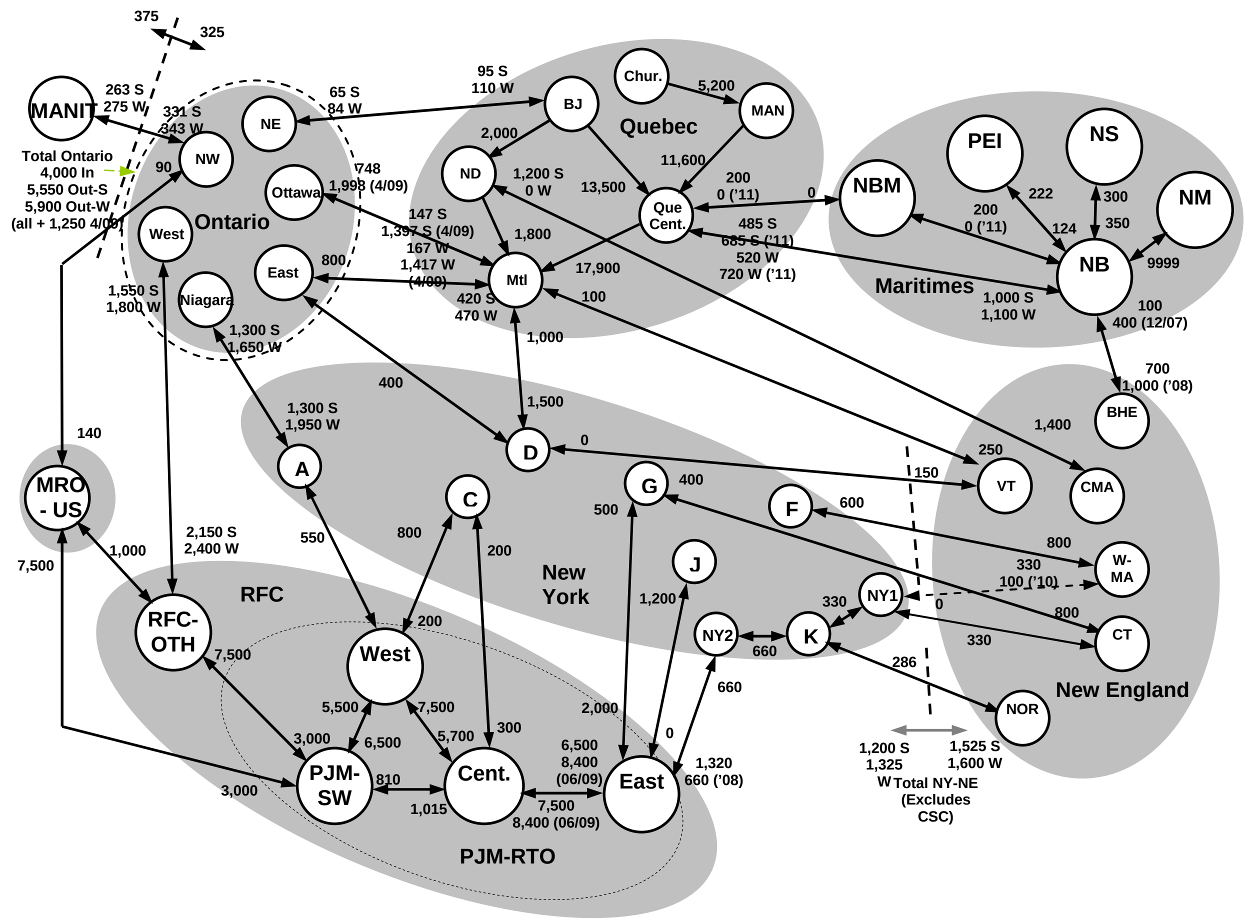
In MARS, chronological system events are developed by combining randomly generated operating histories of the generating resources with inter-Area and intra-Area transfer limits and chronological hourly loads. The capacity margin is determined for each isolated Area at the time of its daily peak load. 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 deficient Areas by a priority list and among Sub-Areas on a shared basis in proportion to Sub-Area 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 illustrates the Areas and transfer limits assumed for the years 2007 to 2009 study period. 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.



Transfer Limits have Annual Ratings unless noted:

S – Summer Rating
W – Winter Rating

Figure 1 - Assumed NPCC Transfer Limits (MW)

The acronyms used in Figure 1 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	RFC	- Reliability*First* Corp.
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
MAN	- Manicouagan	W MA	- Western MA	NS	- Nova Scotia
NE	- Northeast (Ontario)	NBM	- Millbank	NW	- Northwest (Ontario)
MRO	- Midwest Reliability Organization	VT	- Vermont	RFC	- Reliability*First* Corp.
		Que Centre	- Québec Centre	CSC	- Cross Sound Cable

(2) Load Model

Figures 2 (a) and 2 (b) shows the resulting diversity in load shapes between the NPCC Areas forecast for the years 2007 and 2009, respectively. The Canadian Maritimes and Quebec are winter peaking while the US Areas and Ontario are summer peaking. This seasonal difference in the annual peak load contributes to the interconnection assistance available to each Area.

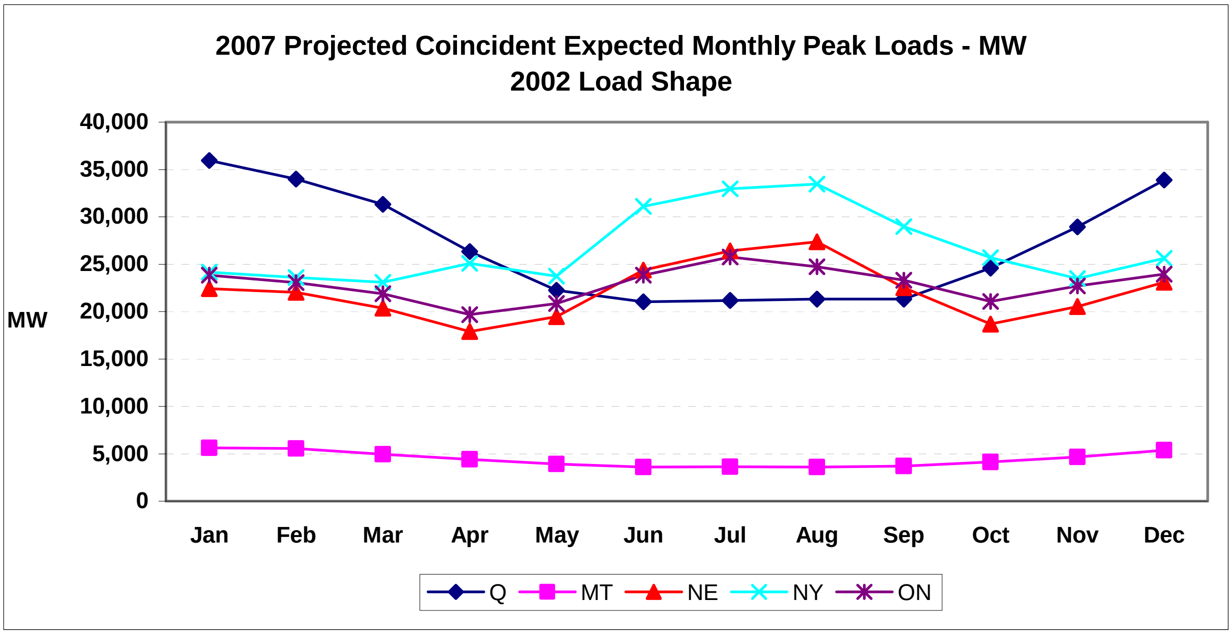


Figure 2 (a) - 2007 Forecast Monthly Peak Loads for NPCC Areas

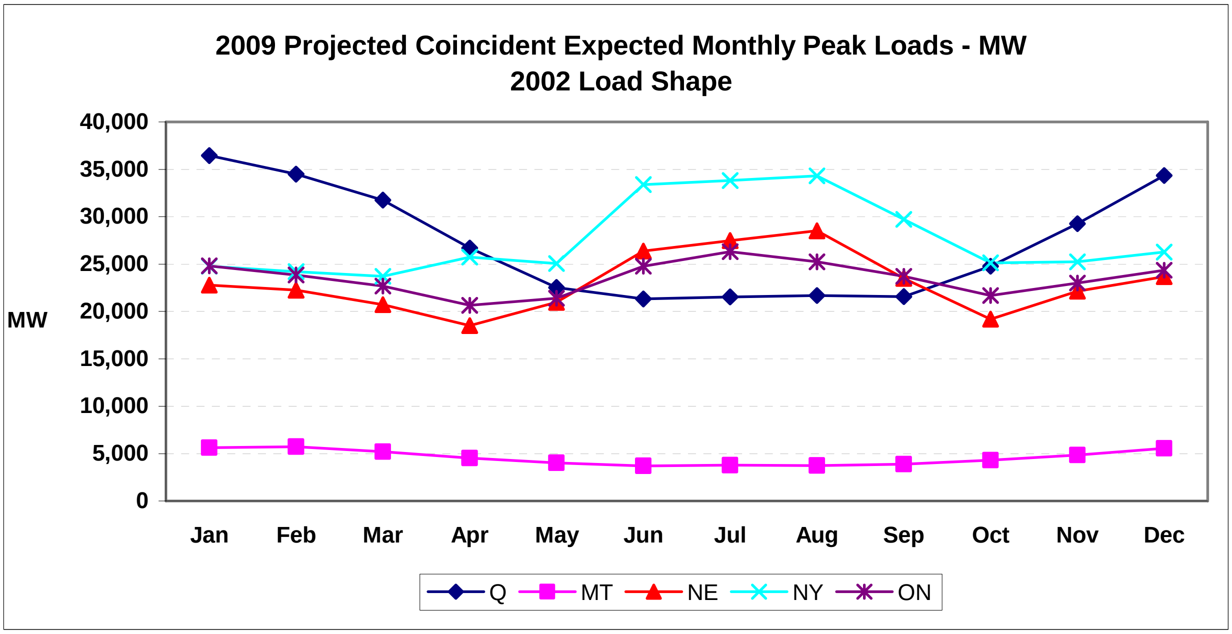


Figure 2 (b) - 2009 Forecast Monthly Peak Loads for NPCC Areas

(3) Generation Resources

Each Area provided its projections of "As Is" available resources consistent with their forecasts for the years 2007 (Table 3(a)) and 2009 (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 2007 - MW
"As Is"

	Q (Jan) [1]	MT (Jan)	NE (Aug)	NY (Aug)	ON (Jul)
Assumed Capacity	32,825	6,858	30,181	38,372	29,785
Purchase(+) / Sale(-)	6,043	-200	90	2,903	0
Peak Load	35,930	5,624	27,360	33,447	25,276
Reserve (%)	8	18	11	23	18
Scheduled Maintenance	(1)	0	36	110	1,403

Table 3 (b)
NPCC Capacity and Load Assumptions for Peak Month 2009 - MW
"As Is"

	Q (Jan) [1]	MT (Jan)	NE (Aug)	NY (Aug)	ON (Jul)
Assumed Capacity	33,638	6,999	30,181	38,797	34,439
Purchase (+) / Sale (-)	6,142	-200	80	76	0
Peak Load	36,437	5,723	28,495	34,300	26,299
Reserve (%)	9	19	6	13	31
Scheduled Maintenance	(1)	805	58	629	722

(4) 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.

(5) Assistance Priority

Table 4 indicates the priority order followed when allocating reserves and operational assistance to Areas with a deficiency. Areas listed with equal priority 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.

Table 4
Priority Order for Providing Emergency Assistance

Area Providing Assistance	1ST	2ND
Québec	MT ON	NE NY
Maritimes Area	Q ON	NE NY
New York	NE	Q MT ON
New England	NY	Q MT ON
Ontario	Q MT	NE NY
Millbank Units	Q	MT
PJM	NE NY	
RFC-OTH	PJM	
MRO-US	ON	

Areas listed with equal priority received assistance on a shared basis in proportion to their deficiency. The Millbank Station, although located within the Maritimes, has two of its units contracted to Québec. These units are modeled as a resource for Québec first, to reflect their priority order of assistance.

(6) Operating Procedure Assumptions

Table 5 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 5
NPCC Operating Procedures Assumptions (Peak Month 2007)
(MW)

Actions	Q (Jan)	MT (Jan)	NE (Aug)	NY (Aug)	ON (Jul)
1. Curtail Load / Utility Surplus	935	0	616	0	188
LRP/SCR/EDRP	0	0	0	1,398	0
Manual Voltage Reduction	0	0		0.54% of load	0
Appeals					1.0% of load
2. No 30-min Reserves	500	229	578	600	473
3. Voltage Reduction or Interruptible Loads *	250	534	1.86% of load	1.45% of load	2.60% of load
ELRP					159
4. No 10-min Reserves	750	603	1,000	0	945
General Public Appeals	0	0	0	222	0
5. General Public Appeals	0	0	0		
No 10-min Reserves				1,200	
EDRP					115

* Interruptible Loads for Maritimes (implemented only for the Area), Voltage Reduction for all others

(7) Load Forecast Uncertainty

Table 6 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, Table 6 shows the values assumed for July, 2007 corresponding to the occurrence of the NPCC system peak load. Table 6 also shows the probability of occurrence assumed for the entire year 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.

Table 6
Per Unit Variation in Load Assumed for the Peak Month 2007

Area	Per-Unit Variation in Load						
Q (Jan)	1.0700	1.0550	1.0450	1.0000	0.9550	0.9450	0.9300
MT (Jan)	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE (Aug)	1.2253	1.0995	1.0030	0.9289	0.9064	0.8792	0.8587
NY (Aug)	1.1049	1.0710	1.0283	0.9871	0.9411	0.8944	0.8582
ON (Jul)	1.1054	1.0702	1.0351	1.0000	0.9649	0.9298	0.8946
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

3.3 METHODOLOGY

The Tie Benefits Methodology used in this Review involved determining the amount of load increase that an interconnected Area can accommodate while maintaining a given level of reliability. The specific Steps are summarized below:

Step 1 – Isolate the “As Is” [1] Areas after scheduling firm contracts and removing any internal transmission constraints. Bring each isolated Area to be approximately “At Criteria” [2] (0.1 days/year LOLE) by adjusting the hourly loads, subject to any locational requirements, in each Area proportionally across all sub-Areas.

Step 2 – Interconnect the Areas and restore internal transmission constraints in all Areas except for the Area of interest. Starting with the “As Is” loads in each Area, increase the sub-Area loads, subject to any locational requirements, proportionately in the Area of interest until it returns to the LOLE calculated in Step 1 (approximately 0.1 days/year).

Step 3 – Isolate the Areas after scheduling firm contracts and removing the internal transmission constraints. Add a given amount of “perfect” (100% available) 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” loads for neighboring Areas.

[1] The “As-Is” assumption refers to the modeling of systems with resources that are expected to be in-place for the years 2007 or 2009, as supplied by the CP-8 Working Group in August 2007.
[2] The “At Criterion” assumption refers to modeling the adequacy condition of each of the NPCC Areas and neighboring Regions being at a criterion level of 0.1 days/year LOLE simultaneously.

While increasing the sub-Area loads proportionately is a good approach in estimating the amount of load increase 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 load increase 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 loads to determine the amount of assistance (non-coincident) that the other Areas can provide (Step 2). In order to provide a valid comparison with the results of Step 2, the internal constraints were also ignored in Step 1 as the loads in each Area were adjusted to bring each isolated Area to criterion. This approach thus provides an estimate of the amount of assistance (non-coincident) that's available, regardless of whether or not an Area can make use of all of it due to internal constraints.

In Step 2, the Areas were then interconnected and their sub-Area loads adjusted, one Area at a time, until the Area of interest returned to the LOLE of the previous step. During this part of the process, the internal constraints were ignored in the Area of interest, but 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. This provided an estimate of the amount by which each Area's peak load can be increased when interconnected with the other Areas.

In Step 3, the Areas were isolated again, this time using the adjusted peak loads of the previous step, with the interconnections replaced with fixed capacity. This step converts the "expected peak load" value of the interconnections into an annual fixed capacity amount. In some cases the fixed capacity was greater than the increase in the expected peak load, and in some cases it was less. Two factors impact the conversion from expected peak load increase to fixed capacity.

The first involves the fact that the loads were not being increased by a fixed MW amount, but rather on a percentage basis. For instance, if the peak load was increased by 1,000 MW, then it will amount to an increase of 900 MW in an hour for which the original load was 90% of the peak. The fixed capacity, however, is a fixed MW amount for the entire year. Consequently, 1,000 MW of additional perfect capacity representing the outside tie assistance would be expected to more than offset a 1,000 MW increase in peak load, and that the equivalent fixed capacity amount would actually be less than the increase in the expected peak load. This would always be true in the absence of load forecast uncertainty, which leads to the second factor.

With load forecast uncertainty, a given MW increase in the expected peak load would actually result in a larger MW increase at the higher load forecast uncertainty load levels, which is where most of the risk occurs. As a result, the tie assistance from the outside as represented by the fixed capacity amount would have to be greater than the expected peak load increase in order to maintain the same LOLE. This results in two forces working in opposite directions, and depending on the Area's load shape and load forecast uncertainty multipliers, one will predominate over the other.

The above methodology was used for both 2007 and 2009 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 hourly loads in each Area proportionally across all sub-Areas, subject to any locational requirements.
>
> **Step 5** - Remove the internal transmission constraints in the Area of interest and increase its sub-Area loads, subject to any locational requirements, proportionally until it returns to the LOLE in Step 4; loads in the other Areas as adjusted in Step 4.
>
> **Step 6 –** Isolate the Areas after scheduling firm contracts and removing internal transmission constraints. Add a given amount of "perfect" (100% available) capacity to each Area for the entire year until the Area LOLE returns to 0.1 days/year.

These additional Steps were applied for the years 2007 and 2009 to provide an estimate of the amount of **"At Criteria" Annual Tie Benefit** available if each Area just met criterion.

3.4 RESULTS

The **Annual Tie Benefits** are shown in Table 7 (a) for the year 2007 and Table 7 (b) for the year 2009. 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 7(a) and Table 7(b) is the Area's total import capability at time of their peak load. 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.

When the **"At Criteria" Annual Tie Benefit** and the **"As Is" Annual Tie Benefit** are both close to the actual Area's import limits, the Area's **Annual Tie Benefit** is more limited by its ability to import the assistance than it is by the ability of the other Areas to assist.

A larger difference between an Area's **"As Is"** and **"At Criteria" Annual Tie Benefit** indicates the extent to which its **Annual Tie Benefit** is more limited by the available assistance in the neighboring Areas than the size of the capability of its tie lines.

Table 7 (a)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2007 - MW

Area	Total Import Capacity at time of Area Peak	Net Firm Imports at Time of Area Peak (+) = Import (-) = Export	Without Internal Constraints "At criteria" Annual Tie Benefit	Without Internal Constraints "As Is" Annual Tie Benefit
Q	2,567	-276	2,264	2,534
MT	1,200	0	1,026	1,200
NE	4,535	367	3,492	4,407
NY	8,640	2,115	5,418	7,015
ON	4,000	0	3,760	4,000

Table 7 (b)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2009 – MW

Area	Total Tie Capacity At time of Area Peak	Net Firm Imports at Time of Area Peak (+) = Import (-) = Export	Without Internal Constraints "At criteria" Annual Tie Benefit	Without Internal Constraints "As Is" Annual Tie Benefit
Q	2,567	-276	1,618	2,440
MT	1,500	0	1,291	1,491
NE	4,835	357	4,110	4,701
NY	8,640	-52	3,648	6,203
ON	5,250	0	5,245	5,250

3.5 COMPARISON OF AREA INTERCONNECTION ASSISTANCE

Table 8 shows the interconnection assistance assumed in recent Area studies and the results from this Review. When interpreting these results, there are two important points that are critical to recognize; first, the data used in recent Area studies may have been considerably different from that used in this Review, and second, the underlying methodology may vary for each NPCC Area. Additional information follows for the three NPCC Areas (New England, New York, and Ontario) that assume interconnection assistance in their resource adequacy assessments. 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.

Table 8
COMPARISON OF ASSUMED AND ESTIMATED
ANNUAL INTERCONNECTION ASSISTANCE – MW

NPCC Area (Year of Review)	Tie Benefit Assumption Reported in Recent NPCC Triennial Reviews of Resource Adequacy	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2007	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2009
Québec (2006)	0	2,264 – 2,534	1,618 – 2,440
Maritimes (2006)	0	1,026 - 1,200	1,291 – 1,491
New England (2006)	2,000	3,492 – 4,407	4,110 – 4,701
New York (2006)	2,300	5,418 – 7,015	3,698 – 6,203
Ontario (2006)	1,200	3,760 – 4,000	5,245– 5,250

New England

In setting the NEPOOL Installed Capacity Requirement for the 2007 – 2008 Power Year [1], ISO-NE assumed summer Tie Reliability Benefits of 600 MW from New York, 200 MW from New Brunswick, with a monthly Hydro-Québec Interconnection Capacity Credit ranging from 200 MW to 1,200 MW. The Hydro- Québec Interconnection Capacity Credits are the values made in an informational filing to FERC on October 31, 2006.

New York

The New York State Reliability Council established the annual statewide installed reserve margin for the New York Control Area for the May 2007 through April 2008 period at 16.5 percent [2]. This equates to an Installed Capacity

[1] See: http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2007/icr_2007-2008_report.pdf page 15.
[2] "New York Control Area Installed Capacity Requirements for the Period May 2007 Through April 2008." See: http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

Requirement of 1.165 times the forecasted New York Control Area 2007 peak load. Based on this study, the New York ISO determined the locational installed capacity requirements for the New York Control Area for the 2007 – 2008 Capability Year beginning May 1, 2007 [1].

Those studies assumed a total of 227 MW of firm purchases from PJM, New England, and Ontario, and an additional 1,200 MW from Hydro-Québec, 345 MW from New England and 983 MW from PJM. The New England to Long Island (Cross Sound Cable) tie line was modeled with a 305 MW firm purchase. This results in 3,060 MW of expected summer external installed capacity (2,755 MW without the Cross Sound Cable tie line). Assuming such arrangements permits the New York Control Area installed reserve margin to be 6.4 percentage points lower than otherwise required.

Ontario

Over the most recent 18 month period under study, [2] the Independent Electricity Market Operator (IESO) for Ontario has reported that it expects to meet the NPCC resource adequacy criterion. The IESO forecast considers periodic reliance on interconnection benefits as well as potential use of other operating actions, including outage rescheduling and use of emergency operating procedures. The IESO reports [3] that the actual hourly import levels experienced from market opening in May 2002 up to September 2006 indicate an average import level of 1,087 MW for all hours. During the 7,004 hours when Ontario demand exceeded 20,000 MW, the average import level was 1,404 MW. During the 837 hours when Ontario demand exceeded 23,000 MW the average import level was 2,082 MW, and occasionally reached the Ontario coincident import capability of approximately 4,000 MW.

4.0 CONCLUSIONS

The CP-8 Working Group concluded that:

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

[1] "Locational Installed Capacity Requirements Study Covering The New York Control Area For the 2007 – 2008 Capability Year." See: http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/lcr_review2_16.pdf

[2] "18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System From October 2007 to March 2009." See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2007sep.pdf

[3] See: https://www.npcc.org/publicFiles/documents/adequacy/Ontario%20Comprehensive%202006.pdf