Northeast Power Coordinating Council, Inc.
Multi-Area Probabilistic Reliability Assessment
For
Summer 2008

April 30, 2008

Conducted by the
CP-8 Working Group
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<th>Name</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
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The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE Energy, Andrew Ford, the PJM Interconnection, Frank Ciani and Ken Wei, New York ISO, and Curt Dahl, Long Island Power Authority, and thanks them for their assistance in this analysis.
FOREWORD

Use of operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the Northeast Power Coordinating Council, Inc. (NPCC) geographic areas (Areas) during the 2008 summer period under the expected load forecast conditions, which are based upon the probability-weighted average of the seven load levels simulated. Recently added resources and transmission capacity in the NPCC region, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to minimize the expected need for the use of these operating procedures in 2008.

If reductions in anticipated resources, delay of expected transmission projects and/or additional constraints materialize coincident with higher than expected loads, New England, New York, and to a lesser extent, Ontario may experience conditions during the summer of 2008 that could require use of their operating procedures designed to mitigate resource shortages.
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SUMMER 2008 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

EXECUTIVE SUMMARY

Introduction
This study assessed NPCC Area reliability for the year 2008 by estimating the annual Loss of Load Expectation (LOLE) and projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2008 (May through September). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2008", May 2008.¹

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by the Working Group to conduct the simulations.

Results
All NPCC Areas demonstrated an annual LOLE of 0.1 days/year or less, under the Base Case assumptions and the expected load forecast.²

For the May - September 2008 period, Figure EX-1a shows the range of the expected use of the indicated operating procedures under the Base Case assumptions and the expected load forecast.²

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¹ See: http://www.npcc.org/seasonal.asp?Folder=CurrentYear
² The results are based on the weighted average of the seven load levels simulated, weighted by the probabilities assumed for each.
Figure EX-1b shows the range of the expected use of the indicated operating procedures under the Severe Case assumptions and the expected load forecast.²

![Figure EX-1b: Range of the Expected Use of Indicated Operating Procedures for Summer 2008 Considering Severe Case Assumptions (May – September) (Expected Load Forecast)](image)

For the May - September 2008 period, Figure EX-2 shows the expected use of the indicated operating procedures under the Severe Case assumptions and the extreme load level (which represents the second to highest load level, having approximately a 6% chance of occurring).
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Conclusions
As shown in Figure EX-1a and EX-1b, use of the indicated operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the NPCC Areas during the 2008 summer period under the Base Case and Severe Case, expected load assumptions, which are based on the probability-weighted average of the seven load levels assumed. The expected usage of these operating procedures is significantly less than one occurrence. Recently added resources and transmission capacity in the NPCC region, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to minimize the expected need for the use of these operating procedures in 2008.

As shown in Figure EX-2, only if the severe set of resource unavailability assumptions used in this analysis all occur coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures), would New England, New York, and to a lesser extent, Ontario experience conditions that could require use of their operating procedures designed to keep electricity supplies and demand in balance. For this unlikely simultaneous combination of extreme weather and severe conditions, reducing the 30-minute operating reserve is more likely to be required in Norwalk, southwestern Connecticut, New York City and Long Island, New York.
INTRODUCTION

This study assessed the short-term reliability of Northeast Power Coordinating Council, Inc. (NPCC) for the year 2008 by estimating the annual Loss of Load Expectation and use of Area operating procedures to mitigate resource shortages for the summer (June through August) and shoulder (May and September) months. The Working Group closely coordinated its efforts with the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2008", May 2008.

The development of this Working Group was in response to recommendation (5) from the "June 1999 Heat Wave – NPCC Final Report", August 1999 that states:

“The NPCC Task Force on Coordination of Planning (TFCP) should explore the use of a multi-area reliability study tool as a part of an annual resource adequacy review to gain insight into the effects of maintenance schedules and transmission constraints on regional reliability.”

The database developed for the NPCC CP-8 Working Group's "Multi-Area Probabilistic Reliability Assessment For Winter 2007/08", November 20, 2007, was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the year 2008 assessment period.

This report is organized in the following manner: after a brief Introduction, specific Model Assumptions are presented, followed by an Analysis of the results based on the scenarios simulated. The Working Group's Objective and Scope of Work is shown in Appendix A. Tables presenting the corresponding results for the Base Case and Severe Case simulations are listed in Appendix B. Appendix C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 2.87 was used in this assessment.

See: http://www.npcc.org/documents/reports/Seasonal.aspx
MODEL ASSUMPTIONS

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. Table 1 summarizes each Area's summer peak load assumptions for the year 2008. The values shown for Québec and the Maritimes Area show both their actual summer peak and the peak during the period of NPCC’s peak.

Table 1
Assumed NPCC 2008 Summer Peak Loads – MW

<table>
<thead>
<tr>
<th>Area</th>
<th>2002 Load Shape</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Month</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Québec</td>
<td></td>
<td>21,887</td>
<td>23,397</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20,728</td>
<td>22,158</td>
<td>August</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td></td>
<td>3,750</td>
<td>4,125</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3,482</td>
<td>3,830</td>
<td>July</td>
</tr>
<tr>
<td>New England</td>
<td></td>
<td>27,970</td>
<td>30,736</td>
<td>August</td>
</tr>
<tr>
<td>New York</td>
<td></td>
<td>33,727</td>
<td>36,199</td>
<td>August</td>
</tr>
<tr>
<td>Ontario</td>
<td></td>
<td>25,493</td>
<td>28,132</td>
<td>July</td>
</tr>
</tbody>
</table>

An explanation of each Area’s expected load forecast and methodology can be found in the companion NPCC CO-12 Working Group Report, “NPCC Reliability Assessment for Summer 2008”, May 2008.

NPCC Areas have different definitions for their extreme peak load forecasts. A brief summary of the basis of each NPCC Area's extreme peak load forecasts follows.

Québec
Québec doesn't forecast "extreme load" per se. Its reliability model includes a load forecast uncertainty which takes into account weather, economic, demographic and alternative heating fuels uncertainties.

---

4 Extreme peak value based on load forecast uncertainty for referenced peak month.
5 The Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the area administrated by the Northern Maine Independent System Administrator (NMISA).
6 The forecast of New England’s 90/10 peak load for the summer of 2008 by ISO-NE is 29,900 MW.
7 The New York peak load forecast was subsequently revised to 33,809 by the NYISO.
8 The Ontario peak load forecast used was unadjusted for expected conservation. The IESO estimates an expected value of 24,892 MW with conservation included.
SUMMER 2008 MULTI-AREA
PROBABILISTIC RELIABILITY ASSESSMENT

Maritimes Area
The Maritimes Area doesn’t forecast “extreme load”; however, load forecast uncertainty is modeled in its reliability analysis. The load forecast uncertainty factors are developed by comparing the historical forecast values of load to the actual loads experienced.

New England
The Regional Transmission Organization of New England (ISO-NE) forecasts an extreme peak value having a 10% chance of being exceeded. ISO-NE assumes a weather condition that is defined by a three day weighted temperature-humidity index (WTHI) to forecast its summer peak load. The reference case value of the WTHI (80.1) is the 50th percentile of the portion of a WTHI distribution that encompasses the range of WTHI values at which the seasonal peak would occur. The extreme case value of the WTHI (82.0) is the 90th percentile of that distribution.

Although it is difficult to characterize a "normal" dry bulb temperature and the dew point temperature (because the three day weighting of the WTHI can be any number of combinations of temperature and humidity), a reasonable approximation would be 90 degrees F with a dew point of 70.

New York
The New York Independent System Operator (NYISO) bases its extreme load forecast on “one in 15 year” weather extreme for high temperature. The NYISO characterizes extreme weather conditions in terms of the NYISO summer index, which incorporates dry bulb and dew point values (temperature and humidity), as well as a build-up effect (through lagged elements in the equation).

Ontario
Ontario’s Independent Electricity System Operator (IESO) uses a multivariate econometric model to forecast energy and peak demand on the IESO controlled grid. Demand is defined as loads plus losses and peak demand refers to the highest hourly value.

The IESO does not directly provide a forecast of "extreme load" for this assessment. The IESO determines a value for load forecast uncertainty representing one standard deviation in demand, derived from the impact of temperature, humidity, cloud cover and wind speed on peak demand. The IESO expected demand and IESO load forecast uncertainty values were provided as input to this assessment.
Load Shape

In previous analyses, the Working Group has used two load shape assumptions for the analysis; the 1995 load shape and the 2002 load shape. That selection was based on the review of the weather characteristics and corresponding loads for the years from 1988 through 2002. Based on comparison of the results from the previous analyses, and recent weather experience, the Working Group concluded that the 2002 load shape was representative of a reasonable expected coincidence of Area load for summer 2008.

Figure 1 (a) - 2008 Projected Monthly Expected Peak Loads for NPCC Areas - 2002 Load Shape

The growth rate in each month’s peak was used to escalate Area loads to match the Area's year 2008 demand and energy forecasts for both load shapes. The impacts of Demand-Side Management programs were included in each Area's load forecast. Figure 1(a) shows the diversity in the NPCC area load shapes used in this analysis for the 2002 load shape assumption.

Figure 1(b) show the forecast daily summer peaks (June through August) modeled for the summer-peaking NPCC Areas (New England, New York, and Ontario) assuming the 2002 load shape. New England and New York closely track each other, while Ontario shows a similar pattern but with a bit more variation. The Ontario demand forecast modeled did not include the expected effects of conservation, which amounts to approximately 600 MW.

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 the associated probabilities of occurrence.

While the per unit variations in Area and sub Area load can vary on a monthly basis, Table 2 shows the values assumed for August, corresponding to the assumed occurrence of the NPCC system peak load (assuming the 2002 load shape). Table 2 also shows the probability of occurrence assumed for each of the seven load levels modeled.
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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, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are shaded in Table 2.

Table 2
Per Unit Variation in Load Assumed for the Month of August 2008

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>1.0920 1.0690 1.0460 1.0000 0.9540 0.9310 0.9080</td>
</tr>
<tr>
<td>MT</td>
<td>1.1000 1.1000 1.0500 1.0000 0.9500 0.9000 0.9000</td>
</tr>
<tr>
<td>NE</td>
<td>1.2184 1.0989 1.0022 0.9279 0.9139 0.8546 0.8326</td>
</tr>
<tr>
<td>NY 10</td>
<td>1.1047 1.0733 1.0317 0.9857 0.9337 0.8867 0.8529</td>
</tr>
<tr>
<td>ON</td>
<td>1.1218 1.0812 1.0406 1.0000 0.9594 0.9188 0.8782</td>
</tr>
<tr>
<td>Prob.</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
</tbody>
</table>

Generation

Tables 3 (a) and 3 (b) summarize the summer 2008 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Also shown in Table 3 (a) is each Area's annual weighted average unit availability percentage, based on each Area’s capacity according to the following relationship:

Annual Weighted Average Availability (%) = (1-P.O.R.) x (1- F.O.R.)

Where:  
P.O.R. = Total Hours on Planned Outage/Total Number of Hours  
F.O.R. = Total Hours on Forced Outage/Total Number of Hours not on Planned Outage

10 New York assumes different multipliers for Zone I, New York City (Zone J) and Long Island (Zone K). Values shown represent the weighted average value based on coincident zonal peak load.
Table 3 (a)  
NPCC Capacity and Load Assumptions for indicated Summer 2008 peak period - MW
Base Case - Expected Load

<table>
<thead>
<tr>
<th></th>
<th>Q 11 (August)</th>
<th>MT (July)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON 12 (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>31,766</td>
<td>6,699</td>
<td>31,268 13</td>
<td>38,427</td>
<td>28,750</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>-681</td>
<td>-180</td>
<td>90</td>
<td>2,399</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load 14</td>
<td>20,728</td>
<td>3,482</td>
<td>27,970</td>
<td>33,727 7</td>
<td>25,493 8</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>50</td>
<td>87</td>
<td>12</td>
<td>21</td>
<td>13</td>
</tr>
<tr>
<td>Annual Weighted Average Unit Availability (%)</td>
<td>95.6</td>
<td>88.50</td>
<td>90.1</td>
<td>85.9</td>
<td>85.8</td>
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<tr>
<td>Scheduled Maintenance 15</td>
<td>0</td>
<td>1,734</td>
<td>0</td>
<td>150</td>
<td>63</td>
</tr>
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</table>

Table 3 (b)  
NPCC Capacity and Load Assumptions for indicated Summer 2008 peak period - MW
Severe Assumptions Scenario - Extreme Load

<table>
<thead>
<tr>
<th></th>
<th>Q 11 (August)</th>
<th>MT (July)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON 12 (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>31,121</td>
<td>6,202</td>
<td>31,132</td>
<td>38,427</td>
<td>27,944</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>-681</td>
<td>-180</td>
<td>420</td>
<td>2,069</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load 14</td>
<td>22,158</td>
<td>3,830</td>
<td>30,736 6</td>
<td>36,199</td>
<td>28,132</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>37</td>
<td>57</td>
<td>3</td>
<td>12</td>
<td>0</td>
</tr>
<tr>
<td>Scheduled Maintenance 15</td>
<td>0</td>
<td>1,734</td>
<td>0</td>
<td>1,179</td>
<td>799</td>
</tr>
</tbody>
</table>

11 Capacity shown for Québec adjusted for scheduled maintenance. Annual Weighted Average Unit Availability for Québec does not include scheduled maintenance.
12 Capacity shown for Ontario has been seasonally adjusted.
13 Includes 166 MW of Other Demand Resources (primarily consisting of the Energy Efficiency program), which was not reflected in the load forecast.
14 Based on the 2002 Load Shape assumption.
15 Maintenance shown is for the week of the monthly peak load.
Unit Availability
Details regarding the NPCC Area’s assumptions for generator unit availability are described in the respective Area’s most recent "NPCC Triennial Review of Resource Adequacy", updated for the 2008 summer period as described below.

Ontario
Ontario’s generating unit availability was modeled as described in the IESO “18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System” (dated March 12, 2008).

Ontario market participants provided the majority of generation data. F.O.R. and P.O.R. were based on forecast values for generating units, which reflect past experience and future expectations based on recent maintenance activities. However, for some of the generating units F.O.R. and P.O.R. values were based on North American Reliability Council (NERC) Generator Availability Data System (GADs) data for similar type units.

New England
This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon each unit’s historical five-year average of scheduled maintenance. Individual generating unit forced outage assumptions were based on the unit’s historical data and North American Reliability Council (NERC) average data for the same class of unit. A more detailed description of the modeling assumptions can be found at the ISO New England Web site.

New York

16 See: http://www.npcc.org/adequacy.cfm
18 See: http://www.nerc.com/~gads/
21 See: http://www.nysrc.org/pdf/Reports/Final%202008%20IRM%20Report%2012-14-07%20_2_.pdf
Transfer Limits
Figure 2 depicts the system that was represented in this Assessment, showing Area and assumed Base Case transfer limits for the year 2008. New York Area internal transmission representation was consistent with the assumptions used in the New York ISO February 28, 2008 Technical Study Report 20 - "Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2008 – 2009 Capability Year" and the “New York Control Area Installed Capacity Requirement for the Period May 2008 – April 2009” New York State Reliability Council, December 14, 2007 report. 21

Figure 2 - Assumed Transfer Limits

Transfer limits between and within some Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the sub-Area representation for Ontario 17, New York 21, and New England 22 are provided in the respective references. The acronyms and notes used in Figure 2 are defined as follows:
SUMMER 2008 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

New England internal transmission representation is consistent with the initial draft assumptions being developed through ISO-NE’s stakeholder process for their 2008 Regional System Plan. 22

Phase angle regulators (PARs) are installed on three of the four Michigan - Ontario interconnections. One PAR, on Keith to Waterman 230 kV circuit J5D has been in service and regulating since 1975. The other two available PARs, on circuits L51D and L4D, which had been bypassed pending completion of agreements between the IESO, the Midwest ISO, Hydro One and International Transmission Company, were placed in service on April 14, 2008 and are expected to start regulating before the summer. All parties have committed to completing the necessary operating agreements to meet this schedule. The operation of the phase angle regulators will assist in the management of system congestion and control of circulating flows. The fourth PAR, responsible for controlling the tie flow on 230 kV circuit B3N, remains unavailable and is undergoing replacement. This PAR will be located in Michigan at the Bunce Creek terminal of B3N.

Operating procedures to Mitigate Resource Shortages

Each NPCC 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.

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

Table 4 summarizes the load relief assumptions modeled for each NPCC Area. 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 4 was a reasonable approximation for this analysis.

Table 4
NPCC Operating Procedures to Mitigate Resource Shortages
2008 Summer Load Relief Assumptions - MW

<table>
<thead>
<tr>
<th>Actions</th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>154</td>
</tr>
<tr>
<td>Appeals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1%</td>
</tr>
<tr>
<td>LRP/SCR/EDRP</td>
<td>0</td>
<td>0</td>
<td>1,128</td>
<td>1,399</td>
<td>0</td>
</tr>
<tr>
<td>Manual Voltage Reduction</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.45%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>of load</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>500</td>
<td>162</td>
<td>1,185</td>
<td>600</td>
<td>473</td>
</tr>
<tr>
<td>3. Voltage Reduction or</td>
<td>250</td>
<td>548</td>
<td>2.18% of load</td>
<td>1.58% of load</td>
<td>1.5% of load</td>
</tr>
<tr>
<td>Interruptible Loads 25</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ELRP 26</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>750</td>
<td>324</td>
<td>1,000</td>
<td>*</td>
<td>945</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>222</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. EDRP</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>109</td>
</tr>
<tr>
<td>5% Voltage Reduction</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1.1%</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,200</td>
<td>0</td>
</tr>
</tbody>
</table>

* New York issues appeals prior to reducing 10-min Reserve.

23 Derated value shown accounts for assumed availability.
24 Effective value.
25 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.
26 Emergency Load Reduction Program.


Assistance Priority

Table 5 indicates the priority order followed when allocating reserves and assistance to Control Areas with a resource 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. It was assumed that PJM-RTO assists everyone with equal priority.

Table 5
Priority Order for Providing Emergency Assistance

<table>
<thead>
<tr>
<th>Area Providing Assistance</th>
<th>1&lt;sup&gt;ST&lt;/sup&gt;</th>
<th>2&lt;sup&gt;ND&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td>MT ON</td>
<td>NE NY</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td>Q ON</td>
<td>NE NY</td>
</tr>
<tr>
<td>New York</td>
<td>NE Q MT ON</td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>NY Q MT ON</td>
<td>ME NY</td>
</tr>
<tr>
<td>Ontario</td>
<td>Q MT NE NY</td>
<td>ME NY</td>
</tr>
<tr>
<td>Millbank Units</td>
<td>Q MT NE NY</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>NE NY</td>
<td></td>
</tr>
<tr>
<td>RFC-OTH</td>
<td>PJM</td>
<td></td>
</tr>
<tr>
<td>MRO-US</td>
<td>ON</td>
<td></td>
</tr>
</tbody>
</table>
Modeling of Neighboring Regions
For the scenarios studied, a detailed representation of the neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 6 and Figure 3.

Table 6
PJM-RTO, RFC-OTH, and MRO-US 2008 Assumptions

<table>
<thead>
<tr>
<th></th>
<th>PJM-RTO</th>
<th>RFC-OTH</th>
<th>MRO-US</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>141,984</td>
<td>106,446</td>
<td>32,893</td>
</tr>
<tr>
<td>Peak Month</td>
<td>July</td>
<td>July</td>
<td>July</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>165,720</td>
<td>131,179</td>
<td>37,143</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>17</td>
<td>23</td>
<td>13</td>
</tr>
<tr>
<td>Weighted Unit Availability (%)</td>
<td>88.2</td>
<td>87.7</td>
<td>88.2</td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>3,400</td>
<td>2,206</td>
<td>1,700</td>
</tr>
<tr>
<td>Voltage Reduction</td>
<td>2,201</td>
<td>0</td>
<td>1,100</td>
</tr>
<tr>
<td>No 30-min Reserves</td>
<td>2,100</td>
<td>1,470</td>
<td>1,200</td>
</tr>
<tr>
<td>Interruptible Load</td>
<td>1,673</td>
<td>2,700</td>
<td>950</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>1,300</td>
<td>736</td>
<td>500</td>
</tr>
<tr>
<td>Appeals</td>
<td>400</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (%)</td>
<td>93.66 +/- 5.50, 11.00, 16.50</td>
<td>91.83 +/- 7.02, 14.04, 21.07</td>
<td>92.75 +/- 6.23, 12.47, 18.70</td>
</tr>
</tbody>
</table>

The diversity between the NPCC monthly peak loads and those of PJM-RTO, RFC-Other, and MRO-US are shown in Figure 3.

27 Load and capacity assumptions for RFC-Other based on NERC’s Electricity and Supply Database (ES&D) available at: http://www.nerc.com/~esd/
ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations.

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2006 NERC Electricity Supply & Demand (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR. The MAIN and ECAR boundaries do not correctly define the new RFC boundaries, but this definition insures consistency within the use of the 2006 NERC ES&D data. The correct load and capacity for the non-PJM MAIN and ECAR region data are drawn out to model the reserves for this area.

Unit data was from the publicly available NERC data. From that data we represented each individual unit in the non-PJM RFC region, assigning each unit performance
characteristics based on NERC class averages. The NERC class average characteristics were obtained from the 2006 update of NERC pc-GAR application, using the latest five year period of 2001-2005 for the determination of the class average data.

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

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. This allowed a straight forward approach to develop the load and capacity data public sources such as the 2006 NERC ES&D data. From that data we represented each individual unit in the MRO-US area, assigning each unit performance characteristics based on NERC class averages. The NERC class average characteristics were obtained from the 2006 update of NERC pc-GAR application, using the latest five year period of 2001-2005 for determining of the class average data.

The MRO-US boundary definition was based on the NERC data which still included the MAIN region. Going forward, the NERC data boundaries will change due to the new RFC region and the corresponding boundary changes between RFC, MRO and SERC. For this model, the previous MRO, MAIN, ECAR and SERC boundaries applied with this expected to evolve for future studies as more current data becomes available.

PJM-RTO
Load Model
The load model used for the PJM-RTO corresponds to the PJM Planning division's technical methods to produce a load model of the 2007 forecast year. The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2008, for the forecast monthly loads. This study modeled load forecast uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal

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PJM zones or regions, the period years the model is based on, sampling size, and how many years ahead in the future the load forecast.

Expected Resources
The generation resources correspond to the publicly available EIA-411 data, submitted on or before April 1, 2007. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Active Load Management (ALM) is reflected in this model’s Emergency Operating Procedure level 1, corresponding to the publicly available data on the PJM web site. This modeling of Active Load Management corresponds to the PJM Operations Staff ability to call up to 10 ALM events, in a peak period.

Expected Transmission Projects
The transfer values shown in the study are reflective of peak load flow model 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, per the TEAC information available on the PJM web site.

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31 See: [http://www.pjm.com/committees/teac/teac.html](http://www.pjm.com/committees/teac/teac.html)
Summer 2007 Review
Table 7 compares NPCC Area’s actual 2007 summer peak demands against the forecast assumptions.

Table 7
NPCC 2007 Summer Peak Loads Actual versus Forecast – MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Actual Peak</th>
<th>Date</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>QUEBEC</td>
<td>23,367</td>
<td>May 17</td>
<td>22,231</td>
<td>23,454</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td>21,272</td>
<td>June 19</td>
<td>21,331</td>
<td>22,611</td>
<td></td>
</tr>
<tr>
<td></td>
<td>21,411</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maritimes</td>
<td>3,293</td>
<td>June 27</td>
<td>3,915</td>
<td>4,307</td>
<td>May</td>
</tr>
<tr>
<td>Area</td>
<td>3,423</td>
<td>August 3</td>
<td>3,624</td>
<td>3,986</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3,359</td>
<td>August 8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>26,055</td>
<td>June 27</td>
<td>27,360</td>
<td>30,082</td>
<td>August</td>
</tr>
<tr>
<td></td>
<td>25,914</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>26,145</td>
<td>August 3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>31,741</td>
<td>July 10</td>
<td>33,447</td>
<td>35,822</td>
<td>August</td>
</tr>
<tr>
<td></td>
<td>32,101</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>32,169</td>
<td>August 8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ontario</td>
<td>25,737</td>
<td>June 26</td>
<td>25,762</td>
<td>27,570</td>
<td>July</td>
</tr>
<tr>
<td></td>
<td>25,467</td>
<td>June 27</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25,584</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Ontario Summary

IESO Voltage Reduction
On June 12, 2007, the IESO implemented a voltage reduction of 5% across much of the province of Ontario.

The load forecast for the day was significantly exceeded, with a high temperature of four Celsius degrees above forecast, ultimately resulting in a peak demand 1,300 MW higher than projected. There was a combination of planned and forced outages, including three units at the Pickering plant that contributed to lower than expected resources. Cold
generation brought on-line to meet operating reserve and increased energy commitments was slower to load than expected.

Emergency Energy was purchased from the MISO to supplement operating reserve requirements. Voltage reductions had already been included as a component of Ontario’s operating reserve. The loss of the 500 kV circuit D501P at 12:42 PM rejected 750 MW in northeastern Ontario, requiring the implementation of the 5% voltage reduction province-wide (with the exception of the Niagara area) to achieve a load generation balance.

**IESO Appeals for Reduced Electricity Consumption in the GTA**
On June 26, 2007 the IESO asked consumers in the Greater Toronto Area (GTA) to reduce their use of electricity during peak demand times over the next two days.

High temperatures and high humidity levels resulted in increased demand for electricity through air conditioning use. There were also limitations on the generation and transmission system serving the GTA as a result of equipment outages.

As a precautionary measure, the IESO also asked customers to reduce demand to help relieve the strain on the system serving the GTA.

**IESO Appeals for Reduced Electricity Consumption**
On August 2, 2007, the IESO asked consumers to reduce their use of electricity as hot weather put a strain on Ontario's electricity system.

Consumers and businesses were asked to reduce their electricity consumption, where possible, from noon until 8:00 p.m.

**New York Summary**

**Brooklyn Voltage Reduction**
On Wednesday, August 9, 2007 Consolidated Edison Inc urged customers to conserve electricity and implemented a voltage reduction in northwest Brooklyn as heavy air conditioning demand due to excessive heat and humidity strained the power system.

None of Con Edison's customers lost power by Wednesday afternoon due to the 5 percent voltage reduction, which the company used to relieve pressure on the system caused by the loss of three feeder cables or power lines in the area.

**Major Emergency Declared by the NYISO**
On September 9, 2007 a shortage of total 10 Minute Reserve was caused when, during evening load pickup, a number of units were derated due to energy limitations resulting
in a reduction of 2,700 MW of capacity. In addition, unexpected weather conditions resulted in increased loads observed during the same period.

To correct this, the NYISO purchased 300 MW of emergency to maintain reserve requirements. A NERC EEA 1 (Energy Emergency Alert) was declared. Load Relief Was Not Required.

New England Summary

Implementation of ISO Operating Procedure #4 on Thursday, August 2, 2007
On Thursday, August 2, 2007 ISO New England implemented Operating Procedure #4 system-wide in New England due to higher than expected heat and humidity. Temperatures over the eastern portion of New England ran 6 degrees above forecast with dew points throughout New England averaging 4 degrees above forecast. The peak hour demand was 25,978 MW for hour ending 17:00, 1,178 MW above the forecast of 24,800 MW. ISO New England implemented M/LCC Procedure #2 at 14:30. At 15:30 New England went deficient in 30 minute operating reserves and implemented OP#4 Actions 1 and 6 system-wide. OP#4 Actions 1 and 6 were cancelled at 18:00. M/LCC#2 was cancelled at 20:30.

Implementation of ISO Operating Procedure #4 on Saturday, September 8, 2007
On Saturday, September 8, 2007 ISO New England implemented actions of Operating Procedure #4 system-wide in New England due to higher than expected heat and humidity. Temperatures throughout New England ran 6 degrees above forecast with dew points throughout the area averaging 2 degrees above forecast. The peak hour demand was 21,876 MW for hour ending 15:00, 1,526 MW above the forecast of 20,350 MW. ISO New England did not experience a 30 minute operating reserve deficiency until 16:00 when an additional 500 MW of external sales were delivered. ISO New England implemented M/LCC Procedure #2 at 12:00. At 16:12 ISO New England implemented OP#4 Actions 1 and 6 system-wide. M/LCC#2 and OP#4 Actions 1 and 6 were cancelled at 21:00.

For the May - September 2007 period, Figure EX-1 (2007) (from last year’s assessment) shows the expected use of the indicated operating procedures under Base Case, expected load assumptions. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

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Figure EX-1 (2007)
Range of the Expected Use of Indicated Operating Procedures for Summer 2007
Considering Base Case Assumptions (May – September)
(Expected Load Level)

Figure EX-2 (2007)
Summer 2007 – Expected Use of the Indicated Operating Procedures
Severe Case Assumptions, Extreme Load Level
(May – September)
For the May - September 2007 period, Figure EX-2 (2007) (from last year’s assessment) shows the expected use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (which represents the second to highest load level, having approximately a 6% chance of occurring).

When comparing actual occurrences with the estimates, it is important to recognize that Areas may invoke these actions in any order, depending on the situation faced at the time.

With this in mind, the Working Group believes that modeling and assumptions used in the analyses provided a reasonable estimate of the risk of calling on these procedures. Comparison with the results from the last year’s assessment shows that the actual occurrences were within the estimated range.

**PJM Summary**

**PJM ASKS CONSUMERS TO CONSERVE ELECTRICITY**
On August 8, 2007 the PJM Interconnection, requested the public in its eastern states to conserve electricity. The call for conservation of electricity was a precaution during the extremely hot, humid weather experienced.

**PJM MID-ATLANTIC VOLTAGE REDUCTION**
On August 8, 2007 the PJM Interconnection canceled the voltage reduction it ordered at 3:55 p.m. PJM had ordered utilities in the East to reduce voltage to meet the extremely high demand for electricity during the heat wave. PJM also canceled its request to consumers to reduce their use of electricity.

The voltage reduction applied to the Mid-Atlantic region. It affected the service territories of Atlantic City Electric; Baltimore Gas & Electric Co.; Delmarva Power; Jersey Central Power & Light Co. (JCP&L); Metropolitan Edison Co. (Met-Ed); PECO, an Exelon Company; Pepco; Pennsylvania Electric Co. (Penelec); PPL Electric Utilities; PSE&G; and UGI Utilities, Inc. The 5 percent voltage reduction ended at 5:11 p.m. (EDT) for most of the region and at 6:14 p.m. (EDT) for the Baltimore/Washington areas.

**DEMAND RESPONSE SETS NEW RECORD IN PJM INTERCONNECTION**
On August 10, 2007 consumers’ reductions in the use of electricity, (demand response), set a record this week in PJM Interconnection during a power supply emergency.

PJM reported that 1,945 megawatts (MW) of consumer use of electricity were voluntarily reduced on Wednesday, August 8, 2007 the day PJM ordered voltage reductions in its Mid-Atlantic Region. This represented the largest amount of demand response experienced by PJM in one day. By comparison, the 5 percent voltage reduction lowered use by about 1,000 MW.
Summer 2008 Results
The Working Group modified the Working Group’s 2007 MARS database for the conditions expected for the year 2008. Table 8 shows the estimated annual Loss of Load Expectation (LOLE) calculated from the 2002 load shape for the expected load forecast under Base Case assumptions.

Table 8
Estimated Average Annual LOLE (days/year) - Base Case Assumptions

<table>
<thead>
<tr>
<th></th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOLE</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
<td>0.003</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
</tr>
</tbody>
</table>

Table 10 (see Appendix B) show the estimated need for the indicated operating procedures (in days/period) for May through September 2008 for the Base Case assumptions for all NPCC Areas for the 2002 load shape assumptions, respectively. Figure 7a shows the range of the expected use of the indicated operating procedures under the Base Case assumptions for the expected load level. Figure 7b shows the range of the expected use of the indicated operating procedures under the Base Case assumptions for the extreme load level. The expected load level results were based on the probability-weighted average of the seven load levels simulated. The extreme load is the second to highest load level, having approximately a 6% chance of occurring.

Figure 7a
Expected Use of the Indicated Operating Procedures for Summer 2008
Base Case Assumptions (May – September)
(Expected Load Level)
**Base Case Assumptions**

The following summary of Base Case assumptions represents system conditions consistent with those assumed in the NPCC CO-12 Working Group's "Reliability Assessment for Summer 2008", May 2008. The Base Case assumptions are summarized below:

**System**
- As-Is System for the year 2008
- Transfers allowed between Areas
- Cross Sound Cable & Neptune Cable in-service
- 2002 Load Shape adjusted to Area’s year 2008 forecast
  (expected and extreme assumptions)

**PJM-RTO**
- As-Is System for the Summer 2008 period – based on appropriate
  PJM RPM base residual auctions, 2008 -2011 delivery years
- Based on the PJM 2007 Reserve Requirement Study 33
- 2002 Load Shapes adjusted to the 2008 forecast provided by PJM
- Load forecast uncertainty of 93.66% +/- 5.5%, 11%, and 16.5%
- Operating Reserve 3,400 MW
  (30-min. 2,765 MW; 10-min. 634 MW)
- ~2,500 MW of high ambient temperature generator derates

---

RFC ‘Other’ 34
- As-Is System for the Summer 2008 period – based on NERC ES&D database, updated by the respective ISOs
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 91.83% +/- 7%, 14%, and 21%
- Operating Reserve 2,206 MW
  (30-min. 1,470 MW; 10-min. 736 MW)

MRO-US
- As-Is System for the Summer 2008 period - based on NERC ES&D database, updated by the respective ISOs
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 92.75% +/- 6.2 %, 12.5 %, and 18.7%
- Operating Reserve 1,700 MW
  (30-min. 1,200 MW; 10-min. 500 MW)

Ontario
- Forecast consistent with the IESO’s 2008Q1 18-Month Outlook 17
- Michigan/Ontario phase shifters in-service
- B3N phase shifter out-of-service
- Ripley Wind Power Project in-service
- Portlands Energy Center in-service
- Expected conservation effects not modeled
- Price Sensitive Demand Response (effective) ranges from 411 MW to 541 MW during study period
- ~ 471 MW of installed Wind Generation
  (10% capacity on peak assumption)

New England
- All existing capacity modeled
- ~ 140 MW capacity addition
- ~ 1,600 MW Demand Response Program, including:
  Real-Time Demand Response
  Real-Time Profiled Response
- ~ 1,000 MW New Brunswick to New England Tie capability

New York
- All cables in service
- Assumptions consistent with the NYCA Installed Capacity Requirements for the Period May 2008 Through April 2009

34 “RFC Other” refers to previous (before RFC) NERC regional boundaries of ECAR and MAIN, excluding PJM’s territory.
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- ~2,755 MW of external Installed Capacity from Contracts
- ~1,205 MW of effective load reduction from SCR (July/August)
- ~193 MW of effective load reduction from EDRP (July/August)

Maritimes
- ~175 MW of installed wind generation (18% assumed on peak)

Quebec
- All existing capacity modeled
- all three units of the new Peribonka hydraulic station in-service
- over 1,500 MW of firm sales to New York, New England, and Ontario (Cornwall)

New York
The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the February 28, 2008 New York ISO report 35 - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2008 – 2009 Capability Year" and New York State will meet the capacity requirements described in the “New York Control Area Installed Capacity Requirements for the Period May 2008– April 2009” New York State Reliability Council, December 14, 2007 Technical Study Report. 36

The New York unit ratings were obtained from the “2007 Load & Capacity Data of the NYISO” (Gold Book 37). The following changes (nominal ratings shown) announced after the Gold Book was published were modeled in this study:

Existing Resources
All in-service New York generation resources were modeled.

Retirements:

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntley 65 &amp; 66</td>
<td>165</td>
<td>Zone A</td>
</tr>
<tr>
<td>Lovett 3, 4 &amp; 5</td>
<td>405</td>
<td>Zone G</td>
</tr>
<tr>
<td>Russell Station</td>
<td>236</td>
<td>Zone B</td>
</tr>
<tr>
<td>Ogdensburg</td>
<td>77</td>
<td>Zone E</td>
</tr>
</tbody>
</table>

New Units: (Units installed during 2007)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gilboa Sta #2 uprate</td>
<td>30</td>
<td>Zone F</td>
</tr>
</tbody>
</table>

Planned Units for 2008
These units had a signed interconnection agreement by August 1, 2007.

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(Nameplate - MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prattsburgh Wind Park</td>
<td>55</td>
<td>Zone B</td>
</tr>
</tbody>
</table>

Wind generators were modeled as hourly load modifiers. For example, the New York ISO has stated that the output of the unit varies between 0 and 198 MW based on wind data collected near the Flat Rock site during 2002. This 2002 hourly wind data corresponds to the 2002 hourly load shape also used in this assessment. Characteristics of this data indicate an overall 30% capacity factor, with a capacity factor of approximately 11% during the summer peak hours.

Special Case Resources and Emergency Demand Response Programs

<table>
<thead>
<tr>
<th>SCR</th>
<th>Registered (MW)</th>
<th>Modeled (MW)</th>
<th>EDRP</th>
<th>Registered (MW)</th>
<th>Modeled (MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>695</td>
<td>669</td>
<td></td>
<td>181</td>
<td>82</td>
<td>upstate New York</td>
</tr>
<tr>
<td></td>
<td>469</td>
<td>395</td>
<td></td>
<td>124</td>
<td>56</td>
<td>New York City</td>
</tr>
<tr>
<td></td>
<td>160</td>
<td>141</td>
<td></td>
<td>125</td>
<td>56</td>
<td>Long Island</td>
</tr>
<tr>
<td></td>
<td>1,323</td>
<td>1,205</td>
<td></td>
<td>430</td>
<td>194</td>
<td>Total</td>
</tr>
</tbody>
</table>

Special Case Resources (SCRs) are loads capable of being interrupted on demand, and distributed generators, rated 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual.

The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis, and be paid for their ability to restore operating reserves.

For this study, the New York ISO recommended that the SCR programs be modeled as a 1,323 MW operating procedure step, discounted to 1,205 MW in July and August (and further discounted in other months proportionally to the monthly peak load).

The EDRPs were modeled as a 194 MW operating procedure with a limit of five calls per month. Based on the operational experience of the NYISO with the EDRP programs, the amount modeled represents a discounted amount from the forecast registered amount of approximately 430 MW.

Since customer participation in these programs varies over time, it is recognized that the actual amount of SCR/EDRP resources available for this summer may be different than the amount assumed in this study. The New York ISO believes the value modeled in this study represents a reasonable approximation for this analysis.
New England
The New England generating unit’s ratings were consistent with those used for the 2008/2009 Installed Capacity Requirement calculation. A summary of these assumptions follows:

Existing Resources
All in-service New England generation resources were modeled.

Retirements
No retirements and/or deactivations were assumed for this study.

Units planned for operation in 2008
Capacity additions are based on those generating units with I.3.9 Application approval and under construction as of November 1, 2007. Capacity additions expected to be in-service by the 2008-2009 Capability Year (as indicated by their System Impact Study (SIS) Queue expected in-service date) were included within the resource capacity mix as shown in the following table.

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Summer MW</th>
<th>Unit Type</th>
<th>Fuel Type</th>
<th>State</th>
<th>SIS Queue Projected Commercial Operation Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>GMP Essex Diesel</td>
<td>8</td>
<td>IC</td>
<td>Oil</td>
<td>VT</td>
<td>10/31/2007</td>
</tr>
<tr>
<td>Covanta Haverhill</td>
<td>1.6</td>
<td>IC</td>
<td>Landfill Gas</td>
<td>MA</td>
<td>11/1/2007</td>
</tr>
<tr>
<td>Indeck Alexandria</td>
<td>16.6</td>
<td>ST</td>
<td>Biomass/Wood waste</td>
<td>MA</td>
<td>2/1/2008</td>
</tr>
<tr>
<td>Cos Cob Redevelopment</td>
<td>36</td>
<td>GT</td>
<td>Oil</td>
<td>CT</td>
<td>2/1/2008</td>
</tr>
<tr>
<td>L’Energia</td>
<td>74</td>
<td>CC</td>
<td>Natural Gas/Oil</td>
<td>MA</td>
<td>6/15/2008</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>136.2</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Demand Response Resources
The demand response resources provide real time peak load relief within 30-minutes or 2-hours of a request by ISO New England, during or in anticipation of expected operable capacity shortage conditions, to implement ISO-NE Operating Procedure No. 4, *Actions During a Capacity Deficiency* (OP4). The profiled resources, which provide relief in under 2-hours but do not have interval meters installed, are also included in this study. Demand Resources enrolled in these programs as of November 1, 2007 were used as the starting value to project enrollment of summer 2008 and winter 2008-2009 capacity.

Demand Response performance was measured by actual response during 2007 event response audits which occurred on August 14, 2007 and September 15, 2007. To calculate the percent historical performance, the actual load curtailed or generation provided during such events was divided by the MW of resources enrolled within the program.
The Demand Response resources and their performance ratings are shown in the following table.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Summer MW</th>
<th>Winter MW</th>
<th>Performance (%)</th>
<th>Summer MW</th>
<th>Winter MW</th>
<th>Performance (%)</th>
<th>Profiled Summer MW</th>
<th>Winter MW</th>
<th>Performance (%)</th>
<th>Total Summer MW</th>
<th>Winter MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>397.9</td>
<td>436.2</td>
<td>49</td>
<td>1.0</td>
<td>0.9</td>
<td>0.2</td>
<td>0.2</td>
<td>0.0</td>
<td>0.0</td>
<td>398.9</td>
<td>437.2</td>
</tr>
<tr>
<td>ME</td>
<td>360.7</td>
<td>395.4</td>
<td>100</td>
<td>86.4</td>
<td>88.1</td>
<td>100</td>
<td>12.7</td>
<td>13.9</td>
<td>0</td>
<td>453.8</td>
<td>497.4</td>
</tr>
<tr>
<td>NEMA</td>
<td>119.4</td>
<td>130.9</td>
<td>57</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>119.4</td>
<td>130.9</td>
</tr>
<tr>
<td>NH</td>
<td>30.3</td>
<td>32.2</td>
<td>63</td>
<td>2.9</td>
<td>2.2</td>
<td>67</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>32.3</td>
<td>34.4</td>
</tr>
<tr>
<td>RI</td>
<td>52.7</td>
<td>68.7</td>
<td>68</td>
<td>5.7</td>
<td>6.3</td>
<td>44</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>68.4</td>
<td>73.0</td>
</tr>
<tr>
<td>SEMA</td>
<td>53.7</td>
<td>58.8</td>
<td>47</td>
<td>4.2</td>
<td>4.6</td>
<td>56</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>57.9</td>
<td>63.4</td>
</tr>
<tr>
<td>VT</td>
<td>22.5</td>
<td>24.7</td>
<td>74</td>
<td>1.5</td>
<td>1.6</td>
<td>0</td>
<td>0.8</td>
<td>7.5</td>
<td>100</td>
<td>30.8</td>
<td>33.8</td>
</tr>
<tr>
<td>WCMCA</td>
<td>86.5</td>
<td>94.8</td>
<td>75</td>
<td>22.1</td>
<td>24.3</td>
<td>63</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>108.6</td>
<td>119.1</td>
</tr>
</tbody>
</table>

Total 1516.4 1662.3 117.0 128.3 19.5 21.4 1653.0 1811.9

* SWCT Resources are also included in the CT values.

**Ontario**

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the IESO “18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System” (dated March 9, 2007, available from the IESO web site).

**Existing Resources**

All in-service Ontario generation resources were modeled.

**2007 Resource Additions**

Since the last summer assessment, the net installed capacity connected to the IESO grid has increased by 83 MW. The increase is made up by the Ripley Wind Power Project (76 MW) and an upgrade (7 MW) to an existing nuclear unit.

**2008 Resource Additions**

The following resources were assumed to become available for the summer of 2008:

<table>
<thead>
<tr>
<th>Proponent/Project Name</th>
<th>Zone</th>
<th>Fuel Type</th>
<th>Capacity MW</th>
<th>Estimated Effective Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Durham College District Energy Project</td>
<td>Toronto</td>
<td>Gas</td>
<td>2.3</td>
<td>2008-Q1</td>
</tr>
<tr>
<td>Great Northern Tri-Gen Facility</td>
<td>West</td>
<td>Gas</td>
<td>11.5</td>
<td>2008-Q2</td>
</tr>
<tr>
<td>Countryside London Cogeneration Facility</td>
<td>West</td>
<td>Gas</td>
<td>12</td>
<td>2008-Q2</td>
</tr>
<tr>
<td>Portlands Energy Centre Phase I</td>
<td>Toronto</td>
<td>Gas</td>
<td>250</td>
<td>2008-Q2</td>
</tr>
<tr>
<td>Warden Energy Centre</td>
<td>Toronto</td>
<td>Gas</td>
<td>5</td>
<td>2008-Q2</td>
</tr>
<tr>
<td>Umbata Falls Hydroelectric Project</td>
<td>Northwest</td>
<td>Water</td>
<td>23</td>
<td>2008-Q2</td>
</tr>
</tbody>
</table>

For the purposes of this assessment, the IESO assumed that wind generation has a dependable contribution of 10% of the installed generation capacity.

For Curtail Load/Utility Surplus, the study assumed 154 MW is available from Utility Surplus (a/k/a “Stretch” Capability). The Emergency Demand Response Program is assumed to be available to contribute 109 MW during the study period.

Price Sensitive Demand Response is assumed to range from 411 MW to 541 MW during the summer 2008 study period (May to September) in the Base Case.

The Emergency Load Response Program (ELRP) is estimated to result in about 179 MW of load to be available to respond if/when required.

**Retirements**
None.
SUMMER 2008 MULTI-AREA
PROBABILISTIC RELIABILITY ASSESSMENT

Severe Case Scenario
Table 9 shows the estimated annual average Loss of Load Expectation (LOLE) calculated from the 2002 load shape for the expected load forecast under Severe Case assumptions.

Table 9
Estimated Average Annual LOLE (days/year)
Severe Assumptions Scenario

<table>
<thead>
<tr>
<th></th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOLE</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
<td>0.0085</td>
<td>0.0015</td>
<td>.0003</td>
</tr>
</tbody>
</table>

Table 11 (see Appendix B) show the estimated need for the indicated operating procedures (in days/period) during May through September 2008 for the Severe Case Scenario for all NPCC Areas for the 2002 load shape assumptions.

Figure 8 shows the expected use of the indicated operating procedures occurrences under the Severe Case assumptions for the expected load. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

Figure 9 shows the corresponding results for the extreme load (represents the second to highest load level, having approximately a 6% chance of occurring). New England, New York, and to a lesser extent, the Ontario are expected to need to use these procedures in response to a capacity deficiency for this Scenario. Tables 12(a) and (b) show the corresponding results for the New York City and southwestern Connecticut localities, respectively (for the 2002 load shape assumption).
SUMMER 2008 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

Figure 9
Summer 2008 – Expected Use of the Indicated Operating Procedures
Severe Case Assumptions, Extreme Load Level
(May – September)

The Severe Case Scenario assumptions are summarized below:

**System**
- As-Is System for the year 2008
- Transfers allowed between Areas
- Transfer capability between NPCC and MRO/RFC- ‘Other’ reduced by 50%
- 2002 Load Shape adjusted to Area’s year 2008 forecast (expected and extreme assumptions)

**PJM-RTO**
- Based on the following PJM 2007 Reserve Requirement Study – Appendix B (Sensitivity Cases) assumptions:
  - Load forecast uncertainty increased by one percent
  - Forced Outage rates increased for all units by 1.5 percent
  - ~2,000 MW on maintenance extended through the summer period
  - ~5,000 MW of additional high ambient temperature generator derates

---

39 “RFC Other” refers to previous (before RFC) NERC regional boundaries of ECAR and MAIN, excluding PJM’s territory.
Ontario
- ~750 MW of maintenance extended into the summer period
- ~298 MW of Price Sensitive Demand Response
  (~243 MW lower than the highest Base Case value)
- Hydro resource energy 10% lower than Base Case
  (10% reduction in capacity)

New England
- ~140 MW capacity addition assumed delayed
- 1385 Line (Northport to Norwalk Harbor cable) in-service date delayed beyond the summer period
- 50% reduction in Demand Response Program assumed
- Maintenance overrun by 4 weeks

New York
- Extended maintenance of 1,000 MW in the lower Hudson Valley throughout summer
- 1385 Line (Northport to Norwalk Harbor cable) in-service date delayed beyond the summer period
- 50% reduction in effectiveness of SCR and EDRP programs

Maritimes
- No generation from wind assumed
- ~459 MW of natural gas-fired generation assumed unavailable due to fuel disruptions (July/August)

Quebec
- Gentilly-2 nuclear station (648 MW) unavailable for the summer
SUMMER 2008 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

Conclusions

Use of the indicated operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the NPCC Areas during the 2008 summer period under the Base Case and Severe Case, expected load assumptions. The expected load level is the probability-weighted average of the seven load levels assumed. The expected usage of these operating procedures is significantly less than one occurrence. Recently added resources and transmission capacity in the NPCC region, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to minimize the expected need for the use of these operating procedures in 2008.

Only if the severe set of resource unavailability assumptions used in this analysis all occur coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures), would New England, New York, and to a lesser extent, Ontario experience conditions that could require use of their operating procedures designed to keep electricity supplies and demand in balance. For this unlikely simultaneous combination of extreme weather and severe conditions, reducing the 30-minute operating reserve is more likely to be required in Norwalk, southwestern Connecticut, New York City and Long Island, New York.
Objective and Scope of Work

1. **Objective**
   Using the G.E. Multi-Area Reliability Simulation (MARS) program, review NPCC Area reliability resulting from the anticipated resource and transmission capacity reported for the year 2008 under Base Case and Severe Case assumptions, and summarize the range of results for the summer and shoulder season months (the period from May to September).

2. **Scope**
   In meeting this objective, the CP-8 Working Group will review the short-term resource adequacy of NPCC and neighboring Areas for the year 2007, recognizing uncertainty in forecasted demand, scheduled outages of transmission, forced and scheduled outages of generation facilities, and the impact of proposed load response programs. Reliability will be measured by calculating the Loss of Load Expectation (LOLE) and estimated use of Area emergency operating procedures. A report summarizing the results of the assessment will be published no later than May 1, 2008. The assessment will:

   1. Review last summer’s CP-8 Working Group Summer assessments with respect to actual Area experience;
   2. Consider the impacts of Sub-Area transmission constraints;
   3. Incorporate, to the extent possible, a detailed GE MARS reliability representation for the regions bordering NPCC;
   4. Coordinate assessment assumptions with the NPCC Task Force on Coordination of Operations; and,
   5. Examine any impact of evolving market rules on overall NPCC interconnection assistance and other assumptions.
## APPENDIX B

### Table 10 - Base Case Assumptions

**Expected Need for Indicated Operating Procedures (days/period)**

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Quebec</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min VR</td>
<td>10-min Appeal</td>
<td>30-min VR</td>
<td>10-min Appeal</td>
<td>Discon</td>
</tr>
<tr>
<td><strong>2002 Load Shape-Expected Load</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
</tr>
<tr>
<td>Jun</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jul</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.001</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.004</td>
</tr>
<tr>
<td><strong>2002 Load Shape-Extreme Load</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.025</td>
</tr>
<tr>
<td>Jun</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.005</td>
</tr>
<tr>
<td>Jul</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.001</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.008</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.042</td>
</tr>
</tbody>
</table>

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction; "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load
### Table 11 - Severe Case Scenario

- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Hydro-Quebec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002 Load Shape-Expected Load</td>
<td>30-min VR 10-min Appeal</td>
<td>30-min VR 10-min Appeal</td>
<td>30-min VR 10-min Appeal</td>
<td>Discon 30-min VR 10-min Appeal</td>
<td>Discon 30-min VR 10-min Appeal</td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.004</td>
<td>0.002</td>
</tr>
<tr>
<td>Jun</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jul</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
<td>-</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.007</td>
<td>0.002</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.001</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.015</td>
<td>0.004</td>
</tr>
<tr>
<td>2002 Load Shape-Extreme Load</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.038</td>
<td>0.012</td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.007</td>
<td>0.001</td>
</tr>
<tr>
<td>Jun</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.024</td>
<td>0.007</td>
</tr>
<tr>
<td>Jul</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.075</td>
<td>0.021</td>
</tr>
<tr>
<td>Aug</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.009</td>
<td>0.002</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.153</td>
<td>0.043</td>
</tr>
</tbody>
</table>

Notes:
- "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;
- "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load
### APPENDIX B

**Table 12 (a) - Severe Case Scenario – New York City Locality**
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Area - J (NYC)</th>
<th></th>
<th>Area K (LI)</th>
<th></th>
<th>New York</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min VR Appeal 10-min Discon</td>
<td>30-min VR Appeal 10-min Discon</td>
<td>30-min VR Appeal 10-min Discon</td>
<td>30-min VR Appeal 10-min Discon</td>
<td>30-min VR Appeal 10-min Discon</td>
<td></td>
</tr>
<tr>
<td><strong>2002 Load Shape – Expected Load</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jun</td>
<td>- .1195</td>
<td>- 0.0095</td>
<td>- 0.0005</td>
<td>- 0.127</td>
<td>- 0.017</td>
<td>- 0.016</td>
</tr>
<tr>
<td>Jul</td>
<td>0.070</td>
<td>0.023</td>
<td>0.008</td>
<td>0.005</td>
<td>0.0765</td>
<td>0.002</td>
</tr>
<tr>
<td>Aug</td>
<td>.229</td>
<td>0.015</td>
<td>0.219</td>
<td>0.002</td>
<td>0.2565</td>
<td>0.001</td>
</tr>
<tr>
<td><strong>2002 Load Shape – Extreme Load</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jun</td>
<td>- 1.478</td>
<td>- 0.955</td>
<td>- 0.052</td>
<td>- 1.550</td>
<td>- 0.054</td>
<td>- 0.051</td>
</tr>
<tr>
<td>Jul</td>
<td>0.832</td>
<td>0.1405</td>
<td>0.009</td>
<td>0.005</td>
<td>0.915</td>
<td>0.002</td>
</tr>
<tr>
<td>Aug</td>
<td>- 0.395</td>
<td>0.015</td>
<td>0.006</td>
<td>0.002</td>
<td>- 0.866</td>
<td>0.001</td>
</tr>
<tr>
<td>May-Sept</td>
<td>2.310</td>
<td>0.729</td>
<td>0.0695</td>
<td>0.0575</td>
<td>2.5195</td>
<td>0.015</td>
</tr>
</tbody>
</table>

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" – and initiate Voltage Reduction; "10-min" – and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" – and disconnect customer load
# APPENDIX B

## Table 12(b) - Severe Case Scenario – Norwalk & Southwestern Connecticut
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe</th>
<th>Case Results</th>
<th>SW CT</th>
<th>Norwalk</th>
<th>New England</th>
</tr>
</thead>
<tbody>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Jun</td>
<td>0.021</td>
<td>0.001</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jul</td>
<td>0.139</td>
<td>0.021</td>
<td>0.095</td>
<td>0.006</td>
</tr>
<tr>
<td>Aug</td>
<td>0.149</td>
<td>0.024</td>
<td>0.015</td>
<td>0.009</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>0.309</td>
<td>0.046</td>
<td>0.245</td>
<td>0.014</td>
</tr>
</tbody>
</table>

### 2002 Load Shape – Expected Load

<table>
<thead>
<tr>
<th>Severe</th>
<th>Case Results</th>
<th>SW CT</th>
<th>Norwalk</th>
<th>New England</th>
</tr>
</thead>
<tbody>
<tr>
<td>May</td>
<td>0.001</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jun</td>
<td>0.008</td>
<td>-</td>
<td>.0985</td>
<td>.0035</td>
</tr>
<tr>
<td>Jul</td>
<td>1.4135</td>
<td>.10125</td>
<td>0.004</td>
<td>0.004</td>
</tr>
<tr>
<td>Aug</td>
<td>1.538</td>
<td>0.048</td>
<td>0.011</td>
<td>0.005</td>
</tr>
<tr>
<td>Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>5.0325</td>
<td>.0605</td>
<td>0.015</td>
<td>0.009</td>
</tr>
</tbody>
</table>

Notes: 
"30-min" - reduce 30-minute Reserve Requirement; "VR" – and initiate Voltage Reduction; 
"10-min" – and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" – and disconnect customer load
APPENDIX C

Multi-Area Reliability Simulation Program Description

General Electric’s Multi-Area Reliability Simulation (MARS) program \(^{41}\) allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

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

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

Reliability Indices

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

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

The Working Group used both the daily LOLE and Operating Procedure indices for this analysis. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

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

Resource Allocation Among Areas

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

\(^{41}\) See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm
APPENDIX C

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation
MARS has the capability to model the following different types of resources:
  - Thermal
  - Energy-limited
  - Cogeneration
  - Energy-storage
  - Demand-side management

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

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

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

Thermal Units
In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.
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Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

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

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

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

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

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

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

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

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

Contracts
Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

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