Multi-Area Probabilistic Reliability Assessment

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Abstract

This paper presents the results of a probabilistic assessment of Northeast Power Coordinating Council (NPCC) Area reliability for the year 2000 [1]. The annual Loss of Load Expectation (LOLE) and projected use of Area emergency operating procedures for the period June through August 2000 was estimated. The General Electric Muti-Area Reliability Simulation (MARS) program was used for the analysis. Base Case conditions corresponded to the assumptions presented in NPCC's comprehensive summer 2000 outlook [2]. Five additional scenarios, with two load shape assumptions were simulated for expected and extreme load forecasts.

1. Background

Northeast Power Coordinating Council's (NPCC) Reliability Coordinating Committee directed its Task Force on Coordination of Planning (TFCP) to explore 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 [3]. The CP-8 Working Group (Working Group) was charged with this task.

The General Electric (GE) Multi-Area Reliability Simulation (MARS) program was used for the assessment. GE was contracted to run the MARS simulations under the direction of the Working Group.

The TFCP also directed the Working Group to perform a benchmark analysis for 1999 using the MARS program. The MARS database developed by the previous NPCC CP-5 Working Group [4] was used as a starting point for the analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the year 2000 assessment period, as well as the actual load and maintenance conditions that occurred in 1999. Internal Area transmission constraints were represented in the New York and in the Maritime Area for the analysis.

2. 1999 Benchmark

The MARS program was used to model 1999 system conditions. The following conditions were modeled:

- As-Is System for the year 2000 Rolled Back to 1999 conditions
- Actual 1999 Loads with No Load Forecast Uncertainty modeled
- Transfers Allowed Between Areas
- ECAR - 1,550 MW of fully available capacity
- Actual Unit Planned Outages for Week of June 7 for NE and NY
- Program Maintenance for All Other Units

The results are summarized in Table 1 for New England and Table 2 for New York. Given the assumptions used and the information available for the comparison, the Working Group concluded that the MARS program closely estimated the number of times Emergency Operating Procedures were called during the week of June 7th for New England and New York[1].

Table 1.
1999 Results for New England
Expected Need for EOPs (days/week)

Week of	**31-May**	**7-Jun**	**14-Jun**
Actual Load (MW)	18,954	20,922	18,608
Planned Outages (MW)	5,212	5,519	1,545
Generation to Maximum	1.296	2.038	0.004
Curtail Interruptible Load	0.808	2.016	0.004
Reduce 30-min Reserves	0.444	2.004	0.001
Voltage Reduction	0.123	2.001	0.001
Reduce 10-min Reserves	0.059	1.928	0.001
General Public Appeals /Disconnect Load	0.001	0.419	-

[1] A detailed description of the events occurring during June 1999 can be found in Reference [3].

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Table 2.
1999 Results for New York
Expected Need for EOPs (days/week)

Week of	**31-May**	**7-Jun**	**14-Jun**
Actual Load (MW)	25,345	28,380	23,516
Planned Outages (MW)	5,142	3,801	2,891
Generation to Maximum	0.007	1.109	0.001
Curtail Interruptible Load	0.004	0.722	-
Reduce 30-min Reserves	0.002	0.441	-
Voltage Reduction	0.001	0.146	-
Reduce 10-min Reserves	0.001	0.046	-
General Public Appeals /Disconnect Load	-	0.001	-

These results provided confidence that the overall MARS model structure and generator Forced Outage Rate assumptions were adequate to apply the MARS program in a meaningful investigation of the impacts of the conditions that may be experienced for the summer of 2000.

3. Summer 2000 Analysis

3.1 Load Representation

The loads in the MARS program[2] were modeled on an hourly, chronological basis for each Area. The program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies. Table 3 below summarizes each Area's load assumptions for the year 2000.

Table 3.
Assumed NPCC Peak Loads - MW

Area	Expected Peak	Extreme Peak	Month of Peak
Hydro-Quebec (HQ)	31,691	34,610	February
Maritime Area[3] (MT)	5,141	5,655	January
New England (NE)	23,250	24,222	July
New York (NY)	30,200	31,499	July
Ontario (ON)	22,834	24,426	July

[2] A summary description of the GE MARS program capabilities can be found in Reference [1].

[3] Maritime Area represents New Brunswick, Nova Scotia, and Prince Edward Island.

3.2 Load Shape

Since the load shape is a function of weather conditions, the Working Group agreed to use two load shapes in this analysis; one based on the 1995 hourly loads (as used in the previous NPCC CP-5 Working Group analysis), and another based on the 1999 hourly loads.

After reviewing the weather characteristics of the years from 1988 through 1997, the NPCC CP-5 Working Group selected 1995 as representative of a typical year for their analysis [4].

Working Group members were asked to identify any load reductions resulting from Emergency Operating Procedures in the 1999 load shape, if known. Information was only available for New England, and was included in New England's reconstituted 1999 hourly load shape.

The growth rate in each month's peak was used to escalate their Area's loads to match the Area's year 2000 demand and energy forecasts for both load shapes. The impacts of Demand-Side Management programs were included in each Area's load forecast for both load shapes.

3.3 Load Forecast Uncertainty

Uncertainty on the annual peak load forecast was also 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 and calculates weighted-average values based on input probabilities of occurrence.

For this study, seven load levels were modeled. While the per unit variations in the load can vary on a monthly basis, Table 4 shows the values used for July, which historically has generally been the peak month for New England, New York, and Ontario. Table 4 also shows the probability of occurrence for each load level.

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 were reported for two load conditions: expected and extreme. The values for the expected load conditions were 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 4.

Table 4.
Per Unit Variation in Load for the Month of July

Area				
HQ	1.0679	1.0679	1.0340	1.0000
MT	1.1000	1.1000	1.0500	1.0000
NE	1.1028	1.0418	1.0018	1.0000
NY	1.0430	1.0430	1.0220	1.0000
ON	1.1046	1.0697	1.0349	1.0000
Prob.	0.0062	0.0606	0.2417	0.3830

Area			
HQ	0.9660	0.9321	0.9321
MT	0.9500	0.9000	0.9000
NE	0.9982	0.9582	0.8972
NY	0.9480	0.9240	0.9240
ON	0.9651	0.9303	0.8954
Prob.	0.2417	0.0606	0.0062

3.4 Generation

Table 5 summarizes the Installed Capacity assumptions for the NPCC Areas used in the analysis. Base Case conditions were chosen to reflect the assumptions used in the companion NPCC comprehensive summer 2000 outlook [2].

Table 5.
NPCC Installed Capacity and Load Assumptions for Summer 2000 - MW

	HQ	MT	NE [4]	NY	ON [5]
Installed Capacity	36,320	6,031	24,865	35,797	26,383
Purchase/Sale	0	0	21	-161	-54
Peak Load	18,983	3,263	23,250	30,200	22,834
Margin (%)	91	85	7	18	15

[4] Does not include the capacity equivalent of the Hydro-Quebec Phase II Firm Energy Contract (1,500 MW).

[5] Does not include the Hydro-Quebec Banking Agreement (800 MW).

3.5 Transfer Limits

Base Case transfer limits were chosen to reflect the assumptions used in the companion NPCC comprehensive summer 2000 outlook [2]. Internal Area transmission constraints were represented in the New York and Maritime Areas for this analysis. Tie transfer limits between Areas were modeled with seasonal ratings (summer, winter) where appropriate.

3.6 Emergency Operating Procedures

Emergency operating procedures are steps undertaken by an Area as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements that can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for an Area to begin emergency operating procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) 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 6 summarizes the Emergency Operating Procedure load relief assumptions modeled for each NPCC Area.

Table 6.
NPCC Emergency Operating Procedures Load Relief Assumptions - MW

EOP Actions	HQ	MT	NE	NY	ON
Gen to Max	0	0	0	800	0
Curtail Load	0	0	320	400	260
Reduce 30-min Reserves	0	229	575	600	441
Voltage Red	300	0		523	580
% of Load			0.0214		
Reduce 10-min Reserves	1,250	646	1,300	1,200	881
Cdn Int Loads	1,200	611	0	0	190
General Appeals	0	0	0	153	200

Areas may invoke EOP actions in any order, depending on the situation faced at the time; however, the Working Group agreed that modeling the EOPs as in the order indicated in Table 6 was a reasonable approximation for this analysis.

3.7 Emergency Assistance Priority

Table 7 indicates the priority order followed when allocating reserves and emergency assistance to Areas with a deficiency. In this analysis, each EOP step was initiated simultaneously in all Areas and sub-Areas.

Table 7.
EOP Priority Order Modeled

Area Providing Assistance	Priority of Assistance			
	First	Second	Third	Fourth
HQ	MT	ON	NE	NY
MT	HQ	ON	NE	NY
NE	NY	MT	HQ	ON
NY	NE	HQ	ON	MT
ON	HQ	MT	NY	NE

4. Results

The Working Group modified the previous CP-5 Working Group MARS database for the conditions expected for the year 2000.

4.1 Base Case Assumptions

Table 8 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast under Base Case assumptions. The Base Case assumptions are summarized below:

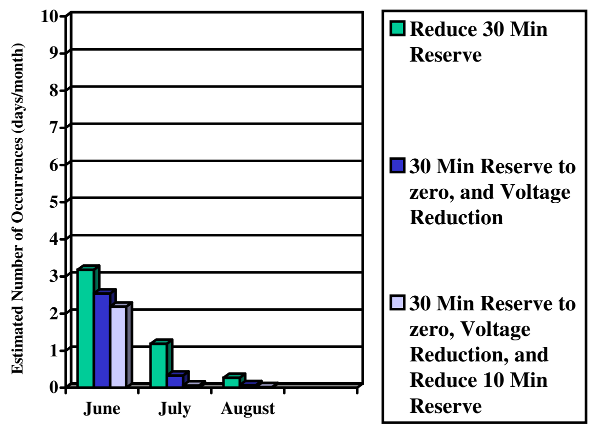
- As-Is System for the year 2000
- Transfers Allowed Between Areas
- ECAR - 1,550 MW of fully available capacity
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions
- 1999 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions

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

Base Case	HQ	MT	NE	NY	ON
LOLE	<.0005	<.0005	.043	.1095	.002

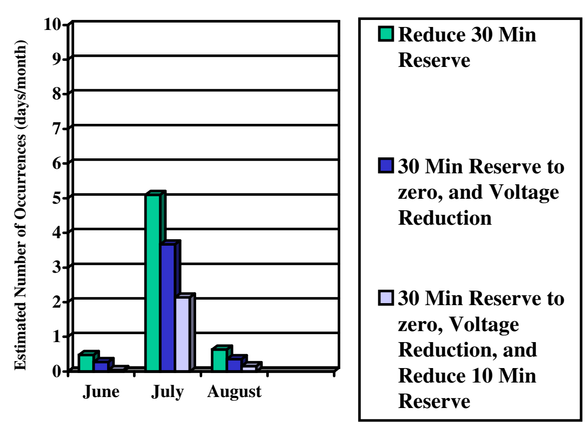
Figure 1 shows the estimated range of emergency operating procedures (EOP) occurrences for New England for the Base Case assumptions. Figure 2 shows the estimated range of EOP occurrences for New York for the Base Case assumptions. The simulations indicate only the New England, New York and Ontario Areas are expected to need to use their Emergency Operating Procedures in response to a capacity deficiency for Base Case assumptions.

Figure 1.
New England
Summer 2000 -Range of Estimated Use of Emergency Operating Procedures
Base Case Assumptions



For example, Figure 1 shows that the potential for New England to reduce its 30 minute reserve requirement in response to a capacity deficiency ranges (in June 2000) from 0.101 (1995 Load shape - expected load forecast assumptions) to 3.185 (1999 Load Shape - under the extreme load assumptions).

Figure 2.
New York
Summer 2000 - Range of Estimated Use of Emergency Operating Procedures
Base Case Assumptions



5. Sensitivity Analysis

A scenario approach was taken in order to gain insight into the impact that the identified assumptions have on the reliability of the system. The following sections describe the scenarios modeled and the results of the MARS simulations.

5.1 NPCC Isolated Scenario

Table 9 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. The NPCC Isolated Scenario assumptions are summarized below:

- As-Is System for the year 2000
- No Transfers through PJM to New York
- No Imports from ECAR
- 1995 Load Shape adjusted to year 2000 load forecast, expected and extreme assumptions
- 1999 Load Shape adjusted to year 2000 load forecast, expected and extreme assumptions

5.2 Reduced Capacity Scenario

Table 9 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. The NPCC Reduced Capacity Scenario assumptions are summarized below:

- As-Is System for the year 2000 Reduced as Follows
- Four NE Summer Unit Additions Delayed 3 Months (849 MW)
- Transfers Allowed Between Areas
- ECAR Imports Limited to 700 MW
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions
- 1999 Revised Load Shape Adjusted to year 2000 forecast, expected and extreme assumptions

5.3 Maintenance Overrun Scenario

Table 9 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. The Maintenance Overrun Scenario assumptions are summarized below:

- As-Is System for the year 2000
- Transfers Allowed Between Areas
- ECAR - 1,550 MW of fully available capacity
- Additional Summer Maintenance (NE - 560 MW, NY - 400 MW)
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions
- 1999 Revised Load Shape Adjusted to year 2000 forecast, expected and extreme assumptions

5.4 "Worst Case" Scenario

Table 9 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. This is a sensitivity case that assumes all of the previous scenario assumptions would occur at the same time. The "Worst Case" Scenario assumptions are summarized below:

- As-Is System for the year 2000 Reduced as Follows
- Four NE Summer Additions Delayed 3 Months (849 MW)
- No Transfers from PJM to New York
- 0 MW Imports from ECAR
- Additional Summer Maintenance (NE - 560 MW, NY - 400 MW)
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions
- 1999 Revised Load Shape adjusted to year 2000 forecast, expected and extreme assumptions

5.5 ECAR/MAAC Represented -Base Case Assumptions

Table 10 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. The scenario assumptions are summarized below:

- As-Is System for the year 2000
- Transfers Allowed Between Areas
- MAAC and ECAR Modeled w/ Load Forecast Uncertainty
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions

5.6 ECAR/MAAC Represented - "Worst Case" Assumptions

Table 11 shows the estimated average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations for the expected load forecast for this scenario. The scenario assumptions are summarized as follows:

- As-Is System for the year 2000 Reduced as Follows
- Four NE Summer Additions Delayed 3 Months (849 MW)
- MAAC and ECAR Modeled w/ Load Uncertainty
- No Transfers through PJM to New York
- ECAR to ON Transfer Limits Set to 0 MW
- ECAR to MAAC Transfer Limits Reduced to 50% (1,075/1,275 MW)
- Additional Summer Maintenance (NE - 560 MW, NY - 400 MW)
- 1995 Load Shape adjusted to year 2000 forecast, expected and extreme assumptions

6. Average Annual LOLE Summary

Table 9 summarizes the average annual Loss of Load Expectation (LOLE) calculated from the results of the 1995 load shape and 1999 load shape simulations, assuming the expected year 2000 load forecast. The Table 9 shows the relative impacts that the assumptions of each case has on the LOLE reliability index for each Area. Case abbreviations are defined following Table 9.

Table 9.
Average Annual LOLE Summary (days/year)

Case	HQ	MT	NE	NY	ON
BC	<.0005	<.0005	.0430	.1095	.0020
NI	<.0005	<.0005	.0445	.3790	.0495
RC	<.0005	<.0005	.0705	.1095	.0100
MO	<.0005	<.0005	.0385	.1585	.0020
WC	<.0005	<.0005	.0665	.4775	.0530

Case	Description
BC	- Base Case Assumptions
NI	- NPCC Isolated Scenario
RC	- Reduced Capacity Scenario
MO	- Maintenance Overrun Scenario
WC	- "Worst Case" Scenario

6.1 ECAR/MAAC Representation

Table 10 compares the average annual Loss of Load Expectation (LOLE) calculated for the Base Case (from Table 8) with the Base Case assumptions for the detailed ECAR/MAAC representation.

Table 10.
Comparison of Average Annual LOLE (days/year)
Base Case

Case	HQ	MT	NE	NY	ON
BC	<.0005	<.0005	.0430	.1095	.0020
EMBC	<.0005	<.0005	.0040	.2530	.0010

Case	Description
BC	- Base Case Assumptions
EMBC	- ECAR/MAAC Modeled - Base Case Assumptions

Table 11 compares the average annual Loss of Load Expectation (LOLE) calculated for the "Worst Case" Scenario with the "Worst Case" assumptions for the detailed ECAR/MAAC representation.

Table 11.
Comparison of Average Annual LOLE (days/year)
"Worst Case"

Case	HQ	MT	NE	NY	ON
WC	<.0005	<.0005	.0665	.4775	.0530
EMWC	<.0005	<.0005	.0120	.7770	.0720

Case	Description
WC	- "Worst Case" Scenario
EMWC	- ECAR/MAAC Modeled - "Worst Case" Assumptions

As shown above in Tables 9, 10, and 11, the amount of modeling detail assumed for neighboring NPCC Areas (ECAR/MAAC) has an effect on the results. As a result of this analysis, the Working Group recommended that the future NPCC study effort be expanded to include participation by representatives from the ECAR/MAAC Areas, in order to gain greater modeling detail.

7. Emergency Operating Procedures Summary

7.1 Summer Season Totals (June-August)

Table 12 shows the total number of EOP occurrences (days) expected for June, July and August for each scenario for (a) the 1995 Load Shape - Expected Load Forecast, and (b) the 1995 Load Shape - Extreme Load assumption.

Table 12(a).
EOP Summary (days)
1995 Load Shape - Expected Load Forecast for the year 2000

Case	EOP	NE	NY	ON*
BC	30 Min	.342	2.277	.165
	VR	.114	1.411	.068
	10 Min	.034	0.709	.001
NI	30 Min	.462	5.093	.795
	VR	.160	3.526	.441
	10 Min	.054	1.970	.035
RC	30 Min	.910	2.284	.446
	VR	.323	1.414	.197
	10 Min	.110	0.709	.008
MO	30 Min	.625	2.736	.203
	VR	.215	1.785	.081
	10 Min	.069	0.961	.003
WC	30 Min	1.693	5.662	1.076
	VR	0.665	4.035	0.546
	10 Min	0.245	2.344	0.044

* Includes use of Canadian only Interruptible loads in the last EOP step

Table 12(b).
EOP Summary (days)
1995 Load Shape - Extreme Load Assumption for the year 2000

Case	EOP	NE	NY	ON*
BC	30 Min	2.553	6.230	1.393
	VR	3.430	4.271	0.608
	10 Min	0.183	2.395	0.007
NI	30 Min	3.226	11.135	4.381
	VR	1.357	8.642	2.653
	10 Min	0.410	5.515	0.284
RC	30 Min	5.102	6.283	3.113
	VR	2.267	4.286	1.568
	10 Min	0.699	2.394	0.051
MO	30 Min	4.038	7.034	1.695
	VR	1.611	4.960	0.780
	10 Min	0.426	2.974	0.007
WC	30 Min	7.387	11.842	5.736
	VR	4.106	9.299	3.493
	10 Min	1.717	6.185	0.325

*Includes use of Canadian only Interruptible loads in the last EOP step

Table 13 shows the total number of EOP occurrences (days) expected for June, July and August for each scenario for (a) the 1999 Load Shape - Expected Load Forecast, and (b) the 1999 Load Shape - Extreme Load assumption.

Table 13(a).
EOP Summary (days)
1999 Load Shape - Expected Load Forecast for the year 2000

Case	EOP	NE	NY	ON*
BC	30 Min	.924	.776	.306
	VR	.521	.448	.125
	10 Min	.312	.227	.007
NI	30 Min	1.086	1.823	1.494
	VR	0.611	1.157	0.777
	10 Min	0.352	0.592	0.065
RC	30 Min	1.373	.782	.745
	VR	0.798	.450	.338
	10 Min	0.474	.227	.022
MO	30 Min	.941	.880	.320
	VR	.495	.507	.130
	10 Min	.275	.254	.006
WC	30 Min	1.584	2.336	1.699
	VR	0.872	1.288	0.860
	10 Min	0.486	0.658	0.072

* Includes use of Canadian only Interruptible loads in the last EOP step

Table 13(b).
EOP Summary (days)
1999 Load Shape - Extreme Load Assumption for the year 2000

Case	EOP	NE	NY	ON*
BC	30 Min	3.655	2.361	2.018
	VR	2.685	1.438	0.991
	10 Min	2.218	0.781	0.042
NI	30 Min	3.970	4.757	7.061
	VR	2.887	3.208	4.417
	10 Min	2.316	1.810	0.546
RC	30 Min	4.966	2.390	4.217
	VR	3.429	1.452	2.230
	10 Min	2.592	0.787	0.042
MO	30 Min	4.313	2.688	2.166
	VR	3.103	1.654	1.057
	10 Min	2.292	0.895	0.042
WC	30 Min	5.870	5.369	7.926
	VR	4.188	3.628	4.886
	10 Min	3.105	2.263	0.613

*Includes use of Canadian only Interruptible loads in the last EOP step

7.2 Min/Max Summary

The minimum and maximum number of times emergency operating procedures were called was tabulated from all the scenarios studied in this analysis [1].

Table 14 illustrates the estimated range of times (occurrences in days/month, rounded to the nearest day) an Area may reduce its 30-minute reserve requirement in reaction to a capacity deficiency for the summer of 2000.

Table 14.
Min/max Range of occurrence (estimated days/month)
EOP Action: reduce the 30-minute reserve requirement

	Load	NE	NY	ON*
June	Expected	0-1	0	0-1
	Extreme	1-4	0-1	1-3
July	Expected	0-1	0-5	0-1
	Extreme	0-4	1-9	0-4
Aug.	Expected	0	0-1	0
	Extreme	0-1	0-2	0-1

* Excludes use of Canadian only interruptible load.

Table 15 illustrates the estimated range of times (occurrences in days/month, rounded to the nearest day) an Area may reduce its 30-minute reserve requirement to zero and implement an Area-wide Voltage Reduction in reaction to a capacity deficiency for the summer of 2000.

Table 15.
Min/Max Range of occurrence (estimated days/month)
EOP Action: reduce 30-minute reserve requirement to zero and initiate voltage reduction

	Load	NE	NY	ON*
June	Expected	0-1	0	0
	Extreme	1-3	0-1	0-2
July	Expected	0	0-3	0
	Extreme	0-2	1-7	0-2
Aug.	Expected	0	0-1	0
	Extreme	0-1	0-2	0-1

* Excludes use of Canadian only interruptible load.

Table 16 illustrates the estimated range of times (occurrences in days/month, rounded to the nearest day) an Area may reduce its 30-minute reserve requirement to zero, implement an Area-wide voltage reduction, and reduce its 10-minute reserve requirement in reaction to a capacity deficiency for the summer of 2000.

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Table 16.
Min/Max Range of occurrence (estimated days/month)
EOP Action: reduce 30-minute reserve requirement to zero, initiate voltage reduction, and reduce 10-minute reserve requirement

	Load	NE	NY	ON*
June	Expected	0	0	0
	Extreme	0-3	0	0
July	Expected	0	0-2	0
	Extreme	0-1	1-5	0
Aug.	Expected	0	0	0
	Extreme	0	0-1	0

* Includes use of Canadian only interruptible load.

8. Conclusions

The benchmark simulations of the summer of 1999 provided confidence that the overall MARS model structure and generator Forced Outage Rate assumptions were adequate to apply the MARS program in a meaningful investigation of the impacts of the conditions that may be experienced for the summer of 2000.

Based on the conditions modeled and the assumptions used in this analysis, the following conclusions follow for the summer of the year 2000:

1. The New England and New York Control Areas have the potential to see the greatest use of their emergency operating procedures during the months of June and July, respectively.

2. Uncertainty surrounding the load forecast and load shape significantly influences the number of times and when emergency operating procedures are anticipated to be used by an Area in response to a capacity deficiency.

3. The amount of modeling detail assumed for neighboring NPCC Areas (ECAR/MAAC) has an effect on the results.

9. References

[1] NPCC Task Force on Coordination of Planning, "NPCC Summer 2000 Multi-Area Probabilistic Reliability Assessment", CP-8 Working Group, NPCC, May 2000.

[2] NPCC Task Force on Coordination of Operation, "NPCC Reliability Assessment for Summer 2000", Ad Hoc Operations Planning Working Group, NPCC, May 2000.

[3] "June 1999 Heat Wave – NPCC Final Report", NPCC, August 1999, Recommendation No. 5.

[4] NPCC Task Force on Coordination of Planning, "Review of Interconnection Assistance Reliability Benefits", CP-5 Working Group, NPCC, June 1999.

10. Acknowledgements

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11. Biography

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