NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2001 THROUGH APRIL 2002

New York State Reliability Council, L.L.C.

Executive Committee Resolution
and
Technical Study Report

December 14, 2000

NEW YORK STATE RELIABILITY COUNCIL, L.L.C.

APPROVAL OF STATE-WIDE INSTALLED RESERVE MARGIN FOR THE MAY 1, 2001 THROUGH APRIL 30, 2002 CAPABILITY YEAR

WHEREAS, reliable electric service is critical to the economic and social welfare of the millions of residents and businesses in the State of New York; and

WHEREAS, the reliable and efficient operation of the New York State (NYS) Power System is fundamental to achieving and maintaining reliability of power supply; and

WHEREAS, The New York State Reliability Council, L.L.C.'s (NYSRC) principal mission is to establish Reliability Rules for use by the New York Independent System Operator (NYISO) to maintain the integrity and reliability of the NYS Power System; and

WHEREAS, the NYSRC is responsible for determining the state-wide annual Installed Capacity requirement; and

WHEREAS, the technical results of the Multi-Area Reliability Simulation study conducted by the NYSRC Installed Capacity (ICAP) Working Group show that the required New York Control Area's (NYCA) installed reserve margin (IRM) for the May 1, 2001 through April 30, 2002 capability year is 17.1% under base case conditions; and

WHEREAS, the study considered the following sensitivities and determined that the IRM could vary from 12.7% to 23.8% depending on key assumptions, including but not limited to:

- Interconnection support during emergencies
- Load forecast uncertainty distribution
- Generating capacity uncertainties
- Locational capacity requirements
- NYCA installed capacity located in neighboring control areas; and

WHEREAS, the above results have a 99% confidence limit of +/- 0.5%; and

WHEREAS, it is considered prudent to take into account the additional factors (such as those identified below) when establishing the NYCA IRM:

- The combined impact of the sensitivity testing and the confidence limit on the base case IRM;
- The changes in electric dispatch protocols associated with transition to the NYISO and neighboring ISOs; and
- Other uncertainties associated with electric industry restructuring, including regulatory and legislative actions

WHEREAS, it is deemed that an adder of 0.9% above the base case IRM of 17.1% will adequately consider the effects of the more probable sensitivity scenarios, the intangibles with the new markets, and the NYSRC's desire to act conservatively;

WHEREAS, with due recognition that the current NYCA IRM is set at 18.0%;

NOW, THEREFORE BE IT RESOLVED, that, in light of the study results and the factors noted above, which argue for a conservative approach, the NYSRC sets the NYCA IRM at 18.0% for the May 1, 2001 through April 30, 2002 capability year; and be it further

RESOLVED, that the NYSRC ICAP Working Group be directed to monitor the actual operating experience of the NYISO and factor this experience into its IRM recommendation for the period commencing May 1, 2002.

Adopted by the NYSRC Executive Committee on December 11, 2000.

TECHNICAL STUDY REPORT

December 14, 2000
New York State Reliability Council, L.L.C.
ICAP Working Group

TABLE OF CONTENTS

APPENDIX A
ICAP RELIABILITY MODEL AND ASSUMPTIONS

APPENDIX B
DETAILS OF STUDY RESULTS

INTRODUCTION

Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the state-wide annual Installed Capacity Requirements (ICR) for New York State consistent with North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC) standards. This report describes an engineering study conducted by the NYSRC for determining the appropriate Installed Reserve Margin (IRM) for the period May 2001 through April 2002 (year 2001) in compliance with the Agreement. The ICR relates to the IRM through the following equation:

ICR = (1+IRM) x Forecasted New York Control Area (NYCA) Peak Load

The New York Independent System Operator (NYISO) will implement the statewide ICR as determined by the NYSRC in accordance with the NYSRC Reliability Rules and the "NYISO Installed Capacity Requirements" manual.

EXECUTIVE SUMMARY

The technical NYSRC study described in this report shows that the required year 2001 state-wide IRM requirements to be 17.1%[1] using base case assumptions. The study also showed that for various scenarios (some of them extreme) testing the IRM's sensitivity to changes in several key study assumptions, the required IRM would vary from 12.7% to 23.8%.

The required IRM of 17.1% determined in this study compares to the 15.5% requirement for year 2000 as shown in last year's report "*New York Control Area Installed Capacity Requirements For The Period May 2000 Through April 2001*" dated January 31, 2000. This IRM increase is attributed to the net effect of several changes of base case study assumptions. The most significant change is the expectation that there will be an 1100 MW installed capacity (ICAP) sale during the 2001 summer by Hydro Quebec (HQ) to NYCA and the PJM Interconnection (PJM), which is in addition to an existing sale of 400 MW to Con Edison. These HQ transactions (1500 MW) will utilize the full HQ-NYCA interconnection capacity, which would have the impact of effectively eliminating any direct HQ to NYCA emergency assistance benefits.

STUDY PROCEDURE

This study used a probabilistic approach for determining required reserves. The technique commonly used in the electric power industry for such studies, calculates the probabilities of outages of generating units, together with a model of daily peak-hour loads, to determine the number of days per year of expected capacity shortages. The resulting measure, termed the "loss-of-load expectation" (LOLE) index, provides a consistent measure of generation system reliability. The acceptable LOLE

[1] At the 99% confidence level, the IRMs calculated for this study have a bandwidth of ± 0.5%.

in New York is stated in the NYSRC Reliability Rules. The NYSRC Reliability Rules (Section 3.1.1) states:

> "Adequate resource capability shall exist in New York State such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring systems, uncertainty of load forecasting, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to resource deficiency will be, on the average, no more than once in ten years."

This NYSRC Reliability Rule is consistent with the NPCC resource adequacy design criterion, as follows:

> "Each Area's resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years."

The results of the study determine an IRM, however, in day-to-day operations the actual available operating margin may be more or less than this IRM.

The probabilistic analysis used a state-of -the-art computer model called the Multi-Area Reliability Simulation (MARS) Program. The MARS model is described in detail in Appendix A. This model includes a detailed load, generation, and transmission capacity representation of the New York Control Area, as well as the four external control areas interconnected to New York. Appendix A also addresses the key parameters and assumptions used in the study.

Appendix B describes the details of the study results.

STUDY RESULTS

The results of this study shows that the statewide required IRM is 17.1% for the year 2001. This conclusion is based on a MARS analysis using base case study assumptions described in Appendix A. Maintaining a minimum installed reserve of 17.1% over the forecast NYCA 2001 summer peak would achieve applicable NYSRC and NPCC reliability criteria under these study assumptions. A description of the cases in the analysis, referenced below, is shown in Appendix B, Table B-1.

- *Interconnection Support During Emergencies.* The reliability of the NYCA is enhanced by receiving emergency assistance from interconnected control areas, in accordance with operating agreements, during emergency conditions. This permits the NYCA to operate at a reserve level 6.1 percentage points (Table B-1, Case 2 - Case 1) lower than otherwise required, under the base case assumptions used in this study. These assumptions include external ICAP purchases from HQ that reduce emergency assistance from HQ to zero over the direct ties.

- *Load Forecast Uncertainty*. It is recognized that some uncertainty exists relative to forecast NYCA loads for any given year. This uncertainty was represented using a load forecast probability distribution (this probability distribution includes a range of loads from 28,200 MW to 32,200 MW) based on an analysis of the sensitivity of load levels to different weather conditions, as well as load forecasting error. The impact of representing this load forecast probability distribution in the base case, instead of a single point representation, results in a required IRM increase of 2.6 percentage points (Case 1 - Case 10).

- *Generating Capacity Uncertainties.* To account for such things as unit deratings due to the possibility of ambient air and water temperatures above test conditions, environmental restrictions, units cycling more than previously (causing a higher forced outage rate) or other unusual but not quantifiable occurrences, an adder of one percentage point has been added to the reserve requirement. This IRM adder more than covers the sum of the maximum potential capacity deratings of those NYCA generating units subject to temperature and environmental restrictions.

- *Locational Capacity Requirements.* The MARS model used in this study provided an assessment of the adequacy of the NYCA transmission system to deliver energy from one area to another for meeting load requirements. The study found that under the conditions assumed, there are transmission constraints into the New York City and Long Island load areas which could impact the LOLE of these areas, as well as the statewide LOLE.

  To minimize these potential LOLE impacts, NYISO studies have shown that a minimum generating capacity, i.e., locational installed capacity, must be maintained in each of the New York City and Long Island areas. This locational capacity requirement, monitored by the NYISO, supplements the state-wide IRM requirement covered in this report. The most recent NYISO study (*Locational Installed Capacity Requirements Study, May 22, 2000*) confirmed that the LSEs serving the New York City and Long Island areas must maintain minimum installed capacity to load ratios of 0.80 and 0.93, respectively, for these areas. These minimum locational capacities are maintained in this NYSRC IRM study's base case representation.

- *NYCA Installed Capacity Located in Neighboring Control Areas (External ICAP).* Locating a portion of the NYCA's required installed capacity in neighboring control Areas[2] without increasing interconnection capacity, has the effect of reducing the amount of interconnection support available during emergencies, thus increasing the required IRM. The base case assumed an NYCA external ICAP of 2253 MW, comprised of 1000 MW from HQ and 1253 MW from PJM. (This external ICAP assumption includes 1653 MW of presently "grand-fathered" capacity, in addition to another purchase of 600 MW from HQ.) The base case also assumed an ICAP sale of 500 MW from HQ to PJM. This 1100 MW of additional sales by HQ, beyond that which is grand-fathered, is expected in 2001 due to the qualification of HQ as an ICAP supplier.

  The ICAP transactions, as represented in this study, will fully utilize the 1500 MW HQ to NYCA interconnection capacity. This will have the impact of effectively eliminating any direct

[2]PJM (Pennsylvania, New Jersey and Maryland Interconnection), ISO New England (NE), Ontario's Independent Electric Market Operator (IMO), and Hydro-Quebec (HQ).

emergency assistance benefits from HQ, thus increasing the required IRM by 3.1 percentage points (Case 1 - Case 8).

The appropriate IRM required for meeting reliability criteria depends on the study assumptions used in the analysis in addition to the many factors which influence the reliability of the system. Use of assumptions different than those used in the base case yields different required IRM outcomes. Figure 1 shows the sensitivity of IRM results to several alternate assumptions. The sensitivity study results in this figure show a required IRM range of 12.7% to 23.8%.

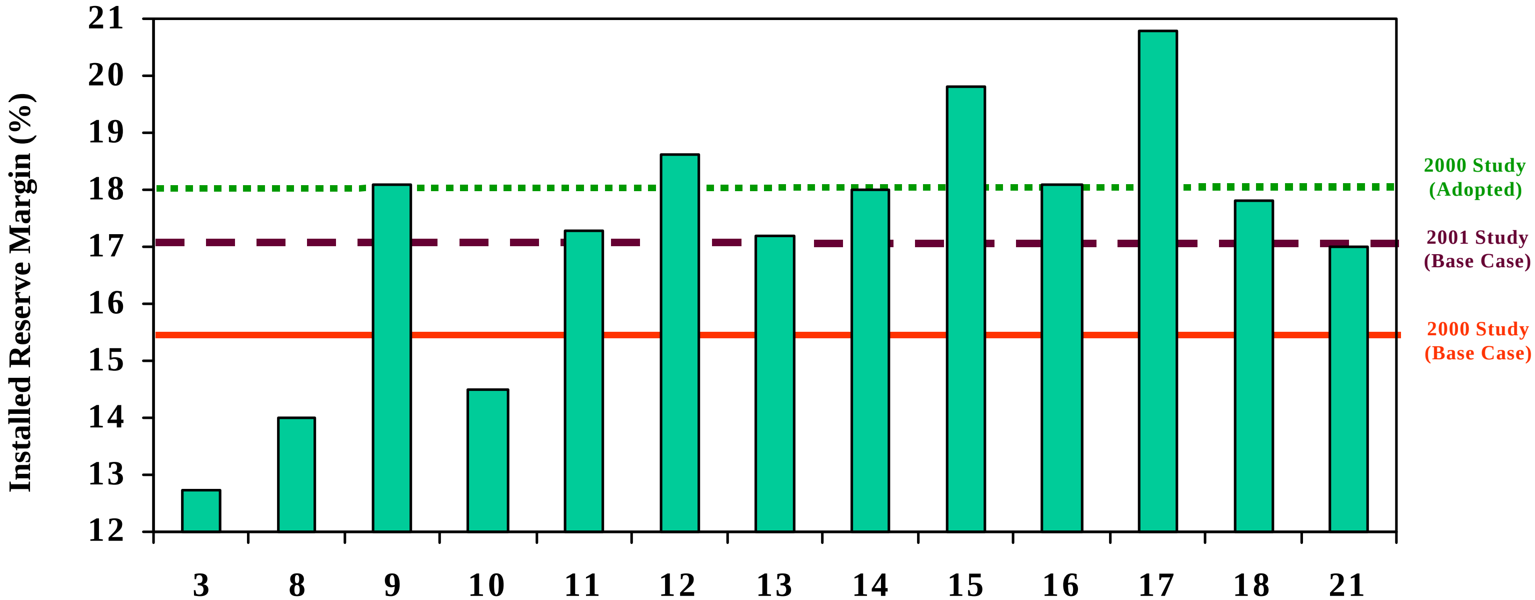
The NYISO will implement emergency operating procedures (EOPs) as required to minimize customer disconnections. The study indicates that if a 17.1% IRM is maintained under base case conditions, then on average, voltage reductions will be required twice per year and firm load disconnection due to inadequate resources will occur not more than once in every ten years (see Appendix B, Table B-2 for expected average use of other EOPs).

In addition to the sensitivity cases shown in Table 1, a supplemental case was run that showed the impact of extreme load conditions (1000 MW higher than forecast) on the LOLE for an IRM of 17.1%. This case, described in Appendix B, showed that the NYSRC LOLE criterion of 0.1 days/year is met under this extreme load condition.

COMPARISON TO 2000 STUDY

The results of this study show a 1.6% higher required IRM than the previous study conducted for the 2000-2001 capability year, which showed a base case required ICAP of 15.5%. The primary reason for this increase is this study's external ICAP representation, which is discussed above. Table 1 shows a comparison of the required IRM impacts of key parameters associated with these two studies. The table further shows which parameters are related to model improvements versus those related to updated assumptions.

Figure 1
COMPARISON OF NYSRC BASE CASE & SENSITIVITY IRM RESULTS



Sensitivities – changes from Base Case Assumptions

3	No External ICAP	**14**	1 in 15 Years Disconnections
8	Grand Fathered External ICAP Only	**15**	1 in 15 Years Disconnections & No Statewide Voltage Reductions
9	Remove HQ-IMO Tie	**16**	No NYC Voltage Reductions
10	No Load Forecast Uncertainty	**17**	No Emergency Assistance from PJM
11	Without Addition of New Units & Capacity	**18**	Reduce All Internal Transfer Limits by 10%
12	No Statewide Voltage Reductions	**21**	Additional 100 MW Special Case Resources in NYC
13	Delay All Planned New Capacity		

Table 1

COMPARISON WITH 2000 STUDY

Parameter	IRM % Change	IRM %
Previous Study IRM (2000 Study)		**15.5**
IMPROVEMENTS IN 2001 STUDY:		
· Remove 2000 study FOR uncertainty IRM adder	-1.5	
· Add generating capacity uncertainty IRM adder	+1.0	
· Other improved modeling	+1.3	
Net IRM Change from 2000 Study	+0.8	
New Study IRM (2001 Study) - Impact of Model Improvements Only		**16.3**
UPDATED ASSUMPTIONS IN 2001 STUDY:		
· Updated external ICAP representation	+2.7	
· Updated transfer limits	+0.9	
· Updated generating unit ratings	+0.8	
· Updated EOPs	-0.2	
· New generating units and other additional capacity	-0.2	
· Represent HQ-IMO tie	-1.0	
· Updated load forecast uncertainty representation	-2.2	
Net IRM Change from 2000 Study	+0.8	
New Study IRM (2001 Study) - Impact of Model Improvements & Updated Assumptions		**17.1**

APPENDIX A

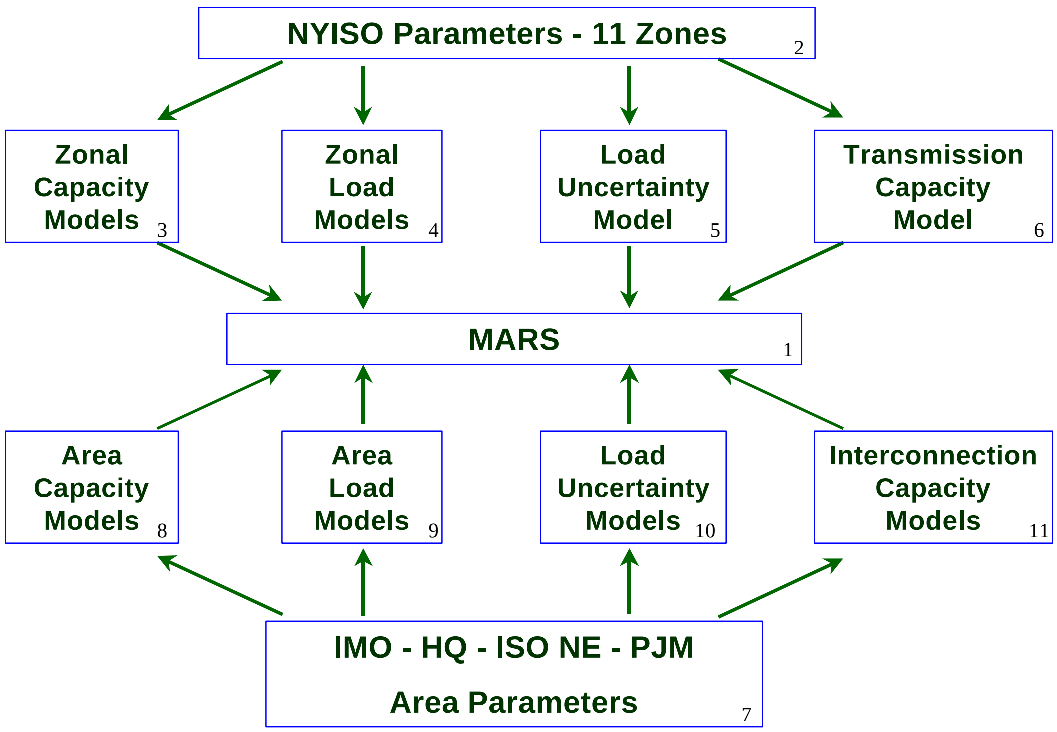
ICAP RELIABILITY MODEL
AND
ASSUMPTIONS

MARS
Capacity Models - Units, FORs, Maintenance, Etc.
Load Models
Uncertainty Models: Load, FOR
Transmission Capacity Model

Table A-1
Details on ICAP Modeling

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	**MARS**	**The General Electric Multi-Area Reliability Simulation Program**		**See page 10**
2	**11 Zones**	**Load Areas**	**Fig. A-2 page 12**	**NYISO Accounting & Billing Manual**
3	**Zonal Capacity Models**	**Generator Models for each generating unit in zone .**		**See page 13**
		Historical Outage Data.	**GADS Data**	**See Page 14**
		Unit Ratings.	**2000 Gold Book**	
	Emergency Operating Procedures	**Reduces load during emergency conditions to maintain operating reserves.**	**ISO**	**See page 21**
	Capacity Uncertainties	**Account for temperature, deratings, environmental restrictions, etc.**		**See page 22**
4	**Zonal Load Models**	**Hourly loads**	**NYPP Historical load shape for 1995.**	**See page 24**
			ISO peak forecasts.	**2000 Gold Book.**
5	**Load Uncertainty Model**	**Account for forecast errors due to weather and economic conditions.**	**Historical Data**	**See page 26**
6	**Transmission Capacity Model**	**Emergency transfer limits of transmission interfaces between zones.**	**NYPP & ISO transmission studies.**	**See page 29**
7	**IMO, HQ, ISO NE-PJM Area Parameters**	**See the following items 8-11.**		
8	**Area Capacity Models**	**Generator Models in neighboring Areas**	**NPCC CP-8 study for NPCC Areas. MAAC Report and NERC Average outage rates for PJM**	**See page 23**
9	**Area Load Models**	**Hourly Loads**	**NPCC CP-8 study for NPCC Areas PJM Web site**	**See page 24**
10	**Load Uncertainty Models**	**Account for forecast errors due to weather and economic conditions**	**CP-8 Study**	**See page 26**
11	**Interconnection Capacity Models**	**Emergency transfer limits of transmission interfaces between areas.**	**NPCC CP-8 Study**	**See page 29**

Figure A-1
NYCA ICAP Modeling



MULTI-AREA RELIABILITY SIMULATION PROGRAM (MARS)

The General Electric Company's MARS program, which was jointly developed by General Electric and Associated Power Analysts as an Empire State Electric Energy Research Corporation (ESEERCO) project managed by NYPP staff, enables the electric utility planner to quickly and accurately assess the ability of a power system, comprised of any number of interconnected areas, to adequately satisfy customer load requirements.

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

MARS calculates, on an area and pool basis, the standard reliability indices of daily and hourly Loss of Load Expectation (LOLE) (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). To model the impact of emergency operating procedures, the program also calculates the expected number of days per year at specified positive and negative margin states.

In addition to calculating the expected values for the reliability indices, MARS (through a separate post-processor program) also produces probability distributions that show the actual yearly variations in reliability that the system could be expected to experience.

Monte Carlo Simulation for Reliability Evaluations

In determining the reliability of a utility system, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units, the forced outages of transmission capacity, and deviations from the forecasted loads. Monte Carlo simulation is a widely-accepted technique for modeling the effects of such random events.

Monte Carlo simulation approaches can be categorized as "non-sequential" and "sequential". A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour to be independent of every other hour. Because of this, it cannot accurately model issues that involve time correlations, such as unit starting times or postponable unplanned outages, and cannot be used to calculate time-related indices such as frequency and duration.

A sequential Monte Carlo simulation, the approach used by MARS, steps through the year chronologically, recognizing the fact that the status of a piece of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. The sequential simulation can model issues of concern that involve time correlations, and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the Multi-Area Reliability Program 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 one assumes 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:

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

The table below shows the calculation of the state transition rates from historical data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1:

TR (1 to 2) = (10 transitions) / (5000 hours) = 0.002

Example of State Transition Rates

Time-in-State Data		
State	**MW**	**Hours**
1	200	5000
2	100	2000
3	0	1000

Transition Data			
From State	**To State** 1	2	3
1	0	10	3
2	6	0	12
3	9	8	0

State Transition Rates			
From State	**To State** **1**	**2**	**3**
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state of each other state.

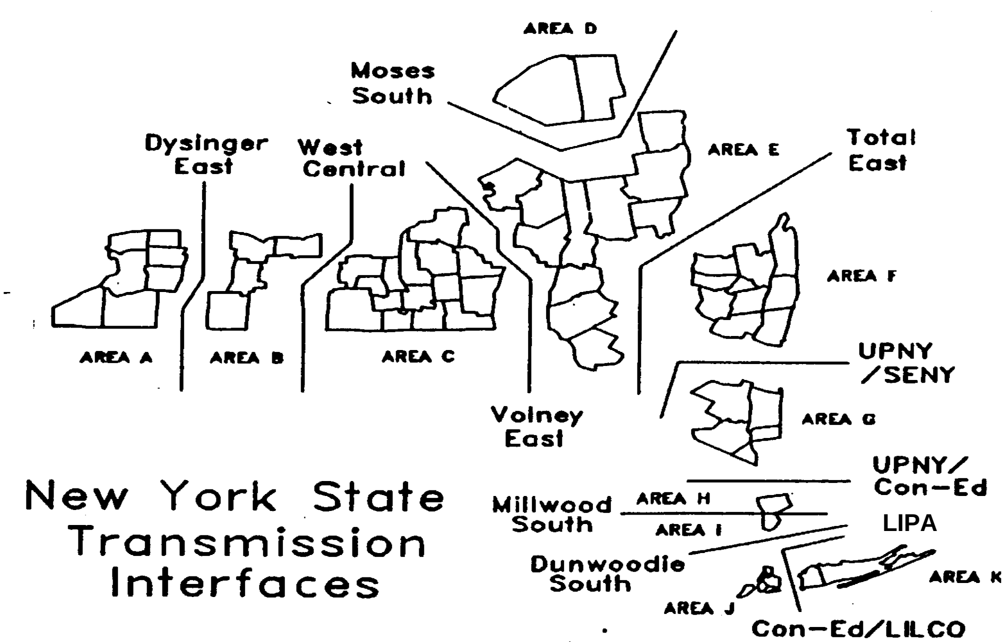
Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when then next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system , its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, as a result of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

The number of replications simulated is determined such that the standard error of the estimate of the LOLE is 0.05. This standard error places a confidence interval of ninety-five percent around the LOLE estimate. Sixteen hundred (1600) replications were simulated in the Base Case.

Figure A-2

NYCA Zones



CAPACITY MODELS - UNITS, FORS, MAINTENANCE, ETC.

The capacity model includes unit ratings, full and partial forced outage representation, maintenance outages, EOPs and firm transactions. For this study, all units located within NYCA , including those without capacity contracts, were included. These assumptions provided a total of 36042 MW capacity plus 1653 MW of grand-fathered external ICAP contracts resulting in a total of 37695 MW. This is used along with a NYCA peak load forecast of 30500 MW as the starting point for the year 2001.

NYCA Models

Ratings

The unit ratings were obtained from the "2000 Load & Capacity Data of the NYISO" (Gold Book). The following changes that were announced after the Gold Book was published are modeled in this study:

- KeySpan combustion turbine ratings will be up-rated 79 MW to reflect the addition of water injection by 6/1/01.
- In-City capacity increased by 157.3 MW from that reported in the Gold Book. This increased capacity is due to more recent capacity testing.
- ENRON's barge mounted capacity of 66 MW on Long Island by 6/1/01.
- The Hickling and Jennison units, having a combined capacity of 157 MW, are on long term cold stand-by.
- 396 MW of new NYPA combustion turbines in NY City by 6/1/01[3].
- 79.9 MW of new NYPA combustion turbines on Long Island by 6/1/01[3].
- 70 MW additional capacity from Linden Cogen due to water injection by 5/1/01.
- Long Island Municipal Electric capacity of 59 MW included.
- Western NY Municipal Electric capacity of 37.5 MW included (15 MW of Special Case Resources).
- Special Case Resources: 31 MW in NY City, 40 MW in the central region and 85 MW in the west. A Special Case Resource is a load capable of being interrupted on demand, and distributed generators, rated at 100 kW or higher, that are not visible to the ISO's Market Information System.

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[3] Documented assumptions as of November 15, 2000.

External Capacity

There are 1653 MWs of grand-fathered capacity modeled as purchases by NYCA, consisting of 400 MW from HQ and the remainder from PJM. The Base Case assumes the following external ICAP in addition to the grand-fathered ICAP: six hundred (600) MW (summer only) is assumed purchased by the NYCA from HQ and five hundred (500) MW (summer only) purchased by PJM from HQ. The latter is assumed to be wheeled through NYCA.

Hydro Units

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model that is based on historical water flows and unit performance. The Niagara Project is modeled at 2550 MW summer and 2571 MW winter. The St. Lawrence Project is modeled at 830 summer and 755 MW winter.

While energy production from these projects is expected to be lower in 2001 due to lower than average water flows in the Niagara and St. Lawrence Rivers, the projects will still be able to achieve their maximum capacity ratings in the event of a system emergency.

The data for the smaller hydro units was compared to historical data obtained from online hydro generation data. The net result was a decrease in hydro ratings in most months. An adjustment for hydro rating changes was made for each month by adding or subtracting the appropriate MW value. The adjustment ranged from positive 47 MW to a negative 234 MW.

Forced and Partial Outages

The unit forced outage states for the majority of the large steam units was obtained from the ten year average NERC - Generating Availability Data System (GADS) outage data collected by NYPP and the ISO for the years 1987 through 1996. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the MARS program. In some specific instances, certain historical years for specific units have been removed from the data base at the previous request of the former NYPP member companies because certain outages were the result of extraordinary circumstances. An -89 MW generator is added to the capacity model, based on historical analysis, to account for such extraordinary outages that are not included in the forced outage rates.

Figure A-3, which is based on NERC-GADS data for New York units, shows that there is no significant upward or downward trends for the types of generator units modeled in the study except for an improvement in the availability of nuclear units for the years 1998 and 1999. Since the 1998 and 1999 data only includes a few units, it was not considered to be a significant trend. Therefore, the Working Group concluded that the ten year historic outage rates is appropriate for this study.

In addition, Figure A-4 provides NERC-GADS data industry-wide. Again, there do not appear to be any significant upward or downward trends present.

The forced outage rates for combustion turbines, IPP's (except former LILCO units) and hydro units did not come from the NERC-GADS data, but were provided by the former NYPP member companies.

FIGURE A-3

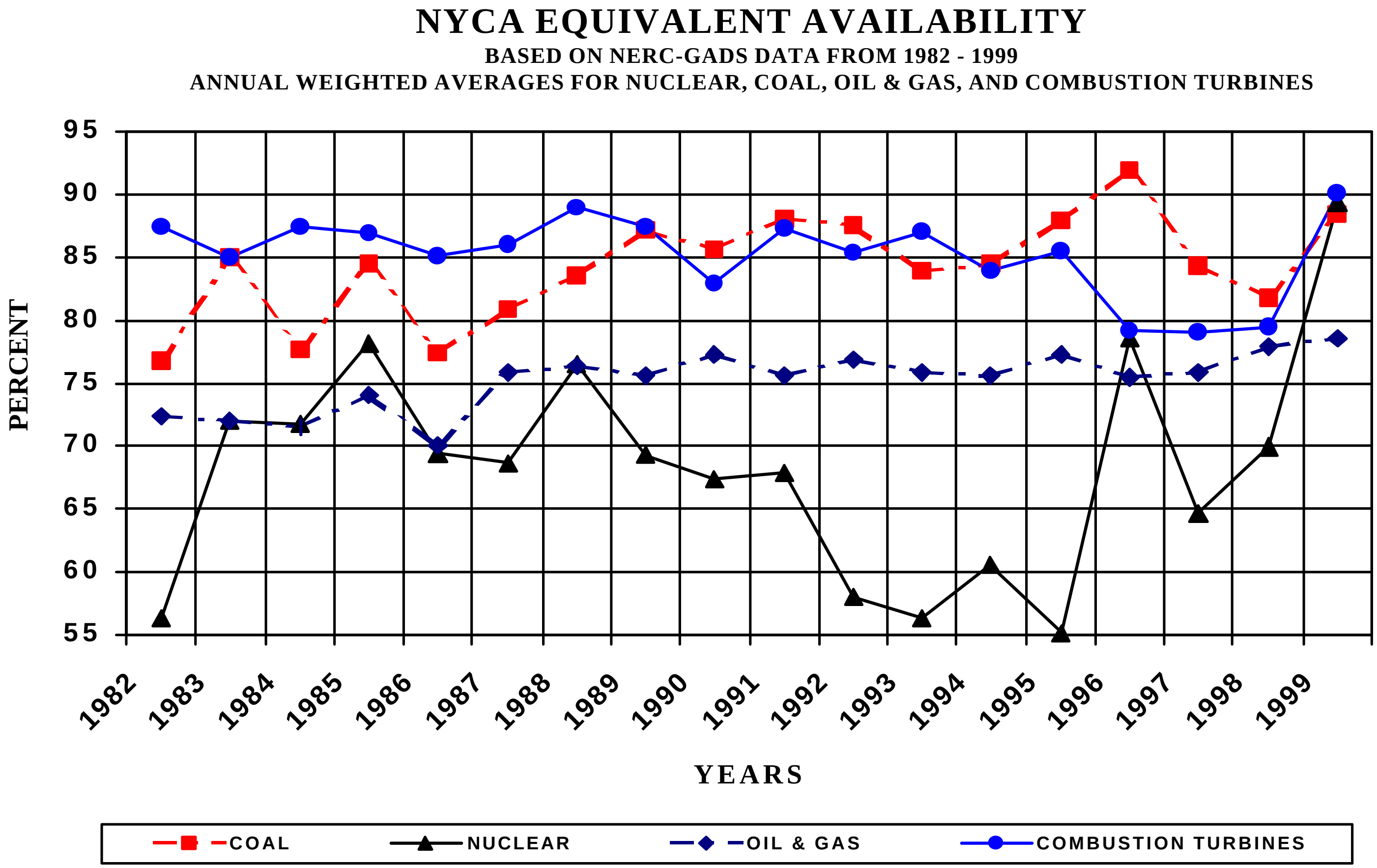
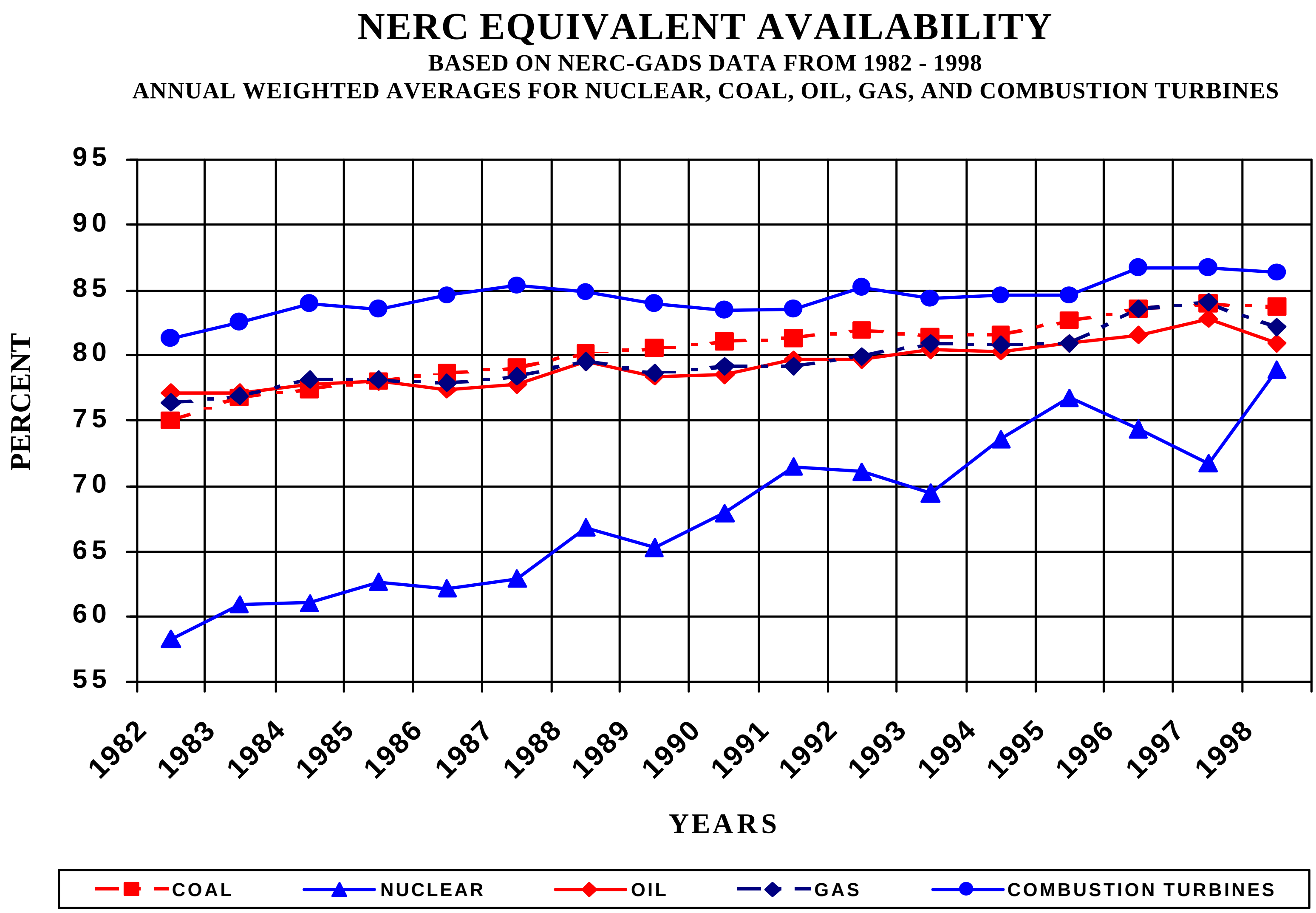

NYCA EQUIVALENT AVAILABILITY
BASED ON NERC-GADS DATA FROM 1982 - 1999
ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES
PERCENT
95
90
85
80
75
70
65
60
55
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
YEARS
COAL
NUCLEAR
OIL & GAS
COMBUSTION TURBINES

Figure A-4


NERC EQUIVALENT AVAILABILITY
BASED ON NERC-GADS DATA FROM 1982 - 1998
ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL, GAS, AND COMBUSTION TURBINES
PERCENT
95
90
85
80
75
70
65
60
55
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
YEARS
COAL
NUCLEAR
OIL
GAS
COMBUSTION TURBINES

Maintenance Schedule

The maintenance schedule was developed from a 10 year average of the same NERC-GADS data that was used to obtain the forced outage rates. This included all types of maintenance outages. The NERC-GADS historical data also correlated well with the total maintenance data reported in the former NYPP on-line dispatch data at the time it was developed.

An outage pattern for each former NYPP company was developed from the historical data. Maintenance of the largest unit for each company is scheduled for the period when historically the most maintenance occurred. This proceeds through to the smallest unit.

A recent check by the ISO of the projected maintenance outage schedule showed less maintenance than has historically been the case, since this projection only included long term scheduled outages. The Working Group felt that it was conservative to continue to use the same historical maintenance schedule that was used last year.

Table A-2 shows the megawatts of NYCA capacity on scheduled or maintenance outages used in the MARS program.

Unit Equivalent Availability

Table A-3 compares the actual 1987-1996 average equivalent availability for NYCA units by class of unit used in the study with the NERC database for the years 1994-1998.

The equivalent availability factor accounts for forced, partial, scheduled and maintenance outages.

TABLE A-2

NYCA WEEKLY SCHEDULED OUTAGE (MW) SUMMARY FOR 2001

WEEK	PEAK LOAD	SCHEDULED OUTAGES	WEEK	PEAK LOAD	SCHEDULED OUTAGES
1	24,112	775	28	26,573	237
2	24,414	2,535	29	30,416	280
3	22,644	2,285	30	30,210	503
4	22,934	2,390	31	30,500	893
5	22,696	2,612	32	30,483	872
6	25,240	2,765	33	30,205	867
7	23,832	4,282	34	29,884	828
8	22,156	4,483	35	25,532	805
9	23,082	4,828	36	25,861	632
10	22,630	6,289	37	26,140	974
11	22,803	6,496	38	24,774	1,624
12	20,776	7,454	39	23,068	2,697
13	20,692	8,002	40	22,041	3,908
14	21,785	7,732	41	23,328	4,729
15	21,303	9,599	42	22,337	6,853
16	19,847	10,105	43	21,520	7,764
17	19,586	11,151	44	22,429	7,029
18	19,860	10,072	45	22,410	6,809
19	20,965	8,911	46	23,055	6,888
20	21,258	7,890	47	22,608	6,745
21	22,756	6,217	48	23,428	6,210
22	23,007	5,189	49	23,594	5,128
23	25,362	4,350	50	25,304	4,534
24	24,720	2,590	51	25,395	3,983
25	30,066	2,410	52	24,889	2,394
26	26,677	2,261	53	23,158	1,659
27	25,763	1,719			

Table A-3
EQUIVALENT AVAILABILITY (%)

Unit Class	NYPP Units NERC-GADS 10 Year Average	1999 NERC-GADS Report 5 Year National Average
COAL		
0 - <100 MW	85.80	85.58
100 - <200 MW	81.65	84.92
200 - <300 MW	-	84.09
300 - <400 MW	-	81.21
400 - <500 MW	-	81.09
600 - <800 MW	-	84.50
800 - <1000 <W	-	85.29
1000+ MW	-	80.87
500 - <1300 MW	77.47	-
COAL & OIL 500<1300 MW	91.44	-
OIL		
0 - <100 MW	90.70	88.03
100 - <200 MW	81.06	83.37
300 - <400 MW	76.58	78.62
400 - <500 MW	89.11	-
400 - <600 MW	-	81.89
600 - <800 MW	-	81.38
800 - <1000 MW	-	85.02
500 - <1300 MW	72.80	-
OIL & GAS		
0 - <100 MW	84.6	
100 - <200 MW	80.33	
200 - <300 MW	73.34	
500 - <1300 MW	79.29	
NUCLEAR		
400 - <500 MW	83.29	-
400 - <800 MW	-	72.71
500 - <1300 MW	62.72	-
800 - <1000 MW	-	75.51
1000+ MW	-	74.51
COMBUSTION TURBINES		
0 - <100 MW	86.31	85.81-85.50

Emergency Operating Procedures (EOPS)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed below were provided by the NYISO based on NYISO experience.

Table A-4

Emergency Operating Procedures

Step	Procedure	Effect	Percentage	MW Value
1	Purchase	Increase capacity	N/A	Varies
2	Cancel firm sales	Load relief	N/A	0 MW
3	5% manual voltage Reduction*	Load relief	0.26	80 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	1.97	600 MW
5	5% remote voltage reduction*	Load relief	1.14	348 MW
6	8% remote voltage reduction	Load relief	**	**
7	Curtail Company use	Load relief	0.15	48 MW
8	Voluntary industrial curtailment	Load relief	1.00	305 MW
9	General public appeals	Load relief	0.50	153 MW
10	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	N/A	1200 MW
11	Customer disconnections	Load relief	N/A	As needed

**   These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast peak load of 30500 MW.*
*** If the 8% remote voltage reduction were included, the Con Edison system could expect an additional 0.47% or 144 MW of load reduction.*

The above values are based on the year 2000 actual results associated with a forecast of 30200 MW. Using these same values (some of which are load sensitive) with the higher 2001 forecast of 30500 MW is conservative. All of these procedures, except for Step 6, which is not readily available to the ISO operator were included in the computer runs. Exclusion of Step 6 in the study results in an additional measure of conservatism. The above table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency.   The amount of help that is provided by EOPs related to load, such as voltage reduction, will vary with the load level. The EOPs (excluding Step 6) presented in Table A-4 were modeled in the MARS program.

Transactions

All firm sales are modeled as listed in the "2000 Load & Capacity Data of the NYISO" (Gold Book) for the year 2001.

Capacity Uncertainties

An adder of one percentage point has been included in the results to represent such things as unit deratings due to the possibility of ambient air and water temperatures above test conditions, environmental restrictions, units cycling more than previously (causing a higher forced outage rate) or other unusual but not quantifiable occurrences.

NEIGHBORING AREAS

The NPCC members Area models are based on the models that they provided for the NPCC study "Summer 2000 Multi-Area Probabilistic Reliability Assessment" dated May 2000 (CP-8). This study looked at the reliability models of the NPCC Areas to be sure that assistance from their neighbors wasn't being double counted. These models have been updated to include the current forecasts and changes in generating capacity.

The representation of neighboring Areas is done in a conservative manner to account for reserve sharing uncertainties. Installed reserve levels in neighboring areas were assumed lower than required to meet their reliability criterion. This assumption lowers the emergency assistance to the NYCA from these areas.

Electric Supply and Demand Database

The PJM capacity model is based on the 1998 NERC Electric Supply and Demand database. Unit availabilities are based on Weighted Equivalent Availability Factors, by unit size and fuel type, from the NERC Generating Unit Statistical Brochure. PJM's load model is based on its actual 1995 loadshape.

The EOPs were removed from the ISO-NE and IMO models (the only ones other then New York that explicitly modeled EOPs) to avoid the difficulty in modeling the sequence and coordination of implementing them. This is a conservative measure.

Assistance from the East Central Area Reliability Council (ECAR) and the Maritime Provinces was not considered, therefore, limiting the emergency assistance to the NYCA from the immediate neighboring areas. This consideration is another measure of conservatism added to the analyses.

LOAD MODELS

The Load Model included in the MARS program is an hourly load model that models all 8760 hours of the year in chronological order. The CP-8 study concluded that the historical year 1995 was a good load shape to use to represent the forecasted year 2001. It did not have any extreme variations such as a very high peak that only occurred for a day or two.

The load model was developed by taking the actual loads for the year 1995 for each Area and moving the summer and winter peak load weeks into the same calendar week. Then the actual peak days were also made to occur on the same calendar day. This was done to be conservative. Even if the peaks did not occur on the same day for each Area in 1995, they could in the future; based on weather patterns. This method also minimizes the amount of help that will be obtained from neighboring Areas over system peak conditions.

The hourly loads were then adjusted by the ratio of annual forecasted peak load for the year 2001 to the actual 1995 peak load.

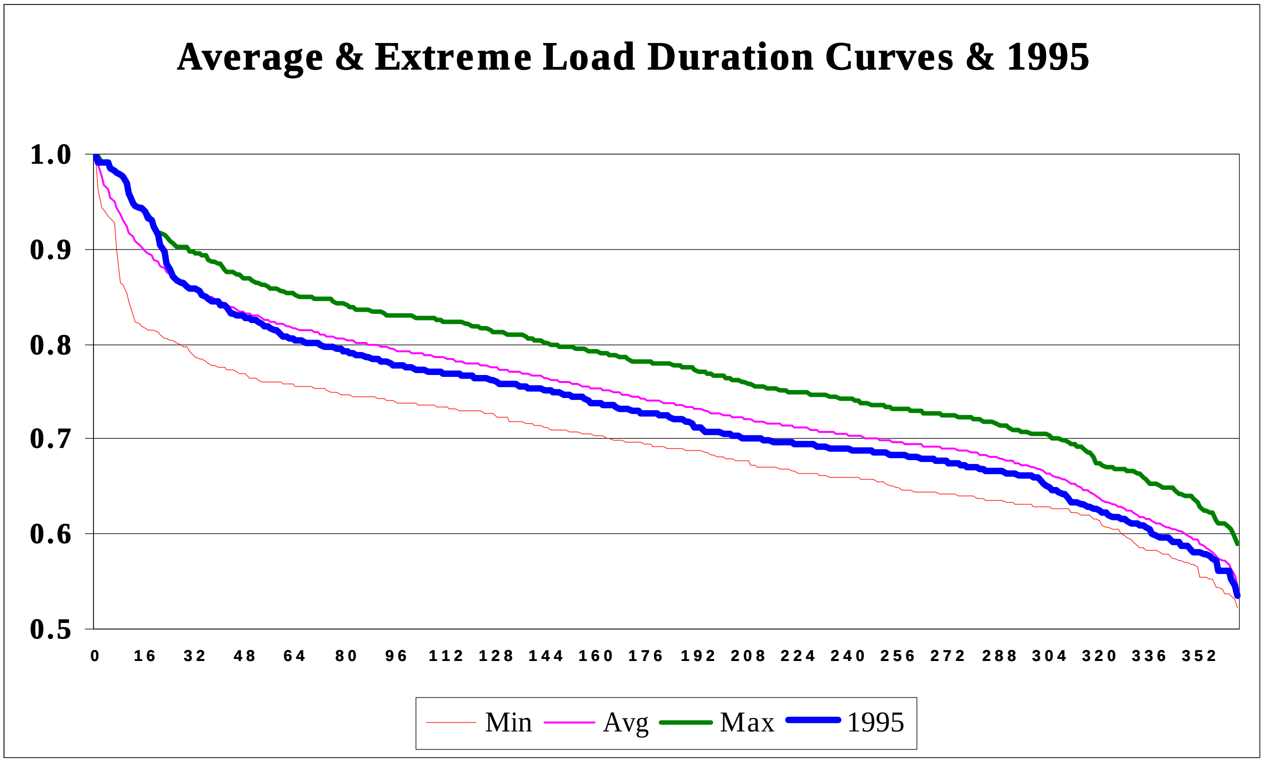
Installed Reserve Study Load Shape

The load shape used in the Installed Reserve Study, and the Locational Requirements study before that, is based on work done for the 2000 CP8 study.

The CP8 Working Group decided to base its study year load shape on an actual year load shape instead of a synthetic typical year because of the inherent ambiguity is defining a typical year's characteristics. The actual year decided upon was 1995. Each area ranked recent years according to the representativeness of their load shapes. Criteria were to include the seasonal distribution of peaks and energies, and the shape of the load duration curve. Years reflecting unusual economic conditions were excluded. 1995 was the consensus choice for the most representative year.

Each area (the IMO, HQ, ISO-NE and NYISO) was to produce a load forecast for the study year based on its 1995 load shape, updated to reflect its most recent peak load and energy forecasts.

Subzonal load shapes were developed by applying weights. Subzonal loads were aggregated to the appropriate zones to produce the input used in MARS. This is the same method that has always been used to produce zonal load shapes from company load shape input.



The chart shows maximum, minimum, average load duration curves, as well as the 1995 load duration curve. Points on the maximum curve show the highest values for each ordered hour for the years 1988-1997. In other words, for the second highest hour, the value on the maximum curve is the highest of all the second points of each load duration curve for 1988-1997. Similarly for the minimum and average curves. 1995 has the desirable property of having relatively many hours near the maximum curve in the top twenty hours. The use of the 1995 load shape as the basis for the study's load shape model, because of this characteristic, provides a relatively higher annual LOLE than alternative load shapes.

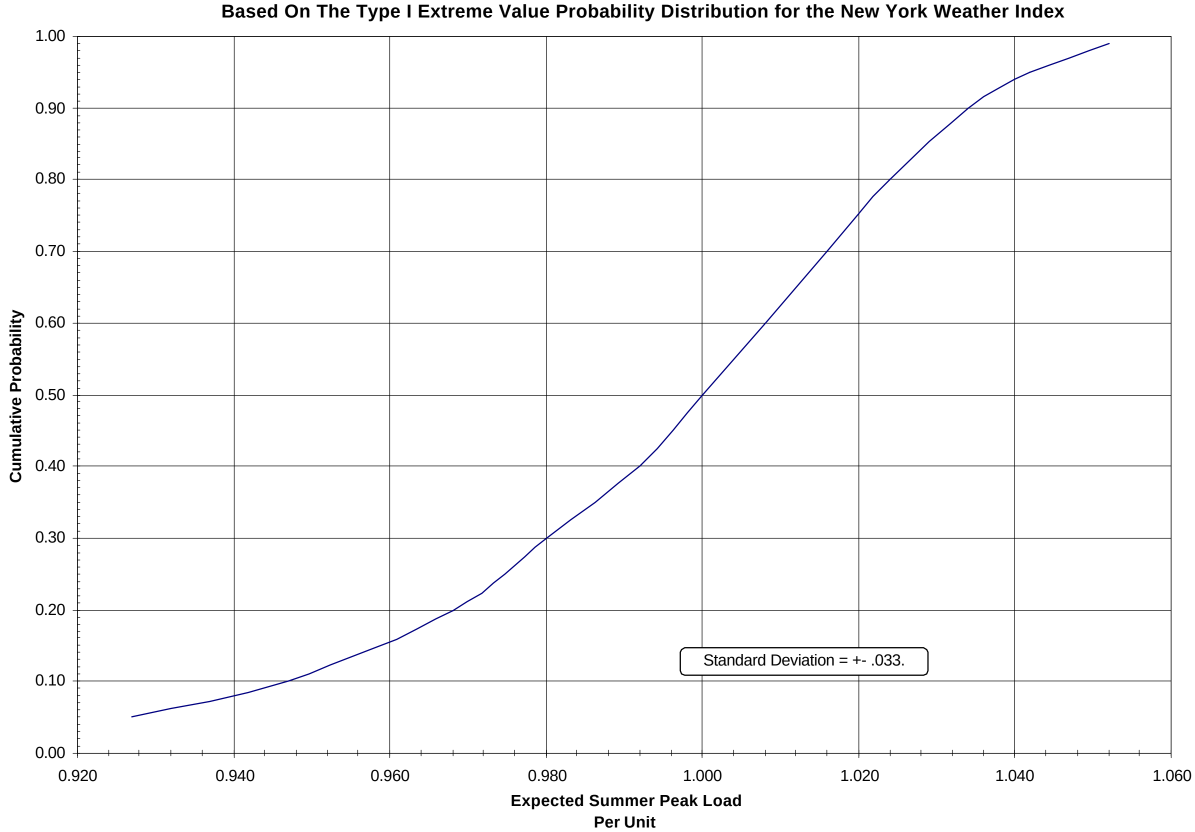
LOAD UNCERTAINTY MODEL

Load Forecast Uncertainty

The intent of the study is to determine a near-term installed reserve margin for NYCA (i.e. 2001-2002); and, therefore, weather uncertainty is the dominant effect. The "portfolio effect" associated with combining or joining the weather and forecast distributions yields a seven-state distribution which is slightly tighter than the weather distribution by itself. A NYCA peak load forecast for 2001 of 30,500 MW was used to translate the per-unit distributions into the seven-state load distributions.

Weather Impact: Exhibit I below shows how the NYCA load can vary per unit for weather. This cumulative probability distribution is based on weather data from 1950 through 1999 and the most recent weather response of the NYCA system. The probability distribution for the weather variable is derived by mapping the weather data into the type I extreme probability distribution. This distribution was developed by the U.S. Department of Commerce to measure annual return times of extreme events such as maximum rain falls and floods. The temperature variable which is mapped is the 3 day weighted average (or distributed lag designed to capture build-up effects) of the 2 p.m. dry bulb and dew point temperature. The annual maximum of this variable is plotted on type I extreme probability paper to determine the annual probability of occurrence or return time for this variable.

Exhibit I: Cumulative Probability Distribution Per Unit for Expected Summer Peak Load Based On The Type I Extreme Value Probability Distribution for the New York Weather Index



The weather-response function is derived by regressing the NYCA peak loads that occur during extreme conditions against the weather variable. This response function when combined with the weather distribution produces the per unit load distribution. This analysis includes the weather conditions associated with the 1999 peak load.

As can be seen in the cumulative probability distribution the load can vary in a given year from 0.92 of the expected load (i.e., 1) to 1.06 of the expected load. The forecast error one year ahead in today's low growth environment should be on the order of ± 1.5%. Below is a seven state probability model for load variation due to weather that is consistent with the needs of the MARS model:

Prob. %	Per Unit of Peak Load	Load (MW)
0.62	0.920	28060
6.06	0.934	28490
24.17	0.965	29430
38.30	1.000	30500
24.17	1.025	31260
6.06	1.049	31990
0.62	1.060	32330

Load Growth Uncertainty: This error consists of the forecast error of ±1.5%. This results in the following distribution:

Prob. %	Per Unit of Peak Load	Load (MW)
0.62	0.985	30040
6.06	0.990	30200
24.17	0.995	30350
38.30	1.000	30500
24.17	1.005	30650
6.06	1.010	30810
0.62	1.015	30960

This data has been updated from the 2000 report.

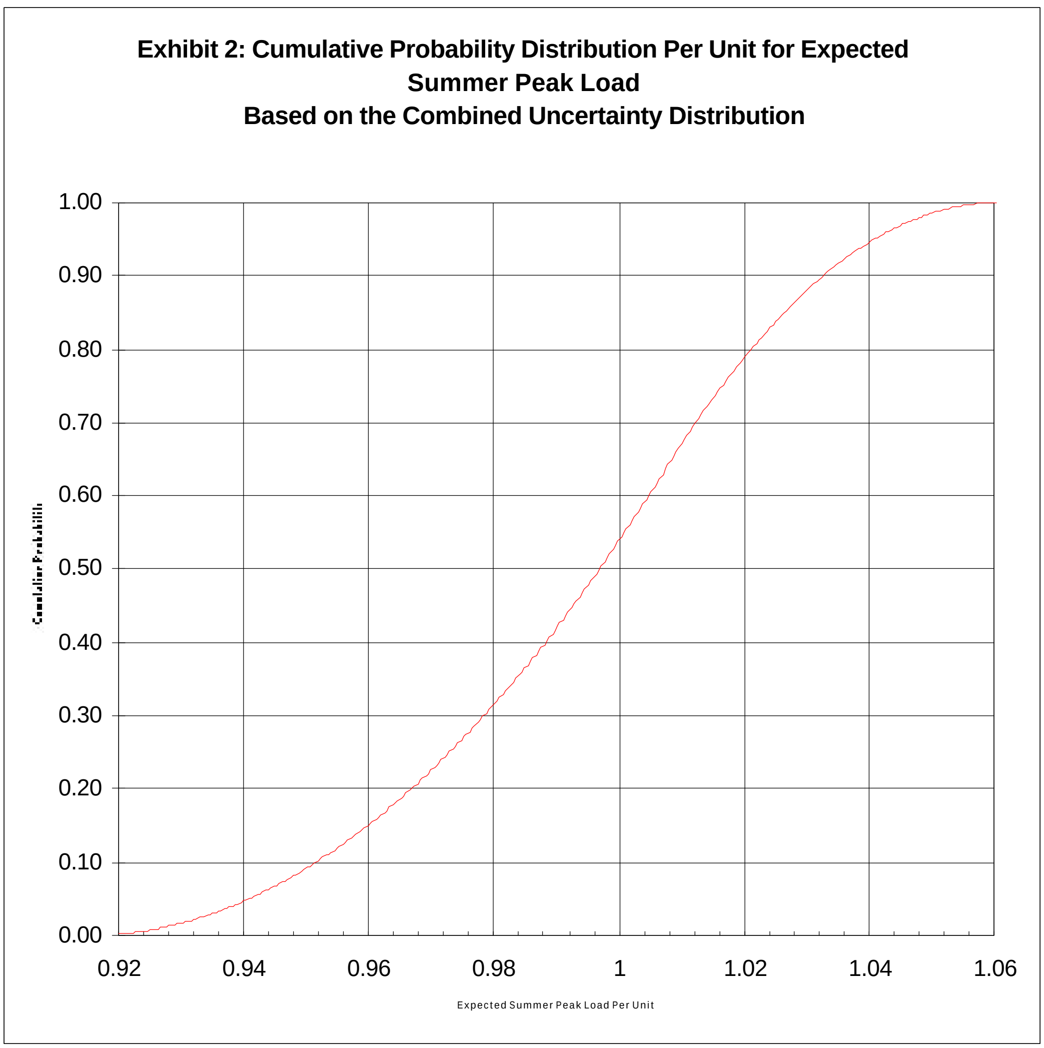
The load growth uncertainty is now ± 1.5% as opposed to last years value of -0% and +3%. This reflects the use of the ISO forecast, instead of the Transmission Owner forecasts, and therefore includes load that might have been unaccounted for in the past.

<u>Combined Uncertainty</u>: The probability distribution for the two distributions must be combined into a single distribution. The result of this process was the following distribution for load uncertainty one-year ahead:

Prob. %	Per Unit of Peak Load	Load (MW)
0.62	0.921	28100
6.06	0.937	28580
24.17	0.965	29440
38.30	0.997	30410
24.17	1.022	31180
6.06	1.044	31830
0.62	1.056	32200

The same probability distribution is used for all areas but with each areas own load variation.

Below is a graph showing the cumulative combined probability:



TRANSMISSION CAPACITY MODEL

The NYCA is divided into 11 Load Zones. The boundaries between these zones and between adjacent control Areas are called interfaces. The maximum value of power that can flow across these interfaces is modeled. Different limits can be modeled in each direction. See the diagram on the next page.

The values are the emergency transfer limits and were provided by the CP-8 database for external interfaces and NYPP transmission studies for internal interfaces. The NYPP values were taken from a letter from the NYPP Transmission Planning Advisory Subcommittee to the NYPP Resource Planning Subcommittee dated May 10, 1996. The Dysinger-East and West Central limits were revised based on the 1997 NYPP Summer Operating Study.

Changes from last years study:

- The IMO and ISO-NE limit revisions are based on those reported in the NYISO Summer 2000 Operating Study report.

- The Hydro Quebec limit is based on a recent ISO decision to respect a 1500 MW voltage limit on the interface with HQ.

- The interfaced limit with PJM reflects the more conservative assumptions of the NYISO Summer 2000 Operating Study report about availability over the Con Edison PARS.

- NYPA's FACTS Phase I project consisting of two (2) Statcoms at Marcy and a capacitor bank at Oakdale was assumed in-service. In addition, the Fraser SVC was assumed in-service.

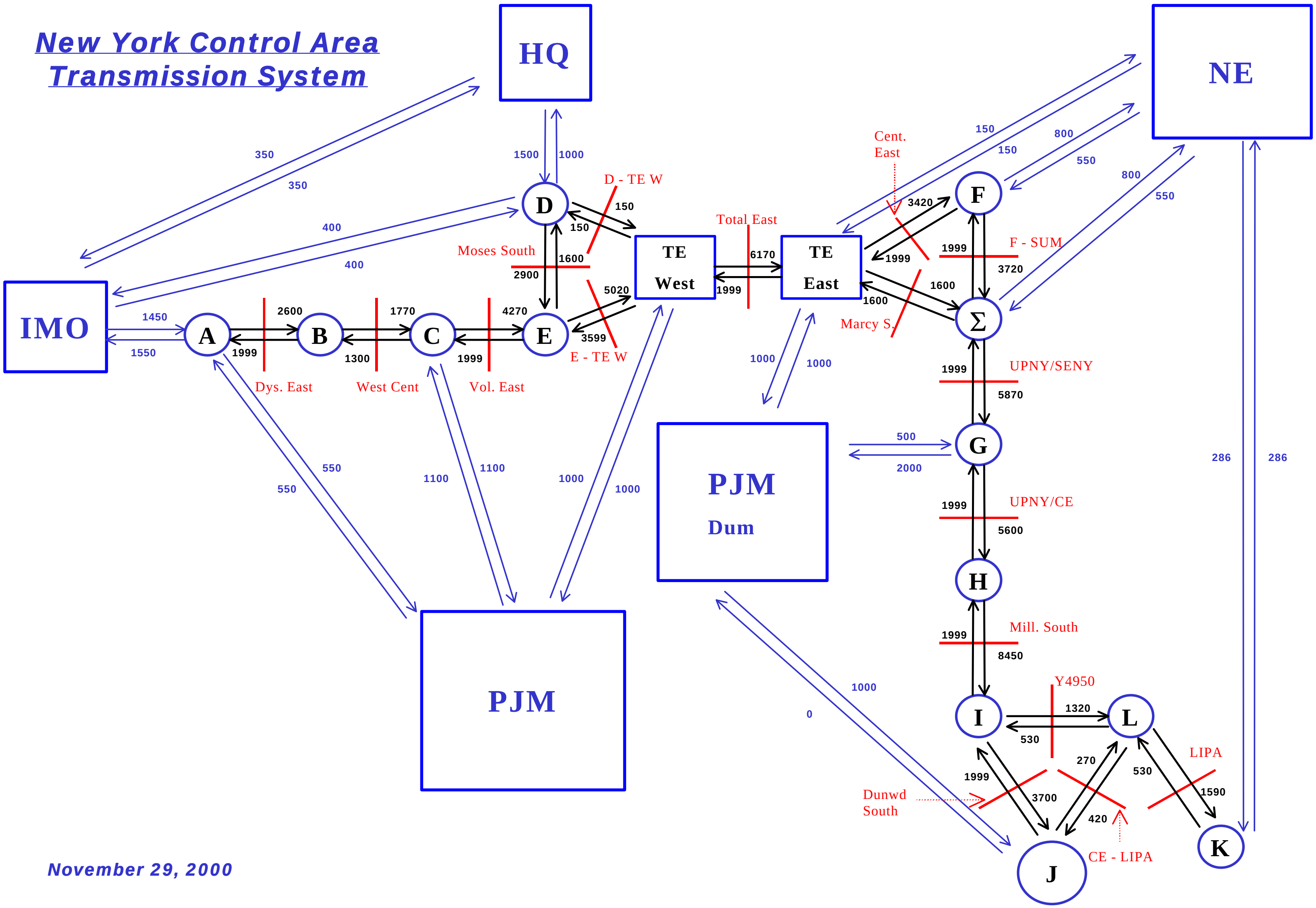
- The Norwalk Harbor tie limit was increased to reflect work performed at Northport by LIPA.

- The LIPA import limit was increased to reflect operating to STE post contingency ratings which would occur prior to shedding load.

The emergency limits are used because the study is looking for times when the system is in trouble, and at that time the emergency limits would be used.

The downstate cable systems were modeled with forced outages. This is because when a cable does fail it takes weeks to repair. These forced outages are modeled as a distribution of MW reduction in transfer limit and a probability of occurrence. The starting point transfer limit for Dunwoodie-South is approximately the sum of the normal ratings on the 345 kV and 138 kV cables from the North. This starting point transfer limit is possible because of the phase angle regulator control and generator quick start capability within the Con Edison system.

New York Control Area Transmission System



November 29, 2000

There are some explanations needed to clarify the above-mentioned diagram. All the power flows into New York from PJM, are set up to go through the Total East interface. The PJM Dummy area is set up to model the flows that can be allowed with the Con Edison/PJM phase shifters. While it is possible to have a flow of 3500 MW into this dummy area, only 1000 MW can reach area J through the two Hudson Farragutt and the Linden Goethals phase shifters.

The Σ area is also a dummy area that limits the total flow from upstate to downstate.

Area L is another dummy area that limits the flows between areas I, J and K.

COMPARISON OF ASSUMPTIONS USED IN THE 2000AND 2001REPORT

While some of the following assumptions have not been updated, they have all been reviewed to be sure that they are still current and appropriate.

BASE CASE ASSUMPTION	2000 REPORT	2001 REPORT
NYCA Capacity	Only units with ICAP contracts	All Capacity in the NYCA
NYCA Unit Ratings	Based on 1999 Yellow Book	Based on 2000 Gold Book
Planned Capacity	Current	Current, See Page 13
Unit Availability	NERC-GADS 1987-1996	NERC-GADS 1987-1996
Unit Maintenance Schedule	NERC-GADS 1987-1996	NERC-GADS 1987-1996
Generating Capacity Uncertainty	+1.5% adder for forced outage rate uncertainty	+1.0% adder for temperature, environmental, etc.
Neighboring Areas - all except PJM	NPCC CP-5 Study	NPCC CP-8 Study
Neighboring Area - PJM	Developed from public information	Used model developed for 2000 Report.
Load Model	1995 NYCA shape	1995 NYCA shape
Peak Load Forecast	1999 Yellow Book	2000 Gold Book
Load Model Uncertainty	Included weather and load growth models	Includes weather and an updated load growth model
External ICAP	Grandfathered plus 1500 MW from PJM	Grandfathered plus 600 MW from HQ and 500 MW HQ to PJM
Emergency Operating Procedures	Current	Updated for 2001 Report
Locational Capacity Requirements	NYC - 80% min., LI - 93% min.	Used assumptions from 2000 Study
Transfer Limits	Current	Current. The significant changes are: 1. use of emergency limits on the Con Ed - LIPA interface; 2. reduce HQ - NYCA direct tie from 1800 MW to 1500 MW; and 3. include HQ-IMO tie.

APPENDIX B

DETAILS OF STUDY RESULTS

INTRODUCTION

Appendix B provides details of the MARS case results referenced in the body of this report. This includes results of the base case and various sensitivities cases, as well as an analysis of emergency operating procedures for the base case IRM.

BASE CASE AND SENSITIVITY CASE RESULTS

Table B-1 summarizes the 2001 capability year IRM requirements under base case assumptions, as well as under a range of assumption changes from the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination.

TABLE B-1
STUDY RESULTS

Case #	Description	NYCA Ext ICAP Rep.(MW)	NYCA Ext. Ties Rep.?	IRM *
1	**Base Case** **	**2253**	**Yes**	**17.1%**
2	NYCA Isolated	0	No	23.2%
3	No ext ICAP	0	Yes	12.7%
4	2000 Study Load Forecast Uncertainty	2253	Yes	19.3%
5	2000 Study EOPs	2253	Yes	17.3%
6	2000 Study Transfer Limits (excludes effect of HQ-IMO Tie)	2253	Yes	16.2%
7	2000 Study NE-LI Tie Limit	2253	Yes	17.3%
8	Grandfathered External ICAP Only	1653	Yes	14.0%
9	Remove HQ-IMO Tie	2253	Yes	18.1%
10	No Load Forecast Uncertainty	2253	Yes	14.5%
11	Without Addition of New Units & Additional Capacity	2253	Yes	17.3%
12	No Statewide Voltage Reductions	2253	Yes	18.6%
13	Delay All Planned New Capacity	2253	Yes	17.3%
14	1 in 15 Years Disconnections	2253	Yes	18.0%
15	1 in 15 Years Disconnections & No Statewide Voltage Reductions	2253	Yes	19.8%
16	No NYC Voltage Reductions	2253	Yes	18.1%
17	No Emergency Assistance from PJM	2253	Yes	20.8%
18	Reduce All Internal Transfer Limits by 10%	2253	Yes	17.8%
19	Extreme Load	2253	Yes	***
20	50% of Planned Capacity Delayed	2253	Yes	17.3%
21	Additional 100 MW Special Case Resources in NYC	2253	Yes	17.0%
22	Combined Case 12, 17 & 20	2253	Yes	23.8%

* Installed reserve required to maintain NYSRC criterion of 0.1 days/year LOLE.

** Base Case model and assumptions are described in Appendix A.

*** Refer to the description of the sensitivity results on page 36.

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. In the base case, the study shows that approximately two voltage reductions per year would be implemented to meet the once in 10 years disconnection criterion. The expected frequency of all EOPs for the base case are provided in Table B-2.

TABLE B-2
Implementation of Emergency Operating Procedures *
Base Case Assumptions (IRM = 17.1%)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Emergency Purchases	9.9
5% manual voltage reduction	2.4
30 Minute reserve to zero	2.3
5% remote control voltage reduction	1.4
Voluntary load curtailment	0.9
Public Appeals	0.7
10 minute reserve to zero	0.5
Customer disconnections	0.1

* See Appendix A, Table A-4

.

SENSITIVITIES

The following sensitivity cases were run:

Analyses were conducted that reduced all internal transmission limits and inter-Area transfer limits by 10%. The results of this analysis increased the required IRM by 0.7 percentage points. (Case 18 - Case 1).

Analyses were conducted to show the effect of load uncertainties. The following cases were run:

> The base case with no load forecast uncertainty reduced the IRM by 2.6%. (Case 1 - Case 10).
>
> An extreme weather sensitivity assumed the 90% percentile load of 31,500 MW using the 1999 load shape reduced the statewide LOLE to 0.02 days/year (Case 19).

Analyses were conducted to compare the effects of changing study assumptions from the 2000 to the 2001 Study. The following cases were run:

> The load forecast uncertainty model revision reduced the required IRM by 2.2 percentage points. (Case 4 - Case 1).
>
> The EOP model revision reduced the required IRM by 0.2 percentage points. (Case 5 - Case 1).
>
> The transfer limits model revisions increased the required IRM by 0.9 percentage points. (Case 1 - Case 6).
>
> A case was run to isolate the effect of the increased capability from NE to Long Island. The increased capability reduced the required IRM by 0.2 percentage points. (Case 7 - Case 1).

Other sensitivities run were:

> The base case excluding all external ICAP reduced the required IRM by 4.4 percentage points. (Case 1 - Case 3).
>
> A case with one in fifteen year disconnections (0.07 LOLE) resulted in an increase of 0.9 percentage points in the IRM from the base case. (Case 14 - Case 1).
>
> The base case with no statewide voltage reductions resulted in an increase of 1.5 percentage points in the IRM. (Case 12 - Case 1).
>
> A case with one in fifteen year disconnections (0.07 LOLE) and no statewide voltage reductions resulted in an increase of 2.7 percentage points in the IRM from the base case. (Case 15 - Case 1).

The base case with no voltage reductions allowed in NYC resulted in an increase of 1.0 percentage points in the IRM. (Case 16 - Case 1)

The base case with no emergency assistance available from PJM resulted in an increase of 3.7 percentage points in the IRM. (Case 17 - Case 1).

The base case with only grandfathered external ICAP resulted in a decrease of 3.1 percentage points in the IRM. (Case 1- Case 8).

The delay of half and all of the new planned capacity each increased the required IRM by 0.2 percentage points respectfully from the base case. (Case 20 and Case 13 - Case 1).

The effect of delaying all new planned capacity and capacity produced from additional capacity testing increased the required IRM by 0.2 percentage points from the base case. (Case 11 - Case 1).

An extreme sensitivity was run that assumed no statewide voltage reductions, no emergency assistance from PJM and the delay of 50% of planned new capacity. This sensitivity increased the IRM by 6.7 percentage points from the base case (Case 22 - Case 1).

The results of all cases are presented in Table B-1.