NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENTS FOR THE PERIOD MAY 2000 THROUGH APRIL 2001

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

Executive Committee Resolution
and
Technical Study Report

January 31, 2000

APPROVAL OF STATE-WIDE INSTALLED RESERVE MARGIN FOR THE MAY 1, 2000 THROUGH APRIL 30, 2001 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'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, 2000 through April 30, 2001 capability year is 15.5% under base case conditions; and

WHEREAS, the study considered the following sensitivities and determined that the IRM could vary from 11.8% to 17.0% depending on key assumptions:

- Internal and external transfer limits
- Load forecast uncertainty distribution
- Source and magnitude of external ICAP
- Emergency assistance from neighboring areas
- Generator unit availabilities; 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
- Other uncertainties associated with electric industry restructuring, including regulatory and legislative actions; and
- Further consideration and review of the experiences of the Summer of 1999, including the impact on New York City and other major load areas

WHEREAS, with due recognition that the current NYCA IRM is set at 22.0%;

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 set the NYCA IRM at 18.0% for the May 1, 2000 through April 30, 2001 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, 2001.

Adopted by the NYSRC Executive Committee on January 31, 2000.

TECHNICAL STUDY REPORT

January 31, 2000
New York State Reliability Council, L.L.C.
ICAP Working Group

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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 2000 through April 2001 (year 2000) 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 2000 state-wide IRM requirements to be 15.5%[1] using base case assumptions. The study also showed that for various scenarios tested, the IRM sensitivity of changing several key study assumptions, the required IRM would vary from 11.8% to 17.0%.

The IRM of 15.5% determined in this study compares to the current 22% requirement, which is based on a 1987 study prepared by the New York Power Pool (NYPP) and an 18% requirement based on a NYPP study conducted in 1996. This latest study's six and one-half percentage point reduction in the required IRM from the current 22% requirement can be attributed primarily to the present use of smaller generating units and higher actual average system unit availability and lower system load factor (sharper peak) than represented in the 1987 study.

STUDY PROCEDURE

This study used a probabilistic approach for determining required reserves. The technique used, which is 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, for determining 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 in New York is stated in the NYSRC Reliability Rules and is consistent with NPCC Standards. This reliability criterion is as follows:

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

> "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 resourc**e** deficiencies, on the average, will be no more than once in ten years."

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 study procedure, methodology and results in some detail.

STUDY RESULTS

The results of this study shows that the statewide required IRM is 15.5% for the year 2000. This conclusion is based on a MARS analysis using base case study assumptions described in Appendix A and the study procedure described in Appendix B. Maintaining a minimum installed reserve of 15.5% over the forecast NYCA 2000 summer peak would achieve applicable NYSRC and NPCC reliability criteria under these study assumptions. The base case analysis (for details see Appendix B, Table B-2) included a representation and assessment of the following parameters:

- *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 11.2 percentage points (Table B-2, Case 2 - Case 4) lower than otherwise required, under the base case assumptions used in this study.

- *Load Forecast Uncertainty.* It is recognized that some uncertainty exists relative to forecast NYCA loads for the year 2000. This uncertainty was represented using a load forecast probability distribution 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 3.7 percentage points (Case 13 - Case 9).

- *Generating Unit Forced Outage Uncertainty.* Although the forced outage rate (FOR) of each generating unit modeled in the study is based on historical averages, on any given day, system capacity on forced outage may be significantly higher or lower than the expected value. This phenomenon was recognized in the MARS analysis using a FOR uncertainty model derived from historical trends. This has the effect of increasing the required IRM by 1.5 percentage points (Case 13 - Case 6).

- *Transmission Constraints.* Use of the MARS model in this study included an assessment of the adequacy of the NYCA transmission system to deliver the necessary 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 impact the LOLE of these areas, as well as the statewide LOLE. The study showed that the statewide required IRM must be increased by 0.8 percentage points (Case 4 - Case 3) to compensate for the reliability impacts of these transmission constraints.

  In addition, forced outage rates were applied to the cable system interfaces in the southeastern NYCA. The study showed that the statewide required IRM must be increased by 0.9 percentage points (Case 13 - Case 7) to compensate for the reliability impacts of these transmission constraints.

- *NYCA installed capacity located in neighboring control areas (external ICAP).* Locating a portion of the NYCA's required installed capacity in neighboring control areas PJM (Pennsylvania, New Jersey, and Maryland Interconnection), ISO New England (NE), Ontario Independent Market Operator (OH), or Hydro-Quebec (HQ), 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 a maximum external ICAP of 3150 MW, made up of approximately 1650 MW of "grandfathered" external ICAP with the remaining 1500 MW located in PJM. Only PJM was selected for the location of 1500 MW of external ICAP in the base case because it is the only control area that currently meets NYISO's non-recallability requirements for ICAP suppliers. This external ICAP representation increases the required IRM by 0.4 percentage points (Case 13 - Case 4). Figure1 shows the required IRM impacts of considering alternate external ICAP representations.

The required value of installed capacity 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 2 shows the sensitivity of IRM results to several alternate assumptions. The sensitivity study results in this figure show a required IRM range of 11.8 to 17.0%.

The NYISO will implement emergency operating procedures (EOPs) as required to minimize customer disconnections. The study indicates that if a 15.5% 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-1 for expected average use of other EOPs).

COMPARISON TO 1987 NYPP STUDY

The results of this study, as well as a prior NYPP study (using similar assumptions) conducted in 1996, show a lower required IRM than that of a 1987 NYPP study which showed a required IRM of 22%. The 1987 study was the basis of NYPP's required IRM through 1999. The primary reasons for this are: a) higher generating unit availability in today's system, b) addition of smaller generating units during the 1990's and c) a lower system load factor. On the other hand, the representation of load forecast and forced outage uncertainties in the 1996 study and this most recent study, partially offsets the IRM reduction benefits of higher unit availability and smaller units. Also, this study for the first time applied forced outage rates to the cable system interfaces in southeastern NYCA providing an additional offset. Table 1 is a comparison of the required IRM impacts of key parameters associated with these studies.

In comparison to the prior studies, the 1999 study utilized an improved model and data base.

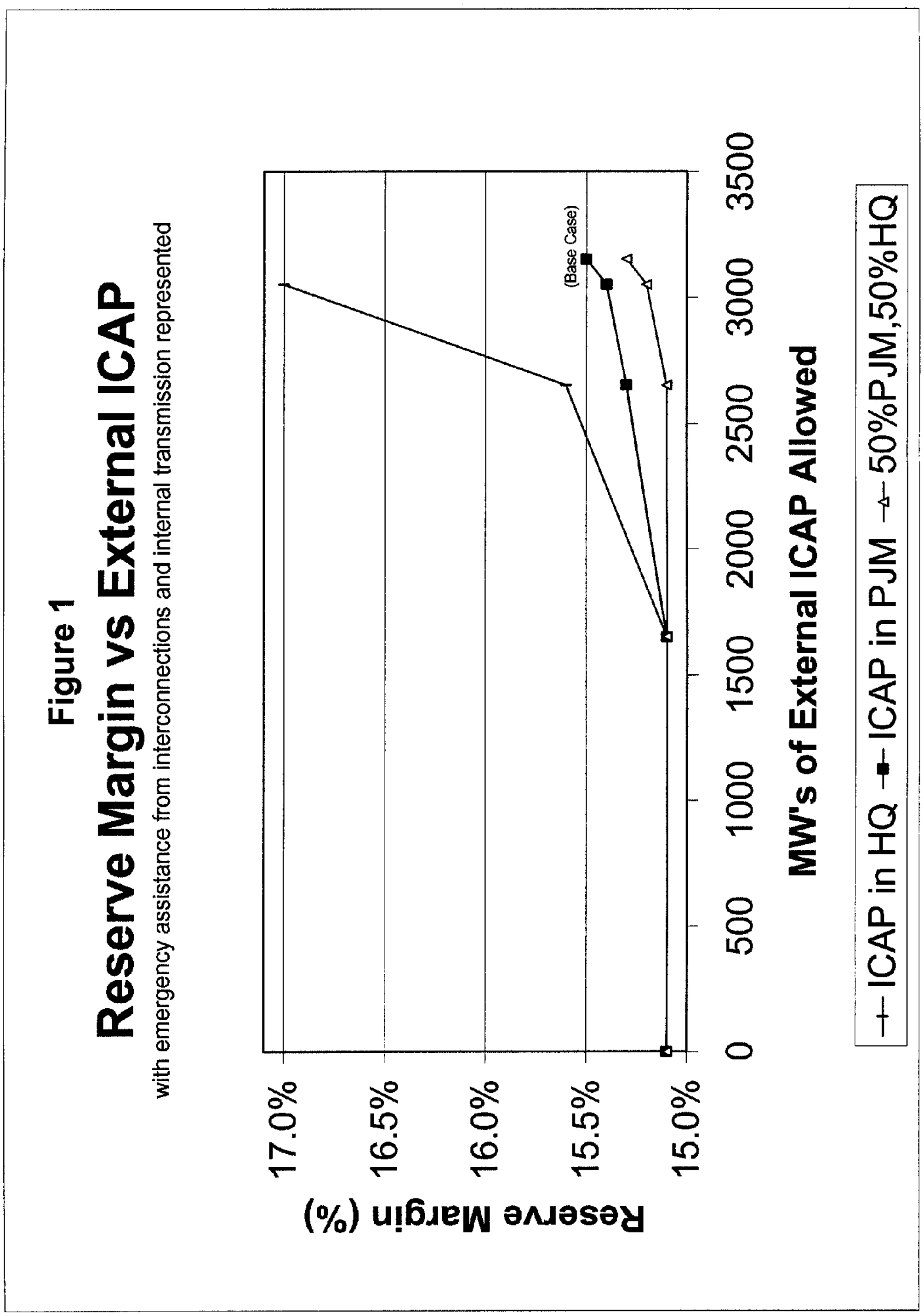
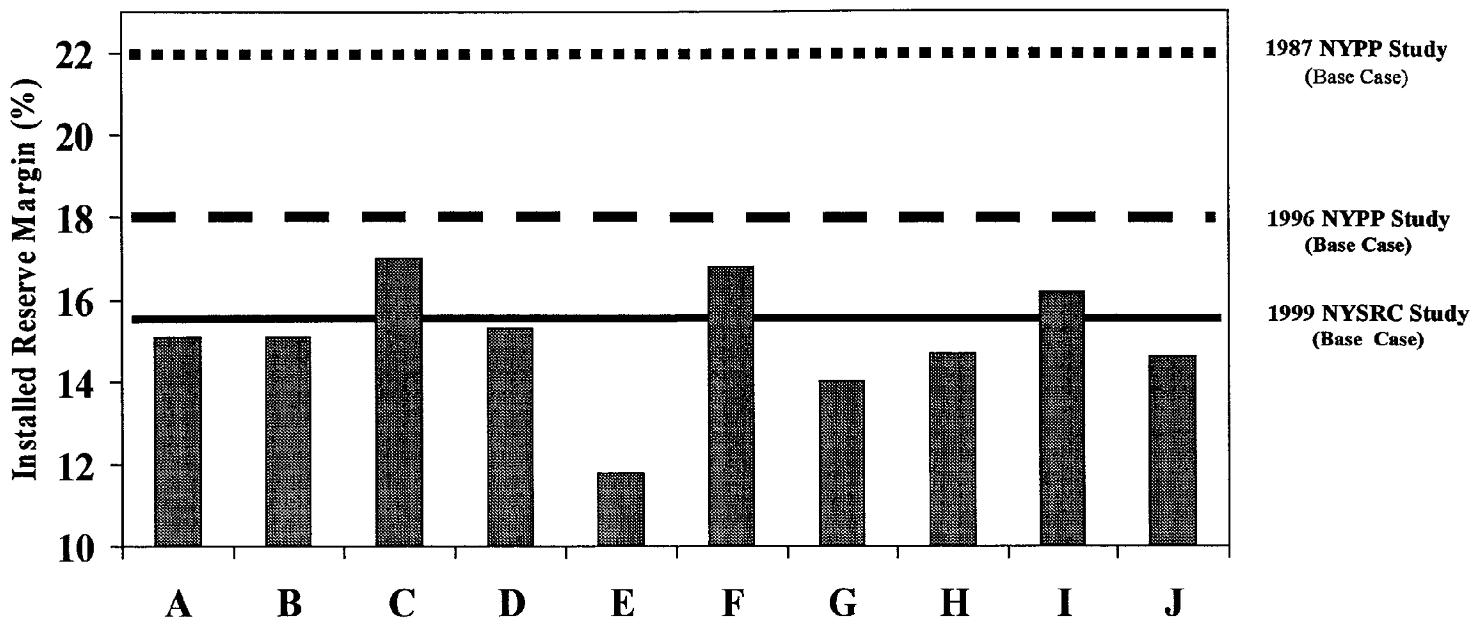


Figure 1
Reserve Margin vs External ICAP
with emergency assistance from interconnections and internal transmission represented

Figure 2

NYSRC BASE CASE & SENSITIVITY IRM RESULTS



	Sensitivities – changes from Base Case assumptions
A	No Grandfathered (GF) or External ICAP – **15.1%** **(Case 4)**
B	Only GF external ICAP represented – **15.1%** **(Case 11)**
C	External ICAP – all 1400 MW (beyond GF) from HQ – **17.0%** **(Case 15)**
D	External ICAP – 750 MW each (beyond GF) from HQ & PJM – **15.3%** **(Case 16)**
E	Load Forecast Uncertainty not represented – **11.8%** **(Case 9)**
F	Greater Load Forecast Uncertainty than in base case – **16.8%** **(Case 10)**
G	Forced Outage Rate Uncertainty not represented – **14.0%** **(Case 6)**
H	Internal Transmission Limits not represented – **14.7%** **(Case 5)**
I	Internal (not cable system) & External Transmission Limits reduced by 10% – **16.2%** **(Case 8)**
J	Cable interface Forced Outage Rates not represented – **14.6%** **(Case 7)**

Table 1
COMPARISON WITH 1987 STUDY

	1996 Study		*1999 Study*	
	Increment	***Pool Requirement***	***Increment***	***Pool Requirement***
Pool Requirement 1987		**22%**		**22%**
Correct Hydro Calculation	**+ 1%**	**23%**	**+ 1%**	**23%**
Revised Load Model	**- 2%**	**21%**	**- 6.0%**	**17.0%**
Generation Mix (Smaller Units)	**- 4%**	**17%**	**- 4%**	**13.0%**
NYPP Unit Availability (+5%)	**- 8%**	**9%**	**- 8%**	**5.0%**
Tie Assistance (Modeling Improvements)	**+ 4%**	**13%**	**+ 3%**	**8.0%**
Unit FOR Uncertainty	**+ 2.5%**	**15.5%**	**+ 1.5%**	**9.5%**
Load Forecast Uncertainty	**+ 2.5%**	**18%**	**+ 4%**	**13.5%**
Internal Transmission Constraints	**0%**	**18%**	**+1%**	**14.5%**
Forced Outage Rates on Cable System	**0%**	**18%**	**+1%**	**15.5%**

Note: The difference in impacts between the 1996 and 1999 study are due to improved model and database.

APPENDIX A

ICAP RELIABILITY MODEL
AND
ASSUMPTIONS

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

Figure A-1
NYCA ICAP Modeling

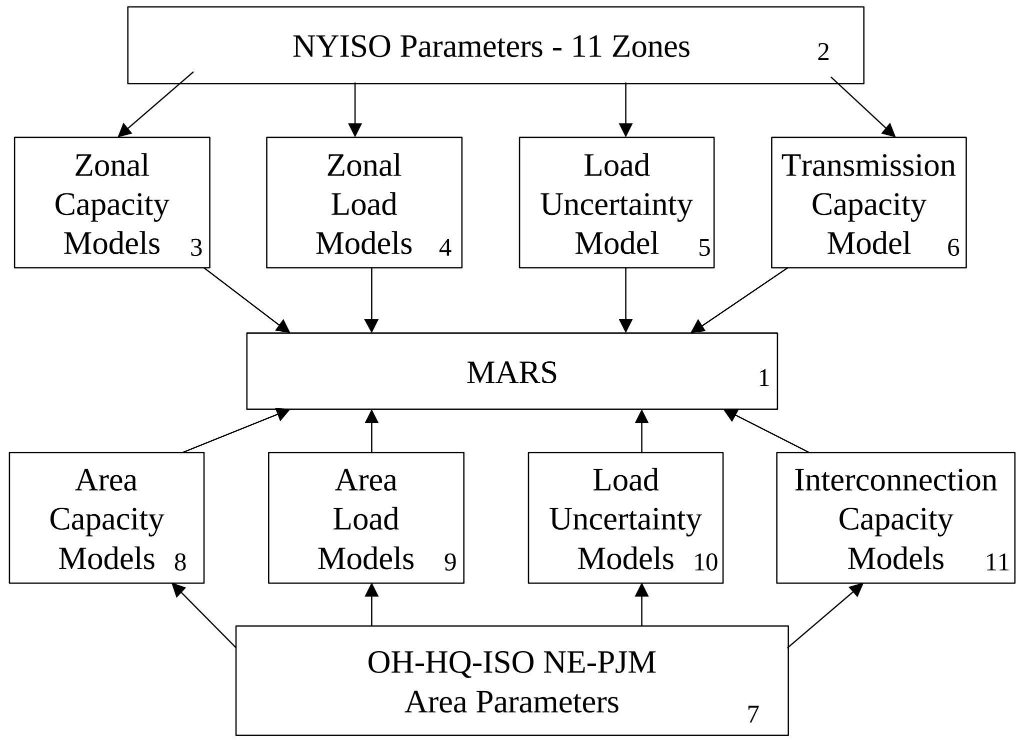


Table A-1

Details on ICAP Modeling

Diagram Box No.	Name of Parameter	Description	Source	Reference
1	**MARS**	**The General Electric Multi-Area Reliability Simulation Program**		**See page 11 of this report.**
2	**11 Zones**	**Load Areas**	**Fig. A-2 page 13 of this report.**	**NYISO Accounting & Billing Manual**
3	**Zonal Capacity Models**	**Generator Models for each generating unit in zone .**		**See page 14 of this report.**
		Historical Outage Data.	**GADS Data**	**See Page 14**
		Forced Outage Rate Uncertainty	**GADS Data**	**See page 15**
	Emergency Operating Procedures	**Unit Ratings.**	**1999 Yellow Book.**	
		Reduces load during emergency conditions to maintain operating reserves.	**ISO**	**See page 23 of this report.**
4	**Zonal Load Models**	**Hourly loads**	**NYPP Historical load shape for 1995.**	**See page 25 of this report.**
			NYPP peak forecasts.	**1999 Yellow Book.**
5	**Load Uncertainty Model**	**Account for forecast errors due to weather and economic conditions.**	**Historical Data**	**See page 27 of this report.**
6	**Transmission Capacity Model**	**Emergency transfer limits of transmission interfaces between zones.**	**NYPP transmission studies.**	**See page 30 of this report.**
7	**OH, HQ, ISO NE-PJM Area Parameters**	**See items 8-11.**		
8	**Area Capacity Models**	**Generator Models in neighboring Areas**	**NPCC CP-5 study for NPCC Areas. MAAC Report and NERC Average outage rates for PJM**	**See page 24 of this report.**
9	**Area Load Models**	**Hourly Loads**	**NPCC CP-5 study for NPCC Areas PJM Web site**	
10	**Load Uncertainty Models**	**Account for forecast errors due to weather and economic conditions**	**CP-5 Study**	**See page 29 of this report.**
11	**Interconnection Capacity Models**	**Emergency transfer limits of transmission interfaces between areas.**	**NPCC CP-5 Study**	**See page 30 of this report.**

MULTI-AREA RELIABILITY SIMULATION PROGRAM (MARS)

The General Electric Company's MARS program 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, 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. 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 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:

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

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

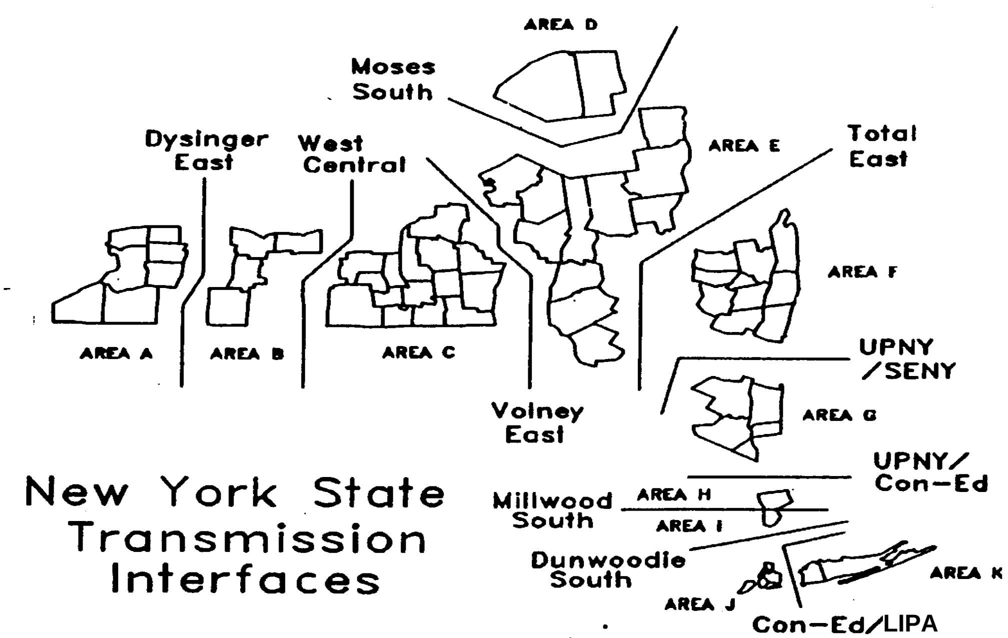
From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state of each other state.

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.

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 1550 MW of Energy Only NUGs were excluded. Energy Only NUGs are generators without capacity contracts. These assumptions provided an initial IRM of 12.8% based on a forecast NYCA peak load of 29550 MW..

NYCA Models

Ratings

The unit ratings were obtained from the "1999 Load and Capacity Data Report of the New York Power Pool" (Yellow Book). The Energy Only NUGs are not included, because they have no contractual requirements to provide capacity to the NYCA.

Units that are not in the NYCA are modeled in their actual locations and firm purchases from them are modeled as transactions.

Hydro Units

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model that is based on historical water flows. The Niagara Project is modeled at 2514 MW summer and 2524 MW winter. The St. Lawrence Project is modeled at 889 MW.

While energy production from these projects is expected to be lower in 2000 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 intervals. An adjustment was made for each interval 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 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 are 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 NYPP member companies because certain outages were the result of extraordinary circumstances. A -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 GADS data for N.Y. units, shows that historically, there are no upward or downward availability trends for the types of generator units modeled in the study. Therefore, the Working Group concluded the 10 year average of historic outage rates is appropriate for this study.

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 member companies.

Forced Outage Uncertainty

The forced outages rates used in the study are average or expected values. However, on any day the capacity on forced outage can be significantly higher or lower than the expected value. When they are above the expected value, there is a significant impact on system reliability. Including forced outage uncertainty in the analysis captures this phenomenon.

The NERC-GADS data for the years 1982-1991 was used to generate a methodology for Forced Outage Rate Uncertainty.

- Actual MWs - the NERC-GADS events are used to generate the Actual MWs on Forced Outage for each hour of this ten year period.

- Expected MWs - For each hour, all units that are not on maintenance are multiplied by their Forced Outage Rates. These MWs are added together.

The difference between the Actual MWs and the Expected MWs is the margin used to generate the following model. The results are shown graphically in Figure A-4.

The margins for the 87,600 hours are ranked in ascending order and are divided into bins with a range of ten MWs. A Dalenius-Hodges[1] approach was used, in which the number of occurrences in each bin are used to determine the optimal states for a seven state model.

Each state has a mean MW and a probability calculated from all the hours that fall within it. This is shown graphically in Figure A-5.

[1] Tore Dalenius and Joseph L. Hodges, Jr., "Minimum Variance Stratification," Journal of the American Statistical Association, vol. 54, March 1959, pp. 88-101.

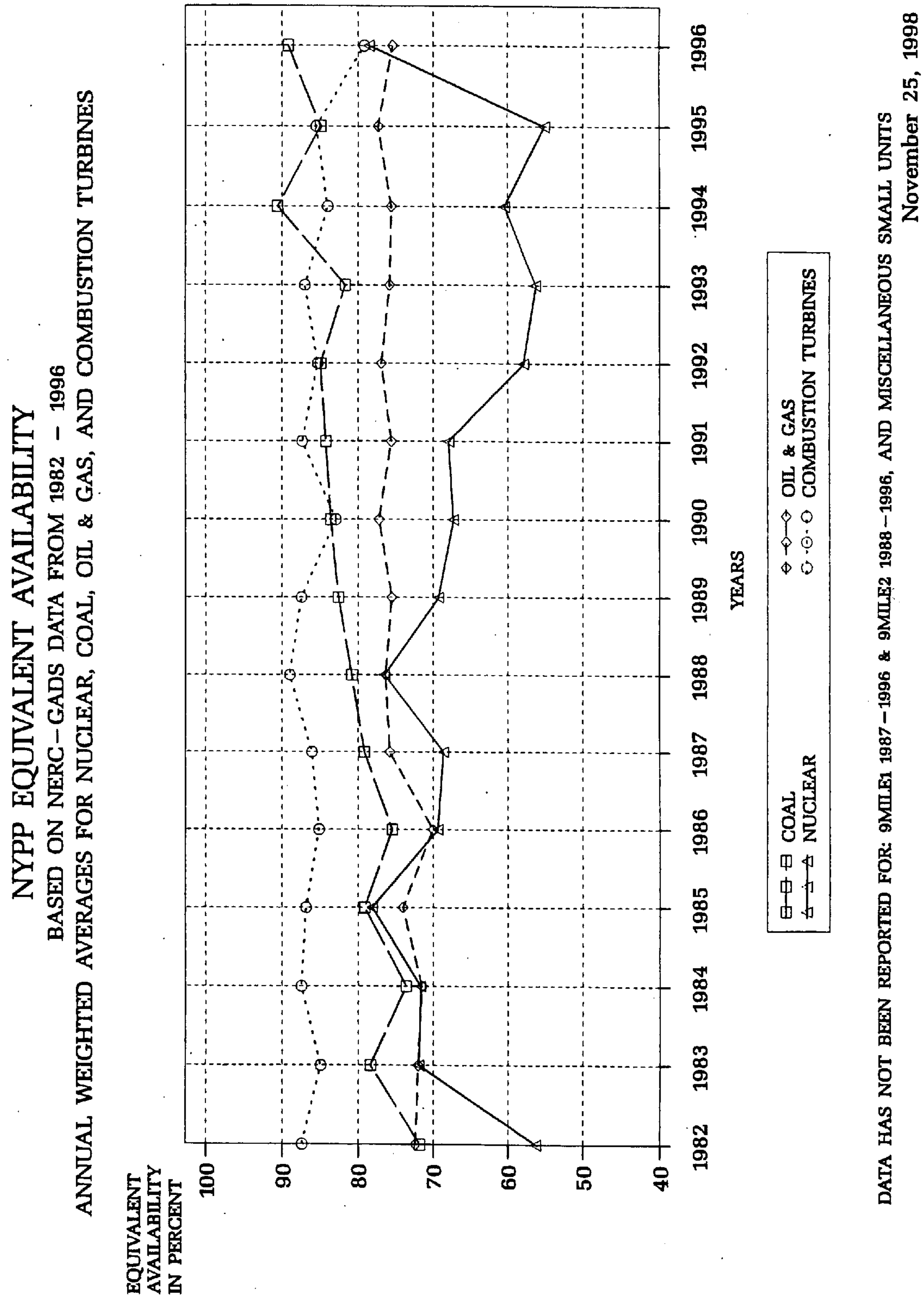
William G. Cochran, Sampling Techniques, New York: John Wiley & Sons, third edition, 1977.

Leslie Kish, Survey Sampling, New York: John Wiley & Sons, 1965.

A reliability run is made for each of the seven states with the mean MW subtracted from the system capacity.

The annual LOLE of each run is then multiplied by the probability for that state and totaled to obtain the annual LOLE which incorporates forced outage uncertainty. This results in an increase of 1.5 percentage points to the NYCA reserve requirement.

Figure A-3



NYPP EQUIVALENT AVAILABILITY
BASED ON NERC-GADS DATA FROM 1982 - 1996
ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES
EQUIVALENT AVAILABILITY IN PERCENT
100
90
80
70
60
50
40
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
YEARS
COAL
NUCLEAR
OIL & GAS
COMBUSTION TURBINES
DATA HAS NOT BEEN REPORTED FOR: 9MILE1 1987-1996 & 9MILE2 1988-1996, AND MISCELLANEOUS SMALL UNITS
November 25, 1998

Figure A-4

Distribution of Actual Deviation of Forced Outages Around Expected Value

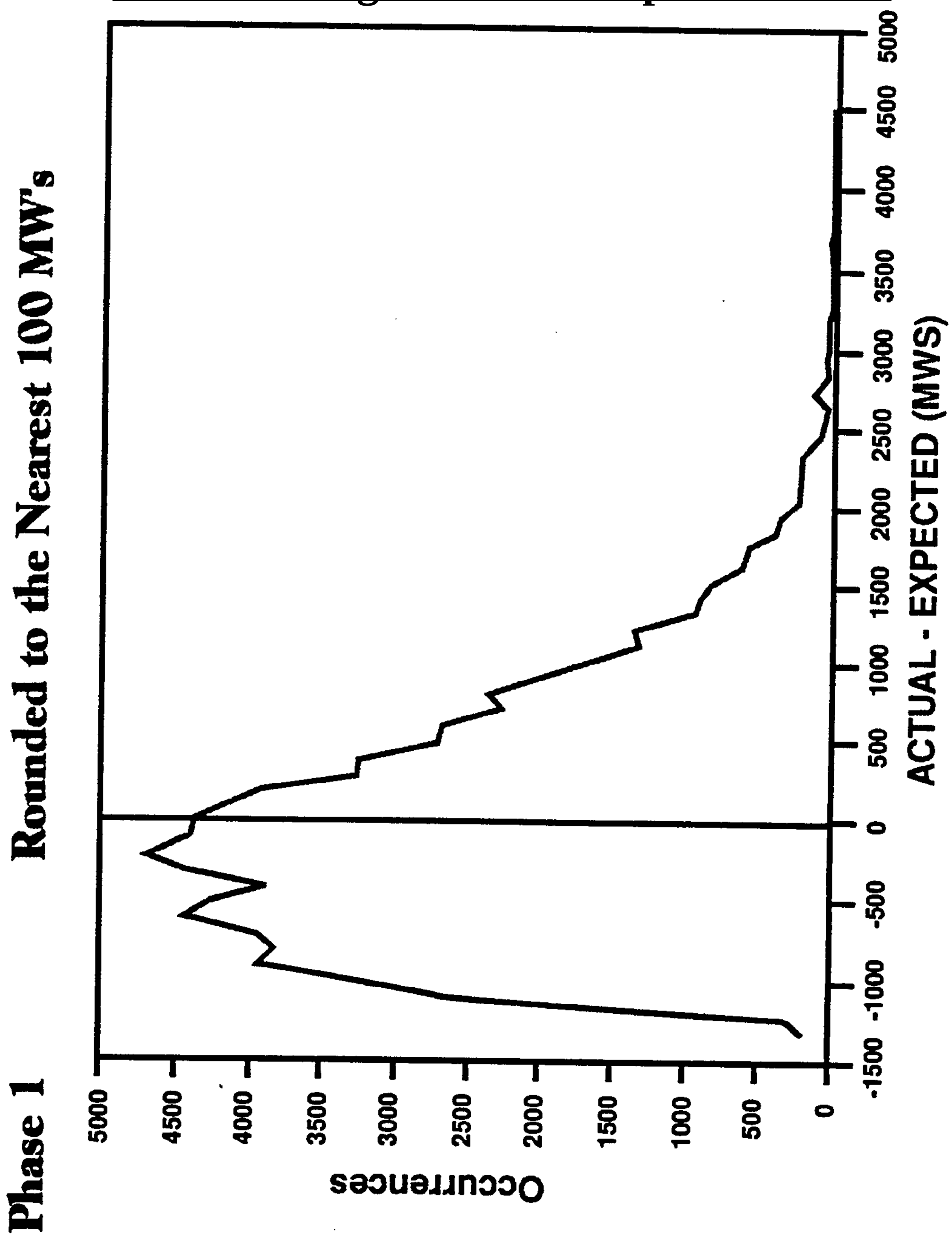
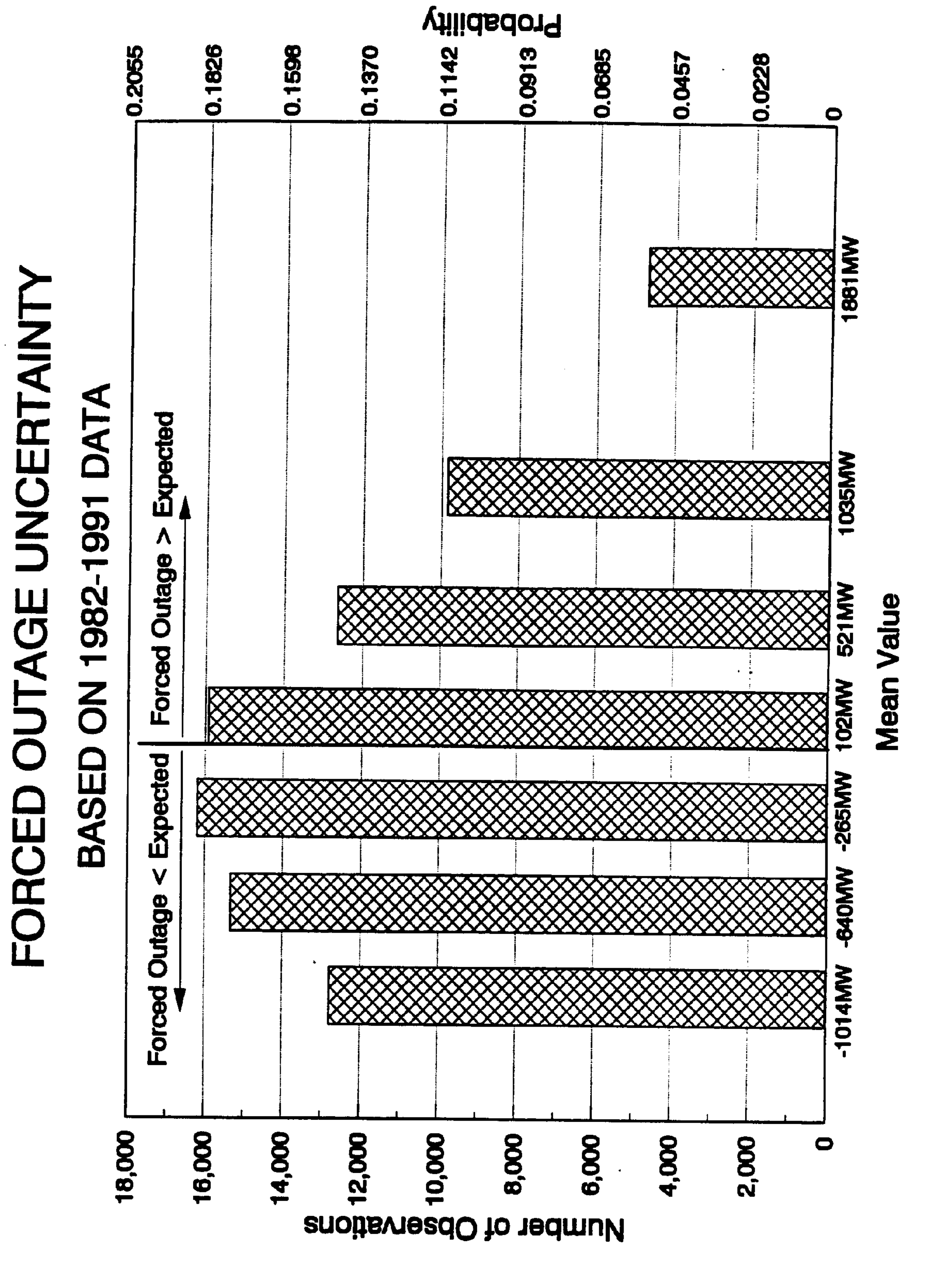


Figure A-5


FORCED OUTAGE UNCERTAINTY
BASED ON 1982-1991 DATA
Forced Outage < Expected
Forced Outage > Expected
Number of Observations
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Probability
0.2055
0.1826
0.1598
0.1370
0.1142
0.0913
0.0685
0.0457
0.0228
0
-1014MW
-640MW
-265MW
102MW
521MW
1035MW
1881MW
Mean Value

Maintenance Schedule

The maintenance schedule was developed from a 10 year (1987-1996) average of the NERC-GADS maintenance data. This included all types of maintenance outages. The NERC-GADS historical data also correlates well with the total maintenance data reported in the NYPP on-line dispatch data.

An outage pattern for each company is 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.

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 NYPP 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

WEEKLY RESERVE SUMMARY (MW) FOR POOL _NYPP_ FOR 2000
(MAINTENANCE SCHEDULED ON A POOL BASIS)

WEEK	PEAK LOAD	SCHED. OUTAGES	WEEK	PEAK LOAD	SCHED. OUTAGES
1	23,366	767	28	25,752	240
2	23,659	2,128	29	29,475	275
3	21,944	1,878	30	29,275	472
4	22,225	1,964	31	29,556	849
5	21,995	2,185	32	29,540	822
6	24,460	2,728	33	29,270	817
7	23,095	4,245	34	28,959	788
8	21,471	4,445	35	24,742	768
9	22,369	4,787	36	25,061	615
10	21,931	5,944	37	25,331	966
11	22,098	6,157	38	24,008	1,616
12	20,134	6,874	39	22,355	2,423
13	20,053	7,407	40	21,360	3,352
14	21,111	7,439	41	22,607	4,143
15	20,644	9,173	42	21,647	6,266
16	19,234	9,665	43	20,855	7,239
17	18,981	10,001	44	21,736	6,758
18	19,247	8,872	45	21,717	6,547
19	20,318	7,790	46	22,342	6,613
20	20,601	6,810	47	21,909	6,540
21	22,053	5,258	48	22,703	6,032
22	22,296	4,240	49	22,864	5,078
23	24,578	3,404	50	24,521	4,477
24	23,956	1,770	51	24,609	3,927
25	29,136	1,633	52	24,119	2,362
26	25,852	1,479	53	22,442	1,641
27	24,966	1,254			

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.

Table A-4

Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Purchase	Increase capacity	Varies
2	Cancel firm sales	Load relief	0 MW
3	5% manual voltage Reduction	Load relief	58 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW
5	5% remote voltage reduction	Load relief	465 MW
6	8% remote voltage reduction	Load relief	142 MW
7	Curtail member loads	Load relief	47.5 MW
8	Voluntary industrial curtailment	Load relief	352 MW
9	General public appeals	Load relief	153 MW
10	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
11	Customer disconnections	Load relief	As needed
Note: MW values are the maximum for year 2000 based on a summer load of 29550 MW.			

These procedures except for Step 6 were included in the computer runs because this is not readily available to the ISO operator.

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. This is modeled in the MARS program.

Transactions

All firm sales are modeled as listed in the "1999 Load and Capacity Data Report of the New York Power Pool" for the year 2000. The base case (New York as an isolated area) does not include firm purchases.

Neighboring Areas

The NPCC members Area models are based on the models that they provided for the NPCC study Review of Interconnection Assistance Reliability Benefits dated May 12, 1999 (CP-5). This study looked at the reliability models of the NPCC Areas to be sure that assistance from their neighbors wasn't being double counted.

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, 1993-1997. PJM's load model was obtained by scaling its actual 1995 loadshape to meet its 2000 projected summer peak.

The EOPs were removed from the NE and OH 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.

The assistance from East Central Area Reliability Council (ECAR) and the Maritime Provinces was also removed, limiting the outside help to the NYCA from the immediate neighboring Areas.

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 CP5 study concluded that the historical year 1995 was a good load shape to use to represent the forecasted year 2000. 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 2000 to the actual 1995 peak load.

Installed Reserve Study Load Shape

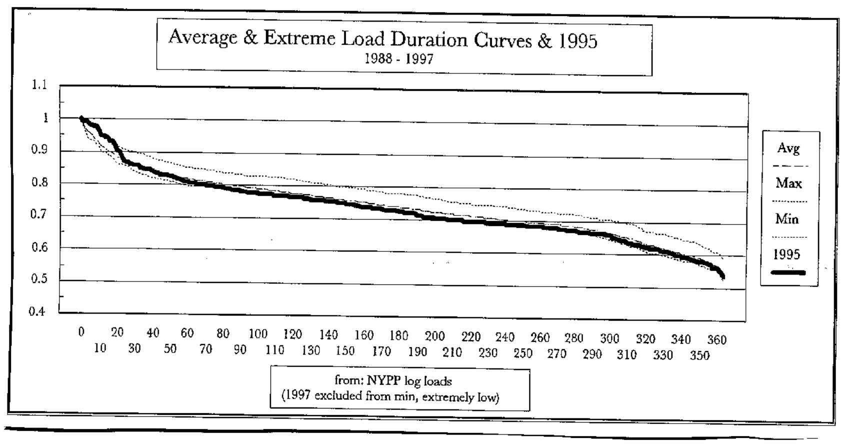
The load shape used in the Installed Reserve Study, and the Locational Requirements study before that, is based on work done for the 1999 CP5 study.

The CP5 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 Maritimes, OH, HQ, NE and NYPP) 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.

For NYPP, actual company load shapes for 1995 were used as templates and scaled up to meet the 1998 Yellow Book forecasts of summer and winter peaks and annual energies. Minor adjustments were made so that predicted NYPP summer and winter peaks were obtained.

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.

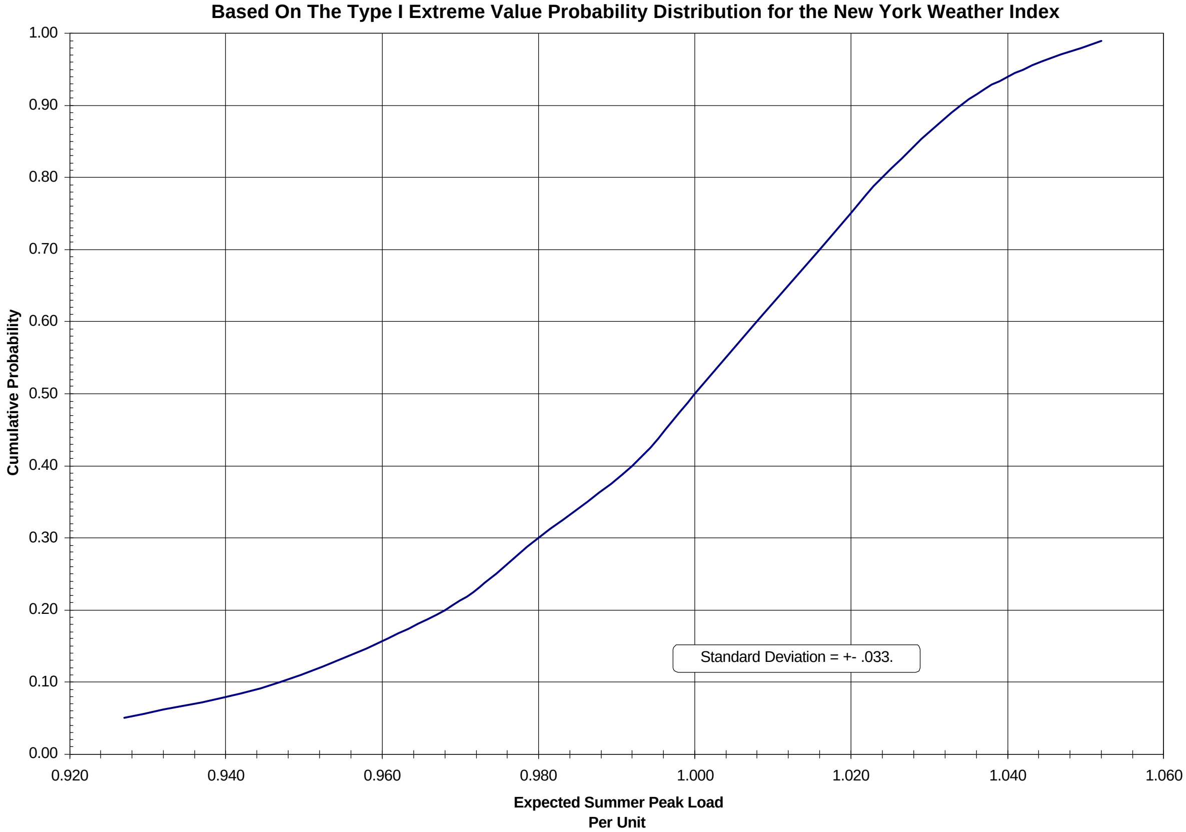
LOAD UNCERTAINTY MODEL

Load Forecast Uncertainty

The load model is a major underpinning of a LOLE study. However, it is also one of the major sources of uncertainty. This uncertainty arises from the fact that the study is based on load projections or forecast. The actual experienced load will vary from the forecast as a result of weather and forecast error. Historically, in NY, the total error has been dominated by weather in the near term and forecast error in the long term. The study is based on the year 2000. Thus, weather will be the dominant effect in this study. Also, when the two error structures are convolved together the combined effect should not be much larger than the effect of the larger effect by itself. Also, even if the LSE/Member System forecast were correct for their customer load, the load seen by the NYCA would exceed that forecast because of unaccounted for load of 1-2% (i.e.,wheel through and/or unaccounted for losses, and some load).

Weather Impact: Exhibit I below shows how the NYCA load can very per unit for weather. This cumulative probability distribution is based on weather data from 1950 to present 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

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



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.

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.

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 you will find 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	27185
6.06	0.934	27600
24.17	0.965	28515
38.30	1.000	29550
24.17	1.025	30289
6.06	1.049	31000
0.62	1.060	31325

Load Growth Uncertainty: This error consists of the forecast error of +-1.5% plus unaccounted for load of 1.5%. The unaccounted for load will tend to skew this error distribution to the positive side. This results in the following distribution:

Prob. %	Per Unit of Peak Load	Load (MW)
0.62	1.000	29550
6.06	1.005	29698
24.17	1.010	29846
38.30	1.015	29993
24.17	1.020	30141
6.06	1.025	30289
0.62	1.030	30437

<u>Combined Uncertainty</u>: The probability distribution for the two distributions must be combined or convolved 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	0.935	27630
6.06	0.948	28015
24.17	0.980	28960
38.30	1.015	29995
24.17	1.040	30730
6.06	1.066	31500
0.62	1.077	31825

The same probability distribution is used for all areas but with each areas own load variation from the CP-5 study.

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 CP5 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.

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.

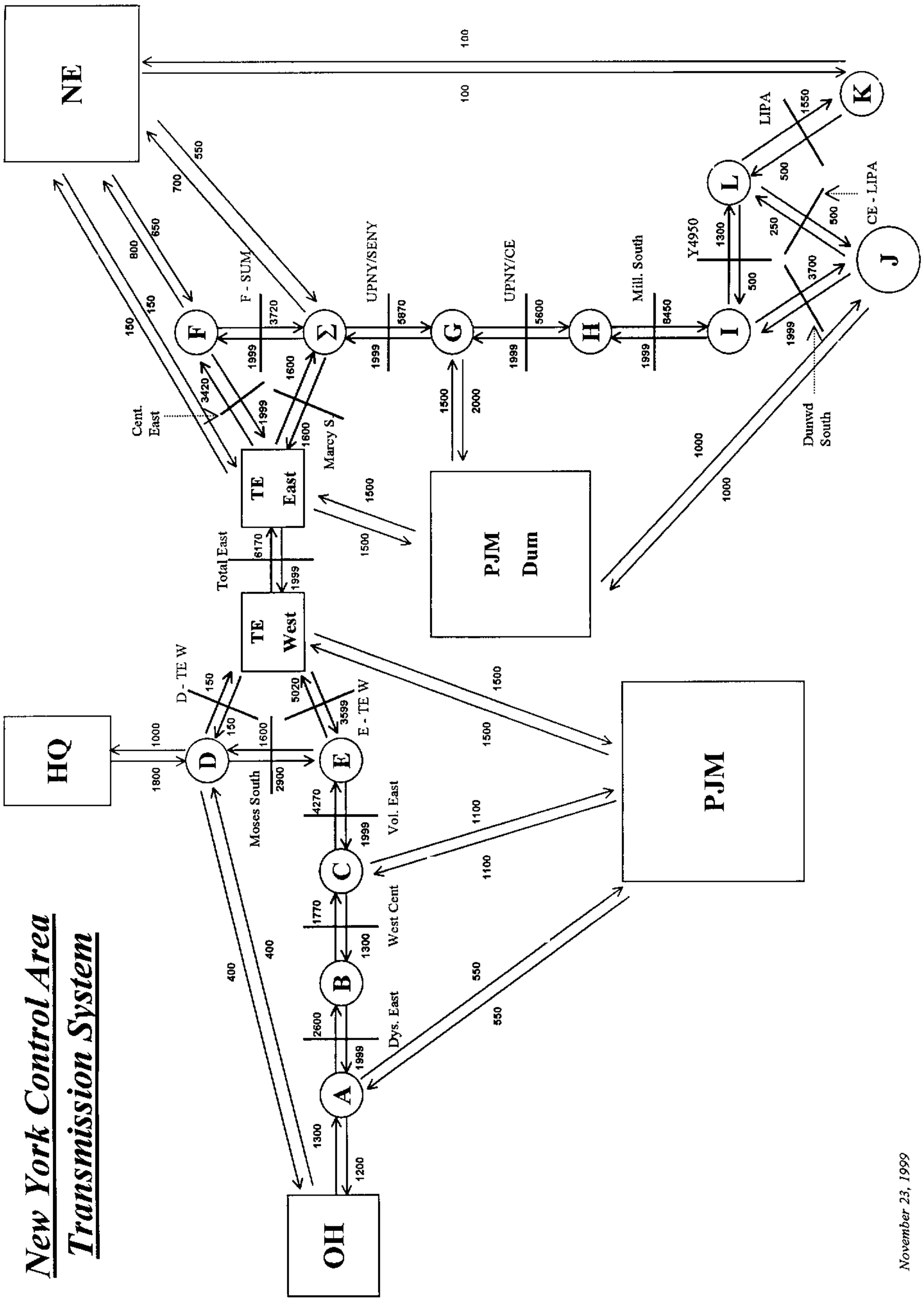
The downstate cable systems were modeled with forced outages. This is because when a cable does fail it takes weeks to repair. These forced outages are modeled as a distribution of MW reduction in transfer limit and a probability of occurrence. The starting point transfer limit for Dunwoodie-South is 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.

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.

New York Control Area Transmission System



November 23, 1999

APPENDIX B

STUDY PROCEDURE, METHODOLOGY AND RESULTS

STUDY CONSIDERATIONS AND ISSUES

This study took into account the latest data available to model both NYCA and the neighboring control areas. This data included unit availability, loads and transmission limitations under the newly formed NYISO. A comprehensive reliability computer model called the "Multi-Area Reliability Simulation (MARS) Program" was used to conduct the study. MARS was developed by the General Electric Co. in 1989 in conjunction the Empire State Electric Energy Research Corporation (ESEERCO) and with NYPP.

The MARS Program is used by the NYISO and previously NYPP because it can more accurately reflect the reliability of the NYCA. MARS can model the unique nature of the NYCA, where 47% of the load is downstate and 61% of generation is located upstate and is connected by a constrained transmission system.

STUDY PROCEDURE

The data base used for the study modeled the NYCA and the neighboring control areas that include HQ, NE, PJM and OH systems. Data was included for individual generating units, loads and interconnections as well as internal NYCA transmission.

The data base includes all the known generating units located within NYCA known to have capacity contracts. Generator unavailability was included through full and partial outage rates. Most of this data is based on historical data from NERC-GADS data base. Also included was load and forced outage uncertainties. Forced outage uncertainty represents the impact of multiple unit outages occurring in unusual and severe combinations.

A simulation was made to compare the IRM of the NYCA on an isolated basis to a NYPP study completed in 1996. The phrase "on an isolated basis" refers to the representation of the NYCA without interconnections to the neighboring control areas. The results of this analysis showed an IRM of 26.3% compared to approximately 27% in a 1996 NYPP study. Both studies included load and forced outage uncertainty. The result was considered a very good match, considering the lower load factor model used in the current study.

The following analyses were conducted to obtain the final results:

Impact of the interconnections to the other neighboring control areas.
Impact of including forced outage rate uncertainty.
Impact of including transmission limitations within NYCA.
Impact of allowing ICAP to be purchased from outside of NYCA.

METHODOLOGY

The procedure followed to obtain the IRM for the isolated NYCA is described below. The MARS model was initially run with an assumed IRM (12.8%) in the base system, as described in Appendix A. The run resulted in a Loss of Load Expectation (LOLE) greater than the NYCA criterion of 0.1 days/year. Additional runs of MARS were made that decreased the NYCA load proportionately across all zones, until a NYCA LOLE of 0.1 days/year was reached. The ratio of capacity to this adjusted load provides the IRM.

The initial analysis that interconnected the NYCA with the neighboring control areas showed that in some cases, the neighboring control areas were more reliable then NYCA. The NYCA results showed an over-dependence on interconnection assistance from the neighboring control areas due to modeling deficiencies in these areas (i.e., no data to represent internal transmission constraints). To reduce this over dependence, load was added to these neighboring control areas until the NYCA LOLE (Loss of Load Expectation) was 0.1 days/year. The NYCA load was then adjusted until 0.1 days per year was reached and the IRM was re-calculated. This analysis produced an IRM of 14.3% (Case 3).

The next step in the process was to add the transmission limitations within NYCA and rerun MARS. The results of this run provided an LOLE greater than the 0.1 days/year criterion. Again the NYCA load was adjusted until 0.1 days per year was reached yielding an IRM 15.1% (Case 4).

The final step was to determine the impact on the IRM of purchasing ICAP from areas outside NYCA. The impact is to increase the IRM because the transmission system between NYCA and the neighboring control areas, that had been used solely for emergency help, is now partially used to import ICAP, leaving less transmission available to bring in emergency assistance.

To determine the impact of purchasing ICAP external to the NYCA involves several steps. First, the impact of the grand-fathered contracts was determined. These contracts consist of:

400 MW Hydro-Quebec to Con Edison
953 MW Homer City units to New York State Gas & Electric
300 MW PSE&G to Orange & Rockland

The results showed no impact on the IRM of adding the grand-fathered contracts. This occurred because the level of grand-fathered contracts was not high enough to negatively impact assistance from neighboring control areas.

Finally, analyses were conducted to determine the effect of external ICAP in addition to the grand-fathered contracts on the IRM. Additional external ICAP was purchased only from PJM because this is the only control area that currently meets the NYISO's recallability requirements for ICAP suppliers. In these cases, capacity representing ICAP to be purchased external to the NYCA was reduced in the NYCA and the same amount of capacity added to the PJM system. In addition, a contract sale was included from PJM to NYCA for the same amount of capacity. The results from the MARS run was a NYCA LOLE greater than 0.1 days/year. Load was then reduced in NYCA, until the 0.1 days/year criterion was reached. This increased the IRM as more and more capacity was assumed to be located in PJM.

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, for example, 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-1.

TABLE B-1
Implementation of Emergency Operating Procedures *
Base Case Assumptions (IRM = 15.5%)

Emergency Operating Procedure	Expected Implementation (Days/Year)
5% manual voltage reduction	2.8
30 Minute reserve to zero	2.7
5% remote control voltage reduction	1.6
Voluntary load curtailment	0.9
Public Appeals	0.6
10 minute reserve to zero	0.5
Customer disconnections	0.1

* See Appendix A, Table A-4

Additional analyses were conducted to determine the impact of forced outage uncertainty. The results of this analysis showed a 1.5% (Case 13 - Case 6) increase in the IRM. This 1.5% increase was added to the results of all the installed reserve margin calculations.

SENSITIVITIES

The following sensitivity cases were run:

Additional external ICAP was assumed purchased from HQ. The NYISO is working with HQ to qualify HQ's capacity for ICAP purposes. The results from this analysis showed that the IRM rose more quickly than the analysis that assumed ICAP purchased from PJM. Purchases of ICAP from HQ significantly effects the assistance that can be provided from this neighboring control area.

Also, an analysis was run showing a combination of simultaneous external ICAP purchases from both PJM and HQ. This analysis produced an IRM similar but somewhat smaller than the sensitivity where external ICAP was purchased only from PJM. PJM is a summer peaking control area and HQ is a winter peaking control area. This seasonal diversity results in less of an effect on assistance to the NYCA when ICAP purchases are split between these areas than when ICAP purchases are made from either one or the other of these areas.

Analyses were conducted that reduced all internal transmission limits (except cable interfaces) and inter-Area transfer limits by 10%. The cable systems in southeastern NYCA were modeled at their normal ratings including a forced outage model. The results of this analysis increased the NYCA IRM by 0.7% (Case 8 - Case 13). Including forced outage rates on the cable system interfaces increased the IRM by 0.9% (Case 13 - Case 7).

Additionally, analyses were conducted to show the effect of certain other uncertainities. The results of including generator forced outage rate uncertainty increased the IRM by 1.5 percentages points (Case 13 - Case 6) and load forecast uncertainty increased the IRM by 3.7% (Case 13 - Case 9). Including load forecast uncertainty greater than that in the base case increased the IRM by 1.3% (Case 10 - Case 13).

The results of all cases are presented in Table B-2.

TABLE B-2
STUDY RESULTS

Case #	Description	Cap (MW)	NYPP Int. Limits?	Areas Connected	NYPP LOLE *	Reserve Margin **
1	NYCA isolated with no internal ties		no	no	0.096	25.7%
2	NYCA isolated with internal ties		yes	no	0.096	26.3%
3	NYCA connected with other areas (No Grand-fathered or external ICAP)		no	yes	0.102	14.3%
4	NYCA with internal ties (No Grandfathered or external ICAP)		yes	yes	0.099	15.1%
	Sensitivity Based on Base Case					
5	NYCA connected with other areas (No Grand-fathered or external ICAP)		no	yes	0.102	14.7%
6	Forced outage rate uncertainty not represented	3153	yes	yes	0.100	14.0%
7	Effect of removing transition rates on downstate cables	3153	yes	yes	0.102	14.6%
8	Effect of limiting interfaces to 90%	3153	yes	yes	0.100	16.2%
9	Load forecast uncertainty not represented	3153	yes	yes	0.100	11.8%
10	Greater load forecast uncertainty than in Base Case	3153	yes	yes	0.100	16.8%
	External ICAP Purchase Sensitivities					
11	Grandfathered ICAP contracts only	1653	yes	yes	0.101	15.1%
	From PJM Only					
12	Grandfathered plus 1000 MW PJM ICAP	2653	yes	yes	0.101	15.3%
13	Grandfathered plus 1500 MW PJM ICAP (Base Case)	3153	yes	yes	0.103	15.5%
	From HQ Only					
14	Grandfathered plus 1000 MW HQ ICAP	2653	yes	yes	0.100	15.6%
15	Grandfathered plus 1400 MW HQ ICAP	3053	yes	yes	0.099	17.0%
	From PJM (50%) & HQ (50%)					
16	Grandfathered plus 1500 MW ICAP	3153	yes	yes	0.098	15.3%

* LOLE expressed in days/year.

** All values include the impact of forced outage uncertainty.
Forced Outage Rate Uncertainty adder = 15.5% - 14.0% = 1.5% (Case 13 - Case 6)