NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2003 THROUGH APRIL 2004

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

Executive Committee Resolution
And
Technical Study Report

<u>January 10, 2003</u>

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

APPROVAL OF NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD
MAY 1, 2003 THROUGH APRIL 30, 2004

1. 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

2. 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

3. 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

4. WHEREAS, the NYSRC is responsible for determining the New York Control Area ("NYCA") annual Installed Capacity Requirement; and

5. WHEREAS, the study results in the Technical Study Report, dated January 10, 2003, conducted by the NYSRC Installed Capacity ("ICAP") Subcommittee, show that the required NYCA installed reserve margin (IRM) for the May 1, 2003 through April 30, 2004 capability year is 17.5% under base case conditions; and

6. WHEREAS, in light of the Technical Study results, the modeling and assumption changes made to simulate actual operating conditions and system performance, the numerous sensitivity studies evaluated, and with due recognition that the current NYCA IRM is set at 18.0%;

7. NOW, THEREFORE BE IT RESOLVED, that in consideration of the factors addressed above, the NYSRC sets the NYCA IRM requirement at 18.0% for the May 1, 2003 through April 30, 2004 capability year, which equates to an Installed Capacity Requirement of 1.18 times the forecasted NYCA 2003 peak load.

TECHNICAL STUDY REPORT

January 10, 2003
New York State Reliability Council, L.L.C.
Installed Capacity Subcommittee

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INTRODUCTION

Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the statewide annual Installed Capacity Requirements (ICR) for the New York Control Area (NYCA) 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 NYCA required installed reserve margin (IRM) for the period May 2003 through April 2004 (year 2003) in compliance with the NYSRC Agreement. The ICR relates to the IRM through the following equation:

$$ICR = (1+IRM) \times \text{Forecasted NYCA Peak Load}$$

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" manual. The NYISO will also translate the required IRM to an "unforced capacity" basis, in accordance with a 2001 NYISO filing to FERC. This concept is described later in the report.

Definitions of certain terms in this report can be found in the NYSRC Glossary in the *NYSRC Reliability Rules for Planning and Operating the New York State Power System*, http://www.nysrc.org.

EXECUTIVE SUMMARY

The technical NYSRC study described in this report shows that the base case for the year 2003 statewide IRM requirement to be 17.5%[1] using base case assumptions. The study also presents results for various other scenarios, some more likely than others, intended to assess the sensitivity of base case assumptions on the IRM. Both base case and sensitivity cases results, taken together, provide the technical basis for the NYSRC determination of the required statewide IRM requirement for the year 2003.

This year's study utilized several model improvements and updated parameters since the 2002 study:

- Special Case Resource (SCR) and Emergency Demand Response Program (EDRP) capacity has been increased to reflect the greater expected utilization by the NYISO of these programs. The 2002 study modeled SCRs as energy limited ICAP resources while the 2003 study models them as full ICAP resources, thereby increasing their value in supporting reliability. These resources are discounted to reflect their expected participation. The study considers the SCR resources as 100% available at all times, that is, with no outage rates, and voluntary EDRP resources responding to the assumed quantity with 100% certainty. The 100% availability refers to the discounted value of the SCRs and EDRPs. This discount anticipates that some may not respond.

- A major update to the NYCA transmission model has also been incorporated which includes updated Long Island cable interface characteristics.

1 Each study result, whether the base case or a sensitivity case, has a 99% accuracy expectation that has been estimated to be in the order of 0.5%.

- NYSRC continues to monitor historical generating unit availability trends using a ten year average so as to properly project future availability rates. The outage rates for the year 2001 were lower than the ten year average and this was reflected in this years study assumptions. If this trend continues, it will eventually lead to a modeling of lower forced outage rates. However, for this years study, the ten year average forced outage rates actually increased slightly, because the year 1991, which was dropped from the average, actually had a lower average forced outage rate then the year 2001.

- An updated load shape model has been incorporated in this study. Previous studies utilized a 1995 load shape. An analysis conducted by the NYISO has shown that while there has been a trend since 1995 towards fewer days close to the annual peak load, there was a significant reversal in 2002 back to 1995 level that appears to contradict this trend. As a result, the base case load shape has been updated to better reflect the downward recent trends and separate cases run to assess the sensitivity of the IRM to various load shapes. It was found that the load shape has a significant impact on IRM requirements. This is best illustrated by looking at the NYCA isolated cases. For example, fixing all base case assumptions, except the load shape model, results in an IRM requirement ranging from 22.7% to 23.6%, assuming the use of a 1998 load shape and the previous 1995 load shape, respectively, compared to the above IRM requirement of 23.2% using the new base case load shape. The number of days above the 0.95 per unit peak value are as follows: 15 for 1995, 6 for 1998 and 12 for the base case used in the study. An additional sensitivity study was made using the 2002 load shape, which had 13 days above 0.95 per unit peak value, resulting in an IRM of 24.2%. Each study considers both internal and external load shapes in a deterministic manner with no probability range assigned to them.

- This study also calculated the sensitivity of required IRM to changes in several key study assumptions. Sensitivity testing varying the level of SCR and EDRP around base case assumptions from +75 MW to -354 MW changes the required IRM to 17.3% and 18.7%, respectively. Reducing the level of emergency assistance from each of NYCA's neighboring control areas (individually) yields a required IRM between 17.5 and 17.9%. Reduced external ICAP of 572 MW and 0 MW, which increases the emergency assistance provided by external resources, results in a required IRM of 17.3% and 17.0% respectively. Without load forecast uncertainty results in a required IRM of 14.8%. A complete listing of all sensitivity studies is contained in Table B-1.

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 in New York is stated in the NYSRC Reliability Rules. NYSRC Reliability Rule A-R1, Statewide Installed Reserve Margin Requirements, states:

> "Adequate resource capacity shall exist in the New York Control Area (NYCA) such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYCA

> transmission transfer capability, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to a resource deficiency will be, on the average, no more than once in ten years."

This NYSRC Reliability Rule is consistent with NPCC Standards. The NPCC resource adequacy design criterion is 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 a required IRM; however, in day-to-day operations the actual available operating reserve 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 NYCA, 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. The initial input includes all generating units and the forecasted load. The load is adjusted upwards until the results are an LOLE of 0.1 days per year which then yields the required reserve margin.

Appendix B provides details of the study results.

STUDY RESULTS

The results of this study show that under the base case assumptions, the statewide required IRM is 17.5% for the year 2003. The MARS analysis using base case study assumptions is described in Appendix A. Maintaining a minimum installed reserve of 17.5% over the forecasted NYCA 2003 summer peak would achieve applicable NYSRC and NPCC reliability criteria under these study assumptions. A description of the cases prepared for this study is shown in Appendix B, Table B-1.

The major parameters that affect NYCA IRM requirements are described below:

- *Interconnection Support During Emergencies.* The reliability of the NYCA is improved by receiving emergency assistance support from interconnected control areas, in accordance with control area reserve sharing agreements, during emergency conditions. This permits a required NYCA IRM that is 5.7 percentage points lower than otherwise required, under base case study assumptions (Table B-1, Case 2 – Case 1).

- *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 28,420 MW to 33,160 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 2.7 percentage points (Table B-1, Case 1 – Case 7).

- *Resource Capacity Availability.* IRM requirements are highly dependent on the availability of generating units and other types of resource capacity. A detailed analysis was performed to update the forced, partial, and scheduled maintenance representations of the NYCA generating units included in the model to reflect 1992-2001 availability performance and 2003-04 planned outages. To represent the capacity of gas turbines and hydro under abnormal conditions, the capacity model calibrates deratings for these types of generating units under ranges of high ambient temperature and adverse water conditions, respectively.

- *Locational Installed 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 zone to another for meeting load requirements. Previous studies found that, under the conditions assumed, there are transmission constraints into the New York City and Long Island zones that could impact the LOLE of these zones, as well as the statewide LOLE.

  To minimize these potential LOLE impacts, NYISO studies have shown that a minimum resource ICAP, i.e., locational ICAP, must be maintained in each of the New York City and Long Island zones. These locational ICAP requirements recognized by NYSRC Reliability Rule A-R2 supplement the statewide IRM requirement covered in this report. The most recent NYISO study (*Locational Installed Capacity Requirements Study,* dated February 28, 2002) determined that the LSEs serving the New York City and Long Island zones must maintain a minimum ICAP to load ratios of 0.80 and 0.93, respectively, for these zones. These minimum locational ICAP requirements were recognized 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 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 expected NYCA external ICAP of 1477 MW, comprised of 1000 MW from HQ, 360 MW from ISO New England, and 117 MW from PJM. This is 195 MW less than was assumed in last year's study.

  In this study, the external ICAP transactions represented increased the required IRM by 0.5 percentage points (Table B-1, Case 1 - Case 5).

- *Special Case Resources and Emergency Demand Response Program.* Special case resources (SCRs) are ICAP resources that include loads that are capable of being interrupted and distributed generation that may be activated on demand. A total of 560 MW of SCR resources are assumed in the study. The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves. A total of 354 MW of EDRP capacity is assumed in this study. Both SCR and EDRP capacity are included in the Emergency Operating Procedure model.

The appropriate IRM required for meeting reliability criteria depends on the study assumptions used in the analysis in addition to the many factors that 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 required IRM results to several alternate assumptions. The sensitivity study results in this figure show a required IRM range of 14.8% to 23.2%.

The NYISO will implement emergency operating procedures (EOPs) as required to minimize customer disconnections. The study indicates that if an 17.5% IRM is maintained under base case conditions, then on average, firm load disconnection due to inadequate resources will occur not more than once in every ten years in accordance with NYSRC and NPCC criteria (see Appendix B, Table B-2 for expected average use of voltage reductions and other EOPs. The program calculates the frequency of the occurrence of EOPs.).

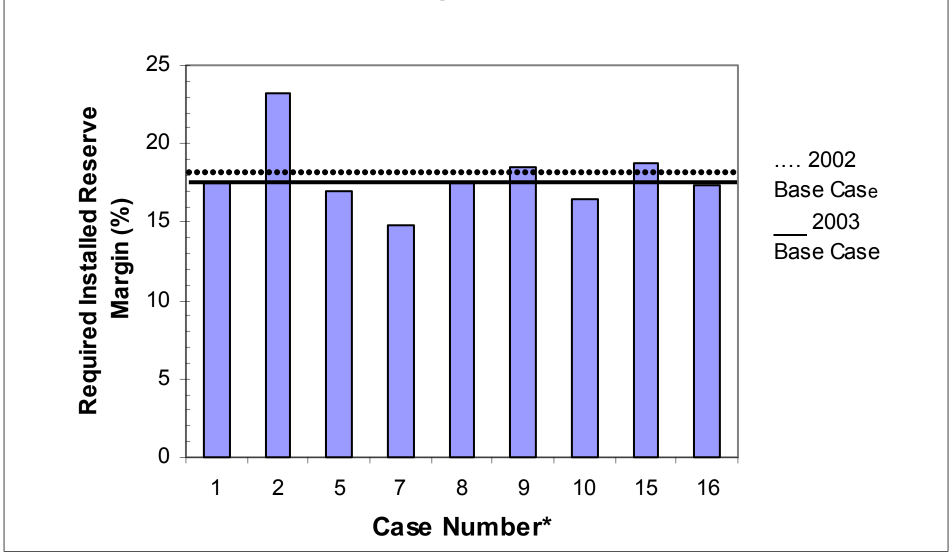
UNFORCED CAPACITY

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage rates of individual units. This is referred to as "UCAP" which stands for "unforced capacity." In order to maintain consistency between the rating of a unit (UCAP) and the statewide reserve margin, the reserve margin must be translated to an unforced capacity basis. The conversion to UCAP is, essentially, a translation from one index to another and not a reduction of actual installed resources, so no degradation in reliability is expected. This is because the NYISO employs a translation methodology that adjusts UCAP requirements to ICAP in a manner that assures compliance with NYSRC resource adequacy rule AR-1. The conversion to unforced capacity provides financial incentives to decrease the forced outage rates, thus improving reliability.

COMPARISON TO 2002 STUDY

The results of this study show a required statewide IRM, using base case assumptions, that is lower than that shown in the previous study, which was conducted for the 2002-2003 capability year. Table 1 shows the comparison of the required IRM impacts of key parameters associated with these two studies. The table shows that the primary factors effecting the IRM requirements are the new load shape, the updates to external Areas and modeling more EDRPs and SCRs. The net effect of these factors, along with the others listed in the Table, is a required base case statewide IRM that is one-half percentage point lower than determined in the previous study.

Figure 1



* Refers to Appendix B, Table B-1

Sensitivities – Changes from Base Case Assumptions:

Case #	Description
1	Base Case
2	NYCA Isolated
5	No External ICAP
7	No Load Forecast Uncertainty
8	Without Planned Units for 2003
9	Reduce all Internal Transfer Limits by 10%
10	Reduce unit Forced outage rates by 10%
15	Remove all 354 MW of EDRP
16	Include an additional 75 MW of SCRs in NYC

Table 1

COMPARISON WITH 2002 STUDY*- NYCA

Parameter	IRM % Change	IRM %
Previous Study IRM (2002 Study)		**18.0**
New version of GE MARS program	+0.4	
Updated Transfer Limits	+0.0	
Updated Load Shape	-3.0	
Change the modeling and amounts of SCR and EDRP	-1.5	
New resources, transition rates, maintenance schedule, external ICAP contracts and Gold Book updates	+0.1	
Updated External Areas	+3.5	
Net IRM Change from 2002 Study	-0.5	
New Study IRM (2003 Study) Results		**17.5**

*See report titled "New York Control Area Installed Capacity Requirements for the period May 2002 through April 2003", dated December 14, 2001, for 2002 study model description and assumptions.

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APPENDIX A

ICAP RELIABILITY MODEL AND ASSUMPTIONS

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

INTRODUCTION

Appendix A provides details of the modeling and assumptions for the NYCA IRM study covered in this report.

Table A-1 lists the study parameters in the Figure A-1 models, the source for the study assumptions, and where in Appendix A the assumptions are described. Figure A-1 depicts the computer program and related load, capacity and transmission models used for the study.

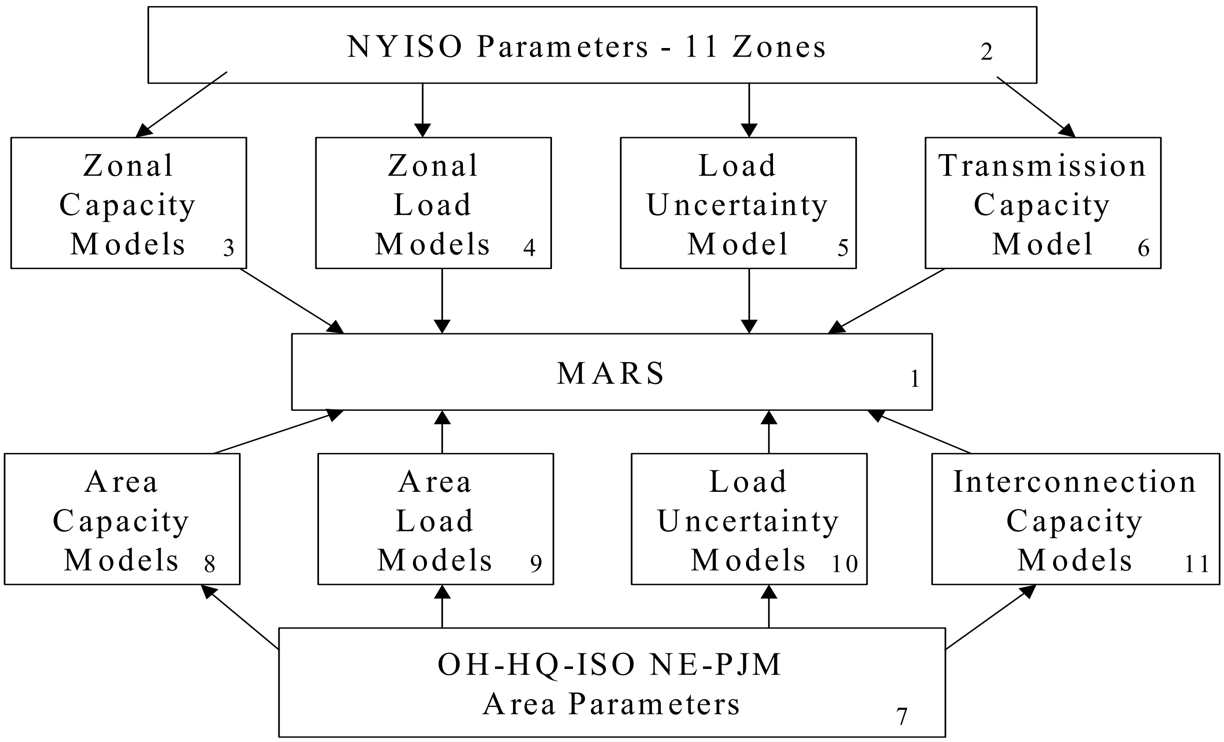
Finally, the last page of Appendix A compares the assumptions used in the 2002 and 2003 IRM reports.

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 12
2	11 Zones	Load Areas	Fig. A-2 page 16	NYISO Accounting & Billing Manual
3	Zone Capacity Models Emergency Operating Procedures	Generator Models for each generating unit in zone. Generating Availability. Unit Ratings. Reduces load during emergency conditions to maintain operating reserves.	 GADS Data 2002 Gold Book[1] NYISO	See page 17 See page 18 See page 28
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	See page 25 31,330 MW Gold Book
5	Load Uncertainty Model	Account for forecast errors due to weather and economic conditions.	Historical Data	See page 27
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between zones.	NYISO transmission studies	See page 29
7	IMO, HQ, ISO-NE, PJM control area Parameters	See the following items 8-11.		
8	Control area Capacity Models	Generator Models in neighboring control areas	NPCC CP-8 study for NPCC Areas. MAAC Report and NERC Average outage rates for PJM	See page 32
9	Control area Load Models	Hourly Loads	NPCC CP-8 study for NPCC Areas PJM Web site.	See page 25
10	Load Uncertainty Models	Account for forecast errors due to weather and economic conditions	NPCC CP-8 Study	See page 27
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	NPCC CP-8 Study	See page 29

1. "2002 Load & Capacity Data" Report issued by the NYISO.

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 New York Power Pool (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 MARS 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	5
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. Three thousand and sixty three (3,063) replications were simulated in the Base Case.

Using the Program

Below are the primary study parameters that are input into the MARS program. These parameters are described and referenced in boxes shown in ICAP Modeling Table A-1 and Figure A-1.

1. All known generators for all modeled Areas and their associated MW ratings and transition rates. (See Figure A-1 Boxes 3 and 8)
2. The transfer limits of the transmission system between Zones and/or Areas (across the interfaces between the Zones and/or Areas) in both directions. (See Boxes 6 and 11)
3. Groupings of interface flows that would limit the total flows to less then the sum of the individual flows in or out of an Area. (See Box 6)
4. The transition rates for the cable interfaces. (See Box 6)
5. The 8760 hourly loads for each of the Zones and Areas. (See Boxes 2, 4 and 9)
6. The list of emergency operating procedures. (See Box 3)
7. All firm transactions between Areas and Zones, including an estimate of the amount of generation external to NYCA that will that will count as firm capacity. (See Box 3)
8. Generator maintenance schedules. (See Box 3)
9. The load forecast uncertainty probability table. (See Boxes 5 and 10)

The peak loads of all Areas are aligned to be on the same day, even though they may have historically occurred at different times. This is a conservative approach, using the assumption that peak conditions could be the result of a wide spread heat wave. This would result in minimizing the amount of assistance that NYCA could receive from the other Areas.

After a computer run is made the results are usually more reliable then the target of 0.1 days per year due to the current level of generation available. To get to the desired results of 0.1 days/yr. the load in NYCA is increased proportionally to the load in each Zone. This is an iterative process.

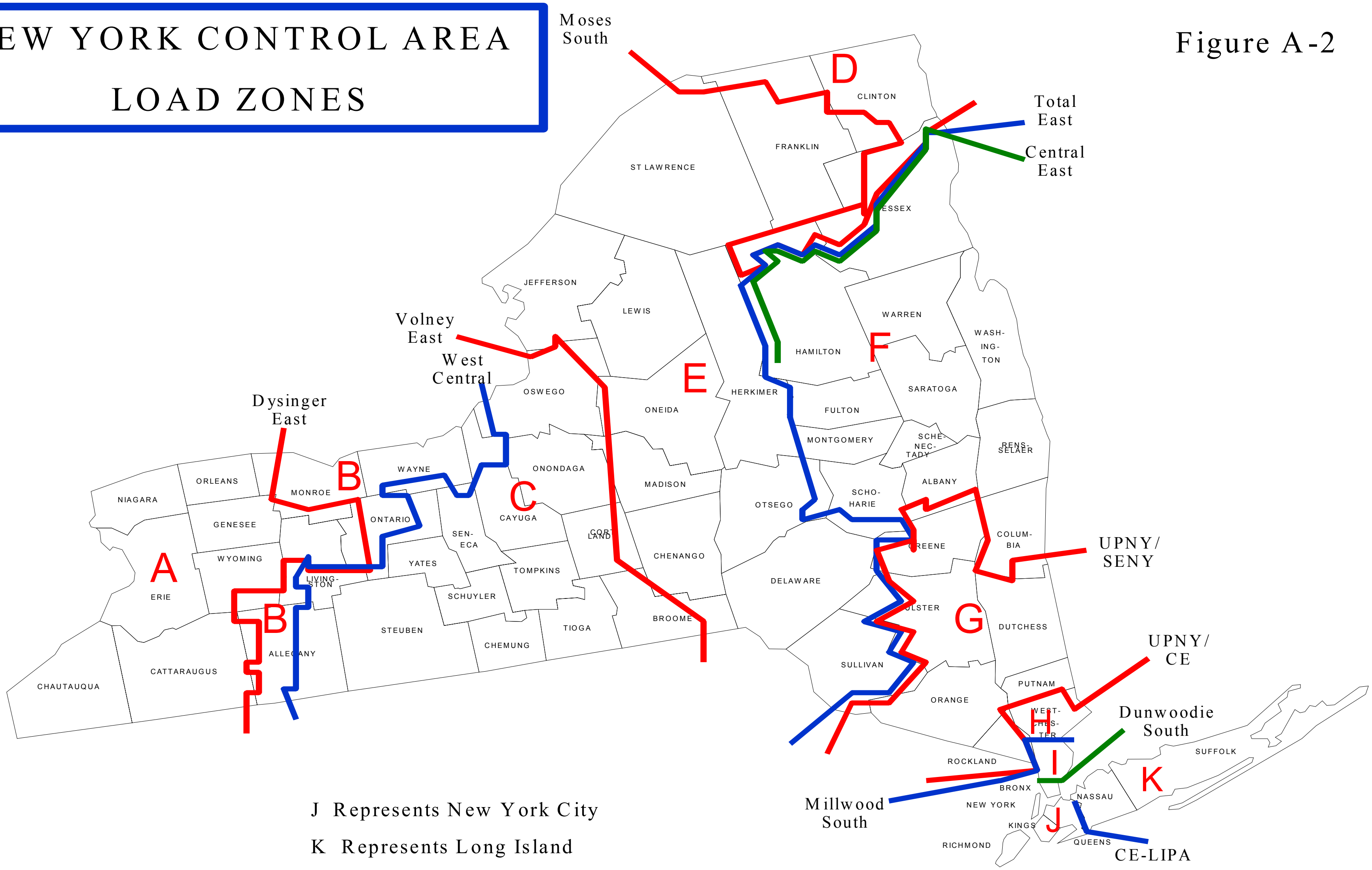
An alternative to changing load to arrive at the target LOLE is to remove generation. However, if generators are removed the question arises as to which type of generators should be removed and from what location. By raising the load as described above, the generation mix remains unchanged.

A final step is to check that none of the surrounding Areas are more reliable then NYCA on an isolated basis. If they are, then their loads are increased until this is no longer the case. This is done so that NYCA is not overly dependent on its neighboring systems. A final iteration of the NYCA load gives the desired 0.1 days/yr.

From this, the NYCA generating capacity modeled minus net sales is divided by the peak NYCA load to determine the IRM.

NEW YORK CONTROL AREA LOAD ZONES

Figure A-2



J Represents New York City

K Represents Long Island

NEW YORK CONTROL AREA

CAPACITY MODELS

The capacity model includes unit ratings, full and partial forced outage representation, maintenance outages, Emergency Operating Procedures (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 38,119 MW of capacity. This figure was arrived at by adding the below additions, as well as the 560 MW of SCR's, to the 2002 Gold Book number and subtracting 303 MW of firm sales.

Existing and Planned Units

Ratings

The unit ratings were obtained from the NYISO "2002 Load & Capacity Data" (Gold Book). The following changes that were installed after the Gold Book was published are modeled in this study:

- **Retirements:**
  None

- **New Units: (Units installed during 2002)**
  KeySpan-Glenwood – 79.9 MW, Long Island
  FP&L-Far Rockaway – 44 MW, Long Island
  PP&L-Shoreham - 79.9 MW, Long Island
  PP&L-Brentwood – 79.9 MW, Long Island
  Calpine-Bethpage - 44 MW, Long Island
  KeySpan-Port Jefferson – 79.9 MW, Long Island
  Unit upgrades – 32.5 MW

- **Planned Units for 2003:** (These units had a signed interconnection agreement by August 1, 2002.)
  PG&E-Athens – 1080 MW, Central New York State
  Units without interconnection agreements are modeled in the sensitivity cases.

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. While energy production from the Niagara and St. Lawrence River projects is expected to be below average in 2003 (but better than in 2002) due to below average water flows, the projects will still be able to achieve their maximum capacities in the event of a system emergency.

For other hydro facilities, a detailed analysis of annual hydro output variation was performed a number of years ago resulting in a hydro derate model for MARS. This analysis had set the hydro derating at approximately 25%. In light of the extreme derating observed during the summer 2001 period, it was decided that a derating of 45% would be appropriate for the 2002 Study. It is considered appropriate that the same 45% derating be used in this study.

Special Case Resources and the Emergency Demand Response Program

Special Case Resources (SCRs) are loads capable of being interrupted on demand, and distributed generators, rated at 100 kW or higher, that are not visible to the NYISO's Market Information System. SCRs are an ICAP resource. The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves.

For this study, SCRs and EDRPs were modeled as EOPs. The values of these programs are discounted to 80.75 % and 40 % respectively of the total reported, based on the summer 2002 experience. The discount to 40 % of the EDRP program avoids the impact of double counting them in the SCR program. The SCRs are modeled as 560 MW and the EDRPs as 354 MW. In last years study, these programs were modeled as limited energy resources instead of EOPs.

External Capacity From Contracts

There is 572 MW of grandfathered capacity modeled as firm purchases by NYCA, consisting of 400 MW from HQ, (summer only) 117 MW from PJM, and 55 MW summer and 90 MW winter from New England. There was also an additional firm winter purchase of 81 MW from Ontario Hydro. The Base Case assumes the following additional external ICAP: 600 MW (summer only) from HQ and a 500 MW wheel from HQ through NYCA to New England. The New England to Long Island tie is modeled with a 305 MW firm purchase. This totals 1477 MW of expected external ICAP during the summer and 588 MW during the winter not including the 500 MW wheel.

Transactions

All firm sales are modeled as listed in the Gold Book for the year 2003.

Generating Availability

Forced and Partial Outages

The unit forced outage states for the majority of the large steam units were obtained from the ten-year average NERC - Generating Availability Data System (GADS) outage data collected by NYPP and the NYISO for the years 1992 through 2001. 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.

A detailed analysis of all the NYCA units' equivalent forced outage rates was performed and confirmed that the continuing use of the ten-year historical average forced outage rate data was appropriate. There is no obvious difference in any trends when looking at the five and ten year averages. Using a ten-year average is more likely to capture uncertainties in the forced outage rates. Figure A-3 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd) over the 1992 through 2001 period. The graph presents unit weighted averages for four zones with the NYCA and a NYCA total aggregate. The year 2001 was added which had a slightly higher average forced outage rate then the year 1991, which was dropped.

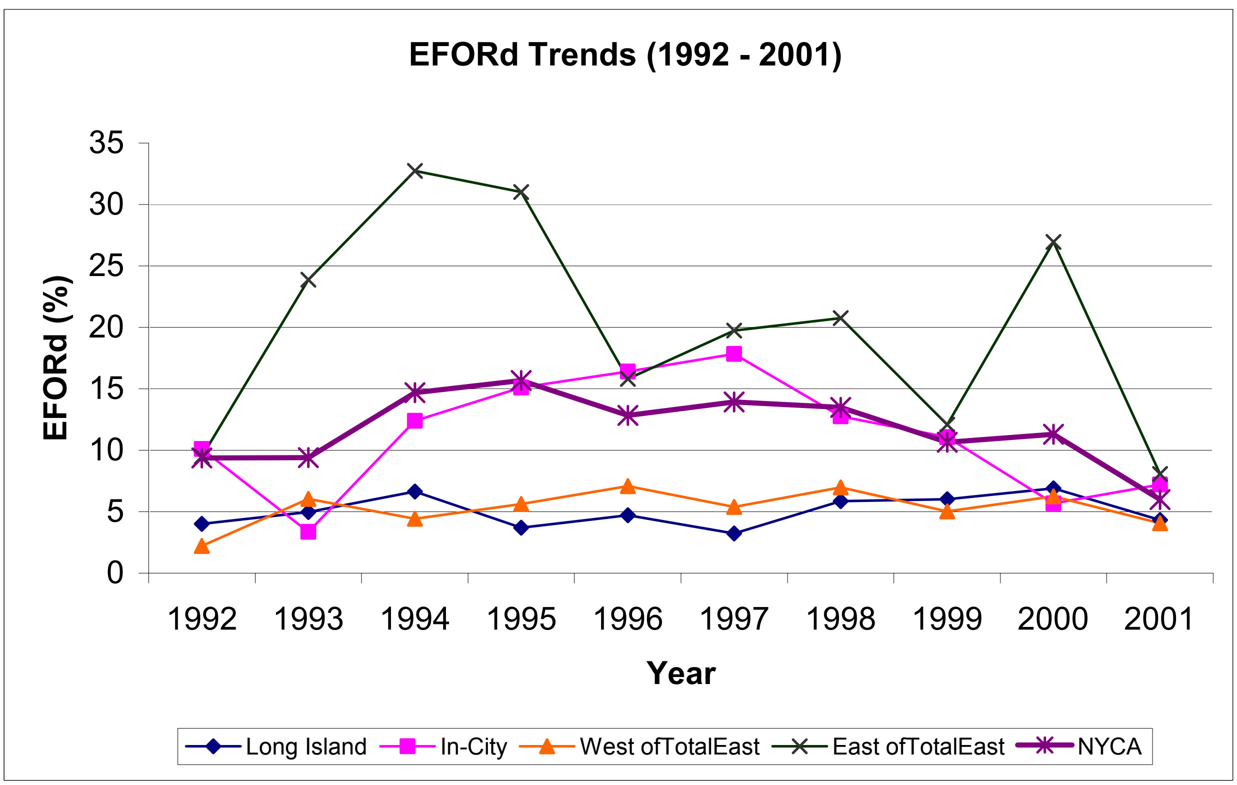
Combustion Turbine Temperature Adjustments

A model of combustion turbine derating due to temperature in excess of DMNC test conditions was developed based on two parameters. The first parameter relates NYCA load to temperature and the second parameter relates combustion turbine derate to temperatures above DMNC conditions.

The NYISO's Load Forecasting staff provided the NYCA load to temperature relationship. It was determined that the NYCA load increases by approximately 250 MW per degree above normal design conditions of 92° F. An analysis was performed to determine the derating of combustion turbine units based on higher then expected temperatures. It was determined that combustion turbines derates amounted to 640 MW due to the 100° F downstate temperatures experienced over the summer 2001 peak. DMNCs are normally set at normal design condition temperatures around 92° F. Thus, the 640 MW derate over an eight degree spread produces a derate of 80 MW per degree F. This value is still appropriate for use this year even though there are more combustion turbines. This is because the new units are capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so they are not impacted by the temperature derating in obtaining an output of 79.9 MW.

An hourly derate model was developed that was active when the expected hourly load exceeded the normalized peak load forecast of 31,330 MW. Loads above this value would be simulated in the higher than forecast load uncertainty evaluation. The 80 MW per degree derate when weighted by the higher than expected peak load uncertainties and probabilities of occurrence produced an expected equivalent average derate of approximately 93 MW.

Figure A-3



Scheduled Maintenance

The total amount of scheduled maintenance, which includes both planned and maintenance outages, was developed from a ten-year average of the same NERC-GADS data that was used to obtain the forced outage rates.

The forecast of the planned outages for the study period were obtained from the generation owners, and where necessary, the length of the outage was extended so that it equaled the ten-year historical outage time period. Figure A-4 provides a graph of scheduled outage trends over the 1992 through 2001 period for NYCA generators.

Figure A-4

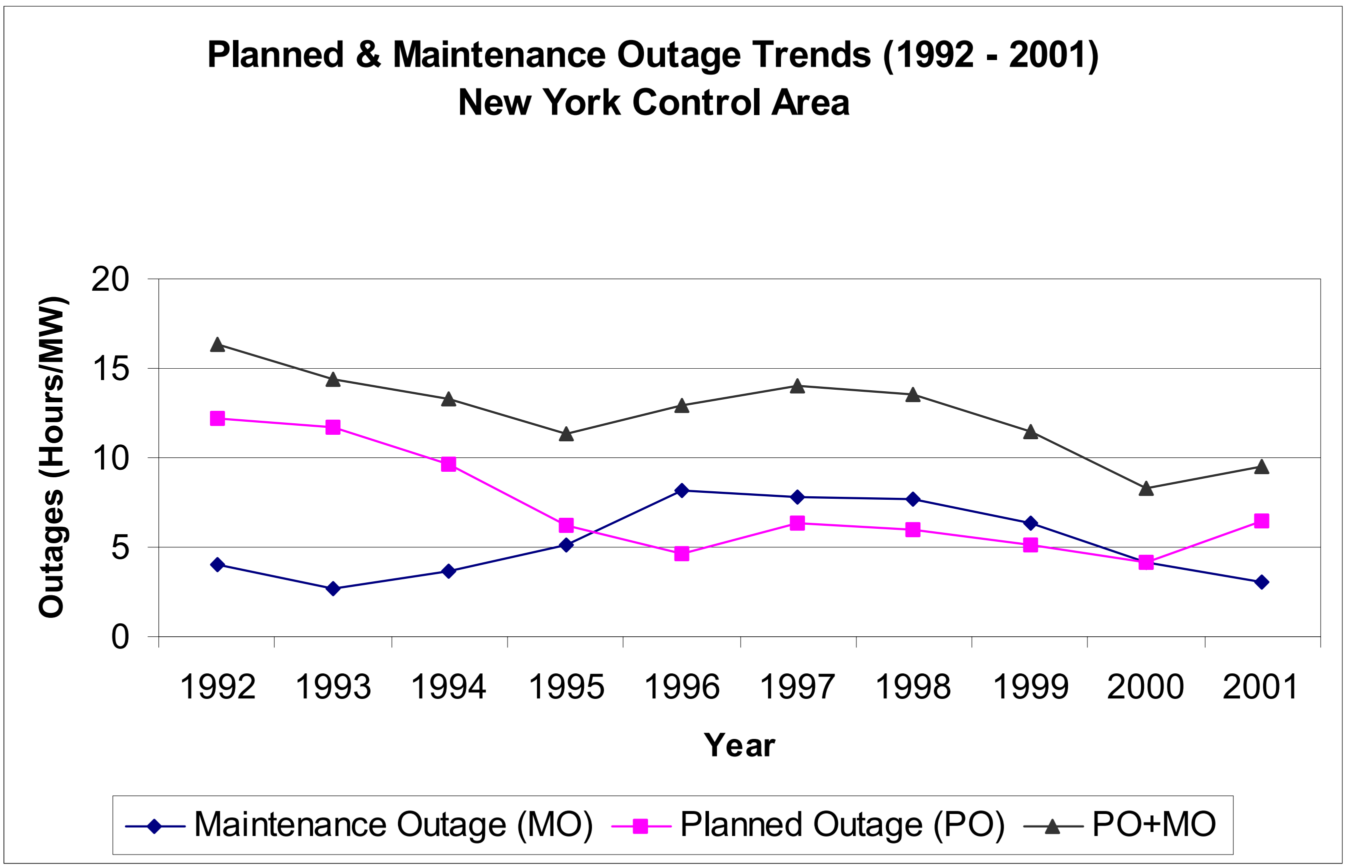
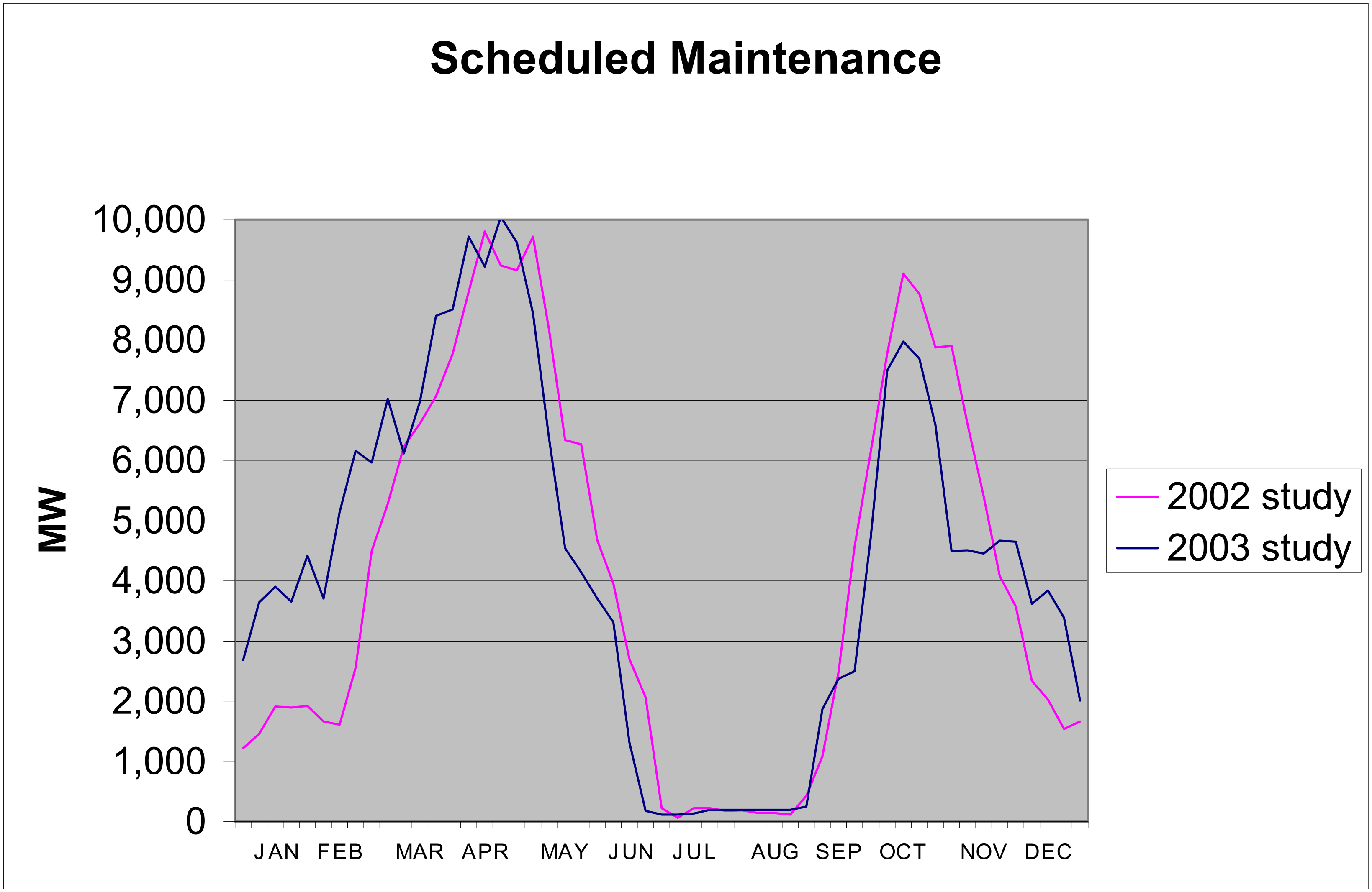


Figure A-5 shows the amount of capacity assumed to be on scheduled outages that was used in the 2002 and 2003 studies. The shift in maintenance out of the summer period as compared to earlier studies is continuing and has a significant impact on the results. It is consistent with the way scheduled outages are now being performed. A check of the actual POs for the summer of 2001 showed an average outage of approximately 50 MW. There was a considerable amount of maintenance outages, but they were scheduled during low load periods and therefore did not impact system reliability.

The planned outages in the current study over the 2003 summer period ranges from 114 MW to 253 MW.

Figure A-5


Scheduled Maintenance
MW
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2002 study
2003 study

Equivalent Availability

The equivalent availability factor accounts for forced, partial, scheduled and maintenance outages. Figure A-6, which is based on NERC-GADS data for New York units, shows that there are no significant upward or downward trends for the types of generator units modeled in the study. Therefore, the Working Group concluded that the ten-year historic outage rates are appropriate for this study.

Figure A-7 provides NERC-GADS data industry-wide. Again, there does not appear to be any significant upward or downward trend present. Note that the year 2001 data from NERC is not available at this date.

Figure A-6

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2001

ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES

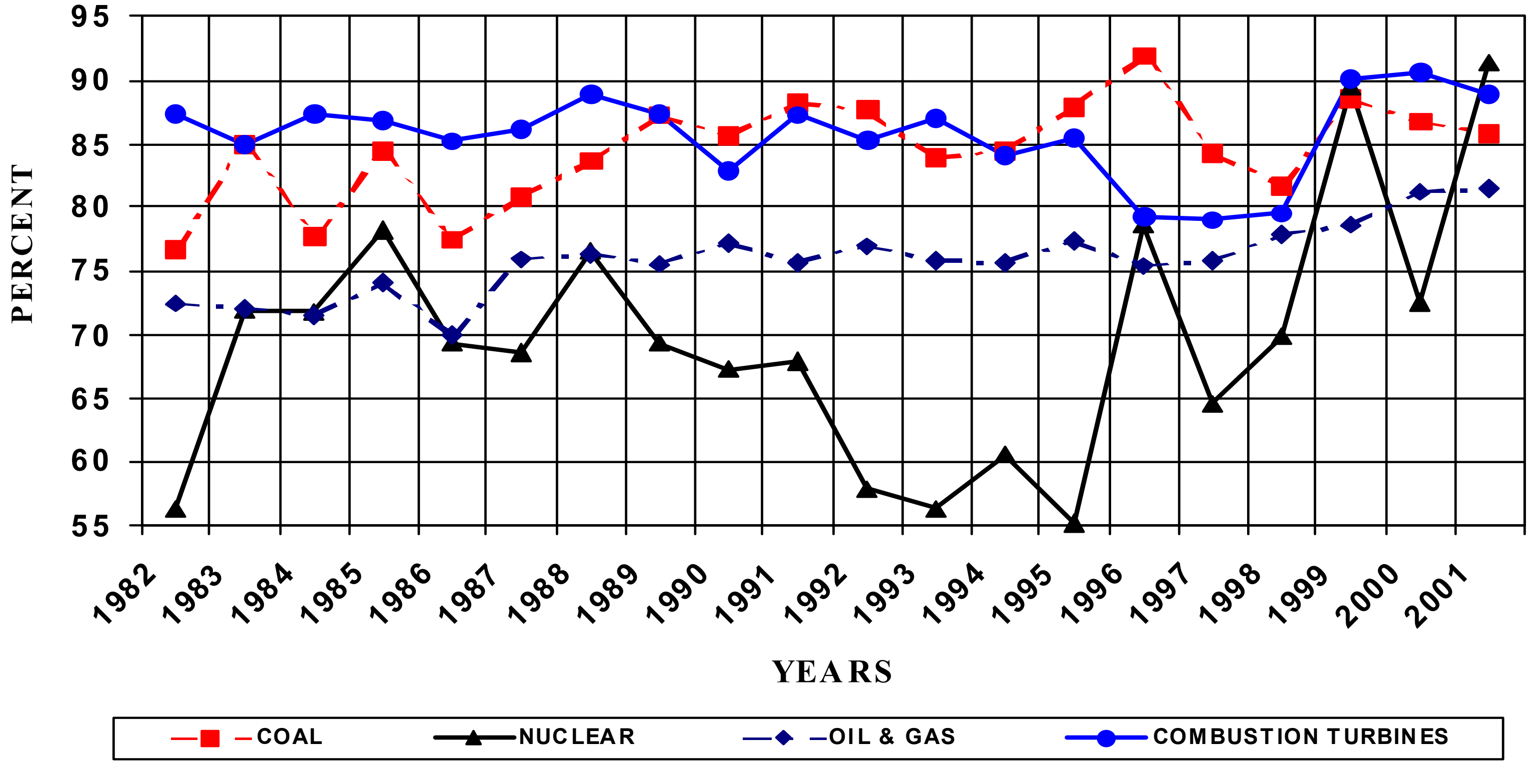
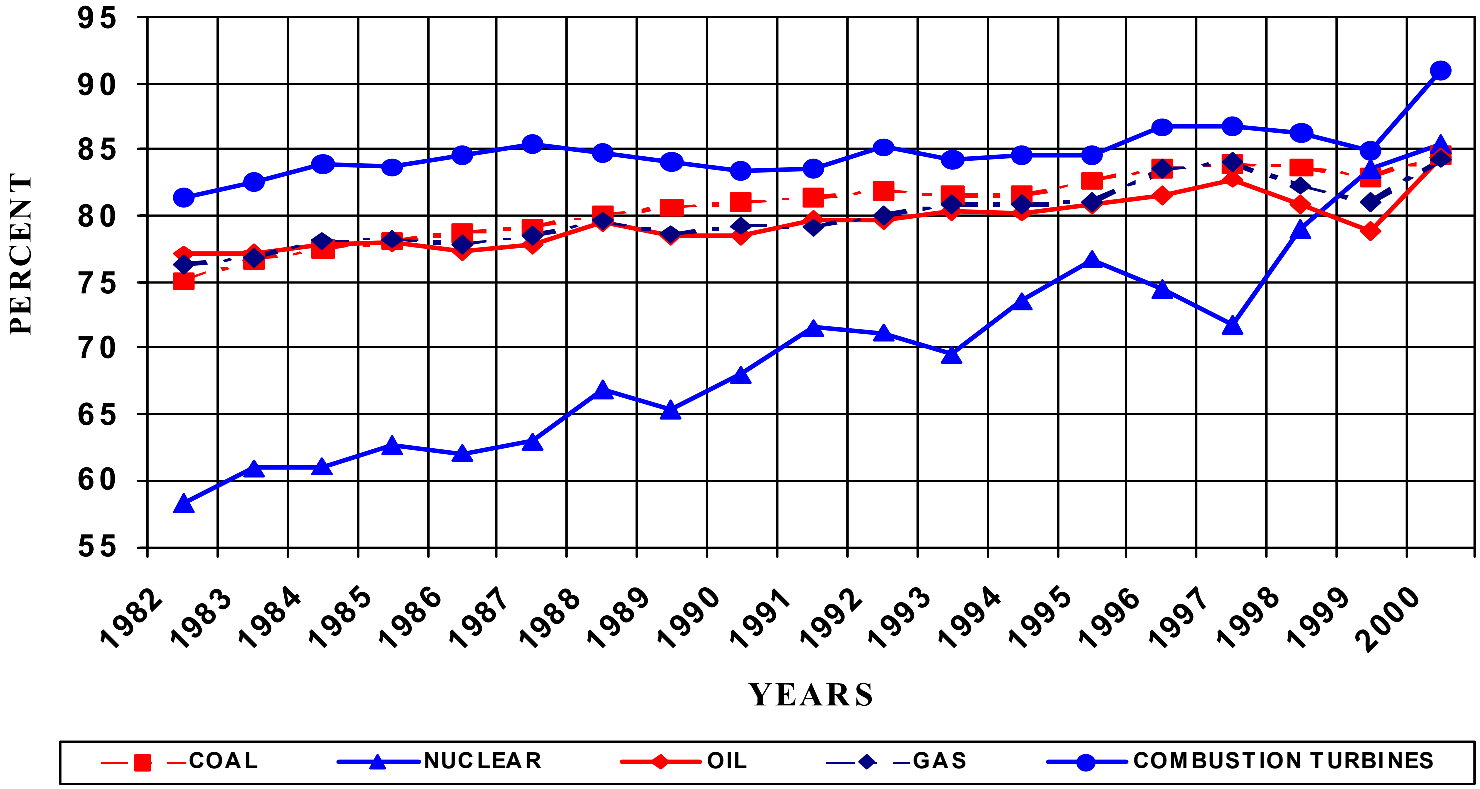


Figure A-7

NERC EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2000

ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL, GAS, AND COMBUSTION TURBINES



LOAD MODELS

An 8,760-hour chronological model is input to the MARS program for each Control Area or zone modeled. Over the past several years, the IRM study has been performed using the 1995 hourly loads. This year, there was extensive analysis that looked at historical load shapes that pointed toward a trend in recent years. This trend was toward load shapes that experienced fewer peak days near the annual peak. Because of this, a 1998 load shape was chosen, mid-year, for analysis in the IRM study.

Toward the end of the study year, the 2002 actual summer experience became available which contradicted this trend. This data showed a dramatic increase in the number of days with daily peaks near the annual peak.

In light of this new data, the Installed Capacity Subcommittee (ICS) agreed to adopt a base case load shape that was inclusive of this new experience. The base case load shape, as shown in figure A-8, exhibits a number of peak days near the annual peak that is between the 1995 shape (as well as the actual 2002 experience) and the 1998 shape. The figure shows that in 1995 there were 15 peak days above 0.95 p.u. (per unit) of the highest peak day. For the 2002 shape, there were 13 days above the .95 p.u. level. For the 1998 shape, there are only six days above the 0.95 p.u. level. For the base case load shape, there are 12 days.

Figure A-8

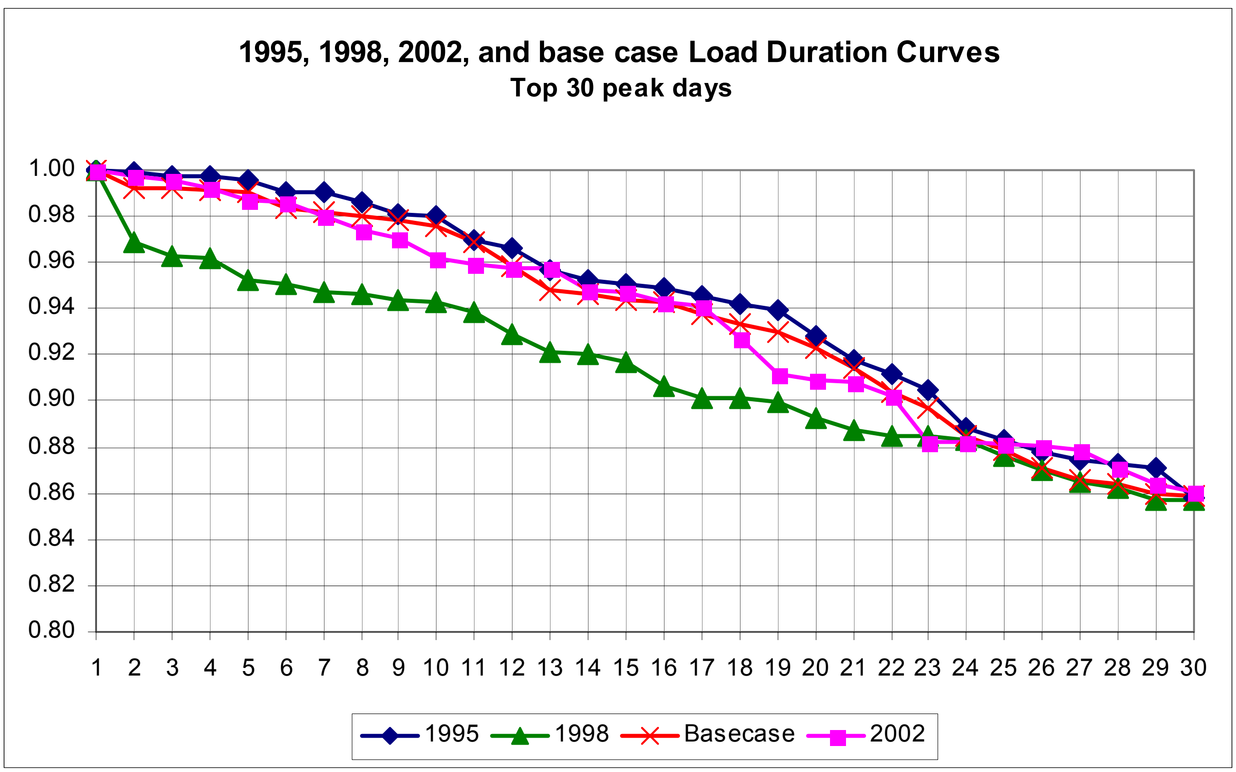
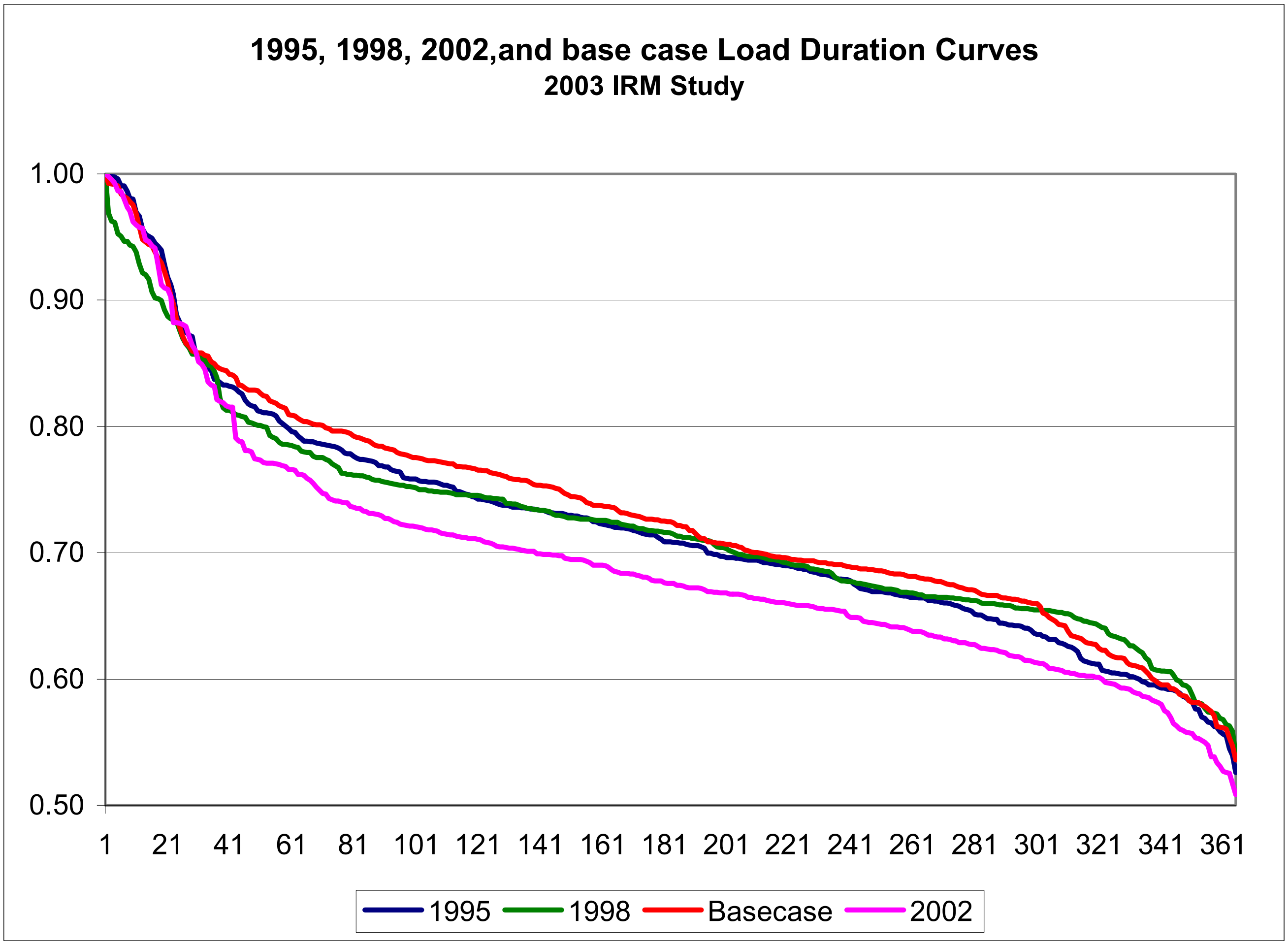


Figure A-9 shows Load Duration Curves for these shapes over the full year.

Figure A-9



The load shape for a zone that is input into MARS is an hourly aggregate of sub-zone loads. Sub-zone loads in NYCA are developed by applying appropriate weights to the Transmission District load shapes.

Each Control Area's (the IMO, HQ, ISO-NE and NYISO) load forecast for the study year is based on its base case load shape, updated to reflect its most recent peak load forecast. The NYCA forecast 2003 peak load used for this study is the most recent estimate of 31,330 MW.

Load Forecast Uncertainty

Load forecast uncertainty covers both the uncertainties of weather and load growth as they affect the load forecast. The intent of the study is to determine a near-term installed margin for NYCA (i.e., 2003). Weather uncertainty and load growth uncertainty both affect the level of the peak load projected for next year, 31,330 MW. A load forecast distribution is used to represent this uncertainty in the MARS model. The distribution is presented below

Prob. %	Per Unit of Peak Load Forecast	Load (MW)
0.62	0.9070	28420
6.06	0.9660	30260
24.17	0.9770	30610
38.30	1.0000	31330
24.17	1.0250	32110
6.06	1.0499	32740
0.62	1.0584	33160

This distribution was used in last year's IRM study as well. After reviewing the 2002 actual peak experience, it was confirmed that it is appropriate to use the same distribution for the 2003 IRM study.

(See the New York State Reliability Council's report "New York Control Area Installed Capacity Requirements for the Period May 2001 Through April 2002" for the derivation of this distribution.)

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 experience.

Table A-2
Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Purchase	Increase capacity	Varies
2	Cancel firm sales	Load relief	0 MW
3	Special Case Resources	Load relief	560MW
4	Emergency Demand Response Prog.	Load relief	354 MW
5	5% manual voltage Reduction	Load relief	83 MW*
6	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW
7	5% remote voltage reduction	Load relief	489 MW*
8	8% remote voltage reduction	Load relief	153 MW**
9	Curtail Company use	Load relief	58 MW
10	Voluntary industrial curtailment	Load relief	260 MW
11	General public appeals	Load relief	30 MW
12	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
13	Customer disconnections	Load relief	As needed

**   These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast 2003 peak load of 31,330 MW.*
*** If the 8% remote voltage reduction were included, the NYCA could expect an additional 153 MW of load reduction.*

The above values are based on the year 2002 results associated with a 2003 peak load forecast of 31,330 MW. Exclusion of Step 8 in the study is 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 8) presented in Table A-2 were modeled in the MARS program.

The values for the voluntary industrial curtailment and public appeals are reduced from those used last year to reflect the increase in the customers participating in the paid programs (SCR and EDRP).

TRANSMISSION CAPACITY MODEL

The NYCA is divided into 11 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 Figure A-10.

The NYCA transmission system is not explicitly modeled in the General Electric Multi-Area Reliability Simulation ("MARS") program; transfer limits between zones are utilized. Failure rates for overhead lines and underground cables are similar but the repair time for an underground cable is much longer therefore, forced transmission outages are included in the MARS model for the underground cable system from surrounding zones entering into New York City and Long Island. The MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are calculated based on the individual make-up of each interface, which includes failure rates and repair times for the cable, and for any transformer and/or phase angle regulator on that particular cable.

For the Con Edison system, a failure rate for each cable is calculated on a per-mile basis using the entire Consolidated Edison underground electric system history from 1988 to the present on a voltage class basis. Typically, the more years included and the larger the cable and equipment population included in the study, the better the results are in predicting the future performance of the underground electric system. Industry standard data is used for a conservative estimate of expected failures on each transformer and phase angle regulator. Once a failure rate and a repair time are created for each component, they are combined to form a single cable system model for each cable. Each single cable system model is then combined together with the other single cable system models that make-up that particular interface to obtain a composite interface model. This provides a conservative estimated transition rate for each of the three cable interfaces into New York City.

The transition rates for the three transmission interfaces into New York City, and the Long Island – Con Edison interface were recalculated. The transition rates associated with the New York City interfaces did not change from what was previously utilized. These assumptions remain valid and the failure rates and repair times are still considered accurate and conservative. Transition rates for the Long Island – Con Edison cable interface were revised to reflect increased unavailability of Long Island interties.

The transmission capability model used in the 2002 IRM study was reviewed to assess the need to update the limits. The Summer 2002 Operating Study Report and database, the 2001 Area Transmission Review and database, and the 2002 Area Transmission Review database were used in the assessment. When the results in the above reports were not sufficient to make an assessment, additional analysis was done with the databases. Most of the limits reported in the above studies that differed from the October 4, 2001 diagram were different for base case conditions and study assumptions rather than a change in transfer capability, and thus do not need updating. Exceptions to the above include the following:

- The Rockland Electric Company (RECO) load that exists in PJM load was moved from Area G to the PJM dummy area. This was done to reflect the change in the obligation to serve this load. Since this load is radially connected to the NYCA, its impact is still reflected in the transfer limits.

- The Central East limit of October 4, 2001 was already updated to reflect the impact of the Marcy FACTS device. Additional impacts on the Central East Limit have reduced this limit approximately by 70 MW net.

- The Athens generation was modeled as a single unit in the area F and appropriate limits were reduced slightly to reflect this.

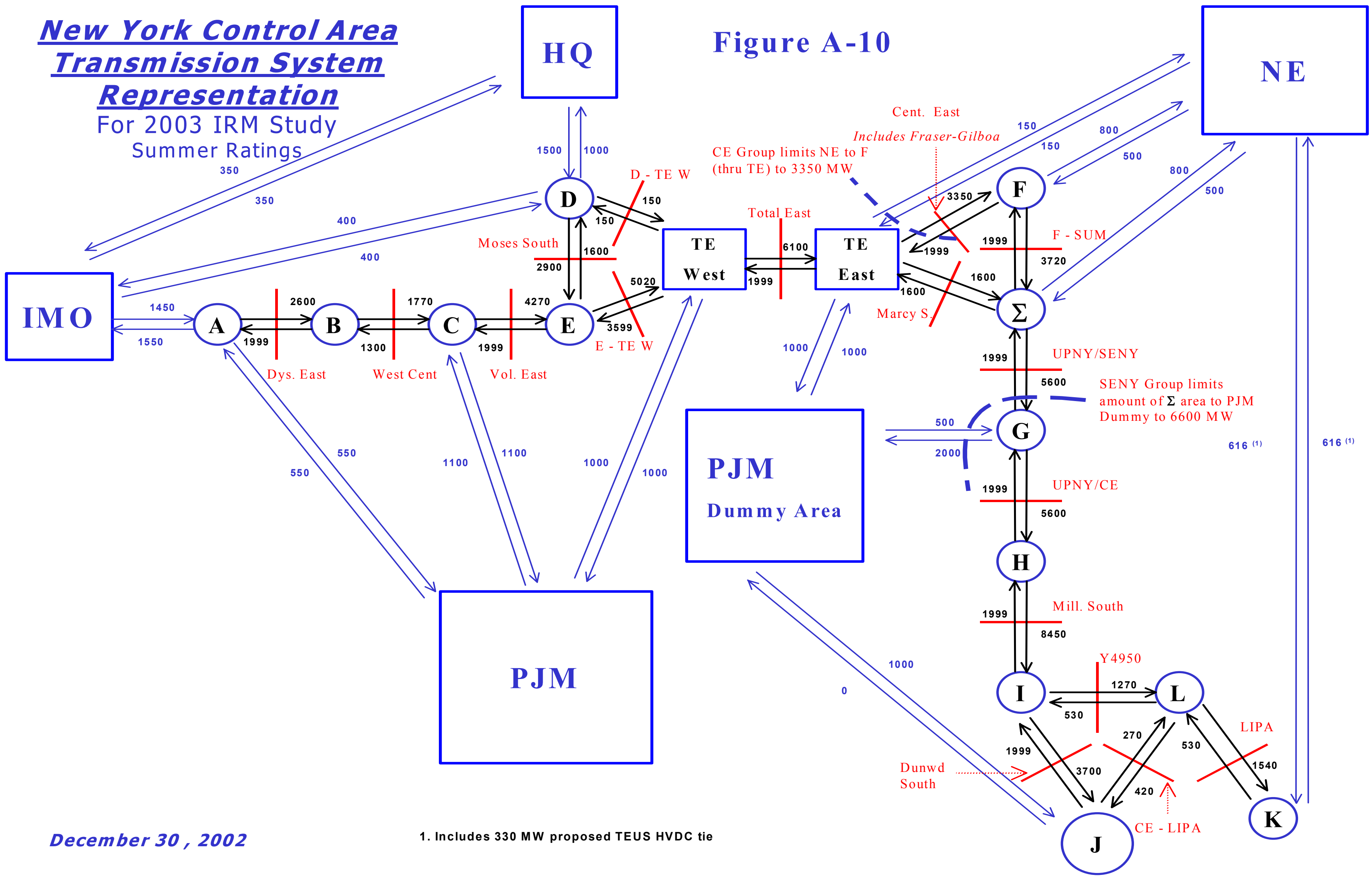
There are some explanations needed to clarify the above-mentioned diagram. All the power flows into New York City from PJM are set up to go through the Total East interface. The PJM Dummy area is set up to model the flows that can be allowed with the Con Edison/PJM phase shifters. While it is possible to have a flow of 3,500 MW into this dummy area, only 1,000 MW can reach area J through the two Hudson-Farragut and the Linden-Goethals phase shifters.

The grouping on Central East of 3350 MW reflects the maximum simultaneous flow from New England to Area F through Total East – East.

The grouping on UPNY-SENY of 6600 Mw reflects the maximum simultaneous flow from the Summation Area through Area G to PJM Dummy Area.

The Summation (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.



December 30 , 2002

1. Includes 330 MW proposed TEUS HVDC tie

NEIGHBORING CONTROL AREA REPRESENTATION

The NPCC control area models are based on the models that they provided for the NPCC study "Summer 2001 Multi-Area Probabilistic Reliability Assessment for the Summer 2001" dated May 2001 (CP-8). This IRM study looked at the reliability models of the NPCC Control areas to be sure that the reliability of neighboring control areas was no better than that of the NYCA.

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

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 load shape.

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.

The assistance from 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 control areas. This consideration is another measure of conservatism added to the analyses.

ASSUMPTION SUMMARY

COMPARISON OF ASSUMPTIONS USED IN THE 2002AND 2003 REPORTS

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	2002 REPORT	2003 REPORT
NYCA Capacity	All Capacity in the NYCA	All Capacity in the NYCA
NYCA Unit Ratings	Based on 2001 Gold Book	Based on 2002 Gold Book
Planned Capacity	Updated to time of study	Current, See Page 16.
Unit Availability	NERC-GADS 1991-2000	NERC-GADS 1992-2001
Unit Maintenance Schedule	Historical adjusted for forecasted time of year	Historical adjusted for forecasted time of year
Neighboring Control areas – all except PJM	NPCC CP-8 2001 Study	NPCC CP-8 2001 Study.
Neighboring Control area – PJM	Developed from public information	Same as last year
Load Model	1995 NYCA shape	Base Case NYCA shape
Peak Load Forecast	ISO staff forecast of 30,650 MW (adjusted for loss of Rockland load.)	Gold Book forecast of 31,330 MW
Load Model Uncertainty	Included weather and load growth uncertainty models	Includes updated load growth uncertainty model
External ICAP	Grandfathered plus 300 MW from ISO-NE and 800 MW HQ	Grandfathered plus 600 MW from HQ and a 500 MW wheel from HQ to New England
Emergency Operating Procedures	1056 MW load relief	1824 MW load relief (Includes 560 MW SCRs and 354 MW EDRPs)
SCRs and EDRPs	515 MW SCRs	Included in EOPs
Locational Capacity Requirements	Used results from 2001 NYISO Locational Requirements Study	Used results from 2002 NYISO Locational Requirements Study
Transfer Limits	Updated	2002 NYISO Assessment.

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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 required IRM.

BASE CASE AND SENSITIVITY CASE RESULTS

Table B-1 summarizes the 2003 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 ****	**1477**	**Yes**	**17.5 %**
2	NYCA Isolated (with base case load shape)	0	No	23.2 %
3	NYCA Isolated with 1998 load shape	0	No	22.7 %
4	NYCA Isolated with 1995 load shape	0	No	23.6 %
5	No External ICAP	0	Yes	17.0 %
6	Grandfathered External ICAP Only	572	Yes	17.3 %
7	No Load Forecast Uncertainty	1477	Yes	14.8 %
8	Without planned units for 2003	1477	Yes	17.5 %
9	Reduce All Internal Transfer Limits by 10%	1477	Yes	18.5 %
10	Reduce unit forced outage rates by 10%	1477	Yes	16.5% ***
11	No Emergency Assistance from PJM	1360	Yes	17.7 %
12	No Emergency Assistance from NE	1117	Yes	17.9 %
13	No Emergency Assistance from HQ	477	Yes	17.7 %
14	No Emergency Assistance from IMO	1477	Yes	17.5 %
15	Remove all 354 MW of EDRP	1477	Yes	18.7 %
16	Include an additional 75 MW of SCRs in NYC	1477	Yes	17.3 %
17	2002 Load Shape for all Areas	1477	Yes	17.6%
18	NYCA Isolated with 2002 load shape	0	No	24.2 %
19	LOLE based on a 17.0% IRM	1477	Yes	0.126 days/yr.
20	LOLE based on 12.2% IRM and last year's study.	1672	Yes	0.754 days/yr.

* Installed reserve required to maintain NYSRC criterion of 0.1 days/year LOLE except for cases 18 & 19.

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

*** Calculated outside of the MARS program.

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1days/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 for each of the EOPs for the base case is provided in Table B-2.

TABLE B-2
Implementation of Emergency Operating Procedures *
Base Case Assumptions (IRM = 17.5%)

Emergency Operating Procedure	**Expected Implementation (Days/Year)**
Emergency Purchase	6.3
Require SCRs	3.6
Require EDRPs	2.6
5% manual voltage reduction	2.1
30 minute reserve to zero	2.0
5% remote control voltage reduction	1.2
Voluntary load curtailment	0.7
Public appeals	0.5
10 minute reserve to zero	0.4
Customer disconnections	0.1

* See Appendix A, Table A-2