NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2005 THROUGH APRIL 2006

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

Executive Committee Resolution
And
Technical Study Report

December 10, 2004

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

APPROVAL OF NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD MAY 1, 2005 THROUGH APRIL 30, 2006

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 December 10, 2004, conducted by the NYSRC Installed Capacity Subcommittee, show that the required NYCA installed reserve margin (IRM) for the May 1, 2005 through April 30, 2006 capability year is 17.6% 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, 2005 through April 30, 2006 capability year, which equates to an Installed Capacity Requirement of 1.18 times the forecasted NYCA 2005 peak load.

NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2005 THROUGH APRIL 2006

TECHNICAL STUDY REPORT

December 10, 2004
New York State Reliability Council, LLC
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 annual statewide 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 establishing the NYCA required installed reserve margin (IRM) for the period of May 2005 through April 2006 (Year 2005) in compliance with the NYSRC Agreement. The ICR relates to the IRM through the following equation:

$$ICR = (1 + IRM\% / 100) \times \text{Forecasted NYCA Peak Load}$$

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 translates the required IRM to an "Unforced Capacity" (UCAP) basis, in accordance with a 2001 NYISO filing to FERC. Also, in June 2003 the NYISO replaced its monthly Deficiency Auction with a Spot Market Auction based on FERC approved "Demand Curves." These Unforced Capacity and Demand Curve concepts are 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/documents.html.

EXECUTIVE SUMMARY

The NYSRC Base Case evaluation for Year 2005 results in a NYCA IRM requirement of **17.6%**. In addition to calculating a Base Case IRM requirement, the study evaluated IRM requirement impacts of modeling enhancements and the updating of key study assumptions, as well as the results of various sensitivity cases performed. These results are depicted in Table 1 and Figures 2 and 3, and in Appendix B-1. When taken together, the Base Case, sensitivity case results and other relevant factors provide the basis for the NYSRC determination of the final NYCA IRM requirement for Year 2005.

Based on the error range of the Monte Carlo simulation used for the IRM reliability calculation, there is a 99.7% probability that the Base Case IRM result is within the range of 17.1% to 17.9%.[1]

Resource Capacity Availability

This year a major effort was launched to review historic NYCA generating unit outage performance. As a result of this review improved capacity availability representations

1 The statistical significance of the 17.1, 17.6 and 17.9 IRM requirement percentages are a 0.15%, 50% and 99.85% probability, respectively, of meeting the one in ten criterion, assuming perfect accuracy in all input parameters.

were adopted for the 2005 IRM requirement study. Prior to this year outage rate determination considered a ten-year historic period. However, due to recent performance improvements the NYSRC concluded that a five-year history actually offered more representative performance data.

The available capacity in the model reflects a capacity reduction of 711 MW that was calculated by the NYISO and approved by the NYSRC. The available capacity has been generally overstated by generation owners in 2002-03 data submissions to the NYISO. In turn, the NYISO has taken steps to avoid future capacity overstatements by improving its generating unit reporting requirements. These capacity representation enhancements – use of a five-year historical period and a DMNC adjustment - increased the IRM requirement by 1.3 percentage points from last year's study. Table 1 shows the impacts of these and other modeling changes incorporated into this study that resulted in a net increase of the Base Case IRM requirement of 0.5 percentage point from last year's requirement.

Transmission Constraints

This study found that representation of transmission system transfer capability within NYCA has a significant impact on the 2005 NYCA IRM requirement. For example, the IRM requirement would be 1.7 percentage points less than the Base Case IRM requirement of 17.6% if the study assumed no transmission constraints within NYCA.

The impact of transmission constraints on statewide IRM requirements depends on the level of resource capacity in New York City (NYC) and Long Island (LI). Locational Capacity Requirements (LCR) for NYC and LI (annually prepared by the NYISO) have not yet been developed for the 2005-06 capability year. While this study is not intended to establish LCR, transmission constraints within the NYCA can impact LCR as well as IRM requirements. Recognizing this relationship and the potential impact on reliability, the NYSRC and NYISO are jointly considering methods of "anchoring" the LCR to ensure the NYCA IRM requirement will meet NYSRC Reliability Rule A-R1.

STUDY PROCEDURE

This study utilizes a probabilistic approach for determining the NYCA IRM requirements. This technique calculates the probabilities of generating unit outages, in conjunction with load and transmission representations, to determine the days per year of expected capacity shortages.

The General Electric Multi-Area Reliability Simulation (MARS) is the primary analytical tool used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA Zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. MARS calculates "Loss of Load Expectation" (LOLE, expressed in days per year), to provide a consistent measure of system reliability.

Appendix A includes details of the reliability calculation process, information about the MARS program, modeling parameters, and other assumptions. The procedure used in this study is in accordance with NYSRC Policy 5-0, *Procedure for Establishing New York Control Area Installed Capacity Requirements*, www.nysrc.org/polices.html.

Sensitivity analyses were also performed to determine variations to the Base Case IRM requirement. These analyses are used in conjunction with Base Case results to form the basis for the final NYCA IRM requirement established by the NYSRC. Base Case study results and the sensitivity analyses are presented in Appendix B.

RELIABILITY CRITERION

The acceptable LOLE reliability level used for establishing NYCA IRM requirements is dictated by the NYSRC Reliability Rules, wherein Rule A-R1 (*Statewide Installed Reserve Margin Requirements)* states:

> *The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures.*

This NYSRC Reliability Rule is consistent with the NPCC Resource Adequacy Standard in NPCC Document A-2.

BASE CASE STUDY RESULTS

Year 2005 IRM Base Case study results show a required NYCA IRM of 17.6%. (Refer to Appendix A for Base Case study assumptions.) Accordingly, we conclude that maintaining the NYCA installed reserve of 17.6% over the forecasted NYCA 2005 summer peak season will achieve applicable NYSRC and NPCC reliability criteria for Base Case study assumptions.

Major parameters that influence NYCA IRM requirements include:

- ***Interconnection Support During Emergencies.*** NYCA reliability can be improved by receiving emergency assistance support from other interconnected Control Areas — in accordance with control area reserve sharing agreements during emergency conditions. Assuming such arrangements in the Base Case permits the NYCA IRM to be 8.0 percentage points lower than is otherwise required (Table B-1, Case 2-Case 1).

- ***Load Forecast Uncertainty (LFU).*** It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the model by using a load forecast probability distribution that is sensitive to different weather and economic conditions. Recognizing the unique LFU of individual NYCA areas, the LFU model is subdivided into three areas: New York City (NYC), Long Island (LI), and the rest of New York State. Compared to single point representation, i.e., no LFU, the impact of this three-area load forecast uncertainty model yields a 3.6 percentage point increase in IRM requirements. (Table B-1, Case 4 – Case 1).

- ***Resource Capacity Availability.*** Generating unit forced and partial outages are modeled in MARS by inputting a multi-state outage model that represents an "equivalent demand forced outage rate" (EFORd) for each unit represented. Outage data is received by the NYISO from generator owners based on specific reporting requirements established by the NYISO. Capacity unavailability is modeled by considering forced and partial outages that occur over an appropriate historic time period. Through 2003 the NYSRC IRM studies utilized a 10-year period. In 2004 close review of NYCA availability trends indicated that average performance of generating units improved in recent years. (See Figure A-5 in Appendix A.) Therefore, the NYSRC decided to base the 2005 IRM study on a five-year historical period.

  Although generating unit availability has improved in recent years, a recent NYISO Market Monitoring review of actual outage data revealed that this recorded improvement has been somewhat offset by overstating the availability of certain resources reported to the NYISO. There are two primary reasons this overstatement: (1) In the past generator owners have not been required to report partial and forced outages that were attributed to transmission failures, fuel shortages, or environmental limitations; (2) Recent NYISO audits discovered that in certain cases, GADS data supplied by generation owners have overstated unit availability. The NYISO has since taken steps to improve future generating unit availability reporting requirements. To account for this resource availability overstatement, this study incorporates a reduction in statewide DMNC capacity of 711 MW. This adjustment is based on a detailed analysis conducted by the NYISO and approved by the NYSRC.

  Incorporation of the new MARS capacity modeling enhancements described above resulted in an IRM requirement increase of 1.3 percentage points from last year's study (see Table 1).

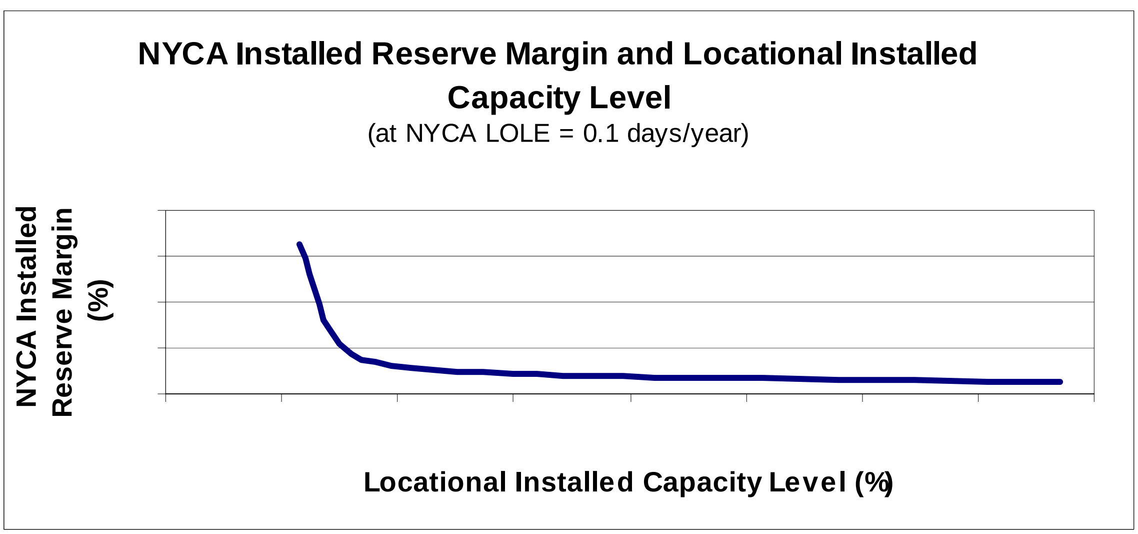
  The capacity model also reflects an improved gas turbine derate representation that calibrates gas turbine capacity deratings under ranges of high ambient temperatures. This improved turbine derate representation resulted in a decrease of 0.6 percentage points from last year's study. (See Table 1)

- ***NYCA Transmission Constraints.*** MARS is capable of determining the impact of transmission constraints on the NYCA LOLE. This study, as with previous MARS studies, consistently reveal that the transmission system into NYC and LI may constrain delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints. First, NYCA IRM requirement analyzes must consider the impacts of transmission constraints into NYC and LI (see Reliability Criterion section). Second, a minimum Locational Capacity Requirement (LCR) must be maintained in each of the NYC and LI zones.

  The impact of transmission constraints on statewide IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements*, the NYISO is required to calculate and establish appropriate LCR. The most recent NYISO study (*Locational Installed Capacity Requirements Study*, dated February 20, 2004) determined that for 2004 the LCR for NYC and LI were 80% and 99%, respectively.

  Figure 1 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI. This figure shows that the IRM requirement can be impacted significantly depending on the level of capacity within these zones, particularly above the "knee" of the curve where the IRM requirement rises much faster than the locational installed capacity level can be reduced. The Base Case assumptions resulted in the Base Case IRM requirement of 17.6%, which reflects NYC and LI locational installed capacity levels of 83% and 99%, respectively.

Figure 1



  Results from the sensitivity cases shown in Figures 2 and 3 (see Sensitivity Case Results section) show IRM requirement impacts for changes of locational installed capacity level assumptions from the Base Case. Observations from these results include:

- If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 15.9%, 1.7 percentage points less than the Base Case requirement. (Figure 3).

- If the NYC and LI locational installed capacity levels were increased from the Base Case assumptions to 86% and 102%, respectively, the IRM requirement could be reduced to 16.1% (Figure 2).

- Setting the NYC and LI locational installed capacity level to the 2004 LCR of 80% and 99%, respectively, could increase the IRM requirement to 20.3% (Figure 2).

- If the LI locational installed capacity level were also reduced to 96% from the previous observation, the NYSRC reliability criterion cannot be maintained even for very high levels of IRM.

These results illustrate the significant impact on IRM requirements when changing locational installed capacity levels. Recognizing this relationship and the potential impact on reliability, the NYSRC and NYISO are jointly considering methods of "anchoring" the LCR to ensure the NYCA IRM requirement will meet NYSRC Reliability Rule A-R1.

- ***Special Case Resources (SCRs)***. SCRs are ICAP resources that include loads that are capable of being interrupted — and distributed generation that may be activated on demand. This study assumed 975 MW of SCR capacity resource capacity in July and August (and lesser amounts during other months).

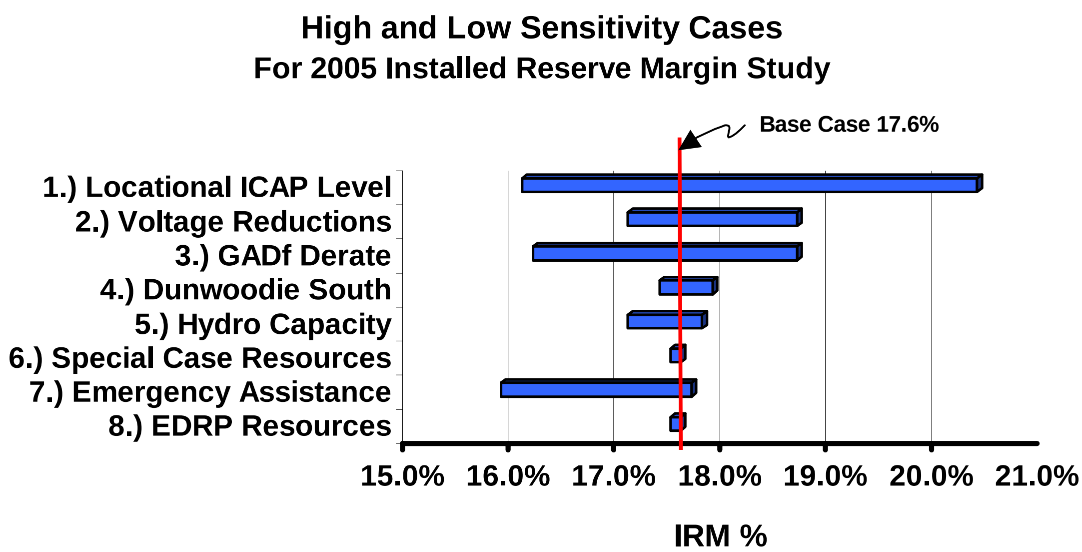
- ***Emergency Demand Response Programs (EDRP).*** EDRP allow registered interruptible loads and standby generators to participate on a voluntary basis - and be paid for their ability to restore operating reserves. This study assumed 299 MW of EDRP capacity resources in July and August (and less in other months). The study also assumed a maximum of five monthly EDRP calls. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model.

- ***Other Emergency Operating Procedures.*** The NYISO will implement EOPs as required to minimize customer disconnections. If a 17.6% IRM is maintained, firm load disconnections due to inadequate resources will not occur more than once in every ten years on average — in accordance with NYSRC and NPCC criteria. (Refer to Appendix B, Table B-2, for the expected use during 2004 of SCRs, EDRP, voltage reductions, and other EOPs.)

SENSITIVITY CASE STUDY RESULTS

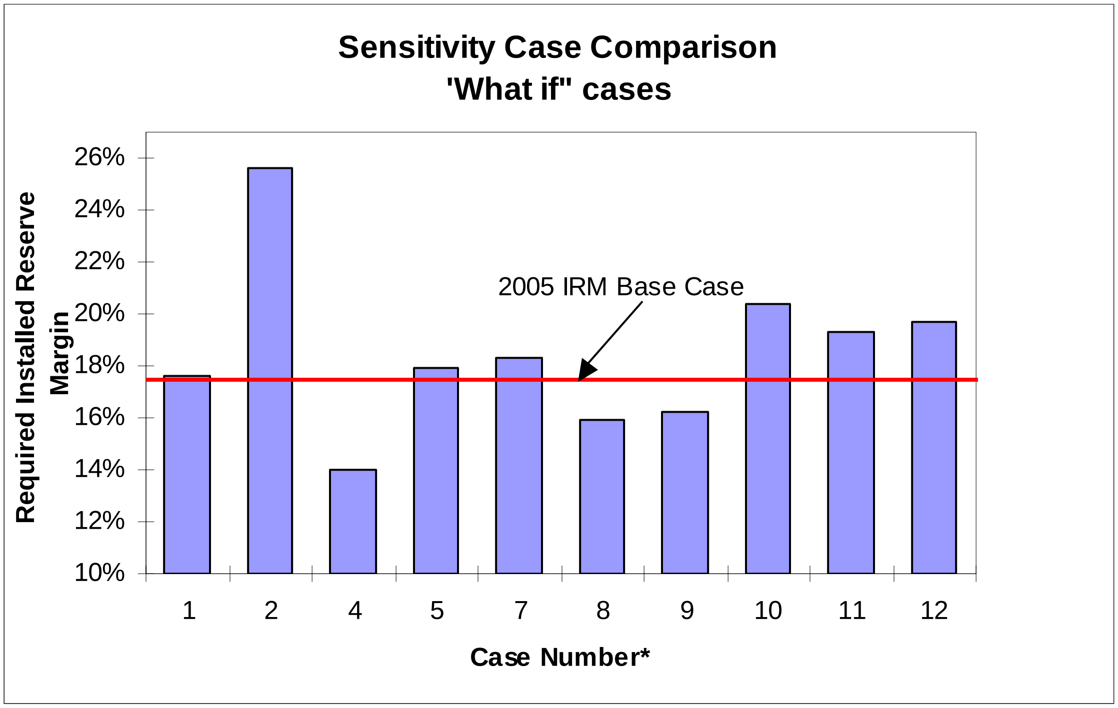
Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from the Base Case will, of course, yield different results. Figure 2 shows the sensitivity of IRM results using reasonable high and low ranges of several key base case assumptions. Figure 3 shows the sensitivity of IRM results for several "what if" sensitivity cases. Compared to the Base Case requirement of 17.6%, the sensitivity study results depicted in Figure 2 show a required IRM range of 15.9% to 20.4% (16.9% to 18.3% if the high and low sensitivity case IRM results are averaged). Sensitivity case results are also listed in Appendix B, Table B-1.

Figure 2



Case	Description
1.) Locational ICAP Level	Varies the capacity to load ratios in NYC/LI from 80/99 % to 87/102 % (base case = 83/99 %).
2.) Voltage Reductions	Varies remote voltage reductions from 247 MW to 592 MW (base case = 493 MW).
3.) GADf Derate	Varies derate from 300 to 1,000 MW (base case = 711 MW).
4.) Dunwoodie South	Evaluates this interface rating at 3,330 and 4,000 MW (base case = 3,600 MW).
5.) Hydro Capacity	Derates Hydro resources (not St. Lawrence or Niagara) by 25% to 65% (base case = 45%).
6.) Special Case Resources	Varies the amount of SCRs modeled from 780 MW to 1,170 MW (base case = 975 MW).
7.) Emergency Assistance	Varies the reserve margins of the external Control Areas (as they're modeled) by +/- 10%.
8.) EDRP Resources	Varies the amount of EDRP modeled from 209 MW to 329 MW (base case = 269 MW)

Figure 3



* Refers to Table B-1, Appendix B.

Case #	Description
1	Base Case
2	NYCA Isolated
4	No Load Forecast Uncertainty
5	Without Planned Units for 2005
7	Add Flat Rock (240 MW)
8	No Internal NCYA transmission constraints
9	Relocate SCR's to Zones J and K
10	Remove SCRs and EDRP
11	IRM at an LOLE of 0.05 days/year (1/20)
12	No voltage reductions

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

NYISO Translation of NYCA Capacity Requirements to Unforced Capacity:

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity or "UCAP". To maintain consistency between the rating of a unit (UCAP) and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the Summer and Winter Capability Seasons.

Additionally, any Locational Capacity Requirements in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another — and is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts UCAP requirements to ICAP in a manner that assures compliance with NYSRC Resource Adequacy Rule A-R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

NYISO Implementation of a Spot Market Auction based on a Demand Curves:

Effective June 1, 2003 the NYISO replaced its monthly Capacity Deficiency Auction with a monthly Spot Market Auction based on three FERC-approved Demand Curves. Demand Curves are developed for zones J, K, and the rest of NYCA.

The existence of Demand Curves does not impact the determination of IRM requirements by the NYSRC.

COMPARISON WITH YEAR 2004 STUDY RESULTS

The results of the Year 2005 IRM study show that the IRM requirement has increased 0.5 percentage points from the Year 2004 IRM Study. Table 1 compares several key parameters. The primary drivers that increased the IRM requirement include updating the generating unit capacity availability representation and an updated gas turbine capacity derate model described previously in the report.

Table 1

COMPARISON WITH 2004 STUDY*

Parameter	IRM Req. Change (%)	IRM Req. (%)
Previous 2004 Study – Base Case IRM Result		**17.1**
Updated Peak Load Forecast & Load Uncertainty Model	+0.2	
Five-year historical outages (from 10 year) for forced and partial outage rates (-1.0 %) Capacity reduction of 711 MW (+2.3%)	+1.3	
Updated Gas Turbine Capacity Derate Model	-0.6	
New Generating Units & Retirements	-0.3	
Updated SCR and EDRP capacity & other EOPs	-0.1	
Net Change from 2004 Study	+0.5	
New 2005 Study – Base Case IRM Result		**17.6**

* See report titled "New York Control Area Installed Capacity Requirement for the Period 2004 through 2005", dated December 11, 2003, for a 2004 Study description and study assumptions.

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APPENDIX A

NYCA INSTALLED CAPACITY REQUIREMENT RELIABILITY CALCULATION MODELS AND ASSUMPTIONS

Description of MARS Program;
Load, Capacity, Transmission and Outside World Models;
And Assumptions.

A-1 Introduction

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

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A-1.

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. Finally, the last page of Appendix A compares the assumptions used in the 2004 and 2005 IRM reports.

Table A-1

Details on Study Parameters

Internal NYCA Modeling:

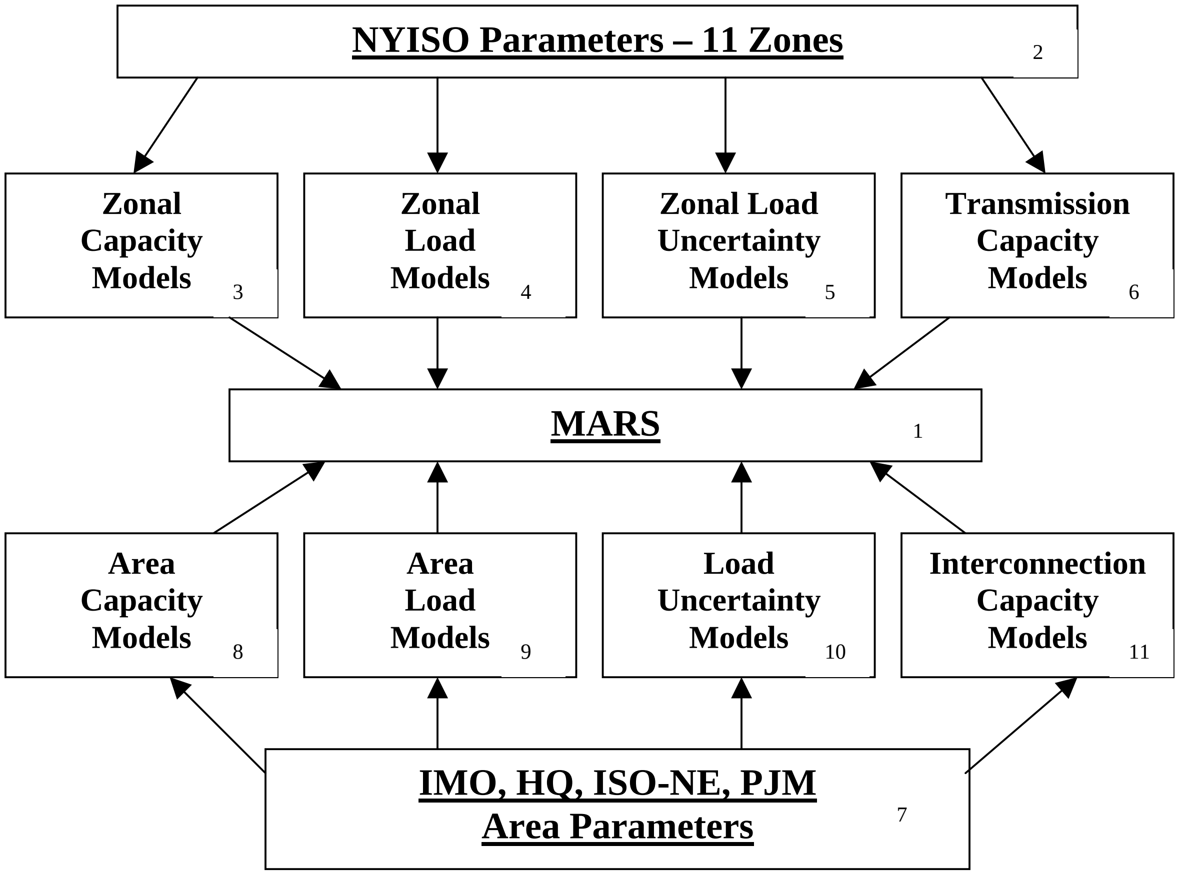
Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	MARS	The General Electric Multi-Area Reliability Simulation Program		See page 14
2	11 Zones	Load Areas	Fig. A-2 page 17	NYISO Accounting & Billing Manual
3	Zone Capacity Models Emergency Operating Procedures	-Generator Models for each generating unit in Zone. -Generating Availability. -Unit Ratings. -Locational Installed Capacity Level Reduces load during emergency conditions to maintain operating reserves.	GADS Data 2004 Gold Book* NYISO	See page 22 See page 22 See page 30
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	See page 19 32,320 MW Gold Book
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historic Data	See page 21
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	See page 32

External Control Area Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
7	IMO, HQ, ISO-NE, PJM control area Parameters	See the following items 8-11.		
8	External Control Area Capacity Models	Generator Models in neighboring control areas	NPCC CP-8 study for NPCC Areas. NERC Report for PJM	See page 35
9	External Control Area Load Models	Hourly Loads	NPCC CP-8 study for NPCC Areas PJM Web site.	See page 35
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	NPCC CP-8 Study	See page 36
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	NPCC CP-8 Study	See page 32

* "2004 Load & Capacity Data" Report issued by the NYISO.

Figure A-1
NYCA ICAP Modeling



A-2 Computer Program Used for Reliability Calculation

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Sections A-3 and A-5.6 for a description of these Zones and Outside World Areas).

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, transmission and demand-side options.

MARS calculates the standard reliability indices of daily and hourly 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). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A-5.3).

In addition to calculating the expected values for the reliability indices, MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured by the use of a load forecast uncertainty model.

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, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by MARS) steps through the year chronologically, recognizing the status 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. 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 hours is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

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

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

The table below shows the calculation of the state transition rates from historic 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 to 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 the 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 LOLE estimate is 0.05. Twenty three hundred and eleven (2311) replications were simulated in the Base Case. This year, the standard error in LOLE results in an IRM range of 17.1% to 17.9%[2] for a Base Case confidence interval of 99.7%. The IRM calculation is based on a series of Monte Carlo runs. Each IRM calculation (including the Base Case and sensitivity cases) has an accuracy range associated with the number of Monte Carlo trials. The statistical significance of the 17.1, 17.6 and 17.9 IRM requirement percentages are a 0.15%, 50% and 99.85% probability, respectively, of meeting the one in ten criterion, assuming perfect accuracy in all input parameters.

A-3 Representation of the NYCA Zones

Figure A-2 depicts the NYCA Zones represented in MARS.

A-4 Conduct of the MARS Analysis

An updated MARS software version (executable version 2.59) was tested to ensure that the new version produced acceptable results. The test compares results derived using the current MARS version 2.59 with results based on a previous MARS version 2.57 using the same assumptions.

The current base is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's Base Case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

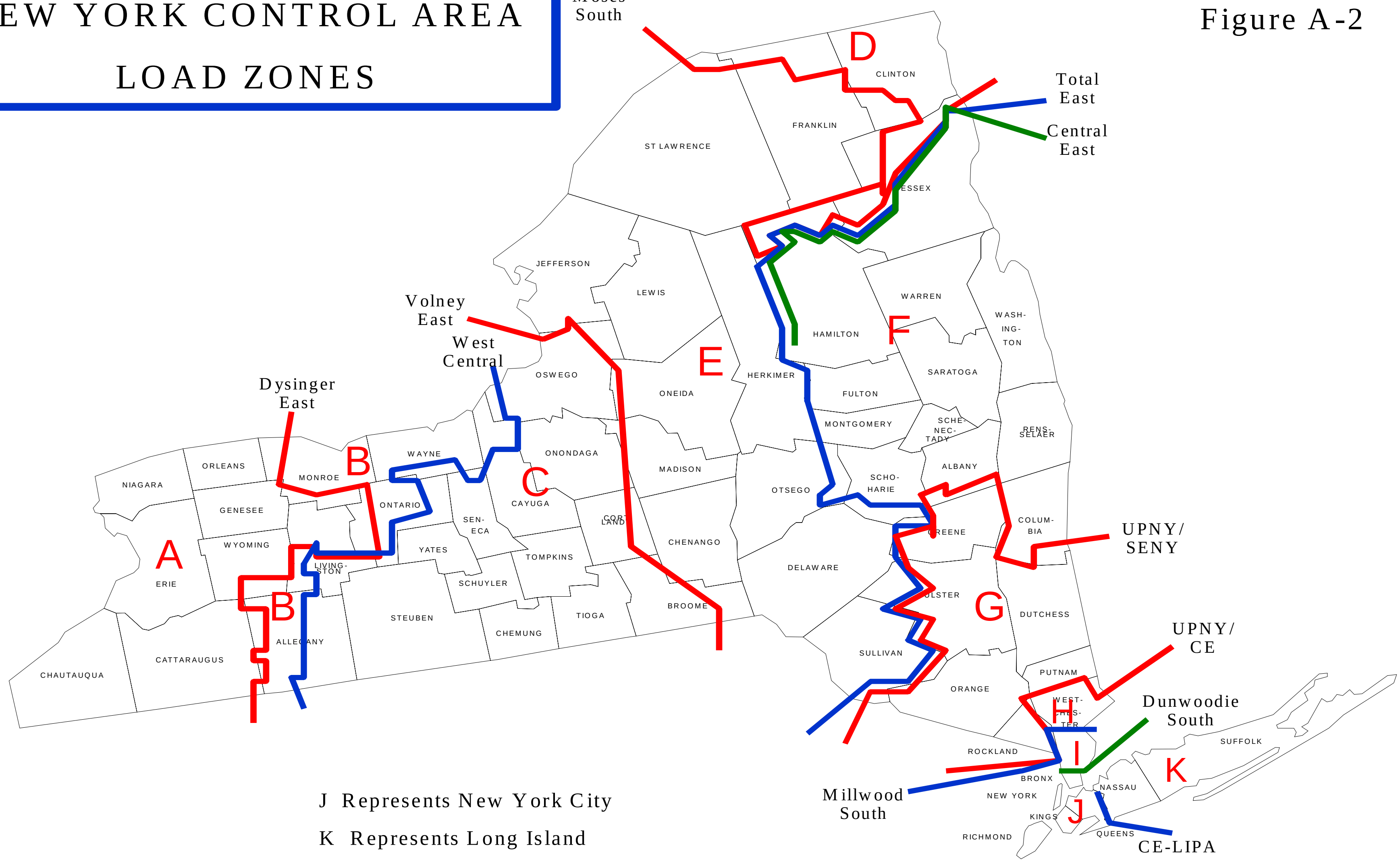
Below are the primary study parameters that are input into the MARS program. These parameters are described in detail in Section A-5 and referenced in the boxes shown in Table A-1 and Figure A-1.

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)

2 The IRM range is skew because the relationship between the IRM and the LOLE is non-linear.

NEW YORK CONTROL AREA LOAD ZONES

Figure A-2



The top three 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 the base case data and models are fully input into the MARS program, an initial reliability simulation is run and the LOLE result compared to the LOLE criterion target of disconnecting firm load once in 10 years, or 0.1 days per year. If there is not a match, MARS is re-run in an iterative process by increasing/decreasing the loads in the Zones proportionally in order to yield a higher/lower LOLE result, until the result matches the 0.1 days per year LOLE target. This final case defines the base case from which the required NYCA IRM is determined. This iterative process is also used for the pre-base case simulations described above.

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.

In addition to running a base case using the input assumptions described below, a number of sensitivity studies are run to show the IRM requirement outcomes for different assumptions.

A-5 Input Data and Models

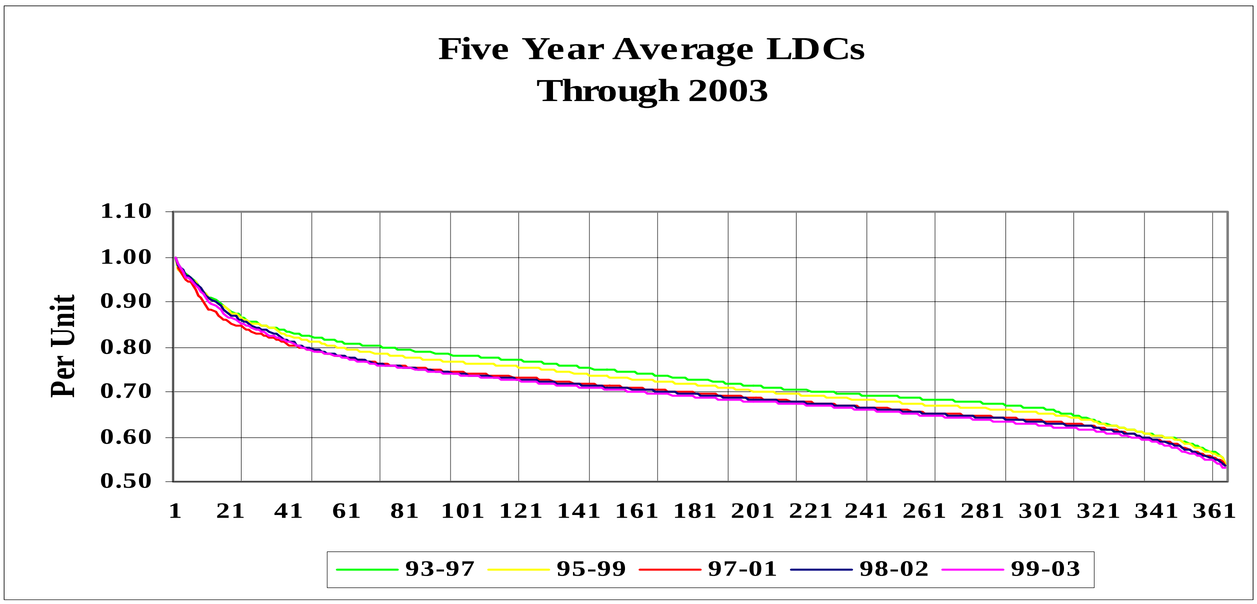
A-5.1 NYCA LOAD MODEL

The 2004 IRM study (last year's study) was performed using a load shape based on 2002 actual values. For the 2005 IRM study, Load Forecasting staff evaluated the 2003 hourly load shape. The purpose was to determine if the 2003 experience offered any new information that would cause a re-evaluation of whether or not to use the 2002 load shape. It concluded that it did not.

The year 2003 was fairly typical. However, it had several anomalies that prevented its being adopted in favor of 2002. Its peak day (June 26) occurred outside the normal interval in which peaks occur. The peak itself, 30,333 MW, was low and was adjusted upwards by over 1000 MW to its weather-normalized level (31,400 MW). In addition, the 2003 blackout affected loads on August 14 – 16. The first of these days could have been a peak day if the blackout had not occurred and reconstructing a "normal" peak for it would have presented novel problems.

The year 2003 data supported the previous study's conclusion to adopt the 2002 load shape. The trend towards fewer high-risk days per year appears to have stabilized as shown on Figure A-3.

Figure A-3



In this figure, points on each average load duration curve are determined by finding the average of the corresponding points of the load duration curves for the five years indicated. The average curves lay successively one beneath the prior one, until the final two curves. This indicates that, for 2002 and 2003 at least, the trend towards fewer and fewer daily peaks near the annual peak has abated.

The shift of load from Zones A – I to Zones J and K also appears to have stabilized:

Share of NYCA Peak Load Accounted for by Load In:	J	K	A - I
1995	32.2%	13.4%	54.4%
1996	32.2%	13.4%	54.4%
1997	32.8%	13.9%	53.3%
1998	33.1%	14.4%	52.5%
1999	34.0%	15.3%	50.7%
2000	34.4%	15.3%	50.2%
2001	34.5%	15.4%	50.1%
2002	34.2%	15.7%	50.1%
2003	34.0%	15.8%	50.2%

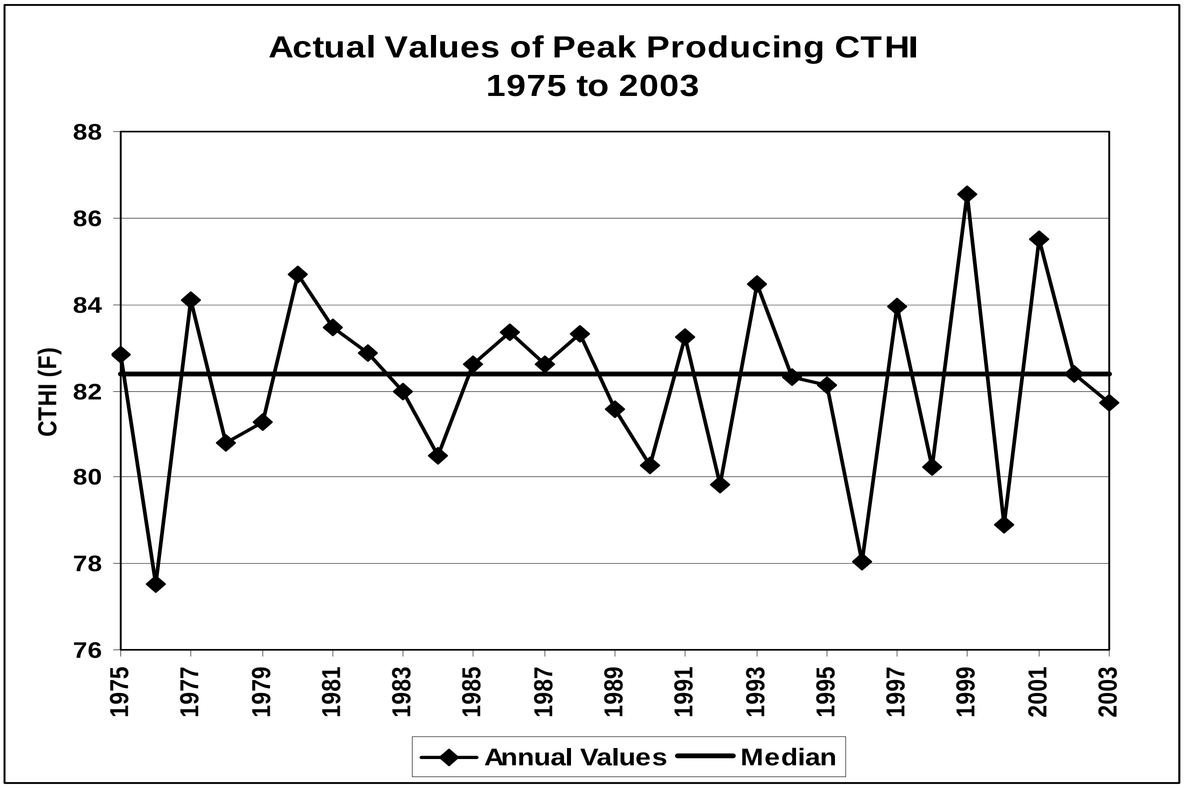
(Average of current and preceding two years.)

This supports the continued use of the 2002 load model for the current IRM study.

Weather Analysis

Weather conditions for 2002 were evaluated for the 2004 IRM study as part of the analysis that concluded the 2002 load shape should be used. For the 2005 study, a limited analysis was performed whose purpose was to determine if, based on information obtained since that decision, the conclusion was still valid. Figure A-4 shows the peak producing values of the NYCA Combined Temperature Humidity Index (CTHI) for the last 29 years. 2002 is the year in which the observed value is identical to the design condition. This supports the conclusion that 2002 is still a valid year for study purposes.

Figure A-4



Based on these considerations, the ICS concluded that the 2002 load shape was appropriate to use for the 2005 IRM Study

A-5.1.1 ZONAL LOAD FORECAST UNCERTAINITY

For 2005, new load forecast uncertainty models were provided by Consolidated Edison and LIPA for Zones J and K respectively. The models are presented below.

2005 Load Forecast Uncertainty Models

Multiplier	NYCA Tot	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0584	1.0457	1.1409	1.0413
0.0606	1.0499	1.0368	1.0924	1.0309
0.2417	1.0250	1.0173	1.0457	1.0206
0.3830	1.0000	1.0000	1.0000	1.0000
0.2417	0.9770	0.9682	0.9543	0.9852
0.0606	0.9460	0.9488	0.9076	0.9561
0.0062	0.9070	0.9410	0.8591	0.8987

The NYCA Net (i.e., Zones A – I) was determined by taking out the load weighted J and K contribution to uncertainty form the NYCA Total uncertainty. Load forecast uncertainty for the State, as a whole was unchanged.

A-5.2 NYCA Capacity Model

The capacity model input to MARS incorporates the several types of resource capacity used to serve load in the NYCA. The following were changes made to the existing capacity shown in table III-2 of the "2004 Load and Capacity Data" (Gold Book):

- **Retirements:**

Hudson Ave. 10	65 MW	NYC
Albany Steam	356 MW	Zone F
Waterside	166 MW (10/05)	NYC
Freeport Electric	15 MW	Long Island

- **New Units: (Units installed during 2004)**

KeySpan Ravenswood	270 MW	NYC
Freeport	94 MW	Long Island
Stonybrook reclaim	33 MW	Long Island
Cedars unit incorporation*	200 MW	Zone D

- **Planned Units for 2005:** (These units had a signed interconnection agreement by August 1, 2004.)

East River Repowering	288 MW	NYC
Poletti Expansion	500 MW	NYC
Bethlehem	750 MW	Zone F
Bethpage	79.9 MW	Long Island
Pinelawn	79.9 MW	Long Island
Flat Rock	240 MW	Zone E - sensitivity case

*In the 2004 IRM study, this unit was modeled externally to NYCA as part of HQ

This section describes how each resource type is modeled in MARS.

Generating Units

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State. This model requires the following input data:

Unit Ratings. The rating for each generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. The 2004 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

Unit Performance. Performance data for all generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the "equivalent demand forced outage rate" (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. Through 2003, the NYSRC IRM studies utilized a 10-year period. In 2004, close review of NYCA availability trends indicated that average performance of generating units improved in recent years (See Figure A-5). Therefore, the NYSRC decided to base the 2005 IRM study on a five-year historical period.

The multi-state model for each unit is derived from five years of historic events if it is available. For units with less then five years of historic events, the available years of event data collected since the inception of the NYISO is used if it appears to be reasonable. For the remaining units NERC class-average data is used.

The unit forced outage states for the majority of the large steam units were obtained from the five-year average NERC - GADS outage data collected by NYPP and the NYISO for the years 1999 through 2003. 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 recent NYISO Market Monitoring review of actual outage data revealed that, although generating unit availability has shown improvement in recent years, this recorded improvement has been somewhat mitigated by the overstatement of the availability of certain resources reported to the NYISO. There are two primary reasons this overstatement: (1) In the past generator owners have not been required to report partial and forced outages that were attributed to transmission failures, fuel shortages, or environmental limitations; (2) Recent NYISO audits discovered that in certain cases, GADS data supplied by generation owners have overstated unit availability. The NYISO has since taken steps to improve future generating unit availability reporting requirements. To account for this resource availability overstatement, this study incorporates a reduction in statewide DMNC capacity of 711 MW. This is documented in the "Report Adjusting for the Current Overstatement of Resource Availability in Resource Adequacy Studies", dated August 13, 2004.

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage component is obtained from the generator owners, and where necessary, extended so that the scheduled maintenance period equals the historic average using the same period used to determine EFORd averages.

Figure A-5

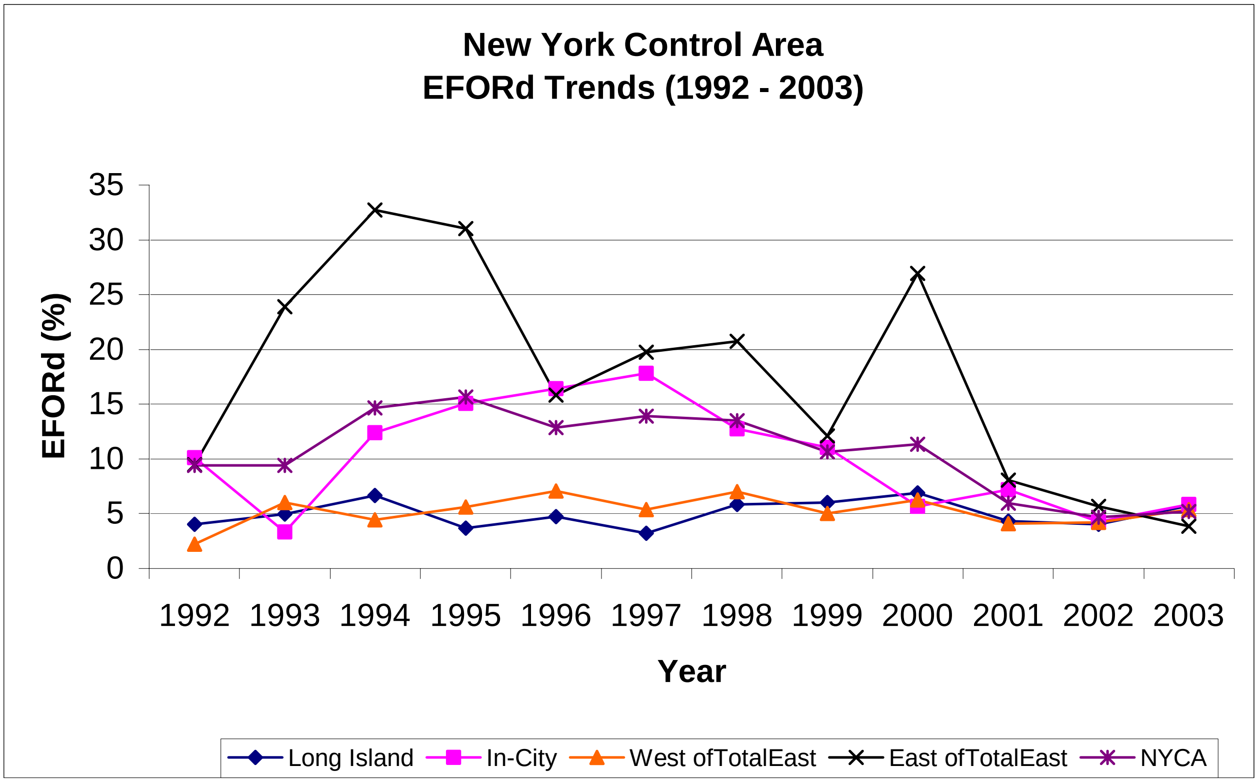


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd) from 1992 through 2003. The graph presents unit weighted averages for four Zones within the NYCA along with a NYCA total aggregate.

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 is a continued trend of improved reliability.

Figure A-7 provides NERC-GADS data industry-wide. The continued improved availability is similar to that experienced in the NYCA. Note that the year 2003 data from NERC is not available at this date.

Figure A-6

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 – 2003

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

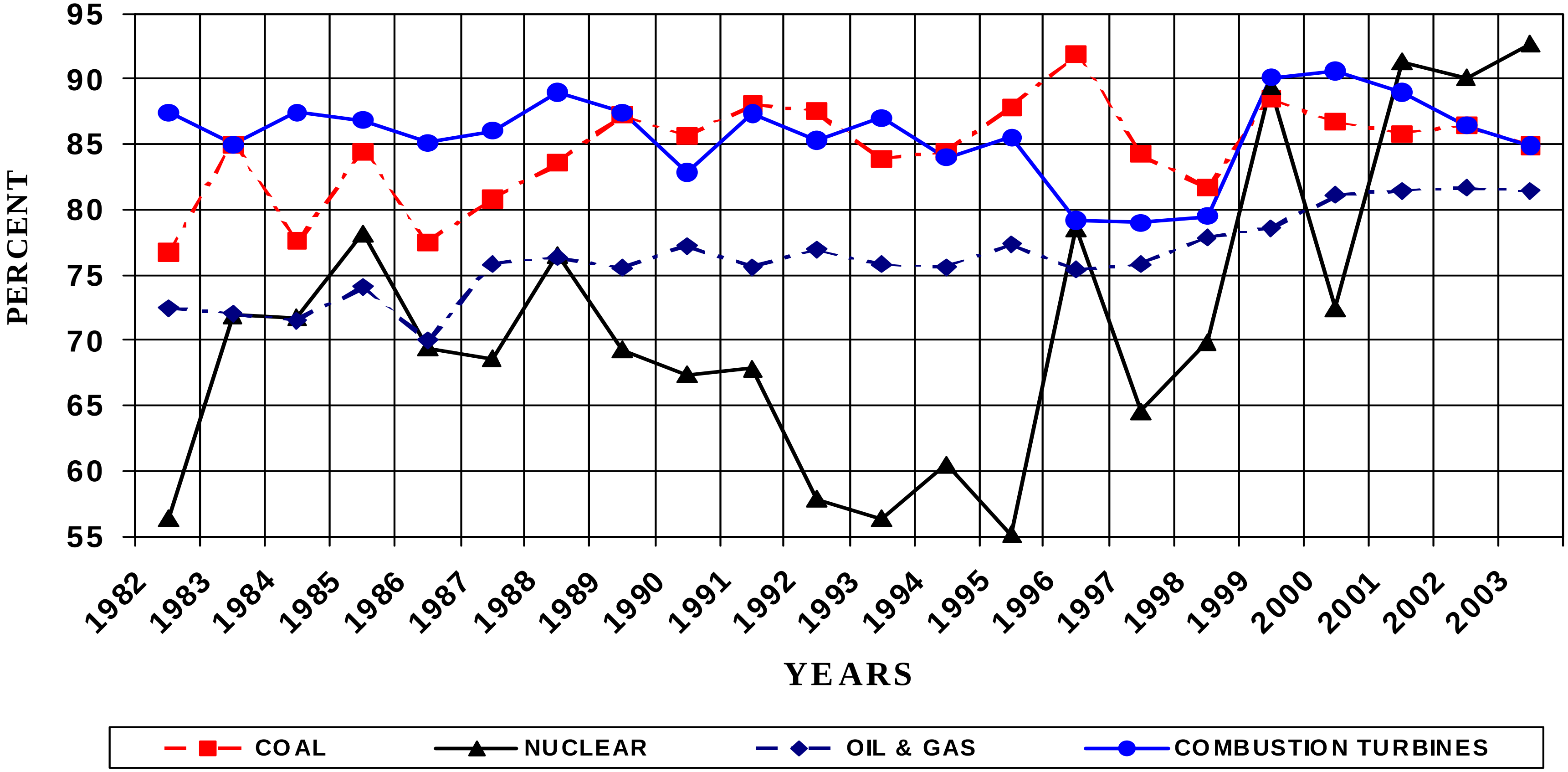
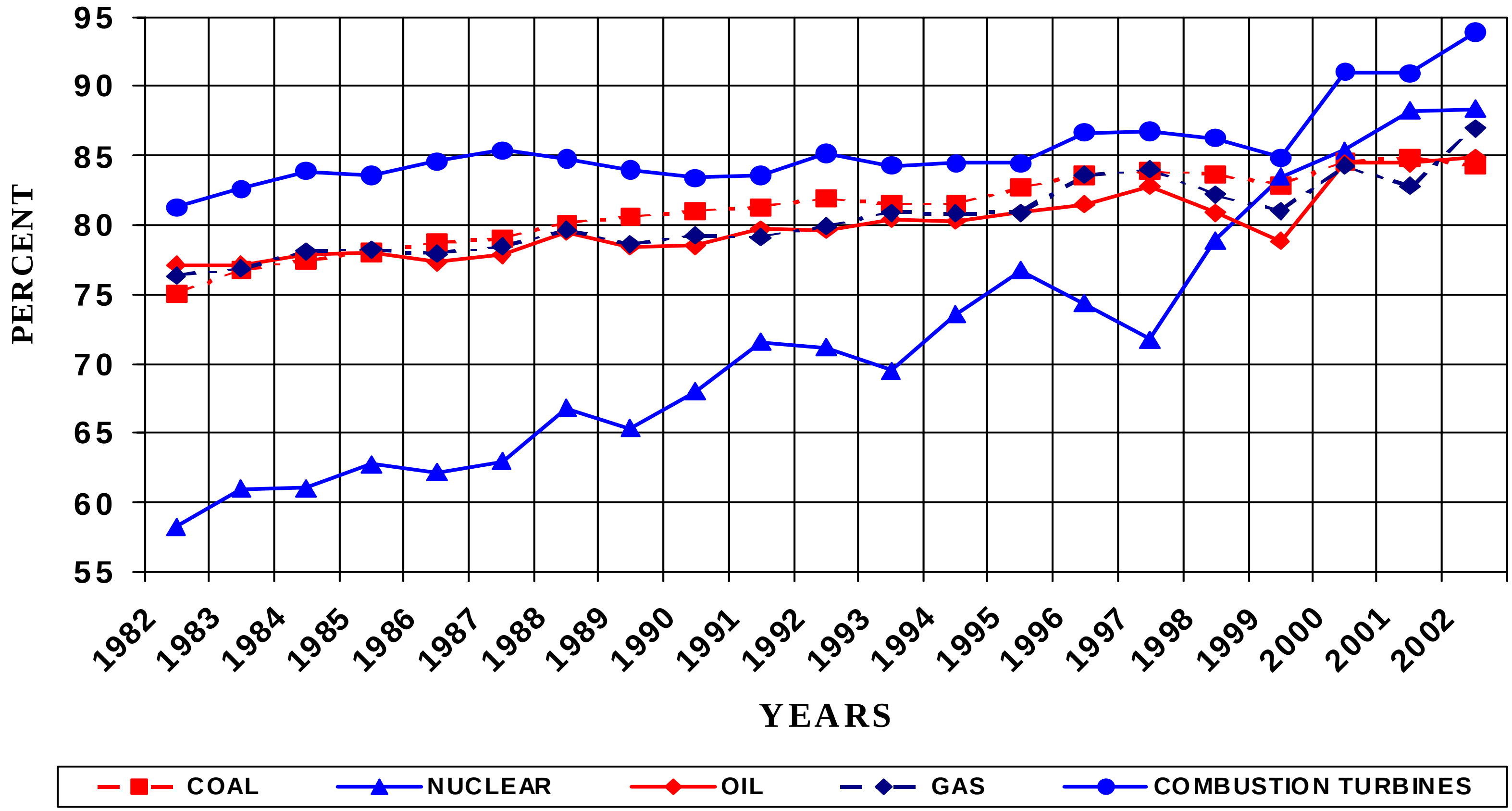


Figure A-7

NERC EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2002

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



Scheduled Maintenance. The total amount of scheduled maintenance, including both planned and maintenance outages, was developed from a five-year average of the same NERC-GADS data 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 five-year historic outage time period. Figure A-8 provides a graph of scheduled outage trends over the 1999 through 2003 period for NYCA generators.

Figure A-8

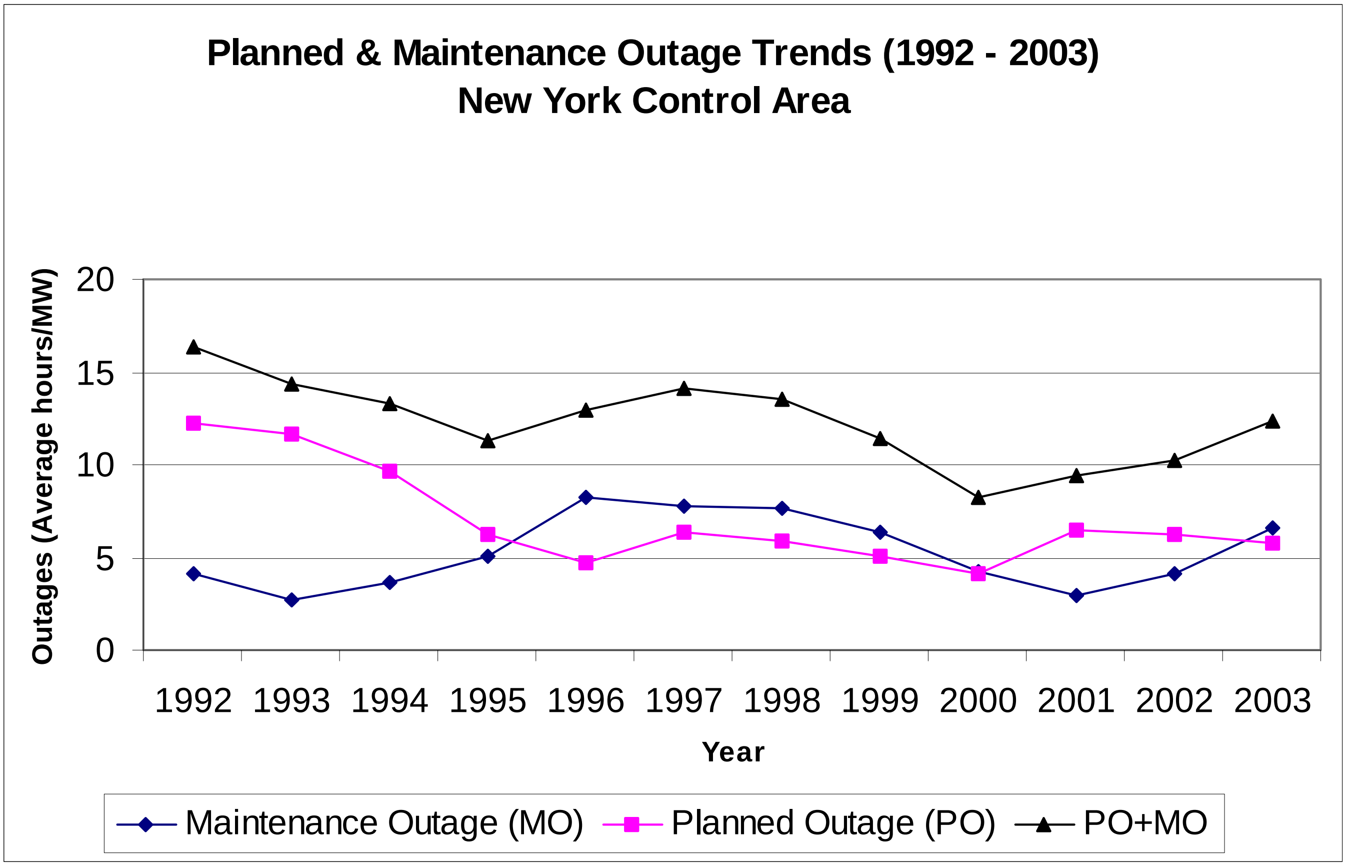
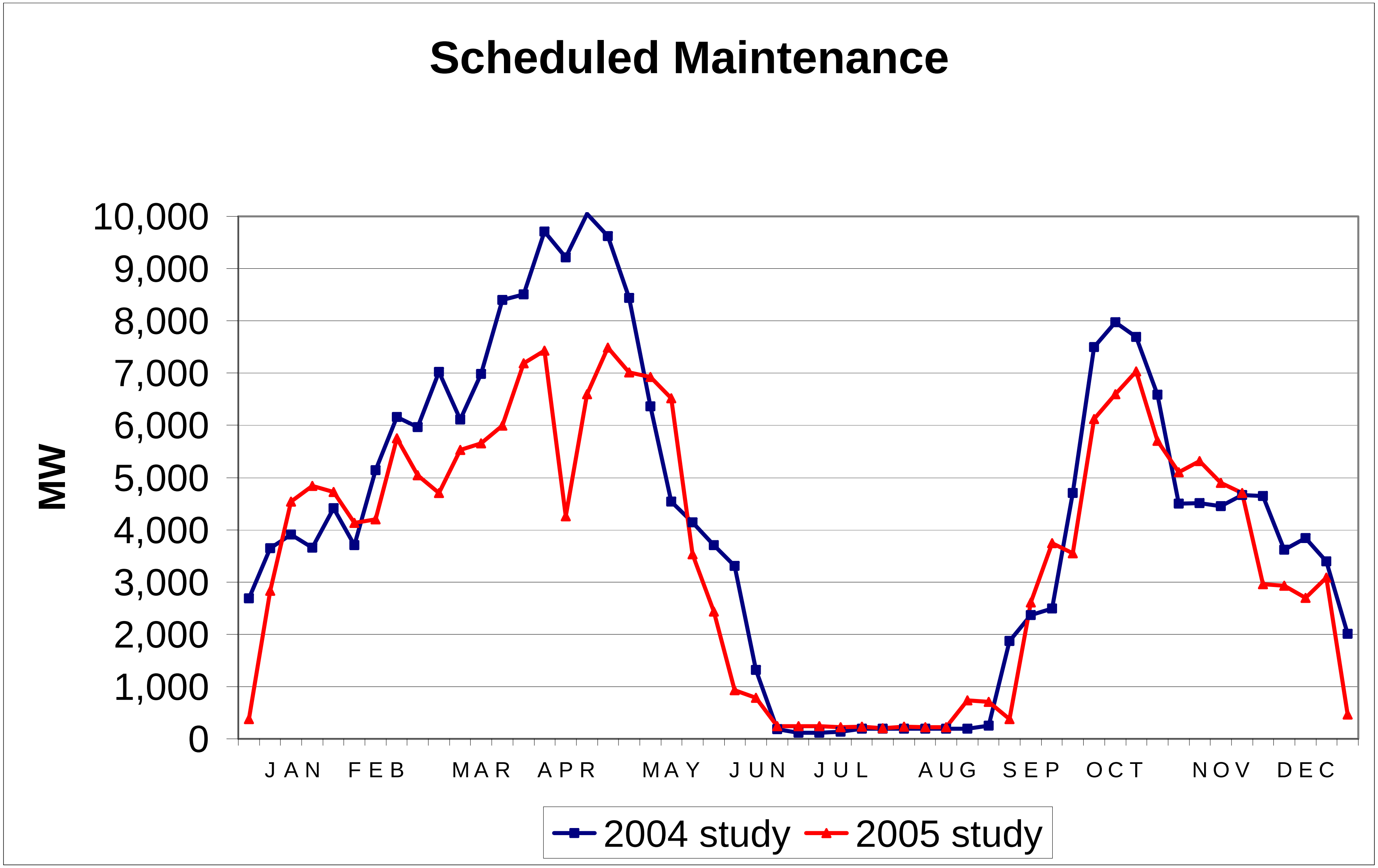


Figure A-9 shows the amount of capacity assumed to be scheduled out in the 2004 and 2005 studies.

The planned outages in the current study over the 2005 summer period are approximately 200 MW.

Figure A-9


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
2004 study
2005 study

Combustion Turbine Units. Observations of combustion turbine performance over the past several years have indicated that the output of these units is limited at temperatures above design conditions. Last year, this reduced output was captured by applying a derate against the load uncertainty levels above the forecast load level. Although this derate has been measured as a steady value each year (80 MW per degree above 92 degrees F), the load level derate may have been overly conservative. This year, through program modification, a derate has been applied directly against those units that are impacted when the load levels exceed forecast.

This does not affect all units because many of 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. About one quarter of the existing 3,700 MW of Combustion Turbines fall into this category.

Hydro Units. The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model based on historic water flows and unit performance. The remaining 1040 MW of hydro facilities are simulated in MARS with a 45% hydro derate model, representing deratings in accordance with recent historic hydro water conditions.

Special Case Resources (SCRs) and Emergency Demand Response Program (EDRP)

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

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

MARS models SCRs and EDRP as EOP steps and will activate these steps to minimize the probability of customer load disconnection. Both MARS and NYISO operations only activate EOPs in zones where they are capable of be delivered.

For this year's study the NYISO has recommended that SCRs be modeled as a 975 MW EOP step, discounted to 897 MW in July and August (and further discounted in other months proportionally to the monthly peak load). EDRP are modeled as a 269 MW EOP step with a limit of five calls per month. This EOP is discounted based on actual experience from the forecast registered amount of 599 MW.

External Installed Capacity from Contracts

An input to the study is the amount of NYCA installed capacity that is assumed located outside NYCA. Some of this capacity is grandfathered.

Transactions

The NYISO has recommended that the following inter-area capacity transactions to be modeled in this study:

There is 227 MW of grandfathered summer capacity modeled as firm purchases by NYCA, consisting of 117 MW from PJM, and 55 MW from New England and 55MW from Ontario. The Base Case assumes the following additional summer external ICAP: 1200 MW from HQ, 345 MW from New England and 983 MW from PJM. This totals 2755 MW of expected summer external ICAP). The expected amount of external ICAP for the winter is 2331 MW. The New England to Long Island (Cross Sound Cable) is modeled as a tie between New England and Long Island.

NYISO studies have indicated that the maximum external ICAP that can be purchased without impacting reliability is 2755 MW.

All firm sales are modeled as listed in the Gold Book for the year 2005.

A-5.3 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	Special Case Resources	Load relief	897 MW*
2	Emergency Demand Response Prog.	Load relief	269 MW
3	5% manual voltage Reduction	Load relief	83 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	493 MW**
6	Curtail Company use	Load relief	11 MW
7	Voluntary industrial curtailment	Load relief	128 MW**
8	General public appeals	Load relief	13 MW
9	Emergency Purchases	Load relief	Varies
10	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
11	Customer disconnections	Load relief	As needed

**   The SCR's are modeled as 975 MW, however they are discounted to 897 MW in July and August and further discounted in other months.*
** *   These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast 2005 peak load of 32,320 MW.*

The above values are based on the year 2004 results associated with a 2005 peak load forecast of 32,320 MW. 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 presented in Table A-2 were modeled in the MARS program.

The value for the voluntary industrial curtailment is reduced from that used last year to reflect the increase in the customers participating in the paid programs (SCR and EDRP).

A-5.4 Transmission Capacity Model

The NYCA is divided into 11 Zones. The boundaries between Zones and between adjacent control Areas are called interface ties. These ties are used in the MARS model to allow and limit the assistance among NYCA Zones and adjacent control Areas. While the NYCA transmission system is not explicitly modeled in the MARS program, a transportation algorithm is utilized with limits on the interface ties between the Areas and Zones represented in the model. Interface tie groupings and dependent interface tie limits have been developed such that the transmission model closely resembles the standard eleven-Zone NYCA model. The interface tie limits employed are developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and refined with additional analysis specifically for the MARS representation. The new topology and interface limits are shown in Figure 10.

The interface tie limits used in the 2004 IRM study were reviewed to assess the need to update the limits resulting from more recent studies. The Summer 2003 and 2004 Operating Study Reports and databases and the 2001, 2002, and 2003 Area Transmission Reviews and databases were primarily 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, or other studies were referenced. Most of the limits reported in the above studies that differed from 2004 IRM 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:

<u>1) General Topology and Ratings Changes</u>

With the system that is projected for the summer of 2005, the Central East plus Fraser Gilboa, CE Group, and Total East interfaces were reduced by 100 MW. The major factors for this are the addition of Athens and Bethlehem, load growth, voltage concerns and impacts on flow distributions on the major transmission circuits in this area.

The Northport to Norwalk Harbor Cable Tie and the Cross Sound Cable were modeled independently by adding one dummy area between Zone K and Area NE, to allow for modeling of separate transition rates for those cables.

<u>2) Insertion of Series Reactors Impact on Dunwoodie South Interface</u>

The Dunwoodie South Interface transfer limit is dependent on the relationship of flows on the two Dunwoodie to Rainey and two Sprainbrook to W 49th St. 345 kV cable circuits. The maximum transfer limit is achieved at perfect balancing of the flows on these cables. Balancing of these flows is highly dependent on system dispatch conditions. Since the flow imbalance can be very significant at times, the transfer limit has been historically derated by approximately 200 MWs from its maximum to maintain conservatism. The insertion of series reactors in each of the two Dunwoodie to Rainey and two Sprainbrook to W 49th St. 345 kV cable circuits will greatly increase the impedance of these circuits, and thus impact the distribution and balancing of flows on these four cables. The range of potential imbalance is actually reduced by this impedance change, thus suggesting an increase in transfer limit, but with the present uncertainty of a reactor insertion procedure and other system impacts of these series reactors, this interface limit was not changed in order to maintain conservatism.

Cable Interfaces

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.

Interconnection Support During Emergencies

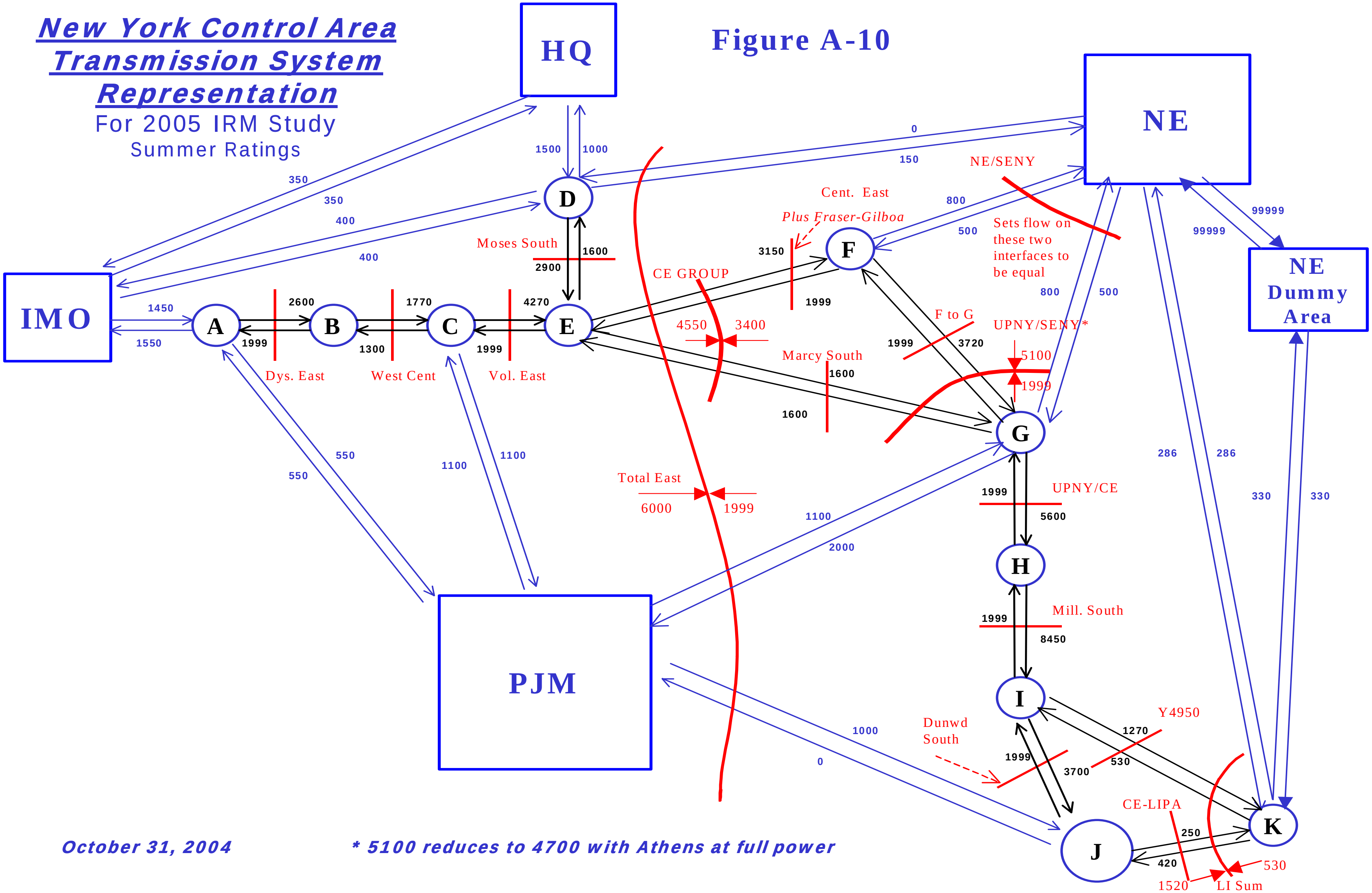
Base case assumptions considered the full capacity of transfer capability from external Control Areas (adjusted for grandfathered contracts and estimated external capacity purchases) in determining the level of external emergency assistance.

New York Control Area Transmission System Representation

For 2005 IRM Study

Summer Ratings

Figure A-10



October 31, 2004

** 5100 reduces to 4700 with Athens at full power*

A-5.5 Locational Capacity Requirements

The MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, i.e., locational ICAP, which shall be electrically located within the Zone in order to ensure that sufficient energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to two transmission-constrained Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A-R2 and monitored by the NYISO, supplement the statewide IRM requirement. The Locational Installed Capacity Requirements Study performed by NYISO determines LSEs requirements for affected Zones. The locational installed capacity levels used to calculate the IRM for the 2005 study met or exceeded the 2004 Locational ICAP Requirement of 99% for Long Island and 80% for NYC, respectively. This year's Base Case IRM reflects locational installed capacity levels of 83% for NYC and 99% for LI.

A-5.6 Outside World Load and Capacity Models

NYCA reliability largely depends on emergency assistance from its interconnected Control Areas in NPCC and PJM, based on reserve sharing agreements with the Outside World Areas. Load and capacity models of the Outside World Areas are therefore represented in the MARS analyses. The load and capacity models for ISO-NE, IMO and Hydro-Quebec are based on data received from the Outside World Areas, as well as NPCC sources. The PJM capacity model is based on data from the NERC Electric Supply and Demand database.

The primary consideration for developing the final load and capacity models for the Outside World Areas is to avoid overdependence on the Outside World Areas for emergency capacity support. For this purpose, a rule is applied whereby either an Outside World Area's LOLE cannot be lower than 0.100 days/year LOLE, or its isolated LOLE cannot be lower than that of the NYCA. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA. Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within the Outside World Areas that may limit emergency assistance to the NYCA. This recognition is considered implicitly.

The year 2002 is used in this study for both the NYCA and the Outside World Area load shapes. In order to avoid overdependence from emergency assistance, the three highest summer load peak days of the Outside World Areas' are modeled to match the same load sequence as NYCA.

The NPCC Control Area representations are based on the models provided for the NPCC study titled "Summer 2001 Multi-Area Probabilistic Reliability Assessment" dated May 2001 (CP-8). 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 2002 load shape.

The EOPs were removed from the ISO-NE and IMO models (the only ones other than 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.

The load forecast uncertainty model for the outside world model is from the CP-8 study.

A-6 Assumption Summary -Comparison of Assumptions Used in the 2004 Study and 2005 Study

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	2004 Study	2005 Study
NYCA Capacity	All Capacity in the NYCA	All Capacity in the NYCA
NYCA Unit Ratings	Based on 2003 Gold Book	Based on 2004 Gold Book
Planned Capacity	Updated to time of study	Updated to time of study
Forced and partial outage rates	NERC-GADS 1993-2002	NERC-GADS 1999-2003 plus a 711 MW DMNC derating.
Planned outages	Based on schedules received by NYISO as of Sept. 2002 & adjusted for history	Based on schedules received by NYISO as of Sept. 2003 & adjusted for history
Non NYPA hydro modeling	45% derating	45% derating
Unit Maintenance Schedule	Historic adjusted for forecasted time of year	Historic 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	Base Case NYCA 2002 shape	Base Case 2002 NYCA shape
Peak Load Forecast	Gold Book forecast of 31,890 MW	Gold Book forecast of 32,320 MW
Load Forecast Uncertainty	Includes improved uncertainty model that models three Areas of NYCA separately	Includes improved uncertainty model that models three Areas of NYCA separately
External ICAP	Grandfathered plus 1200 MW from HQ, 345 MW from New England and 983 MW from PJM	2755 M Total, 55 from Ontario, 1200 from HQ, 400 from NE and 1100 from PJM
Emergency Operating Procedures	1658 MW load relief (Includes 652 MW SCRs and 225 MW EDRPs)	1874 MW load relief (Includes 877 MW SCRs and 269 MW EDRPs)
Locational ICAP Levels	Assure Base Case results meet or exceed the minimum levels of the 2003 NYISO Locational Requirements Study.	Assure Base Case results meet or exceed the minimum levels of the 2004 NYISO Locational Requirements Study.
Transfer Limits	2003 NYISO Assessment	2004 NYISO Assessment

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APPENDIX B

DETAILS OF STUDY RESULTS

B-1 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.

B-2 Base Case and Sensitivity Case Results

Table B-1 summarizes the 2005 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 Sensitivity Results

Case #	Description	NYCA Ext ICAP Rep.(MW)	Required IRM[3]
1	**Base Case**	**2755**	**17.6 %**
2	NYCA Isolated	0	25.6 %
3	NYCA Isolated with no EOPs (except SCRs)	0	29.4 %
4	No Load Forecast Uncertainty	2755	14.0 %
5	Without planned units for 2005	2755	17.9 %[4]
6	No Internal Transfer Limits	2755	15.9 %
7	Include Flat Rock (240 MW)	2755	18.3 %
8	No Emergency Assistance from NE	2755	25.1 %
9	Relocate all SCRs to Zones J and K	2755	16.2 %
10	Remove both EDRPs and SCRs	2755	20.4 %
11	IRM at an LOLE of 0.05 days/year (1/20)	2755	19.3 %
12	No voltage reductions	2755	19.7 %
13	CSC out of service	2755	21.9%
14	Model CSC as UDR	2755	17.9 %
15	Remove Cedar (200 MW) unit	2755	17.3%

3 Installed Reserve Margin required to meet an LOLE of 0.100 days/year unless otherwise noted (as in case 11)
4 Retirements (Albany Steam and Waterside) will not occur if planned units are not completed (see section A-5.2)

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 1.6 remote 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 = 17.6%)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	4.4
Require EDRPs	2.5
5% manual voltage reduction	2.4
30 minute reserve to zero	2.3
5% remote control voltage reduction	1.6
Curtail Company use	1.2
Voluntary load curtailment	1.1
Public appeals	1.1
Emergency purchases	1.1
10 minute reserve to zero	0.4
Customer disconnections	0.1

* See Appendix A, Table A-2