New York Control Area Installed Capacity Requirements for the Period May 2010 through April 2011

Technical Study Report

December 4, 2009

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. This year's report covers the period May 2010 to April 2011 (2010 capability year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2010 capability year is 17.9% under base case conditions.

For this base case, the study also determined Minimum Locational Capacity Requirements (MLCRs) of 79.6% and 104.9% for New York City (NYC) and Long Island (LI), respectively. In its role of setting the appropriate locational capacity requirements (LCRs), the New York Independent System Operator (NYISO) will consider these MLCRs.

These study results satisfy and are consistent with NYSRC Reliability Rules, Northeast Power Coordinating Council (NPCC) reliability criteria, and North American Electric Reliability Corporation (NERC) reliability standards.

The above 2010 base case IRM study value of 17.9 % represents a 1.7% *increase* from the base case IRM requirement determined by the 2009 IRM Study.

Table 1 shows the IRM impacts that have resulted in a net 1.7% increase from the 2009 IRM base case value of 16.2%. The principle drivers for this increase in required IRM are:

1. A Special Case Resource (SCR) performance model that better represents the likely load reduction during peak periods.
2. The continuing trend of increasing generating unit forced outage rates in NYCA. This trend is particularly significant for units located in New York City and Long Island.

The increase in the IRM caused by these and other factors are tempered to some extent by IRM reductions primarily caused by increased emergency assistance (as a result of updated Outside World modeling) from neighboring control areas, an improved process for modeling loop flow during NYCA emergencies, and planned non-wind generation facilities and retirements.

Two environmental initiatives were evaluated for the 2010 IRM Study that had the potential to impact IRM requirements. The first is a set of regulations to implement the Regional Greenhouse Gas Initiative (RGGI), which will place a limit on CO_2 emissions from certain fossil fueled generators. The second initiative is to bring air quality in New York State into compliance with National Ambient Air Quality Standards (NAAQS) for ozone, and will focus on the reduction of NOx emissions for power plants. A review of these initiatives by the NYISO concluded that neither is expected to impact IRM requirements in 2010, and therefore were not included in the 2010 base case. A sensitivity case to examine possible IRM impacts after 2010 was included in the study.

The study also evaluated IRM impacts of several sensitivity cases. These results are depicted in Table 2 and in Appendix Table B-2. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case 17.9% IRM will fully meet NYSRC and the NPCC resource adequacy criteria.

The base case and sensitivity case IRM results, along with other relevant factors, will be considered in a separate NYSRC Executive Committee process, in which the Final NYCA IRM requirement for the 2010 capability year is adopted.

INTRODUCTION

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA IRM for the period of May 1, 2010 through April 30, 2011 (2010 capability year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

ICR = (1 + %IRM Requirement /100) x Forecasted NYCA Peak Load

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2010 capability year.

The NYISO will implement the final NYCA IRM 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. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. These Unforced Capacity and Demand Curve concepts are described later in the report. The schedule for conducting the 2010 IRM study was based on meeting the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2010 IRM Study are in accordance with NYSRC Policy 5-3, *Procedure for Establishing New York Control Area Installed Capacity Requirements*, dated July 11, 2008. The primary reliability criterion used in the IRM study requires, on average, a Loss of Load Expectation (LOLE) of no more than once in 10 years for the NYCA. This NYSRC resource adequacy criterion is consistent with NPCC reliability criteria and NERC reliability standards. IRM study procedures include the use of two study methodologies, the *Unified* and the *IRM Anchoring Methodologies.* The above reliability criterion and methodologies are discussed in more detail later in the report. In addition to calculating the NYCA IRM requirement, these methodologies identify corresponding MLCRs for NYC and LI. In its role of setting the appropriate LCRs, the NYISO will utilize the same study methodologies and procedures as in the 2010 IRM Study, and will consider the MLCR values determined in this study.

Two emerging energy issues that have the potential of impacting IRM requirements are covered in the *Models and Key Input Assumptions* section of this report: the growing capacity of wind generation and environmental initiatives.

Previous NYCA 2000 to 2009 IRM Study reports can be found at www.nysrc.org/reports.asp. Table B-1 in Appendix B provides a comparison of previous NYCA base case and Final IRMs for the 2000 through 2010 capability years. 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 Manual*, at www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

NYSRC RESOURCE ADEQUACY RELIABILITY CRITERION

The acceptable LOLE reliability level used for establishing NYCA IRM Requirements is dictated by the NYSRC Reliability Rule A-R1, *Statewide Installed Reserve Margin Requirements,* which 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 emergency transfer capability, and capacity and/or load relief from available operating procedures.*

This NYSRC Reliability Rule is consistent with the NPCC Resource Adequacy Criterion in NPCC Document A-2, *NPCC Basic Criteria for Design and Operation of the Interconnected Power System.*

In accordance with NYSRC Rule A-R2, *Load Serving Entity (LSE) Installed Capacity Requirements*, the NYISO is required to establish LSE installed capacity requirements, including locational capacity requirements, in order to meet the statewide IRM Requirements established by the NYSRC for maintaining NYSRC Rule A-R1 above.

The full NYSRC Reliability Rule A-R2 can be found in the NYSRC Reliability Rules Manual on the NYSRC Web site, at
www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

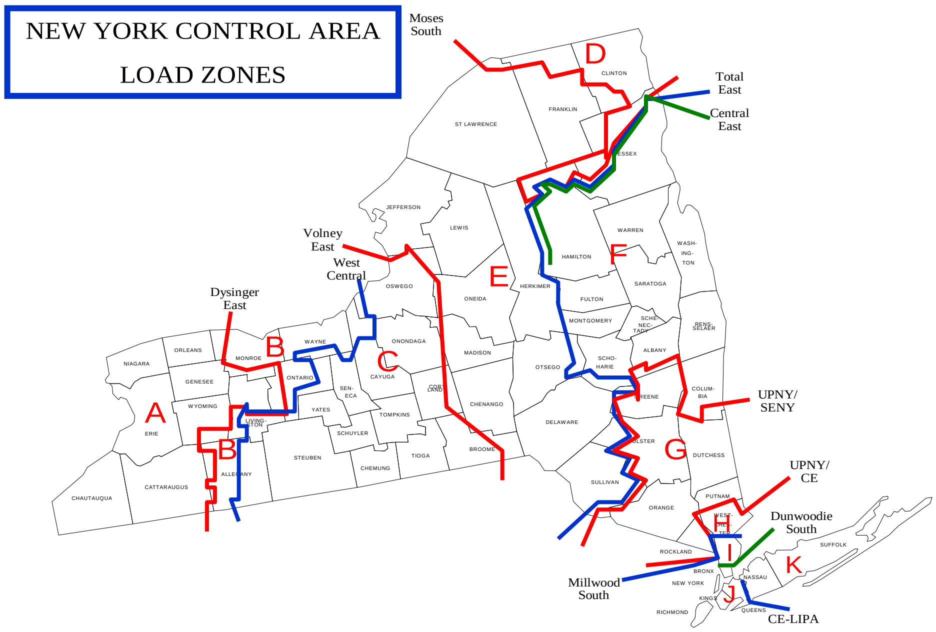
IRM STUDY PROCEDURES

The study procedures used for the 2010 IRM Study are described in detail in NYSRC Policy 5-3, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-3 describes the computer program used for the reliability calculation in addition to the procedures and types of input data and models used for the IRM Study. Policy 5-3 can be found on the NYSRC Web site at,
www.nysrc.org/policies.asp.

This study utilizes a *probabilistic approach* for determining 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 resource capacity shortages.

General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program 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. The eleven NYCA zones are depicted in Figure 1 below. GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability.

Figure 1: NYCA Load Zones



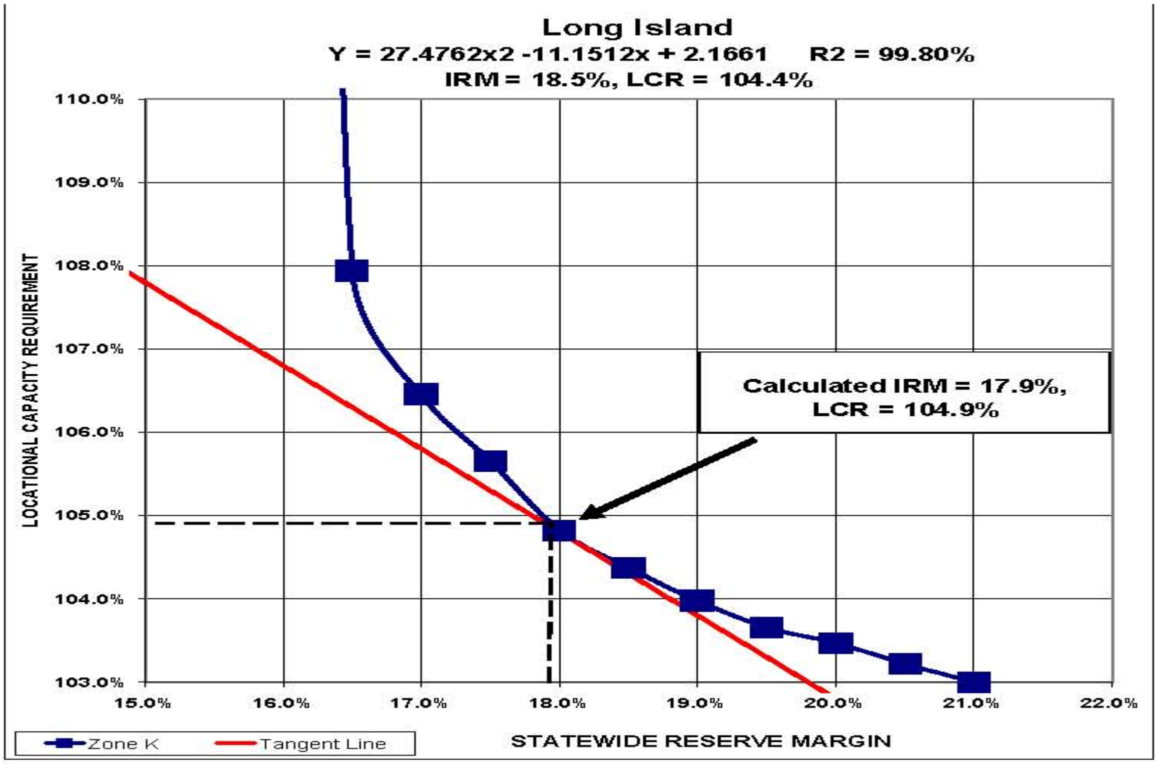
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs, as illustrated in Figure 2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. Note that all points above the curve are more reliable than criteria, and vise versa. This methodology develops a pair of curves, one for NYC (Zone J) and one for LI (Zone K). Appendix A of Policy 5-3 provides a more detailed description of the Unified Methodology.

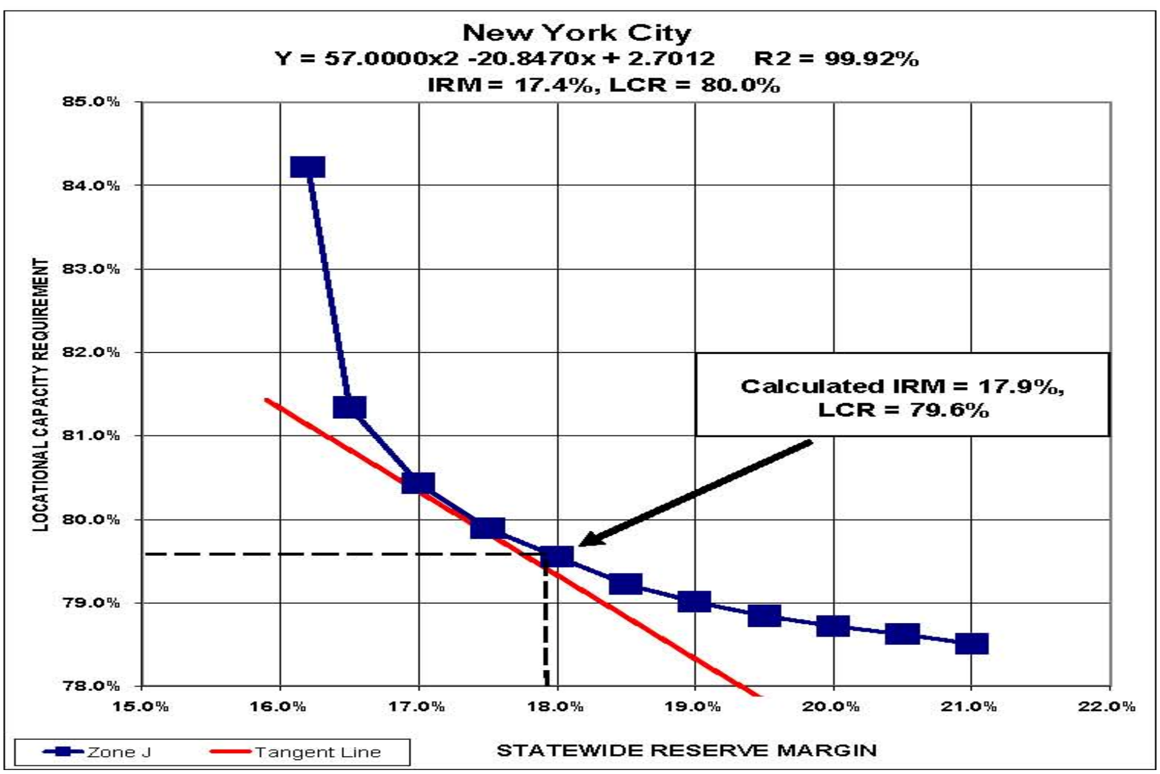
Base case NYCA IRM requirements and related MLCRs are established by a supplemental procedure (termed the *IRM Anchoring Methodology*) which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the bend (or "knee") of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan 45 degree inflection point. Appendix B of Policy 5-3 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

BASE CASE STUDY RESULTS

Results of the NYSRC technical study show that the required NYCA IRM is 17.9% for the 2010 capability year under base case conditions. Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI.

Figure 2: NYCA Locational ICAP Requirements vs. Statewide ICAP Requirements





The points on the NYC and LI curves were calculated using the methodologies described in the previous "IRM Study Procedures" section.

The inflection points on these curves, from which the above base case study results are based, were evaluated using the Tan 45 analysis, also previously described. Accordingly, we conclude that maintaining a NYCA installed reserve of 17.9% for the 2010 capability year, together with MLCRs of 79.6% and 104.9% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A. The 79.6% MLCR for NYC is similar to that calculated for the 2009 IRM Study, while the 104.9% MLCR for LI represents an increase of about 8 percentage points from that calculated in the 2009 Study. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2010 capability year.

A Monte Carlo simulation error analysis shows that there is a 99.7% probability that the above base case result is within a range of 17.5% and 18.4% (see Appendix A). Within this range the statistical significance of the 17.5%, 17.9%, and 18.4% numbers are a 0.15%, 50%, and 99.85% probability of meeting the one day in ten LOLE, assuming perfect accuracy of all parameters and using a standard error of 0.05. If a standard error of 0.025 were used, the band would tighten from 17.7% to 18.1%. This analysis demonstrates that there a high level of confidence that the base case IRM value of 17.9% is in full compliance with NYSRC and NPCC reliability rules and criteria.

MODELS AND KEY INPUT ASSUMPTIONS

This section describes the models and related input assumptions for the 2010 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission System Model, and Outside World Model*. Potential IRM impacts of pending environmental initiatives are also addressed. The input assumptions for the base case were based on information available prior to October 1, 2009. Appendix A provides more details of these models and assumptions. Table A-5 compares key assumptions with those used for the 2009 IRM Study.

<u>Load Model</u>

- ***Peak Load Forecast****:* A 2010 NYCA summer peak load forecast of 32,976 MW was assumed in the study. This forecast is a reduction of 867 MW from the 2009 summer peak forecast used in the 2009 IRM Study. The 2010 NYCA load forecast was completed by the NYISO staff in collaboration with the Load Forecasting Task Force in October 2009, and is based on actual 2009 summer load conditions. Use of this 2010 peak load forecast in the 2010 IRM study resulted in an increase from the 2009 IRM requirement by 0.3% (see Table 1). This increase is driven by the ratio of downstate to upstate peak load forecast. Even though the overall forecast was lower than last year, the ratio of downstate peak load to upstate peak load increased. The NYISO will prepare a final 2010 summer forecast in early 2010 for use in NYISO locational capacity requirement study. It is expected that both the October and final 2010 summer peak load forecasts will be similar.

- ***Load Shape Model****:* The 2010 IRM Study was performed using a load shape based on 2002 actual values. The same 2002 load shape was used in the four previous IRM studies and is consistent with the load shape assumption used by adjacent NPCC Control Areas. An analysis comparing the 2002 load shape to actual load shapes from 1999 through 2008 concluded that the 2002 load shape continues to be the best suited for the 2010 IRM Study.

- ***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 base case 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, separate LFU models are prepared for four areas: Zone H and I, Zone J (NYC), Zone K (LI), and Zones A-G (the rest of New York State).

  New load forecast uncertainty models and data were prepared by, Consolidated Edison (Zones H, I, and J), LIPA (Zone K), and the NYISO. Appendix Section A-5.2.1 describes these models in more detail. Use of the new LFU models for the 2010 IRM Study increased IRM requirements by 0.2%.

Capacity Model

The capacity model in MARS incorporates the several considerations, as discussed below:

- ***Planned Non-Wind Facilities, Retirements and Reratings****:* Planned non-wind facilities and retirements that are represented in the 2010 IRM Study are shown in Appendix A. The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual. This updated parameter decreased the IRM by 0.4% from the 2009 Study IRM. Appendix A shows the ratings of all resource facilities that are included in the 2010 IRM Study capacity model.

- ***Generating Unit Availability****:* Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an "equivalent forced outage rate on demand" (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 the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period – the time span considered for the 2010 IRM Study covered the 2004–2008 period.

  Improvements of generating unit availability performance lead to stabilization of NYCA forced outage rates during the 2001-2006 period. This improved performance from previous years permitted required NYCA IRMs to be significantly reduced. However, during 2007-2008, NYCA generators experienced a trend towards higher forced outage rates, especially in NYC and LI (see Appendix Figure A-5). The higher forced outage rates during this two-year period caused the EFORd five-year rolling average used for the 2009 IRM Study to increase by 0.3%, and another 0.3% for the 2010 IRM Study, as compared to that used for the 2008 IRM Study. This resulted in IRM increases of 1.2% and 1.4% in the 2009 and 2010 IRM Studies, respectively (see Table 1).

- ***Wind Generation:*** It is projected that by the end of the 2010 Capability Period there will be 20 wind-powered generation locations in NYCA with a total capacity of 1,326 MW. This represents an increase of 117 MW since the 2009 capability period. All of these wind farms are located in upstate New York, in Zones A – E.

  The 2010 IRM Study base case assumes that the projected 1,326 MW of wind capacity will operate at an 11.0% capacity factor during the summer peak period. This assumed capacity factor is based on an analysis of actual hourly wind generation data collected for wind facilities in New York State during the June through August period, between the hours of 2:00 p.m. and 5:00 p.m. This test period was chosen because it covers the time when virtually all of the annual NYCA LOLE is distributed.

  The increased wind capacity of 117 MW from 2009 to 2010 is responsible for increasing the base case IRM from the 2009 IRM Study by 0.2% (see Table 1). Overall, the projected 1,326 MW of wind capacity in the 2010 IRM base case accounts for 4.0% of the 2010 IRM requirement (see Table 2). These IRM impacts are a direct result of the very low capacity factor of wind facilities during the summer peak period, as noted above. The impact of wind capacity on *unforced capacity* is discussed in Appendix B, Section B-3, "The Effect of Wind Resources on the NYCA IRM & UCAP Markets" A detailed summary of existing and planned wind resources is shown in Appendix A, section A-5.8.

- ***Emergency Operating Procedures (EOPs):***

  -- 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 assumes SCR base case value of 2,575 MW in July with lesser amounts during other months based on historical experience. Also assumed is a limit of four calls per month in July and August for Department of Environmental Conservation limited generation (about a total of 30 hours).

  An improved historical SCR performance model that better represents the likely load reduction during peak periods was utilized in the 2010 IRM Study. This model is based on an analysis of historical SCR load reduction performance which is described in Section A-5.3 of Appendix A. Use of this improved modeling process resulted in a 1.5% IRM increase from the 2009 IRM Study (see Table 1).

  -- **Emergency Demand Response Programs (EDRP)**. EDRP allows registered interruptible loads and standby generators to participate on a voluntary basis - and be paid for their ability to restore operating reserves. The 2010 Study assumes 329 MW of EDRP capacity resources will be registered in 2010. This EDRP capacity was discounted to a base case value of 148 MW reflecting past performance, and is implemented in the study in July and August (lesser amounts during other months), while being limited to a maximum of five EDRP calls per month. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model.

-- Other Emergency Operating Procedures. In accordance with NYSRC criteria, the NYISO will implement EOPs as required to minimize customer disconnections. Projected 2010 EOP capacity values are based on recent actual data and NYISO forecasts. (Refer to Appendix B, Table B-3, for the expected use of SCRs, EDRP, voltage reductions, and other types of EOPs during 2010). The updated EOP model increased the IRM by 0.3% from the 2009 IRM.

- ***Unforced Capacity Deliverability Rights (UDRs):*** The Capacity Model includes UDRs which are capacity rights that allow the owner of an incremental controllable transmission project to extract the locational capacity benefit derived by the NYCA from the project. Non-locational capacity, when coupled with a UDR, can be used to satisfy locational capacity requirements. The owner of UDR facility rights designates how they will be treated by the NYSRC and NYISO for resource adequacy studies. The NYISO calculates the actual UDR award based on the performance characteristics of the facility and other data.

  LIPA's 330 MW HVDC Cross Sound Cable, 660 MW HVDC Neptune Cable, and the 300 MW Linden VFT project are facilities that are represented in the 2010 Study as having UDR capacity rights. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance which may reduce locational and IRM requirements. The 2010 IRM study incorporates the elections that the facility owners have made for the 2010 capability year.

Transmission System Model

A detailed transmission system model is represented in the GE-MARS study. The transmission system topology, which includes eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Figure A-13 in Appendix A. The transfer limits employed for the 2010 IRM Study were developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO, and refined with additional analysis specifically for the GE-MARS representation. Transmission Owner input and study results and internal constraints from neighboring control areas were also 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 GE-MARS model for the underground cable system from surrounding zones entering into New York City and Long Island. The GE-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.

The interface limit of Dunwoodie-South (Zones I to J) was increased from 3,925 MW, assumed in the 2009 IRM Study, to 4,000 MW based on recent studies performed by Con Edison and the NYISO. This increase in limit was due to better flow balancing of the circuits comprising the interface. In addition, the Moses South interface (Zones D to E) was reduced from 2,900 MW to 2,600 MW based on different base case flow patterns.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. The 2010 IRM study, as with previous GE-MARS studies, reveals that the transmission system into NYC and LI is constrained and can impede the delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints: (1) the NYCA IRM requirement considers transmission constraints into NYC and LI, and (2) minimum LCRs must be maintained for both NYC and LI (See NYSRC Resource Adequacy Reliability Criteria section).

The impact of transmission constraints on NYCA 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 LCRs. The most recent NYISO study (*Locational Installed Capacity Requirements Study*, dated January 15, 2009, at http://www.nyiso.com/public/services/planning/resource_adequacy_planning.jsp, determined that for the 2009 capability year, the required LCRs for NYC and LI were 80% and 97.5%, respectively. A LCR Study for the 2010 capability year is scheduled to be completed by the NYISO by February 2010.

Results from this study illustrate the impact on the IRM requirement for changes of LCR level assumptions from the base case. Observations from these results include:

- **Unconstrained NYCA Case –** If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 15.5%, 2.4 percentage points less than the base case IRM requirement (see Table 2). Therefore, relieving these transmission constraints is equivalent to adding approximately 960 MW of generation in NYCA.

- **Downstate NY Capacity Levels –** If the NYC and LI LCR levels were *increased* from the base case results to 80.5% and 106%, respectively, the IRM requirement could be reduced by 0.9 percentage points, to 17.0%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 79% and 104%, respectively, the IRM requirement must increase by 1.1 percentage points, to 19.0% (see Figure 2).

These results illustrate the significant impact on IRM caused by transmission constraints and implementing different LCR levels, assuming all other factors being equal.

Outside World Model

The Outside World Model consists of those Control Areas contiguous with NYCA; Ontario, Quebec, New England, and PJM. NYCA reliability can be improved and IRM requirements can be reduced by recognizing available emergency capacity assistance support from these neighboring interconnected control areas — in accordance with control area agreements during emergency conditions. Assuming such interconnection support arrangements in the base case reduces the NYCA IRM requirements by approximately 7.3 percentage points (see Table 2). A model for representing neighboring control areas, similar to that applied in previous IRM studies, was utilized in his study.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency assistance support. For this purpose, from Policy 5-3, a rule is applied whereby an Outside World Area's LOLE cannot be lower than its own LOLE criterion, its isolated LOLE cannot be lower than that of the NYCA, and its IRM can be no higher than that Area's minimum requirement.

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 either explicitly, or through direct multi-area modeling providing there is adequate data available to accurately model transmission interfaces and load areas within these Outside World Areas. For this study, two of the Outside World Areas – New England and PJM – are each represented as multi-areas (five zones for New England and three zones for PJM). This level of granularity better captures the impacts of transmission constraints within these areas, particularly on their ability to provide emergency assistance to the NYCA.

The Southwest Connecticut interface was increased from 2,350 MW, assumed in the 2009 IRM Study, to 3,200 MW to reflect system upgrades in New England. With the installation of new facilities in Southern New England, the limits for New England to New York Interface Grouping were reduced to reflect simultaneous export limits internal to New England when exports to Long Island are at their maximum. These changes are summarized in Table A-10. Updated Outside World Area load, capacity, and transmission representations in the 2010 IRM Study improved emergency assistance to NYCA, resulting in an IRM reduction of 0.5%.

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

Studies performed by NYISO and evaluated by General Electric, showed that in GE-MARS, NYCA internal transmission interface capability could be utilized by external control area loop flow through the NYCA, ahead of when the NYCA needs full use of its internal interfaces to avoid loss of load during NYCA emergencies. Study process changes have been made to prevent this anomaly. This process allows the use of the NYCA transmission system for loop flow in GE-MARS, but more appropriately, only after the NYCA has maximized its use of those interfaces to minimize LOLE. Use of this improved process for correctly modeling loop flow resulted in an IRM decrease of 0.4% (see Table 1).

Environmental Initiatives

There are two environmental initiatives with the potential to impact future operation and availability of fossil fueled generating plants in New York State, as well as IRM requirements. The NYS Department of Environmental Conservation (DEC) recently enacted regulations to implement the Regional Greenhouse Gas Initiative (RGGI), which will place a limit on CO_2 emissions from fossil fueled generators with a capacity greater than 25 MW in the ten member states. Although RGGI program requirements are expected to be applicable for the year 2010, an assessment by the NYISO concludes that potential impacts of RGGI on energy supply is very low, with impacts on the capacity market even smaller. *Therefore, 2010 IRM base case assumptions do not include RGGI capacity restrictions.*

The second initiative is focused on bringing air quality in New York State into compliance with National Ambient Air Quality Standards (NAAQS) for ozone. Ground level ozone is the product of hydrocarbon and NOx emissions and sunlight. Fossil-powered generating stations are the fourth largest source of NOx emissions in New York State. Strategies for the control of ozone will likely focus on the reduction of NOx emissions from power plants. The State Implementation Plan (SIP) to achieve compliance with the ozone standard is currently being reviewed by the US Environmental Protection Agency (EPA). The SIP has three design elements that will affect fossil fueled generators in New York State. The first is a regional program to budget NOx emissions and provide for tradable NOx allowances known as CAIR. This EPA program has been the subject of extensive litigation and EPA is planning to revise the regulatory defects and restart the program in 2011. The second element is the Ozone Transport Commission (OTC) High Electric Demand Day (HEDD) program to reduce emissions from older peaking units. For the third element, the DEC has recently initiated the process to develop new standards for Reasonable Available Control Technology (RACT) for the control of NOx from all but the newest fossil fueled generators in New York State. It is reasonable to plan for potentially significant new NOx emission limitations for fossil fueled generators. *Although plans for the reduction of ambient ozone are under development, NOx regulations are not expected to be in effect in 2010, and are therefore not included in the 2010 IRM base case assumptions.*

A sensitivity case to examine possible IRM impacts after 2010 of a NOx regulation implementation scenario was included in the study (see Tables 2 and B-2).

COMPARISON WITH 2009 IRM STUDY RESULTS

The results of this 2010 IRM Study show that the base case IRM represents an increase of 1.7 percentage points above the 2009 IRM Study IRM value. Table 1 compares the estimated IRM impacts of changing several key study assumptions from the 2009 Study. The estimated percent IRM change for each parameter was calculated from the results of a parametric analysis. These results were grouped and then normalized such that the sum of the +/- % changes totals the 1.7 percentage point IRM increase from the 2009 Study.

As observed in Table 1, the principle drivers that have <u>increased</u> IRM requirements from the 2009 capability year are as follows:

(1) Improved SCR Performance Model. Refer to *Emergency Operating Procedures* under the "Models and Key Assumptions" section.

(2) Continued decline in NYCA generating unit availability. Refer to *Generating Unit Availability* under the "Models and Key Assumptions" section.

Also shown in Table 1 are the principle drivers that have <u>decreased</u> IRM requirements from the 2009 capability year, as follows:

(1) An updated Outside World Model. Refer to *Outside World Model* under the "Models and Key Assumptions" section.

(2) An improved process for modeling loop flow during emergencies. Refer to *Outside World Model* under the "Models and Key Assumptions" section.

(3) New Non-Wind Units, Retirements & Reratings. Refer to *Planned Non-Wind Units, Retirements & Reratings* under the "Models and Key Assumptions" section.

Table 1: Parametric IRM Impact Comparison with 2009 Study

Parameter	Estimated IRM Change (%)	IRM (%)
2009-10 Study – Base Case IRM		**16.2**
Updated Parameters Causing a Higher IRM:		
Improved SCR Performance Model	+ 1.5	
Updated Generating Unit EFORs	+ 1.4	
Updated NYCA Load Forecast	+ 0.3	
Updated EOPs	+ 0.3	
New Wind Capacity (117 MW)	+ 0.2	
New Load Forecast Uncertainty Model	+ 0.2	
Total of Other Parameters	+ 0.3	
Total IRM Increase	**+ 4.2**	
Updated Parameters Causing a Lower IRM:		
Updated Outside World Model	- 0.5	
Improved Process for Modeling Loop Flow	- 0.4	
New Non-Wind Units, Retirements & Reratings	- 0.4	
Updated Cable Outage Rates	- 0.2	
Capacity Purchases	- 0.2	
Capacity Sales	- 0.2	
Total of Other Parameters	- 0.6	
Total IRM Decrease	**- 2.5**	
Net Change From 2009-10 Study		**+ 1.7**
2010-11 Study – Base Case IRM		**17.9**

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. Table 2 shows IRM requirement results and related NYC and LI locational capacities for three groups of selected sensitivity cases. Certain of these sensitivity cases – particularly those included under the "Base Case Assumption Uncertainties" group – are important input when the NYSRC Executive Committee develops the final NYCA 2010 IRM. A complete summary of all sensitivity case results are shown in Appendix B, Table B-2. Table B-2 also includes a description and explanation of each sensitivity case.

Table 2: Sensitivity Cases
NYCA 2010 IRM and Related NYC and LI Locational Capacities Impacts

Case	Case Description	IRM (%)	% Change From Base Case	NYC (%)	LI (%)
0	Base Case	17.9	--	79.6	104.9
2009 IRM Impacts of Major MARS Parameters					
1	NYCA Isolated	25.2	+7.3	84.6	110.3
2	No Internal NYCA Transmission Constraints	15.5	-2.4	78.0	102.5
3	No Load Forecast Uncertainty	11.9	-6.0	75.5	98.9
4	No Wind Capacity (1326 MW)	13.9	-4.0	79.6	104.9
5	No SCRs and EDRPs	15.9	-2.0	78.5	104.4
6	No External Purchases	17.8	-0.1	79.6	104.9
2009 IRM Impacts of Base Case Assumption Uncertainties					
7	Higher Outside World Reserve Margins	15.4	-2.5	77.9	102.4
8	Lower Outside World Reserve Margins	22.4	+4.5	82.7	109.4
9	Higher EFORd’s	18.2	+0.3	79.8	105.2
10	Lower EFORd’s	14.0	-3.9	76.9	101.0
11	Higher than Forecast Peak Load	17.9	0.0	79.6	104.9
12	Alternate External Purchase Assumption	17.9	0.0	79.6	104.9
13	Alternate External Sale Assumption	18.2	+0.3	79.8	105.1
14	Alternate HQ Energy Wheel Assumption	18.7	+0.8	80.2	105.7
15	Alternate Zonal Capacity Shift Methodology	18.3	+0.4	80.5	110.4
16	Increase Con Ed Energy Efficiency Program by 100 MW	17.8	-0.1	79.5	104.8
17	1 Year Outage of Indian Point 2	22.7	+4.8	82.9	110.0
Future Year IRM Impacts of Possible System Changes After 2010					
18	NOx Regulation Scenario	26.3	+8.4	85.4	113.4

Due primarily to time and resource constraints, there was no attempt to develop Table 2 sensitivity results utilizing the Tan 45 “inflection point” method. Sensitivity studies, with the exception of wind sensitivities, which use the TAN 45 method, use a method for performing sensitivity tests developed by GE for use in past IRM studies. This method adds or removes capacity to all zones to achieve LOLE = 0.1 and obtain IRM and LCR results. While this method is efficient for calculating the impact of system changes for a large number of sensitivity cases, it may introduce anomalies for the small number of sensitivity cases which disproportionately alter the Upstate or Downstate regions (e.g. Wind or Neptune).

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 translated to 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 periods.

Additionally, any LCRs 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.

The increase in wind resources increases the IRM because wind capacity has a much lower peak period capacity factor than traditional resources. On the other hand, there is a negligible impact on the need for unforced capacity. See Appendix B for a more detailed explanation.

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.

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Appendix A

NYCA Installed Capacity Requirement Reliability Calculation Models and Assumptions

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Description of the GE-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 (GE-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 on the following page.

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, section A-5 compares the assumptions used in the 2008 and 2009 IRM reports.

Figure A-1: NYCA ICAP Modeling

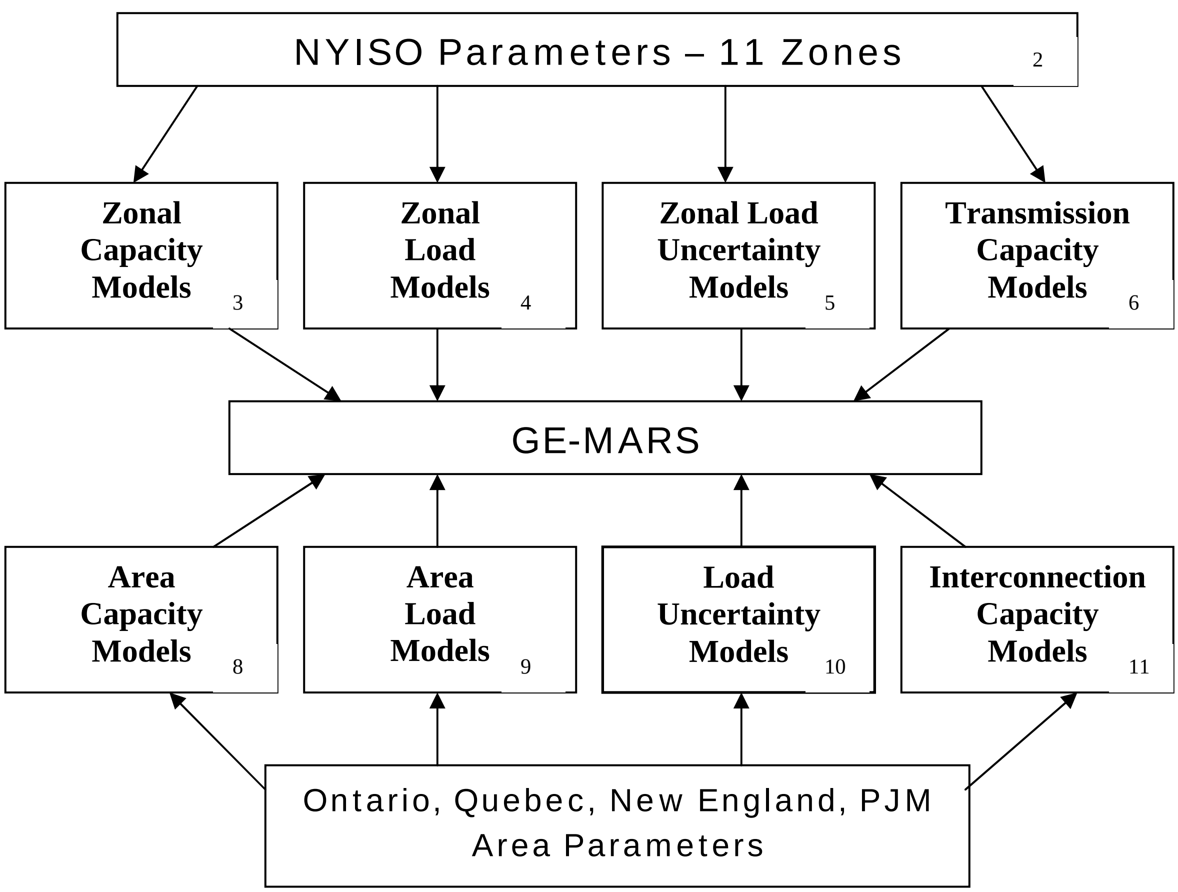


Table A-1: Details on Study Modeling
(Refer to Figure A-1)

Internal NYCA Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	GE-MARS	**General Electric Multi-Area** Reliability Simulation Program		Section A-2
2	11 Zones	Load areas	Fig. A-3	NYISO Accounting & Billing Manual
3	Zone Capacity Models	-Generator Models for each generating unit in Zone. -Generating Availability. -Unit Ratings.	GADS Data 2009 "Gold Book"*	Section A-5.3
	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves.	NYISO	Section A-5.4
4	Zone Load Models	Hourly loads	NYCA load shapes NYISO peak forecasts	Section A-5.2 32,976MW NYISO Oct. forecast
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historical Data	Section A-5.1.1
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	Section A-5.5

External Control Area Modeling:

7	Ont., Quebec, NE, PJM control area Parameters	See the following items 8-11.		
8	External Control Area Capacity Models	Generator Models in neighboring control areas	Supplied by External Control Areas	Section A-5.7
9	External Control Area Load Models	Hourly Loads	Same as above	Section A-5.7
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	Supplied by External Control Areas	Section A-5.7
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Areas	Figure A-11

* "2009 Load & Capacity Data" Report issued by the NYISO.

A-2 Computer Program Used for Reliability Calculations

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 GE-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. GE-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-5.4).

In addition to calculating the expected values for the reliability indices, GE-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 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 GE-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 GE-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 any given hour 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 (TR) from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

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

Table A-2 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

Table A-2: 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, because 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.

A-2.1 Error Analysis

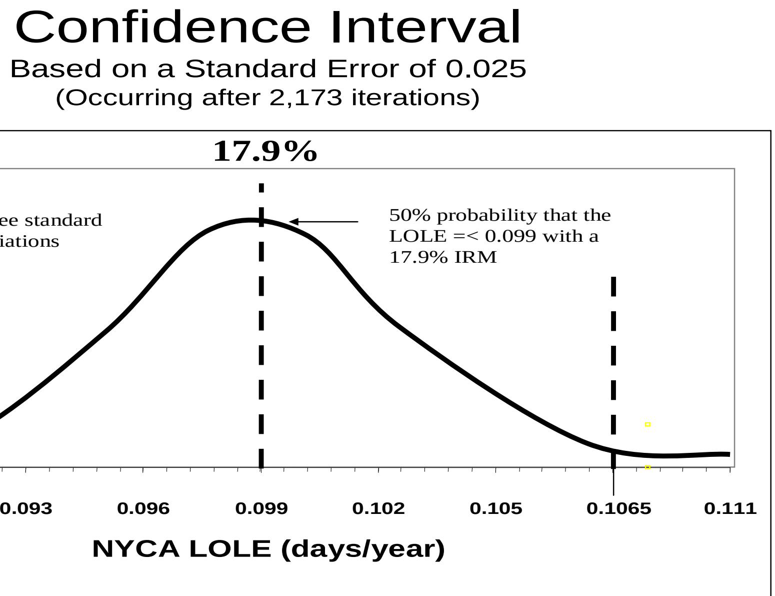
An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (e.g., days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of three standard deviations in each direction (plus and minus) defines a confidence interval of 99.7%.

For this analysis, the Base Case required 469 replications to converge to a daily LOLE for NYCA of 0.092 days/year with a standard error of 0.05 per unit. For a 99.7% confidence interval (plus and minus three standard deviations about the mean), the IRMs that would result in a NYCA LOLE of 0.085 days/year and 0.115 days/year were computed. The resulting IRM values of 17.5% and 18.4% define the % confidence interval, and are shown in Figure A-2. The statistical significance of the 17.5%, 17.9%, and 18.4% numbers are a 0.15%, 50% and 99.85% probability of meeting the one in ten criterion, assuming perfect accuracy in all parameters and using a standard error of 0.05. The Base Case required 2173 replications to converge to a standard error of 0.025. At that point the LOLE for NYCA was 0.099 days/year. If a standard error of 0.025 were used, the confidence interval band would tighten from 17.7% to 18.1%. It should be recognized that a 17.9% IRM, with a 50% probability of meeting the one in ten LOLE criterion, is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

Figure A-2: Confidence Interval



The lines at NYCA LOLE = 0.0915 and 0.1065represent 0.099 LOLE +/- 3 σ.

A-3 Representation of the NYCA Zones

Figure A-3, on the following page, depicts the NYCA Zones represented in GE-MARS.

A-4 Conduct of the GE-MARS Analysis

The study was performed using version 2.98 of the GE-MARS software program. This new version has been benchmark tested by the NYISO.

The current base case 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.

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher then all the others in that size and type category. If something is found, the ISO reviews the data and either confirms that it is correct as is, or institutes a correction. The results of this data scrub are shown in Table A-3.

The top three summer peak loads of all Areas external to NYCA are aligned to be on the same days as that of NYCA, 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 reducing the amount of assistance that NYCA could receive from the other Areas.

Figure A-3: NYCA Load Zones

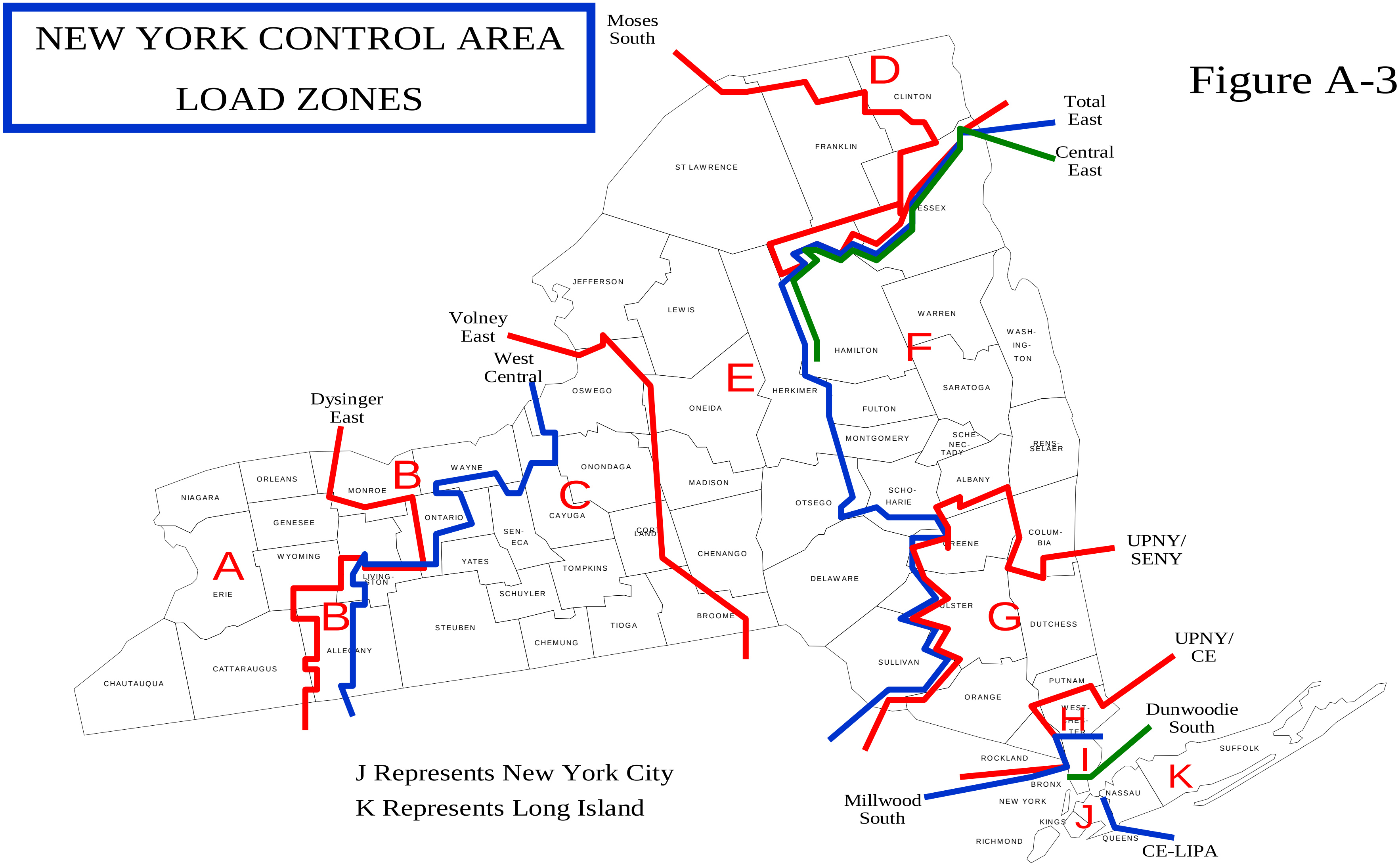


Table A-3: GE Data Scrub*

#	Issue*	Disposition	Effect on IRM
1	Ability to forecast EFOR given recent large changes	Will Pursue this with GE as part of lessons learned.	None
2	Model shows 1339 MW of wind versus 1326 MW.	Model corrected. LOLE improved from 0.100 to 0.099	None
3	SCRs in model do not seem to match assumptions	Explained - GE used a different basis for calculating the values	None
4	Sales in model to not appear to match assumptions	Corrected in Base Case model with no effect on LOLE	None
5	Assumptions mention all Areas will share reserves equally	Changed to reflect that all NPCC Areas will share equally.	None
6	Inconsistencies noted between assumptions and model regarding the topology	These inconsistencies were correct in the Base case model with the two below exceptions	None
6a	A-OH tie modeled at 1325 MW instead of diagram's 1550 MW	Changed model to reflect correct rating – no change in LOLE	None
6b	Sales (on border ties) totaled 1,007 MW in the model but only 934 MW in matrix	Sales corrected to 934 MW with no effect on LOLE.	None
7	Load Forecast Uncertainty modeled for the PJM RECO load.	Model corrected with no effect	None
8	Maintenance scheduled by Area and not zone	This assumption could be reviewed in the future	None
9	UDRs scheduled on interfaces in actual direction only.	The final model schedules in both directions on interfaces.	None

*No material changes to the MARS model were required due to these issues.

A-4.1 Methodology

This year's study continued to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and locational installed capacity requirements. The following describes how the tangent 45 inflection point is calculated:

The IRM/LCR characteristic consists of two constituents; 1) a curve function ("the knee of the curve", and 2) straight line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tangent 45 inflection point calculation. Consideration of IRM/LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tangent 45 calculation. The procedure for determining the best fit curve function used for the calculation of the Tangent 45 inflection point to define the basecase requirement is based on the following criteria summarized below:

1) Start with all points on IRM/LCR Characteristic
2) Develop regression curve equations for all different point to point segments consisting of at least four points
3) Rank all the regression curve equations based on the following:
    - Sort regression equations with highest R^2
    - Ensure calculated IRM is within the selected point pair range, i.e. if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid
    - Ensure the *calculated* IRM and corresponding LCR do not violate the 0.1 LOLE criteria
    - Check result to ensure consistent with visual inspection methodology used in past years studies

This approach produced a quadratic curve function with R^2 correlation approaching 1.000 as the basis for the Tangent 45 calculation. First derivatives were calculated for the NYC and Long Island zones for each of the equations and solved for the 45 degree slope resulting in an average value of 17.9%. The above methodology was adopted by the NYSRC Executive Committee at the November 7, 2007 meeting and was incorporated into Policy 5-3.

Table A-4: Details of TAN 45 Derivation

# of Points		Equation	Resulting IRM	Resulting R^2	Violate 0.1 Criteria
4	NYC Long Island	57.0000 * X2 -20.8470 * X +2.7012 44.0000 * X2 -17.1520 * X +2.7104	17.9	99.79	No
5	NYC Long Island	38.8571 * X2 -14.6240 * X +2.1681 34.8571 * X2 -13.7966 * X +2.4028	18.0	99.67	No
6	NYC Long Island	31.0000 * X2 -11.8976 * X +1.9319 30.0714 * X2 -12.0881 * X +2.2505	18.0	99.61	No
7	NYC Long Island	25.5714 * X2 -9.9921 * X +1.7651 27.4762 * X2 -11.1512 * X +2.1661	18.1	99.54	No
8	NYC Long Island	21.7619 * X2 -8.6398 * X +1.6453 23.0714 * X2 -9.5435 * X +2.0198	18.1	99.37	No
9	NYC Long Island	18.6883 * X2 -7.5363 * X +1.5466 19.2814 * X2 -8.1449 * X +1.8912	18.0	99.14	No
10	NYC Long Island	15.9091 * X2 -6.5275 * X +1.4554 25.8182 * X2 -10.6747 * X +2.1351	18.1	98.70	No

A-5 Input Data and Models

A-5.1 Base Case Modeling Assumptions

Table A-5 summarizes the major assumptions used in the 2010 Study:

Table A-5: Base Case Modeling Assumptions for 2010 NYCA IRM Study

Parameter	**2009 Study Modeling Assumptions**	**20010 Study Modeling Assumptions**	**Described in following section**
NYCA Load Model			
Peak Load	October forecast: • 33,843MW for NYCA • 12,009MW for Zone J • 5,441MW for Zone K	October forecast: • 32,976 MW for NYCA • 11,822 MW for Zone J • 5,365 MW for Zone K	Section A-5.2
Load Shape Model	2002 Load Shape	2002 Load Shape	Section A-5.2
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Section A-5.2.1
Capacity Resources			
Generating Unit Capacities	Updated DMNC test values per 2008 Gold Book plus Noble Wind Units; Bliss 101 MW, Ellenburg 81 MW, and Clinton 100.5 MW. Also, 30 MW increase in rating of Gilboa Unit #1	Updated DMNC test values per 2009 Gold Book	Section A-5.3
New Generation Units	• 1,208.7 MW wind	LIPA Solar 30MW, Caithness 310 MW, Uprate Gilbos #3 & 4 60MW, Sherman Island Uprt 8.5 MW, 74th Street GT#2 19.7MW, Riverbay 24MW, & 305.5 MW wind See appendix D for details.	.Section A-5.3
Modeling Wind Generation Resources	Derived from hourly wind data with average Summer Peak Hour capacity factor of 11%	Derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %	Section A-5.3
Retirements	• None known for 2009 Capability Year.	• Poletti 1(891 MW) • Greenidge 3 (52 MW) • Westover 7 (40.2 MW)	Section A-5.3
Availability & Maintenance			
Forced & Partial Outage Rates	5-year (2003-07) GADS data (Those units with less than five years data will use available representative data.)	5-year (2004-08) GADS data (Those units with less than five years data will use available representative data.)	Section A-5.3
Planned Outages	Based on schedules received by NYISO & adjusted for history	Based on schedules received by NYISO & adjusted for history	Section A-5.3

Parameter	2009 Study Modeling Assumptions	20010 Study Modeling Assumptions	Described in following section
Summer Maintenance	Continue with approximately 150 MW after reviewing last year's data.	Continue with approximately 150 MW after reviewing last year's data.	Section A-5.3
Gas Turbines Ambient Derate	The derate model based on provided temperature correction curves. The same as last year	The derate model based on provided temperature correction curves. The same as last year.	Section A-5.3
Non-NYPA Hydro Capacity Modeling	45% derating	45% derating	Section A-5.3
Emergency Operating Procedures (EOPs) & Assistance			
Special Case Resources	2107 MW (July 09) based on 3 year historical growth rate. Monthly variation based on historical experience. Limit to 4 calls per month in July and August for DEC limited generation (about 30 hour total). See SCR determinations.	2575 MW (July 10) based on3 year historical experience. Limit to 4 calls per month in July and August for DEC limited generation. (about 30 hour total)	Section A-5.3
EDRP Resources	356 MW registered; modeled as 160 MWs in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	329 MW registered; modeled as 148 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	Section A-5.3
External Capacity Purchases	3046 MW total: • 1200 from HQ, • 50 from NE, • 1280 from PJM, • 350 from Ontario (350 MW HQ wheel), 166 MW from Cedars	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1090 MW from Quebec. Equivalent Contracts modeled	Grandfathered contracts per FERC. Section A-5.3
Capacity Sales	Approx 303 MW of firm sales accounted for in Model.	In addition to the long term firm sales of 303 MW, include known firm contracts of 641 MW to NE FCM market. Equivalent Contracts modeled.	Section A-5.3
Capacity Wheel-throughs	None modeled	None modeled	
Emergency Operating Procedures	811 MW of non-SCR/EDRP MWs. See Attachment D.	700 MW of non-SCR/EDRP MWs.	Section A-5.4
Transmission System Model			
Interface Limits	Based on 2008 Operating Study, 2008 Operations Engineering Voltage Studies, 2008 Comprehensive Planning Process, and additional analysis.	Based on 2009 Operating Study, 2009 Operations Engineering Voltage Studies, 2009 Comprehensive Planning Process, and additional analysis.	Section A-5.5

Parameter	2009 Study Modeling Assumptions	20010 Study Modeling Assumptions	Described in following section
New Transmission Capability	None Identified as new for this study	Linden VFT - 300 MW.	Section A-5.5
Transmission Cable Forced Outage Rate	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Section A-5.5
Unforced Capacity Deliverability Rights (UDRs)	LIPA has notified the NYISO that the amount of UDR's for the Neptune Cable and Cross Sound Cable is confidential data.	UDRs have been issued for the Cross Sound Cable, Neptune cable and Linden VFT Projdect.	Per transmission owner notification
Other Modeling Considerations			
GE-MARS computer Model Version	Version 2.92	Version 2.98	Section A-2
Outside World Area Models	Single Area representations for Ontario and Quebec. Three zones modeled for PJM. Five zones modeled for New England derived from 14 zones provided	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Five zones modeled for New England derived from 14 zones provided	Section A-5.7
Reserve Sharing between Areas	Canadian Provinces have indicated that they will share reserves equally among all.	All Control Areas have indicated that they will share reserves equally among all. Loop Flow switch(s) are in the "No" position to not allow a Control Area to send capacity through one system and back into itself in order to avoid the congestion that could be relieved by transmission projects.	Section A-5.7

A-5.2 NYCA Load Model

Methodology for Determining the Summer IRM Peak Load Forecast

Prior to 2007, the load forecast used to develop GE-MARS runs was based on the most recent Load and Capacity (Gold Book) report, which is released in April or May of the current year. The Gold Book uses load data from the previous summer. This means that the forecast used for the IRM study had always been over one year old. Beginning with the 2007 IRM Study, the Executive Committee of the NYSRC requested a forecast for the IRM study year to be prepared after the most recent summer. This meant advancing the schedule for the installed capacity (ICAP) forecast, normally not released until January of the next year.

The procedure for preparing the ICAP forecast is detailed in the NYISO Load Forecasting Manual and authorized by the FERC under the NYISO tariff. It calls for a joint effort by the NYISO and participating transmission organizations in the NYISO's Load Forecasting Task Force (LFTF). In particular, the ICAP forecast is based in large part on data provided by the Transmission Owners (TOs). For the IRM forecast however, it is not possible to obtain all load data, complete the weather normalization process, and produce a forecast to meet the IRM schedule according to the procedures detailed in the manual. To meet the request of the NYSRC, the NYISO and TOs use as much data and results as possible from the TOs. To further aid this process, the NYISO also requests an expedited updated economic forecast from Moody's Economy.com. This economic forecast is now provided in August one month earlier than in previous studies.

Using these abbreviated methods, the NYISO and the TOs jointly produced and reviewed a forecast in September 2009 they recommended for use in the 2010 IRM study. The weather adjustment was based on actual load data from 2006 (a very hot year) and 2009, in which June and July were well below normal in terms of temperature and humidity.

Due to both much lower weather conditions and the impact of the current recession, the actual 2009 peak was 3,086 MW (-9.1%) below the 2009 ICAP forecast. After making a weather adjustment of +2,085 MW, the adjusted forecast was still 1,001 MW (3.0%) below the forecast.

The 2010 forecast was produced by applying regional load growth factors (RLGFs) to each TO's weather-normalized peak for the summer of 2009. In most cases, the RLGFs were based upon updated economic outlooks prepared by the TOs. For the case of Consolidated Edison, the NYISO used a forecast provided by Con-Ed that excluded the impact of its 2010 planned energy efficiency programs. This was due to several factors that would reduce the impact these energy efficiency programs could be expected to have by June 1, 2010. These factors were (a) the economic recession reduced customer participation in energy efficiency programs across the state, (b) Con-Ed's actual 2009 impacts were below their planned impacts, and (c) the 2010 planned impacts were year-end results. The 2010 Base Case IRM forecast is shown below in Table A-6-1.

Subsequently, the NYISO and Consolidated Edison conferred to discuss these issues. Con-Ed then provided a revised forecast that made accounted for these factors. This forecast is shown in Table A-6-2 and is included as Scenario 8 in the 2010 IRM study. The Scenario 8 forecast is 90 MW lower than the Base Case forecast for the NYCA.

Table A-6-1
2010 NYCA Area Base Case Peak Load Forecast

2010 New York Control Area Peak Load Forecast for NYSRC

Summary of 2008 & 2009 Summer Peaks

(a)	(b)	(c)	(d)=(b)*(c)	(e)	(f)	(g)	(h)=(g)-(d)	(i)=(g)/(b)
Transmission District	2008 Weather Adjusted MW	2009 RLGF Forecast	2009 ICAP Forecast - MW	2009 Actual MW	Weather Adjustment	2009 Weather Adjusted MW	MW Over/ Under	2009 RLGF - Actual
Central Hudson	1,194	1.0020	1,196	1,084	79	1,163	-33	0.9740
Con-Edison	13,850	1.0139	14,043	11,962	1,770	13,732	-311	0.9915
LIPA	5,402	1.0055	5,432	5,063	226	5,289	-143	0.9791
Niagara Mohawk	6,749	0.9970	6,728	6,813	-199	6,614	-114	0.9801
NYPA	587	1.0012	588	312	1	313	-275	0.5332
NYSE&G	3,090	1.0070	3,112	3,044	58	3,102	-10	1.0039
O&R	1,154	1.0221	1,180	1,017	78	1,095	-85	0.9489
RG&E	1,644	1.0050	1,652	1,549	72	1,621	-31	0.9860
NYCA Total	33,670	1.0109	33,930	30,844	2,085	32,929	-1,001	0.9780

2010 Base Case Forecast
for NYSRC Installed Reserve Margin Study

Transmission District	2009 Weather Adjusted MW	Adjusted RLGFs	NYSRC 2010 Forecast - MW	2009 Gold Book Forecast	Difference in MW
Central Hudson	1,163	1.0000	1,163		
Con-Edison	13,732	1.0010	13,746		
LIPA	5,289	1.0000	5,289		
Niagara Mohawk	6,614	1.0050	6,647		
NYPA	313	1.0202	319		
NYSE&G	3,102	0.9970	3,093		
O&R	1,095	1.0030	1,098		
RG&E	1,621	1.0000	1,621		
NYCA	32,929	1.0014	32,976	33,441	-465

Locality Peaks	NYSRC 2010 Forecast - MW	2009 Gold Book Forecast	Difference in MW
New York City	11,822	11,950	-128
Long Island	5,365	5,413	-48

Table A-6-2

2010 NYCA Area Scenario 8 Peak Load Forecast

2010 Scenario 8 Forecast for NYSRC Installed Reserve Margin Study					
Transmission District	2009 Weather Adjusted MW	Adjusted RLGFs	NYSRC 2010 Forecast - MW	2009 Gold Book Forecast	Difference in MW
Central Hudson	1,163	1.0000	1,163		
Con-Edison	13,732	0.9945	13,656		
LIPA	5,289	1.0000	5,289		
Niagara Mohawk	6,614	1.0050	6,647		
NYPA	313	1.0202	319		
NYSE&G	3,102	0.9970	3,093		
O&R	1,095	1.0030	1,098		
RG&E	1,621	1.0000	1,621		
NYCA	32,929	0.9987	32,886	33,441	-555
Locality Peaks			NYSRC 2010 Forecast - MW	2009 Gold Book Forecast	Difference in MW
New York City			11,725	11,950	-225
Long Island			5,365	5,413	-48

A-5.2.1 Zonal Load Forecast Uncertainty

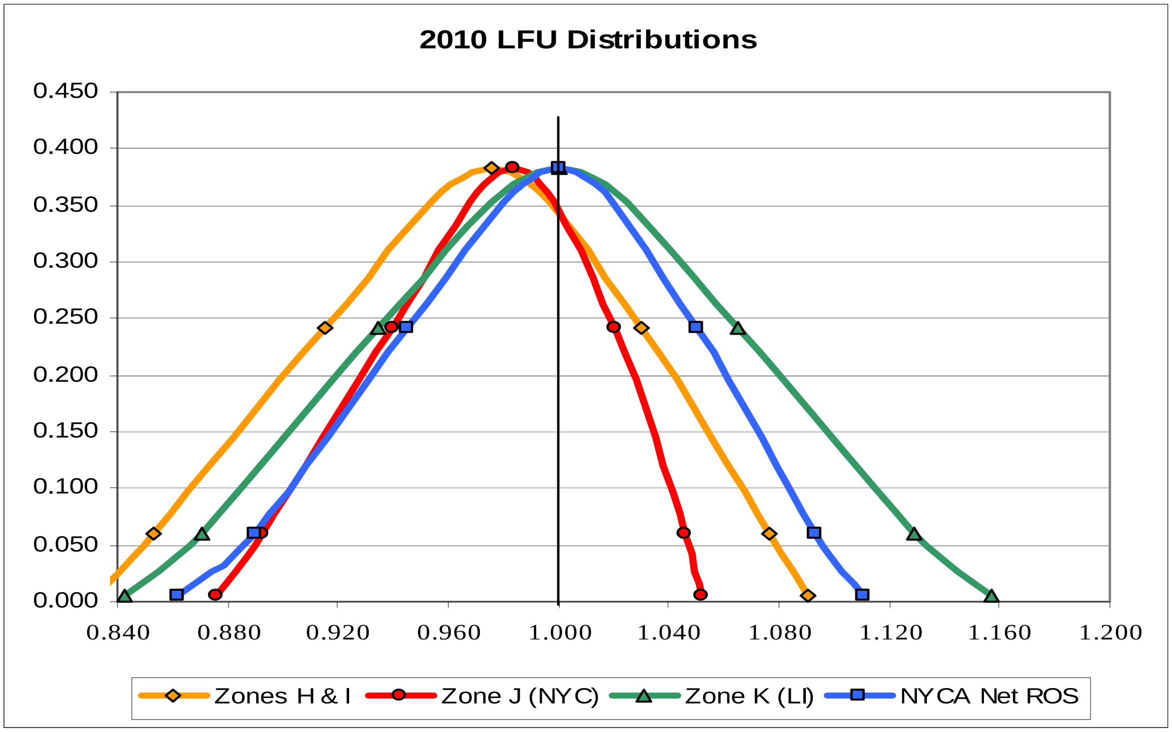
For 2010, new load forecast uncertainty models were provided by Consolidated (for Zones H, I and J) and LIPA (for Zone K). Additional models were developed by the NYISO for Zones A-G. The results of these models are presented in Table A-8. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A-4.

Table A-8
2010 Load Forecast Uncertainty Models

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.6%	86.2%	83.2%	87.6%	84.3%
2	6.1%	89.0%	85.3%	89.3%	87.1%
3	24.2%	94.5%	91.5%	94.0%	93.5%
4	38.3%	100.0%	97.6%	98.3%	100.0%
5	24.2%	105.1%	103.1%	102.0%	106.5%
6	6.1%	109.3%	107.7%	104.6%	112.9%
7	0.6%	111.1%	109.0%	105.2%	115.7%

Hi-Med	-13.8%	-14.4%	-10.8%	-15.7%
Low - Med	-11.1%	-11.5%	-6.9%	-15.7%
Delta	-24.9%	-25.9%	-17.6%	-31.4%

Figure A-4 2010 LFU Distributions



The Con Edison model for Zones H, I & J model reflects the fact that the load forecast used for Zone J has a 1 in 3 probability of occurrence (67th percentile) instead of 1 in 2 probability (50th percentile). The LIPA model is only marginally different than that used in 2009. The approach developed by the NYISO in 2006 for the remaining zones is maintained in the 2010 IRM study. The models for Zones A to G were developed by estimating weather response equations, taking care to examine the behavior both below and above design conditions. The LFU models for Zones H, I and J were developed jointly by the NYISO and by Con-Ed, using methods similar to those for the zones.

This method has previously been reviewed by the NYISO Load Forecasting Task Force. They reviewed the weather response equations used to estimate uncertainty distributions for all NYISO zones including estimates the NYISO made for Zones H, I, J and K.

A-5.3 NYCA Capacity Model

2009 "Gold Book" Changes:

The capacity model input to GE-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 "2008 Load and Capacity Data" (also known as "The Gold Book"):

- **Retirements:**
  - **Poletti 1** — **891 MW** — **Zone J**
  - **Greenidge Unit 3** — **52 MW** — **Zone C**
  - **Westover Unit 7** — **40 MW** — **Zone C**

  - **New Units: (Units installed during 2009)**
  - High Sheldon Wind Farm — 112.5 MW — Zone C
  - Wind Park Bear Creek, LLC — 22 MW — Zone C
  - Noble Weathersfield Wind park — 126 MW — Zone C

- **Planned Units for 2010:**
  (These units had a signed interconnection agreement by August 1, 2009.)

  - Gilboa Station 3 uprate — 30 MW — Zone F
  - Gilboa Station 4 uprate — 30 MW — Zone F
  - LIPA Solar — 30 MW — Zone K
  - Caithness LI — 310 MW — Zone K
  - Sherman Island uprate — 8.5 MW — Zone F
  - 74th Street GT#2 — 19.7 MW — Zone J
  - Riverbay — 24 MW — Zone J
  - New wind units:
    - Steel Winds II — 45 MW — Zone A

* The total amount of wind in the model is 1,326.1 MW (nameplate rating). A complete list of wind units is provided in Appendix D

The total amount of statewide resource capacity in the model is 40,630 MW. This figure includes SCRs and is net of purchases and sales.

The section below describes how each resource type is modeled in GE-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:

With the exception of wind units, 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. Wind units are rated at their nameplate, or full rated value, in the model. The 2009 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:

With the exception of wind units, performance data for 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. The NYSRC is continuing to use a five-year historical period for the 2010 IRM Study. Figure A-5 shows the trend of EFORd for various regions within NYCA. Figure A-6 shows a rolling 5 year average of the same data.

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 the NYISO for the years 2004 through 2008. 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 GE-MARS program.

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 five year period used to determine EFORd averages. Figure A-9 provides a graph of scheduled outage trends over the 1994 through 2008 period for the NYCA generators

Wind generators are modeled as an hourly load modifier. The output of the unit varies between 0 and the nameplate value based on wind data collected near the plant sites during 2002. The 2002 hourly wind data corresponds to the 2002 hourly load shape also used in the model. Characteristics of this data indicate an overall 30% capacity factor with a capacity factor of approximately 11% during the summer peak hours. A total of 1,326.1MW of installed capacity associated with wind generators is included in this study. The breakout of the wind units can be seen in appendix D.

Figure A-5: Annual EFORd Trends

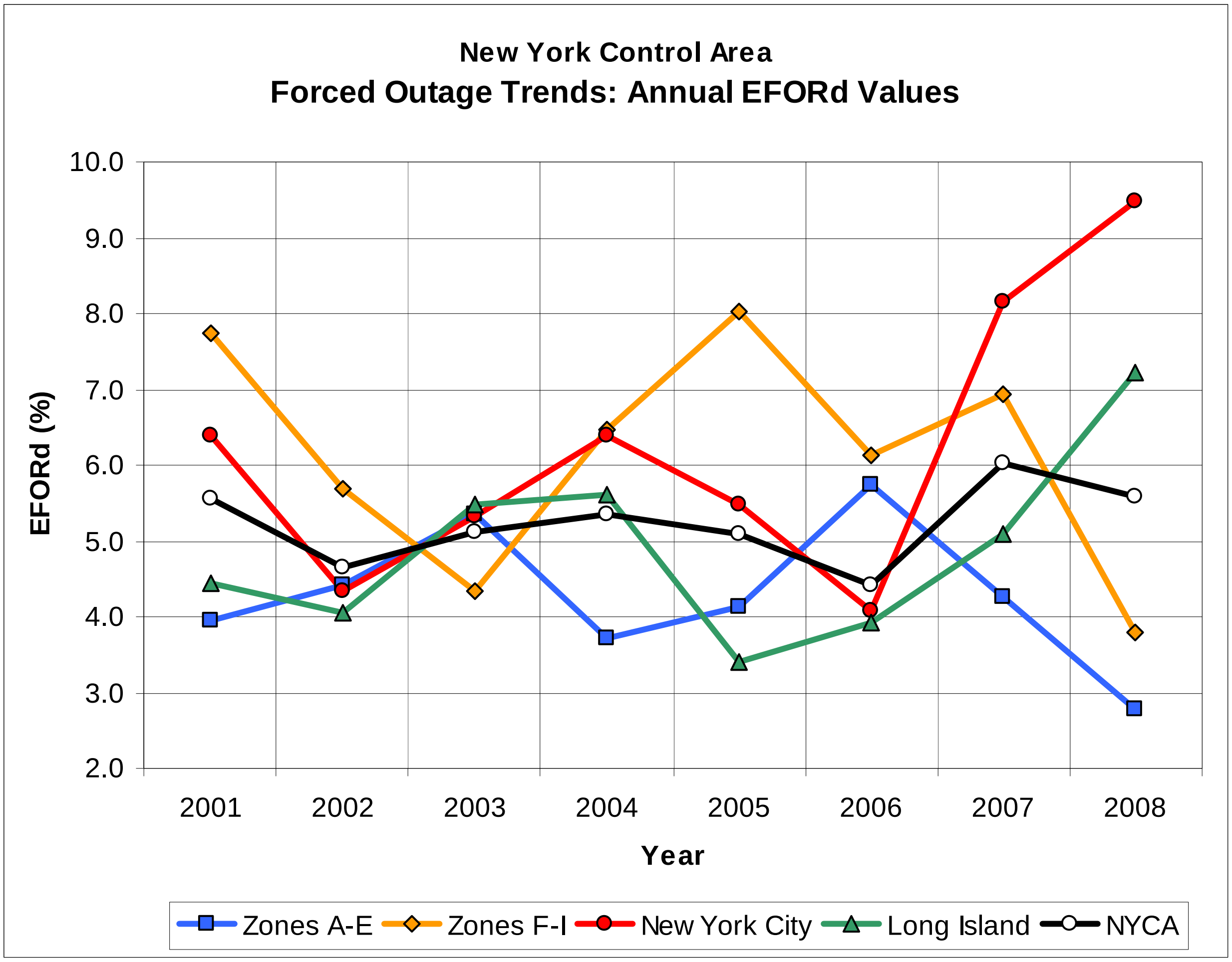
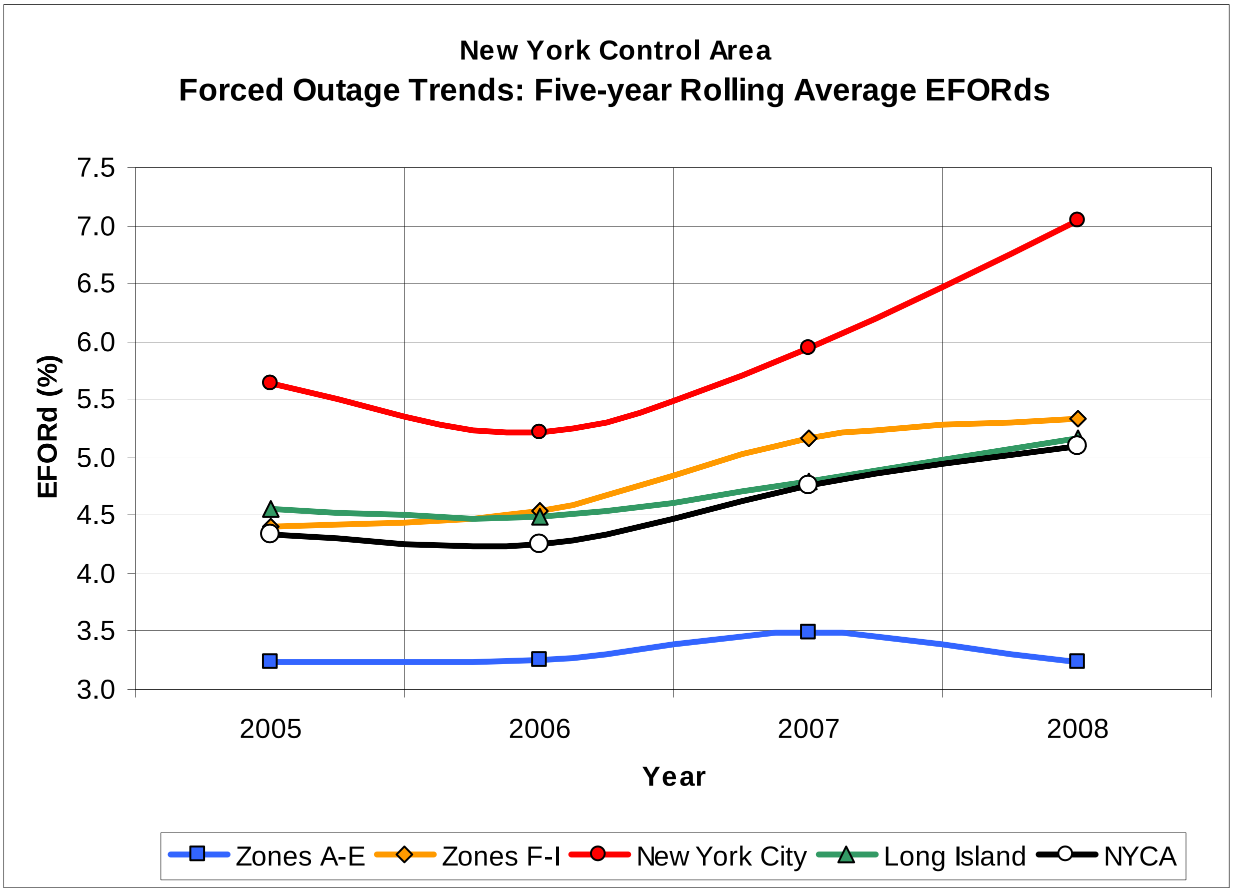


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate. Figure A-6 shows five year rolling averages for EFORd.

Figure A-6: EFORd Rolling Average Trends



Equivalent Availability:

The equivalent availability factor accounts for forced, partial, scheduled, and maintenance outages. Figure A-7, which is based on NERC-GADS data for New York units, shows that the continued trend of improved reliability that was occurring before this year has been reversed.

Figure A-8 provides NERC-GADS data industry-wide.

Figure A-7: NYCA Equivalent Availability

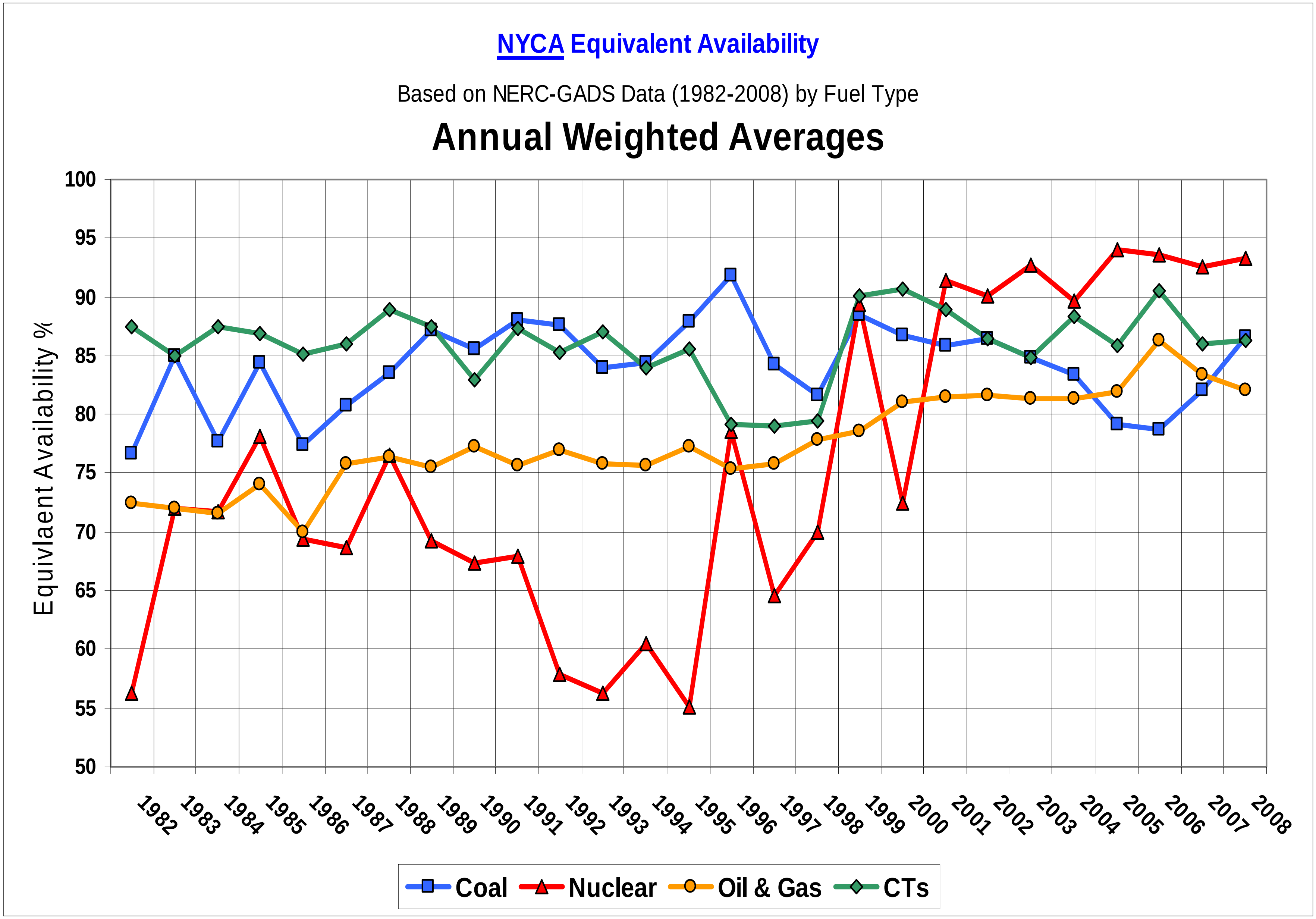


Figure A-8: NYCA Equivalent Availability - 5 Year Rolling Average

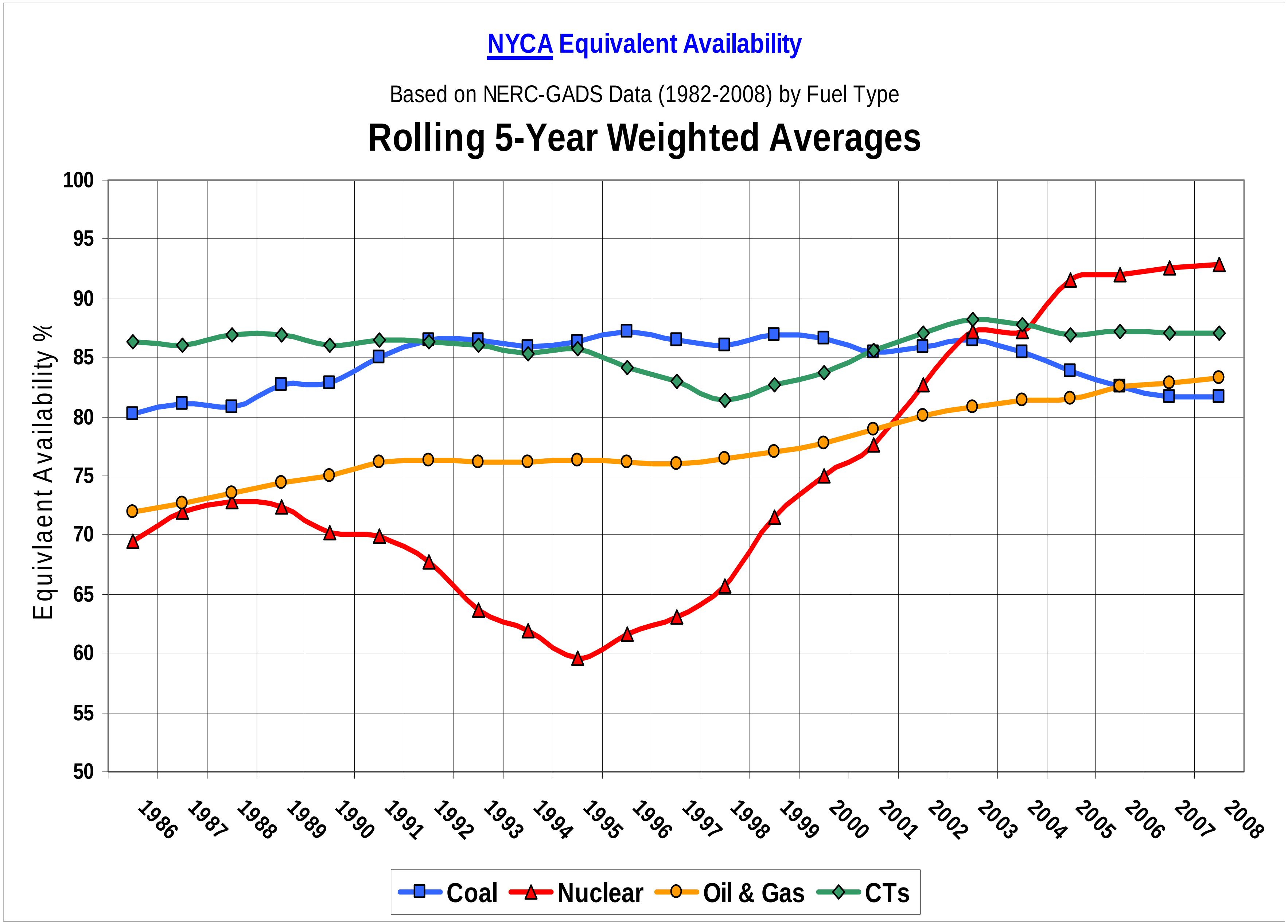


Figure A-9: NERC Region Equivalent Availability

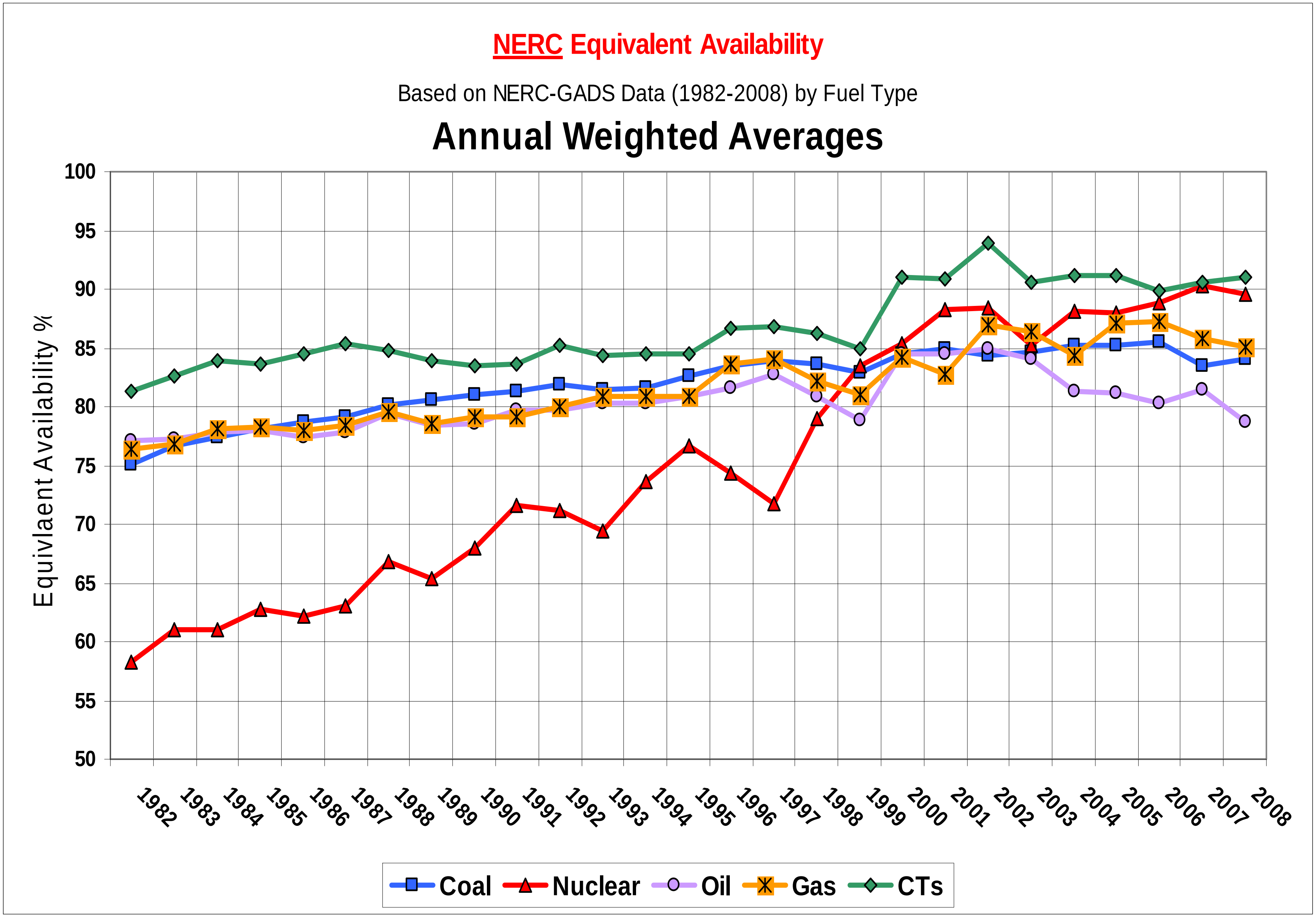


Figure A-10: NERC Region Equivalent Availability – 5 Year Rolling Average

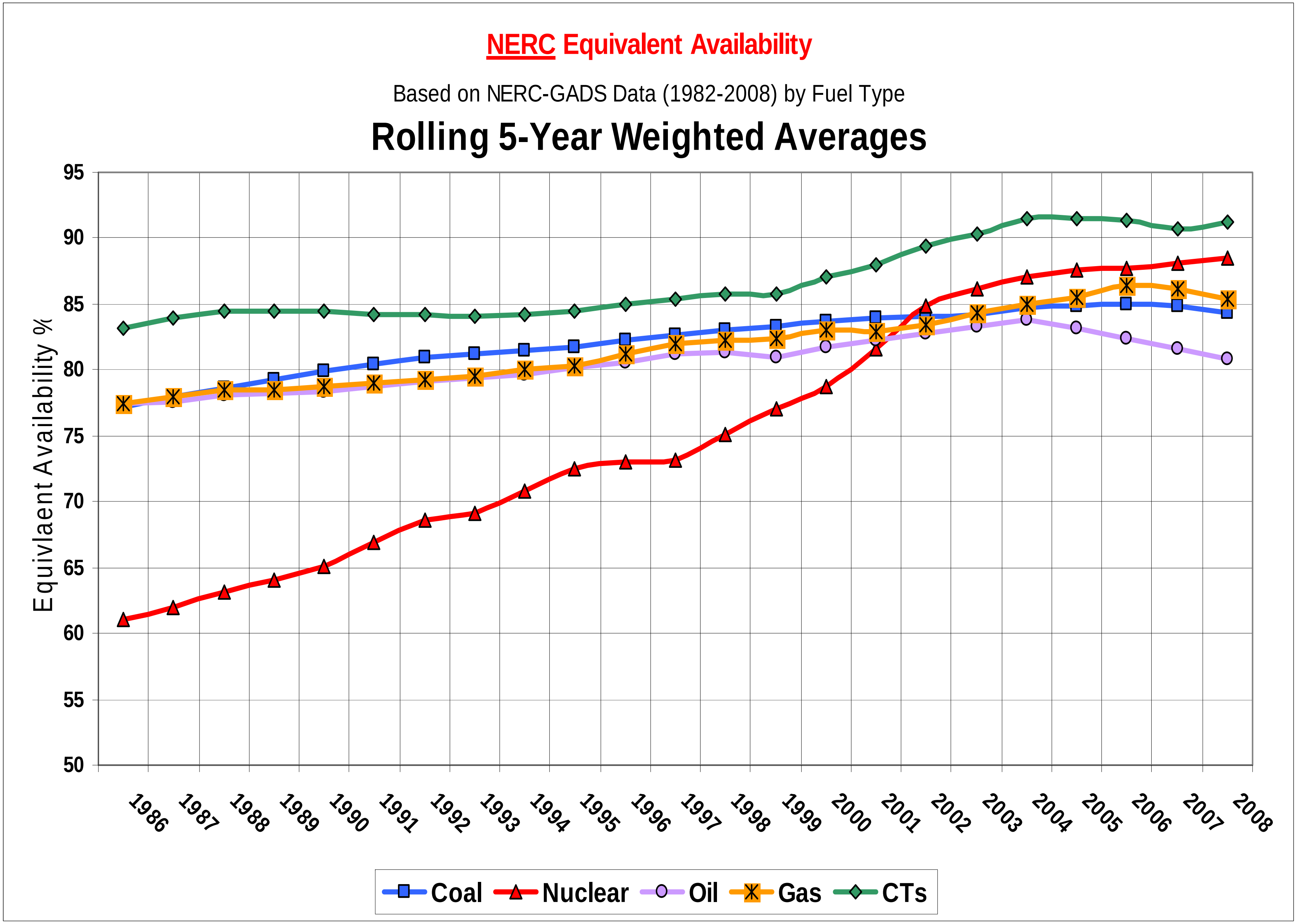


Figure A-11: Planned & Maintenance Outage Rates

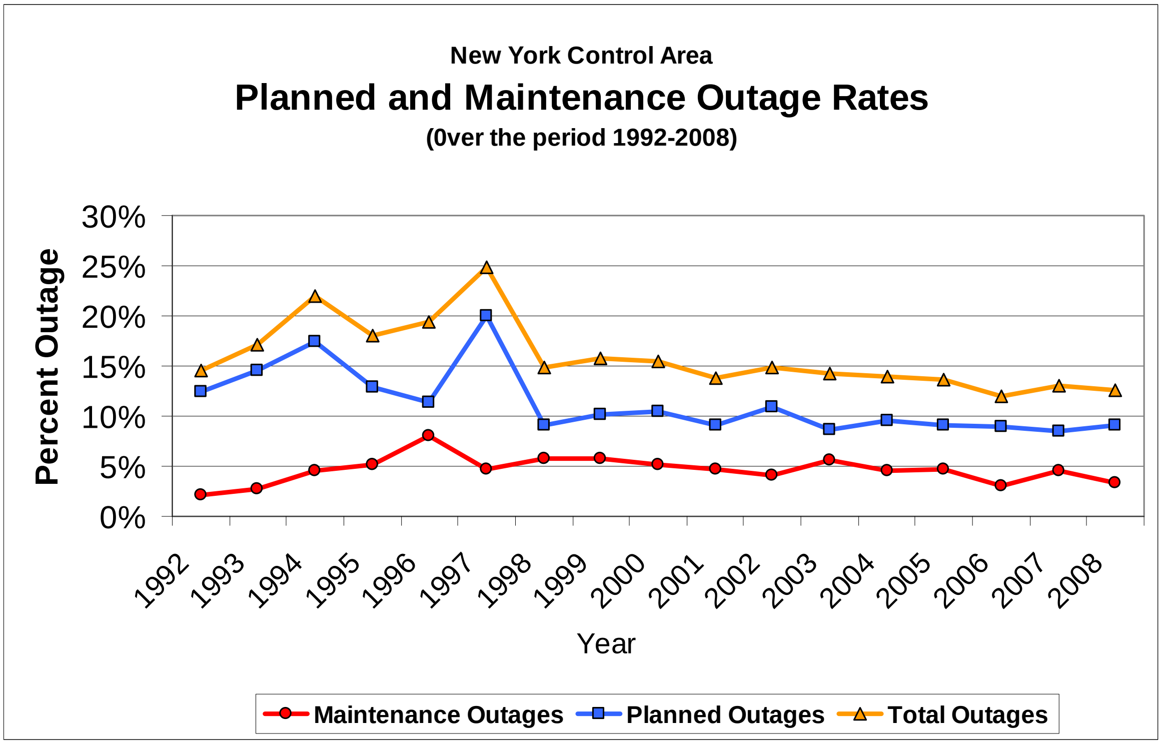
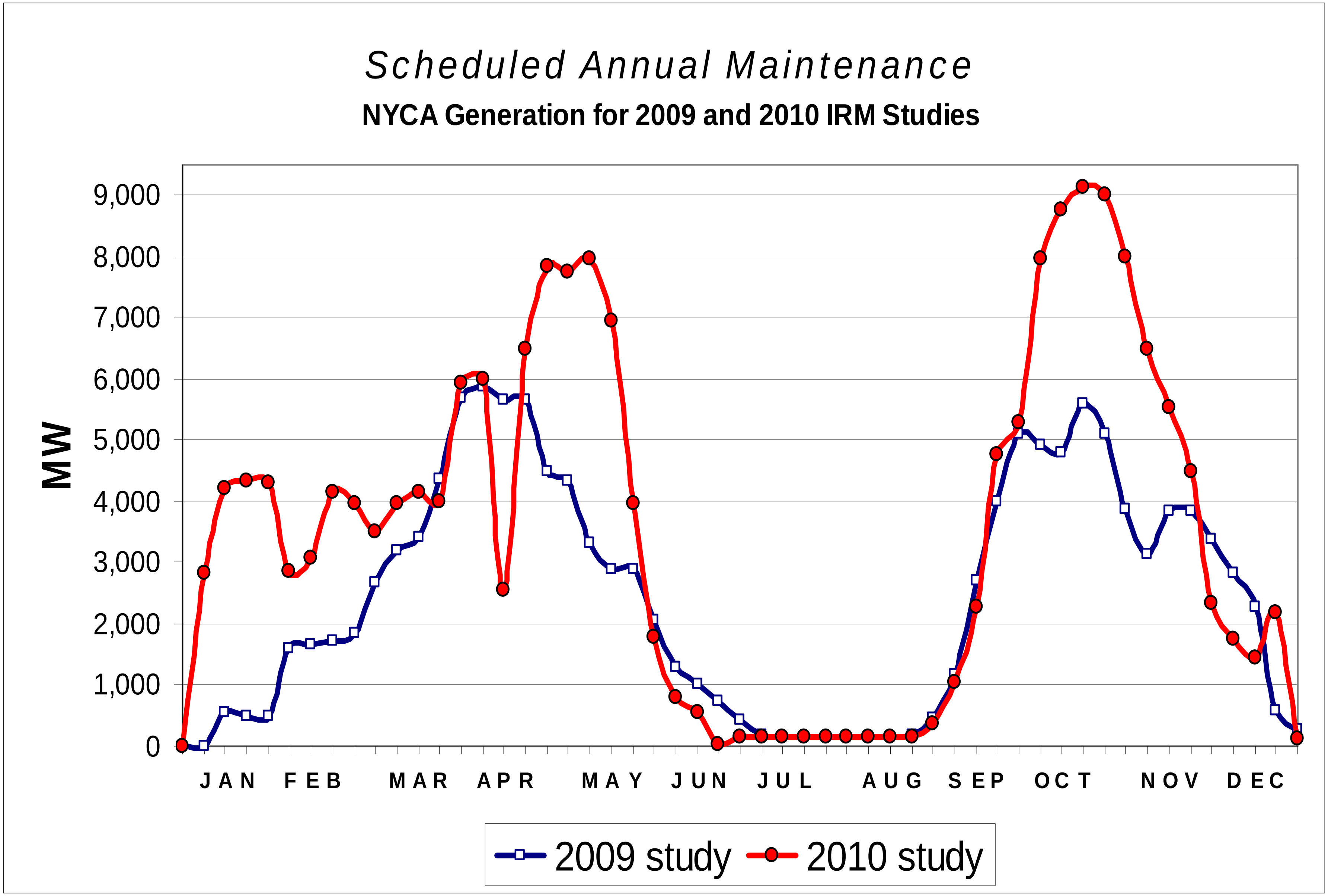


Figure A-11 shows the historic percentage of planned and maintenance outage hours for the years 1992 through 2008.

Figure A-12 shows the amount of capacity assumed to be scheduled out in the 2009 and 2010 studies.

The planned outages in the current study over the 2010 summer period are approximately 150 MW.

Figure A-12: Scheduled Maintenance



Combustion Turbine Units:

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in *g*as turbine and combined cycle capacity output are captured in the GE-MARS model using deratings based on ambient temperature correction curves. Based on its review of historical 2006 and 2007 data, the NYISO staff has concluded that the existing combined cycle temperature correction curves are still valid and appropriate. These temperature corrections curves, provided by the Market Monitoring Unit of the NYISO, show unit output versus ambient temperature conditions over a range starting at 60 degrees F to over 100 degrees F. Because generating units are required to report their DMNC output at peak or "design" conditions (an average of temperatures obtained at the time of the transmission district previous four like capability period load peaks), the temperature correction for the combustion turbine units is derived for and applied to temperatures above transmission district peak loads.

Review of the simple cycle combustion turbine data, however, has led the NYISO to introduce to the model what is termed a bias. The NYISO plans to extend this analysis in the future to include other capacity limited resources. Although this analysis indicates a bias at design temperatures, it also shows an approximate 1/3rd reduction from the 2007 IRM study, in the amount of correction occurring at higher temperatures. The net effect of replacing the 2007 IRM Study's simple cycle combustion turbine derate model with this year's updated model is a slight reduction in LOLE. An NYISO report on this analysis, *Adjusting for the Overstatement of the Availability of the Combustion Turbine Capacity in Resource Adequacy Studies*, dated October 22, 2007, can be found at www.nyiso.com.

The derate 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 simple cycle Combustion Turbines fall into this category.

The accuracy of temperature corrections for all combustion turbines will continue to be evaluated as operational data becomes available.

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 approximately 1,040 MW of hydro facilities are simulated in GE-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. Performance factors for SCRs are shown below:

	Forecast ICAP	Performance
Rest of State	1,628 MW	0.7035
Zone J	605 MW	0.7023
Zone K	342 MW	0.7646

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.

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

For this year's study, the NYISO has recommended that SCRs be modeled with monthly values. For the months of July and August, the values are 2,575 MW, 2,344 MW, respectively. These values are the result of applying three year historic growth rates to the latest participation numbers. Of the 2,575 MW of SCRs modeled in July, approximately 12% are generators that may be subject to DEC emission restrictions. Because of these restrictions, those units are restricted in the summer months to a total of approximately 30 hours

EDRPs are modeled as a 148 MW EOP step in July and August (and they are also further discounted in other months) with a limit of five calls per month. This EOP is discounted based on actual experience from the forecast registered amount of 329 MW.

External Installed Capacity from Contracts:

An input to the study is the amount of NYCA installed capacity that is assumed located outside the NYCA. This year only grandfathered capacity is modeled.

The following inter-area capacity transactions are modeled in this study:

> The base case assumes the following summer external ICAP: 1090 MW from HQ, 50 MW from New England, and 1080 MW from PJM. This totals 2,200 MW of grandfathered summer external ICAP.

In addition to the firm sales listed in the 2009 Gold Book, there are approximately 641 MW of sales committed in 2010 as a result of the New England's Forward Capacity Market (FCM) auctions.

In calculating the IRM, all sales are subtracted from the Installed capacity.

A-5.4 Emergency Operating Procedures (EOPS)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed in Table A-9 were provided by the NYISO based on experience.

Table A-9: Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	2575 MW*
2	Emergency Demand Response Programs (EDRPs).	Load relief	329 MW**
3	5% manual voltage Reduction	Load relief	72 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	479 MW***
6	Voluntary industrial curtailment	Load relief	61 MW***
7	General public appeals	Load relief	88 MW
8	Emergency Purchases	Load relief	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
10	Customer disconnections	Load relief	As needed

* *The SCR's are modeled as monthly values. The value for July is 25,757 MW.*
** *The EDRPs are modeled as 329 MW discounted to 148 MW in July and August and further discounted in other months. They are limited to 5 calls a month.*
*** *These EOPs are modeled in the program as a percentage of the hourly peak. The associated MW value is based on a forecast 2010 peak load of 32,976 MW.*

The above values are based on a NYISO forecast that incorporates 2008 operating results. This forecast is applied against a 2010 peak load forecast of 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.

A-5.5 Transmission Capacity Model

Introduction

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 GE-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 GE-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 GE-MARS representation. The new topology and interface limits are shown in Figure A-9.

The interface tie limits used in the 2009 IRM study were reviewed to assess the need to update the transfer limits and topology resulting to reflect results from more recent studies. The following are the sources of the updated transfer limits:

- The Summer 2007 and 2008 and 2009 Operating Study Reports.
- The 2005 Comprehensive Area Transmission Review.
- The Reliability Needs Assessment (RNA) in the 2009 Comprehensive Reliability Planning Process.
- Specific interface studies and analyses conducted only for ICS to update the transfer limits.
- Transmission Owner input.
- Input from neighboring regions on internal constraints.

The assessments are based on the assumptions regarding external models, loop flow switches, and topology being held constant from the previous year.

Considerations in Applying Emergency Transfer Limits

The transfer capability limits must be consistent with the requirements of the NERC Standards, NPCC Criteria and NYSRC Rules, and the NYISO Manuals and the NYISO OATT. The contingencies applicable to the determination of transfer capability limits as detailed within the Criteria and Rules include six types of contingencies, referred to as (a) through (g). The NYISO determines emergency transfer limits in the evaluation of thermal loading constraints only. In the Emergency Transfer Condition facility loadings must be within in normal ratings pre-contingency, and not exceed the short-time emergency rating (STE) for the (a) or (d) contingencies. Application of ETC is in accordance the provisions of the NYISO *Transmission & Dispatch* and the *Emergency Operation* Manuals. The NYISO determines transfer limits for the emergency transfer condition based on thermal constraints, but transient and voltage stability constraints are based on the entire set of contingencies. When a stability-based transfer limit is more constraining than the thermal limit, it is the controlling limit regardless of the transfer condition (normal or emergency).

Changes in Individual Interfaces

The interface limit for I to J was maintained at 4000 MW based on recent studies performed by Con Edison and the NYISO.

Other Changes are reflected in Table A-10 below.

.

Changes in Topology and Interface Groupings

Many changes were made to the PJM East to New York interfaces. These changes are summarized in Table A-10 and the footnotes.

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 GE-MARS model for the underground cable system from surrounding Zones entering into New York City and Long Island. The GE-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, the transition rates were calculated based on five year historical failures of their entire system of underground cables, transformers, and phase angle regulators that are the three major components of the cable interface system into New York City. The failure rates and repair rates for transformers, and phase angle regulators were calculated by voltage classification, and the cables' failure rates and repair rates were calculated by voltage classification and on a per-mile basis. Typically, 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.

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.

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.

Table A-10: Interface Limit Changes for 2010 IRM Modeling

Interface Name		2009 Limit	2010 Limits, Base Case	Comments
HQ to Ontario	+	350	900	To reflect the installation of new HVDC tie, derated to reflect internal limits.
	-	350	900	
PJM Interfaces		Three Area	Four Area, RECO Load Separated	PJM provided updates through MARS database update. Limits reviewed by NYISO. Limits maintained to reflect potential internal limits. RECO Load split out. PJM East to New York Interfaces were changed as per below footnotes
PJM Cent to East	+	6500	6500	
	-	6500	6500	
PJM West to Cent	+	4000	4000	
	-	4000	4000	
I into J	+	4000	4000	Maintained Rating
	-	1,999	1,999	
Simultaneous J Import			Sum of All Previous Ties into J	Interface is for monitoring
Northport Tie		286/200	286/200	Maintained Unit Nomogram with update of New England Limits
Updates to Transfer Limits to Reflect New England Upgrades				
ME/NH	+	1400	1600	New England bubble diagram reduced. Limits extracted from New England 2009 Analyses for Interface Limits for use in Transportation Models with simultaneous impacts
	-	1400	1600	
Southwest Connecticut	+	2350	3200	
	-	2350	3200	
ROP – Roct	+	2200	2500	
	-	2200	2500	

A. **PJM East to New York –** The 2009 topology had the PJM East bubble connected to NYCA Zones G, J and K. This interface was updated to reflect the installation of the Linden VFT, changes in modeling assumptions reflecting loop flow, and the improved treatment of the RECO load. The topology was modified as follows:
    1. Linden VFT – Since this new interconnection is into Staten Island, the old Staten Island model was reviewed and updated with the VFT model. The existing limitations to the export of power from Staten Island to NYC were captured by a simplified model to approximate the limitation by derating the total 1500 MW interface limit of the PJM EAST to Zone J (or A,B, and C lines) to 1200 MW. This simplification was implemented versus a more detailed unit dependent nomogram or a separate Staten Island subzone as

previous testing determined the three methods to be equivalent. The new model split the A line from this interface and combined it with the VFT into a new interface from PJM East to Zone J. With the VFT insertion, it was determined that the unit dependent limit on this interface would be implemented. To model the Staten Island Export, which is internal to Zone J, the impact of this internal limit was projected to the PJM East to Zone Interface by the use of a dynamic transfer limit with unit dependent model. When all generation on Staten Island is available (Arthur Kill 2&3 and Linden Cogen as two units), the A PAR controlled line and the VFT can not be utilized to their maximum rating of 800 MW, but is limited to 200 MW. This is captured in a unit nomogram that modifies the interface limit based on unit availability. If AK2 in unavailable the limit is 320 MW. If two or more of the units are unavailable, the limit is 800 MW.

2. RECO Load – This load is served by PJM and is radial to the southern part of the Orange and Rockland system (in Zone G) and also connects to one of the 345 kV lines to New Jersey. The new model split the RECO load into its own bubble linked to Zone G.
3. PSEG-Coned Wheel – Modifications to the interfaces and bubbles were made to more explicitly model the split of flows from Ramapo to RECO and the J and K lines to New Jersey.

B. **Astoria East Generation –** Generation at Astoria East may be bottled when they are all available. Astoria 2, Astoria 5, Astoria Energy (SCS), Astoria GTs2-3-4, Hell Gate, North Queens GTs (approx. 1,714 MW) were placed in a separate bubble with an export limit of 1344 MW.

C. **LI Sum DC Tie –** Implemented to capture limitations on flows from Western Long Island to Zones I and J when the PJM to LI DC tie is out of service or flows are limited to less than full rating. An interface grouping is constructed to represent this simultaneous limitation.

i. LI Sum DC Tie = I to K + J to K +0.13 K to PJM East

ii. Derivation of 0.13 coefficient: Analysis was performed to determine the transfer limit at the DC at full output and zero output and a linear relationship was assumed:

(535 MW – 448 MW) / 660 MW = 0.13

iii. Limits developed for this grouping are effective only for the Long Island west direction. When flows are from PJM to Long Island, the flows on K to J and K to I can be higher than 448, up to the present 535 MW limit.

D. **Dynamic Transfer Limit for Western LI export limit that is dependent on Western Long Island Generation availability**. Since there are over twenty units ranging in size from 14 MWs to 195 MWs in Western Long Island, only the large units are included in the Unit Status List (greater than 100 MW).

i. From study results, reducing Barrett, Far Rockaway and Glenwood generation by 429 MWs leads to a 365 MW reduction in the Western LI export limit and a reduction in the K to J (Jamaica Export) limit of 168 MW, giving a ratio of approximately 0.851 and 0.39, respectively. The reduction occurs primarily with deliveries to Valley Stream and then to Jamaica, so the focus is on units affecting this area. Since Far Rockaway 4 (110 MW) is downstream of Valley stream, its impact is assumed to be one for one.

E. Impacts Interface K to J (Jamaica Export) and LISUM). Begin at 508 MW, LISUM 535 MW

F. Grouping the Units to minimize number of dynamic transfer limit tables:

a) Grouping: BARS01, BARS02
   i. One Barrett Unavailable Reduce by 75 MW, 163 MW, Two Barrett Unavailable Reduce by 150 MW, 326 MW

b) FROCS4 always Unavailable, then combined with:
   i. BARS01, BARS02 Unavailability, Reduce Only K to J
   ii. One Barrett Unavailable Reduce by 182 MW, Two Barrett units Unavailable Reduce by 257 MW

Figure A-13: NYCA Transmission System Representation

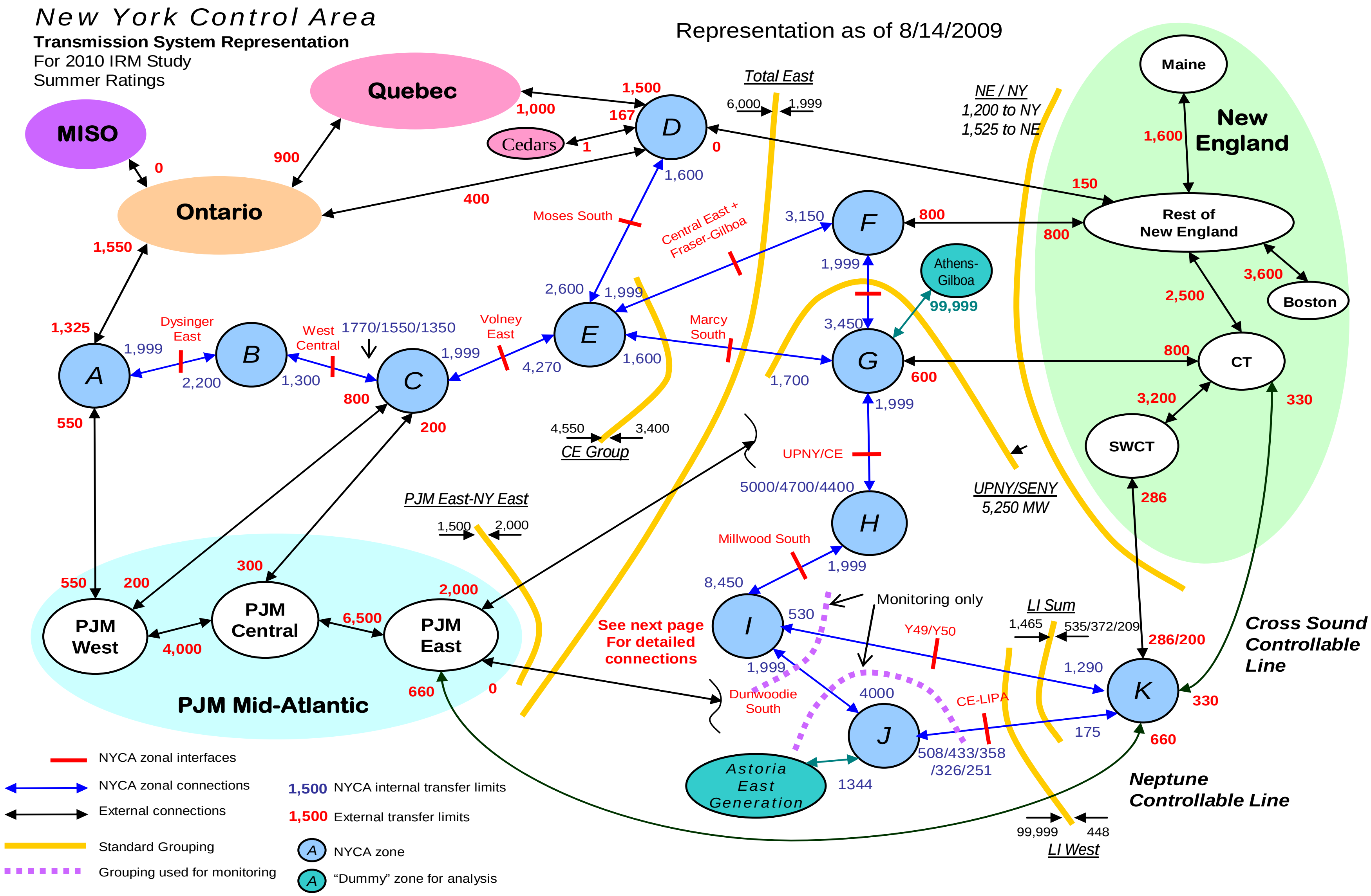
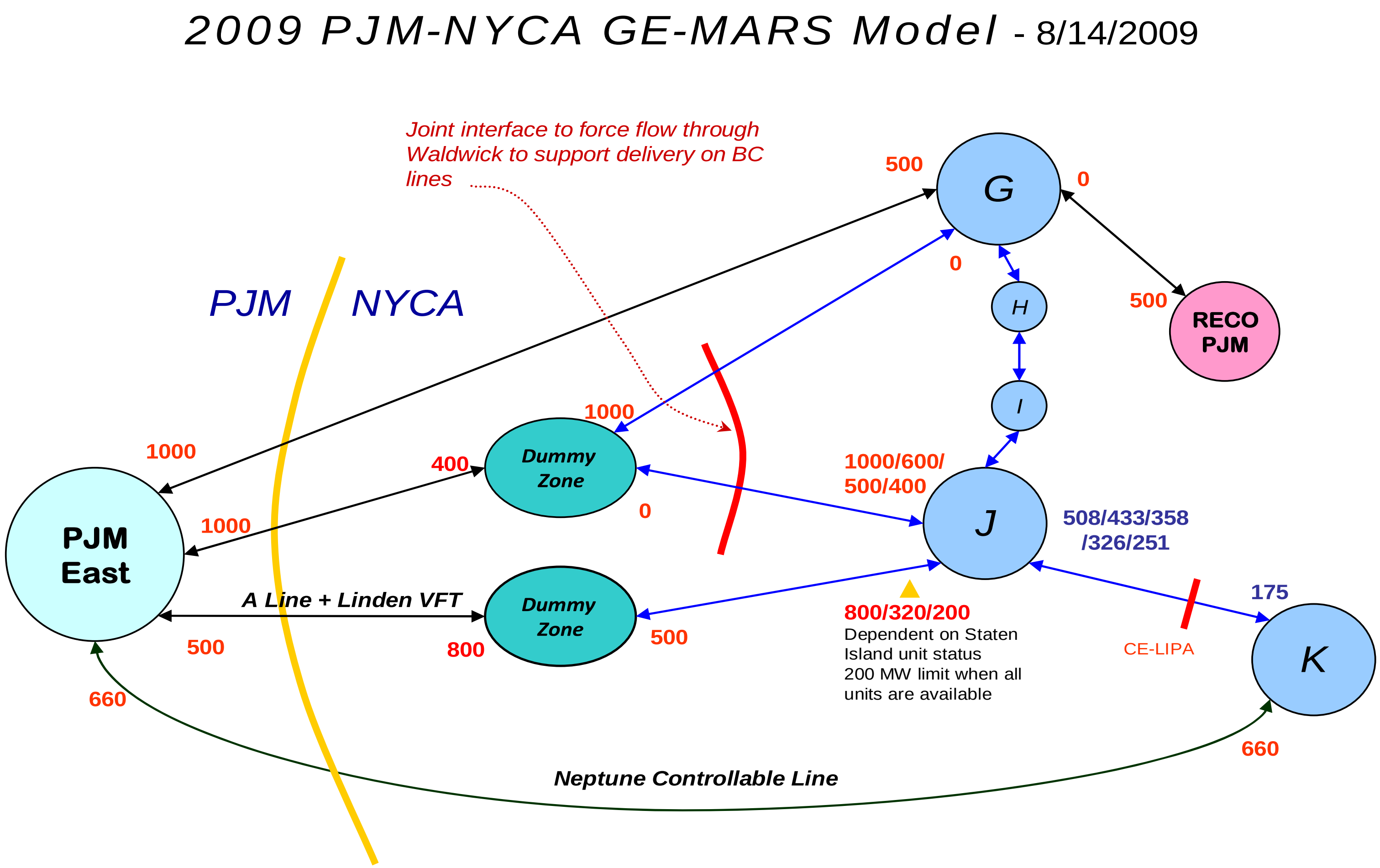


Figure A-13.1: NYCA-PJM Transmission Interface Representation



A-5.6 Locational Capacity Requirements

The GE-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. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A-5.7 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 GE-MARS analyses. The load and capacity models for New England, Ontario, PJM, and Quebec are based on data received from the Outside World Areas, as well as NPCC sources.

The primary consideration for developing the final load and capacity models for the Outside World Areas is to avoid over-dependence 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 for those Areas that have not supplied internal transmission constraint data.

The year 2002 is used in this study for both the NYCA and the Outside World Area load shapes. In order to avoid over-dependence 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.

For this study, both New England and PJM continue to be represented as multi-area models, based on data provided by these Control Areas.

The EOPs were removed from the Outside World Areas to avoid the difficulty in modeling the sequence and coordination of implementing them. This is a conservative measure.

The assistance from Reliability First Corporation (RFC), with the exception of PJM Mid Atlantic, 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 was supplied from the external Control Areas.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-3 is as follows:

Table A-11: Outside World Reserve Margin Modeling

Area	2009 Study Reserve Margin	2010 Study Reserve Margin	2009 Study LOLE (Days/year)	2010 Study LOLE (Days/year)
Quebec	39.1%*	36.2%*	0.113	0.111
Ontario	15.7%	15.3%	0.131	0.141
PJM-Mid-Atlantic	7.4%	12.0%	0.686	0.289
New England	10.5%	12.0%	0.117	0.152

*This is the summer margin; the winter margin is 6.7%

A-5.8 NYCA Wind Resource Generation Summary

Renewable Generating Projects (Wind) Under Consideration for Inclusion in the 2010-2011 Installed Reserve Margin Study

Facility	New Nameplate Capacity (MW)	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	New Wind Capacity for 2010 IRM[5] (MW)	Wind Capacity Modeled for 2010 IRM[5] (MW)
Wind Facilities as of March 1, 2009 and Not Part of RPS							
Horizon Wind, Madison	11.6	E			2000 Sept		11.6
Wester New York Wind Corp, Wethersfield	6.6	B			2000 Oct		0
Canastota Wind Power, Fenner	30.0	C			2001 Dec		0
Constellation Power, Steel Wind	20.0	A			2007 Jan		20
Coral Power, Munnsville	34.5	E			2007 Aug		34.5
High Sheldon Wind Farm	112.5	C	NYSEG	144	2009 Feb	112.5	112.5
Non-RPS Total	**215.2**					**112.5**	**178.6**
NYSERDA RPS Projects							
1st Main Tier Solicitation - 2005[1]							
Maple Ridge 1 & 2 (Previously called Flat Ro	321	E	NG	171	2006 Feb		321
Wind Park Bear Creek, LLC	22	into C	NYSEG		2006 Feb	22	22
Totals for 1st Main Tier	**321.0**					**22**	**343**
2nd Main Tier Solicitation - 2006[2]							
UPC Canandaigua I[7]	82.5	C	NYSEG	135	2008 Jun		82.5
UPC Canandaigua II[7]	42.5	C	NYSEG	199	2008 Jun		42.5
Noble Altona Windpark	99.0	D	NYPA	174	2008 Sept		99.0
Noble Bliss Windpark	100.5	A	Village of Arcade	173	2008 May		100.5
Noble Chateaugay Windpark I	106.5	D	NYPA	214	2008 Sept		106.5
Noble Belmont/Ellenburg II[6]	21.0	D	NYPA	213	2009 Dec		21.0
Noble Clinton Windpark I & II	100.5	D	NYPA	172 & 211	2008 May		100.5
Noble Ellenburg Windpark	81.0	D	NYPA	175	2008 May		81.0
Totals for 2nd Main Tier	**633.5**					**-**	**633.5**
3rd Main Tier Solicitation - 2007[3]							
Noble Wethersfield Windpark	126.0	C	NYSEG	177	2008 Dec	126.0	126
3rd Main Tier Soliciation - 2008 Total New Nameplate Capacity	**126.0**					**126.0**	**126**
Total for Main Tier	**1,080.5**					**148.0**	**1,102.50**
National Grid							
Steel Winds II	45	A	National Grid	234	May-2010	45	45
National Grid Total	**45**					**45**	**45**
Total Capacity of All Categories	**1,662**					**305.5**	**1,326.1**

Notes:

1. The first main tier solicitation contracts did not include an option for an extension. Units were required to be online by January 1, 2006 except for the Bear Creek who was required to be online in February 2006.
2. The second main tier solicitation contracts were expected to be online by January 1, 2008 unless the developer asked for an extension by December 1, 2007 in which case the project would be required to be online by November 1, 2008.
3. The third main tier solicitation contracts are expected to be on-line by January 1, 2009 unless the developer asks for an extension by December 5, 2008 in which case the project would be required to be on-line by November 30, 2009.
4. NYISO Study Queue Project Status Key: 1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS/SIS Pending, 5=SRIS/SIS in Progress, 6=SRIS/SIS Approved, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Completed, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn
5. Assume all wind projects with RPS contracts are online for the forecast year.
6. Noble Belmont/Ellenberg II requested additional time to construct this project. The request was granted and additional security was required.
7. Canandaigua I sometimes referred to as Cohocton Wind Farm. Canandaigua II sometimes referred to as Dutch Hill Wind Farm.

Appendix B

Details of Study Results

B-1 Introduction

Appendix B provides details of the GE-MARS case results referenced in the body of this report. This includes results of the inflection point case and various sensitivities cases, as well as an analysis of emergency operating procedures for the inflection point case required IRM. A history of the IRM values is given below in Table B-1.

B-2 Historical IRMs

Table B-1: NYCA Historical IRM and LCR Information

Capability Year	Base Case IRM	NYCA IRM Final Approved by NYSRC-EC	NYCA Equivalent UCAP Requirement	*LCR for NYC Final Approved by NYISO-OC**	*LCR for LI Final Approved by NYISO-OC**
2000	**15.5%**	18.0%		***80%***	***107%***
2001	**17.1%**	18.0%		***80%***	***98%***
2002	**18.0%**	18.0%		***80%***	***93%***
2003	**17.5%**	18.0%		***80%***	***95%***
2004	**17.1%**	18.0%	11.9%	***80%***	***99%***
2005	**17.6%**	18.0%	12.0%	***80%***	***99%***
2006	**18.0%**	18.0%	11.6%	***80%***	***99%***
2007	**16.0%**	16.5%	11.3%	***80%***	***99%***
2008	**15.0%**	15.0%	8.4%	***80%***	***94%***
2009	**16.2%**	16.5%	7.2%	***80%***	***97.5%***
2010	**17.9%**	18.0%	***TBD***	***TBD***	***TBD***

* The NYISO Operating Committee.

B-3 The Effect of Wind Resources on the NYCA IRM & UCAP Markets

Wind generation is generally classified as an “intermittent" or "variable generation" resource with limited dispatchability. The effective capacity of wind generation can be quantified and modeled using the GE-MARS program similar to conventional fossil-fired power plants. There are various modeling techniques to input wind generation in GE-MARS; the one that ICS has adopted uses historical hourly wind farm generation outputs. This data can be scaled to the nameplate capacity and assigned geographically to new and existing wind generation units.

The effective capacity of wind generation can be either calculated statistically directly from historical hourly wind generation outputs, and/or by using the following information:

- Generation site hourly wind data: This data is translated to power output by using power curves that relate wind speed to generator's power output for each of the turbines in the wind farm,
- Maintenance cycle and duration,
- and EFOR

In general, wind effective capacity depends mostly on the availability of the wind (fuel), is usually less than 40% of the wind turbine's nameplate, during the winter the average effective capacity of wind turbines is higher than during the summer, and in both seasons, is significantly lower than conventional fossil-fired power plants.

The IRM calculation using GE-MARS is mostly based on the adequacy of resources during the summer peak days when the average wind speeds are the lowest, therefore the summer effective capacity of the wind farms is of significant importance to estimate their contribution to reliability.

The effective summer capacity for wind farms varies mostly with the geographic location of the farm. Based on the NYISO's hourly data information obtained from different New York State sites, which ICS uses for the study, a wind farm located on land Upstate has a 10%-11% effective capacity, on land downstate, 30%, and off-shore, 38%. For example, a 100 MW wind farm located off-shore is equivalent to have a conventional fossil-fired power plant of 38 MW with zero EFORd.

Wind generation increases the reliability of the NYCA by adding more resources to the system, which in turn lower the LOLE calculated by the GE-MARS program. Because the amount of nameplate capacity of wind resources added is larger relative to the wind's effective capacity, the system IRM increases.

The effective capacity of a wind farm or turbine is also equal to their UCAP and their nameplate to their ICAP. ICAP can be translated to UCAP by using an EFORd translation factor.

Using the GE-MARS program, the effective capacity of wind generation can be quantified and modeled on the same basis as a conventional fossil-fired power plant using ICAP and an availability or performance considerations. Wind, as well as all generating resources in the NYCA has an expected level of availability – or conversely a level of expected unavailability which is considered when solving the GE-MARS program for LOLE.

The GE-MARS analysis considers seasonal variability in wind generation output relative to periods of peak system load, when generating resources have the greatest impact of overall system reliability as measured by LOLE. This seasonal variability in wind availability results in a low peak availability factor for wind resources in the NYCA.

The NYISO adopted a 90% deration factor for upstate land-based wind generators a 70% deration factor for downstate land-based wind generators and a 62% deration factor for offshore-based wind facilities. Because wind has much higher unavailability compared to fossil generation, the addition of wind generation to the resource portfolio will increase Statewide and Locational ICAP based capacity requirements in the NYCA as calculated by the GE-MARS program.

The NYISO administers the capacity requirements to all loads in the NYCA. In 2002, the NYISO adopted the UCAP methodology for determining system requirements, unit ratings and market settlements. The UCAP methodology uses individual generating unit data for output and availability to determine an expected level of resources that can be considered for system planning, operation and marketing purposes. EFORd is developed from this process for each generating unit and applied to the units DMNC test value to determine the resulting level of UCAP:

UCAP = ICAP * (1-EFORd)

Individual unit EFORd factors are taken in aggregate on both a Statewide and Locational basis and used to effectively "translate" the IRM and LCRs previously determined in the MARS Analysis in terms of ICAP, into an equivalent UCAP basis.

The equivalent EFORd of wind plants is significantly higher than fossil based resources due to their low peak availability – and accounted for in the GE-MARS analysis. Therefore, adding wind resources to the overall NYCA generation portfolio causes an increase to the overall system EFORd, which in turn translates to a higher overall IRM.

A system that requires a specific level of UCAP to meet its LOLE requirement when resources with higher unavailability are added to the resource mix will need to increase the installed capacity resource base to maintain the same level of UCAP or resource adequacy.

Although the impact of low capacity factor resource additions increase the IRM on an ICAP basis, it should be noted that its effect on a UCAP basis is negligible. As an example of this, take a system with a 10,000 MW ICAP requirement and an EFORd of 10%. Its UCAP requirement (ICAP*(1-EFOR)) would then be 9,000 MW. Suppose we then add 1,000 MW of low capacity factor resource at its summer EFORd of 90%. Because the load carrying capability of this resource is only 100 MW during the summer peak, the ICAP requirement would go up by roughly the non-load carrying component (900 MW). The new ICAP requirement would then become roughly 10,900 MW. The weighted average EFORd of the new system becomes (10,000*0.1 +1,000*0.9)/(10,000+1,000) = 17.3%. The UCAP requirement then becomes 9,014 MW, which is essentially unchanged from the initial 9,000 MW UCAP requirement.

B-4 Sensitivity Case Results

Table B-2 summarizes the 2010 capability year IRM requirements under inflection point case assumptions, as well as under a range of assumption changes from this 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 inflection point case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the base case results of 17.9% NYCA, 79.6% NYC, and 104.9% LI reserve margins. Capacity is then added or removed from all zones in NYCA until the NYCA LOLE approaches criteria.

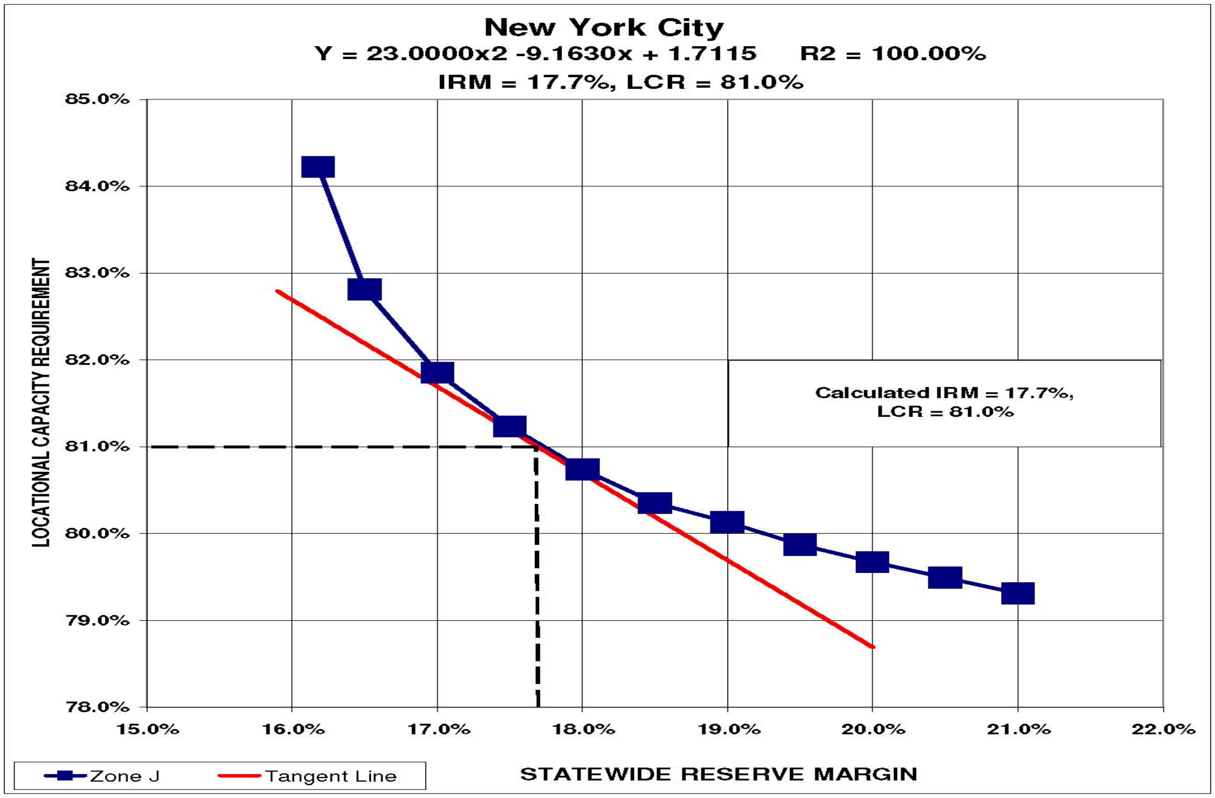
Table B-2: Description & Explanation of 2010 Sensitivity Cases

Case No.	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
	Transmission Sensitivities			
T1	**No Internal NYCA Transmission Constraints ("Free-Flowing" System)**	**15.5%**	**N.A.**	**N.A.**
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements. See the "Base Case – NYCA Transmission Constraints" section of the report.			
T2	**HQ emergency assistance from HQ direct ties**	**18.7%**	**80.2%**	**105.7%**
	This case shows the impact on NYCA reliability if HQ fully utilizes the Chateauguay and Cedars ties for sales (without altering assistance on indirect ties).			
	Assistance From Outside World Sensitivities			
A1	**NYCA Isolated (No Emergency Assistance or Non-UDR Capacity from Outside World Areas)**	**25.2%**	**84.6%**	**110.3%**
	This case examines a scenario where the NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). UDRs are allowed. See the "Base Case Results – Interconnection Support during Emergencies" section of the report.			
A2	**Increase each external Control Area's IRM by 10 percentage points.**	**15.4%**	**77.9%**	**102.4%**
	Examine the NYCA IRM under the conditions where external Control Area's have additional capacity which could help NYCA in emergencies. The LOLE values for PJM, New England, Ontario, and Quebec are 0.141, 0.007, 0.000, and 0.002 days/year, respectively.			
A3	**Decrease each external Control Area's IRM by 10 percentage points.**	**22.4%**	**82.7%**	**109.4%**
	Examine the NYCA IRM under conditions where external Control Areas have less capacity available to help NYCA in emergencies The LOLE values for PJM, New England, Ontario, and Quebec are 2.931, 2.470, 5.409, and 2.748 days/year, respectively.			

Case No.	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
A4	**No external contract purchases.**	**17.8%**	**79.6%**	**104.9%**
	To determine impact of removing grandfathered contracts. UDRs remain.			
A5	**Model <u>actual</u> external capacity purchase contracts instead of <u>equivalent</u> purchases. (Non UDRs)**	**17.9%**	**79.6%**	**104.9%**
	Establish contracts of 1090 MW over Chateauguay and Cedars ties. Add contracts from PJM to zones A and C totaling 1080 MW.			
A6	**Model <u>actual</u> capacity sales contracts instead of <u>equivalent</u> sales.**	**18.2%**	**79.8%**	**105.1%**
	Create contracts; D-NE, F-NE, G-NE, A-PJMW, C-PJMC totaling 933 MW.			
	Generation Unit Availability Sensitivities			
G1	**Increase EFORds from Base Case (represented by assuming the maximum annual EFORds during the 2004-08 period**	**18.2%**	**79.8%**	**105.2%**
	This shows the impact of the NYCA units having higher EFORds than the base case. Higher EFORds indicate less capacity available to meet the criterion. Note that NYCA is near its five year high EFORd			
G2	**Decrease EFORds from Base Case (represented by assuming the minimal annual EFORds during the 2004-2008 period**	**14.0%**	**76.9%**	**105.2%**
	This shows the impact of the NYCA units having lower EFORs than the base case. Lower EFORds indicate more capacity available to meet the criterion.			
G3	**Prolonged outage of Indian Point 2 for 2009**	**22.7%**	**82.9%**	**110.0%**
	This shows the impact of an extended outage of IP 2 for the entire study year either by regulations or operational problems. Reflects revised interface transfer limits.			
G4	**Remove all wind generation**	**13.9%**	**79.6%**	**104.9%**
	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact that the wind generation has on the IRM requirement.			
G5	**Alternate zonal capacity shift.**	**18.3%**	**80.5%**	**110.4%**
	This shows the impact of the way the study points are arrived at for the IRM curve. Removes capacity from zones A, C, D, F, G and H to arrive at the study point. See Figure A-14.			
G6	**8,000 MW of wind**	**33.5%**	**82.4%**	**113.3%**
	Remove the existing wind and put in the 8,000 MW of wind used in the recent NYISO wind study. This adds wind in NYC, Long Island, and zones upstate in the amounts of 700, 700, 6600 MW, respectively. This sensitivity is based upon the high penetration case from the 2009 NYISO wind study and is not a potential wind resource for 2010.			

Load Sensitivities				
L1	**No Load Forecast Uncertainty**	**11.9%**	**75.5%**	**98.9%**
	This scenario represents “perfect vision” for 2010 peak loads, assuming that the forecast peak loads for NYCA have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and, to a smaller degree, economic uncertainties on IRM requirements.			
L2	**Increase Con Ed energy efficiency program.**	**17.8%**	**79.5%**	**104.8%**
	Gives the estimated impact of a reduced peak load of 100 MW in zone J.			
L3	**Higher than Forecast Peak Load**	**17.9%**	**79.6%**	**104.9%**
	Use Gold Book forecast of 33,767 MW to show the impact of increased load on system reliability.			
Emergency Operating Procedure Sensitivity				
EP1	**No SCRs or EDRPs**	**15.9%**	**78.5%**	**104.4%**
	Verifies the impact of SCR and EDRP on the IRM.			
Environmental Initiative Sensitivities				
EN1	**NOx regulation implementation**	**26.3_%**	**85.4_%**	**113.4_%**
	This case assumes that the environmental restrictions for NOx regulation occur in 2010 without phase in over several years (forecast to be 2011-2014). These HEDD and LFB units were reduced by the same amount of tonnage as was assumed in the 2009 IRM study.			

Figure B-1 Curve for Sensitivity Case G5



"The knee of the curve shown at 17.7% in Figure B-1, is higher than the 17.4% (zone J specific) knee for the base case. This is an indication that if the alternate shift methodology (sensitivity G5) is employed, the IRM would increase by 0.3% to a value of 18.2%"

B-5 Nitrogen Oxide Scenario Description

There are several regulatory regimes under consideration for control of nitrogen oxide emissions. Of these, two are considered in the 2010 IRM Study. These, taken together, are comparable to the HEDD sensitivity examined in the 2009 RNA Study.

There are two components to the HEDD (High Electric Demand Day) Program, the LFB (Load Following Boiler) initiative, and the HECT (High Emitting Combustion Turbine) initiative. Descriptions of these can be found in Appendix C of the 2010 IRM Report and in the 2009 Resource Needs Assessment (RNA). The unit deratings that each determined would be necessary to meet emissions goals were combined in the 2010 NOx Sensitivity. Meeting ozone standards through NOx emission reductions cannot be achieved solely by reducing, or even eliminating, electric generating sources of these emissions. Therefore, studying the impact of these combined initiatives is warranted, from a reliability point of view, since both, at least, may be considered if New York State is to come in compliance with mandated ozone levels.

In developing this sensitivity, the first step was to reduce the DMNC of the affected units to levels consistent with those developed in the 2009 RNA in its evaluation of these programs. The resulting LOLE = 1.1days per year, approximately _11_times as great as the design criteria established by NPCC. This was calculated by counting the underated capacity of the identified HECT and LFB units in the numerator of the IRM calculation (and in the J and K LCR calculations) and observing and reporting the results. Hence, LOLE = 0.100 days/year is associated with a NYCA reserve margin of 17.9% and J and K LCRs of 79.6% and 104.9%, respectively.

Following customary procedures in performing sensitivities, capacity was then added to all Areas in New York until LOLE =0.100 was restored. However, the MW deratings attributable to the HECT and LFB deratings were maintained in the numerators of these calculations. The resulting Reserve Margin was 26.3% for NYCA. J and K LCRs were 85.4% and 113.4%, respectively. (MLCRs for J and K changed as a result of the methodology employed.)

Since NYCA's reserve margin is approximately 18%, and Zones J and K have capacity requirements equal to approximately 80% and 105% of their peak loads respectively, the implementation of the HECT and LFB initiatives pose severe challenges for accepted electric industry reliability standards. Meeting them may well be beyond the solutions available in the near term.

B-6 Frequency of Implementing Emergency Operating Procedures

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 8.8 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-3.

Table B-3: Implementation of Emergency Operating Procedures *
Base Case Assumptions (IRM = 17.9 %)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	18.4
Require EDRPs	9.9
5% manual voltage reduction	9.7
30 minute reserve to zero	9.0
5% remote control voltage reduction	8.8
Voluntary load curtailment	6.7
Public appeals	4.9
Emergency purchases	4.7
10 minute reserve to zero	4.5
Customer disconnections	0.1

* See Appendix A, Table A-9

Appendix C Environmental Scenarios

The State of New York is required to comply with the National Ambient Air Quality Standards (NAAQS) for criteria pollutants, including ozone, which have been established by the U.S. Environmental Protection Agency (EPA). New York State has not achieved compliance with the NAAQS for ozone. Ground level ozone is the product of hydrocarbons (HC) and NOx emissions, and sunlight. Fossil-powered generating stations are the fourth largest source of NOx emission in New York, behind area sources, non-road sources and on road mobile sources, each of which are responsible for significantly higher NOx emissions.

The State Implementation Plan (SIP) to achieve compliance with NAAQS is currently being reviewed by EPA. The SIP has three design elements that will affect fossil fueled generators in New York. First is a regional program to budget NOx emissions and provide for tradable NOx Allowances, know as CAIR. This EPA program was overturned
in court, and the EPA is currently examining its next steps. The second element is the Ozone Transport Commission (OTC) High Electric Demand Day (HEDD) program to reduce emissions from older peaking units. Third, DEC has recently initiated the process to develop new standards for Reasonable Available Control Technology for the control of NOx from all but the newest fossil fueled generators in New York.

It is reasonable to evaluate the potential impact of significant new NOx emission limitations on the bulk power system. The 2007 RNA analyzed the potential impact of the OTC-HEDD program on the targeted plants for the “design day” and determined that proposed program would lead to exceedances of reliability criteria. This year, the analysis reviewed the impact of the OTC-HEDD emission reductions on targeted units for all high ozone days during the period 2005 to 2007. In addition, potential impacts of DEC’s preliminary proposal to update NOx RACT standards for all units will also be examined.

A review of recent generation and air quality data should aid in the understanding of the nature of possible reduction requirements. According to DEC data, throughout the period of 2005-2007 there have been a total of 49 days when New York’s air quality did not meet the existing NAAQS for ozone of 84 ppb. With the new standard of 75 ppb in place, it is reasonable to expect that additional exceedances would have been recorded with the current level of emissions. The NYISO analyzed the same dataset to determine the potential impact of the OTC HEDD program. The analysis was conducted in two parts, looking first at the High Emitting Combustion Turbines (HECT), and then at the Load Following Boilers (LFB). The complete OTC HEDD analysis would include both HECT and LFB being limited in capacity simultaneously and would result in greater LOLEs than the sum of the single class evaluations.

Retrofit emission reduction technologies may not be economically feasible or available at all for many of the HECTs and some of the LFBs. The analysis conducted assumed that the proposed emission reductions are achieved through capacity limitations. The impacts of those capacity limitations result in LOLEs >0.1 as shown in Table C-1. This analysis shows a reduction in the magnitude of the LOLEs which can be attributed to the increased use of SCR resources. The analysis shows that these SCR resources will be called upon significantly more than current practice. Programs designed to reduce NOx emissions from the HECT units will require at a minimum, equivalent capacity replacement, to maintain resource adequacy.

NYSDEC has started the review process for updating Reasonably Available Control Technology (RACT) standards for all fossil generating units with the exception of the most recent additions. This proposal could affect approximately 25,000 MW of capacity in New York. The analysis is based on the assumption that 75% of the required reduction can be achieved by the affected units. Further, the remaining affected units are assumed to achieve 50% of the required reductions. The balance of the required reductions is assumed to be achieved through capacity derating. For purposes of this analysis, the derating was assumed to be distributed evenly across all capacity. The results of the analysis, shown in Table C-1 below, indicate that the resource adequacy criterion would be exceeded over the next several years. The results also indicate significant increased reliance on SCR resources.

Table C-1 Environmental Impacts on LOLE

Year	OTC HEDD HECTs	OTC HEDD LFBs	New DEC NOx RACT
2011	0.03	0.04	0.17
2012	0.03	0.04	0.20
2013	0.04	0.05	0.23
2014	0.05	0.07	0.22

Appendix D Assumptions Matrix

Base Case Modeling Assumptions for 2010-2011 NYCA IRM Requirement Study

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
Peak Load	33,730 MW for NYCA, 11,955 MW for zone J, and 5460 MW for zone K.	To be provided by NYISO on October 1, 2009. The final projection is expected to show negative load growth due to conservation measures and lower economic activity.	Forecast based on examination of 2009 weather normalized peaks. Top three external Area peak days aligned with NYCA. (Sensitivity will use a higher load) The interim modeling is done using the Gold Book Forecast of 33,441 MW for NY, 11,950 MW for NYC and 5,476 MW for LI.
Load Shape Model	2002 Load Shape	2002 Load Shape	After evaluating 2008 data, analysis indicates 2002 load shape is an appropriate representation for this analysis.
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Method used and accepted by NYISO and ICS based on collected data and input from LIPA and Con Ed *(see Attachments A and A-1)*. (A sensitivity will use a higher LFU.)

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
Existing Generating Unit Capacities	Updated DMNC test values plus Noble Wind Units; Bliss 101 MW, Ellenburg 81 MW, and Clinton 100.5 MW. Also, 30 MW increase in rating of Gilboa Unit #1.	Updated DMNC test values	2009 Gold Book units
Proposed New Units	Those listed on attachments B and B1.	Those listed on *Attachments B and B1*.	Units built since the 2009 Gold Book and those non-renewable units with Interconnection agreements signed by August 1st. Renewables based on RPS agreements and ICS input.
Wind Resource Modeling	(1209 MW) Derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %.	(1,326 MW) Derived from hourly wind data with average Summer Peak Hour availability factor of approximately 11%.	Based on collected hourly wind data. Summer Peak Hour capacity factor based on June 1-Aug 31, hours (beginning) 2-5 PM.
Solar Resource Modeling	None	Hourly solar readings converted to MW output with average Summer Peak Hour availability factor of approximately 65%. (30 MW)	Based on collected hourly solar data. Summer Peak Hour capacity factor based on June 1-Aug 31, hours (beginning) 2-5 PM.
Retirements	None known for 2009 Capability Year.	Poletti 1 retirement (891 MW 2/10), Greenidge Unit 3 (52 MW 12/09), and Westover Unit 7 (40.2 MW 12/09).	2009 Gold Book plus units indicated by PSC notification.
Forced & Partial Outage Rates	5-year (2003-07) GADS data. (Those units with less than five	5-year (2004-08) GADS data. (Those units with less than five	Most recent 5-year period *(see Attachments C and C-1)*.

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
	years data will use available representative data.)	years data could use available representative data.)	
Planned Outages	Based on schedules received by NYISO & adjusted for history.	Based on schedules received by NYISO & adjusted for history.	Updated schedules.
Summer Maintenance	Continue with approximately 150 MW after reviewing last year's data.	Continue with approximately 150 MW after reviewing last year's data.	No basis for change after review of most recent data.
Combustion Turbines Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves.
Environmental Impacts	No reliability impact due to RGGI in basecase. Sensitivities studies to address range of potential cases.	No impact on unit availability due to RGGI . The base case assumes that any forthcoming NOx RACT rule will not require compliance by summer 2010.	Sensitivity with NOx implementation impacts.
Non-NYPA Hydro Capacity Modeling	45% derating.	45% derating.	Review of historic and most recent data.
Special Case Resources	2107 MW (July 09) based on 3 year historical growth rate. Monthly variation based on historical experience. Limit to 4 calls per month in July and August for DEC limited generation. (about 30 hour total). See SCR	2575 MW (July 10) based on 3 year historical growth rate. Monthly variation based on historical experience. Limit to 4 calls per month in July and August for DEC limited generation. (about 30 hour total). See SCR determinations *in Attachment F*.	Those sold for the program, discounted to historic availability. and distributed according to zonal performance. Methodology for determination of derates has changed to account for more accurate peak hour performance. … *See SCR determinations in*

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
	determinations in Attachment G.		*Attachment F and F-1.*
EDRP Resources	356 MW registered; modeled as 160 MWs in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	329 MW registered; modeled as 148 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	Those registered for the program, discounted to historic availability. (45% overall) July & August values calculated from 2009 July and August registrations.
External Capacity - Purchases	3,046 MW total, 1200 from HQ, 50 from NE, 1280 from PJM, 350 MW from Ontario (HQ wheel through Ontario), and 166 MW from Cedars.	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1090 MW from Quebec. Equivalent[1] Contracts modeled.	Grandfathered contracts per FERC. (Sensitivity cases using actual contracts.and with no contracts modeled.)
Capacity - Sales	Approx 303 MW of firm sales accounted for in Model.	In addition to the long term firm sales of 303 MW, include known firm contracts of 641 MW from NE FCM market. Equivalent Contracts modeled.	Other firm contracts are becoming known, such as from neighbor's forward capacity markets. (sensitivity using actual contracts)
Capacity Wheel-throughs	None modeled	None modeled	At the August 14, 2009 Executive Committee meeting it was agreed ICS in conjunction with NYISO Operations staff, will review HQ energy wheel outside of the IRM study process and report back to

1 Equivalent contracts are modeled to remove capacity from the zone where the contracts originate and derate the interface tie where the capacity exits New York.

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
			Executive Committee with findings .
EOPs (other than SCR and EDRP)	811 MW of non-SCR/EDRP MWs. See Attachment D.	700 MW of non-SCR/EDRP MWs. *See Attachment D.*	Based on TO information, measured data, and NYISO forecasts.
Interface Limits	Based on 2008 Operating Study, 2008 Operations Engineering Voltage Studies, 2008 Comprehensive Planning Process, and additional analysis.	Based on 2009 Operating Study, 2009 Operations Engineering Voltage Studies, 2009 Comprehensive Planning Process, and additional analysis.	NYISO engineering studies and additional analysis and input from other external Control Areas. *See Attachments E and E-1*
New Transmission Capability	None Identified as new for this study.	Linden VFT - 300 MW.	Based on NYISO analysis and model provided by Con Ed.
Transmission Cable Forced Outage Rate	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Based on TO analysis.
Unforced Capacity Deliverability Rights (UDR)	LIPA has notified the NYISO that the amount of UDR's for the Neptune Cable and Cross Sound Cable is confidential data.	UDRs have been issued for the Cross Sound Cable, Neptune cable, and Linden VFT Project.	Contracted amounts of capacity are confidential and are included as capacity internal to NYCA.
Model Version	Version 2.92	Version 2.98	Per testing and recommendation by ICS.
Outside World Area Models	Single Area representations for Ontario and Quebec. Three zones modeled for PJM. Five zones modeled for New	Single Area representations for Ontario and Quebec. Three zones modeled for PJM. Five zones modeled for New England derived	The load and capacity data (including zonal information if available) is provided by the neighboring Areas. This updated

Parameter	2009 Study Modeling Assumptions	Recommended 2010 Study Modeling Assumptions	Basis for Recommended 2010 Assumptions
	England derived from 14 zones provided.	from 14 zones provided.	data is then adjusted as described in Policy 5.
Reserve Sharing between Areas	Canadian Provinces have indicated that they will share reserves equally among all.	All Control Areas have indicated that they will share reserves equally among all. Loop Flow switch(s) are in the “No” position to not allow a Control Area to send capacity through one system and back into itself in order to avoid the congestion that could be relieved by transmission projects.	NPCC CP-8 working group has identified this arrangement as more representative. GE has performed analysis on loop flow switch issue. NYISO has issued white paper on this topic.

Approved NYSRC Executive Committee 8/14/09

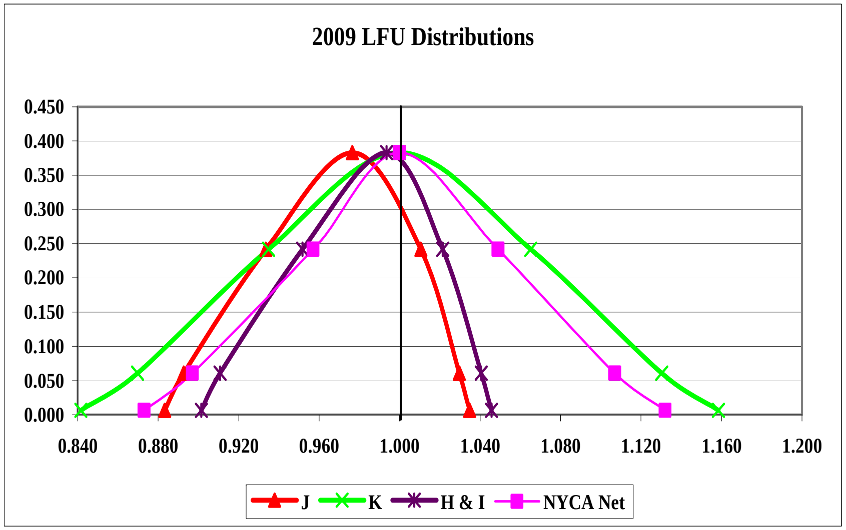
Attachment A
NYCA Load Forecast Uncertainty

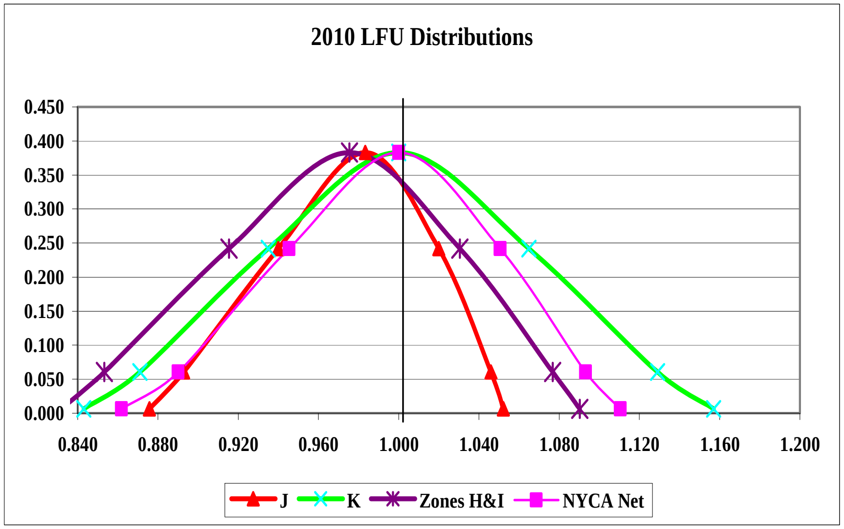
2009 Load Forecast Uncertainty Models

Multiplier	Zones H&I	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0457	1.0348	1.1584	1.1320
0.0606	1.0406	1.0297	1.1303	1.1070
0.2417	1.0215	1.0106	1.0651	1.0490
0.3830	0.9935	0.9765	1.0000	1.0000
0.2417	0.9517	0.9336	0.9349	0.9570
0.0606	0.9108	0.8926	0.8697	0.8970
0.0062	0.9014	0.8833	0.8416	0.8730

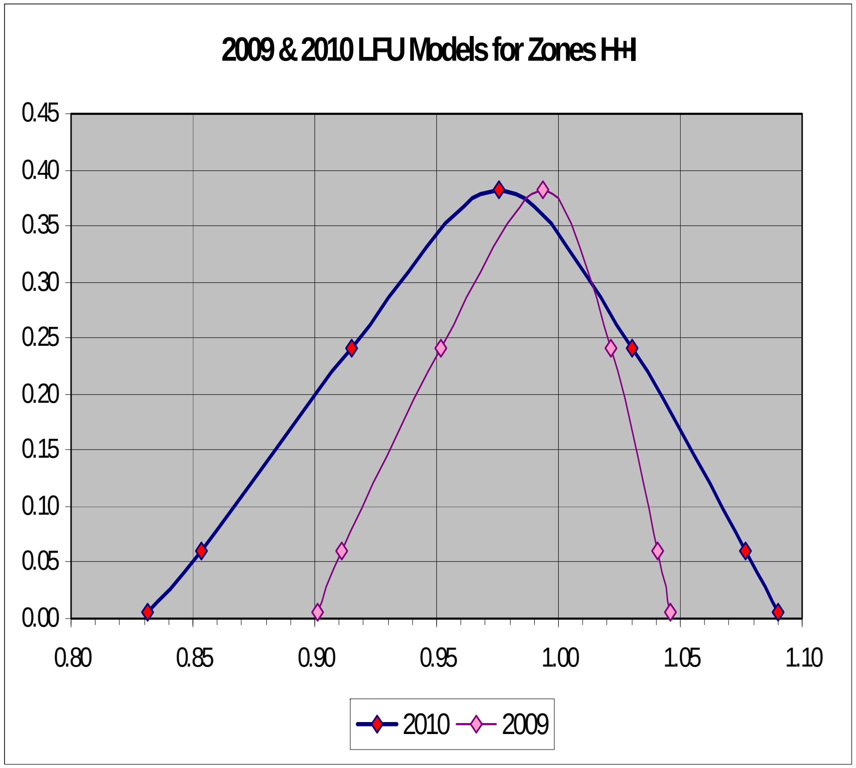
2010 Load Forecast Uncertainty Models

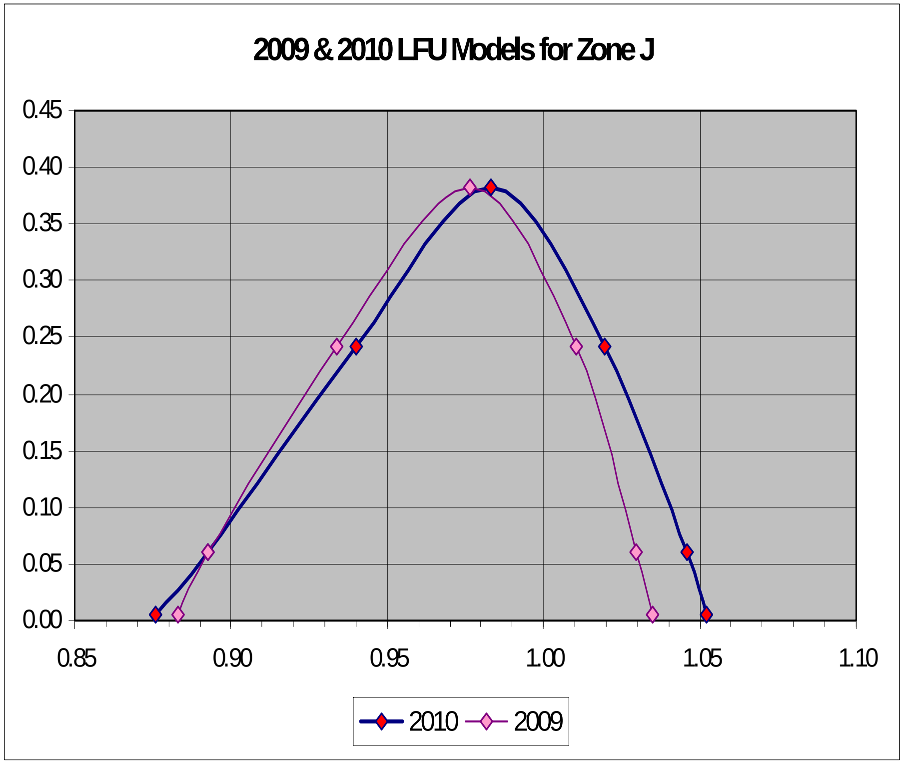
Multiplier	Zones H&I	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0903	1.0522	1.1570	1.1105
0.0606	1.0768	1.0460	1.1290	1.0932
0.2417	1.0305	1.0200	1.0650	1.0506
0.3830	0.9755	0.9833	1.0000	1.0000
0.2417	0.9154	0.9400	0.9350	0.9453
0.0606	0.8533	0.8928	0.8710	0.8901
0.0062	0.8317	0.8758	0.8430	0.8619



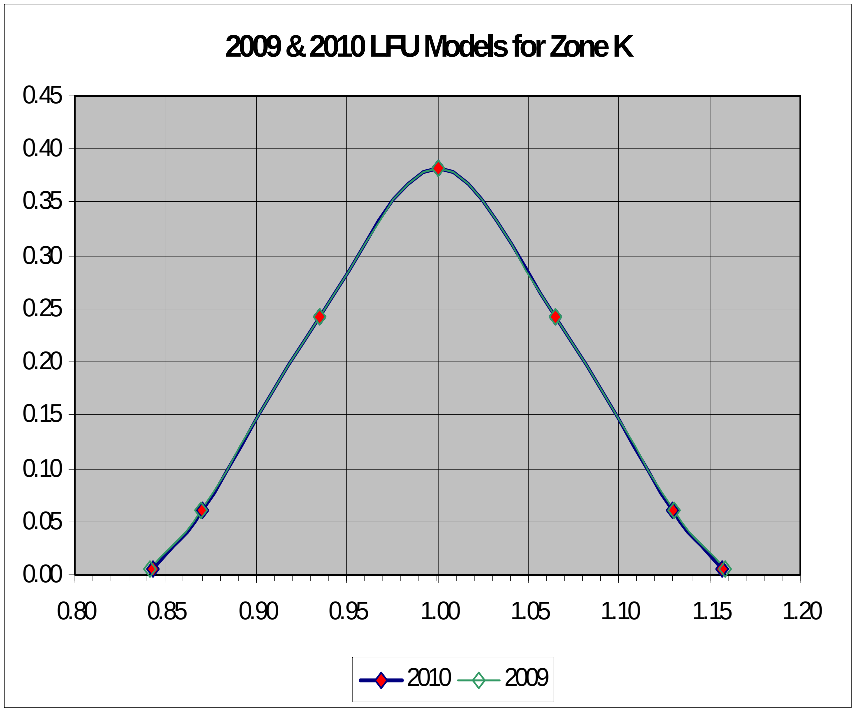


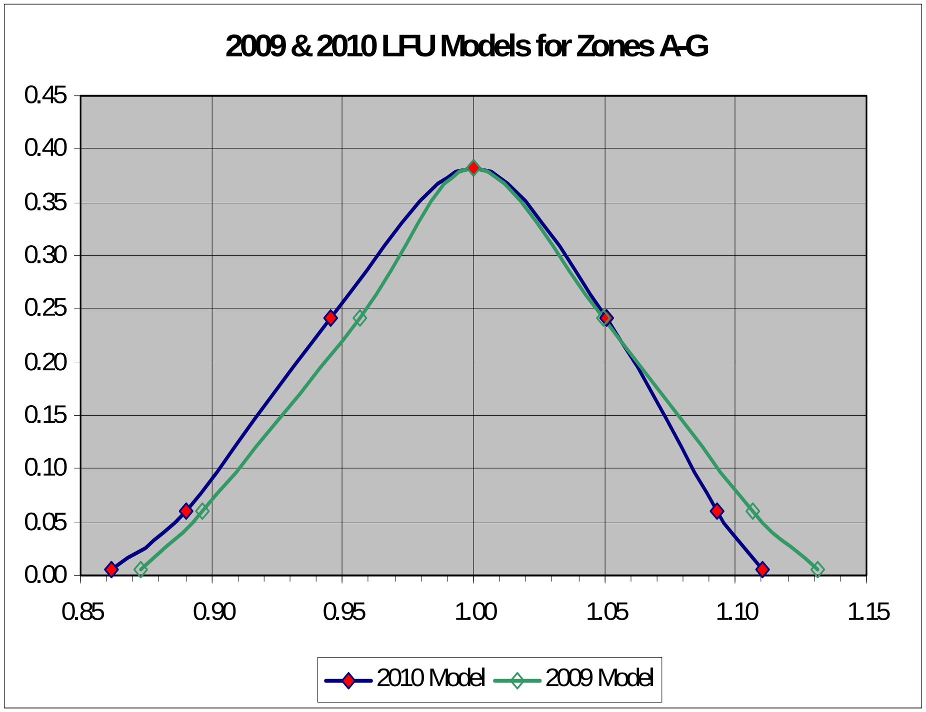
Attachment A-1
Comparison of Zonal LFU
(2009 vs 2010 analysis results)





Attachment A-1continued
Comparison of Zonal LFU
(2009 vs 2010 analysis results)





Attachment B

List of (non-wind)proposed Units

To be in-service by Summer of 2010

Project Name	IS Date	Zone	MW
LIPA Solar	6/10	K	30
Caithness LI	6/09	K	310
Uprate Gilboa #3	6/09	F	30
Uprate Gilboa #4	6/10	F	30
Sherman Island Uprt	3/09	F	8.5
74^{th} Street GT#2	7/09	J	19.7
Riverbay	7/09	J	24

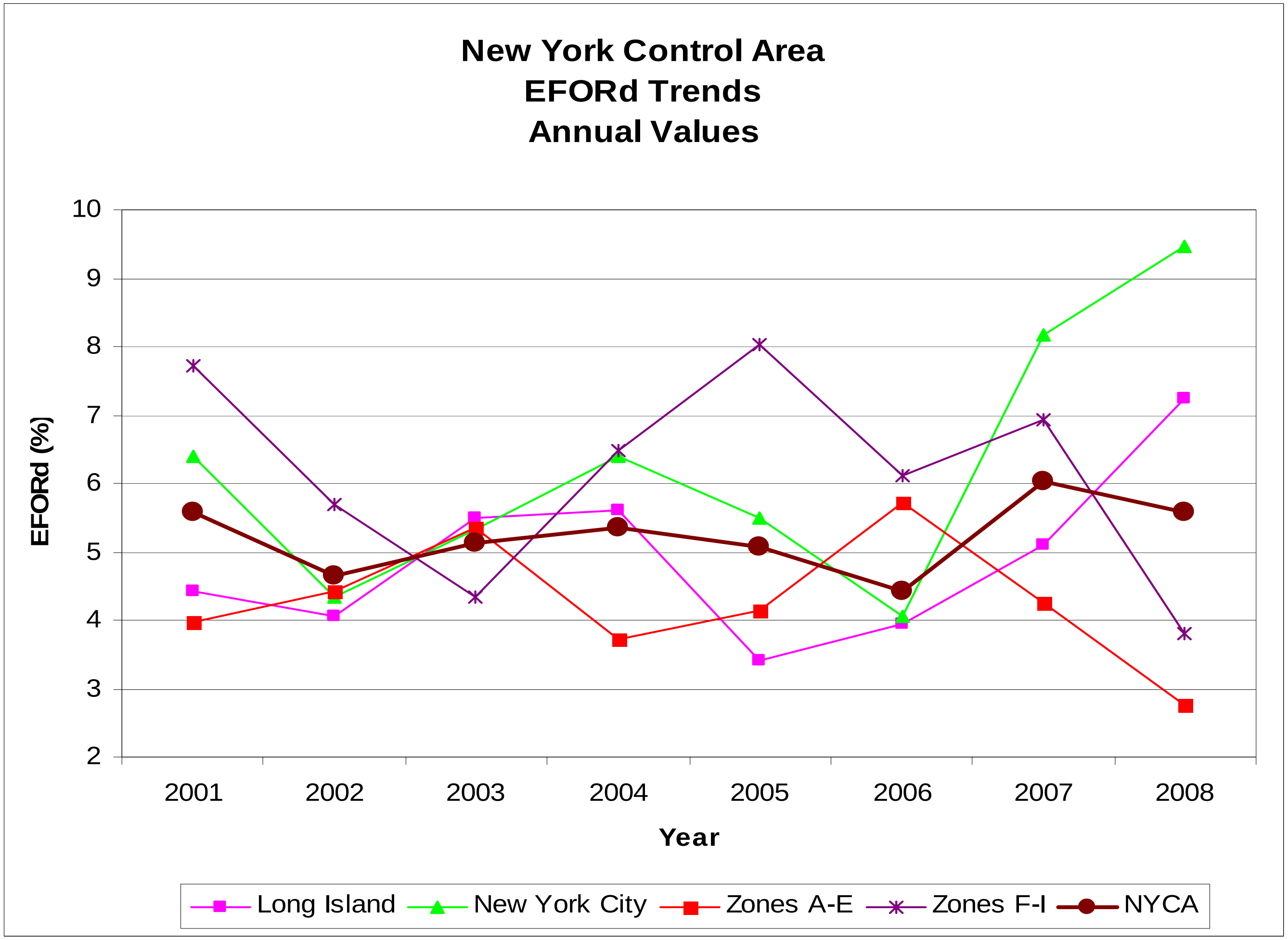
Attachment B1

Renewable Generating Projects (Wind) for Inclusion in the 2010-2011 Installed Reserve Margin Study

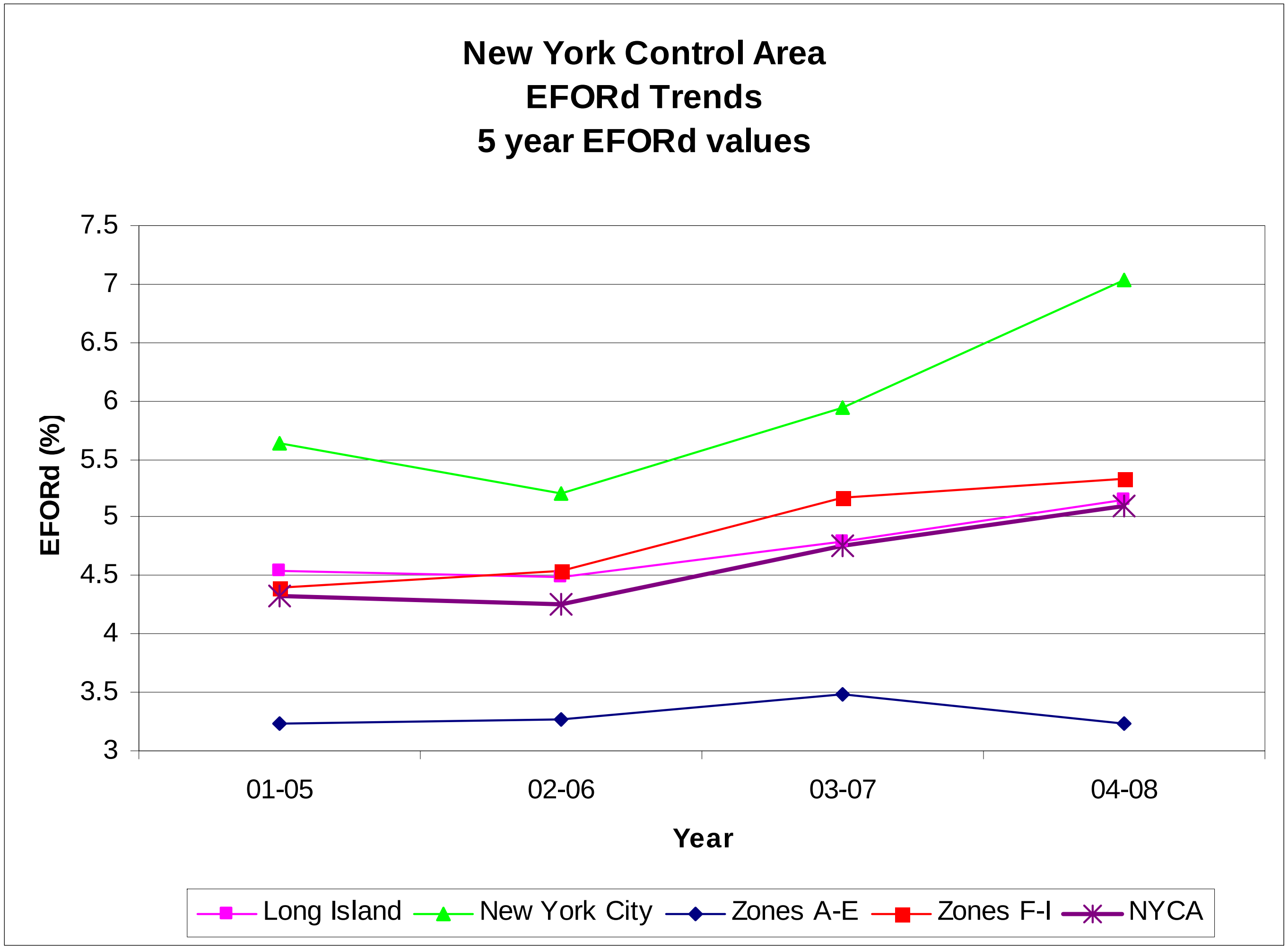
Facility	New Nameplate Capacity (MW)	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	New Wind Capacity for 2010 IRM[5] (MW)	Wind Capacity Modeled for 2010 IRM[5] (MW)
Wind Facilities as of March 1, 2009 and Not Part of RPS							
Horizon Wind, Madison	11.6	E			2000 Sept		11.6
Wester New York Wind Corp, Wethersfield	6.6	B			2000 Oct		0
Canastota Wind Power, Fenner	30.0	C			2001 Dec		0
Constellation Power, Steel Wind	20.0	A			2007 Jan		20
Coral Power, Munnsville	34.5	E			2007 Aug		34.5
High Sheldon Wind Farm	112.5	C	NYSEG	144	2009 Feb	112.5	112.5
Non-RPS Total	**215.2**					**112.5**	**178.6**
NYSERDA RPS Projects							
1st Main Tier Solicitation - 2005[1]							
Maple Ridge 1 & 2 (Previously called Flat Ro	321	E	NG	171	2006 Feb		321
Wind Park Bear Creek, LLC	22	into C	NYSEG		2006 Feb	22	22
Totals for 1st Main Tier	**321.0**					**22**	**343**
2nd Main Tier Solicitation - 2006[2]							
UPC Canandaigua I[7]	82.5	C	NYSEG	135	2008 Jun		82.5
UPC Canandaigua II[7]	42.5	C	NYSEG	199	2008 Jun		42.5
Noble Altona Windpark	99.0	D	NYPA	174	2008 Sept		99.0
Noble Bliss Windpark	100.5	A	Village of Arcade	173	2008 May		100.5
Noble Chateaugay Windpark I	106.5	D	NYPA	214	2008 Sept		106.5
Noble Belmont/Ellenburg II[6]	21.0	D	NYPA	213	2009 Dec		21.0
Noble Clinton Windpark I & II	100.5	D	NYPA	172 & 211	2008 May		100.5
Noble Ellenburg Windpark	81.0	D	NYPA	175	2008 May		81.0
Totals for 2nd Main Tier	**633.5**					-	**633.5**
3rd Main Tier Solicitation - 2007[3]							
Noble Wethersfield Windpark	126.0	C	NYSEG	177	2008 Dec	126.0	126
3rd Main Tier Soliciation - 2008 Total New Nameplate Capacity	**126.0**					**126.0**	**126**
Total for Main Tier	**1,080.5**					**148.0**	**1,102.50**
National Grid							
Steel Winds II	45	A	National Grid	234	May-2010	45	45
National Grid Total	**45**					**45**	**45**
Total Capacity of All Categories	**1,662**					**305.5**	**1,326.1**

Notes:
1. The first main tier solicitation contracts did not include an option for an extension. Units were required to be online by January 1, 2006 except for the Bear Creek who was required to be online in February 2006.
2. The second main tier solicitation contracts were expected to be online by January 1, 2008 unless the developer asked for an extension by December 1, 2007 in which case the project would be required to be online by November 1, 2008.
3. The third main tier solicitation contracts are expected to be on-line by January 1, 2009 unless the developer asks for an extension by December 5, 2008 in which case the project would be required to be on-line by November 30, 2009.
4. NYISO Study Queue Project Status Key: 1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS/SIS Pending, 5=SRIS/SIS in Progress, 6=SRIS/SIS Approved, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Completed, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn
5. Assume all wind projects with RPS contracts are online for the forecast year.
6. Noble Belmont/Ellenberg II requested additional time to construct this project. The request was granted and additional security was required.
7. Canandaigua I sometimes referred to as Cohocton Wind Farm. Canandaigua II sometimes referred to as Dutch Hill Wind Farm.

Attachment C



Attachment C-1

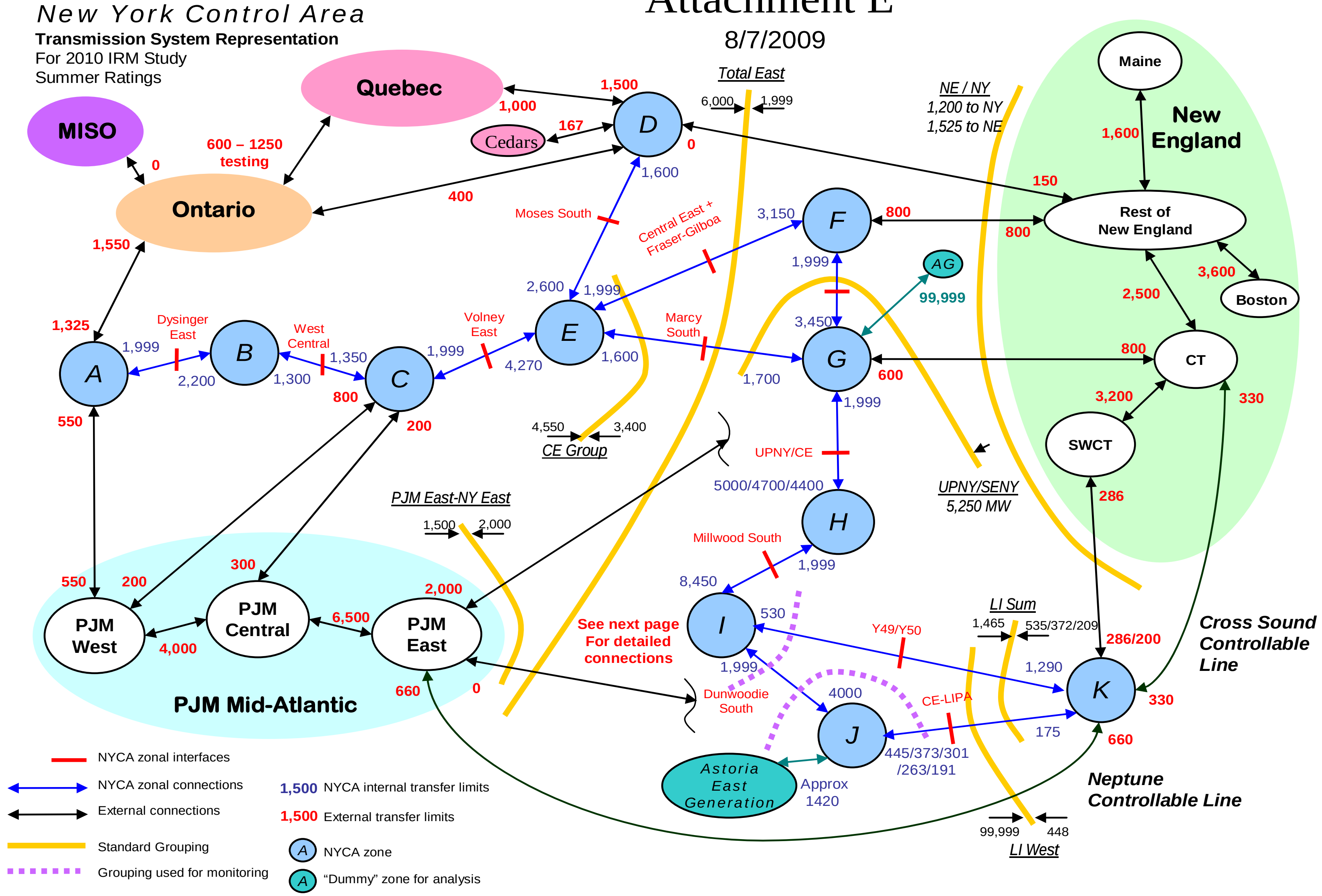


Attachment D
Emergency Operating Procedures

Step	Procedure	Effect	2009 MW Value	2010 MW Value
1	Special Case Resources	Load relief	2107 MW (representing the amount sold)	2575 MW (representing the amount sold)
2	Emergency Demand Response Program	Load relief	356 MW	329 MW
3	5% manual voltage Reduction	Load relief	80 MW	72 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW	600 MW
5	5% remote voltage reduction	Load relief	514 MW	479 MW
6	Voluntary industrial curtailment	Load relief	129 MW	61 MW
7	General public appeals	Load relief	88 MW	88 MW
8	Emergency Purchases	Increase capacity	Varies	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW	1200 MW
10	Customer disconnections	Load relief	As needed	As needed

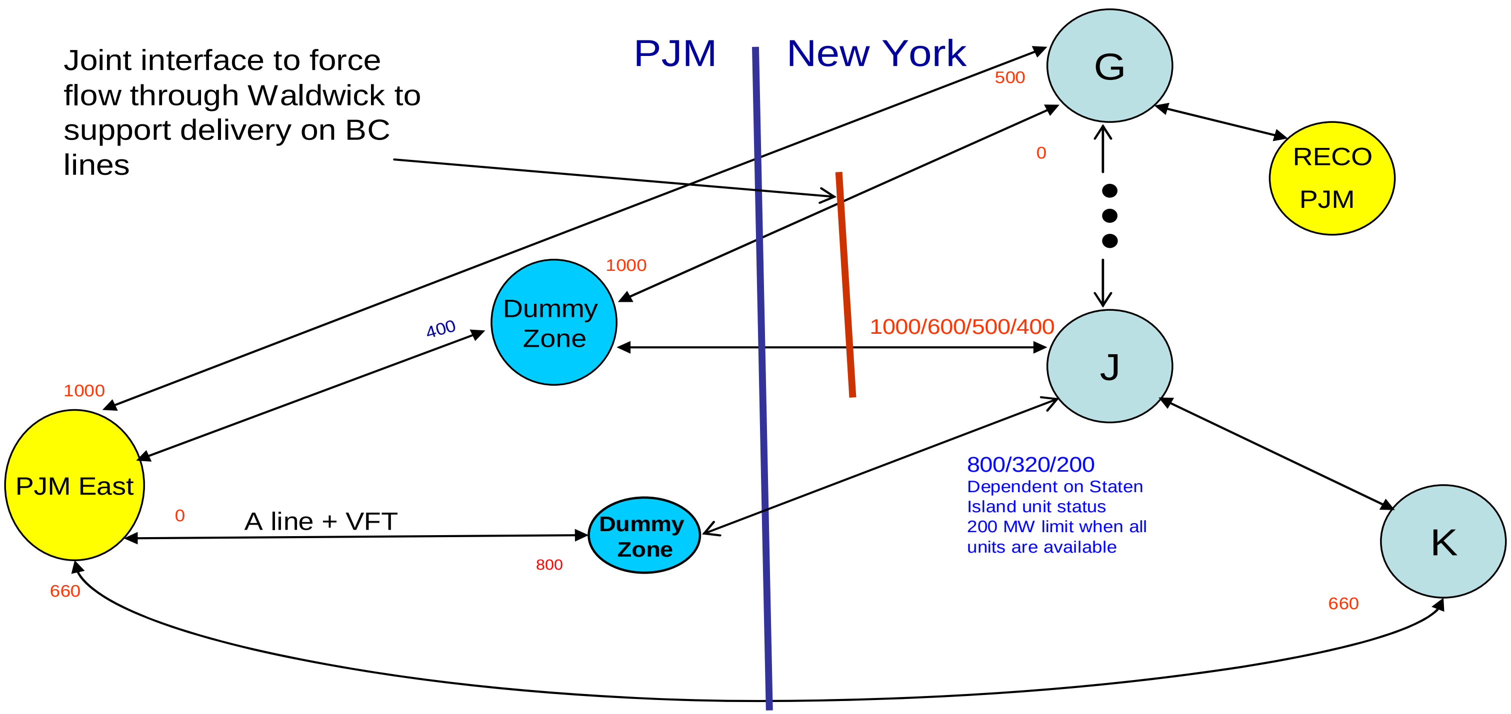
Attachment E

8/7/2009



Attachment E-1

2009 PJM-NYCA MARS Model - 8/7/2009



Attachment F
SCR Determinations

Growth Rate

		MW (UCAP)		MW (UCAP)
2007	**Jul 07**	1328.8	**Aug 07**	1356.9
2008	**Jul 08**	1700.4	**Aug 08**	1683.4
2009	**Jul 09**	1922.0	**Aug 09**	1952.9
Average Annual:		20.3%		20.0%
2010 Projected:		2311.5		2342.9

Translation

	UCAP	Factor*:	ICAP Estimate	ICAP Actual**
July	2311.5	0.92	2,512.5	2,575.0
August	2342.9	0.92	2,546.6	2,616.0
			Modeling	
July	2311.5	0.8	1,849.2	
August	2342.9	0.8	1,874.3	

*This value is the APMD based factor (92%). The second factor (80%) is based on the attachment F-1 analysis that compares the CBL method to the APMD method. See Attachement F-1 for more details.
**The actual value is the sum of the individually calculated zonal values.

Attachment F-1

Performance Factors for SCR Determinations

Historical Analysis of SCR Performance Using Various Baseline Methodologies

The NYSRC Installed Capacity Subcommittee requested the NYISO to provide historical information as to the load reduction performance of ICAP Special Case Resources (SCRs) under two different baseline assumptions.

<u>Average Peak Monthly Demand Methodology</u>

SCR Performance is determined by comparing the actual hourly interval metered energy with the Average Peak Monthly Demand (APMD):

$$RED\_MW_{gn} = APMD_{gm} – AMD_{gn}$$

where:

- RED_MW_{gn} is the Installed Capacity Equivalent performance that Resource g supplies during hour n of an SCR event;
- $APMD_{gm}$ is the Average of Peak Monthly Demands for Resource g applicable to Capability Period m, using data submitted in its Special Case Resource Certification, and
- AMD_{gn} is the metered hourly integrated energy for Resource g in hour n of an SCR event.

Performance using this measure compares actual reduction with the reduction capability sold as ICAP by the SCR.

It should be noted that APMD during 2006 was based on the peak hour at any time during the day; ICAP market rules were modified for 2007 and beyond to use peak hours between noon and 8 pm only. This rule change if in place in 2006 may have reduced the APMD aggregate values shown in the Tables below and resulted in lower performance measurement using the APMD approach.

<u>Customer Baseline Load Methodology</u>

Performance for purposes of determining energy payment is based upon the NYISO's Emergency Demand Response Program (EDRP) method of performance measurement, which calculates a Customer Baseline Load (CBL) from recent historical data to determine what energy consumption would have been if the participant had not reduced load. The CBL is determined as follows:

- Beginning with the weekday two days prior to the demand response event, look back ten weekdays and determine the five highest energy consumption days corresponding to the time period of the event. For example, if the demand response event occurs between noon and 4 pm, the baseline consumption is determined by the five previous days with the highest energy consumption between noon and 4 p.m.

- Take the average of the five readings for each hour to determine the baseline for that hour.

The difference between the hourly CBL and hourly interval meter readings serves as the measure of load reduction.

<u>August 2, 2006 Results</u>

A detailed analysis of the August 2, 2006 event was performed using on the subset of SCR data where performance data using both baseline measures was submitted. On August 2, SCRs in Zones A, B, C, J and K were activated. Table 1 contains the declared ICAP aggregated by capacity region for SCRs reporting both CBL and APMD data; a total of 805.7 MW of ICAP equivalent was sold for these resources.

Table 1

Commitment (based on Declared values) for August 2006 (ICAP Equivalent)

For resources reporting CBL and APMD data
(APMD - CMD)

Zones	**CBL + APMD Data**
ROS (A+B+C)	422.3
J	225.0
K	158.4
Total	805.7

Table 2 contains load reduction performance through the APMD method (top) and CBL method (bottom). The ratio of CBL performance to APMD performance was 582.8/826.3 or 70.5%. By capacity region, the ratios are:

- ROS (Zones A, B and C): 69.3%
- Zone J: 66%
- Zone K: 81.3%

The CBL methodology can understate load reduction if loads on the event day are not weather-adjusted. Of the 913 SCRs reporting both APMD and CBL data, 129 reported CBL data using the weather sensitive model. For resources using the weather sensitive model, the ratio of CBL to APMD performance was 78.2% vs. the 70.5% ratio for all resources reporting CBL and APMD.

Table 2

Curtailment by Hour for August 2, 2006 Resources reporting CBL and APMD data	
APMD-AMD methodology	
Zones	**Average**
ROS (A+B+C)	454.5
J	224.8
K	147.0
Total	826.3
CBL Methodology	
Zones	**Average**
ROS (A+B+C)	314.8
J	148.3
K	119.5
Total	582.8

Analysis of All 2006 Events Using FERC Compliance Report Data

At the request of the ICS, the NYISO performed a similar analysis using data from all EDRP/SCR events in 2006. This analysis did not work with a stratified sample of SCRs who reported both APMD- and CBL-based performance data, but did factor in the number of SCRs reporting data of each type. For each Capacity Region and Locality, Table 3 contains:

- the reported load reduction using the CBL method (CBL MW)
- the reported load reduction using the APMD method (APMD MW)
- the number of SCRs reporting CBL-based data (#cbl_cust)
- the number of SCRs reporting APMD-based data (#apmd_cust)
- the ratio of CBL-to-APMD reported MW reductions, unadjusted for the number of responses (CBL-to-APMD ratio)
- the ratio of customers reporting CBL vs. APMD data (Cust report ratio)
- the CBL-to-APMD MW reduction, adjusted for the number of responses by dividing the CBL-to-APMD ratio by the Cust report ratio.

As can be seen from the last column of Table 3, the overall performance ratios, with some exceptions, are close to the 66%-88.3% figures determined from the August 2 detailed analysis. The July 18 results for ROS and Zone K are less accurate for the following reasons:

- ROS results involved only one Zone with few SCRs registered, with greater statistical error,
- Zone K results included APMD data and not CBL data from some customers who did report both in subsequent events.

Table 3

2006 EDRP/SCR Event Analysis Based on FERC Compliance Report

Date	Zone	CBL MW	APMD MW	#cbl_cust	#apmd_cust	CBL-to-APMD ratio	Cust_report_ratio	Performance Ratio
18-Jul	*ROS*	4.4	12.9	15	17	0.341	0.882	0.387
	J	134.1	290.7	554	788	0.461	0.703	0.656
	K	95.1	92.4	208	262	1.029	0.794	1.296
19-Jul	*J*	108.9	243.6	546	745	0.447	0.733	0.610
1-Aug	*J*	144.8	166.3	549	454	0.871	1.209	0.720
	K	114.5	50.3	241	78	2.276	3.090	0.737
2-Aug	*ROS*	276.5	473.0	119	148	0.585	0.804	0.727
	J	147.4	219.2	562	663	0.673	0.848	0.793
	K	108.0	79.9	237	148	1.351	1.601	0.844
3-Aug	*J*	142.8	231.6	576	667	0.617	0.864	0.714
	K	106.4	77.9	239	144	1.366	1.660	0.823