New York Control Area Installed Capacity Requirements for the Period May 2009 through April 2010

Technical Study Report

December 5, 2008

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 2009 to April 2010 (2009 capability year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2009 capability year is 16.2% under base case conditions.

For this base case, the study also determined Minimum Locational Capacity Requirements (MLCRs) of 79% and 97% 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 and Northeast Power Coordinating Council (NPCC) reliability criteria, and North American Electric Reliability Corporation (NERC) reliability standards.

The above 2009 base case IRM Study value of 16.2% is 1.2 percentage point more than the base case IRM requirement determined by the 2008 IRM Study. The principle drivers for this increase in required IRM in order of IRM impacts are:

1. An increase in the NYCA average generating unit forced outage rate in 2007. This increase was particularly significant for units located in NYC.
2. An updated load forecast load uncertainty model.
3. The addition of 825 MW of new wind-powered generation.

The net increase in the IRM caused by these and other factors are tempered to some extent by IRM reductions primarily caused by increased emergency assistance from neighboring control areas made possible by transmission improvements in New England and a projected increase in special case resource capacity and performance.

Table 1 shows the IRM impacts of these and lesser factors that have resulted in a net 1.2% increase from the 2008 IRM base case value of 15.0%.

The 2009 IRM Study also examined environmental regulations that are presently being developed by environmental regulators in New York and the Northeast that, when implemented, may impact IRM requirements. One of these environmental initiatives is designed to reduce ozone emissions of NO_X; the other initiative is designed to reduce CO_2 emissions. An NYISO analysis on the implementation of these regulations concluded that neither initiative will impact 2009 capability year IRM requirements, although both initiatives can potentially affect IRMs in future years.

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 of meeting the reliability index within the NYSRC and the NPCC resource adequacy criteria.

The base case and sensitivity case results, along with other relevant factors, will be considered by the NYSRC Executive Committee when it develops and adopts the Final NYCA IRM requirement for the 2009 capability year.

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, 2009 through April 30, 2010 (2009 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% / 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 2009 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 2009 IRM study was based on meeting the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2009 IRM Study are in accordance with NYSRC Policy 5-2, *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 2009 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 2008 IRM Study reports can be found at www.nysrc2.org/reports.asp. Table B-1 in Appendix B provides a comparison of previous NYCA base case and Final IRMs for the 2000 through 2009 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.nysrc2.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.nysrc2.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

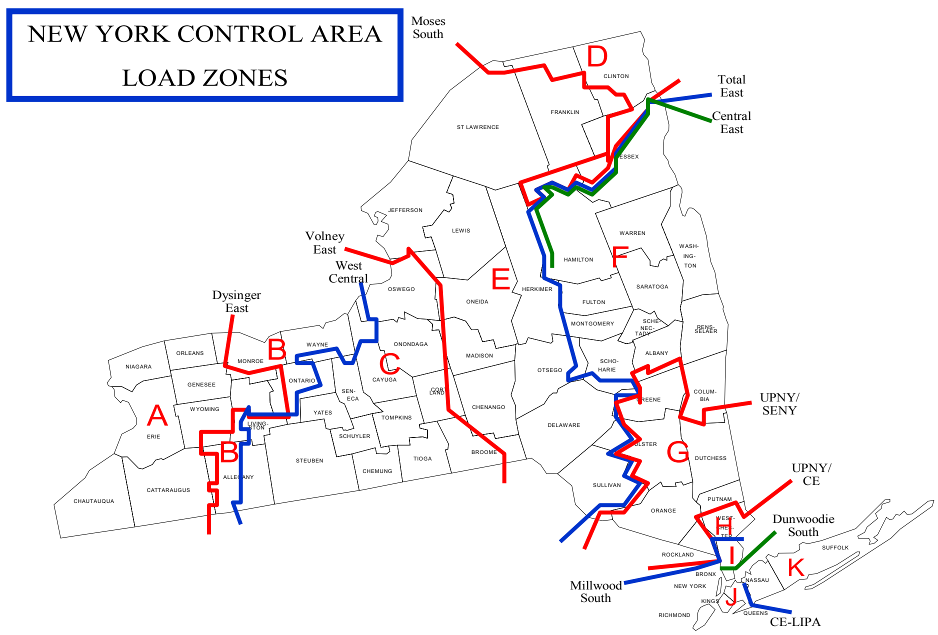
IRM STUDY PROCEDURES

The study procedures used for the 2009 IRM Study are described in detail in NYSRC Policy 5-2, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-2 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 5-2 can be found on the NYSRC Web site at,
www.nysrc2.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



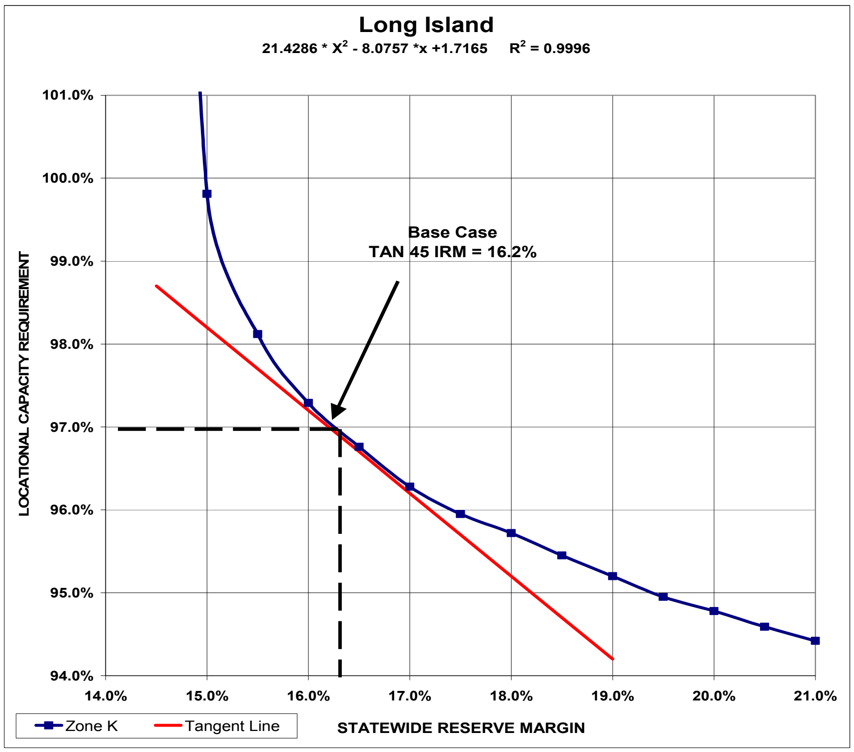
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. This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

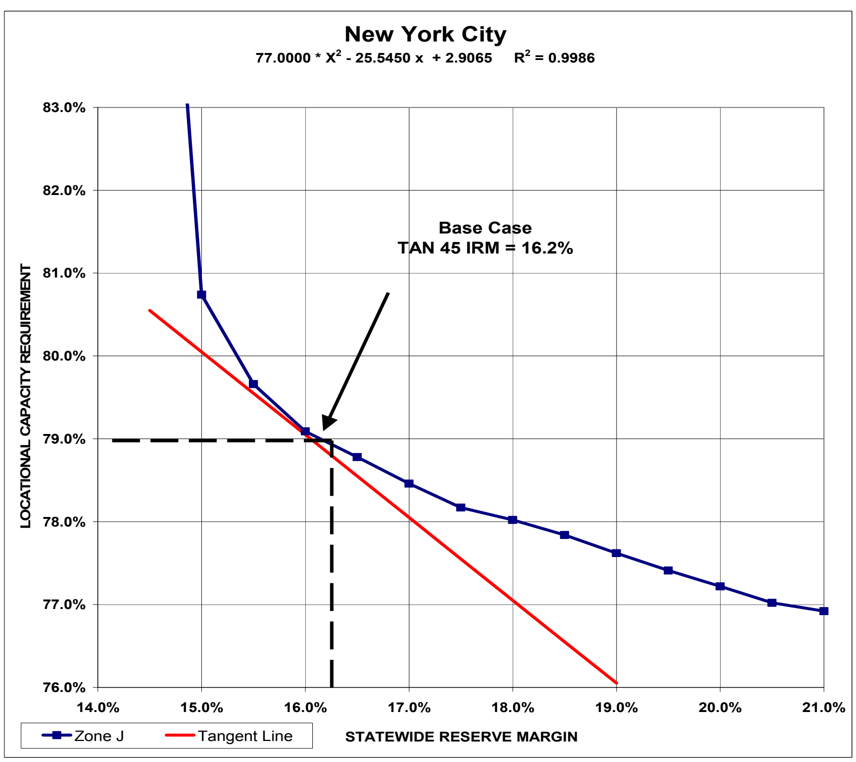
Base case NYCA IRM requirements and related MLCRs are established by a supplemental procedure (termed the *IRM Anchoring Methodology*) which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the 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 5-2 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 16.2% for the 2009 capability year under base case conditions. Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI. The points on the NYC and LI curves were calculated using the methodologies described in the previous "IRM Study Procedures" section.

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





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 16.2% for the 2009 capability year, together with MLCRs of 79% and 97% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A. The 97% MLCR for LI represents a 3.0% increase from that calculated in the 2008 IRM Study. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2009 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 15.8% and 16.6% (see Appendix A). Within this range the statistical significance of the 15.8%, 16.2%, and 16.6% 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 16.0 to 16.4%. The base case IRM value of 16.2% 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 2009 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, 2008. Appendix A provides more details of these models and assumptions.

Load Model

- ***Peak Load Forecast***: A 2009 NYCA summer peak load of 33,843 MW was assumed in the study. This is a reduction of about 450 MW from last year's forecast for the 2009 summer peak. The 2009 NYCA load forecast was prepared by the NYISO staff in collaboration with the Load Forecasting Task Force in October 2008 and is based on actual 2008 summer load conditions. Use of this updated 2009 peak load forecast in the 2009 IRM study resulted in a reduction from 2008 IRM requirements of 0.3% (see Table 1). Although the NYISO will prepare a Final 2009 summer forecast in early 2009 for use in NYISO locational capacity requirement study, it is expected that both the October and Final 2009 summer peak forecasts will be similar.

- ***Load Shape Model***: The 2009 IRM Study was performed using a load shape based on 2002 actual values. The same 2002 load shape was used in the three previous IRM studies and is consistent with the load shape assumption used by other adjacent Control Areas. An analysis comparing the 2002 load shape to actual load shapes from 1999 through 2007 concluded that the 2002 load shape continues to be the best suited for the 2009 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, the LFU model is subdivided into four areas: Zone H and I, Zone J (NYC), Zone K (LI), and Zones A-G (the rest of New York State). A change in the 2009 IRM base case LFU calculation methodology for zones H, I and J models was agreed to by the corresponding Transmission Owner and the NYISO. Use of this updated methodology increases base case IRM requirements from the 2008 IRM Study by 0.9%. This IRM increase is primarily due to changes in the portions of the new LFU model representing Zones H, I, and J.

Capacity Model

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

- ***Resource Facility Ratings****:* 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. Appendix A shows the new resource facilities that are included in the 2009 IRM Study capacity model.

- ***Resource Capacity 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 2009 IRM Study covered the 2003–2007 period.

  The 2008 IRM Report stated that generating unit availability performance had stabilized over the six years period between 2001 and 2006. This improvement of generating unit availability permitted the required 2008 IRM to be reduced from previous years. However, in 2007, the NYCA average generator EFOR increased from 4.4% in 2006 to 6.0% in 2007. Of significance, the NYC zone's average generator EFOR doubled from 4.0% in 2006 to 8.0% in 2007. These higher EFORs caused the 5-year rolling average used for the 2009 IRM Study to increase by 0.3% for NYCA and 0.7% for NYC, compared to that used for the 2008 IRM Study. This resulted in an increase of 1.2% in the base case IRM from the 2008 IRM study. A joint study by the NYSRC and NYISO will be conducted during 2009 to analyze EFOR trends.

- ***Wind Generation:*** It is projected that by the end of the 2009 Capability Period there will be 16 wind-powered generation locations in NYCA with a total capacity of 1,209 MW. This represents an increase of 825 MW since the 2008 Capability Period. All of these wind farms are located in upstate New York, in Zones A – E. Zone D will have the most wind farms – seven – during the 2009 Capability Period.

The 2009 IRM Study base case assumes that the projected 1,209 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 projected 1,209 MW of wind capacity in the 2009 base case increases 2009 IRM requirements by 1.2% (see Table 2). This increased IRM is a direct result of the very low capacity factor of wind facilities during the summer peak period, as noted above. The increased wind capacity of 825 MW from 2008 to 2009 is responsible for increasing the base case IRM from the 2008 IRM Study by 0.8% (see Table 1). The impact of wind capacity on *unforced capacity* is discussed in the "NYISO Implementation of the NYCA IRM Requirement" section of the report.

Wind developers are planning to install an additional 1,750 MW of wind capacity between 2010 and 2014, 950 MW of which will be located on Long Island. See Appendix A for more details.

A detailed summary of existing and planned wind resources is shown in Appendix D.

- ***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 values of 2147 MW, 2107 MW, and 2084 MW in June through August 2009, respectively (lesser amounts during other months),. The above SCR capacity is projected to increase 15%, based on historic monthly SCR growth. Base case SCR capacities were distributed though out the zones according to actual zonal registrations. Increased registrations as well as projected growth have resulted in an increase of approximately 900 MW above the 2008 base case SCR capacity value. Approximately 12% of NYCA SCRs would be considered Department of Environmental Conservation-limited generation, and are limited to a maximum of four calls per month in July and August. In addition to the increased SCR MW capacity projected, the effectiveness of the program has slightly improved on a statewide basis with an average availability factor increase from 92% to 93%. This improved effectiveness was greater in the zones exhibiting high LOLE risk (Zones J and K), and resulted in an IRM reduction of 0.9% from 2008 IRM requirements (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 2009 Study assumes 365 MW of EDRP capacity resources will be registered in 2009. This EDRP capacity was discounted to a base case value of 160 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 2009 EOP capacity values are based on historical 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 2009, assuming an IRM of 16.2 %.)

- ***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 and 660 MW HVDC Neptune Cable are facilities that are represented in the 2009 Study as having UDR capacity rights. LIPA has 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 2009 IRM study incorporates the elections that LIPA has made for the 2009 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-11 in Appendix A. The transfer limits employed 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 utilized.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. The 2009 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 February 28, 2008, at http://www.nyiso.com/public/services/planning/resource_adequacy_planning.jsp, determined that for the 2008 capability year, the required LCRs for NYC and LI were 80% and 94%, respectively.

Three changes of transmission interface capability from the 2008 IRM Study were reflected in the 2009 IRM Study. First, the interface limit from Zone I to Zone J increased from 3925 MW to 4000 MW. This increase was due to better flow balancing of the circuits comprising the interface. Regarding the second change, the Moses South interface was reduced from 2900 MW to 2600 MW. Finally, the Dysinger East interface was reduced from 2600 MW to 2200 MW, based on different base case flow patterns. The combined effect of these revised interface limits is that there is no net impact on the base case IRM as compared to the 2008 IRM Study (see updated transmission topology in Table 1).

As previously discussed, Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI for the base case. This figure shows that the IRM requirement can be impacted significantly depending on the level of capacity within these zones, particularly to the right of the "inflection point" of the curve where the IRM requirement rises much faster than the locational installed capacity levels are reduced. For base case assumptions, the inflection point in Figure 2 results in the base case IRM requirement of 16.2% and MLCRs for NYC and LI of 79% and 97%, respectively.

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 14.5%, 1.7 percentage points less than the base case IRM requirement (see Table 2). Therefore, relieving these transmission constraints is equivalent to adding approximately 500 MW of generation in NYCA.

- **Downstate NY Capacity Levels** – If the NYC and LI LCR levels were *increased* from the base case results to 81% and 100%, respectively, the IRM requirement could be reduced by 1.2 percentage points, to 15.0%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 77.5% and 95%, respectively, the IRM requirement must increase by about 3.3 percentage points, to 19.5% (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.

<u>Outside World Model</u>

The Outside World Model consists of Control Areas in 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 5.5 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 5-2, 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.

For the 2009 IRM Study the transfer limit of the Southwest Connecticut interface increased from the 1100 MW transfer limit used for the 2008 IRM Study to 2350 MW. This New England system upgrade was primarily responsible for decreasing the base case IRM attributed to the Outside World Model by 1.4%, compared to the 2008 base case IRM (see Table 1). The limitations across the Northport-Norwalk Harbor cable were modeled as a function of the availability of Norwalk Harbor generation and the limitations from Eastern PJM system across the Con Edison Hudson-Farragut and Linden-Goethals interconnections continue to be modeled as a function of the availability of Northern New Jersey generation including Linden, Hudson, and Bergen.

Environmental Initiatives

There are two environmental initiatives with the potential to impact the operation and availability of fossil fueled generating plants in New York State as well as IRM requirements. NYS DEC recently enacted regulations to implement the Regional Greenhouse Gas Initiative (RGGI) which, in 2009, will place a limit on CO_2 emissions from fossil fueled generators with a capacity greater than 25 MW in the ten member states. 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 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. Specific plans for the reduction of ambient ozone remain under development and are not expected to be effective in 2009.

RGGI will require most affected generators to own one allowance for each ton of CO_2 emitted. RGGI will effectively make affected fossil fueled units energy limited units for reliability purposes, to the extent that those units will be limited in their operations to the number of RGGI allowances they are able to obtain. The compliance period is three years.

The first sub-regional auction was completed on September 25, 2008 at which 6.7% of the 2009 allowances were sold to 59 entities for $3.07 per allowance. The next auction for 16.7% of the 2009 allowances was planned for December 17, 2008. Four more auctions are planned for 2009. If the new RGGI Allowance market operates under unremarkable circumstances, bulk power system reliability is not expected to be negatively impacted in the near term. If, on the other hand, market disruptions occur or the RGGI market is allowed to converge with the world CO_2 allowance markets, undesirable outcomes will quickly occur. Convergence with world markets would lead to allowance prices in the range of $35 to $50/ton and the likely exit from the marketplace of the coal capacity in New York, which may place significant strain on other resources.

The State Implementation Plan (SIP) to achieve compliance with the ozone standard is currently being reviewed by EPA. The SIP has three design elements that will affect fossil fueled generators in New York State. First is a regional program to budget NOx emissions and provide for tradable NOx Allowances, know as CAIR. This EPA program has been vacated by the U.S. Court of Appeals for the District of Columbia Circuit. A motion for rehearing of the order is pending a decision in that court. The second element is the Ozone Transport Commission (OTC) High Electric Demand Day (HEDD) program to reduce emissions from older peaking units. Third, 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. It is reasonable to plan for potentially significant new NOx emission limitations for fossil fueled generators. Appendix C provides a NYISO report on the analysis of the potential impacts of NOx emission limitations.

To summarize, although the implementation of the RGGI program is occurring for the 2009 calendar year, the NYISO's assessment of potential impacts on energy supply is very low, with complications to the capacity market even smaller. In terms of NOx regulation, several efforts are underway, but none are expected to impact 2009 reliability and IRM requirements.

COMPARISON WITH 2008 IRM STUDY RESULTS

The results of this 2009 IRM Study show that the base case IRM represents an increase of 1.2 percentage points above the 2008 IRM Study IRM value. Table 1 compares the estimated IRM impacts of changing several key study assumptions from the 2008 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 1.2 percentage point IRM reduction from the 2008 Study. The principle drivers that have increased and decreased IRM requirements from the 2008 capability year are:

(1) A decline in NYCA generating unit availability. This factor has *increased* the IRM. Refer to *Resource Capacity Availability* under the "Models and Key Assumptions" section. (See Table 1, Updated Generating Unit EFORs).

(2) An updated load forecast uncertainty model. This factor has *increased* the IRM.

Refer to *Load Forecast Uncertainty* under the "Models and Key Assumptions" section. (See Table 1, Updated Load Forecast Uncertainty Model.)

(3) An 825 MW increase of wind generation capacity. This factor has *increased* the IRM. Refer to *Wind Generation* under the "Models and Key Assumptions" section. (See Table 1, Updated Load Forecast Uncertainty Model.)

(4) An updated Outside World Model. This factor has *decreased* the IRM. Refer to *Outside World Model* under the "Models and Key Assumptions" section. (See Table 1, Outside World Model.)

(5) An updated SCR model. This factor has *decreased* the IRM. Refer to *Special Case Resources* under the "Models and Key Assumptions" section. (See Table 1, Updated SCRs.)

Table 1: Parametric IRM Impact Comparison with 2008 Study

Parameter	Estimated IRM Change (%)	IRM (%)
2008-09 Study – Base Case IRM		**15.0**
Updated Parameters Causing a Higher IRM:		
Updated Generating Unit EFORs	+ 1.5	
Updated Load Forecast Uncertainty Model	+ 0.9	
New Wind Capacity (825 MW)	+ 0.8	
New Non-Wind Units, Retirements & Reratings	+ 0.4	
Updated Existing Unit Capacities	+ 0.3	
Updated EOPs	+ 0.2	
Updated EDRPs	+ 0.1	
Total IRM Increase	**+ 4.2**	
Updated Parameters Causing a Lower IRM:		
Updated Outside World Model	- 1.4	
Updated SCRs	- 0.9	
Updated NYCA Load Forecast	- 0.3	
Updated Cable Outage Rates	- 0.2	
Updated Planned Outages	- 0.1	
Updated Reserve Sharing Model	- 0.1	
	-	
Total IRM Decrease	**- 3.0**	
Updated Parameters Having No IRM Impacts:		
Updated Transmission Topology	--	
Updated External Capacity Purchases	--	
Net Change From 2008-09 Study		**+ 1.2**
2009-10 Study – Base Case IRM		**16.2**

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 2009 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 2009 IRM Impacts and Related NYC and LI Locational Capacities

Case	Case Description	IRM (%)	% Change From Base Case	NYC (%)	LI (%)
0	Base Case	16.2	--	79	97
	2009 IRM Impacts of Major MARS Parameters				
1	NYCA Isolated	21.7	+ 5.5	83	102
2	No Internal NYCA Transmission Constraints	14.5	- 1.7	78	95
3	No Load Forecast Uncertainty	9.7	- 6.5	74	92
4	No Wind Capacity	15.0	- 1.2	78	96
5	No SCRs and EDRPs	17.0	+ 0.8	80	98
	2009 IRM Impacts of Base Case Assumption Uncertainties				
6	Higher Outside World Reserve Margins (+10%)	8.5	- 7.7	73	91
7	Lower Outside World Reserve Margins (-10%)	18.4	+ 2.2	81	99
8	Higher $EFOR_{ds}$	17.9	+1.7	80.3	98.5
9	Lower $EFOR_{ds}$	14.5	-1.7	77.7	95.5
10	Lower NYCA Transmission Limits (-10%)	16.4	+ 0.2	79	97
11	Higher NYCA Transmission Limits on Interfaces with Dynamic Ratings (+10%)	15.0	- 1.2	78	96
12	Higher NYCA 2009 Load Forecast (+340MW)	16.4	+ 0.2	79	97
13	Lower NYCA 2009 Load Forecast (-340MW)	16.0	- 0.2	79	97
14	Alternate LFU Model	16.5	+0.3	79.2	97.2
	Future Year IRM Impacts of Possible System Changes After 2009				
15	HEDD Scenario	28.6	+ 12.4	88	107
16	RGGI Scenario Range	16.5-17.1	+0.3 to + 0.9	79.2-79.7	97.3-97.8
17	Poletti Retirement	16.1	- 0.1	79	97

* Locational Reserve Margin levels computed based on resulting capacity/load ratio.

Due primarily to time and resource constraints, there was no attempt to develop Table 2 sensitivity results utilizing the Tan 45 "inflection point" method. All sensitivity studies 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). In 2009, ICS will examine the appropriate sensitivity study methodology to be used for the 2010 IRM Study.

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

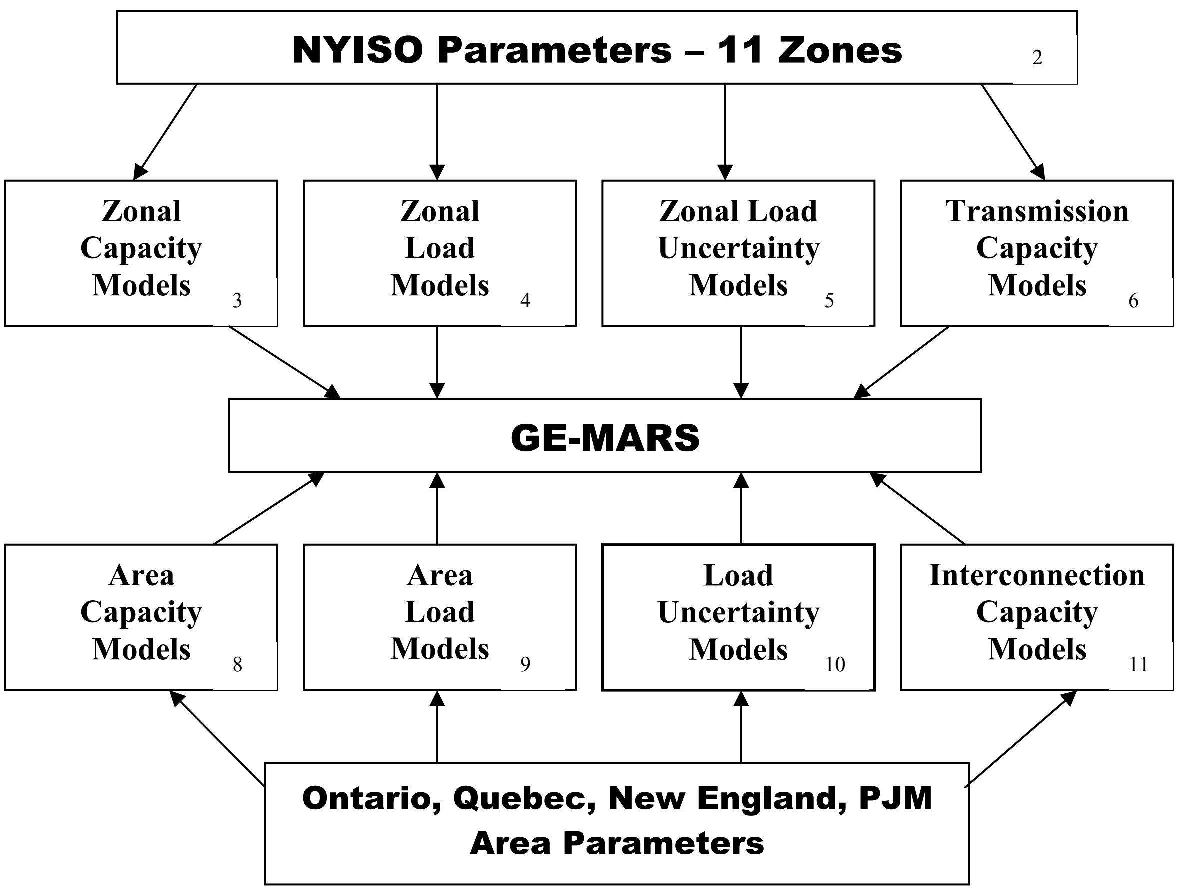


Table A-1: Details on Study Modeling
(Refer to Figure A-1)

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 2008 "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 33,843MW 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

* "2008 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

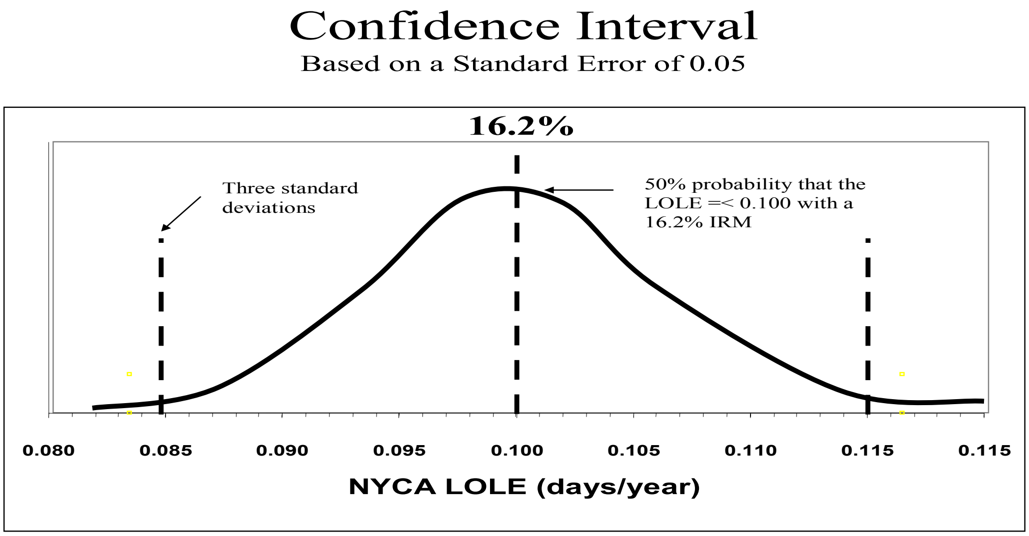
An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical 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 315 replications to converge to a daily LOLE for NYCA of 0.096 days/year with a standard error of 0.05 per unit, which corresponded to an IRM of 16.2% as shown in Figure A-2. 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 15.8% and 16.6% define the % confidence interval. The statistical significance of the 15.8%, 16.2%, and 16.6% 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 1497 replications to converge to a standard error of 0.025. At that point the LOLE for NYCA was 0.100 days/year. If a standard error of 0.025 were used, the band would tighten from 16.0 to 16.4%. It should be recognized that a 16.2% 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 = 0.115 and 0.085 represent 0.100 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 2.92 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

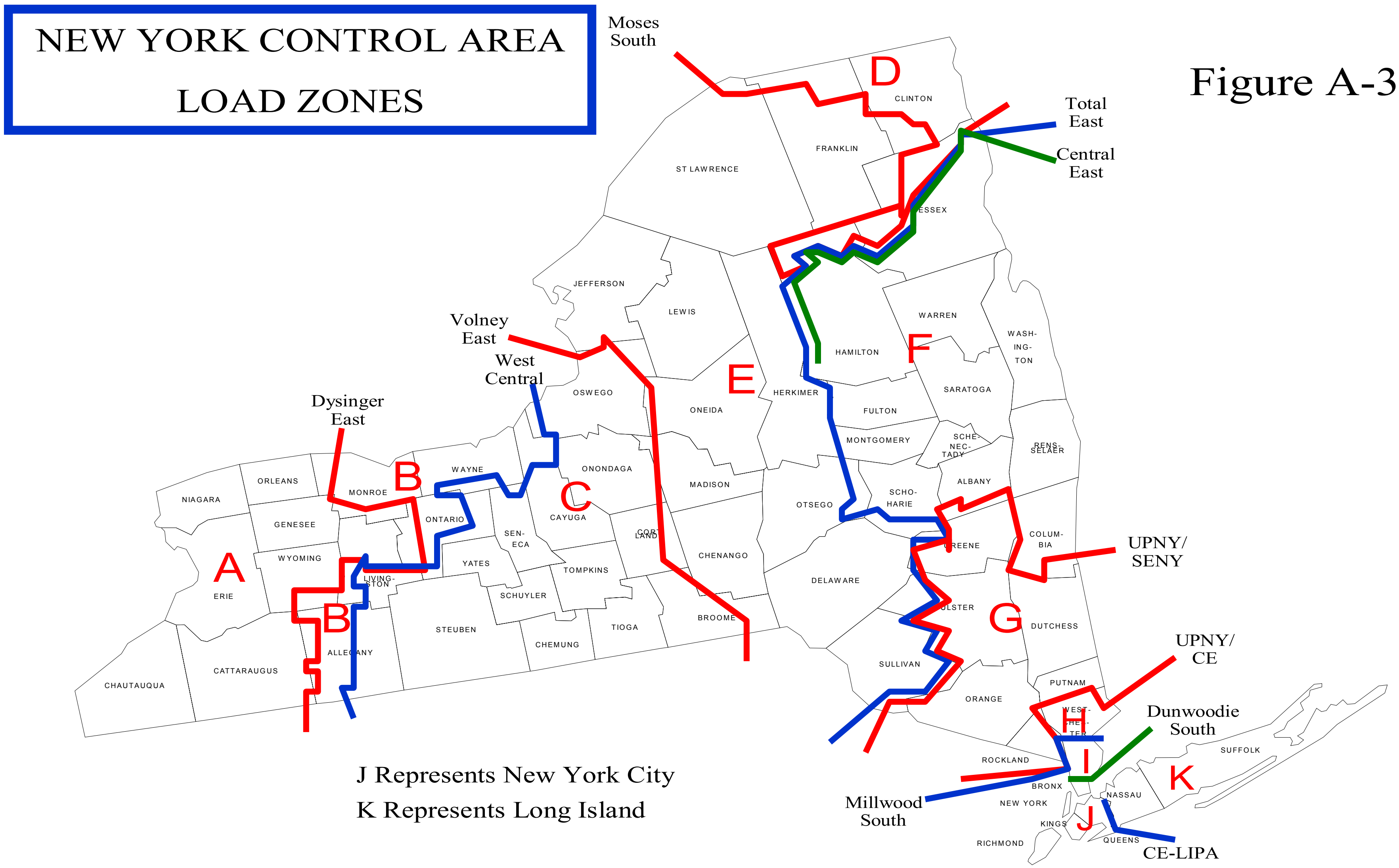


Table A-3: GE Data Scrub*

#	Issue	Disposition	Effect On IRM
1	EFORd > 90% for several Small Units	Units identified as correctly having large EFORd's.	None
2	Planned derates not fully updated.	Update Completed and verified.	None
3	Total East grouping limit in reverse direction does not match transmission topology map.	Topology map corrected. Arrows also added to reflect direction of grouping interface limits.	None
4	External Control Area has excessive gas turbine derates.	Checked with Area, representative group of units used to model derate of total system.	None
5	External contracts add up differently in assumptions matrix.	Assumptions matrix updated to reflect ending of Ontario grandfathered contracts on 12/31/08	None
6	GE could not initially verify EOP steps that involve percent of peaks.	Peak data provided to GEs. GE verified EOP Numbers.	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 16.2%. As shown in Table A-4, the result of approximately 16.2% IRM was determined for "best fit" equations based on 4 points through 12 point segments. The case with a 13 point segment produced an inflection point below the actual IRM/LCR points in violation of 0.1 LOLE criteria. Lastly, the resulting MLCR values described above were increased to the next higher whole integer. The above methodology was adopted by the NYSRC Executive Committee at the November 7, 2007 meeting and was incorporated into Policy 5-2.

Table A-4: Details of TAN 45 Derivation

# of Points		Equation	Resulting IRM	Resulting R^2	Violate 0.1 Criteria
4	NYC Long Island	77.0000x2 - 25.5450x + 2.9065 20.0000x2 - 7.6000x + 1.6770	16.2	99.91	No
5	NYC Long Island	50.8571x2 - 17.3623x + 2.2669 21.4286x2 - 8.0757x + 1.7165	16.3	99.56	No
6	NYC Long Island	35.3571x2 - 12.4488x + 1.8782 27.1429x2 - 10.0357x + 1.8843	16.4	99.24	No
7	NYC Long Island	28.7143x2 - 10.3164x + 1.7075 21.9048x2 - 8.3019x + 1.7412	16.4	99.12	No
8	NYC Long Island	23.2381x2 - 8.5367x + 1.5633 17.5952x2 - 6.8582x + 1.6206	16.4	98.80	No
9	NYC Long Island	18.3333x2 - 6.9230x + 1.4311 14.1602x2 - 5.6937x + 1.5223	16.4	98.59	No
10	NYC Long Island	14.5606x2 - 5.6667x + 1.3270 12.1970x2 - 5.0203x + 1.4648	16.3	98.39	No
11	NYC Long Island	11.8275x2 - 4.7456x + 1.2499 10.5734x2 - 4.4570x + 1.4162	16.1	98.25	No
12	NYC Long Island	9.7053x2 - 4.0220x + 1.1886 9.2937x2 - 4.0078x + 1.3770	15.9	98.16	No

A-5 Input Data and Models

A-5.1 Base Case Modeling Assumptions

Table A-5 summarizes the major assumptions used in the 2009 Study:

Table A-5: Base Case Modeling Assumptions for 2009 NYCA IRM Study

Parameter	2008 Study Modeling Assumptions	2009 Study Modeling Assumptions	Described in following section
NYCA Load Model			
Peak Load	October forecast: • 33,730 MW for NYCA, • 11,955 MW for Zone J • 5,460 MW for Zone	October forecast: • 33,843MW for NYCA • 12,009MW for Zone J • 5,441MW 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	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	Section A-5.3
New Generation Units	Gold Book (table III) units plus • Prattsburgh Wind Park - 55 MW (11/07) • Gilboa unit 2 uprate of 30 MW (6/07)	• See section A-5.3 • 1,208.7 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	• Lovett 3, 4, 5 (404.8 MW) • Russell Station (236.4 MW) • Huntley 65 & 66 (165 MW) • Ogdensburg (76.7 MW)	• None known for 2009 Capability Year	Section A-5.3
Availability & Maintenance			
Forced & Partial Outage Rates	5-year (2002-06) GADS data (Those units with less than five years data will use available representative data.)	5-year (2003-07) 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
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

Parameter	2008 Study Modeling Assumptions	2009 Study Modeling Assumptions	Described in following section
Gas Turbines Ambient Derate	The derate model was updated after analyzing historical performance	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	• 1323 MW sold; • modeled as 1205 MW.	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.	Section A-5.3
EDRP Resources	• 430 MW registered; • modeled as 193.5 MW	• 365 MW registered; • modeled as 160 MW	Section A-5.3
External Capacity	2,921 MW total: • 1200 from HQ, • 50 from NE, • 1300 from PJM, • 205 from Ontario, 166 MW from Cedars	3046 MW total: • 1200 from HQ, • 50 from NE, • 1280 from PJM, • 350 from Ontario (350 MW HQ wheel), • 166 MW from Cedars	Based on NYISO forecast. Section A-5.3
Emergency Operating Procedures	1503 MW load relief excluding SCR and EDRP values	1411 MW load relief excluding SCR and EDRP values	Section A-5.4
Transmission System Model			
Interface Limits	Based on 2007 Operating Study, 2007 Operations Engineering Voltage Studies, 2007 Comprehensive Planning Process, and additional analysis.	Based on 2008 Operating Study, 2008 Operations Engineering Voltage Studies, 2008 Comprehensive Planning Process, and additional analysis.	Section A-5.5
New Transmission Capability	• Introduction of Millwood Capacitor bank, • Neptune line including EGC to Newbridge to Ruland Road • Mott Haven substation • NUSCO 1385 cable reconductoring Completion of Bethel to Norwalk 345Kv	None Identified as new for this study.	Section A-5.5
Transmission Cable Forced Outage Rate	All existing Cable EFORs updated on LI and NYC (based on 2002-2006 availability with adjustment to NUSCO cable due to reconductoring	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Section A-5.5
Unforced Capacity Deliverability Rights (UDRs)	Dummy zone in NY attached to zone K and NE with 330 MW tie and 330 MW of NE units in dummy zone (for CSC).	LIPA has notified the NYISO that the amount of UDR's for the Neptune Cable and Cross Sound Cable is confidential data.	Per transmission owner notification

Parameter	2008 Study Modeling Assumptions	2009 Study Modeling Assumptions	Described in following section
Other Modeling Considerations			
GE-MARS computer Model Version	Version 2.83	Version 2.92	Section A-2
Outside World Area Models	Updated models for PJM and NE to include zonal representations	Single Area representations for Ontario and Quebec. Three 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 assist each other first; US Control Areas assist each other first.	Canadian Provinces have indicated that they will share reserves equally among all.	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 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 2008 which they recommended for use in the 2009 IRM study. This forecast was based upon weather-normalized peaks load in 2006, 2007, and 2008 for each of the TOs, NYPA, and other NY municipalities for the hour of the NYISO coincident peak.

The 2009 forecast was produced by applying regional load growth factors (RLGFs) to each TO's weather-normalized peak for the summer of 2008. Where possible, the RLGFs were based upon new economic outlooks prepared by the TOs. Otherwise, the most recent data from Economy.com was used to adjust the RLGFs used in the 2008 ICAP forecast.

The final NYSRC forecast is based upon the most recent data available for the IRM study that maintains the schedule for the IRM study, as shown in Table A-6 on the following page.

Table A-6: 2009 NYCA Area Peak Load Forecast

Summary of 2007 & 2008 Results

Transmission District	2007 Weather Adjusted MW	2008 RLGF - Forecast	2008 ICAP Forecast - MW	2008 Weather Adjusted MW	MW Over/ Under	2008 RLGF - Actual
Central Hudson	1,191	1.0190	1,214	1,201	-13	1.0084
Con-Edison	13,684	1.0166	13,911	13,767	-144	1.0061
LIPA	5,306	1.0101	5,359	5,304	-55	0.9996
Niagara Mohawk	6,763	1.0000	6,763	6,693	-70	0.9896
NYPA	593	0.9763	579	573	-6	0.9663
NYSE&G	3,104	1.0120	3,141	3,108	-33	1.0013
O&R	1,164	1.0244	1,192	1,180	-12	1.0137
RG&E	1,639	1.0060	1,649	1,632	-17	0.9957
NYCA Total	33,444	1.0109	33,808	33,458	-350	1.0004

2009 Final Forecast
for NYSRC Installed Reserve Margin Study

Transmission District	2008 Weather Adjusted MW	Regional Load Growth Factors	NYSRC 2009 Forecast - MW	Difference in MW	2008 Gold Book Forecast for 2009
Central Hudson	1,201	1.0125	**1,216**		
Con-Edison	13,767	1.0166	**13,996**		
LIPA	5,304	1.0149	**5,383**		
Niagara Mohawk	6,693	1.0000	**6,693**		
NYPA	573	1.0052	**576**		
NYSE&G	3,108	1.0070	**3,130**		
O&R	1,180	1.0244	**1,209**		
RG&E	1,632	1.0050	**1,640**		
NYCA	33,458	1.0115	**33,843**	-324	34,167

Locality Peaks	NYSRC 2009 Forecast - MW	Difference in MW	2008 Gold Book Forecast for 2009
New York City	**12,009**	-126	12,135
Long Island	**5,441**	-43	5,484

Load Shape Analysis

The 2009 IRM study was performed using a load shape based on 2002 actual values. The 2002 load shape was compared to load shapes from 1999 through 2007. The conclusion reached this year was the same as in previous years - that the 2002 load shape is best suited for the IRM study.

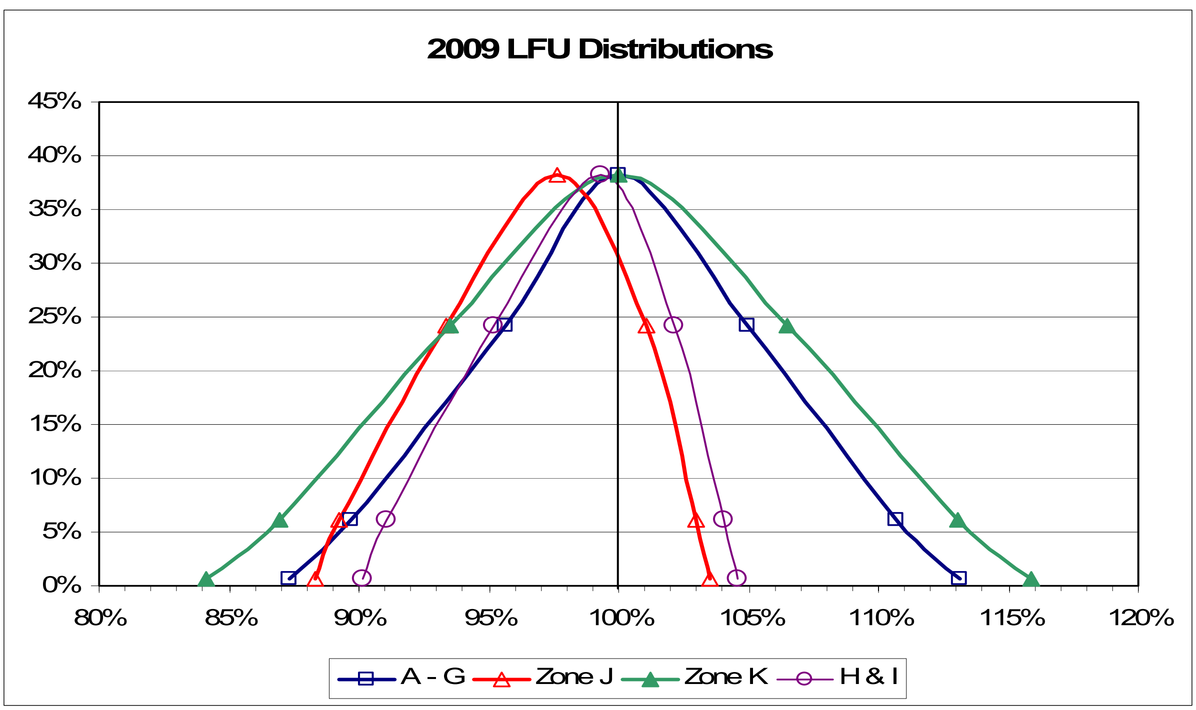
A-5.2.1 Zonal Load Forecast Uncertainty

The process followed in this and previous years is for LIPA and Con-Ed to provide Load Forecast Uncertainty (LFU) models to the Installed Capacity Subcommittee (ICS) for their respective Transmission Districts, and for the NYISO to develop an LFU model for the rest of the state. 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. The MARS program computes LOLE for each of the per-unit level ("Bin Number") shown on table A-7 (below) by multiplying the load from the zonal hourly load shape model (see Section A-5.2) times each of the per unit levels shown. MARS next accumulates the hourly LOLE hits for each per-unit level on an annual basis and weights the resulting LOLE based on the probability or likelihood shown. Lastly, the sum of the probability weighted LOLEs for all the Bin Numbers are calculated to obtain the final LOLE associated with each replication.

Table A-7: 2009 Load Forecast Uncertainty Models

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.6%	87.3%	90.1%	88.3%	84.2%
2	6.1%	89.7%	91.1%	89.3%	87.0%
3	24.2%	95.7%	95.2%	93.4%	93.5%
4	38.2%	100.0%	99.3%	97.6%	100.0%
5	24.2%	104.9%	102.1%	101.1%	106.5%
6	6.1%	110.7%	104.1%	103.0%	113.0%
7	0.6%	113.2%	104.6%	103.5%	115.8%

Figure A-4: 2009 LFU Distributions



The LIPA model is only marginally different from that used in 2008. The Con Edison LFU models for Zones H, I & J model reflect the fact that the load forecast in these zones have a 1 in 3 probability of occurrence (67th percentile) instead of 1 in 2 probability (50th percentile) as is the case elsewhere in the state.

The approach developed by the NYISO in 2006 for Zones A to G was maintained in the 2009 IRM study. The LFU models for these zones were developed by estimating weather response functions, with due consideration of its behavior both below and above design conditions. The NYISO's 2009 LFU results are similar to its 2008 results, except for the treatment of the highest and lowest bins. The NYISO followed the approach recommended by LIPA, which is to truncate the distribution of the weather variable at the tails. This has the effect of reducing the overall bandwidth across the 7 bins. The rationale for this is that only 30 years of weather data are available, but 100 years would be needed to determine the extremes empirically.

The development of load forecast uncertainty models is complicated by two factors. First, there is a paucity of data at extremely high summer weather conditions. In cool years, temperatures may not even reach, let alone exceed, design conditions. Second, the response of electric demand to temperature and humidity is non-linear.

There is sufficient evidence to show that load response always increases with temperature during the summer. Below design conditions, the response accelerates due to thermal build-up in buildings as well as human behavioral factors. As peak load conditions are approached and surpassed, the weather response decelerates because HVAC equipment reaches full load operation and the diversity factors and duty cycles of the universe of electric motors begin to converge. As a result, load response tends to flatten or saturate.

The methodologies used by LIPA and the NYISO to estimate the load forecast uncertainty are essentially the same, although some details in execution and results are different.

A-5.2.1.1 Supplemental Zonal Load Forecast Uncertainty Discussion

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, the LFU model is subdivided into four areas: Zones H and I, Zone J (NYC), Zone K (LI), and Zones A-G (the rest of New York State).

The process followed in this and previous years is for transmission owners of zones H, I, J, and K to provide Load Forecast Uncertainty (LFU) models to the Installed Capacity Subcommittee (ICS) for their respective Transmission Districts, and for the NYISO to develop an LFU model for the rest of the state. As a matter of practice, the NYISO develops its own estimates of LFU for the zones H, I, J, and K and compares its results to those of the Transmission Owners. During the course of its LFU review in 2007 and 2008, the NYISO noted that its methods and results were in close correspondence to zone K but significantly different than zones H, I, and J.

The LFU received from the H, I and J Transmission Owner had slightly higher upper load levels than last year's, but lower than the NYISO would have expected. In light of this discrepancy, the ICS will encourage the LFTF to work this issue through in 2009.

All else equal, the effect on reliability of wider bandwidths and higher per-unit loads in the upper bins would tend to increase the number of occurrences of loss of load events and ultimately result in a higher installed reserve margin. This was confirmed by testing.

As requested by the Chair of the ICS, the NYISO will work to produce an LFU method and procedures report to the ICS for its review and consideration that further define this method. The NYISO will also present this methodology to the NYISO's Load Forecasting Task Force for review and discussion. If acceptable to the ICS, the NYISO may wish to recommend to the NYSRC that this method be included in Policy 5-2 Procedure for Establishing New York Control Area Installed Capacity Requirements.

The following analysis and sensitivity case L2 demonstrates how the change in the 5th bin for Zones H, I, and J and the large decrease in the last bins of zones A and G led to changes in the IRM. This result is consistent with a sensitivity case in which 2009 LFU models were replaced by 2008 models. Therefore, the increase of 0.9% in the IRM appears to be due primarily to the changes in the zones H, I, and J LFU Models.

In the table below, the LFU models in 2008 and 2009 are shown on the left. Beneath them is percentage change from 2008 to 2009. To the right of each LFU Model tables are the MW values obtained by multiplying the 2009 forecast by the per-unit MW values in each probability bin. The table on the bottom right is the difference between the two tables above it, with positive values indicating an increase in MW for that bin in 2009 compared to 2008. No MW values are shown for the three lowest bins because there are seldom if ever any loss-of-load events at these load levels.

Table A-8: MW Comparison of 2008 & 2009 LFU Models

2008 Load Uncertainty Models -Base Case

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.0062	0.8410	0.8530	0.8710	0.8390
2	0.0606	0.8940	0.8780	0.8860	0.8680
3	0.2417	0.9470	0.9160	0.9190	0.9340
4	0.3830	1.0000	0.9640	0.9640	1.0000
5	0.2417	1.0490	1.0000	1.0000	1.0660
6	0.0606	1.0980	1.0330	1.0230	1.1310
7	0.0062	1.1470	1.0590	1.0330	1.1600

2009 MW Distributed into 2008 LFU Models

Probability	A - G	H & I	Zone J	Zone K
0.0062	12,115	1,695	10,460	4,565
0.0606	12,879	1,744	10,640	4,723
0.2417	13,642	1,820	11,037	5,082
0.3830	14,406	1,915	11,577	5,441
0.2417	15,112	1,987	12,009	5,800
0.0606	15,818	2,052	12,286	6,154
0.0062	16,524	2,104	12,406	6,312

2009 Load Uncertainty Models -Base Case

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.0062	0.8730	0.9010	0.8830	0.8420
2	0.0606	0.8970	0.9110	0.8930	0.8700
3	0.2417	0.9570	0.9520	0.9340	0.9350
4	0.3830	1.0000	0.9930	0.9760	1.0000
5	0.2417	1.0490	1.0210	1.0110	1.0650
6	0.0606	1.1070	1.0410	1.0300	1.1300
7	0.0062	1.1320	1.0460	1.0350	1.1580

2009 MW Distributed into 2009 LFU Models

Probability	A - G	H & I	Zone J	Zone K
0.0062	12,579	1,791	10,608	4,579
0.0606	12,918	1,809	10,720	4,732
0.2417	13,782	1,891	11,212	5,087
0.3830	14,406	1,974	11,727	5,441
0.2417	15,116	2,029	12,137	5,795
0.0606	15,942	2,067	12,366	6,150
0.0062	16,303	2,077	12,427	6,303

2009 Increase/Decrease in Bin Per-Unit MW

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.0062				
2	0.0606				
3	0.2417				
4	0.3830	0.0000	0.0295	0.0125	0.0000
5	0.2417	0.0003	0.0215	0.0106	-0.0009
6	0.0606	0.0086	0.0076	0.0067	-0.0007
7	0.0062	-0.0153	-0.0133	0.0018	-0.0016

2009 Increase/Decrease in Bin Per-Unit MW

Probability	A - G	H & I	Zone J	Zone K
0.0062				
0.0606				
0.2417				
0.3830	0	59	150	0
0.2417	4	43	127	-5
0.0606	124	15	80	-4
0.0062	-220	-26	22	-9
Sum	-92	90	379	-17

NYCA MW	Zones A - G MW	Zones H & I MW	Zone J MW	Zone K MW
33,843	14,406	1,987	12,009	5,441

Examining the 2009 MW increase / decrease results, we see that there are net increases in the two zones provided by the zones H, I, and J model, that the zone K model is virtually unchanged, and that the NYISO model for Zones A-G has a net decrease.

The NYISO and transmission owners have begun the process of exchanging information and methods on development of improved LFU models. However, given time constraints, separate results were not available for Zone J and Zones H & I, which are required in order to conduct the IRM study.

A-5.3 NYCA Capacity Model

2008 "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:**
  - **None**

- **New Units: (Units installed during 2008)**
  - Gilboa Station 1 uprate 30 MW Zone F
  - Noble Wind Units:
    - Bliss 101 MW Zone A
    - Ellenburg 81 MW Zone D
    - Clinton 100.5 MW Zone D

- **Planned Units for 2009:**

  (These units had a signed interconnection agreement by August 1, 2008.)
  -
  - Caithness 310 MW Zone K
  - Albany Landfill 2 MW Zone F
  - Co-op City (River Bay) 45 MW Zone J
  - DANC 4.8 MW Zone E
  - Clinton 4.8 MW Zone D
  - Hyland 4.8 MW Zone B
  - A set of wind units* 885 MW Various

* The total amount of wind in the model is 1208.7 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 42,050 MW. This figure is net of 303 MW of sales, includes SCRs, but does not include short term ICAP purchases as described later in this section under the heading of "External Installed Capacity from Contracts". For zone J there are 10,702 MW, and for zone K there are 6,153 MW.

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 2008 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 2009 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 2003 through 2007. 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 1993 through 2007 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 1,208.7 MW 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

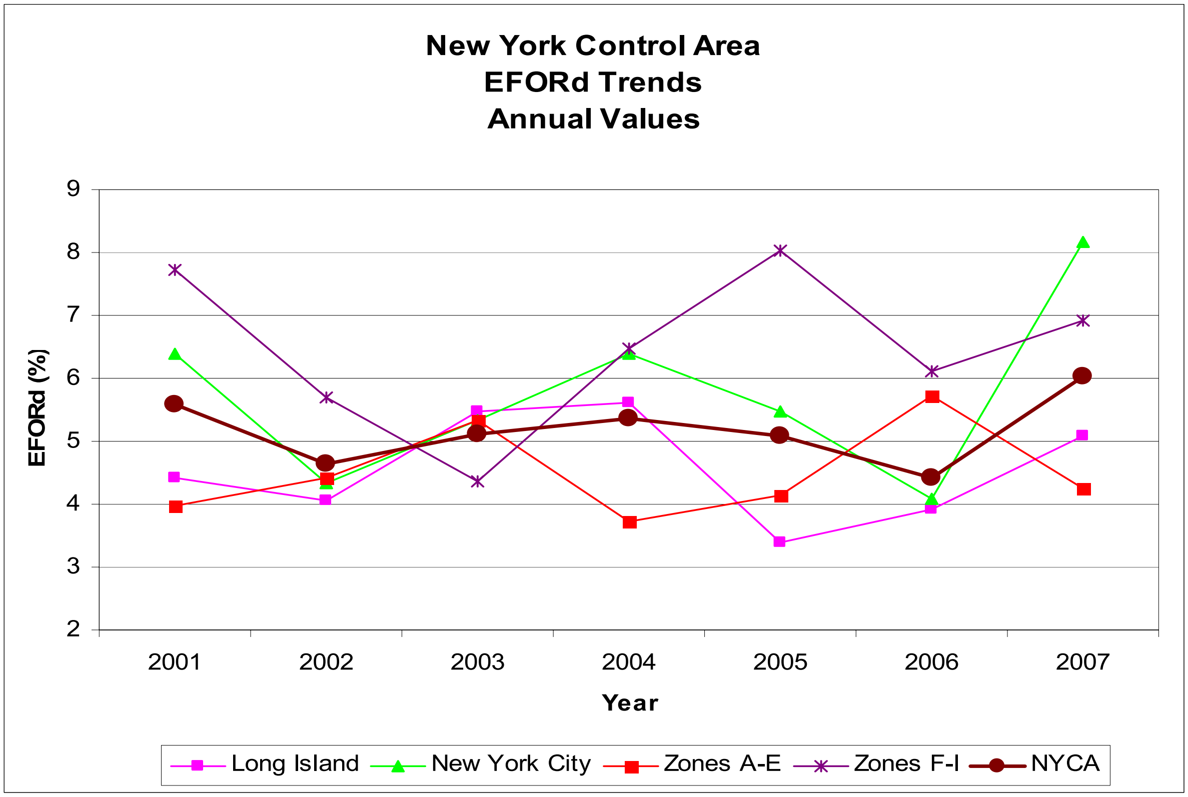
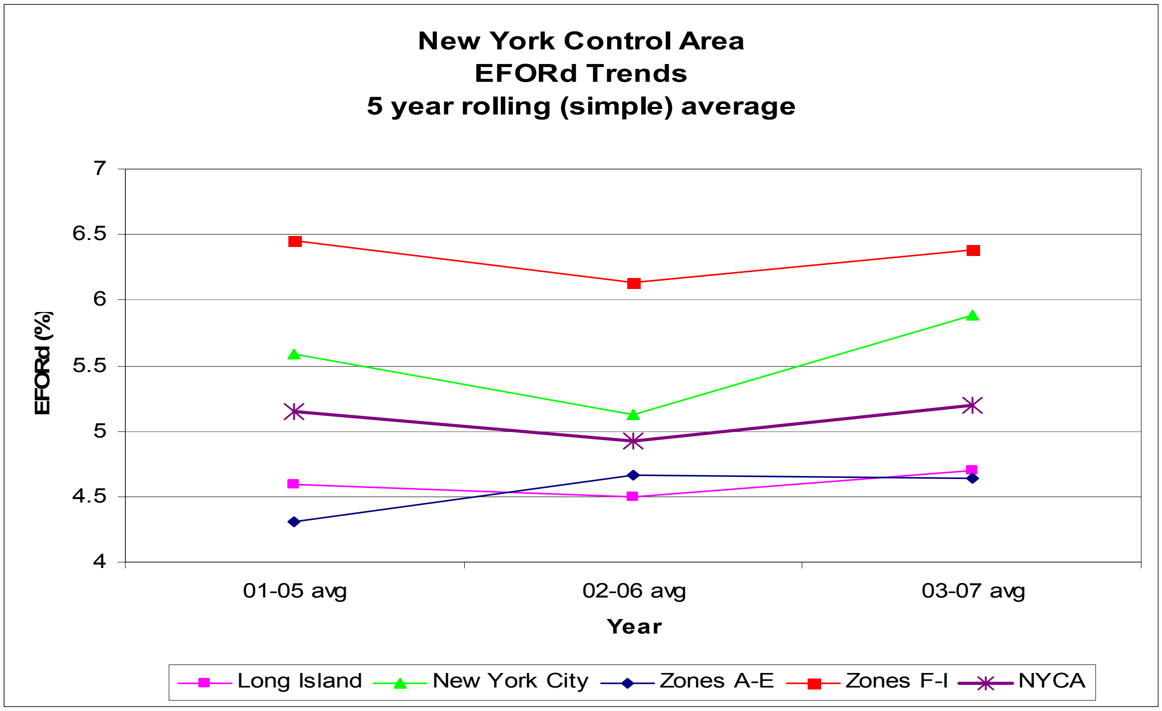


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate. Figure A-6 shows five year rolling averages for EFORd.

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

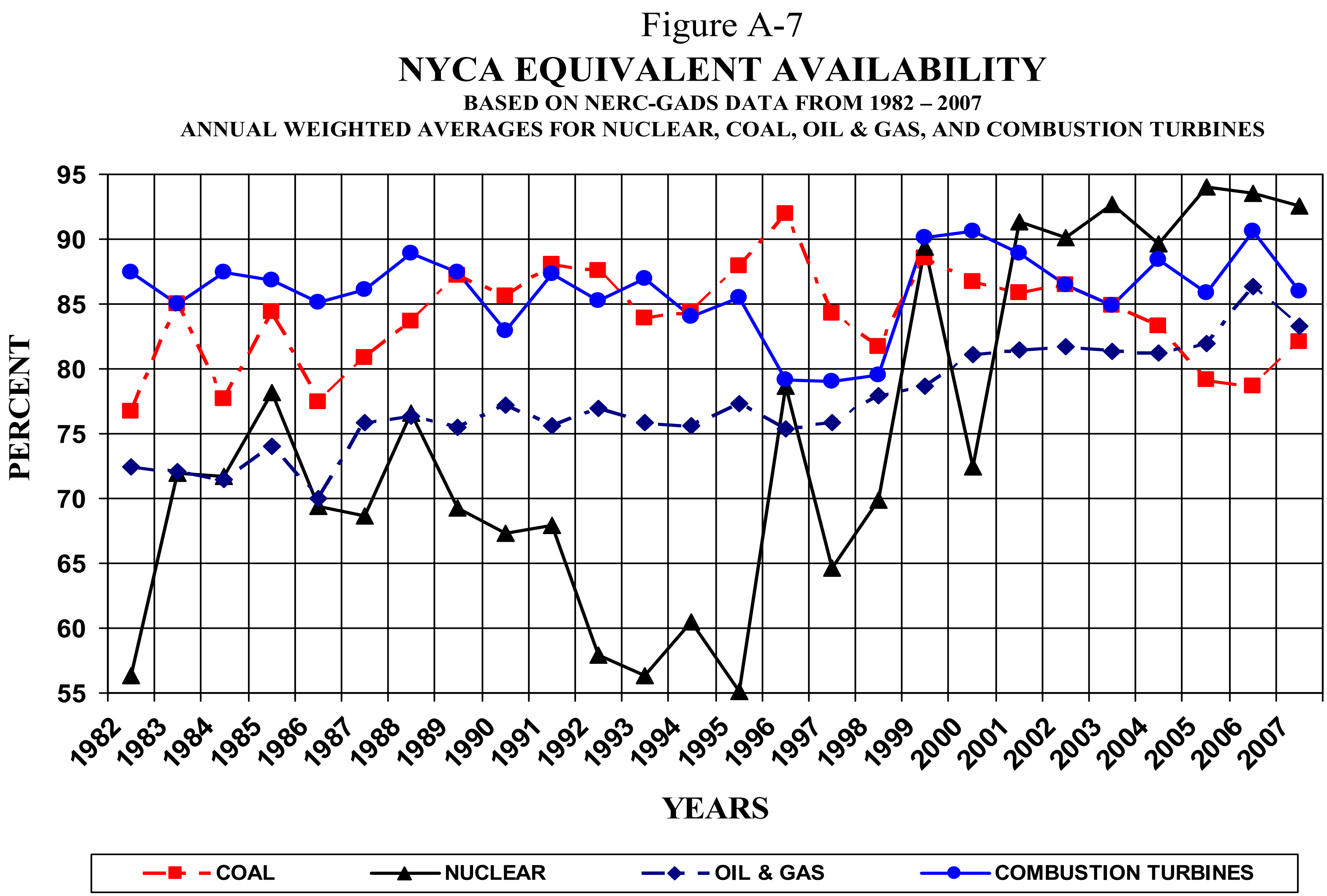


Figure A-8: NYCA Equivalent Availability - 5 Year Rolling Average

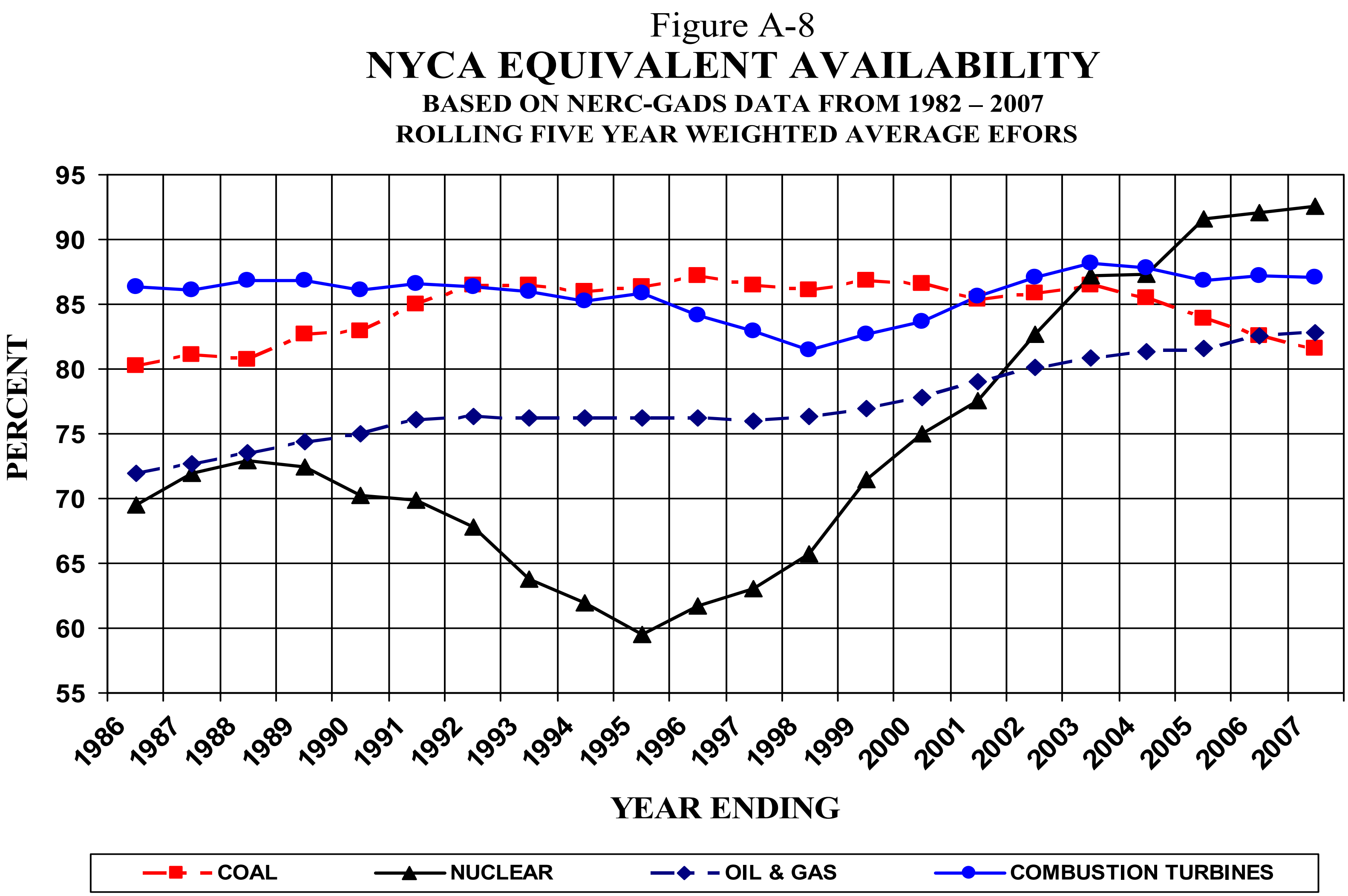


Figure A-9: NERC Region Equivalent Availability

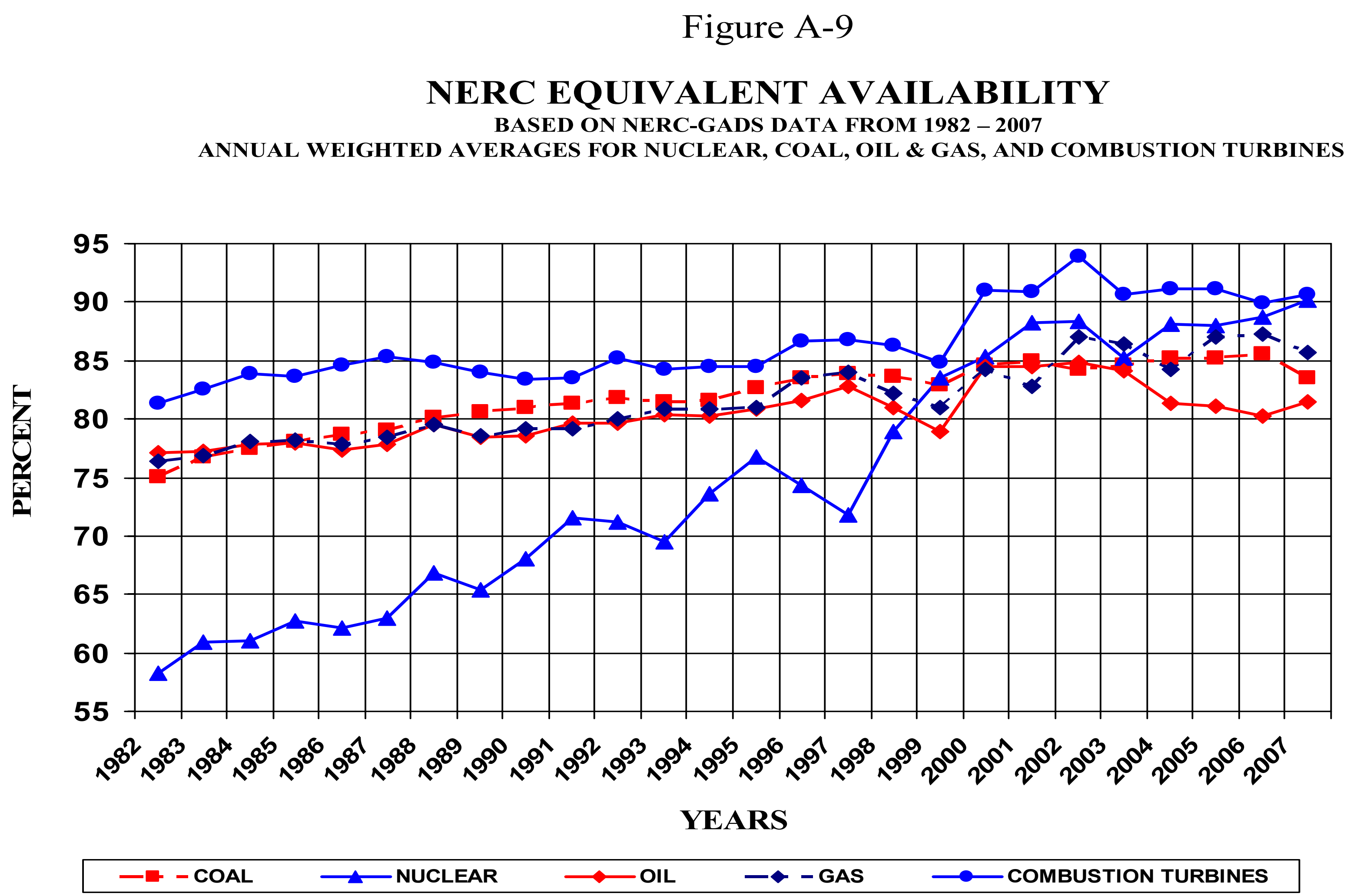


Figure A-10: NERC Region Equivalent Availability – 5 Year Rolling Average

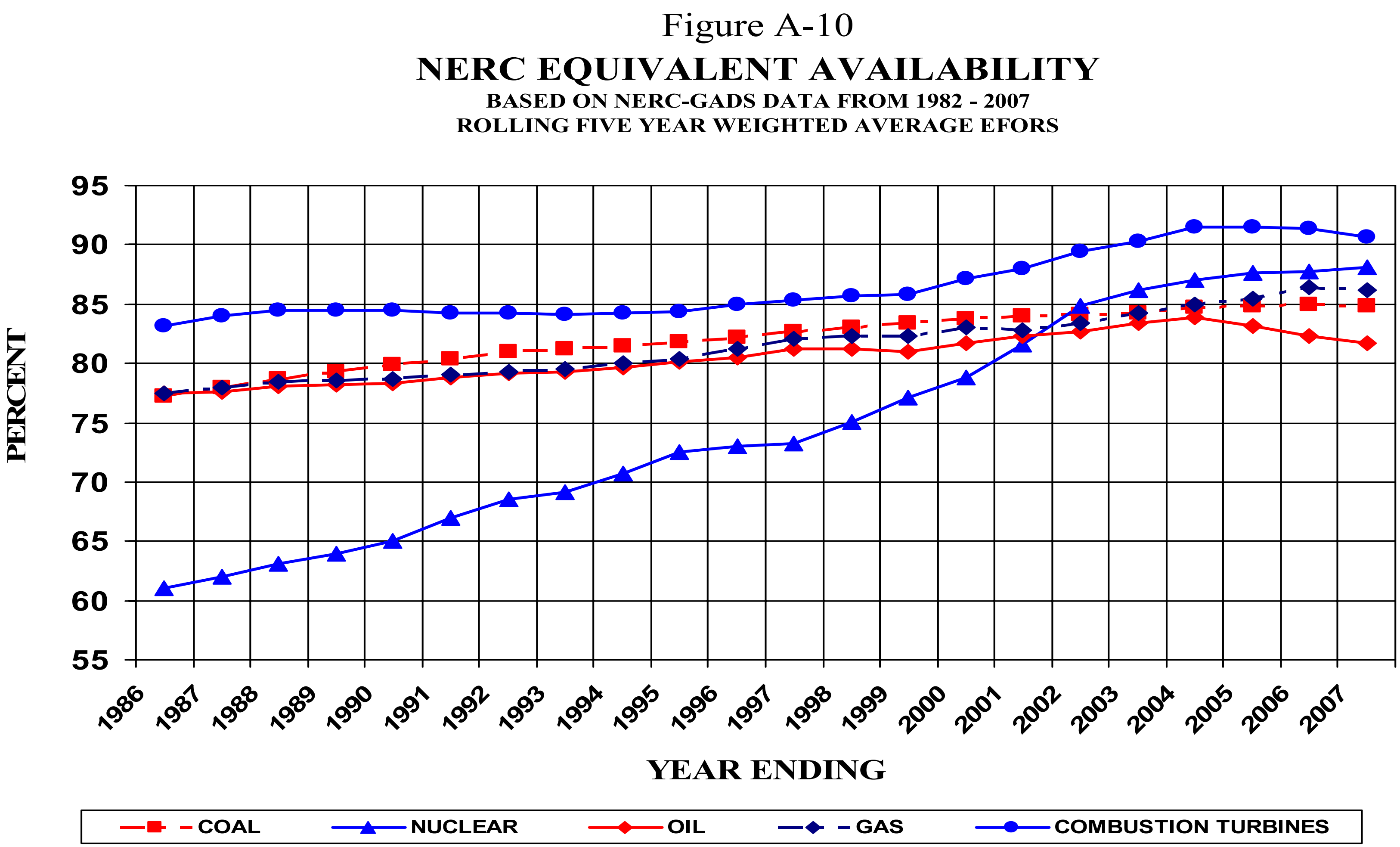


Figure A-11: Planned & Maintenance Outage Rates

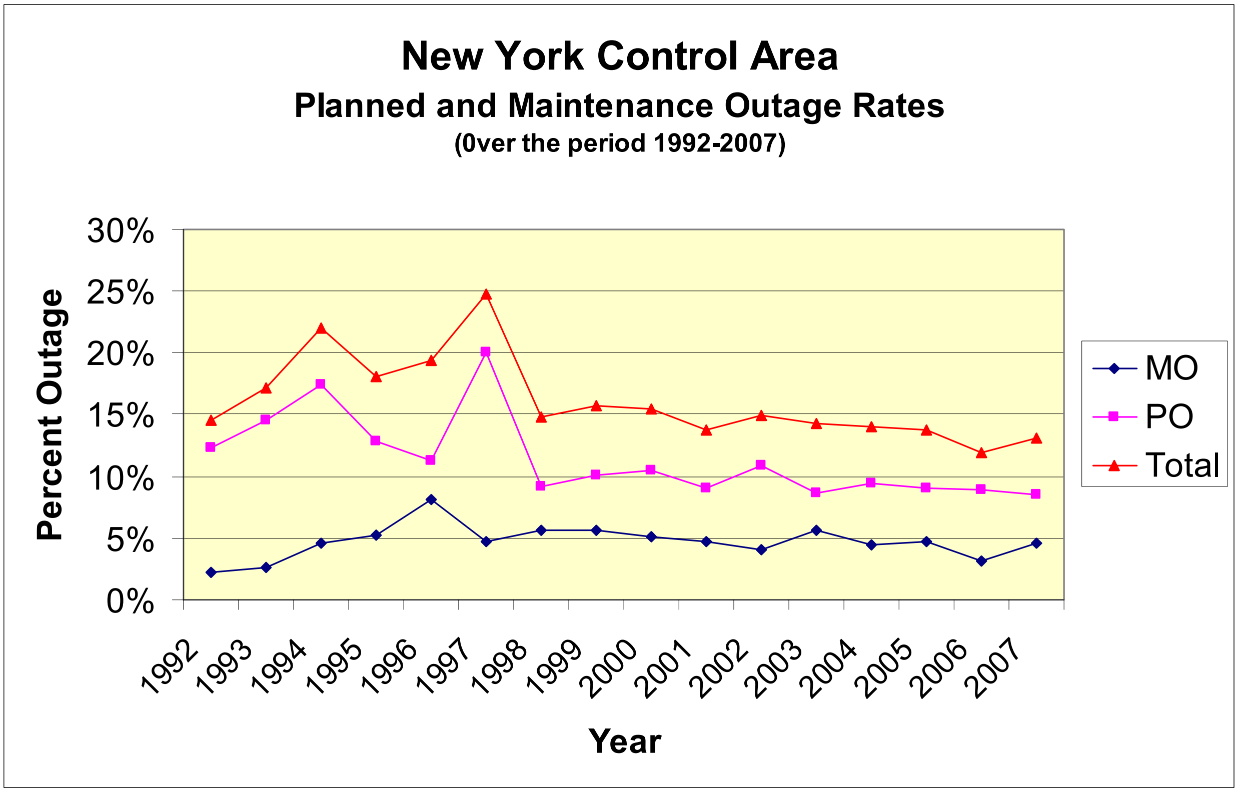
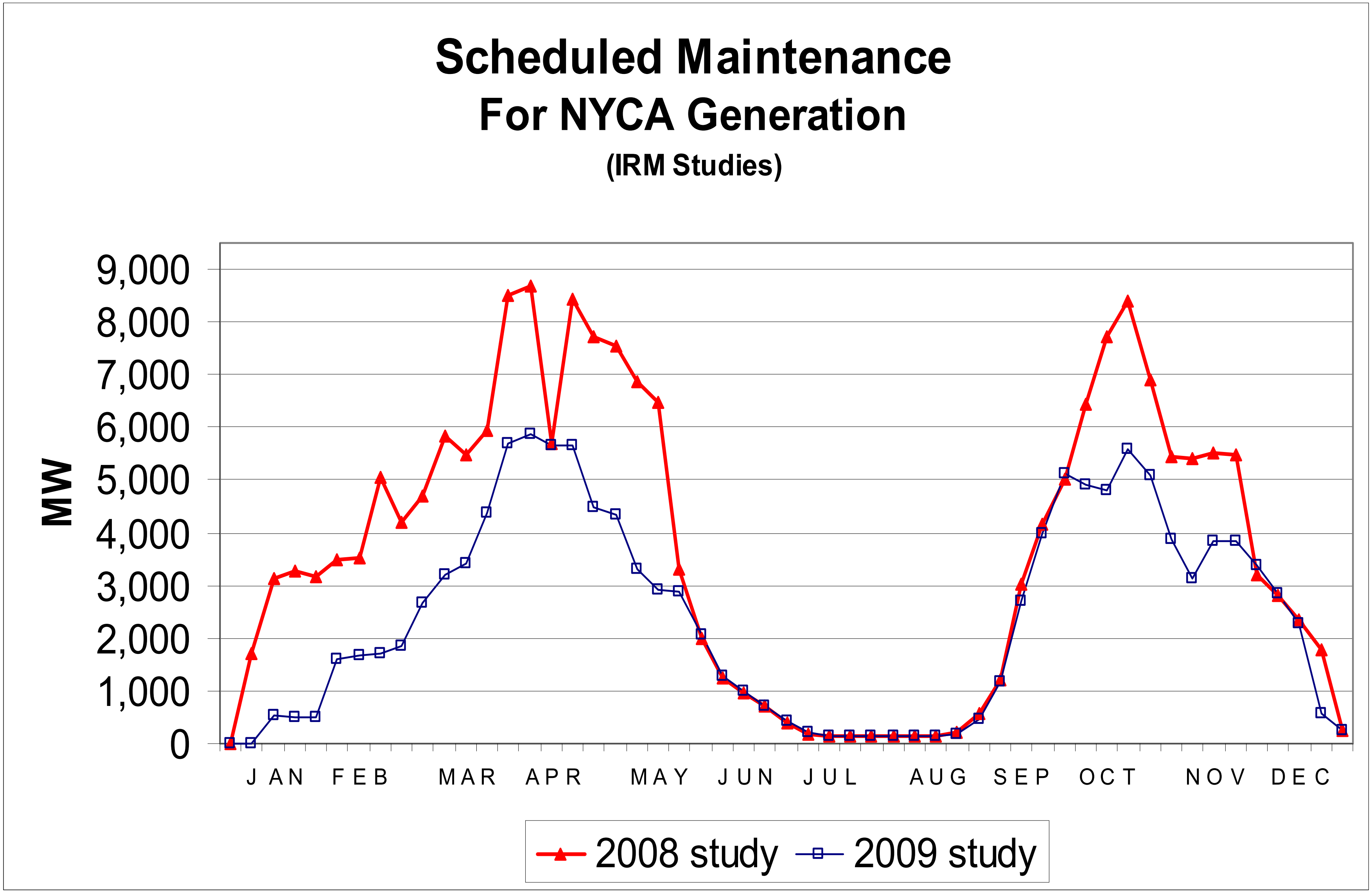


Figure A-9 shows the historic percentage of planned and maintenance outage hours for the years 1992 through 2006.

Figure A-10 shows the amount of capacity assumed to be scheduled out in the 2008 and 2009 studies.

The planned outages in the current study over the 2009 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 gas 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 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:

	July	Aug
Rest of State	0.9561	0.9577
Zone J	0.8805	0.8829
Zone K	0.8933	0.8938

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 June through August, the values are 2,147 MW, 2107 MW, and 2084 MW, respectively. These values are the result of applying three year historic growth rates to the latest participation numbers. Of the 2,107 MW of SCRs modeled in June, 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 160 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 365 MW.

External Installed Capacity from Contracts:

An input to the study is the amount of NYCA installed capacity that is assumed located outside NYCA. Some of this capacity is grandfathered. The balances of contracts are based on a NYISO forecast that reflects historical contracts and current contractual activity.

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

> The base case assumes the following summer external ICAP: 350 MW from Ontario (350 MW HQ wheel), 1200 MW from HQ, 50 MW from New England, 166 MW from Cedars and 1280 MW from PJM. This totals 3,046 MW of expected summer external ICAP.

All firm sales are modeled as listed in the 2008 Gold Book for the year 2009.

In calculating the IRM, all sales are subtracted from the Installed capacity. Purchases are not included.

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	2107 MW*
2	Emergency Demand Response Programs (EDRPs).	Load relief	365 MW**
3	5% manual voltage Reduction	Load relief	80 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	514 MW***
6	Voluntary industrial curtailment	Load relief	129 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 2,107 MW.*
** *The EDRPs are modeled as 365 MW discounted to 160 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 2009 peak load of 33,843 MW.*

The above values are based on a NYISO forecast that incorporates 2007 operating results. This forecast is applied against a 2009 peak load forecast of 33,843 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 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 increased from 3925 MW to 4000 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.

The Southwest Connecticut interface was increased from 1100 MW to 2350 MW to reflect system upgrades in New England.

The Moses South interface was reduced from 2,900 MW to 2,600 MW based on different base case flow patterns.

<u>Changes in Topology and Interface Groupings</u>

With the installation of the 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.

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 2009 IRM Modeling

Interface Name		2008 Limit	2009 Limits, Base Case	Comments
PJM Interfaces		Three Area	Maintain Three Area, RECO Load Treatment	PJM provided updates through MARS database update. Limits reviewed by NYISO. Limits maintained to reflect potential internal limits.
PJM Cent to East	+	6500	6500	
	-	6500	6500	
PJM West to Cent	+	4000	4000	
	-	4000	4000	
Moses South	+	2,900	2,600	Base Case Flow Changes
	-	1,600	1,600	
Dysinger East	+	2,600	2,200	Voltage Limited, Tested for simultaneous Flow from Ontario and PJM
	-	1,999	1,999	
I into J	+	3925	4000	Updated Ratings, Power Flow Analysis with MVA ratings, and improved flow balancing
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				
NE/NY	+	1550	1200	New England bubble diagram reduced. Limits extracted from New England 2008 Analyses for Interface Limits for use in Transportation Models with simultaneous impacts
	-	1750	1525	
Southwest Connecticut	+	1100	2350	
	-	1100	2350	

A. **Dysinger East** – Tested for simultaneous flow from Ontario, PJM, and Zone A to zones GHI, Ontario and Zone A to zones GHI, Ontario and Zone A to PJM and zones GHI. The model was also tested with Ginna in and out of service in the load flow sensitivity. Thermal limits varied with shift assumptions but voltage limit is more controlling. West Central and Dysinger East interfaces were tested together and Dysinger East limit was implemented.

B. **Astoria West** - Unit Sensitive Model, Four Astoria West GTs are in a Separate Area, with a unit sensitive limit combined with a load level of 10,250 in Zone J. This limit starts at 200 MW and reduces to 30 MW for four condition sets built from the combinations resulting when considering all three NYPA CC units available, and two or three of the Astoria units (3, 4, or 5) out of service.

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 +0.4 K to PJM East

ii. Derivation of 0.4 coefficient: Analysis was performed to determine the transfer limit at the DC at full output and zero output and a linear relationship was assumed:

(576 MW – 306 MW) / 660 MW = 0.4

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 306, up to the present 576 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 393 MW reduction in the Western LI export limit and a reduction in the K to J (Jamaica Export) limit of 160 MW, giving a ratio of approximately 0.91 and 0.37, 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.

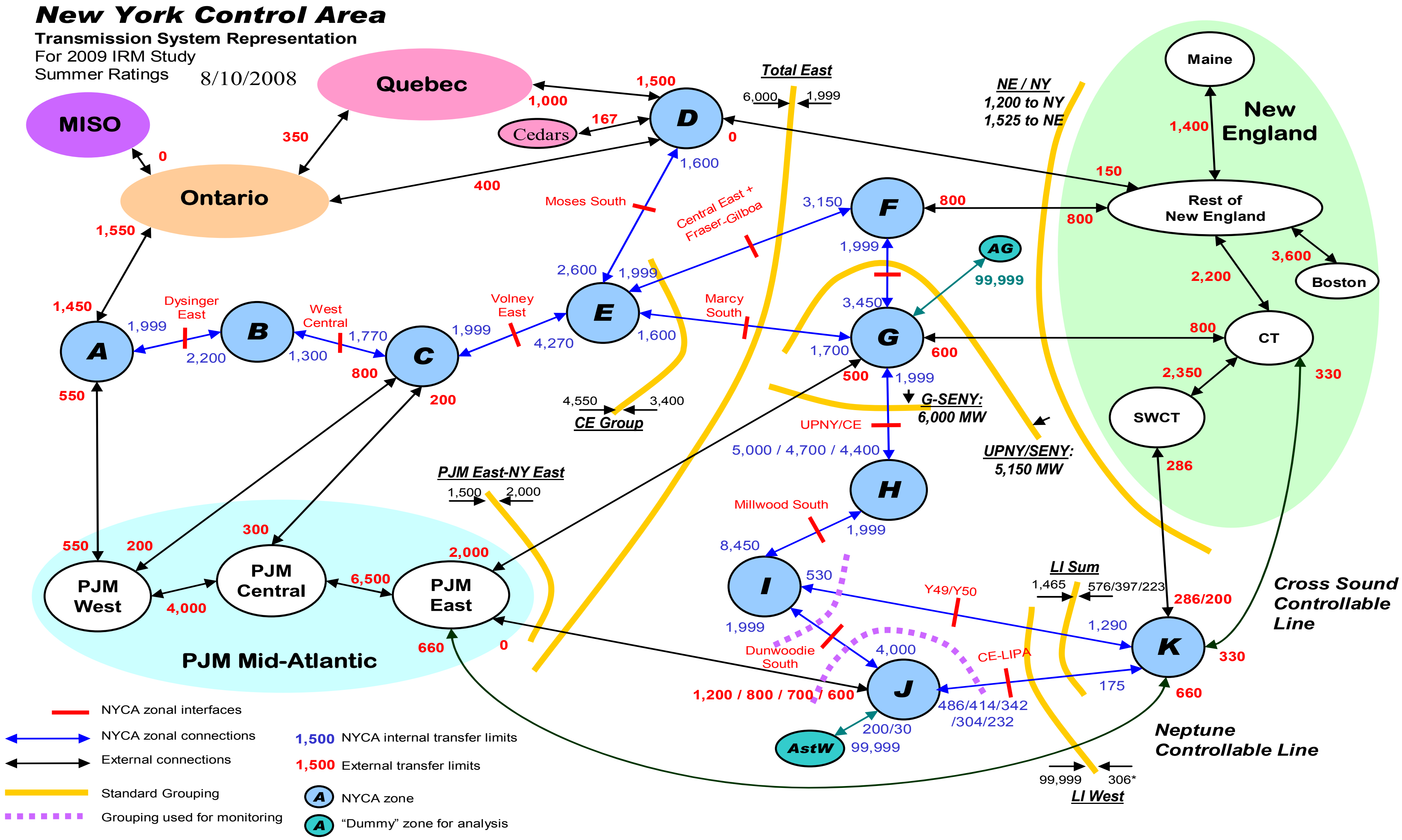
E. Impacts Interface K to J (Jamaica Export) and LISUM). Begin at 486 MW, LISUM 576 MW

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

a) Grouping: BARS01, BARS02
   i. One Unavailable Reduce by 72 MW, 179 MW, Two Unavailable Reduce by 144 MW, 353 MW

b) FROCS4 always Unavailable, then combined with:
   i. BARS01, BARS02 Unavailability, Reduce Only K to J
   ii. One Unavailable Reduce by 182 MW, Two Unavailable Reduce by 254 MW

Figure A-13: NYCA Transmission System 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 5-2 is as follows:

Table A-11: Outside World Reserve Margin Modeling

Area	2008 Study Reserve Margin	2009 Study Reserve Margin	2008 Study LOLE (Days/year)	2009 Study LOLE (Days/year)
Quebec	29.4%*	39.1%*	0.264	0.113
Ontario	13.4%	15.7%	0.115	0.131
PJM-Mid-Atlantic	11.4%	7.4%	0.705	0.686
New England	7.8%	10.5%	7.474	0.117

*This is the summer margin; the winter margin is 7.2%

The Canadian Provinces have indicated that they will share reserves on a non-discriminatory basis. This year's model reflects that change.

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%	***TBD***	***TBD***	***TBD***

* The NYISO Operating Committee.

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-3 Sensitivity Case Results

Table B-2 summarizes the 2009 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 16.2% NYCA, 79% NYC, and 97% 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 2009 Sensitivity Cases

Case No.	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
	Transmission Sensitivities			
T1	**No Internal NYCA Transmission Constraints ("Free-Flowing" System)**	**14.5%**	**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	**Increase NYCA interface ratings by 10%**	**15.0%**	**78.1%**	**96.0%**
	This case shows the impact on NYCA reliability if higher transfer limits were available.			
T3	**Reduce NYCA interface ratings by 10%**	**16.4%**	**79.1%**	**97.2%**
	This case shows the impact on NYCA reliability if lower transfer limits were available.			
	Assistance From Outside World Sensitivities			
A1	**NYCA Isolated (No Emergency Assistance or Non-UDR Capacity from Outside World Areas)**	**21.7%**	**83.1%**	**101.6%**
	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). See the "Base Case Results – Interconnection Support during Emergencies" section of the report.			

* Locational Reserve Margin levels computed based on resulting capacity/load ratio.

A2	**Increase each external Control Area's IRM by 10%.**	**8.5%**	**73.4%**	**90.6%**
	Examine the NYCA IRM under the conditions where external Control Area's have additional capacity which could help NYCA in emergencies.			

A3	**Decrease each external Control Area's IRM by 10%**	**18.4%**	**80.6%**	**98.8%**
	Examine the NYCA IRM under conditions where external Control Areas have less capacity available to help NYCA in emergencies			
A4	**Wheel 100 MW from MISO to NY.**	**16.2%**	**79.0%**	**97.0%**
	To determine if this wheel can be accommodated without effecting resource reliability.			
	Generation Unit Availability Sensitivities			
G1	**Increase EFORds from Base Case (represented by assuming the maximum annual EFORds during the 2003-07 period**	**17.9%**	**80.3%**	**98.5%**
	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. In this case, zones A-E EFORd was raised by 1.09%, zones F-I EFORd was raised by 1.65%, zone J's was raised by 2.27%, and zone K's by 0.91%.			
G2	**Decrease EFORds from Base Case (represented by assuming the minimal annual EFORds during the 2003-2007 period**	**14.5%**	**77.7%**	**95.5%**
	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. In this case, zones A-E EFORd was lowered by 0.93%, zones F-I EFORd was lowered by 2.03%, zone J's was lowered by 1.82%, and zone K's by 1.30%.			
G3	**Prolonged outage of Indian Point 2 for 2009**	**21.0%**	**82.5%**	**101.0%**
	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**	**15.0%**	**78.1%**	**96.0%**
	This shows the impact that the wind generation has on the IRM requirement.			
G4a	**Remove wind, but maintain NYC and LI LCRs at 79% and 97%, respectively.**	**12.8%**	**79%**	**97%**
	This shows the effect of replacing upstate wind with upstate average EFORd units. A more precise impact would be found if a new LCR-IRM curve were preformed.			
G5	**Caithness 310 MW unit is not in service for study**	**16.1%**	**78.9%**	**96.9%**
	This shows the impact of a delay of the in-service date for Caithness beyond the study period.			
G6	**Retire Poletti generating unit**	**16.1%**	**78.9%**	**96.9%**
	This shows the impact if the Poletti unit (Zone J) is retired for the study period.			
G7	**Increase UDR contracts on the Neptune.**	**16.3%**	**79.1%**	**97.1%**
	This shows increases the amount of contracts by 300 on the Neptune controllable lin.			

Load Sensitivities				
L1	**No Load Forecast Uncertainty**	**9.7%**	**74.1%**	**91.5%**
	This scenario represents "perfect vision" for 2009 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	**Change to load forecast uncertainty methodology for zones H, I, and J.**	**16.5%**	**79.2%**	**97.2%**
	This methodology introduces a wider distribution for Zones H, I, and J by using an updated approximation for the combined H, I and J zones.			
L4	**Increase base case load forecast by 340 MWs**	**16.4%**	**79.2%**	**97.2%**
	Shows the impact of increased load on system reliability			
L5	**Decrease base case load by 340 MWs.**	**16.0%**	**78.9%**	**96.9%**
	Shows the impact of decreased load on system reliability			

Emergency Operating Procedure Sensitivity				
EP1	**No SCRs or EDRPs**	**17.0%**	**79.6%**	**97.7%**
	Verifies the impact of SCR and EDRP participation in the market			
Environmental Initiative Sensitivities				
EN1	**HEDD Plus LFA Scenario**	**28.6%**	**88.1%**	**107.4%**
	This case assumes that the environmental restrictions proposed for the year 2010 are modeled in this study for the year 2009. 2,970 MW is removed. If no new capacity is added, the LOLE would be 1.826 days/year.			
EN2	**RGGI Scenario Range**	**16.5-17.1%**	**79.2-79.7%**	**97.3-97.8%**
	This case assumes a range of environmental restriction scenarios. In the lower range, a future year loss of 965 MW occurs. In the higher range case, a future year loss of 1195 MW occurs. See the complete description below this table. .			

Miscellaneous LOLE Sensitivities				
M1	**Run the base case to 5,000 replications.**	**0.098**	**0.079**	**0.061**
	This shows the results of the LOLE changes from the base case of 0.100 for NYCA, 0.067 for NYC and 0.077 days/year for LI, when running the model to 5,000 replications. The standard error at this point was 0.0144.			

Regional Greenhouse Gas Initiative (RGGI) Scenario Description

Appendix C contains a description of RGGI and the possible impacts it will have on reliability of the New York Control Area. NYISO staff is developing several scenarios that will be included in the 2009 Resource Needs Assessment. These will examine how coal generation might be impacted by alternative gas and CO2 allowance price scenarios. In general, coal units which are located in zones with lower Locational Marginal Prices and that have higher heat rates are expected to be impacted the most. Coal units fell into five groupings based on how these two factors affected their net revenue.

Although the RNA does not postulate an unacceptable reliability impact until 2017 or later, that is in part because of the level and performance of Special Case Resources (SCRs) included in the study and because its load forecast reflects some level of success for the Energy Efficiency Portfolio Standard, which aims to electricity use by 15% by 2015.

The RGGI scenario for the 2009 IRM study examined the effect on reliability if the two groupings of coal units showing the most adverse change in net revenue were to retire. These are future year scenarios, since no coal units are expected to retire because of RGGI in the IRM study horizon. Nevertheless, these scenarios may provide insight into a reliability risk that may confront NYCA in the future, especially should coal and CO2 emissions prices and load levels turn out to be higher than expected.

In Sensitivity S19A, 964.8 MW of coal capacity are retired. In the S19B, all the units in S19A and an additional 229.9 MW are retired, for a total of 1194.7 MW. In both sensitivities, NYCA is assumed to regain its 16.2% Reserve Margin through adding capacity to the Areas where coal units were retired (capacity in J and K was not affected). In S19A, the result was an LOLE = 0.111 and in S19B the LOLE = 0.136.

Following customary procedures in performing sensitivities, capacity was then added to all Areas in New York until LOLE =0.100 was restored. The resulting Reserve Margins were 16.51% for S19A (J and K LCRs of 79.23% and 97.26%, respectively) and 17.14% for S19B (J and K LCRs of 79.69% and 97.78%, respectively). MLCRs for J and K changed as a result of the methodology employed.

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Nitrogen Oxide Scenario Description

There are several regulatory regimes under consideration for control of nitrogen oxide emissions. Of these, two are considered in the 2009 IRM Study. These, taken together, are comparable to the HEDD sensitivity examined in the 2008 IRM 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 A of the 2009 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 2009 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 = 1.826 days per year, approximately twenty 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 = 1.826 days/year is associated with a NYCA reserve margin of 16.2% and J and K LCRs of 79% and 97%, 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 28.61% for NYCA. J and K LCRs were 88.13% and 107.39%, respectively. (MLCRs for J and K changed as a result of the methodology employed.)

Since NYCA's reserve margin is approximately 24%, and Zones J and K have capacity equal to approximately 89% and 113% 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-4 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 1.5 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 = 16.2 %)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	7.7
Require EDRPs	7.5
5% manual voltage reduction	6.9
30 minute reserve to zero	6.7
5% remote control voltage reduction	3.8
Voluntary load curtailment	2.3
Public appeals	2.1
Emergency purchases	2.0
10 minute reserve to zero	1.8
Customer disconnections	0.1

* See Appendix A, Table A-9

Appendix C Environmental Scenarios

2009 Installed Reserve Margin Study
Environmental Scenarios

The 2008 Installed Reserve Margin (IRM) studies conducted by the NYISO for the New York State Reliability Council (NYSRC) examined the potential impact on reliability of two developing environmental initiatives. The Regional Greenhouse Gas Initiative (RGGI) was proposed to place a cap on carbon dioxide (CO_2) emissions starting in 2009. The High Electric Demand Day (HEDD) initiative proposed to reduce ozone precursor emissions of NOx from High Emitting Combustion Turbines (HECT) and Load Following Boilers (LFB) in 2009. The analysis of the RGGI scenario determined that the IRM would need to be increased from 15.0% to 17.1% if the number of allowances available to New York generators was limited to 52 million. The analysis of the HEDD scenario showed that the IRM would need to be increased to 24.6%.

This year we find that the RGGI proposal continues to make progress in its development. The RGGI member states have created RGGI, Inc. to support program implementation. RGGI, Inc. in turn has selected contractors to finalize the design and implementation of allowance auction, support services for the development and implementation of emissions and allowance tracking systems, and other services. RGGI, Inc. is currently seeking services to assist in the market monitoring function for the auction. The format of the auction will use uniform prices and be held quarterly. The auction plan calls for auctioning current and future vintages.

The RGGI auction has a number of unique features including opening up the auction to bidders outside the regulated community. This auction design feature will provide direct access to non-emitting entities including, non-emitting generators, transmission owners, financial institutions, brokerages, fuel suppliers, fuel transporters, energy traders, load serving entities, non-RGGI emitters, and assorted special interest groups.

The first sub-regional allowance auction is now scheduled for September 25, 2008. This auction will offer 6.7% of 2009 allowances as shown below in Table1.

Table 1. First RGGI Auction Sept. 25, 2008

State	Cap (000,000) Tons	% of 2009 Allowances
CT	1.37	12.80%
DE	0.00	0.00%
MA	4.35	16.29%
MD	5.33	14.21%
ME	0.87	14.75%
NH	0.00	0.00%
NJ	0.00	0.00%
NY	0.00	0.00%
RI	0.44	16.30%
VT	0.20	16.67%
Total	12.56	6.68%

The first auction with participation from all states will not be until sometime in 2009. A potential impact of the RGGI program on electricity markets is the possibility of a shift in the supply-demand balance of allowances that moves from economically-based shifts in production patterns to a shortage of allowances that manifest itself as a reliability problem. It is important to understand that constraining carbon emissions limits the energy production possible from the existing fossil fueled generating fleet. Just as there is a cap to the number of allowable emissions, there is also a floor or a minimum number of allowances that are necessary to maintain acceptable levels of reliability of the electric system. Should the supply of allowances available to fossil fueled generators, fall below the floor, electric system reliability would be at risk.

Several situations can be postulated that can result in an insufficient supply of allowances for New York generators, after accounting for fuel switching, offsets, and energy efficiency programs. Disruptions in the fuel supply and delivery system can rapidly alter the emissions profile of the generating fleet. The disruptions in natural gas supply and delivery systems following the hurricanes Rita and Katrina resulted in an immediate increase in New York CO_2 emissions of approximately 8 million tons. The loss of a major nuclear plant could translate into the need for an additional 10 million tons/yr. of CO_2 allowances. The current RGGI proposal calls for the auctioning of allowances in the form of a portfolio of allowances of the participating states. During the first auction that New York participates in, New York allowances will be leaving New York. It is also possible that non-RGGI-effected entities could remove significant quantities of allowances from the New York market for other purposes.

The consequences of finding the supply of allowances below the floor that is necessary for New York -RGGI-affected generators to maintain reliable operation of the electric system are potentially serious threats to bulk power system reliability. Therefore, it is incumbent upon energy planners to understand where this floor is. Energy and environmental policy makers need to be mindful of this floor when they are designing the RGGI allowance auction, emissions and allowance tracking systems, and the market monitoring function.

To examine the impact of allowance scarcity on New York's reliability, the ABB GridView market simulation software will be used to forecast generation dispatch, transmission congestion, and market clearing prices for a series of assumed allowance prices. For a subset of these prices where the demand transitions from elastic to inelastic, LOLEs will be determined. Within this allowance price range, the minimum number of allowances necessary to maintain electric system reliability, or the "floor" will be identified. This configuration will be used as input to the IRM studies and made available to the New York policy makers.

New York's State Implementation Plan (SIP) to achieve compliance with National Ambient Air Quality Standards (NAAQS) for ozone has been based on an approach that included the United States Environmental Protection Agency's (USEPA) Clean Air Interstate Rule (CAIR), the Ozone Transport Commission's agreement to achieve specific reductions from units that operate generally on High Electric Demand Days (HEDD) and regionally updated NOx RACT standards for non-New Source Performance Standard generating units. NOx emissions contribute to high concentrations of ozone. SO_2 contributes to the formation of PM 2.5. CAIR had been promulgated in 2005 as a regulatory mechanism to bring large portions of the Eastern United States into compliance with National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM 2.5). The CAIR program sought to achieve NAAQS through the reduction of NOx and SO_2 emissions, mainly from power plants through the use of a "cap and trade" system of emission permits known as allowances. On July 11, 2008, The United States Court of Appeals for the District of Columbia Circuit vacated the USEPA's Clear Air Interstate Rule (CAIR).

While the plan attempted to balance reasonable future progress towards achieving air quality goals, costs of and time to implement emission control technology, and the policies of the states involved; ultimately the Court decided that CAIR did not fit well within the specific requirements of the Clean Air Act (CAA). The CAA requires each state to develop a State Implementation Plan (SIP) to achieve the NAAQS. These plans are built upon regulatory programs to control emissions within the state. In situations in which cross-boundary conditions contribute significantly to a neighboring states' air quality problem, states were required to identify necessary reductions to protect its neighbors. CAIR had sought to satisfy this requirement on a regional basis using a cap and trade allowance system for the region.

New York's SIP to achieve compliance with NAAQS was submitted to USEPA in August 2007 and is currently under review. The SIP depended upon reductions to be achieved under CAIR through the use of SO_2 and NOx allowances. The New York SIP also commits to achieve an additional reduction in NOx emission of 50 tons/day on High Electric Demand Days (HEDD) as part of the Ozone Transport Commission (OTC) process agreed to last year. Since the Court eliminated the elements of EPA's NOx control program that went beyond its acid rain and existing NOx SIP Call trading programs, the validity of New York's further NOx control efforts is in question.

For 2008, the NYISO's Comprehensive Reliability Planning Process (CRPP) and NYSRC considered the possible implementation of a HEDD program in 2009. With the July 11, 2008 Court of Appeals decision to vacate CAIR, this scenario has now been called into question and appears unlikely.

The Court ruling moves the industry away from an arena in which the emission reductions and the schedule were known, the reductions were to be determined in a competitive market place, emitters were awarded allowances to offset their increased capital and operating costs, and state regulators had SIPs that were workable. The new world after this court decision is very uncertain. The requirement to achieve NAAQS remains, however, SIPs will likely require major revisions, and the tools available will likely be less market driven, and may revert to a command and control approach. As a result, we do not have sufficient information for developing longer term forecasts for prices and power flows in the face of this uncertainty.

Summary:

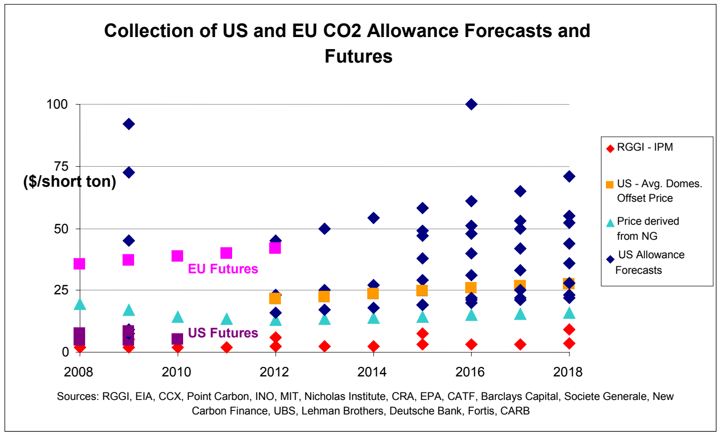
Issue	With CAIR	Today
Emission Inventory	Known	Unknown
Estimated Emissions for Individual Sources	Estimates could be forecasted	Unknown
Allowance Prices	Functioning Markets	Unknown if not worthless
Impact on Electricity Prices	Studies indicated $1-5/MWH	Near term slightly lower Long term unknown
Regulatory Schedule	Known	Unknown
Dispatch Patterns	Could be forecasted	Unknown

Given the degree of uncertainty created by this decision, it appears unlikely that a new NOx control program will be in effect in 2009.

Recommendation: The 2009 IRM study should include the impacts of the RGGI proposal in the base case with the assumption that it is an unremarkable year in terms of fuel supply and delivery and further that the new RGGI auction and secondary allowance markets operate without collusion, economic withholding, or significant allowance retirements. A separate scenario should be analyzed to determine the allowance floor that produces an acceptable LOLE with a somewhat higher IRM. Given the vacatur of the CAIR program and the general disruption it has caused, it appears unlikely that the DEC will put additional NOx controls in place for 2009, whether in the form of HEDD or otherwise. Accordingly, it does not appear that a HEDD scenario would represent a reasonably likely future factor in setting to the 2009 IRM. Nevertheless, the 2009 IRM study could carry forward a HEDD scenario based upon the assumptions contained in the 2008 IRM Study scenario, if the NYSRC Installed Capacity Subcommittee wishes to do so.

Conclusions

- **Given**
  - *the range of forecasts for CO_2 allowance costs*
  - *estimates that allowance supply and demand will be somewhat in balance*
  - *the three year compliance period*
  - *the* GridView *analysis that less than 100MW of Capacity will be forced below 50 % Capacity Factor at prices below $20/ton…*
- **It is reasonable to forecast no negative impact on reliability in 2009**



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Appendix D: NYCA Renewable Resource Generation Summary

NYCA Renewable Resource Generation Summary

Renewable Capacity Included in the 2009-2010 IRM Study

Final, as of August 13, 2008

Generation Owner - Facility Name (Connecting Transmission Owner)	NYCA Zone	Gen Type	Nameplate Capacity (MW) Installed	Contract Capacity (MW)	NYISO IC Queue Project Status[4]	Projected/ Actual In-Service Date	New Wind Capacity for 2009 IRM[5] (MW)	Total Wind Capacity Modeled for 2009 IRM[5] (MW)
Wind Facilities as of January 1, 2008 and Not Part of RPS								
Horizon Wind - Madison	E	W	11.6	NA		2000 Sep		11.6
Wester New York Wind Corp. - Wethersfield	B	W	6.6	NA		2000 Oct		0.0
Canastota Wind Power - Fenner Wind Farm	C	W	30.0	NA		2001 Dec		30.0
Constellation Power - Steel Wind	A	W	20.0	NA		2007 Jan		20.0
Coral Power - Munnsville	E	W	34.5	NA		2007 Aug	34.5	34.5
Non-RPS Total			**102.7**				**34.5**	**96.1**
NYSERDA RPS Projects								
1st Main Tier Solicitation (2005) [1]								
Spier Falls		H	0.8	0.8				
Higley Falls		H						
Browns Falls		H						
Maple Ridge 1 & 2 (previously named Flat Rock) (National Grid)	E	W	321.0	231.0	14	2006 Feb		321.7
Bear Creek	PA	W	22.0	22.0		2006 Feb		0.0
Subtotal 1st Main Tier			**343.8**	**253.8**			**0.0**	**321.7**
2nd Main Tier Solicitation (2006) [2]								
Niagara Generating Facility	A	B	26.0	26.0		2008 May		
Allens Falls	D	H	0.3	0.3	na			
Browns Falls	E	H	0.4	0.4	na			
Colton	E	H	0.7	0.7	na			
Eagle	E	H	0.5	0.5	na			
East Norfolk	E	H	0.9	0.9	na			
Higley Falls	E	H	1.9	1.9	na			
Norfolk	E	H	1.5	1.5	na			
Norwood	E	H	0.5	0.5	na	2008 May		
Oswego Falls	C	H	0.6	0.6	na	2008 Jul		
Raymondville		H	0.7	0.7		2008 Jun		
UPC - Canandaigua Cohocton Wind Farm (NYSEG)	C	W	82.5	8.3	10	2008 Jun	82.5	82.5
UPC - Canandaigua Dutch Hill Wind Farm (NYSEG)	D	W	42.5	4.3	9	2008 Jun	42.5	42.5
Noble - Altona Windpark (NYPA)	D	W	99.0	96.9	10	2008 Sep	99.0	99.0
Noble - Bliss Windpark (Village of Arcade)	A	W	100.5	95.5	10	2008 May	100.5	100.5
Noble - Chateaugay Windpark I (NYPA)	D	W	106.5	101.2	9	2008 Sept	106.5	106.5
Noble - Belmont / Ellenburg II (NYPA)	D	W	21.0	20.0	NA	2008 Sept	21.0	21.0
Noble - Clinton Windpark I & II (NYPA)	D	W	100.5	95.5	10 / 9	2008 May	100.5	100.5
Noble - Ellenburg Windpark (NYPA)	D	W	81.0	77.0	10	2008 May	81.0	81.0
Windfarm Prattsburgh (NYSEG)	C	W	55.5	5.6	11	2008 Nov	55.5	55.5
Totals for 2nd Main Tier			**723.0**	**538.0**			**689.0**	**689.0**
3rd Main Tier Solicitation (2007) [3]								
Prorated, based on completion percentage in 2008.	A, D	W	101.9	95.5	10	2008 May	101.9	101.9
Totals for 3rd Main Tier			**249.0**				**101.9**	**101.9**
Subtotal NYSERDA			**1,315.8**	**791.8**			**790.9**	**1,112.6**
Long Island Power Authority (LIPA)								
Winergy - Offshore (LIPA)	K	W	10.8	na	2	2010-2011		
Long Island Cable Project (LIPA)	K	W	940.0	na	2	2012, 2014		
Subtotal LIPA			**950.8**				**0.0**	**0.0**
New York Power Authority (NYPA)								
Marble River LLC - Marble River Wind Farm (NYPA)	D	W	84.0	na	10	12/1/2009		
Marble River LLC - Marble River II Wind Farm (NYPA)	D	W	134.0	na	10	12/1/2009		
Jericho Rise Wind Farm LLC (NYPA)	E	W	79.2	na	6	2009-2011		
Horizon Wind - North Slope Wind (NYPA)	D	W	109.5	na	5	2009-2010		
Noble - Burke Windpark (NYPA)	D	W	120.0	na	5	2010 Oct		
Babcock & Brown LP - Hounsfiled Wind (NYPA)	E	W	268.8	na	2	2010 Sep		
Subtotal NYPA			**795.5**				**0.0**	**0.0**
Total Capacity of All Categories			**3,164.8**				**825.4**	**1,208.7**

Notes:

NYCA Zones: **A** = West, **B** = Genesee, **C** = Central, **D** = North, **E** = Mohawk Valley, **F** = Capital, **G** - Hudson Valley, **H** = Millwood, **I** = Dunwoodie, **J** = New York City , **K** = Long Island;
Areas Outside NYCA: **PA** = Pennsylvania

Generator Type: **B** = Biomass, **H** = Hydro, **W** = Wind

1. The first main tier solicitation contracts did not include an option for an extension. Units were required to be on-line by January 1, 2006 except for the Bear Creek who was required to be on-line in February 2006.
2. The second main tier solicitation contracts were expected to be on-line 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 on-line 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 Tier 1 and Tier 2 RPS contracts are online for the forecast year. For Tier 3 RPS contracts, prorate the capacity of the wind farms with contracted capacity by the ratio of Tier 2 projects that came online by May 2008 divided by total Tier 2 projects.