New York Control Area Installed Capacity Requirements

For the period May 2012 - April 2013

Technical Study Report

December 2, 2011

New York State Reliability Council, LLC
Installed Capacity Subcommittee

TABLE OF CONTENTS

Appendices

Appendix Tables

Appendix Figures

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 2012 to April 2013 (2012 Capability Year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2012 Capability Year is 16.1% under base case conditions.

This study also determined Minimum Locational Capacity Requirements (MLCRs) of 83.9% and 99.2% for New York City (NYC) and Long Island (LI), respectively. In its role of setting the appropriate locational capacity requirements (LCRs), the New York Independent System Operator (NYISO) will consider these MLCRs.

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

The 16.1% IRM base case for 2012 represents a *0.6% increase* from the 2011 base case IRM of 15.5%. Table 1 shows the IRM impacts of individual study parameters that result in this change. The principal drivers that increased the required IRM are:

- A 337 MW increase in wind-powered generation
- Updated NYCA purchase and sale capacity projections
- Reduced availability of NYCA generating units

The above IRM drivers together accounted for an IRM increase of 1.3% from the 2011 base case value. There were several updated study parameters that reduced the IRM.

Over the next decade, several state and federal environmental regulations will affect generation resources in New York State. The only regulation that could possibly affect generation operations in the 2012 Capability Year is the newly enacted Cross State Air Pollution Rule (CSAPR). Overall, CSAPR will affect 167 generating units representing 23,275 MW of capacity in New York. Although the regulation requirements will start in 2012, a NYISO analysis showed that the NYCA can operate reliably with the program in 2012 without impacting IRM requirements.

This study also evaluated IRM impacts of several sensitivity cases. These results are summarized in Table 2 and in greater detail in Appendix Table B-1. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case 16.1% IRM will fully meet NYSRC and the NPCC resource adequacy criteria.

The base case and sensitivity case IRM results, along with other relevant factors, will be considered in a separate NYSRC Executive Committee process in which the Final NYCA IRM requirement for the 2012 Capability Year is adopted. The 2012 IRM Study also evaluated Unforced Capacity (UCAP) trends. This analysis shows that UCAP margins have steadily decreased over the past five years despite variations in IRM requirements and increases in low capacity factor wind generation.

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, 2012 through April 30, 2013 (2012 Capability Year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

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

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2012 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 (ICAP) 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 UCAP and Demand Curve concepts are described later in the report. The schedule for conducting the 2012 IRM Study was based on meeting the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2012 IRM Study are in accordance with NYSRC Policy 5-5, *Procedure for Establishing New York Control Area Installed Capacity Requirement*. The primary reliability criterion used in the IRM study requires a Loss of Load Expectation (LOLE) of no greater than 0.1 days/year 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 2012 IRM Study, and will consider the MLCR values determined in this study.

Two major improvements in the IRM study process were implemented in the 2012 IRM Study. First, the process for reviewing input data accuracy was improved. Second, a preliminary base case was prepared which was used as the basis for conducting sensitivity studies and data accuracy review. These study improvements are described in the report.

Previous NYCA 2000 to 2011 IRM Study reports can be found at www.nysrc.org/reports.asp. Table C-1 in Appendix C provides a comparison of previous NYCA base case and final IRMs for the 2000 through 2011 Capability Years. This table and Figure 3 shows UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix D).

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 NPCC Resource Adequacy Design Criteria in Section 5.2 of NPCC Directory 1, *Design and Operation of the Bulk Power System*.

In accordance with NYSRC Rule A-R2, *Load Serving Entity (LSE) Installed Capacity Requirements*, the NYISO is required to establish LSE installed capacity requirements, including locational capacity requirements, in order to meet the statewide IRM Requirements established by the NYSRC for maintaining NYSRC Rule A-R1 above. The full NYSRC Reliability Rule A-R2 can be found in the NYSRC Reliability Rules Manual on the NYSRC Web site, at www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

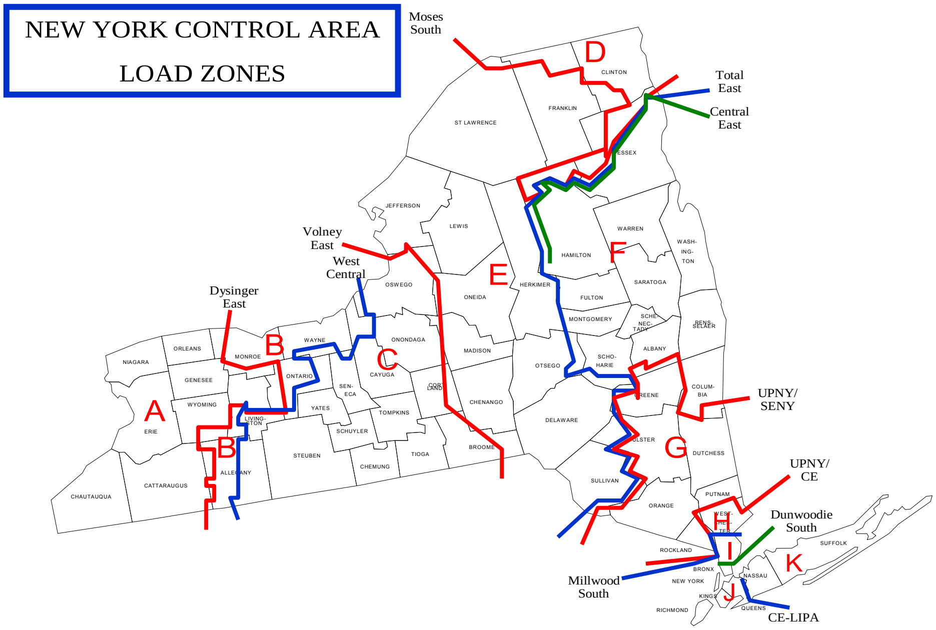
IRM STUDY PROCEDURES

The study procedures used for the 2012 IRM Study are described in detail in NYSRC Policy 5-5, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-5 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study. Policy 5-5 can be found on the NYSRC Web site at, www.nysrc.org/policies.asp.

This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator 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 external Control Areas are: Ontario, New England, Quebec, and the PJM Interconnection. 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. The GE-MARS program is described in detail in Appendix A.

Figure 1: NYCA Load Zones



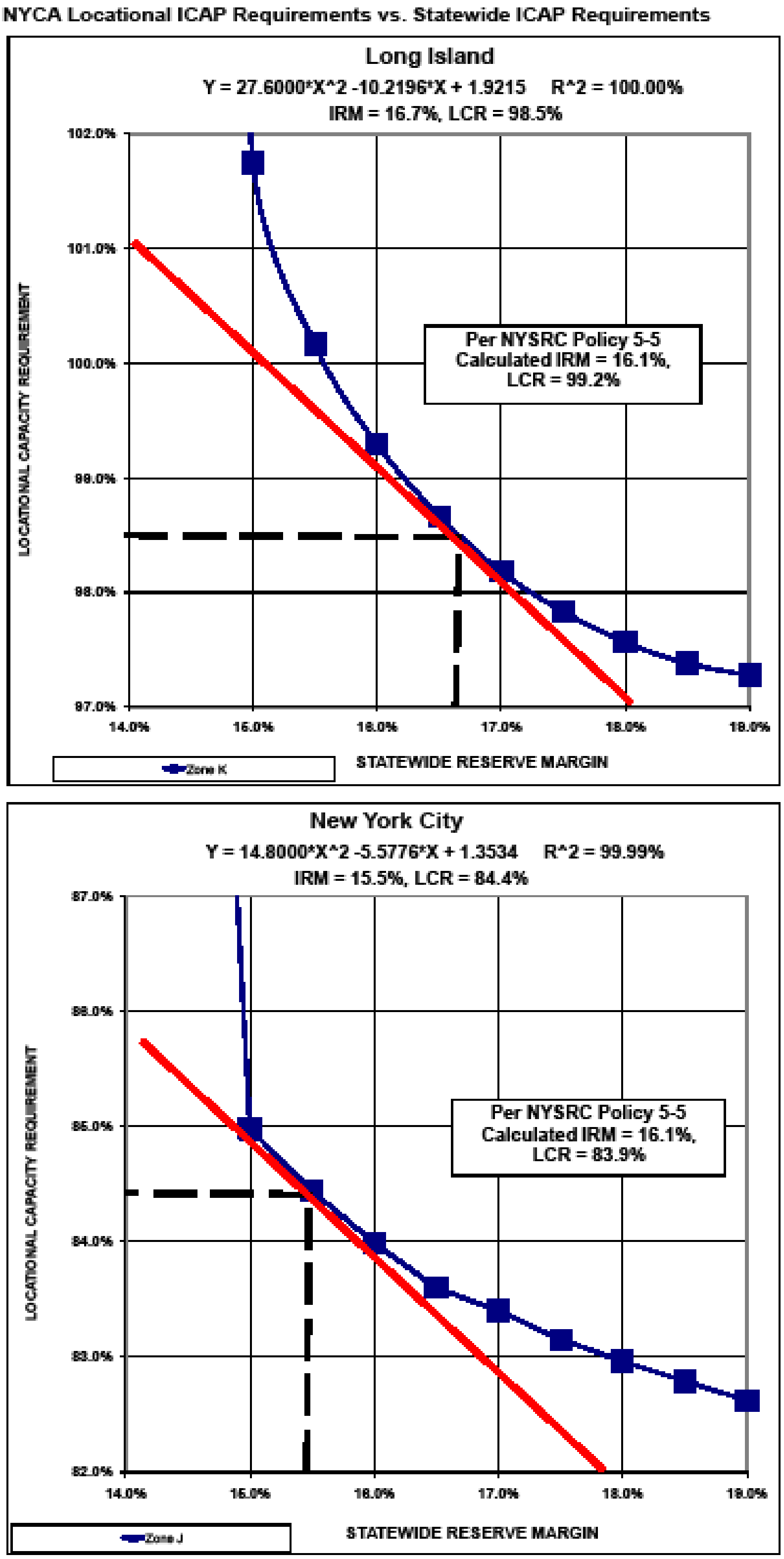
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs, as illustrated in Figure 2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. Note that all points above the curve are more reliable than criteria, and vice versa. This methodology develops a pair of curves, one for NYC (Zone J) and one for LI (Zone K). Appendix A of Policy 5-5 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 5-5 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 16.1% for the 2012 Capability Year under base case conditions. Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI.

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



The tangent points on these curves were evaluated using the Tan 45 analysis. Accordingly, it can be concluded that maintaining a NYCA installed reserve of 16.1% for the 2012 Capability Year, together with MLCRs of 83.9% and 99.2% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.

Comparing these results to the 2011 IRM Study, the 83.9% NYC MLCR increased 2.9%, while the LI MLCR decreased 2.1%. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2012 Capability Year.

A Monte Carlo simulation error analysis shows that there is a 95% probability that the above base case result is within a range of 15.7% and 16.5% (see Appendix A) when targeting a standard error of 0.025 per unit. This analysis demonstrates that there is a high level of confidence that the base case IRM value of 16.1% 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 2012 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, 2011. Appendix A provides more details of these models and assumptions. Table A-4 compares key assumptions with those used for the 2011 IRM Study.

Load Model

- ***Peak Load Forecast****:* A 2012 NYCA summer peak load forecast of 33,335 MW was assumed in the study, an increase of 463 MW from the 2011 summer peak forecast used in the 2011 IRM Study. The 2012 load forecast was completed by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force on October 3, 2011, and considers actual 2011 summer load conditions. Use of this 2012 peak load forecast in the 2012 IRM study had no impact on IRM requirements compared to the 2011 Study (Table 1). The NYISO will prepare a final 2012 summer forecast in early 2012 for use in the NYISO 2012 Locational Capacity Requirement Study. It is expected that the NYISO’s October 2011 summer peak load forecast for 2012 and the final 2012 forecast will be similar.

- ***Load Shape Model****:* The 2012 IRM Study was performed using a load shape based on 2002 actual values. This same load shape was used in the five previous IRM studies and is consistent with the load shape assumption used by adjacent NPCC Control Areas. An analysis comparing the 2002 load shape to actual load shapes from 1999 through 2010 concluded that the 2002 load shape continues to be the best suited for the 2012 IRM Study.

- ***Load Forecast Uncertainty (LFU):*** It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather and economic conditions. Recognizing the unique LFU of individual NYCA areas, separate LFU models are prepared for four areas: New York City (Zone J), Long Island (Zone K), Westchester (Zones H and I), and the rest of New York State (Zones A-G).

The load forecast uncertainty models and data used for the 2012 IRM Study were updated by Consolidated Edison for Zones H, I, and J; Long Island Power Authority (LIPA) for Zone K; and the NYISO. Appendix Section A-5.2.1 describes these models in more detail. Recognition of load forecast uncertainty in the 2012 IRM Study has an effect of increasing IRM requirements by 6.3%. Use of updated LFU models for the 2012 IRM Study decreased IRM requirements by 0.2% from the 2012 IRM Study.

Capacity Model

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

- ***Planned Non-Wind Facilities, Retirements and Reratings***:

  Planned non-wind facilities and retirements that are represented in the 2012 IRM Study are shown in Appendix A. This includes the addition of 22.5 MW of solar capacity located on Long Island. 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. Planned non-wind facilities, retirements and reratings had the overall effect of decreasing the IRM by 0.3% from the 2011 IRM Study. Appendix A shows the ratings of all resource facilities that are included in the 2011 IRM Study capacity model.

- ***Wind Generation:***

  It is projected that by the end of the 2012 summer period there will be a total wind capacity of 1,648 MW in New York State. All wind farms are located in upstate New York, in Zones A-E. See Appendix A for details. The 2012 summer period wind capacity projection is 337 MW higher than the forecast 2011 wind capacity assumed for the 2011 IRM Study.

  The 2012 IRM Study base case assumes that the projected 1,648 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 increase in projected wind capacity from the value of 1,333 MW used in the 2011 IRM Study, to 1,648 MW forecast used for this study, results in a 0.5% increase to the IRM (Table 1).

  Overall, inclusion of the projected 1,648 MW of wind capacity in the 2012 Study accounts for 4.7% of the 2011 IRM requirement (Table 2). This relatively high IRM impact is a direct result of the very low capacity factor of wind facilities during the summer peak period. The impact of wind capacity on *unforced capacity* is discussed in Appendix C, Section C.3, "Wind Resource

Impact on the NYCA IRM and UCAP Markets." A detailed summary of existing and planned wind resources is shown in Appendix A, Section A-3.2.

- ***Generating Unit Availability:***

  Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an equivalent forced outage rate (EFOR) for each unit represented. Outage data used to determine the EFOR is received by the NYISO from generator owners based on outage data 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 2012 IRM Study covered the 2006-2010 period. The five-year EFOR calculated for this period slightly exceeded the 2005-2009 average value used for the 2011 IRM Study, causing the IRM to increase by 0.4% (Table 1). Figure A-5 depicts NYCA 2001 to 2010 EFOR trends.

  In past NYSRC IRM studies, the model used to represent thermal generator outage rates has been based on the calculation of an EFOR, irrespective of the demand. However, the NYISO uses the concept of Unforced Capacity (UCAP) to establish both the LSE obligation to buy, and the amount each generator can sell into the capacity market. UCAP values are derived from the Equivalent Forced Outage Rate during demand periods (EFORd). Since EFORs are the same or lower than EFORds, the model's representation in past IRM studies has been considered conservative in that it calculates an IRM that is higher than would be calculated if EFORd was used as the basis.

  Over the past year, the ICS has investigated a method by which transition rates (used as the model input to represent forced outage rates) can be developed to better match the market's EFORd values. An independent consulting firm, Associated Power Analysts (APA), was retained by the NYISO to help develop this method. Although the APA/EFORd method has not been fully developed, tested and reviewed by ICS as of November 2011, a sensitivity case was prepared to demonstrate the approximate IRM impact of implementing the APA/EFORd method.

  The IRM impact of this sensitivity case is shown in Table 2 (Case13). As expected, use of the new EFORd model results in a lower IRM; however, the magnitude of the IRM reduction is uncertain until the model is fully developed and validated. It is expected that the new EFORd model will be implemented in the 2013 IRM Study once approved by ICS.

- ***Capacity Availability of Firm Purchases and Sales:***

  The availability of the resources participating in the New York market changes as firm sales and purchases change. Highly available resources acquired through capacity purchases reduce IRM requirements. Similarly, firm sales of highly available resources increase the IRM. Firm capacity sales that were modeled in the 2011 IRM Study as a result of New England's Forward Capacity Market (FCM) have dissolved as those contracts were bought out by internal New England resources. As a result of this activity, those units which were scheduled to supply capacity to New England from New York now participate in the New York market.

  The overall availability of those returning units was lower than that of the existing resource mix. As a result, the IRM increased by 0.4% (Table1).

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

  -- Special Case Resources (SCRs). SCRs are ICAP resources that include loads that are capable of being interrupted on demand and distributed generators that may be activated on demand. This study assumes a SCR base case value of 2,192 MW in August 2012 with lesser amounts during other months based on historical experience.

  The SCR performance model is based on an analysis of historical SCR load reduction performance which is described in Section A-5.3 of Appendix A. Due to the possibility that some of the potential SCR program capacity may not be available during peak periods, projections are discounted for the base case based on previous experience with these programs, as well as any operating limitations. An updated SCR model used for the 2012 IRM Study resulted in an IRM decrease of 0.3% from the 2011 IRM Study (see Table 1). This was primarily due to an improved methodology for assessing performance of SCR resources. SCRs, because of their obligatory nature, are considered capacity resources in setting the IRM.

  -- 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 2012 Study assumes 148 MW of EDRP capacity resources will be registered in 2012, a reduction from 2011. This EDRP capacity was discounted to a base case value of 95 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. Unlike SCRs, EDRP are not considered capacity resources because they are not required to respond when called upon to operate.

  -- Other Emergency Operating Procedures. In accordance with NYSRC criteria, the NYISO will implement EOPs as required to minimize customer disconnections. Projected 2012 EOP capacity values are based on recent actual data and NYISO forecasts. (Refer to Appendix B, Table B-3, for the expected use of SCRs, EDRP, voltage reductions, and other types of EOPs during 2012.). The updated EOP model, excluding the SCR impact noted above, slightly decreased the IRM from the 2011.

- ***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 High Voltage Direct Current (HVDC) Cross Sound Cable, 660 MW HVDC Neptune Cable, and the 300 MW Linden Variable Frequency Transformer (VFT) project are facilities that are represented in the 2012 IRM Study as having UDR capacity rights. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance which may reduce locational and IRM requirements. The 2012 IRM study incorporates the elections that these facility owners made for the 2012 Capability Year.

Transmission System Topology

A detailed transmission system model is represented in the GE-MARS study. The transmission system topology, which includes eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Figure A-13 in Appendix A. The transfer limits employed for the 2012 IRM Study were developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional analysis conducted specifically for the GE-MARS representation.

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. A recent extended cable outage caused an increase in the average cable forced outage rate (FOR), resulting in a slight IRM increase.

The NYCA transmission topology remains relatively consistent between the 2011 and 2012 IRM studies. The only change is the announced retirement of the Far Rockaway and Glenwood generating units on Long Island. The loss of this 235 MW of generation capability results in less transfer capability from Long Island into the New York City and the Upstate zones. This reduced capability, however, does not result in an increased IRM because the flows on these lines are predominately toward Long Island. Appendix A describes the basis for this change in more detail.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. The 2012 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 (refer to the NYSRC Resource Adequacy Reliability Criteria section).

The impact of transmission constraints on NYCA IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements,* the NYISO is required to calculate and establish appropriate LCRs. The most recent NYISO study (*Locational Installed Capacity Requirements Study*, dated January 14, 2011, at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies, determined that for the 2011 Capability Year, the required LCRs for NYC and LI were 81.0% and 101.5%, respectively. A LCR Study for the 2012 Capability Year is scheduled to be completed by the NYISO in January 2012.

Results from 2012 IRM Study illustrate the impact on the IRM requirement for changes of the base case NYC and LI LCR levels of 83.9% and 99.2%, respectively. Observations from these results include:

- **Unconstrained NYCA Case –** If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 13.8%, 2.3% less than the base case IRM requirement. (See Table 2.) As a result, relieving NYCA transmission constraints would make it possible to reduce the 2012 NYCA installed capacity requirement by approximately 770 MW.

- **Downstate NY Capacity Levels –** If the NYC and LI LCR levels were *increased* from the base case results to 85% and 102%, respectively, the 2012 IRM requirement could be reduced by 1.1%, to 15.0%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 83.0% and 97.5%, respectively, the IRM requirement must increase by 1.9%, to 18.0% (Figure 2).

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

Outside World Model

The Outside World Model consists of those Control Areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection. 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. Representing such interconnection support arrangements in the 2012 IRM Study base case reduces the NYCA IRM requirements by 8.6% (Table 2). A model for representing neighboring control areas, similar to 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 5-5, 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. In addition, EOPs are not represented in Outside World Area models.

Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within those Areas that may limit emergency assistance into 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 Outside World Areas – New England and the PJM Interconnection – are each represented as multi-areas, i.e., 13 zones for New England and four zones for the PJM Interconnection. Such granularity better captures the impacts of transmission constraints within these areas, particularly on their ability to provide emergency assistance to the NYCA.

For the 2012 IRM Study, there is a projected increase in transfer capability between Ontario and New York's Zone A. This increase – 400 MW into NY and 300 MW into Ontario – is a result of the reinstatement of previously inoperable ties along with transmission improvements within Ontario. These changes are summarized in Table A-8.

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

Updated Outside World Area load, capacity, and transmission representations in the 2012 IRM Study results in an IRM increase from the 2011 IRM Study by 0.1%.

Environmental Initiatives

Several state and federal environmental regulations will affect generation resources in New York State over the next decade. The only regulation that could possibly affect generation operations in the 2012 Capability Year is the newly enacted (July 2011) Cross State Air Pollution Rule (CSAPR). As a result of CSAPR, affected generators will need allowances for emissions of SO2 or NOx. Overall, up to 64% of the existing NYCA fleet's capacity will have some level of exposure to the new regulations. The first reduction starts in 2012 with additional reductions required in 2014. A NYISO analysis examined multiple scenarios: all showed that the NYCA will have sufficient resources to meet the program's requirements in 2012 (phase one) with no effect on IRM requirements.

Compliance actions for the second phase that begins in 2014 will likely include emission control retrofits, fuel switching, and new clean efficient generation. The NYISO analysis indicates that CSAPR Phase 1 will not result in any immediate reliability impacts However, Phase 2, coupled with the forecasted impacts of the four programs discussed in the Appendix (NOx RACT, BART, MACT, and BTA), and the current economic realities (low capacity payments and less expensive natural gas) could lead to plant retirements potentially affecting reliability and IRM requirements in New York as early as 2014.

Data Base Quality Assurance Reviews

It is critical that the data base used for IRM studies undergo sufficient review in order to verify its accuracy. To accomplish this objective, this year the NYSRC significantly improved its process for reviewing the accuracy of the study's data base, while continuing to respect confidentiality issues.

The NYISO, General Electric (GE), and the New York Transmission Owners (TOs) conducted independent data quality assurance reviews after the base case assumptions were developed and prior to preparation of the final base case. Masked and encrypted input data was provided by the NYISO to the transmission owners for their reviews. The NYISO, GE, and TO reviews found several minor data errors, none of which affected IRM requirements in the preliminary base case. The data found to be in error by these reviews were corrected before being used in the final base case studies. A summary of these quality assurance reviews is shown in Appendix A.

COMPARISON WITH 2011 IRM STUDY RESULTS

The results of this 2012 IRM Study show that the base case IRM result represents a 0.6% increase from the 2011 IRM Study base case value. Table 1 compares the estimated IRM impacts of updating several key study assumptions and revising models from those used in the 2011 Study. The estimated percent IRM change for each parameter in Table 1 was calculated from the results of a parametric analysis in which a series of IRM studies were conducted to test the IRM impact of individual parameters. The results of this analysis were normalized such that the net sum of the -/+ % parameter changes totals the 0.6 % IRM increase from the 2011 Study. Table 1 also summarizes the reason for the IRM change for each study parameter from the 2011 Study.

The principal drivers shown in Table 1 that increased the required IRM from the 2011 IRM base case are: increased wind capacity, updated purchases and sales assumptions, and updated generating unit EFORs, which together, increased the 2011 IRM by 1.3%.

The parameters in Table 1 are discussed under *Models and Key Input Assumptions*. A more detailed description of these changes and their IRM impacts can be found in Appendix A.

Table 1: Parametric IRM Impact Comparison – 2012 IRM Study vs. 2011 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)	Reasons for IRM Changes
2011 IRM Study – Final Base Case IRM		**15.5**	
2012 Updated Parameters that Increase the IRM:			
New Wind Capacity (337 MW)	+0.5		Wind generator performance has low availability.
Updated Purchases and Sales	+0.4		Loss of sales contracts resulted in poor performing units remaining in NY.
Updated Generating Unit EFORs	+0.4		FOR increases in Downstate units higher relative to Upstate units.
Updated Cable Outage Rates	+0.1		Increase in cable FORs due to recent extended outage.
Updated Outside World Model	+0.1		Higher New England load growth relative to capacity increase results in reduced emergency assistance available to NYCA.
Total IRM Increase	**+1.5**		
2012 Updated Parameters that Decrease the IRM:			
Revised SCR model	-0.3		Improved methodology of assessing performance of SCR resources.
New Generating Capacity	-0.2		New generating capacity has higher availability relative to existing fleet.
Updated Load Forecast Uncertainty Model	-0.2		Recent historical data shows less load uncertainty in Zones J and K.
Updated Non-SCR/EDRP EOPs	-0.1		Increase in EOP capabilities in Downstate relative to Upstate.
Retirements	-0.1		Retirement of poorer performing generating units.
Total IRM Decrease	**-0.9**		
2012 Updated Parameters that do Not Change the IRM:			
Updated EDRP Capacity	0		
Updated Maintenance	0		
New Solar Capacity	0		
Updated Load Forecast	0		
Updated Existing Generating Unit Capacities	0		
Total IRM Change	**0**		
Net Change From 2011 Study		**+0.6**	
2012 IRM Study – Final Base Case IRM		**16.1**	

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. Many of these sensitivity case results are important considerations when the NYSRC Executive Committee develops the Final NYCA IRM for 2012. A complete summary of all sensitivity case results is shown in Appendix B, Table B-2. Table B-2 also includes a description and explanation of each sensitivity case. A preliminary base case was used as the basis for developing the sensitivity case values in Table 2. This table reflects adjustments made to the preliminary base case sensitivity study results to reflect the final base case IRM. Further, there was no attempt to develop sensitivity results utilizing the Tan 45 "inflection point" method.

Table 2: Sensitivity Cases
NYCA 2012 IRM and Related NYC and LI Locational Capacity Impacts

Case	Case Description	IRM (%)	% Change From Base Case	NYC LCR (%)	LI LCR (%)
0	Base Case	16.1	--	84	99
	2012 IRM Impacts of Major MARS Parameters				
1	NYCA isolated	24.7	+8.6	90	105
2	No internal NYCA transmission constraints	13.8	-2.3	0[1]	0[1]
3	No load forecast uncertainty	8.8	-7.3	79	93
4	No wind capacity (1,648 MW)	11.4	-4.7	84	99
5	No EDRPs	16.3	+0.2	84	99
6	No SCRs and EDRPs	15.5	-0.6	84	101
	2012 IRM Impacts of Base Case Assumption and Model Changes				
7	Higher Outside World reserve margins	11.9	-4.2	81	96
8	Lower Outside World reserve margins	22.6	+6.5	89	104
9	Higher EFORds	18.7	+2.6	86	101
10	Lower EFORds	15.6	-0.5	83	99
11	Alternate load shape model	13.7	-2.4	82	97
12	Alternate wind shape model	15.8	-0.3	84	99
13	Use of a new EFORd model now under development	15.1[2]	-1.0	83	98
14	Lower SCR use	N/A[3]			
15	Retire Indian Point Units 2 and 3	21.6[4]	+5.5	92	107
16	300 MW wheel from Quebec to New England	16.2	+0.1	84	99
17	One in two Con Edison load forecast	17.3[5]	+1.2	85	100
18	Updated PJM representation	15.2[6]	-0.9	82	97

1 There would not be a need to establish minimum locational capacity requirements if there were no internal NYCA transmission constraints.
2 This is an interim result as the new EFORd model is still under development and the implementation software has not been fully reviewed nor validated. It is expected, however, that the IRM using this new model will be lower than the 2012 base case IRM after it is fully developed and adopted in 2012. See "Generating Unit Availability".
3 Preliminary analysis provided for an upcoming 2012 SCR study report suggests that if SCR response were limited to six hours on the top 15 peak load days, then the IRM could increase by several percentage points. The methodology and results are currently being examined and are not expected to yield conclusive information until the 2012 SCR study is complete.
4 There was no evaluation of transfer limits, therefore, no changes in transfer limits for this sensitivity. In addition, replacement capacity was introduced in all zones to bring the LOLE back to 0.10 days/year.
5 This sensitivity results in the same MW requirements as the base case. The change from a 1–in–3 base case forecast for Con Edison to a 1-in-2 forecast results in both a lower represented peak and a higher Installed Reserve Margin and New York City Locational Capacity Requirement over this lower peak.
6 The PJM model update was not received in time to include in the base case. The revised PJM representation has not been vetted at the ICS.

NYISO IMPLEMENTATION OF NYCA CAPACITY REQUIREMENTS

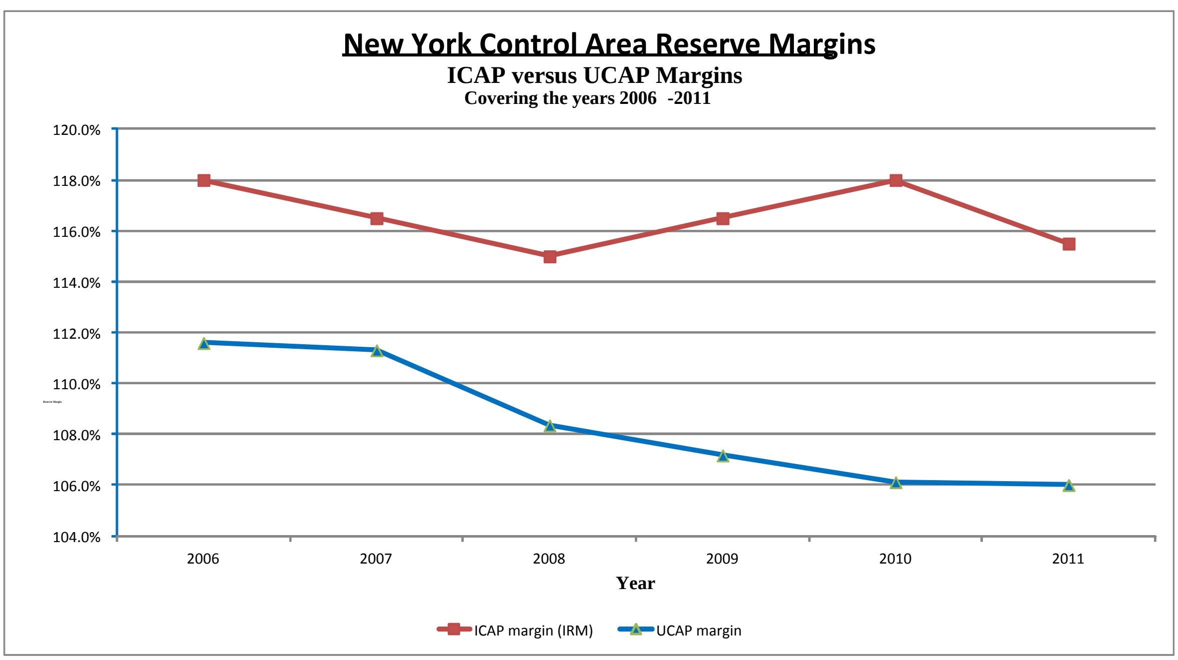
NYISO Translation of NYCA ICAP Requirements to UCAP Requirements

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity (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; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures 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 UCAP. Figure 3 below illustrates that UCAP reserve margins have steadily decreased over the 2006-2011 period, despite variations of UCAP requirements. This indicates a lower burden on New York loads over time. Appendix C offers a more detailed explanation.

Figure 3: NYCA Reserve Margins



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 Zone J (New York City), Zone K (Long Island), and the NYCA. The existence of Demand Curves does not impact the determination of IRM requirements by the NYSRC.

Appendix A

NYCA Installed Capacity Requirement

Reliability Calculation Models and Assumptions

Description of the GE MARS Program: Load, Capacity, Transmission, Outside World Model, and Assumptions

A. Reliability Calculation Models and Assumptions

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 below.

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-3 compares the assumptions used in the 2010 and 2011 IRM reports.

Figure A-1: NYCA ICAP Modeling

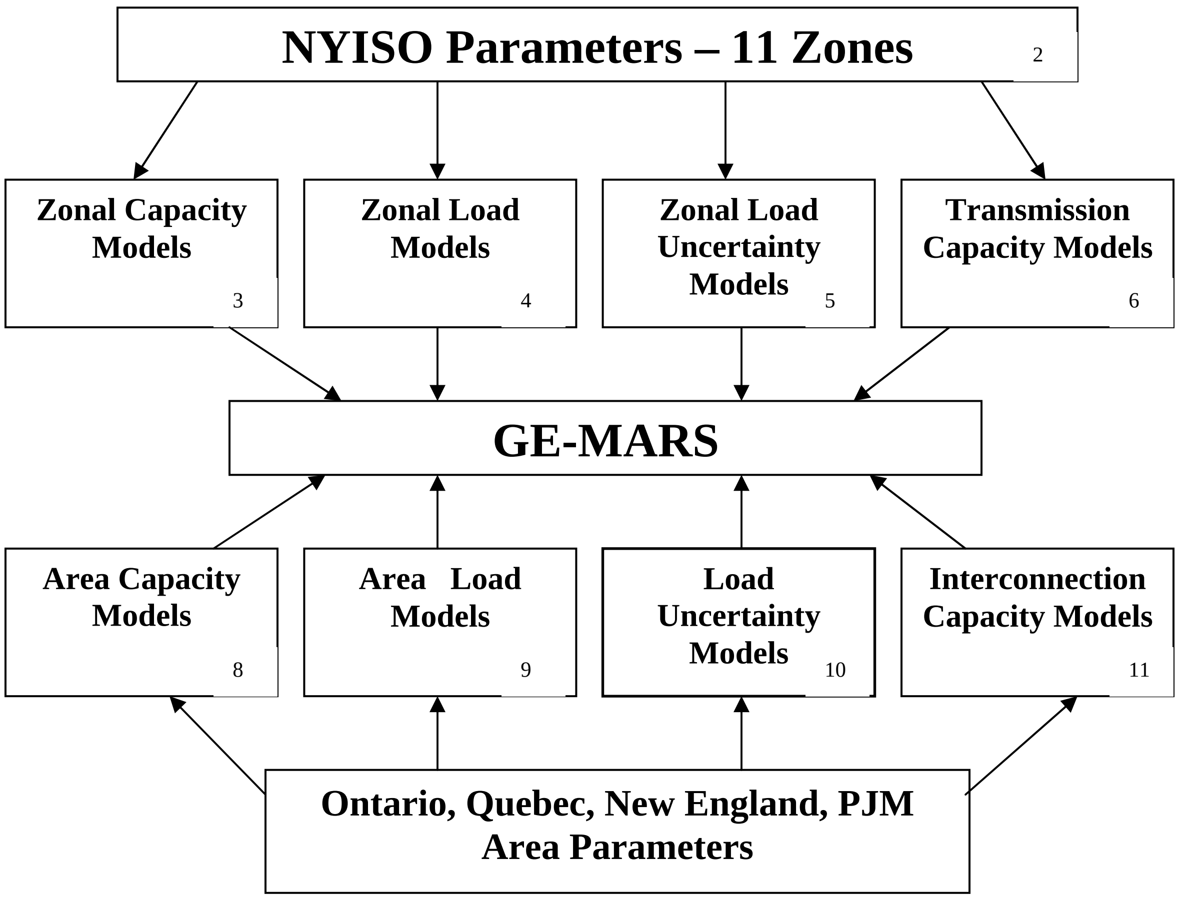


Table A-1: Modeling Details

Box #	Parameter	Description	Source	Reference
Internal NYCA Modeling				
1	GE MARS	General Electric Multi-Area Reliability Simulation Program		Section A-1
2	11 Zones	Load Areas	Fig A-1	NYISO Accounting & Billing Manual
3a	Zone Capacity Models	Generator models for each generating in zone. Generator availability Unit ratings	GADS data 2011 Gold Book[7]	Section A-3.2
3b	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A-3.5
4	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A-3.1
5	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A-3.1
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between zones	NYISO Transmission Studies	Section A-3.3
External Control Area Modeling				
7	Ontario, Quebec, ISONE, PJM Control Area Parameters	See 8-11	Supplied by External Control Area	
8	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A-3.4
9	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A-3.4
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to economic conditions	Supplied by External Control Area	Section A-3.4
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A-3.3

7 2011 Load and Capacity Data Report, http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

A.1 GE MARS

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-3.5).

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 from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A-1).

Equation A-1

$$Transition\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Tume\ in\ State\ A}$$

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 (Equation A-2).

Equation A-2

$$Transition\ (1\ to\ 2) = \frac{10\ Transitions}{5000} Hours$$

$$= 0.002$$

Table A-2: State Transition Rate Example

Time in State Data				Transition Data			
State	MW	Hours		From State	To State 1	To State 2	To State 3
1	200	5000		1	0	10	5
2	100	2000		2	6	0	12
3	0	1000		3	9	8	0

State Transition Rates			
From State	To State 1	To State 2	To State 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.1.1 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 two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

For this analysis, the Base Case required 386 replications to converge to a daily LOLE for NYCA of 0.098 days/year with a standard error of 0.05 per unit. The Base Case required 1427 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, there is 95% probability (confidence interval) that the actual IRM is between 15.7% and 16.5%. It should be recognized that a 16.1% IRM is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using version 3.12 of the GE-MARS software program. This new version was 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 than 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 Tables A-9 through A-11.

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.

A.2 Methodology

The 2012 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and locational installed capacity requirements. The IRM/LCR characteristic consists of two constituents: 1) a curve function ("the knee of the curve", and 2) the 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 base case requirement is based on the following criteria summarized below:

1. Start with all points on the IRM/LCR curve
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 R^2 value
4. Eliminate those points where the calculated IRM is outside the selected curve point range
5. Use the highest R^2 equation that meets criteria to calculate values for IRM and LCR
6. Verify that the calculated IRM and corresponding LCR values do not violate the 0.1 LOLE criterion

This approach produces a quadratic curve function with R^2 correlation approaching 1.000 as the basis for the Tangent 45 calculation. First derivatives are 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 16.1%. The above methodology was adopted by the NYSRC Executive Committee and is incorporated into Policy 5-5.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A-3: Load Model

Load Model			
Parameter	**2011 Study Assumption**	**2012 Study Assumption**	**Explanation**
Peak Load	October forecast: NYCA – 32,872 MW Zone J – 11,463 Zone K - 5414	October forecast: NYCA – 33,335 MW Zone J – 11,607 Zone K - 5521	Forecast based on examination of 2011 weather normalized peaks. Top three external Area peak days aligned with NYCA
Load Shape Model	2002 Load Shape	2002 Load Shape	The 2002 load shape is still appropriate. A sensitivity case using a composite loadshape for the years 2006-2010 was produced.
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Based on collected data and input from LIPA, Con Ed, and NYISO. Method and values accepted by LFTF

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that detailed in the NYISO Load Forecasting Manual for the ICAP forecast. The NYISO's Load Forecasting Task Force had three meetings in September 2011 to review analyses prepared by the NYISO of the weather response during the summer. Regional load growth factors (RLGFs) for 2011 were updated by each Transmission Owner based on projections provided to the LFTF in August 2011 by Moody's Analytics. The 2012 forecast was produced by applying the RLGFs to each TO's weather-normalized 2011 summer peak.

The 2011 peak forecast was 32,712 MW. The actual peak of 33,865 MW occurred on Friday, July 22, 2011. Load and losses as measured in the Transmission Districts was 33,784 MW. The NYISO activated Special Case Resources (SCRs) and the Emergency Demand Response Program (EDRP) in all Zones but Zone D on that day to curtail load. It is estimated that the impact due to SCRs and EDRP was 1,430 MW. The weather was above design conditions throughout the state. The weather adjustment for the NYCA was -2,194 MW. After accounting for the impacts of weather and the demand response, the weather-adjusted peak load was determined to be 33,020 MW, 308 MW (0.96%) above the forecast. The 2012 forecast for the NYCA is 33,335 MW, shown below in Table A-5, was recommended to the NYSRC by the LFTF.

2012 NYSRC Installed Reserve Margin Study - 2012 Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Transmission District	2011 Actual MW	SCR/EDRP Estimate MW	2011 Load, No Demand Response	Weather Adjustment MW	2011 Adjusted MW	Regional Load Growth Factors	2012 IRM Preliminary Forecast
Central Hudson	1,209	29	1,238	-107	1,131	1.0075	1,139
Con Ed	13,166	490	13,656	-445	13,211	1.0090	13,330
LIPA	5,944	128	6,072	-718	5,354	1.0174	5,447
NGrid	6,917	485	7,402	-494	6,908	1.0080	6,963
NYPA	553	0	553	-3	550	1.0165	559
NYSEG	3,263	177	3,440	-293	3,147	1.0070	3,169
O&R	1,165	30	1,195	-72	1,123	1.0030	1,126
RG&E	1,567	91	1,658	-62	1,596	1.0040	1,602
Grand Total	33,784	1,430	35,214	-2,194	33,020	1.0095	33,335

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Locality	2011 Actual MW	SCR/EDRP Estimate MW	2011 Load, No Demand Response	Weather Adjustment MW	2011 Adjusted MW	Regional Load Growth Factors	2012 IRM Preliminary Forecast
Zone J - NYC	11,423	442	11,865	-362	11,503	1.0090	11,607
Zone K - LI	5,944	128	6,072	-645	5,427	1.0174	5,521

(2) Zonal Load Forecast Uncertainty

For 2012, updated load forecast uncertainty (LFU) models were provided by Consolidated Edison for Zones H, I and J, and by LIPA for Zone K. The NYISO developed new LFU models for the Upstate zones, but after review and discussion of the results with the Load Forecasting Task Force, retained the 2011 LFU model. The results of these models are presented in Table A-6. Each row represents the probability that a given load level will occur on a per-unit basis, by zone. Results are also shown in Figure A-4.

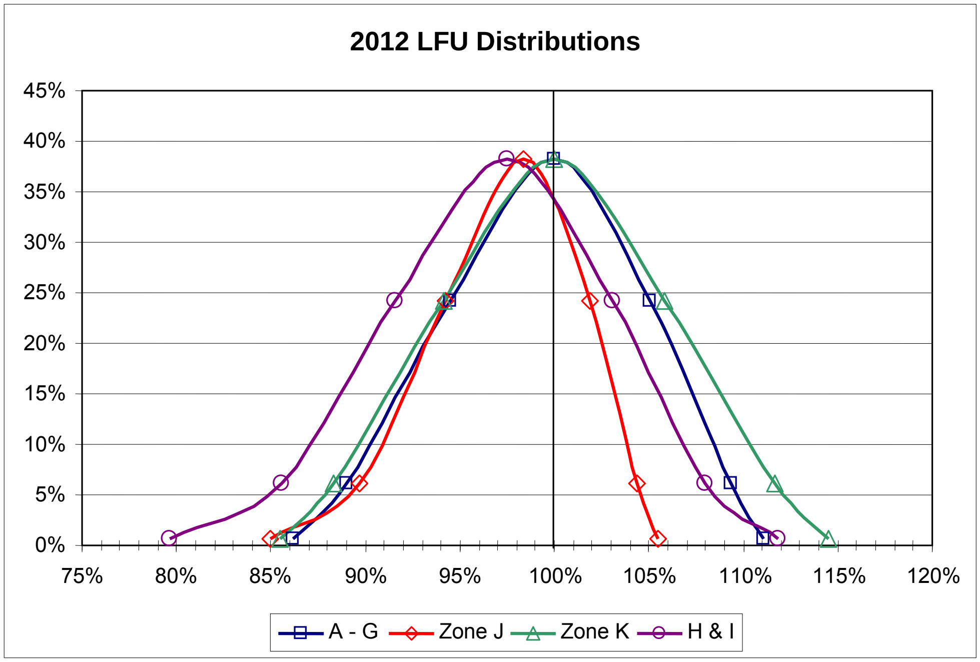
Table A-4: 2012 Load Forecast Uncertainty Models

2012 Load Forecast Uncertainty Models

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.6%	86.2%	79.7%	84.9%	85.5%
2	6.1%	89.0%	85.5%	89.7%	88.3%
3	24.2%	94.5%	91.6%	94.2%	94.1%
4	**38.3%**	**100.0%**	**97.5%**	**98.4%**	**100.0%**
5	24.2%	105.1%	103.1%	101.9%	105.9%
6	6.1%	109.3%	108.0%	104.4%	111.7%
7	0.6%	111.1%	111.8%	105.5%	114.5%

	13.8%	17.9%	13.4%	14.5%
Med - High	11.1%	14.3%	7.1%	14.5%
Delta	24.9%	32.1%	20.5%	29.0%

Figure A-2: 2012 LFU Distributions



A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State, that have met specific criteria to offer capacity in the New York Control Area. The 2011 Load and Capacity Data Report is the primary data source for these resources. Table A-5 provides a summary of the capacity resource assumptions in the 2012 IRM study.

Table A-5: Capacity Resources

Capacity Resources			
Parameter	**2011 Study Assumption**	**2012 Study Assumption**	**Explanation of Change**
Generating Unit Capacities	Updated DMNC values per 2010 Gold Book Use the minimum of CRIS or DMNC value	Updated DMNC values per 2011 Gold Book Use the minimum of CRIS or DMNC value	Annual update of the Load & Capacity Data Report
Planned Generator Units	Astoria Energy II 550 MW Empire Generating – 635 MW	Astoria Energy II Zone J – 576 MW 5/2011 Bayonne Energy Center Zone J – 500 MW 5/2012	
Wind Modeling	(1,260 MW) Derived from hourly wind data with average Summer Peak Hour availability factor of approximately 11%	(1,648 MW) Derived from hourly wind data resulting in an average Summer Peak Hour availability of approximately 11%	Based on collected hourly wind data. Summer Peak Hour capacity factor based on June 1-Aug 31, hours (beginning) 2-5 PM
Solar Modeling	Forecast of 15 MW of total solar capacity, centered on Long Island	Forecast of 38.5 MW of total solar capacity	Based on collected hourly solar data during summer Peak Hours (June 1-Aug 31, hours (beginning) 2-5 PM)
Retirements	Energy Systems North East – 74.5 MWs		
Forced Outage Rates	5-year (2005-09) GADS data. (Those units with less than five years data could use available representative data.)	5-year (2006-10) GADS data. (Those units with less than five years data could use available representative data.)	Most recent 5-year period. Includes proxy data for unit(s) that are deemed suspect as part of the GADS screening process.
Planned Outages	Based on schedules received by NYISO and adjusted for history	Based on schedules received by NYISO and adjusted for history	Updated schedules.
Summer Maintenance	Nominal 150 MW	Nominal 50 MW	Value based on review of prior year's data with adjustment for unit history
Gas Turbine Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves
Small Hydro Derate	45% derate	45% derate	No Change

(1) Generating Unit Capacities

The capacity rating for each thermal 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. Additionally, each generating resource has an associated capacity CRIS (Capacity Resource Interconnection Service) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled.

Wind units are rated at their nameplate, or full rated value, in the model. The 2011 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

(2) Planned Generator Units

Generating units not included the Load and Capacity Data Report but that have met specific criteria for inclusion in the IRM study were also modeled. These include units that went into service after the data report was published or that plan to be in service for the summer 2012 capability period based upon a signed interconnection agreement (by August 1, 2011). Two new units are included in the 2012 IRM Study:

a) Astoria Energy II – 576 MW in Zone J

b) Bayonne Energy Center – 500 MW in Zone j

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers. The output of each 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 1648 MW of installed capacity associated with wind generators is included in this study. New wind units (264.3 MW) for the 2012 IRM study include:

a) Belmont/Ellenburg – 5.3 MW in Zone D
b) Cody Road – 10 MW in Zone C
c) Howard Wind – 57.4 MW in Zone C
d) Marble River Wind Farm – 108.2 MW in Zone D
e) Stony Creek Wind Farm – 44.3 MW in Zone C
f) Prattsburgh Wind Farm – 39.1 MW in Zone D

Table A-6: Included Wind Generation

Wind Generation Projects in the NYCA						
Considered for Inclusion in the 2012-2013 IRM Study						
Facility Name	**Zone**	**Connecting Transmission Owner**	**NYISO Interconnection Study Queue Project Number**	**Projected/ Actual In-Service Date**	**New Wind Capacity for 2012 IRM (MW)**	**Total Wind Capacity for 2012 IRM (MW)**
Steel Wind	A	National Grid		2007 Jan		20.0
Bliss Wind Power	A	Village of Arcade	173	2008 May		100.5
Canandaigua Wind Power	C	NYSEG	135&199	2008 Jun		125.0
Cody Road	C	National Grid	180A	2011 Dec	10.0	10.0
Hardscrabble Wind[1]	C	National Grid	156	2011 Sept		74.0
Howard Wind	C	NYSEG	182	2011 Dec	57.4	57.4
Wethersfield Wind Power	C	NYSEG	177	2008 Dec		126.0
High Sheldon Wind Farm	C	NYSEG	144	2009 Feb		112.5
Altona Wind Power	D	NYPA	174	2008 Sept		97.5
Chateaugay Wind Power	D	NYPA	214	2008 Sept		106.5
Clinton Wind Power	D	NYPA	172 & 211	2008 May		100.5
Ellenburg Windpark	D	NYPA	175	2008 May		81.0
Munnsville	E	NYSEG	127A	2007 Aug		34.5
Maple Ridge 1	E	National Grid	171	2006 Feb		231.0
Maple Ridge 2	E	National Grid	171	2006 Feb		90.7
Madison Wind Power	E	NYSEG	N/A	2000 Sept		11.5
Allegany Wind	A	National Grid	237	2011 Oct	72.5	72.5
Prorated Units to account for probability[2]:						
Belmont/Ellenburg II	D	NYPA	213	2011 Dec	5.3	5.3
Windfarm Prattsburgh	C	NYSEG	113	2011 Oct	39.1	39.1
Stony Creek Wind Farm	C	NYSEG	263	2012 Aug	44.3	44.3
Marble River Wind Farm 1 and 2	D	NYPA	161 & 171	2012 Jan	108.2	108.2
TOTAL CAPACITY - ALL CATEGORIES					**336.8**	**1,648.0**

1. Hardscrabble Wind has been called Fairfield Wind, after the town that it is in.

2. ICS has forecast that only 50% of the proposed active projects will be complete in time for this study.

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers. The output of each unit varies between 0 and the nameplate value based on solar data collected near the plant sites. Characteristics of this data indicate an overall 65% capacity factor during the summer peak hours. A total of 38.5 MW of solar capacity was modeled in Zone K that includes:

a) BP Solar – 32 MW

b) EnXco – 6.5 MW

(5) Retirements

There were seven unit retirements or units mothballed as compared to the 2011 Load and Capacity Data Report. The units include:

a) Barrett GT7 – 17 MW in Zone K

b) Far Rockaway ST4 – 105 MW in Zone K

c) Glenwood ST4 – 116 MW in Zone K

d) Glenwood ST5 – 113.2 MW in Zone K

e) Greenidge 4 (mothballed) – 106.1 MW in Zone C

f) Project Orange – 40 MW in Zone C

g) Westover 8 (mothballed) – 80.8 MW in Zone C

(6) Forced Outages

Performance data for thermal 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 2012 IRM Study. Figure A-3 shows the trend of EFORd for various regions within NYCA. Figure A-4 shows a rolling 5 year average of the same data.

Figures A-5 and A-6 show the availability trends of the NYCA broken out by fuel type.

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

The unit forced outage states for the majority of the NYCA units were obtained from the five-year NERC-GADS outage data collected by the NYISO for the years 2006 through 2010. 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. Where the NYISO had suspect data for a unit that could not be resolved prior to this study, NERC class average data was substituted for the year(s) of suspect data. Figures A-7 and A-8 show the unit availabilities of the entire NERC fleet on an annual and 5-year historical basis.

Figure A-3: NYCA Annual EFORds

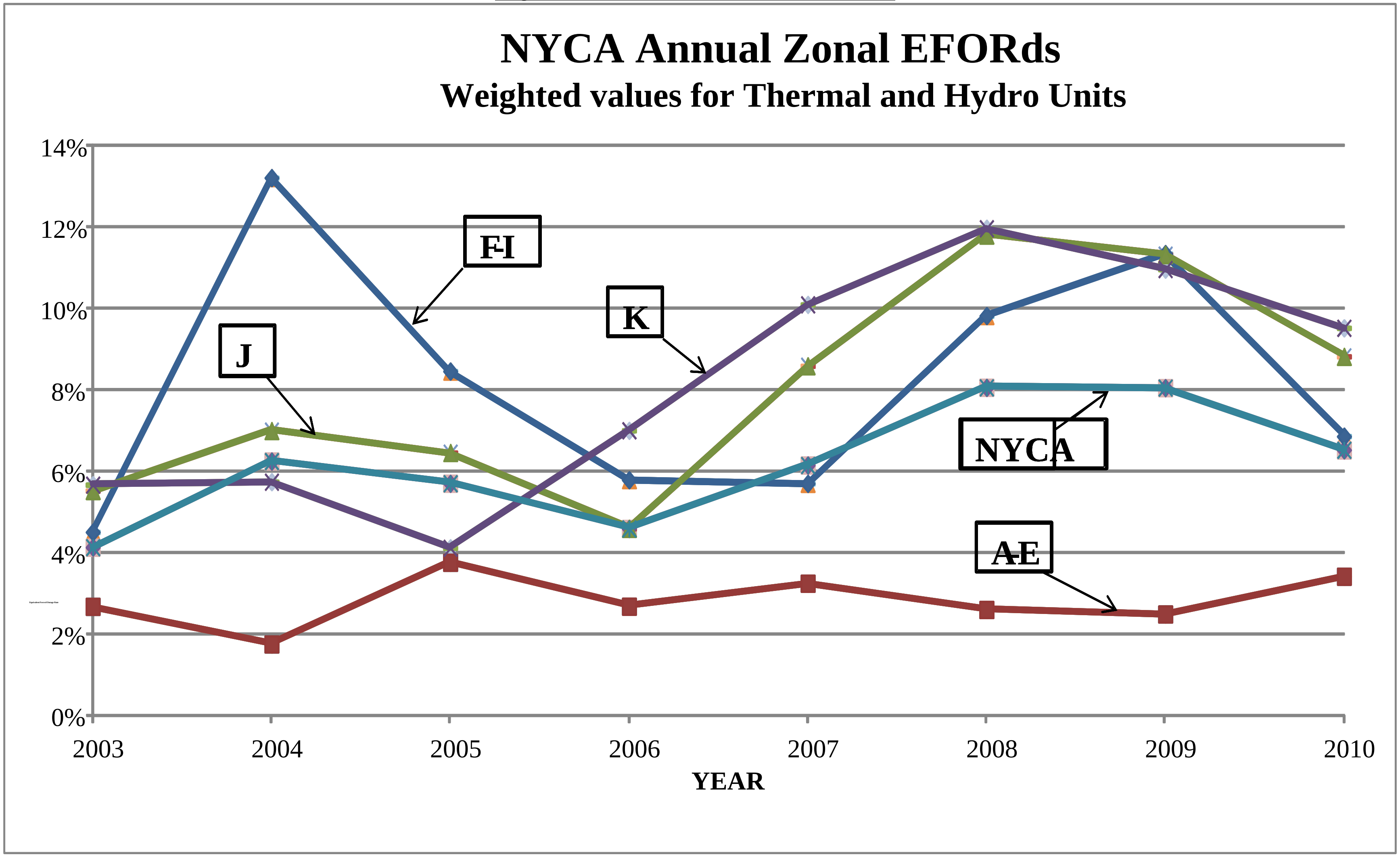


Figure A-4: Five-Year rolling EFORds

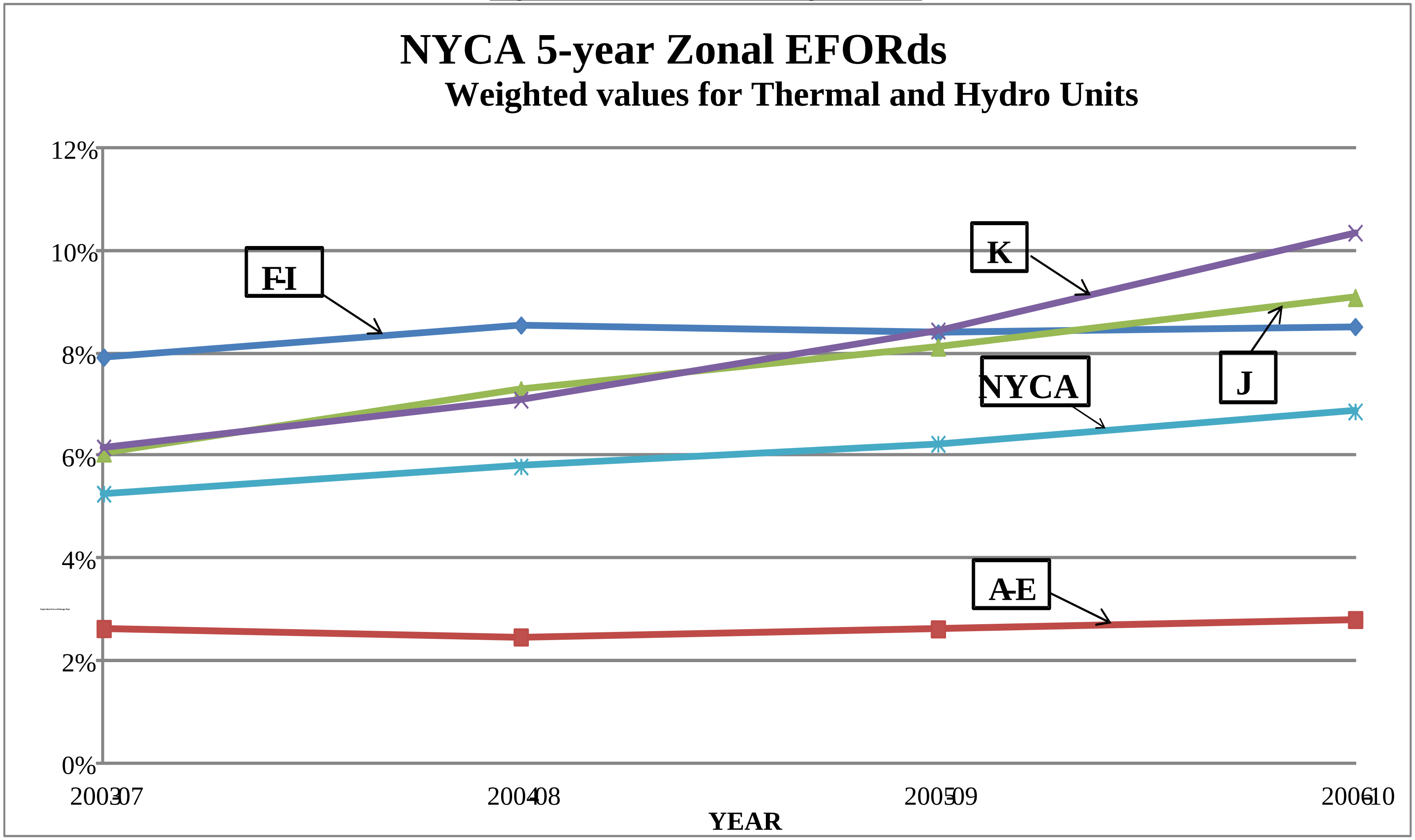


Figure A-5: NYCA Annual Availability by Fuel

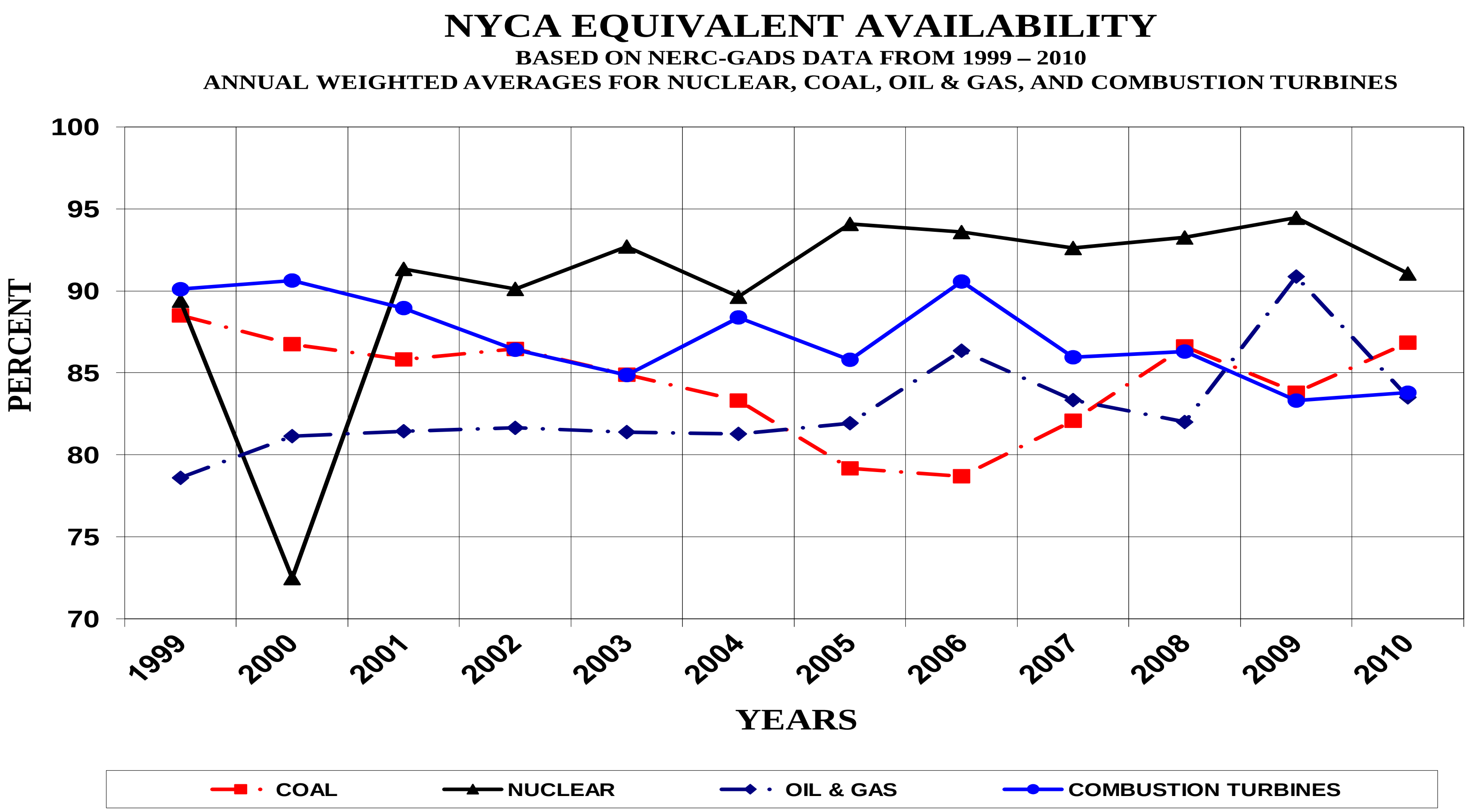


Figure A-6: NYCA Six-Year Availability by Fuel

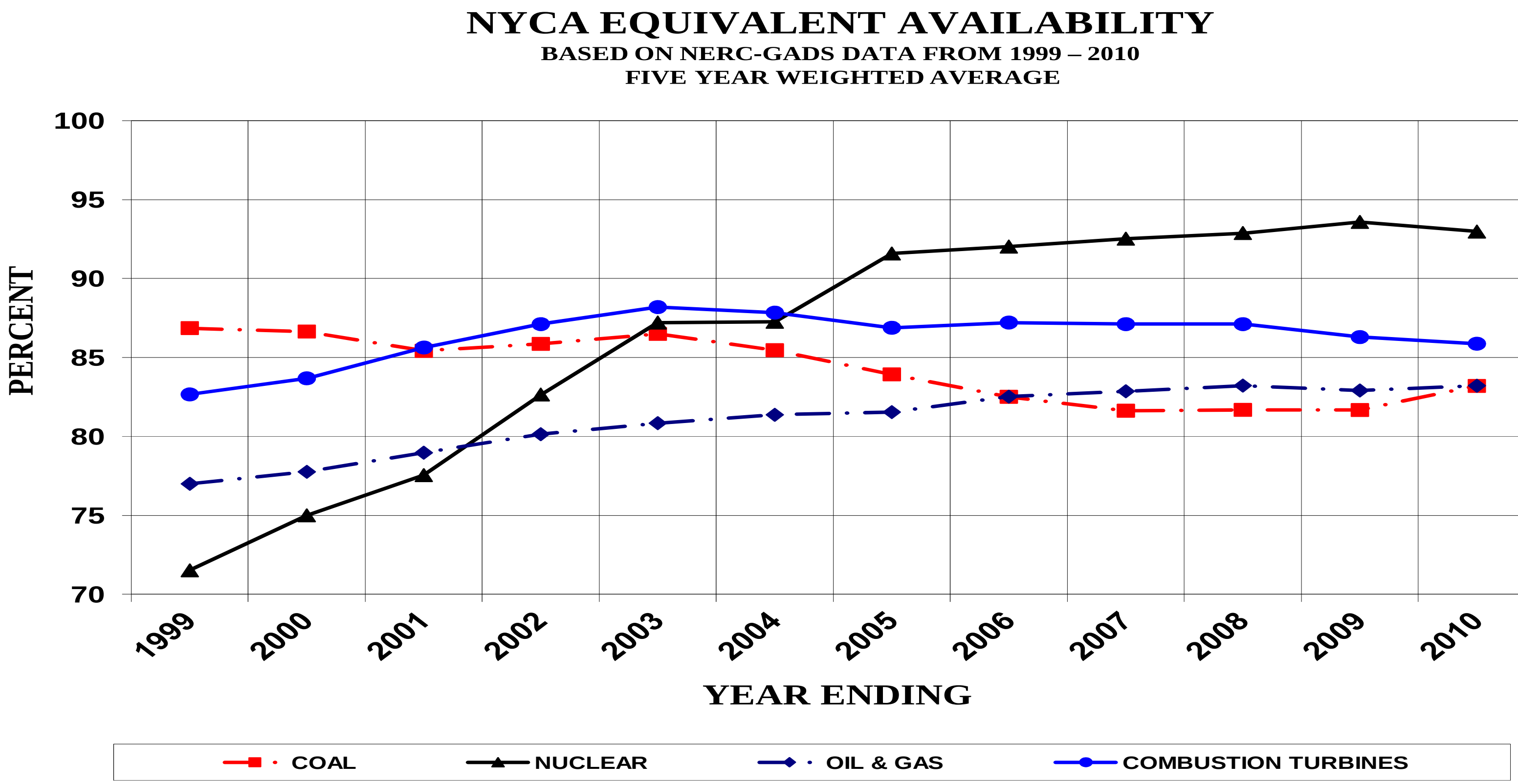


Figure A-7: NERC Annual Availability by Fuel

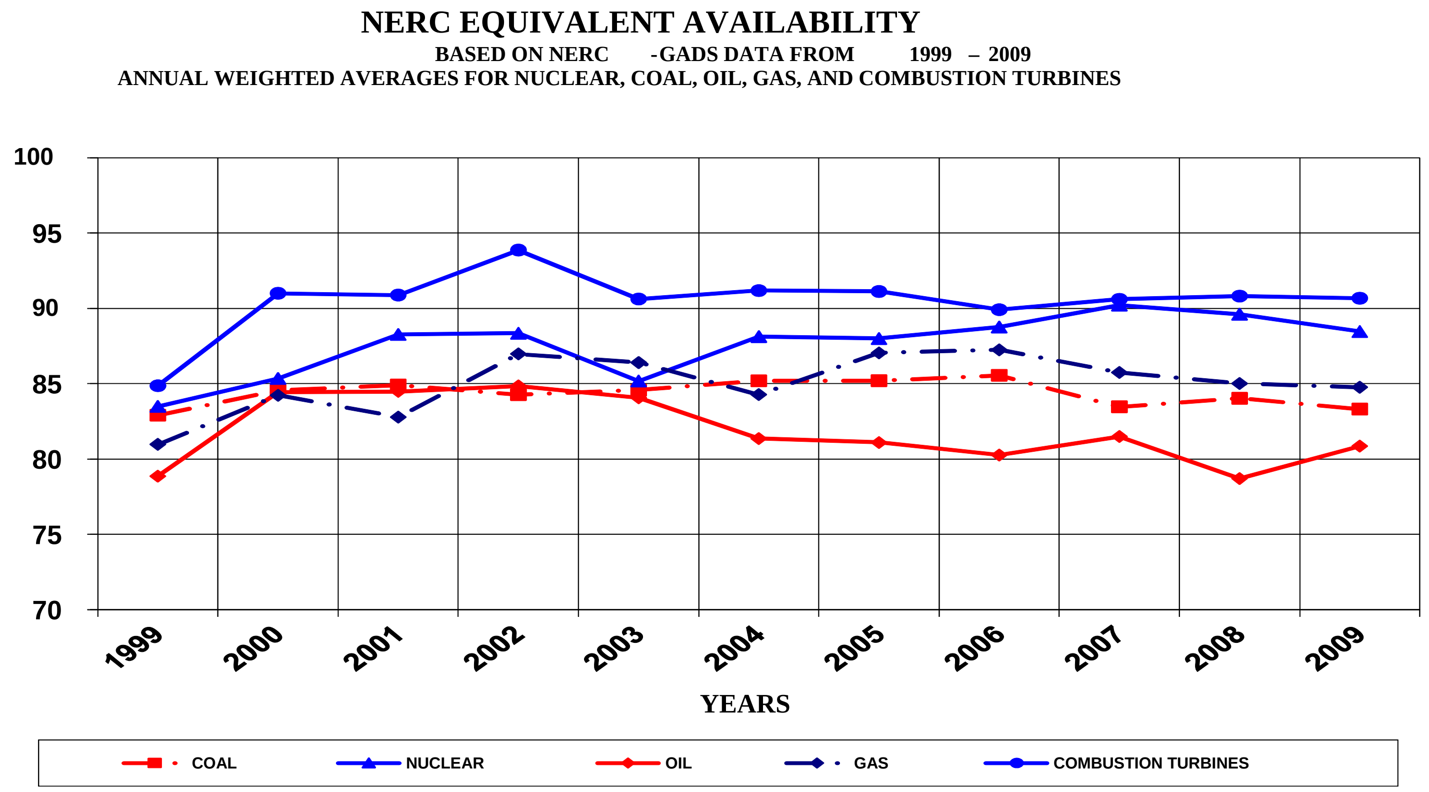
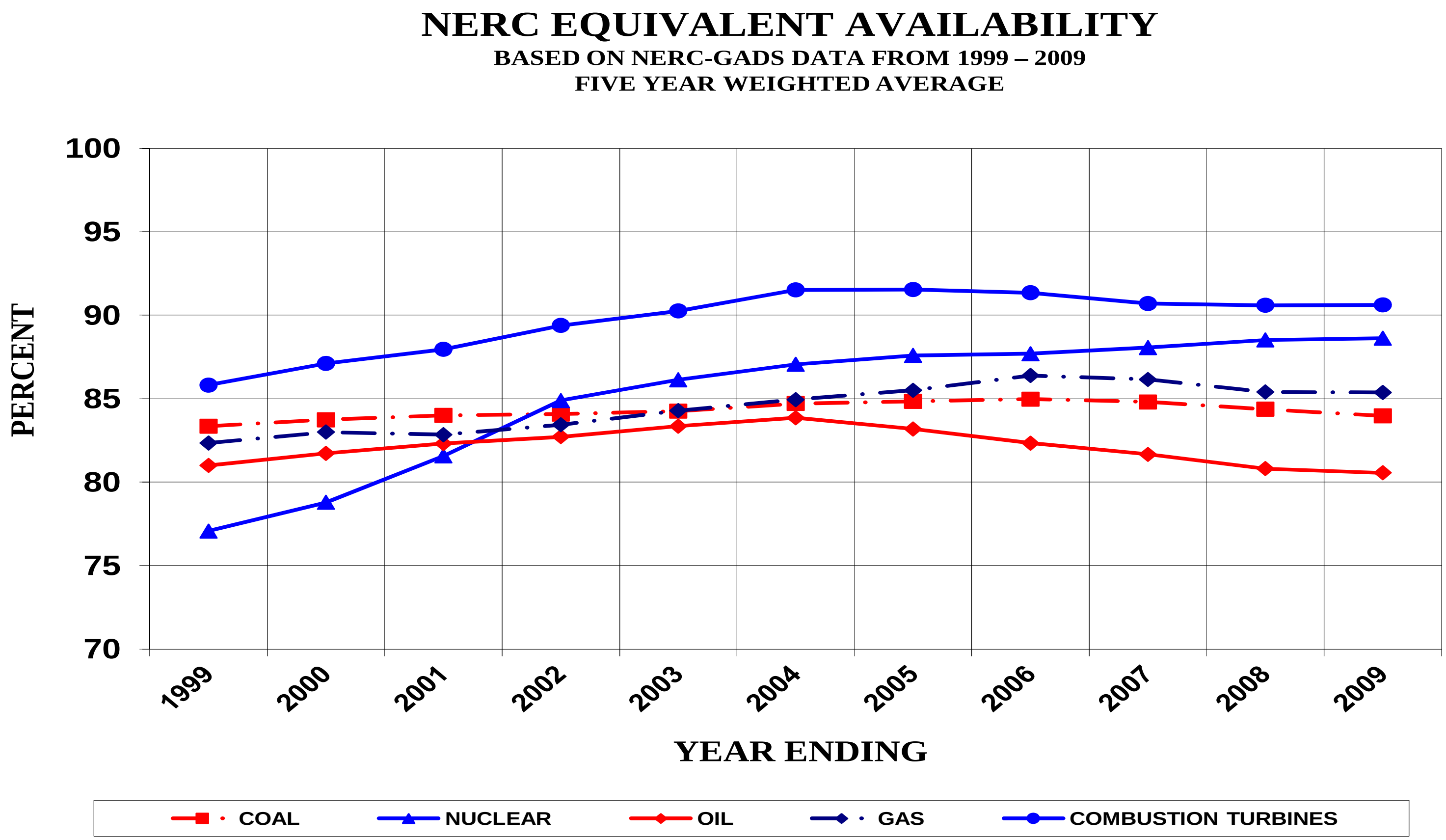


Figure A-8: NERC Five-Year Availability by Fuel



(7) Planned Outages and Summer Maintenance

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage component is obtained from the generator owners, and where necessary, extended so that the scheduled maintenance period equals the historic average using the same five year period used to determine EFORd averages. Figure A-9 provides a graph of scheduled outage trends over the 1994 through 2010 period for the NYCA generators.

Typically, generator owners do not schedule maintenance during the summer peak period. However, it is highly probable that some units will need to schedule maintenance during this period. Each year, the previous five year period is reviewed to determine the scheduled maintenance MW during the previous peak periods. An assumption is determined as to how much to model in the current study. For the 2012 IRM study, a nominal 50 MW of summer maintenance is modeled. The amount is equally divided between upstate and downstate. Figure A-10 shows the weekly scheduled maintenance for the 2011 IRM study compared to this study.

(8) Gas Turbine Ambient Derate

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

Review of the simple cycle combustion turbine data, however, has led the NYISO to introduce to the model what is termed a bias. The NYISO plans to extend this analysis in the future to include other capacity limited resources. A 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 on the NYISO web site.

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.

(9) Hydro derates

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model based on historic water flows and unit performance. The remaining approximately 1,000 MW of run of river hydro facilities are simulated in GE-MARS with an availability reduced using a monthly derate with the highest derated values of 45% occurring during the summer months of July and August. These monthly derates are derived using recent historic hydro water conditions.

Figure A-9: Planned and Maintenance Outage Rates

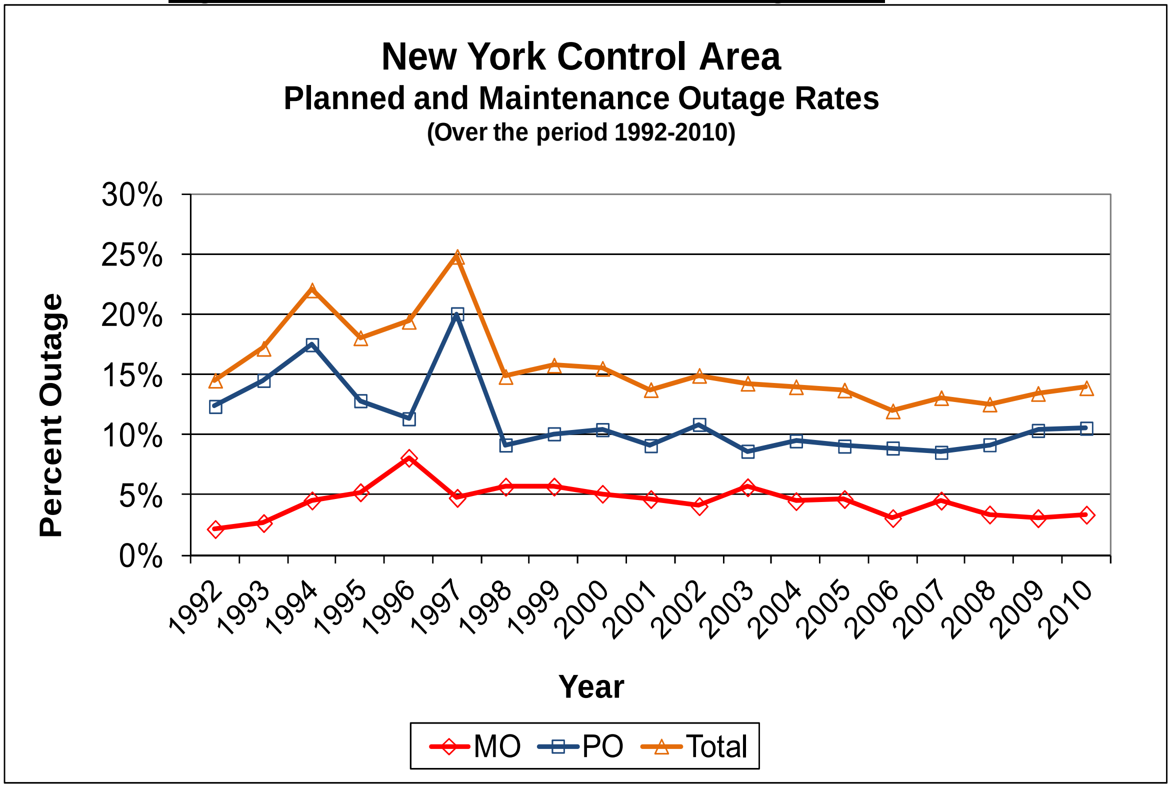
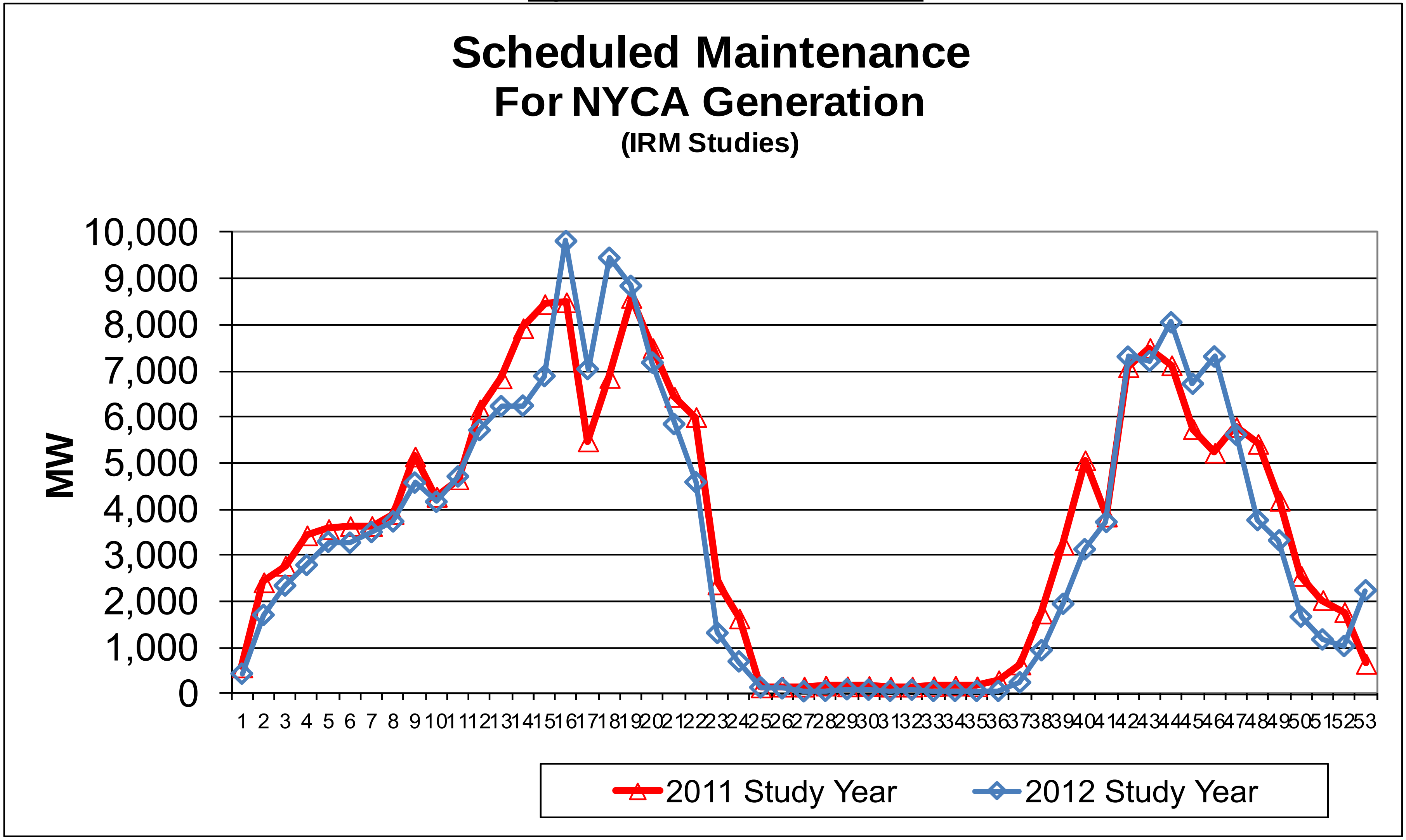


Figure A-10: Scheduled Maintenance



A.3.3 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. The transfer limits employed for the 2012 IRM Study were developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional analysis conducted specifically for the GE-MARS representation. The assumptions for the transmission model included in the 2012 IRM study are listed in Table A-7.

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. A recent extended cable outage caused an increase in the average cable FOR, resulting in a slight IRM increase.

Based on a recent study performed by LIPA, and reviewed by NYISO staff, LIPA export limits were revised due to retirement of Far Rockaway ST 04, Glenwood ST 04 and Glenwood ST 05. The LI Sum (Y49, Y50, 901, 903) export limit was decreased from 535 MW, assumed in the 2011 IRM study, to 285 MW. The LIPA to Con Ed (Zone K to Zone J or the 901 and 903 circuits) export limit was decreased from 508 MW to 430 MW. Dynamic limits and nomograms associated with these interfaces were also updated based on the study scenarios.

Table A-7: Transmission System Model

Transmission System Model			
Parameter	**2011 Study Assumption**	**2012 Study Assumption**	**Explanation of Change**
Interface Limits	Based on 2011 Operating Study, 2011 Operations Engineering Voltage Studies, 2011 Comprehensive Planning Process, and additional analysis including interregional planning initiatives	All changes viewed and commented on by TPAS	Based on 2011 Operating Study, 2011 Operations Engineering Voltage Studies, 2011 Comprehensive Planning Process, and additional analyses including interregional planning initiatives
New Transmission Capability	Upgrade on Northport Norwalk Cable (NNC) line to 428 MW from 286 MW	None Identified	Based on TO provided models and NYISO review.
Transmission Cable Forced Outage Rate	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history	All existing Cable EFORs updated on LI and NYC to reflect 5 year history	Based on TO analysis
Unforced Capacity Deliverability Rights (UDRs)	No new projected UDRs	No new projected UDRs	Contracted amounts of capacity are confidential and are included as capacity internal to NYCA

Figure A-11 shows the system transmission representation for this year's study. Figure A-11.1 shows a more detailed representation of the interconnections surrounding the PJM/NYCA downstate interface. Finally, Figure A-11.2 shows the 13 zone New England Representation in more detail.

Figure A-11: 2012 Transmission Representation

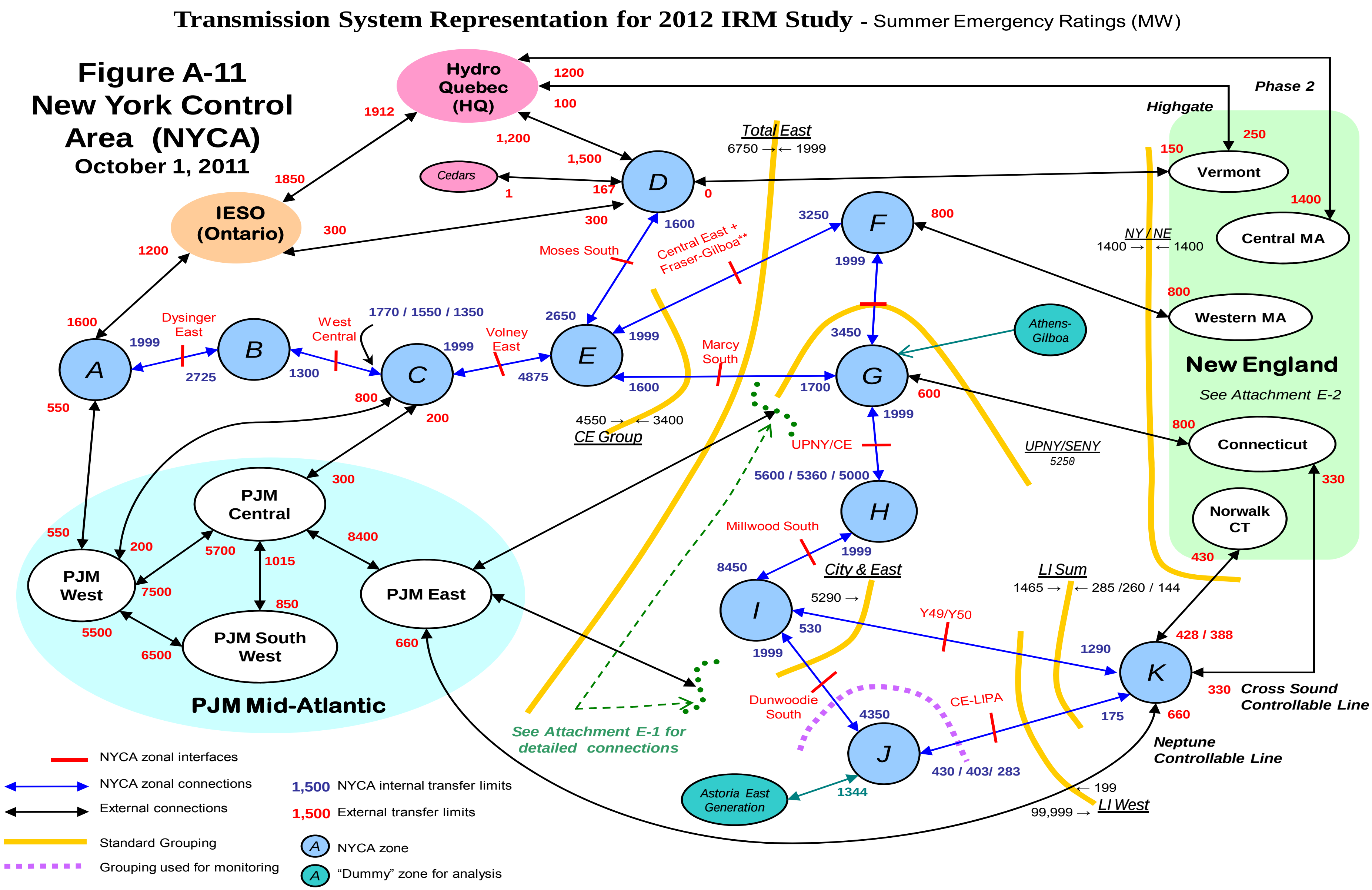
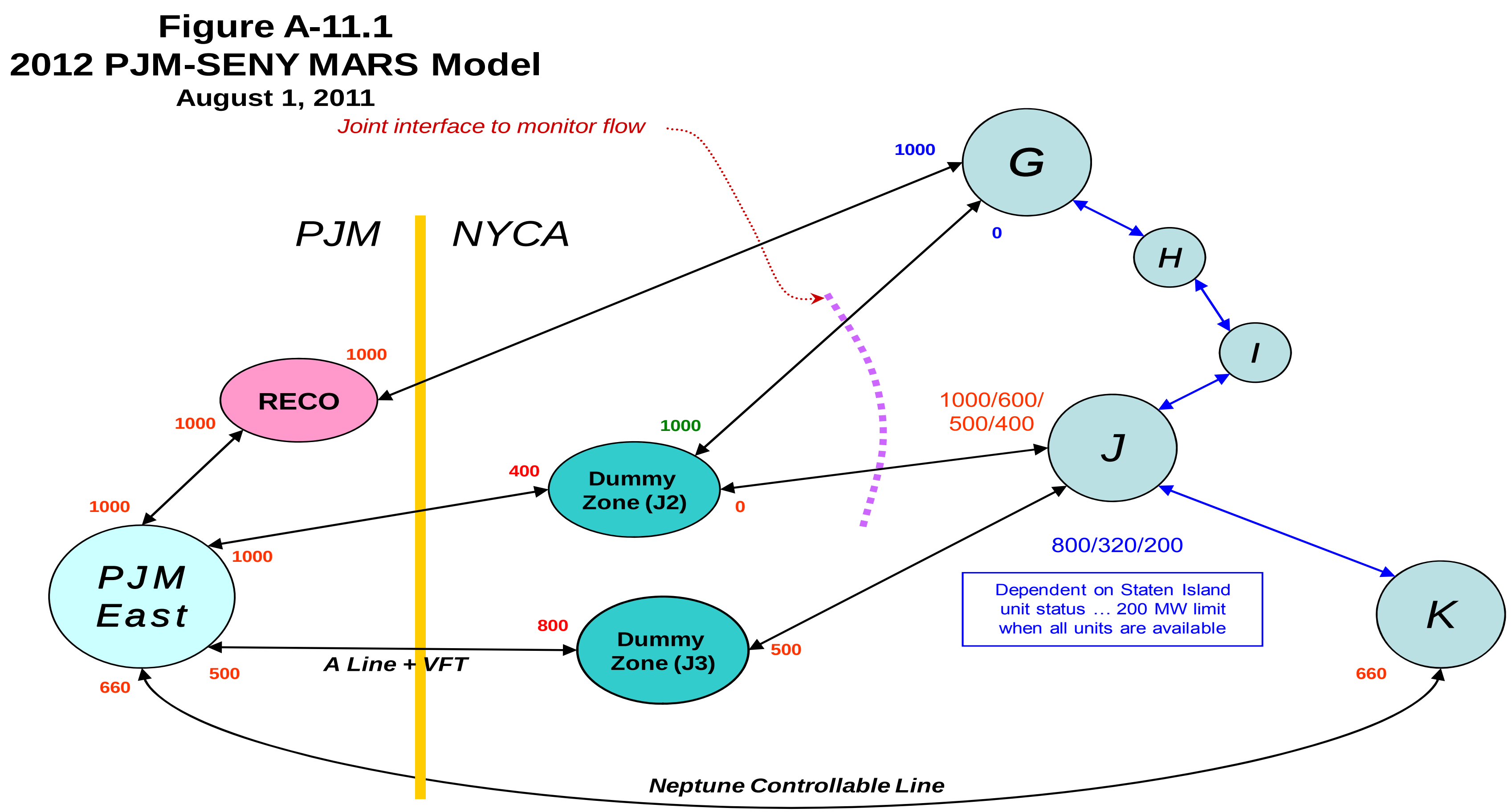


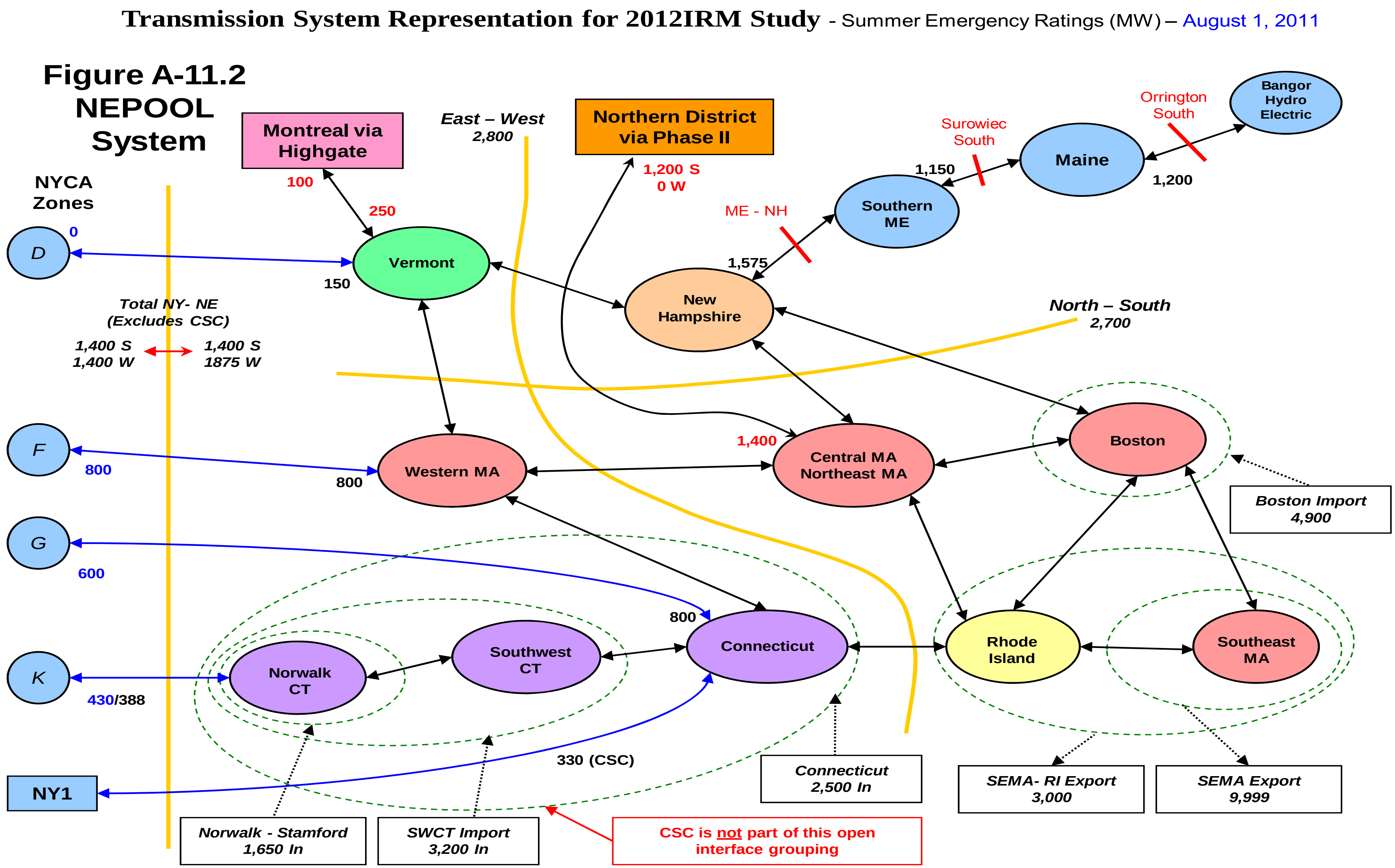
Figure A-12: PJM – NY Interface Model

Transmission System Representation for 2012 IRM Study - Summer Emergency Ratings (MW)



(PJM East to RECO) + (J2 to J) + (PJM East to J3) = 2000

Figure A-13: Full New England Representation



A.3.4 External Area Representations

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 5-5 is as follows:

Table A-8: External Area Representations

External Area Representations			
Parameter	**2011 Study Assumption**	**2012 Study Assumption**	**Explanation of Change**
Capacity Purchases	Grandfathered amounts of 50 MW from NE, 37 MW from PJM, and 1,090 MW from Quebec modeled as actual contracts on border interfaces. Also, 1,043 MW modeled as de-ration on the upstate ties to PJM	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1,090 MW from Quebec. All contracts modeled as equivalent contracts	Equivalent contracts do not require an additional re-adjustment of external areas per Policy 5
Capacity Sales	In addition to the long term firm sales of 303 MW (nominal value), include known firm contracts of 716 MW as a result of NE FCM market auctions. Contracts modeled on border interfaces	Long term firm sales of 303 MW (nominal value)	During NE FCM reconfiguration auctions, the sales positions for 2012 were bought out by internal NE parties
Capacity Wheels	None modeled. A sensitivity case may be run	None modeled. A sensitivity case will be run	The ISO tariff is silent about capacity wheels through NYCA
External Area Modeling	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England	The load and capacity data is provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally among all	All NPCC Control Areas have indicated that they will share reserves equally among all	Per NPCC CP-8 working group assumption

A.3.5 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-10 were provided by the NYISO based on operator experience. Table A-9 lists the assumptions modeled.

Table A-9: Assumptions for Emergency Operating Procedures

Emergency Operating Procedures			
Parameter	**2011 Study Assumption**	**2012 Study Assumption**	**Explanation of Change**
Special Case Resources	2498 MW (Aug 11) based on NYISO growth rate forecast. Monthly variation based on historical experience	2192 MW (Jul 12) based on registrations and NYISO growth rate forecast. Monthly variation based on historical experience	Those sold for the program, discounted to historic availability. Sensitivity
EDRP Resources	260 MW registered; modeled as 172 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month	148 MW registered; modeled as 95 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month	Those registered for the program, discounted to historic availability (64% overall). Summer values calculated from 2011 July registrations
EOP Procedures	737 MW of non-SCR/EDRP MWs	735 MW of non-SCR/EDRP MWs	Based on TO information, measured data, and NYISO forecasts

The values in Table A-10 are based on a NYISO forecast that incorporates 2011 operating results. This forecast is applied against a 2012 peak load forecast of 33,335 MW. The 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 assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A-10: Emergency Operating Procedures Values

Emergency Operating Procedures			
Step	**Procedure**	**Effect**	**MW Value**
1	Special Case Resources (SCRs)	Load relief	2192 MW*
2	Emergency Demand Response Programs (EDRPs).	Load relief	148 MW**
3	5% manual voltage Reduction	Load relief	62 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	442 MW***
6	Voluntary industrial curtailment	Load relief	143 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 August is 2,498 MW.*
*** The EDRPs are modeled as 260 MW discounted to 172 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 2011 peak load of 32,872MW.*

A.3.6 Location 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.3.7 Special Case Resources and Emergency Demand Response Program

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

	Forecast ICAP	Performance
Zones A-E	1199 MW	89.4%
Zones F-I	277 MW	87.7%
Zone J	554 MW	74.5%
Zone K	162 MW	82.7%

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.

SCRs are modeled with monthly values. For the month of August, the value is 2192 MW. This value is the result of applying three year historic growth rates to the latest participation numbers.

EDRPs are modeled as a 95 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 148 MW.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

General Electric was asked to review the input data for errors. GE has 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 than 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-11.

Table A-11: GE MARS Data Scrub

GE Findings				
Item	**Description**	**Disposition**	**Change Require d**	**Effect on IRM**
1	Solar cap of 38.5 MW shows a July reading of 30.8 MW	Peak occurs in August at 38.5 MW Database is correct as is	No	No
2	Stony Creek Wind Farm has incorrect In-Service date	Corrected date	Yes	No
3	The assumption matrix called for 50 MW of scheduled maintenance during the summer period. The actual scheduled maintenance modeled during the peak week was 63.5 MW	The NYISO models specific units for the maintenance. An exact MW match is not expected	No	No
4	The assumption matrix says that all contracts are being modeled as equivalent contracts, but the transfer limits between New York and PJM show 1,080 MW of contracts being modeled as adjustments to the transfer limits	The 1080 MW of derates on the PJM to NY ties represent the grandfathered contracts (37 MW) and the 1043 MW of electric transmission capacity reserved for native load (ETCNL)	No	No
5	Under "Reserve Sharing between Areas" in the assumption matrix, the comment should probably state that the NPCC Control Areas will share reserves equally "among themselves". There are reserve sharing arrangements in the data, but they are such that PJM is always last	It was changed in the description for this year's sharing and is now changed for the description to last year's sharing	No	No
6	The MIF data shows that the ties from HQ to VT and HQ to CMA are being zeroed for the initial non-firm and EOP calculations. This may have been done intentionally to prevent HQ from providing	GE confirms that this modeling assumption performs as intended	No	No

	assistance to New England until New York was also ready to accept outside assistance			
7	The UPNY/SENY interface group shown in the diagram does not appear to include Marcy South, while the MIF data includes it	Diagram is incorrect and will be revised.	No	No
8	The New England Imports appear to be defined as exports in the MIF, although it should not matter since the limits are the same for both directions	Imports to them, exports to us. OK as long as signage is correct	No	No
9	We were not able to check the PJ_GPJ_J interface group in the MIF since it does not appear on the diagram	The description of this grouping appears on the lower left corner of attachment E-1	No	No
10	The ratings on the A to ONT interface in the MIF are reversed from those shown on the diagram	Diagram is incorrect. Update diagram	No	No
11	The tie from HUDV to NE has a rating of 600 MW in the MIF compared to 800 MW on the diagram	Limit value corrected	Yes	No
12	The tie from PJM-C to PJM-SW has a rating of 810 MW in the MIF compared to 850 MW in the diagram	Rating corrected	Yes	No
13	The assumption matrix mentioned a total of 2,192 MW of SCR for July, while the MIF had 1,862 MW based on the coincident peak loads for the zone	Attachment F of the assumptions matrix shows that the 2192 MW is an ICAP value while the 1862 MW is the UCAP modeled.	No	No
14	The assumption matrix showed 95 MW of EDRP being modeled for July and August, while the MIF had 88.6 MW in July and 89.2 MW in August	A revised EOP table has been issued to correct for the several MW shortfall.	Yes	No
15	EFORd analysis	The original analysis made adjustments to 19 units where the EFORs were unrealistic. These adjustments are described in the IRM Study Report Appendix A	No	No

A.4.2 NYISO Data Scrub

The NYISO also performs a review of the MARS data independently from GE. Table A-12 shows the results of this review.

Table A-12 NYISO MARS Data Scrub

NYISO Findings				
Item	**Description**	**Disposition**	**Change Required**	**Effect on IRM**
1	The transfer limits from Ontario into zone A should show 1600 MW of import into NY and 1200 MW of export	Final database and Assumptions Matrix (AM) have been corrected	Yes	No
2	The LFU for PJM's RECO load had not been updated	Final database has been updated to include the latest LFU information	Yes	No
3	Need identified to break the new unit called Bayonne into 8 units, per their reporting determination	Final database has been updated to include this information	Yes	No[8]
4	Stony Creek start date had not been updated	December start state changed to Aug per AM	Yes	No
5	Dynamic rating tied to a retired unit (Far Rockaway ST4)	Dynamic rating re-worked	Yes	No
6	Duplication of Wading River Unit in transition rate table	Software takes the latest entry of data. This entry was correct	No	No

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions from a masked database provided. Table A-13 shows these results.

Table A-13: Transmission Owner MARS Data Scrub

Transmission Owner Findings				
Item	**Description**	**Disposition**	**Change Required**	**Effect on IRM**
1	Interface ratings for LI to Con Ed should have changed with Far Rockaway retirement	A nomogram was developed to represent the interface changes without the retired units.	Yes	No
2	EOP table SCR values fall short of the Assumption Matrix listed values	A revised EOP table was issued to correct for the MW shortfall	Yes	No

8 Although the change in NYCA was less than a 0.001 days/year reduction, the LOLE was reduced in NYC by 0.002 days/year.

3	In the "INF-DATA-00" table, the full interface name "AREA_K - NORWICH" should be "AREA_K - NORWALK" for the NYCA to ISONE interface "LI_NE "	Correct name in MIF	No	No
4	There is an extra letter "x" at the end of the data line of "@MAY2011** 'AMRFF2 '	This was introduced in the masking process. Preliminary base case mif is correct.	No	No
5	There are some differences of the unit maximum capacities found between the NYISO database and the NYISO Gold Book 2011	Assumption matrix assumes the lesser of DMNC vs. CRIS MW values for the model.	No	No
6	Wind shape totals exceed the 1648 MW listed	There was a mismatch in the mif and the wind shapes sent to TOs. The mif was updated and is now correct	No	No

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B-1 summarizes the 2012 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the base case 16.5% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criteria. The values in Table B-1 are the sensitivity results adjusted to the 16.1% final base.

Table B-1: Sensitivity Case Results

	Sensitivity Cases for 2012 IRM Study			
Item	**Description**	**IRM (%)**	**NYC (%)**	**LI (%)**
	Transmission Sensitivities			
2	**No Internal NYCA Transmission Constraints (Free Flow System)**	13.8	NA	NA
	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.			
16	**Model 300 MW Wheel from HQ to NE through NYCA**	16.2	84.0	99.3
	A 300 MW wheel from Quebec to NE was modeled as an equivalent contract (derate Chateauquay tie by 300 MW and also derate ties from zones F and G to New England by an aggregate 300 MW).			
	Assistance from Outside World Modeling			
1	**NYCA Isolated**	24.7	90.1	105.7
	This case examines a scenario where the NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). UDRs are allowed. See the "Base Case Results – Interconnection Support during Emergencies" section of the report.			
7	**Higher Outside World Margins**	11.9	80.8	96.0
	Increases each external Control Area's Reserve Margin by lowering their load by 10%. Examines the NYCA IRM under the conditions where external Control Area's have additional capacity which could help NYCA in emergencies.			
8	**Lower Outside World Margins**	22.6	88.6	104.1
	Decreases each external Control Area's Reserve Margin by increasing their load by 10%. Examines the NYCA IRM under conditions where external Control Areas have less capacity available to help NYCA in emergencies.			

18	**Updated PJM Model**	15.2	82.1	97.4
	The PJM data was late to arrive. This sensitivity incorporates the PJM changes from last year's representation. The revised PJM representation has not been vetted at the ICS.			
	Generation Sensitivities			
9	**Increase EFORs from Base Case**	18.7	85.8	101.1
	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. The case is accomplished by increasing thermal unit EFORs by 1.0 percentage point.			
10	**Decrease EFORs from Base Case**	15.6	83.5	98.8
	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. The case is accomplished by reducing thermal unit EFORs by 1.0 percentage point (Units already better than 1.0 %EFOR were left alone).			
15	**Retirement of Indian Point 2 and 3**	21.6	91.9	107.2
	Removes the Indian Point plant and returns capacity (as per the sensitivity procedure) to all NY zones. This case did not evaluate the impact of the retirement on transfer capability and kept all interface ratings unchanged.			
4	**Remove all wind generation**	11.4	83.9	99.2
	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact that the wind generation has on the IRM requirement.			
12	**Composite Wind Profile**	15.8	83.7	99.0
	Use the years 2002, 2004, 2005, and 2006 to construct a composite wind shape based on the hourly means of those years.			
13	**Alternate EFORd calculation**	15.1	83.2	98.4
	This method creates generator unit forced outage rates that approach the NYISO market EFORds. . This is an interim result as the new EFORd model is still under development and the implementation software has not been fully reviewed nor validated. It is expected, however, that the IRM using this new model will be lower than the 2012 base case IRM after it is fully developed and adopted in 2012.			
	Load Sensitivities			
3	**No Load Forecast Uncertainty**	8.8	78.7	93.7
	This scenario represents "perfect vision" for 2012 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 on IRM requirements.			
17	**Replace Con Ed's 1:3 forecast with a 1:2 forecast**	17.3	85.2	99.6
	This sensitivity shows the impact of using a 1 in 2 peak load forecast instead of the current 1 in 3 forecast for Con Edison. Note that the capacity requirements when expressed in MWS are unchanged as a result of this case. The 16.1% IRM applied against the peak load forecast yield a requirement of 1.161x33335 = 38,702MW. The resultant 17.27% applied against the lower forecast of 33,005 essentially equals the same value of 38,704MW. The LCR requirement for NYC in MW also does not change.			
11	**Create a composite load shape**	13.7	82.1	97.4

	A composite hourly load shape was constructed based on the hourly averages of the years 2005, 2006, 2007, 2009, and 2010.			
Emergency Operating Procedures				
5	**No EDRP Program**	16.3	84.0	99.3
	Highlights the impacts of the Emergency Demand Resource Program only.			
6	**No SCRs or EDRPs**	15.5	83.5	100.8
	Verifies the impact of SCRs and EDRPs on IRM.			

B.2 Environmental Initiatives

The NYISO's 2010 Comprehensive System Planning Process (CSPP) indentified new environmental regulatory programs designed to improve air quality and address the impact of a power plant's cooling water systems on aquatic life. These were assessed for the potential impacts on reliability. These regulatory initiatives, which are being promulgated by both state and federal environmental regulatory agencies, cumulatively will require considerable investment by the owners of New York's existing thermal power plants in order to comply if they are promulgated as currently proposed. The programs assessed were the following:

1. NOx RACT - Reasonably Available Control Technology
2. BART - Best Available Retrofit Technology
3. MACT - Maximum Achievable Control Technology
4. BTA - Best Technology Available

The NYISO has determined that as many as 23,947 MW in the existing fleet or 64% of existing NYCA capacity will have some level of exposure to the new regulations as detailed in the 2010 RNA and further discussed in this review. The New York State Department of Environmental Conservation (NYSDEC) has estimated the cost to comply with the BTA policy alone could exceed $8 Billion if all affected units were required to retrofit by installing cooling towers. The magnitude of the combined investments required to comply with the four initiatives could lead to multiple unplanned plant retirements.

Since the publication of the CSPP, significant developments in the environmental regulatory landscape have taken place:

In July 2011, the USEPA replaced the Clean Air Transport Rule (CATR) proposal with the finalized Cross State Air Pollution Rule (CSAPR). The rule requires significant additional reductions of SO_2 and NOx emissions beyond those previously proposed in CATR. CSAPR establishes a new emission allowance system for units greater than 25 MW nameplate capacity. Affected Generators will need one allowance for each ton emitted in a year. In NY, CSAPR will affect 167 units that represent 23,275 MW of capacity. The first reduction starts in 2012 with additional reductions required in

2014. The USEPA has proposed a technical correction to provide additional emission allowances for NY generators. With these additional allowances there are multiple scenarios which show that NY can operate reliably with the program in 2012. Compliance actions for the second phase that begins in 2014 will likely include emission control retrofits, fuel switching, and new clean efficient generation. USEPA has estimated NY's Annual Allowance costs for 2012 at $65 Mil.

USEPA issued a proposal in March 2011 to establish emission rate standards for the Maximum Achievable Control Technology (MACT) for hazardous air pollutants (HAP) from coal and oil fueled steam generators with a nameplate capacity greater than 25 MW. MACT will affect 32 units that represent 10,844 MW of capacity. The majority of the NY coal fleet has installed emission control equipment that will put compliance within reach. Several coal fired units, however, may need to fuel switch or undertake extensive emission control retrofits. The heavy oil fired units will need to either make significant investments in emission control technology, or switch to cleaner fuels in order to comply with the proposed standards. The rule is scheduled to be finalized in November of this year with compliance requirements beginning in late 2014. The NYISO joined other RTOs in seeking a regulatory "safety valve" to maintain reliable electric system operation during the period when environmental retro fits or replacement units are being built.

USEPA has proposed Section 316 b rules that set standards for the design and operation of open cycle cooling systems. This rule will be implemented by NYSDEC which has finalized a policy for the implementation of this rule known as Best Available Technology. NY power plants with open cycle cooling systems will need to conduct studies and demonstrate that their systems can be modified to achieve reductions in aquatic impacts equivalent to 90% of the reductions that could be achieved by the use of a closed cycle cooling system, e.g. cooling tower. This policy is activated upon renewal of a plant's State Pollutant Discharge Elimination System (SPDES) permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4000-7000 MW of capacity could be required to retrofit closed cycle cooling systems. The most publically recognized application of this policy is Indian Point.

The class of steam electric units constructed between 1963 and 1977 are subject to continuing emission reductions required by the Clean Air Act. The reductions are required to reduce their respective impacts on visibility levels at National Parks. In NY, 8, 243 MW of capacity is affected. The owners of these units have submitted their visibility impact analyses and plans for Best Available Retrofit Technology (BART) to NYSDEC and the Federal Land Managers for approval. The oil fired units are proposing alternatives that include the status quo, lower sulfur fuels, and low NOx combustion systems. One coal fired plant owner claims the filing is competitive business information. Two smaller coal plant owners have planned to retire small boilers. The plants are required to have implemented their plans by January 2014.

NYSDEC promulgated revised regulations for the control of Nitrogen Oxides emissions from fossil fueled electric generating units (NOx RACT). Emission reductions required by these revised regulations must be in place by July 2014. Generators must file compliance plans which are due January 2012

While the CSAPR is the only regulation that implements new requirements in 2012, generation owners will need to consider the cumulative effect of this series of new regulatory requirements that may lead to increased operating costs as well as demands for additional capital. These demands, when viewed against a competitive market place which includes cleaner more efficient generators that burn increasing plentiful and economically attractive supplies of natural gas (and have lower operating costs), may influence some owners to curtail operations or retire plants.

B.3 Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. For the base case, the study shows that approximately 9.5 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-2.

Table B-2: Implementation of Emergency Operating Procedures *

Base Case Assumptions (IRM = 16.1 %)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	21.0
Require EDRPs	10.4
5% manual voltage reduction	10.0
30 minute reserve to zero	9.7
5% remote control voltage reduction	9.5
Voluntary load curtailment	6.5
Public appeals	4.9
Emergency purchases	4.4
10 minute reserve to zero	4.1
Customer disconnections	0.1

* See Appendix A, Table A-7

Appendix C

ICAP to UCAP Translations

C. ICAP to UCAP Translation

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

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

Table C-1 summarizes historical values (since 2000) for NYCA capacity parameters including Base Case IRMs, approved IRMs, UCAP requirements and LCRs (for NYC and LI).

Table C-1: Historical NYCA Capacity Parameters

Capability Year	Base Case IRM (%)	EC-Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYC LCR (%)	LI LCR (%)
2000	15.5	18.0		80	107
2001	17.1	18.0		80	98
2002	18.0	18.0		80	93
2003	17.5	18.0		80	95
2004	17.1	18.0	11.9	80	99
2005	17.6	18.0	12.0	80	99
2006	18.0	18.0	11.6	80	99
2007	16.0	16.5	11.3	80	99
2008	15.0	15.0	8.4	80	94
2009	16.2	16.5	7.2	80	97.5
2010	17.9	18.0	6.1	80	104.5
2011	15.5	15.5	8.2	81	101.5
2012	16.1	16.0	TBD	TBD	TBD

C.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO Web site, the NYISO Staff regularly posts ICAP and UCAP calculations for both the summer and winter Capability Periods. This publicly available information can be found on the NYISO web site.[9]

Information has been compiled by the NYISO on this site since 2006 and includes complete information through 2010. This information is provided for Locational Areas and for the Transmission District Loads.

The Locational Areas include NYC, LI and the entire NYCA. Exhibits C-1(a) through C-1(c) summarizes translation of ICAP requirements to UCAP requirements for these Locational Areas. The charts and tables included in these exhibits utilize data from the 2006-2010 capability periods (and limited to "summer" only, for purposes of simplicity).

Importantly, this data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, Derating Factors, UCAP Requirements, IRM and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation also helps one more easily visualize the annual changes in capacity requirements.

Several interesting observations can be made from these results. For example, in the NYCA chart (Figure C-1), the IRM for 2009 was 16.5% with a calculated UCAP requirement of 36,362.4 MW. Despite the increase in 2010 to an 18% IRM, the UCAP requirement actually decreased to 35,045.3 MW.

These charts also depict the dynamics of the LCRs upon the NYC and LI locational areas. For example, in the New York City chart (Figure C-2), the LCR for NYC remained constant at 80% from 2006 through 2010. Over this period, the required UCAP for NYC increased through 2009 and decreased in 2010.

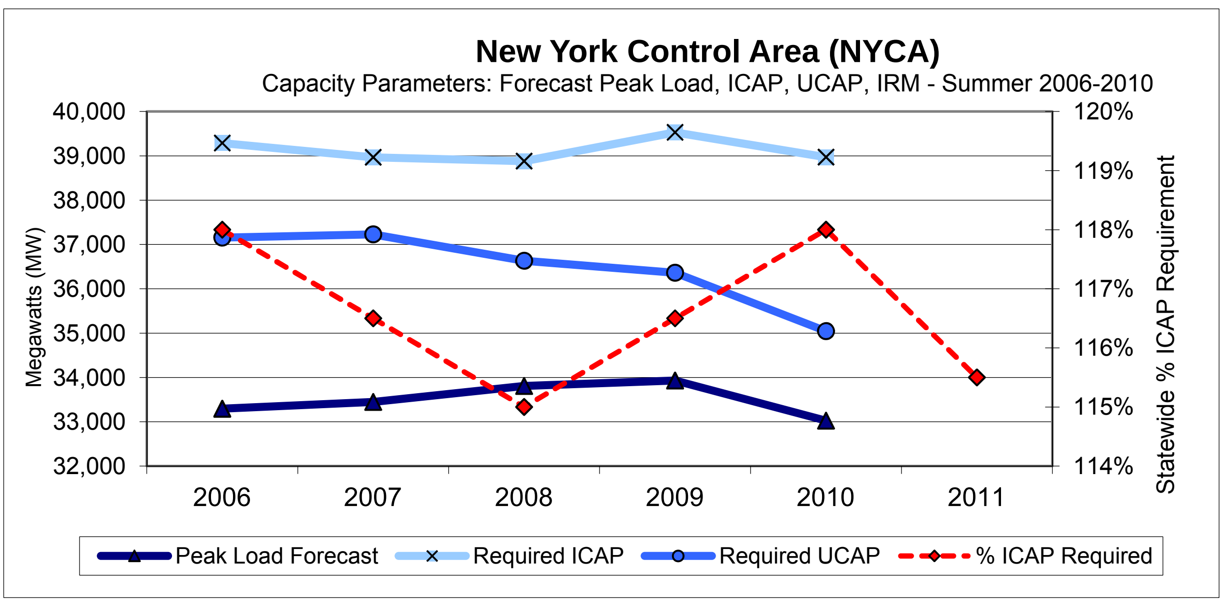
For Long Island (Figure C-3), the more volatile LCR produced ICAP and UCAP curves of similar shape; it is easy to see how LCR influences these parameters. From 2009 to 2010, the LCR for LI increased from 97.5% to 104.5% from 2009 to 2010 with a commensurate increase in ICAP and UCAP requirements.

9 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

C.1.1 New York Control Area ICAP to UCAP Translation

Table C-2: NYCA ICAP to UCAP Translation

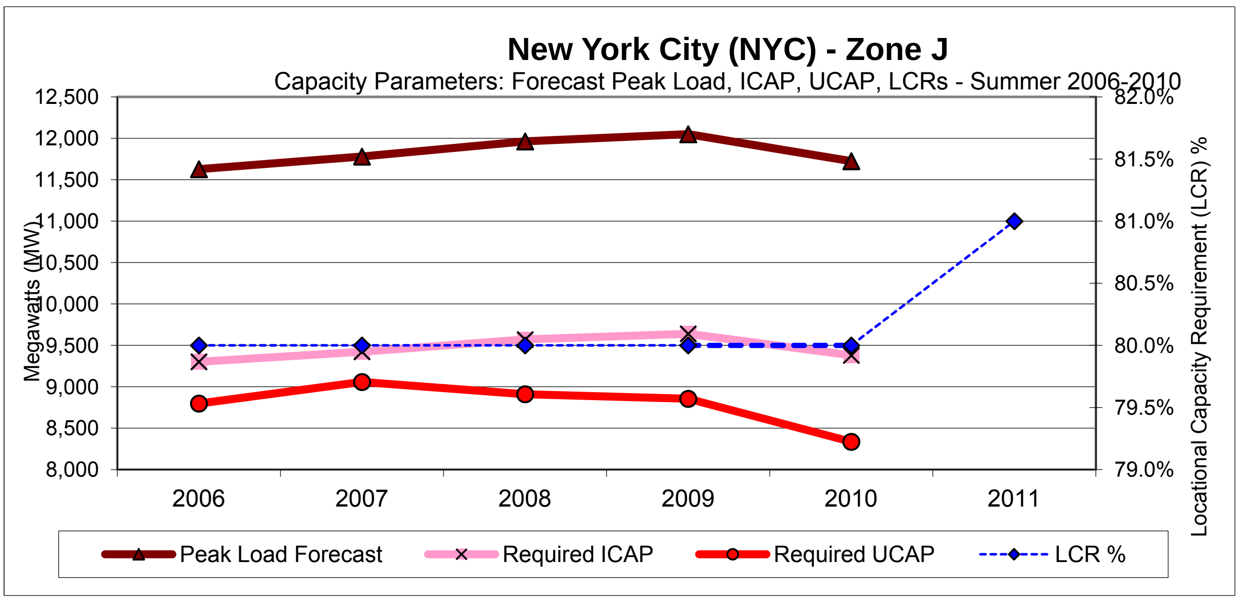
Year	Forecast Peak Load (MW)	ICAP Requireme nt (%)	Derate Factor (%)	ICAP Requiremen t (MW)	UCAP Required (MW)	Effective UCAP (%)
2006	33,295	118.0	.0543	39,288	37,154	111.6
2007	33,447	116.5	.0446	38,966	37,228	111.3
2008	33,806	115.0	.0578	38,880	36,633	108.4
2009	33,930	116.5	.0801	39,529	36,362	1072
2010	33,025	118.0	.1007	38,970	35,045	106.1
2011	32,712	115.5	.0820	37,783	34,684	106.0
2012		TBD		TBD		



C.1.2 New York City ICAP to UCAP Translation

Table C-3: New York City ICAP to UCAP Translation

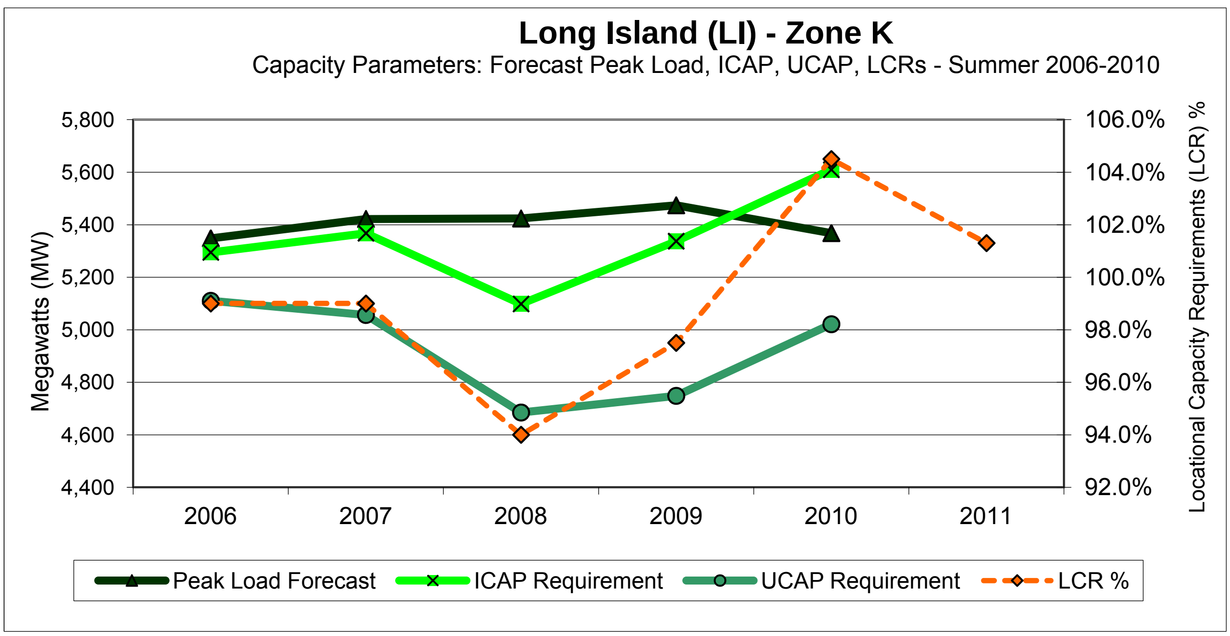
Year	Forecast Peak Load (MW)	ICAP Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Required (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9302	8798	75.7
2007	11,780	80.0	0.0388	9424	9058	76.9
2008	11,964	80.0	0.0690	9571	8911	74.5
2009	12,050	80.0	0.0814	9640	8855	73.5
2010	11,725	80.0	0.1113	9380	8336	71.1
2011	11,514	81.0	0.0530	9326	8832	76.7
2012		TBD		TBD		



C.1.3 Island ICAP to UCAP Translation

Table C-4: Long Island ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Required (MW)	Effective UCAP (%)
2006	5348	99.0	0.0348	5295	5110	95.6
2007	5422	99.0	0.0580	5368	5056	93.3
2008	5424	94.0	0.0811	5098	4685	86.4
2009	5474	97.5	0.1103	5337	4749	86.7
2010	5368	104.5	0.1049	5610	5021	93.5
2011	5434	101.5	0.0841	5516	5052	93.0
2012		TBD		TBD		

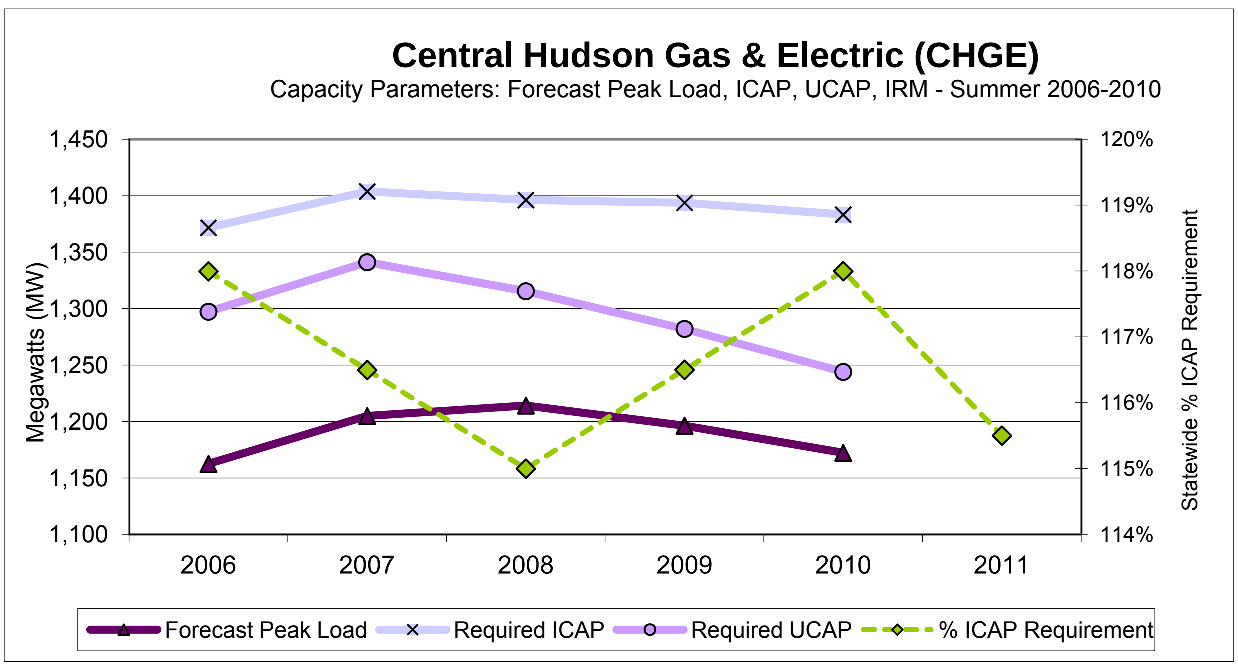


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

Table C-C-1: Central Hudson Gas & Electric ICAP to UCAP Translation

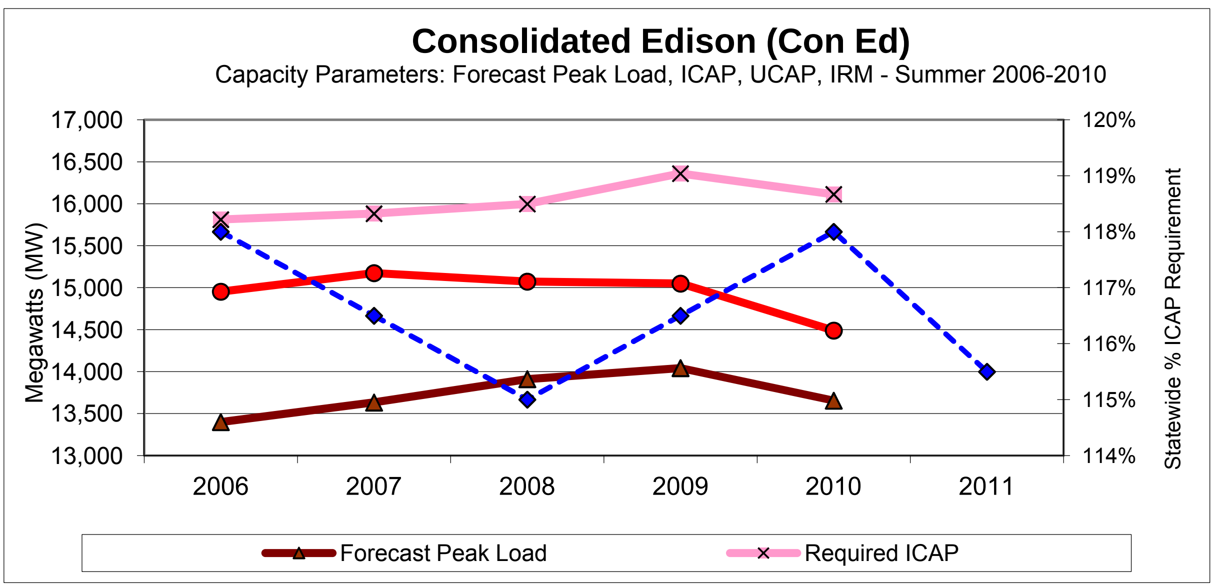
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1163	1372	1297	118.0	111.6
2007	1205	1404	1341	116.5	111.3
2008	1214	1396	1316	115.0	108.4
2009	1196	1394	1282	116.5	107.2
2010	1172	1383	1244	118.0	106.1
2011	1177	1359	1248	115.5	106.0



C.2.2 Consolidated Edison (Con Ed)

Table C-C-2: Con Ed ICAP to UCAP Translation

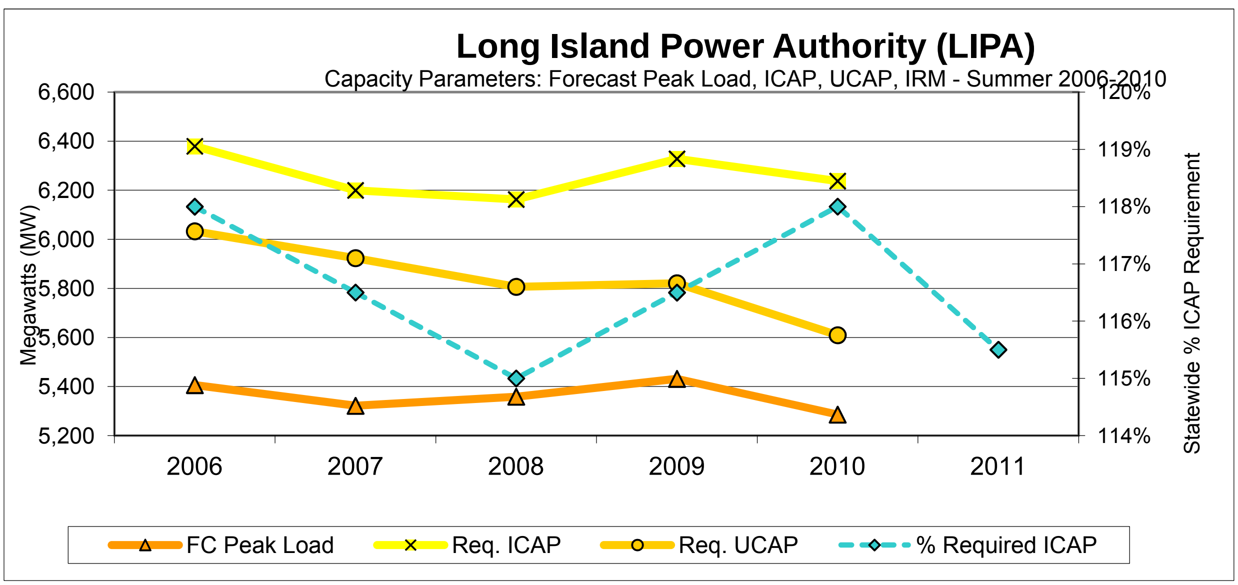
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	13,400	15,812	14,953	118.0	111.6
2007	13,634	15,883	15,175	116.5	111.3
2008	13,911	15,998	15,073	115.0	108.4
2009	14,043	16,360	15,050	116.5	107.2
2010	13,655	16,113	14,490	118.0	106.1
2011	13,451	15,535	14,261	115.5	106.0



C.2.3 Long Island Power Authority (LIPA)

Table C-C-3: LIPA ICAP to UCAP Translation

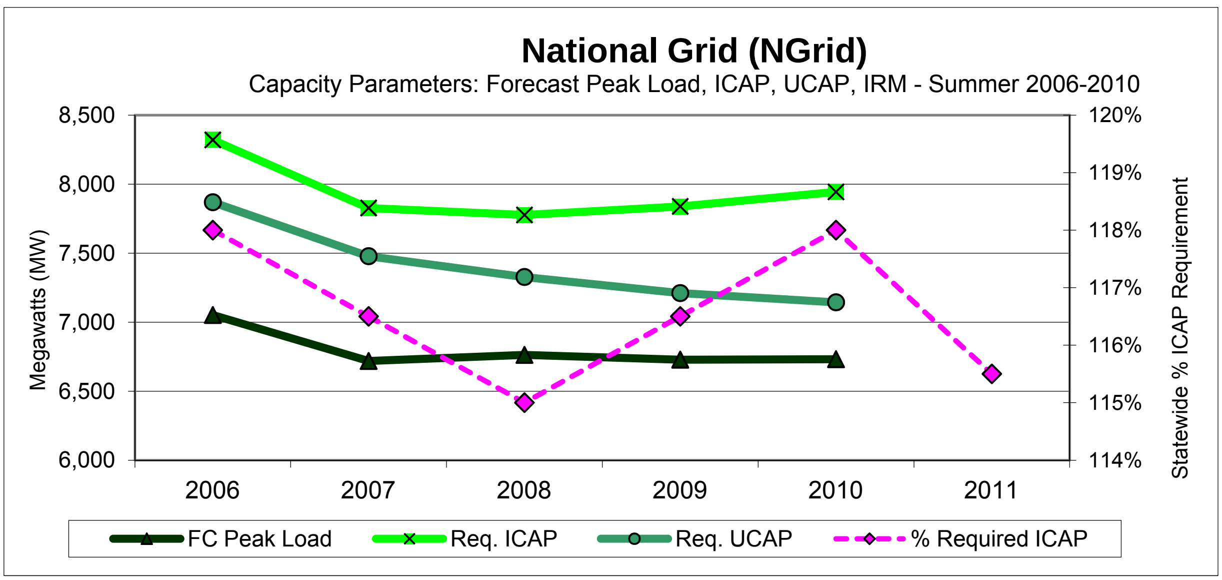
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	5406	6379	6033	118.0	111.6
2007	5322	6200	5923	116.5	111.3
2008	5359	6163	5807	115.0	108.4
2009	5432	6328	5821	116.5	107.2
2010	5286	6238	5609	118.0	106.1
2011	5404	6242	5370	115.5	106.0
2012					



C.2.4 National Grid (NGRID)

Table C-C-4: NGRID ICAP to UCAP Translation

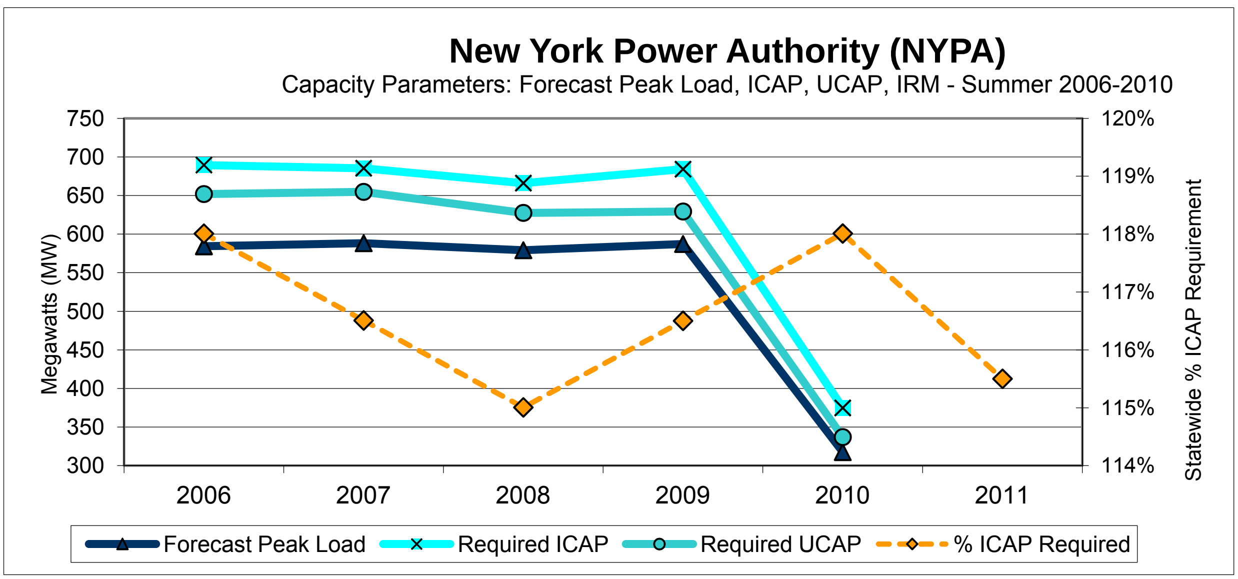
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	7052	8321	7869	118.0	111.6
2007	6719	7827	7478	116.5	111.3
2008	6763	7777	7327	115.0	108.4
2009	6728	7839	7211	116.5	107.2
2010	6732	7944	7144	118.0	106.1
2011	6575	7594	6971	115.5	106.0
2012					



C.2.5 New York Power Authority (NYPA)

Table C-C-5: NYPA ICAP to UCAP Translation

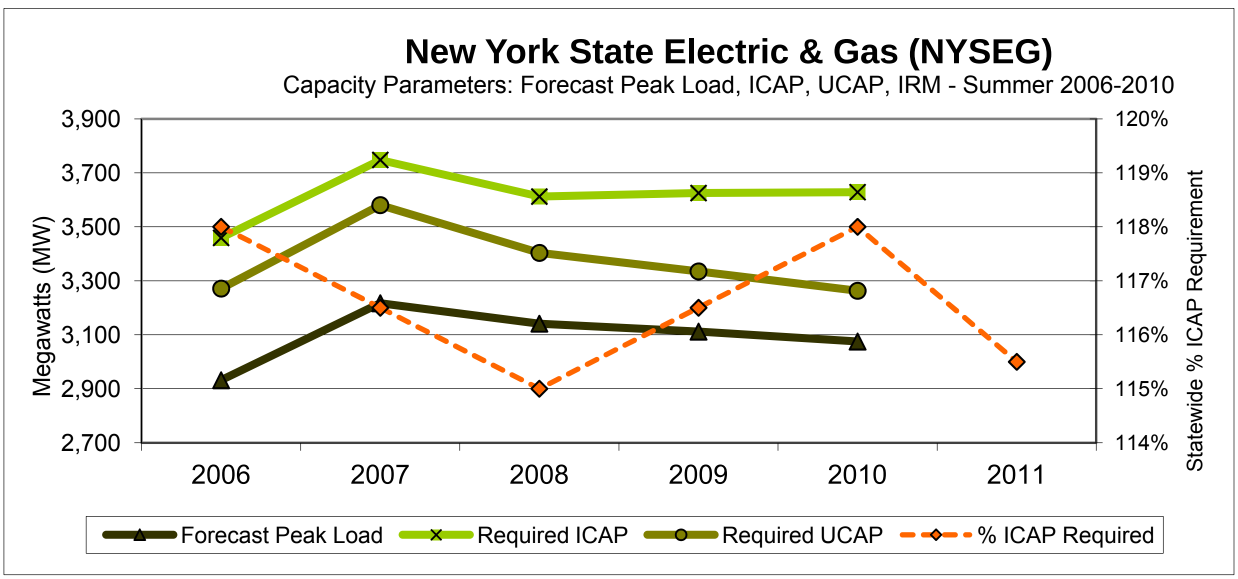
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	584	689	652	118.0	111.6
2007	588	685	655	116.5	111.3
2008	579	666	628	115.0	108.4
2009	587	684	629	116.5	107.2
2010	318	375	337	118.0	106.1
2011	320	369	339	115.5	106.0



C.2.6 York State Electric & Gas (NYSEG)

Table C-C-6: NYSEG ICAP to UCAP Translation

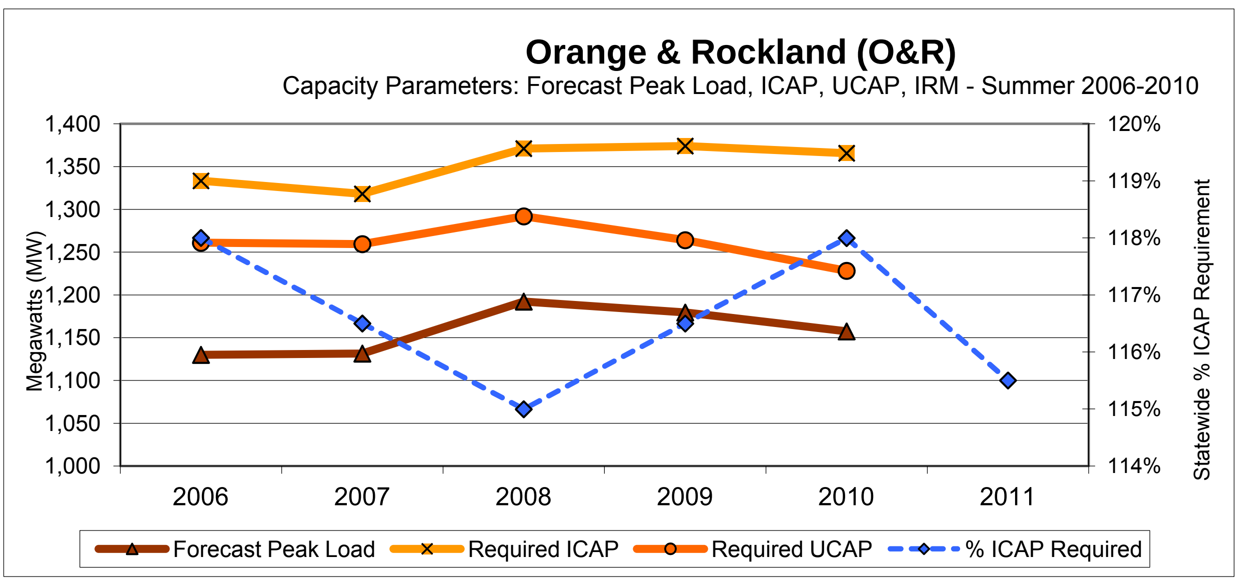
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	2932	3459	3271	118.0	111.6
2007	3217	3748	3581	116.5	111.3
2008	3141	3612	3404	115.0	108.4
2009	3112	3625	3335	116.5	107.2
2010	3075	3629	3263	118.0	106.1
2011	3037	3508	3220	115.5	106.0
2012					



C.2.7 Orange & Rockland (O & R)

Table C-C-7: O & R ICAP to UCAP Translation

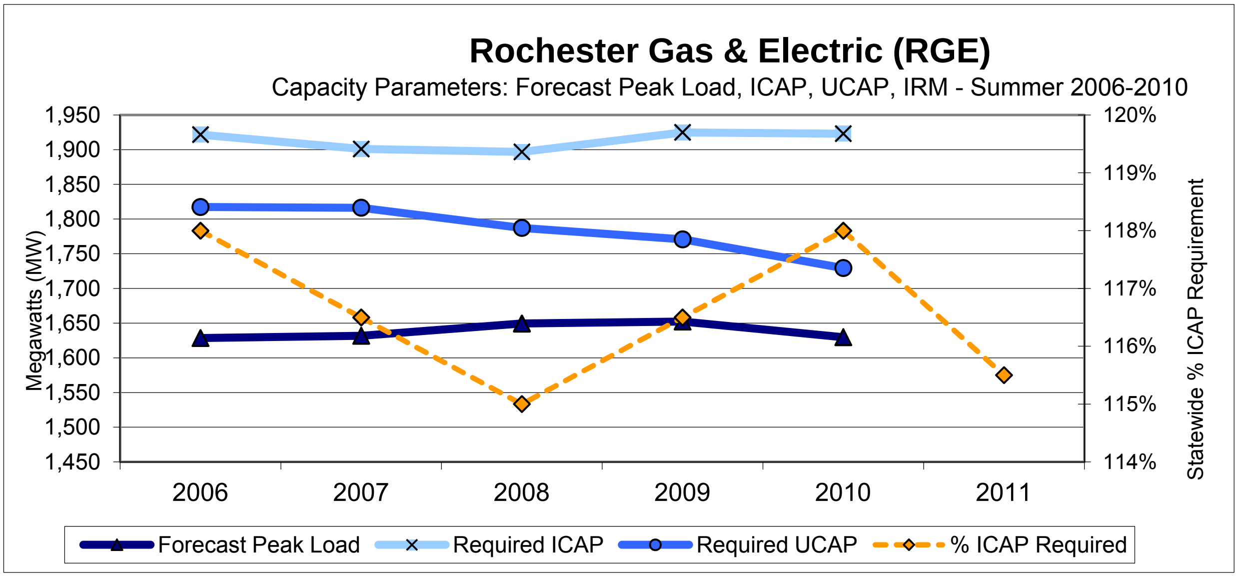
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1130	1333	1261	118.0	111.6
2007	1132	1318	1259	116.5	111.3
2008	1192	1371	1292	115.0	108.4
2009	1180	1374	1264	116.5	107.2
2010	1157	1366	1228	118.0	106.1
2011	1173	1355	1243	115.5	106.0
2012					



C.2.8 Rochester Gas & Electric (RGE)

Table C-C-8: RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1629	1922	1817	118.0	111.6
2007	1632	1901	1816	116.5	111.3
2008	1649	1897	1787	115.0	108.4
2009	1652	1925	1771	116.5	107.2
2010	1630	1923	1729	118.0	106.1
2011	1576	1821	1671	115.5	106.0
2012					



C.3 Wind Resource Impact on the NYCA IRM and UCAP Markets

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

Several new wind generation resources have been added to the NYCA. However due to the intermittent nature of the wind, these resources cannot always be counted on to be available when the NYCA needs them.

For a wind farm or turbine, the nameplate capacity is the ICAP while the effective capacity is equal to the UCAP value. Seasonal variability and geographic location are factors that also affect wind resource availability. The effective capacity of wind generation can be either calculated statistically directly from historical hourly wind generation outputs, and/or by using the following information:

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

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

C.3.1 GE MARS Modeling of Wind Generation

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

Based on the NYISO's hourly data information obtained from different New York State sites used in the study, a wind farm located in Upstate has a 10%-11% effective capacity; whereas Downstate and off-shore wind facilities exhibit 30% and 38% effective capacity, respectively. For example, a 100-MW off-shore wind farm is equivalent to a 38-MW conventional fossil-fired power plant with a zero EFORd.

Therefore, based on best current information, the NYISO has adopted the following availability factors:

1. Land-base wind generators, upstate (10%)
2. Land-base wind generators, downstate (30%)
3. Off-shore wind generators (38%)

Because of its much higher unavailability compared to fossil generation, adding wind generation to the resource portfolio helps increase Statewide and Locational ICAP-based capacity requirements in the NYCA. GE-MARS models wind on the same basis as conventional fossil-fired generation using ICAP with availability and performance considerations. All generating resources within NYCA (including wind) have an expected level of availability – or conversely, expected unavailability which is considered when solving for LOLE using the GE-MARS program.

It should be noted that, although low-capacity factor resources increase the IRM on an ICAP basis, it has a negligible impact on a UCAP basis. Consider the following example:

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

1. System ICAP = 10,000 MW with 10% EFORd
2. System UCAP = (ICAP*(1-EFOR)) → (10,000 * (1 - 0.1)) = 9,000 MW
3. Add 1,000 MW of wind (low capacity factor resource) with summer EFORd @ 90% → (1000 * (1 - 0.9)) = 100 MW
4. 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 → 1000 -100 = 900 MW
5. New ICAP requirement → 10,000 + 900 = 10,900 MW ICAP
6. Weighted average EFORd for new system →
7. ((10,000 * 0.1) + (1,000 * 0.9)) / (10,000 + 1,000) = 17.3%.
8. UCAP requirement → (10,900 * (1 – 0.173)) = 9,014 MW

Given that 1000 MW of ICAP were added to this system, this 9014 MW result is relatively close to the initial 9,000 MW UCAP requirement.

Appendix D

Glossary of Terms

D. Glossary - NYSRC Approved Terms only

Availability - A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

Capability Period - Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the NYISO. A summer capability period followed by a winter capability period shall be referred to as a "Capability Year." Each capability period shall consist of on-peak and off-peak periods.

Capacity - The rated continuous load-carrying ability, expressed in megawatts ("MW") or megavolt-amperes ("MVA") of generation, transmission or other electrical equipment

Contingency – An actual or potential unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area (CA) - An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Demand – The rate at which energy must be generated or otherwise provided to supply an electric power system.

Emergency - Any abnormal system condition that requires automatic or immediate, manual action to prevent or limit loss of transmission facilities or generation resources that could adversely affect the reliability of an electric system.

External Installed Capacity (External ICAP) – Installed capacity from resources located in control areas outside the NYCA that must meet certain NYISO requirements and criteria in order to qualify to supply New York LSEs.

Firm Load - The load of a market participant that is not contractually interruptible. Interruptible Load – The load of a market participant that is contractually interruptible.

Generation - The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Installed Capacity (ICAP) - Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.

Installed Capacity Requirement (ICR) – The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.

Installed Reserve Margin (IRM) - That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.

Interface – The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

Load - The electric power used by devices connected to an electrical generating system. (IEEE Power Engineering)

Load Relief - Load reduction accomplished by voltage reduction or load shedding or both.

Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.

Load Shedding – The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. Load shall normally all be shed within 5 minutes of the order.

Load Serving Entity (LSE) – In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.

Locational Capacity Requirement (LCR) - Due to transmission constraints, that portion of the NYCA ICAP requirement that must be electrically located within a 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.

New York Control Area (NYCA) – The control area located within New York State which is under the control of the NYISO. See Control Area.

New York Independent System Operator (NYISO) – The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.

New York State Bulk Power System (NYS Bulk Power System or BPS) – The portion of the bulk power system within the New York control area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.

New York State Reliability Council, LLC (NYSRC) – An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.

New York State (NYS) Transmission System - The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.

Operating Limit - The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.

Operating Procedures - A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Operating Reserves – Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load, and can do so within a specified time period.

Reserves – In normal usage, reserve is the amount of capacity available in excess of the demand.

Resource – The total contributions provided by supply-side and demand-side facilities and/or actions.

Stability – The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Thermal Limit – The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.

Transfer Capability – The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Transmission District – The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.

Transmission Owner – Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/ISO Agreement.

Voltage Limit – The maximum power flow through some particular point in the system considering the application of voltage assessment criteria.

Voltage Reduction – A means of achieving load reduction by reducing customer supply voltage, usually by 3, 5, or 8 percent. If ordered by the NYISO to go into voltage reduction, transmission owner system dispatchers shall immediately comply with that order. Quick response voltage reduction shall normally be accomplished within ten (10) minutes of the order.

Zone – A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal price that is calculated as a weighted average price based on generator LBMPs and generator bus load distribution factors. A "zone" outside the NY control area is referred to as an external zone. Currently New York State is divided into eleven zones, corresponding to ten major transmission interfaces that can become congested.

E. 2012 IRM Assumptions Matrix

Base Case Modeling Assumptions for 2012-2013 NYCA IRM Requirement Study

Parameter	2011 Study Modeling Assumptions	Recommended 2012 Study Modeling Assumptions	Basis for Recommended 2012 Assumptions	Model change	Poss-ible Impact
Peak Load	Oct 1 IRM forecast: 32,872 MW for NYCA, 11,463 MW for zone J, and 5414 MW for zone K.	Oct 1, 2011 Forecast: 33,335 MW for NYCA, 11,607 MW for zone J, and 5521 for zone K	Forecast based on examination of 2011 weather normalized peaks. Top three external Area peak days aligned with NYCA		Low (+)
Load Shape Model	2002 Load Shape	2002 Load Shape	2002 load shape is still appropriate. A sensitivity with a shape that is closer to the mean will be performed.		None
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Zonal model updated to reflect current data.	Based on collected data and input from LIPA, Con Ed, and NYISO. Method and values accepted by LFTF *(see Attachment A)*.		Low (+)
Solar Resource Modeling	Forecast of 15 MW of total solar capacity, centered on Long Island. *See Attachment B-2.*	Forecast of 38.5 MW of total solar capacity. *See Attachment B-2.*	Based on collected hourly solar data during summer Peak Hours (June 1-Aug 31, hours (beginning) 2-5 PM).		Low (+)
Wind Resource Modeling	(1,260 MW) Derived from hourly wind data with average Summer Peak Hour availability factor of approximately 11%. *See Attachment B-1.*	(1,648 MW) Derived from hourly wind data resulting in an average Summer Peak Hour availability of approximately 11%. *See Attachment B-1.*	Based on collected hourly wind data. Summer Peak Hour capacity factor based on June 1-Aug 31, hours (beginning) 2-5 PM.		Med (+)

Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Parameter	2011 Study Modeling Assumptions	Recommended 2012 Study Modeling Assumptions	Basis for Recommended 2012 Assumptions	Model change	Poss-ible Impact
Wind Shape Model	2002 Wind Generation Profile	2002 Wind Generation Profile	A sensitivity will be performed using blended load shapes.		None
Existing Generating Unit Capacities	Updated DMNC test values. Use the minimum of DMNC or CRIS values.	Updated DMNC test values. Use the minimum of DMNC or CRIS values.	2011 Gold Book units		Low (-)
Proposed New Units	Those listed on *Attachment B.*	Those listed on *Attachment B.*	Units built since the 2011 Gold Book and those non-renewable units with Interconnection agreements signed by August 1st. Renewables based on RPS agreements and ICS input.		Low (-)
Retirements	Energy Systems North East (ESNE) retirement of 74.5 MW from zone A	578.1 MW of retirements and mothballing as listed in *Attachment B-3*	Owners of these plants have notified the NYISO of their intention to retire or mothball.		Low (-)
Forced & Partial Outage Rates	5-year (2005-09) GADS data. (Those units with less than five years data could use available representative data.)	5-year (2006-10) GADS data. (Those units with less than five years data could use available representative data.)	Most recent 5-year period. *(see Attachments C and C-1)* Includes proxy data for unit(s) that are deemed suspect as part of the GADS screening process.		Low (+)
EFORd	Sensitivity on EFORd "True-up" performed.	APA paper indicates an acceptable methodology to develop EFORd transition rates based on GADS data.	Sensitivity using Associated Power Analysts (APA) methodology. New Model will be used in 2013 IRM Base Case.	Non-std	None
Planned Outages	Based on schedules received by NYISO & adjusted for history.	Based on schedules received by NYISO & adjusted for history.	Updated schedules.		None
Summer	Use 150 MW after reviewing	Use nominal value of 50 MW	Review of most recent data.		Low (-)

Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Parameter	2011 Study Modeling Assumptions	Recommended 2012 Study Modeling Assumptions	Basis for Recommended 2012 Assumptions	Model change	Poss-ible Impact
Maintenance	last year's data.	after reviewing last year's data.			
Combustion Turbines Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves.		Low (+)
Environmental Impacts	No impact on unit availability due to RGGI . The base case assumes that any forthcoming NOx RACT rule will not require compliance by summer 2011.	No impacts for base case.	An analysis of Cross State Air Pollution Rules (CSAPR) indicates 2012 impacts can be mitigated with existing fleet.	Std.	None
Non-NYPA Hydro Capacity Modeling	45% derating.	45% derating.	No Change		None
Special Case Resources	2498 MW (Aug 11) based on NYISO growth rate forecast. Monthly variation based on historical experience.	2192 MW (Jul 12) based on registrations and NYISO growth rate forecast. Monthly variation based on historical experience.	Those sold for the program, discounted to historic availability. Sensitivity. *See SCR determinations in Attachment F*.	Std.	Med (-)
EDRP Resources	260 MW registered; modeled as 172 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	148 MW registered; modeled as 95 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	Those registered for the program, discounted to historic availability(64% overall). Summer values calculated from 2011 July registrations.		Low (+)
External Capacity - Purchases	Grandfathered amounts of 50 MW from NE, 37 MW from PJM, and 1,090 MW from Quebec modeled as actual contracts on border interfaces. Also, 1,043 MW modeled as	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1,090 MW from Quebec. All contracts modeled as equivalent contracts.	Equivalent contracts do not require an additional re-adjustment of externals areas per Policy 5.		None

Parameter	2011 Study Modeling Assumptions	Recommended 2012 Study Modeling Assumptions	Basis for Recommended 2012 Assumptions	Model change	Poss-ible Impact
	de-ration on the upstate ties to PJM.				
Capacity - Sales	In addition to the long term firm sales of 303 MW (nominal value), include known firm contracts of 716 MW as a result of NE FCM market auctions. Contracts modeled on border interfaces.	Long term firm sales of 303 MW (nominal value).	During NE FCM reconfiguration auctions, the sales positions for 2012 were bought out by internal NE parties.		Low (+)
Capacity Wheels-through	None modeled. A sensitivity case may be run.	None modeled. A sensitivity case will be run.	The ISO tariff is silent about capacity wheels through NYCA.		None
EOPs (other than SCR and EDRP)	737 MW of non-SCR/EDRP MWs.	735 MW of non-SCR/EDRP MWs.	Based on TO information, measured data, and NYISO forecasts. *See Attachment D*.		None
Interface Limits	Based on 2010 Operating Study, 2010 Operations Engineering Voltage Studies, 2010 Comprehensive Planning Process, and additional analyses including interregional planning initiatives. Operation of M29 Line (improvement in transfer from zone I to zone J by 350MW).	All changes viewed and commented on by TPAS.	Based on 2011 Operating Study, 2011 Operations Engineering Voltage Studies, 2011 Comprehensive Planning Process, and additional analyses including interregional planning initiatives. *See Attachments E, E-1, and E-2*.		None
New Transmission	Upgrade on Northport Norwalk Cable (NNC) line to	None Identified.	Based on TO provided models and NYISO review.		None

Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Parameter	**2011 Study Modeling Assumptions**	**Recommended 2012 Study Modeling Assumptions**	**Basis for Recommended 2012 Assumptions**	**Model change**	**Poss-ible Impact**
Capability	428 MW from 286 MW.				
Transmission Cable Forced Outage Rate	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Based on TO analysis.		Low (+)
Unforced Capacity Deliverability Rights (UDR)	No new projected UDRs	No new projected UDRs	Contracted amounts of capacity are confidential and are included as capacity internal to NYCA.		None
Model Version	Version 3.01	Version 3.12	Per testing and recommendation by ICS.		None
Outside World Area Models	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England.	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England.	The load and capacity data is provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5.		None
Reserve Sharing between Areas	All NPCC Control Areas have indicated that they will share reserves equally among all.	All NPCC Control Areas have indicated that they will share reserves equally among all.	Per NPCC CP-8 working group assumption.		None

Attachment A
NYCA Load Forecast Uncertainty

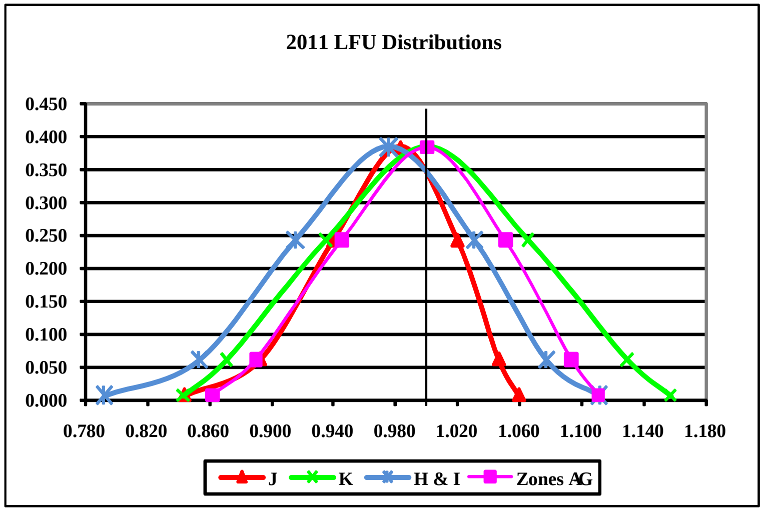
2011 and 2012 LFU Models

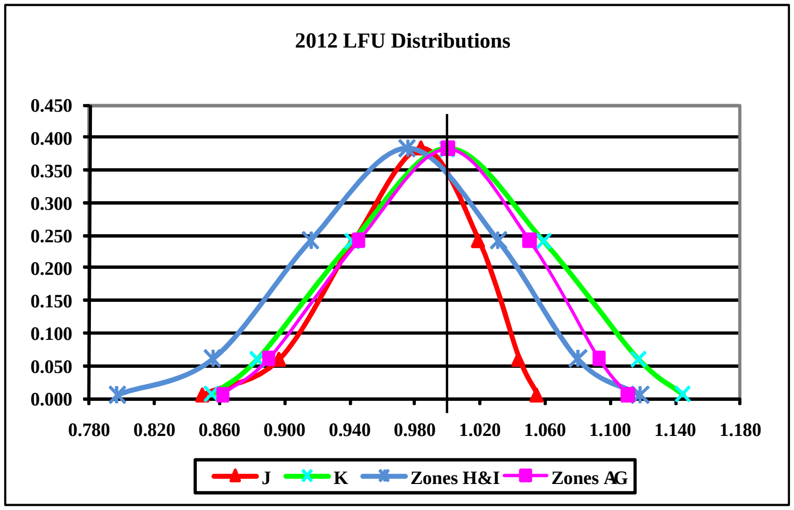
2011 Load Forecast Uncertainty Models

Multiplier	Zones H&I	Con Ed (J)	LIPA (K)	Zones A-G
0.0062	1.1111	1.0594	1.1570	1.1105
0.0606	1.0771	1.0464	1.1290	1.0932
0.2417	1.0306	1.0198	1.0650	1.0506
0.3830	0.9755	0.9832	1.0000	1.0000
0.2417	0.9154	0.9399	0.9350	0.9453
0.0606	0.8533	0.8927	0.8710	0.8901
0.0062	0.7921	0.8441	0.8430	0.8619

2012 Load Forecast Uncertainty Models

Multiplier	Zones H&I	Con Ed (J)	LIPA (K)	Zones A-G
0.0062	1.1181	1.0549	1.1448	1.1105
0.0606	1.0801	1.0437	1.1171	1.0932
0.2417	1.0312	1.0189	1.0585	1.0506
0.3830	0.9753	0.9839	1.0000	1.0000
0.2417	0.9157	0.9422	0.9415	0.9453
0.0606	0.8554	0.8966	0.8829	0.8901
0.0062	0.7968	0.8495	0.8552	0.8619





Attachment B

List[10] of Proposed Units

To be in-service by summer of 2012

Project Name		IS Date	Zone	MW
New Generation				
	Astoria Energy II	**5/11**	**J**	**576**
	Bayonne Energy Center	**5/12**	**J**	**500**

10 The list on this page does not show wind and solar units which are presented on Attachments B-1, and B-2, respectively.

Attachment B1

Renewable Generating Wind Projects for Inclusion in the 2012-2013 Installed Reserve Margin Study

Wind Generation Projects in the NYCA

Considered for Inclusion in the 2012-2013 IRM Study

Facility Name	Owner / Developer	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	Current Status	Existing Wind Capacity (MW)	New Wind Capacity for 2012 IRM(MW)	Total Wind Capacity for 2012 IRM (MW)
Steel Wind	Constellation Power	A	National Grid		2007 Jan	Operating	20.0		20.0
Bliss Wind Power	Noble Bliss Windpark, LLC	A	Village of Arcade	173	2008 May	Operating	100.5		100.5
Canandaigua Wind Power	Canandaigua Power Partners, LLC	C	NYSEG	135&199	2008 Jun	Operating	125.0		125.0
Cody Road	Green Power	C	National Grid	180A	2011 Dec			10.0	10.0
Hardscrabble Wind[1]	Hardscrabble Wind Power, LLC	C	National Grid	156	2011 Sept	Operating	74.0		74.0
Howard Wind	Howard Wind, LLC	C	NYSEG	182	2011 Dec			57.4	57.4
Wethersfield Wind Power	Noble Wethersfield Windpark, LLC	C	NYSEG	177	2008 Dec	Operating	126.0		126.0
High Sheldon Wind Farm	Sheldon Energy, LLC.	C	NYSEG	144	2009 Feb	Operating	112.5		112.5
Altona Wind Power	Noble Altona Windpark, LLC	D	NYPA	174	2008 Sept	Operating	97.5		97.5
Chateaugay Wind Power	Noble Chateaugay Windpark, LLC	D	NYPA	214	2008 Sept	Operating	106.5		106.5
Clinton Wind Power	Noble Clinton Windpark, LLC	D	NYPA	172 & 211	2008 May	Operating	100.5		100.5
Ellenburg Windpark	Noble Ellenburg Windpark, LLC	D	NYPA	175	2008 May	Operating	81.0		81.0
Munnsville	Coral Power	E	NYSEG	127A	2007 Aug	Operating	34.5		34.5
Maple Ridge 1	Flat Rock Windpower, LLC	E	National Grid	171	2006 Feb	Operating	231.0		231.0
Maple Ridge 2	Flat Rock Windpower, LLC	E	National Grid	171	2006 Feb	Operating	90.7		90.7
Madison Wind Power	Madison Windpower, LLC	E	NYSEG	N/A	2000 Sept	Operating	11.5		11.5
Allegany Wind	Allegany Wind, LLC	A	National Grid	237	2011 Oct			72.5	72.5
Prorated Units to account for probability[2]									
Belmont/Ellenburg II	Noble Environmental Power LLC	D	NYPA	213	2011 Dec			5.3	5.3
Windfarm Prattsburgh	Windfarm Prattsburgh, LLC	C	NYSEG	113	2011 Oct			39.1	39.1
Stony Creek Wind Farm	Invenergy, LLC	C	NYSEG	263	2012 Aug			44.3	44.3
Marble River Wind Farm 1 and 2	Horizon Wind Energy, LLC	D	NYPA	161 & 171	2012 Jan			108.2	108.2
TOTAL CAPACITY - ALL CATEGORIES							**1,311.2**	**336.8**	**1,648.0**

1. Hardscrabble Wind has been called Fairfield Wind, after the town that it is in.

2. ICS has forecast that only 50% of the proposed active projects will be complete in tiime for this study.

Attachment B-2

List of Solar proposed Units

To be in-service by summer of 2012

Project Name	IS Date	Zone	MW
BP Solar	11/11	K	32.0
Enxco	5/12	K	6.5

Attachment B-3

List of Retired and Mothballed Units

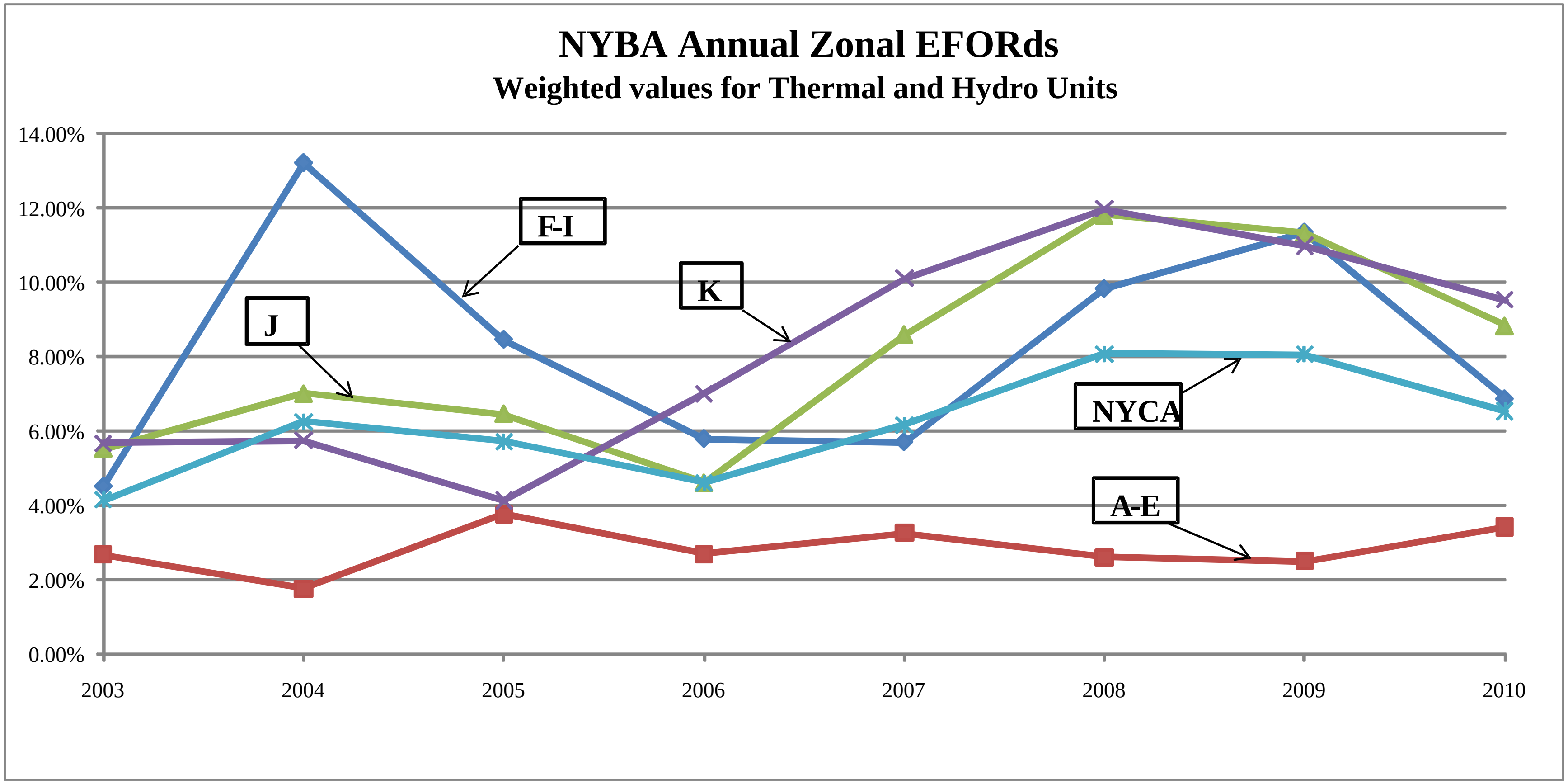
Unit	Type	Zone	MW
Westover 8*	Protective lay-up	C	80.8
Greenidge 4*	Protective lay-up	C	106.1
Project Orange*	Retirement	C	40
Glenwood ST04	Retirement	K	116.0
Glenwood ST05	Retirement	K	113.2
Far Rockaway ST04	Retirement	K	105
Barrett GT7*	Retirement	K	17
		Total:	578.1

*** Units had already shown 0 MW of summer capability in the 2011 Gold Book.**

Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

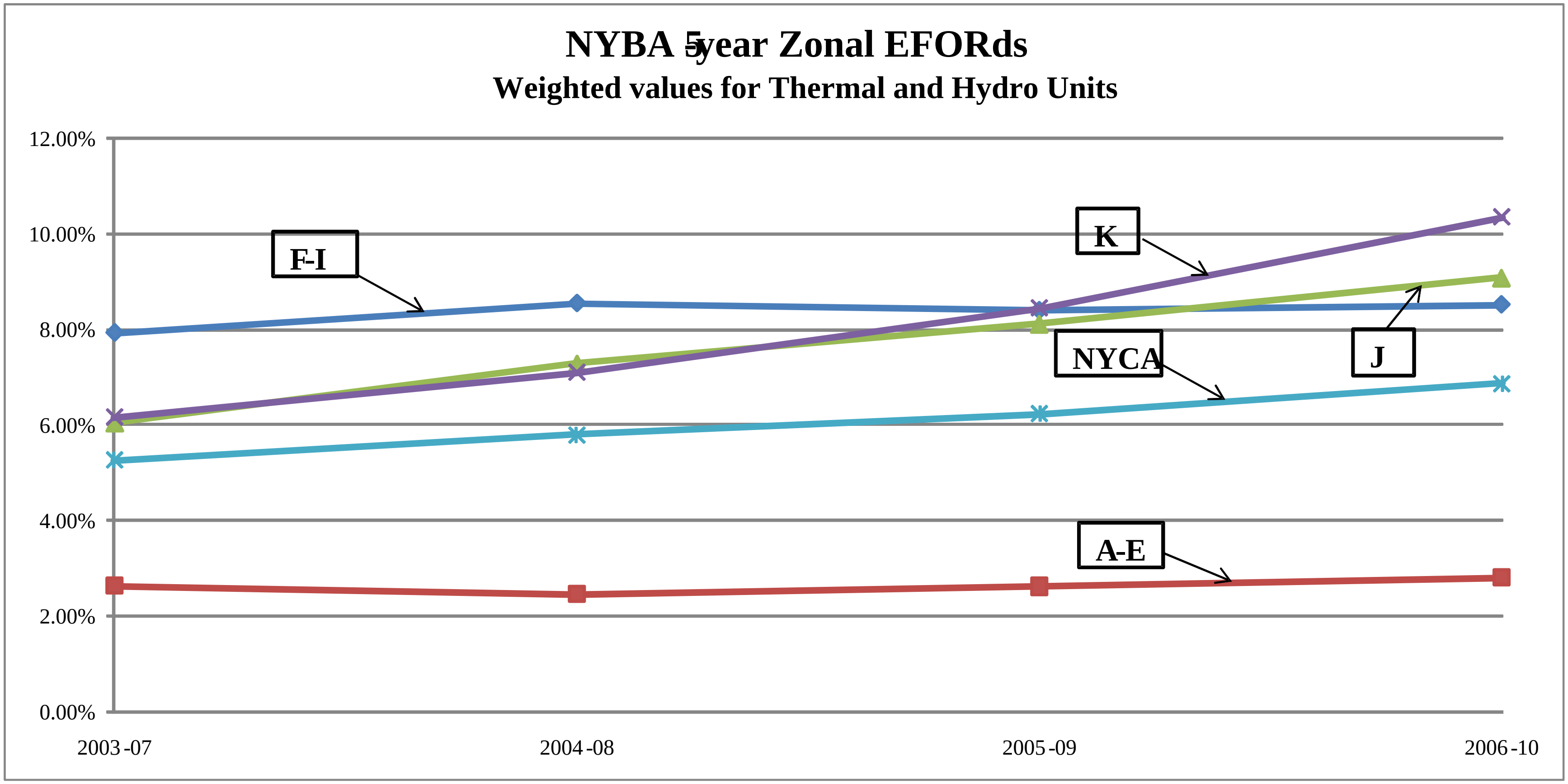
Attachment C



Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Attachment C-1

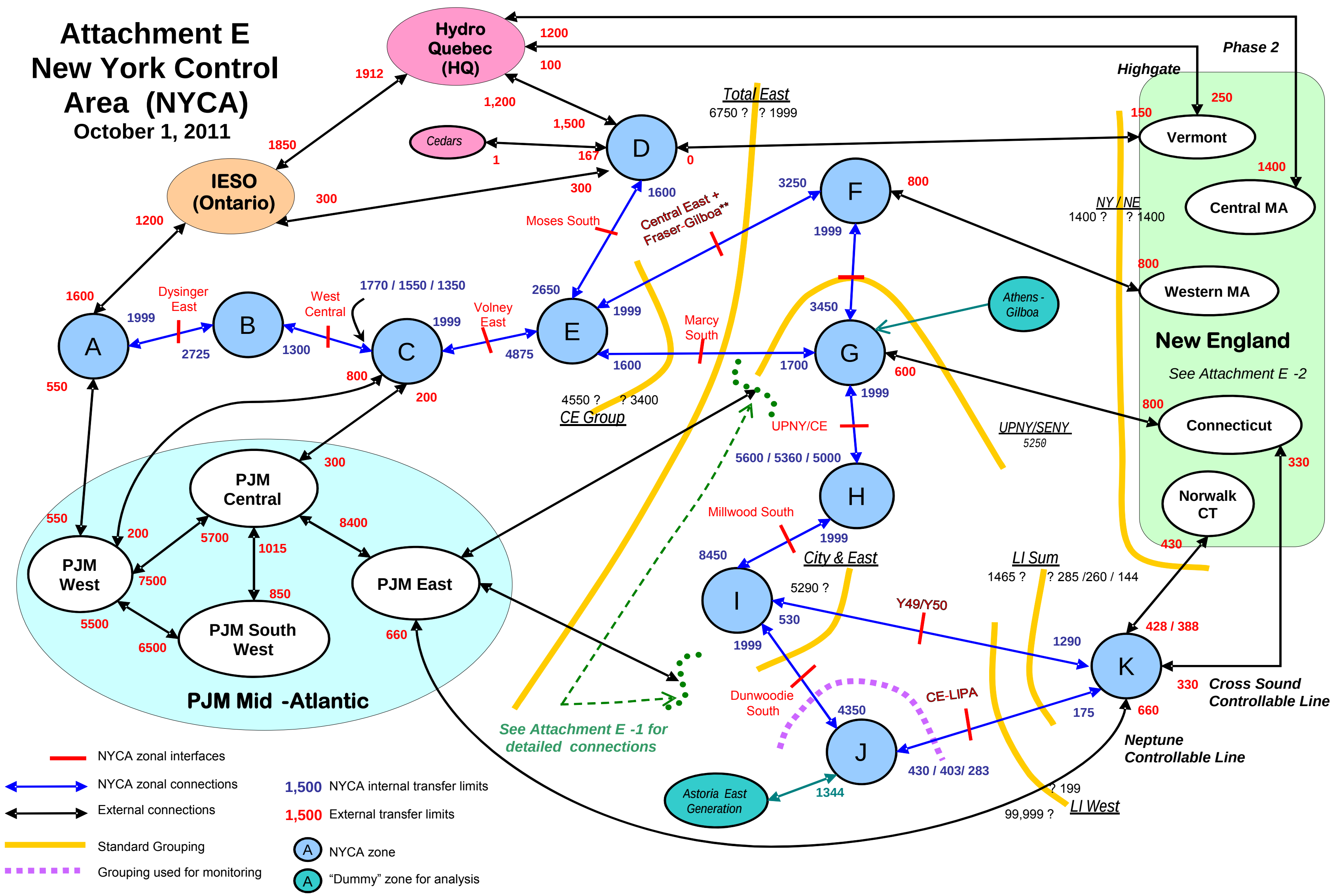


Attachment D
Emergency Operating Procedures

Step	Procedure	Effect	2011 MW Value	2012 MW Value
1	Special Case Resources	Load relief	2498 MW (representing the amount sold)	2192 MW (representing the amount sold)
2	Emergency Demand Response Program	Load relief	260 MW	148 MW
3	5% manual voltage Reduction	Load relief	71 MW	62 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW	600 MW
5	5% remote voltage reduction	Load relief	478 MW	442 MW
6	Voluntary industrial curtailment	Load relief	100 MW	143 MW
7	General public appeals	Load relief	88 MW	88 MW
8	Emergency Purchases	Increase capacity	Varies	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW	1200 MW
10	Customer disconnections	Load relief	As needed	As needed

Appendix E Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

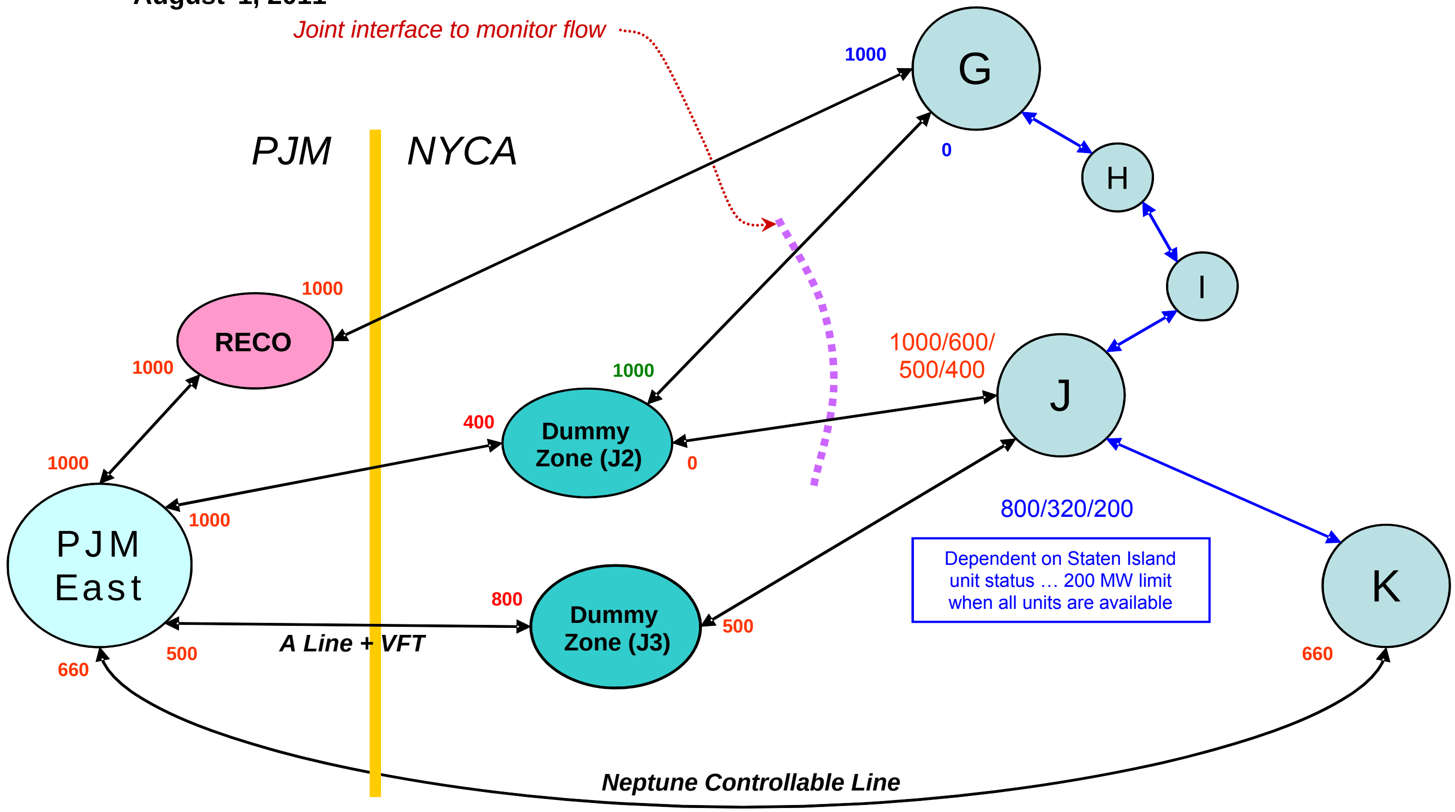
Transmission System Representation for 2012 IRM Study - Summer Emergency Ratings (MW)



Appendix E Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Transmission System Representation for 2012 IRM Study - Summer Emergency Ratings (MW)

Attachment E-1
2012 PJM-SENY MARS Model
August 1, 2011

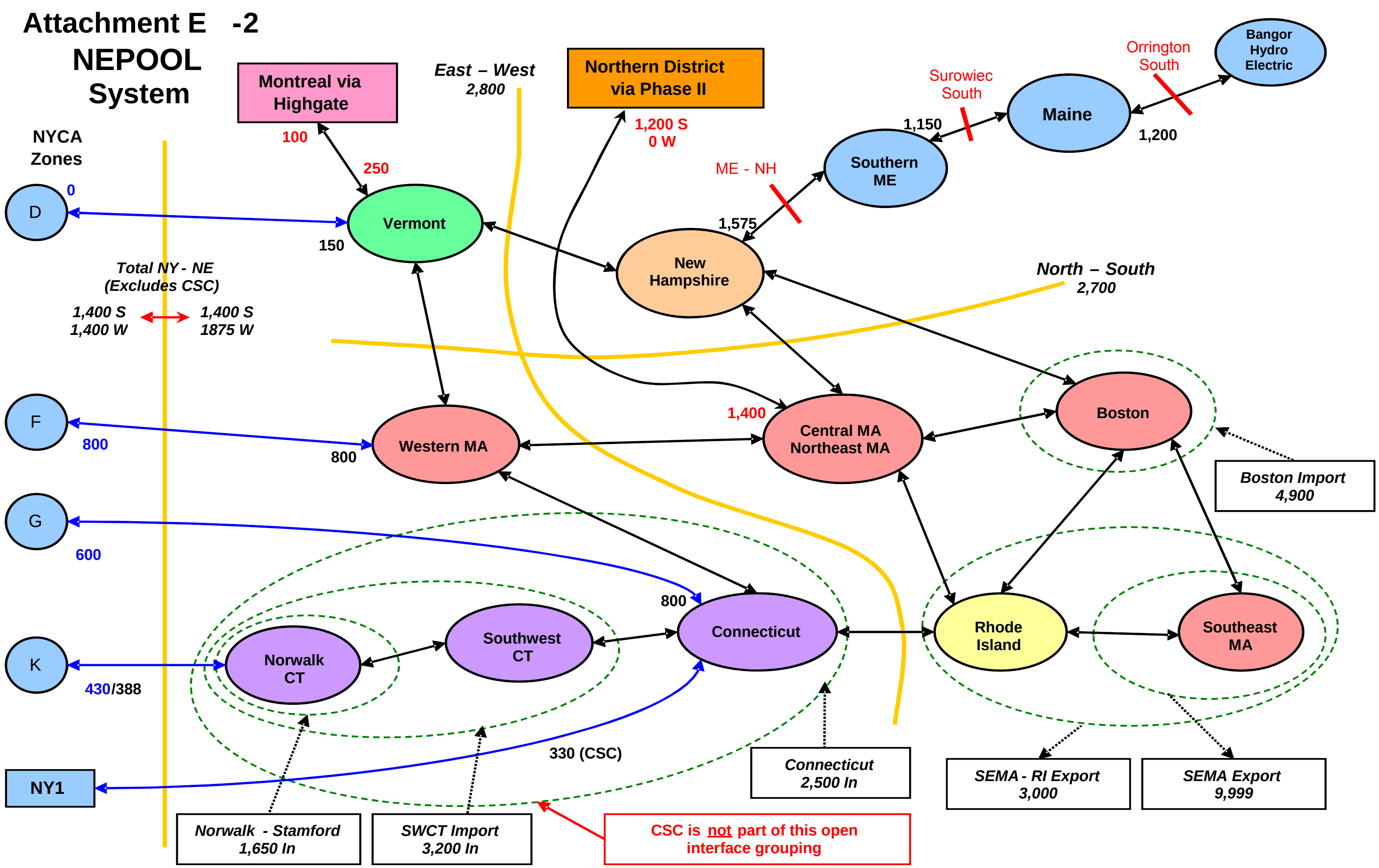


(PJM East to RECO) + (J2 to J) + (PJM East to J3) = 2000

Appendix E

Range: Low < 0.5%, Medium 0.5% - 1%, High > 1%

Transmission System Representation for 2012IRM Study - Summer Emergency Ratings (MW) – August 1, 2011



Attachment F
SCR Determinations

	A	B	C	D	E	F
		=A*3.5%		=B/C		=B*E
Zones	**July 2011 Registrations** [1]	**2012 Forecast** [2]	**Performance Factor**	**2012 ICAP**	**Translation Factor** [3]	**In Model Value**
A-E	1090.0	1128.3	0.943	1199	0.95	1072
F-I	247.0	255.7	0.923	277	0.95	243
J	420.3	435.1	0.786	554	0.95	413
K	136.0	140.8	0.867	162	0.95	134
Total	1893.3	**1959.8**		2192		1862

1. Based on ACL
2. These values represent a 3.5% growth from July 2011 ICAP based registrations
3. This translation factor is used to capture the difference between ACL and CBL values.