New York Control Area Installed Capacity Requirements For the Period May 2011 through April 2012

Technical Study Report

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New York State Reliability Council, LLC
Installed Capacity Subcommittee

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EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. This year's report covers the period May 2011 to April 2012 (2011 Capability Year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2011 Capability Year is 15.5% under base case conditions.

For this base case, the study also determined Minimum Locational Capacity Requirements (MLCRs) of 81.0% and 101.3% for New York City (NYC) and Long Island (LI), respectively. In its role of setting the appropriate locational capacity requirements (LCRs), the New York Independent System Operator (NYISO) will consider these MLCRs.

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

The above 2011 base case IRM study value of 15.5% represents a *2.4% decrease* from the base case 17.9% IRM requirement determined by the 2010 IRM Study. Table 1 shows the IRM impacts of individual study parameters that result in this change. The principal drivers that decrease the required IRM are:

- An updated Outside World representation
- An updated NYCA load forecast

These IRM drivers together account for an IRM decrease of 1.7% from the 2010 base case value.

Several environmental initiatives that are to be implemented on state and federal regulatory levels have been identified as having the potential to impact future operation and availability of fossil fueled generating plants in New York State, as well as IRM requirements. A review of these initiatives by the NYISO concluded that none are expected to impact IRM requirements in 2011, and therefore were not included in the 2011 base case.

The study also evaluated IRM impacts of several sensitivity cases. These results are summarized in Table 2 and in greater detail in Appendix Table B-2. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case 15.5% 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 2011 Capability Year is adopted.

INTRODUCTION

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA IRM for the period of May 1, 2011 through April 30, 2012 (2011 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:

$$\textbf{ICR = (1 + \%IRM Requirement /100) x Forecasted NYCA Peak Load}$$

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 2011 capability year.

The NYISO will implement the final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules and the NYISO Installed Capacity Manual. The NYISO translates the required IRM to an Unforced Capacity (UCAP) basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. These Unforced Capacity and Demand Curve concepts are described later in the report. The schedule for conducting the 2011 IRM Study was based on meeting the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2011 IRM Study are in accordance with NYSRC Policy 5-4, *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 2011 IRM Study, and will consider the MLCR values determined in this study.

Previous NYCA 2000 to 2010 IRM Study reports can be found at www.nysrc.org/reports.asp. Table B-1 in Appendix B provides a comparison of previous NYCA base case and Final IRMs for the 2000 through 2010 capability years. Definitions of certain terms in this report can be found in the NYSRC Glossary in the *NYSRC Reliability Rules for Planning and Operating the New York State Power System Manual*, at www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

NYSRC RESOURCE ADEQUACY RELIABILITY CRITERION

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

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

This NYSRC Reliability Rule is consistent with 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

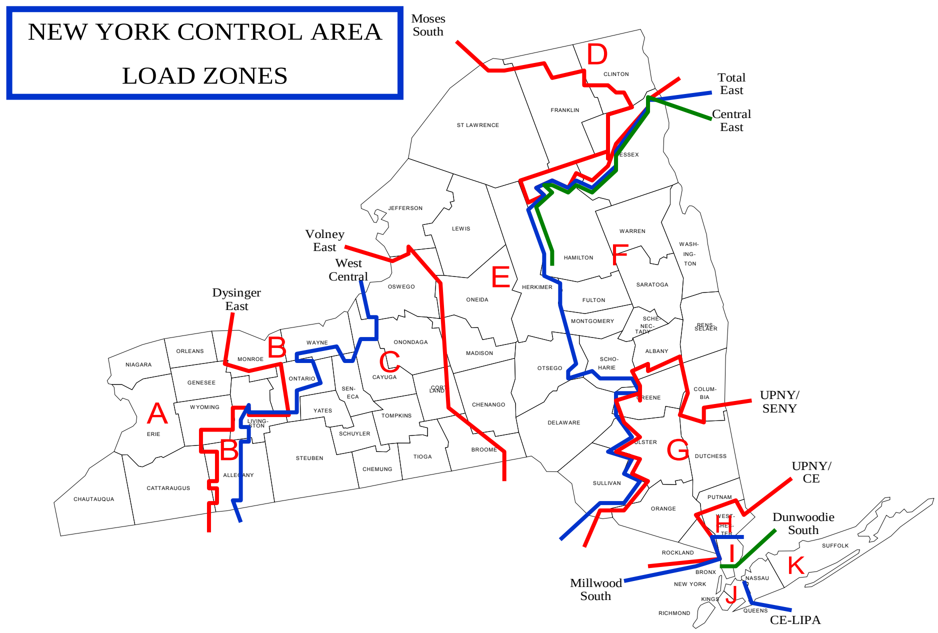
The study procedures used for the 2011 IRM Study are described in detail in NYSRC Policy 5-4, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-4 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study. Policy 5-4 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 eleven

NYCA zones are depicted in Figure 1 below. GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability.

Figure 1: NYCA Load Zones



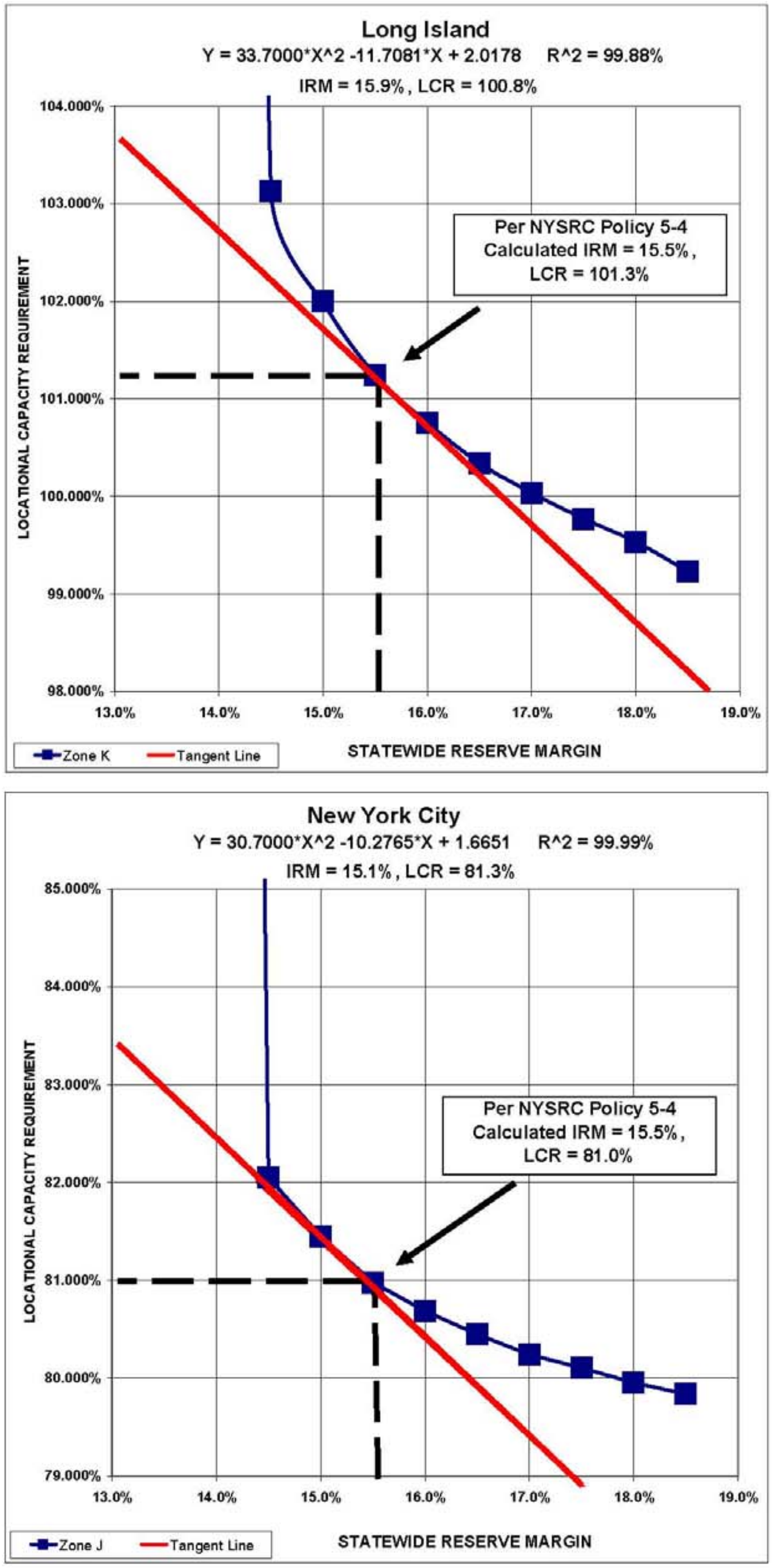
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs, as illustrated in Figure 2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. Note that all points above the curve are more reliable than criteria, and vice versa. This methodology develops a pair of curves, one for NYC (Zone J) and one for LI (Zone K). Appendix A of Policy 5-4 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 5-4 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 15.5% for the 2011 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 from which the above base case study results are based were evaluated using the Tan 45 analysis, also previously described. Accordingly, we conclude that maintaining a NYCA installed reserve of 15.5% for the 2011 Capability Year, together with MLCRs of 81.0% and 101.3% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A. The 81.0% MLCR for NYC represents an increase of 1.4 percentage points from that calculated in the 2010 IRM Study, while the 101.3% MLCR for LI represents a decrease of 3.6 percentage points from that calculated in the 2010 Study. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2011 Capability Year.

A Monte Carlo simulation error analysis shows that there is a 99.7% probability that the above base case result is within a range of 15.0% and 16.1% (see Appendix A). Within this range the statistical significance of the 15.0%, 15.5%, and 16.1% numbers are a 0.15%, 50%, and 99.85% probability of meeting the one day in ten LOLE, assuming perfect accuracy of all parameters and using a standard error of 0.05. If a standard error of 0.025 were used, the band would tighten from 15.2% to 15.8%. This analysis demonstrates that there is a high level of confidence that the base case IRM value of 15.5% 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 2011 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, 2010. Appendix A provides more details of these models and assumptions. Table A-4 compares key assumptions with those used for the 2010 IRM Study.

Load Model

- ***Peak Load Forecast****:* A 2011 NYCA summer peak load forecast of 32,872 MW was assumed in the study. This forecast is a reduction of 104 MW from the 2010 summer peak forecast used in the 2010 IRM Study. The above 2011 load forecast was completed by the NYISO staff in collaboration with the Load Forecasting Task Force on October 1, 2010, and considers actual 2010 summer load conditions. Use of this 2011 peak load forecast in the 2011 IRM study resulted in a decrease from the 2010 IRM requirement by 0.8% (see Table 1). This IRM decrease is driven by a reduction of the downstate load forecast used in the 2011 Study. The downstate percentage of the peak load forecast compared to the total NYCA peak load forecast was reduced from 53.76% to 53.34%. NYISO will prepare a final 2011 summer forecast in early 2011 for use in the NYISO 2011 Locational Capacity Requirement Study. It is expected that the October 2010 summer peak load forecast for 2011 and the final 2011 forecast will be similar.

- ***Load Shape Model**:* The 2011 IRM Study was performed using a load shape based on 2002 actual values. The same 2002 load shape was used in the four previous IRM studies and is consistent with the load shape assumption used by adjacent NPCC Control Areas. An analysis comparing the 2002 load shape to actual load shapes from 1999 through 2009 concluded that the 2002 load shape continues to be the best suited for the 2011 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 2011 IRM Study were updated by Consolidated Edison (Zones H, I, and J), LIPA (Zone K), and the NYISO. Appendix Section A-5.2.1 describes these models in more detail. Use of updated LFU models for the 2011 IRM Study increased IRM requirements by 0.1%.

<u>**Capacity Model**</u>

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 2011 IRM Study are shown in Appendix A. This includes the addition of 15 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. This updated parameter increased the IRM by 0.2% from the 2010 Study IRM. 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 2011 summer period there will be 12 wind-powered generation locations in NYCA with a total capacity of 1,333 MW. All of these wind farms are located in upstate New York, in Zones A-E. See Appendix A for details. The 2011 summer period wind capacity projection is 7 MW higher than the forecast 2010 wind capacity assumed for the 2010 IRM Study.

  The 2011 IRM Study base case assumes that the projected 1,333 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.

Overall, the projected 1,333 MW of wind capacity in the 2011 IRM base case accounts for 3.9% of the 2010 IRM requirement (see Table 2). This IRM impact is a direct result of the very low capacity factor of wind facilities during the summer peak period, as noted above. The impact of wind capacity on *unforced capacity* is discussed in Appendix B, Section B-3, "The Effect of Wind Resources on the NYCA IRM & UCAP Markets" A detailed summary of existing and planned wind resources is shown in Appendix A, Section A-5.8.

- ***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 2011 IRM Study covered the 2005–2009 period. The five-year EFOR calculated for this period slightly exceeded the 2004-2008 average value used for the 2010 IRM Study, causing the IRM to increase by 0.4% (see Table 1). Figure A-5 depicts NYCA 2001 to 2009 EFOR trends.

- ***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 SCR base case value of 2,498 MW in August 2011 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. The SCR growth rate methodology was improved for this year's IRM study. The updated SCR model used for the 2011 IRM Study resulted in an IRM decrease of 0.4% from the 2010 IRM Study (see Table 1). 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 2011 Study assumes 260 MW of EDRP capacity resources will be registered in 2011. This EDRP capacity was discounted to a base case value of 172 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 2011 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 2011). The updated EOP model, excluding the SCR impact noted above, decreased the IRM by 0.5% from the 2010 IRM.

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

  LIPA's 330 MW HVDC Cross Sound Cable, 660 MW HVDC Neptune Cable, and the 300 MW Linden VFT project are facilities that are represented in the 2011 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 2011 IRM study incorporates the elections that the facility owners have made for the 2011 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 2011 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.

The interface limit of Dunwoodie-South (Zones I to J) was increased from 4,000 MW, assumed in the 2010 IRM Study, to 4,350 MW based on recent studies performed by Con Edison and the NYISO. The increase in the Dunwoodie-South limit was primarily due to the expected operation of the new M29 line. There were also several transfer limit increases made for the PJM to NYCA interfaces and Northport Tie for the 2011 Study. Appendix A describes the basis for these changes in more detail.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. The 2011 IRM study, as with previous GE-MARS studies, reveals that the transmission system into NYC and LI is constrained and can impede the delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints: (1) the NYCA IRM requirement considers transmission constraints into NYC and LI, and (2) minimum LCRs must be maintained for both NYC and LI (See NYSRC Resource Adequacy Reliability Criteria section).

The impact of transmission constraints on NYCA IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements*, the NYISO is required to calculate and establish appropriate LCRs. The most recent NYISO study (*Locational Installed Capacity Requirements Study*, dated January 7, 2010 (addendum dated February 11, 2010), at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp, determined that for the 2010 Capability Year, the required LCRs for NYC and LI were 80.0% and 104.5%, respectively. A LCR Study for the 2011 Capability Year is scheduled to be completed by the NYISO in January 2011.

Results from 2011 IRM Study illustrate the impact on the IRM requirement for changes of the base case NYC and LI LCR levels of 81.0% and 101.3%, respectively. Observations from these results include:

- **Unconstrained NYCA Case –** If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 13.2%, 2.3 percentage points less than the base case IRM requirement (see Table 2). Therefore, relieving these transmission constraints is equivalent to adding approximately 640 MW of generation in NYCA.

- **Downstate NY Capacity Levels –** If the NYC and LI LCR levels were *increased* from the base case results to 82.0% and 103.0%, respectively, the IRM requirement could be reduced by 1.0 percentage points, to 14.5%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 80.0% and 99.6%, respectively, the IRM requirement must increase by 2.5 percentage points, to 18.0% (see Figure 2).

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

Outside World Model

The Outside World Model consists of those control areas contiguous with NYCA: Ontario, Quebec, New England, and PJM. NYCA reliability can be improved and IRM requirements can be reduced by recognizing available emergency capacity assistance support from these neighboring interconnected control areas — in accordance with control area agreements during emergency conditions. Representing such interconnection support arrangements in the 2011 IRM Study base case reduces the NYCA IRM requirements by 10.1 percentage points (see Table 2). A model for representing neighboring control areas, similar to that applied in previous IRM studies, was utilized in his study.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency assistance support. For this purpose, from Policy 5-4, 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 the Outside World Areas that may limit emergency assistance to the NYCA. This recognition is considered either explicitly, or through direct multi-area modeling providing there is adequate data available to accurately model transmission interfaces and load areas within these Outside World Areas. For this study, two of the Outside World Areas – New England and PJM – are each represented as multi-areas, i.e., 13 zones for New England and four zones for PJM. (This is an increase from five and three zones, respectively, represented for these Areas in the 2010 Study.) This level of granularity better captures the impacts of transmission constraints within these areas, particularly on their ability to provide emergency assistance to the NYCA.

For the 2011 IRM Study the Quebec to Ontario interface was increased to 1,850 MW, from 900 MW used in the 2010 Study. The addition of Highgate Phase 2 facility in Vermont increased the Quebec-New England interface capability. In addition, the transfer limits for two PJM interfaces – Central-East and West-Central – were increased. These changes had the collective effect of improving emergency assistance capability to NYCA from the Outside World in the 2011 IRM Study. The 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.

The updated Outside World Area load, capacity, and transmission representations in the 2011 IRM Study, plus an increase in the number of zones represented for New England and PJM described above, results in an IRM reduction from the 2010 study by 0.9 percentage points.

Environmental Initiatives

Five environmental initiatives that are to be implemented on state and federal regulatory levels have been identified as having the potential to impact future operation and availability of fossil fueled generating plants in New York State, as well as IRM requirements. They are: Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), Best Available Retrofit Technology (BART), Maximum Achievable Control Technology (MACT), Best Technology Available (BTA), and Clean Air Transport Rule (CATR). A review of these initiatives by the NYISO concluded that none are expected to impact IRM requirements in 2011, and therefore were not included in the 2011 base case. The NYSRC will continue to monitor these environmental initiatives as to the possibility of IRM impacts beyond 2011.

COMPARISON WITH 2010 IRM STUDY RESULTS

The results of this 2011 IRM Study show that the base case IRM result represents a 2.4 percentage point decrease from the 2010 IRM Study base case value. Table 1 compares the estimated IRM impacts of updating several key study assumptions and changing models from those used in the 2010 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 2.4 percentage point IRM decrease from the 2010 Study.

The principal drivers shown in Table 1 that decreased the required IRM from the 2010 IRM base case are an updated representation of the Outside World Model and an updated NYCA load forecast, which together, decreased the 2010 IRM by 1.7 percentage points.

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

Table 1: Parametric IRM Impact Comparison with 2010 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)
2010 IRM Study – Base Case IRM		**17.9**
2011 Updated Parameters that Lower the IRM:		
Updated Outside World Model	-0.9	
Updated NYCA Load Forecast	-0.8	
Updated Capacity Purchases	-0.5	
Updated Non-SCR EOPs	-0.5	
Updated SCRs	-0.4	
Updated Transmission Model	-0.3	
New Generation Capacity	-0.1	
Total IRM Decrease	**-3.5**	
2011 Updated Parameters that Increase the IRM:		
Updated Generating Unit EFORs	+0.4	
Updated Existing Generation Capacities	+0.2	
Updated Cable Outage Rates	+0.2	
Updated Maintenance	+0.2	
Updated Load Forecast Uncertainty Model	+0.1	
Total IRM Increase	**+1.1**	
Net Change From 2010 Study		**-2.4**
2011 IRM Study – Base Case IRM		**15.5**

SENSITIVITY CASE STUDY RESULTS

Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from the base case will, of course, yield different results. Table 2 shows IRM requirement results and related NYC and LI locational capacities for three groups of selected sensitivity cases. Certain of these sensitivity cases – particularly those included under the “Base Case Assumption Uncertainties” group – are important input when the NYSRC Executive Committee develops the final NYCA 2011 IRM. 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. The 15.5% base case and preliminary base cases were used as the basis for developing the sensitivity case values in Table 2. Further, there was no attempt to develop sensitivity results utilizing the Tan 45 “inflection point” method.

Table 2: Sensitivity Cases
NYCA 2011 IRM and Related NYC and LI Locational Capacities Impacts

Case	Case Description	IRM (%)	% Change From Base Case	NYC LCR (%)	LI LCR (%)
0	Base Case	15.5	--	81	101
2011 IRM Impacts of Major MARS Parameters					
1	NYCA isolated	25.6	+10.1	88	110
2	No internal NYCA transmission constraints	13.2	-2.3	N/A	N/A
3	No load forecast uncertainty	7.6	-7.9	75	95
4	No wind capacity (1,333 MW)	11.6	-3.9	81	101
5	No SCRs and EDRPs	15.4	-0.1	81	101
2011 IRM Impacts of Base Case Assumption Uncertainties					
6	Higher Outside World reserve margins	11.0	-4.5	78	97
7	Lower Outside World reserve margins	20.6	+5.1	85	106
8	Higher EFORd's	17.3	+1.8	82	102
9	Lower EFORd's	14.0	-1.5	80	100
10	Derate Dunwoodie-South interface by 350 MW	15.7	+0.2	81	101
11	300 MW wheel from HQ to NE through NYCA	15.6	+0.1	81	101
12	One-year outage of Indian Point 2	21.3	+5.8	85	106
13	Retire Indian Point 2&3	21.9	+6.4	90	113
14	Alternate to base case wind profile	14.3	-1.2	81	101
15	Retire Units that have notified PSC	15.5	0	81	101
Other Sensitivity Cases					
16	Implement an alternative methodology for calculating EFORd's	14.2	-1.3	77	99

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

NYISO Translation of NYCA Capacity Requirements to Unforced Capacity

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

Additionally, any LCRs in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another, and is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts UCAP requirements to ICAP in a manner that 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 unforced capacity. See Appendix B for a more detailed explanation.

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

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

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Description of the GE-MARS Program;
Load, Capacity, Transmission, and
Outside World Models; and Assumptions

A-1 Introduction

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

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A-1 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-5 compares the assumptions used in the 2010 and 2011 IRM reports.

Figure A-1: NYCA ICAP Modeling

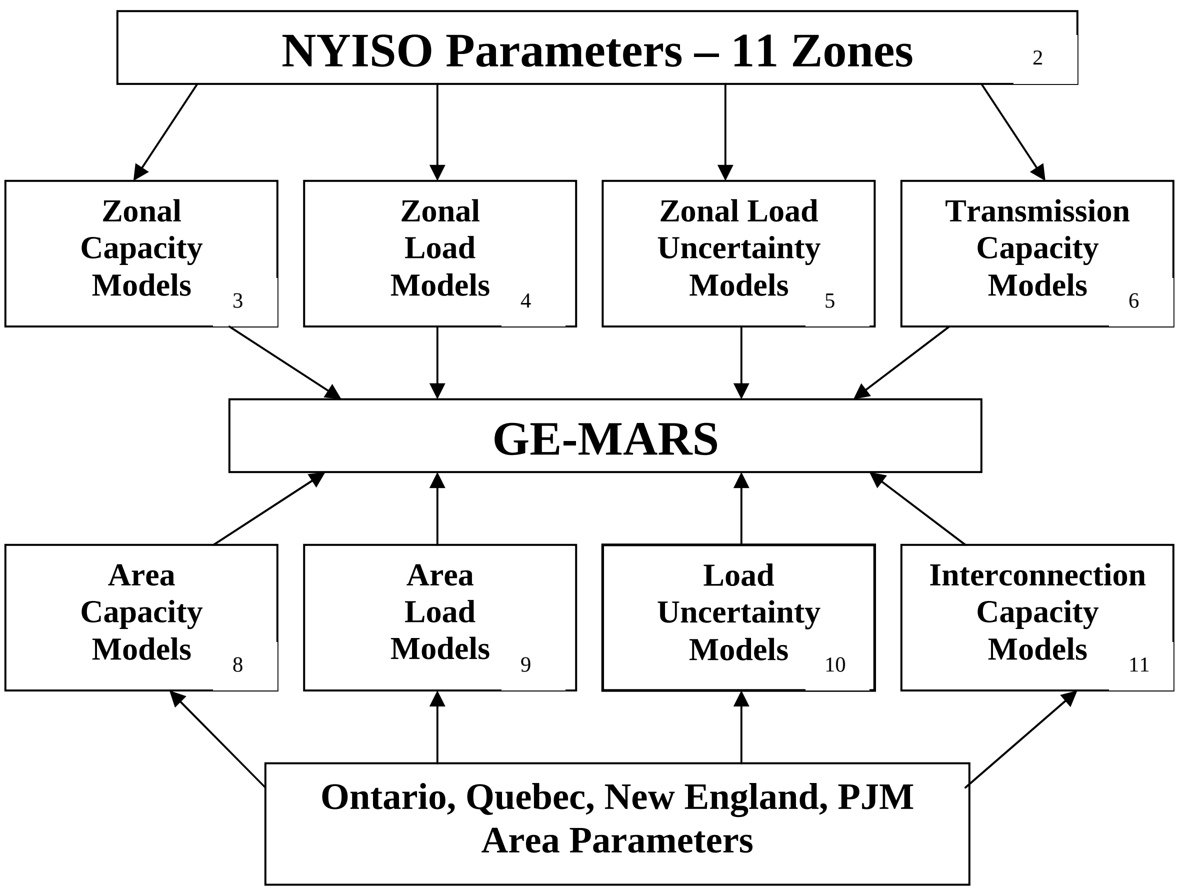


Table A-1: Details on Study Modeling (Refer to Figure A-1)

Internal NYCA Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	GE-MARS	**General Electric Multi-Area** Reliability Simulation Program		Section A-2
2	11 Zones	Load areas	Fig. A-3	NYISO Accounting & Billing Manual
3	Zone Capacity Models Emergency Operating Procedures	-Generator Models for each generating unit in Zone. -Generating Availability. -Unit Ratings. Reduces load during emergency conditions to maintain operating reserves.	GADS Data 2010 "Gold Book"* NYISO	Section A-5.3 Section A-5.4
4	Zone Load Models	Hourly loads	NYCA load shapes NYISO peak forecasts	Section A-5.2 32,872 MW NYISO Oct. forecast
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historical Data	Section A-5.1.1
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	Section A-5.5

External Control Area Modeling:

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

* "2010 Load & Capacity Data" Report issued by the NYISO.

A-2 Computer Program Used for Reliability Calculations

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

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A-5.4).

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

Monte Carlo simulation approaches can be categorized as "non-sequential" and "sequential". A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential simulation can model issues of concern that involve time correlations, and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS Program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

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

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

Table A-2 shows the calculation of the state transition rates from historic data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1:

TR (1 to 2) = (10 transitions) / (5000 hours) = 0.002

Table A-2: Example of State Transition Rates

Time-in-State Data		
State	**MW**	**Hours**
1	200	5000
2	100	2000
3	0	1000

Transition Data			
From State	**To State** 1	2	3
1	0	10	5
2	6	0	12
3	9	8	0

State Transition Rates			
From State	**To State** 1	2	3
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

A-2.1 Error Analysis

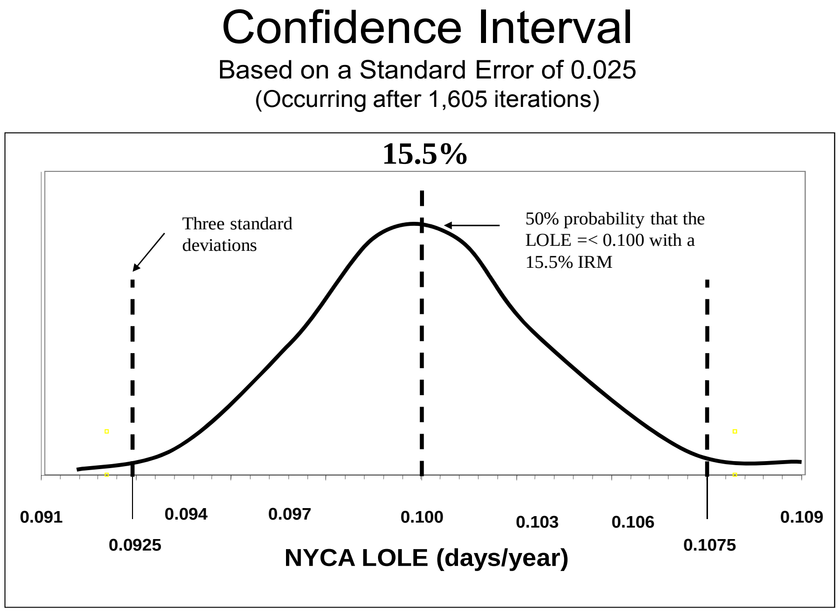
An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical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

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

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

For this analysis, the Base Case required 438 replications to converge to a daily LOLE for NYCA of 0.099 days/year with a standard error of 0.05 per unit. For a 99.7% confidence interval (plus and minus three standard deviations about the mean), the IRMs that would result in a NYCA LOLE of 0.085 days/year and 0.115 days/year were computed. The resulting IRM values of 15.0% and 16.1% define the 99.7% confidence interval, and are shown in Figure A-2. The statistical significance of the 15.0%, 15.5%, and 16.1% numbers are a 0.15%, 50% and 99.85% probability of meeting the one in ten criterion, assuming perfect accuracy in all parameters and using a standard error of 0.05. The Base Case required 1605 replications to converge to a standard error of 0.025. At that point the LOLE for NYCA was 0.096 days/year. If a standard error of 0.025 were used, the confidence interval band would tighten from 15.2% to 15.8%. It should be recognized that a 15.5% IRM, with a 50% probability of meeting the one in ten LOLE criterion, is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

Figure A-2: Confidence Interval



The lines at NYCA LOLE = 0.0925 and 0.1075 represent 0.099 LOLE +/- 3 σ.

A-3 Representation of the NYCA Zones

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

A-4 Conduct of the GE-MARS Analysis

The study was performed using version 3.01 of the GE-MARS software program. This new version has been benchmark tested by the NYISO.

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

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher 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-3.

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

Figure A-3: NYCA Load Zones

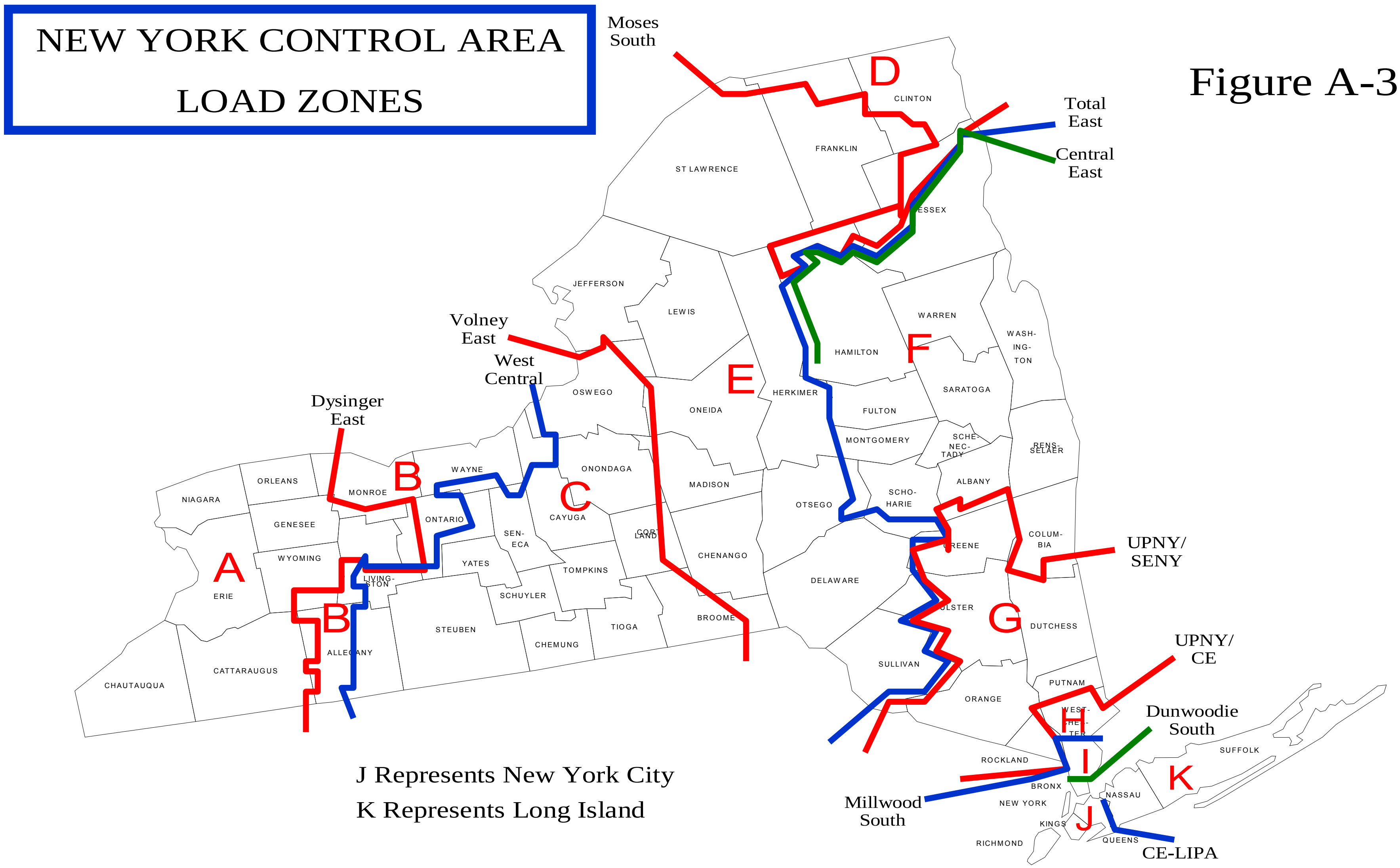


Table A-3: GE Data Scrub

Item	Description	Disposition	Change Req'd	Effect on IRM
1	The Assumption Matrix (AM) called for 150 MW of scheduled maintenance during the summer period. The actual scheduled maintenance modeled during the peak week was 184 MW.	Actual units are chosen making exact values difficult. No action taken.	No	No
2	Attachment F of the AM shows a value of 1,864 MW for August SCRs. Applying the August zonal peaks to the percentages in the EOP-DATA table produced a total of 1,842 MW[1].	The SCR work must be done before the IRM forecast comes out in October. MW values are based on the 2010 Gold Book values.	No	No
3	We calculated the capacity sales to PJM and NE based on the tie ratings in Attachment E and the tie ratings in the MIF. This resulted in 195 MW of sales to PJM that were not listed in the assumption matrix, and 814 MW of sales to NE compared to the 716 MW in the assumption matrix.	The 195 MW to PJM and the difference of 98 MW to New England are the NYPA federal power contracts which are described nominally as 303 MW, but are lower in 2011.	No	No
4	Under Reserve Sharing Between Areas, the comment should probably state that "All NPCC Control Areas ..." will share reserves equally. There are reserve sharing arrangements in the data, but they are such that PJM is always last.	This description will be changed in the AM and in the IRM study report	No	No
5	The 5% remote voltage reduction was calculated to be worth 500 MW compared to the 478 MW shown in Attachment D.	This discrepancy is also due to having to use the Gold Book forecast, instead of the October forecast.	No	No[2]
6	The CEDARS unit is missing from the (Quebec) data. The area exists but has no capacity.	GE had given the ISO advance notice of this item. All runs shown have this correction incorporated.	No	No
A comparison of the system topology in Attachment E with the MIF data found these inconsistencies:				
7	The MIF shows limits of 1,660 MW (positive direction) and 1,220 MW (negative direction) on the interface from A to Ontario. Attachment E shows these limits to be 910 MW and 1,200 MW.	The limits are correct in the model. Attachment E had been changed in the AM after the issuance to GE.	No	No
8	The MIF has dynamic limits on LI Sum of 535, 372, and 209 MW. The diagram shows 535, 370, and 202 MW.	The limits in the model have been changed. A subsequent run shows no difference in the IRM.	No[3]	No
9	The MIF has dynamic limits on CE-LIPA in the negative direction of 508,	The limits in the model have been changed. A subsequent run shows no	No[4]	No

1 The ICAP value of the SCRs total 2485 MW. The values shown here are the UCAP values.
2 The ICS viewed these discrepancies as non material and offsetting.
3 Because later changes were needed, these limits now match the diagram.
4 Because later changes were needed, these limits now match the diagram.

Item	Description	Disposition	Change Req'd	Effect on IRM
	433, 358, 326, and 251 MW. The diagram shows 508, 432, 355, 325, and 248 MW.	difference in the IRM.		
10	The diagram shows an interface group that includes G to H and G to PJM-East, with ratings of 6,600 MW and 2,999 MW that are not in the MIF.	This grouping is no longer needed with the new SENY model. It has been removed from the diagram.	No	No
11	The diagram on Attachment E is missing some of the NE to Quebec ratings that are on E-2.	It has been corrected on the diagram.	No	No
12	The MIF has limits of 6,500 MW from between PJM-Central and PJM-East, as opposed to 8,400 MW on the diagram. The MIF has 4,000 MW from PJM-West to PJM-Central while the diagram has limits of 5,700 MW and 7,500 MW.	The limits in the model have been changed. A subsequent run shows a reduction in the LOLE. ICS has re-run the LCR-IRM curve.	Yes	Yes. The combined results of this update and the next one indicate a 0.6 % lower IRM.
13	The interface group shown on Attachment E-1 includes PJM-East to RECO, J2 to J, and PJM-East to J3, the limits in the MIF appear to be opposite to the 2000 MW limit on the diagram.	The limits in the model have been changed. A subsequent run shows a reduction in the LOLE. ICS has re-run the LCR-IRM curve.	Yes	Yes. See above.

A-4.1 Methodology

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

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

1) Start with all points on IRM/LCR Characteristic
2) Develop regression curve equations for all different point to point segments consisting of at least four points
3) Rank all the regression curve equations based on the following:
   - Sort regression equations with highest R^2

- Ensure calculated IRM is within the selected point pair range, i.e. if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid
- Ensure the *calculated* IRM and corresponding LCR do not violate the 0.1 LOLE criteria
- Check result to ensure consistent with visual inspection methodology used in past years studies

This approach produced a quadratic curve function with R^2 correlation approaching 1.000 as the basis for the Tangent 45 calculation. First derivatives were calculated for the NYC and Long Island zones for each of the equations and solved for the 45 degree slope resulting in an average value of 15.5%. The above methodology was adopted by the NYSRC Executive Committee at the November 7, 2007 meeting and is incorporated into Policy 5-4.

A-5 Input Data and Models

A-5.1 Base Case Modeling Assumptions

Table A-4 summarizes the major assumptions used in the 2011IRM Study:

Table A-4: Base Case Modeling Assumptions for 2011 NYCA IRM Study

Parameter	2010Study Modeling Assumptions	20011 Study Modeling Assumptions	Described in following section
NYCA Load Model			
Peak Load	October forecast: • 32,976 MW for NYCA • 11,822 MW for Zone J • 5,365 MW for Zone K	October forecast: • 32,872 MW for NYCA • 11,463 MW for Zone J • 5,414 MW for Zone K	Section A-5.2
Load Shape Model	2002 Load Shape	2002 Load Shape	Section A-5.2
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Section A-5.2.1
Capacity Resources			
Generating Unit Capacities	Updated DMNC test values per 2009 Gold Book	Updated DMNC test values per 2010 Gold Book	Section A-5.3
New Generation Units	LIPA Solar 30MW, Caithness 310 MW, Uprate Gilboa #3 & 4 60MW, Sherman Island Uprt 8.5 MW, 74th Street GT#2 19.7MW, Riverbay 24MW, & 305.5 MW wind.	Empire Generating 635 MW, River Bay 24 MW, Fulton County Land Fill 3.2 MW, Astoria Energy II 550 MW, uprate Gilboa 4 30 MW, EnXco Solar 15 MW, Fairfield Wind 74 MW.	.Section A-5.3
Modeling Wind Generation Resources	Derived from hourly wind data with average Summer Peak Hour capacity factor of 11%	Derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %	Section A-5.3

Parameter	2010Study Modeling Assumptions	20011 Study Modeling Assumptions	Described in following section
Retirements	• Poletti 1(891 MW) • Greenidge 3 (52 MW) • Westover 7 (40.2 MW	Energy Systems North East (ESNE) 74.5 MW	Section A-5.3
Availability & Maintenance			
Forced & Partial Outage Rates	5-year (2004-08) GADS data (Those units with less than five years data will use available representative data.)	5-year (2005-09) GADS data (Those units with less than five years data will use available representative data.)	Section A-5.3
Planned Outages	Based on schedules received by NYISO & adjusted for history	Based on schedules received by NYISO & adjusted for history	Section A-5.3
Summer Maintenance	Continue with approximately 150 MW after reviewing last year's data.	Continue with approximately 150 MW after reviewing last year's data.	Section A-5.3
Gas Turbines Ambient Derate	The derate model based on provided temperature correction curves. The same as last year	The derate model based on provided temperature correction curves. The same as last year.	Section A-5.3
Non-NYPA Hydro Capacity Modeling	45% derating	45% derating	Section A-5.3
Emergency Operating Procedures (EOPs) & Assistance			
Special Case Resources	2575 MW (July 10) based on3 year historical experience. Limit to 4 calls per month in July and August for DEC limited generation. (about 30 hour total)	2498 MW (Aug 11) based on NYISO growth rate forecast. Monthly variation based on historical experience. .	Section A-5.3
EDRP Resources	329 MW registered; modeled as 148 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	260 MW registered, modeled as172 MW in July and August and proportional to monthly peaks in other months. Limit to 5 calls per month.	Section A-5.3
External Capacity Purchases	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1090 MW from Quebec. Equivalent Contracts modeled	Grandfathered amounts of 50 MW from NE, 37 MW from PJM, 1090 MW from Quebec modeled as actual contracts on boarder interfaces. Also 1043 MW modeled as de-ration on the upstate ties to PJM.	Grandfathered contracts per FERC. Section A-5.3
Capacity Sales	In addition to the long term firm sales of 303 MW, include known firm contracts of 641 MW to NE FCM market. Equivalent Contracts modeled	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	Section A-5.3
Capacity Wheel-throughs	None modeled	None modeled except for a sensitivity case.	

Parameter	2010Study Modeling Assumptions	20011 Study Modeling Assumptions	Described in following section
Emergency Operating Procedures	700 MW of non-SCR/EDRP MWs	737 MW of non-SCR/EDRP MWs.	Section A-5.4
Transmission System Model			
Interface Limits	Based on 2009 Operating Study, 2009 Operations Engineering Voltage Studies, 2009 Comprehensive Planning Process, and additional analysis	Based on 2010 Operating Study, 2010 Operations Engineering Voltage Studies, 2010 Comprehensive Planning Process, and additional analysis.	Section A-5.5
New Transmission Capability	Linden VFT - 300 MW.	350MW increase in transfer capability on Dunwoodie South due to forecast completion of M29 project.	Section A-5.5
Transmission Cable Forced Outage Rate	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Section A-5.5
Unforced Capacity Deliverability Rights (UDRs)	UDRs have been issued for the Cross Sound Cable, Neptune cable and Linden VFT Project.	No new projected UDRs.	Per transmission owner notification
Other Modeling Considerations			
GE-MARS computer Model Version	Version 2.98	Version 3.01	Section A-2
Outside World Area Models	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Five zones modeled for New England derived from 14 zones provided	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New. England.	Section A-5.7
Reserve Sharing between Areas	All NPCC Control Areas have indicated that they will share reserves equally among all. Loop Flow switch(s) are in the "No" position to not allow a Control Area to send capacity through one system and back into itself in order to avoid the congestion that could be relieved by transmission projects.	All Control Areas in NPCC have indicated that they will share reserves equally.	Section A-5.7

A-5.2 NYCA Load Model

Methodology for Determining the Summer IRM Peak Load Forecast

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 2010 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 2010 by Moody's Analytics. The 2011 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2010.

The 2010 peak forecast was 33,025 MW. The actual peak of 33,452 MW occurred on Tuesday, July 6, 2010. The NYISO activated Special Case Resources (SCRs) in Zone J on that day to curtail load. It is estimated that the impact due to SCRs plus all other demand response impacts was 500 MW. After accounting for the impacts of weather and the demand response, the weather-adjusted peak load was determined to be 32,625 MW, 400 MW (-1.2%) below the forecast. The 2011 forecast for the NYCA is 32,872 MW.

The 2011 Base Case IRM forecast is shown below in Table A-5. The LFTF recommends this forecast to the NYSRC for its use in the 2011 IRM study.

Table A-5: 2011 NYCA Peak Load Forecast

Summary of 2009 & 2010 Summer Peaks

(a) Transmission District	(b) 2009 Weather Adjusted MW	(c) 2010 RLGF Forecast	(d)=(b)*(c) 2010 Forecast - MW	(e) 2010 Actual MW	(f) Weather, Losses & SCR/EDRP Adjustment	(g)=(e)+(f) 2010 Weather Adjusted MW	(h)=(g)-(d) Adjusted MW Over/ Under Forecast	(i)=(g)/(b) 2010 RLGF (Actual)
Central Hudson	1,174	0.9999	1,173.4	1,230	-70	1,160	-13	0.9885
Con-Edison	13,563	0.9944	13,486.8	13,037	118	13,155	-332	0.9699
LIPA	5,256	0.9988	5,250.3	5,822	-477	5,345	95	1.0169
Niagara Mohawk	6,888	1.0049	6,921.8	7,200	-280	6,920	-2	1.0046
NYPA	308	1.0169	312.8	343	-8	335	22	1.0891
NYSE&G	3,086	1.0029	3,095.1	3,153	-138	3,015	-80	0.9770
O&R	1,152	0.9965	1,148.0	1,144	-4	1,140	-8	0.9896
RG&E	1,637	0.9999	1,636.8	1,582	-27	1,555	-82	0.9500
NYCA Total	33,063	0.9988	33,025.0	33,511	-886	32,625	-400	0.9867
Zone J Locality	11,791	0.9944	11,725	11,213	137	11,350	-375	0.9626
Zone K Locality	5,374	0.9988	5,368	5,822	-436	5,386	18	1.0022

2011 Forecast for NYSRC Installed Reserve Margin Study

(a) Transmission District	(b) 2010 Weather Adjusted MW	(c) Reallocation of Losses	(d)=(b)+(c) 2010 Weather Adjusted MW	(e) Adjusted RLGFs	(f)=(d)*(e) NYSRC 2011 Forecast MW	(g) 2010 Gold Book Forecast	(h)=(f)-(g) Difference in MW
Central Hudson	1,160	-1	1,159	1.0040	1,164		
Con-Edison	13,155	192	13,347	1.0100	13,480		
LIPA	5,345	41	5,386	1.0052	5,414		
Niagara Mohawk	6,920	-231	6,689	1.0070	6,736		
NYPA	335	5	340	1.0070	342		
NYSE&G	3,015	-19	2,996	1.0070	3,017		
O&R	1,140	9	1,149	1.0040	1,154		
RG&E	1,555	4	1,559	1.0040	1,565		
NYCA	32,625	0	32,625	1.0076	32,872	33,160	-288

A-5.2.1 Zonal Load Forecast Uncertainty

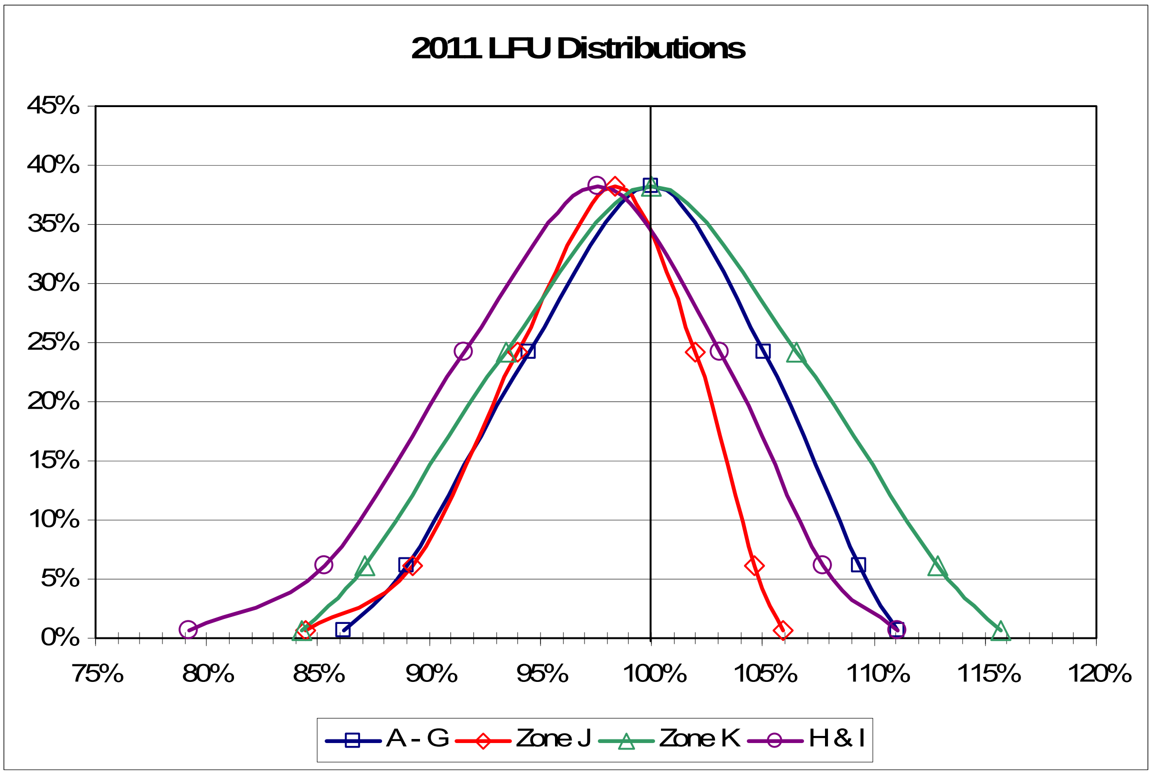
For 2011, a slight revision to the load forecast uncertainty models were provided by Consolidated Edison for Zones H, I and J. The revision affected the lowest and the highest bins and had the effect of increasing the overall bandwidth for those Zones by a small amount. No other changes were made to the 2011 LFU models. The results of these models are presented in Table A-6. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A-4.

Table A-6: 2011 Load Forecast Uncertainty Models

Bin No.	Probability	A - G	H & I	Zone J	Zone K
1	0.6%	86.2%	79.2%	84.4%	84.3%
2	6.1%	89.0%	85.3%	89.3%	87.1%
3	24.2%	94.5%	91.5%	94.0%	93.5%
4	38.3%	100.0%	97.6%	98.3%	100.0%
5	24.2%	105.1%	103.1%	102.0%	106.5%
6	6.1%	109.3%	107.7%	104.6%	112.9%
7	0.6%	111.1%	111.1%	105.9%	115.7%

Hi-Med	-13.8%	-18.3%	-13.9%	-15.7%
Low - Med	-11.1%	-13.6%	-7.6%	-15.7%
Delta	-24.9%	-31.9%	-21.5%	-31.4%

Figure A-4



The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology for determining the LFU models has been reviewed by the NYISO Load Forecasting Task Force.

A-5.3 NYCA Capacity Model

2010 "Gold Book" Changes:

The capacity model input to GE-MARS incorporates the several types of resource capacity used to serve load in the NYCA. The following were changes made to the existing capacity shown in Table III-2 of the "2010 Load and Capacity Data" (also known as "The Gold Book"):

- **Retirements:**
  - **Energy Systems North EAST (ESNE) 74.5 MW Zone A**

- **Planned Units for 2010:**

  (These units had a signed interconnection agreement by August 1, 2010.)

o Empire Generating	635 MW	Zone F
o Riverbay	24 MW	Zone J
o Fulton County Land Fill	3.2 MW	Zone F
o Astoria Energy II	550 MW	Zone J
o Uprate Gilboa #4	30 MW	Zone F

New Wind*

o Fairfield Wind Project	74 MW	Zone C

New Solar

o EnXco Solar	15 MW	Zone K

* The total amount of wind in the model is 1,333 MW (nameplate rating). A complete list of wind units is provided in Appendix C

The total amount of statewide resource capacity in the model is 43,460 MW. This figure includes SCRs and is net of purchases and sales.

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

Generating Units:

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

Unit Ratings:

With the exception of wind units, the rating for each generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Wind units are rated at their nameplate, or full rated value, in the model. The 2010 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

Unit Performance:

With the exception of intermittent resources, performance data for generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the “equivalent demand forced outage rate” (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2011 IRM Study. Figure A-5 shows the trend of EFORd for various regions within NYCA. Figure A-6 shows a rolling 5 year average of the same data.

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

The unit forced outage states for the majority of the large steam units were obtained from the five-year NERC-GADS outage data collected by the NYISO for the years 2005 through 2009. 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.

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 2009 period for the NYCA generators

Wind generators are modeled as an hourly load modifier. The output of the unit varies between 0 and the nameplate value based on wind data collected near the plant sites during 2002. The 2002 hourly wind data corresponds to the 2002 hourly load shape also used in the model. Characteristics of this data indicate an overall 30% capacity factor with a capacity factor of approximately 11% during the summer peak hours. A total of 1,333 MW of installed capacity associated with wind generators is included in this study. The breakout of the wind units can be seen in appendix C.

Figure A-5: Annual EFORd Trends

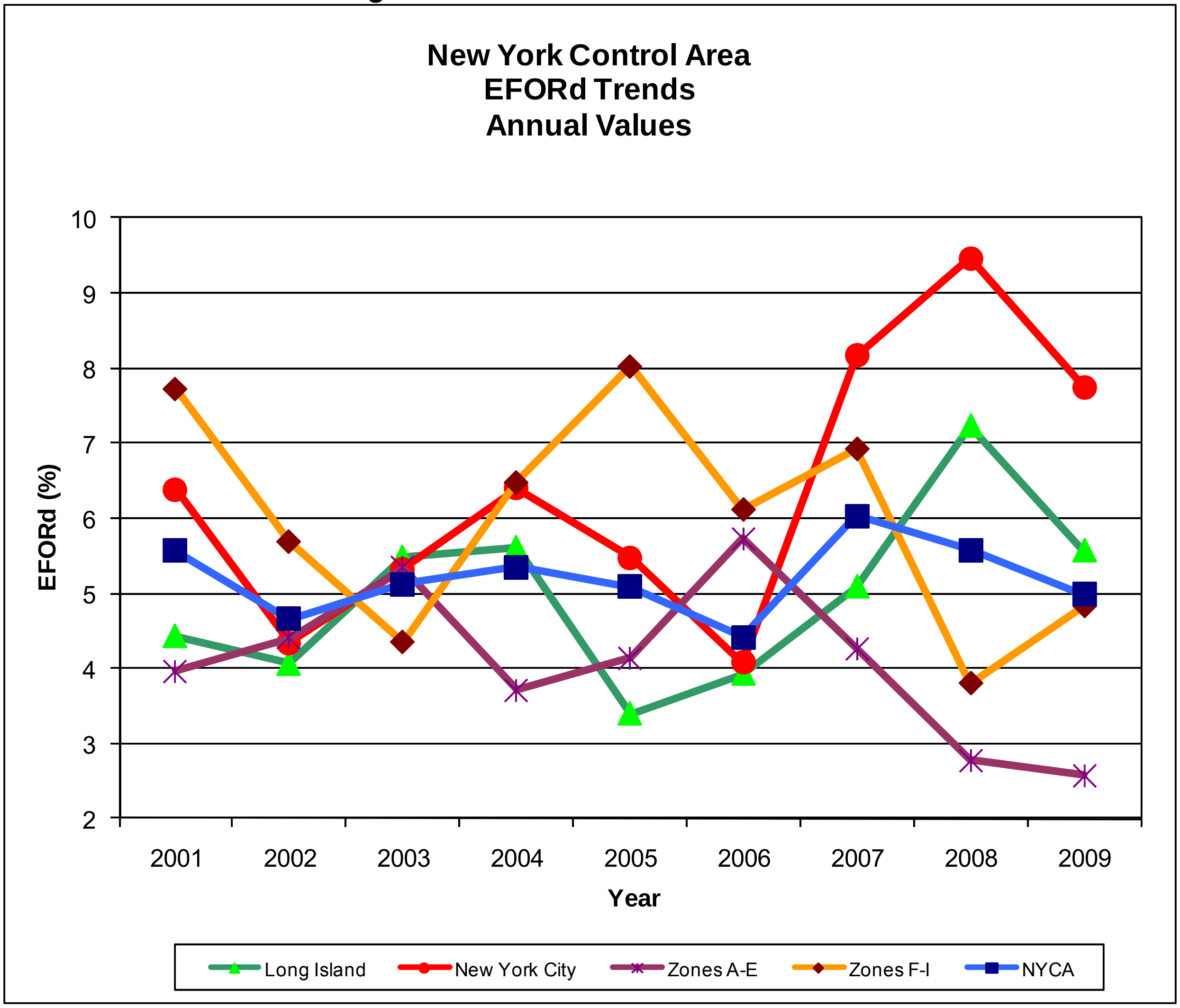


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate. Figure A-6 shows five year rolling averages for EFORd.

Figure A-6: EFORd Rolling Average Trends

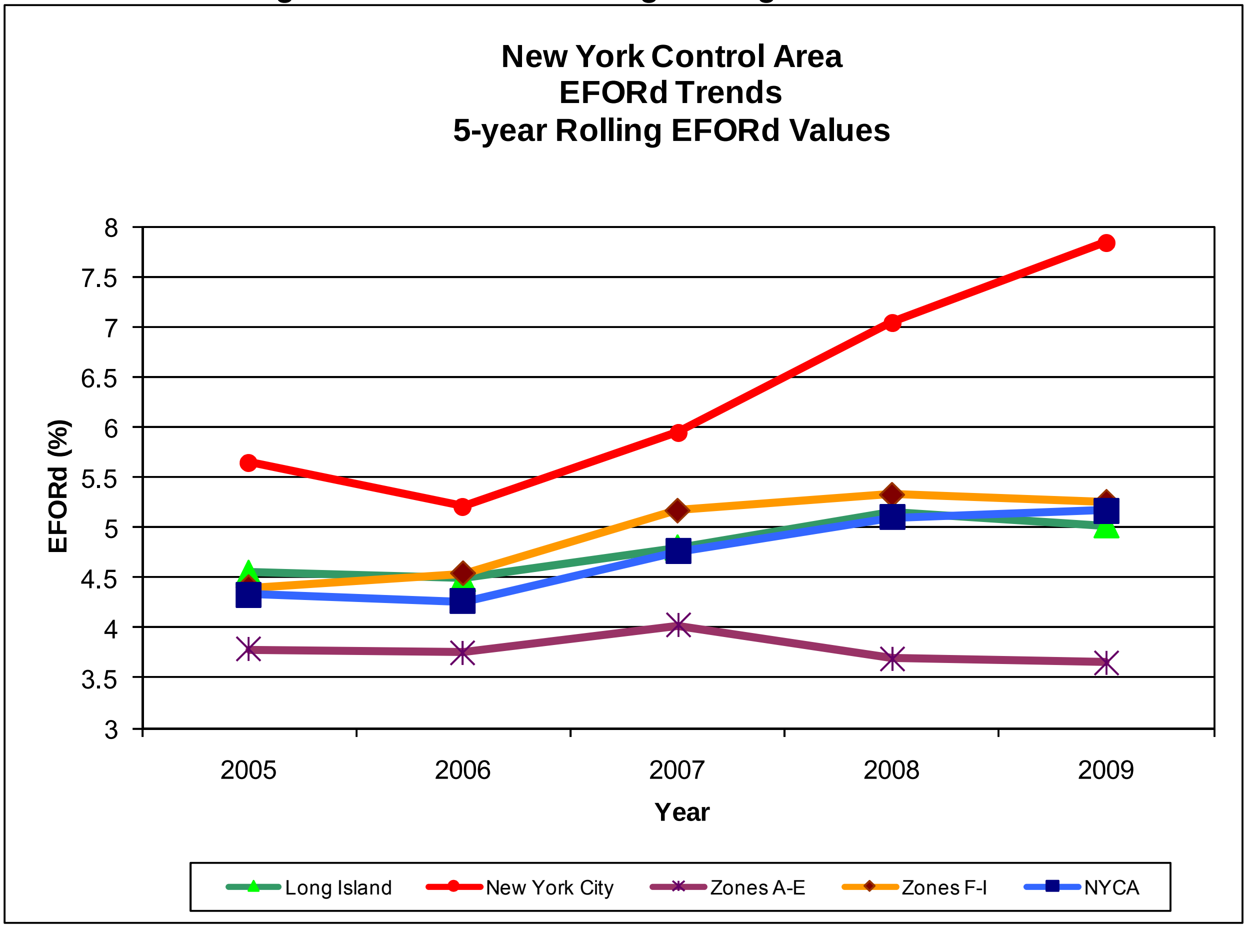


Figure A-6 removes units that have retired from all five years of each affected point. These graphs represent thermal unit performance only.

Equivalent Availability:

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

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

Figure A-7: NYCA Equivalent Availability

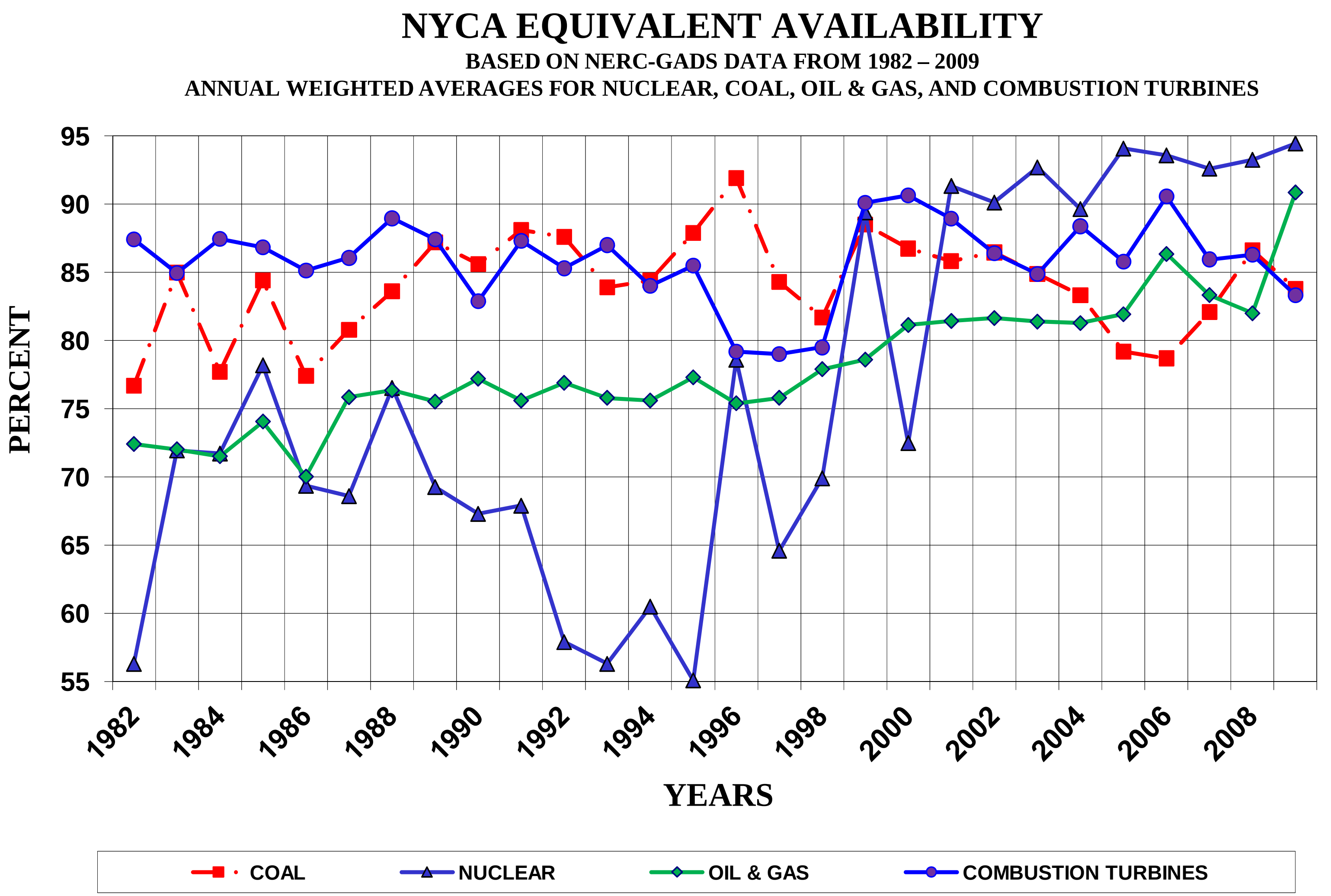


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Figure A-8: NYCA Equivalent Availability - 5 Year Rolling Average

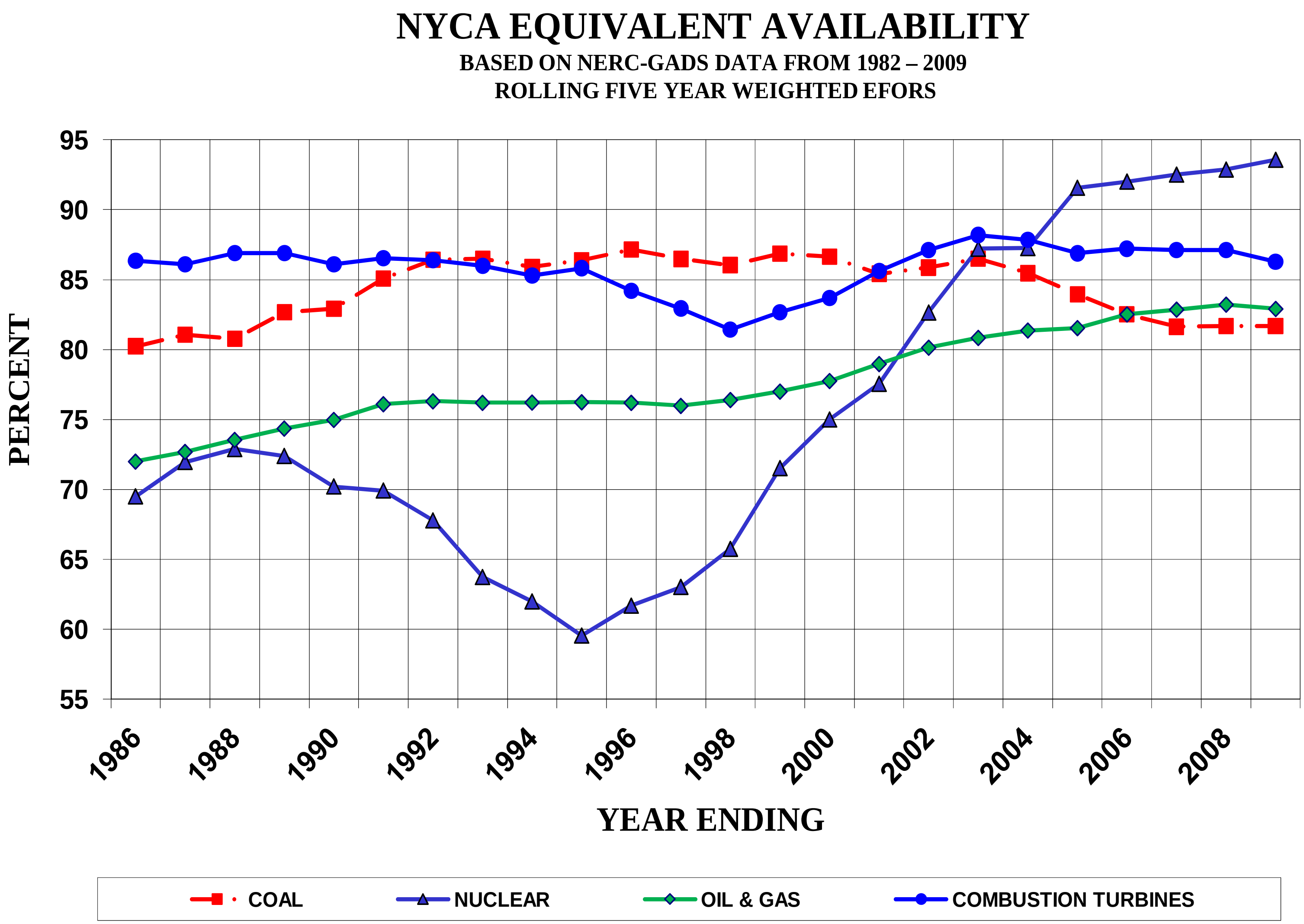

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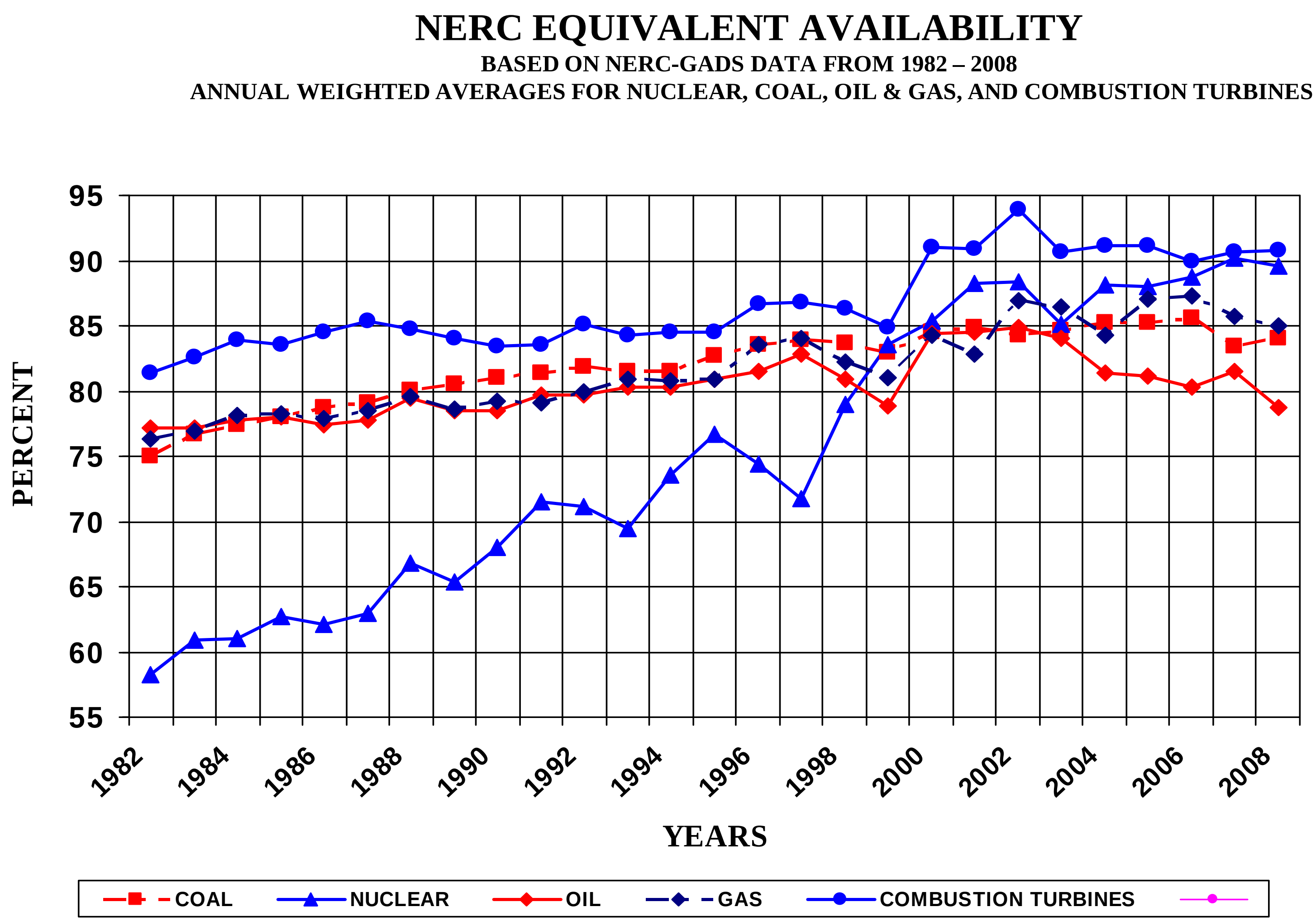
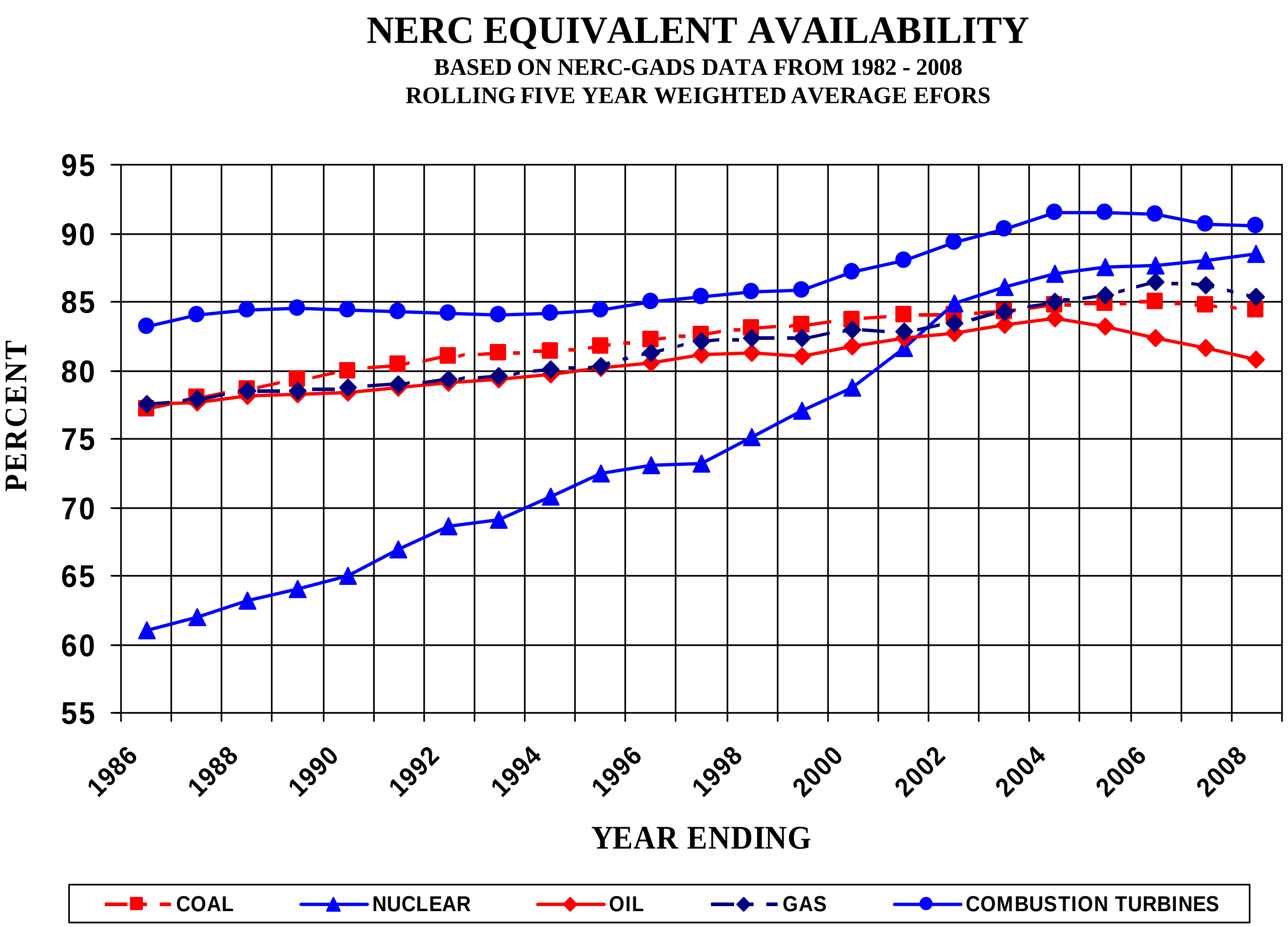
Figure A-9: NERC Region Equivalent Availability



Sent to ICS on 6/28/2010

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



Sent to ICS on 6/28/2010

Figure A-11: Planned & Maintenance Outage Rates

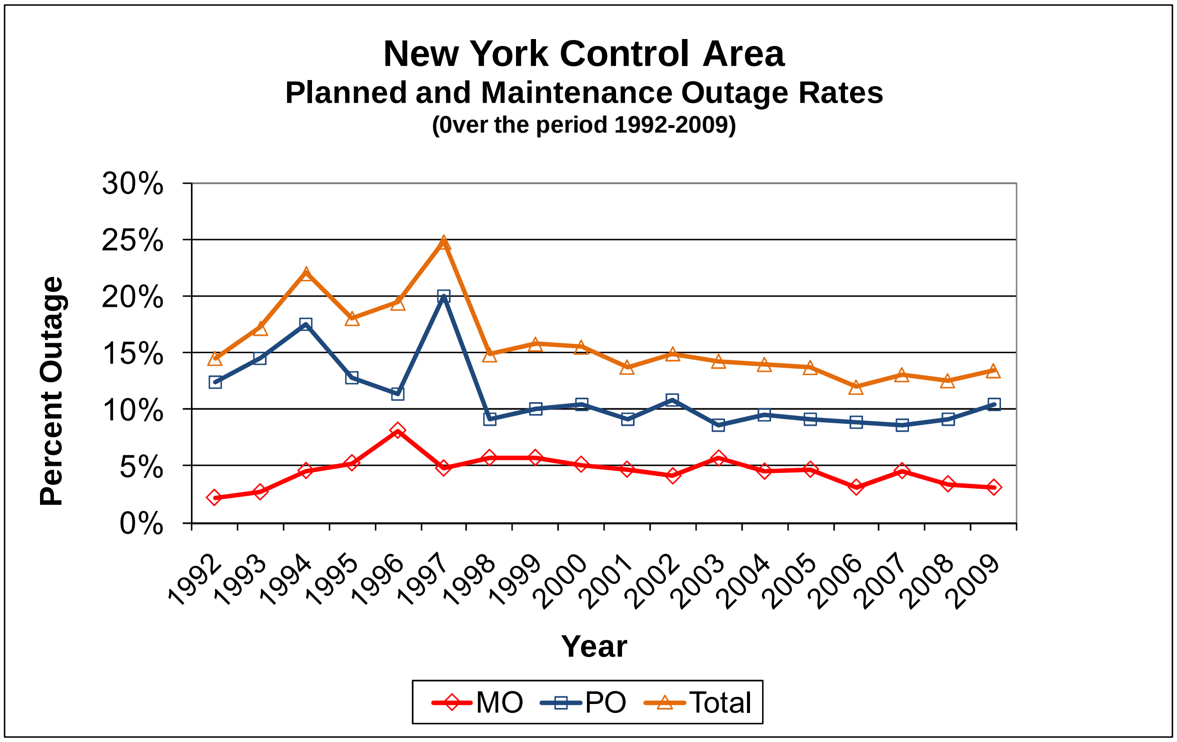
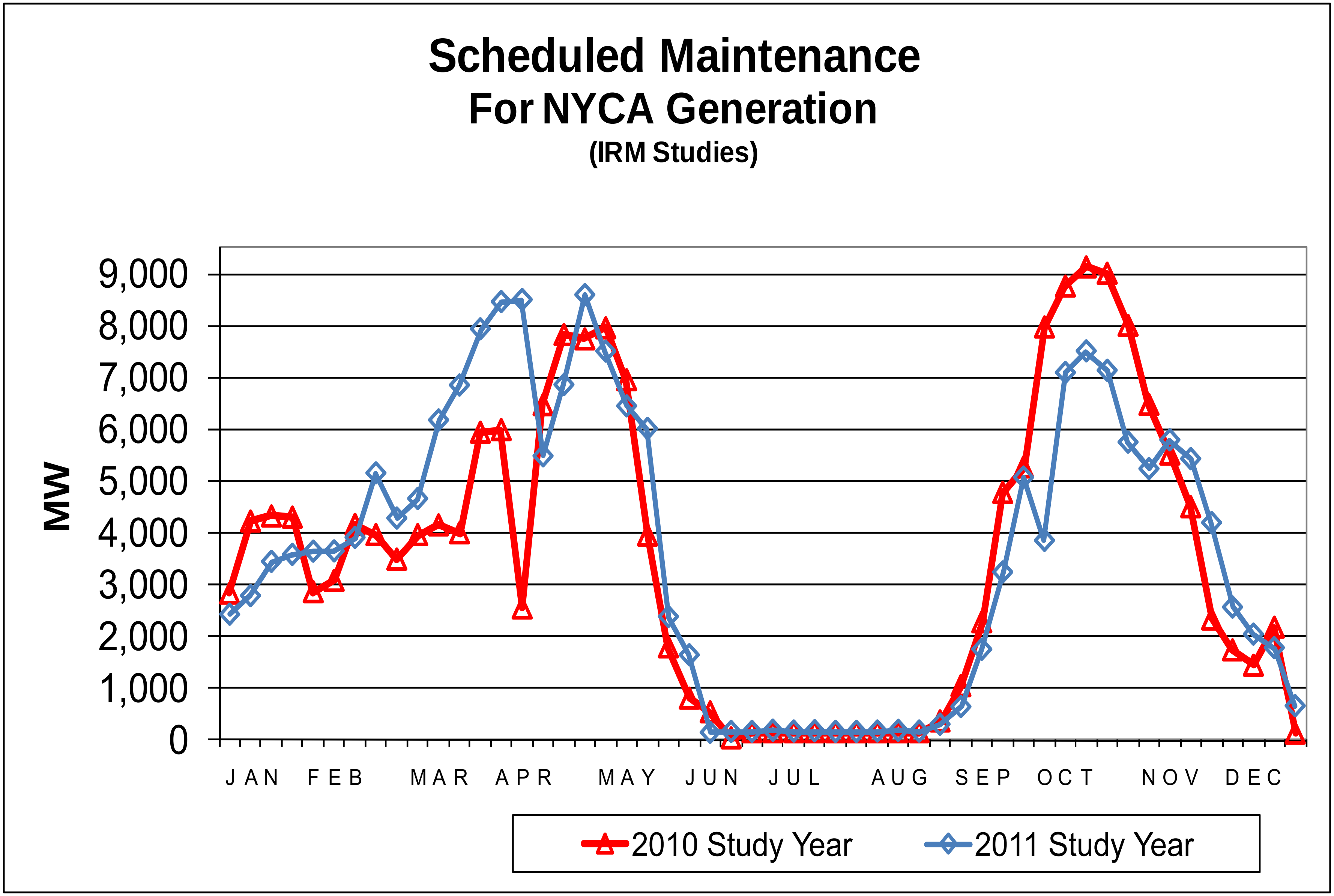


Figure A-11 shows the historic percentage of planned and maintenance outage hours for the years 1992 through 2009.

Figure A-12 shows the amount of capacity assumed to be scheduled out in the 2010 and 2011 studies.

The planned outages in the current study over the 2011 summer period are approximately 150 MW.

Figure A-12: Scheduled Maintenance



Combustion Turbine Units:

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

Review of the simple cycle combustion turbine data, however, has led the NYISO to introduce to the model what is termed a bias. The NYISO plans to extend this analysis in the future to include other capacity limited resources. An NYISO report on this analysis, *Adjusting for the Overstatement of the Availability of the Combustion Turbine Capacity in Resource Adequacy Studies*, dated October 22, 2007, can be found at www.nyiso.com.

The derate does not affect all units because many of the new units are capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so they are not impacted by the temperature derating in obtaining an output of 79.9 MW. About one quarter of the existing 3,700 MW of simple cycle Combustion Turbines fall into this category.

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

Hydro Units:

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model based on historic water flows and unit performance. The remaining approximately 1,000 MW of hydro facilities are simulated in GE-MARS with a 45% hydro derate model, representing deratings in accordance with recent historic hydro water conditions.

Review of Operational Data for Run of River Hydro

Zone	MWs	Derate
A	3.0	
B	14.4	
C	82.4	59.6%
D	48.8	49.9%
E	370.6	40.0%
F	284.0	48.3%
G	47.5	38.2%
I	1.7	
Weighted	Average*	45.7%

*Values for Zones A, B, and I, have been removed from the table for confidentiality reasons, but are included in the total derate calculation.

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

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

	Forecast ICAP	Performance
Zones A-E	1320.3 MW	77.2%
Zones F-I	370.3 MW	75.9%
Zone J	610.4 MW	70.1%
Zone K	196.8 MW	69.7%

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.

For this year's study, the NYISO has recommended that SCRs be modeled with monthly values. For the month of August, the value is 2498 MW. This value is the result of applying three year historic growth rates to the latest participation numbers.

EDRPs are modeled as a 172 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 260 MW.

External Installed Capacity from Contracts:

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

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

> The base case assumes the following summer external ICAP purchases: 1090 MW from Quebec, 50 MW from New England, and 37 MW from PJM. In addition to these contracts, an allowance is made for 1,043 MW modeled as de-ration on the upstate ties to PJM to represent an option for contracts to be placed on those ties.
>
> In addition to the long term firm sales of 303 MW (nominal value), there are approximately 716 MW of sales committed in 2011 as a result of the New England's Forward Capacity Market (FCM) auctions.

A-5.4 Emergency Operating Procedures (EOPS)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed in Table A-7 were provided by the NYISO based on experience.

Table A-7: Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	2498 MW*
2	Emergency Demand Response Programs (EDRPs).	Load relief	260 MW**
3	5% manual voltage Reduction	Load relief	71 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	478 MW***
6	Voluntary industrial curtailment	Load relief	100 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.*

The above values are based on a NYISO forecast that incorporates 2010 operating results. This forecast is applied against a 2011 peak load forecast of 32,872 MW. The above table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency.

The amount of help that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

A-5.5 Transmission Capacity Model

Introduction

The NYCA is divided into 11 Zones. The boundaries between Zones and between adjacent control Areas are called interface ties. These ties are used in the GE-MARS model to allow and limit the assistance among NYCA Zones and adjacent control Areas. While the NYCA transmission system is not explicitly modeled in the GE-MARS program, a transportation algorithm is utilized with limits on the interface ties between the Areas and Zones represented in the model. Interface tie groupings and dependent interface tie limits have been developed such that the transmission model closely resembles the standard eleven-Zone NYCA model. The interface tie limits employed are developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and refined with additional analysis specifically for the GE-MARS representation. The new topology and interface limits are shown in Figure A-9.

The interface tie limits used in the 2010 IRM study were reviewed to assess the need to update the transfer limits and topology resulting to reflect results from more recent studies. The following are the sources of the updated transfer limits:

- The Summer 2008 and 2009 and 2010 Operating Study Reports.
- The 2005 Comprehensive Area Transmission Review.
- The 2010 Reliability Needs Assessment (RNA)
- Specific interface studies and analyses conducted only for ICS to update the transfer limits.
- Transmission Owner input.
- Input from neighboring regions on internal constraints.

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

Considerations in Applying Emergency Transfer Limits

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

Changes in Individual Interfaces

The interface limit for I to J was increased to 4350 MW based on recent studies performed by Con Edison and the NYISO.

Other Changes are reflected in Table A-8 below.

.

Changes in Topology and Interface Groupings

Many changes were made to the PJM East to New York interfaces. These changes are summarized in Table A-8 and the footnotes.

Cable Interfaces

Failure rates for overhead lines and underground cables are similar but the repair time for an underground cable is much longer. Therefore, forced transmission outages are included in the GE-MARS model for the underground cable system from surrounding Zones entering into New York City and Long Island. The GE-MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are calculated based on the individual make-up of each interface, which includes failure rates and repair times for the cable, and for any transformer and/or phase angle regulator on that particular cable.

For the Con Edison system, the transition rates were calculated based on five year historical failures of their entire system of underground cables, transformers, and phase angle regulators that are the three major components of the cable interface system into New York City. The failure rates and repair rates for transformers, and phase angle regulators were calculated by voltage classification, and the cables' failure rates and repair rates were calculated by voltage classification and on a per-mile basis. Typically, the larger the cable and equipment population included in the study, the better the results are in predicting the future performance of the underground electric system.

Once a failure rate and a repair time are created for each component, they are combined to form a single cable system model for each cable. Each single cable system model is then combined together with the other single cable system models that make-up that particular interface to obtain a composite interface model. This provides a conservative estimated transition rate for each of the three cable interfaces into New York City.

Interconnection Support during Emergencies

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

Table A-8: Interface Limit Changes for 2011 IRM Modeling

Interface Name		2010 Limits, Base Case	2011 Limits, Base Case	Comments
HQ to Ontario	+	900	1850	To reflect the installation of new HVDC tie and CP8 update Model reduction
	-	900	1817	
PJM Interfaces		Three Area, RECO Load Separated	Four Area, plus RECO Load Separated and moved	PJM provided updates through MARS database update. Limits reviewed by NYISO. Limits maintained to reflect potential internal limits. RECO Load bubble moved. PJM East to New York Interfaces modified to add new joint interface
PJM Cent to East	+	6500	8400	
	-	6500	8400	
PJM West to Cent	+	4000	5700	
	-	4000	5700	
I into J	+	4000	4350	M29 In service
	-	1,999	1999	
PJM East to SENY Joint Interface	+ -			Changed Definition to account for RECO load bubble and simultaneous limits
Northport Tie		286/200	428/388	Unit Nomogram(Northport) with update of New England Limits
Updates to Transfer Limits to Reflect New England CP8				
				Full CP8 Model used
Ontario to Zone A and Zone D	+	1325,400	1200,300	Limits reduced to reflect internal Ontario constraints
	-	1550,400	910,300	

A. **PJM East to New York –** This interface was updated to reflect the installation of the Linden VFT, changes in modeling assumptions reflecting loop flow, and the improved treatment of the RECO load. The topology was modified as follows:
   1. RECO Load – This load is served by PJM and is radial to the southern part of the Orange and Rockland system (in Zone G) and also connects to one of the 345 kV lines to New Jersey. The new model split the RECO load into its own bubble between Zone G and PJM East.

Description of key system changes – Numerous system changes on the Bulk and Non Bulk systems, such as cap banks and an overall lower load forecast were evaluated. Specifically, in an area of the system that is sensitive to zonal load level and system dispatch, the following changes were made in the MARS model:

B. **Dysinger East/West Central** – As in previous analysis, West Central and Dysinger East interfaces were tested together as there is limited generation in Zone B. Thermal limits and voltage limits varied with shift assumptions and base case loadings and the voltage limit were found to be more controlling. The model was also tested with Ginna in and out of service. In the 2009 IRM, the Dysinger East limit was implemented as more controlling than West Central by reducing the limit to the low value of the range of limits from varied base case conditions and shifts. For the 2010 IRM, the controlling interface was moved to West Central, and a nomogram was created to make the more controlling West/Central interface sensitive to load level. For the 2011 IRM, the West Central nomogram and Dysinger/East limit was assessed. Based on this assessment, the West/Central nomogram continues as more controlling and the Dysinger East limits was increased to be more reflective of the upper range of its limit variation because of the more controlling West/Central limit.

C. **Volney East** – This interface limit was increased with an assessment of the limiting contingency cited in last year's assessment. The previously identified limiting element/contingency can be removed by redispatch in zones E and F, or by varying the shift to more of an adjacent zone to adjacent zone shift in the procedure. The Fraser to Cooper Corners line is an element of the Marcy/South interface and is more appropriately captured in that interface limit in the MARS model. By modifying the shift, base case conditions, or citing a limiting element/contingency more appropriate for this interface, the limit varies by 400 to 600 MW. A conservative increase from 4270 to 4875 was implemented based on this variability.

The variations in these three interfaces will be accounted for in the MARS model.

Figure A-13: NYCA Transmission System Representation

Transmission System Representation for 2011 IRM Study - Summer Ratings (MW) - August 25, 2010

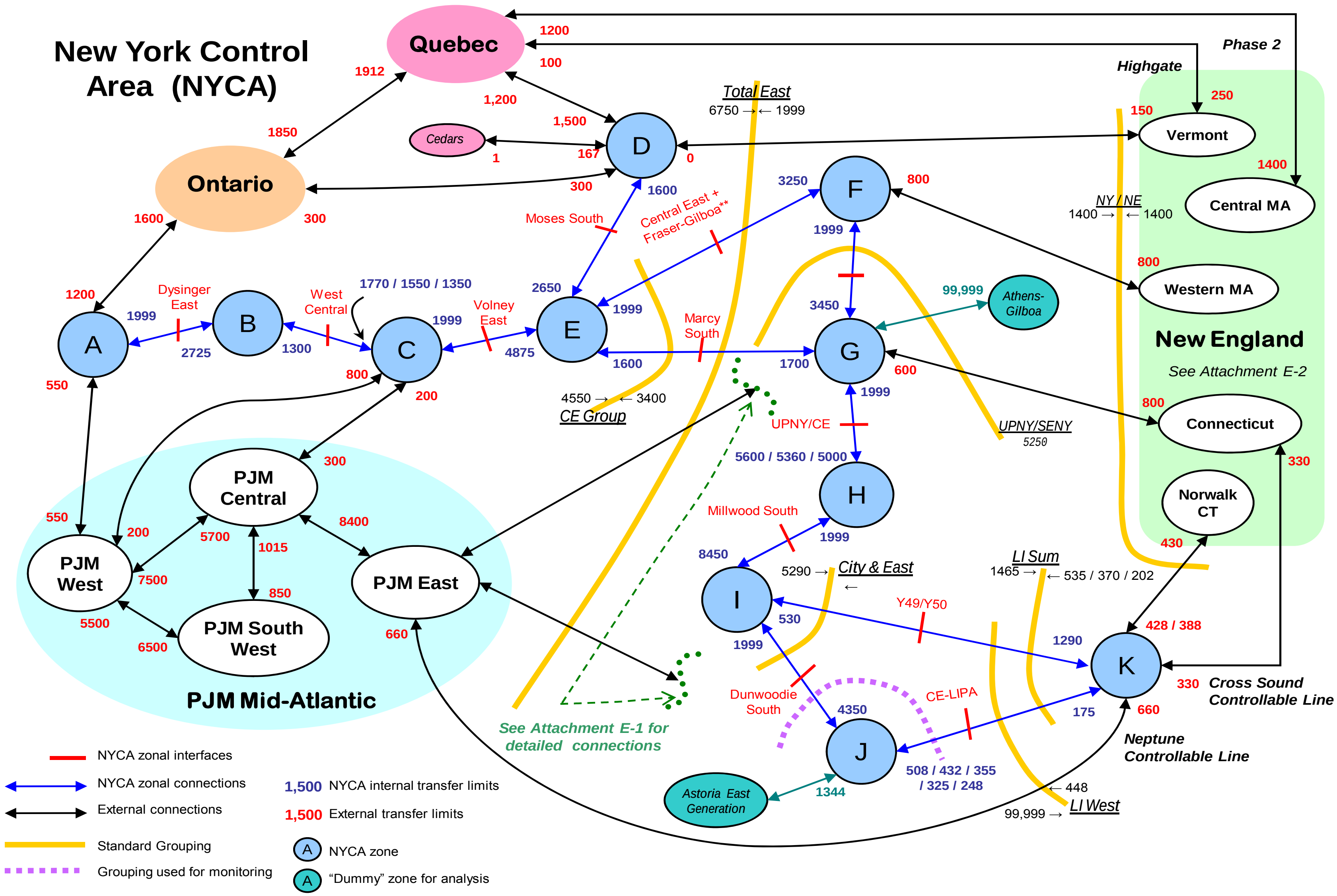
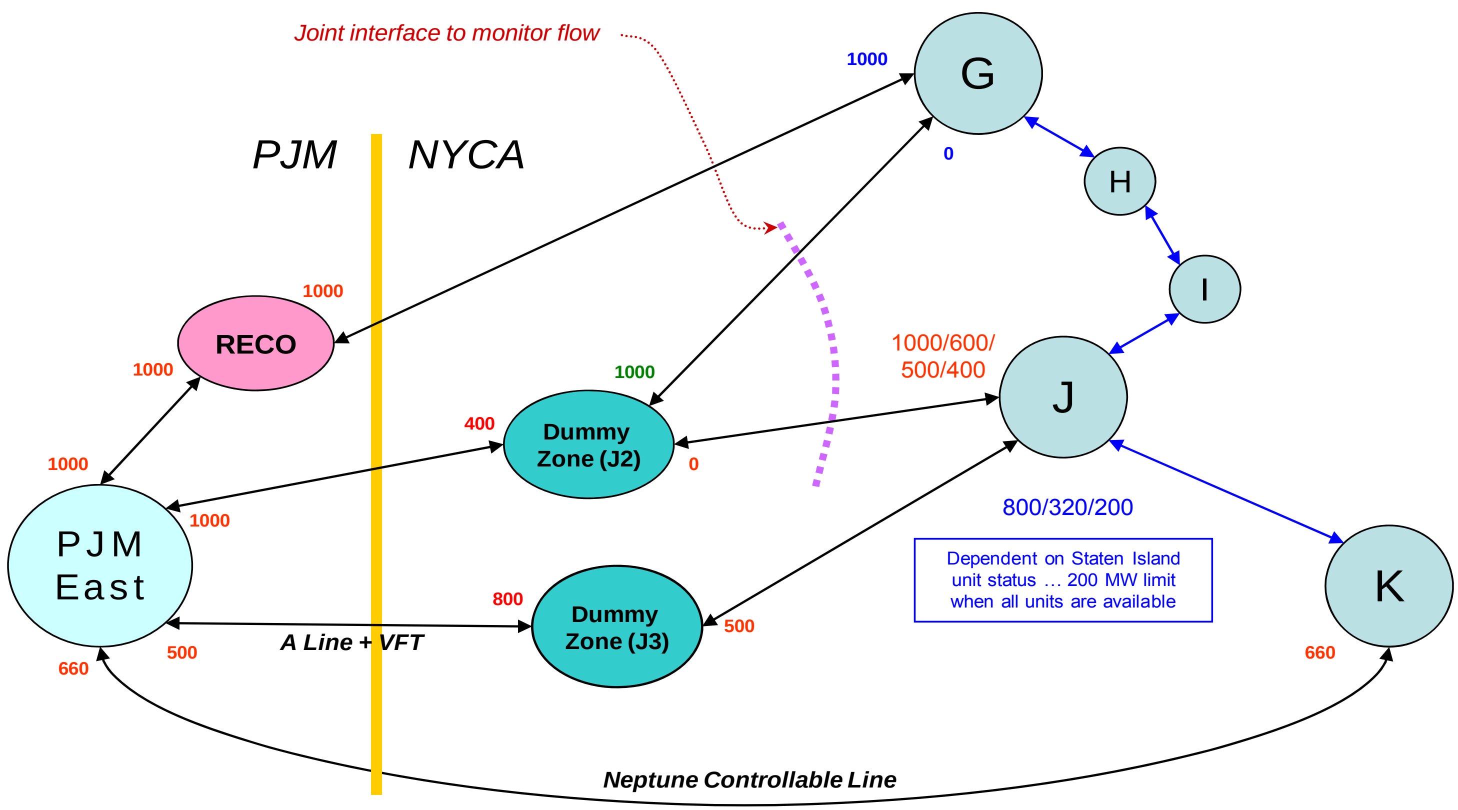


Figure A-13.1: NYCA-PJM Transmission Interface Representation

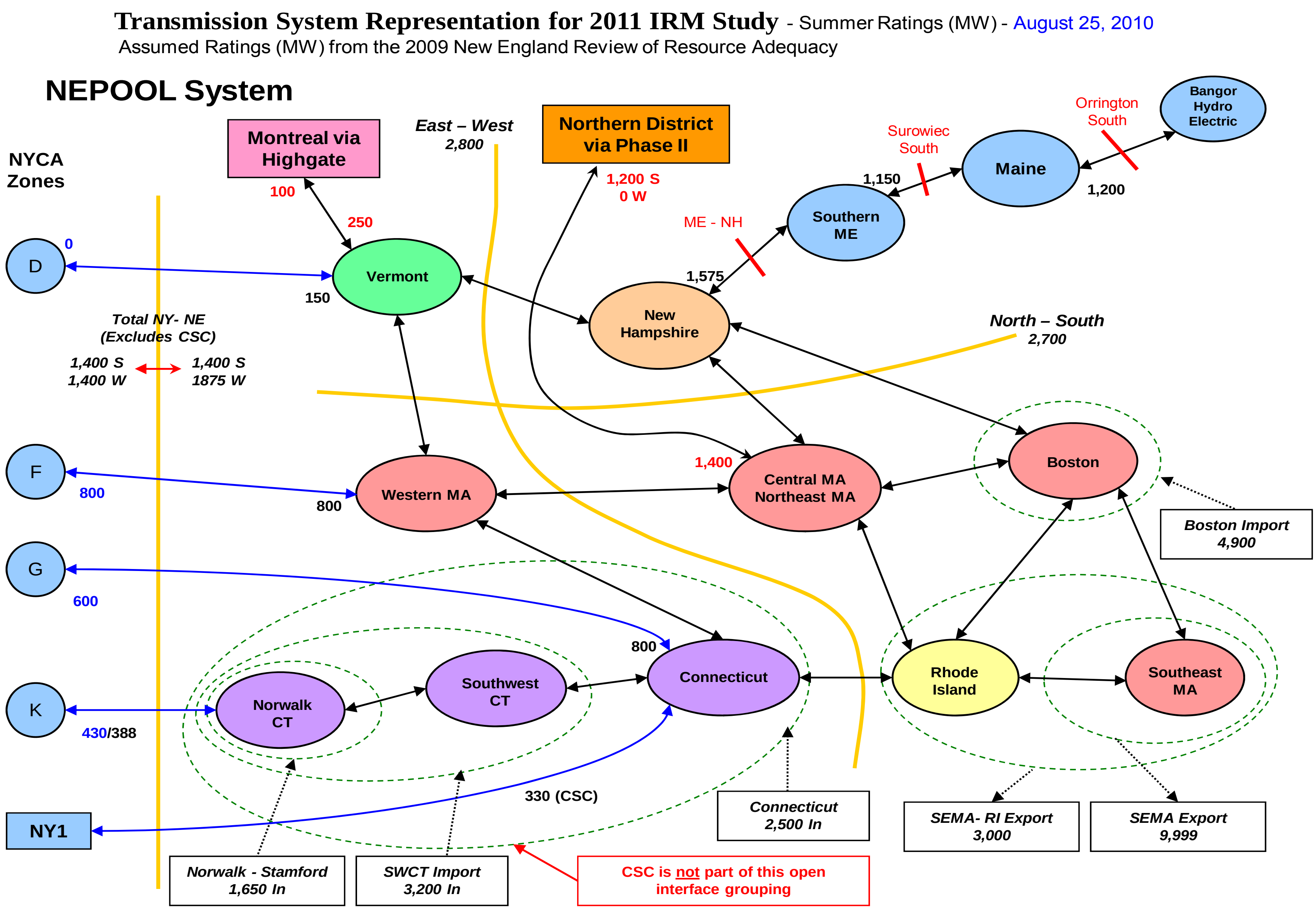
Transmission System Representation for 2011 IRM Study - Summer Ratings (MW) - August 25, 2010

2010 PJM-SENY MARS Model



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

Figure A-13.1: NYCA-PJM Transmission Interface Representation



A-5.6 Locational Capacity Requirements

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

These locational ICAP requirements, recognized by NYSRC Reliability Rule A-R2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A-5.7 Outside World Load and Capacity Models

NYCA reliability largely depends on emergency assistance from its interconnected Control Areas in NPCC and PJM, based on reserve sharing agreements with the Outside World Areas. Load and capacity models of the Outside World Areas are therefore represented in the GE-MARS analyses. The load and capacity models for New England, Ontario, PJM, and Quebec are based on data received from the Outside World Areas, as well as NPCC sources.

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

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

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

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

The assistance from Reliability First Corporation (RFC), with the exception of PJM Mid Atlantic, and the Maritime Provinces was not considered, therefore, limiting the emergency assistance to the NYCA from the immediate neighboring control areas. This consideration is another measure of conservatism added to the analyses.

The load forecast uncertainty model for the outside world model was supplied from the external Control Areas.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-4 is as follows:

Table A-9: Outside World Reserve Margin Modeling

Area	2010 Study Reserve Margin	2011 Study Reserve Margin	2010 Study LOLE (Days/year)	2011 Study LOLE (Days/year)
Quebec	36.2%	30.8%*	0.111	0.111
Ontario	15.3%	15.0%	0.141	0.391
PJM-Mid-Atlantic	12.0%	19.2%	0.289	0.354
New England	12.0%	10.6%	0.152	0.1398

*This is the summer margin; the winter margin is 3.1%

A-5.8 NYCA Wind Resource Generation Summary

Renewable Generating Projects (Wind) Under Consideration for inclusion in the 2011-2012 Installed Reserve Margin Study

Facility	Nameplate Capacity (MW)	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	New Wind Capacity for 2011 IRM (MW)	Total Wind Capacity for 2011 IRM (MW)
Steel Winds II	0.0	A	National Grid	234	2010 Nov	15/0[1]	0.0
Bliss Windpark	100.5	A	Village of Arcade	173	2008 May		100.5
Steel Wind	20.0	A			2007 Jan		20.0
High Sheldon Wind Farm	112.5	C	NYSEG	144	2009 Feb		112.5
Canandaigua I[2]	82.5	C	NYSEG	135	2008 Jun		82.5
Canandaigua II[2]	42.5	C	NYSEG	199	2008 Jun		42.5
Wethersfield Wind Power	126.0	C	NYSEG	177	2008 Dec		126.0
Bear Creek	22.0	C			2006 Feb		22.0
Altona Windpark	97.5	D	NYPA	174	2008 Sept		97.5
Chateaugay Windpark I	106.5	D	NYPA	214	2008 Sept		106.5
Belmont/Ellenburg II	0.0	D	NYPA	213	2011 Oct		0.0
Clinton Windpark I & II	100.5	D	NYPA	172 & 211	2008 May		100.5
Ellenburg Windpark	81.0	D	NYPA	175	2008 May		81.0
Maple Ridge 1 & 2	321.7	E	National Grid	171	2006 Feb		321.7
Madison	11.5	E	NYSEG		2000 Sept		11.5
Munnsville	34.5	E	NYSEG		2007 Aug		34.5
Fairfield Wind Project[3]		C	NYSEG	156	2011 Sept	74.0	74.0
Marble River Wind Farm		D	NYPA	161 & 171	2011 Oct		
TOTAL CAPACITY - ALL CATEGORIES						**0.0**	**1,333.2**

Notes:

1. The CRIS value for this unit is zero MW, therefore, the capacity does not count in the IRM study.
2. Canandaigua I sometimes referred to as Cohocton Wind Farm. Canandaigua II sometimes referred to as Dutch Hill Wind Farm.
3. Fairfield Wind was previously called Hardscrabble Wind.

Appendix B

Details of Study Results

B-1 Introduction

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

B-2 Historical IRMs

Table B-1: NYCA Historical IRM and LCR Information

Capability Year	Base Case IRM	NYCA IRM Final Approved by NYSRC-EC	NYCA Equivalent UCAP Requirement	*LCR for NYC Final Approved by NYISO-OC**	*LCR for LI Final Approved by NYISO-OC**
2000	**15.5%**	18.0%		***80%***	***107%***
2001	**17.1%**	18.0%		***80%***	***98%***
2002	**18.0%**	18.0%		***80%***	***93%***
2003	**17.5%**	18.0%		***80%***	***95%***
2004	**17.1%**	18.0%	11.9%	***80%***	***99%***
2005	**17.6%**	18.0%	12.0%	***80%***	***99%***
2006	**18.0%**	18.0%	11.6%	***80%***	***99%***
2007	**16.0%**	16.5%	11.3%	***80%***	***99%***
2008	**15.0%**	15.0%	8.4%	***80%***	***94%***
2009	**16.2%**	16.5%	7.2%	***80%***	***97.5%***
2010	**17.9%**	18.0%	6.1%	***80%***	***104.5%***
2011	**15.5%**	15.5%	**TBD**	***TBD***	***TBD***

* The NYISO Operating Committee.

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

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

This data can be scaled to the nameplate capacity and assigned geographically to new and existing wind generation units.

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

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

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

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

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

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

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

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

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

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

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

UCAP = ICAP * (1-EFORd)

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

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

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

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

B-4 Sensitivity Case Results

Table B-2 summarizes the 2011 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 15.5% IRM and LCR results, then add or remove capacity from all zones in NYCA until the NYCA LOLE approaches criteria. The 15.5% base case and preliminary cases were used as the basis for developing the sensitivity case values shown in Table B-2.

Table B-2: Description & Explanation of 2011 Sensitivity Cases

Table 2 Case #	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
	Transmission Sensitivities			
2	**No Internal NYCA Transmission Constraints[a] ("Free-Flowing" System)**	**13.2 %**	**N.A.**	**N.A.**
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements. See the "Base Case – NYCA Transmission Constraints" section of the report.			
11	**Model 300 MW Wheel from HQ to NE through NYCA[b].**	**15.6 %**	**81 %**	**101 %**
	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). In addition, Quebec to New England Highgate and Phase II were modeled in the base case.			
10	**Derate Dunwoodie South interface by 350 MW[b].**	**15.7 %**	**81 %**	**101 %**
	Shows the impact of a reduced transfer capability.			
	Assistance From Outside World Sensitivities			
1	**NYCA Isolated[b]**	**25.6 %**	**88 %**	**110 %**
	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.			

Table 2 Case #	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
6	**Higher Outside World Margins**[b]	11.0 %	78 %	97 %
	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.			
7	**Lower Outside World Margins**[b]	20.6 %	85 %	106 %
	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.			
	Generation Sensitivities			
8	**Increase EFORs from Base Case**[a]	17.3 %	82 %	102 %
	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 having the five year system EFOR match the highest year over the five year period.			
9	**Decrease EFORds from Base Case**[a]	14.0 %	80 %	100 %
	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.			
12	**Outage of Indian Point 2 for 2011**[a]	21.3 %	85 %	106 %
	This shows the impact of an extended outage of IP 2 for the entire study year, either by regulatory or operational problems.			
13	**Retirement of Indian Point 2 & 3**[b]	21.9 %	90 %	113 %
	Removes the Indian Point plant and return capacity (as per the sensitivity procedure) to all NY zones.			
4	**Remove all wind generation**[b]	13.8 %	81 %	101 %
	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.			
14	**Use 2006 wind profile**[b]	14.3%	81 %	101 %
	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact of an alternate wind profile.			
15	**Generator Retirements**[a]	15.5 %	81 %	101 %
	Retire units that have notified PSC. These upstate units are Greenidge 4 (108 MW), Westover 8 (80 MW), Project Orange (90 MW), and Energy Systems North East (74.5 MW)			

Load Sensitivities				
3	**No Load Forecast Uncertainty**[a]	**7.6 %**	**75 %**	**95 %**
	This scenario represents “perfect vision” for 2011 peak loads, assuming that the forecast peak loads for NYCA have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and, to a smaller degree, economic uncertainties on IRM requirements.			
Emergency Operating Procedure Sensitivity				
5	**No SCRs or EDRPs**[a]	**15.4 %**	**81 %**	**101 %**
	Verifies the impact of SCRs and EDRPs on IRM.			
Other Sensitivities				
16	**Alternate Methodology for calculating EFORds**[a]	**14.2 %**	**77 %**	**99 %**
	This method creates generator unit forced outage rates that match the NYISO market EFORds			

a) IRM and LCRs are estimated based on preliminary case sensitivity results.
b) IRM and LCRs are based on 15.5% base case sensitivity results.

B-5 Environmental Initiatives

New York has a long history in the development of environmental policies and regulations that govern the permitting, construction and operation of power generation and transmission facilities. Notwithstanding the remarkable progress towards achieving New York's clean energy and environmental goals, more remains to be accomplished. The 2009 New York State Energy Plan[5] provides a long range vision and framework for New York's energy usage. The State's Department of Environmental Conservation (NYSDEC) annual publication of its regulatory agenda[6] describes the new environmental initiatives that it will focus on during the coming year. The U.S. Environmental Protection Agency (USEPA) also publishes a similar report on its regulatory agenda.[7]

One of the purposes of this section is to identify possible future outcomes resulting from differing base case assumptions. The purpose of this environmental perspective is to gain insight into the population of resources that are likely to be faced with major capital investment decisions in order to achieve compliance with several evolving environmental program initiatives. The premise of this review is that the risk of unplanned retirements is directly related to the capital investment decisions resource owners need to make in order to achieve compliance with the new regulatory program requirements.

Five new regulatory programs are identified for this review: Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), Best Available Retrofit Technology (BART), Maximum Achievable Control Technology (MACT), Best Technology Available (BTA) and, Clean Air Transport Rule (CATR). These programs were selected because they generally affect widespread areas across the state and, if implemented as proposed, are expected to require compliance actions prior to 2015. Recapitalization decisions may be made within the next two year. Further, the individual or combined impact is likely to require substantial additional capital investment by existing generators and therefore could lead to unplanned retirements.

The NYISO retained GE to study the overall impact of the NOx RACT regulation. GE concluded that the regulation could be complied with by 2014 and the cost of retrofit systems that would be required could be accommodated within the forecasted net inframarginal revenues.

The NYSDEC have been completed the promulgation process for the BART rule. Visibility impact studies conducted by the owners of units subject to BART regulations. Some affected units will need to undertake emission control retrofit projects.

USEPA is scheduled to release a proposed rule March 2011 to limit emissions of certain substances classified as hazardous air pollutants (HAPs). The rule will define a level of

5 (http://www.nysenergyplan.com/stateenergyplan.html)

6 http://www.dos.state.ny.us/info/register/2010/jan6/pdfs/regagenda.pdf.

7http://www.reginfo.gov/public/do/eAgendaMain;jsessionid=9f8e890430d77ed37246b4ab417e9961cfca348ec55b.e34ObxiKbN0Sci0RbxaSc3qRc3n0n6jAmljGr5XDqQLvpAe?operation=OPERATION_GET_AGENCY_RULE_LIST&currentPub=true&agencyCd=2000&Image58.x=36&Image58.y=15

emissions control known as Maximum Achievable Control Technology (MACT). The rule will establish limits for HAPs such as hydrogen chloride (HCl), hydrogen fluoride (HF), mercury (Hg), dioxin and furans, as well as for parameters such as carbon monoxide (CO), and particulate matter (PM). These limits will apply to coal fired generators and may apply to electric generators that are fueled by heavy oil. The anticipated compliance date is November 2014. In addition, NYS DEC has promulgated Part 246: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units, which establishes emission limitations that are currently in effect in New York to reduce mercury emissions. Phase II of this regulation requires additional reductions from coal fired boilers in 2015. The Phase II emission limitations may be equivalent to the limits USEPA will establish next year. The USEPA has proposed limitations on mercury emissions from oil fired boilers that supply generators less than 25 MW. Similar limitations for large oil fired boilers are likely.

NYS DEC has circulated a draft policy document "Best Technology Available (BTA) for Cooling Water Intake Structures." The proposed policy will prescribe reductions in fish mortality for existing power plants that use open cycle cooling systems. The performance goals call for the use of wet, closed-cycle cooling systems at existing generating facilities. The policy does provide some limited relief for plants with historical capacity factors less than 15%. The NYSDEC has estimated that cost of retrofitting this technology could exceed $8 Billion.

As part of the NYISO's Reliability Needs Assessment (RNA), each potentially affected NYCA unit was examined to determine its current emission profile and level of technology installed. The current performance was compared to emission rate, emission cap, or prescribed technology required to comply with each of these regulations. Affected units, where the capital expenditures required to comply with the new regulation are above the average level routinely expected over the life of a generating unit, were classified as a group that is at an increased risk of unplanned retirement. This review has identified 18,609 MW of capacity in the higher risk group or 49.7% of the NYCA installed generating capacity.

A review of the above initiatives by the NYISO concluded that none are expected to impact IRM requirements in 2011, and therefore were not included in the 2011 base case. The NYSRC will continue to monitor these environmental initiatives as to the possibility of IRM impacts beyond 2011.

B-6 Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. For the base case, the study shows that approximately 6.4 remote voltage reductions per year would be implemented to meet the once in 10 years disconnection criterion. The expected frequency for each of the EOPs for the base case is provided in Table B-3.

Table B-3: Implementation of Emergency Operating Procedures *
Base Case Assumptions (IRM = 15.5 %)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	19.6
Require EDRPs	9.9
5% manual voltage reduction	9.3
30 minute reserve to zero	9.0
5% remote control voltage reduction	6.4
Voluntary load curtailment	4.7
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

Base Case Modeling Assumptions

Base Case Modeling Assumptions for 2011-2012 NYCA IRM Requirement Study

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
Peak Load	33,025 MW for NYCA, 11,725 MW for zone J, and 5368 MW for zone K.	Oct 1 IRM forecast: 32,872 MW for NYCA, 11,463 MW for zone J, and 5414 MW for zone K.	Forecast based on examination of 2010 weather normalized peaks. Top three external Area peak days aligned with NYCA
Load Shape Model	2002 Load Shape	2002 Load Shape	After evaluating 2009 data, analysis indicates 2002 load shape is an appropriate representation for this analysis.
Wind Generation Profile	2002 Wind Generation Profile	2002 Wind Generation Profile	Hourly wind readings correlate with hourly loads. Sensitivity using 2006 wind readings as basis.
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Method used and accepted by NYISO and ICS based on collected data and input from LIPA, Con Ed, and NYISO *(see Attachment A).*
Proposed New Units	Those listed on *Attachments B and B1.*	Those listed on *Attachment B.*	Units built since the 2010 Gold Book and those non-renewable units with Interconnection agreements signed by August 1st. Renewables based on RPS

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
			agreements and ICS input.
Wind Resource Production Modeling	(1,326 MW) Derived from hourly wind data with average Summer Peak Hour availability factor of approximately 11%.	(1,333 MW) Derived from hourly wind data with average Summer Peak Hour availability factor 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.
Solar Resource Modeling	Hourly solar readings converted to MW output with average Summer Peak Hour availability factor of approximately 65%. (30 MW)	Forecast of 15 MW of total solar capacity, centered on Long Island. *See Attachment B-2.*	Based on collected hourly solar data. Summer Peak Hour capacity factor based on June 1-Aug 31, hours (beginning) 2-5 PM.
Retirements	Poletti 1 retirement (891 MW 2/10), Greenidge Unit 3 (52 MW 12/09), and Westover Unit 7 (40.2 MW 12/09).	Energy Systems North East (ESNE) retirement of 74.5 MW from zone A	2010 Gold Book plus units indicated by PSC notification.
Forced & Partial Outage Rates	5-year (2004-08) GADS data. (Those units with less than five years data could use available representative data.)	5-year (2005-09) 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.
Planned Outages	Based on schedules received by NYISO & adjusted for history.	Based on schedules received by NYISO & adjusted for history.	Updated schedules.

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
Summer Maintenance	Modeled 150 MW after reviewing last year's data.	Use 150 MW after reviewing last year's data.	Review of most recent data.
Combustion Turbines Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves. Add derates for new units.	Operational history indicates derates in line with manufacturer's curves.
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 2010 .	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.	NYISO review and recommendation.
Non-NYPA Hydro Capacity Modeling	45% derating.	45% derating.	Review of historic and most recent data. *See Attachment G*
Special Case Resources	2575 MW (July 10) based on 3 year historical growth rate. Monthly variation based on historical experience. Limit to 4 calls per month in July and August for proposed DEC limited generation. (about 30 hour total).	2498 MW (Aug 11) based on NYISO growth rate forecast. Monthly variation based on historical experience.	Those sold for the program, discounted to historic availability. and distributed according to zonal performance. Methodology for growth rate forecast has improved. *See SCR determinations in Attachment F.*
EDRP Resources	329 MW registered; modeled	260 MW registered; modeled as	Those registered for the program,

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
	as 148 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	172 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month.	discounted to historic availability. (66% overall[8]) August values calculated from 2010 August registrations.
External Capacity - Purchases	Grandfathered amounts of 50 MW from NE, 1080 MW from PJM and 1090 MW from Quebec. Equivalent9 Contracts modeled.	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 contracts per FERC. De-ration to account for ETCNL.
Capacity - Sales	In addition to the long term firm sales of 303 MW, include known firm contracts of 641 MW from NE FCM market. Equivalent Contracts modeled.	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.	Other firm contracts are becoming known, such as from neighbor's forward capacity markets.
Capacity Wheels-through	None modeled. Sensitivity Modeled	None modeled. A sensitivity case may be run.	The ISO tariff is silent about capacity wheels through NYCA.
EOPs (other than SCR and EDRP)	700 MW of non-SCR/EDRP MWs.	737 MW of non-SCR/EDRP MWs.	Based on TO information, measured data, and NYISO forecasts. *See Attachment D.*

8 The 66% value is from the January 16th, 2007 NYISO filing to FERC.

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
Interface Limits	Based on 2009 Operating Study, 2009 Operations Engineering Voltage Studies, 2009 Comprehensive Planning Process, and additional analysis.	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).	NYISO engineering studies and additional analysis and input from other external Control Areas. Power factor improvement initiatives and lower forecast loads have resulted in higher transfer capability on the Dysinger East, West Central, and Volney East interfaces. *See Attachments E, E-1, and E-2.*
New Transmission Capability	Linden VFT - 300 MW.	Upgrade on Northport Norwalk Cable (NNC) line to 428 MW from 286 MW.	Based on TO provided models and NYISO review. NNC rating is per preliminary TO study. Confirmation to occur before final base case.
Transmission Cable Forced Outage Rate	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	Based on TO analysis.
Unforced Capacity Deliverability Rights (UDR)	UDRs have been issued for the Cross Sound Cable, Neptune cable, and Linden VFT Project.	No new projected UDRs	Contracted amounts of capacity are confidential and are included as capacity internal to NYCA.

Parameter	2010 Study Modeling Assumptions	Recommended 2011 Study Modeling Assumptions	Basis for Recommended 2011 Assumptions
Model Version	Version 2.98	Version 3.01	Per testing and recommendation by ICS.
Outside World Area Models	Single Area representations for Ontario and Quebec. Three zones modeled for PJM. Five zones modeled for New England derived from 13 zones provided.	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 between Areas	All Control Areas have indicated that they will share reserves equally among all.	All Control Areas have indicated that they will share reserves equally among all.	Per NPCC CP-8 working group assumption.

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

Attachment A
NYCA Load Forecast Uncertainty

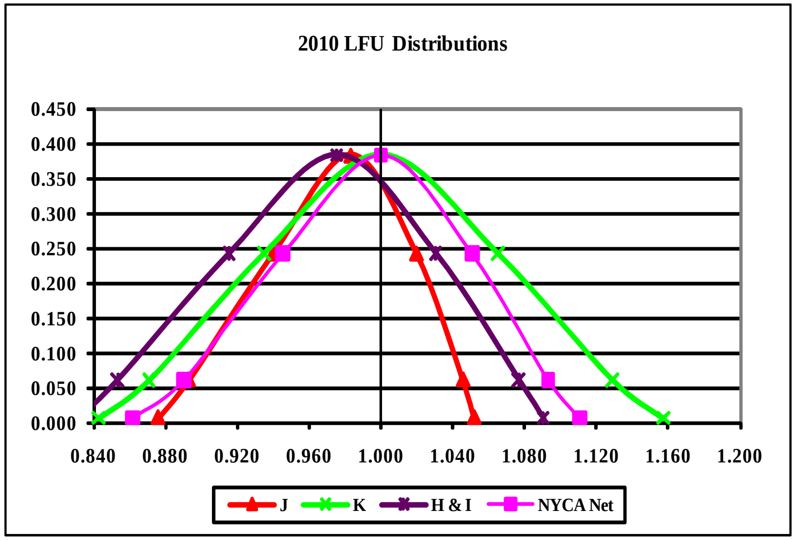
2009 and 2010 LFU Models

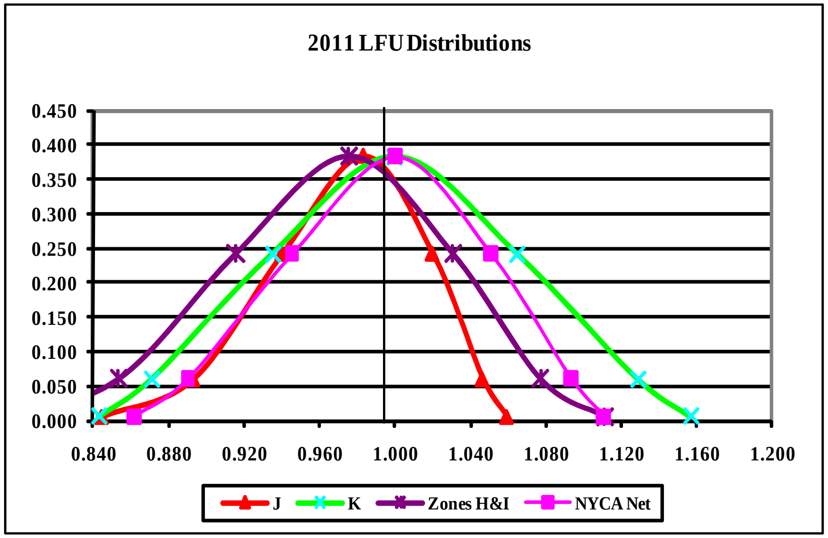
2010 Load Forecast Uncertainty Models

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

2011 Load Forecast Uncertainty Models

Multiplier	Zones H&I	Con Ed (J)	LIPA (K)	NYCA Net
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





Attachment B

List of Proposed Units

To be in-service by summer of 2011

Project Name	IS Date	Zone	MW
Empire Generating	7/10	F	635
Riverbay	6/10	J	24
Fulton County Land Fill	5/10	F	3.2
Astoria Energy II	5/11	J	550
Uprate Gilboa #4	6/10	F	30
Total			1,242.2

Attachment B1

Renewable Generating Projects (Wind) for Inclusion in the 2011-2012 Installed Reserve Margin Study

Wind Generation Projects in the NYCA

Considered for Inclusion in the 2011-2012 IRM Study

Facility Name	Owner / Developer	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	Current Status	Modeled in 2010 IRM	Existing Wind Capacity (MW)	New Wind Capacity for 2011 IRM (MW)	Total Wind Capacity for 2011 IRM (MW)
Steel Winds II	First Wind	A	National Grid	234	2010 Nov		45.0	0.0	15/0[1]	0.0
Bliss Windpark	Noble Bliss Windpark, LLC	A	Village of Arcade	173	2008 May	Operating	100.5	100.5		100.5
Steel Wind	Constellation Power	A			2007 Jan	Operating	20.0	20.0		20.0
High Sheldon Wind Farm	Sheldon Energy, LLC.	C	NYSEG	144	2009 Feb	Operating	112.5	112.5		112.5
Canandaigua I[2]	Canandaigua Power Partners, LLC	C	NYSEG	135	2008 Jun	Operating	82.5	82.5		82.5
Canandaigua II[2]	Canandaigua Power Partners, LLC	C	NYSEG	199	2008 Jun	Operating	42.5	42.5		42.5
Wethersfield Wind Power	Noble Wethersfield Windpark, LLC	C	NYSEG	177	2008 Dec	Operating	126.0	126.0		126.0
Bear Creek	Wind Park Bear Creek, LLC	C			2006 Feb	Operating	22.0	22.0		22.0
Altona Windpark	Noble Altona Windpark, LLC	D	NYPA	174	2008 Sept	Operating	99.0	97.5		97.5
Chateaugay Windpark I	Noble Chateaugay Windpark, LLC	D	NYPA	214	2008 Sept	Operating	106.5	106.5		106.5
Belmont/Ellenburg II	Noble Environmental Power LLC	D	NYPA	213	2011 Oct		21.0	0.0		0.0
Clinton Windpark I & II	Noble Clinton Windpark, LLC	D	NYPA	172 & 211	2008 May	Operating	100.5	100.5		100.5
Ellenburg Windpark	Noble Ellenburg Windpark, LLC	D	NYPA	175	2008 May	Operating	81.0	81.0		81.0
Maple Ridge 1 & 2	Flat Rock Wind Power, LLC	E	National Grid	171	2006 Feb	Operating	321.0	321.7		321.7
Madison	Horizon Wind	E	NYSEG		2000 Sept	Operating	11.6	11.5		11.5
Munnsville	Coral Power	E	NYSEG		2007 Aug	Operating	34.5	34.5		34.5
Fairfield Wind Project[3]	PPM Energy	C	National Grid	156	2011 Sept				74.0	74.0
Marble River Wind Farm	Horizon Wind Energy	D	NYPA	161 & 171	2011 Oct					
TOTAL CAPACITY - ALL CATEGORIES							**1,326.1**	**1,259.2**	**74.0**	**1,333.2**

Notes:

1. The CRIS value for this unit is zero MW, therefore, the capacity does not count in the IRM study.
2. Canandaigua I sometimes referred to as Cohocton Wind Farm. Canandaigua II sometimes referred to as Dutch Hill Wind Farm.
3. Fairfield Wind was previously called Hardscrabble Wind.

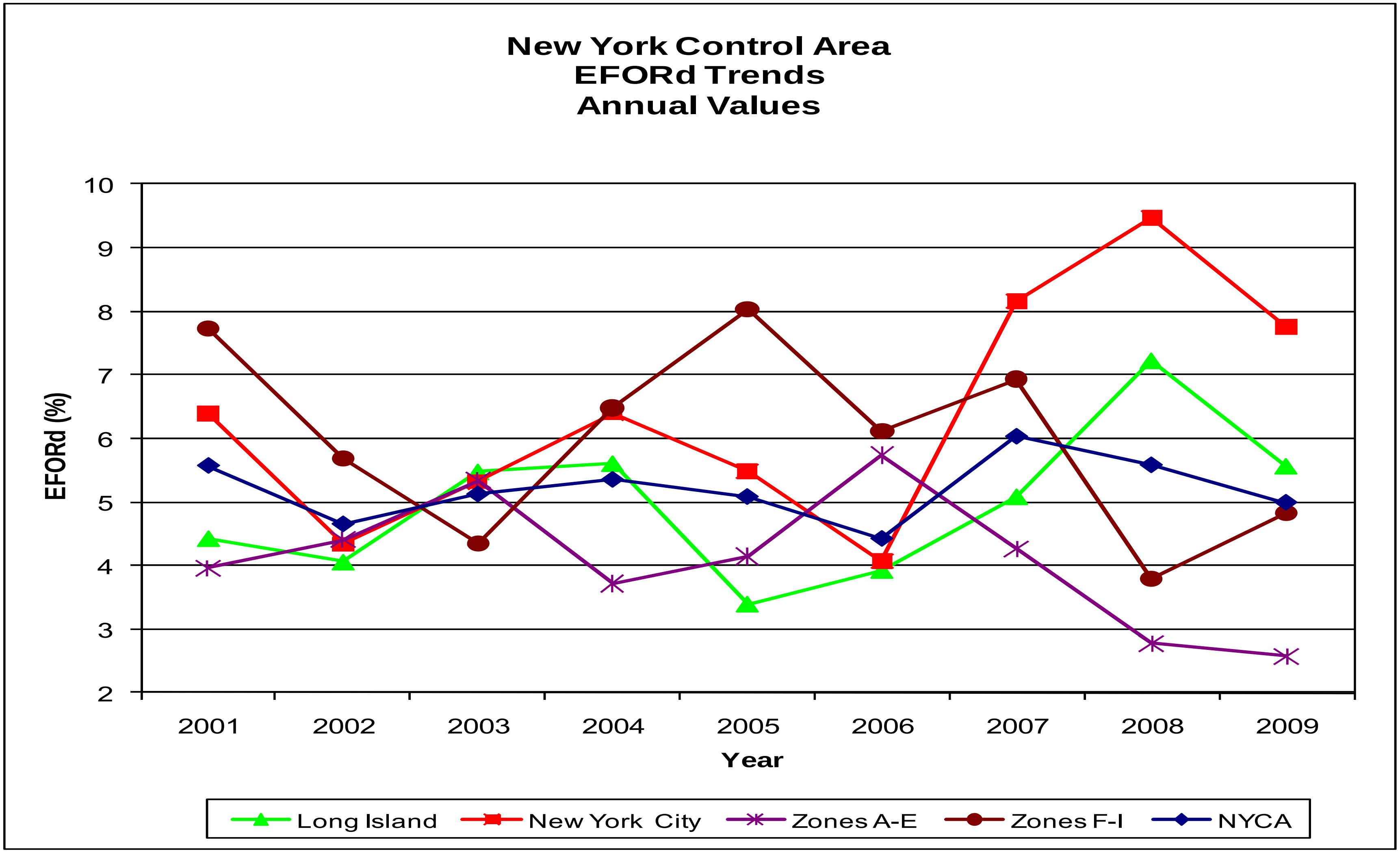
Attachment B-2

List of Solar proposed Units

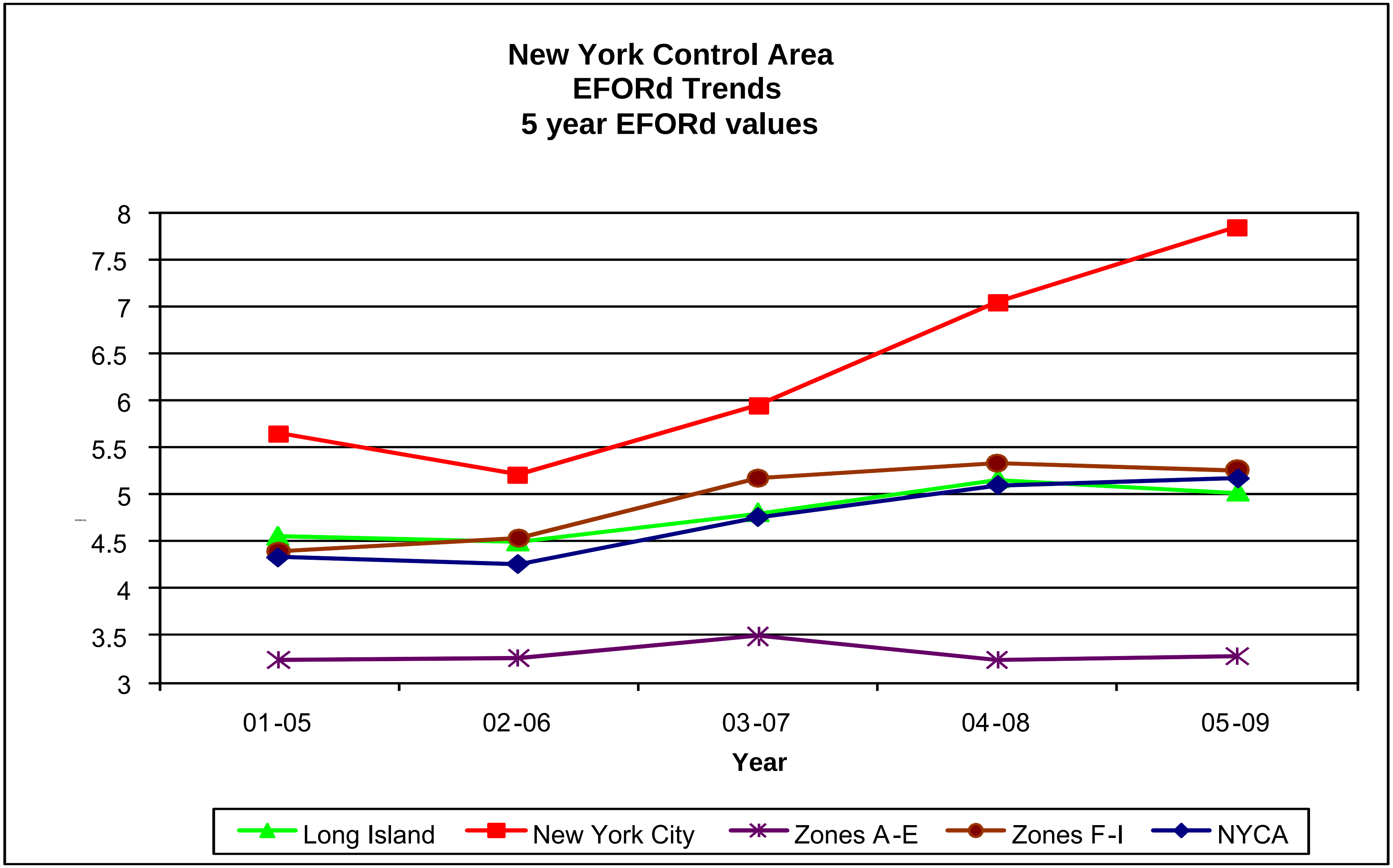
To be in-service by summer of 2011

Project Name	IS Date	Zone	MW
EnXco Solar	5/11	K	15.0
Total			15.0

Attachment C



Attachment C-1



C-1 removes units that have retired from all five years of each affected point. These graphs represent thermal unit performance only.

Attachment D

Emergency Operating Procedures

Step	Procedure	Effect	2010 MW Value	2011 MW Value
1	Special Case Resources	Load relief	2575 MW (representing the amount sold)	2498 MW (representing the amount sold)
2	Emergency Demand Response Program	Load relief	329 MW	260 MW
3	5% manual voltage Reduction	Load relief	72 MW	71 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	479 MW	478 MW
6	Voluntary industrial curtailment	Load relief	61 MW	100 MW
7	General public appeals	Load relief	88 MW	88 MW
8	Emergency Purchases	Increase capacity	Varies	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW	1200 MW
10	Customer disconnections	Load relief	As needed	As needed

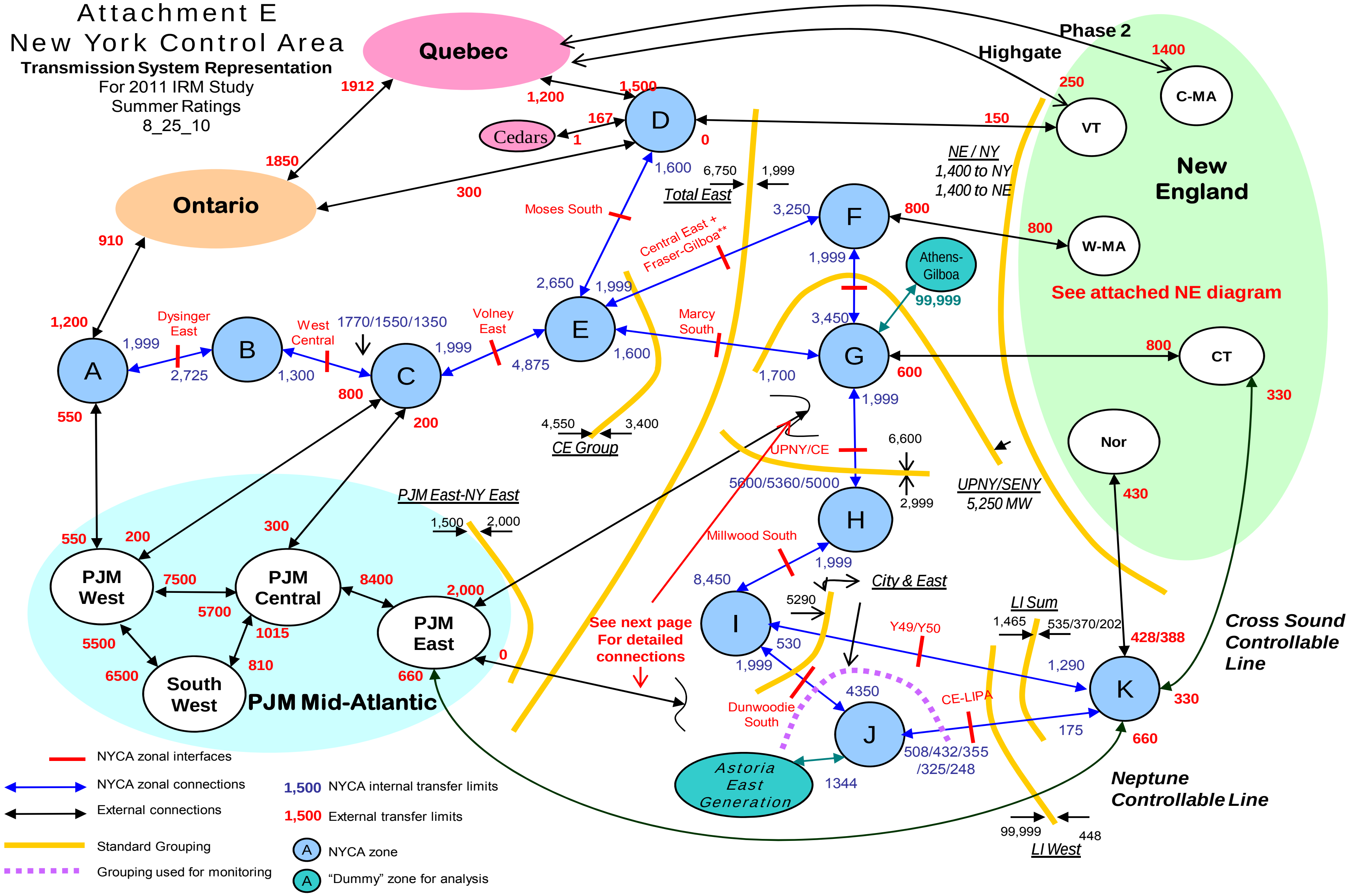
Attachment E
New York Control Area

Transmission System Representation

For 2011 IRM Study

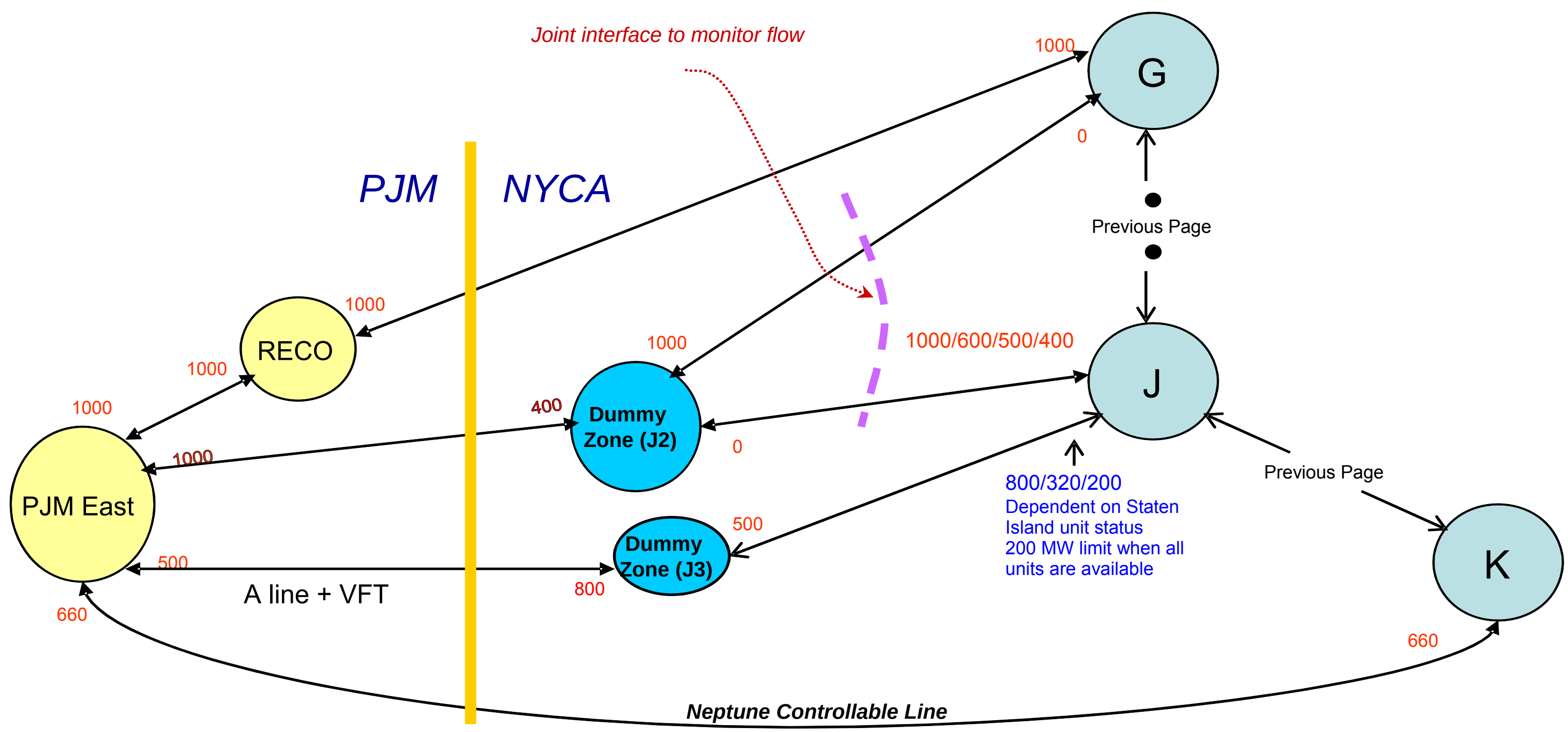
Summer Ratings

8_25_10



Attachment E -1
New York Control Area
Transmission System Representation
For 2011 IRM Study
Summer Ratings
8_9_10

2010 PJM -SENY MARS Model



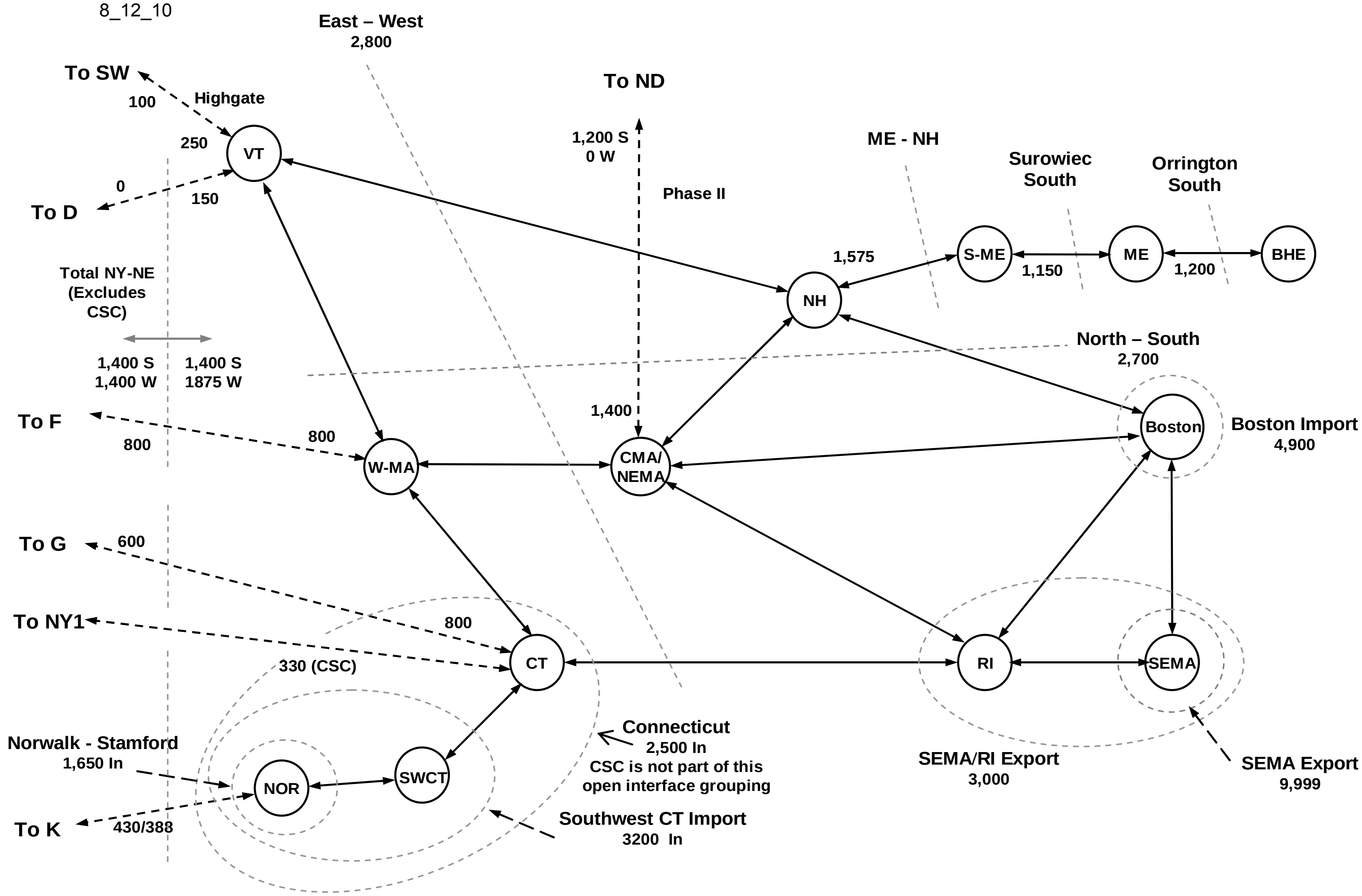
(PJM East to RECO) + (J2 to J) + (PJM East to J3) = 2000

Attachment E-2

Transmission System Representation
For 2011 IRM Study
Summer Ratings
8_12_10

NEPOOL System (Assumed Ratings - MW)

From 2009 New England Review of Resource Adequacy



Attachment F
SCR Determinations

SCR Performance

Zones	August Registrations	Performance Factor	2010 ICAP	2011 ICAP Forecast[1]	Performance Factor	2011 UCAP	Translation Factor[2]	Modeled in 2011 IRM
A-E	1140.0	0.964	1182.7	1320.3	0.964	1272.6	0.80	1018.1
F-I	314.9	0.949	331.7	370.3	0.949	351.5	0.80	281.2
J	478.9	0.876	546.8	610.4	0.876	534.6	0.80	427.7
K	153.5	0.871	176.3	196.8	0.871	171.3	0.80	137.1
Total	2087.25		2237.5	**2497.9**		2330.1		1864.1

1. These values represent a 11.636% growth from August 2010 ICAP based registrations
2. The paper appearing as attachment F-1 in 2010 IRM assumption matrix showed a translation factor range of 72 to 84 percent. As a result of that paper, the ICS adopted a value of 80% for the translation factor. Since no new information has been produced, the figure is still valid.

Attachment G

Review of Operational Data for Run of Rivcr Hydro

Zone	MWs	Derate
A	3.0	
B	14.4	
C	82.4	59.6%
D	48.8	49.9%
E	370.6	40.0%
F	284.0	48.3%
G	47.5	38.2%
I	1.7	
Weighted	Average*	45.7%

*Values for Zones A, B, and I, have been removed from the table for confidentiality reasons, but are included in the total derate calculation.