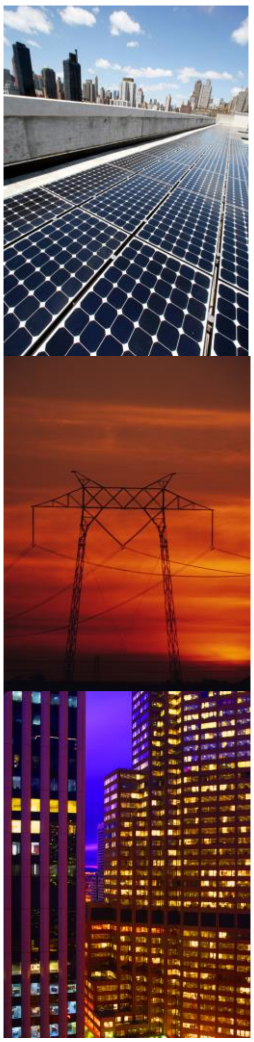

Appendices

New York Control Area Installed Capacity Requirement

For the Period May 2014 to April 2015

December 6, 2013

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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Appendix A

NYCA Installed Capacity Requirement

Reliability Calculation Models and Assumptions

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

A. Reliability Calculation Models and Assumptions

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

Table A-1 lists the study parameters in the Figure A-1 models, the source for the study assumptions, and where in Appendix A the assumptions are described. Finally, section A-3 compares the assumptions used in the 2013 and 2014 IRM reports.

Figure A-1 NYCA ICAP Modeling

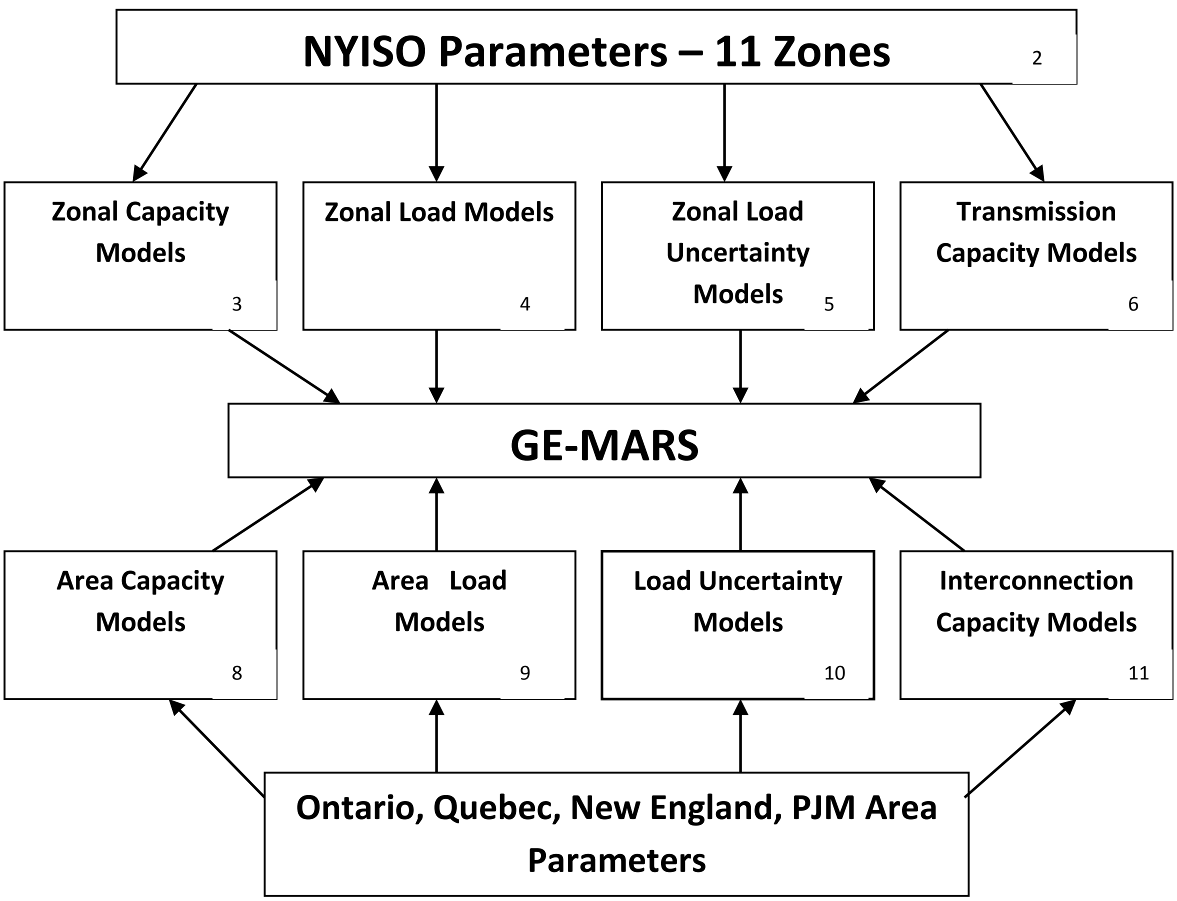


Table A-1 Modeling Details

#	Parameter	Description	Source	Reference
Internal NYCA Modeling				
1	GE MARS	General Electric Multi-Area Reliability Simulation Program		Section A-1
2	11 Zones	Load Areas	Fig A-1	NYISO Accounting & Billing Manual
33	Zone Capacity Models	Generator models for each generating in zone Generator availability Unit ratings	GADS data 2013Gold Book[1]	Section A-3.2
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A-3.5
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A-3.1
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A-3.1
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between zones	NYISO Transmission Studies	Section A-3.3
External Control Area Modeling				
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See 8-11	Supplied by External Control Area	
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A-3.4
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A-3.4
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to economic conditions	Supplied by External Control Area	Section A-3.4
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A-3.3

[1] 2013 Load and Capacity Data Report, http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

A.1 GE MARS

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

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A-3.5).

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

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

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

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

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A-1).

Equation A-1 Transition Rate Definition

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

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 (Equation A-2).

Equation A-2 Transition Rate Calculation Example

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours}$$
$$= 0.002$$

Table A-2 State Transition Rate Example

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

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

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

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

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

A.1.1 Error Analysis

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

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

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

For this analysis, the Base Case required 238 replications to converge to a daily LOLE for NYCA of 0.100 days/year with a standard error of 0.05 per unit. The Base Case required 883 replications to converge to a standard error of 0.025. For our cases, the model was run to 1,000 replications at which point the standard error was 0.023. The confidence interval at this point ranges from 16.8% to 17.2%. At that point the LOLE for NYCA was 0.100 days/year. It should be recognized that a 17.0% IRM is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using version 3.16.5 of the GE-MARS software program. This new version was benchmark tested by the NYISO.

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

General Electric was asked to review the input data for errors. They have developed a program called “Data Scrub” which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the ISO reviews the data and either confirms that it is correct as is, or institutes a correction. The results of this data scrub are shown in Section A-4.

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

A.2 Methodology

The 2014 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and locational installed capacity requirements. The IRM/LCR characteristic consists of two constituents: 1) a curve function (“the knee of the curve”, and 2) the straight line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tangent 45 inflection point calculation.   Consideration of IRM/LCR point pairs remote to the “knee of the curve” may impact the calculation of the quadratic curve function used for the Tangent 45 calculation. The procedure for determining the best fit curve function used for the calculation of the Tangent 45 inflection point to define the base case requirement is based on the following criteria summarized below:

- Start with all points on the IRM/LCR curve
- Develop regression curve equations for all different point to point segments consisting of at least four points
- Rank all the regression curve equations based on the R^2 value
- Eliminate those points where the calculated IRM is outside the selected curve point range
- Use the highest R^2 equation that meets criteria to calculate values for IRM and LCR
- Verify that the calculated IRM and corresponding LCR values do not violate the 0.1 LOLE criterion

This approach produces a quadratic curve function with R^2 correlation approaching 1.000 as the basis for the Tangent 45 calculation. First derivatives are calculated for the NYC and Long Island zones for each of the equations and solved for the 45 degree slope resulting in an average value of 17.0%. The above methodology was adopted by the NYSRC Executive Committee and is incorporated into Policy 5-7.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A-3 Load Model

Parameter	2013 Study Assumption	2014 Study Assumption	Explanation
Peak Load	October Forecast: NYCA - 33,278 MW Zone J - 11,532 MW Zone K - 5,553 MW	October Forecast: NYCA - 33,655MW Zone J - 11,740 MW Zone - 5,461K MW	Forecast based on examination of 2013 weather normalized peaks. Top three external Area peak days aligned with NYCA
Load Shape Model	2002 Load Shape	Multiple Load Shapes Model using years 2002, 2006 and 2007	Using new feature of the MARS Program
Load Uncertainty Model	Statewide and zonal model updated to reflect current data	Statewide and zonal model updated to reflect current data	Based on collected data and input from LIPA, Con Ed, and NYISO. Method and values accepted by LFTF

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that detailed in the NYISO Load Forecasting Manual for the ICAP forecast. The NYISO's Load Forecasting Task Force had three meetings in September and October 2013 to review analyses prepared by the NYISO and Transmission Owners of the weather response during the summer. Regional load growth factors (RLGFs) for 2014 were updated by each Transmission Owner based on projections provided to the LFTF in August 2014 by Moody's Analytics. The 2014 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2013.

The results of the analysis are shown in Table A-4. The 2013 peak forecast was 33,279 MW. The actual peak of 33,919 MW (col. 2) occurred on Friday, July 19, 2013. The NYISO activated Special Case Resources (SCRs) in all eleven zones on that day to curtail load. It is estimated that the impact due to SCRs was 933 MW (col. 4). After accounting for the impacts of weather and the demand response, the weather-adjusted peak load was determined to be 33,502 MW (col. 6), 223 MW (+0.7%) above the forecast. The Regional Load Growth Factors are shown in column 9. The 2014 forecast for the NYCA is 33,655 MW (col. 10).

The LFTF recommends this forecast to the NYSRC for its use in the 2014 IRM study.

Table A-4 NYCA Peak Load Forecast

2014 Forecast for NYSRC IRM Study

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Transmission District	**2013 Actual MW**	**2013 Estimated SCR & Muni Self-Gen**	**SCR/EDRP Estimate MW**	**Weather Adjustment MW**	**2013 Weather Normalized MW**	**Loss Reallocation MW**	**2013 WN MW, Adj for Losses**	**Regional Load Growth Factors**	**2014 IRM Preliminary Forecast**
Central Hudson	**1,162.3**	0.0	13.0	-71.0	**1,104.3**	-2.0	**1,102.3**	**1.0000**	**1,102.0**
Con Ed	**13,287.0**	0.0	290.0	-252.0	**13,325.0**	241.0	**13,566.0**	**1.0130**	**13,742.0**
LIPA	**5,672.8**	0.0	62.0	-347.8	**5,387.0**	67.0	**5,454.0**	**1.0000**	**5,454.0**
NGrid	**7,189.0**	53.0	365.0	-446.0	**7,161.0**	-353.0	**6,808.0**	**1.0040**	**6,835.0**
NYPA	**588.0**	0.0	7.0	-3.0	**592.0**	10.0	**602.0**	**0.8660**	**521.0**
NYSEG	**3,291.0**	0.0	143.0	-209.0	**3,225.0**	-1.0	**3,224.0**	**1.0030**	**3,234.0**
O&R	**1,127.7**	0.0	13.0	5.0	**1,145.7**	16.0	**1,161.7**	**1.0060**	**1,169.0**
RG&E	**1,600.9**	0.0	40.0	-79.0	**1,561.9**	22.0	**1,583.9**	**1.0090**	**1,598.0**
NYCA Total	**33,918.7**	**53.0**	**933.0**	**-1,402.8**	**33,501.9**	**0.0**	**33,501.9**	**1.0046**	**33,655.0**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Locality	**2013 Actual MW**	**2013 Estimated SCR & Muni Self-Gen**	**SCR/EDRP Estimate MW**	**Weather Adjustment MW**	**2013 Weather Normalized MW**	**Loss Reallocation MW**	**2013 WN MW, Adj for Losses**	**Regional Load Growth Factors**	**2014 IRM Preliminary Forecast**
Zone J - NYC	**11,456.0**	0.0	270.0	**-136.0**	**11,590.0**	0.0	**11,590.0**	**1.0130**	**11,740.0**
Zone K - LI	**5,756.8**	0.0	62.0	**-357.8**	**5,461.0**	0.0	**5,461.0**	**1.0000**	**5,461.0**

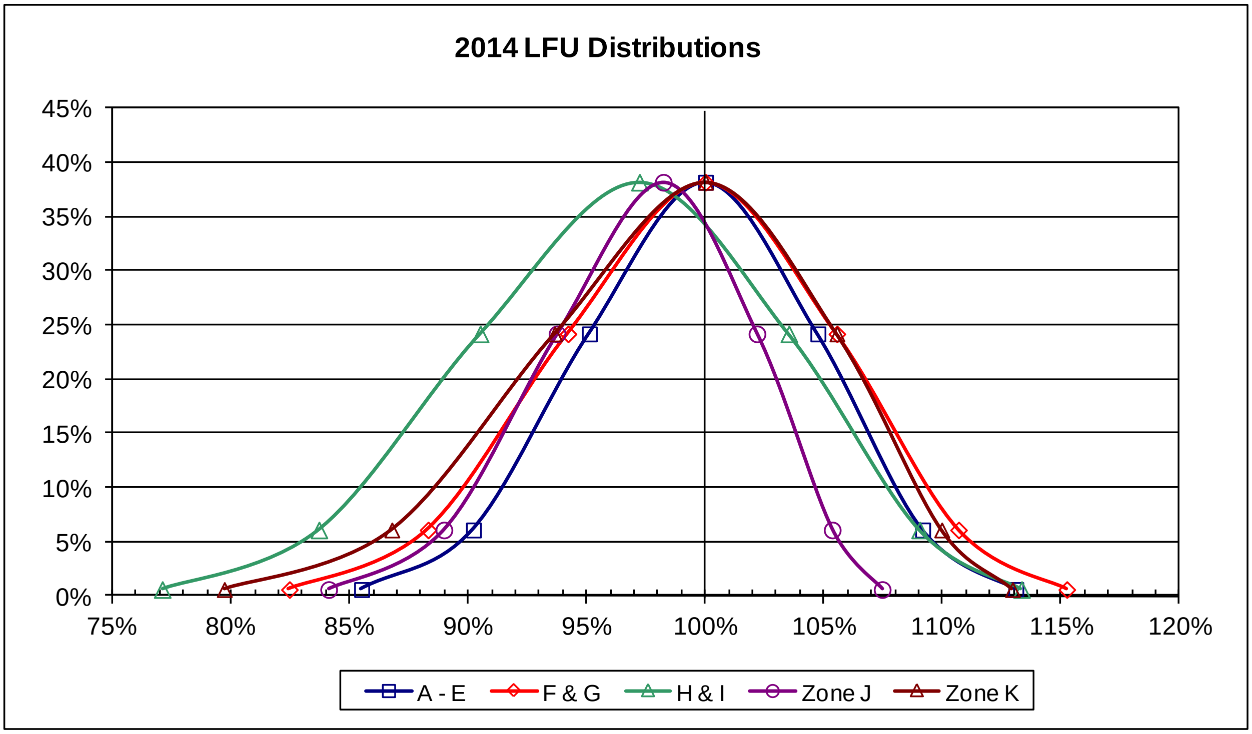
(2) Zonal Load Forecast Uncertainty

For 2014, updated models were provided by Con-Ed and LIPA for Zones H&I, J and K. The NYISO developed models for Zones A through G and reviewed the models for the other zones. The results of these models are presented in Table A-5. 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-2.

Table A-5 2014 Load Forecast Uncertainty Models

2014 Load Forecast Uncertainty Models						
Bin No.	Probability	A - E	F&G	H & I	Zone J	Zone K
1	0.62%	85.50%	82.45%	77.09%	84.11%	79.71%
2	6.06%	90.21%	88.30%	83.70%	88.97%	86.77%
3	24.17%	95.10%	94.20%	90.50%	93.74%	93.64%
4	38.30%	100.00%	100.00%	97.21%	98.22%	100.00%
5	24.17%	104.74%	105.54%	103.52%	102.17%	105.54%
6	6.06%	109.16%	110.67%	109.03%	105.34%	109.96%
7	0.62%	113.09%	115.24%	113.33%	107.45%	112.95%
	Low - Med	14.5%	17.5%	20.125%	14.1%	20.3%
	Hi-Med	13.1%	15.2%	16.115%	9.2%	12.9%
	Delta	27.6%	32.8%	36.240%	23.3%	33.2%

Figure A-2 LFU Distributions

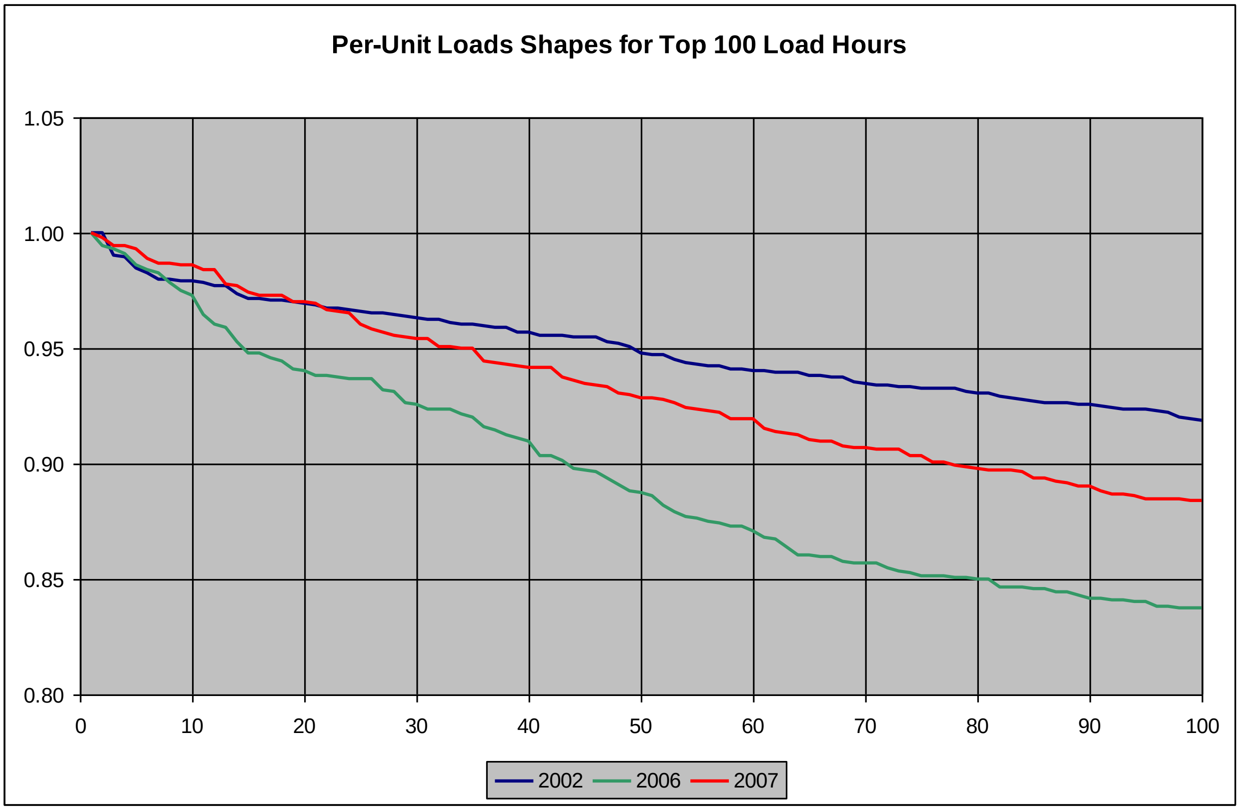


The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology for determining the LFU models has been reviewed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

(3) Zonal Load Shape Models for Load Bins

Beginning with this year's IRM Study, multiple load shapes were used in the load forecast uncertainty bins. Three historic years were selected from those available, as discussed in the NYISO's 2013 report, 'Modeling Multiple Load Shapes in Resource Adequacy Studies'. The year 2007 was assigned to the first five bins (from cumulative probability 0% to 93.32%). The year 2002 was assigned to the next highest bin, with a probability of 6.06%. The year 2006 was assigned to the highest bin, with a probability of 0.62%. The three load shapes for the NYCA as a whole are shown on a per-unit basis for the highest one hundred hours in Figure A-3. The year 2007 represents the load duration pattern of a typical year. The year 2002 represents the load duration pattern of many hours at high load levels. The year 2006 represents the load duration pattern of a heat wave, with a small number of hours at high load levels followed by a sharper decrease in per-unit values than the other two profiles. See Appendix F for more details.

Figure A-3 Per Unit Load Shapes



A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State, that have met specific criteria to offer capacity in the New York Control Area. The 2013 Load and Capacity Data Report is the primary data source for these resources. Table A-6 provides a summary of the capacity resource assumptions in the 2014 IRM study.

Table A-6 Capacity Resources

Parameter	2013 Study Assumption	2014 Study Assumption	Explanation
Generating Unit Capacities	Updated DMNC values per 2012 Gold Book. Use the minimum of CRIS or DMNC value.	Updated DMNC values per 2013 Gold Book. Use the minimum of CRIS or DMNC value.	Annual update of the Load & Capacity Data Report
Planned Generator Units	EnXco Solar - Zone K, 13.1 MW (12/12) FIT – Solar - Zone K 17 MW (6/13)	105 MW of capacity was repowered or returned to service. See below.	Based on information in the Load and Capacity Report and from the NYISO RNA Project Tracking Group
Wind Modeling	(1,584 MW) Derived from hourly wind data resulting in an average Summer Peak Hour availability of approximately 11%	Wind Capacity – 1366.60 MWs Summer Peak hour availability of approximately 18%	Number decreased due to a (2013 IRM) forecast project not participating in NY Capacity Market (Marble River)
Solar Modeling	Existing 31.5 MW plus forecast 30.1 MW of new units. Output checked against actual hourly solar data.	Existing 31.5 MW plus forecast 12.5 MW of new units. See below.	Based on collected hourly solar data during summer Peak Hours June 1-Aug 31, hours beginning HB14-HB18
Retirements	747 MW of Retirements after publication of the 2012 Gold Book	164 MW retirements reported See below	Policy 5 guidelines on retirement disposition in IRM studies
Forced Outage Rates	5-year (2007-11) GADS data. (Those units with less than five years data could use available representative data.)	5-year (2008-12) GADS data. (Those units with less than five years data could use available representative data.)	Most recent 5-year period. Includes proxy data for unit(s) that are deemed suspect as part of the GADS screening process.
Planned Outages	Based on schedules received by NYISO and adjusted for history	Based on schedules received by NYISO and adjusted for history	Updated schedules.
Summer Maintenance	Nominal 50 MW	Nominal 40 MW	Value based on review of prior years data showing a declining amount
Gas Turbine Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves
Small Hydro Derate	45% derate	45% derate	No Change

(1) Generating Unit Capacities

The capacity rating for each thermal generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Additionally, each generating resource has an associated capacity CRIS (Capacity Resource Interconnection Service) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled.

Wind units are rated at their nameplate, or full rated value, in the model. The 2013 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model. The following units are being returned to service:

Black River Facility (biofuel) formerly Ft. Drum 44.1 MW Zone E
Astoria GT-10 (return to service} 15.6 MW Zone J
Astoria GT – 11 (return to service) 17.2 MW Zone J

(2) Planned Generator Units

Generating units not included the Load and Capacity Data Report but that have met specific criteria for inclusion in the IRM study were also modeled. These include units that went into service after the data report was published or that plan to be in service for the summer 2014 capability period, based upon a signed interconnection agreement (by August 1, 2013). Only one unit, the LI Feed-in Tariff - 12.5 MW in Zone K, is included in the 2014 IRM Study.

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate value based on 2012 production data. Characteristics of this data indicate a capacity factor of approximately 17% during the summer peak hours. A total of 1366.6 MW of installed capacity associated with wind generators is included in this study. See Appendix E for more details on Wind Modeling.

Table A-7 Wind Generation

Facility Name	Zone	Connecting Transmission Owner	NYISO Interconnection Study Queue Project Number	Projected/ Actual In-Service Date	New Wind Capacity for 2014 IRM (MW)	Total Wind Capacity for 2014 IRM (MW)
Existing Units						
Steel Wind	A	National Grid		2007 Jan		20.0
Bliss Wind Power	A	Village of Arcade	173	2008 May		100.5
Canandaigua Wind Power	C	NYSEG	135&199	2008 Jun		125.0
Hardscrabble Wind	E	National Grid	156	2011 Sept		74.0
Howard Wind	C	NYSEG	182	2011 Dec		55.4
Wethersfield Wind Power	C	NYSEG	177	2008 Dec		126.0
High Sheldon Wind Farm	C	NYSEG	144	2009 Feb		112.5
Altona Wind Power	D	NYPA	174	2008 Sept		97.5
Chateaugay Wind Power	D	NYPA	214	2008 Sept		106.5
Clinton Wind Power	D	NYPA	172 & 211	2008 May		100.5
Ellenburg Windpark	D	NYPA	175	2008 May		81.0
Munnsville	E	NYSEG	127A	2007 Aug		34.5
Maple Ridge 1	E	National Grid	171	2006 Feb		231.0
Maple Ridge 2	E	National Grid	171	2006 Feb		90.7
Madison Wind Power	E	NYSEG	N/A	2000 Sept		11.5
Marble River Wind Farm 1 and 2	D	NYPA	161 & 171	2012 Oct		0.0
Proposed Units						
TOTAL CAPACITY - ALL CATEGORIES					**0.0**	**1,366.6**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate MW value based on 2012 production data. Characteristics of this data indicate an overall 65% capacity factor during the summer peak hours. A total of 44 MW of solar capacity was modeled in Zone K that includes:

Existing:

Long Island Solar Farm 31.5 MW

Proposed:

Feed-in-Tariff 12.5 MW

(5) Retirements

There were three unit retirements or units mothballed as compared to the 2013 Load and Capacity Data Report. The units include:

- Trigen-Syracuse – 70 MW in Zone C
- Dunkirk 1 - 75 MW in Zone A

- Chateauguay Power – 19 MW in Zone D

(6) Forced Outages

Performance data for thermal generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the "equivalent demand forced outage rate" (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2014 IRM Study. Figure A-4 shows the trend of EFORd for various regions within NYCA. Figure A-5 shows a rolling 5 year average of the same data.

Figures A-6 and A-7 show the availability trends of the NYCA broken out by fuel type.

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

The unit forced outage states for the majority of the NYCA units were obtained from the five-year NERC-GADS outage data collected by the NYISO for the years 2008 through 2012. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program. Where the NYISO had suspect data for a unit that could not be resolved prior to this study, NERC class average data was substituted for the year(s) of suspect data. Figures A-8 and A-9 show the unit availabilities of the entire NERC fleet on an annual and 5-year historical basis.

Figure A-4 NYCA Annual Zonal EFORds

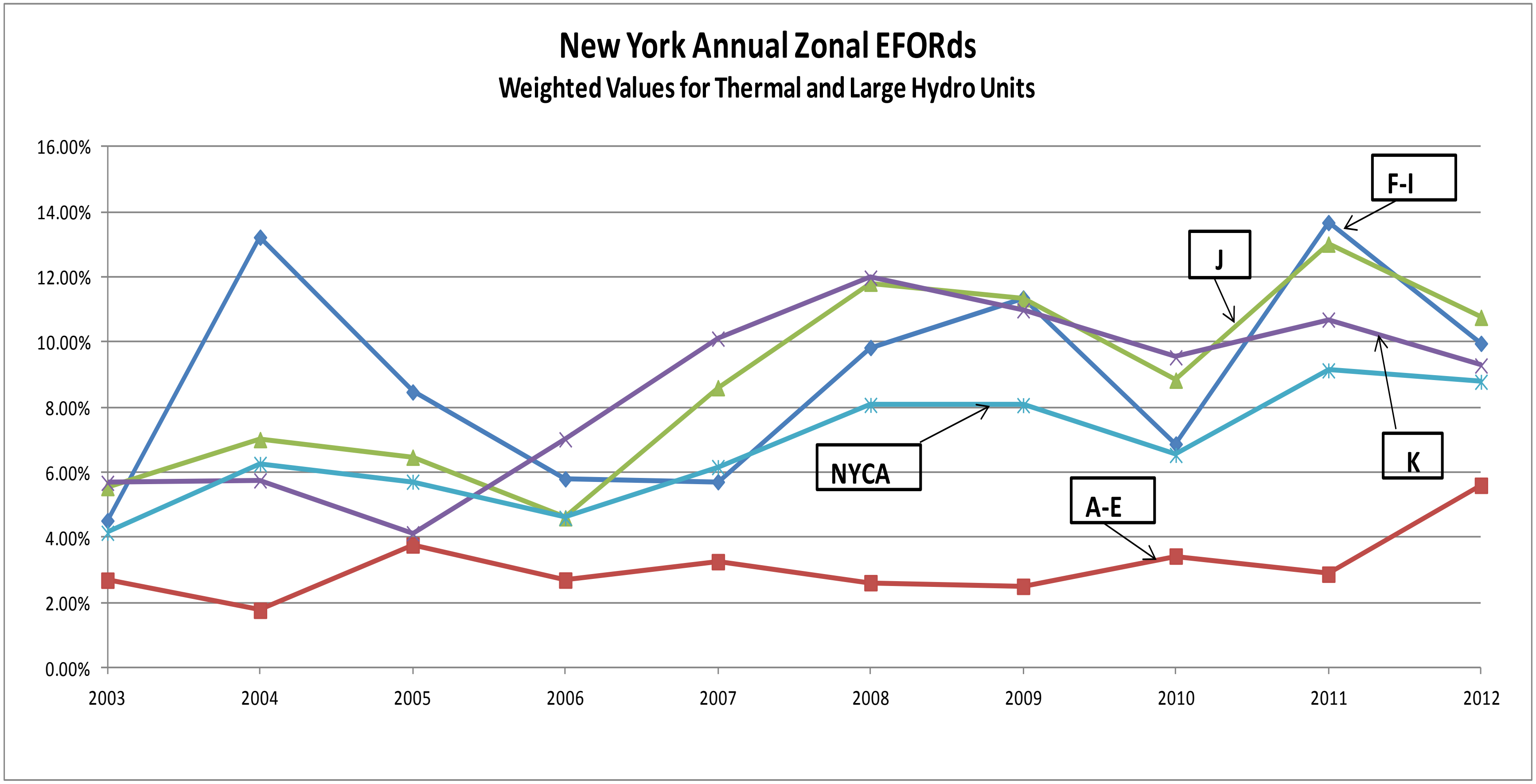


Figure A-5 Five-Year Zonal EFORds

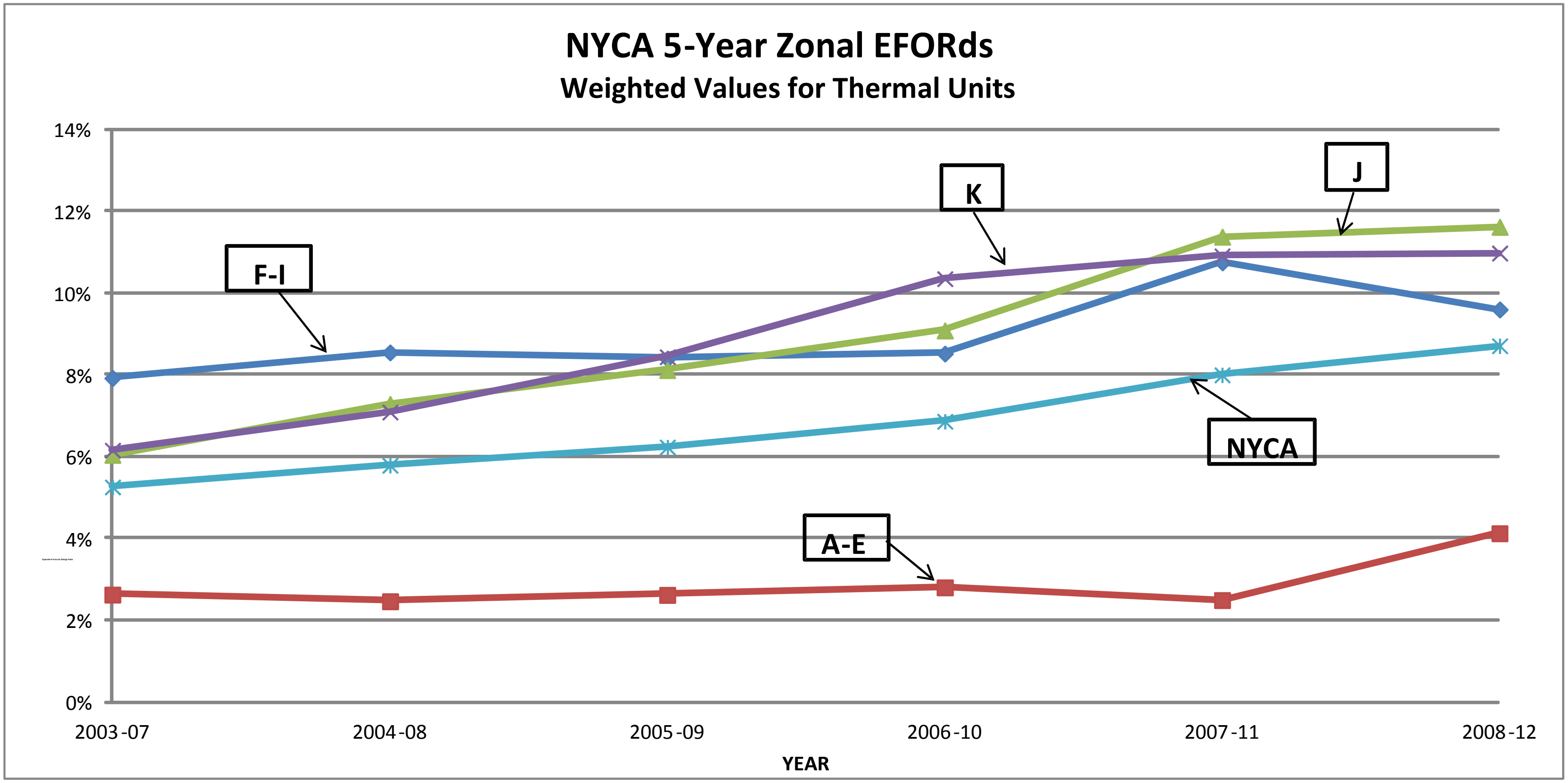


Figure A-6 NYCA Annual Availability by Fuel

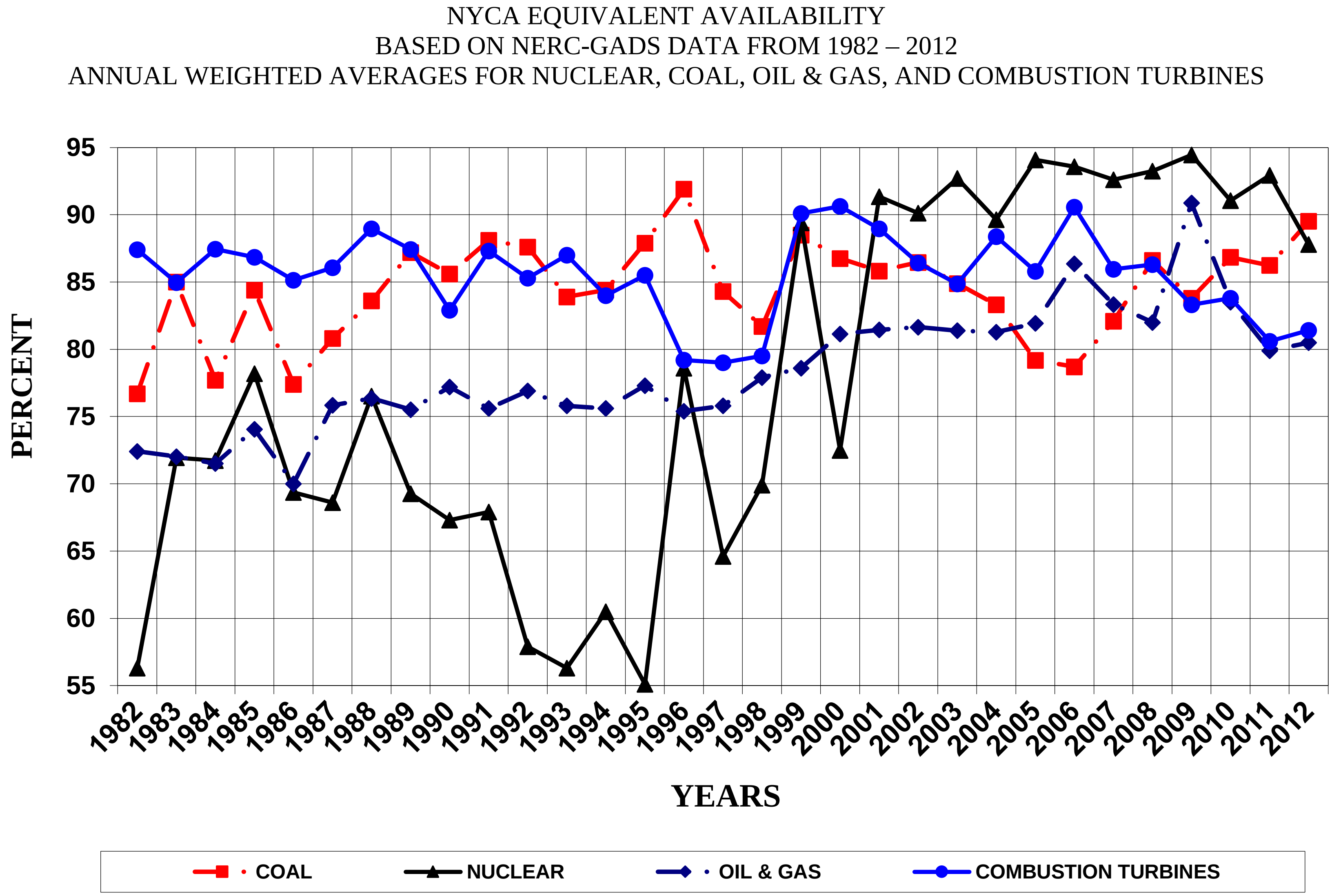


Figure A-7 NYCA Five-Year Availability by Fuel

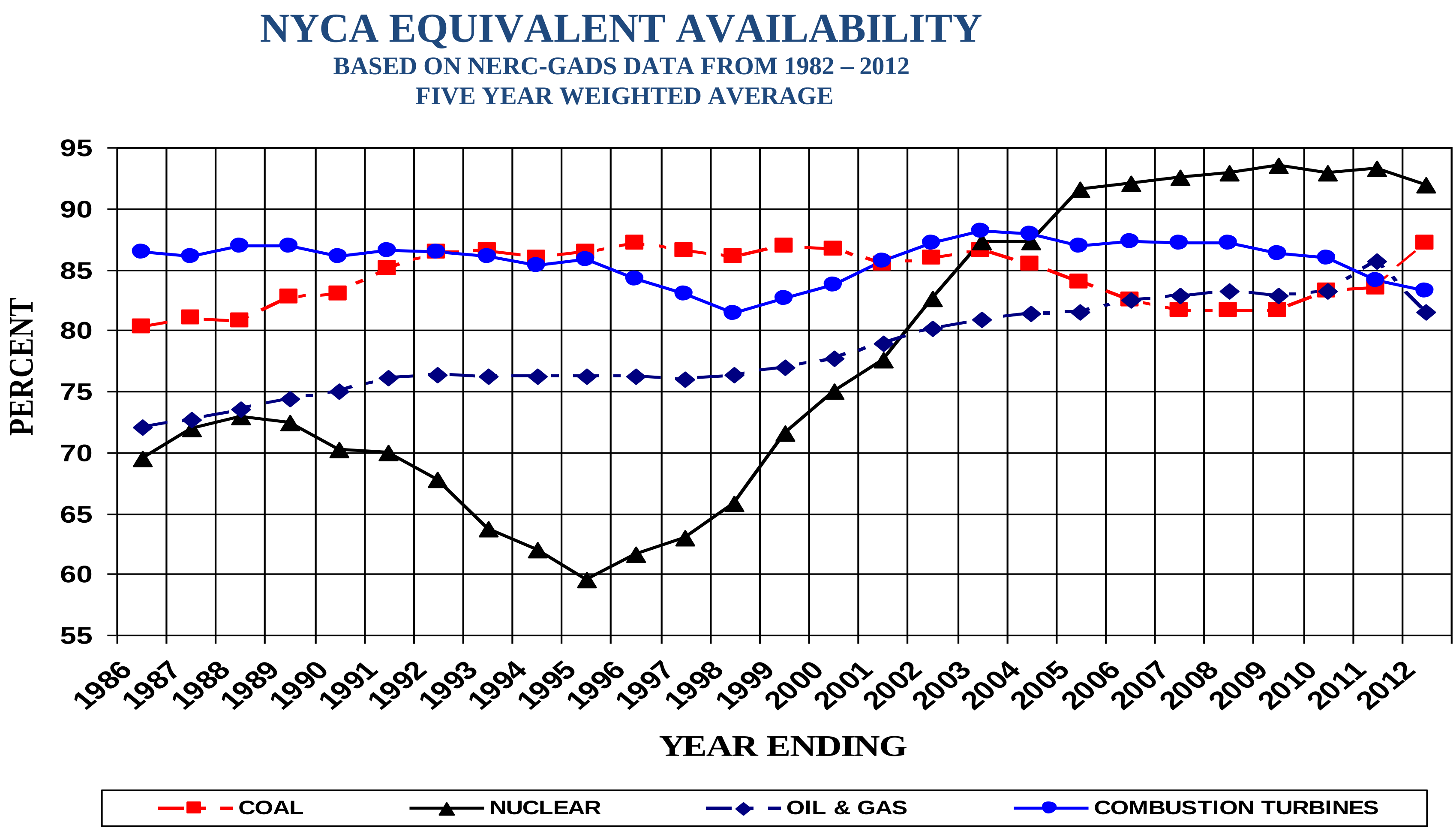


Figure A-8 NERC Annual Availability by Fuel

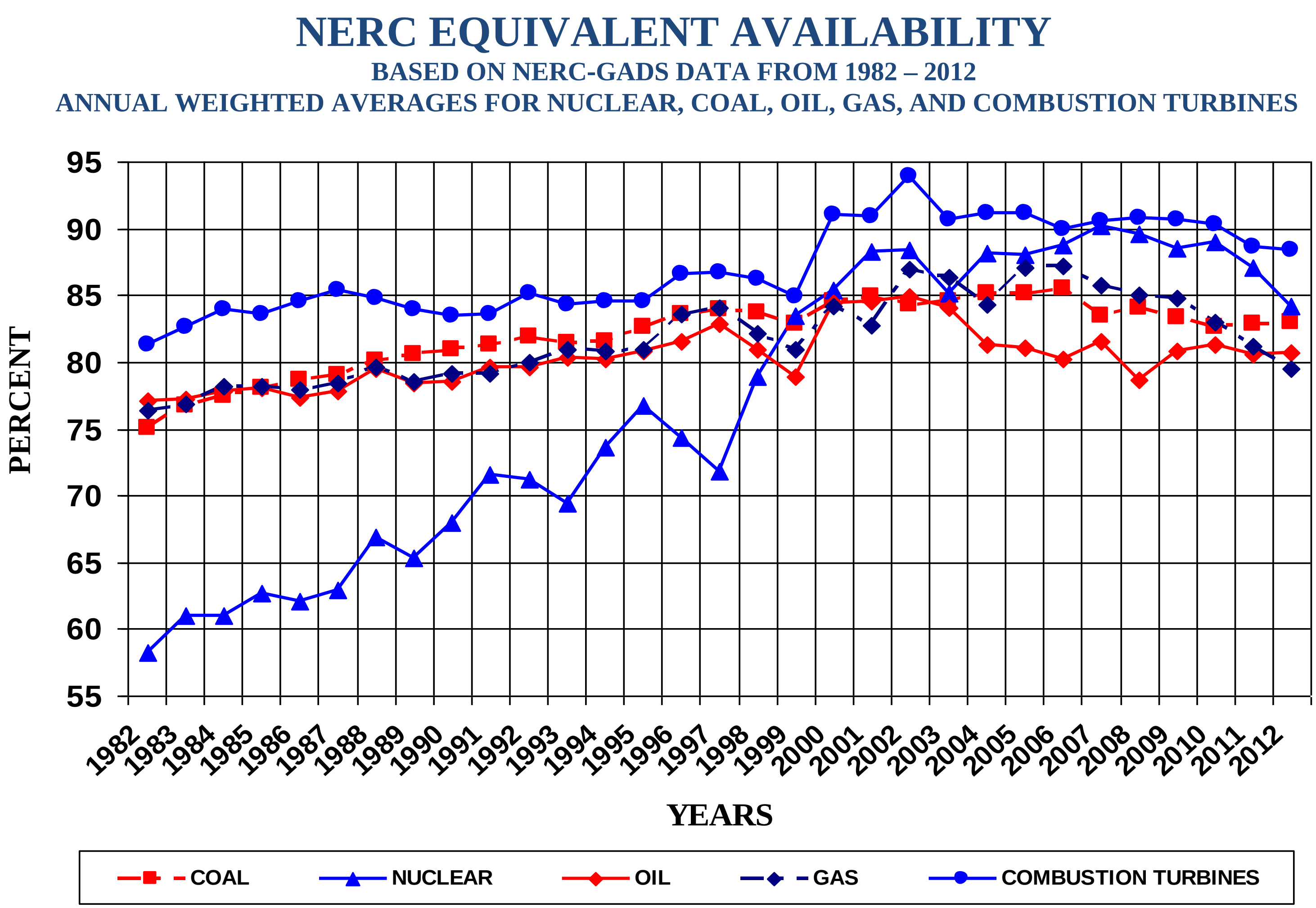
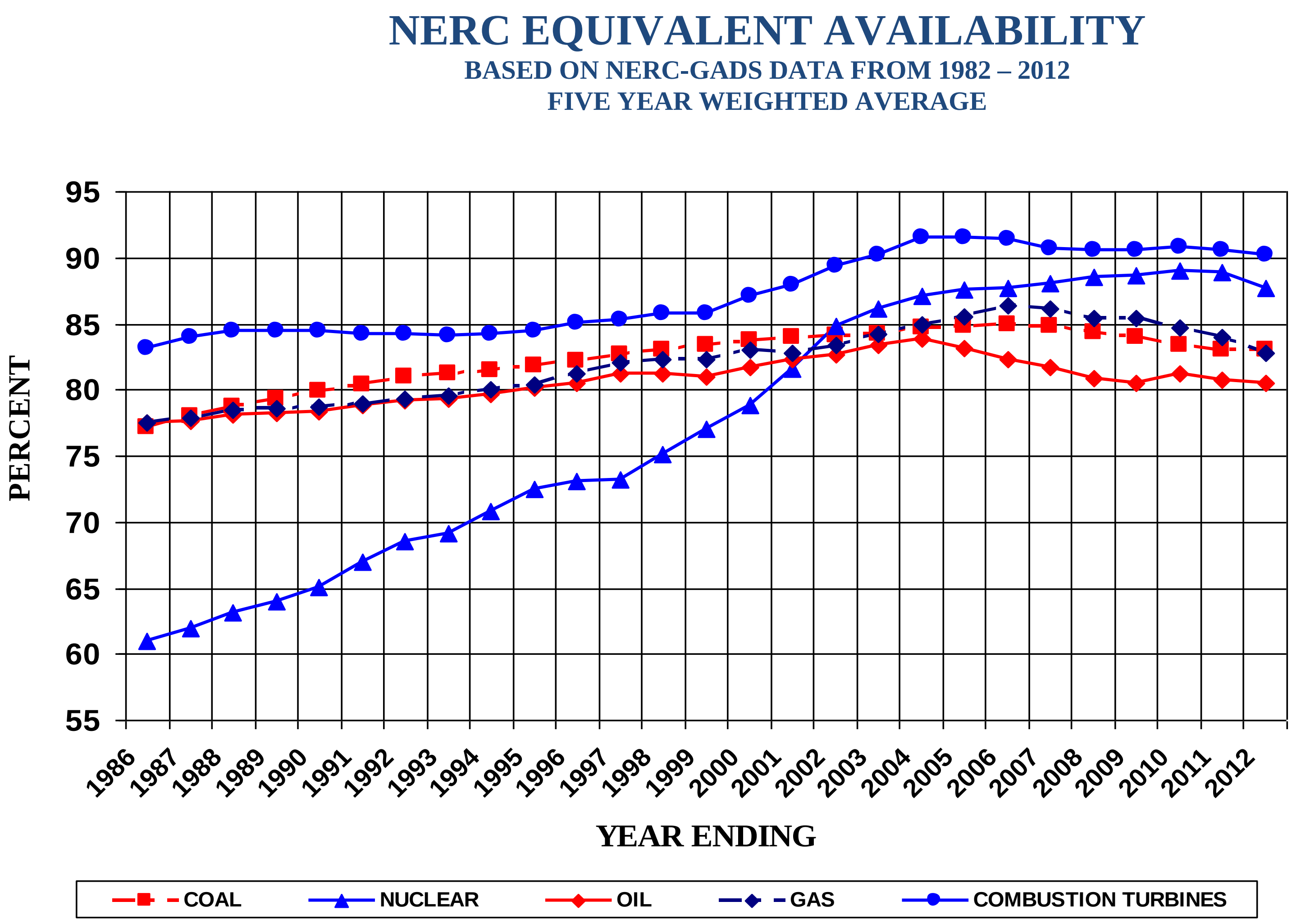


Figure A-9 NERC Five-Year Availability by Fuel



(7) Outages and Summer Maintenance

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage component is obtained from the generator owners, and where necessary, extended so that the scheduled maintenance period equals the historic average using the same five year period used to determine EFORd averages. Figure A-10 provides a graph of scheduled outage trends over the 1992 through 2012 period for the NYCA generators.

Typically, generator owners do not schedule maintenance during the summer peak period. However, it is highly probable that some units will need to schedule maintenance during this period. Each year, the previous five year period is reviewed to determine the scheduled maintenance MW during the previous peak periods. An assumption is determined as to how much to model in the current study. For the 2014 IRM study, a nominal 40 MW of summer maintenance is modeled. The amount is equally divided between upstate and downstate. Figure A-11 shows the weekly scheduled maintenance for the 2013 IRM study compared to this study.

(8) Gas Turbine Ambient Derate

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

A NYISO report on this analysis, *Adjusting for the Overstatement of the Availability of the Combustion Turbine Capacity in Resource Adequacy Studies*, dated October 22, 2007, can be found on the NYISO web site.

The derate does not affect all units because there are units capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so they are not impacted by the temperature derating in obtaining an output of 79.9 MW. About one quarter of the existing 3,700 MW of simple cycle Combustion Turbines fall into this category. The accuracy of temperature corrections for all combustion turbines will continue to be evaluated as operational data becomes available.

(9) Hydro Derates

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

Figure A-10 Planned and Maintenance Outage Rates

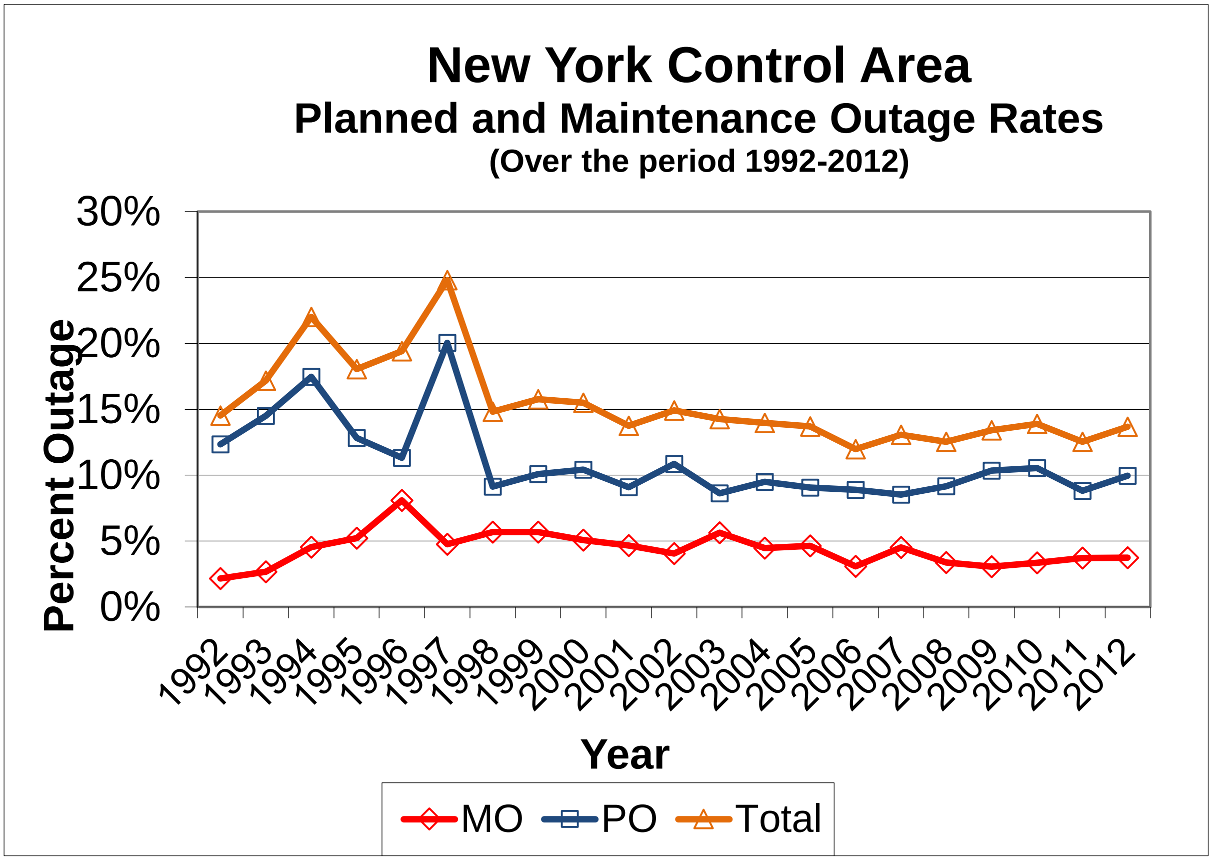
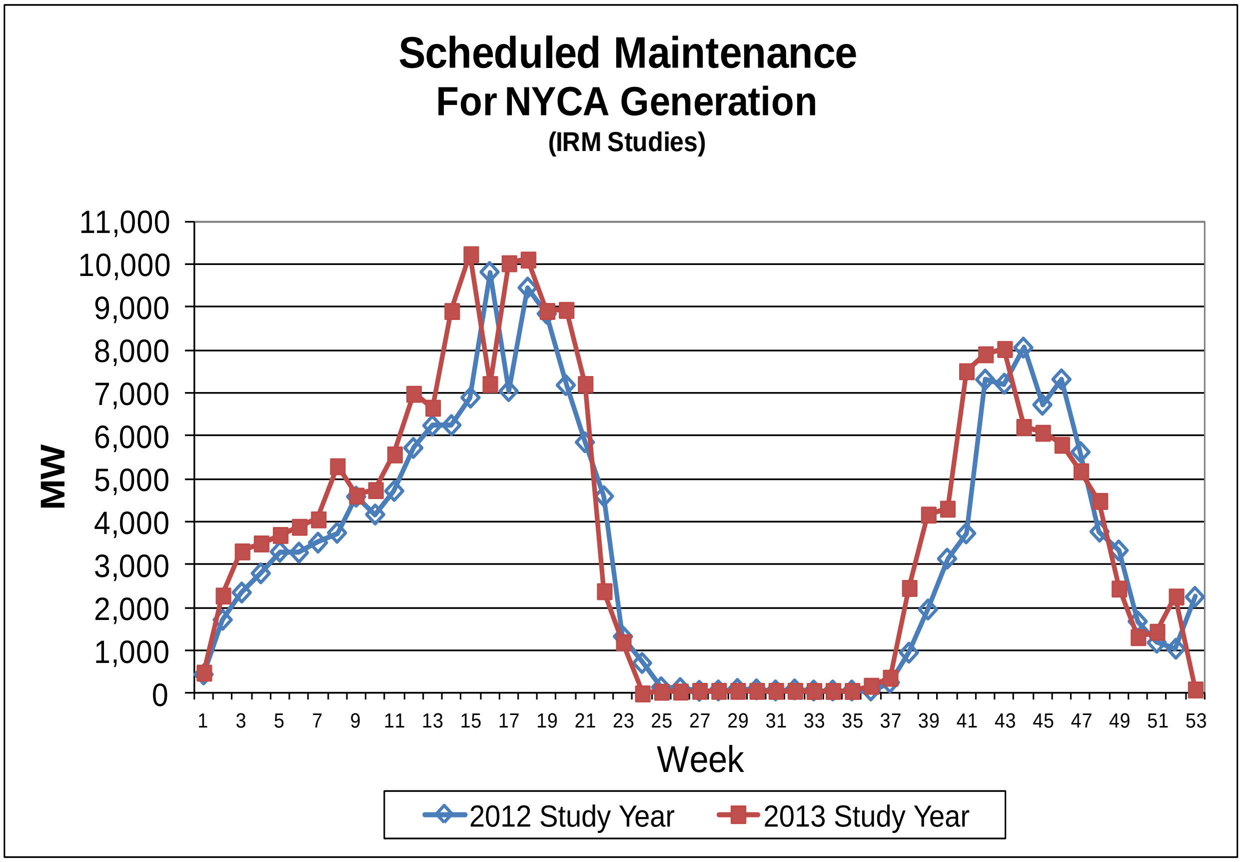


Figure A-11 Scheduled Maintenance



A.3.3 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Figure A-12. The transfer limits employed for the 2014 IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional assessments conducted specifically for this cycle of the development of the topology. The assumptions for the transmission model included in the 2014 IRM study are listed in Table A-8.

Forced transmission outages are included in the GE-MARS model for the underground cables that connect New York City and Long Island to surrounding zones. 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 circuits comprising each interface, which includes failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that particular cable.

The TOs provided updated transition rates.

The interface transfer limits were updated for the 2014 IRM Study model based on transfer limit analysis performed for the 2012 Comprehensive System Planning Process. LIPA performed analysis to update the dynamic limits associated with the LIPA to Con Ed limits and the Long Island Group interface, which included the LIPA ties to Zone I and Zone J. The analysis was reviewed by NYISO staff and incorporated into the model. The model for the Cross-Sound Cable was changed for 2014 based on the latest CP-8 topology. That change was made to more accurately reflect the source of the capacity rights. A model for HTP was developed based on the existing assumptions for a controllable interface with UDRs and associated capacity rights.

Table A-8 Transmission System Model

Parameter	2013 Study Assumption	2014 Study Assumption	Explanation
Interface Limits	Based on 2012 Operating Study, NYISO Voltage Studies, 2012 Comprehensive Planning Process analysis, ATR, and additional analysis including interregional planning initiatives	Based on 2013 Operating Study, NYISO Voltage Studies, 2012 Comprehensive Planning Process analysis, ATR, and additional analysis including planning initiatives	Changes in transfer limits are reviewed and commented on by TPAS.
New Transmission	HTP DC controlled tie-line and LI upgrades	VFT increase to 315 MW from 300 MW	Equipment Upgrades
Transmission Cable Forced Outage Rate	All Existing Cable EFORs updated on LI and NYC to reflect 5 year history	All existing Cable EFORs updated on LI and NYC to reflect 5 year history	Based on TO analysis
Unforced Capacity Deliverability Rights (UDRs)	HTP DC controlled tie-line	No new projected UDRs	No new facilities

Figure A-12 shows the system transmission representation for this year's study. Figure A-13 shows a more detailed representation of the interconnections surrounding the PJM/NYCA downstate interface. Finally, Figure A-14 shows the 13 zone New England Representation in more detail.

As can be seen from the figures, the changes made to interface limits are as follows:

Table A-9 Interface Limits Updates

	2013		2014		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
West Central	1770/1500/1350		1300		-50	
Dysinger East	2725		2650		-75	
A line +VFT	800	800	815	815	15	15
J3 - J	800/320/200		815/700/550/200			

Dysinger East was reduced to reflect the impacts of system changes in Zone A. In addition, three dynamic ratings were removed from West Central and a single limit of 1300 is active for all system conditions. The limits for the A line and VFT interfaces were increase to 815 MW to reflect the VFT change from 300 MW to 315 MW. In addition the dynamic ratings were updated to reflect the upgrades of the Gowanus and Goethals substations.

Figure A-12 2014 Transmission Representation

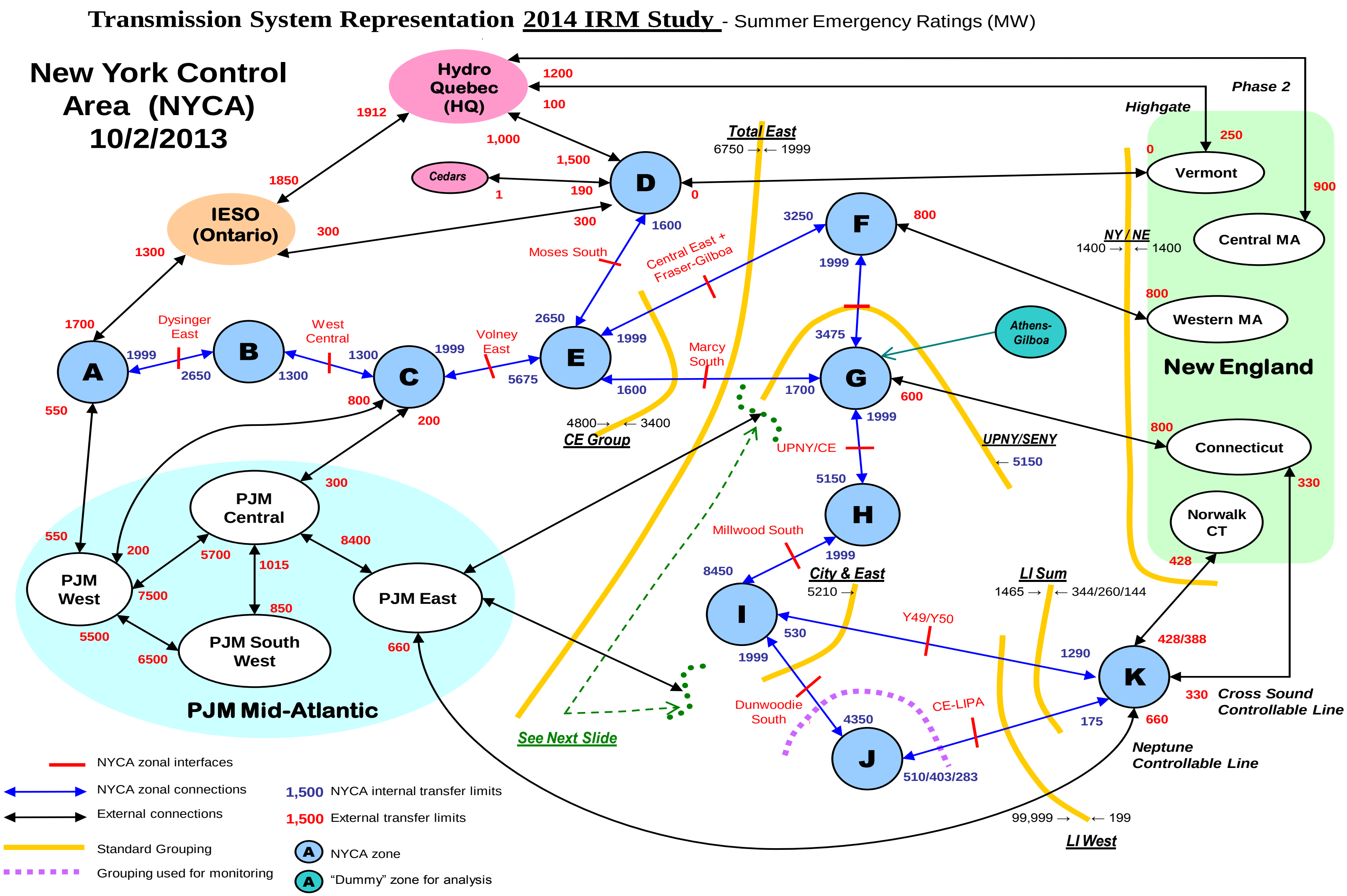
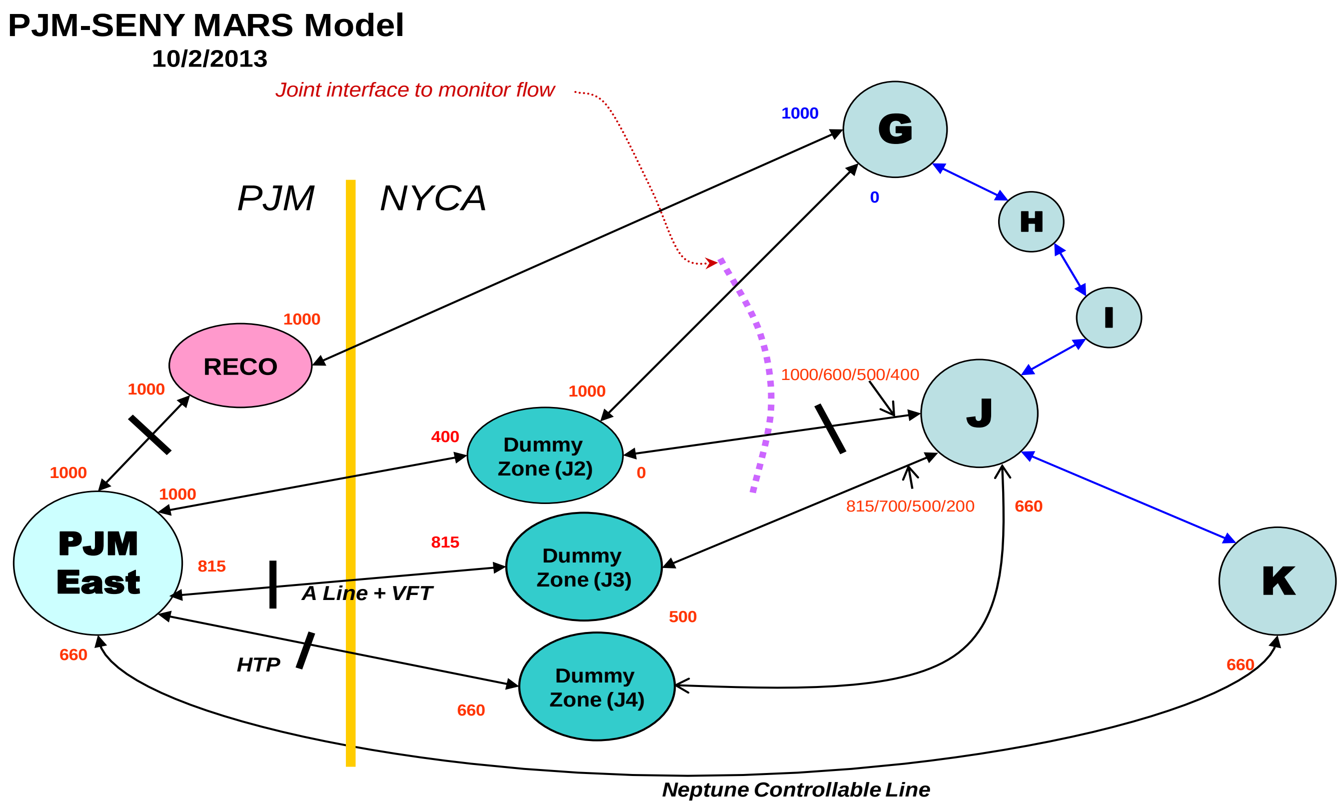


Figure A-13 PJM – NY Interface Model

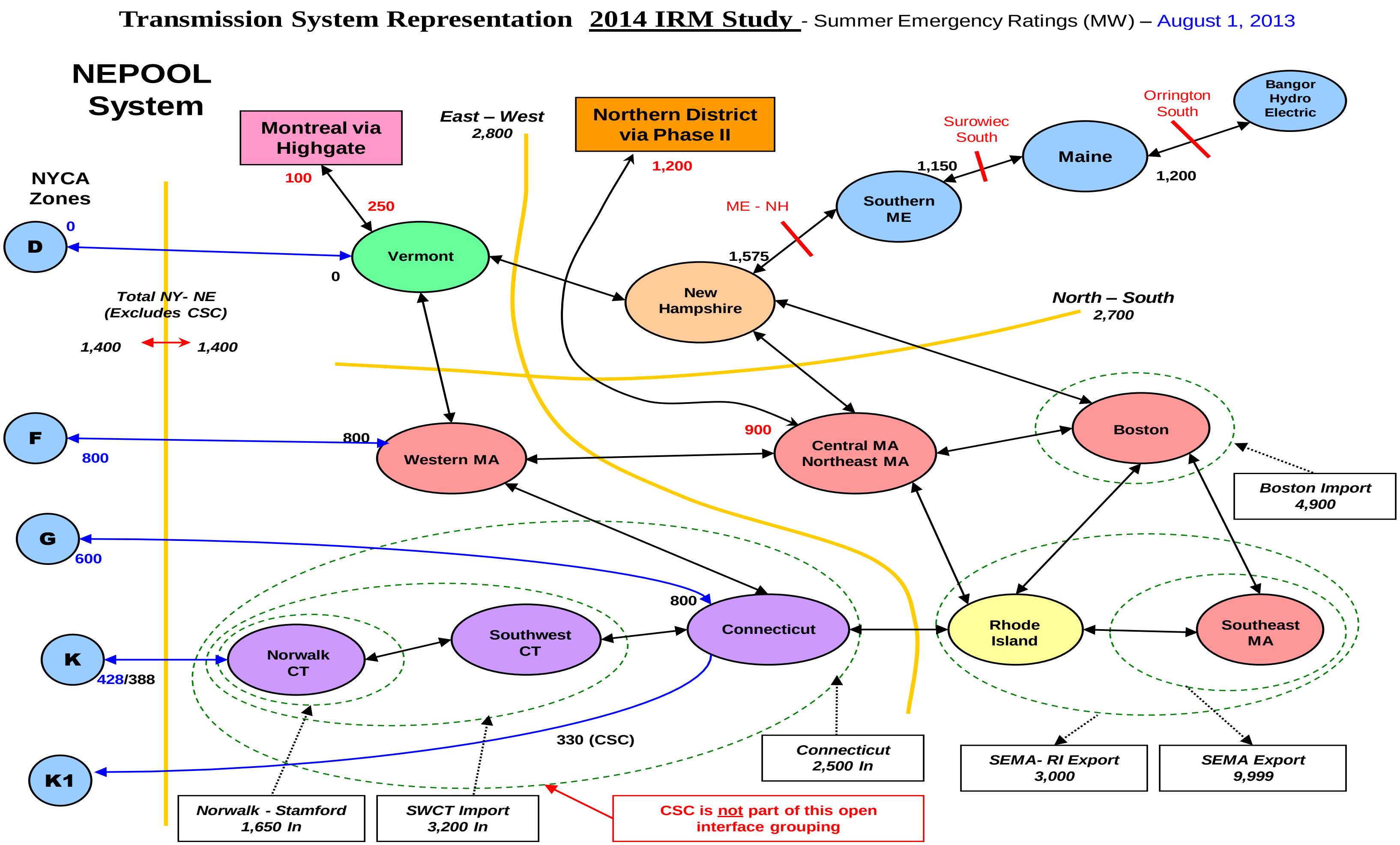
Transmission System Representation **<u>2014 IRM Study</u>** - Summer Emergency Ratings (MW)



<u>(PJM East to RECO) + (J2 to J) + (PJM East to J3) + (PJM East to J4) = 2000 MW. The reverse limit is 1500 MW</u>

Based on the delays in supporting transmission projects, the 2000 MW. Limit is maintained This interface grouping contains those interfaces with the Bold hash mark. MARS will distribute this flow accordingly. This limit will change to 2340 MW when additional transmission and generation comes into service in 2016.

Figure A-14 Full New England Representation



A.3.4 External Area Representations

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

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

Load shape models in the past IRM studies assumed a load shape based on a single historical year, 2002. The year 2002 had 13 days where the daily peak load was within 90% of the system peak, more days than in other years during the 1999-2012 year period. Use of the 2002 model therefore exposures the system to a relatively higher risk of LOLE events, which may result in inappropriately high IRM levels. Accordingly, in 2011 and 2012 the ICS worked with the NYISO to replace the 2002 load shape model with one that better represents year to year historical demand response to weather condition variations. See Appendix F for more details.

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 5-7 is as follows:

Table A-10 External Area Representations

Parameter	2013 Study Assumption	2014 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: ISONE – 50 MW (through 12/2013) PJM – 1080 MW HQ – 1090 MW All contracts modeled as equivalent contracts	Grandfathered amounts: PJM – 1080 MW HQ – 1090 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of 283 MW	Long term firm sales of 279 MW	These are long term federally monitored contracts.
Capacity Wheels	None modeled. A sensitivity case may be run	None modeled. A sensitivity case will be run	The ISO tariff is silent about capacity wheels through NYCA
External Area Modeling	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Four zones modeled for PJM. Thirteen zones modeled for New England	The load and capacity data is provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally among all	All NPCC Control Areas have indicated that they will share reserves equally among all	Per NPCC CP-8 working group assumption

Table A-11 Outside World Reserve Margins

Area	2013 Study Reserve Margin	2014 Study Reserve Margin	2013 Study LOLE (Days/Year)	2014 Study LOLE (Days/Year)
Quebec	24.1%*	38.3%*	0.100	0.103
Ontario	13.1%	10.8%	0.103	0.104
PJM-Mid-Atlantic	11.2%	14.4%	0.425	0.292
New England	12.3%	10.3%	0.104	0.115

*This is the summer margin.

Table A-11, above, shows the final reserve margins and LOLEs for the Control Areas external to NYCA.

A.3.5 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed in Table A-13 were provided by the NYISO based on operator experience. Table A-12 lists the assumptions modeled.

Table A-12 Assumptions for Emergency Operating Procedures

Parameter	2013 Study Assumption	2014 Study Assumption	Explanation
Special Case Resources	July 2013 – 1767 MW based on registrations and NYISO growth rate forecast and modeled as 1437 MW. Monthly variation based on historical experience (no limit on the number of calls)	July 2014 – 1195 MW based on registrations and modeled as 758 MW. Monthly variation based on historical experience (no limit on the number of calls)	Those sold for the program, discounted to historic availability.
EDRP Resources	143.9 MW registered; modeled as 14.4 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month	July 2013 – 93.9 MW registered; modeled as 12.8 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month	Those registered for the program, discounted to historic availability. Summer values calculated from July 2013 registrations.
EOP Procedures	765 MW of non-SCR/EDRP MWs	721 MW of non-SCR/EDRP MWs	Based on TO information, measured data, and NYISO forecasts

The values in Table A-12 are based on a NYISO forecast that incorporates 2013 operating results. This forecast is applied against a 2014 peak load forecast of 33,655 MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A-13 Emergency Operating Procedures Values

Parameter	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	1195 MW* (based on sales)
2	Emergency Demand Response Programs (EDRPs).	Load relief	94/13 MW**
3	5% manual voltage Reduction	Load relief	73 MW***
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	655 MW
5	5% remote voltage Reduction	Load relief	444 MW***
6	Voluntary industrial curtailment	Load relief	116 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	1310 MW
10	Customer disconnections	Load relief	As needed

** The SCR's are modeled as monthly values. The value for July is 1195 MW.*
*** The EDRPs are modeled as 94 MW discounted to 13 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 2014 peak load of 33,655 MW.*

A.3.6 Location Capacity Requirements

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

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

A.3.7 Special Case Resources and Emergency Demand Response Program

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

Table A-14 SCR Performance

Zones	Forecast SCRs (MW)	Overall Performance (%)
A - E	551.3	84.3
F - I	170.8	80.4
J	381.5	70.8
K	91.7	67.2

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

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

SCRs are modeled with monthly values. For the month of July, the value is 1195.3 MW. This value is the result of applying historic growth rates to the latest participation numbers.

EDRPs are modeled as a 13 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 from the forecast registered amount of 94 MW based on actual experience.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

General Electric was asked to review the input data for errors. GE has developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the NYISO 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-15.

Table A-15 GE MARS Data Scrub

Item	Description	Disposition	Model Change	Effect on IRM
1	**EOP:** The matrix lists 13 MW for EDRP, the MIF has 14.79	Corrected for final Base Case	Yes	No
2	**EOP:** The matrix lists 444 MW for 5% Rem VR, the MIF has 452.23 at the time of NYCA's peak.	New peak load forecast increases available amount.	No	No
3	Excessive increase in EFORd for unit	Verified with the NYISO staff	No	No
4	HYDQUE had a different peak load for load level 3	Corrected during preliminary case runs	Yes*	No
5	Moses and St. Lawrence have large deltas between the Gold Book and the MIF	The Federal Power sales to external areas are subtracted from the DMNC.	No	No
6	One of the biggest increases was a unit which went from an EFOR of 0.0575 (and a rating of 0 MW) to an EFOR of 0.4909.	Our records indicate that the previous year's EFORd for this unit was 0.4864 (although it had a zero rating for the summer).	No	No

*Change was incorporated before release of the preliminary base case results

A.4.2 NYISO Data Scrub

The NYISO also performs a review of the MARS data independently from GE. Table A-16 shows the results of this review.

Table A-16 NYISO MARS Data Scrub

Item	Description	Disposition	Model Change	Effect on IRM
1	Redundant transition rates for interface WH_PJME data (6-state overridden by 2-state)	Redundant (2 state) rates removed. Correction made during preliminary case runs	Yes*	No
2	3 units in zone K needing per unit capacity updates	Corrected during preliminary case runs	Yes	Yes
3	AREA_F included in GRP_A_E	Corrected during preliminary case runs (Groupings are informational only)	No	No
4	Redundant AREA_J2 and missing AREA_J4 in GRP_G_J	Corrected during preliminary case runs (Groupings are informational only)	No	No
5	Six units with materially different EFORds than the Market calculated EFORds	The transition rates (thus the EFORds) were hand calculated for the final base case and have been verified by APA**	Yes	Yes
6	Winter maintenance on several units caused LOLE events in Isolated sensitivity.	These units never are fully out on maintenance. The winter maintenance has been removed with very little (0.05) effect on the base case.	Yes	Yes

*Change was incorporated before release of the preliminary base case results

** Associate Power Analysts

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions from a masked database provided. Table A-17 shows these results.

Table A-17 Transmission Owner Data Scrub

Item	Description	Disposition	Model Change	Effect on IRM
1	**INF-TRLM**: Volney East should be 4875? (5675 in model)	5675 MW is the new value for the 2014 IRM study and is correctly represented and modeled.	No	No
2	**INF-TRLM**: NEPT_PJE 1320? Topology map shows 660	Per GE, when unit is not needed in NY, the capacity can be used in PJM. Also if NY has available margin, it can be supplied over the 660 MW cable[2]. Not shown intentionally.	No	No
3	**INF-TRLM**: PJ_GPJ_J 1500 in the model? Not specifically shown in the topology.	The 1500 MW reverse direction rating has been updated in the note under the diagram.	No	No
4	**INF-TRLM**: Shouldn't HQ-CMA reverse be rated at 1200 MW, 0 in model?	The diagram has been updated to show summer ratings for this tie. A winter value was inadvertently shown.	No	No
5	**MOD-MDMW**: What happened to the other DSPs in Ontario? Only TRO-DSP has entries in MOD-MDMW. EST-DSP, ESS-DSP, etc. do not have MDMW values.	Per policy 5, EOPs are removed. The TRO-DSP was missed and has now been removed and tested. This had no effect because we needed to add load to Ontario per policy 5.	Yes	No
6	**UNT-MXCP**: ID-883 "Salmon Falls Hydro" in ISO-NE had different ratings than 2013 CELT values. (MARS has .546 for Jan, .122 for Jun)(CELT has .565 for Jan, 0 for Jun)	This data comes from the CP-8 working group and has been updated since publication of the NE CELT Report.	No	No
7	**UNT-MXCP**: FTDRUM 0 MW in GB, but 44.1 in MIF?	Fort Drum will be operating as Black River Facility, using biofuels. Model is good.	No	No
8	**INF-DYLM**: Condition sets 9, 10, 11: shouldn't they say, in negative direction, 550 according to the topology?	Preliminary case sent out needed corrections which were made during preliminary case runs. The diagram is being updated.	No	No
9	**EOP-DATA**: Area K step 9 "Public Appeals" should be 88. It's 80 in the MIF (why only K? how is this determined?)	The mif shows an additional 8 MWs in zone B. These values are based on TO supplied information.	No	No
10	**LOD-DATA**: What's the method of "adjustment" of non-coincident peaks? I.e. which zones to adjust and the amount of adjustment?	The localities are set as forecast, zones A-F are adjusted proportionally to their existing load until the system forecast is met.	No	No

[2] This means that up to 660 MW can return. It assumes the tie is fully loaded with contracts even though that might not be the case. Contract amounts are confidential.

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B-1 summarizes the 2014 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 preliminary base case 17.1% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criteria. The values in Table B-1 are the sensitivity results adjusted to the 17.0% final base.

Table B-1 Sensitivity Case Results

Item	Description	IRM (%)	NYC (%)	LI (%)
	Transmission Sensitivities			
2	**No Internal NYCA Transmission Constraints (Free Flow System)**	14.5	NA	NA
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements. See the "Base Case – NYCA Transmission Constraints" section of the report.			
	Assistance from Outside World Modeling			
1	**NYCA Isolated**	25.9	91.0	115.1
	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.			
6	**Higher Outside World Margins**	11.1	80.5	101.5
	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**	24.4	90.0	113.8
	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			
4	**Remove all wind generation**	13.5	84.7	106.9

	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact that the wind generation has on the IRM requirement.			
8	**Retire units that have mothball status but were in Base Case per Policy 5 rules.**	16.8	84.7	106.9
	Retire Dunkirk #2 (last remaining unit) and Cayuga Units. These are upstate units, so freeze J and K at base case levels.			
Load Sensitivities				
3	**No Load Forecast Uncertainty**	8.2	78.4	98.8
	This scenario represents "perfect vision" for 2014 peak loads, assuming that the forecast peak loads for NYCA have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather on IRM requirements.			
Emergency Operating Procedures				
5	**No SCRs or EDRPs**	15.7	83.1	107.4
	Shows the impact of SCRs and EDRPs on IRM.			
9	**Limit SCRs 5 calls per month**	17.6	85.2	107.5
	Shows the impact on the IRM of limited help from SCRs			

B.1.1 Sensitivity Number 10, the removal of the Indian Point Units 1 and 2, without adding any additional capacity resulted in an LOLE of 0.92.

B.2 Environmental Regulations

Several new environmental regulatory programs are scheduled to arrive starting in 2014. These state and federal regulatory initiatives cumulatively will require considerable investment and changes in operating methods for New York's existing thermal power plants in order to comply with these new regulatory requirements. The programs assessed here are the following:

a) NOx RACT – Reasonably Available Control Technology

b) BART – Best Available Retrofit Technology for regional haze

c) MACT – Maximum Achievable Control Technology for hazardous air pollutants

d) CSAPR – Cross State Air Pollution Rule

e) BTA – Best Technology Available for cooling water intake structures

f) RGGI- Regional Greenhouse Gas Initiative

B.2.1 Cross State Air Pollution Rule (CSAPR)

The NYISO has determined that as much as 33,200 MW in the existing fleet or 88% of 2012 Summer Capacity will have some level of exposure to the new regulations. One of the recent significant developments in the environmental regulatory landscape that has taken place is the appeal of CSAPR to the US Supreme Court[3]. In July 2011, the USEPA replaced the Clean Air Transport Rule (CATR) proposal with the finalized CSAPR. The rule requires significant additional reductions of SO2 and NOx emissions beyond those previously identified. The CSAPR establishes a new allowance system for units larger than 25 MW of nameplate capacity. Affected Generators will need one allowance for each ton emitted in a year. In New York, CSAPR will affect 154 units that represent 25,900 MW of capacity. The USEPA has estimated New York's annual allowance costs for 2012 at $65 million. There are multiple scenarios which show that New York's generation fleet can operate in compliance with the program in the first phase. Compliance actions for the second phase may include emission control retrofits, fuel switching, and new clean efficient generation. If the USEPA's appeal is successful, it may be reasonable to expect delayed in the implementation of the rules, perhaps until 2016, which could place it on a schedule that is near concurrent with MATS.

B.2.2 Mercury and Air Toxics Standards (MATS)

The USEPA finalized a new regulation in February 2012 to establish emission rate standards for the Maximum Achievable Control Technology (MACT) for hazardous air pollutants (HAP) from coal and oil fueled steam generators with a nameplate capacity greater than 25 MW. MACT will affect 23 units that represent 9,900 MW of capacity. The majority of the New York coal fleet has installed emission control equipment that may place compliance within reach. The heavy oil fired units will need to either make significant investments in

[3] EME Homer City Generation v. U.S. EPA (11-1302, et al.)

emission control technology, or switch to, or maintain a cleaner mix of fuels in order to comply with the proposed standards. Given the current outlook for the continued attractiveness of natural gas compared to heavy oil, it is anticipated that compliance will be achieved by dual fuel units through the use of natural gas to maintain fuel ratios such that the effective capacity factor on oil is less than 8%. Compliance requirements begin in March 2015. The NYISO joined other RTOs in seeking a regulatory "safety valve" which delay the compliance requirements for identified units needed to maintain reliable electric system operation during the period when environmental retrofits or replacement units are being built. One coal fired unit in New York has sought consideration for extension of the compliance deadline to March 2017.

B.2.3 Best Technology Available (BTA)

The USEPA has proposed new Section 316 b rules providing standards for the design and operation of power plant cooling systems. This rule will be implemented by NYSDEC which has finalized a policy for the implementation of this rule known as Best Available Technology for plant cooling water intake structures. New York power plants with open cycle cooling systems will need to conduct studies and demonstrate that their systems can be modified to achieve reductions in aquatic impacts equivalent to 90% of the reductions that could be achieved by the use of a closed cycle cooling system, e.g., using cooling towers. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4,400-7,300 MW of capacity could be required to retrofit closed cycle cooling systems. The most publically recognized application of this policy is the Indian Point nuclear power plant.

B.2.4 Best Available Retrofit Technology (BART)

The class of steam electric units constructed between 1963 and 1977 are subject to continuing emission reductions required by the Clean Air Act. The reductions are required to reduce their respective impacts on visibility levels at National Parks. In New York, 16 units with 8,400 MW of capacity are affected. The owners of these units have submitted their plans for Best Available Retrofit Technology (BART) and have received modified Title V air permits incorporating the final plans. The oil fired units are proposing the alternatives that include maintaining the *status quo*, lower sulfur fuels, and low NOx combustion systems. Danskammer has announced its retirement. Two smaller coal plant owners have chosen to retire small boilers. The new permit limitations become effective January 1, 2014. No additional capacity losses are anticipated as a direct result of the implementation of BART.

B.2.5 Reasonably Available Control Technology for Nitrogen Oxides (NOx RACT)

The NYSDEC has promulgated revised regulations for the control of Nitrogen Oxides (NOx) emissions from fossil-fueled electric generating units. These regulations are known as NOx RACT (Reasonably Available Control Technology) for oxides of nitrogen. In NY 254 units are affected with 27,800 MW of capacity. Emission reductions required by these revised regulations must be in place by July 2014. Generators have all filed compliance plans with NYSDEC. Several have chosen to request that plans be classified as Business Protected Information. NYSDEC has challenged this classification.

Using publically available information from USEPA and USEIA, estimated NOx emission rates can be determined across the operating spectrum for various combinations of fuels for specific units greater than 25 MW. Using this information, the NYISO has analyzed potential NOx emissions under the lower NOx RACT standards to determine if the system emission averaging plans can be achieved. The analysis has focused on Zone J and concluded that the TC Ravenswood emission plan should be able to be complied with while not imposing operating limits on the affected units. The NRG emission averaging plan includes Arthur Kill and the Astoria Gas Turbines. The analysis shows that operation of the complete fleet of gas turbines will be limited to approximately four hours. Similarly, the analysis shows that the US PowerGen fleet of gas turbines will be limited to approximately three hours of operation. Given that this analysis is based upon historic performance which was occurred when the emission limits were higher, it is possible that the boilers could achieve lower emission rates and therefore the gas turbines could operate for more extended periods. No generator owners have informed the NYISO of limitations on use of the high emitting gas turbines.

The older gas turbines in these emission bubbles can be expected to continue to operate at periods of high prices for limited durations until end of life limits are reached. One such limit is the number of starts permissible for older GE Frame V machines.

Table B-2 NRG Hours of GT Operation

NRG – Hours of GT Operation		
	Current NOx RACT	2014 NOx RACT
Min Gen	11	4
DMNC	23	4

Table B-3 Astoria Hours of GT Operation

AST – Hours of GT Operation		
	Current NOx RACT	2014 NOx RACT
Min Gen	7	3
DMNC	16	3

B.2.6 Regional Greenhouse Gas Initiative.

The Regional Greenhouse Gas Initiative established a cap over CO_2 emissions from most fossil fueled power plants with more than 25 MW in 2009. The cap has proven to be oversupplied and therefore auctions have tended to clear at or near the floor for most of the period. In 2012 the RGGI States undertook a program review which concluded in February 2012. The program review called for reducing the cap by 45% to 91,000,000 tons for 2014 and then applying annual reductions of 2.5% until 2020. The program further provides that the cap will be reduced by the amount of unused allowances that have been previously distributed. The floor clearing price will be set at $2.00 and escalate at 2.5% annually. A key provision to keep the allowance and electricity markets functioning is the provision of a Cost Containment Reserve (CCR). If demand exceeds supply at predetermined trigger prices an additional 10,000,000 allowances will be added to the market. Trigger prices are set to rise to $10/ton in 2017 and escalate at 2.5% thereafter. RGGI Inc. modeling analyses show that the trigger prices will be reached on several occasions throughout the period. Already economically disadvantaged coal units, will be further handicapped by this fee which would add up to $5/MWh in cost compared to an old combined cycle and up to $10/MWh for non-emitting machines. Coal fueled units may be limited to operation in peak periods.

B.2.7 New Source Performance Standards for CO_2 (NSPS CO_2)

The USEPA has released a revised rule for final comments that is designed to limit CO_2 emissions from new fossil fueled steam generators and combined cycle units. The rules are generally less stringent than the NYSDEC's Part 251 that is applicable in NY. USEPA's rule provides for an exemption for simple cycle turbines with limited sales to the grid. Both rules may effectively eliminate the development of new or repowered coal fired projects.

B.2.8 Reciprocating Internal Combustion Engines New Source Performance Standards and Maximum Achievable Control Technology (RICE NSPS and RICE MACT)

In January 2013 the USEPA finalized two new rules that apply to engine powered generators typically used as emergency generators. Some of the effected generators also participate in the NYSIO's Special Case Resource (SCR) or Emergency Day-ahead Response (EDRP) Programs. EPA finalized National Emission Standards for Hazardous Air Pollutants (NESHAP), and New Source Performance Standards, for Reciprocating Internal Combustion Engines (RICE). The new rules are designed to allow older emergency generators that do not meet the EPA's rules to comply by limiting operations in non- emergency events to less than 15 hours per year. These resources can participate in utility and ISO emergency demand response programs, however the engine operation to limited to a maximum of 100 hours per year for testing and utility or ISO emergency demand response operations for which a Level 2 Energy Emergency Alert was called by the grid operator.

The New York DEC is also developing rules to control emissions of NOx and particulate matter (PM10 and 2.5) from engine driven generators that participate in emergency demand response program. The proposed rules will apply to all such generators above 150 kW in NYC and above 300 kW in the Rest of State not already covered by a Title V Permit to stricter NOx and PM limits. Engines purchased since the 2005 and 2006 depending upon specific type should be able to operate within the proposed limits. Older engines can be retrofitted with emission control packages, replaced with newer engines, or cease participation in the demand response programs. The proposed rule is generally comparable to rules already in place in a number of neighboring states. NYSDEC's estimated compliance schedule is still developing, with a currently contemplated schedule for compliance of mid-2015.

B.2.9 Summary of Environmental Programs

The cumulative effect of this series of new regulatory requirements will be increased operating costs for the affected units as well as demands for additional capital. These demands when viewed in the competitive market place that is also increasingly occupied by cleaner more efficient generators that burn natural gas as well as low operating cost renewables, may influence some owners to curtail operations or retire plants.

The table below summarizes the new environmental requirements that are scheduled to become effective in the near term and the amounts of capacity that would be affected by each of these regulations. In addition, the quantities of capacity and number of units that have announced or are expected to undertake environmental control projects to achieve compliance are also tabulated.

Table B-4 Summary of Environmental Programs

Program	Status	Compliance Deadline	Approximate Capacity Affected	Potential Retrofits
NOx RACT	In effect	Jul-14	27,800 MW (245 Units)	2,400 MW (7 Units)
BART	In effect	Jan-14	8,400 MW (16 Units)	1,500 MW (4 Units)
MATS	In effect	3/1/2015/16/17	9,900 MW (23 Units)	200 MW (1 Units)
BTA	In effect	Upon Permit Renewal	16,500 MW (35 Units)	4,400 to 7,300 MW
CSAPR	Implementation is stayed while the rule is in litigation	Jan. 2012 and Jan. 2014	25,900 MW (154 Units)	1,900 MW (7 Units)
RGGI	In effect	In effect	26,000 MW (158 Units)	N/A

B.3 Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. For the base case, the study shows that approximately 6.3 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-5.

Table B-5 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs	9.2
2	Require EDRPs	6.8
3	5% manual voltage reduction	6.6
4	30 minute reserve to zero	6.5
5	5% remote control voltage reduction	6.3
6	Voluntary load curtailment	4.6
7	Public appeals	3.6
8	Emergency purchases	3.4
9	10 minute reserve to zero	3.2
10	Customer disconnections	0.1

B.4 Parametric Impact Comparison

The following table shows the parametric impact of the changes made from the 2013 Report, including the changes in LCRs for Zones J and K.

Table B-6 Full Parametric Analysis, 2013 versus 2014

Parameter	Estimated IRM Change (%)	IRM (%)	Estimated LCR Changes (%) Zones J/K		Reasons for IRM Changes
2013 IRM Study – Final Base Case		**17.1**	**83.7**	**102.0**	
2014 Parameters that Increase the IRM					
Updated Generating Unit EFORd's	+0.7		0.1	0.2	Yearly improvement but 5 year worsening for all zones
Updated SCR/EDRP	+0.8		1.3	1.9	Less SCR lowering outweighed by less effectiveness from 83 to 61%
Updated DNMC Ratings	+0.5		-0.1	0.4	Downstate to upstate ratio of capacity getting smaller (Storm Sandy)
Retirements	+0.3		2.2	2.8	Downstate retirements affect IRM (Location driver)
Updated Cable Outage Rates	+0.1		0.2	0.3	Increased outages on Cables being experienced
Updated Non-SCR/EDRP EOPs	+0.1		0.1	0.1	Less EOP participation
Mothballed Units Returned to Service	+0.1		0.2	0.0	Good location outweighed by poor historic performance
Updated Maintenance	+0.1		0.1	0.0	New Load Shape (2007) stresses system slightly in shoulder months
Total IRM Increase	**+2.7**		**+4.1**	**+5.7**	**Estimated LCR change**
2014 Parameters that decrease the IRM and LCRs					
New Multiple Load Shape Model	-0.9		-0.7	-1.0	New load shapes are less stressful in upper bins (less days near peak)
Updated Neighboring Control Area Models	-0.8		-2.0	-2.1	PJM shows lower loads than forecast earlier
Remove Marble River	-0.5		0.0	0.0	Removal of 2013 IRM forecast poor performing unit
Updated Load Forecast	-0.1		-0.1	2.6	Downstate load growth diminished
Updated LFU	-0.2		-0.2	-0.2	Zone J unchanged, other zones have less uncertainty
Updated Topology	-0.2		-0.1	-0.1	UPNY/SENY increase
Use 2012 Wind Shape	-0.1		0.0	0.0	More efficient wind observed
Total IRM Decrease	**-2.8**		**-3.1**	**-0.8**	**Estimated LCR change**
2014 Parameters that do not change the IRM					
New MARS Version	0				
Updated Study Year	0				
Net Change from 2013 Study		**-0.1**	**+1.0**	**+4.9**	**Estimated LCR change Total**
Preliminary 2014 IRM Study Base Case IRM		**17.0***	**84.7**	**106.9**	**LCRs from tan 45 analysis**

Appendix C

ICAP to UCAP Translations

C. ICAP to UCAP Translation

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

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

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

Table C-1 Historical NYCA Capacity Parameters

Capability Year	Base Case IRM (%)	EC-Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYISO - Approved NYC LCR (%)	NYISO – Approved LI LCR (%)
2000	15.5	18.0		80	107
2001	17.1	18.0		80	98
2002	18.0	18.0		80	93
2003	17.5	18.0		80	95
2004	17.1	18.0	11.9	80	99
2005	17.6	18.0	12.0	80	99
2006	18.0	18.0	11.6	80	99
2007	16.0	16.5	11.3	80	99
2008	15.0	15.0	8.4	80	94
2009	16.2	16.5	7.2	80	97.5
2010	17.9	18.0	6.1	80	104.5
2011	15.5	15.5	6.0	81	101.5
2012	16.1	16.0	5.4	83	99
2013	17.1	17.0	6.6	86.0	105.0

C.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO Web site, the NYISO Staff regularly posts ICAP and UCAP calculations for both the summer and winter Capability Periods. This publicly available information can be found on the NYISO web site.[4]

Information has been compiled by the NYISO on this site since 2006 and includes complete information through 2013. This information is provided for Locational Areas and for the Transmission District Loads.

The Locational Areas include NYC, LI and the entire NYCA. Exhibits C-1(a) through C-1(c) summarizes translation of ICAP requirements to UCAP requirements for these Locational Areas. The charts and tables included in these exhibits utilize data from the 2006-2013 capability periods (and limited to "summer" only, for purposes of simplicity).

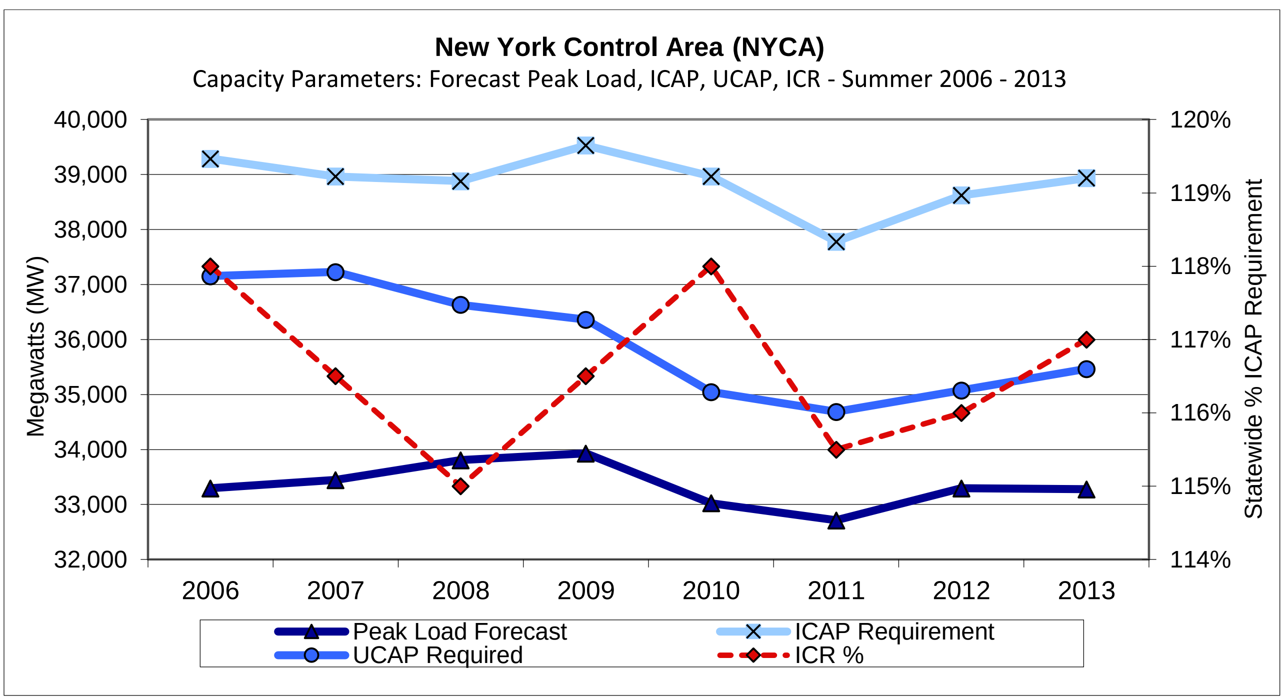
Importantly, this data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, Derating Factors, UCAP Requirements, IRM and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation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

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

C.1.1 New York Control Area ICAP to UCAP Translation

Table C-2 NYCA ICAP to UCAP Translation

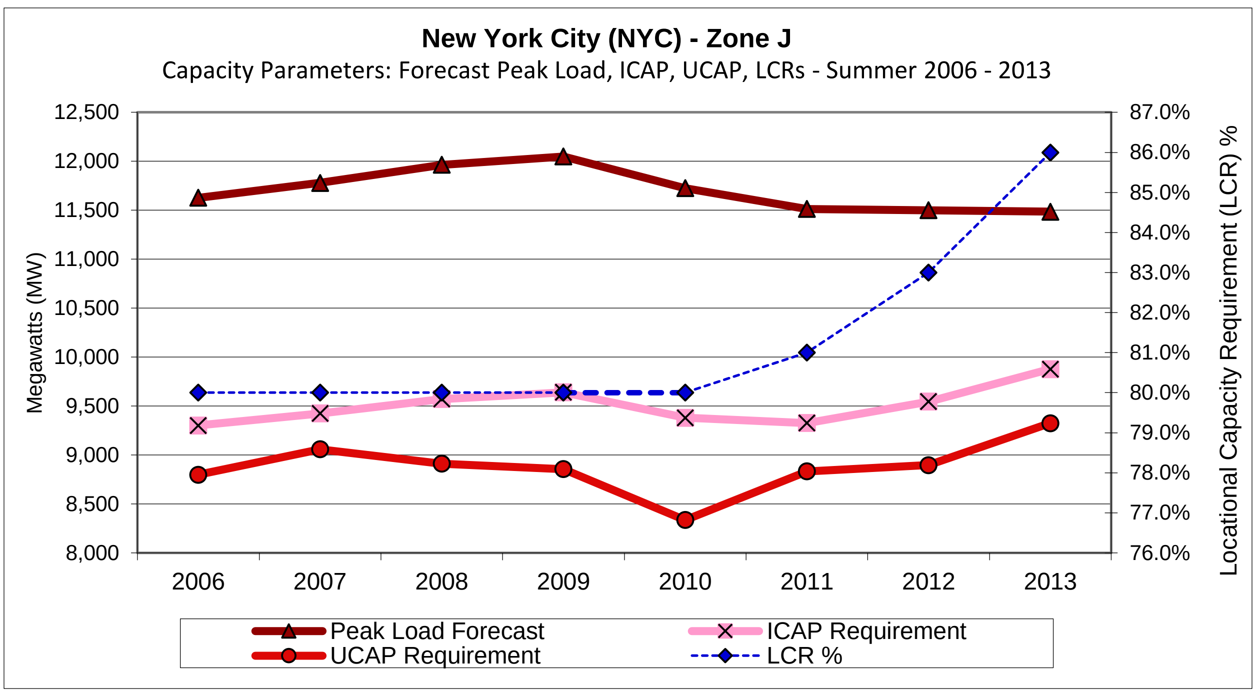
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	39,529	36,362	107.2
2010	33,025	118.0	0.1007	38,970	35,045	106.1
2011	32,712	115.5	0.0820	37,783	34,684	106.0
2012	33,295	116.0	0.0918	38,622	35,076	105.4
2013	33,279	117.0	0.0891	38,936	35,467	106.6



C.1.2 New York City ICAP to UCAP Translation

Table C-3 New York City ICAP to UCAP Translation

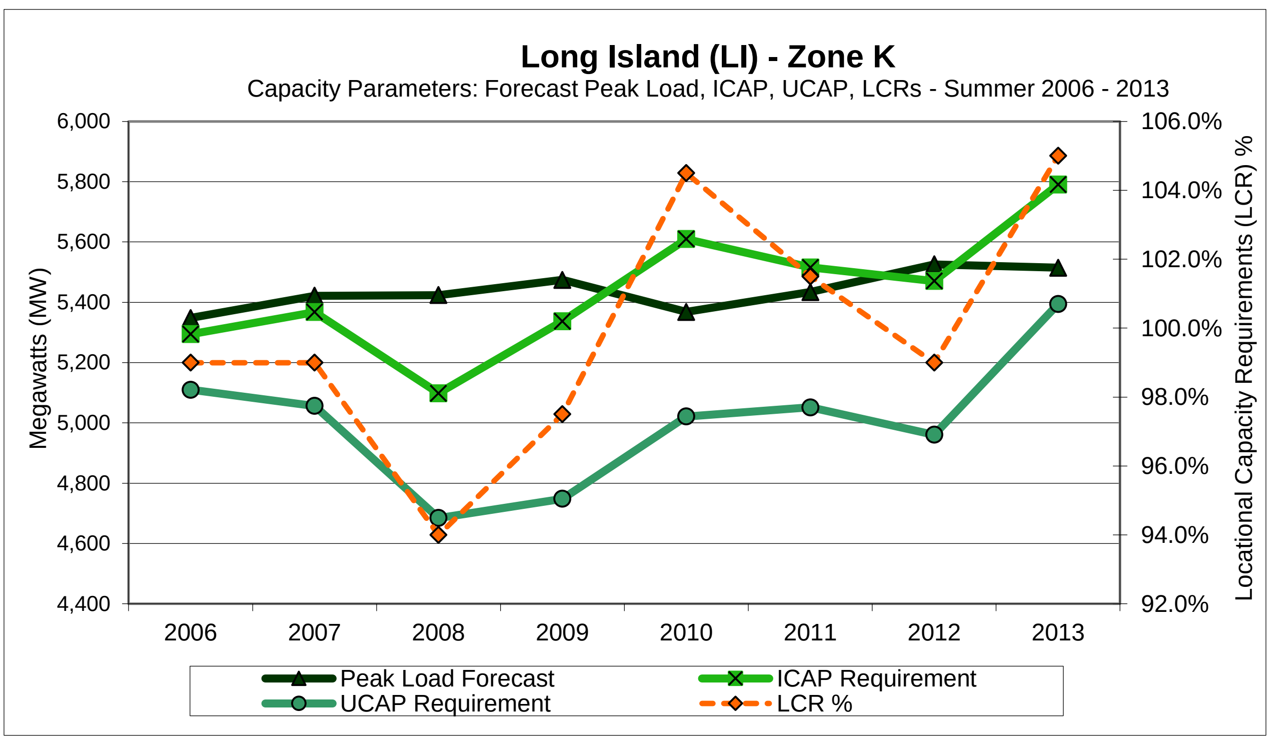
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855	73.5
2010	11,725	80.0	0.1113	9,380	8,336	71.1
2011	11,514	81.0	0.0530	9,326	8,832	76.7
2012	11,500	83.0	0.0679	9,545	8,897	77.4
2013	11,485	86.0	0.0559	9,877	9,325	81.2



C.1.3 Long Island ICAP to UCAP Translation

Table C-4 Long Island ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,748	86.7
2010	5,368	104.5	0.1049	5,610	5,021	93.5
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
2013	5,515	105.0	0.0684	5,790	5,394	97.8

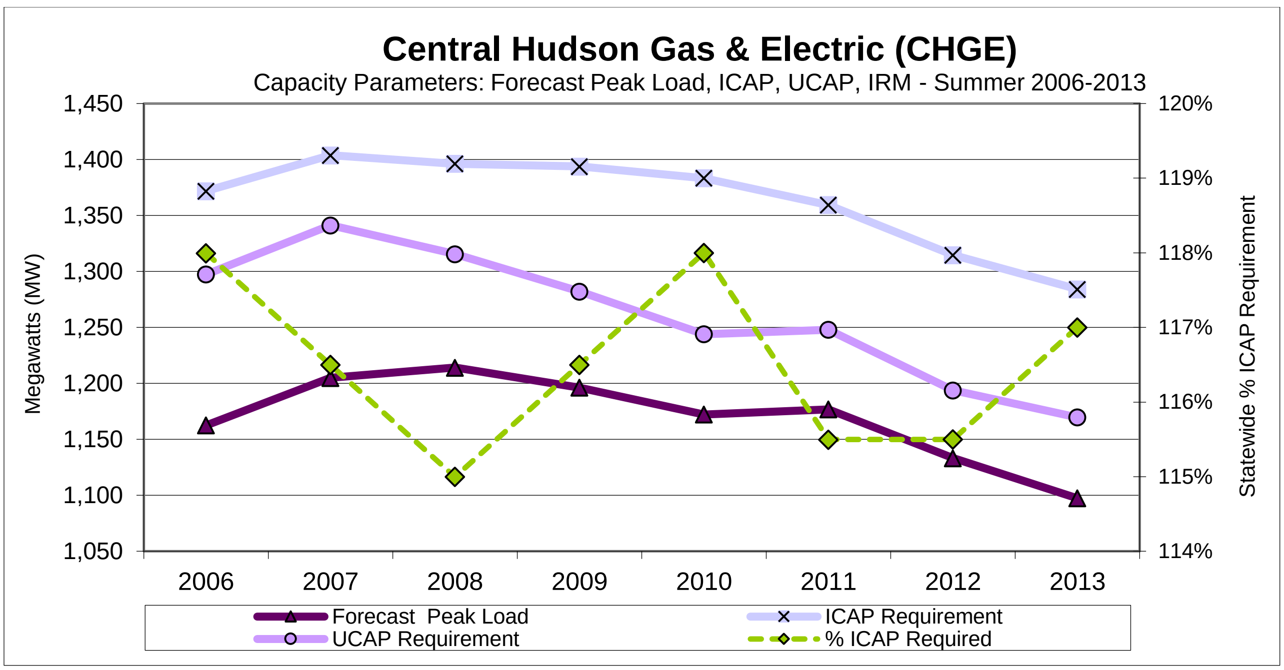


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

Table C-5 Central Hudson Gas & Electric ICAP to UCAP Translation

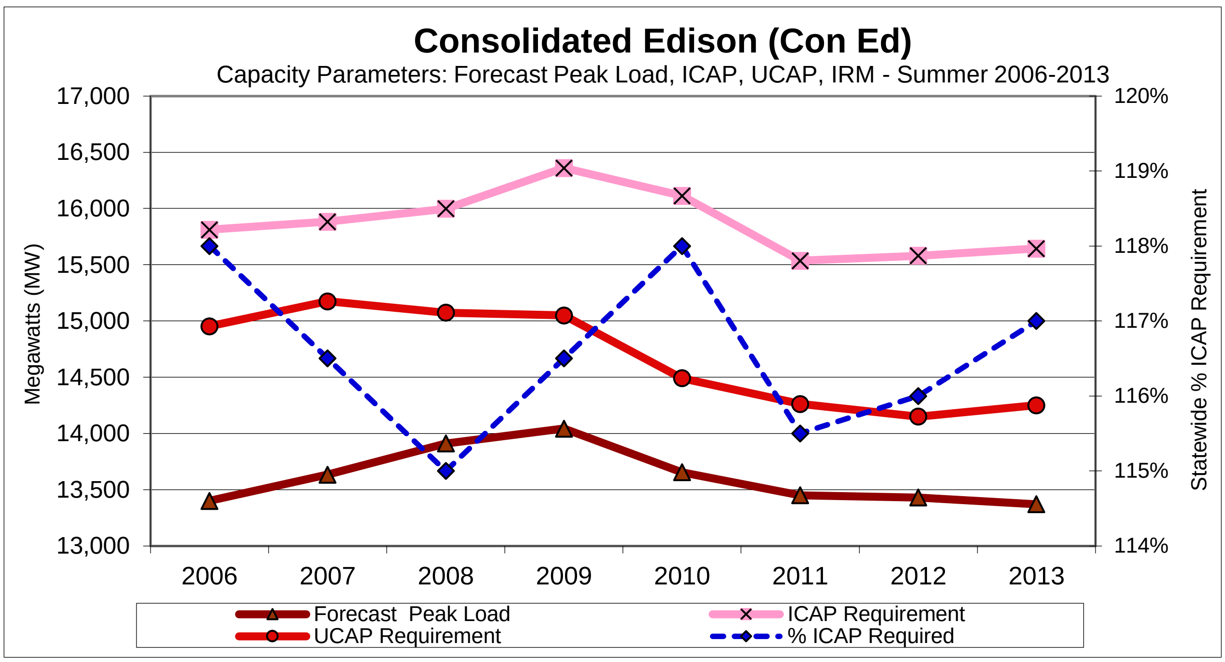
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1,163	1,372	1,297	118.0%	111.6%
2007	1,205	1,404	1,341	116.5%	111.3%
2008	1,214	1,396	1,316	115.0%	108.4%
2009	1,196	1,394	1,282	116.5%	107.2%
2010	1,172	1,383	1,244	118.0%	106.1%
2011	1,177	1,359	1,248	115.5%	106.0%
2012	1,133	1,315	1,194	115.5%	106.0%
2013	1,098	1,284	1,170	117.0%	106.6%



C.2.2 Consolidated Edison (Con Ed)

Table C-6 Con Ed ICAP to UCAP Translation

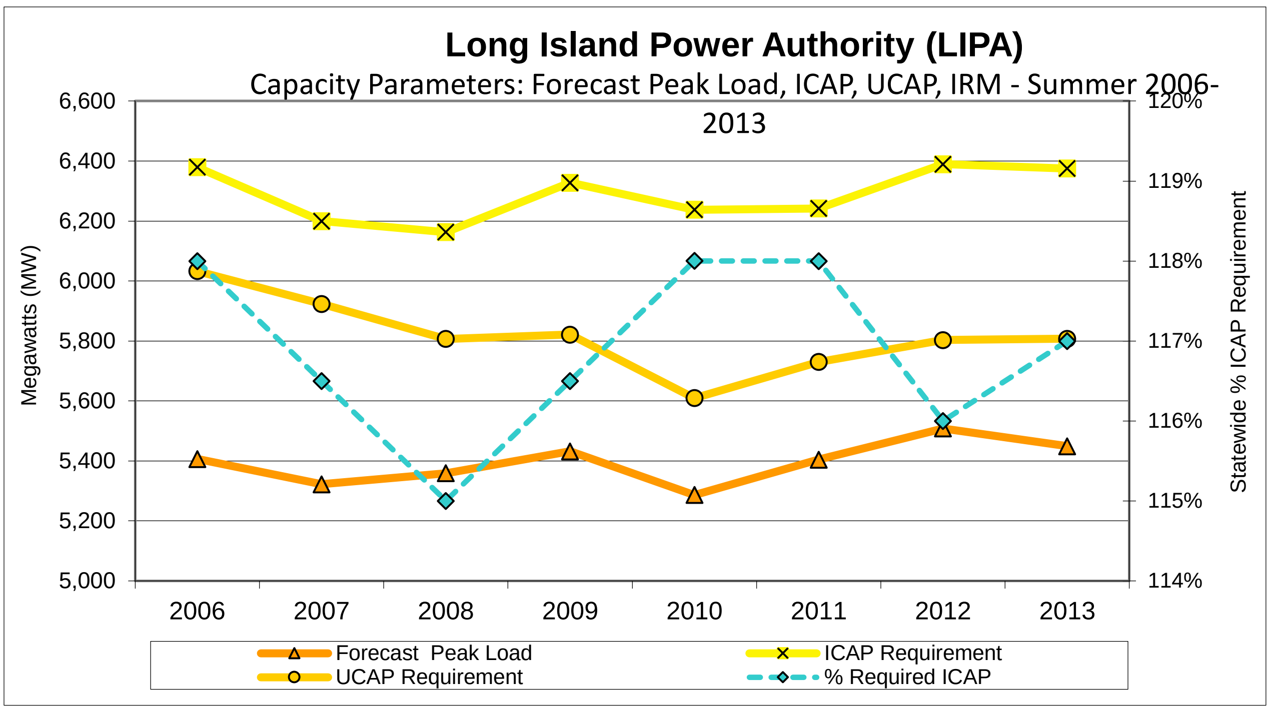
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	13,400	15,812	14,953	118.0%	111.6%
2007	13,634	15,883	15,175	116.5%	111.3%
2008	13,911	15,998	15,073	115.0%	108.4%
2009	14,043	16,360	15,050	116.5%	107.2%
2010	13,655	16,113	14,490	118.0%	106.1%
2011	13,451	15,535	14,261	115.5%	106.0%
2012	13,431	15,579	14,149	116.0%	105.4%
2013	13,371	15,644	14,250	117.0%	106.6%



C.2.3 Long Island Power Authority (LIPA)

Table C-7 LIPA ICAP to UCAP Translation

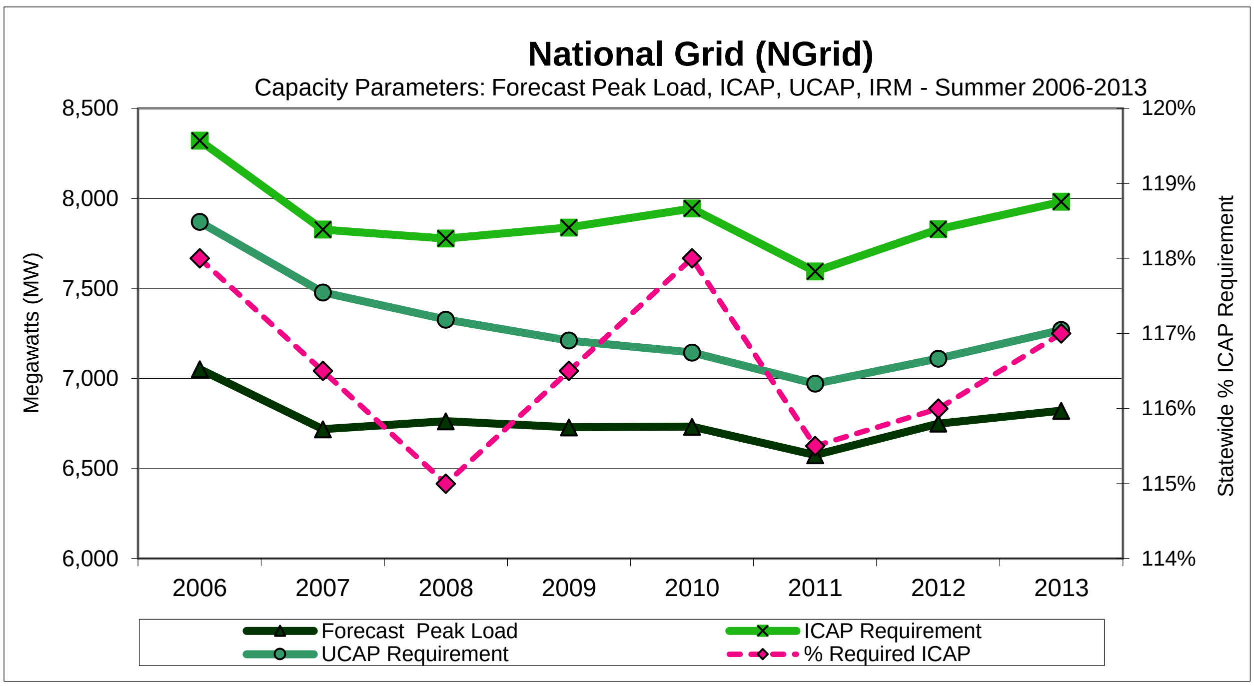
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	5,406	6,379	6,033	118.0%	111.6%
2007	5,322	6,200	5,923	116.5%	111.3%
2008	5,359	6,163	5,807	115.0%	108.4%
2009	5,432	6,328	5,821	116.5%	107.2%
2010	5,286	6,238	5,609	118.0%	106.1%
2011	5,404	6,242	5,730	118.0%	111.6%
2012	5,508	6,390	5,803	116.0%	105.4%
2013	5,449	6,375	5,807	117.0%	106.6%



C.2.4 National Grid (NGRID)

Table C-8 NGRID ICAP to UCAP Translation

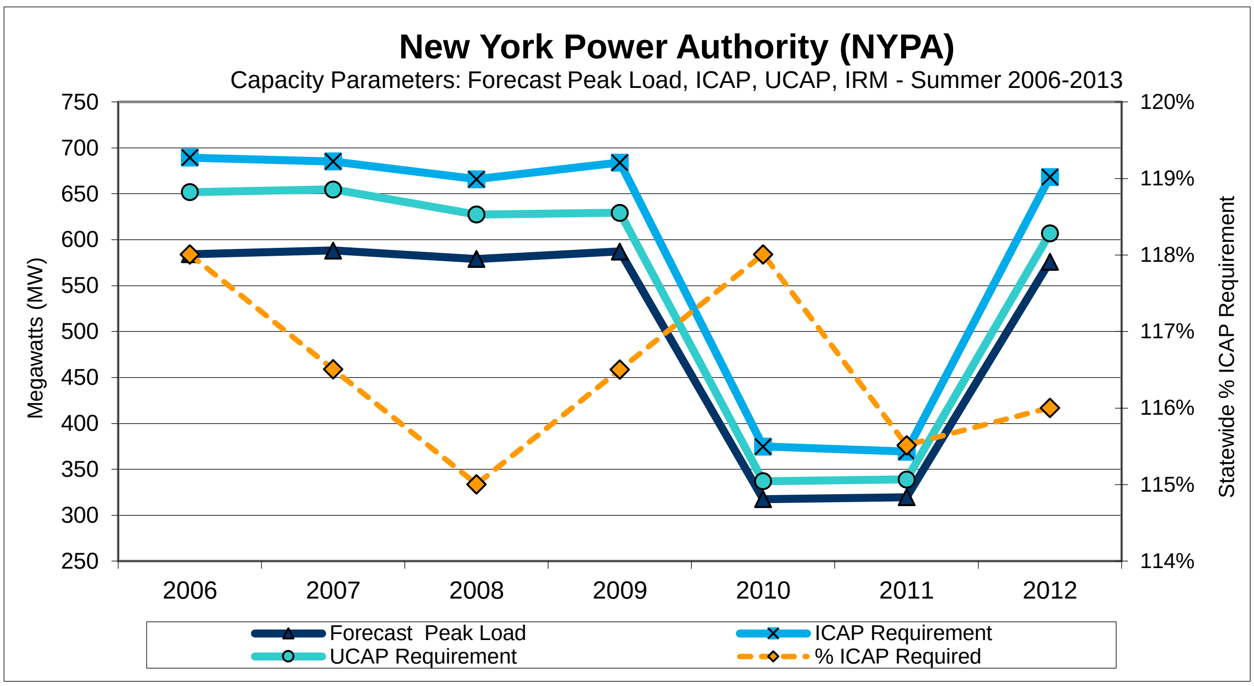
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	7,052	8,321	7,869	118.0%	111.6%
2007	6,719	7,827	7,478	116.5%	111.3%
2008	6,763	7,777	7,327	115.0%	108.4%
2009	6,728	7,839	7,211	116.5%	107.2%
2010	6,732	7,944	7,144	118.0%	106.1%
2011	6,575	7,594	6,971	115.5%	106.0%
2012	6,749	7,829	7,110	116.0%	105.4%
2013	6,821	7,981	7,270	117.0%	106.6%



C.2.5 New York Power Authority (NYPA)

Table C-9 NYPA ICAP to UCAP Translation

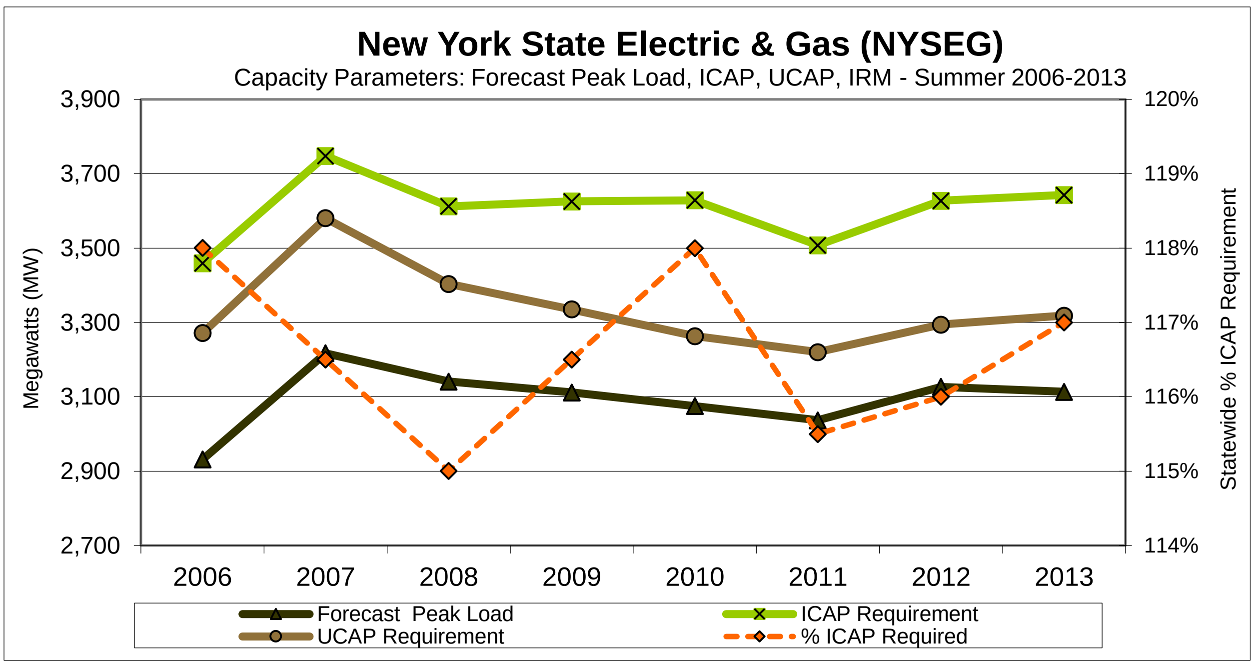
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	584	689	652	118.0%	111.6%
2007	588	685	655	116.5%	111.3%
2008	579	666	628	115.0%	108.4%
2009	587	684	629	116.5%	107.2%
2010	318	375	337	118.0%	106.1%
2011	320	369	339	115.5%	106.0%
2012	576	668	607	116.0%	105.3%
2013	589	690	628	117.0%	106.6%



C.2.6 New York State Electric & Gas (NYSEG)

Table C-10 NYSEG ICAP to UCAP Translation

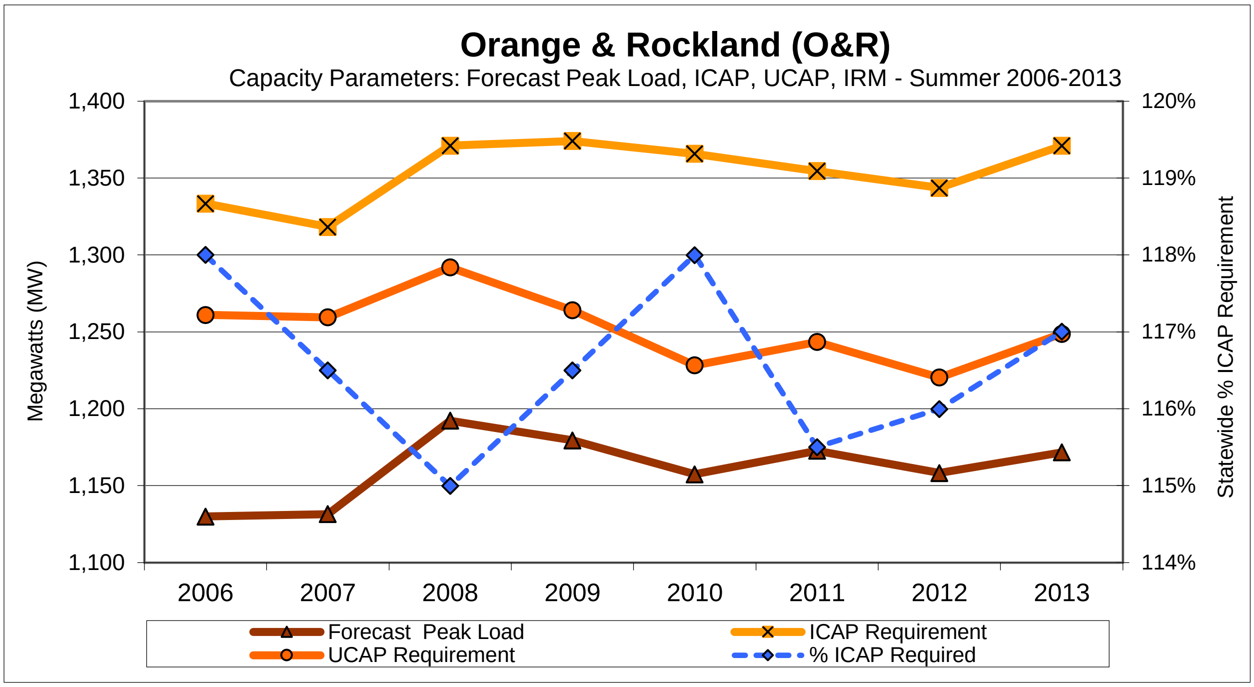
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	2,932	3,459	3,271	118.0%	111.6%
2007	3,217	3,748	3,581	116.5%	111.3%
2008	3,141	3,612	3,404	115.0%	108.4%
2009	3,112	3,625	3,335	116.5%	107.2%
2010	3,075	3,629	3,263	118.0%	106.1%
2011	3,037	3,508	3,220	115.5%	106.0%
2012	3,127	3,627	3,294	116.0%	105.4%
2013	3,113	3,643	3,318	117.0%	106.6%



C.2.7 Orange & Rockland (O & R)

Table C-11 O & R ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1,130	1,333	1,261	118.0%	111.6%
2007	1,132	1,318	1,259	116.5%	111.3%
2008	1,192	1,371	1,292	115.0%	108.4%
2009	1,180	1,374	1,264	116.5%	107.2%
2010	1,157	1,366	1,228	118.0%	106.1%
2011	1,173	1,355	1,243	115.5%	106.0%
2012	1,158	1,344	1,220	116.0%	105.4%
2013	1,172	1,371	1,249	117.0%	106.6%

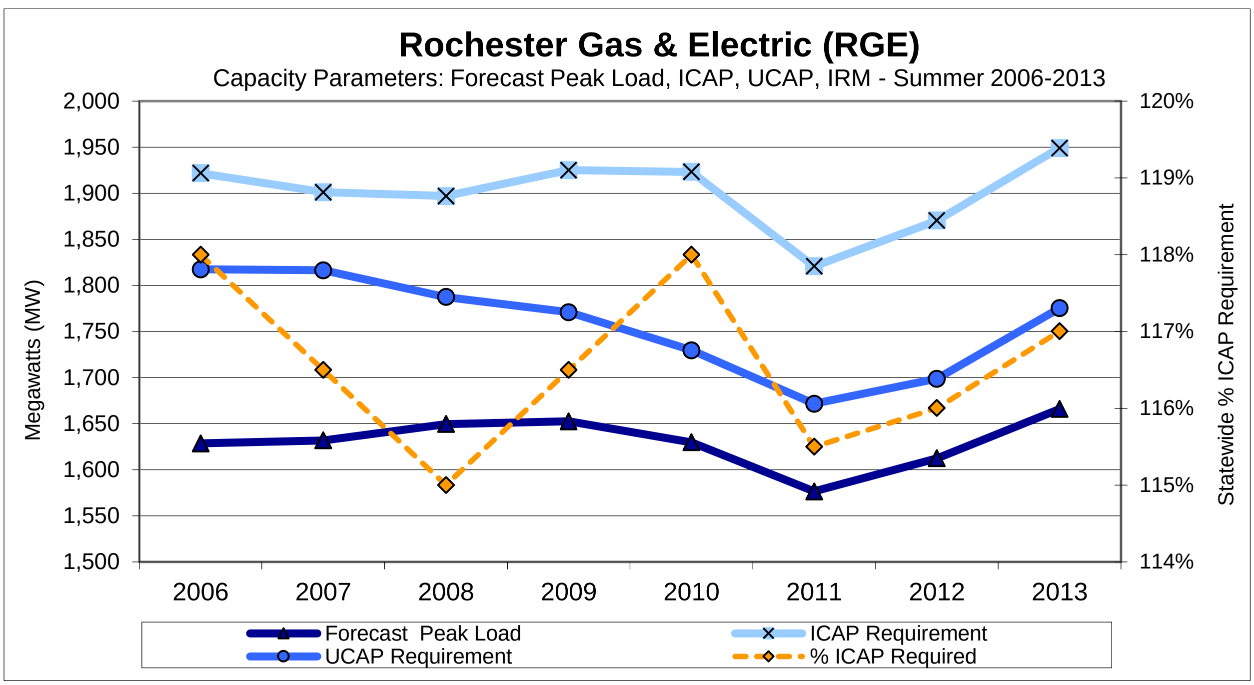


C.2.8 Rochester Gas & Electric (RGE)

Table C-12 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2006	1,629	1,922	1,817	118.0%	111.6%
2007	1,632	1,901	1,816	116.5%	111.3%
2008	1,649	1,897	1,787	115.0%	108.4%
2009	1,652	1,925	1,771	116.5%	107.2%
2010	1,630	1,923	1,729	118.0%	106.1%
2011	1,576	1,821	1,671	115.5%	106.0%
2012	1,612	1,870	1,699	116.0%	105.4%
2013	1,666	1,949	1,775	117.0%	106.6%

(1)



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

Wind generation is generally classified as an “intermittent" or "variable generation" resource with a limited ability to be dispatched. The effective capacity of wind generation can be quantified and modeled using the GE-MARS program similar to conventional fossil-fired power plants. There are various modeling techniques to model wind generation in GE-MARS; the method that ICS has adopted uses historical New York hourly wind farm generation outputs. The most recent full year for which New York wind generation is available is 2012. This data can be scaled to the nameplate capacity and assigned geographically to new and existing wind generation units.

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

- Generation site hourly wind data. This data is translated to power output by using power curves that relate wind speed to the generator’s power output for each of the turbines in the wind farm
- Maintenance cycle and duration
- EFOR (not related to fuel)

In general, effective wind capacity depends primarily on the availability of the wind (fuel); Wind farms in New York on average have annual capacity factors that are on the order of 25% based on their nameplate ratings. A wind plants output can range from close to nameplate under favorable wind conditions to zero when the wind doesn’t blow. On average a wind plants output is higher on average at night and higher output on average in the winter versus the summer.

Another measure of a wind generators contribution to resource adequacy is its effective capacity which is its output peak the during the summer peak hours of 2 PM to 6 PM for the months of June through August. The calculation of the effective capacity value for wind generation in New York based on the 2012 production data was 18%. This means on average about 18% of a wind generator nameplate rating will be available across the summer peak hours.

Appendix D

Glossary of Terms

D. Glossary

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.
Capability Period	Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the NYISO. A summer capability period followed by a winter capability period shall be referred to as a "Capability Year." Each capability period shall consist of on-peak and off-peak periods.
Capacity	The rated continuous load-carrying ability, expressed in megawatts ("MW") or megavolt-amperes ("MVA") of generation, transmission or other electrical equipment.
Contingency	An actual or potential unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
Control Area (CA)	An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.
Demand	The rate at which energy must be generated or otherwise provided to supply an electric power system.
Emergency	Any abnormal system condition that requires automatic or immediate, manual action to prevent or limit loss of transmission facilities or generation resources that could adversely affect the reliability of an electric system.
External Installed Capacity (External ICAP)	Installed capacity from resources located in control areas outside the NYCA that must meet certain NYISO requirements and criteria in order to qualify to supply New York LSEs.
Firm Load	The load of a market participant that is not contractually interruptible. Interruptible Load – The load of a market participant that is contractually interruptible.
Generation	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).
Installed Capacity (ICAP)	Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.
Installed Capacity Requirement (ICR)	The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.

Term	Definition
Installed Reserve Margin (IRM)	That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power used by devices connected to an electrical generating system. (IEEE Power Engineering)
Load Relief	Load reduction accomplished by voltage reduction or load shedding or both. Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.
Load Shedding	The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. Load shall normally all be shed within 5 minutes of the order.
Load Serving Entity (LSE)	In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.
Locational Capacity Requirement (LCR)	Due to transmission constraints, that portion of the NYCA ICAP requirement that must be electrically located within a zone, in order to ensure that sufficient energy and capacity are available in that zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to two transmission constrained zones, New York City and Long Island, and are normally expressed as a percentage of each zone's annual peak load.
New York Control Area (NYCA)	The control area located within New York State which is under the control of the NYISO. See Control Area.
New York Independent System Operator (NYISO)	The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.

Term	Definition
New York State Bulk Power System (NYS Bulk Power System or BPS)	The portion of the bulk power system within the New York control area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.
New York State Reliability Council, LLC (NYSRC)	An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.
New York State (NYS) Transmission System	The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.
Operating Limit	The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.
Operating Procedures	A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.
Operating Reserves	Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load, and can do so within a specified time period.
Reserves	In normal usage, reserve is the amount of capacity available in excess of the demand.
Resource	The total contributions provided by supply-side and demand-side facilities and/or actions.
Stability	The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
Thermal Limit	The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.
Transmission District	The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.

Term	Definition
Transmission Owner	Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/ISO Agreement.
Voltage Limit	The maximum power flow through some particular point in the system considering the application of voltage assessment criteria.
Voltage Reduction	A means of achieving load reduction by reducing customer supply voltage, usually by 3, 5, or 8 percent. If ordered by the NYISO to go into voltage reduction, transmission owner system dispatchers shall immediately comply with that order. Quick response voltage reduction shall normally be accomplished within ten (10) minutes of the order.
Zone	A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal price that is calculated as a weighted average price based on generator LBMPs and generator bus load distribution factors. A "zone" outside the NY control area is referred to as an external zone. Currently New York State is divided into eleven zones, corresponding to ten major transmission interfaces that can become congested.

Appendix E

Evaluation of Wind Modeling in Probabilistic Resource Adequacy Studies

A NYISO WHITE PAPER

June 20, 2013

E. Evaluation of Wind Modeling

I. Objective

The objective of this paper is twofold. The first objective is to study the use of actual wind production data instead of simulated data. The second objective is to examine the effects of modeling wind by selecting randomly a wind profile/shape within a specified time frame or window. This is a feature which is now available in the GE MARS model.

II. Background

To date, wind modeling in the IRM studies has been based on 2002 simulated wind plant shapes that were developed by AWS TruePower for the General Electric Wind Study. These wind shapes were developed from hourly wind readings taken at a given altitude, along with other meteorological information, and forecasting the hourly electric output of a modern wind turbine. Of the 100+ sites studied, the NYISO has used the output of 33 of these sites around NY to simulate output of installed wind farms. There is now available actual wind production data from NYCA generators that can be compared to the simulated data. Also, GE has added functionality to the MARS model which allows for the daily wind shape for each day during a simulation year to be modeled randomly. However, the MARS model allows only a single year wind shape to be input for this purpose.

III. Using Actual NYCA Wind Production Data for Modeling Wind

Currently, the MARS model uses an hourly load shape based on 2002 hourly loads and simulated wind generation shapes that were based on 2002 meteorological data compiled for the NYSERDA/NYISO wind study conducted by GE Energy. Simulated data was used to ensure the alignment of load and wind. Hourly simulated wind megawatt output by site was also provided for years 2001, 2002, 2003, and for the summer months of years 1999 and 2000.

Over the last several years, the NYISO has collected hourly wind generation output, with an installed base that now exceeds 1,600 MW. The first year that the installed base exceeded a 1,000 MW was 2009 with an installed base of 1,267 MW. The implicit summer capacity value is defined as the wind generation capacity factor between the hours of 1400 and 1800 for the summer months of June through August. The shapes developed for the wind study are based on summer capacity values in the 10% to 11% range. Actual wind generation for the years 2009 through 2012 have resulted in much higher capacity values. Table I presents the summer capacity value or UCAP values experienced for the years 2009 through 2012.

Table I: Summer Wind Capacity Values

Year	Capacity Value
2009	14.4%
2010	15.2%
2011	18.4%
2012	18.2%

The increasing numbers can be attributed to two factors. One is difference in wind conditions from year-to-year and the other is that new wind turbines entering service are larger and are designed with hubs that are much higher in the air. The result is that more efficient wind plants capture more of the available wind and convert it into electricity. NYCA capacity has increased by approximately 10% between 2010 and 2011 and remained at that level through 2012.

To obtain some insights as to how wind conditions in NY varied during this timeframe, AWS TruePower was asked if they could provide any insights into wind conditions based on the wind plants they monitor in NY. They indicated that just looking at average wind speed could provide misleading results as to potential changes in wind generation potential from year-to-year. Their initial thoughts were that the best approach for monitoring NY wind conditions would be to monitor wind plant performance or output year-to-year. However, there is very limited history available at this point. They were able to provide the NYISO aggregate wind plant capacity factors for the wind plants they monitor in NY for four seasons and the years 2010 through 2012. Table II presents the results provided by AWS TruePower/MESO.

Table II: Seasonal Wind Capacity Factors

For Plants Monitored by AWS TruePower

Season/Year	2010	2011	2012	Mean	Standard Deviation
Winter (Dec-Feb)	23.3	22.8	32.7	27.0	5.8
Spring (Mar-May)	21.4	21.1	24.1	22.2	3.9
Summer (Jun-Aug)	16.4	16.0	15.8	16.1	2.4
Autumn (Sep-Nov)	27.2	24.7	21.5	24.5	5.4

The data provided by AWS TruePower/MESO paints a slightly different picture than the capacity value data as to year-to-year variation in wind generator output. This makes the point that you need to look at how the average wind conditions distribute over the hours of the day. In addition, it also shows that wind conditions are at a minimum in the summer and that the summer has the least year-to-year variability. It also shows, based on wind plant capacity factors and the AWS monitored plants, that 2012 had below average wind conditions which is the opposite conclusion that could be drawn from the NYISO capacity value data.Given that actual wind generation data is now available for NY, this suggests that, at a minimum, updating the wind shapes to capture the NYISO's current fleet of wind generation units should be investigated. The first step was to plot the average summer load shape that results from using the 2002 wind shape for simulating NYCA wind plant output versus the 2012 shape, which is the most recent year of wind generation available for the NYCA. Figure 1 presents those results.

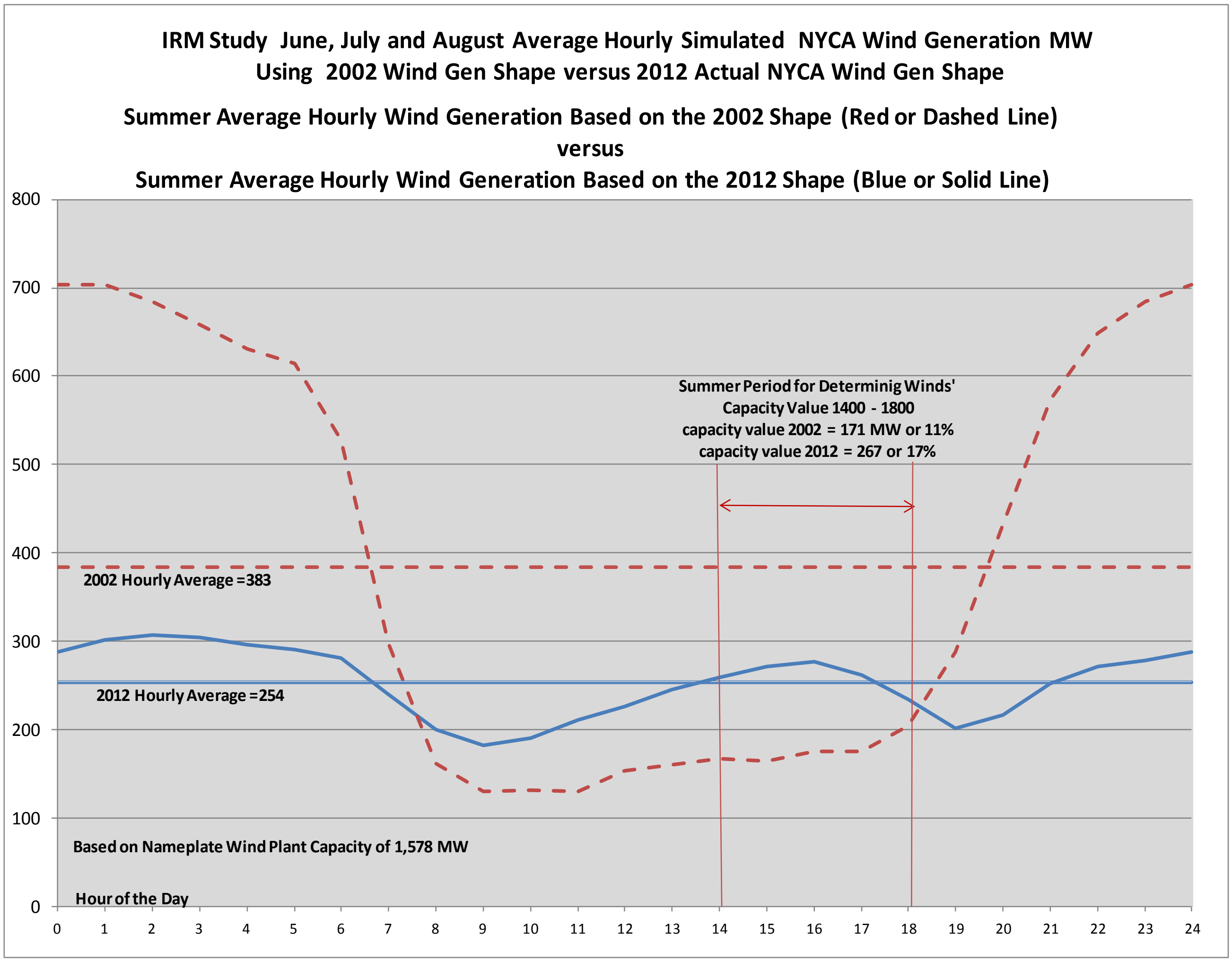


Figure 1: Plot of Average Daily Wind Generation

The plot of the average summer hourly wind generation based on the 2002 shape versus 2012 shape presents results that are very different. The 2012 shape is based on actual NYISO wind plant production, while the 2002 shape is derived from simulated wind plant data that was developed for the NYSERDA/NYISO wind study published in 2005. The shape based on actual 2012 wind plant generation results is a much flatter load shape with a much lower average hourly wind generation (254 MW VS. 383 MW), but a higher summer capacity value (267 MW VS 171 MW), which on average results in an additional 96 MW of wind generation being available in the 1400 to 1800 hour timeframe.

The wind shape in the final 2013/2014 IRM base case was replaced with the 2012 shape. The following results are based on the final IRM base case of 17.1%. Here the IRM is 17.1% with LCRs of 83.7% for zone J and 102.0% for zone K. Starting at an LOLE of 0.100 days/year under the above conditions, the 2002 simulated wind data was replaced by 2012 wind production data. The LOLE improved to a value of 0.096

days/year. Rebalancing upstate zones to achieve 0.100 LOLE dropped the IRM from17.10% to 16.85%) or an increase in load carrying capability of approximately 80 MW.

The first observation is that, even though the 2002 shape results in a much higher average overall hourly wind generation than the 2012, the 2012 which has a higher capacity value results in a decrease in LOLE. The decrease in LOLE translates to a 0.25% drop in IRM and an 80 MW benefit or increase in load carrying capability. These results are consistent with the difference in load shape. The resulting conclusion is that the shape for modeling wind generation derived from actual NYISO wind generation production should replace that currently being used.

A sensitivity was conducted where the wind generation for the peak week of 2012 was aligned with peak load week of 2002. No change in LOLE was observed which reinforces the absence of correlation observed between wind generation and load.

IV. Random Wind Shape Modeling

A new feature that has been added to MARS allows for a daily wind shape to be selected randomly within a range of daily wind shapes. In addition to investigating the new feature, a secondary question was to determine for the purpose of modeling wind generation in reliability studies whether the year selected for modeling wind generation needed to be aligned with or the same as the year selected to model the load shape. The premise of using this feature is that the relationship between wind generation and load during peak hours has very little correlation and essentially behaves as a random variable. Therefore, having the year used for modeling load aligned with the year for simulating wind is not essential. The result of very little correlation would also be an important consideration in the use of the new feature that allows the use of different load shapes for each load forecasting uncertainty (LFU) bin. Since MARS allows only one wind shape to be input, this would eliminate any concern that it is essential to have the wind and load shapes based on the same year. The NYISO analyzed wind data for the years 2009 through 2012 to determine the correlation between load and wind generation. Figure 2 below presents a plot of wind generation as a per unit of nameplate and load as a per unit of the weather normalized peak for the top thirty daily peaks for each of the years. The top 30 peak days are analyzed because of their importance from an LOLE perspective as determined in the SCR study.

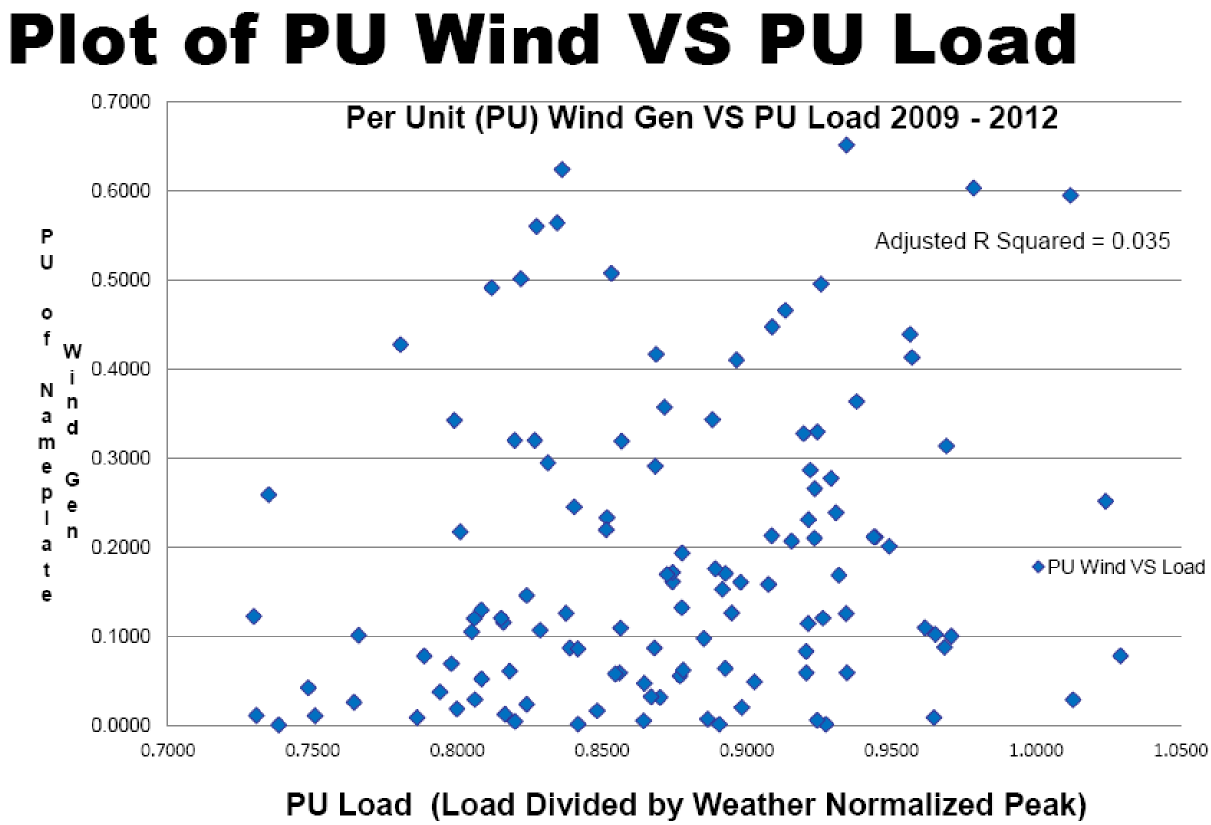


Figure 2: Per Unit Wind versus Load

This data was also analyzed on a per year-by-year basis showing actual MW and presented to the ICS at their January 25, 2013 meeting. The full presentation is included in this document as Appendix A. The conclusion from this analysis is that there is essentially zero correlation between the wind generation and load, and therefore having the year for modeling loads and the year for simulating wind generation aligned is not essential for MARS modeling. This conclusion is based on the lack of relationship observed from actual NYISO wind generation and load. It also means that using the new feature in MARS, which allows daily wind shapes to be selected randomly, can be run independently of whatever year that is being used to model the loads.

V. Random Wind Modeling Test Results

GE added new functionality as described previously to MARS that allows for wind generation to be modeled randomly by selecting a wind shape for a particular day randomly within a specified window of day shapes. Also, GE had added the capability to utilize different year load shapes for each load forecasting uncertainty (LFU) bin. The underlying premise of being able to use this new wind feature is that the correlation between wind and load is statistically equivalent to zero. Examination presented above revealed that the daily peak hour wind generation does not correlate strongly, if at all, with the daily load. Since the year used in modeling wind doesn't need to be cotemporaneous with the year used for load modeling, the random feature of MARS for modeling wind could be used and should be investigated. It also means that this new feature could be used with multiple year load shapes.

Using the new feature in MARS and starting from the IRM base case updated with the 2012 wind data, the model was allowed to randomly pick a daily load shape up to 5 days before and 5 days after the actual calendar day for each plant. Turning on this random feature caused the LOLE to remain unchanged at 0.100 days/year. An additional analysis was performed allowing a +/- 10 day window around each day. Again, the results were unchanged.

These results are not surprising given how the random modeling feature functions in MARS. It samples shapes from the specified window whether it be +/- 5 or +/- 10 days and in effect creates an average or smoothed profile for the year from within which it is sampling. However, the averages, in particular the capacity value between the hours of 1400 and 1800 for June, July and August remains essentially unchanged for the sampling windows selected which explains why no material change in LOLE is observed when the random feature is turned on.

It would preferable that the sampling of wind shapes be across years rather than within years. This method would capture the variations in capacity values and capacity factors. This concept has been discussed with GE Energy, who owns and maintains MARS model, as a possible future enhancement.

VI. Conclusions

Comparing the 2002 simulated wind generation versus the one based on 2012 actual wind generation resulted in entirely different average shapes. From a reliability modeling perspective, the shape that results in a higher summer capacity value will provide the greatest reliability benefit. The random feature in MARS did not result in any change in LOLE since it samples shapes from a single year that is input and therefore no meaningful change in capacity value resulted for the sampling windows selected. The primary conclusions from the analysis presented herein are: 1) The correlation between load and wind generation is statistically not different from zero; 2) the need to align the particular year used to model load and the year to model the wind generation is not a critical consideration for LOLE modeling; 3) being able to only input one wind shape per wind generation unit is no longer a limitation in modeling multiple load shapes; and 4) the random feature in MARS works as designed but does not provide any additional value for conducting reliability simulations as currently designed.

VII. Recommendations

1. The NYISO is recommending that the modeling of wind for the 2014 IRM study should be based on a wind shape derived from actual NYCA wind generation.

2. The analysis presented herein has demonstrated that the correlation between load and wind generation is not statistically significant and that wind generation from hour-to-hour and day-to-day exhibits the time series characteristics of a random walk. A random walk is defined as a process where the current value of a variable is composed of the past value plus an error term defined as white noise. The implication of a process of this type is that the best prediction for the next period is the current value. Therefore, the NYISO is recommending that the 2014 IRM study model wind generation based on wind generation from the year 2012. The 2015 IRM study would base its simulation of wind generation on 2013 actual wind generation and so on for the foreseeable future. Use of the most current year of data (e.g., 2012) would capture the current mix of NYISO wind plants.

3. The NYISO is recommending that the new random modeling feature for wind not be adopted at this time because, based on the NYISO's testing, it doesn't appear to provide any additional information for conducting reliability simulations and would require further evaluation.

4. The random modeling feature should be revisited at the time when this functionality in MARS is modified to sample from wind generation across years rather than within a specific year.

5. Given the fact that only one wind shape year for each wind generating unit can be input into MARS, the NYISO has concluded that this fact should no longer be a consideration or a barrier to adopting the multiple load shape functionality now available in MARS.

6. At the June 5, 2013 New York State Reliability Council Meeting Installed Capacity Subcommittee meeting (ICS) the NYISO was asked to conduct some additional sensitivities using the 2012 wind plant data but run it with the version that incorporates the multiple load shapes. One sensitivity should be conducted with the random feature turned on and another sensitivity run with the feature turned off. The results of those sensitivities will be reported at the next ICS meeting scheduled for June 26, 2013.

Information on the sensitivity can be found at the NYSRC website in the minutes for ICS meeting # 149.

Appendix F

Modeling Multiple Load Shapes

A NYISO WHITE PAPER

F. Modeling Multiple Load Shapes

Modeling Multiple Load Shapes in Resource Adequacy Studies

June 19, 2013

I. Objective

The objective of this report is to document the results of our efforts in utilizing a new feature in MARs that allows the use of multiple load shapes. Part of this effort was to establish criteria for choosing the appropriate load shape to include in each of the seven Load Forecast Uncertainty (LFU) bins.

Then, after choosing the appropriate load shapes, efforts were needed to incorporate the historic demand response into the external control area load shapes and to align them to the NYISO top three peak days.

II. Background

In IRM studies to date, hourly load modeling was restricted to a shape based on a single year. NYSIO attempted to use a year based on the hourly averages of several years, but this was ultimately rejected. Average load shapes did not capture the impact of heat waves on the system[6]. If the average load shape had five days within 90% of the peak, what would happen in a year where there were considerably more days near the peak? For example, the year 2002 had 13 days where the daily peak load was within 90% of the system peak. Using the five day case would result in an under built system and an artificially low IRM, unable to withstand a 2002 type year. To avoid this, average load shapes were no longer considered, and the analysis turned to using a single historic load shape year.

The use of the single load shape year of 2002 however raised concerns that it might be a too conservative study assumption. The LFU modeling accounts for weather conditions above and below the expected or design weather conditions by

[6] The reference to heat waves is indirectly related to the number of days where the system peak is within 90% of its actual peak.

increasing the peak load forecast based on multipliers which are derived from how the power system responds to varying temperature and humidity conditions.

Each of the LFU bins has a probability assigned to it such that the weighted average of each of the bin peak loads summed to the expected or design peak load forecast. These probabilities are actually applied to the LOLE calculated for each LFU bin to calculate an overall LOLE. For the upper LFU bin or extreme weather conditions, the much higher peak load in conjunction with a load shape which had an above average number of days near the peak would compound the load forecast uncertainty and result in what was thought to be by some an overly conservative model. The new modeling feature offers the ability to select appropriate load shapes for each LFU bin. This functionality allows for the selection of load shape year for each LFU bin which more closely aligns with what might be expected. In this way, the concern of the compounding of uncertainty can be mitigated and a model that appears to be overly conservative avoided.

III. Assigning Load Shapes to LFU Bins

The MARS model for calculating LOLE has the capability to probabilistically evaluate the impact of loads that exceed forecast or are less than forecast based on a load forecast uncertainty (LFU) distribution. The probability distribution presented in Table 1 is divided into seven uncertainty bins as a percent of the forecast with the following probabilities:

Table 1

LFU Probability Distribution

Bin	Prob.	Cum Prob.	Bin Mid Point	Peak as % of the Design Day
1	0.0062	0.0062	0.0031	85.2%
2	0.0606	0.0668	0.0365	90.0%
3	0.2417	0.3085	0.1877	95.0%
4	0.3830	0.6915	0.5000	100.00%
5	0.2417	0.9332	0.8124	104.7%
6	0.0606	0.9938	0.9635	109.0%
7	0.0062	1.0000	0.9969	112. 5%
sum	1.0000			

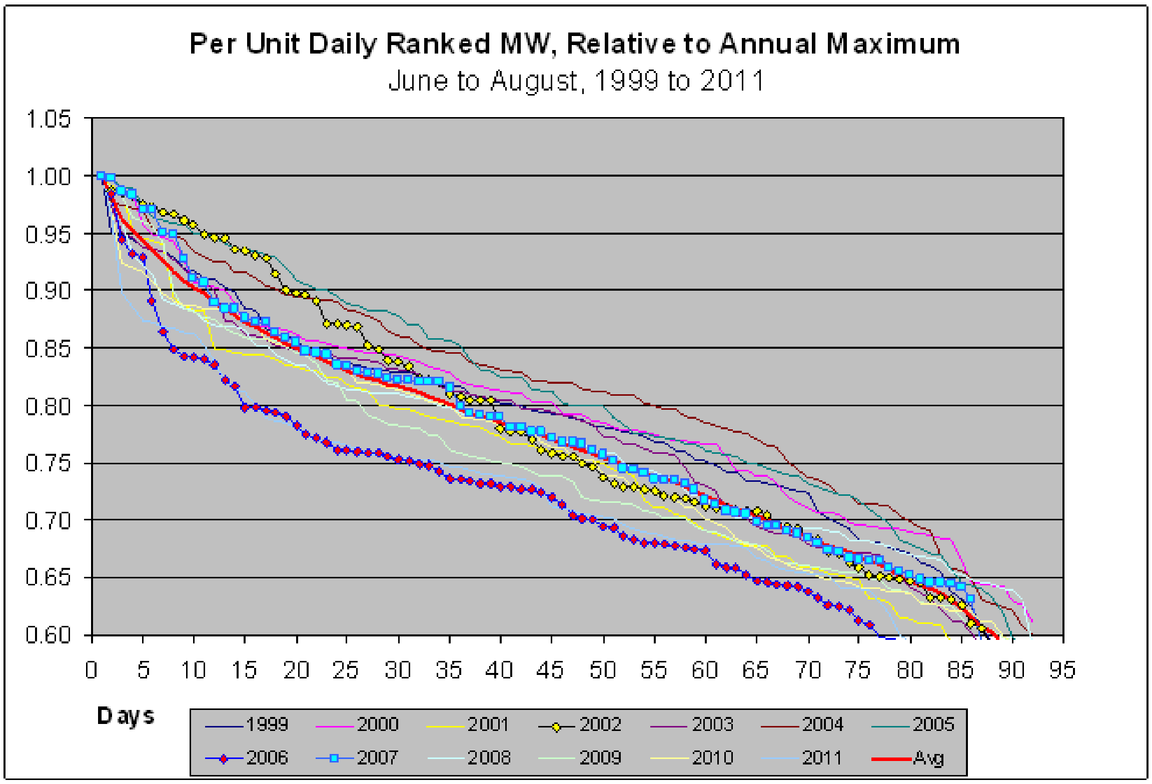
Another key aspect of the impact of loads on reliability is the overall load shape. It is known that a flatter load shape will require a higher installed reserve margin than a more peaked load shape. For the flatter shape you have more hours or daily peaks occurring at higher load levels than for the more peaked shape. The result is more hours with higher potential for a loss-of-load (LOL) event in the flatter shape versus the more peaked shape. The relative shape of the load profile as a per unit of the peak is an important risk factor that needs to be considered in establishing an installed reserve margin.

Figure I presents a daily peak load duration curve as a per unit of the daily annual maximum peak load for the top 95 days of the year or less for the years 1999 to

2011. The curves with the higher per unit values would be considered a flatter load shape curve. The ones with lower per unit values would be considered a more peaked load shape curve from an LOLE perspective. However, it should be noted that these per unit values are based on the annual peak which could have been experienced at weather conditions that were considerably above or below the design conditions.

Figure 1

Multi-Year Load Duration Curve



Prior to the release of MARS version 3.15, the model only had the capability to input one load shape. As a result, historical data was analyzed and load shape which was flatter than the average shape was used to capture the impact of the risk exposure for the years that would have a higher number or duration of peak days closer to the peak than a year that was average. This turned out to be the year 2002. However, this engendered significant discussion as to whether the year chosen was too conservative or should an average year be used. As discussed earlier, there is a risk if the load shape that is included in the base case does not have enough hours at higher loads. An average load shape could not capture this risk. The new MARS version release 3.16 introduced the capability to utilize different load shapes in the LFU bins, potentially solving this problem.

In order to use this capability a process will need to be developed to identify and assign load shapes to the LFU bins. The process must rank historical load shapes by their relation to the design conditions and then further classify them by the number of times the shape stresses the system. A metric was developed that took annual peak and divided it by the weather adjusted peak for the year. In addition to the data for the years 1999 to 2011, data for 2012 is now available to analyze. This metric indicates whether an experienced peak was close to design, above design or below design conditions. This metric can be rank ordered and provides an indication of which LFU bin a particular year could be assigned to. Table 2 presents the results of that process which rank ordered from the lowest to highest per unit value.

Table 2

Rank Order of the Annual Peak as a Per Unit (PU) of the Design Peak

Lowest to Highest

Rank or Bin	Year	Annual Peak As a Per Unit of Design
1	2004	0.91
2	2009	0.94
3	2000	0.95
4	2007	0.97
5	2008	0.98
6	2003	0.99
7	2005	1.00
8	2012	1.00
9	1999	1.03
10	2002	1.03
11	2001	1.05
12	2010	1.06
13	2006	1.08
14	2011	1.08

The annual peaks as a per unit (PU) of the weather normalized peak or design peak range between 90% and 108% of the expected peak load. The observed data covers the range from LFU bin 2 to approximately LFU bin 6.

The next step was to develop a metric that relates to the number of times the system is stressed, or the relative "peakedness" of the load shapes that were observed in each of the bins. The SCR study indicated that from an LOLE perspective it was the top thirty peak days where the greatest potential for loss-of-load events existed. To measure the relative peakedness of the different years of load shapes a metric which measures the magnitude of daily peaks relative to the annual peak was developed. This metric divides the annual peak into the daily peak for the top thirty days to create a per unit (PU) measure of the daily peak relative to the annual peak. Creating a metric that is a PU of the annual peak is consistent with how the shapes are input into MARS. The thirty days of PU values are then averaged together. A higher thirty day average implies that a particular year had relatively more load days that were closer to the peak than a year with a lower average. This measure, however, does not recognize whether the year had weather conditions that exceeded or were below design conditions. Therefore, the thirty day averages were mapped into the rank or bins that were defined by taking the weather normalized peaks and dividing it into the annual peak for a given year. Table 3 presents the mapping of the thirty day PU average with the PU of the annual peak divided by the normalized peak for that year.

Table 3

PU Annual Peak Ranking and Associated Load Shape PU

Rank or Bin	Year	Annual Peak As a Per Unit of Design	Avg. of the Thirty Top Peak Days as PU of the Annual Peak	Cumulative Probability
1	2004	0.91	0.92	0.071
2	2009	0.94	0.87	0.143
3	2000	0.94	0.90	0.214
4	2007	0.97	0.89	0.286
5	2008	0.98	0.87	0.357
6	2003	0.99	0.88	0.429
7	2005	1.00	0.93	0.500
8	2012	1.00	0.90	0.571
9	1999	1.03	0.88	0.643
10	2002	1.03	0.92	0.714
11	2001	1.05	0.87	0.786
12	2010	1.06	0.87	0.857
13	2006	1.08	0.87	0.929
14	2011	1.08	0.83	1.000
Average		1.00	0.89	

The average for the annual peaks as a PU of the normalized peaks is 1.0 which is what would be expected. The average of thirty day PU is 0.89 which aligns with year 2007. However, year 2007 was 3% below design conditions. If we define those PU that are above the average of 0.89 as flatter load shapes and those that were below 0.89 as more peaked, we see that, out of 14 observations, 5 were above the average or could be characterized as flatter shapes while 8 were below the average or relatively more peaked shape. It appears the highest bins tend to be more peaked while the middle set of bins tend vary above and just below the average with the higher PU average occurring close to design or above. Below design conditions you have a mix of the flatter and more peaked shapes. The end result is, that as defined by the thirty highest PU average days, the flatter shapes and the more peaked shapes are distributed at, above and below design conditions except the more peaked shapes tend to dominate at the upper extremes but are also observed at below design conditions. The conclusion is that there is no straight forward or clear cut way to statistically assign shapes to the LFU bins. Overall, the correlation of the relative flatness of a curve year and its exposure to above or below design conditions is not clear except at the extremes. This makes it difficult to accurately assess the year shapes between the middle and the extreme bin. Over time and given the accumulation of more data, a statistical based method for assigning load year shape years to LFU bins could emerge.

Ideally, if there were sufficient observations and MARS was configured appropriately, the best approach would to calculate the probability of the occurrence of load shapes by LFU bins and weight the LOLE results for each shape within an LFU bin and then weight the LOLE results across the LFU bins. Unfortunately, there aren't sufficient observations to do this and MARS would need to be restructured accordingly. Therefore, the NYISO is proposing to use a combination of 2007 which was tested as a sensitivity in the 2013 IRM study to represent the average or typical shape, the 2002 to capture risk associated with a flatter load shape and the shape that has been used in IRM studies for the last several years and the 2006 shape to represent a more peaked or have a PU shape less than the average shape associated with extreme conditions. In addition, this keeps the number year shapes that have to be processed to a more manageable level.

IV. Results of Using Multiple Load Shapes

Table 4 presents the combination of load shapes that the NYISO tested by LFU bin. These shapes are selected such that they capture the impact of the typical year shape, the risk of year shape were the occurrence of the number of peak load days as a per unit of the annual peak load is higher than the expected shape and a year shape were the occurrences of the number of peak load days as a per unit of the annual peak is less than the expected year. Two cases were tested. Case one was a combination of year 2007 as the typical or base shape being assigned to LFU bins 1 through 5. Year 2002 is assigned to bin 6 which gives it weight of approximate 6.1%. Load shape year 2006 was assigned to LFU bin 7 in order to account for the load shape at extreme conditions which would most likely be more peaked and below average based on the PU ranking. The second case was with 2002 in bin 5 and 6 instead of 2007 in bin 5 which gives 2002 a weight of approximately 30.2%.

Table 4

Load Shape Year by LFU Bin and Associated Probability

Bin	Prob.	Cum Prob.	Peak as % of the Design Day	Proposed Load Shape By LFU Bin
1	0.0062	0.0062	85.2%	2007
2	0.0606	0.0668	90.0%	2007
3	0.2417	0.3085	95.0%	2007
4	0.3830	0.6915	100.0%	2007
5	0.2417	0.9332	104.7%	2007 or 2002
6	0.0606	0.9938	109.0%	2002
7	0.0062	1.0000	112. 5%	2006
sum	1.0000			

Because the load shapes of 2007 and 2006 when combined with 2002 in the aggregate represent a less conservative shape than 2002 by itself, it was observed that the LOLE's of the external areas as well NYCA had dropped below 0.100 days/year. Policy 5-7 specifies that external control areas whose LOLEs are below the 0.100 days/year criteria need to be adjusted back to at least 0.100. Table 5 below shows the LOLE results for the IRM base case, the initial multi-load shape case, and the final adjusted multi-load shape case. It should be noted such an adjustment for the external areas was not made for the sensitivity contained in the 2013 IRM study. As a result, a large part of the 2.7% reduction observed in the IRM for the 2007 load shape sensitivity conducted for the 2013 IRM study can most likely be attributed to increased assistance from neighboring areas whose resulting LOLE was better than 0.1.

Table 5

Multiple Load Shape LOLE Results

Control Area	IRM base case	Initial MLS* case	Final MLS* case
New York	0.100	0.065	0.100
PJM	0.424	0.291	0.306
New England	0.104	0.044	0.100
Ontario	0.104	0.033	0.100
Quebec	0.100	0.061	0.103

*Multiple Load Shape

Table 6 presents the LOLE results for the 2013 IRM study base case versus the final Multiple-Load Shape (MLS) for case 1 by load level or LFU bin with NYCA at 0.100 days/year LOLE.

Table 6

Load Level Risk for NYCA

LFU (Bin)	Base Case LOLE	MLS LOLE
1	0.0010	0.0000
2	0.0010	0.0010
3	0.0020	0.0010
4	0.0130	0.0010
5	0.0130	0.0120
6	0.6780	1.2520
7	5.6710	3.3410

Finally, the effect on the IRM can be estimated using the "sensitivity" method utilized by the ICS. Once the external control areas are at or above the 0.100 LOLE criteria, capacity can be removed from all zones within NYCA, until the NYCA LOLE returns to the 0.100 days/year criterion. Table 7 shows these margin results indicating that the IRM would drop on the order of 0.6% for case 1 and 0.5% drop for case 2 due to the use of the Multiple Load Shape modeling when compared to the 2013 IRM base case.

Table 7

Multiple Load Shape Margin Results

Area	**Base Case Margin**	**MLS Case 1 Margin**	**MLS Case 2 Margin**
NYCA	**17.1%**	16.5%	16.6%
NYC	**83.7%**	83.2%	83.3%
LI	**102.0%**	101.4%	101.5%

V. Conclusion

The multiple load shape functionality contained in the MARS model has been found to be functioning properly and as designed. Although there was not a direct way to map load shapes into LFU bins on a statistical or probabilistic basis, the NYISO concluded that a good approach would be to use a combination of load shape years 2007, 2002 and 2006. Load shape year 2007 which had been tested as a sensitivity last year is selected to represent the average or typical load shape. Load shape year 2002, which has been the study load shape for the last several years, is selected to represent a flatter shape or a shape with a higher number of days of risk exposure than the typical. Load shape year 2006 to capture a more peaked shape which would most likely be experienced at the extremes. The combination of these load shapes on a weighted basis, represent a less conservative load shape than using 2002 by itself. In addition, the use of just three load shape years to adequately model the LOLE risk resulting from varying load shapes will be much easier to maintain and update because the number of different load shape years is kept to reasonable number.

The use of the multiple load shape approach resulted in a reduction in the IRM as discussed above by 0.6% for case 1 and 0.5% for case 2 when compared to the 2013 IRM base case. Also, the analysis shows that the majority of the risk resides in the LFU bins at the higher load levels. This isn't surprising given that loss-of-load events are rare (extreme events) and this analysis is about adequately modeling the risk associated with those extreme events. These LOLE events are most likely to be observed when the system is most stressed which includes the higher loads or LFU bins. At an LOLE of 0.1 which was derived from 1,000 years of simulations or 36,500 daily peaks one would expect only about 100 loss-of-load events on average.

VI. Recommendation

The NYISO is recommending that multiple load shape modeling be implemented for the upcoming 2014 IRM study using load shape years 2007 to represent the typical year, 2002 (much flatter than typical) and 2006 (more peaked than typical).