2nd Draft – 11/17/2021 ICS Meeting Appendices

New York Control Area Installed Capacity Requirement

For the Period May 2022 To April 2023

December 3, 2021

New York State Reliability Council, LLC
Installed Capacity Subcommittee

Table of Contents

Table of Tables & Figures

Appendices

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 New York Control Area (NYCA) Installed Reserve Margin (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, the source for the study assumptions, and where the assumptions are described in Appendix A. Finally, section A.3 compares the assumptions used in the 2021 and 2022 IRM reports.

Figure A.1 NYCA ICAP Modeling

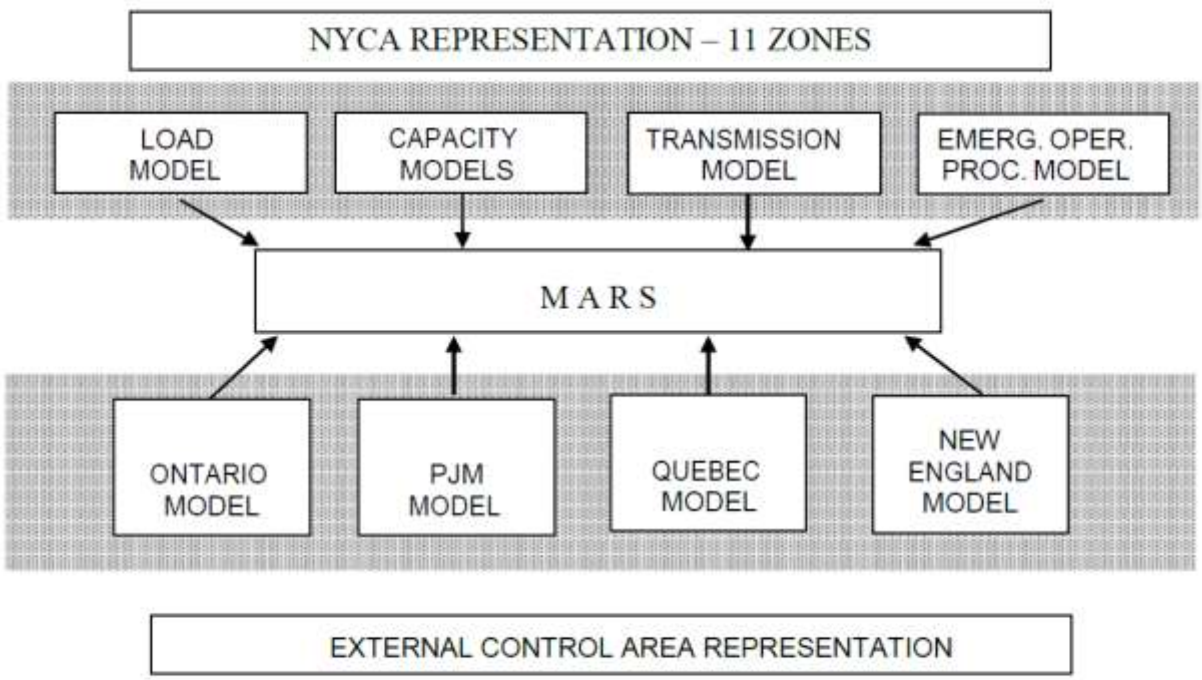


Table A.1 Modeling Details

#	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
3	Zone Capacity Models	Generator models for each generating in Zone Generator availability Unit ratings	GADS data 2021 Gold 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 items 9-12 in this table	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 weather 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] 2021 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 using 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 of the years. 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

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours} = 0.0002$$

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 261 replications to converge to a standard error of 0.05 and required 1,140 replications to converge to a standard error of 0.025. For our cases, the model was run to 2,750 replications at which point the daily LOLE of 0.100 days/year for NYCA was met with a standard error less than 0.025. The confidence interval at this point ranges from 19.0% to 19.2%. It should be recognized that an IRM of 19.1% 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 4.2.1765 of the GE-MARS software program. This version has been benchmark tested by the NYISO.

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

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the ISO reviews the data and either confirms that it is correct as is or institutes a correction. The results of this data scrub are shown in 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 2021 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and the preliminary locational installed capacity requirements. The IRM/preliminary LCR characteristic consists of a curve function, "a knee of the curve" and straight-line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tan 45 inflection point calculation. Inclusion of IRM/preliminary LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tan 45 calculation.

The procedure for determining the best fit curve function used for the calculation of the Tan 45 inflection point to define the base case requirement is based on the following methodology:

1) Start with all points on IRM/preliminary LCR Characteristic.
2) Develop regression curve equations for all different point to point segments consisting of at least four consecutive points.
3) Rank all the regression curve equations based on the following:
   - Sort regression equations with highest R2.
   - Remove any equations which show a negative coefficient in the first term. This is the constant labeled 'a' in the quadratic equation: ax2+bx+c
   - Ensure calculated IRM is within the selected point pair range, i.e., if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid.
   - In addition, there must be at least one statewide reserve margin point to the left and right of the calculated tan 45 point.
   - ~~Ensure~~ Determine that the calculated IRM and corresponding preliminary LCR do not violate the 0.1 LOLE criteria.
   - Check results to ~~ensure~~ determine that they are consistent with visual inspection methodology used in past years' studies.

This approach identifies the quadratic curve functions with highest R^2 correlations as the basis for the Tan 45 calculation. The final IRM is obtained by averaging the Tan 45 IRM points of the NYC and LI curves. The Tan 45 points are determined by solving for the first derivatives of each of the "best fit" quadratic functions as a slope of -1. Lastly, the resulting preliminary LCR values are identified.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A.3 Load Model

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
Peak Load	October 1, 2020 NYCA: NYCA: 32,243.0 MW NYC: 11,232.3 MW LI: 5,282.0 MW G-J: 15,385.3 M	October 1, 2021 NYCA: NYCA: 32,138.6 MW NYC: 10,943.7 MW LI: 5,158.5 MW G-J: 15,193.4 MW	Forecast based on examination of 2021 weather normalized peaks, 2022 economic and expected weather projections, and Transmission Owner projections.
Load Shape Model	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	No Change
Load Uncertainty Model	Statewide and zonal models updated to reflect current data	Statewide and zonal models updated to reflect current data	Updated from 2021 IRM. Based on TO and NYISO data and analyses.

A.3.2 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 NYSIO and Transmission Owners developed regression models to evaluate the relationship between regional weather and Transmission District summer weekday peak loads, using data from the summer of 2021 and other recent summers as needed. The resulting estimates of weather response (i.e., the MW increase in load per degree of increase in the weather variable) by Transmission District were used to develop 2021 Transmission District weather adjustments, which normalize the peaks to typical summer peak weather conditions. For purposes of the IRM and ICAP forecasts, the NYISO evaluates the system peak load that occurs during non-holiday weekdays in July and August. In 2021, the system peak load during this period was on August 26th, Hour Beginning 16. The system peak load of 30,296.6 MW is shown by Transmission District in Table A.4 (col. 2). The total MW adjustment (col. 3), including the weather adjustment, and estimated demand response, self-generation, and municipal load impacts were added to the system peak, producing the 2021 weather normalized peak load of 31,557.6 MW (col. 4).

Transmission Owners developed updated estimates of the Regional Load Growth Factor (RLGF) for their territories. The RLGF represents the ratio of forecasted 2022 summer peak load to the 2021 weather normalized peak, based on the anticipated load growth in the territory. The final RLGFs (col. 5) were reviewed by the NYISO and discussed with the Transmission Owners as needed. The 2022 forecast before adjustments (col. 6) is the product of the 2021 weather normalized peaks and the RLGFs. Large load adjustments are added in column 7, reflecting anticipated load growth from specific projects. The resulting sum (col. 8) represents the 2022 IRM forecast of 31,980.4 MW before BTM:NG adjustments. This forecast is 197.6 MW lower than the 2022 forecast from the 2021 Gold Book. The lower forecasted value is primarily attributed to the slower than expected ongoing recovery of load levels from the COVID-19 pandemic in New York City. For purposes of modeling in the IRM study, the forecast of BTM:NG (Behind-the-Meter Net Generation) resource load is added in column 9, producing a total forecast of 32,138.6 MW inclusive of BTM:NG load (col. 10).

The Locality forecasts are reported in the second table below. These forecasts are the product of the weather normalized coincident peak load in the Locality, the non-coincident to coincident peak (NCP to CP) ratio in the Locality, and the RLGF(s) of the Transmission District(s) in the Locality. The NCP to CP ratios by Locality were calculated using the historical 15-year ratio (excluding outlier years). The Locality forecasts of 10,943.7 MW (Zone J Locality), 5,158.5 (Zone K Locality), and 15,193.4 MW (G-to-J Locality), inclusive of BTM:NG loads, are shown in column 11.

The third table below shows the 2022 non-coincident peak load forecast by Zone. First, the Zonal coincident peak forecasts were calculated by sharing out the Transmission District peak forecasts to their Zonal components, using historical shares derived from peak and near-peak load hours over the most recent five summers. Second, the Zonal non-coincident peak forecasts were calculated by multiplying the coincident peak forecast by the Zonal NCP to CP ratio. The Zonal forecasts shown below include the projected impacts of BTM:NG and large load projects.

The peak load forecasts, along with the regression models, weather adjustments, RLGFs, and NCP to CP ratios used to derive them were discussed and approved by the NYISO Load Forecasting Task Force (LFTF) and the NYSRC Installed Capacity Subcommittee (ICS). The LFTF recommends the 2022 peak load forecast to the NYSRC for its use in the 2022 IRM study.

Table A.4 2022 Final NYCA Peak Load Forecast

2022 IRM Forecast									
(1)	(2)	(3)	(4) = (2) + (3)	(5)	(6) = (4) * (5)	(7)	(8) = (6) + (7)	(9)	(10) = (8) + (9)
Transmission District	2021 Actual MW, 8/26/2021 HB 16	Total Adjustment (Demand Response + Self Gen + Muni + Wthr Adjustment) MW	2021 Weather Normalized MW	Regional Load Growth Factor	2022 Forecast, Before Adjustments MW	Large Load Forecast MW	2022 IRM Forecast, With Large Load Forecast, Before BTM:NG Adjustment MW	BTM:NG Forecast MW	TO Forecast, With Large Load and BTM:NG Forecast MW
Con Edison	11,588.1	624.3	12,212.4	1.0187	12,440.4	0.0	12,440.4	22.1	12,462.5
Cen Hudson	1,053.7	31.1	1,084.8	0.9950	1,079.4	0.0	1,079.4	0.0	1,079.4
LIPA	5,018.4	121.4	5,139.8	0.9800	5,037.0	0.0	5,037.0	39.8	5,076.8
Nat. Grid	6,701.3	298.5	6,999.8	1.0000	6,999.8	55.0	7,054.8	1.7	7,056.5
NYPA	357.3	-1.4	355.9	1.2897	459.0	0.0	459.0	0.0	459.0
NYSEG	2,991.9	83.2	3,075.1	1.0020	3,081.3	140.0	3,221.3	42.1	3,263.4
O&R	1,038.2	78.8	1,117.0	1.0045	1,122.0	0.0	1,122.0	0.0	1,122.0
RG&E	1,547.7	25.1	1,572.8	0.9960	1,566.5	0.0	1,566.5	52.5	1,619.0
NYCA	30,296.6	1,261.0	31,557.6		31,785.4	195.0	31,980.4	158.2	32,138.6
				2022 Forecast from 2021 Gold Book			32,178.0		
				Change from 2021 Gold Book			-197.6		

Table A.5 2022 Final NYCA Peak Load Forecast (continued)

2022 IRM Forecast - Locality										
(1)	(2)	(3)	(4)	(5) = (3) * (4)	(6)	(7) = (5) + (6)	(8)	(9) = (7) - (8)	(10)	(11) = (7) + (10)
Locality	2021 Locality Peak MW	2021 Weather Normalized Locality Peak MW	Regional Load Growth Factor	2022 Locality Peak Forecast, Before Adjustments MW	Large Load Forecast MW	2022 IRM Locality Peak Forecast, With Large Load Forecast, Before BTM:NG Adjustments MW	2022 Forecast from 2021 Gold Book MW	Change from Gold Book Forecast	BTM:NG Forecast MW	Locality Peak Forecast, With Large Load and BTM:NG Forecast MW
Zone J - NYC	10,046.1	10,721.3	1.0187	10,921.3	0.0	10,921.3	11,268.0	-346.7	22.4	10,943.7
Zone K - LIPA	5,130.6	5,222.6	0.9800	5,118.0	0.0	5,118.0	5,153.0	-35.0	40.4	5,158.5
Zones G-to-J	14,078.2	14,940.0	1.0155	15,171.1	0.0	15,171.1	15,435.0	-263.9	22.3	15,193.4

A.3.3 Zonal Load Forecast Uncertainty

The 2022 load forecast uncertainty (LFU) models were updated during the Spring of 2021. Three aspects of the models were considered for updating. First, the NYISO reviewed the 2020 weather response for the several zones and concluded there was no need to update the load-weather relationship used in the 2021 IRM Study. Second, the NYISO adjusted the locations of the Z-values used to determine the temperatures of each of the seven bins used to represent a normal distribution of the weather variable. This was done by setting the Z-value equal to the location of the midpoint of the *area* of each bin. Previously, the Z-values were set to the mid-point of each bin's *boundaries*. Finally, the NYISO reviewed the historical load shapes used to represent hourly loads and decided to maintain the use of historical loads from the years 2002, 2006 and 2007. The NYISO is currently conducting additional analyses related to the selection of hour load shapes for the IRM Study.

Review of Load-Weather Relationship the NYISO developed new 2022 models for all of the LFU modeling regions (i.e., Zones A-E, Zones F&G, Zones H&I, Zone J, and Zone K) to establish the load-weather relationship during 2020. The models used existing data from 2018, 2019 and new data from 2020. The NYISO then compared the results of the 2022 models to those developed in 2020 for the 2021 IRM Study (Table A-1). The NYISO observed a slightly different weather response and lower load levels during the Summer of 2020. This was attributed to COVID-19 restrictions being in place and then lifted throughout the peak weather period. In addition, the 2020 weather conditions offered few data points at or above design temperatures across the LFU modeling areas. Given the lower load levels and uncertainties regarding the impact of COVID on the weather-sensitivity of the system, the load-weather relationship established during the 2021 IRM Study was kept unaltered and used in the 2022 IRM LFU models.

Con Ed and LIPA both agreed with the final LFU models presented at LFTF and ICS and the decision to maintain the use of the 2021 LFU models. The ICS approved the 2021 LFU model results for use in the 2022 IRM Study.

Review of Z-values for Each Bin Although the load-weather relationship established in the 2021 IRM Study was unaltered, the 2022 LFU model results are different from those used in 2021 IRM study, due to the change in location of the Z-value of each bin. Table A.5 shows the difference.

Table A.5 Difference Between 2022 LFU Models and 2021 LFU Models

Delta (LFU 2022 - LFU 2021)								
Bin	Bin Probability	Equal Area Z-Value	A-E	F&G	H&I	J	K	NYCA (Winter)
1	0.0062	2.74	-1.24%	-1.32%	-1.01%	-0.78%	-0.75%	-1.21%
2	0.0606	1.79	-1.10%	-1.17%	-1.06%	-0.84%	-1.24%	-0.88%
3	0.2417	0.89	-0.64%	-0.69%	-0.70%	-0.56%	-0.68%	-0.44%
4	0.3830	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.2417	-0.89	0.66%	0.72%	0.84%	0.67%	1.08%	0.36%
6	0.0606	-1.79	1.15%	1.29%	1.54%	1.27%	1.98%	0.58%
7	0.0062	-2.74	1.35%	1.55%	1.92%	1.59%	1.08%	0.63%

The deviations originate from using a different set of bin centers (Z-values) for the probability bins. In the prior LFU models, these points were located at the midpoints of the bins, equidistant from upper and lowers bounds of each bin based on the Z-value. This approach assumes that the normal distribution can be approximated by rectangles centered at the midpoint of each bin. For the 2022 LFU models, an alternate set of bin centers were used in which the Z-value divides the area of each bin equally. The new set of Z-values reflects an improved representation of the LFU multiplier's probability of occurrence (Figure A-1). The Equal-Area based bin structure and the resulting LFU multipliers were presented at both the LFTF and ICS and were approved. The comparison between Equidistant and Equal-Area based bin structure is shown in Figure A.2 and Table A.6.

Figure A.2 Bin Centers (LFU 2022 and LFU 2021)

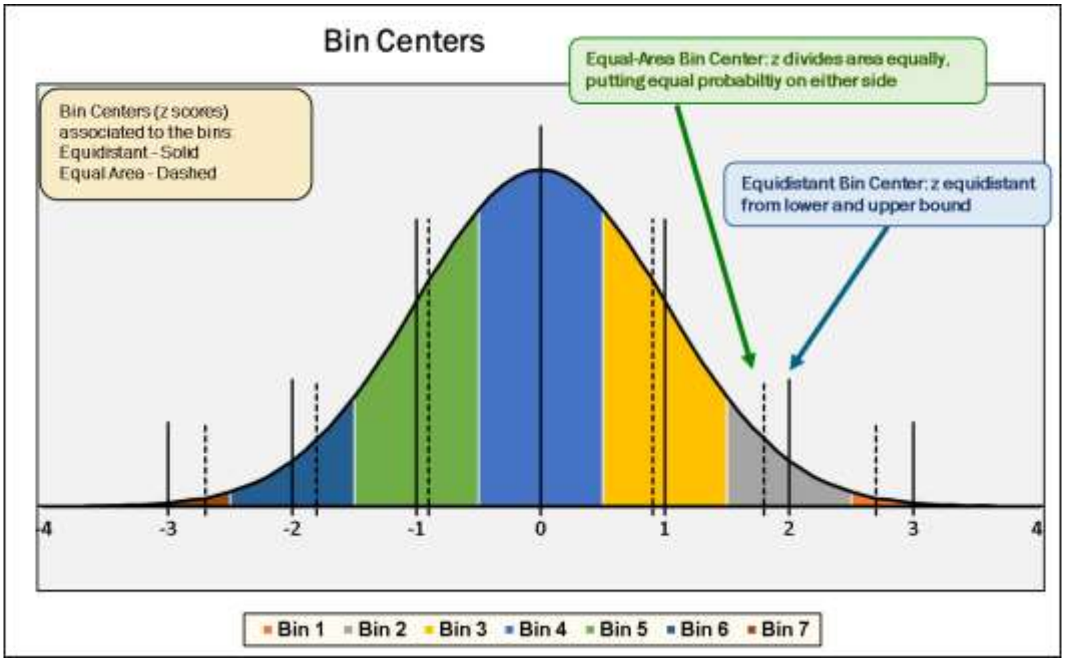


Table A.6 Equidistant and Equal-Area Bin Structure

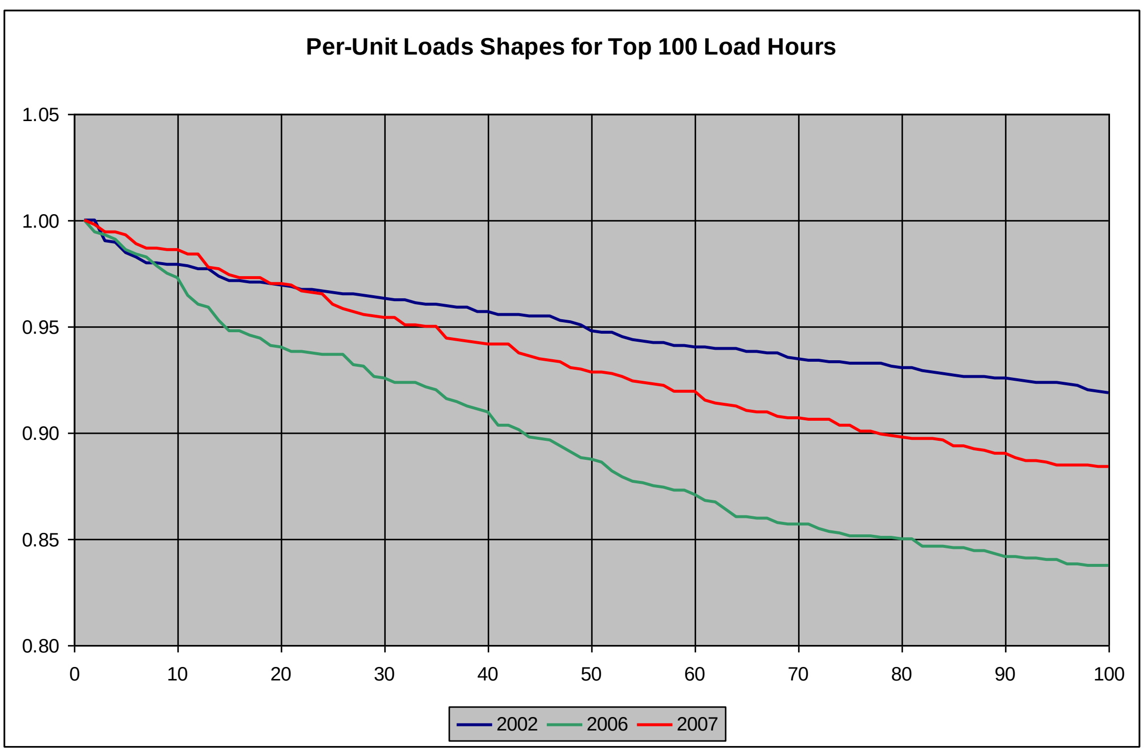
LFU Models 2021 (Equidistant)								
Bin	Bin Lower Bound	Bin Upper Bound	Bin Probability	Associated Z-Value	Probabiltiy Left	Probabiltiy Right	Left Percentage	Right Percentage
1	2.5	+ Inf	0.0062	3.00	0.0049	0.0013	78%	22%
2	1.5	2.5	0.0606	2.00	0.0441	0.0165	73%	27%
3	0.5	1.5	0.2417	1.00	0.1499	0.0918	62%	38%
4	-0.5	0.5	0.3829	0.00	0.1915	0.1915	50%	50%
5	-1.5	-0.5	0.2417	-1.00	0.0918	0.1499	38%	62%
6	-2.5	-1.5	0.0606	-2.00	0.0165	0.0441	27%	73%
7	- Inf	-2.5	0.0062	-3.00	0.0013	0.0049	22%	78%

LFU Models 2022 (Equal-Area)								
Bin	Bin Lower Bound	Bin Upper Bound	Bin Probability	Associated Z-Value	Probabiltiy Left	Probabiltiy Right	Left Percentage	Right Percentage
1	2.5	+ Inf	0.0062	2.74	0.0031	0.0031	50%	50%
2	1.5	2.5	0.0606	1.79	0.0303	0.0303	50%	50%
3	0.5	1.5	0.2417	0.89	0.1209	0.1209	50%	50%
4	-0.5	0.5	0.3829	0.00	0.1915	0.1915	50%	50%
5	-1.5	-0.5	0.2417	-0.89	0.1209	0.1209	50%	50%
6	-2.5	-1.5	0.0606	-1.79	0.0303	0.0303	50%	50%
7	- Inf	-2.5	0.0062	-2.74	0.0031	0.0031	50%	50%

Review of Historical Zonal Load Shapes for Load Bins Beginning with the 2014 IRM Study, multiple years of historical load shapes were assigned to 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.

The load duration curves were reviewed as part of the 2021 IRM Study. Load duration curves were examined from the period 2002 through 2019. It was observed that the year 2012 was similar to the year 2007, the year 2013 was similar to 2006, and the year 2018 was similar to the year 2002. As a result of this review, the ICS accepted the NYISO's recommendation to continue the use of the current three load shapes.

Figure A.3 Per Unit Load Shapes

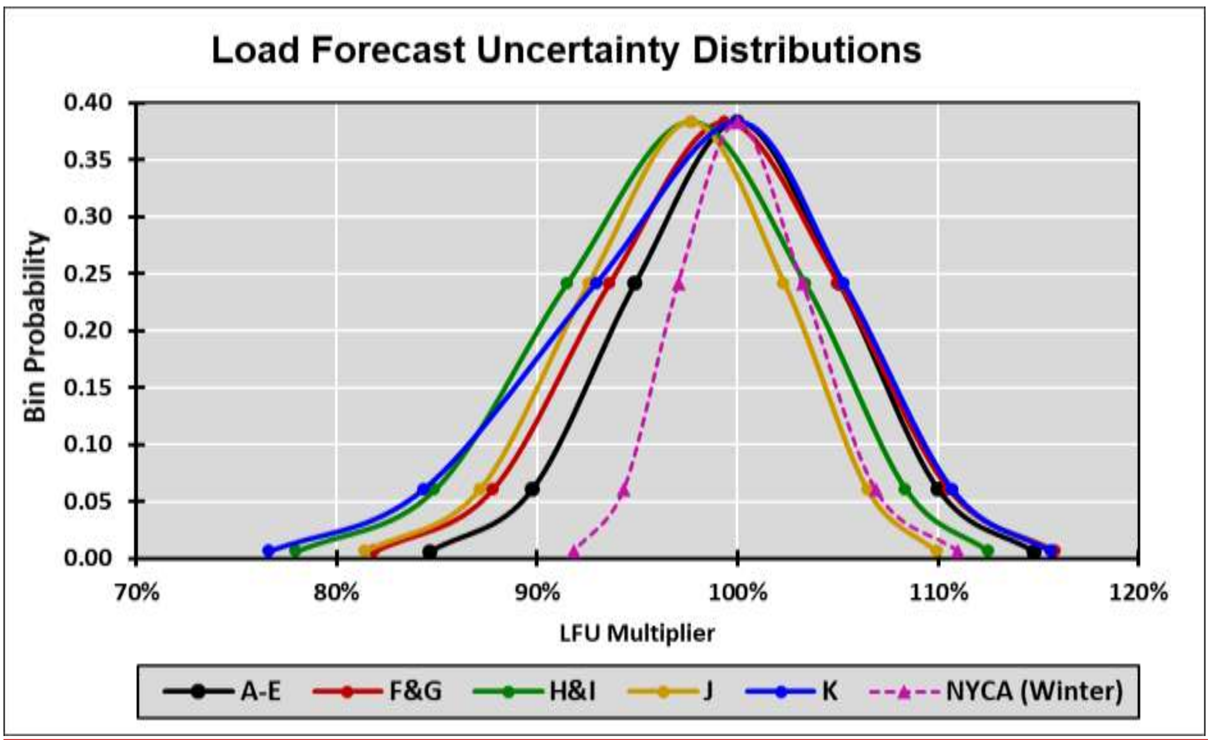


The 2022 LFU model results are presented in Table A.7. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A.4.

Table A.7 2022 Summer and Winter Load Forecast Uncertainty Models

LFU Models 2022								
Bin	Bin Probability	Equal Area Z-Value	A-E	F&G	H&I	J	K	NYCA (Winter)
1	0.0062	2.74	114.78%	115.85%	112.55%	109.95%	115.63%	111.01%
2	0.0606	1.79	110.01%	110.53%	108.40%	106.49%	110.73%	106.89%
3	0.2417	0.89	105.06%	105.01%	103.36%	102.33%	105.30%	103.25%
4	0.3830	0.00	100.00%	99.36%	97.68%	97.67%	100.00%	100.00%
5	0.2417	-0.89	94.88%	93.61%	91.50%	92.58%	92.96%	97.05%
6	0.0606	-1.79	89.73%	87.77%	84.89%	87.13%	84.32%	94.34%
7	0.0062	-2.74	84.63%	81.88%	77.98%	81.38%	76.60%	91.85%

Figure A.4 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 and results for determining the 2022 LFU models have been reviewed by the NYISO Load Forecasting Task Force.

(1) Additional Discussion of the 2022 LFU Models

The Load Forecast Uncertainty (LFU) models are meant to measure the load response to weather at high peak-producing temperatures as well as other factors such as the economy. However, economic uncertainty is relatively small compared to temperature uncertainty one year ahead. As a result, the LFTF, the NYISO, and the ICS have agreed that it is sufficient to confine the LFU for the 1-year ahead IRM study only to weather. Thus, the LFU is largely based on the slope of load vs. temperature, or the weather response of load. If the weather response of load increases, the slope of load vs. temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase. The LFU multipliers in the 2021 LFU model included summer 2018 and 2019 data. Both years were also included in the 2021 LFU model. In general, the load response to weather in 2018 and 2019 was steeper than it was in previous hot summers.

2018 and 2019 summer weekday base load in most areas declined relative to earlier years. This decline was larger than the decline in summer peak load over the same period. Thus, a contributing factor to increase in slope of load versus weather is due to a downward trend in base load. This also contributed to larger LFU multipliers in the upper bins.

The recent year-over-year decline in the ICAP load forecast continues to be a mitigating factor which somewhat offsets the increase in LFU. Even though the LFU multipliers and the resultant IRM percent will increase, the peak load used as the starting point to calculate the final MW capacity requirement continues to decrease.

A.3.4 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 2020 Load and Capacity Data Report is the primary data source for these resources. Table A.8 provides a summary of the capacity resource assumptions in the 2021 IRM study.

Table A.8 Capacity Resources

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
Generating Unit Capacities	2020 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2021 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2021Gold Book publication
Planned Generator Units	56.6 MW of project related re-ratings.	111.2 MW of project related re-ratings.	Unit rerates
Wind Resources	126.5 MW of Wind Capacity additions totaling 1865.7 MW of qualifying wind	158.1 MW of Wind Capacity additions totaling 2017.5 MW of qualifying wind	Renewable units based on RPS agreements, interconnection queue, and ICS input.
Wind Shape	Actual hourly plant output over the period 2015-2019. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2016-2020. New units will use zonal hourly averages or nearby units.	Program randomly selects a wind shape of hourly production over the years 2016-2021 for each model iteration.
Solar Resources (Grid connected)	0 MW of Solar Capacity additions totaling 31.5 MW of qualifying Solar Capacity.	182.9 MW of Solar Capacity additions totaling 214.4 MW of qualifying Solar Capacity.	ICAP Resources connected to Bulk Electric System
Solar Shape	Actual hourly plant output over the period 2015-2019. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2016-2020. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2016-2020 for each model iteration.

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
BTM- NG Program	One new BTM NG resources Forecast load adjustment of 65.2 MW	One new BTM NG resources Forecast load adjustment of 149.4 MW	Both the load and generation of the BTM:NG Resources are modeled.
Retirements, Mothballed units, and ICAP ineligible units	1,104 MW of unit deactivations and 192.7 MW of unit removals	19.1 MW of unit deactivations	2021 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2015-2019) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2016-2020) GADS data for each unit represented. Those units with less than five years – use representative data.	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2016-2020)
Planned Outages	Based on schedules received by the NYISO	Based on schedules received by the NYISO	Updated schedules
Summer Maintenance	Nominal 50 MWs – divided equally between Zones J & K	Nominal 50 MWs – divided equally between Zones J & K	Review of most recent data
Gas Turbine Ambient De-rate	De-rate based on provided temperature correction curves.	De-rate based on provided temperature correction curves.	Operational history indicates de-rates in line with manufacturer's curves
Small Hydro Resources	Actual hourly plant output over the period 2015-2019.	Actual hourly plant output over the period 2016-2020.	Program randomly selects a Hydro shape of hourly production over the years 2016-2020 for each model iteration.

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
Large Hydro	Probabilistic Model based on 5 years of GADS data	Probabilistic Model based on 5 years of GADS data	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2016-2020)
Energy Limited Resources (ELR)	ELR modeled with duration limitation	Based upon elections made by August 1st, 2021. Such an election would override any of the above assumptions.	Existing elections are made by August 1st and will be incorporated into the model.

(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 the lower of their CRIS value or their nameplate value in the model. The 2021 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

(2) Planned Generator Units

There are 111.2 MW of new thermal units and unit re-ratings (summer ratings).

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2016-2020. Each calendar production year represents an hourly wind shape for each wind facility from which the GE MARS program will randomly select. New units will use the zonal hourly averages of current units within the same zone. As shown in table A.9, a total of 2,017.5 MW of installed capacity associated with wind generators.

Table A.9 Wind Generation

Wind				
Resource	Zone	CRIS (MW)	Summer Capability (MW)	MARS Modeled Capability**
Bliss Wind Power [WT]	A	100.5	100.5	100.5
Canandaigua Wind Power [WT]	C	125.0	125.0	125.0
High Sheldon Wind Farm [WT]	C	112.5	118.1	112.5
Howard Wind [WT]	C	57.4	55.4	55.4
Orangeville Wind Farm [WT]	C	94.4	93.9	93.9
Wethersfield Wind Power [WT]	C	126.0	126.0	126.0
Altona Wind Power [WT]	D	97.5	97.5	97.5
Chateaugay Wind Power [WT]	D	106.5	106.5	106.5
Clinton Wind Power [WT]	D	100.5	100.5	100.5
Ellenburg Wind Power [WT]	D	81.0	81.0	81.0
Jericho Rise Wind Farm [WT]	D	77.7	77.7	77.7
Marble River Wind [WT]	D	215.2	215.2	215.2
Hardscrabble Wind [WT]	E	74.0	74.0	74.0
Madison Wind Power [WT]	E	11.5	11.6	11.5
Maple Ridge Wind [WT01]	E	231.0	231.0	231.0
Maple Ridge Wind [WT02]	E	90.7	90.8	90.7
Munnsville Wind Power [WT]	E	34.5	34.5	34.5
Cassadaga Wind [WT]	A	126.0	126.5	126.0
Arkwright Summit Wind Farm [WT]*	A	78.4	78.4	78.4
Roaring Brook [WT]	E	79.7	79.7	79.7
Total		**2020.0**	**2023.8**	**2017.5**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers using hourly production data over the period 2016-2020. Each calendar production year represents an hourly solar shape for each solar facility which the GE MARS program will randomly select from. A total of 214.4 MW of solar capacity was modeled.

(5) Retirements/Deactivations/ ICAP Ineligible

There are ~~three~~ 2 units totaling ~~1104~~ 19.1 MW that have become deactivated.

(6) Unforced Capacity Deliverability Rights (UDRs)

The capacity model includes UDRs, which are capacity rights that allow the owner of an incremental controllable transmission project to provide locational capacity benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights. This decision determines how this transfer capability will be represented in the MARS model. The IRM modeling accounts for both the availability of the resource that is identified for each UDR line as well as the availability of the UDR facility itself. The following facilities are represented in the 2022 IRM Study as having UDR capacity rights: :LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, and the 315 MW Linden Variable Frequency Transformer. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs they plan on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance, which may reduce locational and IRM capacity requirements. The 2022 IRM Study incorporates the confidential elections that these facility owners made for the 2022 Capability Year. Hudson Transmission Partners 660 MW HVDC Cable has been granted UDR rights but has lost its right to import capacity and therefore is modeled as being fully available to support emergency assistance.

(7) Energy Limited Resources

The capacity model now includes Energy Limited resources (ELR). The NYISO filed, and FERC approved, tariff changes that enhance the ability of duration limited resources to participate in the NYISO markets. These rules allow output limited resources to participate in the markets consistent with those limitations and requires owners of those resources to inform the NYISO of their elected energy output duration limitations. Effective May 1, 2021, generation resources may participate in an Energy Limited Resource (ELR) program administered by the NYISO. Under this program, participating generators were required to submit their elected limitations to the NYISO on a confidential basis by August 1st for the upcoming capability year (i.e., August 1, 2021) for the Capability Year beginning on May 1, 2022).

(8) Performance Data

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 2022 IRM Study.

Figure A.5 shows a rolling 5-year average of the same data.

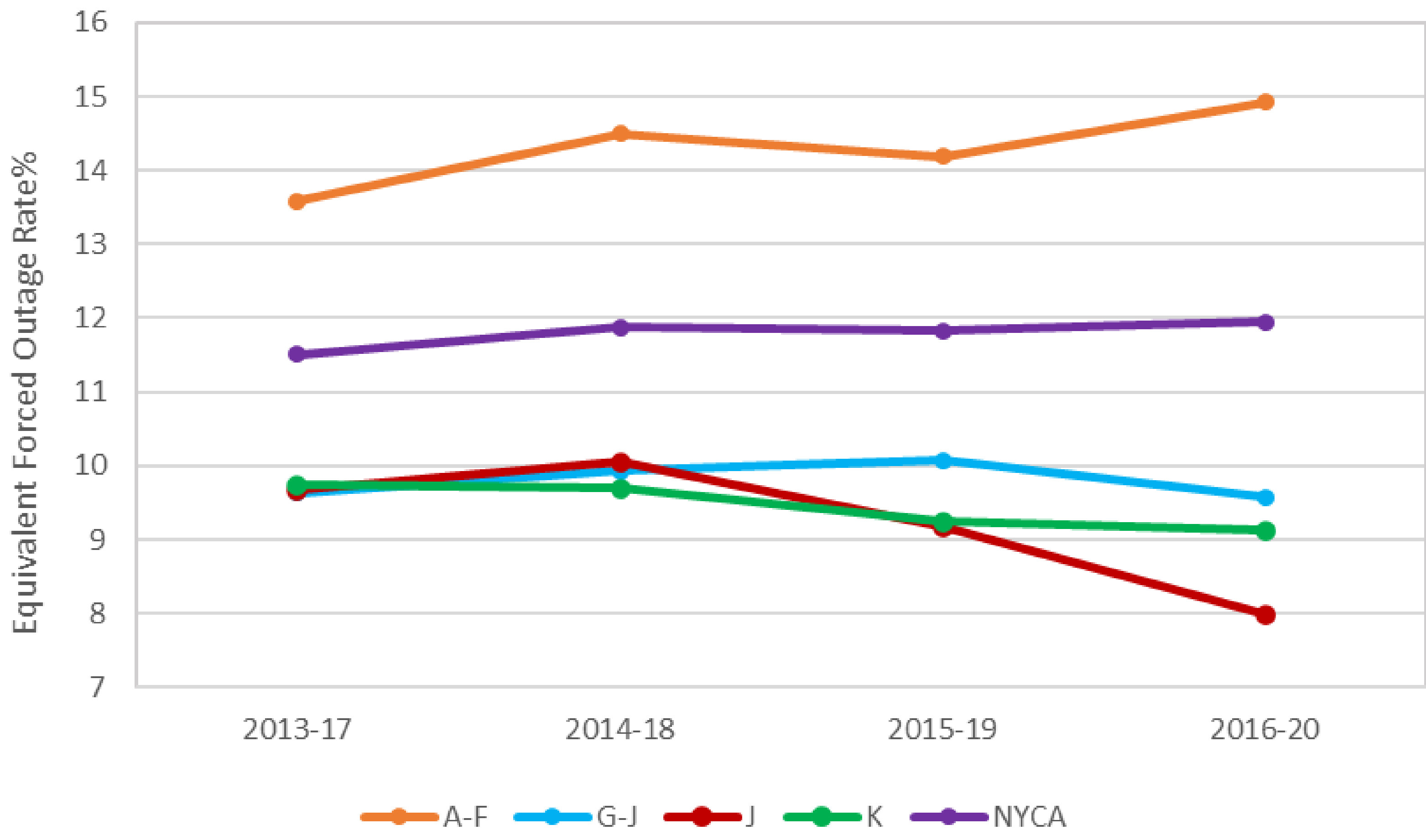
Figures A.6 and A.7 show the availability trends of the NYCA broken out by fuel type.

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 most of the NYCA units were obtained from the five-year NERC GADS outage data collected by the NYISO for the years 2016 through 2020. 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.

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.5 Five-Year Zonal EFORds



The resources included in the calculation of these values include thermal, large hydro, wind, solar, landfill gas, and run-of-river resources with CRIS.

Figure A.6 NYCA Annual Availability by Fuel

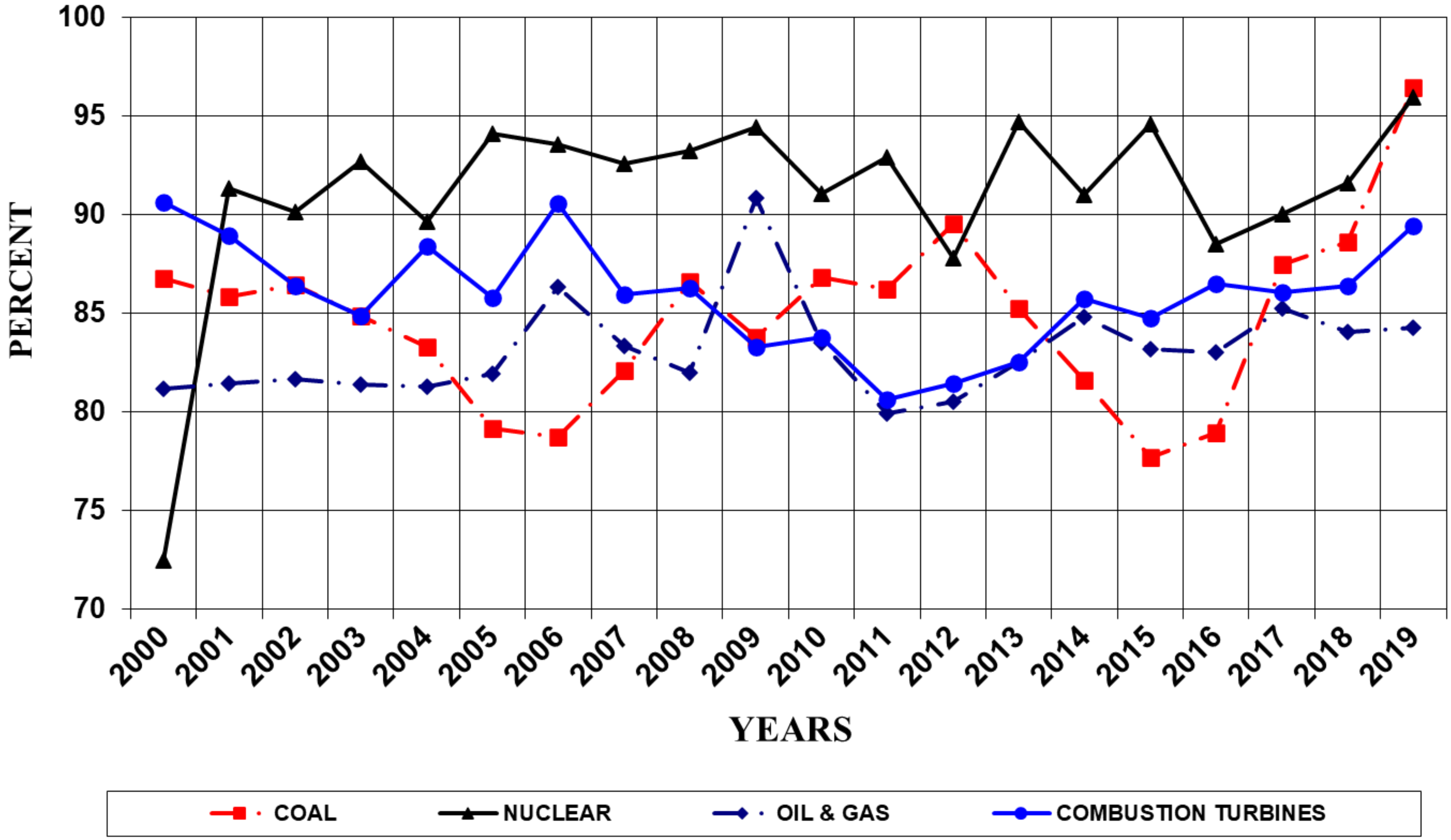


Figure A.7 NYCA Five-Year Availability by Fuel

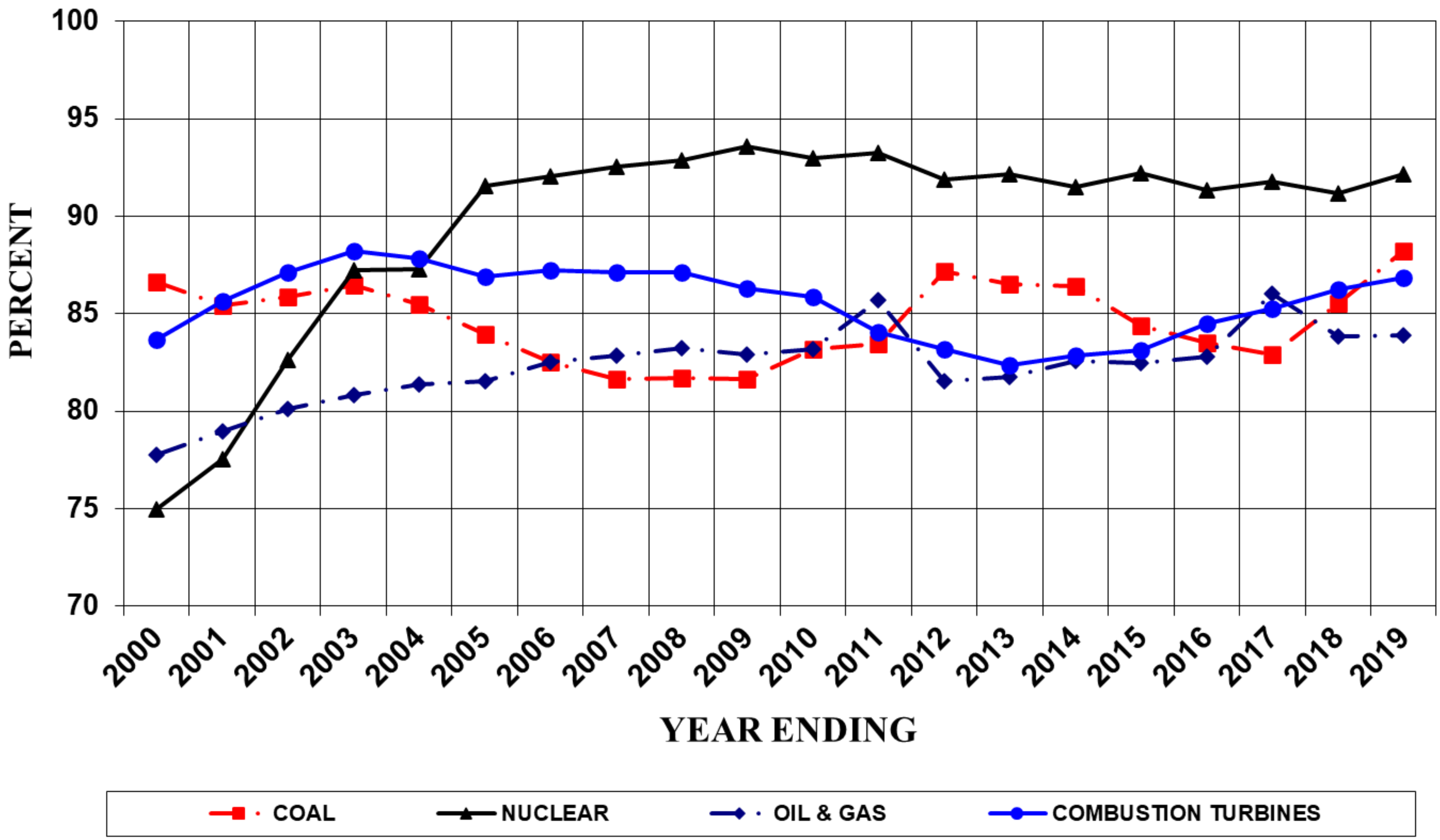


Figure A.8 NERC Annual Availability by Fuel

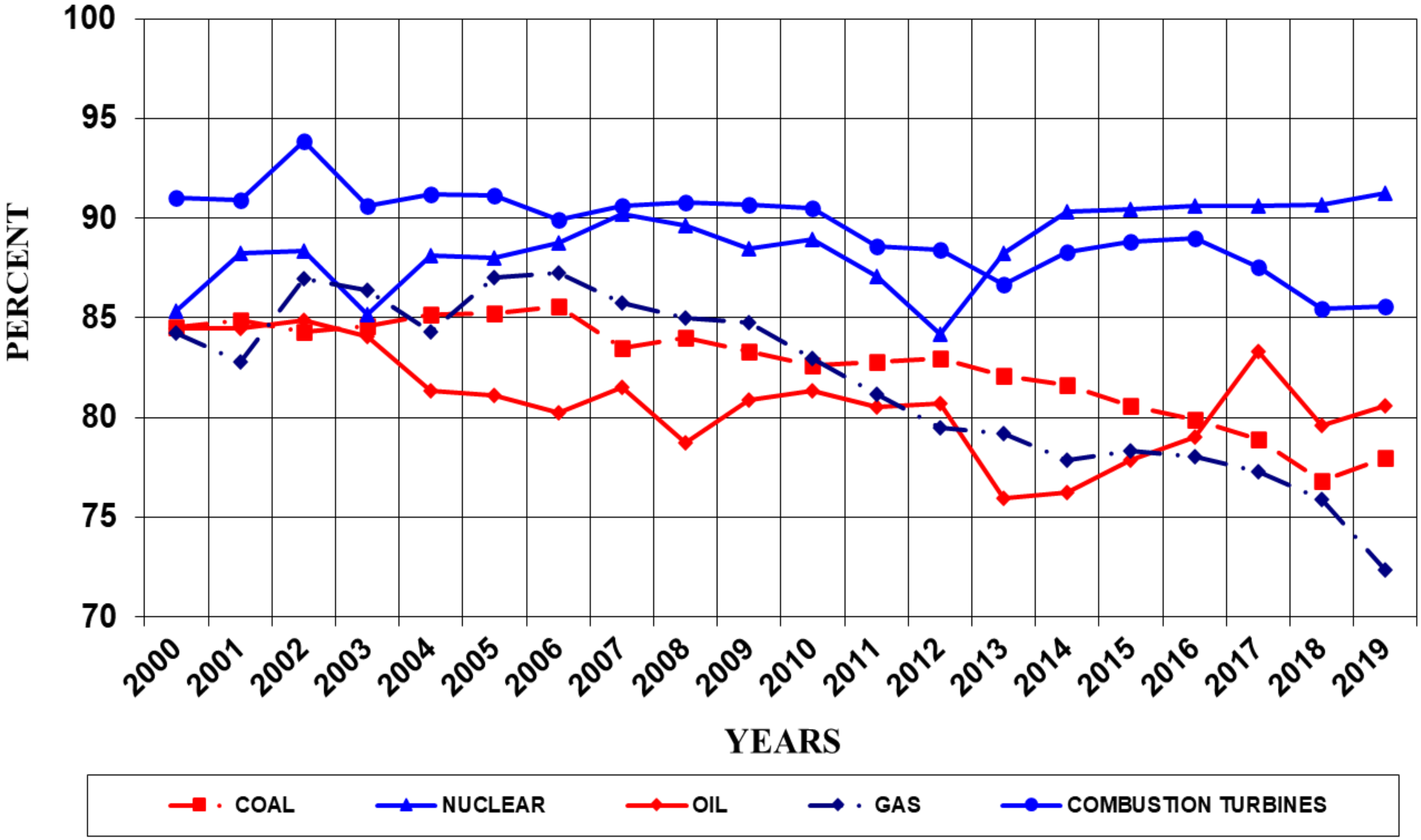
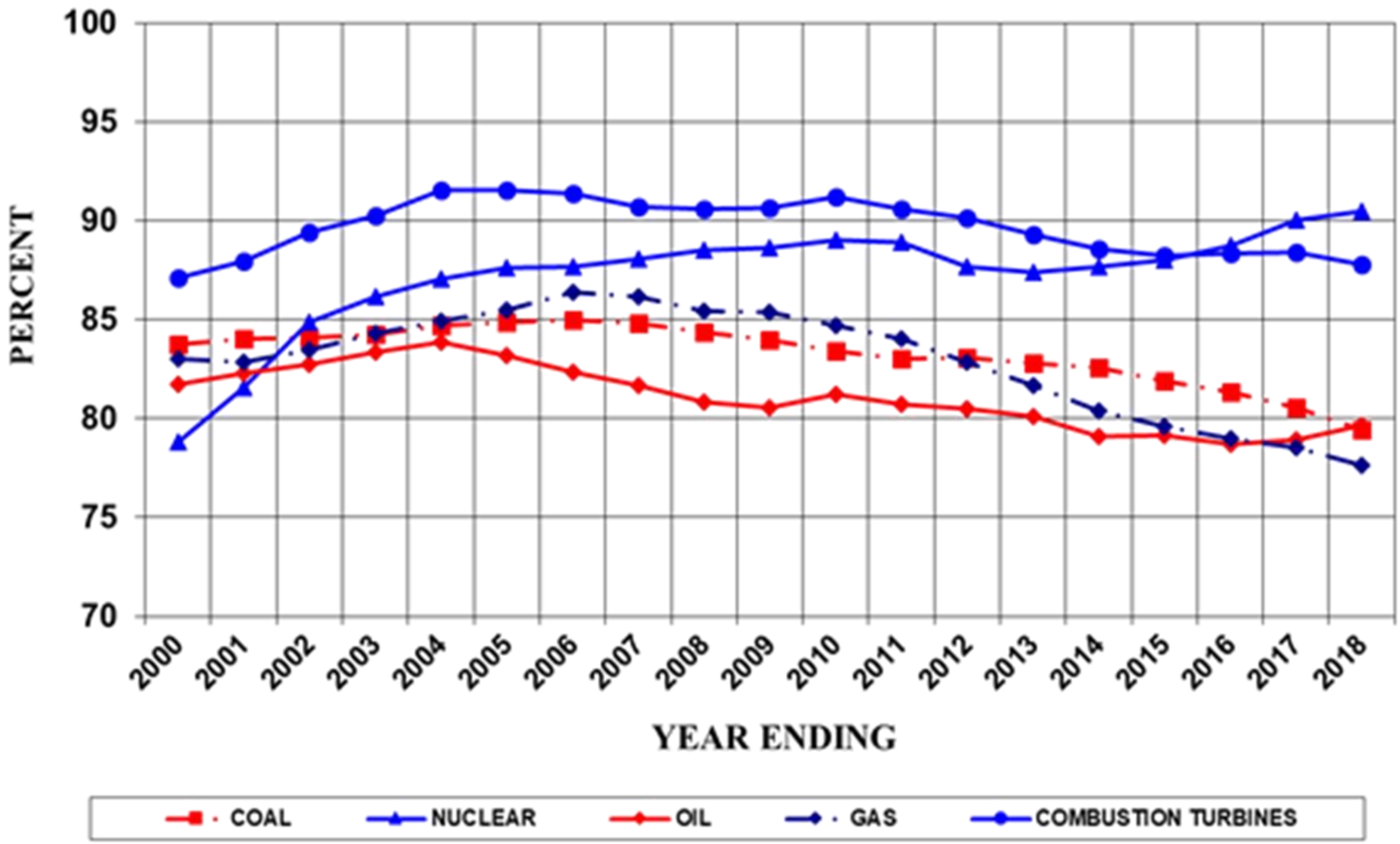


Figure A.9 NERC Five-Year Availability by Fuel



(9) Outages and Summer Maintenance

For the 2022 IRM Study, planned and scheduled maintenance was removed because it caused excess EOP usage. This had no impact on LOLE or IRM. The nominal 50 MWs of summer maintenance, however, remained constant. The 0.1% differential in the Preliminary Base Case is associated with the summer maintenance assumption and can be attributed to changing the unit that was selected for summer maintenance. For the 2022 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is nominally divided equally between Zone J and Zone K.

~~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 (PO) component is obtained from the generator owners. When this information is not available, the unit's historic average planned outage duration is used. Figure A.10 provides a graph of scheduled outage trends over the 2003 through 2020 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 summer capability period is reviewed to determine the scheduled maintenance MW during the previous peak period. An assumption is determined as to how much to model in the current study. For the 2022 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is nominally divided equally between Zone J and Zone K. Figure A.11 shows the weekly scheduled maintenance for the 2022 IRM Study compared to this study.~~

(10) Gas Turbine Ambient De-rate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in gas turbine and combined cycle capacity output are captured in the GE-MARS model using de-ratings based on ambient temperature correction curves. Based on its review of historical 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.

(11) Large Hydro De-rates

Hydroelectric projects are modeled consistent with the treatment of~~as are~~ thermal units, with a probability capacity model based on five years of unit performance. See Table A.8 above entitled: Capacity ~~Models~~Resources.

A.3.5 Transmission System Model

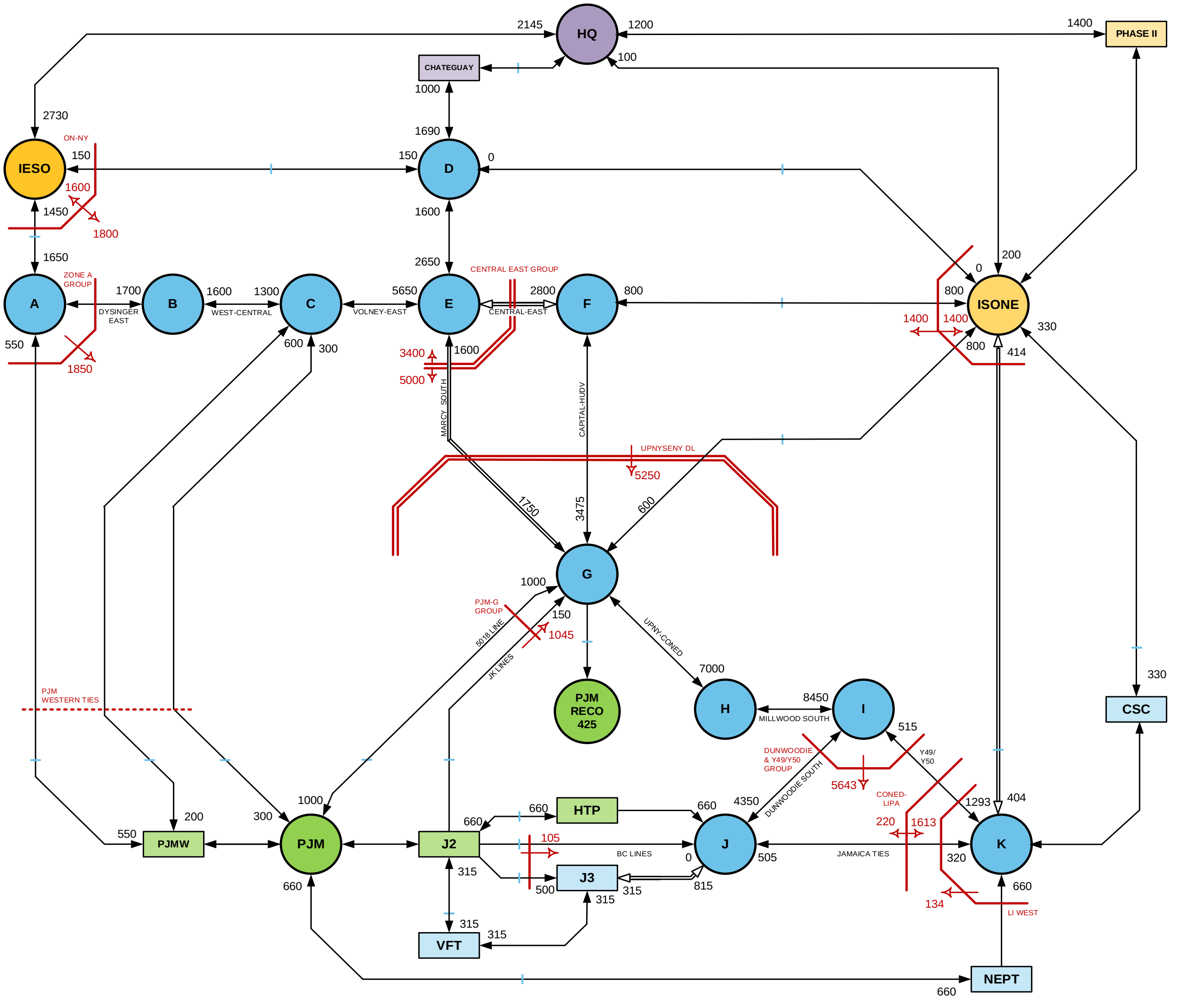
A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Zones and four External Control Areas, along with transfer limits, is shown in Figure A.10. The transfer limits employed for the 2022 IRM Study were developed from emergency transfer limit analyses included in various studies performed by the NYISO and based upon input from Transmission Owners and neighboring regions. The NYISO's Transmission Planning and Advisory Subcommittee (TPAS) also reviewed and approved the topology. A list of those studies is shown in Table A.10, below. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the 2021 IRM Study are listed in Table A.8, which reflects changes from last year's model. The changes that are captured in this year's model are: 1) an update to Western NY limits due to inclusion of the WNY Public Policy Transmission Project; 2) an uprate of the Cedars Import Limit; 3) derates to Central East as a result of the Porter-Rotterdam (30 & 31) being out of service; 4) a change to LIPA dynamic ratings based on updates from the TO including a decrease of load forecast in the West of Newbridge area.

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 were calculated based on the probability of occurrence from the historic failure rates and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, including failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that cable. The TOs provided updated transition rates for their associated cable interfaces.

Table A.10 Transmission System Model

Parameter	2021 Model Assumptions	2022 Model Assumptions Recommended	Basis for Recommendation
Western NY Limits – Public Policy Impacts	Zone A export limit – 1850 Zone A to B limit – 1700 Zone B to C limit - 1300	Zone A export limit – 2650 Zone A to B limit – 2200 Zone B to C limit - 1500	In depth review of Western NY was conducted due to various system changes. Focusing on large load projects and reviewing West Central reverse limit.
Cedars Import Limit	1690 of import capability to Zone D from Chateguay	1770 of import Capability to Zone D from Chateguay	Cedar Rapids Transmission Upgrade of 80 MWs was included in the 2020 RNA base case
IESO/NYISO PARS in Zone D	Modeled IESO PAR the same as in 2020. Resulting in and 1850 export limit from IESO, with a 1650 import limit.	No modeling change	The status of the PAR is uncertain for the next year, due to the uncertainty, there was no change made despite May 5th presentation.
Derates to Central East	Central East Dynamic limit table ranging from 3100 to 2645 MWs. Central East + Marcy Group Dynamic Limit table ranging from 5000 to 4310 MWs	Central East Dynamic limit table ranging from 2800 to 2415 MWs. Central East + Marcy Group Dynamic Limit table ranging from 4515 to 3935 MWs	Received updates that the Porter-Rotterdam (30 & 31) lines will be out of service. Derates applied to both individual and group limits.
LIPA Dynamic Ratings	ConEd-LIPA Dynamic Rating table for Zone K to I and J ran at 220/200/130 MWs	ConEd-LIPA Dynamic Rating table for Zone K to I and J ran at 220/220/130 MWs	NYISO received updates from TO; a decrease of load forecast in the West of Newbridge area increases limit in the one Barret unit scenario
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis or NYISO analysis where applicable
UDR line Unavailability	Five-year history of forced outages	Five-year history of forced outages	NYISO/TO review

Figure A.10 2022 IRM Topology



Notes

1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW

2. NYCA EA simultaneous import limit: 3,500 MW

3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- xx "Dummy Bubble" i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Table A.11 shows the dynamic limits used in the topology VS. the 2021 IRM study.

Table A.11 Interface Limits Updates

	2020		2021		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
Zone A to B	1700	-	2200	-	500	-
Zone A Export Limit	1850	-	2650	-	800	-
Zone B to C	1300	-	1500	-	200	-
Chateguay to Zone D	1690	1000	1770	1000	80	0
Central East	3100/3050/2990/ 2885/2770/2645	-	2800/2740/2650/ 2605/2490/2415	-	-300/-310/-340/-280/-280/-230	-
Central East + Marcy Group	5000/4925/4840/ 4685/4510/4310	-	4515/4425/4290/ 4230/4055/3935	-	-485/-500/-550/-455/-455/-375	-
Zone K to Zones I and J Group	1613	220/200 /130	1613	220/220/ 130	0	0/20/0

The topology for the 2021 IRM Study features five changes from the topology used in the 2020 IRM Study.

1. Update to Western NY Limits – Public Policy
   Various Western NY transfer limits were updated, as shown in figure A.9, due to research surrounding the addition of the Western NY Public Policy Transmission Project. An in-depth review was completed to capture various system changes. The review focused on large load projects and reviewing the West-Central reverse limit.

2. Increase of the Cedars Import Limit
   The Cedar Rapids transmission interface transfer limit into Zone D was upgraded by 80 MWs. This value was included and studied in the 2020 RNA base case.

3. PARS related to IESO and Zone D

The IESO PAR was modeled the same in the 2022 IRM Study as it was in the 2021 Study. The status of the PAR is uncertain for next year, despite earlier reporting. As part of the sensitivity study, the inclusion of the PAR was researched. The impact on the IRM was minimal.

4. Derates to Central East

The NYSIO received updated information that highlighted the removal of the Porter-Rotterdam (30 & 31) lines will be out of service for the 2022 IRM Study. The derates resulting from this factor were applied to both the individual and group limit. The details of how the lines were impacted are captured in table A.9.

5. Updates to LIPA Dynamic Rating Table

The NYISO received an update from LIPA. Due to the load forecast decrease in the West of Newbridge area, the one Barrett unit scenario was increased in the Dynamic Limit table.

A.3.6 External Area Representations

NYCA reliability depends in part on emergency assistance from its interconnected Control Area neighbors (New England, Ontario, Quebec and PJM) based on reserve sharing agreements with these external Control Areas. Load and capacity models of these Areas are therefore represented in the GE-MARS analyses with data received directly from the Areas and through NPCC sources.

The primary consideration for developing the final load and capacity models for the external Control Areas is to avoid over-dependence on the external Control Areas for emergency capacity support.

For this reason, a limit is placed on the amount of emergency capacity support that the NYISO can receive from external Control Areas in the IRM study. The 3,500 MW value of this limit for this IRM study is based on a recommendation from the ICS and the NYISO that considers the amount of ten-minute reserves that are available in the external Control Areas above an Area's required reserve, along with other factors.

In addition, an external Control Area's LOLE assumed in the IRM Study cannot be lower than its LOLE criteria and its Reserve Margin can be no higher than its minimum requirement. If the Area's reserve margin is lower than its requirement and its LOLE is higher than its criterion, pre-emergency Demand Response can be represented. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA.

Another consideration for developing models for the external Control Areas is to recognize internal transmission constraints within the external Control 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. Additionally, EOPs are removed from the external Control Area models.

Finally, the top three summer peak load days of an external Control Area should be specified in the load model to be coincident with the NYCA top three peak load days. The purpose of this is to capture the higher likelihood that there will be considerably less load diversity between the NYCA and external Control Areas on the hot summer days.

For this study, both New England and PJM continue to be represented as multi-area models, based on data provided by these Control Areas. Ontario and Quebec are represented as single area models. 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 5-10 is as follows:

Table A.12 External Area Representations

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of 265.9 MW	Long term firm sales of 265.9 MW	These are long term federally monitored contracts.
External Area Modeling	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	The load and capacity data are 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	All NPCC Control Areas have indicated that they will share reserves equally	Per NPCC CP-8 working group assumption.

Table A.13 shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The 2022 external area model was updated from 2021 but still includes a 3,500 MW limit for emergency assistance (EA) imports during any given hour. As per Table 7-1 of the IRM study report, the difference in between the isolated case and the final base case was 8.6% in 2022 VS. 6.9% in 2021.

Table A.13 Outside World Reserve Margins

Area	2021 Study Reserve Margin	2022 Study Reserve Margin	2021 Study LOLE (Days/Year)	2022 Study LOLE (Days/Year)
Quebec	38.1%*	30.8%*	0.108	0.108
Ontario	21.2%	15.3%	0.110	0.103
PJM	15.1%	14.5%	0.177	0.173
New England	9.8 %	11.2%	0.100	0.102

*This is the summer margin.

A.3.7 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. EOP steps 2 through 10 listed in Table A.15 were provided by the NYISO based on operator experience. Table A.14 lists the assumptions modeled.

The values in Table A.15 are based on a NYISO forecast that incorporates 2021 (summer) operating results. This forecast is applied against a 2022 peak load forecast of 32,138.6 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.14 Assumptions for Emergency Operating Procedures

Parameter	2021 Study Assumption	2022 Study Assumption	Explanation
Special Case Resources*	July 2020 –1195 MW based on registrations and modeled as 822 MW of effective capacity. Monthly variation based on historical experience	July 2021 –1164.2 MW based on registrations and modeled as 810 MW of effective capacity. Monthly variation based on historical experience	SCRs sold for the program discounted to historic availability. Summer values calculated from July 2021 registrations. Performance calculation updated per ICS presentations on SCR performance.
Other EOPs	844.4 MW of on- SCR/non-EDRP resources	863.6 MW of non- SCR resources	Based on TO information, measured data, and NYISO forecasts.
EOP Structure	10 EOP Steps Modeled	10 EOP Steps Modeled	Based on agreement with ICS

- The number of SCR calls is limited to 5 per month when calculating LOLE.

Table A.15 Emergency Operating Procedures Values

Step	Procedure	2021 MW Value	2022 MW Value
1	Special Case Resources – Load, Gen	1,195 MW Enrolled/ 822 MW modeled	1,164 MW Enrolled/ 812 MW modeled
2	5% manual voltage Reduction	59.64 MW	60.43 MW
3	Thirty-minute reserve to zero	655 MW	655 MW
4	5% remote voltage reduction	445.42 MW	483.09 MW
5	Voluntary industrial curtailment	259.36 MW	240.05 MW
6	General Public Appeals	80 MW	80 MW
7	Emergency Purchases	Varies	Varies
8	Ten-minute reserves to zero	1,310 MW	1,310 MW
9	Customer disconnections	As needed	As needed
10	Adjustment used if IRM is lower than technical study margin	As needed	As needed

A.3.8 Locational Capacity Requirements

The GE-MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, *i.e.,* locational ICAP, which shall be electrically located within the Zone to ensure that enough energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. For the purposes of the IRM study, Locational ICAP requirements are 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.2 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.3.9 Special Case Resources

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 in Table A.16:

Table A.16 SCR Performance

For 2022 IRM - Final SCR Model Values							
			ICS Adjustment Factors				
Program	Super Zone	Superzone Performance Factor	ACL to CBL Factor	Fatigue Factor	Effective Performance Factor	SCR ICAP MW based on July 2021 Enrollment Data	Final Model Values MW
SCR	A-F	87.4%	93.6%	100%	81.8%	636.0	520.3
SCR	G-I	76.8%	84.5%	100%	64.9%	84.9	55.1
SCR	J	70.1%	74.6%	100%	52.3%	406.5	212.4
SCR	K	73.5%	82.2%	100%	60.4%	36.8	22.2
Total						1164.2	810.0
							69.6%

Table A.16 note 1: These values represent no growth from July 2021 ICAP based enrollments. Table A.15 note 2: The Performance Factor is based on the average coincident load (ACL) methodology. Table A.15 note 3: The SCR Adjustment factor (3) captures two different performance derates; 1) Calculated Translation Factor (TF) between ACL and customer baseline load (CBL) values, and the Fatigue Factor (FF=1.00)

GE-MARS model accounts for SCRs as a EOP step and will activate this step 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 registered value is 1164.2 MW. The effective value of 810.0 MW is used in the model.

A.4 MARS Data Scrub (needs updating)

A.4.1 GE Data Scrub

General Electric (GE) 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 the right value as is or institutes an update. The results of this data scrub are shown in Table A.17 for the preliminary base case.

Table A.17 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Name changes for three units were identified between the 2020 and 2021 study	Name changes were reviewed and accepted	No	N/A
2	Retirement dates for four units have changed	Retirement dates were verified	No	N/A
3	Many units had a change in capacity that exceeded 10 MW	Change in capacity verified	No	N/A
4	14 units changed MARS Areas	Changes were verified, all were related to topology updates	Yes	N/A
5	Two-line ratings were found inconsistent with diagrams previously presented	Diagrams updated to correct values	No	N/A
6	12 units identified with large EFORd change	These units, part of a larger annual review, where confirmed to be correct	No	N/A
7	Fewer EOP Steps than previous study	Verified update to 2021 model	No	N/A
8	Energy, even though not an explicit IRM assumption, appears higher in the model, for the base study year, than gold book forecast	A known effect of growing historical load shapes to meet future peaks. Initiative underway to study alternatives.	No	N/A
9	Changes to shape-based random groups	Change verified in order to align production shape years	No	N/A
10	Penetration factors changed for various units	Penetration factors verified	No	N/A
*Preliminary Base Case				

A.4.2 NYISO Data Scrub (needs updating)

The NYISO also performs a review of the MARS data independently from GE. Table A.18 shows the results of this review for the preliminary base case.

Table A.18 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Study Year Change causes unreasonable result	We did not change study year per GE suggestion and ICS approval	N	0
2	UPNYSENY forward limit was incorrect	Corrected for the PBC case	Y	~0.0%
3	IJ to K reverse limit updated	Corrected for the PBC case	Y	~0.0%
4	Dynamic Limit table	Corrected for the PBC case	N	0
5	25 MW of Summer Maintenance for Zone J was assigned to Zone K	Corrected for PBC case	Y	~0.0%
*Preliminary Base Case				

*Preliminary Base Case

A.4.3 Transmission Owner Data Scrub (needs updating)

In addition to the above reviews, two transmission owners scrub the data and assumptions using a masked database provided by the NYISO. All their findings reiterated the previous findings. Table A.19 shows their unique results.

Table A.19 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	VFT Rating from NYCA to PJM was not correct	Value was updated	Y	0
2	Update to E to G static line rating	Value updated	Y	0
*Preliminary Base Case				

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Results

Table B.1 summarizes the 2022-2023 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 18.6% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criterion. The values in Table B.1 on top of next page are the sensitivity results adjusted to the 19.1% final base case.

Table B.1 Sensitivity Case Results

Case	Description	IRM (%)	IRM % Change from Base Case	LOLH (at criteria) See note 1	EUE (at criteria) See note 2
0	**2022 IRM Final Base Case**	19.1	-	0.341	211.4
	IRM Impacts of Key MARS Study Parameters				
1	**NYCA Isolated (no emergency) assistance)**	27.7	8.6	0.298	166.7
2	**No Internal NYCA transmission constraints**	17.2	-1.9	0.365	309.0
3	**No Load forecast uncertainty**	11.2	-7.9	0.251	62.2
4	**Remove all wind generation**	13.5	-5.6	0.346	219.6
5	**No SCRs**	16.4	-2.7	0.324	181.9
	IRM Impacts of Base Case Assumption Changes				
6	**Advanced completion of Zone D PAR repair**	19	-0.1	0.345	214.8
7	**Enhanced Energy Limited Resource (ELR) functionality test. (Tan 45).**	18.3	-0.8	0.361	250.4
8	**Extended partial outage of Neptune UDR**	20.3	1.2	0.342	177.6
9	**Revert to 2021 IRM Study Cable Forced Outage Rates (Tan 45)**	19	-0.1	0.343	216.0
	Note 1 - LOLH: Loss of Load Hours: The expected number of hours during loss of load events each year when the system's hourly demand is projected to exceed the generating capacity. **Note 2 - EUE: Expected Unserved Energy: The expected amount of energy (MWh) during loss of load events that cannot be served each year.**				

B.2 Impact of Environmental Regulations

Federal, state, and local government regulatory programs may impact the operation and reliability of New York's bulk power system. Compliance with state and federal regulatory initiatives and permitting requirements may require investment by the owners of New York's existing thermal power plants to continue in operation. If the owners of those plants must make significant investments to comply, the cost of these investments could impact their availability, and therefore new resources may be needed to maintain the reliability of the bulk power system. Other regulatory initiatives being undertaken by the State of New York may preclude certain units from continuing in operation in their current configuration. Prior studies have identified the amounts of capacity that may be negatively impacted by new and developing regulations. Most recently, New York has enacted the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA) and promulgated various regulations collectively intended to limit Greenhouse Gas (GHG) emissions and support the development of new renewable energy, energy storage, and energy efficiency resources. This section reviews the status of various regulatory programs.

B.2.1 Combustion Turbine NOx Emission Limits

The New York State Department of Environmental Conservation (DEC) has finalized Part 227-3 which significantly lowers NOx emission limits for simple cycle gas turbines. The proposed rule will require compliance actions for units with approximately 3,300 MW of capacity (nameplate) located predominantly in southeastern New York and requires the owners of affected facilities to file compliance plans by March 2020. The rule will be applicable during the ozone season (May 1- September 30) and establishes lower emission limits in two phases, effective May 1, 2023 and May 1, 2025. The proposed rule also provides for emission averaging plans where the output of the affected facility can be averaged on a daily basis with the output of near-by storage resources or new renewable energy resources under common control. The NYISO used compliance plans submitted by generators under Part 227-3 to develop the assumed outage pattern of the impacted units in the 2020 RNA Base Case starting in May 2023. The plans indicate that approximately 1,100 MW and 1,800 MW of nameplate capacity are proposed to be unavailable during the summers of 2023 and 2025, respectively. The rule provides for the continued operation of facilities necessary for compliance with reliability standards for a period of up to two years with the possibility of another two-year period if permanent solutions have been identified but not completed.

B.2.2 U.S. Clean Water Act: Best Technology Available for Plant Cooling Water Intake

The U.S. Environmental Protection Agency (EPA) has issued a new Clear Water Act Section 316b rule providing standards for the design and operation of power plant cooling systems. This rule is being implemented by the DEC, which has finalized a policy for the implementation of the Best Technology Available (BTA) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from the DEC, the NYISO has estimated that 14,000 MW of nameplate capacity is affected by this rule, some of which could be required to undertake major system retrofits, including closed-cycle cooling systems.

Indian Point Energy Center had been involved in an extended renewal of its State Pollution Discharge Elimination System (SPDES) Permit. Entergy retired Unit #2 on April 30, 2020 and plans to retire Unit #3 on April 30, 2021.

Plant	Status as of June 2020
Arthur Kill	BTA in place, verification under review
Astoria	BTA in place, verification under review
Barrett	Permit drafting underway with equipment enhancements, SAPA extended
Bowline	BTA in place, 15% Capacity Factor, BTA Decision made, requested hearings
Brooklyn Navy Yard	BTA Decision pending
Cayuga	Retired
Danskammer	BTA in place
East River	BTA in place
Fitzpatrick	BTA studies being evaluated
Ginna	BTA studies being evaluated
Greenidge	BTA Decision made, installing upgrades, studies being evaluated
Indian Point	BTA in place, limit operations
Nine Mile Pt 1	BTA studies being evaluated
Northport	BTA in place, verification under review
Oswego	Leaning towards Capacity Factor limitation
Port Jefferson	BTA in place, 15% Capacity Factor, verification, SAPA extended
Ravenswood	BTA in place, verification under review
Roseton	BTA in place, studies being evaluated
Somerset	Retired
Wheelabrator Westchester	BTA in place, installing upgrades

B.2.3 Part 251: Carbon Dioxide Emissions Limits

The DEC promulgated a rule establishing an emission limit for CO2 for existing fossil-fueled generating units. New York's coal-fired generation accounted for less than 1% of the total energy produced in the state in 2019. As of April 2020, all coal-fired generation facilities supplying the New York bulk power system deactivated. NYISO generator deactivation assessments found no reliability needs associated with these deactivations.

B.2.4 New York City Residual Oil Elimination

New York City passed legislation in December 2017 that will prohibit the combustion of fuel oil numbers 6 and 4 in electric generators within New York City by 2020 and 2025, respectively. The rule applies to about 3,000 MW of generation in New York City. Affected generators have filed compliance plans with NYC agencies to switch to compliant fuels. The affected generators are developing new fuel storage and handling equipment necessary to convert their facilities to comply with the law.

B.2.5 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a multi-state carbon dioxide emissions cap-and-trade initiative that requires affected generators to procure emissions allowances authorizing them to emit carbon dioxide. Through a program review, the RGGI states agreed to several program changes, including a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that emit greenhouse gases. The DEC has proposed regulations incorporating these agreed upon program-wide changes and extending RGGI applicability in New York to certain generators of 15 MW (nameplate) or larger. The proposed emission allowance caps are not likely to trigger reliability concerns as the program design provides for mechanisms that consider reliability on various timescales, including multi-year compliance periods, allowance banking provisions, the Cost Containment Reserve, and periodic program reviews. New Jersey rejoined RGGI in 2020 since withdrawing from the program in 2011 and Virginia will begin RGGI participation in 2021. The Governor of Pennsylvania has issued an executive order directing the Pennsylvania Department of Environmental Protection to prepare draft rules for limiting CO_2 emissions from power plants with methods that would allow for the trading of allowances with RGGI.

B.2.6 Distributed Generator NOx Emission Limits

The DEC has adopted Part 222, a rule to limit the NOx emissions from small behind the meter generators that operate as an economic dispatch source in the New York City Metropolitan Area located at facilities with NOx emissions less than 25 tons of NOx per year and driven by reciprocating or rotary internal combustion engines. The proposed emission limits will become effective in two phases, May 1, 2021 and May 1, 2025. The facility must either obtain a registration or permit by March 15, 2021 and must notify the DEC whether the generator will operate as an economic dispatch source subject to the provisions of Part 222. The first emission limitations can be achieved by engines manufactured subsequent to 2000 and some subset of older engines.

B.2.7 Cross-State Air Pollution Rule (CSAPR)

The CSAPR limits emission of SO_2 and NO_X from fossil fuel fired EGUs >25 MW in 27 eastern states by establishing new caps and restricting allowance trading programs. Emissions above the statewide trading limit require additional penalty allowances. NYCA Ozone Season NO_X emissions are highly sensitive to the continued operation of the NYCA nuclear generation fleet. 2020 ozone season NO_X emissions were reportedly 3,561 tons across New York; 30% below the 5,135-ton ozone season budget. The CSAPR ozone season occurs May 1-September 30. The USEPA recently proposed a Revised CSAPR Update which proposes to reduce the ozone season NOx budget in 12 of the current CSAPR ozone season states between 2021 and 2024. The proposed budget for New York for 2021 is 3,137 tons dropping to 3,119 tons in 2024.

B.2.8 Climate Leadership and Community Protection Act (CLCPA)

The CLCPA requires, among other things, that 70% of electric energy be generated from renewable resources by 2030 and 100% of electric energy be provided by zero emission resources by 2040. The statute will require the displacement of New York's fossil-fueled generating fleet with renewable resources. During this transition, the NPCC and NYSRC resource adequacy rules will require the New York Control Area to maintain resource adequacy for the New York bulk electric system. In addition, the Greenhouse Gas ("GHG") emission reduction requirements will likely necessitate electrification of the building space and water heating and transportation sectors as an approach to reduce economy-wide emissions. The act builds upon programs and targets already established by the Clean Energy Standard (CES) and in other state policies. The combined set of requirements for new resources are outlined below.

Offshore Wind Development

The CLCPA requires 9,000 MW of offshore wind (OSW) capacity to be developed by 2035. Previously, the New York PSC issued an order directing that NYSERDA, with the involvement of the Long Island Power Authority (LIPA) and the New York Power Authority (NYPA) to procure OSW RECs (ORECs) from developers for up to 2,400 MW of offshore wind. NYSERDA has executed contracts with the winners of the inaugural 2018 OREC solicitation for an initial procurement of two OSW projects totaling nearly 1,700 MW. More recently the PSC gave NYSERDA approval to procure up to the 9,000 MW OSW target without seeking further Commission approval.

Comprehensive Energy Efficiency Initiative

The PSC has approved an order containing utility budgets and targets to accelerate energy efficiency deployment in New York State through 2025. A portion of the 185 TBtu all-fuels energy savings target will come from directed utility programs to expand access to and experience with heat pumps to replace/augment existing conventional heating sources, as well as from increased deployment of more conventional utility energy efficiency programs.

Storage Deployment Target

The CLCPA requires 3,000 MW of energy storage capacity to be developed by 2030. This goal builds on top of the goal to deploy 1,500 MW energy storage capacity by 2025 outlined in NYSERDA's Energy Storage Roadmap.

Distributed Solar Program

The CLCPA requires 6,000 MW of distributed solar capacity by 2025, which is an expansion of the existing 3,000 MW NY-Sun program. The PSC has been charged with developing the regulatory mechanisms to ensure that the incremental 3,000 MW distributed solar comes on line by 2025. Currently, NYSERDA administers the NY-Sun program.

The table below describes the timing and requirements of the major combined clean energy and efficiency policies in New York State.

Year	New York State Policy Mandate
2025	6,000 MW Distributed PV 185 TBtu Energy Efficiency of which 30,000 GWH is attributable to the electricity sector 1,500 MW Energy Storage Resources
2029	Expiration of the Zero Emission Credit Program
2030	3,000 MW Energy Storage Resources 2,400 Off Shore Wind Resources 70% of NY electricity from renewable resources 40% reduction in New York State's GHG emissions compared to 1990
2035	9,000 MW Off Shore Wind Resources
2040	Zero Emissions from the electric power sector
2050	85-100% reduction in New York State's GHG emissions compared to 1990

The PSC issued an Order on October 15 modifying the existing Clean Energy Standard to align with the requirements of the CLCPA. Specifically, the order increased the 2030 Renewable Energy Standard from 50% to 70% and modified the definition of eligible renewable energy resources to align with the CLCPA. This Order authorized the procurement schedules for Tier 1 and Offshore Wind resources needed to achieve the 2030 mandates. The Order also addressed treatment of pre-existing resources by defining criteria for Tier 2 resource solicitations and included a new Tier 4 specifically to recognize incremental renewable energy delivered into Zone J. Notably, controllable HVDC is defined as eligible for Tier 4 Renewable Energy Credits.

Also required by the CLCPA, the DEC has proposed a rule to create an updated GHG Inventory. The rule implements a new approach to accounting for climate impacts of emissions of various GHGs and setting numerical economy wide GHG limits defined in the CLCPA. The proposed inventory and methodology more highly weight the impact of methane emissions relative to the emissions of carbon dioxide among the inventoried GHGs. The 1990 inventory, methodology, and limits will be finalized as regulations during 2020. In addition, proposed natural gas fueled projects potentially face new challenges under the CLCPA, which requires state agencies to consider consistency with the statewide GHG emission limits when issuing permits.

The CLCPA creates a Climate Action Council (CAC) which is tasked with development and approval of a final scoping plan in 2022. The CAC holds meetings to organize the planning process and has convened several advisory panels focused on various sectors of the economy (such as power generation, transportation, and energy efficiency and housing) to perform more detailed evaluations. The work of the advisory panels will inform the CAC scoping plan contents.

To inform policymakers, the NYISO and its consultants completed two studies in 2020 examining the impact of the CLCPA targets on the future supply mix needed to match future expected hourly loads. Both the Brattle *Grid in Transition* and the Analysis Group *Climate Change Phase 2 Study* showed the long-term need for emissions-free dispatchable resources to operate during extended periods of reduced renewable resource output. These studies showed a need for resources with these characteristics even after including the impact of energy storage and load flexibility in the potential supply. The studies also imply increasing ramping demands placed on supply resources primarily to respond to the increased intermittent output of renewable generation.

B.2.9 Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA)

The AREGCBA was signed into law April 3, 2020 to assist in the achievement of the clean energy and environmental targets outlined in the CLCPA. The Act requires the PSC to establish new planning processes to enable the transmission and distribution expansion to support the CLCPA targets. On May 14, 2020, the PSC commenced a proceeding to implement the Act with respect to utility-based plans for upgrades to local transmission and distribution needed to support the mandates of the CLCPA. Utilities submitted preliminary upgrade proposals by August 1, 2020. On October 15, 2020, the PSC designated the Northern New York transmission projects as priority transmission projects to be carried out by NYPA. The DPS-led working group filed a report at the PSC on November 2, 2021. The report addresses local transmission system needs, proposals for planning transparency, accounting for CLCPA benefits in planning and investment criteria, and cost containment, cost allocation and cost recovery mechanisms for transmission projects. The DPS held a technical conference on the report and recommendations on November 23, 2020.

The AREGCBA also creates an Office of Renewable Energy Siting in the Department of State to speed the permitting timeline of large-scale renewable energy facilities. It also directs the PSC and NYSERDA to advance “Build Ready” projects that package sites and 20-year renewable energy credit contracts in competitive procurements with interested developers. On October 15, 2020, the PSC issued an order to authorize NYSERDA to begin procurement of Build Ready sites and projects as early as 2022.

B.3 Frequency of Implementing Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2022 EOP capacity values are based on recent actual data and NYISO forecasts. ~~For this year's IRM study, load and generator SCRs were combined into one step and the EDRP was eliminated.~~ SCR calls were limited to 5 per month. Table B.2 below presents the expected EOP frequencies for the 2022 Capability Year assuming the 19.1% base case IRM with ELR modeling. Table B.3 presents SCR calls by months.

Table B.2 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs (Load and Generator)	38.1
2	5% manual voltage reduction	24.3
3	30-minute reserve to zero	23.6
4	5% remote controlled voltage reduction	23.2
5	Voluntary load curtailment	20.2
6	Public appeals	20.0
7	Emergency purchases	20.0
8	10-minute reserve to zero	0.3
9	Customer disconnections	0.1

Note 1: These results are subject to additional study in 2021.
Note 2: The expected implementation days per year reported in each EOP step are the expected number of days that MARS calls for that EOP step. If a EOP step has a limitation on the number of days that it can provide load relief, such as the 5 days per month limit for SCRs, it will provide no load relief after the 5th day.

Table B.3 SCR Calls Per Month

Month	Days/Month
JAN	2.4
FEB	4.2
MAR	1.5
APR	0.0
MAY	0.2
JUN	5.8
JUL	7.0
AUG	10.6
SEP	4.1
OCT	0.5
NOV	0.2
DEC	1.6

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, LI and G-J).

Table C.1 Historical NYCA Capacity Parameters

Capability Year (May - April)	Base Case IRM (%)	EC Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYISO Approved J LCR (%)	NYISO Approved K LCR (%)	NYISO Approved G-J LCR (%)
2000	15.5	18.0		80.0	107.0	
2001	17.1	18.0		80.0	98.0	
2002	18.0	18.0		80.0	93.0	
2003	17.5	18.0		80.0	95.0	
2004	17.1	18.0	11.90	80.0	99.0	
2005	17.6	18.0	12.00	80.0	99.0	
2006	18.0	18.0	11.59	80.0	99.0	
2007	16.0	16.5	11.30	80.0	99.0	
2008	15.0	15.0	8.35	80.0	94.0	
2009	16.2	16.5	7.17	80.0	97.5	
2010	17.9	18.0	6.12	80.0	104.5	
2011	15.5	15.5	6.03	81.0	101.5	
2012	16.1	16.0	5.35	83.0	99.0	
2013	17.1	17.0	6.58	86.0	105.0	
2014	17.0	17.0	6.38	85.0	107.0	88.0
2015	17.3	17.0	7.01	83.5	103.5	90.5
2016	17.4	17.5	6.21	80.5	102.5	90.0
2017	18.1	18.0	7.04	81.5	103.5	91.5
2018	18.2	18.2	8.08	80.5	103.5	94.5
2019	16.8	17.0	6.72	82.8	104.1	92.3
2020	18.9	18.9	9.03	86.6	103.4	90.0
2021	20.7	20.7	10.11	80.3	102.9	87.6

C.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO Web site3, NYISO Staff regularly post summer and winter Capability Period ICAP and UCAP calculations for NYCA Locational Areas and Transmission District Loads. This information has been compiled and posted since 2006.

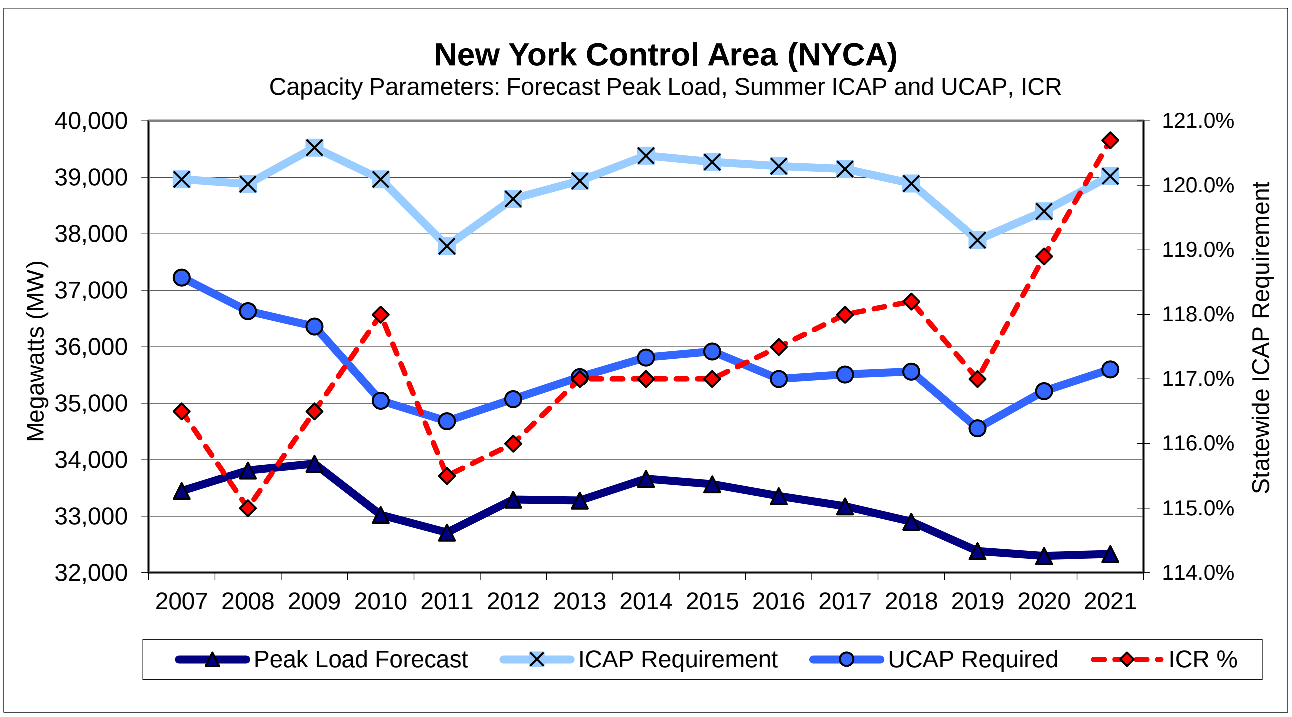
Locational ICAP/UCAP calculations are produced for NYC, LI, G-J Locality and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the summer capability periods for the most recent 15 years beginning in 2007 .

This data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, De-rating Factors, UCAP Requirements, IRMs, 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.

C.1.1 New York Control Area ICAP to UCAP Translation

Table C.2 NYCA ICAP to UCAP Translation

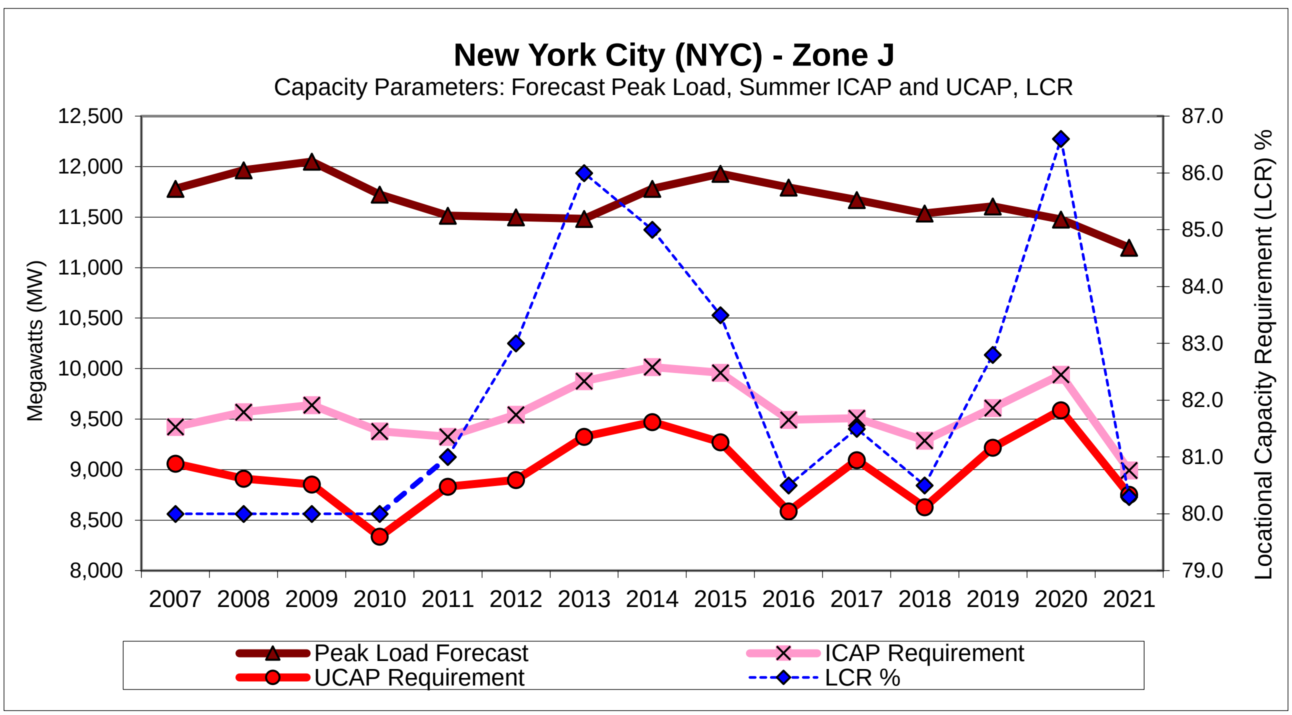
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	39,529	36,362	107.2
2010	33,025	118.0	0.1007	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
2014	33,666	117.0	0.0908	39,389	35,812	106.4
2015	33,567	117.0	0.0854	39,274	35,920	107.0
2016	33,359	117.5	0.0961	39,197	35,430	106.2
2017	33,178	118.0	0.0929	39,150	35,513	107.0
2018	32,903	118.2	0.0856	38,891	35,562	108.1
2019	32,383	117.0	0.0879	37,888	34,558	106.7
2020	32,296	118.9	0.0830	38,400	35,213	109.3
2021	32,333	120.7	0.0877	39,026	35,604	110.1



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

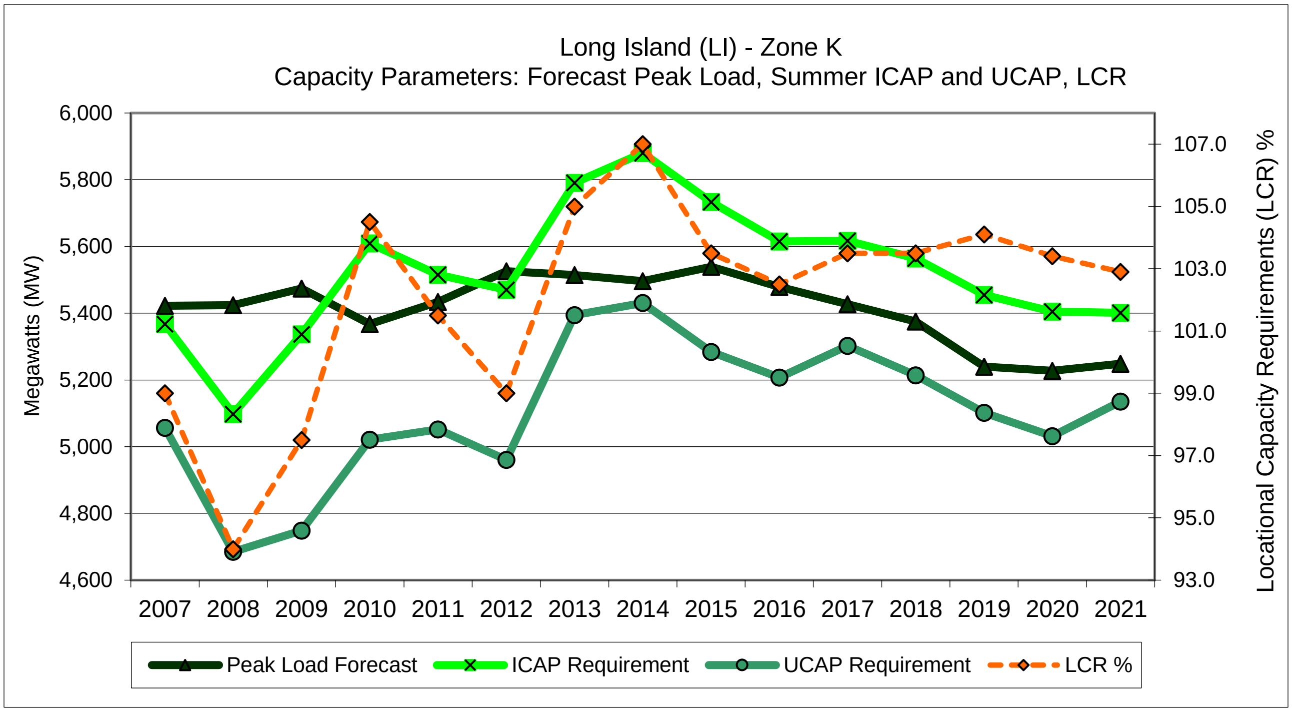
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855	73.5
2010	11,725	80.0	0.1113	9,380	8,336	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
2014	11,783	85.0	0.0544	10,015	9,471	80.4
2015	11,929	83.5	0.0692	9,961	9,272	77.7
2016	11,794	80.5	0.0953	9,494	8,589	72.8
2017	11,670	81.5	0.0437	9,511	9,095	77.9
2018	11,539	80.5	0.0709	9,289	8,630	74.8
2019	11,607	82.8	0.0409	9,611	9,217	79.4
2020	11,477	86.6	0.0351	9,939	9,590	83.6
2021	11,199	80.3	0.0269	8,993	8,751	78.1



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

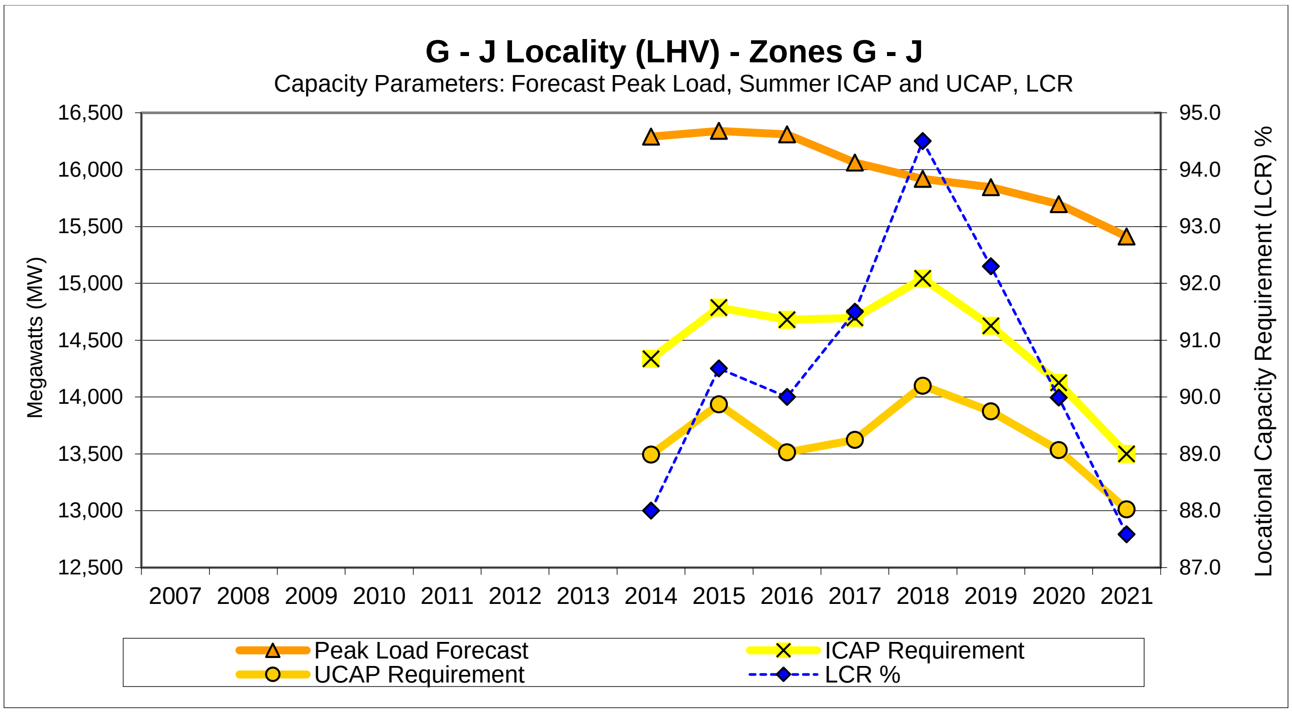
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,749	86.8
2010	5,368	104.5	0.1049	5,610	5,021	93.5
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
2014	5,496	107.0	0.0765	5,880	5,431	98.8
2015	5,539	103.5	0.0783	5,733	5,284	95.4
2016	5,479	102.5	0.0727	5,615	5,207	95.0
2017	5,427	103.5	0.0560	5,617	5,302	97.7
2018	5,376	103.5	0.0628	5,564	5,214	97.0
2019	5,240	104.1	0.0647	5,455	5,102	97.4
2020	5,228	103.4	0.0691	5,405	5,032	96.3
2021	5,249	102.9	0.0491	5,401	5,136	97.9



C.1.4 GHIJ ICAP to UCAP Translation

Table C.5 GHIJ ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2014	16,291	88.0	0.0587	14,336	13,495	82.8
2015	16,340	90.5	0.0577	14,788	13,934	85.3
2016	16,309	90.0	0.0793	14,678	13,514	82.9
2017	16,061	91.5	0.0731	14,696	13,622	84.8
2018	15,918	94.5	0.0626	15,042	14,100	88.6
2019	15,846	92.3	0.0514	14,625	13,874	87.6
2020	15,695	90.0	0.0418	14,124	13,534	86.2
2021	15,411	87.6	0.0361	13,498	13,011	84.4

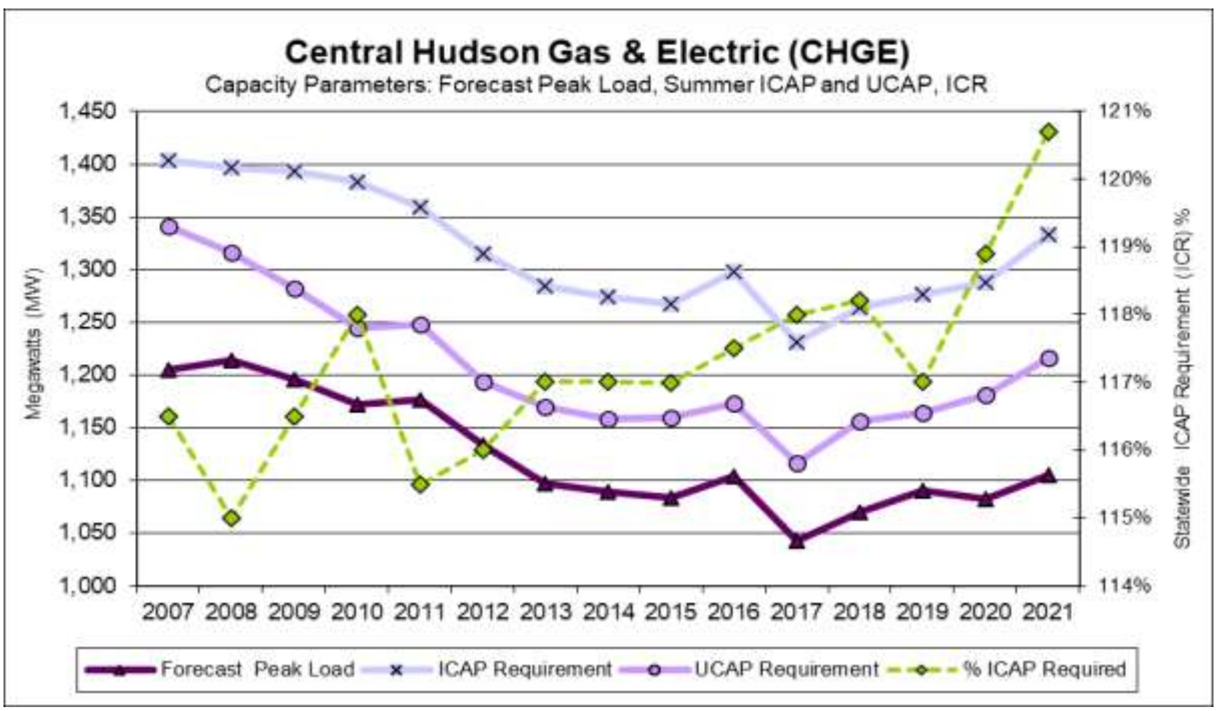


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

Table C.6 Central Hudson Gas & Electric ICAP to UCAP Translation

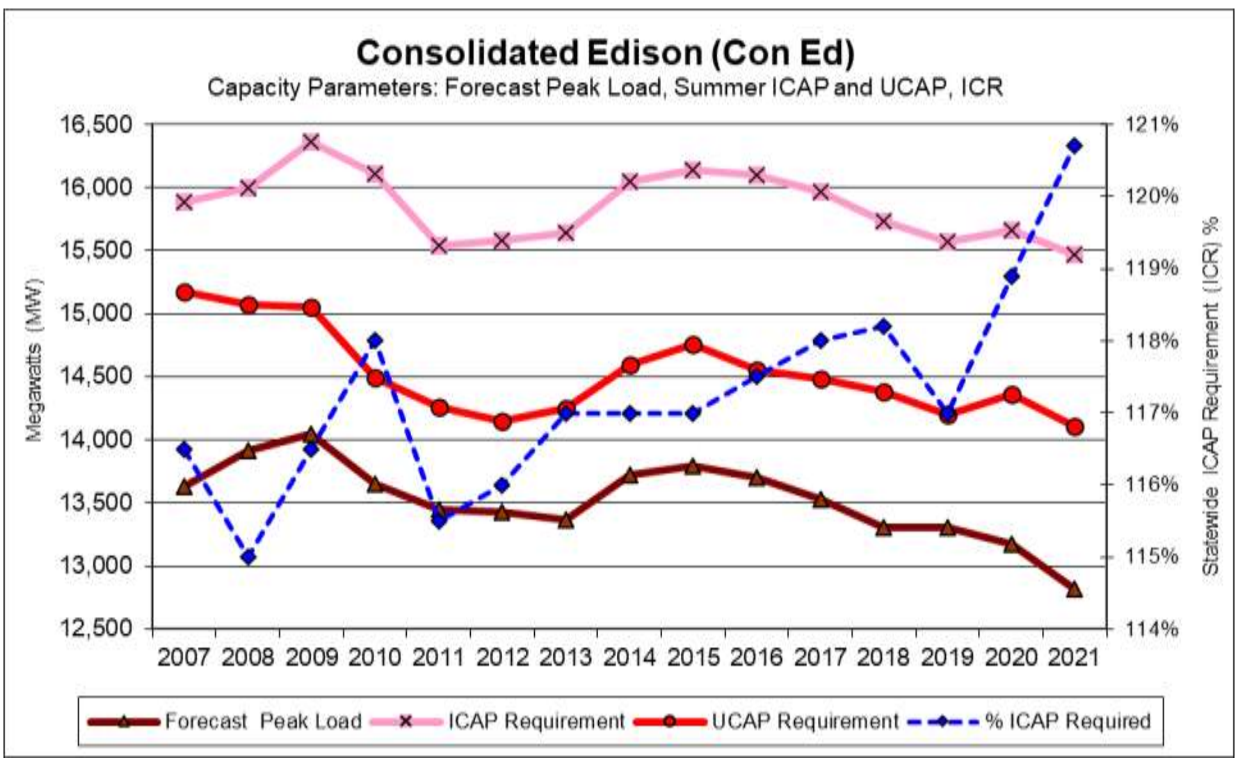
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2007	1,205.0	1,403.8	1,341.2	116.5%	111.3%
2008	1,214.1	1,396.2	1,315.5	115.0%	108.4%
2009	1,196.3	1,393.7	1,282.1	116.5%	107.2%
2010	1,172.3	1,383.3	1,244.0	118.0%	106.1%
2011	1,176.9	1,359.3	1,247.9	115.5%	106.0%
2012	1,133.3	1,314.6	1,193.9	116.0%	105.3%
2013	1,097.5	1,284.1	1,169.7	117.0%	106.6%
2014	1,089.2	1,274.4	1,158.7	117.0%	106.4%
2015	1,083.6	1,267.8	1,159.5	117.0%	107.0%
2016	1,104.2	1,297.4	1,172.7	117.5%	106.2%
2017	1,043.1	1,230.9	1,116.5	118.0%	107.0%
2018	1,069.7	1,264.4	1,156.2	118.2%	108.1%
2019	1,090.8	1,276.3	1,164.1	117.0%	106.7%
2020	1,082.7	1,287.3	1,180.5	118.9%	109.0%
2021	1,104.5	1,333.1	1,216.2	120.7%	110.1%



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

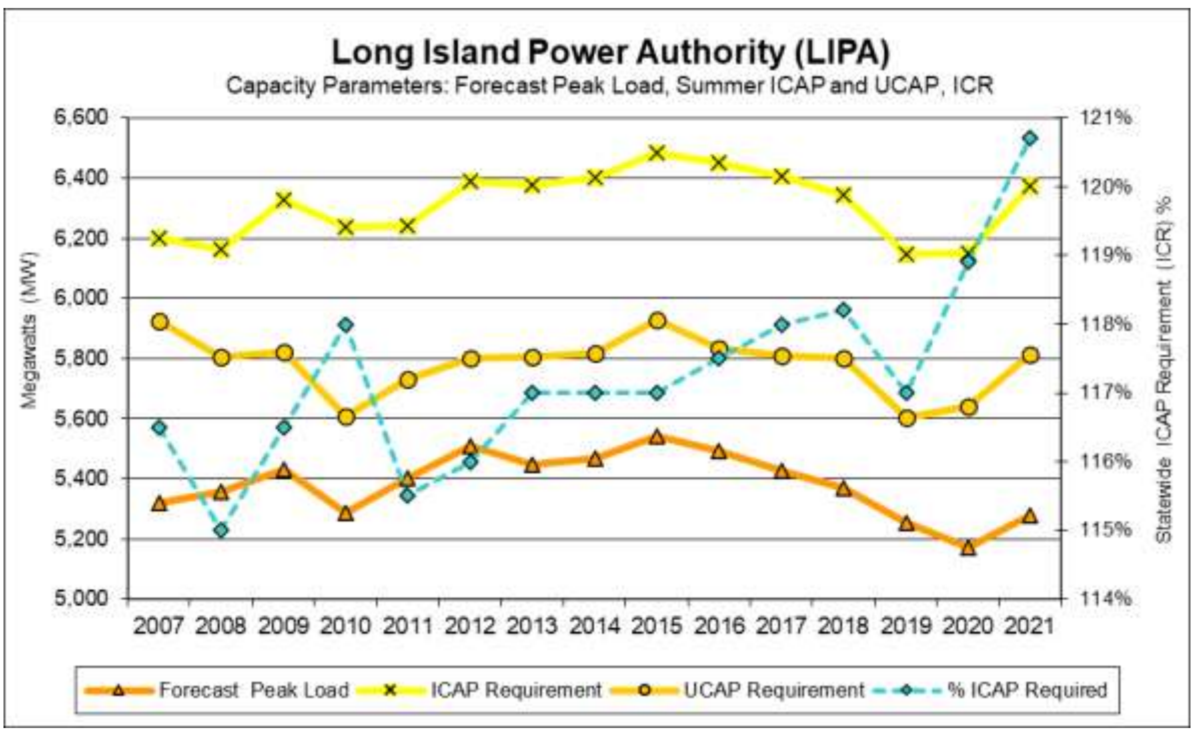
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	13,633.6	15,883.1	15,174.7	116.5%	111.3%
2008	13,911.1	15,997.8	15,073.1	115.0%	108.4%
2009	14,043.0	16,360.1	15,049.6	116.5%	107.2%
2010	13,654.9	16,112.8	14,490.2	118.0%	106.1%
2011	13,450.5	15,535.3	14,261.4	115.5%	106.0%
2012	13,430.5	15,579.4	14,149.2	116.0%	105.4%
2013	13,370.8	15,643.8	14,250.0	117.0%	106.6%
2014	13,718.7	16,050.9	14,593.5	117.0%	106.4%
2015	13,793.0	16,137.8	14,759.6	117.0%	107.0%
2016	13,704.6	16,102.9	14,555.4	117.5%	106.2%
2017	13,534.0	15,970.1	14,486.5	118.0%	107.0%
2018	13,309.6	15,732.0	14,385.3	118.2%	108.1%
2019	13,305.5	15,567.4	14,199.1	117.0%	106.7%
2020	13,170.0	15,659.1	14,359.4	118.9%	109.0%
2021	12,816.7	15,469.8	14,113.1	120.7%	110.1%



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

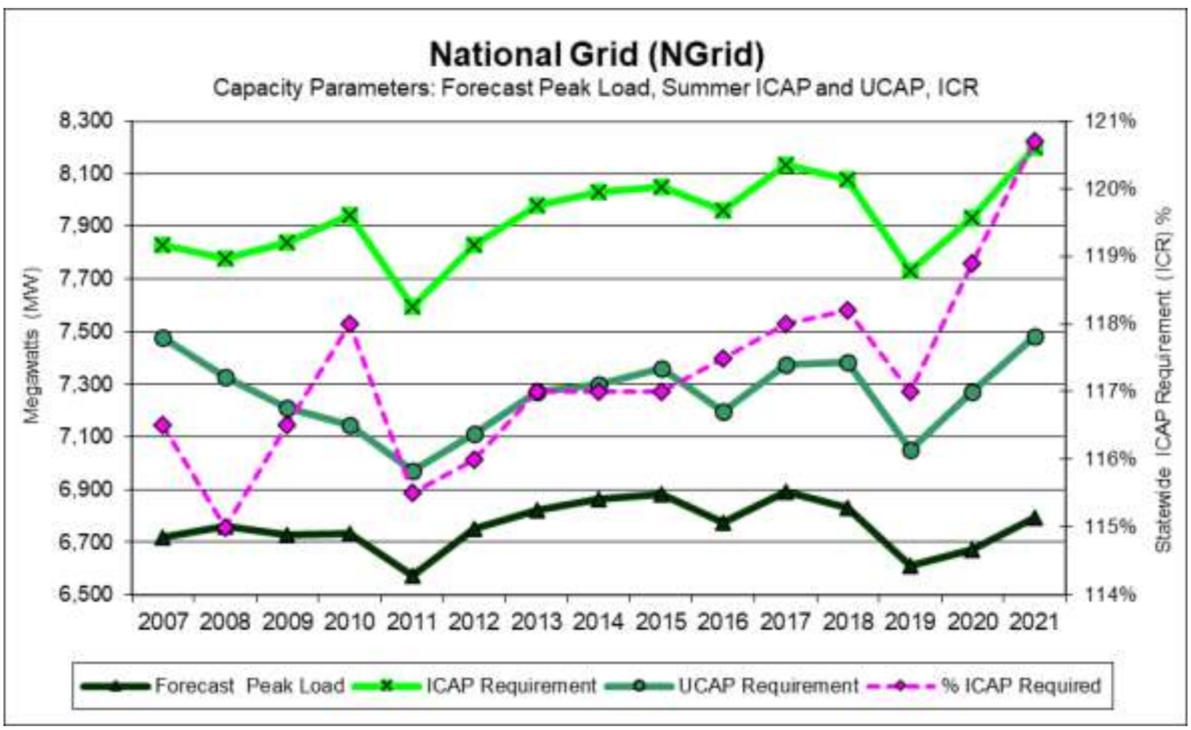
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	5,321.8	6,199.9	5,923.4	116.5%	111.3%
2008	5,358.9	6,162.7	5,806.5	115.0%	108.4%
2009	5,431.7	6,327.9	5,821.1	116.5%	107.2%
2010	5,286.0	6,237.5	5,609.4	118.0%	106.1%
2011	5,404.3	6,242.0	5,730.1	115.5%	106.0%
2012	5,508.3	6,389.6	5,803.1	116.0%	105.4%
2013	5,448.9	6,375.2	5,807.2	117.0%	106.6%
2014	5,470.1	6,400.0	5,818.9	117.0%	106.4%
2015	5,541.3	6,483.3	5,929.7	117.0%	107.0%
2016	5,491.3	6,452.3	5,832.2	117.5%	106.2%
2017	5,427.2	6,404.1	5,809.1	118.0%	107.0%
2018	5,368.1	6,345.1	5,802.0	118.2%	108.1%
2019	5,253.0	6,146.0	5,605.8	117.0%	106.7%
2020	5,172.9	6,150.6	5,640.1	118.9%	109.0%
2021	5,279.7	6,372.6	5,813.7	120.7%	110.1%



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

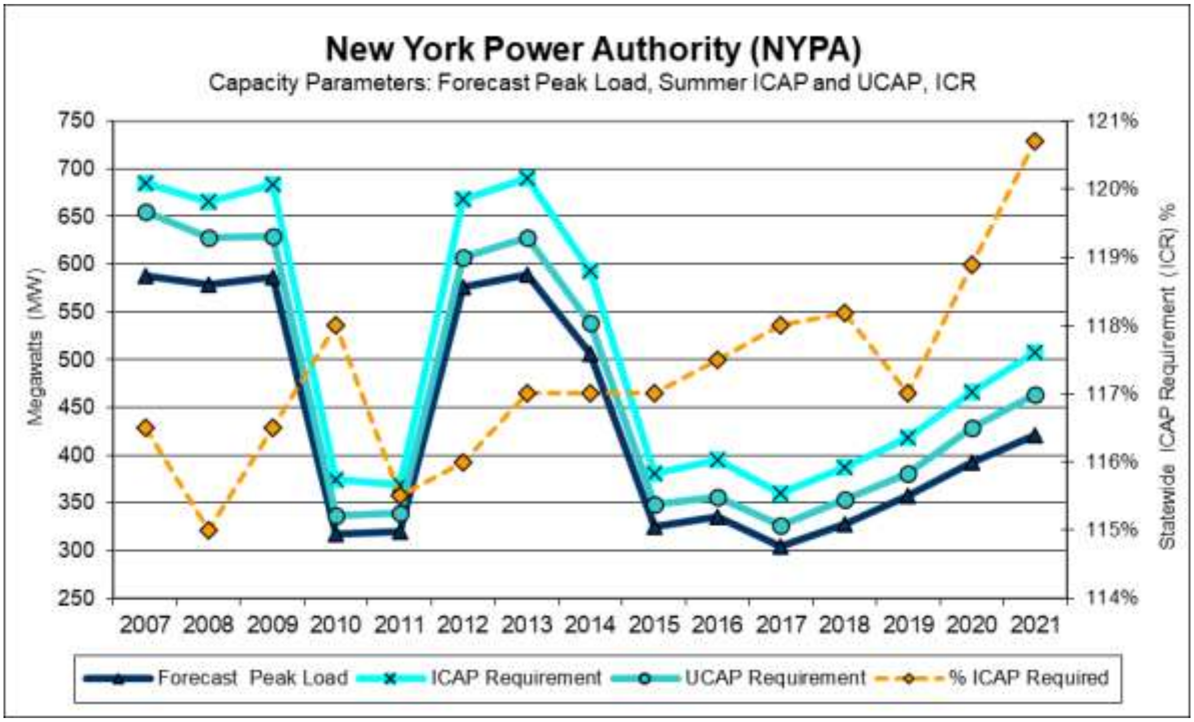
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	6,718.6	7,827.2	7,478.1	116.5%	111.3%
2008	6,762.5	7,776.9	7,327.3	115.0%	108.4%
2009	6,728.4	7,838.6	7,210.7	116.5%	107.2%
2010	6,732.1	7,943.9	7,144.0	118.0%	106.1%
2011	6,574.7	7,593.8	6,971.1	115.5%	106.0%
2012	6,749.1	7,828.9	7,110.3	116.0%	105.4%
2013	6,821.3	7,980.9	7,269.8	117.0%	106.6%
2014	6,861.9	8,028.4	7,299.4	117.0%	106.4%
2015	6,880.3	8,049.9	7,362.5	117.0%	107.0%
2016	6,776.0	7,961.8	7,196.7	117.5%	106.2%
2017	6,891.4	8,131.9	7,376.4	118.0%	107.0%
2018	6,833.0	8,076.6	7,385.2	118.2%	108.1%
2019	6,608.8	7,732.3	7,052.6	117.0%	106.7%
2020	6,670.2	7,930.9	7,272.6	118.9%	109.0%
2021	6,793.0	8,199.2	7,480.1	120.7%	110.1%



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

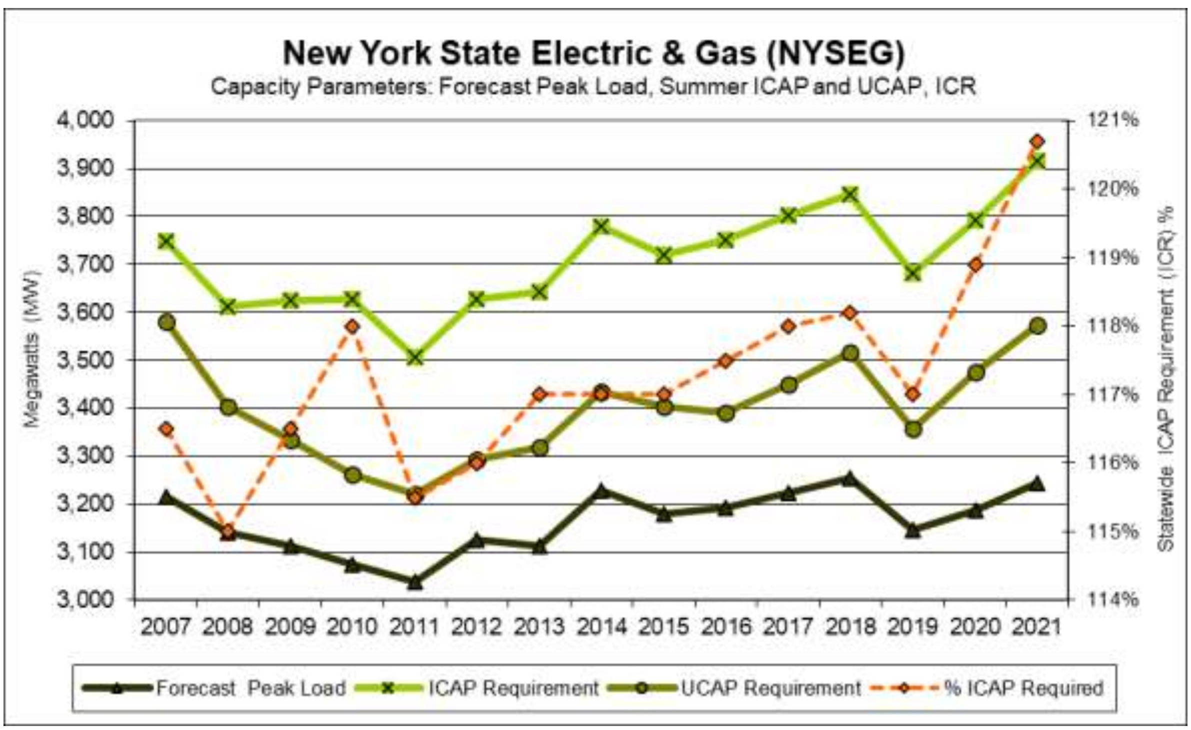
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2007	588.2	685.3	654.7	116.5%	111.3%
2008	579.1	666.0	627.5	115.0%	108.4%
2009	587.2	684.1	629.3	116.5%	107.2%
2010	317.6	374.8	337.0	118.0%	106.1%
2011	319.7	369.3	339.0	115.5%	106.0%
2012	576.1	668.3	606.9	116.0%	105.3%
2013	589.3	689.5	628.1	117.0%	106.6%
2014	506.3	592.4	538.6	117.0%	106.4%
2015	325.8	381.2	348.6	117.0%	107.0%
2016	336.0	394.8	356.9	117.5%	106.2%
2017	305.0	359.9	326.5	118.0%	107.0%
2018	327.6	387.2	354.1	118.2%	108.1%
2019	357.5	418.3	381.5	117.0%	106.7%
2020	392.7	466.9	428.2	118.9%	109.0%
2021	420.8	507.9	463.4	120.7%	110.1%



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

Table C.11 NYSEG ICAP to UCAP Translation

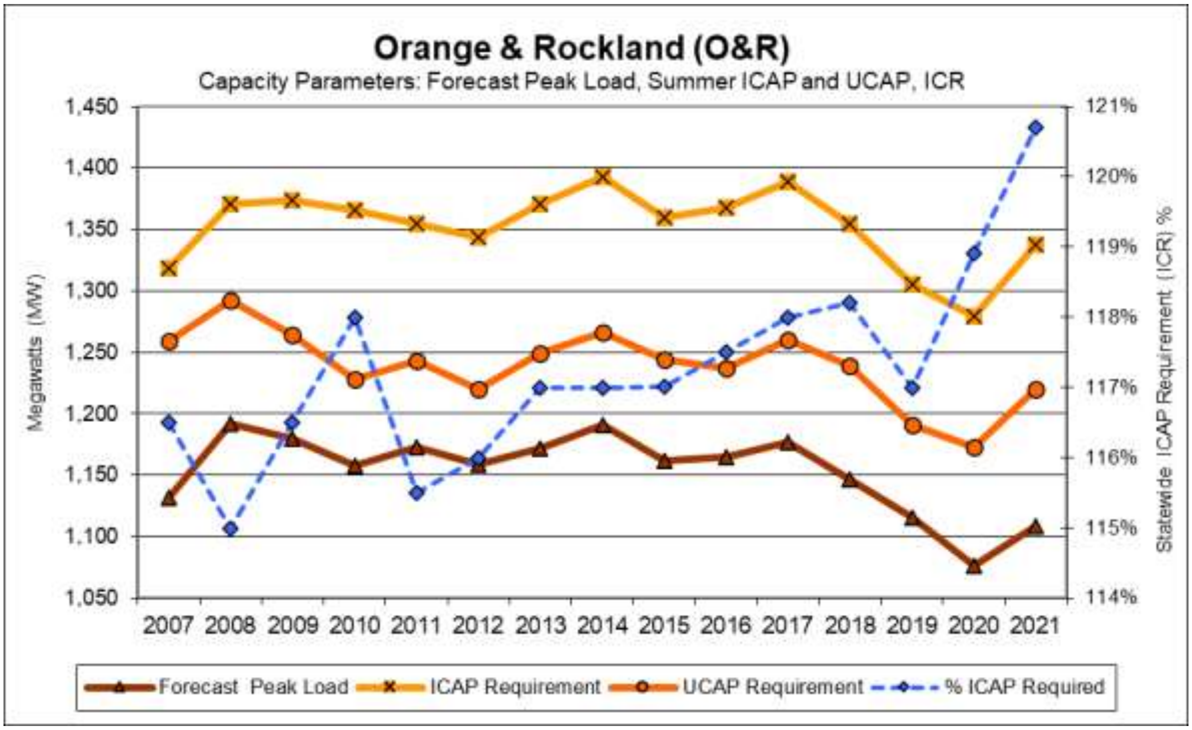
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	3,216.9	3,747.7	3,580.5	116.5%	111.3%
2008	3,141.1	3,612.3	3,403.5	115.0%	108.4%
2009	3,111.8	3,625.3	3,334.9	116.5%	107.2%
2010	3,075.0	3,628.5	3,263.1	118.0%	106.1%
2011	3,037.0	3,507.7	3,220.1	115.5%	106.0%
2012	3,126.7	3,627.0	3,294.0	116.0%	105.4%
2013	3,113.4	3,642.7	3,318.1	117.0%	106.6%
2014	3,229.1	3,778.1	3,435.0	117.0%	106.4%
2015	3,179.8	3,720.4	3,402.7	117.0%	107.0%
2016	3,191.6	3,750.1	3,389.7	117.5%	106.2%
2017	3,222.9	3,803.0	3,449.7	118.0%	107.0%
2018	3,254.0	3,846.2	3,517.0	118.2%	108.1%
2019	3,146.6	3,681.5	3,357.9	117.0%	106.7%
2020	3,188.4	3,791.0	3,476.3	118.9%	109.0%
2021	3,244.8	3,916.5	3,573.0	120.7%	110.1%



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

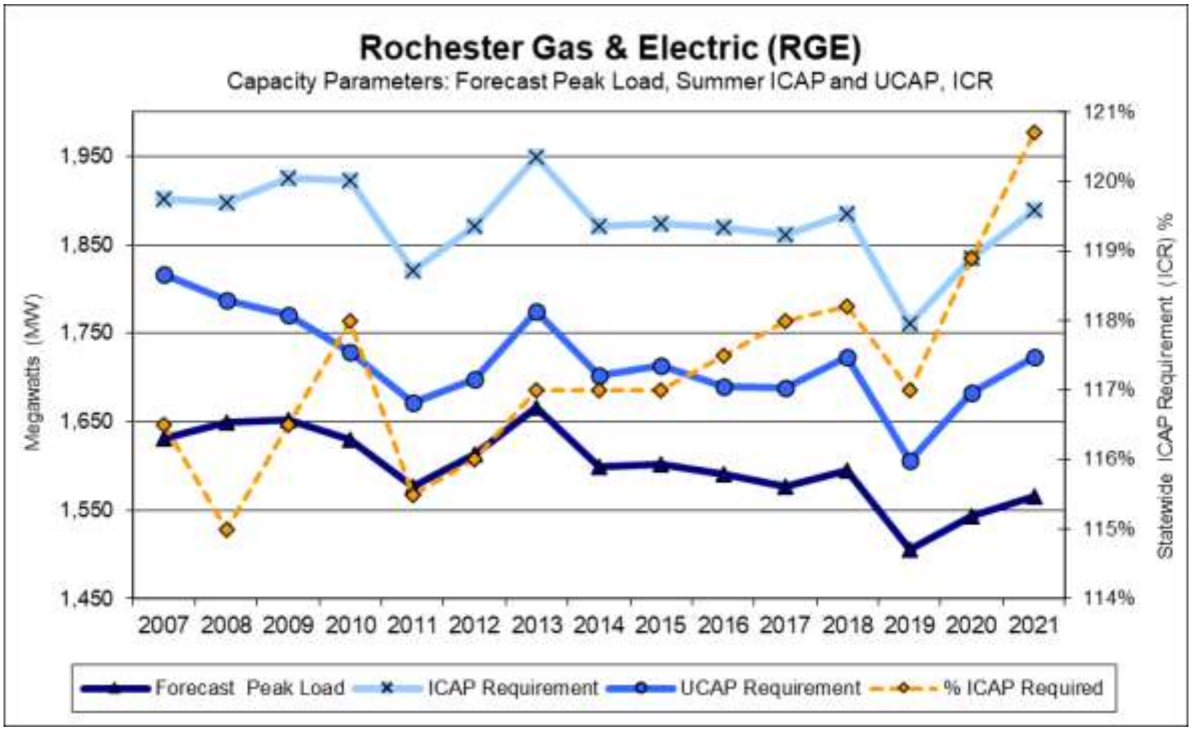
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	1,131.5	1,318.2	1,259.4	116.5%	111.3%
2008	1,192.3	1,371.1	1,291.9	115.0%	108.4%
2009	1,179.5	1,374.1	1,264.0	116.5%	107.2%
2010	1,157.4	1,365.7	1,228.2	118.0%	106.1%
2011	1,172.7	1,354.5	1,243.4	115.5%	106.0%
2012	1,158.3	1,343.6	1,220.3	116.0%	105.4%
2013	1,171.7	1,370.9	1,248.7	117.0%	106.6%
2014	1,190.8	1,393.2	1,266.7	117.0%	106.4%
2015	1,162.2	1,359.8	1,243.7	117.0%	107.0%
2016	1,164.3	1,368.1	1,236.6	117.5%	106.2%
2017	1,177.3	1,389.2	1,260.2	118.0%	107.0%
2018	1,146.2	1,354.8	1,238.8	118.2%	108.1%
2019	1,115.5	1,305.1	1,190.4	117.0%	106.7%
2020	1,075.9	1,279.3	1,173.1	118.9%	109.0%
2021	1,108.4	1,337.8	1,220.5	120.7%	110.1%



C.2.8 Rochester Gas & Electric (RGE)

Table C.13 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2007	1,631.8	1,901.0	1,816.3	116.5%	111.3%
2008	1,649.4	1,896.8	1,787.2	115.0%	108.4%
2009	1,652.3	1,924.9	1,770.7	116.5%	107.2%
2010	1,629.7	1,923.0	1,729.4	118.0%	106.1%
2011	1,576.4	1,820.7	1,671.4	115.5%	106.0%
2012	1,612.3	1,870.3	1,698.6	116.0%	105.4%
2013	1,665.7	1,948.9	1,775.2	117.0%	106.6%
2014	1,599.6	1,871.5	1,701.6	117.0%	106.4%
2015	1,601.3	1,873.5	1,713.5	117.0%	107.0%
2016	1,590.8	1,869.2	1,689.6	117.5%	106.2%
2017	1,576.9	1,860.7	1,687.9	118.0%	107.0%
2018	1,594.3	1,884.5	1,723.1	118.2%	108.1%
2019	1,505.5	1,761.4	1,606.6	117.0%	106.7%
2020	1,543.3	1,835.0	1,682.7	118.9%	109.0%
2021	1,565.2	1,889.2	1,723.5	120.7%	110.1%



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 like 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 for the previous five calendar years. This data can be scaled to create wind profiles for new wind generation facilities.

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:

- Production hourly wind data.
- Maintenance cycle and duration
- EFOR (not related to fuel)

In general, effective wind capacity depends primarily on the availability of the wind. Wind farms in New York on average have annual capacity factors that are based on their nameplate ratings. A wind plant’s output can range from close to nameplate under favorable wind conditions to zero when the wind does not blow. On average, a wind plant’s output is higher at night, and has higher output on average in the winter versus the summer.

Another measure of a wind generator’s contribution to resource adequacy is its effective capacity which is its expected output during the summer peak hours of 2 p.m. to 6 p.m. for the months of June through August. The effective capacity value for wind generation in New York is based on actual hourly plant output over the previous five-year period – 2016 through 2020 for this year’s study, for new units the zonal hourly averages or averages for nearby units will be used. Wind shapes years are selected randomly from those years for each simulation year.

Appendix D

Glossary of Terms

D. Glossary

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility can provide service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.
Bubble	A symbolic representation introduced for certain purposes in the GE-MARS model as an area that may be an actual zone, multiple areas or a virtual area without actual load.
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.
Energy Limited Resource (ELR)	Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day.
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).

Term	Definition
Installed Capacity (ICAP)	Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.
Installed Capacity Requirement (ICR)	The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.
Installed Reserve Margin (IRM)	That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power used by devices connected to an electrical generating system. (IEEE Power Engineering)
Load Relief	Load reduction accomplished by voltage reduction or load shedding or both. Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.
Load Shedding	The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. Load shall normally all be shed within 5 minutes of the order.
Load Serving Entity (LSE)	In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.
Locational Capacity Requirement (LCR)	Due to transmission constraints, that portion of the NYCA ICAP requirement that must be electrically located within a zone, in order to ensure that sufficient energy and capacity are available in that zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to three transmission constrained zones, New York City, Long Island, and the Lower Hudson Valley, 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.

Term	Definition
New York Independent System Operator (NYISO)	The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.
New York State Bulk Power System (NYS Bulk Power System or BPS)	The portion of the bulk power system within the New York Control Area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.
New York State Reliability Council, LLC (NYSRC)	An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.
New York State (NYS) Transmission System	The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.
Operating Limit	The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.
Operating Procedures	A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.
Operating Reserves	Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load, and can do so within a specified time period.
Reserves	In normal usage, reserve is the amount of capacity available in excess of the demand.
Resource	The total contributions provided by supply-side and demand-side facilities and/or actions.
Stability	The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
Thermal Limit	The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Term	Definition
Transmission District	The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.
Transmission Owner	Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/NYISO Agreement.
Unforced Capacity:	The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.
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.