August 19, 2013 NYISO Demand Curve Reset Proposal
Comments of the Indicated New York Transmission Owners
August 30, 2013

Central Hudson, Con Edison, National Grid, NYPA, and NYSEG/RG&E offer the following comments on the August 19, 2013 draft of the Proposed NYISO Installed Capacity Demand Curves for the Capability Years 2014/2015, 2015/2016 and 2016/2017 ("NYISO Proposal"). The indicated New York Transmission Owners are continuing their review of various aspects of the NYISO Proposal and the detailed assessment ("Final Report") prepared by Sargent & Lundy ("S&L") and National Economic Research Associates ("NERA"), and may provide additional comments at a later date.

Technology Choice

The Market Services Tariff ("MST") requires the NYISO to determine the Cost of New Entry ("CONE") based upon the cost of a peaking plant. It further states that a "peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable." (MST Section 5.14.1.2)

The NYISO Proposal would base the CONE for the statewide capacity market on the cost of a single-unit, simple cycle Frame turbine without Selective Catalytic Reduction (SCR) and for other markets on the cost of a two-unit, simple cycle LMS 100 plant. The NYISO Proposal presents the cost of a Frame turbine with SCR in various regions of the state as a supplement to the various units evaluated in the Final Report. With the exception of the plant utilized to determine the CONE for the statewide market, none of these units fulfills the requirements of the Market Services Tariff.

1. **The Proposed Lower Hudson Valley Proxy Unit Is Not Economically Viable**

The simple cycle GE LMS 100 plant chosen by the NYISO as the proxy unit in the Lower Hudson Valley (LHV) is not economically viable as required under the MST. As shown in the table below, at least three technologies are more cost-effective than a simple cycle GE LMS 100 plant. An LMS 100 plant would likely be unable to compete with these alternatives under equilibrium conditions. In fact, there are no projects in the interconnection queue that resemble the chosen proxy unit, except for a single project in New York City.

Table 1. Comparison of Net Costs for Potential LHV Proxy Units

Technology	**Net CONE ($/kw-year)**	**Difference**
2 GE LMS 100 (With SCR) - Dutchess	$171.75	
Combined Cycle - Rockland	$156.39	-8.94%
2 Frame GTs (With SCR) – Dutchess	$109.31	-36.36%
2 Frame GTs (With SCR) – Rockland	$106.76	-37.84%
1 Frame GT (No SCR) – Dutchess (Interruptible Gas) [1]	$119.47	-30.44%
1 Frame GT (No SCR)– Dutchess (Peaking Contract) [1]	$111.11	-35.31%

[1] See Appendix for details of these calculations.

2. The Assumption That The LHV Proxy Unit Must be Dual Fuel Capable Is Flawed

The NYISO Proposal for the Lower Hudson Valley CONE rejects the use of a Frame Unit without SCR based upon the finding that the proxy unit must be dual fuel capable. While the Indicated NYTOs appreciate and support the NYISO's efforts to examine and address fuel security issues across the state, we do not believe it is reasonable to reflect the cost of dual fuel capability in the Lower Hudson Valley CONE at this time.

The NYISO Proposal appears to endorse the reasoning outlined in the Final Report for assuming the Lower Hudson Valley proxy unit will be dual fuel capable:

> "[M]ore severe air quality issues in [Zones G-K] and, correspondingly more stringent NOx emission requirement, eliminates the option of accepting an annual operational limit to comply with applicable emission rate limitations. The maximum number of hours that the unit could run with an operational limit for NOx would be too low to consider the unit practical or economical in these Zones. Further, the applicable peaking plant for this area is assumed to be a dual fuel unit. Burning oil would increase NOx emissions and further reduce the allowable operating hours." (Final Report, p. 7)

We find this reasoning to be flawed in two important respects. First, emissions requirements in most areas of the Lower Hudson Valley are no more restrictive than in Zone C or Zone F. As show in Figure II-1 of the Final Report and Tables 1 and 2 of the NYISO Proposal, Prevention of Significant Deterioration ("PSD") emissions thresholds in Zone F and most of the Lower Hudson Valley, including Dutchess, Putnam, Sullivan, Ulster and portions of Orange counties, are effectively identical. The more restrictive emissions restrictions described in the Final Report apply only in Rockland, Westchester and lower Orange counties. Table II-6 of the Final Report acknowledges that fact a simple cycle GT could operate up to 1,056 hours per year in Dutchess County without exceeding NOx emission limits, a level that is virtually identical to the 1,075 hours per year permitted in Zone F. We note that two of the three major generation projects proposed in Zones G, H and I in recent years would be located in areas where NOx emissions of up to 40 tons per year would be permitted.

The consultants have conceded this point. At the August 13, 2013 Installed Capacity Working Group (ICAPWG) meeting, the consultants indicated that if they had not assumed that it was preferable for the proxy unit located in the Hudson Valley capacity zone to be dual fuel capable, then there was no technical reason why the simple cycle Frame turbine without SCR could not be used as the proxy unit for the Dutchess County location if it was economically viable.

Second, we question whether it is reasonable to assume that a proxy unit constructed in the Lower Hudson Valley during the three-year reset period (i.e., May 2014 through April 2017) must be dual fuel capable. At present, there is no NYISO dual fuel requirement for generators in the Lower Hudson Valley. Some LDCs – i.e., Con Edison, O&R and Central Hudson – require generators that interconnect with their gas systems to install back-up fuel capability, but the interstate pipelines serving the area, as is typical, have no such requirement. Moreover, neither the NYISO's interconnection requirements nor its capacity market rules require generators to be dual fuel capable, and no proposal to create such a requirement has been made. It is uncertain, at best, that such a dual fuel requirement will take effect in the next three years. Even if such a requirement were adopted during the reset period, it is unlikely that it would apply retroactively to projects already in the interconnection queue or in service before May 2017.

The NYISO Proposal contends that units must be dual fuel capable because (1) a review of gas service tariffs of the Local Distribution Companies (LDC) serving the Hudson Valley reveals that they require generators to have back-up fuel, and (2) recent projects that have been completed or have been proposed in these areas have been dual fuel capable. However, of the three projects presently seeking to interconnect in the Lower Hudson Valley, none have proposed to interconnect to an LDC gas system; each would interconnect directly to an interstate pipeline.[2] Additionally, although two of the projects have proposed to install back-up fuel capability, one has stated that it will be a gas-only facility.[3]

Table 2. LHV Projects in the Interconnection Queue (as of August 2013)

Project	Type	Summer MW	Fuel	Gas Source
CPV Valley I	CC	678	Dual	Millennium
Cricket Valley	CC	1,120	Gas only	Iroquois
Bowline Repowering	CC	775	Dual	Millennium

We suspect this is because these projects see an economic benefit to installing dual fuel capability. But, the gas-fired generation projects proposed in the Lower Hudson Valley are significantly different than the simple cycle plants reviewed in the Final Report. All are combined cycle plants and each is significantly larger than the proxy units evaluated in the report. Projects with these characteristics are likely intended to run at a much higher capacity factor than the simple cycle units evaluated in the Final Report and would potentially benefit, to a greater extent, from the protection dual fuel capability provides against fuel-related outages.

More specifically, large natural gas fired combined cycle generating facilities typically are operated as "base load" generating facilities, not as "peaking" generating facilities. Therefore, these combined cycle generating facilities would be committed and dispatched to operate throughout most of the year and would expect to receive a larger portion of their revenue from the NYISO energy market to pay for their generating facilities' costs. As such, it may be financially worthwhile for generating companies to choose to install dual fuel capability for combined cycle generating facilities in order to continue to receive electric energy revenues during the very cold winter days (e.g., ambient temperature below 20 degrees Fahrenheit) when non-firm natural gas transportation may not be available or when it is more

2 At the very least, the NYISO Proposal should exclude the cost of connecting to an LDC gas system and the associated 27¢ per dth transportation charge. Since none of the projects in the interconnection queue are seeking to interconnect with an LDC's gas system, the cost of LDC transportation is unnecessary and should, therefore, be eliminated from the LHV unit's costs.

3 Cricket Valley Final Environmental Impact Statement, Page 1-13. (Link)

economical to dispatch oil fired generators before gas fired generators because the daily spot market natural gas price exceeds the price of oil, as occurs from time to time. However, in the absence of a comprehensive NYISO dual fuel requirement, it is not reasonable to assume that a simple cycle turbine would need to be dual fuel capable.

3. **A Frame Turbine With SCR Should Serve As The Basis for The CONE Wherever It Is the Most Cost Effective Option**

The NYISO Proposal provides the estimated cost of a simple cycle Frame turbine plant with SCR in various regions of the state, but recommends against using those estimates as the basis for the CONEs in those areas. The NYISO Proposal further states that the consultants were skeptical that this configuration was feasible and accepts their recommendation to base the CONEs on other units because of "technical challenges, unsuccessful projects and lack of market acceptance". (p. 27) The Final Report states that a simple cycle Frame turbine plant with SCR was not evaluated due to problems with controlling exhaust temperatures for inclusion of SCR technology. It cites various instances when Frame turbines with SCRs have failed to operate properly.

However, there is evidence that exhaust temperatures could be reduced prior to treatment with SCR. In fact, GE has developed a design specifically to achieve that purpose. At least some market participants consider the potential technical issues identified by the consultants sufficiently resolved. The Marsh Landing Generating Station in California, which is owned by NRG Energy, Inc. (formerly owned by GenOn prior to its merger with NRG), combines Frame model turbines in simple cycle configuration with SCR. The facility commenced commercial operation on May 1, 2013. Notably, the facility utilizes the same Siemens SGT6-5000F technology that was examined by the consultants in their Final Report.

In addition, we note that the PJM tariff requires that the reference resource used to determine its demand curve be modeled as a Frame unit with SCR technology.

> "Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in CONE Areas 1, 2, 3, and 4, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh." - PJM OATT, Attachment DD, 2.58

By failing to evaluate these options, the report fails to demonstrate that the recommended CONE is based on an economically-viable plant. We, therefore, urge the NYISO to utilize the Frame model turbine with SCR as the proxy unit in any region where that option is the most cost-effective.

Zero-Crossing Points

In the presentation made at the August 22, 2013 ICAPWG meeting, David Patton described a new approach for setting the zero-crossing points for the ICAP demand curves for 2014-17, which is based on the marginal impact that additional capacity in a capacity zone has on loss of load expectation (LOLE). Dr. Patton also "recommend[ed that] the NYISO establish [his proposal] as the methodology that will be employed in future [demand curve] resets and for new capacity zones."

The TOs believe it would be premature to commit at this time to using this methodology in future demand curve resets. Complete data from Dr. Patton's analysis that include the LOLE at each level of capacity in a capacity zone, and the resulting change in LOLE associated with the addition of capacity in each capacity zone, have not yet been presented to market participants, much less made available to them for their review. This review may lead to other questions about the proposed approach; for example, while Dr. Patton's presentation claimed that the marginal impact on LOLE of additional capacity in a capacity zone was roughly a linear function of the amount of capacity in that capacity zone, including additional data points may make the existence of any such relationship much less clear. Moreover, Dr. Patton has not presented any evidence demonstrating that the marginal impact on LOLE of additional capacity in a capacity zone will continue to be a linear function of the amount of capacity in that capacity zone in the future.

The August 22 meeting was the first, and only time that Dr. Patton's proposal was discussed with market participants, so market participants have not had sufficient opportunity to review and critique it. Moreover, significant aspects of the proposed methodology remain unclear. For example, in Dr. Patton's analysis, capacity was added in Load Zones A, C and D (i.e., in the portion of the NYCA that is not included in another capacity zone) to determine the impact of additional capacity on the rate of change in LOLE, but in his analysis for the new G-J capacity zone, capacity was added throughout the G-J capacity zone, despite the fact that Load Zone J comprises its own capacity zone; the rationale for this inconsistency is unclear. Further, while we understand that Dr. Patton's analysis assumed that all capacity zones were originally at their respective minimum capacity requirements in the "base case," and then evaluated how the marginal impact on LOLE changed as capacity was added within each capacity zone, whether Dr. Patton's assumption was the correct "base case" assumption is open for discussion.

Accordingly, the demand curve filing that the ISO must make by Nov. 30, 2013 should not include tariff changes that would bind the ISO to use this procedure in future demand curve resets. According to Sec. 5.14.1.2 of the Services Tariff, which describes the process leading to that filing, the filing is supposed to "incorporat[e] the results of the periodic review" conducted by the NYISO, and the purpose of the periodic review is "to determine the parameters of the ICAP demand curves for the next three Capability Years." Consequently, that filing should not include tariff changes that would modify the methodology used in subsequent reviews. Instead, any such changes should go through the ISO's normal governance process, with market participants given a full opportunity to review the proposal, recommend changes to it as they wish, and conclude whether the final proposal deserves their support.

Life Cycle

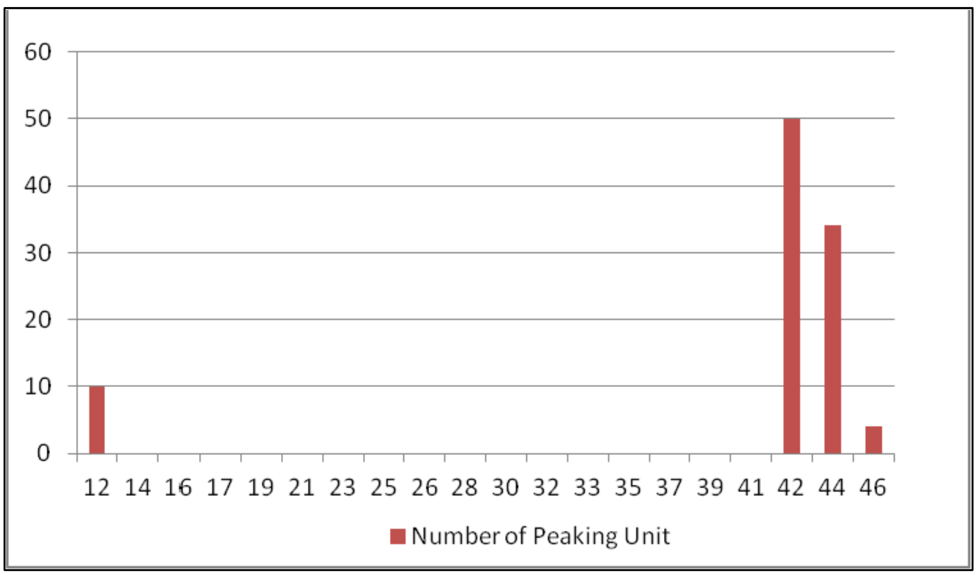
The NYISO Proposal adopts the consultants' recommendation to use a 20-25 year life cycle for the proxy units. The Final Report explains that the 20-25 years life cycle is "an economic life that represents the period over which an investor would analyze cost recovery" (Final Report, p. 91-92). The only justification offered for using a shorter term than in the past is that "although a new peaking unit will likely physically last thirty years or more, investors will use a shorter time horizon in determining the levelized cost."

In past two demand curve reset cycles, the consultants have based their CONE estimates on a 30 year life cycle. By contrast, the newly-issued report proposes a 25-year life for the combined cycle and for the LMS 100 plants and a 20-year life for the Frame model generator. This change causes the effective amortization periods for the proxy generators to be far shorter than the effective amortization periods used in the last reset. NYC has declined from 17.5 years to 14.5, NYCA has declined from 20.5 years to 17.5, and LI has declined from 20.5 years to 17.5.

No citations or sources are provided to support for the claim that investors will examine the proxy unit's value over a 20-25 year period. Further, the report offers no explanation for the use of a shorter life cycle in the ROS region than in other areas of the state. The assumptions made by NERA regarding technological progress are the same as in the last reset, so there is no reason to believe that accelerated technological progress will make these plants economically obsolete sooner than would have been expected when the last reset was performed.

Simple cycle units older than 40 years are common in New York, as shown in the table below.

Chart 1. Age of New York City Peaking Units



The use of a 20-25 year life cycle amounts to an assertion that investors will place a value of zero on potential cash flows more than 20 or 25 years in the future. This conclusion is contradicted by the results of NERA's financial model, which indicate that each of the plants evaluated will remain economic beyond the 20-25 year life cycle. Even if we assume that the unit will receive no energy revenues, its capacity payment (at Net CONE) will exceed its remaining O&M, site leasing, insurance, and tax costs. The NPV of the residual cash flow after year 25 (i.e.,(Net CONE – O&M – Property Tax – Ins)*(1-tax rate)), is over $1200/kW or over 60% of the initial investment. The high residual value demonstrates the reason why most of existing peaking units continue to operate well past 40 years. Even when many of them have low capacity factor (1% or less), they continue to receive a steady capacity payment.

At the very least, the consultants' analysis should have utilized a higher residual value for the proxy units. The proposed 5% residual value outside the ROS and 0% residual value for the ROS Frame plant do not properly recognize the additional net revenues that the proxy unit will receive during the remainder of its useful life and are not consistent with the sales price that older plants have often realized in New York.

If the NYISO retains the life cycle recommended by its consultants, it should update the proxy unit's residual value to reflect the likelihood that they will have a useful life of 40 years.

Net Energy and Ancillary Service Market Revenues

The NYISO Proposal adopts the proposed energy and ancillary service revenue estimates prepared by the consultants. We note that consultants have taken great pains to adjust their estimates of the proxy unit's revenues to reflect current conditions, e.g., by reflecting the addition of the Hudson Transmission Partners, Astoria Energy II and Hess Bayonne project. It seems only reasonable to also recognize the significant change in energy and ancillary service market rules that could affect the proxy unit's market revenues. These changes include changes to scarcity pricing and operating reserves reference level caps and, for the combined cycle option, frequency regulation market changes.

The NYISO's failure to include the impact of recent changes to scarcity pricing procedures is particularly troubling. Those changes allow for scarcity pricing to be triggered if one or more load zones experiences a reserve shortage after demand response is activated, even If all of East of Central East and the NYCA have sufficient reserves.

The Final Report contends that the revised scarcity pricing rules have already been accounted for in the consultants' analysis because they are reflected in the MAPS based adjustments to the consultants' econometric analysis (see pp. 75-76). We agree that scarcity pricing should be reflected in the MAPS analysis, but do not agree that this is a complete solution. The MAPS-based adjustments are calculated on the basis for two different comparisons: 1) a comparison of a baseline and adjusted resource mix and 2) a comparison of a baseline level of surplus and a reduced level of surplus. The results of the econometric analysis are adjusted to reflect the differences between these two sets of conditions.

The problem is that in instances where scarcity pricing would be triggered in both the baseline and the revised scenario, the MAPS output would presumably show little or no change in price. Thus, the results of the econometric analysis will not be revised. In those instances, the historical data used in the econometric analysis should be revised as if the revised scarcity pricing procedures had been in effect.

The Final Report further argues that historical real-time prices utilized as a component already reflect the impact of the scarcity pricing rules (see pg. 76). This contention is incorrect, since the revised rules were only placed into effect in July 2013 and could not have been reflected in the historical data.

Some observers have suggested that the scarcity pricing changes would only affect real-time prices, which constitute a minor part of the proxy unit's revenues. We note that although scarcity pricing is implemented in real-time, adjusting day-ahead revenues is also appropriate over the long-term, because day-ahead and real-time prices should be assumed to converge.

APPENDIX

CENTRAL HUDSON ESTIMATE

FRAME TURBINE NET CONE WITHOUT SCR IN DUTCHESS COUNTY

Market Participants from the Generator voting sector expressed concerns that without the dual fuel capability or a year round firm natural gas transportation contract, a simple cycle electric generating facility may not be able to operate during the very cold winter days when non-firm transportation natural gas delivery may be restricted or unavailable.

At the 8/13/2013 ICAPWG meeting, NERA indicated that for the Zone F area, there are approximately 540 hours over a 3-year time period (i.e.,180 hours per year) when the ambient temperature would be less than 20 degrees Fahrenheit such that non-firm natural gas transportation may be restricted or unavailable. As shown in the Appendix D table below, taken from the NYISO Proposal, the Zone G (Dutchess County) ambient temperature (19.3 degree Fahrenheit during winter) is warmer than the Zone F ambient temperature (15.3 degree Fahrenheit during winter). Therefore, there are probably less than 540 hours over a 3-year time period (less than 180 hours per year) in the Zone G (Dutchess County) area when the ambient temperature would be less than 20 degrees Fahrenheit such that non-firm transportation natural gas delivery may be restricted or unavailable.

24 Appendix D: Temperature and Relative Humidity Assumptions

Table A1 - Site Assumptions for Capacity and Heat Rate Calculations						NYISO Proposed Change Revised 8/13/2013	
Load Zone	Weather Basis	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity	Ambient Temperature (°F)	Relative Humidity
C - Central	Syracuse	421	Summer	79.7	67.7		
			Winter	17.3	73.7		
			Spring-Fall	59.0	60.0		
			Summer DMNC	91.2	42.4	92.3	48.0
			Winter DMNC	14.2	65.0	14.6	81.0
			ICAP	90.0	70.0		
F - Capital	Albany	275	Summer	80.7	67.2		
			Winter	15.3	70.7		
			Spring-Fall	59.0	60.0		
			Summer DMNC	92.4	42.5	92.4	48.0
			Winter DMNC	11.9	84.5	12.0	60.0
			ICAP	90.0	70.0		
G - Hudson Valley	Poughkeepsie (Dutchess Co.)	165	Summer	82.3	77.7		
			Winter	19.3	74.0		
			Spring-Fall	59.0	60.0		
			Summer DMNC	94.4	41.0		
			Winter DMNC	18.0	57.6		
			ICAP	90.0	70.0		
G - Hudson Valley	Newburgh (Rockland Co.)	165	Summer	82.3	77.7		
			Winter	19.3	74.0		
			Spring-Fall	59.0	60.0		
			Summer DMNC	95.4	40.3	94.4	43.0
			Winter DMNC	19.3	48.5	18.0	27.8
			ICAP	90.0	70.0		

Source: NYISO Proposal, p. 44

There are more economical options (lower cost options) that can be used to address and to price in this non-firm transportation winter natural gas supply disruption concern for the proxy unit located in the Dutchess County location than using the dual fuel capability assumption option proposed in the Final Report and in the NYISO Proposal. The following are two options that can be used to replace the dual fuel capability assumption option:

1) The NYISO can use the SGT6-5000F(5) combustion turbine simple cycle ("Frame GT") electric generating facility without SCR as the proxy unit in the Dutchess County location and eliminate any net energy revenue for this generating facility on days when the maximum temperature is less than 20 degrees Fahrenheit in computing the net CONE cost. This is the conceptual approach that NERA used to compute the net CONE cost for the SGT6-5000F(5) combustion turbine simple cycle ("Frame GT") electric generating facility without SCR for the proxy unit in the Zone F location.

   Using the information provided on Table 5 and on Table 6 as reproduced on the next two pages, taken from the NYISO Proposal, the Annual Fixed Cost of $110.08/kW-year developed for a Zone F SGT6-5000F(5) Frame GT with SCR from Table 6 (based on the 25-year Amortization Period) looks comparable to the Annual Fixed Cost of $107.29/kW-year developed for the Zone F SGT6-5000F(5) GT from Table 5 used to compute NERA's net CONE cost for the Zone F proxy unit. Therefore, the annual fixed cost for a Dutchess County SGT6-5000F(5) Frame GT without SCR is probably in the ballpark of $137.94/kW-year as shown in Table 6 (based on the 25-year amortization period).[4] Using the Energy and Ancillary Service Net Revenue for a Zone F SGT6-5000F(5) Frame GT of $18.48/kW-year from Table 5, based on NERA's conceptual approach of eliminating any net energy revenue for a SGT6-5000F(5) GT generating facility on days when the maximum temperature is less than 20 degrees Fahrenheit, the estimated net CONE cost for a SGT6-5000F(5) combustion turbine simple cycle ("Frame GT") electric generating facility without SCR to be used as the proxy unit in the HV Dutchess County location would be in the ballpark of $119.46/kW-year ([$137.94/kW-year] - [$18.48/kW-year]).

[4] We further note that the capital costs of other plant configurations and technologies are also approximately 25% more expensive in Dutchess County than in Zone F.

Table 5: Demand Curve Values at Reference Point for Capacity Years 2014/2015

	2010 DC Value for 2013/2014 2013 dollars/kW-year			*2013 Update for 2014/2015 2014 dollars/kW-year*		
	Annual Fixed Cost	**Energy and AS Net Revenues**	**Net Costs**	**Annual Fixed Cost**	**Energy and AS Net Revenues**	**Net Costs**
Recommended Proxy Units						
ROS Frame 7	123.8	27.5	**96.3**	N/A	N/A	N/A
Zone C SGT6-5000 (F) GT	n/a	n/a	n/a	106.1	15.48	**90.62**
Zone F SGT-5000(F) GT	n/a	n/a	n/a	107.29	18.48	**88.81**
NYC LMS100	288.3	97.3	**191**	299.54	54.5	**245.04**
HV Dutchess LMS100	n/a	n/a	n/a	220.15	47.12	**173.03**
HV Rockland LMS100	n/a	n/a	n/a	224.8	53.06	**171.75**
LI LMS 100	259.4	151.8	**107.6**	247.62	114.64	**132.98**

Source: NYISO Proposal, p. 25

Table 6: Demand Curve Values at Reference Point for Capability Years 2014/2015 SGT6-5000F (5) with SCR in One and Two Unit Simple Cycle Configurations

	20-year Amortization Period *2014 dollars/kW-year*			**25-year Amortization Period** *2014 dollars/kW-year*		
	Annual Fixed Cost	**Energy and AS Net Revenues**	**Net Costs**	**Annual Fixed Cost**	**Energy and AS Net Revenues**	**Net Costs**
Single Unit						
Zone C	117.92	15.10	102.82	108.99	15.10	93.89
Zone F	119.10	17.76	101.34	110.08	17.76	92.32
NYC	214.86	33.49	181.37	204.86	33.49	171.37
HV Dutchess	149.22	27.93	121.29	137.94	27.93	110.01
HV Rockland	152.08	32.77	119.32	140.50	32.77	107.73
LI	166.96	86.67	80.28	152.26	86.67	65.58

Source: NYISO Proposal, p. 26

2) A second more sensible option to maximize its economic viability is for the NYISO to use the SGT6-5000F(5) combustion turbine simple cycle ("Frame GT") electric generating facility without SCR in Dutchess County as the proxy unit for the Lower Hudson Valley and to include the cost of purchasing natural gas peaking contracts in the Annual Fixed Cost for the proxy unit instead of eliminating some of proxy unit's net energy revenue. Such contracts typically allow the customer to purchase

delivered gas at an index price by providing notice one day in advance to the supplier during a specified number of winter days (e.g., 5, 10, 15 or 30 days).

The fixed cost to purchase natural gas peaking contracts average approximately $0.55/dth based on Central Hudson's past 3 years of actual purchases. These natural gas peaking contracts are for natural gas delivery to the Pleasant Valley city gate (which is in Dutchess County) using the Iroquois Gas Transmission System, LP (Iroquois) pipeline. Central Hudson has been purchasing 10-day natural gas peaking contracts for many years to serve its LDC natural gas customer load on the 5 to 10 coldest winter days in the year in combination with the purchases of year-round firm natural gas interstate pipeline transportation capacity. The purchase of these peaking contracts is more economical than if Central Hudson was to purchase year-round firm natural gas interstate pipeline transportation capacity to serve its LDC natural gas customer load on the 10 or less very cold winter days in the year when this additional natural gas pipeline transportation capacity may be used. The companies from which Central Hudson purchased these natural gas peaking contracts either hold or obtain firm transportation capacity to the Pleasant Valley city gate and have a contractual commitment to deliver the natural gas when requested by Central Hudson, with notice in accordance with the terms of these peaking service agreements.

For winter operation, it is estimated that an electric simple cycle generating facility in Zone G may be dispatched up to 12 hours per day on the very cold winter days when the electric usage is significantly higher than an average winter day. Using the generator performance data in Table 4 shown below, taken from the NYISO Proposal, purchasing 30,000 dth per day of 15-day natural gas peaking contracts should provide sufficient reliable natural gas deliveries to operate a single SGT6-5000F(5) combustion turbine generator at full output for up to 12 hours per day and be able to reliably get the natural gas deliveries during the 180 hours or less per year when non-firm transportation natural gas deliveries may be restricted or unavailable. The computation to support the natural gas peaking contract purchase requirement is shown below.

Table 4: Performance and Variable Operating and Maintenance Costs for Generating Plants Evaluated

	2x GE LMS 100	1x1x1 Siemens STG6-5000(F)*	12x Wartsila 18V50	1x Siemens STG6-5000(F)*
Zone F Albany				
Heat Rate (Summer) Btu/kWh	9,223	7,197	8,512	10,708
Heat Rate (Winter) Btu/KWh	9,056	7,097	8,512	10,248
Capacity (Summer) MW	198.41	314.11	199.40	213.70
Capacity (Winter) MW	200.91	325.34	199.40	226.20
ICAP (Summer) MW	187.97	308.11	190.82	211.70
ICAP (Winter) MW	200.81	324.24	199.40	226.20
Variable O&M $/MWh	5.38	1.03	10.69	0.25
Variable O&M ($/Start)		9,164		9,164

Source: NYISO Proposal, p. 20

Natural Gas Peaking Contract purchase requirement computation:

(Maximum Quantity of Natural Gas to be used by 1x SGT6-5000F(5) combustion turbine generator)	=	(12 hours / day)	*	(226.2 MW)	*	(10,248 Btu / kWH)	*	(1,000 kWH / MWH)	*	(1 dth / 1,000,000 Btu)
(Maximum Quantity of Natural Gas to be used by 1x SGT6-5000F(5) combustion turbine generator)	=	(27,818 dth / day)								

(Number of Days needed for Natural Gas Peaking Contracts)	=	(180 hours / year)	÷	(12 hours / day)
(Number of Days needed for Natural Gas Peaking Contracts)	=	(15 days / year)		

(Annual Fixed Cost of Natural Gas Peaking Contracts)	=	($0.55 / dth)	*	(30,000 dth / day)	*	(15 days / year)
(Annual Fixed Cost of Natural Gas Peaking Contracts)	=	($247,500 / year)				

(Annual Fixed Cost of Natural Gas Peaking Contracts in $/kW-year)	=	($247,500 / year)	*	(1 / 226.2 MW)	*	(1 MW / 1,000 kW)
(Annual Fixed Cost of Natural Gas Peaking Contracts in $/kW-year)	=	($1.10 / kW-year)				

As shown in the calculation above, it is estimated that the purchase of 30,000 dth per day of 15-day natural gas peaking contracts would increase the Annual Fixed cost for the proxy unit by a ballpark of $1.10/kW-year. Using the Annual Fixed Cost of $137.94/kW-year and the Energy and Ancillary Service Net Revenue of $27.93/kW-year developed for a HV Dutchess County SGT6-5000F(5) GT from Table 6 (based on the 25-year Amortization Period), the estimated net CONE cost for this SGT6-5000F(5) combustion turbine simple cycle ("Frame GT") electric generating facility without SCR to be used as the proxy unit in the HV Dutchess County location would be in the ballpark of $111.11/kW-year ([$137.94/kW-year] + [$1.10/kW-year] - [$27.93/kW-year]).

It should be noted that these natural gas peaking contracts can be structured in 5,000 dth blocks or in any other size blocks a natural gas fired electric generating facility may want to contract for. The 30,000 dth per day of natural gas peaking contracts can be purchased from several different companies to avoid purchasing all 30,000 dth from one specific company in order to mitigate the counterparty risk. If an electric generating facility purchased a total of 30,000 dth (in 5,000 dth blocks) of 15-day natural gas peaking contracts to be delivered on the Iroquois pipeline to a location in Dutchess County during the winter months, the electric generating facility can either (a) call for 30,000 dth per day to be delivered over a total of 15 different Gas days, or (b) call for 5,000 dth per day to be delivered over a total of 90 different Gas days, or (c) call for any other combinations in between these 2 range points depending on the forecasted natural gas needs for a particular Gas Day based on the NYISO dispatch schedule for the Dutchess County electric generating facility and the peaking service calls made to date.

Summary of Net CONE costs for the 3 different assumption options:

The following table summarizes the net CONE costs computed using the 3 different assumption options for the proxy unit in the HV Dutchess County location:

2013 Update for 2014/2015
(2014 dollars / kW-year)

Proxy Unit in the HV Dutchess County location		Annual Fixed Cost	Energy and AS Net Revenues		Net CONE Cost
Option 1: Dual Fuel [LMS100]		$220.15	$47.12		**$173.03**
Option 2: Eliminate Energy and AS Net Revenues on very cold Winter days [SGT6-5000F(5) GT]		$137.94	$18.48		**$119.46**
Option 3: Natural Gas Peaking Contracts [SGT6-5000F(5) GT]		$139.04	$27.93		**$111.11**

As shown in the table above (options 2 and 3 in comparison to option 1), the more economical option is to set the net CONE cost using the SGT6-5000F(5) combustion turbine simple cycle (“Frame GT”) electric generating facility without SCR as the proxy unit for the Dutchess County location, not the LMS100 combustion turbine electric generating facility.

This error in selecting the incorrect technology for the proxy unit will result in increased capacity costs for the zone “G-H-I” load of approximately $160 million/year to $230 million/year.