Attachment IV

NEW YORK INDEPENDENT SYSTEM OPERATOR

Proposed NYISO Installed Capacity Demand Curves For Capability Years 2014/2015, 2015/2016 and 2016/2017

Final

9/6/2013

This report was prepared based on NERA/S&L's August 2, 2013 final study report, the April 18 and May 22 drafts of that report, progress reports to the ICAPWG, additional information provided to NYISO by NERA/S&L, and Stakeholders' input.

Revision No.	Date	Description

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1 EXECUTIVE SUMMARY

Section 5.14.1.2 of the Services Tariff requires the New York Independent System Operator, Inc. (NYISO) to initiate an independent review of the ICAP Demand Curves every three years in accordance with the ISO Procedures to determine the parameters of the ICAP Demand Curves for the next three Capability Years. This Demand Curve Reset (DCR) cycle is the fifth DCR cycle which covers the 2014/15, 2015/16, and 2016/17 capability years.

In addition to the three existing Demand Curves encompassing NYCA, Zone J, and Zone K capacity regions, this year FERC approved the creation of a New Capacity Zone (NCZ) consisting of Zones G,H,I, and J, mandating a creation of the fourth Demand Curve. NYISO selected National Economic Research Associates, Inc. (NERA), with Sargent and Lundy (S&L) as a subcontractor to NERA (collectively identified as the Consultants) to perform the independent DCR review. NYISO concurs with the Consultants recommendations for the 2014-17 DCR in all but two instances, and recommends the following changes:

- a change in zero crossing point assumptions; and
- a change in temperature and relative humidity assumptions in some locations in determining net ICAP.

The change in zero crossing points from Consultants' recommended 116.5% to NYISO recommended 118% in NYC and from 113.5% to 112% in NYCA resulted in a 5% decrease in the NYC monthly reference point - a $1.34 impact, and in a 3.5% increase in the NYCA monthly reference point - a $0.30 impact. The temperature and relative humidity change has a small effect on the ICAP values used in the demand curve model, and makes a small difference in the calculated reference prices. Table I below shows the impact of both changes on the annual and monthly reference points. The biggest impact is in Zone J where the monthly reference price decreased by 4.7% or $1.25, and in NYCA where the monthly reference price increased by 4.1% or $0.35 in comparison to the values recommended by the Consultants, when both impacts are accounted for.

Table I: Annual and Monthly Reference Points ($/kW)

Capacity Region	Original NERA Ref. Points	Impact W/Revised Temperatures		Impact W/Revised ZCP		Impact W/Revised Temp. & ZCP	
NYC	**$/kW**	**$/kW**	**% Change**	**$/kW**	**% Change**	**$/kW**	**% Change**
Annual	245.04	245.07	*0.0%*	240.08	*-2.0%*	240.11	*-2.0%*
Monthly	26.82	26.91	*0.3%*	25.48	*-5.0%*	25.57	*-4.7%*
LI							
Annual	132.98	133.02	*0.0%*	132.98	*0.0%*	133.07	*0.1%*
Monthly	13.18	13.26	*0.6%*	13.18	*0.0%*	13.28	*0.8%*
NCZ (Zone G)							
Annual	171.75	171.74	*0.0%*	171.75	*0.0%*	171.73	*0.0%*
Monthly	17.88	17.86	*-0.1%*	17.88	*0.0%*	17.86	*-0.1%*
NYCA (Capital Frame)							
Annual	88.81	88.82	*0.0%*	89.49	*0.8%*	89.50	*0.8%*
Monthly	8.49	8.53	*0.5%*	8.79	*3.5%*	8.84	*4.1%*

2 Introduction

The Installed Capacity (ICAP) obligation for New York Load Serving Entities and the market prices for the associated ICAP are determined according to the results of monthly ICAP Spot Market Auctions using separately-established downward sloping ICAP Demand Curves for New York City (NYC), Long Island (LI) and the New York Control Area (NYCA).[1] Section 5.14.1.2 of the Services Tariff requires the New York Independent System Operator, Inc. (NYISO) to initiate an independent review of the ICAP Demand Curves every three years in accordance with the ISO Procedures to determine the parameters of the ICAP Demand Curves for the next three Capability Years. On April 30, 2013 the NYISO filed tariff revisions which were approved by FERC on August 13, 2013, to establish and recognize a New Capacity Zone (NCZ). The approval of the NCZ, which encompasses NYISO Load Zones G, H, I, and J (the "G-J Locality"), requires the development of a new ICAP Demand Curve based on a peaking unit located in the NCZ. Crucial to this review is a determination of the cost of a peaking plant in the NYCA and in each Locality, including the NCZ, along with its projected net Energy and Ancillary Services revenues. "For purposes of this review, 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."[2] Once the appropriate peaking plants are identified the appropriate shape and slope of the ICAP Demand Curves can be determined for the NYCAP and each locality.

In the first quarter of 2012, NYISO selected FTI Consulting to perform a comprehensive evaluation of the New York capacity market. A preliminary draft report was issued for stakeholder comments on November 7, 2012, and a final report was issued on March 13, 2013.[3] The FTI report contained three recommendations which had a direct bearing on the review of the ICAP Demand Curve:

1. Simple cycle combustion turbine vs. a combined cycle unit to establish Cost of New Entry (CONE) to anchor the demand curve.
2. Feasibility of demand response as a workable basis for establishing CONE
3. Use of the incremental reliability value of capacity as a basis for setting zero crossing points for the demand curve.

In accordance with the Services Tariff, in the third quarter of 2012 the NYISO solicited proposals from qualified Consultants to identify appropriate methodologies to develop the ICAP Demand Curve parameters for the three Capability Years beginning in May

[1] Capitalized terms that are not otherwise defined herein shall have the meaning specified in the Market Administration and Control Area Services Tariff (Services Tariff), and if not defined therein, then in the Open Access Transmission Tariff (OATT).

[2] Services Tariff Section 5.14.1.2.

[3] Evaluation of the New York Capacity Market, March 5, 2013, prepared by FTI Consulting, available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf

2014. The team of NERA (National Economic Research Associates, Inc.), with Sargent and Lundy (S&L) as a subcontractor to NERA (collectively identified as the Consultants) was selected to perform the independent review. The Consultants began their analysis in November 2012, and as part of their analysis, they considered the recommendations made in the FTI report. Through twelve Installed Capacity Working Group (ICAPWG) meetings between December 2012 and August 2013, NYISO market participants and stakeholders provided feedback to the Consultants on the Consultant's assumptions, methodology, analysis, estimates, and preliminary results. On April 18, 2013, the Consultants released the first preliminary draft of their report for stakeholder review and comment ("NERA/S&L Report")[4] and on May 22, 2013, a revised draft report was issued to stakeholders.[5] Subsequently, progress reports on resolution of specific comments from market participants were presented to the ICAPWG on June 18, July 9, and July 24, 2013. The final version of the NERA/S&L Report was released on August 2, 2013.[6]

This report contains the NYISO's response to the Consultant's work and the NYISO's ICAP Demand Curves recommendations for the three Capability Years beginning May 1, 2014(CY 2014/15, CY 2015/16 and CY 2016/17). In preparing these recommendations, NYISO has taken into account the NERA/S&L Report, comments from the Market Monitoring Unit, and comments provided by stakeholders. The NYISO's preparation included consideration of all of the written and oral comments from stakeholders throughout the process on presentations by NERA/S&L and the draft NERA/S&L Reports.

The Consultants considered many risks that a developer would consider when making a decision on whether to invest in New York. For example, the Consultants evaluated the risk that the level of supply will exceed the minimum required in each Locality and in the NYCA considering the slope and zero crossing points of the Demand Curves. The Consultants determined, and the NYISO agrees, that the probability is quite low that the reliability processes in place for New York will allow the level of capacity in either Locality or in the NYCA to fall below the minimum requirement. Because of these processes, there is a risk that a developer will not earn revenues above the cost of new entry (CONE), which are necessary to offset the times in which it earns revenues below the CONE, because it could only earn those revenues if there is insufficient capacity to

[4] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (Preliminary Draft), April 18, 2013, prepared by NERA Economic Consulting, available at *http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-04-18/DraftDemandCurveStudyReport041813ICAP.pdf*

[5] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (Interim Draft Final Report), May 22, 2013, prepared by NERA Economic Consulting, available at *http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-05-22/NYISO%20Report%20Draft%202_%205-16-2013_SENT.pdf*

[6] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (Final Report), August 2, 2013, prepared by NERA Economic Consulting, available at *http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-13/Demand%20Curve%20FINAL%20Report%208-2-13.pdf*

meet the minimum requirements. (The Demand Curves set reference values at 100 % of the minimum ICAP requirement.)[7] The Consultants' methodology reflects this risk by allowing the amortization period to vary. The results, as explained in the NERA/S&L Report, are amortization periods of 17.5 years for NYCA and LI, 18.5 year for the NCZ, and 14.5 years for NYC. In addition, the Consultant's also specifically considered the merchant risk inherent in a project that relies on the capacity market for a significant share of its revenue.

This report sets forth the NYISO staff's set of recommendations for adjusting the current ICAP Demand Curve parameters and the underlying assumptions leading to those recommendations. The NYISO's Market Monitor Unit (MMU) has been involved in reviewing the Consultant's work product and in the development of the NYISO's ICAP Demand Curve update recommendations. The schedule shown in Appendix E identifies the remaining steps in the Demand Curve update process, culminating in the NYISO's filing with the Federal Energy Regulatory Commission on or before November 30, 2013 of the results of the NYISO's review and the updated Demand Curves approved by the NYISO Board of Directors.

3 Specific Technologies Evaluated by the Consultants

Following a broader review of available generating technologies, the Consultants focused on three natural gas/fuel oil fired technologies: simple cycle gas turbines, combined cycle gas turbines, and reciprocating internal combustion engines. Within these technologies the following specific units were selected:

General LMS100 Hybrid Aeroderivative Gas Turbine

Siemens SGT6-5000F(5) Gas Turbine (Simple Cycle, and Combined Cycle)

Wartsila 18V50DF/18V50SG Reciprocating Internal Combustion Engines

Important selection criteria included compliance with environmental requirements, efficiency, commercial availability and industry experience, operational flexibility, and scale. Further, while the NYISO tariff specifically requires that the Reference Cost for the demand curve be based on a peaking unit, it was important in view of the conclusions in the FTI report and specific concerns of the NYISO's Independent Market Monitor Unit that combined cycle technology be fully evaluated.

3.1 Environmental Requirements

There has been one significant change in environmental requirements since the previous reset of the demand curves that impacts the applicable technologies reviewed by the Consultant. The principal change is EPA's regulation of six greenhouse gas

[7] The Services Tariff sets forth the manner in which Locational Minimum Installed Capacity Requirements and the NYCA Minimum Installed Capacity Requirement is set annually.

emissions, including carbon dioxide.[8] This impacts the classification of all technology reviewed by the Consultants as a Major Source pursuant to New York State Department of Environmental Conservation (NYSDEC) air quality regulations[9] which implement EPA rules on Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NNSR). An overlay of the two sets of regulations results in the following thresholds provided in Tables 1 and Table 2 for annual emissions.

Table 1: Applicable Major Source Thresholds for PSD/NNSR

Emissions Thresholds for PSD/NNSR			
NYCA Zones		**Emissions**	**Threshold (tons/year)**
C, F		NO_x	100
J, K		NO_x	25
G	Rockland County	NO_x	25
	Other Counties	NO_x	100
All Zones		CO_2e	100, 000

Table 2: Significant Project Thresholds for NOx BACT/LAER

Significant Project Thresholds for BACT/LAER			
NYCA Zones		**Emissions**	**Threshold (tons/year)**
C, F		NO_x	40
J, K		NO_x	2.5
G	Rockland County	NO_x	2.5
	Dutchess County	NO_x	40

The change in air quality regulations is significant in two ways:

[8] On June 3, 2010 issued a New Source Review final rule for the regulation of Greenhouse Gases (GHGs) under its PSD and Title V programs, also known as the "GHG Tailoring Rule." This rule addresses EPA's regulation of GHGs by establishing major source applicability threshold levels for GHG emissions and other conforming changes under the state's PSD and Title V programs.

[9] All technologies evaluated have been classified as Major Sources due to each having the potential to emit 100,000 tons per year of greenhouse gas emissions. See 6 NYCRR Part 231, New Source Review for New and Modified Facilities.

First, the PSD rules now include greenhouse gases (GHG), and require that sources with the potential to emit more than 100,000 tons of carbon dioxide equivalent emissions (CO_2e undergo a Best Available Control Technology (BACT) review.[10] All three of the technologies selected would exceed the 100,000 tons/year threshold and be subject to this requirement. Since the underlying US Environmental Protection Agency regulations became effective in December 2011, there has been relatively little experience with BACT review for GHG. There are no post combustion controls for $CO_{2.}$ It is conceivable that a BACT review could be based on cycle efficiency or operational limits to control emissions; however, no permits have been issued on this basis. A straightforward example of the cost to limit emissions of CO_2 can be based on a comparison of the costs of the LMS100 and Siemens SGT6-5000F(5), which indicates that the cost per ton of CO2 emissions reduced by choosing the more efficient, but more costly LMS100, is in excess of $500/ton. When compared to the current cost of RGGI allowances, which sold for $3.21/ton in the most recent auction, the additional cost is not justified.

Second, since the EPA did not regulate CO_2e as part of the New Source Review requirements in the last DCR, the ROS unit was able to avoid major source status, and hence BACT/LAER analysis, by capping its emissions below the 100 tons/year major source threshold. In this DCR, however, the ROS unit is subject to LAER for NOx, which it complies with by meeting the 40 tons per year significance project threshold by taking an annual operational permit limit of 1075 hours.

Another significant change is in environmental restrictions on water withdrawal for cycle cooling requirements. NYDEC Policy CP-52 seeks a performance goal of dry closed-cycle cooling for all new industrial facilities sited in the marine and coastal district and the Hudson River up to the Federal Dam in Troy irrespective of the amount of water they would withdraw for cooling. Consultation with NYSDEC confirmed that this requirement would be imposed on all technologies. While simple cycle machines have relatively low cooling water requirements, the costs of the combined cycle unit are more significantly affected. Dry cooling was included in the development of estimated capital cost and performance for all of the technologies.

3.2 GE LMS100

The LMS100 is a General Electric aeroderivative combustion turbine with a nominal rating of approximately 100 MW that combines the technology of heavy-duty frame engines and aeroderivative turbines to provide cycling capability without the maintenance impact experienced by frame machines; higher simple-cycle efficiency than current aeroderivative machines; fast starts (10 minutes); and high availability and reliability. The LMS100™ system, developed by General Electric in 2004, combines the 6FA compressor technology with CF6®/LM6000™ technology. The airflow from the

[10] In general, a BACT analysis for a pollutant results in an achievable emission limit that is based on the maximum degree of control that can be achieved by a proposed major source when taking into account, on a case-by case basis, technical feasibility, cost, and other energy, environmental, and economic impacts.

low pressure compressor enters an intercooler, which reduces the temperature of the airflow before it enters the high-pressure compressor (HPC). Given the NYSDEC policy on cooling water withdrawal, dry cooling was included in the evaluation for all locations except Zone C. The exhaust gas temperatures are compatible with selective catalytic reduction technology, which pursuant to the DEC's NSR regulations, is required post-combustion control technology that meets LAER for NO_x .

This unit was considered and chosen as the basis for the Reference Cost for the demand curve for Zones J and K in the previous two resets. The Consultant's reported that since the first unit was commissioned in 2006, there have been 56 LMS100s sold with 162,000+ cumulative hours as of end of 2012.

3.3 SGT6-5000F(5)

The Consultant's reported that more than 180 Siemens SGT6-5000F class (60hz) gas turbines have been sold in the past twenty years, with more than 5.3 million hours of fleet operation. The SGT6-5000F(5) combustion turbine, with a nominal rating of 220 MW, has consistently had reliability of 99% better. The operational flexibility of combined cycle plants, in terms of start-up times and turndown capability has improved significantly in the past decade. A SGT6-5000F(5) gas turbine can reach full load within 10-12 minutes, and a combined cycle plant is capable of ramping from zero to load full load in 45 minutes or less. A Siemens SGT6-5000F(5) combustion turbine remains emission compliant to 40-50% of the base turbine load with a 6-7% degradation in heat rate. These characteristics allow for load following in cycling applications. In a simple-cycle configuration, high exhaust temperatures make the application of SCR technology for NOx control problematic. As the permit strategy for NOx, this unit would take an annual operational limit to cap emissions below the 40 tons/year significance level of NOx. A Frame F unit was considered and chosen as the basis for the Reference Price for the demand curve for Zones in ROS in the previous two resets, although its annual operational limit was based upon the 100 tons/year major source threshold for NOx.

In combined cycle operation, with the higher efficiency and lower exhaust temperatures, the Siemens SGT6-5000F(5) is compatible with the SCR technology required to meet LAER for NOx.

3.4 Combined Cycle

The Market Monitoring Unit has requested that the NYISO consider basing the Demand Curve on a plant other than peaking plant because using a peaking plant to establish the Demand Curve, if it was not the lowest net cost unit, may lead to inefficiencies. Therefore, at the NYISO's request, NERA/S&L also examined the localized levelized costs and net energy and ancillary service revenues of the lowest net cost plant, not a peaking plant, which was determined through a screening process to be a combined cycle unit. The Siemens SGT6-5000F(5) combined cycle plant would result in a lower Demand Curve in the locations examined other than NYC and the Capital and Central regions. In NYC the Siemens SGT6-5000F(5) combined cycle plant would not result in a lower Demand Curve even if it was able to operate in a cycling mode and qualify for the tax abatement. NERA does not, however, recommend the Demand Curve be set in any location based on the Siemens SGT6-5000F(5) combined cycle plant as it does not meet the current requirement of being a peaking plant as set forth in the Services Tariff. The Service Tariff calls for the plant with the lowest fixed cost and highest variable cost that is economically viable. The Consultants provided the costs for these units for informational purposes.

3.5 Wartsilla 18V50DF/SG Reciprocating Internal Combustion Engines

The Wartsila 18V50DF and 18V50SG were evaluated as a higher efficiency alternative to simple cycle gas turbines.   However, the combustion process used in these engines increases emission rates for both NOx, CO, and VOC's as compared to a simple cycle gas turbine. Each unit is capable of approximately 18 to 20 MW, so multiple units are required to achieve an output comparable to a simple cycle gas turbine. This allows for an excellent turndown efficiency and minimum load capability when multiple units are installed. The Consultant's report states that there are more than 200 units of these types operating worldwide and an additional 600 units of a comparable design.

3.6 Additional SGT6-5000F(5) Frame Turbine Technology Evaluations

At the time the second draft of the Consultant's report was issued, some NYISO market participants specifically requested that NYISO direct the Consultant's to evaluate a simple cycle SGT6-5000F(5) equipped with selective catalytic reduction to meet LAER requirements for NO_x. This request was based on two considerations: (1) the recent completion of the Marsh Landing Generating Station, near Antioch, California, consisting of four similar Siemens units in simple cycle operation with selective catalytic reduction, and the PJM tariff, which requires that CONE be based on a two-unit simple cycle GE 7FA installation with selective catalytic reduction.

In selection of specific candidate technologies, the Consultants had concluded that selective catalytic reduction, which would be required to meet LAER requirements for NO_x emissions, could be successfully deployed only with aeroderivative gas turbines and with frame units in combined cycle operation. The Consultants reevaluated the use of selective catalytic reduction technology on the SGT6-5000F(5), and again reached this conclusion based on the following:

- Consideration of the design and operational challenges inherent in introducing diluent air to achieve uniformly lower gas turbine exhaust temperatures to allow successful operation of current selective catalytic reduction technology.
- Current Sargent and Lundy experience with clients developing power projects
- Two previous unsuccessful deployments of frame gas turbines with selective catalytic reduction in Kentucky and Puerto Rico
- The very limited experience (May 1, 2013 commercial operation date) with the

recently completed Marsh Landing Generating Plant in California.

Further, the fact that PJM selected GE Frame 7 technology with SCRs as the proxy unit, as indicated by some market participants is not relevant, because the criteria used by PJM's consultants in selecting that technology was "….three potential suppliers of hot SCR controls [stated]that they have received inquiries and budget requests for hot SCRs on large F-class turbines for projects currently under development in the USA" and that the Marsh Landing plant was scheduled to be completed in 2013.[11] There was apparently little or no effort expended to assess the technical feasibility of the technology, or to show that the technology had been previously applied in a significant number of applications, and was therefore a proven, reliable technology. The NYISO believes that its DCR process is more rigorous, and at the July 9, 2013 ICAPWG meeting, the Consultants:

1. Indicated that SCRs have not been successfully applied to CTs with higher exhaust temperatures , and
2. Recommended "that [the] proxy unit not be based on simple cycle F-class CT with SCR because of technical challenges, unsuccessful projects, and lack of market acceptance."

An additional alternative emerged from this review, however. In the previous demand curve reset, the Demand Curve Reference Price for ROS was based on two simple cycle GE 7FA units with a limit on operating hours to stay below the 100 tons/year significance level for NO_x emissions. The limit on operating hours was higher than the expected dispatch hours based on the modeling to determine net energy revenues. In this review, it was determined that a single Siemens SGT6-5000F(5) without selective catalytic reduction, relying on dry low NO_x combustion for emissions control, could operate up to 1075 hours annually while firing natural gas and remain under the currently applicable threshold of 40 tons/year. Based on modeling to determine the net energy revenues for this alternative, the average annual expected estimated dispatch hours for this unit ranged from 982 to 1025 hours.[12] The emissions-based limit was lowered to 950 hours in all cases to account for the lack of perfect foresight. Further, while the emissions of CO_2, would exceed the threshold of 100,000 tons/year, the cap on operating hours, imposed for NO_x control, would also be a plausible option to achieve BACT for GHG in the case of a peaking unit. Thus, this alternative was added to the options for which demand curve reference prices would be developed. NYISO concurred with this addition.

3.7 Considerations of Scale

The size of the generating plant, consisting of one or more units, as chosen and evaluated by the Consultants achieves a balance of two considerations. First, in terms of

[11] Cost of New Entry Estimates For Combustion Turbine and Combined Cycle Plants in PJM, The Brattle Group, August 24, 2011 available at http://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx

[12] The average consists of cases where annual operation is well under this level and also cases where operation is well in excess of 1075 hours per year.

unit cost ($/kW), multiple units offer some economies of scale. On the other hand, the NYISO tariff specifically requires that in determining the Reference Cost, the net energy revenues for the reference plant be determined at equilibrium (at the Local Capacity Requirements or the Installed Reserve Margin for the NYCA) plus the capacity of the plant. The NYISO believes that this balance was achieved with the Consultant's choices:

- Two unit LMS100 installation at a nominal 200 MW rating
- Single SGT6-5000F(5) unit simple cycle plant at a nominal 215 MW rating, without SCR, and a 950 annual operating hour limit
- SGT6-5000F(5) combined cycle plant (1x1x1 configuration) at a nominal 300 MW rating
- 12 Wartsila 18V50DF/18V50SG units with a nominal 200 MW rating

In the sections that follow, the development of the elements of fixed and variable costs and determination of net revenues is reviewed. The most significant issues, based on process complexity, relative importance as drivers of cost, and interest expressed by market participants are dealt with in specific sections.

4 Dual Fuel Capability

In the previous demand curve reset, dual fuel capability was assumed only for New York City, where the Con Edison gas service tariff requires this capability. In this review, it was further determined that the Local Reliability Rule IR-3 requires that at certain load levels in Zone J, all dual fuel units dispatched on gas be capable of switching to oil in 45 seconds. The most recent application of this rule, which is intended to deal with the electric system contingency of loss of gas supply, was approved by the NYISO Operating Committee on April 10, 2013. The Consultants determined that the GE LMS 100 and the Wartsila 18V50DF units were capable of meeting this requirement. The Siemens SGT6-5000F(5) is capable of switching fuel in about ten minutes; Siemens was asked by the Consultants to develop a cost adder for the capability to switch fuel in less than one minute. A similar modification has been developed by GE for 7FA units operating in New York City.

Due to the recent experience where some facilities faced operational limitations burning gas in the Lower Hudson Valley, some market participants expressed interest in whether dual fuel capability should also be assumed for the peaking plant in other regions. After a teleconference with the Department of Public Service and a review of the gas service tariffs of the local distribution companies (LDC), the Consultants determined that projects siting in the Lower Hudson Valley and Long Island would likely be required to have dual fuel capability. The LDC tariffs require dual fuel capability for electric generating facilities. While dual fuel capability would not be required for units that interconnect to the interstate gas pipelines, including the dual fuel requirement expands the siting options for the proxy unit in these areas. In addition, this recommendation that dual fuel be required for the proxy unit in these regions is further supported by a review of the recent projects that have been completed or have been proposed for these areas, the majority of which have included dual fuel capability. Cost estimates were developed for dual fuel capability for the plants in these areas based on the following considerations.

- LDC tariffs require or support dual fuel capabilities:
    - Orange & Rockland and Central Hudson in Zone G
    - Con Ed in Zones H, I and J
    - National Grid in Zone K

- Most generators connected in recent years or planning to connect directly to interstate pipelines also are dual fuel.

While some market participants have argued that projects would likely bypass the LDC where possible, in Zone G in particular, NYISO concurs with including dual fuel capability in the capital cost estimates for units located in Zones J, K, and G.

Other market participants have argued that dual fuel capability should also be included in Zones C and F, or alternatively, that the net energy revenues and EFORd should be adjusted for gas unavailability. The Consultants have included the effect of gas unavailability on estimated net energy revenues for those zones.

5 Interconnection Costs

Effective October 2008, the Federal Energy Regulatory Commission (Commission) approved modifications to the NYISO's interconnection process that created two types of interconnection service:

- Energy Resource Interconnection Service (ERIS), which allows a new project to participate in the NYISO's energy market but not as an Installed Capacity Supplier, and
- Capacity Resource Interconnection Service (CRIS), whereby a new project can participate in both the NYISO's Energy and Capacity markets

New projects requesting interconnection are responsible for System Upgrade Facilities (SUF) costs identified in individual system reliability impact studies (SRIS) and Class Year studies.

New projects requesting CRIS Rights are evaluated within the Class Year study process using the deliverability test defined in Sec. 25.7.8 of the OATT. The projects that are determined to be deliverable in full or in part are awarded CRIS Rights up to their MW deliverability level. For those projects deemed undeliverable in full or in part, the NYISO determines the least cost system upgrade(s) to achieve full deliverability (termed System Deliverability Upgrade costs, or SDU costs). Projects identified as fully or partially non-deliverable are assigned a share of the total SDU costs, in $/MW, based upon their impact on the constrained facility/facilities. Projects accepting their SDU costs are granted CRIS Rights.

Substations with open breaker positions were identified by NYISO in coordination with the transmission owners for each region. The Consultants developed estimates of SUF costs based on the bus type and voltage used in NYISO deliverability studies, using a larger contingency of 20%, than for the plant cost estimates. Additional costs of protection SUFs, headroom payments, and Connecting Transmission Owner (CTO) Attachment Facilities (AF) were based on an average of these costs for representative projects from class year (CY) studies for CY09, CY10 and CY11. Market participants raised the possibility that interconnections in Zone J might have to include an allowance for "storm hardening" costs following evaluations that took place following Superstorm Sandy. A review with Con Edison of the substations selected for the interconnection estimates indicated that none of these substations required elevation.

Deliverability studies completed by the NYISO indicated that both the gas turbine and combined cycle plants were deliverable at all substations in all zones, except for the Shoemaker substation in Zone G, where the combined cycle plant was not deliverable. The SDU identified was to replace conductors on segments of 138 kV overhead transmission line totaling approximately 11-mile. The combined cycle plant was deliverable at the two other locations in Zone G, however, and no SDU costs have been included.

6 Capital Investment and Other Plant Costs

Capital cost estimates, which are provided in the NERA/S&L Report on pages 46-47 and in more detail in Table A-3, are summarized in Table 3 below. Included in these costs are direct costs within the engineering, procurement and construction (EPC) contracts, owner's costs not covered by the EPC including social justice costs, financing costs during construction, working capital, and initial inventories. For locations in Zone J, an incremental cost of increasing plant elevations by 3.5 ft. for flood protection was developed from a comparison of potential sites to the inundation maps prepared by FEMA following Superstorm Sandy. Inlet evaporative cooling was included for all gas turbine technologies because of the benefits to efficiency and power output. For those regions where dual fuel capability is included, that capital cost is shown as a separate incremental cost, which may be subtracted from the total for comparison, and the additional costs incurred in start-up testing has been included in owner's costs. An adder of 2% on gas turbine cost was included for the Siemens SGT-5000 (F) combined cycle plant in New York City for the provision of fuel swapping capability during operation. Based on guidance from NYSDEC, dry cooling was assumed for the LMS 100 plant, as well as for the combined cycle plant, in all zones except Zone C, even though the cooling requirement for the LMS 100 is limited to the intercooler. Emission controls include water injection and selective catalytic reduction on the GE LMS 100, dry low NOx combustion (water injection when firing oil) and selective catalytic reduction on the Siemens SGT-5000 (F) combined cycle plant, and dry low NOx combustion on the Siemens SGT-5000 (F) simple cycle unit.

Table 3: Capital Investment Costs for Generating Plants Evaluated ($2013)

	2x GE LMS 100	1x1x1 Siemens SGT6-5000F(5)	12x Wartsila 18V50	1x Siemens SGT6-5000F(5)
Zone C Syracuse				
Total Capital Cost	248,097,000	401,318,000	363,385,000	146,057,000
ICAP MW	186.25	301.67	197.94	205.40
$/kW	$1,332	$1,330	$1,836	$711
Zone F Albany				
Total Capital Cost	262,976,000	426,692,000	368,228,000	148,346,000
ICAP MW	183.6	302.03	188.30	206.50
$/kW	$1,432	$1,413	$1,955	$718
Zone J New York City				
Total Capital Cost	341,838,000	618,120,000	505,144,000	
ICAP MW	184.00	303.89	188.30	
$/kW	$1,858	$2,034	$2,683	
Reduction if single fuel	9,951,000	11,762,000	14,438,000	
Zone K Long Island				
Total Capital Cost	315,636,000	552,611,000	461,829,000	
ICAP MW	185.516	304.87	188.30	
$/kW	$1,701	$1,813	$2,453	
Reduction if single fuel	9,926,000	9,307,000	14,500,000	
Zone G Hudson Valley (Dutchess County)				
Total Capital Cost	285,805,000	472,338,000	405,662,000	
ICAP MW	184.402	302.78	188.30	
$/kW	$1,550	$1,560	$2,154	
Reduction if single fuel	8,371,000	8,509,000	13,496,000	
Zone G Hudson Valley (Rockland County)				
Total Capital Cost	293,070,000	490,669,000	416,350,000	
ICAP MW	184.402	302.78	188.30	
$/kW	$1,589	$1,621	$2,211	
Reduction if single fuel	8,595,000	8,640,000	13,657,000	

7 Property Taxes

7.1 New York City Tax Abatement

On May 18, 2011, legislation was enacted to amend the New York State Real Property Tax law to provide property tax abatements to electric generating facilities located in New York City. This tax abatement is applicable to peaking units as defined in the NYISO tariff, or to units which average no more than 18 run hours per start annually, for which a New York City construction permit is obtained prior to April 1, 2015. The tax abatement is for 100 % of the abatement base for the first 15 years.

For the LMS 100 plant, the Consultants determined that it was reasonable to assume that a unit completed for operation during the capability periods covered by this reset would have received its construction permit prior to the April 1 deadline, and accounted for the effect of the tax abatement in the determination of levelized carrying charges. The more efficient combined cycle plant would not be expected to qualify for the abatement because of the restriction to an annual average on run times. As a sensitivity case, the Consultants developed net energy revenues with a dispatch for the combined cycle plant that approximated compliance with the limit on average run times per start. Such a restriction on dispatch would potentially qualify the plant for the tax abatement, but significantly reduce net energy revenues. NYISO concurs with the assumption that the abatement should be applicable in developing reference prices, and, further, fully expects that the abatement provision will be extended. A bill (New York State Assembly Bill number 7806-A) containing an extension passed both houses of the New York State Legislature in June 2013, but was vetoed by the Governor because of "unwarranted expansion" provisions not related to the property tax abatement for generating facilities. In his Veto message No.203 to the NYS Assembly, the Governor stated that "if the Legislature were to pass a bill that extends, but not expands, the programs in this bill, I would sign the bill."[13]

7.2 Payments in Lieu of Taxes in Balance of State

In the initial drafts of the Consultant's report, a property tax rate of two 2 % has been used for localities other than New York City, and no tax abatement has been assumed in developing fixed costs or the levelized carrying charges. Comments from market participants indicated that recently completed generating plants have negotiated substantially reduced property tax rates with the localities. NERA confirmed that four plants—the Athens, Bethlehem, and Empire projects in the Hudson Valley, and the Caithness project on Long Island were able to negotiate payments in lieu of taxes (PILOT) at rates substantially below the assumed rate of two 2%, and that the rates revert back to the full rates, but only after 15-20 years. While property abatements are not a matter of right, as in New York City, NERA concluded that it is reasonable to use a reduced rate of 1%, since there are multiple tax jurisdictions in each of the other regions, and an incentive to have projects located in these jurisdictions. Some market participants have further argued that the tax rate should be based on an average of the rates negotiated for the three plants in the Hudson Valley, suggesting a rate of 0.45% in the first year, escalating to 0.81% in the twentieth year. The Consultants final recommendation for a uniform rate of 0.75% in all regions other than New York City was based on a review of PILOT agreements. The NYISO concurs with this resolution as a reasonable representation of property tax rates based on the available data.

8 Fixed Operating and Maintenance Costs

Fixed operating and maintenance costs are discussed in the Consultant's Report on pages 47-50 and summarized in Table A-3. It is assumed that the land associated with the plant site is leased. Property taxes are based on those typical in the jurisdictions chosen for

[13] Veto message No.203, regarding State Assembly Bill number 7806-A, from NYS Governor Andrew Cuomo, to the NYS Assembly.

each market (NYC, LI and Capital Zone). For dual fuel plants, an allowance for periodic operations and emissions testing is included. One significant issue raised by market participants in the generation sector was a recent increase in insurance costs. The Consultants revised the estimate based on updated sources.

9 Performance Characteristics and Variable Operating and Maintenance Costs

The Consultants have developed performance characteristics, emissions, and start-up costs for the generating plants evaluated.[14] A change from the last reset is in reference temperatures used for determining capacity ratings for ICAP. The NYISO bases ICAP ratings for generating units on Dependable Maximum Net Capability (DMNC) tests which are corrected to the average of the ambient temperature at the time of the NYISO seasonal peak loads over the last four years. NYISO supplied this temperature data for each region, which the Consultants used as the basis for the ICAP rating used in determining capacity revenues in the demand curve model. Average summer and winter conditions for each region, as determined by the Consultants, were used in determining the capacity ratings used for estimating net energy revenues.

Variable O&M costs are discussed in the NERA/S&L report.[15] Variable O&M costs are primarily driven by periodic maintenance cycles: for the LMS-100, maintenance is recommended every 50,000 factored operating hours; for the Siemens STG6-500(F), the shorter of 48,000 hours or 2,400 factored starts is recommended. Other variable O&M costs are directly proportional to plant generating output, as outlined in the NERA/S&L Report. Start-up times and fuel requirements have also been developed.[16]

Representative performance parameters and variable operation and maintenance costs are summarized in the Table 4 below. Fuel costs are discussed in the NERA/S&L Report.[17] In addition to the direct fuel costs, which are determined statistically from historical fuel prices, the analysis captures transportation costs.

[14] NERA/S&L Report Appendix A-2
[15] NERA/S&L Report, pp. 51-52; Table A-2.
[16] NERA/S&L Report Table A-7.
[17] NERA/S&L Report pp 52-53.

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

	2x GE LMS 100	1x1x1 Siemens SGT6-5000F(5)*	12x Wartsila 18V50	1x Siemens SGT6-5000F(5)*
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
Zone J New York City				
Heat Rate (Summer) Btu/kWh	9,313	7,237	8,512	
Heat Rate (Winter) Btu/KWh	9,159	7,104	8,512	
Capacity (Summer) MW	194.53	313.96	198.86	
Capacity (Winter) MW	198.51	325.90	199.40	
ICAP (Summer) MW	186.34	308.10	189.90	
ICAP (Winter) MW	199.1	327.42	199.40	
Variable O&M $/MWh	5.52	1.06	11.22	
Variable O&M ($/Start)		9,376		
Zone K Long Island				
Heat Rate (Summer) Btu/kWh	9,227	7,196	8,512	
Heat Rate (Winter) Btu/KWh	9,086	7,081	8,512	
Capacity (Summer) MW	198.01	316.66	198.08	
Capacity (Winter) MW	200.11	326.97	199.40	
ICAP (Summer) MW	189.74	311.19	190.76	
ICAP (Winter) MW	199.92	325.79	199.40	
Variable O&M $/MWh	5.47	1.05	11.18	
Variable O&M ($/Start)		9,358		
Zone G Hudson Valley (Rockland County)				
Summer Heat Rate (Btu/kWh)	9,271	7,217	8,517	
Winter Heat Rate (Btu/KWh)	9,068	7,090	8,512	
Summer Capacity (MW)	193.00	310.92	192.74	
Winter Capacity (MW)	200.53	325.86	199.40	
Summer ICAP (MW)	185.93	306.04	189.49	
Winter ICAP (MW)	200.47	325.16	199.40	
Variable O&M ($/MWh)	5.48	1.05	11.00	
Variable O&M ($/Start)		9,290		
*The Siemens STG6-5000(F) also has a variable O&M cost per start.				

10 Development of Levelized Carrying Charges

A discussion of the elements used in developing levelized carrying charges can be found in the NERA/S&L report.[18] The annual carrying charge rate is determined using the same methodology that was used for the previous Demand Curve reset study, with the exception that the current New York City property abatement is more appropriately treated in the levelized carrying charge than as a fixed operations and maintenance cost. Financing assumptions were discussed at length by stakeholders and in written comments, and are discussed in detail in the NERA/S&L Report.[19] Stakeholders provided differing views on a number of issues, including:

- Corporate versus project financing
- Merchant power plant risk
- Assumptions concerning equity beta

The Consultants initially proposed the following financial parameters for determining the Weighted Average Cost of Capital (WACC):

- 50/50 debt/equity ratio
- 6.5 % interest
- 12.5 % return on equity rate on debt

The return on equity was based on application of the Capital Asset Pricing Model (CAPM), which yielded a rate of 11.1 %, and the judgment of the Consultants that the higher rate of 12 % reflected the risk inherent in merchant power plant development. Market participants requested a revised analysis, using updated equity beta figures in particular, which was presented at the June 22 ICAPWG meeting. The revised CAPM analysis yielded an average of 10.8 % for generators with a mix of contracted and merchant assets in their portfolios. The Consultants again recommended a 12 % return on equity, reflecting their judgment that the CAPM analysis is biased low in the current environment. The Consultants also considered, however, an increase of 50 to 100 basis points to reflect risk inherent in merchant generating projects relying on the capacity market for a significant portion of revenues. Alternatively, the Consultants considered a reduction in the underlying base amortization period from 30 years to 25 years.

The final recommendation of the Consultants is a return on equity of 12.5 %, a 7.0 % cost of debt, and an underlying amortization period of 25 years. For the Siemens simple cycle frame unit, a shorter amortization period of 20 years is recommended. The increase of 50 basis points in the debt and equity rates is based on recent increases in interest rates. The NYISO notes that consistent with the previous demand curve reset, the methodology in the demand curve model developed by the Consultants does not strictly assume a fixed period, but rather considers the risk of excess capacity, the slope of the Demand Curve,

[18] NERA/S&L Report, pp. 48-52 and pp. 77- 82.

[19] NERA/S&L Report, pp. 83 – 90.

and the slope of the energy and ancillary service net revenue function in determining a separate "implied" amortization period for each region.

The Consultants have proposed a set of financing assumptions that reflect projects associated with a larger corporate capital structure, but also recognize the possibility of a peaking unit not associated with a larger corporate capital structure being developed. The NYISO believes that the debt/equity parameters and the amortization periods chosen provide a reasonable balance, and concur with the Consultant's recommendations.

In developing the financial parameters described above, the Consultants used a long term inflation rate of 2.3% and a short term rate of 2.2%. The Consultants recommend the short term rate of 2.2% for escalating the demand curves over the three applicable capability periods. The NYISO also concurs in this recommendation.

11 Regulatory Risk

The Consultants considered NYISO initiatives currently underway to significantly revise those tariff provisions dealing with mitigation. Those initiatives include (1) a repowering exemption, (2) a merchant plant exemption, and (3) raising the offer floor under the buyer-side mitigation rules from 75% to 100% of mitigation net CONE. The Consultants concluded that a regulatory risk function was not required in view of these initiatives, a view shared by some market participants. The NYISO is committed to moving these initiatives forward. However, the Consultants recommended that the need for a regulatory risk adjustment be considered in each reset process.

12 Assumptions Regarding the Expected Level of Capacity

In the September 11, 2011 order approving the present demand curves, FERC directed that net energy revenues be determined at the locational minimum capacity requirements and NYCA installed reserve margin plus the capacity of the reference plant. In the demand curve model, this establishes the installed capacity baseline around which the Monte Carlo analysis operates to determine both capacity and net energy revenues to determine the reference price level and effective amortization period.

13 Energy and Ancillary Services Revenues

The Consultants used historical data from November 1, 2009 through October 31, 2012 to benchmark the operation of the NYISO system in order to determine likely projected Energy and Ancillary Services Revenues. The Consultants then developed a statistical model that described the effect of various cost drivers on the observed zonal LBMP values. The primary causal variables identified were load, temperature, daily natural gas prices and the addition of two major plants in New York City, Astoria Energy 2 and Bayonne Energy Center, during the historical period. Through dummy variables, the statistical model was adjusted to reflect the two new major plant additions in New York City as operating for the entire historical period. The model allows the Consultants to conceptually vary any identified causal variable – one that affects LBMPs either directly or indirectly – to create an estimate of price under differing conditions, with respect to that variable, for the period May 2014 to April 2017.

In order to adjust this forecast to further reflect the expected resource mix, as well as conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant, the Consultant utilized GE Energy Consulting (GE Energy) to conduct production costs simulations of the NYISO dispatch in the May 2014 to April 2017 period. GE Energy conducted these simulations using their Multi-Area Production Simulation (MAPS) software, using a model version and database consistent with the simulations used for the most recent Congestion Assessment and Economic Planning Study (CARIS).[20] LBMP adjustment factors were developed to address the following requirements.

1. An adjustment to the resource mix for retirements and resource additions which occurred after the historical period.
2. An adjustment to baseline conditions for the demand curve model, i.e., equilibrium capacity conditions plus the capacity of the reference plant
3. Factors for discrete capacity levels above and below this point to provide the demand curve model with the ability to adjust capacity levels in its determination of capacity and net energy revenues.

Finally, adjustment factors were developed to correct the zonal LBMP estimates in the model to nodal estimates. These factors are based on LBMP data for the historical period, and are developed on a monthly/hourly basis (288 factors).

The statistical model was used to dispatch the peaking units, and the combined cycle unit for calculating both day-ahead and real-time energy revenues, while recognizing start-up parameters and operating constraints.

The Consultant's report addressed several considerations that were raised by stakeholders, including:

- Specification of gas prices, including use of intra-day prices
- Locations selected for gas price basis
- Use of forward gas prices instead of historical gas prices
- Model specification for Astoria Energy 2 and Bayonne Energy Center
- Scarcity pricing
- Adjustment of ancillary service revenues for changes in NYISO market rules

The NYISO agrees with the Consultant's resolution of these issues and specifically notes the following:

[20] Two adjustments from the CARIS 2 resource mix were required, the retirement of the Danskammer Plant, and an agreement to continue operation of the Athens Special Protection System (SPS).

1. The combination of econometric modeling and MAPS represents a significant improvement in capturing the effects of capacity excess, and is the only way to capture some of the changes in resource mix.
2. The Consultants tested a number of alternative econometric model specifications.
3. The choice of locations for representation of gas prices has been closely examined, and it is consistent with CARIS.
4. Sensitivity results comparing historic gas prices and gas price forecasts are comparable.
5. A comparison of predicted prices for the three year period showed reasonable agreement with forward electric prices.

Ancillary services revenues were estimated from data supplied by NYISO. For the peaking units, ancillary services revenues come largely from 10 minute non-spin reserves and voltage support. Because 10-minute non-spin reserves currently come in large part from older gas turbines in the eastern region of the NYISO, an adjustment was made to the revenue data to account for the relatively high capacity factors of the LMS 100. It was determined that the Siemens SGT6-5000(F) simple cycle unit could not reach full output in 10 minutes, hence it could only qualify for 30-minute non-spin reserve.

Ancillary services revenues for the combined cycle plant come primarily from regulation and voltage support.

14 Demand Response

The Consultant did not consider demand response technology based on its review of the FTI report. That report states that "[t]he costs to power consumers of reducing consumption in order to provide incremental demand response would not provide a workable basis for setting net CONE, because it is inherently customer specific, rather than a generic cost that can be benchmarked as in the case of a generating facility.[21]" Moreover, the Consultant found that "[t]he NYISO does not have and is not aware of appropriate data to define the fixed and variable costs that are comparable to a generator, either by "generic" demand response resource category, or in the aggregate. This data issue has been discussed in the ICAP Working Group and there is general agreement that data is not available that could be used in this reset."[22]

The NYISO concurs with the Consultant's rationale for not considering Special Cases resources as the basis for setting net CONE in the Demand Curve Reset. For a more

[21] Evaluation of the New York Capacity Market, March 5, 2013, prepared by FTI Consulting, available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf

[22] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (Final Report), August 2, 2013, prepared by NERA Economic Consulting, available at *http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-13/Demand%20Curve%20FINAL%20Report%208-2-13.pdf*

detailed account of NYISO considerations in evaluating the suitability of demand response being used as the basis to set net CONE, see Appendix C.

15 Choice of Peaking Unit by Region

Table 5 below summarizes the demand curve reference prices developed by the Consultants, and includes the separate components of fixed costs and net energy and ancillary revenues. For all regions, reference prices are shown for the two-unit GE LMS 100 plant, and for the SGT6-5000F(5) combined cycle plant. For NYISO Zones C and F, the alternative of a single SGT6-5000F(5) with dry low NO_x combustion and with an annual limit of 950 hours of operation is included. As noted previously, for the remainder of the regions, the limited number of permissible operating hours for this alternative would have been unreasonable. Reference prices for plants based on the Wartsila 18V50DF and 18V50SG are not included in this summary, since these units were found to have a higher installed cost in dollars/kW than the LMS 100.

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 SGT6-5000F (5) GT	n/a	n/a	n/a	106.1	15.48	**90.62**
Zone F SGT6-5000F(5) 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**
Other Technologies						
Zone C CCGT	n/a	n/a	n/a	194.24	59.88	**134.35**
Zone F CCGT	n/a	n/a	n/a	205.54	67.15	**138.4**
NYC CCGT	n/a	n/a	n/a	482.46	100.84	**381.62**
HV Dutchess CCGT	n/a	n/a	n/a	253.49	79.9	**173.58**
HV Rockland CCGT	n/a	n/a	n/a	257.62	101.23	**156.39**
LI CCGT	n/a	n/a	n/a	287.06	190.56	**96.49**
Zone C LMS100*	n/a	n/a	n/a	175.77	23.12	**152.65**
Zone F LMS100*	223.69	63.12	160.57	188.14	36.02	**152.12**

* In the April 18 and May 22 drafts of the report the Consultants included demand curve reference prices based on the LMS100 in Zones C and F. While not included in the Consultant's final report, NYISO included them for reference.

15.1 Additional Consideration of Siemens SGT6-5000F (5) SCGT with SCR

To ensure a thorough examination of all alternatives, the NYISO directed the Consultants to develop cost and performance data and reference prices for the SGT6-5000F (5) with SCR in one and two unit simple cycle configurations. The capital cost estimates reflect addition of an SCR and diluent air mixing unit, and the performance reflects operation of this equipment and its impact on heat rate and net output. It has been assumed that the equipment would operate successfully, without additional operation and maintenance expenses or higher forced outage rates.

The Consultants clearly do not recommend this plant configuration as a viable proxy unit, but NYISO has nevertheless elected to present the additional reference prices in Table 6, to provide a more complete picture of the implications of proxy unit choice on demand curve reference prices. The capital costs, performance, and operating and maintenance cost are summarized in Appendix B.

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	118.92	15.10	103.82	109.90	15.10	94.80
Zone F	120.08	17.76	102.33	110.98	17.76	93.22
NYC	209.09	33.49	175.60	199.40	33.49	165.91
HV Dutchess	147.54	27.93	119.61	136.42	27.93	108.49
HV Rockland	150.43	32.77	117.67	139.01	32.77	106.24
LI	166.96	86.67	80.28	152.26	86.67	65.58
Two Units						
Zone C	108.85	14.99	93.86	100.37	14.99	85.38
Zone F	109.74	17.66	92.08	101.18	17.66	83.51
NYC	199.56	32.55	167.01	189.56	32.55	157.01
HV Dutchess	144.65	27.40	117.25	133.18	27.40	105.78
HV Rockland	147.09	31.97	115.12	135.27	31.97	103.30
LI	164.77	83.76	81.01	146.21	83.76	62.46

Note: The reference prices were developed with the NYISO recommended zero crossing points.

For NYC, LI and the NCZ, for which the Consultants recommend that the demand curves be based on a two-unit GE LMS 100 plant, the SGT6-5000F (5) with SCR produces a reference price, in both single and two-unit configurations, that is below both the LMS 100 and the combined cycle plant. For the NYCA, the SGT6-5000F (5) with SCR produces a reference price that is above the recommended configuration without SCR, but like the recommended plant, below the reference price based on the two-unit LMS 100 plant, as well as the combined cycle plant. Thus, were the reference price the single basis for a recommendation, this plant configuration would represent a significant alternative. However, the NYISO concurs with the Consultant's recommendation that the " proxy unit not be based on simple cycle F-class[a] simple cycle F-class CT with SCR because of technical challenges, unsuccessful projects and lack of market acceptance

15.2 NYISO Recommendation

The NYISO tariff currently requires that the demand curve reference price be based on a peaking plant, and further requires that it be based on the peaking plant with the lowest fixed cost and highest variable cost. The second requirement would translate into the alternative with the lowest fixed cost and lowest energy and ancillary services revenues, reflecting the higher variable costs. For Zones C and F, which would determine the reference price for the NYCA, this is the Siemens SGT6-5000F (5) GT, with dry low NO_x combustion for NO_x emissions control and a cap on operating hours, an alternative which emerged during the review process. In this case, Zone F is also the lowest reference price and is the recommended NYCA peaking plant for the NYCA.

The choice of peaking unit by region is summarized in the Table 7.

Table 7: Choice of Peaking Unit

Choice of Peaking Unit	
NYCA	SGT6-5000F (5) GT (No SCR)
Zone J	GE LMS100
Zone K	GE LMS100
Zones G-J	GE LMS100

16 Combined Cycle Unit

The FTI report did not make a firm recommendation concerning the choice between continued use of a peaking unit to establish net CONE versus an estimated net CONE based on a combined cycle unit. Rather, the FTI report concluded that either of these resources may be the least-cost source of incremental capacity in the future. The FTI report also noted that prior to April 1, 2012, all recent capacity additions east of the Central East interface in New York have been in the form of combined cycle units. The Bayonne Energy Center, which is comprised of aeroderivative gas turbines, came on line after April 1, 2012. Finally, the FTI report also noted that if the costs and revenues of a combined cycle unit are used to determine net CONE, particular care would need to be taken in estimating energy and ancillary service revenues. The Consultants have addressed this concern in developing the appropriate dispatch logic in the determination of net energy revenues, and in choosing simple cycle and combined cycle gas turbine options for evaluation that are of such a scale that they are similarly close to capacity equilibrium conditions.

In State of the Market Reports, the NYISO's independent Market Monitor Unit has recommended that NYISO consider basing the demand curve on a generating plant other than a peaking plant because of concern that continued use of a peaking units may lead to market inefficiencies if it is not the lowest net cost unit.

For these reasons, the NYISO directed the Consultant's to fully develop demand curve reference prices for combined cycle technology. Comparison of these reference prices to those for the simple cycle gas turbines indicates that for every region except New York City, the Siemens SGT6-5000F (5) combined cycle plant has a lower cost than the GE LMS 100 plant. For the NYCA, however, the demand curve recommendation is based on the lower reference price for the Siemens SGT6-5000F (5) simple cycle unit. It is also important to note that the difference between the NYC reference prices for the GE LMS 100 and the combined cycle plant are significantly driven by the limited applicability of the property tax abatement. As explained in Section 7, the NYC property tax abatement is available only to peaking units as defined by the NYISO tariff, or to units that run an average of no more than 18 hours per start. The reference price for the NYC combined cycle plant was developed using an appropriate dispatch logic which would allow for operation at minimum generation level overnight; consequently it would not qualify for the tax abatement. As sensitivity, the Consultants developed an estimate of the reference price in a scenario in which the combined cycle plant would cycle in a fashion than closely approximates the limit of 18 hours per start; in this case, the LMS 100 still had a lower reference price. A comparison can also be made in which neither unit is eligible for the abatement; in this case the LMS 100 also has a slightly lower reference price.

The NYISO developed a tariff revision that would have required that the demand curve be based on the proxy plant that results in the lowest demand curve reference price. This tariff revision was brought before the NYISO Business Issues Committee on March 13, 2013, where a motion to approve narrowly failed, with a vote of 57% affirmative.[23]

[23] The proposed tariff revision can be found as a redline to Section 5.14 of the Market Services Tariff at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2013-03-13/agenda_10_MST%205%2014%20Redline%20ICAP%20Demand%20Curve%20proxy%20plant%20Redline%20to%20e-tariff%20base.pdf. Subsequently, a group of market participants took the proposed amendment to the NYISO Management Committee, however, a consensus among market participants was not reached that would have allowed a vote.

NYISO believes that the above comparison of reference values confirms that the proposed tariff revision was appropriate.

17 Demand Curves Slope and Length – Zero Crossing Point

The FTI report contained an analysis conducted in 2012 of the zero crossing point for the NYCA, Zone J, Zone K and NCZ demand curves. The Consultants reviewed the FTI report, and stated ”FTI concluded that while in general the zero crossing points and linear shape of the current Demand Curves did track reliability value, the correspondence between the demand curve and reliability value would be enhanced by slightly reducing the NYC zero crossing point and slightly increasing the NYCA zero crossing point”.[24] FTI based these recommendations on an assessment of the incremental reliability value of capacity in NYCA, Zone J, Zone K and in the NCZ. The assessment of incremental reliability value was based on analyses of loss of load expectation (LOLE) vs. incremental capacity additions using the Multi-Area Reliability Simulation (MARS) model. These analyses showed a diminishing reduction in LOLE with incremental capacity additions. The addition of capacity to the area of concern was effectuated by shifting capacity into the area of concern in a manner consistent with Policy 5 of the New York State Reliability Council Reliability Rules.

The FTI report suggested moving the zero crossing points for the Zone J and the NYCA curves from 118% and 112% to 115 % and 115% respectively. For Zone K, the FTI report recommended retaining the current 118% zero-crossing point.

The Consultants recommended moving the zero crossing points for Zone J and the NYCA to a point halfway between the current zero crossing point and the FTI recommendations, to 116.5% and 113.5% respectively. For Zone K, the Consultants recommended retaining the existing crossing point. This recommendation was consistent with the FTI report. For the new capacity zone, comprised of zones G-J, the Consultants recommended a zero crossing point midway between Zone J and NYCA, or 115%.

Subsequently, the MMU also independently reviewed the analyses conducted for the FTI report, and conducted several discussions with FTI, NERA and the NYISO. These discussions focused on the capacity shifting methodology. The MMU sponsored the recommendation that the zero crossing point analysis using the capacity shifting methodology could be improved by adding capacity to the area of concern without shifting it out of the other areas in the NYCA. FTI, NERA and the NYISO have agreed that there are merits to adopting a capacity addition methodology as opposed to the shifting methodology utilized in the FTI study. The FTI study highlighted that the shifting methodology 1) offered the advantage of keeping the capacity in the NYCA

[24] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (Final Report), August 2, 2013, prepared by NERA Economic Consulting, Executive Summary, available at
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-13/Demand%20Curve%20FINAL%20Report%208-2-13.pdf

constant, but resulted not in an estimate of the zero crossing point (the value at which the incremental value of capacity is zero), but rather of the point at which the incremental value of capacity in the NYCA was equal to the value of incremental capacity in the zone(s) of interest. FTI, NERA and the NYISO agreed that utilizing the addition methodology would be an improvement to the analysis. Rather than continuing to introduce capacity into the zone(s) of interest until the change in LOLE becomes zero, the MMU proposed that the change in LOLE be assessed only in the range of typical excess – where the market is expected to clear – i.e., in the 100 to 112% range. The zero crossing point could then be established by extending the change in LOLE trend line down to the capacity surplus axis. The NYISO conducted analysis requested for the MMU to complete this analysis in mid-August and the MMU presented this approach and initial results to stakeholders at the August 22 Installed Capacity Working Group. Stakeholders had several concerns regarding the analysis being introduced so late in the reset process. The general concern was that stakeholders had little information to review and very little time to reflect on the sufficiency of the MMU's methodology to support the resulting changes to the zero crossing point. Stakeholders also commented, and the NYISO and the MMU concurred, that market certainty is a paramount objective in the demand curve reset process and that it is not clear at this time whether the proposed methodology would support the market certainty goal.

The comparison of the above mentioned recommendations for the zero crossing points is presented in Table 8 below.

Table 8: Comparison of Zero Crossing Points

	Zero Crossing Points			
Capacity Zone	**Current DC**	**FTI Report Recommendation**	**Consultants' Recommendation**	**MMU's Recommendation**
NYCA	112%	115%	113.5%	114%
NYC	118%	115%	116.5%	116%
NCZ (G-J)		110%	115%	114%
LI	118%	118%	118%	118%

17.1 NYISO Recommendation

In its review of the various methodologies and recommendations regarding the zero crossing points, the NYISO found that the analyses conducted were highly sensitive to methodology, input assumptions, and transmission system topology. In addition, the NYISO agrees that adopting any methodology to adjust the zero crossing point at this time could result in fluctuations to the recommended zero crossing point at each Demand Curve reset, introducing undue volatility and uncertainty in the market.

The NYISO contends there is insufficient information to demonstrate that a revised methodology would send a more accurate market price signal or otherwise better align the ICAP Demand Curves with the system reliability. Thus, there would not necessarily be a benefit that could, in whole or part, offset the additional uncertainty that might be introduced. Therefore, the NYISO proposes to make no changes to the existing NYCA, NYC and LI zero crossing points, and the NYISO also recommends to establish a 115% zero crossing point for the NCZ based on the midpoint between the current NYCA and NYC zero crossing points. The magnitude of the NYISO's NCZ 115% zero crossing recommendation is the same as the Consultant's recommendation. Consistent with the requirement that each triennial Demand Curve reset review assess the zero crossing point, the NYISO will gather information and conduct additional analysis over the next two to three years and continue the assessment of the appropriate zero crossing methodology in the next-following Demand Curve reset. Table 9 shows the NYISO's recommended zero-crossing points.

Table 9: NYISO's Recommended Zero Crossing Points

	Zero Crossing Points
Capacity Zone	**NYISO Recommendation**
NYCA	112%
NYC	118%
NCZ (G-J)	115%
LI	118%

18 Winter/Summer Adjustment

The NYISO ICAP market operates in two six-month Capability Periods with different amounts of capacity available in each. The primary reason for this variation is that gas turbine and combined cycle generating units are normally capable of higher output in winter than summer due to lower ambient temperature conditions. Installed capacity imported from External Control Areas, new generation and retirements also influence the quantity of capacity available.

The reference value determined by the Consultants and recommended by NYISO is a $/kW-year value. The ICAP Demand Curve reference point used in monthly ICAP Spot Market Auctions must include adjustments to take these seasonal effects into account. Each monthly Demand Curve reference point is set to the level that would permit a peaking unit to be paid an amount over the course of the year that is equal to the annual reference value established by this update.

The Services Tariff specifies that the translation of the annual net revenue requirement into monthly values take into account "seasonal differences in the amount of Capacity available in the ICAP Spot Market Auctions."[25] The NYISO makes this translation using

[25] Services Tariff Section 5.14.1.2.

a ratio of the amount of capacity available in the winter to the amount available in summer, the Winter/Summer Capacity Ratio. In its September 15, 2011 Order, FERC directed indicated that NYISO " revise its demand curve parameters so that the same levels of excess capacity, and the underlying mix of resources, are used to calculate deliverability costs and the winter/summer adjustment."

In addition, the Consultants include the Summer/Winter Capacity Ratio in the demand curve model for a more accurate representation of the impact of seasonal capacity levels on capacity and energy and ancillary service revenues over the lifetime of the peaking unit. The model uses the same winter-to-summer capacity ratios used for the translation into monthly reference prices. Those ratios are summarized and compared to the values used in the previous demand curve reset in Table 10 below.

Table 10: Winter/Summer Capacity Ratios

Winter /Summer Capacity Ratios (Including Proxy Unit)				
Year	**NYCA**	**Zone J**	**Zones G-J**	**Zone K**
2013	1.047	1.087	1.068	1.070
2010	1.045	1.089	N/A	1.066

19 ICAP Demand Curves, Reference Values, and Reference Points

19.1 NYISO Recommendation

Appendix A to this report contains a summary of the annual and monthly NYISO's recommended Demand Curve parameters by Capacity region for the three years covered by the Current Demand Curve reset period and plots of the Demand Curves for each Capacity Zone on an ICAP basis.

Table 11 below summarizes the NYISO's recommended parameters for the 2014-2015 Demand Curve period and reflect the effect of the NYISO recommended zero crossing points and a change to a more representative location for relative humidity data in determining net ICAP. The latter change had a small effect on the ICAP values used in the model, and made a small difference in the calculated reference prices. The NYISO proposed changes in temperature and relative humidity values are outlined in Appendix D.

Table 11: NYISO's Recommended Demand Curve Parameters, 2014-2015

DC Parameters	NYCA	Zone J	Zones G-J	Zone K
Reference Point ($/kW-yr)	89.50	240.11	171.73	133.07
Reference Point ($/kW-mo)	8.84	25.57	17.86	13.28
Zero Crossing (% of req)	112.0	118.0	115.0	118.0
Summer DMNC (MW)	210.1	185.5	186.3	187.9
Escalation Factor (%)	2.2	2.2	2.2	2.2

20 Independent Review of Demand Curve Parameters

The NYISO has consulted with the Market Monitor Unit, Dr. David Patton, regarding the conclusions in this report. He independently monitors and evaluates the patterns of bids, offers and market outcomes in the New York capacity markets. He believes that the stability provided by the demand curves facilitates the forward contracting for both capacity and energy that is needed to support investment in new and existing generation.

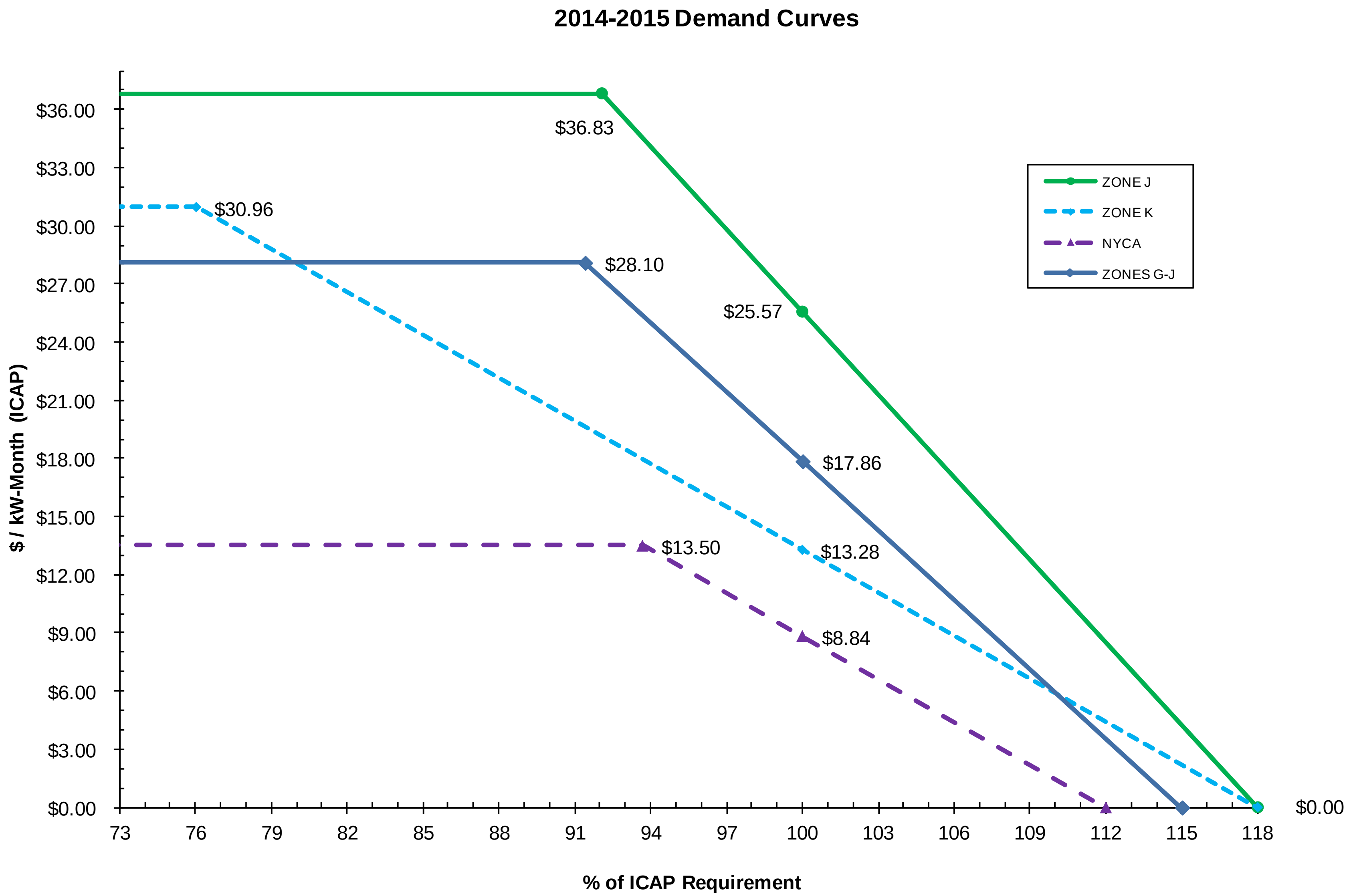
Dr. Patton generally concurred with most of the conclusions in this report. However, he expressed concern with the Consultant's proposed revisions to the zero-crossing points for NYCA, Zone J and NCZ, and recommended a new analytic methodology for establishing NYISO's zero crossing points for its capacity demand curves. For the reasons set forth in Section 17.1, NYISO did not adopt the specific zero-crossing point recommendations that resulted from application of this methodology.

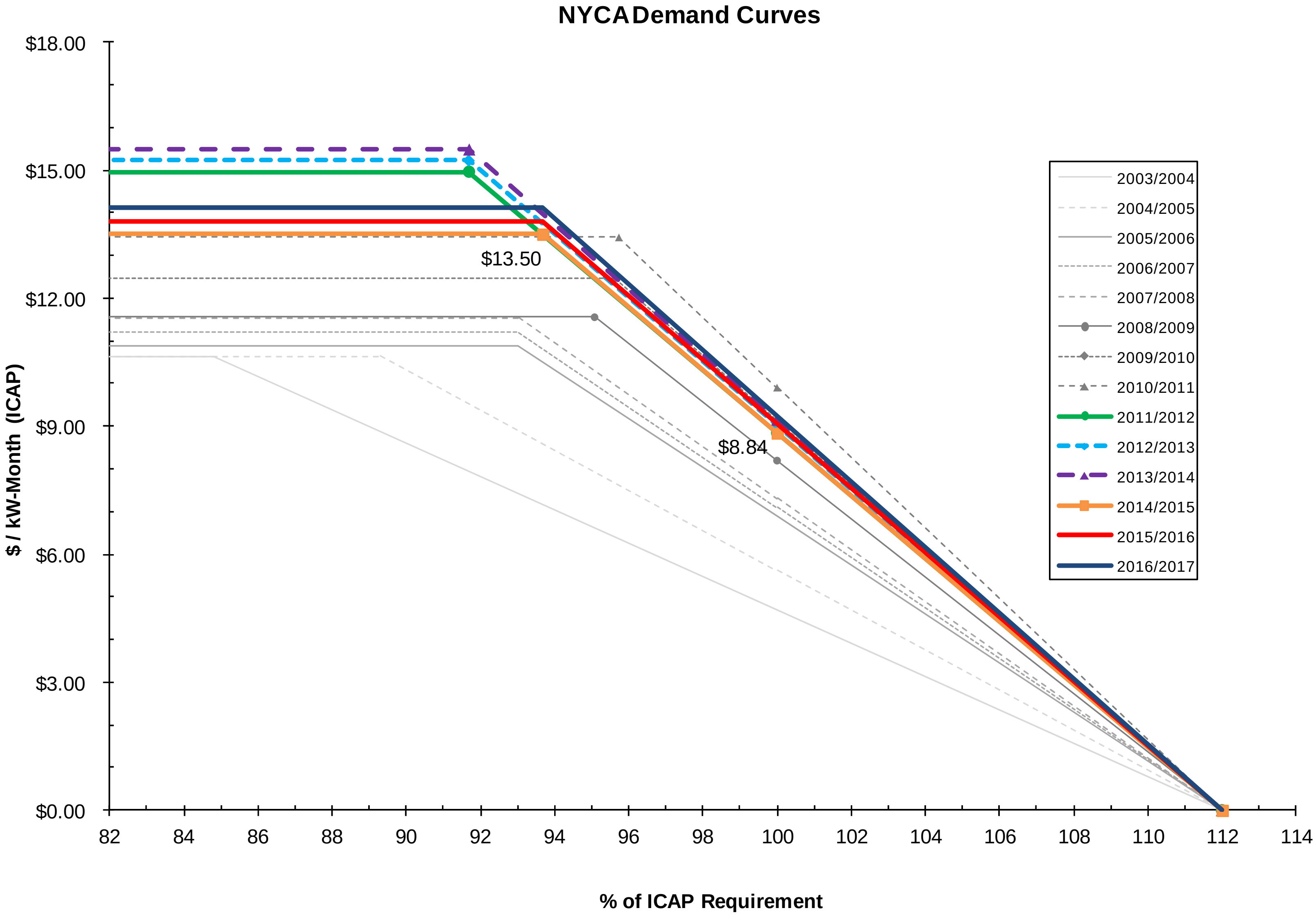
21 Appendix A: NYISO's Recommended Demand Curve Parameters and Demand Curves

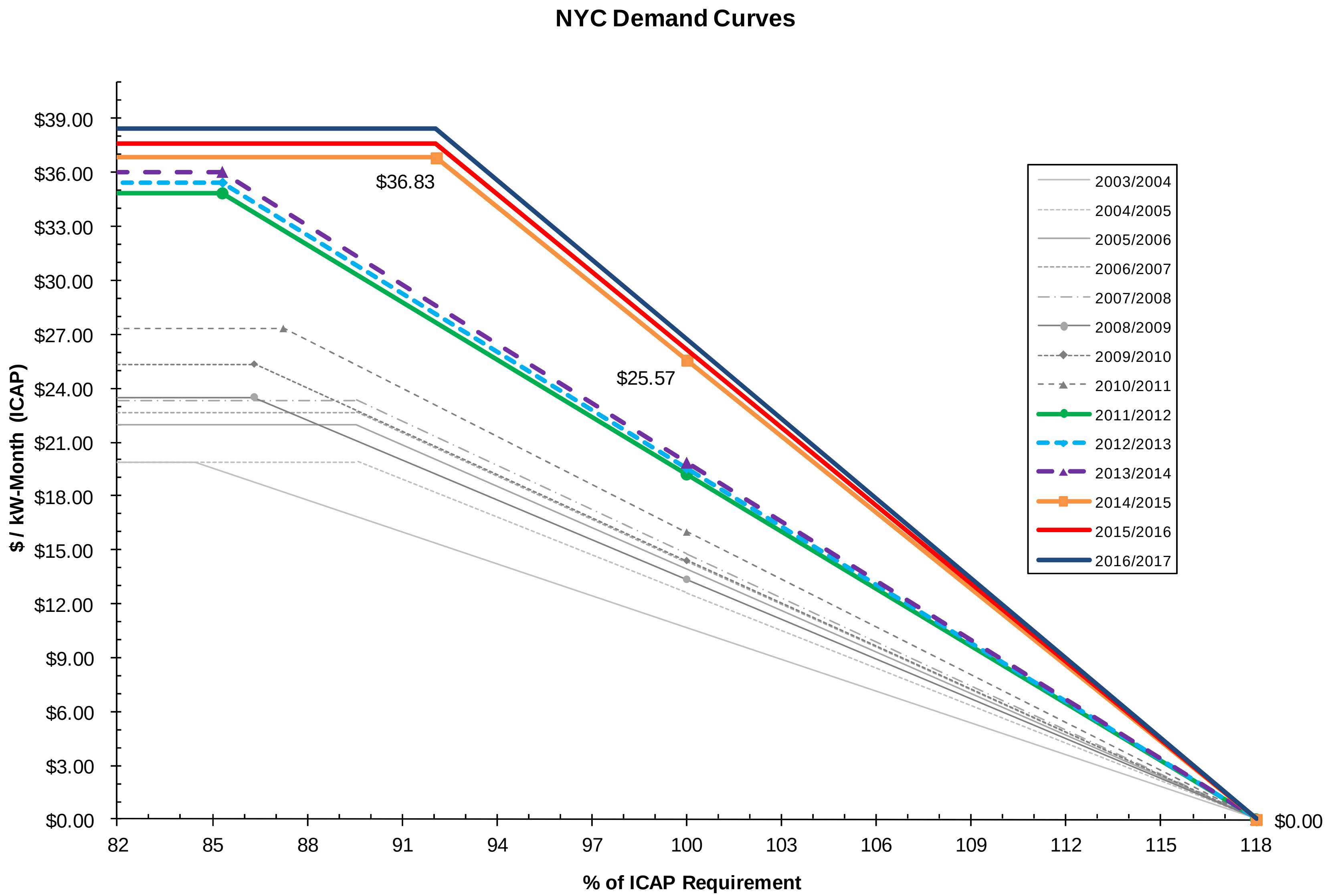
2014/2015					
	NYCA	NYC	LI	NCZ	
Annual Revenue Req. (per KW)	$107.98	$294.60	$247.71	$224.79	$/kW-Year (ICAP basis)
Net Revenue (per kW)	$18.48	$54.50	$114.64	$53.06	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$89.50	$240.11	$133.07	$171.73	$/kW-Year (ICAP basis)
Net Plant Capacity -ICAP (MW)	206.50	184.00	185.52	184.40	Average Degraded Capacity (NERA/S&L Report)
Total Annual Revenue Req. =	$18,481,512	$44,178,887	$24,686,220	$31,667,796	
Ratio of Winter to Summer DMNCs	1.047	1.087	1.070	1.068	Adjusted from 2012 GB values
Summer DMNC	210.1	185.5	188.0	186.3	Net Summer Capacity (DMNC Rating Convention)
Winter DMNC	226.2	198.7	199.8	200.4	Net Winter Capacity (DMNC Rating Convention)
Summer Reference Point =	$8.84	$25.57	$13.28	$17.86	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.41	$13.18	$8.10	$9.74	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$1,857,284	$4,743,900	$2,495,976	$3,327,497	
Monthly Revenue (Winter) =	$1,223,742	$2,618,866	$1,618,202	$1,951,623	
Seasonal Revenue (Summer) =	$11,143,704	$28,463,399	$14,975,856	$19,964,980	
Seasonal Revenue (Winter) =	$7,342,452	$15,713,196	$9,709,211	$11,709,740	
Total Annual Revenue =	$18,486,156	$44,176,595	$24,685,067	$31,674,719	validates "Total Annual Revenue Req." is met
Demand Curve Parameters					
ICAP Monthly Reference Point =	$8.84	$25.57	$13.28	$17.86	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$13.50	$36.83	$30.96	$28.10	$/kW-Month (ICAP basis)
Demand Curve Length	112.0%	118.0%	118.0%	115.0%	

2015/2016					Escalation Factor = 2.2%
	NYCA	NYC	LI	NCZ	
Annual Revenue Req. (per KW)	$110.35	$301.08	$253.16	$229.74	$/kW-Year (ICAP basis) - (LMS-100 updated)
Net Revenue (per kW)	$18.88	$55.70	$117.17	$54.22	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$91.47	$245.39	$136.00	$175.51	$/kW-Year (ICAP basis)
Net Plant Capacity -ICAP (MW)	206.5	184.0	185.5	184.4	Average Degraded Capacity (NERA/S&L Report)
Total Annual Revenue Req. =	$18,888,106	$45,150,822	$25,229,317	$32,364,487	
Ratio of Winter to Summer DMNCs	1.047	1.087	1.070	1.068	Adjusted from 2012 GB values
Summer DMNC	210.1	185.5	188.0	186.3	Net Summer Capacity (DMNC Rating Convention)
Winter DMNC	226.2	198.7	199.8	200.4	Net Winter Capacity (DMNC Rating Convention)
Summer Reference Point =	$9.03	$26.13	$13.56	$18.25	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.53	$13.47	$8.30	$9.95	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$1,897,203	$4,847,794	$2,548,602	$3,400,158	
Monthly Revenue (Winter) =	$1,250,886	$2,676,489	$1,658,157	$1,993,701	
Seasonal Revenue (Summer) =	$11,383,218	$29,086,766	$15,291,612	$20,400,945	
Seasonal Revenue (Winter) =	$7,505,316	$16,058,934	$9,948,944	$11,962,208	
Total Annual Revenue =	$18,888,534	$45,145,700	$25,240,556	$32,363,153	validates "Total Annual Revenue Req." is met
Demand Curve Parameters					
ICAP Monthly Reference Point =	$9.03	$26.13	$13.56	$18.25	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$13.79	$37.64	$31.65	$28.72	$/kW-Month (ICAP basis)
Demand Curve Length	112.0%	118.0%	118.0%	115.0%	

2016/2017					Escalation Factor = 2.2%
	NYCA	NYC	LI	NCZ	
Annual Revenue Req. (per KW)	$112.78	$307.71	$258.73	$234.79	$/kW-Year (ICAP basis) - (LMS-100 updated)
Net Revenue (per kW)	$19.30	$56.92	$119.74	$55.42	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$93.48	$250.79	$138.99	$179.37	$/kW-Year (ICAP basis)
Net Plant Capacity -ICAP (MW)	206.5	184.0	185.5	184.4	Average Degraded Capacity (NERA/S&L Report)
Total Annual Revenue Req. =	$19,303,644	$46,144,140	$25,784,362	$33,076,506	
Ratio of Winter to Summer DMNCs	1.047	1.087	1.070	1.068	Adjusted from 2012 GB values
Summer DMNC	210.1	185.5	188.0	186.3	Net Summer Capacity (DMNC Rating Convention)
Winter DMNC	226.2	198.7	199.8	200.4	Net Winter Capacity (DMNC Rating Convention)
Summer Reference Point =	$9.23	$26.70	$13.85	$18.65	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.65	$13.77	$8.47	$10.16	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$1,939,223	$4,953,544	$2,603,108	$3,474,682	
Monthly Revenue (Winter) =	$1,278,030	$2,736,099	$1,692,120	$2,035,780	
Seasonal Revenue (Summer) =	$11,635,338	$29,721,265	$15,618,645	$20,848,089	
Seasonal Revenue (Winter) =	$7,668,180	$16,416,594	$10,152,718	$12,214,677	
Total Annual Revenue =	$19,303,518	$46,137,859	$25,771,363	$33,062,766	validates "Total Annual Revenue Req." is met
Demand Curve Parameters					
ICAP Monthly Reference Point =	$9.23	$26.70	$13.85	$18.65	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$14.10	$38.46	$32.34	$29.35	$/kW-Month (ICAP basis)
Demand Curve Length	112.0%	118.0%	118.0%	115.0%	


2014-2015 Demand Curves
$36.00
$33.00
$30.00
$27.00
$24.00
$21.00
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$ / kW-Month (ICAP)
73
76
79
82
85
88
91
94
97
100
103
106
109
112
115
118
% of ICAP Requirement
$36.83
$30.96
$28.10
$25.57
$17.86
$13.50
$13.28
$8.84
$0.00
ZONE J
ZONE K
NYCA
ZONES G-J


NYCA Demand Curves
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$ / kW-Month (ICAP)
82
84
86
88
90
92
94
96
98
100
102
104
106
108
110
112
114
% of ICAP Requirement
$13.50
$8.84
2003/2004
2004/2005
2005/2006
2006/2007
2007/2008
2008/2009
2009/2010
2010/2011
2011/2012
2012/2013
2013/2014
2014/2015
2015/2016
2016/2017


NYC Demand Curves
$39.00
$36.00
$33.00
$30.00
$27.00
$24.00
$21.00
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$ / kW-Month (ICAP)
82
85
88
91
94
97
100
103
106
109
112
115
118
% of ICAP Requirement
$36.83
$25.57
$0.00
2003/2004
2004/2005
2005/2006
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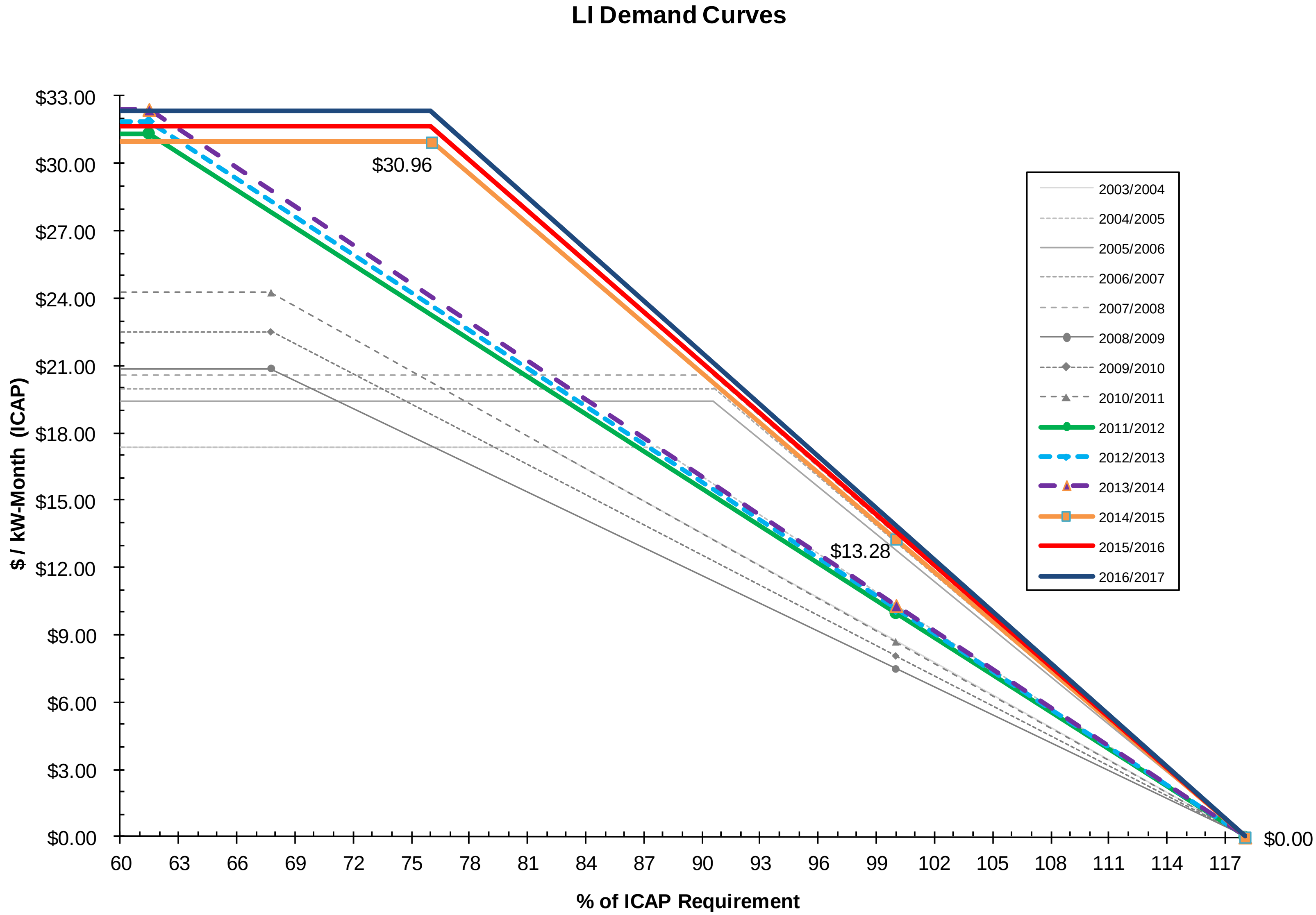
2014/2015
2015/2016
2016/2017


LI Demand Curves
$33.00
$30.00
$27.00
$24.00
$21.00
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$ / kW-Month (ICAP)
60
63
66
69
72
75
78
81
84
87
90
93
96
99
102
105
108
111
114
117
% of ICAP Requirement
$30.96
$13.28
$0.00
2003/2004
2004/2005
2005/2006
2006/2007
2007/2008
2008/2009
2009/2010
2010/2011
2011/2012
2012/2013
2013/2014
2014/2015
2015/2016
2016/2017

22 Appendix B: SGT6-5000F (5) GT with SCR

This appendix contains information on a plant configuration not recommended by NERA/S&L, and not recommended by the NYISO, but is provided at the request of some market participants. Sargent & Lundy stated at the July 9 ICAPWG meeting that the "Simple cycle SGT6-5000F(5) with SCR is not considered due to technical challenges, operating risks, lack of successful operating experience, and potential permitting hurdles." Note that the costs below may be understated since no adjustments were made for failed catalysts, increased O&M due to unproven technology, EFORd impacts, etc.

SGT6-5000F (5) GT with SCR
Capital Costs

	1x Siemens SGT6-5000F(5)	2x Siemens SGT6-5000F(5)
Zone C Syracuse		
Total Capital Cost	162,418,000	287,938,000
ICAP MW	203.75	407.49
$/kW	$797	$707
Zone F Albany		
Total Capital Cost	164,793,000	292,402,000
ICAP MW	204.91	409.83
$/kW	$804	$714
Zone J New York City		
Total Capital Cost	236,302,000	398,623,000
ICAP MW	205.30	410.59
$/kW	$1,151	$964
Zone K Long Island		
Total Capital Cost	210,407,000	365,434,000
ICAP MW	206.77	413.54
$/kW	$1,018	$884
Zone G Hudson Valley (Dutchess County)		
Total Capital Cost	186,348,000	328,774,000
ICAP MW	205.60	411.20
$/kW	$906	$798
Zone G Hudson Valley (Rockland County)		
Total Capital Cost	191,139,000	337,955,000
ICAP MW	205.60	411.20
$/kW	$930	$822

SGT6-5000F (5) GT with SCR
Performance and O&M Costs

	1x Siemens SGT6-5000F(5)	2x Siemens SGT6-5000F(5)
Zone F Albany		
Heat Rate (Summer) Btu/kWh	10,789	10,789
Heat Rate (Winter) Btu/KWh	10,304	10,304
Capacity (Summer) MW	212.07	424.13
Capacity (Winter) MW	225.25	450.50
ICAP (Summer) MW	210.06	420.12
ICAP (Winter) MW	225.27	450.54
Variable O&M $/MWh	1.65	1.65
Variable O&M ($/Start) per unit	9,164	9,164
Zone J New York City		
Heat Rate (Summer) Btu/kWh	10,869	10,869
Heat Rate (Winter) Btu/KWh	10,416	10,416
Capacity (Summer) MW	211.62	423.24
Capacity (Winter) MW	223.66	447.32
ICAP (Summer) MW	209.63	419.26
ICAP (Winter) MW	223.58	447.17
Variable O&M $/MWh	1.65	1.65
Variable O&M ($/Start) per unit	9,376	9,376
Zone K Long Island		
Heat Rate (Summer) Btu/kWh	10,790	10,790
Heat Rate (Winter) Btu/KWh	10,345	10,345
Capacity (Summer) MW	213.72	427.45
Capacity (Winter) MW	225.19	450.38
ICAP (Summer) MW	212.59	425.18
ICAP (Winter) MW	225.22	450.44
Variable O&M $/MWh	1.65	1.65
Variable O&M ($/Start) per unit	9,358	9,358
Zone G Hudson Valley (Rockland County)		
Summer Heat Rate (Btu/kWh)	10,809	10,809
Winter Heat Rate (Btu/KWh)	10,314	10,314
Summer Capacity (MW)	210.02	420.03
Winter Capacity (MW)	225.23	450.47
Summer ICAP (MW)	209.57	419.13
Winter ICAP (MW)	225.23	450.47
Variable O&M ($/MWh)	1.65	1.65
Variable O&M ($/Start) per unit	9,290	9,290

23 Appendix C: Demand Response as a Basis for CONE

In the recommendations for the previous demand curve reset, the NYISO concluded:

> ”…demand response presently available generally does not have the ability to respond to longer deployments under current market rule designs. Further, there is not an established set of parameters or characteristics for a particular technology of demand response to be identified with any reasonable measure of certainty. Even if an identified technology could be ascertained with certainty, the fixed and variable costs made it unsuitable for consideration in the current Demand Curve reset review.”

The NYISO made a commitment to consider the use of Demand Response as the peaking unit in this reset cycle, contingent upon better definition of the process for identifying demand response resource technology types, and the methodology and a means to quantifying the fixed and variable costs associated with those technologies.

Demand response as basis for setting the CONE was specifically addressed in the FTI report, which concluded the following:

> “The cost to power consumers of reducing consumption in order to provide incremental demand response would not provide a workable basis for setting net CONE because it is inherently customer specific, reflecting the net cost of reduced consumption unique to that consumer, rather than a generic cost that can be benchmarked in the same manner as the cost of building a generating facility.”

In addition to the conclusions in the FTI report, which are summarized in more detail in the following section, additional conclusions can be drawn from NYISO characterizations of demand response effectiveness developed for assessments of resource adequacy, and from NYISO experience in participation of Special Case Resources in the capacity market.

23.1 The FTI Report

The FTI Report recognized that it is essential to allow demand response to participate in capacity markets to achieve efficient outcomes, i.e., to avoid incurring the cost of building and maintaining capacity that costs more than the value of the load it serves. However, while demand response is an important participant in capacity markets, neither the “cost” nor the offer price of demand response resources provide an appropriate exogenous measure of the long-run cost of this capacity. Participation of Special Case Resources in the NYISO capacity market, in effect allows the NYISO to procure only the amount of physical generating capacity needed to meet firm load. i.e., load that will not be curtailed in response to high prices or NYISO instructions. Thus, demand response resources can be used to meet forecasted peak load, but cannot be used to meet forecasted firm load, because by definition, firm load is the load that must be met after the load of Special Case Resources and other demand response is off the system.

The costs of providing demand response fall broadly into two categories: the communications and infrastructure costs of the demand response provider, and the value of the power consumption that must be reduced to provide the demand response, net of avoided energy market costs, and any energy market payments. The value of the power depends on the specific characteristics of the individual demand response provider, and on the probability of being called upon, which in turn depends on system characteristics, including the mix and quantity of demand response and physical generation, both firm and intermittent. While this value could in principle be determined for individual customers, using customer specific information, each customer would have its own unique value, rather than a single value that would be appropriate for anchoring a capacity demand curve.

In summary, FTI concluded that there is no well-defined exogenous cost of demand response that can be determined and used as a benchmark for the long-run cost of capacity in NYISO markets. The estimated long-run cost of physical generation is a more reliable long-run benchmark for the capacity market demand curve.

In comments on the FTI report, NYISO market participants suggested that the cost of demand response could be determined by resource type or in the aggregate. The NYISO responded, consistent with the FTI report, that it had no data that could be used for this purpose.

The above conclusions were reviewed in a presentation at the ICAPWG meeting of January 22, 2013.

23.2 Other Considerations

In 2012, the NYISO completed a study of Special Case Resources for the Installed Capacity Subcommittee of the New York State Reliability Council. This study characterizes the effectiveness of SCR for the purpose of the reliability assessments that are used to determine the Installed Reserve Margin (IRM) for the NYCA and the Local Capacity Requirements (LCR) for the capacity zones. The recommendation to ICS for the 2012 IRM study contains four factors--a translation factor, the SCR performance factor, the Effective Capacity Value, and a fatigue factor for the overall representation of SCR. The first factor is simply a matter of measurement (ACL vs CBL). The second is analogous to one minus EFORd for a generator, and the last two factors, each recommended at 0.95, are intended to better represent the effectiveness of the resource. In comparison to a generator, the zonal SCR performance factor is typically lower than one minus the historical generator EFORd used to translate the demand curves from ICAP to UCAP for each zone, and are certainly lower than the comparable figure based on the forced outage rate used proxy unit in the Consultant's study. Further, for a firm generating resource, the other two factors are not necessary for representation in the study.

The FTI report observed that if a demand response resource expects to be called rarely, the expected value of the interrupted load will be lower, because few interruptions would be expected. On the other hand, if the demand resource expects to be interrupted more frequently, the expected value of the interrupted load would be higher. This observation is consistent with the NYISO's experience in dealing with Special Case Resources through the Installed Capacity Working Group. Participants have consistently expressed concern about the actual number of SCR activations at a given point in a capability period, or the potential that activations might be "excessive." While quantification of the actual costs of demand response is problematic, and demand response is not an appropriate resource for the demand curve "proxy" unit, this observation does provide some insight into the "directionality" of these costs. Capacity prices determined under a demand curve based on an appropriately selected physical generating resource may be perceived as too low if the expected number of activations rises. Or stated differently, the more performance of Special Case Resources is expected to approach that of peaking generation resources, the higher the cost of providing this service will be perceived by those customers participating in the capacity market.

Today, demand response is called upon sporadic intervals with durations of four to seven hours —far less than the commitment of a physical generator. If DR was called upon in a manner similar to the obligations of a physical generator, the perceived cost would be expected to increase dramatically from current levels.

24 Appendix D: Temperature and Relative Humidity Assumptions

NYISO Proposed Change

Table A1 - Site Assumptions for Capacity and Heat Rate Calculations

Load Zone	Weather Basis	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity	Revised 8/13/2013 Ambient Temperature (°F)	Revised 8/13/2013 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		
J - New York City	New York City	20	Summer	83.0	64.3		
			Winter	28.0	61.7		
			Spring-Fall	59.0	60.0		
			Summer DMNC	94.6	40.6	94.6	43.3
			Winter DMNC	37.7	77.1	37.8	11.6
			ICAP	90.0	70.0		
K - Long Island	Long Island	16	Summer	80.7	69.3		
			Winter	28.0	66.2		
			Spring-Fall	59.0	60.0		
			Summer DMNC	93.9	37.0	93.9	43.2
			Winter DMNC	22.1	80.0	22.1	26.6
			ICAP	90.0	70.0		

25 Appendix E: Timeline

New York Independent System Operator, Inc.
Final Timeline for Fall 2013 Determination of New ICAP Demand Curves
For the 2014/2015 through 2016/2017 Capability Years

The NYISO anticipates following the timeline set forth below to complete the remaining aspects of the Periodic Independent Review of the ICAP Demand Curves, as provided for in Section 5.14.1.2 of the Services Tariff. Stakeholder and NYPSC review and input has been provided through the several ICAP Working Group meetings since the August 2, 2013 release of the NERA/S&L Report.

All comments received from stakeholders will be posted on the ICAP Working Group page of the NYISO website. All deadlines should be considered as of "close of business," and should be provided to the NYISO electronically at the website address that will be provided to the ICAP Working Group.

- August 19, 2013 – NYISO issues proposed ICAP Demand Curves, initiating thirty-day period for stakeholder submissions of comments (limited to twenty pages) and/or requests for oral argument before the NYISO Board of Directors' Market Performance Committee.

- August 22, 2013 - NYISO presents proposed ICAP Demand Curves to ICAPWG.

- August 29, 2013 – Stakeholders' submission of comments to the proposed ICAP Demand Curves.

- September 11, 2013 – NYISO presents final proposed ICAP Demand Curves to ICAPWG.

- September 30, 2013 – Close of thirty-day comment period.

- October 14, 2013 – NYISO Board of Directors' Reliability and Markets Committee considers stakeholder comments and hears oral arguments, if requested. Total time for oral argument shall be limited to no more than 90 minutes.

- November 19, 2013 – at its regular November meeting, the NYISO Board of Directors acts on the new ICAP Demand Curves.

- November 29, 2013 – NYISO submits the NYISO Board-issued ICAP Demand Curves to the Commission.

- By February 1, 2014 – Anticipated Commission action on filing.