NEW YORK INDEPENDENT SYSTEM OPERATOR

Proposed NYISO Installed Capacity Demand Curves For Capability Year 2017/2018 and Annual Update Methodology and Inputs For Capability Years 2018/2019, 2019/2020, and 2020/2021

NYISO Staff Final Recommendations

09/15/2016

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1. Executive Summary

During this ICAP Demand Curve reset (DCR) process, the Federal Energy Regulatory Commission approved modifications to Section 5.14.1.2 of the Market Administration and Control Area Services Tariff to: (i) increase the period between resets from three years to four years; (ii) provide for the implementation of a formulaic and transparent process to annually update certain parameters of the ICAP Demand Curves for the Capability Years between resets; and (iii) implement a more transparent and predictable methodology for estimating net Energy and Ancillary Services revenues expected to be earned by a peaking plant. This reset period encompasses the 2017/2018, 2018/2019, 2019/2020, and 2020/2021 Capability Years.

Analysis Group Inc. (AGI), with Lummus Consultants International, Inc. (LCI) as a subcontractor to AGI (collectively identified as the Consultants), was selected to serve as the independent consultant for this DCR. As further described herein, the New York Independent System Operator, Inc. (NYISO) concurs with the Consultants recommendations for this DCR and the ICAP Demand Curves for the 2017/2018 Capability Year in all but one instance. Specifically, the NYISO recommends a gas only peaking plant configuration with selective catalytic reduction (SCR) pollution controls for Load Zones C and F, rather than the dual fuel configuration recommended by the Consultants.

The table below shows the impact of the change recommended by the NYISO on the ICAP Demand Curve reference point values for the 2017/2018 Capability Year.

Table 1: 2017/2018 Capability Year Comparison of ICAP Demand Curve Reference Point Prices for the Simple Cycle Siemens SGT6-5000F (5) with SCR

Capacity Region	Consultants' Recommended Fuel Requirement	Consultants' Recommended Reference Point Price	NYISO Recommended Fuel Requirement	NYISO Recommended Reference Point Price	
		$/kW-mo.		$/kW-mo.	% Change
NYC	Dual	18.61	Dual	18.61	*0.00%*
Long Island	Dual	12.72	Dual	12.72	*0.00%*
G-J Locality	Dual	14.84	Dual	14.84	*0.00%*
NYCA	Dual	11.22	Gas Only	10.72	*-4.46%*

% change calculated relative to Consultants' reference point prices, as set forth in the Consultants Final Report as updated on September 13, 2016.

2. Introduction

Section 5.14.1.2 of the Market Administration and Control Area Services Tariff (Services Tariff) requires the New York Independent System Operator, Inc. (NYISO) to conduct periodic reviews of the ICAP Demand Curves. This ICAP Demand Curve reset (DCR) process is the fifth such review. Analysis Group, Inc. (AGI), together with its engineering consultant subcontractor Lummus Consultants International, Inc. (LCI), were selected by the NYISO to serve as the independent demand curve consultant (collectively identified as the "Consultants") to lead market participants through the DCR process.

As part of this reset, the NYISO proposed to its stakeholders that it would review the current DCR process and identify potential enhancements thereto, including an assessment of increasing the period between resets. The NYISO and its stakeholders requested that AGI facilitate this review and make recommendations with regard to the following: (i) whether there were identifiable benefits to changing the period between resets to four, five or six years; and (ii) approaches and methodologies to determining ICAP Demand Curves to account for changes in market conditions over time, including enhancements to market rules.

Based on its analyses, the Consultants and the NYISO ultimately recommended certain enhancements to the current DCR process. The NYISO developed tariff revisions to implement these enhancements and discussed the proposed revisions with its stakeholders. The proposed tariff revisions implemented the following changes to the DCR process:

(i) increase the period between DCRs to four years; and

(ii) provide for the NYISO to conduct formulaic and transparent annual updates to certain parameters of the ICAP Demand Curves for the second through fourth Capability Years covered by each reset period.[1]

To facilitate a more formulaic and transparent reset process, the revisions also provided for the implementation of a transparent, repeatable, and predictable methodology to estimate net Energy and Ancillary Services (EAS) revenues expected to be earned by a "peaking plant" from participation in the NYISO-administered markets.[2] The alternative methodology replaces the econometric modeling utilized by the DCR independent consultant for the past three resets. The revised net EAS revenue estimation approach relies on a co-optimized, historic dispatch model that not only significantly improves transparency, but it also is a critical enhancement that will enable the implementation of formulaic annual updates for the NYISO to administer, but which also can be executed by interested stakeholders.

The proposed tariff revisions were filed with the Federal Energy Regulatory Commission (FERC) on May 20, 2016.[3] On July 18, 2016, FERC issued an order accepting the proposed

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[1] Reference to the term "reset period" herein means the period of Capability Years for which ICAP Demand Curves resulting from methodologies and inputs established during each DCR are in effect. For example, the reset period associated with this DCR encompasses the 2017/2018 through 2020/2021 Capability Years.

[2] The Services Tariff requires use of the costs and projected net EAS revenues for a "peaking plant" in determining the values of the ICAP Demand Curves. 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." The Services Tariff defines a "peaking plant" to mean "the number of units (whether one or more) that constitute the scale identified in the periodic review."

[3] Docket No. ER16-1751-000, *New York Independent System Operator, Inc.*, Proposed Services Tariff Revisions to Implement Enhancements to the Periodic Reviews of the ICAP Demand Curves (May 20, 2016).

tariff revisions.[4] The impact of these changes is reflected throughout the Consultants' work, as well as in the NYISO recommendations contained herein.

This report contains: (i) the NYISO's response to the Consultant's work and stakeholder comments; (ii) the NYISO's recommendations for the ICAP Demand Curves applicable for the 2017/2018 Capability Year (CY 2017/18); and (iii) the methodologies and inputs to be used in the annual update process for the three succeeding Capability Years (CY 2018/19, CY2019/20 and CY 2020/21). In preparing these recommendations, NYISO has considered the Consultants' work to date and comments provided by stakeholders and the Market Monitoring Unit (MMU). The NYISO's development of the recommendations set forth herein included consideration of all of the written and oral comments from stakeholders throughout the process, presentations by the Consultants, the Consultants' Draft Report issued June 23, 2016, and the Consultants' Final Report as updated on September 13, 2016.

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 MMU has been involved in reviewing the Consultants' work product and has participated in several working discussions with the Consultants and NYISO staff. The MMU, which has participated and contributed to the development of both the Consultant's work and the NYISO's recommendations herein, has reviewed this Staff Final Recommendations and provides comments in Appendix IV. The schedule shown in Section 15 identifies the remaining steps in the DCR process, culminating in the NYISO's filing with FERC on or before November 30, 2016 of the results of the NYISO's review and the updated ICAP Demand Curves for CY 2017/18, as approved by the NYISO Board of Directors (Board).

3. Specific Technologies Evaluated by the Consultants

Following a broader review of available generating technologies, the Consultants focused on three technologies for consideration as potential peaking units: simple cycle frame gas turbines, simple cycle aeroderivative gas turbines, and reciprocating internal combustion engines. Within these general technologies the following specific units were selected as candidates for a complete evaluation in peaking plant applications:

- General Electric LMS100PA+, a Hybrid Aeroderivative Gas Turbine;
- Siemens SGT6-5000F(5) , an F class "Frame" Gas Turbine;
- Wartsila 18V50DF/18V50SG , Reciprocating Internal Combustion Engines.

Important selection criteria utilized by the Consultants in determining the specific technologies to evaluate included compliance with environmental requirements, efficiency, commercial availability and industry experience, operational flexibility, and scale.

In addition to the evaluation of these peaking plants technologies, the Consultants also evaluated certain frame turbine technologies in a combined cycle configuration for informational purposes only. Specifically, the Consultants evaluated the larger Siemens SGT6-8000(H), which to date has been used only in combined cycle applications, in addition to the Siemens SGT6-5000F(5) in combined cycle configuration. The combined cycle configuration is a 1x1x1 plant employing "Flex" technology, which is smaller than a 2x1 plant, thereby reducing interconnection requirements, and offering better cycling characteristics (start-up times, ramp rates, and turndown).

[4] *New York Independent System Operator, Inc.*, 156 FERC ¶ 61,039 (2016).

Additionally, in response to the request of certain stakeholders, the NYISO requested that the Consultants develop and provide cost data, net EAS revenue estimates and calculated ICAP Demand Curve reference prices for the GE 7HA.02 H class frame machine. The Consultants' report includes the data for the higher capacity H class machine in a simple cycle configuration for informational purposes only. Although the NYISO has requested that the Consultants provide this information, it is important to note that the NYISO is not aware of any H frame units that are currently operating in a simple cycle configuration.

4. Dual Fuel Capability

In the previous (2013) demand curve reset, peaking plants with dual fuel capability were selected and approved by FERC in Load Zones G, J and K. Load Zones J and K have Local (Electric) Reliability Rules, as well as gas LDC requirements for dual fuel capability. The gas LDC tariffs in Load Zone G also include an alternative fuel requirement for gas-fired electric generation facilities connecting to the LDC gas system.[5] Other considerations, including relative costs of dual fuel capability versus a firm gas contract coupled with an interstate pipeline connection, siting flexibility[6] and New York's growing reliance on natural gas for power generation were also considered by FERC in approving the inclusion of dual fuel capability for the peaking plant in Load Zone G.[7] Although ultimately not included, dual fuel capability for the peaking plants in Load Zones C and F was also evaluated in the last reset. In the absence of dual fuel capability, certain reductions to the net EAS revenue estimates for the peaking plants in Load Zones C and F were implemented for the last reset.

In this DCR, inclusion of dual fuel capability for peaking plants in all locations was once again evaluated. In addition to considering dual fuel requirements, the evaluation included an assessment of the economic tradeoffs between the increased cost to install and maintain dual fuel capability against the increased revenue potential dual fuel generators have when oil is more economic than natural gas or natural gas becomes physically unavailable. Additionally, since the amount of capacity that a generator is qualified to sell is dependent on performance, there is a potential that a generator with dual fuel capability could avoid possible decreases in future capacity payments by avoiding derates during periods when gas becomes physically unavailable.

In addition, there are concerns arising from the increased reliance on natural gas in the New York Control Area for power generation, and the stress that continues to put on the current natural gas distribution system on high peak days. Thus, dual fuel capability provides a form of fuel assurance, and a financial hedge going forward in market and regulatory conditions which could drive significant increases in gas demand in future years without supporting additional infrastructure to increase gas supply availability.

Notably, however, in Load Zones C, F and G, developers may have the option to potentially avoid any applicable dual fuel requirements imposed by gas LDC tariffs by seeking to directly connect with an interstate pipeline. The Consultants noted, however, that there are potential siting and development benefits available to generators with dual fuel capability. Specifically,

[5] Central Hudson Gas and Electric Corporation Service Classification 14 Interruptible Transportation to Electric Generation Facilities requires that customers maintain "a five-day fuel inventory"; Orange and Rockland Utilities, Inc. Service Classification 14 requires that the customer "install and maintain facilities, acceptable to the Company, for using alternative fuels during periods in which the Company requires the customer to discontinue service."

[6] There are limited siting locations in Load Zones G-K where proxy plants could connect to the interstate pipelines, which is obviated by assuming the peaking plant may interconnect to the LDC gas system with dual fuel capability.

[7] *See, e.g., New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 83 (2014).

"adding dual fuel capability would expand the geographical flexibility for power plant siting , by supporting the siting of plants on (and obtaining gas supply from) the distribution systems of local gas distribution companies. Expanding such geographic flexibility increases the potential of finding sites that coincidentally minimize the costs to obtain both natural gas and electrical interconnection."

Based on increased revenue potential, siting benefits, the reliability benefits derived from enhanced fuel assurance, and the financial hedge that dual fuel can provide, the Consultants determined that a developer would more often than not select to include dual fuel capability in a new, peaking generator project in New York State.

In response to stakeholder requests, NYISO requested that the Consultants develop ICAP Demand Curve reference point prices for gas only units in Load Zones C, F, and G for direct comparison with the results for dual fuel units.

NYISO agrees that dual fuel capability provides reliability benefits, particularly in consideration of the potential future unit retirements and increasing levels of intermittent renewable resources, both of which may further increase reliance on gas fired capacity in New York. In Load Zones C and F, however, there is a lack of mandatory dual fuel requirements or other factors (such as a need for siting flexibility by assuming interconnections to the LDC system[8]) which would mandate dual fuel technology.[9] Combining the lack of a mandatory dual fuel requirement with the current status of general gas availability in these areas, and the fact that the estimated incremental net EAS revenues for dual fuel units in Load Zones C and F do not offset the increased capital costs of such capability over the historic period analyzed in determining the ICAP Demand Curves for CY 2017/18, the NYISO has concluded that, for this DCR, a gas only peaking plant in Load Zones C and F remains reasonable.

Accordingly, the NYISO concurs with the Consultants' recommendation to include dual fuel capability for the peaking plants in Load Zones G, J and K, but recommends that a gas only design be utilized for Load Zones C and F. The NYCA ICAP Demand Curve reference point price impact of utilizing a gas only design with selective catalytic reduction (SCR) pollution control technology in Load Zones C and F is shown in the table below:

[8] A distinction can be made between Load Zone G and Load Zones C and F in terms of geography and gas pipeline infrastructure. Load Zone G is a more limited geographic area containing two gas LDCs, each with multiple city gate connections. (Orange and Rockland Utilities, Inc. has connections with Algonquin, Tennessee, and Millennium; Central Hudson has connections with Iroquois, Tennessee, Algonquin, and Millennium). The ability to site a generating facility within the LDC system intuitively offers flexibility, which is depicted in the LDC maps shown in Appendix 3 Gas Infrastructure Serving Generation in the NYISO, found in the EPIC Gas Electric Documents at http://nebula.wsimg.com/25c735be8bca76b9acf5cee4c082f2eb?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

[9] The NYISO has currently identified a project to look at performance assurance and dual fuel requirements for Installed Capacity Suppliers in the NYCA. The NYISO and its stakeholders are currently evaluating this project as part of the 2017 project prioritization process.

Table 2: 2017/2018 Capability Year NYCA ICAP Demand Curve Reference Point Price Impact of Utilizing a Gas Only Design in Load Zones C and F for the Simple Cycle Siemens SGT6-5000F (5) with SCR Peaking Plant

Capacity Region	Original Analysis Group Ref. Points	Reference Point w/ Gas Only Requirement in Zones C and F	
	($/kW-Mo)	($/kW-Mo)	*% Change*
NYCA	11.22	10.72	*-4.46%*

Note: Impact calculated relative to Consultants' reference point prices, as set forth in the Consultants Final Report as updated on September 13, 2016.

5. Environmental Requirements

The environmental regulatory framework is a significant factor in capital costs, fixed and variable operation and maintenance costs, and potential operating restrictions for all of the generation technologies evaluated. Since the last reset, this framework has changed significantly.

5.1. New York State Public Service Law Article 10

Under Article 10 of the New York State Public Service Law, a comprehensive environmental review is conducted for all proposed electric generating plants with a rating greater than 25 MW. The process for all required state permits, including the air and water quality permits required by the New York State Department of Environmental Conservation (NYSDEC) is integrated into this proceeding, which is conducted by the Board on Electric Generation Siting and the Environment (Siting Board). In review of applications under Article 10, the Siting Board is required to issue a decision that provides the basis for issuance of all required environmental permits, and contains findings which determine that the facility will serve the public interest and minimize or avoid adverse environmental impacts to the maximum extent practicable. The Siting Board's findings must consider both the state of available technology, and the nature and cost of reasonable alternatives.

5.2. Cooling Water Requirements

Under Section 316(b) of the Clean Water Act, combined cycle power plants are required to employ "closed cycle" cooling for rejection of heat from the steam turbine condenser. This typically utilizes either mechanical draft cooling towers or air cooled condensers. NYSDEC 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, NY irrespective of the amount of water they would withdraw for cooling. Thus, in developing cost estimates for the informational combined cycle plants, dry cooling was assumed by the Consultants for all Load Zones, except Load Zone C.

The cooling water requirements for simple cycle gas turbines and reciprocating engines are much less stringent. Notably, however, the GE LMS100 aeroderivative gas turbine requires compressor inter-stage cooling, which can be accomplished with either wet or dry cooling. The Consultants confirmed with GE that most LMS100 units are being sold with dry cooling.

Therefore, in developing cost estimates, dry cooling was assumed by the Consultants for the LMS100. The Consultants also assumed dry cooling for the Wartsilla 18V50DF units.

5.3. Air Permit Requirements

5.3.1. New Source Performance Standards

The U.S. Environmental Protection Agency (EPA) has promulgated New Source Performance Standards (NSPS) for newly constructed combustion turbines and reciprocating engines. These emission rate (or concentration) based standards are applicable to all power plants utilizing these technologies, regardless of location.

For combustion turbines, the applicable standards are as follows:

Subpart KKKK requires combustion turbines (simple cycle and combined cycle plants) with heat inputs greater than 850 MMBtu/hour to limit NOx emissions to less than 15 ppmv @ 15 percent O_2 while firing natural gas and to less than 42 ppmv @ 15 percent O_2 while firing liquid fuels. Each of the combustion turbines evaluated in this DCR, with the exception of the Siemens SGT6-5000F5, would require the installation of SCR emissions control technology in order to reduce combustion turbine NOx emissions below 15 ppmv @ 15 percent O_2 while firing natural gas. The Siemens SGT6-5000F(5) NOx emissions while firing natural gas are 9 ppmv @ 15 percent O_2.

Subpart TTTT establishes NSPS for CO_2 emissions for “base-load” and “non-base load” combustion turbines. Base-load combustion turbines must meet an emission limit of 1,000 lbs CO_2/MWh-g or 1,030 lbs CO_2/MWh-n, and the limit applies to all sizes of affected base-load units. This standard can currently be met only by combined cycle plants.

Non-base load units must meet a heat input based emission limit based on clean fuels (on a lbs CO_2/MMBtu basis). Non-base load status is based on a sliding scale for capacity factor based on a unit’s net lower heating value (LHV) efficiency at ISO conditions. The Consultants estimated the net LHV efficiency at ISO conditions for the units being evaluated. In order to avoid being subject to the “baseload” NSPS standard, the peaking units need to limit their capacity factors over a 12-operating month or a three-year rolling average basis to below the applicable capacity factor limit depicted in the table below.

Table 3: NSPS Capacity Factor Limits for Peaking Units

Combustion Turbine	Capacity Factor Limit (%)
GE LMS100PA+	42.4
Siemens SGT6-5000F(5)	38.4
GE 7HA.02	40.9

5.3.2. New Source Review

New units subject to New Source Review (NSR), and required to make a Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) determination for a pollutant covered by the applicable NSPS, are often required to meet more stringent emission limits than the NSPS limits. There are two levels of NSR to determine air permit requirements:

- The preconstruction review process for new or modified major sources located in attainment areas is performed under the Prevention of Significant Deterioration (PSD) requirements; and
- The preconstruction review for new or modified major sources located in nonattainment areas is performed under the Nonattainment New Source Review (NNSR) program.

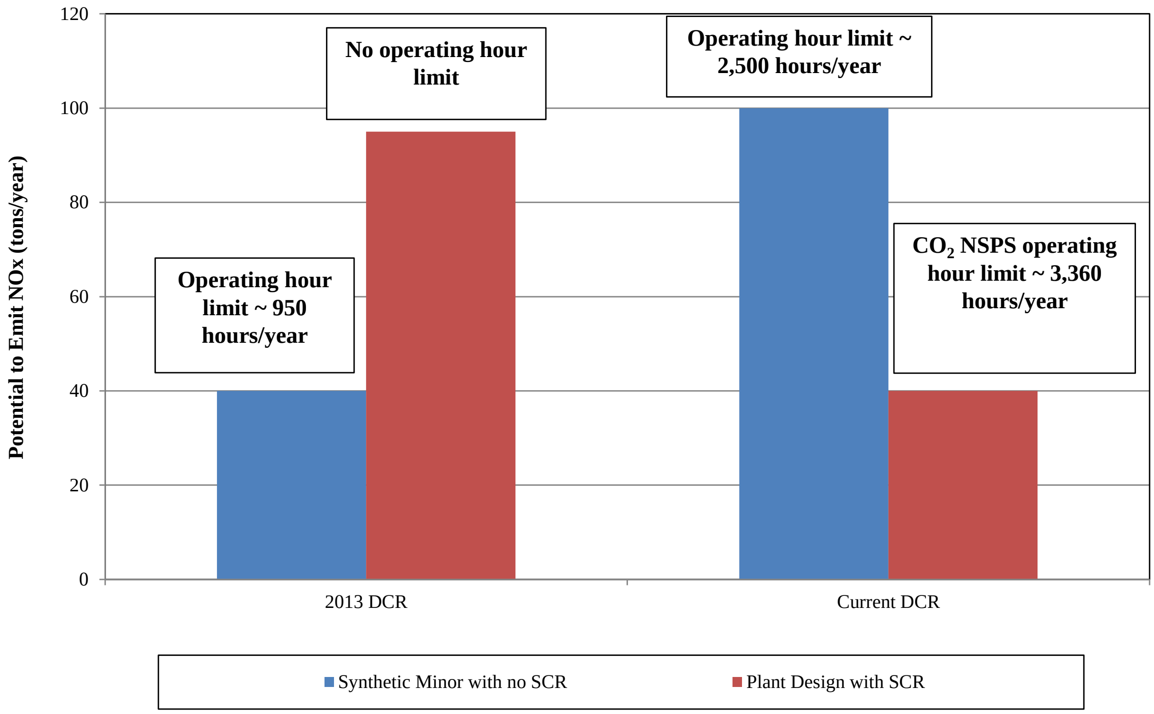
In the last reset, the EPA's "Tailoring Rule" was in effect, which required that emission sources which exceeded the annual emissions threshold of 100,000 tons of CO_2 be subject to BACT for CO_2, and also for NOx at an emissions threshold of 40 tons per year. This meant that a peaking plant located in an attainment area, could avoid a NSPS BACT review for NOx, which would otherwise require installation of SCR emissions control technology, by accepting an enforceable emissions cap of 40 tons annually. The Siemens SGT6-5000F(5), which could achieve an emissions rate of 9 ppm with dry-low-NOx combustion firing gas only, could meet this requirement with a cap on annual operating hours of approximately 1,000 hours. For plants located in non-attainment areas for ozone, the more restrictive threshold of 25 tons per year would apply, thus requiring SCR.

On June 23, 2014, the U.S. Supreme Court issued a decision which determined that EPA may not treat greenhouse gases (GHGs) as an air pollutant to determine whether a source is a major source required to obtain a PSD permit.[10] However, the court held that EPA can require PSD permits (which are otherwise required) to contain limitations on GHG emissions based on the application of BACT. This decision has the effect of modifying the annual emission thresholds for NSR in attainment areas for this DCR. For plants located in the current, non-attainment areas, the limit of 25 tons per year is still applicable, thereby continuing to require SCR. For those areas in attainment, however, a higher limit of 100 tons per year is applicable. For the Siemens SGT6-5000F(5), this would translate into a less restrictive cap on operating hours of approximately 2,500 hours annually for those areas in attainment.

To put these regulatory changes in perspective, a comparison of the potential to emit under alternative regulatory outcomes is informative. The figure below, which is taken from the Consultants' Final Report, shows that for the Siemens SGT6-5000F(5), the annual NOx emissions from a unit without SCR is 2.5 times greater than the NOx emissions of a unit with SCR. Unlike the last reset, the uncontrolled unit does not represent the configuration that minimizes NOx emissions to the maximum extent practicable. Therefore, it appears that such a unit would be unable to achieve compliance with the findings required by the Siting Board for issuance of a Certificate of Environmental Compatibility and Public Need pursuant to Article 10.

[10] *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S. Ct. 2427 (2014).

Figure 1: Potential to Emit (PTE) NOx Emissions, Alternative Means of Compliance



Further, the NYISO has conducted an online review of recently permitted electric generating units in New York and has been unable to find any instance where a unit received a PSD pre-construction permit by accepting a federally-enforceable, annual hourly operating limit in lieu of implementing backend NOx emission controls that comply with BACT.

There are other significant developments that must also be considered, however, in determining the likely outcome of the integrated Article 10 and NSR processes.

First, on October 1, 2015, EPA revised the national ambient air quality standard (NAAQS) for ozone from 75 ppb to 70 ppb. Final designations of non-attainment areas are scheduled to be issued by October 1, 2017, and are likely to be based on 2014-2016 data. Based on 2013-2015 preliminary data, NYSDEC has determined that the counties in and adjacent to the New York City Metropolitan Area, including Long Island and Westchester and Rockland counties will be designated non-attainment. NYSDEC will be required to revise its State Implementation Plan (SIP) to achieve attainment in the areas designated as non-attainment under the revised standard. The revised SIP may contain additional control measures for existing sources and could also affect NSR requirements.

Second, on December 3, 2015, EPA proposed revisions to NOx emissions budgets for electric generating units under the Cross State Air Pollution Rule (CSAPR). These proposed regulations would reduce the ozone-season NOx emissions budget for New York to 4,450 tons, a reduction of 58% from the present budget, and a reduction of approximately 20% compared to actual 2014 emissions by covered plants in New York of 5,547 tons.

The Consultants have weighed development and permitting risks and the potential for significant additional cost of future SCR retrofitting (relative to the cost of including SCR in the original plant design),[11] and concluded that "the developer of a new unit in any Load Zone in New York would more likely than not seek to include SCR technology at the time of construction."

The NYISO concurs with the Consultants' conclusion, and recommends the inclusion of SCR for the peaking plants in all locations.

5.4. Emissions Cap and Trade Programs

Stationary combustion sources in New York State are subject to three different cap-and-trade programs. The aim of these programs is to limit the emissions of CO_2, NOx, and SO_2. The three programs are the following: CSAPR, the CO_2 Budget Trading Program (*i.e.*, the Regional Greenhouse Gas Initiative), and the SO_2 Acid Rain Program. All of these programs apply to any fossil-fuel powered electric generating unit (EGU) with a nameplate capacity equal to or greater than 25 MW. Consequently, the costs of CO_2, NOx, and SO_2 allowances were included in the development of net EAS revenue estimates.[12]

CSAPR is aimed at reducing the power sector's contribution to ozone and particulate matter pollution through the control of NOx and SO_2 emissions from EGUs. CSAPR is implemented in New York State by creating three different budgets of tradable allowances: an annual NOx budget (6 NYCRR 244), an annual SO_2 budget (6 NYCRR 245), and a seasonal (May 1 to September 30) NOx budget (6 NYCRR 243).

The SO_2 Acid Rain Program (40 CFR Parts 72-78) similarly limits the amount of SO_2 and NOx emitted from EGUs. While this program was first implemented in 1995, it still applies to EGUs in New York State and has not been impacted by the implementation of CSAPR.

The CO_2 Budget Trading Program (6 NYCRR Part 242) is New York's program for implementing the Regional Greenhouse Gas Initiative (RGGI) that applies to nine northeastern states. It seeks to reduce CO_2 emissions from the EGUs in the participating states by each state accepting a cap on CO_2 emissions from EGUs. CO_2 allowances are then distributed through auctions and traded through the program.

6. Interconnection Costs

NYISO's offers two types of interconnection service:

> Energy Resource Interconnection Service (ERIS), which allows a new project to participate in the NYISO's energy market, 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 as necessary for the project to reliably interconnect pursuant to the NYISO Minimum Interconnection Standard (MIS). These costs are preliminarily identified in individual System Reliability Impact Studies (SRIS) or System Impact Studies (SIS) and are finalized in the applicable Facilities Study. Projects requesting CRIS are also responsible for the costs of any System Deliverability Upgrades (SDU) identified as necessary under the NYISO Deliverability Interconnection Standard (DIS) in the Class Year Study.

[11] LCI has estimated that retrofitting a peaking plant that did not contemplate including an SCR at the time of construction would result in the cost of installing the SCR system at a later date being approximately 40% higher in cost than if the SCR had been included as part of the original plant design.
[12] The cost of ERCs is included in the capital cost estimates for the peaking plants

New projects requesting CRIS are evaluated within the Class Year Study process under the DIS pursuant to the process described in Attachment S of the NYISO Open Access Transmission Tariff (OATT). The projects that are determined to be deliverable in full or in part have the option to accept only their deliverable MW (allowing them to obtain CRIS up to the level of 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 (referred to herein as SDU costs). In accordance with the requirements of Attachment S of the OATT, 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. Such projects have the option to accept or reject their SDU Project Cost Allocation. If they accept the SDU Project Cost Allocation and post Security as required by Attachment S of the OATT, the project is awarded CRIS at the MW level requested.

In the last DCR process, candidate substations with open breaker positions were identified by NYISO in coordination with the transmission owners for each region for purposes of assessing deliverability of the peaking plants being evaluated. After review by NYISO Planning, these interconnection locations were retained for use in this DCR. In addition, a second substation location for Long Island (*i.e.*, Barrett) was included as part of the deliverability assessment for this DCR. The table below identifies the substation locations that were utilized for each Load Zone for this DCR.

Table 4: Interconnection Substation Locations for DCR Deliverability Assessment

Zone	Location
C	Sithe
F	Rotterdam
G	Ladentown, Shoemaker
H	East Fishkill
J	Rainey, Hudson Avenue, East 179th St.
K	Ruland Road, Barrett

With respect to the MIS, the Consultants developed estimates for MIS costs based on the identified bus type and voltage. A contingency of 20% was applied to the MIS cost estimates.

The NYISO planning staff conducted a deliverability analysis for the various peaking plant technologies, as well as the informational combined cycle units and informational simple cycle H frame unit, utilizing the deliverability methodology consistent with the NYISO's Class Year deliverability study process and the New Capacity Zone (NCZ) study. This analysis used the assumptions for the NCZ study that commenced in September 2015. The assumptions for this study were presented at a September 28, 2015 Installed Capacity working group (ICAPWG) meeting and the results of the study were presented to the ICAPWG on January 13, 2016. The only difference for current deliverability analysis done for the DCR was that NYISO planning staff adjusted the capacity resources in the model to posture the system at the tariff prescribed

level of excess conditions for the DCR (*i.e.*, the applicable minimum Installed Capacity requirement, plus the capacity of the relevant peaking plant).
For the DIS, deliverability studies completed by the NYISO indicated that both the simple cycle gas turbines and combined cycle plants were deliverable at all evaluated substations in all Load Zones, except for the evaluated substations in Load Zone K. For Long Island, the deliverability assessment for this DCR concluded that neither the simple cycle peaking plants nor the units evaluated for informational purposes were deliverable.

The SDU identified for the peaking plant technologies on Long Island was to replace conductors on segments of 69 kV overhead transmission line totaling approximately 3 miles. The SDU identified for the informational combined cycle plant, as well as the informational simple cycle H frame unit, in Load Zone K was to replace conductors on the 69 kV overhead transmission line and either the addition of a new 138 kV underground cable or replacement of conductors on a 138 kV line, depending on which substation was chosen.

The cost of the 69 kV reconductoring SDU was estimated at $15.5M, based on an estimate provided to the NYISO by PSEG Long Island. The SDU for the combined cycle plant and the informational simple cycle H frame unit included the $15.5M for the 69 kV reconductoring, plus the additional cost of the 138 kV upgrades. The estimated cost of the 138 kV upgrades ranged from $64.6M to $191M, depending on the substation and upgrades required. The Consultants utilized an average of these costs for the purpose of estimating the SDU costs for the informational combined cycle plant and the information simple cycle H frame unit. Consistent with the MIS costs, the Consultants applied a contingency of 20% to the estimated SDU costs, resulting in an estimated SDU cost of $18.48M for the peaking plants on Long Island and $174M for the informational combine cycle plants and the informational simple cycle H frame unit on Long Island. The Consultants included the estimated cost of the SDU in the Owners Cost portion of the capital cost estimates for the Long Island plants.

The NYISO assessed whether any Incremental TCC award would be available to serve as an offset to the SDU costs for the evaluated peaking plant technologies on Long Island. NYISO concluded that no Incremental TCC award would be available for the 69 kV reconductoring required for the peaking plant technologies because the 69 kV system on Long Island is currently not secured in the Day-Ahead Market or the TCC auctions.[13]

Market Participants questioned whether the peaking plants in Load Zone J and Load Zone G should be charged with a portion of the SDU costs incurred by other projects as a partial reimbursement to the developers funding certain system upgrades. Specifically, some stakeholders questioned whether certain system upgrades that were included as part of the proposed Champlain Hudson Power Express project were factored into the determination that the evaluated peaking plant technologies for Load Zone J were deliverable. In addition, some stakeholders raised concerns regarding whether the SDU for the proposed CPV Valley generation project affected the determination that the evaluated peaking plants for Load Zone G were deliverable.

The NYISO reviewed the concerns raised by these stakeholders and determined that in neither case did the cited upgrades affect the results of the NYISO's deliverability analysis. With

[13] Because the combined cycle units and simple cycle H frame unit are being provided for informational purposes only, the NYISO did not conduct an assessment as to whether any Incremental TCC award may be available to serve as an offset to the SDU costs for these informational units.

respect to the system upgrades included as part of the Champlain Hudson Power Express project, such upgrades were not included as part of the system topology used for the DCR deliverability analysis. For Load Zone G, the evaluated peaking plants, as well as the informational combined cycle plants and the informational simple cycle H frame unit, were found to be deliverable across UPNY-SENY as an Other Interface both with and without the proposed CPV Valley project and the associated Leeds-Hurley series compensation SDU.

7. Capital Investment and Other Plant Costs

Capital cost estimates, which are presented in detail in Section II.E and Appendix B of the Consultants' Final Report, are summarized in the tables below to facilitate comparisons between the various technologies evaluated. Included in these costs are direct costs within the engineering, procurement and construction (EPC) contracts and owner's costs not covered by the EPC, including social justice costs, financing costs during construction, working capital, and initial inventories.

For locations in Load 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. The Consultants developed cost estimates for dual fuel units in all locations. For the estimates including dual fuel capability the additional costs incurred in start-up testing has been included in the owner's costs. In response to stakeholder requests, the Consultants also developed cost estimates for gas only units in Load Zones C, F and G.

An adder of 2% on gas turbine costs was included for the Siemens SGT-5000(F) unit in New York City for the provision of fuel swapping capability during operation.

Dry cooling was assumed for the LMS100, and for the combined cycle plants in all locations, except Load Zone C.

Emission controls on the Siemens SGT-5000(F) include dry low NOx combustion (water injection when firing oil) and SCR in all locations. As noted in Section 5.3 above, due to the NOx emissions rates for all other technologies, SCR is required in order to comply with NSPS requirements for NOx. The cost of Emission Reduction Credits (ERC) where required under NSR is included in the Owners Costs.

For informational purposes, the Consultants also provided capital costs and performance data for the selected combined cycle units, as well as the simple cycle H frame unit.

Table 5: Capital Investment Costs ($2015) for Dual Fuel Peaking Plants Evaluated

	2x GE LMS 100	1x Siemens SGT6-5000F(5)	12x Wartsila 18V50
Dual Fuel			
Zone C Syracuse			
Total Capital Cost	291,611,000	236,780,000	357,731,000
ICAP MW	185.9	215.83	200.17
$/kW	$1,569	$1,097	$1,787
Zone F Albany			
Total Capital Cost	280,525,000	225,138,000	348,672,000
ICAP MW	186.98	217.0	200.17
$/kW	$1,500	$1,038	$1,742
Zone J New York City			
Total Capital Cost	337,370,000	276,652,000	424,796,000
ICAP MW	187.59	217.57	200.17
$/kW	$1,798	$1,272	$2,122
Zone K Long Island			
Total Capital Cost	344,553,000	287,635,000	433,115,000
ICAP MW	188.9	219.12	200.17
$/kW	$1,824	$1,313	$2,164
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost	309,613,000	254,676,000	386,089,000
ICAP MW	187.79	217.96	200.17
$/kW	$1,649	$1,168	$1,929
Zone G Hudson Valley (Rockland County)			
Total Capital Cost	312,577,000	257,515,000	389,832,000
ICAP MW	187.79	217.96	200.17
$/kW	$1,664	$1,181	$1,947

Table 6: Capital Investment Costs ($2015) for Gas Only Peaking Plants Evaluated

	2x GE LMS 100	1x Siemens SGT6-5000F(5)	12x Wartsila 18V50
Gas Only with SCR			
Zone C Syracuse			
Total Capital Cost	$279,656,000	$220,448,000	$332,351,000
ICAP MW	185.9	215.83	200.17
$/kW	$1,500	$1,020	$1,660
Zone F Albany			
Total Capital Cost	$268,473,000	$208,983,000	$319,171,000
ICAP MW	186.98	217.0	200.17
$/kW	$1,440	$960	$1,590
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost	$297,488,000	$236,286,000	$355,872,000
ICAP MW	187.79	217.96	200.17
$/kW	$1,580	$1,080	$1,780
Zone G Hudson Valley (Rockland County)			
Total Capital Cost	$300,339,000	$238,255,000	$359,056,000
ICAP MW	187.79	217.96	200.17
$/kW	$1,600	$1,090	$1,790

Table 7 Capital Investment Costs ($2015) for Dual Fuel Plants
Provided for Informational Purposes

Dual Fuel	1x GE 7HA.02	1x1x1 Siemens SGT6-8000H (CC)	1x1x1 Siemens SGT6-5000F (CC)
Zone C Syracuse			
Total Capital Cost	320,359,000	544,307,000	516,543,000
ICAP MW	313.5	385.24	328.58
$/kW	$1,022	$1,413	$1,572
Zone F Albany			
Total Capital Cost	309,701,000	572,110,000	540,854,000
ICAP MW	315.12	381.02	326.02
$/kW	$983	$1,502	$1,659
Zone J New York City			
Total Capital Cost	377,117,000	767,675,000	728,024,000
ICAP MW	316.34	382.78	327.69
$/kW	$1,192	$2,006	$2,222
Zone K Long Island			
Total Capital Cost	549,017,000	920,601,000	882,797,000
ICAP MW	318	385.24	329.36
$/kW	$1,726	$2,390	$2,680
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost	341,901,000	636,457,000	603,203,000
ICAP MW	316.34	382.69	327.5
$/kW	$1,081	$1,663	$1,842
Zone G Hudson Valley (Rockland County)			
Total Capital Cost	345,482,000	645,856,000	611,267,000
ICAP MW	316.34	382.69	327.5
$/kW	$1,092	$1,688	$1,866

Table 8: Capital Investment Costs ($2015) for Gas Only Plants
Provided for Informational Purposes

	1x GE 7HA.02	1x1x1 Siemens SGT6-8000H (CC)	1x1x1 Siemens SGT6-5000F (CC)
Gas only with SCR			
Zone C Syracuse			
Total Capital Cost	284,809,000	520,749,000	494,175,000
ICAP MW	313.5	385.24	328.58
$/kW	$908	$1,352	$1,503
Zone F Albany			
Total Capital Cost	273,627,000	548,359,000	518,297,000
ICAP MW	315.12	381.02	326.02
$/kW	$868	$1,439	$1,590
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost	305,060,000	611,991,000	579,961,000
ICAP MW	316.34	382.69	327.5
$/kW	$964	$1,599	$1,771
Zone G Hudson Valley (Rockland County)			
345,482	308,275,000	621,417,000	587,936,000
ICAP MW	316.34	382.69	327.5
$/kW	$974	$1,623	$1,795

8. Performance Characteristics and Variable Operating and Maintenance Costs

The Consultants developed performance characteristics, start-up costs, and variable operation and maintenance costs, by location, for each technology evaluated, which were used in the determination of net EAS revenues and the ICAP Demand Curve parameters for CY 2017/18 (see Sections II.E and II.F, as well as Appendix B of the Consultants' Final Report). To facilitate comparisons between the technologies, these characteristics are summarized in the tables below, averaged across all locations.

Table 9: Performance Characteristics and Variable Operating and Maintenance Costs for Peaking Plants Evaluated ($2015)

Technology	GE LMS LMS100PA+	Siemens SGT6-5000F5	Wartsila 18V50DF
Configuration	2 x 0	1 x 0	12 x 0
Net Plant Capacity (Average ICAP, MW)	187	219	200
Net Plant Capacity - Summer (Average MW)	200	225	200
Net Plant Capacity - Winter (Average MW)	216	231	202
Net Plant Heat Rate - Summer (Average Btu/kWh, HHV)	9,205	10,227	10,227
Net Plant Heat Rate - Winter (Average Btu/kWh, HHV)	9,003	9,987	9,987
Non-Spin Reserves	10 min	30 min	10 min
Dual Fuel Capability	ULSD	ULSD	ULSD
Post Combustion Controls	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
Natural Gas Variable O&M Costs (Average $/MWh)	$5.49	$0.76	$7.93
ULSD Variable O&M Costs (Average $/MWh)	$9.41	$2.57	$7.93
Variable Cost per Start (Average $/Start)	N/A	$10,583	N/A
Fuel Required per Start (Average MMBtu/Start)	61	350	8
Gas Only Capability with SCR	Natural Gas	Natural Gas	Natural Gas
Post Combustion Controls	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
Natural Gas Variable O&M Costs (Average $/MWh)	$5.44	$0.76	$7.79
Variable Cost per Start (Average $/Start)	N/A	$10,400	N/A

Table 10: Performance Characteristics and Variable Operating and Maintenance Costs for Plants Evaluated for Informational Purposes Only ($2015)

Technology	GE 7HA.02	Siemens SGT6-5000F5 CC	Siemens SGT6-8000H CC
Configuration	1 x 0	1 x 1 x 1	1 x 1 x 1
Net Plant Capacity (Average ICAP, MW)	316	328	383
Net Plant Capacity - Summer (Average MW)	323	340	396
Net Plant Capacity - Winter (Average MW)	344	340	439
Net Plant Heat Rate - Summer (Average Btu/kWh, HHV)	9,532	6,830	6,658
Net Plant Heat Rate - Winter (Average Btu/kWh, HHV)	9,312	6,773	6,645
Non-Spin Reserves	30 min	-	-
Dual Fuel Capability	ULSD	ULSD	ULSD
Post Combustion Controls	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
Natural Gas Variable O&M Costs (Average $/MWh)	$1.02	$1.07	$1.04
ULSD Variable O&M Costs (Average $/MWh)	$4.92	$1.41	$1.26
Variable Cost per Start (Average $/Start)	$16,283	$10,583	$15,983
Fuel Required per Start (Average MMBtu/Start)	391	3,100	4,000
Gas Only Capability with SCR	Natural Gas	Natural Gas	Natural Gas
Post Combustion Controls	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
Natural Gas Variable O&M Costs (Average $/MWh)	$1.02	$1.07	$1.04
Variable Cost per Start (Average $/Start)	$16,000	$10,400	$15,700

9. Development of Levelized Carrying Charges

An extensive evaluation and development of the levelized carrying charges is included in Section III Consultants' Final Report. The development of the annual levelized carrying charges utilizes a similar methodology employed in the last DCR process, but with slight alterations based on analysis performed by the Consultants and input from the stakeholders.

9.1. Financial Parameters

The Consultants recommended the use of the following financial parameters:

- 20 year amortization period
- 13.4% Return on Equity (ROE)
- 7.75% cost of debt
- 55/45 debt to equity ratio
- 10.3% Weighted Average Cost of Capital (WACC)
- 8.60% (NYCA, LI, and the G-J Locality) and 8.36% (NYC) After-tax Weighted Average Cost of Capital (ATWACC)

The amortization period was based on evaluations of the associated financial risk of investing in a peaking plant in New York. The Consultants found the perceived risks of changes in market structures, technology, regulations, and underlying demand cause investors to seek a shorter amortization period than the expected physical life of the peaking plant. Accordingly, the Consultants recommend an amortization period of 20 years, which is also consistent with the assumptions utilized for the demand curves in neighboring capacity markets (*i.e.,* ISO-NE and PJM).

Some Market Participants have suggested that the assumed amortization period should be shortened given the uncertainty about the level of capacity in the NYISO market and future energy and regulatory policies in New York. Alternatively, other Market Participants have argued that the recommended amortization period be extended to better reflect the expected physical life of a peaking plant.

After evaluating the Consultants' recommendation and comments from stakeholders, the NYISO concludes that an amortization period of 20 years reflects an appropriate balance. Notably, a 20-year amortization period is consistent with the assumption utilized in the last DCR process.

The Consultants determination of the cost of debt was based upon market evaluations of publically traded companies and independent power producers (IPPs).

The return on equity (ROE) was determined by evaluating ROE values associated with project finance estimates, Capital Asset Pricing Model (CAPM) estimates of IPPs, and those produced by independent studies on new power plants. The Consultants sought to balance the differences in the ROE estimated from the different sources and a final ROE of 13.4% was recommended by the Consultants. Some Market Participants have suggested that the ROE should be increased to better reflect the risk associated with the New York market, while others felt the ROE was excessive and did not reflect the CAPM methodology used in previous resets.

A debt to equity (D/E) ratio of 55/45 was recommended by the Consultants based on the evaluation of current and historical IPP company capital structures, expected trends, and other researchers' estimates of D/E ratios of merchant generation projects. Some Market Participants have suggested the D/E ratio be increased to be more representative of current IPP financial structures.

After review of the Consultants' recommendations and the comments from stakeholders, the NYISO finds the Consultants' recommendations to be justifiable based on the analysis they performed and the Consultants' application of reasonable judgment based on knowledge of current market conditions.

9.2. Property Taxes

9.2.1. New York City Tax Abatement

The New York State Real Property Tax law provides property tax abatements to certain electric generating facilities located in New York City. This tax abatement is applicable to the peaking unit for the New York City ICAP Demand Curve for the first 15 years of the project's operation. Units are eligible for this abatement as long as a building permit is obtained or construction is commenced on or before April 1, 2019. Accordingly, the Consultants assumed that a peaking plant in New York City would receive this abatement and incur taxes only for years 16 and beyond. The Consultants recommend a property tax rate for New York City of 4.8%, which is equal to the Class 4 Property Tax rate of 10.4% multiplied by the 45% assessment ratio.

The NYISO agrees with the Consultants' recommendations for property taxes applicable to peaking plants in Load Zone J.

9.2.2. Payments in Lieu of Taxes in Balance of State

The Consultants have recommended that a property tax rate of 0.75% be used for all locations other than New York City, assuming that the peaking plant will enter into a Payment in Lieu of Taxes (PILOT) agreement, which will be effective for the 20 year amortization period. While this rate was used in the last reset, the Consultants' recommendation was based on its own review of current PILOT agreements, and was found to be in a range consistent with current data available through the Office of the New York State Comptroller. Specifically, the Consultants reviewed eleven PILOT agreements for gas-fired plants in New York. Based on this dataset, the Consultants calculated a median effective tax rate of 0.83%.

The NYISO reviewed the Consultants' analysis along with the comments received from stakeholders that suggest that the Consultants' recommendation could be higher or lower. The NYISO also reviewed the alternative methodology proposed by certain stakeholders contesting the Consultants' analysis. Additionally, the NYISO obtained and reviewed information for an additional, recently negotiated PILOT agreement that was not available to the Consultants. As a result of this review and analysis described in the Appendix I, the NYISO did not find sufficient evidence to move to a lower or a higher tax rate and therefore concludes that the 0.75% tax rate recommended by the Consultants is reasonable.

In particular, the alternative methodology suggested by certain stakeholders does not address the larger underlying uncertainties regarding selection of an appropriate tax rate for a peaking plant because such alternative methodology was based on three PILOT agreements for significantly larger combined cycle facilities. The available tax rate data shows substantial variability. As noted by the Consultants, PILOT agreements are typically developed based on project specific and regional economic conditions and tax rates for the generators analyzed vary from almost zero to over 2%.

Therefore, the NYISO recommends maintaining the Consultants' recommended 0.75% property tax rate. The Consultants' recommendation is within the range of observed tax rates, is consistent with tax rate accepted by FERC in the last reset, and other methods of analysis have not demonstrated outcomes with sufficiently higher certainty to warrant a change to the Consultants' recommendation.

10. Net Energy and Ancillary Services Revenues

10.1. Net Energy and Ancillary Services Revenue Model

The Consultants developed and deployed a simulated dispatch model to project the net EAS revenues for the units evaluated. The model uses a rolling 3-year historical set of LBMPs and reserve prices (both adjusted for tariff-prescribed level of excess [LOE] conditions), coincident fuel and emission allowance prices, and non-fuel variable costs and operational characteristics of the peaking plant technology. This same model will be used as part of the annual update process to derive updated net EAS revenue estimates on an annual basis.

The logic used in the model follows what one would expect a competitive supplier with perfect foresight to offer (*i.e.*, optimal dispatch, with offers set at the opportunity cost of producing energy or reserves). The model accounts for the option of supplying in either the Day-Ahead Market ("DAM") or the real-time market ("RTM"), as well as the option to supply either energy or reserves, on an hourly basis. Unit parameters (capability and heat rate) are taken into account separately for the Summer Capability Period and Winter Capability Period. Annual revenues are adjusted downward based on the plant's EFORd, and a flat adder ($/kW-year) is applied to account for voltage support service ("VSS") revenues.

The Consultants have addressed key considerations in dispatch model design and implementation, as well as specific considerations that were raised by stakeholders. The NYISO concurs with the commitment and dispatch logic of the net EAS revenue model developed by the Consultants and addresses certain, specific aspects of the model in the following sections.

10.2. Gas Hubs Selected for Each Load Zone

Selection of representative gas hubs is not a simple and straightforward consideration. The Consultants' recommended gas hub selections were derived using a balanced approach, which considers various relevant factors, including geographic location, correlation with electric prices, depth of available historical data, and precedent. The Consultants' analysis and conclusions are described in detail in Section IV.B.2(b)(ii) of the Consultants' Final Report.

The following gas hubs were used by the Consultants to develop net EAS revenue estimates in their Final Report:

Table 11: Consultants' Recommended Gas Hubs

Load Zone	Natural Gas Index
Load Zone C	TETCO M3
Load Zone F	Iroquois Zone 2
Load Zone G	Iroquois Zone 2
Load Zone J	Transco Zn 6 NY
Load Zone K	Transco Zn 6 NY

Market participants have provided comments suggesting certain specific alternatives to the Consultants recommended gas hubs. Certain stakeholders contend that TGP Z6 should be used for Load Zones F and G. Other stakeholders have recommended that Millennium or TETCO M3 be used for Load Zone G west of the Hudson River (*i.e.*, Rockland County) or an unspecified blend of gas hub prices be used for Load Zone G, and either Millennium or Dominion be used for Load Zone C.

A review of these specific suggestions compared to the Consultants' recommendations results in the following conclusions:

1. For Load Zone G, Millennium is geographically appropriate for the portion of the Load Zone west of the Hudson River, but has low correlation with LBMPs and relatively low trade volume and history compared to Iroquois Zone 2.
2. For Load Zone C, both the Millennium and Dominion pipelines cross the Load Zone, however, neither is well correlated with LBMPs, and the liquidity (trade volume and history) is inferior to TETCO M3.
3. For Load Zone F, Iroquois Zone 2 meets the criteria slightly better than TGP Z6 overall, and, in the judgment of the Consultants, is less likely to be affected by supply conditions in ISO-NE.

At the request of stakeholders, NYISO staff developed estimates of net EAS revenues and ICAP Demand Curve reference point prices for certain of the suggested alternatives for informational purposes. The results of NYISO staff's analysis are summarized in the following table:

Table 12: Net EAS Revenue Gas Hub Sensitivities[14]

Dual Fuel	**2017/2018 Capability Year Annual Average Net EAS Revenues ($/kW-year)**				
Load Zone	Consultants' Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C	$45.08	$80.46	-	-	-
F	$41.37	-	-	-	$37.12
G (Dutchess)	$39.42	-	-	-	$38.19
G (Rockland)	$39.29	-	$84.15	$114.51	$38.15
Gas Only With SCR	**2017/2018 Capability Year Annual Average Net EAS Revenues ($/kW-year)**				
Load Zone	Consultants' Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C	$41.41	$80.46	-	-	-
F	$34.50	-	-	-	$30.21
G (Dutchess)	$32.80	-	-	-	$31.11
G (Rockland)	$32.68	-	$78.55	$109.36	$31.08
Gas Only Without SCR	**2017/2018 Capability Year Annual Average Net EAS Revenues ($/kW-year)**				
Load Zone	Consultants' Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$42.31	$79.28	-	-	-
F – Capital	$34.84	-	-	-	$30.68

The NYISO concurs with the Consultants' recommended gas hub selections.

[14] Additional data regarding gas hub sensitivities, including ICAP Demand Curve reference point prices, is provided in Appendix II.

10.3. Adjustment to Historic Energy and Reserve Prices to Account for the Tariff-Prescribed Level of Excess Conditions

The Services Tariff requires that net EAS revenue estimates be determined for the peaking plant under conditions where the available capacity in each capacity region is equal to the applicable minimum Installed Capacity requirement, plus the capacity of the applicable peaking plant. As was done in the prior reset, the Consultants generated level of excess adjustment factors (LOE-AF) utilizing production cost simulations, which were by performed by GE Energy Consulting (GE Energy) using its Multi-Area Production Simulation (MAPS) software. These LOE-AF values are used to adjust historic LBMPs used in the net EAS revenue model to approximate what the historic LBMPs may be under the system conditions specified by the Services Tariff.

For the Consultants' June 23, 2016 Draft Report, GE Energy relied on supply and load assumptions within the 2015 Congestion Assessment Resource Integration Study ("CARIS") Phase 1 base case data. Based on these model simulations, the Consultants developed a set of LOE-AF. The Consultants developed monthly LOE-AF values by Load Zone for three periods: (i) off-peak (all hours not included in the defined period for on-peak); (ii) on-peak (7 a.m. to 11 p.m. Monday through Friday, excluding NERC defined holidays; and (iii) high on-peak (subset of on-peak hours, with the summer period defined as June through August from 2 p.m. to 5 p.m. and the winter period defined as December through February from 4 p.m. to 7 p.m.). Annual average LOE-AFs ranged from 1.02 in Load Zone F to 1.04 in Load Zone J.

The NYISO concurs with the methodology used by the Consultants to derive the applicable LOE-AF values for each Load Zone, as well as the recommended segmentation of LOE-AF into monthly values across three defined time periods.

The Consultants initially used the 2015 CARIS Phase 1 database to calculate indicative LOE-AF values for their June 23, 2016 Draft Report because the 2016 CARIS Phase 2 database was not available at that time. The Consultants, however, indicated in the stakeholder process that it would develop final LOE-AF values using the 2016 CARIS Phase 2 database because it would contain the most recent resource addition and retirement assumptions, as well as updated load and gas price forecasts. Once the 2016 CARIS Phase 2 database became available in mid July 2016, the Consultants utilized GE Energy to run the MAPS simulation software using the 2016 CARIS Phase 2 database developed by NYISO planning to produce the updated LOE-AF values.[15] The 2016 CARIS Phase 2 database incorporated an updated gas price forecast that included lower prices than the 2015 CARIS Phase 1 database, an updated load forecast that included lower loads than the 2015 CARIS Phase 1 database, and captured approximately 2,500 megawatts of anticipated generator retirements and 800 megawatts of new generator additions that were not included in the 2015 CARIS Phase 1 database. The Consultants presented the LOE-AF values calculated using 2016 CARIS Phase 2 database at the August 10, 2016 ICAPWG meeting, noting that updated results produced numerous LOE-AF values below one in Load Zones C and F.

For the Consultants' Final Report, the LOE-AF values, which are summarized in the table below, reflect use of the 2016 CARIS Phase 2 database. As further described in Appendix D of the Consultants' Final Report, to reflect the tariff-prescribed level of excess, load was sequentially increased in Load Zones K, J, and the G-J Locality for purposes of determining LBMPs under

[15] The 2016 CARIS Phase 2 database was developed by NYISO planning consistent with Attachment Y of the NYISO OATT and the NYISO planning procedures. The database was reviewed with NYISO stakeholders at the July 13, 2016 Business Issues Committee (BIC) meeting.

the tariff prescribed level of excess conditions. For the NYCA, however, a load reduction in Load Zones A-F was required to reach the required level of excess for the NYCA after accounting for the adjustments to Long Island, New York City and the G-J Locality. This can be attributed to the number of retirements in these zones reflected in the 2016 CARIS Phase 2 database. Further details regarding the LOE-AF values utilized by the Consultants are provided in Appendix D of the Consultants' Final Report.

Table 13: Level of Excess Adjustment Factors (based on 2016 CARIS Phase 2 database)

Load Zone	Month	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Capital Load Zone F	Off-peak	1.033	1.024	1.011	1.004	1.004	1.004	1.000	1.007	1.006	1.011	1.013	1.005
	On-peak	1.026	1.028	1.024	1.009	0.995	0.992	0.990	0.996	0.991	0.998	1.017	1.005
	High On-peak	1.019	1.036	-	-	-	0.977	0.971	0.977	-	-	-	1.018
Central Load Zone C	Off-peak	0.979	0.985	0.982	0.992	0.994	1.001	0.998	1.003	1.004	1.008	0.983	0.993
	On-peak	0.97	0.985	0.975	0.992	0.988	0.987	0.985	0.993	0.988	0.995	0.99	0.994
	High On-peak	0.972	0.960	-	-	-	0.969	0.965	0.972	-	-	-	0.970
Hudson Valley Load Zone G	Off-peak	1.029	1.023	1.010	1.010	1.009	1.016	1.016	1.022	1.016	1.022	1.013	1.013
	On-peak	1.027	1.032	1.024	1.018	1.008	1.015	1.018	1.019	1.012	1.013	1.024	1.023
	High On-peak	1.046	1.043	-	-	-	1.030	1.033	1.043	-	-	-	1.040
New York City Load Zone J	Off-peak	1.03	1.019	1.010	1.01	1.017	1.025	1.031	1.029	1.022	1.026	1.013	1.014
	On-peak	1.052	1.056	1.029	1.019	1.012	1.03	1.047	1.047	1.023	1.023	1.028	1.039
	High On-peak	1.057	1.054	-	-	-	1.035	1.162	1.129	-	-	-	1.037
Long Island Load Zone K	Off-peak	1.042	1.022	1.010	1.005	1.017	1.017	1.033	1.024	1.023	1.026	1.028	1.014
	On-peak	1.045	1.033	1.012	1.002	1.013	1.025	1.033	1.023	1.025	1.027	1.061	1.047
	High On-peak	1.028	1.021	-	-	-	1.033	1.129	1.070	-	-	-	1.024

The NYISO staff also considered the LOE-AF values calculated using the 2016 CARIS Phase 2 database at the August 19, 2016 ICAPWG meeting. As part of this review, the NYISO staff noted that on August 1, 2016, the New York State Public Service Commission (NYPSC) issued an order establishing a Clean Energy Standard in New York that included a requirement for Load Serving Entities to purchase zero-emission credits (ZECs) from qualifying nuclear plants in New York.[16] Certain stakeholders contend that this order should cause the NYISO to adjust the 2016 CARIS Phase 2 database to return to service both the Ginna and Fitzpatrick nuclear units, totaling over 1,400 MW.[17] Other stakeholders, however, have argued that the NYISO should conform to the established precedent of alignment with the current status of the NYISO planning base cases for other current assessments. NYISO staff directed GE Energy to rerun the 2016 CARIS Phase 2 analysis with Ginna and Fitzpatrick placed back in service; no other modifications were made to the 2016 CARIS Phase 2 database as part of this supplemental analysis. NYISO staff utilized the results of this adjusted 2016 CARIS Phase 2 case to calculate alternative LOE-AF values. The resulting LOE-AF values were discussed with stakeholders at the September 8, 2016 ICAPWG meeting and are provided in Appendix III.

[16] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Adopting a Clean Energy Standard (issued and effective August 1, 2016).
[17] The 2016 CARIS Phase 2 database currently assumes that both of these nuclear plants will retire in 2017.

Comparison of the results for various cases has led NYISO staff to conclude that the results based on 2016 CARIS Phase 2 database are directionally correct given the location and ratings of the two nuclear units at issue that are assumed to retire in 2017 in such database. Notably, at this time, the owners of the Ginna and Fitzpatrick nuclear units have not rescinded any retirement notices since issuance of the NYPSC's August 1, 2016 Clean Energy Standard order, nor provided any other notifications to the NYISO that would meet the requirements of the CARIS base case inclusion rules to return the units to service at this time. As a result, based on the information available at this time, the NYISO staff concludes that LOE-AF values reflected in Table 13 above, calculated using the 2016 CARIS Phase 2 database without any adjustments to the resource mix assumptions currently provided therein, are the appropriate LOE-AF values for establishing the ICAP Demand Curves for this reset period.

10.4. Dual Fuel

Dual fuel operation (*i.e.*, the ability to select the most economic fuel alternative for producing energy) was incorporated into the net EAS revenues model.

Some stakeholders have recommended that the model be further refined to include additional logic to account for the potential of gas unavailability in determining estimated net EAS revenues for a gas-only unit. In the last reset, a simple rule was developed that curtailed gas supply for gas-only units on days when the maximum temperature did not exceed 20 degrees Fahrenheit (^{o}F).

The Consultants worked with NYISO and the MMU to confirm the adequacy of the previous approach or develop a more representative alternative. It was determined that continued application of the logic from the last reset could no longer be justified based on more recent operational experience.

Some stakeholders have also argued that the model should incorporate additional logic to reflect the difficulty of replenishment of ultra low-sulfur diesel fuel at dual fuel plants during winter conditions, or, in the alternative, increase the assumed on-site fuel storage. NYISO has reviewed the Consultants' on-site storage recommendation and concluded that the fuel oil storage incorporated in the peaking plant configuration (96 hours) is consistent with Con Edison requirements, LCI experience, and the results of the net EAS model. Further, NYISO has found no basis for incorporation of an algorithm limiting revenues from operation on oil into the EAS model.

NYISO has thus concluded that the net EAS revenue model provides the most representative assessment of dual fuel optionality that is achievable with readily available data, and meets the needs for use in annual updates.

10.5. Use of Real-Time Dispatch Prices

The net EAS revenues model utilizes zonal integrated hourly Real-Time Dispatch (RTD) prices for purposes of assessing real-time dispatch for the plants. Market Participants asked that the Consultants evaluate the use of a coordinated Real-Time Commitment (RTC) and RTD similar to the NYISO's Real-Time Market. Broadly stated, the concerns raised by these stakeholders were that units are actually committed in RTC, and that use of only RTD prices may overstate net EAS revenues.

Hourly integrated validated RTC prices are currently not publicly available; however, the Consultants developed a comparison of hourly RTC and RTD prices over a three year period used for purposes of their Draft Report (*i.e.*, May 2013 through April 2016) and found no significant systematic differences. The Consultants also developed net EAS revenue estimates using hourly integrated RTC prices for the same three-year period. Relative to outcomes with RTD prices, the results with RTC prices (for both commitment and settlement) lowered net EAS revenues by $0.03/kW-mo. (Load Zones C and F) to $0.21/kW-mo. (Load Zone K) for the simple cycle F-Class frame unit with dual fuel and SCR. The effect on run-time hours for the F-Class frame unit with dual fuel and SCR ranged from a reduction by 10 (Load Zone C) to 101 hours (Load Zone J) to an increase by 2 hours (Load Zone K).

The Consultants concluded that neither the comparison of RTC and RTD prices nor the analysis of net EAS revenue estimates from using RTC prices indicated that a coordinated RTC/RTD process would produce a meaningful difference in net EAS revenues. The Consultants also concluded that the approach using corrected hourly integrated RTD prices balances tradeoffs between accuracy, transparency, and feasibility. The NYISO concurs with the Consultants' conclusions.

Some market participants requested that additional analysis be completed to provide assurance that the dispatch model is not systematically overestimating real-time EAS revenues by using only RTD prices. Specifically, it was requested that the MMU provide monthly net revenue estimates for comparison with the Consultants' results. The requested information was provided by the MMU at the August 10, 2016 ICAPWG meeting for the period May 2013 through December 2015 using its own model, with the gas hubs and unit performance and variable costs used in the Consultants' net EAS revenues model.

The models use similar approaches, which are compared in the table below, however, the Consultants' model is specifically targeted toward the DCR and annual update process.

Table 14: Comparison of AGI and Potomac Economics EAS Models

	AGI	Potomac Economics
Day-Ahead Commitment	Settle at greater of DAM or RTM prices (given opportunity cost of buyouts)	Settle at greater of DAM or RTM prices (given opportunity cost of buyouts)
	Financial buyouts	Financial buyouts and Day Ahead Margin Assurance Payments (DAMAP)
Real-time Commitment	Two-hour look ahead with RTD prices	Hourly integrated RTC price; RTD for settlement, one hour look ahead and Bid Production Price Guarantee (BPCG)
	Starts based on comparison of start-up costs and prices	Starts based on comparison of start-up costs and prices; but limited to one start per day in DAM
Reserves	Opportunity/bid cost	No opportunity/bid cost
Price Resolution	Zonal	Nodal
Intraday fuel premium	Average fuel premium	Average fuel premium
Level of Excess Adjustment Factors	Yes	No

NYISO has completed a comparison of the outcomes from the two models and concluded that the differences are not significant, and can be largely attributed to the level of excess adjustment and the use of nodal prices instead of zonal prices in the MMU model, especially as it relates to outcomes for Load Zones J and K. This further supports the NYISO's concurrence with the RTM modeling logic included in the net EAS revenues model developed by the Consultants.

10.6. Fuel Price at Time of Unit Commitment

The net EAS revenues model includes intraday fuel premium/discount values for purposes of determining real-time gas prices. The intraday premium represents an additional cost to obtain natural gas in real-time, when the unit was not committed DAM (for energy or reserves). The intraday discount represents an additional cost to sell natural gas in real-time, when a unit buys out of a physical DAM energy or reserves commitment. The net EAS revenues model assumes an annual average premium/discount, based on the 2015 State of the Market Report using the following assumptions: 10% (Load Zones C and F), 10% (Load Zone G), 20% (Load Zone J), and 30% (Load Zone K). The values are used for determining real-time gas prices for every real-time hour.

Market Participants expressed concerns that these premiums could result in either an overstatement or understatement of net EAS revenues because they would not explicitly capture the "true cost" of gas in real-time. Certain stakeholders contend that this potential misstatement of net EAS revenues is not symmetrical and likely results in an overestimate of net EAS revenues due to significantly understating "true" real-time gas costs on certain critical days (*i.e.*, peak load days in the winter during which constraints and/or other limitations on the natural gas system may arise).

The Consultants undertook an analysis to determine whether use of the recommended intraday premium/discount values is likely to result in any meaningful over/understatement of net EAS revenues. The results of this assessment suggested that net EAS revenues in winter months are not significantly overstated. Further, the potential understatement of revenues in other months appears to likely offset any overstatement in winter months. Finally, alternative approaches would require assumptions about the "true cost" of obtaining or selling intraday gas that are difficult to determine given the diversity of potential plant fuel arrangements and the variety of fuel supply situations that can emerge under different market conditions.

The NYISO concurs with the Consultants' analysis, and supports use of the intraday gas premiums/discount values recommended by the Consultants that were developed by the MMU. NYISO further notes that an analysis by the NYISO Market Mitigation and Analysis department of confidential information regarding resource bids confirms that these values are reasonable representations of real-time gas costs.

10.7. Cost of Providing Reserves

In response to comments from some Market Participants, the Consultants updated the net EAS revenues model to include an opportunity cost of providing reserves.

NYISO agrees that the opportunity cost of holding or obtaining adequate fuel supplies is an appropriate cost for this service and concurs with the opportunity cost adder included in the model by the Consultants.

11. Development of Demand Curves

11.1. Demand Curve Model

The Consultants have developed a "Demand Curve Model" to calculate the applicable reference point (*i.e.*, $/kW-mo.) for each ICAP Demand Curve. The model incorporates a number of improvements which are specifically aimed at improving transparency and facilitation of a formulaic annual update process.

The model develops an annual reference value (ARV) for a given peaking plant by calculating levelized fixed costs or gross cost of new entry (CONE), and subtracting the applicable net Energy EAS revenues estimate, as determined by the net EAS revenues model. The ARV represents the revenue required by the peaking plant from the capacity market in order to recover its costs, and is commonly referred to as "net CONE."

In developing reference point values for the ICAP Demand Curves, the model must satisfy three considerations:

(1) The ICAP Spot Market Auctions, and thus the peaking plant's revenue stream from the capacity market, are monthly. This means that the Demand Curve Model must calculate the reference point price for each ICAP Demand Curve such that the peaking plant receives adequate revenue from the 12 monthly capacity payments it would be provided.

(2) The NYISO ICAP market is comprised of two seasons, the Summer Capability Period and the Winter Capability Period. These Capability Periods reflect the temperature sensitivity of the output of some units in the NYCA and differing amounts of capacity available from certain Installed Capacity Suppliers during different periods of the year (*e.g.*, Special Case Resources and certain imports). As a result, different amounts of capacity are sold in each season, with corresponding differences in market clearing prices.

The Services Tariff specifies that the translation of the applicable peaking plant's annual net revenue requirement (*i.e.*, net CONE) into monthly values take into account "seasonal differences in the amount of Capacity available in the ICAP Spot Market Auctions." This means that the Demand Curve Model must yield reference point price values for each ICAP Demand Curve such that the applicable peaking plant receives adequate revenue from the sum of six months at summer prices and six months at winter prices.

The NYISO makes this translation using a ratio of the amount of capacity available in the winter to the amount available in summer for each capacity region, commonly referred to as the winter-to-summer ratio.

(3) The tariff requires that the reference point for each ICAP Demand Curve result in adequate revenue if the applicable peaking plant were to enter the market when total capacity supplies equal the applicable minimum Installed Capacity requirement. This means that the capacity market will, after accounting for the addition of the applicable peaking plant, have a small amount of excess capacity beyond the applicable minimum Installed Capacity requirement. This level of excess is equal to the tariff-prescribed level of excess conditions used in determining the cost and revenues of the applicable peaking plant for purposes of the DCR. The capacity revenue the applicable peaking plant receives will thus reflect the capacity price at this level of excess. Therefore, the Demand Curve Model must calculate a reference point price for

each ICAP Demand Curve such that the applicable peaking plant receives adequate capacity payments at the level of excess condition.

11.1.1. Winter-to-Summer Ratio

Because the NYISO operates a capacity market with two distinct six-month Capability Periods, in calculating the reference point for each ICAP Demand Curve, the Services Tariff requires that seasonal differences in capacity availability be accounted for in establishing the ICAP Demand Curves. This seasonal adjustment is intended to reflect the fact that differences in capacity availability between the Summer Capability Period and Winter Capability Period contribute to differences in capacity prices throughout the year. To provide for revenue adequacy for the applicable peaking plant when needed to maintain the applicable minimum Installed Capacity requirement, these seasonal differences must be accounted for as part of translating the annual net CONE value for each ICAP Demand Curve to a monthly value for use in the NYISO's ICAP Spot Market Auctions (*i.e.,* the reference point for each ICAP Demand Curve). The winter-to-summer ratio is used to account for these seasonal differences in capacity availability.

As part of the enhancements to the DCR process recently approved by FERC, the methodology for calculating the winter-to-summer ratio for each capacity region was improved. The new methodology relies on data published by the NYISO regarding capacity available to be offered in the ICAP Spot Market Auction for each month during the same 36-month historic data period used by the net EAS revenues model.[18] The NYISO will adjust the historic data to account for certain capacity market entry and exit actions by resources, as further described in Section 5.14.1.2.2.3 of the Services Tariff. The winter-to-summer ratio for each capacity region is calculated as the average of the winter-to-summer ratio calculated for each 12-month period (*i.e.*, September through the following August) encompassed by the historic data set. For each 12-month period, the applicable winter-to-summer ratio is calculated as: (i) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six winter months included in the 12-month period (i.e. November through the following April); divided by (ii) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six summer months included in such 12-month period (i.e., September and October and May through August of the following year).

The preliminary winter-to-summer ratio values calculated using the revised methodology and utilized for purposes of calculating the ICAP Demand Curve reference point values set forth in the Consultants' Final Report are shown in the table below.

[18] For the 2017/2018 Capability Year, the winter-to-summer ratio values for each capacity region, except for the G-J Locality, will be based on monthly values of capacity available to be offered in the ICAP Spot Market Auctions for the period from September 2013 through August 2016. Because the G-J Locality did not exist prior to May 1, 2014, its winter-to-summer ration value for the 2017/2018 Capability Year will be based on data from September 2014 through August 2016.

Table 15: Final Winter-to-Summer Ratio Values for the 2017/2018 Capability Year ICAP Demand Curves

Capacity Region	Capability Year	Winter-to-Summer Ratio
NYCA	2017-2018	1.037
G-J	2017-2018	1.054
New York City	2017-2018	1.077
Long Island	2017-2018	1.075

11.1.2. Adjustment for Tariff-Prescribed Level of Excess Conditions

The LOE for each peaking plant is defined as the ratio of the applicable minimum Installed Capacity requirement plus the average degraded net plant capacity for the peaking plant to the applicable minimum Installed Capacity requirement. The LOE varies by capacity region, depending on the applicable minimum Installed Capacity requirement, and the applicable MW rating of the peaking plant. The minimum Installed Capacity requirement values are based on the 2016 Gold Book peak load forecast for 2016 and the Installed Reserve Margin (IRM) or Locational Minimum Installed Capacity Requirement (LCR) values, as applicable, for the 2016/2017 Capability Year.

The following table provides the applicable 2016 peak load forecasts, IRM/LCR values (in percentage terms), and the resulting LOE by technology, expressed as a percentage.

Table 16: Level of Excess by Technology, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2016)	2016-2017 IRM/LCR	LOE (%) by Technology					
			LMS100 PA	SGT6-PAC 5000F(5)	Wartsila 18V50DF	1x0 GE 7HA.02	5000F CC	8000H CC
NYCA	33,360	117.5%	100.5%	100.6%	100.5%	100.8%	100.8%	101.0%
G-J	16,309	90.0%	101.3%	101.5%	101.4%	102.2%	102.2%	102.6%
NYC	11,795	80.5%	102.0%	102.3%	102.1%	103.3%	103.5%	104.0%
LI	5,478	102.5%	103.4%	103.9%	103.6%	105.7%	105.9%	106.9%

The previous demand curve model used a numerical procedure (Monte Carlo analysis) to produce an ARV that accounted for tariff-prescribed level of excess conditions. As an enhancement, the Consultants propose to update the current ICAP Demand Curve reference point formula (see Section 5.5 of the NYISO Installed Capacity Manual) to expressly include terms that ensure the peaking plant is revenue adequate at the tariff-prescribed level of excess conditions. Specifically, the Consultants noted that the required adjustment to derive the reference point value for each ICAP Demand Curve depends on the size of the peaking plant, the applicable minimum Installed Capacity requirement, and the applicable zero-crossing point. Thus, the Consultants developed a closed form solution for determining the reference point value for each ICAP Demand Curve, while simultaneously considering (1) the monthly nature of the ICAP Spot Market Auctions, (2) the seasonal nature of the NYISO ICAP market, and (3) the tariff requirement that the peaking plant is revenue adequate at the tariff-prescribed level of excess conditions. The previous ICAP Demand Curve reference point price formula and enhanced formula recommended by the Consultants are shown below.

Current ICAP Demand Curve Reference Point Price formula (see Section 5.5 of the NYISO Installed Capacity Manual):
$$\boldsymbol{RP = \frac{ARV * AssmdCap}{6 * \left[SDMNC + SDMNC * \left(1 - \frac{WSR - 1}{ZCPR - 1}\right)\right]}}$$
ICAP Demand Curve Reference Point Price formula proposed by Consultants:
$$\boldsymbol{RP = \frac{ARV * AssmdCap}{6 * \left[SDMNC * \left(1 - \frac{LOE_z - 1}{ZCPR_z - 1}\right) + WDMNC * \left(1 - \frac{LOE_z - 1 + WSR - 1}{ZCPR - 1}\right)\right]}}$$

Variable	Units	Description
RP	\$/kW-mo.	The price at ICAP Demand Curve reference point
ARV	\$/kW-yr	The annual reference value of the peaking plant, calculated as the difference between gross CONE (including fixed O&M) and net EAS revenues
AssmdCap	kW	The average degraded net plant capacity of the peaking plant
SDMNC	kW	The summer Dependable Maximum Net Capability (DMNC) of the peaking plant
WDMNC	kW	The winter DMNC of the peaking plant
WSR	%	The ratio of winter to summer capacity, as calculated by the NYISO
ZCPR	%	The zero crossing point of the ICAP Demand Curve
LOE	%	The ratio of the tariff-prescribed level of excess to the applicable minimum Installed Capacity requirement

The revised formula recommended by the Consultants reduces the complexity and increases the transparency of calculating the ICAP Demand Curve reference point prices. The transition to a fully formulaic demand curve model aligns well with the NYISO's adoption of annual updates and its stated goals of improving the simplicity, transparency, and repeatability of the DCR process.

As part of the annual updates, the applicable ARVs for each ICAP Demand Curve will be updated by using a composite escalation factor to adjust the levelized annual cost value for the applicable peaking plant, and by using the net EAS revenues model to update net EAS revenues using the latest 3-year series of price and cost values. The winter-to-summer ratio values will also be updated annually. The values for the remainder of the variables described in the formula above will be fixed for the duration of the reset period.

The NYISO agrees with the Consultants' recommended revisions to the formula used to calculate ICAP Demand Curve reference point prices.

11.2. Zero Crossing Point

In the last reset, the zero crossing points for the ICAP Demand Curves were set at 112 percent of IRM for NYCA, 118 percent of LCR for Load Zone K (Long Island), 118 percent of LCR for Load Zone J (New York City), and 115 percent of LCR for the G-J Locality. This decision retained the then-current zero crossing point values for the NYCA, New York City and Long Island ICAP Demand Curves, and set the zero crossing point for the G-J Locality ICAP Demand Curves midway between the zero crossing point values for the New York City and NYCA ICAP Demand Curves. Prior to this decision in the last reset, two separate analyses were performed to inform decisions regarding the zero crossing point values for the ICAP Demand Curves. The Consultants' Final Report briefly summarizes these analyses that were conducted by FTI and the MMU, and points to recommendations in the 2015 State of the Market Report that recommend an evaluation of an alternative methodology to determining the IRM and LCRs.

In response to the recommendation in the 2015 State of the Market Report, the NYISO established an LCR Task Force through the ICAPWG that is reviewing alternative methods for the LCR process. The Consultants recommend that further assessment of the zero crossing point values should be performed after the assessment of the LCR methodology is complete. The Consultants note that while the LCR and zero crossing points represent different measures with different functions within the ICAP Demand Curves, these values are related in so far as the zero crossing point values help define the marginal value of capacity beyond the applicable minimum Installed Capacity requirement. Therefore, the approach to establishing the zero crossing point values and IRM/LCRs should be consistent. Considering these factors, the Consultants recommend that the zero crossing point values for the ICAP Demand Curves remain unchanged.

The NYISO concurs with this recommendation to retain the current zero crossing point values for the duration of this reset period. Any assessment of potential future revisions to the zero crossing point values should be reserved until the next DCR.

11.3. ICAP Demand Curve Reference Points

Results from the net EAS revenues model and the demand curve model for the 2017/2018 Capability Year from the Consultants' Final Report are shown in the tables below, which include gross CONE, net EAS revenues, ARV and ICAP Demand Curve reference point values for the peaking plant technologies evaluated, as well as the simple cycle GE 7HA.02 unit evaluated for informational purposes. The tables also include values for gas only with SCR configurations in Load Zones C, F and G.

Table 17: 2017/2018 Capability Year ICAP Demand Curve Parameters for Peaking Plant Technologies: Gross CONE ($/kW-yr), Net EAS ($/kW-yr), Annual Reference Value ($/kW-yr), and Monthly Reference Point ($/kW-mo.)

		C Central	F Capital	G Rockland	G Dutchess	J NYC	K LI
Dual Fuel							
Wartsila 18V50DF	Gross CONE	$259.85	$254.61	$286.91	$284.07	$334.65	$317.85
	Net EAS	$57.38	$67.02	$61.89	$61.98	$74.66	$129.82
	Annual Reference Value (Net CONE)	$202.46	$187.58	$225.01	$222.09	$259.99	$188.02
	Reference Point	$20.94	$19.40	$25.65	$25.31	$32.31	$26.33
GE LMS100PA+	Gross CONE	$227.43	$218.50	$243.17	$240.92	$281.10	$265.24
	Net EAS	$55.56	$61.38	$57.80	$57.71	$70.25	$117.42
	Annual Reference Value (Net CONE)	$171.88	$157.12	$185.37	$183.21	$210.85	$147.82
	Reference Point	$16.40	$15.05	$19.48	$19.30	$24.28	$19.07
Siemens SGT6-5000F(5)	Gross CONE	$162.79	$154.99	$176.64	$174.79	$209.11	$194.96
	Net EAS	$46.19	$42.38	$40.26	$40.39	$55.26	$104.20
	Annual Reference Value (Net CONE)	$116.60	$112.61	$136.39	$134.41	$153.85	$90.77
	Reference Point	$11.56	$11.22	$15.09	$14.84	$18.61	$12.72
Gas Only with SCR							
Wartsila 18V50DF	Gross CONE	$218.14	$210.84	$239.33	$237.09		
	Net EAS	$47.70	$50.09	$46.95	$46.98		
	Annual Reference Value (Net CONE)	$169.27	$160.75	$192.37	$190.11		
	Reference Point	$17.62	$16.73	$22.23	$21.97		
GE LMS100PA+	Gross CONE	$216.83	$207.89	$232.47	$230.29		
	Net EAS	$52.02	$55.61	$50.62	$50.57		
	Annual Reference Value (Net CONE)	$164.81	$152.28	$181.84	$179.72		
	Reference Point	$15.73	$14.59	$19.11	$18.93		
Siemens SGT6-5000F(5)	Gross CONE	$150.55	$142.92	$162.68	$161.37		
	Net EAS	$42.43	$35.35	$33.48	$33.61		
	Annual Reference Value (Net CONE)	$108.12	$107.58	$129.20	$127.76		
	Reference Point	$10.72	$10.72	$14.30	$14.11		

Table 18: 2017/2018 Capability Year ICAP Demand Curve Parameters for Additional Peaking Plants Evaluated for Information Only: Gross CONE ($/kW-yr), Net EAS ($/kW-yr), Annual Reference Value ($/kW-yr), and Monthly Reference Point ($/kW-mo.)

		C Central	F Capital	G Rockland	G Dutchess	J NYC	K LI
Dual Fuel							
GE7HA.02 Simple Cycle	Gross CONE	$149.58	$144.50	$160.76	$159.19	N.A.	$241.06
	Net EAS	$52.35	$48.03	$46.44	$46.59	N.A.	$113.58
	Annual Reference Value ((Net CONE)	$97.23	$96.47	$114.32	$112.60	N.A.	$127.48
	Reference Point	$9.91	$9.89	$13.52	$13.42	N.A.	$21.42
Gas Only							
GE7HA.02 Simple Cycle	Gross CONE	$132.40	$127.19	$143.02	$141.60	N.A.	N.A
	Net EAS	$48.53	$42.35	$39.51	$39.76	N.A.	N.A
	Annual Reference Value (Net CONE)	$83.87	$84.83	$103.51	$101.84	N.A.	N.A
	Reference Point	$8.55	$8.70	$12.24	$12.14	N.A.	N.A.

11.4. Annual Updates

In accordance with the requirements of Section 5.14.1.2.2 of the Services Tariff, the ICAP Demand Curves will be updated annually for each of the three successive Capability Years encompassed by this reset period (*i.e.*, the 2018/2019 Capability, 2019/2020 Capability Year and 2020/2021 Capability Year) through the demand curve model based on the updating of (1) gross CONE values, (2) net EAS revenue estimates using the net EAS revenues model, and (3) the winter-to-summer ratio values. Updates to gross CONE and net EAS revenues are described in greater detail below. The winter-to-summer ratio will be updated annually by the NYISO in accordance with the requirements of Section 5.14.1.2.2.3 of the Services Tariff.

The table below summarizes certain of the factors used in the annual updates to ICAP Demand Curve reference point prices, indicating in bold those parameters that are updated annually. The remaining parameters are fixed for the reset period.

Table 19: Overview of ICAP Demand Curve Annual Updating for the Recommended Peaking Plant

		Value by Location			
Factor Used in Annual Updates for Each ICAP Demand Curve	**Type of Value**	**NYCA**	**G-J**	**J**	**K**
ICAP Demand Curve Values					
Zero-crossing point	Fixed for Reset Period	112%	115%	118%	118%
Reference Point Price Calculation					
Peaking Plant Net Degraded Capacity (DMNC ICAP MW)	Fixed for Reset Period	217.0	128.0	217.6	219.1
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed for Reset Period	224.6	226.8	226.9	224.9
Peaking Plant Winter Capability Period DMNC	Fixed for Reset Period	230.3	230.3	228.7	230.3
Installed Capacity Requirements (IRM/LCR)	Fixed for Reset Period	117.5%	90.0%	80.5%	102.5%
Peak load forecast (2016)	Fixed for Reset Period	33,360	16,309	11,795	5,478
Monthly Available Capacity Values for Use in Calculating WSR	NYISO Published Values;	This data is updated annually and is publically available via the NYISO Website.			

The NYISO will post the results of each annual update and the resulting ICAP Demand Curve values on or before November 30th of the year preceding the beginning of the Capability Year to which the updated ICAP Demand Curves will apply.

11.4.1. Updates to Gross CONE

The gross CONE value of each peaking plant will be updated based on a single state-wide, technology-specific composite escalation factor representing the cost-weighted average of inflation indices for four major components of plant construction costs: wages, turbines, materials and components, and other costs. The single set of cost-component weights is calculated to reflect each component's share of total installed capital costs. The table below provides the applicable index to be used for each cost component, and the weighting factors for each component. The weighting factors and indices relied upon will be held fixed for the duration of the reset period, but the values resulting from the changes in the values of the indices will be updated annually.

Table 20: Composite Escalation Rate Indices and Component Weights

Cost Component	Index Value	Interval	Component Weight SGT6-5000F(5)
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual	Annually	28%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	37%
Gas and Steam Turbine Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Turbines and Turbine Generator Sets (97)	Monthly	20%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	15%

The composite escalation rate (and the rate associated with the general component) will be updated annually and finalized using data published by indices as of October 1st of the year prior to the start of the Capability Year to which the relevant ICAP Demand Curves will apply.

11.4.2. Updates to Net EAS

Net EAS revenues will be recalculated annually using the same net EAS revenues model used to estimate net EAS revenues for the 2017/2018 Capability Year, but model inputs will include the most recent three-year data available for Energy and reserve market prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges. Other peaking plant costs and operational parameters (*e.g.*, heat rate, variable O&M costs) needed to run the model, as well as the applicable LOE-AF values, remain fixed for the duration of the reset period.

The table below contains a summary of the factors used in the net EAS revenues calculation, with an indication of data source and whether or not they are updated annually (items in bold are updated annually).

Table 21: Overview of Treatment of Net EAS Model Parameters for Annual Updating for the Recommended Peaking Plant

Factor Used in Annual Updates for Each ICAP Demand Curve	Value by Location: NYCA	G-J	J	K
Net EAS Revenue Model, including Commitment and Dispatch Logic	(Fixed for Reset Period) http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp; Reference Docs\2017-2021 Demand Curve Reset\Net EAS Model			
Peaking plant	1x0 Siemens SGT6-5000F5 with SCR/CO	1x0 Siemens SGT6-5000F5 with SCR/CO	1x0 Siemens SGT6-5000F5 with SCR/CO	1x0 Siemens SGT6-5000F5 with SCR/CO
Variable Cost per Start ($/Start) (per unit)[19]	$10,300	$10,500	$11,000	$10,900
Net Plant Heat Rate (HHV basis), Degraded	* See Table 9 above			
Energy Prices (day-ahead and real-time)	* This data is publically available through the NYISO DSS System, via the NYISO Website			
Operating Reserves Prices (day-ahead and real-time)	* This data is publically available through the NYISO DSS System, via the NYISO Website			
Level of Excess Adjustment Factors	See Table 13 above			
Ancillary Services Adder for Voltage Support Service ($/kW-yr.)	$1.43	$1.43	$1.43	$1.43
Peaking plant primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Peaking plant secondary (if any) Fuel Type	-	ULSD	ULSD	ULSD
Fuel tax adder - Gas	-	-	6.9%	1.0%
Fuel tax adder - ULSD	-	-	4.5%	-
Transportation cost adder – Gas ($/MMBtu)	$0.27	$0.27	$0.20	$0.25
Transportation cost adder –ULSD ($/MMBtu)	$2.00	$1.50	$1.50	$1.50
Real-time intraday gas premium/discount	10%	10%	20%	30%
Fuel Pricing Point - Gas	Iroquois Zone 2	Iroquois Zone 2	Transco Zn 6 NY	Transco Zn 6 NY
Fuel Pricing Point - ULSD	New York Harbor	New York Harbor	New York Harbor	New York Harbor
Fuel Price Data source - Gas	SNL Financial			

[19] The startup cost is calculated as the startup fuel quantity multiplied by the applicable day ahead fuel price, plus the variable O&M cost per start. The startup fuel quantity is provided in the Performance Data section of Appendix B in Consultants' Final Report for the 1x0 Siemens SGT6-5000F5 with SCR/CO

Fuel Price Data Source - ULSD	https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EER_EPD2DXL0_PF4_Y35NY_DPG&f=D
Peaking plant Variable Operating and Maintenance Cost	* This data is available in Variable O&M Cost section of Appendix B of the Consultants Final Report dated September 13, 2016 for the 1x0 Siemens SGT6-5000F5
Peaking plant CO2 Emissions Rate	* This data is available in Performance Data section of Appendix B of the Consultants Final Report dated September 13, 2016 for the 1x0 Siemens SGT6-5000F5
Peaking plant NOx Emissions Rate	* This data is available in Performance Data section of Appendix B of the Consultants Final Report dated September 13, 2016 for the 1x0 Siemens SGT6-5000F5
Peaking plant SO2 Emissions Rate	* This data is available in Performance Data section of Appendix B of the Consultants Final Report dated September 13, 2016 for the 1x0 Siemens SGT6-5000F5
CO2 Emission Allowance Cost	REGGI Regional Allowance Auction Results, available on RGGI's website at https://www.rggi.org/market/co2_auctions/results
NOx Emission Allowance Cost	SNL Financial
SO2 Emission Allowance Cost	SNL Financial
NYISO Rate Schedule 1 Charges for Injection Billing Units	http://www.nyiso.com/public/markets_operations/market_data/miscellaneous/index.jsp?docs=rate-schedule-1

NYISO will collect LBMP and reserve price data for the three-year period ending August 31st of the year prior to the beginning of the Capability Year to which the updated ICAP Demand Curves will apply. Similarly, data from the specified sources for fuel prices and emission allowance prices will be collected and processed for the same time period. These data would then be used in net EAS revenues model to determine net EAS revenues of the applicable peaking plant for the upcoming Capability Year.

12. NYISO Recommendations

12.1. Choice of Peaking Unit Technology

The NYISO concurs with the Consultants' recommendation of a single, simple cycle Siemens SGT6-5000F(5) turbine with SCR as the peaking plant in all locations. Given the current environmental regulatory framework and permitting requirements, NYISO believes that SCR is clearly required to assure that the peaking plant is reasonably capable of being constructed.

NYISO concurs with the Consultants' recommendation for dual fuel in Load Zones G, J and K. However, the NYISO recommends use of a gas only unit in Load Zones C and F.

For those capacity regions in which multiple locations were considered, the NYISO concurs with the Consultants' recommendation to generally select the location that represents the lowest monthly reference point prices for each applicable ICAP Demand Curve. Accordingly, Load Zone G (Dutchess County) was selected for the G-J Locality ICAP Demand Curve. Based on the NYISO's recommended change to use a gas-only configuration with SCR for the peaking plant in Load Zones C and F, the results in the Consultants' Final Report indicate that the resulting reference point price for the NYCA ICAP Demand Curve would be the same for each location. Therefore, the NYISO concurs with the Consultants' recommendation to select Load Zone F as the location for the NYCA ICAP Demand Curve. As it relates to the NYISO's recommended gas-only with SCR configuration, Load Zone F produces a lower annual net cost of new entry (or annual reference value) than Load Zone C. Selection of Load Zone F is also consistent with the location used for the NYCA ICAP Demand Curve in prior resets.

At the request of some stakeholders, a full evaluation of a simple cycle GE 7HA.02 unit was developed for informational purposes. In recommending the smaller Siemens SGT6-5000F(5) as the technology for the peaking plant in all locations, the Consultants noted that there are no simple cycle H frame units that are currently in operation or that have proven operating experience. The NYISO concurs with this rationale, and notes that it is consistent with precedent from previous resets.

In particular, the peaking unit technology changed from the GE LM6000 to the LMS100 in 2007 for New York City and Long Island, and from GE LMS100 to the Siemens SGT5000F(5) with SCR in 2013 for New York City, Long Island and the G-J Locality. In both cases there was at least limited operational experience with the technology chosen.[20]

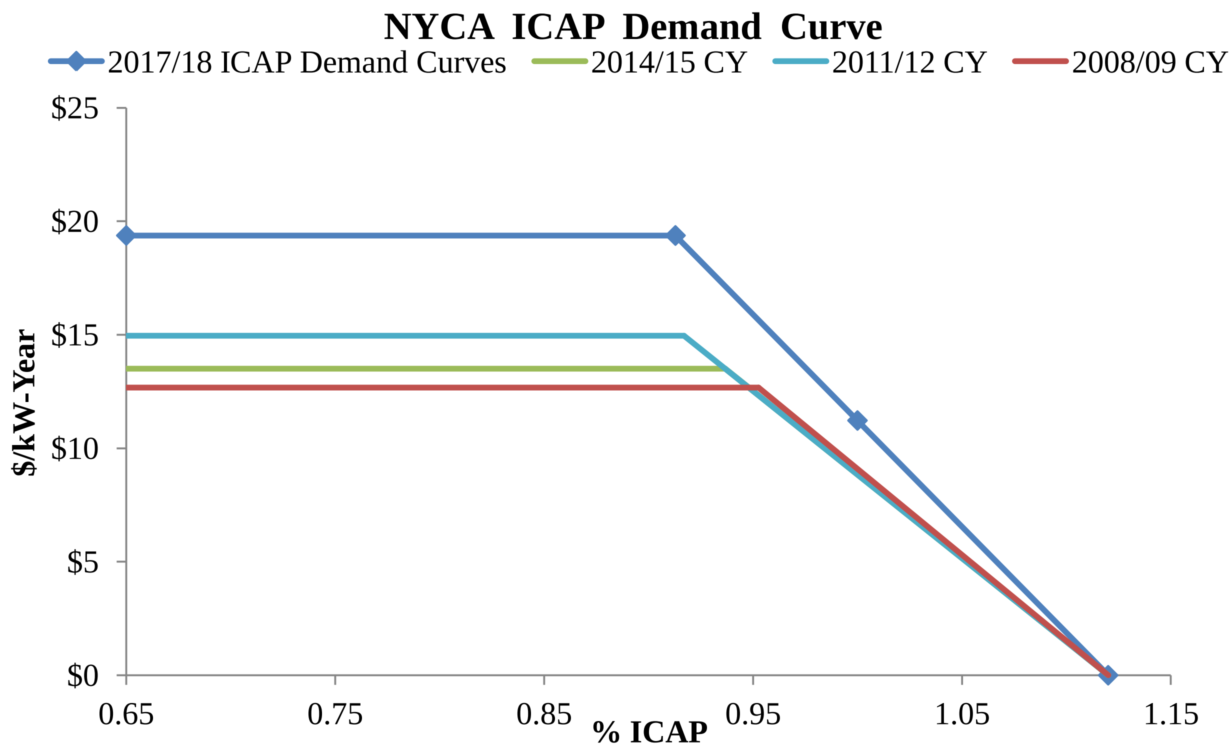
NYISO also notes that the GE7HA.02 does not meet the 45 second automatic fuel swap requirement of Local Reliability Rule 3 in Load Zone J and thus is not a viable option for the New York City ICAP Demand Curve. For Zone K, the SDU costs associated with the larger H frame unit results in a higher ICAP Demand Curve reference point price for this unit, compared to the recommended Siemens SGT6-5000F(5) unit.

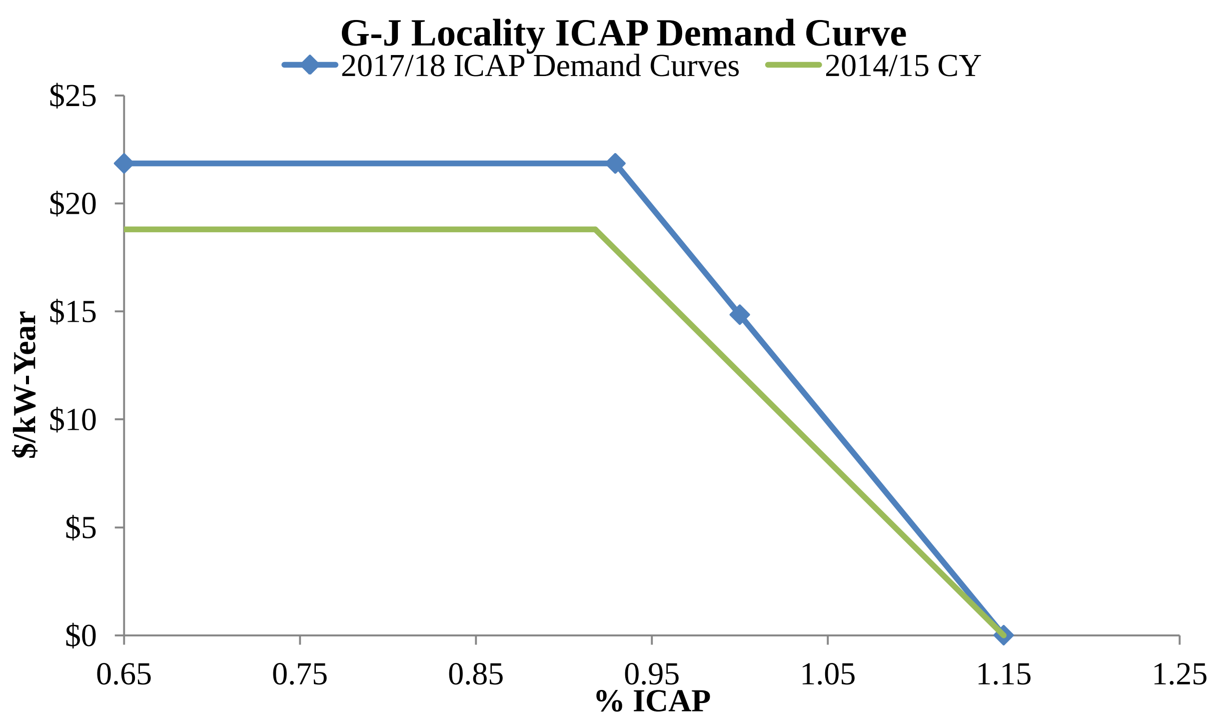
2017/2018 Capability Year ICAP Demand Curve Parameters

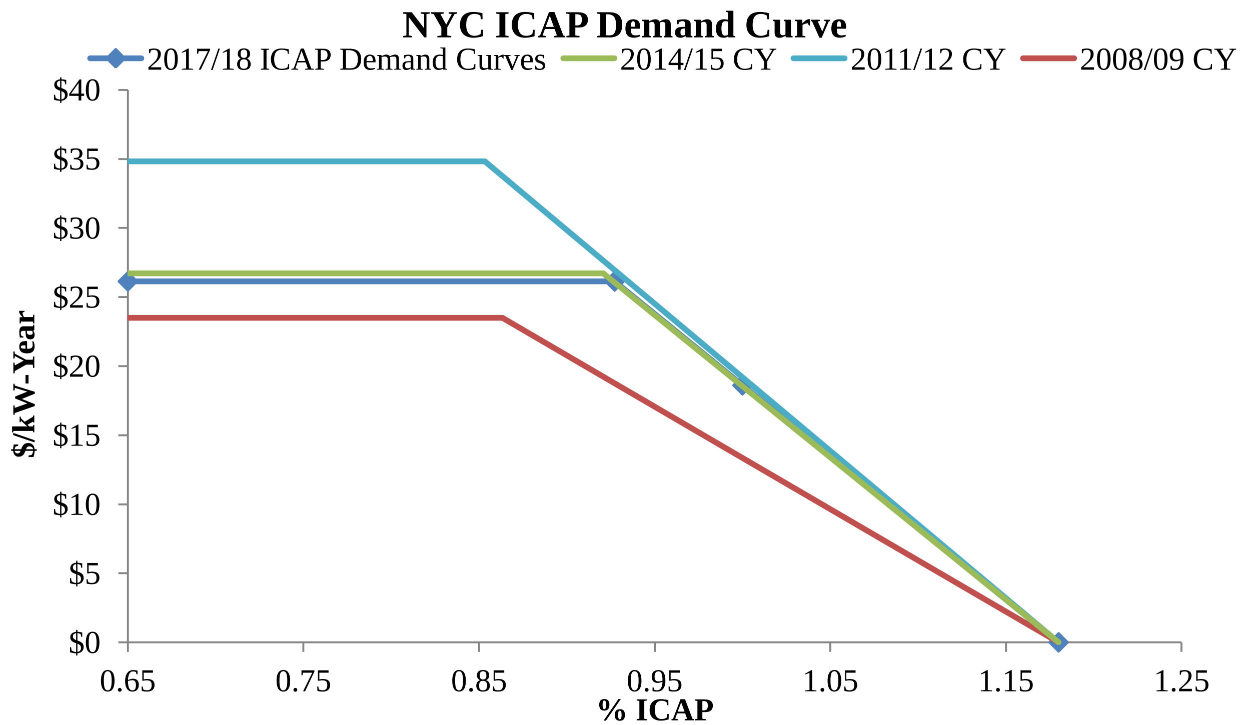
Technology	Region	NYCA	G-J	J	K
Siemens SGT6-5000F(5) with SCR	Fuel	**Gas Only**	**Dual Fuel**	**Dual Fuel**	**Dual Fuel**
	Gross CONE ($/kW-yr)	$142.92	$174.79	$209.11	$194.96
	Net EAS Revenues ($/kW-yr)	$35.35	$40.39	$55.26	$104.20
	Annual Reference Value ($/kW-yr)	$107.58	$134.41	$153.85	$90.77
	Reference Point ($/kW-mo.)	$10.72	$14.84	$18.61	$12.72

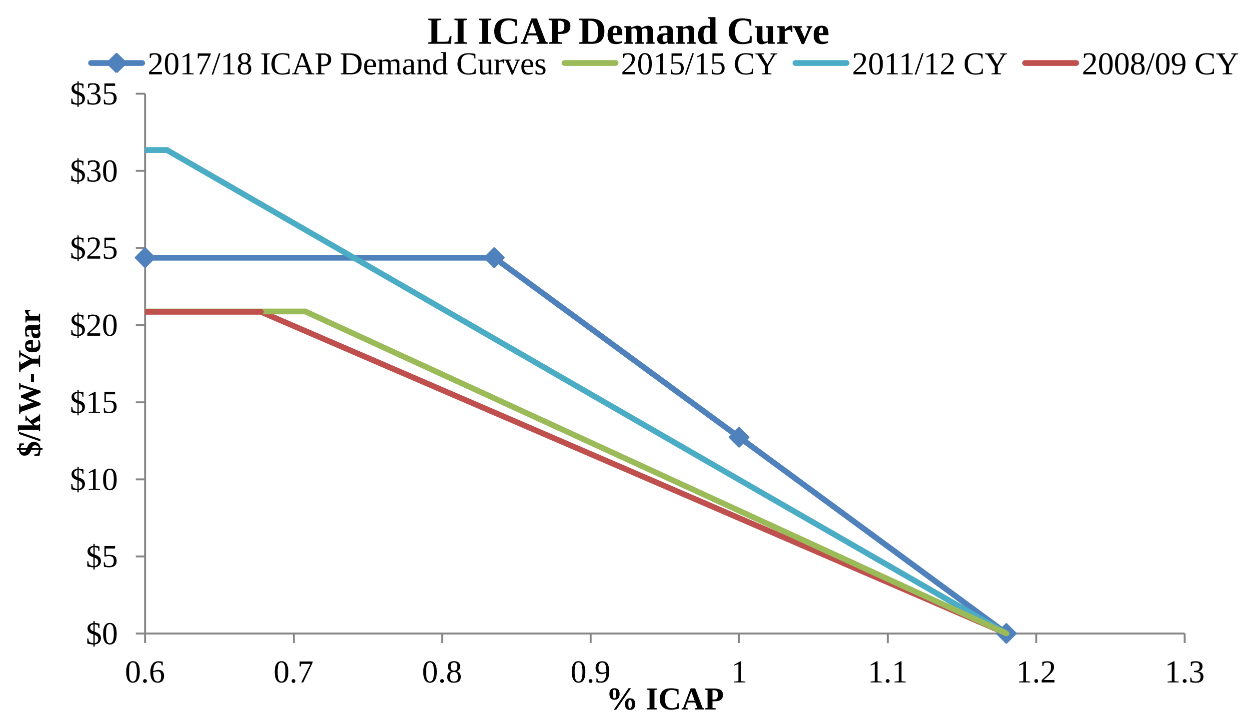
[20] In the case of the LMS100, one simple cycle unit had operated for nearly 600 hours over a period of 9 months. With respect to the simple cycle Siemens F class frame with SCR, one plant consisting of four such units had operated for approximately 500 hours over a period of 7 months.

ICAP Demand Curves for the 2017/2018 Capability Year






NYC ICAP Demand Curve
2017/18 ICAP Demand Curves
2014/15 CY
2011/12 CY
2008/09 CY
$/kW-Year
$40
$35
$30
$25
$20
$15
$10
$5
$0
0.65
0.75
0.85
0.95
1.05
1.15
1.25
% ICAP


LI ICAP Demand Curve
2017/18 ICAP Demand Curves
2015/15 CY
2011/12 CY
2008/09 CY
$/kW-Year
$35
$30
$25
$20
$15
$10
$5
$0
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
% ICAP

13. Informational Combined Cycle Unit

In addition to the evaluation of the peaking plant technologies, the Consultants evaluated the larger Siemens SGT6-8000(H), which to date has been used only in combined cycle applications, and the Siemens SGT6-5000F(5) in combined cycle configuration. The combined cycle configuration is a 1x1x1 plant employing “Flex” technology, which is smaller than a 2x1 plant, thereby reducing interconnection requirements, and offering better cycling characteristics (start-up times, ramp rates, and turndown).

The capital cost information is included in the summary in Section 7 above and the performance and variable operation and maintenance cost information is summarized in Section 8 above.

Net EAS revenue estimates were developed using a net EAS revenues model which used simplified commitment and dispatch logic. The model includes DAM energy commitment, real-time market energy dispatch and the ability to buy out of a DAM energy commitment. The model also includes logic to permit the plant to operate at minimum load between commitments, if net losses are lower than start-up costs.

A flat annual adder of $3.70/kW year was developed for ancillary service revenues based on NYISO settlement data for 2013-2015 for comparable units in the NYCA. This is an annual average of data from 13 comparable units greater than 200 MW and annual net ancillary services revenues greater than $100,000. A separate adder for VSS of $1.43 kW-yr was also included.

Results from the net EAS revenues model and the demand curve model for the 2017/2018 Capability Year from in Appendix F of the Consultants’ Final Report are shown in the tables below, which include gross CONE, net EAS revenues, ARV and ICAP Demand Curve reference point values for the combined cycle plants evaluated for informational purposes. The tables also include values for gas only with SCR configurations in Load Zones C, F and G.

Table 22: 2017/2018 Capability Year ICAP Demand Curve Parameters for Combined Cycle Plants, Evaluated for Information Only: Gross CONE ($/kW-yr), Net EAS ($/kW-yr), Annual Reference Value ($/kW-yr), and Monthly Reference Point ($/kW-mo.)

		C Central	F Capital	G Rockland	G Dutchess	J NYC *	K LI
Dual Fuel							
Siemens SGT6-5000F 1 x 1 x 1 CC	Gross CONE	$245.19	$258.60	$291.35	$287.73	$462.49	$402.94
	Net EAS	$88.39	$87.03	$86.54	$86.52	$129.00	$199.63
	Annual Reference Value (Net CONE)	$156.80	$171.58	$204.81	$201.21	$333.49	$203.31
	Reference Point	$16.44	$18.06	$24.96	$24.55	$46.10	$35.93
Siemens SGT6-5000H 1 x1 x 1 CC	Gross CONE	$220.01	$233.56	$262.81	$259.22	$416.32	$359.11
	Net EAS	$93.13	$90.87	$90.49	$90.63	$133.54	$207.70
	Annual Reference Value (Net CONE)	$126.88	$142.69	$172.32	$168.59	$282.79	$151.41
	Reference Point	$12.74	$14.43	$20.72	$20.28	$39.42	$29.20
Gas Only with SCR							
Siemens SGT6-5000F 1 x 1 x 1 CC	Gross CONE	$234.15	$247.39	$279.84	$276.26		
	Net EAS	$83.86	$77.63	$77.45	$77.43		
	Annual Reference Value (Net CONE)	$150.29	$169.76	$202.39	$198.83		
	Reference Point	$15.76	$17.87	$24.66	$24.26		
Siemens SGT6-5000H 1x1x1 CC	Gross CONE	$209.96	$223.32	$252.36	$248.75		
	Net EAS	$88.57	$79.89	$80.55	$80.69		
	Annual Reference Value (Net CONE)	$121.39	$143.43	$171.81	$168.06		
	Reference Point	$12.19	$14.51	$20.66	$20.22		

The NYC result is shown without the property tax abatement. Combined cycle units in normal operation would not be expected to meet the average run time per start limitation to qualify for the abatement.

Comparison of the above results with results for comparable peaking unit configurations evaluated by the Consultants leads to the following general conclusions:

- The combined cycle units result in higher ICAP Demand Curve reference point prices than the Siemens SGT6-5000F in all locations;
- The combined cycle units result in higher ICAP Demand Curve reference point prices than the GE LMS100 in all locations, except for Load Zones C and F; and
- The combined cycle units result in lower ICAP Demand Curve reference point prices than the Wartsila 18V50DF in all locations, except Load Zone J.

14. MMU Review of Recommended ICAP Demand Curve Parameters

The MMU consulted with both NYISO staff and the Consultants at various stages throughout the DCR process and helped inform the Consultants' work and these recommendations. The MMU's comments regarding the DCR, the Consultants' Final Report and NYISO staff's recommendations are provided in Appendix IV.

15. Timeline

Stakeholders will be allowed to provide written comments to the Board, followed by presentations to the Board, in October. Written comments will be due on or before October 3, 2016 and oral presentations will be made on October 17, 2016. The Board will then direct NYISO staff to file the Board's final recommended ICAP Demand Curve parameters for the 2017/2018 Capability Year with FERC on or before November 30, 2016. The revised ICAP Demand Curves, as approved by FERC, would take effect on May 1, 2017.

Appendix I

Payments in Lieu of Taxes Outside New York City

Payments in Lieu of Taxes Outside New York City

Certain stakeholders raised concerns regarding the analysis performed by the Consultants relating to property tax rates for generators located outside of NYC. These stakeholders contend that the Consultants' analysis overstates the effective tax rates for the plants analyzed due to its use of a single year's PILOT payments made in 2014 and capital expenditures made prior to 2014, without adjustment of the underlying capital expense to express it in 2014 dollars. These stakeholders also noted that PILOT payments typically increase over the life of the agreement; therefore, use of a single year's PILOT payments may not accurately reflect the effective levelized tax rate for each plant pursuant to their respective PILOT agreements over time. These stakeholders also contend that the calculation of a weighted average effective tax rate should be based on each plant's capital expenditure value rather than weighted based on PILOT payment value, as was calculated by the Consultants. Other stakeholders expressed that changes in laws and policies since the last reset could result in higher tax rates under PILOT agreements going forward.

The NYISO has reviewed the analysis undertaken by the Consultants and considered the concerns noted above. The NYISO has also discussed with the Consultants stakeholders concerns with its approach used in developing the recommendation for property tax rates outside NYC. The Consultants explained that use of a single year's PILOT payments is reasonable because PILOT payments typically escalate over time so that payments are roughly constant in real dollar terms. Use of a historical, known escalation factor (*e.g.*, actual, historic GDP deflator values) to convert the capital expenditure value for each plant analyzed to 2014 dollars fails to account for the fact that each PILOT agreement was negotiated at a different point in time and based on the respective parties' own forward looking inflation estimates at such time. These expectations of inflation at the time each PILOT agreement was negotiated are used, in part, to inform the escalation of PILOT payments over time. Thus, based on the forward looking expectations of inflation at the time of negotiation, typical PILOT payments do not generally decline in real dollar terms over the term of the agreement. Substitution of actual inflation that has occurred for the parties' expectations of inflation at the time a PILOT agreement was negotiated may result in the calculation of inaccurate effective tax rates for a given agreement.

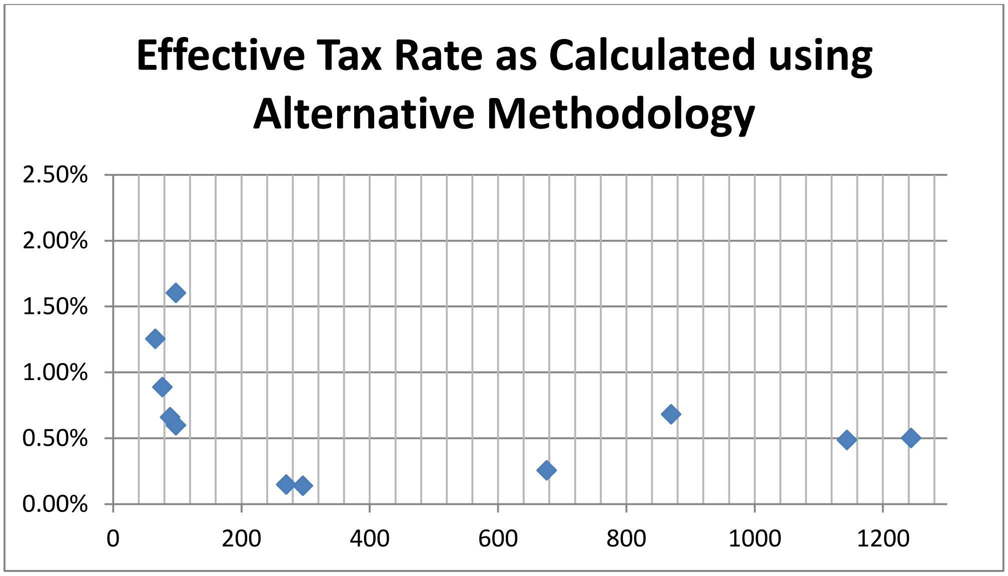
Certain stakeholders advocating for a reduction of the property tax rate outside NYC have provided an analysis that relies on the full payment schedules for only three PILOT agreements. The NYISO has also reviewed this analysis for the three units evaluated. The Consultants' analysis, however, accounts for a larger number of facilities and a greater range in facility size. This broader sample set provides important observations regarding the apparent variation in tax rates depending on the size of a facility. The broader data set utilized by the Consultants demonstrates that tax rates for smaller plants, which may be more representative of a peaking plant, are typically higher than the rates negotiated by larger combined cycle plants. This suggests that the tax rate for the smaller megawatt size peaking unit may be higher than that historically available for combined cycle units.

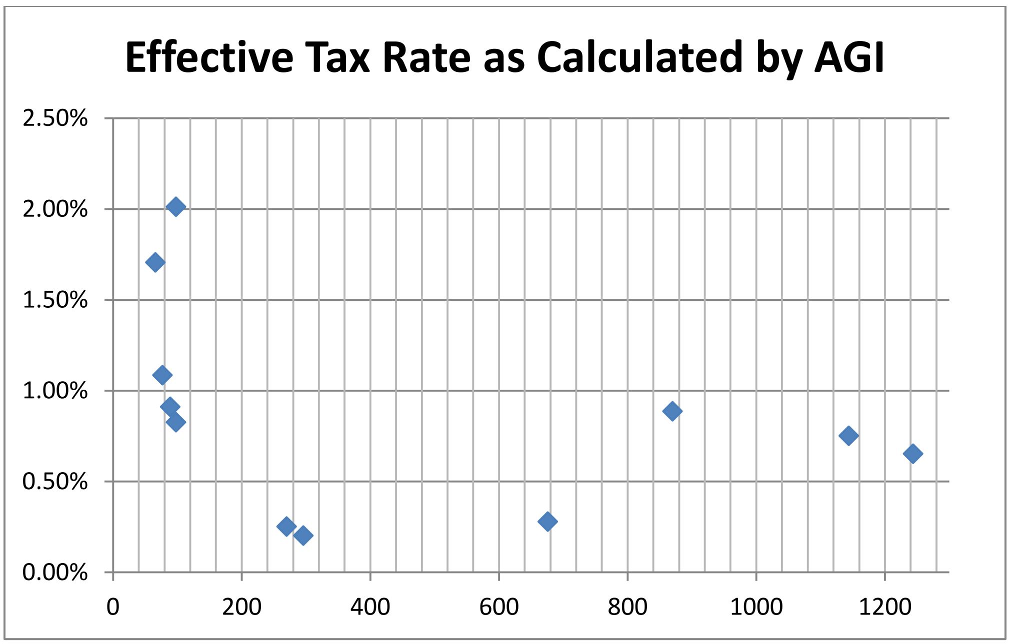
Certain PILOT agreements also indicate that required payments (and, thus, the resulting effective tax rates) include other considerations, such as the number of jobs delivered and/or the net revenues earned by a plant. Accordingly, actual tax payments could be higher than the agreed upon base PILOT payments based on the performance of the plant. For example, the effective tax rates calculated based on the PILOT agreements for certain combined heat and power facilities tend to fall at the low end of the range in the Consultants' analysis. This may be reflective of base PILOT payments that do not account for the potential of performance-based or other adjustments that may increase the actual tax payments by such facilities above the level of the base PILOT payments.

While the NYISO finds that the analysis conducted by the Consultants was reasonable, the NYISO performed the additional analysis requested by adjusting the capital expenditure values for each plant analyzed to 2014 dollar terms using actual, historic inflation based on the GDP deflator. This additional analysis does not change the NYISO's conclusion that the 0.75% tax rate recommended by the Consultants is both appropriate and reasonable.

Both methods clearly demonstrate that effective tax rates generally decline as the MW value of a plant increases. This supports use of a rate that is more representative of units that are similar in size to the peaking plant. Based on the dataset developed by the Consultants, the effective tax rates for units that are more similarly situated to the peaking plant (*i.e.*, units outside NYC that are less than 300 MW) range from 0.25% to 2.01%, with a median value of 1%. The alternative results derived from adjusting the underlying capital expenditure of the units analyzed by the Consultants to 2014 dollar terms provide similar results. For units located outside NYC that are less than 300 MW, the effective tax rates range from 0.15% to 1.6%, with a median value of 0.77%. This information supports the conclusion that the 0.75% tax rate recommended by the Consultants is a reasonable value that is within the range of tax rates that a generator similar in size to the peaking plant would be likely to incur.

The NYISO also assessed stakeholder comments that suggested that tax rates may have increased from the historical dataset due to systemic historical policy changes. The NYISO requested and obtained from the Orange County Industrial Development Agency a copy of the recent PILOT agreement negotiated by CPV Valley, LLC. Although the CPV Valley facility is a large combined cycle facility that may not be directly comparable to a peaking plant, the 0.18% average effective tax rate, in real dollar terms, over the first 20 years of its PILOT agreement demonstrates that the changes in law and policy since the last reset have not had an adverse impact on tax rates afforded to new fossil-fuel fired generators in New York. In fact, when compared to three other recent combined cycle facilities constructed in New York (*i.e.*, Athens, Bethlehem and Empire), the effective tax rate for the CPV plant is the lowest. This information supports the reasonableness of the Consultants decision to inform its recommended tax rate for outside NYC using publicly available data regarding PILOT payments of other gas fired generation facilities in New York and does not suggest that effective tax rates pursuant to PILOT agreements have materially increased since the last reset.


Effective Tax Rate as Calculated using Alternative Methodology
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
0
200
400
600
800
1000
1200


Effective Tax Rate as Calculated by AGI
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
0
200
400
600
800
1000
1200

Generator[21]	Capacity (MW)	Project Amount ($MM)	PILOT Pmts. per AG	Effective Tax Rate per AG	Year	Real Effective Tax Rate
Athens	1244	$ 750.0	$ 4,896,986	0.65%	2001	0.50%
Independence	1144	$ 800.0	$ 6,013,333	0.75%	1992	0.49%
Bethlehem	870	$ 400.0	$ 3,546,496	0.89%	2001	0.68%
Empire	676	$ 358.0	$ 1,000,000	0.28%	2009	0.26%
Saranac	270	$ 166.5	$ 420,000	0.25%	1989	0.15%
Syracuse	98	$ 8.0	$ 66,123	0.83%	1998	0.60%
Freeport	98	$ 59.5	$ 1,197,293	2.01%	2003	1.60%
Beaver Falls	89	$ 9.0	$ 81,999	0.91%	1998	0.66%
Pinelawn	77	$ 92.0	$ 998,500	1.09%	2004	0.89%
Carthage	66	$ 6.0	$ 102,370	1.71%	1999	1.26%

Using $2014 Project Costs
Units Outside NYC Below 300 MW

Min	0.15%
Max	1.60%
Straight line Mean	0.86%
Median	0.77%
Weighted Ave by PILOT Payment	1.08%
Weighted Ave by Project Amount	0.65%

Using Nominal $ Project Costs
Units Outside NYC Below 300 MW

Min	0.25%
Max	2.01%
Straight line Mean	1.13%
Median	1.00%
Weighted Ave by PILOT Payment	1.36%
Weighted Ave by Project Amount	0.84%

[21] Beaver Falls and Saranac are combined heat and power or co-generation facilities and provide multiple products and benefits to the community and therefore may not be directly applicable data points to inform the PILOT payments one might expect for a peaking plant that solely produces electric power and related products for sale in the NYISO-administered wholesale market.

Appendix II

GAS Hubs Sensitivities: Net EAS Revenue Estimates for the 2017/2018 Capability Year ICAP Demand Curves

Appendix II: Gas Hub Sensitivities: Net EAS Revenue Estimates for the 2017/2018 Capability Year ICAP Demand Curves

Table 1: Annual Net EAS revenues for gas hub sensitivities.

Dual Fuel	**Annual Average Net EAS Revenues ($/kW-year)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$45.08	$80.46	-	-	-
F – Capital	$41.37	-	-	-	$37.12
G – Dutchess	$39.42	-	-	-	$38.19
G – Rockland	$39.29	-	$84.15	$114.51	$38.15
Gas Only With SCR	**Annual Average Net EAS Revenues ($/kW-year)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$41.41	$80.46	-	-	-
F – Capital	$34.50	-	-	-	$30.21
G – Dutchess	$32.80	-	-	-	$31.11
G – Rockland	$32.68	-	$78.55	$109.36	$31.08
Gas Only Without SCR	**Annual Average Net EAS Revenues ($/kW-year)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$42.31	$79.28	-	-	-
F – Capital	$34.84	-	-	-	$30.68

Table 2: Gas Hub Sensitivities: 2017/2018 ICAP Demand Curve Reference Point Prices

Dual Fuel	**Monthly Reference Price ($/kW-month)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$11.56	$7.97	-	-	-
F – Capital	$11.22	-	-	-	$11.66
G – Dutchess	$14.84	-	-	-	$14.98
G – Rockland	$15.09	-	$10.01	$6.56	$15.22
Gas Only With SCR	**Monthly Reference Price ($/kW-month)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$10.72	$6.75	-	-	-
F – Capital	$10.72	-	-	-	$11.16
G – Dutchess	$14.11	-	-	-	$14.30
G – Rockland	$14.30	-	$9.09	$5.60	$14.48
Gas Only Without SCR	**Monthly Reference Price ($/kW-month)**				
Zone	AG Final Report	Dominion North	TETCO M3	Millennium East	TGP Z6
C – Central	$9.08	$5.33	-	-	-
F – Capital	$9.08	-	-	-	$9.50

The following section includes detailed information on the net EAS results from the gas hub sensitivities conducted by the NYISO in response to stakeholder requests.

Siemens SGT6-5000F5 Dual Fuel using Dominion North for Load Zone C and TETCO M3 for Load Zone G (Rockland)

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,286	0	2,286	$106.41	$0.00	$106.41
G	Hudson Valley (Rockland)	2,973	66	3,039	$92.87	$7.08	$99.94

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	3,354	0	3,354	$69.19	$0.00	$69.19
G	Hudson Valley (Rockland)	3,362	0	3,362	$50.67	$0.00	$50.67

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,818	0	2,818	$29.91	$0.00	$29.91
G	Hudson Valley (Rockland)	3,367	0	3,367	$42.09	$0.00	$42.09

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,070	0	484	0	0	0	0	0	216	0	5,990	0	8,760
G	Hudson Valley (Rockland)	2,829	0	727	0	16	1	68	0	194	0	4,925	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	3,199	0	880	820	15	0	32	0	140	0	3,521	153	8,760
G	Hudson Valley (Rockland)	3,163	0	1,063	641	0	0	87	0	199	0	3,519	88	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,183	0	220	0	545	2	5,118	0	90	0	626	0	8,784
G	Hudson Valley (Rockland)	2,961	13	562	395	345	0	3,877	82	61	0	487	1	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$102.04	$0.00	$5.21	$0.00	$0.00	$0.00	$0.00	$0.00	$4.37	$0.00	$0.00	$0.00	$111.62
G	Hudson Valley (Rockland)	$94.72	$0.00	$21.69	$0.00	$1.09	$0.00	$0.09	$0.00	$4.13	$0.00	$0.00	$0.00	$121.73

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$67.74	$0.00	$8.19	$0.00	$0.09	$0.00	$0.01	$0.00	$1.36	$0.00	$0.00	$0.00	$77.39
G	Hudson Valley (Rockland)	$48.24	$0.00	$14.55	$0.00	$0.00	$0.00	$0.11	$0.00	$2.42	$0.00	$0.00	$0.00	$65.32

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$20.64	$0.00	$1.89	$0.00	$8.87	$0.01	$16.25	$0.00	$0.40	$0.00	$0.00	$0.00	$48.06
G	Hudson Valley (Rockland)	$36.05	$0.13	$5.76	$1.25	$5.66	$0.00	$11.61	$0.27	$0.38	$0.00	$0.00	$0.00	$61.10

Siemens SGT6-5000F5 Gas Only with SCR using Dominion North for Load Zone C and TETCO M3 for Load Zone G (Rockland)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,286	0	2,286	$106.41	$0.00	$106.41
G	Hudson Valley (Rockland)	2,978	0	2,978	$93.61	$0.00	$93.61

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	3,354	0	3,354	$69.19	$0.00	$69.19
G	Hudson Valley (Rockland)	3,361	0	3,361	$51.10	$0.00	$51.10

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,818	0	2,818	$29.91	$0.00	$29.91
G	Hudson Valley (Rockland)	3,367	0	3,367	$42.09	$0.00	$42.09

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,070	0	484	0	0	0	0	0	216	0	5,990	0	8,760
G	Hudson Valley (Rockland)	2,779	0	678	0	0	0	0	0	199	0	5,104	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	3,199	0	880	820	15	0	32	0	140	0	3,521	153	8,760
G	Hudson Valley (Rockland)	3,160	0	1,037	658	0	0	7	0	201	0	3,609	88	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,183	0	220	0	545	2	5,118	0	90	0	626	0	8,784
G	Hudson Valley (Rockland)	2,961	13	562	395	345	0	3,877	82	61	0	487	1	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$102.04	$0.00	$5.21	$0.00	$0.00	$0.00	$0.00	$0.00	$4.37	$0.00	$0.00	$0.00	$111.62
G	Hudson Valley (Rockland)	$88.84	$0.00	$12.55	$0.00	$0.00	$0.00	$0.00	$0.00	$4.77	$0.00	$0.00	$0.00	$106.16

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$67.74	$0.00	$8.19	$0.00	$0.09	$0.00	$0.01	$0.00	$1.36	$0.00	$0.00	$0.00	$77.39
G	Hudson Valley (Rockland)	$48.64	$0.00	$12.99	$0.00	$0.00	$0.00	$0.00	$0.00	$2.46	$0.00	$0.00	$0.00	$64.09

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$20.64	$0.00	$1.89	$0.00	$8.87	$0.01	$16.25	$0.00	$0.40	$0.00	$0.00	$0.00	$48.06
G	Hudson Valley (Rockland)	$36.05	$0.13	$5.76	$1.25	$5.66	$0.00	$11.61	$0.27	$0.38	$0.00	$0.00	$0.00	$61.10

Siemens SGT6-5000F5 Dual Fuel using TGP Zone 6 for Load Zone F, Load Zone G (Dutchess), and Load Zone G (Rockland)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	727	133	860	$21.31	$11.58	$32.88
G	Hudson Valley (Dutchess)	1,017	127	1,144	$23.02	$11.32	$34.34
G	Hudson Valley (Rockland)	999	127	1,126	$22.72	$11.31	$34.03

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	967	40	1,007	$14.07	$1.14	$15.20
G	Hudson Valley (Dutchess)	1,218	28	1,246	$15.34	$1.73	$17.07
G	Hudson Valley (Rockland)	1,218	28	1,246	$15.30	$1.73	$17.02

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	748	0	748	$13.85	$0.00	$13.85
G	Hudson Valley (Dutchess)	968	0	968	$16.88	$0.00	$16.88
G	Hudson Valley (Rockland)	947	0	947	$16.82	$0.00	$16.82

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	634	0	345	0	64	0	411	0	162	0	7,144	0	8,760
G	Hudson Valley (Dutchess)	911	0	276	0	67	1	455	0	166	0	6,884	0	8,760
G	Hudson Valley (Rockland)	894	0	293	0	67	1	455	0	165	0	6,885	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	759	0	295	0	12	0	221	0	236	0	7,237	0	8,760
G	Hudson Valley (Dutchess)	1,039	0	499	0	28	0	339	0	179	0	6,676	0	8,760
G	Hudson Valley (Rockland)	1,039	0	499	0	28	0	339	0	179	0	6,676	0	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	362	14	149	0	314	7	5,526	0	72	0	2,340	0	8,784
G	Hudson Valley (Dutchess)	656	13	125	0	274	2	5,422	0	38	0	2,254	0	8,784
G	Hudson Valley (Rockland)	633	13	138	0	276	2	5,430	0	38	0	2,254	0	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$21.26	$0.00	$20.93	$0.00	$5.38	$0.00	$0.35	$0.00	$6.24	$0.00	$0.00	$0.00	$54.17
G	Hudson Valley (Dutchess)	$23.54	$0.00	$16.72	$0.00	$5.26	$0.00	$0.38	$0.00	$5.53	$0.00	$0.00	$0.00	$51.45
G	Hudson Valley (Rockland)	$23.27	$0.00	$16.97	$0.00	$5.25	$0.00	$0.38	$0.00	$5.51	$0.00	$0.00	$0.00	$51.39

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$8.15	$0.00	$7.88	$0.00	$0.87	$0.00	$0.28	$0.00	$6.18	$0.00	$0.00	$0.00	$23.37
G	Hudson Valley (Dutchess)	$11.16	$0.00	$8.99	$0.00	$1.73	$0.00	$0.43	$0.00	$4.18	$0.00	$0.00	$0.00	$26.49
G	Hudson Valley (Rockland)	$11.13	$0.00	$8.99	$0.00	$1.73	$0.00	$0.43	$0.00	$4.17	$0.00	$0.00	$0.00	$26.44

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$3.42	$0.23	$1.81	$0.00	$8.84	$0.03	$13.61	$0.00	$1.58	$0.00	$0.00	$0.00	$29.52
G	Hudson Valley (Dutchess)	$7.31	$0.13	$2.36	$0.00	$8.37	$0.01	$12.98	$0.00	$1.19	$0.00	$0.00	$0.00	$32.35
G	Hudson Valley (Rockland)	$7.21	$0.13	$2.38	$0.00	$8.42	$0.01	$13.01	$0.00	$1.19	$0.00	$0.00	$0.00	$32.34

Siemens SGT6-5000F5 Gas Only with SCR using TGP Zone 6 for Load Zone F, Load Zone G (Dutchess), and Load Zone G (Rockland)

September, 2013 - August, 2014								
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	768	0	768	$25.96	$0.00	$25.96
G	Hudson Valley (Dutchess)	1,054	0	1,054	$27.09	$0.00	$27.09
G	Hudson Valley (Rockland)	1,036	0	1,036	$26.78	$0.00	$26.78

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	988	0	988	$14.58	$0.00	$14.58
G	Hudson Valley (Dutchess)	1,251	0	1,251	$16.77	$0.00	$16.77
G	Hudson Valley (Rockland)	1,251	0	1,251	$16.72	$0.00	$16.72

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
F	Capital	748	0	748	$13.85	$0.00	$13.85
G	Hudson Valley (Dutchess)	968	0	968	$16.88	$0.00	$16.88
G	Hudson Valley (Rockland)	947	0	947	$16.82	$0.00	$16.82

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	565	0	278	0	0	0	0	0	203	0	7,714	0	8,760
G	Hudson Valley (Dutchess)	851	0	209	0	0	0	0	0	203	0	7,497	0	8,760
G	Hudson Valley (Rockland)	834	0	226	0	0	0	0	0	202	0	7,498	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	746	0	244	0	0	0	3	0	242	0	7,525	0	8,760
G	Hudson Valley (Dutchess)	1,053	0	468	0	0	0	3	0	198	0	7,038	0	8,760
G	Hudson Valley (Rockland)	1,053	0	468	0	0	0	3	0	198	0	7,038	0	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	362	14	149	0	314	7	5,526	0	72	0	2,340	0	8,784
G	Hudson Valley (Dutchess)	656	13	125	0	274	2	5,422	0	38	0	2,254	0	8,784
G	Hudson Valley (Rockland)	633	13	138	0	276	2	5,430	0	38	0	2,254	0	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$15.09	$0.00	$11.45	$0.00	$0.00	$0.00	$0.00	$0.00	$10.87	$0.00	$0.00	$0.00	$37.41
G	Hudson Valley (Dutchess)	$17.49	$0.00	$5.54	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$32.63
G	Hudson Valley (Rockland)	$17.21	$0.00	$5.80	$0.00	$0.00	$0.00	$0.00	$0.00	$9.57	$0.00	$0.00	$0.00	$32.58

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$8.00	$0.00	$4.83	$0.00	$0.00	$0.00	$0.00	$0.00	$6.58	$0.00	$0.00	$0.00	$19.41
G	Hudson Valley (Dutchess)	$11.63	$0.00	$7.30	$0.00	$0.00	$0.00	$0.00	$0.00	$5.14	$0.00	$0.00	$0.00	$24.07
G	Hudson Valley (Rockland)	$11.60	$0.00	$7.30	$0.00	$0.00	$0.00	$0.00	$0.00	$5.12	$0.00	$0.00	$0.00	$24.02

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
F	Capital	$3.42	$0.23	$1.81	$0.00	$8.84	$0.03	$13.61	$0.00	$1.58	$0.00	$0.00	$0.00	$29.52
G	Hudson Valley (Dutchess)	$7.31	$0.13	$2.36	$0.00	$8.37	$0.01	$12.98	$0.00	$1.19	$0.00	$0.00	$0.00	$32.35
G	Hudson Valley (Rockland)	$7.21	$0.13	$2.38	$0.00	$8.42	$0.01	$13.01	$0.00	$1.19	$0.00	$0.00	$0.00	$32.34

Siemens SGT6-5000F5 Dual Fuel using Millennium East for Load Zone G (Rockland)

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,296	66	3,362	$108.46	$7.08	$115.53

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,351	0	3,351	$126.17	$0.00	$126.17

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,366	0	3,366	$50.87	$0.00	$50.87

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,183	0	668	44	16	1	68	0	163	0	4,602	15	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,273	0	697	2,317	0	0	1	0	78	0	2,252	142	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,129	16	496	1,505	210	0	2,892	189	27	0	298	22	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$110.99	$0.00	$19.74	$0.00	$1.09	$0.00	$0.09	$0.00	$3.45	$0.00	$0.00	$0.00	$135.37

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$125.52	$0.00	$7.93	$0.01	$0.00	$0.00	$0.00	$0.00	$0.65	$0.00	$0.00	$0.00	$134.12

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$47.30	$0.15	$4.59	$4.76	$3.45	$0.00	$8.79	$0.60	$0.12	$0.00	$0.00	$0.00	$69.75

Siemens SGT6-5000F5 Gas Only with SCR using Millennium East for Load Zone G (Rockland)

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,360	0	3,360	$109.31	$0.00	$109.31

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,351	0	3,351	$126.17	$0.00	$126.17

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
G	Hudson Valley (Rockland)	3,366	0	3,366	$50.87	$0.00	$50.87

Run Hours September, 2013 - August, 2014													
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,177	0	619	0	0	0	0	0	183	0	4,781	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,273	0	697	2,317	0	0	1	0	78	0	2,252	142	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	3,129	16	496	1,505	210	0	2,892	189	27	0	298	22	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$105.13	$0.00	$10.60	$0.00	$0.00	$0.00	$0.00	$0.00	$4.17	$0.00	$0.00	$0.00	$119.90

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$125.52	$0.00	$7.93	$0.01	$0.00	$0.00	$0.00	$0.00	$0.65	$0.00	$0.00	$0.00	$134.12

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
G	Hudson Valley (Rockland)	$47.30	$0.15	$4.59	$4.76	$3.45	$0.00	$8.79	$0.60	$0.12	$0.00	$0.00	$0.00	$69.75

Siemens SGT6-5000F5 Gas Only without SCR using Dominion North for Load Zone C

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,450	0	2,450	$108.27	$0.00	$108.27

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,460	0	2,460	$63.04	$0.00	$63.04

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,492	0	2,492	$29.19	$0.00	$29.19

Run Hours September, 2013 - August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,216	0	522	0	0	0	0	0	234	0	5,788	0	8,760

Run Hours September, 2014 - August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	2,408	0	912	1,868	2	0	32	11	50	0	3,232	245	8,760

Run Hours September, 2015 - August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,938	0	216	405	469	2	4,989	83	85	0	583	14	8,784

Net EAS Revenues September, 2013-August, 2014														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$103.84	$0.00	$5.36	$0.00	$0.00	$0.00	$0.00	$0.00	$4.44	$0.00	$0.00	$0.00	$113.63

Net EAS Revenues September, 2014-August, 2015														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$62.46	$0.00	$8.41	$0.05	$0.00	$0.00	$0.01	$0.00	$0.57	$0.00	$0.00	$0.00	$71.51

Net EAS Revenues September, 2015-August, 2016														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$20.40	$0.00	$1.87	$1.23	$8.43	$0.01	$15.83	$0.28	$0.36	$0.00	$0.00	$0.00	$48.40

Appendix III

Level of Excess Adjustment Factors

Appendix III: Level of Excess Adjustment Factors (LOE-AF)

This information was presented to stakeholders at the September 8, 2016 ICAPWG meeting.

Table 1: Level of Excess Adjustment Factors for the CARIS Phase 2 Database.

Load Zone	Month	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Capital	Off-peak	1.033	1.024	1.011	1.004	1.004	1.004	1	1.007	1.006	1.011	1.013	1.005
	On-peak	1.026	1.028	1.024	1.009	0.995	0.992	0.99	0.996	0.991	0.998	1.017	1.005
	High On-peak	1.019	1.036	-	-	-	0.977	0.971	0.977	-	-	-	1.018
Central	Off-peak	0.979	0.985	0.982	0.992	0.994	1.001	0.998	1.003	1.004	1.008	0.983	0.993
	On-peak	0.97	0.985	0.975	0.992	0.988	0.987	0.985	0.993	0.988	0.995	0.99	0.994
	High On-peak	0.972	0.96	-	-	-	0.969	0.965	0.972	-	-	-	0.97
Hudson Valley	Off-peak	1.029	1.023	1.01	1.01	1.009	1.016	1.016	1.022	1.016	1.022	1.013	1.013
	On-peak	1.027	1.032	1.024	1.018	1.008	1.015	1.018	1.019	1.012	1.013	1.024	1.023
	High On-peak	1.046	1.043	-	-	-	1.03	1.033	1.043	-	-	-	1.04
New York City	Off-peak	1.03	1.019	1.01	1.01	1.017	1.025	1.031	1.029	1.022	1.026	1.013	1.014
	On-peak	1.052	1.056	1.029	1.019	1.012	1.03	1.047	1.047	1.023	1.023	1.028	1.039
	High On-peak	1.057	1.054	-	-	-	1.035	1.162	1.129	-	-	-	1.037
Long Island	Off-peak	1.042	1.022	1.01	1.005	1.017	1.017	1.033	1.024	1.023	1.026	1.028	1.014
	On-peak	1.045	1.033	1.012	1.002	1.013	1.025	1.033	1.023	1.025	1.027	1.061	1.047
	High On-peak	1.028	1.021	-	-	-	1.033	1.129	1.07	-	-	-	1.024

Table 2: Level of Excess Adjustment Factors for the CARIS Phase 2 Database with Ginna and Fitzpatrick generators included.

Load Zone	Month	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Capital	Off-peak	1.0232	1.0028	1.0095	1.0045	1.0120	1.0021	1.0121	1.0199	1.0132	1.0252	1.0141	1.0119
	On-peak	1.0266	1.0287	1.0296	1.0083	1.0089	1.0074	1.0198	1.0244	1.0226	1.0235	1.0308	1.0049
	High On-peak	1.0264	1.0410	-	-	-	0.9924	1.0018	1.0078	-	-	-	1.0285
Central	Off-peak	1.0901	1.0524	1.0280	1.0224	1.0210	1.0174	1.0205	1.0190	1.0218	1.0238	1.0432	1.0290
	On-peak	1.0498	1.0146	1.0360	1.0191	1.0149	1.0159	1.0161	1.0187	1.0175	1.0185	1.0400	1.0358
	High On-peak	1.0631	1.0310	-	-	-	1.0044	0.9969	0.9995	-	-	-	1.0340
Hudson Valley	Off-peak	1.0522	1.0268	1.0192	1.0172	1.0256	1.0222	1.0303	1.0330	1.0278	1.0336	1.0282	1.0249
	On-peak	1.0508	1.0415	1.0387	1.0290	1.0311	1.0418	1.0483	1.0420	1.0441	1.0343	1.0484	1.0360
	High On-peak	1.0727	1.0818	-	-	-	1.0684	1.0610	1.0797	-	-	-	1.0663
New York City	Off-peak	1.0540	1.0217	1.0179	1.0169	1.0296	1.0273	1.0313	1.0309	1.0231	1.0339	1.0270	1.0175
	On-peak	1.0818	1.0652	1.0419	1.0280	1.0108	1.0287	1.0489	1.0503	1.0266	1.0268	1.0409	1.0436
	High On-peak	1.0653	1.0665	-	-	-	1.0422	1.1612	1.1344	-	-	-	1.0237
Long Island	Off-peak	1.0692	1.0222	1.0163	1.0057	1.0248	1.0168	1.0310	1.0202	1.0194	1.0345	1.0163	1.0232
	On-peak	1.0716	1.0306	1.0070	1.0033	1.0153	1.0215	1.0297	1.0232	1.0174	1.0256	1.0214	1.0489
	High On-peak	1.0706	1.0235	-	-	-	1.0356	1.1300	1.0845	-	-	-	1.0522

Table 3: Net EAS Revenue Estimates for the 2017/2018 Capability Year ICAP Demand Curves Resulting from the Different LOE-AFs

Load Zone	Net EAS ($/kW-year)		
	No LOE-AF	CARIS 2	CARIS 2 Adj.
Central - Gas Only	$43.04	$41.41	$47.48
Capital - Gas Only	$32.73	$34.50	$34.74
Hudson Valley (Dutchess) - Dual	$36.87	$39.42	$40.92
Hudson Valley (Rockland) - Dual	$36.71	$39.29	$40.86
New York City	$47.19	$53.94	$55.66
Long Island	$94.63	$101.69	$102.48

Table 4: Reference Point Prices for the 2017/2018 Capability Year ICAP Demand Curves Resulting from the Different LOE-AFs

Load Zone	Reference Point Price ($/kW-month)		
	No LOE-AF	CARIS 2	CARIS 2 Adj.
Central - Gas Only	$10.56	$10.72	$10.10
Capital - Gas Only	$10.90	$10.72	$10.70
Hudson Valley (Dutchess) - Dual	$15.15	$14.86	$14.68
Hudson Valley (Rockland) - Dual	$15.37	$15.08	$14.91
New York City	$19.45	$18.61	$18.40
Long Island	$13.74	$12.72	$12.61

Appendix IV

MMU Comments to Staff Recommendations

POTOMAC ECONOMICS

MEMORANDUM

TO: Brad Jones

FROM: David Patton
Pallas LeeVanSchaick
Raghu Palavadi Naga

DATE: September 12, 2016

RE: Market Monitoring Unit Comments on Demand Curve Reset

A. Introduction

Every four years, the NYISO conducts the Demand Curve Reset ("DCR") process to ensure that the capacity demand curves are set sufficiently high to incentivize market based entry to satisfy the NYISO's resource adequacy needs. The Market Monitoring Unit ("MMU") 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.

As MMU, we are expected to provide comments on the DCR study and recommendation.[22] This memo discusses specific elements of the methodology and whether the market is likely to provide the efficient incentives for new investment.

B. Comments

We generally concurred with most of the conclusions in the DCR study. We have limited comments on specific elements of the DCR study and recommendations.

Use of Ad Hoc Adjustments in the Net Revenue Analysis

We support the decision not to make an ad hoc adjustment to the estimated E&AS net revenues to account for unusual market outcomes in January 2014 during the Polar Vortex period. While the MMU agrees that this particular month of data will tend to inflate the estimated E&AS net

[22] NYISO MST Section 30.4.6.3.1 states: "The ICAP Demand Curve periodic review schedule and procedures shall provide an opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed ICAP Demand Curves."

revenues future expectations, making an ad hoc downward adjustment for this particular issue would require a broader assessment of whether to make ad hoc adjustments for several other "one-time" issues, which would tend to offset the adjustment for the Polar Vortex. Ultimately, the NYISO revised its net revenue methodology this year to be simpler and to manage such concerns through annual formulaic adjustments based on 36 months of rolling historic data. This process should cause the effects of these anomalous market outcomes on the net revenues to be unbiased and offset over time.

Fuel Type for the Zone F Unit

We agree with the Consultants' recommendation to use a dual fuel unit for Zone F rather than the NYISO's recommendation to use a gas-only unit. Although the Consultants estimated that the net CONE would be slightly lower for a gas-only unit than for a dual fuel unit, the Consultants' identified several difficult-to-quantify advantages for the dual fuel unit that were not captured in their quantitative analysis. In addition, the Consultants' model may over-estimate the net revenue of the gas-only unit during periods with high gas prices because it assumes just a 10 percent gas premium (or discount) on intraday purchases (or sales) under all conditions, regardless of factors such as the quantity of the intraday purchase (or sale). This simplifying assumption was not very significant for the dual fuel unit because it would burn oil during such periods, but this concern is significant for the gas-only unit. Ultimately, the demand curve should be set based on the most economic type of resource, which is most likely the dual fuel unit. In addition, the use of a dual fuel unit would make the analysis less sensitive to the Consultants' assumptions about gas availability during tight gas market conditions, and it would be more consistent with recent entry decisions in Zone F.[23]

Gas Transport Charge for Zone F Unit

New entrants in Zone F are likely to interconnect on an interstate pipeline rather than to an LDC. Therefore, it would be appropriate to assume a gas transportation adder for this zone that does not include a distribution component of approximately $0.20/MMbtu. Thus, we recommend this be removed from the net revenue estimates.

Gas Hub for Zone G Unit

We disagree with the decision to use the Iroquois Zone 2 index for the demand curve unit is Zone G because this index will tend to cause under-estimates of net revenues. Generators in

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[23] It has been suggested that the fuel type of the Zone F unit may not be important if the Zone C unit is more economic than the Zone F unit. However, Zone C is not a suitable location for the demand curve unit for the rest-of-state region (i.e., Zones A-F) because significant new entry in Zone C would lead to a need to create a new capacity zone to separate Zones A-E from Zone F. The last New Capacity Zone ("NCZ") Study showed very little headroom was available on the E→F interface before it would become necessary to create a new capacity zone to separate Zone F from Zones A-E.

Zone G face a range of different gas market conditions that depend on where they interconnect. The Tetco M3 gas hub is at the low extreme, while the Iroquois Zone 2 gas hub forms an upper bound. Generators at the southwest end of the zone generally have better opportunities to obtain gas at the lower end of the spectrum, while generators at the northeast end of the zone will find gas more expensive. Neither of the two closest available trading hubs is representative of the costs a new entrant would likely face in the future, so it would be appropriate to use a blend of the two indices in this reset with a majority based on the Iroquois Zone 2 index.

It has been suggested that the Tetco M3 index would be appropriate if we assume that all new units would be built in Orange County on the border with New Jersey. However, if all new entry began to occur in the southwest portion of Zone G, it would cause transmission bottlenecks within the zone that would make the capacity ineffective for maintaining reliability of Southeast New York and it is likely that gas pipeline constraints would become more common upstream of Orange County.

C. Recommended Tariff Change for Future Demand Curve Resets

Tariff changes made earlier this year modified the pricing location for the Zone J net revenue analysis to be the Zone J LBMP (which is a weighted-average of nodes within the zone). This was a change from recent demand curve resets, which had used a relatively unconstrained node on the 345kV system in Zone J where interconnection costs and cost information was readily available. Although the tariff now requires the use of the Zone J LBMP rather than the LBMP of a representative node, it would be beneficial for the NYISO to reconsider this before the next DCR, since the zonal average price may not be representative of the locations where generators could be built.

Currently, this issue has limited significance since the average LBMPs for unconstrained portions of the 345kV system were just 1-2 percent below the average Zone J LBMP, but this inconsistency will become important if congestion becomes more prevalent in the future. For example, if the Zone J LBMP rises in the future because of intra-city congestion at locations where new generation cannot be built, the net revenues will be overstated. This will, in turn, reduce the demand curves in Zone J and undermine the incentives to build needed capacity in the zone.