Attachment III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER17-____-000**

AFFIDAVIT OF PAUL J. HIBBARD, DR. TODD SCHATZKI, AND CRAIG AUBUCHON

I. Qualifications

A. Paul Hibbard

1. My name is Paul J. Hibbard. I am a Principal at Analysis Group, Inc. (AGI), an economic, finance and strategy consulting firm headquartered in Boston, Massachusetts, where I work on energy and environmental economic, policy, and strategy consulting. My business address is 111 Huntington Avenue, 14th Floor, Boston, Massachusetts 02199.

2. I have been with AGI for twelve years since 2003. First, from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010 I served as Chairman of the Massachusetts Department of Public Utilities (DPU, or Department). While Chairman, I served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. I also served as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnection States' Planning Council.

3. I worked in energy and environmental consulting with Lexecon, Inc. from 2000 to 2003. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, State Implementation Plans and emission control programs for the electric industry, with a focus on criteria pollutants and carbon dioxide (CO_2), as well as various policy issues

related to controlling pollutants from electric power generators within the Commonwealth. From 1991 to 1998, I worked in the Electric Power Division of the DPU on the restructuring of the electric industry in Massachusetts, the setting of company rates, the quantification of environmental externalities, integrated resource planning, energy efficiency, utility compliance with state and federal emission control requirements, regional electricity market structure development, and coordination with other states on electricity and gas policy issues through the staff subcommittee of the New England Conference of Public Utility Commissioners.

4. I hold an M.S. in Energy and Resources from the University of California, Berkeley, and a B.S. in Physics from the University of Massachusetts at Amherst. My curriculum vitae is attached as Exhibit A.

B. Dr. Todd Schatzki

5. My name is Todd Schatzki. I am a Vice President at AGI, also in its Boston office.

6. I have been with AGI since 2005. I have worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, utility ratemaking and retail electricity markets. I have testified to both state and federal energy commissions on these issues. I have also provided litigation support in many cases, including alleged wholesale electricity price manipulation.

7. Prior to joining Analysis Group, I held research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis, and was an economist at both LECG, LLC, and National Economic Research Associates. I am currently the co-chair for the Northeast Energy and Commerce Association's Power Markets Committee.

8. I hold a Ph.D. in Public Policy from Harvard University, an M.C.P. from the Massachusetts Institute of Technology in Environmental Policy, and a B.A. in Physics from Wesleyan University. My curriculum vitae is attached as Exhibit B.

C. Craig Aubuchon

9. My name is Craig P. Aubuchon. I am a Manager at AGI, also in its Boston office.

10. I have been with AGI for four years, since 2012. During that period, I have worked on a wide range of environmental and energy market policy issues. My energy market work has a particular focus on wholesale markets in the Northeast. On recent engagements, I have assessed the range and sensitivity of net revenues for individual generating units under future scenarios; evaluated potential ratepayer impacts of various long-term investments in gas and electric markets in support of winter reliability programs; evaluated the reliability implications of National climate policies; and assessed tradeoffs and market performance of various alternative capacity market designs. Prior to AGI, I worked for the Federal Reserve Bank of St. Louis, where I supported research and policy considerations related to financial markets and macroeconomic policy.

11. I hold a Master's in Public Administration and a Master's in Environmental Science from Indiana University, and a B.A. in Economics from Washington University in St. Louis. My curriculum vitae is attached as Exhibit C.

II. Purpose and Summary of Affidavit

12. Section 5.14.1.2 of the New York Independent System Operator, Inc. (NYISO) Market Administration and Control Area Services Tariff (Services Tariff) requires that locational ICAP Demand Curves be established periodically through an independent review of the ICAP Demand Curve parameters by an independent consultant.[1] In order to develop the recommended ICAP Demand Curve parameters, the independent consultant develops the initial assumptions and analysis, and reviews these with the NYISO and stakeholders through a stakeholder process. This process culminates in the filing with the Federal Energy Regulatory Commission (FERC) of the ICAP Demand Curves approved by the

[1] Capitalized terms that are not specifically defined in this Affidavit shall have the meaning set forth in the filing letter to which this Affidavit is attached or, if not defined therein, the meaning set forth in the Services Tariff.

NYISO Board of Directors. This process is commonly referred to as the ICAP Demand Curve reset (DCR) process.

13. AGI was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2017/2018 Capability Year. AGI worked with Lummus Consultants International, Inc. (LCI) to complete the tariff-required periodic review process (together, AGI and LCI are referred to in this Affidavit as the Consultants).

14. On July 18, 2016, FERC approved proposed enhancements to the DCR process, including:[2]

    - *DCR Periodicity* – Changing the period between DCRs from three to four years.
    - *Net EAS Revenue Estimation* – Modifying the method for estimating net Energy and Ancillary Services (EAS) revenues of a peaking plant in a way that increases the transparency, accuracy and understandability of net EAS revenue projections.
    - *Annual Updating* – Updating ICAP Demand Curve parameters annually based on the most recent historical costs and market price information, as well as a technology-specific escalation factor based on publicly-available indices.

15. The enhancements were designed to improve the stability of DCR results and allow for the gradual evolution of ICAP Demand Curve reference point prices (RP) over the years between DCRs. This approach will add stability to market outcomes through more accurate and timely incorporation of changes in industry and market conditions into RPs.

16. The purpose of this affidavit is twofold. First we provide a summary of the Final Report completed by AGI and LCI for the DCR process (Final Report),[3] including a description of the analytic framework and stakeholder process, and our recommendations on ICAP Demand Curve parameters and related issues. The Final Report is attached hereto as Exhibit D. Second, we describe our evaluation of certain key issues, all of which are described more fully in the Final Report – namely, (1) items related to *technology and*

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

[3] Hibbard, Schatzki, Aubuchon, Llop, Berk, Richert, Frazier, and Vivenzio, *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, September 13, 2016 (hereafter, the Final Report or Consultants' Report).

capital costs (in particular, the recommendation to include selective catalytic reduction (SCR) emissions controls and dual fuel capability in all zones,[4] and the selection of property tax rates); (2) items related to the *net EAS revenues model* (in particular, the selection of pricing indices for natural gas by NYISO load zone and various calculation methods and logic tied to electricity and fuel prices applied in the model); and (3) items related to the *financial parameters* used in establishing levelized localized embedded costs for the peaking plants.

III. Overview and Summary of the Final Report

17. The creation of ICAP Demand Curves for NYCA and each Locality (i.e., the G-J Locality, Zone J (New York City, or NYC) and Zone K (Long Island, or LI)) includes five specific tasks, our assessment of which is described in detail in the Final Report and summarized below:

- *Assessment of the peaking plant technology* **–** selection of the peaking plant representing the technology with the lowest fixed and highest variable costs that is economically viable, considering how the peaking plant could be practically constructed within each location, and how a potential developer would choose amongst various design capabilities and environmental control technologies when making investment decisions given project development and operational risk, and opportunities for revenues over the economic life of the project.[5]

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[4] We recognize that the NYISO differs from our recommendations with respect to dual fuel capability. While the NYISO proposes dual fuel capability for the NYC, LI and G-J Locality ICAP Demand Curves, the NYISO proposes to maintain the gas-only peaking plant design for the NYCA ICAP Demand Curve that was accepted by FERC in the last reset.

[5] Services Tariff, Section 5.14.1.2. In 2011, FERC found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 37 (2011)). In the last DCR, which resulted in the establishment of ICAP Demand Curves for the 2014/15, 2015/16, and 2016/17 Capability Years (2013 DCR), FERC found that "[a]n economically viable technology must be physically able to supply capacity to the market, but other than this requirement … economic viability determinations are a 'matter of judgment.'" (*See New York Independent System Operator, Inc*., 146 FERC ¶ 61,043 at P 60 (2014)). As noted in the accompanying *Affidavit of Thomas A. Vivenzio and Dr. William F. Frazier* (LCI Affidavit), we have applied the following criteria in this DCR to inform our decisions regarding the appropriate peaking unit technology and associated plant design: (i) whether the technology is generally available to most market participants; (ii) whether the technology has sufficient operating experience to demonstrate that it is proven; (iii) whether the technology is capable of being cycled to provide peaking service; and (iv) whether the technology

- *Estimation of the gross cost of new entry* – the gross cost of new entry (CONE) is the fixed annual costs of the peaking plant, including the recovery of and return on upfront capital costs, taxes, insurance and fixed operations and maintenance (O&M), resulting in a levelized fixed charge calculated to ensure recovery of capital costs and taxes given financial parameters that reflect the specific risks associated with merchant plant development in the NYISO markets.

- *Estimation of net EAS revenues for the peaking plant technology* – expected EAS revenues for the peaking plants, net of operating costs, are estimated using a model we constructed for this purpose. The model includes an adjustment of historic locational based marginal prices (LBMPs) and reserve prices to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[6]

- *Determination of a reference point price and ICAP Demand Curve in NYCA and each Locality* – combining gross CONE estimates and expected net EAS revenues to calculate the RP for the ICAP Demand Curves for NYCA and each Locality, and establishing the shape and slope of the ICAP Demand Curves in consideration of the zero-crossing points (ZCP) and the winter-to-summer ratio (WSR).[7]

- *Annual updating* – consistent with the DCR process enhancements approved by FERC in July 2016, the ICAP Demand Curve parameters are to be updated annually based on escalation of installed capital costs, recalculation of net EAS revenues using updated electricity price and fuel/emission cost data, and updated WSR values.

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is capable of complying with applicable environmental requirements. These factors are consistent with the technology screening criteria used in the 2013 DCR.

[6] *See* Services Tariff, Section 5.14.1.2. The Services Tariff requires that net EAS revenues be estimated for the peaking plant technology under system conditions that reflect the applicable minimum Installed Capacity requirement (ICR) plus the capacity of the peaking plant, which we define as the LOE. The derivation of LOE adjustment factors (LOE-AF) and how LBMPs and reserve prices are adjusted to reflect LOE conditions are described in detail in Section III of the Final Report.

[7] The NYISO operates its capacity market in two separate, six-month Capability Periods. This construct recognizes the differences in the amount of capacity available over the course of each year and the impact of these differences on revenues throughout the year. The WSR is used to account for the differences in capacity available. The WSR is discussed in detail in Section IV of the Final Report.

18. The steps described above involve a complex mix of historical data, forecasts, and modeling techniques geared towards developing an accurate representation of New York's electricity market structures and dynamics. It involves extensive review of relevant data and analytic methods, and requires a selection of methods, models and data from among a range of alternatives based on the application of decision criteria and professional judgment.

19. The Final Report, and the analyses and conclusions contained therein, were developed by AGI and LCI in an open and transparent process in consultation with the NYISO and stakeholders over an eleven-month period, beginning in October 2015 and ending with the issuance of the Final Report in September 2016. Throughout, we developed quantitative and qualitative analyses, proposed and final recommendations on every DCR issue, and presented and discussed these issues with stakeholders across numerous stakeholder meetings.[8] Specifically, over the course of eleven months we (1) established guiding principles for evaluating DCR alternatives, (2) evaluated approaches taken in capacity markets in other relevant ISO/RTO jurisdictions, (3) identified options for potential enhancements of the DCR process, (4) highlighted key issues related to technology costs, net EAS modeling, financial parameters, and ICAP Demand Curve RP calculations, and (5) presented analyses on and discussed potential benefits and drawbacks of each issue considered. Our final analyses and recommendations, as comprehensively documented in the Final Report, were greatly aided and improved by the full scope of comments and opinions heard throughout the stakeholder process.

20. In the end, however, the conclusions and recommendations in the Final Report represent our independent views, consistent with our assignment, the requirements of the Services Tariff and the structures and rules of the New York markets. The process of establishing ICAP Demand Curve parameters required analysis of a wide array of quantitative market, financial, and economic data and factors, as well as the application of reasoned judgment where the empirical evaluation is limited by sparse, uncertain, and variable historical data

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[8] *See* Consultants' Report at 4. Table 1 of the Final Report identifies the meetings held as well as the topics discussed in each meeting.

or forecast assumptions. The viewpoints of NYISO and stakeholders were important inputs to the analyses, but, in the end, our final recommendations reflect a combination of factors, including these viewpoints, our empirical evaluation, and our knowledge and judgment. The analyses were conducted with a set of objectives and criteria which were developed to help guide the analysis and provide a framework for the evaluation of process and analytic alternatives.

21. Specifically, we evaluated potential DCR issues applying, where relevant, the following objectives and criteria:

- *Economic Principles* – recommendations on DCR issues should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO-administered markets.
- *Accuracy* – ICAP Demand Curve parameters should, with as much certainty as feasible, reflect the actual net cost of new entry (net CONE) in New York.
- *Transparency* – The calculations to determine net CONE should be clear and transparent to Market Participants (MPs), understandable, and allow MPs to develop market expectations.
- *Feasibility* – The DCR process should be practical and feasible from regulatory and administrative perspectives, considering the administrative burden on both the NYISO and MPs.
- *Historical Precedent and Performance* – The resolution of DCR issues should, as much as possible, be informed by quantitative analysis based on historical data, and draw from lessons learned in the neighboring markets with experience in administration of capacity markets (ISO New England, Inc. (ISO-NE) and PJM Interconnection, L.L.C. (PJM)). Consistency between DCRs also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

22. We applied the methods, models and equations summarized herein and described in detail in the Final Report to identify the RPs and other ICAP Demand Curve parameters for

NYCA and Localities for the Capability Year 2017/2018. These values are presented in the Final Report.[9]

23. These results reflect a number of conclusions on key market and technology issues that we comprehensively evaluated throughout the DCR process including:

- The Siemens SGT6-5000F5 (F Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, the F Class Frame machine would be built with SCR emissions control technology across all locations.

- Based on market expectations for fuel availability and fuel assurance, changes in market structures, and developer expectations going forward, the F Class Frame machine would more often than not be built with dual fuel capability in all locations.

- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55 percent debt and 45 percent equity; a 7.75 percent cost of debt; and a 13.4 percent return on equity, for a WACC of 10.3 percent. Based on current tax rates, this translates to a nominal after tax WACC (ATWACC) of 8.60 percent for locations outside New York City and 8.36 percent for New York City.

- Net EAS revenues should be estimated for the peaking plant technologies using gas prices consistent with and reflective of the LBMPs used within each Load Zone for the purposes of estimating revenue streams over the plant's economic life. The choice of gas price indices should also reflect, in part, reasonable expectations for a long-term equilibrium in delivered natural gas prices that would be available to a hypothetical new peaking plant. To that end, net EAS revenues have been, and should be, estimated using the following gas price indices for this reset period: TETCO M3 for Load Zone C; Iroquois Zone 2 for Load Zones F and G; and Transco Zone 6 for Load Zones J and K.

[9] Consultants' Report at 95-98.

- RPs should be established at the tariff prescribed LOE conditions and account for seasonal differences in system capacity. To promote transparency and allow for model updates, RPs should be calculated using a standardized formula, which is defined and described in the Final Report.

- ICAP Demand Curves should maintain the current ZCP ratios (ZCPR). The ZCPR, along with the RP, defines the shape and slope of the ICAP Demand Curves. ZCPR should remain 112 percent (NYCA), 115 percent (G-J Locality), and 118 percent (NYC and LI).

24. The Final Report contains an organized and detailed presentation on these and other issues and conclusions. Section II of the Final Report contains our assessment of the peaking plant technology. Section III of the Final Report contains our estimation of gross CONE. Section IV of the Final Report contains our method for estimating the net EAS revenues of the peaking plants. Section V of the Final Report contains our method for determining the ICAP Demand Curve parameters, including RPs. Finally, Section VI of the Final Report describes the process by which ICAP Demand Curve parameters will be updated annually for the upcoming Capability Year.

25. In the remainder of this affidavit, we provide further explanation of our review and conclusions on certain key items. Specifically, in Section IV, we discuss issues related to technology and capital costs. In Section V, we discuss the method for and issues related to calculation of net EAS revenues. Finally, in Section VI, we discuss items related to the financial parameters used in establishing levelized localized embedded costs for the peaking plants.

IV. Technology Costs

26. The Services Tariff specifies that the DCR shall assess "…the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State …." In the Final Report, we evaluate a number of factors that go into the calculation of gross CONE for each peaking plant. The LCI Affidavit discusses a number of the technology and cost factors related to the identified peaking plants, including their assessment related to the need and costs of SCR emissions control technology. In this section, we supplement LCI's

discussion with an explanation of our findings on dual fuel capability and the assessment of property taxes in the calculation of gross CONE.

27. While our study reflects generic sites within each Load Zone, we did develop separate estimates for both Rockland County (West of the Hudson River) and Dutchess County (East of the Hudson River) for Load Zone G. This is consistent with the 2013 DCR, and the use of these two locations provides for a consideration of differences in environmental requirements that apply throughout Load Zone G. In addition, in response to stakeholder comments, LCI reviewed construction labor costs for Orange County, which is also West of the Hudson River in Load Zone G. LCI determined that there was not a materially significant difference between such costs in Orange County in comparison to Rockland County. Therefore, the continued use of Rockland County as a potential alternative location within Load Zone G is appropriate and reasonable.

A. Dual Fuel Capability

28. The recommended technology choice requires determining for each location whether the peaking plant should be a natural gas-only resource or have the capability to operate on both natural gas and oil (dual fuel). In the 2013 DCR, FERC approved peaking plants with dual fuel capability in the G-J Locality, New York City (i.e., Load Zone J) and Long Island (i.e., Load Zone K) and a gas-only peaking plant design for the NYCA ICAP Demand Curve. FERC's approval of dual fuel capability for the G-J Locality recognized that a peaking plant developer would recognize certain siting benefits associated with selecting dual fuel capability, and would find dual fuel capability more economic than the alternative way of achieving the same level of fuel assurance (e.g., entering into an obligation for firm interstate pipeline transportation capacity).[10]

29. In this DCR, we evaluated whether to recommend including dual fuel capability in Load Zones J and K only; in the G-J Locality, Load Zone J, and Load Zone K as in the last reset; or in all locations. As with many of the technology choices considered, we evaluated potential recommendations through a review of relevant data and considerations tied to

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

what developers are most likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

30. In contrast to the 2013 DCR, we recommend that the peaking plant technology in all locations should include dual fuel capability. This recommendation reflects a number of tradeoffs a developer would consider when deciding whether or not to include dual fuel capability in a development project in New York state and whether, on balance, a developer would *more likely than not* decide to include dual fuel capability based on such considerations. Specifically, the following observations inform our conclusion:

- Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are modest increases in capital costs associated with the installation of dual fuel capability, and in annual costs tied to maintaining dual fuel systems, testing dual fuel capability, and carrying an inventory of fuel for dual fuel operations. On the other hand, these modest increases in cost could be outweighed, perhaps significantly, by the value associated with potential increases in net EAS revenues from operating on oil when the price for fuel oil is less than that of natural gas.

- Potential peaking plant developers would also consider various risks and benefits associated with project development and siting. Specifically, 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 interconnections.

- Finally, a developer would likely view the addition of dual fuel capability favorably in light of reasonable expectations of net changes in New York State's reliance on natural gas in the coming years, due to increased demand from known new entry (e.g., CPV Valley Energy Center) and replacement of potential retirements.

B. Property Taxes and Insurance

31. Our assessment of the total gross CONE includes both property taxes and insurance. These costs both vary with the total cost of the plant and are expressed as a percentage of total capital cost expressed above.

32. With respect to insurance, we include additional costs equal to 0.6 percent of the installed capital costs. This value does not vary by location. This value is based on LCI's professional experience and review of similar projects. It is also consistent with the 2013 DCR.

33. In contrast, property taxes can be based on the effective tax rate (including an assessment ratio) and the market value of the plant, or be negotiated as a Payment in Lieu of Taxes (PILOT) agreement, with a series of annual payments made for an agreed upon period of time. Therefore, property taxes are expected to vary based on project specific and regional economic conditions, the unique circumstances of each county, and period in which tax rates are set or PILOT agreements are negotiated. In New York City, we assume that the peaking plant will receive the applicable property tax exemption, and will only incur taxes for years 16 and beyond. After the exemption period, the property tax rate equals 4.8 percent, which is equal to the product of (1) the Class 4 Property rate (10.4 percent) and (2) the 45 percent assessment ratio. Because tax payments vary over the life of the unit, we include these costs in our levelized fixed charge.

34. Outside of New York City, we assume that the peaking plant will enter into a PILOT agreement, which will be effective for the full twenty year amortization period. To assess the range of potential PILOT rates, we collected tax data for eleven natural gas power plants. Publicly available information on annual PILOT payments is available through the Office of the New York State Comptroller.[11] These projects include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large combined cycle units. Based on reported capital costs provided with the Comptroller data, the effective PILOT tax rate in our sample ranged from 0.2 percent to

[11] *See* http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm

2.01 percent. The median value of these rates was 0.83 percent and rates have generally increased over time.

35. Based on our analysis and professional judgement, we recommend an effective PILOT rate for the peaking plant of 0.75 percent. This recommendation is consistent with the 0.83 median value from the sample of PILOTs we reviewed. We also found that tax rates for smaller plants, such as the peaking plants evaluated in our study, were among the higher values in our sample. This value is the same as the value used in the 2013 DCR.

V. Net EAS Revenues Model

36. Net EAS revenues are estimated based on the rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and data on the non-fuel variable costs and operational characteristics of the peaking plant technology. Our approach assumes that average annual net revenues earned over the prior three years provide a reasonable estimate of forward-looking expectations, particularly in light of the annual updating mechanism, which ensures that ICAP Demand Curve parameters evolve (with a lag) consistent with actual EAS market outcomes.

37. Throughout the stakeholder process, we solicited feedback on both the model logic used to estimate net EAS revenues and the choice of gas hubs used to price fuel inputs. In this section, we first discuss the net EAS revenues model logic. We then discuss our choice and selection of the relevant natural gas hub pricing locations.

1. Net EAS revenues model logic

38. Our simulated net EAS revenues model estimates the net EAS revenues earned by the peaking plant on an hourly basis assuming dispatch of the plant and market offers set at the opportunity cost of producing energy or providing reserves. In the model, the peaking plant can earn revenues through supplying in one of four markets, based on its technical capabilities: (1) day-ahead market (DAM) commitment for Energy, (2) DAM commitment for either ten- or thirty- minute reserves, (3) real-time market (RTM) dispatch for Energy, or (4) RTM provision for reserves. When applicable, dual-fuel capability is accounted for

through the option to generate using natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

39. In addition, a unit maintains the ability to buy out of either DAM Energy or reserves commitments, based on real-time prices and whether or not a change in operating status is sufficiently profitable, after accounting for real-time fuel costs. Real-time fuel costs reflect a premium for purchases and discount for sales relative to day-ahead gas prices, which vary by Load Zone. These intraday premiums/discounts reflect potential operating or other opportunity costs to securing (or not using) fuel in real-time, which may be incurred due to balancing charges with an LDC, illiquidity in the market during periods of tight gas supply, or imperfect information on the part of either the buyer or seller. This additional cost is incorporated into RTM buy out decisions for all units.

40. Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-spinning reserve markets at their opportunity cost of holding or obtaining adequate fuel supplies. Here, the opportunity cost reflects the real time intraday premium when buying or discount when selling natural gas. Dual fuel units do not face an opportunity cost to provide reserves when ULSD costs are lower than natural gas costs.

41. The net EAS revenues model uses historical LBMPs, which reflect actual system conditions, including levels of historical surplus capacity. To address the Services Tariff requirement that RPs reflect system conditions at the minimum installed capacity requirement (plus the capacity of the peaking unit), and consistent with the 2013 DCR, we developed a set of LOE adjustment factors (LOE-AF) that modify the historical LBMPs and reserve prices used in the net EAS revenue calculations to approximate prices under LOE conditions. Specifically, we developed adjustment factors for each month and capacity zone, with unique factors for on-peak hours, high on-peak hours (defined as a subset of on-peak hours, for both summer and winter periods), and off-peak hours.

42. We developed these LOE-AF by comparing forecasted hourly energy prices at current conditions and at the tariff-prescribed LOE conditions. Hourly prices for each of these two modeling cases were developed using the NYISO 2016 Congestion Assessment Resource

Integration Study (CARIS) Phase 2 base case dataset. The tariff-prescribed LOE conditions were estimated by adjusting system loads in each Load Zone so that the resulting ratio of peak load to available resources equaled the reserve margin consistent with the required LOE conditions. Loads were scaled in a nested fashion, with sub-zones scaled first, before moving to the full NYCA region (i.e., final adjustments to achieve the tariff-prescribed LOE conditions for NYCA are achieved by scaling load in Load Zones A-F after accounting for the load adjustments already made in the other sub-zone areas). LOE-AF values were developed as the ratio of average LBMPs in the base case (i.e., current system conditions) to average LBMPs in the LOE conditions case for each Load Zone. LBMPs were first averaged within each month and period across all of the modeled years 2017 to 2021. The resulting average LOE-AF values across all months and periods ranged from 0.99 in Load Zone C to 1.04 in Load Zone J. Pursuant to the Services Tariff, the set of LOE-AF values, calculated at the time of the DCR, will remain set for the duration of the reset period, and will be applied to historical LBMPs and reserve prices used in each subsequent Capability Year's net EAS revenues calculation as part of the annual updates during the reset period.

43. Finally, hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, with the applicable and relevant amortization schedule for each unit based on its startup time and consideration of whether the unit is committed/dispatched in the DAM or RTM. Total annual net EAS revenues are the sum of all hourly revenues. However, on an annual basis, units are constrained by applicable environmental run time limitations for New Source Performance Standards (NSPS) based on the applicable three year rolling average capacity factor for each unit. Finally, total net EAS revenues include an incremental adder of $1.43/kW-year, which is based on historical data provided by NYISO and included to account for voltage support service (VSS) revenues that are not accounted for in the model.

44. The net EAS revenues model logic is designed to provide an appropriate balance with respect to our evaluation criteria, and in particular, to provide an accurate and transparent model, which can reasonably and feasibly be updated by any interested stakeholders on an annual basis. In practice, however, an individual unit's historical and actual net EAS

revenues may differ from the modeled revenues of the hypothetical peaking plant considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to unit-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical peaking plant.

45. For example, one issue in model development is the choice of NYISO LBMPs used in the model for RTM commitment and dispatch. One option was to use prices for both Real-Time Commitment ("RTC") and RTD (i.e., using RTC prices for RTM commitment and RTD for determining real-time net EAS revenues in a manner similar to the NYISO's Real-Time Market). Our review of RTC and RTD prices for the historic period indicated that these prices were not sufficiently different, and that RTC prices were both higher and lower than the observed RTD prices, depending on the interval. Integrating staggered 15-minute RTC and 5-minute RTD would also add significant complexity to the model structure. Therefore, we relied only on hourly integrated RTD prices when estimating net EAS revenues for the hypothetical peaking plant.

46. A second issue in model development relates to how we capture differences between day-ahead and day-of (or intraday) natural gas prices. The model assumes an annual average premium (when purchasing fuel real-time) and discount (when selling fuel real-time) of 10 percent for Load Zones C, F and G, 20 percent for Load Zone J, and 30 percent for Load Zone K. These parameters are sourced from the Market Monitoring Unit (MMU), and used in the MMU's estimation of net EAS revenues as part of their State of the Market reports. These values are based, in part, on the MMU's consideration of confidential market data and their professional judgement with respect to what represent reasonable average factors.

2. Net EAS revenues model natural gas pricing locations

47. The second key consideration with respect to the net EAS revenues model is the choice of natural gas pricing points (gas hubs) for each location. Despite the existence of numerous pricing hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a peaking plant in a given Load Zone. Individual gas indices reflect a number of factors, including existing and future contracts from LDCs and merchant generators, wholesale gas market conditions, and expectations about

potential supply expansions (or lack thereof). Therefore, we developed our recommendations for the appropriate gas hub pricing points for each location based on a consideration of multiple factors, including market dynamics, gas hub liquidity, geography, and precedent and continuity for the use of similar hubs in other NYISO studies (e.g., CARIS) and assessments, including assessments by the MMU.

48. An important factor in our identification of an appropriate gas index was the historical relationship between gas prices and LBMPs. In some cases, it is apparent from comparison of gas indices and zonal LBMPs, that during certain periods (particularly winter months) zonal LBMPs did not reflect marginal supply from facilities relying on fuel prices at certain gas price indices nearby to that Load Zone. To the extent that a peaking plant could receive delivery of gas at these prices during these period, these price differentials suggest a profitable opportunity for short-term arbitrage between natural gas and electricity markets. However, these arbitrage opportunities likely do not reflect a long-run equilibrium given the potential that increasing demands over time on these gas delivery lines and other factors will likely tend to bring these markets into equilibrium. In addition, because gas indices capture pricing over broad geographic areas, indices may not capture variation in pricing within these zones, particularly in more constrained areas.

49. For Load Zones J and K, Transco Zn 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to these zones and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets.

50. For upstate zones, including Load Zones C, F and G, the natural gas indices associated with certain pipelines in close proximity to these zones do not currently reflect a reasonable expectation of the long-run equilibrium between gas and electricity markets. For example, in Load Zone C, the Dominion and Millennium pipelines cross portions of the zone, but the implied pricing from these indices does not capture any of the observed spikes in electricity markets during winter months. In light of these factors, and consistent with both the gas hub assumptions for the 2013 DCR and the NYISO 2015 CARIS Phase 1 study, we recommend the use of TETCO M3 as the natural gas index for Load Zone C.

51. Similarly, our recommendation for Load Zone F reflects a balance of considerations, including an assessment of a reasonable expectation of the long-run equilibrium between gas and electricity markets. We also considered the potential for the natural gas index to be influenced by market activities outside of the NYISO market that would not be expected to affect delivered gas prices within the NYISO market. In particular, TGP Z6, which was used in the 2015 CARIS Phase 1 study and the 2013 DCR for Load Zone F, is potentially influenced by supply conditions in ISO-NE (including liquefied natural gas supplies), although it is likely that such supply conditions would not affect pricing in the NYCA. While there are currently limited differences between these indices over the past three years, differences could emerge in the future, which would affect annual updates. Consequently, we recommend the use of Iroquois Zone 2 for Load Zone F.

52. For Load Zone G, we recommend the use of the Iroquois Zone 2 pricing hub. This recommendation reflects the same balance of considerations as discussed for other Load Zones. In addition to Iroquois Zone 2, we also considered TGP Z6, TETCO M3 and Millennium for Load Zone G. Consistent with other zones, we found that the implied pricing from the Millennium index does not capture the observed spikes in Load Zone G during winter months. In contrast, the TETCO M3 hub, which was used in the 2013 DCR for the Rockland County location in Load Zone G, does partially capture market dynamics in Load Zone G. However, it has not been included in recent NYISO planning studies, such as the 2015 CARIS Phase I study. Instead, we recommend Iroquois Zone 2, which more fully reflects market dynamics and is consistent with gas hubs used in more recent NYISO studies.

53. While the 2013 DCR used separate gas hubs for both Rockland and Dutchess Counties in Load Zone G, our review of TETCO M3 suggested this distinction was not necessary for the current DCR. Other studies that provide a historical snapshot of net EAS revenues do consider a blended gas price for Load Zone G, where a blended price could reflect a combination from the Millennium gas hub west of the Hudson and Iroquois Zone 2 east of the Hudson. However, we believe the use of a blended gas index may be particularly challenging within the current annual update process. For example, it is unclear how a model rule could be developed for the respective weight of each index, and if that weight

should change over time. In addition, it is unclear how to consider new gas hubs and price indices such as Millennium, which has relatively few years of available data and market liquidity, with other pricing hubs that have a robust history of trades going back several DCRs and have been relied upon by the NYISO and stakeholders across multiple studies. Therefore, we recommend a single gas hub (Iroquois Zone 2) for all of Load Zone G.

VI. Financial Parameters

54. The development of a new generation facility requires the upfront capital investment costs for the construction of the facility. We developed financial parameters to translate these upfront technology and development costs into an annualized value that is an element of gross CONE for each Load Zone. The parameters used in this translation include:

1. The *weighted average cost of capital* required by the developer, based on the developer's required return on equity (ROE), its cost of debt (COD), and the project's capital structure as reflected in the ratio of debt to equity (D/E ratio);
2. The term, in years, over which the project is assumed to recover its upfront investment, referred to the *amortization period* (AP); and
3. Applicable *tax rates*, which affect the costs of different types of capital.

55. We developed these parameters in parallel, considering the interrelationships among them, to appropriately reflect the financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market context. Many factors can affect investor risks – such as uncertainty and variability in fuel prices and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; the development of energy and environmental policies with implications for industry demand, costs, and revenues; and the pace and nature of technological change. Our selection also reflects available data on individual components of the WACC and the AP, recognizing that these factors can vary with features specific to circumstances, including location, corporate structure, prevailing economic/financial conditions, fuel and electricity market expectations, financial hedges (such as power purchase agreements), and the nature and impact of current and potential future market and regulatory factors.

56. Ultimately, the recommended WACC and AP reflect our view of the risks associated with the merchant development of a peaking plant in the NYISO market context, and the return

required by investors to compensate for those risks. Our recommendations are based on our professional judgment, reflecting the particular circumstances of merchant development of a peaking plant in the NYISO market context; the many sources of information identified and described below; past professional experience, including conversations with developers and the finance community; and our view of current industry conditions and market factors, including past experience with merchant development in the NYISO markets.

1. Amortization Period

57. The AP is the term over which the project developer expects to recover upfront capital costs, including the return on investment. This period is the project's "economic life," which can differ from the potential physical life of the unit, due to financial considerations, particularly risks associated with assuming revenues streams far into the future. The AP reflects a balance of factors. On the one hand, plant owners will earn net revenues over the full physical life of the unit, which is reasonably estimated as thirty years for a peaking plant. On the other hand, many factors create risks to future cash flows, including changes in markets, technologies, regulations, policies, and underlying demand from consumers. To account for these risks, investors typically assume an economic life less than the plant's physical life. Notably, units may require significant capital expenditures to retrofit or upgrade to maintain the units in operation. Consistent with our assumption for a shorter economic life than physical life, our analysis does not consider these incremental investments in the discounted cash flow analysis.

58. Given these factors, we recommend an AP of 20 years for all technologies and Load Zones. This is an appropriate assumption given the balance of considerations between a shorter and longer period. This assumption is also consistent with the 2013 DCR and the ISO-NE and PJM capacity market demand curves, which have used or currently use a twenty year AP. Our recommendation is also consistent with assumptions used in independent studies by the California Energy Commission and the National Energy Technology Laboratory that evaluate the cost of new plant development by independent power producers (IPPs).[12]

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[12] California Energy Commission, "Comparative Costs of California Central Station Electricity Generation," CEC 200-2009-07SF, January 2010, Table 19 (hereinafter, CEC 2010 Study); National Energy Technology Laboratory,

2. Weighted Average Cost of Capital

59. The WACC for use in the DCR will reflect the project-specific risks associated with the development of a new peaking plant by a merchant developer within New York. The WACC, reflecting both the "cost" of different sources of capital – that is, the required return on equity and the cost of debt – and the proportion of each type of capital in the project's capital structure, are developed in tandem because of the interrelationship between these elements.

60. We developed our recommended cost of capital based on data from a number of different sources, including: (i) financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets, including cost of debt, return on equity and debt-to-equity ratios; and (ii) independent assessments developed by financial analysts, including so-called "fairness opinions" and assessments of the costs of merchant plant development, including assessments of plants financed through a so-called "project finance" approach. Our recommendations also reflect: (i) the information and data identified below; (ii) our professional experience, including conversations with developers and other professionals in the finance community; and (iii) an appropriate balancing of these various sources of information and experiences considering the market risks that would be faced by a new merchant peaking plant being developed within the NYISO markets.

61. When developing our recommended financial parameters, we view the appropriate WACC for the peaking plant as bounded from below by the company-wide WACCs typical of established IPPs, and from above by the WACCs that are more representative of project-financed developments. On the one hand, the appropriate cost of capital for a specific project should reflect the particular risks faced by that project. This project-specific risk is typically greater than the risks associated with the company or investors that are considering the development of that project because these companies tend to have

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"Investment Decisions for Baseload Power Plants," 402/012910, January 29, 2010, p. II-8 (hereinafter, NETL 2010 Study).

portfolios of assets that balance and mitigate risks. These portfolios include various financial assets, including financial hedges and long-term contracts, as well as portfolios of physical assets spanning varied geographies (including regions with different load profiles), technologies, fuels and vintages. On the other hand, we assume that the project would not be developed through a stand-alone project finance approach.

62. Below, we describe information used in developing the individual financial parameters that bear on the recommended WACC, recognizing the interrelationships among these parameters in determining the WACC.

a) Cost of Debt

63. The cost of debt reflects a project developer's ability to raise funds on debt markets. Our research found that debt costs for relevant publicly-traded IPPs since 2013 have ranged from approximately 5 percent to 8 percent. At present, all publicly-traded IPPs have below-investment grade credit ratings, with generic debt costs for B rated firms nearing 8 percent in recent months. Based on these factors, we recommend a COD of 7.75 percent. This reflects a value toward the upper end of the reported range, which is consistent with the somewhat greater risk posed by a single peaking plant, in comparison to an IPP company.

b) Return on Equity

64. Our recommended ROE is developed using data from several sources, including estimates for the return on equity for publicly traded IPPs and other independent studies. Our analysis of the return on equity for five IPP companies based on the capital asset pricing model (CAPM) found ROEs ranging from 10.0 to 12.5 percent, with an average of 11.1 percent (using Value Line betas) and 9.2 to 12.3 percent, with an average of 10.5 percent (using Bloomberg betas). Independent studies by the California Energy Commission (CEC) and the National Energy Technology Laboratory (NETL) assumed a return on equity for new combustion turbines developed by IPPs of 15.5 percent (NETL) and 14.47 percent (CEC, in its "average case").[13] While information on return on equity for project

[13] CEC 2010 Study, p. 59, Table 18; NETL 2010 Study, p III-15, Exhibit 3-1.

finance is more limited, we note that past studies find return on equity values that range from approximately fifteen to twenty percent.[14]

65. Based on this information, we recommend a ROE of 13.4 percent, reflecting a balance between the lower IPP values (which range up to 12.5 percent) and higher project finance values.

c) Debt to Equity Ratio

66. The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of the capital supporting the investment. Thus, a merchant peaking plant technology could reasonably be developed through a range of capital structures. We recommend a D/E ratio of 55 percent debt to 45 percent equity given a balance of tradeoffs involved with greater or lesser leverage. Our analysis found that the capital structure of IPP companies (at the corporate, not the project level) are high compared to historical levels, although current *corporate* level capital structure may not be particularly informative of the appropriate *project-level* capital structure for a new development going forward.[15] Moreover, the limited fixed revenues streams for a merchant peaking plant in NYISO may limit debt levels well below amounts observed at the company level, at present. Consistent with this view, independent sources find much lower levels of debt for merchant generation developments and combustion turbine projects similar to the peaking plant (e.g., CEC assumes a D/E ratio of 40/60 for merchant fossil

[14] *See, e.g.*, EPA Integrated Planning Model, Chapter 8 Financial Assumptions, which reports a 16.1 percent ROE at a 55 percent debt ratio and 3.8 percent risk free rate; DOE National Energy Technology Laboratory (NETL) (2008), which indicates that a 15 to 20 percent ROE is common for low and high risk power projects at debt ratios of 50 to 70 percent (DOE-NETL, "Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects", September 2008.); and Etsy (2003), which notes that Calpine typically sought an 18-22 percent as a project finance developer circa 2002, with a debt ratio of 65 percent. (Etsy, B. and Kane, M. "Calpine Corporate: The Evolution from Project to Corporate Finance." Harvard Business School, Case Study 9-201-098.)

[15] Note that a desire by these companies to deleverage (i.e., lower debt share), which has been expressed by the companies themselves and analysts, may place pressure to lower debt levels of individual projects. *See*, e.g., UBS Financial ("We believe all IPPs will accelerate their debt paydown efforts…") (How to Value Power? December 8, 2015.)

generation, while NETL assumes a D/E ratio of 30/70 for IPP combustion turbines).[16] Thus, given this balance of considerations, our selection of a 55/45 D/E equity ratio appears conservative (i.e., tending to produce a lower WACC than if a more leveraged capital structure were assumed).

d) WACC

67. Our assessment of factors related to the calculation of the WACC has considered: (i) the data on return on equity, cost of debt and debt-to-equity ratio described above; (ii) facts and circumstances unique to NYISO markets, including the extent of past experience with merchant development; (iii) the rapidly changing nature of federal and state energy and environmental policies; and (iv) likely project/ownership structures for new peaking plant development in the State.

68. The resulting WACC consistent with the recommended values for return on equity, cost of debt and debt-to-equity ratio is 10.3 percent.

69. The calculation of an after-tax WACC reflects common tax treatments and appropriate tax rates for applicable taxes, including Federal income taxes (assumed to be 35 percent), corporate New York State taxes (7.1 percent),[17] and the New York City business corporation taxes (8.85 percent).[18] These result in composite income tax rates of 45.37 percent (NYC) and 39.62 percent (all other locations). Using these values, the nominal ATWACC is 8.60 percent in NYCA, LI, and the G-J Locality and 8.36 percent in NYC.

70. The recommended ATWACC is consistent with previous and currently approved capital cost values in NYISO and other RTOs (e.g., ISO-NE and PJM). The current ATWACC in ISO-NE and PJM is 8 percent, while the current ATWACC for the NYISO as approved during the 2013 DCR, is 8.4 percent. The slightly higher ATWACC recommended for this DCR reflects a combination of factors. Relative to the other ISOs/RTOs, developers within the NYISO region may face greater project-specific risk that arise from the lack of long-

[16] CEC 2010 Study, p. 59, Table 18; NETL 2010 Study, p III-18, Exhibit 3-2.

[17] *See* New York Department of Taxation and Finance, Form CT-3/4-I.

[18] *See* http://www1.nyc.gov/site/finance/taxes/business-business-corporation-tax.page.

term contracts, greater uncertainty over the mix of supply and demand resources that will result from changes in regional markets and energy policies over time, expectations for relatively flat load growth, and potentially more challenging siting and development opportunities within New York. Relative to the 2013 DCR, the higher ATWACC reflects the full combination of changes in balance sheets (through greater use of debt), higher debt costs, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments.

VII. Conclusion

71. AGI was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2017/2018 Capability Year. AGI worked with Lummus Consultants International (LCI) to complete the tariff-required periodic review.

72. During this process, we developed quantitative and qualitative analyses, proposed and final recommendations on every DCR issue, and presented and discussed these issues with stakeholders across numerous stakeholder meetings. Specifically, over the course of eleven months we (1) established guiding principles for evaluating DCR alternatives, (2) evaluated approaches taken in capacity markets in other relevant ISO/RTO jurisdictions, (3) identified options for potential enhancements of the DCR process, (4) highlighted key issues related to technology and capital costs, net EAS modeling, financial parameters, and ICAP Demand Curves RP calculations, and (5) presented analyses on and discussed potential benefits and drawbacks of each issue considered.

73. Our final analyses and recommendations are presented in Sections IV, V, and VI above, and comprehensively documented in the Final Report.

74. This concludes our affidavit.

ATTESTATION

I am a witness identified in the foregoing Affidavit of Paul J. Hibbard, Dr. Todd Schatzki, and Craig Aubuchon dated November 17, 2016 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Paul J. Hibbard
November 17, 2016

Subscribed and sworn to before me
this 17th day of November 2016.

Katherine A. Barber
Notary Public

My commission expires: 4/6/23

KATHERINE A. BARBER
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 6, 2023

ATTESTATION

I am a witness identified in the foregoing Affidavit of Paul J. Hibbard, Dr. Todd Schatzki, and Craig Aubuchon dated November 17, 2016 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Dr. Todd Schatzki
November 17, 2016

Subscribed and sworn to before me
this 17th day of November, 2016.

Katherine A. Barber
Notary Public

My commission expires: 4/6/23

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Craig Aubuchon
November 17, 2016

Subscribed and sworn to before me
this 17th day of November, 2016.

Katherine A. Barber
Notary Public

My commission expires: 4/6/23

KATHERINE A. BARBER
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 6, 2023

Exhibit A

PAUL J. HIBBARD

Principal

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111 Huntington Ave.
Tenth Floor
Boston, MA 02199

Paul Hibbard is an expert on economics, strategy, regulation, and policy in the electric and natural gas industries. Throughout his career, he has administered and promoted an agenda of advanced ratemaking and policy initiatives for energy companies. Mr. Hibbard has also provided technical and strategic advice to government, industry, business, public interest groups, and trade organizations on energy market structure, electric and natural gas infrastructure planning and siting, utility resource solicitation and procurement, emission allocation and environmental policy, renewable resource program design and administration, transmission pricing, climate change policy, utility ratemaking practices, and the transfer of U.S. federal and state emission control programs to other countries.

Mr. Hibbard has a comprehensive background merging business development, technical analysis, resource planning and development modeling, economics, and public policy in energy and environmental fields. Prior to joining Analysis Group, Mr. Hibbard was Chairman of the Massachusetts Department of Public Utilities. He was appointed to that position by Governor Deval Patrick in April, 2007. As Chairman, Mr. Hibbard carried out a forward-looking ratemaking and policy agenda to advance energy efficiency and renewable resources, coordinate regional efforts in the development of energy resources and associated infrastructure, and promote the administration of fair and efficient transmission pricing models in regional and national contexts. During his term as Chairman, Mr. Hibbard provided testimony on resource planning, competitive electricity markets, and transmission pricing in hearings before Committees of the Massachusetts Legislature and the U.S. House of Representatives, the Federal Energy Regulatory Commission, and state and regional planning councils. Mr. Hibbard served as a member on the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. He was also appointed as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnect States' Planning Council.

Prior to 2007, Mr. Hibbard held Vice President, Manager, and Senior Consultant positions at Analysis Group and Lexecon, Inc., providing technical and policy analysis and strategic advice to energy sector clients in a wide range of market, policy and infrastructure areas. From 1991-2000, Mr. Hibbard worked for both utility and environmental regulatory agencies in Massachusetts on utility resource planning, industry restructuring, market design, and power plant emission control and allowance allocation mechanisms.

EDUCATION

Ph.D. program (coursework), Nuclear Engineering, University of California, Berkeley

M.S. in Energy and Resources, University of California, Berkeley
Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs

B.S. in Physics, University of Massachusetts, Amherst

PROFESSIONAL EXPERIENCE

2010 – Present Analysis Group, Inc., Boston, MA
Principal
Vice President ('10 – '15)

2007 – 2010 MA Department of Public Utilities, Boston, MA
Chairman
Member, Energy Facilities Siting Board
Manager, New England States Committee on Electricity
Treasurer, Executive Committee, Eastern Interconnect States' Planning Council
Representative, New England Governors' Conference Power Planning Committee
Member, NARUC Electricity Committee, Procurement Work Group

2003 – 2007 Analysis Group, Inc., Boston, MA
Vice President
Manager ('03 – '05)

2000 – 2003 Lexecon Inc., Cambridge, MA
Senior Consultant
Consultant ('00 – '02)

1998 – 2000 Massachusetts Department of Environmental Protection, Boston, MA
Environmental Analyst

1991 – 1998 Massachusetts Department of Public Utilities, Boston, MA
Senior Analyst, Electric Power Division

1988 – 1991 University of California, Berkeley, CA
Research Assistant, Safety/Environmental Factors in Nuclear Designs

SELECTED PUBLIC SECTOR EXPERIENCE

- ***Chairman, Department of Public Utilities –*** Chaired the state's public utilities commission during a period of aggressive change in state policies affecting electricity and natural gas industries, including initial implementation of several new state energy laws and initiatives restructuring the setting of utility rates, promoting the expansion of energy efficiency and demand response, facilitating the retail and wholesale market integration of renewable and low-carbon resources, and revising state policy on the siting of major generation and transmission infrastructure. Oversaw the issuance of initial regulations and policy related to revenue decoupling, net metering, long-term contracting for renewables, and power system emergency planning and outage restoration. Also, led Massachusetts' work with regulators across the Northeast to pursue large-scale renewable resource development through coordinated procurement strategies, to develop coordinated positions related to national transmission development proposals, and to establish a regional presence on transmission-related provisions in federal legislation. As Chairman, served as administrative and policy head of an agency of nearly 150 employees, responsible for agency management and growth, budgeting, legislative matters, press inquiries, and setting of the policy agenda. Responsible for overseeing completion of all dockets jurisdictional to the DPU, including rate cases and associated tariff matters, forecast and supply planning for electric and natural gas industries, and state oversight of natural gas pipeline safety and public transit authorities. Also responsible for all interaction with the Governor's office, Legislature, and Executive Office of Energy and Environmental Affairs, as well as representing the state in regional deliberations related to electric and natural gas utility policy, electricity market design and oversight, and regional power system reliability issues.

- ***Member, Energy Facilities Siting Board*** – Sitting member of state Board with responsibility to review all proposals for major generation and transmission infrastructure projects within the state, as well as state intervention in federal review of natural gas pipeline infrastructure. Involved technical, environmental, and economic review of jurisdictional power plants, transmission lines, and other energy infrastructure, as well as ruling on proposals for exemption from state and local zoning ordinances.

- ***Manager, New England States Committee on Electricity*** – State representative on regional group chartered to develop New England regional policy positions on electricity market and transmission planning issues. Included consideration of group development issues, input into regional determinations of installed capacity requirement, consideration of regional approaches to transmission planning and the consideration of non-transmission alternatives, and coordinated development of a regional RFP/RFI for the solicitation of renewable power under long-term contracts for the New England states.

- ***Treasurer, Executive Committee, Eastern Interconnect States' Planning Council*** – Elected Treasurer of steering committee for state council formed under a U.S. DOE grant, to coordinate with power system operators on developing long-range plans for the transmission system spanning 41 states in the Eastern U.S. Coordinated New England states' approach to policy issues stemming from council efforts.

- ***Representative, NEGC Power Planning Committee*** – Represented Governor's Office in all discussions related to regional energy/environmental issues, including transmission cost allocation, regional energy policy coordination, and development of mechanisms and approaches for procurement of renewable power through long-term contracts with sources in New England and Eastern Canada. Engaged in collaborative discussions with counterparts representing the Eastern Canadian Premiers.

SELECTED CONSULTING EXPERIENCE

Government, Foundations, Commissions, Cooperatives

- ***For Massachusetts Attorney General*** – Coauthored a report evaluating electric and natural gas infrastructure in New England from the perspectives of reliability, cost, and emissions of greenhouse gases (2015).

- ***For Advanced Energy Economy Institute*** – Coauthored a report on the status of the electric industry in the State of Ohio, and developed recommendations on state energy policy in consideration of current market and technological circumstances in the state.

- ***For the Energy Foundation and industry groups*** – coauthored multiple white papers on the reliability, cost and market efficiency impacts of EPA's proposed regulations to control emissions of carbon dioxide from existing electric generating facilities. Presented results in numerous conference, stakeholder, and regulatory settings.

- ***For a foundation*** **–** Led a study of the economic impacts of a state clean energy policy (2013–2014).

- ***For the Massachusetts Department of Energy Resources*** **–** Provided testimony on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013).

- ***For the Advanced Energy Economy Institute*** – Facilitated a regional symposium for New England Public Utility Commissioners and staff related to advanced energy technology development and commercialization, and the legal and regulatory structures needed to facilitate integration of emerging technologies (2013).

- ***For the Regional Greenhouse Gas Initiative*** – conducted a bill impact analysis related to changes to retail customer electric bills in New England, New York, and RGGI PJM states associated with various changes considered by RGGI to program cap level and use of allowance revenues (2012).

- ***For Advanced Energy Economy Institute*** – Participated in an on-going project advising AEE with respect to their national program to support Public Utility Commission consideration of policies and regulations related to the development and integration of advanced energy technologies (2012 – 2013).
- ***For the Merck Family Fund*** – Developed an interactive tool to compare the impacts of energy, economic, environmental, legislative and regulatory policies and programs across the U.S. states (2012).
- ***For Advanced Energy Economy Institute*** – Co-authored a Report on the perspectives of CEOs at advanced energy companies doing business in California on California's energy policies. Conducted over 30 interviews with energy business leaders to get perspectives and recommendations for policy changes (2012).
- ***For the Barr Foundation*** – Co-authored a Report on the benefits and costs associated with reducing natural gas leaks on natural gas distribution systems through implementation of targeted infrastructure replacement ratemaking mechanisms in Massachusetts, Rhode Island, and Ohio. Developed a cost-benefit model to quantify the impacts of such programs (2012 – 2013).
- ***For American Clean Skies Foundation*** – developed a dispatch price and emissions model to forecast power system outcomes in the PJM Interconnection, Midwest Independent System Operator, and Southwest Power Pool regions (2012).
- ***For a National Environmental Organization*** – Conducted a comprehensive national review of energy efficiency monitoring and verification programs, in order to support development of a protocol that could be used to allow EE to be used as a compliance tool in national carbon emission control regime (2012 – 2013).
- ***For the Merck Family Fund –*** Co-lead a project to carry out an analysis of the economic impacts of the Northeast States' use of revenues collected from the auctioning of carbon allowances associated with Regional Greenhouse Gas Initiative (2011).
- ***For Advanced Energy Economy –*** Developed industry background info on electric industry structure, regional planning and market structures and operations, and state energy policy organization and initiatives. Assisted with development of web-based information platform (2011).
- ***For the American Clean Skies Foundation –*** Authored a paper on the redesign of wholesale electricity market structures to efficiently integrate a higher level of variable resources (2012). Co-authored a white paper examining electric reliability and air emission issues associated with the potential retirement of the Potomac River Generating Station in Alexandria, Virginia (2011).
- ***For the Public Service Commission of Colorado –*** Co-authored a white paper on design of incentives for the PV Solar energy market (2011).
- ***For a National Environmental Organization*** – Conducted an economic analysis of key U.S. cities that are or have been in nonattainment under the National Ambient Air Quality Standards, to explore relationships between air quality control requirements and the local economy (2011).
- ***For a National Environmental Organization*** – Completed a comprehensive report on the full scope of energy efficiency and demand response programs administered by New York electric utilities and the New York Independent System Operator. Assessed the potential for additional innovative programs to improve energy efficiency and demand response in New York City (2010).
- ***For the National Commission on Energy Policy –*** Authored white papers on (1) the implications for U.S. energy infrastructure of the damage to Gulf Coast energy facilities from Hurricanes Katrina and Rita (2006); (2) the practical and economic implications of various mechanisms for the allocation of carbon dioxide emission allowances to the electric sector under potential federal carbon control regimes (2005), and (3) national energy infrastructure needs for the electricity, natural gas, and petroleum industries, and for addressing the long-term impacts of energy production and use associated with spent nuclear fuel and carbon dioxide (2004).

- ***For the Attorney General, State of North Carolina –*** Managed project in support of expert testimony on the economic and financial feasibility of requiring the installation of controls to reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from coal-fired power plants owned by the Tennessee Valley Authority (TVA). Project is in the context of a public nuisance lawsuit brought by the NC Attorney General against TVA (2006).

- ***For the Energy Foundation*** – Coauthored a Report (with Dr. Susan Tierney) documenting best practices in energy facility siting regulations in the U.S., and analyzing in particular the impact of California's energy facility siting process on that state's electricity crisis (2002). Supported a foundation-based program to provide international assistance to China's efforts to privatize and restructure its electric industry, and to develop regulations to control air emissions from power plants in that country (2000 – 2003).

- ***For the Massachusetts Technology Collaborative –*** Managed projects in support of the MTC's renewable and premium power programs, including (1) creation of a standard financial pro-forma for wind and landfill gas technologies in New England under various assumptions related to capital and operating costs, financing, discount rates, and the impact of state and federal policies to support renewable development; (2) development of an economic model to determine the financial impact on potential wind and combined heat and power facilities of proposed changes to utility standby service tariffs; and (3) research, strategic, and regulatory support of MTC's efforts to advance distributed generation in Massachusetts to promote renewable resources and improve power reliability for commercial and industrial customers (2000 – 2002).

- ***For the Massachusetts Health and Educational Facilities Authority (MHEFA) PowerOptions Program*** – Managed several projects providing regulatory, economic, and strategic advice to PowerOptions to assist in their selection and pricing of retail electricity products from competitive electricity suppliers. Over a three-year period projects included analyses of forward prices and wholesale markets for capacity and reserves; analysis of contract price options, terms and conditions; and analysis of congestion pricing implications for retail supply (2002 – 2004).

OTHER ELECTRIC AND NATURAL GAS INDUSTRY EXPERIENCE

- ***For a Consortium of Solar Companies*** – Developed a white paper on the appropriate evaluation and treatment of behind-the-meter solar PV generation from the perspective of net metering policies in Massachusetts (2015).

- ***For a Group of Owners of Electric Generating Facilities*** – Developed a comprehensive quantitative and qualitative critique of a utility proposal to invest in electricity storage capability in the State of Texas. Drafted a report for circulation to legislative, regulatory, and market interests reporting results of the critique and analysis (2015).

- ***For an Energy Resource Developer*** – Conducted a financial and ratepayer analysis of the benefits of a project to develop a power plant and natural gas pipeline in the State of Maine. Submitted testimony to the Maine Public Utilities Commission describing results (2014 – 2015).

- ***For an Energy Storage Company*** – Developed an optimization analysis to evaluate the security, reliability, economic, and environmental benefits and costs of multiple battery storage installations across the Hawaiian Islands in different industry settings (renewable generator, island utility, military base, hotel/resort). Drafted report presenting results considering the state's unique energy price and fuel security context (2014 – 2015).

- ***For the New York Independent System Operator*** – Developed a model to compare cost, resource, and emission outcomes of alternative designs for a capacity market in New York State. Coauthored a report presenting results of analysis and a comprehensive review of benefits and drawbacks of moving from a spot to a forward capacity market structure. Presented results to NYISO Senior Management and several meetings of New York electricity market participants and stakeholders (2014 – 2015).

- ***For Multiple Regional Transmission Organizations*** – Provided Board of Director and Senior Management level strategic support for considering the changing structures of retail regulation and wholesale market incentives within their regions (2014 – 2015).
- ***For Calpine Corporation –*** Provided testimony on the costs and benefits of different proposals for generation capacity in Florida (2014).
- ***For a Regional Transmission Operator*** – Conducted internal analysis of financial risk associated with the RTO's position in administering the trading of power system transmission rights (2014).
- ***For a Regional Transmission Operator*** – Conducted a top-to-bottom review of the content and design of the RTO's Rate Schedule 1 tariff for collection of operational costs from market participants. Presented results of the analysis to the RTO's Board of Directors and Senior Management (2014).
- ***For a Retail Electricity Supplier*** – Provided analytic and strategic support with respect to the supplier's participation in a state regulatory proceeding related to changing the nature of and rate structure for electric distribution service (2014).
- ***For Ambri Inc. –*** Led a study of the economic feasibility of using battery storage in conjunction with wind and solar for a micro-grid application (2013 – 2014)
- ***For Calpine Corporation –*** Provided testimony on the costs and benefits of different proposals for generation capacity in Minnesota (2013)
- ***For the New England Independent System Operator –*** Assisted on several project related to addressing co-dependence of electric and natural gas systems in New England through a mix of short- and long-term market rule changes and administrative actions. Assistance included review of market structures to improve unit performance, particularly under stressed natural gas system conditions; quantification of the costs of potential natural gas and electric system infrastructure and contractual responses to market rules and administrative actions (e.g., dual-fuel capability, new pipeline investment, liquefied natural gas purchasing, and firm natural gas transportation agreements); and assistance with a series of discussions between ISO-NE and regional electricity and natural gas market participants. Also quantified the potential benefits of improved performance associated with reduced system interruptions (2012 – 2013).
- ***For the New England Independent System Operator*** – Developed an economic supply/demand model of the Forward Capacity Market to estimate the cost impact of integrating into the FCM auctions and pricing structure a new long-term performance incentive design element (2012 – 2013).
- ***For Calpine Corporation*** – Filed a Report with the U.S. Environmental Protection Agency on the impact of emergency generation demand response programs on the costs and emissions associated with power system dispatch in the PJM electricity market (2012).
- ***For the New England Independent System Operator*** – Organized and help lead a strategic planning initiative to address unit retirement, fuel mix, operational performance, and wind resource integration issues. Oversaw comprehensive generating unit performance analysis and electric-gas system risk review. Conducted a thorough internal risk assessment and key-challenge solution development, facilitating meetings, developing organizational and concept documents to explore outcomes and assist in deliberations with states and regional industry stakeholders, and participating in external meetings to gain input and feedback (2010 – 2012).
- ***For a Regional Transmission Organization*** – Conducted a top-to-bottom review of its external market monitoring function, and a comprehensive best-practices survey of all internal and external market monitoring functions at U.S. Regional Transmission Organizations and Independent System Operators (2012).
- ***For a Wind Power Development Company*** – Conducted a regional review of wind power development projects and an assessment of potentially valuable projects for acquisition based on power system location and siting viability (2012).

- ***For an International Power Company*** – Conducted a review of a regional utility's compliance with FERC requirements for transmission open access; developed strategies for the filing of complaints of anticompetitive conduct before the FERC (2011 – 2012).

- ***For a Regional Transmission Organization*** – Comprehensively reviewed and suggested changes to the design of regional market structures; oversaw data review and analysis related to key market design features and asset performance (2011).

- ***For an Energy Services Company –*** Oversaw and conducted an analysis of business, legal and regulatory conditions related to a legal dispute over the legitimacy of a contract for energy and water management services. Co-authored a report to be used in development of legal strategy and legal proceedings (2012).

- ***For Direct Energy*** – Assisted with development of strategies to increase retail choice in Pennsylvania, including the design of an Opt-In descending-clock auction to increase migration from default service to competitive supply. Prepared comments and analysis on utility contract structures. Provided testimony before the Pennsylvania Public Utilities Commission (2011).

- ***For Algonquin Gas*** – Submitted affidavits and testified in bankruptcy court on the impact on power plant value of changes in market rules related to the Forward Capacity Market in New England. Also provided testimony on the impact on power system reliability of the availability of firm transportation contracts for natural gas supplied to power plants in New England (2010).

- ***For an Independent System Operator*** – Conducted a best practices and performance metrics analysis to benchmark the ISO's performance against industry peers with respect to responsiveness to consumers, stakeholders, and policymakers. Drafted a report with comprehensive benchmarking and performance metric recommendations; participated in stakeholder discussions (2010).

- ***For a Power Generators Trade Association*** – Developed and facilitated an all-day group discussion concerning key economic, environmental, legal and policy challenges to the economic viability of existing and new power generation capacity in regional wholesale electricity markets (2010).

- ***For a Coalition of Electric Companies*** – Coauthored a report, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," reviewing the impact on power plant operations of proposed Environmental Protection Agency rules to reduce emissions of sulfur dioxide, nitrogen oxides, mercury, and other hazardous air pollutants. Presented findings to numerous regional and national industry and regulatory groups (2010).

- ***For an Industry Coalition*** – Conducted a study and coauthored a white paper (with Dr. Susan Tierney) for the New England Energy Alliance on New England energy infrastructure needs and policy issues (e.g., facility siting policies, RGGI/climate change) influencing the future addition of energy infrastructure in the region (2006).

- ***For an Interstate Pipeline Company and Offshore LNG Developer*** – Authored a Report related to recent developments in the supply and demand for natural gas in New England, and surveyed the development, regulatory and commercial status of proposed LNG projects across the U.S. (2006); coauthored a Report (with Dr. Susan Tierney) providing an overview of Northeastern natural gas markets and conditions, and an assessment of natural gas supply and demand conditions (2005).

- ***For Independent System Operators*** – Managed several projects and coauthored reports or analyses for the Northeast region's ISOs/RTOs, related to ISO/RTO annual strategic plans; market monitoring and mitigation best practices; and the links between wholesale electricity markets and local distribution company retail prices (2002 – 2006).

- ***For Electric Utilities*** – Managed or participated in numerous engagements with wires-only as well as vertically-integrated electric utilities within New England and across the country related to rate case strategy and regulatory support; strategic planning; power supply resource planning and procurement (including the role of independent monitor of utility procurements); price and environmental analyses related to the siting of new high-voltage transmission lines; and evaluation of the allocation of SO_2 and NO_x emission allowances under the EPA CAIR program (2001 – 2006).

- ***For a Developer of a Land-Based LNG Facility –*** Assisted in the preparation of confidential reports on U.S. natural gas supply/demand conditions, market pricing indices, U.S. LNG facilities' status, Northeast interstate and intrastate pipeline infrastructure conditions and prospects, and LNG supply contract prices, terms and conditions (2006).
- ***For Retail Energy Providers*** – Managed projects and authored or coauthored confidential reports on the experience with retail competition in the U.S., a benefit/cost analysis of wholesale electricity competition, and comparative analyses of retail electricity prices for utility and competitive retail suppliers in select states (2004 – 2006).
- ***For Merchant Generating Companies/Coalitions*** – Managed production cost dispatching analyses for strategic planning related to the construction of new generating capacity in New England; assisted in the development of regulatory proposals for new wholesale market organizations and policies in New England (2001 – 2002).
- ***For a Renewable Power Developer Association*** – Provided testimony on the potential negative effects – and remedial policy options – related to the impact of locational marginal pricing on the development and operation of renewable generating resources in New England (2001).
- ***For a Major Interstate Pipeline Owner/Operator –*** Modeled the electrical load characteristics of pipeline operations and utility rate structures to quantify the extent to which the company was being overcharged for electricity services. Supported company intervention in public utility commission proceedings and with analytical support in settlement negotiations (2002).

OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Advanced Energy Economy (2011).

SELECTED REPORTS, TESTIMONY AND PRESENTATIONS

Paul J. Hibbard and Craig P. Aubuchon, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*, Report for the Massachusetts Office of the Attorney General, November 2015.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO*, Report for the Energy Foundation, June 8, 2015.

Paul J. Hibbard, *Net Metering in the Commonwealth of Massachusetts: A Framework for Evaluation*, May 2015.

Paul Hibbard, Todd Schatzki, Craig Aubuchon, and Charles Wu, *NYISO Capacity Market: Evaluation of Options*, Report for the New York Independent System Operator, May 2015.

Paul J. Hibbard and Andrea M. Okie, *Ohio's Electricity Future: Assessment of Context and Options*, Report of Advanced Energy Economy, April 2015.

"Markets, Infrastructure, and Policy: New England at a Crossroads," Presentation to US/Canada Cross-Border Power Summit, April 2014.

"Siting Infrastructure: Economic and Siting Hurdles," Presentation to US/Canada Cross-Border Power Summit, April 2014.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: The Case of PJM*, Report for the Energy Foundation, March 16, 2015.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: Tools and Practices*, Report for the Energy Foundation, February, 2015.

Andrea M. Okie, Paul J. Hibbard, and Susan F. Tierney, *Tools States Can Utilize for Managing Compliance Costs and the Distribution of Economic Benefits to Consumers Under EPA's Clean Power Plan*, Electricity Forum, February 2015.

Paul J. Hibbard, Katherine A. Franklin, and Andrea M. Okie, *The Economic Potential of Energy Efficiency*, Report for the Environmental Defense Fund, December 2014.

Paul J. Hibbard, Andrea M. Okie, and Katherine A. Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels*, Report for the Environmental Defense Fund and National Resources Defense Council, December 2014.

EPA's Proposed Clean Power Plan and States' Planning for Implementation," Presentation to Power-Gen International Annual Conference, December 2014.

"Storage/Renewables Valuation: A Case Study Hitting Multiple Perspectives," Presentation to the Caribbean Renewable Energy Forum 2014, October 2014.

"Electric Industry Transformation: A New World, or a Step Through the Looking Glass?" Presentation to New England Independent System Operator Quarterly Meeting, September 2014.

"Consumers, Markets, and Infrastructure: New England at a Crossroads," Presentation to the New England Consumer Liaison Group, September 2014.

"Columbia River Treaty Hydropower: Perspectives on Power Benefits," Presentation to LSI Conference on the Columbia River Treaty, September 2014.

Before the Florida Public Service Commission, Docket No. 140110-E1, Direct Testimony of Paul J. Hibbard on Behalf of Calpine Construction Finance Company, L.P., July 2014.

"States in Control: EPA's Clean Power Plan and State Implementation," Presentation at National Association of Regulatory Utility Commissioners Summer Meetings, July 2014.

"Project Vigilance: Value of Ambri Batteries at Joint Base Cape Cod," Presentation to Raab Restructuring Roundtable, Boston MA, June 2014.

Hibbard, Paul and Todd Schatzki, *Further Explanation on Rate Calculations*, Memo to ISO New England Markets Committee on setting the compensation rate for the ISO Winter Program, May 28, 2014.

Hibbard, Paul J., Susan F. Tierney, and Pavel G. Darling, *Economic Impact of the Green Communities Act in the Commonwealth of Massachusetts: Review of the Impacts of the First Six Years*," March 4 2014.

Paul J. Hibbard and Andrea Okie, *Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments: Recommended Framework for Proposed Guidance on Quantifying Energy Savings and Emission Reductions in Section 111(d) State Plans Implementing the Carbon Pollution Standards for Existing Power Plants*, Report for Environmental Defense Fund, March 2014.

"Climate Policy and the Economy," Presentation to 2014 JISEA Annual Meeting, NREL, Golden CO, March 2014.

Federal Energy Regulatory Commission, Docket Nos. ER14-1050-000 and ER14-1050-001, Testimony of Paul Hibbard and Todd Schatzki on Behalf of ISO New England Inc., February 12, 2014.

Hibbard, Paul, Steve Carpenter, Pavel Darling, Margaret Reilly, and Susan Tierney, *Project Vigilance: Functional Feasibility Study for the Installation of Ambri Energy Storage Batteries at Joint Base Cape Cod*, Report for demonstration project under the MassInnovate Program of the Massachusetts Clean Energy Center, February 2014.

State of Minnesota, Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240, Rebuttal Testimony of Paul Hibbard, October 18, 2013.

State of Minnesota, Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240, Direct Testimony of Paul Hibbard, September 27, 2013.

"Market Monitoring at US RTOs," Presentation to 12th Annual Gas and Power Institute, Houston, TX, August 2013.

Testimony of Paul J. Hibbard before the House Committee on Energy and Commerce, Subcommittee on Energy and Power, *The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges*, March 19, 2013.

Hibbard, Paul, Andrea Okie and Susan Tierney, *California's Advanced Energy Economy – Advanced Energy Business Leaders' Perspectives and Recommendations on California's Energy Policies*, Prepared for the Advanced Energy Economy Institute, February 2013.

Paul Hibbard, *Information from the Literature on the Potential Value of Measures that Improve System Reliability*, Memo to ISO New England, January 24, 2013.

Paul Hibbard, *Information on the Range of Costs Associated with Potential Market Responses to Address the Risks Associated with New England's Reliance on Natural Gas*, Memo to ISO New England, January 24, 2013.

Craig Aubuchon and Paul Hibbard, *Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs*, Report for the Barr Foundation, January 2013.

Hibbard, Paul J., Andrea M. Okie, and Pavel G. Darling, *Demand Response in Capacity Markets: Reliability, Dispatch and Emission Outcomes*, The Electricity Journal, November 2012.

"The Electric Generation Landscape – A Marathon of Challenges," Presentation to SNL Generation Landscape, Chicago IL, October 2012.

"Economics, EPA, and Old Capacity…Bring Out Your Dead," Presentation to LSI Energy in the Northeast, Boston MA, September 2012.

Hibbard, Paul J., *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, Report to the U.S. Environmental Protection Agency on behalf of Calpine Corporation, August 2012.

"Uncertainty in Electricity Infrastructure Development – Key Drivers, International Context," Presentation to NCEA Annual Conference, Brainerd, MN, June 2012.

Hibbard, Paul J. and Todd Schatzki, *The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects*, The Electricity Journal, May 2012.

"Economic Impacts of RGGI," presentation to the New Hampshire Environmental Business Council, April 2012.

Testimony of Paul J. Hibbard before the California Legislature, *The Economic Impacts of RGGI's First Three Years*, California Select Committee on the Environment, the Economy, and Climate Change, March 27, 2012.

Testimony of Paul J. Hibbard before the New Hampshire Legislature, *RGGI and the Economy – Following the Dollars*," NH House Committee on Science, Technology, and Energy, February 14, 2012.

Testimony of Paul J. Hibbard before the Massachusetts Legislature, *RGGI and the Economy – Following the Dollars*," Massachusetts Senate Committee on Global Warming and Climate Change, February 13, 2012.

"Economic Impacts of RGGI: Following the Dollars," presentation (with Sue Tierney) to the California Business Climate Network, February 2012.

Hibbard, Paul J. and Susan F. Tierney, *Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years*, The Electricity Journal, December 2011.

"Public Policy Transmission: Competition and Cooperation," presentation to the Energy Bar Association Renewables Subcommittee, Washington DC, November 2011.

"Competitive Markets and Wind Power: Challenge and Opportunity," presented to the Governors' Wind Energy Coalition, Washington DC, November 2011.

Hibbard, Paul J., Susan F. Tierney, Andrea M. Okie and Pavel G. Darling, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States; Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*, November 15, 2011.

Testimony before the Pennsylvania Public Utilities Commission on Retail Opt-In Auctions, November 10, 2011.

"Interdependence and Opportunity: The Growing Link Between Electricity and Natural Gas," presentation to the COGA Energy Epicenter Conference, Denver CO, August 2011.

"Potomac River Generating Station: Update on Reliability and Environmental Considerations," with Pavel Darling and Susan Tierney, July 19, 2011.

Hibbard, Paul J., *Retirement is Coming; Preparing for New England's Capacity Transition*, Public Utilities Fortnightly, June, 2011

Schatzki, Todd, Paul Hibbard, Pavel Darling and Bentley Clinton, *Generation Fleet Turnover in New England: Modeling Energy Market Impacts*, June, 2011.

"Solar Development Incentives: *Status of Colorado's Solar PV Program, Practices in Other States, and Suggestions for Next Steps," with Susan Tierney and Andrea Okie, June 30, 2011.*

"The Balancing Act: Challenges in Traversing the Modernization of New England's Infrastructure," presentation to NECA Annual Conference, Mystic CT, May 2011.

"Renewables v. Gas: The Future of New England Infrastructure," presentation to the EBC Energy Seminar, Waltham, MA, April, 2011.

"Upcoming Power Sector Environmental Regulations: Framing the Issues About Potential Reliability/ Cost Impacts," presentation to Raab Restructuring Roundtable, Boston MA, October 2010.

"Carbon Regulation: Action and Convergence Spanning the Pond," presentation to Energy Smart Conference, Boston MA, October 2010.

"Renewables Development – A Tricky Time to be Placing Bets," presentation to NECA Renewables Committee, Boston MA, October 2010.

"Energy Infrastructure Challenges in the Current Policy Environment, A Wide Angle Point of View," presentation to NARUC, Providence RI, September 2010.

"Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," with Susan F. Tierney, Michael J. Bradley, Christopher Van Atten, Amlan Saha, and Carrie Jenks. August 2010.

"Renewables Development – National Policies, New England Progress," presentation to National Association of State Energy Officials Annual Meeting, Boston MA, September 2010.

"Northeast US and Eastern Canada – Competitive Markets and Renewable Resource Development," presentation to LSI Conference on US/Canada Energy Transactions, Vancouver BC, August 2010.

"Renewables in the Northeast – Local Opportunities, National Context," presentation to Council of State Governments, Portland ME, August 2010.

"Deregulation and Sustainable Energy," class lecture, MIT (Jonathan Raab Energy Course), Cambridge MA, March 2010.

"Transmission for Renewables," presentation to Raab Restructuring Roundtable, Boston MA, March 2010.

"Federal Transmission Legislation," comments to Capitol Hill Briefing of the Coalition for Fair Transmission Policy, Washington DC, April 2010.

"Transmission Planning & Cost Allocation Alternatives under Order 890," comments to the Energy Bar Association's 64th Meeting, Washington DC, April 2010.

"US Electric Power Transmission: The Battle of the Jurisdictions," comments to CERAWeek 2010, March, 2010.

"New England Blueprint and the Federal Context," presentation to ISO-NE Consumer Liaison Group Meeting, Westborough MA, February 2010.

"Interconnection-Wide Planning and Renewable Energy," comments to the National Wind Coordinating Collaborative, Transmission Update Briefing, December 2009.

"Infrastructure Planning," comments to Northeast Energy and Commerce Association Power Markets Conference, Westborough MA, November 2009.

"Transmission for Renewables - Risks and Opportunities for the Northeast," Presentation to Governor's Clean Energy Innovation Forum, New Brunswick, NJ, October 2009.

"Renewable Energy Development – The Role of Markets and Planning," presentation to Northeast Power Planning Council General Meeting, Cambridge MA, September, 2009.

"Transmission Planning," comments to FERC Technical Conference on Transmission Planning Processes Under Order No. 890, Docket No. AD09-8-000, Philadelphia, PA, September, 2009.

"New England Governors' Blueprint – Purpose and Context," presentation to the Raab Restructuring Roundtable, Boston MA, September 2009.

"Wind, Transmission, and Federal Legislation," comments to MIT Wind Group, Cambridge MA, Fall, 2009.

"National Transmission Policy," comments to The Energy Daily's Transmission Siting Policy Summit, Washington DC, September 2009.

Testimony to the Massachusetts' Joint Committee on Telecommunications, Utilities and Energy Hearing to Review Implementation of the Green Communities Act, Boston MA, July 8, 2009.

"Federal Transmission Legislation," comments to the National Association of State Utility Consumer Advocates, Boston MA, July 2009.

"Renewable Energy Development - The Role of Markets and Planning," presentation to Governor's Wind Energy Coalition, Washington DC, July 2009.

"Transmission and Renewables: ISO and Regulator Perspectives" comments to the Raab Restructuring Roundtable, Boston MA, June 2009.

"Renewable Development In and For New England; Massachusetts' Perspective," presentation to Law Seminars International, Boston MA, June 2009.

"Roadmap to New Renewable Resources in New England," comments on New England Governors' Blueprint to NECPUC Annual Symposium, Newport, RI, May 2009.

"Comments of Chairman Paul Hibbard," presented to EBC Energy Seminar: New Transmission – The Key to Renewable Resource Integration in New England, Boston MA, April, 2009.

"Coordinating Wind and Transmission Development – Who Pays?" Comments to 2009 Platts Wind Power Development Conference, Chicago, IL, March, 2009.

"Integrating Energy and Environmental Regulations in Massachusetts," presentation to Northeast Sustainable Energy Association Building Energy Conference'09, Boston, MA, March, 2009.

"One Reason for the GCA: Energy Pricing in Massachusetts," presentation to the South Shore Coalition, Hingham MA, January 2009.

"Non-Reliability Transmission: State Choice and Control," presentation to the New England Conference of Public Utility Commissioners Transmission Group, Chelmsford MA, January 2009.

"Regulation and Renewable Energy Policy," panel moderator, Center for Resource Solutions National Renewable Energy Marketing Conference, Denver, CO, October, 2008.

"Energy Pricing in Massachusetts (…And What We Should Do About it)," presentation to Berkshire Gas Large Commercial and Industrial Customer Annual Meeting, Lenox MA, October, 2008.

"Conversation With Chairman Hibbard," presentation to New England Energy Alliance, Boston MA, September, 2008.

"Creating the Path: Delivering Clean Energy through Transmission Improvements," presentation to ISO-NE Lights, Power, Action Conference, Boston MA, September, 2008.

"Distributed Resources, the Decoupling Model, and the Green Communities Act," presentation to Raab Restructuring Roundtable, Boston MA, September, 2008.

"Resource Planning: The Contribution of Efficiency and Renewables in Massachusetts," presentation to Law Seminars International Renewable Energy in New England Conference, Boston MA, September 2008.

"Remarks to Economic Studies Working Group," ESWG Committee Meeting, Westborough MA, July 2008.

"Power Trade: Market Context and Opportunities," presentation to New England Governors' Council/Eastern Canadian Premiers' Energy Dialogue, Montreal Canada, May 2008.

"New England Transmission Investment," presentation to Municipal Electric Association of Massachusetts Annual Business Meeting, North Falmouth MA, April 2008.

"Bringing Power from the North," presentation to the Raab Restructuring Roundtable, Boston MA, February 2008.

"Natural Gas: Drivers of Supply, Demand, and Prices," comments to Guild of Gas Managers, November 2007.

“Generation and Demand Outlook for New England,” presentation to NECA Dinner Meeting, Cambridge MA, September, 2007.

“Comments on ISO’s Draft Regional System Plan,” presentation to ISO Planning Advisory Committee, Boston MA, September 2007.

“Regulatory Pressures, Policy Opinions,” presentation to Environmental Business Council, Boston MA, July 2007.

“Is New England Ensuring the Adequacy and Cost Effectiveness of the Region’s Transmission Grid?” Panel moderator, New England Conference of Public Utility Commissioners Annual Symposium, Mystic CT, June 2007.

“Energy Regulation in Massachusetts – Concerns and Options,” presentation to the Raab Restructuring Roundtable, Boston MA, June, 2007.

“View From the Regulatory Bench,” comments to the New England Energy Conference and Exposition, Groton CT, May 2007.

“Energy for New England – The Demand, Supply and Price Context,” presentation to Massachusetts Municipal Wholesale Electric Cooperative Annual Meeting, Boylston MA, May 2007.

“Demand Resources in New England: New Opportunities and Future Directions,” Presentation at ISO-NE Annual Demand Resources Summit, Westborough MA, May 2007.

“Power Supply for the New England Region,” presentation to the Boston Bar Association, Boston MA, March 2007.

“Fuel Supplies and the Need for Fuel Diversity: Forecast for Global Fuel Markets and the Likely Impact on Electric Generation in the Northeast,” presentation to LSI Seminar on Resource Adequacy and Reliability in the Northeast, October 16, 2006.

“Consumers and Politicians Claim They Want Cheap, Reliable and Clean Energy – Do They Have the Will to Make That Happen?” – presentation to NAESCO New England Regional Meeting, September 28, 2006.

“The Need for New LNG Infrastructure in Massachusetts and New England: An Update,” Report prepared for Northeast Gateway Energy Bridge, L.L.C., and Algonquin Gas Transmission, LLC, August, 2006.

“Natural Gas & LNG for New England: What’s Needed & How To Get It,” presentation to the Foundation for American Communications Meeting on *New England’s Energy Needs – Who Pays and Who Suffers?*” May 17, 2006.

“Energy Policy Act Section 1813 Comments: Report of the Ute Indian Tribe of the Uintah and Ouray Reservation for Submission to the US Departments of Energy and Interior,” (with Susan F. Tierney, and In Cooperation With The Ute Indian Tribe of the Uintah and Ouray Reservation), May 15, 2006.

“US Energy Infrastructure Vulnerability: Lessons From the Gulf Coast Hurricanes,” Report to the National Commission on Energy Policy, March 2006.

“New England Energy Infrastructure – Adequacy Assessment and Policy Review” (with Susan F. Tierney), prepared for the New England Energy Alliance, November, 2005.

“Federal Legislative Developments in Energy,” presentation to LSI Seminar on Energy in the Northeast, October 2005.

“The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project,” (with Susan F. Tierney), prepared for Northeast Gateway Energy Bridge, L.L.C., and Algonquin Gas Transmission, LLC, June, 2005.

"Climate Change Policy – New Business and Regulatory Risks," presentation to EnviroExpo & Conference, May, 2005.

"Carbon Cap & Trade Allocation Options – Practical Considerations," "Carbon Trading Program Emission Allowances: Practical Considerations for Allocation," and "Allocation of Carbon Allowances to Mitigate Electric Sector Costs," Reports to the National Commission on Energy Policy, May 2005.

"U.S. Energy Infrastructure: Demand, Supply and Facility Siting," Report to the National Commission on Energy Policy, November 2004.

"Comments of Susan F. Tierney and Paul. J. Hibbard on their own behalf," before the *Federal Energy Regulatory Commission, in the Matters of Solicitation Processes for Public Utilities (Docket No. PL04-6-000) and Acquisition and Disposition of Merchant Generation Assets by Public Utilities (Docket No. PL04-9-000),* on the role of independent monitors and independent evaluators in public utility resource solicitations, July 1, 2004.

"Energy and Environmental Policy in the United States: Synergies and Challenges in the Electric Industry" (with Susan F. Tierney), prepared for Le Centre Français sur les Etats-Unis (The French Center on the United States), July, 2003.

"Controlling China's Power Plant Emissions after Utility Restructuring: The Role of Output-Based Emission Controls" (with B.A. Finamore, N. Seidman, and T. Szymanski), *The Sinosphere Journal*, July 2002.

"Siting Power Plants in the New Electric Industry Structure: Lessons from California and Best Practices for Other States" (with S. Tierney), *The Electricity Journal*, June 2002.

"Siting Power Plants: Recent Experience in California and Best Practices in Other States" (with S. Tierney), prepared for The Hewlett Foundation and The Energy Foundation, February 2002.

"Setting and Administering Output-Based Emission Standards for the Power Sector: A Case Study of the Massachusetts Output-Based Emission Control Programs" (with N. Seidman and B. Finamore), prepared for the China Sustainable Energy Program, October 2001.

Before the Federal Energy Regulatory Commission, New England Power Pool and ISO New England, Inc., Docket No. ER01-2329, Joint Affidavit (with J. Besser) on behalf of the New England Renewable Power Producers Association, July 3, 2001.

"Output-Based Emission Control Programs – U.S. Experience" (with N. Seidman, B. Finamore, and D. Moskovitz), prepared for the China Sustainable Energy Program, May 2000.

"P2 and Power Plants: The Massachusetts Allowance Trading Program," in *Proceedings of the National Pollution Prevention Roundtable*, March 2000.

"Safety and Environmental Comparisons of Stainless Steel with Alternative Structural Materials for Fusion Reactors" (with A.P. Kinzig and J.P. Holdren), *Fusion Technology*, August 1994.

"Utility Environmental Impacts: Incentives and Opportunities for Policy Coordination in the New England Region," US EPA CX817494-01-0, RCEE Core Group, June 1994.

"Final Report: Code Development Incorporating Environmental, Safety, and Economic Aspects of Fusion Reactors," UC-BFE-027, Fusion Environmental and Safety Group, University of California, Berkeley, 1991.

Exhibit B

TODD SCHATZKI, Ph.D.
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Dr. Schatzki is an expert in energy and environmental economics and policy, and specializes in the application of microeconomics, econometrics, and data analysis to complex business and policy problems. He has worked with clients on corporate strategy, public policy design, and problems arising in regulation and litigation.

Dr. Schatzki has worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, utility ratemaking and retail electricity markets. He has submitted testimony to both state and federal energy commissions. His research has been supported by organizations such as the Electric Power Research Institute, Edison Electric Institute, Federal Energy Regulatory Commission, and National Association of Regulatory Utility Commissioners. His work has appeared in journals such as the *Journal of Environmental Economics and Management*, *the Electricity Journal*, *Public Utilities Fortnightly*, and *AEI-Brooking Joint Center for Regulatory Studies.* He has also provided litigation support in many cases, including several high profile cases involving alleged wholesale electricity price manipulation and the implications of such manipulation for derivative contracts.

Prior to joining Analysis Group, he had research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis (Vienna, Austria), and was an economist at LECG, LLC and National Economic Research Associates.

EDUCATION

1998 Ph.D., Public Policy, Harvard University, Cambridge, MA

Specialized Fields: Microeconomics, econometrics, industrial organization, natural resource and environmental economics

- Doctoral Fellow, Harvard University, Cambridge, MA (1993-1995)
- Crump Fellowship, Harvard University, Cambridge, MA (1995-1996)
- Pre-doctoral Fellow, Harvard Environmental Economics Program

1993 M.C.P., Environmental Policy and Planning (Urban Studies and Planning,), M.I.T., Cambridge, MA

1986 B.A., Physics, Wesleyan University, Middletown, CT

PROFESSIONAL EXPERIENCE

2005-present	Analysis Group, Inc.
2001-2005	LECG, LLC, *Managing Economist*
1998-2001	National Economic Research Associates, Inc., *Senior Consultant*
1997-1998	Harvard Institute for International Development, *Consultant*
1996-1997	Department of Economics, Harvard University, *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987-1991	Tellus Institute, *Research Associate*

SELECTED CASE WORK

Energy

- **New England Electricity Markets.** Confidential assessment of interactions between state policies affecting electric power resources, including long-term contracts, and wholesale electricity markets.
- **New York Independent System Operator**. Demand curve reset for the New York ISO ICAP market including development annual updating process between resets and ICAP Demand Curve parameters.
- **ISO New England.** Assessment of framework for evaluating capacity market offers from elective transmission projects for market mitigation.
- **Barclays**. Provide analysis of allegations of manipulation of western U.S. electric power exchange markets.
- **Southwest Power Pool Power Suppliers**. Provides analysis and testimony related to what types of costs are appropriately short run marginal costs and thereby should be incorporated into energy market resource offers.
- **New York Independent System Operator**. Evaluation of capacity market rule changes including a forward market structure and multi-year price lock-in, including quantitative economic analysis of changes in market outcomes under alternative market structures.
- **Ameren Missouri**. Analysis of the economic impact of the Mark Twain Project, a new transmission project designed to support renewable energy requirements and other objectives (using PROMOD)
- **ISO New England.** Assistance to the ISO New England market monitor in the development of a de-list offer model consistent with new market rules.
- **Zaremba v. Encana**. Evaluate operating agreements, the structure of the oil and gas industry, and trends in gas pricing in regards to antitrust claims in the market for oi land gas leases.
- **ISO New England.** Assistance in the development of a Winter fuel assurance programs for 2013/14, 2014/15 and 2015/16, including oil inventory, dual fuel, liquefied natural gas and demand response programs

- **Ameren Transmission.** Analysis of the impact of the Multi Value Project No. 16, a new transmission project, on energy market competition in Illinois (using PROMOD).
- **Vancouver Energy**. Assessment of economic impacts of a new energy distribution terminal, including change in economic activity, property value impacts and changes in rail congestion
- **ISO New England.** Assessment of the economic costs associated with winter 2013/2014 reliability programs, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **ISO New England.** Assessment of and testimony regarding the economic and reliability impacts of proposed capacity market rules introducing new performance incentives
- **ITC Midwest.** Analysis of and testimony regarding the LMP and production cost impacts of new transmission infrastructure (using PROMOD)
- **Entergy.** Evaluation of economic damages associated with an alleged contract breach
- **Ameren Transmission.** Analysis of the impact of the Illinois River Project, a new transmission project, on energy market competition in Illinois (using PROMOD)
- **Dayton Power and Light.** Evaluation of the aggregate benefits created by a proposed rate plan
- **Corporation with distribution companies across multiple jurisdictions.** Regulatory assessment considering current ratemaking models, regulatory environment and alternative ratemaking structures
- **ISO New England.** Assessment of the costs, feasibility and effectiveness of technical options to securing fuel supply for gas-fired generators
- **ISO New England.** Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies
- **Pacific Gas and Electric.** Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **Confidential Technology Company.** Analyzed the regional economic impacts of a prototype biofuels production facility at two potential development sites using the IMPLAN model.
- **ISO New England.** Statistical analysis of the performance of resources responding to system contingencies
- **Direct Energy.** Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions
- **ISO New England.** Assistance developing design enhancements for the region's Forward Reserve Markets
- **Confidential Client.** Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software)
- **Confidential Client.** Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software)
- **Confidential Regulated Utility.** Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development
- **Commonwealth Edison.** Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements
- **New England Power Generators Association.** Analysis of impacts of proposed electric power company merger

- **Confidential Technology Company.** Development of a quantitative model of energy savings associated with end-use technological modifications..
- **Confidential Regulated Utility.** Development of a white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load and service challenges
- **EDF Group.** Analysis of financial and credit implications of the sale of a portion of power generation assets
- **New England States Committee on Electricity.** Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy
- **National Grid Utilities.** Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC.** Analysis of "best practices" in state policies for competitive procurement of retail electricity supply
- **New York ISO.** Analysis of single-clearing-price versus pay-as-bid market designs
- **Confidential System Operator.** Analysis of metrics for characterizing the economic value provided by regional transmission organizations
- **TransCanada.** Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts
- **New York ISO.** Analysis of market implications of fuel diversity issues
- **Confidential.** Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding
- **Confidential.** Financial and strategic analysis of gas supply contracting alternatives
- **Confidential.** Analysis of value of generating assets using real options analysis
- **Confidential.** Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts
- **Confidential.** Financial and strategic analysis of renewable generation technologies

Environment

- ***Florida v. Georgia.*** Analysis of economic issues related to current and proposed alternative apportionment of water between the states of Florida and Georgia before the U.S. Supreme Court.
- ***New Jersey DEP v. Occidental Chemical Corp. et al.*** One behalf of Maxus, assessment of reliability of analyses and conclusions reached regarding settlement of claims related to environmental contamination.
- **Chevron.** Development of a white paper on post-2020 climate policy for California
- ***New Jersey DEP v. ExxonMobil***. Assessment of methods for valuation of environmental contamination.
- **American Petroleum Institute.** Assessment of issues related to the impact of changes to National Ambient Air Quality Standard Requirements on oil and gas exploration and production
- **Greater Boston Real Estate Board.** Development of a white paper on mandatory building energy labeling/benchmarking policies

- **Little Hoover Commission.** Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system
- **Exelon.** Analysis of the economic and market consequences of EPA's Clean Air Transport Rule
- **Chevron.** Assessment of lessons learned from Federal requirements for regulatory review for the potential development of state requirements
- **Western States Petroleum Association and Chevron.** Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board
- **Honeywell.** Analysis of proposed limits on HFC consumption under domestic climate policy
- **Electric Power Research Institute.** Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006)
- **Confidential.** Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs
- **Confidential.** Quantitative analysis of the impacts for technology, consumers and asset owners of a market-based domestic climate policy
- **Toyota.** Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements
- **Barajas Airport.** Evaluated the regional economic impacts of runway expansions at the Barajas airport in Spain.

Finance and Commercial Damages

- Analysis of financial and credit implications of the sale of a portion of power generation assets
- Analysis of bond pricing, transactions and holdings related to default of sovereign bonds
- Analysis of transfers between financial institutions within credit card networks
- Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement
- Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product
- Analysis of damages from breach of commodity swap contract (petroleum)
- Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution

Antitrust

- Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement (retail consumer products)
- In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data
- Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement (retail consumer product)

- Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages (office systems)
- Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by DOJ and private parties
- Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents (scientific equipment)
- Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement (medical devices)
- Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent (scientific equipment)

ARTICLES AND PAPERS

"Beyond AB 32: Post-2020 Climate Policy for California" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2014.

"Three Lingering Design Issues Affecting Market Performance in California's GHG Cap-and-Trade Program" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2013.

"Using the Value of Allowances from California's GHG Cap-and-Trade System" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"Implications of Policy Interactions for California's Climate Policy" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," (with Paul Hibbard), *The Electricity Journal*, May 2012.

"California's Cap-and-Trade Decisions," Forbes.com, August 19, 2010.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," (with Susan F. Tierney), *The Electricity Journal*, March 2009.

"Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation" (with Susan F. Tierney and Rana Mukerji), *Public Utilities Fortnightly*, March 2008.

"Free Greenhouse Gas Cuts: Too Good to Be True?" (with Judson Jaffe and Robert Stavins) VoxEU.org, January 3, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy" (with Robert N. Stavins and Judson Jaffe), AEI-Brookings Joint Center for Regulatory Studies, Related Publication 07-01. Jan 2007.

"Options, Uncertainty and Sunk Costs: An Empirical Analysis of Land Use," Journal of Environmental Economics and Management, Vol. 46, p. 86-105, 2003.

"The database on the economics and management of endangered species (DEMES)," (with David Cash, Andrew Metrick, and Martin Weitzman) in *Protecting Endangered Species in the United States: Biological Needs, Political Realities, Economic Choices*. Cambridge University Press, 2001

"The Issue of Climate," *Fundamentals of the Global Power Industry, Petroleum Economist, 2000.*

Review of “Sustainable Cities: Urbanization and the Environment in International Perspective,” *Environmental Impact Assessment Review*, (Vol. 12, No, 4), 1993.

“Bottle Bills and Municipal Recycling,” *Resource Recycling*, June 1991.

WORKING PAPERS

“Quality *and* Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes,” June 23, 2014.

“Reliability and Resource Performance,” May 16, 2012.

“Can Cost Containment Raise Costs? Allowance Reserves in Practice,” March 2012.

Schatzki, Todd, Paul Hibbard, Pavel Darling and Bentley Clinton, Generation Fleet Turnover in New England: Modeling Energy Market Impacts, June, 2011.

"A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," with William Hogan and Scott Harvey. Presented at the IDEI Conference on Competition and Coordination in the Electricity Sector, Toulouse, France, January 16-17, 2004.

“Estimating Structural Change in Industries with Application to Cartels,” June 2003.

“The Pollution Control and Management Response of Thai Firms to Formal and Informal Regulation,” (with Theodore Panayotou) draft, 1999.

“Differential Industry Response to Formal and Informal Environmental Regulations in Newly Industrializing Economies: The Case of Thailand,” (with Theodore Panayotou and Qwanruedee Limvorapitak), Harvard Institute for International Development 1997 Asia Environmental Economics Policy Seminar, Bangkok, Thailand, February 1997.

“The Effects of Uncertainty on Landowner Conversion Decisions,” John F. Kennedy School of Government, Center for Science and International Affairs, Environment and Natural Resources Program, Discussion Paper 95-14, December 1995.

REVIEW OF ACADEMIC ARTICLES

Economics of Energy & Environmental Policy, Ecological Economics, Journal of Environmental Economics and Management

SELECTED PRESENTATIONS

“State Policy and Wholesale Power Markets: Emerging Issues Across the Markets,” Northeast Energy and Commerce Association, Power Markets Conference, November 1, 2016.

“Net Metering,” EUCI Workshop on Residential Demand Charges, October 20, 2016.

“Evaluating Carbon Risk Measures Under Policy Uncertainty,” Workshop, EUCI U.S./Canada Cross-Border Power Summit, March 14-15, 2016.

“Implications of Policy Initiatives for Wholesale Markets,” Northeast Energy and Commerce Association, Power Markets Conference, November 17, 2015.

“The Western United States’ Impact On Global Climate Change Policy”, 2015 WSPA Issues Conference, September 30, 2015.

“Capacity Performance (and Incentive) Reform” and “Out of Market Actions,” EUCI Conference: Capacity Markets: Gauging Their Real Impact on Resource Development & Reliability, August 31-September 1, 2015.

"California Climate Goals for 2030 to 2050," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Local and Regional Climate Protection Efforts," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Current Regional Transmission Planning and Issues in New England," Law Seminar International Transmission in the Northeast, March 19, 2015.

"Stakeholder Assessment and Outlook for the Markets," Power Markets Conference, Northeast Energy and Commerce Association, October 20, 2014.

"Market Changes to Promote Fuel Adequacy – Capacity Markets to Promote Fuel Adequacy," moderator of panel discussion, Northeast Energy Summit 2014, September 17-19, 2014.

"Quality *and* Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes," Center for Research In Regulated Industries 27th Annual Western Conference June 26, 2014.

"Climate Policy Choices – RPS, Cap-and-Trade & the Implications for Actions (and Exits) that Affect Emissions," Electric Utilities Environmental Conference, February 4, 2014.

"Multiple Dimensions of Gas-Electric Coordination Concerns," Electric Utilities Environmental Conference, February 3, 2014.

"The Economics of Cap-and-Trade in the California Power Markets," EUCI Conference, California Carbon Policy Impacts on Western Power Markets, January 27, 2014.

"An Economic Perspective on Building Labeling Policies," Greater Boston Real Estate Board, April 26, 2013.

"Market-Based Policies to Address Climate Change," Sustainable Middlesex, May 4, 2013.

"Market Forces and Prospects/Economic Ripple Effects, 5-10 Years Ahead," Air & Waste Management Association, New England Section, October 12, 2012.

"Gas and Electric Coordination: Is It Needed? If So, To What End?" Harvard Electric Policy Group, Cambridge, MA, October 11, 2012.

"Reliability and Resource Performance," Center for Research In Regulated Industries 31st Annual Eastern Conference May 16, 2012.

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," International Industrial Organization Conference, Boston, MA, April 9, 2011.

"Ratemaking Mechanisms/Tools as Carrots for Achieving Desirable Regulatory Outcomes," Conference on Electric Utility Rate Cases, Law Seminars International, Boston, Massachusetts, November 9, 2010.

"Evolving Issues in Revenue Decoupling: Designs for an Era of Rising Costs," Center for Research In Regulated Industries 29th Annual Eastern Conference May 19, 2010.

"Aligning Interest with Duty: Revenue Decoupling as a Key Element of Accomplishing Energy Efficiency Goals," National Conference of State Legislatures, Fall Forum, December 8, 2009.

"Federal Proposals to Limit Carbon Emissions and How They Would Affect Market Structures – Regional Trading Programs' Futures in Light of New Federal Interest in Reducing GHG Emissions," Energy in California, Law Seminars International, San Francisco, California, September 15, 2009.

"Current Market, Technology and Regulatory Risks: Impact on Investment and Implications for Policy", Utility Rate Case, Issues and Strategy 2009, Law Seminars International, Las Vegas, Nevada, February 9, 2009.

"An Economic Perspective on the Benefits of Going Green," Harvard Electricity Policy Group, Atlanta, Georgia, December 11-12, 2008.

"Implications of Current Regulatory, Technology and Market Risks," Energy in California, Law Seminars International, San Francisco, California, September 22-23, 2008.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," National Association of Regulatory Utility Commissioners Summer Committee Meetings, Portland, Oregon, July 20, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy, Key Findings and Lessons Learned," POWER Research Conference on Electricity Markets and Regulation, University of California at Berkeley, March 21, 2008.

"Preliminary Findings: Study of Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," National Association of Regulatory Utility Commissioners Annual Meeting, Washington, D.C., February 17, 2008.

"The ABC's of California's AB 32: Issues and Analysis, Cost Analyses and Policy Design" Environmental Market Association Webinar, April 12, 2007.

SELECTED CONSULTING REPORTS

Study to Establish New York Electricity Market ICAP Demand Curve Parameters (Hibbard, P., Aubuchon, C., Berk, E. and Llop, C.), Prepared for the New York Independent System Operator, June 2016.

NYISO Capacity Market: Evaluation of Options, (with Hibbard, P., Aubuchon, C., and Wu, C.), Prepared for the New York Independent System Operator, May 2015.

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives (with Paul Hibbard), prepared for ISO New England, September 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis, with Rodney Frame and Pavel Darling, Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, April 9, 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project, with Rodney Frame and Pavel Darling, Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, March 22, 2013.

Analysis of Reserve Resources: Activation Response following Contingency Events, prepared for ISO New England, May 29, 2012.

Economic and Environmental Implications of Allowance Benchmark Choices (with Robert N. Stavins), prepared for the Western States Petroleum Association, October 2011.

Next Steps for California Climate Policy II: Moving Ahead under Uncertain Circumstances (with Robert N. Stavins), prepared for the Western States Petroleum Association, April 2010.

Options for Addressing Leakage in California's Climate Policy (with Jonathan Borck and Robert N. Stavins), prepared for the Western States Petroleum Association, February 2010.

Addressing Environmental Justice Concerns in the Design of California's Climate Policy (with Robert N. Stavins), prepared for the Western States Petroleum Association and the AB 32 Implementation Group, November 2009.

Next Steps for California with Federal Cap-and-Trade Policy On the Horizon (with Robert N. Stavins and Jonathan Borck), prepared for the Western States Petroleum Association, July 2009.

Evolving GHG Trading Systems Outside Its Borders: How Should California Respond? (with Robert N. Stavins and Jonathan Borck), prepared for the Western States Petroleum Association, July 2009.

Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, (with Susan Tierney) prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008.

Uniform Pricing versus Pay-as-bid: Does it Make a Difference?, (with Susan Tierney and Rana Mukerji) prepared for the New York Independent System Operator, March 2008.

Prospects for the U.S. Nuclear Industry, (co-author), prepared for a major Japanese electric power company, January 2001.

Costs and Benefits of Fish Protection Alternatives at Mercer Generating Station, (with David Harrison and Michael Lovenheim), prepared for Public Service Enterprise Group, September 2000.

Economic Evaluation of EPA's Proposed Rules for Cooling Water Intake Structures for New Facilities, (with David Harrison) prepared for the Utility Water Act Group, November 2000.

The Impacts of Revised Salem Refueling Schedules on the Wholesale and Retail Electric Market, (with David Harrison and Gene Meehan) prepared for Public Service Enterprise Group as a filing to New Jersey Department of Environmental Protection, September 2000.

Setting Baselines for Greenhouse Gas Credit Trading Programs: Lessons from Experience with Environmental and Non-Environmental Program, (with David Harrison) Electric Power Research Institute Report #1000147, December 2000.

Fueling Electricity Growth for a Growing Economy, Background Paper, (with David Harrison) prepared for the Edison Electric Institute, July 2000.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 2 Executive Report (Contributor), Electric Power Research Institute, Technical Report 1000097, December 2000.

Economic Evaluation of Alternative Revised Refueling Outage Schedules for Salem Power Plant, (with D. Harrison and J. Murphy), prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, July 2000.

Critical Review of "Economic Impacts of On Board Diagnostic Regulations," (with D. Harrison and S. Chamberlain) prepared for Alliance of Automobile Manufactures, January 2000.

Costs and Benefits of Alternative Revised Refueling Outage Schedules, (with D. Harrison and J. Murphy), prepared for Public Service Electric and Gas Company, July 1999.

Costs and Benefits of Fish Protection Alternatives at the Salem Facility, (with D. Harrison and J. Murphy) prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, March 1999.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 1 Executive Report, (Contributor) Electric Power Research Institute, February 1999.

Economic Benefits of Barajas Airport to the Madrid Region and the Neighboring Communities, (with D. Harrison, J. Garcia-Cobos, and D. Rowland) prepared on behalf of the Spanish Government, January 1999.

Costs and Benefits of Alternatives for Modifying Cooling Water Intake at the Hudson Facility, (with D. Harrison, D. Rowland and J. Murphy), prepared for Public Service Electric and Gas Company, November 1998.

Disposal Cost Fee Study, (with Frank Ackerman, Gretchen McClain, Irene Peters, and John Schall) prepared for the California Integrated Waste Management Board, 1991.

The Marginal Cost of Handling Packaging Materials in the New Jersey Solid Waste System, (with John Schall) prepared for The Council of State Governments and the New Jersey Department of Environmental Protection, 1990.

Energy Implications of Alternative Solid Waste Management Systems, (with Monica Becker and Allen White), prepared for the Northeast Regional Biomass Program, Coalition of Northeastern Governors Policy Research Center, 1990.

TESTIMONY AND OTHER FILINGS

Pre-Filed Testimony on behalf of Vancouver Energy, Washington Energy Facilities Site Evaluation Council, Case No. 15-001, May 2016.

Surrebuttal Testimony on behalf of Ameren Transmission Company of Illinois, Missouri Public Service Commission, Case No. EA-2015-0146, November 16, 2015.

Affidavit on behalf of Joint Filing Group, Southwest Power Pool, Federal Energy Regulatory Commission, Docket No. ER15-2268-000, August 31, 2015.

Direct Testimony on behalf of Ameren Transmission Company of Illinois, Missouri Public Service Commission, Case No. EA-2015-0146, May 29, 2015.

Rebuttal Testimony on behalf of Ameren Transmission Company of Illinois, Illinois Commerce Commission, Docket No. 14-0514, March 5, 2015.

Rebuttal Testimony on behalf of MidAmerican Transmission Company, Illinois Commerce Commission, Docket No. 14-0494, March 5, 2015.

Direct Testimony on behalf of Ameren Transmission Company of Illinois, Illinois Commerce Commission, Docket No. 14-0514, August 21, 2014.

Direct Testimony on behalf of MidAmerican Transmission Company, Illinois Commerce Commission, Docket No. 14-0494, August 4, 2014.

Rebuttal Testimony on behalf of ITC Midwest LLC, Minnesota Public Utilities Commission, Docket No. CN-12-1053, April 25, 2014.

Direct Testimony on behalf of ITC Midwest LLC, Minnesota Public Utilities Commission, Docket No. CN-12-1053, February 24, 2014.

Testimony on behalf of the ISO New England, Federal Energy Regulatory Commission, Docket No. ER14-1050-001, February 12, 2014.

Affidavit on behalf of the ISO New England, Performance Incentives Market Rule Changes, Federal Energy Regulatory Commission, Docket No. ER14-1050-001, January 14, 2014.

Comments submitted to the California Air Resources Board Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program, August 2011 (with Robert N. Stavins).

Comments submitted to the Little Hoover Commission's Study of Regulatory Reform in California, January 2011 (with Robert N. Stavins).

Comments submitted to the California Air Resources Board Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program, December 2010.

Comments submitted to the California Air Resources Board Regarding Cost Containment Provisions of Preliminary Draft Cap-and-Trade Regulation, July 2010.

Comments submitted to the Economics and Allocation Advisory Committee, California Air Resources Board regarding draft report "Allocating Emissions Allowances Under California's Cap-and-Trade System," December 1, 2009 (with Robert N. Stavins).

Exhibit C

CRAIG P. AUBUCHON

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Mr. Aubuchon specializes in the economic and statistical analysis of complex issues in the areas of energy, environment, and finance. He has consulted to individual utilities, system and region planners, and private developers within the electricity, natural gas, and water markets on a wide range of cases, including individualized project finance and asset valuations, planning evaluations and production cost modeling of system reliability and regional environmental emissions, and consumer impact analyses for regulator consideration. His recent research considers the application of cost-benefit analysis across regulatory frameworks, including the economic value of water and energy within different sectors. He has presented research findings at industry conferences and in peer-reviewed publications and client-specific consulting reports.

Mr. Aubuchon has also supported several academic affiliates through all phases of the litigation process, including pre-trial discovery and expert report and trial preparation. His recent work has included managerial and analytical support for a comprehensive evaluation of the economic value of water in the equitable apportionment of the Apalachicola-Chattahoochee-Flint River Basin. He has also assisted in the assessment of anticompetitive conduct arising from industry mergers and alleged market manipulation or company policies. These matters span a wide range of industries, including heavy manufacturing, pharmaceuticals, financial markets, and consumer card payments.

Prior to joining Analysis Group, Mr. Aubuchon worked at the Federal Reserve Bank of St. Louis, where he specialized in the fields of monetary policy, financial markets, and international trade.

PROFESSIONAL EXPERIENCE

2012–Present	Analysis Group – Boston, MA *Associate, Manager*
2011	American Water Works Association – Washington, District of Columbia *Summer Associate, Government and Regulatory Affairs*
2007–2010	Federal Reserve Bank of St. Louis – St. Louis, MO *Senior Research Associate*

EDUCATION

2012	M.P.A., School of Public and Environmental Affairs, Indiana University
2012	M.S.E.S., School of Public and Environmental Affairs, Indiana University
2006	B.A., Economics and Environmental Studies, *summa cum laude*, Washington University in St. Louis

SELECTED ENERGY AND ENVIRONMENT CASEWORK & EXPERIENCE

- ***Testimony support in equitable apportionment matter before the U.S. Supreme Court***
  Supported academic expert affiliate in all phases of litigation. Provided analytical and managerial support in a comprehensive evaluation of the economic value of water to municipal and industrial and agricultural water users in the Apalachicola-Chattahoochee-Flint River Basin.

- ***Testimony support in rate case proceeding and review of prudence***
  As part of traditional rate case filing, supported Expert testimony and evaluated the precedent and standards applied to utility investments. Included detailed review and application of both the known and measurable and prudence standards.

- ***Evaluation of capital structure and cost of capital for a regulated Transmission Owner***
  Provided strategic and analytical support to the Vermont Electric Power Company. Reviewed the reasonable range of capital structure for the Vermont Transco. Conducted peer-group benchmarking and qualitative review of additional risk factors.

- ***NYISO 2017-2021 Demand Curve Reset***
  Managed the Analysis Group team selected to be the independent consultant for the New York Independent System Operator 2017-2021 Demand Curve Reset. Project included monthly presentations to market participants and filing of proposed demand curve values with the Federal Energy Regulatory Commission. Oversaw the development of a detailed net energy and ancillary service revenues model and a demand curve model. Included assessment of market conditions, including cost of capital for new power plant construction in New York.

- ***Evaluation of winter reliability in New England wholesale power markets***
  Worked on behalf of the Massachusetts Attorney General Office; evaluated power system reliability in New England, including an analysis of expected natural gas pipeline capacity, natural gas demand, and electric system generation. Assessed a wide range of potential options to meet stressed system conditions, including market responses, additional infrastructure (gas pipelines and transmission), and increased energy efficiency and distributed energy resources. Evaluated impact on natural gas prices, wholesale electric prices, total consumer impact (including cost of supply options) and total environmental emissions.

- ***Evaluation of net revenues and consumer impacts for the continued operation of a large baseload generating units under future climate policies***
  Worked with a large investor owned utility to assess the potential range of future generator revenues, consumer impacts, and utility revenues under various long term forecasts of climate policy, macroeconomic conditions, and utility procurements.

- ***Evaluation of EPA Clean Power Plan compliance strategies and system reliability impacts***
  Prepared a series of white papers that evaluated system reliability impacts of the EPA's proposed Clean Power Plan. Included a discussion of tools and practices available to system regulators, utilities and merchant owners for compliance under various State Implementation Plans. Reports covered in national press and included as evidence in formal testimony before U.S. Congressional committees.

- ***Asset sale negotiations and expert testimony support for integrated resource planning resource procurement***
  Demonstrated value over life of asset to consumers, including detailed evaluation of resource adequacy needs, long term growth forecasts, and state policy. Developed detailed financial model to assess and advise on consumer impacts of various power purchase agreement structures, including asset sale. Client selected by utility for resource procurement at target price.

- ***Market demand analysis for natural gas pipeline***
  Assessed market demand for a new natural gas pipeline in the Ohio. Evaluated market conditions in all end-user categories, including electric power sector. Issued final report, which was included as part of pre-filing in FERC Docket PF15-10-000.

- ***Evaluation of Capacity Market Designs for Independent System Operator***
  Supported the New York Independent System Operator in an evaluation of capacity market designs, including the implications of transitioning to a forward market. Included detailed quantitative analysis of impacts to load and generation under different market scenarios. Comprehensive qualitative analysis of resource adequacy issues, state policy goals, and system reliability.

- ***Financial analysis and cost benefit analysis of emerging storage technology***
  Conducted detailed financial analysis and cost benefit analysis of emerging storage technology. Evaluated net benefits over asset life, considering value streams from energy, distribution, and transmission services. Assessed avoided costs for existing utilities.

- ***Macroeconomic Evaluation of State Energy Policy***
  Worked with an interdisciplinary team to evaluate the macroeconomic impact of the Massachusetts' Green Communities Act. Gathered necessary demand and supply assumptions, and used electric dispatch production simulation software (PROMOD) to model the impact of additional renewable energy generation and energy efficiency load reductions on region and state level impacts to direct costs and generator emissions.

- ***Strategic recommendations for non-market attributes of clean energy production***
  Provided economic analysis of carbon markets and clean energy production. Worked with a leading energy provider to consider future design of clean energy standards and impact to business valuation. Defined a set of plausible future scenarios and used electric dispatch production simulation software (PROMOD) to model changes in electricity costs and region-wide emissions. Benchmarked and compared model results to current markets and future policy goals.

- ***Testimony support in long term utility resource competitive procurement of energy***
  Provided expert testimony support including evaluation of competing generation resource bids. Included a detailed consideration of power supply economics and scenario analysis of state energy policy and relevant critique of opposing party testimony. Client was selected for negotiations of a power purchase agreement.

- ***Cost-Benefit Analysis of Utility Infrastructure Replacement Programs***
  Conducted a cost-benefit analysis of accelerated infrastructure replacement programs used by natural gas local distribution companies. Shared findings with the Massachusetts Executive Office of Energy and Environmental Affairs and Massachusetts Department of Public Utilities.

- ***Strategic Analysis of Alternative Rate Structures***
  Provided support in the preparation of an internal consulting report for a leading U.S. energy provider interested in the strategic considerations of alternative rate structures, including an emphasis on reliability and efficiency goals.

- ***Evaluation, Monitoring, and Verification for Energy Efficiency Study***
  Analyzed future regulation scenarios for a major environmental non-profit, focusing on potential evaluation, monitoring, and verification protocol design for energy efficiency and carbon dioxide credits under future New Source Performance Standards.

- ***Economic Valuation of Hydropower Plant***
  Assessed the economic value of hydropower production and electricity markets for a major stakeholder in the Northeast.

- ***Damage Assessment for Major Utility Provider***
  Provided support for expert testimony and report, including a detailed analysis of the statistical sampling procedures used during an audit of utility cost allocations.

SELECTED ECONOMIC AND FINANCIAL CASEWORK & EXPERIENCE

- ***Support Department of Justice with a comprehensive market analysis of large credit card provider***

  Supported expert testimony, including market analysis on the use of credit and debit transactions. Evaluated claims of market power and monopoly pricing behavior by analyzing confidential transactional and account level data.

- ***Class Action certification and damages analysis for a leading pharmaceutical manufacturer***

  Supported expert testimony, including an evaluation of class action certification claims related to anti-competitive actions by a major pharmaceutical company. Modeled consumer level impacts of coupon and rebate programs, and estimated reasonable damages under scenarios of but-for generic entry of competing drugs.

- ***Anti-trust evaluation of a vertical merger of heavy industrial manufacturers***

  Economic analysis of a vertical integration between two large industrial parts manufacturers. Provided expert support and conducted statistical analysis of price impacts to competition firms.

- ***Economic assessment of Franchise – Franchisee relationships in the Automobile Industry***

  Supported expert testimony and critiqued opposing expert's class certification report. Considered the economic impact of state level reimbursement laws of warranty repairs by auto manufacturers to auto dealerships.

- ***Assessment and Benchmark of Organizational Capability to manage risk in technologically complex industries***

  Worked with an interdisciplinary team to support expert testimony. Analyzed the organizational culture of a major oil and gas company and assessed capabilities for appropriate risk management.

SELECT CONSULTING REPORTS

"Electric System Reliability and EPA's Clean Power Plan: The Case of MISO", (with S. Tierney and P. Hibbard), Report for the Energy Foundation, June 2015.

"Ohio Natural Gas Market Study: Prepared for the NEXUS Gas Transmission Project", (with S. Tierney and P. Darling), Prepared for the NEXUS Gas Transmission Project, June 2015.

"NYISO Capacity Market: Evaluation of Options", (with P. Hibbard, T. Schatzki, and C. Wu), Report for the New York Independent System Operator, May 2015.

"Electric System Reliability and EPA's Clean Power Plan: The Case of PJM", (with S. Tierney and P. Hibbard), Report for the Energy Foundation, March 2015.

"Electric System Reliability and EPA's Clean Power Plan: Tools and Practices", (with S. Tierney and P. Hibbard), Report for the Energy Foundation, February 2015.

"Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs" (with P. Hibbard), Prepared on behalf of the Barr Foundation, available 2013

"Does a Water Economy Exist? The Impact of the Availability of Water on Employment in U.S. Metropolitan Areas," developed under EPA Contract Number EP-W-10-002, Importance of Water Study, September 2012

"Lessons from Short-Term Supply Disruptions: Providing Confidence and Context to FEMA's Methodology," developed under EPA Contract Number EP-W-10-002, Importance of Water Study, September 2012

PUBLICATIONS

"The Currency of Connections: An Analysis of the Urban Economic Impact of Social Capital" (with T.A. Engbers and B.M. Rubin), *Economic Development Quarterly*, September 2016.

"What is Water Worth?" (with S. Tierney), Analysis Group Forum, Fall/Winter 2013 and Wall Street Journal *MoneyBeat*, March 2014

"Evaluating the Embedded Energy in Real Water Loss" (with J.A. Roberson), *Journal of American Water Works Association*, 106(3), pp. E129-E138, March 2014

"From What Perspective? Distributional Accounting within Cost Benefit Analysis," *Journal of American Water Works Association*, 105(11, pp. E619-627, November 2013

"The Economic Value of Water: Providing Confidence and Context to FEMA Methodology" (with K.M. Morley), *Journal of Homeland Security and Emergency Management*, 10(1), pp. 1-21, April 2013

"Rate Structures as Conservation Tools: Price Perception and Non-Price Controls" (with J.A. Roberson), *Journal of American Water Works Association*, 104(8), pp. E446-E456, August 2012

"Outsourcing – how much of it do we do, and what impact does it have? Some evidence from Germany" (with S. Bhaumik and S. Bandyopadhyay), *St. Louis Review,* 94(4), pp. 287-304, July/August 2012

"A primer on Social Security systems and reforms" (with C. Garriga and J.C. Conesa), *St. Louis Review*, 93(1), pp. 19-35, January/February 2011

"The Geographic Distribution and Characteristics of U.S. Bank Failures, 2007-2010: Do Bank Failures Still Reflect Local Economic Conditions?" (with D.C. Wheelock), *St. Louis Review*, 92(5), pp. 395-415, September/October 2010

"What's Under the TARP?" *Economic Synopses*, No. 20, April 2009

"The Fed's Response to the Credit Crunch" *Economic Synopses*, No. 6, January 2009

"The Microfinance Revolution: An Overview" (with R. Segupta), *St. Louis Review*, 90(1), pp. 9-30, January/February 2008

PRESENTATIONS

"Embodied Energy of Lost Water: Evaluating the Energy Efficiency of Infrastructure Investments" (with J.A. Roberson), Water Environment Federation: Energy and Water 2013 Conference, Nashville, TN, May 2013.

"Boom Times: Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs," Society of Benefit Cost Analysis, Annual Conference, February 2013

"Lessons from Short-Term Supply Disruptions: Providing Confidence and Context to FEMA's Methodology," Importance of Water EPA Technical Workshop, September 2012

"Does a Water Economy Exist? The Impact of the Availability of Water on Employment in U.S. Metropolitan Areas," Importance of Water EPA Technical Workshop, September 2012

"Price Perception and Non-Price Controls Under Conservation Rate Structures," AWWA Sustainable Water Management Conference and Exposition, March 2012

Exhibit D

Study to Establish New York Electricity Market ICAP Demand Curve Parameters

Values for the 2017/18 ICAP Demand Curves

With data for the period September 1, 2013 through August 31, 2016

Analysis Group, Inc.
Lummus Consultants International, Inc.

September 13, 2016

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This Report provides values for the 2017/18 ICAP Demand Curves. *All numerical results presented in this Report include the most current and finalized data as required for the estimation of net EAS revenues and escalation of capital costs. Net EAS revenues are estimated using data for the three-year period September 2016 through August 2016.*

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ACRONYMS AND GLOSSARY

Capitalized terms that are not specifically defined in this Report shall have the meaning set forth in the NYISO Market Administration and Control Area Services Tariff and Open Access Transmission Tariff.

Acronym or Abbreviation	Description
AF	Attachment Facilities
ATWACC	After Tax Weighted Average Cost of Capital
BACT	Best Available Control Technology
BPCG	Bid Production Cost Guarantee
Btu	British Thermal Units
CAES	Compressed Air Energy Storage
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CB&I	Chicago Bridge & Iron Company
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CSAPR	Cross State Air Pollution Rule
CSO	Capacity Supply Obligation
CSPP	Comprehensive System Planning Process
CT	Combustion Turbines
CTO	Connecting Transmission Owner
CY	Class Year
DAMAP	Day Ahead Marginal Assurance Payment
DCR	ICAP Demand Curve reset
DMNC	Dependable Maximum Net Capability
DOL	NY Department of Labor
EAS	Energy and Ancillary Services
EERP	Expected Economy-wide Risk Premium
EFORd	Equivalent Demand Forced Outage Rate
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, Construction
ERC	Emission Reduction Credits

Acronym or Abbreviation	Description
FERC	Federal Energy Regulatory Commission
FEMA	Federal Emergency Management Agency
FICA	Federal Insurance Contributions Act
FTE	Full Time Equivalent
GADS	Generating Availability Data System
GE	General Electric International, Inc.
GHG	Greenhouse Gases
GTP	GE Gas Turbine Performance Estimating Program
HHV	Higher Heating Values
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
ICR	Installed Capacity Requirement (MW)
IRM	Installed Reserve Margin (%)
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
kW-mo	Kilowatt-month
kW-year	Kilowatt-year
LAER	Lowest Achievable Emission Rate
LBMP	Location Based Marginal Pricing
LCR	Locational Capacity Requirement (%)
LDC	Local Distribution Company
LFG	Landfill Gas
LHV	Lower Heating Value
LI	Long Island
LIPA	Long Island Power Authority
LOE	Level of excess
LOE - AF	Level of excess adjustment factor
LOLE	Loss of Load Expectation
MHPS	Mitsubishi Hitachi Power Systems
MIS	Minimum Interconnection Standard
MMBtu	Million Btu

Acronym or Abbreviation	Description
MMU	Market Monitoring Unit (Potomac Economics)
MPs	Market Participants
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hour
NA	Not applicable
NAAQS	National Ambient Air Quality Standards
NEPA	New Entry Price Adjustment
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NNSR	Nonattainment New Source Reviews
NOx	Nitrogen Oxides
NRC	U.S. Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
NYC	New York City
NYCA	New York Control Area
NYCRR	New York Codes, Rules and Regulations
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
O&M	Operations and Maintenance
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, L.L.C.
POI	Points of Interconnection
PPA	Power Purchase Agreement
ppb	Parts per billion
ppmvd	Parts per million by volume on a dry basis
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration

Acronym or Abbreviation	Description
PSEG Long Island	PSEG Long Island LLC
psig	Pounds per square inch gauge
PTE	Potential to Emit
PV	Photovoltaic
P&W	Pratt & Whitney Power Systems
REV	New York Reforming the Energy Vision proceeding
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
ROS	Rest of State
RP	Reference point price
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SDU	System Deliverability Upgrades
SER	Significant Emission Rates
Siemens	Siemens Energy Inc.
SiPEP	Siemens Performance Estimating Program
SO_2	Sulfur Dioxide
SUF	System Upgrade Facilities
UARG	Utility Air Regulatory Group
UCAP	Unforced Capacity
ULSD	Ultra-low Sulfur Diesel
U.S.	United States
USEPA IPM	United States Environmental Protection Agency Integrated Planning Model
VOC	Volatile Organic Compounds
VSS	Voltage Support Service
WACC	Weighted Average Cost of Capital
WSR	Winter-to-summer ratio
ZCP	Zero Crossing Point
ZCPR	Zero Crossing Point ratio

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I. INTRODUCTION AND SUMMARY

A. Introduction

Section 5.14.1.2 of the New York Independent System Operator, Inc. (NYISO) Market Administration and Control Area Services Tariff (Services Tariff) requires that locational ICAP Demand Curves be established periodically through a review by an independent consultant, and be reviewed with stakeholders and the NYISO through a process that culminates in the filing with the Federal Energy Regulatory Commission (FERC) of ICAP Demand Curves approved by the NYISO Board of Directors in November of the relevant year.

On September 30, 2015, the NYISO contracted with Analysis Group Inc. (AGI) to conduct the independent review of ICAP Demand Curves, to be used starting in Capability Year 2017/2018. Analysis Group, Inc. (AGI) teamed with Lummus Consultants International (LCI) to complete the development of ICAP Demand Curve parameters, described in this Report.

B. Study Purpose and Scope

The purpose of this Report is to summarize the results of our study of the ICAP Demand Curve process and parameters. As required by the Services Tariff, the Report evaluates the net cost of a peaking plant, 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", with the scale (i.e., number and size of units) identified in the consultant's review.[1] The Services Tariff identifies multiple requirements for the development of ICAP Demand Curve parameters. Our review and analysis conforms to these various requirements. For example, the Services Tariff requires that the periodic review of ICAP Demand Curves:

> "…assess (i) the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements, and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[2]

The costs and revenues are to be determined under conditions that reflect a need for new capacity in NYCA and in each Locality. Specifically, the Services Tariff requires that:

> "…[t]he cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in

[1] Services Tariff, Section 5.14.1.2.

[2] Services Tariff, Section 5.14.1.2.

> which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity…"[3]

Several additional elements to be included in the consultant's review are specified in the Services Tariff, including the following:

- The appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves declines to zero (the zero crossing point, or ZCP);
- The translation of the annual net revenue requirement of the peaking plant into monthly values that reflect differences in seasonal capability; and
- The escalation factor and inflation component of the escalation factor applied to the ICAP Demand Curves.[4]

Finally, the Services Tariff specifies the process for selecting the independent consultant, and sets forth a schedule for the consultant's ICAP Demand Curve review and review of the consultant's findings and report by stakeholders, NYISO, the Market Monitoring Unit (MMU), and the NYISO Board of Directors. The entire process – herein referred to as the ICAP Demand Curve reset (DCR) process – is to be completed and filed with FERC no later than November 30 of the year prior to the first Capability Year in which the ICAP Demand Curves shall apply (in this case, the Capability Year beginning May 1, 2017).

NYISO's request for proposals (RFP) for an independent consultant to complete the DCR evaluation identified certain specific items to be reviewed by the consultant in this reset, in addition to those described above. In particular, the RFP required that the consultant provide, prior to completion of the Report:

> "…recommendations regarding extending beyond the three-year period for the ICAP Demand Curves. The consultant will also provide recommendations to enhance the projection of Energy and Ancillary Services revenues. These recommendations are intended to inform the NYISO, its independent Market Monitoring Unit, and stakeholders in their consideration of modifying the Services Tariff prescribed cycle for resetting the ICAP Demand Curves to a period of longer than the current three-year period."

This Report describes the review by and contains the recommendations of AGI and LCI with respect to the ICAP Demand Curves to be implemented beginning with the 2017/2018 Capability Year. The Report also summarizes our evaluation of and recommendations for potential enhancements to the projection of Energy and Ancillary Services (EAS) revenues, and the extension of the DCR period beyond three years. These specific items were considered and discussed with stakeholders early in the

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[3] Services Tariff, Section 5.14.1.2.

[4] Services Tariff, Section 5.14.1.2.

DCR process, culminating in a filing with FERC on May 20, 2016.[5] FERC accepted these changes on July 18, 2016.[6]

C. Study Process

AGI and LCI have conducted the ICAP Demand Curve review in an open and transparent process that involved the full vetting of issues raised by stakeholders and with the NYISO. AGI and LCI have worked with the NYISO throughout the process to conduct an orderly and transparent presentation of key issues for discussion with stakeholders, and to ensure that the ICAP Demand Curve review was consistent with the requirements under the Services Tariff and the structure and experience of New York's wholesale electricity markets. Table 1 contains a list of stakeholder meetings in which AGI or LCI participated, and the issues discussed with stakeholders in each meeting.

AGI/LCI's review of ICAP Demand Curve issues with NYISO and stakeholders helped identify important scoping issues, evaluate concepts and metrics relevant to the DCR process, and provide guidance for AGI/LCI's consideration of and recommendations on key DCR issues and outcomes. While the content of and findings in this Report rest solely with AGI and LCI, it reflects the results of a productive and deliberative process involving full and substantive input throughout a comprehensive and nearly year-long stakeholder process.

[5] Tariff changes were filed with FERC on May 20, 2016 in Docket No. ER16-1751-000. AGI and LCI worked with stakeholders through the ICAPWG to discuss potential changes to the DCR process. These meetings discussed the range of options related to key issues described throughout this report, evaluation criteria for selecting particular options, and AGI's evaluation of those issues. AGI presented its initial recommendations on DCR process changes to the ICAPWG on January 26, 2016; provided additional details on February 19, 2016; quantitative backcasting of proposed changes on March 3, 2016; and presented an overview of changes to both the Business Issues Committee and Management Committee on March 17 and 30, respectively. The motion to approve the proposed enhancements to the DCR process passed the Management Committee with 69.68 percent affirmative votes.

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

Table 1: Summary of AGI and LCI Stakeholder Engagement

Date	Committee / Working Group	Topic
October 19, 2015	ICAPWG	Introduction and overview Initial scoping issues and environmental regulations update
November 18, 2015	ICAPWG	DCR period extension Tradeoffs and considerations
December 16, 2015	ICAPWG	Interrelated threshold issues Periodicity; net EAS revenues; annual updates Technology screening criteria and environmental permitting considerations
January 26, 2016	ICAPWG	Initial recommendations on periodicity, net EAS revenues, and annual updates
February 19, 2016	ICAPWG	Additional details on initial recommendations for periodicity, net EAS revenues, and annual updates Status update on peaking unit technology capital cost estimates
March 3, 2016	ICAPWG	Additional backcasting analysis Comparison of variability within resets (annual updates) and between resets (due to DCR)
March 17, 2016	Business Issues Committee	Overview of recommended DCR changes
March 30, 2016	Management Committee	Overview of recommended DCR changes
April 25, 2016	ICAPWG	Annual updates parameters, net EAS revenues model status, and overview of financial parameters Initial capital cost estimates and operating parameters
June 2, 2016	ICAPWG	Initial gas hub recommendations Initial financing parameter recommendations
June 15, 2016	ICAPWG	Updated electrical interconnection cost estimates, updated capital cost estimates, and updated Variable O&M cost estimates Initial consideration of dual fuel and emission control technology Initial review of ICAP Demand Curve shape and slope
June 27, 2016	ICAPWG	Presentation of Draft Report
July 20, 2016	ICAPWG	Overview of Stakeholder Feedback on Draft Report Review of net EAS revenues model, Real-Time Commitment Prices and Intraday Fuel Premium/Discount Values Preliminary informational combined cycle net EAS revenue model logic
August 10, 2016	ICAPWG	Response to Stakeholder Feedback on Draft Report Review of level of excess adjustment factors Review of informational combined cycle results

Note: All materials are posted and available on the NYISO website, available here: http://www.nyiso.com/public/markets_operations/committees/index.jsp

D. Changes to the DCR Process and Net EAS Calculation Method

As noted above, the RFP for an independent ICAP Demand Curve consultant required an initial phase to review the potential extension of time between DCR processes and enhancements to the approach for estimating net EAS revenues. In this initial phase, AGI fully evaluated options related to DCR periods and net EAS revenue estimation through the stakeholder process and ultimately recommended several enhancements to the DCR process, including the following:

- ***DCR Periodicity*** – Changing the period covered by each reset from three to four years.
- ***Net EAS Revenue Estimation*** – Modifying the approach taken to estimating net EAS revenues of the peaking plant in a way that increases the transparency and repeatability of net EAS calculations.
- ***Annual Updating*** – Updating ICAP Demand Curve parameters annually based on the most recent, publicly-available historical information related to market prices and technology-specific escalation indices.

The proposed enhancements were recommended in order to improve the stability and predictability of DCR results, and to allow for the gradual evolution of ICAP Demand Curve reference point prices (RP) over the years between DCRs. This approach enables annual updating of RPs through formulaic adjustments based on publicly-available data inputs. These proposed changes, as well as associated changes to the Services Tariff, were filed for approval with FERC on May 20, 2016, and were accepted by FERC on July 18, 2016.[7] These changes are discussed in more detail in context throughout the Report.

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

E. Study Analytic Approach and Outline

The creation of ICAP Demand Curves for NYCA and each Locality includes four specific tasks, organized and described in this Report as follows:

1. ***Assessment of the peaking plant technology (Section II).*** In this step, we evaluate and develop information on technologies with the goal of fulfilling the Services Tariff's requirement that the peaking plant be the technology with the lowest fixed and highest variable costs and be economically viable.[8] Specifically, we evaluate available technologies consistent with the Services Tariff's definition in NYCA and each Locality with respect to capital costs, operating costs, operating parameters, and applicable siting and environmental permitting requirements. Based on these factors, we also consider how the peaking plant could be practically constructed within each Locality, and how a potential developer would evaluate various design capabilities and environmental control technologies when making investment decisions in consideration of project development and operational risk, and opportunities for revenues over the economic life of the project.[9] The technology choice assessment, including the recommended technology, its installed capital cost, and operational costs and parameters, is presented in Section II.

2. ***Estimation of the gross cost of new entry (gross CONE) (Section III).*** In this step, we estimate the fixed annual costs of the peaking plant, including the recovery of and return on upfront capital costs, taxes, insurance and fixed operations and maintenance (O&M). A levelized fixed charge is calculated to ensure recovery of capital costs and taxes given financial parameters that reflect the specific risks associated with merchant plant development in the NYISO markets.

3. ***Estimation of net EAS revenues for the peaking plant technology (Section IV).*** In this step, expected EAS revenues for the peaking plants in NYCA and each Locality, net of operating costs, are estimated using a model constructed by AGI for this purpose. The model includes a mechanism to adjust the location based marginal prices (LBMPs) and reserve prices used in the net EAS revenues model to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[10]

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[8] Services Tariff, Section 5.14.1.2.

[9] In 2011, FERC found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 37 (2011)). In the last reset, which resulted in the establishment of ICAP Demand Curves for the 2014/15, 2015/16, and 2016/17 Capability Years (2013 DCR), FERC found that "[a]n economically viable technology must be physically able to supply capacity to the market, but other than this requirement … economic viability determinations are a 'matter of judgment.'" *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 60 (2014)). AGI discusses this issue in greater detail in Section II.

[10] The Services Tariff requires that net EAS revenues be estimated for the peaking plant technology under system conditions that reflect the applicable minimum Installed Capacity requirement (ICR) plus the capacity of the peaking plant, which AGI defines as the level of excess (LOE). The derivation of LOE adjustment factors (LOE-AF) and how locational based marginal prices (LBMPs) and reserve prices are adjusted to reflect LOE conditions are described in detail in Section III. *See* Services Tariff, Section 5.14.1.2.

4. ***Determination of reference point price and ICAP Demand Curve in NYCA and each Locality (Section V).*** In this step, gross CONE estimates (from Section III) with expected net EAS revenues (from Section IV) are combined to calculate RP for the ICAP Demand Curves for NYCA and each Locality. Other parameters that govern the shape and slope of the ICAP Demand Curves, including the ZCP and the winter-to-summer ratio (WSR) are also considered.
5. ***Annual updating of NYISO ICAP Demand Curve reference point prices (Section VI).*** In this step, RPs and ICAP Demand Curves are updated annually based on escalation of installed capital costs, recalculation of net EAS revenues using updated electricity prices, fuel prices, emission cost data, and determination of the WSR.[11]

In this study, we analyze the currently prescribed Localities for the ICAP Market, which includes the G-J Locality, Zone J (New York City, or NYC) and Zone K (Long Island, or LI), as well as the state as a whole, or the NYCA.

Each of the steps described above involves a complex mix of historical data, forecasts, and modeling techniques geared towards developing an accurate representation of New York electricity market structures and dynamics. It involves extensive review of relevant data and analytic methods, and requires a selection of methods, models and data from among a range of alternatives based on the application of decision criteria and professional judgment. It also involves review of proposals and recommendations of the independent consultants with the NYISO and stakeholders on the purpose, effectiveness and appropriateness of selected methods and data.

AGI and LCI developed their recommendations for this ICAP Demand Curve reset through the continuous interaction with stakeholders over a nearly year-long period. AGI and LCI received feedback on proposals and analyses from NYISO and stakeholders in written and verbal form across numerous meetings of the ICAP Working Group (ICAPWG), as well as meetings of the Business Issues Committee (BIC) and Management Committee (MC).

The DCR process requires not only analysis of a wide array of quantitative market, financial, and economic data and analytics, but also the application of reasoned judgment when the empirical evaluation is limited by sparse, uncertain, and variable historical data and forecast assumptions. Consequently, at the outset of the process AGI established a set of objectives and criteria against which it would review and consider DCR process and methodological issues on both quantitative and qualitative bases. The objectives and criteria were developed to help guide the analysis and provide a framework for the evaluation of process and analytic alternatives. Specifically, AGI established that potential DCR issues should be evaluated against the following objectives and criteria:

[11] The NYISO operates its capacity market in two separate, six-month Capability Periods. This construct recognizes the differences in the amount of capacity available over the course of each year and the impact of these differences on revenues throughout the year. The WSR is used to account for the differences in capacity available. The WSR is discussed in greater detail in Section IV.

- *Economic Principles* – Proposed changes to ICAP Demand Curve processes and parameters should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO electricity markets.
- *Accuracy* – ICAP Demand Curve parameters should reflect the actual cost of new entry in New York with as much certainty as is feasible.
- *Transparency* – The DCR calculations and periodic updates to net CONE should be clear and transparent to Market Participants (MPs), and calculation and update methods should be understandable and allow MPs to develop market expectations.
- *Feasibility* – The DCR design and implementation should be practical and feasible from regulatory and administrative perspectives, considering the administrative burden on both the NYISO and MPs.
- *Historical Precedent and Performance*[12] – DCR designs should be informed by quantitative analysis based on historical data (to the extent feasible), and should draw from lessons learned in the markets with experience in administration of capacity markets (NYISO, ISO New England Inc. (ISO-NE), and the PJM Interconnection, L.L.C. (PJM)). Consistency between DCRs also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

F. Summary of Recommendations and Overview of RP Results

AGI has applied the methods, models and equations described in this Report to identify the RPs and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2017/2018. These values are presented in Tables 2 and 3, below.

To arrive at these results, AGI and LCI considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of RP values. Specifically, AGI and LCI preliminarily conclude the following:

- The Siemens SGT6-5000F5 (F Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, the F Class Frame machine would be built with SCR emission control technology across all locations.

- Based on market expectations for fuel availability and fuel assurance, changes in market structures, and developer expectations, the F Class Frame machine would be built more often than not with dual fuel capability in all locations.

[12] With respect to this objective, and in order to inform recommendations through quantitative analysis based on historical data, AGI conducted a comprehensive "backcasting analysis," evaluating how different proposed approaches to net EAS calculations and updating of ICAP Demand Curve parameters compared with respect to the stability, predictability, and levels for installed capital costs, net EAS revenues, and calculated ICAP Demand Curve parameters. This backcasting analysis was presented to stakeholders on March 3, 2016 and is included in the filing with FERC in Docket No. ER16-1751-000.

- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55 percent debt and 45 percent equity; a 7.75 percent cost of debt; and a 13.4 percent return on equity, for a WACC of 10.3 percent. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 8.6 percent and 8.36 percent, respectively.

- Net EAS revenues should be estimated for the peaking plant technologies using gas hubs that reflect gas prices consistent with LBMPs within each Load Zone. The choice of gas hub and gas prices should also reflect, in part, reasonable expectations for a long-term equilibrium in delivered natural gas prices that would be available to a hypothetical new peaking plant. To that end, net EAS revenues are estimated using the following gas hubs:
  - Load Zone C: TETCO M3
  - Load Zones F and G: Iroquois Zone 2
  - Load Zones J and K: Transco Zone 6

- RPs should be established at the Services Tariff-prescribed LOE conditions and account for seasonal differences in system capacity. To promote transparency and allow for model updates, RPs should be calculated using a standardized formula, which is defined and expressed herein.

- ICAP Demand Curves should maintain the current ZCP ratios (ZCPR). The ZCPR, along with the RP, defines the shape and slope of the ICAP Demand Curve. ZCPR will remain 112 percent (NYCA), 115 percent (G-J Locality), and 118 percent (Load Zone J and K).

Table 2 provides the parameters of the 2017/18 ICAP Demand Curves consistent with the conclusions and technology findings described above. Table 3A-C provides additional information for the other technologies evaluated (including for informational purposes) results using alternative assumptions with respect to fuel capability.

Table 2: ICAP Demand Curve Parameters ($2017)
Siemens SGT6-5000F5 with Dual Fuel Capability and SCR Technology

		Current Year (2017-2018)					
Parameter	**Source**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
Gross Cost of New Entry ($/kW-Year)	[1]	$162.79	$154.99	$174.79	$176.65	$209.11	$194.96
Net EAS Revenue ($/kW-Year)	[2]	$46.19	$42.38	$40.39	$40.26	$55.26	$104.20
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$116.60	$112.61	$134.41	$136.39	$153.85	$90.77
ICAP DMNC (MW)	[4]	215.8	217.0	218.0	218.0	217.6	219.1
Total Annual Reference Value	[5] = [3] * [4]	**$25,165,303**	**$24,434,068**	**$29,295,019**	**$29,728,169**	**$33,472,776**	**$19,889,028**
Level of Excess (%)	[6]	100.6%	100.6%	101.5%	101.5%	102.3%	103.9%
Ratio of Summer to Winter DMNCs	[7]	1.037	1.037	1.054	1.054	1.077	1.075
Summer DMNC (MW)	[8]	224.4	224.6	226.8	226.1	226.9	224.9
Winter DMNC (MW)	[9]	230.3	230.3	230.3	230.3	228.7	230.3
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$11.03	$10.71	$13.37	$13.60	$16.24	$9.96
Winter ($/kW-Month)	[11]	$7.47	$7.25	$8.03	$8.16	$8.28	$4.66
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,474,926	$2,403,974	$3,033,195	$3,074,535	$3,684,898	$2,241,130
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,719,302	$1,668,364	$1,849,317	$1,880,151	$1,893,897	$1,073,717
Seasonal Revenue (Summer)	[14] = 6 * [12]	$14,849,557	$14,423,841	$18,199,168	$18,447,211	$22,109,385	$13,446,778
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,315,810	$10,010,185	$11,095,899	$11,280,905	$11,363,382	$6,442,303
Total Annual Reference Value	[16] = [14]+[15]	**$25,165,367**	**$24,434,026**	**$29,295,068**	**$29,728,116**	**$33,472,767**	**$19,889,081**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$11.56	**$11.22**	**$14.84**	**$15.09**	**$18.61**	**$12.72**
ICAP Max Clearing Price ($/kW-Month)		$20.35	$19.37	$21.85	$22.08	$26.14	$24.37
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Note: Net EAS revenues are estimated using data for the three-year period September 2013 through August 2016.

Table 3A: Comparison of Reference Point Prices by Technology and Capability $2017/kW-mo.

Monthly Reference Point Price ($/kW-Month)							
Fuel type	**Technology**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
Dual Fuel	Wartsila 18V50	$20.94	$19.40	$25.31	$25.65	$32.31	$26.33
	LMS100 PA	$16.40	$15.05	$19.30	$19.48	$24.28	$19.07
	SGT6-PAC5000F(5) SC	$11.56	$11.22	$14.84	$15.09	$18.61	$12.72
Gas only with SCR	Wartsila 18V50	$17.62	$16.73	$21.97	$22.23	-	-
	LMS100 PA	$15.73	$14.59	$18.93	$19.11	-	-
	SGT6-PAC5000F(5) SC	$10.72	$10.72	$14.11	$14.30	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$9.08	$9.08	$12.29	-	-	-

Table 3B: Comparison of Gross CONE by Technology and Capability $2017/kW-year

Gross CONE ($/kW-Year)							
Fuel type	**Technology**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
Dual Fuel	Wartsila 18V50	$259.85	$254.61	$284.07	$286.91	$334.65	$317.85
	LMS100 PA	$227.43	$218.50	$240.92	$243.17	$281.10	$265.24
	SGT6-PAC5000F(5) SC	$162.79	$154.99	$174.79	$176.65	$209.11	$194.96
Gas only with SCR	Wartsila 18V50	$218.14	$210.84	$237.09	$239.33	-	-
	LMS100 PA	$216.83	$207.89	$230.29	$232.47	-	-
	SGT6-PAC5000F(5) SC	$150.55	$142.92	$161.37	$162.68	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$134.96	$126.79	$144.72	-	-	-

Table 3C: Comparison of Net EAS by Technology and Capability $2017/kW-mo.

Net EAS ($/kW-Year)							
Fuel type	**Technology**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
Dual Fuel	Wartsila 18V50	$57.38	$67.02	$61.98	$61.89	$74.66	$129.82
	LMS100 PA	$55.56	$61.38	$57.71	$57.80	$70.25	$117.42
	SGT6-PAC5000F(5) SC	$46.19	$42.38	$40.39	$40.26	$55.26	$104.20
Gas only with SCR	Wartsila 18V50	$48.87	$50.09	$46.98	$46.95	-	-
	LMS100 PA	$52.02	$55.61	$50.57	$50.62	-	-
	SGT6-PAC5000F(5) SC	$42.43	$35.35	$33.61	$33.48	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$43.35	$35.70	$33.48	-	-	-

Note: Net EAS revenues are estimated using data for the three-year period September 2013 through August 2016.

II. TECHNOLOGY OPTIONS AND COSTS

A. Overview

The Services Tariff specifies that the ICAP Demand Curve review shall assess and consider the following:

> "… the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements"[13]

In this section we consider the gross CONE for two types of plants:

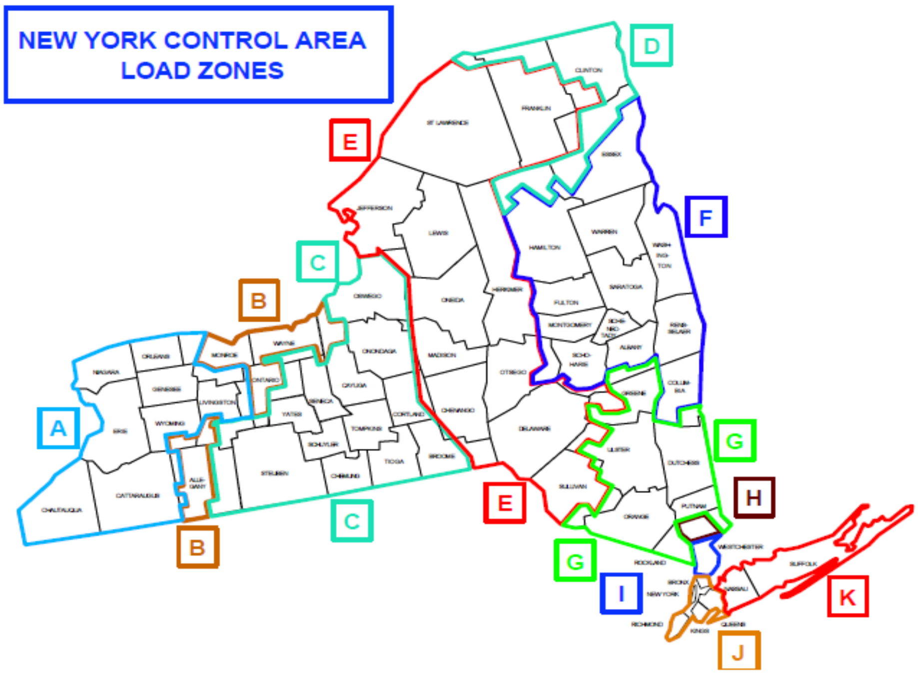
1. Peaking plant – The peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable. The FERC precedent regarding peaking plant technology indicates that "only reasonably large scale, standard generating facilities that could be practically constructed in a particular location should be considered."[14]
2. Combined Cycle Plant – A combined cycle plant is also included in the analysis for informational purposes only. A combined cycle plant, is defined as "the unit with technology that results in the lowest cost net of energy and ancillary services (EAS) revenues under current conditions, accounting for the amount of capacity excess associated with the technology. Technology choice parameters are included in the current Report. Net EAS revenues, gross costs, and RPs will be provided for informational purposes in the final Report.

In Section II.B, we apply screening criteria to identify alternative simple cycle technologies that will be evaluated in the DCR study. Section II.C summarizes plant environmental and siting requirements, which have implications for installed capital costs, and fixed and variable operations costs. The capital costs, fixed O&M costs, and variable O&M costs are evaluated in Sections II.D, II.E and II.F, respectively. Section II.G described technical specifications needed to evaluate net EAS revenues.

[13] Services Tariff, Section 5.14.1.2.

[14] *See*, e.g., *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058, at P 37.

Figure 1: Load Zones and Localities



B. Technology Screening Criteria

LCI was engaged to select peaking unit technology options and combined cycle option(s) to evaluate for each ICAP Demand Curve. LCI evaluated peaking technology options for Load Zones C, F, G, J, and K (see Figure 1).

To comply with the Service Tariff requirements, LCI utilized the following screening criteria for technology selection:

- Standard generating facility technology – available to most market participants;
- Proven technology – operating experience at a utility power plant;
- Unit characteristics that can be economically dispatched;
- Ability to cycle and provide peaking service;
- Can be practically constructed in a particular location; and
- Can meet environmental requirements and regulations.

The analysis of potential technologies identified only simple cycle technologies, which are described in Section II.2. The generating technologies described in Table 4 did not meet the screening criteria and thus were not considered viable peaking unit technologies.

Table 4: Technologies Not Meeting Technology Screening Criteria

Generating Technologies[1]	Failed Screening Criteria
Intermittent resources - wind, solar photovoltaic (PV), concentrating solar	Inability to be dispatched
Dispatchable renewable resources hydroelectric, biofuels, municipal solid waste (MSW) landfill gas (LFG)	Limited fuel availability; cannot provide peak service and cycle daily
Energy Storage - fuel cells, batteries, flywheel, pumped hydro and compressed air energy storage (CAES)	Fuel cell, batteries, flywheel are not economically viable; CAES and pumped hydro have site specific requirements and costs
Nuclear and coal-fired resources	Long lead time; high fixed costs

Note: Demand response was also considered. The conclusion was that demand response cannot provide the response of a generator, nor can the fixed and variable costs be determined on a comparable basis.

1. Simple Cycle Technologies

Described in Section II.B.6, below, are the peaking technologies that satisfy the screening criteria and reflect the following key features for each technology option:

1. *Aeroderivative Combustion Turbines*

- Number of starts does not impact maintenance schedule;
- Fast start up time (~10 minutes) and ramp rates;
- Generally require water injection for NO_x control in addition to a selective catalytic reduction (SCR) system; and
- Reasonably sized units (50 to 100 MW) available where multi-unit plants are advantageous.

2. *Frame Combustion Turbines*

- New frame peaking units in the United States will most likely be F technology or higher;
- Most efficient advanced frame units range in size from 231 to 337 MW;
- Water injection only required with liquid fuel;
- Fast start capability – can provide significant capacity in 10 minutes and full output in 10 to 14 minutes; conventional start is 23 to 30 minutes;
- Maintenance cost impacted by starts; and
- G and H technology units have higher NO_x emissions than F technology units but lower CO_2 emissions on a per MWh basis.

3. *Reciprocating Internal Combustion Engines (RICE)*

- Small output units that can be installed in multi-unit blocks;
- Fast start up time as low as five minutes for natural gas engine and seven minutes for dual fuel engine;
- Extremely fast shutdown, as low as one minute;
- Very high efficiency, good part load performance;

- Performance not impacted by ambient conditions (elevation, temperature);
- Only requires moderate natural gas pressure (gas compression is not needed);
- Installed cost similar to aeroderivative combustion turbines;
- Maintenance independent of number of starts; and
- Emissions are higher than combustion turbines.

2. Aeroderivative Combustion Turbine Peaking Options

The aeroderivative combustion turbines that were considered as candidate peaking unit technologies are shown in Table 5.

Table 5: Aeroderivative Technology Combustion Turbines

Aeroderivative Combustion Turbine[1]	Experience	Generating Capacity[2] (MW)	LHV Heat Rate[3] (Btu/kWh)
General Electric (GE) LM6000	First introduced in 1997; Good Experience	51-58 depending on model	8,140 - 8,367 depending on model
Rolls-Royce (Siemens) Trent 60	First introduced in 1996; Good experience	66	8,303
GE LMS100	First introduced in 2006; Good experience	103-116 depending on model	7,776 - 7,828 depending on model
P&W (MHPS)[4] FT4000 SwiftPac 60/120	First introduced in 2012; First unit went operational on June 29, 2015	70 single unit 140 twin pac design	8,265 - 8,245

Notes:

[1] Performance in the above table from: Gas Turbine World 2014-2015 Handbook (ISO Conditions)
[2] At International Standards Organization (ISO) conditions
[3] Lower Heating Value
[4] Pratt & Whitney Power Systems (Mitsubishi Hitachi Power Systems)

The screening of the aeroderivative combustion turbine models indicated that the GE LMS100PA+ and the Pratt & Whitney Power Systems (P&W) FT4000 SwiftPac 120 were the best candidates because of their high power generation efficiencies and their larger generation capacity, which resulted in a lower $/kW capital cost due to economy of scale. The GE LMS100PA+ and the P&W FT4000 SwiftPac 120 are very competitive. The GE LMS100 was selected as an option in the 2013 DCR and, since the FT4000 does not have the extensive experience of the LMS100, LCI selected the LMS100 PA+ to be the aeroderivative combustion turbine for evaluation in the current DCR.

3. *Frame Combustion Turbine Peaking Option*

The candidate peaking technologies considered included available advanced frame combustion turbines as shown in Table 6.

Table 6: Advanced Frame Technology Combustion Turbines

Frame Combustion Turbine[1]	Experience (as of the date of the Report)	Generating Capacity[2] (MW)	LHV Heat Rate (Btu/kWh)
GE 7FA.05	First 7FA.05 in operation in 4th Q 2014; 14 units in operation	231	8,640
Siemens SGT6-5000F5	First 5000F5 in operation in 2013; 23 units in operation	242	8,749
GE 7HA.01	None operating	275	8,240
MHPS M501GAC	First 501GAC in operation in 2011; 9 units in operation	276	8,574
Siemens SGT6-8000H	First 8000H in operation in 2012; 14 units in operation	296	8,530
MHPS M501JAC[3]	None operating[3]	310	8,325
GE 7HA.02	None operating	337	8,210

Notes:

[1] Performance in the above table from: Gas Turbine World 2014-2015 Handbook (ISO Conditions)
[2] At International Standards Organization (ISO) conditions
[3] MHPS supplies advanced frame J-technology combustion turbines; M501J, which is steam cooled and M501JAC, which is air-cooled. There are 20 M501J units operating in combined cycle plants. The M501JAC is operating as a commercial combined cycle plant in the MHPS T-Point demonstration facility in Japan. Four of the M501J combined cycle units in Korea operated as a M501JAC in simple cycle while the combined cycle facilities were completed. These four units operated for about six months as M501JAC simple cycle units before being converted to the M501J steam cooling.

The results of the screening of the advanced frame combustion turbine models are:

- The GE & Siemens F class combustion turbines are similar in output and performance;
- The Siemens H technology and the Mitsubishi Hitachi Power Systems (MHPS) G machines are similar in output and performance—both have combined cycle but no simple cycle experience;
- The GE and Siemens F technology are the only advance frame combustion turbine options with proven simple cycle peaking application experience;
- The Siemens 5000F is the only advanced frame combustion turbine with hot Selective Catalytic Reduction (SCR) operating experience;

- The Siemens 5000F is capable of meeting the Con Ed 45 second fuel transfer in New York City[15].
- The MHPS M501JAC has four units that operated for about six months in Korea before being converted to steam cooled single shaft M501J combined cycle units; and
- The GE H technology does not have any commercial operating experience.

Three offers for capacity have cleared the ISO-NE forward capacity market auctions that identified H class frame machines as the potential underlying technology for the future projects related to these offers. Two offers propose to use the H machine in a combined cycle configuration, while one proposes to use it in a simple cycle configuration. None of these plants have received permits or begun construction.[16] To our knowledge, there are no GE7HA.02 units that are currently in operation or with proven operating experience. After receiving comments from stakeholders, NYISO requested that the GE 7HA.02 also be included in the DCR study for informational purposes. Data for the GE 7HA.02 is included in Appendix A for informational purposes only.

The Siemens 5000F5 was selected as the frame combustion peaking option for this DCR Study because it has significant operating experience in simple cycle with a hot SCR at the Marsh Landing Power Plant and can meet the ConEd New York City 45-second natural gas to liquid fuel transfer requirement.

4. Reciprocating Internal Combustion Turbine Peaking Option

The only RICEs options that were considered include the Wartsila 18V50SG (gas only) and 18V50DF (dual fuel). The principal RICE technologies currently evaluated for large utility peaking applications in the U.S. are the Wartsila 20V34SG/DF (10 MW), the Wartsila 18V50SG/DF (18 MW) and the GE Jenbacher J920 (9.5 MW). However, the Jenbacher J920 is a gas only engine so it cannot be utilized if dual fuel capability is required. The Wartsila 18V50SG/DF engines were the RICE option in the 2013 DCR. This Wartsila engine has extensive experience. There are 84 gas engines operating (24 in the U.S.) and 134 dual fuel engines (10 in the U.S.).

Since it provides the largest unit capacity, offers both gas only and dual fuel options and has extensive experience, LCI believes the Wartsila 18V50SG/DF should be the RICE technology evaluated for the current DCR.

The key characteristics of the Wartsila 18V50SG and 18V50DF engines include the following:

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[15] LCI notes that the GE 7FA.05 upgraded liquid fuel system uses a water fuel emulsion and the liquid fuel lines are flushed with water after use and filled with pressurized water, which must be drained as part of the gas to liquid fuel transfer. This process increases the fuel transfer time to 150 seconds.

[16] In February 2016, the ISO-NE filed the results of its 10th Forward Capacity Auction (FCA), for the capability year 2019-2020. Three new gas fired power plants totaling more than 1,800 MW of capacity cleared in that auction. These units include the Burrillville Energy Center 3 (997 MW combined cycle, Rhode Island), Bridgeport Harbor 6 (484 MW combined cycle, Connecticut), and Canal Station 3 (333 MW combustion turbine, Massachusetts). All three plants have indicated that they will use the GE7HA.02 combustion turbine.

- Low emissions design option with emission rates close to combustion turbines
- 18V50SG
  - Net capacity 18.478 MW
  - LHV heat rate 7,463 Btu/kWh
- 18V50DF
  - Net capacity 16.769 MW (firing natural gas or distillate oil)
  - LHV heat rate 7,614 Btu/kWh firing natural gas and 8,194 Btu/kWh firing distillate

5. Selected Simple Cycle Technology for Review

Based on the screening criteria and considerations presented above, costs were developed for the following peaking plants. Consistent with the 2013 DCR, the intent was to select peaking plant sizes in the 200 MW size range. Therefore, the following units were considered for each peaking plant technology:

- Two GE LMS100 PA+ units
- One Siemens SGT6-5000F unit
- Twelve Wartsila 18V50SG/DG engines
- One GE 7HA.02 (informational purposes only)

6. Combined Cycle Power Plant for Information Purposes

The most likely candidates for new combined cycle plants are based on the advanced frame combustion turbines as shown in Table 7.

Table 7: Latest Advanced Combined Cycle Plant Options

Frame Combustion Turbine[1]	1x1 Combined Cycle		2x1 Combined Cycle	
	Unfired Capacity (MW)	LHV Heat Rate (Btu/kWh)	Unfired Capacity (MW)	LHV Heat Rate (Btu/kWh)
GE 7FA.05	359	5,740	723	5,700
Siemens SGT6-5000F5	360	5,882	720	5,812
GE 7HA.01	406	5,570	817	5,540
Mitsubishi Hitachi M501GAC	412.4	5,735	828.6	5,726
Siemens SGT6-8000H	440	5,687	880	<5,687
Mitsubishi Hitachi M501JAC	450	5,594	900	<5,594
Mitsubishi Hitachi M501J	470	5,549	942.9	5,531
GE 7HA.02	501	5,530	1005	5,510

Note: Performance in the above table from: Gas Turbine World 2014-2015 Handbook (ISO Conditions).

The 2x1 combined cycle power plant configuration is the most common design in the industry. However, since it is twice the capacity of the 1x1 combined cycle power plant configuration, it could require expensive system deliverability upgrades. To provide peaker-type flexibility, the combined cycle plant would have to cycle frequently and start as quickly as possible. Fast start 1x1 combined cycle power plant configuration designs can hot start in about 35 minutes, whereas 2x1 combined cycle power plant configurations require 50 minutes or more. Therefore, without additional information to justify the additional capacity of a 2x1 combined cycle power plant; the 1x1 combined cycle configuration was selected for evaluation, with data presented for informational purposes only.

The combined cycle technologies evaluated are:

- 1x1 Siemens 5000F5 Flex Plant (combined cycle)
- 1x1 Siemens 8000H Flex Plant (combined cycle)

The Siemens SGT6-8000H was the first H technology unit to reach commercial operation in combined cycle application (there are none in simple cycle peaking application). The Siemens SGT6-8000H has several years of combined cycle operating experience.

C. Plant Environmental and Siting Requirements

Environmental considerations, which can have significant impact on the design and permitting of new peaking unit technology options and new combined cycle power plant options, include air emissions, heat rejection, and water use. The conceptual designs and cost estimates developed for each peaking unit technology option and combined cycle option evaluated for gross cost of new entry include the necessary equipment and operating costs in order to meet the federal and New York State environmental requirements and regulations within each of the Load Zones evaluated in this DCR.

1. Air Permitting Requirements and Impacts on Plant Design

Each of the candidate peaking unit technologies and each of the combined cycle options would be required to obtain an air permit from the New York State Department of Environmental Conservation (NYSDEC). The air permit will require the new source to meet various Federal and New York State requirements. These requirements, among others, include New Source Performance Standards (NSPS), New Source Review (NSR), and National Emission Standards for Hazardous Air Pollutants (NESHAP). As discussed below, the peaking unit technologies and combined cycle plants will also need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment.

a) New Source Performance Standards

The peaking unit technologies and combined cycle options will be subject to NSPS, which are included in 40 CFR Part 60. The NSPS that are expected to apply to each of the generating options include:

- Subpart KKKK – Stationary Combustion Turbines (simple cycle and combined cycle plants)

- Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (RICE – dual fuel)
- Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines (RICE – gas only)
- Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (simple cycle and combined cycle plants)

Subpart KKKK requires combustion turbines with heat inputs greater than 850 MMBtu/hour to limit NO_X 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 5000F5, would require the installation of an SCR in order to reduce combustion turbine NO_X emissions below 15 ppmv @ 15 percent O_2 while firing natural gas. The Siemens 5000F5 NO_X emissions while firing natural gas are 9 ppmv @ 15 percent O_2

Subpart TTTT establishes NSPS 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. Non-base load units must meet an emission limit based on clean fuels and is an input based standard (e.g., 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. LCI estimated the net LHV efficiency at ISO conditions for the GE LMS100PA+ (42.4 percent), the Siemens 5000F5 (38.4 percent), and the GE 7HA.02 (40.9 percent). 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 less than the net LHV efficiency at ISO conditions. Subpart TTTT does not affect the reciprocating internal combustion engines.

Table 8 compares Subpart TTTT requirement to the requirements of NYCRR Part 251 - CO_2 Performance Standards for Major Electric Generating Facilities. Each of the peaking unit technology options and combined cycle options are expected to meet both the Subpart TTTT and NYCRR Part 251 requirements.

Table 8: Comparison of 40 CRF Part 60 Subpart TTTT to NYCRR Part 251 Requirements

Generating Facility Type	Subpart TTTT	NYCRR Part 251
Simple Cycle Combustion Turbine Gas-Fired	120 lbs. CO_2/MMBtu	1,450 lbs. CO_2/MWh-g or 160 lbs. CO_2/MMBtu
Simple Cycle Combustion Turbine Multi-Fuel Fired[2]	120 to 160 lbs. CO_2/MMBtu	1,450 lbs. CO_2/MWh-g or 160 lbs. CO_2/MMBtu
Combined Cycle Combustion Turbines	1,000 lbs./MWh-g or 1,030 lbs./MWh-n	925 lbs. CO_2/MWh-g or 120 lbs./MMBtu
Stationary Internal Combustion Engines (gaseous fuels)	N.A.	925 lbs. CO_2/MWh-g or 120 lbs./MMBtu
Stationary Internal Combustion Engines (liquid fuel or liquid and gaseous fuels)	N.A.	1,450 lbs. CO_2/MWh-g or 160 lbs./MMBtu

Notes:
[1] New York Codes, Rules and Regulations (NYCRR).
[2] For units determined to be non-base load units

It should be noted that new units subject to 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.

b) New Source Review

There are two types of NSR permitting requirements, which are different under each of the NSR programs.

- The preconstruction review process for new or modified major sources located in attainment and unclassifiable areas is performed under the Prevention of Significant Deterioration (PSD) requirements.
- The preconstruction review for new or modified major sources located in nonattainment areas is performed under the Nonattainment New Source Review (NNSR) program. NNSR only applies to the pollutants that are classified as nonattainment.

The PSD major source thresholds are listed in Table 9. The major source threshold for new combined cycle facilities is lower (100 tons/year) than the major source threshold for new simple combustion turbines or RICE (250 tons/year). The annual emissions are based on the potential to emit (PTE) at 8,760 hours/year of operation (unless a federally enforceable lower operating hour restriction is included in the air permit). If a new source is determined to be a major PSD source then PSD review would be performed for any pollutant that exceeds the Significant Emission Rates (SER) listed in Table 9.

On June 23, 2014, the Supreme Court issued a decision in Utility Air Regulatory Group (UARG) v Environmental Protection Agency (EPA), which challenged the EPA "Tailoring Rule".[17] As a result of this court decision, 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. However, EPA can require PSD permits (which are otherwise required) to contain limitations on GHG emissions based on the application of BACT. This decision resulted in changes in PSD "major source" thresholds used in this DCR compared to the 2013 DCR, at which time the Tailoring Rule was in effect.

The Supreme Court decision resulted in changes in PSD "major source" thresholds used in this DCR compared to the 2013 DCR. During the 2013 DCR the GHG major source threshold of 100,000 tons CO_2/year would result in each of the peaking unit technologies and combined cycle options being "major" PSD sources. As described earlier, a major PSD source would be subject to PSD review for any pollutant that exceeds the SERs listed in Table 9, which is 40 tons/year for NO_X. For the current DCR, as shown in Table 9, the PSD major source thresholds are 100 tons/year for combined cycle facilities and 250 tons/year for the peaking unit technologies.

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

Table 9: PSD Major Facility Thresholds and Significant Emission Rates

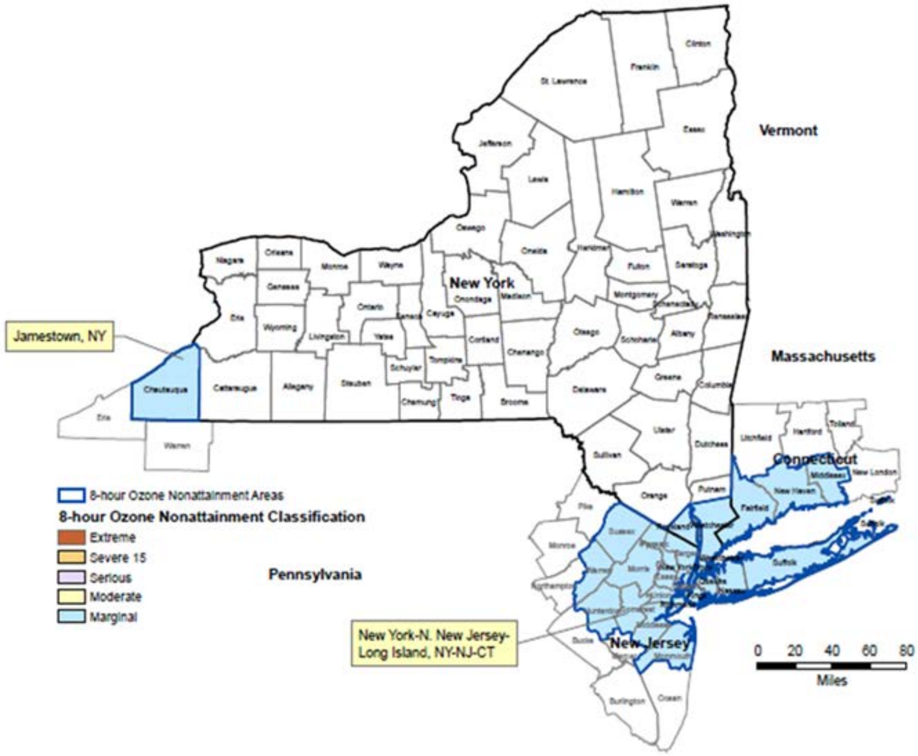
Pollutant	NGCC Major Source Threshold (tons/year)	CT and RICE Major Source Threshold[1] (tons/year)	Significant Emissions Rate (tons/year)
Carbon monoxide (CO)	100	250	100
Nitrogen oxides (NO_X)	100	250	40
Sulfur dioxide (SO_2)	100	250	40
Coarse particulate matter (PM-10)	100	250	15
Fine particulate matter (PM-2.5)	100	250	10
Ozone (O_3): as VOCs or NO_X	100	250	40
Greenhouse gases (GHG): as CO_2e	Note 2	Note 2	75,000
NGCC – natural gas combined cycle; CT – combustion turbine; RICE – reciprocating internal combustion engine			

Notes:
[1] CT and RICE major source thresholds are 250 tons/year since these sources are not one of the source categories listed in section 201-2.1(b)(21)(iii)(a) through (z) of 6 NYCRR.
[2] Per NYSDEC October 15, 2014 Enforcement Discretion for State GHG Tailoring Rule Provisions Memorandum, GHGs alone will not trigger Prevention of Significant Deterioration New Source Review (PSD NSR).

Any pollutant subject to PSD review is required to perform a BACT analysis. BACT is a case-by case determination and includes cost-effectiveness considerations. In cases where a BACT analysis is required in New York State, it is expected that a SCR system would be required for nitrogen oxide (NO_X) control and an oxidation catalyst would be required for carbon monoxide (CO) and/or volatile organic compounds (VOC) control. In addition to BACT requirements, an air quality impact analysis, and an analysis of other impacts (e.g., soils, vegetation, and visibility) are required for all pollutants subject to PSD review.

NNSR only applies to the pollutants for which a given area is classified as in nonattainment. The current nonattainment areas in New York State are illustrated in Figure 2. These areas are nonattainment for the eight-hour ozone National Ambient Air Quality Standard (NAAQS). NNSR also applies throughout New York State for precursors of ozone (NO_X and VOC) since all of New York State is in the Ozone Transport Region (OTR). Since NO_X and VOC are treated as nonattainment pollutants statewide, proposed facilities may be required to comply with both the PSD requirements for attainment pollutants and NNSR requirements for nonattainment pollutants.

Figure 2: Current Nonattainment Areas in New York



On October 1, 2015, the EPA revised the eight-hour ozone NAAQS from 75 parts per billion (ppb) to 70 ppb. States' recommendations for area attainment status are due by October 2016 and the EPA plans to issue final area designations by October 1, 2017. The area designations will likely be based on 2014-2016 ozone monitoring data. Figure 3 illustrates the expected nonattainment areas in New York State for the 2015 eight-hour ozone NAAQS, based on preliminary 2013 to 2015 monitoring data. LCI confirmed with the NYSDEC that based on the latest ozone monitoring data, the 2015 eight-hour ozone NAAQS is not expected to result in changes to nonattainment major source thresholds or offset requirements for NO_x and VOCs that are currently in place in New York State regulations. Since the basis of final area designations will include 2016 ozone monitoring data, which has not been collected, it is possible there could be changes to the nonattainment areas depicted in Figure 3.

Figure 3: Expected Nonattainment Areas for the 2015 8-Hour Ozone NAAQS

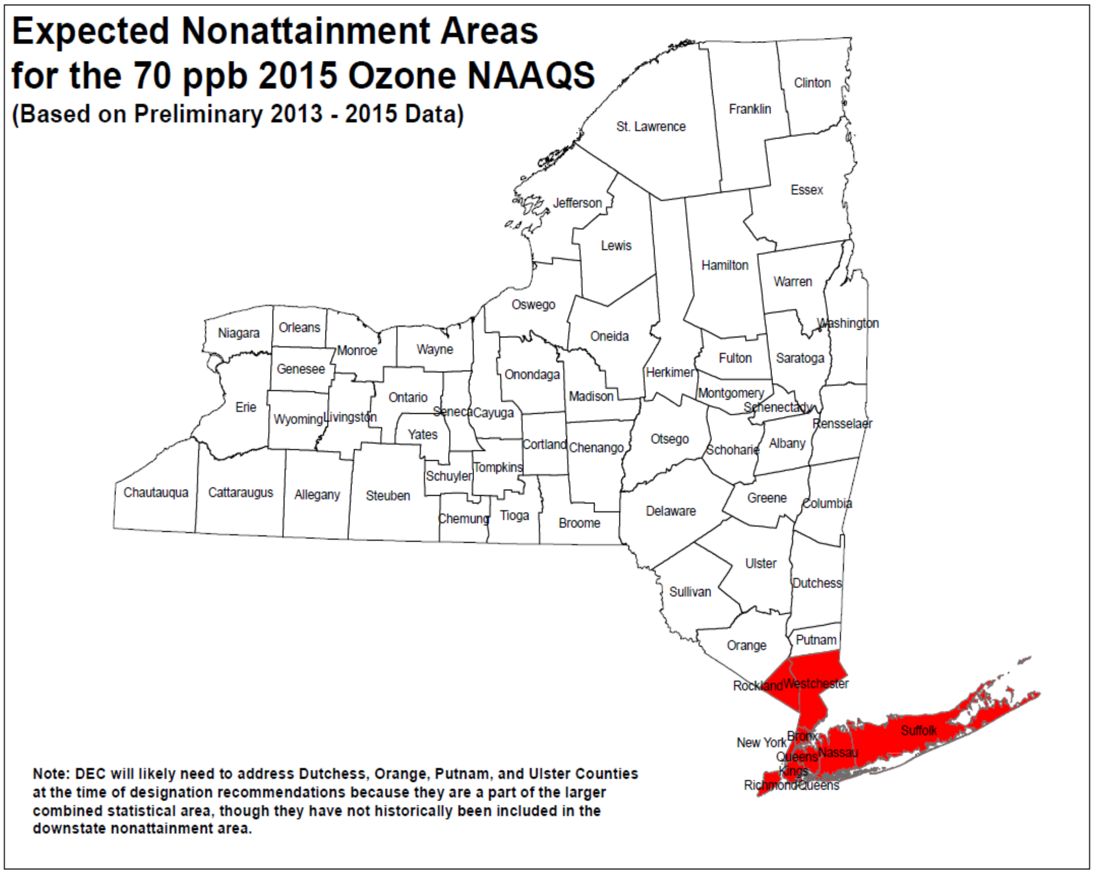


Table 10 presents the nonattainment major facility thresholds and emission offset ratios for each ozone nonattainment classification. Nonattainment areas classified as Severe include the New York City Metropolitan Area and the Lower Orange County Metropolitan Area. The New York City Metropolitan Area includes all of the City of New York, and Nassau, Suffolk, Westchester and Rockland Counties. The Lower Orange County Metropolitan Area includes the Towns of Blooming Grove, Chester, Highlands, Monroe, Tuxedo, Warwick, and Woodbury. The remaining areas in the State are classified as either Marginal, Moderate or in the OTR.[18] Table 11 summarizes the ozone nonattainment classification and NNSR major source thresholds for NO_X and VOC for each of the Load Zones.

[18] Notably, Orange County includes areas that are both Severe and Marginal/Moderate nonattainment areas. Orange County is located within the G-J Locality, west of the Hudson River. Consistent with the 2013 DCR, AGI and LCI considered peaking plant technologies located in either Rockland County (west) or Dutchess County (east) in Load Zone G. The use of these two locations provides for a consideration of differences in attainment areas on peaking plant siting and permitting costs. AGI and LCI did not consider specific locations within a county, which would be required to develop an accurate estimate for Orange County, given the differences in nonattainment designations throughout the region. Notably, however, LCI did review construction labor costs for Orange County and

Table 10: NNSR Major Facility Thresholds and Offset Ratios

Contaminant	Major Facility Threshold (tons/year)	Emission Offset Ratios
Marginal, Moderate, or Ozone Transport Region (OTR):		
Volatile Organic Compounds (VOC)	50	At least 1.15:1
Nitrogen oxides (NO_X)	100	At least 1.15:1
Severe:		
Volatile Organic Compounds (VOC)	25	At least 1.3:1
Nitrogen oxides (NO_X)	25	At least 1.3:1

Table 11: Ozone Nonattainment Classification and Major Source Thresholds by Load Zone

	K - Long Island	J - NYC	G - Dutchess	G - Rockland	F- Capital	C- Central
Ozone nonattainment classification [(1)]	Severe	Severe	Moderate	Severe	Moderate	Moderate
NNSR NOx Major Source Threshold (tons/year)	25	25	100	25	100	100
NNSR VOC Major Source Threshold (tons/year)	25	25	50	25	50	50
[(1)] Moderate classification due to location being in the Ozone Transport Region						

NNSR major sources located in nonattainment areas for ozone are required to install LAER technology. LAER is a rate that has been achieved or is achievable for a defined source and does not consider cost-effectiveness. SCR systems for NO_X control and an oxidation catalyst for VOC emissions are expected LAER technologies for combustion turbine or RICE facilities subject to NNSR.

Standard design for RICE includes SCR and CO catalyst. Each of the combustion turbines evaluated in this DCR, with the exception of the Siemens 5000F5, would require the installation of an SCR in order to meet the NSPS for combustion turbines while firing natural gas. For a dual fuel plant design, the Siemens 5000F5 would require an SCR as a result of NNSR major source thresholds triggering LAER technology.

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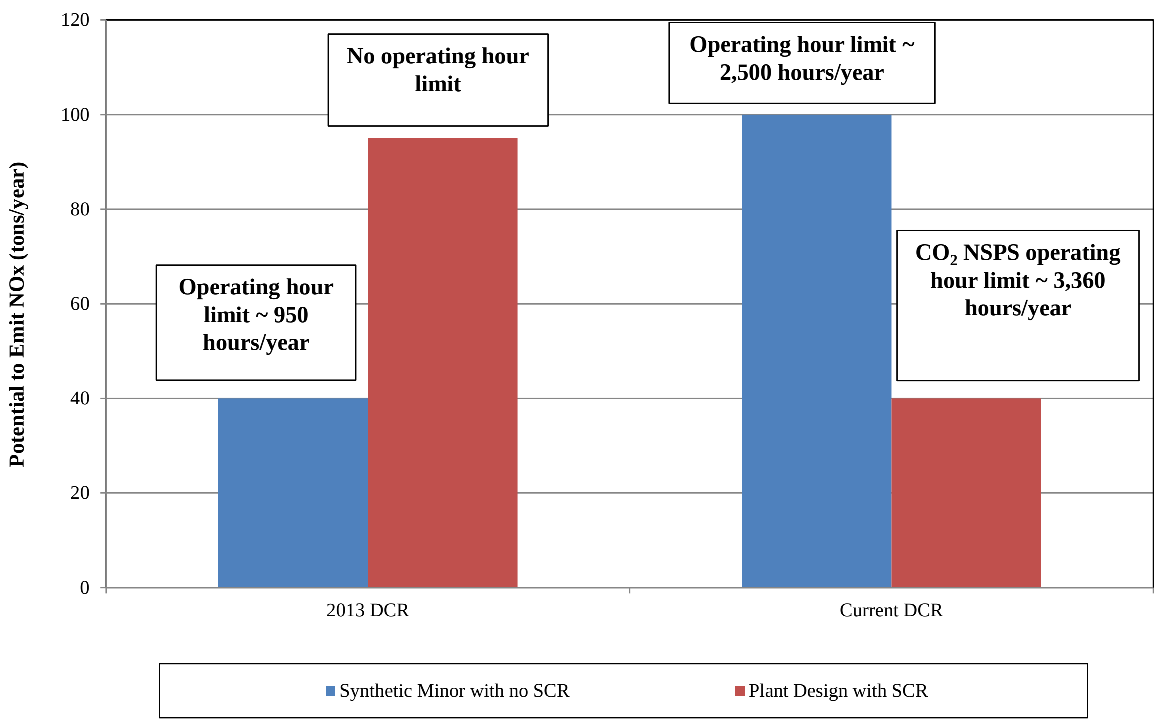
determined that there was not a materially significant difference between such costs in Orange County in comparison to Rockland County.

During the 2013 DCR a "synthetic minor" permitting approach was assumed for the Siemens 5000F5 simple cycle plant for gas only designs in Load Zones C and F. An annual run time limit of 950 hours/year was utilized in the energy dispatch model to ensure the plant would not trigger BACT review for NO_X and thus avoid the addition of an SCR in Load Zones C and F. By comparison, for the 2013 DCR, a 5000F5 gas only simple cycle plant with an SCR and no operating hour restrictions would have a potential to emit (PTE) NO_X of approximately 95 tons/year.

As a result of changes to the implementation of the GHG Tailoring Rule, the 40 tons/year NO_X limitation, which existed during the 2013 DCR, would not apply for the current DCR. Load Zones C, F, and G (Dutchess) have a NNSR major source threshold for NO_X of 100 tons/yr. This would require a 5000F5 simple cycle plant to accept a federally enforceable operating hour restriction of approximately 2,500 hours/year to avoid LAER NOx control technology (i.e., SCR).

For the current DCR the NSPS for CO_2 emissions from "non-base load" combustion turbines would require an operating hour restriction of approximately 3,360 hours/year for a 5000F5 simple cycle plant. A 5000F5 simple cycle plant with SCR, limited to 3,360 hours/year of operation would have the PTE approximately 40 tons/year of NO_X. Figure 4 compares potential to emit NO_X emissions for the 5000F5 for alternative means of compliance applicable during the 2013 DCR and the current DCR.

Figure 4: Potential to Emit (PTE) NO_x Emissions, Alternative Means of Compliance



Including an SCR on a 5000F5 simple cycle gas only plant mitigates certain siting, permitting, and future market risks, which are considered by power plant project developers. As discussed below, the peaking unit technologies will need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment. In issuing a certificate, the Siting Board is required to determine the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[19] As shown in Figure 4, and in contrast to the 2013 DCR, a 5000F5 simple cycle plant with SCR would have a lower PTE than a gas only plant with an operating limit. A power plant design without state-of-the-art emission controls may receive significant local and environmental opposition, which could lengthen the project permitting schedule and adversely affect local community relations. A power plant developer is also likely to consider the risks associated with potential future NO_x control requirements, including items under current review or implementation (e.g., CSAPR Update Rule discussed below, and 2015 revision of ozone NAAQS discussed earlier).

There would also be permitting risks to the extent the developer may seek to modify a gas only air permit to allow future dual fuel operations. Due to the changes in emission profiles (including start-up emissions) for a dual fuel plant, dual fuel at a gas only permitted site could create unacceptable permit restrictions in demonstrating compliance with NAAQS. In short, the decision to construct a facility anywhere in New York State without SCR introduces development risks and the potential for significant additional future SCR retrofitting cost (relative to the cost of an SCR included in the original plant design).[20] Future retrofits may be warranted or required due to regulatory action or interest in seeking conversion on behalf of the power plant owner.

Considering the mix of project development and future risks discussed above, it is AGI's and LCI's opinion 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.

In addition to installing LAER, major sources in nonattainment areas are required to secure emission offsets, or emission reduction credits (ERCs), at the ratios of required ERCs to the facility's PTE presented in Table 12. The ERCs must be the same as for the regulated pollutant requiring the emission offset and obtained from within the nonattainment area in which the new source will locate. Under certain conditions the ERCs may be obtained from other nonattainment areas of equal or higher classification. NO_X and VOC ERCs for major sources locating in an attainment area of New York State may be obtained from any location within the OTR, including other states in the OTR provided an interstate reciprocal trading agreement is in place.

The cost of securing emission offsets was included in the total capital investment estimates for each technology option. Table 12 summarizes the controlled emission rate assumptions for NO_X and VOC (with an SCR and oxidation catalyst) used to estimate ERC requirements for each plant. Table 12 also lists CO and CO_2 emission rates for each technology option.

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[19] New York Public Service Law, Section 168(3)(c) requires that "the adverse environmental effects of the construction and operation of the facility will be minimized or avoided to the maximum extent practicable…"

[20] Based on its professional judgment and experience, LCI estimates that retrofitting a peaking plant that did not contemplate including an SCR at the time of construction could 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 considered in the original plant design.

Table 12: Emissions Rate Assumptions[1]

	NO_x (ppmvd)[2]	CO (ppmvd)[2]	VOC (ppmvd)[2]	CO_2 (lb/MWh)[3]
Natural Gas Firing				
2x0 LMS100PA+	2.5	5	2.5	1,020
1x0 Siemens 5000F5	2.5	2	1	1,130
1x0 GE 7HA.02	2.5	2	1	1,063
12x0 Wartsila 18V50DF	4	10	15	956
1x1x1 Siemens 5000F5	2	2	1	752
1x1x1 Siemens 8000H	2	2	1	733
Ultra-Low Sulfur Diesel Firing				
2x0 LMS100PA+	5	5	5	1,360
1x0 Siemens 5000F5	5	2	1	1,560
1x0 GE 7HA.02	5	2	1	1,511
12x0 Wartsila 18V50DF	20	10	15	1,370
1x1x1 Siemens 5000F	5	2	1	1,160
1x1x1 Siemens 8000H	5	2	1	1,050

Notes:
[1] Emission rates assume an SCR and oxidation catalyst is installed on all technology options.
[2] Parts per million on a dry basis, measured at 15% O_2.
[3] Based on full load, gross plant heat rate at ISO conditions, higher heating value (HHV) basis, clean and new condition. Greenhouse gas (GHG) BACT limits will be higher than the values in this table as heat rate degradation, site conditions and part load performance are considered in project-specific BACT determinations.

2. *Cap and Trade Program Requirements*

New stationary combustion sources in New York State are also subject to cap-and-trade program requirements including:

- CO_2 Budget Trading Program (6 NYCRR Part 242)
- Cross State Air Pollution Rule (CSAPR) Trading Program
- CSAPR NO_X Ozone Season Trading Program (6 NYCRR Part 243)
- CSAPR NO_X Annual Trading Program (6 NYCRR Part 244)
- CSAPR SO_2 Trading Program (6 NYCRR Part 245)
- SO_2 Acid Rain Program (40 CFR Parts 72-78)

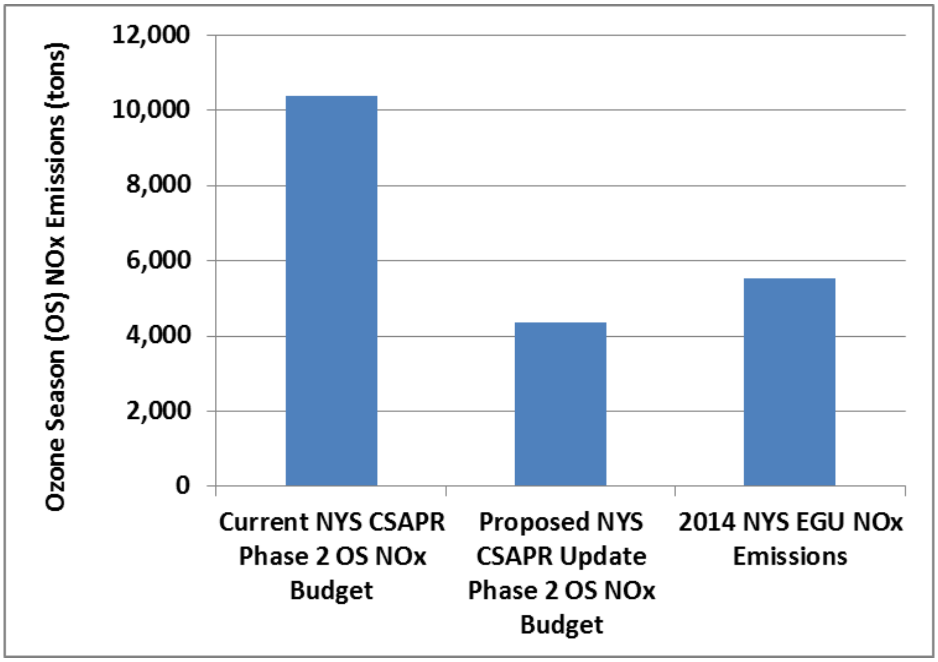
In general, the CO_2 Budget Trading Program regulations apply to any fossil fuel-fired unit that serves a generator with a nameplate capacity equal to or greater than 25 MW and generates electricity for sale. Part 242 establishes the cap-and-trade provisions pursuant to the Regional Greenhouse Gas Initiative (RGGI), a nine-state cooperative effort to reduce greenhouse gas emissions from electrical generating facilities by means of a cap-and-trade program. Under RGGI, each participating state has committed to state regulations that will cap and then reduce the amount of the CO_2 that electrical generating facilities are allowed to emit. CO_2 allowances are obtained through a CO_2 allowance auction system and are traded using CO_2 Budget Trading Programs.

In general, Parts 243, 244, and 245 CSAPR regulations apply to any stationary fossil fuel-fired boiler or combustion turbine that serves a generator with a nameplate capacity equal to or greater than 25 MW producing electricity for sale.

The cost of CO_2, NO_X, and SO_2 allowances are included in the economic dispatch and accounted for in the net EAS revenue estimates for each technology option. In addition, the cost of ERCs is included in the capital cost estimates for each Load Zone as required by NNSR air permitting requirements.

On November 16, 2015, the EPA proposed an update to the CSAPR to address the 2008 ozone NAAQS by issuing the proposed CSAPR Update Rule. Starting in 2017, this proposal would reduce summertime NO_X emissions from power plants in 23 states in the eastern U.S., including New York State. Figure 5 presents a comparison of the current and proposed CSAPR Update Phase 2 ozone season NO_X budgets for New York State and actual 2014 electric generating unit (EGU) NO_X emissions in 2014. The CSAPR Update Rule proposes to reduce the 2017 ozone season NO_X emissions cap for New York State by 58 percent. The proposed reduction in the New York State ozone season NO_X budget may place upward pressure on future NO_X allowance prices. The CSAPR Update Rule would affect new combustion turbine peaking unit technologies and combined cycle units.

Figure 5: New York State CSAPR Ozone Season NO_x Budgets and Electric Generating Units (EGUs) NO_x Emissions



3. *Plant Cooling Requirements*

The major source of heat rejection for combined cycle power plants is the steam turbine condenser. New combined cycle power plants typically use mechanical draft cooling towers or air cooled condensers (ACCs). Both cooling methods can meet Clean Water Act Section 316(b) Rule requirements for new facilities. At some locations new combined cycle power plants are moving towards the use of ACCs driven by environmental and/or water scarcity concerns. The New York Department of Environmental Conservation issued NYSDEC Policy CP-#52, which seeks a performance goal of dry cooling for industrial facilities sited in coastal zones and the Hudson River up to Troy. Therefore, it has been assumed that the combined cycle options would be designed with ACCs in all Load Zones, except Load Zone C. In this Load Zone combined cycle options would be designed with wet mechanical draft cooling towers.

Simple cycle combustion turbine plants and RICE plants have minor heat rejection requirements when compared to combined cycle plants. The GE LMS100 has a compressor inter-stage cooling requirement that can be met with wet or dry cooling options. General Electric has indicated that the vast majority of orders for the LMS100 include dry cooling. Therefore, dry cooling was assumed for the LMS 100PA+ plants in all Load Zones. The cooling requirements for the RICE plants are also based on dry cooling.

4. *Other Permitting Requirements*

Public Service Law Article 10 requires any proposed electric generating facilities with a nameplate generating capacity of 25 MW or more to obtain a Certificate of Environmental Compatibility and Public Need. The Article 10 process includes stakeholder intervention processes, including funding provisions by the project developer. The Article 10 Siting Board is to issue a finding and requires that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable. The Siting Board must consider both the state of available technology and the nature and cost of reasonable alternatives.

6 NYCRR Part 487 establishes a regulatory framework for undertaking an analysis of environmental justice issues associated with the siting of an electric generating facility in New York State pursuant to Article 10. Part 487 is intended to enhance public participation and review of environmental impacts of proposed electric generating facilities in environmental justice communities and reduce disproportionate environmental impacts in overburdened communities. Specific analysis requirements are evaluated on a case-by-case basis. The estimates of total capital investment for each technology option include expenditures to conduct environmental justice analysis as part of the project development costs.

D. Dual Fuel Capability

The recommended technology choice also requires determining for each location whether the peaking plant should be a natural gas-only resource or have the capability to operate on both natural gas and oil (dual fuel). In the 2013 DCR, FERC approved peaking plants with dual fuel capability in Load Zones G, J and K. FERC's approval recognized that a peaking plant developer would recognize certain siting benefits associated with selecting dual fuel capability, and would find dual fuel capability more economic than the alternative way of achieving the same level of fuel assurance (i.e., entering into an obligation for firm interstate pipeline transportation capacity).[21]

In this DCR, we have evaluated whether to recommend including dual fuel capability in Load Zones J and K only; in Load Zones G, J, and K as in the last reset; or in all locations. As with many of the technology choices considered, we evaluated potential recommendations against a review of relevant data and considerations tied to what developers are most likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

Based on our evaluation, AGI recommends that the peaking plant technology in all locations should include dual fuel capability. This recommendation is based on the consideration of a number of tradeoffs a developer would consider when deciding whether or not to include dual fuel capability in a development project in New York state and whether, on balance, a developer would more likely than not decide to include dual fuel capability based on such considerations. Specifically, the following observations inform the conclusion that the answer to this question is yes in each Load Zone:

- Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are modest increases in capital costs associated with the installation of dual fuel capability, and in annual costs tied to maintaining dual fuel systems, testing dual fuel capability, and carrying an

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

inventory of fuel for dual fuel operations.[22] On the other hand, these modest increases in cost would be outweighed, perhaps significantly, by the value associated with potential increases in net EAS revenues from operating on oil when the price for fuel oil is less than that of natural gas, and when able to operate when gas supplies would otherwise be curtailed (which would tend to be among the higher-priced winter hours). These potential enhancements to net EAS revenues would be further magnified to the extent that future market rule changes increase the value of higher performance during periods with high LBMPs due to tight natural gas markets, particularly in winter months. Moreover, the value of dual fuel optionality may be greater under LOE market conditions, particularly to the extent that such conditions arise due to shifts in generation resources that increase reliance on gas-fired resources.

- Potential peaking plant developers would also consider various risks and benefits associated with project development and siting. Specifically, 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.[23] Expanding such geographic flexibility increases the potential of finding sites that coincidentally minimize the costs to obtain both natural gas and electrical interconnections.
- Finally, a developer would likely view the addition of dual fuel capability favorably in light of reasonable expectations of net changes in New York state's reliance on natural gas in the coming years, due to increased demand from known new entry (e.g., CPV Valley Energy Center) and replacement of potential retirements (e.g., aging coal and nuclear capacity).

E. Capital Investment Costs

Capital cost estimates were prepared for the construction of the following simple cycle technologies in New York Load Zones, C, F, G, J, and K:

- Two GE LMS100 PA+ units
- One Siemens SGT6-5000F unit
- Twelve Wartsila 18V50SG/DG engines
- One GE 7HA.02 (informational purposes only)

In addition, for informational purposes, capital cost estimates were prepared for the construction of the following combined cycle technologies in New York Load Zones, C, F, G, J, and K:

[22] For example, adding dual fuel capability in Load Zone F would increase gross CONE by $12.06/kW-year, or 8.4 percent of gross CONE for a gas-only peaking plant with SCR. Net of net EAS revenues (including the additional revenues associated with operating on oil when more profitable), this leads to an increase in the RP of $0.50/kW-month, or 4.7 percent of the RP for a gas-only peaking plant with SCR. As described in Section II, a quantitative analysis of net EAS revenues for gas only with SCR operations may overstate actual revenues, thus understating the gas only with SCR RP.

[23] Several LDCs either require or provide specific rate schedules for generators (and developers) that include dual fuel capabilities. This includes National Grid in Load Zones C, E, F and K; Orange & Rockland and Central Hudson in Load Zone G; and Con Edison in Load Zone J.

- 1x1 Siemens 5000F5 Flex Plant (combined cycle)
- 1x1 Siemens 8000H Flex Plant (combined cycle)

The capital investment costs include direct installed cost of the plant, owner's costs, financing costs during construction and working capital and inventories. The direct installed cost of the plant is comprised of the cost to engineer, procure and construct (EPC) each plant, electrical interconnection cost and gas interconnection cost. Table 13 provides the conceptual design features for the plants in each of the Load Zones evaluated.

Table 13: Recommended Peaking Plant Design Capabilities and Emission Control Technology

	K-Long Island	J-New York City	G-Dutchess	G-Rockland	F-Capital	C-Central
Combined Cycle Plant Cooling	Dry	Dry	Dry	Dry	Dry	Wet
LMS100PA+ Cooling	Dry	Dry	Dry	Dry	Dry	Dry
Fuel Capability	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel
Post Combustion Controls for: 2 x Aero CTs, 1 x Frame CT, and 12 x RICEs	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
CT – combustion turbine; RICE – reciprocating internal combustion engine						

1. Plant Design Basis

The plant design basis is conceptual and consistent with new facility design features that would be constructed in the current market. Key design assumptions include:

1. Site Conditions – In all Load Zones except Load Zone J, the cost estimate is based on a greenfield site. Land requirements for greenfield conditions are summarized below. In New York City, Load Zone J, new peaking units would most likely be built on a brownfield site. Therefore, the New York City, Load Zone J capital cost estimate includes an allowance for demolition and site remediation of the brownfield site. The availability of large sites in New York City and Long Island is limited. Therefore, the land requirement for the combined cycle facilities in Load Zones J and K was reduced from 20 acres, as shown in Table 20, to 15 acres.

2. Storm Hardening – Costs were included to raise the Load Zone J, New York City site 3.5 feet to satisfy floodplain zoning requirements and New York City building codes to prevent damage to the facility from flooding that occurred due to Hurricane Sandy in 2012. LCI considered that new power projects in Load Zone J would most likely be located on brownfield sites along the waterfront. The Federal Emergency Management Agency (FEMA) minimum site elevation requirement is 14 feet NAVD88. LCI found

that site elevations along the waterfront ranged from 10 feet to greater than 16 feet NAVD88.[24]

3. Fuel – The capital cost estimate was developed based on dual fuel in all Load Zones and a cost reduction for gas fuel only designs was determined. Capital cost estimates for gas only plants with SCR in Load Zones C, F, and G are included in Appendix B. Dual fuel units include a cost for fuel oil inventory, with storage levels based on the capability to provide one week of on-peak operations (6 days at 16 hours per day). The delivered cost for the initial fuel oil inventory is assumed to be $14/MMBtu, based on data from the EIA March 2016 Short-term Energy Outlook. Initial commissioning for each peaking unit assumes 40 hours of full load oil use for guarantee and emissions performance testing; fixed O&M costs for peaking plants in dual fuel configuration also include annual fuel oil testing costs to demonstrate capability, plus the costs of emissions testing on oil every five years.[25] As discussed in Section II, when estimating net EAS revenues for dual fuel units, variable costs of fuel are based on the EIA New York Harbor ULSD spot price and include a transportation and tax adder applicable to each Load Zone. This cost implicitly requires that all oil burned is replenished on an on-going basis. Applicable costs for fuel inventory and emissions testing are included for each peaking plant in Appendix B.

4. Cooling Design – As summarized in Table 13 it was concluded that the combined cycle cooling in Load Zones K-Long Island, J-New York City, G-Dutchess and Rockland, and F-Capital would include a dry cooling design and Load Zone C-Syracuse would include a wet cooling design. The LMS100PA+ performance is approximately the same for wet and dry cooling of the intercooler. The LMS100PA+ requires water injection when firing natural gas, so although there is a slight increase in capital cost for dry cooling, LCI selected dry cooling for the LMS100PA+ in all Load Zones. GE has advised that most customers are selecting dry cooling.

5. Inlet Cooling – Inlet air evaporative coolers were included for the aeroderivative and frame combustion turbines (for simple and combined cycle plants). The inlet air evaporative coolers are operated when the ambient temperature exceeds 59°F. The evaporative cooler increases the water content of the air, which reduces its temperature typically 85 percent to 90 percent of the difference between the dry bulb and wet bulb temperature. Consequently, the largest temperature reduction occurs when the relative humidity is low. Since the air to fuel ratio in combustion is very high and the density of

[24] LCI notes that the 500-year flood elevation is 18 feet NAVD88. It is reasonable to expect that developers will evaluate the cost of raising the site elevation to 18 feet NAVD88 or raise the elevation of critical equipment above 18 feet NAVD to the cost of insurance and plant availability in the event of a 500-year flood. This type of evaluation would be part of a Load Zone J site selection study or a site specific design plant design. A site selection study was beyond the scope of this DCR study.

[25] *See* LCI, "Preliminary Cost and Performance Data Peaking Unit and Combined Cycle Technologies", presented to the ICAPWG April 25, 2016.

air increases as the temperature is lowered, the mass flow through the turbine is higher at lower temperature, which increases the MW generated.

6. Gas Pressure – The natural gas pressure was assumed to be 450 psig in all Load Zones except Load Zone J, New York City. For Load Zone J a 250 psig gas pressure was assumed. Natural gas compressors were included to increase the fuel gas pressure to that required by the combustion turbines.

7. Emission Control Equipment – For natural gas only, the Siemens 5000F5 frame combustion turbine could potentially receive an air permit without an SCR system in Load Zones C, F, and G (Dutchess). However, as explained earlier, AGI and LCI do not believe the Siemens 5000F5 frame combustion turbine can be practicably constructed in any Load Zone without an SCR. With dual fuel, all technologies would require an SCR system for NO_X emission reduction.

8. Black Start Capability – Black start capability has not been included since the NYISO offers a proxy payment to black start generators, or a generator can submit its actual costs for reimbursement.

2. EPC Cost Estimate

The EPC cost estimates are provided in 2015 dollars. The EPC cost estimates were not prepared for a specific site and do not include preliminary engineering activities. Contingency is included to account for uncertainties in the quantities and pricing, which may increase during detailed design and procurement. A contingency of 10 percent was applied to the total direct and indirect project costs, which is typical practice for construction projects of this type.

1. Equipment and Material Costs - The equipment and material costs were obtained from LCI proprietary power plant cost and performance simple cycle, combined cycle and reciprocating internal combustion engine models. Inputs to these models are derived from estimates developed by CB&I Fossil Power Estimating Group (CB&I Power). CB&I Power and LCI are owned by Chicago Bridge & Iron Company N.V. (CB&I), a large engineering, construction, and consulting company focused on the global energy industry. These estimates were updated in the fourth quarter of 2015 and include the latest vendor budgetary pricing. The materials costs were adjusted for location using the city cost indices published in the RSMeans® Building Construction Cost Data 2013 estimating reference for Syracuse in Load Zone C, Albany in Load Zone F, Poughkeepsie and Sufferen in Load Zone G, Queens in Load Zone J, and Riverhead in Load Zone K.

2. Labor - In developing the plant construction costs, a totally subcontracted construction approach was assumed. Construction craft base pay and supplemental (fringe) benefits were obtained from the Prevailing Wage Rate Schedule published by the New York State Department of Labor on June 1, 2015. Subcontracted labor rates were developed by adding

Federal Insurance Contributions Act (FICA) tax, workmen's compensation, small tools, construction equipment and subcontractor overhead and profit. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area.[26] Labor rates are based on Onondaga County for Load Zone C, Albany County for Load Zone F, Dutchess County and Rockland County for Load Zone G, Queens County for Load Zone J, and Suffolk County for Load Zone K.

Direct installation labor man-hours in the CB&I Power estimates are for an ideal location and must be adjusted for locations where productivity is reduced due to a variety of factors, including weather, union rules, construction parking and laydown space limitations, etc. CB&I purchased the Shaw Group, which was the EPC Contractor for two combined cycle plants in New York City and LCI was the Lender's Engineer for a combined cycle plant in the Albany area. Based on this experience, a labor productivity adjustment of 1.45 (i.e. ideal man-hours are multiplied by 1.45) was applied to Load Zone J, 1.4 for Load Zone K and 1.2 for all other Load Zones.

3. Owner's Costs

Owner's costs include items such as development costs, project management oversight, Owner's Engineer, legal fees, financing fees, startup and testing, and training. These costs have been estimated as 9 percent of direct capital costs, plus the cost of ERCs. In addition, social justice costs were estimated to be 0.9 percent of EPC costs in New York City and 0.2 percent of EPC costs in all the other Load Zones.

ERCs were included in the owner's costs for the 2x LMS100PA+ combustion turbine, 1x Siemens SGT6-5000F combustion turbine, 1x GE 7HA.02 combustion turbine and 1x1 Siemens 5000F combined cycle plants in Load Zones J, K and G (Rockland County). ERCs were required in all Load Zones for the 12x Wartsila 18V50DF engines and the 1x1 Siemens 8000H combined cycle plants. ERC requirements were based on:

- 4,000 hours/year total permitted hours of operation for peaking unit technologies, and 8,760 hours/year for combined cycle plants
- 720 hours/year of permitted ultra-low sulfur diesel (ULSD) operation for both peaking unit technologies and combined cycle plants
- The NNSR major source thresholds and offset ratios for each Load Zone that are summarized in Table 9.

[26] The union construction craft labor rates are county specific. For example, the union construction craft labor rates for Onondaga and Albany Counties are lower than for Dutchess and Rockland Counties. The union construction craft labor rates for Orange County for most power plant craft positions (boilermaker, insulator, electrician, pipefitter, operating engineer, ironworker) are the same as Rockland County. However, the union construction craft rates for millwrights, carpenters and laborers are lower for Orange County than for Rockland County. Based on the percentages of the total labor man-hours provided by these crafts, LCI estimated that the construction labor cost would be 3.6 percent lower in Orange County than Rockland County. The total capital cost estimate for the Siemens SGT6-5000F frame combustion turbine would be about 1 percent lower if the plant were located in Orange County rather than Rockland County, which is not a materially, significant difference and within the accuracy of the current estimates for a unit located within Rockland County.

ERC price assumptions for NO_X and VOC ERCs in each Load Zone were based on discussions with an emissions broker familiar with the current ERC market in New York State and are listed in Table 14.

Table 14: ERC Price Assumptions

	K-Long Island	J-New York City	G-Dutchess	G-Rockland	F-Capital	C-Central
NO_x ERCs ($/ton)	$5,000	$5,000	$2,000	$5,000	$2,000	$2,000
VOC ERCs ($/ton)	$5,000	$5,000	$3,000	$5,000	$3,000	$3,000

Construction financing costs were developed based on construction drawdown schedules for each technology option and the ATWACC presented in Section IV. The financing cost was calculated from the monthly cash flows associated with the capital cost estimates in Appendix B, which were based on the EPC project durations in Table 15.

Table 15: EPC Project Durations for Each Technology

Technology	Project Duration (months)
2x0 LMS100PA+	18
1x0 Siemens 5000F5	25
1x0 GE 7HA.02	25
12x0 Wartsila 18V50DF	25
1x1x1 Siemens 5000F5	29
1x1x1 Siemens 8000H	29

Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. These costs have been estimated as 1 percent of direct capital costs plus the cost of an inventory of ULSD fuel equivalent to six days of full load operation for 16 hours per day priced at $14/MMBtu.[27]

[27] Based on the U.S. Energy Information Administration (EIA) "March 2016 Short-Term Energy Outlook, costs of distillate fuel oil delivered to electric generating plants", the delivered price of ULSD in 2017 is assumed to be $14/MMBtu.

4. *Summary of Capital Investment Costs*

Capital investment costs for each Load Zone and combustion turbine option with dual fuel design are summarized in Tables 16 and 17. Capital investment costs for gas only with SCR designs (and without SCR for the 1x0 Siemens SGT6-5000F) are included in Appendix B.

Table 16: Capital Cost Estimates, Dual Fuel ($2015 million)

	K - Long Island	J - NYC	G (Dutchess)	G (Rockland)	F – Capital	C - Central
Peaking Unit Technologies						
2x0 GE LMS100PA+	$345	$337	$310	$313	$281	$292
1x0 Siemens 5000F5	$288	$277	$255	$258	$225	$237
1x0 GE 7HA.02	$549	$377	$342	$345	$310	$320
12x0 Wartsila 18V50DF	$433	$425	$386	$390	$349	$358
Combined Cycle Plants						
1x1x1 Siemens 5000F5	$883	$728	$603	$611	$541	$517
1x1x1 Siemens 8000H	$921	$768	$636	$646	$572	$544

Table 17: Capital Cost Estimates, Dual Fuel ($2015/kW)

	K - Long Island	J - NYC	G (Dutchess)	G (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
2x0 GE LMS100PA+	$1,820	$1,800	$1,650	$1,660	$1,500	$1,570
1x0 Siemens 5000F5	$1,310	$1,270	$1,170	$1,180	$1,040	$1,100
1x0 GE 7HA.02	$1,730	$1,190	$1,080	$1,090	$980	$1,020
12x0 Wartsila 18V50DF	$2,160	$2,120	$1,930	$1,950	$1,740	$1,790
Combined Cycle Plants						
1x1x1 Siemens 5000F5	$2,680	$2,220	$1,840	$1,870	$1,660	$1,570
1x1x1 Siemens 8000H	$2,390	$2,010	$1,660	$1,690	$1,500	$1,410

5. Electrical Interconnection Costs

Interconnection costs include Minimum Interconnection Standard (MIS) costs and System Deliverability Upgrade (SDU) costs. To determine the need for SDU cost, the NYISO planning group investigated the ability of a new plant to deliver up to 490 MWs at eight points of interconnection (POI) that are representative of locations available for capacity additions in Load Zones C, F, G, J and K.

MIS Costs

MIS costs are comprised of:

- Developer Attachment Facilities (DAF)
- System Upgrade Facilities (SUFs) at the POI
- SUFs beyond the POI
- Connecting Transmission Owner (CTO) Attachment Facilities (AF)

The DAF costs begin at the high side bushing of the generator step up transformer (GSU). The costs of the generator breaker installed in the isolated phase bus duct between the generator terminals and the GSU low side bushings, isolated phase bus duct and GSU(s) are included in the plant EPC cost. The DAF cost is comprised of the plant switchyard and a transmission line to the POI. The plant switchyard cost is a separate line item in the capital cost. Therefore, the electrical interconnection cost is comprised of the MIS cost excluding the plant switchyard. LCI believes that a project is likely to treat the SDU cost as a separate Owner's Cost in the capital cost estimate since the Owner has no role in the SDU design and construction; therefore, it was not included in the electrical interconnection cost.

The interconnecting transmission line between the plant switchyard and the POI is assumed to be one mile long in Zone J (New York City) and three miles long in all other Load Zones. All interconnecting transmission lines are assumed to be installed overhead.

The cost of the SUFs at the POI were based on the assumption that the interconnection is an expansion of an existing substation and requires the addition of a three breaker ring bus with gas insulated switchgear (GIS). New relay protection and control equipment is installed in an existing control building at the POI.

LCI reviewed recent interconnection agreements in New York State to develop a conceptual interconnection design (DAF and SUF at POI) as a basis for preparing cost estimates. These interconnection agreements also provided costs for CTO-AF and cost for other SUFs. The other SUFs would occur at substations that are connected to the POI. The CTO-AF costs and the other SUF costs are much lower than the DAF and SUF at POI costs. The CTO-AF and other SUF costs were also very consistent. Therefore, LCI used the published CTO-AF and other SUF costs based on recent interconnection agreements reviewed.

The costs for the switchyard, transmission line to POI and SUFs at POI were estimated by LCI. Budget pricing was obtained for the major electrical components. Bulk materials costs, installation labor costs, construction indirect and other indirect costs such as design, engineering and procurement were factored. A 20 percent contingency was applied to the DAF and SUFs at POI costs.

The switchyard portion of the DAF cost, which is included as a line item in EPC portion of the capital cost estimate is dependent on the number of GSUs, the GSU capacity and high side voltage. The SUFs at the POI are dependent on the interconnection voltage, which is the same as the GSU high side voltage. Based on the New York transmission distribution map, the interconnection voltages in the load zones are as follows:

Table 18: Interconnection Voltages

K - Long Island	J - NYC		G (Dutchess / Rockland)	F - Capital	C - Central
138 kV	345 kV	138 kV	345 kV	230 kV	345 kV

The DAF and SUFs at POI costs increase with the interconnection voltage. The cost for a 230 kV interconnection is only slightly greater than for a 138 kV interconnection. However, the cost for a 345 kV interconnection is more than twice the cost of a 138 kV interconnection. Consequently, for Zone J without additional information to justify the expense of a 345 kV interconnection, the lower 138 kV interconnection cost was assumed for the capital cost estimates.

SDU Cost

Studies were performed by the NYISO to determine if SDUs would be required for the plants included in this study. The results showed that SDUs would only be required for Zone K, Long Island. The SDU required for the 2x0 GE LMS 100 plant, the 1x0 Siemens 5000F5 plant and the 12x0 Wartsila RICE plant is re-conductoring of the Elwood- Pulaski 69 kV line. PSEG Long Island estimated that the cost would be $15.5 million.

In addition to the Elwood- Pulaski 69 kV line re-conductoring, the larger capacity informational combined cycle technologies (1x1x1 Siemens 5000F and 1x1x1 Siemens 8000H) and the informational simple cycle 1x0 GE 7HA.02 will require new or re-conductoring of the Barrett-Valley Stream or Barrett-EGC 138 kV lines. PSEG Long Island estimated costs of the 138 kV re-conductoring at $64.6 million, $129 million or $191 million depending on the plant location. Since the site location is unknown, the average cost of the 138 kV line re-conductoring was used in the capital cost estimates.

LCI reviewed the SDU costs developed by PSEG Long Island and found the costs to be reasonable. However, since these are budgetary non site specific estimates, a 20 percent contingency was applied to the total SDU cost estimated by PSEG Long Island and, as discussed previously, the SDU cost was included as an Owner's Cost.

6. Gas Interconnection Cost

LCI researched publicly available gas interconnection costs for recent projects. The research included New York State as well as projects in neighboring ISOs. Based on this research and LCI's experience with gas laterals, an installed pipeline cost of $200,000 per inch diameter per mile was used. Using recent combined cycle projects in New York State (with one project next to the pipeline and another project 8 miles from the pipeline[28]), LCI developed costs reflecting an average gas lateral length of four miles. Assuming a typical 16-inch diameter pipe interconnection and a length of four miles the gas interconnection cost equals to $12.8 million. The average cost for a metering and regulation station was estimated at $2.8 million, which results in a total gas interconnection cost of $15.6 million. This cost was applied to all Load Zones.

These costs represent a generalized estimate to interconnect with either an interstate natural gas pipeline or a gas local distribution company (LDC) distribution system. As described above, units with dual fuel capability are expected to have greater geographic siting flexibility, including the ability to interconnect with an LDC. Interconnection costs to an LDC may be higher or lower than comparable interconnection costs to an interstate pipeline, depending on such things as distance, terrain, and existing right-of-way. For example, in LCI's professional opinion, it is reasonable to expect that the interconnection for Load Zone J would be shorter than estimated above with a smaller pipeline diameter; however, the difficulty of installing a pipeline in New York City would likely offset any savings from a smaller and shorter pipeline. This would result in an installed pipeline cost greater than $200,000 per inch diameter per mile in New York City. LCI believes that its non-site specific cost for Load Zone J of $15.8 million for a 1 mile 16 inch diameter interconnect to a lower pressure LDC pipeline plus a metering station is reasonable.

F. Fixed & Variable Operating and Maintenance Costs

In addition to the initial capital investment, there are other costs associated with the peaking unit and combined cycle options. These include the fixed operating and maintenance (O&M) costs, the variable O&M costs, and fuel costs. The following sections describe the components that are included in the fixed O&M and the variable O&M. Appendix B contains tables that provide a breakdown of the fixed and variable O&M cost estimates for each generating technology in each Load Zone and all locations for both dual fuel and gas only with SCR designs.

1. Fixed O&M Costs

The fixed O&M includes two components, fixed plant expenses and fixed non-operating expenses. Fixed plant expenses are O&M expenses that are not affected by plant operation, i.e. not related to fuel consumption or annual electric generation.

a) Fixed Plant Expenses

Typical fixed plant expenses include plant staff labor cost, routine O&M, routine planned maintenance, and administrative and general costs. The LCI proprietary power plant cost and performance simple cycle, combined cycle and reciprocating internal combustion engine models were used to develop the fixed plant expenses. These models include a detailed O&M cost program, which

[28] For example, Cricket Valley Energy Project gas interconnect is 500 feet long; CPV Valley gas interconnect is 8 miles long.

calculates routine materials and contract labor costs and administrative & general costs for power plants of all types and sizes based on LCI experience.

The plant staff labor costs are based on the staffing levels in Table 19. The full time equivalent (FTE) employees are comprised of O&M staff, management and administrative staff.

Table 19: Staffing Levels

	K - Long Island	J - NYC	G (Dutchess)	G (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
2x0 GE LMS100PA+	9	10	9	9	9	9
1x0 Siemens 5000F5	9	10	9	9	9	9
1x0 GE 7HA.02	9	10	9	9	9	9
12x0 Wartsila 18V50DF	14	14	14	14	14	14
Combined Cycle Plants						
1x1x1 Siemens 5000F5	20	20	20	20	20	20
1x1x1 Siemens 8000H	20	20	20	20	20	20

In assessing the plant staff average labor rate and benefits, LCI examined the wage rate information for power plant workers from the New York Department of Labor (DOL) website, as well as the operating and maintenance labor rates used in the 2013 DCR. The DOL wage rates for various occupations are available for all Load Zones and are dependent on reported information from employers. As a result of LCI's review, it was determined that the DOL wage rates are inconsistent and not necessarily representative of the current wage rates. Therefore, LCI escalated the labor rates from the 2013 DCR for this study using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator.[29] Notably, the DOL data reviewed by LCI in assessing plant staff average labor rate and benefits for fixed O&M cost purposes is separate from the DOL data that was relied in developing the construction labor costs in connection with the capital investment cost estimates. The data utilized in developing the capital investment cost estimates represents union construction labor rates by county throughout New York State and does not raise the same concerns LCI noted with respect to employer reported information underlying the DOL data regarding wage rate information for power plant workers.

The cost of performing the required tests for operating on ULSD fuel is significant. Consequently, the ULSD testing cost was included as a fixed O&M cost and calculated assuming the unit

[29] As described in Section II.H and Section IV, the annual change in the GDP implicit price deflator represents the general component of the composite escalation factor, as defined in Section 5.14.1.2.2.1 of the Services Tariff. When escalating costs from $2013 to $2015, the two-year cumulative change as measured between the second quarters of 2013 and second quarter of 2015 was used. At the time of this Report, 2015 final values for the labor component of the composite escalation rate were not available. *See* Section V.

would be operated on ULSD fuel for one hour per month to demonstrate capability and for 15 hours every five years for stack tests required by the unit's air permit.

b) *Site Leasing Costs*

The site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. LCI developed site leasing costs using values from the 2013 DCR study, escalated to $2015 using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator.[30]

Table 20: Site Leasing Cost Assumptions ($2015)

	New York City	Long Island	Rest of State
Land Requirement - 2 x LMS100PA+ (acres)	6	6	6
Land Requirement - Simple Cycle SGT6-5000F5 & 7HA.02	10	10	10
Land Requirement - Reciprocating Engines (acres)	10	10	10
Land Requirement - Combined Cycle (acres)	15	15	20
Lease Rate ($/acre-year)	$246,900	$23,700	$19,600

[30] *See* prior footnote.

c) *Total Fixed Operations and Maintenance*

The total fixed O&M expenses including the fixed plant expenses and site leasing costs are shown in Table 21. As described below, property taxes and insurance are estimated separately as a percentage of total installed costs. Property taxes and insurance are not included in Table 21.

Table 21: Fixed O&M Estimates ($2015/kW-year)

	K - Long Island	J - NYC	G - (Dutchess)	G - (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
Dual Fuel Capability						
2x0 GE LMS100PA+	$15.95	$25.86	$14.37	$14.45	$12.35	$11.93
1x0 Siemens 5000F5	$15.09	$27.77	$13.63	$13.69	$11.89	$11.51
1x0 GE 7HA.02	$12.01	$20.72	$10.94	$10.97	$9.70	$9.44
12x0 Wartsila 18V50DF	$23.26	$35.01	$20.33	$20.61	$16.48	$15.57
Natural Gas with SCR						
2x0 GE LMS100PA+			$12.65	$12.74	$10.64	$10.20
1x0 Siemens 5000F5			$11.86	$11.93	$10.12	$9.74
1x0 GE 7HA.02			$9.34	$9.37	$8.10	$7.83
12x0 Wartsila 18V50SG			$16.71	$16.97	$13.24	$12.41
Combined Cycle Plants						
Dual Fuel Capability						
1x1x1 Siemens 5000F5	$23.89	$34.52	$21.88	$21.95	$19.18	$18.30
1x1x1 Siemens 8000H	$20.91	$30.05	$19.20	$19.26	$16.88	$16.11
Natural Gas with SCR						
1x1x1 Siemens 5000F5			$20. 67	$20.75	$17.97	$17.10
1x1x1 Siemens 8000H			$17.98	$18.04	$15.65	$14.90

Note: The $/kW-year is calculated based on each plant degraded ICAP net output.

d) *Taxes*

Property taxes are equal to the product of (1) the unadjusted property tax rate for the given jurisdiction, (2) an assessment ratio, and (3) the market value of the plant, reflecting the installed capital cost exclusive of any SDU costs.

Outside of New York City, the effective property tax rate is assumed to be 0.75 percent based the assumption that the peaking plant will enter into a Payment in Lieu of Taxes (PILOT) agreement, which will be effective for the full amortization period. PILOTs are typically developed based on project specific and regional economic conditions and are expected to vary based on the unique circumstances of each county and project at the time of negotiations. The 0.75 percent rate was used in the 2013 DCR, and this rate was found to be in a range that is consistent with current PILOTs based on a review of data available through the New York State Comptroller Office.[31]

In New York City, the property tax rate equals 4.8 percent, which is equal to the product of (1) the Class 4 Property rate (10.4 percent) and (2) the 45percent assessment ratio.[32] Power plant equipment that is not rate regulated by the New York Public Service Commission should be treated as general commercial real property (Class 4).

However, the New York City tax code offers a tax exemption for the peaking unit for the NYC ICAP Demand Curve for the first 15 years of the project's operations. [33] Accordingly, it is assumed that each peaking plant receives this exemption and incurs taxes only for years 16 and beyond.

e) Insurance

Based on LCI's professional experience and review of similar projects, insurance costs are estimated as 0.6 percent of the installed capital costs. This value is also consistent with the 2013 DCR and is used within the ISO-NE determination of total costs.[34]

2. Variable O&M Costs

Variable O&M costs are directly related to plant electrical generation and start-ups and consist of two components.

- One variable operating cost component includes the consumables such as ammonia for the SCR, chemicals, and lube oil for the RICEs, water, and other production-related expenses including SCR and oxidation catalyst replacement. The cost on a $/MWh for the SCR ammonia consumption, the SCR and oxidation catalyst replacement, lube oil, water, other chemicals and consumables are included in Appendix B.
- The other variable operating cost component is major equipment maintenance. For the simple cycle combustion turbines, the major maintenance variable cost component is for

[31] The Office of the New York State Comptroller provides financial data for local governments, including Industrial Development Agencies (IDA). *See* http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm AGI identified PILOT agreements for 11 natural gas plants, with effective PILOT tax rates ranging from 0.2% to 2.01%, and the median value of these rates was 0.83 percent. These projects include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large combined cycle units. AGI did not review recent PILOT payments for existing coal or nuclear units, which may have a different long-term outlook for energy revenues than gas plants.

[32] *See* http://www1.nyc.gov/site/finance/taxes/property-tax-rates.page and https://www1.nyc.gov/site/finance/taxes/property-determining-your-assessed-value.page.

[33] Units are eligible for this abatement as long as they obtain a building permit or commence construction by April 1, 2019. *See* New York Real Property Tax Law, Section 489-aaaaaa et seq.

[34] *See* Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, FERC Docket No. ER14-1639-000, filed April 1 2014. (hereafter, "Newell and Ungate (2014)"). Insurance is described on page 38.

the combustion turbine. For the RICE plant, the major maintenance variable cost component is for the engine major maintenance. For the combined cycle plants, the major maintenance variable cost component also includes the major steam cycle equipment such as the steam turbine, heat recovery steam generator and condenser.

The combustion turbine major maintenance consists of combustion inspections, hot gas path inspections, and major inspections. Depending on dispatch and engine technology, these maintenance activities occur based on equivalent operating hours or equivalent starts. For the GE LMS100PA+ aeroderivative combustion turbine, a complete maintenance cycle occurs over 50,000 operating hours. For the SGT6-5000 F5 and the GE 7HA.02 frame combustion turbines, a complete maintenance cycle occurs over 48,000 equivalent operating hours or 2,400 factored starts, whichever limit is reached first. For the RICE, the major maintenance activities occur at varying intervals.

A summary of the variable maintenance cost assumptions is provided in Table 22 for each technology option. The variable costs per start apply to the frame combustion turbines and are provided in Table 23. A summary of the variable O&M cost for each technology option in each Load Zone is provided in Table 24 and Appendix B.

Table 22: Variable O&M Assumptions ($2015)

Technology	2x LMS100PA+	1x SGT6-5000F5	12x 18V50DF	1x 7HA.02	1x1x1 SGT6-5000F	1x1x1 SGT6-8000H
Complete Major Maintenance Cycle (operating hours)	50,000	48,000	Varies by Engine Component	48,000	48,000 (combustion turbine only)	48,000 (combustion turbine only)
Complete Major Maintenance Cycle (factored starts)	N/A	2,400	N/A	2,400	2,400 (combustion turbine only)	2,400 (combustion turbine only)
Cost of Parts for Complete Maintenance Cycle ($million) [1]	$14.8	$22.1	N/A	$34	$22.1 combustion turbine only)	$33.4 (combustion turbine only)
Labor Hours Needed for Complete Maintenance Cycle [1]	14,000	21,400	N/A	32,100	21,400 (combustion turbine only)	32,400 (combustion turbine only)

Note: Estimates per combustion turbine

Table 23: Variable Costs per Start ($2015/Start)

	K - Long Island	J - NYC	G - (Dutchess)	G - (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
1x0 Siemens 5000F5	$10,900	$11,000	$10,500	$10,600	$10,300	$10,200
1x0 GE 7HA.02	$16,700	$16,900	$16,200	$16,300	$15,800	$15,700
Combined Cycle Plants						
1x1x1 Siemens 5000F5	$10,900	$11,000	$10,500	$10,600	$10,300	$10,200
1x1x1 Siemens 8000H	$16,500	$16,600	$15,900	$16,000	$15,500	$15,400

Note: Excludes fuel consumed and revenues from electricity produced during start.

Table 24: Natural Gas Variable O&M Costs ($2015/MWh)

	K - Long Island	J - NYC	G - (Dutchess)	G - (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
LMS100PA+	$5.60	$5.62	$5.48	$5.50	$5.39	$5.37
1x0 Siemens 5000F5	$0.76	$0.76	$0.76	$0.76	$0.76	$0.76
1x0 GE 7HA.02	$1.02	$1.02	$1.02	$1.02	$1.02	$1.02
12x0 Wartsila 18V50 DF	$8.19	$8.24	$7.90	$7.95	$7.68	$7.62
Combined Cycle Plants						
1x1x1 Siemens 5000F5	$1.06	$1.07	$1.02	$1.02	$0.98	$1.25
1x1x1 Siemens 8000H	$1.02	$1.03	$0.99	$1.00	$0.96	$1.22

Note: Based on natural gas firing and degraded average summer/winter capacity rating.

G. Operating Characteristics

The plant operating characteristics used to evaluate the technology options in each Load Zone are:

- Summer and winter degraded capacity ratings, summer dependable maximum net capability (DMNC), winter DMNC and ICAP plant capacity (net output) and net heat rate (fuel efficiency);
- Average degradation of net capacity and net heat rate as plant ages;
- Equivalent demand forced outage rate (EFORd); and
- Plant startup time and fuel required for startup.

The net output and net heat rate for all the combustion turbine and combined cycle technology options are impacted by ambient conditions (temperature and relative humidity) and site elevations. The site elevations in each Load Zone are defined in Table 25.

Table 25 also provides the ambient temperatures and relative humidity for the summer, winter, summer DMNC, winter DMNC and ICAP. The summer and winter ambient conditions in each Load Zone are determined at the average winter and summer conditions. The summer and winter DMNC ambient conditions in each Load Zone are determined at the average of the ambient conditions recorded at the time of the Transmission District's seasonal peak during the previous four like Capability Periods, as recorded at the nearest approved weather station. The ICAP ambient condition is defined as 90°F and 70 percent relative humidity. The ICAP DMNC value is used to express capital costs and fixed O&M on an equivalent $/kW and $/kW-year basis. Net EAS revenues utilize performance values (e.g., heat rate) associated with average summer and winter conditions, respectively, since net EAS revenues are calculated throughout the full year.

Table 25: Ambient Conditions for Current DCR

Load Zone	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity
C - Central	421	Summer	77.7	46.9
		Winter	28.4	72.8
		Spring-Fall	59.0	60.0
		Summer DMNC	91.6	34.2
		Winter DMNC	11.4	73.3
		ICAP	90.0	70.0
F - Capital	275	Summer	78.1	48.0
		Winter	29.2	68.3
		Spring-Fall	59.0	60.0
		Summer DMNC	92.3	35.8
		Winter DMNC	10.9	61.7
		ICAP	90.0	70.0
G - Hudson Valley	165	Summer	78.9	51.0
		Winter	32.6	66.9
		Spring-Fall	59.0	60.0
		Summer DMNC	91.2	36.0
		Winter DMNC	13.1	69.85
		ICAP	90.0	70.0
G - Hudson Valley	165	Summer	79.9	48.2
		Winter	33.2	65.4
		Spring-Fall	59.0	60.0
		Summer DMNC	93.7	29.2
		Winter DMNC	14.5	65.9
		ICAP	90.0	70.0
J - New York City	20	Summer	81.1	41.2
		Winter	38.1	55.0
		Spring-Fall	59.0	60.0
		Summer DMNC	95.1	25.4
		Winter DMNC	22.2	46.7
		ICAP	90.0	70.0
K - Long Island	16	Summer	78.0	52.7
		Winter	35.9	62.2
		Spring-Fall	59.0	60.0
		Summer DMNC	88.6	50.2
		Winter DMNC	17.5	46.9
		ICAP	90.0	70.0

The detailed plant performance data for each technology option in each Load Zone is provided in Appendix B. LCI used the following sources to develop the performance information:

- Siemens Performance Estimating Program (SiPEP) to develop the new and clean performance for the 1x0 SGT6-5000F5 simple cycle plant, the 1x1x1 SGT6-5000F5 combined cycle plant and the 1x1x1 Siemens SGT6-8000H combined cycle plant;
- GE Gas Turbine Performance (GTP) program to determine the GE 7HA.02 new and clean performance;
- Obtained new and clean performance from GE for the LMS100PA+ and used Thermoflow software to adjust the performance for elevation and ambient conditions;
- Performance for the Wartsila 18V50DF engine was provided by Wartsila.

LCI adjusted these performance results for gas compressor auxiliary power and transformer losses. The power plant performance begins to degrade once the facility begins to operate. Some of the degradation is not recoverable, however, most of the performance loss is recovered after major equipment overhauls. LCI developed average degradation curves for output and heat rate over the plant economic life, which show percent degradation between major overhauls and percent of degraded output recovered versus operating hours. These curves are typical and published in papers and are available from the combustion turbine manufacturers. For RICE, only the heat rate degrades between major overhauls.

The plant performance degradation percentages used to calculate degraded output and heat rate from new and clean percentages are shown in Table 26. The degraded net plant capacity and degraded net plant heat rates at the ICAP ambient conditions (90°F and 70 percent relative humidity) for each Load Zone are shown in Tables 27 and 28, respectively. Performance for all ambient conditions is provided in Appendix B. Average degraded net plant capacities are used throughout the economic analysis as described in Sections III and IV. The use of the average degraded net plant capacity is used to reflect expected operations over the life of the unit.

Table 26: Average Plant Performance Degradation over Economic Life

Plant	Average Degradation of Net Output	Average Degradation of Net Heat Rate
2x0 GE LMS100PA+	2.5%	0.8%
1x0 Siemens SGT6-5000F5	3%	1.8%
12x0 Wartsila 18V50DF	0%	0.5%
1x0 GE 7HA.02	3%	1.8%
1x1x1 Siemens SGT6-5000F5 Combined Cycle	1.8%	1.1%
1x1x1 Siemens SGT6-8000H Combined Cycle	1.8%	1.1%

Table 27: Average Degraded Net Plant Capacity ICAP (MW)

	K - Long Island	J - NYC	G (Dutchess)	G (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
2x0 GE LMS100PA+	189	188	188	188	187	186
1x0 Siemens 5000F5	219	218	218	218	217	216
1x0 GE 7HA.02	318	316	316	316	315	313
12x0 Wartsila 18V50DF	200	200	200	200	200	200
Combined Cycle Plants						
1x1x1 Siemens 5000F5	329	328	327	327	326	329
1x1x1 Siemens 8000H	385	383	383	383	381	385

Table 28: Average Degraded Net Plant Heat Rate ICAP (Btu/kWh)

	K - Long Island	J - NYC	G (Dutchess)	G (Rockland)	F - Capital	C - Central
Peaking Unit Technologies						
2x0 GE LMS100PA+	9,260	9,320	9,260	9,260	9,260	9,260
1x0 Siemens 5000F5	10,310	10,380	10,300	10,300	10,310	10,310
1x0 GE 7HA.02	9,570	9,620	9,570	9.570	9,570	9,570
12x0 Wartsila 18V50DF	8,380	8,380	8,380	8,380	8,380	8,380
Combined Cycle Plants						
1x1x1 Siemens 5000F5	6,930	6,960	6,930	6,930	6,940	6,850
1x1x1 Siemens 8000H	6,750	6,790	6,760	6,760	6,760	6,650

EFORd is defined as “A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.”[35] The North American Electric Reliability Corporation’s (NERC) Generating Availability Data System (GADS) continuously collects availability/reliability data from more than 7,700 power plants in the US and Canada. The data is organized by plant type, size ranges and plant age ranges. LCI reviewed the NERC GADS data as well as our in-house database of key performance indicator data. LCI selected EFORd values to reflect our experience with newer and well-maintained plants and information from the original equipment manufacturers. We have assumed an EFORd of 2.2 percent for the simple cycle combustion turbine plants, 3 percent for the combined cycle plants and 1 percent for the RICE plant.

The original equipment manufacturers (Siemens, GE and Wartsila) provided start-up times and start up curves that were used to calculate the start-up fuel consumption. The start-up data is included in Appendix B. For the simple cycle frame combustion turbines both conventional start- up and fast start- up information is provided. For the combined cycle plant the start-up data is for a warm start, which is defined as a start that occurs more than eight hours, but less than or equal to 48 hours after a shutdown.

[35] *See* IEEE-SA Standards Board, “IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity” Sponsor Power System Analysis, Computing, and Economics Committee of the IEEE Power Engineering Society Approved December 29, 2006 American National Standards Institute.

III. GROSS COST OF NEW ENTRY

Gross CONE encompasses all costs associated with plant construction and operations aside from those arising from providing energy and ancillary services, which are addressed in Section IV. Gross CONE includes the recovery of capital costs, including a return on investment. The annualized cost associated with a capital investment reflects the financial parameters described in Section III.A that capture the investor's cost of capital and the period over which the return of and return on the upfront capital investment is assumed to be recovered. Section III.B describes the translation of these up-front capital costs, along with time-varying tax costs, into a levelized fixed charge (e.g., an annual carrying charge) that allows full recovery of the plant's capital costs over the course of the plant's economic life. Finally, Section III.C provides estimates of the gross CONE, including the levelized fixed charge, fixed O&M expenses, and insurance.

A. Financial Parameters

The development of a new generation facility requires the upfront capital investment costs for the construction of the facility. The financial parameters translate these upfront technology and development costs into an annualized value that is an element of gross CONE for each Load Zone. The difference in annualized gross CONE and net EAS revenues is defined as the annual reference value (ARV). That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technologies. This translation from up-front to annualized value is reflected in the so-called "levelization" factor. The parameters that affect the levelization factor (the "financial parameters") include:

1. The weighted average cost of capital required by the developer, based on the developer's required return on equity (ROE), its cost of debt (COD), and the project's capital structure (as reflected in the ratio of debt to equity (D/E ratio);
2. The term, in years, over which the project is assumed to recover its upfront investment, referred to the amortization period (AP); and
3. Applicable tax rates, which affect the costs of different types of capital.

These elements are not determined in isolation. Appropriate values for these parameters need to reflect the interrelationships among them, and as a whole appropriately reflect the financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market context.

The selection of these financial assumptions should capture industry expectations of costs, and reflect project-specific risks, including development risks and risks to future cash flows for a merchant developer, based on investor expectations over the life of the project. Many factors can affect investor risks – such as uncertainty and variability in fuel prices and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; the development of energy and environmental policies with implications for industry demand, costs, and revenues; and the pace and nature of technological change. Further, data that may be available on individual components of the WACC and the AP can vary with factors specific to circumstances, including location, corporate structure, prevailing economic/financial conditions, fuel and electricity market expectations, financial hedges (such as power purchase agreements), and the nature and impact of current and potential future market and regulatory factors.

Ultimately, the recommended WACC and the AP reflect our view of the risks associated with the merchant development of a peaking plant in the NYISO market context, and the return required by investors to compensate for those risks. AGI's recommendations are based on our professional judgment, reflecting the particular circumstances of merchant development of a peaking plant in the NYISO market context; the many sources of information identified and described below; past professional experience, including conversations with developers and people in the finance community; and AGI's view of industry conditions and market factors at the time of the DCR, including past experience with merchant development in the NYISO markets.

AGI also presents its thoughts on some of the key perspectives with respect to development entities and approaches, and key existing and emerging development, market, and regulatory risks that are needed to interpret available data and information. Finally, AGI presents its recommended assumptions for WACC and AP based on our careful review of all of these factors from the perspective of potential generating resource developers in the New York electricity market.

1. Amortization Period

The AP is the term over which the project developer expects to recover upfront capital costs, including the return on investment. In the context of the DCR model, it is the period of time (in years) over which the discounted cash flow from net EAS revenue streams (net of annual fixed costs) are netted out against the upfront capital investment cost of the peaking plant. In this sense, what is often referred to as the "economic life" of the asset can, in principle, differ materially from the potential physical life of the unit; while the physical life of the plant reflects the expected physical operating life (usually before major overhauls would be required), the economic life reflects financial considerations, particularly risks associated with assuming revenues streams far into the future.

The AP must balance risks over the full physical life of the unit. On the one hand, plant owners will earn net revenues over the full physical life of the unit (while incurring costs for maintenance overhauls over time). An expected physical life of thirty years is reasonable for a peaking plant, while other technologies can have longer physical lives.[36] On the other hand, many factors create risks to future cash flows. These include changes in markets, technologies, regulations, policies, and underlying demand from consumers. To the extent that any of these changes lead to a long-term outlook for revenues that is less than assumed in the current analysis or captured in annual updates, investors would tend to under recover total costs. To account for these risks, investors may seek a shorter AP.

Given these factors, AGI recommends an AP of 20 years for all technologies and Load Zones. This is an appropriate assumption given the balance of considerations between a shorter and longer

[36] Units may require significant capital expenditures to retrofit or upgrade units to maintain in operation. The current analysis does not consider these incremental investments in the discounted cash flow analysis.

period. This assumption is also consistent with the 2013 DCR[37] and the ISO-NE and PJM capacity market demand curves, all of which have used or currently use a twenty year AP. Note that both ISO-NE and PJM demand curves reflect a twenty year AP for both peaking plants and combined cycle technologies, with the latter typically entailing relatively less long-term revenue stream risk, and correspondingly longer APs, all else equal.[38] Our recommendation is also consistent with assumptions used in independent studies by the California Energy Commission and the National Energy Technology Laboratory that evaluate the cost of new plant development by independent power producers (IPPs).[39] An amortization period of twenty years promotes consistency and continuity across regions, and represents an appropriate reflection of the balance of risks and uncertainty faced by project developers in New York markets.

2. Weighted Average Cost of Capital

The cost of capital for a new peaking plant will reflect the proportion of each source of capital in the project's capital structure – that is, the ratio of debt to equity – and the "cost" of different sources of capital – that is, the required return on equity and the cost of debt. These costs, in turn, reflect project's capital structure, because this structure affects that likelihood that debt will be paid and equity will receive returns (in excess of project costs). Thus, the return on equity, cost of debt and capital structure are inter-related.

The appropriate WACC for use in the DCR will reflect the project-specific risks associated with the development of a new peaking plant by a merchant developer within the NYCA. However, data is not available to observe directly the WACC for such a project. As a result, AGI developed its recommended WACC based on data from a number of different sources.

- **Metrics from publicly traded companies.** AGI considered financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets – that is, IPPs. Data on these companies include various data or analytic measures of COD, ROE and D/E ratios based on publicly report data. AGI's assessment considers these data, with an understanding that project-level and company-level WACC's will differ when specific projects are more or less risky than the company as a whole.[40]

[37] In the 2013 DCR, a 20 year AP was used for F-Class combustion turbine peaking technologies.

[38] *See* Newell and Ungate (2014), p. 42. *See* also Newell, et al. "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, With June 1, 2018 Online Date" Prepared for PJM Interconnection, May 15, 2014, p. 39.

[39] California Energy Commission, "Comparative Costs of California Central Station Electricity Generation," CEC 200-2009-07SF, January 2010, Table 19; National Energy Technology Laboratory, "Investment Decisions for Baseload Power Plants," 402/012910, January 29, 2010, p. II-8.

[40] "The company cost of capital is *not* the correct discount rate if the new project is more or less risky than the firm's existing business. Each project should in principle be evaluated at its *own* opportunity cost of capital." Brealey, Richard, Steward Myers, and Franklin Allen, *Principles of Corporate Finance*, Ninth Edition, New York: McGraw-Hill/Irwin, 2008, p. 239.

- **Independent assessments.** AGI considered a variety of independent assessments, including: estimated WACC for publicly traded companies developed by financial analysts (e.g., in the context of so-called "fairness opinions"); and assessments of the costs of merchant plant development. These independent assessments include information on the WACC under different corporate structures, including so-called "project finance," in which the project is financed as a stand-alone entity without recourse to a company's balance sheet.

AGI's recommendations are based on its professional judgment, reflecting the information and data identified below; past professional experience, including conversations with developers and people in the finance community; and an appropriate balancing of these various sources of information and experiences considering the market risks faced by a new merchant peaking plant being developed within the NYISO markets.

In evaluating these data, AGI views the appropriate WACC for the peaking plant as bounded from below by the WACCs typical of established IPPs, and from above by the WACCs that are more representative of project-financed developments. As noted above, the appropriate cost of capital for a specific project should reflect the particular risks faced by that project, not the risks associated with the company or investors that are considering the development of that project.[41] The WACC for a new merchant project is generally greater than that for publicly-traded IPP companies because these companies tend to have portfolios of assets that balance and mitigate risks, and thus lower the WACC. These portfolios include various financial assets, including financial hedges and long-term contracts, as well as portfolios of physical assets spanning varied geographies (including regions with different load profiles), technologies, fuels and vintages.

On the other hand, AGI assumes that the project would not be developed through project finance by a private entity. Development of the peaking plant through such financing within the NYISO market context could require a higher WACC than through a project developed using the balance sheet of a larger entity, such as a publicly traded IPP (balance sheet financing).[42]

Given these factors, in developing its recommendations, AGI assumes that the WACC appropriate for a new merchant peaking plant in the NYISO market would be greater than the WACC for IPP companies, but less than that of a project-financed project. Below, AGI evaluates the individual financial parameters that bear on the recommended WACC, recognizing these bounds and the interrelationships among these parameters in determining the WACC.

Cost of Debt

The cost of debt_reflects a project developer's ability to raise funds on debt markets. Figure 6 reports debt costs for four publicly-traded IPPs power companies, Calpine Corporation, Dynegy Inc.,

[41] As noted in one text, "It is clearly silly to suggest that [a company] should demand the same rate of return from a very safe project as from a very risky one." Brealey, Myers and Allen, 2008, p. 240.

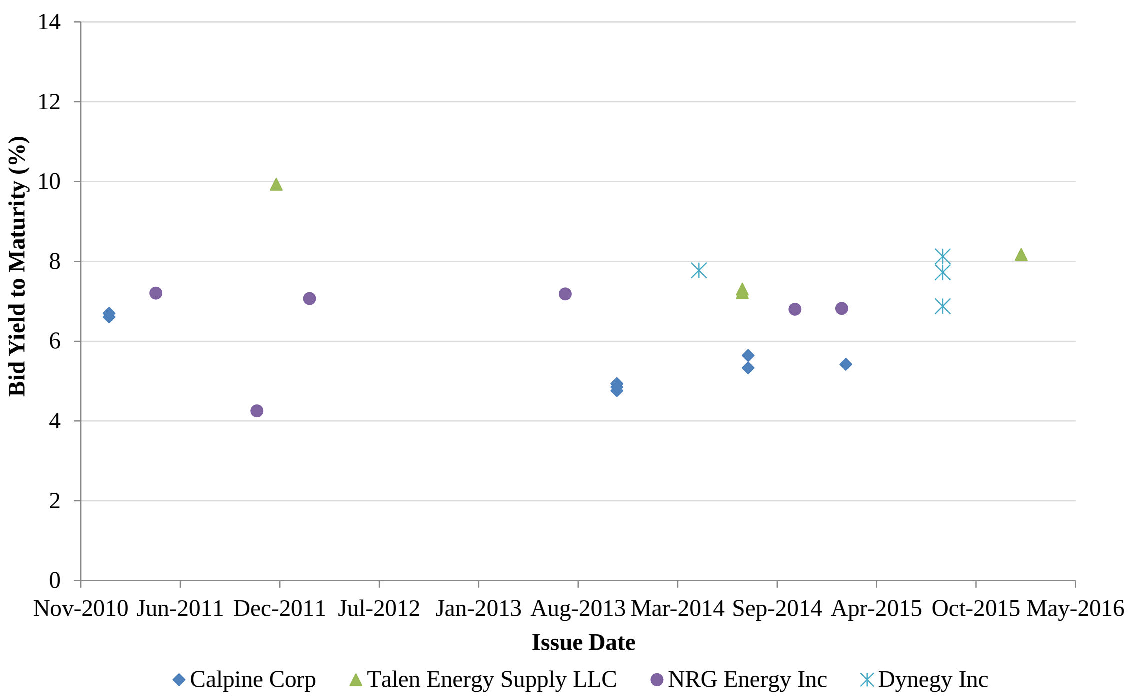
[42] Larger entities, including publicly traded IPPs, may use project finance to develop projects.

NRG Energy Inc., and Talen Energy Supply LLC. Yields since 2013 range from approximately 5 percent to 8 percent.

At present, all four IPPs listed above have below-investment grade credit ratings: Calpine and Dynegy are B rated, while NRG and Talen are B+ rated. Figure 6 shows that the COD issued by IPPs has been slightly higher in recent months, as compared to values from the past one to two years. This trend is supported by historically low CODs,[43] and the prospect of increases in Federal Reserve interest rates.[44] AGI also considered data on the generic cost of corporate debt. Figure 7 provides the generic corporate COD for companies with BB and B credit ratings. The figure shows that COD for below-investment grade issues has generally increased over the past year or two ago, with rates spiking within the past year.

Based on these factors, AGI recommends a COD of 7.75 percent. This reflects a value toward the upper end of the reported range, which is consistent with the somewhat greater risk posed by a single peaking plant, in comparison to an IPP company. Further, recent trends in the COD for both IPP issued debt and generic debt suggest that more recent values, which are somewhat higher, may be more representative.

Figure 6: Cost of Debt for Independent Power Producers, by Issuance, 2010-2016



Note and Source: Accessed on May 2016 from Bloomberg, L.P. Additional detail is provided in Appendix C.

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[43] *See* Appendix C which provides data back to 2010 on the cost of debt as measured by the 30-year Treasury constant maturity.

[44] On June 15, 2016, the Federal Open Market Committee indicated that they expect "economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate" and noted that these rates are "below levels that are expected to prevail in the longer run." (FOMC Press Release, June 15, 2016).

Figure 7: Generic Corporate Bond Yields, by Credit Grade

Source: St. Louis Federal Reserve Bank of St. Louis, FRED. Bank of America Merrill Lynch US and Corporate Index Effective Yields.

Return on Equity

The recommended ROE is developed using data from several sources. One source of data is the estimated return on equity for publicly traded IPPs. Table 29 reports the estimated ROE for five companies based on the capital asset pricing model (CAPM).[45] Appendix C provides further details on these calculations. Company betas are obtained from Value Line and Bloomberg. With Value Line betas, estimated ROEs range from 10.0 percent (for Calpine) to 12.5 percent (Dynegy), with an average of 11.1 percent. With Bloomberg betas, estimated ROEs range from 9.2 percent (for Calpine) to 12.3 percent (Talen Energy), with an average of 10.5 percent.

A second source of data is independent estimates of the ROE for new power plants developed as an element of analyses of the cost of new plant generation. Two such studies are developed by the

[45] Other approaches not utilized include the Discounted Cash Flow (DCF) and historical risk premium. Similarly, AGI notes that utility regulators may consider a variety of information and models (including CAPM, DCF, or historical risk premiums) when setting the ROE for regulated utilities. Therefore, AGI did not consider a comparison of CAPM estimates of ROEs for regulated utilities when estimating the relevant ROE for a merchant power plant developer. This is consistent with the assumption that the rate of return for a safe project is not the same as the return from a risky one (see fn 41).

California Energy Commission (CEC) and the National Energy Technology Laboratory (NETL). These studies evaluate the cost of new plants, including combustion turbines developed by IPPs. NETL assumes a ROE of 15.5 percent, while CEC assumes an ROE of 14.47 percent (in its "average case").[46]

A third source of data is estimates of the ROE for project finance. Based on several independent sources, ROEs for project finance range from approximately fifteen to twenty percent since 2003.[47]

Based on this information, AGI recommends a ROE of 13.4 percent, reflecting a balance between the lower IPP values (which range up to 12.45 percent) and higher project finance values.

Table 29: Overview of Treatment of Net EAS Model Parameters for Annual Updating

Company	Ticker	Debt Share (2015 Q4)	Value Line Beta	Value Line Cost of Equity	Bloomberg Beta	Bloomberg Cost of Equity
Merchant Generators						
Calpine	CPN US	68.8%	1.00	10.00%	0.89	9.22%
NRG Energy	NRG US	72.3%	1.10	10.70%	1.04	10.27%
Dynegy	DYN US	70.5%	1.35	12.45%	1.02	10.11%
Talen Energy	TLN US	75.6%	-	-	1.33	12.30%
Group Average			1.15	11.05%	1.07	10.47%

Notes and Sources: CAPM estimates are based on a seven percent market risk premium from Ibbotson, SBBI 2015 Classic Yearbook, and a three percent risk free rate based on the Thirty-Year Treasury Constant Maturity Rate. Company beta values are from Value Line and Bloomberg; current debt-to-equity ratios as of 2015 Q4 are from Bloomberg.

Debt to Equity Ratio

The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of the capital supporting the investment. Thus, a merchant peaking plant technology could reasonably be developed through a range of capital structures.

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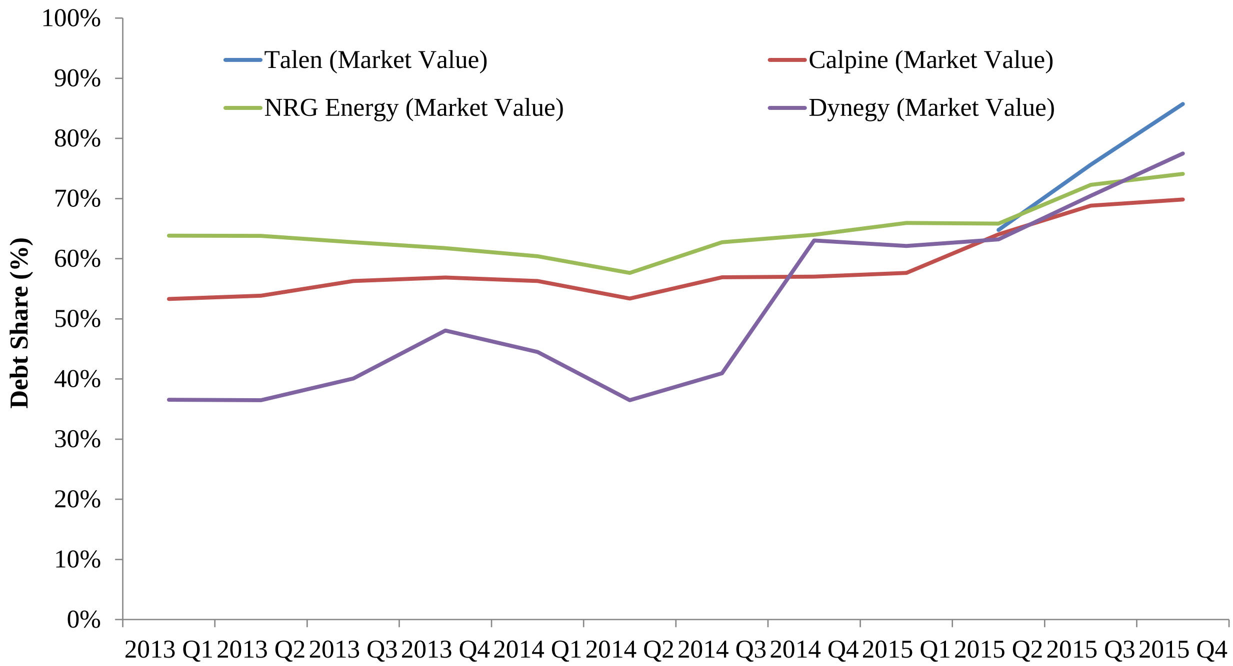
[46] California Energy Commission, 2010, p. 59, Table 18; National Energy Technology Laboratory, 2010, p III-15, Exhibit 3-1.

[47] *See*, for example, EPA Integrated Planning Model, Chapter 8 Financial Assumptions, which reports a 16.1 percent ROE at a 55 percent debt ratio and 3.8 percent risk free rate; DOE National Energy Technology Laboratory (NETL) (2008), which indicates that a 15 to 20 percent ROE is common for low and high risk power projects at debt ratios of 50 to 70 percent (DOE-NETL, "Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects", September 2008.); and Etsy (2003), which notes that Calpine typically sought an 18-22 percent as a project finance developer circa 2002, with a debt ratio of 65 percent. (Etsy, B. and Kane, M. "Calpine Corporate: The Evolution from Project to Corporate Finance." Harvard Business School, Case Study 9-201-098.)

AGI recommends a D/E ratio of 55 percent debt to 45 percent equity given a balance of tradeoffs involved with greater or lesser leverage. On the one hand, the capital structure of IPP companies (at the corporate, not the project level) currently reflects higher levels of debt than have been historically carried. Figure 8, which shows the debt share of capital for Calpine, Dynegy and NRG over the past 3 years, illustrates this effect.[48] While corporate level capital structure may not be particularly informative of the appropriate project-level capital structure, we consider the general trend toward higher leverage, given historically low debt costs, in our assessment.[49] On the other hand, many sources indicate that the limited fixed revenues streams for a merchant peaking plant in NYISO would limit debt level. For example, CEC assumes a D/E ratio of 40/60 for merchant fossil generation, while NETL assumes a D/E ratio of 30/70 for IPP combustion turbines.[50] Thus, from the standpoint of typical structures, a 55/45 D/E equity ratio appears conservative (i.e., tending to a lower WACC).

Figure 8: Debt to Capital Share, Independent Power Producers, 2013-2015



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[48] The market value of equity is calculated as enterprise value minus cash and near-cash items; data for the calculations is from Bloomberg, L.P.

[49] Note that a desire by these companies to deleverage (i.e., lower debt share), which has been expressed by the companies themselves and analysts, may place pressure to lower debt levels of individual projects. *See*, e.g., UBS Financial ("We believe all IPPs will accelerate their debt paydown efforts…") (How to Value Power? December 8, 2015.)

[50] California Energy Commission, 2010, p. 59, Table 18; National Energy Technology Laboratory, 2010, p III-18, Exhibit 3-2.

Note and Source: The market value of equity is calculated as the enterprise value minus cash and near cash items. Bloomberg L.P., accessed May 2016.

Calculation of the WACC

AGI's assessment of factors related to the calculation of the WACC has considered the data on the following: ROE, COD, and D/E ratios presented above; facts and circumstances unique to NYISO markets, including the extent of past experience with merchant development; the rapidly-changing nature of federal and state energy and environmental policies; and likely project/ownership structures for new peaking plant development in the State. The calculation of the before-tax WACC is shown in equation 1.

$$WACC = Debt\ Ratio * COD + (1 - Debt\ Ratio) * ROE \tag{1}$$

The ATWACC is calculated as:

$$ATWACC = Debt\ Ratio * COD * (1 - composite\ tax\ rate) + (1 - Debt\ Ratio) * ROE \tag{2}$$

This calculation reflects the common tax treatment of interest as a deductible expense for corporate income tax purposes. Income taxes reflect Federal tax rates (assumed to be 35 percent), corporate New York State tax rates (7.1 percent),[51] and the New York City business corporation tax rate (8.85 percent).[52] These result in composite income tax rates of 45.37 percent (NYC) and 39.62 percent (all other locations).

Using these equations and the considerations presented above, AGI recommends a WACC of 10.3 percent, based on a debt ratio of 55 percent, a COD of 7.75 percent, and a ROE of 13.4 percent. This results in a nominal ATWACC of 8.60 percent in NYCA, LI, and the G-J Locality and 8.36 percent in NYC.

The recommended ATWACC is consistent with previous and currently approved capital cost values in NYISO and other RTOs (e.g., ISO-NE and PJM). The current ATWACC in ISO-NE and PJM is 8 percent, while the current ATWACC for the NYISO as approved during the 2013 DCR is 8.4 percent. The slightly higher ATWACC in this report reflects a combination of factors. Relative to the other RTOs, developers within the NYISO region may face greater project-specific risk that arises from the lack of long-term contracts, greater uncertainty over the mix of supply and demand resources that will result from changes in regional markets and energy policies over time, expectations for relatively flat load growth, and potentially more challenging siting and development opportunities within New York. Relative to the

[51] *See* New York Department of Taxation and Finance, Form CT-3/4-I.

[52] *See* http://www1.nyc.gov/site/finance/taxes/business-business-corporation-tax.page.

2013 DCR, the higher ATWACC reflects the full combination of changes in balance sheets (through greater use of debt), higher debt costs, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments. A second source of comparison is independent evaluations of publicly traded companies. Analyst and so-called "fairness opinions" have reported estimated ATWACC consistent with those estimated in this study.[53] For example, the fairness opinion that evaluated the NRG and GenOn merger in October 2012 estimated that the cost of capital for NRG ranged from 7 percent to 8.5 percent, while the cost of capital for GenOn ranged from 8.5 percent to 9.5 percent.[54]

B. Levelization Factor

To estimate the ARV, it is necessary to translate one time installed capital costs into annualized cost over the economic life of the plant. This annualized cost is fixed over the plant's economic life, such that an owner receiving revenues equal to this cost would have enough funds to offset exactly the original upfront investment, including a return on capital. AGI refers to this amount as the levelized fixed charge (e.g., an "annual carrying charge") This charge reflects both the recovery of and return on upfront capital costs and the tax payments associated with this investment that vary over time due to depreciation schedules and variation in certain tax levels over time (i.e., 15-year NYC property taxes abatement).

The levelization factor is the ratio of the levelized fixed charge to total installed capital costs. This factor is developed in three steps. First, annual costs are calculated as the sum of principal debt payments, interest on debt, income tax requirements, property taxes, and the target cash flow to equity.[55] Second, the net present value of the total carrying costs is levelized over the economic life of the unit using the real ATWACC. Third, the levelization factor is calculated as the ratio of the levelized fixed charge to the total installed capital cost.

Annualized costs, including the required ROE, are expressed in constant real dollars. The analysis assumes forward-looking inflation of 2 percent annually in both costs and revenues streams. This inflation rate reflects the combined effect of many factors likely to affect future operational costs and net EAS revenues. The recommended value is consistent with the current long-term inflation forecasts from the Survey of Professional Forecasters as reported by the Philadelphia Federal Reserve Bank in the Q1

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[53] Independent assessments performed by financial analysts reported in the PJM 2011 estimates of the cost of new entry range from 7.1 to 12.0 percent. (Brattle Group, "Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," August 24, 2011, Tables 45).

[54] Notably, and in contrast to the CAPM approach used in consideration of other qualitative factors presented above, JP Morgan and Credit Suisse used a discounted cash flow model to estimate the after tax free cash flows for each company. *See* NRG and GenOn Proposed Transaction, Joint Proxy Statement, Filed Pursuant to Rule 424(b)(3), Registration No. 333-183334, October 5, 2012. ATWACC estimates are presented on pages 63, 70, and 75.

[55] Similarly, using the required cash flow to equity, income taxes can be calculated as:

$$Income\ Tax = \frac{t}{(1-t)} * (Cash\ Flow\ to\ Equity + Principal\ Debt\ Payments - Depreciation)$$

2016,[56] as well as long-term inflation in electricity prices as reported by the EIA Annual Energy Outlook.[57]

Table 30 provides a summary of all financial parameters used in each location, including financing costs, tax rates, depreciation schedules, and the assumed amortization period. Property tax rates were discussed in Section II. Annual depreciation schedules are provided in Table 31. Depreciation schedules are based on the Federal Internal Revenue Service (IRS) Publication 946 and follow the half-year convention. Peaking plants are depreciated with a 15-year schedule; combined cycle units are depreciated with a 20-year schedule.

Table 30: Summary of Financial Parameters by Location

Finance Category	NYCA	G-J	NYC	LI
Inflation Factor (%)	2.00%	2.00%	2.00%	2.00%
Debt Fraction (%)	55.00%	55.00%	55.00%	55.00%
Debt Rate (%)				
Nominal	7.75%	7.75%	7.75%	7.75%
Real	5.64%	5.64%	5.64%	5.64%
Equity Rate (%)				
Nominal	13.4%	13.4%	13.4%	13.4%
Real	11.18%	11.18%	11.18%	11.18%
Composite Tax Rate (%)	39.62%	39.62%	45.37%	39.62%
Federal Tax Rate	35%	35%	35%	35%
State Tax Rate	7.10%	7.10%	7.10%	7.10%
City Tax Rate	0.00%	0.00%	8.85%	0.00%
WACC Nominal (%)	10.29%	10.29%	10.29%	10.29%
ATWACC Nominal (%)	8.60%	8.60%	8.36%	8.60%
ATWACC Real (%)	6.47%	6.47%	6.23%	6.47%
Amortization Period (Years)	20	20	20	20
Tax Depreciation Schedule	15-Year MACRS (Simple Cycle); 20-Year MACRS	15-Year MACRS (Simple Cycle); 20-Year MACRS	15-Year MACRS (Simple Cycle); 20-Year MACRS	15-Year MACRS (Simple Cycle); 20-Year MACRS
Fixed Property Tax Rate (%)	0.75%	0.75%	4.8%, with 15 year abatement	0.75%
Insurance Rate (%)	0.60%	0.60%	0.60%	0.60%
Levelized Fixed Charge (%)	12.71%	12.71%	13.12%	12.66%

Note: The table provides the levelized fixed charge (%) for the Frame Class unit with SCR. The levelized fixed charge (%) for NYC and LI differ from NYCA and the G-J Locality based on the treatment of property taxes and capital costs. NYC reflects the 15-year property tax abatement. LI reflects the separate treatment of SDU costs.

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[56] The Survey of Professional Forecasters forecast headline CPI of 2.08 percent between 2016-2020 and 2.12 percent between 2016-2025 and headline PCE of 1.88 percent between 2016-2020 and 1.97 percent between 2016-2025. *See* https://www.phil.frb.org/research-and-data/real-time-center/survey-of-professional-forecasters/2016/survq116.

[57] *See* EIA AEO 2016, May 2016, Table 3 Energy Prices by Sector and Source. The EIA forecasts real price growth for residential electricity of 0.2 percent for the period 2015 to 2040 and nominal price growth of 2.3 percent for the Nation as a whole. For the mid-Atlantic, which includes portions of the PJM RTO footprint, the EIA AEO forecasts real growth of 0.8 percent and nominal growth of 2.9 percent.

Table 31: Modified Accelerated Cost Recovery Tax Depreciation Schedules

Year	Tax Depreciation	
	15 Year (Simple Cycle)	20 Year (Combined Cycle)
1	5.00%	3.75%
2	9.50%	7.22%
3	8.55%	6.68%
4	7.70%	6.18%
5	6.93%	5.71%
6	6.23%	5.29%
7	5.90%	4.89%
8	5.90%	4.52%
9	5.91%	4.46%
10	5.90%	4.46%
11	5.91%	4.46%
12	5.90%	4.46%
13	5.91%	4.46%
14	5.90%	4.46%
15	5.91%	4.46%
16	2.95%	4.46%
17	0.00%	4.46%
18	0.00%	4.46%
19	0.00%	4.46%
20	0.00%	4.46%
21	0.00%	2.23%

Source: IRS Publication 946.

C. Annualized Gross Costs

Using the levelization factor developed above and the capital and fixed O&M costs presented in Section II, Table 32 provides annualized gross CONE values for each peaking plant within each location.

Table 32: Gross CONE by Peaking Plant and Load Zone ($2017/kW-Year)

Peaking Plant Technology		C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
SGT6-PAC5000F(5) SC	**Dual Fuel**						
	Fixed O&M	$11.90	$12.29	$14.09	$14.15	$28.71	$15.60
	Insurance	$6.80	$6.44	$7.25	$7.33	$7.89	$7.62
	Levelized Fixed Charge	$144.09	$136.27	$153.46	$155.17	$172.52	$171.74
	Gross CONE	$162.79	$154.99	$174.79	$176.65	$209.11	$194.96
	Gas only with SCR						
	Fixed O&M	$10.07	$10.46	$12.26	$12.34	-	-
	Insurance	$6.34	$5.97	$6.72	$6.78	-	-
	Levelized Fixed Charge	$134.15	$126.49	$142.38	$143.56	-	-
	Gross CONE	$150.55	$142.92	$161.37	$162.68	-	-
LMS100 PA	**Dual Fuel**						
	Fixed O&M	$12.29	$12.73	$14.81	$14.90	$26.66	$16.44
	Insurance	$9.70	$9.28	$10.20	$10.29	$11.12	$10.68
	Levelized Fixed Charge	$205.44	$196.48	$215.91	$217.98	$243.32	$238.12
	Gross CONE	$227.43	$218.50	$240.92	$243.17	$281.10	$265.24
	Gas only with SCR						
	Fixed O&M	$10.51	$10.97	$13.04	$13.13	-	-
	Insurance	$9.30	$8.88	$9.80	$9.89	-	-
	Levelized Fixed Charge	$197.02	$188.04	$207.46	$209.45	-	-
	Gross CONE	$216.83	$207.89	$230.29	$232.47	-	-
Wartsila 18V50DF	**Dual Fuel**						
	Fixed O&M	$15.97	$16.90	$20.85	$21.14	$35.91	$23.85
	Insurance	$11.00	$10.72	$11.87	$11.98	$13.06	$12.75
	Levelized Fixed Charge	$232.88	$226.98	$251.34	$253.78	$285.68	$281.25
	Gross CONE	$259.85	$254.61	$284.07	$286.91	$334.65	$317.85
	Gas only with SCR						
	Fixed O&M	$12.73	$13.58	$17.14	$17.41	-	-
	Insurance	$9.26	$8.90	$9.92	$10.01	-	-
	Levelized Fixed Charge	$196.15	$188.37	$210.03	$211.91	-	-
	Gross CONE	$218.14	$210.84	$237.09	$239.33	-	-

Note: Property taxes are included in the levelized fixed charge.

IV. ENERGY AND ANCILLARY SERVICES REVENUES

A. Overview

The Services Tariff requires that the periodic review of ICAP Demand Curves be established considering, in part,

> "…the likely projected annual Energy and Ancillary Services revenues of the peaking plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[58]

The costs and revenues are to be determined under conditions that reflect a need for new capacity in NYCA and each Locality. Specifically, the Services Tariff requires that:

> "…[t]he cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity…"[59]

AGI refers to these conditions as the LOE conditions.

In this Section, we present the method used to estimate the net EAS revenues of the peaking plant for NYCA and each Locality. Consistent with the LOE requirement, net EAS revenues are calculated under conditions in which system resources equal either (1) NYCA Minimum Installed Capacity Requirement (ICR) plus the capacity of the peaking plant in NYCA, or (2) Locational Minimum Installed Capacity Requirement (LCR) plus the capacity of the peaking plant in individual Localities.[60]

First, AGI summarizes its approach for estimating net EAS at the time of each DCR, including a description of the net EAS model, the data inputs, and the approach to adjusting prices to be consistent with market conditions LOE market conditions. Second, AGI summarizes the process for annually updating estimated net EAS revenues over the reset period. Finally, AGI presents the results of applying the net EAS revenues model for the 2017/2018 Capability Year.

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[58] Services Tariff, Section 5.14.1.2.

[59] Services Tariff, Section 5.14.1.2.

[60] Note that ICR is defined in terms of MW, equal to total capacity needs (i.e., peak demand plus reserve requirements, in MW). The ICR is based on the Installed Reserve Margin (IRM), which is the level of reserve capacity in excess of peak load required in the NYCA, denominated in percentage terms. Throughout this report, AGI uses both terms, when appropriate. For example, when describing system capacity need in MW, AGI uses ICR. When referencing the required level of reserves in percentage terms, AGI uses IRM.

B. Approach to Estimating Net EAS Revenues

1. Overview

For each Capability Year, RPs in NYCA and each Locality are based on estimated gross CONE (described in Section III, above) less the expected net revenues the peaking plant would earn in NYISO's energy and ancillary services markets. The net revenues earned from participating in these markets reflect the prices paid for supply of Energy and Ancillary Services net of the fuel and variable costs of production. Because RPs are established to ensure sufficient revenues for new entry, estimates of net EAS revenues should reflect the forward-looking expectation of net revenues under LOE conditions consistent with the requirements of the Services Tariff.

Net EAS revenues are estimated at the time of the DCR based on the simulated dispatch of the peaking plant using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and data on the non-fuel variable costs and operational characteristics of the peaking plant technology. AGI's approach assumes that annual average net revenues earned over the prior three years provide a reasonable estimate of forward-looking expectations, particularly in light of the annual updating mechanism, which ensures that capacity prices evolve (with a lag) consistent with actual EAS market outcomes.

AGI's model estimates the net EAS revenues of the peaking plant on an hourly basis for the historical 3-year period assuming that the resource earns the maximum possible revenues by supplying energy or reserves in either the Day-Ahead (DAM) or Real-Time Market (RTM). Each year, as part of an annual updating of RPs, net EAS revenues will be recalculated using the same model, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges.

2. Net EAS Model Construct

a) Model Logic

The AGI simulated dispatch model uses a "dispatch logic" consistent with NYISO energy and ancillary services markets.[61] Specifically, the AGI model estimates the net EAS revenues earned by the peaking plant on an hourly basis assuming dispatch of the plant and market offers set at the opportunity cost of producing energy or providing reserves.[62] In the model, the peaking plant can earn revenues through supplying in one of four markets: (1) DAM commitment for Energy, (2) DAM commitment for

[61] In practice, an individual unit's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical peaking plant considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to unit-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical peaking plant.

[62] AGI assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant, and thus do not account for the downward pressure that this additional supply may have on realized prices. In this regard, the estimates may tend to overstate revenues.

reserves,[63] (3) RTM dispatch for Energy, or (4) RTM provision for reserves. In addition, a unit maintains the ability to buy out of either DAM Energy or reserves commitments, based on changes in Real-Time dispatch (RTD) prices. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual-fuel capability is accounted for through the option to generate on natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

Figures 9 and 10 contain schematics of the commitment/dispatch logic for the DAM and RTM, respectively. The model first determines whether to commit the plant to supply energy or reserves in the DAM based on the net revenues of each position. Similar to DAM commitment, RTM dispatch determines the operating state (supplying energy, supplying reserves, not supplying) contingent on the peaking plant's DAM commitment. Thus, the plant can change operating status from its DAM commitment if such a switch in operating status is sufficiently profitable in real-time. Real-time fuel costs reflect a premium for purchases and discount for sales relative to day-ahead gas prices, which vary by Load Zone. These intraday premiums/discounts reflect potential operating or other opportunity costs to securing (or not using) fuel in real-time, which may be incurred due to balancing charges with an LDC, illiquidity in the market during periods of tight gas supply, or imperfect information on the part of either the buyer or seller.[64] This additional cost in incorporated into RTM buy out decisions for all units. As illustrated in Figure 5, peaking plants can exist in one of nine operating states in each hour, based on the DAM and RTM choices. These "operating" states include:

- DAM Energy commitment, with RTM Energy dispatch
- DAM Energy commitment, with a buy out and a RTM reserves dispatch
- DAM Energy commitment, with a buy out and no dispatch in the RTM
- DAM reserves commitment, with a RTM reserves dispatch
- DAM reserves commitment, with a buy out and a RTM Energy dispatch
- DAM reserves commitment, with a buy out and no dispatch in the RTM
- No DAM commitment, with no dispatch in the RTM

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[63] The model also accounts for technological limits on reserves. For example, LMS units will qualify for 10-minute non-spinning reserves, while the Frame machines only qualify for 30-minute non-spinning reserves. LCI, through discussions with GE, determined that the GE 7HA.02 could qualify for 30-minute reserves with a 21-minute start time through the use of a purge credit start, whereby the fuel system has been pre-purged.

[64] These costs are based on estimates reported by the NYISO Market Monitoring Unit (MMU) based on their review of available data. The real time premium/discount is applied to all operating hours throughout the year. In practice, these annual average values may over-estimate net EAS revenues during some hours (e.g. winter months) if the DAM-RTM price difference is driven by changes in gas market conditions and under-estimate net EAS revenues during other hours (e.g., during periods of gas liquidity). During periods of gas liquidity, this could either overstate the true cost of selling out of a gas position in real-time or overstate the true cost of purchasing gas in real-time, thereby foregoing a potential RTM dispatch. On net, these effects would tend to both decrease and increase real time net EAS revenues in various hours throughout the year. AGI assessed net EAS revenues during periods when the RTD price was more than twice the DAM price and found that net EAS revenues estimated by the model were not meaningfully overstated during these periods. AGI's analysis further suggested that the understatement of net EAS revenues during other moths would likely offset any over-statement during winter months. See AGI, "Stakeholder Comments Related to Net Energy and Ancillary Services Revenues Model", presented to the ICAPWG on July 20, 2016.

- No DAM commitment, with an Energy dispatch in the RTM
- No DAM commitment, with a reserves dispatch in the RTM

In contrast, the net EAS revenues model for combined cycle units only considers the energy commitment and dispatch of the unit in both DAM and RTM, including the ability to buy out of a DAM energy commitment in the RTM. Units are assigned a flat annual adder of $3.70/kW-year for net ancillary services revenues, based on settlement data from 2013 to 2015 provided by the NYISO for comparable units. An incremental adder of $1.43/kW-yr is provided to account for voltage support service (VSS) revenues.

When evaluating an Energy commitment in either the DAM or RTM, the model ensures that all costs, including amortized start-up costs, can be recovered.[65] In the DAM, start-up costs for the Frame combustion turbine can be recovered over the full run-time block, which is determined dynamically based on profitable hours. In contrast, within the RTM, Frame combustion turbine units must recover their startup costs over two hours; in both the DAM and RTM; aeroderivative and RICE units recover start-up costs over the first hour of commitment. Units are also constrained by applicable run time limitations as described in Section II.C. When modeled with SCR technology, the NSPS limitation for CO_2 becomes the limiting constraint. LCI estimated the following three-year rolling average capacity factors at the net LHV efficiency under ISO conditions: GE LMS100PA+ (42.4 percent), the Siemens SGT6-5000F5 (38.4 percent), and the GE 7HA.02 (40.9 percent).[66] F-class gas only units without SCR in Load Zones C, F and G (Dutchess County) would also be subject to a 2,500 hour environmental run time limit for NO_X NSPS. Estimates for these units are provided for informational purposes only.

Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-spinning reserve markets at their opportunity cost of holding or obtaining adequate fuel supplies. Here, the opportunity cost reflects the real time intraday premium (discount) of buying (in real time) or selling (from a day-ahead procurement) natural gas. Dual fuel units do not face an opportunity cost to provide reserves when ULSD prices (plus applicable transportation charges) are lower than natural gas prices (plus applicable charges).

[65] The model does not allow a unit to be committed uneconomically. To the extent that a unit would be committed uneconomically by the NYISO, units would be eligible to receive either Day Ahead Margin Assurance Payment (DAMAP) or a Bid Production Cost Guarantee (BPCG) payment. These payments would compensate a unit for its costs, offsetting losses on a daily basis. AGI assessed the potential impact of using RTC prices within the net EAS revenues model, and did not find RTC prices to have a meaningful impact on estimated revenues for a hypothetical peaking plant at the tariff prescribed level of excess conditions. Using RTC prices to both commit and dispatch the unit (as an indicative analysis of total impact), AGI found that the use of RTC prices would lower net EAS revenues for the Siemens SGT6-5000F5 unit with dual fuel and SCR between $0.03/kW-month (Load Zones C and F) and $0.21/kW-month (Load Zone K), with changes in total run time hours from an increase of 2 hours (Load Zone K) to a decrease of 101 hours (Load Zone J). See AGI, "Stakeholder Comments Related to Net Energy and Ancillary Services Revenues Model", presented to the ICAPWG on July 20, 2016.

[66] In contrast, the model evaluates environmental run time limits on an annual basis. If a unit is committed above its environmental run time limit, the model removes the least profitable energy (either DAM or RTM) run-time block and allows the unit to earn DAM reserve revenues at the prevailing DAM reserve price.

Figure 9: Net EAS Revenues Model Day-Ahead Commitment Logic

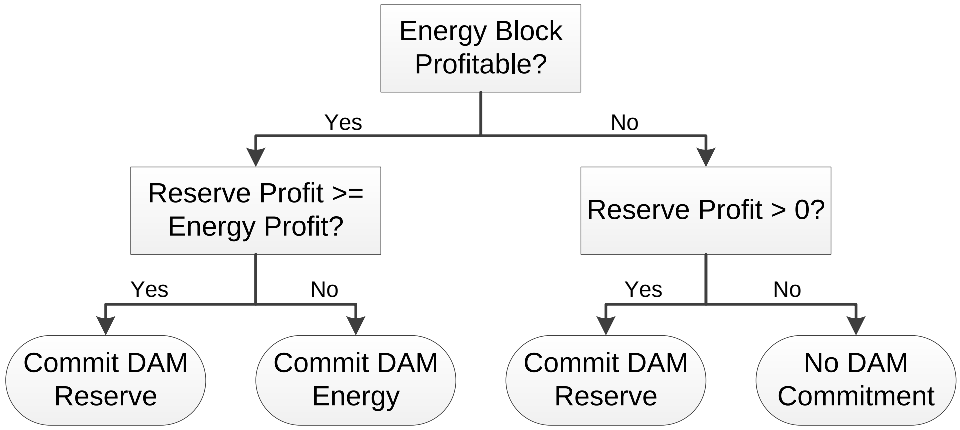
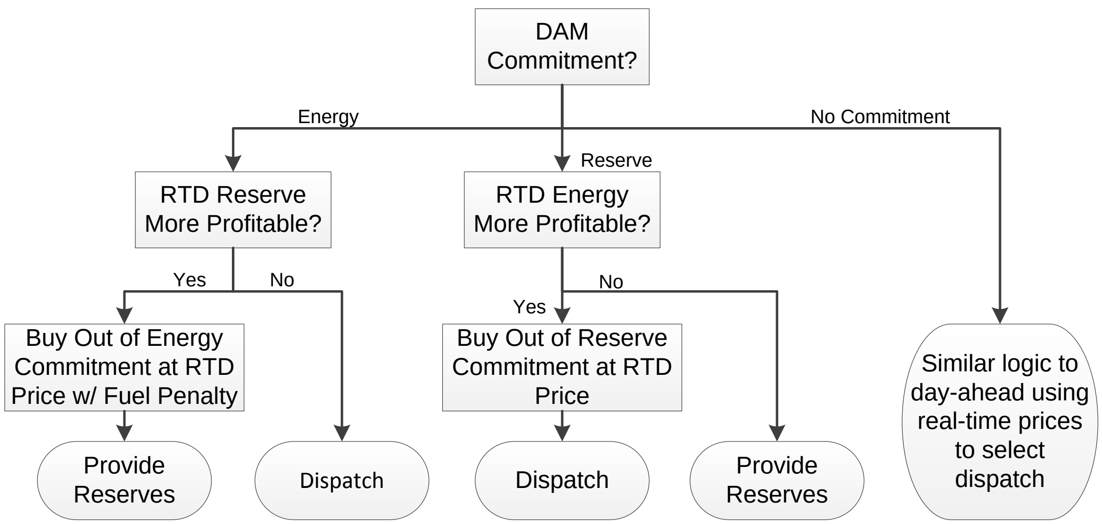


Figure 10: Net EAS Revenues Model Real-Time Supply Logic



The net EAS revenues model estimates hourly revenues streams for the peaking plants based on prices over the three-year historical period. Within this hourly model, peaking plants are assumed to be fully committed for the duration of the hour. That is, the net EAS revenues model for peaking plants does not allow for partial dispatch or minimum load operations. In contrast, the net EAS revenues estimates for the informational combined cycle units assume the unit may be committed at minimum load between energy commitments, to the extent that this would be more profitable than incurring an additional startup cost.

Equation 3 provides a simplified representation of the net EAS revenues (NEAR) calculation used when considering energy dispatch in each hour, where profits are determined using parameters specific to each Load Zone and, when applicable, each peaking plant:[67]

$$NEAR = LOE\text{–}AF * LBMP - HR * P(fuel) - VOM - ASC - EC - RS1 \qquad (3)$$

Where:

$LOE - AF$ = LOE adjustment factors for each Load Zone and time period

$LBMP$ = Hourly LBMPs (either DAM or RTD) for each Load Zone

HR = Heat rate for the applicable peaking plant and Load Zone

$P(fuel)$ = Price of fuel (natural gas or oil), which varies by day and Load Zone, including relevant transportation costs and real time intraday premium/discount

VOM = Variable operations and maintenance costs

ASC = Amortized startup cost (dynamically determined)

$RS1$ = NYISO Rate Schedule 1 charge (varies periodically, but is constant across Load Zone and technology)

EC = Emission costs, where costs are a function of both emission rates and allowance prices for CO_2, NO_X (annual and seasonal) and SO_2 (CSPAR and Acid Rain) that is:

$$EC = (CO2Rate * CO2\_Price) + (NOxRate * NOx\_Price) + (SO2Rate * SO2\_Price)$$

When estimating total annual net EAS revenues, the model separately considers relevant unit parameters for Summer and Winter Capability Periods, including each plant's seasonal capacity and heat rate. Total annual revenues are the sum of revenues earned during each hour of the year reflecting seasonal ratings, with energy and reserves revenues derated by the peaking plant's EFORd. As a final step, the model calculates the annual average net EAS revenues as the simple average of all revenues over the three-year period, plus a flat adder for providing VSS.[68]

An important component of the net EAS revenues model is the ability of the model to assess units in either dual fuel or gas only with SCR operation. When evaluating fuel commitment decisions, the

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[67] That is, equation 3 does not fully represent the tradeoffs between DAM and real-time Energy and reserve profits, or the ability of the unit to buy out of its commitment.

[68] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Historical average annual net EAS revenues are escalated from the three-year midpoint (here, $2015) into real dollars (here, $2017) for the ICAP Demand Curves using the GDP implicit price deflator.

model compares the applicable fuel costs in each hour. For a dual fuel unit, the peaking plant is assumed to operate on the most economic fuel for a full run-time block. Units are not allowed to fuel switch within an individual block.

Notably, the current model does not consider potential limitations in gas only with SCR operations; all gas units are assumed to be able to procure fuel as needed, at historical prices.[69] Previous assessments, including the 2013 DCR, have evaluated net EAS revenues for gas only units assuming limitations in fuel availability at temperatures below 20 degrees Fahrenheit.[70] As described in Section II, AGI considered potential limitations in fuel availability as part of its qualitative review. To the extent limitations in fuel availability are not captured in the current economic model, net EAS revenues for gas only units would tend to be overstated.

b) Model Data

The data used in the net EAS model includes hourly locational marginal prices and daily fuel prices and emission allowance prices (for CO_2, SO_2, and NO_x) for the three-year period (September through August) ending in the year prior to the beginning of the Capability Year to which the relevant ICAP Demand Curves will apply.[71] Other peaking plant costs and operational parameters (e.g., heat rate, VOM costs) needed to run the model are established at the time of the DCR, and described in Section II and Appendix A.

i) LBMPs and Reserve Prices

DAM and RTD LBMPs and reserve prices (ten- and thirty-minute non-spin reserves) use zonal integrated hourly average values that are available through the NYISO market and operation data.

In addition to energy market revenues and non-spin reserves, the peaking plant units would also qualify for VSS payments. These revenues are determined on an annual basis and are not part of the hourly dispatch decision. VSS payments are added to the final determination of annual net EAS revenues and are based on actual settlement data provided by the NYISO. The annual average VSS revenue was found to be \$1.43/kW-year. This value is applied as a flat adder to all technologies and all Load Zones.

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[69] Similarly, the model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AGI does not expect OFOs to meaningfully affect the net EAS revenues of dual fuel units, particularly in Load Zone J and K, where OFOs are more common. To the extent that OFO days are correlated with periods of high natural gas prices, these units would already be expected to run on oil.

[70] *See*, for example, the Eastern Interconnect Planning Collaborative, "Final Draft Gas-Electric System Interface Study Target 3 Report" March 27, 2015, which used a 20-degree threshold to reflect the non-firm character of typical transportation service. Similarly, the 2013 DCR assumed a 20-degree limit to relevant gas only operations with SCR as well. *See* NERA Economic Consulting, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*, August 2, 2013 (NERA Report), p. 76. (hereafter "NERA Report")

[71] For the model results presented in this Report, we use data for the three-year period from September 2013 through August 2016.

ii) Oil and Natural Gas Prices

Natural gas prices are based on price indices for natural gas market hubs selected by AGI for each Load Zone as reported by SNL Financial (SNL). SNL gas indices are developed using price and volume data submitted from market participants for actual next-day transactions, and represent volume-weighted average prices for next day delivery, excluding outliers that are greater than two standard deviations from the mean.[72] AGI's net EAS revenues model aligns gas day delivery and DAM LBMPs, and applies a fixed intraday premium or discount for real time gas purchases, as discussed below.

Despite the existence of numerous pricing hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a peaking plant in a given Load Zone. AGI considered numerous gas index options for the peaking plants in question, based on several selection considerations:

- *Market Dynamics.* The gas index should reflect gas prices consistent with LBMPs, recognizing that other factors such as transmission congestion also influence the frequency and level of spikes in LBMPs. Ideally, the gas index used in peaking plant net EAS revenues calculations would reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions.
- *Liquidity*. The natural gas index should have a consistent depth of historical data available, representing trades occurring at sufficient volumes over a reasonable period of time.
- *Geography*. The natural gas index (which typically reflects average trading prices over a broad geographic area) should represent trades across lines that have an appropriate geographic relationship to potential peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points. While recognizing the relevance of geographic proximity, AGI also considered whether gas indices fail to capture fully variation in pricing within geographic Load zones, particularly to the extent that such pricing differs for regions relevant to delivery to a peaking plant in NYCA.
- *Precedent/Continuity.* The natural gas index selected should reflect and be supported by information collected from multiple sources and used for similar NYISO planning and market evaluation purposes. While the appropriate choice of gas index can vary in accordance with the purpose and objectives of the study, consistency and continuity should be considered when other factors do not clearly indicate an alternative.

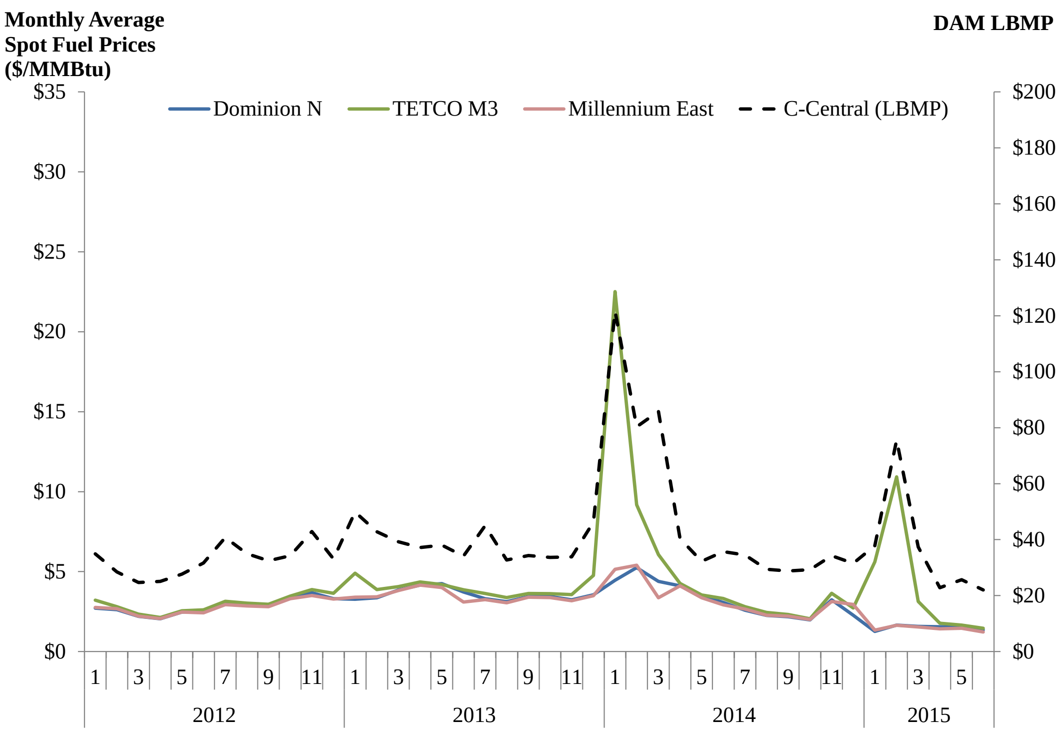
An important factor in our identification of an appropriate gas index was the historical relationship between gas prices and LBMPs. In some cases, it is apparent from comparison of gas indices and zonal LBMPs, that during certain periods (particularly winter months) zonal LBMPs did not reflect marginal supply from facilities relying on fuel prices at certain gas price indices nearby to that Load

[72] *See* SNL Natural Gas and Power Index Methodology and Code of Conduct, 2014. While SNL data is used in this report and for the purposes of providing a recommendation to RPs, the net EAS revenues model can be used with any gas price series (either actual, provided by an alternative data provider, or speculative, as defined by a user input in order to test sensitivities). As part of its analysis, AGI compared fuel prices across multiple sources; day-ahead gas prices were consistent across several vendors and would therefore be expected to provide similar results.

Zone. Figure 6, which compares gas indices with LBMPs for Load Zone C, illustrates this. LBMPs are related with certain gas indices (i.e., TETCO M3), thus indicating that marginal units may rely on fuel from these sources. However, other gas indices (i.e., Dominion North and Millennium East) show little relationship during winter months. To the extent that a peaking plant could receive delivery of gas at these prices during these period, these price differentials suggest a profitable opportunity for short-term arbitrage between natural gas and electricity markets. However, AGI does not believe that such arbitrage opportunities reflect a long-run equilibrium given the potential that new (peaking plant) entry increases congestion on these gas delivery lines and other factors that will tend to bring these markets into equilibrium.

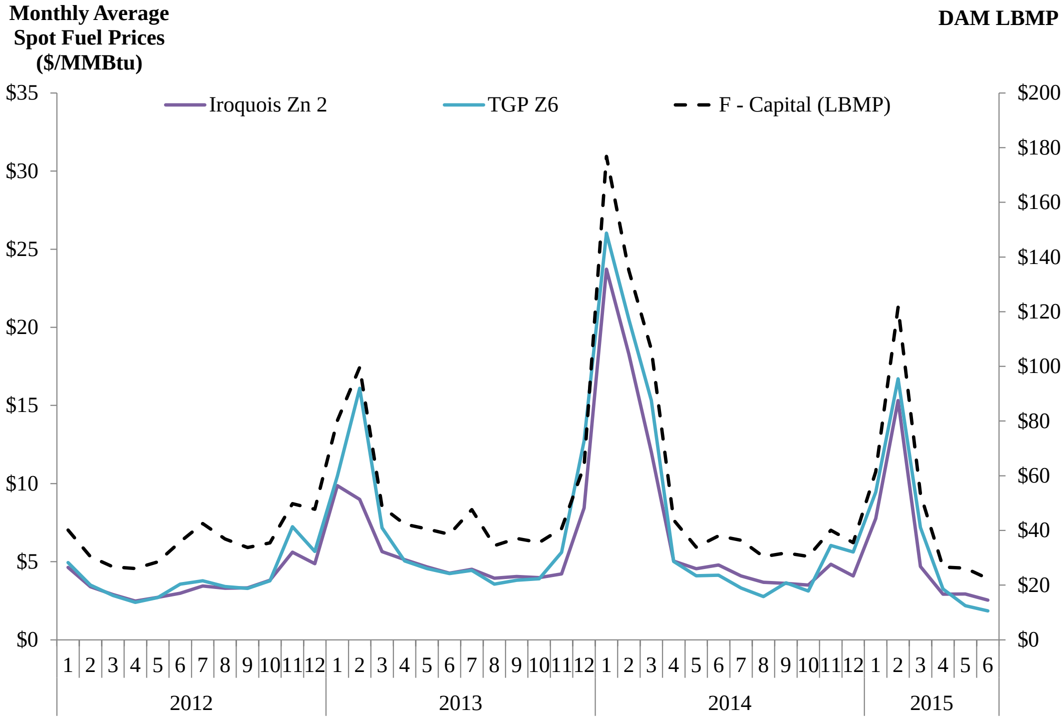
Figures 11 to 14 provide comparisons of gas prices for various hubs and LBMPs for Load Zone C, Load Zone F, Load Zone G, and Load Zones J and K, respectively.

Figure 11: Natural Gas Price Indices and Load Zone C LBMPs



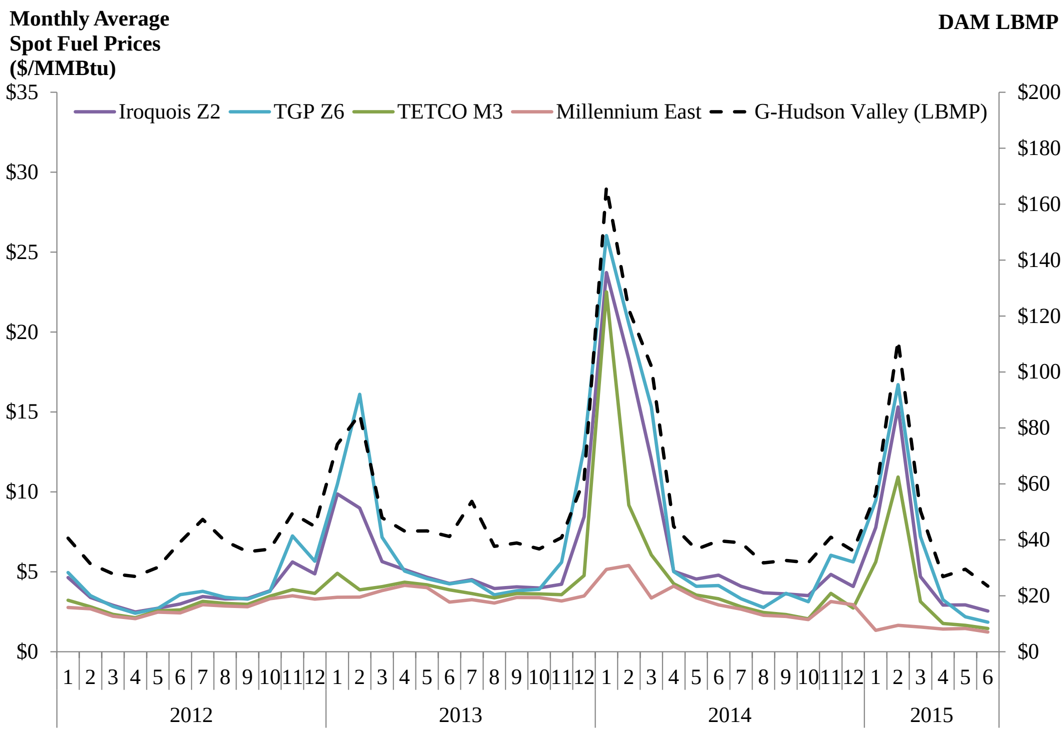
Source: ICE (Millennium East); SNL (All Others).

Figure 12: Natural Gas Price Indices and Load Zone F LBMPs



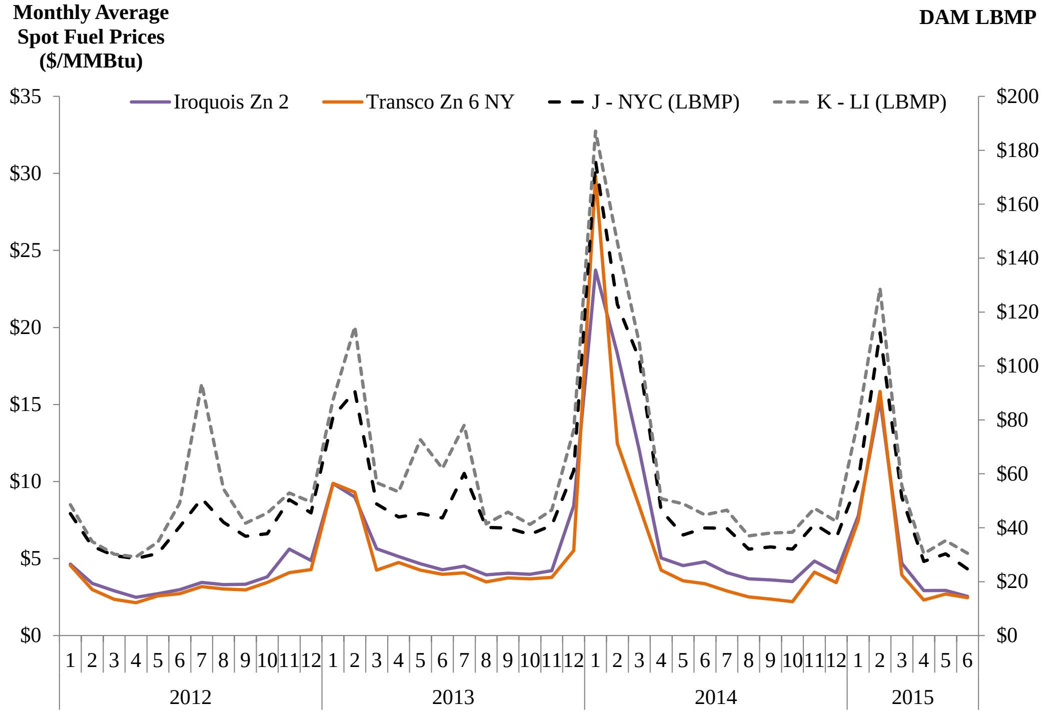
Source: SNL Financial.

Figure 13: Natural Gas Price Indices and Load Zone G LBMPs



Source: ICE (Millennium East); SNL (All Others).

Figure 14: Natural Gas Price Indices and Load Zone J and K LBMPs



Source: SNL Financial.

Table 33 identifies the gas hubs selected by AGI based on the considerations listed above, along with input and discussions with NYISO and stakeholders. Table 34 summarizes AGI's assessment of potentially applicable natural gas indices for each Load Zone along the criteria identified above.

For Load Zones J and K, Transco Zn 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to these zones and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets.

For upstate zones, including Load Zones C, F and G, the natural gas indices associated with certain pipelines in close proximity to these zones do not reflect a reasonable expectation of the long-run equilibrium between gas and electricity markets. In Load Zone C, while the Dominion and Millennium pipelines cross portions of the zone, the implied pricing from these indices does not capture any of the spikes in electricity markets during winter months. Consequently, while gas delivery on these pipelines may reflect a short-run arbitrage opportunity between gas and electricity markets, it is not reasonable to expect such arbitrage to persist over the plant's economic life. In addition, because gas indices capture pricing over broad geographic areas, indices may not capture variation in pricing within these zones, particularly in more constrained areas. In light of these factors, AGI recommends the use of TETCO M3 as the natural gas index for Load Zone C.

For both Load Zone F and Load Zone G, AGI recommends the use of Iroquois Zone 2 as the natural gas index for these zones. Like Zone C, these recommendations reflect a balance of considerations, including an assessment of a reasonable expectation of the long-run equilibrium between gas and electricity markets. In making this recommendation, AGI also considered the potential for the natural gas index to be influenced by market activities outside of the NYISO market that would not be expected to affect delivered gas prices within the NYISO market. In particular, TGP Z6, which is used in the CARIS I database, is potentially influenced by supply conditions in ISO-NE (including liquefied natural gas supplies), although it is likely that such supply conditions would not affect pricing in the NYCA. While there are currently limited differences between these indices over the past three years, differences could emerge in the future, which would affect annual updates. Consequently, AGI recommends the use of Iroquois Zone 2 for Load Zones F and G.

Table 33: Recommended Gas Index by Load Zone

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

Table 34: Natural Gas Hub Selection Criteria, By Load Zone

Load Zone C				
Decision Criteria		TETCO M3	Dominion N	Millennium
Market Dynamics		Yes	Low LBMP correlation	No
Liquidity		Yes	Increasing / shorter history	Low volume / low trades
Geography		No	Yes	Yes
Recommendation		✔		
Precedent	2013 DCR	Yes	No	No
	CARIS (2015) Phase I	Yes	No	No
	IMM (2015)	No	Yes	No

Load Zone F			
Decision Criteria		TGP Z6	Iroquois Zn 2
Market Dynamics		Yes	Yes
Liquidity		Yes	Variable
Geography		No	Yes
Recommendation			✔
Precedent	2013 DCR	Yes (Load Zone F)	Yes (Load Zone G)
	CARIS (2015) Phase I	Yes (Load Zone F and G)	No
	IMM (2015)	No	Yes (Load Zone F)

Load Zone G					
Decision Criteria		TGP Z6	TETCO M3	Iroquois Zn 2	Millennium
Market Dynamics		Yes	Partial	Yes	Low correlation
Liquidity		Yes	Yes	Variable	Low volume / low trades
Geography		No	No	Yes	Yes
Recommendation				✔	
Precedent	2013 DCR	No	Yes	Yes	No
	CARIS (2015) Phase I	Yes	No	No	No
	IMM (2015)	No	Yes	Yes	No

Load Zones J and K			
Decision Criteria		Transco Zone 6 NY (Load Zones J and K)	Iroquois Zn 2 (Load Zone K)
Market Dynamics		Yes	Yes
Liquidity		Yes	Variable
Geography		Yes	Yes
Recommendation		✔	
Precedent	2013 DCR	Yes	No
	CARIS (2015) Phase I	Yes	No
	IMM (2015)	Yes (Zone J)	Yes (Zone K)

Oil prices are based on the New York Harbor Ultra –Low Sulfur Number 2 Diesel spot price as reported by the Energy Information Administration (EIA).[73]

Table 35 identifies assumptions for various additional costs associated with the use of natural gas or ULSD. Both natural gas and oil incur transportation and tax costs. Natural gas transport costs range from $0.20 to $0.27 per MMBtu, while oil transport costs range from $1.50 to $2.00 per MMBtu.[74] Within the net EAS model, if the plant was not committed Day-Ahead, real-time net EAS revenues reflect natural gas fuel costs that include an additional intraday gas premium, which ranges from 10 to 30 percent across Load Zones. The use of these premiums (discounts) is described above.

Table 35: Fuel Cost Adders by Capacity Region

Capacity Region	Gas Transportation ($/MMBtu)	Intraday Gas Premium/Discount	Tax (Gas; ULSD)	Oil Transportation ($/MMBtu)
NYCA	$0.27	10%	-	$2.00
G-J	$0.27	10%	-	$1.50
NYC	$0.20	20%	6.9% (Gas); 4.5% (ULSD)	$1.50
LI	$0.25	30%	1.0% (Gas)	$1.50

Notes & Sources: Potomac Economics, 2015 State of the Market Report, Table A-2 and page A-23. NYC ULSD tax is based on current sales tax rates. *See* New York State Department of Taxation and Finance, Publication 718-A Enactment and Effective Dates of Sales and Use Tax Rates.

iii) Emission Allowance Prices:

Allowance prices for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are obtained from SNL Financial, and represent national annual prices for both pollutants, and seasonal prices for NO_x.[75] For years prior to 2015, SO_2 Acid Rain prices are acquired from the auction clearing price reported by the EPA.[76] SNL Financial reports this data series from 2015 forward.

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[73] Data is available from the EIA. *See* https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=eer_epd2dxl0_pf4_y35ny_dpg&f=d

[74] As discussed in Section II, dual fuel units are assumed to maintain a 96 hour fuel oil inventory. Fuel burn above 96 hours is assumed to be replaced at the daily spot price plus the applicable oil transportation cost. The model does not include limitations to, or assumptions for, the time necessary to refuel each tank. This assumption is supported by estimated oil burn rates projected by the net EAS revenues model. Using data for the period August 2013 through July 2016, AGI found that for the Siemens SGT6-5000F5 with dual fuel and SCR, the minimum number of days to burn 96 hours of fuel oil was 7 days (Load Zone J), 19 days (Load Zone K), and 55 days (Load Zone F and G). The maximum total annual oil burn is 123 hours (Load Zone K) in 2013-2014. See Appendix E for additional details regarding operations on oil projected by the net EAS revenues model.

[75] Annual and seasonal allowance prices are reported on each weekday. Daily values are applied to all hours in the day. Allowance prices are carried forward from a Friday through the subsequent weekend when data is not reported.

[76] Prior to 2015, SO_2 auction prices are reported on an annual basis, here: https://www.epa.gov/airmarkets/so2-allowance-auctions.

CO_2 allowances prices are obtained from the Regional Greenhouse Gas Initiative's (RGGI) auction results, representing RGGI-region clearing prices established on a quarterly basis.[77]

iv) Other Data

As noted earlier, the LBMPs, reserve prices, fuel prices, and emission allowance prices are all updated annually to recalculate the net EAS inputs to annual updates of the RPs. The net EAS revenues model requires additional input data to carry out the calculations, which are not updated as part of the annual update process, related to peaking plant operating characteristics and peaking plant operating costs. With respect to operating characteristics these data include heat rate, emissions rates, summer/winter DMNC, operating capabilities (e.g., start time), and location (to identify the appropriate LBMPs and gas hubs). With respect to operating costs these data include VOM costs, unit start-up costs, natural gas transportation cost adders and taxes, and RTD fuel premiums. These data are summarized in Table 35 and Appendix B.

c) Level of Excess Adjustment Factors

The net EAS revenues model incorporates adjustment factors to zonal LBMPs and reserve prices to account for the Services Tariff requirement that RPs reflect system conditions with capacity equal to the minimum Installed Capacity Requirement plus the capacity of the peaking plant in NYCA and each Locality (the LOE condition).[78] Consistent with the 2013 DCR, this Services Tariff requirement is addressed through the development of a set of LOE adjustment factors (LOE-AF) that modify the historical LBMPs and reserve prices used in the net EAS revenue calculations to approximate prices under LOE conditions.

For example, if actual LBMPs are based on system conditions with resource margins well above the LOE value, net EAS revenues would likely be lower than the peaking plant would experience under LOE conditions. In this case, the adjustment factors should tend to increase net EAS revenue estimates (i.e., reflect a multiplier greater than one). Conversely, if actual LBMPs are at system conditions reflecting a shortage of resources relative to LOE conditions, estimated net EAS revenues would likely exceed those that the peaking plant would experience at LOE conditions, leading to adjustment factors of less than one.[79]

AGI has developed a set of LOE-AFs based on production cost model simulations conducted by GE Energy Consulting (GE), using GE's Multi-Area Production System (MAPS, or GE-MAPS). GE-MAPS generates hourly, locational marginal prices based on a detailed production cost simulation system

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[77] RGGI auction results are available here: https://www.rggi.org/market/co2_auctions/results

Quarterly prices are assigned to daily costs. Quarter 1 represents the period January through March; Q2 represents April through June; Q3 includes July through September; and Q4 includes October through December.

[78] Services Tariff, Section 5.14.1.2.

[79] If actual system conditions on which historical prices are based are exactly the same as the LOE conditions, then the adjustment factor (for that given time period and Load Zone) would be 1.0.

of NYISO and connected power regions, with system operations and dispatch based on forecasted load, generating asset operational and cost characteristics, and a representation of constraints on the transmission system. For the purposes of this Report, GE relied on supply and load assumptions within the 2016 Congestion Assessment Resource Integration Study (CARIS) Phase 2 Base Case data.[80]

Estimated LOE-AFs are developed through the comparison of two modeling cases. A base case represents current system conditions ("as found" conditions), while an "LOE" case represents system conditions at the tariff prescribed LOE. LOE-AFs are developed as the ratio of average LBMPs in the base case to average LBMPs in the LOE case for each Load Zone, where LBMPs are first averaged within each month and period across all of the modeled years 2017 to 2021.[81] Three periods are evaluated: on-peak, high on-peak, and off-peak, defined as follows:

- *On-peak* hours are defined as all hours beginning 7 am and ending 11 pm, inclusive, Monday through Friday except for NERC defined holidays
- *High On-peak*[82] is defined as a subset of on-peak hours, for both the summer and winter periods as follows:
    - Summer: June, July and August from 2 pm to 5 pm inclusive
    - Winter: December, January, and February, from 4 pm to 7 pm inclusive
- *Off-peak* are all hours not defined as included within on-peak hours

To model system conditions appropriate under the LOE case, system loads were adjusted in each Load Zone so that the resulting ratio of peak load to available resources equaled the reserve margin consistent with LOE market conditions – i.e., ICR/LRC plus the capacity of the peaking plant (assumed to be 200 MW) – in that Load Zone.

Within GE-MAPS, LBMPs are modeled in every hour of each year of the DCR period (2017 – 2021) under this base-case representation. Each LOE-AF (by Load Zone, month and weekly period) reflects the average over the four-year DCR period. A single set of LOE-AFs was developed. This set of LOE-AFs, calculated at the time of the DCR, will remain set for the duration of the reset period, and will be applied to historical LBMPs and reserve prices used in each subsequent Capability Year's net EAS revenues calculation during the reset period.

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[80] The 2016 CARIS Phase 2 database was presented to the BIC on July 13, 2016. The 2016 CARIS Phase 2 database reflects current changes to system conditions and updated parameters, including updated generator additions and retirements, 2016 Gold Book peak load and energy forecasts, and updated fuel and emission price forecasts. See the July 5, 2016 ESPWG presentation for additional details regarding the 2016 CARIS Phase 2 database.

[81] AGI also reviewed LOE-AF estimated as the average of annual ratios. That is, take the average LBMP by month and period, and estimate LOE-AF as the ratio within each year before averaging. LOE-AFs were consistent across methodologies.

[82] These definitions correspond to the summer and winter peak periods as defined in the NYISO ICAP Manual (Section 4.5.1), which are used to calculate the UCAP for wind and solar energy generators. AGI reviewed average annual LBMPs by Load Zone and month and confirmed that peak periods are consistent with this definition.

As described in Equation (1), LBMPs and reserve prices are multiplied by the LOE-AFs to approximate prices that would be faced by a peaking plant at LOE market conditions, consistent with the requirements of the Services Tariff. For example, if the three-year average LBMP during a peak hour in a Load Zone in July is $50/MWh, and the LOE-AF for peak hours in July is 1.02, then the LBMP used in net EAS calculations would be $50 * 1.02 = $51/MWh.

Average LOE-AF across all months and periods ranged from 0.99 in Load Zone C to 1.04 in Load Zone J. Appendix D contains the full set of LOE-AFs used in the net EAS revenues analysis by Load Zone, month and period based on the GE-MAPS analysis.

C. Results

The values in this Report are for the 2017/2018 Capability Year. For subsequent Capability Years encompassed by this reset period, the net EAS revenues will be calculated using the same model, but with updated data as part of the annual update process described in Section VI below.

Net EAS results for the Capability Year 2017/2018, by location, are summarized in Tables 36 and 37. Included are the average annual net EAS revenues (in nominal $/kW-year) over the three-year historic period, summarized by peaking plant type and Load Zone, as well as average annual values for run hours, unit starts, and hours of operation per start. Appendix E includes detailed data for each peaking plant, with net EAS revenues reported by DAM commitment and RTM dispatch, fuel use, and year.

Table 36: Net EAS Model Results by Load Zone, Dual Fuel Capability ($2015)

		Annual Average Net EAS Revenues ($/kW-year)			Annual Average Run Hours		
Load Zone		GE LMS LMS100PA+	Siemens SGT6-5000F5	Wartsila 18V50DF	GE LMS LMS100PA+	SGT6-5000F5	Wartsila 18V50DF
C	Central	$54.22	$45.08	$56.00	2,350	1,968	2,283
F	Capital	$59.90	$41.37	$65.41	1,390	769	1,491
G	Hudson Valley (Dutchess)	$56.32	$39.42	$60.49	1,493	882	1,602
G	Hudson Valley (Rockland)	$56.42	$39.29	$60.41	1,489	879	1,598
J	New York City	$68.56	$53.94	$72.86	2,997	2,492	3,038
K	Long Island	$114.60	$101.69	$126.70	3,712	3,363	4,557

		Annual Average Unit Starts			Annual Average Hours per Start		
Load Zone		GE LMS LMS100PA+	Siemens SGT6-5000F5	Wartsila 18V50DF	GE LMS LMS100PA+	SGT6-5000F5	Wartsila 18V50DF
C	Central	358	151	362	6.6	13.0	6.3
F	Capital	376	115	381	3.7	6.7	3.9
G	Hudson Valley (Dutchess)	352	127	367	4.2	6.9	4.4
G	Hudson Valley (Rockland)	353	126	366	4.2	7.0	4.4
J	New York City	397	188	397	7.6	13.2	7.6
K	Long Island	230	173	411	16.1	19.4	11.1

Notes:
[1] Results reflect data for the period September 2013 through August 2016.
[2] Estimates include a $1.43/kW-year adder for VSS revenues for all units, based on settlement data provided by NYISO.
[3] Run time limits were applied based on NSPS.

Table 37: Net EAS Model Results by Load Zone, Natural Gas with SCR ($2015)

		Annual Average Net EAS Revenues ($/kW-year)			Annual Average Run Hours		
Load Zone		GE LMS LMS100PA+	Siemens SGT6-5000F5	Wartsila 18V50DF	GE LMS LMS100PA+	SGT6-5000F5	Wartsila 18V50DF
C	Central	$50.77	$41.41	$47.70	2,337	1,964	1,994
F	Capital	$54.27	$34.50	$48.89	1,344	736	900
G	Hudson Valley (Dutchess)	$49.36	$32.80	$45.85	1,451	855	1,145
G	Hudson Valley (Rockland)	$49.41	$32.68	$45.82	1,448	852	1,136
J	New York City						
K	Long Island						

		Annual Average Unit Starts			Annual Average Hours per Start		
Load Zone		GE LMS LMS100PA+	Siemens SGT6-5000F5	Wartsila 18V50DF	GE LMS LMS100PA+	SGT6-5000F5	Wartsila 18V50DF
C	Central	356	150	192	6.6	13.1	10.4
F	Capital	375	113	98	3.6	6.5	9.2
G	Hudson Valley (Dutchess)	349	123	134	4.2	6.9	8.5
G	Hudson Valley (Rockland)	350	122	125	4.1	7.0	9.1
J	New York City						
K	Long Island						

Notes:
[1] Results reflect data for the period September 2013 through August 2016.
[2] Estimates include a $1.43/kW-year adder for VSS revenues for all units, based on settlement data provided by NYISO.
[3] Run time limits were applied based on NSPS.

V. ICAP DEMAND CURVE MODEL AND REFERENCE POINT PRICES

A. Introduction

Within the NYISO ICAP market, the ICAP Demand Curves are designed to ensure that the ICAP market provides sufficient revenues to support the development of new peaking plant resources to maintain resource adequacy. In Sections III and IV, AGI established the values for gross CONE and net EAS revenues for the peaking plant technologies in all Load Zones. The difference in annualized gross CONE and net EAS revenues is defined as the ARV.[83] That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technologies. This section describes how the resulting ARVs are translated into RP's that form an anchor for the slope of the ICAP Demand Curve in each capacity region, thereby accounting for the tariff-prescribed LOE conditions and seasonal nature of the ICAP markets. With these conclusions in hand, AGI presents the resulting ICAP Demand Curve parameters for each capacity region for Capability Year 2017/2018. Section VI summarizes the procedures for annual updating of ICAP Demand Curve parameters through the formulaic approach established at the time of this DCR.

B. ICAP Demand Curve Shape and Slope

The ICAP Demand Curves are designed with three basic elements: a cap on prices, a floor on prices (at zero), and sloped demand curve that determines prices for varying levels of capacity between this cap and floor. In principle, the ICAP Demand Curve slope reflects the declining marginal value of additional capacity in terms of incremental improvements in reliability – that is, as the quantity of capacity increases. Incremental capacity provides diminishing value in terms of reductions in loss of load expectation (LOLE). The sloped portion of the demand curve, in principle, captures this declining value. However, at some point, this value becomes so small that incremental capacity provides no meaningful improvement in reliability. To capture this limit, the ICAP Demand Curve includes the ZCP, which reflects the point at which incremental capacity provides no incremental value. Along with capturing the declining marginal value of capacity, a sloped demand curve also reduces the volatility of capacity market prices, which can reduce developer financial risk thereby providing a market environment more conducive to capital investment to support resource adequacy, and reduces incentives for the exercise of market power.

The ICAP Demand Curves are constructed such that the peaking plant would exactly recover its ARV when the system is at the LOE – that is, ICR/LCR plus the capacity of the peaking plant. Given differences in costs between Load Zones, separate ICAP Demand Curves are established for NYCA and

[83] In prior DCR's, the term Annual Reference Value referred to an adjusted estimate of the revenue requirement to account for the tariff proscribed LOE requirement. Within the AGI framework, the Annual Reference Value reflects the peaking plant's revenue requirement with no adjustments.

each Locality. Each ICAP Demand Curve is comprised of three portions (each of which is a straight line) reflecting the three components discussed above:

1. Price cap: A horizontal line with the price equal to 1.5 times the monthly gross CONE value for each capacity region;
2. Sloped segment: A sloped straight-line segment that intersects with number (1) and passes through two points: (a) the point at which the capacity is equal to the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, and the price is equal to the NYCA/Locality RP, and (b) the zero crossing point at which the price is equal to zero; and
3. Price floor: A horizontal line with the price equal to zero and the quantity includes all quantities greater than the ZCP quantity.[84]

Ultimately, the slope of the sloped portion of the line is determined by the RP and ZCP. As described below, the RP is a function of the ARV, the ZCPR, and the impact of additional capacity from the tariff prescribed LOE conditions and seasonal factors. The following sections provide additional detail on the ZCPR, WSR, and LOE factors. Following this discussion, the RP formula and ICAP Demand Curve geometry is presented in greater detail.

1. Zero crossing point

In the 2013 DCR, the ZCPRs for NYCA and the Localities 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 Load Zones G-J. This decision retained the then-current ZCP's, and to set the ZCP for Zones G-J midway between the values for Zones J and NYCA. Prior to this decision, two separate analyses of the ZCP were performed to inform ZCP decisions. The first analysis was a study completed by FTI that evaluated the economics of setting the ZCP, based on GE-MARS analysis of loss of load expectations associated with varying levels of capacity in the market.[85] While FTI had recommended increasing the ZCPRs beyond these values, the consultant during the last reset ultimately recommended adjusting ZCPs to a point midway between then-current values and the values recommended by FTI. After the completion of the DCR consultant's report, an analysis was performed by Potomac Economics, the NYISO's Independent Market Monitor, that was also based on GE-MARS modeling completed by NYISO Planning staff.[86]

Both the FTI and MMU recommendations were based on assessments of the point at which additional capacity beyond the ICR provided little or no marginal value in terms of improved reliability (as reflect in LOLE). However, the analyses differed in two key respects. First, the underlying MARS modeling used in the FTI analysis was based on "shifts" in capacity from the local zones to the NYCA. In

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[84] Similar to ICR and IRM, when referencing the ZCP in percentage terms relative to IRM or LCR, AGI uses the term zero crossing point ratio.

[85] NERA Report, pp. 14-15.

[86] The MMU analysis was presented at the August 22, 2013 ICAPWG meeting.

contrast, the modeling used by MMU relied on adding incremental capacity to each Locality and NYCA. Second, FTI relied on judgement to determine the ZCP – that is, relying on visual inspection to determine the point at which incremental value was near zero. The MMU quantitatively fit curves through scenarios outcomes to determine where the change in LOLE became zero.

Since the 2013 DCR, no additional studies have been conducted to inform the determination of ZCPs for NYCA and each locality. However, as part of its State of the Market Report, the MMU has recommended that the NYISO consider revising process for setting the IRM and LCR consistent with the capacity addition method discussed above.[87] In response, the NYISO established an LCR Task Force through the ICAPWG that is reviewing alternative methods for the LCR process. AGI recommends that further assessment of the ZCPR should be performed after the assessment of the LCR methodology is complete. While the LCR and ZCPR represent different measures with different functions within the ICAP Demand Curve, these values are related in so far as the ZCPR helps define the marginal value of capacity beyond the applicable minimum Installed Capacity requirement. Therefore, an approach to establishing the ZCP should be internally consistent with the IRM and LCR setting processes. Considering these factors, AGI recommends that the ZCPRs remain unchanged.

2. Winter-to-Summer Ratio

The WSR captures differences in the quantity of capacity available between winter and summer seasons given differences in seasonal operational capability. The ICAP Demand Curve accounts for differences in the prices that would prevail, all else equal, between seasons due to these seasonal differences in capacity. Figure 15 illustrates the differences in price during the winter season when there is a higher quantity of system capacity.

The NYISO presented its proposal for calculating the WSR at the March 24, 2016 ICAPWG meeting.[88] The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year. Total ICAP is equal to the sum of total UCAP available (including generation, Special Case Resources, and imports) listed in monthly reports published by the NYISO, converted to ICAP using a locational EFORd. These totals will be adjusted for certain resource entry and exit circumstances.[89] Both total

[87] *See* Patton, David B., Lee VanSchaick, Pallas, and Chen, Jie. "2015 State of the Market Report for the New York ISO Markets.", Potomac Economics, May 2016, pp. x-xi and 64-70.

[88] *See* NYISO, *NYISO's Winter-to-Summer Ratio Calculation Methodology: Comparing NYISO's Original Proposal and a Revised Approach* (presented at the March 24, 2016 ICAPWG meeting) available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2016-03-24/WSR%2003242016%20ICAPWG%20Final%2003232016.pdf.

[89] Broadly, these adjustments seek to include resource changes in all months of the applicable twelve-month period.

For new entry of a generator that comes online after September of the 12-month period, the NYISO will add the resource's applicable summer or winter MW to any month in which the entering MW are not already included. New entry includes new generator projects, generators returning from a mothball status, or returning from an ICAP Ineligible Force Outage Status. It does not include resources returning from an Inactive Reserves state.

For resource exit, the NYISO will remove the resource's MW for any months in which it is represented in the applicable 12-month period. Exit includes generator retirements, mothball, or ICAP Ineligible Force Outage State.

winter ICAP and total summer ICAP are calculated as a rolling average from the same three-year historical period that is used when calculating net EAS revenues.

Figure 15: Illustration of the Reference Point Price, Level of Excess, and Seasonal Capacity

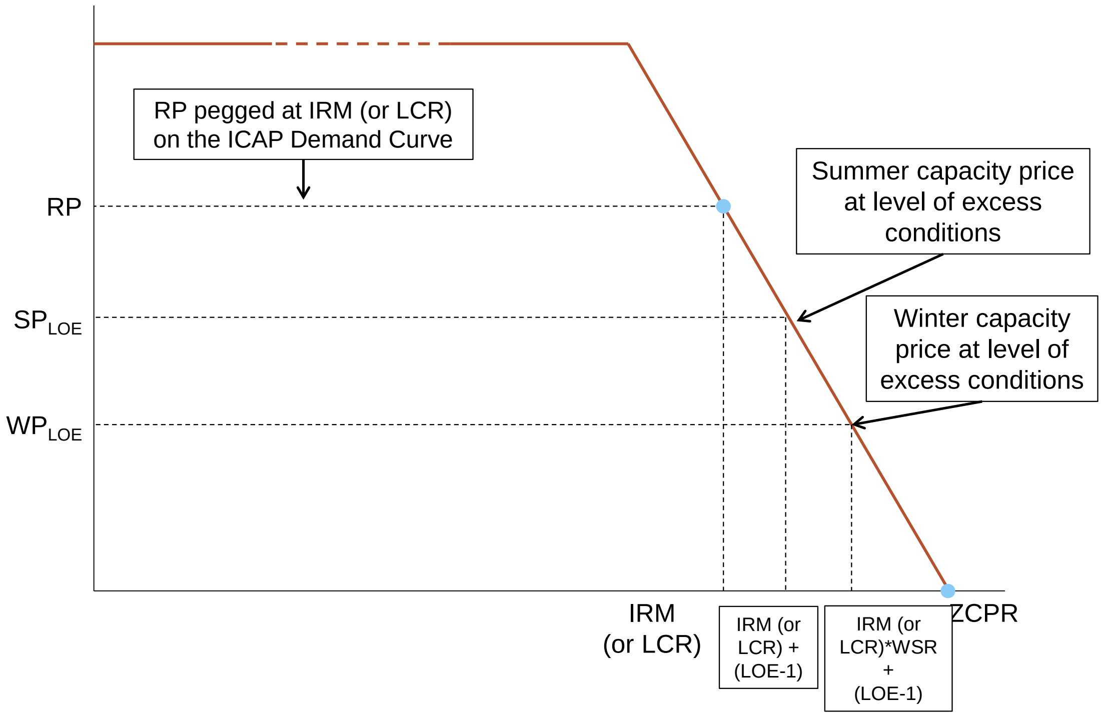


Table 38 provides the final WSR values used in this Report and reflect data for the three-year period from September 2013 through August 2016.

Table 38: Winter-to-Summer Ratio by Location

Capacity Region	Capability Year	Winter-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

Source: NYISO.

3. *Level of Excess Criterion*

The LOE for each peaking plant is defined as the ratio of the minimum Installed Capacity requirement plus the average degraded net plant capacity to the minimum Installed Capacity requirement. The LOE is expressed in percentage terms and defined by the following equation, where all capacities are expressed in MW.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)} \qquad (4)$$

The LOE varies by capacity region, depending on the ICR or LCR requirement, and by peaking plant. The ICR/LCR values are based on the 2016 Gold Book estimate for peak load in 2016 and the IRM/LCR values from the 2016-2017 Locational Minimum Installed Capacity Requirement Study. Table 39 provides the peak load, IRM/LCR target (in percentage terms), and the LOE by Locality and technology, expressed as a percentage.

Table 39: 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-PAC5000F(5) SC	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%

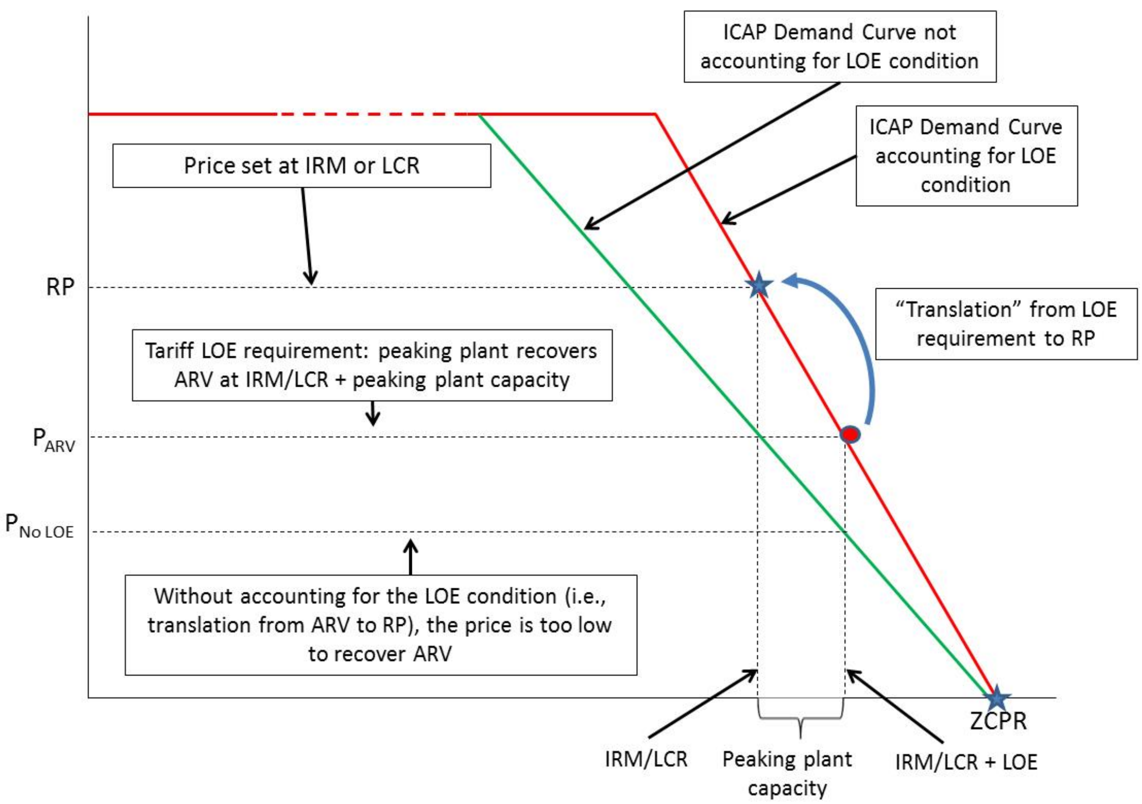
Source: Average degraded net capacity by technology is provided in Table 27.

C. Reference Point Price Calculations

Figure 16 illustrates the "geometry" of the ICAP Demand Curve and the LOE requirements, which in turn determine the RP. The ICAP Demand Curve slope is determined by two conditions: (1) the requirement that peaking plant earns its revenue requirement at the LOE, illustrated by the red dot in Figure 16, with the price P_{ARV} and the quantity "IRM/LCR + LOE"; and (2) the ZCPR. These two points define the red line in Figure 16, which is the ICAP Demand Curve slope. Having defined the ICAP Demand Curve slope, the RP can be calculated at the appropriate quantity for each capacity region – that is, the IRM for NYCA and the LCR for each Locality. This calculation requires a translation that is defined below.

Figure 16 also illustrates the ICAP Demand Curve slope absent the LOE requirement (the green line, set so that the peaking plant recovers its ARV at the IRM/LCR). When the RP is calculated *without* an adjustment to account for the tariff prescribed LOE condition, the price earned by the hypothetical peaking plant at the LOE (i.e., $P_{No\ LOE}$ in Figure 16) would be insufficient to recover ARV.

Figure 16: Illustration of the Reference Point Price and Level of Excess Requirement



Equation (5) defines the RP as a function of both the seasonal capacity adjustment (the WSR) and the LOE requirement:

$$RP = \frac{ARV * AssmdCap}{6 * \left[SDMNC * \left(1 - \frac{LOE-1}{ZCPR-1}\right) + WDMNC * \left(1 - \frac{(LOE-1)+(WSR-1)}{ZCPR-1}\right)\right]} \qquad (5)$$

Where:

ARV is the annual reference value for the relevant peaking plant ($/kW-year)

SDMNC is the summer dependable maximum net capability for the relevant peaking plant (MW)

WDMNC is the winter dependable maximum net capability for the relevant peaking plant (MW)

AssmdCap is the average degraded net plant capacity for the relevant peaking plant

LOE is the ratio of IRM/LCR plus the assumed capacity of the relevant peaking plant to IRM/LCR (%)

WSR is the ratio of total winter ICAP to total summer ICAP, as calculated by the NYISO for the relevant capacity region

ZCPR is the ZCP ratio of the ICAP Demand Curve for the relevant capacity region

RP is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region

Along with accounting for the LOE requirement, Equation 5 also accounts for differences in the capacity market revenue and peaking plant capacity between Summer and Winter capability periods. These differences in seasonal prices were illustrated in Figure 15. Thus, the plant's ARV (defined in $/kW-year) is met through different revenue streams in each season – that is:

$$ARV * AssmdCap = 6 * SP * SDMNC + 6 * WP * WDMNC \qquad (6)$$

Where:

SP and WP represent the assumed summer and winter capacity prices at the tariff prescribed LOE conditions as illustrated in Figures 15 and 16.

Equation 5 reflects the solution to the revenue adequacy requirement in Equation 6, given the following equations for *SP* and *WP*:

$$SP = RP \times \left(1 - \frac{LOE-1}{ZCPR-1}\right)$$

$$WP = RP \times \left(1 - \frac{(LOE-1)+(WSR-1)}{ZCPR-1}\right)$$

D. ICAP Demand Curve Parameters for NYCA and Each Locality

AGI has applied the methods, models and equations described in this Report to identify the RPs and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2017/2018. These values are presented in Tables 40 and 41A, below. Figure 17A-D provides a comparison of these ICAP Demand Curve parameters relative to ICAP Demand Curve parameters for the 2008/09 Capability Year, 2011/12 Capability Year, and the 2014/15 Capability Year.[90]

To arrive at these results, AGI and LCI considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of RPs. Specifically, we conclude the following:

- The Siemens SGT6-5000F5 (F Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, the F Class Frame machine would be built with SCR emission control technology across all locations.

- Based on market expectations for fuel availability and fuel assurance, changes in market structures, and developer expectations going forward, the F Class Frame machine would more often than not be built with dual fuel capability in all locations.

- The WACC used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55 percent debt and 45 percent equity; a 7.75 percent cost of debt; and a 13.4 percent return on equity, for a WACC of 10.3 percent. Based on current tax rates in New York City and NY State, this translates to a nominal ATWACC of 8.36 percent for Load Zone J and 8.6 percent for all other Load Zones, respectively.

- Net EAS revenues should be estimated for the peaking plant technologies using gas hubs that reflect gas prices consistent with LBMPs within each Load Zone. The choice of gas hub and gas prices should also reflect, in part, reasonable expectations for a long term equilibrium in delivered natural gas prices that would be available to a hypothetical new peaking plant. To that end, net EAS revenues are estimated using the following gas hubs:
  - Load Zone C: TETCO M3
  - Load Zones F and G: Iroquois Zone 2
  - Load Zones J and K: Transco Zone 6

- To promote transparency and allow for model updates, RPs should be calculated using a standardized formula, which is defined and expressed herein.

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[90] All values are expressed in nominal dollars.

- ICAP Demand Curves should maintain the current zero crossing point ratios. The ZCPR, along with the RP, defines the shape and slope of the ICAP Demand Curve. ZCPR will remain 112 percent (NYCA), 115 percent (G-J Locality), and 118 percent (Load Zones J and K).

Table 40 provides the parameters of the ICAP Demand Curves for the 2017/18 Capability Year consistent with the conclusions and technology findings described above. Tables 41A-C provides additional information for the other technologies evaluated (including for informational purposes) results using alternative assumptions with respect to fuel capability.

Table 40: ICAP Demand Curve Parameters ($2017)
Siemens SGT6-5000F5 with Dual Fuel Capability and SCR Technology

Parameter	Source	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
		Current Year (2017-2018)					
Gross Cost of New Entry ($/kW-Year)	[1]	$162.79	$154.99	$174.79	$176.65	$209.11	$194.96
Net EAS Revenue ($/kW-Year)	[2]	$46.19	$42.38	$40.39	$40.26	$55.26	$104.20
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$116.60	$112.61	$134.41	$136.39	$153.85	$90.77
ICAP DMNC (MW)	[4]	215.8	217.0	218.0	218.0	217.6	219.1
Total Annual Reference Value	[5] = [3] * [4]	**$25,165,303**	**$24,434,068**	**$29,295,019**	**$29,728,169**	**$33,472,776**	**$19,889,028**
Level of Excess (%)	[6]	100.6%	100.6%	101.5%	101.5%	102.3%	103.9%
Ratio of Summer to Winter DMNCs	[7]	1.037	1.037	1.054	1.054	1.077	1.075
Summer DMNC (MW)	[8]	224.4	224.6	226.8	226.1	226.9	224.9
Winter DMNC (MW)	[9]	230.3	230.3	230.3	230.3	228.7	230.3
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$11.03	$10.71	$13.37	$13.60	$16.24	$9.96
Winter ($/kW-Month)	[11]	$7.47	$7.25	$8.03	$8.16	$8.28	$4.66
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,474,926	$2,403,974	$3,033,195	$3,074,535	$3,684,898	$2,241,130
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,719,302	$1,668,364	$1,849,317	$1,880,151	$1,893,897	$1,073,717
Seasonal Revenue (Summer)	[14] = 6 * [12]	$14,849,557	$14,423,841	$18,199,168	$18,447,211	$22,109,385	$13,446,778
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,315,810	$10,010,185	$11,095,899	$11,280,905	$11,363,382	$6,442,303
Total Annual Reference Value	[16] = [14]+[15]	**$25,165,367**	**$24,434,026**	**$29,295,068**	**$29,728,116**	**$33,472,767**	**$19,889,081**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$11.56	**$11.22**	**$14.84**	**$15.09**	**$18.61**	**$12.72**
ICAP Max Clearing Price ($/kW-Month)		$20.35	$19.37	$21.85	$22.08	$26.14	$24.37
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Table 41A: Comparison of RP by Technology and Capability $2017/kW-month

Monthly Reference Point Price ($/kW-Month)							
Fuel type	Technology	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Dual Fuel	Wartsila 18V50	$20.94	$19.40	$25.31	$25.65	$32.31	$26.33
	LMS100 PA	$16.40	$15.05	$19.30	$19.48	$24.28	$19.07
	SGT6-PAC5000F(5) SC	$11.56	$11.22	$14.84	$15.09	$18.61	$12.72
Gas only with SCR	Wartsila 18V50	$17.62	$16.73	$21.97	$22.23	-	-
	LMS100 PA	$15.73	$14.59	$18.93	$19.11	-	-
	SGT6-PAC5000F(5) SC	$10.72	$10.72	$14.11	$14.30	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$9.08	$9.08	$12.29	-	-	-

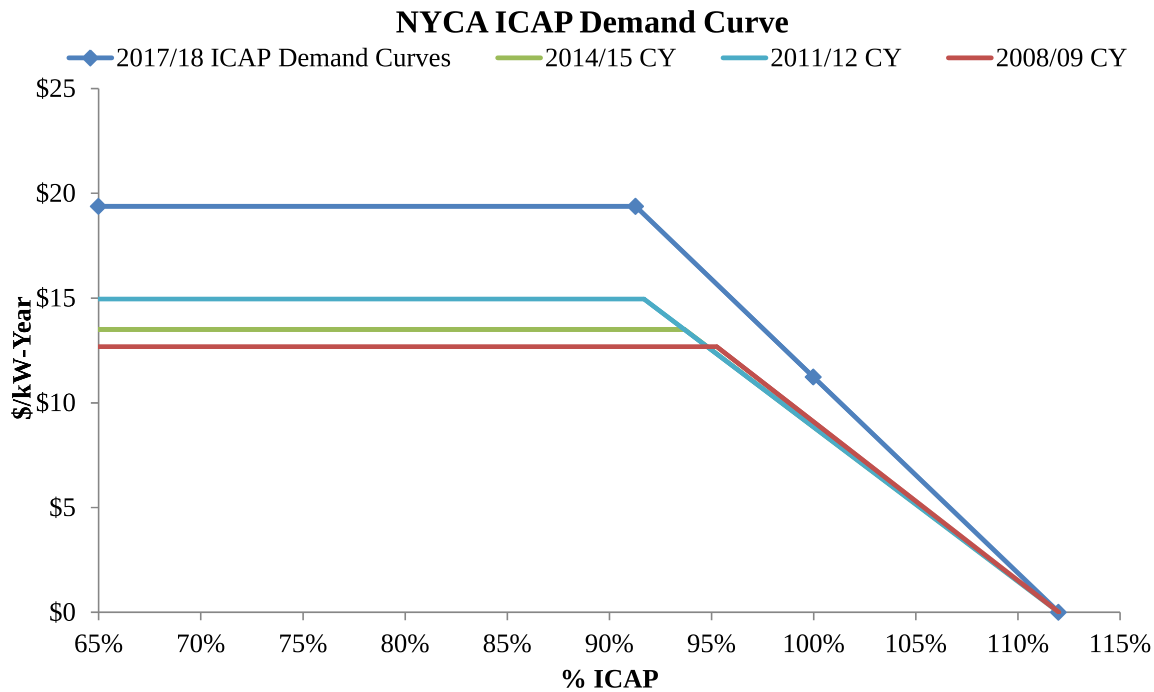
Table 41B: Comparison of Gross CONE by Technology and Capability $2017/kW-year

Gross CONE ($/kW-Year)							
Fuel type	Technology	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Dual Fuel	Wartsila 18V50	$259.85	$254.61	$284.07	$286.91	$334.65	$317.85
	LMS100 PA	$227.43	$218.50	$240.92	$243.17	$281.10	$265.24
	SGT6-PAC5000F(5) SC	$162.79	$154.99	$174.79	$176.65	$209.11	$194.96
Gas only with SCR	Wartsila 18V50	$218.14	$210.84	$237.09	$239.33	-	-
	LMS100 PA	$216.83	$207.89	$230.29	$232.47	-	-
	SGT6-PAC5000F(5) SC	$150.55	$142.92	$161.37	$162.68	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$134.96	$126.79	$144.72	-	-	-

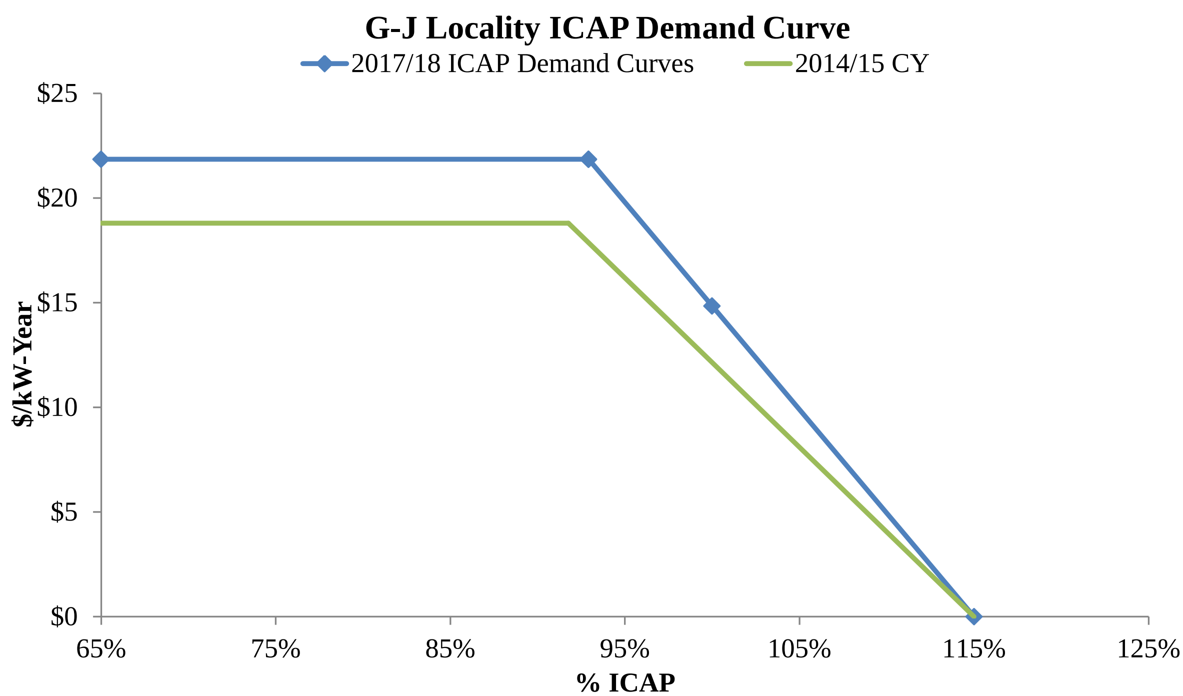
Table 41C: Comparison of Net EAS by Technology and Capability $2017/kW-month

Net EAS ($/kW-Year)							
Fuel type	Technology	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Dual Fuel	Wartsila 18V50	$57.38	$67.02	$61.98	$61.89	$74.66	$129.82
	LMS100 PA	$55.56	$61.38	$57.71	$57.80	$70.25	$117.42
	SGT6-PAC5000F(5) SC	$46.19	$42.38	$40.39	$40.26	$55.26	$104.20
Gas only with SCR	Wartsila 18V50	$48.87	$50.09	$46.98	$46.95	-	-
	LMS100 PA	$52.02	$55.61	$50.57	$50.62	-	-
	SGT6-PAC5000F(5) SC	$42.43	$35.35	$33.61	$33.48	-	-
Informational Gas only without SCR	SGT6-PAC5000F(5) SC	$43.35	$35.70	$33.48	-	-	-

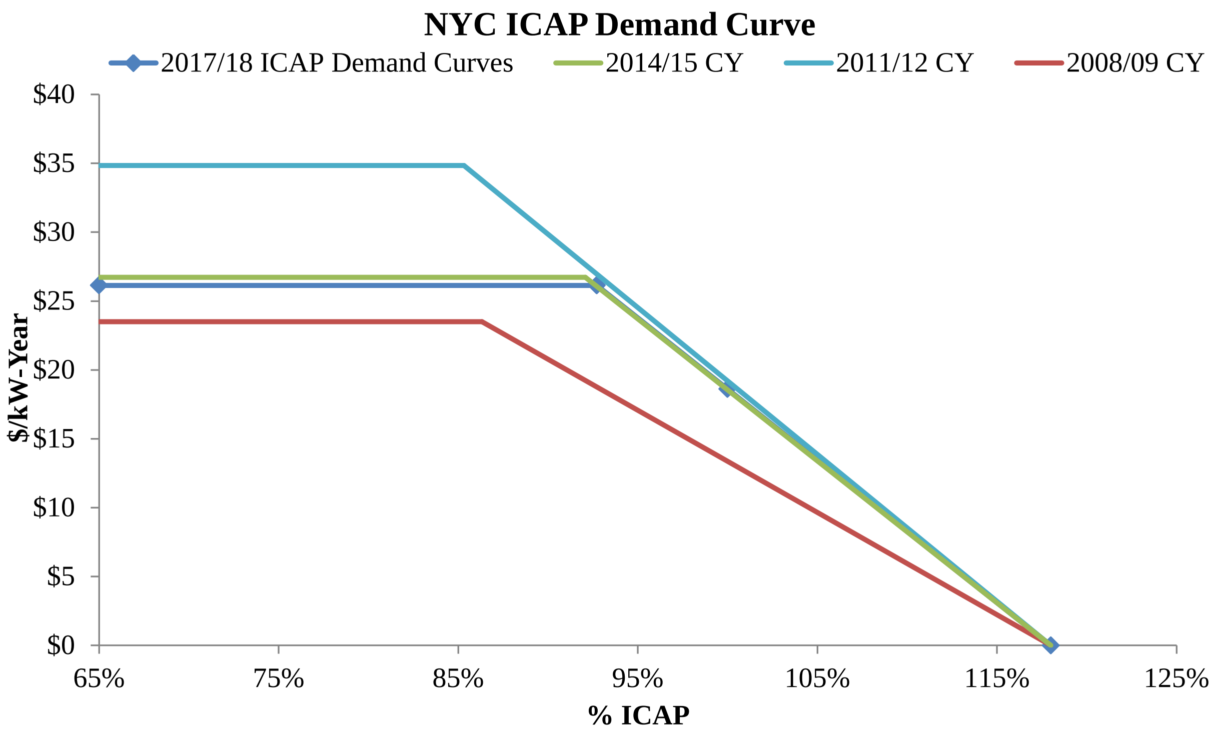
Figure 17: Comparison of ICAP Demand Curves for the 2017/18 Capability Year with Prior ICAP Demand Curve Parameters



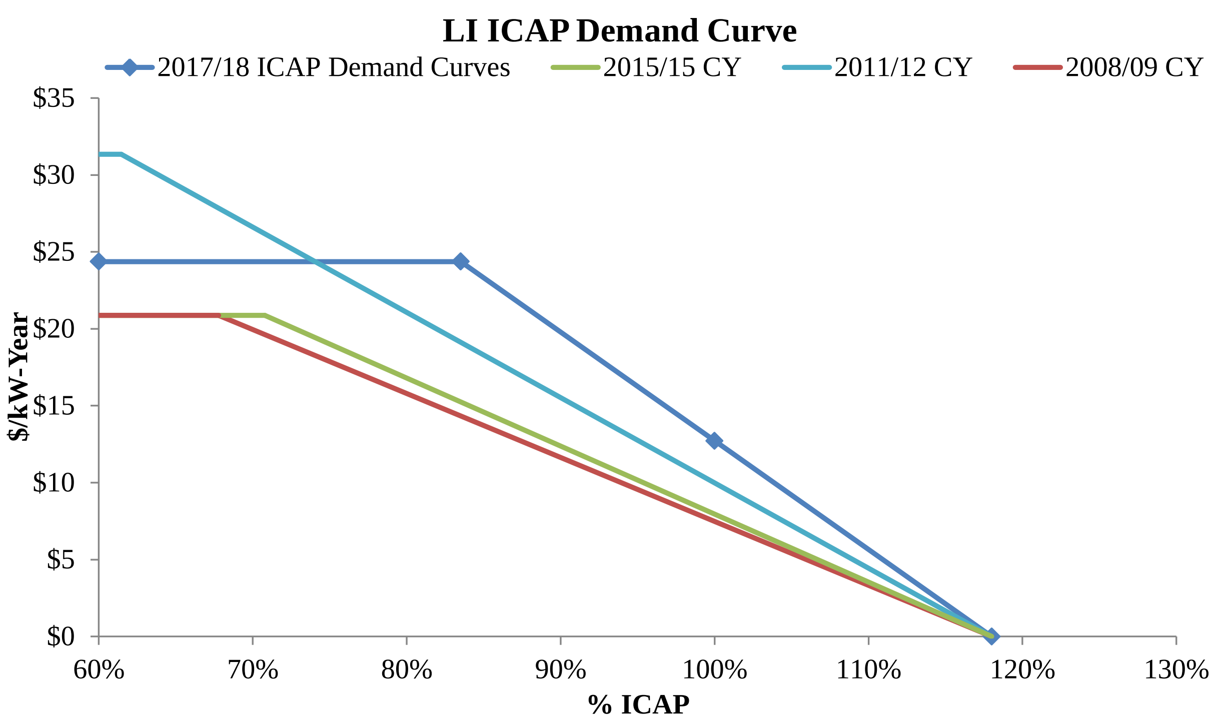
Note: 2017/18 ICAP Demand Curve for the NYCA is based on Load Zone F.



Note: 2017/18 ICAP Demand Curve for the G-J Locality is based on Load Zone G (Dutchess County).



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
65%
75%
85%
95%
105%
115%
125%
% 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
60%
70%
80%
90%
100%
110%
120%
130%
% ICAP

VI. ANNUAL UPDATING OF ICAP DEMAND CURVE PARAMETERS

As described above, AGI's demand curve model (DCM) calculates the RPs for each Locality and NYCA based input values for revenue requirements (i.e., ARV), financial parameters, "shape" parameters and other parameters (WSR, and various capacity values). Outputs of the DCM provide the applicable ICAP Demand Curve parameters for the Capability Year in question and associated financial metrics. These outputs include the gross CONE ($/kW-year), net EAS revenues ($/kW-year), ARV ($/kW-year and total $/year), ICAP monthly RP ($/kW-Month), ICAP Demand Curve maximum clearing price ($/kW-Month), and ICAP Demand Curve length (%).

ICAP Demand Curves will be updated annually based the updating of (1) gross CONE, (2) net EAS revenues, and (3) the WSR. Updates to gross CONE and net EAS revenues will be based on the data and models discussed in Sections III and IV, and described in greater detail below. The WSR will be updated by NYISO and account for resource entry and exit decisions that occur during the prior year that would lead to changes in system resource conditions that are expected to persist over time.[91] However, changes in the WSR will occur gradually, because the WSR will be measured over a rolling 3-year period.

Table 42 contains a summary of the factors used in the ICAP Demand Curve calculations, with an indication of data source and whether or not they are updated annually (items in BOLD are updated annually).

Table 42: Overview of ICAP Demand Curve Annual Updating

(Items in **bold** print are to be updated annually)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
ICAP Demand Curve Values	
Zero-crossing point	Fixed for Reset Period
Reference Point Price Calculation	
Peaking Plant Net Degraded Capacity	Fixed Value (Fixed for Reset Period)
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed Value (Fixed for Reset Period)
Peaking Plant Winter Capability Period DMNC	Fixed Value (Fixed for Reset Period)
Installed Capacity Requirements (IRM/LCR)	Fixed Value (Fixed for Reset Period)
Monthly Available Capacity Values for Use in Calculating WSR	**NYISO Published Values**

The NYISO will post updated ICAP Demand Curve values on or before November 30th of the calendar year immediately preceding the beginning of the Capability Year for which the updated ICAP Demand Curves will apply.

The updating process will calculate updated RP values for the upcoming Capability Year. However, for the upcoming reset period, the RP values applied in constructing the ICAP Demand Curves will be subject to a "collar" on the magnitude of year-to-year changes in the RP as a result of the annual

[91] *See* "NYISO's Winter-to-Summer Ratio Calculation Methodology: Comparing NYISO's Original Proposal and a Revised Approach", ICAPWG, March 24, 2016.

updating process. The purpose of the RP collar is to mitigate potential RP volatility during the first DCR period during which the proposed enhancements to the DCR process apply (i.e., four-year period between DCRs, new net EAS method, and annual updating).

Specifically, in each year, the change in the RP will be limited to a 12 percent (increase) and an 8 percent (decrease) relative to the RP value that is currently in effect (hereafter, the “currently effective” RP). Note that the collar is calculated relative to the currently effective RP value, not the (calculated) RP value, thus limiting year-to-year changes in the currently effective RP.

A. Annual Updates to Gross CONE

An element of annual updates is the update of gross CONE. In each year, the gross CONE of each peaking plant will be updated based on a single state-wide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components: wages, turbines, materials and components, and other costs. In each year, the annual composite escalation rate is calculated as:

$$Annual\ Composite\ Escalation_{\ t} = \sum_{i=1}^{4}(weight_i) * \left(\frac{Index_{i,t}}{Index_{i,t-1}} - 1\right) \tag{7}$$

The single set of cost-component weights are calculated for each peaking plant technology reflecting each component's share of total peaking plant installed capital costs. Table 45 provides the (publicly available) index to be used for each cost component, the approach taken to calculating the index value used in annual updating, and each component's weight for each peaking plant technology. The weights and indices relied upon will be held fixed over the reset period, but the values resulting from the indices will be updated annually based on the indices and component weights described in Table 43.

The general component of the composite escalation factor between Q2 2015 and Q2 2016 was 1.2 percent. The composite escalation factor for the recommended peaking unit technology based on the data available as of this Report is 1.51 percent.

The composite escalation rate (and the rate associated with the general component thereof) 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.

Table 43: Composite Escalation Rate Indices and Component Weights, by Technology (2017-18 Capability Year)

Cost Component	Index	Interval	Calculation of Index Value	Growth Rate	Component Weight, by Technology					
					LMS100 PA	SGT6-PAC5000F(5) SC	Wartsila 18V50	1x0 GE 7HA.02	5000F CC	8000H CC
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	Most recent annual value	5.40%	25%	28%	20%	26%	41%	41%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	Average of finalized February, March, April values	-0.58%	30%	37%	30%	31%	26%	26%
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	Average of finalized February, March, April values	0.39%	30%	20%	36%	27%	18%	19%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	1.22%	15%	15%	15%	15%	15%	15%
Composite Escalation Rate					**1.48%**	**1.57%**	**1.20%**	**1.20%**	**2.30%**	**2.31%**

Note: Although the indices and weighting factors presented in the table above are final, the calculated escalation rates are indicative only and reflect the most current data available for each index at the time of this Report. Final escalation rates for the 2017-2018 Capability Year, calculated in accordance with the requirements of the Services Tariff, will be provided in the NYISO's filing with FERC on or before November 30, 2016.

B. Annual Updating of Net EAS

1. Updating Approach and Timing

Net EAS revenues would be recalculated using the same net EAS revenues model used to estimate net EAS revenues for the 2017/18 Capability Year, but model inputs would 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 and the LOE-AFs described above would not be updated for the purposes of annual recalculation of net EAS.

Table 44 contains a summary of the factors used in the net EAS calculation, with an indication of data source and whether or not they are updated annually (items in **bold** are updated annually).

Table 44: Overview of Treatment of Net EAS Model Parameters for Annual Updating

(Items in **bold** print are to be updated annually)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
Net EAS Revenue Model, including Commitment and Dispatch Logic	Fixed for Reset Period
Peaking plant Physical Operating Characteristics, including start time requirements, start-up cost minimum down time and run time requirements, operating hours restrictions and/or limitations (if any), heat rate	Fixed for Reset Period
Energy Prices (day-ahead and real-time)	NYISO Published Values
Operating Reserves Prices (day-ahead and real-time)	NYISO Published Values
Level of Excess Adjustment Factors	Fixed for Reset Period
Annual Value of other ancillary services not determined by net EAS Model (*e.g.*, voltage support service)	Fixed Value (Fixed for Reset Period)
Peaking plant primary and secondary (if any) Fuel Type	Fixed for Reset Period
Fuel tax and transportation cost adders	Fixed Value (Fixed for Reset Period)
Real-time intraday gas premium	Fixed Value (Fixed for Reset Period)
Fuel Pricing Point (*e.g.*, natural gas trading hub)	Fixed for Reset Period
Fuel Price	Subscription Service Data Source or Publicly Available Data Source
Peaking plant Variable Operating and Maintenance Cost	Fixed Value (Fixed for Reset Period)
Peaking plant CO_2 Emissions Rate	Fixed Value (Fixed for Reset Period)
CO_2 Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source
Peaking plant NO_x Emissions Rate	Fixed Value (Fixed for Reset Period)
NO_x Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source
Peaking plant SO_2 Emissions Rate	Fixed Value (Fixed for Reset Period)
SO_2 Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source
NYISO Rate Schedule 1 Charges	NYISO Published Values

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

Updated net EAS revenues values would be combined with updated gross CONE values in the DCM to establish the RPs and ICAP Demand Curve parameters for NYCA and each Locality by November 30th of the year preceding the beginning of the Capability Year to which the updated ICAP Demand Curves will apply.

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APPENDICES

A. Summary of Results for Informational Purposes: GE 7HA.02

This appendix provides the results for the GE 7HA.02 for informational purposes. As discussed in Section II, several H class frame machines have recently cleared in forward capacity market auctions; however, there are no GE7HA.02 units that are currently in operation or that have proven operating experience.

Additional information for the GE 7HA.02 is included in the following appendices, including detailed capital costs, operating costs, operating characteristics, and net EAS revenues.

Appendix A Table 1: Summary of GE 7HA.02

1x0 GE 7HA.02							
Fuel type	**Technology**	**C - Central**	**F - Capital**	**G - Hudson Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
Dual Fuel	Gross CONE ($/kW-year)	$149.58	$144.50	$159.19	$160.76	-	$241.06
	Net EAS ($/kW-year)	$52.35	$48.03	$46.59	$46.44	-	$113.58
	Monthly Reference Point Price ($/kW-Month)	$9.91	$9.89	$13.42	$13.52	-	$21.42
Gas only with SCR	Gross CONE ($/kW-year)	$132.40	$127.19	$141.60	$143.02	-	-
	Net EAS ($/kW-year)	$48.53	$42.35	$39.76	$39.51	-	-
	Monthly Reference Point Price ($/kW-Month)	$8.55	$8.70	$12.14	$12.24	-	-

B. Detailed Technology Specifications: Total Capital Investments, Fixed and Variable O&M Costs, and Performance Data

The following appendix was prepared by LCI and provides additional detail on the total capital investments, fixed and variable O&M costs, and performance data.

Information is provided in the following sections organized by:

- Fuel type (dual fuel or gas only with SCR)
    - Total Capital Investment
    - Fixed and Variable O&M
    - Performance Data

Information is presented for the following technologies:

Simple Cycle Technologies:

- Two GE LMS100 PA+ units
- One Siemens SGT6-5000F unit
- Twelve Wartsila 18V50SG/DG engines
- One GE 7HA.02 (for informational purposes only)

Combined Cycle Technologies (for informational purposes only)

- 1x1 Siemens 5000F5 Flex Plant (combined cycle)
- 1x1 Siemens 8000H Flex Plant (combined cycle)

Total Capital Investments

Dual Fuel

2x0 GE LMS100PA+, Dual Fuel All Zones

	2x0 GE LMS100PA+, Dual Fuel, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$122,818,000	$124,677,000	$122,818,000	$122,818,000	$122,818,000	$122,818,000
Spare Parts	$629,000	$629,000	$629,000	$629,000	$629,000	$629,000
Subtotal	$123,447,000	$125,306,000	$123,447,000	$123,447,000	$123,447,000	$123,447,000
Construction						
Construction Labor & Materials	$92,463,000	$97,969,000	$68,847,000	$70,633,000	$58,879,000	$56,146,000
Plant Switchyard	$1,483,000	$1,509,000	$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$4,163,000	$7,738,000	$3,387,000	$3,538,000	$2,847,000	$2,847,000
Engineering & Design	$6,104,000	$6,104,000	$6,104,000	$6,104,000	$6,104,000	$6,104,000
Construction Mgmt. / Field Engr.	$3,199,000	$3,312,000	$2,742,000	$2,742,000	$2,742,000	$2,742,000
Subtotal	$134,923,000	$141,256,000	$123,504,000	$125,676,000	$99,084,000	$108,878,000
Startup & Testing						
Startup & Training	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000
Testing	-	-	-	-	-	-
Subtotal	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000
Contingency	$17,119,000	$18,155,000	$15,324,000	$15,464,000	$14,564,000	$14,367,000
Subtotal - EPC Costs	$278,384,000	$287,612,000	$265,170,000	$267,482,000	$239,990,000	$249,587,000
EPC Costs for Gas Only			$257,521,000	$259,770,000	$232,404,000	$242,084,000
Decreased EPC for Gas Only ($million)			$7.6	$7.7	$7.6	$7.5
Non-EPC Cost Components						
Owner's Costs						
Permitting	$2,784,000	$2,876,000	$2,652,000	$2,675,000	$2,400,000	$2,496,000
Legal	$2,784,000	$2,876,000	$2,652,000	$2,675,000	$2,400,000	$2,496,000
Owner's Project Mgmt. & Misc. Engr.	$4,176,000	$4,314,000	$3,978,000	$4,012,000	$3,600,000	$3,744,000
Fuel Oil Testing	$746,000	$746,000	$746,000	$746,000	$746,000	$746,000
Social Justice	$557,000	$2,589,000	$530,000	$535,000	$480,000	$499,000
Owner's Development Costs	$8,352,000	$8,628,000	$7,955,000	$8,024,000	$7,200,000	$7,488,000
Financing Fees	$5,568,000	$5,752,000	$5,303,000	$5,350,000	$4,800,000	$4,992,000
Studies (Fin, Env, Market, Interconnect)	$1,392,000	$1,438,000	$1,326,000	$1,337,000	$1,200,000	$1,248,000
Emission Reduction Credits	$281,000	$281,000	$0	$281,000	$0	$0
System Deliverability Upgrade Costs	$18,480,000	$0	$0	$0	$0	$0
Subtotal	$45,120,000	$29,500,000	$25,142,000	$25,635,000	$22,826,000	$23,709,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$13,562,000	$13,493,000	$12,919,000	$13,031,000	$11,692,000	$12,159,000
Non-EPC Portion	$2,198,000	$1,384,000	$1,225,000	$1,249,000	$1,112,000	$1,155,000
Working Capital and Non-Fuel Inventories	$2,784,000	$2,876,000	$2,652,000	$2,675,000	$2,400,000	$2,496,000
Fuel Inventory	$2,505,000	$2,505,000	$2,505,000	$2,505,000	$2,505,000	$2,505,000
Subtotal - Non-EPC Costs	$66,169,000	$49,758,000	$44,443,000	$45,095,000	$40,535,000	$42,024,000
Total Capital Investment	**$344,553,000**	**$337,370,000**	**$309,613,000**	**$312,577,000**	**$280,525,000**	**$291,611,000**

1x0 Siemens SGT6-5000F5, Dual Fuel All Zones

	1x0 Siemens 5000F5, Dual Fuel, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$81,082,000	$81,742,000	$81,082,000	$81,082,000	$81,082,000	$81,082,000
Spare Parts	$424,000	$424,000	$424,000	$424,000	$424,000	$424,000
Subtotal	$81,506,000	$82,166,000	$81,506,000	$81,506,000	$81,506,000	$81,506,000
Construction						
Construction Labor & Materials	$84,797,000	$89,802,000	$63,163,000	$64,789,000	$53,176,000	$50,821,000
Plant Switchyard	$1,483,000	$1,509,000	$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$3,395,000	$6,311,000	$2,762,000	$2,886,000	$2,377,000	$2,265,000
Engineering & Design	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000	$5,800,000
Construction Mgmt. / Field Engr.	$2,968,000	$3,073,000	$2,544,000	$2,544,000	$2,507,000	$2,507,000
Subtotal	$125,954,000	$131,119,000	$116,693,000	$118,678,000	$92,372,000	$102,432,000
Startup & Testing						
Startup & Training	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000
Testing						
Subtotal	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000	$2,895,000
Contingency	$13,228,000	$13,960,000	$11,589,000	$11,715,000	$10,837,000	$10,659,000
Subtotal - EPC Costs	$223,583,000	$230,140,000	$212,683,000	$214,794,000	$187,610,000	$197,492,000
EPC - Gas Only (with SCR)			$200,573,000	$202,000,000	$177,396,000	$187,129,000
Decreased EPC for Gas Only ($million)			$12.1	$12.8	$10.2	$10.4
Non-EPC Cost Components						
Owner's Costs						
Permitting	$2,236,000	$2,301,000	$2,127,000	$2,148,000	$1,876,000	$1,975,000
Legal	$2,236,000	$2,301,000	$2,127,000	$2,148,000	$1,876,000	$1,975,000
Owner's Project Mgmt. & Misc. Engr.	$3,354,000	$3,452,000	$3,190,000	$3,222,000	$2,814,000	$2,962,000
Fuel Oil Testing	$931,000	$931,000	$931,000	$931,000	$931,000	$931,000
Social Justice	$447,000	$2,071,000	$425,000	$430,000	$375,000	$395,000
Owner's Development Costs	$6,707,000	$6,904,000	$6,380,000	$6,444,000	$5,628,000	$5,925,000
Financing Fees	$4,472,000	$4,603,000	$4,254,000	$4,296,000	$3,752,000	$3,950,000
Studies (Fin, Env, Market, Interconnect)	$1,118,000	$1,151,000	$1,063,000	$1,074,000	$938,000	$987,000
Emission Reduction Credits	$328,000	$328,000	$0	$328,000	$0	$0
System Deliverability Upgrade Costs	$18,480,000	$0	$0	$0	$0	$0
Subtotal	$40,309,000	$24,042,000	$20,497,000	$21,021,000	$18,190,000	$19,100,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$15,571,000	$15,428,000	$14,812,000	$14,959,000	$13,066,000	$13,754,000
Non-EPC Portion	$2,807,000	$1,612,000	$1,428,000	$1,464,000	$1,267,000	$1,330,000
Working Capital and Non-Fuel Inventories	$2,236,000	$2,301,000	$2,127,000	$2,148,000	$1,876,000	$1,975,000
Fuel Inventory	$3,129,000	$3,129,000	$3,129,000	$3,129,000	$3,129,000	$3,129,000
Subtotal - Non-EPC Costs	$64,052,000	$46,512,000	$41,993,000	$42,721,000	$37,528,000	$39,288,000
Total Capital Investment	**$287,635,000**	**$276,652,000**	**$254,676,000**	**$257,515,000**	**$225,138,000**	**$236,780,000**

1x0 GE 7HA.02, Dual Fuel All Zones

	1x0 GE 7HA.02, Dual Fuel, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$127,188,000	$128,575,000	$127,188,000	$127,188,000	$127,188,000	$127,188,000
Spare Parts	$665,000	$665,000	$665,000	$665,000	$665,000	$665,000
Subtotal	$127,853,000	$129,240,000	$127,853,000	$127,853,000	$127,853,000	$127,853,000
Construction						
Construction Labor & Materials	$107,570,000	$113,714,000	$80,495,000	$82,516,000	$68,617,000	$65,576,000
Plant Switchyard	$1,483,000	$1,509,000	$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$5,833,000	$10,844,000	$4,748,000	$4,954,000	$4,107,000	$3,902,000
Engineering & Design	$6,280,000	$6,280,000	$6,280,000	$6,280,000	$6,280,000	$6,280,000
Construction Mgmt. / Field Engr.	$4,181,000	$4,322,000	$3,583,000	$3,583,000	$3,583,000	$3,583,000
Subtotal	$152,858,000	$161,293,000	$137,530,000	$139,992,000	$111,099,000	$120,380,000
Startup & Testing						
Startup & Training	$3,400,000	$3,400,000	$3,400,000	$3,400,000	$3,400,000	$3,400,000
Testing						
Subtotal	$3,400,000	$3,400,000	$3,400,000	$3,400,000	$3,400,000	$3,400,000
Contingency	$18,539,000	$19,563,000	$16,461,000	$16,622,000	$15,557,000	$15,322,000
Subtotal - EPC Costs	$302,650,000	$313,496,000	$285,244,000	$287,867,000	$257,909,000	$266,955,000
EPC Costs for Gas Only			$258,951,000	$261,343,000	$232,271,000	$241,762,000
Decreased EPC for Gas Only ($million)			$26	$27	$26	$25
Non-EPC Cost Components						
Owner's Costs						
Permitting	$3,027,000	$3,135,000	$2,852,000	$2,879,000	$2,579,000	$2,670,000
Legal	$3,027,000	$3,135,000	$2,852,000	$2,879,000	$2,579,000	$2,670,000
Owner's Project Mgmt. & Misc. Engr.	$4,540,000	$4,702,000	$4,279,000	$4,318,000	$3,869,000	$4,004,000
Fuel Oil Testing	$1,325,000	$1,325,000	$1,325,000	$1,325,000	$1,325,000	$1,325,000
Social Justice	$605,000	$2,821,000	$570,000	$576,000	$516,000	$534,000
Owner's Development Costs	$9,080,000	$9,405,000	$8,557,000	$8,636,000	$7,737,000	$8,009,000
Financing Fees	$6,053,000	$6,270,000	$5,705,000	$5,757,000	$5,158,000	$5,339,000
Studies (Fin, Env, Market, Interconnect)	$1,513,000	$1,567,000	$1,426,000	$1,439,000	$1,290,000	$1,335,000
Emission Reduction Credits	$457,000	$457,000	$0	$457,000	$0	$0
System Deliverability Upgrade Costs	$174,000,000	$0	$0	$0	$0	$0
Subtotal	$203,627,000	$32,817,000	$27,566,000	$28,266,000	$25,053,000	$25,886,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$21,078,000	$21,016,000	$19,866,000	$20,048,000	$17,962,000	$18,592,000
Non-EPC Portion	$14,182,000	$2,200,000	$1,920,000	$1,969,000	$1,745,000	$1,803,000
Working Capital and Non-Fuel Inventories	$3,027,000	$3,135,000	$2,852,000	$2,879,000	$2,579,000	$2,670,000
Fuel Inventory	$4,453,000	$4,453,000	$4,453,000	$4,453,000	$4,453,000	$4,453,000
Subtotal - Non-EPC Costs	$246,367,000	$63,621,000	$56,657,000	$57,615,000	$51,792,000	$53,404,000
Total Capital Investment	**$549,017,000**	**$377,117,000**	**$341,901,000**	**$345,482,000**	**$309,701,000**	**$320,359,000**

12x0 Wartsila 18V50DF, Dual Fuel All Zones

	12x0 Wartsila 18V50DF, Dual Fuel, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$126,883,000	$126,883,000	$126,883,000	$126,883,000	$126,883,000	$126,883,000
Spare Parts	$2,322,000	$2,322,000	$2,322,000	$2,322,000	$2,322,000	$2,322,000
Subtotal	$129,205,000	$129,205,000	$129,205,000	$129,205,000	$129,205,000	$129,205,000
Construction						
Construction Labor & Materials	$152,650,000	$159,216,000	$118,109,000	$120,043,000	$103,699,000	$96,747,000
Plant Switchyard	$2,967,000	$3,018,000	$7,549,000	$7,578,000	$3,862,000	$7,376,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$4,252,000	$7,904,000	$3,459,000	$3,614,000	$2,908,000	$3,717,000
Engineering & Design	$5,940,000	$5,940,000	$5,940,000	$5,940,000	$5,940,000	$5,940,000
Construction Mgmt. / Field Engr.	$2,145,000	$2,222,000	$1,838,000	$1,838,000	$1,838,000	$1,838,000
Subtotal	$195,465,000	$202,924,000	$175,545,000	$177,883,000	$144,828,000	$152,969,000
Startup & Testing						
Startup & Training	$1,731,000	$1,731,000	$1,731,000	$1,731,000	$1,731,000	$1,731,000
Testing						
Subtotal	$1,731,000	$1,731,000	$1,731,000	$1,731,000	$1,731,000	$1,731,000
Contingency	$21,356,000	$22,200,000	$18,783,000	$18,934,000	$17,703,000	$17,260,000
Subtotal - EPC Costs	$347,757,000	$356,060,000	$325,264,000	$327,753,000	$293,467,000	$301,165,000
EPC Costs for Gas Only			$302,270,000	$304,652,000	$271,082,000	$282,281,000
Decreased EPC for Gas Only ($million)			$23.0	$23.1	$22.4	$18.9
Non-EPC Cost Components						
Owner's Costs						
Permitting	$3,478,000	$3,561,000	$3,253,000	$3,278,000	$2,935,000	$3,012,000
Legal	$3,478,000	$3,561,000	$3,253,000	$3,278,000	$2,935,000	$3,012,000
Owner's Project Mgmt. & Misc. Engr.	$5,216,000	$5,341,000	$4,879,000	$4,916,000	$4,402,000	$4,517,000
Fuel Oil Testing	$702,000	$702,000	$702,000	$702,000	$702,000	$702,000
Social Justice	$696,000	$3,205,000	$651,000	$656,000	$587,000	$602,000
Owner's Development Costs	$10,433,000	$10,682,000	$9,758,000	$9,833,000	$8,804,000	$9,035,000
Financing Fees	$6,955,000	$7,121,000	$6,505,000	$6,555,000	$5,869,000	$6,023,000
Studies (Fin, Env, Market, Interconnect)	$1,739,000	$1,780,000	$1,626,000	$1,639,000	$1,467,000	$1,506,000
Emission Reduction Credits	$981,000	$981,000	$220,000	$981,000	$220,000	$220,000
System Deliverability Upgrade Costs	$18,480,000	$0	$0	$0	$0	$0
Subtotal	$52,158,000	$36,934,000	$30,847,000	$31,838,000	$27,921,000	$28,629,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$23,793,000	$23,449,000	$22,254,000	$22,425,000	$20,079,000	$20,606,000
Non-EPC Portion	$3,569,000	$2,432,000	$2,111,000	$2,178,000	$1,910,000	$1,959,000
Working Capital and Non-Fuel Inventories	$3,478,000	$3,561,000	$3,253,000	$3,278,000	$2,935,000	$3,012,000
Fuel Inventory	$2,360,000	$2,360,000	$2,360,000	$2,360,000	$2,360,000	$2,360,000
Subtotal - Non-EPC Costs	$85,358,000	$68,736,000	$60,825,000	$62,079,000	$55,205,000	$56,566,000
Total Capital Investment	**$433,115,000**	**$424,796,000**	**$386,089,000**	**$389,832,000**	**$348,672,000**	**$357,731,000**

1x1x1 Siemens STG6-5000F5 CC, Dual Fuel All Zones

	1x1x1 Siemens 5000F5 CC, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$152,808,000	$153,468,000	$152,808,000	$152,808,000	$152,808,000	$137,947,000
Spare Parts	$1,875,000	$1,875,000	$1,875,000	$1,875,000	$1,875,000	$1,875,000
Subtotal	$154,683,000	$155,343,000	$154,683,000	$154,683,000	$154,683,000	$139,822,000
Construction						
Construction Labor & Materials	$303,824,000	$321,285,000	$223,057,000	$228,404,000	$188,005,000	$172,702,000
Plant Switchyard	$1,483,000	$1,509,000	$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$7,815,000	$16,242,000	$6,325,000	$6,609,000	$5,541,000	$5,571,000
Engineering & Design	$26,000,000	$26,000,000	$26,000,000	$26,000,000	$26,000,000	$26,000,000
Construction Mgmt. / Field Engr.	$9,264,000	$9,594,000	$7,940,000	$7,940,000	$7,940,000	$7,359,000
Subtotal	$375,897,000	$399,254,000	$305,746,000	$311,612,000	$255,998,000	$252,671,000
Startup & Testing						
Startup & Training	$10,600,000	$10,600,000	$10,600,000	$10,600,000	$10,600,000	$10,600,000
Testing						
Subtotal	$10,600,000	$10,600,000	$10,600,000	$10,600,000	$10,600,000	$10,600,000
Contingency	$37,303,000	$39,257,000	$31,267,000	$31,674,000	$28,679,000	$26,461,000
Subtotal - EPC Costs	$578,483,000	$604,454,000	$502,296,000	$508,569,000	$449,960,000	$429,554,000
EPC Costs for Gas Only			$486,806,000	$493,050,000	$435,048,000	$414,798,000
Decreased EPC for Gas Only ($million)			$15.5	$15.5	$14.9	$14.8
Non-EPC Cost Components						
Owner's Costs						
Permitting	$5,785,000	$6,045,000	$5,023,000	$5,086,000	$4,500,000	$4,296,000
Legal	$5,785,000	$6,045,000	$5,023,000	$5,086,000	$4,500,000	$4,296,000
Owner's Project Mgmt. & Misc. Engr.	$8,677,000	$9,067,000	$7,534,000	$7,629,000	$6,749,000	$6,443,000
Fuel Oil Testing	$1,270,000	$1,270,000	$1,270,000	$1,270,000	$1,270,000	$1,270,000
Social Justice	$1,157,000	$5,440,000	$1,005,000	$1,017,000	$900,000	$859,000
Owner's Development Costs	$17,354,000	$18,134,000	$15,069,000	$15,257,000	$13,499,000	$12,887,000
Financing Fees	$11,570,000	$12,089,000	$10,046,000	$10,171,000	$8,999,000	$8,591,000
Studies (Fin, Env, Market, Interconnect)	$2,892,000	$3,022,000	$2,511,000	$2,543,000	$2,250,000	$2,148,000
Emission Reduction Credits	$545,000	$545,000	$0	$545,000	$0	$0
System Deliverability Upgrade Costs	$174,000,000	$0	$0	$0	$0	$0
Subtotal	$229,035,000	$61,657,000	$47,481,000	$48,604,000	$42,667,000	$40,790,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$47,338,000	$47,599,000	$41,104,000	$41,617,000	$36,821,000	$35,151,000
Non-EPC Portion	$18,742,000	$4,855,000	$3,885,000	$3,977,000	$3,492,000	$3,338,000
Working Capital and Non-Fuel Inventories	$5,785,000	$6,045,000	$5,023,000	$5,086,000	$4,500,000	$4,296,000
Fuel Inventory	$3,414,000	$3,414,000	$3,414,000	$3,414,000	$3,414,000	$3,414,000
Subtotal - Non-EPC Costs	$304,314,000	$123,570,000	$100,907,000	$102,698,000	$90,894,000	$86,989,000
Total Capital Investment	**$882,797,000**	**$728,024,000**	**$603,203,000**	**$611,267,000**	**$540,854,000**	**$516,543,000**

1x1x1 Siemens SGT6-8000H CC, Dual Fuel All Zones

	1x1x1 Siemens 8000H CC, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	$168,178,000	$169,378,000	$168,178,000	$168,178,000	$168,178,000	$151,782,000
Spare Parts	$1,948,000	$1,948,000	$1,948,000	$1,948,000	$1,948,000	$1,948,000
Subtotal	$170,126,000	$171,326,000	$170,126,000	$170,126,000	$170,126,000	$153,730,000
Construction						
Construction Labor & Materials	$316,783,000	$335,037,000	$232,524,000	$238,994,000	$195,988,000	$179,543,000
Plant Switchyard	$1,483,000	$1,509,000	$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability	$11,911,000	$9,024,000	$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$8,596,000	$17,026,000	$6,957,000	$7,269,000	$6,096,000	$6,128,000
Engineering & Design	$26,000,000	$26,000,000	$26,000,000	$26,000,000	$26,000,000	$26,000,000
Construction Mgmt. / Field Engr.	$9,427,000	$9,763,000	$8,081,000	$8,081,000	$8,081,000	$7,439,000
Subtotal	$389,800,000	$413,959,000	$315,986,000	$323,003,000	$264,677,000	$260,149,000
Startup & Testing						
Startup & Training	$10,750,000	$10,750,000	$10,750,000	$10,750,000	$10,750,000	$10,750,000
Testing						
Subtotal	$10,750,000	$10,750,000	$10,750,000	$10,750,000	$10,750,000	$10,750,000
Contingency	$39,474,000	$41,524,000	$33,173,000	$33,663,000	$30,471,000	$28,057,000
Subtotal - EPC Costs	$610,150,000	$637,559,000	$530,035,000	$537,542,000	$476,024,000	$452,686,000
EPC Costs for Gas Only			$513,692,000	$521,153,000	$460,279,000	$437,104,000
Decreased EPC for Gas Only ($million)			$16.3	$16.4	$15.7	$15.6
Non-EPC Cost Components						
Owner's Costs						
Permitting	$6,102,000	$6,376,000	$5,300,000	$5,375,000	$4,760,000	$4,527,000
Legal	$6,102,000	$6,376,000	$5,300,000	$5,375,000	$4,760,000	$4,527,000
Owner's Project Mgmt. & Misc. Engr.	$9,152,000	$9,563,000	$7,951,000	$8,063,000	$7,140,000	$6,790,000
Fuel Oil Testing	$1,259,000	$1,259,000	$1,259,000	$1,259,000	$1,259,000	$1,259,000
Social Justice	$1,220,000	$5,738,000	$1,060,000	$1,075,000	$952,000	$905,000
Owner's Development Costs	$18,305,000	$19,127,000	$15,901,000	$16,126,000	$14,281,000	$13,581,000
Financing Fees	$12,203,000	$12,751,000	$10,601,000	$10,751,000	$9,520,000	$9,054,000
Studies (Fin, Env, Market, Interconnect)	$3,051,000	$3,188,000	$2,650,000	$2,688,000	$2,380,000	$2,263,000
Emission Reduction Credits	$653,000	$653,000	$231,000	$653,000	$231,000	$231,000
System Deliverability Upgrade Costs	$174,000,000	$0	$0	$0	$0	$0
Subtotal	$232,047,000	$65,031,000	$50,253,000	$51,365,000	$45,283,000	$43,137,000
Financing (incl. AFUDC, IDC)						
EPC Portion	$49,930,000	$50,205,000	$43,374,000	$43,988,000	$38,954,000	$37,044,000
Non-EPC Portion	$18,989,000	$5,121,000	$4,112,000	$4,203,000	$3,706,000	$3,530,000
Working Capital and Non-Fuel Inventories	$6,102,000	$6,376,000	$5,300,000	$5,375,000	$4,760,000	$4,527,000
Fuel Inventory	$3,383,000	$3,383,000	$3,383,000	$3,383,000	$3,383,000	$3,383,000
Subtotal - Non-EPC Costs	$310,451,000	$130,116,000	$106,422,000	$108,314,000	$96,086,000	$91,621,000
Total Capital Investment	**$920,601,000**	**$767,675,000**	**$636,457,000**	**$645,856,000**	**$572,110,000**	**$544,307,000**

Fixed and Variable O&M Costs

Dual Fuel

2x0 GE LMS100PA+, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	2x0 LMS100PA+, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)	5op/3maint + supv/Admin/	5op/4maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M	$1,772,000	$2,269,000	$1,524,000	$1,556,000	$1,162,000	$1,076,000
Material and Contract Services	$774,000	$753,000	$734,000	$719,000	$710,000	$703,000
Fuel Oil Testing	$325,000	$348,000	$323,000	$322,000	$321,000	$321,000
Adminstrative and General	incl	incl	incl	incl	incl	incl
Subtotal Fixed O&M	$2,871,000	$3,370,000	$2,581,000	$2,597,000	$2,193,000	$2,100,000
$/kW-year	**$15.2**	**$18.0**	**$13.7**	**$13.8**	**$11.7**	**$11.3**
Other Fixed Costs						
Site Leasing Costs	$142,000	$1,481,000	$117,000	$117,000	$117,000	$117,000
Total Fixed O&M without tax and insurance	$3,013,000	$4,851,000	$2,698,000	$2,714,000	$2,310,000	$2,217,000
$/kW-year	**$16.0**	**$25.9**	**$14.4**	**$14.5**	**$12.4**	**$11.9**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	$2.84	$2.84	$2.84	$2.84	$2.84	$2.84
Major Maintenance Labor	$0.54	$0.56	$0.42	$0.44	$0.33	$0.31
Unscheduled Maintenance	incl	incl	incl	incl	incl	incl
SCR Catalyst and Ammonia	$0.53	$0.53	$0.53	$0.53	$0.53	$0.53
CO Oxidation Catalyst	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$1.51	$1.51	$1.51	$1.51	$1.51	$1.51
Total Variable O&M ($/MWh)	**$5.6**	**$5.6**	**$5.5**	**$5.5**	**$5.4**	**$5.4**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	$5.84	$5.84	$5.84	$5.84	$5.84	$5.84
Major Maintenance Labor	$1.07	$1.12	$0.85	$0.89	$0.67	$0.62
Unscheduled Maintenance	incl	incl	incl	incl	incl	incl
SCR Catalyst and Ammonia	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84
CO Oxidation Catalyst	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$1.69	$1.69	$1.69	$1.69	$1.69	$1.69
Total Variable O&M ($/MWh)	**$9.6**	**$9.7**	**$9.4**	**$9.4**	**$9.2**	**$9.2**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts	na	na	na	na	na	na
Major Maintenace Labor	na	na	na	na	na	na
Total ($/factored start)	na	na	na	na	na	na

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

1x0 Siemens SGT6-5000F5, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	1x0 Siemens 5000F5, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)	5op/3maint + supv/Admin/	5op/4maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M	$1,772,000	$2,269,000	$1,524,000	$1,556,000	$1,162,000	$1,076,000
Material and Contract Services	$913,000	$889,000	$866,000	$849,000	$838,000	$830,000
Fuel Oil Testing	$385,000	$415,000	$384,000	$383,000	$383,000	$382,000
Adminstrative and General	incl	incl	incl	incl	incl	incl
Subtotal Fixed O&M	$3,070,000	$3,573,000	$2,774,000	$2,788,000	$2,383,000	$2,288,000
$/kW-year	**$14.0**	**$16.4**	**$12.7**	**$12.8**	**$11.0**	**$10.6**
Other Fixed Costs						
Site Leasing Costs	$237,000	$2,469,000	$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance	$3,307,000	$6,042,000	$2,970,000	$2,984,000	$2,579,000	$2,484,000
$/kW-year	**$15.1**	**$27.8**	**$13.6**	**$13.7**	**$11.9**	**$11.5**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	-	-	-	-	-	-
Major Maintenance Labor	-	-	-	-	-	-
Unscheduled Maintenance	-	-	-	-	-	-
SCR Catalyst and Ammonia	$0.49	$0.49	$0.49	$0.49	$0.49	$0.49
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12
Total Variable O&M ($/MWh)	**$0.76**	**$0.76**	**$0.76**	**$0.76**	**$0.76**	**$0.76**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	-	-	-	-	-	-
Major Maintenance Labor	-	-	-	-	-	-
Unscheduled Maintenance	-	-	-	-	-	-
SCR Catalyst and Ammonia	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$1.41	$1.41	$1.41	$1.41	$1.41	$1.41
Total Variable O&M ($/MWh)	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.6**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts	$9,200	$9,200	$9,200	$9,200	$9,200	$9,200
Major Maintenace Labor	$1,700	$1,800	$1,300	$1,400	$1,100	$1,000
Total ($/factored start through first major)	**$10,900**	**$11,000**	**$10,500**	**$10,600**	**$10,300**	**$10,200**

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

1x0 GE 7HA.02, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	1x0 GE 7HA.02, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)	5op/3maint + supv/Admin/	5op/4maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M	$1,772,000	$2,269,000	$1,524,000	$1,556,000	$1,162,000	$1,076,000
Material and Contract Services	$1,303,000	$1,268,000	$1,236,000	$1,211,000	$1,195,000	$1,183,000
Fuel Oil Testing	$508,000	$548,000	$506,000	$506,000	$505,000	$505,000
Adminstrative and General	incl	incl	incl	incl	incl	incl
Subtotal Fixed O&M	$3,583,000	$4,085,000	$3,266,000	$3,273,000	$2,862,000	$2,764,000
$/kW-year	**$11.3**	**$12.9**	**$10.3**	**$10.3**	**$9.1**	**$8.8**
Other Fixed Costs						
Site Leasing Costs	$237,000	$2,469,000	$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance	$3,820,000	$6,554,000	$3,462,000	$3,469,000	$3,058,000	$2,960,000
$/kW-year	**$12.0**	**$20.7**	**$10.9**	**$11.0**	**$9.7**	**$9.4**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	-	-	-	-	-	-
Major Maintenance Labor	-	-	-	-	-	-
Unscheduled Maintenance	-	-	-	-	-	-
SCR Catalyst and Ammonia	$0.62	$0.62	$0.62	$0.62	$0.62	$0.62
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25
Total Variable O&M ($/MWh)	**$1.0**	**$1.0**	**$1.0**	**$1.0**	**$1.0**	**$1.0**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	-	-	-	-	-	-
Major Maintenance Labor	-	-	-	-	-	-
Unscheduled Maintenance	-	-	-	-	-	-
SCR Catalyst and Ammonia	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$3.78	$3.78	$3.78	$3.78	$3.78	$3.78
Total Variable O&M ($/MWh)	**$4.9**	**$4.9**	**$4.9**	**$4.9**	**$4.9**	**$4.9**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts	$14,200	$14,200	$14,200	$14,200	$14,200	$14,200
Major Maintenace Labor	$2,600	$2,700	$2,000	$2,100	$1,600	$1,500
Total ($/factored start through first major)	**$16,800**	**$16,900**	**$16,200**	**$16,300**	**$15,800**	**$15,700**

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

12x0 Wartsila 18V50DF, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	12x0 Wartsila 18V50DF, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin
Labor - Routine O&M	$3,692,000	$3,807,000	$3,176,000	$3,241,000	$2,420,000	$2,241,000
Material and Contract Services	$335,000	$326,000	$318,000	$311,000	$307,000	$304,000
Fuel Oil Testing	$391,000	$406,000	$380,000	$378,000	$376,000	$375,000
Adminstrative and General	incl	incl	incl	incl	incl	incl
Subtotal Fixed O&M	$4,418,000	$4,539,000	$3,874,000	$3,930,000	$3,103,000	$2,920,000
$/kW-year	**$22.1**	**$22.7**	**$19.4**	**$19.6**	**$15.5**	**$14.6**
Other Fixed Costs						
Site Leasing Costs	$237,000	$2,469,000	$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance	$4,655,000	$7,008,000	$4,070,000	$4,126,000	$3,299,000	$3,116,000
$/kW-year	**$23.3**	**$35.0**	**$20.3**	**$20.6**	**$16.5**	**$15.6**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	$4.39	$4.39	$4.39	$4.39	$4.39	$4.39
Major Maintenance Labor	$1.34	$1.39	$1.05	$1.10	$0.83	$0.77
Unscheduled Maintenance	incl	incl	incl	incl	incl	incl
SCR Ammonia (note 2)	$1.16	$1.16	$1.16	$1.16	$1.16	$1.16
CO Oxidation Catalyst	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
Lube Oil	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07
Miscellaneous	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
Total Variable O&M ($/MWh)	**$8.2**	**$8.2**	**$7.9**	**$8.0**	**$7.7**	**$7.6**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	$4.39	$4.39	$4.39	$4.39	$4.39	$4.39
Major Maintenance Labor	$1.34	$1.39	$1.05	$1.10	$0.83	$0.77
Unscheduled Maintenance	incl	incl	incl	incl	incl	incl
SCR Ammonia (note 2)	$1.16	$1.16	$1.16	$1.16	$1.16	$1.16
CO Oxidation Catalyst	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
Other Chemicals and Consumables	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07
Water	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
Total Variable O&M ($/MWh)	**$8.2**	**$8.2**	**$7.9**	**$8.0**	**$7.7**	**$7.6**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts	na	na	na	na	na	na
Major Maintenace Labor	na	na	na	na	na	na
Total ($/factored start)	na	na	na	na	na	na

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

Note 2: SCR catalyst replacement cost included in major maintenance

1x1x1 Siemens STG6-5000F5 CC, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	1x1x1 5000F5 Combined Cycle Plant, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin
Labor - Routine O&M	$3,781,000	$3,899,000	$3,252,000	$3,318,000	$2,479,000	$2,295,000
Material and Contract Services	$2,560,000	$2,492,000	$2,429,000	$2,380,000	$2,349,000	$2,326,000
Fuel Oil Testing	$398,000	$429,000	$396,000	$396,000	$395,000	$395,000
Adminstrative and General	$772,000	$789,000	$698,000	$705,000	$639,000	$606,000
Subtotal Fixed O&M	$7,511,000	$7,609,000	$6,775,000	$6,799,000	$5,862,000	$5,622,000
$/kW-year	**$22.8**	**$23.2**	**$20.7**	**$20.8**	**$18.0**	**$17.1**
Other Fixed Costs						
Site Leasing Costs	$356,000	$3,703,000	$392,000	$392,000	$392,000	$392,000
Total Fixed O&M without tax and insurance	$7,867,000	$11,312,000	$7,167,000	$7,191,000	$6,254,000	$6,014,000
$/kW-year	**$23.9**	**$34.5**	**$21.9**	**$22.0**	**$19.2**	**$18.3**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	$0.62	$0.62	$0.62	$0.62	$0.62	$0.62
Major Maintenance Labor	$0.19	$0.20	$0.15	$0.16	$0.12	$0.11
Unscheduled Maintenance	incl above	incl above	incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.01	$0.01	$0.01	$0.01	$0.01	$0.29
Total Variable O&M ($/MWh)	**$1.06**	**$1.07**	**$1.02**	**$1.02**	**$0.98**	**$1.25**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	$0.62	$0.62	$0.62	$0.62	$0.62	$0.62
Major Maintenance Labor	$0.19	$0.20	$0.15	$0.16	$0.12	$0.11
Unscheduled Maintenance	incl above	incl above	incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia	$0.28	$0.28	$0.28	$0.28	$0.28	$0.28
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.16	$0.16	$0.16	$0.16	$0.16	$0.44
Total Variable O&M ($/MWh)	**$1.4**	**$1.4**	**$1.4**	**$1.4**	**$1.3**	**$1.6**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenance Parts	$9,200	$9,200	$9,200	$9,200	$9,200	$9,200
Major Maintenance Labor	$1,700	$1,800	$1,300	$1,400	$1,100	$1,000
Total ($/factored start through first major)	**$10,900**	**$11,000**	**$10,500**	**$10,600**	**$10,300**	**$10,200**

1x1x1 Siemens SGT6-8000H CC, Dual Fuel All Zones

Fixed and Variable O&M Cost Estimates	1x1x1 8000H Combined Cycle Plant, Dual Fuel					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin
Labor - Routine O&M	$3,781,000	$3,899,000	$3,252,000	$3,318,000	$2,479,000	$2,295,000
Material and Contract Services	$2,642,000	$2,572,000	$2,506,000	$2,456,000	$2,424,000	$2,400,000
Fuel Oil Testing	$470,000	$506,000	$468,000	$467,000	$467,000	$466,000
Adminstrative and General	$806,000	$823,000	$730,000	$737,000	$670,000	$655,000
Subtotal Fixed O&M	$7,699,000	$7,800,000	$6,956,000	$6,978,000	$6,040,000	$5,816,000
$/kW-year	**$20.0**	**$20.4**	**$18.2**	**$18.2**	**$15.9**	**$15.1**
Other Fixed Costs						
Site Leasing Costs	$356,000	$3,703,000	$392,000	$392,000	$392,000	$392,000
Total Fixed O&M without tax and insurance	$8,055,000	$11,503,000	$7,348,000	$7,370,000	$6,432,000	$6,208,000
$/kW-year	**$20.9**	**30.1**	**$19.2**	**$19.3**	**$16.9**	**$16.1**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51
Major Maintenance Labor	$0.16	$0.17	$0.13	$0.13	$0.10	$0.09
Unscheduled Maintenance	incl above	incl above	incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.01	$0.01	$0.01	$0.01	$0.01	$0.28
Total Variable O&M ($/MWh)	**$1.02**	**$1.03**	**$0.99**	**$1.00**	**$0.96**	**$1.22**
ULSD Variable O&M ($/MWh)						
Major Maintenance Parts	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51
Major Maintenance Labor	$0.16	$0.17	$0.13	$0.13	$0.10	$0.09
Unscheduled Maintenance	incl above	incl above	incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
CO Oxidation Catalyst	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.16	$0.16	$0.16	$0.16	$0.16	$0.41
Total Variable O&M ($/MWh)	**$1.3**	**$1.3**	**$1.2**	**$1.2**	**$1.2**	**$1.4**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenance Parts	$13,900	$13,900	$13,900	$13,900	$13,900	$13,900
Major Maintenance Labor	$2,600	$2,700	$2,000	$2,100	$1,600	$1,500
Total ($/factored start through first major)	**$16,500**	**$16,600**	**$15,900**	**$16,000**	**$15,500**	**$15,400**

Total Capital Investments

Gas Only

2x0 GE LMS 100PA+, Gas Only, with SCR/CO Catalyst

	2x0 GE LMS 100PA+, Gas Only, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment			$119,652,000	$119,652,000	$119,652,000	$119,652,000
Spare Parts			$629,000	$629,000	$629,000	$629,000
Subtotal			$120,281,000	$120,281,000	$120,281,000	$120,281,000
Construction						
Construction Labor & Materials			$66,340,000	$68,081,000	$56,376,000	$53,721,000
Plant Switchyard			$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability			$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement			$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep			$3,048,000	$3,185,000	$2,562,000	$2,562,000
Engineering & Design			$5,948,000	$5,948,000	$5,948,000	$5,948,000
Construction Mgmt. / Field Engr.			$2,672,000	$2,672,000	$2,672,000	$2,672,000
Subtotal			$120,432,000	$122,545,000	$96,070,000	$105,942,000
Startup & Testing						
Startup & Training			$2,000,000	$2,000,000	$2,000,000	$2,000,000
Testing						
Subtotal			$2,000,000	$2,000,000	$2,000,000	$2,000,000
Contingency			$14,808,000	$14,944,000	$14,053,000	$13,861,000
Subtotal - EPC Costs			$257,521,000	$259,770,000	$232,404,000	$242,084,000
Non-EPC Cost Components						
Owner's Costs						
Permitting			$2,575,000	$2,598,000	$2,324,000	$2,421,000
Legal			$2,575,000	$2,598,000	$2,324,000	$2,421,000
Owner's Project Mgmt. & Misc. Engr.			$3,863,000	$3,897,000	$3,486,000	$3,631,000
Fuel Oil Testing			$0	$0	$0	$0
Social Justice			$515,000	$520,000	$465,000	$484,000
Owner's Development Costs			$7,726,000	$7,793,000	$6,972,000	$7,263,000
Financing Fees			$5,150,000	$5,195,000	$4,648,000	$4,842,000
Studies (Fin, Env, Market, Interconnect)			$1,288,000	$1,299,000	$1,162,000	$1,210,000
Emission Reduction Credits			$0	$239,000	$0	$0
System Deliverability Upgrade Costs			$0	$0	$0	$0
Subtotal			$23,692,000	$24,139,000	$21,381,000	$22,272,000
Financing (incl. AFUDC, IDC)						
EPC Portion			$12,546,000	$12,656,000	$11,322,000	$11,794,000
Non-EPC Portion			$1,154,000	$1,176,000	$1,042,000	$1,085,000
Working Capital and Non-Fuel Inventories			$2,575,000	$2,598,000	$2,324,000	$2,421,000
Fuel Inventory			$0	$0	$0	$0
Subtotal - Non-EPC Costs			$39,967,000	$40,569,000	$36,069,000	$37,572,000
Total Capital Investment			**$297,488,000**	**$300,339,000**	**$268,473,000**	**$279,656,000**

1x0 Siemens 5000F5, Gas Only, with and without SCR/CO Catalyst

	1x0 Siemens 5000F5, Gas Only, with and without SCR/CO Catalyst						
	G - Hudson Valley (Dutchess)	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	F - Capital	C - Central	C - Central
SCR/CO Catalyst Included?	**No**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**
EPC Cost Components							
Equipment							
Equipment	$62,836,000	$78,184,000	$78,184,000	$62,836,000	$78,184,000	$62,836,000	$78,184,000
Spare Parts	$424,000	$424,000	$424,000	$424,000	$424,000	$424,000	$424,000
Subtotal	$63,260,000	$78,608,000	$78,608,000	$63,260,000	$78,608,000	$63,260,000	$78,608,000
Construction							
Construction Labor & Materials	$51,518,000	$56,125,000	$57,694,000	$43,591,000	$47,570,000	$41,659,000	$45,331,000
Plant Switchyard	$3,774,000	$3,774,000	$3,789,000	$1,931,000	$1,931,000	$3,688,000	$3,688,000
Electrical Interconnection & Deliverability	$23,050,000	$23,050,000	$23,270,000	$10,981,000	$10,981,000	$21,751,000	$21,751,000
Gas Interconnect & Reinforcement	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep	$2,704,000	$2,826,000	$2,327,000	$2,762,000	$2,762,000	$2,886,000	$2,377,000
Engineering & Design	$4,930,000	$5,437,000	$5,437,000	$4,930,000	$5,437,000	$4,930,000	$5,437,000
Construction Mgmt. / Field Engr.	$2,072,000	$2,384,000	$2,384,000	$2,072,000	$2,384,000	$2,072,000	$2,384,000
Subtotal	$103,648,000	$109,196,000	$110,501,000	$81,867,000	$86,665,000	$92,586,000	$96,568,000
Startup & Testing							
Startup & Training	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Testing							
Subtotal	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Contingency	$9,269,000	$10,769,000	$10,891,000	$8,669,000	$10,123,000	$8,521,000	$9,953,000
Subtotal - EPC Costs	$178,177,000	$200,573,000	$202,000,000	$155,796,000	$177,396,000	$166,367,000	$187,129,000
Non-EPC Cost Components							
Owner's Costs							
Permitting	$1,782,000	$2,006,000	$2,020,000	$1,558,000	$1,774,000	$1,664,000	$1,871,000
Legal	$1,782,000	$2,006,000	$2,020,000	$1,558,000	$1,774,000	$1,664,000	$1,871,000
Owner's Project Mgmt. & Misc. Engr.	$2,673,000	$3,009,000	$3,030,000	$2,337,000	$2,661,000	$2,496,000	$2,807,000
Fuel Oil Testing	$0	$0	$0	$0	$0	$0	$0
Social Justice	$356,000	$401,000	$404,000	$312,000	$355,000	$333,000	$374,000
Owner's Development Costs	$5,345,000	$6,017,000	$6,060,000	$4,674,000	$5,322,000	$4,991,000	$5,614,000
Financing Fees	$3,564,000	$4,011,000	$4,040,000	$3,116,000	$3,548,000	$3,327,000	$3,743,000
Studies (Fin, Env, Market, Interconnect)	$891,000	$1,003,000	$1,010,000	$779,000	$887,000	$832,000	$936,000
Emission Reduction Credits	$0	$0	$270,000	$0	$0	$0	$0
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0	$0
Subtotal	$16,393,000	$18,453,000	$18,854,000	$14,334,000	$16,321,000	$15,307,000	$17,216,000
Financing (incl. AFUDC, IDC)							
EPC Portion	$12,409,000	$13,969,000	$14,068,000	$10,850,000	$12,355,000	$11,587,000	$13,033,000
Non-EPC Portion	$1,142,000	$1,285,000	$1,313,000	$998,000	$1,137,000	$1,066,000	$1,199,000
Working Capital and Non-Fuel Inventories	$1,782,000	$2,006,000	$2,020,000	$1,558,000	$1,774,000	$1,664,000	$1,871,000
Fuel Inventory	$0	$0	$0	$0	$0	$0	$0
Subtotal - Non-EPC Costs	$31,726,000	$35,713,000	$36,255,000	$27,740,000	$31,587,000	$29,624,000	$33,319,000
Total Capital Investment	**$209,903,000**	**$236,286,000**	**$238,255,000**	**$183,536,000**	**$208,983,000**	**$195,991,000**	**$220,448,000**

1x0 GE 7HA.02, Gas Only, with SCR/CO Catalyst

	1x0 GE 7HA.02, Gas Only, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment			$117,833,000	$117,833,000	$117,833,000	$117,833,000
Spare Parts			$665,000	$665,000	$665,000	$665,000
Subtotal			$118,498,000	$118,498,000	$118,498,000	$118,498,000
Construction						
Construction Labor & Materials			$68,369,000	$70,203,000	$57,870,000	$55,165,000
Plant Switchyard			$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability			$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement			$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep			$4,093,000	$4,271,000	$2,686,000	$2,559,000
Engineering & Design			$5,338,000	$5,338,000	$5,338,000	$5,338,000
Construction Mgmt. / Field Engr.			$3,189,000	$3,189,000	$3,189,000	$3,189,000
Subtotal			$123,413,000	$125,660,000	$97,595,000	$107,290,000
Startup & Testing						
Startup & Training			$2,350,000	$2,350,000	$2,350,000	$2,350,000
Testing						
Subtotal			$2,350,000	$2,350,000	$2,350,000	$2,350,000
Contingency			$14,690,000	$14,835,000	$13,828,000	$13,624,000
Subtotal - EPC Costs			$258,951,000	$261,343,000	$232,271,000	$241,762,000
Non-EPC Cost Components						
Owner's Costs						
Permitting			$2,590,000	$2,613,000	$2,323,000	$2,418,000
Legal			$2,590,000	$2,613,000	$2,323,000	$2,418,000
Owner's Project Mgmt. & Misc. Engr.			$3,884,000	$3,920,000	$3,484,000	$3,626,000
Fuel Oil Testing			$0	$0	$0	$0
Social Justice			$518,000	$523,000	$465,000	$484,000
Owner's Development Costs			$7,769,000	$7,840,000	$6,968,000	$7,253,000
Financing Fees			$5,179,000	$5,227,000	$4,645,000	$4,835,000
Studies (Fin, Env, Market, Interconnect)			$1,295,000	$1,307,000	$1,161,000	$1,209,000
Emission Reduction Credits			$0	$374,000	$0	$0
System Deliverability Upgrade Costs			$0	$0	$0	$0
Subtotal			$23,825,000	$24,417,000	$21,369,000	$22,243,000
Financing (incl. AFUDC, IDC)						
EPC Portion			$18,035,000	$18,201,000	$16,176,000	$16,837,000
Non-EPC Portion			$1,659,000	$1,701,000	$1,488,000	$1,549,000
Working Capital and Non-Fuel Inventories			$2,590,000	$2,613,000	$2,323,000	$2,418,000
Fuel Inventory			$0	$0	$0	$0
Subtotal - Non-EPC Costs			$46,109,000	$46,932,000	$41,356,000	$43,047,000
Total Capital Investment			**$305,060,000**	**$308,275,000**	**$273,627,000**	**$284,809,000**

12x0 Wartsila 18V50SG, Gas Only, with SCR/CO Catalyst

	12x0 Wartsila 18V50SG, Gas Only, with SCR/CO Catalyst					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment			$110,125,000	$110,125,000	$110,125,000	$110,125,000
Spare Parts			$2,235,000	$2,235,000	$2,235,000	$2,235,000
Subtotal			$112,360,000	$112,360,000	$112,360,000	$112,360,000
Construction						
Construction Labor & Materials			$114,275,000	$116,108,000	$100,433,000	$96,747,000
Plant Switchyard			$7,549,000	$7,578,000	$3,862,000	$7,376,000
Electrical Interconnection & Deliverability			$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement			$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep			$3,459,000	$3,614,000	$2,908,000	$3,717,000
Engineering & Design			$5,400,000	$5,400,000	$5,400,000	$5,400,000
Construction Mgmt. / Field Engr.			$1,762,000	$1,763,000	$1,762,000	$1,762,000
Subtotal			$171,095,000	$173,333,000	$140,946,000	$152,353,000
Startup & Testing						
Startup & Training			$1,574,000	$1,574,000	$1,574,000	$1,574,000
Testing						
Subtotal			$1,574,000	$1,574,000	$1,574,000	$1,574,000
Contingency			$17,241,000	$17,385,000	$16,202,000	$15,994,000
Subtotal - EPC Costs			$302,270,000	$304,652,000	$271,082,000	$282,281,000
Non-EPC Cost Components						
Owner's Costs						
Permitting			$3,023,000	$3,047,000	$2,711,000	$2,823,000
Legal			$3,023,000	$3,047,000	$2,711,000	$2,823,000
Owner's Project Mgmt. & Misc. Engr.			$4,534,000	$4,570,000	$4,066,000	$4,234,000
Fuel Oil Testing			$0	$0	$0	$0
Social Justice			$605,000	$609,000	$542,000	$565,000
Owner's Development Costs			$9,068,000	$9,140,000	$8,132,000	$8,468,000
Financing Fees			$6,045,000	$6,093,000	$5,422,000	$5,646,000
Studies (Fin, Env, Market, Interconnect)			$1,511,000	$1,523,000	$1,355,000	$1,411,000
Emission Reduction Credits			$174,000	$530,000	$174,000	$174,000
System Deliverability Upgrade Costs			$0	$0	$0	$0
Subtotal			$27,983,000	$28,559,000	$25,113,000	$26,144,000
Financing (incl. AFUDC, IDC)						
EPC Portion			$20,681,000	$20,844,000	$18,547,000	$19,314,000
Non-EPC Portion			$1,915,000	$1,954,000	$1,718,000	$1,789,000
Working Capital and Non-Fuel Inventories			$3,023,000	$3,047,000	$2,711,000	$2,823,000
Fuel Inventory			$0	$0	$0	$0
Subtotal - Non-EPC Costs			$53,602,000	$54,404,000	$48,089,000	$50,070,000
Total Capital Investment			**$355,872,000**	**$359,056,000**	**$319,171,000**	**$332,351,000**

1x1x1 Siemens 5000F5 CC, Gas Only

	1x1x1 Siemens 5000F5 CC, Gas Only					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment			$149,105,000	$149,105,000	$149,105,000	$134,245,000
Spare Parts			$1,875,000	$1,875,000	$1,875,000	$1,875,000
Subtotal			$150,980,000	$150,980,000	$150,980,000	$136,120,000
Construction						
Construction Labor & Materials			$216,127,000	$221,447,000	$181,614,000	$166,455,000
Plant Switchyard			$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability			$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement			$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep			$6,325,000	$6,609,000	$5,541,000	$5,571,000
Engineering & Design			$26,000,000	$26,000,000	$26,000,000	$26,000,000
Construction Mgmt. / Field Engr.			$7,836,000	$7,836,000	$7,836,000	$7,255,000
Subtotal			$298,712,000	$304,551,000	$249,503,000	$246,320,000
Startup & Testing						
Startup & Training			$6,890,000	$6,890,000	$6,890,000	$6,890,000
Testing						
Subtotal			$6,890,000	$6,890,000	$6,890,000	$6,890,000
Contingency			$30,224,000	$30,629,000	$27,675,000	$25,468,000
Subtotal - EPC Costs			$486,806,000	$493,050,000	$435,048,000	$414,798,000
Non-EPC Cost Components						
Owner's Costs						
Permitting			$4,868,000	$4,931,000	$4,350,000	$4,148,000
Legal			$4,868,000	$4,931,000	$4,350,000	$4,148,000
Owner's Project Mgmt. & Misc. Engr.			$7,302,000	$7,396,000	$6,526,000	$6,222,000
Fuel Oil Testing			$0	$0	$0	$0
Social Justice			$974,000	$986,000	$870,000	$830,000
Owner's Development Costs			$14,604,000	$14,792,000	$13,051,000	$12,444,000
Financing Fees			$9,736,000	$9,861,000	$8,701,000	$8,296,000
Studies (Fin, Env, Market, Interconnect)			$2,434,000	$2,465,000	$2,175,000	$2,074,000
Emission Reduction Credits			$0	$494,000	$0	$0
System Deliverability Upgrade Costs			$0	$0	$0	$0
Subtotal			$44,786,000	$45,856,000	$40,023,000	$38,162,000
Financing (incl. AFUDC, IDC)						
EPC Portion			$39,836,000	$40,347,000	$35,601,000	$33,944,000
Non-EPC Portion			$3,665,000	$3,752,000	$3,275,000	$3,123,000
Working Capital and Non-Fuel Inventories			$4,868,000	$4,931,000	$4,350,000	$4,148,000
Fuel Inventory			$0	$0	$0	$0
Subtotal - Non-EPC Costs			$93,155,000	$94,886,000	$83,249,000	$79,377,000
Total Capital Investment			**$579,961,000**	**$587,936,000**	**$518,297,000**	**$494,175,000**

1x1x1 Siemens 8000H CC, Gas Only

	1x1x1 Siemens 8000H CC, Gas Only					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment			$163,865,000	$163,865,000	$163,865,000	$147,469,000
Spare Parts			$1,948,000	$1,948,000	$1,948,000	$1,948,000
Subtotal			$165,813,000	$165,813,000	$165,813,000	$149,417,000
Construction						
Construction Labor & Materials			$225,461,000	$231,888,000	$189,482,000	$173,189,000
Plant Switchyard			$3,774,000	$3,789,000	$1,931,000	$3,688,000
Electrical Interconnection & Deliverability			$23,050,000	$23,270,000	$10,981,000	$21,751,000
Gas Interconnect & Reinforcement			$15,600,000	$15,600,000	$15,600,000	$15,600,000
Site Prep			$6,957,000	$7,269,000	$6,096,000	$6,128,000
Engineering & Design			$26,000,000	$26,000,000	$26,000,000	$26,000,000
Construction Mgmt. / Field Engr.			$7,975,000	$7,975,000	$7,975,000	$7,334,000
Subtotal			$308,817,000	$315,791,000	$258,065,000	$253,690,000
Startup & Testing						
Startup & Training			$6,990,000	$6,990,000	$6,990,000	$6,990,000
Testing						
Subtotal			$6,990,000	$6,990,000	$6,990,000	$6,990,000
Contingency			$32,072,000	$32,559,000	$29,411,000	$27,007,000
Subtotal - EPC Costs			$513,692,000	$521,153,000	$460,279,000	$437,104,000
Non-EPC Cost Components						
Owner's Costs						
Permitting			$5,137,000	$5,212,000	$4,603,000	$4,371,000
Legal			$5,137,000	$5,212,000	$4,603,000	$4,371,000
Owner's Project Mgmt. & Misc. Engr.			$7,705,000	$7,817,000	$6,904,000	$6,557,000
Fuel Oil Testing			$0	$0	$0	$0
Social Justice			$1,027,000	$1,042,000	$921,000	$874,000
Owner's Development Costs			$15,411,000	$15,635,000	$13,808,000	$13,113,000
Financing Fees			$10,274,000	$10,423,000	$9,206,000	$8,742,000
Studies (Fin, Env, Market, Interconnect)			$2,568,000	$2,606,000	$2,301,000	$2,186,000
Emission Reduction Credits			$0	$494,000	$0	$0
System Deliverability Upgrade Costs			$0	$0	$0	$0
Subtotal			$47,259,000	$48,441,000	$42,346,000	$40,214,000
Financing (incl. AFUDC, IDC)						
EPC Portion			$42,036,000	$42,647,000	$37,666,000	$35,769,000
Non-EPC Portion			$3,867,000	$3,964,000	$3,465,000	$3,291,000
Working Capital and Non-Fuel Inventories			$5,137,000	$5,212,000	$4,603,000	$4,371,000
Fuel Inventory			$0	$0	$0	$0
Subtotal - Non-EPC Costs			$98,299,000	$100,264,000	$88,080,000	$83,645,000
Total Capital Investment			**$611,991,000**	**$621,417,000**	**$548,359,000**	**$520,749,000**

Fixed and Variable O&M Costs

Gas Only

2x0 LMS100PA+, Gas Only

Fixed and Variable O&M Cost Estimates	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	2x0 LMS100PA+, Gas Only					
	Fixed O&M ($/year)					
Staffing (note 1)			5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M			$1,524,000	$1,556,000	$1,162,000	$1,076,000
Material and Contract Services			$734,000	$719,000	$710,000	$703,000
Fuel Oil Testing			$0	$0	$0	$0
Adminstrative and General			incl	incl	incl	incl
Subtotal Fixed O&M			$2,258,000	$2,275,000	$1,872,000	$1,779,000
$/kW-year			**$12.0**	**$12.1**	**$10.0**	**$9.6**
Other Fixed Costs						
Site Leasing Costs			$117,000	$117,000	$117,000	$117,000
Total Fixed O&M without tax and insurance			$2,375,000	$2,392,000	$1,989,000	$1,896,000
$/kW-year			**$12.6**	**$12.7**	**$10.6**	**$10.2**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts			$2.84	$2.84	$2.84	$2.84
Major Maintenance Labor			$0.42	$0.44	$0.33	$0.31
Unscheduled Maintenance			incl	incl	incl	incl
SCR Catalyst and Ammonia			$0.53	$0.53	$0.53	$0.53
CO Oxidation Catalyst			$0.11	$0.11	$0.11	$0.11
Other Chemicals and Consumables			$0.07	$0.07	$0.07	$0.07
Water			$1.51	$1.51	$1.51	$1.51
Total Variable O&M ($/MWh)			**$5.5**	**$5.5**	**$5.4**	**$5.4**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts			na	na	na	na
Major Maintenace Labor			na	na	na	na
Total ($/factored start)			na	na	na	na

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

1x0 Siemens 5000F5, Gas Only

Fixed and Variable O&M Cost Estimates	1x0 Siemens 5000F5, Gas Only						
	G - Hudson Valley (Dutchess)	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	F - Capital	C - Central	C - Central
	Fixed O&M ($/year)						
SCR (Yes/No)	**Yes**	**No**	**Yes**	**Yes**	**No**	**Yes**	**No**
Staffing (note 1)	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M	$1,524,000	$1,524,000	$1,556,000	$1,162,000	$1,162,000	$1,076,000	$1,076,000
Material and Contract Services	$866,000	$866,000	$849,000	$838,000	$838,000	$830,000	$830,000
Fuel Oil Testing	$0	$0	$0	$0	$0	$0	$0
Adminstrative and General	incl	incl	incl	incl	incl	incl	incl
Subtotal Fixed O&M	$2,390,000	$2,390,000	$2,405,000	$2,000,000	$2,000,000	$1,906,000	$1,906,000
$/kW-year	**$11.0**	**$11.0**	**$11.0**	**$9.2**	**$9.2**	**$8.8**	**$8.8**
Other Fixed Costs							
Site Leasing Costs	$196,000	$196,000	$196,000	$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance	$2,586,000	$2,586,000	$2,601,000	$2,196,000	$2,196,000	$2,102,000	$2,102,000
$/kW-year	**$11.9**	**$11.9**	**$11.9**	**$10.1**	**$10.1**	**$9.7**	**$9.7**
	Variable O&M ($/MWh)						
Natural Gas Variable O&M ($/MWh)							
Major Maintenance Parts	-	-	-	-	-	-	-
Major Maintenance Labor	-	-	-	-	-	-	-
Unscheduled Maintenance	-	-	-	-	-	-	-
SCR Catalyst and Ammonia	$0.49	-	$0.49	$0.49	-	$0.49	-
CO Oxidation Catalyst	$0.08	-	$0.08	$0.08	-	$0.08	-
Other Chemicals and Consumables	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Water	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12
Total Variable O&M ($/MWh)	**$0.76**	**$0.19**	**$0.76**	**$0.76**	**$0.19**	**$0.76**	**$0.19**
	Variable O&M (Cost per Start)						
Variable O&M - Cost per start							
Major Maintenace Parts	$9,200	$9,200	$9,200	$9,200	$9,200	$9,200	$9,200
Major Maintenace Labor	$1,300	$1,300	$1,400	$1,100	$1,100	$1,000	$1,000
Total ($/factored start through first major)	**$10,500**	**$10,500**	**$10,600**	**$10,300**	**$10,300**	**$10,200**	**$10,200**

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

1x0 GE 7HA.02, Gas Only

Fixed and Variable O&M Cost Estimates	1x0 GE 7HA.02, Gas Only					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)			5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/	5op/3maint + supv/Admin/
Labor - Routine O&M			$1,524,000	$1,556,000	$1,162,000	$1,076,000
Material and Contract Services			$1,236,000	$1,211,000	$1,195,000	$1,183,000
Fuel Oil Testing			$0	$0	$0	$0
Adminstrative and General			incl	incl	incl	incl
Subtotal Fixed O&M			$2,760,000	$2,767,000	$2,357,000	$2,259,000
$/kW-year			**$8.7**	**$8.7**	**$7.5**	**$7.2**
Other Fixed Costs						
Site Leasing Costs			$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance			$2,956,000	$2,963,000	$2,553,000	$2,455,000
$/kW-year			**$9.3**	**$9.4**	**$8.1**	**$7.8**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts			-	-	-	-
Major Maintenance Labor			-	-	-	-
Unscheduled Maintenance			-	-	-	-
SCR Catalyst and Ammonia			$0.62	$0.62	$0.62	$0.62
CO Oxidation Catalyst			$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables			$0.07	$0.07	$0.07	$0.07
Water			$0.25	$0.25	$0.25	$0.25
Total Variable O&M ($/MWh)			**$1.0**	**$1.0**	**$1.0**	**$1.0**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts			$14,200	$14,200	$14,200	$14,200
Major Maintenace Labor			$2,000	$2,100	$1,600	$1,500
Total ($/factored start through first major)			**$16,200**	**$16,300**	**$15,800**	**$15,700**

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

12x0 Wartsila 18V50SG, Gas Only

Fixed and Variable O&M Cost Estimates	12x0 Wartsila 18V50SG, Gas Only					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing (note 1)			6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin	6 op/6 maint + Supv/Admin
Labor - Routine O&M			$3,176,000	$3,241,000	$2,420,000	$2,241,000
Material and Contract Services			$318,000	$311,000	$307,000	$304,000
Fuel Oil Testing			$0	$0	$0	$0
Adminstrative and General			incl	incl	incl	incl
Subtotal Fixed O&M			$3,494,000	$3,552,000	$2,727,000	$2,545,000
$/kW-year			**$15.8**	**$16.1**	**$12.4**	**$11.5**
Other Fixed Costs						
Site Leasing Costs			$196,000	$196,000	$196,000	$196,000
Total Fixed O&M without tax and insurance			$3,690,000	$3,748,000	$2,923,000	$2,741,000
$/kW-year			**$16.7**	**$17.0**	**$13.2**	**$12.4**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts			$4.39	$4.39	$4.39	$4.39
Major Maintenance Labor			$1.05	$1.10	$0.83	$0.77
Unscheduled Maintenance			incl	incl	incl	incl
SCR Ammonia (note 2)			$1.16	$1.16	$1.16	$1.16
CO Oxidation Catalyst			$0.13	$0.13	$0.13	$0.13
Lube Oil			$1.07	$1.07	$1.07	$1.07
Miscellaneous			$0.10	$0.10	$0.10	$0.10
Total Variable O&M ($/MWh)			**$7.9**	**$8.0**	**$7.7**	**$7.6**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenace Parts			na	na	na	na
Major Maintenace Labor			na	na	na	na
Total ($/factored start)			na	na	na	na

Note 1: staffing in Zones G, F & C could be reduced if call in staffing for nights & weekend is acceptable

Note 2: SCR catalyst replacement cost included in major maintenance

1x1x1 5000F 5 Combined Cycle Plant, Gas Only

Fixed and Variable O&M Cost Estimates	1x1x1 5000F5 Combined Cycle Plant, Gas Only					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing			12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin
Labor - Routine O&M			$3,252,000	$3,318,000	$2,479,000	$2,295,000
Material and Contract Services			$2,429,000	$2,380,000	$2,349,000	$2,326,000
Fuel Oil Testing			$0	$0	$0	$0
Adminstrative and General			$698,000	$705,000	$639,000	$606,000
Subtotal Fixed O&M			$6,379,000	$6,403,000	$5,467,000	$5,227,000
$/kW-year			**$19.5**	**$19.6**	**$16.8**	**$15.9**
Other Fixed Costs						
Site Leasing Costs			$392,000	$392,000	$392,000	$392,000
Total Fixed O&M without tax and insurance			$6,771,000	$6,795,000	$5,859,000	$5,619,000
$/kW-year			**$20.7**	**$20.7**	**$18.0**	**$17.1**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts			$0.62	$0.62	$0.62	$0.62
Major Maintenance Labor			$0.15	$0.16	$0.12	$0.11
Unscheduled Maintenance			incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia			$0.08	$0.08	$0.08	$0.08
CO Oxidation Catalyst			$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables			$0.07	$0.07	$0.07	$0.07
Water			$0.01	$0.01	$0.01	$0.29
Total Variable O&M ($/MWh)			**$1.0**	**$1.0**	**$1.0**	**$1.3**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenance Parts			$9,200	$9,200	$9,200	$9,200
Major Maintenance Labor			$1,300	$1,400	$1,100	$1,000
Total ($/factored start through first major)			**$10,500**	**$10,600**	**$10,300**	**$10,200**

1x1x1 8000H Combined Cycle Plant, Gas Only

Fixed and Variable O&M Cost Estimates	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
	Fixed O&M ($/year)					
Staffing			12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin	12op/4 maint + supv/Admin
Labor - Routine O&M			$3,252,000	$3,318,000	$2,479,000	$2,295,000
Material and Contract Services			$2,506,000	$2,456,000	$2,424,000	$2,400,000
Fuel Oil Testing			$0	$0	$0	$0
Adminstrative and General			$730,000	$737,000	$670,000	$655,000
Subtotal Fixed O&M			$6,488,000	$6,511,000	$5,573,000	$5,350,000
$/kW-year			**$17.0**	**$17.0**	**$14.6**	**$13.9**
Other Fixed Costs						
Site Leasing Costs			$392,000	$392,000	$392,000	$392,000
Total Fixed O&M without tax and insurance			$6,880,000	$6,903,000	$5,965,000	$5,742,000
$/kW-year			**$18.0**	**$18.0**	**$15.7**	**$14.9**
	Variable O&M ($/MWh)					
Natural Gas Variable O&M ($/MWh)						
Major Maintenance Parts			$0.51	$0.51	$0.51	$0.51
Major Maintenance Labor			$0.13	$0.13	$0.10	$0.09
Unscheduled Maintenance			incl above	incl above	incl above	incl above
SCR Catalyst and Ammonia			$0.19	$0.19	$0.19	$0.19
CO Oxidation Catalyst			$0.08	$0.08	$0.08	$0.08
Other Chemicals and Consumables			$0.07	$0.07	$0.07	$0.07
Water			$0.01	$0.01	$0.01	$0.28
Total Variable O&M ($/MWh)			**$1.0**	**$1.0**	**$1.0**	**$1.2**
	Variable O&M (Cost per Start)					
Variable O&M - Cost per start						
Major Maintenance Parts			$13,900	$13,900	$13,900	$13,900
Major Maintenance Labor			$2,000	$2,100	$1,600	$1,500
Total ($/factored start through first major)			**$15,900**	**$16,000**	**$15,500**	**$15,400**

Performance Data

2x0 GE LMS100PA+, Dual Fuel All Zones

		2x0 LMS100PA+ Dual Fuel All Zones					
Item	**Units**	**K - Long Island**	**J - NYC**	**G - LHV (Dutchess)**	**G - LHV (Rockland)**	**F - Capital**	**C - Central**
Performance Values (per unit)							
Net Plant Capacity, Degraded							
Net Plant Capacity - Summer	MW	102	101	101	101	101	101
Net Plant Capacity - Winter	MW	109	109	109	109	109	108
DMNC Summer	MW	96.8	96.1	96.4	96.8	95.8	95.8
DMNC Winter	MW	109	109	109	109	108	108
ICAP	MW	94.4	93.8	93.9	93.9	93.5	92.9
Net Plant Heat Rate (HHV basis), Degraded							
Net Plant Heat Rate - Summer	Btu/kWh	9,130	9,200	9,160	9,170	9,140	9,120
Net Plant Heat Rate - Winter	Btu/kWh	8,980	9,040	8,990	8,990	8,980	8,980
Net Plant Heat Rate - DMNC Summer	Btu/kWh	9,240	9,280	9,210	9,220	9,230	9,210
Net Plant Heat Rate - DMNC Winter	Btu/kWh	8,980	9,040	8,990	8,990	8,990	8,990
Net Plant Heat Rate - ICAP	Btu/kWh	9,260	9,320	9,260	9,260	9,260	9,260
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	8.3	8.3	8.2	8.2	8.2	8.2
SO_2 Emissions Rate	lb/hr	2.0	2.0	2.0	2.0	2.0	2.0
CO_2 Emissions Rate	lb/hr	109,000	108,000	108,000	108,000	108,000	108,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	8.7	8.7	8.7	8.7	8.7	8.6
SO_2 Emissions Rate	lb/hr	2.2	2.2	2.2	2.2	2.1	2.1
CO_2 Emissions Rate	lb/hr	115,000	115,000	115,000	114,000	114,000	114,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	19.0	19.0	18.9	18.9	18.8	18.7
SO_2 Emissions Rate	lb/hr	1.5	1.5	1.5	1.5	1.5	1.5
CO_2 Emissions Rate	lb/hr	160,000	160,000	160,000	159,000	159,000	158,000
Other Performance Values (per unit)							
Fuel Required per Start	MMBtu/Start	61	61	61	61	61	61
Can startup in time for 10-minute non-spinning reserve?	Yes/No	Yes	Yes	Yes	Yes	Yes	Yes
EFORd outage rate	%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%

1x0 Siemens SGT6-5000F5, Dual Fuel All Zones

Item	Units	1x0 Siemens 5000F5, Dual Fuel All Zones					
		K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)		note: Siemens 5000F5 is designed to minimize ambient temperature impact on output; machine reaches mechanical limit at 59F- lower ambient temerature does not increase output					
Net Plant Capacity, Degraded							
Net Plant Capacity - Summer	MW	230	229	230	230	230	230
Net Plant Capacity - Winter	MW	230	229	230	230	230	230
DMNC Summer	MW	225	227	227	226	225	224
DMNC Winter	MW	230	229	230	230	230	230
ICAP	MW	219	218	218	218	217	216
Net Plant Heat Rate (HHV basis), Degraded							
Net Plant Heat Rate - Summer	Btu/kWh	10,180	10,230	10,190	10,190	10,180	10,190
Net Plant Heat Rate - Winter	Btu/kWh	10,040	10,110	10,030	10,030	10,020	10,010
Net Plant Heat Rate - DMNC Summer	Btu/kWh	10,280	10,310	10,240	10,250	10,260	10,250
Net Plant Heat Rate - DMNC Winter	Btu/kWh	10,050	10,110	10,040	10,040	10,040	10,030
Net Plant Heat Rate - ICAP	Btu/kWh	10,310	10,380	10,300	10,300	10,310	10,310
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	20.9	20.9	20.9	20.9	20.9	20.9
SO_2 Emissions Rate	lb/hr	5.2	5.2	5.2	5.2	5.2	5.2
CO_2 Emissions Rate	lb/hr	274,000	274,000	275,000	275,000	274,000	275,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	20.6	20.6	20.6	20.6	20.5	20.5
SO_2 Emissions Rate	lb/hr	5.1	5.1	5.1	5.1	5.1	5.1
CO_2 Emissions Rate	lb/hr	271,000	271,000	270,000	270,000	270,000	270,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	44.6	44.6	44.6	44.6	44.5	44.5
SO_2 Emissions Rate	lb/hr	3.5	3.5	3.5	3.5	3.5	3.5
CO_2 Emissions Rate	lb/hr	377,000	377,000	376,000	376,000	376,000	376,000
Other Performance Values (per unit)							
Fuel Required per Start (fast start - 11 min. full load)	MMBtu/Start	160	160	160	160	160	160
Fuel Required per Start (regular start - 28 min. to full load)	MMBtu/Start	350	350	350	350	350	350
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%

1x0 GE 7HA.02, Dual Fuel All Zones

Item	Units	1x0 GE, 7HA02 Dual Fuel All Zones					
		K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)							
Net Plant Capacity, Degraded							
Net Plant Capacity - Summer	MW	328	326	326	326	325	323
Net Plant Capacity - Winter	MW	341	338	339	339	339	337
DMNC Summer	MW	326	314	318	322	321	322
DMNC Winter	MW	344	341	342	342	341	339
ICAP	MW	318	316	316	316	315	313
Net Plant Heat Rate (HHV basis), Degraded							
Net Plant Heat Rate - Summer	Btu/kWh	9,360	9,410	9,360	9,360	9,350	9,350
Net Plant Heat Rate - Winter	Btu/kWh	9,200	9,260	9,190	9,190	9,180	9,180
Net Plant Heat Rate - DMNC Summer	Btu/kWh	9,420	9,450	9,400	9,400	9,410	9,390
Net Plant Heat Rate - DMNC Winter	Btu/kWh	9,140	9,210	9,140	9,130	9,130	9,130
Net Plant Heat Rate - ICAP	Btu/kWh	9,570	9,620	9,570	9,570	9,570	9,570
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	27.3	27.3	27.2	27.2	27.0	26.9
SO_2 Emissions Rate	lb/hr	6.7	6.7	6.7	6.7	6.7	6.7
CO_2 Emissions Rate	lb/hr	359,000	359,000	357,000	357,000	356,000	354,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	27.9	27.9	27.8	27.8	27.7	27.5
SO_2 Emissions Rate	lb/hr	6.9	6.9	6.9	6.9	6.8	6.8
CO_2 Emissions Rate	lb/hr	367,000	367,000	365,000	365,000	364,000	362,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	60.5	60.5	60.2	60.2	60.0	59.7
SO_2 Emissions Rate	lb/hr	4.7	4.7	4.7	4.7	4.7	4.6
CO_2 Emissions Rate	lb/hr	511,000	511,000	508,000	508,000	507,000	504,000
Other Performance Values (per unit)							
Fuel Required per Start (fast start - 10 min. full load)	MMBtu/Start	204	204	204	204	204	204
Fuel Required per Start (regular start - 21 min. to full load)	MMBtu/Start	391	391	391	391	391	391
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%

12x0 Wartsila 18V50DF, Dual Fuel All Zones

		12x0 Wartsila 18V50DF, Dual Fuel All Zones					
Item	**Units**	**K - Long Island**	**J - NYC**	**G - LHV (Dutchess)**	**G - LHV (Rockland)**	**F - Capital**	**C - Central**
Performance Values (per unit)							
Net Plant Capacity (no degradation)							
Net Plant Capacity - Summer	MW	16.7	16.7	16.7	16.7	16.7	16.7
Net Plant Capacity - Winter	MW	16.8	16.8	16.8	16.8	16.8	16.8
DMNC Summer	MW	16.7	16.7	16.7	16.7	16.7	16.7
DMNC Winter	MW	16.8	16.8	16.8	16.8	16.8	16.8
ICAP	MW	16.7	16.7	16.7	16.7	16.7	16.7
Net Plant Heat Rate (HHV basis), Degraded							
Net Plant Heat Rate - Summer	Btu/kWh	8,410	8,410	8,410	8,410	8,410	8,410
Net Plant Heat Rate - Winter	Btu/kWh	8,350	8,350	8,350	8,350	8,350	8,350
Net Plant Heat Rate - DMNC Summer	Btu/kWh	8,410	8,410	8,410	8,410	8,410	8,410
Net Plant Heat Rate - DMNC Winter	Btu/kWh	8,350	8,350	8,350	8,350	8,350	8,350
Net Plant Heat Rate - ICAP	Btu/kWh	8,380	8,380	8,380	8,380	8,380	8,380
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	2.0	2.0	2.0	2.0	2.0	2.0
SO_2 Emissions Rate	lb/hr	0.3	0.3	0.3	0.3	0.3	0.3
CO_2 Emissions Rate	lb/hr	16,400	16,400	16,400	16,400	16,400	16,400
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	2.0	2.0	2.0	2.0	2.0	2.0
SO_2 Emissions Rate	lb/hr	0.31	0.31	0.31	0.31	0.31	0.31
CO_2 Emissions Rate	lb/hr	16,400	16,400	16,400	16,400	16,400	16,400
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	11.2	11.2	11.2	11.2	11.2	11.2
SO_2 Emissions Rate	lb/hr	0.21	0.21	0.21	0.21	0.21	0.21
CO_2 Emissions Rate	lb/hr	22,900	22,900	22,900	22,900	22,900	22,900
Other Performance Values (per unit)							
Fuel Required per Start	MMBtu/Start	7.5	7.5	7.5	7.5	7.5	7.5
Can startup in time for 10-minute non-spinning reserve?	Yes/No	Yes	Yes	Yes	Yes	Yes	Yes
EFORd outage rate	%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

12x0 Wartsila 18V50SG, Gas Only

Item	Units	12x0 Wartsila 18V50SG, Gas Only K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)							
Net Plant Capacity (no degradation)							
Net Plant Capacity - Summer	MW			18.4	18.4	18.4	18.4
Net Plant Capacity - Winter	MW			18.5	18.5	18.5	18.5
DMNC Summer	MW			18.4	18.4	18.4	18.4
DMNC Winter	MW			18.5	18.5	18.5	18.5
ICAP	MW			18.4	18.4	18.4	18.4
Net Plant Heat Rate (HHV basis), Degraded							
Net Plant Heat Rate - Summer	Btu/kWh			8,330	8,330	8,330	8,330
Net Plant Heat Rate - Winter	Btu/kWh			8,280	8,280	8,280	8,280
Net Plant Heat Rate - DMNC Summer	Btu/kWh			8,330	8,330	8,330	8,330
Net Plant Heat Rate - DMNC Winter	Btu/kWh			8,280	8,280	8,280	8,280
Net Plant Heat Rate - ICAP	Btu/kWh			8,330	8,330	8,330	8,330
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr			1.3	1.3	1.3	1.3
SO_2 Emissions Rate	lb/hr			0.3	0.3	0.3	0.3
CO_2 Emissions Rate	lb/hr			17,900	17,900	17,900	17,900
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr			1.3	1.3	1.3	1.3
SO_2 Emissions Rate	lb/hr			0.34	0.34	0.34	0.34
CO_2 Emissions Rate	lb/hr			17,900	17,900	17,900	17,900
Other Performance Values (per unit)							
Fuel Required per Start	MMBtu/Start			7.5	7.5	7.5	7.5
Can startup in time for 10-minute non-spinning reserve?	Yes/No			Yes	Yes	Yes	Yes
EFORd outage rate	%			1.0%	1.0%	1.0%	1.0%

1x1x1 Siemens STG6-5000F5 CC, Dual Fuel All Zones

Item	Units	1x1x1 5000F5 CC, Unfired					
		K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)							
Net Plant Capacity							
Net Plant Capacity - Summer	MW	344	342	341	342	342	342
Net Plant Capacity - Winter	MW	343	341	342	342	341	341
DMNC Summer	MW	331	329	329	330	327	334
DMNC Winter	MW	341	340	340	340	340	340
ICAP	MW	329	328	327	327	326	329
Net Plant Heat Rate (HHV basis)							
Net Plant Heat Rate - Summer	Btu/kWh	6,820	6,880	6,840	6,830	6,820	6,790
Net Plant Heat Rate - Winter	Btu/kWh	6,760	6,780	6,760	6,760	6,770	6,770
Net Plant Heat Rate - DMNC Summer	Btu/kWh	6,930	7,040	6,990	6,960	6,970	6,810
Net Plant Heat Rate - DMNC Winter	Btu/kWh	6,790	6,810	6,790	6,800	6,800	6,800
Net Plant Heat Rate - ICAP	Btu/kWh	6,930	6,960	6,930	6,930	6,940	6,850
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	16.7	16.7	16.6	16.6	16.6	16.5
SO_2 Emissions Rate	lb/hr	5.2	5.2	5.1	5.1	5.1	5.1
CO_2 Emissions Rate	lb/hr	274,000	275,000	273,000	273,000	273,000	272,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	16.4	16.4	16.4	16.4	16.4	16.4
SO_2 Emissions Rate	lb/hr	5.1	5.1	5.1	5.1	5.1	5.1
CO_2 Emissions Rate	lb/hr	271,000	271,000	271,000	270,000	270,000	270,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	44.7	44.7	44.6	44.6	44.6	44.6
SO_2 Emissions Rate	lb/hr	3.5	3.5	3.5	3.5	3.5	3.5
CO_2 Emissions Rate	lb/hr	378,000	377,000	377,000	377,000	377,000	376,000
Other Performance Values (per unit)							
Fuel Required per Start (warm start)	MMBtu/Start	3,100	3,100	3,100	3,100	3,100	3,100
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%

1x1x1 Siemens SGT6-8000H CC, Dual Fuel All Zones

Item	Units	1x1x1 8000H CC, Unfired					
		K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)							
Net Plant Capacity							
Net Plant Capacity - Summer	MW	407	404	404	404	404	408
Net Plant Capacity - Winter	MW	435	431	434	434	434	438
DMNC Summer	MW	393	392	392	393	390	399
DMNC Winter	MW	442	440	442	442	441	447
ICAP	MW	385	383	383	383	381	385
Net Plant Heat Rate (HHV basis)							
Net Plant Heat Rate - Summer	Btu/kWh	6,660	6,720	6,670	6,670	6,660	6,570
Net Plant Heat Rate - Winter	Btu/kWh	6,610	6,640	6,620	6,620	6,630	6,550
Net Plant Heat Rate - DMNC Summer	Btu/kWh	6,750	6,830	6,790	6,770	6,780	6,600
Net Plant Heat Rate - DMNC Winter	Btu/kWh	6,650	6,670	6,650	6,650	6,660	6,590
Net Plant Heat Rate - ICAP	Btu/kWh	6,750	6,790	6,760	6,760	6,760	6,650
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	19.2	19.3	19.1	19.1	19.1	19.0
SO_2 Emissions Rate	lb/hr	6.0	6.0	5.9	5.9	5.9	5.9
CO_2 Emissions Rate	lb/hr	317,000	318,000	315,000	315,000	315,000	314,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	20.4	20.3	20.4	20.4	20.4	20.3
SO_2 Emissions Rate	lb/hr	6.3	6.3	6.3	6.3	6.3	6.3
CO_2 Emissions Rate	lb/hr	336,000	335,000	336,000	336,000	337,000	335,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	55.4	55.3	55.4	55.5	55.6	55.3
SO_2 Emissions Rate	lb/hr	4.3	4.3	4.3	4.3	4.3	4.3
CO_2 Emissions Rate	lb/hr	468,000	467,000	468,000	468,000	469,000	467,000
Other Performance Values (per unit)							
Fuel Required per Start (warm start)	MMBtu/Start	4,000	4,000	4,000	4,000	4,000	4,000
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%

1x1x1 Siemens 5000F5 CC, With Duct Firing, Dual Fuel All Zones

Item	Units	1x1x1 5000F5 CC, with Duct Burners					
		K - Long Island	J - NYC	G - LHV (Dutchess)	G - LHV (Rockland)	F - Capital	C - Central
Performance Values (per unit)							
Net Plant Capacity							
Net Plant Capacity - Summer	MW	369	368	368	369	369	370
Net Plant Capacity - Winter	MW	375	373	374	374	374	373
DMNC Summer	MW	357	355	355	357	354	364
DMNC Winter	MW	374	372	374	374	374	373
ICAP	MW	361	354	354	354	353	350
Net Plant Heat Rate (HHV basis)							
Net Plant Heat Rate - Summer	Btu/kWh	6,970	7,020	6,980	6,970	6,970	6,930
Net Plant Heat Rate - Winter	Btu/kWh	6,910	7,290	6,910	6,910	6,920	6,930
Net Plant Heat Rate - DMNC Summer	Btu/kWh	7,080	7,210	6,900	7,120	7,140	6,950
Net Plant Heat Rate - DMNC Winter	Btu/kWh	6,940	7,310	6,950	6,950	6,960	6,970
Net Plant Heat Rate - ICAP	Btu/kWh	6,980	7,120	7,090	7,090	7,090	7,130
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	18.3	18.4	18.2	18.2	18.3	18.2
SO_2 Emissions Rate	lb/hr	5.7	5.7	5.7	5.7	5.7	5.6
CO_2 Emissions Rate	lb/hr	301,000	302,000	301,000	301,000	301,000	300,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	18.4	19.3	18.4	18.4	18.4	18.4
SO_2 Emissions Rate	lb/hr	5.7	6.0	5.7	5.7	5.7	5.7
CO_2 Emissions Rate	lb/hr	303,000	318,000	303,000	303,000	303,000	302,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	50.0	52.5	49.9	49.9	50.0	49.9
SO_2 Emissions Rate	lb/hr	3.9	4.1	3.9	3.9	3.9	3.9
CO_2 Emissions Rate	lb/hr	422,000	443,000	422,000	422,000	422,000	421,000
Other Performance Values (per unit)							
Fuel Required per Start	MMBtu/Start	3,100	3,100	3,100	3,100	3,100	3,100
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%

1x1x1 Siemens 8000H CC, With Duct Firing, Dual Fuel All Zones

		1x1x1 8000H CC, with Duct Burners					
Item	**Units**	**K - Long Island**	**J - NYC**	**G - LHV (Dutchess)**	**G - LHV (Rockland)**	**F - Capital**	**C - Central**
Performance Values (per unit)							
Net Plant Capacity							
Net Plant Capacity - Summer	MW	450	447	447	448	448	454
Net Plant Capacity - Winter	MW	479	475	478	479	479	482
DMNC Summer	MW	436	434	435	435	433	446
DMNC Winter	MW	486	483	485	485	485	490
ICAP	MW	428	427	427	427	426	431
Net Plant Heat Rate (HHV basis)							
Net Plant Heat Rate - Summer	Btu/kWh	6,850	6,910	6,870	6,860	6,860	6,750
Net Plant Heat Rate - Winter	Btu/kWh	6,750	6,770	6,750	6,760	6,770	6,700
Net Plant Heat Rate - DMNC Summer	Btu/kWh	6,950	7,040	7,010	6,980	7,000	6,790
Net Plant Heat Rate - DMNC Winter	Btu/kWh	6,780	6,800	6,780	6,780	6,790	6,730
Net Plant Heat Rate - ICAP	Btu/kWh	6,990	7,000	6,990	6,990	6,990	6,890
Natural Gas Emission Rates - Summer							
NO_X Emissions Rate	lb/hr	21.9	21.9	21.8	21.8	21.8	21.8
SO_2 Emissions Rate	lb/hr	6.8	6.8	6.8	6.8	6.8	6.7
CO_2 Emissions Rate	lb/hr	361,000	361,000	359,000	359,000	360,000	359,000
Natural Gas Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	22.9	22.9	22.9	23.0	23.0	22.9
SO_2 Emissions Rate	lb/hr	7.1	7.1	7.1	7.1	7.1	7.1
CO_2 Emissions Rate	lb/hr	378,000	377,000	378,000	378,000	379,000	378,000
ULSD Emission Rates - Winter							
NO_X Emissions Rate	lb/hr	62.3	62.1	62.3	62.4	62.5	62.3
SO_2 Emissions Rate	lb/hr	4.8	4.8	4.8	4.9	4.9	4.8
CO_2 Emissions Rate	lb/hr	527,000	525,000	526,000	527,000	528,000	526,000
Other Performance Values (per unit)							
Fuel Required per Start	MMBtu/Start	4,000	4,000	4,000	4,000	4,000	4,000
Can startup in time for 10-minute non-spinning reserve?	Yes/No	No	No	No	No	No	No
EFORd outage rate	%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%

C. Financing Parameters

This appendix provides additional detail on the data presented in Section III.

The first table provides follow up detail on each debt issuance shown in Figure 6. The second figure includes additional detail on the data used to estimate the risk free rate within the CAPM model and Table 30.

Appendix C Table 1: Additional Detail on Cost of Debt for Independent Power Producers, by Issuance, 2010 – 2016

Company	Ticker	Maturity Type	Currency	Bloomberg Composite Rating	Bid Yield to Maturity	Issued Amount	Collateral Type	Issue Date	Maturity	Years to Maturity
Calpine Corp	CPN	CALLABLE	USD	BB	6.61	1,200,000,000	SR SECURED	1/14/2011	1/15/2023	12.0
Calpine Corp	CPN	CALLABLE	USD	BB	6.70	1,200,000,000	SR SECURED	1/14/2011	1/15/2023	12.0
Calpine Corp	CPN	CALLABLE	USD	BB	4.93	750,000,000	SR SECURED	10/31/2013	1/15/2022	8.2
Calpine Corp	CPN	CALLABLE	USD	BB	4.94	490,000,000	SR SECURED	10/31/2013	1/15/2024	10.2
Calpine Corp	CPN	CALLABLE	USD	BB	4.76	750,000,000	SR SECURED	10/31/2013	1/15/2022	8.2
Calpine Corp	CPN	CALLABLE	USD	BB	4.85	490,000,000	SR SECURED	10/31/2013	1/15/2024	10.2
Calpine Corp	CPN	CALLABLE	USD	B	5.33	1,250,000,000	SR UNSECURED	7/22/2014	1/15/2023	8.5
Calpine Corp	CPN	CALLABLE	USD	B	5.64	1,550,000,000	SR UNSECURED	7/22/2014	1/15/2025	10.5
Calpine Corp	CPN	CALLABLE	USD	B	5.42	650,000,000	SR UNSECURED	2/3/2015	2/1/2024	9.0
Talen Energy Supply LLC	TLN	CALLABLE	USD	B+	8.17	600,000,000	SR UNSECURED	1/22/2016	6/1/2025	9.4
Talen Energy Supply LLC	TLN	CALLABLE	USD	B+	9.93	712,415,000	SR UNSECURED	12/16/2011	12/15/2021	10.0
Talen Energy Supply LLC	TLN	CALLABLE	USD	B+	7.30	1,250,000,000	SR UNSECURED	7/10/2014	7/15/2019	5.0
Talen Energy Supply LLC	TLN	CALLABLE	USD	B+	7.21	1,250,000,000	SR UNSECURED	7/10/2014	7/15/2019	5.0
NRG Energy Inc	NRG	CALLABLE	USD	B+	6.82	1,000,000,000	COMPANY GUARNT	1/26/2015	5/1/2024	9.3
NRG Energy Inc	NRG	CALLABLE	USD	B+	6.80	1,100,000,000	COMPANY GUARNT	10/24/2014	7/15/2022	7.7
NRG Energy Inc	NRG	AT MATURITY	USD	B+	4.25	1,200,000,000	COMPANY GUARNT	11/7/2011	1/15/2018	6.2
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.07	1,200,000,000	COMPANY GUARNT	2/21/2012	5/15/2021	9.2
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.20	1,098,875,000	COMPANY GUARNT	4/18/2011	9/1/2020	9.4
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.18	990,000,000	COMPANY GUARNT	7/19/2013	3/15/2023	9.7
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.35	1,100,000,000	COMPANY GUARNT	8/20/2010	9/1/2020	10.0
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.35	1,100,000,000	COMPANY GUARNT	8/20/2010	9/1/2020	10.0
NRG Energy Inc	NRG	CALLABLE	USD	B+	7.35	1,100,000,000	COMPANY GUARNT	8/20/2010	9/1/2020	10.0
Dynegy Inc	DYN	CALLABLE	USD	B	7.78	500,000,000	COMPANY GUARNT	4/14/2014	6/1/2023	9.1
Dynegy Inc	DYN	CALLABLE	USD	B	6.87	2,100,000,000	COMPANY GUARNT	8/17/2015	11/1/2019	4.2
Dynegy Inc	DYN	CALLABLE	USD	B	8.12	1,250,000,000	COMPANY GUARNT	8/17/2015	11/1/2024	9.2
Dynegy Inc	DYN	CALLABLE	USD	B	7.72	1,750,000,000	COMPANY GUARNT	8/17/2015	11/1/2022	7.2

Source: Bloomberg, L.P.

Appendix C Figure 1 provides additional detail on the risk free rate used in the CAPM model. AGI used a 3 percent risk free rate based on the 30-year Treasury Constant Maturity Rate. AGI selected a 3 percent risk free rate to be consistent with average rates over the same period used to estimate historical capital structures, debt issuance, and equity betas. Over the three-year period June 2013 to June 2016, the average 30-year treasury constant maturity rate was 3.14 percent. Over the prior year, June 2015 to June 2016, the rate was 2.83 percent.

Appendix C Figure 1: Historical 30 Year Treasury Constant Maturity Rate

2010-Present

Source: St. Louis Federal Reserve Bank of St. Louis, FRED. 30 Year Treasury Constant Maturity Rate.

D. Level of Excess Adjustment Factors

This appendix provides additional detail on LOE-AF, reported by Load Zone, month, and period.

As described in Section III, GE Energy Consulting (GE) used its Multi-Area Production System (MAPS, or GE-MAPS) to model LBMPs for each Load Zone under current "as found" conditions and tariff prescribed LOE conditions. GE-MAPS generates hourly, locational marginal prices based on a detailed production cost simulation system of NYISO and connected power regions, with system operations and dispatch based on forecasted load, generating asset operational and cost characteristics, and a representation of constraints on the transmission system. For the purposes of this Report, GE relied on supply and load assumptions within the 2016 Congestion Assessment Resource Integration Study (CARIS) Phase 2 Base Case data.

Total system capacity was equal to MAPS summer capacity (including derates for wind and solar) plus firm net imports and UDRs. System load included are based on the 2016 CARIS Phase 2 "as found" input assumptions. To estimate LOE conditions, load in each Load Zone was scaled equally in all hours until peak load is equal to the ICR (or LCR) plus the capacity of the peaking plant. When scaling load, GE first removed behind the meter resources (i.e., solar). Once the LOE condition was met, GE added solar resources back to the system resources. GE scaled loads to meet LCR and ICR in each Locality and NYCA in the following order: Load Zone K, then Load Zone J, then the G-J Locality, and, lastly, Load Zones A-F. When applying the 2016 CARIS Phase 2 database, this method requires a reduction in load in Load Zones A-F to reach the ICR. Table 1 provides the peak (MW) without solar for each Locality or Load Zones at the "as found" and "at criterion" conditions (i.e., tariff-prescribed LOE conditions), based on the 2016 Gold Book, GE MAPS and CARIS load shapes, and the required adjustments for level of excess conditions.

Appendix D Table 1: Peak Load by Region, without Solar (MW)

As-Found					
Load Zones	**2017**	**2018**	**2019**	**2020**	**2021**
A-F	12,017	12,021	12,016	11,872	11,860
GHI	4,532	4,520	4,509	4,552	4,555
J	11,783	11,782	11,794	11,878	11,868
K	5,540	5,530	5,539	5,532	5,572
NYCA	33,836	33,818	33,829	33,604	33,579

At-Criterion					
Load Zones	**2017**	**2018**	**2019**	**2020**	**2021**
A-F	11,825	10,362	10,361	10,377	10,379
GHI	5,219	5,214	5,208	5,395	5,439
J	12,709	12,709	12,709	12,709	12,709
K	5,720	5,720	5,720	5,720	5,720
NYCA	35,436	33,970	33,970	33,970	33,970

Source: GE Analysis; 2016 Gold Book.

Appendix D Table 2: Level of Excess Adjustment Factors by Load Zone, Month, and Time Period

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	0.970	0.985	0.975	0.992	0.988	0.987	0.985	0.993	0.988	0.995	0.990	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	1.030	1.019	1.010	1.010	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	1.030	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

Note: Off-peak period is defined as all hours not included in the defined period for on-peak; on-peak period is defined as 7 am to 11 pm, inclusive, Monday through Friday, excluding NERC defined holidays; high on-peak is defined as a subset of on-peak hours, with summer period defined as June-Aug 2 pm to 5 pm inclusive and winter period defined 4 pm to 7 pm inclusive.

E. Net EAS Revenue Model Technical Appendix

The net EAS revenues model was first provided to stakeholders on May 20, 2016 and is developed in SAS v. 9.4. The model was posted with all publicly available data, and placeholder values for all data available through subscription services (including fuel prices and emissions allowance prices).

This appendix provides additional detail on net EAS revenues results. Results are organized by peaking plant technology and combined cycle plants[92] in both dual fuel and gas only with SCR operations and provides a breakdown of results by:

- By Year (Years 1, 2 and 3 in the current sample);
- Fuel type (dual fuel, gas only with SCR, or gas without SCR (Frame only) provided for informational purposes); and
- DAM and RTM commitment/dispatch decisions.

The table below provides results for the Siemens SGT6-5000F5 operating with dual fuel capability for the period September 2013 through August 2014. The table provides results consistent with the logic structure illustrated in Figures 9 and 10 (Section IV) and can be read as follows: The light blue panel indicates the DAM commitment decision based on the consideration of DAM LBMPs, DAM reserve prices, gas prices, and other costs as described in Section IV. In the DAM, the unit can commit to energy, commit to reserves, or make no commitment. This provides the starting point for considering the RTM dispatch, which is shown in the purple panel immediately below. Here, the light purple panel indicates the final RTM dispatch, after evaluating RTD prices and intraday costs. In the RTM, the unit can provide energy, provide reserves, or buyout of its DAM commitment (either energy or reserves). Each column in the table represents a decision state.

For example, the first column indicates the total hours and total net EAS revenues for the instances when the peaking plant is committed DAM for energy and then provides energy in the RTM. For the Siemens SGT6-5000F5 unit in 2013-14, the unit earned $26.51/kW-year in Load Zone G (Dutchess County) over 692 run time hours. In contrast, column 9 (read left to right) indicates the run time hours and total net EAS revenues for the instances when the peaking plant had no DAM commitment (either energy or reserves) but provides energy in the RTM. Here, the unit operated 182 hours (in Load Zone G [Dutchess County]) and earned $6.31/kW-year in such circumstances during 2013-14. For 2013-14, the Siemens SGT6-5000F5 unit in Load Zone G (Dutchess County) earned a total net EAS revenues, exclusive of VSS payments (i.e., an additional 1.43/kW-yr), of $55.75/kW-year.

In contrast, the "buyout" columns provide the total hours and revenues in which it was economic for the unit to buyout of its DAM commitment. Absent the buyout decision, the unit would have earned revenues at its original DAM commitment. Finally, the "limited" columns provide data on the number of hours that the unit is subject to its environmental run time limitation. In these instances, and as discussed in Section IV, the unit earns revenues at the DAM reserves price.

[92] Additional details on the informational combined cycle plant results are provided in Appendix F.

The final column indicates the total net EAS revenues for the unit. The total is the sum of revenues for each of the commitment states illustrated in each column in the table. Note that these tables do not include the flat adder for VSS payments ($1.43/kW-yr), which is included in the final annual average net EAS revenues presented in Section IV.

Appendix E Table 1: EXAMPLE NET EAS REVENUES DETAIL
DAM and RTD Commitment
Siemens SGT6-5000F5 Dual Fuel, September 2013 – August 2014

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	1,009	0	453	0	5	2	135	0	253	0	6,903	0	8,760
F	Capital	545	0	395	0	43	0	263	0	186	0	7,328	0	8,760
G	Hudson Valley (Dutchess)	692	0	287	0	43	1	286	0	182	0	7,269	0	8,760
G	Hudson Valley (Rockland)	692	0	287	0	43	1	286	0	182	0	7,269	0	8,760
J	NYC	2,402	0	379	0	31	1	179	0	126	0	5,642	0	8,760
K	Long Island	3,222	0	561	1,213	36	0	107	13	102	0	3,451	55	8,760

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	$34.82	$0.00	$16.05	$0.00	$0.51	$0.00	$0.20	$0.00	$7.21	$0.00	$0.00	$0.00	$58.79
F	Capital	$26.98	$0.00	$24.66	$0.00	$4.12	$0.00	$0.21	$0.00	$7.05	$0.00	$0.00	$0.00	$63.02
G	Hudson Valley (Dutchess)	$26.51	$0.00	$18.82	$0.00	$3.87	$0.00	$0.23	$0.00	$6.31	$0.00	$0.00	$0.00	$55.75
G	Hudson Valley (Rockland)	$26.49	$0.00	$18.82	$0.00	$3.87	$0.00	$0.23	$0.00	$6.28	$0.00	$0.00	$0.00	$55.69
J	NYC	$65.38	$0.00	$12.67	$0.00	$3.20	$0.00	$0.22	$0.00	$3.77	$0.00	$0.00	$0.00	$85.23
K	Long Island	$114.73	$0.00	$16.67	$0.00	$3.79	$0.00	$0.10	$0.03	$7.22	$0.00	$0.00	$0.00	$142.54

The appendix also includes detailed tables for net energy revenues, exclusive of reserves and buyouts. These tables provide additional information on the breakdown of energy revenues by fuel type. It does not include any revenues for reserves or buyouts. This illustrates that the Siemens SGT6-5000F5 unit in Load Zone G (Dutchess County) provided energy over 917 total hours for 2013-14 (the 692 hours of DAM-energy to RTM-energy, plus 43 hours of DAM-reserves to RTM-energy and the 182 hours of no DAM commitment to RTM-energy). Here, the unit operated 104 total hours on oil during 2013-14 and earned $10.02/kW-yr while operating on oil.

Appendix E Table 2: EXAMPLE NET EAS REVENUES DETAIL
DAM and RTD Commitment
Siemens SGT6-5000F5 Dual Fuel, September 2013 – August 2014

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,253	14	1,267	$41.19	$1.34	$42.54
F	Capital	661	113	774	$27.71	$10.43	$38.15
G	Hudson Valley (Dutchess)	813	104	917	$26.68	$10.02	$36.69
G	Hudson Valley (Rockland)	813	104	917	$26.63	$10.01	$36.64
J	New York City	2,444	115	2,559	$55.30	$17.04	$72.35
K	Long Island	3,237	123	3,360	$113.89	$11.85	$125.74

1. GE LMS100PA+ Dual Fuel

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,863	39	1,902	$51.49	$3.97	$55.46
F	Capital	1,199	158	1,357	$38.23	$13.66	$51.89
G	Hudson Valley (Dutchess)	1,389	141	1,530	$37.97	$12.69	$50.66
G	Hudson Valley (Rockland)	1,387	141	1,528	$38.03	$12.68	$50.71
J	New York City	3,139	167	3,306	$71.97	$23.75	$95.72
K	Long Island	3,462	238	3,700	$128.64	$27.36	$156.00

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,558	19	2,577	$26.36	$0.70	$27.06
F	Capital	1,385	77	1,462	$25.17	$1.90	$27.07
G	Hudson Valley (Dutchess)	1,450	79	1,529	$24.55	$2.09	$26.64
G	Hudson Valley (Rockland)	1,446	76	1,522	$24.57	$2.21	$26.77
J	New York City	2,592	70	2,662	$33.35	$2.46	$35.81
K	Long Island	3,573	141	3,714	$77.63	$6.19	$83.82

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,570	0	2,570	$28.39	$0.00	$28.39
F	Capital	1,350	0	1,350	$22.07	$0.00	$22.07
G	Hudson Valley (Dutchess)	1,419	0	1,419	$22.46	$0.00	$22.46
G	Hudson Valley (Rockland)	1,417	0	1,417	$22.55	$0.00	$22.55
J	New York City	3,023	0	3,023	$37.24	$0.00	$37.24
K	Long Island	3,721	0	3,721	$72.35	$0.00	$72.35

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	1,440	0	548	0	16	7	207	0	446	0	6,096	0	8,760
F	Capital	859	7	531	0	320	29	2,136	0	178	6	4,694	0	8,760
G	Hudson Valley (Dutchess)	1,043	8	403	0	338	23	2,017	0	149	6	4,773	0	8,760
G	Hudson Valley (Rockland)	1,041	8	403	0	338	23	2,019	0	149	6	4,773	0	8,760
J	NYC	3,022	7	351	0	47	1	177	0	237	1	4,917	0	8,760
K	Long Island	3,564	0	234	1,464	39	0	88	13	97	0	3,158	103	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	2,015	0	799	0	80	0	737	0	482	1	4,646	0	8,760
F	Capital	801	62	372	0	403	25	2,866	0	258	3	3,970	0	8,760
G	Hudson Valley (Dutchess)	948	37	376	0	354	14	2,885	0	227	3	3,916	0	8,760
G	Hudson Valley (Rockland)	940	37	376	0	356	16	2,888	0	226	3	3,918	0	8,760
J	NYC	2,329	30	514	0	57	0	320	0	276	2	5,232	0	8,760
K	Long Island	3,549	16	560	502	28	0	165	8	137	0	3,671	124	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	1,767	0	313	0	671	3	5,206	0	132	0	692	0	8,784
F	Capital	432	60	295	0	876	22	5,764	0	42	1	1,292	0	8,784
G	Hudson Valley (Dutchess)	689	19	242	0	693	14	5,805	0	37	0	1,285	0	8,784
G	Hudson Valley (Rockland)	681	19	241	0	699	15	5,807	0	37	0	1,285	0	8,784
J	NYC	2,420	1	437	0	458	3	2,737	0	145	0	2,583	0	8,784
K	Long Island	3,443	0	528	407	118	4	1,146	100	160	0	2,816	62	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	$45.34	$0.00	$16.88	$0.00	$0.52	$0.02	$0.28	$0.00	$9.60	$0.00	$0.00	$0.00	$72.64
F	Capital	$35.92	$0.17	$29.49	$0.00	$9.45	$0.08	$4.03	$0.00	$6.52	$0.04	$0.00	$0.00	$85.70
G	Hudson Valley (Dutchess)	$35.42	$0.39	$24.66	$0.00	$9.91	$0.06	$4.07	$0.00	$5.33	$0.04	$0.00	$0.00	$79.89
G	Hudson Valley (Rockland)	$35.39	$0.39	$24.66	$0.00	$10.00	$0.06	$4.07	$0.00	$5.32	$0.04	$0.00	$0.00	$79.94
J	NYC	$87.61	$0.34	$8.45	$0.00	$2.98	$0.01	$1.16	$0.00	$5.12	$0.00	$0.00	$0.00	$105.68
K	Long Island	$145.58	$0.00	$3.26	$0.23	$3.98	$0.00	$0.48	$0.07	$6.44	$0.00	$0.00	$0.00	$160.05

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	$20.41	$0.00	$10.50	$0.00	$0.94	$0.00	$0.78	$0.00	$5.71	$0.00	$0.00	$0.00	$38.34
F	Capital	$13.66	$2.50	$9.71	$0.00	$7.37	$0.12	$4.11	$0.00	$6.04	$0.34	$0.00	$0.00	$43.84
G	Hudson Valley (Dutchess)	$14.92	$2.04	$9.52	$0.00	$6.97	$0.04	$4.07	$0.00	$4.76	$0.34	$0.00	$0.00	$42.66
G	Hudson Valley (Rockland)	$14.87	$2.04	$9.52	$0.00	$7.14	$0.05	$4.07	$0.00	$4.77	$0.34	$0.00	$0.00	$42.80
J	NYC	$29.21	$1.87	$9.93	$0.00	$1.62	$0.00	$0.85	$0.00	$4.98	$0.34	$0.00	$0.00	$48.80
K	Long Island	$75.92	$0.98	$9.99	$0.09	$1.26	$0.00	$0.39	$0.03	$6.64	$0.00	$0.00	$0.00	$95.30

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	$17.66	$0.00	$3.23	$0.00	$10.18	$0.01	$15.76	$0.00	$0.56	$0.00	$0.00	$0.00	$47.39
F	Capital	$4.87	$3.39	$4.30	$0.00	$16.59	$0.11	$16.00	$0.00	$0.61	$0.00	$0.00	$0.00	$45.87
G	Hudson Valley (Dutchess)	$9.42	$0.37	$3.91	$0.00	$12.51	$0.04	$15.35	$0.00	$0.53	$0.00	$0.00	$0.00	$42.13
G	Hudson Valley (Rockland)	$9.36	$0.37	$3.91	$0.00	$12.66	$0.04	$15.35	$0.00	$0.53	$0.00	$0.00	$0.00	$42.22
J	NYC	$27.21	$0.00	$5.26	$0.00	$7.65	$0.01	$4.40	$0.00	$2.37	$0.00	$0.00	$0.00	$46.90
K	Long Island	$63.47	$0.00	$10.07	$0.40	$2.47	$0.00	$1.21	$0.12	$6.41	$0.00	$0.00	$0.00	$84.15

2. GE LMS100PA+ Natural Gas with SCR

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,868	0	1,868	$51.73	$0.00	$51.73
F	Capital	1,259	0	1,259	$45.50	$0.00	$45.50
G	Hudson Valley (Dutchess)	1,442	0	1,442	$43.54	$0.00	$43.54
G	Hudson Valley (Rockland)	1,440	0	1,440	$43.60	$0.00	$43.60
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,573	0	2,573	$26.79	$0.00	$26.79
F	Capital	1,424	0	1,424	$26.91	$0.00	$26.91
G	Hudson Valley (Dutchess)	1,492	0	1,492	$26.23	$0.00	$26.23
G	Hudson Valley (Rockland)	1,488	0	1,488	$26.25	$0.00	$26.25
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,570	0	2,570	$28.39	$0.00	$28.39
F	Capital	1,350	0	1,350	$22.07	$0.00	$22.07
G	Hudson Valley (Dutchess)	1,419	0	1,419	$22.46	$0.00	$22.46
G	Hudson Valley (Rockland)	1,417	0	1,417	$22.55	$0.00	$22.55
J	New York City						
K	Long Island						

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	1,411	0	511	0	8	0	90	0	449	4	6,287	0	8,760
F	Capital	770	7	481	0	271	28	1,979	0	218	10	4,996	0	8,760
G	Hudson Valley (Dutchess)	977	3	337	0	283	22	1,800	0	182	10	5,146	0	8,760
G	Hudson Valley (Rockland)	975	3	337	0	283	22	1,802	0	182	10	5,146	0	8,760
J	NYC													
K	Long Island													

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	2,014	0	797	0	75	0	643	0	484	1	4,746	0	8,760
F	Capital	772	51	338	0	385	25	2,750	0	267	4	4,168	0	8,760
G	Hudson Valley (Dutchess)	912	18	365	0	339	14	2,649	0	241	4	4,218	0	8,760
G	Hudson Valley (Rockland)	910	18	365	0	338	14	2,651	0	240	4	4,220	0	8,760
J	NYC													
K	Long Island													

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	1,767	0	313	0	671	3	5,206	0	132	0	692	0	8,784
F	Capital	432	60	295	0	876	22	5,764	0	42	1	1,292	0	8,784
G	Hudson Valley (Dutchess)	689	19	242	0	693	14	5,805	0	37	0	1,285	0	8,784
G	Hudson Valley (Rockland)	681	19	241	0	699	15	5,807	0	37	0	1,285	0	8,784
J	NYC													
K	Long Island													

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	$41.86	$0.00	$10.93	$0.00	$0.07	$0.00	$0.08	$0.00	$9.80	$0.23	$0.00	$0.00	$62.96
F	Capital	$27.84	$0.17	$22.26	$0.00	$5.94	$0.07	$3.49	$0.00	$11.71	$0.31	$0.00	$0.00	$71.80
G	Hudson Valley (Dutchess)	$27.99	$0.02	$14.85	$0.00	$5.90	$0.05	$3.17	$0.00	$9.64	$0.31	$0.00	$0.00	$61.95
G	Hudson Valley (Rockland)	$27.96	$0.02	$14.85	$0.00	$5.99	$0.05	$3.17	$0.00	$9.64	$0.31	$0.00	$0.00	$62.01
J	NYC													
K	Long Island													

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	$20.27	$0.00	$10.31	$0.00	$0.77	$0.00	$0.58	$0.00	$5.75	$0.00	$0.00	$0.00	$37.68
F	Capital	$13.17	$1.72	$7.86	$0.00	$7.03	$0.12	$3.88	$0.00	$6.71	$0.35	$0.00	$0.00	$40.85
G	Hudson Valley (Dutchess)	$14.31	$0.98	$8.83	$0.00	$6.54	$0.04	$3.26	$0.00	$5.39	$0.36	$0.00	$0.00	$39.70
G	Hudson Valley (Rockland)	$14.29	$0.98	$8.83	$0.00	$6.57	$0.04	$3.25	$0.00	$5.40	$0.36	$0.00	$0.00	$39.71
J	NYC													
K	Long Island													

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	$17.66	$0.00	$3.23	$0.00	$10.18	$0.01	$15.76	$0.00	$0.56	$0.00	$0.00	$0.00	$47.39
F	Capital	$4.87	$3.39	$4.30	$0.00	$16.59	$0.11	$16.00	$0.00	$0.61	$0.00	$0.00	$0.00	$45.87
G	Hudson Valley (Dutchess)	$9.42	$0.37	$3.91	$0.00	$12.51	$0.04	$15.35	$0.00	$0.53	$0.00	$0.00	$0.00	$42.13
G	Hudson Valley (Rockland)	$9.36	$0.37	$3.91	$0.00	$12.66	$0.04	$15.35	$0.00	$0.53	$0.00	$0.00	$0.00	$42.22
J	NYC													
K	Long Island													

3. *Siemens SGT6-5000F5 Dual Fuel*

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,253	14	1,267	$41.19	$1.34	$42.54
F	Capital	661	113	774	$27.71	$10.43	$38.15
G	Hudson Valley (Dutchess)	813	104	917	$26.68	$10.02	$36.69
G	Hudson Valley (Rockland)	813	104	917	$26.63	$10.01	$36.64
J	New York City	2,444	115	2,559	$55.30	$17.04	$72.35
K	Long Island	3,237	123	3,360	$113.89	$11.85	$125.74

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,353	3	2,356	$21.11	-$0.02	$21.09
F	Capital	811	28	839	$17.91	$0.84	$18.75
G	Hudson Valley (Dutchess)	863	21	884	$16.45	$1.13	$17.58
G	Hudson Valley (Rockland)	863	21	884	$16.40	$1.12	$17.53
J	New York City	2,244	39	2,283	$24.59	$1.71	$26.30
K	Long Island	3,334	21	3,355	$67.28	$0.86	$68.14

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,282	0	2,282	$23.47	$0.00	$23.47
F	Capital	694	0	694	$11.72	$0.00	$11.72
G	Hudson Valley (Dutchess)	845	0	845	$14.41	$0.00	$14.41
G	Hudson Valley (Rockland)	835	0	835	$14.29	$0.00	$14.29
J	New York City	2,633	0	2,633	$29.46	$0.00	$29.46
K	Long Island	3,373	0	3,373	$65.30	$0.00	$65.30

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	1,009	0	453	0	5	2	135	0	253	0	6,903	0	8,760
F	Capital	545	0	395	0	43	0	263	0	186	0	7,328	0	8,760
G	Hudson Valley (Dutchess)	692	0	287	0	43	1	286	0	182	0	7,269	0	8,760
G	Hudson Valley (Rockland)	692	0	287	0	43	1	286	0	182	0	7,269	0	8,760
J	NYC	2,402	0	379	0	31	1	179	0	126	0	5,642	0	8,760
K	Long Island	3,222	0	561	1,213	36	0	107	13	102	0	3,451	55	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	2,028	0	730	0	15	0	159	0	313	0	5,515	0	8,760
F	Capital	563	0	267	0	7	0	221	0	269	0	7,433	0	8,760
G	Hudson Valley (Dutchess)	625	0	371	0	21	0	304	0	238	0	7,201	0	8,760
G	Hudson Valley (Rockland)	625	0	366	0	21	0	304	0	238	0	7,206	0	8,760
J	NYC	2,124	0	504	0	22	0	305	0	137	0	5,668	0	8,760
K	Long Island	3,228	0	722	626	8	0	249	4	119	0	3,764	40	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	1,801	0	260	0	394	2	5,445	0	87	0	795	0	8,784
F	Capital	326	15	137	0	312	9	5,852	0	56	0	2,077	0	8,784
G	Hudson Valley (Dutchess)	488	0	137	0	315	5	5,840	0	42	0	1,957	0	8,784
G	Hudson Valley (Rockland)	488	0	137	0	305	7	5,848	0	42	0	1,957	0	8,784
J	NYC	2,320	0	354	0	229	0	2,792	0	84	0	3,005	0	8,784
K	Long Island	3,179	0	572	766	62	0	770	25	132	0	3,236	42	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	$34.82	$0.00	$16.05	$0.00	$0.51	$0.00	$0.20	$0.00	$7.21	$0.00	$0.00	$0.00	$58.79
F	Capital	$26.98	$0.00	$24.66	$0.00	$4.12	$0.00	$0.21	$0.00	$7.05	$0.00	$0.00	$0.00	$63.02
G	Hudson Valley (Dutchess)	$26.51	$0.00	$18.82	$0.00	$3.87	$0.00	$0.23	$0.00	$6.31	$0.00	$0.00	$0.00	$55.75
G	Hudson Valley (Rockland)	$26.49	$0.00	$18.82	$0.00	$3.87	$0.00	$0.23	$0.00	$6.28	$0.00	$0.00	$0.00	$55.69
J	NYC	$65.38	$0.00	$12.67	$0.00	$3.20	$0.00	$0.22	$0.00	$3.77	$0.00	$0.00	$0.00	$85.23
K	Long Island	$114.73	$0.00	$16.67	$0.00	$3.79	$0.00	$0.10	$0.03	$7.22	$0.00	$0.00	$0.00	$142.54

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	$16.75	$0.00	$8.66	$0.00	$0.07	$0.00	$0.18	$0.00	$4.26	$0.00	$0.00	$0.00	$29.93
F	Capital	$7.95	$0.00	$8.74	$0.00	$0.64	$0.00	$0.24	$0.00	$10.16	$0.00	$0.00	$0.00	$27.74
G	Hudson Valley (Dutchess)	$8.13	$0.00	$8.77	$0.00	$1.13	$0.00	$0.38	$0.00	$8.32	$0.00	$0.00	$0.00	$26.73
G	Hudson Valley (Rockland)	$8.11	$0.00	$8.59	$0.00	$1.12	$0.00	$0.38	$0.00	$8.29	$0.00	$0.00	$0.00	$26.50
J	NYC	$22.31	$0.00	$8.86	$0.00	$1.03	$0.00	$0.35	$0.00	$2.95	$0.00	$0.00	$0.00	$35.50
K	Long Island	$61.03	$0.00	$13.84	$0.00	$0.51	$0.00	$0.26	$0.00	$6.60	$0.00	$0.00	$0.00	$82.25

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	$16.57	$0.00	$2.37	$0.00	$6.45	$0.01	$16.38	$0.00	$0.45	$0.00	$0.00	$0.00	$42.23
F	Capital	$3.68	$0.25	$2.04	$0.00	$7.05	$0.04	$15.01	$0.00	$0.98	$0.00	$0.00	$0.00	$29.05
G	Hudson Valley (Dutchess)	$6.47	$0.00	$2.42	$0.00	$7.36	$0.02	$14.63	$0.00	$0.57	$0.00	$0.00	$0.00	$31.48
G	Hudson Valley (Rockland)	$6.46	$0.00	$2.42	$0.00	$7.27	$0.02	$14.66	$0.00	$0.57	$0.00	$0.00	$0.00	$31.39
J	NYC	$22.95	$0.00	$3.48	$0.00	$5.17	$0.00	$3.85	$0.00	$1.34	$0.00	$0.00	$0.00	$36.78
K	Long Island	$59.00	$0.00	$9.60	$0.33	$1.24	$0.00	$0.73	$0.04	$5.06	$0.00	$0.00	$0.00	$76.01

4. Siemens SGT6-5000F5 Natural Gas with SCR

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,254	0	1,254	$41.28	$0.00	$41.28
F	Capital	691	0	691	$31.64	$0.00	$31.64
G	Hudson Valley (Dutchess)	843	0	843	$30.22	$0.00	$30.22
G	Hudson Valley (Rockland)	843	0	843	$30.17	$0.00	$30.17
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,357	0	2,357	$21.15	$0.00	$21.15
F	Capital	822	0	822	$18.33	$0.00	$18.33
G	Hudson Valley (Dutchess)	878	0	878	$17.06	$0.00	$17.06
G	Hudson Valley (Rockland)	878	0	878	$17.01	$0.00	$17.01
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,282	0	2,282	$23.47	$0.00	$23.47
F	Capital	694	0	694	$11.72	$0.00	$11.72
G	Hudson Valley (Dutchess)	845	0	845	$14.41	$0.00	$14.41
G	Hudson Valley (Rockland)	835	0	835	$14.29	$0.00	$14.29
J	New York City						
K	Long Island						

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	1,000	0	395	0	0	0	0	0	254	1	7,110	0	8,760
F	Capital	475	0	330	0	0	0	0	0	216	0	7,739	0	8,760
G	Hudson Valley (Dutchess)	636	0	222	0	0	0	0	0	207	0	7,695	0	8,760
G	Hudson Valley (Rockland)	636	0	222	0	0	0	0	0	207	0	7,695	0	8,760
J	NYC													
K	Long Island													

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	2,032	0	713	0	12	0	59	0	313	0	5,631	0	8,760
F	Capital	542	0	216	0	0	0	11	0	280	0	7,711	0	8,760
G	Hudson Valley (Dutchess)	631	0	346	0	0	0	9	0	247	0	7,527	0	8,760
G	Hudson Valley (Rockland)	631	0	341	0	0	0	9	0	247	0	7,532	0	8,760
J	NYC													
K	Long Island													

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	1,801	0	260	0	394	2	5,445	0	87	0	795	0	8,784
F	Capital	326	15	137	0	312	9	5,852	0	56	0	2,077	0	8,784
G	Hudson Valley (Dutchess)	488	0	137	0	315	5	5,840	0	42	0	1,957	0	8,784
G	Hudson Valley (Rockland)	488	0	137	0	305	7	5,848	0	42	0	1,957	0	8,784
J	NYC													
K	Long Island													

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	$33.98	$0.00	$7.27	$0.00	$0.00	$0.00	$0.00	$0.00	$7.30	$0.00	$0.00	$0.00	$48.56
F	Capital	$20.78	$0.00	$14.37	$0.00	$0.00	$0.00	$0.00	$0.00	$10.86	$0.00	$0.00	$0.00	$46.01
G	Hudson Valley (Dutchess)	$20.73	$0.00	$8.19	$0.00	$0.00	$0.00	$0.00	$0.00	$9.49	$0.00	$0.00	$0.00	$38.41
G	Hudson Valley (Rockland)	$20.71	$0.00	$8.19	$0.00	$0.00	$0.00	$0.00	$0.00	$9.46	$0.00	$0.00	$0.00	$38.36
J	NYC													
K	Long Island													

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	$16.86	$0.00	$8.01	$0.00	$0.09	$0.00	$0.02	$0.00	$4.19	$0.00	$0.00	$0.00	$29.17
F	Capital	$7.75	$0.00	$5.80	$0.00	$0.00	$0.00	$0.01	$0.00	$10.58	$0.00	$0.00	$0.00	$24.14
G	Hudson Valley (Dutchess)	$8.44	$0.00	$7.16	$0.00	$0.00	$0.00	$0.00	$0.00	$8.63	$0.00	$0.00	$0.00	$24.23
G	Hudson Valley (Rockland)	$8.41	$0.00	$6.98	$0.00	$0.00	$0.00	$0.00	$0.00	$8.60	$0.00	$0.00	$0.00	$23.99
J	NYC													
K	Long Island													

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	$16.57	$0.00	$2.37	$0.00	$6.45	$0.01	$16.38	$0.00	$0.45	$0.00	$0.00	$0.00	$42.23
F	Capital	$3.68	$0.25	$2.04	$0.00	$7.05	$0.04	$15.01	$0.00	$0.98	$0.00	$0.00	$0.00	$29.05
G	Hudson Valley (Dutchess)	$6.47	$0.00	$2.42	$0.00	$7.36	$0.02	$14.63	$0.00	$0.57	$0.00	$0.00	$0.00	$31.48
G	Hudson Valley (Rockland)	$6.46	$0.00	$2.42	$0.00	$7.27	$0.02	$14.66	$0.00	$0.57	$0.00	$0.00	$0.00	$31.39
J	NYC													
K	Long Island													

5. Siemens SGT6-5000F5 Natural Gas without SCR (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,301	0	1,301	$41.44	$0.00	$41.44
F	Capital	697	0	697	$31.89	$0.00	$31.89
G	Hudson Valley (Dutchess)	858	0	858	$30.42	$0.00	$30.42
G	Hudson Valley (Rockland)						
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,494	0	2,494	$22.50	$0.00	$22.50
F	Capital	872	0	872	$17.83	$0.00	$17.83
G	Hudson Valley (Dutchess)	946	0	946	$15.71	$0.00	$15.71
G	Hudson Valley (Rockland)						
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,496	0	2,496	$25.58	$0.00	$25.58
F	Capital	740	0	740	$12.54	$0.00	$12.54
G	Hudson Valley (Dutchess)	918	0	918	$15.12	$0.00	$15.12
G	Hudson Valley (Rockland)						
J	New York City						
K	Long Island						

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	1,050	0	421	0	0	0	0	0	251	1	7,037	0	8,760
F	Capital	478	0	346	0	0	0	0	0	219	0	7,717	0	8,760
G	Hudson Valley (Dutchess)	655	0	253	0	0	0	0	0	203	0	7,649	0	8,760
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

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	2,159	0	759	36	13	0	52	0	322	0	5,411	8	8,760
F	Capital	584	0	252	0	0	0	11	0	288	0	7,625	0	8,760
G	Hudson Valley (Dutchess)	704	0	354	0	0	0	9	0	242	0	7,451	0	8,760
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

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	1,998	0	174	22	406	2	5,335	0	92	0	755	0	8,784
F	Capital	340	0	175	0	343	9	5,785	0	57	0	2,075	0	8,784
G	Hudson Valley (Dutchess)	556	0	157	0	316	5	5,757	0	46	0	1,947	0	8,784
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

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	$34.88	$0.00	$7.26	$0.00	$0.00	$0.00	$0.00	$0.00	$6.56	$0.00	$0.00	$0.00	$48.70
F	Capital	$21.06	$0.00	$14.48	$0.00	$0.00	$0.00	$0.00	$0.00	$10.83	$0.00	$0.00	$0.00	$46.37
G	Hudson Valley (Dutchess)	$21.10	$0.00	$8.35	$0.00	$0.00	$0.00	$0.00	$0.00	$9.32	$0.00	$0.00	$0.00	$38.77
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

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	$18.20	$0.00	$8.25	$0.00	$0.10	$0.00	$0.01	$0.00	$4.20	$0.00	$0.00	$0.00	$30.76
F	Capital	$8.13	$0.00	$6.23	$0.00	$0.00	$0.00	$0.01	$0.00	$9.70	$0.00	$0.00	$0.00	$24.06
G	Hudson Valley (Dutchess)	$9.06	$0.00	$7.22	$0.00	$0.00	$0.00	$0.00	$0.00	$6.65	$0.00	$0.00	$0.00	$22.94
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

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	$18.75	$0.00	$1.51	$0.11	$6.38	$0.01	$15.98	$0.00	$0.45	$0.00	$0.00	$0.00	$43.18
F	Capital	$4.03	$0.00	$2.39	$0.00	$7.47	$0.04	$14.85	$0.00	$1.04	$0.00	$0.00	$0.00	$29.81
G	Hudson Valley (Dutchess)	$7.01	$0.00	$2.56	$0.00	$7.50	$0.02	$14.32	$0.00	$0.61	$0.00	$0.00	$0.00	$32.02
G	Hudson Valley (Rockland)													
J	NYC													
K	Long Island													

6. *Wartsila 18V50DF Dual Fuel*

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,013	41	2,054	$54.85	$4.77	$59.62
F	Capital	1,334	180	1,514	$43.01	$13.53	$56.54
G	Hudson Valley (Dutchess)	1,559	167	1,726	$43.10	$12.02	$55.12
G	Hudson Valley (Rockland)	1,554	167	1,721	$43.15	$12.02	$55.16
J	New York City	3,352	205	3,557	$78.82	$28.64	$107.46
K	Long Island	5,134	277	5,411	$150.41	$30.07	$180.48

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,424	27	2,451	$25.70	$1.17	$26.87
F	Capital	1,453	169	1,622	$27.13	$6.54	$33.67
G	Hudson Valley (Dutchess)	1,565	120	1,685	$26.48	$4.23	$30.71
G	Hudson Valley (Rockland)	1,562	120	1,682	$26.41	$4.22	$30.63
J	New York City	2,619	132	2,751	$33.72	$5.75	$39.47
K	Long Island	4,045	204	4,249	$80.71	$9.17	$89.88

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,343	0	2,343	$27.58	$0.00	$27.58
F	Capital	1,338	0	1,338	$22.40	$0.00	$22.40
G	Hudson Valley (Dutchess)	1,394	0	1,394	$23.18	$0.00	$23.18
G	Hudson Valley (Rockland)	1,391	0	1,391	$23.14	$0.00	$23.14
J	New York City	2,807	0	2,807	$36.62	$0.00	$36.62
K	Long Island	4,011	0	4,011	$74.05	$0.00	$74.05

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	1,604	0	598	0	22	6	216	0	428	0	5,886	0	8,760
F	Capital	998	7	641	0	338	28	2,262	0	178	5	4,303	0	8,760
G	Hudson Valley (Dutchess)	1,210	5	520	0	340	20	2,102	0	176	6	4,381	0	8,760
G	Hudson Valley (Rockland)	1,205	5	512	0	339	20	2,115	0	177	6	4,381	0	8,760
J	NYC	3,299	1	433	0	42	1	158	0	216	1	4,609	0	8,760
K	Long Island	5,165	0	287	0	44	0	67	0	202	1	2,994	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	1,895	15	823	0	93	0	888	0	463	1	4,582	0	8,760
F	Capital	936	41	382	0	435	22	3,251	0	251	3	3,439	0	8,760
G	Hudson Valley (Dutchess)	1,100	20	391	0	374	11	3,175	0	211	3	3,475	0	8,760
G	Hudson Valley (Rockland)	1,098	19	389	0	374	11	3,179	0	210	3	3,477	0	8,760
J	NYC	2,380	11	543	0	81	0	419	0	290	3	5,033	0	8,760
K	Long Island	3,931	16	685	0	46	0	147	0	272	0	3,663	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	
C	Central	1,532	0	333	0	679	3	5,407	0	132	0	698	0	8,784
F	Capital	420	60	257	0	874	22	5,910	0	44	0	1,197	0	8,784
G	Hudson Valley (Dutchess)	644	7	239	0	713	15	5,954	0	37	0	1,175	0	8,784
G	Hudson Valley (Rockland)	645	7	227	0	709	15	5,969	0	37	0	1,175	0	8,784
J	NYC	2,144	1	433	0	523	3	3,224	0	140	0	2,316	0	8,784
K	Long Island	3,486	0	590	0	324	4	1,564	0	201	0	2,615	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	
C	Central	$49.83	$0.00	$17.14	$0.00	$0.75	$0.02	$0.29	$0.00	$9.04	$0.00	$0.00	$0.00	$77.07
F	Capital	$40.91	$0.17	$34.09	$0.00	$9.04	$0.08	$4.27	$0.00	$6.59	$0.04	$0.00	$0.00	$95.20
G	Hudson Valley (Dutchess)	$41.01	$0.04	$27.36	$0.00	$8.51	$0.06	$4.24	$0.00	$5.60	$0.05	$0.00	$0.00	$86.87
G	Hudson Valley (Rockland)	$40.95	$0.04	$27.30	$0.00	$8.56	$0.06	$4.26	$0.00	$5.66	$0.05	$0.00	$0.00	$86.87
J	NYC	$100.23	$0.01	$6.30	$0.00	$2.76	$0.01	$1.05	$0.00	$4.47	$0.00	$0.00	$0.00	$114.83
K	Long Island	$168.39	$0.00	$4.05	$0.00	$3.59	$0.00	$0.34	$0.00	$8.49	$0.00	$0.00	$0.00	$184.87

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	$20.10	$0.12	$11.04	$0.00	$1.00	$0.00	$0.83	$0.00	$5.77	$0.00	$0.00	$0.00	$38.85
F	Capital	$19.10	$1.52	$9.11	$0.00	$8.68	$0.12	$4.85	$0.00	$5.89	$0.34	$0.00	$0.00	$49.62
G	Hudson Valley (Dutchess)	$18.92	$1.07	$9.86	$0.00	$7.27	$0.04	$4.45	$0.00	$4.52	$0.35	$0.00	$0.00	$46.48
G	Hudson Valley (Rockland)	$18.86	$1.04	$9.83	$0.00	$7.26	$0.04	$4.46	$0.00	$4.51	$0.35	$0.00	$0.00	$46.36
J	NYC	$32.65	$0.91	$10.28	$0.00	$2.07	$0.00	$0.78	$0.00	$4.75	$0.35	$0.00	$0.00	$51.79
K	Long Island	$79.45	$1.03	$12.87	$0.00	$1.89	$0.00	$0.31	$0.00	$8.55	$0.00	$0.00	$0.00	$104.09

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	$15.68	$0.00	$3.28	$0.00	$11.35	$0.01	$16.94	$0.00	$0.56	$0.00	$0.00	$0.00	$47.80
F	Capital	$4.98	$3.45	$4.04	$0.00	$16.75	$0.12	$17.14	$0.00	$0.66	$0.00	$0.00	$0.00	$47.13
G	Hudson Valley (Dutchess)	$9.48	$0.11	$3.97	$0.00	$13.17	$0.04	$16.52	$0.00	$0.53	$0.00	$0.00	$0.00	$43.83
G	Hudson Valley (Rockland)	$9.47	$0.11	$3.81	$0.00	$13.13	$0.04	$16.60	$0.00	$0.53	$0.00	$0.00	$0.00	$43.70
J	NYC	$25.30	$0.00	$5.32	$0.00	$9.25	$0.01	$5.73	$0.00	$2.06	$0.00	$0.00	$0.00	$47.67
K	Long Island	$62.05	$0.00	$10.96	$0.00	$6.21	$0.00	$1.85	$0.00	$5.80	$0.00	$0.00	$0.00	$86.87

7. Wartsila 18V50DF Natural Gas with SCR

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,875	0	1,875	$50.52	$0.00	$50.52
F	Capital	1,107	0	1,107	$37.88	$0.00	$37.88
G	Hudson Valley (Dutchess)	1,408	0	1,408	$39.34	$0.00	$39.34
G	Hudson Valley (Rockland)	1,402	0	1,402	$39.27	$0.00	$39.27
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,291	0	2,291	$23.23	$0.00	$23.23
F	Capital	1,023	0	1,023	$18.34	$0.00	$18.34
G	Hudson Valley (Dutchess)	1,231	0	1,231	$18.24	$0.00	$18.24
G	Hudson Valley (Rockland)	1,217	0	1,217	$18.07	$0.00	$18.07
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,816	0	1,816	$17.76	$0.00	$17.76
F	Capital	569	0	569	$7.05	$0.00	$7.05
G	Hudson Valley (Dutchess)	796	0	796	$11.16	$0.00	$11.16
G	Hudson Valley (Rockland)	788	0	788	$11.24	$0.00	$11.24
J	New York City						
K	Long Island						

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	1,694	0	647	0	4	0	112	0	177	6	6,120	0	8,760
F	Capital	989	9	638	0	50	43	2,275	0	68	19	4,669	0	8,760
G	Hudson Valley (Dutchess)	1,255	5	522	0	78	38	2,012	0	75	19	4,756	0	8,760
G	Hudson Valley (Rockland)	1,249	5	520	0	78	39	2,018	0	75	19	4,757	0	8,760
J	NYC													
K	Long Island													

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	2,026	15	871	0	56	0	839	0	209	1	4,743	0	8,760
F	Capital	889	63	417	0	65	43	3,438	0	69	7	3,769	0	8,760
G	Hudson Valley (Dutchess)	1,089	39	433	0	82	27	3,197	0	60	10	3,823	0	8,760
G	Hudson Valley (Rockland)	1,079	39	428	0	83	28	3,208	0	55	10	3,830	0	8,760
J	NYC													
K	Long Island													

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	1,593	0	339	0	122	14	5,912	0	101	0	703	0	8,784
F	Capital	463	62	268	0	97	74	6,593	0	9	5	1,213	0	8,784
G	Hudson Valley (Dutchess)	693	7	230	0	94	53	6,500	0	9	5	1,193	0	8,784
G	Hudson Valley (Rockland)	674	7	244	0	105	53	6,494	0	9	5	1,193	0	8,784
J	NYC													
K	Long Island													

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	$46.76	$0.00	$12.03	$0.00	$0.04	$0.00	$0.10	$0.00	$3.71	$0.42	$0.00	$0.00	$63.08
F	Capital	$32.75	$0.23	$27.71	$0.00	$0.62	$0.14	$3.99	$0.00	$4.51	$1.46	$0.00	$0.00	$71.40
G	Hudson Valley (Dutchess)	$33.37	$0.07	$19.53	$0.00	$1.24	$0.14	$3.59	$0.00	$4.73	$1.47	$0.00	$0.00	$64.15
G	Hudson Valley (Rockland)	$33.31	$0.07	$19.52	$0.00	$1.24	$0.14	$3.60	$0.00	$4.72	$1.47	$0.00	$0.00	$64.07
J	NYC													
K	Long Island													

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	$20.21	$0.12	$11.69	$0.00	$0.58	$0.00	$0.71	$0.00	$2.44	$0.00	$0.00	$0.00	$35.75
F	Capital	$15.73	$2.31	$9.25	$0.00	$0.89	$0.23	$5.01	$0.00	$1.73	$0.64	$0.00	$0.00	$35.79
G	Hudson Valley (Dutchess)	$16.48	$1.90	$9.58	$0.00	$0.82	$0.11	$4.11	$0.00	$0.93	$0.98	$0.00	$0.00	$34.92
G	Hudson Valley (Rockland)	$16.39	$1.90	$9.51	$0.00	$0.82	$0.12	$4.15	$0.00	$0.85	$0.98	$0.00	$0.00	$34.72
J	NYC													
K	Long Island													

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	$16.04	$0.00	$3.28	$0.00	$1.31	$0.07	$18.87	$0.00	$0.41	$0.00	$0.00	$0.00	$39.98
F	Capital	$5.41	$3.42	$3.96	$0.00	$1.61	$0.49	$20.20	$0.00	$0.04	$0.06	$0.00	$0.00	$35.18
G	Hudson Valley (Dutchess)	$9.85	$0.11	$3.87	$0.00	$1.26	$0.24	$18.77	$0.00	$0.05	$0.06	$0.00	$0.00	$34.20
G	Hudson Valley (Rockland)	$9.66	$0.11	$4.01	$0.00	$1.53	$0.24	$18.76	$0.00	$0.05	$0.06	$0.00	$0.00	$34.40
J	NYC													
K	Long Island													

8. GA 7HA.02 Dual Fuel (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,752	30	1,782	$45.93	$2.63	$48.56
F	Capital	918	136	1,054	$31.10	$12.22	$43.32
G	Hudson Valley (Dutchess)	1,159	139	1,298	$31.82	$12.53	$44.36
G	Hudson Valley (Rockland)	1,158	139	1,297	$31.78	$12.53	$44.31
J	New York City						
K	Long Island	3,352	222	3,574	$124.40	$25.74	$150.15

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,886	10	2,896	$26.26	$0.28	$26.54
F	Capital	1,153	70	1,223	$19.28	$1.43	$20.71
G	Hudson Valley (Dutchess)	1,264	59	1,323	$17.98	$2.03	$20.02
G	Hudson Valley (Rockland)	1,261	55	1,316	$17.86	$1.95	$19.81
J	New York City						
K	Long Island	3,489	91	3,580	$77.06	$4.27	$81.33

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,719	0	2,719	$27.69	$0.00	$27.69
F	Capital	857	0	857	$13.85	$0.00	$13.85
G	Hudson Valley (Dutchess)	1,126	0	1,126	$16.98	$0.00	$16.98
G	Hudson Valley (Rockland)	1,115	0	1,115	$16.79	$0.00	$16.79
J	New York City						
K	Long Island	3,589	0	3,589	$70.08	$0.00	$70.08

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	1,523	0	626	0	7	2	122	0	252	0	6,228	0	8,760
F	Capital	820	0	562	0	38	0	184	0	196	0	6,960	0	8,760
G	Hudson Valley (Dutchess)	1,048	0	425	0	51	0	240	0	199	0	6,797	0	8,760
G	Hudson Valley (Rockland)	1,048	0	425	0	51	0	240	0	198	0	6,798	0	8,760
J	NYC													
K	Long Island	3,467	0	291	2,160	32	0	81	13	75	0	2,598	43	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	2,519	0	980	0	13	0	136	0	364	0	4,748	0	8,760
F	Capital	887	0	445	0	10	0	125	0	326	0	6,967	0	8,760
G	Hudson Valley (Dutchess)	1,063	0	446	0	18	0	263	0	242	0	6,728	0	8,760
G	Hudson Valley (Rockland)	1,059	0	445	0	18	0	263	0	239	0	6,736	0	8,760
J	NYC													
K	Long Island	3,449	0	718	1,224	19	0	172	7	112	0	3,003	56	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	2,207	0	209	0	429	2	5,225	0	83	0	629	0	8,784
F	Capital	430	0	303	0	379	6	5,796	0	48	0	1,822	0	8,784
G	Hudson Valley (Dutchess)	745	13	218	0	335	2	5,689	0	46	0	1,736	0	8,784
G	Hudson Valley (Rockland)	745	13	218	0	324	2	5,700	0	46	0	1,736	0	8,784
J	NYC													
K	Long Island	3,445	0	560	1,367	36	0	760	36	108	0	2,424	48	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	$42.42	$0.00	$17.41	$0.00	$0.62	$0.00	$0.17	$0.00	$5.51	$0.00	$0.00	$0.00	$66.15
F	Capital	$33.75	$0.00	$28.28	$0.00	$3.28	$0.00	$0.11	$0.00	$6.29	$0.00	$0.00	$0.00	$71.72
G	Hudson Valley (Dutchess)	$33.71	$0.00	$22.35	$0.00	$4.32	$0.00	$0.16	$0.00	$6.33	$0.00	$0.00	$0.00	$66.87
G	Hudson Valley (Rockland)	$33.68	$0.00	$22.35	$0.00	$4.31	$0.00	$0.16	$0.00	$6.31	$0.00	$0.00	$0.00	$66.82
J	NYC													
K	Long Island	$143.13	$0.00	$3.51	$0.01	$3.12	$0.00	$0.08	$0.03	$3.90	$0.00	$0.00	$0.00	$153.77

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	$21.62	$0.00	$10.36	$0.00	$0.11	$0.00	$0.16	$0.00	$4.81	$0.00	$0.00	$0.00	$37.06
F	Capital	$12.97	$0.00	$10.60	$0.00	$0.18	$0.00	$0.12	$0.00	$7.56	$0.00	$0.00	$0.00	$31.42
G	Hudson Valley (Dutchess)	$13.19	$0.00	$10.07	$0.00	$0.89	$0.00	$0.32	$0.00	$5.93	$0.00	$0.00	$0.00	$30.41
G	Hudson Valley (Rockland)	$13.09	$0.00	$10.06	$0.00	$0.89	$0.00	$0.32	$0.00	$5.83	$0.00	$0.00	$0.00	$30.19
J	NYC													
K	Long Island	$74.24	$0.00	$11.86	$0.01	$0.94	$0.00	$0.18	$0.01	$6.15	$0.00	$0.00	$0.00	$93.39

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	$20.68	$0.00	$1.80	$0.00	$6.58	$0.01	$16.27	$0.00	$0.43	$0.00	$0.00	$0.00	$45.77
F	Capital	$4.81	$0.00	$4.20	$0.00	$8.27	$0.03	$15.13	$0.00	$0.77	$0.00	$0.00	$0.00	$33.21
G	Hudson Valley (Dutchess)	$9.07	$0.13	$3.14	$0.00	$7.27	$0.01	$14.58	$0.00	$0.64	$0.00	$0.00	$0.00	$34.84
G	Hudson Valley (Rockland)	$9.05	$0.13	$3.14	$0.00	$7.10	$0.01	$14.61	$0.00	$0.64	$0.00	$0.00	$0.00	$34.68
J	NYC													
K	Long Island	$66.10	$0.00	$9.43	$0.74	$0.82	$0.00	$0.80	$0.05	$3.16	$0.00	$0.00	$0.00	$81.10

9. GA 7HA.02 Natural Gas with SCR (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,753	0	1,753	$46.05	$0.00	$46.05
F	Capital	963	0	963	$37.23	$0.00	$37.23
G	Hudson Valley (Dutchess)	1,202	0	1,202	$36.40	$0.00	$36.40
G	Hudson Valley (Rockland)	1,201	0	1,201	$36.36	$0.00	$36.36
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,900	0	2,900	$26.48	$0.00	$26.48
F	Capital	1,199	0	1,199	$20.80	$0.00	$20.80
G	Hudson Valley (Dutchess)	1,301	0	1,301	$19.43	$0.00	$19.43
G	Hudson Valley (Rockland)	1,298	0	1,298	$19.31	$0.00	$19.31
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,719	0	2,719	$27.69	$0.00	$27.69
F	Capital	857	0	857	$13.85	$0.00	$13.85
G	Hudson Valley (Dutchess)	1,126	0	1,126	$16.98	$0.00	$16.98
G	Hudson Valley (Rockland)	1,115	0	1,115	$16.79	$0.00	$16.79
J	New York City						
K	Long Island						

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	1,500	0	577	0	0	0	0	0	253	1	6,429	0	8,760
F	Capital	734	0	505	0	0	0	0	0	229	0	7,292	0	8,760
G	Hudson Valley (Dutchess)	971	0	363	0	0	0	0	0	231	0	7,195	0	8,760
G	Hudson Valley (Rockland)	971	0	363	0	0	0	0	0	230	0	7,196	0	8,760
J	NYC													
K	Long Island													

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	2,527	0	969	0	8	0	41	0	365	0	4,850	0	8,760
F	Capital	867	0	387	0	0	0	5	0	332	0	7,169	0	8,760
G	Hudson Valley (Dutchess)	1,047	0	411	0	0	0	6	0	254	0	7,042	0	8,760
G	Hudson Valley (Rockland)	1,047	0	402	0	0	0	6	0	251	0	7,054	0	8,760
J	NYC													
K	Long Island													

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	2,207	0	209	0	429	2	5,225	0	83	0	629	0	8,784
F	Capital	430	0	303	0	379	6	5,796	0	48	0	1,822	0	8,784
G	Hudson Valley (Dutchess)	745	13	218	0	335	2	5,689	0	46	0	1,736	0	8,784
G	Hudson Valley (Rockland)	745	13	218	0	324	2	5,700	0	46	0	1,736	0	8,784
J	NYC													
K	Long Island													

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	$40.42	$0.00	$9.51	$0.00	$0.00	$0.00	$0.00	$0.00	$5.63	$0.01	$0.00	$0.00	$55.56
F	Capital	$26.24	$0.00	$20.63	$0.00	$0.00	$0.00	$0.00	$0.00	$10.99	$0.00	$0.00	$0.00	$57.86
G	Hudson Valley (Dutchess)	$26.11	$0.00	$13.06	$0.00	$0.00	$0.00	$0.00	$0.00	$10.29	$0.00	$0.00	$0.00	$49.46
G	Hudson Valley (Rockland)	$26.09	$0.00	$13.06	$0.00	$0.00	$0.00	$0.00	$0.00	$10.27	$0.00	$0.00	$0.00	$49.42
J	NYC													
K	Long Island													

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	$21.68	$0.00	$9.99	$0.00	$0.05	$0.00	$0.02	$0.00	$4.75	$0.00	$0.00	$0.00	$36.48
F	Capital	$12.75	$0.00	$7.85	$0.00	$0.00	$0.00	$0.00	$0.00	$8.06	$0.00	$0.00	$0.00	$28.65
G	Hudson Valley (Dutchess)	$12.97	$0.00	$8.39	$0.00	$0.00	$0.00	$0.00	$0.00	$6.46	$0.00	$0.00	$0.00	$27.83
G	Hudson Valley (Rockland)	$12.95	$0.00	$7.98	$0.00	$0.00	$0.00	$0.00	$0.00	$6.36	$0.00	$0.00	$0.00	$27.29
J	NYC													
K	Long Island													

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	$20.68	$0.00	$1.80	$0.00	$6.58	$0.01	$16.27	$0.00	$0.43	$0.00	$0.00	$0.00	$45.77
F	Capital	$4.81	$0.00	$4.20	$0.00	$8.27	$0.03	$15.13	$0.00	$0.77	$0.00	$0.00	$0.00	$33.21
G	Hudson Valley (Dutchess)	$9.07	$0.13	$3.14	$0.00	$7.27	$0.01	$14.58	$0.00	$0.64	$0.00	$0.00	$0.00	$34.84
G	Hudson Valley (Rockland)	$9.05	$0.13	$3.14	$0.00	$7.10	$0.01	$14.61	$0.00	$0.64	$0.00	$0.00	$0.00	$34.68
J	NYC													
K	Long Island													

10. 1x1x1 5000F5 Combined Cycle Dual Fuel (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,988	78	6,066	$94.09	$10.01	$104.10
F	Capital	4,018	395	4,413	$75.36	$39.48	$114.85
G	Hudson Valley (Dutchess)	4,681	355	5,036	$73.00	$36.05	$109.05
G	Hudson Valley (Rockland)	4,683	355	5,038	$73.00	$36.04	$109.04
J	New York City	7,358	245	7,603	$148.17	$33.63	$181.79
K	Long Island	8,326	336	8,662	$230.49	$39.40	$269.88

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,127	43	6,170	$62.82	$2.22	$65.04
F	Capital	3,655	259	3,914	$44.21	$13.80	$58.01
G	Hudson Valley (Dutchess)	4,230	197	4,427	$45.75	$8.08	$53.83
G	Hudson Valley (Rockland)	4,230	197	4,427	$45.78	$8.07	$53.85
J	New York City	6,082	247	6,329	$77.03	$11.44	$88.48
K	Long Island	7,994	367	8,361	$143.00	$19.40	$162.40

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,383	0	5,383	$49.43	$0.00	$49.43
F	Capital	4,606	0	4,606	$35.05	$0.00	$35.05
G	Hudson Valley (Dutchess)	5,039	0	5,039	$37.33	$0.00	$37.33
G	Hudson Valley (Rockland)	5,052	0	5,052	$37.37	$0.00	$37.37
J	New York City	7,125	0	7,125	$73.54	$0.00	$73.54
K	Long Island	8,410	0	8,410	$124.62	$0.00	$124.62

Run Hours August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,149	0	808	0	917	0	1,886	0	8,760
F	Capital	3,681	0	839	0	732	0	3,508	0	8,760
G	Hudson Valley (Dutchess)	4,215	0	878	0	821	0	2,846	0	8,760
G	Hudson Valley (Rockland)	4,218	0	881	0	820	0	2,841	0	8,760
J	NYC	6,792	0	288	0	811	0	869	0	8,760
K	Long Island	7,742	0	98	0	920	0	0	0	8,760

Run Hours August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,227	0	703	0	943	0	1,887	0	8,760
F	Capital	3,155	0	910	0	759	0	3,936	0	8,760
G	Hudson Valley (Dutchess)	3,606	0	1,144	0	821	0	3,189	0	8,760
G	Hudson Valley (Rockland)	3,610	0	1,144	0	817	0	3,189	0	8,760
J	NYC	5,490	0	497	0	839	0	1,934	0	8,760
K	Long Island	7,030	0	395	0	1,331	0	4	0	8,760

Run Hours August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	4,511	0	506	0	872	0	2,895	0	8,784
F	Capital	3,667	0	918	0	939	0	3,260	0	8,784
G	Hudson Valley (Dutchess)	3,983	0	1,012	0	1,056	0	2,733	0	8,784
G	Hudson Valley (Rockland)	3,988	0	1,012	0	1,064	0	2,720	0	8,784
J	NYC	6,137	0	492	0	988	0	1,167	0	8,784
K	Long Island	7,308	0	373	0	1,102	0	1	0	8,784

Net EAS Revenues August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$93.69	$0.00	$13.69	$0.00	$10.40	$0.00	$0.00	$0.00	$117.78
F	Capital	$106.76	$0.00	$13.12	$0.00	$8.08	$0.00	$0.00	$0.00	$127.97
G	Hudson Valley (Dutchess)	$100.62	$0.00	$13.07	$0.00	$8.43	$0.00	$0.00	$0.00	$122.13
G	Hudson Valley (Rockland)	$100.63	$0.00	$13.08	$0.00	$8.41	$0.00	$0.00	$0.00	$122.12
J	NYC	$174.69	$0.00	$5.55	$0.00	$7.10	$0.00	$0.00	$0.00	$187.34
K	Long Island	$264.61	$0.00	$1.55	$0.00	$5.27	$0.00	$0.00	$0.00	$271.44

Net EAS Revenues August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$57.42	$0.00	$7.10	$0.00	$7.62	$0.00	$0.00	$0.00	$72.14
F	Capital	$49.73	$0.00	$10.14	$0.00	$8.27	$0.00	$0.00	$0.00	$68.14
G	Hudson Valley (Dutchess)	$46.56	$0.00	$15.65	$0.00	$7.27	$0.00	$0.00	$0.00	$69.48
G	Hudson Valley (Rockland)	$46.56	$0.00	$15.65	$0.00	$7.29	$0.00	$0.00	$0.00	$69.50
J	NYC	$80.51	$0.00	$8.12	$0.00	$7.96	$0.00	$0.00	$0.00	$96.59
K	Long Island	$154.71	$0.00	$5.07	$0.00	$7.69	$0.00	$0.00	$0.00	$167.47

Net EAS Revenues August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$43.59	$0.00	$4.07	$0.00	$5.84	$0.00	$0.00	$0.00	$53.50
F	Capital	$28.32	$0.00	$8.27	$0.00	$6.73	$0.00	$0.00	$0.00	$43.32
G	Hudson Valley (Dutchess)	$31.67	$0.00	$8.99	$0.00	$5.66	$0.00	$0.00	$0.00	$46.32
G	Hudson Valley (Rockland)	$31.68	$0.00	$8.99	$0.00	$5.69	$0.00	$0.00	$0.00	$46.37
J	NYC	$67.02	$0.00	$4.84	$0.00	$6.51	$0.00	$0.00	$0.00	$78.37
K	Long Island	$121.16	$0.00	$5.59	$0.00	$3.46	$0.00	$0.00	$0.00	$130.21

11. 1x1x1 5000F5 Combined Cycle Gas only with SCR (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,989	0	5,989	$94.30	$0.00	$94.30
F	Capital	4,225	0	4,225	$89.17	$0.00	$89.17
G	Hudson Valley (Dutchess)	4,800	0	4,800	$78.60	$0.00	$78.60
G	Hudson Valley (Rockland)	4,802	0	4,802	$78.59	$0.00	$78.59
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,159	0	6,159	$64.13	$0.00	$64.13
F	Capital	3,803	0	3,803	$50.58	$0.00	$50.58
G	Hudson Valley (Dutchess)	4,322	0	4,322	$50.09	$0.00	$50.09
G	Hudson Valley (Rockland)	4,322	0	4,322	$50.12	$0.00	$50.12
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,383	0	5,383	$49.43	$0.00	$49.43
F	Capital	4,606	0	4,606	$35.05	$0.00	$35.05
G	Hudson Valley (Dutchess)	5,039	0	5,039	$37.33	$0.00	$37.33
G	Hudson Valley (Rockland)	5,052	0	5,052	$37.37	$0.00	$37.37
J	New York City						
K	Long Island						

Run Hours August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,085	0	799	0	904	0	1,972	0	8,760
F	Capital	3,479	0	877	0	746	0	3,658	0	8,760
G	Hudson Valley (Dutchess)	3,957	0	950	0	843	0	3,010	0	8,760
G	Hudson Valley (Rockland)	3,960	0	953	0	842	0	3,005	0	8,760
J	NYC									
K	Long Island									

Run Hours August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,216	0	711	0	943	0	1,890	0	8,760
F	Capital	3,039	0	924	0	764	0	4,033	0	8,760
G	Hudson Valley (Dutchess)	3,516	0	1,122	0	806	0	3,316	0	8,760
G	Hudson Valley (Rockland)	3,520	0	1,122	0	802	0	3,316	0	8,760
J	NYC									
K	Long Island									

Run Hours August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	4,511	0	506	0	872	0	2,895	0	8,784
F	Capital	3,667	0	918	0	939	0	3,260	0	8,784
G	Hudson Valley (Dutchess)	3,983	0	1,012	0	1,056	0	2,733	0	8,784
G	Hudson Valley (Rockland)	3,988	0	1,012	0	1,064	0	2,720	0	8,784
J	NYC									
K	Long Island									

Net EAS Revenues August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$84.82	$0.00	$10.97	$0.00	$9.48	$0.00	$0.00	$0.00	$105.27
F	Capital	$76.85	$0.00	$17.84	$0.00	$12.32	$0.00	$0.00	$0.00	$107.01
G	Hudson Valley (Dutchess)	$67.50	$0.00	$22.16	$0.00	$11.11	$0.00	$0.00	$0.00	$100.76
G	Hudson Valley (Rockland)	$67.51	$0.00	$22.16	$0.00	$11.08	$0.00	$0.00	$0.00	$100.75
J	NYC									
K	Long Island									

Net EAS Revenues August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$56.47	$0.00	$7.25	$0.00	$7.66	$0.00	$0.00	$0.00	$71.38
F	Capital	$42.66	$0.00	$11.01	$0.00	$7.91	$0.00	$0.00	$0.00	$61.59
G	Hudson Valley (Dutchess)	$42.87	$0.00	$14.15	$0.00	$7.23	$0.00	$0.00	$0.00	$64.24
G	Hudson Valley (Rockland)	$42.87	$0.00	$14.15	$0.00	$7.25	$0.00	$0.00	$0.00	$64.27
J	NYC									
K	Long Island									

Net EAS Revenues August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$43.59	$0.00	$4.07	$0.00	$5.84	$0.00	$0.00	$0.00	$53.50
F	Capital	$28.32	$0.00	$8.27	$0.00	$6.73	$0.00	$0.00	$0.00	$43.32
G	Hudson Valley (Dutchess)	$31.67	$0.00	$8.99	$0.00	$5.66	$0.00	$0.00	$0.00	$46.32
G	Hudson Valley (Rockland)	$31.68	$0.00	$8.99	$0.00	$5.69	$0.00	$0.00	$0.00	$46.37
J	NYC									
K	Long Island									

12. 1x1x1 8000H Combined Cycle Dual Fuel (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,199	86	6,285	$100.79	$10.99	$111.78
F	Capital	4,245	398	4,643	$85.20	$35.82	$121.02
G	Hudson Valley (Dutchess)	4,897	369	5,266	$80.32	$37.85	$118.17
G	Hudson Valley (Rockland)	4,868	369	5,237	$80.06	$37.85	$117.91
J	New York City	7,551	277	7,828	$153.84	$35.78	$189.62
K	Long Island	8,157	320	8,477	$244.07	$38.14	$282.21

September, 2014 - August, 2015							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,312	43	6,355	$67.19	$2.38	$69.57
F	Capital	3,684	282	3,966	$46.81	$14.85	$61.65
G	Hudson Valley (Dutchess)	4,349	226	4,575	$48.27	$9.65	$57.92
G	Hudson Valley (Rockland)	4,337	226	4,563	$48.14	$9.65	$57.78
J	New York City	6,240	254	6,494	$79.80	$12.29	$92.09
K	Long Island	7,499	332	7,831	$148.90	$18.25	$167.15

September, 2015 - August, 2016							
		Run-Time Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,392	0	5,392	$51.46	$0.00	$51.46
F	Capital	4,878	0	4,878	$36.95	$0.00	$36.95
G	Hudson Valley (Dutchess)	5,100	0	5,100	$39.23	$0.00	$39.23
G	Hudson Valley (Rockland)	5,069	0	5,069	$38.98	$0.00	$38.98
J	New York City	7,199	0	7,199	$76.34	$0.00	$76.34
K	Long Island	7,961	0	7,961	$130.05	$0.00	$130.05

Run Hours August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,362	0	782	0	923	0	1,693	0	8,760
F	Capital	3,893	0	805	0	750	0	3,312	0	8,760
G	Hudson Valley (Dutchess)	4,419	0	866	0	847	0	2,628	0	8,760
G	Hudson Valley (Rockland)	4,396	0	888	0	841	0	2,635	0	8,760
J	NYC	6,923	0	272	0	905	0	660	0	8,760
K	Long Island	7,836	0	98	0	641	0	185	0	8,760

Run Hours August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,464	0	670	0	891	0	1,735	0	8,760
F	Capital	3,248	0	949	0	718	0	3,845	0	8,760
G	Hudson Valley (Dutchess)	3,724	0	1,144	0	851	0	3,041	0	8,760
G	Hudson Valley (Rockland)	3,722	0	1,144	0	841	0	3,053	0	8,760
J	NYC	5,579	0	546	0	915	0	1,720	0	8,760
K	Long Island	7,124	0	423	0	707	0	506	0	8,760

Run Hours August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	4,609	0	579	0	783	0	2,813	0	8,784
F	Capital	3,849	0	914	0	1,029	0	2,992	0	8,784
G	Hudson Valley (Dutchess)	4,081	0	1,049	0	1,019	0	2,635	0	8,784
G	Hudson Valley (Rockland)	4,060	0	1,068	0	1,009	0	2,647	0	8,784
J	NYC	6,254	0	533	0	945	0	1,052	0	8,784
K	Long Island	7,335	0	449	0	626	0	374	0	8,784

Net EAS Revenues August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$99.04	$0.00	$13.31	$0.00	$12.74	$0.00	$0.00	$0.00	$125.09
F	Capital	$111.79	$0.00	$12.35	$0.00	$9.23	$0.00	$0.00	$0.00	$133.37
G	Hudson Valley (Dutchess)	$106.29	$0.00	$10.78	$0.00	$11.88	$0.00	$0.00	$0.00	$128.95
G	Hudson Valley (Rockland)	$106.12	$0.00	$10.90	$0.00	$11.79	$0.00	$0.00	$0.00	$128.81
J	NYC	$180.52	$0.00	$4.14	$0.00	$9.10	$0.00	$0.00	$0.00	$193.76
K	Long Island	$271.16	$0.00	$1.56	$0.00	$11.05	$0.00	$0.00	$0.00	$283.77

Net EAS Revenues August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$61.04	$0.00	$6.64	$0.00	$8.53	$0.00	$0.00	$0.00	$76.22
F	Capital	$52.33	$0.00	$10.19	$0.00	$9.32	$0.00	$0.00	$0.00	$71.84
G	Hudson Valley (Dutchess)	$49.44	$0.00	$14.81	$0.00	$8.48	$0.00	$0.00	$0.00	$72.73
G	Hudson Valley (Rockland)	$49.33	$0.00	$14.81	$0.00	$8.45	$0.00	$0.00	$0.00	$72.59
J	NYC	$82.58	$0.00	$8.46	$0.00	$9.52	$0.00	$0.00	$0.00	$100.56
K	Long Island	$158.52	$0.00	$5.48	$0.00	$8.63	$0.00	$0.00	$0.00	$172.63

Net EAS Revenues August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$45.19	$0.00	$4.55	$0.00	$6.27	$0.00	$0.00	$0.00	$56.00
F	Capital	$29.06	$0.00	$8.52	$0.00	$7.89	$0.00	$0.00	$0.00	$45.47
G	Hudson Valley (Dutchess)	$32.14	$0.00	$9.06	$0.00	$7.09	$0.00	$0.00	$0.00	$48.29
G	Hudson Valley (Rockland)	$31.97	$0.00	$9.18	$0.00	$7.01	$0.00	$0.00	$0.00	$48.16
J	NYC	$68.29	$0.00	$4.95	$0.00	$8.05	$0.00	$0.00	$0.00	$81.29
K	Long Island	$122.76	$0.00	$6.28	$0.00	$7.29	$0.00	$0.00	$0.00	$136.33

13. 1x1x1 8000H Combined Cycle Gas only with SCR (for informational purposes only)

September, 2013 - August, 2014							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,200	0	6,200	$101.01	$0.00	$101.01
F	Capital	4,462	0	4,462	$91.47	$0.00	$91.47
G	Hudson Valley (Dutchess)	5,022	0	5,022	$85.83	$0.00	$85.83
G	Hudson Valley (Rockland)	4,993	0	4,993	$85.56	$0.00	$85.56
J	New York City						
K	Long Island						

September, 2014 - August, 2015							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,354	0	6,354	$68.93	$0.00	$68.93
F	Capital	3,833	0	3,833	$53.45	$0.00	$53.45
G	Hudson Valley (Dutchess)	4,448	0	4,448	$52.77	$0.00	$52.77
G	Hudson Valley (Rockland)	4,436	0	4,436	$52.64	$0.00	$52.64
J	New York City						
K	Long Island						

September, 2015 - August, 2016							
		Run-Time Hours			**Net Energy Revenues ($/kW-year)**		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	5,392	0	5,392	$51.46	$0.00	$51.46
F	Capital	4,878	0	4,878	$36.95	$0.00	$36.95
G	Hudson Valley (Dutchess)	5,100	0	5,100	$39.23	$0.00	$39.23
G	Hudson Valley (Rockland)	5,069	0	5,069	$38.98	$0.00	$38.98
J	New York City						
K	Long Island						

Run Hours August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,290	0	782	0	910	0	1,778	0	8,760
F	Capital	3,705	0	842	0	757	0	3,456	0	8,760
G	Hudson Valley (Dutchess)	4,168	0	933	0	854	0	2,805	0	8,760
G	Hudson Valley (Rockland)	4,145	0	955	0	848	0	2,812	0	8,760
J	NYC									
K	Long Island									

Run Hours August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	5,461	0	670	0	893	0	1,736	0	8,760
F	Capital	3,112	0	963	0	721	0	3,964	0	8,760
G	Hudson Valley (Dutchess)	3,612	0	1,142	0	836	0	3,170	0	8,760
G	Hudson Valley (Rockland)	3,610	0	1,142	0	826	0	3,182	0	8,760
J	NYC									
K	Long Island									

Run Hours August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	4,609	0	579	0	783	0	2,813	0	8,784
F	Capital	3,849	0	914	0	1,029	0	2,992	0	8,784
G	Hudson Valley (Dutchess)	4,081	0	1,049	0	1,019	0	2,635	0	8,784
G	Hudson Valley (Rockland)	4,060	0	1,068	0	1,009	0	2,647	0	8,784
J	NYC									
K	Long Island									

Net EAS Revenues August 2013 - July 2014										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$89.27	$0.00	$11.34	$0.00	$11.74	$0.00	$0.00	$0.00	$112.34
F	Capital	$80.92	$0.00	$17.05	$0.00	$10.55	$0.00	$0.00	$0.00	$108.52
G	Hudson Valley (Dutchess)	$72.37	$0.00	$19.78	$0.00	$13.45	$0.00	$0.00	$0.00	$105.61
G	Hudson Valley (Rockland)	$72.21	$0.00	$19.90	$0.00	$13.35	$0.00	$0.00	$0.00	$105.46
J	NYC									
K	Long Island									

Net EAS Revenues August 2014 - July 2015										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$60.20	$0.00	$6.64	$0.00	$8.73	$0.00	$0.00	$0.00	$75.58
F	Capital	$44.59	$0.00	$11.07	$0.00	$8.86	$0.00	$0.00	$0.00	$64.52
G	Hudson Valley (Dutchess)	$44.43	$0.00	$14.19	$0.00	$8.35	$0.00	$0.00	$0.00	$66.97
G	Hudson Valley (Rockland)	$44.32	$0.00	$14.19	$0.00	$8.32	$0.00	$0.00	$0.00	$66.83
J	NYC									
K	Long Island									

Net EAS Revenues August 2015 - July 2016										
Day-Ahead Commitment		Energy				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	$45.19	$0.00	$4.55	$0.00	$6.27	$0.00	$0.00	$0.00	$56.00
F	Capital	$29.06	$0.00	$8.52	$0.00	$7.89	$0.00	$0.00	$0.00	$45.47
G	Hudson Valley (Dutchess)	$32.14	$0.00	$9.06	$0.00	$7.09	$0.00	$0.00	$0.00	$48.29
G	Hudson Valley (Rockland)	$31.97	$0.00	$9.18	$0.00	$7.01	$0.00	$0.00	$0.00	$48.16
J	NYC									
K	Long Island									

F. Summary of results for informational combined cycle plants

This appendix provides results for the informational combined cycle plants considered in Section II.6. These results are provided for informational purposes only.

As discussed in Section IV, net EAS revenues for the informational combined cycle plants are estimated using an energy only version of the net EAS revenues model. That is, for the informational combined cycle plants, the model estimates net energy revenues for both DAM energy commitments and RTM energy dispatches, while also allowing the unit to buyout of a DAM energy commitment when it is profitable to do so. The model allows combined cycle plants to operate at minimum load between profitable energy blocks, if the losses while operating at minimum load are less than an additional startup cost. The informational plants are allowed to operate at minimum load for up to 24 hours. For the informational Siemens SGT6-5000F combined cycle, minimum load is approximately 163 MW with an 8,313 MMBtu/MWh heat rate. For the Siemens SGT6-8000H, minimum load is approximately 228 MW with an 7,498 MMBtu/MWh heat rate.[93] Based on the results for the data utilized for this Report (i.e., September 2013 through August 2016), the model estimates that the informational combined cycle plants would operate at tariff prescribed LOE conditions with annual average capacity factors ranging between approximately 50 percent (Load Zone F) to 97 percent (Load Zone K).

Net EAS revenues are calculated as the average net energy revenues over the three-year modeling period, plus two additional flat adders for ancillary services and VSS revenues. VSS revenues are assumed to be $1.43/kW-year. Average ancillary services revenues are assumed to be $3.70/kW-year. This value is based on the average total ancillary revenues, as estimated by the NYISO, using settlement data for 13 comparable combined cycle plants greater than 200 MW for the period 2013 through 2015. Average $/kW-year values are based on both summer and winter DMNC values for the comparable plants analyzed, as reported in the 2016 Gold Book. The model logic does not include a run time limit for combined cycle plants in NYC for the purposes of meeting the property tax abatement requirement of 18 hours per start. Instead, results are presented for Load Zone J assuming property tax payments at the current assessed rate.

[93] Values represent averages across all Load Zones and summer/winter periods.

Appendix F Table 1A: Reference Point Prices $2017/kW-month

Monthly Reference Point Price ($/kW-Month)						
Technology	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Informational Combined cycle - Dual fuel	$16.44	$18.06	$24.96	$24.55	$46.10	$35.93
	$12.74	$14.43	$20.72	$20.28	$39.42	$29.20
Informational Combined cycle - Gas only	$15.76	$17.87	$24.66	$24.26	-	-
	$12.19	$14.51	$20.66	$20.22	-	-

Appendix F Table 1B: Gross CONE $2017/kW-month

Gross CONE ($/kW-Year)						
Technology	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Informational Combined cycle - Dual fuel	$245.19	$258.60	$291.35	$287.73	$462.49	$402.94
	$220.01	$233.56	$262.81	$259.22	$416.32	$359.11
Informational Combined cycle - Gas only	$234.15	$247.39	$279.84	$276.26	-	-
	$209.96	$223.32	$252.36	$248.75	-	-

Appendix F Table 1C: Net EAS revenues $2017/kW-month

Net EAS ($/kW-Year)						
Technology	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Informational Combined cycle - Dual fuel	$88.39	$87.03	$86.54	$86.52	$129.00	$199.63
	$93.13	$90.87	$90.49	$90.63	$133.54	$207.70
Informational Combined cycle - Gas only	$83.86	$77.63	$77.45	$77.43	-	-
	$88.57	$79.89	$80.55	$80.69	-	-

Appendix F Table 2A: Net EAS Model Results by Load Zone

Dual Fuel Capability ($2015)

		Annual Average Net EAS Revenues ($/kW-year)		Annual Average Run Hours	
Load Zone		1x1x1 5000F5 CC	1x1x1 8000H CC	1x1x1 5000F5 CC	1x1x1 8000H CC
C	Central	$86.27	$90.90	5,873	6,011
F	Capital	$84.94	$88.69	4,311	4,496
G	Hudson Valley (Dutchess)	$84.44	$88.45	4,834	4,980
G	Hudson Valley (Rockland)	$84.46	$88.32	4,839	4,956
J	New York City	$125.90	$130.33	7,019	7,174
K	Long Island	$194.83	$202.71	8,478	8,090

		Annual Average Unit Starts		Annual Average Hours per Start	
Load Zone		1x1x1 5000F5 CC	1x1x1 8000H CC	1x1x1 5000F5 CC	1x1x1 8000H CC
C	Central	57	48	103.3	124.4
F	Capital	71	57	60.7	79.3
G	Hudson Valley (Dutchess)	77	62	62.8	79.9
G	Hudson Valley (Rockland)	77	63	63.1	78.7
J	New York City	66	46	106.9	157.1
K	Long Island	22	28	388.3	288.9

Notes:
[1] Results reflect data for the period September 2013 through August 2016.
[2] Estimates include a $1.43/kW-year adder for VSS revenues and $3.70/kW-year adder for ancillary service revenues for all units, based on settlement data provided by NYISO.
[3] Run time limits were applied based on NSPS.

Appendix F Table 2B: Net EAS Model Results by Load Zone

Gas only with SCR Capability ($2015)

		Annual Average Net EAS Revenues ($/kW-year)		Annual Average Run Hours	
Load Zone		1x1x1 5000F5 CC	1x1x1 8000H CC	1x1x1 5000F5 CC	1x1x1 8000H CC
C	Central	$81.85	$86.44	5,844	5,982
F	Capital	$75.77	$77.97	4,211	4,391
G	Hudson Valley (Dutchess)	$75.57	$78.75	4,720	4,857
G	Hudson Valley (Rockland)	$75.59	$78.61	4,725	4,833
J	New York City				
K	Long Island				

		Annual Average Unit Starts		Annual Average Hours per Start	
Load Zone		1x1x1 5000F5 CC	1x1x1 8000H CC	1x1x1 5000F5 CC	1x1x1 8000H CC
C	Central	57	48	103.4	125.5
F	Capital	73	58	58.0	75.3
G	Hudson Valley (Dutchess)	78	64	60.3	75.5
G	Hudson Valley (Rockland)	78	65	60.6	74.3
J	New York City				
K	Long Island				

Notes:
[1] Results reflect data for the period September 2013 through August 2016.
[2] Estimates include a $1.43/kW-year adder for VSS revenues and $3.70/kW-year adder for ancillary service revenues for all units, based on settlement data provided by NYISO.
[3] Run time limits were applied based on NSPS.

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