Attachment III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER25-____-000**

AFFIDAVIT OF PAUL J. HIBBARD, DR. TODD SCHATZKI, JOSEPH CAVICCHI, CHARLES WU, AND DR. DANIEL STUART

I. Qualifications

A. Paul Hibbard

1. My name is Paul J. Hibbard. I am a Principal at Analysis Group, Inc. (AG), 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 AG for eighteen years. 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 National Association of Regulatory Utility Commissioners (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 Principal at AG in its Boston office. My business address is 111 Huntington Avenue, 14th Floor, Boston, Massachusetts 02199.

6. I have been with AG since 2005. I am an economist with expertise and experience in energy and environmental economics, regulation and policy. My experience in energy markets and regulation includes wholesale and retail electricity markets, natural gas markets, and other fuels markets. I have extensive experience in wholesale electricity markets in many regions of North America, including work in markets for energy, capacity and ancillary services. I have helped in the review and redesign of organized wholesale markets, performed economic analysis of the impacts of proposed market rules and infrastructure changes, evaluated the rules and procedures for reviewing cost-based offers by market monitors in organized markets, developed cost-based rates for programs, estimated the cost of new entry, including cost of capital, for capacity market demand curves, evaluated the conduct of market participants with respect to allegations of market manipulation, and assessed economic damages associated with disputes regarding wholesale power contracts. I have worked with independent system operators in New England and New York, and other work has involved many organized and non-organized wholesale markets, including Alberta Electric System Operator, California Independent

System Operator, ISO-New England, Midcontinent Independent System Operator, Inc., New York ISO, PJM Interconnection ("PJM"), Southwest Power Pool and Western US wholesale electricity markets. In other cost-of-service ratemaking work, I have analyzed impacts on financial viability and condition, assessed ratemaking structures, including decoupling and various capital tracking mechanisms, compute the required cost of capital, and estimated cost of service. Across engagements, I have worked on behalf of regulated utilities, independent power producers, system and market operators, market monitors, and other market participants. I have submitted testimony to federal, state and provincial (Canada) regulatory commissions.

7. Prior to joining AG, 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.

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. Joseph Cavicchi

9. My name is Joseph Cavicchi. I am a power system economist and Vice President at AG in its Boston office. I am also a registered professional engineer (mechanical) in the State of Massachusetts. My business address is 111 Huntington Avenue, 14th Floor, Boston, Massachusetts 02199.

10. Throughout my career I have been directly involved with corporations, private and public institutions, and state and federal regulatory authorities in connection with the economics of the electricity industry. For the past 27 years, I have been working almost exclusively on economic issues related to the electricity industry. I have conducted economic analyses evaluating the impact of regulatory policies on electricity markets, applied rigorous analytical modeling tools to power system operations, evaluated contracting disputes and assessed financial damages, analyzed the effectiveness of market power mitigation frameworks in conjunction with antitrust analyses, and led economic investigations of market participant bidding behavior associated with allegations of market manipulation. In

addition, during the first decade of my career I worked as a mechanical engineer and project manager at a complex that simultaneously produced (cogenerated) steam and electricity to support building operations.

11. My curriculum vitae is attached as Exhibit C.

D. Charles Wu

12. My name is Charles Wu. I am a Vice President at AG, also in its Boston office.

13. I have been with AG for 10 years. First, from January 2012 to July 2015, and most recently, from July 2017 to the present. During that period, I have worked on economic analyses of energy, electricity, and carbon allowance markets, and have designed and run models of large-scale electrical systems to simulate operations during stressed conditions. I have also provided litigation support in cases related to trade disputes, mergers and acquisitions, and statistical sampling.

14. I hold a M.B.A. from the MIT Sloan School of Management, a M.A. in Economics from Northwestern University, and an S.B. in Economics from the Massachusetts Institute of Technology. My curriculum vitae is attached as Exhibit D.

E. Dr. Daniel Stuart

15. My name is Daniel Stuart. I am a Manager at AG, also in its Boston Office.

16. I have been with AG for 3 years. During this period, I have applied economic and statistical analysis to regulatory proceedings, litigation, and policy matters related to energy and environmental policy. I have supported experts in Federal Energy Regulatory Commission rate litigation, state regulatory proceedings, and civil litigation related to the provision of electric utility service. I have also coauthored white papers on alternative pathways for power sector decarbonization in New England, the economic impacts of the Regional Greenhouse Gas Initiative on Northeastern states, the potential impacts of heavy-duty vehicle electrification on the electric distribution system, regulatory innovation needed to meet state decarbonization goals, and cost containment mechanisms in Washington State's cap-and-invest program.

17. I hold a Ph.D. in Public Policy from Harvard University, and an BA. in Economics from the Swarthmore College. My curriculum vitae is attached as Exhibit E.

II. Purpose and Summary of Affidavit

18. Section 5.14.1.2.2 of the NYISO Market Administration and Control Area Services Tariff (Services Tariff) requires that the ICAP Demand Curves be comprehensively evaluated every four years through a review of the ICAP Demand Curve parameters. An independent consultant assists with conducting the periodic reviews.[1] In order to develop 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 or Commission) of the ICAP Demand Curves approved by the NYISO Board of Directors. This process is commonly referred to as the ICAP Demand Curve reset (DCR).

19. AG was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2025-2026 Capability Year and continuing through the 2028-2029 Capability Year (2025-2029 DCR). AG worked with 1898 & Co. to complete the tariff-required periodic review process (together, AG and 1898 & Co. are referred to in this Affidavit as the "Independent Consultant").[2]

20. The purpose of this affidavit is twofold. First, we provide a summary of the final report completed by AG and 1898 & Co. for the 2025-2029 DCR (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 F. 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 design*

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[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.

[2] 1898 & Co. & Co. is a business, technology, and security consultancy, which is a part of Burns & McDonnell.

[3] Hibbard, Schatzki, Cavicchi, Wu, Stuart, Lind, McInerney, and Swope, Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years - Final Report (Updated Version), October 2, 2024 (hereafter, the "Final Report").

(for example, the recommendations related to a lithium-ion battery energy storage system [BESS] duration to be used in each location evaluated as part of the DCR); (2) items related to the *net Energy and Ancillary Services (EAS) revenues model* (for example, details on modeling of BESS participation in the market); (3) items related to *property and mortgage recording taxes* (for example, details related to the availability of property tax and mortgage recording tax abatements/exemptions to developers); (4) items related to the *financial parameters* used in establishing levelized localized embedded costs for the peaking plants; and (5) items related to the *annual update process* (for example, recommendations related to the choice of indices for the purpose of adjusting gross cost of new entry values in years 2-4 of the reset period).

III. Overview and Summary of the Final Report

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

22. *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, BESS durations, and environmental control technologies when making investment decisions given applicable laws and regulations, project development and operational risk, and opportunities for revenues over the economic life of the project.[4]

[4] Services Tariff, Section 5.14.1.2.2. 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 DCR which resulted in the establishment of ICAP Demand Curves for the 2014-2015, 2015-2016, and 2016-2017 Capability Years (2014-2017 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 Matthew E. Lind, Kieran McInerney, and Chad Swope*, which is set forth in Attachment IV of the filing letter to which this Affidavit is attached (1898 & Co. Affidavit), we have applied the following criteria in this DCR to inform our decisions regarding the appropriate technology and associated plant design: (i) standard generating facility technology – available to most market participants; (ii) proven technology – operating experience at a utility power plant; (iii) unit characteristics that can be economically dispatched; (iv) ability to cycle and provide peaking service; (v) can be practically constructed in a particular location; and (vi) can meet environmental requirements and regulations. These factors are consistent with the technology screening criteria accepted by the Commission and used in prior DCRs.

23. *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 costs (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.

24. *Estimation of net EAS revenues for the peaking plant technology* – expected EAS revenues for the peaking plants, net of operating costs, are estimated using models we constructed for this purpose (one for fossil-fueled technologies, and one for BESS). The net EAS model used for the peaking plant includes an adjustment of historical locational based marginal prices (LBMPs) and reserve prices to reflect market conditions at the Services Tariff-prescribed level of excess (LOE) conditions assumed for purposes of the DCR.[5]

25. *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 a reference point price for each ICAP Demand Curve, and establishing the shape and slope of the ICAP Demand Curves in consideration of the zero-crossing points (ZCP) and other factors including the seasonal availability of capacity (as represented by the winter-to-summer ratio [WSR] and the summer-to-winter ratio [SWR]), the LOE, and relative reliability risk by season (*i.e.*, summer and winter loss of load expectation [SLOLE and WLOLE, respectively]).[6]

26. *Annual updating* – as required by the Services Tariff, the ICAP Demand Curve parameters are to be updated annually based on escalation of installed capital costs, recalculation of net

[5] *See* Services Tariff, Section 5.14.1.2.2. The Services Tariff requires that net EAS revenues be estimated for each peaking plant 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 factor values and how LBMPs and reserve prices are adjusted to reflect LOE conditions are described in detail in Section IV and Appendix C of the Final Report.

[6] 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. Beginning with the 2025-2026 Capability Year, the NYISO will implement enhancements to the current methodologies for translating the annualized gross CONE values and net CONE to monthly values used in establishing the ICAP Demand Curves. The enhancements provide for express accounting of relative seasonal reliability risks and were approved by FERC in February 2024. The exact formulas employed to calculate winter and summer reference point prices are discussed in detail in Section V of the Final Report.

EAS revenues using updated electricity price and other data, updated WSR and SWR values, and updated SLOLE and WLOLE values.

27. 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.

28. The Final Report, and the analyses and conclusions contained therein, were developed by AG and 1898 & Co. in an open and transparent process in consultation with the NYISO and stakeholders over a roughly one-year period beginning in August 2023 and ending with the issuance of the Final Report in October 2024. Throughout, we developed quantitative and qualitative analyses, proposed and finalized recommendations, and presented and discussed the analyses and recommendations with stakeholders across numerous stakeholder meetings.[7] To assist in completion of the DCR, we: (1) established guiding principles for evaluating DCR alternatives; (2) evaluated approaches taken in past DCRs, as well as capacity markets in other relevant independent system operator and regional transmission organization (ISO/RTO) jurisdictions; (3) highlighted key issues related to technology costs, net EAS modeling, financial parameters, and ICAP Demand Curve reference point price calculations; and (4) 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.

29. 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 requires analysis of a wide array of quantitative market,

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[7] *See* Final Report at pp. 3-4. Table 1 of the Final Report identifies the meetings held as well as the topics discussed in each meeting.

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 or forecast assumptions. The viewpoints of NYISO and stakeholders, as well as the Market Monitoring Unit (MMU), 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.

30. Specifically, we evaluated DCR-related matters applying, where relevant, the following objectives and criteria:

31. *Economic Principles* – proposed ICAP Demand Curve parameters and methods should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO-administered markets.

32. *Accuracy* – ICAP Demand Curve parameters should reflect the actual net cost of new entry in New York with as much certainty as feasible.

33. *Transparency* – The DCR calculations and periodic updates to net CONE should be clear and transparent to Market Participants (MPs), and annual update methods and calculations should be understandable and allow MPs to develop market expectations.

34. *Feasibility* – The DCR design and implementation should be practical and feasible from regulatory and administrative perspectives.

35. *Historical Precedent and Performance* – 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 PJM). Consistency between DCRs (to the extent feasible and warranted) also promotes market stability, which in turn reduces financial risk and developers’ cost of entry.

36. We applied the methods, models and equations summarized herein and described in detail in the Final Report to identify recommended reference point prices and other ICAP Demand Curve parameters for the 2025-2026 Capability Year, as well as the methods and

inputs to be used in the annual updates to determine the ICAP Demand Curves for the 2026-2027 through 2028-2029 Capability Years.

37. Our recommendations and results reflect a number of conclusions on key market and technology issues that we comprehensively evaluated throughout the DCR including:

38. The two-hour BESS represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a BESS would use lithium-ion technology and a modular, purpose-built enclosure (PBE) form factor. In the 2021-2025 DCR, we evaluated BESS technologies with energy discharge durations of 4, 6, and 8 hours. In this DCR, we also evaluated a BESS with a two-hour duration and found that to be the appropriate peaking plant technology option for all locations.

39. For the two-hour BESS, we assume a twenty-year amortization period and incorporate additional costs for capacity augmentation to ensure consistent performance and nominal capacity value over the assumed life of the resource. Capacity augmentation costs are included in the two-hour BESS' variable operations and maintenance (VOM) costs, reflecting the fact that capacity augmentation costs are related to the total throughput of the battery, and the fixed operations and maintenance (FOM), reflecting augmentation costs unrelated to cycling and throughput, as well as an initial overbuild component. Capacity augmentation costs during the life of the resource are allocated among a VOM and FOM component.

40. The appropriate method to evaluate the selection of the appropriate peaking plant technology is to identify the viable technology option that minimizes the cost of Unforced Capacity (UCAP). An economic evaluation focused solely on the cost of ICAP would fail to account for variation in Capacity Accreditation Factors (CAFs) and derating factors across technology options evaluated for this DCR.

41. The state of New York has begun a process to decarbonize the power sector over the next couple of decades, including passage of the Climate Leadership and Community Protection Act (CLCPA) in 2019. The CLCPA does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology during the 2025-2029 reset period. It does,

however, affect the development and operation of such facilities, which could in turn affect present-day financial analysis parameters (*e.g.*, the appropriate amortization period). For this DCR, our review included two categories of units that at least initially were powered using fossil fuels. First, we reviewed installation and operation of a fossil unit in each location designed to exclusively run on fossil fuels (and thus assumed to not operate in 2040 or beyond). Second, we reviewed installation and operation of a unit initially operating on fossil fuels, but retrofitted to operate on hydrogen fuel beginning in 2040. For the fossil-only unit, we applied a 13-year amortization period to reflect CLCPA's requirement for 100 percent of load to be served by zero-emissions resources by 2040, and consistent with the decisions by FERC accepting this amortization period method in the 2021-2025 DCR.[8] For the fossil-hydrogen unit, we studied the potential costs associated with retrofitting a turbine to run on hydrogen fuel, and the costs of storing associated hydrogen fuel onsite as a "proxy" for a potential zero-emission fuel option to comply with the requirements of the CLCPA for 100% of New York energy demand to be served by zero-emissions resources by January 1, 2040. Notably, the CLCPA does not define what constitutes a zero-emissions resource, and New York has not yet established final rules to establish such eligibility/qualification.

42. For the fossil-fuel fired unit analysis, the GE 7HA.03 frame turbine represents the highest variable cost, lowest fixed cost simple cycle gas turbine (SCGT) peaking plant option that is economically viable for all locations except Load Zone K. The GE 7HA.02 option represents a lower fixed cost SCGT technology option for Load Zone K considering the System Deliverability Upgrade (SDU) cost that would be applicable to the GE7HA.03 for Load Zone K. Such SDU costs are not applicable to a GE 7HA.02 option for Load Zone K. To be economically viable and practically constructible, a 7HA.03 SCGT (for all locations other than Load Zone K) and 7HA.02 SCGT (for Load Zone K) would be built with selective catalytic reduction (SCR) emission control, whether constructed as gas-only or dual-fuel.

[8] *New York Independent System Operator, Inc.*, 183 FERC ¶ 61,130, Docket No. ER21-502, (May 19, 2023); and *New York Independent System Operator, Inc.*, 185 FERC ¶ 61,010 (October 4, 2023).

43. Based on market expectations for fuel availability and fuel assurance, changes in market structures related to capacity accreditation, consideration of applicable reliability and local distribution company (LDC) retail gas tariff requirements, and developer expectations, we expect that developers would include dual fuel capability as part of the applicable SCGT technology design in all locations.

44. Consistent with the previous two resets, we assume that the developer of a peaking plant would enter into a Payment in Lieu of Taxes (PILOT) agreement in all locations outside of Load Zone J to obtain available reductions in applicable property taxes. Based on a review of PILOT data available from the New York State Comptroller's Office, a 0.6% effective property tax rate represents a reasonable assumption that is consistent with current PILOT agreements for natural gas plants and BESS projects in New York. For Load Zone J, we assume that the developer of a peaking plant would be subject to a property tax rate equals 4.77%, which is equal to the product of (1) the Class 4 Property rate (10.592%) and (2) a 45% assessment ratio.

45. We have also considered the impact of property tax abatements. Energy storage plants are provided a 15-year property tax abatement statewide, and the fossil-fueled SCGT option for Load Zone J is afforded a 15-year tax abatement in Load Zone J. Although the Load Zone J specific tax abatement was scheduled to expire for construction activities occurring after April 1, 2025, Chapter 332 of the Laws of the State of New York of 2024 enacted an extension of the tax abatement to cover the 2025-2029 reset period. As such, 15-year property tax abatements are assumed for energy storage plants statewide, and for fossil-fueled SCGT options in Load Zone J.

46. Based upon a historical record of energy projects receiving mortgage recording tax exemptions in New York, we assume the peaking plant technology option would qualify for abatement of mortgage recording taxes through an appropriate arrangement with a tax-exempt industrial development agency/authority (IDA). Specifically, based on publicly available date, we identified seventeen generation projects throughout New York that have received mortgage recording tax exemptions. The projects include fossil-fired generation facilities, energy storage projects, and renewable energy facilities. Because tax-exempt entities are not exempt from the component of the mortgage recording tax applicable to real

property located in a county that is part of a transportation district, we assume that the peaking plant technology options will incur additional tax payments of 30 cents per $100 of mortgage debt for counties within the Metropolitan Commuter Transportation District (Load Zones G (Dutchess County), G (Rockland County), J, and K), and 25 cents per $100 of the mortgage debt for counties within the Central New York Regional Transportation District (Load Zone C) and the Capital District Transportation Authority (Load Zone F).

47. For the purpose of modeling net EAS revenues for BESS technologies in the real-time market (RTM), it is appropriate to use Real-Time Dispatch prices transacting on a nominal 5-minute basis. Consistent with the 2017-2021 and 2021-2025 DCRs, we continue to model net EAS revenues for fossil peaking plant options in the RTM using average hourly prices.

48. The financial parameters should take into consideration technology-specific risk factors, such as uncertainty with respect to future CAFs for BESS versus SCGT technologies, differences in factors driving technological change in each category, and differences in the applicability of various state and federal energy and environmental policies to each technology. In consideration of these factors, the financial parameters that underlie the weighted average cost of capital (WACC) for each technology can, and should, be different.

49. For SCGT technologies, the WACC used to develop the levelized gross CONE should reflect a capital structure of 55 percent debt and 45 percent equity; a 6.7 percent cost of debt; and a 14.0 percent cost of equity, for a WACC of 9.99 percent. Based on current tax rates in New York State and New York City, this translates to a nominal after tax WACC (ATWACC) of 9.02 percent for all locations other than Load Zone J and 8.76 percent for Load Zone J.

50. For BESS technologies, the WACC used to develop the levelized gross CONE should reflect a capital structure of 55 percent debt and 45 percent equity; a 7.2 percent cost of debt; and a 14.5 percent cost of equity, for a WACC of 10.49 percent. Based on current tax rates in New York State and New York City, this translates to a nominal ATWACC of 9.45 percent for all locations other than Load Zone J and 9.17 percent for Load Zone J.

51. BESS technologies qualify for a 5-year modified accelerated cost recovery system (MACRS) depreciation schedule. If a BESS developer does not have sufficient tax liability to fully monetize the accelerated depreciation benefit, they could enter into financing agreements with a tax equity partner or leverage tax liability of a holding company if developed as part of a portfolio of projects under a common holding company. AG did not assume any incremental costs associated with monetizing the portion of the accelerated depreciation benefit in excess of project-specific tax liabilities. A reasonable alternative, as we understand has been directed by the NYISO Board of Directors, would be to assume that the BESS developer enters into a tax financing agreement similar to the assumed tax financing agreement for the investment tax credit (as discussed in the 1898 & Co. Affidavit). In this circumstance, the same credit transfer price of 8% could be applied to the portion of the accelerated depreciation benefit in excess of taxable income.

52. The ICAP Demand Curves should maintain the current ZCP values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

53. Consistent with the previous two resets, the annual update process should continue to update ICAP Demand Curves based on updates of (1) gross CONE, (2) net EAS revenues, (3) seasonal capacity availability (beginning with the 2025-2026 Capability Year, SWR and WSR), and (4) beginning with the 2025-2026 Capability Year, the relative seasonal reliability risks (SLOLE and WLOLE). Consistent with the existing requirements of the Services Tariff, AG recommends the gross CONE of each peaking plant should be updated based on a state-wide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components: labor/wages, turbines/storage batteries, materials, and other costs.

54. 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 options and costs. 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 reference point prices.

Finally, Section VI of the Final Report describes the process by which ICAP Demand Curve parameters will be updated annually for the subsequent three Capability Years covered by this reset period (*i.e.*, the 2026-2027 through 2028-2029 Capability Years).

55. 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 the technology screening process. In Section V, we discuss the models and data employed for the calculation of net EAS revenues. In Section VI, we discuss our review of property and mortgage recording taxes. In Section VII, we discuss items related to the financial parameters used in establishing levelized localized embedded costs for the peaking plants. Finally, in Section VIII we provide an overview of the annual update methodology, and address certain concerns raised regarding the annual updating methodology.

IV. Technology Options

56. The Services Tariff specifies that the DCR shall assess "…the current localized levelized embedded cost of a peaking plant in each NYCA Locality, [and] 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 accompanying 1898 & Co. Affidavit discusses a number of the technology and cost factors related to the identified peaking plants. In this section, we supplement 1898 & Co.'s discussion with an explanation of our findings with respect to the technology screening and selection process, the selection of the two-hour BESS as the appropriate peaking plant technology, and issues related to the evaluation of SCGT technologies (*i.e.*, emissions controls and dual fuel capability).

57. As described in 1898 & Co.'s Affidavit, 1898 & Co. used screening criteria for peaking technology selection consistent with past DCRs, including that the technology must (1) be a standard generating facility technology, available to most market participants; (2) be a proven technology, with operating experience at a utility power plant; (3) have unit characteristics that can be economically dispatched; (4) have the ability to cycle and provide peaking service; (5) can be practically constructed in a particular location; and (6) can meet environmental requirements and regulations. 1898 & Co.'s analysis of potential options identified both simple cycle turbine technologies and energy storage technologies as technical candidates for peaking operation.

58. While our study reflects generic sites within each Load Zone, we developed 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 previous two resets that addressed the ICAP Demand Curves for the 2017-2018 through 2020-2021 Capability Years (the 2017-2021 DCR) and the 2021-2022 through 2024-2025 Capability Years (the 2021-2025 DCR). The use of these two locations provides for a consideration of differences in environmental requirements and other factors that apply throughout the lower Hudson Valley (*i.e.*, Load Zones G, H, and I).

59. In the 2021-2025 DCR we evaluated 4-, 6-, and 8-hour BESS durations. At that time, we concluded that BESS was a viable technology, but SCGT options represented lower cost alternatives to 4-, 6-, and 8-hour BESS durations in all locations. In this DCR, we expanded the set of BESS technologies evaluated to include a 2-hour BESS duration in addition to 4-, 6-, and 8-hour BESS durations. The addition of a 2-hour duration was introduced during the development of preliminary cost data for other technology options and, in part, was intended to ensure that a viable option that may represent the lowest fixed cost technology option was not excluded from the comprehensive evaluation for the 2025-2029 DCR.

60. We identified BESS plants based on lithium-ion battery technology as the most likely candidates for new utility-scale energy storage plants at this time. BESS plants of these sizes and types are deployed in significant quantities across the U.S. and are the most commercially mature battery storage technology in the market at this time. We specifically evaluated the following systems for comparison to traditional simple cycle gas turbine technologies:

- 200 MW, 2-hour (400 MWh stored energy) lithium-ion
- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

61. The metric transacted in the NYISO-administered capacity market is UCAP. As such, to reflect the impact of CAFs and derating factors on the choice of the appropriate peaking plant technology option for each ICAP Demand Curve, AG considers the relevant UCAP reference point prices for each technology option in selecting the appropriate peaking plant

technology for each demand curve. An economic evaluation of the peaking plant technology options without consideration of CAFs or derating factors would fail to appropriately reflect the marginal reliability contribution of each peaking plant technology option towards meeting New York State Reliability Council, L.L.C. (NYSRC) resource adequacy requirements for the upcoming Capability Year. The selected peaking plant technology for each capacity region should result in curves representing the lowest cost on a UCAP basis.

62. Based on this reference technology evaluation, and the information provided by 1898 & Co., we conclude that the two-hour battery energy storage system represents the highest variable cost, lowest fixed cost peaking plant that is economically viable, and thus should be selected to serve as the peaking plant underlying all ICAP Demand Curves for the 2025-2029 DCR.

A. SCGT Alternatives

63. Evaluation of the SCGT alternatives 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). For the 2021-2025 DCR, FERC approved peaking plants with dual fuel capability for the G-J Locality, NYC, and LI ICAP Demand Curves, and a gas-only peaking plant design for the NYCA ICAP Demand Curve.[9] FERC recognized that dual fuel capability is mandatory in NYC and LI.[10] With respect to dual fuel capability in Load Zone G, FERC agreed that dual fuel capability comes with increased revenue potential, siting benefits, and reliability benefits, plus it can serve as a hedge to mitigate electricity price spikes during times of high natural gas prices.[11] FERC also agreed that "the G-J Locality is a relatively geographically constrained region; therefore, the inclusion of dual fuel capability is important for providing increased siting flexibility,"[12] and that current concerns regarding the ability to expand natural gas pipeline infrastructure and capacity in New York underscore the reliability benefits gained from

[9] *New York Independent System Operator, Inc.*, 175 FERC ¶ 61,012 (2021) (2021-2025 DCR Initial Order).

[10] *Id.* at P 19 and 40.

[11] *Id*. at P 40-44

[12] *Id*. at P 40.

dual fuel capability in the G-J Locality.[13] FERC's acceptance of dual fuel capability for NYC, LI, and the G-J Locality as part of the 2017-2021 was based on similar reasons.[14]

64. In this DCR, we again evaluated whether to recommend including dual fuel capability in all locations. In the case of NYC and LI, dual fuel capability remains mandatory due to existing local electric reliability rules and LDC tariff requirements. For all other locations where dual fuel capability is not mandatory, we evaluated potential recommendations through 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.

65. Based on our evaluation, we recommend that the peaking plant design should include dual fuel capability in all locations. 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 the development of a SCGT 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 this conclusion:

66. The NYSRC imposes strict local reliability standards to NYC and LI to ensure that the loss of a gas-fired generation facility in those zones does not lead to a loss of electric load, and NYISO maintains a "minimum oil burn program" to implement these standards.[15] NYSRC's local electric reliability rules highly incentivize dual fuel capability for units in NYC and LI. Additionally, nearly all gas fired generation in Load Zones J and K is connected to the LDC gas system, and several LDC gas tariffs require dual fuel capability for generators. Such LDC requirements are in place for National Grid in Load Zones C, F and K; Orange & Rockland and Central Hudson in Load Zone G; and Con Edison in Load Zone J.

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[13] *Id*. at P 40-44

[14] *Id.* at P 40-41.

[15] *See, e.g.*, New York State Reliability Rules and Compliance Manual, Version 47, June 14, 2024, Section 2.G.2-3, available at https://www.nysrc.org/wp-content/uploads/2024/07/RRC-Manual-V47-final-7-2-24.pdf; NYISO Technical Bulletin 156, April 1, 2019, available at https://www.nyiso.com/documents/20142/2931465/TB_156.pdf.

67. Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are 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 on-site inventory of fuel for operations on the alternate stored fuel. On the other hand, these increases in cost could be outweighed by the value associated with potential increases in net EAS revenues from operating on the alternate fuel when the price for the alternate fuel is less than that of natural gas, and allowing production when gas supplies would otherwise be curtailed (such as during certain winter periods when gas supplies may be scarce due to higher demand for all end uses).

68. Consistent with previous DCRs, the economic argument for dual fuel is weaker in Load Zones C and F than in Load Zone G (Dutchess) or Load Zone G (Rockland). However, 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 during winter peak periods.

69. Due to the potential impact of fuel availability capacity accreditation rules to be implemented beginning with the 2026-2027 Capability Year, in addition to other risks associated with gas-only peaking operation and opportunities for additional revenues, we conclude developers in Load Zones C and F would more likely than not decide to include dual fuel capability in such locations. Accordingly, we recommend the inclusion of dual fuel capability as part of the SCGT options in all locations for this reset.

B. SCR Emissions Control Technology

70. The accompanying 1898 & Co. Affidavit discusses a number of the technology and cost factors related to the peaking plants evaluated in this DCR, including their assessment related to the need and costs of SCR emissions control technology for the fossil-fired SCGT options. In this section, we supplement 1898 & Co.'s discussion of whether a developer would likely include SCR emissions control technology as part of the design for the SCGT options for this reset.

71. Considering the balance of costs and risks discussed in our Final Report, it is AG's and 1898 & Co.'s opinion that the developer of a new fossil-fired SCGT plant in all locations

evaluated for the 2025-2029 DCR would seek to include SCR emissions control technology for a gas only or dual fuel plant at the time of construction due to economic considerations.

72. First, SCR emissions controls provide optionality to operate above the synthetic minor operating limit, which could be financially valuable in the future. Future net EAS revenues may be greater than net revenues in the historical years evaluated given the potential increases in demand for operation from the peaking plant from increased levels of renewables and potential retirements of gas turbines downstate due to environmental and regulatory requirements, including the "peaker rule" implemented by the New York State Department of Environmental Conservation.

73. Second, the installation of SCR emissions controls could mitigate potential permitting and siting risk associated with building a new dual fuel unit in the lower Hudson Valley without back-end emissions control technology.

74. Third, GE does not offer a version of the SCGT 7HA.03 capable of 15 ppm NO_x to comply with NSPS KKKK without SCR emissions controls. As such, configurations without SCR emissions controls are assumed to use a SCGT 7HA.02. The SCGT 7HA.02 can be tuned to meet 15 ppm NOx. The 7HA.02 is a smaller turbine than the 7HA.03. As a result, on a $/kW basis, the SCGT 7HA.02 without SCR emissions controls is similar in cost to the SCGT 7HA.03 with SCR emissions controls. Moreover, due to higher efficiency and operating limits, net EAS revenues are anticipated to be higher for the SCGT 7HA.03 than SCGT 7HA.02.

75. Because the annual net cost is lower for the SCGT 7HA.03 with SCR emissions controls than the SCGT 7HA.02 without SCR emissions controls in all applicable locations, AG and 1898 & Co. recommend SCR emissions controls for the SCGT technology in all locations.

V. Net EAS Revenues Models

76. Net EAS revenues are estimated based on the simulated dispatch of each peaking plant using a rolling three-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), the applicable fuel and emission allowance prices (for the SCGT), and data on the non-fuel variable costs and operational characteristics of the peaking plant

technology. Our 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 ICAP Demand Curve parameters evolve (with a lag) consistent with actual EAS market outcomes (as adjusted for LOE conditions).

77. To model the different market behavior and input costs of fossil fuel peaking plants and battery storage plants, we created separate net EAS revenue models for each technology option. Throughout the stakeholder process, we solicited feedback on the model logic used to estimate net EAS revenues. In this section, we first discuss the net EAS revenues model logic for fossil fuel peaking plants. We then discuss our choice and selection of the relevant natural gas hubs for the fossil model. Finally, we discuss the net EAS revenues model logic for battery storage plants.

1. Net EAS Revenues Fossil Model Logic

78. Our simulated net EAS revenues fossil model estimates the net EAS revenues earned by a SCGT peaking plant on an hourly basis assuming dispatch of the plant and the variable operating costs of producing energy or providing reserves. In the model, the peaking plant can earn revenues through supplying in one of four markets: (1) Day-Ahead Market (DAM) commitment for energy, (2) DAM commitment for reserves, (3) RTM dispatch for energy, or (4) RTM supply of reserves. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual fuel capability (if applicable) is accounted for through the option to generate on natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

79. 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 SCGT units.

80. 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 an assumed cost for taking a reserve position. This cost can reflect many factors, including performance (forced outage) risks and costs. and risks associated with securing fuel supplies to fulfill a reserve obligation. Depending on the resource type, these fuel-related costs can reflect the cost of holding fuel supplies or the expected cost of obtaining adequate fuel supplies in the intraday markets, and risk premiums associated with taking an uncovered reserve position. Based on a review of historical bid data from dual fuel units in Load Zones J and K provided by the MMU, the opportunity cost to taking a day-ahead reserve position is assumed by the model at $2.00/MWh for dual fuel units in all Load Zones.[16]

81. If the generator receives a day-ahead reserve position, the cost to actually supply energy into the RTM reflects the market fuel price plus a real time intraday premium when buying or discount when selling natural gas. Dual fuel units do not face a cost to provide reserves when ULSD costs are lower than natural gas costs.

82. 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 reference point prices reflect system conditions at the prescribed LOE conditions, and consistent with the 2021-2025 DCR, we developed a set of LOE adjustment factors (LOE-AFs) 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 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.

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[16] Patton, David and Pallas LeeVanSchaick to Analysis Group and Burns & McDonnell, "MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and the forthcoming draft of NYISO Staff DCR Recommendations," August 5, 2020, pp. 7-9, available at: https://www.nyiso.com/documents/20142/13609298/MMU-2020-DCR-Draft-Report-Comments.pdf.

83. AG 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), based on supply and load assumptions from the 2021-2040 System and Resource Outlook base case for model years 2021-2022, and the 2023-2042 System and Resource Outlook base case for model years 2023-2027. 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. For the 2025-2029 DCR, GE developed LOE cases for both a nominal 200 MW peaking plant, and a nominal 400 MW peaking plant. The resulting LOE-AFs derived using the LOE case with a nominal 200 MW peaking plant are used for the BESS options, while the resulting LOE-AFs using the LOE case with a nominal 400 MW peaking plant are used for the SCGT options.

84. To better align LOE-AFs and the historical prices they are applied to, AG calculated LOE-AFs by averaging Day-Ahead LBMPs for each month, relevant Load Zone, and period (*i.e.*, "on-peak," "high on-peak," and "off-peak;" consistent with the groupings used in the 2021-2025 DCR). DAM LBMPs are weighted by how many times the given month and year combination are utilized as an input in the net EAS revenue estimates over the reset period. The exact LOE-AFs used in the net EAS modeling are provided in Appendix C of the Final Report.

85. For the SCGT options, hourly net revenues are calculated to ensure that 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. Dual fuel capability (if applicable) is accounted for through the option to generate on natural gas or ULSD based on a comparison of fuel prices. Total annual net EAS revenues are the sum of all hourly revenues, derated by the peaking plant's technology-specific Equivalent Demand Forced Outage Rate (EFORd).

86. Finally, voltage support service (VSS) revenues are determined outside the net EAS model. For the 2025-2029 DCR, AG recommends that the applicable annual VSS adder be determined formulaically based on the compensation structure described in Rate Schedule 2 of the Services Tariff. AG recommends that the annual VSS compensation for the

peaking plant technology options evaluated in this study be determined as a value equal to the VSS compensation rate, multiplied by the sum of: (1) the technology's lagging reactive capability (expressed in MVAr) and (2) the absolute value of the technology's leading reactive capability (expressed in MVar).

87. For the 1x0 GE 7HA.03 technology option, 1898 & Co. determined that (based on a nominal capacity rating of 400 MW) the lagging reactive capability is 300 MVar and the leading reactive capability is -180 MVAr. For the 1x0 GE 7HA.02 technology option, 1898 & Co. determined that (based on a nominal capacity rating of 330 MW) the lagging reactive capability is 225 MVar and the leading reactive capability is -125 MVAr.

88. The VSS revenue adder will be updated annually as part of the annual updates for this reset period to reflect NYISO's published VSS compensation rate at the time of conducting each such annual update. Based on the current VSS compensation rate of $3,307.31/MVAr for the 2024-2025 Capability Year, the VSS revenue adder is $3.97/kW-year for the 1x0 GE 7HA.03, and $3.51/kW-year for the 1x0 GE 7HA.02 for purposes of determining the 2025-2026 Capability Year ICAP Demand Curves.

89. The net EAS logic is designed to provide an accurate and transparent model for the SCGT options, 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 SCGT options considered in the DCR. 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 assumed for the hypothetical SCGT options.

2. Net EAS Revenues Model Natural Gas Pricing Locations

90. A key consideration with respect to the net EAS revenues model for the fossil peaking plants 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, consistent with the 2017-2021 and 2021-2025 DCRs, 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 and assessments, including assessments by the MMU.

91. After assessing each potential gas hub against these criteria, we recommend the use of the following natural gas hubs in the net EAS calculations in each zone:

- Load Zone C: Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November),
- Load Zone F: Iroquois Zone 2,
- Load Zone G (Dutchess County): Iroquois Zone 2,
- Load Zone G (Rockland County): Tennessee Zone 6,
- Load Zone J: Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January),
- Load Zone K: Iroquois Zone 2.

92. These recommendations are generally consistent with the 2021-2025 DCR. Changes in recommendations were made for Load Zones C, G (Rockland County), and J for the following reasons:

- In Load Zone C, a number of pipelines, including those owned by Tennessee Gas Pipeline (TGP), Dominion, and Millennium, cross the zone. Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, we recommend the use of Tennessee Zone 4 (200L) as the natural gas index for Load Zone C for the April – November period. For the winter months of December-March, we recommend the use of Dawn Ontario as the gas hub for Load Zone C. Dawn Ontario is far more liquid than other natural gas hubs in the region, such as Niagara. Additionally, Dawn Ontario's prices closely track other natural gas hubs in the region.

- For Load Zone G (Rockland County), we recommend the use of Tennessee Zone 6 as the natural gas index. Certain indices with geographic proximity did not provide a reasonable expectation of the long-run equilibrium between gas and electricity markets or exhibited other concerns such as liquidity. In particular, the Millennium pipeline crosses through Rockland County, but it may not have the required flexibility of supply for a fossil peaking plant during all seasons. The Millennium pipeline also has limited reported trading volume in years before 2019, which raise liquidity concerns for use as a proxy gas pricing hub. By contrast, Tennessee Zone 6 is a liquid trading hub which reasonably reflects the fuel cost of a generator such as the fossil peaking plant technology options evaluated in this study, which is expected to operate intermittently throughout the year. While the Tennessee Zone 6 gas hub delivery point is outside Rockland County, the TGP system delivers to points along the southern side of Rockland County west of the Hudson River.

- For Load Zone J, Transco Zone 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to Load Zone J and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets. However, during winter months, prices available for interruptible/non-firm natural gas are more representative of pricing for Iroquois Zone 2, likely due to prioritization of firm gas use for retail LDC gas demand using Transco Zone 6 NY capacity. To improve the correlation between zonal LBMPs and natural gas hubs, we recommend Transco Zone 6 NY for February – November and Iroquois Zone 2 for December – January for Load Zone J.

3. Net EAS Revenues Battery Model Logic

93. For BESS options, the dispatch logic of the net EAS revenues model maximizes net EAS revenues while accounting for the battery technology’s unique technical properties, including limited energy storage capacity, the need for a balancing of energy charges and discharges, energy losses during charging, and operational practices that can reduce battery degradation. The battery storage dispatch model is split into two steps: (1) daily DAM

commitments, and (2) daily RTM dispatch (to capture profitable opportunities for charging and discharging given DAM commitments).

94. For the first step, we use a DAM model consistent with the method employed in the 2021-2025 DCR for the BESS options evaluated during that reset. Due to the physical energy limitations of a battery, the DAM model determines charge and discharge of the battery simultaneously in hour-pairs in the DAM energy and reserve markets. Each hour-pair includes an hour in which the battery purchases energy (to charge the battery) and an hour in which it supplies energy (through discharge of the battery). This logic ensures there is always a balance between energy inflows and outflows. For each hour-pair, the models account for energy losses when charging and assumes the full charge or discharge of the battery's capacity. However, because of charging losses, more time is required for a full charge of the battery than is required for a full discharge; thus, to maintain the energy balance of inflows and outflows of power, additional charging time is required for any given level of stored energy.

95. Along with consuming and supplying energy, the battery can supply reserves. The battery is assumed to be eligible to provide 10-minute spinning reserves when it has no DAM or RTM energy discharge position but has at least one hour capability of stored energy and/or was scheduled to be charging for the hour. When the battery is charging, the model assumes it can supply reserves at either its full capacity or the amount of energy that remains stored plus, if actively charging, the amount of power scheduled to be withdrawn from the grid for charging purposes.

96. The DAM model determines whether to commit a set of hour-pairs to charge and discharge energy in the DAM based on maximizing net revenues in the energy and reserve markets for a cycle-day. For each cycle-day, the model generates every feasible day-ahead position hour-pair given the current position of the battery storage resource. The logic then ranks the profitability of adding each set of hour-pair positions to the current position. If adding the hour-pair to the battery's position increases profitability relative to doing nothing, the model will do so and repeat this process. At the end of each modeled day, the battery model requires the battery to charge until achieving a state of charge of 200 MW to ensure the ability to earn reserve revenue at nameplate capacity overnight.

97. For the second step, the RTD interval pricing model employs a conceptually distinct approach from the DAM model. Unlike DAM LBMPs, RTD transacts on a nominal 5-minute basis. Batteries are capable of providing quick charging and discharging on a 5-minute basis. Moreover, 5-minute intervals may have higher volatility and greater opportunities for energy arbitrage revenues for batteries than LBMPs averaged over a 60-minute interval basis. As such, we developed a method to model net EAS revenues in NYISO's RTM using RTD prices. As a point of comparison, we also present results in the Final Report for a net EAS model that evaluates potential real-time revenue earnings using hourly real-time prices consistent with the RTM model employed in the 2021-2025 DCR (see Appendix E of the Final Report).

98. Our approach begins with developing a bidding strategy to identify profitable RTM charging or discharging opportunities. Intuitively, a reasonable bidding strategy has to identify profitable opportunities for charging in real-time (when the RTD LBMP is sufficiently low) or discharging in real-time (when the RTD LBMP is sufficiently high).

99. Given a day-ahead schedule of hourly DAM LBMPs, we define real-time discharge bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Charge\ Cost_i + Hurdle\ Rate_s + Discharging\ Cost$$

where:

- *Expected Subsequent Charge Cost$_i$* equals 115% * (DAM LBMP + NYISO Rate Schedule 1 costs), where DAM LBMP is set based on the lowest cost DAM hourly LBMP following interval *i*, and NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations.
- *Hurdle Rate$_s$* is calculated *ex ante* using historic data for three separate seasons *s* and established as fixed values for the entire reset period.
- *Discharging Costs* reflect the net costs associated with real-time discharge including NYISO Rate Schedule 1 costs, VOM, and any DAM reserve buyout costs.

100. Similarly, we define real-time *charging* bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Discharge\ Revenue_i - Hurdle\ Rate_s - Charging\ Cost$$

where:

- $Expected\ Subsequent\ Discharge\ Revenue_i$ equals 85% * (DAM LBMP – NYISO Rate Schedule 1 costs – VOM), where DAM LBMP is set based on the highest revenue DAM hourly LBMP following interval i, NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations, and VOM reflects charges associated with variable operations and maintenance (*e.g.*, capacity augmentation costs).
- *Hurdle Rate*$_s$ is calculated *ex ante* using historic data for each separate season *s* and established as fixed values for the entire reset period.
- *Charging Costs* reflect the net costs associated with charging, including NYISO Rate Schedule 1 costs. Because charging allows batteries to earn incremental reserve revenues, charging costs are reduced by the applicable RTD reserve price for 10-minute spinning reserves during charging periods in real-time.

101. Because NYISO posts the Day-Ahead schedule by 11 a.m. on the day prior to the Dispatch Day, this bidding strategy is feasible for real-world battery operators. These bids/offers represent the RTD LBMPs required to deviate from the day-ahead schedule and could be submitted to NYISO well in advance of the applicable real-time market deadline (*i.e.*, currently 75 minutes before the start of the operating hour). This bidding strategy reflects the fact that, in real-time, a resource operator would not know with certainty future RTD LBMPs and could use the DAM LBMP as an approximation for future real-time prices. However, once these RTM positions are entered into, the RTD interval pricing model will use actual RTD LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position. As such, there is no "perfect foresight" embedded in the battery's RTM bidding strategy within the RTD interval pricing model, and it is possible for the hypothetical battery operator to make a mistake in the sense of failing to maximize net EAS revenues on an *ex post* basis.

102. Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for future real-time price uncertainty. The hurdle rate captures the opportunity cost of limited available energy (*i.e.*, the fact that, if the battery used its limited energy to earn revenues in low priced hours, it may not have sufficient stored energy to earn higher revenues in the future). We calculate the revenue-maximizing hurdle rate directly by using the RTD

interval pricing model to estimate net EAS revenues under alternative hurdle rates from $0 to $250 over the September 1, 2021 to August 31, 2024 period (*i.e.*, the three year historical data period applicable for the 2025-2026 Capability Year), and selecting the hurdle rate that yields the highest net EAS revenues.

103. To capture other relevant market rules and operational practices in the NYISO's RTM, AG implemented additional enhancements within the RTD interval pricing model beyond the inclusion of 5-minute pricing intervals:

1. As in the DAM model, batteries require at least one hour of stored energy (also referred to as a BESS unit's "state of charge" or "SOC") to earn reserve revenue. To operationalize this constraint, the RTD interval pricing model will buy out of DAM reserve positions whenever SOC < $\frac{1}{Rated\ Battery\ Duration}$
2. Addition of sub-5-minute intervals due to RTD Corrective Action Mode (RTD-CAM) activations.
3. Seasonal hurdle rates, which are separately optimized in three distinct seasons: Winter (December, January, and February), Summer (June, July, and August), and Shoulder (all other months).
4. Sufficient SOC to meet DAM energy and reserve positions during Peak Load Window (PLW) hours. The model requires the BESS to achieve a RTM SOC equal to or greater than the DAM SOC at the beginning of the PLW. If the RTM SOC is greater than the DAM SOC during PLW hours, then the battery can discharge until RTM SOC is equal to the DAM SOC. The PLW hours assumed by the model are hour beginning 1 p.m. through hour beginning 8 p.m. for Summer Capability Period months and hour beginning 4 p.m. through hour beginning 9 p.m. for Winter Capability Period months.

104. As with the fossil model, the battery model uses historical LBMPs and reserve prices, as modified using the LOE-AFs to approximate prices under the tariff-prescribed LOE conditions. The model calculates the annual average net EAS revenues as the simple average of all energy and reserves revenues over the three-year period, derated by the plant's assumed unavailability factor of 2 percent.

105. Consistent with the fossil model, VSS revenues are determined outside the BESS net EAS model using the formulaic approach described above for the fossil model. For purposes of the VSS adder for the BESS options, 1898 & Co. determined that the lagging reactive capacity for the BESS options evaluated in this study is 124 MVAr while the leading reactive capability is -124 MVAr. Based on the current VSS compensation rate of $3,307.31/MVAr, the formula described above produces a $4.10/kW-year VSS revenue adder for the BESS options for use in determining the ICAP Demand Curves for the 2025-2026 Capability Year.

VI. Property and Mortgage Recording Taxes

106. 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 applicable peaking plant technology option, reflecting the installed capital cost exclusive of any SDU costs.

107. Outside of Load Zone J, the effective property tax rate is assumed to be 0.6% for all years not subject to a property tax abatement based on the assumption that the peaking plant will enter into a PILOT agreement, which will be effective for the full period not covered by an abatement. For the SCGT options, the 0.6% rate would apply to all years of the assumed 13-year amortization period for locations outside Load Zone J, and years 16-20 of the assumed 20-year amortization period for the BESS options in such locations. 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. A 0.75% rate was used in the prior two resets. However, a review of PILOT data available from the New York State Comptroller's Office indicated that 0.6% is a reasonable assumption for the 2025-2029 DCR and is consistent with current PILOT agreements for plants in New York.[17]

[17] The Office of the New York State Comptroller provides financial data for local governments, including Industrial Development Agencies (IDA). *See* Office of the New York State Comptroller, "Financial Data for Local Governments," http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm. AG identified PILOT agreements for 10 natural gas plants, with effective PILOT tax rates ranging from 0.15% to 5.63%, and the median value of these rates was 0.67%, calculated as the ratio of current PILOT payments to initial project dollar amount. Available data indicates that PILOT payments may not be fixed over time, with some increasing, some decreasing and some remaining constant over the duration of the PILOT agreement. The projects in the sample include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large

108. For Load Zone J, we assume the peaking plant technology options will be subject to a property tax rate of 4.77%, which is equal to the product of (1) the Class 4 Property rate (10.592%) and (2) the 45% assessment ratio.[18] This 4.77% property tax rate applies to any years of the assumed amortization period of a given technology option that is not subject to an abatement. For the SCGT option, an available abatement in Load Zone J would cover the full 13-year assumed amortization period. For the BESS options, the 4.77% tax rate for Load Zone J applies for years 16-20 of the assumed 20-year amortization period.

109. We also considered the impact of property tax abatements. Energy storage plants are provided a 15-year property tax abatement statewide. This energy storage abatement is assumed to apply in all locations evaluated. In addition, the peaking plant underlying the NYC ICAP Demand Curve has historically received a 15-year tax abatement in Load Zone J.[19] As recently extended by Chapter 332 of the Laws of the State of New York of 2024, the SCGT options in Load Zone J qualify for a specific tax abatement. For the SCGT options in Load Zone J, this abatement covers the full duration of the assumed 13-year amortization period.

110. New York State imposes a tax on the privilege of recording a mortgage on real property located within the state.[20] Similar to our assessment of effective property tax rates by reviewing data on PILOT tax agreements, AG reviewed data on energy projects that have received mortgage recording tax exemptions in New York. Based on publicly available data, AG identified examples of seventeen generation projects that have received mortgage recording tax exemptions in New York. These projects include fossil-fired generators,

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combined cycle units. AG also reviewed PILOT agreements for 4 battery projects, with effective PILOT tax rates ranging from 0.03% to 1.92% with a median of 0.21%.

[18] *See* New York City Department of Finance, "Property Tax Rates," https://www.nyc.gov/site/finance/property/property-tax-rates.page and New York City Department of Finance, "Determining Your Assessed Value," https://www.nyc.gov/site/finance/property/calculating-your-property-taxes.page.

[19] *See* New York State Department of Taxation and Finance, Exemption Administration Manual, Section 4.01, RPTL Section 487, and New York Real Property Tax Law Section 489-BBBBBB(3)(b-1).

[20] New York State Department of Taxation and Finance, "Mortgage recording tax," https://www.tax.ny.gov/pit/mortgage/mtgidx.htm

renewable generation facilities (*i.e.*, solar and wind), and battery storage plants.[21] As such, to appropriately reflect typical opportunities for tax abatement for developers of new generation in New York, AG assumes the peaking plant technology options in all locations would qualify for abatement of mortgage recording taxes through an appropriate arrangement with a tax-exempt IDA.

111. However, IDAs are not exempt from a component of the mortgage recording tax applicable to real property located in a county that is part of a transportation district.[22] As such, AG assumes that the peaking plant technology options will incur additional tax payments of 30 cents per $100 of mortgage debt for counties within the Metropolitan Commuter Transportation District (*i.e.*, Load Zones G (Dutchess County), G (Rockland County), J, and K), and 25 cents per $100 of the mortgage debt for counties within the Central New York Regional Transportation District (*i.e.*, Load Zone C) and the Capital District Transportation Authority (*i.e.*, Load Zone F).[23] These tax payments are assumed to occur when the mortgage is recorded, prior to the plant being put into service.

112. Stakeholders have raised the concern that BESS technology options would not qualify for IDA benefits due to an alleged absence of assumed full-time employees (FTE) for energy storage options. As discussed in the 1898 & Co. Affidavit, the FOM estimates for the BESS options are based on market indicative cost information rather than specific FTE buildups. The 1898 & Co. confidential O&M cost source information is based on observations from contracts and/or proposals from original equipment manufacturers (OEMs)/integrators/other third-party providers. While this cost information does not provide exact FTE quantities, the FOM cost estimates are designed to provide sufficient allowance for full-time staff.

[21] New York Office Of Information Technology Services, "Industrial Development Agencies' Project Data," https://data.ny.gov/api/views/9rtk-3fkw/rows.csv?accessType=DOWNLOAD&bom=true&format=true&sorting=true

[22] New York State Department of Taxation and Finance, "Industrial Development Agencies and Authorities in Transportation Districts No Longer Exempt from the Additional Mortgage Recording Tax," https://www.tax.ny.gov/pdf/memos/mortgage/m16_1r.pdf

[23] New York State Department of Taxation and Finance, "Mortgage recording tax," https://www.tax.ny.gov/pit/mortgage/mtgidx.htm

VII. Financial Parameters

113. The development of a new generation facility requires 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 location. The parameters used in this translation include:

1. The *weighted average cost of capital* required by the developer, based on the developer's required cost of equity (COE), 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.

114. We developed the parameters to reflect the particular financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market context. The values were chosen in an integrated fashion to properly account for the interrelationships among the financial parameters. Many factors can affect the development risks of a new peaking plant, including uncertainty and variability in fuel prices and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; energy and environmental policies with implications for industry demand, resource mix and infrastructure, costs, and revenues; and the pace and nature of technological change. Our selections reflect available data on individual components of the WACC and the AP, recognizing that the values for these components 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.

115. 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; 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 generation development in wholesale markets.

1. Amortization Period

116. The AP is the term over which the project developer expects to recover upfront capital costs, including the return of and on investment. In the context of the DCR, 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. The AP, often referred to as the "economic life" of the asset, can differ from the plant's expected physical or operational life. While the physical life of the plant reflects the expected length of time the plant will remain in operation (usually before major overhauls would be required), the economic life can differ due to financial considerations, particularly risks associated with assuming future revenue streams in light of potential 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.

117. Consistent with the 2021-2025 DCR, for fossil peaking technology options, we recommend an assumed AP that reflects the requirement of the CLCPA that all load in New York be supplied by zero-emissions resources as of 2040.[24] In principle, the owner of a fossil generating facility constructed now could implement plant modifications prior to 2040 that would allow the plant to continue to operate, for example, by using a zero-carbon fuel (*e.g.*, hydrogen) in place of the current fossil fuels.

[24] New York State, Chapter 106 of the Law of 2019. Requirements established by the CLCPA include: (1) a goal to reduce GHG emissions 85% over 1990 levels by 2050, with an incremental target of at least a 40% reduction by 2030; (2) producing 70% of electricity from renewable resources by 2030 and 100% from zero-emissions resources by 2040; (3) increasing energy efficiency by 23% over 2012 levels; (4) building 6 GW of distributed solar by 2025, 3 GW of energy storage by 2030, and 9 GW of offshore wind by 2035; (5) electrification of the transportation sector, as well as water and space heating in buildings.

118. However, as discussed in the 1898 & Co. Affidavit, there are no zero-carbon fuels widely available today with commercial operating experience. Additionally, New York has not yet implemented rules to define the eligibility of fuels, technologies, or other options to qualify as zero-emissions in compliance with the CLCPA. 1898 & Co. evaluated the potential of emerging technologies like hydrogen, ammonia, biodiesel, and renewable natural gas to serve as a potential "proxy" for a zero-carbon fuel substitute for a SCGT beginning in 2040. All three major gas turbine OEMs are performing research and development on dry low emissions combustor technology capable of firing 100% hydrogen. However, the combustor technology is not expected to be commercially available until the 2030 timeframe, and infrastructure to support hydrogen delivery and storage is estimated to exceed $2 billion. As such, we view the assumption that zero-carbon fuels will be commercially available by 2040 as excessively speculative, inconsistent with FERC precedent, and potentially inconsistent with CLCPA's 2040 zero-emission requirement given the absence of current program rules to define eligible zero-emission options for conversion of fossil units.

119. Recognizing this, we think it is reasonable to assume that developers of a new fossil peaking plant in New York would require accelerated return of their capital investment given substantial uncertainty about the financial returns of a fossil peaking plant under the CLCPA starting in 2040 due to the uncertain availability and cost of zero-emission technologies, markets, and alternative fuels.

120. Given these factors, we recommend an AP of 13 years for all fossil peaking plant technology options in all locations, which represents the average economic operating life of the fossil peaking plant technology options over the four-year period covered by this DCR. An amortization period of 13 years for all fossil peaking plant technology options strikes a reasonable balance between many considerations, including the general regulatory and technological risk faced by investors in fossil fuel resources within New York, the specific operational limits posed by the CLCPA regarding fossil fuel use for electricity generation beginning in 2040, and the uncertainty that exists at this time regarding the availability and cost of conversion technologies and/or fuels to extend a plant's economic life beyond 2039. Moreover, a 13-year amortization period is consistent with the method recommended by

AG in the 2021-2025 DCR, which was accepted by FERC in an order issued on May 19, 2023 in Docket No. ER21-502.[25]

121. The BESS options face a different set of considerations than the fossil peaking plant technology options. Unlike fossil plants, battery storage plants do not face the same regulatory constraints from the CLCPA that would limit future operations beyond 2039. Given this, we recommend an AP for battery storage technologies of 20 years. This recommendation reflects several considerations.

122. *First*, a 20-year amortization period is consistent with the typical expected operating lifetime of a utility-scale lithium-ion battery before major overhauls would be required (as further discussed below). Consistent with 1898 & Co.'s industry experience, 20-year warranties and performance guarantees for battery performance are now common in the industry. Additionally, on-going battery augmentation assumed in BESS fixed and variable O&M costs for this study would maintain plant energy output capability over the assumed economic life of twenty years. This assumption mitigates degradation of BESS capability. However, the BESS equipment would likely be replaced with new equipment after the 20-year warranty period, so a 20-year amortization period ensures recovery of investment before more substantial upgrades beyond typical augmentation may be required.

123. *Second*, the U.S. electricity sector has gained substantial experience with the development of BESS since the last reset. For the 2021-2025 DCR, we recommended a 15-year amortization period for a combination of factors, including uncertainties from limited operating experience and the potential for technology performance improvements. Since that time, there has been substantial growth in U.S. BESS deployment that mitigates these uncertainties. There is nearly 20 GW of BESS in service today, with the vast majority placed in service since the last reset.[26] Further, significant quantities of additional capacity are currently under development.[27] Thus, the increased operating experience of BESS

[25] *New York Independent System Operator, Inc.*, 183 FERC ¶ 61,130 (2023).

[26] Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), June 2024, available at: https://www.eia.gov/electricity/data/eia860m/.

[27] *Id*.

technologies has diminished uncertainties present for the 2021-2025 DCR that supported the recommendation of a 15-year amortization period for BESS.

2. Weighted Average Cost of Capital and Corporate Tax Rates

124. The WACC for use in the DCR reflects 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 cost of 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. An entity will choose the appropriate capital structure for a given project based on the expected costs of debt and equity, which, in turn, will vary depending on the chosen project's capital structure, because this structure affects the likelihood that debt will be paid and equity will receive return of and on investment.

125. 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, cost of 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 power 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 New York and operating in the NYISO markets.

126. In developing our recommended WACC for the peaking plant technology options evaluated for this study, we take into account technology-specific considerations and risks. BESS options face certain unique financial risks:

   1. *First*, battery storage faces physical performance risks. Battery storage operation – generally and within New York – faces uncertainties affecting the expected

economic and physical lifetime of new battery units, including the potential for cell degradation, wear and tear on balance-of-system components, uncertain market dispatch outcomes, and potential variations in operational modes and uses in system operations.

2. *Second*, battery storage faces market performance risks. One such risk arises because battery storage is still a relatively early-stage technology and likely to experience further improvements in operational performance over time, particularly cycling energy losses. Thus, the first wave of battery storage plants to operate in New York may be less competitive than battery units that enter the market at a later date with more advanced and/or efficient technologies.

3. *Third*, there is market risk related to CAFs that are used in determining the quantity of UCAP a resource can supply. Going forward, CAFs will vary each year depending on the mix of resources in the system, load profiles and other factors. Under certain circumstances, changes in CAFs can affect future capacity market revenue streams. Moreover, future CAF values are unknown given potential temporal and geographic variations in the expansion of, for example, battery storage technology and intermittent renewables in New York, which could tend to have countervailing impacts on battery storage CAFs depending on the timing, magnitude, and types of future resource additions.

127. AG's recommended financial parameters are intended to capture incremental financial risk associated with BESS projects. AG considered potential differences in financial risk between BESS projects of varying output durations given, among other things, their potential differences in future CAF values. For example, a longer-duration battery storage plant could in theory experience relatively more stable future CAF values, and thus lower financial risk, than a 2-hour battery storage plant. Given existing evidence on CAF variation and heterogeneity in the many factors affecting financial parameters, AG is not persuaded that BESS financial parameters should be differentiated by BESS duration at this time. Moreover, even if we believed differences in this single risk factor could warrant a downward adjustment to the financial parameters for longer-duration BESS at this time, this would not affect our recommended peaking plant technology or associated reference

point prices, as these longer-duration BESS would still be substantially more costly than the 2-hour BESS.

128. Development of a fossil-fired peaking plant in New York State would also face certain unique risks. For example, the state's objective to decarbonize the electricity sector could lead to policies that make fossil-fired resources less competitive than alternatives (*e.g.*, the potential implementation of a future "cap-and-invest" program for the state's broader economy) prior to the CLCPA's requirement for electricity load to be served 100% by zero-emissions resources starting in 2040.

129. All else equal, rational investors demand a higher remuneration for their capital when they face higher risk, especially if the risk cannot be diversified. Therefore, the technology-specific risks described above are likely to affect the WACC. As a result, AG recommends different cost of debt, cost of equity, and WACC values for the SCGT and BESS technology options.

a) Cost of Debt

130. The cost of debt reflects a project developer's ability to raise funds on debt markets. We gathered data on the cost of debt, as measured by the average yield to maturity of long-term bonds, for four power companies with meaningful ownership of merchant units: AES, Constellation, NRG, and Vistra (the "Proxy Group" companies). Those companies are publicly traded and, therefore, have the advantage of providing sufficient information to compute the COD and the cost of equity capital. Between June 2, 2024 and August 31, 2024, the average yield to maturity of these bonds has ranged from 5.43% to 6.32%.

131. Two out of the four companies listed above have below-investment grade long-term debt credit ratings as of August 31, 2024 (NRG and Vistra are both rated BB). AES and Constellation have credit ratings above investment grade (equal to BBB- and BBB+, respectively) as of August 31, 2024. AG also considered data on the generic cost of corporate debt. Between June 2, 2024 and August 31, 2024, the average yield to maturity for B, BB, and BBB rated bonds is 7.16%, 6.08%, and 5.45%, respectively.

132. Certain stakeholders raised concerns that the data we utilized did not account for the recent actions taken by the Federal Reserve to reduce benchmark rates in September 2024 and November 2024. The recent reductions in benchmark rates do not directly translate to the longer-term debt costs we assessed for this study. Given the assumed economic lives of the peaking plant technology options, long-term debt costs are more appropriate to assess than short-term rates, which are more directly impacted by the recent Federal Reserve reductions. Moreover, the anticipated action of the Federal Reserve to begin reducing benchmark rates in September 2024 and likely implement further reductions before the end of the year was known to the market well in advance of the action taken in September 2024. As a result, the data we used through August 31, 2024 reasonably incorporate market expectations of such forthcoming reductions. In fact, based on data through November 15, 2024, relatively limited changes have been observed in the generic debt issuance data we reviewed. Although the average yields to maturity have reduced slightly to 7.07%, 6.02%, and 5.44% for B, BB, and BBB rated bonds, respectively, there is no basis for concluding that the reduction is associated with the change in benchmark rates, rather than other macroeconomic factors, and such limited changes do not warrant any reassessment of our recommended values.[28]

133. Certain other stakeholders contend that our recommended COD value is understated. To support their position, these stakeholders cited to recent debt financings for fossil-fired generation facilities indicating debt costs ranging from 9-9.5%. These financings are less reliable for estimating cost of capital for the peaking plant technologies evaluated for this study, however, because there is no public information on the other elements of the financing associated with this debt, notably the capital structure. Thus, we cannot assess whether these debt costs are consistent with our assumed capital structure. As noted above and recognized by the Commission, the cost of debt is affected by the capital structure through the risk of default on the debt.[29]

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[28] Federal Reserve Bank of St. Louis, FRED, ICE BofA US High Yield Index Effective Yield (series BAMLH0A2HYBEY, BAMLH0A1HYBBEY, and BAMLC0A4CBBBEY), accessed on November 15, 2024.

[29] The Commission recognizes the need for the "cost of debt be consistent with the capital structure." *See BP Pipelines (Alaska) Inc. et al.*, 119 FERC ¶ 63,007 at P 224 (2007).

134. Based on these factors, AG recommends a COD of 7.20% for BESS units. This recommendation reflects a number of factors, including risks consistent with B rated debt issues; recent corporate debt costs; differences between COD to independent power producer (IPP) entities relative to generic debt indices (for comparable levels of credit quality); and differences between corporate and project-specific risks (controlling for comparable B rated riskiness). For the SCGT units, we recommend a COD of 6.70%. This recommendation reflects similar considerations to our BESS recommendation, but the assumption of slightly lower technology-risks and the yield of debt issues with ratings between BB- and B-.

b) Cost of Equity

135. The COE is the cost incurred to remunerate equity investors for their required return on equity on their investment. Our recommended COE is developed primarily relying on estimated cost of equity capital for the same four IPPs that served as the Proxy Group for the cost of debt: AES, Constellation, NRG, and Vistra. We estimate the COE using the Capital Asset Pricing Model (CAPM) across a range of scenarios based on different assumptions used to estimate key parameters of the COE, such as beta, different subsamples of IPPs, and different Equity Risk Premia (ERP).

136. In developing our estimates, we note independent estimates of the COE for new power plants developed in other, but related, contexts. Net CONE studies in neighboring markets provide a benchmark for comparison. PJM and ISO-NE have used COE values ranging from 12.8% to 13.8% in recent net CONE studies. These values reflect different methodologies and data sources. Our recommendations also reflect certain publicly available sources of information on project financing, as well as other information gathered through related professional activities.

137. Our assessment accounts for a mix of other market and regulatory risks, including: changes in loads, particularly in light of new loads (*e.g.*, data centers, semiconductor manufacturing load, and bitcoin data mining facilities) and policy efforts to increase electrification of heating and transportation; the mix of resources in the NYCA system given legislative changes, such as the CLCPA and policies to achieve its ends (*e.g.*, potential procurements by state agencies, such as the New York State Energy Research and Development

Authority); and technology-specific changes in CAFs given these changes in loads and system resources, along with the general risks facing new merchant investment.

138. Based on this information, for the BESS options, AG recommends a COE of 14.5%, reflecting a balance between the IPP values (which range from 9.57% to 15.90%) and project-specific considerations. For the SCGT options, AG recommends a COE of 14.0%, which also reflects a balance between the IPP values and project-specific considerations, including the recognition of a differential in risk to equity for the SCGT options relative to the BESS options.

c) Debt to Equity Ratio

139. 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 project could reasonably be developed through a range of capital structures.

140. AG recommends a D/E ratio of 55% debt to 45% equity given a balance of tradeoffs involved with greater or lesser leverage. Our assumption reflects the inter-relation of the capital structure with the cost of debt and return on equity, and different approaches to project development (*e.g.*, balance sheet and project finance), and accounts for various indirect costs of financing (such as financial hedges) implicitly and not explicitly.

141. In early 2024, corporate capital structure was generally similar across the Proxy Group companies and in line with our recommendation. Since, capital structures have diverged somewhat, while their average across companies maintains a value consistent with our recommendation. While a corporate level capital structure is not necessarily informative to the capital structure for a given project, it does inform the capital structure for assets in the industry which is relevant to new project capital structure. Our recommendation is also

consistent with the capital structure adopted in recent similar studies for ISO-NE and PJM, which assume values similar to recommended 55% debt value for the 2025-2029 DCR.[30]

d) WACC

142. AG's assessment of factors related to the calculation of the WACC has considered the data on the following: COE, COD, and debt-to-equity ratios presented above; facts and circumstances unique to the NYISO markets, including the extent of past experience with merchant development; the rapidly-changing nature of federal and state energy and environmental policies, including passage of the CLCPA; and likely project/ownership structures for new peaking plant development in New York.

143. The calculation of the ATWACC 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 21%), corporate New York State tax rates (6.5%), and, for Load Zone J, the New York City business corporation tax rate (8.85%). These tax rates result in composite income tax rates of 33.13% (Load Zone J) and 26.14% (all other locations).

144. Given the considerations presented above, for the BESS options, AG recommends a WACC of 10.49%, based on a debt ratio of 55%, a COD of 7.20%, and a COE of 14.50%. This results in a nominal ATWACC of 9.45% in NYCA, LI, and the G-J Locality, and 9.17% in NYC. For the SCGT options, AG recommends a WACC of 9.99%, based on a debt ratio of 55%, a COD of 6.7 %, and a COE of 14.0%. This results in a nominal ATWACC of 9.02% in NYCA, LI, and the G-J Locality, and 8.76% in NYC.

145. We also considered approved cost of capital values in NYISO and other neighboring market (*e.g.*, ISO-NE and PJM) for net CONE evaluations. These evaluations used ATWACC values which range between 7.5% and 8.89%.

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[30] *See, e.g.*, ISO New England Inc. and New England Power Pool, Docket No. ER24- -000; Targeted Adjustment to Certain Forward Capacity Market Parameters to Reflect the Minimum Offer Price Rule Elimination, *dated* November 15, 2023; The Brattle Group, PJM Cost of New Entry: Estimates for Combustion Turbines and Combined Cycle Plants in PJM with June 1, 2018 Online Date, report prepared for PJM Interconnection, L.L.C., May 15, 2014; ISO New England, Inc., 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, April 1, 2014; Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis, report prepared for ISO New England, Inc., January 13, 2017.

146. Relative to the 2021-2025 DCR, the higher ATWACC reflects the slightly lower cost of debt, the higher risk-free rate, the changes in tax law, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments.

3. Monetization of Accelerated Depreciation Benefits in Excess of Project-Specific Tax Liabilities

147. Consistent with previous DCRs, we translate one-time installed capital costs into a levelized fixed charge ("annual carrying charge") over the assumed economic life of the plant. 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 tax depreciation schedules and variation in certain tax levels over time (*i.e.*, availability of a 15-year property tax abatement for battery storage options in all locations and the availability of a 15-year tax abatement for fossil peaking plant technology options in Load Zone J).

148. BESS technologies qualify for a 5-year MACRS depreciation schedule. The accelerated depreciation benefit can lower the project's tax liabilities in a given year, but it is not refundable. If a BESS developer does not have sufficient tax liability on a project-specific basis and is not considered part of a portfolio of assets under a common holding company with sufficient tax liabilities at the holding company level, they will typically enter into financing agreements with tax equity partners to fully monetize the accelerated depreciation benefit.

149. In its Final Report, AG did not assume any incremental costs associated with monetizing the portion of the accelerated depreciation benefit in excess of project-specific tax liabilities in a given year. A reasonable alternative, as we understand has been directed by the NYISO Board of Directors, would be to assume that the BESS developer enters into a tax financing agreement similar to the tax financing agreement assumed for the investment tax credit. In this circumstance, the same credit transfer price of 8% applied to the investment tax credit could be reasonably applied to the portion of the accelerated depreciation benefit in excess of taxable income to account for the cost of leveraging a third-party arrangement to monetize the accelerated depreciation benefit.

VIII. Annual Update Process

150. Consistent with the previous two DCRs, the Services Tariff requires that the ICAP Demand Curves be updated annually based on the updating of (1) gross CONE, (2) net EAS revenues, and (3) seasonal capacity availability (SWR and WSR). Additionally, given NYISO's seasonal reference point prices for the 2025-2026 Capability Year, relative seasonal reliability risks (SLOLE and WLOLE) will also be updated each year.

151. An element of annual updates is the update of gross CONE. In each year, the Services Tariff requires that gross CONE of the peaking plant be updated based on a statewide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components (as prescribed by the Services Tariff): labor/wages, turbines/storage batteries, materials, and other costs. The same weighting factors and indices will be used over the reset period, but the values resulting from the indices will be updated annually.

152. For SCGT technology options, AG recommends the same indices for the 2025-2029 reset period that were approved by FERC for the 2021-2025 period.[31] For BESS technology options, AG recommends the use of a storage battery index that excludes lead acid batteries to better isolate factors impacting costs for lithium-ion batteries for the "storage batteries" component, while the remaining components (*i.e.*, labor/wages, materials and other costs) use the same indices recommended for the SCGT technology options.[32]

153. The component weights are based on the engineering, procurement, and construction (EPC) costs for the SCGT and BESS options. EPC costs have been used for each of the past two resets as representative of the general cost breakdown of the peaking plants into the tariff-

[31] Specifically, construction labor costs are measured using the Bureau of Labor Statistics (BLS) Quarterly Census of Employment and Wages, New York – Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay; materials costs are measured using the BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction; gas and steam turbine costs are measured by BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets; and other costs are measured using the U.S. Bureau of Economic Analysis (BEA) Gross Domestic Product Implicit Price Deflator, seasonally adjusted.

[32] Specifically, we recommend that storage battery costs be measured using the BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Storage Batteries (Excluding Lead Acid), Including Parts for All Storage Batteries.

prescribed cost components because EPC costs represent the majority of the total costs for each plant. All locations are considered to derive a representative, statewide average weighting for each cost component. For the 2025-2029 DCR, the types of EPC costs considered in determining the weighting value for each component is as follows:

- Labor/wages component: This category accounts for the labor costs and related construction tools from the EPC contractor and subcontractors.
- Materials component: This category accounts for construction commodity materials (*i.e.*, cable, conduit, piping, concrete, steel, piles, etc.), main power transformer, controls related equipment, fire protection equipment, chemical feed equipment, and all other project equipment besides the major equipment accounted for in the turbine/storage battery category described below.
- Turbines/storage batteries component: This category accounts for the major equipment purchases. For the SCGT options, this includes the combustion turbine package and SCR emissions control equipment, as applicable. For the BESS options, this includes modular battery enclosures, inverters, and medium voltage transformers.
- Other costs component: This category is intended to capture the remaining EPC cost items such as construction management, engineering, startup, escalation, and EPC warranties that are not otherwise accounted for by another category.

154. Certain stakeholders raised concerns regarding the use of only EPC costs to derive the applicable component weighting factors. Such stakeholders contend that the weighting factors should instead be derived from the categorization of total plant costs. While we continue to believe that use of EPC costs, as has been done for the past two resets, is reasonable and appropriate, we conducted an alternative analysis to identify the resulting weighting factors that would be derived from the use of total plant costs. The table below provides the resulting weighting factors by cost component for this alternative methodology.

Table 1: Composite Escalation Rate Indices and Component Weights Based on Total Project Costs Instead of EPC Costs, by Technology (2025-2026 Capability Year)

					Component Weight, by Technology								
Cost Component	**Index**	**Interval**	**Calculation of Index Value**	**Annual Growth Rate**	**25 ppm, Dual Fuel and SCR**	**25 ppm, Gas Only and**	**25ppm, Dual Fuel and SCR**	**15ppm, Dual Fuel and No SCR**	**15ppm, Gas Only and No SCR**	**2-Hour BESS**	**4-Hour BESS**	**6-Hour BESS**	**8-Hour BESS**
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	3.40%	18%	18%	24%	20%	19%	17%	14%	13%	13%
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	1.32%	13%	14%	15%	17%	17%	14%	11%	10%	9%
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	4.69%	22%	26%	17%	19%	20%	-	-	-	-
Storage Battery Costs	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Storage Batteries (Excluding Lead Acid), Including Parts for All Storage Batteries (790105)	Monthly	Average of finalized February, March, April values	0.18%	-	-	-			42%	49%	52%	54%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	2.64%	47%	42%	44%	44%	44%	27%	26%	25%	24%
Total					100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes: [1] Annual growth rates reflect the most recent data available for each index as of August 31, 2024. [2] Component weights are reflective of total project costs including owner's costs instead of EPC costs, as depicted in the Final Report.

155. The resulting weighting factors by component are different using total plant costs. For example, for the BESS options, the use of total costs results in a reduction in the weighting factor value for the "storage batteries" component and a corresponding increase in the value for the "other costs" component. However, the resulting impact of such changes on the calculated escalation factor is limited. For example, for the 2-hour duration battery, the composite escalation rate using the applicable index data available as of August 31, 2024 was 1.55% based on weightings derived from total project costs compared to 1.08% for weightings derived from EPC costs.

156. Finally, we conducted a re-evaluation of the gross CONE annual updating methodology, finding that:

1. Annual updates are not designed to replicate the comprehensive assessment undertaken during each DCR. The DCRs provide for the consideration of policy changes and market factors specific to a particular technology option, and can result in changes in gross CONE that are unrelated to simply capturing inflationary changes in costs over time.

2. Escalated EPC costs from the 2021-2025 DCR for the 1x0 GE 7HA.02 underestimated EPC costs determined as part of this study for the same technology. Escalated EPC costs from the 2021-2025 DCR for the 4-hour BESS overestimated EPC costs determined as part of this study for the same technology. Notably, these comparisons do not control for differences in underlying project design and scope between the 2021-2025 and 2025-2029 DCRs that can materially impact the estimated project costs.

3. We did not identify alternative indices that offer more specific information on costs related to new SCGT or BESS units.

4. It is unclear going forward whether the use of the current methodology will result in gross CONE values higher or lower than the analogous values from a full DCR.

157. As a result of the re-evaluation, we do not recommend any changes to the annual updating methodology for gross CONE.

IX. Conclusion

158. AG was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2025-2026 Capability Year. AG worked with 1898 & Co. to complete the tariff-required periodic review.

159. Our final analyses and recommendations are presented in Sections III-VIII above, and comprehensively documented in the Final Report.

160. This concludes our affidavit.

ATTESTATION

I am the witness identified in the foregoing 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 26, 2024

Subscribed and sworn to before me
this 26 day of November, 2024

Notary Public

My commission expires: 07/31/2031

Michelle Yvonne Igoe
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Commission Expires
July 31, 2031

ATTESTATION

I am the witness identified in the foregoing 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.

Todd Schatzki
November 26, 2024

Subscribed and sworn to before me
this 26 day of November, 2024

Notary Public

Kelly Owens
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Comm. Expires August 9, 2030

My commission expires: August 9, 2030

ATTESTATION

I am the witness identified in the foregoing 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.

Joseph Cavicchi
November 26th, 2024

Subscribed and sworn to before me
this 26 day of November, 2024

Notary Public

My commission expires: August 9, 2030

Kelly Owens
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Comm. Expires August 9, 2030

ATTESTATION

I am the witness identified in the foregoing 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.

Charles Wu
November 26, 2024

Subscribed and sworn to before me
this 26th day of November, 2024

Notary Public

My commission expires: 11/08/2030

ALANA A BERNAZZANI
Notary Public
Commonwealth of Massachu
My Commissi
November

ALANA A BERNAZZANI
Notary Public
Commonwealth of Massachusetts
My Commission Expires
November 8, 2030

ATTESTATION

I am the witness identified in the foregoing 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.

Daniel Stuart
November 26, 2024

Subscribed and sworn to before me
this 26 day of November, 2024

Notary Public

My commission expires: August 9, 2030

Kelly Owens
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Comm. Expires August 9, 2030

Exhibit A

PAUL J. HIBBARD
Principal

Direct: 617 425 8171
Fax: 617 425 8001
paul.hibbard@analysisgroup.com

111 Huntington Avenue
14th Floor
Boston, MA 02199

Mr. Hibbard is an expert on economics, strategy, regulation, and policy in the electric and natural gas industries. He has a comprehensive background merging business development, technical analysis, resource planning and development modeling, economics, and public policy in the energy and environmental fields. Mr. Hibbard has 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 US federal and state emission control programs to other countries.

Prior to joining Analysis Group, Mr. Hibbard was chairman of the Massachusetts Department of Public Utilities. During his tenure, he 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. He also has provided testimony on resource planning, competitive electricity markets, and transmission pricing in hearings before committees of the Massachusetts legislature and the US House of Representatives, the Federal Energy Regulatory Commission (FERC), and state and regional planning councils.

EDUCATION

M.S.	Energy and resources, University of California, Berkeley *Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs* *(Ph.D. coursework in nuclear engineering)*
B.S.	Physics, University of Massachusetts Amherst

PROFESSIONAL EXPERIENCE

2010–Present	**Analysis Group, Inc.** *Principal (2015–Present)* *Vice President (2010–2015)*
2007–2010	**Massachusetts Department of Public Utilities** *Chairman* *Member, Energy Facilities Siting Board* *Manager, New England States Committee on Electricity (NESCOE)* *Treasurer, Executive Committee, Eastern Interconnect States' Planning Council*

2007–2010 **Massachusetts Department of Public Utilities** (continued)
Representative, New England Governors' Conference (NEGC)
Power Planning Committee
Member, National Association of Regulatory Utility Commissioners (NARUC)
Electricity Committee, Procurement Work Group

2003–2007 **Analysis Group, Inc.**
Vice President (2005–2007)
Manager (2003–2005)

2000–2003 **Lexecon Inc.**
Senior Consultant (2002–2003)
Consultant (2000–2002)

1998–2000 **Massachusetts Department of Environmental Protection**
Environmental Analyst

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

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

SELECTED PUBLIC-SECTOR EXPERIENCE (MASSACHUSETTS)

- ***Chairman, Department of Public Utilities***
  - Chaired the state's public utilities commission during a period of aggressive change in state policies affecting the 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.
  - Led Massachusetts's 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 establish a regional presence on transmission-related provisions in federal legislation.
  - As chairman, served as the administrative and policy head of an agency of nearly 150 employees, and was responsible for agency management and growth, budgeting, legislative matters, press inquiries, and policy agenda-setting.
  - Oversaw the completion of all dockets jurisdictional to the department, 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.
  - 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 the state board responsible for reviewing 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. Review involved technical, environmental, and economic evaluation 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, NESCOE***
  State representative of the regional group chartered to develop New England regional policy positions on electricity market and transmission planning issues. Responsibilities included consideration of group development issues, input into regional determinations of the 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 Interconnection States' Planning Council***
  Elected treasurer of the steering committee for the state council formed under a US Department of Energy (DOE) grant to coordinate with power system operators on developing long-range plans for a transmission system spanning 41 states in the eastern US. Coordinated New England states' approach to policy issues stemming from council efforts.

- ***Representative, NEGC Power Planning Committee***
  Represented the governor's office in all discussions related to regional energy/environmental issues, including transmission cost allocation, regional energy policy coordination, and development of mechanisms for and approaches to 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, and Cooperatives

- ***For the Natural Resources Defense Council (NRDC)*** – Coauthored a public report on the Clean Electricity Payment Program's (CEPP) positive impact on the US economy if adopted (2021).
- ***For Advanced Energy Economy (AEE)*** – Coauthored a public report on the potential economic impacts of applying stimulus funds to electrification of the US transportation sector using estimated spending levels from President Biden's American Jobs Plan (2021).
- ***For AEE*** – Coauthored a public report on the potential economic impacts of applying stimulus funds to develop advanced energy technologies, products, and services in the US using estimated spending levels from President Biden's American Jobs Plan (2021).
- ***For the Coalition for Green Capital*** – Coauthored a white paper examining the potential of the federally authorized Clean Energy and Sustainability Accelerator that could address economic and climate crises (2021).
- ***For AEE*** – Coauthored a series of public reports on the economic impacts in select states of potential stimulus spending on clean and advanced energy resources (2020).
- ***For a municipal association*** – Drafted a white paper related to the fuel mix and emission characteristics of the portfolio of generating assets and power contracts used by municipal electric light companies in Massachusetts (2020).
- ***For the Wellesley Municipal Light Plant (WMLP)*** – Coauthored two white papers on the greenhouse gas (GHG) impacts of the WMLP power portfolio, and considerations for the WMLP associated with achieving continued reductions in carbon emissions over the ensuing decades (2020).

- ***For the Georgetown Climate Center* –** Conducted a bill impact analysis related to Virginia's proposed implementation of a carbon cap-and-trade program (2018).
- ***For Energy New England*** – Provided strategic assistance on energy market and public policy issues in New England (2017).
- ***For the Environmental Defense Fund* –** Coauthored a white paper related to historical power system emission trends (2015).
- ***For the Massachusetts Attorney General*** – Coauthored a report evaluating electric and natural gas infrastructure in New England from the perspectives of reliability, cost, and GHG emissions (2015).
- ***For AEE*** – 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 the state's market and technological circumstances at the time.
- ***For the Energy Foundation and industry groups*** – Coauthored multiple white papers on the reliability, cost, and market efficiency impacts of the US Environmental Protection Agency's (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 AEE*** – Facilitated a regional symposium for the New England Conference of 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 (RGGI)*** – Conducted a bill impact analysis related to changes to retail customer electric bills in New England, New York, and RGGI Pennsylvania, New Jersey, and Maryland Interconnection (PJM) states associated with various changes considered by RGGI to program cap level and use of allowance revenues (2012).
- ***For AEE* –** Participated in a project advising AEE with respect to its 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 US (2012).
- ***For AEE*** – Coauthored 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*** – Coauthored 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 the 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 energy efficiency to be used as a compliance tool in national carbon emission control regimes (2012–2013).

- ***For the Merck Family Fund –*** Co-led 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 RGGI (2011).
- ***For AEE –*** Developed background on electric industry structure, regional planning and market structures and operations, and state energy policy organization and initiatives. Assisted with the development of a 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). Coauthored 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 –*** Coauthored a white paper on the design of incentives for the photovoltaic (PV) solar energy market (2011).
- ***For a national environmental organization*** – Conducted an economic analysis of key US cities that were or had 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 (NYISO). Assessed the potential for additional innovative programs to improve energy efficiency and demand response in New York City (2010).
- ***For the North Carolina Attorney General –*** Managed a 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). The project was in the context of a public nuisance lawsuit brought by the North Carolina Attorney General against TVA (2006).
- ***For the National Commission on Energy Policy –*** Authored white papers on (1) the implications for US 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 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).
- ***For the Energy Foundation*** – Coauthored a report (with Dr. Susan Tierney) documenting best practices in energy facility siting regulations in the US, 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 (MTC) –*** Managed projects in support of the MTC's renewable and premium power programs, including the (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).

ENERGY INDUSTRY STAKEHOLDERS

- ***For PECO Energy*** – Provided testimony on traditional ratemaking principles as applied to PECO's cost of providing gas delivery service (2021).
- ***For the Hingham Municipal Lighting Plant (HMLP)*** – Conducted an internal evaluation of the impact of decarbonization of residential and commercial energy use in the town, and its effect on HMLP's investments and operations (2020).
- ***For a natural gas interstate pipeline company*** – Coauthored a white paper and presention showing options to decarbonize the company's operations. The study included an analysis of its GHG footprint, identification of options and pathways to reduce net GHG emissions from operations to zero over time, and the development of recommendations for senior management (2020).
- ***For Oracle Corporation*** – Conducted an analysis of and report on the GHG emission reduction impacts of various types of energy efficiency programs and measures, with a focus on the comparison of structural and behavioral energy efficiency programs (2020).
- ***For NYISO*** – Conducted a study of the parameters used as the basis to set the NYISO's installed capacity demand curves for the four capability years beginning with the summer 2021 capability period (2020).
- ***For NYISO*** – Conducted an internal study of the potential reliability impacts on the electric grid due to changes in system mix and operations associated with a changing climate, and with state programs to address climate change (2020).
- ***For NYISO*** – Conducted a study of the potential risks to New York power system operations associated with an increased reliance on natural gas for power generation (2020).
- ***For Commonwealth Edison*** – Provided testimony on issues associated with a request for a certificate of public convenience and necessity by NextEra related to the proposed acquisition of the transmission assets of Rochelle Municipal Utilities (2020).
- ***For Repsol Energy North America*** – Provided strategic assistance related to the potential impacts of electric system market rules and public policy on the potential marketability of liquefied natural gas (LNG) in New England (2020).
- ***For Liberty Utilities*** – Provided testimony on the need for and economic and environmental impacts of the proposed Granite Bridge pipeline and LNG project in the State of New Hampshire (2020).
- ***For NYISO*** – Coauthored a white paper for NYISO on the potential impacts of a proposed carbon pricing mechanism in New York on power prices; energy policy; and economic, environmental, and public health impacts in New York (2020).
- ***For NTE Energy*** – Provided testimony before the Connecticut Siting Council on the need for and potential benefits associated with a proposed new natural gas-fired power plant in the State of Connecticut (2020).
- ***AltaGas*** – Provided testimony before the Maryland and District of Columbia public utility commissions on the potential environmental impacts of a proposed merger between AltaGas and Washington Gas (2017–2018).

- ***For Calpine Corporation* –** Coauthored a white paper on the design of a proposed carbon trading mechanism in Massachusetts (2017).
- ***For Vermont Gas*** – Provided testimony on the prudence of Vermont Gas' decisions and investments with respect to the Addison natural gas project (2017).
- ***For the Vermont Electric Power Company (VELCO)*** – Coauthored a white paper on VELCO's capital structure associated with its transmission assets and operations (2016).
- ***For the Merck Family Fund*** – Coauthored a white paper on economic principles associated with the trading of emission allowances associated with RGGI (2016).
- ***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 stating the 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 the 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 a report presenting the results, considering the state's unique energy price and fuel security context (2014–2015).
- ***For NYISO*** – Developed a model to compare cost, resource, and emission outcomes of alternative designs for a capacity market in the State of New York. Coauthored a report presenting the results of the analysis and a comprehensive review of the benefits and drawbacks of moving from a spot to a forward capacity market (FCM) 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 (RTOs)*** – Provided strategic support at the board-of-director and senior-management levels 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 an RTO*** – Conducted an internal analysis of the 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 the 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 (ISO-NE) –*** Assisted on several projects related to addressing the codependence 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, LNG 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 ISO-NE*** – Developed an economic supply/demand model of the FCM to estimate the cost impact of integrating a new long-term performance incentive design element into the FCM auctions and pricing structure (2012–2013).
- ***For Calpine Corporation*** – Filed a report with the EPA 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 ISO-NE*** – Organized and helped 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. Facilitated meetings and developed organizational and concept documents to explore outcomes and assist in deliberations with states and regional industry stakeholders, and participated in external meetings to gain input and feedback (2010–2012).
- ***For an RTO*** – 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 US RTOs and independent system operators (ISOs) (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 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. Coauthored a report to be used in the development of legal strategy and legal proceedings (2012).
- ***For an international power company*** – Conducted a review of a regional utility's compliance with the FERC requirements for transmission open access, and developed strategies for the filing of complaints of anticompetitive conduct before the FERC (2011–2012).
- ***For an RTO*** – 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 Direct Energy*** – Assisted with the 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 FCM 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 RTO*** – 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 the report "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," which reviewed the impact on power plant operations of proposed EPA 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 US (2006); coauthored a report (with 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 Clean Air Interstate Rule (CAIR) program (2001–2006).
- ***For a developer of a land-based LNG facility –*** Assisted in the preparation of confidential reports on US natural gas supply/demand conditions, market pricing indices, US 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 US, 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 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).

- ***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).

OTHER PROFESSIONAL ACTIVITIES

AEE
Advisory Board (2011)

SELECTED REPORTS, TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Offshore Wind Procurement: The Driver of Economy-Wide Decarbonization, with Megan Accordino, Ph.D., (September 20, 2024)

Rebuttal Testimony of Paul J. Hibbard before the Pennsylvania Public Utility Commission, Docket Nos. R-2024-3047822 and R-2024-3047824 on behalf of Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (September 12, 2024)

Supplemental Testimony of Paul J. Hibbard before the Federal Energy Regulatory Commission, Docket Nos. ER21-2818-004 and EL22-4-000 (consolidated), on behalf of Northwest Rural Public Power District (April 24, 2024)

Rebuttal Testimony of Paul J. Hibbard before the Pennsylvania Public Utility Commission, Docket Nos. R2023-3043189 (Water) and R-2023-3043190 (Wastewater) on behalf of Pennsylvania-American Water Company (February 21, 2024)

Direct Testimony of Paul J. Hibbard before the Federal Energy Regulatory Commission, Docket Nos. ER21-2818-000 and EL22-4-000, on behalf of Northwest Rural Public Power District (February 15, 2024)

Testimony of Paul J. Hibbard before the Rhode Island Public Utilities Commission, Docket No. 22-20-NG on behalf of The Narragansett Electric Company, d/b/a Rhode Island Energy (September 1, 2022)

Answering Testimony of Paul J. Hibbard before FERC, Docket No. ER20-2441-002 on behalf of McKenzie Electric Cooperative, Inc. (July 15, 2022)

Testimony of Paul J. Hibbard before the US District Court, Southern District of Florida, Ft. Lauderdale Division on behalf of Simon Property Group et al., Case No. 0:20-cv-60981-AMC (June 6, 2022)

Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power Zero-Emission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations, with Scott Ario and Elisa Gan (May 6, 2022)

Affidavit of Paul Hibbard and Charles Wu before FERC, Docket No. ER22-772-000 on behalf of NYISO (January 5, 2022)

Modifications to the BSM Construct in the NYISO Capacity Market: Analysis of Potential Capacity Market Competitiveness and Reliability Outcomes, with Charles Wu (December 2021)

Economic Impact of a Clean Electricity Payment Program, with Pavel Darling and Luke Daniels (September 2021)

"Why Hydrogen?," presentation during the EBC Energy Resources Webinar: Future of Green Hydrogen – Earthshot Effort to Meet the Needs of Climate Change (September 30, 2021)

"Decarbonization and The Power System," presentation during the Northeast Public Power Association RodE&O Conference and Expo, Engineering Track (September 22, 2021)

"Net Zero Carbon: What Is It and What Should It Be?," presentation during the LDC Gas Forum (September 14, 2021)

"Net Zero Carbon: What Is It and What Should It Be?," presentation during the NEPPA Annual Conference, General Session (August 23–24, 2021)

"Motivating Customers to Decarbonize with an Eye Toward Equity," presentation during the 2021 NARUC Summer Policy Summit (July 18, 2021)

Economic Impact of Stimulus Investment in Advanced Energy for America, with Pavel Darling (June 2021)

Economic Impact of Stimulus Investment in Transportation Electrification, with Pavel Darling (June 2021)

"A Step Through the Looking Glass – Outlook for Natural Gas in the Northeast," Webinar for the Northeast Gas Association (NGA) Regional Market Trends Forum, What are the Market Pathways and Their Various Implications (April 29, 2021)

Accelerating Job Growth and an Equitable Low-Carbon Energy Transition: The Role of the Clean Energy Accelerator, with Susan F. Tierney (January 2021)

"Carbon Pricing: This Is the Way," presentation on a plenary panel to the New England Restructuring Roundtable (December 11, 2020)

"Approaches to Meeting Decarbonization Mandates: Important Decisions with Cost, Equity, and Reliability Implications," presentation during the EUCI Decarbonization Summit on state decarbonization opportunities (December 9, 2020)

"Approaches to Meeting Decarbonization Mandates: Important Decisions with Cost, Equity, and Reliability Implications," presentation during the New England Energy Summit on state decarbonization opportunities (November 23, 2020)

Affidavit of Paul J. Hibbard before FERC, Docket No. ER21-502-000 on behalf of NYISO (November 30, 2020)

Economic Impact of Stimulus Investment in Advanced Energy (series of 10 state-specific reports), with Pavel G. Darling (September–October 2020)

Climate Change Impact and Resilience Study – Phase II: An Assessment of Climate Change Impacts on Power System Reliability in New York State, with Charles Wu, Hannah Krovetz, Tyler Farrell, and Jessica Landry (September 2020)

Presented virtually at the Annual NECA Conference on how New England can transition away from fossil fuels, as well as the costs, reliability, and societal implications of moving toward low-carbon alternatives (September 30, 2020)

Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report, with Todd Schatzki, Charles Wu, Christopher Llop, Matthew Lind, Kiernan McInerney, and Stephanie Villarreal (September 9, 2020)

Utility energy efficiency program performance from a climate change perspective: A comparison of structural and behavioral programs, with Jonathan Baker, Mona Birjandi-Feriz, and Hannah Krovetz (August 2020)

"Energy Efficiency for Climate, Not Ratepayers," presentation on a plenary panel to the American Council for an Energy-Efficient Economy (ACEEE) Summer Study Session (August 19, 2020)

For the New England Power Generators Association (NEPGA), coauthored a report assessing the potential use of carbon pricing in New England; the analysis applied tested industry models to identify effective and efficient economy-wide pricing of carbon dioxide (CO_2) emissions consistent with New England states' GHG emission reduction targets (June 23, 2020)

Carbon Pricing for New England: Context, Key Factors, and Impacts, with Joseph Cavicchi (June 2020)

"Decarbonization and Wholesale Markets in New England – Looking Ahead: Achieving 80% GHG Reduction by 2050," presentation on a plenary panel to the Association of Energy Engineers Conference, "ISO-NE in 2050: Getting to an advanced energy future in New England," Boston, MA (March 18, 2020)

"Decarbonization and Natural Gas in the Northeast," panel moderator and presenter at the EUCI conference on Natural Gas Decarbonization, Denver, CO (January 22–23, 2020)

Fuel and Energy Security in New York State: An Assessment of Winter Operational Risks for a Power System in Transition, with Charles Wu (November 2019)

Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets, with Susan F. Tierney (October 2019)

"Natural Gas in Power Generation: Role Going Forward," 7th Annual Maine Natural Gas Conference to discuss power generation in the New England region. Falmouth, ME (October 3, 2019)

Direct Testimony of Paul J. Hibbard before the New Hampshire Public Utilities Commission on the need for and economic and environmental impacts of proposed Liberty Utilities Granite Bridge pipeline and LNG project, Docket No. DG 17-152 (June 28, 2019)

Rebuttal Testimony on Reopening of Paul J. Hibbard before the Illinois Commerce Commission on Behalf of Commonwealth Edison, Docket No. 18-0843 (May 31, 2019)

Pre-filed Testimony of Paul J. Hibbard before the Connecticut Siting Council on behalf of NTE Connecticut LLC, Docket No. 470 (January 18, 2019)

Vehicle Fuel-Economy and Air Pollution Standards: A Literature Review of the Rebound Effect, with Susan F. Tierney, Benjamin Dalzell, Grace Howland, Jonathan Baker, Tom Beckford, Sarah Centanni, Asie Makarova, and Scott Ario (June 28, 2018)

"An Expanding Carbon Cap-and-trade Regime? A Decade of Experience with RGGI Charts a Path Forward," with Susan F. Tierney and Pavel G. Darling, *The Electricity Journal* (June 2018)

Testimony of Paul J. Hibbard before the District of Columbia on behalf of AltaGas, Case No. 1142 (May 25, 2018)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States, review of RGGI's third three-year compliance period (2015–2017), with Susan F. Tierney, Pavel G. Darling, and Sarah Cullinan (April 2018)

Post-Settlement Testimony of Paul J. Hibbard before the Maryland Public Service Commission on behalf of AltaGas, Case No. 9449 (January 5, 2018)

Rebuttal Testimony of Paul J. Hibbard before the Public Service Commission of the District of Columbia on behalf of AltaGas, Formal Case No. 1142 (October 27, 2017)

Capacity Resource Performance in NYISO Markets: An Assessment of Wholesale Market Options, with Todd Schatski and Sarah Bolthrunis (November 2017)

RGGI and Emissions Allowance Trading: Options for Voluntary Cooperation Among RGGI and Non-RGGI States, with Ellery Berk (July 2017)

"Analytical Issues in Linking," presentation on Virginia and the Regional Greenhouse Gas Initiative, Virginia Commonwealth University, Richmond, VA (July 12, 2017)

Electricity Markets, Reliability and the Evolving U.S. Power System, with Susan Tierney and Katherine Franklin (June 2017)

"Storage and Microgrids – New Applications," panel presentation during the Electricity Advisory Committee's Energy Storage Session (June 8, 2017)

Supplemental Affidavit of Paul J. Hibbard before FERC, Docket No. ER17-386-000 on behalf of NYISO (December 18, 2016)

Affidavit of Paul J. Hibbard before FERC, Docket No. ER17-386-000 on behalf of NYISO (November 18, 2016)

Evaluation of Vermont Transco, LLC Capital Structure, with Craig Aubuchon and Mike Cliff (October 2016)

Rebuttal Testimony of Paul J. Hibbard before the State of Vermont Public Service Board on behalf of Vermont Gas Systems Inc., Docket Nos. 8698 and 8710 (September 26, 2016)

RGGI and CO_2 Emissions Trading Under the Clean Power Plan: Options for Trading Among Generating Units in RGGI and Other States, Susan Tierney and Ellery Berk (July 12, 2016)

Affidavit of Paul J. Hibbard before the FERC, Docket No. ER16-1751-000 on behalf of the NYISO (May 20, 2016)

Declaration of Paul J. Hibbard and Andrea M. Okie in the US Court of Appeals for the District of Columbia Circuit, Case No. 15-1363 (and consolidated cases) on behalf of multiple parties (December 8, 2015)

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, with Craig Aubuchon (November 2015)

Testimony of Paul J. Hibbard before the Senate Committee on Global Warming and Climate Change, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas* (November 24, 2015)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Altantic States, review of RGGI's Second Three-Year Compliance Period (2012–2014), with Andrea Okie, Susan Tierney, and Pavel Darling (July 14, 2015)

Electric System Reliability and EPA's Clean Power Plan: The Case of MISO, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (June 8, 2015)

Net Metering in the Commonwealth of Massachusetts: A Framework for Evaluation (May 2015)

NYISO Capacity Market: Evaluation of Options, report for the NYISO, with Todd Schatzki, Craig Aubuchon, and Charles Wu (May 2015)

Ohio's Electricity Future: Assessment of Context and Options, report for Advanced Energy Economy, with Andrea Okie (April 2015)

Electric System Reliability and EPA's Clean Power Plan: The Case of PJM, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (March 16, 2015)

Electric System Reliability and EPA's Clean Power Plan: Tools and Practices, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (February 2015)

Tools States Can Utilize for Managing Compliance Costs and the Distribution of Economic Benefits to Consumers Under EPA's Clean Power Plan, Electricity Forum, with Andrea Okie and Susan Tierney (February 2015)

The Economic Potential of Energy Efficiency, report for the Environmental Defense Fund, with Katherine Franklin and Andrea Okie (December 2014)

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, with Andrea Okie and Katherine Franklin (December 2014)

"EPA's Proposed Clean Power Plan and States' Planning for Implementation," presentation to the 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 the 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 the LSI Conference on the Columbia River Treaty (September 2014)

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

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

"EPA's Clean Power Plan: States' Tools for Reducing Costs and Increasing Benefits to Consumers," with Andrea Okie and Susan Tierney, *The Electricity Journal* (July 2014)

Direct Testimony of Paul J. Hibbard on behalf of Calpine Construction Finance Company, L.P., before the Florida Public Service Commission, Docket No. 140110-E1 (July 14, 2014)

"Project Vigilance: Value of Ambri Batteries at Joint Base Cape Cod," presentation to the Raab Restructuring Roundtable, Boston MA (June 2014)

Further Explanation on Rate Calculations, with Todd Schatzki, memo to the New England Independent System Operator Markets Committee on setting the compensation rate for the ISO Winter Program (May 28, 2014)

"Markets, Infrastructure, and Policy: New England at a Crossroads," presentation to the US/Canada Cross-Border Power Summit (April 2014)

"Siting Infrastructure: Economic and Siting Hurdles," presentation to the US/Canada Cross-Border Power Summit (April 2014)

Economic Impact of the Green Communities Act in the Commonwealth of Massachusetts: Review of the Impacts of the First Six Years," with Susan Tierney and Pavel Darling (March 4, 2014)

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 the Environmental Defense Fund, with Andrea Okie (March 2014)

"Climate Policy and the Economy," presentation to the 2014 Joint Institute for Strategic Energy Analysis Annual Meeting, NREL, Golden CO (March 2014)

Testimony of Paul Hibbard and Todd Schatzki on behalf of the New England Independent System Operator before the Federal Energy Regulatory Commission, Docket Nos. ER14-1050-000 and ER14-1050-001 (February 12, 2014)

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, with Steve Carpenter, Pavel Darling, Margaret Reilly, and Susan Tierney (February 2014)

Testimony of Paul J. Hibbard before the Maine Public Utilities Commission on behalf of Loring Holdings LLC; testimony described the results of 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 (2014–2015)

Rebuttal Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240 (October 18, 2013)

Direct Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240 (September 27, 2013)

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives, with Todd Schatzki (September 2013)

"Market Monitoring at US RTOs," presentation to the 12th Annual Gas and Power Institute, Houston, TX (August 2013)

Testimony of Paul J. Hibbard before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Department of Energy Resources, DPU 13-07 (May 31, 2013)

Testimony of Paul 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)

Testimony of Paul J. Hibbard, on behalf of the Massachusetts Department of Energy Resources, on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013)

California's Advanced Energy Economy – Advanced Energy Business Leaders' Perspectives and Recommendations on California's Energy Policies, with Andrea Okie and Susan Tierney, Advanced Energy Economy Institute, (February 2013)

Information from the Literature on the Potential Value of Measures that Improve System Reliability, memo to the New England Independent System Operator (January 24, 2013)

Information on the Range of Costs Associated with Potential Market Responses to Address the Risks Associated with New England's Reliance on Natural Gas, New England Independent System Operator (January 24, 2013)

Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs, with Craig Aubuchon, report for the Barr Foundation, (January 2013)

"Demand Response in Capacity Markets: Reliability, Dispatch and Emission Outcomes," *The Electricity Journal*, with Andrea Okie and Pavel Darling (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)

Paul Hibbard, *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, report to the EPA 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)

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

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

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

Testimony of Paul 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 tothe California Business Climate Network, with Susan Tierney (February 2012)

"Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years," with Susan Tierney, *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," presentation to the Governors' Wind Energy Coalition, Washington, DC (November 2011)

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, with Susan Tierney, Andrea Okie, and Pavel Darling (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 Colorado Oil & Gas Association 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)

"Retirement is Coming: Preparing for New England's Capacity Transition," *Public Utilities Fortnightly* (June 2011)

Generation Fleet Turnover in New England: Modeling Energy Market Impacts, with Todd Schatzki, Pavel Darling, and Bentley Clinton (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 the 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 the Raab Restructuring Roundtable, Boston, MA (October 2010)

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

"Renewables Development – A Tricky Time to be Placing Bets," presentation to the 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 the 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 the LSI Conference on US/Canada Energy Transactions, Vancouver, BC (August 2010)

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

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

"Deregulation and Sustainable Energy," class lecture, Massachusetts Institute of Technology (Jonathan Raab Energy Course), Cambridge, MA (March 2010)

"Transmission for Renewables," presentation to the Raab Restructuring Roundtable, Boston, MA (March 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 the New England Independent System Operator 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 the Northeast Energy and Commerce Association Power Markets Conference, Westborough, MA (November 2009)

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

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

"Transmission Planning," comments to the Federal Energy Regulatory Commission 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 the 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 before 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 the 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 the New England Governors' Blueprint to the New England Conference of Public Utilities Commissioners Annual Symposium, Newport, RI (May 2009)

"Comments of Chairman Paul Hibbard," presentation to the 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 the 2009 Platts Wind Power Development Conference, Chicago, IL (March 2009)

"Integrating Energy and Environmental Regulations in Massachusetts," presentation to the Northeast Sustainable Energy Association Building Energy Conference, 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 the Berkshire Gas Large Commercial and Industrial Customer Annual Meeting, Lenox, MA (October 2008)

"Conversation with Chairman Hibbard," presentation to the New England Energy Alliance, Boston, MA (September 2008)

"Creating the Path: Delivering Clean Energy through Transmission Improvements," presentation to the New England Independent System Operator Lights, Power, Action Conference, Boston, MA (September 2008)

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

"Resource Planning: The Contribution of Efficiency and Renewables in Massachusetts," presentation to the 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 the New England Governors' Council/Eastern Canadian Premiers' Energy Dialogue, Montreal, Canada (May 2008)

"New England Transmission Investment," presentation to the 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 the 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 the Independent System Operator Planning Advisory Committee, Boston, MA (September 2007)

"Regulatory Pressures, Policy Opinions," presentation to the 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 to the New England Independent System Operator 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 the Law Seminars International 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 the National Association of Energy Service Companies 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, LLC, 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, 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" prepared for the New England Energy Alliance, with Susan Tierney (November 2005)

"Federal Legislative Developments in Energy," presentation to the Law Seminars International Seminar on Energy in the Northeast (October 2005)

"The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project," prepared for Northeast Gateway Energy Bridge, LLC, and Algonquin Gas Transmission, LLC, with Susan Tierney (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," prepared for Le Centre Français sur les Etats-Unis (The French Center on the United States), with Susan Tierney (July 2003)

"Controlling China's Power Plant Emissions after Utility Restructuring: The Role of Output-Based Emission Controls," with Barbara A. Finamore, Nancy Seidman, and Tara 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 Susan Tierney, *The Electricity Journal* (June 2002)

"Siting Power Plants: Recent Experience in California and Best Practices in Other States," with Susan 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," prepared for the China Sustainable Energy Program, Paul Hibbard, N. Seidman, and B. Finamore (October 2001)

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

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

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

"Safety and Environmental Comparisons of Stainless Steel with Alternative Structural Materials for Fusion Reactors," with Ann P. Kinzig, and John 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.
Principal

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todd.schatzki@analysisgroup.com	Boston, MA 02199

Dr. Schatzki is economist with expertise in markets and regulated industries, particularly energy markets and regulation. Within the energy sector, his expertise includes market design, finance, competition, ratemaking and market impacts and benefit-cost analysis in the electricity, natural gas, petroleum, and renewable energy sectors. He supports clients in a range of contexts, including regulatory and rulemaking proceedings, litigation, policy analysis, and strategic and financial advice.

His expertise in the electricity sector includes wholesale electricity market design; market conduct and competitive analysis; financial analysis, including valuation and cost of capital; utility regulation and ratemaking; economic analysis of new market rules, regulations, and infrastructure investments; and contract analysis and disputes. His clients include electricity system operators, market monitors, generation, transmission and distribution companies, government agencies, and non-government agencies. Dr. Schatzki has testified before U.S. state and federal, as well as Canadian provincial, regulatory commissions. He has also provided testimony at bankruptcy court and arbitration.

Dr. Schatzki has worked extensively on environmental economics, policy, and regulation, with his work focusing recently on the intersection of climate policy and energy markets, and disputes involving water resources and environmental contamination. His research has been published in distinguished energy- and environment-related publications, and he has provided research for prominent organizations such as the Electric Power Research Institute, the Edison Electric Institute, and the Federal Energy Regulatory Commission.

EDUCATION

1998 Ph.D., public policy, Harvard University

Specialized fields: Microeconomics, econometrics, industrial organization, natural resources, and environmental economics

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

1993 M.C.P., environmental policy and planning (urban studies and planning), Massachusetts Institute of Technology

1986 B.A., physics, Wesleyan University

PROFESSIONAL EXPERIENCE

2005–Present Analysis Group, Inc.
Principal

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 CONSULTING AND LITIGATION EXPERIENCE

Energy

- **Talen Energy**
  Assessment of market, economic and ratemaking issues associated with co-location of generation and load.
- **Ameren Illinois**
  Analysis of economic and rate impacts to customers of existing transmission assets owned by GridLiance.
- **New York ISO**
  Demand curve reset for the New York ISO ICAP market including development of ICAP Demand Curve, financial parameters and after-tax weighted average cost of capital.
- **Ameren Transmission Company of Illinois**
  Analysis of the economic impact of the Northern Missouri Grid Transformation Program, a part of MISO's Long Range Transmission Planning portfolio (using PROMOD).
- **Talen Energy**
  Estimation of the cost of service including cost of capital for two fossil-fired facilities for potential cost of service agreement.
- **Private equity firm**
  Assessment of potential transmission asset acquisition, including future investment potential, regulated return on capital, and market considerations.
- **Ameren Illinois and Ameren Transmission Company of Illinois**
  Analysis of the economic impact of the Central Illinois Grid Transformation Program, the Illinois portions of MISO's Long Range Transmission Planning portfolio (using PROMOD).
- **Renewable fuel producer**
  Assessment of production, supply chain and input contract issues for a renewable fuel producer.
- **ISO New England**
  Assessment of prompt and seasonal capacity market approaches for New England's capacity market in light of region's grid resource transition.
- **ISO New England**
  Analysis of the cost of capital of new entry for the ISO New England Forward Capacity Market.
- **Distributed energy resource company**
  Evaluation of market impact associated with a distributed energy resource business.
- **ISO New England**
  Assessment of the impact of wholesale market rule modifications on credit risks and financial assurance policy.

- **Xcel Energy**
  Evaluation of causes and potential remedies to growing system congestion, including transmission rights, interconnection and transmission planning market rules and procedures.
- **ISO New England**
  Updating rate and developing indexed rate approach for ISO New England's Inventoried Energy Program in light of volatile fuel markets.
- **ISO New England**
  Study of economic and market consequences of alternative policy approaches to future decarbonization of New England's electricity system.
- **Portland General Electric**
  Analysis of electricity trading.
- **Cheniere Energy**
  Analysis of life-cycle emissions associated with liquefied natural gas usage given substitution of existing energy sources.
- **Crescent Dunes Solar Energy Project**
  Analysis of economic issues associated with the future economic viability of the Crescent Dunes Solar Energy Projects.
- **New York ISO**
  Demand curve reset for the New York ISO ICAP market including development ICAP Demand Curve parameters, financial parameters and battery storage economic model.
- **Public Generating Pool and PacifiCorp**
  Develop a white paper evaluating mechanisms for the electricity sector to comply with zero-carbon emission requirements.
- **ISO New England**
  Assistance to market monitor in evaluating capacity market offers with respect to consideration of proposed Energy Security Improvements market rules changes.
- **Continental Buchanan**
  Analysis regarding contractual dispute over synthetic gypsum produced at coal-fired power generation facilities.
- **Singapore Electric Power Generators**
  Analysis of need for and design of proposed capacity market for Singapore's wholesale electric power market.
- **Ameren Missouri**
  Assessment of reliability and accuracy of evaluation, measurement and verification (EM&V) analysis of Ameren's energy efficiency programs performed by third-party consultant.
- **ISO New England**
  Assessment of the economic and operational impact of proposed Energy Security Improvements, market rule changes designed to address energy security concerns.
- **ISO New England**
  Assistance to market monitor in evaluating capacity market offers with respect to consideration of ISO New England's inventoried energy program.
- **Ameren Missouri**
  Assessment of economic issues associated with participation of baseload (coal-fired) power plants in RTO/ISO markets, including self-commitment and incremental energy offers.

- **ISO New England**
  Analysis of costs of securing energy inventory, including forward LNG contracts, for purposes of establishing the rate for ISO New England's inventoried energy program.
- **Capital Power**
  Analysis of design of proposed capacity market for Alberta, Canada.
- **New England Electricity Markets**
  Confidential analyses related to natural gas supply contracts, including contracts from liquefied natural gas terminals, and market rules to mitigate fuel security challenges.
- **Global Crude Oil Producer**
  Analysis of alternative approaches and contractual structures for marketing crude oil, including econometric analysis of customer price responsiveness.
- **New York ISO**
  Evaluation of performance issues associated with capacity market resources and potential changes to market designs.
- ***Merced v. Barclays***
  Analysis of alleged monopolization of western US electric power markets.
- **ISO New England**
  For the New England Power Pool (NEPOOL) 2016 Economic Analysis, analysis of Forward Capacity Market implications of alternative scenarios with varying assumptions about retirements and clean energy resources.
- **New England Electricity Markets**
  Confidential assessment of interactions between state policies affecting electric power resources, including long-term contracts, and wholesale electricity markets.
- ***FERC v. Barclays***
  Analysis of alleged manipulation of western US electric power exchange markets.
- **New York ISO**
  Demand curve reset for the New York ISO ICAP market including development annual updating process between resets and ICAP Demand Curve parameters.
- **Confidential Client**
  Analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suit.
- **ISO New England**
  Assessment of framework for evaluating capacity market offers from elective transmission projects for market mitigation.
- **Southwest Power Pool Power Suppliers**
  Analysis and testimony related to the types of costs are appropriately short-run marginal costs and thereby should be incorporated into energy market resource offers.
- **New York ISO**
  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 oil and gas leases.
- **ISO New England**
  Assistance in the development of winter fuel assurance programs for 2013/2014, 2014/2015 and 2015/2016, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **Ameren Transmission**
  Analysis of the impact of 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**
  Analysis of 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.
- ***In the Matter of Current and Future Conditions of Baltimore Gas and Electric Company***
  Analysis of financial and credit implications of the sale of a portion of power generation assets.
- **National Grid**
  Development of an internal 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.
- **Niagara Mohawk**
  Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments.
- **New England States Committee on Electricity**
  Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy.
- **Rhode Island Energy (National Grid)**
  Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments.
- **Massachusetts Electric (National Grid)**
  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.
- ***Vitol S.A. Inc. vs. BP Products North America, Inc.***
  Analysis of damages from breach of commodity swap contract (petroleum).
- **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

- **Western States Petroleum Association**
  Analysis of the design and initial performance of Washington GHG cap-and-trade market rule, particularly with regard to linkage and cost containment provisions.
- ***Koch Industries, Inc. and Koch Supply & Trading, LP v. Government of Canada***
  Evaluation of market design, market participant, policy issues and compensation associated with termination of Ontario's GHG cap-and-trade program.
- **Economic Impact of Lotusland Resort Development**
  Analysis of the employment, income and tax benefits of a new resort development in Napa Valley, California.
- **Novartis**
  Evaluation of global greenhouse gas emission impacts associated with alternative asthma treatments and greenhouse gas emission impacts of asthma exacerbations.
- **California State Auditor**
  Assist the Auditor in its assessment of GHG-related transportation regulation and program evaluations performed by the California Air Resources Board.
- **Western States Petroleum Association**
  Analysis of approaches to transitioning to long-run efficient climate policies.
- **Western States Petroleum Association**
  Analysis of the implications of a GHG cap-and-trade market rule for other climate policies for the state of Oregon.
- **Greater Boston Real Estate Board**

Development of a white paper evaluating mandatory residential energy labeling/benchmarking policies.

- **Western States Petroleum Association**
  Analysis of key changes to California's GHG cap-and-trade market rule for the 2021–2030 compliance period.
- ***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 US Supreme Court.
- **Western States Petroleum Association and Chevron**
  Analysis of key regulatory issues in the design of California's GHG cap-and-trade system for the 2021–2030 period
- ***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.
- ***C&A Carbone v. County of Rockland***
  Support of expert testimony regarding a violation of the dormant commerce clause.
- ***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**
  Analysis of alleged monopolization of energy price indices.
- **Mirant**
  Analysis of long-term contracts for electricity supply entered into following the California Electricity Crisis.

- **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**
  Evaluation of the regional economic impacts of runway expansions at the Barajas airport in Spain.

Finance and Commercial Damages (Non-Energy)

- ***K.C. Company, Inc. v. Pella Corp.***
  Assessment the business structure of a potential regional distributor for consistency with the distribution system and strategy.
- ***Todd J. Mortier et al. v. LivaNova USA, Inc.***
  Analysis of economic framework for medical device investments and strategic and economic considerations related to investment in certain heart valve replacement technologies.
- ***Anderson, et al. v. American Family Insurance***
  Analysis of reliability of methodologies to estimate diminution in property value associated with remediated property damage.
- **Confidential Client**
  Support during settlement, including analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- ***Becarra, et al. v. The Argentine Republic***
  Analysis of bond pricing, transactions, and holdings related to default of sovereign bonds.
- ***Capital One Financial v. Commissioner of Internal Revenue***
  Analysis of transfers between financial institutions within credit card networks.
- **Confidential Client**
  Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement.
- ***Kourosh A. Dastgheib v. Genentech***
  Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product.
- **Confidential Client**
  Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution.

Antitrust (including Financial Markets)

- ***City of Philadelphia, et al. v. Bank of Am. Corp., et al.***
  Analysis of alleged manipulation of variable rate demand obligation market.
- ***Nypl et al. v. JPMorgan Chase & Co., et al.***
  Analysis of impact of alleged manipulation of foreign exchange benchmarks on retail transactions.
- **BlackRock**
  Analysis of potential impact of common ownership on competition, including econometric analysis of such impacts in the commercial airline industry.

- ***Allianz Global Investors GmbH et al. v. Bank of America Corporation et al.***
  Analysis of economic issues associated with alleged manipulation of foreign exchange benchmarks.
- ***Central Garden & Pet v. Monsanto***
  Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement.
- ***In re: Vitamins Antitrust Litigation***
  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.
- **Confidential Retail Consumer Product Company**
  Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement.
- ***Michlin Diazo Products v. Oce-USA and Oce Printing Systems***
  Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages.
- **Confidential Petrochemical Company**
  Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by the Department of Justice (DOJ) and private parties.
- **Confidential Scientific Equipment Company**
  Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents.
- ***Endobionics, Inc. v. Medtronic, Inc.***
  Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement.
- **Confidential Scientific Equipment Company**
  Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent.

TESTIMONY AND OTHER FILINGS

- **Declaration**
  Federal Energy Regulatory Commission, Docket No. ER24-2172-000, Amendment to ISA, Susquehanna Nuclear
  September 24, 2024
- **Rebuttal Testimony on Behalf of Ameren Illinois Company**
  Illinois Commerce Commission, Docket No. 23- 0061, GridLiance Heartland LLC Application for Certificate of Public Convenience and Necessity
  August 26, 2024
- **Direct Testimony on Behalf of Ameren Transmission Company of Illinois**
  Missouri Public Service Commission, File No. EA-2024-0303, Application for Certificate of Convenience and Necessity
  July 9, 2024
- **Direct Testimony on Behalf of Ameren Illinois Company**
  Illinois Commerce Commission, Docket No. 23- 0061, GridLiance Heartland LLC Application for Certificate of Public Convenience and Necessity
  June 17, 2024
- **Testimony on Behalf of Talen Energy Company**
  Federal Energy Regulatory Commission, Docket No. ER24- 1790-000, Brandon Shores LLC, Continuing Operations Rate Schedule
  April 18, 2024

- **Testimony on Behalf of Talen Energy Company**
  Federal Energy Regulatory Commission, Docket No. ER24-1787-000, H.A. Wagner LLC, Continuing Operations Rate Schedule
  April 18, 2024
- **Affidavit on Behalf of the New England Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER24-1407-000, Revisions to ISO New England Tariff to Further Delay the Nineteenth Forward Capacity Auction
  April 5, 2024
- **Direct Testimony on Behalf of Ameren Illinois and Ameren Transmission Company of Illinois**
  Illinois Commerce Commission, Docket No. 24-0088, Application for Certificate of Public Convenience and Necessity
  February 5, 2024
- **Affidavit on Behalf of the New England Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER24-401-000, Targeted Adjustments to Certain Forward Capacity Market Parameters to Reflect the Minimum Offer Price Rule Elimination, Analysis of the After-Tax Weighted Average Cost of Capital of New Entry for the ISO New England Forward Capacity Market
  November 15, 2023
- **Declaration on Behalf of Distributed Energy Resource Company**
  Federal Energy Regulatory Commission, Declaration in Response to Preliminary Findings (confidential)
  September 2023
- **Testimony on Behalf of ISO New England**
  Federal Energy Regulatory Commission, Docket No. ER23-1588-000, Revisions to Update the Inventoried Energy Program
  April 7, 2023
- **Testimony**
  In re: Tonopah Solar Energy LLC, Case No. 20-11884 (KBO), in the U.S. Bankruptcy Court for the District of Delaware
  November 20, 2020
- **Affidavit on Behalf of the New York Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER21-502-000, 2021-2025 ICAP Demand Curve Reset Proposal
  November 18, 2020
- **Affidavit on Behalf of the New England Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. EL18-182-000, Filing of Energy Security Improvements
  April 14, 2020
- **Expert Report**
  Continental Buchanan, LLC v. GenOn Mid-Atlantic LLC, American Arbitration Association, Case No. 01-19-0002-8683
  April 3, 2020.
- **Testimony on Behalf of Ameren Missouri**
  Missouri Public Service Commission, Case No. ER-2019-0335, Regarding Unit Commitments and Unit Offers
  January 21, 2020
- **Testimony (Additional Evidence) on Behalf of Capital Power**
  Alberta Utilities Commission, Proceeding No. 23757, Regarding the Design for Alberta's Capacity Market, April 4, 2019

- **Testimony on Behalf of ISO New England**
  Federal Energy Regulatory Commission, Docket No. ER19-1428-000, Inventoried Energy Program
  March 25, 2019
- **Testimony (Evidence) On Behalf of Capital Power**
  Alberta Utilities Commission, Proceeding No. 23757, Regarding Design for Alberta's Capacity Market
  February 28, 2019
- **Direct Testimony on Behalf of Ameren Transmission Company of Illinois**
  Missouri Public Service Commission, Case No. EA-2017-0345, Application for Certificate of Convenience and Necessity
  September 14, 2017
- **Supplemental Affidavit on Behalf of New York Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER17-386-000, ICAP Demand Curve Reset Proposal
  December 21, 2016
- **Affidavit on Behalf of New York Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER17-386-000, Proposed ICAP Demand Curve and Parameters for Annual Updates
  November 18, 2016
- **Testimony and 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 ISO New England**
  Federal Energy Regulatory Commission, Docket No. ER14-1050-001
  February 12, 2014
- **Affidavit on Behalf of ISO New England, Performance Incentives Market Rule Changes**
  Federal Energy Regulatory Commission, Docket No. ER14-1050-001
  January 14, 2014
- **Comments Regarding AB 32 Cap-and-Trade Program Amendments Related to Allowance Allocations (with Robert N. Stavins)**
  California Air Resources Board
  August 2013
- **Comments Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program (with Robert N. Stavins)**
  California Air Resources Board
  August 2011
- **Comments Submitted to the Little Hoover Commission's Study of Regulatory Reform in California (with Robert N. Stavins)**
  January 2011
- **Comments Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program**
  California Air Resources Board
  December 2010
- **Comments Regarding Cost Containment Provisions of Preliminary Draft Cap-and-Trade Regulation**
  California Air Resources Board
  July 2010
- **Comments Regarding the Draft Report "Allocating Emissions Allowances Under California's Cap-and-Trade System" (with Robert N. Stavins)**
  Economics and Allocation Advisory Committee, California Air Resources Board
  December 1, 2009

ARTICLES AND PAPERS

"Impact of Choice of Inhalers for Asthma Care on Global Carbon Footprint and Societal Costs: A Long-term Economic Evaluation," with Kponee-Shovein, K., et al, *Journal of Medical Economics*, 25(1):940-953, 2022.

"Carbon footprint and associated costs of asthma exacerbation case amount UK adults," with Kponee-Shovein, K., et al, *Journal of Medical Economics*, April 26, 2022.

"Transitioning to Long-Run Effective and Efficient Climate Policies", with Robert Stavins and Rebecca Scott, The Harvard Project on Climate Agreements, Discussion Paper 19-94, April 2019.

"GHG Cap-and-Trade: Implications for Effective and Efficiency Climate Policy in Oregon," with Robert N. Stavins, The Harvard Project on Climate Agreements, Discussion Paper 18-92, November 2018.

"Key Issues Facing California's GHG Cap-and-Trade System for 2021-2030," with Robert N. Stavins, M-RCBG Faculty Working Paper 2018-02, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, July 2018.

"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.

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"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.

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"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.

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Co-Located Load, Market, Economic and Rate Implications, prepared for Talen Energy, with Joseph Cavicchi, Megan Accordino, October 2024.

Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years - Final Report, prepared for the New York Independent System Operator, Hibbard, P., Schatzki, T., Cavicchi, J., Wu, C. and Stuart, D., September 2024.

Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets, prepared for ISO New England, with Joseph Cavicchi, Phillip Ross, January 2024.

Pathways Study, Evaluation of Pathways to a Future Grid, prepared for ISO New England, with Llop C., et al., April 2022.

Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years - Final Report, prepared for the New York Independent System Operator, Hibbard, P., Schatzki, S. Wu, C. and Llop, C., September 9, 2020.

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Achieving Western States Greenhouse Gas (GHG) Reduction Objectives: Least-Cost Compliance in a Constantly Evolving Policy Environment, with Joseph Cavicchi, prepared for the Public Generating Pool and PacifiCorp, August 2020.

Capacity Resource Performance in NYISO Markets, An Assessment of Wholesale Market Options, with Hibbard, P. and Bolthrunis, S., prepared for the New York Independent System Operator, October 2017.

Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios, An Element of the ISO New England 2016 Economic Analysis, with Llop, C., prepared for ISO New England, July 3, 2017.

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

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

Options for Addressing Leakage in California's Climate Policy, with Borck, J. and Stavins, R., prepared for the Western States Petroleum Association, February 2010.

Addressing Environmental Justice Concerns in the Design of California's Climate Policy, with Stavins, R., 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 Stavins, R. and Borck, J., prepared for the Western States Petroleum Association, July 2009.

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

Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, with Tierney, S., 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 Tierney, S. and Mukerji, R., prepared for the New York Independent System Operator, March 2008.

Prospects for the U.S. Nuclear Industry, coauthor, prepared for a major Japanese electric power company, January 2001.

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

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

The Impacts of Revised Salem Refueling Schedules on the Wholesale and Retail Electric Market, with Harrison, D. and Meehan, G., 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 Harrison, D., Electric Power Research Institute Report #1000147, December 2000.

Fueling Electricity Growth for a Growing Economy, Background Paper, with Harrison, D., 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 Harrison, D. and Murphy, J., 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 Harrison, D. and Chamberlain, S., prepared for Alliance of Automobile Manufacturers, January 2000.

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

Costs and Benefits of Fish Protection Alternatives at the Salem Facility, with Harrison, D. and Murphy J., 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 Harrison, D., Garcia-Cobos J., and Rowland, D., prepared on behalf of the Spanish Government, January 1999.

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

Disposal Cost Fee Study, with Ackerman, F., McClain, G., Peters, I., and Schall, J., prepared for the California Integrated Waste Management Board, 1991.

The Marginal Cost of Handling Packaging Materials in the New Jersey Solid Waste System, with Schall, J., 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 Becker, M., and White, A., prepared for the Northeast Regional Biomass Program, Coalition of Northeastern Governors Policy Research Center, 1990.

WORKING PAPERS

Reassessing Common Ownership: Corrections to Azar, Schmalz, and Tecu, with Mark Egland, Owen Hearey, and Channing Verbeck, October 2, 2019.

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.

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

The Pollution Control and Management Response of Thai Firms to Formal and Informal Regulation, with Theodore Panayotou, 1999.

Differential Industry Response to Formal and Informal Environmental Regulations in Newly Industrializing Economies: The Case of Thailand, with Theodore Panayotou and Qwanruedee Limvorapitak, presented at 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.

SELECTED PRESENTATIONS

"Effects of Technology Shifts on Power Markets, System Operations, and Customers," Energy Bar Association, Annual Meeting, April 2024.

"Making Wholesale Electricity Markets Work for Clean Energy Transition," Renewable Energy Markets, September 20, 2023.

"Pathways Study: Evaluation of Pathways to a Future Grid for New England," Restructuring Roundtable, June 10, 2022.

"The Transmission Evolution: The Role of Transmission in Supporting Clean and Carbon-Free Initiatives," 2021 Energy Bar Association Western Chapter Annual Meeting, February 25, 2021.

"Achieving Western States Greenhouse Gas (GHG) Reduction Objectives: Effective, Least-Cost Compliance in a Constantly Evolving Policy Environment," Washington CETA Markets Work Group, August 28, 2020.

"Market Implications of Evolving "Cleaner", "Greener" Resource Mixes," 2020 Energy Bar Association Midwest Chapter Annual Meeting, March 10, 2020.

"Regional Generation Trends – State Policy Drivers and Responses," EBA Energizer, Energy Bar Association, Power Generation and Marketing Subcommittee, December 3, 2019.

"Cost Containment – Which Cap-and-Trade Features Matter Most?" Climate Forum on California's Cap-And-Trade Program, International Emissions Trading Association, Carbon Market Compliance Association, Latham and Watkins, LLC, September 19, 2018.

"Northeast Power Markets Outlook: Addressing the Capacity and Reliability Crunch" and "Natural Gas: Cross-Border Trade, Market Dynamics, and Infrastructure Woes," EUCI 4TH Annual US Canada Cross-Border Energy Summit, March 12–13, 2018.

"Implications of the Expansion of "Non-Traditional" Resources for the Northeast Power Markets," Northeast Energy and Commerce Association's Power Markets Conference, November 14, 2017.

"The FERC's Anti-Market Manipulation Rule: Trends and Developments," webinar, The Knowledge Group, April 12, 2017.

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

"Net Metering," workshop, EUCI, 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, DC, 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.

Exhibit C

JOSEPH CAVICCHI
Vice President

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Mr. Cavicchi is an expert on the economics of wholesale and retail electricity markets. With more than 27 years of consulting experience, he advises a wide range of clients on issues associated with wholesale power market design and market power mitigation frameworks, wholesale and retail contracting practices, and regulatory and contract disputes arising in these marketplaces. In these engagements, Mr. Cavicchi has conducted economic analyses evaluating the impact of regulatory policies on electricity markets, applied rigorous analytical modeling tools to power system operations, evaluated contracting disputes and assessed financial damages, analyzed the effectiveness of market power mitigation frameworks in conjunction with antitrust analyses, and led economic investigations of market participant bidding behavior associated with allegations of market manipulation. He has extensive experience as an expert witness before the Federal Energy Regulatory Commission (FERC) and other federal and state regulatory authorities and has provided testimony in court and arbitration proceedings. Mr. Cavicchi presents and publishes frequently on issues relevant to electricity market design and evolution. He is a registered professional mechanical engineer in the Commonwealth of Massachusetts.

EDUCATION

1997	S.M., technology policy, Massachusetts Institute of Technology
1992	S.M., environmental engineering, Tufts University
1987	B.S., mechanical engineering, University of Connecticut

PROFESSIONAL EXPERIENCE

2019–Present	Analysis Group *Vice President*
1997–2019	Compass Lexecon *Executive Vice President/Senior Vice President (2007–2019)* *Vice President (2001–2006)* *Consultant/Senior Consultant (1997–2001)*
1989–1997	Massachusetts Institute of Technology *Research Assistant/Engineer (1995–1997)* *Project Manager/Staff Mechanical Engineer (1989–1995)*
1987–1988	Carrier Building Systems and Services *Project Engineer*

SELECTED CONSULTING EXPERIENCE

Electric Generation Companies, Trade Associations, and Independent System Operators

Conducts power system economic analyses to investigate the interaction of regulatory policies and rules with wholesale power markets, the results of which form the basis for a wide variety of reports, presentations, and papers. Conducts wholesale market power screening analyses and evaluates the impacts of mergers and acquisitions on wholesale and retail markets. Analyzes power market designs and runs workshops and seminars on power market design features.

Develops Federal Energy Regulatory Commission cost-of-service rate schedules for electric power generation resource asset owners. Oversees cost-of-service data compilation, schedule development, and calculation of cost of capital. Formulates overall cost of service schedules that combine rate-base, return on rate-base, and other ongoing fixed and variable costs to maintain generation resource operations.

Electricity Generation and Transmission Facility Developers

Oversees the development and implementation of security-constrained unit commitment and dispatch modeling for proposed electricity generation units and transmission facilities located in the Northeastern, Mid-Atlantic, and Midwestern US. The analyses typically focus on going-forward generation and transmission resource economic evaluations, and on assessing the impacts of different resource mixtures on local and regional air pollutant emissions and projected wholesale and retail electricity prices. In addition, these analyses often include an estimate of the impact of particular resource investments on social welfare.

SELECTED EXPERT TESTIMONY

- **PPL Electric Utilities Corporation**
  Before the Pennsylvania Public Utility Commission, *Docket No. P-2024-3047290, PPL Electric Utilities Corporation*
  Statement No. 2. Direct Testimony of A. Joseph Cavicchi, March 12, 2024. Written, Public.
  Statement No. 2-R. Rebuttal Testimony of A. Joseph Cavicchi, July 1, 2024. Written, Public.

- ***Peaker Power, LLC, v. Shell Energy North America (US), L.P.***
  Before the Texas Harris County District Court, 165th Judicial District, Cause No. 2021-16610
  Expert Report of A. Joseph Cavicchi, August 22, 2022. Declaration of A. Joseph Cavicchi, September 9, 2022. Deposition Testimony of A. Joseph Cavicchi, October 5, 2022.

- **Narragansett Electric Company, d/b/a Rhode Island Energy**
  Before the Rhode Island Public Utility Commission, *Docket No. 4978, Last Resort Service Rate Filing*
  Pre-Filed Direct Testimony of A. Joseph Cavicchi, July 21, 2022. Hearing Testimony of A. Joseph Cavicchi, September 19, 2022.

- **Olin Chlorine 7 f/k/a Dow Mitsui Chlor-Alkali LLC**
  Before the American Arbitration Association International Centre for Dispute Resolution, Olin Chlorine 7 f/k/a Dow Mitsui Chlor-Alkali LLC, and Blue Cube Operations, LLC, Claimants, and Dow Hydrocarbons and Resources LLC, Respondent, Case No. 01-21-0004-3837
  Expert Report of Allen Joseph Cavicchi, February 1, 2022. Confidential.

- **PJM Interconnection, L.L.C.**
  United States of America, Before the Federal Energy Regulatory Commission, *Docket No. ER22-26-000*
  Direct Testimony of A. Joseph Cavicchi and Megan H. Accordino, Ph.D., October 1, 2021.

- **Twin Eagle Resource Management**
  City of Raton vs. Twin Eagle, State of New Mexico, County of Colfax, Eighth Judicial District, Resource Management, No: D-809-CV-2019-00020
  Deposition Testimony, December 3, 2020.

- **PPL Electric Utilities Corporation**
  Before the Pennsylvania Public Utility Commission, *Docket No. P-2020-3019356, PPL Electric Utilities Corporation*
  Statement No. 2. Direct Testimony of A. Joseph Cavicchi, March 25, 2020. Written, Public.
  Statement No. 2-R. Rebuttal Testimony of A. Joseph Cavicchi, July 23, 2020. Written, Public.

- **PJM Power Providers Group**
  United States of America, Before the Federal Energy Regulatory Commission, *Docket Nos. ER19-1486-000 and EL19-58-000*
  Affidavits of A. Joseph Cavicchi on behalf of the PJM Power Providers ("P3") Group, May 15, 2019 and June 20, 2019. Written, Public.

- **NextEra Energy Resources, LLC**
  United States of America, Before the Federal Energy Regulatory Commission, Docket No. ER18-1639-000
  Answering Testimony of A. Joseph Cavicchi on behalf of NextEraEnergy Resources, LLC, August 23, 2018. Written, Public and Confidential. Deposition Testimony of A. Joseph Cavicchi, September 10, 2018. Oral, Public. Testimony of A. Joseph Cavicchi, October 8, 2018, Oral, Public and Confidential.

- **CXA La Paloma, LLC**
  United States of America, Before the Federal Energy Regulatory Commission. RE : CXA La Paloma, LLC v. California Independent System Operator Corporation, Docket No. EL18-177
  Affidavit of Jeffrey Tranen and Joseph Cavicchi, June 20, 2018. Written, Public.

- **Talen Montana, LLC and Talen Energy Marketing, LLC**
  United States of America, Before the Federal Energy Regulatory Commission. RE : Triennial Market-Based Rate Update for the Northwest Region, Talen Montana, L.L.C. et al., Dockets ER 15-2013 et al.
  Affidavit of A. Joseph Cavicchi, April 27, 2018. Written, Public.

- **Talen Montana, LLC and Talen Energy Marketing, LLC**
  United States of America, Before the Federal Energy Regulatory Commission. RE : Triennial Market-Based Rate Update for the Northwest Region, Talen Montana, L.L.C. et al., Dockets ER 10-2016 et al.
  Affidavit of A. Joseph Cavicchi, December 20, 2016. Written, Public.

- **PPL Electric Utilities Corporation and LG&E Energy Marketing Inc.**
  United States of America, Before the Federal Energy Regulatory Commission. RE : Triennial Market-Based Rate Update for the Northeast Region, PPL Electric Utilities Corporation et al., Dockets ER 10-2010 et al.
  Affidavit of A. Joseph Cavicchi, December 20, 2016. Written, Public.

- **NextEra Energy Resources, LLC**

Before the Commonwealth of Massachusetts, Department of Public Utilities, *Docket D.P.U. 16-05*, *Petition for Approval of Gas Infrastructure Contracts with Algonquin Gas Transmission Co. for the Access Northeast Project*
Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi, June 20, 2016 (corrected June 28, 2016), Written, Public and Confidential. Surrebuttal Testimony of Joseph P. Kalt and A. Joseph Cavicchi, July 18, 2016. Written, Public and Confidential.

- **NextEra Energy Resources, LLC**
  Before the Commonwealth of Massachusetts, Department of Public Utilities, *Docket D.P.U. 15-181*, *Petition for Approval of Gas Infrastructure Contracts with Algonquin Gas Transmission Co. for the Access Northeast Project*
  Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi, June 13, 2016 (corrected June 28, 2016), Written, Public and Confidential. Surrebuttal Testimony of Joseph P. Kalt and A. Joseph Cavicchi, July 12, 2016. Written, Public and Confidential.

- **PPL Electric Utilities Corporation**
  Before the Pennsylvania Public Utility Commission, *Docket No. P-2016-2526627, PPL Electric Utilities Corporation*
  Statement No. 2. Direct Testimony of A. Joseph Cavicchi, January 29, 2016. Written, Public. Statement No. 2-Supp. Supplemental Testimony of A. Joseph Cavicchi, March 9, 2016, Written, Public. Statement No. 2-R Rebuttal Testimony of A. Joseph Cavicchi, May 23, 2016. Written, Public.

- **Calpine Corporation et al.**
  United States of America, Before the Federal Energy Regulatory Commission. Calpine Corporation et al., Complainants v. PJM Interconnection, L.L.C., Respondent. RE: Complaint Requesting Fast Track Processing, PJM Interconnection, L.L.C., Docket No. EL 16-49-000
  Affidavit of A. Joseph Cavicchi, March 21, 2016. Written, Public.

- **PJM Power Providers Group**
  Before the Public Utilities Commission of Ohio, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, Case No. 14-1693-EL-RHR et al.*
  Supplemental Testimony of A. Joseph Cavicchi on behalf of the PJM Power Providers Group and The Electric Power Supply Association, December 28, 2015. Written, Public and Confidential. Deposition of A. Joseph Cavicchi on behalf of the PJM Power Providers Group and The Electric Power Supply Association, January 5, 2016. Deposition Testimony of A. Joseph Cavicchi, January 5, 2016. Testimony of A. Joseph Cavicchi, January 7, 2016. Oral, Public.

- **Exelon Generation Company, LLC**
  United States of America, Before the Federal Energy Regulatory Commission, *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, Into Markets Operated by the California, Independent System Operator Corporation, And the California Power Exchange, Docket EL 00-95-280 et al.*
  Affidavit of A. Joseph Cavicchi in Support of the Exelon Generation Company, LLC's Fuel Cost Allowing Filing, December 4, 2015. Written, Public.

- **PJM Power Providers Group**
  Before the Public Utilities Commission of Ohio, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, *Case No. 14-1693-EL-RHR et al.*

Direct Testimony of A. Joseph Cavicchi on behalf of the PJM Power Providers Group and The Electric Power Supply Association, September 11, 2015, Written, Public and Confidential. Testimony of A. Joseph Cavicchi on behalf of the PJM Power Providers Group and The Electric Power Supply Association, October 20, 2015. Oral, Public.

- **Iberdrola Renewables, LLC**
  United States of America, Before the Federal Energy Regulatory Commission, Docket Nos. EL02-60-007 and EL02-62-006, consolidated
  Prepared Answering Testimony of A. Joseph Cavicchi on behalf of Iberdrola Renewables, LLC, July 21,2015 Written, Public & Confidential. Deposition of A. Joseph Cavicchi on behalf of the Iberdrola Renewables, LLC, September, 24, 2015. Oral, Confidential. Testimony of A. Joseph Cavicchi, December 3, 2015. Oral, Public.

- **PPL Electric Utilities Corporation**
  Before the Pennsylvania Public Utility Commission, *Docket No. P-2014-2417907, PPL Electric Utilities Corporation*
  Statement No. 2. Direct Testimony of A. Joseph Cavicchi, April 25, 2014, Written, Public. Statement No. 2-R Rebuttal Testimony of A. Joseph Cavicchi, July 28, 2014. Written, Public.

- **San Diego Gas and Electric Company**
  Naturener USA, LLC, et al. v. San Diego Gas & Electric Company, in the Montana Ninth Judicial District Court, Toole County, Declaration, January 22, 2014. Non-Public.

- **PPL EnergyPlus**
  United States of America, Before the Federal Energy Regulatory Commission. RE : Triennial Market-Based Rate Update for the Northeast Region, PPL Electric Utilities Corporation et al., Dockets ER 10-2010 et al.
  Affidavit of A. Joseph Cavicchi, December 31, 2013. Written, Public.

- **PPL EnergyPlus**
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"The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing," prepared for the Electric Power Supply Association (March 2014).

"Anatomy of Sealed-Bid Auctions. Bringing Flexibility and Efficiency to Energy RFPs," with Andrew Lemon, *Public Utilities Fortnightly*, pp. 20-64 (June 2009).

"U.S. Centralized Wholesale Electricity Markets: An Update," *International Association for Energy Economics Newsletter*, pp. 8-12 (First Quarter 2007).

"Power Procurement. What's in Your Mix? Why Competitive Markets Are Scaring Regulators," with Andrew Lemon, *Public Utilities Fortnightly*, pp. 49-54 (November 2006).

"Competition and Regulation in the Power Industry, Part III: Tensions Evolve Between Regulation and Competition," with Charles Augustine and Joseph Kalt, *Electric Light & Power*, volume 84.01, pp. 24-25 (January/February 2006).

"Gradualism in Retail Restructuring." with Charles Augustine and Joseph P. Kalt, *Electric Light & Power*, volume 83:05, pp. 26-30 (September/October 2005).

"Competition and Regulation in the Power Industry: Can the Two Coexist?" with Charles Augustine and Joseph Kalt, *Electric Light & Power*, volume 83.04, pp. 28-31 (July/August 2005).

"Ensuring The Future Construction of Electricity Generation Plants: The Challenge of Maintaining Reliability in New U.S. Wholesale Electricity Markets," with Andrew Kolesnikov, *International Association for Energy Economics Newsletter* (First Quarter 2005).

"Electricity Company Affiliate Asset Transfer Self Build Policies: Renewed Regulatory Challenges," with Scott T. Jones, *The Electricity Journal* (November 2004).

"Onward Restructuring," *Hart Energy Markets*, Vol. 9, No. 9, p. 64 (September 2004).

"Competition and Regulation in the North American Electricity Industry: Can These Two Seemingly Opposed Forces Coexist?" with Charlie Augustine and Joseph P. Kalt, 24th Annual North American Conference of the USAEE/IAEE Proceedings, Washington, DC (July 9, 2004).

"Wholesale Electricity Procurement Strategies for Serving Retail Demand," *International Association for Energy Economics Newsletter* (First Quarter 2004).

"Economic and Environmental Benefits of the Kings Park Energy Project: System Production Modeling Report," with Susan F. Tierney (January 25, 2002).

"Economic and Environmental Benefits of the Wawayanda Energy Center: System Production Modeling Report," with Susan F. Tierney (August 24, 2001).

"Air Pollution Reductions Resulting from the Kings Park Energy Project," with Susan F. Tierney (January 24, 2001).

PRESENTATIONS AND SPEAKING ENGAGEMENTS

"Overview of Ancillary Services, Regulation and Reserve Products in Wholesale Markets," EUCI Ancillary Services Fundamentals and Market Dynamics (June 18, 2024).

"Overview of Ancillary Services, Regulation and Reserve Products in Wholesale Markets," EUCI Ancillary Services Fundamentals and Market Dynamics (January 6, 2023).

"Getting ELCC Right – Managing the Changing Fleet," EUCI Applying ELCC in ISOs and Utility Balancing Areas to Ensure Resource Adequacy (December 14, 2021).

"Overview of Ancillary Services, Regulation and Reserve Products in Wholesale Markets," EUCI Ancillary Services Fundamentals and Market Dynamics (August 25, 2021).

"Market Power Monitoring and Mitigation in RTO/ISOs," EUCI Electricity Market Power, Manipulation, Regulation and Enforcement (April 20, 2021).

"Critical Elements of Ancillary Services Market Design and Costing," EUCI Ancillary Services Fundamentals and Market Dynamics Workshop (December 1, 2020).

"Achieving Western States Green House Gas (GHG) Reduction Objectives: Effective, Least-Cost Compliance in a Constantly Evolving Policy Environment," presented with Todd Schatzki, Washington CETA Markets Workgroup (August 28, 2020).

"Carbon Pricing for New England," NEPOOL Participants Committee Meeting (August 6, 2020).

"Fundamentals of Capacity Market Design and Performance," EUCI Capacity Markets Workshop, (July 29, 2020).

"Fundamentals of Capacity Market Design and Performance," EUCI Capacity Markets Workshop, Philadelphia, PA (May 1, 2019).

"Critical Elements of Ancillary Services Market Design and Costing," EUCI Ancillary Services Markets Conference, Charleston, SC (March 19, 2019).

"Accommodating the Growing Supply of Zero-Emission Resources in U.S. Wholesale Power Markets, Institute for Energy Law Alternative & Renewable Energy Practice Committee, (January 23, 2019).

"Implementing Order No. 841: What Should We Expect?" K&L Gates, Energy Storage Association, Edison Electric Institute, 2nd Annual Energy Storage Conference, Washington, DC (November 29, 2018).

"Dumping Energy: Renewable Energy, Cost-Effective Curtailment and Remediating Negative Pricing Conditions," EUCI Conference, Minneapolis, MN (July 12, 2018).

"Enhanced Reliability Unit Commitment: Fundamentals Design Elements 9-13," presented with Scott Harvey and Susan Pope, Independent Electricity System Operator of Ontario, Toronto, Ontario (November 27, 2017).

"Enhanced Reliability Unit Commitment: Fundamentals Design Elements 1-8," presented with Scott Harvey and Susan Pope, Independent Electricity System Operator of Ontario, Toronto, Ontario (October 30, 2017).

"The Growing Conflict between FERC Jurisdictional Electric Markets and State Policies," 2017 White & Case Energy Conference (October 18, 2017).

"Enhanced Reliability Unit Commitment: Overview and Design Elements," presented with Scott Harvey and Susan Pope, Independent Electricity System Operator of Ontario, Toronto, Ontario (October 11, 2017).

"Critical Elements of Ancillary Services Market Design and Costing," EUCI Ancillary Services Markets Workshop, Austin Texas (February 17, 2017).

"What Are the Implications for Adequacy and Future Generation Builds?" Infocast, Panelist, RPM and CP BRA Auction Results, PJM Market Summit 2016 (September 8, 2016).

"What Are the Implications for Adequacy, and Future Generation Builds?" Infocast, Panelist, RPM and CP BRA Auction Results, PJM Market Summit 2015 (September 17, 2015).

Panelist, Congressional Staff Briefing regarding the financial repercussions of the EPA's Clean Power Plan to public power plants, electric co-operatives, and merchant power plants, Stranded Assets Panel – Focusing on Financial Impacts to Public Power, Co-Ops, and Merchant Power Plants Under EPA's 111 (d) Clean Power Plan, Washington DC (March 2, 2015).

"Lessons Learned from Existing Scarcity and Shortage Pricing Rules," Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Scarcity and Shortage Pricing, Offer Mitigation, and Offer Caps Workshop, Federal Energy Regulatory Commission, Docket No. AD14-14-000 (October 28, 2014).

"Impacts of Officer Caps and Market Power Mitigation," Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Scarcity and Shortage Pricing, Offer Mitigation, and Offer Caps Workshop, Federal Energy Regulatory Commission, Docket No. AD14-14-000 (October 28, 2014).

Led a Congressional Staff Briefing examining section 111(d) of the Clean Air Act, Stranded Assets Panel – Focusing on the Impacts of EPA's GHG Proposal for Existing Plants Under 111(d), Washington, DC (July 30, 2014).

"Forward Capacity Auctions: Financial, Physical, or Both," EUCI (November 7, 2013).

"Capacity Market Performance Incentives," EUCI (November 7, 2013).

"Fundamentals of Capacity Market Design and Performance," EUCI (November 6, 2013).

"Electricity Industry Fundamentals," EUCI (January 29-30, 2013).

"Market Power Monitoring and Mitigation in Electric Capacity Markets," Capacity Markets: Achieving Market Price Equilibrium?, EUCI (October 4, 2012).

"Market Power Monitoring and Mitigation in Electric Capacity Markets," Capacity Markets: Achieving Market Price Equilibrium?, EUCI (November 7, 2011).

"Economics and Regulation of Large Scale Renewable Resource Electricity System Transmission Additions," Center for Research in Regulated Industries, Eastern Conference, Rutgers University (May 6, 2010).

"PJM's RPM Auctions: Emerging and Unsettled Issues," NECA Power Markets Conference (November 1, 2007).

"Locational Capacity Markets: Understanding the Upside," New York City, July 8, 2006.

"Competition and Regulation in the North American Electricity Industry: Can These Two Seemingly Opposed Forces Coexist?" 24th Annual North American Conference of the USAEE/IAEE, Washington, DC (July 9, 2004).

"Merchant Transmission Investment Regimes: An Outsider's Observations," The East Coast Energy Group (April 16, 2004).

"Wholesale Procurement Strategies for the Restructured Electricity Markets: Experiences from the Field," Platts First Annual Electricity Market Design Imperative, Chicago, IL (November 6, 2003).

"Power Plant Technologies and Characteristics," The Harvard Institute for International Development's Third Annual Program on Climate Change and Development, Cambridge, MA (June 19, 2000).

"Transmission Planning & Investment in the RTO Era," with John Farr and Susan F. Tierney, workshop at Infocast Conference on Transmission Pricing, Chicago, IL (May 1, 2000).

"The US Market for Merchant Plants—Outlooks, Opportunities and Impediments," CBI's 4th Annual Profit from Merchant Plants Conference (January 31, 2000).

"Projecting Electricity Prices for a Restructured Electricity Industry," EXNET Merchant Power Plant Conference, Washington, DC (June 3, 1999).

"Transmission Planning and Competitive Generation Markets: The New England Case," EUCI conference on Transmission Restructuring for Retail Competition, Denver, CO (March 25, 1999).

"Key Issues in Ancillary Service Markets," IBC's conference on Pricing and Selling Ancillary Services in a Competitive Market Conference, San Francisco, CA (March 11, 1999).

"Successfully Forecasting the Price of Energy and Other Products," workshop presented at IBC's conference on Successful Load Profiling, San Francisco, CA (December 2, 1998).

"International Perspective: Lessons from the US Deregulation Experience," Nordic Power '98, Stockholm, Sweden (October 7, 1998).

"Successfully Forecasting the Price of Energy and Other Products in a Restructured Electric Power Industry," workshop presented at IBC's 3rd Strategic Forum on Market Price Forecasting, Baltimore, MD (August 24, 1998).

"Managing Market Share Loss with the Opening of Retail Markets to Competition," Electric Utility Business Environment Conference, Denver, CO (June 24, 1998).

"Multi-Attribute Trade-Off Analysis for Water and Electricity Policy Development," presented in Mendoza, Argentina, (July 1996 and April 1997).

"The Basics of Cogeneration," Tufts University Forum on Energy Conservation (December 1993).

"Implications and History of the MIT Cogeneration Project," presented to the Massachusetts Society of Professional Engineers (November 1993).

CERTIFICATIONS/ACCREDITATIONS

1992–Present Registered Professional Engineer, Commonwealth of Massachusetts

PROFESSIONAL ASSOCIATIONS AND MEMBERSHIPS

2002–2012 Board of Directors, Northeast Energy and Commerce Association

Exhibit D

CHARLES WU
Vice President

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14th Floor
Boston, MA 02119

Mr. Wu has experience consulting on energy economics, securities, trade disputes, M&A, and statistics. His work supporting academic affiliates in litigation matters has included performing antitrust analyses of commodity markets, calculating payments to creditors in bankruptcy, estimating damages based on lost royalties, critiquing statistical sampling for mortgage-backed securities, and Monte Carlo simulation modeling of statistical tests. He has supported experts in trial during utility bankruptcy proceedings. He has conducted numerous economic impact analyses related to energy, electricity, and carbon allowance markets, and has designed and run simulations of large-scale distributed networks to predict operational efficiency and costs to consumers. Mr. Wu has developed operational models of power plant and natural gas availability to analyze fuel and energy security during extreme weather conditions. He has also assisted market regulatory authorities with matters related to market and auction design, with impacts on millions of customers. Mr. Wu has also worked previously at Microsoft, where he used order-level data from across Microsoft's hardware supply chain to visualize the timing of international distribution center inbound and outbound shipments.

EDUCATION

2017	M.B.A., enterprise management, MIT Sloan School of Management
2011	M.A., economics, Northwestern University
2010	S.B., economics, Massachusetts Institute of Technology

PROFESSIONAL EXPERIENCE

2012–Present	Analysis Group, Inc. *Vice President (2023–Present)* *Manager (2020–2023)* *Associate (2015–2019)* *Senior Analyst (2012–2014)*
2016	Microsoft Corporation *Supply Chain Analytics Intern*

SELECTED CONSULTING EXPERIENCE

Electricity Market Analysis

- **Capacity market and resource accreditation reform in New York State**
  Led an analysis of future New York capacity market outcomes under proposed reforms to market mitigation and resource accreditation rules. Modeled changes to supply and demand parameters under multiple accreditation and resource scenarios over a decade-long modeling period.

- **Fuel security analysis for New York State**
  Led an analysis of electrical system resilience and reliability under conditions consistent with climate change impacts in New York State. Developed sets of generation, transmission, and storage resources potentially needed to meet New York's 2040 climate goals. Modeled weather, transmission constraints, resource scenarios, and physical disruptions over seasonal modeling periods.

- **Fuel security analysis for New York State**
  Led modeling to analyze electrical system reliability during extreme winter conditions in New York State. Analyzed weather and operational data for power plants and gas distribution companies to predict natural gas usage and availability. Modeled transmission constraints, resource scenarios, and physical disruptions over a short-term modeling period.

- **Supply and demand modeling for wholesale electricity markets**
  Designed and programmed predictive models for electricity supply and demand in New England and New York capacity markets using power plant-level cost data on hundreds of regional generation assets. Modeled outcomes used by regulatory clients to set electricity policy affecting 34.5 million consumers.

Economic Impact Analysis

- **Economic impact analysis of carbon trading program**
  Led a team of five analysts and associates to quantify the economic and employment impacts of the nine-state Regional Greenhouse Gas Initiative (RGGI) carbon trading program. Coordinated team's collection and integration of data into a multi-region model of hourly electricity prices.

- **Economic impact modeling for electrical distribution system**
  Led a team that analyzed the economic impact of a potential change in ownership of a California electrical distribution system on ratepayers. Managed data collection and integration processes.

Other Energy Economics

- **Analysis of utility system loads and revenues for utility bankruptcy**
  Led a team to review and modify forecasts of long-term electrical demand and revenues in utility bankruptcy, including projections of energy efficiency, distributed generation, and electric vehicle demand. Supported experts during bankruptcy trial proceedings.

- **Strategy study for battery recycling**
  Consulted to a participant in the battery recycling market, and conducted a study of recycled battery market, recycling business model, and strategic considerations.

- **Simulation analyses for electrical transmission infrastructure**
  Ran simulations of electrical transmission and analyzed results to show efficacy of proposed high-voltage transmission lines in the Midwest. Analyses were used to gain regulatory approval for five major projects with over $2 billion in combined capital investment.

- **Valuation for new power plant**
  Created a dynamic discounted cash flow model to predict revenues for a proposed 85 megawatt

(MW) gas turbine power plant in Maine under a variety of fuel price and generation scenarios. Results were used by client to determine a bid for a 15-year power purchase agreement (PPA) worth $300 million.

Data Analytics for Litigation and Arbitration

- **Financial modeling for royalties**
  Led team of three analysts in construction of a financial model based on sales invoices that was used to calculate damages in international arbitration concerning natural gas royalties. Served as main point of contact with client on quantitative issues. Analyses led to award of $56.3 million to client.

- **Statistical sampling for mortgage-backed securities**
  Designed and implemented analyses to support statistical expert evaluating sampling in MBS litigation.

- **Statistical analysis for trade dispute**
  Designed and led implementation of a Monte Carlo statistical simulation model to support a testifying expert in a high-profile international tobacco trade litigation matter; work led to withdrawal of two opposing experts' testimonies.

SELECTED HONORS AND AWARDS

2010 Graduate Research Fellowship, National Science Foundation

Exhibit E

DANIEL N. STUART, PH.D.
Manager

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Boston, MA 02199

Dr. Stuart specializes in applying economic and statistical analysis to regulatory proceedings, litigation, and policy matters related to energy and environmental policy. He has supported experts in Federal Energy Regulatory Commission (FERC) rate litigation, state regulatory proceedings, and civil litigation related to the provision of electric utility service. Dr. Stuart has also coauthored white papers on alternative pathways for power sector decarbonization in New England, the economic impacts of the Regional Greenhouse Gas Initiative (RGGI) on Northeastern states, the potential impacts of heavy-duty vehicle (HDV) electrification on the electric distribution system, regulatory innovation needed to meet state decarbonization goals, and cost containment mechanisms in Washington State's cap-and-invest program.

EDUCATION

2021	Ph.D., public policy, Harvard University *Field: Energy and environmental economics and policy*
2013	B.A., economics (*honors*), Swarthmore College

PROFESSIONAL EXPERIENCE

2021–Present	Analysis Group, Inc. *Manager (2024–Present)* *Associate (2021–2023)*
2014–2016	Energy Policy Institute at The University of Chicago *Senior Pre-Doctoral Fellow*
2013–2014	Massachusetts Institute of Technology *Economics Research Assistant*

SELECTED CONSULTING EXPERIENCE

Litigation Related to the Provision of Electric Service

- **Electric rate dispute at FERC and North Dakota state court**
  Supported expert testimonies and depositions in a Section 206 proceeding at FERC and in a civil suit in North Dakota state court. The rate dispute involved a not-for-profit electric distribution cooperative in the upper Midwest and two generation and transmission cooperatives regarding the price it had been charged for energy. Of note, the client alleged that the electric energy prices it paid were improperly inflated by the mismanagement of an uneconomic synthetic fuel facility.

- **Class action suit related to electric master-metering**
  US District Court, Southern District of Florida
  Supported expert testimonies and depositions in a class action suit that involved the provision of electricity service from commercial landlords to tenants. Ruling in favor of the client, the judge denied certification of the class and dismissed the case with prejudice, citing the supported expert's opinions in their findings.

Power System and Economic Impact Analysis

- **Economic impact analysis of carbon trading program**
  Led a team of analysts and associates to quantify the economic and employment impacts of the multi-state RGGI carbon trading program. Coordinated the team's collection and integration of data into a multi-region model of hourly electricity prices and associated macroeconomic impacts. Lead author of the resulting white paper.

- **Power system analysis of alternative market designs to support decarbonization**
  Developed methods to quantify future contract prices for renewable energy procurements in a study funded by ISO New England (ISO-NE) that evaluated alternative market mechanisms to achieve decarbonization goals. Assisted with power sector modeling, including calculation of marginal emissions rates, dynamic clean energy credits for a forward clean energy market, and marginal abatement costs for alternative market designs.

Regulatory and Policy Analysis

- **Analysis of the impacts of HDV electrification on the electric distribution system**
  Coauthored a white paper quantifying the level of electric distribution system upgrades required to meet proposed Environmental Protection Agency (EPA) regulations. Conducted novel research to evaluate key features supporting reliable power system growth, including legal and regulatory requirements, distribution system planning and performance, financial and ratemaking incentives, and enabling strategies and technologies.

- **Analysis of policies needed to enable distribution utility investment required for Massachusetts to meet its decarbonization targets**
  Coauthored a white paper evaluating the required level of distribution utility investment under deep decarbonization scenarios. Conducted novel research on the current pace of utility investment across the US in response to state decarbonization goals, and the regulatory policies and innovation required to enable needed investment.

- **Analysis of the performance and prospects for Washington State's cap-and-invest program**
  Coauthored a white paper evaluating market outcomes, policy reforms, and the performance of cost containment mechanisms in Washington State's cap-and-invest program. Conducted novel research and analysis on allowance prices in international emissions trading systems, the impacts of linking the Washington cap-and-invest program to the California-Quebec emissions trading systems, and the economic consequences of sales from the allowance price containment reserve.

SELECTED REPORTS AND PUBLICATIONS

Performance and Prospects for Washington State's Cap-and-Invest Program, with Robert Stavins and Todd Schatzki (January 2024)

Massachusetts' Energy Transition: Innovation for Electric Utility Regulation, with Paul Hibbard, Susan Tierney, and Grace Howland (September 2023)

Heavy Duty Vehicle Electrification: Planning for and Development of Needed Power System Infrastructure, with Paul Hibbard, Laurie Hakes, and Sam Churchill (June 2023)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: Review of RGGI's Fourth Three-Year Compliance Period (2018-2020) and Options for RGGI States to Advance Key Equity Priorities, with Paul Hibbard (May 2023)

Pathways Study: Evaluation of Pathways to a Future Grid, prepared for ISO-NE, with Todd Schatzki, Christopher Llop, Phillip Ross, Jenny Shen, Tyler Farrell, Conor McManamy, Luke Daniels, and Shaina Ma (April 2022)

Robust Decarbonization of the US Power Sector: Policy Options, with James H. Stock, National Bureau of Economic Research Working Paper 28677 (April 2021)

SELECTED PRESENTATIONS AND SPEAKING ENGAGEMENTS

"The Impact of Decarbonization on Electric Utility Infrastructure Planning and Investment," EUCI Decarbonization Strategies & Implementation Conference (January 23, 2024)

"Robust Decarbonization of the US Power Sector: Policy Options," Center for Research in Regulated Industries (CRRI) Annual Western Conference (June 23, 2022)

"Robust Decarbonization of the U.S. Power Sector: Policy Options," Annual Conference of the American Economic Association (January 7, 2022)

"Strategic Non-Reporting Under the Clean Water Act," Annual Conference of the Association of Environmental and Resource Economists (June 5, 2020)

SELECTED HONORS AND AWARDS

2021	Ana Aguado Prize for best doctoral student paper, Harvard Environmental Economics Program (HEEP)
2019–2021	Terence M. Considine Fellowship in Law and Economics, Harvard Law School
2016–2021	Pre-Doctoral Fellow, HEEP
2017–2020	Graduate Research Fellowship (in economics), National Science Foundation
2018–2019	Vicki Norberg-Bohm Fellowship, HEEP

Exhibit F

Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years

Final Report (Updated Version)

Analysis Group, Inc.
1898 & Co.

October 2, 2024

Report Authors

<u>Analysis Group, Inc.</u>

Paul Hibbard
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Chad Swope, PE

This Report provides values for the 2025-2026 Capability Year Installed Capacity (ICAP) Demand Curves as well as methodologies and inputs to be used in determining the ICAP Demand Curves for the 2026-2027, 2027-2028, and 2028-2029 Capability Years. *All numerical results presented in this Report include data as required for the estimation of net Energy and Ancillary Services (EAS) revenues and escalation of capital costs. Net EAS revenues are estimated using data for the three-year period September 2021 through August 2024.*

Legal Notice

Table of Contents

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
AC	Alternating Current
AF	Attachment Facilities
AFUDC	Allowance For Funds Used During Construction
AIS	Air Insulated Switchgear
AP	Amortization Period
ARV	Annual Reference Value
ASC	Startup Cost
ATWACC	After Tax Weighted Average Cost of Capital
BACT	Best Available Control Technology
BESS	Battery Energy Storage System
BPCG	Bid Production Cost Guarantee
Btu	British Thermal Units
CAFs	Capacity Accreditation Factors
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CEQR	New York City Environmental Quality Review
CFR	Code of Federal Regulations
CLCPA	Climate Leadership and Community Protection Act
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Cost of Debt
COE	Cost of Equity
CONE	Cost of New Entry
CPV	Competitive Power Ventures

Acronym or Abbreviation	Description
CRIS	Capacity Resource Interconnection Service
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbines
CTO	Connecting Transmission Owner
DAF	Developer Attachment Facilities
DAM	Day-Ahead Market
DAMAP	Day-Ahead Margin Assurance Payment
DCF	Discounted Cash Flow
DCR	Quadrennial ICAP Demand Curve Reset Process
D/E Ratio	Ratio of Debt to Equity
DMNC	Dependable Maximum Net Capability
EAS	Energy and Ancillary Services
EC	Emissions Costs
EFORd	Equivalent Demand Forced Outage Rate
EIA	U.S. Energy Information Administration
EOL	End-Of-Life
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, Construction
ERC	Emission Reduction Credits
ERP	Equity Risk Premia
FERC	Federal Energy Regulatory Commission
FEMA	Federal Emergency Management Agency
FICA	Federal Insurance Contributions Act
FTE	Full Time Equivalent
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GE	General Electric International, Inc.
GE-MAPS	GE's Multi-Area Production System

Acronym or Abbreviation	Description
GHG	Greenhouse Gases
GIS	Gas Insulated Switchgear
GSU	Generator Step Up Transformer
HHV	Higher Heating Values
HR	Heat Rate
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
ICR	NYCA Minimum Installed Capacity Requirement (MW)
IDC	Interest During Construction
IPP	Independent Power Producer
IRM	NYCA Installed Reserve Margin (%)
IRS	Internal Revenue Service
ISO	International Organization for Standardization
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
kW-month	Kilowatt-month
kW-year	Kilowatt-year
LAER	Lowest Achievable Emission Rate
LBMP	Locational Based Marginal Pricing
LCR	Locational Minimum Installed Capacity Requirement
LDC	Local Distribution Company
LFP	Lithium Iron Phosphate
LI	Long Island (Load Zone K)
LOE	Level of excess
LOE-AF	Level of excess adjustment factor
LOLE	Loss of Load Expectation
MECL	Minimum Emissions Compliant Load

Acronym or Abbreviation	Description
MHPS	Mitsubishi Hitachi Power Systems
MIS	Minimum Interconnection Standard
MMBtu	Million Btu
MMU	Market Monitoring Unit (Potomac Economics)
MPs	Market Participants
MPT	Main Power Transformer
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NCA	Lithium Nickel Cobalt Aluminum Oxide
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMC	Lithium Nickel Manganese Cobalt Oxide
NNSR	Nonattainment New Source Reviews
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NYC	New York City (Load Zone J)
NYCA	New York Control Area
NYCRR	New York Codes, Rules and Regulations
NYISO	New York Independent System Operator, Inc.
NYSDEC	New York State Department of Environmental Conservation
NYSRC	New York State Reliability Council, L.L.C.
O_2	Oxygen
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OFO	Operational Flow Order

Acronym or Abbreviation	Description
OTR	Ozone Transport Region
PBE	Purpose-Built Enclosure
PCS	Power Conversion System
P(fuel)	Price of Fuel
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, L.L.C.
POI	Point of Interconnection
ppmvd	Parts per million by volume on a dry basis
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
PTE	Potential to Emit
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
ROE	Return on Equity
ROS	Rest of State (Load Zones A-F)
RP	Reference point price
RS1	NYISO Rate Schedule 1 Charge
RTD	Real-Time Dispatch
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SDU	System Deliverability Upgrades
SER	Significant Emission Rates
Siemens	Siemens Energy Inc.
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

Acronym or Abbreviation	Description
SRP	Summer Reference Point Price
SUF	System Upgrade Facilities
SWR	Summer-to-winter ratio
tpy	Tons per year
UARG	Utility Air Regulatory Group
UCAP	Unforced Capacity
ULSD	Ultra-low Sulfur Diesel
UOL	Upper Operating Unit
U.S.	United States
VOC	Volatile Organic Compounds
VOM	Variable Operations and Maintenance Costs
VSS	Voltage Support Service
WACC	Weighted Average Cost of Capital
WRP	Winter Reference Point Price
WSR	Winter-to-summer ratio
ZCP	Zero Crossing Point
ZCPR	Zero Crossing Point Ratio

Figures and Tables

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 Installed Capacity (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.

On July 20, 2023, the NYISO contracted with Analysis Group Inc. (AG) to conduct the independent review of ICAP Demand Curves, to be used starting in Capability Year 2025-2026. AG teamed with 1898 & Co. to complete the development of ICAP Demand Curve parameters, described in this Final Report (Report).[1]

B. Study Purpose and Scope

The purpose of this Report is to summarize the results of our study of the ICAP Demand Curve 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.[2] 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 for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services … including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review"[3]

The costs and revenues are to be determined under conditions that reflect specified excess supply conditions 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 which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity…"[4]

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[1] 1898 & Co. is a business, technology, and security consultancy which is a part of Burns & McDonnell.
[2] NYISO, Market Services Tariff (hereafter "Services Tariff"), Section 5.14.1.2.2.
[3] Services Tariff, Section 5.14.1.2.2.
[4] Services Tariff, Section 5.14.1.2.2.

Several additional elements to be included in the quadrennial 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 (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.[5]

The Services Tariff also specifies the process for selecting the independent consultant, and development of a schedule for the consultant's analysis 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, 2025).

C. Study Process

AG and 1898 & Co. have conducted the ICAP Demand Curve review in an open and transparent process that involved the full vetting of issues raised by stakeholders. AG and 1898 & Co. 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 AG or 1898 & Co. participated, and the issues discussed with stakeholders at each meeting.

AG/1898 & Co.'s review of ICAP Demand Curve matters with stakeholders helped identify important scoping issues, evaluate concepts and metrics relevant to the DCR process, and provide guidance for AG/1898 & Co.'s consideration of and recommendations on key DCR issues and outcomes. While the content of and findings in this Report rest solely with AG and 1898 & Co., it reflects the results of a productive and deliberative process involving full and substantive input throughout a comprehensive stakeholder process that unfolded over the course of approximately one year.

[5] Services Tariff, Section 5.14.1.2.2.

Table 1: Summary of AG and 1898 & Co. Stakeholder Engagement

Date	Topic
August 24, 2023	Introduction to team and DCR process/timeline
September 26, 2023	High-level considerations for technology screening process Initial discussion of potential peaking plant technologies for evaluation
November 8, 2023	Discussion of technology screening criteria and peaking plant technologies for evaluation Review of net Energy and Ancillary Services (EAS) revenue model for thermal/fuel-fired and battery technologies Process for selecting gas hubs for pricing in the thermal/fuel-fired net EAS revenue model
December 15, 2023	Technology screening overview Preliminary scope assumptions for SCGT and battery storage technologies
January 25, 2024	Discussion of level of excess adjustment factors (LOE-AFs) Preliminary recommendations for net EAS revenue models (i.e., thermal/fuel-fired, and storage) Review of financial parameters
February 29, 2024	Proposed approach for LOE-AFs Preliminary recommendations of gas hubs for pricing in the thermal/fuel-fired net EAS revenue model Update on battery net EAS model enhancements
March 13, 2024	Methodological changes to net EAS storage model to allow for 5-minute interval pricing in the real-time energy market Preliminary assessment of potential magnitude of impacts associated with using 5-minute real-time pricing for net EAS storage model
March 25, 2024	Preliminary net EAS revenue results Initial results of 5-minute real-time battery modeling Technology selection considerations Preliminary unit performance, capital costs, and O&M estimates
April 17, 2024	Updated recommendations of gas hubs for pricing in the thermal/fuel-fired net EAS revenue model Discussion of financial parameter considerations for capital structure, cost of debt, cost of equity, amortization period, and property taxes Continued discussion of 5-minute real-time battery modeling enhancements
May 20, 2024	Continued discussion of 5-minute real-time battery modeling enhancements Evaluation of selective catalytic reduction (SCR) emission controls and dual fuel for thermal/fuel-fired technology options Preliminary reference point prices

	Updated preliminary BESS unit performance, capital cost, and O&M estimates
May 30, 2024	Preliminary financial parameter recommendations for capital structure, cost of debt, cost of equity, amortization period, and property taxes Updated preliminary BESS unit performance, capital cost, and O&M estimates
June 13, 2024	Summary of preliminary findings in draft report, discussion of updates to previously discussed assumptions, updated evaluation of peaking plant technology options, and associated reference point prices
July 23, 2024	Discussion of updated LOE-AFs, discussion of updated methodology for voltage support service revenue adder, and discussion of stakeholder feedback on the draft report
August 1, 2024	Summary of findings in interim final report, discussion of updates to previously discussed assumptions, updated evaluation of peaking plant technology options, associated reference point prices, and discussion of the annual update process
August 22, 2024	Continued discussion of the annual update process
September 10, 2024	Discussion of enhancement to BESS net EAS model to ensure sufficient state of charge during peak load window hours to meet day-ahead energy and reserve positions
September 24, 2024	Summary of findings in final report, discussion of updates to previously discussed assumptions, and associated reference point prices

Note: [1] All materials are posted and available on the NYISO website, available here: https://www.nyiso.com/icapwg

D. 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:

- ***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.[6] 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 life and other operating parameters, degree of successful commercialization and operational history, and applicable siting and environmental permitting requirements. Based on these factors, we also consider whether and how the peaking plant could be practically constructed within each Locality and ROS, 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.[7] The technology choice assessment, including the recommended technology, its installed capital cost, and operational costs and parameters, is presented in **Section II**.
- ***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 options, 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.
- ***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 models constructed by AG for this purpose. The models include a mechanism to adjust the location based marginal prices (LBMPs) and reserve prices used in the applicable net EAS revenues model to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[8]
- ***Determination of the reference point price and ICAP Demand Curve in NYCA and each Locality (Section V).*** In this step, gross CONE estimates (from **Section III**) and expected net EAS revenues (from **Section IV**) are combined to calculate the reference point price (RP) values 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, seasonal reliability risks, and seasonal differences in the quantity of available capacity, are also considered.

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[6] Services Tariff, Section 5.14.1.2.2.
[7] FERC has found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058, Docket No. ER11-2224-000, at P 37 (January 28, 2011)). FERC has also held 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, Docket No. ER14-500-000, at P 60 (January 28, 2014)). FERC has further clarified that the "peaking plant represents the hypothetical marginal plant, and, therefore, must be able to be replicated." (*See New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028, Docket No. ER17-386-000 at P 65 (January 17, 2017)). These considerations are discussed in greater detail in Section II.
[8] 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 AG defines as the "level of excess" or LOE. The derivation of the LOE-AFs and how historical market prices are adjusted to reflect LOE conditions are described in detail in Section III. *See* Services Tariff, Section 5.14.1.2.2.

- ***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 amount of capacity available seasonally.[9]

In this study, we analyze the currently prescribed Localities for the ICAP Market, which includes the G-J Locality, New York City or NYC (Load Zone J) and Long Island or LI (Load Zone K), 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 appropriate 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 reasonable alternatives based on the application of decision criteria and professional judgment. It also involves a comprehensive review with stakeholders of the purpose, effectiveness, and appropriateness of selected assumptions, methods and data.

AG and 1898 & Co. developed their recommendations for this DCR through the continuous interaction with stakeholders over a nearly year-long period. AG and 1898 & Co. received feedback on proposals and analyses from NYISO and stakeholders in written and verbal form across numerous meetings of the ICAP Working Group (ICAPWG).

The DCR 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, AG established a set of objectives and criteria against which it reviewed and considered DCR-related matters 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, AG established that potential DCR issues should be evaluated against the following objectives and criteria:

- *Economic Principles* – Proposed changes to ICAP Demand Curve parameters and methods should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO administered 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 annual update methods and calculations 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.

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[9] 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 seasonal availability of capacity is used to account for the differences in capacity available. These factors are discussed in greater detail in Section IV.

- *Historical Precedent and Performance* – 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 (to the extent feasible and warranted) also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

E. Summary of Recommendations and Overview of RP Results

AG has applied the methods, models and equations described in this Final Report to identify RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2025-2026. These values are presented in **Table 2**, below.

To arrive at these results, AG and 1898 & Co. considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the RP values provided herein. Specifically, AG and 1898 & Co. conclude the following:

- The two-hour battery energy storage system (BESS) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a BESS would use lithium-ion technology and a modular, purpose-built enclosure (PBE) form factor.
- For the two-hour BESS, we assume a twenty-year amortization period, and incorporate additional costs for capacity augmentation to ensure consistent performance and nominal capacity value over the assumed life of the resource. Capacity augmentation costs are included in the two-hour BESS' variable operations and maintenance (VOM) costs, reflecting the fact that capacity augmentation costs are related to the total throughput of the battery.
- The appropriate method to evaluate the peaking plant technology is to identify the technology that minimizes the cost of Unforced Capacity (UCAP). An economic evaluation focused solely on the cost of ICAP would fail to account for variation in Capacity Accreditation Factors (CAFs) and derating factors across technology options.[10]
- The state of New York has begun a process to decarbonize the power sector over the next couple of decades, including passage of the Climate Leadership and Community Protection Act (CLCPA) in 2019. The CLCPA does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology during the 2025-2029 DCR period. It does, however, affect the development and operation of such facilities, which could in turn affect present-day financial analysis parameters (e.g., the appropriate amortization period). For this DCR, our review included two categories of units that at least initially were powered using fossil fuels. First, we reviewed installation and operation of a fossil unit in each location designed to exclusively run on fossil fuels (and thus assumed to not operate in 2040 or beyond). Second, we reviewed installation and operation of a unit initially operating on fossil fuels, but retrofitted to operate on hydrogen fuel beginning in 2040. For the fossil-only unit, we applied a 13-year amortization period to reflect CLCPA's requirement for 100% of load to be served by zero-emissions resources by 2040, and consistent with the decisions by FERC accepting this amortization period method in the 2021-

[10] On June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. On July 2, 2024, the NYISO filed a request with FERC to authorize updating the CAFs for the 2024-2025 Winter Capability Period. On August 15, 2024, FERC issued an order granting the NYISO's request. As such, AG uses NYISO's revised 2024-2025 Winter Capability Period CAFs for this final report.

2025 DCR.[11] For the fossil-hydrogen unit, we studied the potential costs associated with retrofitting a turbine to run on hydrogen fuel, and the costs of storing associated hydrogen fuel onsite.

- For the fossil-fuel fired unit analysis, the GE 7HA.03 frame turbine represents the highest variable cost, lowest fixed cost simple cycle gas turbine (SCGT) peaking plant option that is economically viable for all locations except Load Zone K. The GE 7HA.02 option represents a lower fixed cost SCGT technology option for Load Zone K considering the System Deliverability Upgrade (SDU) cost that would be applicable to the GE7HA.03 for Load Zone K. Such SDU costs are not applicable to a GE 7HA.02 option for Load Zone K. To be economically viable and practically constructible, a 7HA.03 SCGT (for all locations other than Load Zone K) and 7HA.02 SCGT (for Load Zone K) would be built with selective catalytic reduction (SCR) emission control, whether constructed as gas-only or dual-fuel.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures related to capacity accreditation, consideration of applicable reliability and local distribution company (LDC) retail gas tariff requirements, and developer expectations, we expect that developers would include dual fuel capability in all locations.
- For SCGT technologies, the weighted average cost of capital (WACC) used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 14.0% cost of equity, for a WACC of 9.99%. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 9.02% for all locations other than Load Zone J and 8.76% for Load Zone J.
- For BESS technologies, the WACC used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 7.2% cost of debt; and a 14.5% cost of equity, for a WACC of 10.49%. Based on current tax rates in NY State and New York City, this translates to a nominal ATWACC of 9.45% for all locations other than Load Zone J and 9.17% for Load Zone J.
- For the purposes of modeling net EAS revenues for BESS technologies in the real-time market (RTM), it is appropriate to use Real-Time Dispatch prices transacting on a nominal 5-minute basis. Consistent with the 2017-2021 and 2021-2025 DCRs, we continue to model net EAS revenues for fossil peaking plant options in the RTM using average hourly prices.
- The ICAP Demand Curves should maintain the current zero crossing point (ZCP) values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

Table 2 provides parameters for the 2025-2026 Capability Year ICAP Demand Curves for each location, consistent with the conclusions and technology findings described above. **Table 3** through **Table 5** provide additional information for the other technologies evaluated. For all locations, the appropriate peaking plant technology and design, as well as the net EAS model structure (including the granularity of real-time prices used by such models) selected as the basis for the 2025-2026 Capability Year ICAP Demand Curves remain fixed for the four-year duration of the reset period.

[11] New York Independent System Operator, Inc., 183 FERC ¶ 61,130, Docket No. ER21-502, (May 19, 2023); and New York Independent System Operator, Inc., 185 FERC ¶ 61,010 (October 4, 2023).

Table 2: 2025-2026 Capability Year ICAP Demand Curve Parameters ($2025 ICAP)

2-Hour BESS (RTD interval pricing net EAS model)

		Current Year (2025-2026)					
Parameter	**Source**	**C - Central**	**F - Capital**	**G - Hudson Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
Gross Cost of New Entry ($/kW-Year)	[1]	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
Net EAS Revenues ($/kW-Year)	[2]	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$66.52	$45.66	$49.85	$45.75	$130.74	$43.92
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Winter to Summer DMNCs	[7]	1.033	1.033	1.050	1.050	1.057	1.083
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.21	$4.95	$5.40	$4.96	$14.16	$4.76
Winter ($/kW-Month)	[11]	$3.88	$2.66	$2.91	$2.67	$7.63	$2.56
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,441	$989	$1,080	$991	$2,833	$952
Monthly Revenue (Winter)	[13]=[11]*[9]	$776	$533	$582	$534	$1,525	$512
Seasonal Revenue (Summer)	[14]=6*[12]	$8,647	$5,936	$6,480	$5,948	$16,996	$5,710
Seasonal Revenue (Winter)	[15]=6*[13]	$4,656	$3,196	$3,489	$3,203	$9,152	$3,075
Total Annual Reference Value	[16]=[14]+[15]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$7.53	$5.17	$6.06	$5.56	$16.16	$6.02
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$5.69	$3.91	$5.21	$4.78	$13.63	$7.77
Summer ICAP Maximum Clearing Price ($/kW-Month)		$20.71	$20.86	$23.09	$22.35	$39.50	$26.99
Winter ICAP Maximum Clearing Price ($/kW-Month)		$15.65	$15.76	$19.86	$19.22	$33.30	$34.86
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS. [2] The net EAS revenues are estimated using data for the three-year period September 1, 2021 through August 31, 2024 and the seasonal capacity availability values are based on data for the same period. [3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [4] Assumes a $4.10/kW-year voltage support service (VSS) revenue adder for lithium-ion BESS.

Table 3: Comparison of Indicative UCAP Reference Point Prices by Technology ($2025 UCAP Per kW-Month)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Summer Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$24.50	$20.80	$29.26	$27.22	$39.40	$74.52
	Gas Only, with SCR	$23.08	$19.49	$30.25	$26.38	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$27.43	$25.80	-	$29.23	-	-
	Gas Only, no SCR	$25.73	$23.97	-	$28.37	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$33.66
2-hour BESS	Battery Storage	$13.92	$9.56	$11.17	$10.25	$29.84	$11.60
4-hour BESS	Battery Storage	$21.71	$17.60	$20.18	$19.09	$42.37	$16.50
6-hour BESS	Battery Storage	$25.09	$21.84	$24.62	$23.49	$46.64	$24.70
8-hour BESS	Battery Storage	$31.68	$28.82	$32.00	$30.66	$57.12	$33.54
Winter Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$17.99	$15.14	$26.54	$24.69	$35.86	$253.29
	Gas Only, with SCR	$16.95	$14.18	$27.43	$23.92	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$19.65	$17.60	-	$25.34	-	-
	Gas Only, no SCR	$18.43	$16.35	-	$24.59	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$78.82
2-hour BESS	Battery Storage	$10.52	$7.22	$9.60	$8.81	$25.16	$14.99
4-hour BESS	Battery Storage	$16.40	$13.30	$17.35	$16.41	$35.72	$21.31
6-hour BESS	Battery Storage	$18.96	$16.50	$21.17	$20.20	$39.33	$31.90
8-hour BESS	Battery Storage	$23.94	$21.78	$27.51	$26.36	$48.16	$43.32

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County). [3] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period. [4] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [5] Assumes a $3.97/kW-year voltage support service (VSS) revenue adder for the 1x0 GE 7HA.03, $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02, and $4.10/kW-year VSS revenue adder for lithium-ion BESS. [6] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year. [7] UCAP reference point prices reflect the applicable CAF values for the 2024-2025 Winter Capability Period and an assumed derating factor values of 4.1% for the 1x0 GE 7HA.03 and 1x0 GE 7HA0.2 units and 2.0% for the BESS units. AG and 1898 & Co. acknowledge that NYISO staff has recommended use of 2.5% derating factor for the BESS units; therefore, the indicative UCAP reference point prices for the BESS units presented herein differ from those presented in NYISO staff's final recommendations.

Table 4: Comparison of Gross CONE by Technology ($2025/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$270.61	$267.39	$285.53	$268.54	$351.15	$493.88
	Gas Only, with SCR	$258.89	$256.01	$285.71	$257.07	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$284.49	$281.00	-	$280.72	-	-
	Gas Only, no SCR	$270.18	$267.10	-	$266.71	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$293.98
2-hour BESS	Battery Storage	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
4-hour BESS	Battery Storage	$189.05	$190.40	$196.11	$190.25	$317.01	$202.88
6-hour BESS	Battery Storage	$264.35	$266.22	$274.27	$266.07	$424.81	$283.81
8-hour BESS	Battery Storage	$338.82	$341.25	$351.53	$340.96	$541.77	$364.11

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County).

Table 5: Comparison of Net EAS by Technology ($2025/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$68.32	$97.17	$80.03	$77.34	$87.44	$111.91
	Gas Only, with SCR	$68.32	$96.55	$73.28	$71.82	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$54.24	$65.49	-	$62.73	-	-
	Gas Only, no SCR	$54.24	$66.89	-	$55.17	-	-
1x0 GE 7HA.02	Dual Fuel, with SCR	-	-	-	-	-	$105.27
2-hour BESS	Battery Storage	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
4-hour BESS	Battery Storage	$63.57	$88.64	$87.34	$87.39	$90.35	$109.40
6-hour BESS	Battery Storage	$65.98	$93.58	$93.60	$93.69	$94.49	$120.99
8-hour BESS	Battery Storage	$66.48	$93.54	$95.12	$95.24	$94.89	$124.71

Notes: [1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024. [2] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [3] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County). [4] Assumes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03, $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02, and $4.10/kW-year VSS revenue adder for lithium-ion BESS. [5] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year.

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"[12]

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," and the peaking plant is defined as "the number of units (whether one or more) that constitute the scale identified in the periodic review."[13] 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] In this section, we consider the following:

1. Simple Cycle Plant – Simple cycle plants consist of one or more fuel-fired combustion turbines. This study analyzes multiple types and generations of simple cycle technologies, as well as various fuel options including natural gas, liquid fossil fuels, and/or hydrogen.

2. Energy Storage Plant - A battery storage plant is also included in the analysis. Battery storage options with duration capabilities of 2-hours, 4-hours, 6-hours, and 8-hours have been evaluated.

In Section II.B, we apply screening criteria to identify alternative technology options that will be evaluated in the DCR study. Section II.C summarizes applicable environmental and siting requirements, which have implications for installed capital costs, and fixed and variable operations costs. Dual fuel capability for fossil-fired SCGT options, 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 describes technical and performance characteristics needed to evaluate net EAS revenues.

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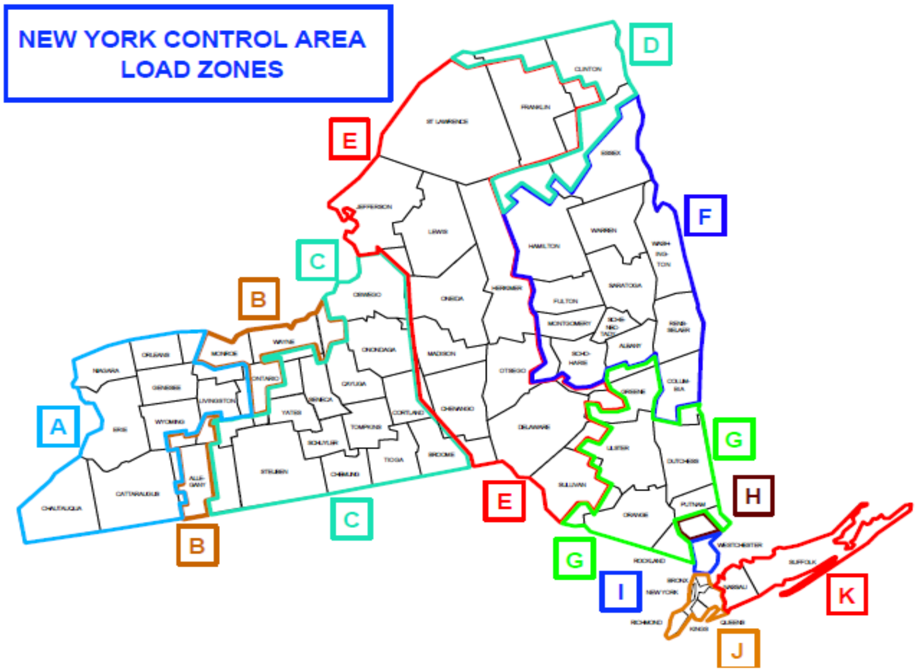
12 Services Tariff, Section 5.14.1.2.2.
13 Services Tariff, Section 5.14.1.2.2.
14 See, e.g., *New York Independent System Operator, Inc.,* 134 FERC ¶ 61,058, Docket No. ER11-2224-000, at P 37 (January 28, 2011).

Figure 1: Load Zones and Localities



B. Technology Screening Criteria

1898 & Co. was engaged to select simple cycle gas turbine and energy storage technology option(s) to evaluate as the potential peaking plant for each ICAP Demand Curve. 1898 & Co. evaluated peaking plant technology options for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K (see **Figure 1**). Additionally, a simple cycle turbine option that could potentially comply with the 2040 zero-emissions energy supply requirement of the CLCPA by retrofitting to operate on hydrogen fuel (selected as a proxy for a potential zero-emissions fuel option) beginning in 2040 was evaluated for informational purposes only.

To comply with the Service Tariff requirements, 1898 & Co. utilized the following screening criteria for peaking 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 options identified both simple cycle turbine technologies and energy storage technology as technical candidates for peaking operation. Simple cycle turbine technologies are the current peaking plant technology underlying each of the ICAP Demand Curves. Energy storage technology is capable of peaking operation within discharge duration and state of charge limitations, which are constraints that do not apply to simple cycle turbine technologies with reliable fuel supply. Energy storage technologies were included alongside simple cycle turbine technologies for economic evaluation. Selected representative battery technologies are described in Section II.B.6.

1. Simple Cycle Turbine Technologies

Described below are the peaking plant technology options 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 (less than 10 minutes) and ramp rates
- Reasonably sized units (approximately 20 to 100 MW) available where multi-unit plants are advantageous
- Typically require higher fuel gas pressures than frame units
- Decades of utility scale operating experience

2. *Frame Combustion Turbines*

- Commercially available frame units range in size from approximately 50 to 430 MW.
- Larger frame units typically provide lower cost per kW of output (benefit of economies of scale)
- F-class turbines exhibit nominal output in the 200-250 MW range.
- Advanced class turbines, which may also be labeled G, H, or J-class, exhibit nominal output in the 275 – 430 MW range.
- Frame units typically include dry low emissions combustion systems for NO_x control on natural gas operation. Water injection is required for NO_x controls with liquid fuel operation. A selective catalytic reduction (SCR) emissions controls system will be required for units with NOx emissions greater than 15 ppm.
- F class units can provide significant capacity in 10 minutes and full output in 11 to 14 minutes; Maintenance impacts may apply to fast starts.
- Advanced class units have similar startup capabilities, though fast start packages are available for full load in 10 minutes, assuming purge credit and start permissives are met. Maintenance impacts may apply with fast start capability.
- Major maintenance cost may be based on operating hours or start quantity, depending on operation. In general, each gas turbine model will have a number of operating hours and number of starts prior to reaching a maintenance interval. Whichever is reached first, hours or starts, will dictate when major maintenance should occur.
- Depending on the application, frame turbine models may be available with different NO_x emissions rates. Performance is impacted by the NO_x emissions rate controls.
- Decades of utility scale operating experience

3. *Reciprocating Internal Combustion Engines (RICE)*

- Utility scale applications most commonly rely on heavy duty, medium speed engines in the 9-11MW and 18-20 MW classes.
- Compression ignition models have gas and liquid fuel capability. Spark ignition models are only capable of gas operation.
- Fast start up time as low as five minutes for natural gas engine and seven minutes for dual fuel engine. Engine jacket temperature must be kept warm to accommodate start times under 10 minutes.
- Shutdown as quickly as one minute
- High efficiency, good partial load performance
- Altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines.
- Gas pressure requirements are lower than combustion turbines.
- Installed costs are often similar to those of aeroderivative combustion turbine facilities of similar size.
- Maintenance intervals are based on operating hours and are independent of number of starts.
- Reciprocating engines are typically installed with SCR emissions controls to control NO_x emissions to approximately 5ppm on natural gas fuel.

2. Aeroderivative Combustion Turbine Peaking Options

The aeroderivative combustion turbines that were considered as candidate peaking plant technologies are shown in **Table 6**. Output and heat rate information is based on manufacturer specifications and heat rates were converted to higher heating value (HHV). Many aeroderivative technologies are offered with model variants for water injection combustion, dry low emissions combustion, wet compression, intercooling, and other options that may impact performance.

Table 6: Aeroderivative Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	LM6000	First introduced in 1997. Mature technology with multiple model variants.	45 - 58 depending on model	9,100 - 9,700 depending on model
General Electric	LMS100	First introduced in 2006. Mature technology with multiple model variants.	100 - 117 depending on model	8,600 - 8,800 depending on model
Siemens	SGT-A35	Core technology based on Rolls Royce RB211. Mature technology.	31-37	9,400
Mitsubishi Hitachi Power Systems	FT4000	First introduced in 2012. Single and twin pack designs available.	72 SWIFTPAC 70 144 SWIFTPAC 140	9,150
Mitsubishi Hitachi Power Systems	FT8	First introduced in the early '90s. Single and twin pack designs available.	31 SWIFTPAC 30 62 SWIFTPAC 60	10,350

Notes:
[1] Data from Original Equipment Manufacturer (OEM) literature. Based on nominal output at ISO conditions (59°F and 60% relative humidity)

[2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

Preliminary screening of the aeroderivative combustion turbine models indicated that the fixed costs per kW for the aeroderivative combustion turbines would be higher than the frame combustion turbines. The larger advanced class frame combustion turbines also offer a competitive heat rate and 10-minute start times for flexibility. Since a frame combustion turbine was selected as the representative technology in the 2021-2025 DCR and there have been no changes that would improve the relative position of the aeroderivative models, no further analysis of the aeroderivative combustion turbine models was performed.

3. *Frame Combustion Turbine Peaking Option*

The candidate frame combustion turbine technologies evaluated for consideration are shown in **Table 7**.

Table 7: Advanced Frame Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	7HA.03	First introduced in 2019, first units went commercial in North America in 2022	430	8,750
General Electric	7HA.02	First introduced in 2017, fleet operating hours of more than 1.4 million hours	384	8,890
Siemens	SGT6-9000HL	First commercial operation in 2022	440	8, 770
Mitsubishi Hitachi Power Systems	501JAC	First unit installed in North America in 2020 and over 1 million fleet operating hours	453	8,610
General Electric	7HA.01	First introduced in 2012	290	9,010
Siemens	SGT6-8000H	Installed fleet has accumulated more than 3 million fired operating hours	310	9,390
Mitsubishi Hitachi Power Systems	MHPS 501GAC	First commercial operation in 2014, mature technology	283	9,470
General Electric	GE 7FA.05	First 7F.05 in operation in 2014 - F-Class is GE fleet leader	239	9,850
Siemens	Siemens SGT6-5000F	Installed fleet has accumulated >15million operating hours	260	9,470

Notes:
[1] Data from OEM literature. Based on nominal output at ISO conditions (59°F and 60% relative humidity) [2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

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

- The GE & Siemens F-class combustion turbines are similar in performance and cost.

- The H/J-class combustion turbines (GE 7HA.03, Siemens 9000HL, and Mitsubishi 501JAC) are similar in performance and cost.
- While the F-class technology has more operational experience than the H/J-class technology, both have proven operational experience in simple cycle peaking configuration with SCR emissions controls.
- The J-class combustion turbines have the lowest fixed costs per Kw compared to the other frame combustion turbines. Since a G/H-class frame combustion turbine was selected as the representative technology in the 2021-2025 DCR and there have been no changes that would improve the relative position of the smaller F-class and G/H-class models, no further analysis of the smaller frame combustion turbine models was performed.

Two options for the DCR study were chosen from among the frame combustion turbines: The first was a H/J class combustion turbine unit, represented by a 7HA.03, a technology which offers low fixed cost, with high efficiency, and operational experience in North America. The 7HA.03 would require SCR emissions controls. The second was the GE 7HA.02, which has the option to be tuned to NOx emissions of 15ppm. The 7HA.02, tuned to 15 ppm NOx emissions, is able to be installed without SCR emissions controls. The 7HA.02 is an advanced class unit with operational experience in North America, and currently serves as the peaking plant technology underlying each of the ICAP Demand Curves.

4. Reciprocating Internal Combustion Turbine Peaking Option

Reciprocating engines are generally competitive with aeroderivative gas turbines, but the initial screening and the results of prior DCRs indicate that RICE technology is not likely to be the lowest cost alternative. Therefore, RICE units were not considered for further study in the DCR.

5. Selected Simple Cycle Turbine Technology for Review

Based on the screening criteria and considerations presented above, costs were developed for the options indicated below.

- One GE 7HA.03 unit with SCR emissions controls
- One GE 7HA.02 unit, tuned to 15 ppm NOx emissions, without SCR emissions controls (Load Zones C, F, G (Dutchess County) only)
- One GE 7HA.02 unit, tuned to 25 ppm NOx emissions, with SCR emissions controls (Load Zone K only)

6. Energy Storage Power Plant

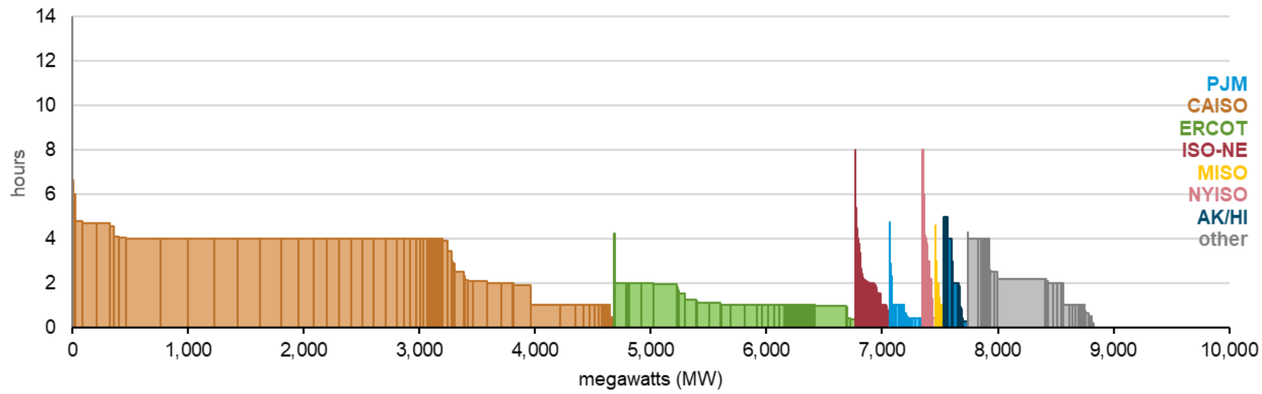
The lithium-ion battery storage market is growing, largely due to declining costs for lithium-ion battery technology and continued penetration of intermittent renewable energy sources. In December 2018, the New York State Public Service Commission (PSC) issued an order establishing a target of 3,000 MW of energy storage by 2030, which was subsequently codified as a requirement in the CLCPA. In 2022, PSC doubled the 2030 storage target to 6,000 MW.

The most likely candidate for new energy storage facilities are battery energy storage systems (BESS) based on lithium-ion technology, which is the most commercially mature battery storage technology in the market at this time. Pumped hydro is the most mature storage technology, with decades of successful operating experience, but this technology is limited in siting potential and requires longer permitting and implementation timelines than battery technologies. Non-lithium technologies were considered in the initial screening process, but preliminary evaluations suggested that the capital costs were higher than similarly sized lithium-ion systems and the market is still maturing for non-lithium alternatives at utility scale. The DCR study includes the following systems for comparison to traditional simple cycle turbine technologies:[15]

- 200 MW, 2-hour (400 MWh stored energy) lithium-ion
- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

As shown in **Figure 2**, all of these systems are deployed in the United States today, with significant quantities of 2-hour and 4-hour lithium-ion battery systems installed across the country, including in California and Texas:

Figure 2. Power capacity and duration of large-scale battery storage by region[16]



The market for lithium-ion batteries is dynamic, and while the stationary storage market is growing, most of the technology innovation and pricing is currently being driven by the electric vehicle market. Lithium-ion represents a broader technology class that includes dozens of battery cathode chemistries, each with its own advantages and disadvantages. Three chemistries have emerged as the leaders in today's market:

- Lithium nickel manganese cobalt oxide (NMC)
- Lithium iron phosphate (LFP)
- Lithium nickel cobalt aluminum oxide (NCA)

Each technology has different energy density, performance, and cost considerations, but all three technologies are generally suitable for the application considered in this DCR study. Since manufacturers and integrators of all three technologies are competing directly today for the same projects, the costs presented in this study are intended to

[15] The installed battery cell capacity is sized to provide the stated gross MW for the design discharge duration.
[16] Graph reproduced from EIA report: "Battery Storage in the United States: An Update on Market Trends," July 24, 2023, available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/

represent a snapshot of the market pricing as it currently stands. These costs are not intended to be directly representative of one chemistry or one OEM.

Technology development in the stationary storage market is trending toward the modular, purpose-built enclosure (PBE) form factor. Battery modules are loaded into modular enclosures in a factory setting and integrated with unit level controls, safety, and thermal management systems. Battery cell and module manufacturers often have their own line of PBE products, but they also commonly sell their battery modules to other integrators who make competing PBE products. The costs in this DCR study assume the use of the modular PBE form factor, but because of the numerous participants and competitive nature of the BESS market, the costs are not intended to represent a specific product provider or battery OEM.

A known limitation of lithium-ion technology is energy capacity degradation. Over time, the energy capacity degrades due to age and cycling behavior. The power (MW) does not degrade, so the BESS can still discharge 200 MW over time, but as the energy capacity (MWh) degrades, the duration of 200 MW discharge becomes shorter. Therefore, for example, a 200 MW, 4-hour discharge duration today will have less than 4-hour discharge duration at rated power in the future.

Should an owner wish to maintain the rated energy capacity of the BESS over time, then the system will likely require augmentation. Augmentation means that new BESS units would be added to the project at intervals over the assumed project life. The original installation would typically be designed to account for future capacity augmentation, and the actual augmentation costs may be part of a long-term agreement that may also account for routine maintenance. Augmentation costs were considered in the O&M estimates for the DCR study. Because the degradation is impacted by both time and cycling, the study accounts for a “fixed” component of the augmentation cost estimate and a “variable” component of the augmentation cost estimate. Notably, this structure is likely not how the costs are encountered by actual BESS project owners, but it is reasonable to include such a breakdown for this DCR study that considers a range of cycling possibilities driven by the operation of each BESS technology option to earn net EAS revenues in the NYISO-administered markets.

The fixed O&M costs in this study are intended to account for routine BESS equipment maintenance, extended warranties, performance guarantees, the fixed component of the augmentation estimate, balance of plant maintenance, and asset management. Fixed O&M costs are levelized for the assumed project life of each technology. The variable O&M costs in this study are intended to represent the variable component of capacity augmentation, accrued in terms of $/MWh discharged in the net EAS model.

BESS facility roundtrip efficiencies (the fraction of energy charged that can be later discharged) are commonly 80 - 90% when measured on the alternating current (AC) side of the system. The BESS roundtrip efficiency assumed for this study is 85%.

7. Informational Analysis of Hydrogen Fuel Retrofit of SCGT

The State of New York passed the Climate Leadership and Community Protection Act (CLCPA) in 2019 which establishes a goal of 100% zero emissions electricity by 2040. While there is not a precise definition of a “zero emissions” resource, we assume for purposes of this study that it would consist of a generation resource that produces zero direct CO_2 emissions during operation. As such, fossil fuel-fired peaking units are not expected to be able to operate beyond 2040. 1898 & Co. evaluated potential retrofit technologies to comply with the CLCPA for informational purposes.

Post combustion carbon capture has two primary challenges with meeting the CLCPA's zero emissions energy supply requirement. First, carbon capture technology is currently limited to 90%-95% CO_2 capture rate. This obviously means that some CO_2 emissions would still be produced by the generation resource. Additionally, current carbon capture technology would not be capable of fast startup times and flexible ramp rates that would be expected from the peaking plant technology. Due to these reasons, post combustion carbon capture was not evaluated any further.

Subject to the ultimate regulatory/program requirements to be established for implementing the CLCPA's zero-emissions energy requirement, there are several potential carbon-free fuels that could be viable in 2040, such as hydrogen, ammonia, biodiesel, and renewable natural gas to name a few. All of these are considered emerging technologies and have no commercial operating experience. While each of these fuels pose different benefits and challenges, hydrogen was selected as the proxy fuel to evaluate for informational purposes for this study. All three major gas turbine OEMs are performing research and development on dry low emissions combustor technology capable of firing 100% hydrogen. This combustor technology is expected to be commercially available by 2030. However, at the time of drafting this report, there are no combustion turbines in commercial operation firing 100% hydrogen fuel. For the purposes of this analysis, 1898 & Co. made the following assumptions:

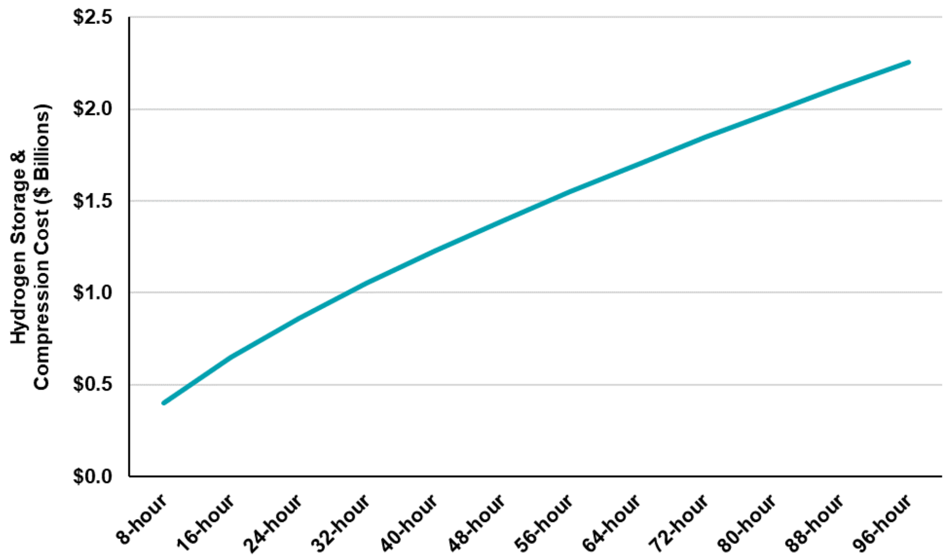
- Hydrogen is assumed to be delivered to the plant site. Pipeline costs have not been considered.
- On-site hydrogen storage is assumed to be needed.
- Hydrogen delivered to site would not require any additional treatment.

The hydrogen combustion retrofit would include the following scope:

- Replace all fuel piping with stainless steel welded piping.
- Replace gas turbine combustor hardware with dry low emissions combustors capable of 100% hydrogen combustion.
- No changes required to the gas turbine compressor, transition pieces, turbine section hardware, or auxiliaries.
- Gas turbine controls would be re-tuned.
- Replace select gas turbine instrumentation (such as flame detection and gas detection).

The hydrogen combustion retrofit scope is estimated to cost approximately $35 million in 2024 dollars. This does not include onsite storage of hydrogen (and associated compression). **Figure 3** shows the estimated capital costs for onsite hydrogen storage and compression based on duration. The costs of 96 hours of on-site storage is estimated to exceed $2 billion.

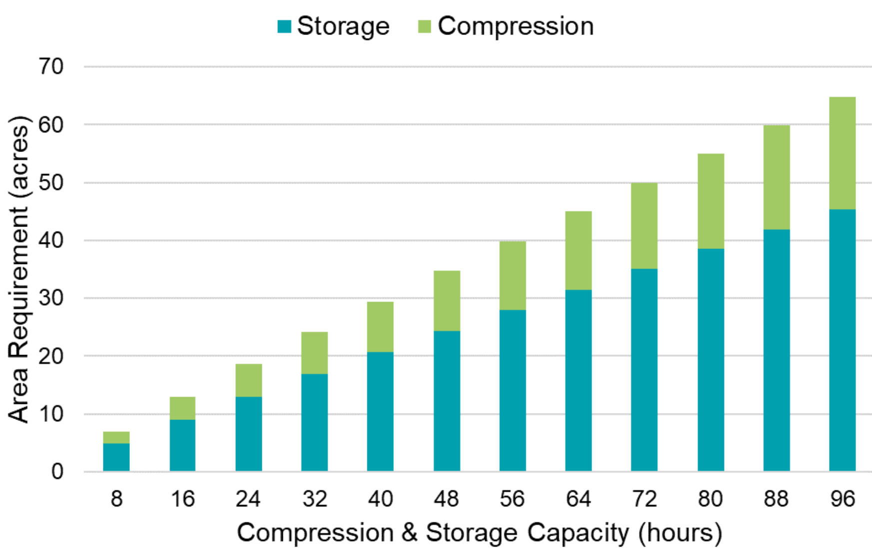
Figure 3: Hydrogen Storage & Compression Cost



The capital cost estimates provided above do not include the costs associated with producing and transporting hydrogen to site. This would need to be considered as an incremental operational expense. As such, the cost of retrofitting a fossil fuel-fired peaking unit to burn 100% hydrogen is currently cost prohibitive.

Figure 4 shows the estimated space requirements for onsite hydrogen storage and compression based on storage duration. It should be noted that cost and space requirements are estimated based on equipment being installed at grade on a single level and not installed in a multi-level structure to conserve space.

Figure 4: Hydrogen Storage & Compression Space Requirement



While technologies capable of complying with the CLCPA's zero-emissions energy supply requirement should continue to be monitored, AG and 1898 & Co. did not conduct any further evaluation of hydrogen as a potential peaking plant technology option for this study.

C. Plant Environmental and Siting Requirements

The conceptual designs and cost estimates developed for each fossil plant technology option 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 locations evaluated in this DCR.

1. Air Permitting Requirements and Impacts on Plant Design

Each of the candidate fossil peaking plant technologies would be required to obtain an air permit from the New York State Department of Environmental Conservation (NYSDEC). The air permit will require the plant to meet various Federal and New York State requirements. These requirements, among others, include New Source Performance Standards (NSPS), New Source Review (NSR), National Emission Standards for Hazardous Air Pollutants (NESHAP) and those specified in the New York State Codes, Rules, and Regulations (NYCRR). As discussed below, the fossil peaking plant technologies 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 fossil peaking plant technologies 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 TTTTa – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (stationary combustion turbines)

These sections of the NSPS are technology specific and do not vary based on the installation location of the gas turbine. Subpart KKKK requires combustion turbines with heat inputs greater than 850 MMBtu/hour to limit NO_x emissions to less than 15 ppm while firing natural gas and to less than 42 ppm while firing liquid fuels (e.g., ULSD).[17] These standards apply to all the combustion turbine options with heat inputs greater than 850 MMBtu/hr, including the GE 7HA.03 and GE 7HA.02 units. Based on the typical vendor data, the 7HA.03 machine used in this DCR has a NO_x emissions rate of 25 ppm, so it would require SCR emissions controls to satisfy Subpart KKKK.

The base model 7HA.02 emits 25ppm NO_x, which would require SCR emissions controls to comply with Subpart KKKK. However, GE also offers a version of the 7HA.02 unit tuned to emit 15 ppm NO_x, which would not require SCR emissions controls to satisfy Subpart KKKK. There are no hardware changes to the GE 7HA.02 turbine, but the unit is controlled for a lower combustion temperature to reduce NO_x production. Because firing temperature is also proportional to the turbine's output and efficiency, there is also a performance impact (approximately 5% reduction in output).

[17] All emissions rates are listed in parts per million by volume at 15% O2 on a dry basis.

Subpart TTTTa establishes CO_2 limits for new stationary combustion turbines that commence construction after May 23, 2023 and are capable of selling greater than 25 MW of electricity. Station combustion turbines are split into three categories based on a 3-year rolling average capacity factor; low load, intermediate load, and base load. Low load is defined as having a capacity factor less than 20%. Intermediate load is defined as having a capacity factor between 20% and 40%. Base load is defined as having a capacity factor greater than 40%. The CO_2 emissions limits for low load, intermediate load, and base load stationary combustion turbines is provided in **Table 8** below. The 7HA.02 and 7HA.03 units are expected to be able to comply with the intermediate load CO_2 emission limit without any controls. The base load CO2 emissions limit would only be achievable with post combustion carbon capture which is impractical for the units considered in this DCR study. In order to avoid being subject to the base load NSPS standard, which these turbines in simple-cycle mode cannot meet, the peaking plant needs to limit their capacity factors over a 12-operating month or a three-year rolling average basis to less than 40% capacity factor. This limits each of the fossil peaking plant technology options to 3,504 hours of operation based on a 12-month rolling average.[18]

New York State also has performance standards for CO_2 emissions in the NYCRR. **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 fossil peaking plant technology options must comply with both Subpart TTTT and NYCRR Part 251 requirements.

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

Stationary Combustion Turbine	Subpart TTTTa	NYCRR Part 251
Low Load (< 20% Capacity Factor)	120 to 160 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g[2] or 160 lb CO_2/MMBtu
Intermediate Load (20% < Capacity Factor < 40%)	1170 lb CO_2/MWh-g	
Base Load (Capacity Factor > 40%)	100 lb CO_2/MWh-g[1]	

Notes:
[1] Base load limit is 800 lb CO_2/MWh-g prior to 2032.
[2] MWh-g refers to gross generation output.

[18] For modeling purposes, we apply the runtime limitations for peaking plant operations by model year, instead of on a rolling average basis.

b. New Source Review

The NSPS requirements discussed above are technology specific, not location specific. In addition to NSPS, new fossil peaking plant technologies will be subject to the EPA's New Source Review (NSR) program, which considers the impacts to the air quality in the vicinity of the emission source. If a project site is located in an area where a criteria pollutant's concentration is below its respective National Ambient Air Quality Standard (NAAQS), then the area is in "attainment" for that pollutant. Areas where a criteria pollutant's ambient concentration is above its NAAQS is classified as a "nonattainment" area, and there are multiple levels of nonattainment (i.e. moderate vs. severe). The NSR program is split into two permitting pathways/regimes: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR). The preconstruction review process for new or modified major sources located in attainment and unclassifiable areas is performed under the PSD requirements. Preconstruction reviews for new or modified major sources located in nonattainment areas is performed under the NNSR program.

In order to improve a nonattainment area's air quality, the NNSR permitting pathway has more stringent permitting thresholds and requires stricter permitting analyses. In an attainment area, a source that would qualify for a PSD permit would need to perform a Best Available Control Technology (BACT) analysis, which reviews control technologies that have been installed on similar units for applicability to the new source. BACT analyses allow for the evaluation of cost feasibility when determining the control technology required. On the other hand, in a nonattainment area, a source applying for a permit under NNSR review is required to go through a Lowest Achievable Emission Rate (LAER) analysis, which does not take cost into consideration when determining applicable control technologies and thus typically has much more stringent control requirements. The NNSR only applies to the pollutants that are classified as nonattainment for a project area (meaning that one pollutant could undergo NNSR review if the site location is a nonattainment area for that pollutant, while the other pollutants could be subject to PSD review if the site location for such other pollutants is classified as attainment).

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 (250 tons/year). The annual emissions are typically based on the potential to emit (PTE) at 8,760 hours/year of operation. 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**.

However, it is possible to "synthetically limit" a unit's operating profile to maintain emissions for applicable pollutants below the PSD thresholds (both the major source threshold and the SER threshold). By synthetically limiting the PTE, the facility will become a "synthetic minor source", requiring less strict permitting analyses. For example, a BACT analysis would not be required as a part of a federal synthetic minor permitting application. Synthetic minor sources do have more reporting and recordkeeping requirements to verify that the synthetic limits are maintained during operation of the facility. Synthetic minor sources do have more reporting and recordkeeping requirements to verify that the synthetic limits are maintained during operation of the facility.

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".[19] As a result of this court decision, EPA may

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

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 only if another pollutant is also subject to PSD.

For the current DCR, as shown in **Table 9**, the PSD major source thresholds are 250 tons/year for the fossil peaking plant technologies.

Table 9: PSD Major Facility Thresholds and Significant Emission Rates

Pollutant	CT Major Source Threshold[1] (tons/year)	Significant Emissions Rate (tons/year)
Carbon monoxide (CO)	250	100
Nitrogen oxides (NO_x)	250	40
Sulfur dioxide (SO_2)	250	40
Coarse particulate matter (PM_{10})	250	15
Fine particulate matter ($PM_{2.5}$)	250	10
Volatile organic compounds	250	40
Greenhouse gases (GHG): as CO_2e	See Note 2	75,000

Notes:
[1] CT 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 Enforcement Discretion for State GHG Tailoring Rule Provisions Memorandum (October 15, 2014), GHGs alone will not trigger Prevention of Significant Deterioration New Source Review (PSD NSR).

As mentioned above, any pollutant subject to PSD review (i.e. exceeds the PTE thresholds in **Table 9**) is required to perform a BACT analysis. Absent application of a synthetic operating limit, it is expected that in order for a new fossil-fuel-fired peaking plant technology option in New York State to meet the BACT standard, SCR emissions controls 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 (air dispersion modeling), 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 5**. 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 5: Current Nonattainment Areas in New York

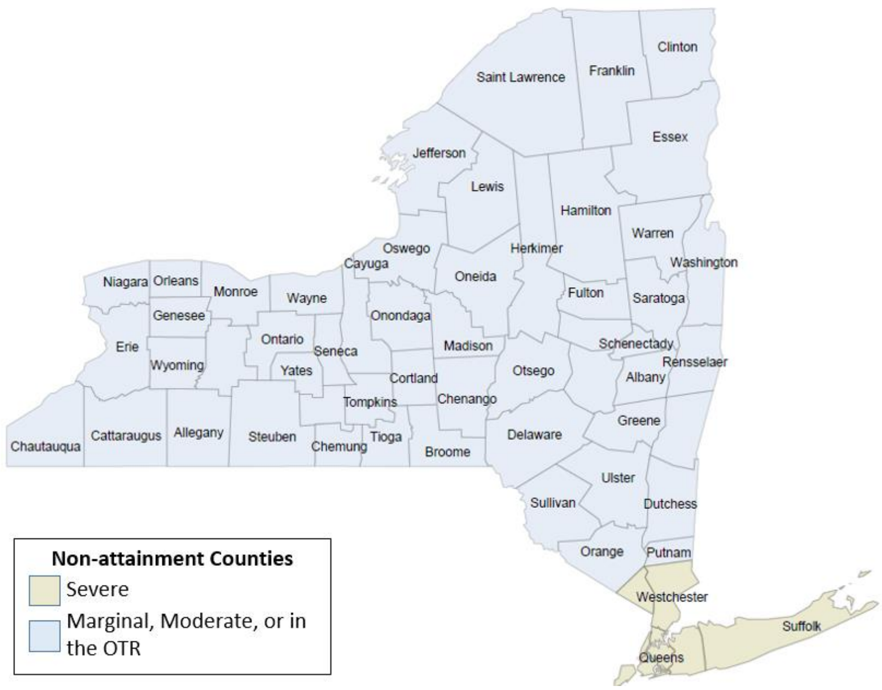


Table 10 presents the nonattainment major facility thresholds and emission offset ratios for each ozone nonattainment classification. Nonattainment areas classified as Severe include the New York City Metropolitan Area and the Lower Orange County Metropolitan Area. The New York City Metropolitan Area includes all of the New York City, as well as 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. **Table 11** summarizes the ozone nonattainment classification and NNSR major source thresholds for NO_X and VOC for each of the locations evaluated as part of this DCR. There have been no changes to ozone nonattainment since the 2021-2025 DCR.

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

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

Note: [1] Moderate nonattainment classification due to location in the Ozone Transport Region.

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

Similar to the PSD permitting process, a synthetic limit (e.g., application of an annual operating hours cap/limit) could be applied to a new source or facility, which would bring the annual PTE below the thresholds listed above in **Table 10** and **Table 11**. Since the facility would no longer be subject to NNSR, the LAER analysis would no longer be required.

The GE 7HA.03 peaking plant technology option with a 25 ppm NO_x emissions rate would already require the installation of SCR emissions controls per the NSPS Subpart KKKK limits discussed in the prior section. The control technology requirements (required to meet the NSPS or expected to meet LAER requirements as a part of NNSR absent any consideration of a synthetic limitation) are summarized in **Table 12** below.

Table 12: Control Technology Requirements for Fossil Technologies Analyzed at Greenfield Sites at Maximum Annual Run Hours

	C - Central		F - Capital		G - Dutchess		G - Rockland		J -NYC		K - Long Island	
	Moderate		Moderate		Moderate		Severe		Severe		Severe	
Technology	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst
1x0 GE 7HA.02, 15 ppm NO_x	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
1x0 GE 7HA.02, 25 ppm NO_x	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1x0 GE 7HA.03, 25 ppm NO_x	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Notes: [1] Values shown are for maximum annual hours of operation (3,504 hours for SCGT technologies).

In addition to the “maximum-hour” compliance analysis performed above, 1898 & Co. also analyzed other methodologies of compliance—specifically limiting the annual hours of operation of each technology in order to reduce emissions below the NNSR threshold to remove the requirement to perform a LAER analysis. The approximate hours per year restriction to eliminate the need to perform LAER for operating solely on natural gas or operating solely on ultra-low sulfur diesel (ULSD) fuel are shown in **Table 13** and **Table 14** below. The limits displayed in the tables are estimated based on lb/hr emissions rates at ISO conditions. The dispatch analyses take into account seasonal emissions differences due to different seasonal heat rates and capacities, so annual limits in the net EAS model for fossil plants may be different than those shown below.

NO_x emissions are higher for fuel oil operation than natural gas operation. In the case of a unit including dual fuel capability, the synthetic limit may be reached with fewer hours than a gas only unit, based on the quantity of each fuel used over the course of the year. Since the NOx emission rate of the 25 ppm base design of the GE 7HA.02 is above the NSPS KKKK, this unit will require SCR emissions controls to comply with the NSPS standard, which is not influenced by potential application of annual operating hours or project location. Therefore, it is included in the tables below, but not included in the synthetic minor analyses performed.

Table 13: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using Natural Gas Only at a Greenfield Site

Technology	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
	Moderate	Moderate	Moderate	Severe	Severe	Severe
1x0 GE 7HA.02, 15 ppm NOx	997	997	997	N/A[1]	N/A[1]	N/A[1]
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[1,2]	N/A[1,2]	N/A[1,2]
1x0 GE 7HA.03, 25 ppm NOx	N/A[2]	N/A[2]	N/A	N/A[1,2]	N/A[1,2]	N/A[1,2]

Notes:
[1] SCR emissions controls are required for these load zones due to being subject to LAER
[2] SCR emissions controls are required for these units per the NSPS KKKK rule.
[3] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59°F and 60% relative humidity).

Table 14: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using ULSD Only at a Greenfield Site

Technology	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
	Moderate	Moderate	Moderate	Severe	Severe	Severe
1x0 GE 7HA.02, 15 ppm NOx	332	332	332	N/A[1]	N/A[1]	N/A[1]
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[1,2]	N/A[1,2]	N/A[1,2]
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[1,2]	N/A[1,2]	N/A[1,2]

Notes:
[1] SCR emissions controls are required for these load zones due to being subject to LAER
[2] SCR emissions controls are required for these units per the NSPS KKKK rule.
[3] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59°F and 60% relative humidity).

Including SCR emissions controls on a simple cycle plant can serve to mitigate certain siting, permitting, and future market risks which are considered by power plant project developers. The fossil peaking plant 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 that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[20]

However, with availability of a synthetic minor approach that may limit run hours, the installation of SCR emissions controls in part reflects economic tradeoffs to the plant developer, with up-front capital costs and additional operating costs balanced against relaxed runtime restrictions. If the unit's expected hours of operation would not be expected to exceed the runtime restriction, then it may not be economic for a new plant to install SCR emissions controls. Considering the balance of costs and risks discussed above, it is AG's and 1898 & Co.'s opinion that the developer of a new plant in all Load Zones would seek to include SCR emissions control technology for a gas only or dual fuel plant at the time of construction due to economic considerations. *First*, SCR

[20] 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…"

emissions controls provides optionality to operate above the synthetic minor operating limit, which could be financially valuable in the future. Future net EAS revenues may be greater than net revenues in the historical years evaluated given the potential increases in demand for operation from the peaking plant from increased levels of renewables and potential retirements of gas turbines downstate due to the NYDEC "peaker rule" (see Section II.C.3 for details on the "peaker rule"). *Second*, the installation of SCR emissions control could mitigate potential permitting and siting risk associated with building a new dual fuel unit in the lower Hudson Valley (see Section II.D for more details on dual fuel) without back-end emissions control technology. *Third*, GE does not offer a version of the SCGT 7HA.03 capable of 15 ppm NOx to comply with NSPS KKKK without SCR emissions controls. As such, configurations without SCR emissions controls are assumed to use a SCGT 7HA.02. The SCGT 7HA.02 can be tuned to meet 15 ppm NOx. The 7HA.02 is a smaller turbine than the 7HA.03. As a result, as depicted in **Table 24**, on a $/kW basis, the SCGT 7HA.02 without SCR emissions controls is a similar cost as the SCGT 7HA.03 with SCR emissions controls. Moreover, due to higher efficiency and operating limits, net EAS revenues are anticipated to be higher for the SCGT 7HA.03 than SCGT 7HA.02 (as depicted in **Table 15**). Because the annual net cost is lower for the SCGT 7HA.03 with SCR emissions controls than the SCGT 7HA.02 without SCR emissions controls in all applicable locations, AG and 1898 & Co. recommend SCR emissions controls for the SCGT technology in all locations.

Table 15: Net EAS Revenues (Historical Data Period: 9/1/2021-8/31/2024)

Unit	Zone	SCR	Gas Only	Net EAS Revenues ($/kW-year)
SCGT 7HA.02	C	No	Yes	$54.24
SCGT 7HA.03	C	Yes	Yes	$68.32
SCGT 7HA.02	F	No	Yes	$66.89
SCGT 7HA.03	F	Yes	Yes	$96.55
SCGT 7HA.02	G (Dutchess)	No	Yes	$55.17
SCGT 7HA.03	G (Dutchess)	Yes	Yes	$71.82

Notes:
[1] See Section IV.B for a discussion of the net EAS model for fossil peaking unit technologies.

In addition to installing emissions controls technologies to meet 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 10**. 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. The estimated cost of the ERCs were based on the maximum NO_x emissions from natural gas operation. The annual hours were restricted to those needed to comply with NSPS Subpart TTTTa. The annual emissions used in the ERC cost calculations were based on the controlled emission rate assumptions that are shown in **Table 16**.

Table 16: Emissions Rate Assumptions for Fossil Plants

	NO_X (ppm) [1]	CO (ppm) [1]	VOC (ppm) [1]	CO_2 (lb/MWh) [2]
Natural Gas Firing without SCR/CO Catalyst				
1x0 GE 7HA.02, 15 ppm NO_x	15	9	2	1,120
Natural Gas Firing with SCR				
1x0 GE 7HA.03, 25 ppm NO_x	2	2	1	1,087
Ultra-Low Sulfur Diesel Firing without SCR				
1x0 GE 7HA.02, 15 ppm NO_x	42	12	2.4	1,490
Ultra-Low Sulfur Diesel Firing with SCR				
1x0 GE 7HA.02, 25 ppm NO_x	6	2	2	1,450
Ultra-Low Sulfur Diesel Firing with SCR				
1x0 GE 7HA.03, 25 ppm NO_x	6	2	2	1,400

Notes:
[1] Parts per million on a dry basis, measured at 15% O_2.
[2] Based on full load, net plant heat rate at ISO conditions, higher heating value (HHV) basis, clean and new condition.

2. Cap and Trade Program Requirements

The fossil peaking plant technology options 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 Group 2 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)
- Nonattainment and Ozone Transport Region (OTR) SIP Requirements (40 CFR 51.116 and 40 CFR 51.1316)

The CO_2 Budget Trading Program regulations would apply to all fossil peaking plant technologies assessed. 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 CO_2 that electrical generating facilities are allowed to emit in total across the RGGI region. CO_2 allowances are obtained by generators 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 fossil peaking plant technology option. In addition, the cost of ERCs is included in the capital cost estimates for each applicable location as required by NNSR air permitting requirements.

The Clean Air Act sets out specific requirements for a grouping of northeastern states that make up the Ozone Transport Region. It was determined that the NOx, CO, and VOC emissions from these states impacted several other regions/states downwind. States in the OTR region must submit a State Implementation Plan (SIP) and install more stringent controls on equipment in order to control the production of ozone, even if a county or area meets the ozone standards. These requirements are discussed above and have been incorporated into the NYDEC New Source Review for New and Modified Facilities which would apply to the fossil peaking plant technology options assessed for this DCR study.

3. "Peaker Rule"

In 2020, New York State adopted 6 NYCRR Subpart 227-3, "Ozone Season Oxides of Nitrogen (NO_x) Emission Limits for Simple Cycle and Regenerative Combustion Turbines," ("NYDEC Peaker Rule"). This applies to owners and operators of simple cycle and regenerative combustion turbines that are electric generating units with a nameplate capacity of 15 MW or greater that inject power into the transmission or distribution systems, only during the ozone season (May 1 to September 30). By May 1, 2025, the NO_x emission limits will be 25 ppmvd for natural gas and 42 ppmvd for distillate or other liquid fuel oils. As shown in **Table 12** above, the new fossil peaking plant technology options assessed for this DCR comply with these thresholds. Therefore, this rule will not directly impact the fossil peaking plant technology options evaluated in this study.

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 intervener funding provisions by the project developer. In its review, the New York State Board on Electric Generation Siting and the Environment (Siting Board) is required to find that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable. In doing so, 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 assessment also requires determining for each location whether the fossil peaking plant technology option should be a natural gas-only resource or have the capability to operate on both natural gas and ULSD (dual fuel). The current peaking plants include dual fuel capability for the NYC, LI, and G-J Locality ICAP Demand Curves. The current peaking plant for the NYCA ICAP Demand Curve is a gas-only design.

In this DCR, we have evaluated whether to recommend including dual fuel capability in each location. 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 likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

The incremental costs for dual fuel capability (which would be deducted for a gas only unit) are assumed to be $26.9 million (2024 $), as shown in the capital cost estimates in Appendix A. The capital costs include gas turbine combustion system modifications provided by the OEM, a fuel oil storage tank with 96 hours of storage capacity, piping (fuel and water), and associated electrical and controls modifications. The owner's costs include the purchase of the fuel inventory and the additional fuel requirements for startup and commissioning.

Based on our evaluation, 1898 & Co. and AG recommend that the peaking plant technology design should include dual fuel capability in all locations. 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:

- The New York State Reliability Council, L.L.C. (NYSRC) imposes strict local reliability standards to NYC and LI to ensure that the loss of a gas facility in those zones do not lead to a loss of electric load, and NYISO maintains a "minimum oil burn program" to implement these standards.[21] NYSRC's local electric reliability rules highly incentivize dual fuel capability for units in NYC and LI. Additionally, nearly all gas fired generation in Load Zones J and K is connected to the LDC gas system, and several LDC gas tariffs require dual fuel capability for generators. Such LDC requirements are in place for National Grid in Load Zones C, F and K; Orange & Rockland and Central Hudson in Load Zone G; and Con Edison in Load Zone J.
- Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are 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 on-site inventory of fuel for operations on the alternate stored fuel. On the other hand, these increases in cost could be outweighed by the value associated with potential increases in net EAS revenues from operating on the alternate fuel when the price for the alternate fuel is less than that of natural gas, and allowing production when gas

[21] New York State Reliability Rules and Compliance Manual, Version 46, June 10, 2022, Section 2.G.2-3, available at https://www.nysrc.org/wp-content/uploads/2023/07/RRC-Manual-V46-final.pdf; NYISO Technical Bulletin 156, April 1, 2019, available at https://www.nyiso.com/documents/20142/2931465/TB_156.pdf/132c16f5-5718-cbd5-2b59-fb564f6ee389.

supplies would otherwise be curtailed (such as during certain winter periods when gas supplies may be scarce due to higher demand for all end uses). For example, **Table 17** provides estimates of the impact of dual fuel on net EAS revenues for the historical data period 9/1/2021-8/31/2024. Consistent with previous DCRs, the economic argument for dual fuel is weaker in Load Zones C and F than in Load Zone G (Dutchess) or Load Zone G (Rockland).

- However, 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 during winter peak periods.
- Due to the potential impact of fuel availability capacity accreditation rules to be implemented beginning with the 2026-2027 Capability Year, in addition to other risks associated with gas-only peaking operation and opportunities for additional revenues, developers in Load Zones C and F would more likely than not decide to include dual fuel capability.

Table 17: Net EAS Revenues (Historical Data Period: 9/1/2021-8/31/2024)

Unit	Zone	Net EAS Revenues without Dual Fuel ($/kW-year)	Net EAS Revenues with Dual Fuel ($/kW-year)	Percentage Difference	Oil Run Hours (with Dual Fuel)
SCGT 7HA.03	C	$68.32	$68.32	0.00%	0
SCGT 7HA.03	F	$96.55	$97.17	0.64%	141
SCGT 7HA.03	G (Dutchess)	$71.82	$77.34	7.69%	114
SCGT 7HA.03	G (Rockland)	$73.28	$80.03	9.21%	104

Notes:
[1] See Section IV.B for a discussion of the net EAS model for fossil peaking unit technologies.

E. Capital Investment Costs

Unless otherwise noted, capital cost estimates were prepared for the construction of the following technologies in New York Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K:

- One GE 7HA.03 unit with SCR emissions controls
- One GE 7HA.02 unit, tuned to 15 ppm NOx emissions, without SCR emissions controls (Load Zones C, F, and G (Dutchess County) only)
- One GE 7HA.02 unit, tuned to 25 ppm NOx emissions, with SCR emissions controls (Load Zone K only)

Capital cost estimates were also prepared for the following energy storage technologies.

- 200 MW, 2-hour (400 MWh stored energy) lithium-ion
- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

In addition, for informational purposes, capital cost estimates were prepared for converting the 7HA.03 simple cycle facility to combust carbon free hydrogen in lieu of natural gas beginning in 2040 as a proxy for a potential option to comply with the CLCPA's 2040 zero-emissions energy requirement.

The capital investment costs include the installed cost of the plant, owner's costs, and financing costs during construction. The installed cost estimate is based on a developer entering into an engineer, procure, construct (EPC) contract for project execution. Owner's cost estimates include the electric and gas interconnection facilities, owner development and management activities, fuel inventory (applicable for fossil units with dual fuel capability), builder's risk insurance, and owner's contingency.

Table 18 provides the conceptual design features for the plants in each of the locations evaluated.

Table 18: Recommended Fossil Peaking Plant Design Capabilities and Emission Control Technology

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fuel Capability	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel
Combustion System NO_x Control	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry
	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection
GE 7HA.02 NO_x emissions tuning	15 ppm	15 ppm	15 ppm	N/A	N/A	25 ppm
Post Combustion Controls for GE 7HA.02 simple cycle	None	None	None	N/A	N/A	SCR
GE 7HA.03 NO_x emissions tuning	25 ppm	25 ppm	25 ppm	25 ppm	25 ppm	25 ppm
Post Combustion Controls for GE 7HA.03 simple cycle	SCR	SCR	SCR	SCR	SCR	SCR

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 generic, greenfield site. Assumed land requirements for greenfield conditions are summarized below. In New York City, it is assumed that a peaking plant would most likely be built on a brownfield site at low elevation. Therefore, the New York City capital cost estimate includes a nominal allowance for demolition of existing facilities.

2. Storm Hardening – Costs were included to raise the Load Zone J site 4 feet as an allowance to accommodate floodplain zoning requirements and New York City building codes to prevent damage to the facility from flooding analogous to those which occurred due to Hurricane Sandy in 2012. 1898 & Co. considered that the peaking plant 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. Site elevations along the waterfront may be as low as 10 feet NAVD88.

3. Fuel – The capital cost estimates were developed based on the fuel assumptions shown above in **Table 18** for the fossil peaking plant technology options. The cost delta to add or remove dual fuel capability is also shown in the costs in Appendix A. Dual fuel units include a cost for fuel oil inventory, with storage levels based on the capability to provide 96 hours of operation (equivalent to 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 $3.00 per gallon. Initial commissioning for each fossil peaking plant technology option assumes 50 hours of full load oil use for guarantee and emissions performance testing.

4. Inlet Cooling – Inlet air evaporative coolers were included for the fossil peaking plant technology option. 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% to 90% 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 air increases as the temperature is lowered, the mass flow through the turbine is higher at lower temperature, which increases the MW generated.

5. Gas Pressure – For the fossil peaking plant technology options, the natural gas pressure was assumed to be 250 psig in all locations evaluated. Natural gas compressors were included in the EPC estimates to increase the fuel gas pressure to that required by the combustion turbine options assessed.

6. Emission Control Equipment – In Load Zones C, F, and G-Dutchess, the NO_x limit to trigger PSD is 100 tons per year (tpy). For the fossil peaking plant technology options with NOx emissions rates equal to or less than 15 ppm (such as the 15 ppm NO_x variant of the GE 7HA.02 unit) could potentially receive an air permit without SCR emissions controls by assuming a run-hour limitation to stay below 100 tpy. Analyses by 1898 & Co. and AG suggest that the run hour limitations in Load Zones C, F, and G-Dutchess would significantly limit potential operating hours and EAS revenues such that a 7HA.02 without SCR emissions controls would be less favorable financially. Therefore, for the fossil peaking plant technology options, 1898 & Co. recommends considering the GE 7HA.03 with SCR emissions controls in all locations.

7. Black Start Capability – Black start capability has not been included in the cost estimate for any of the fossil plants or batteries given that the compensation for this service is cost based. Accordingly, the costs of such capability would be recovered in the compensation for such service, and thus have been excluded from both the cost and revenue estimates. This is consistent with the approach for black start capability from the 2021-2025 DCR.

8. Noise Mitigation – Preliminary noise modeling was performed to determine mitigation system assumptions for all technologies. Software modeling was performed with the facility placed in the center of a parcel with the acreage defined in the assumptions for this study. NYSDEC provides guidance for circumstances under which sound creates significant noise impacts within the Program Policy Memorandum titled Assessing and Mitigating Noise Impacts. Projects in New York City are also anticipated to be subject to the New York City Environmental Quality Review (CEQR) requirements and the New York City Noise Control Code. Based on 1898 & Co.'s experience, noise mitigation costs are dependent on the permitting process for a specific site, and such costs may not necessarily be avoided at a larger site, as exemplified by recent projects in New York.[22] Based on the modeling results and 1898 & Co.'s permitting experience, the design basis assumes that all simple cycle gas turbine options would be installed indoors. For all fossil peaking plant technology options, the buildings also include administrative facilities, control room, and warehouse space. All technologies assessed in this study (i.e. fossil peaking plant technology options and BESS options) include a nominal allowance for sound barrier walls (these are not the same as the walls of the building, but rather a separate, strategically located barrier to mitigate noise impacts for compliance with the threshold described herein). The location and dimensions of the sound walls will vary depending on several site-specific conditions, but the preliminary model results suggest that an allowance for barriers is warranted to meet the threshold of a 6 dBA increase of the assumed ambient sound levels.

9. Water Supply and Wastewater – For all locations except Load Zone J, water supply is assumed to be raw water from an onsite well. Load Zone J assumes a municipal water connection. All locations include a tank for process/fire water. Wastewater and facility drains are collected in onsite tanks and pumped out via trucks for disposal.

10. Energy Storage Sizing – 1898 & Co.'s recent project experience suggests that there is a strong market trend toward modular PBE products for stationary storage projects, and this form factor is assumed for the cost basis. However, because there is a large quantity of OEMs and integrators competing directly in the storage space, and because information supporting the cost estimates is typically proprietary, the costs are not intended to represent a specific product or manufacturer. 1898 & Co. is not selecting a unique design basis, but the sizing process and criteria would be similar among available products. The project is sized to accommodate the power and energy requirements at the point of interconnection (POI), and to account for performance degradation and subsequent augmentation.

Table 19 below shows the assumed losses for the non-battery equipment used in BESS systems.

[22] For example, CPV Valley Energy Center, completed in 2018, is a combined cycle facility that occupies approximately 35 acres of a 122-acre parcel. A majority of the project equipment is located within an acoustical building, the gas turbine is equipped with inlet and exhaust silencers, and the air-cooled condenser utilized low noise fans. In addition, Cricket Valley Energy Center, completed in 2020, is a combined cycle facility that occupies approximately 57 acres of a 193-acre parcel. A majority of the project equipment is located in within acoustical buildings, the gas turbine is equipped with inlet and exhaust silencers, the air-cooled condenser and fin-fan coolers utilized low noise fans, and other items are surrounded by sound barriers. Competitive Power Ventures, "About CPV Valley," https://cpv.com/our-projects/cpv-valley-energy-center/about-cpv-valley-2/. Cricket Valley Energy Center, "Final Environmental Impact Statement," https://www.cricketvalley.com/wp-content/uploads/2017/11/CVE-FEIS-Section-1-Project-Description-final.pdf

Table 19: Key BESS Sizing Assumptions

BESS Sizing Assumptions	
POI Rating (MW)	200
POI Power Factor Capability	0.85
Inverter Loss (%)	1.80%
MV Transformer Loss (%)	0.80%
MV Collection Loss (%)	0.10%
Main Power Transformer Loss (%)	0.40%
Transmission Line to POI Loss (%)	0.10%

Additional sizing considerations are product specific, including the efficiency of the batteries, depth of discharge limitations, the capacity degradation that may occur between shipment and the commercial operations date, and the peak auxiliary load rating (driven by the thermal management system). 1898 & Co. considered information from multiple providers, including those that can be used in Load Zone J, to determine a generic sizing profile for the 200 MW BESS options.[23]

Because energy capacity degrades due to time and cycling behavior, projects that require consistent energy discharge capability over time must be designed to account for degradation. This is done through overbuild and/or augmentation strategies. Overbuild means additional energy capacity is included in the beginning of life (BOL) installation and incorporated in the initial capital cost. Augmentation means that additional battery enclosures will be added at intervals during the assumed project life to maintain the desired energy discharge capability. There is considerable nuance in overbuild/augmentation strategies, and they will vary based on any number of site specific and owner specific conditions or incentives.

1898 & Co. is accounting for an assumed 20-year project life with full rated energy discharge capability maintained over such assumed life, which impacts the capital cost and O&M cost. The BOL energy discharge capability and capital cost assumes 4 years of energy discharge capacity overbuild. The O&M cost considers the augmentation costs over the 20-year assumed project life. 1898 & Co. considered multiple products and providers when reviewing degradation curves and the related overbuild and augmentation assumptions. Additional information on augmentation is provided in Section F below.

The sizing results are shown in **Table 20** below:

[23] BESS technologies that can be used in Load Zone J are those that have received the New York City Fire Department Bureau of Fire Prevention Certificate of Approval. A list of approved products can be found here: https://www.nyc.gov/assets/fdny/downloads/pdf/business/coa-energy-storage-systems.pdf.

Table 20: BESS Sizing Results

BESS Sizing Results				
Rated Power at POI (MW)	200	200	200	200
Discharge Duration at Rated Power (hours)	2	4	6	8
Rated Nominal Energy at POI (MWh)	400	800	1200	1600
Years of Overbuild Assumed (years)	4	4	4	4
BOL Installed Energy Capability Incl. Overbuild (MWh AC at POI)	452	903	1,355	1,806

2. EPC Cost Estimate

EPC cost estimates were prepared for a generic site and do not include preliminary engineering or development activities. The information provided herein was developed solely for the purposes of this study and is not intended for any other purpose such as project specific budgeting, design, or construction activities. The capital cost estimates are based on 1898 & Co. experience as an EPC contractor, engineering design firm, and consultant in the power generation and energy storage industries. 1898 & Co. has recent project execution experience, consulting experience, and/or firm proposal experience on simple cycle turbine and energy storage projects.

Direct costs include the labor, materials, engineered equipment, subcontracts, and construction equipment to construct the facility. This includes site preparation, foundations, structural steel, equipment installation, buildings, associated piping, electrical, and controls tasks. Indirect costs include the construction management, engineering, and startup activities, as well as warranty and general administrative costs. Contingency is included to account for uncertainties in the quantities and pricing, which may increase during detailed design and procurement. In this case, a contingency of 10% was applied to the total direct and indirect project costs, which is typical practice for construction estimates of this type. A 10% EPC contractor fee is also applied to all estimated EPC costs.

- Equipment and Material Costs - Frame turbine costs are based on budgetary estimates from the respective OEMs. As previously noted and further described below, for BESS options, the costs presented in this study are intended to represent a snapshot of the market pricing as it currently stands. These costs are not intended to be directly representative of one chemistry or one OEM. Other equipment and material quantities and costs are based on recent 1898 & Co. project experience with cost estimates, designs, and/or execution for simple cycle turbine and energy storage projects. For all technologies, the EPC electrical scope ends at the high side of the generator step up transformer (GSU), also called the main power transformer (MPT) on storage projects. GSU/MPT costs and installation are included in the EPC cost.
- Labor - Labor costs are based on man-hour durations within each craft multiplied by the respective labor rates. Costs are based on the EPC contractor self-executing the steel, piping, and equipment scopes. All other craft scopes are assumed to be subcontracted. Construction craft base pay and supplemental (fringe) benefits were obtained from the RSMeans Labor Rates for the Construction Industry (RSMeans) for a representative municipality for each Load Zone evaluated. RSMeans is an industry standard construction cost database that includes locational labor rates that are updated annually. Burdened labor rates were developed by adding Federal Insurance Contributions Act (FICA) tax, state and federal unemployment taxes, general liability insurance, and workmen’s compensation insurance. All-in wage

rates were developed by adding allowances for small tools, supervision, construction equipment, and subcontractor overhead and profit. Work is assumed to be performed on a 50-hour work week by qualified union craft labor available in the respective area. Direct installation labor man-hours for the base cost 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. Based on 1898 & Co. experience, man-hours were multiplied by a labor productivity factor for each Load Zone evaluated.

- Energy Storage - Estimates for the BESS options were developed through a similar process, but the estimate results are intended to be indicative of the current state of the BESS market as of Q2 2024, rather than any particular BESS product or provider. To reach these indicative numbers, 1898 & Co. internally performed estimates using two types of modular PBE technology: a “DC” enclosure, where the battery enclosure and power conversion system (PCS) skid are separate; and an “AC” enclosure where inverters are included in the battery enclosure. 1898 & Co. considered major equipment pricing from multiple providers of DC enclosures and AC enclosures, including those that would be suitable for inclusion in Load Zone J, but because of the confidentiality and competitive nature of the equipment estimates, equipment cost breakouts will not be disclosed in the DCR study. It is also noted that the BESS facility estimates account for the physical space and full substation buildout in the BOL capital cost to accommodate the eventual end-of-life (EOL) energy discharge capability. This shifts some cost from the O&M cost to the capital cost, but would also reduce outage requirements during eventual augmentation estimates.

3. Owner’s Costs

Owner’s costs include allowances for items such as development activities, project management oversight, Owner’s Engineer, legal fees, financing fees, ERCs, fuel inventories, builder’s risk insurance, and additional contingency. In Appendix A, 1898 & Co. includes the interconnection costs under the Owner’s cost umbrella, but those items are discussed in more detail in the following sections.

Owner’s costs can vary greatly depending on the project owner and project opportunity. Key assumptions for Owner’s costs are included below:

- The Owner cost line items for lateral items such as gas line, transmission line, and interconnecting switchyard are intended to be standalone estimates, inclusive of the land, development, and execution activities for those items. For BESS options, the transmission line and interconnecting switchyard cost estimates include sales tax for equipment and materials. Sales tax is not included on labor/installation-related activities.
- Owner development, oversight, permitting, and management related activities are duration-based, with assumptions for personnel cost for the Owner and/or consultants, plus expenses. Temporary utilities are duration-based costs for power consumed during construction.
- Allowances are included for spare parts, legal fees, and area development concessions that often arise as part of project permitting/siting.
- For the fossil peaking plant technology option, applicable ERC price assumptions for NO_x and VOCs in each location are based on discussions with emissions brokers familiar with the current ERC market in New York. The price assumptions are shown in **Table 21**.

- The Startup and Testing Consumables allowance accounts for fuel and consumables during startup. For the BESS options, the allowance is for an assumed net cost of charging and discharging during site testing.
- For the fossil peaking plant technology options, initial fuel inventory accounts for 96 hours of fuel oil storage for the options that include dual fuel capability.
- The sales tax line is intended to be the sales tax for major equipment.
  - For the fossil peaking plant options, the value is shown as zero dollars, as the study assumes that the project owner would receive a tax exemption certificate for capital purchases. Construction supplies and consumables would still be taxable. As applicable, consumable material unit costs in the EPC estimates account for sales tax.
  - Sales tax is included in this line item for major equipment for the energy storage technology options, as bulk energy storage is not currently eligible for an as-of-right state sales tax exemption. Sales tax on construction materials is included within the EPC cost line item. Sales tax on materials and equipment has also been included in the transmission line and switchyard Owner's costs for energy storage technologies.
  - Sales tax is not included on BESS, transmission line, or switchyard labor/installation related activities in the cost estimates, as they are assumed to be capital improvement projects.
- Land lease costs during construction are included in the Owner's costs.
- The Builders risk insurance allowance is based on 0.45% of the EPC capital cost. Builder's risk insurance allowances for the switchyard, transmission line, and, for fossil peaking plant technology options, gas pipeline are included in those line items.
- Owner's contingency is based on 5% of the total installed cost including EPC and all Owner's costs.

Table 21: ERC Price Assumptions

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K-Long Island
NO_x ERCs ($/ton)	$1,350	$1,350	$1,350	$15,000	$15,000	$15,000
VOC ERCs ($/ton)	$5,500	$5,500	$5,500	$19,500	$19,500	$19,500

- Construction financing costs, including allowance for funds used during construction (AFUDC) and interest during construction (IDC), were estimated during the construction period for each plant type using the financing assumptions discussed in Section III. Specifically, we assume a 55/45 split of debt and equity, 6.7% cost of debt, and 14.0% cost of equity for SCGT technology options, and a 55/45 split of debt and equity, 7.2% cost of debt, and 14.5% cost of equity for BESS technology options.
  - Total construction periods (including pre-construction engineering and approvals) were assumed to differ for each technology, ranging from 30 months for the 2-hour BESS units to 42 months for the 8-hour BESS and fossil peaking plant technology options.
  - For Load Zone J, construction financing costs are estimated at 9.12% of overnight capital costs for SCGT technology options, 7.80% for a 2-hour BESS unit, 8.40% for a 4-hour BESS unit, 9.90% for a 6-hour BESS unit, and 12.30% for an 8-hour BESS unit.

- For all other locations, construction financing costs are estimated at 9.26% of overnight capital costs for SCGT technology options, 7.90% for the 2-hour BESS units, 8.53% for the 4-hour BESS units, 10.06% for 6-hour BESS units, and 12.50% for 8-hour BESS units.
- Reflective of the fact that the investment tax credit (ITC) is only available on the basis of energy property that is placed in service during the taxable year for which the taxpayer is claiming the credits, the AFUDC is calculated on pre-ITC project costs for BESS technology options.

4. Electrical Interconnection Costs

Interconnection costs include Minimum Interconnection Standard (MIS) costs and, if applicable, System Deliverability Upgrade (SDU) costs. The NYISO planning department conducted a deliverability analysis to determine whether any of the SCGT options or BESS options being evaluated may require SDUs to obtain Capacity Resource Interconnection Service (CRIS).

All technology options were found to be fully deliverable in all locations, except for the 7HA.03 frame turbine option for Load Zone K. Load Zone K SDU costs for the 7HA.03 frame turbine option were estimated to be at least $300 million, while Load Zone K SDU costs were zero for the 7HA.02 frame turbine and all BESS options (i.e., these options were all fully deliverable without incurring any need for SDUs). Given the high SDU costs for the 7HA.03 turbine option, 1898 & Co. developed cost and performance information for a 7HA.02, tuned to 25 ppm NOx emissions, with SCR emissions controls and dual fuel capability for Load Zone K. As discussed below, the 7HA.02 option represents a lower fixed cost SCGT technology option for Load Zone K considering the SDU cost applicable to a 7HA.03 frame turbine option.

MIS costs are comprised of Developer Attachment Facilities (DAF), System Upgrade Facilities (SUFs) at the POI, SUFs beyond the POI, and Connecting Transmission Owner (CTO) Attachment Facilities (AF). The DAF costs begin at the high side bushing of the GSU. The cost of the GSU/MPT is included in the EPC estimate. 1898 & Co. included separate estimates for the interconnecting switchyard and the transmission line in the Owner's costs.

The transmission line between the facility and the POI is assumed to be one mile long in Load Zone J (New York City) and three miles long in all other locations. The transmission line in Load Zone J is assumed to be installed underground,[24] while the lines in all other locations are assumed to be installed overhead.

The cost of the switchyard was based on the assumptions below:

- Air insulated switchgear (AIS) for all locations except Load Zone J, which would include gas insulated switchgear (GIS) technology.[25]
- Gas turbine project voltage assumptions: 345 kV high side voltage for all locations except Load Zone K, which is assumed to be 138 kV.

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[24] According to Consolidated Edison Transmission Planning Criteria (TP-7100-18, August 2019) and its fundamental design principles, underground transmission is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, nearly all existing transmission in New York City is already underground. As a result, 1898 & Co. assumed an underground interconnection for the plants evaluated in this study.

[25] According to Consolidated Edison Transmission Planning Criteria (TP-7100-18, August 2019) and its fundamental design principles, GIS switchyard is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, it is 1898 & Co.'s experience that power generation facilities and switchyards in dense urban areas such as those in Load Zone J require GIS facilities due to space constraints and aesthetic considerations.

- BESS project voltage assumptions: 115 kV high side voltage for Load Zones C, F, and G (Dutchess County), and 138 kV high side voltage for Load Zones J, K, and G (Rockland County).
- 3-position ring bus for 1x GE 7HA.03, 1x GE 7HA.02, and BESS options.

The costs for the switchyard, transmission line to POI and SUFs at POI were estimated by 1898 & Co. 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 into the estimates developed for this study. A right-of-way (ROW) allowance of $1 million per mile is included for transmission line estimates in all locations except Load Zone J. For Load Zone J, the ROW allowance for the underground transmission line is estimated using an O&M cost line item for a revocable consent payment.

5. Gas Interconnection Cost

For the fossil peaking plant technology options, gas interconnection cost estimates are based on 1898 & Co.'s experience with gas laterals and available information on pipeline projects recently planned or completed in New York. Recent projects in New York and Connecticut suggest that 5 miles is a reasonable assumption for gas lateral length in all Load Zones except Load Zone J. 1898 & Co. developed costs reflecting an average gas lateral length of one mile in Load Zone J and five miles in all other locations, with a 16-inch diameter pipeline for the GE 7HA.02 and GE 7HA.03 options. The average cost for a metering and regulation station was estimated at $3.5 million in all locations.

These costs represent a generalized estimate to interconnect with either an interstate natural gas pipeline or a gas 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. Project-specific interconnection costs for an actual plant may be higher or lower, depending on a multitude of factors including distance, terrain, and existing right-of-way.

6. Water Supply Costs

Water supply is only required for the fossil peaking plant technology options. The BESS technology options do not use water. For the fossil peaking plant technology options, Load Zone J assumes a municipal water connection and the line item accounts for a 1-mile, 8" diameter water line. The estimated cost for the water line connection in Load Zone J is based on 1898 & Co.'s experience and review of publicly available information for water main installation and/or restoration in Load Zone J. For all other locations, the water supply for the fossil peaking plant technology options is based on an onsite well that is included in the EPC capital cost, so there are no costs shown in this Owner's Cost line item.

7. Investment Tax Credit

1898 & Co. developed assumptions regarding the net value of the federal investment tax credit (ITC) for the BESS options to align with current industry trends. These ITC assumptions and allowances are based on 1898 & Co.'s knowledge of confidential project-specific eligible cost information, correspondence with tax consultants and developers, and related research.

The BESS options are assumed to meet prevailing wage requirements and, as such, are eligible for a 30% ITC. ITC-eligible costs include equipment required for supplying electricity to the point of change of ownership with the utility, plus related direct and indirect costs. For purposes of this study, the point of change of ownership is assumed to be at ring bus switchyard, while the generation tie transmission line is assumed to be included in the eligible tax basis. The eligible basis excludes the interconnecting switchyard, portions of site prep/civil scope, fencing, external fire protection, noise mitigation, and site security systems. Because Load Zone J project estimates have higher costs for switchyard, fire protection, and site preparation, the percentage of eligible basis is appreciably lower than all other locations on a percentage of total project basis. Legal fees included for tax credit transfer transactions are intended to cover buy-side and sell-side. Recapture insurance is typically included in ITC transfers. Coverage and premium assumptions are the same for all BESS options in all locations. Finally, the current market value for transfer is approximately $0.92 per $1 ITC, net of broker fees is assumed for all locations.

Table 22: Investment Tax Credit Assumptions

ITC Assumption Items	Load Zone J	Other Location
ITC Percentage Assumption, %	30%	30%
Eligible Basis Allowance as Percent of Total Project Cost, %	75%	90%
ITC Transfer Legal Fees (Seller pays both sides), $	$750,000	$750,000
Recapture Insurance Coverage Adder, %	15%	15%
Recapture Insurance Premium Assumption, %	2.5%	2.5%
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%

Given the ITC assumptions described above, the net value of the investment tax credit for the BESS options can be calculated via the following formula:

$$Net\ Value\ of\ ITC\ = (Total\ Project\ Costs) \times (ITC\ Credit\ Percentage) \times (Eligible\ Basis\ Allowance\ Percentage) \times (Assumed\ Value\ of\ Transferable\ Tax\ Credit\ Percentage) - (Legal\ Fees) - (Recapture\ Insurance\ Cost)$$

8. Summary of Capital Investment Costs

Capital investment costs for each location and technology option are summarized in the tables below. For the GE 7HA.03 simple cycle units, dual fuel capability and SCR emissions controls are included for all locations. For the GE 7HA.02 simple cycle units, SCR emissions controls are not included (this option was only considered for Load Zones C, F, and G (Dutchess County)). The fossil peaking plant technology options are assumed to be subject to an annual operating hours limitation for compliance with NSPS for GHG. Cost buildups are included in Appendix A. Capital costs in $/kW units are based on the total capital cost divided by the ICAP performance of each plant option evaluated.

Table 23: Capital Cost Estimates ($2024 million)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with Dual Fuel and SCR)	$656	$667	$663	$704	$831	$1,269
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	$568	$578	$572		-	-
1x0 GE 7HA.02 (with Dual Fuel, with SCR)	-	-	-	-	-	$641
Energy Storage						
BESS 2-hour	$229	$231	$230	$237	$339	$245
BESS 4-hour	$355	$358	$356	$367	$505	$378
BESS 6-hour	$499	$502	$501	$515	$682	$531
BESS 8-hour	$643	$647	$645	$664	$873	$684

Note: [1] All estimates include construction financing costs.

Table 24: Capital Cost Estimates ($2024/kW)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with Dual Fuel and SCR)	$1,687	$1,666	$1,668	$1,771	$2,056	$3,142
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	$1,770	$1,747	$1,744	-	-	-
1x0 GE 7HA.02 (with Dual Fuel, with SCR)	-	-	-	-	-	$1,816
Energy Storage						
BESS 2-hour	$1,150	$1,160	$1,150	$1,190	$1,690	$1,230
BESS 4-hour	$1,780	$1,790	$1,780	$1,830	$2,530	$1,890
BESS 6-hour	$2,500	$2,510	$2,500	$2,580	$3,410	$2,650
BESS 8-hour	$3,220	$3,240	$3,230	$3,320	$4,360	$3,420

Note:
[1] All estimates include construction financing costs.

F. Fixed & Variable Operating and Maintenance Costs

In addition to the initial capital investment, there are ongoing costs associated with the simple cycle and energy storage options. These include fixed operating and maintenance (O&M) costs, 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 A contains tables that provide a breakdown of the fixed and variable O&M cost estimates for each technology in each location evaluated.

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 – SCGT Options

Fixed O&M costs for all technology options were developed using 1898 & Co. proprietary tools that generate cost estimates for plant staff labor, routine maintenance, training, laboratory expenses, safety equipment, building and grounds maintenance, and administrative and general costs.

The plant staff labor costs are based on the staffing levels in **Table 25**. The full-time equivalent (FTE) employees are comprised of O&M staff, management and administrative staff.

Table 25: Staffing Levels and Salaries Used for O&M Estimates

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
SCGT Options	7	7	7	7	7	7
Annual Salary (Wage plus Benefits)						
Full-Time Equivalent Personnel	$158,500	$174,200	$205,700	$257,100	$275,700	$275,700

1898 & Co. updated labor rates for this study using the cumulative change in the average wage rates for the respective Load Zone areas in the RSMeans Labor Rates for the Construction Industry. Note that the labor rates from the RSMeans source were not used for O&M personnel wage rates, but the average labor escalation is anticipated to be reflective of general labor trends.

b. Fixed Plant Expenses – BESS Options

BESS fixed O&M costs were developed using internal tools and market-based cost information from 1898 & Co.'s experience. The BESS fixed O&M costs are intended to account for routine O&M for the BESS equipment and balance-of-plant equipment, extended warranties for BESS equipment, capacity and performance guarantees for the BESS equipment, and allowances for asset management, energy management, standby auxiliary power cost, and a contingency fund for inverter replacement/repair beyond the common extended warranty period. Fixed O&M costs are levelized for the assumed project life of each respective technology. The energy and asset management allowance included in the O&M estimate assumes that Owner salaried personnel will perform these tasks, and the equipment maintenance activities are assumed to be performed by third party personnel through long-term service and/or warranty agreements. An additional allowance is included in the Load Zone J fixed O&M estimate to account for additional O&M scope for fire protection equipment monitoring and maintenance. Sales tax is included for materials and labor related to the third-party agreements, which is included in the sales tax allowance line item.

Fixed O&M costs for BESS also include the “fixed” component of the augmentation cost estimate. In the industry, it is likely that augmentation events would be milestone costs at certain intervals, but for the purposes of accommodating differing cycling scenarios, the total augmentation cost was broken into fixed and variable components. 1898 & Co. built up augmentation estimates for two scenarios: 180 cycles per year for the assumed life of the project and 365 cycles per year for the assumed life of the project. These total lifetime costs were then annualized and algebraically split into the fixed amount that would be common for all cycling scenarios, and the variable amount that follows the cycling/dispatch behavior. Sales tax is included for materials and labor related to augmentation, which is included in the sales tax allowance line item.

c. Site Leasing Costs

The site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. The costs associated with site leasing during construction, including temporary areas for laydown and parking during construction, are included in the EPC pricing. For all technologies, 1898 & Co. estimated annual lease rates by initially escalating the assumed values from the 2021-2025 DCR study to $2024 using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator (Q1 2019-Q1 2024). The resulting escalated values were then compared to the observed range of leasing costs identified by 1898 & Co’s review of a combination of publicly available listing values and additional information provided by stakeholders (including a stakeholder provided assessment by JLL) to assess industrial zoned property in New York.

Based on this assessment, 1898 & Co. determined that, for purposes of this study, the escalated values represent reasonable values for all locations, except Load Zone J. Load Zone J has experienced increased demand for industrial zoned property resulting in property values that have outpaced the GDP based escalation. 1898 & Co. used the JLL report data to determine the sale price over the last 5 years of M-3 zoned property, over 4 acres, without existing buildings, within a 3-mile radius of an existing substation within Load Zone J. Sale price was converted into a lease rate by using a capitalization rate and adding property tax on the underlying property without consideration of additions related to the peaking plant technology options evaluated for this study. 1898 & Co. assumed a capitalization rate of 5.9% to estimate land lease rates based on property values. Property tax values were determined by calculating the assessment value (45% of the purchase price) and then calculating a property tax value (12.094% of the assessment value). This approach was based on information available from the New York City Department of Finance. The per-acre lease rate was then averaged across the properties from the JLL report data. This average was used as the assumed land lease cost in Load Zone J in lieu of escalating the 2021-2025 DCR study assumed values.

Table 26: Site Leasing Cost Assumptions ($2024)

	Load Zone J	Load Zone K	Load Zones C, F, and G
Land Requirement - Simple Cycle Options (acres)	12	15	15
Land Requirement - BESS 2-hour (acres)	6	9	10
Land Requirement - BESS 4-hour (acres)	9	12	14
Land Requirement - BESS 6-hour (acres)	12	16	18
Land Requirement - BESS 8-hour (acres)	15	20	22
Lease Rate ($/acre-year)	$717,000	$30,000	$26,000

d. Total Fixed Operations and Maintenance

The total fixed O&M expenses for all technology options including the fixed plant expenses, site leasing costs, and property insurance are shown in **Table 27**. As described below, property taxes and insurance are estimated separately as a percentage of total installed costs. Property taxes are not included in **Table 27**.

Load Zone J also includes a line item for an annual revocable consent payment associated with the underground interconnecting transmission line for all technology options. This allowance is estimated with guidance/equations from 34 RCNY Section 7-10. Note that the transmission line estimates for all other locations are based on an above ground line and the capital cost estimates include an allowance for ROW acquisition at $1 million per mile.

Table 27: Fixed O&M Estimates ($2024/kW- year)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies[1]						
1x0 GE 7HA.03 (Dual Fuel, with SCR)	$14.9	$14.9	$15.6	$17.0	$38.7	$17.9
1x0 GE 7HA.02 (Dual Fuel, without SCR)	$16.6	$16.6	$16.7	-	-	-
1x0 GE 7HA.02 (Dual Fuel, with SCR)	-	-	-	-	-	$18.7
Energy Storage[2]						
BESS 2-hour	$23.00	$23.24	$23.50	$24.43	$48.48	$25.75
BESS 4-hour	$37.14	$37.55	$37.90	$39.40	$75.55	$41.50
BESS 6-hour	$52.54	$53.07	$53.60	$55.75	$103.66	$58.66
BESS 8-hour	$67.02	$67.72	$68.33	$71.08	$131.05	$74.99

Notes:
[1] Based on degraded performance at ICAP conditions
[2] Based on 200,000 kW net output at point of interconnection.
[3] Fixed O&M reflects capacity augmentation costs assuming a 20-year operating lifetime for BESS technologies.

e. 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 applicable peaking plant technology option, reflecting the installed capital cost exclusive of any SDU costs.

Outside of Load Zone J, the effective property tax rate is assumed to be 0.6% for all fossil peaking plant technology options based on the assumption that the 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. A 0.75% rate was used in the prior two resets. However, a review of PILOT data available from the New York State Comptroller's Office indicated that 0.6% is a reasonable assumption for this study that is consistent with current PILOTs agreements for natural gas plants in New York.[26]

[26] The Office of the New York State Comptroller provides financial data for local governments, including Industrial Development Agencies (IDA). *See* Office of the New York State Comptroller, "Financial Data for Local Governments," http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm. AG identified PILOT agreements for 10 natural gas plants, with effective PILOT tax rates ranging from 0.15% to 5.63%, and the median value of these rates was 0.67%, calculated as the ratio of current PILOT payments to initial project dollar amount. Available data indicates that PILOT payments may not be fixed over time, with some increasing, some decreasing and some remaining constant over the duration of the PILOT agreement. These projects in the sample include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large combined cycle units. AG also reviewed PILOT agreements for 4 battery projects, with effective PILOT tax rates ranging from 0.03% to 1.92% with a median of 0.21%.

In New York City, the property tax rate equals 4.77%, which is equal to the product of (1) the Class 4 Property rate (10.592%) and (2) the 45% assessment ratio.[27]

However, the New York Real Property Tax Law Section 489-BBBBBB(3)(b-1) provides a 15-year tax abatement in New York City for the peaking plant underlying the NYC ICAP Demand Curve.[28] Accordingly, it is assumed that each fossil peaking plant technology option would receive this exemption and incurs taxes only for years 16 and beyond.[29] Notably, however, this Load Zone J specific tax abatement is currently scheduled to expire for construction activities occurring after April 1, 2025. The New York State Legislature recently passed a bill to extend the expiration to include construction activities occurring prior April 1, 2029. However, at time of issuing this report, the extension has not yet been acted on by the New York State Governor. AG and 1898 & Co. are continuing to monitor the status of the extension of this abatement. Although the abatement has initially been considered as applicable for the fossil peaking plant technology options in Load Zone J, if the abatement extension is not enacted, the application of this abatement will be revised with the 4.77% tax rate described above applied to all years of the assumed life of the fossil peaking plant technology options in Load Zone J.

Energy storage plants are provided a 15-year tax abatement statewide pursuant to New York Real Property Tax Law Section 487.[30] A 15-year property tax exemption is assumed for all battery storage plants in all locations for this study.[31] The property tax rate applicable to BESS options for any remaining portion of the assumed life of the plants is the 0.6% rate identified above for locations other than Load Zone J and the 4.77% rate identified above in Load Zone J.

Property tax rates assumed in this report are summarized in the table below:

[27] *See* New York City Department of Finance, "Property Tax Rates," https://www.nyc.gov/site/finance/property/property-tax-rates.page and New York City Department of Finance, "Determining Your Assessed Value," https://www.nyc.gov/site/finance/property/calculating-your-property-taxes.page
[28] *See* New York Real Property Tax Law Section 489-BBBBBB(3)(b-1)
[29] Any underlying level of real property tax on the land leased for the fossil peaking plant technology options in Load Zone J that is not covered by the abatement is assumed to be accounted for within the land lease rate.
[30] *See* New York State Department of Taxation and Finance, Exemption Administration Manual, Section 4.01, RPTL Section 487.
[31] Any underlying level of real property tax on the land leased for the battery storage peaking plant options that is not covered by the abatement are assumed to be accounted for within the land lease rate.

Table 28: Property Tax Rates by Technology

Technology	Load Zone J (NYC)		All Other Locations	
	Years 1-15	Years 16-20	Years 1-15	Years 16-20
Battery Storage	0.00%	4.77%	0.00%	0.60%

Technology	Load Zone J with Extended Abatement	Load Zone J without Extended Abatement	All Other Locations
	Years 1-13	Years 1-13	Years 1-13
Fossil Peaking Plant Technology Options	0.00%	4.77%	0.60%

AG assumes that the peaking plant technology options will qualify for available abatement of mortgage recording taxes through an appropriate arrangement with a tax-exempt industrial development agency/economic development corporation. However, these tax-exempt entities are not exempt from "additional mortgage recording tax" applicable to real property located in a county that is part of a transportation district.[32] As such, AG assumes that the peaking plant technology options will incur additional tax payments of 30 cents per $100 of mortgage debt for counties within the Metropolitan Commuter Transportation District (Load Zones G (Dutchess County), G (Rockland County), J, and K), and 25 cents per $100 of the mortgage debt for counties within the Central New York Regional Transportation District (Load Zone C) and the Capital District Transportation Authority (Load Zone F).[33] These tax payments are assumed to occur when the mortgage is recorded, prior to the plant being put into service.

f. Insurance

Insurance costs are estimated as 0.6% of the EPC capital cost. This same assumption was used for the last two DCRs. This cost assumption is also consistent with values identified from prior 1898 & Co. consulting experience in New York and elsewhere.

2. Variable O&M Costs

For fossil peaking plant technology options, variable O&M costs are directly related to plant electrical generation. Where applicable, variable O&M costs include routine equipment maintenance, makeup water, water treatment, water disposal, ammonia (if SCR emissions controls are included in the design), SCR catalyst replacements (if applicable), CO catalyst replacements (if applicable), and other consumables not including fuel. In the tables in Appendix A, variable O&M for water and SCR emissions controls related items are shown separately.

The fossil peaking plant technology options do not include demineralized water treatment systems in the EPC capital cost, so the O&M assumptions include temporary demineralized water trailers for treatment, as applicable.

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[32] New York State Department of Taxation and Finance, "Industrial Development Agencies and Authorities in Transportation Districts No Longer Exempt from the Additional Mortgage Recording Tax," https://www.tax.ny.gov/pdf/memos/mortgage/m16_1r.pdf
[33] New York State Department of Taxation and Finance, "Mortgage recording tax," https://www.tax.ny.gov/pit/mortgage/mtgidx.htm

Demineralized water is assumed for water injection for NO_x control for fuel oil operation on all fossil peaking plant technology options. This is reflected in the higher cost for water-related O&M for those cases. The GE 7HA.03 and GE 7HA.02 units have dry combustion on gas operation. Water consumed for inlet evaporative cooling is not demineralized. Raw water source is assumed to be well water for all locations except Load Zone J. In Load Zone J, use of municipal water is assumed at $6 per 1,000 gallons.

Wastewater and plant drains are collected in permanent onsite tanks for periodic removal using pump trucks. The variable O&M for fossil peaking plant technology options accounts for the pump truck, hauling, and disposal fees.

Major maintenance, shown in **Table 29**, for combustion turbines is broken out separately from routine variable O&M for all fossil peaking plant technology options. Combustion turbine major maintenance typically consists of combustion inspections, hot gas path inspections, and major inspections. Cost estimates account for a complete cycle through the first major inspection, based on manufacturer budgetary estimate information and 1898 & Co.'s experience.

Major maintenance costs for the frame engine options (GE 7HA.03 and GE 7HA.02) are dependent on the operating profile, so they may be based on dollar per gas turbine start ($/GT-start) basis or dollar per gas turbine hour of operation. In general, if there are more than 36 operating hours per start, the major maintenance cost will be hours based. If there are less than 36 hours per start, the major maintenance cost will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive. The operational profile determines whether the annual maintenance costs will be based on hours or starts for all fossil peaking plant technology options.

A summary of the non-major-maintenance variable O&M cost for each fossil technology option in each location is provided in **Table 30** and Appendix A. For the BESS options, the variable O&M costs in this study are intended to represent the variable component of capacity augmentation, accrued in terms of $/MWh discharged in the net EAS model. Variable O&M costs for BESS units are provided in **Table 31**. For BESS units, sales tax is included for materials and labor related to augmentation, so it is included as a variable O&M line item.

Table 29: Major Maintenance ($2024 USD)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fossil Peaking Plant Technology Options							
1x0 GE 7HA.03 (25 ppm, with SCR)	$/GT-hour	$650	$650	$650	$650	$650	$650
	$/start	$23,100	$23,100	$23,100	$23,100	$23,100	$23,100
1x0 GE 7HA.02 (15 ppm, without SCR)	$/GT-hour	$620	$620	$620	-	-	-
	$/start	$23,000	$23,000	$23,000	-	-	-
1x0 GE 7HA.02 (25 ppm, with SCR)	$/GT-hour	-	-	-	-	-	$620
	$/start	-	-	-	-	-	$23,000

Table 30: Natural Gas Variable O&M Costs ($2024/MWh)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fossil Peaking Plant Technology Options							
1x0 GE 7HA.03 (25 ppm, with SCR)	With SCR	$1.45	$1.45	$1.45	$1.45	$1.54	$1.50
1x0 GE 7HA.02 (15 ppm, without SCR)	No SCR	$0.90	$0.90	$0.90	-	-	-
1x0 GE 7HA.02 (25 ppm, with SCR)	-	-	-	-	-	-	$1.50

Notes:
[1] Excludes fuel consumed and revenues from electricity produced during start.
[2] Based on natural gas operation at 59°F/ 60% RH.

Table 31: BESS Variable O&M Costs ($2024/MWh)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K – Long Island
BESS Technology Options						
2-Hour Duration	$6.88	$6.89	$6.94	$7.00	$7.14	$7.10
4-Hour Duration	$6.53	$6.56	$6.59	$6.65	$6.78	$6.75
6-Hour Duration	$6.31	$6.32	$6.35	$6.42	$6.54	$6.51
8-Hour Duration	$6.43	$6.44	$6.48	$6.54	$6.66	$6.64

Notes:
[1] Variable O&M costs reflect the variable component of capacity augmentation costs levelized over the 20-year assumed lifetime of the BESS unit.

G. Operating Characteristics

The plant operating characteristics used to evaluate the fossil peaking plant technology options in each location 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 forced outage rate on demand (EFORd); and
- Plant startup time and fuel required for startup.

The net output and net heat rate for all the combustion turbine options are impacted by ambient conditions (temperature and relative humidity) and site elevations. The site elevations in each location are identified in **Table 32**.

Table 32 also provides the estimated ambient temperatures and relative humidity for the summer, winter, summer DMNC, winter DMNC, and ICAP for all fossil peaking plant technology options. The summer and winter ambient conditions in each location are determined at the average winter and summer conditions. The summer and winter DMNC ambient conditions are determined at the average of the ambient conditions in each respective zone recorded during the previous twenty NYCA peak periods. The ICAP ambient condition is defined as 90°F and 70% 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.

The detailed plant performance data for each technology option in each location is provided in Appendix A.

Gross performance ratings for GE 7HA.03 and GE 7HA.02 options are based on data requested from GE's online gas turbine performance estimator program at specific ambient conditions from **Table 32**. All performance ratings shown for the fossil peaking plant technology options are based on natural gas operation. Minimum load is defined as the minimum emissions compliant load (MECL), as reflected in the OEM ratings. Appendix A includes full load and minimum load performance estimates at the conditions identified in **Table 32**.

1898 & Co. adjusted these performance results for auxiliary loads, system losses, and performance degradation. Heat rates are calculated for higher heating value (HHV). 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. The plant performance degradation percentages used to calculate degraded output and heat rate from new and clean percentages for the fossil peaking plant technology options are shown in **Table 33**. These degradation adjustments are indicative of average degradation between overhauls, based on 1898 & Co. experience on past projects. The same adjustment values were also assumed for the 2017-2021 and 2021-2025 DCRs.

The net plant capacity and net plant heat rates at the ICAP ambient conditions (90°F and 70% relative humidity) for each location for the fossil peaking plant technology options are shown in **Table 34** and **Table 35**, respectively. Performance for all ambient conditions is provided in Appendix A. 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 plant.

Table 32: Ambient Conditions for 2025-2029 DCR

	Zone C	Zone F	Zone G-R	Zone G-D	Zone J	Zone K
Site Elevation	1099 FT	279 FT	492 FT	492 FT	10 FT	85 FT
ISO Conditions	59°F 60% RH	59°F 60% RH	59°F 60% RH	59°F 60% RH	59°F 60% RH	59°F 60% RH
ICAP Conditions	90°F 70% RH	90°F 70% RH	90°F 70% RH	90°F 70% RH	90°F 70% RH	90°F 70% RH
DMNC Summer Conditions	90°F 48% RH	92°F 46% RH	94°F 43% RH	94°F 43% RH	95°F 43% RH	92°F 50% RH
DMNC Winter Conditions	9°F 56% RH	10°F 59% RH	13°F 58% RH	13°F 58% RH	17°F 46% RH	20°F 50% RH

Table 33: Average Plant Performance Degradation over Economic Life

Plant	Average Degradation of Net Output	Average Degradation of Net Heat Rate
1x0 GE 7HA.03	3%	1.8%
1x0 GE 7HA.02	3%	1.8%

Table 34: Average Net Plant Capacity ICAP (kW)

Natural Gas (kW)	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with SCR)	389,000	400,300	397,400	397,400	404,100	404,000
1x0 GE 7HA.02 (without SCR)	321,026	330,682	328,126	-	-	-
1x0 GE 7HA.02 (with SCR)	-	-	-	-	-	352,992

Note:
[1] Based on degraded ICAP performance. Degradation not included.

Table 35: Average Net Plant Heat Rate ICAP (Btu/kWh)

Natural Gas (Btu/kWh)	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with SCR)	9,070	9,060	9,070	9,070	9,060	9,060
1x0 GE 7HA.02 (without SCR)	9,183	9,173	9,173	-	-	-
1x0 GE 7HA.02 (with SCR)	-	-	-	-	-	9,242

Note:
[1] Based on degraded ICAP performance. Degradation not included.

Table 36: BESS Net Power at POI (MW)

Net Power (MW)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Energy Storage						
BESS 2-hour	200	200	200	200	200	200
BESS 4-hour	200	200	200	200	200	200
BESS 6-hour	200	200	200	200	200	200
BESS 8-hour	200	200	200	200	200	200

Notes:
[1] BESS is sized for 200 MW net at the POI. Energy discharge capability is maintained through capacity augmentation throughout the assumed project life.
[2] Heat rate is not applicable to BESS units because fuel is not directly consumed.

For the fossil peaking plant technology options, 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."[34] The North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS) continuously collects availability/reliability data from more than 5,000 power plants in North America. The data is organized by plant type, size ranges and plant age ranges. 1898 & Co. included EFORd data extracted from NERC GADS based on the performance since 2018 for units that are no more than 10 years old. Based on NERC GADS data, 1898 & Co. recommends a derating factor of 4.1% for the fossil peaking plant technology options. This value is somewhat higher than the 2.9% EFORd assumed in the 2021-2025 DCR.

Based on capacity market rules for energy storage resources, the capacity derating factors for battery units will be calculated based on an Upper Operating Limit (UOL) metric, which depends on both forced outages and average state of charge.[35] Based on OEM data on the expected forced outage rates for new battery installations, a 2% outage rate is assumed for all of the BESS options. This outage rate is somewhat lower than the 3% outage rate assumed in the 2021-2025 DCR.

The original equipment manufacturers provided start-up times and start up curves that were used to calculate the start-up fuel consumption for the fossil peaking plant technology options. The start-up data is included in Appendix A. For the fossil peaking plant technology options, both conventional start- up and fast start- up information is provided. The GE 7HA.03 and GE 7HA.02 units can achieve full output in 10 minutes.

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 upfront capital investment is assumed to be recovered. Section

[34] *See* IEEE-SA Standards Board, "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity," IEEE Standard 762-2006, published March 15, 2007.
[35] NYISO, "Capacity Market Rules for Energy Storage Resources," presentation to the Installed Capacity Working Group, August 23, 2018.

III.B describes the translation of these up-front capital costs, along with time-varying tax costs, into a levelized fixed charge (i.e., an annual carrying charge) that allows full recovery of the plant's capital costs over the course of the plant's assumed 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 supply resource requires the upfront investment of new capital to construct 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 location evaluated. Subtracting the estimated annual net EAS revenues from this annualized gross CONE value produces the annual reference value (ARV), which is often referred to as the net CONE value. 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:

- The weighted average cost of capital required by the developer, based on the developer's required cost of equity (COE), its cost of debt (COD), and the project's capital structure, as reflected in the ratio of debt to equity (D/E ratio);
- The term, in years, over which the project is assumed to recover its upfront investment, referred to as the amortization period (AP); and
- 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 and policy context. While we discuss each item separately below, ultimately our selection of the parameters making up the assumed WACC and the AP is based on an evaluation of how these parameters, in combination, reflect the financial risks of project development.

The selection of these financial assumptions should capture industry expectations about capital 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 in input (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, revenues and the operability of the facility; 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. AG'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 sources of information identified and described below; past professional experience, including conversations with independent power producers and the finance community; and AG's view of industry conditions, market factors, and relevant state policy at the time of this study, including past experience with merchant development in the NYISO markets.

AG also presents its thoughts on some of the key perspectives with respect to development approaches and key existing and emerging development, market, and regulatory risks that are needed to interpret available data and information. Finally, AG presents its recommended assumptions for WACC and AP based on our careful review of all of these factors from the perspective of potential 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 of and on investment. In the context of the DCR, 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. The AP, often referred to as the "economic life" of the asset, can differ from the plant's expected physical or operational life. While the physical life of the plant reflects the expected length of time the plant will remain in operation (usually before major overhauls would be required), the economic life can differ due to financial considerations, particularly risks associated with assuming future revenue streams in light of market, regulatory, and technological uncertainties.

The AP must balance risks over the full physical life of the plant. On the one hand, plant owners will earn net revenues over the full physical life of the plant (while incurring costs for component replacement and maintenance overhauls over time). Based on extensive operating experience, an expected physical life of at least thirty years is reasonable for a fossil peaking plant technology options.[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.

Consistent with the 2021-2025 DCR, for fossil peaking technology options, we recommend an assumed AP that reflects the requirement of the CLCPA that all load in New York be supplied by zero-emissions resources as of 2040.[37] In principle, the owner of a fossil generating facility constructed now could implement plant modifications prior to 2040 that would allow the plant to continue to operate, for example, by using a zero-carbon fuel (e.g., hydrogen) in place of the current fossil fuels. While we recognize this may be possible, the technology and/or markets to accomplish this and continue to operate in compliance with the CLCPA beyond 2039 cannot be assumed to exist at this time. Thus, the developer of a fossil peaking plant would face substantial uncertainty about the financial returns of a fossil peaking plant under the CLCPA starting in 2040, given the uncertain availability and cost of zero-emission technologies, markets, and alternative fuels.

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[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.
[37] New York State, Chapter 106 of the Law of 2019. Requirements established by the CLCPA include: (1) a goal to reduce GHG emissions 85% over 1990 levels by 2050, with an incremental target of at least a 40% reduction by 2030; (2) producing 70% of electricity from renewable resources by 2030 and 100% from zero-emissions resources by 2040; (3) increasing energy efficiency by 23% over 2012 levels; (4) building 6 GW of distributed solar by 2025, 3 GW of energy storage by 2030, and 9 GW of offshore wind by 2035; (5) electrification of the transportation sector, as well as water and space heating in buildings.

To evaluate amortization periods for the fossil peaking plant technology options in light of the CLCPA's 2040 zero-emissions energy requirement, we estimate the number of years over which lenders and investors would seek to recover their investment given the fossil peaking plant technology options considered for this DCR. We do not assume upgrades, modifications or other future design changes to the fossil peaking plant technology options that could potentially facilitate continued operation as a zero-emission resource beginning in 2040. This time period will vary depending on when a fossil peaking plant commences operations. For example, the developer of a fossil-fueled peaking plant that begins operation at the start of the first Capability Year encompassed by this DCR (i.e., commencing operation on May 1, 2025) should not expect an operating life exceeding approximately 14.7 years (i.e., the time between May 1, 2025 and December 31, 2039) without plant retrofits to remain compliant with the CLCPA's zero-emission requirement beginning in 2040. Similarly, a new fossil-fueled plant commencing operations at a later point in time would expect to operate for a shorter economic life. **Table 37** shows the economic life the fossil peaking plant technology options could reasonably assume depending on the Capability Year encompassed by this DCR in which the fossil-fueled peaking plant commences operations.

Given these factors, AG recommends an AP of 13 years for all fossil peaking plant technology options in all locations. This is an appropriate assumption given the balance of risks and uncertainty faced by fossil-fueled peaking plant project developers in New York markets. As shown in **Table 37**, 13 years represents the average economic operating life of the fossil peaking plant technology options over the four-year period covered by this DCR.

An amortization period of 13 years for all fossil peaking plant technology options strikes a reasonable balance between many considerations, including the general regulatory and technological risk faced by investors in fossil fuel resources within New York, the specific operational limits posed by the CLCPA regarding fossil fuel use for electricity generation beginning in 2040, and the uncertainty that exists at this time regarding the availability and cost of conversion technologies and/or fuels that may or may not be available to extend a plant's economic life beyond 2039. Moreover, a 13-year amortization period is consistent with the method recommended by AG in the 2021-2025 DCR, which was accepted by FERC in an order issued on May 19, 2023 in Docket No. ER21-502.[38]

Table 37: Potential Economic Operating Life of Fossil Plants

Capability Year	Potential Operating Life of Fossil Peaking Plant Technology Options	Average Operating Life of Fossil Peaking Plant Technology Options over 4 Capability Years
2025-2026	14.7 Years	13.2 Years
2026-2027	13.7 Years	
2027-2028	12.7 Years	
2028-2029	11.7 Years	

Note: [1] The potential commercial operating life was calculated by counting the number of years between May 1 of each applicable Capability Year and January 1, 2040.

The BESS options face a different set of considerations than the fossil peaking plant technology options. Unlike fossil plants, battery storage plants do not face the same regulatory constraints from the CLCPA that would limit

[38] New York Independent System Operator, Inc., 183 FERC, Docket No. ER21-502, ¶ 61,130 (May 19, 2023).

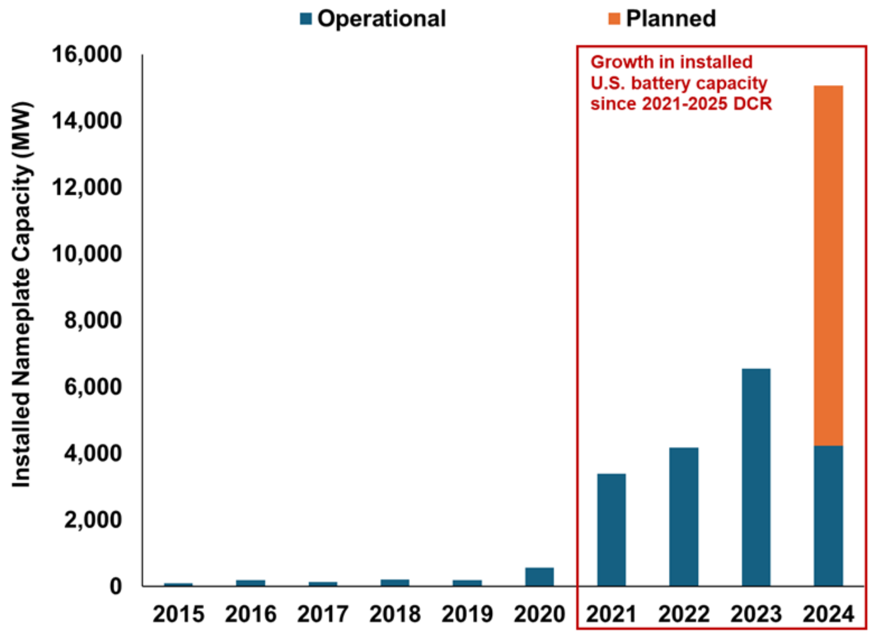
future operations beyond 2039. Given this, we recommend an AP for battery storage technologies of 20 years. This recommendation reflects several considerations.

First, a 20-year amortization period is consistent with the typical expected operating lifetime of a utility-scale lithium-ion battery. Consistent with 1898 & Co.'s industry experience, 20-year warranties and performance guarantees for battery performance are now common in the industry. Additionally, on-going battery augmentation assumed in BESS fixed and variable O&M costs for this study would maintain plant energy output capability over the assumed economic life of twenty years. This assumption mitigates degradation of BESS capability. However, the BESS equipment would be expected to require replacement with new equipment after the 20-year warranty period, so a 20-year amortization period ensures recovery of investment before more substantial upgrades beyond typical augmentation may be required.

Second, the U.S. electricity sector has gained substantial experience with the development of BESS since the last reset. For the 2021-2025 DCR, we recommended a 15-year amortization period for a combination of factors, including uncertainties from limited operating experience and the potential for technology performance improvements. Since that time, there has been substantial growth in U.S. BESS deployment that mitigates these uncertainties. As depicted in **Figure 6**, there is nearly 20 GW of BESS in service today, with the vast majority placed in service since the last reset.[39] Further, significant quantities of additional capacity are currently under development.[40] Thus, the increased operating experience of BESS technologies has diminished uncertainties present for the 2021-2025 DCR that supported the recommendation of a 15-year amortization period for BESS.

[39] Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), June 2024, available at: https://www.eia.gov/electricity/data/eia860m/.
[40] Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), June 2024, available at: https://www.eia.gov/electricity/data/eia860m/.

Figure 6. Annual U.S. Additions in Battery Capacity



Source: [1] U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory, based on Form EIA-860M.

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 and equity capital to their sum – and their "costs" – that is, the cost of debt and the required return on equity. Notably, an entity will choose the appropriate capital structure for a given project based on the expected costs of debt and equity, which, in turn, will vary depending on the chosen project's capital structure, because this structure affects the likelihood that debt will be paid and equity will receive return of and on investment. Thus, the return on equity, cost of debt and capital structure are closely inter-related.

The appropriate WACC for use in the DCR needs to reflect the project-specific risks associated with the development of a new peaking plant by a merchant developer within the NYCA in the timeframe of interest in this DCR (i.e., 2025-2029) under conditions of a need for new capacity as required by the tariff-prescribed level of excess conditions assumed for purposes of the DCR. However, data are not available to directly observe the WACC for such a project and conditions. As a result, AG developed its recommended WACC based on data from a number of different sources.

Our primary source of information is financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets – that is, independent power producers (IPPs). Merger and acquisition activity involving IPP firms has affected the availability of information on these firms. In particular, the purchase of publicly traded firms by private firms limits data availability, even if those firms subsequently are listed publicly at a later date.[41] AG's assessment considers this data, with an understanding that project-level and company-level WACC values will differ when specific projects are more or less risky than the company as a whole.[42]

AG also considers a variety of other sources of information, including estimated WACCs for publicly traded companies developed by financial analysts (e.g., in the context of so-called "fairness opinions") and independent assessments of capital costs and the costs of merchant plant development. These independent assessments include information on the WACC under different corporate structures, including "project finance," in which the project is financed as a stand-alone entity without recourse to a company's balance sheet.

AG's recommendations are based on its professional judgment, reflecting the information and data identified below; past professional experience, including conversations with IPPs and 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 this data, AG views the appropriate WACC for a new peaking plant as being informed by both the WACCs for IPP firms and the appropriate assumptions and adjustments needed to capture stand-alone project factors, including factors specific to New York and each technology evaluated for this study. 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.[43] The WACC for a new merchant project may exceed that of publicly-traded IPP companies because, for example, these companies have portfolios of assets that balance and mitigate risks, and thus lower the overall WACC at the company level. 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. By contrast, publicly available information on financing arrangements for individual projects, whether through stand-alone project finance or via a corporate balance sheet, is limited. Regardless, information on capital costs from corporate IPPs can inform choices about the appropriate WACC for a peaking plant, recognizing the need to account for project-specific risks.

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[41] For example, Talen Energy was formed in June 2015, taken private in in December 2016 and subsequently publicly relisted in May 2023. *See* Munawar, Adnan, "Riverstone completes $5.2B acquisition of Talen Energy," S&P Global Market Intelligence, December 6, 2016, https://www.spglobal.com/marketintelligence/en/news-insights/trending/5183c2giwe8eid5el82qva2 and "Talen Energy Corporation Announces Listing to OTC Pink Market," available at:https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-corporation-announces-listing-otc-pink-market . Energy Capital Partners purchased Calpine in March 2018. *See* Energy Capital Partners, "Consortium Led by Energy Capital Partners Completes Acquisition of Calpine Corporation; Announces Management Roles and Board of Directors," March 8, 2018, https://www.ecpartners.com/news/consortium-led-by-energy-capital-partners-completes-acquisition-of-calpine-corporation-announces-management-roles-and-board-of-directors. Vistra Energy acquired Dynegy in April 2018. *See* Vistra Energy, "Vistra Energy Completes Merger with Dynegy," April 9, 2018, https://investor.vistraenergy.com/investor-relations/news/press-release-details/2018/Vistra-Energy-Completes-Merger-with-Dynegy/default.aspx.]] In 2022, Constellation Energy was spun off from Exelon Corporation. *See* Constellation, "About Constellation," https://www.constellationenergy.com/our-company/our-story/about-constellation.html.

[42] "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.

[43] 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, Richard, Steward Myers, and Franklin Allen, *Principles of Corporate Finance*, Ninth Edition, New York: McGraw-Hill/Irwin, 2008, p. 240.

In developing our recommended WACC for the peaking plant technology options evaluated for this study, we take into account technology-specific considerations and risks. BESS options face certain unique financial risks. *First*, battery storage faces physical performance risks. Battery storage operation – generally and within New York – faces uncertainties affecting the expected economic and physical lifetime of new battery units, including the potential for cell degradation, wear and tear on balance-of-system components, uncertain market dispatch outcomes, and potential variations in operational modes and uses in system operations. As discussed in Section II, we partly address some of the uncertainties associated with future battery operations by analyzing battery storage plants in which the augmentation costs to counter battery cell degradation over an extended timeframe are captured, in part, by O&M costs (with components of such augmentation costs allocated to both fixed and variable O&M), an assumption of initial overbuild captured in up-front capital costs, and recognition that battery projects are backed by twenty-year warranty and performance guarantees.

Second, battery storage faces market performance risks. One such risk arises because battery storage is still a relatively early-stage technology likely to experience further improvements in operational performance, particularly cycling energy losses. Thus, the first wave of battery storage plants to operate in New York may be less competitive than battery units that enter the market at a later date with more advanced and/or efficient technologies. This potential reduced competitiveness may translate into lower expected net revenues over time, particularly toward the end of the assumed life of the asset. These technology effects are more significant for battery technologies, given their early state of technological development, compared to the fossil peaking plant technology options.

Third, there is market risk related to Capacity Accreditation Factors (CAFs) that are used in determining the quantity of UCAP a resource can supply. Going forward, CAFs will vary each year depending on the mix of resources in the system, load profiles and other factors. As the demand curves used in conducting the NYISO's monthly spot auctions are expressed on a UCAP rather than ICAP basis, CAF changes for the peaking plant technology used to establish each curve would lead to shifts in the demand curve and clearing price that would tend to offset the effect of any future declines in the CAFs for such peaking plant technology during the four-year period of this reset. Thus, the financial risk of CAF changes for the 2025-2029 DCR reset period is mitigated for the peaking plant technology selected to establish each demand curve. Under certain circumstances, changes in CAFs can affect future capacity market revenue streams. In particular, if the peaking plant technology were to change in a future reset to a technology that experienced CAF changes uncorrelated with batteries (e.g., the CAFs of a potential future peaking plant technology remained fixed while the prior CAFs of the technology previously utilized to set the curves declined), then future CAF values beyond the four-year period of this reset could reduce the future revenue earnings of a battery. However, future CAF values are unknown given potential temporal and geographic variations in the expansion of, for example, battery storage technology and intermittent renewables in New York, which could tend to have countervailing impacts on battery storage CAFs depending on the timing, magnitude, and types of future resource additions.

AG's recommended financial parameters are intended to capture incremental financial risk associated with BESS projects. AG considered potential differences in financial risk between BESS projects of varying output durations given, among other things, their potential differences in future CAF values. For example, a longer-duration battery storage plant could in theory experience relatively more stable future CAF values, and thus lower financial risk, than a 2-hour battery storage plant. Given existing evidence on CAF variation and heterogeneity in the many factors affecting financial parameters, AG is not persuaded that BESS financial parameters should be differentiated by BESS duration at this time. Moreover, even if we believed differences in this single risk factor could warrant a downward adjustment to the financial parameters for longer-duration BESS at this time, this would not affect our recommended peaking plant technology or associated reference point prices, as these longer-duration BESS would still be substantially more costly than the 2-hour BESS..

Development of a fossil-fired peaking plant in New York State would also face certain unique risks. For example, the state's objective to decarbonize the electricity sector could lead to policies that make fossil-fired resources less competitive than alternatives (*e.g.*, the potential implementation of a future "cap-and-invest" program for the state's broader economy) prior to the CLCPA's requirement for electricity load to be served 100% by zero-emissions resources starting in 2040.

All else equal, rational investors demand a higher remuneration for their capital when they face higher risk, especially if the risk cannot be diversified. Therefore, the technology-specific risks described above are likely to affect the WACC. Below, AG evaluates the individual financial parameters that bear on the recommended WACC based on publicly available information, recognizing the interrelationships among these parameters in determining the WACC, and the need for adjustments for project-specific and technology-specific risks that are not publicly observable.

Cost of Debt ("COD")

The cost of debt reflects a project developer's ability to raise funds on debt markets. **Table 38** below reports the cost of debt measured as the average yield to maturity of long-term bonds observed between June 2, 2024 and August 31, 2024 for four power companies with meaningful ownership of merchant units: AES, Constellation, NRG, and Vistra. Those companies are publicly traded and, therefore, have the advantage of providing sufficient information to compute the COD (and, as explained below, the cost of equity capital). We refer to these companies as the "Proxy Group" for this study. Between June 2, 2024 and August 31, 2024, the average yield to maturity of these bonds has ranged from 5.43% to 6.32%.[44] Further details on these debt issuances are provided in Appendix B.

Two out of the four companies listed above have below-investment grade long-term debt credit ratings as of August 31, 2024 (NRG and Vistra are both rated BB). AES and Constellation have credit ratings above investment grade (equal to BBB- and BBB+, respectively) as of August 31, 2024.

AG also considered data on the generic cost of corporate debt.

Figure 7 below provides the generic corporate COD for companies with BBB, BB, and B credit ratings. The figure shows that the COD decreased following actions by the Federal Reserve to lower interest rates following the

[44] We estimate the reported yields to maturity following the following steps. First, we obtain fixed income securities with remaining maturity between 5 and 20 years after August 31, 2024 issued by AES, NRG, Constellation, Vistra, and their current (as of September 12, 2024) subsidiaries based in the U.S. with relevant energy generation involvement (excluding vertically integrated utilities). Second, for each unique combination of issuer–seniority–expiration date, we select the Committee on Uniform Securities Identification Procedures (CUSIP) number with the largest amount of mid-price yield data available in Bloomberg for the June 2, 2024-August 31, 2024 period. Third, within each issuer and for each day from June 2, 2024 to August 31, 2024, we compute the weighted average daily mid-price yield to maturity, where the weights are the total outstanding face value of each security. Finally, we compute the "average yield to maturity" reported above as the simple average of the obtained weighted daily yields.

COVID-19 outbreak, with rates falling below 4% for BB-rated debt. In 2022, rates for BB-rated debt started to increase gradually following the increases in interest rates by the Federal Reserve. Towards the end of 2022, rates for BB-rated debt stabilized between 6 and 8%. Between June 2, 2024 and August 31, 2024, the average yield to maturity for B, BB, and BBB Bonds is 7.16%, 6.08%, and 5.45%, respectively.

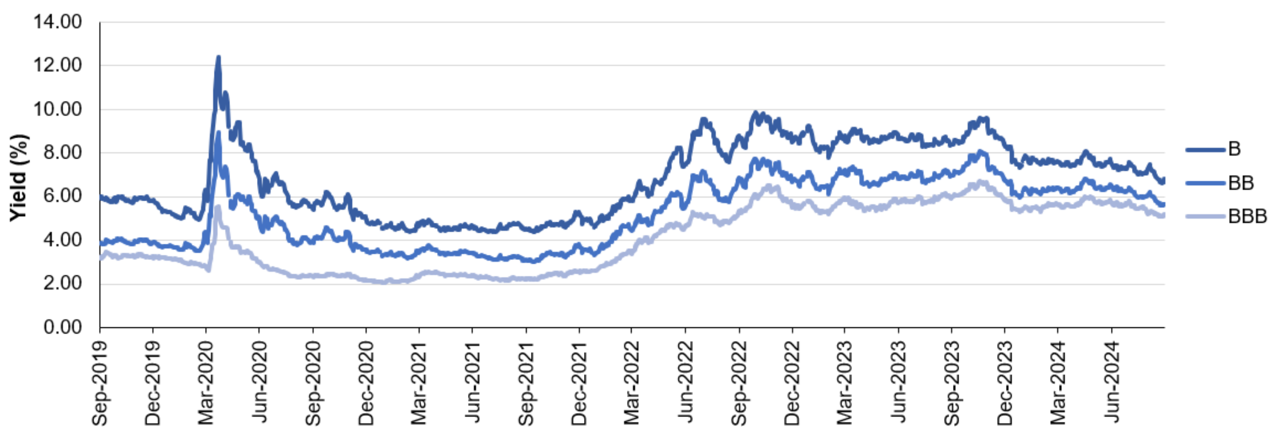
Based on these factors, AG recommends a COD of 7.20% for BESS units. This recommendation reflects a number of factors, including: risks consistent with B-rated debt issues; recent corporate debt costs; differences between COD to IPPs (**Table 37**) relative to generic debt indices (**Figure 5**) (for comparable levels of credit quality); and differences between corporate and project-specific risks (controlling for comparable B-rated riskiness). For the fossil-fired resources SCGT units, we recommend a COD of 6.70%. This recommendation reflects similar considerations to our BESS recommendation, but the assumption of slightly lower technology-risks and the yield of debt issues with ratings between BB- and B-.

Table 38. Bond Yields of Representative IPP Companies, June 2, 2024 through August 31, 2024

Company	Credit Rating	Average Yield to Maturity
AES	BBB-	5.43
Constellation	BBB+	5.58
NRG	BB	5.95
Vistra	BB	6.32
Average	**n/a**	**5.82**
Median	**n/a**	**5.77**
Min	**BB**	**5.43**
Max	**BBB+**	**6.32**

Notes: S&P Capital IQ; Bloomberg Data License.

Figure 7: Bond Yields for B, BB, and BBB Bonds, September 2019 - August 2024



Source: Federal Reserve Bank of St. Louis, FRED, ICE BofA US High Yield Index Effective Yield (series BAMLH0A2HYBEY, BAMLH0A1HYBBEY, and BAMLC0A4CBBBEY).

Cost of Equity ("COE")

The COE is the cost incurred to remunerate equity investors for their required return on equity (ROE) on their investment. Our recommended COE is developed primarily relying on estimated cost of equity capital for the Proxy Group described above. For reference, in the 2021-2025 DCR, AG evaluated the cost of equity for two companies within the current Proxy Group, NRG Energy and Vistra Energy. The Proxy Group used in this study includes up to four IPPs, in part, thanks to increased data availability.

We estimate the COE using the Capital Asset Pricing Model (CAPM).[45] **Table 39** reports the estimated COE values under several scenarios.[46] Each scenario is based on different assumptions used to estimate key parameters of the COE, such as beta, different subsamples of IPPs, and different Equity Risk Premia (ERP). Appendix B provides further details on each scenario and on the computation of COE under the CAPM. As these companies' business activities extend outside of merchant power generation and their generation asset holdings reflect a portfolio of assets with various vintages (and contract structures), their cost of equity is not necessarily directly comparable to the required cost of equity for a new peaking plant project in New York.

Table 39: Cost of Equity for Publicly Traded IPPs

Scenario	Beta Computation	Sample IPPs	Range of COE values using ERP of 5.00%	Range of COE values using ERP of 7.44%
1	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG, AES	10.45% - 10.82%	13.55% - 13.92%
2	Computed using ValueLine (5 years, weekly observations)	Vistra, NRG, AES	10.64% - 11.01%	13.83% - 14.20%
3	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG	11.45% - 12.15%	15.20% - 15.90%
4	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES, Constellation	10.02% - 10.51%	12.97% - 13.46%
5	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES	9.57% - 9.94%	12.25% - 12.62%

Notes: COE estimates are obtained using the CAPM based on a risk-free rate of 4.45%, computed as the 90-day Average of the Twenty-Year Treasury Constant Maturity Rate. "Scenario" describes the scenario considered in the computation of the COE, as detailed in Appendix B. "Beta Computation" describes the way levered betas are obtained. "Sample IPPs" describes the set of IPP used in the computation of COE. "Range of COE values using ERP of 5.00%" and "Range of COE values using ERP of 7.44%" report the COE value ranges obtained under each scenario using an Equity Risk Premium ("ERP") of 5.00% and 7.44%, respectively.

[45] Other approaches not used include the Discounted Cash Flow (DCF) and historical risk premium. Similarly, AG notes that utility regulators may consider a variety of information and models (including CAPM, DCF, or historical risk premiums) when setting the COE for regulated utilities. Therefore, AG did not consider a comparison of CAPM estimates of COE for regulated utilities when estimating the relevant COE for a merchant power plant developer. This choice is consistent with the assumption that the rate of return for a "safer" project is not the same as the return for a riskier project that does not benefit from guaranteed cost recovery.
[46] The values reported in this table assume average levered betas. See Appendix B for a wider set of estimates obtained using different beta values.

In developing our estimates, we note independent estimates of the COE for new power plants developed in other, but related, contexts. Net CONE studies in neighboring markets provide a benchmark for comparison. PJM and ISO-NE have used COEs ranging from 12.8% to 13.8% in recent net CONE studies.[47] These values reflect different methodologies and data sources. Our recommendations also reflect certain publicly available sources of information on project financing, as well as other information gathered through related professional activities.

In general, new investment in a peaking plant in New York faces a mix of market and regulatory risks that could increase or decrease future returns. Future policy and regulatory changes may affect market conditions, including: changes in loads, particularly in light of new loads (e.g., data centers) and policy efforts to increase electrification of heating and transportation; the mix of resources in the NYCA system given legislative changes, such as the CLCPA and policies to achieve its ends (e.g., potential procurements by state agencies, such as the New York State Energy Research and Development Authority); and technology-specific changes in CAFs given these changes in loads and system resources. Market outcomes may also change due to modifications to NYISO market rules over time, such as initiatives targeting potential ancillary service enhancements. Our assessment accounts for these various considerations, along with the general risks facing new merchant investment.

Based on this information, for the BESS options, AG recommends a COE of 14.5%, reflecting a balance between the IPP values (which range from 9.57% to 15.90%) and project-specific considerations. For the SCGT options, AG recommends a COE of 14.0%, which also reflects a balance between the IPP values and project-specific considerations, including the recognition of a differential in risk to equity for the SCGT options relative to the BESS options.

Debt to Equity Ratio

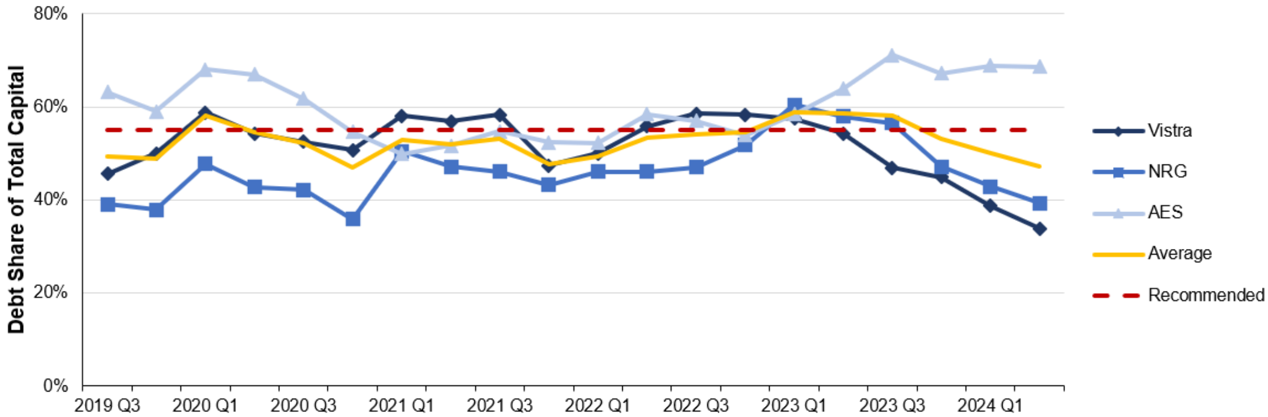
The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of the capital supporting the investment. Thus, a merchant peaking plant project could reasonably be developed through a range of capital structures.

AG recommends a D/E ratio of 55% debt to 45% equity given a balance of tradeoffs involved with greater or lesser leverage. Our assumption reflects the inter-relation of the capital structure with the cost of debt and return on equity, and different approaches to project development (e.g., balance sheet and project finance), and accounts for various indirect costs of financing (such as financial hedges) implicitly and not explicitly. **Figure 8** shows the debt share of capital for AES, NRG, and Vistra, along with their average, over the past 5 years.[48] In early 2024, corporate capital structure was similar across the proxy group companies and in line with our recommendation. Since, capital structures have diverged somewhat, while their average across companies maintains a value consistent with our recommendation. While a corporate level capital structure is not necessarily informative to the capital structure for a given project, it does inform the capital structure for assets in the industry which is relevant to

[47] Appendix B reports a list of these recent studies.
[48] The market value of equity is calculated as enterprise value minus cash and cash equivalents; data for the calculations is from S&P Capital IQ.

new project capital structure. Our recommendation is consistent with the capital structure adopted in recent similar studies for ISO-NE and PJM, which assume values similar to 55% in each study.[49]

Figure 8: Debt Share of Total Capital for Representative IPP Companies, Q3 2019 to Q2 2024



Note: Debt share of Total Capital is equal to net debt divided by the sum of net debt and the market value of equity. Source: S&P Capital IQ (obtained by AG)

Calculation of the WACC

AG's assessment of factors related to the calculation of the WACC has considered the data on the following: COE, COD, and D/E ratios presented above; facts and circumstances unique to the NYISO markets, including the extent of past experience with merchant development; the rapidly-changing nature of federal and state energy and environmental policies, including passage of the CLCPA; and likely project/ownership structures for new peaking plant development in New York. The calculation of the before-tax WACC is shown in equation 1.

$$WACC = Debt\ Ratio * COD + (1 - Debt\ Ratio) * ROE \qquad (1)$$

The ATWACC is calculated as shown below in equation 2:

$$ATWACC = Debt\ Ratio * COD * (1 - composite\ tax\ rate) + (1 - Debt\ Ratio) * ROE \qquad (2)$$

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 21%), corporate New York State tax rates

[49] *See, e.g.,* ISO New England Inc. and New England Power Pool, Docket No. ER24- -000; Targeted Adjustment to Certain Forward Capacity Market Parameters to Reflect the Minimum Offer Price Rule Elimination, *dated* November 15, 2023; The Brattle Group, PJM Cost of New Entry: Estimates for Combustion Turbines and Combined Cycle Plants in PJM with June 1, 2018 Online Date, report prepared for PJM Interconnection, L.L.C., May 15, 2014; ISO New England, Inc., 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, April 1, 2014; Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis, report prepared for ISO New England, Inc., January 13, 2017.

(6.5%),[50] and, for Load Zone J, the New York City business corporation tax rate (8.85%).[51] These tax rates result in composite income tax rates of 33.13% (NYC) and 26.14% (all other locations).[52]

Using these equations and the considerations presented above, for the BESS options, AG recommends a WACC of 10.49%, based on a debt ratio of 55%, a COD of 7.20%, and a COE of 14.50%. This results in a nominal ATWACC of 9.45% in NYCA, LI, and the G-J Locality, and 9.17% in NYC. For the SCGT options, AG recommends a WACC of 9.99%, based on a debt ratio of 55%, a COD of 6.7 %, and a COE of 14.0%. This results in a nominal ATWACC of 9.02% in NYCA, LI, and the G-J Locality, and 8.76% in NYC.

The recommended ATWACC is consistent with previous and currently approved cost of capital values in NYISO and other neighboring market (e.g., ISO-NE and PJM) for net CONE evaluations utilized for capacity market purposes, which range between 7.5% and 8.89%.[53]

The ATWACC proposed for this DCR reflects a combination of factors. Relative to the other ISOs/RTOs, developers within New York 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, potentially more challenging siting and development opportunities within New York, and potential operational and price impacts of the state’s move towards power sector decarbonization over the next two decades. Relative to the 2021-2025 DCR, the slightly higher ATWACC reflects the slightly lower cost of debt, the higher risk-free rate, the changes in tax law, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments.

B. Levelization Factor

To estimate the ARV, it is necessary to translate one-time installed capital costs into an annualized cost over the assumed 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. AG 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., availability of a 15-year property tax abatement for battery storage options in all locations and the potential availability of a 15-year tax abatement for fossil peaking plant technology options in Load Zone J).

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.[54] Second, the net present value

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[50] *See* New York State Department of Taxation and Finance, Form CT-3/4-I.
[51] *See* New York City Department of Finance, “Business Corporation Tax,” http://www1.nyc.gov/site/finance/taxes/business-corporation-tax.page.
[52] The composite rate reflects the fact that state and local taxes are deductible from federal corporate taxes.
[53] Appendix B reports details on previous and currently approved cost of capital values.
[54] Similarly, using the required cash flow to equity, income taxes can be calculated as:

$$\boldsymbol{Income\ Tax} = \frac{\boldsymbol{t}}{\boldsymbol{(1-t)}} * (\boldsymbol{Cash\ Flow\ to\ Equity} + \boldsymbol{Principal\ Debt\ Payments} - \boldsymbol{Depreciation})$$

of the total carrying costs is levelized over the assumed economic life of the plant 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 COE, are expressed in constant real 2024 dollars. Capital costs were estimated by 1898 & Co. as of Q2 2024, so will be escalated to reflect costs as of Q2 2025, when the 2025-2026 Capability Year (which runs from May 1, 2025 - April 30, 2026) begins. The difference between Q2 2025 and Q2 2024 is 4 quarters, or 12 months, so the cost escalation factor applied to the Q2 2024 capital costs will reflect cost escalation as of the last 12 months of available data.

The analysis assumes forward-looking inflation of 2.12% annually in both capital costs and net EAS revenues. 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 Q1 2024,[55] as well as long-term inflation in electricity prices as reported by the EIA Annual Energy Outlook.[56]

Table 40 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.

Table 41 provides depreciation schedules based on the Federal Internal Revenue Service (IRS) Publication 946 and follow the half-year convention. Fossil peaking plant options are depreciated with a 15-year schedule, and BESS options are depreciated with a 5-year schedule.[57] For BESS units, IRS guidance requires that the depreciable tax basis must be reduced by 50% of the value of the credit.[58] As such, we subtract 50% of the “gross” ITC value from the depreciable tax basis prior to calculating tax depreciation, where the “gross” ITC value is defined as the ITC credit percentage (30%) multiplied by total project costs and the eligible basis allowance percentage (as described in Section II).

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[55] The Survey of Professional Forecasters forecast headline CPI of 2.24% between 2024-2033 and headline PCE of 2.00% between 2024-2033. *See* Federal Reserve Bank of Philadelphia, “First Quarter 2024 Survey of Professional Forecasters,” February 9, 2024, https://www.philadelphiafed.org/-/media/frbp/assets/surveys-and-data/survey-of-professional-forecasters/2024/spfq124.pdf
[56] *See* EIA Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 3: Energy Prices by Sector and Source. The EIA forecasts real price growth for residential electricity of -0.2% for the period 2022 to 2050 and nominal price growth of 2.2% for the Nation as a whole. For the mid-Atlantic, which includes portions of the PJM footprint in addition to New York, the EIA AEO forecasts real growth of 0.4% and nominal growth of 2.7%.
[57] Under the Inflation Reduction Act, battery units qualify for a 5-year MACRS depreciation schedule. For additional information, see: https://www.irs.gov/credits-deductions/cost-recovery-for-qualified-clean-energy-facilities-property-and-technology#qualified
[58] IRS (Internal Revenue Service), “Instructions for Form 3468 (2023),” https://www.irs.gov/instructions/i3468

Table 40: Summary of Financial Parameters by Location

Finance Category	NYCA	G-J	NYC	LI	NYCA	G-J	NYC	LI
	SCGT				BESS			
Inflation Factor (%)	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
Debt Fraction (%)	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%
Debt Rate (%)								
Nominal	6.70%	6.70%	6.70%	6.70%	7.20%	7.20%	7.20%	7.20%
Real	4.48%	4.48%	4.48%	4.48%	4.97%	4.97%	4.97%	4.97%
Equity Rate (%)								
Nominal	14.00%	14.00%	14.00%	14.00%	14.50%	14.50%	14.50%	14.50%
Real	11.63%	11.63%	11.63%	11.63%	12.12%	12.12%	12.12%	12.12%
Composite Tax Rate (%)	26.14%	26.14%	33.13%	26.14%	26.14%	26.14%	33.13%	26.14%
Federal Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
State Tax Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
City Tax Rate	0.00%	0.00%	8.85%	0.00%	0.00%	0.00%	8.85%	0.00%
WACC Nominal (%)	9.99%	9.99%	9.99%	9.99%	10.49%	10.49%	10.49%	10.49%
ATWACC Nominal (%)	9.02%	9.02%	8.76%	9.02%	9.45%	9.45%	9.17%	9.45%
ATWACC Real (%)	6.76%	6.76%	6.51%	6.76%	7.18%	7.18%	6.91%	7.18%
Amoritization Period (Years)	13 Years	13 Years	13 Years	13 Years	20 Years	20 Years	20 Years	20 Years
Tax Depreciation Schedule	15-Year MACRS	15-Year MACRS	15-Year MACRS	15-Year MACRS	5-Year MACRS	5-Year MACRS	5-Year MACRS	5-Year MACRS
Fixed Property Tax Rate (%)	0.60%	0.60%	4.77% with 15-Year Abatement	0.60%	0.6% with 15-Year Abatement	0.6% with 15-Year Abatement	4.77% with 15-Year Abatement	0.6% with 15-Year Abatement
Insurance Rate (%)	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%
Levelized Fixed Charge (%)	14.65%	14.65%	14.66%	14.65%	11.15%	11.15%	11.95%	11.15%

Notes: [1] The levelized fixed charge (%) for NYC differs from NYCA, the G-J Locality, and LI based on the treatment of property taxes and capital costs. Levelized fixed charge also vary for the simple cycle fossil peaking plants, and battery plants due to differences among these various options as it relates to the construction timeline, amortization period, and depreciation period. [2] NYC reflects the 15-year property tax abatement for both fossil and battery storage peaking plant options. NYCA, the G-J Locality, and LI reflect a 15-year property tax abatement for the battery storage peaking plants, and a 0.5% property tax rate for fossil peaking plants.

Table 41: Modified Accelerated Cost Recovery Tax Depreciation Schedules

	Tax Depreciation	
Year	5 Year (Battery)	15 Year (Simple Cycle)
1	20.00%	5.00%
2	32.00%	9.50%
3	19.20%	8.55%
4	11.52%	7.70%
5	11.52%	6.93%
6	5.76%	6.23%
7	0.00%	5.90%
8	0.00%	5.90%
9	0.00%	5.91%
10	0.00%	5.90%
11	0.00%	5.91%
12	0.00%	5.90%
13	0.00%	5.91%
14	0.00%	5.90%
15	0.00%	5.91%
16	0.00%	2.95%

Source: [1] Table B-1 of 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 42** provides annualized gross CONE values for each peaking plant within each location.

Table 42: Gross CONE by Peaking Plant Technology and Load Zone ($2025/kW- Year)

Peaking Plant Technology	Source	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03, Dual Fuel with SCR	Fixed O&M	$8.24	$8.29	$9.85	$8.92	$31.46	$10.20
	Insurance	$7.16	$7.10	$7.71	$7.20	$8.44	$8.24
	Levelized Fixed Charge	$255.21	$252.01	$267.96	$252.42	$311.24	$475.44
	Gross CONE	$270.61	$267.39	$285.53	$268.54	$351.15	$493.88
1x0 GE 7HA.03, Gas-only with SCR	Fixed O&M	$8.24	$8.29	$9.86	$8.93	-	-
	Insurance	$6.73	$6.69	$7.71	$6.78	-	-
	Levelized Fixed Charge	$243.92	$241.04	$268.13	$241.36	-	-
	Gross CONE	$258.89	$256.01	$285.71	$257.07	-	-
1x0 GE 7HA.02, Dual Fuel, no SCR	Fixed O&M	$9.90	$9.92	-	$10.00	-	-
	Insurance	$7.20	$7.14	-	$7.23	-	-
	Levelized Fixed Charge	$267.39	$263.93	-	$263.50	-	-
	Gross CONE	$284.49	$281.00	-	$280.72	-	-
1x0 GE 7HA.02, Gas-only, no SCR	Fixed O&M	$9.90	$9.92	-	$10.00	-	-
	Insurance	$6.68	$6.64	-	$6.72	-	-
	Levelized Fixed Charge	$253.59	$250.54	-	$249.99	-	-
	Gross CONE	$270.18	$267.10	-	$266.71	-	-
1x0 GE 7HA.02, Dual Fuel, with SCR	Fixed O&M	-	-	-	-	-	$11.65
	Insurance	-	-	-	-	-	$7.87
	Levelized Fixed Charge	-	-	-	-	-	$274.46
	Gross CONE	-	-	-	-	-	$293.98
2-Hour BESS	Fixed O&M	$18.60	$18.80	$19.86	$19.10	$43.27	$21.08
	Insurance	$4.65	$4.69	$4.83	$4.65	$5.74	$4.95
	Levelized Fixed Charge	$98.66	$99.32	$102.05	$98.92	$163.99	$105.32
	Gross CONE	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
4-Hour BESS	Fixed O&M	$29.80	$30.15	$31.82	$30.56	$66.73	$33.74
	Insurance	$7.72	$7.78	$7.98	$7.73	$9.59	$8.18
	Levelized Fixed Charge	$151.53	$152.46	$156.31	$151.97	$240.69	$160.95
	Gross CONE	$189.05	$190.40	$196.11	$190.25	$317.01	$202.88
6-Hour BESS	Fixed O&M	$41.97	$42.42	$44.85	$43.03	$91.21	$47.47
	Insurance	$11.10	$11.18	$11.47	$11.11	$13.50	$11.78
	Levelized Fixed Charge	$211.28	$212.61	$217.95	$211.93	$320.10	$224.55
	Gross CONE	$264.35	$266.22	$274.27	$266.07	$424.81	$283.81
8-Hour BESS	Fixed O&M	$53.43	$54.03	$57.06	$54.74	$114.94	$60.60
	Insurance	$14.26	$14.37	$14.73	$14.27	$17.41	$15.14
	Levelized Fixed Charge	$271.13	$272.85	$279.74	$271.95	$409.42	$288.36
	Gross CONE	$338.82	$341.25	$351.53	$340.96	$541.77	$364.11

Note: [1] 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 for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services… including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review."[59]

The costs and revenues are to be determined under conditions that reflect specified capacity supply conditions. 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…"[60]

AG refers to these tariff-specified conditions as the "LOE" conditions.

In this Section, we present the method used to estimate the net EAS revenues of the peaking plant technology options for NYCA and each Locality evaluated for this DCR. 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.[61]

First, AG summarizes its approach for estimating net EAS, including a description of the net EAS models (including net EAS models for both the fossil peaking plant and BESS technologies), the data inputs, and the approach to adjusting prices to be consistent with LOE market conditions.[62] Second, AG summarizes the process for annually updating estimated net EAS revenues over the reset period. Finally, AG presents results of applying the net EAS revenues model for the 2025-2026 Capability Year.

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[59] Services Tariff, Section 5.14.1.2.2.
[60] Services Tariff, Section 5.14.1.2.2.
[61] 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, AG uses both terms, when appropriate. For example, when describing system capacity need in MW, AG uses ICR. When referencing the required level of reserves in percentage terms, AG uses IRM.
[62] For BESS options, AG developed a net EAS model that evaluates potential real-time revenue earnings using a net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch prices (i.e., nominal 5-minute interval prices), as well as a net EAS model that evaluates potential real-time earnings using hourly real-time prices. For the 2025-2029, AG recommends use of the net EAS model using RTD interval pricing for the BESS options.

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 at the tariff-prescribed LOE conditions. 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 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. AG'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 RPs evolve (albeit with a lag) to reflect actual EAS market outcomes over time (as adjusted for LOE conditions).

AG's models estimate the net EAS revenues of the peaking plant technology options 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 Market (DAM) or Real-Time Market (RTM). Each year, as part of an annual updating of the ICAP Demand Curves, net EAS revenues will be recalculated using the applicable model for the relevant peaking plant technology selected for each ICAP Demand Curve, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges.

2. Net EAS Model Construct

a. Fossil Peaking Plant Model Logic

For all fossil peaking plant technology options, the AG simulated dispatch model uses a dispatch logic functionally consistent with NYISO energy and ancillary services markets.[63] Specifically, the AG 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.[64] In the model, the fossil peaking plant technology options can earn revenues through supplying in one of four markets: (1) DAM commitment for energy, (2) DAM commitment for reserves, (3) RTM dispatch for energy, or (4) RTM supply of reserves. In addition, a plant maintains the ability to buy out of either DAM energy or reserves commitments, based on changes in RTM prices. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual-fuel

[63] In practice, an individual plant'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 plant-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical peaking plant.
[64] AG assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant.

capability (if applicable) is accounted for through the option to generate on natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

Figure 9 and **Figure 10** contain schematics of the commitment/dispatch logic for the DAM and RTM, respectively, for the fossil peaking plant technology options. 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 fossil peaking plant's DAM commitment. Consistent with the 2017-2021 and 2021-2025 DCRs, the model utilizes historical hourly real-time prices for the RTM. For the 2025-2029 DCR, AG did not evaluate the fossil peaking plant technology options for potential use of Real-Time Dispatch interval prices in real-time.

The fossil peaking 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. The value of this premium varies by location. 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.[65] This additional cost is incorporated into RTM buy out decisions for all fossil peaking plant technology options. As illustrated in **Figure 10**, fossil 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
- No DAM commitment, with an energy dispatch in the RTM
- No DAM commitment, with a reserves dispatch in the RTM

When evaluating an energy commitment in either the DAM or RTM, the model ensures that all costs, including start-up costs, can be recovered.[66] In the DAM, start-up costs for the fossil peaking plant technology options can be recovered over the full runtime block, which is determined dynamically based on profitable hours; within the RTM, fossil peaking plant technology options must recover their startup costs over two hours.

[65] These costs are based on estimates previously 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.

[66] The model does not allow a plant to be committed uneconomically. In actual operation of the markets, to the extent that a plant would be committed uneconomically, it 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 plant for its costs, offsetting losses on a daily basis.

The fossil peaking plant technology options are also constrained by applicable runtime limitations as described in Section II.C. For fossil peaking plants modeled with SCR emissions control technology, the NSPS limitation for CO_2 is a limiting constraint on hours of operation. 1898 & Co. estimated the maximum annual runtimes for all combustion turbines with SCR emissions control technology to be 3,504 hours. For combustion turbines without SCR emissions control technology, the limiting constraint is the NSPS requirement for NO_x emissions. Plants without SCR emission controls in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions. Operating limits are modeled in the Net EAS Revenue model as constraints on the total amount of combined NO_x emissions allowed each year from either natural gas or ULSD operations. Due to differences in heat rate and capacity by season, the exact emissions per run hour also differs by season. The mass of NO_x emissions is calculated for each profitable run hour, and the total amount of emissions per year is limited to the NSPS maximum.[67]

Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-synchronized reserve markets at their opportunity cost to taking a day-ahead reserve position. This cost can reflect many factors, including performance (forced outage) risks and costs and risks associated with securing fuel supplies to fulfill a reserve obligation. Depending on the resource type, these fuel-related costs can reflect the cost of holding fuel supplies or the expected cost of obtaining adequate fuel supplies in the intraday markets, and risk premiums associated with taking an uncovered reserve position. These costs differ between gas-only units and dual fuel units, given a dual fuel unit's flexibility to operate on natural gas or their alternate fuel, which can mitigate the risk of a day-ahead reserve position. Based on a review of historical bid data from dual fuel units in Load Zones J and K provided by the MMU, the opportunity cost to taking a day-ahead reserve position is assumed by the model at $2.00/MWh for dual fuel units in Load Zones G (Dutchess County), G (Rockland County), J, and K.[68] For gas-only units in Load Zones C and F, the opportunity cost is set to the intraday premium of buying natural gas during the operating day.

If a fossil peaking plant receives a day-ahead reserve position, the cost to actually supply energy into the RTM reflects the market fuel price plus a real time intraday premium associated with buying natural gas in real time. Dual fuel plants 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).[69]

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[67] The model evaluates environmental runtime limits on a model-year basis, where model years cover a 12-month period from September 1 to August 31 (e.g. September 1, 2021 to August 31, 2022). If a plant is committed above its applicable environmental emissions limit during that period, the model removes the least profitable energy (either DAM or RTM) runtime blocks until the plant is in compliance. Plants are allowed to earn DAM reserve revenues at the prevailing DAM reserve price during runtime blocks removed in this fashion.

[68] Patton, David and Pallas LeeVanSchaick to Analysis Group and Burns & McDonnell, "MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and the forthcoming draft of NYISO Staff DCR Recommendations," July 31, 2020, pp. 7-9.

[69] This assumption may under- and overstate opportunity costs under some circumstances, but provides a reasonable estimate of opportunity costs on balance across hours and Load Zones.

Figure 9: Net EAS Revenues Model Day-Ahead Commitment Logic for Fossil Peaking Plant Technology Options

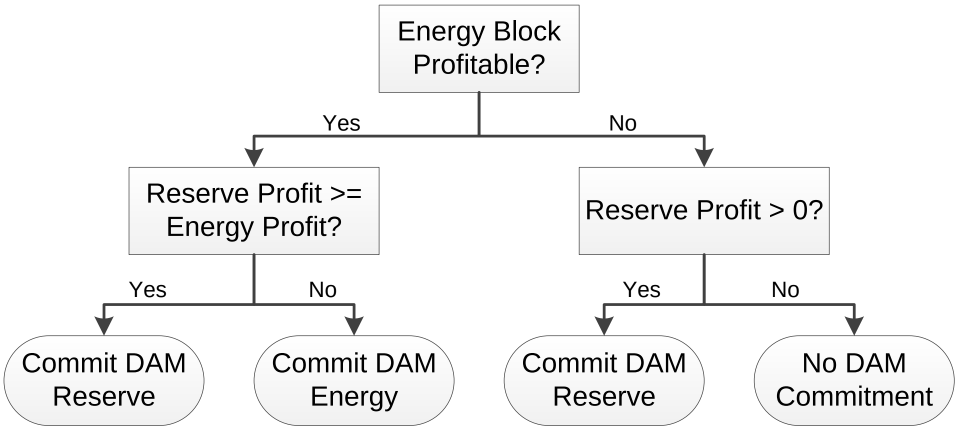
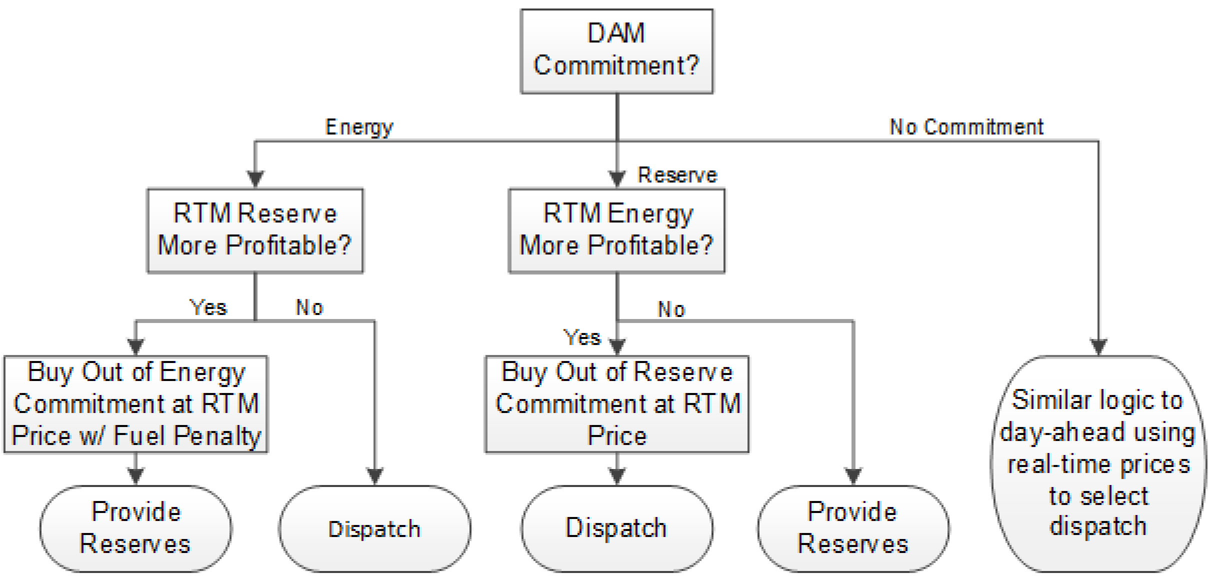


Figure 10: Net EAS Revenues Model Real-Time Supply Logic for Fossil Peaking Plant Technology Options



The net EAS revenues model estimates hourly revenue streams for the fossil peaking plant technology options based on hourly prices for both DAM and RTM over the three-year historical period. Within this hourly model, the fossil peaking plant technology options 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.

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 location and, when applicable, each fossil peaking plant technology option:[70]

$$NEAR = LOE - AF * LBMP - HR * P(fuel) - VOM - ASC - EC - RS1 \qquad (3)$$

Where:

$LOE - AF$ = LOE adjustment factors for each Load Zone and time period

$LBMP$ = Hourly LBMPs (either DAM or RTM) for each Load Zone

HR = Heat rate for the applicable peaking plant and Load Zone

$P(fuel)$ = Price of fuel (natural gas or, if applicable, 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 = Startup cost

RS1 = NYISO Rate Schedule 1 charge (varies annually, 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 for the fossil peaking technology options, the model separately considers relevant unit parameters for Summer and Winter Capability Period months, including each fossil peaking plant's seasonal capacity and heat rate. Total annual revenues are the sum of revenues earned during each hour of the year (reflecting seasonal capacity ratings), with energy and reserves revenues derated by the fossil peaking plant's EFORd.

[70] That is, equation 3 does not fully represent the tradeoffs between DAM and RTM energy and reserve profits, or the ability of the plant to buy out of its DAM commitments.

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 an adder for providing voltage support service (VSS).[71]

An important component of the net EAS revenues model is the ability of the model to assess the fossil peaking plants with either dual fuel capability (if applicable) or gas only operation. When evaluating fuel commitment decisions, the model compares the applicable fuel costs in each hour. For a dual fuel unit, the fossil peaking plant is assumed to operate on the most economic fuel for a full runtime block. The model does not permit fossil peaking plants to fuel switch within an individual block.

Notably, the model does not consider potential limitations in gas only operations; all fossil peaking plants are assumed to be able to procure fuel as needed, at historical prices.[72] As described in Section II, AG considered potential limitations in fuel availability as part of its qualitative review, given NYISO's proposal to incorporate fuel availability considerations in the assignment of capacity accreditation factors. As noted in Section II, AG expects the combination of forthcoming CAF determinations and other factors would lead a developer to install dual-fuel technology in all locations. Consequently, it is not necessary to attempt to model the potential for natural gas fuel limitations in the net EAS modeling process.

b. Battery Model Logic

Like the fossil model, the AG simulated dispatch model for battery storage uses a dispatch logic that is functionally consistent with NYISO energy and ancillary services markets.[73] For BESS options, AG uses a DAM model consistent with the method employed in the 2021-2025 DCR. AG also developed a net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch (RTD) prices (i.e., nominal 5-minute interval prices), as well as a net EAS model that evaluates potential real-time revenue earnings using hourly real-time prices.[74] For the 2025-2029 DCR, AG recommends use of the net EAS model that uses RTD interval prices for the BESS options.

As further detailed below, the dispatch logic of the models developed for the BESS options maximizes net EAS revenues while accounting for the battery technology's unique technical properties, including limited energy storage capacity, the need for a balancing of energy charges and discharges, energy losses during charging, and operational practices that can reduce battery degradation. We first describe how the model accounts for these

[71] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Specifically, net EAS revenues are converted to current year dollars using the Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the three-year historical data period. The net EAS escalation rate is the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the nominal period covered by the historical data, measured as the change from the oldest year to the most recent year of such nominal period. For example, for the historical data period from 9/1/2021-8/31/2024, the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) would be measured over the nominal period from 2022 to 2024.

[72] Similarly, the model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AG does not expect OFOs to meaningfully affect the net EAS revenues of dual fuel plants, 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 plants would already be expected to run on oil.

[73] In practice, an individual plant's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical battery plants considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to plant-specific cost, and operational factors that vary from those of the hypothetical battery plants evaluated in this study.

[74] Additional information regarding the net EAS model using hourly real-time prices is provided in Appendix E.

technical characteristics, and then describe the model's framework for determining participation in the NYISO markets, which follows two steps: (1) daily DAM commitments, and (2) daily RTM dispatch.

Battery Model: DAM Modeling Logic

Due to the physical energy limitations of a battery, the models developed for BESS options determine charge and discharge of the battery simultaneously in hour-pairs in the DAM energy and reserve markets. Each hour-pair includes an hour in which the battery purchases energy (to charge the battery) and an hour in which it supplies energy (through discharge of the battery). This logic ensures there is always a balance between energy inflows and outflows. The model also limits the range of stored energy to between zero and the battery's maximum storage capacity.

For each hour-pair, the models account for energy losses when charging and assumes the full charge or discharge of the battery's capacity. However, because of charging losses, more time is required for a full charge of the battery than is required for a full discharge; thus, to maintain the energy balance of inflows and outflows of power, additional charging time is required for any given level of stored energy.

Along with consuming and supplying energy, the battery can supply reserves. The battery is assumed to be eligible to provide 10-minute spinning reserves when it has no DAM or RTM energy discharge position but has at least one hour capability of stored energy and/or was scheduled to be charging for the hour. The battery can supply reserves at either its full capacity or the amount of energy that remains stored, whichever is smaller. When the battery is charging, the models assume it can supply reserves at either its full capacity or the amount of energy that remains stored plus the amount of power scheduled to be withdrawn from the grid for charging purposes.

At the end of each modeled day, the battery model requires the battery to charge until achieving a state of charge of 200 MW to ensure the ability to earn reserve revenue at nameplate capacity overnight.

The dispatch logic for battery storage is split into two steps: (1) daily DAM commitments, and (2) daily RTM dispatch. **Figure 11** and **Figure 12** illustrate how the model is solved for two illustrative days in the two steps. The left axis (and lines) show the LBMPs and reserve prices determined by the NYISO markets in each hour. The right axis (and bars) shows the battery energy transactions determined by the model; positive values represent MW discharged onto the grid while negative values represent MW withdrawn from the grid for charging. Withdrawal MW should not be mistaken for actual inflows into the battery, as in these cases the battery only received 85% of the energy withdrawn because of charging inefficiencies.

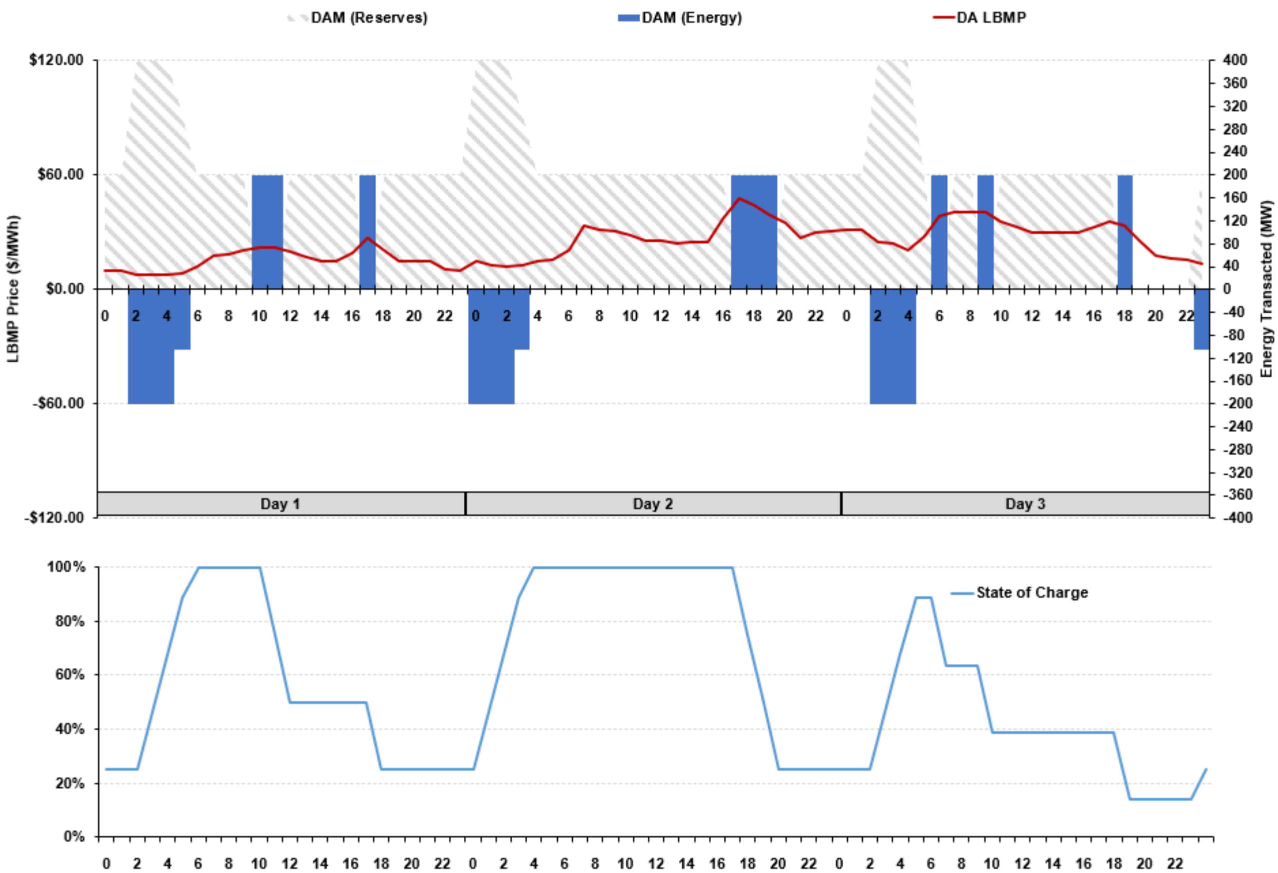
The **first step** determines the daily DAM positions. The model determines whether to commit a set of hour-pairs to charge and discharge energy in the DAM based on maximizing net revenues in the energy and reserve markets for a cycle-day.[75] For each cycle-day, the models generate every feasible day-ahead position hour-pair given the current position of the battery storage resource. The logic then ranks the profitability of adding each set of hour-pair positions to the current position. If adding the hour-pair to the battery's position increases profitability relative to doing nothing, the model will do so and repeat this process. The model will also add hour-pairs to its position in

[75] A cycle-day is defined as a 24-hour period between 10:00 pm and 9:59 pm the following day.

order to hit the target level of energy for the battery (i.e., 200 MW state of charge at the end of each modeled day), even when it does not increase revenues.

This step outputs a full cycle-day of DAM positions, an example of which can be seen for two days in **Figure 11**. Hour-pairs are committed on the first and second DAM days, as depicted by the blue energy discharge bars above the y-axis and corresponding charging hours below the y-axis. The battery resource provides reserves whenever it has energy stored or is charging. In each case, the model cannot feasibly position another hour-pair that would drive greater profits than the determined set of positions.

Figure 11: AG Battery Model DAM Example
Zone C, November 30 - December 2, 2022, 4 Hour Battery



The **second step** determines any incremental RTM positions. In the RTM, the battery plant supplies (and consumes) energy given arbitrage opportunities presented by RTM LBMPs. The plant's RTM operational decisions are contingent on the DAM positions established in Step 1. While we assume the battery does not buy out of a DAM energy position unless there would be a violation of the battery's physical operating limits, the battery can buy out of DAM reserve position and take a RTM energy position instead.

For the 2025-2029 DCR, AG developed a net EAS model that evaluates potential real-time revenue earnings using RTD prices (i.e., nominal 5-minute interval prices), unlike the 2021-2025 DCR, which employed a net EAS model for BESS technologies that employed hourly real-time prices. AG provides a description of the previous hourly real-time price methodology and associated results in Appendix E. For the 2025-2029 DCR, AG recommends use of the net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch prices for all BESS options.

Battery Model: RTM Logic for RTD Interval Pricing Model

To evaluate real-time arbitrage opportunities, the RTD interval pricing model employs a conceptually distinct approach from the DAM model. Unlike DAM LBMPs, RTM LBMPs transact on a nominal 5-minute basis. Batteries are capable of providing quick charging and discharging on a 5-minute basis. Moreover, 5-minute intervals may have higher volatility and greater opportunities for energy arbitrage revenues for batteries than LBMPs averaged over e.g. a 60-minute interval basis. As such, AG has developed a method to model net EAS revenues in NYISO's RTM using RTD prices.

AG's approach begins with developing a bidding strategy to identify profitable RTM charging or discharging opportunities. Intuitively, a reasonable bidding strategy has to identify profitable opportunities for charging in the real-time market (when the RTD LBMP is sufficiently low), or discharging in the real-time market (when the RTD LBMP is sufficiently high). Given a day-ahead schedule of hourly DAM LBMPs, we define real-time discharge bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Charge\ Cost_i + Hurdle\ Rate_s + Discharging\ Costs$$

where:

- *Expected Subsequent Charge Cost*$_i$ equals 115% * (DAM LBMP + NYISO Rate Schedule 1 costs), where DAM LBMP is set based on the lowest cost DAM hourly LBMP following interval *i*, and NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations.
- *Hurdle Rate*$_s$ is calculated *ex ante* using historic data for three separate seasons *s* and established as fixed values for the entire reset period.
- *Discharging Costs* reflect the net costs associated with real-time discharge including NYISO Rate Schedule 1 costs, VO&M, and any DAM reserve buyout costs.

Similarly, we define real-time *charging* bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Discharge\ Revenue_i - Hurdle\ Rate_s - Charging\ Costs$$

where:

- $Expected\ Subsequent\ Discharge\ Revenue_i$ equals 85% * (DAM LBMP – NYISO Rate Schedule 1 costs – VO&M), where DAM LBMP is set based on the highest revenue DAM hourly LBMP following interval *i*, NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations, and VO&M reflects charges associated with variable operations and maintenance (e.g. capacity augmentation costs).
- *Hurdle Rate*$_s$ is calculated *ex ante* using historic data for each separate season *s* and established as fixed values for the entire reset period

- *Charging Costs* reflect the net costs associated with charging, including NYISO Rate Schedule 1 costs. Because charging allows batteries to earn incremental reserve revenues, charging costs are reduced by the applicable RTD reserve price for 10-minute spinning reserves during charging periods in real-time.

Because NYISO posts the Day-Ahead schedule by 11 a.m. on the day prior to the Dispatch Day, this bidding strategy is feasible for real-world battery operators. These bids/offers represent the RTD LBMPs required to deviate from the day-ahead schedule and could be submitted to NYISO well in advance of the real-time market deadline of 75 minutes before the start of the operating hour. This bidding strategy reflects the fact that, in real-time, a resource operator would not know with certainty future RTD LBMPs and could use the DAM LBMP as an approximation for future real-time prices. However, once these RTM positions are entered into, the RTD interval pricing model will use actual RTD LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position. As such, there is no “perfect foresight” embedded in the battery’s RTM bidding strategy within the RTD interval pricing model, and it is possible for the hypothetical battery operator to make a mistake in the sense of failing to maximize net EAS revenues on an *ex post* basis.

Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for future real-time price uncertainty. The hurdle rate captures the opportunity cost of limited available energy i.e. the fact that, if the battery used its limited energy to earn revenues in low priced hours, it may not have sufficient stored energy be earn higher revenues in the future. We calculate the revenue-maximizing hurdle rate directly by using the RTD interval pricing model to estimate net EAS revenues under alternative hurdle rates from $0 to $250 over the September 1, 2021 to August 31, 2024 period, and selecting the hurdle rate that yields the highest net EAS revenues.

To capture other relevant features of NYISO’s RTM, AG implemented additional enhancements within the RTD interval pricing model beyond the inclusion of 5-minute pricing intervals:

1. As in the DAM model, batteries require at least one hour of stored energy to earn reserve revenue (e.g. 25% state of charge [“SOC”] for a 4-hour battery). To operationalize this constraint, the RTD interval pricing model will buy out of DAM reserve positions whenever SOC < $\frac{1}{Rated\ Battery\ Duration}$
2. Addition of sub-5-minute intervals due to activation of RTD Corrective Action Modes (RTD-CAMs).
3. Seasonal hurdle rates which are separately optimized in three distinct seasons: Winter (December, January, and February), Summer (June, July, and August), and Shoulder (all other months).
4. Sufficient SOC to meet DAM energy and reserve positions during Peak Load Window (PLW) hours. The model requires the BESS to achieve a RTM SOC equal to or greater than the DAM SOC at the beginning of the PLW. If the RTM SOC is greater than the DAM SOC during PLW hours, then the battery can discharge until RTM SOC is equal to the DAM SOC. The PLW hours assumed by the model are hour beginning 1 pm through hour beginning 8 pm for Summer Capability Period months and hour beginning 4 pm through hour beginning 9 pm for Winter Capability Period months.

Figure 12 provides an example of the RTM logic of the RTD interval pricing model. In every five-minute interval, the model calculates whether the actual RTD LBMP for such interval is sufficiently high to induce real-time discharging, or sufficiently low to induce real-time charging. Charging and discharging in real-time then impact the battery’s SOC, which subsequently may impact the ability of the battery to meet its previously determined DAM energy and reserve positions. The model buys out of DAM energy and reserve positions which are no longer physically feasible due to charging or discharging deviations in real-time relative to the DAM schedule.

Figure 13 presents marginal net EAS revenues evaluated for different assumed seasonal hurdle rates, compared to if no hurdle rate was used (i.e., a hurdle rate equal to $0/MWh). For each location evaluated in this study, a revenue maximizing opportunity cost value is chosen (i.e., the maximum point on the figure). **Table 43** reports the optimal hurdle rate by location and battery duration. These hurdle rates are used in the RTD interval pricing model and will remain fixed for the four-year reset period of this DCR.

Figure 12: AG Battery Model RTM Example
Zone C, November 30 - December 2, 2022, 4 Hour Battery

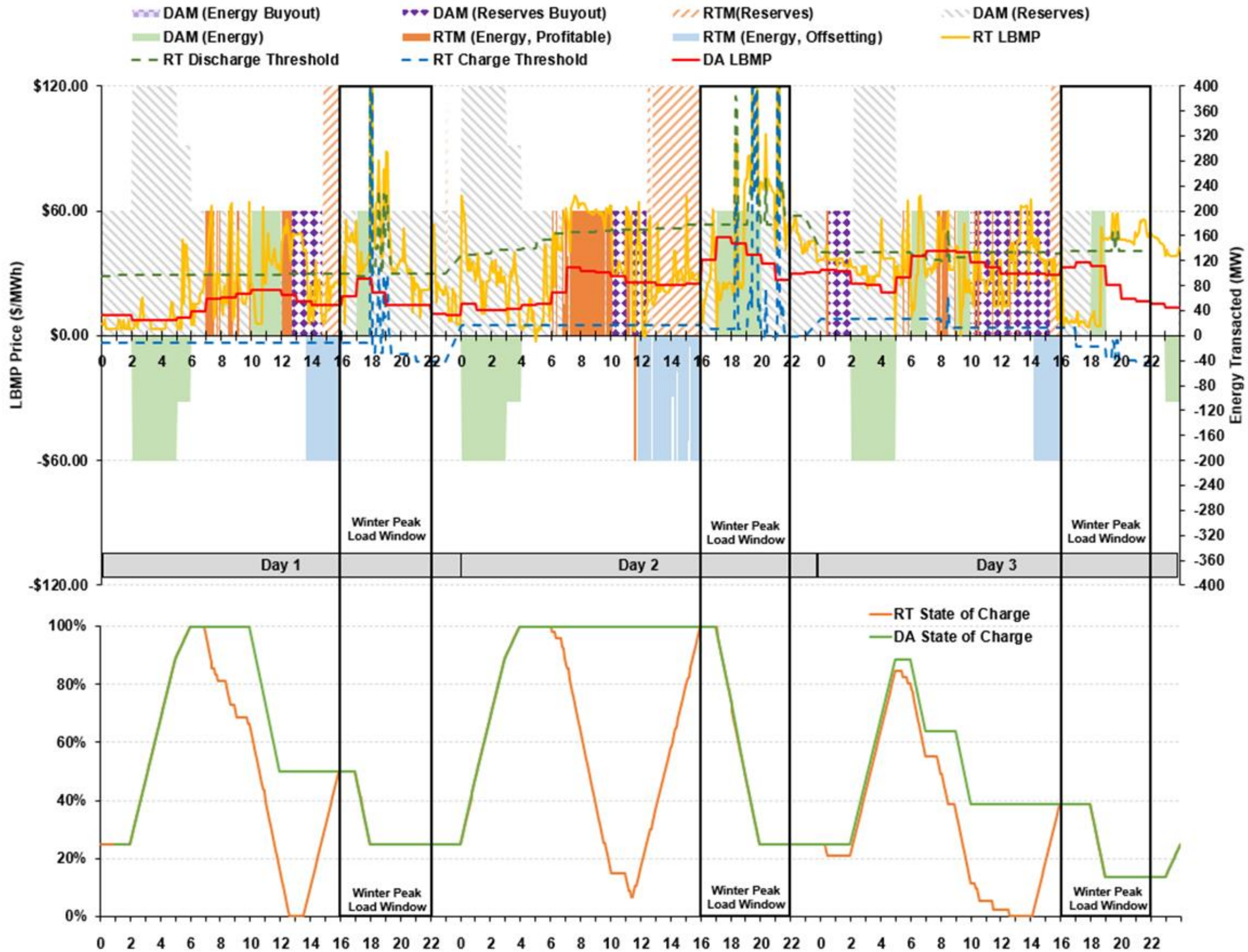
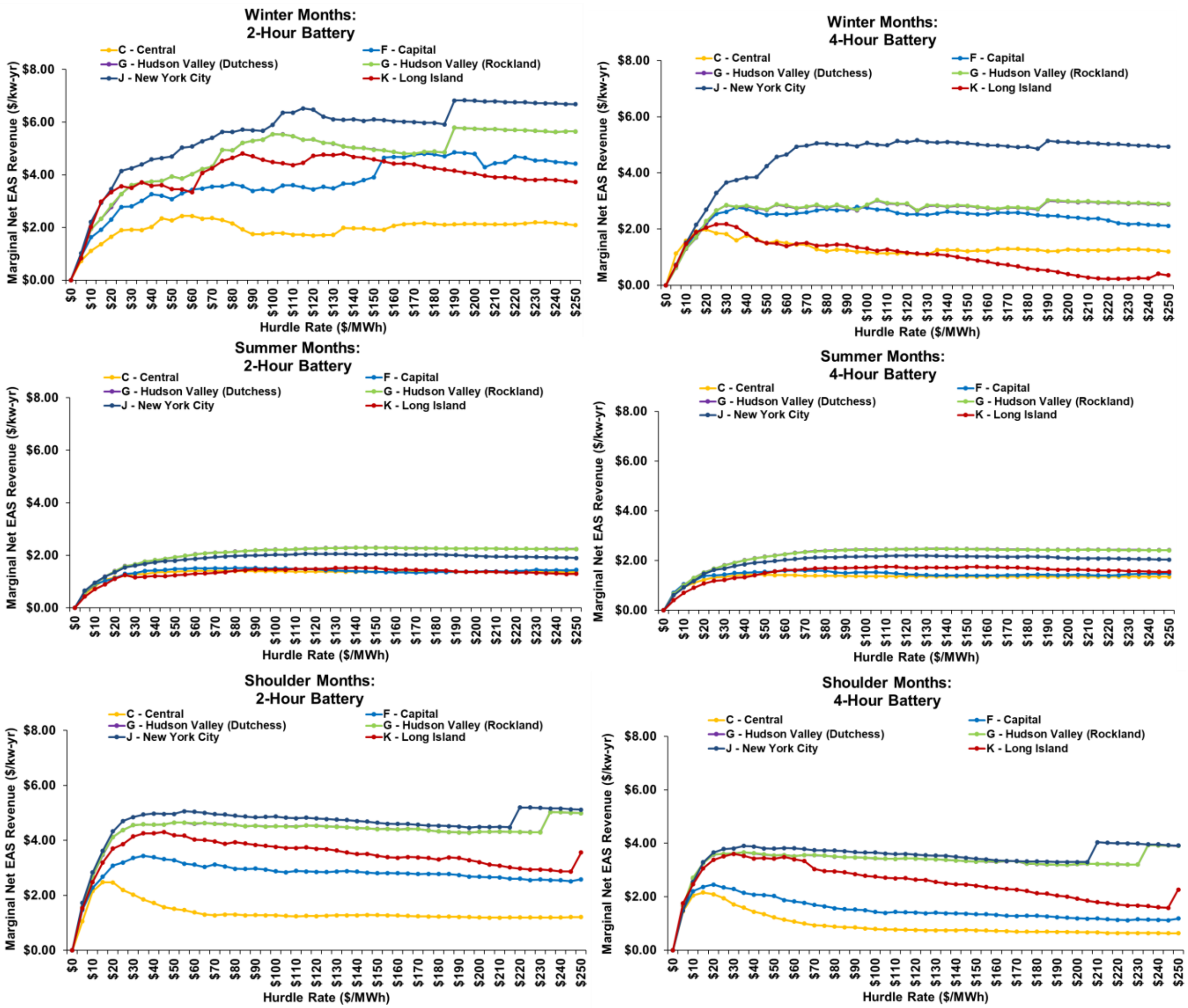
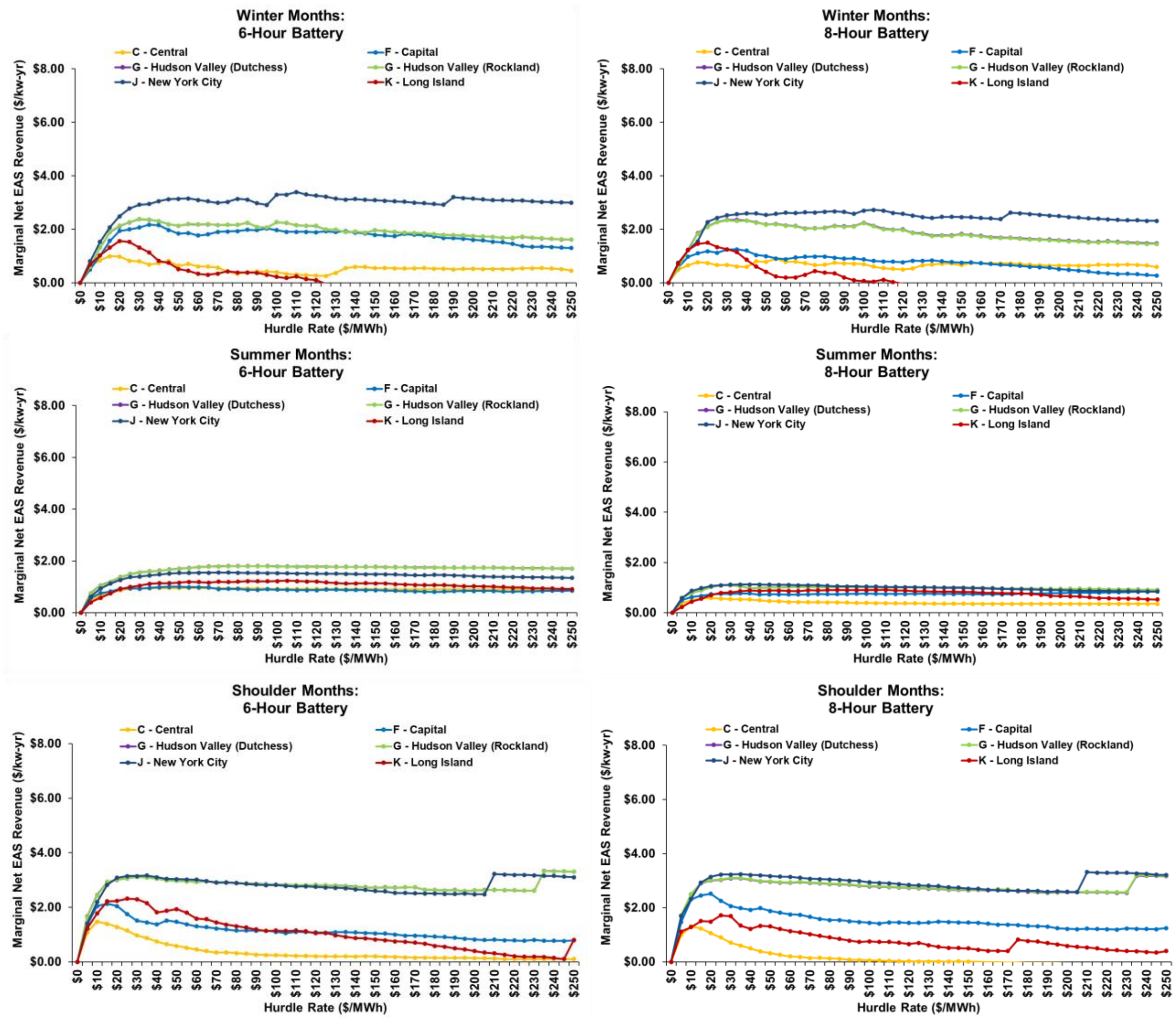


Figure 13: Change in RTM Net EAS Revenues for Alternative Hurdle Rates, by Location and Season
2-Hour BESS and 4-Hour BESS



Notes: [1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh hurdle rate. [2] "Winter months" are December – February, "Summer months" are June – August, and "Shoulder months" are all other months in the year. [3] This assessment was conducted using data for the three-year period September 1, 2021 to August 31, 2024.

Figure 14: Change in RTM Net EAS Revenues for Alternative Hurdle Rates, by Location and Season
6-Hour BESS and 8-Hour BESS



Note: [1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh hurdle rate. [2] “Winter months” are December – February, “Summer months” are June – August, and “Shoulder months” are all other months in the year. [3] This assessment was conducted using data for the three-year period September 1, 2021 to August 31, 2024.

Table 43. Seasonal Hurdle Rates for the 2025-2029 DCR by Location and Duration

2-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$75	$80	$140	$140	$115	$140
Winter	$60	$190	$190	$190	$195	$85
Shoulder	$15	$35	$235	$235	$220	$45

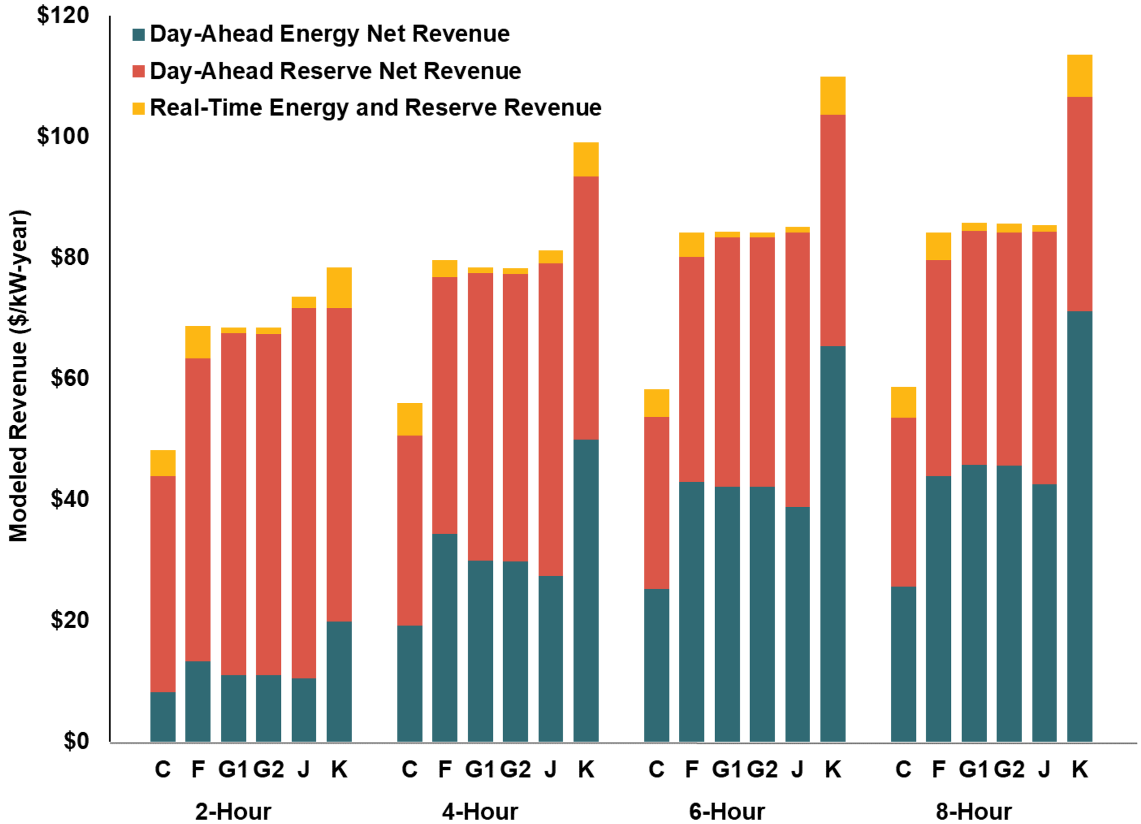
4-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$40	$65	$140	$140	$130	$110
Winter	$20	$95	$105	$105	$125	$30
Shoulder	$15	$20	$235	$235	$210	$30

6-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$55	$50	$90	$90	$70	$105
Winter	$15	$35	$30	$30	$110	$20
Shoulder	$10	$15	$235	$235	$210	$25

8-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$20	$250	$30	$30	$35	$110
Winter	$55	$35	$35	$30	$105	$20
Shoulder	$10	$20	$235	$235	$210	$25

Notes: [1] "Winter" is December – February, "Summer" is June – August, and "Shoulder" is all other months in the year. [2] The seasonal hurdle rate values were determined using data for the three-year period September 1, 2021 to August 31, 2024.

Figure 15. BESS Net EAS Revenues by Market and Product
September 2021 - August 2024 Price Data



Note: [1] "G1" refers to Load Zone G (Dutchess County) and "G2" refers to Load Zone G (Rockland County). [2] Appendix E presents detailed information on net EAS revenues by BESS technology option over the three-year review period including revenues and hours by day-ahead commitment and real-time dispatch behavior. Appendix E also includes results for both the recommended battery model employing Real-Time Dispatch prices, and the hourly pricing battery model employed in the 2021-2025 DCR.

As depicted in **Figure 15,** a significant portion of battery net EAS revenues come from day-ahead reserve revenue. Energy revenues (whether in the DAM or RTM) are generally higher in locations with higher price volatility in the historical three-year period, like Load Zone K.

To summarize, batteries can exist in one of ten operating states in each hour, based on the combination of DAM and RTM positions. These "operating" states include:

- DAM energy position, with RTM energy dispatch
- DAM energy and reserve position, with RTM energy and reserve dispatch
- DAM reserves position, with a RTM reserves dispatch
- DAM reserves position, with a RTM energy dispatch
- DAM reserves position, with a RTM energy and reserve dispatch
- DAM reserves position, with no dispatch in the RTM
- No DAM position, with a RTM reserve dispatch
- No DAM position, with a RTM energy dispatch
- No DAM position, with a RTM energy and reserve dispatch
- No DAM position, with no dispatch in the RTM

The models for BESS options estimate revenues streams for the battery plants based on prices over the applicable three-year historical period. Total annual revenues are the sum of revenues earned during each year with energy and reserves revenues derated by the plant's assumed UOL availability factor.[76] 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 an adder for providing VSS.[77] Unlike the fossil peaking plant model, the batteries have no seasonal differences in unit performance parameters or ratings.

c. Model Data

The data used in the net EAS revenues models include, as applicable by peaking plant technology option, locational energy and reserve prices, daily fuel prices and daily 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.[78] 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 RTM LBMPs and reserve prices use zonal integrated hourly average values that are available through the NYISO market and operation data. For real-time prices, hourly or RTD interval prices are used depending on the peaking plant technology option. For BESS options, AG uses RTD interval prices.[79] Hourly real-time prices are used for all fossil peaking plant technology options.

Reserve prices are based on prices for 10-minute non-spinning reserves for the fossil peaking plant technology options, as 1898 & Co., in discussion with NYISO, has determined that these unit types are capable of supplying 10-minute non-spinning reserves. For BESS options, prices for spinning reserves are used. For the fossil peaking plant technology options, hourly reserve prices are utilized for both DAM and real-time. For BESS options, the RTD interval pricing net EAS model uses hourly spinning reserve prices for the DAM. The RTD interval pricing net EAS model uses RTD interval reserve prices in real-time.

In addition to energy and reserve revenues, all peaking plant technology options can supply VSS. VSS revenues are determined outside the applicable net EAS model. VSS payments are added to the final estimate of annual net EAS revenues determined using the applicable net EAS model and are based on actual settlement data analyzed by the NYISO. For the first year of the 2025-2029 DCR, AG recommends that the applicable annual VSS adder be determined formulaically based on the compensation structure described in Rate Schedule 2 of the Services Tariff. Based on Rate Schedule 2, AG recommends that the annual VSS compensation for the peaking plant technology options evaluated in this study be determined as value equal to the VSS compensation rate, multiplied by the sum of: (1) the technology's lagging reactive capability

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[76] As described in Section II.G, total annual battery revenues are derated by 2% to account for forced outages.

[77] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Specifically, net EAS revenues in historic years are converted to current year dollars using the Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the three-year historical data period. The net EAS escalation rate is the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the nominal period covered by the historical data, measured as the change from the oldest year to the most recent year of such nominal period. For example, for the historical data period from 9/1/2020-8/31/2023, the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) would be measured over the nominal period from 2021 to 2023.

[78] For the results presented in this Final Report for the 2025-2026 Capability Year ICAP Demand Curves, we use data for the three-year period September 1, 2021 through August 31, 2024.

[79] Further information regarding the alternative BESS model using hourly real-time prices is provided in Appendix E. AG recommends use of the RTD interval pricing model for BESS options for the 2025-2029 DCR.

(expressed in MVAr) and (2) the absolute value of the technology's leading reactive capability (expressed in MVar). The VSS revenue adder will be updated annually as part of the annual updates for this reset period to reflect NYISO's published VSS compensation rate at this time of conducting each such annual update.

1898 & Co. determined that the lagging reactive capacity for the BESS options evaluated in this study is 124 MVAr while the leading reactive capability is -124 MVAr. For the 1x0 GE 7HA.03 technology option, 1898 & Co. determined that (based on a nominal capacity rating of 400 MW) the lagging reactive capability is 300 MVar and the leading reactive capability is -180 MVAr. For the 1x0 GE 7HA.02 technology option, 1898 & Co. determined that (based on a nominal capacity rating of 330 MW) the lagging reactive capability is 225 MVar and the leading reactive capability is -125 MVAr.

Based on the current VSS compensation rate of $3,307.31/MVAr, the formula described above produces a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03 technology option, a $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02 technology option, and a $4.10/kW-year VSS revenue adder for the BESS options for use in determining the ICAP Demand Curves for the 2025-2026 Capability Year.[80]

ii. Oil and Natural Gas Prices

For the fossil peaking plant technology options, natural gas prices are based on price indices for natural gas market hubs selected by AG for each location evaluated as reported by S&P Global Market Intelligence (SPGMI). SPGMI gas indices are developed using price and volume data submitted from market participants at various points along identified sections of pipelines, and represent volume-weighted average prices, excluding outliers that are greater than two standard deviations from the mean.[81] AG's net EAS revenues model for the fossil peaking plant technology options 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 gas price index hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a fossil peaking plant in a given location. AG considered several gas index options for each location evaluated in this study, based on the following 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 fossil peaking plant net EAS revenues calculations should seek to reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions that may not be representative of the level of excess conditions prescribed for use in establishing the ICAP Demand Curves.
- *Liquidity*. The natural gas index should have a reasonable 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 pipelines that have an appropriate geographic relationship to the applicable fossil peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points. While recognizing the relevance of geographic proximity, AG also considered whether gas indices fully captured variation in pricing within a given location,

[80] NYISO, "Billing Rates," https://www.nyiso.com/billing-rates
[81] *See,* S&P Global Methodology and specifications guide US and Canada natural gas, May 2020.

particularly to the extent that such pricing variation is relevant to delivery to the relevant fossil peaking plant. **Figure 16** depicts the geographic location of natural gas hubs in and around New York.

- *Precedent/Continuity.* The natural gas pricing selected for each location evaluated in this study should reflect and be supported by information collected from multiple sources and should take into account what is used for other NYISO planning and market evaluation purposes.[82] While the appropriate choice of representative gas pricing can vary in accordance with the purpose and objectives of a particular study/analysis, consistency and continuity should be considered when other factors do not clearly indicate an alternative.

The recommended natural gas pricing for each location was selected based on balancing the considerations listed above, recognizing that the natural gas indices do not necessarily capture all factors affecting the market-based pricing for natural gas to a hypothetical fossil peaking plant.

In considering geography, a fossil peaking plant in certain of the locations evaluated for this study could be directly served by lines represented by particular natural gas indices. In these cases, we have aimed to select among natural gas indices for pipelines that deliver to the location of interest, given consideration of market dynamics, liquidity and precedent/continuity. However, for some locations, available indices that meet all relevant considerations may not represent delivery points within the location of interest. In these cases, selection among available natural gas indices aim to identify the index or indices that reasonably represents the natural gas prices that would be faced by a fossil peaking plant within that location.

Because the price for natural gas to a fossil peaking plant would reflect market-based pricing, an index outside the region may provide a reasonable estimate of prices, particularly given the addition of incremental gas transportation charges within the net EAS model for fossil peaking plant technology options. When selecting an index (and appropriate transportation charges) from among multiple candidates for a given location, many specific factors may be considered, including: the type of service likely to be used for gas delivery, including interruptible service at tariff rates and/or purchase of firm rights released on a shorter term basis by holders of those firm rights (but likely not the purchase of longer-term firm rights to transportation); reasonable estimates of transportation charges from a point of delivery (potentially outside a particular location of interest) to the hypothetical fossil peaking plant given factors such as tariff charges for delivery between points and market prices for other types of service; levels and locations of congestion that would cause differences in market-based prices for natural gas under tight natural gas market conditions; assumptions that seek to avoid either over- or under-estimating expected natural gas prices, given variation in prices across different market conditions, particularly relative to other indices; dual fuel capability, which would cause the fossil peaking plant technology options to switch to lower-cost fuel oil when natural gas prices are high; and the extent to which prices represented by certain natural gas indices (including geographically proximate indices) reasonably represent long-run equilibrium prices that a developer of a hypothetical fossil peaking plant technology option would expect as a new entrant (including consideration of the potential for increases in gas demand from such new entry and other factors to potentially increase congestion on these gas delivery lines and tend to bring differences in multiple potentially representative gas hubs into a long-run equilibrium not represented by short-run historical prices).

[82] In particular, we reviewed gas hubs used in the 2021-2025 DCR study, the MMU's 2022 State of the Market report (2022 SOM), and the 2021-2040 System & Resource Outlook published by NYISO (2021-2040 Outlook).

Figure 16. Geographic Locations of New York Natural Gas Hubs

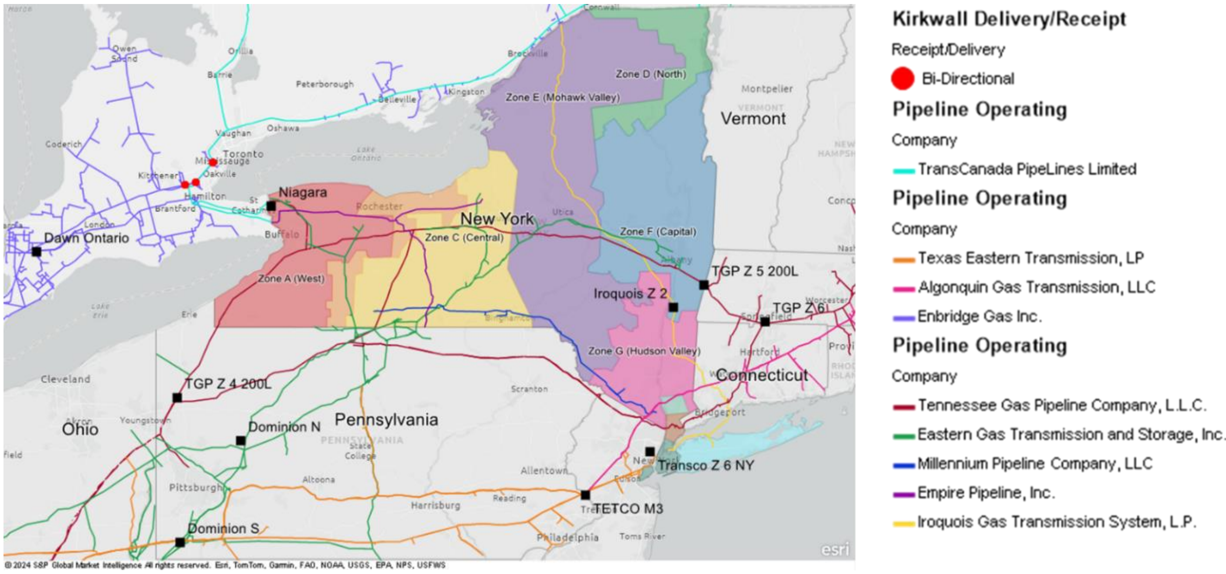
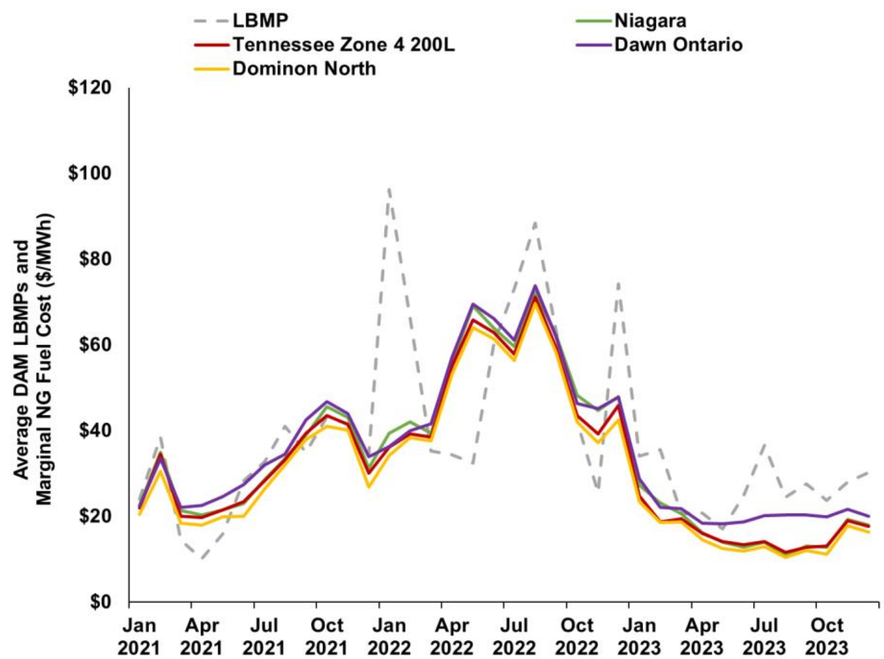


Figure 17 through **Figure 21** provide comparisons of gas prices for various hubs and LBMPs for Load Zone C, Load Zone F, Load Zone G, Load Zones J, and Load Zone K, respectively. These figures compare the monthly average fuel costs for a hypothetical fossil generator (with a heat rate of 8,890 Btu/ kWh) to monthly average DAM LBMPs for 2021 to 2023.[83]

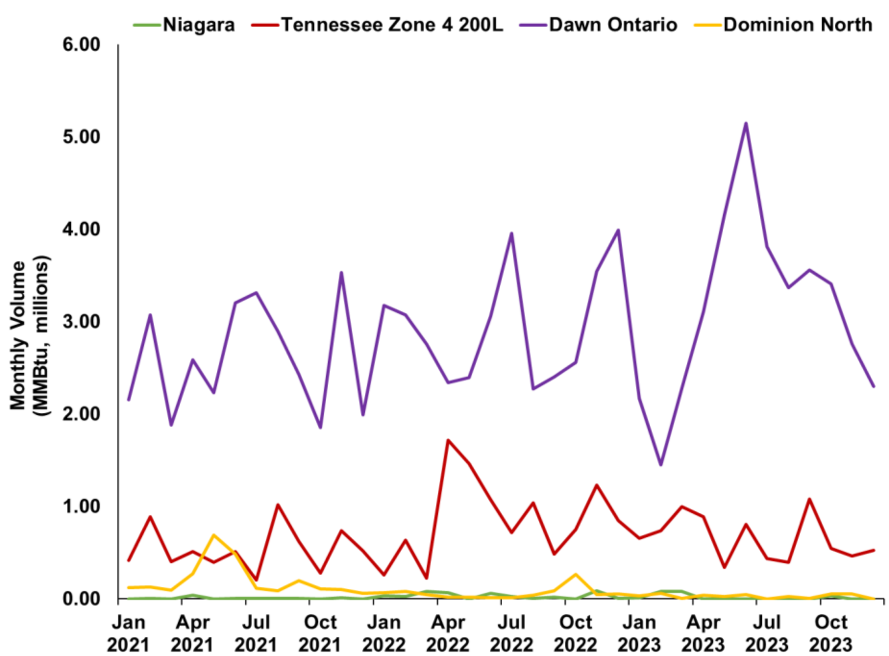
[83] The assumed heat rate of 8,890 Btu/kWh falls within the range of heat rates for both the GE 7HA.03 and GE 7HA.02 units.

Figure 17: Market Dynamics and Liquidity Analysis: Load Zone C

a. Natural Gas Price Indices and DAM LBMPs



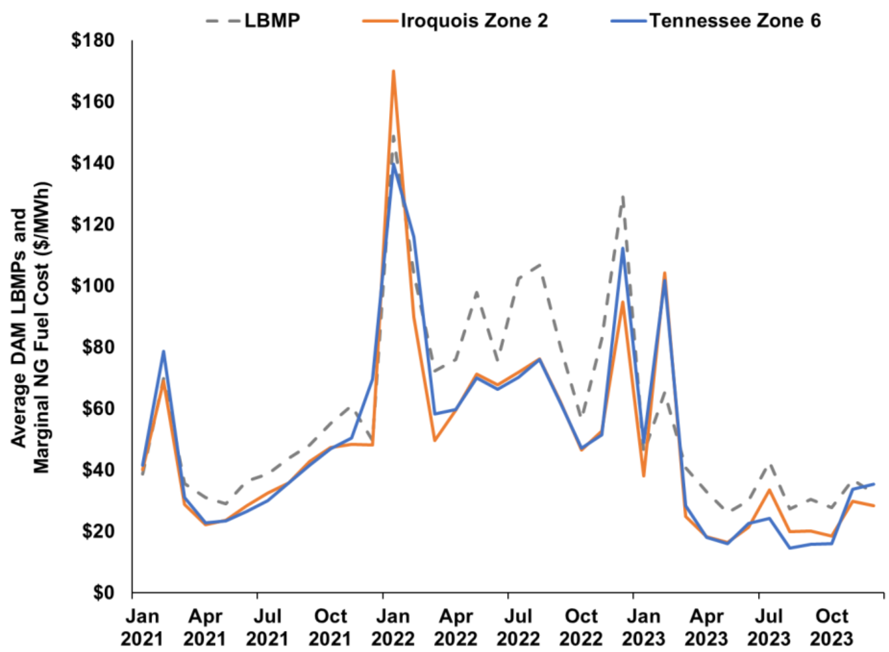
b. Liquidity Analysis



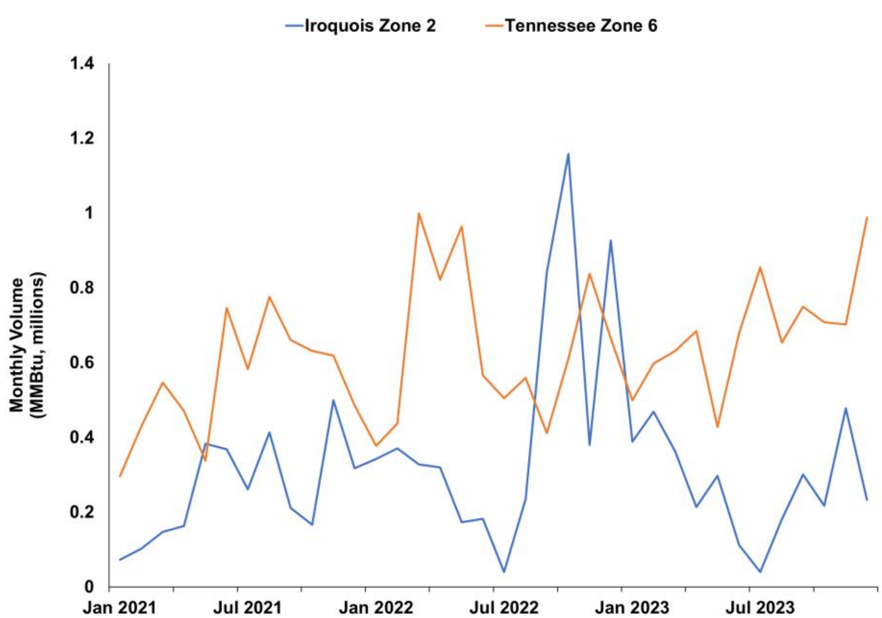
Notes: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 18: Market Dynamics and Liquidity Analysis: Load Zone F

a. Natural Gas Price Indices and DAM LBMPs



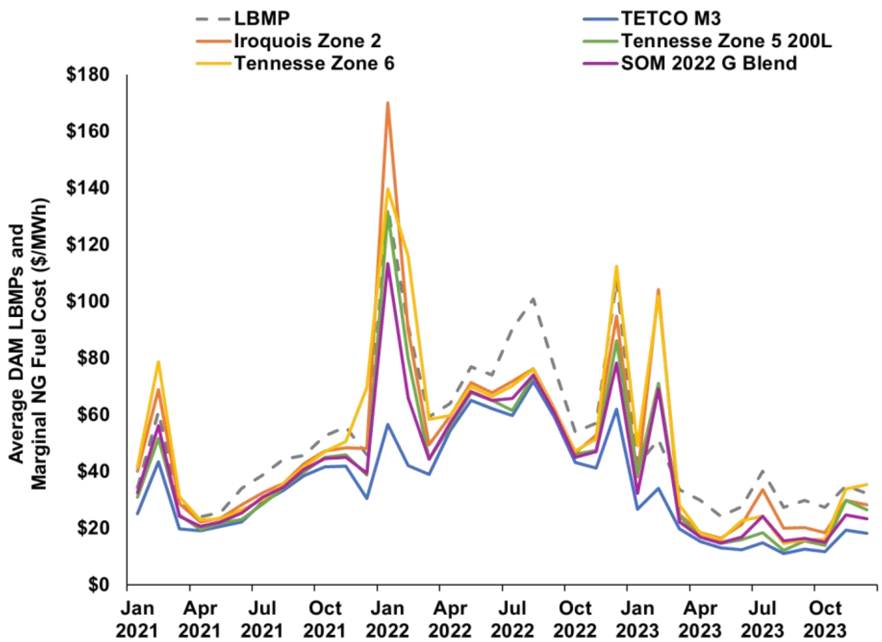
b. Liquidity Analysis



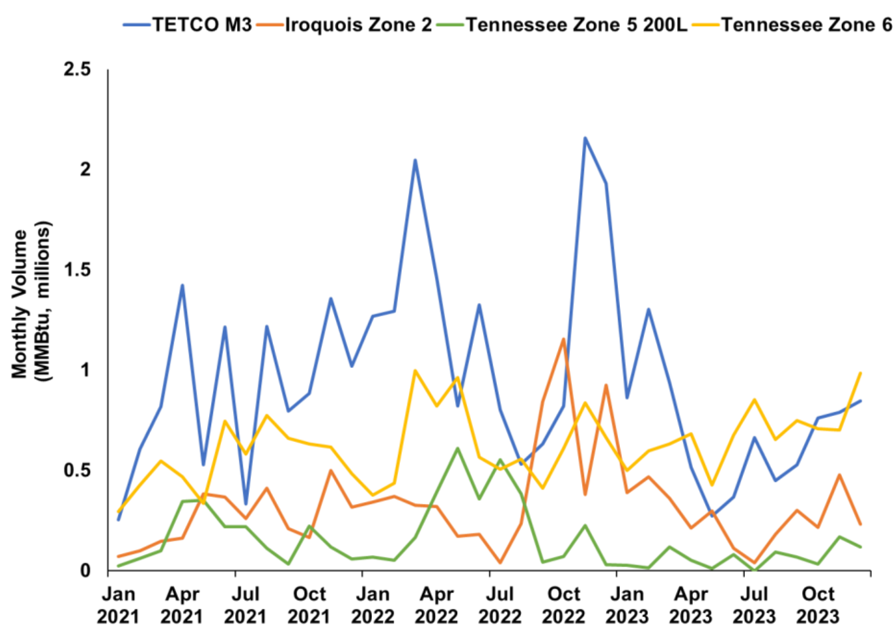
Notes: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 19: Market Dynamics and Liquidity Analysis: Load Zone G

a. Natural Gas Price Indices and DAM LBMPs



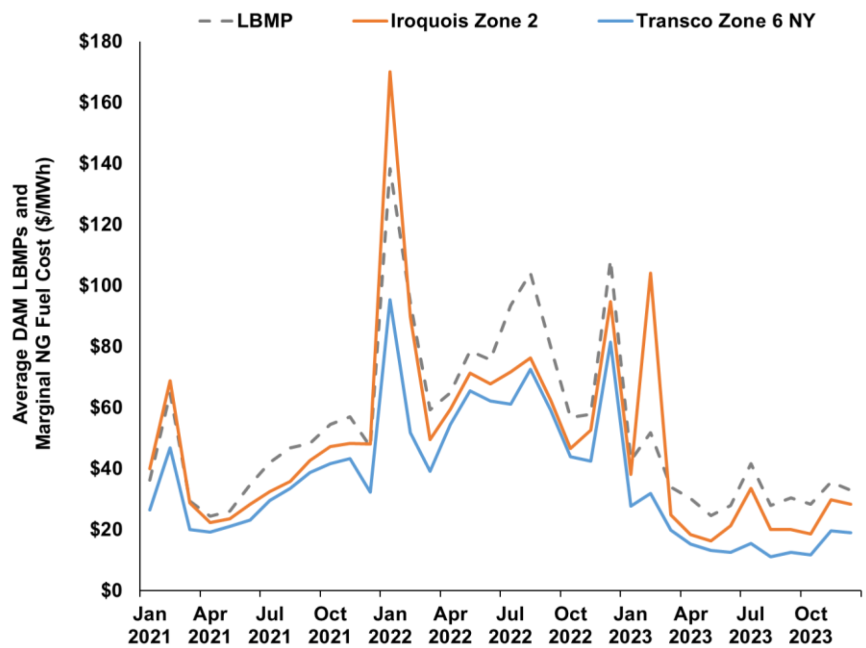
b. Liquidity Analysis



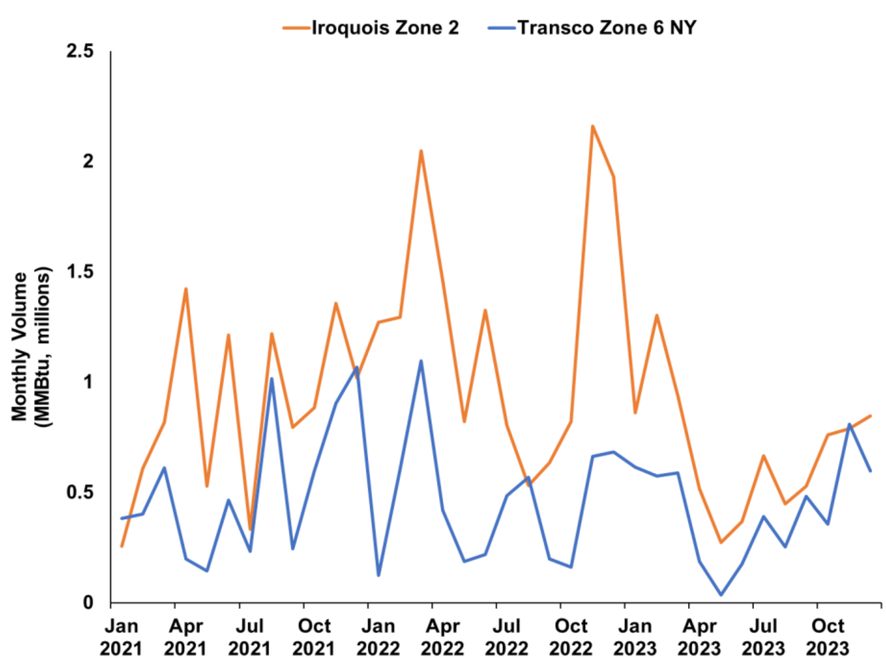
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, “Custom Reports,” https://www.nyiso.com/custom-reports for LBMP data.

Figure 20: Market Dynamics and Liquidity Analysis: Load Zone J

a. Natural Gas Price Indices and DAM LBMPs



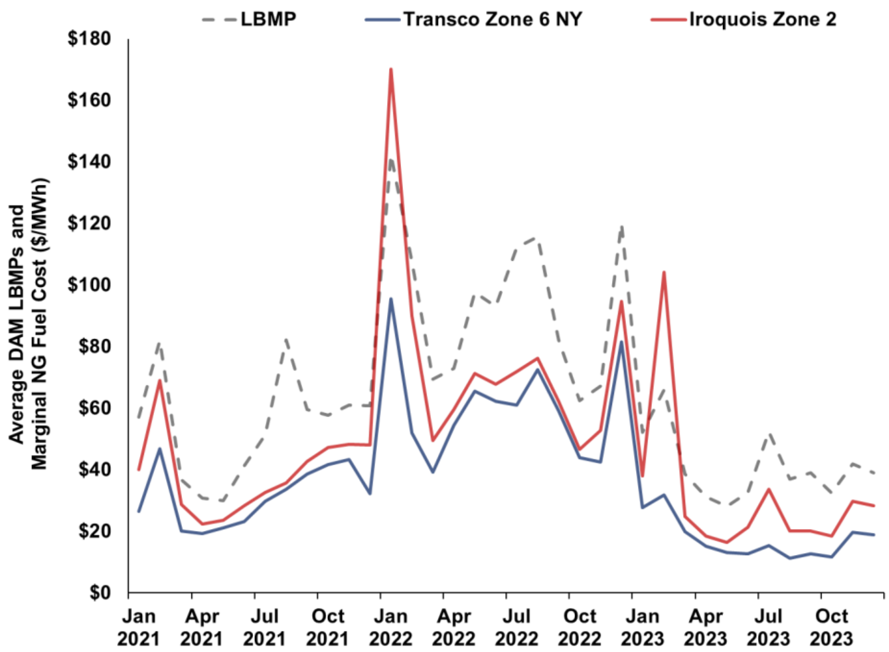
b. Liquidity Analysis



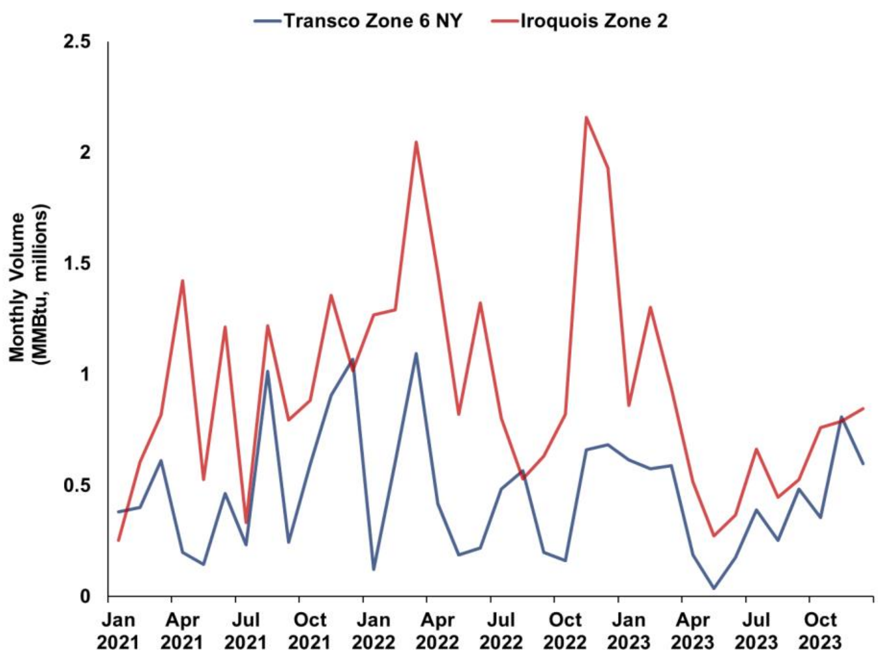
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, “Custom Reports,” https://www.nyiso.com/custom-reports for LBMP data.

Figure 21: Market Dynamics and Liquidity Analysis: Load Zone K

a. Natural Gas Price Indices and DAM LBMPs



b. Liquidity Analysis



Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Table 44 identifies the gas hubs selected by AG based on the considerations listed above, along with consideration of input and discussions with stakeholders and the Market Monitoring Unit. **Table 45** summarizes AG's assessment of potentially applicable natural gas indices for each location based on the criteria identified above.

Table 44: Recommended Gas Index by Location

Load Zone	Natural Gas Index
Load Zone C	Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November)
Load Zone F	Iroquois Zone 2
Load Zone G (Dutchess County)	Iroquois Zone 2
Load Zone G (Rockland County)	Tennessee Zone 6
Load Zone J	Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)
Load Zone K	Iroquois Zone 2

Table 45: Natural Gas Hub Selection Criteria, By Location

Load Zone C [84]				
Decision Criteria	**Dawn Ontario &Tennessee Zone 4 200L Blend**	**2022 SOM Load Zones B,C,E Blend**	**Dominion North**	**2021-2040 Outlook Load Zones A-E Blend**
Market Dynamics	Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation
Liquidity	Medium/High	Low/Medium	Medium	Medium
Geography	Yes	Yes	Yes	No
2021-2025 DCR	No	Yes	No	No
2022 SOM	No	Yes	No	No
2021-2040 Outlook	No	No	No	Yes
Recommendation	✓			

[84] The "Dawn Ontario – Tennessee Zone 4 200L Blend" is comprised of Dawn Ontario spot prices from December to March and Tennessee Zone 4 200L spot prices from April – November; the 2022 SOM utilizes a blend comprised of Niagara spot prices from December to March and Tennessee Zone 4 200L spot prices from April to November for Load Zones B, C and E; the 2021-2040 Outlook uses a blend comprised of the weighted average of spot prices from Dominion South (91%), Tetco M3 (7%), and Columbia (2%) for Load Zones A-E.

Load Zone F[85]		
Decision Criteria	**Iroquois Zone 2**	**Tennessee Zone 6**
Market Dynamics	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	Medium
Geography	Yes	No
2021-2025 DCR	Yes	No
2022 SOM	Part of Load Zone F Blend	Part of Load Zone F Blend
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend
Recommendation	✓	

Load Zone G (Dutchess County)				
Decision Criteria	**Iroquois Zone 2**	**Tetco M3**	**Tennessee Zone 5 200L**	**SOM 2022 Load Zone G Blend[86]**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	High	Medium	Medium
Geography	Yes	No	Yes	Yes/No
2021-2025 DCR	Yes	No	No	No
2022 SOM	Part of Load Zone G Blend	Part of Load Zone G Blend	No	Yes
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Recommendation	✓			

[85] The 2022 SOM utilizes the lesser of the spot prices from a Tennessee Zone 6 and Iroquois Zone 2 for Load Zone F. The "Load Zones F-I Blend" from the 2021-2040 Outlook is comprised of the weighted average of the spot prices from Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%) and Tetco M3 (3%).
[86] The SOM 2022 "Zone G Blend" is comprised of the average of spot prices from Iroquois Zone 2 and Tetco M3.

Load Zone G (Rockland County)					
Decision Criteria	**Iroquois Zone 2**	**Tetco M3**	**Tennessee Zone 6**	**Tennessee Zone 5 200L**	**SOM 2022 Load Zone G Blend**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	High	Medium	Medium	Medium
Geography	No	No	Yes/No	Yes	Yes/No
2021-2025 DCR	No	Yes	No	No	No
2022 SOM	Part of Load Zone G Blend	Part of Zone G Blend	No	No	Yes
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Recommendation			✓		

Load Zone J			
Decision Criteria	**Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)**	**Transco Zone 6 NY**	**Iroquois Zone 2**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	High LBMP Correlation
Liquidity	Medium	Medium	Medium
Geography	Yes	Yes	Yes/No (depending on season)
2021-2025 DCR	Yes	Yes	No
2022 SOM	Yes	Yes	No
2021-2040 Outlook	Yes	Yes	No
Recommendation	✓		

Load Zone K		
Decision Criteria	**Transco Zone 6 NY**	**Iroquois Zone 2**
Market Dynamics	High LBMP Correlation	High LBMP Correlation
Liquidity	Medium	Medium
Geography	Yes	Yes
2021-2025 DCR	No	Yes
2022 SOM	No	Yes
2021-2040 Outlook[87]	Part of Load Zone K Blend	Part of Load Zone K Blend
Recommendation		✓

For Load Zone J, Transco Zn 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to Load Zone J and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets. However, during winter months, prices available for interruptible/non-firm natural gas are more representative of pricing for Iroquois Zone 2, likely due to prioritization of firm gas use for retail LDC gas demand using Transco Zone 6 NY capacity. To improve the correlation between zonal LBMPs and natural gas hubs, AG recommends Transco Zone 6 NY for February – November and Iroquois Zone 2 for December – January (See Table 46) for Load Zone J.

Table 46. Load Zone J Gas Hub-Zonal DAM LBMP Correlation: December - January and February

Month	Gas Hub	Zonal LBMP Correlation	Recommendation
December-January	Transco Zone 6 NY	0.819	
	Iroquois Zone 2	0.895	✓
February	Transco Zone 6 NY	0.736	✓
	Iroquois Zone 2	0.520	

Sources: [A] S&P CapIQ (Fuel Prices; obtained by AG). [B] NYISO (DAM LBMPs). **Notes**: Zonal LBMP correlations calculated from daily averages of hourly DAM zonal LBMPs.

For Load Zone F, Load Zone G (Dutchess County), and Load Zone K, AG recommends the use of Iroquois Zone 2 as the natural gas index. These recommendations reflect a balance of considerations, particularly market dynamics and geography. For Load Zone K in particular, Iroquois Zone 2 reflected the best proxy for gas prices during constrained conditions.

For Load Zone G (Rockland County), AG recommends the use of Tennessee Zone 6 as the natural gas index. Certain indices with geographic proximity did not provide a reasonable expectation of the long-run equilibrium between gas and electricity markets or exhibited other concerns such as liquidity. In particular, the Millennium

[87] The "Load Zone K Blend" from the 2021-2040 Outlook is comprised of the weighted average of the spot prices from Iroquois Zone 2 (51%) and Transco Zone 6 NY (49%).

pipeline crosses through Rockland County, but it may not have the required flexibility of supply for a fossil peaking plant during all seasons. The Millennium pipeline also has limited reported trading volume in years before 2019, which raise liquidity concerns for use as a proxy gas pricing hub. By contrast, Tennessee Zone 6 is a liquid trading hub which reasonably reflects the fuel cost of a generator such as the fossil peaking plant technology options evaluated in this study, that is expected to operate intermittently throughout the year. While the Tennessee Zone 6 gas hub delivery point is outside Rockland County, the Tennessee Gas Pipeline (TGP) system delivers to points along the southern side of Rockland County west of the Hudson River.

In Load Zone C, a number of pipelines, including those owned by TGP, Dominion, and Millennium, cross the zone. Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, AG recommends the use of TGP Zone 4 (200L) as the natural gas index for Load Zone C for the April – November period. For the winter months of December-March, AG recommends the use of Dawn Ontario as the gas hub for Load Zone C. As depicted in **Figure 10(b)**, Dawn Ontario is far more liquid than other natural gas hubs in the region, such as Niagara. Additionally, Dawn Ontario's prices closely track other natural gas hubs in the region.

For fossil peaking plant technology options that include dual fuel capability, 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).[88]

Table 47 identifies assumptions for various additional costs associated with the use of natural gas or ULSD (for plants assumed to include dual fuel capability) for the fossil peaking plant technology options. 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.[89] Within the net EAS model for fossil peaking plant technology options, if the fossil peaking 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% depending on location. The use of these premiums (discounts) is described above.

Table 47: 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

Note: [1] NYC ULSD tax is based on current sales tax rates. **Sources**: [1] Potomac Economics, 2023 State of the Market Report for the New York ISO Markets, May 2024, Table A-29. [2] New York State Department of Taxation and Finance, Publication 718-A: Enactment and Effective Dates of Sales and Use Tax Rates, effective November 2023.

[88] Data is available from the EIA. *See* EIA, "New York Harbor Ultra-Low Sulfur No 2 Diesel Spot Price," https://www.eia.gov/dnav/pet/hist/eer_epd2dxl0_pf4_y35ny_dpgD.htm.

[89] As discussed in Section II, fossil peaking plant technology options that include dual fuel capability 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. This assumption is supported by estimated oil burn rates projected by the net EAS revenues model. Using data for the period September 1, 2021 through August 31, 2024, AG found that for dual fuel fossil peaking plant technology options in all locations – assuming the GE 7HA.03 with dual fuel and SCR emissions controls – no units burn more than 96 hours of fuel oil during a single model year.

iii. Emission Allowance Prices:

For the fossil peaking plant technology options, allowance prices for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are obtained from S&P Global Market Intelligence, and represent national annual prices for both pollutants, and seasonal prices for NO_x.[90] CO_2 allowance prices for the fossil peaking plant technology options are obtained from the Regional Greenhouse Gas Initiative's (RGGI) auction results, representing RGGI-region clearing prices established on a quarterly basis.[91]

iv. Other Fossil Peaking Plant Model 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 ICAP Demand Curves. The net EAS revenues model for fossil peaking plant technology options requires additional input data to carry out the calculations, which are not updated as part of the annual update process. This data falls into three main categories:

1. **Fossil peaking plant operating characteristics**: this data includes heat rates, emissions rates, summer/winter capacity ratings, operating capabilities (e.g., start time), and locations (to identify the appropriate LBMPs and gas hubs) for each fossil peaking plant technology option.
2. **Fossil peaking plant operating costs:** this data includes variable O&M costs, unit start-up costs, natural gas transportation cost adders and taxes, and RTM fuel premiums for each fossil peaking plant technology option.
3. **Fossil peaking plant revenue and pricing data**: this data includes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03 technology option and a $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02 technology option for the 2025-2026 Capability Year, as discussed in Section IV.B.2.c.i of this report. This category also includes level of excess adjustment factors (LOE-AFs), discussed below in Section IV.B.2.d and in Appendix C.

Operating characteristics and costs are summarized further in **Table 47** and Appendix A.

v. Battery Specific Data

The net EAS revenues models for BESS options use the same data as the fossil model for a wide variety of parameters, including LBMPs, LOE-AFs, and Rate Schedule 1 charges. The BESS net EAS models require additional input data. This data falls into three main categories:

1. **BESS operating characteristics:** this data includes charging efficiency, storage duration, and the assumed target charge level (i.e., 50% of the battery's capacity), all provided by 1898 & Co. for each BESS option
2. **BESS operating costs:** these data include variable O&M costs provided by 1898 & Co. for each BESS option
3. **BESS revenue and pricing data:** these data include RTD prices (i.e. nominal 5-minute interval prices), and prices for spinning reserves, which are the basis for reserve prices in the battery model.

[90] 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.
[91] RGGI's quarterly auctions take place at the start of January, April, July, and October; daily costs are assigned based upon the most recent auction price. Results are available at RGGI, "Auction Results," https://www.rggi.org/auctions/auction-results.

These are both available on the NYISO website. For VSS revenues, a $4.10/kW-year adder is applied for the 2025-2026 Capability Year, as discussed in Section IV.B.2.c.i of this report.

d. 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 costs and revenue estimates used in determining the ICAP Demand Curves reflect system conditions with capacity equal to the applicable minimum Installed Capacity Requirement plus the capacity of the peaking plant in NYCA and each Locality (the LOE condition).[92] Consistent with previous DCRs, this Services Tariff requirement is addressed through the development of a set of LOE adjustment factors (LOE-AFs) 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 tariff-prescribed LOE conditions, 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 the tariff-prescribed 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.[93]

AG 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 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 from the 2021-2040 System and Resource Outlook base case for model years 2021-2022, and the 2023-2042 System and Resource Outlook base case for model years 2023-2027. 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. For the 2025-2029 DCR, GE developed LOE cases for both a nominal 200 MW peaking plant, and a nominal 400 MW peaking plant. The resulting LOE-AFs derived using the LOE case with a nominal 200 MW peaking plant are used for the BESS options, while the resulting LOE-AFs using the LOE case with a nominal 400 MW peaking plant are used for the SCGT options.

To better align LOE-AFs and the historical prices they are applied to, AG calculated LOE-AFs by averaging Day-Ahead LBMPs for each month, relevant Load Zone, and period (i.e., "on-peak," "high on-peak," and "off-peak;" consistent with the groupings used in the 2021-2025 DCR). Periods will be defined in the following manner:

- *On-peak* hours are all hours between 7 am and 10:59pm, Monday through Friday except for NERC defined holidays and Peak Load Window hours (below).

[92] Services Tariff, Section 5.14.1.2.2
[93] 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.

- *High On-peak* are the Peak Load Window hours established for the 2024-2025 Capability Year:[94]
  - Summer (June-August): hours beginning 1 pm until 8:59 pm
  - Winter (December-February): hours beginning 4 pm until 9:59 pm
- *Off-peak* are all hours not defined as included within on-peak or peak load window hours.

As depicted in **Table 48**, DAM LBMPs are weighted by how many times the given month and year combination are utilized as an input in the net EAS revenue estimates over the reset period. Over the reset period, the theoretical maximum number of times that LBMPs for a given month could be utilized is 12 (i.e., the rolling three-year historical periods used in the net EAS revenue estimates, multiplied by the four Capability Years covered by the DCR). The LBMP weightings reflect how many times LBMPs from each month and year combination are utilized as an LBMP input over the reset period divided by 12. For example, LBMPs from September 2021 will only be used in the net EAS revenue estimates for the 2025-2026 Capability Year ICAP Demand Curves. Thus, the LBMP weighting for September 2021 is 1/12 = 8%.

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 applicable reserve margin consistent with LOE market conditions – i.e., ICR/LRC plus the capacity of the proposed peaking plant (the 2-hour BESS unit) for each capacity region.

Table 48. LBMP Weightings by Month and Modeled Year to Calculate LOE-AFs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	0%	0%	0%	0%	0%	0%	0%	0%	8%	8%	8%	8%
2022	8%	8%	8%	8%	8%	8%	8%	8%	17%	17%	17%	17%
2023	17%	17%	17%	17%	17%	17%	17%	17%	25%	25%	25%	25%
2024	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
2025	25%	25%	25%	25%	25%	25%	25%	25%	17%	17%	17%	17%
2026	17%	17%	17%	17%	17%	17%	17%	17%	8%	8%	8%	8%
2027	8%	8%	8%	8%	8%	8%	8%	8%	0%	0%	0%	0%

LBMPs and reserve prices will then be 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 given peak hour in a Load Zone in July is \$50/MWh, and the LOE-AF for peak hours in July is 1.02 for such location, then the LBMP for that hour used in net EAS calculations would be \$50 * 1.02 = \$51/MWh.

[94] The 2024-2025 Capability Year Peak Load Windows are available at https://www.nyiso.com/documents/20142/36848677/Peak-Load-Window-for-the-2024-25-Capability-Year.pdf.

Appendix C 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. LOE-AFs are generally similar in magnitude to the 2021-2025 DCR, ranging between 0.905 to 1.278 during the ”high on-peak” period; 0.972 to 1.056 during the ”off-peak” period; and 0.942 to 1.095 during the “on-peak” period. Unlike the 2021-2025 DCR, LOE-AFs sometimes fall below 1 due to net load in the base case being higher than the scaled load in the LOE cases in certain zones.

C. Results

The values in this Final Report are for the 2025-2026 Capability Year. For subsequent Capability Years encompassed by this reset period, the net EAS revenues will be calculated using the same model applicable to the relevant peaking plant technology option selected as the basis for each ICAP Demand Curve, but with updated data as part of the annual update process described in Section VI below.

Net EAS results for the Capability Year 2025-2026, by location, are summarized in **Table 49** through **Table 51**. Included are the average annual net EAS revenues (in nominal $/kW-year) over the three-year historic period, summarized by peaking plant type and location, as well as average annual values for run hours, unit starts, and hours of operation per start. Appendix D includes detailed data for each peaking plant, with net EAS revenues reported by DAM position and RTM dispatch, fuel use, and year.

The net EAS revenues values provided herein are based on data for the three-year period September 2021 through August 2024.

Table 49: Net EAS Model Results for Fossil Peaking Plants by Location, Dual Fuel Capability (2025-2026 Capability Year)

		Annual Average Net EAS Revenues ($/kW-year)			Annual Average Run Hours		
		Combustion Turbine With SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.02
C	Central	$68.32	-	$54.24	1,895.33	-	604.33
F	Capital	$97.17	-	$65.49	2,368.33	-	565.33
G	Hudson Valley (Dutchess)	$77.34	-	$62.73	1,699.33	-	571.00
G	Hudson Valley (Rockland)	$80.03	-	-	1,876.67	-	-
J	New York City	$87.44	-	-	3,297.33	-	-
K	Long Island	$111.91	$105.27	-	3,262.67	2,689.33	-

		Annual Average Unit Starts			Annual Average Hours per Start		
		Combustion Turbine With SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.02
C	Central	109	-	25	17.4	-	24.2
F	Capital	162	-	30	14.6	-	18.8
G	Hudson Valley (Dutchess)	147	-	54	11.5	-	10.5
G	Hudson Valley (Rockland)	148	-	-	12.7	-	-
J	New York City	188	-	-	17.6	-	-
K	Long Island	233	206	-	14.0	13.1	-

		Annual Average Reserve Hours		
		Combustion Turbine With SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.02
C	Central	49	-	92
F	Capital	215	-	218
G	Hudson Valley (Dutchess)	343	-	382
G	Hudson Valley (Rockland)	275	-	-
J	New York City	289	-	-
K	Long Island	204	262	-

Notes: [1] Results reflect data for the period September 1, 2021 through August 31, 2024. [2] Assumes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03 and $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02. [3] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 50: Net EAS Model Results for Fossil Peaking Plants by Location, Natural Gas-Only (2025-2026 Capability Year)

		Annual Average Net EAS Revenues ($/kW-year)		Annual Average Run Hours	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	$68.32	$54.70	1,895.33	604.33
F	Capital	$96.55	$67.35	2,349.33	587.33
G	Hudson Valley (Dutchess)	$71.82	$55.63	1,738.67	590.67
G	Hudson Valley (Rockland)	$73.28	-	1,883.67	-

		Annual Average Unit Starts		Annual Average Hours per Start	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	109.00	25.00	17.4	24.2
F	Capital	163.00	35.33	14.4	16.6
G	Hudson Valley (Dutchess)	149.33	58.00	11.6	10.2
G	Hudson Valley (Rockland)	149.00	-	12.6	-

		Annual Average Reserve Hours	
		Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	49	92
F	Capital	212	215
G	Hudson Valley (Dutchess)	318	354
G	Hudson Valley (Rockland)	258	-

Notes: [1] Results reflect data for the period September 1, 2021 through August 31, 2024. [2] Assumes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03 and $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02. [3] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 51: Net EAS Model Results for BESS by Location

	Current Year (2025-2026)					
Peaking Plant Technology	**C - Central**	**F - Capital**	**G - Hudson Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
Net EAS Revenues						
2-Hour BESS	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
4-Hour BESS	$63.57	$88.64	$87.34	$87.39	$90.35	$109.40
6-Hour BESS	$65.98	$93.58	$93.60	$93.69	$94.49	$120.99
8-Hour BESS	$66.48	$93.54	$95.12	$95.24	$94.89	$124.71
Percentage of Total Discharged Energy Relative to Maximum-Rated Throughput						
2-Hour BESS	68%	59%	51%	51%	51%	61%
4-Hour BESS	80%	78%	70%	71%	69%	84%
6-Hour BESS	78%	76%	71%	71%	67%	82%
8-Hour BESS	67%	66%	64%	63%	61%	73%
Average Daily Hours of Discharge						
2-Hour BESS	1.36	1.18	1.02	1.02	1.02	1.21
4-Hour BESS	3.20	3.11	2.82	2.83	2.74	3.35
6-Hour BESS	4.68	4.58	4.24	4.25	3.99	4.93
8-Hour BESS	5.38	5.31	5.10	5.08	4.86	5.82

Notes:
[1] Results reflect data for the period September 1, 2021 through August 31, 2024.
[2] Assumes a $4.10/kW-year voltage support service (VSS) revenue adder.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E.
[4] Maximum-rated throughput is equal to (nominal output) * (nominal discharge duration) * (number of operating days) for each BESS option.

V. ICAP Demand Curve Model and Reference Point Prices

A. Introduction

The ICAP Demand Curves are designed to ensure that the ICAP market provides sufficient revenues to support the development of the hypothetical peaking plant selected to serve as the basis for each ICAP Demand Curve, as necessary to maintain resource adequacy. In Sections III and IV, AG established the values for gross CONE and net EAS revenues for the peaking plant technology options in all locations evaluated in this study. The difference in annualized gross CONE and net EAS revenues is defined as the ARV. That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technology options. This section describes how the resulting ARVs are translated into RPs 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, AG presents the resulting ICAP Demand Curve parameters for each capacity region for 2025-2026 Capability Year. Section VI summarizes the procedures for annual update of ICAP Demand Curve parameters through the formulaic approach established at the time of this DCR.

Beginning with the 2025-2026 Capability Year, the NYISO will implement enhancements to the current methodologies for translating the annualized gross CONE values and ARVs to monthly values used in establishing the ICAP Demand Curves. The enhancements provide for express accounting of relative seasonal reliability risks. The proposed enhancements will also result in the production of seasonal ICAP Demand Curves (i.e., separate curves applicable to the summer and winter periods encompassed by each Capability Year). Consistent with current requirements, the seasonal curves applicable for each Capability Year will continue to be designed to ensure that the hypothetical peaking plant used to establish each ICAP Demand Curve earns sufficient revenues annually to cover its cost of market entry under the capacity market supply conditions assumed in determining the ICAP Demand Curves (i.e., the tariff-prescribed LOE conditions).[95]

B. Selection of the Peaking Plant Technology

AG will calculate seasonal monthly ICAP/UCAP reference point prices consistent with the above-described new methodology approved by FERC for implementation beginning with the 2025-2026 Capability Year. As specified in the Installed Capacity Manual, the metric transacted in the ICAP market is UCAP:

> *"[E]ach price on each ICAP Demand Curve shall be converted into a price on the corresponding UCAP Demand Curve by dividing it by the product of: (a) the Capacity Accreditation Factor of the peaking plant used to establish the applicable ICAP Demand Curve, and (b) one minus the applicable derating factor of such peaking plant."*[96]

As such, to reflect the impact of Capacity Accreditation Factors (CAFs) and derating factors on the choice of peaking plant technology option for each ICAP Demand Curve, AG considers the relevant UCAP reference point prices for each technology option in selecting the appropriate peaking plant technology for each demand curve. An

[95] FERC Docket No. ER24-701-000, *New York Independent System Operator, Inc.*, Proposed Installed Capacity Demand Curve Enhancements (December 19, 2023); and FERC Docket No. ER24-701-000,*New York Independent System Operator, Inc.*, Letter Order (February 15, 2024).
[96] Installed Capacity Manual, May 2024, available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf

economic evaluation of the peaking plant technology options without consideration of CAFs or derating factors would fail to appropriately reflect the marginal reliability contribution of each peaking plant technology option towards meeting NYSRC resource adequacy requirements for the upcoming Capability Year. The selected peaking plant technology for each capacity region should result in curves representing the lowest cost on a UCAP basis.

For the purposes of this Final Report, AG used NYISO's revised CAFs for the 2024-2025 Winter Capability Period.[97]

C. ICAP Demand Curve Shape and Slope

The ICAP Demand Curves are designed with three basic elements: a cap on the maximum allowable prices, a floor on prices (at zero), and a sloped demand curve that determines prices for varying levels of capacity supply 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, is intended to capture 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 Curves include a ZCP, which reflects the point at which incremental capacity is deemed to provide no incremental value and the price declines to zero. 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. Such sloped design also reduces incentives for the exercise of market power.

The ICAP Demand Curves are constructed such that the applicable peaking plant would recover its ARV when the system is at the LOE – that is, the applicable IRM/LCR plus the capacity of the relevant peaking plant - while also accounting for expected difference in the seasonal availability of capacity supply. Given differences in costs to construct new capacity supply resources between locations throughout New York as well as transmission constraints that limit flows between Load Zones, separate ICAP Demand Curves are established for NYCA and each Locality. Each ICAP Demand Curve is comprised of three portions (each of which is a straight line) reflecting the three components discussed above:[98]

1) Maximum allowable price: A horizontal line with the price equal to 1.5 times the applicable 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

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[97] On June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. On July 2, 2024, the NYISO filed a request with FERC to authorize updating the CAFs for the 2024-2025 Winter Capability Period. On August 15, 2024, FERC issued an order granting the NYISO's request. As such, AG uses NYISO's revised 2024-2025 Winter Capability Period CAFs for this final report.
[98] As described in Section V.A, beginning with the 2025-2026 Capability Year, separate ICAP Demand Curves applicable for each Capability Period encompassed by a Capability Year will be established.

3) Price floor: A horizontal line with the price equal to zero and the quantity includes all quantities greater than the ZCP quantity.[99]

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 ZCP ratios (ZCPR), the impact of additional capacity from the tariff prescribed LOE conditions, and seasonal factors (including the relative reliability risk by season and the expected seasonal differences in capacity availability). The following sections provide additional detail on the ZCPR, seasonal capacity availability 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 2014-2017 DCR, the ZCPs for the ICAP Demand Curves were set at 112% of IRM for NYCA, 118% of LCR for Long Island, 118% of LCR for New York City, and 115% of LCR for the G-J Locality. This decision retained the then-current ZCPs for NYCA, NYC, and LI, and set the ZCP for the G-J Locality midway between the values for NYC 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 ZCPs based on GE-MARS analysis of loss of load expectations associated with varying levels of capacity in the market.[100] While FTI had recommended revising the ZCPs based on the results of its analysis, the independent consultant for the 2014-2017 ultimately recommended adjusting ZCPs to a point midway between then-current values and the values recommended by FTI. After the completion of the independent consultant's study report for the 2014-2017 DCR, an analysis was performed by the MMU that was also based on GE-MARS modeling completed by NYISO staff.[101]

Both the FTI and MMU recommendations for potential changes to ZCPs were based on assessments of the point at which additional capacity beyond the applicable minimum requirement provided little or no marginal value in terms of improved reliability (as reflected in resulting changes to 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 Localities to the NYCA. In contrast, the modeling used by the 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 2014-2017 DCR, no additional studies have been conducted to specifically inform the determination of ZCPs for the ICAP Demand Curves. Considering these factors, AG recommends that the current ZCPs remain unchanged for this DCR.

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[99] When referencing the ZCP in percentage terms relative to applicable IRM or LCR, AG uses the term zero crossing point ratio (ZCPR).
[100] NERA Economic Consulting, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, report for NYISO, August 2, 2013, pp. 14-15.
[101] The MMU analysis was presented at the August 22, 2013 ICAPWG meeting. Potomac Economics, "Preliminary Recommend Zero Crossing Points for the 2014-17 New York ISO Demand Curves," presentation to the NYISO ICAP Working Group, August 22, 2013.

2. Seasonal Capacity Availability

The expected seasonal capacity availability ratios (i.e., the winter-to-summer ratio (WSR) and summer-to-winter (SWR) ratio) capture differences in the expected quantity of capacity available between winter and summer seasons given differences in seasonal operational capability. The ICAP Demand Curves account for differences in the prices that would prevail, all else equal, between seasons due to these seasonal differences in capacity.

The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year. The SWR is calculated as the ratio of total summer ICAP to total winter 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 by using the applicable NYCA or Locality translation factor, which consider CAFs and unit specific derating factors for all relevant resources. These totals are adjusted for certain resource entry and exit circumstances.[102] Both total 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.

Table 52 provides the WSR and SWR values for the 2025-2026 Capability Year ICAP Demand Curves used in producing the results in this Final Report and reflect data for the period September 1, 2021 through August 31, 2024.

Table 52: 2025-2026 Capability Year WSR and SWR by Location

Capacity Region	Capability Year	Winter-Summer Ratio	Summer-Winter Ratio
NYCA	2025-2026	1.033	0.968
G-J Locality	2025-2026	1.050	0.952
New York City	2025-2026	1.057	0.946
Long Island	2025-2026	1.083	0.923

3. Level of Excess Criterion

The LOE for each peaking plant is defined as the ratio of the applicable minimum Installed Capacity requirement plus the average degraded net peaking plant capacity to the applicable minimum Installed Capacity requirement. The LOE is expressed in percentage terms and defined by the following equation, where all capacities are expressed in MW.

[102] Services Tariff, Section 5.14.1.2.2.3. Broadly, these adjustments seek to include resource changes in all months of the applicable twelve-month period based on the resource status that is expected to persist at the end of each 12-month period. For new entry of a resource that comes online after September of a given 12-month period and remains in the market for the remaining months of such 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 does not include resources returning from an Inactive Reserves state. If a resource exits the capacity market after September of a given 12-month period and remains out of the market for the remaining months of such period, 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 that retire, mothball, or enter an ICAP Ineligible Force Outage state.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)} \tag{6}$$

The LOE varies by capacity region, depending on the applicable minimum requirement, and by size of the various peaking plant options evaluated in this study. The ICR/LCR values are based on the peak load forecasts and the IRM/LCR values for the 2024/2025 Capability Year. **Table 53** and **Table 54** provides the applicable forecasted peak load, IRM/LCR values (in percentage terms), and the resulting LOE by capacity region and technology, expressed as a percentage.

Table 53: Fossil Peaking Plant Technology Options Level of Excess by Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2024)	IRM/LCR	LOE (%) by Technology	
			GE 7HA.03	GE 7HA.02
NYCA	31,542	122.00%	101.04%	100.86%
G-J	15,220	81.0%	103.22%	102.66%
NYC	11,168	80.40%	104.50%	-
LI	5,043	105.30%	107.61%	106.65%

Note:
[1] Average degraded net capacity by technology is provided in Table 34.

Table 54: BESS Options Level of Excess by Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2024)	IRM/LCR	LOE (%) by Battery Duration			
			2-hr BESS	4-hr BESS	6-hr BESS	8-hr BESS
NYCA	31,542	122.00%	100.52%	100.52%	100.52%	100.52%
G-J	15,220	81.0%	101.62%	101.62%	101.62%	101.62%
NYC	11,168	80.40%	102.23%	102.23%	102.23%	102.23%
LI	5,043	105.30%	103.77%	103.77%	103.77%	103.77%

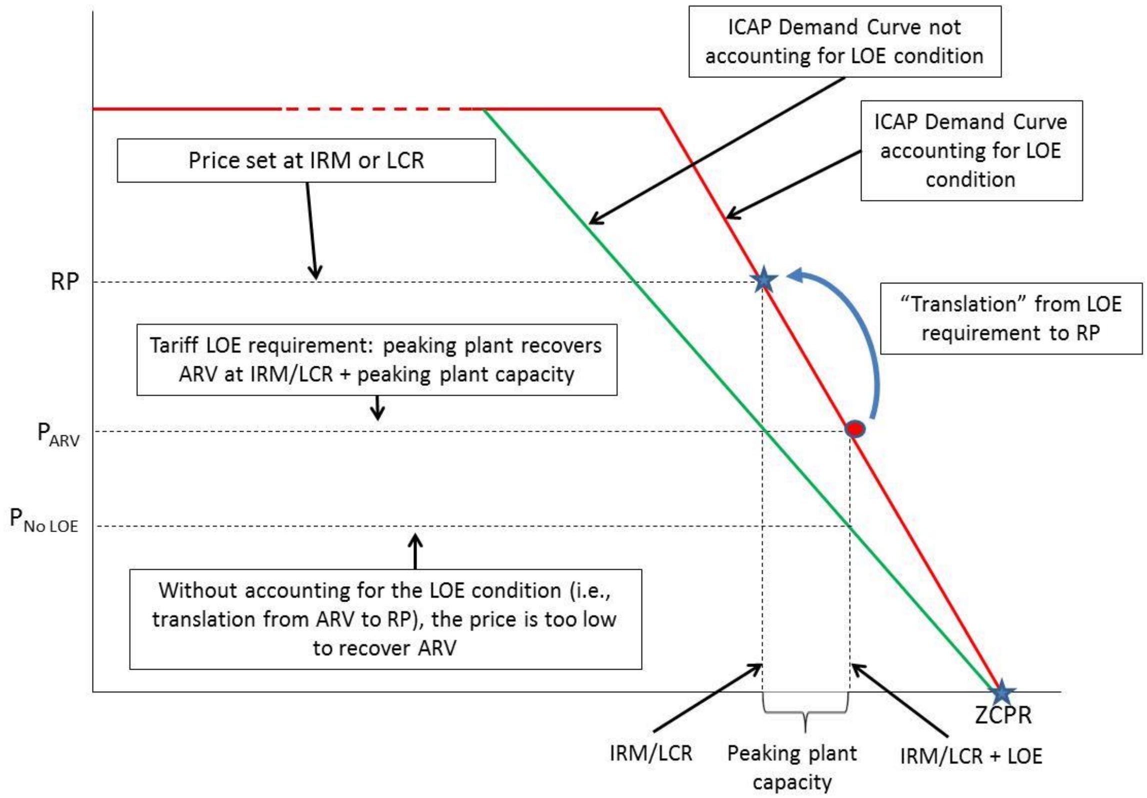
Note:
[1] Refer to Table 35. BESS is sized for 200 MW net at the POI. Energy discharge capability is maintained through capacity augmentation throughout the assumed project life.

D. Reference Point Price Calculations

Figure 22 illustrates the “geometry” of a generic, annual 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 22, with the price P_{ARV} and the quantity equal to the applicable seasonal level of excess conditions; and (2) the ZCPR. These two points define the red line in **Figure 22**, which is the ICAP Demand Curve slope. Having defined the ICAP Demand Curve slope, the seasonal RP can be calculated at the appropriate quantity for each capacity region. This calculation requires a translation that is defined below.

Figure 22 also generically 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 seasonal LOE conditions, the price earned by the hypothetical peaking plant at the LOE (i.e., $P_{No\ LOE}$ in Figure 22) would be insufficient to recover ARV.

Figure 22: Illustration of the Reference Point Price and Level of Excess Requirement



Equations (7) and (8) define the summer reference point price (SRP) and winter reference point price (WRP) as a function of both the seasonal capacity adjustment (WSR and SWR), relative seasonal reliability risk (SLOLE and WLOLE) and the seasonal level of excess requirement:

$$SRP_z = \frac{ARV_z * AssmdCap_z * max\ [min(CPMax, SLOLE), CPMin]}{6*\left[SDMNC_z*\left(1-\frac{(SLOE_Z-1)+max(0,SWR_Z-1)}{ZCPR-1}\right)\right]} \quad (7)$$

$$WRP_z = \frac{ARV_z * AssmdCap_z * max\ [min(CPMax, WLOLE), CPMin]}{6*\left[WDMNC_z*\left(1-\frac{(WLOE_Z-1)+max(0,WSR_Z-1)}{ZCPR-1}\right)\right]} \quad (8)$$

Where:

- *CPMax* is the maximum percentage of the Annual Reference Value (ARV_z) to be recovered by the peaking plant in one Capability Period
- *CPMin* is the minimum percentage of the Annual Reference Value (ARV_z) to be recovered by the peaking plant in one Capability Period (equal to 1 minus *CPMax*)
- *SLOLE* is the percentage of the annual loss of load expectation expected to occur in the Summer Capability Period based on the preliminary base case, as approved by the NYSRC, for the NYCA Installed Reserve Margin study covering the Capability Year for which the monthly ICAP reference point price is calculated
- *WLOLE* is the percentage of the annual loss of load expectation expected to occur in the Winter Capability Period based on the preliminary base case, as approved by the NYSRC, for the NYCA Installed Reserve Margin study covering the Capability Year for which the monthly ICAP reference point price is calculated (equal to 1 minus *SLOLE*)
- SWR_z is the ratio of the amount of ICAP available in the ICAP Spot Market Auctions in the Summer Capability Period to the amount of ICAP available in the ICAP Spot Market Auctions for the Winter Capability Period for location *z* (equal to 1 divided by WSR_z)
- *ARV* is the annual reference value for the relevant peaking plant ($/kW-year)
- $SDMNC_z$ is the summer dependable maximum net capability for the relevant peaking plant (MW)
- $WDMNC_z$ 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
- $SLOE_z$ is the ratio of level of excess that would occur in the Summer Capability Period (i.e., the applicable minimum ICAP requirement, plus $SDMNC_z$) to the applicable minimum ICAP requirement for location z
- $WLOE_z$ is the ratio of level of excess that would occur in the Winter Capability Period (i.e., the applicable minimum ICAP requirement, plus $WDMNC_z$) to the applicable minimum ICAP requirement for location z
- WSR_z is the ratio of total winter ICAP to total summer ICAP, as calculated by the NYISO for the relevant capacity region
- $ZCPR_z$ is the ZCP ratio of the ICAP Demand Curve for the relevant capacity region
- *SRP* is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region for the summer
- *WRP* is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region for the winter

Along with accounting for the seasonal level of excess requirement, Equations (7) and (8) also account for differences in the capacity market revenue and peaking plant capacity between Summer and Winter Capability Periods. Thus, the plant's ARV (defined in $/kW-year) is met through different revenue streams in each season – that is:

$$ARV * AssmdCap = 6 * SP * SDMNC + 6 * WP * WDMNC \quad (8)$$

Where:

- *SP* and *WP* represent the assumed summer and winter capacity prices at the seasonal level of excess conditions.

E. ICAP Demand Curve Parameters

AG has applied the methods, models and equations described in this Final Report to identify RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2025-2026. These values are presented in **Table 55**, below.

To arrive at these results, AG and 1898 & Co. considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the RP values provided herein. Specifically, AG and 1898 & Co. conclude the following:

- The two-hour BESS represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a BESS would use lithium-ion technology and a modular, PBE form factor.
- For the two-hour BESS, we assume a twenty-year amortization period, and incorporate additional costs for capacity augmentation to ensure consistent performance and nominal capacity value over the assumed life of the resource. Capacity augmentation costs are included in the two-hour BESS' VOM costs, reflecting the fact that capacity augmentation costs are related to the total throughput of the battery.
- The appropriate method to evaluate the peaking plant technology is to identify the technology that minimizes the cost of UCAP. An economic evaluation focused solely on the cost of ICAP would fail to account for variation in CAFs and derating factors across technology options.[103]
- The state of New York has begun a process to decarbonize the power sector over the next couple of decades, including passage of the CLCPA in 2019. The CLCPA does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology during the 2025-2029 DCR period. It does, however, affect the development and operation of such facilities, which could in turn affect present-day financial analysis parameters (e.g., the appropriate amortization period). For this DCR, our review included two categories of units that at least initially were powered using fossil fuels. First, we reviewed installation and operation of a fossil unit in each location designed to exclusively run on fossil fuels (and thus assumed to not operate in 2040 or beyond). Second, we reviewed installation and operation of a unit initially operating on fossil fuels, but retrofitted to operate on hydrogen fuel beginning in 2040. For the fossil-only unit, we applied a 13-year amortization period to reflect CLCPA's requirement for 100% of load to be served by zero-emissions resources by 2040, and consistent with the decisions by FERC accepting this amortization period method in the 2021-2025 DCR.[104] For the fossil-hydrogen unit, we

[103] On June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. On July 2, 2024, the NYISO filed a request with FERC to authorize updating the CAFs for the 2024-2025 Winter Capability Period. On August 15, 2024, FERC issued an order granting the NYISO's request. As such, AG uses NYISO's revised 2024-2025 Winter Capability Period CAFs for this final report.

[104] New York Independent System Operator, Inc., 183 FERC ¶ 61,130, Docket No. ER21-502, (May 19, 2023); and New York Independent System Operator, Inc., 185 FERC ¶ 61,010 (October 4, 2023).

studied the potential costs associated with retrofitting a turbine to run on hydrogen fuel, and the costs of storing associated hydrogen fuel onsite.

- For the fossil-fuel fired unit analysis, the GE 7HA.03 frame turbine represents the highest variable cost, lowest fixed cost SCGT peaking plant option that is economically viable for all locations except Load Zone K. The GE 7HA.02 option represents a lower fixed cost SCGT technology option for Load Zone K considering the SDU cost that would be applicable to the GE7HA.03 for Load Zone K. Such SDU costs are not applicable to a GE 7HA.02 option for Load Zone K. To be economically viable and practically constructible, a 7HA.03 SCGT (for all locations other than Load Zone K) and 7HA.02 SCGT (for Load Zone K would be built with SCR emission control technology in all locations except Zone K, whether constructed as gas-only or dual-fuel.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures related to capacity accreditation, consideration of applicable reliability and LDC retail gas tariff requirements, and developer expectations, we expect that developers would include dual fuel capability in all locations.
- For SCGT technologies, the WACC used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 14.0% cost of equity, for a WACC of 9.99%. Based on current tax rates in NY State and New York City, this translates to a nominal ATWACC of 9.02% for all locations other than Load Zone J and 8.76% for Load Zone J.
- For BESS technologies, the WACC used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 7.2% cost of debt; and a 14.5% cost of equity, for a WACC of 10.49%. Based on current tax rates in NY State and New York City, this translates to a nominal ATWACC of 9.45% for all locations other than Load Zone J and 9.17% for Load Zone J.
- For the purposes of modeling net EAS revenues for BESS technologies in the RTM, it is appropriate to use Real-Time Dispatch prices transacting on a nominal 5-minute basis. Consistent with the 2017-2021 and 2021-2025 DCRs, we continue to model net EAS revenues for fossil peaking plant options in the RTM using average hourly prices.
- The ICAP Demand Curves should maintain the current ZCP values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

Table 55 provides parameters for the 2025-2026 Capability Year ICAP Demand Curves for each location, consistent with the conclusions and technology findings described above. **Table 56** through **Table 58** provide additional information for the other technologies evaluated. For all locations, the appropriate peaking plant technology and design, as well as the net EAS model structure (including the granularity of real-time prices used by such models) selected as the basis for the 2025-2026 Capability Year ICAP Demand Curves remain fixed for the four-year duration of the reset period.

Table 55: 2025-2026 Capability Year ICAP Demand Curve Parameters ($2025 ICAP kW)

2-Hour BESS (RTD interval pricing net EAS Model)

		Current Year (2025-2026)					
Parameter	**Source**	**C - Central**	**F - Capital**	**G - Hudson Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
Gross Cost of New Entry ($/kW-Year)	[1]	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
Net EAS Revenues ($/kW-Year)	[2]	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$66.52	$45.66	$49.85	$45.75	$130.74	$43.92
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Winter to Summer DMNCs	[7]	1.033	1.033	1.050	1.050	1.057	1.083
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.21	$4.95	$5.40	$4.96	$14.16	$4.76
Winter ($/kW-Month)	[11]	$3.88	$2.66	$2.91	$2.67	$7.63	$2.56
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,441	$989	$1,080	$991	$2,833	$952
Monthly Revenue (Winter)	[13]=[11]*[9]	$776	$533	$582	$534	$1,525	$512
Seasonal Revenue (Summer)	[14]=6*[12]	$8,647	$5,936	$6,480	$5,948	$16,996	$5,710
Seasonal Revenue (Winter)	[15]=6*[13]	$4,656	$3,196	$3,489	$3,203	$9,152	$3,075
Total Annual Reference Value	[16]=[14]+[15]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$7.53	$5.17	$6.06	$5.56	$16.16	$6.02
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$5.69	$3.91	$5.21	$4.78	$13.63	$7.77
Summer ICAP Maximum Clearing Price ($/kW-Month)		$20.71	$20.86	$23.09	$22.35	$39.50	$26.99
Winter ICAP Maximum Clearing Price ($/kW-Month)		$15.65	$15.76	$19.86	$19.22	$33.30	$34.86
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS. [2] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period**.** [3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [4] Assumes a $4.10/kW-year voltage support service (VSS) revenue adder.

Table 56: Comparison of Indicative UCAP Reference Point Prices by Technology ($2025 UCAP Per kW-Month)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026) C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Summer Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$24.50	$20.80	$29.26	$27.22	$39.40	$74.52
	Gas Only, with SCR	$23.08	$19.49	$30.25	$26.38	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$27.43	$25.80	-	$29.23	-	-
	Gas Only, no SCR	$25.73	$23.97	-	$28.37	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$33.66
2-hour BESS	Battery Storage	$13.92	$9.56	$11.17	$10.25	$29.84	$11.60
4-hour BESS	Battery Storage	$21.71	$17.60	$20.18	$19.09	$42.37	$16.50
6-hour BESS	Battery Storage	$25.09	$21.84	$24.62	$23.49	$46.64	$24.70
8-hour BESS	Battery Storage	$31.68	$28.82	$32.00	$30.66	$57.12	$33.54
Winter Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$17.99	$15.14	$26.54	$24.69	$35.86	$253.29
	Gas Only, with SCR	$16.95	$14.18	$27.43	$23.92	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$19.65	$17.60	-	$25.34	-	-
	Gas Only, no SCR	$18.43	$16.35	-	$24.59	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$78.82
2-hour BESS	Battery Storage	$10.52	$7.22	$9.60	$8.81	$25.16	$14.99
4-hour BESS	Battery Storage	$16.40	$13.30	$17.35	$16.41	$35.72	$21.31
6-hour BESS	Battery Storage	$18.96	$16.50	$21.17	$20.20	$39.33	$31.90
8-hour BESS	Battery Storage	$23.94	$21.78	$27.51	$26.36	$48.16	$43.32

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, and the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County). [3] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period**.** [4] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [5] Assumes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03, $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02, and $4.10/kW-year VSS revenue adder for lithium-ion BESS. [6] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year. [7] UCAP reference point prices reflect the applicable CAF values for the 2024-2025 Winter Capability Period and an assumed derating factor values of 4.1% for the 1x0 GE 7HA.03 and 1x0 GE 7HA0.2 units and 2.0% for the BESS units. AG and 1898 & Co. acknowledge that NYISO staff has recommended use of 2.5% derating factor for the BESS units; therefore, the indicative UCAP reference point prices for the BESS units presented herein differ from those presented in NYISO staff's final recommendations.

Table 57: Comparison of Gross CONE by Technology ($2025/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$270.61	$267.39	$285.53	$268.54	$351.15	$493.88
	Gas Only, with SCR	$258.89	$256.01	$285.71	$257.07	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$284.49	$281.00	-	$280.72	-	-
	Gas Only, no SCR	$270.18	$267.10	-	$266.71	-	-
	Dual Fuel, with SCR	-	-	-	-	-	$293.98
2-hour BESS	Battery Storage	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
4-hour BESS	Battery Storage	$189.05	$190.40	$196.11	$190.25	$317.01	$202.88
6-hour BESS	Battery Storage	$264.35	$266.22	$274.27	$266.07	$424.81	$283.81
8-hour BESS	Battery Storage	$338.82	$341.25	$351.53	$340.96	$541.77	$364.11

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, and the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County).

Table 58: Comparison of Net EAS by Technology ($2025/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$68.32	$97.17	$80.03	$77.34	$87.44	$111.91
	Gas Only, with SCR	$68.32	$96.55	$73.28	$71.82	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$54.24	$65.49	-	$62.73	-	-
	Gas Only, no SCR	$54.24	$66.89	-	$55.17	-	-
1x0 GE 7HA.02	Dual Fuel, with SCR	-	-	-	-	-	$105.27
2-hour BESS	Battery Storage	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
4-hour BESS	Battery Storage	$63.57	$88.64	$87.34	$87.39	$90.35	$109.40
6-hour BESS	Battery Storage	$65.98	$93.58	$93.60	$93.69	$94.49	$120.99
8-hour BESS	Battery Storage	$66.48	$93.54	$95.12	$95.24	$94.89	$124.71

Notes: [1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 through August 31, 2024. [2] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [3] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm for all locations, the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 25 ppm for Load Zone K, and the 1x0 GE 7HA.02 without SCR emissions controls is tuned to NOx emissions rate of 15 ppm for Load Zones C, F, and G (Dutchess County). [4] Assumes a $3.97/kW-year VSS revenue adder for the 1x0 GE 7HA.03, $3.51/kW-year VSS revenue adder for the 1x0 GE 7HA.02, and $4.10/kW-year VSS revenue adder for lithium-ion BESS. [5] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCR emissions controls were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCR emissions controls were limited to 200,000 lbs of NOx emissions in each modeled year.

VI. Annual Updating of ICAP Demand Curve Parameters

As described above, AG's demand curve model calculates the seasonal RPs for each Locality and NYCA based on input values for revenue requirements (i.e., ARV), financial parameters, "shape" parameters and other parameters (seasonal capacity availability, relative seasonal reliability risks, and various capacity values). Outputs of the demand curve model 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 $/year), seasonal ICAP monthly RP ($/kW-Month), seasonal ICAP Demand Curve maximum clearing price ($/kW-Month), and ICAP Demand Curve length (%).

ICAP Demand Curves will be updated annually based on the updating of (1) gross CONE, (2) net EAS revenues, (3) seasonal capacity availability (SWR and WSR), and (4) the relative seasonal reliability risks (SLOLE and WLOLE). 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.

Table 59 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 59: Overview of ICAP Demand Curve Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
ICAP Demand Curve Values	
Zero-crossing point	Fixed for Quadrennial Reset Period
Reference Point Price Calculation	
Peaking Plant Net Degraded Capacity	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Winter Capability Period DMNC	Fixed Value (Fixed for Quadrennial Reset Period)
Installed Capacity Requirements (IRM/LCR)	Fixed Value (Fixed for Quadrennial Reset Period)
Monthly Available Capacity Values for Use in Calculating Seasonal Capacity Availability (SWR and WSR)	**NYISO Published Values**
Relative Seasonal Reliability Risk (SLOLE and WLOLE)	**Based on the preliminary base case, as approved by the NYSRC, for the NYCA Installed Reserve Margin study covering the Capability Year for which the monthly ICAP reference point price is calculated**

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.

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 state-wide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components: wages, turbines or storage batteries, materials and components, and other costs. The growth rate for all indices is a ratio of (1) the most recently available data as of October 1 in the year prior to the start of the Capability Year for which the updated ICAP Demand Curves will apply and (2) the same data values for time periods associated with the most recent finalized data available for each index as of October 1 of the calendar year in which the NYISO files the results of a DCR with the FERC (i.e., October 1, 2024 in the case of this DCR), minus one.[105]

Thus, in each year, the annual composite escalation rate is calculated as:

$$Annual\ Composite\ Escalation_{\ t} = \sum_{i=1}^{4}(weight_i) * \left(\frac{Index_{i,t}}{Index_{i,DCRYear}} - 1\right) \qquad (9)$$

Consistent with the previous two DCRs, the cost-component weighting factors are calculated for each peaking plant technology reflecting each component's relative share of total peaking plant installed EPC capital costs. The same weighting factors and indices will be used over the reset period, but the values resulting from the indices will be updated annually.

The composite escalation rate (and the rate associated with the general component thereof) will be updated annually 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. For future annual updates, gross CONE values are adjusted by applying the composite escalation rate to the gross CONE values underlying the ICAP Demand Curves for the 2025-2026 Capability Year (i.e., the first Capability Year covered by the four year duration of this reset period).

Table 60 provides final recommended indices and component weights and escalation rate indices for each peaking plant technology option for the 2025-2029 DCR.

The component weights are based on the EPC costs for the SCGT and BESS options. All locations are considered to derive a representative, statewide average weighting for each cost component. The types of EPC costs considered in determining the weighting value for each component is as follows:

- Labor component ("Construction Labor Cost"): This category accounts for the labor costs and related construction tools from the EPC contractor and subcontractors.

- Materials component ("Materials Cost"): This category accounts for construction commodity materials (i.e., cable, conduit, piping, concrete, steel, piles, etc.), main power transformer, controls related equipment, fire protection equipment, chemical feed equipment, and all other project equipment besides the major equipment accounted for in the turbine/battery category described below.

- Turbines or batteries component ("Gas and Steam Turbine Cost" or "Storage Battery Costs"): This category accounts for the major equipment purchases. For the SCGT options, this includes the combustion turbine package and SCR emissions control equipment, as applicable. For the BESS options, this includes modular battery enclosures, inverters, and medium voltage transformers.

- Other costs component ("GDP Deflator"): This category is intended to capture the remaining EPC cost items such as construction management, engineering, startup, escalation, and EPC warranties that are not otherwise accounted for by another category.

[105] Services Tariff, Section 5.14.1.2.2.1. *See,* FERC Docket No. ER20-1049-000, *New York Independent System Operator, Inc.*, Proposed Enhancements to the ICAP Demand Curve Annual Update Procedures (February 21, 2020); and FERC Docket No. ER20-1049-000, *New York Independent System Operator, Inc.*, Letter Order (April 3, 2020).

B. Annual Updating of Net EAS

1. Updating Approach and Timing

Net EAS revenues will be recalculated annually using the same net EAS revenues model used to estimate net EAS revenues for the 2025-2026 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 would not be updated for the purposes of annual recalculation of net EAS revenues.

Table 61 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 60: Composite Escalation Rate Indices and Component Weights, by Technology (2025-2026 Capability Year)

					Component Weight, by Technology								
Cost Component	**Index**	**Interval**	**Calculation of Index Value**	**Annual Growth Rate**	**7HA.03, 25 ppm, Dual Fuel and SCR**	**7HA.03, 25 ppm, Gas Only and SCR**	**7HA.02 25ppm, Dual Fuel and SCR**	**7HA.02 15ppm, Dual Fuel and No SCR**	**7HA.02 15ppm, Gas Only and No SCR**	**2-Hour BESS**	**4-Hour BESS**	**6-Hour BESS**	**8-Hour BESS**
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	3.40%	21%	17%	28%	20%	18%	15%	13%	13%	13%
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	1.32%	14%	13%	15%	17%	16%	11%	9%	8%	7%
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	4.69%	31%	35%	22%	25%	26%	-	-	-	-
Storage Battery Costs	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Storage Batteries (Excluding Lead Acid), Including Parts for All Storage Batteries (790105)	Monthly	Average of finalized February, March, April values	0.18%	-	-	-			62%	65%	66%	67%
GDP Deflator	Bureau of Economic Analysis: Gross Domestric Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	2.64%	34%	35%	35%	38%	40%	12%	13%	13%	13%
Total					100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes: [1] Escalation rates in this Report reflect the most current data available for each index.[106] [2] Component weights reflect statewide averages for four major components of gross CONE including construction labor, materials, equipment, and other costs. Component weights are reflective of total project costs including owner's costs and AFUDC.

[106] The recommended index for the "turbine component" of the composite escalation factor is different for BESS options and SCGT options. For SCGT options, the "turbine component" is labeled as "Gas and Steam Turbine Costs" in the table. For BESS options, the "turbine component" is labeled as "Storage Battery Costs" in the table.

Table 61: Overview of Treatment of Net EAS Model Parameters for Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
Net EAS Revenue Model, including Commitment and Dispatch Logic	Fixed for Quadrennial Reset Period
Hurdle Rates for BESS net EAS Revenue Model	Fixed for Quadrennial Reset Period
Peaking plant Physical Operating Characteristics, including start time requirements, start-up cost minimum down time and runtime requirements, operating hours restrictions and/or limitations (if any), heat rate	Fixed for Quadrennial 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 Quadrennial Reset Period
Annual Value of Voltage Support Service	**Formula Methodology with VSS Compensation Rate to be Updated with NYISO Published Values**
Peaking plant primary and secondary (if any) Fuel Type	N/A for BESS; Fixed for Quadrennial Reset Period
Fuel tax and transportation cost adders	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
Real-time intraday gas acquisition premium/purchase discount	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
Fuel Pricing Points (*e.g.*, natural gas trading hub)	N/A for BESS; Fixed for Quadrennial Reset Period
Fuel Price	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant Variable Operating and Maintenance Cost	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking plant CO_2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
CO_2 Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**

Peaking plant NO_x Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
NO_x Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant SO_2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
SO_2 Emission Allowance Cost	N/A for BESS; **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, if applicable for the selected peaking plant technology option, the applicable data sources for fuel prices and emission allowance prices will be collected and processed for the same time period. This 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 to establish the seasonal 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.

VII. References

Regulatory/Legal Documents

ISO New England, Inc., 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, April 1, 2014.

ISO New England, Inc. and New England Power Pool, Target Adjustments to Certain Forward Capacity Market Parameters to Reflect the Minimum Offer Price Elimination, Docket No. ER24- -000 (November 15, 2023).

New York Independent System Operator, Inc., 134 FERC ¶ 61,058, Docket No. ER11-2224-000 (January 28, 2011).

New York Independent System Operator, Inc., 146 FERC ¶ 61,043, Docket No. ER14-500-000 (January 28, 2014).

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GE 7HA.03						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03
Assumed Land Use, Acres	15	15	15	15	12	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3	3	3
ESTIMATED PERFORMANCE (BASED ON NATURAL GAS OPERATION)						
ISO Base Load Performance						
Net Plant Output, kW	411,400	423,600	420,400	420,400	427,600	423,600
Net Plant Heat Rate, Btu/kWh (HHV)	8,930	8,920	8,920	8,920	8,920	8,920
Heat Input, MMBtu/hr	3,670	3,780	3,750	3,750	3,810	3,780
Summer Base Load Performance						
Net Plant Output, kW	400,200	411,800	408,000	408,000	413,900	417,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,000	9,000	9,000	9,000	9,000	9,000
Heat Input, MMBtu/hr	3,600	3,710	3,670	3,670	3,730	3,750
Summer DMNC Base Load Performance						
Net Plant Output, kW	396,900	405,700	403,200	403,200	409,100	408,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,020	9,050	9,020	9,020	9,030	9,030
Heat Input, MMBtu/hr	3,580	3,670	3,640	3,640	3,690	3,690
Winter Base Load Performance						
Net Plant Output, kW	417,500	429,100	426,900	426,900	434,700	438,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,850	8,870	8,850	8,850	8,830	8,830
Heat Input, MMBtu/hr	3,690	3,810	3,780	3,780	3,840	3,870
Winter DMNC Base Load Performance						
Net Plant Output, kW	419,500	433,800	432,500	432,500	439,100	433,400
Net Plant Heat Rate, Btu/kWh (HHV)	8,820	8,860	8,830	8,830	8,830	8,820
Heat Input, MMBtu/hr	3,700	3,840	3,820	3,820	3,880	3,820
ICAP Base Load Performance						
Net Plant Output, kW	389,000	400,300	397,400	397,400	404,100	404,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,070	9,060	9,070	9,070	9,060	9,060
Heat Input, MMBtu/hr	3,530	3,630	3,600	3,600	3,660	3,660

GE 7HA.03						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$423**	**$432**	**$435**	**$495**	**$551**	**$537**
Dual Fuel Breakout Costs, 2024 MM$ (w/o Owner's Costs)	**$26.9**	**$26.9**	**$26.9**	**Included**	**Included**	**Included**
Owner's Costs, 2024 MM$	**$150**	**$151**	**$144**	**$149**	**$209**	**$623**
Owner's Project Development	$1.2	$1.2	$1.2	$1.2	$1.6	$1.2
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Owner's Engineer	$1.6	$1.6	$1.6	$1.6	$2.0	$1.6
Owner's Project Management	$1.6	$1.6	$1.6	$1.6	$2.0	$1.6
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.8	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Construction Power and Water	$0.5	$0.5	$0.5	$0.5	$0.7	$0.5
Permitting Support	$0.7	$0.7	$0.7	$0.7	$1.0	$0.7
Switchyard	$18.19	$18.2	$18.2	$18.2	$51.0	$13.0
Transmission Line and Electrical Interconnection	$26.05	$26.0	$26.0	$26.0	$28.3	$23.0
Gas Interconnection and Reinforcement	$35.4	$35.4	$35.4	$35.4	$15.5	$36.6
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$457.5
Water Supply Infrastructure	$9.6	$9.6	$3.2	$3.2	$6.8	$1.6
Emission Reduction Credits	$0.9	$0.9	$0.9	$3.4	$3.5	$3.5
Public Outreach and Area Development	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Startup/Testing (Fuel & Consumables)	$3.2	$3.2	$3.2	$3.2	$4.1	$3.2
Initial Fuel Inventory	$6.9	$6.9	$6.9	$6.9	$6.9	$6.9
Site Security	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Operating Spare Parts	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0
Land Lease During Construction	$1.5	$1.5	$1.5	$1.5	$34.4	$1.8
Builders Risk Insurance (0.45% of Construction Costs)	$2.0	$2.1	$2.1	$2.2	$2.5	$2.4
Owner's Contingency (5% for Screening Purposes)	$28.6	$29.0	$28.9	$30.6	$36.2	$55.2
AFUDC and Mortgage Recording Tax, 2024 MM$						
EPC Portion of AFUDC	$41.6	$42.5	$42.7	$45.8	$50.2	$49.8
Non-EPC Portion of AFUDC	$13.9	$14.0	$13.4	$13.8	$19.1	$57.7
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.8	$0.8	$1.0	$1.1	$1.3	$1.9
Total Project Costs, 2024 MM$	**$656**	**$667**	**$663**	**$704**	**$831**	**$1,269**
EPC Cost Per kW, 2024 $/kW (Note 1)	**$1,156**	**$1,146**	**$1,162**	**$1,244**	**$1,363**	**$1,330**
Total Cost Per kW, 2024 $/kW (Note 1)	**$1,687**	**$1,666**	**$1,668**	**$1,771**	**$2,056**	**$3,142**

GE 7HA.03						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
ESTIMATED STARTUP FUEL USAGE						
Start to Base Load, MMBtu	376	376	376	376	376	376
FIXED O&M COSTS (Note 2)						
Fixed O&M Cost - LABOR, 2024$MM/Yr	$1.11	$1.22	$1.44	$1.80	$1.93	$1.93
Fixed O&M Cost - OTHER, 2024$MM/Yr	$1.61	$1.61	$1.61	$1.61	$1.61	$1.61
Property Insurance Allowance	$2.70	$2.75	$2.77	$2.97	$3.31	$3.22
Site Leasing Allowance, 2024$/MM/Yr	$0.38	$0.38	$0.38	$0.38	$8.6	$0.5
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$14.9	$14.9	$15.6	$17.0	$38.7	$17.9
LEVELIZED CAPITAL MAINTENANCE COSTS - GAS OPERATION						
Major Maintenance Cost, 2024$/GT-hr or $/engine-hr (Note 3)	$650	$650	$650	$650	$650	$650
Major Maintenance Cost, 2024$/GT-start	$23,100	$23,100	$23,100	$23,100	$23,100	$23,100
Major Maintenance Cost, 2024$/MWh	$1.57	$1.51	$1.52	$1.52	$1.49	$1.53
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - GAS OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$1.45**	**$1.45**	**$1.45**	**$1.45**	**$1.54**	**$1.50**
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00	$0.04	**$1.50**
SCR Related Costs, $/MWh	$0.55	$0.55	$0.55	$0.55	$0.60	$0.60
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - FUEL OIL OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$8.75**	**$8.55**	**$8.59**	**$8.59**	**$8.73**	**$8.49**
Water Related O&M, $/MWh	$6.98	$6.77	$6.82	$6.82	$6.99	$6.72
SCR Related Costs, $/MWh	$0.87	$0.88	$0.87	$0.87	$0.84	$0.87
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90

GE 7HA.03						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (Note 5)						
GT emissions prior to SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	332	341	339	339	345	341
SO2	1	1	1	1	1	1
CO	48	50	50	50	50	50
CO2	432,900	445,770	442,260	442,260	449,280	452,790
Stack emissions with SCR and CO Catalust (lb/hr, HHV) (Note 6)						
NOX	27	27	27	27	28	27
SO2	1	1	1	1	1	1
CO	4	4	4	4	4	4
CO2	432,900	445,770	442,260	442,260	449,280	452,790
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL (Note 7)						
GT Operating, NO SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	556	574	569	569	580	578
SO2	3	3	3	3	3	3
CO	74	77	76	76	77	77
CO2	616,470	635,909	630,818	630,818	642,369	640,557
GT with SCR and CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	79	82	81	81	83	83
SO2	3	3	3	3	3	3
CO	11	11	11	11	11	11
CO2	616,470	635,909	630,818	630,818	642,369	640,557

Notes:
[1] $/kW values based on ICAP net plant performance outputs.
[2] All gas turbine FOM costs assume 7 full time personnel for first unit.
[3] Major maintenance $/hr and $/start are NOT additive. The maintenance will be either starts or hours based depending on operating profile. If average hours/start > 35.6, then maintenance will be hours based.
[4] Gas operation only. VOM assumes the use of temporary trailers for demineralized water treatment, where applicable.
[5] Emissions estimates are shown for steady state operation at ISO conditions for natural gas, unless otherwise stated. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Emissions estimates should not be used for permitting.

[6] SO2 emissions on Natural Gas assume 0.2 gr/100 scf of sulfur in the gas.
[7] Fuel oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

GE 7HA.02						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			1
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02			GE HA.02
Assumed Land Use, Acres	15	15	15			25
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)			Dual Fuel (Natural Gas and Fuel Oil)
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			Fin Fan Heat Exchanger
NO_x Control	Dry Low Nox / Water Injection	Dry Low Nox / Water Injection	Dry Low Nox / Water Injection			Dry Low Nox / Water Injection / SCR
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			Good Combustion Practice
Technology Rating	Mature	Mature	Mature			Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3			3
ESTIMATED PERFORMANCE (BASED ON NATURAL GAS OPERATION)						
ISO Base Load Performance						
Net Plant Output, kW	342,000	352,400	349,700			375,900
Net Plant Heat Rate, Btu/kWh (HHV)	9,070	9,060	9,070			9,060
Heat Input, MMBtu/hr	3,110	3,190	3,170			3,410
Summer Base Load Performance						
Net Plant Output, kW	331,000	340,700	337,400			356,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,120	9,120	9,120			9,220
Heat Input, MMBtu/hr	3,020	3,110	3,080			3,290
Summer DMNC Base Load Performance						
Net Plant Output, kW	327,600	336,600	338,300			356,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,650	9,140	8,110			9,140
Heat Input, MMBtu/hr	3,160	3,080	2,750			3,260
Winter Base Load Performance						
Net Plant Output, kW	357,000	365,000	361,000			388,500
Net Plant Heat Rate, Btu/kWh (HHV)	8,990	8,970	8,960			9,050
Heat Input, MMBtu/hr	3,210	3,280	3,240			3,520
Winter DMNC Base Load Performance						
Net Plant Output, kW	352,800	383,800	366,400			388,700
Net Plant Heat Rate, Btu/kWh (HHV)	9,470	8,960	7,960			8,990
Heat Input, MMBtu/hr	3,340	3,440	2,920			3,500
ICAP Base Load Performance						
Net Plant Output, kW	321,000	330,700	328,100			353,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,180	9,170	9,170			9,240
Heat Input, MMBtu/hr	2,940	3,030	3,010			3,260

GE 7HA.02						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$346.85**	**$355.06**	**$356.54**			**$422**
Dual Fuel Breakout Costs, 2024 MM$ (w/o Owner's Costs)	**$26.9**	**$26.9**	**$26.9**			**$26.9**
Owner's Costs, 2024 MM$	**$146**	**$146**	**$140**			**$137**
Owner's Project Development	$1.2	$1.2	$1.2			$1.2
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3			$0.3
Owner's Engineer	$1.6	$1.6	$1.6			$1.6
Owner's Project Management	$1.6	$1.6	$1.6			$1.6
Owner's Legal Costs	$0.7	$0.7	$0.7			$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1			$0.1
Land	$0.0	$0.0	$0.0			$0.0
Construction Power and Water	$0.5	$0.5	$0.5			$0.5
Permitting Support	$0.7	$0.7	$0.7			$0.7
Switchyard	$18.19	$18.2	$18.2			$13.0
Transmission Line and Electrical Interconnection	$26.05	$26.0	$26.0			$23.0
Gas Interconnection and Reinforcement	$35.4	$35.4	$35.4			$36.6
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0			$0.0
Water Supply Infrastructure	$9.6	$9.6	$3.2			$1.6
Emission Reduction Credits	$0.5	$0.6	$0.6			$3.1
Public Outreach and Area Development	$0.6	$0.6	$0.6			$0.6
Startup/Testing (Fuel & Consumables)	$3.2	$3.2	$3.2			$3.2
Initial Fuel Inventory	$6.9	$6.9	$6.9			$6.9
Site Security	$0.7	$0.7	$0.7			$0.7
Operating Spare Parts	$10.0	$10.0	$10.0			$10.0
Land Lease During Construction	$1.5	$1.5	$1.5			$1.8
						$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$1.7	$1.7	$1.7			$2.0
Owner's Contingency (5% for Screening Purposes)	$24.7	$25.2	$24.9			$27.9
AFUDC and Mortgage Recording Tax, 2024 MM$						
EPC Portion of AFUDC	$34.6	$35.4	$35.5			$41.6
Non-EPC Portion of AFUDC	$13.5	$13.5	$12.9			$12.7
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.7	$0.7	$0.9			$1.0
Total Project Costs, 2024 MM$	**$568**	**$578**	**$572**			**$641**
EPC Cost Per kW, 2024 $/kW (Note 1)	**$1,164**	**$1,155**	**$1,169**			**$1,272**
Total Cost Per kW, 2024 $/kW (Note 1)	**$1,770**	**$1,747**	**$1,744**			**$1,816**

GE 7HA.02						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
ESTIMATED STARTUP FUEL USAGE						
Start to Base Load, MMBtu	240	240	240			240
FIXED O&M COSTS (Note 2)						
Fixed O&M Cost - LABOR, 2024$MM/Yr	$1.10	$1.20	$1.20			$1.93
Fixed O&M Cost - OTHER, 2024$MM/Yr	$1.60	$1.60	$1.60			$1.61
Property Insurance Allowance	$2.24	$2.29	$2.30			$2.69
Site Leasing Allowance, 2024$/MM/Yr	$0.38	$0.38	$0.38			$0.5
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A			N/A
Total Fixed O&M, $/kW-yr	$16.6	$16.6	$16.7			$18.7
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2024$/GT-hr or $/engine-hr (Note 3)	$620	$620	$620			$620
Major Maintenance Cost, 2024$/GT-start	$23,000	$23,000	$23,000			$23,000
Major Maintenance Cost, 2024$/MWh	$1.72	$1.70	$1.70			$1.70
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4)						
Total Variable O&M Cost, 2024$/MWh	**$0.90**	**$0.90**	**$0.90**			**$1.50**
Water Related O&M, $/MWh	$0.00	$0.00	$0.00			$0.00
SCR Related Costs, $/MWh	NA	NA	NA			$0.60
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90			$0.90
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - FUEL OIL OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$8.75**	**$8.55**	**$8.59**			
Water Related O&M, $/MWh	$6.98	$6.77	$6.82			6.72
SCR Related Costs, $/MWh	$0.87	$0.88	$0.87			0.88
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90			0.90

GE 7HA.02						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (Note 5)						
GT emissions prior to SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	332	341	339			341
SO2	1	1	1			1
CO	48	50	50			50
CO2	400,920	413,280	409,680			422,160
GT emissions with SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	NA	NA	NA			27
SO2	NA	NA	NA			1
CO	NA	NA	NA			11
CO2	NA	NA	NA			422,160
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL (Note 7)						
GT Operating, NO SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	556	574	569			578
SO2	3	3	3			3
CO	74	77	76			77
CO2	616,470	635,909	630,818			640,557
GT Operating, with SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	NA	NA	NA			83
SO2	NA	NA	NA			3
CO	NA	NA	NA			17
CO2	NA	NA	NA			640,557

Notes:
[1] $/kW values based on ICAP net plant performance outputs.
[2] All gas turbine FOM costs assume 7 full time personnel for first unit.
[3] Major maintenance $/hr and $/start are NOT additive. The maintenance will be either starts or hours based depending on operating profile. If average hours/start > 35.6, then maintenance will be hours based.
[4] Gas operation only. VOM assumes the use of temporary trailers for demineralized water treatment, where applicable.
[5] Emissions estimates are shown for steady state operation at ISO conditions for natural gas, unless otherwise stated. Estimates account for the impacts of SCR and CO catalysts, as applicable. Emissions estimates should not be used for permitting.

[6] SO2 emissions on Natural Gas assume 0.2 gr/100 scf of sulfur in the gas.
[7] Fuel oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	2	2	2	2	2	2
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	10	10	10	10	6	9
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	2.50	2.50	2.50	2.50	2.50	2.50
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	2	2	2	2	2	2
Net Plant Energy Capacity, kWh	400,000	400,000	400,000	400,000	400,000	400,000
Energy Capacity Installed with Overbuild, kWh AC at POI	451,500	451,500	451,500	451,500	451,500	451,500

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$153.2**	**$154.5**	**$153.3**	**$159.2**	**$189.3**	**$163.2**
Owner's Cost Allowances, 2024 MM$	**$59.2**	**$59.3**	**$59.7**	**$60.5**	**$124.5**	**$63.6**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.7	$0.6
Owner's Project Management	$0.8	$0.8	$0.8	$0.8	$1.1	$0.8
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$8.5	$8.5	$8.9	$8.9	$9.8	$9.0
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Switchyard	$12.1	$12.1	$12.1	$12.5	$39.7	$13.5
Transmission Line and Electrical Interconnection	$21.7	$21.7	$21.7	$21.8	$38.6	$23.4
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.4	$0.4	$0.4	$0.6	$0.4
Operating Spare Parts	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Land Lease During Construction	$0.8	$0.8	$0.8	$0.8	$14.0	$0.9
Builders Risk Insurance (0.45% of Construction Costs)	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Contingency (5% for Screening Purposes)	$10.1	$10.2	$10.1	$10.5	$14.9	$10.8
AFUDC and Mortgage Recording Tax, 2024 MM$	**$17.1**	**$17.2**	**$17.2**	**$17.7**	**$25.0**	**$18.3**
EPC Portion of AFUDC	$12.1	$12.2	$12.1	$12.6	$14.8	$12.9
Non-EPC Portion of AFUDC	$4.7	$4.7	$4.7	$4.8	$9.7	$5.0
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.3	$0.3	$0.4	$0.4	$0.5	$0.4
Total Project Costs, 2024 MM$	**$229**	**$231**	**$230**	**$237**	**$339**	**$245**
EPC Cost Per kW, 2024 $/kW	**$770**	**$770**	**$770**	**$800**	**$950**	**$820**
Total Cost Per kW, 2024 $/kW	**$1,150**	**$1,160**	**$1,150**	**$1,190**	**$1,690**	**$1,230**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$340**	**$340**	**$340**	**$350**	**$420**	**$360**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$510**	**$510**	**$510**	**$530**	**$750**	**$540**
Investment Tax Credit Allowances						
Eligible Basis Allowance as Percent of Total Project Cost, 2024 MM$	90%	90%	90%	90%	75%	90%
Eligible Cost Basis, 2024 MM$	$207	$208	$207	$214	$254	$221
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$62	$62	$62	$64	$76	$66
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$72.1	$72.6	$72.3	$74.6	$88.5	$76.9
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$1.8	$1.8	$1.8	$1.9	$2.2	$1.9
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$2.4	$2.4	$2.4	$2.6	$2.9	$2.8
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3
Site Leasing Allowance, 2024$/MM/Yr	$0.3	$0.3	$0.3	$0.3	$4.3	$0.3
Property Insurance Allowance, 2024$MM/Yr	$0.9	$0.9	$0.9	$1.0	$1.1	$1.0
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$23.00	$23.24	$23.50	$24.43	$48.48	$25.75
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$6.37	$6.38	$6.40	$6.46	$6.56	$6.54
Sales Tax for VOM Items Assumed to be Taxable	$0.51	$0.51	$0.54	$0.54	$0.58	$0.56
Total Variable O&M, $/MWh	$6.88	$6.89	$6.94	$7.00	$7.14	$7.10

Notes
Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.
Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.
Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, stanby/idle aux loads, and an inverter replacement allowance.
Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).
Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.
Note 6: Estimated Costs exclude decommisioning costs and salvage values.

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	4	4	4	4	4	4
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	14	14	14	14	9	12
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	2.75	2.75	2.75	2.75	2.75	2.75
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	4	4	4	4	4	4
Net Plant Energy Capacity, kWh	800,000	800,000	800,000	800,000	800,000	800,000
Energy Capacity Installed with Overbuild, kWh AC at POI	903,000	903,000	903,000	903,000	903,000	903,000

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$255**	**$257**	**$255**	**$263**	**$317**	**$270**
Owner's Cost Allowances, 2024 MM$	**$72.3**	**$72.4**	**$73.1**	**$74.0**	**$148.7**	**$77.4**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Owner's Project Management	$0.9	$0.9	$0.9	$0.9	$1.2	$0.9
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$14.6	$14.6	$15.3	$15.3	$17.0	$15.6
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Switchyard	$12.1	$12.1	$12.1	$12.5	$39.7	$13.5
Transmission Line and Electrical Interconnection	$21.7	$21.7	$21.7	$21.8	$38.6	$23.4
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.4	$0.4	$0.4	$0.6	$0.4
Operating Spare Parts	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Land Lease During Construction	$1.3	$1.3	$1.3	$1.3	$22.6	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.2	$1.2	$1.2	$1.2	$1.4	$1.2
Owner's Contingency (5% for Screening Purposes)	$15.6	$15.7	$15.6	$16.1	$22.2	$16.5
AFUDC and Mortgage Recording Tax, 2024 MM$	**$28.4**	**$28.5**	**$28.5**	**$29.3**	**$39.9**	**$30.2**
EPC Portion of AFUDC	$21.7	$21.9	$21.7	$22.5	$26.6	$23.0
Non-EPC Portion of AFUDC	$6.2	$6.2	$6.2	$6.3	$12.5	$6.6
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.4	$0.5	$0.5	$0.6	$0.8	$0.6
Total Project Costs, 2024 MM$	**$355**	**$358**	**$356**	**$367**	**$505**	**$378**
EPC Cost Per kW, 2024 $/kW	**$1,270**	**$1,280**	**$1,270**	**$1,320**	**$1,580**	**$1,350**
Total Cost Per kW, 2024 $/kW	**$1,780**	**$1,790**	**$1,780**	**$1,830**	**$2,530**	**$1,890**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$280**	**$280**	**$280**	**$290**	**$350**	**$300**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$390**	**$400**	**$390**	**$410**	**$560**	**$420**
Investment Tax Credit Allowances						
Eligible Basis Allowance as Percent of Total Project Cost, 2024 MM$	92%	92%	92%	92%	80%	92%
Eligible Cost Basis, 2024 MM$	$327	$329	$328	$337	$404	$347
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$98	$99	$98	$101	$121	$104
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$113.7	$114.4	$114.0	$117.3	$140.3	$120.7
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$2.8	$2.9	$2.9	$2.9	$3.5	$3.0
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$3.8	$3.9	$3.9	$4.1	$4.7	$4.4
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$1.4	$1.4	$1.4	$1.4	$1.4	$1.4
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5
Site Leasing Allowance, 2024$/MM/Yr	$0.4	$0.4	$0.4	$0.4	$6.5	$0.4
Property Insurance Allowance, 2024$MM/Yr	$1.5	$1.5	$1.5	$1.6	$1.9	$1.6
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$37.14	$37.55	$37.90	$39.40	$75.55	$41.50
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$6.05	$6.07	$6.08	$6.14	$6.23	$6.21
Sales Tax for VOM Items Assumed to be Taxable	$0.48	$0.49	$0.51	$0.51	$0.55	$0.54
Total Variable O&M, $/MWh	$6.53	$6.56	$6.59	$6.65	$6.78	$6.75

Notes
Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.
Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.
Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, stanby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).
Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.
Note 6: Estimated Costs exclude decommisioning costs and salvage values.

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	6	6	6	6	6	6
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	18	18	18	18	12	16
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	3.00	3.00	3.00	3.00	3.00	3.00
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	6	6	6	6	6	6
Net Plant Energy Capacity, kWh	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Energy Capacity Installed with Overbuild, kWh AC at POI	1,354,500	1,354,500	1,354,500	1,354,500	1,354,500	1,354,500

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$366**	**$369**	**$367**	**$378**	**$445**	**$389**
Owner's Cost Allowances, 2024 MM$	**$86.7**	**$86.8**	**$87.7**	**$88.9**	**$174.5**	**$92.8**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Owner's Project Management	$0.9	$0.9	$0.9	$0.9	$1.2	$0.9
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$21.1	$21.1	$22.1	$22.1	$24.0	$22.6
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.1	$1.1	$1.1	$1.1	$1.4	$1.1
Switchyard	$12.1	$12.1	$12.1	$12.5	$39.7	$13.5
Transmission Line and Electrical Interconnection	$21.7	$21.7	$21.7	$21.8	$38.6	$23.4
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.6	$0.6	$0.6	$0.6	$0.7	$0.6
Operating Spare Parts	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Land Lease During Construction	$1.7	$1.7	$1.7	$1.7	$32.3	$1.8
Builders Risk Insurance (0.45% of Construction Costs)	$1.7	$1.7	$1.7	$1.7	$2.0	$1.8
Owner's Contingency (5% for Screening Purposes)	$21.6	$21.7	$21.6	$22.3	$29.5	$22.9
AFUDC and Mortgage Recording Tax, 2024 MM$	**$46.2**	**$46.5**	**$46.5**	**$47.8**	**$62.4**	**$49.2**
EPC Portion of AFUDC	$36.9	$37.1	$36.9	$38.1	$44.1	$39.1
Non-EPC Portion of AFUDC	$8.7	$8.7	$8.8	$8.9	$17.3	$9.3
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.6	$0.6	$0.7	$0.8	$1.0	$0.8
Total Project Costs, 2024 MM$	**$499**	**$502**	**$501**	**$515**	**$682**	**$531**
EPC Cost Per kW, 2024 $/kW	**$1,830**	**$1,850**	**$1,830**	**$1,890**	**$2,230**	**$1,940**
Total Cost Per kW, 2024 $/kW	**$2,500**	**$2,510**	**$2,500**	**$2,580**	**$3,410**	**$2,650**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$270**	**$270**	**$270**	**$280**	**$330**	**$290**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$370**	**$370**	**$370**	**$380**	**$500**	**$390**
Investment Tax Credit Allowances						
Eligible Basis Allowance as Percent of Total Project Cost, 2024 MM$	94%	94%	94%	94%	85%	94%
Eligible Cost Basis, 2024 MM$	$469	$472	$471	$484	$580	$499
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$141	$142	$141	$145	$174	$150
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$162.8	$163.8	$163.3	$167.9	$200.9	$173.0
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$4.1	$4.1	$4.1	$4.2	$5.0	$4.3
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$5.2	$5.3	$5.4	$5.7	$6.5	$6.1
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.5	$0.6	$0.6	$0.6	$0.7	$0.7
Site Leasing Allowance, 2024$/MM/Yr	$0.5	$0.5	$0.5	$0.5	$8.6	$0.5
Property Insurance Allowance, 2024$MM/Yr	$2.2	$2.2	$2.2	$2.3	$2.7	$2.3
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$52.54	$53.07	$53.60	$55.75	$103.66	$58.66
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$5.84	$5.85	$5.86	$5.92	$6.01	$5.99
Sales Tax for VOM Items Assumed to be Taxable	$0.47	$0.47	$0.49	$0.50	$0.53	$0.52
Total Variable O&M, $/MWh	$6.31	$6.32	$6.35	$6.42	$6.54	$6.51

Notes
Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.
Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.
Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, stanby/idle aux loads, and an inverter replacement allowance.
Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).
Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.
Note 6: Estimated Costs exclude decommisioning costs and salvage values.

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	8	8	8	8	8	8
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	22	22	22	22	15	20
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	3.25	3.25	3.25	3.25	3.25	3.25
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	8	8	8	8	8	8
Net Plant Energy Capacity, kWh	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Energy Capacity Installed with Overbuild, kWh AC at POI	1,806,000	1,806,000	1,806,000	1,806,000	1,806,000	1,806,000

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$471**	**$474**	**$471**	**$486**	**$575**	**$500**
Owner's Cost Allowances, 2024 MM$	**$100.3**	**$100.5**	**$101.6**	**$103.0**	**$201.4**	**$107.4**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$1.0	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Project Management	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$27.2	$27.2	$28.4	$28.4	$31.1	$29.1
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.3	$0.2
Permitting Support	$1.1	$1.1	$1.1	$1.1	$1.5	$1.1
Switchyard	$12.1	$12.1	$12.1	$12.5	$39.7	$13.5
Transmission Line and Electrical Interconnection	$21.7	$21.7	$21.7	$21.8	$38.6	$23.4
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.2	$0.2	$0.2	$0.2	$0.3	$0.2
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Operating Spare Parts	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0
Land Lease During Construction	$2.2	$2.2	$2.2	$2.2	$43.0	$2.4
Builders Risk Insurance (0.45% of Construction Costs)	$2.1	$2.1	$2.1	$2.2	$2.6	$2.3
Owner's Contingency (5% for Screening Purposes)	$27.2	$27.4	$27.3	$28.1	$37.0	$28.9
AFUDC and Mortgage Recording Tax, 2024 MM$	**$72.2**	**$72.6**	**$72.5**	**$74.6**	**$96.7**	**$76.9**
EPC Portion of AFUDC	$58.8	$59.3	$58.9	$60.7	$70.7	$62.5
Non-EPC Portion of AFUDC	$12.5	$12.6	$12.7	$12.9	$24.8	$13.4
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.8	$0.8	$0.9	$1.0	$1.3	$1.0
Total Project Costs, 2024 MM$	**$643**	**$647**	**$645**	**$664**	**$873**	**$684**
EPC Cost Per kW, 2024 $/kW	**$2,350**	**$2,370**	**$2,350**	**$2,430**	**$2,870**	**$2,500**
Total Cost Per kW, 2024 $/kW	**$3,220**	**$3,240**	**$3,230**	**$3,320**	**$4,360**	**$3,420**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$260**	**$260**	**$260**	**$270**	**$320**	**$280**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$360**	**$360**	**$360**	**$370**	**$480**	**$380**
Investment Tax Credit Allowances						
Eligible Basis Allowance as Percent of Total Project Cost, 2024 MM$	95%	95%	95%	95%	85%	95%
Eligible Cost Basis, 2024 MM$	$611	$615	$613	$630	$742	$650
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$183	$184	$184	$189	$223	$195
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$211.6	$213.0	$212.3	$218.3	$256.8	$225.1
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$5.3	$5.3	$5.3	$5.5	$6.4	$5.6
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$6.7	$6.8	$6.9	$7.3	$8.2	$7.9
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$2.6	$2.6	$2.6	$2.7	$2.7	$2.7
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9
Site Leasing Allowance, 2024$/MM/Yr	$0.6	$0.6	$0.6	$0.6	$10.8	$0.6
Property Insurance Allowance, 2024$MM/Yr	$2.8	$2.8	$2.8	$2.9	$3.4	$3.0
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$67.02	$67.72	$68.33	$71.08	$131.05	$74.99
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$5.95	$5.96	$5.98	$6.03	$6.12	$6.11
Sales Tax for VOM Items Assumed to be Taxable	$0.48	$0.48	$0.50	$0.51	$0.54	$0.53
Total Variable O&M, $/MWh	$6.43	$6.44	$6.48	$6.54	$6.66	$6.64

Notes

Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.

Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.

Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, stanby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).

Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.

Note 6: Estimated Costs exclude decommisioning costs and salvage values.

B. Additional Detail on Financing Parameters

This appendix provides additional detail on the data presented in Section III.A.2.

B.1 Additional Detail on COD

The table below provides detail on each debt issuance shown in Table 38.

Appendix B Table 1: Additional Detail on Bond Yields of Representative IPP Companies, June 2, 2024 - August 31, 2024

IPP	Issuer	IPP (Ultimate Parent) Rating as of 8/31/2024	Seniority Level	Coupon Rate (%)	Maturity Date	Representative CUSIP	Face Value for Debt with this Seniority, Issuer, and Maturity Date ($/000)	Yield to Maturity 8/30/2024	Yield to Maturity 6/2/2024	Simple average 6/2/24 - 8/31/24
Vistra	Vistra Operations Company LLC	BB	Senior Unsecured	7.75	10/15/2031	92840VAP7	2,900,000	6.58	6.99	6.86
Vistra	Vistra Operations Company LLC	BB	Senior Unsecured	6.875	4/15/2032	92840VAR3	2,000,000	6.21	6.72	6.46
Vistra	Illinois Power Generating Company	BB	Senior Unsecured	7.95	6/1/2032	02360XAH0	275,000	n/a	n/a	n/a
Vistra	Vistra Operations Company LLC	BB	Senior Secured	6.95	10/15/2033	92840VAQ5	2,100,000	5.43	5.90	5.73
Vistra	Vistra Operations Company LLC	BB	Senior Secured	6	4/15/2034	92840VAS1	1,000,000	5.38	5.87	5.69
Vistra	Bruce Mansfield Unit 2007-1	BB	Senior Unsecured	6.85	6/1/2034	U1158RAA3	1,137,000	n/a	n/a	n/a
NRG	NRG Energy, Inc. (NYSE:NRG)	BB	Senior Unsecured	3.625	2/15/2031	629377CR1	2,060,000	5.56	6.19	5.98
NRG	NRG Energy, Inc. (NYSE:NRG)	BB	Senior Unsecured	8.625	4/1/2031	629377AL6	500,000	n/a	n/a	n/a
NRG	NRG Energy, Inc. (NYSE:NRG)	BB	Senior Unsecured	3.875	2/15/2032	629377CS9	960,000	5.57	6.21	5.97
NRG	NRG Energy, Inc. (NYSE:NRG)	BB	Senior Secured	7	3/15/2033	629377CT7	1,480,000	5.55	5.99	5.89
NRG	Midwest Generation LLC	BB	Senior Secured	8.75	5/1/2034	U60027AA4	1,000,000	n/a	n/a	n/a
AES	The AES Corporation (NYSE:AES)	BBB-	Senior Secured	3.95	7/15/2030	00130HCC7	1,400,000	5.07	5.74	5.40
AES	The AES Corporation (NYSE:AES)	BBB-	Senior Unsecured	2.45	1/15/2031	00130HCG8	1,003,110	5.17	5.66	5.46
AES	DPL Capital Trust II	BBB-	Senior Unsecured	8.125	9/1/2031	23330AAC4	31,200	n/a	n/a	9.33
AES	DPL Capital Trust II	BBB-	Unsecured	8.125	9/1/2031	23330AAB6	300,000	n/a	n/a	n/a
AES	DPL Capital Trust II	BBB-	Junior Subordinate	8.125	9/1/2031	U26057AA4	309,300	n/a	n/a	n/a
Constellation	Constellation Energy Generation, LLC	BBB+	Senior Unsecured	5.8	3/1/2033	210385AC4	600,000	5.03	5.46	5.26
Constellation	Constellation Energy Generation, LLC	BBB+	Senior Unsecured	6.125	1/15/2034	210385AD2	500,000	5.07	5.47	5.29
Constellation	Constellation Energy Generation, LLC	BBB+	Senior Unsecured	6.25	10/1/2039	30161MAG8	900,000	5.38	5.79	5.63
Constellation	Constellation Energy Generation, LLC	BBB+	Senior Unsecured	5.75	10/1/2041	30161MAJ2	350,000	5.57	5.86	5.74
Constellation	Constellation Energy Generation, LLC	BBB+	Senior Unsecured	5.6	6/15/2042	30161MAN3	788,200	5.57	5.84	5.73

Notes: S&P Capital IQ; Bloomberg Data License. The table reports the IPP issuer long term rating outstanding as of August 31, 2024 (the rating for Constellation corresponds to the subsidiary Constellation Energy Generation LLC, as S&P does not provide a long-term rating for the parent company), the yield to maturity implied by the midpoint price of the most actively traded CUSIP as of the first and last day of the period considered (June 2, 2024 and August 31, 2024), and the 90-day simple average of the security yields over the same period (daily observations not tabulated, to ease exposition). The list of securities represents the currently-outstanding debt by seniority, maturity and coupon.

B.2 Additional Detail on COE

We estimate the COE for our sample of publicly traded IPPs using the Capital Asset Pricing Model (CAPM), a commonly-used framework for estimating expected returns to equity. The CAPM assumes that the expected rate of return demanded by equity investors—and, therefore, the COE for the enterprise—is equal to a risk-free rate of return plus an additional return commensurate to the risk undertaken by equity investors in funding the specific enterprise.

Specifically, the CAPM is computed as:

$$E(R_i) = r_f + \beta_i[E(R_m) - r_f] \quad \text{[B1]}$$

Where:

- $E(R_i)$ is the expected return of a stock security *i*;
- r_f is the risk-free rate;
- β_i is the sensitivity of the stock security *i* to the market;
- $E(R_m)$ is the expected return of the market.

The term $E(R_m) - r_f$ is referred to as the equity risk premium (ERP), and it measures the additional expected compensation required by equity investors in excess of the risk-free rate. The CAPM reflects an equilibrium or market-clearing price, such that the COE to developers equals the expected return to investors (*i.e.*, $E(R_i)$).

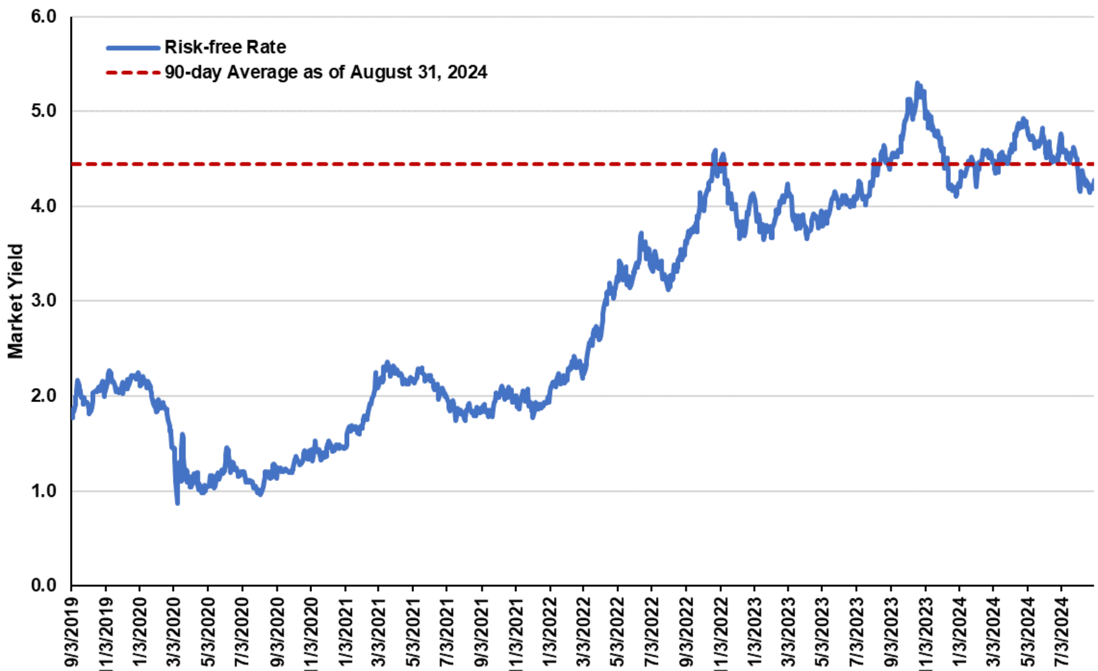
Below, we provide details on the estimation of each parameter in the above equation B1 required to estimate the COE.

a) Risk-free rate

The most commonly used proxy for risk-free rates are long-term governmental bonds, *i.e.*, treasury bonds with maturities equal to 10 years or longer. The economic life of a project for new power generation resources is typically around 20 years (prior to consideration of factors that may result in a shortened period). Consistent with this fact, AG used a 90-day average of the 20-year treasury rate (unique time series identifier: H15/H15/RIFLGFCY20_N.B) downloaded from the Federal Reserve Bank.[1] Over the 90 day period from June 2, 2024 – August 31, 2024, the average rate for 20-year treasury bonds was 4.45%, which we select as the risk-free rate. The figure below reports both the 90-day average and the daily rate observed between September 3, 2019 and August 31, 2023. As the figure shows, the risk-free rate generally increased over the past five years.

[1] Market yield on U.S. Treasury securities at 20-year constant maturity, quoted on investment basis, downloaded from https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Appendix B Figure 1: Risk-free rate – Historical 20 Year Treasury Constant Maturity Rate
September 3, 2019 – August 31, 2024



Source: Federal Reserve Board.

b) Beta

Beta is the sensitivity of a company's stock return to the market's return. Beta is not directly observable and must therefore be estimated. We use the following common approach to estimate beta:

1. *Step 1. Obtain levered betas*. We obtain beta coefficients (referred to as "levered" betas, as they are a function of both the operating risk of a company and its financial risk arising from the company's "leverage" – that is, ratio of debt to equity) from Bloomberg and Value Line. We use two different sources for betas with slightly different characteristics. Our first source is Value Line, which provides beta coefficients estimated over a period of 5 years using weekly stock returns regressed on weekly NYSE Composite Index returns. Our second source is Bloomberg, from which we obtain two sets of beta coefficients: the first estimated using weekly returns over a 2-year period, and the second estimated using monthly returns over a 5-year period. Both sets of coefficients are estimated using S&P 500 Index returns.

2. *Step 2. "Unlever" the betas*. To control for differences in each company's leverage, estimated levered betas are "unlevered" using data on each companies' capital structure. This operation yields "unlevered" or "asset" betas.[2] We estimate the average and upper bound of the unlevered betas from the sample of comparable companies. We evaluate the upper bound, as well as the average, value given that new project-level risk is generally higher than company-level risk for IPPs.

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[2] To "unlever" the beta, we rely on the Hamada equation: $\beta_u = \beta_l / \left[1 + \frac{D}{E}\right]$, where β_u (β_l) is the unlevered (levered) beta and $\frac{D}{E}$ is the debt to equity ratio. See Hamada, Robert S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks," *Journal of Finance* (May 1972): 435–452.

3. *Step 3. "Relever" the beta*. Lastly, we "relever" the resulting average and maximum unlevered beta using the target capital structure of the company being analyzed.[3] The "relevered" beta is the beta we use in the CAPM equation B1 above to estimate the COE.

c) Equity market return and ERP

The ERP is a measure of the additional remuneration that investors require for their invested capital, above the risk-free rate. We use two sources for ERP: (i) the Kroll cost of capital calculator, which provides estimates of ERP for discounted cash flow valuation purposes. Over the 90 day period from December 16, 2023 – March 15, 2024, Kroll recommends an ERP of 5.00%;[4] (ii) our internal computations using a Discounted Cash Flow (DCF) model, which yield a forward-looking ERP of 7.44%.[5]

***

We estimate the COE under five different scenarios. Each scenario reflects different assumptions used in deriving the parameters of the COE, including beta. In Scenario 1 and 3, we estimate beta using values reported by Bloomberg computed with monthly returns and a five-year time period. In Scenario 2 we use ValueLine betas, which are estimated using weekly returns and a five-year time period. In Scenario 4 and 5 we estimate beta using values reported by Bloomberg computed with weekly returns and a two-year time period. Scenario 1, 2, and 5 are estimated using data from Vistra, NRG, AES, while Scenario 3 is estimated only relying on Vistra and NRG, and Scenario 4 is estimated using the full Proxy Group (Vistra, NRG, AES, and Constellation). The table below reports the results for the computation of the COE, including the "delevering" and "relevering" of beta. The observed COE varies from 9.94% to 16.47%.

A maintained assumption of the scenarios above is that the representative IPPs are sufficiently far from insolvency and, thus, their debt is not risky. This assumption is commonly used when calculating the COE.[6] However, some companies in the Proxy Group are below investment grade. Given our sample of companies, we relax the assumption that the representative IPPs have negligible insolvency risk and, for each of the scenarios listed above, we apply a modified estimation method to "unlever" and "relever" the betas in steps 2 and 3 described above. This modified estimation method accounts for the potential impact of default risk on the COE by including a "debt beta."[7] Using this alternative approach, we obtained a range for the COE from 9.68% to 14.85% across the five scenarios, fairly close to the range observed without including a "debt beta."

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[3] To "relever" the beta, we rely on the same Hamada equation, which rearranged yields a levered beta equal to: $\beta_l = \beta_u \times \left(1 + \frac{D}{E}\right)$.

[4] *See* https://www.kroll.com/en/insights/publications/cost-of-capital .

[5] Specifically, we compute the forward-looking ERP as the difference between expected market return and risk-free rate. To compute the expected market return, we apply a constant-growth DCF model for each dividend paying firm in the S&P 500 with expected three to five years growth rates between 0 and 20% as of August 31, 2024. For each stock, the expected return equals to the sum of (i) expected dividend yield (*i.e.,* the current year dividend yield times the expected earnings growth rate for each stock) divided by the stock price and (ii) the expected earnings growth rate for each stock. We compute the expected market return as the average returns for each security, weighted by their market capitalization (*i.e.,* the stock close price times the number of shares outstanding, retrieved through Refinitiv). We obtained the stock price (last closing) and (gross) dividend payments from Refinitiv and used expected earnings growth rates from the Institutional Brokers' Estimate System (IBES).

[6] *See* Koller, Tim, Mark Goedhart, and David Wessels, Valuation – Measuring and Managing the Value of Companies, Fifth Edition, *McKinsey & Company*, *Wiley*, 2010, Chapter 11.

[7] Specifically, assuming that the default risk of companies is non-negligible yields the following modified Hamada formula that we use to unlever beta: $\beta_u = \left[\beta_l + \frac{D}{E} \times \beta_d\right] / \left[1 + \frac{D}{E}\right]$, where β_u (β_l) is the unlevered (levered) beta, β_d is the beta associated to an IPP's debt, and $\frac{D}{E}$ is the debt to equity ratio. Similar to the equity beta, the debt beta is a measure of systematic risk that debt holders hold in the investment. We compute beta debt for the peer group using the CAPM approach and replacing $E(R_i)$ (the expected rate of return) with the cost of debt. Specifically, $K_j^d = R_f + \beta_j^d\,(E(R_m) - r_f)$, which rearranged becomes $\beta_j^d = \frac{K_j^d - R_f}{(R_m - R_f)}$, where β_j^d is the beta debt for each company j, K_j^d is the company cost of debt, R_f and $\left(E(R_m) - r_f\right)$ are the risk-free return and equity risk premium, respectively. To compute the company-specific beta debt, we use the same values for the risk-free and the ERPs used to compute the COE, the average bond yields of each company as described in the main body of this report, and solve the equation for beta.

Appendix B Table 2: Computation of COE under Different Scenario

IPP	Observed Levered Beta β_l	D/E	Unlevered Beta β_u	Risk-free Rate	Target D/E	"Relevered" Levered Beta β_l	ERP	COE using 5.00% ERP	COE using 7.44% ERP
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Scenario 1									
Vistra	1.10	0.51	0.73						
NRG	1.09	0.65	0.66						
AES	1.06	2.18	0.33						
Average β_u			0.57	4.45%	1.22	1.27	5.00% or 7.44%	**10.82%**	**13.92%**
Upper bound β_u			0.73	4.45%	1.22	1.62	5.00% or 7.44%	**12.53%**	**16.47%**
Scenario 2									
Vistra	1.10	0.51	0.73						
NRG	1.10	0.65	0.67						
AES	1.20	2.18	0.38						
Average β_u			0.59	4.45%	1.22	1.31	5.00% or 7.44%	**11.01%**	**14.20%**
Upper bound β_u			0.73	4.45%	1.22	1.62	5.00% or 7.44%	**12.53%**	**16.47%**
Scenario 3									
Vistra	1.10	0.51	0.73						
NRG	1.09	0.65	0.66						
Average β_u			0.69	4.45%	1.22	1.54	5.00% or 7.44%	**12.15%**	**15.90%**
Upper bound β_u			0.73	4.45%	1.22	1.62	5.00% or 7.44%	**12.53%**	**16.47%**
Scenario 4									
Vistra	0.71	0.51	0.47						
NRG	1.01	0.65	0.62						
AES	1.27	2.18	0.40						
Constellation	0.88	0.26	0.70						
Average β_u			0.55	4.45%	1.22	1.21	5.00% or 7.44%	**10.51%**	**13.46%**
Upper bound β_u			0.70	4.45%	1.22	1.55	5.00% or 7.44%	**12.22%**	**16.00%**
Scenario 5									
Vistra	0.71	0.51	0.47						
NRG	1.01	0.65	0.62						
AES	1.27	2.18	0.40						
Average β_u			0.49	4.45%	1.22	1.10	5.00% or 7.44%	**9.94%**	**12.62%**
Upper bound β_u			0.62	4.45%	1.22	1.37	5.00% or 7.44%	**11.28%**	**14.61%**

Notes:
[1] Levered beta obtained using the specifications described in each Scenario (Scenario 1 and 3: values reported by Bloomberg computed with monthly returns and a five-year time period; Scenario 2: Value Line betas estimated using weekly returns and a five-year time period; Scenario 4 and 5: values reported by Bloomberg computed with weekly returns and a two-year time period).
[2] Observed debt to equity structure as of Q2 2024. Equity is the market value of equity at the end of Q2 2024.
[3] Unlevered beta obtained as [1] / (1+[2]).
[4] 90-day average 20-year treasury rate from June 2, 2024 to August 31, 2024 for the market yield on U.S. Treasury securities at 20-year, constant maturity, taken from the Federal Reserve Board.
[5] Recommended debt-to-equity ratio.
[6] Relevered Beta obtained as [3]×(1+[5])
[7] ERP from either Kroll cost of capital calculator or DCF model computed by AG.
[8] and [9] Obtained as [4]+[6]×[7].

B.3 COE, COD, Debt-to-Equity, and ATWACC Estimates from Prior Net CONE Studies

The table below presents COE, COD, capital structure (D/(D+E)), and ATWACC estimates from prior CONE studies for ISO-NE, NYISO, and PJM.

Appendix B Table 3: COE, COD, Capital Structure, and ATWACC Estimates from Prior Net CONE Studies[8]

Period	RTO	COE	COD	D/(D+E)	ATWACC
Past Studies					
2014	ISO-NE	13.8%	7.0%	0.60	8.0%
2014	PJM	13.8%	7.0%	0.60	8.0%
2016 (2017-2021 DCR)	NYISO	13.4%	7.75%	0.55	8.6% (NY State) 8.36% (NYC)
2016	ISO-NE	13.4%	7.75%	0.60	8.1%
2018	PJM	12.8%	6.5%	0.65	7.5%
Most Recent Studies (by RTO)					
2020 (2021-2025 DCR)	NYISO	13.0%	6.7%	0.55	8.52% (NY State) 8.20% (NYC)
2022 (April)	PJM	13.6%	4.7%	0.55	8.0%
2022 (September)	PJM	14.1%	6.3%	0.55	8.85%
2023	ISO-NE	13.8%	6.85%	0.55	8.96%

[8] *See* AG 2023 ATWACC of New Entry for ISO-NE Forward Capacity Market Study; Brattle September 2022 PJM Study; Brattle April 2022 PJM Study; AG 2020 NYISO Study; Concentric 2020 ISO-NE Study; The Brattle Group and Sargent & Lundy, “PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date,” April 19, 2018; Concentric Energy Advisors, “ISO-NE CONE and ORTP Analysis,” December 2, 2016; Analysis Group, Inc. and Lummus Consultants International, Inc., “Study to Establish New York Electricity Market ICAP Demand Curve Parameters,” September 13, 2016; The Brattle Group and Sargent & Lundy, “Cost of New Entry Estimate for Combustion Turbine and Combined Cycle Plants in PJM With June 1, 2018 Online Date,” May 15, 2014; 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, April 1, 2014.

C. Additional Detail on Level of Excess Adjustment Factors

This appendix provides additional detail on the data presented in Section IV.B. The tables below shows the level of excess adjustment factors used in the net EAS revenues model. The "High On Peak" periods are defined consistent with the Summer and Winter Peak Load Windows for the 2024/2025 Capability Year (Summer: hour beginning (HB) 1 p.m. through HB 8 p.m.; Winter: HB 4 p.m. through HB 9 p.m.).

Appendix C Table 1. Level of Excess Adjustment Factors – 200 MW Peaking Plant

Location	Period	January	February	March	April	May	June	July	August	September	October	November	December
Zone C - Central	HighOnPeak	0.933	0.947	-	-	-	0.972	0.939	0.954	-	-	-	0.905
	Off Peak	0.976	0.976	0.982	0.996	1.000	0.995	0.993	1.000	0.983	0.983	0.972	0.972
	On Peak	0.965	0.963	0.972	0.996	1.001	0.984	0.976	0.990	0.966	0.976	0.952	0.942
Zone F - Capital	HighOnPeak	1.040	1.029	-	-	-	1.006	0.952	0.978	-	-	-	0.998
	Off Peak	1.031	1.020	1.019	1.011	1.027	1.010	1.008	1.014	1.005	1.003	1.019	1.035
	On Peak	1.043	1.038	1.023	1.016	1.041	1.007	1.004	1.013	1.002	1.014	1.005	1.022
Zone G - Hudson Valley	HighOnPeak	1.147	1.099	-	-	-	1.082	1.278	1.126	-	-	-	1.150
	Off Peak	1.042	1.026	1.022	1.023	1.034	1.019	1.038	1.032	1.020	1.016	1.026	1.056
	On Peak	1.092	1.066	1.045	1.036	1.064	1.033	1.076	1.063	1.037	1.033	1.055	1.095
Zone J - New York City	HighOnPeak	1.061	1.049	-	-	-	1.046	1.180	1.050	-	-	-	1.058
	Off Peak	1.030	1.025	1.020	1.022	1.031	1.020	1.030	1.028	1.015	1.012	1.019	1.042
	On Peak	1.055	1.051	1.025	1.032	1.051	1.038	1.045	1.039	1.030	1.031	1.022	1.058
Zone K - Long Island	HighOnPeak	1.021	1.055	-	-	-	1.025	1.175	1.032	-	-	-	1.025
	Off Peak	1.018	1.044	1.026	1.007	1.017	1.017	1.018	1.013	1.014	1.015	1.015	1.027
	On Peak	1.015	1.056	1.022	1.006	1.031	1.030	1.032	1.019	1.022	1.025	1.015	1.041

Appendix C Table 2. Level of Excess Adjustment Factors – 400 MW Peaking Plant

Location	Period	January	February	March	April	May	June	July	August	September	October	November	December
Zone C - Central	HighOnPeak	0.991	0.993	-	-	-	1.016	0.988	1.008	-	-	-	0.971
	Off Peak	1.004	0.999	1.010	1.005	1.029	1.017	1.014	1.022	0.996	0.997	0.993	1.004
	On Peak	1.003	0.999	1.007	1.013	1.050	1.022	1.012	1.025	0.993	1.008	0.983	0.991
Zone F - Capital	HighOnPeak	1.043	1.050	-	-	-	1.024	0.994	1.017	-	-	-	1.011
	Off Peak	1.029	1.021	1.017	1.013	1.030	1.019	1.018	1.025	1.009	1.008	1.016	1.034
	On Peak	1.045	1.045	1.032	1.019	1.056	1.022	1.022	1.032	1.007	1.026	1.009	1.020
Zone G - Hudson Valley	HighOnPeak	1.130	1.109	-	-	-	1.085	1.220	1.120	-	-	-	1.111
	Off Peak	1.041	1.026	1.023	1.022	1.039	1.027	1.037	1.037	1.020	1.020	1.028	1.054
	On Peak	1.080	1.071	1.050	1.034	1.086	1.049	1.075	1.074	1.040	1.046	1.055	1.083
Zone J - New York City	HighOnPeak	1.056	1.049	-	-	-	1.039	1.132	1.048	-	-	-	1.046
	Off Peak	1.028	1.017	1.019	1.021	1.033	1.021	1.025	1.029	1.013	1.015	1.020	1.043
	On Peak	1.045	1.036	1.029	1.029	1.055	1.031	1.036	1.038	1.025	1.039	1.023	1.055
Zone K - Long Island	HighOnPeak	0.988	0.988	-	-	-	1.012	1.061	0.998	-	-	-	0.986
	Off Peak	0.999	0.985	0.975	1.004	1.020	1.012	1.003	1.001	1.021	1.031	0.993	1.000
	On Peak	0.988	0.984	0.971	1.001	1.033	1.013	1.010	1.001	1.037	1.056	0.982	0.997

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: SCGT J-Class (7HA.03) with SCR

Run Hours: September 2021 - August 2022															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1698	14	151	0	247	15	1934	0	115	6	0	4580	0	8760
F	Capital	2894	21	558	0	207	19	1158	0	334	3	0	3566	0	8760
G1	Hudson Valley (Dutchess)	2079	5	376	0	428	71	5798	0	0	0	0	3	0	8760
G2	Hudson Valley (Rockland)	2034	12	274	0	413	68	5956	0	0	0	0	3	0	8760
J	NYC	3257	0	108	40	247	69	5029	7	0	0	0	3	0	8760
K	Long Island	3236	6	198	929	268	57	4005	28	0	0	0	33	0	8760

Run Hours: September 2022 - August 2023															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1160	0	124	0	374	63	5982	0	37	4	0	1016	0	8760
F	Capital	1996	139	631	0	397	136	4385	0	105	6	0	965	0	8760
G1	Hudson Valley (Dutchess)	1032	111	237	0	273	390	6717	0	0	0	0	0	0	8760
G2	Hudson Valley (Rockland)	1454	58	230	0	300	251	6467	0	0	0	0	0	0	8760
J	NYC	2991	63	164	0	220	180	5142	0	0	0	0	0	0	8760
K	Long Island	2842	23	316	0	321	247	5011	0	0	0	0	0	0	8760

Run Hours: September 2023 - August 2024															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1635	0	177	0	419	46	6406	0	1	0	0	100	0	8784
F	Capital	820	65	245	0	346	254	6581	0	6	1	0	466	0	8784
G1	Hudson Valley (Dutchess)	1129	79	226	0	157	372	6821	0	0	0	0	0	0	8784
G2	Hudson Valley (Rockland)	1295	68	186	0	134	368	6733	0	0	0	0	0	0	8784
J	NYC	3004	30	44	0	173	526	5007	0	0	0	0	0	0	8784
K	Long Island	2900	17	228	0	221	261	5157	0	0	0	0	0	0	8784

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: SCGT J-Class (7HA.03) with SCR

Net EAS Revenues: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$61.68	$0.33	$3.41	$0.00	$8.70	$0.02	$2.20	$0.00	$2.47	$0.06	$0.00	$0.00	$0.00	$78.87	$82.84
F	Capital	$79.29	$0.43	$14.53	$0.00	$12.72	$0.18	$4.55	$0.00	$12.42	$0.05	$0.00	$0.00	$0.00	$124.17	$128.14
G1	Hudson Valley (Dutchess)	$52.84	$0.24	$7.07	$0.00	$16.11	$0.61	$17.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$94.79	$98.76
G2	Hudson Valley (Rockland)	$60.93	$0.29	$5.24	$0.00	$14.55	$0.58	$19.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$100.68	$104.65
J	NYC	$75.68	$0.00	$2.33	$0.13	$9.22	$0.46	$14.30	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$102.14	$106.11
K	Long Island	$100.52	$0.03	$3.33	$2.62	$13.95	$0.48	$12.44	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$133.49	$137.46

Net EAS Revenues: September 2022 - August 2023																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$31.86	$0.00	$1.44	$0.00	$8.57	$0.24	$13.90	$0.00	$0.53	$0.03	$0.00	$0.00	$0.00	$56.57	$60.54
F	Capital	$48.17	$4.46	$15.42	$0.00	$13.23	$0.47	$10.06	$0.00	$4.25	$0.07	$0.00	$0.00	$0.00	$96.12	$100.09
G1	Hudson Valley (Dutchess)	$20.42	$2.69	$6.37	$0.00	$15.54	$2.00	$22.19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$69.21	$73.18
G2	Hudson Valley (Rockland)	$23.60	$2.31	$5.06	$0.00	$15.22	$1.28	$21.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$68.95	$72.92
J	NYC	$45.28	$2.01	$2.82	$0.00	$12.03	$0.87	$16.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$79.39	$83.36
K	Long Island	$51.82	$0.25	$4.65	$0.00	$24.53	$1.23	$14.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$96.69	$100.66

Net EAS Revenues: September 2023 - August 2024																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$25.16	$0.00	$1.94	$0.00	$5.74	$0.13	$13.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$46.31	$50.28
F	Capital	$12.21	$3.27	$6.36	$0.00	$4.62	$0.87	$15.59	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$42.94	$46.91
G1	Hudson Valley (Dutchess)	$15.95	$2.17	$4.79	$0.00	$2.57	$1.32	$16.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$43.23	$47.20
G2	Hudson Valley (Rockland)	$20.20	$1.59	$3.43	$0.00	$2.15	$1.32	$16.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$45.20	$49.17
J	NYC	$36.65	$0.40	$0.46	$0.00	$2.49	$3.04	$11.19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$54.23	$58.20
K	Long Island	$52.37	$0.15	$2.43	$0.00	$8.14	$0.82	$10.76	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$74.68	$78.65

Notes:
[1] Results reflect data for the period September 1, 2021 through August 31, 2024.
[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.
[4] Assumes $3.97/kW-year VSS revenues for combustion turbine plants.

Dispatch Co-Optimization By Year: Run Hours
Gas Only: SCGT J-Class (7HA.03) with SCR

Run Hours: September 2021 - August 2022															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1698	14	151	0	247	15	1934	0	115	6	0	4580	0	8760
F	Capital	2883	21	542	0	170	9	854	0	363	4	0	3914	0	8760
G1	Hudson Valley (Dutchess)	2278	0	466	0	111	31	1113	0	266	5	0	4490	0	8760
G2	Hudson Valley (Rockland)	2175	7	399	0	103	25	1078	0	267	8	0	4698	0	8760

Run Hours: September 2022 - August 2023															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1160	0	124	0	374	63	5982	0	37	4	0	1016	0	8760
F	Capital	1960	139	619	0	369	135	4348	0	131	8	0	1051	0	8760
G1	Hudson Valley (Dutchess)	1062	101	306	0	167	361	5450	0	110	9	0	1194	0	8760
G2	Hudson Valley (Rockland)	1461	39	253	0	187	252	4921	0	107	7	0	1533	0	8760

Run Hours: September 2023 - August 2024															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	1635	0	177	0	419	46	6406	0	1	0	0	100	0	8784
F	Capital	820	65	245	0	346	254	6581	0	6	1	0	466	0	8784
G1	Hudson Valley (Dutchess)	1059	79	263	0	158	367	6435	0	5	0	0	418	0	8784
G2	Hudson Valley (Rockland)	1218	68	159	0	131	363	6141	0	2	5	0	697	0	8784

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas Only: SCGT J-Class (7HA.03) with SCR

Net EAS Revenues: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$61.68	$0.33	$3.41	$0.00	$8.70	$0.02	$2.20	$0.00	$2.47	$0.06	$0.00	$0.00	$0.00	$78.87	$82.84
F	Capital	$79.03	$0.43	$13.96	$0.00	$9.23	$0.03	$1.31	$0.00	$15.87	$0.16	$0.00	$0.00	$0.00	$120.02	$123.99
G1	Hudson Valley (Dutchess)	$53.39	$0.00	$8.43	$0.00	$4.19	$0.14	$1.68	$0.00	$9.07	$0.15	$0.00	$0.00	$0.00	$77.06	$81.03
G2	Hudson Valley (Rockland)	$61.23	$0.05	$6.77	$0.00	$3.34	$0.09	$2.00	$0.00	$10.12	$0.17	$0.00	$0.00	$0.00	$83.76	$87.73

Net EAS Revenues: September 2022 - August 2023																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$31.86	$0.00	$1.44	$0.00	$8.57	$0.24	$13.90	$0.00	$0.53	$0.03	$0.00	$0.00	$0.00	$56.57	$60.54
F	Capital	$45.74	$4.46	$14.67	$0.00	$8.77	$0.46	$9.65	$0.00	$14.68	$0.09	$0.00	$0.00	$0.00	$98.53	$102.50
G1	Hudson Valley (Dutchess)	$20.39	$1.14	$6.31	$0.00	$4.91	$1.68	$13.83	$0.00	$22.89	$0.16	$0.00	$0.00	$0.00	$71.31	$75.28
G2	Hudson Valley (Rockland)	$23.48	$0.67	$4.37	$0.00	$4.56	$1.07	$12.28	$0.00	$21.50	$0.14	$0.00	$0.00	$0.00	$68.08	$72.05

Net EAS Revenues: September 2023 - August 2024																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$25.16	$0.00	$1.94	$0.00	$5.74	$0.13	$13.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$46.31	$50.28
F	Capital	$12.21	$3.27	$6.36	$0.00	$4.62	$0.87	$15.59	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$42.94	$46.91
G1	Hudson Valley (Dutchess)	$15.72	$2.17	$5.38	$0.00	$2.62	$1.31	$16.05	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$43.26	$47.23
G2	Hudson Valley (Rockland)	$19.96	$1.59	$3.25	$0.00	$2.22	$1.29	$15.51	$0.00	$0.01	$0.10	$0.00	$0.00	$0.00	$43.92	$47.89

Notes:
[1] Results reflect data for the period September 1, 2021 through August 31, 2024.
[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.
[4] Assumes $3.97/kW-year VSS revenues for combustion turbine plants.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: SCGT J-Class (7HA.02) without SCR

Run Hours: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	534	15	120	558	61	21	2120	173	12	8	0	5080	58	8760
F	Capital	427	13	525	1630	79	24	1401	115	61	4	0	4276	205	8760
G1	Hudson Valley (Dutchess)	421	19	276	880	147	89	6705	220	0	0	0	3	0	8760

Run Hours: September 2022 - August 2023															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	401	0	186	136	180	81	6549	50	23	4	0	1147	3	8760
F	Capital	466	93	535	1101	45	169	4800	288	34	6	0	1176	47	8760
G1	Hudson Valley (Dutchess)	367	121	272	220	198	428	7116	38	0	0	0	0	0	8760

Run Hours: September 2023 - August 2024															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	523	77	187	634	79	69	6897	213	0	0	0	104	1	8784
F	Capital	393	47	245	159	191	298	6932	36	0	1	0	482	0	8784
G1	Hudson Valley (Dutchess)	499	78	212	354	81	411	7126	23	0	0	0	0	0	8784

Notes:
[1] Results reflect data for the period September 1, 2021 through August 31, 2024.
[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: SCGT J-Class (7HA.02) without SCR

Net EAS Revenues: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$40.31	$0.20	$2.36	$1.94	$5.46	$0.04	$2.77	$0.24	$0.49	$0.07	$0.00	$0.00	$0.00	$53.89	$57.40
F	Capital	$29.36	$0.39	$16.10	$2.43	$10.22	$0.18	$5.17	$0.45	$4.82	$0.08	$0.00	$0.00	$0.00	$69.20	$72.71
G1	Hudson Valley (Dutchess)	$18.50	$0.26	$5.78	$5.40	$10.63	$0.69	$21.52	$1.13	$0.00	$0.00	$0.00	$0.00	$0.00	$63.89	$67.40

Net EAS Revenues: September 2022 - August 2023																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$25.26	$0.00	$1.93	$0.53	$6.71	$0.31	$15.41	$0.10	$0.67	$0.02	$0.00	$0.00	$0.00	$50.95	$54.46
F	Capital	$24.72	$3.71	$14.07	$2.88	$5.80	$0.63	$11.42	$0.82	$2.72	$0.07	$0.00	$0.00	$0.00	$66.83	$70.34
G1	Hudson Valley (Dutchess)	$11.40	$3.82	$6.72	$1.01	$14.40	$2.20	$24.07	$0.17	$0.00	$0.00	$0.00	$0.00	$0.00	$63.79	$67.30

Net EAS Revenues: September 2023 - August 2024																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$15.39	$2.19	$1.96	$1.42	$2.54	$0.20	$14.31	$0.43	$0.00	$0.00	$0.00	$0.00	$0.00	$38.44	$41.95
F	Capital	$8.13	$2.94	$6.56	$0.45	$3.50	$0.98	$16.38	$0.07	$0.00	$0.01	$0.00	$0.00	$0.00	$39.03	$42.54
G1	Hudson Valley (Dutchess)	$10.07	$2.85	$4.69	$1.26	$1.88	$1.44	$17.33	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$39.57	$43.08

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

[4] Assumes $3.51/kW-year VSS revenues for combustion turbine plants.

Dispatch Co-Optimization By Year: Run Hours
Gas Only: SCGT J-Class (7HA.02) without SCR

Run Hours: September 2021 - August 2022															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	534	15	120	558	61	21	2120	173	12	8	0	5080	58	8760
F	Capital	427	13	510	1625	65	14	1093	89	96	5	0	4625	198	8760
G1	Hudson Valley (Dutchess)	443	15	378	1064	55	38	1325	70	94	5	0	5165	108	8760

Run Hours: September 2022 - August 2023															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	401	0	186	136	180	81	6549	50	23	4	0	1147	3	8760
F	Capital	502	93	529	1027	30	167	4758	277	58	7	0	1263	49	8760
G1	Hudson Valley (Dutchess)	388	106	300	227	117	401	5704	34	89	8	0	1384	2	8760

Run Hours: September 2023 - August 2024															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
C	Central	523	77	187	634	79	69	6897	213	0	0	0	104	1	8784
F	Capital	393	47	245	159	191	298	6932	36	0	1	0	482	0	8784
G1	Hudson Valley (Dutchess)	489	78	217	343	97	411	6673	23	0	0	0	453	0	8784

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas Only: SCGT J-Class (7HA.02) without SCR

Net EAS Revenues: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$40.31	$0.20	$2.36	$1.94	$5.46	$0.04	$2.77	$0.24	$0.49	$0.07	$0.00	$0.00	$0.00	$53.89	$57.40
F	Capital	$29.36	$0.39	$15.44	$2.25	$7.95	$0.04	$1.89	$0.19	$9.00	$0.19	$0.00	$0.00	$0.00	$66.71	$70.22
G1	Hudson Valley (Dutchess)	$18.75	$0.06	$7.21	$2.73	$3.65	$0.19	$2.29	$0.10	$7.15	$0.15	$0.00	$0.00	$0.00	$42.28	$45.79

Net EAS Revenues: September 2022 - August 2023																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$25.26	$0.00	$1.93	$0.53	$6.71	$0.31	$15.41	$0.10	$0.67	$0.02	$0.00	$0.00	$0.00	$50.95	$54.46
F	Capital	$25.52	$3.71	$13.59	$2.55	$2.47	$0.62	$10.95	$0.75	$13.04	$0.09	$0.00	$0.00	$0.00	$73.29	$76.80
G1	Hudson Valley (Dutchess)	$11.42	$2.27	$5.93	$0.82	$4.23	$1.87	$14.78	$0.11	$22.52	$0.16	$0.00	$0.00	$0.00	$64.11	$67.62

Net EAS Revenues: September 2023 - August 2024																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
C	Central	$15.39	$2.19	$1.96	$1.42	$2.54	$0.20	$14.31	$0.43	$0.00	$0.00	$0.00	$0.00	$0.00	$38.44	$41.95
F	Capital	$8.13	$2.94	$6.56	$0.45	$3.50	$0.98	$16.38	$0.07	$0.00	$0.01	$0.00	$0.00	$0.00	$39.03	$42.54
G1	Hudson Valley (Dutchess)	$10.03	$2.85	$4.95	$1.27	$2.29	$1.43	$16.65	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$39.53	$43.04

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

[4] Assumes $3.51/kW-year VSS revenues for combustion turbine plants.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: SCGT J-Class (7HA.02) with SCR

Run Hours: September 2021 - August 2022															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
K	Long Island	2779	5	188	870	284	68	4498	35	0	0	0	33	0	8760

Run Hours: September 2022 - August 2023															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
K	Long Island	2208	78	300	0	322	271	5581	0	0	0	0	0	0	8760

Run Hours: September 2023 - August 2024															
Day-Ahead Commitment		Energy				Reserve				None					Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited	
K	Long Island	2262	61	204	0	213	303	5741	0	0	0	0	0	0	8784

Notes:
[1] Results reflect data for the period September 1, 2021 through August 31, 2024.
[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: SCGT J-Class (7HA.02) with SCR

Net EAS Revenues: September 2021 - August 2022																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
K	Long Island	$89.02	$0.03	$2.99	$2.62	$16.02	$0.55	$13.94	$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$125.24	$128.75

Net EAS Revenues: September 2022 - August 2023																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
K	Long Island	$42.36	$1.76	$4.74	$0.00	$25.65	$1.30	$16.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$92.02	$95.53

Net EAS Revenues: September 2023 - August 2024																
Day-Ahead Commitment		Energy				Reserve				None					Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	None	Limited		
K	Long Island	$45.21	$0.51	$2.31	$0.00	$8.99	$0.94	$12.19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$70.15	$73.66

Notes:

[1] Results reflect data for the period September 1, 2021 through August 31, 2024.

[2] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023; September 1, 2023 to August 31, 2024). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

[4] Assumes $3.51/kW-year VSS revenues for combustion turbine plants.

E. Additional Detail on Net EAS Results for BESS Technologies

This appendix provides net EAS results for the BESS technologies using the RTM model utilizing Real-Time Dispatch prices, and the RTM model utilizing hourly time-weighted/integrated real-time prices in the 2021-2025 DCR. The appendix tables cover yearly revenues and runtimes during the three-year review period broken down by fuel type, as well as revenues and hours/intervals by day-ahead commitment and real-time dispatch behavior.

The RTM model utilizing Real-Time Dispatch prices is described in Section IV.B of the Final Report.

The 2021-2025 DCR approach to evaluating arbitrage opportunities in the RTM is different than the approach utilized in the 2025-2029 DCR. Importantly, in the 2021-2025 DCR, the RTM model uses average hourly RTM LBMPs rather than Real-Time Dispatch prices transacting on a nominal 5-minute basis.

The 2021-2025 RTM model generates every feasible RTM hour-pair given the currently scheduled DAM energy and reserve hourly positions of the battery. When evaluating and ranking the profitability of adding hour-pairs in the RTM, the model calculates an "estimated profit" using the RTM LBMP for the first hour and the DAM LBMP for the second hour. This approach reflects the fact that, in real-time, a resource operator would not know a future RTM LBMP and could use the DAM LBMP as an approximation. However, once these RTM positions are entered into, the model will use RTM LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position.

Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for LBMP uncertainty in the real-time market. This hurdle rate reflects two components - an opportunity cost of limited available energy and a risk premium. The battery model must clear the hurdle rate (i.e., estimate its new position to be more profitable than the hurdle rate) in order to enter into a RTM position.

The opportunity cost of limited available energy reflects that, if the battery used its limited energy to earn revenues in low priced hours, it may not have sufficient stored energy be earn higher revenues in the future. The risk premium accounts for market participant's risk aversion when participating in the real-time market, given the potential for higher volatility of real-time prices and the potential for losses to result from deviations from its DAM positions. We assume the risk premium is $10/MWh, and calculate the revenue-maximizing opportunity cost of limited available energy directly by evaluating marginal net EAS revenues for different assumed hurdle rates and selecting the revenue maximizing opportunity cost value. The hourly results reported in the appendix use the same hurdle rates as estimated in the 2021-2025 DCR.

Dispatch Co-Optimization By Year: Run Intervals
Battery Energy Storage System (BESS) 2-Hour, 5-Minute RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	4,505	2	45	3,752	766	3,675	765	3,021	4,721	77,971	6,875	6	58	24	1,547	4,565	103,168	107,733
F	Capital	4,505	0	11	4,021	493	3,865	585	1,272	2,295	85,556	4,094	11	11	0	1,014	4,574	103,159	107,733
G	Hudson Valley (Dutchess)	4,520	0	0	4,391	76	4,318	99	83	263	92,667	788	0	3	0	525	4,623	103,110	107,733
G	Hudson Valley (Rockland)	4,520	0	0	4,391	76	4,318	99	83	263	92,667	788	0	3	0	525	4,623	103,110	107,733
J	NYC	4,531	1	0	4,367	92	4,316	106	107	321	92,531	765	0	4	0	592	4,619	103,114	107,733
K	Long Island	4,538	0	0	3,826	656	3,768	659	1,399	2,710	85,268	4,032	7	27	0	843	4,614	103,119	107,733

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	4,500	4	0	3,951	498	3,890	563	1,350	2,401	85,243	4,215	8	10	0	1,064	4,568	103,129	107,697
F	Capital	4,525	1	25	4,080	442	3,913	526	1,072	1,857	88,035	2,583	5	51	64	518	4,541	103,156	107,697
G	Hudson Valley (Dutchess)	4,497	0	0	4,384	60	4,360	70	93	220	93,524	329	0	0	0	160	4,595	103,102	107,697
G	Hudson Valley (Rockland)	4,497	0	0	4,384	60	4,360	70	93	220	93,524	329	0	0	0	160	4,595	103,102	107,697
J	NYC	4,507	0	0	4,371	65	4,338	87	115	270	93,398	438	0	0	0	108	4,597	103,100	107,697
K	Long Island	4,560	0	0	4,131	357	4,113	321	1,054	1,851	87,896	2,948	13	29	0	424	4,598	103,099	107,697

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	4,483	0	0	4,047	388	3,957	468	476	1,202	89,192	2,154	3	2	12	867	3,485	103,766	107,251
F	Capital	4,496	0	0	4,259	170	4,086	329	52	387	92,648	402	2	0	36	384	3,497	103,754	107,251
G	Hudson Valley (Dutchess)	4,505	0	0	4,367	56	4,258	161	8	138	93,485	19	0	0	0	254	3,510	103,741	107,251
G	Hudson Valley (Rockland)	4,505	0	0	4,367	56	4,258	161	8	138	93,485	19	0	0	0	254	3,510	103,741	107,251
J	NYC	4,481	0	0	4,364	59	4,329	97	84	245	93,136	153	0	0	0	303	3,516	103,735	107,251
K	Long Island	4,470	0	0	4,113	312	4,084	343	412	1,052	90,671	1,404	6	3	39	342	3,481	103,770	107,251

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 2-Hour, 5-Minute RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$23.42	$0.00	$0.04	-$8.97	-$0.14	-$0.72	$0.00	$20.29	-$10.51	$33.47	$0.44	$0.04	-$0.23	$0.00	$57.12	$61.22
F	Capital	$39.34	$0.00	$0.03	-$17.31	-$0.31	-$1.86	-$0.02	$24.48	-$13.98	$50.50	-$0.90	$0.03	-$0.01	$0.00	$79.97	$84.07
G	Hudson Valley (Dutchess)	$36.91	$0.00	$0.00	-$17.37	$0.04	-$1.95	$0.01	$2.65	-$1.36	$59.22	$0.37	$0.00	$0.00	$0.00	$78.50	$82.60
G	Hudson Valley (Rockland)	$36.89	$0.00	$0.00	-$17.37	$0.04	-$1.95	$0.01	$2.64	-$1.36	$59.22	$0.37	$0.00	$0.00	$0.00	$78.48	$82.58
J	NYC	$36.54	$0.00	$0.00	-$17.48	$0.03	-$1.95	$0.00	$3.19	-$1.88	$64.63	$0.11	$0.00	$0.00	$0.00	$83.20	$87.30
K	Long Island	$47.79	$0.00	$0.00	-$15.80	-$0.30	-$1.81	-$0.04	$25.37	-$16.80	$51.86	-$1.49	$0.13	-$0.07	$0.00	$88.83	$92.93

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$14.37	$0.00	$0.00	-$4.44	-$0.06	$0.39	$0.02	$9.02	-$4.52	$36.60	$0.23	$0.01	$0.00	$0.00	$51.63	$55.73
F	Capital	$28.22	$0.00	-$0.04	-$9.72	-$0.16	-$0.32	-$0.01	$19.27	-$10.10	$50.66	$0.13	$0.06	-$0.41	$0.01	$77.58	$81.68
G	Hudson Valley (Dutchess)	$23.83	$0.00	$0.00	-$9.57	-$0.04	-$0.43	$0.00	$2.89	-$1.35	$59.81	$0.09	$0.00	$0.00	$0.00	$75.23	$79.33
G	Hudson Valley (Rockland)	$23.81	$0.00	$0.00	-$9.57	-$0.04	-$0.43	$0.00	$2.89	-$1.35	$59.81	$0.09	$0.00	$0.00	$0.00	$75.21	$79.31
J	NYC	$23.19	$0.00	$0.00	-$9.64	-$0.04	-$0.43	-$0.01	$3.47	-$1.46	$63.05	$0.00	$0.00	$0.00	$0.00	$78.12	$82.22
K	Long Island	$30.33	$0.00	$0.00	-$9.34	$0.23	-$0.48	-$0.04	$22.07	-$9.94	$53.88	$0.83	$0.24	-$0.38	$0.00	$87.40	$91.50

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$12.66	$0.00	$0.00	-$5.14	-$0.12	-$0.14	-$0.01	$2.91	-$1.88	$27.11	$0.72	$0.00	$0.00	$0.00	$36.10	$40.20
F	Capital	$16.81	$0.00	$0.00	-$6.27	$0.00	-$0.14	$0.00	$0.43	-$0.47	$38.26	$0.16	$0.00	$0.00	$0.00	$48.78	$52.88
G	Hudson Valley (Dutchess)	$17.30	$0.00	$0.00	-$6.54	$0.00	-$0.15	$0.00	$0.21	$0.00	$41.11	$0.00	$0.00	$0.00	$0.00	$51.94	$56.04
G	Hudson Valley (Rockland)	$17.28	$0.00	$0.00	-$6.54	$0.00	-$0.15	$0.00	$0.21	$0.00	$41.11	$0.00	$0.00	$0.00	$0.00	$51.92	$56.02
J	NYC	$16.99	$0.00	$0.00	-$6.51	-$0.02	-$0.13	$0.00	$3.03	-$0.51	$46.57	$0.00	$0.00	$0.00	$0.00	$59.42	$63.52
K	Long Island	$23.69	$0.00	$0.00	-$6.33	-$0.15	-$0.21	-$0.03	$5.61	-$2.78	$38.75	$0.40	$0.03	$0.00	$0.14	$59.11	$63.21

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Intervals
Battery Energy Storage System (BESS) 4-Hour, 5-Minute RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	12,698	31	65	11,968	704	4,097	366	4,255	5,945	61,470	4,772	71	39	98	1,154	4,565	103,168	107,733
F	Capital	12,412	1	23	10,919	1,434	3,999	464	2,640	4,810	67,177	3,028	59	29	163	575	4,574	103,159	107,733
G	Hudson Valley (Dutchess)	12,923	0	0	12,578	185	4,366	84	382	972	74,183	1,580	30	1	20	429	4,623	103,110	107,733
G	Hudson Valley (Rockland)	12,897	0	0	12,554	185	4,366	84	382	971	74,222	1,592	30	1	20	429	4,623	103,110	107,733
J	NYC	12,616	5	0	12,286	153	4,369	78	322	848	75,336	1,282	28	4	40	366	4,619	103,114	107,733
K	Long Island	13,392	16	37	11,934	1,344	3,995	462	3,025	5,236	65,606	2,007	47	33	12	587	4,614	103,119	107,733

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	11,846	14	6	11,233	504	4,121	332	2,256	3,421	70,170	2,866	22	5	24	877	4,568	103,129	107,697
F	Capital	12,946	78	26	11,471	1,470	3,966	492	2,129	4,193	68,983	1,613	17	25	0	288	4,541	103,156	107,697
G	Hudson Valley (Dutchess)	12,256	0	0	11,931	166	4,373	53	384	832	77,077	479	0	0	0	146	4,595	103,102	107,697
G	Hudson Valley (Rockland)	12,194	0	0	11,889	147	4,372	53	388	811	77,218	479	0	0	0	146	4,595	103,102	107,697
J	NYC	11,719	5	0	11,436	100	4,387	40	387	721	78,355	439	0	0	0	108	4,597	103,100	107,697
K	Long Island	13,090	13	10	12,057	851	4,081	360	2,245	3,837	69,619	1,282	38	14	0	200	4,598	103,099	107,697

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	11,448	0	0	10,631	671	4,209	228	1,016	2,149	74,432	1,681	5	2	108	671	3,485	103,766	107,251
F	Capital	11,530	15	0	10,882	489	4,308	150	531	1,303	77,305	386	6	15	60	271	3,497	103,754	107,251
G	Hudson Valley (Dutchess)	11,961	0	0	11,513	287	4,352	80	244	799	77,749	36	1	0	0	229	3,510	103,741	107,251
G	Hudson Valley (Rockland)	11,911	0	0	11,465	287	4,352	80	244	796	77,838	36	1	0	0	241	3,510	103,741	107,251
J	NYC	11,805	0	0	11,487	134	4,394	31	182	539	78,271	165	0	0	0	243	3,516	103,735	107,251
K	Long Island	12,853	0	7	11,632	1,066	4,177	256	923	2,508	72,702	871	12	2	24	218	3,481	103,770	107,251

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 4-Hour, 5-Minute RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$65.50	$0.00	-$0.05	-$28.88	-$0.11	-$4.52	-$0.04	$27.36	-$16.77	$25.18	-$0.36	$0.36	-$0.18	$0.00	$67.48	$71.58
F	Capital	$107.43	$0.00	-$0.10	-$49.12	-$0.79	-$8.28	-$0.14	$37.00	-$28.28	$37.54	-$1.05	$0.34	-$0.09	$0.01	$94.47	$98.57
G	Hudson Valley (Dutchess)	$106.78	$0.00	$0.00	-$51.56	-$0.12	-$8.63	$0.05	$7.11	-$4.68	$44.63	-$0.26	$0.20	$0.00	$0.00	$93.52	$97.62
G	Hudson Valley (Rockland)	$106.51	$0.00	$0.00	-$51.45	-$0.12	-$8.61	$0.05	$7.11	-$4.68	$44.68	-$0.24	$0.20	$0.00	$0.00	$93.46	$97.56
J	NYC	$102.66	$0.00	$0.00	-$50.71	-$0.02	-$8.41	-$0.03	$6.11	-$3.99	$49.71	-$0.23	$0.17	$0.00	$0.00	$95.25	$99.35
K	Long Island	$134.06	$0.00	-$0.06	-$51.23	-$0.44	-$8.71	-$0.23	$41.83	-$33.97	$38.43	-$1.53	$0.26	-$0.08	$0.00	$118.32	$122.42

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$38.08	$0.00	$0.01	-$14.22	$0.96	-$1.80	$0.15	$13.29	-$6.90	$29.56	$1.42	$0.04	$0.00	$0.00	$60.59	$64.69
F	Capital	$77.82	$0.00	$0.07	-$28.80	-$0.34	-$4.29	$0.04	$26.45	-$19.75	$37.62	$0.71	$0.04	-$0.13	$0.00	$89.43	$93.53
G	Hudson Valley (Dutchess)	$64.74	$0.00	$0.00	-$27.20	-$0.12	-$4.10	$0.01	$6.23	-$3.60	$47.11	$0.16	$0.00	$0.00	$0.00	$83.24	$87.34
G	Hudson Valley (Rockland)	$64.47	$0.00	$0.00	-$27.15	-$0.12	-$4.07	$0.01	$6.20	-$3.51	$47.21	$0.16	$0.00	$0.00	$0.00	$83.20	$87.30
J	NYC	$60.57	$0.00	$0.00	-$26.66	-$0.10	-$3.80	-$0.01	$6.31	-$3.18	$50.37	$0.08	$0.00	$0.00	$0.00	$83.58	$87.68
K	Long Island	$82.36	$0.00	$0.04	-$29.61	$0.79	-$4.53	$0.00	$33.62	-$19.20	$40.18	$0.16	$0.48	-$0.15	$0.00	$104.16	$108.26

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$32.56	$0.00	$0.00	-$14.24	-$0.17	-$2.00	-$0.05	$5.20	-$3.93	$21.99	$0.52	$0.00	$0.00	$0.00	$39.89	$43.99
F	Capital	$43.33	$0.00	$0.00	-$16.88	-$0.15	-$2.50	$0.00	$1.80	-$2.27	$31.40	$0.16	$0.01	-$0.04	$0.00	$54.88	$58.98
G	Hudson Valley (Dutchess)	$46.58	$0.00	$0.00	-$18.20	$0.01	-$2.71	$0.00	$0.55	-$0.95	$33.19	$0.01	$0.00	$0.00	$0.00	$58.49	$62.59
G	Hudson Valley (Rockland)	$46.40	$0.00	$0.00	-$18.14	$0.01	-$2.69	$0.00	$0.55	-$0.95	$33.24	$0.01	$0.00	$0.00	$0.00	$58.43	$62.53
J	NYC	$45.63	$0.00	$0.00	-$18.20	-$0.05	-$2.66	$0.00	$3.29	-$0.82	$37.59	$0.02	$0.00	$0.00	$0.00	$64.79	$68.89
K	Long Island	$64.95	$0.00	-$0.01	-$19.33	-$0.18	-$3.03	-$0.09	$8.87	-$6.69	$30.09	$0.30	$0.04	$0.00	$0.00	$74.93	$79.03

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Intervals
Battery Energy Storage System (BESS) 6-Hour, 5-Minute RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	19,355	85	76	18,638	703	4,343	308	5,100	6,834	47,829	3,247	60	55	56	1,044	4,565	103,168	107,733
F	Capital	17,816	12	45	16,707	1,011	4,175	344	4,468	6,498	53,268	2,734	94	1	158	402	4,574	103,159	107,733
G	Hudson Valley (Dutchess)	19,232	0	24	18,393	623	4,365	96	1,504	2,708	59,444	890	46	3	52	353	4,623	103,110	107,733
G	Hudson Valley (Rockland)	19,206	0	24	18,369	623	4,365	96	1,501	2,703	59,502	890	46	3	52	353	4,623	103,110	107,733
J	NYC	18,811	14	0	17,992	563	4,357	120	489	1,508	62,234	1,245	12	3	13	372	4,619	103,114	107,733
K	Long Island	20,518	35	22	19,253	1,060	4,172	392	3,597	5,666	51,102	1,297	86	22	31	480	4,614	103,119	107,733

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	17,393	58	8	16,721	508	4,320	246	3,695	5,101	56,433	2,412	24	5	88	685	4,568	103,129	107,697
F	Capital	19,001	75	36	17,581	1,260	4,370	393	3,429	5,422	54,804	1,082	17	11	12	204	4,541	103,156	107,697
G	Hudson Valley (Dutchess)	18,043	15	0	17,042	742	4,424	118	1,077	2,259	63,440	415	0	0	0	122	4,595	103,102	107,697
G	Hudson Valley (Rockland)	17,983	15	0	16,982	742	4,420	118	1,066	2,247	63,587	415	0	0	0	122	4,595	103,102	107,697
J	NYC	16,957	16	0	16,319	383	4,414	73	457	1,174	67,402	406	0	0	0	96	4,597	103,100	107,697
K	Long Island	19,502	15	9	18,064	1,174	4,037	493	2,951	5,131	55,332	833	31	12	0	113	4,598	103,099	107,697

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	16,084	1	1	15,198	679	4,262	215	1,710	3,081	63,172	2,134	10	2	84	618	3,485	103,766	107,251
F	Capital	16,500	0	3	15,652	626	4,286	216	1,008	2,178	65,939	529	21	0	97	196	3,497	103,754	107,251
G	Hudson Valley (Dutchess)	17,114	1	0	16,328	536	4,296	156	558	1,538	66,480	124	0	0	0	120	3,510	103,741	107,251
G	Hudson Valley (Rockland)	17,102	1	0	16,316	536	4,296	156	558	1,538	66,492	124	0	0	0	132	3,510	103,741	107,251
J	NYC	16,910	0	0	16,265	377	4,285	167	307	1,147	67,554	70	23	0	37	109	3,516	103,735	107,251
K	Long Island	18,825	10	0	17,321	1,247	4,057	488	1,410	3,487	59,671	539	0	0	0	196	3,481	103,770	107,251

Notes:

[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.

[2] For each hour, a unit is committed via day-ahead then dispatched in real time.

[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 6-Hour, 5-Minute RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$98.15	$0.00	-$0.09	-$46.31	$0.20	-$7.88	$0.08	$28.26	-$19.93	$19.62	-$0.70	$0.22	-$0.21	$0.00	$71.42	$75.52
F	Capital	$152.65	$0.00	-$0.29	-$77.15	-$0.44	-$13.35	-$0.26	$51.61	-$38.81	$28.18	-$1.18	$0.43	$0.00	$0.01	$101.38	$105.48
G	Hudson Valley (Dutchess)	$157.31	$0.00	-$0.17	-$77.52	$0.06	-$13.95	-$0.04	$20.96	-$17.17	$34.22	-$0.18	$0.26	$0.00	$0.00	$103.77	$107.87
G	Hudson Valley (Rockland)	$157.00	$0.00	-$0.17	-$77.36	$0.06	-$13.92	-$0.04	$20.95	-$17.15	$34.25	-$0.18	$0.26	$0.00	$0.00	$103.69	$107.79
J	NYC	$152.37	$0.00	$0.00	-$76.51	$0.14	-$13.63	-$0.02	$8.50	-$8.26	$39.48	-$0.33	$0.03	$0.00	$0.00	$101.78	$105.88
K	Long Island	$198.13	$0.00	-$0.04	-$85.47	$0.01	-$15.04	$0.05	$46.69	-$35.38	$29.44	-$1.70	$0.48	-$0.12	$0.03	$137.08	$141.18

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$54.74	$0.00	$0.00	-$22.39	$0.01	-$3.50	$0.04	$18.31	-$9.74	$23.13	$1.19	$0.05	$0.00	$0.00	$61.83	$65.93
F	Capital	$112.41	$0.00	$0.01	-$47.38	-$0.15	-$7.93	-$0.03	$32.62	-$24.43	$27.92	$0.38	$0.04	-$0.05	$0.00	$93.39	$97.49
G	Hudson Valley (Dutchess)	$94.95	$0.00	$0.00	-$40.55	$0.00	-$7.00	$0.00	$14.73	-$11.69	$36.19	$0.05	$0.00	$0.00	$0.00	$86.67	$90.77
G	Hudson Valley (Rockland)	$94.65	$0.00	$0.00	-$40.44	$0.00	-$6.98	$0.00	$14.68	-$11.65	$36.27	$0.05	$0.00	$0.00	$0.00	$86.58	$90.68
J	NYC	$87.54	$0.00	$0.00	-$39.58	$0.10	-$6.72	$0.01	$7.50	-$4.51	$41.76	$0.12	$0.00	$0.00	$0.00	$86.23	$90.33
K	Long Island	$118.86	$0.00	$0.04	-$47.18	$0.40	-$7.85	$0.02	$36.55	-$21.94	$30.90	$0.08	$0.22	-$0.15	$0.00	$109.97	$114.07

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$45.59	$0.00	$0.00	-$21.35	$0.04	-$3.39	$0.01	$7.01	-$5.42	$18.38	$0.64	$0.02	$0.00	$0.00	$41.52	$45.62
F	Capital	$60.66	$0.00	$0.00	-$25.30	$0.07	-$4.09	$0.00	$4.29	-$4.20	$26.30	$0.21	$0.03	$0.00	$0.00	$57.96	$62.06
G	Hudson Valley (Dutchess)	$66.12	$0.00	$0.00	-$27.00	$0.07	-$4.56	$0.01	$2.55	-$2.52	$27.85	$0.08	$0.00	$0.00	$0.00	$62.61	$66.71
G	Hudson Valley (Rockland)	$66.00	$0.00	$0.00	-$26.99	$0.07	-$4.56	$0.01	$2.55	-$2.52	$27.86	$0.08	$0.00	$0.00	$0.00	$62.51	$66.61
J	NYC	$66.02	$0.00	$0.00	-$26.98	$0.07	-$4.47	$0.03	$3.59	-$2.05	$31.05	$0.00	$0.03	$0.00	$0.00	$67.30	$71.40
K	Long Island	$92.33	$0.00	$0.00	-$30.96	$0.13	-$5.05	$0.10	$10.76	-$8.95	$24.56	$0.17	$0.00	$0.00	$0.00	$83.09	$87.19

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Intervals
Battery Energy Storage System (BESS) 8-Hour, 5-Minute RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	22,679	114	74	22,441	162	5,478	443	4,673	5,692	42,205	2,547	35	66	0	1,124	4,565	103,168	107,733
F	Capital	21,234	52	34	20,631	481	4,893	504	4,056	5,491	47,861	1,782	67	13	122	512	4,574	103,159	107,733
G	Hudson Valley (Dutchess)	22,728	3	0	22,106	311	5,332	442	1,743	2,776	50,974	914	34	3	15	352	4,623	103,110	107,733
G	Hudson Valley (Rockland)	22,710	3	6	22,073	332	5,334	440	1,981	3,066	50,626	758	36	5	43	320	4,623	103,110	107,733
J	NYC	22,529	26	0	21,958	251	5,345	412	756	1,565	53,620	910	0	3	0	358	4,619	103,114	107,733
K	Long Island	24,324	65	33	23,451	644	5,230	1,062	3,939	5,768	41,471	1,089	93	39	24	501	4,614	103,119	107,733

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	20,488	70	12	20,140	165	4,891	278	3,191	4,148	51,737	1,725	36	18	86	712	4,568	103,129	107,697
F	Capital	21,859	220	23	21,129	692	5,049	478	3,315	4,615	49,122	999	23	24	0	149	4,541	103,156	107,697
G	Hudson Valley (Dutchess)	21,052	30	0	20,449	313	5,014	237	1,402	2,206	56,558	376	0	0	0	60	4,595	103,102	107,697
G	Hudson Valley (Rockland)	21,020	38	0	20,423	315	5,004	247	1,488	2,303	56,414	373	0	0	0	72	4,595	103,102	107,697
J	NYC	20,320	25	0	19,792	218	4,877	181	745	1,352	59,758	357	0	0	0	72	4,597	103,100	107,697
K	Long Island	22,792	69	4	21,863	675	4,853	891	3,307	4,959	47,550	626	20	8	0	80	4,598	103,099	107,697

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None				Total CAM	Total Non-CAM	Total
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve	None			
C	Central	20,015	0	9	19,429	351	4,848	280	1,659	2,627	56,175	1,108	14	3	85	648	3,485	103,766	107,251
F	Capital	20,231	16	0	19,582	397	4,848	265	1,196	2,077	58,194	239	0	0	48	158	3,497	103,754	107,251
G	Hudson Valley (Dutchess)	20,962	1	0	20,247	412	4,878	424	795	1,757	57,623	44	0	0	0	108	3,510	103,741	107,251
G	Hudson Valley (Rockland)	20,962	1	0	20,238	419	4,880	424	845	1,825	57,451	86	0	0	0	120	3,510	103,741	107,251
J	NYC	20,884	13	0	20,291	247	4,898	401	514	1,284	58,464	36	23	0	37	159	3,516	103,735	107,251
K	Long Island	22,521	8	0	21,302	919	5,073	802	1,917	3,679	50,571	385	0	0	0	74	3,481	103,770	107,251

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 8-Hour, 5-Minute RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$113.68	$0.00	-$0.05	-$57.65	-$0.01	-$9.71	$0.00	$25.30	-$14.96	$17.94	$0.91	$0.14	-$0.35	$0.00	$75.23	$79.33
F	Capital	$179.83	$0.00	-$0.28	-$97.77	-$0.28	-$16.70	-$0.13	$46.27	-$32.62	$24.65	-$1.22	$0.26	-$0.06	$0.01	$101.98	$106.08
G	Hudson Valley (Dutchess)	$184.85	$0.00	$0.00	-$94.99	$0.05	-$16.39	-$0.01	$22.68	-$18.04	$28.77	-$0.32	$0.20	$0.00	$0.00	$106.81	$110.91
G	Hudson Valley (Rockland)	$184.46	$0.00	-$0.03	-$94.75	$0.03	-$16.37	-$0.01	$24.94	-$19.74	$28.27	-$0.29	$0.21	$0.00	$0.00	$106.74	$110.84
J	NYC	$181.17	$0.00	$0.00	-$95.52	-$0.02	-$16.42	$0.08	$10.17	-$8.94	$33.17	-$0.34	$0.00	$0.00	$0.00	$103.35	$107.45
K	Long Island	$233.81	$0.00	-$0.09	-$107.13	-$0.23	-$17.85	-$0.05	$48.17	-$34.96	$23.03	-$1.71	$0.41	-$0.24	$0.02	$143.18	$147.28

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$62.97	$0.00	-$0.01	-$27.44	$0.06	-$4.54	$0.11	$14.81	-$7.85	$21.35	$0.95	$0.06	-$0.01	$0.00	$60.46	$64.56
F	Capital	$127.11	$0.00	$0.09	-$58.14	-$0.13	-$9.29	-$0.12	$29.77	-$21.54	$24.40	$0.40	$0.07	-$0.10	$0.00	$92.53	$96.63
G	Hudson Valley (Dutchess)	$108.02	$0.00	$0.00	-$48.42	-$0.02	-$8.20	$0.07	$14.53	-$10.58	$31.84	$0.05	$0.00	$0.00	$0.00	$87.30	$91.40
G	Hudson Valley (Rockland)	$107.75	$0.00	$0.00	-$48.35	-$0.02	-$8.14	$0.05	$15.32	-$11.15	$31.66	$0.05	$0.00	$0.00	$0.00	$87.18	$91.28
J	NYC	$102.12	$0.00	$0.00	-$47.71	$0.05	-$8.19	-$0.01	$8.22	-$5.00	$36.21	$0.00	$0.00	$0.00	$0.00	$85.69	$89.79
K	Long Island	$136.31	$0.00	$0.02	-$57.37	$0.37	-$9.35	-$0.05	$37.02	-$21.20	$26.05	-$0.01	$0.11	-$0.11	$0.00	$111.80	$115.90

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge			Charge		Extra Charge		Reserve				None			Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Reserve	None	Charge	Reserve	Extra Charge	Reserve	Discharge	Charge	Reserve	None	Discharge	Charge	Reserve		
C	Central	$54.78	$0.00	$0.00	-$27.69	$0.10	-$4.64	-$0.04	$5.25	-$4.29	$16.59	$0.33	$0.09	$0.00	$0.00	$40.49	$44.59
F	Capital	$71.37	$0.00	$0.00	-$31.64	$0.08	-$5.39	-$0.05	$4.89	-$4.35	$23.11	$0.12	$0.00	$0.00	$0.00	$58.13	$62.23
G	Hudson Valley (Dutchess)	$78.19	$0.00	$0.00	-$33.72	$0.10	-$5.55	-$0.08	$3.39	-$3.27	$24.25	$0.01	$0.00	$0.00	$0.00	$63.32	$67.42
G	Hudson Valley (Rockland)	$78.09	$0.00	$0.00	-$33.66	$0.08	-$5.54	-$0.08	$3.81	-$3.66	$24.11	$0.04	$0.00	$0.00	$0.00	$63.17	$67.27
J	NYC	$79.25	$0.00	$0.00	-$34.23	$0.03	-$5.73	-$0.03	$4.05	-$2.34	$26.38	-$0.01	$0.03	$0.00	$0.00	$67.41	$71.51
K	Long Island	$108.26	$0.00	$0.00	-$38.94	$0.19	-$6.40	-$0.03	$11.36	-$9.58	$20.68	$0.14	$0.00	$0.00	$0.00	$85.66	$89.76

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 2-Hour, Hourly RTM Model

Run Hours: September 2021 - August 2022

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	370	372	3	5	315	42	0	88	85	50	7,292	5	2	3	0	23	105	8,760
F	Capital	369	371	7	10	279	68	1	157	153	86	7,151	24	3	4	1	33	43	8,760
G	Hudson Valley (Dutchess)	366	368	1	0	340	24	0	49	50	25	7,491	4	1	1	0	8	32	8,760
G	Hudson Valley (Rockland)	366	368	1	0	340	24	0	49	50	25	7,491	4	1	1	0	8	32	8,760
J	NYC	366	368	3	0	339	23	0	52	54	26	7,479	2	0	1	0	6	41	8,760
K	Long Island	367	369	3	17	310	35	0	105	91	55	7,320	17	1	1	1	27	41	8,760

Run Hours: September 2022 - August 2023

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	365	365	1	2	340	22	0	38	37	26	7,476	0	1	1	0	32	54	8,760
F	Capital	371	371	4	2	326	33	0	62	64	39	7,431	5	2	2	2	12	34	8,760
G	Hudson Valley (Dutchess)	366	366	2	0	355	8	0	18	20	10	7,601	1	1	1	0	0	11	8,760
G	Hudson Valley (Rockland)	366	366	2	0	355	8	0	18	20	10	7,601	1	1	1	0	0	11	8,760
J	NYC	366	366	0	0	357	8	0	19	19	9	7,606	1	0	0	0	0	9	8,760
K	Long Island	370	370	1	3	328	33	0	75	73	38	7,421	10	1	1	0	10	26	8,760

Run Hours: September 2023 - August 2024

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	366	366	0	0	355	11	0	18	18	11	7,566	0	0	0	0	2	71	8,784
F	Capital	367	367	1	0	358	7	0	12	13	8	7,616	0	0	0	0	5	30	8,784
G	Hudson Valley (Dutchess)	367	367	0	0	353	13	0	14	14	13	7,622	0	0	0	0	0	21	8,784
G	Hudson Valley (Rockland)	367	367	0	0	353	13	0	14	14	13	7,622	0	0	0	0	0	21	8,784
J	NYC	366	366	0	0	356	9	1	16	16	10	7,618	1	0	0	0	0	25	8,784
K	Long Island	366	366	1	1	343	21	0	29	29	23	7,568	5	0	0	0	7	25	8,784

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 2-Hour, Hourly RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$23.70	-$10.43	$0.26	-$0.22	-$0.88	$0.23	$9.34	-$4.21	-$0.48	$40.32	$0.13	-$0.08	$0.00	$0.11	$57.79	$61.89
F	Capital	$39.41	-$19.92	$1.14	-$1.02	-$1.99	$0.41	$25.13	-$14.61	-$1.50	$52.19	$0.24	-$0.26	-$0.02	$0.21	$79.40	$83.50
G	Hudson Valley (Dutchess)	$36.91	-$17.86	$0.18	$0.00	-$2.03	$0.16	$7.44	-$4.45	-$0.30	$59.01	$0.05	-$0.07	$0.00	$0.08	$79.12	$83.22
G	Hudson Valley (Rockland)	$36.89	-$17.86	$0.18	$0.00	-$2.03	$0.16	$7.44	-$4.45	-$0.30	$59.01	$0.05	-$0.07	$0.00	$0.08	$79.09	$83.19
J	NYC	$36.56	-$18.07	$0.37	$0.00	-$2.13	$0.12	$8.17	-$4.80	-$0.43	$64.05	$0.00	-$0.12	$0.00	$0.04	$83.75	$87.85
K	Long Island	$47.79	-$19.26	$0.32	-$1.49	-$1.96	$0.21	$15.25	-$6.78	$0.14	$55.86	$0.05	-$0.07	-$0.03	$0.19	$90.22	$94.32

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$14.38	-$5.21	$2.76	-$0.05	$0.36	$0.34	$2.84	-$0.91	-$0.16	$40.02	$0.04	-$0.05	$0.00	$0.17	$54.54	$58.64
F	Capital	$28.62	-$11.53	$0.52	-$0.15	-$0.46	$0.33	$11.95	-$7.21	-$0.12	$52.67	$0.11	-$0.18	-$0.05	$0.06	$74.56	$78.66
G	Hudson Valley (Dutchess)	$23.83	-$9.74	$0.41	$0.00	-$0.54	$0.04	$4.14	-$2.76	$1.07	$59.74	$0.09	-$0.10	$0.00	$0.00	$76.17	$80.27
G	Hudson Valley (Rockland)	$23.81	-$9.74	$0.41	$0.00	-$0.54	$0.04	$4.14	-$2.76	$1.07	$59.74	$0.09	-$0.10	$0.00	$0.00	$76.15	$80.25
J	NYC	$23.19	-$9.84	$0.00	$0.00	-$0.48	$0.05	$5.09	-$3.57	$1.78	$62.95	$0.00	$0.00	$0.00	$0.00	$79.16	$83.26
K	Long Island	$30.33	-$11.10	$0.09	-$0.19	-$0.63	$0.19	$12.51	-$5.69	$0.62	$56.28	$0.06	-$0.06	$0.00	$0.06	$82.46	$86.56

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$12.66	-$5.87	$0.00	$0.00	-$0.18	$0.08	$1.21	-$0.44	-$0.10	$28.26	$0.00	$0.00	$0.00	$0.01	$35.62	$39.72
F	Capital	$16.81	-$6.61	$0.01	$0.00	-$0.13	$0.04	$0.81	-$0.58	-$0.04	$38.36	$0.00	$0.00	$0.00	$0.05	$48.73	$52.83
G	Hudson Valley (Dutchess)	$17.30	-$6.63	$0.00	$0.00	-$0.12	$0.08	$0.65	-$0.30	$0.14	$40.96	$0.00	$0.00	$0.00	$0.00	$52.08	$56.18
G	Hudson Valley (Rockland)	$17.28	-$6.63	$0.00	$0.00	-$0.12	$0.08	$0.65	-$0.30	$0.14	$40.96	$0.00	$0.00	$0.00	$0.00	$52.06	$56.16
J	NYC	$16.99	-$6.64	$0.00	$0.00	-$0.17	$0.07	$1.67	-$0.40	$0.32	$46.26	$0.00	$0.00	$0.00	$0.00	$58.09	$62.19
K	Long Island	$23.69	-$7.24	$0.14	-$0.04	-$0.30	$0.10	$2.28	-$1.05	-$0.10	$39.54	$0.00	$0.00	$0.00	$0.04	$57.06	$61.16

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 4-Hour, Hourly RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,041	1,043	1	6	304	55	0	150	144	78	5,825	2	1	2	1	16	91	8,760
F	Capital	1,012	1,014	7	16	272	71	0	222	212	121	5,732	14	4	5	1	24	33	8,760
G	Hudson Valley (Dutchess)	1,051	1,052	1	4	336	24	0	74	71	37	6,068	4	1	1	0	8	28	8,760
G	Hudson Valley (Rockland)	1,049	1,050	1	4	336	24	0	75	72	37	6,070	4	1	1	0	8	28	8,760
J	NYC	1,025	1,026	3	7	334	21	0	92	88	40	6,087	2	1	1	0	10	23	8,760
K	Long Island	1,092	1,093	5	19	298	43	0	143	130	82	5,788	12	1	0	1	20	33	8,760

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	964	964	1	1	328	35	0	74	74	45	6,199	0	1	1	0	20	53	8,760
F	Capital	1,061	1,061	3	6	315	43	0	119	116	68	5,938	3	2	2	1	8	14	8,760
G	Hudson Valley (Dutchess)	996	996	1	2	340	22	0	62	62	31	6,235	1	1	0	0	1	10	8,760
G	Hudson Valley (Rockland)	991	991	1	2	340	22	0	62	62	31	6,245	1	1	0	0	1	10	8,760
J	NYC	951	951	2	2	343	18	0	61	61	27	6,334	1	0	0	0	1	8	8,760
K	Long Island	1,062	1,062	4	8	312	41	0	128	124	69	5,915	14	2	2	0	6	11	8,760

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	934	934	0	0	349	17	0	38	37	19	6,391	0	0	1	0	4	60	8,784
F	Capital	941	941	1	2	358	7	0	16	16	12	6,461	0	1	0	0	0	28	8,784
G	Hudson Valley (Dutchess)	977	977	3	2	349	12	0	19	20	18	6,388	0	0	0	0	0	19	8,784
G	Hudson Valley (Rockland)	973	973	3	2	349	12	0	19	20	18	6,395	0	0	0	0	0	20	8,784
J	NYC	962	962	2	2	349	13	0	22	22	17	6,413	0	0	0	0	1	19	8,784
K	Long Island	1,050	1,050	2	2	339	23	0	51	51	30	6,162	3	0	0	0	3	18	8,784

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 4-Hour, Hourly RTM Model

Net EAS Revenues: September 2021 - August 2022

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$66.24	-$30.51	$0.06	-$0.16	-$4.32	$0.27	$14.52	-$6.10	-$1.08	$30.98	$0.07	-$0.04	-$0.01	$0.09	$70.00	$74.10
F	Capital	$107.72	-$56.60	$2.25	-$1.81	-$6.42	$0.41	$35.31	-$17.41	-$3.38	$39.37	$0.23	-$0.27	-$0.04	$0.15	$99.50	$103.60
G	Hudson Valley (Dutchess)	$106.78	-$52.75	$0.13	-$0.27	-$8.12	$0.15	$11.09	-$5.85	-$1.11	$45.37	$0.05	-$0.07	$0.00	$0.05	$95.45	$99.55
G	Hudson Valley (Rockland)	$106.51	-$52.64	$0.13	-$0.27	-$8.11	$0.15	$11.20	-$5.91	-$1.11	$45.39	$0.05	-$0.07	$0.00	$0.05	$95.37	$99.47
J	NYC	$102.74	-$51.72	$0.35	-$0.68	-$8.00	$0.12	$13.95	-$7.17	-$1.09	$49.03	$0.15	-$0.12	$0.00	$0.06	$97.61	$101.71
K	Long Island	$134.53	-$58.38	$0.40	-$1.65	-$7.85	$0.22	$22.01	-$10.03	-$1.47	$43.15	$0.06	$0.00	$0.00	$0.11	$121.10	$125.20

Net EAS Revenues: September 2022 - August 2023

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$38.14	-$15.13	$0.75	-$0.04	-$1.76	$0.34	$7.28	-$2.15	-$0.49	$32.07	$0.04	-$0.05	$0.00	$0.10	$59.10	$63.20
F	Capital	$79.08	-$34.51	$0.86	-$0.80	-$4.09	$0.48	$18.65	-$9.53	-$1.42	$39.05	$0.22	-$0.14	-$0.06	$0.04	$87.82	$91.92
G	Hudson Valley (Dutchess)	$64.74	-$27.79	$3.18	-$0.08	-$3.92	$0.34	$10.37	-$5.45	$0.55	$45.46	$0.09	$0.00	$0.00	$0.01	$87.51	$91.61
G	Hudson Valley (Rockland)	$64.47	-$27.68	$3.18	-$0.08	-$3.90	$0.34	$10.37	-$5.46	$0.56	$45.54	$0.09	$0.00	$0.00	$0.01	$87.44	$91.54
J	NYC	$60.61	-$27.09	$0.48	-$0.01	-$3.76	$0.24	$10.79	-$5.75	$1.10	$48.60	$0.00	$0.00	$0.00	$0.01	$85.22	$89.32
K	Long Island	$82.67	-$33.24	$1.33	-$0.57	-$4.54	$0.31	$23.26	-$9.64	$0.64	$41.97	$0.25	-$0.20	$0.00	$0.04	$102.27	$106.37

Net EAS Revenues: September 2023 - August 2024

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$32.56	-$15.39	$0.00	$0.00	-$2.08	$0.10	$2.73	-$1.07	-$0.32	$23.21	$0.00	-$0.03	$0.00	$0.02	$39.73	$43.83
F	Capital	$43.41	-$18.13	$0.02	-$0.15	-$2.38	$0.03	$1.28	-$0.72	-$0.16	$32.03	$0.08	$0.00	$0.00	$0.00	$55.32	$59.42
G	Hudson Valley (Dutchess)	$46.58	-$18.83	$0.18	-$0.12	-$2.46	$0.07	$0.85	-$0.35	$0.13	$33.30	$0.00	$0.00	$0.00	$0.00	$59.34	$63.44
G	Hudson Valley (Rockland)	$46.40	-$18.76	$0.18	-$0.12	-$2.45	$0.07	$0.85	-$0.35	$0.13	$33.35	$0.00	$0.00	$0.00	$0.00	$59.29	$63.39
J	NYC	$45.63	-$18.48	$0.22	-$0.03	-$2.63	$0.10	$2.82	-$0.46	$0.24	$37.23	$0.00	$0.00	$0.00	$0.00	$64.63	$68.73
K	Long Island	$65.02	-$22.06	$0.22	-$0.06	-$3.22	$0.11	$4.68	-$2.11	-$0.36	$31.28	$0.00	$0.00	$0.00	$0.02	$73.49	$77.59

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 6-Hour, Hourly RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,587	1,589	7	6	316	51	0	164	162	104	4,676	0	0	3	1	11	83	8,760
F	Capital	1,452	1,454	15	24	259	73	0	278	271	175	4,698	8	4	2	0	20	27	8,760
G	Hudson Valley (Dutchess)	1,563	1,564	2	5	337	23	0	102	100	49	4,976	3	1	0	0	9	26	8,760
G	Hudson Valley (Rockland)	1,561	1,562	2	5	336	24	0	100	98	50	4,983	3	1	0	0	9	26	8,760
J	NYC	1,526	1,527	3	5	328	32	0	123	119	63	5,000	2	0	2	0	11	19	8,760
K	Long Island	1,668	1,669	7	14	295	59	1	204	197	134	4,456	6	2	2	2	11	33	8,760

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,415	1,415	2	3	336	31	0	85	83	50	5,275	0	0	1	1	13	50	8,760
F	Capital	1,546	1,546	8	12	316	54	0	145	142	101	4,869	1	1	0	2	6	11	8,760
G	Hudson Valley (Dutchess)	1,463	1,463	3	4	343	21	0	74	74	44	5,261	0	1	0	1	1	7	8,760
G	Hudson Valley (Rockland)	1,458	1,458	3	4	343	21	0	73	73	44	5,273	0	1	0	1	1	7	8,760
J	NYC	1,375	1,375	3	3	336	25	0	77	77	45	5,436	0	0	0	0	1	7	8,760
K	Long Island	1,581	1,581	6	13	312	41	0	171	163	101	4,764	14	2	3	0	3	5	8,760

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,312	1,312	1	0	352	16	0	39	39	22	5,632	0	0	1	0	5	53	8,784
F	Capital	1,345	1,345	0	0	362	10	0	29	29	18	5,620	0	0	0	0	2	24	8,784
G	Hudson Valley (Dutchess)	1,395	1,395	0	0	350	18	0	28	28	25	5,535	0	0	0	0	0	10	8,784
G	Hudson Valley (Rockland)	1,394	1,394	0	0	350	18	0	28	28	25	5,536	0	0	0	0	0	11	8,784
J	NYC	1,378	1,378	1	1	351	16	0	32	32	25	5,556	0	0	0	0	0	14	8,784
K	Long Island	1,535	1,535	3	3	341	28	0	72	72	49	5,128	2	0	0	0	0	16	8,784

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 6-Hour, Hourly RTM Model

Net EAS Revenues: September 2021 - August 2022

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$99.23	-$48.30	$0.67	-$0.29	-$7.30	$0.25	$15.44	-$6.67	-$1.61	$24.70	$0.00	-$0.09	-$0.01	$0.06	$76.09	$80.19
F	Capital	$153.28	-$82.64	$2.69	-$2.20	-$9.53	$0.39	$40.55	-$21.15	-$5.16	$30.66	$0.23	-$0.07	$0.00	$0.14	$107.18	$111.28
G	Hudson Valley (Dutchess)	$157.62	-$80.32	$0.20	-$0.60	-$13.38	$0.14	$15.69	-$8.05	-$1.39	$35.90	$0.09	$0.00	$0.00	$0.05	$105.95	$110.05
G	Hudson Valley (Rockland)	$157.31	-$80.16	$0.20	-$0.60	-$13.35	$0.15	$15.56	-$8.00	-$1.38	$35.95	$0.09	$0.00	$0.00	$0.05	$105.82	$109.92
J	NYC	$152.52	-$79.09	$0.45	-$0.43	-$12.83	$0.17	$18.52	-$9.55	-$1.82	$37.62	$0.00	-$0.26	$0.00	$0.06	$105.37	$109.47
K	Long Island	$198.56	-$90.51	$0.73	-$1.23	-$13.23	$0.32	$33.16	-$13.95	-$3.76	$32.86	$0.09	-$0.12	-$0.10	$0.07	$142.88	$146.98

Net EAS Revenues: September 2022 - August 2023

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$54.87	-$23.08	$0.74	-$0.03	-$3.41	$0.23	$8.61	-$2.14	-$0.70	$26.48	$0.00	-$0.05	$0.00	$0.06	$61.58	$65.68
F	Capital	$113.88	-$52.40	$1.83	-$1.34	-$5.90	$0.30	$22.35	-$11.52	-$2.49	$30.37	$0.17	$0.00	-$0.11	$0.03	$95.19	$99.29
G	Hudson Valley (Dutchess)	$95.04	-$42.70	$0.60	-$0.25	-$6.59	$0.22	$13.31	-$6.82	$0.34	$36.42	$0.05	$0.00	-$0.04	$0.01	$89.58	$93.68
G	Hudson Valley (Rockland)	$94.75	-$42.59	$0.60	-$0.25	-$6.57	$0.22	$13.12	-$6.68	$0.38	$36.50	$0.05	$0.00	-$0.04	$0.01	$89.50	$93.60
J	NYC	$87.77	-$40.70	$0.60	-$0.23	-$6.10	$0.27	$13.19	-$6.22	$0.34	$39.66	$0.00	$0.00	$0.00	$0.01	$88.59	$92.69
K	Long Island	$119.17	-$50.74	$3.63	-$1.09	-$7.47	$0.31	$29.80	-$10.76	-$0.78	$32.69	$0.25	-$0.24	$0.00	$0.01	$114.78	$118.88

Net EAS Revenues: September 2023 - August 2024

Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$45.60	-$22.32	$0.01	$0.00	-$3.50	$0.08	$2.84	-$1.07	-$0.35	$20.17	$0.00	-$0.03	$0.00	$0.02	$41.43	$45.53
F	Capital	$60.66	-$26.39	$0.00	$0.00	-$4.14	$0.04	$2.62	-$1.11	-$0.25	$27.41	$0.00	$0.00	$0.00	$0.01	$58.86	$62.96
G	Hudson Valley (Dutchess)	$66.13	-$27.86	$0.00	$0.00	-$4.52	$0.06	$1.53	-$0.28	$0.12	$28.34	$0.00	$0.00	$0.00	$0.00	$63.53	$67.63
G	Hudson Valley (Rockland)	$66.01	-$27.85	$0.00	$0.00	-$4.52	$0.06	$1.53	-$0.28	$0.12	$28.36	$0.00	$0.00	$0.00	$0.00	$63.43	$67.53
J	NYC	$66.02	-$27.55	$0.08	$0.00	-$4.43	$0.05	$4.22	-$0.92	-$0.16	$30.86	$0.00	$0.00	$0.00	$0.00	$68.15	$72.25
K	Long Island	$92.36	-$33.26	$0.40	-$0.16	-$5.38	$0.15	$7.39	-$2.45	-$0.79	$25.85	$0.00	$0.00	$0.00	$0.00	$84.10	$88.20

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 8-Hour, Hourly RTM Model

Run Hours: September 2021 - August 2022																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,855	1,857	8	13	379	81	0	211	206	155	3,895	1	2	2	3	9	83	8,760
F	Capital	1,729	1,731	15	35	300	90	0	321	304	215	3,956	6	6	3	0	23	26	8,760
G	Hudson Valley (Dutchess)	1,842	1,843	3	7	430	33	0	142	138	76	4,211	3	1	1	0	6	24	8,760
G	Hudson Valley (Rockland)	1,841	1,842	3	8	429	33	0	142	137	76	4,214	3	1	1	0	6	24	8,760
J	NYC	1,826	1,827	2	12	412	45	0	150	138	92	4,225	2	0	2	0	9	18	8,760
K	Long Island	1,978	1,979	9	29	384	91	1	294	271	206	3,461	4	1	4	2	11	35	8,760

Run Hours: September 2022 - August 2023																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,667	1,667	2	5	386	28	0	108	103	57	4,668	0	0	2	1	9	57	8,760
F	Capital	1,788	1,788	9	19	370	53	0	188	176	112	4,240	1	0	2	1	5	8	8,760
G	Hudson Valley (Dutchess)	1,708	1,708	5	8	393	23	0	93	90	59	4,658	10	0	0	0	1	4	8,760
G	Hudson Valley (Rockland)	1,706	1,706	5	8	393	23	0	93	90	59	4,661	10	0	0	0	1	5	8,760
J	NYC	1,647	1,647	7	4	378	23	0	89	92	55	4,812	0	0	0	0	1	5	8,760
K	Long Island	1,850	1,850	11	20	380	59	0	212	203	148	4,006	12	2	2	0	3	2	8,760

Run Hours: September 2023 - August 2024																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	1,634	1,634	1	0	409	12	0	44	44	22	4,922	0	0	1	0	5	56	8,784
F	Capital	1,650	1,650	1	5	405	10	0	45	41	28	4,932	0	0	0	0	2	15	8,784
G	Hudson Valley (Dutchess)	1,708	1,708	2	2	413	19	0	43	43	31	4,806	0	0	0	0	0	9	8,784
G	Hudson Valley (Rockland)	1,708	1,708	2	2	413	19	0	43	43	31	4,805	0	0	0	0	0	10	8,784
J	NYC	1,700	1,700	1	6	413	17	0	44	39	30	4,816	0	1	1	0	0	16	8,784
K	Long Island	1,835	1,835	5	8	428	42	0	78	75	73	4,397	2	0	0	0	0	6	8,784

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 8-Hour, Hourly RTM Model

Net EAS Revenues: September 2021 - August 2022																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$114.96	-$58.12	$1.37	-$0.54	-$8.16	$0.38	$19.05	-$8.78	-$2.45	$20.09	$0.17	-$0.06	-$0.04	$0.04	$77.91	$82.01
F	Capital	$180.73	-$100.35	$3.46	-$2.76	-$10.96	$0.52	$44.61	-$23.58	-$6.60	$24.96	$0.42	-$0.11	$0.00	$0.16	$110.50	$114.60
G	Hudson Valley (Dutchess)	$184.89	-$96.36	$0.39	-$0.63	-$15.36	$0.29	$21.49	-$11.35	-$1.78	$29.26	$0.09	-$0.02	$0.00	$0.04	$110.95	$115.05
G	Hudson Valley (Rockland)	$184.57	-$96.23	$0.38	-$0.73	-$15.23	$0.29	$21.61	-$11.32	-$1.91	$29.26	$0.09	-$0.02	$0.00	$0.04	$110.82	$114.92
J	NYC	$181.43	-$96.71	$0.32	-$0.90	-$15.04	$0.25	$22.70	-$11.28	-$2.83	$30.57	$0.00	-$0.26	$0.00	$0.05	$108.31	$112.41
K	Long Island	$234.75	-$110.32	$1.47	-$2.13	-$14.55	$0.56	$46.00	-$19.67	-$6.28	$24.32	$0.05	-$0.25	-$0.10	$0.07	$153.92	$158.02

Net EAS Revenues: September 2022 - August 2023																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$63.11	-$27.72	$0.77	-$0.14	-$3.91	$0.21	$9.72	-$2.94	-$0.81	$23.15	$0.00	-$0.10	$0.00	$0.04	$61.39	$65.49
F	Capital	$129.76	-$61.36	$4.25	-$1.91	-$7.36	$0.40	$26.90	-$13.24	-$2.62	$25.69	$0.00	-$0.11	-$0.05	$0.03	$100.36	$104.46
G	Hudson Valley (Dutchess)	$108.36	-$49.66	$0.97	-$0.48	-$7.55	$0.23	$15.56	-$8.53	-$0.18	$31.57	$0.00	$0.00	$0.00	$0.01	$90.29	$94.39
G	Hudson Valley (Rockland)	$108.16	-$49.60	$0.97	-$0.48	-$7.53	$0.23	$15.55	-$8.53	-$0.18	$31.59	$0.00	$0.00	$0.00	$0.01	$90.17	$94.27
J	NYC	$102.38	-$48.57	$1.90	-$0.23	-$7.43	$0.36	$15.56	-$8.04	$0.19	$33.79	$0.00	$0.00	$0.00	$0.01	$89.91	$94.01
K	Long Island	$136.94	-$59.93	$4.50	-$1.68	-$8.22	$0.35	$36.68	-$13.68	-$2.03	$26.95	$0.25	-$0.10	$0.00	$0.02	$120.05	$124.15

Net EAS Revenues: September 2023 - August 2024																	
Day-Ahead Commitment		Discharge	Charge	Extra Charge				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve	Discharge	Charge	Extra Charge	Reserve		
C	Central	$54.80	-$28.20	$0.11	$0.00	-$4.59	$0.06	$3.45	-$1.30	-$0.43	$17.52	$0.00	-$0.03	$0.00	$0.02	$41.40	$45.50
F	Capital	$71.40	-$32.42	$0.03	-$0.11	-$5.08	$0.04	$4.50	-$1.82	-$0.81	$23.81	$0.00	$0.00	$0.00	$0.01	$59.54	$63.64
G	Hudson Valley (Dutchess)	$78.20	-$34.35	$0.09	-$0.07	-$5.63	$0.09	$3.51	-$1.33	-$0.15	$24.39	$0.00	$0.00	$0.00	$0.00	$64.75	$68.85
G	Hudson Valley (Rockland)	$78.09	-$34.36	$0.09	-$0.07	-$5.62	$0.09	$3.51	-$1.33	-$0.15	$24.39	$0.00	$0.00	$0.00	$0.00	$64.64	$68.74
J	NYC	$79.31	-$34.62	$0.18	-$0.42	-$5.60	$0.12	$6.64	-$1.64	-$0.28	$25.89	$0.07	-$0.09	$0.00	$0.00	$69.55	$73.65
K	Long Island	$108.29	-$40.65	$0.54	-$0.35	-$6.09	$0.24	$7.40	-$2.60	-$1.34	$22.08	$0.00	$0.00	$0.00	$0.00	$87.51	$91.61

Notes:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2021 to August 31, 2024 and the seasonal capacity availability values are based on data for the same period.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] The net EAS revenues for BESS options reflect the net EAS model using hourly time-weighted/integrated real-time prices.
[4] Assumes a $4.10/kW-year VSS revenue adder for lithium-ion BESS.