Attachment III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER16-____-000**

AFFIDAVIT OF PAUL J. HIBBARD

I. Qualifications

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

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

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

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

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

II. Purpose and Summary of Affidavit

5. Section 5.14.1.2 of the New York Independent System Operator's (NYISO) Market Administration and Control Area Services Tariff (Services Tariff) requires that locational Installed Capacity (ICAP) Demand Curves be established periodically through an independent review of the ICAP Demand Curve parameters by an independent consultant, including review 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.[1] This process is commonly referred to as the ICAP Demand Curve reset (DCR) process.

6. The DCR independent consultant develops the initial assumptions and conducts and presents analysis within the stakeholder process, in order to develop the recommended ICAP Demand Curve parameters for the NYISO's November filing to the Commission. Analysis Group Inc. (AGI) was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2017/2018 Capability Year. AGI is currently working with Lummus Consultants International (LCI) to complete the tariff-required periodic review process.

[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.

7. In addition to these responsibilities, the NYISO requested that AGI conduct analysis and present market design proposals and recommendations to address (a) the frequency of the periodic reviews of the ICAP Demand Curves going forward (i.e., extending the period between DCRs from three to four years or longer), and (b) alternative approaches to estimating the net Energy and Ancillary Services (EAS) revenues of a peaking plant.

8. The purpose of this affidavit is to describe and provide rationale for proposed enhancements to the DCR process. Specifically, the first phase of the currently ongoing DCR considered potential changes to the timing between DCRs, and to the method(s) used in evaluating the expected net EAS revenues of a peaking plant from the NYISO-administered markets. Based on this review, the NYISO is proposing enhancements with respect to certain features of the DCR process.

9. The proposed enhancements are described in more detail below, and include the following changes:

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

10. The proposed enhancements are expected to improve the stability of DCR results and allow for the gradual evolution of ICAP Demand Curve reference point prices (RP) over the years between DCRs. This approach will add stability to market outcomes through more accurate and timely incorporation of changes in industry and market conditions into RPs. Finally, the proposed enhancements would reduce the administrative burden of the DCR process.

11. In this affidavit, I explain the process and principles used by AGI to evaluate and recommend potential changes to the DCR process, describe the enhancements being

proposed, evaluate certain stakeholder concerns regarding the proposal, and provide supporting justification to the proposed DCR process enhancements.

III. Principles and Analytic Framework for Assessing Potential Changes

12. The proposed changes to the DCR process were developed, evaluated, and recommended by AGI in consultation with the NYISO and stakeholders over the first six months of the DCR process, culminating in an AGI presentation to the Management Committee (MC) on March 30, 2016. In the months leading up to the MC meeting and stakeholder vote, AGI participated in a deliberative and inclusive process for developing DCR process enhancement recommendations. [2]

13. Specifically, over the course of six months, AGI established principles for evaluating DCR alternatives, summarized approaches taken in various jurisdictions, identified options for potential enhancements of the DCR process, presented potential benefits and drawbacks of each option, and conducted extensive quantitative "backcasting analysis" to demonstrate the potential impacts of alternative approaches.

14. The DCR process requires not only analysis of a wide array of quantitative market, financial, and economic data and factors, but also the application of reasoned judgment where the empirical evaluation of process and methodological alternatives is limited by sparse, uncertain, and variable historical data and forecast assumptions. Consequently, at the outset of the process, AGI established a set of objectives and criteria against which it would review and consider potential enhancements of the DCR process 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.

[2] AGI presented on various DCR process enhancement options and recommendations at Installed Capacity Working Group (ICAPWG) meetings on October 19, 2015, November 18, 2015, December 16, 2015, January 26, 2016, February 19, 2016, and March 3, 2016. A presentation of final recommendations on DCR process enhancements was made to the Business Issues Committee (BIC) on March 17, 2016, and to the MC on March 30, 2016.

15. Specifically, AGI established that potential DCR process changes and analytic methods should be evaluated against the following objectives and criteria:

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

16. In order to inform recommendations through quantitative analysis based on historical data, AGI conducted a comprehensive "backcasting analysis," evaluating how different proposed approaches to net EAS calculations and updating of ICAP Demand Curve parameters compared with respect to the stability and predictability of outcomes. The backcasting analysis method and results are described in Section IV.B. below.

IV. Description of Proposed Changes and Rationale

A. Description of Proposed Changes

17. The NYISO proposes a number of enhancements to the DCR process. These proposed enhancements include: (1) an increase in the length of the period between DCRs, (2) the establishment of net EAS revenue projections through a straightforward method based on

historical data, and (3) the annual updating of ICAP Demand Curve values through annually adjusted gross capital costs based on a technology-specific composite escalation factor and net EAS revenue estimates based on updated market data.

18. <u>DCR Periodicity:</u> Currently, DCRs occur every three years. Installed Capacity Demand Curves are established for the first Capability Year covered by the reset period and then adjusted by the application of a fixed escalation factor to derive the ICAP Demand Curve values for the two subsequent Capability Years covered by the reset period. The proposed enhancements include extending the period between DCRs from three years to four years.

19. <u>Net EAS Revenue Estimation:</u> The proposed enhancements would estimate the net EAS revenues of a peaking plant through a commitment/dispatch model developed as part of each DCR. Net EAS revenue projections would be based primarily on a three-year history of Locational Based Marginal Prices (LBMPs), fuel prices, and the variable costs and operating parameters of the peaking plant for each ICAP Demand Curve.[3] Specifically, the model would estimate net revenues in a manner that ensures the recovery of fixed start-up fuel and other start-up costs. The model would also account for dual-fuel capability, if applicable, through the option to generate Energy on either a peaking plant's primary fuel source (*e.g.*, natural gas) or any applicable backup fuel source (*e.g.*, ultra-low sulfur diesel (ULSD)) based on day-ahead fuel prices.

20. The data used in the net EAS model would include hourly LBMPs, daily fuel prices, and emission allowance prices (for CO_2, SO_2, and NO_x) for the three year period (September through August) ending in the year prior to the Capability Year for which the ICAP Demand Curves will apply.[4] Other peaking plant costs and operational parameters (*e.g.*, heat rate, variable operations and maintenance (O&M) costs) would be established as part

[3] The proposed historical method for calculating net EAS revenues is similar to the method used by PJM.

[4] For example, the ICAP Demand Curves for the 2017/2018 Capability Year would be based on data from September 2013 through August 2016.

of each DCR and remain fixed for the four year reset period. The final output of the model would be the average annual net revenues over the three-year historic period at issue.[5]

21. The net EAS model would also incorporate a set of adjustment factors to meet the Services Tariff requirement related to assumptions about system conditions used in determining ICAP Demand Curve values. Specifically, the Services Tariff requires that the ICAP Demand Curves be based on system conditions where the available capacity of resources is equal to the applicable minimum Installed Capacity Requirement (ICR) plus the capacity of the relevant peaking plant. This requirement is referred to herein as the "Level of Excess," or LOE. For purposes of net EAS revenue projections, a set of adjustment factors would be developed to modify the historic, actual LBMPs used in net EAS revenue calculations to approximate what prices would have been under LOE conditions. For example, if actual, historic LBMPs are based on system conditions with resource margins well above the LOE value, net EAS revenues based solely on such LBMPs would likely be lower than a peaking plant would experience at 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, historic LBMPs are at system conditions reflecting a shortage of resources relative to LOE conditions, estimated net EAS revenues based solely on such LBMPs would likely exceed those that a peaking plant would experience at LOE conditions, leading to adjustment factors with a value of less than one.[6] These adjustment factors are referred to herein as LOE adjustment factors, or LOE-AF. These LOE-AF would be determined as part of each DCR and remain fixed for the four year period covered by the reset.

22. In stakeholder deliberations, a range of alternatives were suggested related to the proposed one-time estimation of LOE-AF. Stakeholder suggestions ranged from eliminating the

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[5] To the extent that the model does not account for certain Ancillary Services revenues (*e.g.*, voltage support service), an adder would be applied to the annual net revenue value produced by the model. The value of any such adder would be determined as part of each DCR and remain fixed for the four year period covered by each reset.

[6] If actual system conditions on which historical prices are based are exactly the same as the LOE conditions, then the adjustment factor would be 1.0.

LOE adjustment altogether to establishing a range of LOE-AFs that would be applied and updated on an annual basis. This issue is further discussed below in Section V.

23. Annual Updating: The proposed enhancements would adjust ICAP Demand Curve values annually based on updated historical information related to market prices and a technology-specific composite escalation factor based on publicly available indices. The annual updating process would address each of the primary components used to estimate RPs. This includes net EAS revenues, localized levelized embedded costs (gross CONE), and the translation of net CONE into the RP.

24. First, the net EAS revenues would be adjusted using the same model developed as part of the DCR. For purposes of the annual updates, net EAS revenues would be calculated using the most recent three years of data available for EAS prices, fuel prices, and emission allowance prices.[7] Other peaking plant costs and operational parameters (*e.g.*, heat rate, variable O&M costs) would be established during each DCR and remain fixed until the next DCR.

25. As discussed in more detail in Section V below, net EAS revenues would be calculated using a static set of LOE-AF determined as part of each DCR. The values of the LOE-AF would not change for the four year period covered by the reset or be updated as part of the annual updating process.

26. Second, the localized levelized embedded cost of each peaking plant would be updated based on a single statewide, technology-specific composite escalation factor representing the cost-weighted average of inflation indices for major plant components (*e.g.*, wages, turbines, materials and components, and general economy-wide inflation).[8] The technology-specific weighting factor for each of the indices would be determined as part of each DCR and held fixed over the four year reset period. These weighting factors would

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[7] For example, in determining the ICAP Demand Curve values for the 2018/2019 Capability Year pursuant to the proposed annual updating process, net EAS revenues would be calculated based on data from September 2014 through August 2017.

[8] Use of a composite escalation factor to annually adjust gross CONE values is similar to the method used by PJM to adjust its CONE values for years between resets.

be determined based on the ratio of the value of each of the cost components for the selected peaking plant technology to the total installed capital costs for the peaking plant. While the weighting factors and indices relied upon would remain fixed for each four year reset period, the change in each index value would be updated annually using the most current finalized data available.

27. Updated values for the localized levelized embedded costs and the net EAS revenues define the unit net CONE. Unit net CONE is translated into a monthly RP for use in the ICAP Spot Market Auctions. 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. To account for these seasonal differences, a winter-to-summer ratio (WSR) is used as part of translating the annual unit net CONE value for each ICAP Demand Curve into a monthly RP. As part of the annual update process, the NYISO proposes to update the WSR based on available ICAP for the same three year period used in the net EAS revenue estimate. The NYISO also proposes to adjust the WSR to account for certain resource entry and exit decisions. These adjustments are intended to provide for WSR values that reflect market changes as they are expected to persist over time.[9] The WSR is an important component of calculating RPs that ensure revenue adequacy for a peaking plant when new entry is needed to maintain the applicable minimum ICR. The proposal to update the WSR annually provides a means to reflect changes in system resource conditions over time and incorporates these changes into RPs.

28. NYISO is also proposing a stakeholder-developed, temporary collar on changes in the RP that would result from the annual update process. In particular, the collar would limit changes in the RP by 12 percent (increase) and 8 percent (decrease) relative to the year before. The collar would remain in effect only for the duration of the period covered by the

[9] *See* NYISO, *NYISO's Winter-to-Summer Ratio Calculation Methodology: Comparing NYISO's Original Proposal and a Revised Approach* (presented at the March 24, 2016 ICAPWG meeting) available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2016-03-24/WSR%2003242016%20ICAPWG%20Final%2003232016.pdf.

current reset and apply only to the RPs resulting from the annual updates for the 2018/2019, 2019/2020 and 2020/2021 Capability Years. AGI reviewed the RP collar proposal and found it to be reasonable. In particular, these values appear consistent with the results of the backcasting analysis presented in Exhibits B1 – B9.

B. Rationale for Proposed Changes

29. The set of proposed enhancements to the DCR process reflects a significant overall improvement over past approaches to setting the ICAP Demand Curve values in New York. The proposed enhancements enable the extension of the period between DCRs and establish a process providing for a more gradual and realistic evolution of RPs over the time between DCRs. The proposed enhancements also vastly improve the transparency of RP estimation and the practicality of the DCR process, and represent an appropriate and reasonable balance of the alternatives and variations considered to date by AGI, the NYISO, and stakeholders.

30. The proposed enhancements meet AGI's established objectives and criteria for review of potential changes to the DCR process and associated analytic methods. Specifically, the changes are grounded in economic principles, reflect the structures and incentives in the NYISO wholesale markets, and meet the established criteria of accuracy, transparency, and feasibility. The proposed changes were informed by a close review of the practices and experiences of past resets conducted by the NYISO, as well as the experience in PJM and ISO-NE. Finally, the empirical backcasting analysis conducted by AGI demonstrates that the results are likely to be at least as reliable as results determined through the approaches previously used for setting the ICAP Demand Curve values, while reducing the volatility that has typically accompanied the changing of ICAP Demand Curve parameters at the time of each reset.

31. With respect to potential changes in periodicity, AGI evaluated (1) maintaining the period between DCRs at three years, (2) extending the period between DCRs from three to four years, and (3) extending the period between DCRs to five or six years. Extending the period between DCRs to four years provides an opportunity to increase market certainty and stability, while reducing the administrative burden of the DCR process for both the

NYISO and its stakeholders. Extending the DCR period by one year is likely to do so without meaningfully increasing the risk that the peaking plant technology will change between DCRs. This is particularly true if, in conjunction with increasing the period between DCRs, the NYISO also moves to annual updating of gross CONE based on a technology-specific composite escalation factor and net EAS revenue calculations using rolling historic market prices (discussed in more detail below). Including annual updates to these parameters further supports moving to a longer reset period by allowing RPs to reflect evolving technological and market trends between DCRs. Extending the period between DCRs to five or six years is not recommended at this time, due primarily to the increased risk of deviation of technology estimates and forecast elements from actual experience with time, and because a longer period between DCRs would limit opportunities for stakeholder and regulatory input.

32. The proposed revisions to the method for estimating net EAS revenues – using recent average historical fuel and electricity price data and a straightforward commitment and dispatch logic rather than an econometric approach that has been used in prior resets – significantly improves this aspect of the DCR process with respect to the key goals of transparency, accuracy, and understandability. It improves the transparency of net EAS revenues calculations, as the technology and market data that go into net EAS revenue estimation are based on readily available data sources. The model itself will be made available to MPs to help improve the accuracy and predictability of RP calculations and forecasting. Finally, the net EAS revenue estimation method is important to the viability of a longer period between DCRs and to the updating of ICAP Demand Curve parameters between DCRs. Enhancing the approach to net EAS revenue calculations through a simplified commitment and dispatch model and reliance on accessible, historical pricing data opens the door to updating ICAP Demand Curve values between DCRs, thereby improving the viability of extending the period between DCRs from three to four years.

33. AGI also reviewed and evaluated a number of alternative methods for estimating net EAS revenues. While AGI rejected the more opaque econometric approach used in past resets, other options were analyzed that had the potential to improve upon the transparency and accuracy of net EAS revenue estimation. Specifically, AGI considered recommending the

development of net EAS revenue projections based on actual margins earned by units of the same vintage and technology as the proposed peaking plant operating in the relevant Load Zones in New York.[10] This method was rejected due to the current lack of relevant comparable assets from which to draw historical margin data for some, if not most, of the ICAP Demand Curves.

34. AGI also considered a slight modification to the proposed net EAS revenue calculations, involving an adjustment for prices in electricity futures markets. Specifically, this alternative would adjust historic LBMPs for differences between past LBMPs and current prices in futures markets (*e.g.*, NYMEX). The purpose of the futures adjustment would be to capture market expectations about future system conditions (as reflected in actual forward-looking trades of market participants) that are not necessarily reflected in historic market prices. A futures adjustment, however, introduces the potential for market manipulation and raises concerns about limited transparency and limited liquidity (particularly in light of limited or lack of liquidity of futures trading that currently exists in certain Load Zones in New York, and the significant decline in futures trading liquidity beyond one year). On balance, AGI determined that the potential downsides outweighed the potential benefits of including a futures adjustment at this time.

35. Annual updating of the RPs also represents a fundamental improvement to the DCR process, and (as noted above) becomes more important with the proposed extension of the period between DCRs to four years. Annual updating of gross CONE based on a weighted average of technology-specific inflation indices allows peaking plant gross costs to continuously evolve with the changes in actual costs associated with designing, procuring and building generation facilities in New York. This will significantly moderate the potential magnitude of "step changes" in RPs for a given technology from one reset to the next.[11]

[10] This is similar to the method used in ISO-NE.

[11] Annual updating of gross CONE does not, however, fully mitigate the risk of step changes in RPs due to the potential for changes in the technology selected to serve as the peaking plant for a given ICAP Demand Curve. Changes in the peaking plant technology remain possible at the time of each reset and have occurred in past resets conducted by the NYISO.

36. Similarly, annual updating of the net EAS revenue calculations using rolling historical market data significantly improves net EAS revenue projections with respect to the key goals of transparency, accuracy, and understandability. Use of readily available historic market data improves the predictability of net EAS revenue calculations, while allowing fundamental market changes to be reflected in RPs on a timely and gradual basis. The process for updating net EAS revenue projections over time relies on a clear and direct application of a formulaic model that relies on the timely inclusion of historical data that is readily available to the NYISO and MPs. This will significantly improve the ability for all parties to evaluate and forecast changes to RPs over time.

37. The backcasting analysis completed by AGI further supports the proposed changes. The analysis first estimated what results *would have been* under candidate net EAS revenue methodologies and annual updating procedures for different peaking plant technologies and capacity regions. These results were then compared to the net EAS revenues projections and ICAP Demand Curve values *actually* produced by the past methods and procedures.

38. The backcasting analysis was used to evaluate installed capital costs, net EAS revenue estimates, and RP results associated with the proposed enhancements to the DCR process, including: (1) updating of installed capital costs annually based on the proposed technology-based composite escalation factor; and (2) the estimation and annual updating of net EAS revenue projections based on the most recent three years of historical market data.

39. AGI's backcasting analysis was not meant to provide a "bright line" test regarding which alternatives to select. Rather, it was designed to provide quantitative input for the decision making process and to inform the choice of approaches going forward by: (1) addressing the comparability of net EAS revenue estimates and ICAP Demand Curve values under alternative methods; and (2) by demonstrating whether different methods are likely to introduce meaningful variation in the resulting values.[12]

[12] It is important to note that, unlike the actual outcomes from past resets, the estimates of outcomes resulting from the proposed enhancements did not include the adjustment to address the tariff-specified LOE conditions.

40. Specifically elements of the backcasting analysis include the following:

- Backcasting analysis was completed for a period spanning years encompassed by the past three resets – 2009 through 2015 – in capacity regions that were in place across all three resets (Long Island (Load Zone K), New York City (Load Zone J), and Rest of State (ROS or NYCA, using Load Zone F)). In each Load Zone, backcasting results are presented for two candidate peaking plant technologies that have been considered and/or selected in past resets – the F Class technology and the LMS 100 technology.[13]

- The backcasting analysis for each Load Zone and technology includes estimation of installed capital costs, net EAS revenues, and RPs using the proposed changes (*i.e.*, the use of rolling average historical data for net EAS revenues and a composite escalation factor updated annually for adjusting installed capital costs). These results are then compared to those based on the actual approach and methodologies applied in past resets (*i.e.*, econometric methodology for estimating net EAS revenues and a fixed escalation factor applied to ICAP Demand Curves for the years between DCRs).

- The backcasting analysis holds constant most factors related to RP calculations in order to isolate and compare how net EAS revenue projections and RPs vary specifically with respect to the two updating factors recommended in NYISO's proposal (*i.e.*, annual updating of gross capital costs and net EAS revenues).[14] In

[13] Across the last three DCRs, either the F Class or the LMS technology was selected as the peaking plant technology in each capacity region. Notably, however, the applicable peaking plant technology in some regions has changed between F Class and LMS from one reset period to the next over the historic period analyzed. For completeness and comparison purposes, AGI provided backcasting analysis for both technologies for all Load Zones and all reset periods.

[14] To estimate reference point prices, AGI relied on the previous demand curve models, which are available on the NYISO's website. AGI relied on two models: the 2007 demand curve model for purposes of analyzing the LMS 100 technology and the most recent 2013 demand curve model for purposes of analyzing the F-class machine. Within both models, the weighted average cost of capital (WACC) and levelized factors were held constant. This allows for the translation of installed capital costs (which varied in the backcasting analysis, consistent with the proposed annually updated escalation factor) into annual gross CONE values.

this way, the backcasting analysis provides insight into how the proposed procedures compare to the historical approach, specifically with respect to the variability of results within reset periods due to annual updating and to the variability of results between DCRs due to methodological changes.

41. The results of the backcasting results are presented in Exhibits B-1 through B-9.

42. The backcasting analysis demonstrates the value and reasonableness of the proposal to estimate net EAS revenues using a historic approach, including updating of historical data inputs, and to update ICAP Demand Curve values annually by applying an annually updated composite escalation factor to gross CONE values. Specifically, the backcasting analysis isolates the impact and value of updating installed capital costs and net EAS annually, as compared to maintaining the current one-time setting of these values as part of each DCR followed by adjustment using a pre-determined, fixed escalation factor for the subsequent years between DCRs.

43. The backcasting analysis demonstrates the relative impact on RPs of changes in underlying installed capital costs and net EAS revenue values, both at the time of each reset, and in time periods between resets. The analysis reveals that variability in RPs can be due to changes in either – or both –installed capital cost values and net EAS revenue estimates. Ultimately, the net effect depends on the relative magnitude of each component, which varies considerably across capacity regions. Overall, the analysis shows that the proposed historical net EAS revenue estimation approach and annual updating of RPs leads to results in line with those that were actually produced under the current procedures. Compared to the current procedures, the proposed enhancements exhibit reduced variability both at the time of each reset and across a longer period of time.

44. Compared to the fixed escalation rates used in prior resets, annual updating of certain parameters, as proposed by the NYISO, tends to increase variability within each reset period, as RPs and the underlying values vary annually in step with actual market and industry changes over time. However, for the same reason, annual updating tends to reduce or eliminate the one-time “step changes” in RPs that are observed from one reset to the next under the current procedures, thus reducing variability at the time of each reset.

More importantly, annual updating improves the ability of capacity market prices to accurately reflect the net CONE (at the LOE) given evolving market conditions (including the impacts of market rule changes). In contrast, under the current procedures using fixed escalation rates, prices did not adjust to changes in market conditions within each reset period, thus creating the risk of under- or over-stating the true net CONE.

V. Level of Excess Adjustment

45. The Services Tariff requires that net EAS revenue projections used in setting RPs be approximated under system conditions where the level of available capacity is equal to the minimum ICR plus the capacity of the peaking plant. This adjustment is intended to ensure that the ICAP Demand Curve values are based on what a new capacity developer would expect under system conditions at the time that new entry would be needed in order to maintain the minimum ICR. These system conditions are not necessarily the same as system conditions that would or will exist at the time of ICAP Spot Market Auctions, during which the ICAP Demand Curves will be used to set capacity market clearing prices. Notably, current and recent past system conditions have generally reflected levels of system resources in excess of the tariff-prescribed LOE conditions.

46. The NYISO’s proposed changes to the DCR process would rely on using a rolling three year period of historical prices and costs to approximate annual net EAS revenues. To meet the LOE requirement, some adjustment of the historical average LBMPs is called for in order to approximate what net EAS revenues would be under the tariff-prescribed conditions. The NYISO proposal would require that the factor(s) to accomplish this adjustment be determined during each DCR and remain fixed for the four year period covered by each reset.

47. Under the NYISO’s proposal, this adjustment would be accomplished through a set LOE-AF used to modify the historic LBMPs used in net EAS revenue calculations. The values of LOE-AF once established would not vary for the four year period covered by a reset.

48. Adjusting LBMPs to reflect LOE system conditions is consistent with the goal of establishing ICAP Demand Curves that are likely to ensure recovery of sufficient revenues by a peaking plant for new entry when needed to maintain the applicable minimum ICR.

From a practical perspective, however, adjusting LBMPs to approximate this theoretical condition is complex. It requires modeling hourly and zonal LBMPs across all hours under two scenarios: first, under expected/forecast conditions, and second, at the tariff-prescribed LOE conditions.

49. AGI does not recommend that the LOE-AF applied to LBMPs be updated or changed as part of the annual update process. Instead, as proposed by the NYISO, the set of LOE-AF established as part of the DCR should remain fixed for all four Capability Years covered by the reset period. In ICAPWG discussions related to the LOE-AFs, AGI and stakeholders presented or reviewed a number of alternative approaches, including (1) having no LOE-AF at all (*i.e.*, removing the LOE requirement from the Services Tariff), (2) executing a full modeling exercise to create a new set of LOE-AF as part of the annual update process in every year, applying modeling assumptions each year based on then-current conditions, and (3) establishing multiple sets – or a matrix – of LOE-AF as part of the DCR across a wide range of *potential* system conditions (*i.e.*, different set deviations from the tariff-prescribed LOE conditions with respect to system supply and demand) and selecting at the time of each annual update the set of LOE-AF that most closely matches actual system conditions at the time of each annual update.

50. The recommendation by some stakeholders to remove the LOE requirement from the Services Tariff flows in large part from concern over the complexity of modeling the required adjustment factors, recognizing that the LOE-AF are necessarily an administrative modeling exercise that requires the use of uncertain economic and fuel price forecasts, resource and demand assumptions that may turn out to be wrong in the year they are applied, and professional judgment in the development and processing of model structure and results. If the actual adjustments have a relatively small impact on the net EAS revenue projections, as they did in the last DCR, which used a methodology similar to that recommended by AGI for the currently ongoing DCR, then the additional complexity and potential inaccuracy introduced by the prescribed LOE condition could outweigh any potential benefits of seeking theoretical purity through an administrative and complicated modeling exercise.

51. Conversely, the alternative suggested by some stakeholders to rerun LOE-AF modeling at the time of each annual update supports the desire to find the right answer from the standpoint of economic principles and reflects a degree of unease with estimating net EAS revenues using LOE-AF based on a one-time forecast of future system conditions across the period covered by the reset. This recommendation would require executing a full modeling effort in each year, at or around the time of the annual updating process, in order to establish a revised set of LOE-AF deemed to be as accurate as possible at the time of the update.

52. Finally, the recommendation of some stakeholders to create a matrix of LOE-AF during each DCR is something of a middle ground between the two other alternatives. It seeks to improve upon the relationship of applied LOE-AF to actual conditions in place on the system at the time of the annual update process, rather than try to forecast these conditions at the time of the DCR for the succeeding three years. Unlike the alternative of determining LOE-AF anew as part of each annual update, this option would not require carrying out a full modeling exercise at the time of the annual updates. Instead, this alternative would involve conducting the necessary modeling during each DCR for a wide range of differences between the tariff-prescribed LOE and *potential* supply/demand conditions, and creating a separate set of LOE-AF for each of the various conditions modeled.[15] At the time of each annual update, the set of LOE-AF selected to modify historic, actual LBMPs would be the set that most closely matches then-current conditions of system excess.

53. With respect to adjusting to account for the specified LOE conditions, it is critical to find the appropriate balance among the principled application of the tariff requirements, transparency, and administrative feasibility, promoted through simplicity in the formulaic application of the annual update process. In striking this balance, it is important to recognize that production cost simulation models, like the GE-MAPS model, are necessarily simplified representations of power system operations and pricing, and require

[15] For example, a full set of LOE-AF could be established during each DCR for supply conditions of two, four and six percent below the postulated tariff-prescribed LOE conditions, as well as two, four and six percent above the postulated tariff-prescribed LOE conditions.

numerous assumptions and judgments in developing the model inputs that represent the system conditions under review. There is an inherent degree of uncertainty and variability in load, resource, and other system assumptions and inputs that must be developed to create a reasonable representation of market outcomes. Consequently, care must be taken both to construct the modeling exercise with an understanding of model abilities and limitations, and to interpret the results in a manner consistent with the level of precision that actually flows from the model construct.

54. In my view, while these conditions do not mean that a reasonable and appropriate approximation cannot be developed, they do suggest that approximating net EAS revenues consistent with the tariff-prescribed LOE conditions is unlikely to be achieved with absolute precision, and requires a practical view towards the exercise and a reasonable degree of judgment in determining the appropriate level of effort.

55. For a number of reasons, I find the proposed one-time determination of a single set of LOE-AF to be applied until the time of the next DCR to be the most reasonable, measured, and appropriate approach. Each of the alternative approaches has merits, but in my view none better meets the set of principles established by AGI to evaluate DCR approaches and issues. In coming to this conclusion, I recognize the potential benefits of each alternative approach, but also recognize the following critical elements of consideration:

- An LOE-AF is warranted from the perspective of economic principles and is consistent with the administrative construct of the ICAP Demand Curves. While there is an inherent degree of uncertainty and judgment involved, the end result from including an adjustment for LOE conditions will be ICAP Demand Curves that are more likely to represent appropriate capacity market price signals for New York;

- It is simply not practical or feasible from an administrative perspective to conduct a full modeling exercise at the time of each annual update. The annual update process is specifically designed to be a formulaic, straightforward recalculation of RPs, and does not and cannot accommodate the type of process that would be required to vet the various assumptions and forecasts required to rerun the modeling effort each year;

- The construction of a matrix of potential sets of LOE-AF during each DCR is an overly-complex approach to establishing the tariff-prescribed adjustment and in the end still fails to represent, from a modeling perspective, the actual conditions that will be in place in future years. While different potential levels of excess can be modeled, in reality the forecasts, resource and load assumptions used to model the LBMPs at each *hypothesized* level of excess will still be different from the conditions that will be in place at the time of each annual update. Under these conditions, the creation of a matrix of LOE-AF provides nothing more than an illusory level of precision, without necessarily improving in a meaningful way upon the calculation of net EAS revenue projections over the period covered by each reset. Further, system and capacity conditions at the time of the annual update will not perfectly align with the modeling results used to develop the matrix, and there will be a degree of judgment required in determining *which set* of LOE-AF are most appropriate to use. This significantly increases the possibility of contentious litigation and controversy arising from the development of updated ICAP Demand Curve values as part of each annual update, which are meant to be formulaic applications of pre-approved approaches.

56. On balance, I conclude that the proposal for a one-time setting of LOE-AF at the time of the DCR – and not including a revisit of the values of LOE-AF at the time of each annual update – reflects a directionally-appropriate adjustment of historic LBMPs from an economic perspective that aligns with the intended purpose of the LOE requirement. This approach also: (i) recognizes the administrative/modeling nature of the LOE-AF approximation and the need for application of best judgement at the time of the modeling process, (ii) does not attempt to overprescribe the LOE-AF estimation procedures or outcomes in view of the uncertainty and volatility in the underlying data and the simplified logic of the modeling construct, and (iii) is the approach that minimizes the need for continuous administration and potential litigation of the approach taken to establish adjustment factors. The proposed method for establishing LOE-AF during each DCR and

fixing these adjustment factors for the four year period covered by each reset represents an appropriate and reasonable balance of the principles of economics, transparency, accuracy, and feasibility.

VI. Conclusions

57. Based on the foregoing, I support NYISO's proposal with respect to extending the period between DCRs from three to four years, altering the approach to estimating net EAS revenues, and creating a process of annual updates to ICAP Demand Curve values between DCRs. The NYISO's proposed changes would establish a process and calculation approach for determining ICAP Demand Curve values that is robust, transparent, formulaic, and repeatable. The proposal also addresses the objectives and criteria established by AGI to evaluate potential changes to the DCR process better than the alternatives reviewed.

58. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of Paul J. Hibbard, dated May 20, 2016 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Paul J. Hibbard
Paul J. Hibbard
May 20, 2016

Subscribed and sworn to before me
this 20th day of May 2016.

Notary Public

My commission expires: 11/3/2017

DENISE VAN VOOREN
Notary Public
Massachusetts
Commission Expires Nov 3, 2017

Exhibit A

Paul J. Hibbard

Principal

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Fax: (617) 425-8001
paul.hibbard@analysisgroup.com

111 Huntington Ave.
Tenth Floor
Boston, MA 02199

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

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

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

EDUCATION

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

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

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

PROFESSIONAL EXPERIENCE

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

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

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

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

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

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

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

SELECTED PUBLIC SECTOR EXPERIENCE

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

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

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

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

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

SELECTED CONSULTING EXPERIENCE

Government, Foundations, Commissions, Cooperatives

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

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

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

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

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

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

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

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

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

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

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

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

Other Electric and Natural Gas Industry Experience

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

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

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

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

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

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

- ***For an International Power Company*** – Conducted a review of a regional utility's compliance with FERC requirements for transmission open access; developed strategies for the filing of complaints of anticompetitive conduct before the FERC (2011 – 2012).
- ***For a Regional Transmission Organization*** – Comprehensively reviewed and suggested changes to the design of regional market structures; oversaw data review and analysis related to key market design features and asset performance (2011).
- ***For an Energy Services Company –*** Oversaw and conducted an analysis of business, legal and regulatory conditions related to a legal dispute over the legitimacy of a contract for energy and water management services. Co-authored a report to be used in development of legal strategy and legal proceedings (2012).
- ***For Direct Energy*** – Assisted with development of strategies to increase retail choice in Pennsylvania, including the design of an Opt-In descending-clock auction to increase migration from default service to competitive supply. Prepared comments and analysis on utility contract structures. Provided testimony before the Pennsylvania Public Utilities Commission (2011).
- ***For Algonquin Gas*** – Submitted affidavits and testified in bankruptcy court on the impact on power plant value of changes in market rules related to the Forward Capacity Market in New England. Also provided testimony on the impact on power system reliability of the availability of firm transportation contracts for natural gas supplied to power plants in New England (2010).
- ***For an Independent System Operator*** – Conducted a best practices and performance metrics analysis to benchmark the ISO's performance against industry peers with respect to responsiveness to consumers, stakeholders, and policymakers. Drafted a report with comprehensive benchmarking and performance metric recommendations; participated in stakeholder discussions (2010).
- ***For a Power Generators Trade Association*** – Developed and facilitated an all-day group discussion concerning key economic, environmental, legal and policy challenges to the economic viability of existing and new power generation capacity in regional wholesale electricity markets (2010).
- ***For a Coalition of Electric Companies*** – Coauthored a report, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," reviewing the impact on power plant operations of proposed Environmental Protection Agency rules to reduce emissions of sulfur dioxide, nitrogen oxides, mercury, and other hazardous air pollutants. Presented findings to numerous regional and national industry and regulatory groups (2010).
- ***For an Industry Coalition*** – Conducted a study and coauthored a white paper (with Dr. Susan Tierney) for the New England Energy Alliance on New England energy infrastructure needs and policy issues (e.g., facility siting policies, RGGI/climate change) influencing the future addition of energy infrastructure in the region (2006).
- ***For an Interstate Pipeline Company and Offshore LNG Developer*** – Authored a Report related to recent developments in the supply and demand for natural gas in New England, and surveyed the development, regulatory and commercial status of proposed LNG projects across the U.S. (2006); coauthored a Report (with Dr. Susan Tierney) providing an overview of Northeastern natural gas markets and conditions, and an assessment of natural gas supply and demand conditions (2005).
- ***For Independent System Operators*** – Managed several projects and coauthored reports or analyses for the Northeast region's ISOs/RTOs, related to ISO/RTO annual strategic plans; market monitoring and mitigation best practices; and the links between wholesale electricity markets and local distribution company retail prices (2002 – 2006).
- ***For Electric Utilities*** – Managed or participated in numerous engagements with wires-only as well as vertically-integrated electric utilities within New England and across the country related to rate case strategy and regulatory support; strategic planning; power supply resource planning and procurement (including the role of independent monitor of utility procurements); price and environmental analyses

related to the siting of new high-voltage transmission lines; and evaluation of the allocation of SO_2 and NO_x emission allowances under the EPA CAIR program (2001 – 2006).

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

OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Advanced Energy Economy (2011).

SELECTED REPORTS, TESTIMONY AND PRESENTATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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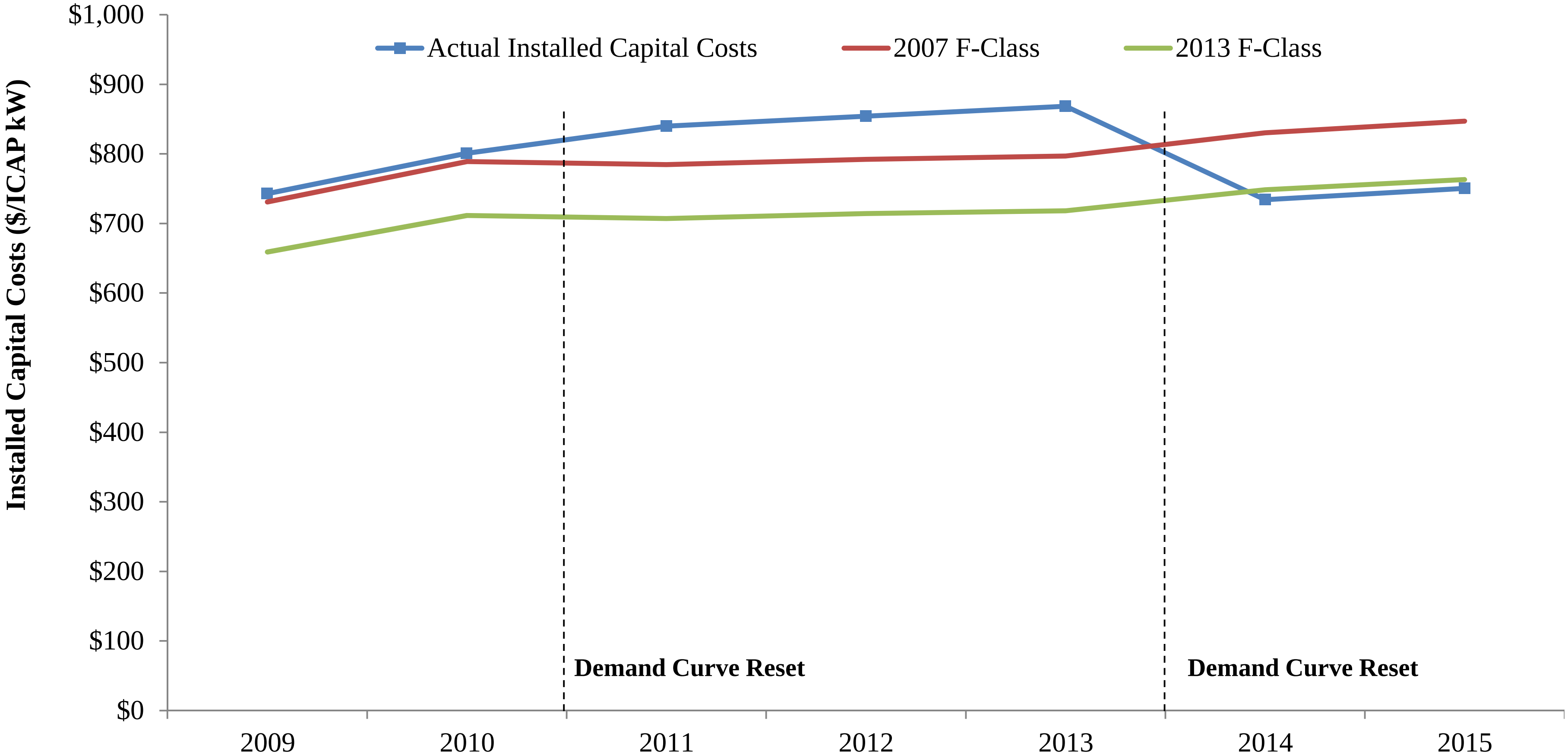
Exhibit B1: Installed Capital Costs (NYCA)



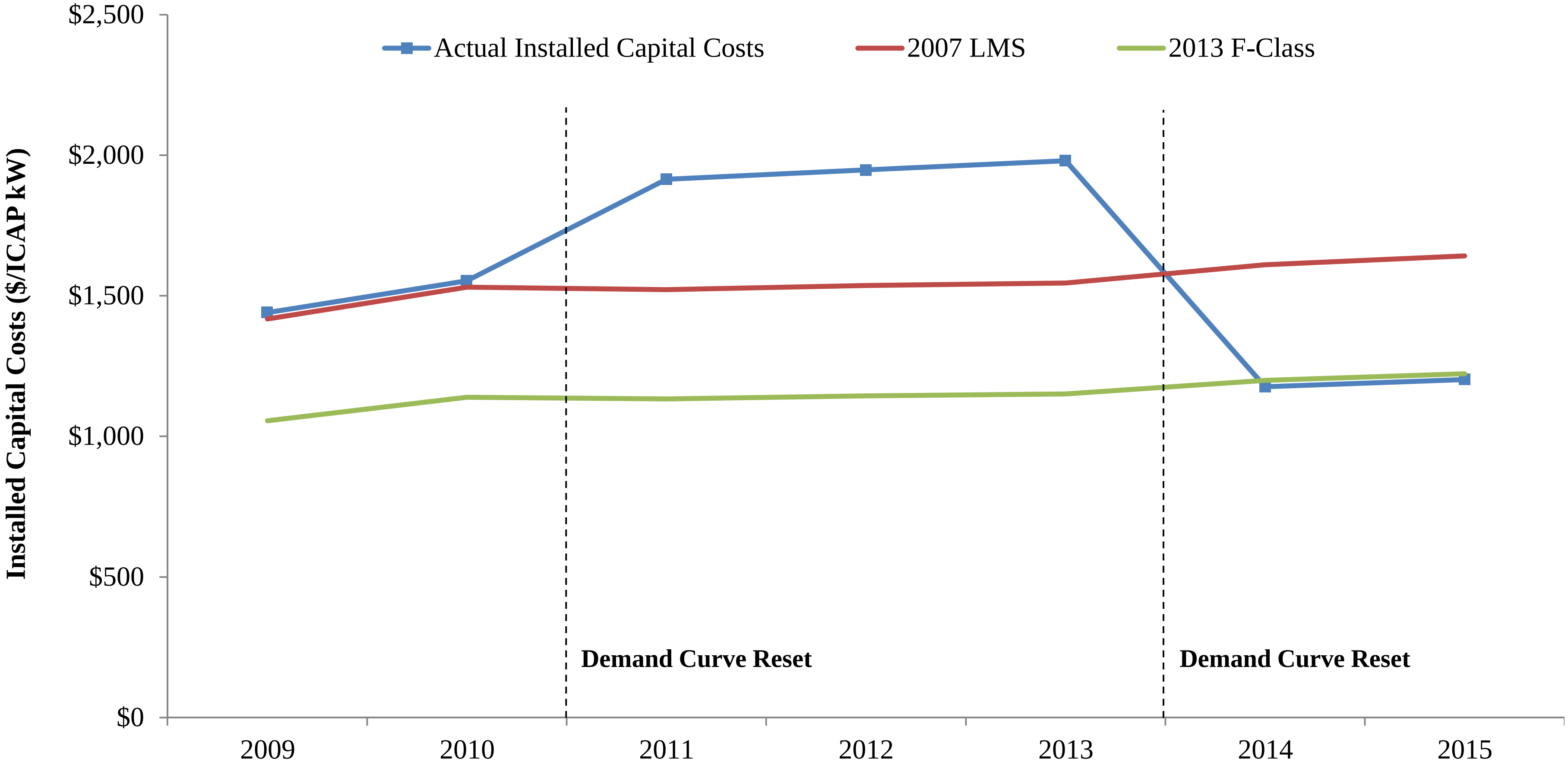
Notes:

1. "Actual" reflects the approved peaking unit technology and installed capital cost for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 F-Class installed capital costs updated annually based on historical escalation factors that are similar to the proposed escalation factor approach.
3. "2013" reflects the 2013 demand curve model, with 2013 F-class installed capital costs with subsequent annual values based on historical escalation factors that are similar to the proposed escalation factor approach.

Sources:

1. "ICAP_Demand_Curve_Model_v75_113007.xls." ICAP Data & Information. NYISO. Last modified December 3, 2007.
2. "REVISED_WSR_Demand_Curve_Model_09-15-11_NYCA.xls." ICAP Data & Information. NYISO. Last modified October 18, 2011.
3. "Demand_Curve_Model_2013-10-30 NYC Siemens SCR.xls." ICAP Data & Information. NYISO. Last modified November 4, 2013.

Exhibit B2: Installed Capital Costs (NYC)



Notes:

1. "Actual" reflects the approved peaking unit technology and installed capital cost for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 LMS installed capital costs updated annually based on historical escalation factors that are similar to the proposed escalation factor approach.
3. "2013" reflects the 2013 demand curve model, with 2013 F-class installed capital costs with subsequent annual values based on historical escalation factors that are similar to the proposed escalation factor approach.

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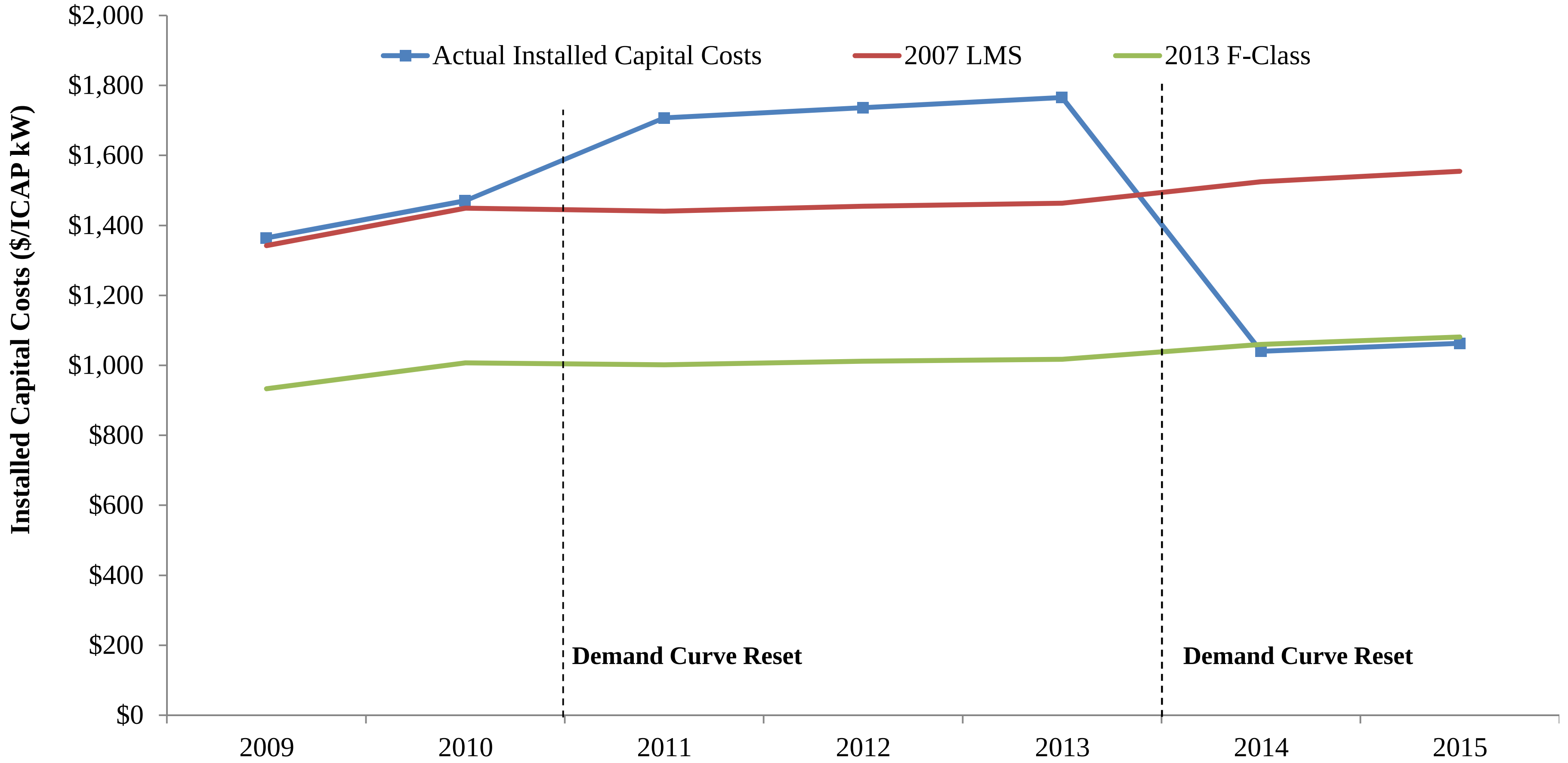
1. "ICAP_Demand_Curve_Model_v75_113007.xls." ICAP Data & Information. NYISO. Last modified December 3, 2007.
2. "REVISED_WSR_Demand_Curve_Model_09-15-11_NYCA.xls." ICAP Data & Information. NYISO. Last modified October 18, 2011.
3. "Demand_Curve_Model_2013-10-30 NYC Siemens SCR.xls." ICAP Data & Information. NYISO. Last modified November 4, 2013.

Exhibit B3: Installed Capital Costs (Long Island)



Notes:
1. "Actual" reflects the approved peaking unit technology and installed capital cost for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 LMS installed capital costs updated annually based on historical escalation factors that are similar to the proposed escalation factor approach.
3. "2013" reflects the 2013 demand curve model, with 2013 F-class installed capital costs with subsequent annual values based on historical escalation factors that are similar to the proposed escalation factor approach.

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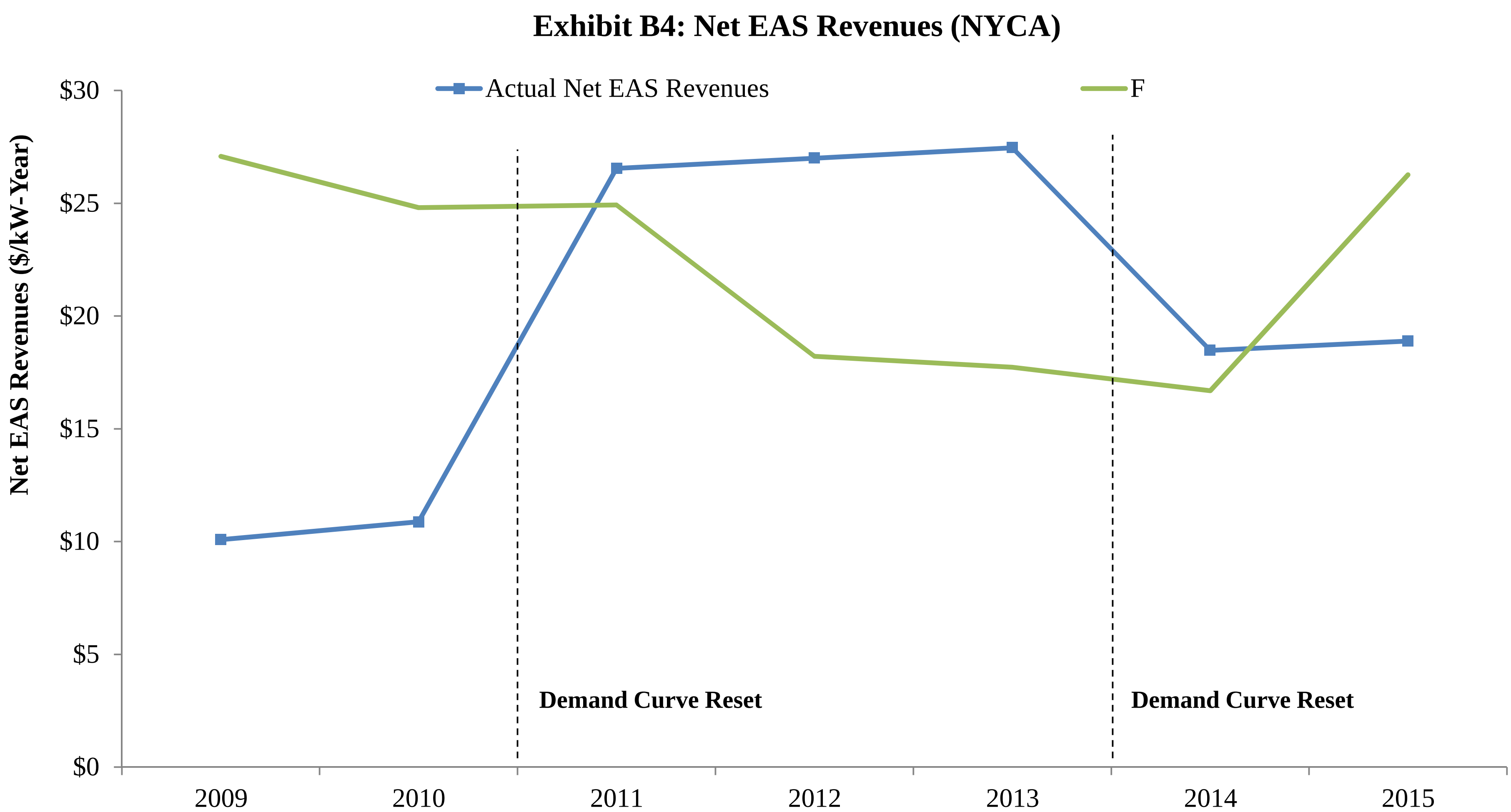
2. "REVISED_WSR_Demand_Curve_Model_09-15-11_NYCA.xls." ICAP Data & Information. NYISO. Last modified October 18, 2011.
3. "Demand_Curve_Model_2013-10-30 NYC Siemens SCR.xls." ICAP Data & Information. NYISO. Last modified November 4, 2013.



Notes:

1. "Actual" reflects the approved peaking unit technology and net EAS revenues for each DCR, with variability between resets and constant escalation within resets.
2. Net EAS revenue estimates are not included for the LMS unit because the LMS was not the peaking unit technology for NYCA in any of the DCRs analyzed.
3. "F" reflects estimated net EAS revenues for the F-Class unit based on historical data in a manner consistent with the proposed historic net EAS revenue estimation methodology.

Sources:

1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
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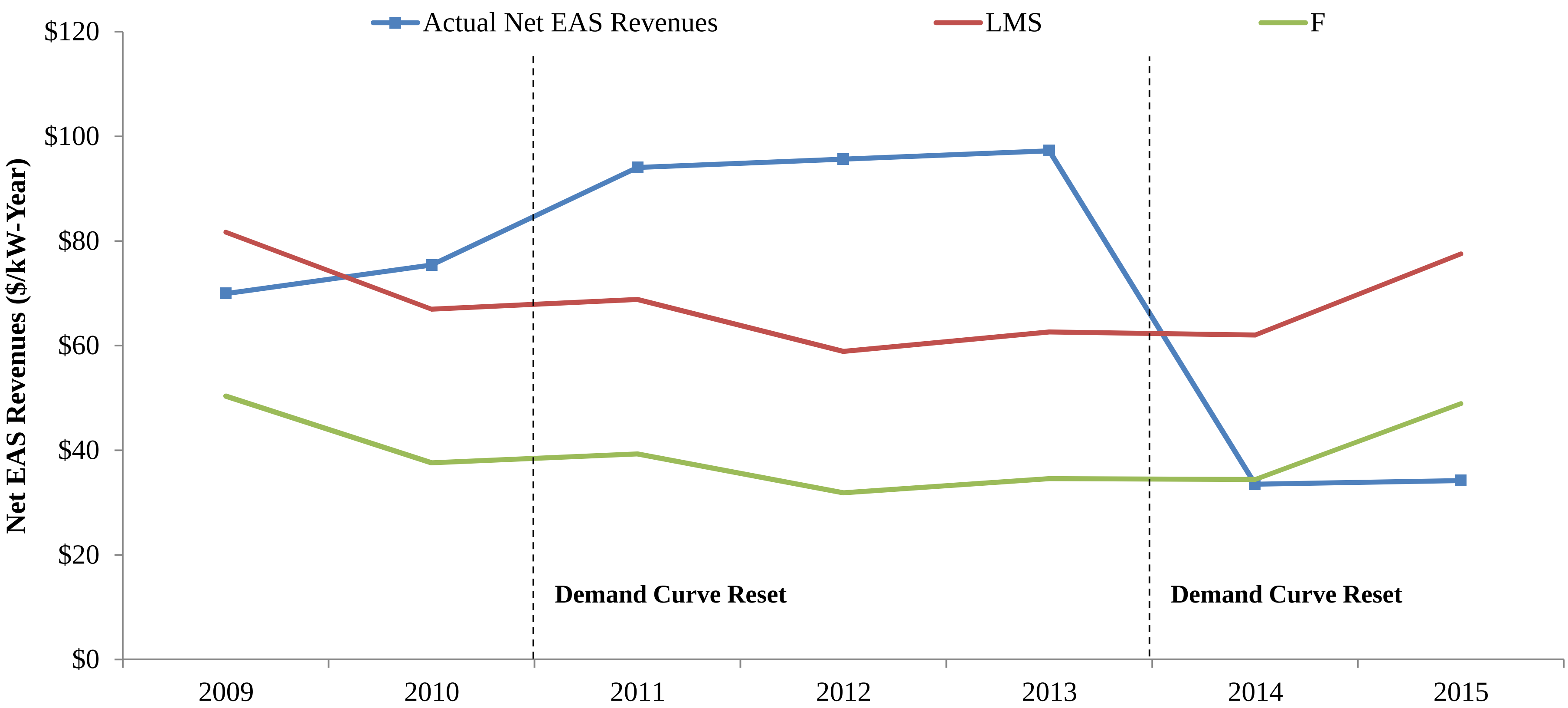
4. Attachment IV. "Cmplt_DCR_flng_FID796_11-27-13.pdf." (Demand Curve Filing.) Tariff, Filing, Order and Docket Search. NYISO. November 27, 2013.

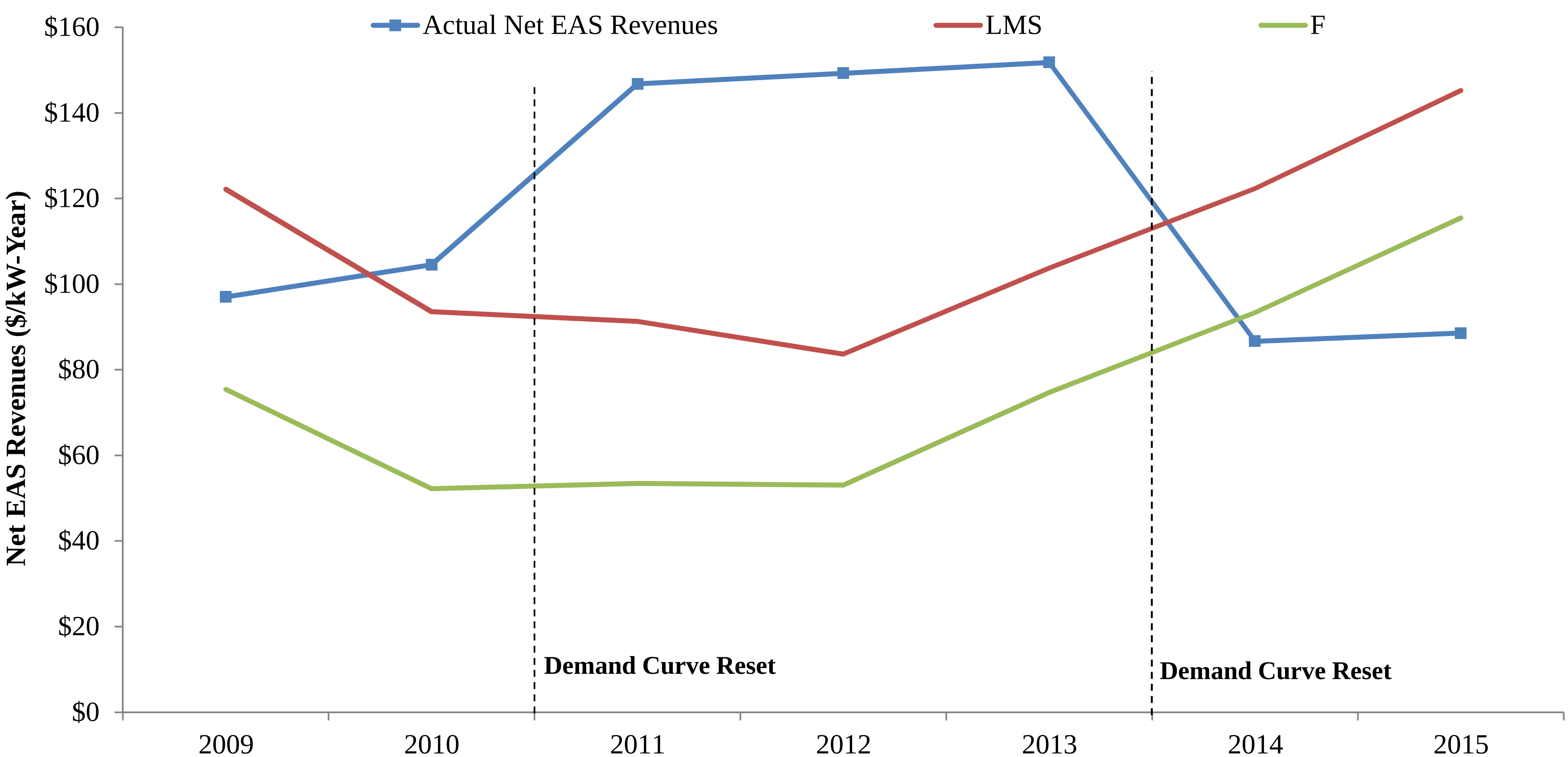
Exhibit B5: Net EAS Revenues (NYC)



Notes:
1. "Actual" reflects the approved peaking unit technology and net EAS revenues for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "LMS" reflects estimated net EAS revenues for the LMS unit based on historical data in a manner consistent with the proposed historic net EAS revenue estimation methodology.
3. "F" reflects estimated net EAS revenues for the F-Class unit based on historical data in a manner consistent with the proposed historic net EAS revenue estimation methodology.

Sources:
1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
3. "2014 - 2017 Final Demand Curves." ICAP Data & Information. NYISO. Last modified March 4, 2014.
4. Attachment IV. "Cmplt_DCR_flng_FID796_11-27-13.pdf." (Demand Curve Filing.) Tariff, Filing, Order and Docket Search. NYISO. November 27, 2013.

Exhibit B6: Net EAS Revenues (Long Island)



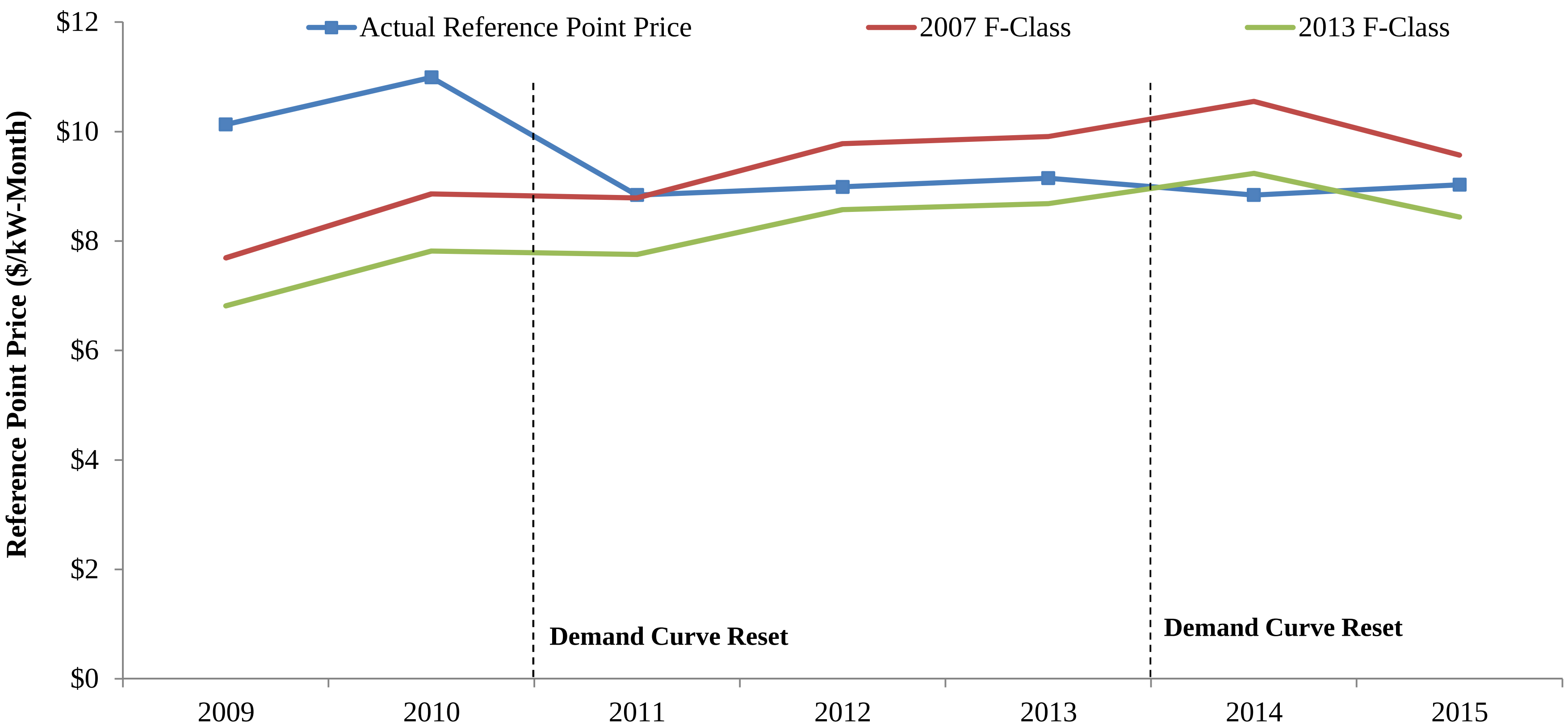
Notes:

1. "Actual" reflects the approved peaking unit technology and net EAS revenues for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "LMS" reflects estimated net EAS revenues for the LMS unit based on historical data in a manner consistent with the proposed historic net EAS revenue estimation methodology.
3. "F" reflects estimated net EAS revenues for the F-Class unit based on historical data in a manner consistent with the proposed historic net EAS revenue estimation methodology.

Sources:

1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
3. "2014 - 2017 Final Demand Curves." ICAP Data & Information. NYISO. Last modified March 4, 2014.
4. Attachment IV. "Cmplt_DCR_flng_FID796_11-27-13.pdf." (Demand Curve Filing.) Tariff, Filing, Order and Docket Search. NYISO. November 27, 2013.

Exhibit B7: Reference Point Prices (NYCA)



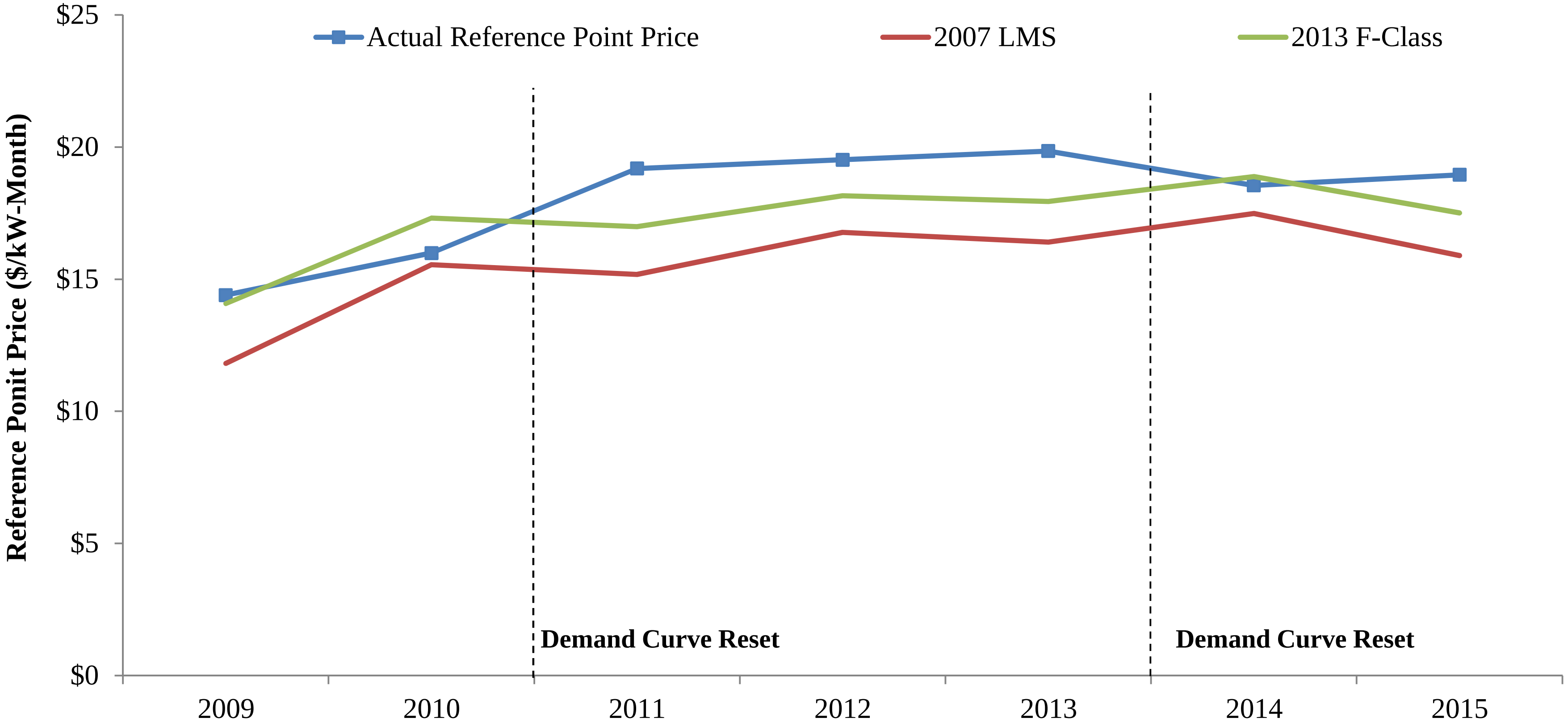
Notes:

1. "Actual" reflects the approved peaking unit technology and reference point prices for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 F-Class installed capital costs updated annually based on historical escalation factors and estimated historical F-Class net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.
3. "2013" reflects the 2013 demand curve model, with 2013 F-Class installed capital costs updated annually based on historical escalation factors and estimated historical F-Class net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.

Sources:

1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
3. "2014 - 2017 Final Demand Curves." ICAP Data & Information. NYISO. Last modified March 4, 2014.
4. Attachment IV. "Cmplt_DCR_flng_FID796_11-27-13.pdf." (Demand Curve Filing.) Tariff, Filing, Order and Docket Search. NYISO. November 27, 2013.

Exhibit B8: Reference Point Prices (NYC)



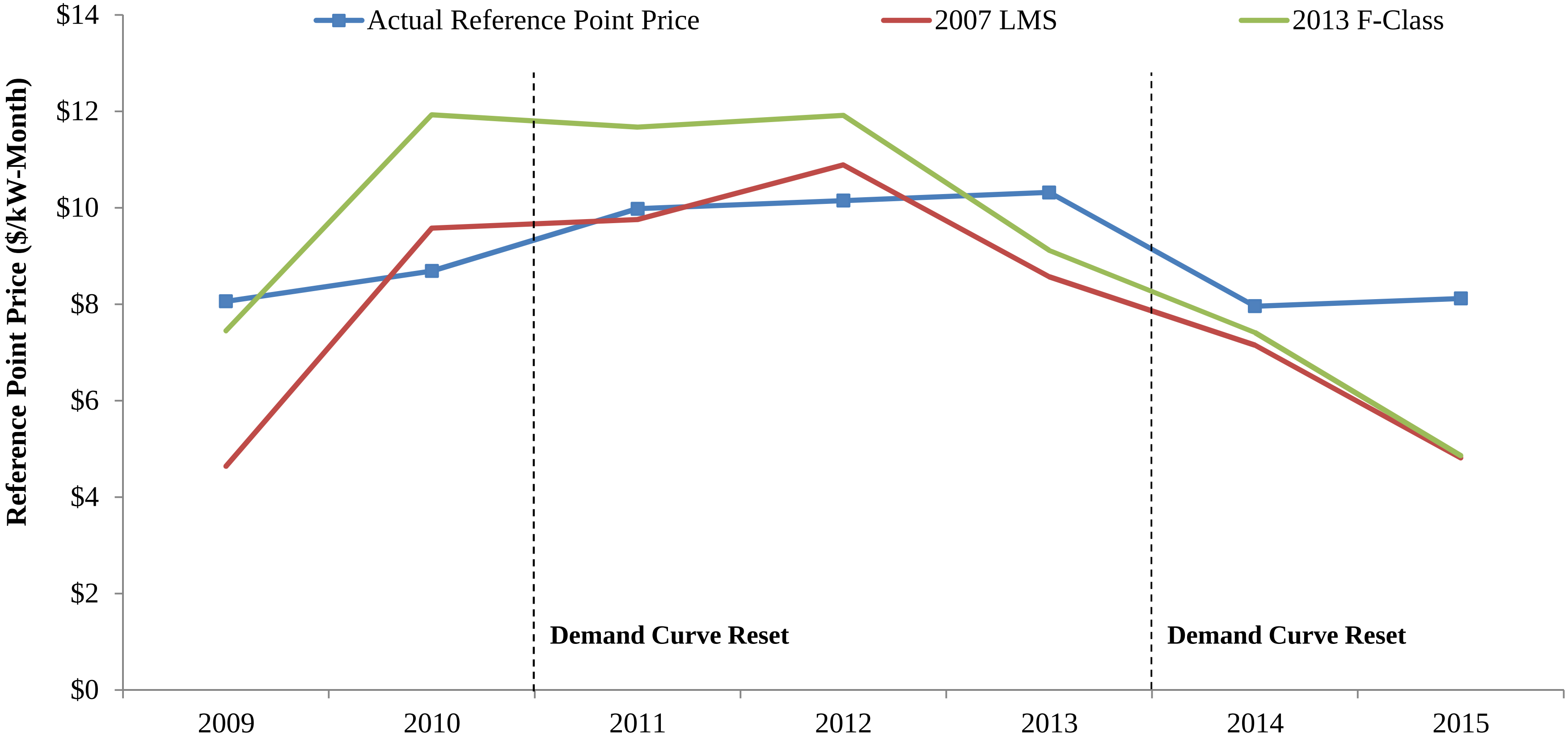
Notes:

1. "Actual" reflects the approved peaking unit technology and reference point prices for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 LMS installed capital costs updated annually based on historical escalation factors and estimated historical LMS net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.
3. "2013" reflects the 2013 demand curve model, with 2013 F-Class installed capital costs updated annually based on historical escalation factors and estimated historical F-Class net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.

Sources:

1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
3. "2014 - 2017 Final Demand Curves." ICAP Data & Information. NYISO. Last modified March 4, 2014.
4. Attachment IV. "Cmplt_DCR_flng_FID796_11-27-13.pdf." (Demand Curve Filing.) Tariff, Filing, Order and Docket Search. NYISO. November 27, 2013.

Exhibit B9: Reference Point Prices (Long Island)



Notes:
1. "Actual" reflects the approved peaking unit technology and reference point prices for each DCR, with variability between resets and constant escalation within resets. The technology changes from the LMS to the F-Class unit in 2014 for NYC and LI.
2. "2007" reflects the 2007 demand curve model, with 2007 LMS installed capital costs updated annually based on historical escalation factors and estimated historical LMS net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.
3. "2013" reflects the 2013 demand curve model, with 2013 F-Class installed capital costs updated annually based on historical escalation factors and estimated historical F-Class net EAS revenues in a manner consistent with the proposed composite escalation factor and historic net EAS estimation approaches.

Sources:
1. "Final NYISO ICAP Demand Curve Recommendations - Capability Years 2008 - 2011." ICAP Data & Information. NYISO. Last modified October 11, 2007.
2. "2011 - 2014 Final Demand Curves." ICAP Data & Information. NYISO. Last modified February 28, 2013.
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