New York ISO
Independent System Operator

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November 30, 2020

By Electronic Delivery

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *New York Independent System Operator, Inc.*, Docket No. ER21-____-000; 2021-2025 ICAP Demand Curve Reset Proposal

Dear Secretary Bose:

In accordance with Section 205 of the Federal Power Act[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission") and Section 5.14.1.2.2 of the New York Independent System Operator, Inc. ("NYISO") Market Administration and Control Area Services Tariff ("Services Tariff"), the NYISO submits the proposed Installed Capacity ("ICAP") Demand Curves for the 2021/2022 Capability Year.[2] The NYISO also proposes the methodologies and inputs for use in conducting annual updates to determine the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Years.

The ICAP Demand Curves, as well the annual update methodologies and inputs proposed herein are the results of the extensive periodic review process required by Section 5.14.1.2.2 of the Services Tariff. This quadrennial review process is commonly referred to as the "ICAP Demand Curve reset" or "DCR." Given the period covered by this periodic review, the NYISO refers to this as the "2021-2025 DCR."[3]

The NYISO respectfully requests: (i) an order accepting the proposed 2021/2022 Capability Year ICAP Demand Curves, as well as the annual update methodologies and inputs to determine the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Years on or before January 29, 2021 (*i.e.*, sixty days after filing); and (ii) an effective date of January 30, 2021 (*i.e.*, the day following the end of the statutory 60-day notice period) for the tariff revisions proposed herein.

[1] 16 U.S.C. § 824d.

[2] Capitalized terms not otherwise defined herein shall have the meaning specified in the Services Tariff.

[3] References to "reset period" herein means the period of Capability Years for which ICAP Demand Curves resulting from the methodologies and inputs established during each DCR remain in effect. For example, the reset period covered by this DCR encompasses the 2021/2022 through 2024/2025 Capability Years.

I. Documents Submitted

The NYISO respectfully submits the following documents with this filing letter:[4]

1. A clean version of the proposed revisions to the Services Tariff ("Attachment I");

2. A blacklined version of the proposed revisions to the Services Tariff ("Attachment II");

3. An Affidavit from Paul J. Hibbard, Dr. Todd Schatzki, Charles Wu, and Christopher Llop of Analysis Group, Inc., including the report titled *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years - Final Report* dated September 9, 2020 ("Attachment III");

4. An Affidavit from Matthew E. Lind and Kieran McInerney of Burns & McDonnell Engineering Company, Inc. ("Attachment IV");

5. An Affidavit from Zachary T. Smith of the NYISO, including the report titled *Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024, 2024-2025 Capability Years - Final Report* dated September 2020 ("Attachment V"); and

6. An Affidavit from Dr. Pallas LeeVanSchaick of Potomac Economics Ltd. ("Attachment VI").

II. Background

Every four years, the NYISO and its stakeholders undertake a comprehensive review to determine the necessary inputs and assumptions for developing the ICAP Demand Curves for the four-year period covered by the reset.

The NYISO develops ICAP Demand Curves based on the estimated cost to construct and operate a hypothetical new capacity supply resource in various locations throughout New York.[5]

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[4] As permitted by the Commission's August 20, 2020 order extending the previous emergency waiver of notarization rules, the affidavits submitted with this filing have not been notarized. *See Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (2020).

[5] Services Tariff § 5.14.1.2.2 refers to the hypothetical new capacity supply resource as a "peaking plant." The Services Tariff defines a "peaking unit" to mean "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable." The Services Tariff defines a "peaking plant" to mean "the number of units (whether one or more) that constitute the scale identified in the [DCR]." The Services Tariff refers to the levelized cost to construct a peaking plant in a given location as the "peaking plant gross cost."

This cost is offset by an estimate of the potential revenues the hypothetical resource could earn from participating in the NYISO-administered energy and ancillary services markets.[6] The resulting net value determines the revenue the hypothetical resource would need to receive from the capacity market to obtain sufficient revenues to support market entry under the system conditions specified for use in the DCR. Specifically, for the purposes of the DCR and establishment of the ICAP Demand Curves, the costs and estimated revenues of each peaking plant are not determined based on current market conditions. Instead, the Services Tariff requires that such costs and revenues be estimated under market conditions in which the available capacity is equal to the applicable minimum Installed Capacity requirement plus the MW value of the peaking plant (referred to herein as the "tariff-prescribed level of excess conditions").[7] This requirement is designed to ensure that the ICAP Demand Curves are established at a level that should provide sufficient revenues to cover the costs of a peaking plant when market entry by such facility is required to maintain reliability.

In February and March 2019, the NYISO collaborated with stakeholders on the development of a request for proposals to select an independent consultant to assist with conducting the DCR and development of the appropriate methodologies and inputs to establish the ICAP Demand Curves for the 2021-2025 reset period.[8] The NYISO issued the request for proposals in April 2019. After review of the proposals submitted, the NYISO ultimately selected Analysis Group, Inc. ("AG") to serve as the independent consultant for the 2021-2025 DCR.[9] Consistent with past DCRs, AG subcontracted with an engineering consultant to assist in the development of certain aspects of the scope of work. For the 2021-2025 DCR, AG subcontracted with Burns & McDonnell Engineering Company, Inc. ("BMCD"). BMCD primarily assisted AG with the assessment of potential technologies to serve as the hypothetical peaking plant used in the establishment of each ICAP Demand Curve, as well as the costs to construct, own and operate such peaking plant options. AG, together with BMCD, are hereinafter referred to collectively as the "Independent Consultant."

The Independent Consultant commenced discussions with stakeholders in August 2019 and continued discussions with stakeholders at the Installed Capacity Working Group ("ICAPWG") over the course of the next 12 months to inform its final report and recommendations for the 2021-2025 DCR. Stakeholders provided input on the Independent Consultant's assumptions, methodologies, analysis, and preliminary results. The Independent Consultant also received input from the Market Monitoring Unit ("MMU") throughout the DCR.

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[6] The Services Tariff refers to the estimate of potential energy market revenue earnings for a peaking plant as the "net Energy and Ancillary Services revenue offset." *See* Services Tariff § 5.14.1.2.2.

[7] Services Tariff § 5.14.1.2.2. For purposes of the 2021-2025 DCR, the specified system conditions are determined based on the NYCA Minimum Installed Capacity Requirement and the applicable Locational Minimum Installed Capacity Requirements established for the 2020/2021 Capability Year.

[8] Services Tariff § 5.14.1.2.2.4.1.

[9] Services Tariff § 5.14.1.2.2.4.2.

Based on its analysis and consideration of the feedback received from stakeholders and the MMU, the Independent Consultant issued its draft report for the 2021-2025 DCR on June 5, 2020.[10] The Independent Consultant reviewed its draft report at the June 10, 2020 ICAPWG meeting. Stakeholders and the MMU submitted written comments in response to the draft report.[11]

After consideration of the feedback received, the Independent Consultant issued an interim version of its final report for the 2021-2025 DCR on August 5, 2020. This interim version reflected the Independent Consultant's final recommendations on inputs, assumptions, and methodologies for the 2021-2025 DCR and updated the preliminary results contained in its draft report accordingly.[12] The Independent Consultant issued the updated version of its final report on September 9, 2020.[13] The updated version reflected the Independent Consultant's recommended ICAP Demand Curves for the 2021/2022 Capability Year using the tariff-prescribed three-year historical data period applicable for such ICAP Demand Curves (*i.e.*, September 1, 2017 through August 31, 2020).[14]

Based on consideration of stakeholder and MMU feedback throughout the DCR, the Independent Consultant's draft report, and comments submitted in response to the Independent

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[10] Services Tariff § 5.14.1.2.2.4.3. The Independent Consultant's draft report provided results and recommendations, including preliminary values for the 2021/2022 ICAP Demand Curves using the historical data period from September 1, 2016 through August 31, 2019. The Independent Consultant noted that: (1) all preliminary results and recommendations remained subject to change; and (2) the calculated values for the 2021/2022 Capability Year ICAP Demand Curves would be updated in the Independent Consultant's final report to reflect the historical data period prescribed by the tariff for use in establishing such curves (*i.e.*, September 1, 2017 through August 31, 2020). The Independent Consultant's draft report is available at: https://www.nyiso.com/documents/20142/13248786/Analysis-Group-2019-2020-DCR-Draft-Report.pdf.

[11] Services Tariff §§ 5.14.1.2.2.4.4 and 5.14.2.2.2.4.5. Comments submitted in response to the Independent Consultant's draft report are available at: https://www.nyiso.com/installed-capacity-market. From this page, the comments can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Stakeholder Comments"→"Consultant's Draft Report."

[12] The historical data period utilized in calculating preliminary values for the 2021/2022 Capability Year ICAP Demand Curves continued to reflect the period from September 1, 2016 through August 31, 2019. The Independent Consultant noted that an updated version of its final report would be issued using the required three-year historical period (*i.e.*, September 1, 2017 through August 31, 2020) to calculate the Independent Consultant's recommended ICAP Demand Curves for the 2021/2022 Capability Year. The Independent Consultant's interim final report is available at: https://www.nyiso.com/documents/20142/14404876/Analysis%20Group%20Interim%20Final%20Demand%20Curve%20Reset%20Report.pdf.

[13] Services Tariff § 5.14.1.2.2.4.6.

[14] The updated version of the Independent Consultant's final report is included as Exhibit E of the *Affidavit of Paul J. Hibbard, Dr. Todd Schatzki, Charles Wu, and Christopher Llop* attached hereto as Attachment III ("AG Affidavit").

Consultant's draft report, NYISO staff issued its draft recommendations for the 2021-2025 DCR on August 5, 2020.[15] NYISO staff reviewed its draft recommendations at the August 10, 2020 ICAPWG meeting. Stakeholders and the MMU submitted written comments in response to NYISO staff's draft recommendations.[16]

After consideration of the feedback provided, NYISO staff issued its final recommendations on September 9, 2020.[17] At the September 22, 2020 ICAPWG meeting, the NYISO reviewed its final recommendations and highlighted aspects that differed from the Independent Consultant's final report and NYISO staff's draft recommendations. These changes included: (1) in coordination with the Independent Consultant, modifying certain logic related to the use of gas price data contained in the model that calculates the net Energy and Ancillary Services revenue offset values for the peaking plants; (2) the proposed gas hub for the peaking plant located in Load Zone C; and (3) enhancements to the translation of the annual peaking plant gross cost values to monthly values used in establishing the maximum clearing price value for each ICAP Demand Curve.[18]

Following issuance of NYISO staff's final recommendations, stakeholders submitted written comments to the NYISO Board of Directors ("Board") regarding the recommendations for the 2021-2025 DCR.[19] Stakeholders also participated in oral presentations before the Board

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[15] Services Tariff § 5.14.1.2.2.4.7. Consistent with the Independent Consultant's draft report, NYISO staff's draft recommendations included preliminary results and recommendations, including preliminary values for the 2021/2022 Capability Year ICAP Demand Curves using historical data for the period from September 1, 2016 through August 31, 2019. NYISO staff noted that the recommendations and results set forth in its draft recommendations were preliminary and subject to change. NYISO staff also noted that updated values for the 2021/2022 Capability Year ICAP Demand Curves using data for the period from September 1, 2017 through August 31, 2020 would be included in its final recommendations. NYISO staff's draft recommendations are available at: https://www.nyiso.com/documents/20142/13248786/NYISO-Staff-Draft-DCR-Recommendations-Final.pdf.

[16] Services Tariff §§ 5.14.1.2.2.4.7 and 5.14.1.2.2.4.5. Comments submitted in response to NYISO staff's draft recommendations are available at: https://www.nyiso.com/installed-capacity-market. From this page, the comments can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Stakeholder Comments"→"NYISO Staff's Draft Report."

[17] Services Tariff § 5.14.1.2.2.4.8. NYISO staff's final recommendations are included as Exhibit A of the *Affidavit of Zachary T. Smith* attached hereto as Attachment V ("NYISO Affidavit").

[18] NYISO, *2021-2025 ICAP Demand Curve Reset: NYISO Staff Final Recommendations* (presented at the September 22, 2020 ICAPWG meeting), available at: https://www.nyiso.com/documents/20142/15473217/2019-2020%20NYISO%20Staff%20Final%20Recommendations.pdf.

[19] Services Tariff § 5.14.1.2.2.4.9. Stakeholders comments submitted to the Board are available at: https://www.nyiso.com/installed-capacity-market. From this page, the comments can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Stakeholder Comments"→"Comments to the NYISO BOD."

on October 19, 2020.[20] After due consideration of: (1) stakeholder comments throughout the DCR, including those provided in writing and orally in response to NYISO staff's final recommendations; (2) comments provided by the MMU throughout the DCR; (3) the Independent Consultant's final report; and (4) NYISO staff's final recommendations, the Board directed NYISO staff to file the results for the 2021-2025 DCR as proposed herein. The Boardapproved proposal reflects the proposed 2021/2022 Capability Year ICAP Demand Curves, as well as the methodologies and inputs to be used in the annual updates to determine the ICAP Demand Curves for the 2022/2023 through 2024/2025 Capability Years, that are set forth in NYISO staff's final recommendations.[21]

As further described herein, the NYISO proposes to use the H class frame turbine as the peaking plant in establishing each of the ICAP Demand Curves. The H class frame turbine replaces the F class frame turbine that the Commission approved for the last reset covering the 2017/2018 through 2020/2021 Capability Years ("2017-2021 DCR").[22] For the New York Control Area ("NYCA") ICAP Demand Curve, the NYISO proposes continued use of a gas-only peaking plant without selective catalytic reduction ("SCR") emissions control technology. The NYISO proposes that the ICAP Demand Curves for the G-J Locality, New York City ("NYC"), and Long Island ("LI") continue to utilize dual fuel peaking plants that include SCR emissions control technology. Based on updates to methodologies, inputs, and assumptions developed during this DCR and proposed herein, the assumed locations of the peaking plants for the NYCA and G-J Locality ICAP Demand Curves are different than those used for the 2017-2021 DCR.[23] The NYISO proposes use of a peaking plant located within Load Zone C as the basis for the NYCA ICAP Demand Curve instead of Load Zone F as was used for the 2017-2021 DCR. The proposed ICAP Demand Curve for the G-J Locality utilizes a peaking plant located within the Rockland County portion of Load Zone G ("Load Zone G (Rockland County)"). The G-J Locality ICAP Demand Curve for the 2017-2021 DCR used a peaking plant located within the Dutchess County portion of Load Zone G ("Load Zone G (Dutchess County)").

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[20] Services Tariff § 5.14.1.2.2.4.10.

[21] NYISO Affidavit at Exhibit A ("NYISO Final Recommendations"); and NYISO Affidavit at ¶ 29.

[22] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 (2017) ("2017-2021 DCR Order"). The Commission also approved use of the F class frame turbine for the reset prior to the 2017-2021 DCR that covered the ICAP Demand Curves for the 2014/2015 through 2016/2017 Capability Years ("2014-2017 DCR"). *See New York Independent System Operator, Inc.*, 146 FERC 61,043 (2014) ("2014-2017 DCR Order").

[23] For the NYCA and G-J Locality ICAP Demand Curves, the DCR assessed more than one generic site location for a potential peaking plant. In these cases, the NYISO proposes selection of the location that results in the lowest reference point price for each ICAP Demand Curve. Thus, the peaking plant locations proposed herein are dependent on the various inputs and assumptions proposed by the NYISO for each location. If the inputs and assumptions for any of these locations were changed, the proposed location for the peaking plant used in determining the NYCA and/or G-J Locality ICAP Demand Curve may also need to be revised.

The DCR serves as a forum for thoroughly vetting proposed methodologies, inputs and assumptions used in establishing the ICAP Demand Curves. The collaborative nature of this open and transparent process helps to reduce the scope of disputed issues. Although the DCR ultimately refined and helped to minimize the number of disputed issues, consensus among divergent stakeholder interests was not achieved on all aspects of the 2021-2025 DCR. The NYISO anticipates that the following disputed matters are likely to be raised in this proceeding: (1) the inclusion of SCR emissions control technology for the Load Zone G (Dutchess County) peaking plant option; (2) the inclusion of dual fuel capability for the peaking plant used in establishing the G-J Locality ICAP Demand Curve; (3) the estimated cost of a gas lateral connection, especially as it relates to the peaking plant used in establishing the G-J Locality ICAP Demand Curve; (4) the estimated land lease cost for the peaking plant in NYC; (5) the assumed level of owner's costs for design, permitting, and financing during construction; (6) the gas hub(s) used in determining the variable operating costs for the Load Zone C peaking plant option; (7) the gas hub used in determining the variable operating costs for the Load Zone G (Rockland County) peaking plant option; (8) the supply resource modeling assumptions used in determining level of excess adjustment factors; (9) the assumed cost of debt, return on equity, and amortization period used in translating the up-front capital costs of developing and owning each peaking plant into an annual levelized value; and (10) the absence of any one-time adjustment to historical data to exclude energy market outcomes impacted by the COVID-19 pandemic. The NYISO addresses each of these issues within this filing.

III. Peaking Plant Technology and Design

Section 5.14.1.2.2 of the Services Tariff defines the peaking unit as the "technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable." The Commission has established that economic viability determinations are a matter of judgment that is informed by the consideration of multiple factors.[24] These factors include: (i) the availability of the technology to most market participants; (ii) existence of sufficient operating experience to demonstrate that the technology is proven and reliable; (iii) whether the technology is dispatchable and capable of being cycled to provide peaking service; and (iv) the ability to achieve compliance with applicable environmental requirements and regulations.[25]

The Commission has also recognized that the peaking plant design for each ICAP Demand Curve must be capable of being replicated.[26] As such, the peaking plant design should

[24] *See*, *e.g.*, 2017-2021 DCR Order at P 18; 2014-2017 DCR Order at P 60; *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 37 (2011) ("2011-2014 DCR Order"); and *New York Independent System Operator, Inc.*, 125 FERC ¶ 61,299 at P 20 (2008) ("2008-2011 DCR Rehearing Order").

[25] *Id*. The Independent Consultant applied these criteria in this DCR to guide determinations regarding the appropriate technology and plant design to use in establishing each ICAP Demand Curve. *See*, *e.g.*, AG Affidavit, Exhibit E at 13 ("Independent Consultant Final Report"); and *Affidavit of Matthew E. Lind and Kieran McInerney* at ¶ 11 attached hereto as Attachment IV ("BMCD Affidavit").

[26] 2017-2021 DCR Order at P 19 and 65.

not represent a single least possible cost design that may support only the construction of a single facility. Establishing the ICAP Demand Curves purely on the basis of a single least possible cost design is likely to result in providing price signals that could sustain only the development of, at best, a single facility. If, however, system conditions dictated a need to develop more than one peaking plant during a given reset period, such a market design would likely fail its objective of supporting new entry when needed and could require reliance on out-of-market action to ensure continued availability of sufficient resources to maintain reliability.

The NYISO carefully evaluated the above-described considerations, as well as the views of all stakeholders, in determining the peaking plant designs proposed herein. The NYISO's proposal is intended to produce ICAP Demand Curves that provide appropriate price signals regarding the value of capacity in each capacity region, while simultaneously ensuring that the curves are capable of providing the needed revenues to elicit new market entry when required to ensure that reliability is maintained.

Although the NYISO has proposed to modify the class of frame turbine technology used in establishing each ICAP Demand Curve, the general plant designs for each location remain consistent with the designs approved by the Commission for the 2017-2021 DCR.[27] The peaking plant proposed for establishing the NYCA ICAP Demand Curves remains a gas-only unit without SCR emissions control technology.[28] For the G-J Locality, NYC, and LI ICAP Demand Curves, the NYISO proposes continued use of a dual fuel peaking plant with SCR emissions control technology.[29]

A. Peaking Plant Technology

Consistent with prior DCRs, the Independent Consultant developed information for a variety of potential peaking plant technology options.[30] The Independent Consultant produced results for the various technology options in Load Zone C, Load Zone F, Load Zone G (Dutchess

[27] 2017-2021 DCR Order at P 2 and 20.

[28] NYISO Final Recommendations at 58-59.

[29] *Id*.

[30] Independent Consultant Final Report at 12-19; AG Affidavit at ¶ 19-23; and BMCD Affidavit at ¶ 10-13.

County), Load Zone G (Rockland County), NYC, and LI. The technology options evaluated included the H class frame turbine,[31] the F class frame turbine,[32] and aeroderivative turbines.[33]

For this DCR, the Independent Consultant also expanded the technologies evaluated to include consideration of battery storage technology for the first time.[34] Consideration of battery storage, in part, recognizes the ongoing transition of the resource mix in New York and state policies to accelerate the transition to a clean energy resource fleet. Rather than select a particular manufacturer or chemistry, the Independent Consultant developed cost estimates for battery storage that are representative of the three most commonly utilized lithium-ion chemistry options (*i.e.*, lithium nickel manganese cobalt oxide ["NMC"], lithium iron phosphate ["LFP"], and lithium nickel cobalt aluminum oxide ["NCA"]). The Independent Consultant assessed 200 MW battery storage plants with discharge durations of 4 hours (800 MWh of energy storage capability), 6 hours (1,200 MWh of energy storage capability), and 8 hours (1,600 MWh of energy storage capability). Due to the availability of alternative lower cost, economically viable technology options, the NYISO does not recommend any battery storage option as the peaking plant for any location in this DCR.[35]

For the 2021-2025 DCR, the NYISO proposes to replace the F class frame turbine used in establishing the ICAP Demand Curves for the 2014-2017 DCR and 2017-2021 DCR with the H class frame turbine.[36] The H class frame turbine is a larger, more efficient, and more flexible technology than the F class frame turbine. The NYISO proposes use of the H class frame turbine for the 2021-2025 DCR because it represents the lowest cost technology option amongst the economically viable options evaluated.

The NYISO considered the H class frame turbine for informational purposes only in the 2017-2021 DCR because, at that time, the H class frame turbine had no actual commercial

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[31] The Independent Consultant selected the GE 7HA.02 unit to serve as the representative H class frame turbine technology. The evaluated peaking plant option consisted of a single H class frame turbine in a simple cycle configuration.

[32] The Independent Consultant utilized the GE 7F.05 as the representative F class frame turbine technology. The peaking plant option assessed consisted of a single F class frame turbine in a simple cycle configuration.

[33] The Siemens SGT-A65 unit served as the representative aeroderivative turbine technology. The peaking plant option evaluated consisted of three aeroderivative units operating in a simple cycle configuration.

[34] Independent Consultant Final Report at 18-19; AG Affidavit at ¶ 30; and BMCD Affidavit at ¶ 13.

[35] NYISO Final Recommendations at 59; Independent Consultant Final Report at 7; and AG Affidavit at ¶ 25 and 31.

[36] NYISO Final Recommendations at 4 and 58-59; Independent Consultant Final Report at 7; and AG Affidavit at ¶ 25.

operating experience in a simple cycle configuration.[37] Since the last DCR, the H class frame turbine has achieved commercial operation and operated successfully in a simple cycle configuration equipped with SCR emissions control technology.[38] For example, the Canal 3 generation facility in Massachusetts, which consists of a single GE 7HA.02 unit operating in a simple cycle configuration and equipped with SCR emissions control technology, commenced commercial operation in June 2019.[39] Consistent with precedent, the successful operation of this facility provides the necessary actual operating experience to support selection of this technology as a peaking plant in New York.[40]

Unless otherwise noted, the remainder of this filing letter addresses matters based on consideration of the H class frame turbine as the peaking plant for each of the ICAP Demand Curves.

B. Environmental Requirements and SCR Emissions Control Technology

The NYISO proposes peaking plant designs consistent with those approved by the Commission for the 2017-2021 DCR.[41] For the 2021-2025 DCR, the NYISO proposes continued use of a gas-only peaking plant without SCR emissions control technology as the basis for the NYCA ICAP Demand Curve.[42] Instead of installing back-end emissions controls, the NYISO proposes that the gas-only peaking plant for the NYCA ICAP Demand Curve operate pursuant to an enforceable permit restriction to limit annual nitrogen oxides ("NOx") emissions below applicable environmental requirements.[43] For the G-J Locality, NYC, and LI ICAP Demand Curves, the NYISO proposes continued use of dual fuel peaking plant designs equipped with SCR emissions control technology.[44]

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[37] *See*, *e.g.*, Docket No. ER17-386-000, *New York Independent System Operator, Inc.*, Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021 at 7-9 (November 18, 2016) ("2017-2021 DCR Filing"); and 2017-2021 DCR Order at P 28.

[38] NYISO Final Recommendations at 59; Independent Consultant Final Report at 17-18; and BMCD Affidavit at ¶ 13.

[39] *See*, *e.g.*, NYISO Final Recommendations at 59; BMCD Affidavit at ¶ 13; and BMCD, *Burns & McDonnell Reaches Substantial Completion for Canal 3*, available at: https://www.burnsmcd.com/insightsnews/in-the-news/2019/09/substantial-completion-for-canal-3.

[40] *See*, *e.g.*, 2017-2021 DCR Order at P 28; 2011-2014 DCR Order at P 57-60; and *New York Independent System Operator, Inc.*, 122 FERC ¶ 61,064 at P 23 (2008) ("2008-2011 DCR Order").

[41] 2017-2021 DCR Order at P 2, 27, 58-59 and 91.

[42] NYISO Final Recommendations at 58-59; and AG Affidavit at ¶ 25.

[43] NYISO Final Recommendations at 14-15; and AG Affidavit at ¶ 40.

[44] NYISO Final Recommendations at 58-59.

1. Overview of Environmental Requirements

The Independent Consultant evaluated the impacts of applicable environmental requirements on the peaking plant design for each location assessed as part of the DCR.[45] This evaluation included consideration of applicable New Source Performance Standards ("NSPS"), as well the requirements imposed by permitting under the New Source Review ("NSR") program. NSPS establishes emissions requirements that apply to the H class frame turbine in all locations. The NSR program establishes additional requirements that vary by location.

NSPS includes both greenhouse gas and NOx emissions standards that affect the H class frame turbine. The carbon dioxide ("CO_2") emissions limits imposed by NSPS effectively results in establishing a maximum allowable operating limit of 3,066 hours annually to comply with the applicable requirements.[46] The NSPS also establishes NOx emissions standards that require the H class frame turbine to limit its NOx emissions rate to less than 15 parts per million by volume ("ppmv") at 15% oxygen ("O_2") when operating on natural gas.[47] The standard model GE 7HA.02 turbine has a NOx emissions rate of 25 ppmv at 15% O_2. As a result, the standard model unit would require the installation of SCR emissions control technology to comply with the NSPS NOx emissions standards.[48] However, GE also offers an alternative 7HA.02 model that has a NOx emissions rate of 15 ppmv at 15% O_2.[49] This alternative model achieves lower NOx emissions by lowering the combustion temperature. This lowered temperature does impact the turbine's efficiency resulting in a reduction in output capability of approximately 5% compared to the standard model.[50] Although slightly less efficient, the alternative model does present an option that can be considered for potential operation without the need to install SCR emissions control technology for compliance with NSPS.

The NSR program subjects new units to an evaluation of their impact on air quality in consideration of the surrounding area in which the new unit is located.[51] Based on a comparison of a criteria pollutant's concentration in a given area to the applicable National Ambient Air Quality Standard ("NAAQS") for such pollutant, an area is designated as either in "attainment" (*i.e.*, pollutant concentration levels below the applicable NAAQS) or "non-attainment" (*i.e.*, pollutant concentration levels in excess of the applicable NAAQS).[52] Further designation is used for non-attainment areas to signify the degree of exceedance (*e.g.*, designation as either "moderate" or "severe" non-attainment). Attainment status for an area affects the

[45] Independent Consultant Final Report at 21-34; BMCD Affidavit at ¶ 22-35; and AG Affidavit at ¶ 36-39.

[46] Independent Consultant Final Report at 21-22; and BMCD Affidavit at ¶ 34.

[47] Independent Consultant Final Report at 21; and BMCD Affidavit at ¶ 23.

[48] Independent Consultant Final Report at 21; and BMCD Affidavit at ¶ 24-25.

[49] *Id*.

[50] *Id*.

[51] Independent Consultant Final Report at 22-30; and BMCD Affidavit at ¶ 26.

[52] Independent Consultant Final Report at 22-23; and BMCD Affidavit at ¶ 26.

preconstruction review process that applies to a new unit. New units constructed in nonattainment areas are subject to significantly more stringent requirements.

New units constructed in attainment areas are subject to permitting under the Prevention of Significant Deterioration ("PSD") program.[53] The PSD programs applies Best Available Control Technology ("BACT") analysis to assess the requirement to include pollutant control technologies. BACT generally assesses pollutant control technologies installed on similar facilities. BACT also permits the consideration of economic feasibility in assessing the need to install a particular control technology. Based on its experience, the Independent Consultant concluded that a new unit in New York subject to a BACT review for NOx emissions would be required to install SCR emissions control technology to reduce NOx emissions.[54]

Alternatively, a new unit could elect to "synthetically limit" its operating profile to maintain compliance with the applicable emissions limit for a particular pollutant.[55] To pursue this alternative, the new unit must accept a cap on allowable emissions below the applicable threshold for such pollutant. New units subject to such an emissions cap are deemed a "synthetic minor source" and are subject to less restrictive analysis. For example, a BACT analysis for potential control technology is not required for a synthetic minor source. The Commission has previously approved use of the synthetic minor approach for gas-only units located in an attainment area to avoid the need to install SCR emissions control technology for reducing NOx emissions.[56]

New units constructed in non-attainment areas are subject to permitting under the Nonattainment New Source Review ("NNSR") program.[57] The NNSR program uses a Lowest Achievable Emissions Rate ("LAER") in assessing the need for back-end controls to reduce emissions of a particular pollutant. Unlike BACT, LAER does not include consideration of cost in determining the need for control technology. As a result, LAER typically results in more stringent requirements than BACT.[58] Given the Independent Consultant's determination that the less stringent BACT analysis would ultimately require installation of SCR emissions control technology in New York, the more stringent LAER assessment for NOx emissions would likewise require installation of SCR emissions control technology to reduce NOx emissions.[59]

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[53] Independent Consultant Final Report at 23-25; and BMCD Affidavit at ¶ 27.

[54] Independent Consultant Final at 24; and BMCD Affidavit at ¶ 29.

[55] Independent Consultant Final Report at 23 and 29-30; and BMCD Affidavit at ¶ 28.

[56] *See*, *e.g.*, 2017-2021 DCR Order at P 60-67; and 2014-2017 DCR Order at P 74-77.

[57] Independent Consultant Final Report at 23 and 26-27; and BMCD Affidavit at ¶ 26.

[58] Independent Consultant Final Report at 23; and BMCD Affidavit at ¶ 27.

[59] BMCD Affidavit at ¶ 34.

2. SCR Emissions Control Technology Analysis

Load Zone G (Rockland County), New York City, and Long Island are designated as severe non-attainment areas. The applicable NOx emissions limit for these locations is 25 tons/year.[60] The Independent Consultant concluded that for these severe non-attainment areas, the NNSR will require the installation of SCR emissions control technology to comply with NSR.[61] For areas where SCR emissions control technology is included, the more efficient, standard model of the GE 7HA.02 is used. Inclusion of SCR emissions control technology allows this more efficient version to comply with the applicable NOx emissions limits under both NSPS and NSR.[62]

Load Zones G (Dutchess County), C, and F are attainment areas. However, because New York State is within the Ozone Transport Region, these locations are subject to a more stringent requirement than would otherwise apply.[63] For these locations, the applicable NOx emissions limit is 100 tons/year.[64] Absent pursuing a synthetic minor approach, if viable, new units in these locations would also require the installation of SCR emissions control technology.[65]

The inclusion of dual fuel capability significantly affects the viability of the synthetic minor approach. Operation on ultra-low sulfur diesel ("ULSD") produces significantly higher NOx emissions than operation on natural gas.[66] In fact, the NOx emissions produced by the H class frame turbine is nearly three times higher when operating on ULSD.[67] This severely limits the number of hours the unit can operate annually under the emissions cap applicable to the synthetic minor approach.[68] Due to the severely constraining nature of the emissions cap for operation on ULSD, the NYISO has never proposed in any past DCR that a dual fuel plant pursue the synthetic minor approach in lieu of installing SCR emissions control technology.[69] The NYISO's prior reliance on the synthetic minor approach has been limited to gas-only plants used for establishing the NYCA ICAP Demand Curve.[70] Since its inception, the NYISO has

[60] Independent Consultant Final Report at 25-26; NYISO Final Recommendations at 12-13; and BMCD at ¶ 32.

[61] Independent Consultant Final Report at 26-27; and BMCD Affidavit at ¶ 34.

[62] Independent Consultant Final Report at 26-27.

[63] BMCD Affidavit at ¶ 27.

[64] Independent Consultant Final Report at 24-26; NYISO Final Recommendations at 13; and BMCD Affidavit at ¶ 27 and 31.

[65] Independent Consultant Final Report at 24 and 27.

[66] Independent Consultant Final Report at 31; and AG Affidavit at ¶ 41.

[67] Independent Consultant Final Report at 31; and NYISO Final Recommendations at 14-15.

[68] Independent Consultant Final Report at 28; BMCD Affidavit at ¶ 35; AG Affidavit at ¶ 41; and NYISO Final Recommendations at 14-15.

[69] NYISO Final Recommendations at 14; and AG Affidavit at ¶ 41.

[70] NYISO Final Recommendations at 14.

established the G-J Locality ICAP Demand Curve using a dual fuel peaking plant design equipped with SCR emissions control technology.[71]

For the NYCA ICAP Demand Curve, the NYISO proposes continued use of a gas-only peaking plant design subject to an emissions cap in lieu of installing SCR emissions control technology.[72] This represents a reasonable and viable option in consideration of the level of annual operation allowed under such emissions cap. For a gas-only H class frame unit, the 100 tons/year NOx limit applicable to a synthetic minor source in Load Zones C or F translates into the ability to operate for approximately 1,060 hours per year.[73] This value is similar to the allowed hours of operation deemed acceptable in prior DCRs.[74] For locations where the NYISO proposes use of a synthetic minor approach, the alternative GE 7HA.02 model is used. As noted above, this alternative model is tuned to emit 15 ppmv of NOx at 15% O_2, thereby achieving compliance with the applicable NSPS emissions requirements for the H class frame turbine.[75] Use of this alternative model does slightly reduce the efficiency and output capability of the turbine compared to the standard GE 7HA.02 model.

The NYISO's proposed inputs and assumptions result in a peaking plant located in Load Zone G (Rockland County) serving as the basis for G-J Locality ICAP Demand Curve.[76] Rockland County is located within a severe non-attainment area. Therefore, as noted above, the Independent Consultant concluded that the LAER analysis would require the peaking plant design to include SCR emissions control technology to reduce NOx emissions.[77]

Although the NYISO's proposed G-J Locality ICAP Demand Curve uses a peaking plant in the Rockland County location, certain stakeholders oppose the NYISO's proposal to include

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[71] *See*, *e.g.*, 2014-2017 DCR Order at P 57; and 2017-2021 DCR Order at P 58-59.

[72] NYISO Final Recommendations at 14-15; Independent Consultant Final Report at 29-30; and AG Affidavit at ¶ 25 and 40.

[73] Independent Consultant Final Report at 28; BMCD Affidavit at ¶ 35; AG Affidavit at ¶ 40; and NYISO Final Recommendations at 15.

[74] For example, for the 2014-2017 DCR, the gas only peaking plant design used in establishing the NYCA ICAP Demand curve was subject to an emission cap that allowed nearly 1,000 hours of operation annually. *See*, *e.g.*, 2014-2017 DCR Order at P 73, n. 55.

[75] Independent Consultant Final Report at 21 and 27-28.

[76] For the G-J Locality ICAP Demand Curve, the DCR assessed two potential locations for the peaking plant - Load Zone G (Dutchess County) and Load Zone G (Rockland County). The NYISO proposes selection of the location that results in the lowest reference point price for each ICAP Demand Curve. Based on the NYISO's proposed inputs and assumptions, the Dutchess County location results in a higher reference point price than the Rockland County location. *See* NYISO Final Recommendations at 59; Independent Consultant Final Report at 8; and AG Affidavit at ¶ 25.

[77] Independent Consultant Final Report at 27.

SCR emission control technology for the peaking plant in the Dutchess County location.[78] If SCR emissions control technology were not included in the peaking plant design for the Dutchess County location, the resulting reference point price for this location would be lower than the Rockland County location.[79] As a result, these stakeholders contend that the NYISO should remove the SCR emissions control technology from the peaking plant design for Load Zone G (Dutchess County) and use this location as the basis for the G-J Locality ICAP Demand Curve for the 2021-2025 reset period.

Dutchess County is designated as an attainment area that is within the Ozone Transport Region.[80] Therefore, similar to Load Zones C and F, the synthetic minor approach may be available to achieve compliance with the NOx emissions limit under the PSD program (*i.e.*, 100 tons/year).[81] However, unlike Load Zones C and F, the proposed peaking plant design for Load Zone G (Dutchess County) includes dual fuel capability. From the perspective of translating the NOx emissions cap required for a synthetic minor source, each hour of operation on ULSD is roughly equivalent to three hours of operation on natural gas. Depending on the number of hours the peaking plant operates on ULSD, the allowed hours of operation could be as low as approximately 312 hours annually.[82] The severely constraining nature of the emissions cap for a dual fuel unit does not produce a viable peaking plant that appropriately supports reliability.[83]

For example, the NYISO recently developed enhancements to the ICAP market to better accommodate the participation of resources subject to daily run-time limitations.[84] The

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[78] NYISO Final Recommendations at 14-15; Independent Consultant Final Report at 30; and AG Affidavit at ¶ 41.

[79] Based on the proposal set forth herein, the resulting G-J Locality ICAP Demand Curve reference point price for Load Zone G (Rockland County) is $14.57/kW-month for the 2021/2022 Capability Year, compared to $14.91 per kW-month for Load Zone G (Dutchess County). If SCR emissions control technology were removed from the recommended design for Load Zone G (Dutchess County) and all other components of the NYISO's proposal were to remain unaltered, the reference point price for Load Zone G (Dutchess County) would decrease to $13.33/kW-month for the 2021/2022 Capability Year. Thus, this revised value would represent the lowest reference point price of the locations evaluated for the G-J Locality ICAP Demand Curve and become the basis for such curve for the 2021-2025 DCR. *See* NYISO Final Recommendations at 60; and NYISO Affidavit at ¶ 25.

[80] Independent Consultant Final Report at 24-25; and NYISO Final Recommendations at 14.

[81] Independent Consultant Final Report at 26; and NYISO Final Recommendations at 14.

[82] Independent Consultant Final Report at 28; AG Affidavit at ¶ 41; BMCD Affidavit at ¶ 35; and NYISO Final Recommendations at 14-15. Comparatively, the synthetic minor approach for the gas-only peaking plant proposed for establishing the NYCA ICAP Demand Curve affords such unit to operate for approximately 1,060 hours annually.

[83] NYISO Final Recommendations at 14-15; and AG Affidavit at ¶ 25 and 41.

[84] Docket No. ER19-2276-000, *New York Independent System Operator, Inc.*, Proposed Tariff Revisions Regarding Establishment of Participation Model for Aggregations of Resources, Including Distributed Energy Resources (June 27, 2019); and *New York Independent System Operator, Inc.*, 170 FERC ¶ 61,033 (2020).

enhancements include adjustments to ICAP payments based on each resource's relative contribution to resource adequacy (*i.e.*, compensation designed to reflect the value of a resource from the perspective of reliability). The NYISO plans to implement these enhancements beginning with the 2021/2022 Capability Year (*i.e.*, the first Capability Year encompassed by the 2021-2025 DCR). Initially, resources must be capable of providing the energy equivalent of their ICAP obligation for at least 6 or 8 hours each day in order to be valued equivalent to a resource that is not subject to any daily run-time limitations (*i.e.*, qualify to receive 100% of the applicable ICAP payment). However, once the incremental penetration level of resources subject to daily run-time limitations exceeds 1,000 MW, only those resources that are capable of operating for at least 8 hours daily will be valued equivalent to a resource that is not subject to any daily run-time limitations. Ensuring the capability to operate 8 hours each day during the period of the Summer Capability Period when load levels tend to be greatest (June - August) would require the ability to operate for approximately 720 hours. The potential for the emissions cap applicable to a synthetic minor source to limit the operation of a dual fuel peaking plant in Load Zone G (Dutchess County) to as little as 312 hours annually does not support this level of resource availability.

The ongoing transition of the resource fleet in New York to greater reliance on weather-dependent renewable resources underscores the critical importance of flexible and controllable resources.[85] The availability of resources such as the peaking plant designs proposed herein will be critical to maintaining system reliability as this transition continues to unfold. Subjecting such resources to unnecessary operating limitations may adversely impact the availability of the flexible and controllable capability offered by such resources to meet system needs and assist with managing the greater variability introduced by a system with growing reliance on weather-dependent resources.

As further described in the following section, the inclusion of dual fuel capability for the peaking plant design used in establishing the G-J Locality ICAP Demand Curve remains appropriate. The Commission should not alter this feature of the proposed peaking plant design. Therefore, the peaking plant design for both the Dutchess County and Rockland County locations should remain a dual fuel plant equipped with SCR emissions control technology.

C. Dual Fuel Capability

The NYISO proposes to maintain the dual fuel capability assumptions approved by the Commission for the 2017-2021 DCR.[86] For the 2021-2025 DCR, the NYISO proposes continued inclusion of dual fuel capability for the peaking plants used to establish the G-J

[85] *See*, *e.g.*, NYISO, *Reliability and Market Considerations for a Grid in Transition* (December 20, 2019), available at: https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf.

[86] *See*, *e.g.*, 2017-2021 DCR Order at P 91.

Locality, NYC, and LI ICAP Demand Curves.[87] The NYISO also proposes continued use of a gas-only design for the peaking plant used to establish the NYCA ICAP Demand Curve.[88]

For NYC and LI, dual fuel capability is mandated and must be included in the proposed peaking plant designs for these regions.[89] Certain local electric reliability rules applicable to NYC and LI require dual fuel capability. Furthermore, in these locations, nearly all gas-fired generators are interconnected to local distribution company ("LDC") gas systems. LDC gas tariffs in NYC and LI require that gas-fired generators connected to the LDC system include dual fuel capability.

In contrast to NYC and LI, dual fuel capability is not explicitly mandated for the proposed peaking plant designs used in establishing the NYCA or G-J Locality ICAP Demand Curves. There are no mandatory dual fuel requirements imposed by local electric reliability rules for these locations. Additionally, although LDC gas tariffs throughout these regions do impose dual fuel requirements for gas-fired generators connected to LDC systems, generators in these areas may have viable options to interconnect to an interstate gas pipeline. Direct connection to an interstate gas pipeline would allow a gas-fired generator to bypass the imposition of dual fuel capability that would apply to an interconnection with a LDC system. Absent mandatory requirements, the NYISO considered additional factors in evaluating whether the appropriate peaking plant design should include dual fuel capability.

The NYISO proposes to retain use of gas-only peaking plant designs for Load Zones C and F.[90] This determination is consistent with considerations for the 2017-2021 DCR.[91] The upstate region of New York is far less geographically constrained than the lower Hudson Valley, NYC, and LI. This presents greater siting flexibility with broader availability of sites and infrastructure to accommodate the interconnection of a new gas-fired plant. The magnitude and severity of gas system constraints is also generally less acute than in the downstate region. This arises, in part, from the connection of gas supply lines in upstate New York to neighboring shale gas producing regions. Based on these factors, the NYISO proposes use of a gas-only peaking plant design in establishing the NYCA ICAP Demand Curve for the 2021-2025 DCR.

The NYISO proposes a different conclusion for the peaking plant design used in establishing the G-J Locality ICAP Demand Curve.[92] Since its inception, the G-J Locality ICAP

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[87] NYISO Final Recommendations at 15-16 and 59; Independent Consultant Final Report at 7 and 34-36; and AG Affidavit at ¶ 25 and 32-35.

[88] *Id*.

[89] NYISO Final Recommendations at 15; Independent Consultant Final Report at 35; and AG Affidavit at ¶ 32 and 35.

[90] NYISO Final Recommendations at 16; Independent Consultant Final Report at 35-36; and AG Affidavit at ¶ 25 and 35.

[91] *See*, *e.g.*, 2017-2021 DCR Filing at 18; and 2017-2021 DCR Order at P 95.

[92] NYISO Final Recommendations at 15-16; Independent Consultant Final Report at 35-36; and AG Affidavit at ¶ 32 and 35.

Demand Curve has used a dual fuel peaking plant design.[93] The conditions supporting this design remain the same for this DCR. The benefits of dual fuel capability in the downstate region, including the lower Hudson Valley, has not diminished since the last reset. In fact, the critical importance of maintaining appropriate incentives to encourage resource flexibility and availability to operate on fuel sources other than solely natural gas have grown. Therefore, the NYISO proposes continued inclusion of dual fuel capability as part of the peaking plant design used for the G-J Locality ICAP Demand Curve.

Certain stakeholders oppose the inclusion of dual fuel capability as part of the peaking plant design used for the G-J Locality ICAP Demand Curve. The Commission has considered the objections raised by these stakeholders in each of the last two resets. These stakeholders contend that in the absence of a mandatory dual fuel requirement for the lower Hudson Valley, such capability should only be included if the incremental energy market revenue that can be achieved for a particular Capability Year fully offsets the additional costs associated with the inclusion of dual fuel capability in the peaking plant design. The assessment of additional considerations, however, continues to support the inclusion of dual fuel capability for the G-J Locality ICAP Demand Curve.

The Commission's prior approval of including dual fuel capability for the peaking plant used in establishing the G-J Locality ICAP Demand Curve has considered multiple factors. These considerations include improved siting flexibility, enhancements to reliability and operational flexibility, and increased revenue earning opportunities when operation on natural gas becomes unavailable or uneconomic due to gas system constraints and competing demand for natural gas.[94]

The inclusion of dual fuel capability provides for increased siting flexibility for a gas-fired peaking plant in the lower Hudson Valley.[95] This enhanced flexibility is especially important for geographically constrained areas, such as the lower Hudson Valley. The increased flexibility provides opportunities for a developer to identify a location for a new generation facility that seeks to minimize both electric and gas interconnection costs. Notably, the DCR does not assume a particular gas interconnection option for any peaking plant (*i.e.*, LDC system connection, or direct connection to an interstate pipeline). Instead, the gas interconnection cost assumptions reflect generic site assumptions and are intended to represent a cost to reasonably accommodate either gas interconnection option.

The ability of pipeline developers to expand the capability of the gas pipeline system in New York remains challenging.[96] Absent expanded capability, competition for the use of natural gas to serve retail gas demands and electricity generation constrains the capability to

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[93] *See*, *e.g.*, 2014-2017 DCR Order at P 83; and 2017-2021 DCR Order at P 92-93.

[94] *Id*.

[95] NYISO Final Recommendations at 15; Independent Consultant Final Report at 35-36; and AG Affidavit at ¶ 32 and 35.

[96] Independent Consultant Final Report at 36; and AG Affidavit at ¶ 35.

simultaneously serve all such demand. The constrained nature of the gas system is generally greater in the downstate region than in upstate New York. In fact, the constrained nature of the gas system downstate and increasing levels of demand for natural gas resulted in certain LDCs imposing restrictions on service to new gas customers for periods during 2019.[97] These constraints underscore the benefits of being able to produce electricity using fuel sources other than natural gas.

This capability also enhances resilience and operational flexibility in maintaining system reliability. The NYISO recently conducted a comprehensive, forward-looking evaluation of fuel and energy security in New York.[98] The study did not identify any near-term reliability risks. The availability of dual fuel capability throughout the current resource fleet was a key contributing factor to the results. In fact, the study highlighted the importance of dual fuel capability to maintaining reliability throughout the ongoing transition to a clean energy system in New York.[99] The study specifically noted the critical importance of dual fuel capability in the downstate region. The study observed:

> Taking into consideration the demand for natural gas by LDCs for serving retail needs, there is simply not enough gas available for power generation under prolonged, severe cold winter conditions to ensure reliable operations, absent the ability of dual-fuel units to switch fuels. While these resources may operate economically - and to the advantage of electricity consumers - most of the year on available non-firm supplies of natural gas, under severe cold weather conditions LDC demand and other firm natural gas transportation commitments (including deliveries to neighboring regions) reduce available natural gas for power generation to levels below that needed for reliable system operations, absent the ability to switch to oil. Maintaining adequate dual fuel and other oil-fired operating capability is critical to reliable operations during adverse winter conditions, especially in the downstate region.[100]

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[97] *See*, *e.g.*, National Grid, *National Grid to Lift Natural Gas Moratorium Immediately for Customers in Brooklyn, Queens and Long Island* (November 25, 2019), available at: https://www.nationalgridus.com/News/2019/11/-National-Grid-to-Lift-Natural-Gas-Moratorium-Immediately-for-Customers-in-Brooklyn,-Queens-and-Long-Island.

[98] *See* NYISO Final Recommendations at 16; and AG, *Fuel and Energy Security in New York State - An Assessment of Winter Operational Risks for a Power System in Transition* (November 2019), available at: https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf ("2019 Fuel Security Study").

[99] 2019 Fuel Security Study at 70-74.

[100] *Id*. at 70-71.

In December 2019, the New York State Department of Environmental Conservation ("NYSDEC") adopted requirements to reduce smog-forming pollutants from simple-cycle combustion turbines ("NYSDEC Peaker Rule").[101] These generators (commonly referred as "peakers") typically operate to maintain reliability during the most stressful operating conditions, such as periods of peak electricity demand. The new regulation, which phases in compliance obligations between 2023 and 2025, affects approximately 3,300 MW of simple-cycle turbines located primarily in the lower Hudson Valley, NYC, and LI. The rule required affected generators to submit compliance plans to the NYSDEC in March 2020. Based on the compliance plans, the NYISO expects that, by May 1, 2025, approximately 1,800 MW of nameplate capacity will likely be unavailable to operate during the summer in order to comply with the rule's emissions requirements.[102] Notably, all but 85 MW of this capacity is either dual fuel or operates on a primary fuel source other than natural gas.[103] It is critically important to maintain appropriate incentives for dual fuel capability in light of the anticipated loss of this resource capability that has historically been available to operate on fuel sources other than natural gas during critical operating conditions.

Based on the foregoing, maintaining dual fuel capability as part of the peaking plant design used in establishing the G-J Locality ICAP Demand Curve remains appropriate and reasonable. The ongoing transition of the resource fleet in New York only serves to highlight the importance of this capability to helping maintain reliability over the coming years.

D. Peaking Plant Costs

The Services Tariff requires that the DCR assess "the localized levelized embedded cost of a peaking plant" used in establishing each ICAP Demand Curve. The Independent Consultant conducted a rigorous evaluation to develop estimates of the capital investments costs to construct the proposed peaking plant designs used for each ICAP Demand Curve.[104] The Independent Consultant also developed estimates of the fixed operations and maintenance ("O&M") and variable O&M costs associated with the ongoing operation of each such peaking plant.[105] The

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[101] 6 NYCRR Subpart 227-3, available at: https://www.dec.ny.gov/regulations/116131.html.

[102] *See* NYISO, *2020 RNA Report* at 12-15 (presented at the October 28, 2020 Management Committee meeting), available at: https://www.nyiso.com/documents/20142/16333532/06%202020%20RNA%20Presentation.pdf.

[103] *See* NYISO, *2020 Load & Capacity Data Report* at Table III-2, available at: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf.

[104] Independent Consultant Final Report at 36-59 and Appendix A; AG Affidavit at ¶ 19-24 and 28-29; and BMCD Affidavit at ¶ 10-20. The Independent Consultant developed cost estimates for generic sites within the following locations for each ICAP Demand Curve: (1) Load Zones C and F for the NYCA ICAP Demand Curve; (2) Load Zone G (Dutchess County) and Load Zone G (Rockland County) for the G-J Locality ICAP Demand Curve; (3) Load Zone J for the NYC ICAP Demand Curve; and (4) Load Zone K for the LI ICAP Demand Curve.

[105] Independent Consultant Final Report at 36-59 and Appendix A; and BMCD Affidavit at ¶ 10-20.

Independent Consultant developed the cost estimates based on BMCD's experience as a contractor, engineering design firm, and consultant in the power generation and energy storage industries. BMCD's experience includes recent work related to both power generation and energy storage projects in New York.[106]

The Independent Consultant developed the cost estimates based on a generic site in each location evaluated.[107] For all locations other than New York City, the Independent Consultant assumed use of a generic greenfield site.[108] For New York City, BMCD assumed use of a brownfield site.[109] The New York City cost estimate also includes an assumed need to raise the existing site elevation by 4 feet to comply with floodplain zoning requirements implemented following Hurricane Sandy.[110]

The NYISO has reviewed the Independent Consultant's cost estimates and considered stakeholder feedback relating thereto. The NYISO proposes to adopt the cost estimates developed by the Independent Consultant for the peaking plants proposed herein for use in establishing the ICAP Demand Curves.[111]

The following sections provide an overview of the cost estimates developed by the Independent Consultant. These sections also address certain concerns raised by stakeholders during the DCR regarding the cost estimates.

1. Capital Investment Costs

The capital investment costs include the installed cost of the peaking plant, owner's costs, and financing during construction. The installed cost estimates reflect use of an engineering, procurement, and construction ("EPC") contract.[112] EPC cost estimates were prepared for a generic site in each location evaluated and do not include preliminary engineering or development activities. Direct costs included within the EPC cost estimates include labor, materials, engineered equipment, subcontracts, and construction equipment.[113] The EPC cost estimates also include certain indirect costs such as construction management, engineering, startup activities, warranty, and other general administrative expenses.[114] The EPC cost

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[106] Independent Consultant Final Report at 36-39; and BMCD Affidavit at ¶ 15-20. [107]

Independent Consultant Final Report at 36-39; and AG Affidavit at ¶ 28-29. [108]

Independent Consultant Final Report at 37.

[109] *Id*. at 37-38.

[110] *Id*. 38.

[111] NYISO Final Recommendations at 17-24.

[112] Independent Consultant Final Report at 42, 45-47 and Appendix A; and BMCD Affidavit at ¶ 14-16.

[113] Independent Consultant Final Report at 42; and BMCD Affidavit at ¶ 15. [114]

Independent Consultant Final Report at 42.

estimates also include a 10% contingency applied to all direct and indirect project costs to account for uncertainties, as well as a 5% EPC contractor fee applied to all direct and indirect costs.[115]

2. Owner's Costs

The owner's costs consist of various categories of costs, including development activities, project management oversight, project engineering, permitting, legal fees, financing during construction, initial fuel inventory for dual fuel plant designs,[116] and emissions reduction credits ("ERCs").[117] The owner's cost also includes estimates for both electric and gas interconnections.[118] Owner's costs also include: (1) an assumed cost of 0.45% applied to all EPC costs for builder's risk insurance; and (2) a 5% contingency applied to all EPC and Owner's costs.[119]

Certain stakeholders contend that the owner's cost estimates are understated and do not appropriately account for certain costs of developing a new gas-fired generator in New York.[120] These stakeholders identified certain owner's cost line items from the 2017-2021 DCR and attempt to compare such line items to the costs developed by BMCD for this DCR.[121] Specific costs identified by such stakeholders include engineering, development, permitting, and financing fees during construction. It is important to recognize that cost categorization and methodology used by BMCD in this DCR differ from those used by a different engineering and design firm that was involved with the 2017-2021 DCR.[122] As a result, attempting to conduct a line-by-line comparison to the owner's cost estimate developed for the 2017-2021 DCR is likely

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[115] *Id*.

[116] For dual fuel plants, the initial fuel inventory provides the capability to operate the proposed peaking plants for 96 hours before needing to replenish the ULSD supply. This represents an onsite reserve to support round-the-clock operation on ULSD for four days (or the capability to operate on ULSD during on-peak periods for six days).

[117] Independent Consultant Final Report at 43-45 and Appendix A; and BMCD Affidavit at ¶ 16. For New York City, the peaking plant design assumes use of municipal water supply. The cost of a water line to the plant to connect to the municipal system is included in the owner's cost. For all other locations, BMCD assumed that the proposed peaking plants obtain water supply from an onsite well. The cost for such onsite well is included as part of the EPC cost estimate. *See* Independent Consultant Final Report at 45.

[118] Independent Consultant Final Report at 44-45. The electric and gas interconnection cost are intended to reflect "all-in" estimates that include development, engineering, permitting, procurement, equipment/materials, and construction. *See* BMCD Affidavit at ¶ 44.

[119] Independent Consultant Final Report at 43.

[120] BMCD Affidavit at ¶ 41-45.

[121] Notably, BMCD was not the engineering and design firm used for the 2017-2021 DCR. [122]

Id. at ¶ 42-44.

to produce inadvertently misleading results.[123] For example, for this DCR, the cost estimates developed for electrical and gas interconnections are intended to reflect "all-in" costs and include the costs related to development, engineering, permitting, procurement, and construction materials. The scope of work and components of project development addressed by the owner's cost estimates by each firm may also differ.[124]

In response to the concerns raised by stakeholders, BMCD conducted a comparative assessment of the aggregate total of the owner's cost components from the 2017-2021 DCR to the same costs for this DCR.[125] Comparing the costs on an aggregate basis provides a more informative comparison and mitigates the potential for inaccurate conclusions that can result merely from the use of divergent cost categorization approaches and methodologies by different engineering and design firms. After escalating the costs from the 2017-2021 DCR to current year dollar values, BMCD's evaluation identified very little divergence in costs.[126] In fact, the observed difference in aggregate owner's costs was only 0.3%.[127] BMCD's assessment also observed a difference of only 0.9% in aggregate total capital investment costs.[128]

Electric Interconnection

The electrical interconnection cost estimates include all necessary costs required to satisfy the Minimum Interconnection Standard.[129] For locations other than New York City, these costs include an assumed three-mile, overhead generator lead between the plant's switchyard and the point of interconnection ("POI").[130] For New York City, BMCD assumed a one-mile, underground interconnecting transmission line between the plant's switchyard and POI.[131] The Independent Consultant assumed that plant switchyards use air insulated switchgear ("AIS") in all locations, except New York City. For New York City, the Independent Consultant assumed the peaking plant's switchyard would include gas insulated switchgear ("GIS").[132]

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[123] *Id*. at ¶ 43.

[124] *Id*. at ¶ 44.

[125] *Id*. at ¶ 45. BMCD conducted this cost comparison using a dual fuel H-class frame turbine peaking plant equipped with SCR emissions control technology in Load Zone G (Dutchess County).

[126] BMCD Affidavit at ¶ 45.

[127] NYISO Final Recommendations at 18-19 and Appendix D; and BMCD Affidavit at ¶ 45. The total difference in owner's cost estimates was less than $200,000 after escalating the estimates from the 2017-2021 DCR to 2020 dollar values.

[128] BMCD Affidavit at ¶ 45.

[129] Independent Consultant Final Report at 44 and Appendix A. These costs include developer attachment facilities, system upgrade facilities, and connecting transmission owner attachment facilities. The estimated cost of the generator step-up transformer is included in the EPC cost estimate.

[130] Independent Consultant Final Report at 44.

[131] *Id*.

[132] *Id*.

The NYISO conducted an assessment to determine whether any of the proposed peaking plants would incur System Deliverability Upgrade ("SDU") costs to obtain Capacity Resource Interconnection Service ("CRIS").[133] The assessment concluded that the proposed peaking plants for each location could be constructed without a need to incur SDU costs.[134]

Gas Interconnection

For locations other than New York City, the gas interconnection cost estimate consists of two components: (1) an estimated cost of $3.5 million for a metering and regulation station; and (2) an estimated average gas lateral cost of $250,000 per inch diameter per mile.[135] Based on its prior experience with gas laterals for generation facilities, BMCD assumed a 5-mile, 16-inch diameter lateral for the peaking plants proposed herein.[136]

For New York City, the estimated gas interconnection assumes a 1-mile, 16-inch diameter lateral for the proposed peaking plant.[137] The total estimated cost of the gas lateral for New York City is $20 million, consisting of a $5 million estimated cost for a metering and regulation station and $15 million for the 1-mile lateral.[138] The lateral costs reflect the reasonable expectation of the increased costs associated with constructing a lateral within New York City.[139]

Certain stakeholders contend that the average per inch diameter per mile costs for a gas lateral are understated, especially in the lower Hudson Valley. The Independent Consultant carefully considered this feedback and conducted additional reviews of its estimated costs during the DCR.[140] Based on the results of its supplemental evaluations, BMCD adjusted its preliminary cost estimates for all locations.[141]

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[133] NYISO Final Recommendations at 16-17. As required by the Commission, the NYISO conducted the deliverability assessment under the tariff-prescribed level of excess conditions used for the DCR. *See*, *e.g.*, 2011-2014 DCR Order at P 53.

[134] NYISO Final Recommendations at 17; and Independent Consultant Final Report at 44.

[135] Independent Consultant Final Report at 45 and Appendix A; and BMCD Affidavit at ¶ 36. [136]

Independent Consultant Final Report at 45; and BMCD Affidavit at ¶ 36.

[137] *Id*.

[138] *Id*.

[139] BMCD Affidavit at ¶ 36. The $15 million lateral cost effectively represents an implicitly higher per inch diameter per mile cost to reflect the greater difficulty of constructing a gas pipeline in New York City.

[140] BMCD Affidavit at ¶ 37; and NYISO Final Recommendations at 19.

[141] *Id*.

For locations other than New York City, BMCD initially assumed an estimated lateral cost of $180,000 per inch diameter per mile.[142] In response to stakeholder concerns, BMCD conducted a further reviewed based on its recent project experience and a review of cost estimates for five recent projects in or near New York.[143] The set of projects reviewed included two recent gas lateral connections for generators interconnected to New York, as well as three interstate pipeline projects.[144] The average per inch diameter per mile costs observed for these projects ranged from approximately $100,000 to $500,000.[145] The average linear cost for these projects was approximately $260,000 per inch diameter per mile.[146] The two gas lateral projects included as part of the assessment established the highest and lowest values within the dataset. Based on the results of the supplemental analysis, BMCD concluded it was reasonable to adjust its initial assumption. As a result, BMCD increased the assumed linear cost of a gas lateral to $250,000 per inch diameter per mile.[147]

3. Fixed O&M

Fixed O&M costs generally address fixed plant expenses not affected by the operation of the plant.[148] Fixed O&M consists of two components: (1) fixed plant expenses (*e.g.*, plant staff labor, routine maintenance, safety equipment, building and grounds maintenance, and administrative and general expenses); and (2) fixed non-operating expenses (*e.g.*, site leasing costs, property taxes, and insurance).[149]

Property Taxes

The property tax treatment for the proposed peaking plants varies by location.[150] The recommended property tax treatment for New York City varies from all other locations due to the availability of a statutorily provided tax abatement. For all other locations, the recommended

[142] NYISO Final Recommendations at 19.

[143] Independent Consultant Final Report at 45; BMCD Affidavit at ¶ 37; and NYISO Final Recommendations at 19.

[144] BMCD Affidavit at ¶ 37; and NYISO Final Recommendations at 19. The supplemental analysis included consideration of costs for the following projects: (1) CPV Valley Millennium Pipeline [gas lateral connection for a generator]; (2) Bayonne Lateral Delivery project [gas lateral connection for a generator]; (3) the Northern Access pipeline project [interstate pipeline project]; (4) the Constitution pipeline project [interstate pipeline project]; and (5) PennEast pipeline project [interstate pipeline project].

[145] BMCD Affidavit at ¶ 37; and NYISO Final Recommendations at 19.

[146] *Id*. Exclusion of the highest and lowest observed linear costs for the dataset produced an average linear cost of approximately $240,000 per inch diameter per mile.

[147] BMCD Affidavit at ¶ 37; and NYISO Final Recommendations at 19.

[148] Independent Consultant Final Report at 48-51; BMCD Affidavit at ¶ 18; and NYISO Final Recommendations at 24.

[149] Independent Consultant Final Report at 48-51.

[150] Independent Consultant Final Report at 50-51; and NYISO Final Recommendations at 29-31.

property tax rate assumes the proposed peaking plant will enter into a payment in lieu of taxes ("PILOT") agreement.

The peaking plant used in establishing the NYC ICAP Demand Curve qualifies for an as-of-right tax abatement pursuant to New York State Real Property Tax law.[151] The statutory tax abatement applies for the first 15 years of the assumed amortization period for the peaking plant. For the remaining duration of the assumed amortization period, the assumed property tax rate is 4.7%.[152]

For locations other than New York City, the applicable property tax rate assumes that each peaking plant will enter into a PILOT agreement.[153] The assumed property tax rate for locations other than New York City is 0.5%.[154] The Independent Consultant developed this rate based on a review of PILOT payment data for eight gas-fired generators in various locations through New York outside of New York City.[155]

Land Lease Costs

Consistent with the methodology used in the last two resets, BMCD initially derived the assumed land lease costs based on escalating the values used in the 2017-2021 DCR.[156] The resulting land lease cost assumptions are as follows: (1) $22,000 per acre-year for Load Zones C, F, G (Dutchess County), and G (Rockland County); (2) $26,000 per acre-year for Long Island; and (3) $270,000 per acre-year for New York City.[157]

Certain stakeholders have raised concerns with the assumed land lease costs for New York City. For the New York City peaking plant, BMCD assumed a land lease cost of $270,000 per acre-year.[158] To support their concerns that the estimated land lease value was understated, certain stakeholders submitted recently conducted real estate appraisals for certain utility properties within New York City.[159] The estimated land lease costs based on such appraisals were approximately double BMCD's proposed land lease cost for New York City. In response to these estimates, BMCD conducted a supplemental evaluation to determine whether the

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[151] New York Real Property Tax Law § 489-BBBBBB(3)(b-1).

[152] Independent Consultant Final Report at 51; and NYISO Final Recommendations at 29-30.

[153] Independent Consultant Final Report at 50-51; and NYISO Final Recommendations at 30-31.

[154] *Id*.

[155] *Id*.

[156] Independent Consultant Final Report at 49.

[157] *Id*.

[158] Independent Consultant Final Report at 49; BMCD Affidavit at ¶ 38-40; and NYISO Final Recommendations at 24.

[159] Independent Consultant Final Report at 49; and BMCD Affidavit at ¶ 38-40.

assumed value (*i.e.*, $270,000 per acre-year) was reasonable or potentially required adjustment.[160]

BMCD's supplemental analysis reviewed data regarding property values for more than 15 representative sites and estimated lease rates relating thereto from a variety of sources.[161] The data sources used included: (1) property tax values for properties adjacent to existing generation facilities within New York City; (2) the stakeholder-provided appraisals; (3) recent market transaction data; and (4) quotes previously obtained by BMCD through discussions with property owners in New York City as part of work conducted for other power generation and energy storage projects in New York City.[162] The supplemental evaluation showed a high level of variability in potential lease costs for representative sites in New York City. The estimated lease costs for the sites evaluated ranged from $10,000 per acre-year to $1 million per acre-year.[163] BMCD's supplemental evaluation included nine sites in New York City adjacent to existing power plants.[164] The average land lease cost estimated for these sites was approximately $160,000 per acre-year.[165] Based on the variability observed, BMCD concluded that the assumed land lease cost of $270,000 per acre-year is reasonable for purposes of this DCR.[166] Given observations of significantly lower costs than the appraisal data for the specific sites provided by stakeholders, the recommended value is consistent with the expectation that a developer in a competitive market would seek to lower its overall costs to the extent practicable.

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[160] Independent Consultant Final Report at 49; BMCD Affidavit at ¶ 19 and 38-40; and NYISO Final Recommendations at 24 and Appendix C.

[161] BMCD Affidavit at ¶ 38-39; and NYISO Final Recommendations at Appendix C.

[162] BMCD Affidavit at ¶ 19 and 38-39; and NYISO Final Recommendations at Appendix C. [163]

BMCD Affidavit at ¶ 39-40; and NYISO Final Recommendations at Appendix C.

[164] BMCD Affidavit at ¶ 39.

[165] BMCD Affidavit at ¶ 39-40; and NYISO Final Recommendations at Appendix C.

[166] BMCD Affidavit at ¶ 40. The NYISO evaluated the potential impact of differing land lease cost assumptions for New York City on the resulting reference point price for the NYC ICAP Demand Curve for the 2021/2022 Capability Year. Increasing the assumed land lease cost to $350,000 per acre-year (*i.e.*, a value that is approximately equal to the average lease cost for sites used in BMCD's supplemental analysis) would result in a $22.75/kW-month reference point price for the 2021/2022 Capability Year NYC ICAP Demand Curve (*i.e.*, an increase of $0.39/kW-month compared to the NYISO's proposal). Utilizing an assumed land lease cost of $540,000 per kW-month (*i.e.*, double the recommended value and similar to the value advocated by stakeholders opposing the recommended value) would increase the reference point price of the NYC ICAP Demand Curve for the 2021/2022 Capability Year to $23.67/kW-month (*i.e.*, an increase of $1.31/kW-month compared to the NYISO's proposal). *See* NYISO Affidavit at ¶ 26.

4. Variable O&M

Variable O&M costs directly relate to the operation of each peaking plant and the production of electricity.[167] These costs include routine equipment maintenance, water usage, water treatment, water disposal, and other consumables including fuel. For peaking plant designs that include SCR emissions control technology, variable O&M costs also include ammonia and catalyst replacements.

Variable O&M also includes major maintenance costs. For the proposed peaking plant designs, major maintenance typically includes turbine, hot gas path, and major inspections. The Independent Consultant assumed recovery of major maintenance costs primarily on a per start basis.[168]

The variable O&M costs and operational and performance specifications for the proposed peaking plants are utilized in estimating the potential revenues such plants could earn from participation in the NYISO-administered Energy and Ancillary Services markets.

IV. Net Energy and Ancillary Services Revenue Estimates

The Services Tariff requires that the DCR assess the likely net energy and ancillary services ("EAS") revenues that a peaking plant could potentially earn from participation in the NYISO-administered markets.[169] The estimated net EAS revenues serve as an offset to the estimated cost to construct and operate a peaking plant. The resulting net value determines the revenue a peaking plant would need to receive from the capacity market to obtain sufficient revenues to support market entry under the tariff-prescribed level of excess conditions.

The estimated net EAS revenues are determined using historical data.[170] The NYISO uses the most recent three years of historical market prices and fuel and other variable operating costs, along with the operating characteristics of the peaking plant, to estimate the potential revenue earnings for each peaking plant. This approach assumes that the estimated average annual net EAS revenues a peaking plant could have earned over the most recent three-year period provides a reasonable estimate of forward-looking expectations. The NYISO updates

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[167] Independent Consultant Final Report at 52-53 and Appendix A; BMCD Affidavit at ¶ 18; and NYISO Final Recommendations at 23-24.

[168] Independent Consultant Final Report at 52-53 and Appendix A. [169]

Services Tariff § 5.14.1.2.2.

[170] *See* Services Tariff § 5.14.1.2.2.2; Docket No. ER16-1751-000, *New York Independent System Operator, Inc.*, Proposed Services Tariff Revisions to Implement Enhancements to the Periodic Reviews of the ICAP Demand Curves at 5-7 (May 20, 2016) ("DCR Process Enhancements Filing"); and *New York Independent System Operator, Inc.*, 156 FERC ¶ 61,039 at P 16 (2016) ("DCR Process Enhancements Order").

these estimates pursuant to the tariff-prescribed annual updating procedures to ensure that the ICAP Demand Curves incorporate changes in market outcomes over time.[171]

A. Net EAS Model

The Services Tariff requires the development of a model to determine the net EAS revenues estimates for each peaking plant.[172] This model is commonly referred to as the "Net EAS Model."

The Independent Consultant, in collaboration with stakeholders and the NYISO, developed the Net EAS Model for use during the 2021-2025 DCR.[173] The proposed Net EAS Model for the 2021-2025 DCR is substantially similar to the Net EAS Model approved by the Commission for the last reset.[174] The revisions to the prior model's commitment and dispatch logic for the 2021-2025 DCR relate to: (1) the manner in which the model applies gas prices in estimating each peaking plant's variable operating cost to produce electricity;[175] and (2) the assumed cost for dual fuel peaking plants to provide Operating Reserves.[176] The NYISO further describes each of these changes to the model's commitment and dispatch logic below.

To enhance transparency and accessibility of the Net EAS Model to stakeholders, the Independent Consultant developed the model for the 2021-2025 DCR using "R" programming language, which is a free, open source software.[177] Comparatively, the 2017-2021 DCR Net EAS Model used "SAS" software that requires obtaining a license to use.

The NYISO proposes to adopt the Net EAS Model developed by the Independent Consultant.[178] The Net EAS Model developed during the DCR is posted on the NYISO website and publicly available to all interested parties.[179] The NYISO used the model in determining the 2021/2022 Capability Year ICAP Demand Curves proposed herein. Subject to updating certain data inputs as required by the tariff prescribed annual updates, the Net EAS Model remains fixed

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[171] *See*, *e.g.*, *New York Independent System Operator, Inc.*, 156 FERC ¶ 61,039 at P 27 (2016); and 2017-2021 DCR Order at P 166.

[172] Services Tariff § 5.14.1.2.2.2.

[173] AG Affidavit at ¶ 42-52.

[174] *See* 2017-2021 DCR Filing at 22-25; and 2017-2021 DCR Order at P 17, n. 27, and 166.

[175] NYISO Final Recommendations at 32-33 and Appendix B; and AG Affidavit at ¶ 51.

[176] NYISO Final Recommendations at 37 and Appendix A, p. 8-10; Independent Consultant Final Report at 80; and AG Affidavit at ¶ 46.

[177] NYISO Final Recommendations at 33. [178]

Id. at 31-33.

[179] Services Tariff § 5.14.1.2.2.2. The Net EAS Model is contained within a zip folder titled "2020-09-09-Report Final Fossil Model" available at: https://www.nyiso.com/installed-capacity-market. From this page, the model can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Final Models and Materials."

for the duration of the 2021-2025 DCR.[180] The NYISO will use this same model in conducting the annual updates to determine the ICAP Demand Curves for the 2022/2023 through 2024/2025 Capability Years.

As previously noted, this DCR was the first to assess energy storage technology as a potential peaking plant. Participation by energy storage in the market is fundamentally different than fossil-fired generators. As a result, the Independent Consultant developed a separate Net EAS Model for the energy storage technology options assessed in this DCR.[181] Due to the availability of lower cost alternatives, the NYISO does not recommend battery storage as the peaking plant in any location for the 2021-2025 DCR.[182] As a result, the NYISO does not propose adoption of the Net EAS Model developed for energy storage resources as part of this filing.[183]

1. General Overview of Net EAS Model

The Net EAS Model determines the estimated annual net EAS revenues each peaking plant could potentially earn based on 36 months of historical data on market prices and variable costs.[184] Generally, for each hour of the historical period, the model determines whether each peaking plant should be committed and dispatched to produce Energy or provide Operating Reserves based on a consideration of historical energy and reserve prices (both as adjusted to account for the tariff-prescribed level of excess conditions), variable operating costs (*i.e.*, fuel and emission allowance prices, non-fuel variable costs, and start-up costs), and the operational characteristics of the peaking plant. The model considers both Day-Ahead and real-time commitment and dispatch opportunities, while respecting the physical operating characteristics of the peaking plant. This includes the ability of the peaking plant to buy-out of a previously determined Day-Ahead commitment in real-time to the extent it would be economically advantageous for the plant to do so, as well as the ability to produce Energy or provide Operating Reserves in real-time in the absence of a prior Day-Ahead commitment. For peaking plants that include dual fuel capability, the model also accounts for such capability through considering whether it is less expensive to operate using natural gas or ULSD.

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[180] Services Tariff § 5.14.1.2.2.2.

[181] Independent Consultant Final Report at 83-90; AG Affidavit at ¶ 53-58; and NYISO Final Recommendations at 38-43.

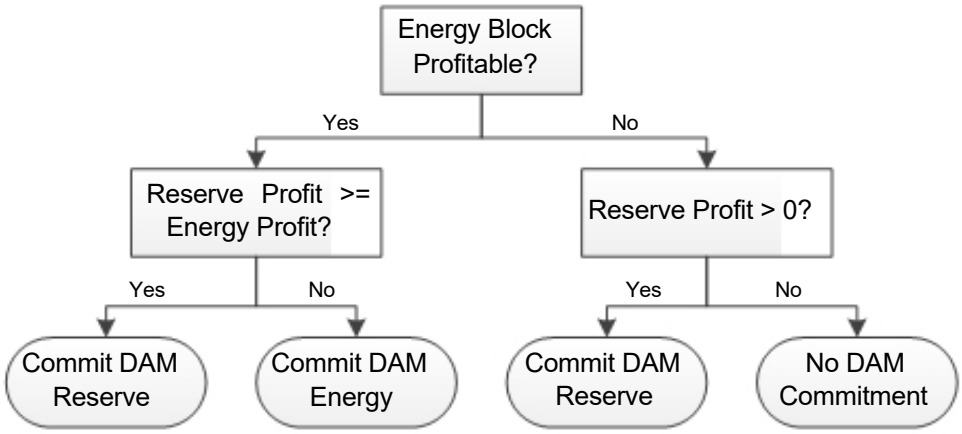
[182] NYISO Final Recommendations at 59; Independent Consultant Final Report at 7; and AG Affidavit at ¶ 25 and 31.

[183] For informational purposes, however, the alternative model developed for energy storage is posted on the NYISO's website and publicly available. This version of the model is contained within a zip folder titled "2020-09-09-Report Final Battery Model" available at: https://www.nyiso.com/installed-capacity-market. From this page, the model can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Final Models and Materials."

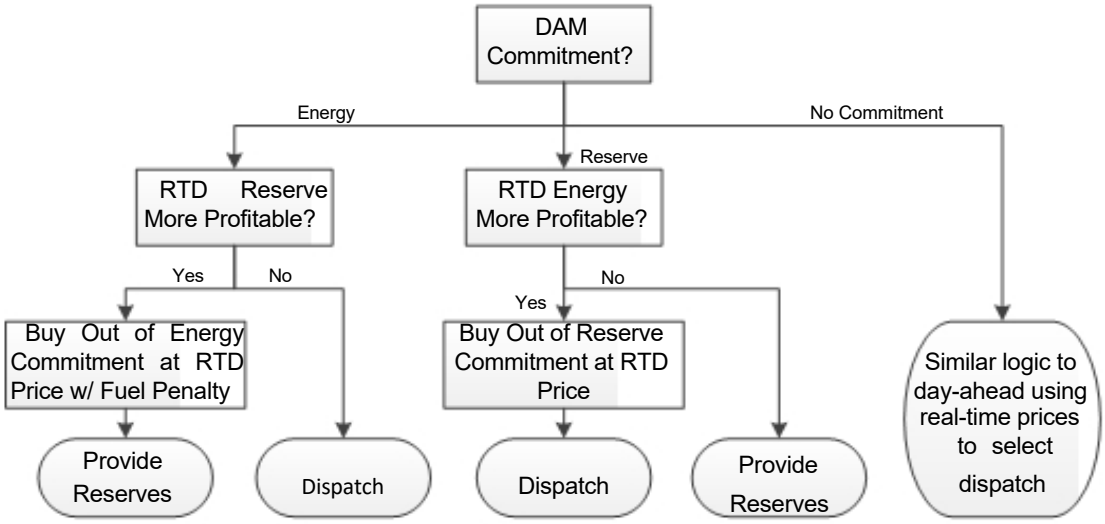
[184] Independent Consultant Final Report at 77-83 and 90-99; AG Affidavit at ¶ 42-52; and NYISO Final Recommendations at 31-33 and 36-38.

The figures below provide an overview of the commitment and dispatch logic of the proposed Net EAS Model.[185]

Net EAS Revenues Model Day-Ahead Commitment Logic



Net EAS Revenues Model Real-Time Commitment and Dispatch Logic



The model also accounts for any operating hour restrictions or emissions limitations imposed on the peaking plant to comply with applicable environmental requirements.[186] These limitations are essentially applied after-the-fact. The model will first determine the optimal dispatch of the peaking plant for a given 12-month period (*i.e.*, September through August). If the optimal dispatch exceeds a specified annual operating limitation, the model will then reduce the number of hours that it determined the peaking plant would otherwise produce Energy to ensure compliance with the specified limitation. In doing so, the model reduces the hours in which the peaking plant would otherwise produce Energy by eliminating the hours with the

[185] Independent Consultant Final Report at 81.

[186] *Id*. at 79-80; and AG Affidavit at ¶ 50.

lowest level of net Energy revenues first. The model continues eliminating hours based on increasing values of net Energy revenues earned in each hour until it has eliminated a sufficient number of hours to ensure compliance with the specified limitation.

An adder to reflect expected revenues for Ancillary Services not accounted for in the model increases the net EAS revenues determined by the model.[187] The value of this adder for the proposed peaking plants is $2.04 per kW-year. This adder accounts for likely voltage support service ("VSS") revenues.[188]

2. Gas Price Alignment Logic

The preliminary Net EAS Model developed as part of the DCR included logic that shifted forward by one day the gas price published for a specific date by S&P Global Market Intelligence ("SPGMI") (*i.e.*, the data vendor proposed by the NYISO as the source of gas price data for the 2021-2025 DCR).[189] This logic was based on an understanding that the gas prices published by SPGMI represented the "trade day" price (or the day before the generator would take delivery of and use the gas to produce electricity).[190]

Certain stakeholders raised concerns that this gas pricing alignment logic was inappropriate and instead produced a misalignment between the gas price used for a specific electric operating day and the natural gas costs a unit would face on such operating day. In response to such concerns, the NYISO and Independent Consultant conducted an additional review of the gas price data published by SPGMI. This supplemental review confirmed that the data published by SPGMI actually represents the "flow day" price (or the day the generator would take delivery of and use the gas to produce electricity).[191]

Due to the incorrect understanding of the gas pricing data, the pricing alignment logic included in the preliminary Net EAS Model for the 2021-2025 DCR was, in fact, unnecessary. The initial gas price alignment logic incorrectly assumed that SPGMI was posting "trade day" prices. As a result, the logic shifted the gas price forward by one day in an unnecessary attempt

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[187] Services Tariff § 5.14.1.2.2.2.

[188] Independent Consultant Final Report at 90; AG Affidavit at ¶ 50; and NYISO Final Recommendations at 57.

[189] This same logic was previously included in the Net EAS Model developed for the 2017-2021 DCR. *See* Docket No. ER21-130-000, *New York Independent System Operator, Inc.*, Exigent Circumstances Filing Requesting Authority Under Section 205 of the Federal Power Act to Address Prospectively a Gas Pricing Logic Alignment Issue Affecting the Net Energy and Ancillary Services Revenue Offset Values Embedded in the 2017-2021 Installed Capacity Demand Curves, Request for Shortened Notice and Comment Period, Request for Expedited Action, Notice of Intent to Implement, and Contingent Request for Commission Action Under Section 206 of the Federal Power Act (October 16, 2020); and Docket No. ER21-130-000, *supra*, Letter Order (October 22, 2020).

[190] NYISO Final Recommendations at 32-33 and Appendix B; and AG Affidavit at ¶ 51. [191]

NYISO Final Recommendations at 33; and AG Affidavit at ¶ 51.

to align the gas price with the electric market day on which the peaking plant would use such gas.[192]

The Independent Consultant and NYISO updated the Net EAS Model for the 2021-2025 DCR to remove the unnecessary gas pricing alignment logic.[193] The updated model uses the gas prices published for a particular date for the same electricity market day that the peaking plant receives delivery of such gas. For any day on which gas price data is not published by SPGMI (*e.g.*, weekends and holidays), the updated model utilizes the next available day on which a gas price is published as the applicable price for the day(s) on which prices are not published by SPGMI. For example, for a non-holiday weekend, the Net EAS Model uses the gas price published by SPGMI on Monday as the applicable gas price for Saturday, Sunday, and Monday.

The 2021/2022 Capability Year ICAP Demand Curves proposed herein were determined using the final, updated version of the model. This version of the model, which the NYISO proposed to adopt for the 2021-2025 DCR, appropriately reflects removal of the prior, unnecessary gas pricing alignment logic.[194]

3. Operating Reserve Cost for Dual Fuel Peaking Plants

The Net EAS Model includes an assumed cost for a peaking plant to take a reserve position.[195] The preliminary model developed for the 2021-2025 DCR assumed a cost to provide reserves equal to the intraday premium for acquiring natural gas, which varies from 10-30% depending on location.

Analysis conducted by the MMU identified that the preliminary model likely overstated the assumed cost to provide reserves, especially for peaking plant designs that include dual fuel capability.[196] The MMU analyzed historical reserve offers by dual fuel resources in Load Zones J and K.[197] Based on the MMU's analysis, the Independent Consultant updated the final version of the Net EAS Model for the 2021-2025 DCR to include an assumed cost to provide reserves of $2.00 per MWh for the proposed dual fuel peaking plants (*i.e.,* Load Zone G (Dutchess County), Load Zone G (Rockland County), NYC, and LI).[198] For gas-only peaking plants (*i.e.*, Load

[192] NYISO Final Recommendations at Appendix B.

[193] NYISO Final Recommendations at 33 and Appendix B; and AG Affidavit at ¶ 51.

[194] *Id*.

[195] NYISO Final Recommendations at 37-38; Independent Consultant Final Report at 80; and AG Affidavit at ¶ 46.

[196] NYISO Final Recommendations at Appendix A, p. 8-10.

[197] *Affidavit of Pallas LeeVanSchaick, Ph.D.* at ¶ 40-44 attached hereto as Attachment VI ("MMU Affidavit").

[198] NYISO Final Recommendations at 37; Independent Consultant Final Report at 80; AG Affidavit at ¶ 46; and MMU Affidavit at ¶ 40-44.

Zones C and F), the final Net EAS Model retains use of the intraday premium for determining the cost to provide reserves.[199]

The 2021/2022 Capability Year ICAP Demand Curves proposed herein were determined using the final, update version of the model. This version of the model, which the NYISO proposed to adopt for the 2021-2025 DCR, reflects the updated assumptions regarding the cost for a peaking plant to provide reserves.

B. Natural Gas Pricing Assumptions

The DCR requires the selection of appropriate data sources for fuel prices.[200] The representative fuel pricing for each location remains fixed for the duration of the reset period.[201] For natural gas prices, this includes both the data source from which the applicable historical prices are determined, as well as the appropriate natural gas hub pricing point(s) for each peaking plant location. Consistent with the 2017-2021 DCR, the NYISO proposes continued use of gas pricing data from SPGMI.[202]

As further described herein, the proposed gas hub for each location was determined based on the consideration of multiple factors. The NYISO's proposed gas pricing for each location is as follows: (1) Load Zone C: the Tennessee Gas Pipeline ("TGP") Zone 4 (200 leg) hub for April through November and the Niagara hub for December through March; (2) Load Zone F: the Iroquois Zone 2 hub; (3) Load Zone G (Dutchess County): the Iroquois Zone 2 hub; (4) Load Zone G (Rockland County): the Texas Eastern Transmission Pipeline ("TETCO") M3 hub; (5) NYC: the Transco Zone 6 NY hub; and (6) LI: the Iroquois Zone 2 hub.[203]

The selection of the appropriate gas hub for each location requires careful consideration because, for nearly all locations, there are multiple available options. Consistent with the 2017-2021 DCR, the Independent Consultant used a multi-factor assessment to determine the appropriate natural gas hub pricing for each location.[204] The criteria considered by the assessment were: (1) market dynamics (*i.e.*, correlation of gas hub prices with LBMPs for the relevant location and the extent to which the gas hub prices reflect New York electricity market dynamics); (2) the liquidity (*i.e.*, selected gas hubs should have sufficient historical data to assess historical trading volumes); (3) geographic proximity (*i.e.*, the selected gas hubs should be located in an area that is accessible to a peaking plant in a particular location); and (4)

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[199] NYISO Final Recommendations at 37; Independent Consultant Final Report at 80; and AG Affidavit at ¶ 46.

[200] Services Tariff § 5.14.1.2.2.2.

[201] *Id*.

[202] NYISO Final Recommendations at 57; and Independent Consultant Final Report at 90.

[203] NYISO Final Recommendations at 33-36 and Appendix A, p. 14-19 and 20-23.

[204] NYISO Final Recommendations at 33-36; Independent Consultant Final Report at 90-99; and AG Affidavit at ¶ 59-60.

precedent/continuity (*i.e.*, assessing the extent to which gas hub options for a particular location have been used in other NYISO-related studies and evaluations).[205]

Use of multiple considerations facilitates the identification of a reasonable and representative gas hub for each location that seeks to avoid material under or over estimating the potential revenue earnings of each peaking plant. This analysis also recognizes the potential need for trade-offs and balancing among the criteria in the selection of an appropriate gas hub. Therefore, strict reliance on a single factor is not appropriate and may result in sub-optimal outcomes. For example, in certain locations, marginal energy prices may often reflect the costs of resources from other areas. As a result, solely assessing market dynamics and correlation to historical energy prices may not accurately capture the gas prices applicable to units in such areas.[206] Additionally, overly strict application of the geographic proximity criteria may fail to accurately capture the dynamics of the gas market and the potential availability of multiple gas supply sourcing arrangements for generators in a given location.

Notably, the selection of an appropriate gas hub for each location does not presume any particular gas purchasing strategy by each peaking plant. Instead, the analysis seeks to identify appropriate pricing that is designed to produce reasonable estimates of the potential energy market revenue earnings for each peaking plant. The analysis recognizes that a generator may have a variety of gas purchasing options available to accommodate its acquisition of the fuel necessary to operate.[207] These options could potentially include contracting arrangements with gas marketers or other entities that hold firm gas transportation rights, short-term purchases of firm capacity releases, and/or the potential use of interruptible gas transmission service.

1. Load Zone C

The NYISO proposes to use a combination of two different gas hubs for Load Zone C for the 2021-2025 DCR.[208] This proposal recognizes historically observed availability constraints during the winter period that may adversely affect the use of a single hub throughout the year. Specifically, the NYISO proposes to adopt the recommendation of the MMU that relies on: (1) the TGP Zone 4 (200 leg) hub outside the winter period (*i.e.*, April through November); and (2) the Niagara hub during the winter period when availability constraints are most likely to limit accessibility to prices consistent with the TGP Zone 4 (200 leg) hub (*i.e.*, December through March).

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[205] NYISO Final Recommendations at 33-34; Independent Consultant Final Report at 90-92; and AG Affidavit at ¶ 59-60.

[206] The 2018 and 2019 State of the Market Reports identified that generators located in central New York (which includes Load Zone C) were only marginal in 20-35% of all real-time intervals during 2018 and 2019. Therefore, during the majority of intervals, resources located in other areas of the State set the prices for this region. *See* NYISO Final Recommendations at Appendix A, p. 18.

[207] Independent Consultant Final Report at 91-92; and MMU Affidavit at ¶ 17, 22, 27-30 and 38.

[208] NYISO Final Recommendations at 34-35; NYISO Affidavit at ¶ 11-14; and MMU Affidavit at ¶ 10-23.

An evaluation conducted by the MMU was a primary consideration in recommending the use of the TGP Zone 4 (200 leg) hub for Load Zone C.[209] The MMU's analysis compared the expected dispatch of gas-fired generators located in Load Zone C using various potential gas hub pricing options to the actual historical operation of such units.[210] The MMU's analysis concluded that use of TGP Zone 4 (200 leg) served as reasonably accurate predictor of historical operations. As a result, the MMU recommended TGP Zone 4 (200 leg) as an appropriate proxy for gas pricing faced by units in Load Zone C.

The NYISO's proposal differs slightly from the Independent Consultant's recommended gas pricing for Load Zone C. The Independent Consultant recommended use of only the TGP Zone 4 (200 leg) for Load Zone C.[211] Subsequent to the Independent Consultant's issuance of its final recommendation, as reflected in the interim version of its final report issued on August 5, 2020, the MMU completed supplemental analysis evaluating whether the TGP Zone 4 (200 leg) was appropriate for use at all times throughout the year.[212] The MMU's supplemental analysis was conducted in response to concerns raised by certain stakeholders as to the availability of gas from TGP Zone 4 (200 leg) during winter months. The MMU's additional analysis identified the presence of historical availability concerns that may prevent a peaking plant located in Load Zone C from accessing gas from TGP Zone 4 (200 leg) during the winter months.[213]

Due to the potential for TGP Zone 4 (200 leg) to be unavailable to a peaking plant in Load Zone C during the winter months, the MMU recommended use of an alternative pricing hub for the winter period (*i.e.*, December through March).[214] Absent use of an alternative pricing hub during the winter, the MMU noted the potential for the Net EAS Model to unnecessarily overestimate the potential revenue earnings of a peaking plant in Load Zone C during the winter period when it would most likely face gas prices in excess of the prices at the TGP Zone 4 (200 leg) hub.[215] After reviewing various alternative pricing hubs for the winter period, the MMU recommended the use of the Niagara hub as an appropriate alternative that avoids the potential

[209] Independent Consultant Final Report at 95; AG Affidavit at ¶ 64; NYISO Final Recommendations at 34; NYISO Affidavit at ¶ 11; and MMU Affidavit at ¶ 13-15.

[210] NYISO Final Recommendations, Appendix A, p. 14-15; AG Affidavit at ¶ 64; and MMU Affidavit at ¶ 13.

[211] Independent Consultant Final Report at 95-96; and AG Affidavit at ¶ 64.

[212] NYISO Final Recommendations at 34-35 and Appendix A, p. 15-19; NYISO Affidavit at ¶ 11; and MMU Affidavit at ¶ 16-23.

[213] NYISO Final Recommendations at 34-35 and Appendix A, p. 16-18; NYISO Affidavit at ¶ 11-13; and MMU Affidavit at ¶ 16-21.

[214] NYISO Final Recommendations at 34-35; NYISO Affidavit at ¶ 13; and MMU Affidavit at ¶ 15, 20-21 and 23.

[215] NYISO Final Recommendations at Appendix A, p. 16-18; and MMU Affidavit at ¶ 14-15 and 21.

for materially overstating or understating the expected revenue earnings of a peaking plant in Load Zone C.[216]

Certain stakeholders object to the NYISO's proposal to use the Niagara hub for Load Zone C during the winter months. These stakeholders advocate for adopting the Independent Consultant's recommendation to use only the TGP Zone 4 (200 leg) hub for the entire year.[217] These stakeholders raise concerns regarding: (1) the opportunity afforded to adequately consider the Niagara hub during the DCR; and (2) the liquidity of trading the Niagara hub.

Certain stakeholders contend that the Niagara hub was not introduced for potential consideration until late in the DCR process, claiming this effectively limited the ability to fully consider use of the Niagara hub in the stakeholder process required by the DCR. These stakeholders contend that potential use of the Niagara hub was not discussed prior to the MMU's submission of comments on August 24, 2020 in response to NYISO staff's draft recommendations.[218]

Contentions that: (1) the Niagara hub was not discussed in the stakeholder process prior to comments submitted in response to NYISO staff's draft recommendations; and/or (2) stakeholders were not afforded an adequate opportunity to present positions regarding the potential use of the Niagara hub, are not accurate. The MMU initially submitted comments addressing potential gas pricing considerations on February 26, 2020.[219] The MMU's comments specifically recommended consideration of the Niagara hub as a potential option for Load Zone C.[220] The Independent Consultant reviewed an assessment of potential gas hubs with stakeholders at the March 26, 2020 ICAPWG meeting. This assessment included consideration of the Niagara hub as a potential candidate for Load Zone C.[221] On August 5, 2020, the MMU

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[216] NYISO Final Recommendations at 34-35; NYISO Affidavit at ¶ 12-13; and MMU Affidavit at ¶ 10-11 and 23.

[217] The NYISO's recommendation for Load Zone C results in a proposed reference point price for the NYCA ICAP Demand Curve of $8.62 per kW-month for the 2021/2022 Capability Year. The resulting reference point price for the 2021/2022 Capability Year ICAP Demand Curve using the Independent Consultant's recommended gas hub for Load Zone C was $8.22 per kW-month. *See* NYISO Final Recommendations at 5; Independent Consultant Final Report at 9; and NYISO Affidavit at ¶ 27.

[218] *See* Potomac Economics, *MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations* (August 24, 2020), available at: https://www.nyiso.com/documents/20142/14871137/MMU-2020-DCR-Draft-Report-Comments-08-24-2020.pdf.

[219] Potomac Economics, *Comments regarding the Gas Pricing Hubs used in the Net Revenue Analysis for the 2020 Demand Curve Reset* (February 26, 2020), available at: https://www.nyiso.com/documents/20142/14871137/MMU-2020-DCR-Draft-Report-Comments-08-24-2020.pdf.

[220] *Id*. at 2.

[221] *See* AG, *NYISO 2019/2020 ICAP Demand Curve Reset: Continued Modeling Discussions* at 21-22 (presented at the March 26, 2020 ICAPWG meeting), available at:

also submitted comments expressly noting that it was continuing to evaluate the Independent Consultant's recommendation to use the TGP Zone 4 (200 leg) hub as the gas pricing for Load Zone C. These comments specifically informed stakeholders that the MMU intended to provide supplemental analysis and its recommended gas pricing for Load Zone C for consideration as part of the NYISO staff's final recommendations.[222] On August 24, 2020, the MMU submitted comments in response to NYISO staff's draft recommendations. In these comments, the MMU presented its supplemental analysis regarding the appropriate gas pricing for Load Zone C and the recommendation to use the Niagara hub for the winter period (*i.e.*, December through March).[223]

After consideration of the feedback provided in response to its draft recommendations, NYISO staff issued its final recommendations on September 9, 2020. At the September 22, 2020 ICAPWG meeting, the NYISO reviewed its final recommendations and highlighted aspects that differed from the Independent Consultant's final report and NYISO staff's draft recommendations. The NYISO expressly noted the proposed change in gas pricing for Load Zone C.[224] Following issuance of NYISO staff's final recommendations, stakeholders were also afforded the opportunity to: (1) submit written feedback to the Board; and (2) present oral comments to the Board. Stakeholders addressed the NYISO's proposed gas pricing for Load Zone C and the use of the Niagara hub in both written and oral comments to the Board. Based on the foregoing, stakeholders were: (1) notified that the Niagara hub was being evaluated as a potential candidate for Load Zone C; and (2) afforded the opportunity to present their positions on this hub during the DCR.

Certain stakeholders also raised concerns regarding the liquidity of trading at the Niagara hub. These stakeholders contend that level of trading activity raises concerns about its appropriateness for use in establishing the NYCA ICAP Demand Curve.[225] In response to these concerns, the NYISO conducted supplemental analysis regarding the relative level of trading at

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https://www.nyiso.com/documents/20142/11554944/Final%20AG%20DCR%20ICAPWG%2003262020.pdf.

[222] Potomac Economics, *MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and the Forthcoming Draft of NYISO Staff DCR Recommendations* at 2 and 11 (August 5, 2020), available at: https://www.nyiso.com/documents/20142/13609298/MMU-2020-DCR-Draft-Report-Comments.pdf.

[223] Potomac Economics, *MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations* at 2 and 10-15 (August 24, 2020), available at: https://www.nyiso.com/documents/20142/14871137/MMU-2020-DCR-Draft-Report-Comments-08-24-2020.pdf.

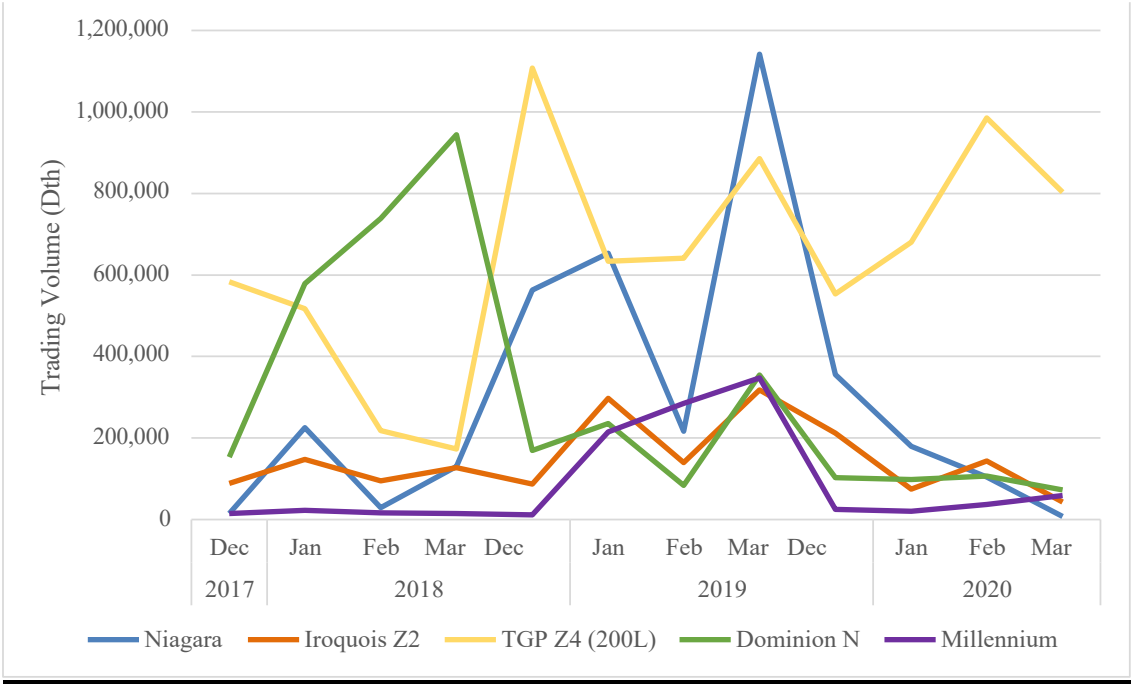
[224] NYISO, *2021-2025 ICAP Demand Curve Reset: NYISO Staff Final Recommendations* at 7-10 (presented at the September 22, 2020 ICAPWG meeting), available at: https://www.nyiso.com/documents/20142/15473217/2019-2020%20NYISO%20Staff%20Final%20Recommendations.pdf.

[225] NYISO Affidavit at ¶ 14.

the Niagara hub, as well as the availability of gas price data for the Niagara hub.[226] To ensure that the analysis properly aligned with the data proposed for use in the 2021-2025 DCR, the supplemental analysis utilized data published by SPGMI (*i.e.*, the proposed data vendor for gas pricing) and focused on the winter period (*i.e.*, December through March) when the hub is proposed for use.

As shown in the figure below, the NYISO's supplemental analysis identified that the trading volumes at the Niagara hub during the winter months for the historical three-year data period used in determining the 2021/2022 Capability Year ICAP Demand Curves was comparable and certain instances greater than trading at other gas hubs considered for Load Zone C (*i.e.*, TGP Zone 4 (200 leg) and Dominion North) or other locations (*i.e.*, Iroquois Zone 2 and Millennium).[227] In addition, the NYISO's review of gas price data confirmed that SPGMI published a gas price for the Niagara hub on all days from December through March on which gas prices were published for the three-year period used in determining the 2021/2022 Capability Year ICAP Demand Curves (*i.e.*, September 1, 2017 through August 31, 2020).[228]

Trading Volume Comparison for Various Gas Hubs Considered in the 2021-2025 DCR



[226] *Id.*

[227] *Id.*

[228] *Id.* Gas price indices, including SPGMI, typically do not publish daily spot gas prices on weekends and holidays.

The NYISO's supplemental analysis demonstrates that the Niagara hub exhibits sufficient liquidity and pricing availability to support its use for the winter period (*i.e.*, December through March).

To appropriately account for the concerns identified by the MMU regarding the accessibility of gas from TGP Zone 4 (200 leg) to a peaking plant in Load Zone C during the winter months when availability constraints are most likely to arise, the NYISO proposes to use the Niagara hub as reasonable proxy for gas pricing likely to be experienced by the peaking plant during such winter months. Use of the Niagara hub during the winter months helps to reduce the potential for unnecessarily overestimating potential revenue earnings by a peaking plant in Load Zone C when gas from TGP Zone 4 (200 leg) may not be readily accessible.

2. Load Zone F

The NYISO proposes continued use of the Iroquois Zone 2 hub to represent the appropriate gas pricing for a peaking plant in Load Zone F.[229] The Commission approved use of this same gas hub for Load Zone F for the 2017-2021 DCR.[230] Selection of Iroquois Zone 2 reflects strong market dynamics, liquidity, and recognition that various other studies use this hub as a proxy for Load Zone F gas costs.[231] Iroquois Zone 2 also represents a geographically appropriate selection for gas accessible to a peaking plant in Load Zone F.

It is important to note that for the 2021-2025 DCR, the NYISO proposes that a peaking plant located in Load Zone C serve as the basis for the NYCA ICAP Demand Curve.[232]

3. Load Zone G (Dutchess County)

The NYISO proposes to use the Iroquois Zone 2 hub as the representative gas pricing for a peaking plant in Load Zone G (Dutchess County).[233] The Iroquois Zone 2 hub represents a reasonably accessible gas source for gas-fired generation located east of the Hudson River. The hub also represents sufficient liquidity and consistency with electric market pricing dynamics.[234]

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[229] NYISO Final Recommendations at 35-36; Independent Consultant Final Report at 95; and AG Affidavit at ¶ 62.

[230] 2017-2021 DCR Filing at 29; and 2017-2021 DCR Order at P 153.

[231] NYISO Final Recommendations at 35-36; and Independent Consultant Final Report at 93, 95 and 97.

[232] NYISO Final Recommendations at 59 and Appendix A, p. 13-14; Independent Consultant Final Report at 116; and AG Affidavit at ¶ 25.

[233] NYISO Final Recommendations at 35; Independent Consultant Final Report at 95; and AG Affidavit at ¶ 62.

[234] NYISO Final Recommendations at 35; and Independent Consultant Final Report at 93, 95 and 97.

The Commission previously approved use of the Iroquois Zone 2 hub for Load Zone G (Dutchess County) in the 2017-2021 DCR based on consideration of these same factors.[235]

Notably, for the 2021-2025 DCR, the NYISO proposes that a peaking plant located in Load Zone G (Rockland County) serve as the basis for the G-J Locality ICAP Demand Curve.[236]

4. Load Zone G (Rockland County)

The NYISO proposes to refine the approach used for the 2017-2021 DCR by separately evaluating gas hubs for each location evaluated in the lower Hudson Valley.[237] The 2017-2021 DCR proposed a single hub to represent Load Zone G rather than separately evaluating gas hubs for Load Zone G (Dutchess County) and Load Zone G (Rockland County).[238]

The proposal to identify separate hubs for each of the locations evaluated in Load Zone G better represents the gas pricing dynamics and pipeline system configuration in the lower Hudson Valley. Separately evaluating the representative gas pricing for Load Zone G (Rockland County) recognizes that locations west of the Hudson River in the lower Hudson Valley (*e.g.*, Rockland County) have ready access to gas pipelines connected to nearby shale gas producing regions that exhibit different market pricing from locations east of the Hudson River (*e.g.*, Dutchess County).

The NYISO proposes use of the TETCO M3 hub as the appropriate proxy for gas pricing likely faced by a peaking plant located in Load Zone G (Rockland County).[239] Notably, the use of separate hubs for each location evaluated in Load Zone G is consistent with the approach used in the 2014-2017 DCR. The 2014-2017 DCR also used Iroquois Zone 2 for Load Zone G (Dutchess County) and TETCO M3 for Load Zone G (Rockland County).[240]

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[235] 2017-2021 DCR Filing at 29-30; and 2017-2021 DCR Order at P 153-157.

[236] NYISO Final Recommendations at 59; Independent Consultant Final Report at 116; and AG Affidavit at ¶ 25. As further described in Section IV.B.4, certain stakeholders advocate for the use of an alternative gas hub for Load Zone G (Rockland County). While the NYISO maintains that its proposal to use TETCO M3 for Load Zone G (Rockland County) is reasonable and appropriate, use of alternative, higher cost hubs (*e.g.*, Iroquois Zone 2 or Algonquin Citygates) as advocated for by certain stakeholders would result in a change to the basis for the G-J Locality ICAP Demand Curve for the 2021-2025 DCR. Either higher priced alternative hub would result in the reference point price for Load Zone G (Rockland County) exceeding the reference point price for Load Zone G (Dutchess County). As a result, adoption of either such alternative would result in use of Load Zone G (Dutchess County) as the basis for the G-J Locality ICAP Demand Curve. *See* NYISO Affidavit at ¶ 27.

[237] Independent Consultant Final Report at 95.

[238] 2017-2021 DCR Filing at 29-30; and Independent Consultant Final Report at 95.

[239] NYISO Final Recommendations at 35-36 and Appendix A, p. 20-23; Independent Consultant Final Report at 95; AG Affidavit at ¶ 63; and MMU Affidavit at ¶ 24-39.

[240] *See* 2017-2021 DCR Filing at 29, n. 126.

Although the TETCO M3 hub is not located within Rockland County, it is geographically appropriate because of connections to other pipelines (*e.g.*, Millennium and Algonquin) that could accommodate deliveries of gas from TETCO M3 into Rockland County.[241] TETCO M3 also exhibits sufficient liquidity and representation of market dynamics recognizing the gas pricing differentials that can arise for different locations in the lower Hudson Valley.[242]

Certain stakeholders contend that the TETCO M3 hub is not an appropriate pricing representation for Load Zone G (Rockland County) due to pipeline constraints and the potential for very limited availability of interruptible transportation service to accommodate deliveries from TETCO M3 into Rockland County. Such stakeholders advocate for use of either the Iroquois Zone 2 hub or the Algonquin Citygates hub as the appropriate proxy for gas pricing in Load Zone G (Rockland County).[243] In response to these concerns, the MMU conducted a supplemental analysis to evaluate the historical availability of capacity on the Algonquin pipeline to facilitate deliveries from TETCO M3 into Rockland County.[244] The MMU's analysis identified that: (1) sufficient transportation capacity is generally available throughout the year to accommodate deliveries on the Algonquin pipeline into Rockland County; (2) the constraints most likely to arise on Algonquin occur downstream of the portions of the pipeline that would serve to deliver gas into Rockland County; and (3) the use of an alternative gas hub, such as the Iroquois Zone 2 hub, would not provide a reasonable estimate of the likely expected revenue earnings of a peaking plant in Load Zone G (Rockland County).[245]

Stakeholders opposing the use of the TETCO M3 hub further contend that the MMU's supplemental analysis does not appropriately account for the actual availability of interruptible service on the Algonquin pipeline to accommodate deliveries into Rockland County. These stakeholders contend that very limited interruptible service is available on the Algonquin pipeline based on evaluations of additional nomination cycle information that includes further nominations of firm service that would take priority over interruptible service. These arguments appear to: (1) misunderstand the purpose of the MMU's analysis; and (2) inaccurately assume that the DCR requires the peaking plant to rely solely on the use of interruptible transmission service.

As previously noted, the DCR does not assume that a peaking plant utilizes any particular gas supply arrangement. Rather, the assessment of the appropriate proxy gas pricing for each location recognizes that a peaking plant has a variety of options for securing natural gas. One such option may be sole reliance on the availability of interruptible service. However, this is not the only option that may be available. In fact, a peaking plant may reasonably pursue other

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[241] NYISO Final Recommendations at 35 and Appendix A, p. 20; AG Affidavit at ¶ 63; and MMU Affidavit at ¶ 25-34.

[242] Independent Consultant Final Report at 93, 95 and 97; and AG Affidavit at ¶ 63. [243]

NYISO Affidavit at ¶ 27.

[244] NYISO Final Recommendations at 35 and Appendix A, p. 20-23; and MMU Affidavit at ¶ 26-37.

[245] NYISO Final Recommendations at Appendix A, p. 20-23; and MMU Affidavit at ¶ 26-39.

arrangements to obtain gas supply, including acquisition of secondary transportation service through arrangements with gas marketers or other entities that may have already secured firm transportation and have unused portions of such rights available at various times.[246]

The MMU's assessment of pipeline capacity utilization more appropriately accounts for the potential availability of capability to accommodate gas deliveries to a peaking plant rather than solely focusing on a single gas supply procurement option (*i.e.*, interruptible service).[247] As demonstrated by the MMU's analysis, pipeline capacity remains available at most times to accommodate the delivery of gas from the TETCO M3 hub to Rockland County. Therefore, use of the TETCO M3 hub as the representative gas pricing for Load Zone G (Rockland County) is appropriate and reasonable.[248]

5. NYC

The NYISO proposes to retain use of the Transco Zone 6 NY hub as the appropriate proxy for gas pricing in NYC.[249] The Commission approved the use of this same hub for NYC in the 2017-2021 DCR.[250] The selection of Transco Zone 6 NY recognizes that it is the geographically appropriate hub. The hub exhibits strong liquidity and consistency with electric market dynamics in Load Zone J, and is widely used as the appropriate proxy for NYC gas pricing across various studies.[251]

6. LI

The NYISO proposes to use the Iroquois Zone 2 hub as the appropriate proxy for gas pricing on Long Island.[252] The Iroquois Zone 2 hub reflects a geographically appropriate selection of gas supply available to a peaking plant on LI.[253] The hub is a sufficiently liquid

[246] MMU Affidavit at ¶ 27-30.

[247] MMU Affidavit at ¶ 26-39.

[248] During those very limited periods when gas constraints may make gas procured at TETCO M3 uneconomic or unavailable, the NYISO's proposal to include dual fuel capability as part of the peaking plant design provides a readily available alternative fuel option to accommodate operation during such periods. *See* NYISO Final Recommendations at Appendix A, p. 20; and MMU Affidavit at ¶ 33.

[249] NYISO Final Recommendations at 36; Independent Consultant Final Report at 95; and AG Affidavit at ¶ 61.

[250] 2017-2021 DCR Filing at 29; and 2017-2021 DCR Order at P 153.

[251] NYISO Final Recommendations at 36; Independent Consultant Final Report at 94-95 and 98; and AG Affidavit at ¶ 61.

[252] NYISO Final Recommendations at 35-36; Independent Consultant Final Report at 95; and AG Affidavit at ¶ 62.

[253] NYISO Final Recommendations at 35-36; and Independent Consultant Final Report at 98.

pricing location that exhibits appropriate consistency with electric market pricing for Load Zone K.[254]

C. Level of Excess Adjustments

The Services Tariff mandates that net EAS revenue estimates for each peaking plant reflect the tariff-prescribed level of excess conditions.[255] Consistent with the methodology approved by the Commission for the 2014-2017 DCR and the 2017-2021 DCR, the NYISO proposes to account for this requirement by using level of excess adjustment factors ("LOE-AFs").[256] The net EAS Model multiplies historical energy and reserve prices by the relevant LOE-AF values to approximate market outcomes under the tariff-prescribed level of excess conditions.[257]

The LOE-AF values are determined using production cost modeling simulations to determine projected LBMPs based on current (or "as found") system conditions and LBMPs under system conditions that reflect the tariff-prescribed level of excess conditions.[258] The LOEAF values are determined by dividing the projected LBMPs under the tariff-prescribed level of excess conditions by the projected LBMPs under "as found" system conditions.[259]

Consistent with the methodology used for the 2017-2021 DCR, GE Consulting conducted the production cost modeling using its Multi Area Production Simulation ("GE-MAPS") software program. The relevant LBMPs for each case were determined for the calendar years related to this reset (*i.e.*, 2021-2025) using the 2019 Congestion Assessment Resource Integration Study ("CARIS") Phase 1 base case dataset. In response to stakeholder feedback, the NYISO adjusted the dataset to reflect: (1) changes to certain resource additions and retirements; and (2) updated peak load forecast values based on the data set forth in the 2020 Load & Capacity Data report.[260]

Certain stakeholders contend that the NYISO should also revise the 2019 CARIS Phase 1 dataset to reflect the potential impacts of the NYSDEC Peaker Rule. As further described in Section III.C above, the new regulation, which phases in compliance obligations between 2023

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[254] NYISO Final Recommendations at 35-36; Independent Consultant Final Report at 94 and 98; and AG Affidavit at ¶ 62.

[255] Services Tariff §§ 5.14.1.2.2 and 5.14.1.2.2.2; and NYISO Affidavit at ¶ 15.

[256] 2014-2017 DCR Filing at 28; 2014-2017 DCR Order at P 2 and 165; 2017-2021 DCR Filing at 34-35; and 2017-2021 DCR Order at P 163.

[257] NYISO Final Recommendations at 43-45; NYISO Affidavit at ¶ 16-17; Independent Consultant Final Report at 100-101 and Appendix C; and AG Affidavit at ¶ 48-49.

[258] NYISO Final Recommendations at 43-44; NYISO Affidavit at ¶ 17; Independent Consultant Final Report at 100-101; and AG Affidavit at ¶ 49.

[259] *Id*.

[260] NYISO Final Recommendations at 43-44; and NYISO Affidavit at ¶ 17-18.

and 2025, affects approximately 3,300 MW of simple-cycle turbines located primarily in the lower Hudson Valley, NYC, and LI. The rule required affected generators to submit compliance plans to the NYSDEC in March 2020. Based on the compliance plans, the NYISO expects that by May 1, 2025 approximately 1,800 MW of nameplate capacity could be unavailable to operate during the summer in order to comply with the rule's emissions requirements.

The NYISO does not recommend adjusting the 2019 CARIS Phase 1 dataset based on the recently submitted compliance plans for purposes of calculating LOE-AF values for the 2021-2025 DCR.[261] Incorporating the potential resource impacts reflected in the compliance plans is likely to produce LOE-AF values that do not accurately reflect the anticipated system conditions throughout the historical data periods used in developing the ICAP Demand Curves. For each Capability Year, the net EAS revenue offset values used in determining the ICAP Demand Curves reflects the most recent three years of historical data.[262] For the 2021-2025 DCR, only a small portion of the data used in developing the ICAP Demand Curves for the last Capability Year (*i.e.*, the 2024/2025 Capability Year) covered by this reset period would reflect the potential impacts to resource availability due to the NYSDEC Peaker Rule. For the 2024/2025 Capability Year ICAP Demand Curve, only 4 months (*i.e.*, May through August 2023) of the 36 months used would reflect expected resource unavailability resulting from the initial implementation of the emissions requirements imposed by the NYSDEC Peaker Rule.[263] Developing LOE-AF values based on potential system conditions that may exist during only 4 months of the historical dataset to be used over the course of the entire reset period would not properly reflect the system conditions expected over this period.

It is also unclear whether simply modeling the resource impacts reflected in the compliance plans would be an accurate reflection of expected system conditions beginning on May 1, 2023.[264] The ongoing 2020 Reliability Needs Assessment ("RNA") has identified certain resource adequacy and transmission security violations that, in part, reflect the potential impacts on resource availability based on the compliance plans submitted in response to the NYSDEC Peaker Rule.[265] Potential solutions to the identified reliability concerns have not yet been determined and could ultimately affect the expected future system conditions.[266] Notably, there

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[261] NYISO Final Recommendations at 44-45 and Appendix A, p. 11-13; and NYISO Affidavit at ¶ 18-21.

[262] Services Tariff § 5.14.1.2.2.2.

[263] NYISO Final Recommendations at 45 and Appendix A, p. 12-13; and NYISO Affidavit at ¶ 20-21.

[264] NYISO Final Recommendations at 44-45 and Appendix A, p. 12; and NYISO Affidavit at ¶ 19-20.

[265] *See* NYISO Affidavit at ¶ 20; and NYISO, *2020 RNA Report* at 17, 21 and 23-25 (presented at the October 28, 2020 Management Committee meeting), available at: https://www.nyiso.com/documents/20142/16333532/06%202020%20RNA%20Presentation.pdf.

[266] *See* NYISO Affidavit at ¶ 20; and *2020 RNA Report* at 35 (presented at the October 28, 2020 Management Committee meeting), available at: https://www.nyiso.com/documents/20142/16333532/06%202020%20RNA%20Presentation.pdf.

are also projects currently proceeding through the NYISO's interconnection process that could serve to replace capacity of the affected generators.[267] In addition, the NYSDEC Peaker Rule includes allowance for an affected resource to remain in service temporarily beyond the specified compliance deadlines if the resource is needed to avoid a reliability issue pending the implementation of a permanent solution to such reliability need.[268]

Based on these considerations, the NYISO's proposal to exclude the potential impacts of the compliance plans submitted in response to the NYSDEC Peaker Rule from the modeling assumptions used for determining LOE-AF values is reasonable and appropriate for the 2021-2025 DCR.

D. Use of Historical Market Data

Certain stakeholders contend that the ICAP Demand Curves for the 2021-2025 DCR should exclude historical data from the 12-month period of September 1, 2019 through August 31, 2020. These stakeholders advocate for eliminating the use of data from this period due to the energy market impacts of the ongoing COVID-19 pandemic.

The Services Tariff does not provide the NYISO authority to discard historical data periods required to be used in developing the ICAP Demand Curves. Specifically, Section 5.14.1.2.2.2 mandates the that the NYISO determine the estimated energy market revenues earnings for each peaking plant using the most recent three years of data for the period ending August 31st of the calendar year immediately prior to the date on which the ICAP Demand Curves become effective. For purposes of the 2021/2022 Capability Year, this provision requires use of historical data for the period from September 1, 2017 through August 31, 2020. Similarly, the provision also mandates use of data from the September 1, 2019 through August 31, 2020 period in determining the ICAP Demand Curves for 2022/2023 and 2023/2024 Capability Years.[269]

In addition, excluding certain data periods undermines the purpose of implementing the historical method for estimating potential market revenue earnings by each peaking plant.[270] The implementation of a historical methodology was designed to improve transparency, predictability, and reflect the impacts of actual market conditions in estimating the potential energy market revenue earnings for each peaking plant. The impacts of the ongoing COVID-19

[267] These projects did not meet the necessary requirements for inclusion in the 2020 RNA base case. *See* NYISO Affidavit at ¶ 20.

[268] *See* 6 NYCRR Part 227-3.6; and NYISO Affidavit at ¶ 20.

[269] The applicable historical data period used in determining the 2022/2023 Capability Year ICAP Demand Curves is September 1, 2018 through August 31, 2021. The 2023/2024 Capability Year ICAP Demand Curves require use of historical data for the period from September 1, 2019 through August 31, 2022.

[270] *See* NYISO Final Recommendations at 45-46; DCR Process Enhancements Filing at 5-7; and DCR Process Enhancements Order at P 16.

pandemic on energy market outcomes are actual events that should be reflected in the data used for establishing the ICAP Demand Curves. Other events, such as severe cold weather events and heat waves, can have material impacts on market outcomes. It is important to recognize that these types of events have occurred in the past and been incorporated in the estimated revenue earnings for peaking plants (*e.g.*, the polar vortex during the 2013-2014 winter, and the bomb cyclone and extended Northeast cold snap during the 2017-2018 winter).

The NYISO and stakeholders explicitly considered the potential for relatively short duration conditions to impact market outcomes and projections of potential revenue earnings. The requirement to develop estimated revenue earnings using three years of historical data was specifically designed to help mitigate the potential for undue impacts from short duration events.[271] Developing these estimates using three years of data aids in reducing the impacts of shorter-term market fluctuations that may otherwise unnecessarily influence the resulting projections.

V. ICAP Demand Curve Parameters

The key parameters necessary for establishing the ICAP Demand Curves are: (i) the maximum allowable price of capacity; (ii) the reference point price; and (iii) the point at which the price of capacity declines to zero (commonly referred to as the zero-crossing point).

A. Levelized Fixed Charge and Financial Parameters

The Services Tariff requires that the DCR assess "the current localized levelized embedded cost of a peaking plant" for each ICAP Demand Curve.[272] This requires the translation of the estimated up-front capital investment costs for each peaking plant, including property tax and insurance, into an annualized level. Among other factors, such as depreciation, this translation accounts for: (i) the assumed weighted average cost of capital ("WACC") required by a developer of the peaking plant to recover its up-front investments costs, plus a reasonable return on that investment; (ii) the term in years over which the developer is assumed to recover its up-front investment costs (commonly referred to as the "amortization period"); and (iii) the applicable tax rates.[273] The WACC is derived from a series of financial parameters related to the development of the peaking plant, including the required return on equity ("ROE"), the cost of debt ("COD"), and the capital structure for the project (as reflected in the ratio of debt to equity ["D/E ratio"]).

The Independent Consultant developed the parameters necessary to translate the up-front investment costs of the peaking plant for each ICAP Demand Curve into an annualized level based on an assessment of relevant data and information, as well as its reasoned judgment and

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[271] DCR Process Enhancements Filing at 7.

[272] Services Tariff § 5.14.1.2.2.

[273] NYISO Final Recommendations at 25-29; Independent Consultant Final Report at 60-74; and AG Affidavit at ¶ 65.

experience.[274] The Independent Consultant designed the parameters to reflect the particular financial risks faced by a developer given the nature of the peaking plant and the New York electricity market context.[275] The Independent Consultant selected the parameters in an integrated fashion due to the interrelationship of the various parameters.[276]

The NYISO proposes to adopt the parameter values recommended by the Independent Consultant.[277] The Independent Consultant's recommended WACC is 9.54%.[278] The Independent Consultant calculated the recommended WACC based on the following assumptions: (1) ROE of 13%; (2) COD of 6.7%; and (3) D/E ratio of 55/45.[279]

1. Return on Equity

The NYISO proposes to adopt the Independent Consultant's recommended ROE of 13%.[280] The Independent Consultant determined the proposed ROE based consideration of various data sources reflecting different potential financing structures for developing a new peaking plant.

The Independent Consultant utilized these various data sources to identify a range of potential ROE values. The data sources included ROE values for publicly traded independent power producers ("IPPs") based on the capital asset pricing model ("CAPM"). This analysis identified ROE values ranging up to 10.5%.[281] The asset portfolios of the companies evaluated include regulated utilities and generation assets, as well as power generation projects with multi-year power purchase agreements.[282] Accordingly, the ROE values for these companies may not fully account for the risk of developing a new peaking plant in New York. Therefore, the Independent Consultant expanded its analysis to consider data and information regarding potential ROE values required to support a stand-alone project finance approach to developing a new peaking plant in New York. The additional information identified ROE values for a stand-alone project finance structure ranging from approximately 12% to 20%.[283] Lastly, the

[274] Independent Consultant Final Report at 60-61; and AG Affidavit at ¶ 65-67.

[275] *Id*.

[276] *Id*.

[277] NYISO Final Recommendations at 25-29.

[278] NYISO Final Recommendations at 25; Independent Consultant Final Report at 70-71; and AG Affidavit at ¶ 25, 70-73 and 79-82.

[279] NYISO Final Recommendations at 25; Independent Consultant Final Report at 63-71; and AG Affidavit at ¶ 25, 65-67 and 70-82.

[280] NYISO Final Recommendations at 26; Independent Consultant Final Report at 67-69; and AG Affidavit at ¶ 70-73 and 76-77.

[281] Independent Consultant Final Report at 67-68; and AG Affidavit at ¶ 76.

[282] *Id*.

[283] Independent Consultant Final Report at 68; and AG Affidavit at ¶ 76.

Independent Consultant considered ROE values recently approved by the Commission as part of similar capacity market valuations in neighboring markets. These values ranged from 12.8% to 13.8%.[284]

Certain stakeholders advocate for use of a higher ROE value contending that the recommended ROE does not appropriately account for the risks of merchant generation investment in New York. Other stakeholders contend that the recommended ROE value is inflated based on consideration of typical ROEs for regulated utilities and a reasonable adder to such values to account for the additional risk attributable to merchant development.

The recommended value reflects a balance between the lower bound of the values observed for IPPs and the higher end of the range observed for stand-alone project finance values.[285] As a result, the recommended 13% value provides for a reasonable and appropriate balancing of the range of ROE values observed.

2. Cost of Debt

The Independent Consultant recommended use of a 6.7% COD.[286] The NYISO proposes to adopt this recommendation as a reasonable and appropriate value based on the analysis conducted by the Independent Consultant.[287]

Certain stakeholders advocate for a higher COD value contending that the recommended value does not adequately account for the risk of investment in a new gas-fired generator in New York. These stakeholders also contend that the recommended value does not account for the cost of hedging instruments that a developer would likely be required to execute to obtain financing. Other stakeholders, including the MMU, recommend use of a lower COD value based on consideration of recent market data.

The Independent Consultant based its recommended value on market data regarding the debt cost for generic B-rated corporate debt, as well as consideration of debt costs incurred by certain IPPs over the past three years.[288] The COVID-19 pandemic has created significant volatility in the financial markets. This volatility has resulted in significant changes in the cost debt over the past year. For example, the debt costs for B-rated firms rose to more than 12% in March 2020 before declining to approximately 6.6% in July 2020 when the Independent Consultant finalized its recommendations.[289] The Independent Consultant recognized that the debt costs could potentially decline further as the financial markets continue to adjust to the

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[284] Independent Consultant Final Report at 68.

[285] Independent Consultant Final Report at 67-69; and AG Affidavit at ¶ 76-77. [286]

Independent Consultant Final Report at 65-67; and AG Affidavit at ¶ 70-75. [287]

NYISO Final Recommendations at 26.

[288] Independent Consultant Final Report at 65-67; and AG Affidavit at ¶ 74-75.

[289] Independent Consultant Final Report at 65 and 67; and AG Affidavit at ¶ 75.

ongoing pandemic. In fact, the Independent Consultant has noted that the current debt cost for generic B-rated corporate debt is approximately 5.7%.[290]

The Independent Consultant also considered available information regarding debt costs incurred by certain publicly traded IPPs. The available information identified a range of debt costs from approximately 4% to 8%.[291]

Based on consideration of the range of COD values that may be appropriate, the Independent Consultant ultimately selected that recommended value of 6.7%.[292] The Independent Consultant's recommendation to use a value slightly above current market values for generic B-rated corporate debt includes consideration of many factors. These considerations include the risk profile for developing a new peaking plant in New York, potential financing approaches including the non-recourse nature of stand-alone project finance debt, and an implicit consideration of costs that may be incurred to secure financing for a new peaking plant in New York such as the execution of hedges.[293]

3. Debt-to-Equity Ratio

The NYISO proposes to adopt the Independent Consultant's recommended D/E ratio of 55/45 for the 2021-2025 DCR.[294] This is the same D/E ratio approved by the Commission for the 2017-2021 DCR.[295]

The recommended D/E ratio recognizes that the appropriate capital structure for a project can vary depending on consideration of several factors, including the nature and certainty of expected project revenue streams, the structure of a project's financing, and the nature of the capital supporting investment in the project.[296] The recommendation considered various potential capital structures that could reasonably support the development of a new peaking plant in New York. The data and information assessed by the Independent Consultant included corporate level capital structures for certain IPPs, assumptions of capital structure used in other studies and evaluations, and consideration of the relative cost of debt.[297] This information identified D/E ratios ranging from 30/70 to 65/35.

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[290] AG Affidavit at ¶ 75.

[291] Independent Consultant Final Report at 65-66; and AG Affidavit at ¶ 75.

[292] Independent Consultant Final Report at 65; and AG Affidavit at ¶ 75.

[293] NYISO Final Recommendations at 26-27; Independent Consultant Final Report at 65-67; and AG Affidavit at ¶ 75.

[294] NYISO Final Recommendations at 26; Independent Consultant Final Report at 69-70; and AG Affidavit at ¶ 25 and 78.

[295] 2017-2021 DCR Filing at 36-38; and 2017-2021 DCR Order at P 179 and 181.

[296] Independent Consultant Final Report at 69; and AG Affidavit at ¶ 78.

[297] Independent Consultant Final Report at 69-70; and AG Affidavit at ¶ 78.

The Independent Consultant's recommended 55/45 D/E ratio represents a reasonable balancing of various considerations as informed by the range of potential capital structures observed. The recommended value acknowledges the generally observed trend toward lower debt leverage at the corporate level by IPPs, and the relative lack of longer-term certain revenue streams for a new merchant peaking plant that primarily derives revenues through participation in competitive wholesale markets.[298]

4. Amortization Period

The amortization period represents the term (in years) over which a merchant investor expects to recover its upfront capital costs to develop a new peaking plant in New York, together with a reasonable return on such investment. The NYISO proposes to adopt the 17-year amortization period recommended by the Independent Consultant for the peaking plants proposed herein.[299]

The recommended amortization period reflects a reduction from the 20-year amortization period approved by the Commission for the 2017-2021 DCR.[300] A primary consideration for using a 17-year amortization period is the recent enactment of the Climate Leadership and Community Protection Act ("CLCPA").[301] The CLCPA requires electricity demand in New York be served by 100% zero-emission resources by January 1, 2040. The proposed 17-year amortization period represents the average period of years between the beginning of each Capability Year encompassed by the 2021-2025 DCR and the January 1, 2040 zero-emission deadline established in the CLCPA.[302]

The Independent Consultant and the NYISO carefully considered divergent stakeholder feedback regarding the appropriate means for addressing the CLCPA's rules regarding fossil fuel use for electricity generation beyond 2040.[303] Certain stakeholders recommended a 15-year amortization period reflecting the fact that new generation projects currently under consideration in New York would be unlikely to enter into service until the later portion of the 2021-2025 reset period. Other stakeholders, including the MMU, recommended retaining a 20-year amortization period in light of the potential for fossil units to undertake future retrofitting or other modifications to convert to alternative zero-emission fuels or otherwise operate on a zero-emission basis in compliance with the CLCPA.

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[298] NYISO Final Recommendations at 26; Independent Consultant Final Report at 69-70; and AG Affidavit at ¶ 78.

[299] NYISO Final Recommendations at 27-29; Independent Consultant Final Report at 61-63; and AG Affidavit at ¶ 25 and 68-69.

[300] 2017-2021 DCR Filing at 36-38; and 2017-2021 DCR Order at P 179.

[301] Chapter 106 of the Laws of the State of New York of 2019; and AG Affidavit at ¶ 69.

[302] NYISO Final Recommendations at 27-28; Independent Consultant Final Report at 62; and AG Affidavit at ¶ 69.

[303] NYISO Affidavit at ¶ 28.

The proposed amortization period does not reflect any supposition that all existing fossil-fired generation will cease operation as of January 1, 2040. Likewise, the proposed 17-year amortization period does not presume that potential retrofitting options will be unavailable or not pursued if economically rational. Rather, the NYISO recognizes that achievement of the CLCPA's zero-emission generation requirement in a manner that balances the ultimate costs to consumers and maintaining reliability will require evolution of the resource mix to include flexible assets capable of operating in compliance with the CLCPA's zero-emission requirement.

Consistent with Commission precedent, however, the NYISO must consider the current state of the CLCPA and regulatory constructs developed to implement its requirements. The Commission has consistently held that determinations in each DCR must take account of laws and regulations as currently effective and avoid speculation as to potential future changes in such laws and regulations.[304]

Although the CLCPA establishes the requirement to transition to zero-emission electric supply by January 1, 2040, it does not does not define eligibility for compliance with this requirement. Instead, the CLCPA requires development and refinement of the regulations and program rules for achieving the 2040 zero-emission requirement over the coming years. At this time, New York has not implemented rules or regulations to specifically define the resource types, fuels, or retrofitting options eligible for operation in compliance with the 2040 zero-emission requirement. As a result, there is currently no basis upon which to assume potential retrofitting or fuel conversion to achieve compliance with the requirements of the CLCPA beginning in 2040.[305]

Given the absence of eligibility rules at present, assuming fuel conversion options, retrofits, or other modifications to permit a fossil-fired generator, such as the peaking plants proposed herein, to operate as a zero-emission resource beginning in 2040 would require the NYISO to speculate what may in the future be defined as compliant with the requirements of the CLCPA.[306] Reliance on such speculation would directly contradict the Commission's prior mandates regarding allowable considerations during each DCR.

Consideration of the potential timeframe for market entry of current projects under consideration in New York likewise does not undermine the proposed 17-year amortization period. The peaking plant used in establishing the ICAP Demand Curves is a hypothetical resource. The DCR implicitly requires that this hypothetical resource be in-service as of May 1, 2021 in order to establish the ICAP Demand Curves for the first Capability Year covered by the 2021-2025 DCR (*i.e.*, the 2021/2022 Capability Year).

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[304] *See*, *e.g.*, 2017-2021 DCR Order at P 61; and 2014-2017 DCR Order at P 74.

[305] NYISO Final Recommendations at 28; Independent Consultant Final Report at 61-62; and AG Affidavit at ¶ 69.

[306] AG Affidavit at ¶ 69.

Based on the consideration of all these factors, the use of a 17-year amortization period for the peaking plants proposed herein is appropriate and reasonable for the 2021-2025 DCR. As additional data and information becomes available over the coming years regarding resources, technologies, and fuels eligible for operation in compliance with the CLCPA's zero-emission requirement for 2040, the NYISO will consider such information in future resets.[307]

B. Reference Point Price

The reference point price is determined, in part, by subtracting the relevant net EAS revenue estimate for a peaking plant from the levelized embedded cost value of the same plant. The resulting value is commonly referred to as the "net cost of new entry" or "Net CONE." The NYISO uses the ICAP Demand Curves in the monthly ICAP Spot Market Auctions. Therefore, the NYISO must translate the annual Net CONE values into monthly values for use in the auctions.

As required by the Services Tariff, the NYISO calculated the resulting reference point prices for each ICAP Demand Curve for the 2021/2022 Capability Year.[308] These calculations account for the requirements that the reference point prices: (1) reflect the tariff-prescribed level of excess conditions; and (2) account for seasonal differences in capacity availability (commonly referred to as the winter-to-summer ratio or "WSR").[309]

The resulting calculations for the 2021/2022 Capability Year are contained in a spreadsheet developed by the Independent Consultant and posted on the NYISO's website (the spreadsheet is commonly referred to as the "Demand Curve Model").[310] This spreadsheet includes the data inputs and calculations necessary to determine: (1) the levelized annual cost to construct each peaking plant; (2) the annual Net CONE value for each peaking plant; and (3) translation of the annual Net CONE value for each peaking plant into a monthly reference point price. The NYISO will use the spreadsheet model to perform these calculations as part of the tariff-prescribed annual updates to determine the ICAP Demands Curves for the 2022/2023 through 2024/2025 Capability Years.

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[307] NYISO Final Recommendations at 28.

[308] NYISO Final Recommendations at 46-53.

[309] *See* Services Tariff §§ 5.14.1.2.2 and 5.14.1.2.2.3; and NYISO Installed Capacity Manual § 5.5. The WSR accounts for the fact that differences in capacity availability during the Summer Capability Period and Winter Capability Period contribute to differences in capacity prices throughout the year. To provide for revenue adequacy for the peaking plant when market entry is needed to maintain the applicable minimum capacity requirements, the NYISO uses the WSR to account for these seasonal differences.

[310] The Demand Curve Model related to the NYISO's proposal is an excel file titled "Demand Curve Model - 2020.10.21 (NYISO Staff Final Recommendations Updated 2021-2022 GDP)" available at: https://www.nyiso.com/installed-capacity-market. From this page, the model can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Final Models and Materials."

C. Maximum Clearing Price

The Services Tariff establishes the maximum allowable price of capacity for each ICAP Demand Curve at a value equal to 1.5 multiplied by the localized levelized embedded cost of each peaking plant (as translated into a monthly value).[311] The NYISO proposes enhancements to the methodology for translating the annual levelized embedded cost value for each peaking plant to a monthly value.[312]

The NYISO's proposed enhancements are intended to provide for improved consistency with the translation of the annual Net CONE values to monthly values. To provide for improved alignment, the NYISO proposes to account for: (1) the tariff-prescribed level of excess conditions; and (2) the applicable WSR values when translating the annual levelized embedded cost value for each peaking plant to a monthly value.[313]

D. Zero-Crossing Point

The NYISO proposes to retain the current zero-crossing point values for the 2021-2025 DCR.[314] The current zero-crossing point values are as follows: (1) 112% of the applicable minimum capacity requirement for the NYCA ICAP Demand Curve; (2) 115% of the applicable minimum capacity requirement for the G-J Locality ICAP Demand Curve; (3) 118% of the applicable minimum capacity requirement for the NYC ICAP Demand Curve; and (4) 118% of the applicable minimum capacity requirement for the LI ICAP Demand Curve.[315]

VI. Annual Updates

The Services Tariff requires that each DCR develop: (1) the proposed ICAP Demand Curves for the first Capability Year covered by the reset period; and (2) the methodologies, inputs, and assumptions used in determining the ICAP Demand Curves for the remaining three Capability Years covered by the reset period pursuant to the tariff-prescribed annual update procedures.[316]

The annual update process consists of updates to the following parameters each year: (i) adjusting the levelized localized embedded cost of the peaking plant for each ICAP Demand

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[311] Services Tariff §§ 5.14.1.2 and 5.14.1.2.2.3; and NYISO Affidavit at ¶ 22.

[312] NYISO Final Recommendations at 5 and 47; and NYISO Affidavit at ¶ 22-23.

[313] *Id*.

[314] *See* Services Tariff § 5.14.1.2.2; NYISO Final Recommendations at 51; and Independent Consultant Final Report at 109.

[315] *See* NYISO Final Recommendations at 51; 2017-2021 DCR Filing at 39-40; and 2017-2021 DCR Order at P 17, n. 27.

[316] *See* Services Tariff § 5.14.1.2.2; DCR Process Enhancement Filing at 9-16; and DCR Process Enhancements Order at P 27 and 29-30.

Curve based on a composite escalation factor;[317] (ii) determining new net EAS revenue estimates for each peaking plant using updated variable cost and market price information;[318] (iii) determining updated WSR values;[319] and (iv) determining the revised values of the ICAP Demand Curves utilizing the updated values described above.[320] The Services Tariff requires that the NYISO post the results of annual updates to its website on or before November 30th of the calendar year prior to the commencement of the Capability Year for which the updated ICAP Demand Curves apply.[321]

A. Annual Update of Peaking Plant Costs

The levelized localized embedded cost of each peaking plant is updated annually using a statewide, technology specific composite escalation factor.[322] The composite escalation factor measures the cost-weighted average change over time of certain inflation indices that relate to the costs of building a peaking plant. The costs of each peaking plant are broken down into the following four components to derive the technology specific weighting factors applicable to each component: (1) changes in construction material costs ("materials component"); (2) changes in turbine generator costs ("turbine component"); (3) changes in labor costs ("labor component"); and (4) changes in the general cost of goods and services ("general component").

For the 2021-2025 DCR, the NYISO essentially proposes the use of two different technologies to serve as the peaking plant. For the NYCA ICAP Demand Curve, the NYISO proposes use of the alternative GE 7HA.02 model that is tuned to emit 15 ppmv of NOx at 15% O_2 ("GE 7HA.02 (15 ppm)"). For the G-J Locality, NYC, and LI ICAP Demand Curves, the NYISO proposes use of the standard GE 7HA.02 model that is tuned to emit 25 ppmv of NOx at 15% O_2 ("GE 7HA.02 (25 ppm)"). The NYISO will calculate a separate composite escalation factor using differing component weighting factors for each technology.

The table below identifies the proposed data sources and weighting factors for each technology.[323]

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[317] Services Tariff § 5.14.1.2.2.1.

[318] Services Tariff § 5.14.1.2.2.2.

[319] Services Tariff § 5.14.1.2.2.3.

[320] *Id*.

[321] Services Tariff § 5.14.1.2.2. For example, the updated ICAP Demand Curves for the 2022/2023 Capability Year will be posted to the NYISO's website on or before November 30, 2021.

[322] *See* Services Tariff § 5.14.1.2.2.1; and 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 Docket No. ER20-1049-000, *supra*, Letter Order (April 3, 2020).

[323] NYISO Final Recommendations at 54-56; and Independent Consultant Final Report at 122-124.

			Weighting Factor	
Cost Component	**Index Value**	**Data Interval**	**GE 7HA.02 (25 ppm)**	**GE 7HA.02 (15 ppm)**
Labor	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	27%	24%
Materials	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	23%	19%
Turbine	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Turbines and Turbine Generator Sets (97)	Monthly	26%	32%
General	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	24%	25%

Section 5.14.1.2.2.4.11 of the Services Tariff requires that the NYISO calculate and report the most recent, unweighted 12-month percentage change for the general component. This value is relevant for certain aspects of the NYISO's buyer-side Installed Capacity market mitigation measures. The 12-month percentage change in the general component using finalized data published by the applicable index as of October 1, 2020 is 0.55%.

B. Annual Update of Net EAS Revenue Projections

The NYISO refreshes the net EAS revenue projections for each peaking plant as part of the annual update process. The Services Tariff requires that the NYISO utilize the same Net EAS Model used to determine the net EAS revenue projections for the 2021/2022 Capability Year, updating the model to replace the oldest twelve month period in the underlying dataset with the most recent twelve month period ending in August.[324]

[324] Services Tariff § 5.14.1.2.2.2. For example, for the annual update to determine ICAP Demand Curve values for the 2022/2023 Capability Year, the net EAS revenue projection will be based on cost and pricing data for the period from September 1, 2018 through August 31, 2021.

The table below summarizes the proposed data inputs and assumptions for the 2021-2025 DCR.[325]

	Data Input Value/Source			
Factor	**NYCA**	**G-J Locality**	**NYC**	**LI**
Net EAS Model	The Net EAS Model is contained within a zip folder titled "2020-09-09-Report Final Fossil Model" available at: https://www.nyiso.com/installed-capacity-market. From this page, the model can be obtained by navigating through the following content sections: "Reference Documents"→"2021-2025 Demand Curve Reset"→"Final Models and Materials"			
Peaking Plant	GE 7HA.02 (15 ppm)	GE 7HA.02 (25 ppm)	GE 7HA.02 (25 ppm)	GE 7HA.02 (25 ppm)
SCR Emissions Control Technology	No	Yes	Yes	Yes
Location	Load Zone C	Load Zone G (Rockland County)	Load Zone J	Load Zone K
Net Output	*See* Independent Consultant Final Report at Appendix A			
Energy Prices (day-ahead and real-time)	This data is publically available on the NYISO website			
Operating Reserves Prices (day-ahead and real-time)	This data is publically available on the NYISO website			
Level of Excess Adjustment Factors	*See* Independent Consultant Final Report at Appendix C			
Ancillary Services Adder for Revenues Not Determined by Net EAS Model ($/kW-yr.)	$2.04	$2.04	$2.04	$2.04
Peaking Plant Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Peaking Plant Secondary Fuel Type (if any)	N/A	ULSD	ULSD	ULSD
Fuel Tax Adder - Gas	N/A	N/A	6.9%	1.0%
Fuel Tax Adder - ULSD	N/A	N/A	4.5%	N/A
Transportation Cost Adder - Gas ($/MMBtu)	$0.27	$0.27	$0.20	$0.25
Transportation Cost Adder - ULSD ($/MMBtu)	N/A	$1.50	$1.50	$1.50
Real-time Intraday Gas Premium/Discount	10%	10%	20%	30%

[325] NYISO Final Recommendations at 56-58; and Independent Consultant Final Report at 125-126. In certain circumstances, these factors will represent a value that will remain fixed for the four-year reset period. In other instances, these factors will relate to a data source that will be used for determining applicable market price or cost information used by the model.

	Data Input Value/Source			
Factor	**NYCA**	**G-J Locality**	**NYC**	**LI**
Fuel Pricing Point - Gas	*December-March*: Niagara -and- *April-November*: TGP Z4 (200L)	TETCO M3	Transco Z6 NY	Iroquois Z2
Fuel Price Data Source - Gas	S&P Global Market Intelligence			
Fuel Pricing Point - ULSD	N/A	New York Harbor	New York Harbor	New York Harbor
Fuel Price Data Source - ULSD	N/A	New York Harbor ULSD No.2 spot prices from U.S. EIA, available at: https://www.eia.gov/dnav/pet/hist/EER_EPD2DXL0_PF4_Y35NY_DPGD.htm		
Peaking plant Variable Operating and Maintenance Costs (including Levelized Major Maintenance Costs)	*See* Independent Consultant Final Report at Appendix A			
Peaking plant CO_2 Emissions Rate	*See* Independent Consultant Final Report at Appendix A			
CO_2 Emission Allowance Cost	RGGI Regional Allowance Auction Results from RGGI, Inc., available at: https://www.rggi.org/auctions/auction-results			
Peaking plant NOx Emissions Rate	*See* Independent Consultant Final Report at Appendix A			
NOx Emission Allowance Cost	S&P Global Market Intelligence			
Peaking plant SO_2 Emissions Rate	*See* Independent Consultant Final Report at Appendix A			
SO_2 Emission Allowance Cost	S&P Global Market Intelligence			
NYISO Rate Schedule 1 Charges for Injection Billing Units	This data is publically available on the NYISO website			

C. Annual Update of ICAP Demand Curve Parameters

The NYISO will utilize the updated levelized embedded cost values and annual net EAS revenue projections to derive the updated values of the ICAP Demand Curves.[326]

[326] Services Tariff § 5.14.1.2.2.3.

The reference point is set at the annual Net CONE value for each peaking plant, translated into a monthly value that accounts for seasonal differences in capacity availability and the tariff-prescribed level of excess conditions.[327] Calculations of the reference point value will use annually updated WSR values. The applicable capacity ratings for each peaking plant used in calculating the reference point price were determined during the DCR and will remain fixed for the 2021-2025 DCR.

The maximum value of each ICAP Demand Curve is set at an amount equal to the monthly value of the updated levelized embedded cost for the applicable peaking plant, multiplied by 1.5.[328]

For the 2021-2025 DCR, the NYISO proposes continued use of the currently effective zero-crossing point values for each ICAP Demand Curve.

The table below summarizes the proposed data inputs for calculating the ICAP Demand Curve parameters for the 2021-2025 DCR.[329]

		Data Input Value			
Factor	**Type of Value**	**NYCA**	**G-J Locality**	**NYC**	**LI**
ICAP Demand Curve Parameter Values					
Zero-crossing point	Fixed for Reset Period	112%	115%	118%	118%
Reference Point Price Calculation					
Peaking Plant Net Degraded Capacity (ICAP MW)	Fixed for Reset Period	326.7	347.0	348.8	348.8
Peaking Plant Summer Capability Period (DMNC MW)	Fixed for Reset Period	329.3	348.2	348.5	351.1
Peaking Plant Winter Capability Period (DMNC MW)	Fixed for Reset Period	344.7	369.9	374.1	373.0

[327] Services Tariff § 5.14.1.2.2.3; and NYISO Installed Capacity Manual § 5.5.

[328] As further described in Section V.C, the NYISO proposes certain enhancements to the translation of the annual levelized embedded cost for each peaking plant to a monthly value for use in calculating the maximum clearing price value.

[329] NYISO Final Recommendations at 50 and 58; and Independent Consultant Final Report at 122 and Appendix A.

		Data Input Value			
Factor	**Type of Value**	**NYCA**	**G-J Locality**	**NYC**	**LI**
Level of Excess	Fixed for Reset Period	100.9%	102.5%	103.5%	106.5%
WSR Values	Updated Annually	These values are updated annually and will be publically available on the NYISO website			

VII. Description of the Proposed Tariff Revisions

The NYISO proposes to revise the table in Section 5.14.1.2 of the Services Tariff to: (1) include the proposed parameters of the ICAP Demand Curves for the 2021/2022 Capability Year, as well as the timing for the posting of ICAP Demand Curves for the 2022/2023 through 2024/2025 Capability Years that will be determined as part of the annual updates encompassed by the 2021-2025 DCR; and (2) remove data entries for the 2016/2017, 2017/2018, 2018/2019, and 2019/2020 Capability Years that are no longer relevant. The NYISO also proposes to update the table in Section 5.14.1.2.2.3 of the Services Tariff with the relevant data values proposed for the 2021/2022 Capability Year ICAP Demand Curves.

VIII. Effective Date

The NYISO respectfully requests that the Commission issue an order on or before January 29, 2021 (*i.e.*, sixty days after filing) accepting: (1) the proposed 2021/2022 Capability Year ICAP Demand Curves; and (2) the annual update methodologies and inputs to determine the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Years. The NYISO also requests an effective date of January 30, 2021 (*i.e.*, the day following the end of the statutory 60-day notice period) for the tariff revisions proposed herein.

Timely Commission action is necessary to: (i) ensure the NYISO's ability to proceed with the necessary steps to conduct the ICAP auctions for the upcoming 2021 Summer Capability Period; and (ii) provide marketplace certainty as to the ICAP Demand Curves that will apply beginning with the 2021 Summer Capability Period. The NYISO's processes and procedures to begin preparation for the 2021 Summer Capability Period ICAP auctions commence in February 2021. The NYISO needs certainty with respect to the ICAP Demand Curves that will apply for the 2021/2022 Capability Year to facilitate timely completion of its auction-related administrative duties.

IX. Stakeholder Process

The NYISO conducted the DCR for the 2021-2025 period in accordance with the requirements of Section 5.14.1.2.2 of the Services Tariff. Pursuant to Section 5.14.1.2.2.4.11 of the Services Tariff, this filing represents the results of the 2021-2025 DCR approved by the

Board for filing with the Commission. The proposal includes: (1) the proposed ICAP Demand Curves for the 2021/2022 Capability Year; and (2) the methodologies and inputs to be used in conducting the tariff-prescribed annual updates to determine the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Years.

X. Communications and Correspondence

Please direct all communications and service in this proceeding to:

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XI. Service

The NYISO will send an electronic link to this filing to the official representative of each of its customers, each participant on its stakeholder committees, the New York State Public Service Commission, and the New Jersey Board of Public Utilities. The NYISO will also post the complete filing on its website at www.nyiso.com.

XII. Conclusion

The NYISO respectfully requests that the Commission: (i) issue an order accepting the results of the 2021-2025 DCR as proposed herein on or before January 29, 2021 (*i.e.*, sixty days after filing); and (ii) establish an effective date of January 30, 2021 (*i.e.*, the day following the end of the statutory 60-day notice period) for the proposed tariff revisions.

Respectfully submitted,

/s/ Garrett E. Bissell
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New York Independent System Operator, Inc.

cc: Jignasa Gadani
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