UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc.	**)))**	**Docket No. ER21-502-000**

REQUEST FOR LEAVE TO ANSWER AND ANSWER OF
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure promulgated by the Federal Energy Regulatory Commission ("Commission"),[1] the New York Independent System Operator, Inc. ("NYISO") hereby submits this Request for Leave to Answer and Answer in response to protests and comments filed in response to the proposal in this proceeding submitted by the NYISO on November 30, 2020 ("2021-2025 DCR Filing").[2]

The 2021-2025 DCR Filing represents the culmination of the quadrennial review of the ICAP Demand Curves required by the NYISO Market Administration and Control Area Services Tariff ("Services Tariff").[3] The periodic reviews (commonly referred to as the "ICAP Demand Curve reset" or "DCR") provide a forum for an open and transparent assessment of the assumptions and parameters for establishing the ICAP Demand Curves.[4] The DCR includes a comprehensive stakeholder process for vetting the necessary assumptions and parameters with all interested parties. The NYISO's proposal in this proceeding establishes the ICAP Demand Curves for the 2021/2022 Capability Year, as well as the methodologies and inputs used in

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[1] 18 C.F.R. §§ 385.212 and 385.213.

[2] Docket No. ER21-502-000, *New York Independent System Operator*, *Inc*., 2021-2025 ICAP Demand Curve Reset Proposal (November 30, 2020).

[3] *See* Services Tariff § 5.14.1.2.2.

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

conducting the tariff-required annual updates to determine the ICAP Demand Curves for the 2022/2023 through 2024/2025 Capability Years.

The proposal submitted by the NYISO reflects careful consideration of all stakeholder feedback and comments provided throughout the DCR and strikes a reasonable balance that establishes appropriate ICAP Demand Curves for the 2021-2025 reset period. Consistent with prior resets, due to divergent stakeholder interests, the NYISO did not achieve consensus on all aspects of its proposal.[5] The NYISO identified open issues and responded to each within the 2021-2025 DCR Filing. The comments and protests submitted in response to the 2021-2025 DCR Filing raised issues previously identified by the NYISO. Although parties do not agree on all aspects of the NYISO's proposal, the NYISO has demonstrated that its proposal for the 2021-2025 DCR is just and reasonable. Accordingly, the NYISO respectfully reiterates its request that the Commission: (1) issue an order on or before January 29, 2021 accepting the NYISO's proposal as set forth in the 2021-2025 DCR Filing; and (2) establish an effective date of January 30, 2021 for the tariff revisions proposed by the NYISO in this proceeding.[6]

I. REQUEST FOR LEAVE TO ANSWER

Rule 213 of the Commission's Rules of Practice and Procedure generally prohibits answers to certain pleadings, including protests.[7] The Commission, however, has discretion to waive such prohibition.[8] The Commission has previously determined that a waiver is

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[5] 2021-2025 DCR Filing at 7.

[6] Timely Commission action is necessary to facilitate the NYISO's ability to proceed with the necessary steps to conduct the ICAP auctions for the upcoming 2021 Summer Capability Period. The processes and procedures to prepare for such auctions commence in February 2021. *See* 2021-2025 DCR Filing at 60.

[7] 18 C.F.R § 385.213(a)(2). The Commission's Rules of Practice and Procedure authorize answers to pleadings styled as "comments."

[8] *Id*.

appropriate in circumstances where an otherwise prohibited answer: (1) will lead to a more complete and accurate record; (2) helps the Commission better understand the issues; (3) clarifies matters in dispute or errors; and/or (4) provides information that will assist the Commission in rendering a decision.[9] This answer clarifies matters in dispute, corrects certain erroneous assertions, provides information that will assist the Commission, and assists in the development of a complete recording in this proceeding.[10] Accordingly, the Commission should accept and consider this answer.

II. ANSWER

The positions advocated by various parties would, if adopted by the Commission, result in placing either upward or downward pressure on the ICAP Demand Curve parameters proposed by the NYISO. The NYISO's proposal for the 2021-2025 DCR strikes a fair and reasonable balance between the divergent positions of protestors. The NYISO's proposal establishes ICAP Demand Curves designed to provide appropriate price signals reflecting the locational value of Installed Capacity. The proposal submitted by the NYISO is just and reasonable. The Commission should accept the NYISO's proposal in this proceeding without modification.

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[9] *See, e.g., New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 (2017) (accepting answers to protests that provided information that assisted the Commission's decision making process); *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 (2011) (accepting answers to protests because they provided information that aided the Commission in better understanding the matters at issue in the proceeding); *New York Independent System Operator, Inc.*, 99 FERC ¶ 61, 246 (2002) (accepting answers to protests that help clarify issues and did not disrupt the proceeding); *New York Independent System Operator, Inc.*, 91 FERC ¶ 61,218 (2000) (accepting an answer deemed useful in addressing issues arising in the proceeding at issue); and *Morgan Stanley Capital Group, Inc. v. New York Independent System Operator, Inc.*, 93 FERC ¶ 61,017 (2000) (accepting an answer that was helpful in the development of the record).

[10] The NYISO has sought to limit the scope of this answer to address certain key disputed issues. Thus, this answer does not respond to all arguments and assertions made by parties in response to the 2021-2025 DCR Filing. The Commission should not construe the NYISO's silence as to any particular assertion or argument in opposition to its proposal as agreement or acquiescence.

A. Peaking Plant Design and Cost Estimates

The NYISO addresses the following issues raised by certain parties: (1) the inclusion of selective catalytic reduction ("SCR") emissions control technology for the proposed peaking plant design in Load Zone G (Dutchess County); (2) cost estimates for a gas interconnection outside New York City; (3) the assumed land lease cost within New York City; and (4) the owner's cost component of the capital cost estimates. The NYISO's proposed assumptions with respect to each of these issues are appropriate and reasonable. The Commission should not direct any changes to such assumptions.

1. <u>The Inclusion of SCR Emissions Control Technology for a Dual Fuel Plant Design Is Appropriate</u>

The NYISO proposes to establish the G-J Locality ICAP Demand Curve based on a peaking plant located in Load Zone G (Rockland County) for the duration of the 2021-2025 reset period.[11] Certain parties, however, contend that the Commission should direct the NYISO to revise the peaking plant design for Load Zone G (Dutchess County) to exclude SCR emissions control technology.[12] The NYISO's proposal to include SCR emissions control technology as part of the dual fuel peaking plant design in Load Zone G (Dutchess County) is reasonable and appropriate.

Opposing parties essentially contend that the inclusion of SCR emissions control technology for the peaking plant located in Load Zone G (Dutchess County) is a purely economic decision for a developer.[13] The NYISO's proposal to include SCR emissions control

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[11] *See, e.g.*, 2021-2025 DCR Filing at 6, 14-16, and 57-58.

[12] This change, if adopted, would result in Load Zone G (Dutchess County) serving as the basis for the G-J Locality ICAP Demand Curve the 2021-2025 reset period.

[13] Docket No. ER21-502-000, *supra*, Comments and Protest of the Consumer Stakeholders at 8-15 (December 21, 2020) ("Consumer Stakeholders Protest"); and Docket No. ER21-502-000, *supra*,

technology for dual fuel peaking plant designs, however, considers several factors other than economics. The proposed inclusion of SCR emissions control technology seeks to ensure that a dual fuel peaking plant is reasonably available to support reliable grid operations.

Since its inception, the ICAP Demand Curves for the G-J Locality have used peaking plant designs that include both dual fuel capability and SCR emissions control technology. This plant design remains appropriate.

The inclusion of dual fuel capability remains reasonable and appropriate for the reasons previously determined by the Commission in prior resets.[14] Factors supporting dual fuel capability for the peaking plant used in determining the G-J Locality ICAP Demand Curve include: (1) improved operational flexibility and availability; (2) enhanced siting flexibility; and (3) additional revenue earning opportunities when operation on natural gas becomes uneconomic or unavailable due to gas system constraints and competing demand for natural gas.[15] Additionally, the ongoing transition of the resource mix in New York and expected changes in the resource fleet heighten the need to retain dual fuel capability as part of the peaking plant design for the G-J Locality ICAP Demand Curve.[16] Dual fuel capability enhances resilience and operational flexibility. Access to sufficient quantities of flexible resources is of paramount importance as the level of reliance on weather-dependent renewable generation increases over

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Limited Protest and Comments of New York Transmission Owners at 6-15 (December 21, 2020) ("NYTOs Protest").

[14] 2021-2025 DCR Filing at 16-20. Contrary to the erroneous assertion by certain parties, the NYISO does not assume that the peaking plants evaluated for Load Zone G (Dutchess County) and Load Zone G (Rockland County) interconnect to a load distribution company ("LDC") gas system. *See* Consumer Stakeholders Protest at 16. The NYSO expressly recognized that these locations provide options for a peaking plant to connect to either a LDC gas system or an interstate pipeline. The inclusion of dual fuel capability provides for improved siting flexibility by preserving the option to connect to a LDC gas system in light of LDC tariff-imposed dual fuel requirements. *See* 2021-2025 DCR Filing at 18.

[15] 2021-2025 DCR Filing at 17-19; and 2021-2025 DCR Filing at Attachment III (*Affidavit of Paul J. Hibbard, Dr. Todd Schatzki, Charles Wu, and Christopher Llop*), ¶ 32-35 ("AG Affidavit").

[16] 2021-2025 DCR Filing at 19-20.

time. As demonstrated by the NYISO's comprehensive fuel security study, dual fuel capability is critically important to maintaining system reliability throughout the ongoing transition of New York's resource fleet to a clean energy system.[17]

The inclusion of dual fuel capability results in the potential for a severely constraining limitation on allowable hours of operation in the absence of including SCR emissions control technology.[18] This limitation arises due to the fact that the nitrogen oxides ("NOx") emissions from operation on ultra-low sulfur diesel ("ULSD") are approximately three times higher than when operating on natural gas.[19] The alternative "synthetic minor" source approach to permitting establishes a single, fixed annual limit on NOx emissions regardless of the fuel used to operate. The severely restrictive nature of the applicable operating limits for a dual fuel peaking plant in the absence of SCR emissions control technology is a primary reason the NYISO has never proposed use of a dual fuel peaking plant design without back-end controls in any prior reset.[20]

The significantly higher emissions resulting from operation using ULSD could result in allowing as little as approximately 312 hours of operation annually for a dual fuel plant without SCR emissions control technology.[21] Availability to support operations during peak load periods could reasonably require the capability to operate at least 720 hours annually.[22] The potential

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[17] *Id.*; and Analysis Group, Inc., *Fuel and Energy Security in New York State – An Assessment of Winter Operational Risks for a Power System in Transition* (November 2019) at 70-74, available at: https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf.

[18] 2021-2025 DCR Filing at 11-16.

[19] *Id*. at 15.

[20] *Id*. at 13.

[21] *Id*. 15-16.

[22] *Id*.

severely limiting nature of an annual emission cap in lieu of installing SCR emissions control technology results in a peaking plant that may not reasonably support reliable grid operations.

The already constrained nature of the gas supply system in the downstate region and difficulties faced in developing incremental gas supply infrastructure increase the likelihood for a dual fuel peaking plant to require use of its alternative fuel source (*i.e.*, ULSD) to provide energy during various periods throughout the year. Inclusion of SCR emissions control technology for all dual fuel peaking plant designs provides important operational availability in support of reliable grid operations. The Commission should reject requests to exclude such back-end controls from a peaking plant located in Load Zone G (Dutchess County).

2. The Assumed Gas Interconnection Costs for Locations Outside New York City Are Reasonable

For locations outside New York City, the NYISO proposes an assumed cost of $250,000 per inch diameter per mile for the linear pipeline costs, plus an additional $3.5 million for a metering and regulation station for the gas interconnection costs of the proposed peaking plants.[23] Certain parties contend that the assumed linear cost component for a gas interconnection outside New York City understates the expected cost in New York.[24] To support this position, these parties rely on the cost of a single, recent gas lateral connection in New York (*i.e.*, the CPV Valley lateral project), and raise concerns regarding the dataset relied on by the

[23] *Id*. at 25-26; and 2021-2025 DCR Filing at Exhibit E of Attachment III, Appendix A. For the proposed peaking plants located outside New York City, the NYISO proposes an assumed 5-mile, 16-inch diameter lateral with an aggregate cost of $23.5 million.

[24] Docket No. ER21-502-000, *supra*, Protest and Supporting Comments of Independent Power Producers of New York, Inc. at 19-21 (December 21, 2020) ("IPPNY Protest"); and Docket No. ER21-502-000, *supra*, Motion to Intervene and Protest of CPV Valley, LLC at 8-12 (December 21, 2020) ("CPV Protest").

independent consultant selected to assist with the 2021-2025 DCR ("Independent Consultant") to confirm the reasonableness of the assumed lateral costs.[25]

In developing the assumed linear cost component of the gas interconnection cost, the Independent Consultant relied on confidential data related to its prior experience with generation projects, including projects located within New York.[26] In addition to non-public data, the Independent Consultant provided information regarding the linear pipeline cost component for several recent gas pipeline and lateral projects.[27] The publicly available data assessed by the Independent Consultant included two gas lateral projects for generators interconnected to the New York Control Area, including the CPV Valley lateral project. The Independent Consultant also evaluated publicly available information regarding three proposed pipeline projects – two related to incremental gas supply infrastructure in New York and a third project in close proximity to New York.[28]

Based on its prior project experience and professional judgment, the Independent Consultant estimated a linear component cost of $250,000 per inch diameter per mile for locations outside New York City. The public cost data confirmed the reasonableness of the value assumed by the Independent Consultant. To determine the estimated linear pipeline cost from the publicly available project data, the Independent Consultant excluded costs related to non-linear equipment and construction components, such as metering, regulating equipment, and compressor station costs.[29] Exclusion of such non-linear cost components provides for

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[25] *Id*.

[26] 2021-2025 DCR Filing at 24-25; and 2021-2025 DCR Filing at Attachment IV (*Affidavit of Matthew E. Lind and Kieran McInerney*), ¶ 36-37 ("BMCD Affidavit").

[27] *Id*.

[28] *Id*.

[29] BMCD Affidavit at ¶ 37.

consistency with the Independent Consultant's identification of a separate cost component for non-linear costs as part of its aggregate gas interconnection cost estimate (*i.e.*, an adder of $3.5 million to the estimated linear pipeline cost). After excluding non-linear component costs, the Independent Consultant identified a range of linear pipeline costs from approximately $100,000 to $500,000 per inch per diameter mile for the public data evaluated.[30] The average linear cost from this dataset was approximately $260,000 per inch diameter per mile.[31] The NYISO's proposed linear cost value is within the above-identified range and nearly equivalent to the average value of the dataset, thereby confirming the reasonableness of the estimate developed based on the Independent Consultant's professional judgment and experience.

Certain parties contend that the inclusion of cost data related to longer-distance pipeline expansion projects undermines the value of the dataset evaluated by the Independent Consultant.[32] Importantly, although the dataset includes costs related to certain pipeline expansions, the two gas laterals for the generators interconnected to New York establish the highest and lowest values of the observed range of linear cost estimates. Excluding consideration of the cost data for longer-distance pipelines, the assumed linear cost remains in a range between these two values and near the midpoint thereof.

Furthermore, use of a dataset relating to multiple projects avoids the potential for establishing costs based on a single project that may have unique circumstances that are not

[30] 2021-2025 DCR Filing at 25; and BMCD Affidavit at ¶ 37.

[31] *Id*. Certain parties erroneously claim that the Independent Consultant excluded consideration of the CPV Valley lateral project and the Bayonne lateral delivery project from its assessment. *See* CPV Protest at 9-10. To the contrary, the Independent Consultant retained these projects as part of the dataset and accounted for them in calculating the average linear cost of $260,000 per inch diameter per mile for all projects within the dataset. Simply as an alternative means of evaluating the data provided from the projects evaluated, the Independent Consultant also noted that the average linear cost would reduce slightly to $240,000 per inch diameter per mile if the highest and lowest observed linear costs were not included in the calculation. *See* 2021-2025 DCR Filing at 25; and BMCD Affidavit at ¶ 37.

[32] IPPNY Protest at 19-20; and CPV Protest at 9-10.

broadly applicable to other gas interconnection projects. Significant variations in costs occur from project to project given the specific circumstances, conditions, and challenges faced by each project.[33] Assessing costs for multiple projects assists with avoiding the inclusion of unnecessary costs that may result from the conditions and circumstances attendant to one particular project. This facilitates an appropriate evaluation for purposes of determining a reasonable cost estimate for a generic, non-site specific estimate as required by the DCR.

CPV Valley, LLC ("CPV") recommends the use of an alternative dataset replacing the longer-distance pipeline project costs with alternative shorter-distance laterals related to various generation projects.[34] CPV contends that such a revised dataset demonstrates that the NYISO's proposed linear cost component is understated. The linear cost estimates calculated by CPV are inaccurate and overstated due to CPV's apparent failure to exclude costs related to non-linear equipment and construction costs as was done by the Independent Consultant.[35] These non-linear components comprise a material portion of total project costs.[36] Failing to exclude these

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[33] BMCD Affidavit at ¶ 37.

[34] CPV Protest at 10-11.

[35] Based on a review of the applications filed with the Commission for the projects evaluated by CPV, it appears CPV estimated the linear costs by utilizing the total aggregate project costs, including non-linear cost components. The *Declaration of Daniel Nugent* included as Attachment A to the CPV Protest confirms this methodological error by generally describing that CPV calculated its linear cost estimates by dividing the total cost for each project by the length thereof. *See* Docket No. CP20-30-000, *Texas Eastern Transmission, LP*, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations at Volume I, Exhibit K (December 19, 2019); Docket No. CP16-473-000, *Texas Eastern Transmission, LP*, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations at Volume I, Exhibit K (June 29, 2016); Docket No. CP16-17-000, *Millennium Pipeline Company, L.L.C.*, Abbreviated Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (November 13, 2015); Docket No. CP14-18-000, *Transcontinental Gas Pipeline Company, LLC*, Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (November 7, 2013); and Docket No. CP09-417-000, *Transcontinental Gas Pipeline Company, LLC*, Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (May 22, 2009).

[36] The cost estimates included in the initial applications submitted to the Commission for each of the projects evaluated by CPV indicate that, on average, non-linear costs accounted for more than 20% of the total estimated project costs. *See* Docket No. CP20-30-000, *Texas Eastern Transmission, LP*,

costs produces inflated linear cost estimates for each project. Additionally, the Bayway lateral project cited by CPV includes a gas lateral providing service to two, distinct customers – a refinery and a gas-fired generator.[37] Despite the nature of the project, CPV's analysis assigns all costs related to the lateral to the generation facility. This assumption is inaccurate and inflates the portion of costs incurred by such generation facility.

The estimated gas lateral costs for the proposed peaking plants outside New York City represent reasonable costs based on the prior experience of the Independent Consultant, including work on generation development projects in New York. The Independent Consultant further supported its linear cost component based on a review of publically available cost data for relevant gas pipeline and gas laterals projects.

3. <u>The Assumed Land Lease Cost Within New York City Is Reasonable and Adequate</u>

Certain parties erroneously insinuate that the NYISO solely based its proposed land lease cost of $270,000 per acre-year for New York City on escalating the value from the last reset.[38] Such assertions are not accurate. While the Independent Consultant initially derived the assumed

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Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations at Volume I, Exhibit K (December 19, 2019); Docket No. CP16-473-000, *Texas Eastern Transmission, LP*, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations at Volume I, Exhibit K (June 29, 2016); Docket No. CP16-17-000, *Millennium Pipeline Company, L.L.C.*, Abbreviated Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (November 13, 2015); Docket No. CP14-18-000, *Transcontinental Gas Pipeline Company, LLC*, Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (November 7, 2013); and Docket No. CP09-417-000, *Transcontinental Gas Pipeline Company, LLC*, Application for a Certificate of Public Convenience and Necessity at Volume I, Exhibit K (May 22, 2009).

[37] *See* Docket No. CP16-473-000, *Texas Eastern Transmission, LP*, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations at Volume I (June 29, 2016).

[38] IPPNY Protest at 20-21.

lease cost value by escalating values from the last reset, the Independent Consultant conducted a supplemental analysis to confirm the reasonableness of the escalated values.[39]

The Independent Consultant's supplemental analysis expressly considered recent appraisal information submitted by certain stakeholders regarding certain existing generator sites located within New York City.[40] The supplemental analysis, in part, sought to determine whether such appraisal data was broadly applicable to potential generation sites within New York City. The supplemental analysis identified significant variability as to lease costs for potential sites within New York City.[41]

This data demonstrated that the appraisal data submitted by certain stakeholders was likely not appropriate for broader application to all potential generation sites within New York City. Notably, the Independent Consultant's supplemental analysis included nine sites adjacent to existing generation facility sites within New York City.[42] The proposed lease cost for the 2021-2025 DCR represents a reasonable value within the range of the average lease cost observed across multiple properties adjacent to existing generation facility sites within New York City (*i.e.*, $160,712 per acre-year) and the average of the appraisal values submitted by certain stakeholders (*i.e.*, $645,509 per acre-year).[43] Selection of a value within this range is consistent with expectation that a developer of new plant in a competitive market will seek to minimize its costs to the extent practicable.

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[39] 2021-2025 DCR Filing at 26-27; and BMCD Affidavit at ¶ 38-40.

[40] *Id*. The stakeholder-provided data included in the Independent Consultant's supplemental analysis is the appraisal data described in the IPPNY Protest. *See* IPPNY Protest at 21-22.

[41] 2021-2025 DCR Filing at 26-27; and BMCD Affidavit at ¶ 38-40.

[42] *Id*.

[43] *Id*.

4. The Estimated Capital Costs, Including the Owner's Cost Component, Appropriately Account for all Cost Categories

Certain parties erroneously assert that the Independent Consultant's estimated owner's cost fails to fully account for certain cost components, including development, engineering, and financing fees during construction.[44] To support their contention, these parties attempt to compare particular costs on a line-item by line-item basis from the last reset to the estimates developed for the 2021-2025 DCR.[45]

The engineering and design firm used for the 2021-2025 DCR is not the same entity used for the last reset.[46] Although both firms developed cost estimates consistent with typical industry practices, the methodologies and cost categorization used by each firm differs.[47] As a result, attempting to conduct line-item by line-item comparisons of the cost estimates from the last reset to those developed for the 2021-2025 DCR is not appropriate and likely to yield misleading results.[48]

To demonstrate that the cost estimates developed for the 2021-2025 DCR appropriately account for all relevant cost considerations, the Independent Consultant conducted a supplemental assessment to provide a reasonable and accurate comparison of its estimates to those from the last reset.[49] This analysis clearly demonstrates that the Independent Consultant's cost estimates for the 2021-2025 DCR appropriately account for the same relevant cost components included in the estimates developed for the last reset. The analysis demonstrates

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[44] IPPNY Protest at 18-19; and CPV Protest at 22-24.

[45] *Id*.

[46] 2021-2025 DCR Filing at 22-23.

[47] 2021-2025 DCR Filing at 22-23; and BMCD Affidavit at ¶ 41-44.

[48] *Id*.

[49] 2021-2025 DCR Filing at 22-23; and BMCD Affidavit at ¶ 45.

that after accounting for inflation of dollar values from the last reset to 2020 dollar values, the aggregate owner's cost estimates developed by the two engineering and design firms differ by less than $200,000 (or approximately 0.3%) for an equivalent peaking plant design and location.[50] The difference for total aggregate capital costs developed by the two firms differs by less than 1%.[51]

Contrary to the assertions of certain parties, the Independent Consultant's supplemental analysis demonstrates that its cost estimates are accurate and complete. The perceived deficiencies raised by certain parties are merely the result of the differences in the methodologies and cost categorization employed by two differing engineering and design firms. Thus, the Commission should accept the proposed capital cost estimates without modification.

B. Net Energy and Ancillary Services Revenue Estimates

Certain parties oppose the gas hubs proposed by the NYISO for use in estimating the variable operating costs of the proposed peaking plants in Load Zone C and Load Zone G (Rockland County). The NYISO's proposed gas hubs for these locations are reasonable and appropriate for the 2021-2025 DCR.[52] The Commission should reject requests to alter the NYISO's proposed gas hubs for Load Zone C and Load Zone G (Rockland County).

1. The Proposed Use of the Niagara Hub for Winter Months for Load Zone C Facilitates Reasonable Estimates of the Potential Energy and Ancillary Services Revenues

Certain parties contend that the Commission should direct the NYISO to eliminate use of the Niagara hub during the winter period (*i.e.*, December through March) for Load Zone C.[53]

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[50] *Id*.

[51] *Id*.

[52] 2021-2025 DCR Filing at 35-40 and 41-43; and 2021-2025 DCR Filing at Attachment VI (*Affidavit of Pallas LeeVanSchaick, Ph.D.*), ¶ 10-39 ("MMU Affidavit").

[53] NYTOs Protest at 16-37; and Consumer Stakeholders Protest at 21-24. Contrary to the misleading insinuations by certain parties, the time allotted for oral presentations to the NYISO Board of

These parties claim that the NYISO's proposal to use the Tennessee Gas Pipeline ("TGP") Zone 4 (200 leg) hub for April through November and the Niagara hub for December through March is less representative of the likely gas prices faced by a peaking plant in Load Zone C than use of either the TGP Zone 4 (200 leg) hub or the Dominion North hub as the sole hub throughout the year.[54] These parties also raise concerns regarding the robustness of the pricing for the Niagara hub.[55]

Parties opposing the NYISO's proposal to use the Niagara hub for the winter period (*i.e.*, December through March) allege that the NYISO's proposal results in lower correlation with historical operation of gas-fired generators located in Load Zone C than use of either the TGP Zone 4 (200 leg) hub or Dominion North hub for the entire year.[56] Such claims rely on an assessment conducted by the Market Monitoring Unit ("MMU") to assist in evaluating various potential gas hub options for Load Zone C.[57] However, these claims fail to account for critical seasonal differences in correlation. The MMU's analysis identified that during stressed winter operating conditions, such as the bomb cyclone and extended Northeast cold snap of the 2017-2018 winter period, both the TGP Zone 4 (200 leg) hub and Dominion North hub significantly

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Directors ("Board") to address the 2021-2025 DCR was equivalent to past resets. *See* NYTOs Protest at 39-40. The Board's determination ultimately reflected its consideration of feedback and comments provided throughout the DCR, including the written comments submitted by parties to the Board on October 9, 2020. The Board's determination was not limited to only consideration of the oral presentations by interested parties on October 19, 2020.

[54] NYTOs Protest at 18-28 and 35-37; and Consumer Stakeholders Protest at 21-24.

[55] NYTOs Protest at 28-35; and Consumer Stakeholders Protest at 23.

[56] NYTOs Protest at 18-28; and Consumer Stakeholders Protest at 24.

[57] MMU Affidavit at ¶ 13-15. Certain parties erroneously allege that the MMU's analysis did not include information related to the use of the Niagara hub prices on the historical dispatch of gas-fired generators in Load Zone C. *See* Consumer Stakeholders Protest at 23. Contrary to these erroneous claims, the analysis conducted by the MMU and submitted as part of the 2021-2025 DCR Filing expressly included results using the Niagara hub prices. *See* MMU Affidavit at ¶ 13.

overestimated the actual, historic operation of gas-fired generators in Load Zone C, resulting in artificially inflated estimates of the potential revenue earnings during these critical periods.[58]

As demonstrated by supplemental analysis conducted by the MMU, the overestimation of potential revenues during winter periods is due to gas pipeline system constraints that limit the availability to deliver gas from the TGP Zone 4 (200 leg) hub to Load Zone C during winter months.[59] This assessment of pipeline capacity utilization demonstrated that sufficient pipeline capacity is often unavailable during the winter months to accommodate deliveries of gas from the TGP Zone 4 (200 leg) hub to a peaking plant in Load Zone C.[60] Failure to account for such conditions could result in artificially overestimating potential energy market revenues during the winter period.

The Niagara hub provides a reasonable and appropriate alternative that better represents likely gas prices faced by a peaking plant in Load Zone C during the winter period. Unlike the TGP Zone 4 (200 leg) hub and the Dominion North hub, the Niagara hub does not result in an artificial overestimate of historic operation by gas-fired generators in Load Zone C during critical winter periods.[61] The Niagara hub also does not experience the historic availability constraints identified with respect to use of the TGP Zone 4 (200 leg) during the winter period.[62]

Certain parties opposing the use of the Niagara hub during the winter period raise potential concerns regarding the level of trading activity and availability of pricing for the

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[58] 2021-2025 DCR Filing at 36-37; and MMU Affidavit at ¶ 13-15 and 22-23. Comparatively, the Dominion North hub exhibited larger magnitude and more persistent overestimates of historic operations during winter periods demonstrating its inferiority to the TGP Zone 4 (200 leg) hub.

[59] 2021-2025 DCR Filing at 36-37; and MMU Affidavit at ¶ 16-21.

[60] *Id*.

[61] 2021-2025 DCR Filing at 36-37; and MMU Affidavit at ¶ 13-15.

[62] MMU Affidavit at ¶ 19 and 21.

Niagara hub.[63] These claims rely on data and information from an entity other than the vendor proposed by the NYISO to serve as the gas price data source for the 2021-2025 DCR. Data and information from a different vendor is less relevant and probative than historical information from the NYISO's proposed vendor (*i.e.*, S&P Global Market Intelligence or "SPGMI").[64] The NYISO's analysis of data and information from SPGMI found that SPGMI published a gas price for the Niagara hub for each day during the December through March period on which gas prices are normally published by indices for the three-year data period used in determining revenue estimates for the 2021/2022 Capability Year ICAP Demand Curves.[65] The NYISO also assessed historic trading activity for the Niagara hub using data obtained from SPGMI. This analysis demonstrated that, during the winter months when the NYSO proposes to use the Niagara hub, trading activity was comparable and in some cases greater than other gas hubs either considered for Load Zone C or proposed for use for other Load Zones.[66]

The NYISO's proposal to use the TGP Zone 4 (200 leg) hub for April through November and the Niagara hub for December through March is reasonable and appropriate. This proposal accounts for identified constraints that limit the availability of gas from the TGP Zone 4 (200 leg) hub to a peaking plant in Load Zone C during winter months. The NYISO's proposal seeks to avoid the potential for unnecessary over- or under-estimating of potential energy market revenues for a peaking plant in Load Zone C.

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[63] NYTOs Protest at 28-35; and Consumers Stakeholders Protest at 23-24.

[64] SPGMI is the successor to SNL Financial. The Commission approved use of SNL Financial as the gas price data vendor for the 2017-2021 reset period. No party has raised any issues or concerns with the NYISO's proposal to continue use of this data vendor for the 2021-2025 DCR.

[65] 2021-2025 DCR Filing at 38-39; and 2021-2025 DCR Filing at Attachment V (*Affidavit of Zachary T. Smith*), ¶ 14 ("NYISO Affidavit").

[66] 2021-2025 DCR Filing at 38-40; and NYISO Affidavit at ¶ 14.

2. Texas Eastern Transmission Pipeline ("TETCO") M3 Is the Appropriate Gas Hub for Load Zone G (Rockland County)

Certain parties assert that the TETCO M3 hub is not an appropriate gas hub for Load Zone G (Rockland County).[67] These parties contend that the Commission should direct the NYISO to use the Iroquois Zone 2 hub for Load Zone G (Rockland County).[68] To support their position, these parties provide information primarily addressing the availability of interruptible transportation service to accommodate deliveries of gas from the TETCO M3 hub to a peaking plant in Load Zone G (Rockland County).[69]

Parties opposing the use of the TETCO M3 hub as the appropriate gas hub for Load Zone G (Rockland County) contend that historic data demonstrates limited availability of interruptible service on the Algonquin pipeline to facilitate deliveries of gas to Load Zone G (Rockland County).[70] These parties also contend that the MMU's analysis is insufficient due to the failure to include information related to interruptible transportation or "IT" flags posted by the Algonquin pipeline.[71] Consistent with other data and information provided by protesting parties, such data relates to the availability of interruptible service and does not otherwise undermine consideration of other gas purchase options that may be available to accommodate deliveries of gas from the TETCO M3 hub to Load Zone G (Rockland County).[72]

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[67] Docket No. ER21-502-000, *supra*, Limited Protest of GenOn Bowline, LLC and GenOn Energy Management, LLC at 10-22 (December 21, 2020) ("GenOn Protest"); IPPNY Protest at 24-28; and CPV Protest at 12-22.

[68] GenOn Protest at 22-25; IPPNY Protest at 28; and CPV Protest at 17-22.

[69] GenOn Protest at 10-22; IPPNY Protest at 24-27; and CPV Protest at 12-17.

[70] *Id*.

[71] GenOn Protest at 8-11 and 12-15; IPPNY Protest at 26-27; and CPV Protest at 15-16.

[72] *Supplemental Affidavit of Pallas LeeVanSchaick, Ph.D.* at ¶ 6-7 and 12-16 attached hereto as Attachment I ("MMU Supplemental Affidavit"). As permitted by the Commission's August 20, 2020 order extending the previous emergency waiver of notarization rules, the MMU Supplemental Affidavit

These parties erroneously presume that the DCR requires or assumes that the peaking plant will rely solely on interruptible service to obtain gas. The NYISO does not assume any particular gas purchasing strategy for the peaking plants.[73] This recognizes that a peaking plant can avail itself of multiple gas purchasing strategies. In addition to interruptible service, a peaking plant could pursue purchases of secondary firm transportation or other arrangements with entities holding unused firm transportation rights.[74]

Focusing solely on availability of the interruptible transportation service as indicated by IT flag data is not dispositive.[75] This information does not fully account for broader utilization of pipeline capacity. Notably, an IT flag data indicator of "N" does not necessarily indicate complete unavailability of such service.[76] IT flag indicators more broadly indicate utilization of interruptible transportation service.[77] An IT flag indicator of "N" may simply reflect that parties have elected not to utilize interruptible transportation service for the period at issue. Non-use of interruptible transportation service can arise from economic decisions to forego such service due to the availability of lower cost alternatives. The MMU's analysis of the pipeline capacity utilization appropriately evaluates the general availability of alternative options to obtain deliveries of gas to a peaking plant in Load Zone G (Rockland County).[78]

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has not been notarized. *See Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (2020).

[73] 2021-2025 DCR Filing at 34-35.

[74] 2021-2025 DCR Filing at 34-35 and 42-43; and MMU Affidavit at ¶ 25 and 27-30.

[75] MMU Supplemental Affidavit at ¶ 11-12.

[76] *Id*. at ¶ 11.

[77] *Id*.

[78] 2021-2025 DCR Filing at 41-43; MMU Affidavit at ¶ 24-39; and MMU Supplemental Affidavit at ¶ 6-7 and 11-16.

Certain parties erroneously allege that the analysis conducted by the MMU is limited to evaluating pipeline capacity utilization following the timely nomination cycle.[79] Such statements are incorrect. The analysis conducted by the MMU and submitted as part of the 2021-2025 DCR Filing considered data regarding pipeline capacity utilization for both the timely and intraday 3 nomination cycles.[80] In assessing the availability of otherwise unused pipeline capacity to accommodate deliveries for the proposed peaking plant in Load Zone G (Rockland County), the MMU utilized the lower of the available pipeline capacity values reported for these two nomination cycles.[81]

The MMU's analysis identified that secondary transportation may often be a more economically rational purchasing strategy.[82] Interruptible transportation is available on the Algonquin pipeline at a cost of $0.2867 per MMBtu.[83] The cost of acquiring secondary transportation depends on an opportunity costs for the owner of the firm transportation rights. The opportunity cost is generally determined based on gas price spreads between less constrained and more constrained pricing points along the path covered by the firm transportation service.[84] This opportunity cost is often lower than the cost of interruptible transportation when available pipeline capacity is not fully utilized. For example, the MMU's analysis identified that when pipeline capacity utilization on the Algonquin pipeline was below 95% of the total capability for segments between Rockland County and Massachusetts, the average difference in gas prices between the TETCO M3 hub and the Algonquin Citygates hub

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[79] CPV Protest at 14-15.

[80] MMU Affidavit at ¶ 33-34.

[81] *Id*.

[82] MMU Affidavit at ¶ 27-30.

[83] *Id*. at ¶ 27.

[84] *Id*. at ¶ 28-30.

was approximately $0.15 per MMBtu.[85] In these cases, an economically rational peaking plant would seek to utilize secondary transportation rather than more expensive interruptible transportation service.

The MMU's analysis concluded that constraints on the Algonquin pipeline typically arise downstream of the segments used to deliver gas from the TETCO M3 hub to Rockland County.[86] Although certain recent projects have upgraded portions of the Algonquin pipeline, these upgrades have not eliminated the fact that pipeline segments downstream of Rockland County experience more frequent constraints than the pipeline segments facilitating deliveries from the TETCO M3 hub to Rockland County.[87] These downstream constraints are unlikely to adversely impact the availability of transportation on the segments of the Algonquin pipeline that facilitate deliveries to Rockland County.[88]

Given the availability of reasonable alternatives to sole reliance on interruptible transportation service, the MMU appropriately analyzed broader pipeline capacity utilization information in determining whether TETCO M3 represented a reasonable gas hub for Load Zone G (Rockland County).[89] The MMU's assessment determined that sufficient pipeline capacity generally remains available to accommodate delivery of the amount of gas used by the proposed peaking plant in Load Zone G (Rockland County).[90]

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[85] *Id*. at ¶ 29-30; and MMU Supplemental Affidavit at ¶ 7.

[86] MMU Affidavit at ¶ 32 and 39; and MMU Supplemental Affidavit at ¶ 6-7 and 14-16.

[87] MMU Supplemental Affidavit at ¶ 13-14.

[88] MMU Affidavit at ¶ 32; and MMU Supplemental Affidavit at ¶ 13-16.

[89] 2021-2025 DCR Filing at 42-43; and MMU Affidavit at ¶ 31-39.

[90] 2021-2025 DCR Filing at 42-43; MMU Affidavit at ¶ 33; and MMU Supplemental Affidavit at ¶ 6-7, 9, and 14-16.

Consideration of additional factors, such as IT flag data and firm service capacity held by "no-notice" shippers would not alter the conclusions of the MMU's assessment.[91] Available pipeline data indicates that constraints and restrictions imposed by Algonquin relate to segments of the pipeline downstream of Rockland County.[92] These limitations do not support a conclusion that similar restrictions and availability limitations exist for the segments of the Algonquin pipeline that facilitate deliveries of gas from the TETCO M3 hub to Rockland County.[93]

Contrary to assertions of certain parties that the peaking plant would be unable to operate for much of the year due to the limited availability of interruptible transportation service,[94] the MMU's analysis concluded that sufficient pipeline capacity was available in nearly all hours to accommodate deliveries of gas in quantities consistent with the estimated operation of the peaking plant in Load Zone G (Rockland County) for the three-year period used in determining the ICAP Demand Curves for the 2021/2022 Capability Year.[95] Certain parties erroneously assert that the MMU's analysis was limited to assessing data on a monthly basis.[96] Contrary to such claims, the analysis conducted by the MMU accounted for daily availability of pipeline capacity.[97] Specifically, the MMU identified that sufficient pipeline capacity remained available to serve the estimated dispatch of the peaking plant, as determined by the net energy and

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[91] MMU Supplemental Affidavit at ¶ 11-12 and 15.

[92] *Id*. at ¶ 6 and 14-16.

[93] *Id*. at ¶ 11-16.

[94] GenOn Protest at 18-19; IPPNY Protest at 27; and CPV Protest at 15-16.

[95] MMU Affidavit at ¶ 34; and MMU Supplemental Affidavit at ¶ 9.

[96] GenOn Protest at 9.

[97] MMU Supplemental Affidavit at ¶ 9-10.

ancillary model, in 89% of all hours for the three-year period from September 1, 2017 through August 31, 2020.[98]

The NYISO's proposal to use separate gas hubs for the two locations evaluated in Load Zone G is consistent with prior DCRs. In fact, the DCR that established the ICAP Demand Curves for the 2014/2015 through 2016/2017 Capability Years used the same gas hubs proposed by the NYISO for this reset – the Iroquois Zone 2 hub for Load Zone G (Dutchess County) and the TETCO M3 hub for Load Zone G (Rockland County).[99] Use of the Iroquois Zone 2 hub for Load Zone G (Rockland County), as recommended by certain parties,[100] would not be appropriate for the 2021-2025 DCR. The Iroquois Zone 2 hub is likely to materially understate potential revenues earnings for a peaking plant in Load Zone G (Rockland County), resulting in an artificially inflated estimate of the net cost of new entry for this location.[101]

The NYISO carefully reviewed and evaluated relevant data and information in selecting TETCO M3 as the gas hub for Load Zone G (Rockland County).[102] The NYISO's proposal appropriately accounts for pipeline capacity availability to facilitate deliveries of gas from the TETCO M3 gas hub to a peaking plant in Load Zone G (Rockland County). TETCO M3 is a reasonable gas hub that appropriately seeks to avoid unnecessary underestimating or overestimating of potential energy market revenues for a peaking plant located in Load Zone G (Rockland County).

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[98] MMU Affidavit at ¶ 34; and MMU Supplemental Affidavit at ¶ 9.

[99] 2021-2025 DCR Filing at 41; and 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 29, n. 126 (November 18, 2016).

[100] GenOn Protest at 22-25; IPPNY Protest at 28; and CPV Protest at 17-22.

[101] 2021-2025 DCR Filing at 41-43; MMU Affidavit at ¶ 35-39; and MMU Supplemental Affidavit at ¶ 6-7 and 9.

[102] 2021-2025 DCR Filing at 41-43; and MMU Affidavit at ¶ 23-39.

C. Financial Parameters

The conversion of upfront capital investment costs for each peaking plant, including property taxes and insurance, into annualized values requires the determination of parameters, such as: (1) the appropriate weighted average cost of capital ("WACC") required by a developer to recover its up-front costs, plus a reasonable return on its investment; and (2) the appropriate term in years over which recovery occurs (commonly referred to as the "amortization period"). The NYISO proposes to adopt the financial parameters developed by the Independent Consultant, including: (1) a return on equity ("ROE") value of 13%; (2) an assumed cost of debt ("COD") equal to 6.7%; (3) a debt-to-equity ratio of 55/45; and (4) a 17-year amortization period.[103]

Certain parties raise concerns regarding the proposed ROE and COD values, as well as the recommended 17-year amortization period. Certain parties advocate for the adoption of lower ROE and COD values.[104] Other parties contend these values are understated and do not adequately account for the risk of investing in a new peaking plant in New York.[105] Parties also express divergent positions with respect to the proposed amortization period. Certain parties advocate for increasing the amortization period to 20 years,[106] while other parties seek adoption of a shorter, 15-year amortization period.[107]

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[103] 2021-2025 DCR Filing at 47-53.

[104] Consumer Stakeholders Protest at 24-26.

[105] IPPNY Protest at 14-19.

[106] Consumer Stakeholders Protest at 18-21; and Docket No. ER21-502-000, *supra*, Motion to Intervene and Comments of the Market Monitoring Unit on the New York ISO's ICAP Demand Curve Reset at 3-13 (December 21, 2020) ("Potomac Economics Comments").

[107] IPPNY Protest at 9-14.

The Independent Consultant developed the proposed values based on a review of relevant market data and information, and its reasoned judgment and professional experience.[108] The proposed values are reasonable and appropriate. The Commission should adopt the proposed financial parameter values without modification.

1. <u>The Proposed ROE and COD Values Are Reasonable and Supported by Relevant Data and Information</u>

Parties advocate divergent positions in favor of either increasing or decreasing the proposed 13% ROE value. The Independent Consultant derived this value following the review of various data sources addressing various project development finance approaches and the returns required by developers of merchant power plants.[109]

The Independent Consultant estimated ROE values for publicly traded independent power producers ("IPPs") of up to 10.5%.[110] The Independent Consultant also identified that stand-alone project finance approaches exhibited ROE values ranging from 12% to 20%.[111] The proposed 13% value is within the range of values identified. Considered in combination with the remaining financial parameters, the value reasonably supports the development of a merchant peaking plant in New York.

Similar to the recommended ROE value, parties express divergent positions seeking to either increase or decrease the recommended 6.7% COD value. Parties advocating for a lower COD value note that the proposed value exceeds the currently observed debt cost for generic B-rated corporate debt.[112] Parties advocating for a higher COD value contend that proposed value

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[108] 2021-2025 DCR Filing at 47-53; and AG Affidavit at ¶ 65-82.

[109] 2021-2025 DCR Filing at 48-49; and AG Affidavit at ¶ 76.

[110] *Id.*

[111] *Id.*

[112] Consumer Stakeholders Protest at 24-25.

does not adequately account for the risk of investing in a merchant peaking plant in New York and the costs attendant thereto, such as the potential need to execute financial hedges to secure financing.[113] The Independent Consultant's assessment of debt costs incurred by publicly traded IPPs since 2017 and financial market data regarding debt costs for corporate debt identified a range of reasonable COD values from 4% to 8%.[114]

The Independent Consultant assumed B-rated corporate debt in assessing the appropriate debt cost because publicly traded IPPs generally exhibit ratings below investment grade and in consideration of the relative risk attendant to pursuing a non-recourse, stand-alone financing approach for project development.[115] In selecting a 6.7% COD value, the Independent Consultant recognized that debt costs for generic B-rated corporate debt would likely decline over time as the financial markets continued to settle in response to the ongoing COVID-19 pandemic.[116] The Independent Consultant, however, recommended a COD value slightly above generic debt ratings in recognition of the fact that: (1) IPPs tend to experience debt costs that somewhat exceed contemporaneous debt cost indices; (2) merchant investment in a new peaking plant in New York faces higher financial risks; and (3) securing debt financing for a merchant peaking plant may impose certain costs not expressly quantified, such as the potential need to execute financial hedges.[117]

The proposed ROE and COD values fall within the range of reasonable assumptions identified by the Independent Consultant. The Independent Consultant fully evaluated relevant

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[113] IPPNY Protest at 17-19; and CPV Protest at 24-26.

[114] 2021-2025 DCR Filing at 49-50; and AG Affidavit at ¶ 74-75.

[115] 2021-2025 DCR Filing at 49-50; and AG Affidavit at ¶ 75.

[116] *Id*.

[117] *Id*.

data and information in developing the recommended values and fully supported the values selected based on the assessment undertaken.

2. The Proposed Amortization Period Is Reasonable Given the Current Status of the Climate Leadership and Community Protection Act Implementation

A primary consideration underlying the NYISO's proposed 17-year amortization period is the requirement established by the Climate Leadership and Community Protection Act ("CLCPA") to transition to 100% zero-emission electricity supply in New York by 2040.[118] Certain parties advocate for increasing the amortization period to 20 years given that fossil-fired generators could potentially pursue retrofitting or other modifications in the future to continue operation in compliance with the CLCPA's zero-emission requirement.[119] Other parties request that the Commission direct the reduction of the amortization to 15 years given the likely timeframe for a new facility to commence operation during the 2021-2025 reset period.[120]

The proposed amortization period represents the average period of years between the beginning of each Capability Year covered by the 2021-2025 reset period and the January 1, 2040 deadline established by the CLCPA for achieving 100% zero-emission electricity supply. The proposed 17-year amortization period reasonably represents the period a new fossil-fuel fired peaking plant can operate absent retrofitting or other modifications to operate in compliance with the CLCPA's zero-emission requirement.[121] Determining the amortization period in this manner is appropriate because the DCR implicitly assumes that the peaking plants

[118] 2021-2025 DCR Filing at 51-53; and AG Affidavit at ¶ 68-69.

[119] Consumer Stakeholders Protest at 18-21; and Potomac Economics Comments at 3-13.

[120] IPPNY Protest at 9-14.

[121] 2021-2025 DCR Filing at 51-53; and AG Affidavit at ¶ 68-69.

underlying each ICAP Demand Curve are initially in service as of May 1, 2021 (*i.e.,* the beginning of the first Capability Year encompassed by this DCR).[122]

Notably, the Services Tariff does not permit the NYISO to recalculate the applicable localized levelized capital cost (commonly referred to the "gross cost of new entry" or "Gross CONE") utilizing differing amortization periods over the course of each reset. As part of the tariff-prescribed annual updates, the Services Tariff limits adjustments to Gross CONE values to only the application of a composite escalation factor to the applicable Gross CONE values underlying the ICAP Demand Curves for the first Capability Year of the reset period.[123] Use of the average period of operation prior to 2040 for the proposed peaking plants over the course of the 2021-2025 reset period reasonably accounts for the requirements of the tariff.

The NYISO's proposed 17-year amortization period also appropriately accounts for the current state of regulations and programs to implement the CLCPA's zero-emission requirement. Regulations and programs to implement the CLCPA's zero-emission requirement will be developed and refined over the coming years. At this time, however, no regulations or programs have been developed and/or implemented to define the eligibility requirements to comply with the 2040 zero-emission requirement.[124] Such regulations and/or programs are necessary to define potential pathways for fossil-fuel fired generation to pursue retrofits or other modifications to facilitate operation as a zero-emission resource. Absent regulations and/or programs to define potential pathways for fossil-fuel fired generation to pursue retrofits or other modifications to facilitate operation as a zero-emission resource, the NYISO is unable to

[122] 2021-2025 DCR Filing at 52.

[123] Services Tariff § 5.14.1.2.2.1.

[124] 2021-2025 DCR Filing at 52-53.

estimate the potential capital costs related to any such conversion or identify with any reasonable certainty the variable operating costs associated with operating as a zero-emission resource.[125]

For the 2021-2025 DCR, assuming any retrofitting or other modifications to facilitate transition to a zero-emission resource in the absence of such regulations and/or programs requires speculation in contravention of Commission precedent.[126] The Commission has consistently held that the NYISO should not speculate as to future laws and/or regulations for purposes of decisions in each DCR.[127] Instead, the Commission requires that the NYISO consider applicable laws and regulations currently in effect at the time of each reset. The requirement to conduct the DCR every four years provides the appropriate means for assessing the implications of changes to existing laws and regulations over time.

Certain parties recommend an alternative approach that involves using a 20-year amortization period, while eliminating energy revenues for the last three years of the 20-year period.[128] This alternative approach is not reasonable because it relies on assumption that the peaking plant is capable of operating to produce energy, if required. Energy production capability hinges on the ability to operate in continued compliance with the CLCPA's zero-emission requirement after 2039. Due to the current absence of regulations or other program rules that would facilitate the potential for fossil-fuel fired generators to pursue retrofitting or other modifications to operate as a zero-emission resource, presumed operation beyond 2039

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[125] AG Affidavit at ¶ 68-69.

[126] 2021-2025 DCR Filing at 52-53; and AG Affidavit at ¶ 69. Notably, certain parties advocating for the use of a 20-year amortization period acknowledge the absence of implementing regulations and the difficulty this presents for this reset in attempting to assess potential pathways for a fossil-fuel fired generator to continue operating beyond 2039 or the costs associated therewith. *See, e.g.*, Potomac Economics Comments at 5-6 and 9.

[127] *See, e.g., New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 at P 61 (2017); and *New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 74 (2014).

[128] Consumer Stakeholders Protest at 20.

would require speculation as to regulations and programs to implement the CLCPA's zero-emission requirement that do not exist at this time.

The proposed 17-year amortization period reasonably accounts for the current state of regulations and programs to implement the CLCPA's zero-emission requirement and the operational life of the proposed peaking plants through 2039. The NYISO will continue to monitor the development of regulations and programs to implement the requirements of the CLCPA over the coming years. The NYISO will consider such information and the implications thereof in future resets.

III. CONCLUSION

The NYISO's proposal for the 2021-2025 DCR is just and reasonable. The NYISO respectfully requests that the Commission: (1) issue an order on or before January 29, 2021 accepting the NYISO's proposal without modification; and (2) establish an effective date of January 30, 2021 for the tariff revisions proposed in this proceeding.

Respectfully submitted,
/s/ Garrett E. Bissell
Garrett E. Bissell
Senior Attorney
New York Independent System Operator, Inc.

Dated: January 5, 2021

cc: Jignasa Gadani
Jette Gebhart
Leanne Khammal
Kurt Longo
John C. Miller
David Morenoff
Larry Parkinson
Douglas Roe
Frank Swigonski
Eric Vandenberg
Gary Will

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. §385.2010.

Dated at Rensselaer, NY this 5th day of January 2021.

/s/ Joy A. Zimberlin

Joy A. Zimberlin
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Attachment I

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER21-502-000**

SUPPLEMENTAL AFFIDAVIT OF PALLAS LEEVANSCHAICK, PH.D.

I. Background

1. My name is Pallas LeeVanSchaick. I am an economist and vice president at Potomac Economics Ltd. ("Potomac Economics"). Potomac Economics is the Market Monitoring Unit ("MMU") for the New York Independent System Operator, Inc. ("NYISO"), and I currently serve as Director of the MMU for NYISO.[1] My credentials and those of the MMU can be found in my previous Affidavit in this proceeding.[2]

2. I provided an Affidavit accompanying NYISO's filing on November 30, 2020 in the above-captioned proceeding (the "LeeVanSchaick Affidavit"), in which I described analysis performed by the MMU which supports the NYISO's proposed use of TETCO M3 as the proxy gas hub for Load Zone G (Rockland County).

3. The purpose of this Supplemental Affidavit is to clarify aspects of the MMU's analysis in response to criticisms raised in the affidavit of Mr. Anthony Scott of BTU Analytics, LLC (the "Scott Affidavit"), which was included as Attachment 1 to the limited protest filed by GenOn Bowline, LLC and GenOn Energy Management, LLC ("GenOn") on December 21, 2020 in this proceeding.[3]

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1 Capitalized terms that are not specifically defined in this Supplemental Affidavit shall have the meaning set forth in the filing to which it is attached or, if not defined therein, the meaning set forth in the NYISO Market Administration and Control Area Services Tariff.

2 Docket No. ER21-502-000, *New York Independent System Operator, Inc.*, 2021-2025 ICAP Demand Curve Reset Proposal at Attachment VI (*Affidavit of Pallas LeeVanSchaick, Ph.D.*) (November 30, 2020).

3 Docket No. ER21-502-000, *supra*, Limited Protest of GenOn Bowline, LLC and GenOn Energy Management, LLC (December 21, 2020) ("GenOn Protest").

II. Summary of the MMU's Analysis Supporting the Use of TETCO M3 as the Gas Hub for Load Zone G (Rockland County)

4. Potomac Economics provided comments and analysis related to the selection of proxy gas hubs at various points throughout the 2021-2025 ICAP Demand Curve reset ("DCR"), in our capacity as MMU for the NYISO. My analysis and its conclusions are further described in the LeeVanSchaick Affidavit. Several key points are summarized below.

5. The DCR requires the NYISO to use a method for estimating the net energy and ancillary services revenues for each peaking plant that is simple, transparent, and based on information that is readily accessible to market participants. Consequently, there may be individual days when an analysis of pipeline data suggests the net energy and ancillary services revenues could potentially be over-estimated, but these should be reasonably balanced against circumstances when the same data suggests they could potentially be under-estimated on other occasions. This seeks to ensure that over the course of the three-year period used in developing estimates of net energy and ancillary services revenues for each Capability Year, such estimates produce a reasonable approximation of potential revenue earnings for each peaking plant. The NYISO's proposal to use the TETCO M3 hub price plus a $0.27/MMBtu transportation cost adder for the proposed dual fuel peaking plant in Load Zone G (Rockland County) strikes a reasonable balance between periods when the actual cost would potentially be lower versus periods when such costs would potentially be higher.

6. Gas from the TETCO M3 hub is transported to Rockland County via the Algonquin pipeline. Pipeline data, including critical notices and daily operationally available capacity data, indicate that while bottlenecks on Algonquin can occur in Rockland County, they are far more prevalent downstream of Rockland County. Hence, it is reasonable to assume a different gas price in Rockland County than at locations further downstream, such as in Connecticut where the Iroquois pipeline interconnects with the Algonquin pipeline. Use of a downstream pricing hub, such as Iroquois Zone 2 (as recommended by Mr. Scott), for the peaking plant in Load Zone G (Rockland County) would be inappropriate because it would ignore: (a) the effects of constraints between Rockland County and the Iroquois pipeline at

the Stony Point and Southeast compressor stations, and (b) that Iroquois Zone 2 often exhibits a substantial premium over prices anywhere along the Algonquin pipeline.[4]

7. Since pipeline constraints can occur upstream of Rockland County, I quantified the possible impact of such constraints in a "restricted by availability" scenario, which used the Iroquois Zone 2 hub price in net Energy and Ancillary Services model proposed by the NYISO for the 2021-2025 DCR ("E&AS Model") on days when pipeline constraints might have occurred upstream of Rockland County.[5] Under this scenario, the annual net cost of new entry ("Net CONE") would have increased by just 1.4 percent compared to an impact of 6.1 percent from using Iroquois Zone 2 as the gas hub for Load Zone G (Rockland County) for all periods. Thus, most of the impact of using the Iroquois Zone 2 gas hub, as Mr. Scott recommends, would be from periods when there were no constraints upstream of Rockland County. Furthermore, the results of the "restricted by availability" scenario should be weighed against the large number of days when the $0.27/MMBtu transportation adder cost assumption would clearly over-estimate the actual cost of transportation service.[6] Based on this analysis, I consider NYISO's use of the TETCO M3 hub price plus $0.27/MMBtu in Rockland County to be reasonable, while the use of the Iroquois Zone 2 hub would significantly understate revenues on the majority of days when transport is available.

8. The remainder of this supplemental affidavit discusses criticisms raised in the Scott Affidavit and clarifies how they were accounted for in the MMU's analysis.

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4 For example, the Iroquois Zone 2 hub price exceeded the Algonquin Citygates hub price on 172 days during 2020 by an average of $0.33/MMBtu according to data published by S&P Global Market Intelligence ("SPGMI"). Since the Algonquin Citygates hub price is the most constrained portion of the Algonquin pipeline, the Algonquin Citygates price should be regarded as a theoretical upper bound for the appropriate gas price in Rockland County.

5 LeeVanSchaick Affidavit at ¶ 35-37.

6 LeeVanSchaick Affidavit at ¶ 29. For the three year period used in estimating net energy and ancillary services revenues for the 2021/2022 Capability Year ICAP Demand Curves (*i.e.*, September 2017 through August 2020), the average spread in gas prices between the Algonquin Citygates hub and the TETCO M3 hub was $0.15/MMBtu during unconstrained periods, which reflect days when the utilization of all Algonquin pipeline segments between Rockland County and Massachusetts were below 95% of the total available pipeline capacity.

III. Responses to Criticisms Raised in the Scott Affidavit

A. The MMU's Analysis Accounts for Daily Gas Price Variation

9. The Scott Affidavit mischaracterizes my analysis as relying on monthly average data and failing to account for daily variations in pipeline availability.[7] In fact, I presented analysis derived from the E&AS Model that specifically accounts for daily transport availability:

- I compared the Load Zone G (Rockland County) peaking plant's daily fuel usage, as determined by the E&AS Model, with available pipeline capacity in Rockland County on the same days. There was sufficient available capacity on the Millennium Mainline segment of the Algonquin pipeline (*i.e.*, the segment that facilitates deliveries from the TETCO M3 hub to Rockland County) to meet 89 percent of the peaking plant's expected operation, compared to 41 percent if the limiting constraint was the Stony Point segment downstream of Rockland County.[8]

- In the "restricted by availability" scenario, I calculated a blended gas price for each day which weighted the TETCO M3 hub proportionately to available capacity on the Millennium Mainline segment of the Algonquin pipeline. I then re-ran the E&AS Model using the blended prices as alternative fuel cost inputs. This resulted in a reduction of the estimated net revenues equivalent to just 1.4 percent of annual Net CONE value for Load Zone G (Rockland County) for the 2021/2022 Capability Year.[9]

10. The E&AS Model simulates hourly dispatch of the peaking plant and captures the effects of the relationship between power and gas prices each day. As such, my analysis already accounts for the impacts of daily variations in gas prices and pipeline capacity.

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7 Scott Affidavit at ¶ 61.

8 LeeVanSchaick Affidavit at ¶ 34.

9 LeeVanSchaick Affidavit at ¶ 35-37.

B. The "IT Flag" Is Not Sufficient to Demonstrate Whether Transport is Available

11. The Scott Affidavit presents data showing that the "IT Flag" on Algonquin's Electronic Bulletin Board is frequently set to "N" in Rockland County, and claims that, as a result, transportation service to Rockland County is unavailable on such days.[10] However, the purpose of the IT flag is to indicate whether interruptible service was utilized as a portion of scheduled capacity.[11] A "N" value may simply indicate that no party scheduled interruptible transport on that day.[12] Since Rockland County currently constitutes a small portion of demand on Algonquin, it is unsurprising that IT deliveries are not consistently scheduled there. Hence, the historical IT flag data presented in the Scott Affidavit does not demonstrate that transport to Rockland County was necessarily unavailable, it only shows that interruptible service was not frequently used.

12. My analysis did not focus on whether interruptible service was historically utilized in Rockland County. Instead, I focused on the daily availability of unutilized pipeline capacity, which would more appropriately evaluate whether transport of gas using either secondary or interruptible service is feasible. The IT flag on its own does not address this – as GenOn notes, it has little or no relationship to available pipeline capacity.[13] It is unreasonable to conclude from the lack of a positive IT indicator (*i.e.*, IT flag indicator of

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10 Scott Affidavit at ¶ 51-53 and 81-85.

11 As required by 18 C.F.R. §284.12(a), Algonquin's tariff states that it has adopted the North American Energy Standards Board (NAESB) Business Practices and Electronic Communication Standards, NAESB WGQ Version 3.1. The NAESB WGQ Additional Standards Version 3.1 defines the IT Indicator as "An indicator which signifies whether or not interruptible transportation service is being utilized at this location." Further description in WGQ Additional Standards states that "When the operationally available capacity at the location is zero (i.e., no capacity is available), the IT indicator is required to be sent to tell the receiver of the dataset whether some portion of the capacity being utilized at the specified location is interruptible, or conversely, that no portion of the capacity being utilized at the specified location is interruptible. The IT indicator may be sent at the discretion of the [Transportation Service Provider] when the operationally available capacity at the location is not zero." Algonquin's Electronic Bulletin Board posts a value for the IT Indicator at each location every day, including days when available capacity is above zero. (Language cited above from the NAESB WGQ Standards is reproduced subject to limited copyright waiver (© 2017 NAESB, all rights reserved)).

12 For example, in Algonquin's Operationally Available Capacity posting for the last intraday cycle on December 29, 2020, the "IT" flag was set to "Y" at three downstream locations in Massachusetts and "N" at all other 186 locations, including at unconstrained upstream locations in New Jersey. This is consistent with the "IT" flag indicating only the locations where interruptible transport was actually scheduled, even if it could possibly have been scheduled at other locations.

13 *See* GenOn Protest at Attachment 2, p. 9.

"Y") that transport on the Algonquin pipeline is impossible even on days when pipeline utilization is far below capacity.[14]

C. Algonquin Pipeline Remains Bottlenecked Downstream of Rockland County

13. The Scott Affidavit alleges that secondary transport service to Rockland County would be priced based on the opportunity cost of selling gas further downstream in New England (*e.g.*, at the Algonquin Citygates hub price).[15] The Scott Affidavit notes that the Algonquin pipeline has undertaken "debottlenecking" projects to increase capacity at the Stony Point and Southeast compressor stations downstream of Rockland County, particularly the Algonquin Incremental Market ("AIM") project completed in early 2017.[16]

14. Pipeline data does not support the notion that there are no bottlenecks between Rockland County and the Algonquin pipeline's primary demand centers in New England. While the AIM project did expand capacity, the Stony Point segment continues to be constrained far more frequently than the Millennium Mainline segment.[17] As noted above, only 41 percent of the Load Zone G (Rockland County) peaking plant's expected operation would have been feasible if it were restricted by available pipeline capacity at Stony Point, compared to 89 percent if restricted by the pipeline capacity available on the Millennium Mainline segment. Additionally, pipeline critical notices regularly restrict both interruptible and secondary transport through the Stony Point compressor station and several other downstream constraints.[18]

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[14] The IT Flag is frequently set to "N" even on days of low demand when the Algonquin pipeline operates far below its maximum capacity. For example, on June 8, 2020, the IT flag was set to "N" at Ramapo, NY and nearly all other locations in both the timely and last intraday cycles, despite the fact that the maximum utilization on the Millennium Mainline segment was just 71 percent and did not exceed 76 percent on any Algonquin pipeline segment.

[15] Scott Affidavit at ¶ 87-93.

[16] Scott Affidavit at ¶ 49.

[17] The data assessed (*i.e.*, September 2017 through August 2020) is after from after the AIM project was placed in service in early 2017. For this post-AIM period, the average utilization of the Stony Point segment (calculated using the higher of "Timely" or "Intraday 3" nomination cycle schedules) was 96 percent, compared to 81 percent on the Millennium Mainline segment.

[18] For example, see the critical notice "AGT Pipeline Conditions for 12/28/20" posted on Algonquin's Electronic Bulletin Board on December 27, 2020, available at: https://infopost.spectraenergy.com/infopost/NoticeListDetail.asp?strKey1=104040&type=CRI&Embed=2&pipe=AG. This language is typical of daily critical notices.

D. Use of Firm No-Notice Capacity Data Would Not Change MMU's Conclusions

15. The Scott Affidavit notes that my analysis did not include data on firm no-notice capacity reserved by pipeline customers, which Mr. Scott contends could impose further restrictions on the quantity of capacity available for purchase by the peaking plant.[19] Incorporation of firm no-notice reservations would not have changed the conclusions of my analysis. First, firm transport rights are mainly held by shippers in New England, not in Rockland County, and pipeline bottlenecks frequently limit the ability to increase flows through Rockland County to points further downstream, as discussed above. Second, there is no evidence from the pipeline critical notices I reviewed that demand from no-notice customers caused secondary or interruptible service for delivery to Rockland County to be cut on any days. Finally, the "restricted by availability" scenario that I conducted conservatively required 110 percent of the Load Zone G (Rockland County) peaking plant's desired fuel consumption to be available in order to receive a full TETCO M3 hub price, accounting for the risk that gas would stop being available before the pipeline reaches 100 percent utilization.

E. Critical Notices Provide Further Support that Bottlenecks Occur Downstream of Rockland County

16. I presented evidence that the Algonquin pipeline routinely issues critical notices curtailing interruptible and secondary transport sourced west of Stony Point for delivery east of Stony Point, but not for points further upstream such as the Millennium Mainline segment that facilitates deliveries through Rockland County.[20] The Scott Affidavit claims that these notices are not relevant because only a small portion of Algonquin's demand is upstream of Stony Point, and that the IT flag is a better indicator of availability.[21] Critical notices, while not the sole focus of my analysis, are valuable data because they indicate curtailment of secondary transport in addition to interruptible transport. The IT flag, which has no relationship to pipeline utilization, does not provide the same information. The persistent

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[19] Scott Affidavit at ¶ 13.

[20] In 2019, Algonquin announced restrictions on interruptible and/or secondary nominations sourced from points west of Stony Point for delivery east of Stony Point on 363 days, but did not announce restrictions on west-to-east transport for delivery west of Stony Point on any days. *See* LeeVanSchaick Affidavit at ¶ 31-34.

[21] Scott Affidavit at ¶ 71-73.

issuance of critical notices restricting secondary transport for Stony Point and other downstream locations is consistent with operationally available capacity data, which shows that sufficient capacity to accommodate the peaking plant is typically available on the Millennium Mainline segment but not on the Stony Pont segment.

F. Restrictions on Oil Firing are Already Included in the Net CONE

17. The Scott Affidavit claims that the peaking plant's ability to run on oil when gas is unavailable is immaterial because environmental permits would limit its ability to do so.[22] Environmental restrictions, including limitations on the allowed hours of oil firing annually, are already included in the optimization of the E&AS Model. The peaking plant is not expected to run on oil frequently due to its high cost. However, the capability to burn oil provides insurance that reliability will not be jeopardized in rare circumstances when gas cannot be obtained, and the cost of dual fuel capability is included in the Net CONE.

IV. Conclusion

18. Based on the forgoing, the MMU supports NYISO's use of the TETCO M3 gas hub for Load Zone G (Rockland County) despite the criticisms raised in the Scott Affidavit. TETCO M3 is a reasonable gas hub that seeks to avoid unreasonable over-estimating or under-estimating of the potential net energy and ancillary services revenues for the Load Zone G (Rockland County) peaking plant.

19. This concludes my affidavit.

Respectfully submitted,

/s/ Pallas LeeVanSchaick
Pallas LeeVanSchaick, Ph.D.
Vice President
Potomac Economics Ltd.

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[22] Scott Affidavit at ¶ 70.