New York ISO
Independent System Operator

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February 12, 2021

By Electronic Delivery

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

Re: Docket No. ER21-502-00_, *New York Independent System Operator, Inc.*; Response to Request for Additional Information

Dear Secretary Bose:

On November 30, 2020, the New York Independent System Operator, Inc. ("NYISO") filed its proposal related to the tariff-prescribed quadrennial review of the Installed Capacity ("ICAP") Demand Curves in the above referenced proceeding ("2021-2025 DCR Filing").[1] The proposal included: (1) revisions to the Market Administration and Control Area Services Tariff ("Services Tariff") related to the proposed ICAP Demand Curves for the 2021/2022 Capability Year; and (2) 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. On January 29, 2021, the Federal Energy Regulatory Commission ("Commission") issued a notice requesting additional information regarding certain aspects of the NYISO's proposal ("Notice").[2] The NYISO hereby submits responses to the questions set forth in the Notice.

As further described herein, the NYISO requests that the Commission: (1) waive the standard 60-day notice period and issue an order accepting the 2021-2025 DCR Filing within 30 days of the date of this filing (*i.e.*, on or before March 15, 2021); and (2) establish an effective date of March 15, 2021 (*i.e.*, thirty days from the date of this filing) for the tariff revisions proposed in this proceeding.[3] Expedited action by the Commission is necessary to: (1) facilitate the NYISO's ability to timely administer the ICAP auctions for the upcoming 2021 Summer Capability Period; and (2) provide certainty to the marketplace regarding the ICAP Demand Curves that will be in effect starting with the 2021 Summer Capability Period.

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[1] Docket No. ER21-502-000, *New York Independent System Operator, Inc.*, 2021-2025 ICAP Demand Curve Reset Proposal (November 30, 2020). Capitalized terms not otherwise defined herein shall have the meaning specified in the Services Tariff.

[2] Docket No. ER21-502-000, *supra*, Deficiency Notice and Request for Additional Information (January 29, 2021).

[3] As part of this filing, the NYISO resubmits the tariff revisions (as Attachments I and II, clean and redline, respectively) that were attached to the 2021-2025 DCR Filing. The resubmitted tariff revisions reflect the updated effective date of March 15, 2021 requested herein, but are otherwise unchanged.

I. Response to Additional Information Request

The NYISO submits the responses below to the questions set forth in the Notice.

Question No. 1.a:

Please provide additional support or examples that describe the anticipated increased revenue earning opportunities that arise for a dual fuel facility when natural gas is unavailable or uneconomic due to natural gas demand or constraints. Please also describe how these anticipated revenues may offset additional capital costs to include dual fuel capability for the peaking facility design for the G-J Locality.

Response:

Competition for natural gas supply places upward pressure on natural gas commodity prices and can result in gas system constraints that limit the ability to flow gas from supply sources to receipt points of gas demand. Such conditions are most likely to occur during the winter due to increased demand for natural gas by retail gas customers. Spikes in gas prices resulting from these conditions can produce circumstances where alternative fuel sources, such as ultra-low sulfur diesel ("ULSD"), are lower cost options for producing electricity than natural gas. Additionally, constraints on the delivery capability of the gas system can result in the need for gas system operators to impose restrictions on the use of the gas system, such as operational flow orders. Such restrictions may make it infeasible or uneconomic for a gas-fired generator to produce electricity using natural gas. During periods of gas price spikes, gas supply scarcity, and/or restrictions on the availability of gas system infrastructure to accommodate deliveries of gas supply, the capability of dual fuel units to operate on an alternative fuel source presents opportunities for operation and revenue earnings unavailable to generators that operate solely on natural gas to produce electricity.

Such conditions are not merely theoretical. These conditions have occurred in New York in recent years. Conditions where electricity production using natural gas may be restricted due to economics and/or delivery constraints are also reasonably likely to recur in the nearer term due to various factors, including: (1) the relatively high reliance on natural gas to produce electricity; (2) the increasing importance of access to flexible resources over the coming years as the electric grid transitions to a clean energy system with rapidly increasing reliance on weather-dependent generation resources; and (3) the relatively low likelihood for significant expansions of gas system transportation capability and/or supply in New York.

During the extreme cold snap experienced during the 2013/2014 winter period, natural gas prices significantly exceeded oil prices presenting opportunities for dual fuel units to operate economically using their alternative, lower cost fuel sources.[4] In fact, natural gas prices

[4] NYISO, *Winter 2013-2014 Cold Weather Operating Performance* (presented at the March 13, 2014 Joint Electric-Gas Coordination Working Group and Market Issues Working Group meeting) at 19, available at: https://www.nyiso.com/documents/20142/1402802/Winter%202013-

exceeded the cost of ULSD for eight days during the extreme cold weather events during the 2013/2014 winter period.[5] Similar conditions arose again the following winter. During the extended cold weather conditions occurring in January 2015 and February 2015, natural gas prices exceeded oil prices in certain areas throughout New York on 26 days.[6] During the bomb cyclone and extended severe cold weather events of the 2017/2018 winter period, natural gas prices in various locations throughout New York exceeded ULSD prices for the duration of the two-week period from December 27, 2017 through January 9, 2018.[7] Notably, despite relatively mild conditions last winter (*i.e.*, 2019/2020 winter), there were brief periods when certain gas prices in downstate regions were nearly equivalent to or exceeded ULSD prices.[8]

While not only presenting additional revenue earning opportunities for generators, dual fuel capability also serves as a price hedging mechanism to mitigate the level of electricity price spikes during periods of high natural gas prices. The 2013/2014 and 2017/2018 winter periods clearly demonstrated the beneficial price protection provided by dual fuel capability. During the 2013/2014 winter period, while gas prices in certain areas of New York increased by nearly 400% in January 2014, compared to December 2013, wholesale electricity prices in New York increased by less than half the spike in gas prices.[9] During the severe cold weather conditions of the 2017/2018 winter, natural gas prices increased by nearly 1,400% in January 2018 compared to December 2017. However, the increase in electricity prices was less than one-quarter of the spike in gas prices during the same period.[10] In both cases, the significantly lower impact on electricity prices was, in part, due to the existence of dual fuel capability and the ability of generators with such capability to operate on a lower cost alternative fuel.[11]

1014%20NYISO%20Cold%20Snap%20Operations%20EGCW-MIWG.pdf ("2013/2014 Winter Operations Report").

[5] *Id*.

[6] NYISO, *Winter 2015 Cold Weather Operations* (presented at the March 31, 2015 Management Committee meeting) at 12 and 19-20, available at: https://www.nyiso.com/documents/20142/1397840/Agenda%205_Winter%202014-15%20Cold%20Weather%20Operations_1.pdf.

[7] NYISO, *Winter 2017-2018 Cold Weather Operations* (presented at the January 31, 2018 Management Committee meeting) at 16 and 19, available at: https://www.nyiso.com/documents/20142/1394512/Winter%202018%20Cold%20Weather%20Operating%20Conditions.pdf ("2017/2018 Winter Operations Report").

[8] NYISO, *Winter 2019-2020 Cold Weather Operations* (presented at the March 25, 2020 Management Committee meeting) at 16, available at: https://www.nyiso.com/documents/20142/11460854/04%202019%20-2020%20OC%20Cold%20Weather%20Operating%20Conditions.pdf.

[9] 2013/2014 Winter Operations Report at 22.

[10] 2017/2018 Winter Operations Report at 19.

[11] 2013/2014 Winter Operations Report at 22; and 2017/2018 Winter Operations Report at 19.

The model proposed by the NYISO for estimating each peaking plant's potential energy and ancillary services revenue earnings ("Net EAS Model") accounts for additional earning opportunities available from the inclusion of dual fuel capability.[12] For peaking plants that include dual fuel capability, the Net EAS Model accounts for such capability through considering whether it is less expensive to operate using natural gas or ULSD in assessing hourly commitment and dispatch determinations for such dual fuel plants. To the extent operation using ULSD is less expensive, the Net EAS Model will use this alternative fuel cost in determining both the peaking plant's operating status as well as revenue earnings. Periods when ULSD is less expensive than natural gas will result in additional revenue for a dual fuel plant that is unavailable to a gas only design. These additional revenues result in a larger offset to the peaking plant's gross capital investments costs and a resulting lower net cost of new entry value.

Significant additional revenues for dual fuel plants can accrue over relatively limited periods when natural gas market price spikes occur. For example, the NYISO's proposed dual fuel peaking plant design for Load Zone G (Rockland County) earned nearly 10% more energy market revenues than estimated for a gas only plant design during the twelve-month period from September 2017 through August 2018 (*i.e.*, the first twelve month period encompassed by the historical three-year period used in determining the ICAP Demand Curves for the 2021/2022 Capability Year).[13] These additional revenues are primarily the result of the dual fuel peaking plant's ability to operate on its lower cost, alternative fuel source (*i.e.*, ULSD) during the bomb cyclone and severe cold weather operations that occurred between late-December 2017 and mid-January 2018. The ability to operate on lower cost ULSD during this brief period of gas price spikes produced an increase in revenue earnings of approximately $1.7 million for this single

[12] 2021-2025 DCR Filing at 30-32. The NYISO proposed to utilize differing assumptions for the cost to provide reserves by dual fuel and gas only plant designs. For dual fuel plants, the NYISO proposed use of a $2.00/MWh cost to provide reserves. The proposed cost for a gas only plant to provide reserves is equal to the intraday premium for acquiring natural gas, which is 10% of the applicable gas cost for the locations evaluated within Load Zone G. (*See* 2021-2025 DCR Filing at 33-34.) The Net EAS Model uses the $2.00/MWh cost for dual fuel plant designs in Load Zone G. If, however, the Commission were to reject the NYISO's proposal to use a dual fuel peaking plant design for determining the G-J Locality ICAP Demand Curve and, instead, direct use of a gas only plant design for the G-J Locality ICAP Demand Curve, the NYISO would need to modify the Net EAS Model to apply the alternative reserve cost logic for gas only plants in Load Zone G. As it relates solely to Load Zone G, the Net EAS Model currently uses the $2.00/MWh cost to provide reserves for both dual fuel and gas only plant designs. For gas only plants in Load Zone G, this results in a slight overstatement of the estimated annual average net energy market revenues used in determining the G-J Locality ICAP Demand Curve for the 2021/2022 Capability Year. As a result, the reference point price values for G-J Locality ICAP Demand Curve using a gas only peaking plant design would be slightly understated. For example, applying the appropriate reserve cost assumption to a gas only H-class frame turbine equipped with selective catalytic reduction emissions control technology located in Load Zone G (Rockland County) would result in an increase of approximately $0.15 per kW-month to the resulting reference point price for this alternative peaking plant design.

[13] 2021-2025 DCR Filing at Attachment III (*Affidavit of Paul J. Hibbard, Dr. Todd Schatzki, Charles Wu, and Christopher Llop*), Appendix D of Exhibit E ("Independent Consultant Final Report").

twelve-month period compared to the revenue earnings estimated for a gas only peaking plant design.[14]

While the three-year historical data period utilized in determining the ICAP Demand Curves for the 2021/2022 Capability Year includes a period of challenging winter operations, the NYISO and the independent consultant selected to assist with the 2021-2025 ICAP Demand Curve reset ("Independent Consultant") recognized that the developer of a peaking plant would reasonably consider a longer time horizon in assessing the potential economic opportunities provided by the inclusion of dual fuel capability.[15] Given recent historical experience, a developer would reasonably consider the potential for recurrence of periods, especially during the winter, when natural gas demand and gas system delivery constraints result in spikes in gas costs and present opportunities to realize additional energy market revenues through the capability to operate on alternative fuels during such periods.

New York law requires that: (1) renewable resources serve 70% of all electricity needs by 2030; and (2) zero-emissions resources serve 100% of all electricity needs by 2040. The aggressive transition to a clean energy system will increase the need for adequate access to flexible generation resources to address the potential for increased volatility arising from a system with growing reliance on weather-dependent, renewable generation resources. The NYISO and the Independent Consultant reasonably expect that a developer would also consider the likely increasing need for reliance on flexible resources, such as the proposed peaking plant, in assessing the benefits of including dual fuel capability for enhancing resource availability throughout the transition to a zero-emission electric system by 2040.

As set forth in the 2021-2025 DCR Filing and the response to Question 1.c below, the NYISO and the Independent Consultant considered a variety of additional, relevant considerations in proposing a dual fuel plant design for determining the G-J Locality ICAP Demand Curve.[16] Consistent with prior resets, the additional supporting considerations included: (1) reliability benefits resulting from enhanced resilience and resource availability during stressed operating conditions; and (2) the conditions present in the lower Hudson Valley. After careful consideration of all relevant factors, the retention of dual fuel capability as part of the peaking plant design for the G-J Locality ICAP Demand Curve remains reasonable and

[14] Inclusion of dual fuel capability resulted in additional revenues of $4.86 per kW-year for the proposed H-class frame turbine plant in Load Zone G (Rockland County) from operating on ULSD during the twelve-month period from September 2017 through August 2018 compared to a gas only plant design. The estimated annual revenue attributable to dual fuel capability is based on a degraded net plant capacity rating of 347 MW for the proposed peaking plant in Load Zone G (Rockland County). *See* Independent Consultant Final Report at Appendix D; and 2021-2025 DCR Filing at 59.

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

[16] 2021-2025 DCR Filing at 17-20; AG Affidavit at ¶ 32-35; and Independent Consultant Final Report at 34-36.

appropriate. The G-J Locality ICAP Demand Curve has continuously utilized a dual fuel plant design since the inception of the G-J Locality in 2014.

Question No. 1.b:

> *Please explain whether, and if so, how the fixed costs needed to construct gas laterals (e.g., metering, regulating equipment, and compressor station costs) for a peaking facility to interconnect to an interstate gas pipeline are considered in this determination. Also, please explain whether the cost to secure firm capacity on an interstate pipeline is included in this assessment and why or why not.*

Response:

The capital investment cost developed for the proposed peaking plant used in establishing the G-J Locality ICAP Demand Curve includes the estimated costs for a gas lateral.[17] The estimated gas lateral cost is intended to accommodate either a connection to a local gas distribution company ("LDC") system or an interstate pipeline. The estimated cost does not vary dependent on the type of interconnection (*i.e.*, LDC system or interstate pipeline). Regardless of the type of interconnection, the NYISO's proposal for the G-J Locality ICAP Demand Curve includes the estimated costs associated with a 5-mile, 16-inch diameter gas lateral, plus the cost of an associated metering and regulation station. The capital cost estimate for the proposed peaking plant used in determining the G-J Locality ICAP Demand Curve includes an aggregate assumed cost of $23.5 million to interconnect the peaking plant to either a LDC system or an interstate pipeline.

Given the expected operating profile of a peaking plant, pursuing long-term firm transportation service from an interstate pipeline would be cost prohibitive.[18] For the three-year historical period used in determining the ICAP Demand Curves for the 2021/2022 Capability Year, the average annual hours the NYISO's proposed peaking plant for G-J Locality ICAP Demand Curve was dispatched to produce electricity was approximately 1,355 hours, which is equivalent to an annual average capacity factor of approximately 15%.[19] Based on the typical level of operation by a peaking plant, securing long-term firm transportation service from an interstate pipeline does not represent a reasonable cost to include as part of the G-J Locality ICAP Demand Curve at this time.[20]

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[17] 2021-2025 DCR Filing at 18 and 24-25; Independent Consultant Final Report at 45; and 2021-2025 DCR Filing at Attachment IV (*Affidavit of Matthew E. Lind and Kieran McInerney*), ¶ 36 ("BMCD Affidavit").

[18] 2021-2025 DCR Filing at Attachment VI (*Affidavit of Pallas LeeVanSchaick, Ph.D.*), ¶ 27 ("MMU Affidavit").

[19] Independent Consultant Final Report at Appendix D. The capacity factor calculation is based on a degraded net plant capacity rating of 347 MW for the proposed peaking plant in Load Zone G (Rockland County).

[20] MMU Affidavit at ¶ 27.

Dual fuel capability provides a reasonable, lower cost alternative for addressing operational limitations that may otherwise arise for a gas-fired peaking plant when gas price spikes occur and/or competing demand for natural gas produces constraints on the gas delivery system. The downstate region, including the lower Hudson Valley, has generally experienced more prevalent gas system constraints than the upstate region of New York. In fact, historical operating experience during severe winter weather conditions has identified that gas system constraints in New York can result in gas only generation resources experiencing forced outages due to an inability to obtain delivery of sufficient quantities of gas.[21] The existence of population centers and greater reliance on gas-fired generation throughout this area contribute materially to the higher likelihood of gas system constraints in the downstate region. In consideration of these circumstances, the inclusion of dual fuel capability as part of the peaking plant design used in determining the G-J Locality ICAP Demand Curve remains a reasonable mechanism for providing enhanced operational flexibility and resource availability.

Question No. 1.c:

> *Please explain the conditions that increase the need for siting flexibility. In your answer, please specify how the constrained conditions identified in 2019 are anticipated to persist.*

Response:

The lower Hudson Valley is a relatively geographically constrained region. The inclusion of dual fuel capability provides increased siting flexibility for the peaking plant by facilitating optionality to select sites that would require either an interconnection to the LDC gas system or the interstate pipeline system.

There are only portions of three interstate pipelines that cross relatively limited areas within the lower Hudson Valley. Given these limitations, siting a new peaking plant in a location that would facilitate ready interconnection to an interstate pipeline may present challenges. Absent identification of sites to accommodate interconnection to an interstate pipeline at a reasonable cost while simultaneously seeking to minimize electrical interconnection costs, a new peaking plant would be required to pursue an interconnection with a LDC gas system. LDC gas tariffs in the lower Hudson Valley include requirements for interconnecting gas-fired generators to have dual fuel capability.[22] The inclusion of dual fuel capability as part of the peaking plant design for the G-J Locality ICAP Demand Curve facilitates opportunities for a developer to connect to either a LDC gas system or interstate pipeline, depending on the

[21] *See*, *e.g.*, 2013/2014 Winter Operations Report at 6, 8, 12 and 15-16; and 2017/2018 Winter Operations Report at 11.

[22] 2021-2025 DCR Filing at 17; Independent Consultant Final Report at 35; and AG Affidavit at ¶ 35.

relative economics of each option. This siting flexibility increases the potential for a developer to identify a location that coincidentally minimizes both electric and gas interconnection costs.[23]

The lower Hudson Valley is also located in the downstate region of New York that has generally experienced greater prevalence of gas delivery constraints than the upstate region. In fact, as noted in the 2021-2025 DCR Filing, increasing demand for natural gas and limitations of the delivery capability of the gas system resulted in imposition of limitations by certain LDCs on accepting requests for new gas service in portions of the lower Hudson Valley during 2019.[24] These conditions arose, in part, due to high levels of gas demand in the region and constraints on the ability of the current gas delivery infrastructure to accommodate increasing gas demands.[25] Continuing concerns regarding the ability to expand pipeline infrastructure and gas pipeline capacity in New York underscore the operational availability and reliability benefits gained from dual fuel capability in this region.

Furthermore, the ongoing transition of New York's electric grid to a clean energy system highlights the importance of including dual fuel capability as part of the peaking plant design for the G-J Locality ICAP Demand Curve for this reset.[26] The rapidly increasing transition of the resource fleet to greater reliance on weather-dependent, renewable resources presents the potential for greater system volatility and uncertainty. The capability to respond to future system conditions and maintain reliability will require ready access to flexible generation resources.[27] The transition of the resource fleet in response to energy and environmental policies is expected to result in significant quantities of fossil generators in the downstate regions ceasing operation in the coming years. These resources provide important resource availability and operational flexibility due to the capability to operate on fuel sources other than natural gas.[28] The NYISO's recent comprehensive fuel security study also identified the critical importance of dual fuel capability, especially in the downstate region, to maintaining system reliability in the near-term as the transition to a clean energy system continues to unfold over the coming years.[29] Based on

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[23] 2021-2025 DCR Filing at 17-18; Independent Consultant Final Report at 35-36; and AG Affidavit at ¶ 32 and 35.

[24] 2021-2025 DCR Filing at 18-19.

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

[26] 2021-2025 DCR Filing at 19-20.

[27] *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.

[28] 2021-2025 DCR Filing at 20.

[29] 2021-2025 DCR Filing at 19; 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.

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.

Question No. 2.a:

Please explain how development, engineering, and financing costs are accounted for in the owner's cost estimate for the 2021-2025 DCR by explaining which categories are intended to reflect these costs, and how these costs were incorporated as "all in" costs for electrical and gas interconnections.

Response:

The capital investment costs for the various peaking plant options assessed as part of the 2021-2025 DCR include the engineering, procurement, and construction ("EPC") costs, owner's costs, and financing costs during construction.[30] Overall, the capital costs are intended to represent the project cycle from development and permitting through design, procurement, installation, and startup. The EPC portion of the estimate represents the installed cost of the generating facility, while the owner's costs include development activities, interconnecting facilities, financing costs, and other items assumed to be outside the scope of the EPC portion of the project. Consistent with prior resets, the cost estimates developed for the peaking plants are based on generic sites within each location evaluated.[31] The methodologies utilized to develop the proposed cost estimates are consistent with typical industry practices for developing cost estimates for generic development projects.[32]

The table in Figure 1 below, which is taken from Appendix A of the Independent Consultant Final Report, provides the detailed overview of the overnight capital investment costs estimated for a dual fuel H-class plant with selective catalytic reduction ("SCR") emissions control technology located in Load Zone G (Dutchess County).[33] This table is provided to serve as a ready reference for identifying the line-item cost categories described below. Further information is provided below for specific line items identified as part of the overnight capital investment cost estimates developed for the 2021-2025 DCR.[34]

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[30] 2021-2025 DCR Filing at 20-28; Independent Consultant Final Report at 36-59 and Appendix A; AG Affidavit at ¶ 28-29; and BMCD Affidavit at ¶ 14-20.

[31] 2021-2025 DCR Filing at 20-21; Independent Consultant Final Report at 36-39; AG Affidavit at ¶ 29; and BMCD Affidavit at ¶ 14-19 and 42-43.

[32] BMCD Affidavit at ¶ 14-15 and 42-43.

[33] This particular plant design and location was selected because it was also used for purposes of providing a comparative analysis to the cost estimates developed during the last reset by a different engineering and design firm. *See* BMCD Affidavit at ¶ 41-45.

[34] *See* Independent Consultant Final Report at Appendix A (refer to the tables providing the breakdown of capital costs for each particular peaking plant design and location).

Figure 1: Capital Costs for 1x GE 7HA.02 with SCR and Dual Fuel in Load Zone G (Dutchess County)

1x0 GE 7HA.02 25ppm Dual Fuel with SCR, Capital Costs	
	ZONE G - Dutchess
ESTIMATED CAPITAL COSTS	
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)	
Labor	$63,180,000
Materials	$61,160,000
Turbines or Batteries	$68,500,000
Other	$64,290,000
EPC Project Capital Cost Subtotal, 2020$	**$257,130,000**
Owner's Cost Allowances, 2020$	
Owner's Project Development	$370,000
Owner's Operational Personnel Prior to COD	$440,000
Owner's Engineer	$1,020,000
Owner's Project Management	$1,130,000
Owner's Legal Costs	$1,000,000
Owner's Start-up Engineering and Commissioning	$270,000
Sales Tax	$0
Construction Power and Water	$550,000
Permitting and Licensing Fees	$1,000,000
Switchyard	$10,250,000
Electrical Interconnection and Deliverability	$11,000,000
Gas Interconnection and Reinforcement	$23,500,000
System Deliverability Upgrade Costs	$0
Emission Reduction Credits	$70,000
Political Concessions & Area Development	$500,000
Startup/Testing (Fuel & Consumables)	$4,500,000
Initial Fuel Inventory	$7,240,000
Site Security	$580,000
Operating Spare Parts	$6,500,000
Builders Risk Insurance (0.45% of Construction Costs)	$1,157,085
Owner's Contingency (5% for Screening Purposes)	$16,410,354
Owner's Cost Allowance Subtotal, 2020$	**$87,487,439**
AFUDC as a Percentage of Capital Costs (%)	6.80%
AFUDC, 2020$	
EPC Portion	$17,484,840
Non-EPC Portion	$5,949,146
AFUDC Subtotal, 2020$	**$23,433,986**
Total Project Costs, 2020$	**$368,051,425**

The proposed EPC cost estimate for each peaking plant includes the engineering, procurement, and construction activities related to a generic site project scope for the generating facility.[35] The generating facility scope ends at the interfaces of the interconnecting facilities. For example, the electrical scope boundary is the high side of the generator step up transformer, and the gas scope boundary is the low side of the gas compressors. The respective interconnecting facilities are included in the owner's costs portion of the cost estimates and, therefore, excluded from the EPC portion.

The EPC portion of the estimate for each peaking plant includes four categories: (1) labor; (2) materials; (3) turbines; and (4) other. The first three categories represent the direct costs to construct the generation facility, including site preparation, foundations, structural steel, equipment installation, buildings, and associated piping, electrical, and controls. The following provides further details regarding the costs accounted for in each of these categories:

- Labor
    - This includes the direct labor for the construction of the generating facility, including the various design alternatives (*i.e.*, gas only or dual fuel and without or without back-end emissions controls).
    - Labor costs are based on duration, in hours, within each craft multiplied by the labor rates for each location evaluated.
    - Labor rates account for base pay, supplemental benefits, taxes, and insurance costs, plus allowances for small tools, supervision, construction equipment, and subcontractor overheard and profit, as applicable for each craft.
- Materials
    - This includes the balance of plant ("BOP") equipment and construction materials for the generating facility. BOP equipment includes all equipment that is not part of the gas turbine equipment scope from the manufacturer.
    - Construction materials include a variety of commodity items including, but not limited to, concrete, piping, cabling, steel, and building materials.
- Turbines
    - This represents the procurement and delivery of the gas turbine for the generating facility.
    - For the example in Figure 1, this is the cost of the GE 7HA.02 gas turbine with dual fuel capability.

The "other" category of the EPC portion represents the indirect costs of the project. This includes the engineering, construction management, startup, warranty, surety, EPC contingency, and EPC fee.

[35] 2021-2025 DCR Filing at 21-22; Independent Consultant Final Report at 42 and Appendix A; and BMCD Affidavit at ¶ 14-15.

The remaining project costs are included in the owner's costs portion of the estimate.[36] The owner's cost portion of the estimate accounts for the interconnecting facility scopes (*e.g.*, electrical interconnection and gas lateral connection), generating project development activities, financing costs, and other items assumed to be outside the scope of the EPC portion of the project. Owner's costs can vary significantly in the field due to a variety of factors including the project scope, location, general regulatory environment, and processes and methodologies employed by a particular project owner/developer. Due to the generic nature of the project estimates developed for the peaking plants, the estimates for individual line items represent allowances for reasonable costs for particular categories rather than cost estimates derived from specific, detailed scopes as would be involved in a more refined cost estimate for a particular project at a specified site location.

Certain owner's cost items that are generally related to the generating facility construction (or in some cases subsequent operation) and accounted for the in the owner's cost portion of the estimates developed for the 2021-2025 DCR include the following items:

- "Owner's Operational Personnel Prior to COD" is an allowance for the payment of operating employee salaries prior the commercial operation date ("COD") of the facility.
- "Owner's Engineer ("OE")" is an allowance for a third-party technical consultant to assist the owner during the project. An OE scope can vary greatly depending on the needs of a particular owner/developer during development and/or project execution and may intersect the project at any point on that timeline.
- "Owner's Project Management" is an allowance for owner personnel to manage and oversee the development and construction of the project.
- "Owner's Legal Costs" is an allowance for legal services during development and execution of the project.
- "Owner's Start-up Engineering and Commissioning" is an allowance for owner oversight of startup and commissioning activities.
- "Sales Tax" is shown as a $0 line item in the owner's costs due to the assumption that the project owner would receive a tax exemption certificate for capital purchases.
- "Construction Power and Water" is an allowance to cover electricity and water consumed during the construction process.
- "System Deliverability Upgrade Costs" are shown as a $0 line item due to the results of an evaluation conducted by the NYISO concluding that the proposed peaking plants could be interconnected without a need to incur System Deliverability Upgrade ("SDU") costs to obtain Capacity Resource Interconnection Service ("CRIS").[37]

[36] 2021-2025 DCR Filing at 22-25; Independent Consultant Final Report at 43-45 and Appendix A; and BMCD Affidavit at ¶ 14, 16-17 and 41-45.

[37] 2021-2025 DCR Filing at 24; and Independent Consultant Final Report at 44.

- "Emission Reduction Credits" account for the cost to secure emissions offsets for the project.
- "Political Concessions and Area Development" is an allowance for the owner to engage with the local community during project development and/or construction.
- "Startup / Testing (Fuel & Consumables)" accounts for the estimated costs of fuel consumed during startup, net of the energy generated during startup.
- "Initial Fuel Inventory" accounts for the first fill of the fuel oil tank for peaking plant designs that include dual fuel capability.
- "Site Security" is an allowance for a security contractor during construction. Note that fencing for the project site is included in the EPC cost.
- "Operating Spare Parts" is an allowance for parts that are commonly purchased and stored at the generating facility.
- "Builder's Risk Insurance" is an allowance based on 0.45% of the total capital cost estimate for the EPC portion.
- "Owner's Contingency" is an allowance based on 5% of the total installed cost for both the EPC and owner's cost portions of the cost estimate.

The interconnection-related facilities required by each peaking plant include the switchyard, electrical interconnection, gas interconnection, and water supply infrastructure (applicable only to New York City).[38] The cost estimates for the electrical interconnection, gas interconnection, and water interconnection, if applicable, are intended to be all-in costs for the respective scope.[39] Thus, the cost estimates for each of these line items account for the total costs for these interconnections, including the reasonably expected costs for development, engineering, procurement, and construction activities. Construction financing costs, however, are accounted for in the estimated cost of financing during construction (as further described below). For the dual fuel H-class peaking plant design located in Load Zone G (Dutchess County) addressed in Figure 1, the following major assumptions apply for interconnecting facilities:

- "Switchyard" assumes a 345 kV, three position ring bus with air insulated switchgear.[40]

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[38] For New York City (*i.e.*, Load Zone J), 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, peaking plant designs assume obtaining water supply from an onsite well. The cost for such onsite well is included as part of the EPC cost estimate. *See* 2021-2025 DCR Filing at 22; and Independent Consultant Final Report at 45.

[39] 2021-2025 DCR Filing at 22-25; Independent Consultant Final Report at 44-45; and BMCD Affidavit at ¶ 44.

[40] For New York City, the switchyard assumes use of gas insulated switchgear. *See* 2021-2025 DCR Filing at 23-24; and Independent Consultant Final Report at 44.

- "Electrical Interconnection and Deliverability" includes a three mile, overhead 345 kV transmission line.[41]
- "Gas Interconnection and Reinforcement" includes a five-mile, 16-inch gas pipeline and associated metering and regulation equipment.[42]
- "Water Supply Infrastructure" is not applicable for locations outside New York City. This applies only for the proposed peaking plant located in New York City, which assumes use of municipal water supply for onsite needs.[43]

Project development generally relates to the activities performed before the EPC phase of the project. The scope and cost of development activities can vary greatly depending on the project scope, site, technology, regulatory environment, and methodologies employed by a particular project owner/developer. As previously noted above, given the generic nature of the project scope used in developing the cost estimates, certain development and management related owner's cost items represent allowances rather than detailed, specific scopes. Examples include the "Owner's Project Development" and "Permitting and Licensing Fees" line items.[44] It is also important to recognize that there are potential overlaps between certain activities. For example, activities represented within the scope of the "Owner's Project Management" line item includes activities related to both the development and project execution phases of a project. In addition, activities accounted for within the respective scopes for the "Owner's Engineer," "Owner's Legal Costs," and "Political Concessions and Area Development" line items may reflect activities occurring during both the development and execution phases of a project.

Construction financing costs, including "Allowance for Funds used during Construction ("AFUDC")" and "Interest during Construction ("IDC")," are included in the owner's costs. The cost estimates identify separate line items related to construction financing costs for the EPC portion of the project, and the non-EPC (including the owner's cost) portion.[45] Construction financing costs were estimated for the assumed construction period for each peaking plant using the same 55/45 split of debt and equity and 6.7% cost of debt proposed for the project as a

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[41] For New York City, this line item assumes a one-mile, underground generation lead to interconnect the generation facility. *See* 2021-2025 DCR Filing at 23-24; and Independent Consultant Final Report at 44.

[42] For New York City, this gas interconnection assumes a one-mile, 16-inch diameter lateral with a total cost of $20 million including the cost of the associated metering and regulation station. *See* 2021-2025 DCR Filing at 24-25; and Independent Consultant Final Report at 45.

[43] For the proposed peaking plant in New York City, the water connection assumes a one-mile, 8-inch connection to the municipal water supply system. *See* 2021-2025 DCR Filing at 22-23; and Independent Consultant Final Report at 45.

[44] The representative allowances for these line items are limited to development activities for the generation facility. As such, the cost of development-related activities for the interconnection facilities are accounted for within the estimated costs for each respective interconnection.

[45] As noted above, the owner's cost portion of the project includes the costs related to the interconnection facilities (*i.e.*, electrical, gas, and, if applicable, water infrastructure) for each peaking plant.

whole.[46] The assumed construction period for each peaking plant accounts for pre-construction engineering and procurement through startup and commissioning. For the proposed H-class peaking plant options, construction financing costs are estimated at 6.8% of overnight capital costs for a 24-month duration. This percentage is applied to the total estimated overnight costs for both the EPC and non-EPC portions of the project.

As previously noted, the engineering and design firm used for the 2021-2025 DCR was different than the entity used in the last reset.[47] Although both firms developed cost estimates consistent with typical industry practices, the methodologies and cost categorization used by each firm differs. Regardless of these differences, the overall scope of project costs considered by both firms is similar.

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 cost estimates to those from the last reset.[48] As indicated in the table below in Figure 2, 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.[49] The table also specifically identifies differences in the categorization of various costs. This is intended to assist with confirming that the overall scope of costs considered in the last reset and the 2021-2025 DCR align. For purposes of this comparative analysis, the Independent Consultant realigned costs for the 2021-2025 DCR in Figure 2, where applicable, according to the cost categories from the prior reset.

[46] *See* 2021-2025 DCR Filing at 49-51; Independent Consultant Final Report at 43, 65-67 and 69-70; and AG Affidavit at ¶ 74-75 and 78.

[47] 2021-2025 DCR Filing at 22-23; and BMCD Affidavit at ¶ 41-45.

[48] 2021-2025 DCR Filing at 22-23; and BMCD Affidavit at ¶ 45.

[49] BMCD Affidavit at ¶ 45.

Figure 2: Capital Costs Comparison for GE 1x 7HA.02 Unit with Dual Fuel and SCR in Load Zone G (Dutchess County)

Zone G-Dutchess County	2016 Report	2016 Escalated	2020 Report	% Dif.
Equipment (see note 1)	$127,188,000	$138,660,851	$129,660,000	
Spare Parts	Moved to Owner's Costs	Moved to Owner's Costs	In Owner's Costs	
Construction Labor and Materials	$80,495,000	$87,755,961	$63,180,000	
Switchyard	$3,774,000	$4,114,429	$10,250,000	
Electrical Interconnection and Deliverability	$23,050,000	$25,129,199	$11,000,000	
Gas Interconnection and Reinforcement	$15,600,000	$17,007,181	$23,500,000	
Site Prep	$4,748,000	$5,176,288	Included in Construction Line Above	
Engineering & Design	$6,280,000	$6,846,480	Included in Other EPC	
Construction Mgmt / Fiel Engr	$3,583,000	$3,906,201	Included in Other EPC	
Startup & Training	$3,400,000	$3,706,693	Included in Other EPC	
Testing	$0	$0	Labor in EPC, Consumables Listed Below	
Contingency	$16,461,000	$17,945,846	Included in Other EPC	
Other EPC Cost in 2020 DCR (see note 2)	N/A	N/A	$64,290,000	
Construction Power and Water	Not Explicitly Broken Out	Not Explicitly Broken Out	$550,000	
Startup/Testing (Fuel & Consumables)	$1,325,000	$1,444,520	$4,500,000	
Site Security	Not Explicitly Broken Out	Not Explicitly Broken Out	$580,000	
Builder's Risk Insurance	Not Explicitly Broken Out	Not Explicitly Broken Out	$1,157,085	
Project Execution Items (2016 Methodology)	**$285,904,000**	**$311,693,651**	**$308,667,085**	**1.0%**
Permitting	$2,852,000	$3,109,261	$1,000,000	
Legal	$2,852,000	$3,109,261	$1,000,000	
Owner's Project Mgmt & Misc. Engr. (see note 3)	$4,279,000	$4,664,982	$2,420,000	
Social Justice	$570,000	$621,416	$500,000	
Owner's Development Costs (see note 4)	$8,557,000	$9,328,875	$370,000	
Financing Fees	$5,705,000	$6,219,613	See AFUDC Below	
Studies (Fin, Env, Market, Interconnect)	$1,426,000	$1,554,631	Not Explicitly Broken Out	
Emission Reduction Credits	$0	$0	$70,000	
System Deliverability Upgrade Costs	$0	$0	$0	
Owner's Operational Personnel Prior to COD	Not Explicitly Broken Out	Not Explicitly Broken Out	$440,000	
Owner's Contingency	Not Explicitly Broken Out	Not Explicitly Broken Out	$16,410,354	
AFUDC - EPC Portion	$19,866,000	$21,657,990	$17,484,840	
AFUDC - Non EPC Portion	$1,920,000	$2,093,191	$5,949,146	
Working Capital and Non-Fuel Inventories (includes spare parts)	$3,517,000	$3,834,247	$6,500,000	
Fuel Inventory	$4,453,000	$4,854,678	$7,240,000	
Owner's Cost Items (2016 Methodology)	**$55,997,000**	**$61,048,147**	**$59,384,340**	**2.7%**
Total Capital Investment	**$341,901,000**	**$372,741,797**	**$368,051,425**	**1.3%**

Notes
1. Equipment in 2020 DCR includes gas turbine and materials lines added together
2. "Other" EPC line item in 2020 DCR includes design engineering, const. mgmt, G&A, field engineering, startup, training, warranty, surety, fee, and EPC contingency
3. In the 2020 DCR, this adds up the Owner PM, Owner's engineer, and Owner startup/commissioning personnel
4. Lateral costs included in 2020 DCR (shown in Project Execution Section) are intended to reflect all-in pricing
5. The total cost for the 2016 DCR lines matches the 2016 report. In this comparison, "spare parts" was moved to the "Working Capital" line in the Owner's costs and "Fuel oil testing" was moved from the Owner's Costs into the "Startup Testing Fuel/Consumables" italicized line item in the Project Costs.

II. Request for Expedited Action

The timing for Commission action in response to the 2021-2025 DCR Filing is critically important to the NYISO's administration of the ICAP market for the upcoming 2021 Summer Capability Period (*i.e.*, the first Capability Period to which the NYISO's proposed ICAP Demand Curves apply). The NYISO has already commenced activities related to the administration of the ICAP market and related auctions for the 2021 Summer Capability Period, which begins on May 1, 2021. Issuance of an order by the Commission within 30 days of this filing approving the NYISO's proposal for the 2021-2025 DCR and the proposed ICAP Demand Curves for the 2021/2022 Capability Year is necessary to provide market certainty and facilitate timely execution of all processes necessary to conduct the ICAP auctions for the upcoming 2021 Summer Capability Period.

The Services Tariff requires the NYISO to conduct the Capability Period Auction for the 2021 Summer Capability Period no later than 30 days prior to May 1, 2021.[50] The NYISO is scheduled begin the Capability Period Auction for the 2021 Summer Capability on March 29, 2021. The Capability Period Auction is a two-sided auction that does not directly utilize the ICAP Demand Curves. Instead, clearing prices in the Capability Period Auction are based on voluntary offers to purchase and sell capacity for the six-month duration of the 2021 Summer Capability Period. Although the Capability Period Auction does not expressly utilize the ICAP Demand Curves, the ICAP Demand Curves provide critical information to sellers and purchasers of capacity that may seek to participate in the Capability Period Auction. Market Participants utilize the ICAP Demand Curves to inform projections regarding the expected value of capacity. The absence of clarity regarding the ICAP Demand Curves that will apply for the 2021/2022 Capability Year hampers Market Participants' ability to develop reasonable projections as to the expected values of capacity for the 2021 Summer Capability Period. Such uncertainty is likely to adversely impact participation and/or the pricing outcomes of the Capability Period Auction. In addition to adversely impacting ICAP auctions, continued uncertainty regarding the ICAP Demand Curves applicable for the 2021/2022 Capability Year is likely to have similar adverse impacts on bilateral market activity.

The NYISO typically provides all necessary information to the marketplace related to administration of the capacity market for a particular Capability Period approximately two weeks prior to the conduct of the Capability Period Auction. This includes determination of the respective capacity requirements for each Load Serving Entity, as well as inputting the applicable ICAP Demand Curves into the NYISO's automated market system and auction software. The finalization of the ICAP Demand Curves used in administering the ICAP auctions also includes the translation of the ICAP Demand Curves to Unforced Capacity terms as required by Section 5.14.1.2.2.4 of the Services Tariff. Absent expeditious resolution of the 2021-2025 DCR, the NYISO will be unable to timely complete all required actions to properly administer the ICAP market for the upcoming 2021 Summer Capability Period due to the need to obtain certainty as to the ICAP Demand Curves that apply for the 2021/2022 Capability Year.

Issuance of an order by the Commission approving the NYISO's proposed results of the 2021-2025 DCR (including the proposed ICAP Demand Curves for the 2021/2022 Capability Year) within 30 days (*i.e.*, on or before March 15, 2021) will timely resolve the current marketplace uncertainty regarding the ICAP Demand Curves applicable beginning May 1, 2021. Such timing will also facilitate the NYISO's ability to complete the processes and procedures necessary to administer the ICAP auctions for the upcoming 2021 Summer Capability Period

[50] *See* Services Tariff § 2.3 (definition of "Capability Period Auction").

while minimizing the extent and nature of adverse disruptions to the typical timeframes for completing such activities.

If the Commission does not issue an order addressing the NYISO's proposal within 30 days, but were to issue an order accepting the NYISO proposal without modification within the standard 60-day notice period (*i.e.*, on or before April 13, 2021), the NYISO would be capable of implementing the ICAP Demand Curves for the 2021/2022 Capability Year prior to conducting the May 2021 ICAP Spot Market Auction. This would, however, require the NYISO to conduct the Capability Period Auction for the 2021 Summer Capability Period (and likely the May 2021 Monthly Auction)[51] in the absence of clarity regarding the ICAP Demand Curves applicable beginning May 1, 2021. As further described above, such uncertainty is likely to adversely impact the efficiency of such auctions, as well as bilateral market activity in advance of the 2021 Summer Capability Period.

Absent issuance of an order by the Commission within 30 days and in light of the potential for issuance of an order that does not accept the NYISO's proposal without modification after such 30-day period, the NYISO would be required to expeditiously consider and potentially pursue interim remedial action to obtain clarity as to the ICAP Demand Curves that will apply beginning May 1, 2021. This could potentially include pursuing a contingent waiver or other appropriate contingent approval from the Commission to extend the duration of the currently-effective ICAP Demand Curves, as set forth in Section 5.14.1.2.2.5 of the Services Tariff, pending resolution of the 2021-2025 DCR and implementation of Commission-accepted ICAP Demand Curves for the 2021/2022 Capability Year.[52] If any such interim remedial action becomes necessary, the NYISO would intend to structure it as contingent to take effect only in the event that the Commission did not issue an order accepting the NYISO's proposal without modification on or before April 13, 2021 (*i.e.*, 60 days from the date of this filing).

III. Service

The NYISO will send an electronic link to this filing to the official representative of each party to this proceeding, 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. In addition, the NYISO will post this filing on its website at www.nyiso.com.

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[51] The NYISO is currently scheduled to begin the May 2021 Monthly Auction on April 9, 2021. Like the Capability Period Auctions, the Monthly Auctions are also two-sided auctions that do not directly utilize the ICAP Demand Curves. Instead, the ICAP Demand Curves provide critically important information used by sellers and buyers to inform their bids and offers for the Monthly Auctions.

[52] *See*, *e.g.*, *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 168 (2011); and *New York Independent System Operator, Inc.*, 135 FERC ¶ 61,002 at P 3 and 10 (2011).

IV. Conclusion

The NYISO respectfully requests that the Commission: (i) issue an order accepting the NYISO's proposed results of the 2021-2025 DCR within 30 days of this filing (*i.e.*, on or before March 15, 2021); and (ii) establish an effective date of March 15, 2021 for the proposed tariff revisions submitted in this proceeding.

Respectfully submitted,

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