Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024, 2024-2025 Capability Years

A Report by the
New York Independent System Operator

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Executive Summary

As required under the Market Administration and Control Area Services Tariff (Services Tariff), the New York Independent System Operator, Inc. (NYISO) has conducted its periodic review of the ICAP Demand Curves. This review covers the ICAP Demand Curves that would be effective for Capability Years 2021-2022, 2022-2023, 2023-2024, and 2024-2025. This report covers the NYISO staff's recommendations for the proposed ICAP Demand Curves, which has been informed by the work performed by the independent consultants, Analysis Group Inc. and Burns & McDonnell (collectively identified as the Consultant), as well as stakeholder comments provided through multiple stakeholder meetings and written comments.

The NYISO staff generally accepts the conclusions, assumptions and recommendations of the Consultant including selection of the GE 7HA.02 turbine be selected as the peaking plant underlying each ICAP Demand Curve. NYISO staff, however, recommends modifying the Consultant's recommended gas hub for Load Zone C. Instead of relying solely on TGP Zone 4 (200L), as recommended by the Consultant, the NYISO staff recommends the use of TGP Zone 4 (200L) for Load Zone C for non-winter months (i.e., April through November) and Niagara for the winter season (i.e., December through March). NYISO staff's recommendation is consistent with recommendation of the Market Monitoring Unit (MMU).

Table 1: Consultant and NYISO Staff Recommended 2021/2022 Capability Year ICAP Demand Curve Parameters and Reference Points for Load Zone C

	Consultant	NYISO Staff
Technology	GE 7HA.02	GE 7HA.02
Dual Fuel	No	No
SCR Included	No	No
Gas Hub	TGP Z4 (200L)	TGP Z4 (200L) & Niagara
Load Zone	C	C
Net EAS Revenue	$36.67	$32.92
Reference Price	$8.22	$8.62
Zero Crossing Point	112%	112%

In addition, NYISO staff has coordinated with the Consultant to revise the logic for assigning gas costs to electricity market days used by the model to estimate net Energy and Ancillary Services revenues of the peaking plant. The updated logic provides for alignment with the gas price data published by the vendor selected as the source for such information for this reset. Based on the review of stakeholder feedback and discussions with the data vendor, the model has been updated to reflect that gas prices published by the vendor for a particular date reflects the price to utilize gas on the specified date (e.g., gas prices published with a Friday date represent the cost to utilize gas on that Friday). Consistent with this revision, the model also utilizes the next available day on which gas price data is published as the price for any day that no price is reported (e.g., for a non-holiday weekend, the gas price published for Monday is used as the applicable gas price for Saturday, Sunday, and Monday).

Last, the NYISO staff is proposing to modify the methodology for determining the monthly value of the gross cost of new entry underlying each ICAP Demand Curve. This monthly value is utilized in calculating the maximum clearing price for each ICAP Demand Curve. NYISO staff proposes to modify the methodology for translating the annual gross cost of new entry values to monthly values by applying a similar methodology to that used in the translation of annual net cost of new entry values to monthly reference point prices. NYISO staff's proposed methodology accounts for seasonal differences in capacity, using the winter-to-summer ratio and percent of capacity at tariff-prescribed level of excess conditions to translate the annual gross cost of new entry values to monthly values. The resulting monthly values are then multiplied by 1.5 to determine the maximum clearing price for each of the ICAP Demand Curves.

A summary of NYISO staff's recommendations for each ICAP Demand Curve, including the 2021-2022 Capability Year ICAP Demand Curve reference point prices associated with such recommendations, is listed below.

Table 2: NYISO Staff's Recommended 2021/2022 Capability Year ICAP Demand Curve Parameters and Reference Points

	NYCA	G-J	New York City	Long Island
Technology	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02
Dual Fuel	No	Yes	Yes	Yes
SCR Included	No	Yes	Yes	Yes
Gas Hub	TGP Z4 (200L) & Niagara	TETCO M3	Transco Z6	Iroquois Z2
Load Zone	C	G (Rockland)	J	K
Reference Price	$8.62	$14.57	$22.36	$19.60
Max Clearing Price	$15.02	$20.31	$27.34	$22.81
Zero Crossing Point	112%	115%	118%	118%

Introduction

Section 5.14.1.2 of the Services Tariff requires the NYISO to conduct periodic reviews of the ICAP Demand Curves. This ICAP Demand Curve reset (DCR) process is the sixth such review. Analysis Group, Inc. (AGI), together with its engineering consultant subcontractor Burns & McDonnell (B&M), were selected by the NYISO to serve as the independent demand curve consultant (i.e., the Consultant) to lead market participants through the DCR process.

As set forth in the Services Tariff, this periodic review shall assess (i) the current localized, levelized, embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, along with (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant, net of the costs of producing such Energy and Ancillary Services. For purposes of this periodic review, a peaking unit is defined as "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."

As part of the last reset, a comprehensive set of revisions to the process were implemented, including extending the period between resets to 4 years, implementing annual updates between resets, and revising the methodology for estimating potential net Energy and Ancillary Services (EAS) revenues earned by the hypothetical peaking plants. The revisions were intended to facilitate a more formulaic and transparent reset process by replacing the previous econometric net EAS revenues model with one based on historic data, and implementing annual updates that recalculate net EAS revenues, adjust the capital costs to construct each peaking plant using a statewide composite escalation factor and recalculate the winter-to-summer ratio (WSR) each year. This updated process allows for the ICAP Demand Curves to respond to market changes in the interim period between resets using a predictable and replicable methodology.

During the current reset, minor modifications were made to the process for performing the annual updates. The changes modify the procedures for annually adjusting capital costs to construct each peaking plant and calculating the composite escalation factor. These enhancements were filed with the Federal Energy Regulatory Commission (FERC) on February 21, 2020. On April 3, 2020, FERC issued an order accepting the process enhancements.

This report contains: (i) the NYISO staff's response to the Consultant's work and stakeholder comments; and (ii) the NYISO staff's recommendations for: (a) the ICAP Demand Curves applicable for the 2021/2022 Capability Year (CY), and (b) the methodologies and inputs to be used in the annual update process for the three succeeding Capability Years (CY 2022/23, CY2023/24 and CY 2024/25). In preparing these recommendations, the NYISO has considered the Consultant's work to date as well as comments provided by stakeholders and the MMU. The NYISO's development of the recommendations set forth herein included consideration of all of the written and oral comments from stakeholders throughout the process, presentations by the Consultant, and the Consultant's draft, interim final and final reports.

This report sets forth the NYISO staff's recommendations for adjusting the current ICAP Demand Curve parameters and the underlying assumptions leading to those recommendations. The MMU has been involved in reviewing the Consultant's work product and provided feedback at various stages throughout the process. The DCR schedule (see the *Timeline* section of this report) identifies the timing for the remaining steps of this reset, culminating in the NYISO's filing with FERC on or before November 30, 2020 of the results of the DCR, as approved by the NYISO Board of Directors (Board).

Specific Technologies Evaluated by the Consultants

The ICAP Demand Curve reset assesses "…the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements." The peaking unit is referred to as the unit with technology that results in the lowest fixed costs and highest variable costs. For this DCR, the Consultant reviewed the following technology types:

1. The simple cycle plants have one or more combustion turbines that are fueled by either natural gas, liquid fossil fuels, or both.
2. The energy storage plants have duration capabilities of 4-hours, 6-hours, or 8-hours.
3. The combined cycle plants are a combination of steam turbines and simple cycle turbines. The combined cycle plants analyzed in this review were for informational purposes only.

The technology options were evaluated for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K.

Selection Criteria

The Consultant used criteria consistent with the last DCR to determine which representative units to evaluate for each technology type. Selection criteria included the following: standard generation facility technology; operating experience at a utility power plant; unit characteristics that can be economically dispatched; ability to cycle and provide peaking service; ability to be practically constructed in a particular location; and ability to meet environmental requirements and regulations.

Discussion of Units Evaluated

Within the three different technology categories, the Consultant selected specific representative units for evaluation. For the simple cycle technologies, the Consultant evaluated three different types that satisfied the selection criteria: aeroderivative combustion turbines, frame combustion turbines, and reciprocating internal combustion engines (RICE).

The aeroderivative combustion turbines that were identified for potential evaluation included five different unit types: GE LM6000, GE LMS100, Siemens SGT-A65, Siemens SGT-A45, and Mitsubishi Hitachi FT4000.[1] Data compared the experience of each of the models, as well as nominal capacity and heat rates. It was noted that the GE LMS100 and Siemens SGT-A65 were the best options of the five when comparing efficiency and capacity through initial screening. Further assessment was done in order to compare two GE LMS100 units at a single plant, as well as three Siemens SGT-A65 units at a single plant, both with and without an selective catalytic reduction (SCR) emissions controls. The Consultant ultimately selected the Siemens SGT-A65 as the representative aeroderivative technology option for purposes of developing detailed plant designs and cost estimates.

For the frame combustion turbines, the Consultant considered seven different units for potential evaluation representing a range of units from both the H/J-class and the F-class.[2] The H/J-class units initially identified included the following: GE 7HA.02, Siemens SGT6-9000HL, Mitsubishi Hitachi 501JAC, and Siemens SGT6-8000H. The F-class units identified as potential options were as follows: Mitsubishi Hitachi MHPS 501GAC, GE 7F.05, and Siemens SGT6-5000F. Similar to the aeroderivative units, the Consultant compared experience with nominal capacity and heat rate. The Consultant selected the GE 7F.05 as the representative unit among the F-class units. For the H/J-class frame turbines, the GE 7HA.02 unit was identified as the representative technology option. The Consultant used these two representative technology options for purposes of developing detailed designs and cost estimates for the frame combustion turbine technology.

The Consultant also considered RICE units as a potential peaking unit technology option. However, based on its initial screening and the results of previous DCRs, it was dismissed as a potential unit type for further evaluation in this DCR. This was, in part, due to the availability of comparable and likely lower cost combustion turbine technology options and the desire to expand the evaluation for this DCR to

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[1] AGI and B&M, Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Interim Final Report (August 5, 2020) at 15-16 (hereinafter referred to as the "Consultant Report")

[2] Consultant Report at 17-18.

include energy storage.[3]

The Consultant also evaluated battery energy storage systems (BESS) with lithium-ion battery technology. Other storage technology considered included pumped hydro and flow batteries. However, choosing pumped hydro would lead to siting and permit limitations which could result in the option being incapable of construction in certain locations, and flow batteries reflected higher capital costs through the initial screening as well as limited operating experience. The Consultant ultimately elected to utilize lithium-ion batteries as the representative technology option for energy storage for this DCR.[4] The Consultant also considered different potential chemistries for lithium-ion battery storage option. The market currently has multiple different chemistries for lithium-ion batteries. Rather than selecting a single chemistry, the costs developed by the Consultant are intended to be representative of the following three commonly utilized options: lithium nickel manganese cobalt oxide (NMC), lithium iron phosphate (LFP), and lithium nickel cobalt aluminum oxide (NCA). The Consultant chose to evaluate 200 MW storage units with the following discharge durations: 4-hour (800 MWh of energy storage capability), 6-hour (1,200 MWh of energy storage capability), and 8-hour (1,600 MWh of energy storage capability).

The Consultant considered various options for informational combined cycle plants, comparing their nominal capacity and heat rate. The combustion turbine model units compared included: GE 7HA.02, Siemens SGT6-9000HL, Mitsubishi Hitachi 501J, Siemens SGT6-8000H, Mitsubishi Hitachi MHPS 501GAC, GE 7F.05, and Siemens SGT6-5000F.[5] The 2x1 and a 1x1 combined cycle power plants were identified as potential design configurations for evaluation. With a quicker start up time and smaller overall size, a 1x1 combined cycle technology design using the GE 7HA.02 was selected by the Consultant for purposes of more detailed evaluation in this DCR. The H-class frame unit was selected for use in the informational combined cycle plant rather than the F-class unit due to the H-class unit's lower cost and better overall performance efficiency.

Units Selected for Evaluation

The selected simple cycle technologies that were used in the review included three Siemens SGT-A65 units (i.e., representative aeroderivative plant), one GE 7F.05 unit (i.e., representative F-class frame turbine plant), and one GE 7HA.02 unit (i.e., representative H-class frame turbine plant). The aeroderivative and F-class plants selected are within the 200 MW size range, while the H-class plant is approximately 350 MW. For the BESS option, the Consultant reviewed three different duration

[3] Consultant Report at 18.

[4] Consultant Report at 18-19.

[5] Consultant Report at 20.

capabilities, analyzing a 4-hour (800 MWh of energy storage capability), 6-hour (1,200 MWh of energy storage capability), and 8-hour (1,600 MWh of energy storage capability) lithium-ion battery. All three of the energy storage options evaluated were 200 MW units.

For informational purposes only, the Consultant chose a 1x1 GE 7HA.02 combined cycle power plant to analyze in additional to the potential peaking plant options. The informational combined cycle plant is approximately 570 MW.

Relevant Environmental Regulations

Environmental regulations can significantly influence the capital costs, fixed and variable operation and maintenance (O&M) costs, and operating restrictions for the peaking plants evaluated during the DCR. In addition to the regulations established prior to the previous DCR, changes in applicable environmental regulations and state policies have been effectuated since the last reset.

Climate Leadership and Community Protection Act (CLCPA)

In July 2019, the New York Governor Andrew Cuomo signed the Climate Leadership and Community Protection Act (CLCPA), codifying into law many of New York's clean energy goals. In addition to establishing clean energy requirements for the state's energy sector, the CLCPA outlines various targets for specific procurement of certain clean energy resources in New York. The CLCPA requires that New York's electric demand be served 100% by zero-emission resources by 2040.[6] Given this legislation, it is reasonable to expect that development of fossil units may be affected in the coming years, specifically in regards to the amortization period assumed for recovering the costs to construct new fossil units as part of this DCR.[7]

New Source Performance Standards (NSPS)

All newly constructed combustion turbines evaluated by the Consultant are subject to NSPS emissions rules as set forth in 40 CFR Part 60, specifically Subpart KKKK – Stationary Combustion Turbines and Subpart TTTT – Standards for Performance for Greenhouse Gas Emissions for Electric Generating Units.

[6] Chapter 106 of the Laws of the State of New York of 2019.

[7] In addition to the CLCPA, the City of New York issued Executive Order No. 52 (EO-52) on February 6, 2020, addressing the City's position regarding new fossil fuel infrastructure within New York City. The New City Mayor's Office of Sustainability submitted correspondence to the NYISO providing the City's interpretation of EO-52 as it relates to this DCR. This correspondence concluded that EO-52 does not prohibit selection of a fossil fuel generation as the peaking plant underlying the New York City ICAP Demand Curve. This correspondence is available on the NYISO's website at:
https://www.nyiso.com/documents/20142/13609265/NYC-DCR2020-EO52-final.pdf/10692944-e224-d895-1357-471249d5fddf.

NSPS rules apply to specific unit technologies, and do not vary based on where the unit is located.

Subpart KKKK requires combustion turbines to abide by specific ppm limits for nitrogen oxides (NO_x) based on whether their heat inputs are above or below 850 MMBtu/hour. For units with heat inputs greater than 850 MMBtu/hour, such as the GE 7F.05 and GE 7HA.02, NO_x emissions must be less than 15 ppmv @ 15% O_2 when firing on natural gas and less than 42 ppmv @ 15% O_2 when firing on oil (ULSD). The GE 7F.05 and GE 7HA.02 units have NO_x emissions of 9 ppmv @ 15% O_2 and 25 ppmv @ 15% O_2, respectively. Therefore, the GE 7F.05 unit would not require the use of a back-end emissions controls to comply with Subpart KKKK, whereas the 25 ppm GE 7HA.02 unit would require SCR emissions controls for compliance with Subpart KKKK.

However, GE also offers a 7HA.02 machine tuned to emit 15 ppmv NO_x @ 15% O_2, allowing the unit to operate in compliance with Subpart KKKK without back end emissions controls. The 15 ppm GE 7HA.02 machine has the same hardware but fires at a lower combustion temperature to reduce NO_x emissions. Due to the reduced firing temperature, there is approximately a 5% reduction in output compared to the base 25 ppmv GE 7HA.02 unit.

For combustion turbines with heat inputs less than 850 MMBtu/hour, such as the Siemens SGT-A65 aeroderivative unit, NO_x emissions are limited to 25 ppm under Subpart KKKK. The Siemens SGT-A65 unit emits 25 ppmv @ 15% O_2. As a result, the Siemens SGT-A65 unit does not require the use of back-end emissions controls under Subpart KKKK.

Subpart TTTT establishes CO_2 emission limits for “base-load” and “non-base load” combustion turbines. Base-load units, such as the informational combined cycle plants evaluated as part of the DCR, are limited to 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n. Non-base load units, such as the simple cycle frame turbine and aeroderivative plants, must meet a heat input based emissions limit, based their capacity factor using a unit’s net lower heating value (LHV) at ISO conditions, over a 12-operating month or a three-year rolling average basis. The Consultant estimated the net efficiency for all simple cycle technologies under consideration to be 35%; therefore, in order to avoid being subject to the base-load NSPS standard, each combustion turbine peaking plant option (i.e., GE 7F.05, GE 7HA.02, and Siemens SGT-A65) is limited to 3,066 hours of operation based on 12-operating months.

New York State also has rules for CO_2 emissions in the New York Codes, Rules, and Regulations (NYCRR) Part 251. New simple cycle and combined cycle plants in NYS must comply with NYCRR Part 251 as well as Subpart TTTT. In general, the NYCRR Part 251 limits that apply to simple cycle units are less stringent than the limits set forth in Subpart TTTT; however, the CO_2 limits set for combined cycles are slightly more stringent under NYCRR Part 251.[8]

New Source Review

In addition to the NSPS requirements noted above, the New Source Review (NSR) program established by the U.S. Environmental Protection Agency (EPA) considers the impact of air quality from new generation resources. The NSR program subjects new units to an evaluation of the air quality in the surrounding area. Depending on the National Ambient Air Quality Standard (NAAQS) in a given location, the area is either an "attainment" or "nonattainment" area based on its criteria for pollutant concentration. A geographic area where a criteria pollutant's concentration is below its respective NAAQS is classified as an attainment area for that pollutant. Conversely, an area where the concentration of a particular pollutant is above the applicable NAAQS is classified as nonattainment area for that pollutant. Additionally, there are varying degrees of nonattainment, such as moderate or severe nonattainment classifications.

There are two pathways to pursue an air permit under the NSR program: Prevention of Significant Deterioration (PSD) and Nonattainment New Resource Review (NNSR). The applicable pathway is dependent upon the classification of the area where a new or modified source is located. The preconstruction review process for new or modified sources located in an attainment area is subject to the PSD requirements. The corresponding process for new or modified sources located in nonattainment areas is performed under the NNSR process.

Nonattainment areas have more stringent requirements, permitting thresholds, and analyses than attainment areas in an effort to improve the location's air quality. In order to qualify for a permit in an attainment area, a source would have to perform a Best Available Control Technology (BACT) analysis for the pollutant(s) at issue. For nonattainment areas, a source would have to perform a Lowest Achievable Emissions Rate (LAER) analysis for the applicable pollutant(s). LAER typically results in more stringent requirements than BACT.

However, under applicable environmental regulations, it is possible for a unit to "synthetically limit" its operation by accepting an annual emissions cap to adhere to the PSD thresholds for applicable pollutants. A unit that synthetically limits its operation will be considered a "synthetic minor source" and will subject to less stringent permitting analyses. This approach has been utilized in prior resets as a means to potentially avoid a requirement to install SCR emissions controls to reduce NO_x emissions for certain gas-only simple cycle combustion turbines located in areas of New York subject to less restrictive

[8] Please refer to Table 9 (p. 22) of the Consultant Report for additional details regarding the applicable CO_2 limits under both Subpart TTTT and NYCRR Part 251.

emissions limits, such as Load Zones C and F. Due to the more stringent emissions limits that apply in severe non-attainment areas, the restrictive nature of the operating limitations that would apply to a synthetic minor source in such areas undermine the viability of this approach in such severe non-attainment areas, such as Load Zones G (Rockland County), J, and K.

The PSD major source threshold for NO_x emissions for new simple cycle combustion turbines is 250 tons/year and is typically based on the potential to emit (PTE) at 8,760 hours/year of operation.[9] Compared to the PSD thresholds, the emission limitations under the NNSR are more stringent. The NNSR thresholds for Volatile Organic Compounds (VOC) and Nitrogen oxides (NO_x) are 50 tons/year and 100 tons/year, respectively, for marginal, moderate, or Ozone Transport Regions and 25 tons/year for both VOC and NO_x in severe non-attainment areas. Since all of NYS is in the Ozone Transport Region (OTR), the NNSR applies throughout NYS for precursors of ozone (VOC and NO_x).[10] As a result, new sources in Load Zones C, F, and G (Dutchess County) are subject to the NO_x emissions limit of 100 tons/year. New sources in Load Zones G (Rockland County), J, and K are subject to the 25 tons/year NO_x emissions limit.

Emissions Cap and Trade Programs

Stationary combustion sources in New York State are subject to three different cap-and-trade programs. The aim of these programs is to limit the emissions of CO_2, NOx, and SO_2. The three programs are the following: Cross State Air Pollution Rule (CSAPR), the CO_2 Budget Trading Program (i.e., the Regional Greenhouse Gas Initiative), and the SO_2 Acid Rain Program. All of these programs apply to all combustion turbine technology options evaluated as part of this DCR. Consequently, the costs of CO_2, NOx, and SO_2 allowances were included in the development of net EAS revenue estimates for all combustion turbine peaking plant options.

CSAPR is implemented in New York State by creating three different budgets of tradable allowances: an annual NO_x budget (6 NYCRR 244), an annual SO_2 budget (6 NYCRR 245), and a seasonal (May 1 to September 30) NO_x budget (6 NYCRR 243).

The CO_2 Budget Trading Program (6 NYCRR Part 242) implements New York's participation in the Regional Greenhouse Gas Initiative (RGGI). RGGI seeks to reduce CO_2 emissions from the fossil-fuel fired electric generation facilities in the participating states through placement of a cap on annual CO_2 emissions from affected generators. CO_2 allowances are primarily distributed through quarterly auctions.

The SO_2 Acid Rain Program (40 CFR Parts 72-78) similarly limits the amount of SO_2 and NO_x emitted

[9] The applicable PSD limit on NOx emissions for new combined cycle units is 100 tons/year.

[10] Please refer to pp. 22-31 of the Consultant Report for further details regarding the New Source Review requirements and applicable emissions limits for this DCR.

from electric generation facilities. While this program was first implemented in 1995, it still applies to generators in New York State and has not been superseded by the implementation of CSAPR.

DEC Peaker Rule

The New York State Department of Environmental Conservation (DEC) recently adopted a rule placing incremental restrictions on the allowable level of NO_x emissions during the higher ozone level season. The new rule applies to "owners and operators of simple cycle and regenerative turbines (SCCTs) that are electric generating units with a nameplate capacity of 15 megawatts (MW) or greater and that inject power into the transmission or distribution systems." All of the combustion turbine technologies evaluated as part of this DCR satisfy the applicable emissions requirements.

Recommendations on SCR Emissions Controls

The Consultant's evaluation considered the inclusion of SCR emissions control technology on combustion turbine peaking plant options in all locations. The Consultant noted that "to be economically viable and practically constructible, the H Class Frame machine would be built with SCR emission control technology" in Load Zone J, Load Zone K, Load Zone G (Dutchess County), and Load Zone G (Rockland County), and without SCR emissions control technology in the other locations assessed (i.e., Load Zone C and Load Zone F).[11]

The NYISO concurs with the recommendation to include SCR emissions controls for the peaking plant in Load Zone G (Dutchess County). An important consideration for the lower Hudson Valley region of G-J Locality is that it consists of areas classified as part of the Ozone Transport Region (i.e., subject to NO_x emissions limit of 100 tons/year), as well as areas classified as severe non-attainment areas (i.e., subject to NO_x emissions limit of 25 tons/year). Additionally, a dual-fuel plant design has not been proposed without SCR emissions controls in any prior reset. The use of a "synthetic minor source" approach has been limited to gas only plant designs located in areas of New York that are subject to less restrictive emissions limits, such as Load Zones C and F.

With respect to the GE 7HA.02 peaking plant option, a "synthetic minor source" approach through application of an emissions limitation would permit annual operation of only approximately 260 hours or less for a dual-fuel design located within the severe non-attainment areas within the lower Hudson Valley. The severity of this limitation is not practical for a resource needed to maintain reliability. Even within the portions of the lower Hudson Valley subject to the less restrictive 100 tons/year NO_x emissions limit, such as Load Zone G (Dutchess County), the allowable hours of operation could be as low as only 300

[11] Consultant Report at 29-30 and 115.

hours annually depending on the number of hours a dual-fuel design may be required to operate on ULSD.[12] As a result, reliance on a "synthetic minor source" approach for a dual-fuel plant design in Load Zone G (Dutchess County) is likewise not practical for a resource needed to maintain reliability.

The inclusion of back-end emissions control technology provides additional flexibility to a unit, given that the SCR emissions controls enable the unit to operate and adhere to various environmental standards in New York State without requiring the application of potentially restrictive operating limits that adversely impact availability to generate. The additional flexibility provides additional resource adequacy value from an operational perspective. The NYISO agrees with the Consultant's recommendation to include SCR emissions controls for all combustion turbine peaking plant options in Load Zones G (Dutchess County), G (Rockland County), J, and K.

The NYISO also concurs with the Consultant's recommendation to utilize the "synthetic minor source" approach for the gas only combustion turbine peaking plant options in Load Zones C and F. This approach results in application of a binding NO_x emissions limits on such plants in lieu of installing SCR emissions controls. Based on a gas only GE 7HA.02 peaking plant option, the applicable emissions limit permits such a peaking plant to operate for approximately 1,000 hours annually. Use of the "synthetic minor source" approach for a gas only combustion turbine in Load Zones C and F is consistent with the approach taken in the last reset and remains a viable alternative for this DCR.

Dual-Fuel Capability

In the last DCR, dual-fuel capability for peaking plants in all locations were evaluated. Ultimately, the selection of peaking plants with dual-fuel capability in Load Zones G, J, and K and gas only peaking plants in Load Zones C and F were accepted by FERC.

Dual-fuel capability is required in Load Zones J and K, and although it is not mandated in Load Zone G, various factors support the inclusion of dual-fuel capability for combustion turbine peaking plant options in the lower Hudson Valley. Considerations such as the cost of dual-fuel capability versus gas only capability, flexibility of siting, and current level of reliance on natural gas for electric generation have been noted in past resets in support of a peaking plant with dual-fuel capability in Load Zone G.

For this DCR, simple cycle and combined cycle units with dual-fuel capability were again evaluated as

[12] The allowable operating hours for a dual-fuel capable "synthetic minor source" subject to a cap on its annual NOx emissions is highly dependent on the runtime hours associated with burning oil as fuel. Comparing NOx emissions rates, a unit running on oil for a single hour is roughly equivalent to the same unit running on natural gas for three hours.

the peaking plant in all locations. Due to technological differences, the battery technologies evaluated during the DCR were not evaluated for dual-fuel capability. During the evaluation, run time requirements based on applicable emissions limitations associated with NSPS requirements, as previously described, for dual-fuel units and the relative economics associated with such operation were considered for the various technologies, consistent with the previous DCR. Specifically, the Consultant's evaluation considered the economic tradeoffs between the additional costs associated with units with dual-fuel capability and the additional revenues associated with having dual-fuel (i.e., ULSD) capability.

Additionally, the NYISO engaged AGI in 2019 to perform a study on fuel and energy security in New York. Based on the study results, the NYISO and AGI concluded that the assessment did not identify any short-term reliability risks. However, given expected changes to the generation fleet and other aspects of the grid, the study highlighted the importance of continuing to monitor various items that could impact fuel and energy security (e.g., dual-fuel availability, generation mix, winter electrical load, renewable entry, fuel disruptions and associated impacts, and gas infrastructure and demand). The study also noted the importance of dual-fuel capability to maintaining reliability throughout the ongoing transition to a clean energy system in New York, especially in the downstate region including the lower Hudson Valley.

The NYISO concurs with the Consultant's recommendations to: (1) include dual-fuel capability for peaking plants in Load Zones G (Dutchess County), G (Rockland County), J, and K; and (2) utilize a gas-only peaking plant design for Load Zones C and F.

Interconnection Costs

The NYISO's interconnection process offers two types of interconnection services. New projects seeking to participate in the NYISO markets must request one or both types of interconnection services, as applicable to the project. Energy Resource Interconnection Service (ERIS) allows a new project to participate in the NYISO's energy market and Capacity Resource Interconnection Service (CRIS) allows a new project to participate in the NYISO's ICAP market.

As required by FERC, a deliverability assessment was conducted to determine whether the peaking plant options being considered may require any System Deliverability Upgrades (SDUs) to obtain CRIS under the tariff prescribed level of excess[13] conditions required for the DCR.

[13] Services Tariff Section 5.14.1.2.2 defines this as conditions in which the available capacity is equal to the sum of (a) the applicable minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues.

Table 3: List of Substations Evaluated

Zone	Location
C	Sithe
F	Rotterdam
G	Ladentown, Shoemaker
H	East Fishkill
J	Rainey, East 179th St.
K	Ruland Road, Holbrook, Riverhead

Deliverability Study

The NYISO planning staff conducted a deliverability analysis for the various peaking plant technologies utilizing the deliverability methodology consistent with the NYISO's Class Year deliverability study process and the case developed for the 2019-2020 New Capacity Zone (NCZ) study.[14] Consistent with FERC's directives, the deliverability analysis for the DCR is conducted under the level of excess conditions prescribed for use in the reset instead of using the "as found" summer peak system conditions used for the NCZ study.

The deliverability analysis indicated that all simple cycle gas turbine and battery energy storage peaking plant options under consideration were fully deliverable in all locations, except for the H-class frame unit on Long Island at only the Ruland Road location. Since the H-class frame unit was fully deliverable at multiple other locations on Long Island, the NYISO does not propose to include any SDU costs in the cost estimate for the H-class frame unit on Long Island. This treatment is consistent with the expectation that a developer would economically choose to construct a new facility on Long Island where additional SDU costs would not be incurred given the identified availability of multiple such locations.

Capital Investment and Other Plant Costs (Overnight Capital Costs)

The Consultant developed capital cost estimates for the various simple cycle and battery storage technologies evaluated for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K. Additionally, capital cost estimates were prepared for the 1x1 GE 7HA.02 combined cycle facility for informational purposes in the same locations. These cost estimates include the costs associated with a developer's engineering, procurement, and construction (EPC) contract, owner's costs (including electric

[14] The assumptions for the NCZ study were presented at the September 24, 2019 Installed Capacity working group (ICAPWG) meeting and the results of the study were presented to the ICAPWG on January 8, 2020. The New Capacity Zone study report was filed with FERC on February 24, 2020. *See* Docket No. ER20-1063-000, *New York Independent System Operator, Inc.*, New Capacity Zone Study Report (February 24, 2020).

and gas interconnection, fuel inventory (for dual-fuel units) and configurations), and construction financing costs and are summarized in the tables below. Section II.E and Appendix A of the Consultant Report includes additional detail on these cost estimates.

The EPC cost estimates are based on a generic site for each peaking plant and include the direct costs to construct the facility as well as indirect costs associated with the construction. In addition to the costs associated with equipment, materials, and labor for each peaking plant, the development of the cost estimates for the battery storage technologies include additional factors. Given the dynamic nature of the market for various battery storage technologies, the Consultant developed cost estimates for battery storage technologies based on current market pricing for lithium-ion battery storage, rather than a specific battery chemical or manufacturer.

The cost estimate for all Load Zones, excluding Load Zone J, is based on a greenfield site. Load Zone J assumes a brownfield site. For Load Zone J, the costs include an assumed need to increase the existing site elevation by 4 feet for all technologies to accommodate the floodplain zoning requirements to prevent flooding damage to facilities, similar to the aftermath of Hurricane Sandy. Additionally, the Consultant assumed that interconnecting electric transmission lines (i.e., generator leads) in Load Zone J would be underground and that the switchyard would include gas insulated switchgear (GIS) technology, as compared to overhead transmission and air insulated switchgear (AIS) in all other locations. Based on construction of projects in New York City in recent years, considerations for constructing electric generation resources in highly dense urban areas such as New York City, as well as existing interconnection requirements and guidelines for new interconnections within Load Zone J, the NYISO concurs with the Consultant's recommended assumptions for interconnection design within New York City.

The Consultant's recommended estimates for owner's costs, including electric and gas interconnection, as described in Section II.E and further detailed in Appendix A of the Consultant Report represent reasonable estimates. The NYISO agrees with the cost estimates developed by the Consultant.

The total owner's costs estimate for the H-class frame turbine, as developed by the Consultant, are similar to the estimates from the prior DCR when accounting for escalation of the 2016 cost estimates. The owner's costs are divided into subcategories, including but not limited to categories such as development, engineering, interconnection and deliverability, and vary by technology type and location. However, there are differences in the manner in which certain costs are categorized by the Consultant compared to the cost estimates developed in the last DCR. For example, the Consultant's assumed costs for electrical and gas interconnections are intended as all-in costs that include development, engineering, procurement, and construction elements. As a result of differences in the cost categorization and methodology employed, attempting to conduct a line-by-line comparison to the estimates developed in the last reset is likely to produce inadvertently misleading results. The Consultant evaluated its total owner's cost estimate to the aggregate total owner's cost estimated for a dual-fuel H-class frame turbine with SCR emissions controls located in Load Zone G (Dutchess County) in 2016 (please refer to Appendix D for additional details). After accounting for inflation to adjust the costs from 2016, the Consultant's analysis indicated that the difference between its total owner's cost estimate and the 2016 estimate was only approximately 0.3%.

In addition, certain stakeholders contend that the estimated costs for a gas interconnection for the peaking plant is understated, especially as it relates to Load Zone G. The Consultant initially utilized an assumed all-in cost estimate of $180,000 per inch diameter per mile plus $3.5 million for metering and regulation equipment to develop the cost estimates for a gas interconnection outside New York City. In response to stakeholder feedback, the Consultant reviewed costs estimates for six recent gas pipeline projects within or near New York.[15] The range of per inch diameter per mile costs observed across these six projects was approximately $100,000 to $500,000. The average linear cost across all six projects was approximately $260,000 per inch diameter per mile, excluding consideration of the highest and lowest linear cost project estimate would produce an average cost of approximately $240,000 per inch diameter per mile. Based on its additional analysis, the Consultant revised its assumed linear cost to $250,000 per inch diameter per mile.

Considerations such as dual-fuel capability, inlet cooling, and emissions controls were evaluated for the simple cycle and combined cycle technologies. The Consultant developed cost estimates for dual-fuel units in all locations, as well as estimates for gas-only units in Load Zones C and F. Inlet evaporative coolers were included in the estimates for all simple cycle and combined cycle units in all locations. Additionally, all locations assumed dry cooling technology for the informational combined cycle plants. The Consultant recommended gas-only peaking plant designs based on the GE 7HA.02 in Load Zones C and F that exclude SCR emissions controls. The Consultant recommended that the dual fuel peaking plant designs for Load Zones G (Dutchess County), G (Rockland County), J, and K that include SCR emissions controls. The NYISO concurs with the Consultant's recommendations.

Considerations such as building and container designs, enclosures, overbuild, and augmentation were evaluated for the battery storage technologies. The evaluation of battery storage technologies includes costs for battery storage installation in large buildings, containers, or enclosures. Accounting for the

[15] The CPV Valley Millennium Pipeline, National Fuel Gas Northern Access, Constitution Pipeline, PennEast Pipeline, National Fuel Gas FM100, and Bayonne Lateral Delivery projects were reviewed during this assessment.

known performance degradation of battery storage over time, the analysis assumed overbuild and future augmentation for the battery storage technology to account for system losses and degradation of the unit's capacity.

Table 4: Capital Investment Costs for Dual-Fuel Peaking Plants with SCR Evaluated ($2020)

	3x0 Siemens SGT-A65	1x0 GE 7F.05 (with SCR)	1x0 GE 7HA.02 (with SCR)
Zone C Central			
Total Capital Cost ($million)	305	271	360
ICAP MW	159	207	344
$/kW	1,920	1,310	1,046
Zone F Capital			
Total Capital Cost ($million)	307	275	363
ICAP MW	159	208	346
$/kW	1,937	1,319	1,050
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost ($million)	332	280	368
ICAP MW	159	209	347
$/kW	2,091	1,337	1,061
Zone G Hudson Valley (Rockland County)			
Total Capital Cost ($million)	342	292	380
ICAP MW	159	209	347
$/kW	2,152	1,398	1,095
Zone J New York City			
Total Capital Cost ($million)	424	381	470
ICAP MW	159	210	349
$/kW	2,670	1,810	1,347
Zone K Long Island			
Total Capital Cost ($million)	350	312	407
ICAP MW	159	210	349
$/kW	2,203	1,482	1,166

Table 5: Capital Investment Costs for Gas-Only Peaking Plants without SCR Evaluated ($2020)

	1x0 GE 7F.05 (without SCR)	1x0 GE 7HA.02 (without SCR)
Zone C Central		
Total Capital Cost ($million)	221	270
ICAP MW	207	327
$/kW	1,068	828
Zone F Capital		
Total Capital Cost ($million)	224	274
ICAP MW	208	329
$/kW	1,078	834

Table 6: Capital Investment Costs for Battery Storage Peaking Plants Evaluated ($2020)

	BESS 4-hour	BESS 6-hour	BESS 8-hour
Zone C Central			
Total Capital Cost ($million)	307	428	549
ICAP MW	200	200	200
$/kW	1,534	2,139	2,744
Zone F Capital			
Total Capital Cost ($million)	309	432	554
ICAP MW	200	200	200
$/kW	1,547	2,159	2,770
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost ($million)	312	435	559
ICAP MW	200	200	200
$/kW	1,560	2,177	2,793
Zone G Hudson Valley (Rockland County)			
Total Capital Cost ($million)	323	451	579
ICAP MW	200	200	200
$/kW	1,615	2,256	2,896
Zone J New York City			
Total Capital Cost ($million)	381	517	652
ICAP MW	200	200	200
$/kW	1,904	2,584	3,262
Zone K Long Island			
Total Capital Cost ($million)	329	464	599
ICAP MW	200	200	200
$/kW	1,644	2,319	2,994

Table 7: Capital Investment Costs for Combined Cycle Plants (Provided for Informational Purposes Only)

	1x1 GE 7HA.02 (with SCR)
Zone C Central	
Total Capital Cost ($million)	690
ICAP MW	495
$/kW	1,393
Zone F Capital	
Total Capital Cost ($million)	704
ICAP MW	499
$/kW	1,413
Zone G Hudson Valley (Dutchess County)	
Total Capital Cost ($million)	770
ICAP MW	501
$/kW	1,538
Zone G Hudson Valley (Rockland County)	
Total Capital Cost ($million)	821
ICAP MW	501
$/kW	1,639
Zone J New York City	
Total Capital Cost ($million)	979
ICAP MW	502
$/kW	1,949
Zone K Long Island	
Total Capital Cost ($million)	915
ICAP MW	503
$/kW	1,821

Performance Characteristics and Fixed and Variable Operating & Maintenance Costs

For each peaking plant option evaluated, the Consultant developed performance characteristics (e.g., plant capacity, heat rates, and reserve capability) and fixed and variable operation and maintenance (O&M) costs for each location.

Performance Characteristics and Variable O&M Costs

Due to technological differences, the evaluation of performance characteristics and variable O&M costs for battery storage technologies differed from the simple cycle and combined cycle units, but aims to capture the same types of costs. As previously noted, the variable O&M costs for the battery storage technologies include costs for capacity augmentation over time, as performance of batteries is known to degrade over time due to the unit's chemistry, discharge duration, and cycling behavior. Additionally, fixed augmentation O&M costs exist for battery storage technologies and vary by duration.

Additional information on the performance characteristics and fixed and variable O&M costs are included in Section II.F and Appendix A of the Consultant Report. For ease of review, the characteristics and variable O&M costs are averaged across all locations for each peaking plant and are summarized in the tables below.

Table 8: Performance Characteristics and Variable Operating and Maintenance Costs for Peaking Plants Evaluated ($2020)

	Siemens SGT-A65	GE 7F.05	GE 7HA.02 25 ppm	GE 7HA.02 15 ppm
Configuration	3x0	1x0	1x0	1x0
Net Plant Output (Average ICAP, MW)	159	209	347	328
Net Plant Output - Summer (Average MW)	167	217	358	340
Net Plant Output - Winter (Average MW)	188	226	370	349
Net Plant Heat Rate - Summer (Average Btu/kWh, HHV)	9,668	10,195	9,360	9,383
Net Plant Heat Rate - Winter (Average Btu/kWh, HHV)	9,445	9,888	9,295	9,327
Non-Spin Reserves	10 min	30 min	10 min	10 min
Post Combustion Controls	SCR/CO Catalyst	SCR	SCR	SCR
Natural Gas Variable O&M Costs (Average $/MWh)	9.96	1.52	1.40	0.93
ULSD Variable O&M Costs (Average $/MWh)	10.00	8.90	11.01	10.21
Fuel Required per Start (Average MMBtu/Start)	100	325	490	490
Variable Cost per Start (Average $/MWh)	-	9,500	26,600	26,600

Table 9: Performance Characteristics and Variable Operating and Maintenance Costs for Battery Storage Peaking Plants Evaluated ($2020)

	BESS 4-hour	BESS 6-hour	BESS 8-hour
Net Plant Output (Average ICAP, MW)	200	200	200
Discharge Duration, hr	4	6	8
Net Plant Energy Capacity, kWh	800,000	1,200,000	1,600,000
Heat Rejection	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC
Non-Spin Reserves	10 min	10 min	10 min
Capacity Augmentation as Variable O&M Costs (Average $/MWh)	12.00	12.00	12.00

Table 10: Performance Characteristics and Variable Operating and Maintenance Costs for Combine Cycle Plants (Provided for Informational Purposes Only) ($2020)

	GE 7HA.02
Configuration	1x1
Net Plant Output (Average ICAP, MW)	500
Net Plant Output - Summer (Average MW)	514
Net Plant Output - Winter (Average MW)	544
Net Plant Heat Rate - Summer (Average Btu/kWh, HHV)	6,365
Net Plant Heat Rate - Winter (Average Btu/kWh, HHV)	6,352
Non-Spin Reserves	-
Post Combustion Controls	SCR/CO Catalyst
Natural Gas Variable O&M Costs (Average $/MWh)	1.59
ULSD Variable O&M Costs (Average $/MWh)	1.77
Fuel Required per Start (Average MMBtu/Start)	3,940
Variable Cost per Start (Average $/MWh)	26,600

Fixed O&M Costs

The fixed O&M costs developed by the Consultant generally capture the fixed plant expenses, site leasing costs, and property taxes and insurance. The Consultant conducted a full evaluation of these costs, based on industry experience, review of various data sources, and propriety tools to ensure the reasonableness of its assumed costs. The NYISO concurs with the overall fixed O&M estimates.

Certain stakeholders argued that the site leasing cost estimate for Load Zone J is insufficient . In response to stakeholder feedback, the Consultant conducted supplemental analysis regarding land lease costs within New York City. The results of this further evaluation revealed a high level of variability in potential lease costs for representative sites within Load Zone J and confirmed that the Consultant's assumed annual land lease cost of $270,000 per acre-year is reasonable. Additional information regarding the supplemental evaluation conducted by the Consultant to confirm the reasonableness of its assumed lease costs within New York City is provided in Appendix C.

Development of Levelized Carrying Charges

A new capacity resource requires an upfront capital investment for its development and construction that must recovered. Therefore, the peaking plant's gross cost, or gross cost of new entry (Gross CONE), must consider financing costs in addition to the upfront capital costs described above. The financial parameters used in the DCR translate the upfront technology and development capital costs into an annualized value that represents the Gross CONE underlying each ICAP Demand Curve. This "levelized fixed charge" accounts for all payments made by a merchant investor to develop and finance construction of the capacity resource and recover those payments over a reasonable term. This includes the recovery of capital costs, return on equity, debt service costs, applicable property and sales tax payments, and tax depreciation among other items.

The financial parameters that affect the levelized fixed charge are described in detail in Section III of the Consultant Report, and are addressed below.

Financial Parameters

The Consultant recommended the following financial parameters for this DCR:

- 9.54% weighted average cost of capital (WACC) derived from:
    - 13.0% return on equity (ROE)
    - 6.7% cost of debt (COD)
    - 55/45 debt to equity ratio
- 8.52% (NYCA, LI, G-J Locality) and 8.2% (NYC) after-tax WACC (ATWACC)
- 17-year amortization period for thermal units (simple cycle and informational combined cycle options), 15-year amortization period for energy storage units (BESS)

Weighted Average Cost of Capital

The Consultant's recommendation on the WACC used for the DCR is derived from analyzing metrics from publicly traded companies, independent assessments performed by the Consultant, professional judgement and past experience, conversations with developers and market participants, and considerations for current and future expected market conditions over the period covered by this reset. The recommended values for the ROE, COD and debt to equity ratio are all considered in tandem to develop a WACC that reflects the specific financial, regulatory, and policy risks attributed to new capacity supply resources seeking to enter the NYISO markets during the study period for the current DCR under the capacity supply excess conditions specified by the tariff for use in determining the ICAP Demand Curves.

The 13.0% ROE recommended by the Consultant is based on estimated ROEs for publicly traded independent power producers (IPPs), the ROEs used in neighboring markets that have similar capacity market constructs, and estimated ROEs for stand-alone project finance developments. In general, estimated ROEs are lower for publicly traded IPPs (6.6%-9.0%) than for project finance structures (up to 20%).[16] Ultimately, the Consultant's recommendation reflects the consideration of all of the above research and the observed changes to the risk-free rate since the last reset, and reasonable expectations for the risk-free rate to remain lower than the last reset over the course of the period of interest for this DCR (i.e. 2021-2025). The NYISO concurs with the recommended 13.0% ROE.

The 6.7% COD recommended by the Consultant is derived from consideration of similar data and information utilized in determining the recommended ROE, such as publicly available information on recent debt offerings from public companies and rates on recent debt offerings for other public companies with similar credit ratings (typically BB to B). The NYISO agrees with the Consultant's recommended COD value.

The Consultant's recommendation for a 55/45 debt to equity ratio is consistent with the prior DCR. This reflects the balancing of various considerations. Current capital structures for publicly traded IPPs reflect less debt than historically observed. It is important to recognize that debt levels observed at the corporate level may not be directly translatable to the project-level capital structures. However, the generally observed trend toward less debt leverage at the corporate level was considered especially in light of the current financial uncertainty caused by the COVID-19 pandemic and uncertainty regarding the timing of economy recovery thereafter. In addition, the relatively limited magnitude of long-term certain revenue streams available to resources that primarily (or wholly) derive revenues through participation in competitive markets, such the NYISO wholesale markets, may tend to limit debt levels for project-level capital structures. Conversely, similar studies in other ISOs/RTOs have utilized higher levels of debt than proposed by the Consultant for purposes of net cost of new entry value determinations in capacity markets administered by such other ISOs/RTOs. The NYISO concurs with the Consultant's recommended debt to equity ratio as a reasonable value in consideration of the data and information evaluated.

Certain stakeholders have expressed that the cost of a financial hedge should also be included in the estimated capital cost to construct a peaking plant. Such stakeholders contend that financial hedges for new merchant power projects are generally paid for upfront and typically structured as short-term revenue puts, which will provide additional payments to generators if their gross energy margin falls below a certain level, helping to ensure that generators have sufficient cash on hand to continue operating

[16] Consultant Report at 67-69.

and making debt payments regardless of market outcomes for the duration of the instrument. The Consultant considered the potential cost of such an instrument and implicitly captured consideration of such potential costs in their cost of debt and assumed capital structure. For example, the Consultant's use of generic B rated corporate debt to establish their recommendation is itself a conservative assumption representing a potentially higher risk project, as well as their recommendation of a 6.7% COD, which is observed to be on the high end of the potential range for B rated corporate debt. Such conservative assumptions are intended to recognize, in part that the Consultant has not otherwise explicitly accounted for the potential costs of a financial hedge, if necessary, to secure financing.

Amortization Period

In the context of the DCR, the amortization period is the term (in years) over which a merchant investor expects to recover upfront capital costs and generate a reasonable return on its investment. This term reflects considerations for the associated financial risks of investing in a new peaking plant in New York, such as perceived risks to changes in market structures, technology, regulations, and underlying electricity demand. Due to these perceived risks, investors generally seek to recover their capital costs (and return on investment) over a term that is shorter than the asset's expected physical life. The Consultant proposed to use an amortization period of 17 years for thermal plants (simple cycle and information combine cycle combustion turbine options) and 15 years for BESS, reflecting the different risks associated with each resource type.

The Consultant's recommended amortization period of 17 years for thermal units reflects a reduction from the 20-year amortization period used during the previous DCR. As detailed in Section III.A.1 of the Consultant Report, there are a number circumstances driving the proposed reduction in the amortization period from 20 years to 17 years for thermal units. A primary consideration is the enactment of the CLCPA, which requires electricity demand in New York to be served by 100% zero-emission resources by January 1, 2040. A fossil fuel-powered unit with a 20-year amortization period that enters the markets at any time between May 1, 2021 and April 30, 2025, (the period covered by the DCR) may not be able to operate under New York State law as of January 1, 2040. This could impair the unit's ability to recover its upfront capital costs and generate a reasonable return on its investment.

Table 11: Potential Economic Operating Life

Capability Year	Potential Operating Life of Fossil Unit	Average Operating Life of Fossil Unit Operating Over 4 Capability Years
2021-2022	18.7 Years	17 Years
2022-2023	17.7 Years	
2023-2024	16.7 Years	
2024-2025	15.7 Years	

Note: The potential commercial operating life was calculated using the number of years between the May 1 start of the Capability Year and January 1, 2040.

The Consultant and the NYISO carefully considered divergent stakeholder feedback regarding the appropriate means for addressing the CLCPA's rules regarding fossil fuel use for electricity generation beginning in 2040. Certain stakeholders recommended using 15 years as the amortization period, reflecting the shortest possible amount of time that a unit entering the market during the later portion of the period covered by this reset could lawfully operate as currently designed. Other stakeholders recommended retaining an amortization period at 20 years in light of the potential for fossil units to undertake future retrofitting or other modifications to convert to alternative zero-emission fuels or otherwise operate on a zero-emission basis in compliance with the CLCPA. At this time, the NYISO believes that there is not sufficient clarity as to which alternative fuels or other operational modifications would qualify as "zero-emission" under the CLCPA, the cost of procuring those fuels for use in generating electricity, and the potential capital costs associated with retrofitting an existing plant to permit continued operation beyond December 31, 2039.

The CLCPA does not define eligibility for compliance with the 2040 zero-emission requirement for the electric sector. Instead, such eligibility is expected to be developed and refined over time through programs and regulations developed to implement the CLCPA. The CLCPA does not require that the initial program rules for achieving the 2040 zero-emission requirement be completed until June 30, 2021. Based on consideration of all these factors, the NYISO agrees with the Consultant's recommendation to use a 17 year amortization period for thermal units in this DCR. As additional data and information becomes available over the coming years regarding resources/technology eligibility and program rules to implement the CLCPA's zero-emission requirement for 2040, this information will be considered in future resets.

During this DCR, BESS was considered as a potential peaking plant option for the first time. Compared to traditional thermal generators, there is little experience developing, operating, and recovering the capital costs associated with this relatively nascent technology in New York. This directly affects the amortization period proposed for use by this technology in the context of the DCR.

Typically, an investor developing a resource based on a new technology with little operational experience will seek to recover its upfront capital costs sooner than if the resource was based on a technology with more proven cash flows. Compared to traditional thermal generators, there is significant uncertainty as to the useful life of BESS, the cost of regular maintenance and augmentation, as well as the revenue opportunities for a unit that primarily generates revenues through arbitraging energy prices throughout the day.

Because of these considerations, the Consultant recommended a 15-year amortization period for BESS. The CLCPA limitations of fossil fuel operation for electric generation beyond 2039 do not apply to energy storage systems; however, the relative lack of experience with BESS as compared to thermal generation would likely cause a BESS developer to seek recovery of its upfront capital costs sooner than a comparable thermal unit. In light of these considerations, the NYISO concurs with the Consultant's recommendation. As additional data and operational experience regarding battery storage resources in New York becomes available over the coming years, this information will be considered in future resets.

Property Taxes

New York City Tax Abatement

Title 2-F of the New York State Real Property Tax law (RPTL) provides property tax abatements to certain electric generating facilities located in New York City as set forth in RPTL § 489-BBBBBB(3)(b-1). Section 489 defines a "peaking unit" as "a generating unit that: (a) is determined by the New York independent system operator or a federal or New York state energy regulatory commission to constitute a peaking unit as set forth in section 5.14.1.2 of the New York independent system operator's market administration and control area services, as such term existed as of April first, two thousand eleven … it may be comprised of a single turbine and generator or multiple turbines and generators located at the same site."[17] This tax abatement is applicable to simple cycle combustion turbine peaking plant options for the New York City ICAP Demand Curve for the first 15 years of the project's operation. Accordingly, the Consultant assumed that simple cycle combustion turbine peaking plant options in New York City would receive this abatement and incur taxes only for years 16 and 17 of the recommended amortization period for thermal units for this DCR.[18]

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[17] RPTL § 489-AAAAAA(17)

[18] The Consultant implicitly assumed that any "base" level of real property taxes on the underlying property where the peaking plant is located that does not qualify for an applicable abatement (i.e., RPTL Section 489 or Section 487) are accounted for as a part of the lease payments the facility pays for the use of such property.

However, a stand-alone storage energy system located in New York City may not qualify as an eligible peaking unit under Title 2-F of the RPTL because it may not be deemed a "generating unit."[19] For stand-alone energy storage systems, a separate 15-year tax abatement is available pursuant to RPTL § 487 to units that are constructed after January 1, 2018 and before January 1, 2025.[20] The tax abatement provided by RPTL § 487 is available statewide. Taxing jurisdictions are able to opt-out of the abatement through the adoption of an ordinance/resolution and filing such with NYSERDA and the NYS Department of Taxation and Finance; absent opt-out, the abatement is available.[21] As of the date of this report, no taxing jurisdiction in New York City has opted out of the abatement for stand-alone energy systems. This tax abatement also provides taxing jurisdictions the authority to compel hybrid storage units (e.g., wind/solar generation integrated with energy storage) to enter into a Payment In Lieu of Taxes (PILOT) agreement in connection with the otherwise available abatement.[22] However, as currently written, the law does not extend this PILOT agreement requirement to stand-alone energy storage facilities. As such, the Consultant assumed that a stand-alone energy storage plant in New York City would receive this abatement, which would apply for all years of the assumed 15 year amortization period recommended for BESS for this DCR.

The Consultant recommends a property tax rate for New York City of 4.7%, which is equal to the Class 4 Property Tax rate of 10.5% multiplied by the 45% assessment ratio for any years in which an abatement is not applicable for a peaking plant option. This property tax rate is assumed to apply in all years of the recommended amortization period for the informational combined cycle plant in Load Zone J. The NYISO agrees with the Consultant's recommendations for property taxes applicable to peaking plants in Load Zone J.

Locations Outside New York City

Outside of New York City, the Consultant assumed a property tax rate of 0.5% for all thermal technology options, assuming that the plants will enter into a PILOT agreement that is effective for the full amortization period assumed for this DCR.[23] The assumed rate was developed by the Consultant based on a review of PILOT data available from the New York State Comptroller's office. Based on their review of eight natural gas plants located outside New York City and after adjustments for inflation to determine the effective PILOT rates as of the time the plants at issue became operational, the Consultant observed

[19] NYPSC Case 13-F-0287, *Petition of AES Energy Storage, LLC for a Declaratory Ruling that Battery-Based Energy Storage Facilities are not Subject to Article 10 of the PSL*, Declaratory Ruling on Applicability of Article 10 of the PSL to Battery-Based Energy Storage Facilities (issued and effective January 24, 2014)

[20] RPTL § 487(5)

[21] RPTL § 487(8)

[22] RPTL § 487(9)

[23] This same property tax rate is also used for the informational combined cycle plants outside New York City.

effective, adjusted PILOT rates ranging from 0.14% to 1.53% and a median rate of 0.52%, the NYISO agrees that 0.5% is a reasonable assumption consistent with current PILOT agreements for natural gas plants in New York.

For stand-alone energy storage systems outside of New York City, as described above, RPTL § 487 provides a 15-year abatement for energy storage systems located throughout New York. There are taxing jurisdictions outside New York City which have opted-out of the abatement under RPTL § 487; however, those jurisdictions represent a limited number of areas associated with locations being studied for the DCR. Therefore, the Consultant assumed, and the NYISO agrees, that a 15-year property tax abatement would apply to stand-alone energy storage plants in all locations evaluated.

Net EAS Revenue

For each Capability Year, ICAP Demand Curve reference point prices in NYCA and each Locality are based on estimated Gross CONE less an estimate of expected net revenues the peaking plant could earn in NYISO's Energy and Ancillary Services markets. These revenues reflect the prices paid for supplying Energy and Ancillary Services, net of the variable costs of production. The DCR estimates net EAS revenues using expected supply excess conditions consistent with the requirements prescribed by the tariff ("LOE conditions").[24]

Net EAS revenues are estimated at the time of the DCR based on the modeled dispatch of the peaking plant using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions). The approach in this DCR, consistent with the last reset, assumes that annual average net revenues earned over the prior three years provide a reasonable estimate of forward-looking expectations, particularly in light of the annual updating mechanism, which ensures that the ICAP Demand Curves evolve over time by incorporating updated actual EAS market outcomes.

The net EAS revenues model estimates the net EAS revenues of the peaking plant on an hourly basis for the historical 3-year period based on maximum possible revenues earned by supplying energy or reserves in either the Day-Ahead Market (DAM) or Real-Time Market (RTM). Each year subsequent to the first year of the reset, as part of an annual updating of the ICAP Demand Curves, net EAS revenues are recalculated using this same model, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges.

[24] *See* Services Tariff Section 5.14.1.2.2. The Services Tariff refers to the supply conditions assumed for purposes of the DCR as the "prescribed level of excess."

Thermal Net EAS Model Logic

The Consultant developed a simulated dispatch model to project the net EAS revenues for the thermal simple cycle combustion turbine peaking plant options evaluated. The model uses a rolling 3-year historical set of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and non-fuel variable costs and operational characteristics of the peaking plant technology. This same model will be used as part of the annual update process to derive updated net EAS revenue estimates on an annual basis.

The logic used in the model follows what one would expect a competitive supplier with perfect foresight to offer (i.e., optimal dispatch, with offers set at the opportunity cost of producing energy or reserves). The model accounts for the option of supplying in either the DAM or RTM, as well as the option to supply either energy or reserves, on an hourly basis. Unit parameters (capability and heat rate) are taken into account separately for the Summer Capability Period and Winter Capability Period. Annual revenues are adjusted downward based on the plant's EFORd, and a flat adder ($/kW-year) is applied to account for an estimate of annual voltage support service ("VSS") revenues.

The Consultant has considered key operational and other assumptions in the dispatch model design and implementation, as well as specific considerations that were raised by stakeholders. Several stakeholders raised concerns with how the coincident fuel prices were applied in the model. The model utilized to produce preliminary results reflected in the Consultant's draft report and interim final report, as well NYISO staff's draft recommendations, was premised on an assumption that the gas prices published by the vendor of such data for a particular date represented the "trading day" price of gas as opposed to the "flow day" price of gas. The trading day price is the price that generators would pay to acquire gas that would flow (and be used to generate electricity) on the following day. As such, the model shifted the reported gas prices for a particular date one day forward to better align the gas price data with the date on which the gas would be utilized to generate electricity. Based on this assumption, the gas price assigned to weekends and holidays was the price for the last day before a weekend/holiday (e.g., for a non-holiday weekend the gas price reported with a Friday date was used as the applicable gas price for Saturday, Sunday, and Monday).

Stakeholders contended that the assumption underlying the logic of assigning gas prices to electricity market days was incorrect. Such stakeholders stated that the gas price data published by the vendor at issue represented the "flow day" price (i.e., the date on which the gas would be utilized to generate electricity) instead of the trading day price. The Consultant and NYISO staff engaged in discussions with the data vendor to better understand the gas pricing data published and whether data for a particular date reflected a "flow day" or "trading day" pricing value. Such additional discussions confirmed that the date listed by vendor for a particular gas price represents the flow date for gas. As such, the model has been updated to apply the gas prices published for a particular date as the applicable gas prices for the same electricity market day. Consistent with this revision, the model also utilizes the next available day on which gas price data is published as the price for any day that no price is reported (e.g., for a non-holiday weekend, the gas price published for Monday is used as the applicable gas price for Saturday, Sunday, and Monday). For more information on this, please see Appendix B of this report.

The NYISO concurs with the commitment and dispatch logic of the net EAS revenues model developed by the Consultant and addresses certain, specific aspects of the model in the following sections.

The Consultant has developed the net EAS revenues model in "R," an open source software programming language that is available to all stakeholders. The model is posted publicly on the NYISO's website.

Gas Hub Selection

The net EAS revenues that are estimated for the thermal peaking plants use selected gas hubs for each location evaluated for purposes of estimating natural gas costs incurred to operate. The gas hub recommendations were derived based on the consideration of a number of factors. NYISO staff's recommended gas hub selection for each of the Load Zones evaluated in the study is shown below.

Table 12: NYISO Staff Recommended Gas Hubs by Location

Location	Gas Hub
Central	TGP Z4 (200L) & Niagara
Capital	Iroquois Z2
Hudson Valley (Dutchess)	Iroquois Z2
Hudson Valley (Rockland)	TETCO M3
NYC	Transco Z6 NY
Long Island	Iroquois Z2

The following selection criteria was used in developing the above recommendations:

- Market Dynamics: The gas hub selected should reflect consistency with LBMPs within the respective Load Zone, maintaining that consistency over a longer period of time.

- Liquidity: The gas hub selected should have sufficient amount of historic data readily available in order to assess historic trade volumes.
- Geography: The gas hub selected should be geographically located in an area that is accessible to the potential peaking plant for a particular location.
- Precedent/Continuity: The gas hubs utilized in other studies and analysis should be taken into consideration to the extent relevant and informative to the objectives of the DCR. The following were considered by the Consultant in developing the gas hub recommendations for this DCR: the gas hubs selected in the last DCR, the gas hubs utilized by the 2019 Congestion Assessment and Resource Integration Study (CARIS) Phase I analysis, and the gas hubs utilized in the 2019 State of the Market Report by the MMU.

The Consultant collected and analyzed historic data regarding market dynamics and liquidity, and included charts and tables in the Consultant Report to compare the data for the different potential gas hubs in each Load Zone.[25]

For Load Zone C, the Consultant recommended TGP Zone 4 (200L) based off of market dynamics, trading liquidity, geography, and an analysis conducted by the MMU evaluating various potential gas hubs that may be appropriate for Load Zone C. The analysis conducted by the MMU concluded that expected dispatch of gas-fired generators in Load Zone C based on historic energy prices better aligned with simulations ran using TGP Zone 4 (200L) than other geographically representative alternatives such as TGP Zone 4 (Marcellus) and Dominion North. Although other alternatives such as TETCO M3 and Dominion South showed good correlation to historic LBMP pricing trends, as well as strong levels of liquidity based on historic trading activity, these hubs were not recommended because they are not geographically representative of gas prices readily accessible to a new gas-fired generator in Load Zone C.

Additional analysis conducted by the MMU and provided in comments in response to NYISO staff's draft recommendations suggests that purchases of gas at TGP Zone 4 (200L) may not be readily accessible in the winter.[26] As a result, the MMU recommended the use of an alternative gas hub during these periods of pipeline constraints. Specifically, the MMU recommended the use of the Niagara gas index during the

[25] Consultant Report at 90-98.

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

winter months of December through March to account for periods when the TGP Zone 4 (200L) pipeline is constrained and may, therefore, be inaccessible to a peaking plant in Load Zone C. The NYISO concurs with the MMU's recommendation to use TGP Zone 4 (200L) for the majority of the year (i.e., April through November) and to use Niagara during winter months (i.e., December through March) as the gas hubs for Load Zone C for this DCR.

For Load Zone G (Dutchess County) Iroquois Zone 2 is recommended, based off of the best fit for market dynamics and geographic location. Although the Millennium pipeline is geographically feasible, it lacks in flexibility of supply. In addition, Millennium lacks historic trading volume, which raises concerns in regards to liquidity.

TETCO M3 is the recommended gas hub for Load Zone G (Rockland County), also due to its correlation to market dynamics and geographic location. Iroquois Zone 2 does exhibit a strong correlation with historic LBMP pricing trends for Load Zone G (Rockland County); however, Iroquois Zone 2 was not recommended for Load Zone G (Rockland County) because it is less representative of a readily accessible pipeline for gas-fired resources located west of the Hudson River within the lower Hudson Valley.

Certain stakeholders have expressed concerns about the feasibility of obtaining gas at the TETCO M3 price, plus a $0.27/MMBtu transportation adder as assumed by this recommendation. As discussed in the MMU's comments in response to NYISO staff's draft recommendations,[27] although TETCO M3 does not cross through Rockland County, the pipeline includes points of interconnection with the Algonquin pipeline that crosses through Rockland County. Gas acquired on TETCO M3 can be transported to Rockland County using the Algonquin pipeline. The cost of such transportation, on an interruptible basis, is currently $0.2421/MMBtu (or slightly less than the $0.27/MMBtu transportation cost adder assumed for Load Zone G [Rockland County]). The MMU also reviewed daily critical notices of announced restrictions on interruptible transportation along the Algonquin pipeline and noted no significant restrictions on the relevant section transporting gas on a west-to-east basis from TETCO M3 to points in Rockland County. In a similar analysis, the New York Transmission Owners (NYTOs) noted that in addition to using the Algonquin pipeline for transportation of gas acquired on TETCO M3 to Rockland County, the Millennium pipeline could also be used to transport gas to other points within Rockland County.[28]

The recommended use of Iroquois Zone 2 for Load Zones F and K strongly represents considerations

[27] MMU Draft Recommendations Comments at 16-18.

[28] *See* New York Transmission Operators, *Comments on "Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024 and 2024-2025 Capability Years"* at 7-9, available at: https://www.nyiso.com/documents/20142/14871137/TO-Comments-on-ISO-Staff-Draft-Recs-on-ICAP-Demand-Curves-for-2021-25-Final.pdf/.

of market dynamics and geography. In the case of each location, Iroquois Zone 2 represents a geographically appropriate pricing location that is accessible to the peaking plants. Iroquois Zone 2 also demonstrates reasonable consistency of pricing trends between the cost of gas and resulting LBMPs over the four-year historic period analyzed by the Consultant.

The Transco Zone 6 NY was recommended for Load Zone J because of its high liquidity as well as pricing consistency with LBMPs. Transco Zone 6 NY is also consistently utilized across a variety of studies/analyses for purposes of representing estimated gas costs for electric generators within New York City.

Based on the foregoing, the NYISO agrees with the Consultant's recommended gas hubs for all locations, excluding Load Zone C for which the NYISO staff recommends the use of TGP Zone 4 (200L) for non-winter months (i.e., April through November) and Niagara during the winter period (i.e., December through March).[29]

Fuel Transportation Adder

The thermal resource net EAS revenues model also incorporates an adder for each Load Zone to estimate the cost of transporting natural gas and/or oil to the hypothetical peaking plant in each location. In keeping with the concept that the costs of the hypothetical peaking unit are generalized to apply to the entire Load Zone, as opposed to a precise location within a Load Zone, the transportation adders are meant to estimate the generalized cost of procuring natural gas or oil within a Load Zone. The transportation adder is not meant to directly calculate the cost of getting gas from a specific point on the pipeline to a specific location within a given Load Zone.

The transportation adders used in the net EAS revenues model range from $0.20 to $0.27 per MMBtu for natural gas and $1.50 to $2.00 per MMBtu for oil, depending on location.[30] These adders were used in the prior DCR and have been carefully reexamined to confirm their continued appropriateness for the current DCR and the recommended gas hubs.[31] Natural gas and oil procured to meet both DAM and RTM

[29] The NYISO is aware of a historic prevalence of gas system constraints particularly in the New York City and Long Island regions. These constraints could become more frequent and/or severe in the future as the ongoing transition of the electric grid unfolds in New York. The NYISO will also continue to monitor the development and evolution of programs and rules to implement and achieve compliance with the requirements of the CLCPA. These factors could limit the availability of new gas interconnections for generators and/or place restrictions on the availability of fuel for operation. The NYISO will continue to consider such impacts when determining the appropriate peaking plant technologies and fuels for evaluation and selection in future resets.

[30] *See* Consultant Report at 98-99.

[31] An analysis by the MMU confirmed that the transportation adders used in this DCR are reasonable. This analysis examined the tariff rates for interruptible service (forward and backward haul) of the various gas hubs selected for use, including neighboring pipelines needed to complete transportation to the specific Load Zone, if

(if the unit did not receive a DAM commitment) schedules will include this adder when calculating the cost to produce electricity for each interval; fuel procured or sold in real-time also incurs an additional intraday premium or discount, as discussed below.

Fuel Premium/Discount

In addition to transportation costs and taxes for each fuel, a real-time intraday price premium relative to day-ahead for purchases, and discount for sales, is applied to natural gas in the thermal resource net EAS revenues model. A generator purchasing natural gas in real-time will receive a more expensive price relative to the day-ahead price for natural gas. Conversely, a generator selling back natural gas in real-time will receive a discounted natural gas price, as compared to the cost initially incurred to purchase such gas day-ahead. These premiums and discounts account for opportunity costs that result from purchasing or selling fuel in real-time. These opportunity costs are observed in the natural gas markets and include factors such as balancing charges, illiquidity in the market, and imperfect information. The premiums and discounts used in the model vary by Load Zone, ranging from 10%-30%.[32]

Additionally, opportunity costs are reflected in the model for resources that take a reserve position in the markets. These costs vary by resource type, given that units with dual fuel capability have flexibility to operate on alternative fuel types which can mitigate this risk as compared to gas only units. The opportunity cost for dual fuel units is assumed to be $2.00/MWh in Load Zones G (Dutchess County), G (Rockland County), J, and K. The opportunity cost for these units is based on the MMU's analysis of historical bid data from dual fuel units in Load Zones J and K.[33] Comparatively, the opportunity cost for gas only units in Load Zones C and F is set to the intraday premium of buying natural gas during the operating day.

Intraday gas premiums and discounts are necessary to use in the model because a generating unit could receive a DAM commitment for one product, but then be dispatched for a different product, or no product, in the RTM. For example, the unit could receive a DAM energy commitment and purchase fuel to meet that commitment, but then receive a reserve schedule in RTM. The lower price received when selling back the fuel in real-time is accounted for in the model when determining whether to schedule the unit for reserves instead of energy in the RTM.

The natural gas price premiums and discounts values used in the model were developed by the MMU

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needed, to develop a generalized estimate for transportation from any one gas hub to a location within the Load Zone to which its fuel costs are assigned.

[32] *See* Consultant Report at 98-99.

[33] MMU Draft Recommendations Comments at 7-9.

and used in the net revenue analysis for gas-fired and dual-fuel units included in its 2019 State of the Market Report.[34] In practice, the natural gas premium or discount is considered in the model when determining whether it is more economic for a unit to meet its DAM schedule or receive a different schedule in RTM.[35]

Table 13: Fuel Adders

Region	Gas Transportation ($/MMBtu)	Intraday Gas Premium/Discount	Tax (Gas/ULSD)	Oil Transportation ($/MMBtu)
NYCA	$0.27	10%	-	$2.00
G-J	$0.27	10%	-	$1.50
NYC	$0.20	20%	6.9% (Gas) 4.5% (ULSD)	$1.50
LI	$0.25	30%	1.0% (Gas)	$1.50

Consideration of Dual-fuel Capability in the Net EAS Model

For units with dual-fuel capability, the thermal resource net EAS revenues model considers the economics associated with operating with either natural gas or ultra-low sulfur diesel (ULSD). The model compares the fuel prices associated with natural gas or ULSD and selects the more economic fuel type for that peaking plant for a given run.[36] It is assumed that the peaking plant operates on this fuel type for a full runtime block, as units are not allowed to switch fuel types within a given run. Additional information on the treatment of dual-fuel capable units in the net EAS revenues model is included in Section IV.B.2.a of the Consultant Report.

Energy Storage Net EAS Model Logic

Energy storage resources participate in the NYISO markets and earn revenue in a way that is fundamentally different from thermal resources. First, the variable cost to produce electricity for a thermal unit is primarily determined by the cost of procuring fuel and the cost of emissions produced from combustion; the cost of fuel for a storage unit is based on the energy cost at the time of charging.

[34] *See* Potomac Economics, *2019 State of the Market Report for the New York ISO Markets* (May 2020) at A-205, available at: https://www.nyiso.com/documents/20142/2223763/NYISO-2019-SOM-Report-Full-Report-5-19-2020-final.pdf/ .

[35] *See* Consultant Report at 78-80.

[36] For dual fuel units, the otherwise applicable opportunity cost for providing reserves day-ahead is eliminated for hours in which ULSD prices (plus applicable transportation charges) are lower than natural gas prices (plus applicable charges).

Second, a thermal unit could theoretically operate continuously, subject to constraints for fuel availability and environmental regulations; a storage unit is theoretically not subject to these constraints, but has a limited amount of energy that can be injected into the grid before it is depleted and it must charge again. The storage units under study for this DCR have an elected duration of 4, 6, or 8 hours, meaning they can inject electricity into the grid at full power (determined by the inverter) for the stated amount of time before the unit is depleted.

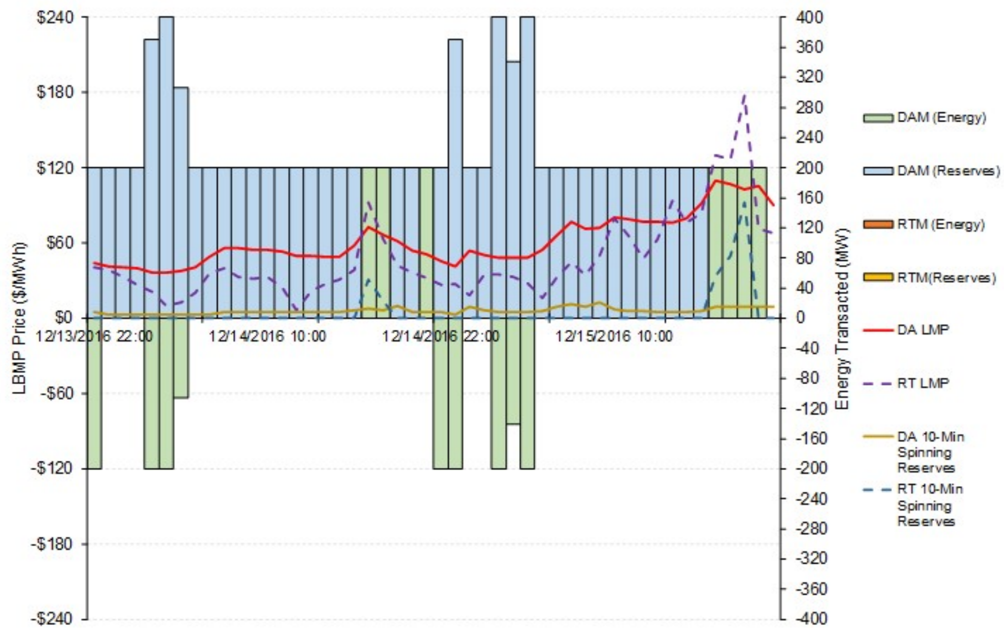
Due to the fundamental differences in how the two different resources types operate and participate in the NYISO markets, the Consultant developed an additional net EAS revenues model using dispatch logic that is specific to the BESS units evaluated. The BESS net EAS revenues model is generally consistent with the net EAS revenues model for thermal resources. The BESS model uses many of the same inputs as the thermal model, such as historic energy and reserve prices, to maximize the net EAS revenue that a theoretical storage unit could earn in the various locations under study at the tariff prescribed LOE conditions.

The energy storage resource net EAS revenues model schedules daily DAM commitments and RTM dispatch through the use of "hour-pairs," where charging and discharging intervals are assigned simultaneously. For example, over the course of a 24 hour day, the model will assign the unit to discharge energy (inject) during hours when energy prices are highest, and charge the unit when energy prices are the lowest; assigning both a charge and discharge constitutes an hour-pair. Throughout each 24-hour period, the model will assign hour-pairs starting with the most profitable pair (assigning dispatch during the interval with the highest LBMP and charging during the hour with the lowest LBMP) and continue assigning hour-pairs until there are no more hour-pairs that are profitable or if the unit receives an infeasible schedule. The model builds on this logic by taking into account the size of the battery in MWh, the amount of energy left in the unit from the previous day, round trip efficiency losses and cell degradation over time, as well as seeking to maintain a target storage level of 50% in order to minimize wear and tear on the unit while it is not charging or discharging.

Like thermal resources, storage resources are capable of providing both energy and reserves. Energy dispatch assignments are based entirely on economics, as described above. Reserves are also assigned based on economics, but do not require hour-pairs to be assigned. The battery can receive reserve revenue if it has at least one hour of stored energy (or charge) and also does not have an energy discharge assigned for that hour. Additionally, a storage unit that is charging can receive reserves on its charging schedule, where it can forgo charging in order to "provide" reserves. As a result, the unit can earn reserves on both the amount of stored energy available (assuming it is has least one hour of charge) as well as if it is actively charging.

The storage model logic is split into three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch. The first step determines the daily DAM positions by assigning hour-pairs that maximize net revenue earned through providing energy and reserves for each "cycle-day," defined as a 24-hour period between from HB 22 (10:00 PM) through HB 21 the following day (9:59 PM). The model first identifies every feasible day-ahead hour-pair given the state of charge at the beginning of each cycle-day, before ranking each hour-pair by profitability (net revenue). Since the model aims to maximize net revenue, hour-pairs that increase the unit's profitability are assigned for commitment, while those that do not are dropped. Figure 1 below provides an example of hour-pairs assigned for a 4-hour BESS during step one over two cycle-days (December 13-14, 2016 and December 14-15, 2016).[37],[38]

Figure 1: AGI Battery Model Step 1 Example: Zone G (Rockland), December 14-15, 2016, 4-Hour Battery



In Figure 1 above, the left y-axis shows the LBMP ($/MWh) and the right y-axis shows the energy transaction amount (MW) for energy and reserves; the x-axis shows time elapsed over the two cycle-day period. DAM energy positions (charge and discharge) are shown in green, with DAM reserve positions shown in blue. Three hour-pairs are assigned for the first cycle-day (i.e., from 12/13/2016 22:00 to 12/14/2016 21:59) and four hour-pairs are assigned for the second cycle-day (i.e., from 12/14/2016

[37] *See* Consultant Report at 85 (Figure 10).

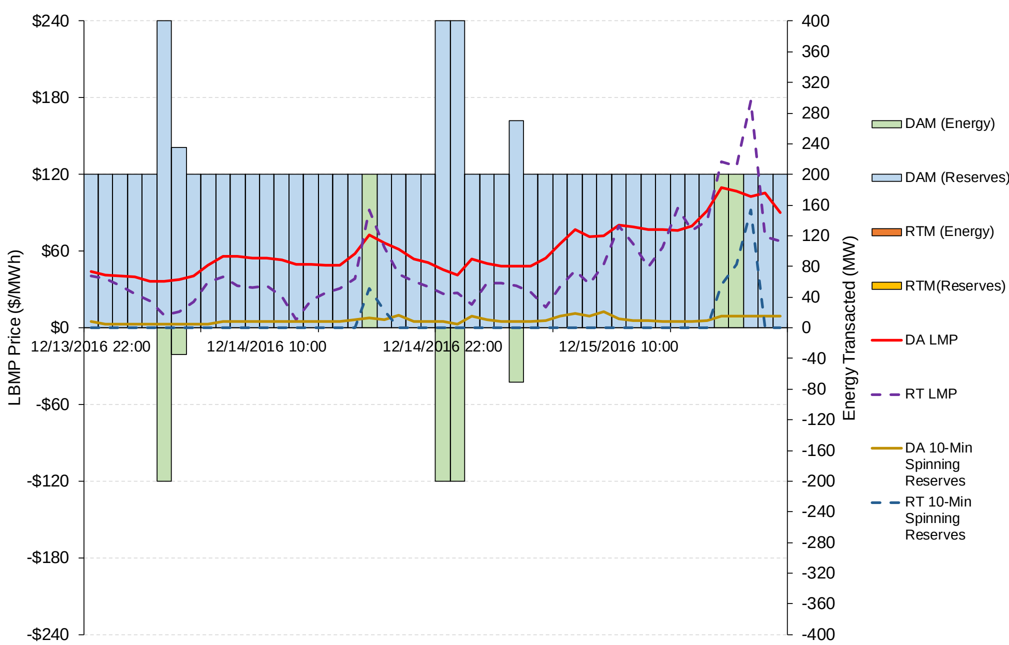
[38] Figures 1, 2 and 3 included herein reflect the results of net EAS revenues model runs performed for the Consultant's draft and interim final report using inputs from September 1, 2016 through August 31, 2019. These charts were not recreated to reflect the updated results of net EAS revenues model runs performed for the Consultant's final report that uses inputs from September 1, 2017 through August 31, 2020.

22:00 to 12/15/2016 21:59). The additional charging shown at 12/14/2016 04:00 and 12/15/2016 03:00 shows the additional charge required to account for round-trip efficiency losses.

DAM reserves can be provided as long as the unit has at least one hour of energy stored, and if the unit has a charging schedule. Prior to the first hour shown, 12/13/2016 22:00, the unit is presumed to be depleted; however, it can sell reserves up to its charging schedule. Once the unit has charged for at least one hour, it can continue selling reserves based on the energy stored. Once the unit begins charging again at 12/14/2016 02:00, it can then sell reserves on the energy stored as well as the charging position, as shown by the higher blue bars, since the unit can forgo charging in order to provide reserves, and also inject to provide reserves, using the energy stored.

The second step attempts to maximize net revenue by either fully discharging (or emptying) the battery each day or forgoing less profitable hour-pairs in earlier days in order to carry stored energy into the next cycle-day to capture more profitable hour-pairs in subsequent days. As shown in Figure 2 below,[39] the energy storage resource net EAS revenues model elects to revise schedules previously identified in step one by removing two hour-pairs from the December 13-14, 2016 and December 14-15, 2016 cycle-days. Note that as a result, two fewer hour pairs are shown on the December 13-14, 2016 and December 14-15, 2016 cycle-days as compared to Figure 1 above. The model similarly evaluated the December 14-15, 2016 cycle-day and December 15-16, 2016 cycle–day (not shown).

Figure 2: AGI Battery Model Step 1 Example: Zone G (Rockland), December 14-15, 2016, 4-Hour Battery



39 *See* Consultant Report at 86 (Figure 11).

The third step consists of performing a similar hour-pair methodology using RTM prices to modify the existing DAM schedule. The model logic can reassign a DAM reserve schedule to a RTM energy hour-pair, but it will not buyout of a DAM energy position to supply energy at RTM prices. Additionally, changes to the RTM energy schedule will impact and update DAM reserve schedules.

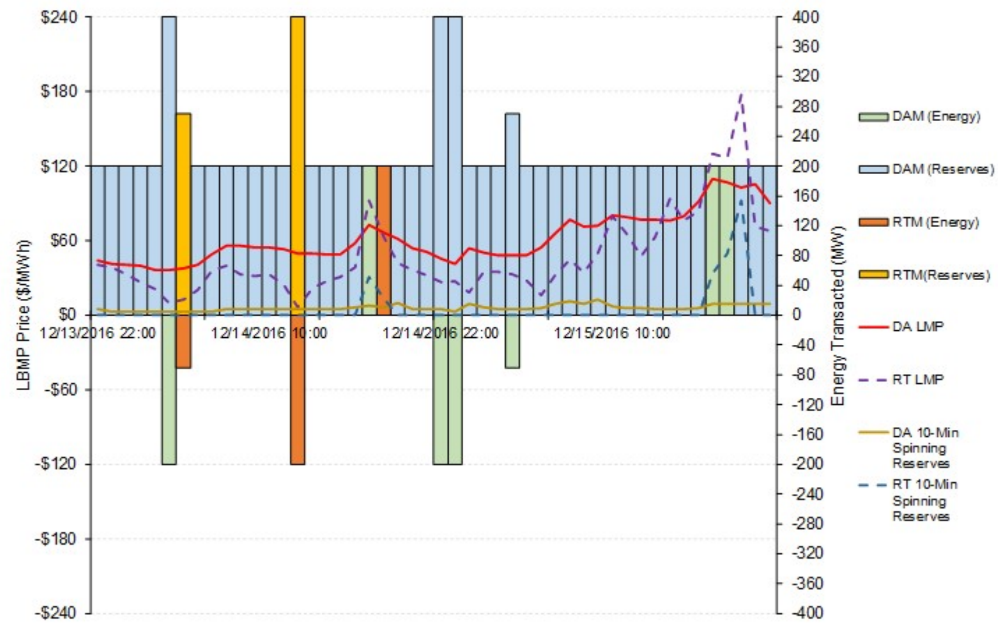
The logic used to generate potential hour-pairs in the RTM is similar to the DAM; however, in the RTM, the unit is not optimized across the day as is done in the DAM. For the RTM, the model uses DAM LBMPs when looking forward in time to decide whether to assign a RTM energy hour-pair. Revenue earnings in the RTM, however, are based on RTM LBMPs.

The RTM dispatch also uses a hurdle rate to account for uncertainty in future RTM prices, which reflects an opportunity cost of having a limited amount of stored energy and a general risk premium associated with discharging now in advance of unknown future RTM LBMPs. This risk premium was estimated iteratively, by running the model with various potential hurdle rate values (at $5/MWh increments) in order to find the hurdle rate that maximized RTM net revenues. The risk premium used in the model is assumed to be $10/MWh, as it generated approximately the highest net revenue across all locations. The resulting aggregate hurdle rates (i.e., opportunity cost value, plus the general risk premium value) were either $15/MWh or $20/MWh depending on location. More information on the RTM hurdle rate assumptions are provided in Section IV.B.2.b of the Consultant Report.

Using the RTM logic described above, Figure 3 below shows that one RTM hour-pair was assigned on both the December 13-14, 2016 and December 14-15, 2016 cycle-days.[40] For both RTM hour-pairs, the battery capitalizes on low RTM LBMPs earlier in the day for charging and higher RTM LBMPs later in the day for discharging; however, the decision to assign a discharge hour later in the day is based on DAM LBMPs and the applicable hurdle rate, as the future RTM LBMP is not known. Additionally, the reserve schedules are updated from DAM to RTM based on the new energy schedules.

[40] *See* Consultant Report at 88 (Figure 13).

Figure 3: AGI Battery Model Step 3 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery



For additional information on how the energy storage resource net EAS revenues model evaluates economics for each interval and assigns dispatch, please see Section IV.B.2.b of the Consultant Report.

Level of Excess Adjustment Factors

Services Tariff Section 5.14.1.2.2 requires that "the cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "prescribed level of excess")."

The historic prices used for estimating net EAS revenues reflect "as found" conditions and adjustments are needed to account for the tariff-prescribed level of excess conditions assumed for the DCR. This adjustment is accomplished through the use of "scaling factors" that are referred to as level of excess adjustment factors (LOE-AFs). LOE-AFs are determined as part of the DCR and remain fixed for the four year reset period.

LOE-AFs were developed using the same methodology as the last reset. Consistent with the last reset, GE Energy Consulting (GE) was contracted to perform a series of Multi-Area Production System (MAPS) runs to simulate wholesale energy prices under various levels of excess to assist in developing the LOE-AFs. For the purposes of the DCR, GE performed two sets of MAPS runs: one run was modeled on the "as-found" system and one run modeled the system at the prescribed level of excess. Both cases were modeled using the base case from the 2019 Congestion Assessment and Resource Integration Studies (CARIS) Phase 1 analysis, adjusted for certain resource additions and retirements known as of June 30, 2020, and updated peak load levels per the 2020 Load & Capacity Data report (i.e., the 2020 Gold Book)..

The output of each MAPS run provides hourly energy clearing prices by Load Zone. Using the two runs, a series of ratios were developed that reflect the price difference between the system at the prescribed level of excess and as-found. These ratios form the LOE-AFs that are used to scale historic hourly market clearing prices in both the energy storage resource and thermal resource net EAS revenues models. These scaled LBMPs estimate prices under the prescribed level of excess conditions to estimate EAS revenue according to the Services Tariff Section 5.14.1.2.2. The table below provides the LOE-AFs used in the model. Additional information regarding the LOE-AFs used for this DCR is set forth in Section IV.B.2.d of the Consultant Report.

Inclusion of DEC Peaker Rule Retirements and Deactivations

Certain stakeholders have requested that the NYISO further modify the base case underlying both the "as-found" and prescribed level of excess runs to account for anticipated retirements and deactivations as a result of the recently adopted 6 NYCRR Subpart 227-3 rules related to ozone season emission limits for simple cycle and regenerative combustion turbines" (hereinafter referred to as the "NYSDEC Peaker Rule"). The rule establishes limitations on NOx emissions for affected generating units . The NYSDEC Peaker Rule phases in compliance obligations between 2023 and 2025. The rule required affected unit owners to submit compliance plans to the NYSDEC in March 2020. Approximately 1,800 MW of nameplate capacity across Load Zones G, J, and K submitted compliance plans indicating an intent to retire or suspend operation during ozone season beginning on either May 1, 2023 or May 1, 2025.

The NYISO has chosen not to reflect the impact of compliance plans submitted in accordance with the NYSDEC Peaker Rule in the modeling for LOE-AFs at this time. Nearly all of the 1,800 MW of nameplate capacity identified in compliance plans are located in Load Zone J. Including these retirements and deactivations would create a system where there may not be enough capacity to meet load absent further adjustments to the modeling assumptions, which does not reflect a likely outcome. Notably, there are several units in the NYISO's interconnection process that could potentially serve as replacements for these plant retirements, but are not far enough along in the process to meet inclusion rules under the various planning studies currently underway. Additionally, the NYSDEC Peaker Rule specifically states that units can remain in operation for up to two, two-year extensions pending implementation of a permanent solution if there is a NYISO-identified reliability need associated with their retirement, as would be the case if there was a capacity deficiency.

Importantly, only four months of market prices capturing resource impacts related to the 2023 requirements of the NYSDEC Peaker Rule would be used in the net EAS revenues model during the period covered by this reset. This would occur as part of the annual update for the 2024-2025 Capability Year ICAP Demand Curves (i.e., the final annual update to occur during the reset period that has a historic data period of September 1, 2020 – August 31, 2023). The NYISO believes that developing LOE-AFs accounting for potential NYSDEC Peaker Rule retirements to apply to all years covered by the DCR (2021-2022 Capability Year through the 2024-2025 Capability Year) does not properly reflect the expected system that will be reflected in the historic data periods used for determining net EAS revenue offset estimates for this period.

Table 14: Level of Excess Adjustment Factors

Load Zone	Peak Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Central (Zone C)	Off-Peak	1.088	1.114	1.085	1.025	1.037	1.050	1.037	1.044	1.033	1.035	1.030	1.050
	On-Peak	1.113	1.122	1.105	1.032	1.047	1.051	1.058	1.061	1.046	1.046	1.043	1.061
	High On-Peak	1.199	1.184	-	-	-	1.064	1.098	1.146	-	-	-	1.111
Capital (Zone F)	Off-Peak	1.015	1.011	1.005	1.016	1.014	1.024	1.027	1.033	1.025	1.027	1.014	1.025
	On-Peak	1.020	1.017	1.001	1.027	1.036	1.030	1.042	1.047	1.036	1.036	1.021	1.035
	High On-Peak	0.991	1.005	-	-	-	1.036	1.068	1.107	-	-	-	1.016
Hudson Valley (Zone G)	Off-Peak	1.029	1.026	1.018	1.017	1.016	1.026	1.026	1.034	1.024	1.029	1.017	1.026
	On-Peak	1.041	1.038	1.019	1.025	1.025	1.030	1.043	1.045	1.034	1.036	1.033	1.041
	High On-Peak	1.027	1.032	-	-	-	1.049	1.085	1.142	-	-	-	1.039
NYC (Zone J)	Off-Peak	1.027	1.023	1.016	1.016	1.015	1.022	1.022	1.028	1.020	1.026	1.014	1.024
	On-Peak	1.025	1.033	1.015	1.021	1.020	1.019	1.027	1.031	1.021	1.028	1.024	1.031
	High On-Peak	1.021	1.025	-	-	-	1.031	1.059	1.118	-	-	-	1.028
Long Island (Zone K)	Off-Peak	1.053	1.057	1.035	1.022	1.032	1.037	1.043	1.039	1.035	1.042	1.038	1.053
	On-Peak	1.083	1.073	1.033	1.025	1.021	1.035	1.070	1.073	1.038	1.045	1.048	1.065
	High On-Peak	1.071	1.066	-	-	-	1.049	1.164	1.268	-	-	-	1.063

Discussion of "One-time Adjustments" to Historic Market Pricing Data

The Consultant evaluated a variety of factors raised by stakeholders that could affect market prices within the period covered by this reset. These considerations include potential changes to reserve requirements and reserve pricing, impacts resulting from implementation of the CLCPA, as well as impacts of the COVID-19 pandemic on wholesale market prices. The Consultant's analysis evaluated whether these changes are known and measurable, how easily market impacts can be accurately estimated, and the efficacy of annual updates in capturing the changes gradually.

As a result of their analysis, the Consultant concluded that it would be inappropriate to propose any one-time adjustments to net EAS revenues estimates in response to the issues raised. Their assessment was supported by the fact that there is substantial uncertainty surrounding the potential impacts of policies, events, and market rule changes that are currently in development. This lack of clarity significantly inhibits the ability to accurately forecast the associated potential market price impacts. The Consultant also determined that annual updates are designed to effectively incorporate the actual impacts of events, as well as market rule and policy changes, into net EAS revenue estimates over time. This approach avoids integrating likely inaccurate adjustments into the multi-year DCR period.

Development of ICAP Demand Curves

The DCR results in the development sloped ICAP Demand Curves which are intended to provide price signals for investments in capacity, reduce unnecessary price volatility, and value additional UCAP beyond NYCA and Locational Minimum Installed Capacity Requirements. A number of factors are considered by the Consultant in setting the ICAP Demand Curves.

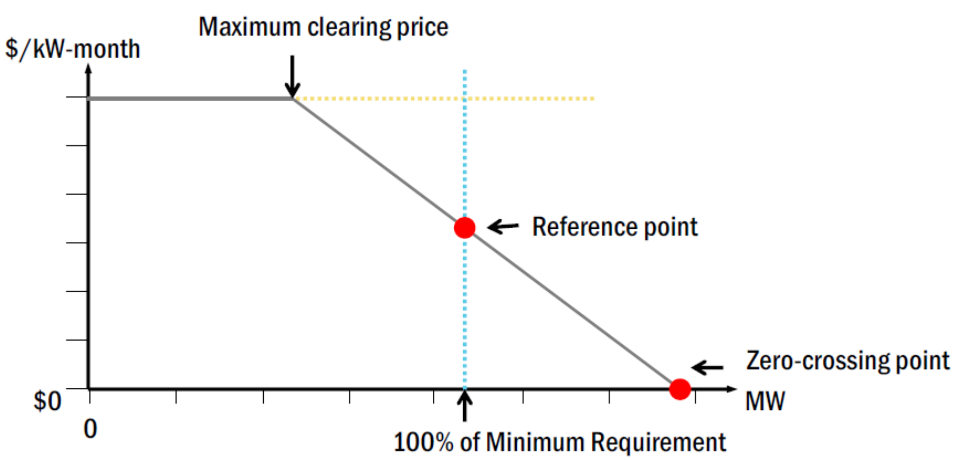
The Consultant, with input from the NYISO and stakeholders, recommend the annual levelized embedded cost of peaking plants that are used in determining the ICAP Demand Curves. An array of inputs are considered in determining this cost, with the inputs made up of initial capital costs, and fixed costs (i.e., costs that do not vary with production from the unit). These include construction and installation costs, fixed O&M costs, and miscellaneous other adjustments, including the cost of back-end emissions control technology and infrastructure related to dual-fuel capability, if applicable to the peaking plant.

Projected annual net EAS revenues of each peaking plant are another key input to the determination of the ICAP Demand Curves. Once the cost of a peaking plant and the estimated net EAS revenue earnings are established, subtracting the net EAS revenues from the cost of the peaking plant yields the annual reference value (ARV), commonly referred to as the “net cost of new entry (net CONE).”

Several factors influence the development of the net CONE. The tariff prescribes that the payments a peaking plant receives should result in adequate revenue to cover costs assuming the plant were to enter the capacity market when total capacity supply is equal to the applicable minimum ICAP requirement plus the MW size of the peaking plant. The net EAS revenues estimate is thus calculated assuming the minimum capacity requirement is fulfilled, plus a small amount of excess capacity beyond the applicable minimum installed capacity requirement. This excess capacity, referred to as the "level of excess," is prescribed by the tariff. In practice, LBMPs used in the model to calculate the net EAS revenue are scaled by LOE-AFs to address this requirement. The net CONE is also calculated such that the peaking plant would receive adequate revenue from the 12 monthly capacity payments it would be provided; the price points of the ICAP Demand Curves are in $/kW-month. The ICAP market consists of two seasons, the Winter Capability Period and the Summer Capability Period. These periods reflect the differing amounts of capacity available in each season. The net CONE established for each peaking plant is adjusted to account for these seasonal differences in the amount of capacity available using the winter-to-summer ratio, as described in further detail below.

The net CONE value, in $/kW-month, accounting for the tariff-prescribed level of excess conditions and seasonal differences in capacity availability establishes the reference point price for each ICAP Demand Curve. A maximum clearing price of 1.5 times the monthly cost to develop the applicable peaking plant is set as the maximum capacity market clearing price for each ICAP Demand Curve.[41] Finally, a zero crossing point for each ICAP Demand Curve is set, based on a predetermined amount above the applicable minimum ICAP requirements. The zero crossing point represents the point at which the value of additional capacity declines to zero.

Figure 4: Illustration of Demand Curve Slope



Inputs for the cost of each peaking plant and the net EAS revenue offset are used to establish ICAP Demand Curves for the NYCA, G-J Locality, New York City (NYC), and Long Island (LI). There is thus a separate net CONE calculation for each capacity region, and a separate ICAP Demand Curve calculated for each capacity region.

[41] The Services Tariff states that: "The maximum value for each ICAP Demand Curve shall be established at 1.5 times the monthly value of the applicable updated peaking plant gross cost". As part of this DCR, the Consultant and NYISO reviewed the current calculation used for setting the maximum clearing price, which takes the relevant annual gross CONE value underlying each ICAP Demand Curve, converts it to a monthly figure by dividing by 12, and multiplies this monthly value by 1.5. Upon reviewing this calculation, the NYISO proposes to apply a similar methodology for accounting for seasonal differences in capacity as is applied to reference point values, by using the winter-to-summer ratio (WSR) and percent of capacity at LOE conditions when calculating the monthly gross CONE values used in establishing the maximum clearing price. The NYISO staff's revised calculation would use the relevant annual gross CONE value underlying each ICAP Demand Curve, and convert it to a monthly figure by dividing by 12, and multiplying that value by both the relevant WSR and capacity at LOE conditions (%). The resulting monthly value would then be multiplied by 1.5 to establish the maximum clearing price for a particular ICAP Demand Curve.

The DCR occurs every four years, with an annual update occurring each year in years two through four of the four-year period encompassed by each reset. The annual updates adjust the estimated net EAS revenues, the levelized cost of the peaking plant, and the winter-to-summer ratio (WSR). These updated parameters are then utilized to establish updated ICAP Demand Curves for each of the intervening years between resets.

The ICAP spot market auction is the only ICAP auction that uses the ICAP Demand Curves, wherein the demand curve replaces bids to purchase capacity. This is because this auction is the last auction before the applicable month when the capacity purchased and sold will be in effect, and thus any remaining Load Service Entity (LSE) capacity obligations that have not already been purchased in prior auctions must be fulfilled in this auction. For the purposes of holding the ICAP Spot Market Auction, the requirements used in the ICAP Demand Curve are converted to UCAP values. All offers to sell capacity that are at or below the demand curve are awarded in the spot auction, and these MW are allocated out to Market Participants based upon deficiencies and LSE capacity requirements, with any excess MW purchased above requirements allocated to LSEs based on load-ratio share.

Duration Adjustment Factors

In June 2019, the NYISO filed its proposed participation model to allow aggregations of resources, including distributed energy resources, to participate in the NYISO-administered Energy and Ancillary Services and ICAP markets and rules to allow resources with daily run-time limitations to participate in the NYISO ICAP market.[42] These market rules were largely accepted by FERC in January 2020 and expect to be implemented in the NYISO markets in 2021.[43] The ICAP market-specific rules subject resources with a daily run-time limitation to different obligations and market rules than capacity suppliers not subject to such limitations, including a reduced ICAP payment based on the resource's contribution to resource adequacy. Starting with the 2021/2022 Capability Year, resources with a daily run-time limitation will be able to elect an Energy Duration Limitation of 2, 4, 6, or 8 hours for participation in the NYISO's ICAP market with corresponding Duration Adjustment Factors of 45%, 90%, 100%, and 100%, respectively. Capacity supply resources that are not subject to a daily run-time limitation will be assigned a Duration Adjustment Factor of 100%, including Intermittent Power Resources.

Given the nature of their technology, it is the NYISO's expectation that battery energy storage facilities will elect Energy Duration Limitations for participation in the ICAP market. As such, the Consultant's

[42] *See* Docket No. ER19-2276-000, *New York Independent System Operator Inc.*, Proposed Tariff Revisions Regarding Establishment of Participation Model for Aggregations of Resources, Including Distributed Energy Resources (June 27, 2019).

[43] *See New York Independent System Operator*, *Inc.*, 170 FERC ¶ 61,033 (2020).

evaluation included BESS options with Energy Duration Limitations of 4, 6, and 8 hours. The applicable Duration Adjustment Factors for the BESS options evaluated were applied in determining ICAP Demand Curve reference point prices that would be associated with the selection of BESS as the peaking plant for each ICAP Demand Curve. Although the values were determined by the Consultant, the BESS options evaluated were ultimately not selected as the peaking plant for any ICAP Demand Curve in this DCR. Further analysis should be done in the future to assess the appropriateness of setting the ICAP Demand Curves, from a reliability perspective, based on a peaking plant that is subject to energy duration limitations and unable to fully meet resource adequacy needs.

Winter-to-Summer Ratio

The NYISO operates a capacity market with two distinct six-month Capability Periods. In calculating the reference point price for each ICAP Demand Curve, the Services Tariff requires that seasonal differences in capacity availability be accounted for. This seasonal adjustment is intended to reflect the fact that differences in capacity availability between the Summer Capability Period and Winter Capability Period contribute to differences in capacity prices throughout the year. To provide for revenue adequacy for the applicable peaking plant when it is needed to maintain the applicable minimum Installed Capacity requirement, these seasonal differences must be accounted for as part of translating the annual net CONE value for each ICAP Demand Curve to a monthly value for use in the NYISO's ICAP Spot Market Auctions (i.e., the reference point price for each ICAP Demand Curve). The WSR is used to account for these seasonal differences in capacity availability.

The WSR methodology relies on data published by the NYISO regarding capacity available to be offered in the ICAP Spot Market Auction for each month during the same 36-month historic data period used by the net EAS revenues model. The NYISO will adjust the historic data to account for certain capacity market entry and exit actions by resources, as further described in Section 5.14.1.2.2.3 of the Services Tariff. The WSR for each capacity region is calculated as the average of the winter-to-summer ratio calculated for each 12-month period (i.e., September through the following August) encompassed by the historic data set. For each 12-month period, the applicable winter-to-summer ratio is calculated as: (i) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six winter months included in the 12-month period (i.e., November through the following April); divided by (ii) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six summer months included in such 12-month period (i.e., September and October and May through August of the following year).

The WSR values used in determining the ICAP Demand Curves for first year of this DCR (i.e., the 2021/2022 Capability Year) are provided in the table below.

Table 15: Final Winter-to-Summer Ratio Values for the 2021/2022 Capability Year ICAP Demand Curves

Capacity Region	Capability Year	WSR
NYCA	2021-2022	1.038
G-J	2021-2022	1.059
NYC	2021-2022	1.076
LI	2021-2022	1.073

Level of Excess Value for Reference Point Price Calculations

The level of excess (LOE) for each peaking plant is defined as the ratio of the applicable minimum Installed Capacity requirement plus the average degraded net peaking plant capacity to the applicable minimum Installed Capacity requirement. The LOE is expressed in percentage terms and defined by the following equation, where all capacities are expressed in MW.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)}$$

The LOE varies by capacity region, depending on the applicable minimum requirement, and by size of the various peaking plant options evaluated in this study. The applicable minimum ICAP requirement values are based on the peak load forecasts and the IRM/LCR values for the 2020/2021 Capability Year. The tables below provide the applicable forecasted peak load, IRM/LCR values (in percentage terms), and the resulting LOE by capacity region and technology, expressed as a percentage.

Table 16: Fossil Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Zone	Peak Load (MW)	2020-2021 IRM/LCR	LOE (%) by Technology				
			3x0 Siemens SGT-A65	1x0 GE 7F.05	1x0 GE 7HA.02 (25ppm)	1x0 GE 7HA.02 (15ppm)	1x1 GE 7HA.02 (CC)
NYCA	32,296	118.9%	100.4%	100.5%	100.9%	100.9%	101.3%
G-J	15,695	90.0%	101.1%	101.5%	102.5%	-	103.5%
NYC	11,477	86.6%	101.6%	102.1%	103.5%	-	105.1%
LI	5,227	103.4%	102.9%	103.9%	106.5%	-	109.3%

Table 17: Battery Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Zone	Peak Load (MW)	2020-2021 IRM/LCR	LOE (%) by Technology		
			4-hr BESS	6-hr BESS	8-hr BESS
NYCA	32,296	118.9%	100.5%	100.5%	100.5%
G-J	15,695	90.0%	101.4%	101.4%	101.4%
NYC	11,477	86.6%	102.0%	102.0%	102.0%
LI	5,227	103.4%	103.7%	103.7%	103.7%

Zero Crossing Point

In the last reset, the zero crossing points for the ICAP Demand Curves were set at 112 percent of IRM for NYCA, 118 percent of LCR for Load Zone K (Long Island), 118 percent of LCR for Load Zone J (New York City), and 115 percent of LCR for the G-J Locality. The NYISO has proposed to establish a future project to further assess the ICAP Demand Curve parameters, including the zero crossing points, in an effort separate from the DCR. As a result, the Consultant recommended that the zero crossing point values for the 2021-2025 ICAP Demand Curves remain unchanged. The NYISO concurs with this recommendation to retain the current zero crossing point values for the duration of this reset period. Any in-depth assessment of potential future revisions to the zero crossing point values would be best conducted as a separate effort outside the context of the DCR.

ICAP Demand Curve Reference Points

The applicable data and information was used to calculate 2021/2022 Capability Year ICAP Demand Curve reference point prices for the various peaking plant options evaluated, as well the informational combined cycle plants.

Table 18: 2021/2022 Capability Year ICAP Demand Curve Parameters for Simple Cycle Combustion Turbine Peaking Plant Options

Technology	Fuel Type & Emission Control	Parameter	Central	Capital	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	New York City	Long Island
1x0 GE 7HA.02	Dual Fuel, with SCR 25ppm	Gross CONE	-	-	$145.32	$149.78	$196.41	$159.77
		Net EAS	-	-	$27.96	$35.15	$33.42	$54.15
		Annual Reference Value (Net CONE)	-	-	$117.35	$114.63	$162.99	$105.62
		Reference Point	-	-	$14.91	$14.57	$22.36	$19.60
	Gas Only, without SCR 15ppm	Gross CONE	$114.75	$115.79	-	-	-	-
		Net EAS	$32.92	$24.56	-	-	-	-
		Annual Reference Value (Net CONE)	$81.83	$91.23	-	-	-	-
		Reference Point	$8.62	$9.52	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	Gross CONE	-	-	$184.57	$192.44	$267.28	$204.82
		Net EAS	-	-	$29.10	$35.21	$33.65	$53.77
		Annual Reference Value (Net CONE)	-	-	$155.47	$157.23	$233.62	$151.05
		Reference Point	-	-	$17.76	$17.96	$28.13	$20.94
	Gas Only, without SCR	Gross CONE	$148.09	$149.86	-	-	-	-
		Net EAS	$36.01	$25.69	-	-	-	-
		Annual Reference Value (Net CONE)	$112.08	$124.17	-	-	-	-
		Reference Point	$11.26	$12.47	-	-	-	-
3x0 Siemens SGT-A65	Dual Fuel, with SCR	Gross CONE	-	-	$285.71	$293.62	$389.96	$302.26
		Net EAS	-	-	$30.74	$34.68	$35.15	$54.22
		Annual Reference Value (Net CONE)	-	-	$254.96	$258.94	$354.80	$248.05
		Reference Point	-	-	$27.16	$27.59	$39.64	$30.41
	Gas Only, with SCR	Gross CONE	$261.26	$264.07	-	-	-	-
		Net EAS	$35.17	$27.52	-	-	-	-
		Annual Reference Value (Net CONE)	$226.09	$236.55	-	-	-	-
		Reference Point	$21.54	$22.51	-	-	-	-

Note: Gross CONE, Net EAS, and Annual Reference Value (Net CONE) shown as $/kw-year. Reference Points shown as $/kw-month

Note: Values shown for Load Zone C are calculated using TGP Z4 (200L) for Apr-Nov and Niagara for Dec-Mar

Table 19: 2021/2022 Capability Year ICAP Demand Curve Parameters for BESS and Informational Combined Cycle Plants

Technology	Fuel Type & Emission Control	Parameter	Central	Capital	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	New York City	Long Island
BESS (200 MW)	4-hr (800 MWh)	Gross CONE	$200.79	$202.46	$204.04	$210.82	$261.74	$214.86
		Net EAS	$47.04	$48.71	$50.17	$49.56	$51.25	$62.47
		Annual Reference Value (Net CONE)	$153.75	$153.75	$153.87	$161.26	$210.49	$152.39
		Reference Point	$17.83	$17.83	$20.10	$21.06	$28.78	$23.85
	6-hr (1200 MWh)	Gross CONE	$279.86	$282.27	$284.49	$294.28	$355.52	$302.63
		Net EAS	$47.80	$48.95	$51.68	$50.08	$52.25	$66.52
		Annual Reference Value (Net CONE)	$232.06	$233.32	$232.81	$244.20	$303.27	$236.11
		Reference Point	$24.23	$24.36	$27.37	$28.70	$37.32	$33.26
	8-hr (1600 MWh)	Gross CONE	$358.90	$362.07	$364.93	$377.72	$449.29	$390.39
		Net EAS	$47.91	$49.43	$51.86	$50.40	$52.48	$68.11
		Annual Reference Value (Net CONE)	$310.99	$312.64	$313.07	$327.32	$396.81	$322.28
		Reference Point	$32.46	$32.64	$36.80	$38.48	$48.84	$45.39
1x1 GE 7HA.02 Informational Combined Cycle	Dual Fuel, with SCR	Gross CONE	-	-	$218.22	$231.74	$388.14	$257.42
		Net EAS	-	-	$49.36	$72.17	$69.24	$111.00
		Annual Reference Value (Net CONE)	-	-	$168.86	$159.58	$318.90	$146.42
		Reference Point	-	-	$24.71	$23.35	$52.28	$43.06
	Gas only, with SCR	Gross CONE	$196.59	$199.81	-	-	-	-
		Net EAS	$54.22	$48.22	-	-	-	-
		Annual Reference Value (Net CONE)	$142.37	$151.59	-	-	-	-
		Reference Point	$15.90	$16.98	-	-	-	-

Note: Gross CONE, Net EAS, and Annual Reference Value (Net CONE) shown as $/kw-year. Reference Points shown as $/kw-month

Note: Values shown for Load Zone C are calculated using TGP Z4 (200L) for Apr-Nov and Niagara for Dec-Mar

Annual Updates

In accordance with the requirements of Section 5.14.1.2.2 of the Services Tariff, the ICAP Demand Curves will be updated annually for each of the three successive Capability Years encompassed by this reset period (i.e., the 2022/2023 Capability Year, 2023/2024 Capability Year, and 2024/2025 Capability Year) through the updating of (1) Gross CONE values, (2) net EAS revenue estimates using the net EAS revenues model, and (3) the winter-to-summer ratio values. Updates to Gross CONE and net EAS revenues are described in greater detail below. The winter-to-summer ratio will be updated annually by the NYISO in accordance with the requirements of Section 5.14.1.2.2.3 of the Services Tariff. The table below summarizes certain of the factors used in the annual updates to ICAP Demand Curve reference point prices, indicating in **bold** those parameters that are updated annually. The remaining parameters are fixed for the reset period.

Table 20: Overview of ICAP Demand Curve Annual Updating

Factor Used in Annual Updates	Type of Value	NYCA	G-J	J	K
ICAP Demand Curve Values					
Zero-crossing point	Fixed for Reset Period	112%	115%	118%	118%
Reference Point Price Calculation					
Peaking Plant Net Degraded Capacity (ICAP MW)	Fixed for Reset Period	344	347	349	349
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC) MW	Fixed for Reset Period	346	348	349	351
Peaking Plant Winter Capability Period DMNC MW	Fixed for Reset Period	366	370	374	373
Installed Capacity Requirements (IRM/LCR)	Fixed for Reset Period	118.9%	90.0%	86.6%	103.4%
Monthly Available Capacity Values for Use in Calculating WSR	**NYISO Published Values**	This data is updated annually and is publicly available via the NYISO's website.			

Updates to Gross CONE

An element of annual updates is the adjustment of Gross CONE values. In each year, the Gross CONE of each peaking plant will be updated based on a state-wide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components: wages, turbines, materials and components, and other costs. The growth rate for all indices is a ratio of (1) the most recently available data as of October 1 in the year prior to the start of the Capability Year for which the updated ICAP Demand Curves will apply and (2) the same data values for time periods associated with the most recent finalized data available for each index as of October 1 of the calendar year in which the NYISO files the results of a DCR with the FERC (i.e., October 1, 2020 in the case of this DCR), minus one.[44]

Thus, in each year, the annual composite escalation rate is calculated as:

$$Annual\ Composite\ Escalation_{\,t} = \sum_{i=1}^{4}(weight_i) * \left(\frac{Index_{i,t}}{Index_{i,DCRYear}} - 1\right) \tag{9}$$

The cost-component weighting factors are calculated for each peaking plant technology reflecting each component's relative share of total peaking plant installed capital costs. The table below provides the (publicly available) index to be used for measuring changes over time for each cost component, and each component's relative weight for each peaking plant technology. The same weighting factors and indices will be used for the duration of the reset period, but the values resulting from the indices will be updated annually based on the indices and component weights described in the table below.

The composite escalation rate (and the rate associated with the general component thereof) will be updated annually as described above. Gross CONE values are adjusted annually by applying the composite escalation rate to the gross CONE values underlying the ICAP Demand Curves for the 2021/2022 Capability Year (i.e., the first Capability Year covered by the four year duration of this reset period).

[44] Services Tariff Section 5.14.1.2.2.1. This methodology represents a change since the last reset. *See* Docket No. ER20-1049-000, *New York Independent System Operator, Inc.*, Proposed Enhancements to the ICAP Demand Curve Annual Update Procedures (February 21, 2020); and Docket No. ER20-1049-000, *supra*, Letter Order (April 3, 2020).

Table 21: Gross CONE Composite Escalation Factor Parameters

Cost Component	Index	Interval	Calculation of Index Value	Component Weight, by Technology	
				1x0 GE 7HA.02 25ppm	1x0 GE 7HA.02 15ppm
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	27%	24%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	Average of finalized February, March, April values	23%	19%
Gas and Steam Turbine Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11) Turbines and Turbine Generator Sets (97)	Monthly	Average of finalized February, March, April values	26%	32%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	24%	25%

Updates to the Net EAS Revenue Offset

Net EAS revenues will be recalculated annually using the same net EAS revenues model used to estimate net EAS revenues for the 2021/2022 Capability Year ICAP Demand Curves, but model inputs will include the most recent three-year data available for energy and reserve market prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges. Other peaking plant costs and operational parameters (e.g., heat rate, variable O&M costs) needed to run the model, as well as the applicable LOE-AF values, remain fixed for the duration of the reset period. The table below contains a summary of the factors used in the net EAS revenues calculation, with an indication of data source and whether or not they are updated annually (items in bold are updated annually).

Table 22: Overview of Annual Updating of Net EAS Revenues

Factor Used in Annual Updates	Type of Value	NYCA	G-J	J	K
Specific peaking plant technology	Fixed for Quadrennial Reset Period	GE 7HA.02 (15ppm)	GE 7HA.02 (25ppm)	GE 7HA.02 (25ppm)	GE 7HA.02 (25ppm)
Net EAS Revenue Model, including Commitment and Dispatch Logic	Fixed for Quadrennial Reset Period	Net EAS Model can be found at www.nyiso.com/installed-capacity-market; Installed Capacity Data\Reference Documents\2021-2025 ICAP Demand Curve Reset\Final Models and Materials.			
Peaking plant net plant output	Fixed for Quadrennial Reset Period	See Table 8 and Appendix A of the Consultant's Final Report			
Energy Prices (day-ahead and real-time)	NYISO Published Values	This data is publicly available through the NYISO website.			
Operating Reserves Prices (day-ahead and real-time)	NYISO Published Values	This data is publicly available through the NYISO website.			
Level of Excess Adjustment Factors	Fixed for Quadrennial Reset Period	See Table 14 above.			
Annual Value of other ancillary services not determined by net EAS Model (e.g., voltage support service) ($/kW-year)	Fixed for Quadrennial Reset Period	$2.04	$2.04	$2.04	$2.04
Peaking plant primary and secondary (if any) Fuel Type	Fixed for Quadrennial Reset Period	Natural Gas	Natural Gas & ULSD	Natural Gas & ULSD	Natural Gas & ULSD
Real-time intraday gas premium/discount values:	Fixed for Quadrennial Reset Period	10%	10%	20%	30%
Fuel tax adders	Fixed for Quadrennial Reset Period	-	-	6.9% (Gas) 4.5% (ULSD)	1.0% (Gas)
Gas transportation adder ($/MMBtu)	Fixed for Quadrennial Reset Period	$0.27	$0.27	$0.20	$0.25
ULSD transportation adder ($/MMBtu)	Fixed for Quadrennial Reset Period	$2.00	$1.50	$1.50	$1.50
Fuel Pricing Points (e.g., natural gas trading hub)	Fixed for Quadrennial Reset Period	TGP Z4 (200L) & Niagara	TETCO M3	Transco Z6 NY	Iroquois Z2
Natural Gas Prices	Subscription Service Data Source or Publicly Available Data Source	S&P Global Market Intelligence			
ULSD Prices	Subscription Service Data Source or Publicly Available Data Source	New York Harbor Ultra-low Sulfur No. 2 Diesel Spot Prices can be found at: https://www.eia.gov/dnav/pet/hist/EER_EPD2DXL0_PF4_Y35NY_DPGD.htm			
Peaking plant Variable Operating and Maintenance Cost	Fixed for Quadrennial Reset Period	See Appendix A of the Consultant's Final Report.			
Peaking plant CO_2 Emissions Rate	Fixed for Quadrennial Reset Period	See Appendix A of the Consultant's Final Report.			
CO_2 Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source	RGGI auction clearing prices can be found at: https://www.rggi.org/Auctions/Auction-Results/Prices-Volumes			
Peaking plant NO_x Emissions Rate	Fixed for Quadrennial Reset Period	See Appendix A of the Consultant's Final Report.			
NO_x Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source	S&P Global Market Intelligence			
Peaking plant SO_2 Emissions Rate	Fixed for Quadrennial Reset Period	See Appendix A of the Consultant's Final Report.			
SO_2 Emission Allowance Cost	Subscription Service Data Source or Publicly Available Data Source	S&P Global Market Intelligence			
NYISO Rate Schedule 1 Charges	NYISO Published Values	https://www.nyiso.com/billing-rates			

NYISO will collect LBMP and reserve price data for the three-year period ending August 31st of the year prior to the beginning of the Capability Year to which the updated ICAP Demand Curves will apply. Similarly, data from the specified sources for fuel prices and emission allowance prices will be collected and processed for the same time period. This data would then be used in net EAS revenues model to determine the estimated net EAS revenues of the applicable peaking plant for the upcoming Capability Year.

Updates to WSR

The WSR captures differences in the quantity of capacity available between winter and summer seasons given differences in seasonal operational capability. The ICAP Demand Curves account for differences in the prices that would prevail, all else equal, between seasons due to these seasonal differences in capacity.

The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year. Total ICAP is equal to the sum of total UCAP available (including generation, Special Case Resources, and imports) listed in monthly reports published by the NYISO, converted to ICAP using a locational EFORd. These totals are adjusted for certain resource entry and exit circumstances.[45] Both total winter ICAP and total summer ICAP are calculated as a rolling average from the same three-year historical period that is used when calculating net EAS revenues.

As part of the annual updates, the NYISO will update the WSR values to reflect historic data for the same three year period used by the net EAS revenues model.

NYISO Recommendations

Choice of Peaking Unit Technology

The NYISO concurs with the Consultant's recommendation to use a single, simple-cycle GE 7HA.02 turbine as the peaking plant technology in all locations, which represents the lowest net cost peaking plant

[45] Services Tariff, Section 5.14.1.2.2.3. Broadly, these adjustments seek to include resource changes in all months of the applicable twelve-month period based on the resource status that is expected to persist at the end of each 12-month period. For new entry of a resource that comes online after September of a given 12-month period and remains in the market for the remaining months of such period, the NYISO will add the resource's applicable summer or winter MW to any month in which the entering MW are not already included. New entry does not include resources returning from an Inactive Reserves state. If a resource exits the capacity market after September of a given 12-month period and remains out of the market for the remaining months of such period, the NYISO will remove the resource's MW for any months in which it is represented in the applicable 12-month period. Exit includes generator retirements, mothball, or ICAP Ineligible Force Outage State.

in each location.[46] Additionally, the NYISO concurs with the recommendation to include SCR emissions controls and dual fuel capability in Load Zones G (Dutchess County), G (Rockland County), J, and K. The NYISO also agrees with the Consultant's recommended use of a gas only design without SCR emissions controls in Load Zones C and F.

For those capacity regions in which multiple locations were considered, the NYISO concurs with the Consultant's recommendation to select the location that represents the lowest monthly reference point prices for each applicable ICAP Demand Curve. Accordingly, based on the results summarized herein, the NYISO staff recommends that the peaking plant located in Load Zone G (Rockland County) be utilized for establishing the G-J Locality ICAP Demand Curve, and the peaking plant located in Load Zone C be utilized for establishing the NYCA ICAP Demand Curve.

Evaluation of BESS, including development of a new net EAS revenues model for energy storage, was evaluated by the Consultants for the first time as part of this DCR. However, BESS was not selected as the representative peaking plant in any location due to the availability of lower cost, viable alternatives in all locations. The NYISO concurs with this conclusion.

Table 23: NYISO Staff Recommended 2021/2022 Capability Year ICAP Demand Curve Parameters

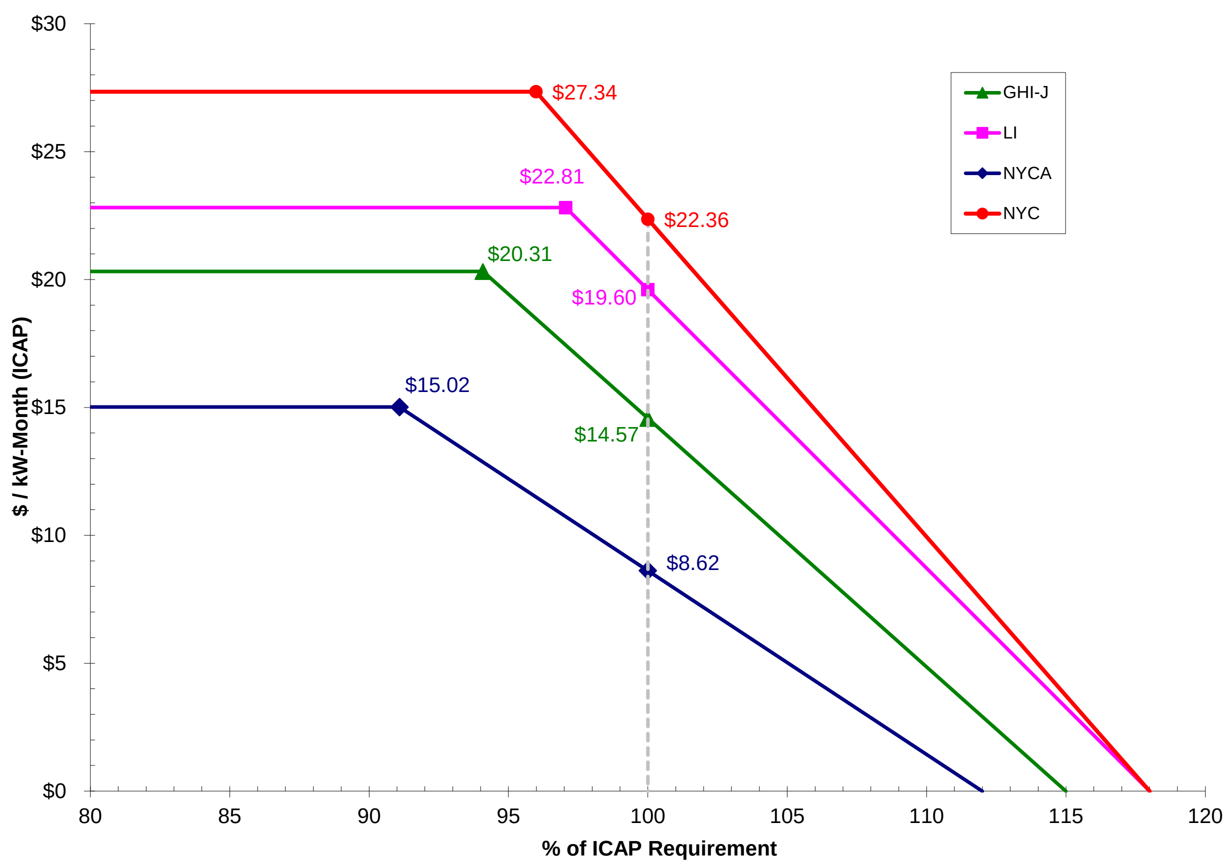
Technology		NYCA	G-J	New York City	Long Island
GE 7HA.02	Configuration	Gas only, no SCR	Dual fuel with SCR	Dual fuel with SCR	Dual fuel with SCR
	Gross CONE	$114.75	$149.78	$196.41	$159.77
	Net EAS	$32.92	$35.15	$33.42	$54.15
	Annual Reference Value (Net CONE)	$81.83	$114.63	$162.99	$105.62
	Reference Point	$8.62	$14.57	$22.36	$19.60
	Max Clearing Price	$15.02	$20.31	$27.34	$22.81

[46] During the last reset, the H-class frame technology was evaluated for informational purposes only because, at the time, a simple-cycle H-class frame unit had not yet achieved commercial operating experience. However, since the last reset, a simple cycle H-class frame turbine with SCR emissions controls has commenced commercial operation. Specifically, the Canal 3 facility in Massachusetts (i.e., a H-class turbine with SCR emissions controls) commenced commercial operation in June 2019.

Table 24: ICAP Demand Curve Parameters ($2021)

		Current Year (2021-2022)					
Parameter	Source	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Gross Cost of New Entry ($/kW-Year)	[1]	$114.75	$115.79	$145.32	$149.78	$196.41	$159.77
Net EAS Revenue ($/kW-Year)	[2]	$32.92	$24.56	$27.96	$35.15	$33.42	$54.15
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$81.83	$91.23	$117.35	$114.63	$162.99	$105.62
ICAP DMNC (MW)	[4]	326.7	328.5	347.0	347.0	348.8	348.8
Total Annual Reference Value	[5] = [3] * [4]	**$26,734,808**	**$29,967,642**	**$40,721,005**	**$39,776,090**	**$56,852,412**	**$36,841,547**
Level of Excess (%)	[6]	100.9%	100.9%	102.5%	102.5%	103.5%	106.5%
Ratio of Summer to Winter DMNCs	[7]	1.038	1.038	1.059	1.059	1.076	1.073
Summer DMNC (MW)	[8]	329.3	334.0	348.3	348.2	348.5	351.1
Winter DMNC (MW)	[9]	344.7	350.5	369.9	369.9	374.1	373.0
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$8.01	$8.84	$12.47	$12.18	$18.00	$12.58
Winter ($/kW-Month)	[11]	$5.28	$5.83	$6.61	$6.45	$8.56	$4.62
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,636,573	$2,952,627	$4,343,614	$4,242,399	$6,273,209	$4,415,188
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,819,223	$2,041,978	$2,443,190	$2,386,965	$3,202,184	$1,725,050
Seasonal Revenue (Summer)	[14] = 6 * [12]	$15,819,440	$17,715,761	$26,061,687	$25,454,395	$37,639,255	$26,491,127
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,915,339	$12,251,868	$14,659,137	$14,321,788	$19,213,103	$10,350,302
Total Annual Reference Value	[16] = [14]+[15]	**$26,734,779**	**$29,967,629**	**$40,720,824**	**$39,776,183**	**$56,852,357**	**$36,841,429**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$8.62	**$9.52**	**$14.91**	**$14.57**	**$22.36**	**$19.60**
ICAP Max Clearing Price ($/kW-Month)		$15.02	$15.15	$19.71	$20.31	$27.34	$22.81
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Figure 5: Proposed 2021-2022 ICAP Demand Curves



MMU Review of Recommended ICAP Demand Curve Parameters

Please see Appendix A.

Timeline

Stakeholders will have the opportunity to provide written comments to the Board by October 9, 2020, with oral presentations to the Board scheduled to occur on October 19, 2020. On or before November 30, 2020, the NYISO will file with FERC the Board's final recommended ICAP Demand Curve parameters for the 2021/2022 Capability Year (i.e., commencing May 1, 2021), as well as the methodologies and assumptions for conducting annual updates of the ICAP Demand Curves for the subsequent three Capability Years (i.e., the 2022/2023, 2023/2024, and 2024/2025 Capability Years).

Appendix A: MMU Comments

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Memorandum

To: Analysis Group, Burns & McDonnell

From: David Patton, Pallas LeeVanSchaick

Date: September 3, 2020

Re: MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations

In accordance with MST 5.14.1.2, the NYISO periodically conducts the ICAP Demand Curve reset ("DCR") process to ensure that the capacity demand curves are set at levels that provide efficient incentives for market based entry that satisfies the NYISO's resource adequacy needs. The NYISO contracted with the Analysis Group and Burns & McDonnell ("the consultants") to perform a study to set the levels of the capacity demand curves in each of the four capacity localities. The consultants provided their Draft DCR Report on June 5, 2020, entitled *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Initial Draft Report* ("Initial Draft Report").

The consultants also proposed certain adjustments to their initial recommendations in response to feedback received on the draft report. These adjustments were discussed at the July 22, 2020 Installed Capacity Working Group ("ICAPWG") meeting and are accounted for herein. NYISO staff issued a report on August 5, 2020 that discusses its proposed demand curves. A revised consultants' report (the "Interim Final Draft Report") was also issued on August 5, 2020. An updated final version of the consultants' report along with NYISO staff's final recommendations will be issued in September 2020.

As the Market Monitoring Unit for the NYISO, Potomac Economics is obliged to review and comment on the independent consultants' report in accordance with Market Services Tariff section 5.14.1.2.2. Throughout the process, we have provided verbal and written feedback to the independent consultants as they developed their draft recommendations in consultation with the NYISO and stakeholders.

We generally support the consultants' methodology and recommendations. However, we identified two assumptions that should be revised because they are not supported by market data or reasonable economic considerations. Both assumptions work to inflate the net cost of new entry ("Net CONE") underlying the capacity demand curves. This is particularly harmful at this time given that NYISO is substantially over supplied and inefficiently high demand curves will serve to impede efficient retirements and perpetuate the current capacity surpluses. Therefore, we recommend the following changes:

- Cost of Debt – Revise downward the cost of debt based on a broader view of the available data that does not over-emphasize the recent COVID-19-related financial market turbulence. This would support a value in the range of 6.0 to 6.5 percent rather than the proposed value of 6.7 percent.
- Amortization Period – Use an amortization period of 20 years rather than 17 years. The 17-year assumption is unreasonably low and ignores publicly available information on how the power system will adapt to the zero-emission provision of the Climate Leadership and Community Protection Act ("CLCPA").

Table 1 summarizes our estimated impact on the annual ICAP reference values (or Net CONE) of each recommendation. The impacts shown in this table are cumulative.

Table 1: Estimated Impact of Proposed Changes on Annual ICAP Reference Value

Issue	Approx. Net CONE Impact ($/kW-year)			
	Zone C	Zone G-Rockland	Zone J	Zone K
Cost of Debt (6.25%)	$1.2	$1.4	$1.8	$1.7
+ Amortization Period	$5.2	$7.4	$5.9	$7.5
Total	**$6.4**	**$8.8**	**$7.7**	**$9.2**

We also recommend the consultants modify the following to ensure that the net revenue estimates are not overstated:

- Correct an error identified in the Net E&AS Model which causes natural gas prices to be misaligned with power prices by one business day.
- For the cost of gas for the Zone C unit, continue to use the TGP Z4 (200L) index plus $0.27/MMBtu for April through November, but replace this index with the Niagara gas index in the months of December through March.

In addition to these changes, we also discuss our support for several of the consultants' recommendations, including:

- Assuming a cost of $2/MWh for selling operating reserves for dual-fueled units. Compared to the previous assumption, this will more accurately reflect the fuel reservation costs of reserve providers in New York with oil backup that would not likely incur large gas procurement costs when selling reserves.
- Model units affected by the NYSDEC "Peaker Rule" as in-service in the database used to calculate level of excess adjustment factors (LOE-AFs). Modeling these units as out-of-service would cause LOE-AFs to not reflect market conditions affecting the LBMP data that will be used to calculate Net E&AS revenues.

- Setting the NYCA demand curve based on the Load Zone C peaking plant, since this unit is expected to be deliverable in Rest of State (i.e., Load Zones A to F).
- Using the TETCO M3 index plus $0.27/MMBtu for the cost of gas in Load Zone G for the Rockland County unit.

A. Impact of COVID-19 on Cost of Debt

In March 2020, the consultants provided an initial recommendation of 6.1 percent for the cost of debt assumption. This was based on recent debt issuances by independent power producers over the last 3 years and variations in bond yields for comparably rated debt for one year through February 2020. The consultants raised the cost of debt to 7.7 percent in the Initial Draft Report to reflect the financial market impacts of the COVID-19 pandemic. These effects proved to be transitory and the consultants subsequently revised it to 6.7 percent. We recommend relying on long-term historical data over at least one year or more, which would support a cost of debt between 6.0 and 6.5 percent.

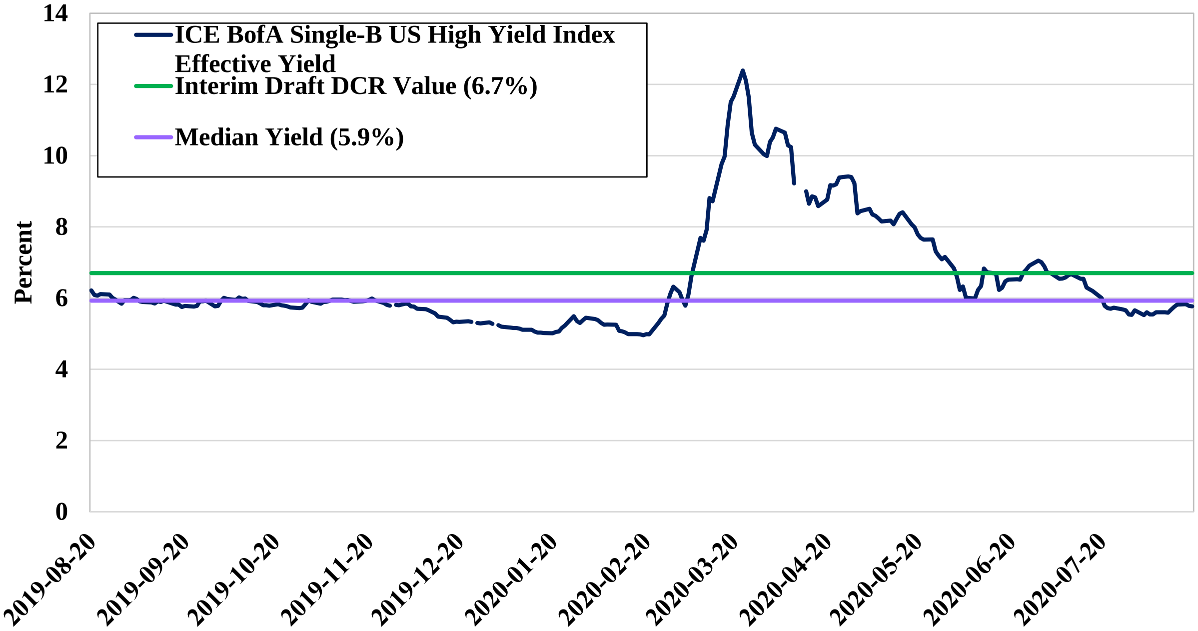
The consultants are right to consider information from recent months, but it should not be given excessive weight. Borrowing costs over the next four years are not likely to resemble the recent elevated rates. Developers of new generators with long project timelines have control over the timing of their investment and would avoid issuing debt during brief periods of market turbulence. The use of an upwardly biased cost of debt would result in an overestimated Net CONE and higher capacity prices than necessary.

Market conditions have changed considerably since the consultants developed their initial recommendation. Figure 1 shows the Single-B US High Yield Index Effective Yield from the Federal Reserve Bank of St. Louis for the year from August 20, 2019 through August 20, 2020. Figure 1 shows that yields began to rise sharply in late February and remained elevated in April and May. These substantial increases reflected severe liquidity issues in the credit markets that have not been sustained. When presenting their rationale for a higher cost of debt in May 2020, the consultants pointed to the sharp increase in debt costs that occurred between March and April. In particular, the consultants highlighted costs of B-rated debt at 12.4 percent on March 23 and 9.3 percent in the week of April 21.[1] Since May, Figure 1 shows that the B-rated corporate debt benchmark has fallen considerably.[2] Yields then fell close to pre-COVID-19 levels in June and fell below 6 percent in August.

1 See Analysis Group presentation to Installed Capacity Working Group on May 19, 2020.

2 The four power companies with meaningful ownership of merchant generation examined by the consultants issued debt in the past three years with ratings that were mostly B and better (BB and BBB-). The use of B-rated bond yields as a benchmark for examining cost of debt is therefore reasonable. Calpine Corp issued debt with B and BB ratings, NRG Energy and Vistra Energy Corp issued debt with BB ratings, and Talen Energy issued debt with B- and B+ ratings. See Appendix C of the Initial Draft Report.

Figure 1: B-Rated Bond Yield, August 2019 to August 2020



The purpose of this analysis is not to suggest that only the most recent yields during August 2020 should be used. Rather, it is to highlight that recent trends should provide grounds for extreme caution in considering how debt yields during a two-month period this year will relate to the cost of borrowing for the entirety of the 2021-2025 demand curve reset period. A principled approach to establishing all demand curve parameters is to seek values that reflect a reasonable expectation of the parameter over the reset period. Such an approach to calculating the cost of debt (e.g., a rule-based method such as using the median over a significant period of time) will avoid giving undue weight to short-term market fluctuations.

It is typical in utility ratemaking to consider long-term data on market indicators. Table 2 below shows median B-rated bond yields over a period of one, two, three, four or five years through August 20, 2020.

Table 2: Median B-Rated Bond Yield Historical Median Daily Values

Period	Median Yield (%)
August 2019 - August 2020	5.93
August 2018 - August 2020	6.45
August 2017 - August 2020	6.35
August 2016 - August 2020	6.21
August 2015 - August 2020	6.39
Interim Final Draft Report	6.70

While the 6.7 percent cost of debt recommended by the consultants in their Interim Final Draft Report is more reasonable than the 7.7 percent draft recommendation, it is still significantly above what a historical review of benchmark rates would support. Median yields over the historical periods shown in Table 2 are consistent with our recommendation to assume a cost of debt between 6.0 and 6.5 percent. It is appropriate for the historical costs used to establish this assumption to include data since the onset of COVID-19, but not to assign it disproportionate weight to this period. In fact, given that current yields are below 6.0 percent, it would be most reasonable to assume a cost of debt at the low end of this recommended range.

B. A 17-Year Amortization Period is Unreasonable

The consultants recommend amortizing the costs of the thermal peaking plant technology over a period of 17 years, down from previous DCRs. Previous resets used an amortization period of 20 years. It is important to recognize that this is already a very conservative assumption given that the consultants assume the project would have $0 residual value at the end of the 20-year period. In reality, resources have substantial residual value and have generally continued to produce substantial net revenue for decades after this 20-year timeframe.

In this reset, the consultants recommend a shorter amortization period due to the requirement that New York's power system be "zero emissions" by 2040 under the CLCPA. This recommendation ostensibly reflects an assumption that the default CONE unit, which would initially be fired on natural gas, would be compelled to retire in 2040. This is an unsupported assumption and is not supported by the studies of the CLCPA mandates.

Hence, we find that adopting a 17-year amortization period is unreasonable and will result in excessively high demand curves. Instead, we recommend maintaining a 20-year amortization period. To the extent that uncertainty is heightened regarding the cost of the fuel that will be used by the peaking plant in 2040, as we discuss below, we recommend accounting for this by eliminating the energy net revenues in the last three years.

This is a conservative assumption because energy net revenues due to increases in shortage pricing would likely be substantial for the peaking plant. However, this approach is not as unreasonably conservative as the 17-year amortization assumption. The effects of adopting this recommendation together with a 6.25 percent COD is shown in the following table.

Table 3: Estimated Effects of Shortening the Amortization Period

Zone	Estimated Net CONE Impact	
	Price Impact ($/kW-year)	Percentage Impact (%)
C	$6.37	8.8%
G (Rockland)	$8.77	9.0%
J	$7.70	5.0%
K	$9.23	8.9%

CLCPA's Potential Effect on the Economic Life of the Peaking Plant

Although state agencies have not issued official regulations or guidance regarding fuels that will be compliant with the CLCPA in 2040, it is already clear that fossil-fueled generators will be able to comply by switching to alternative fuels. Although such fuels are not commercially widespread, such technologies exist and developers in New York are including the flexibility to adopt them in their plans.[3] These technologies are not currently widespread because fossil fuels are less expensive in under current laws and regulations, but these technologies will likely become widespread if New York State and other jurisdictions prohibit the use of less expensive fossil fuels. The consultants' reluctance to make specific assumptions about fuel switching is understandable given the lack of certainty about these technologies. Such uncertainty is inherent regarding conditions and technologies 20 years in the future. The objective should be to use the most reasonable expectation possible and not to be limited by current conditions. Therefore, we find that assuming that all fossil-fuel generators will retire by 2040 is excessively conservative and unreasonable. In fact, recent studies support that this is not a reasonable expectation, including one by the consultant itself.

Recent studies by both Analysis Group and Brattle Group evaluate 17 to 33 GW of fossil fuel-fired generation being converted to CLCPA-compliant zero-emission fuels by 2040. These studies find that large amounts of flexible generation are needed to maintain reliability, generally operating in reserve with very low capacity factors. Brattle Group finds that prohibitively large amounts of renewable and battery resources would be needed to replace the flexibility these resources provide.[4,5]

3 For example, the developer of the proposed Danskammer gas-fired repowering project in Load Zone G states that "A modernized Danskammer can transition to zero-emission hydrogen power when the technology is available to transport and store hydrogen." See https://www.danskammerenergy.com/energy-project/

4 Brattle Group was commissioned by NYISO to conduct long-term modeling of New York's power system complying with CLCPA mandates. Results of Brattle's analysis show over 20 GW of CC, CT and ST capacity maintained by 2040 in a 'reference load' case and over 33 GW in a 'high electrification' case considering demand-side impacts of the CLCPA (an increase from currently existing capacity). In both cases, thermal plants are assumed to operate on a generic zero-emission fuel after 2040. A scenario assuming that a dispatchable zero-emission fuel of this type cannot be used had dramatic results including additional 'overbuild' of 80 GW of renewables and 27 GW of energy storage relative to the base case, curtailment of 50% of renewable generation, and serious challenges satisfying UCAP reserve margins. See https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/69397029-ffed-6fa9-cff8-c49240eb6f9d

5 Analysis Group was commissioned by NYISO to analyze challenges to NYISO system reliability in 2040 as part of the NYISO's Climate Change Phase II study. In developing assumptions for cases with a resource mix consistent with CLCPA mandates, Analysis Group found a need for 17 to 29 GW of "generic dispatchable" technology to meet demand during periods of low intermittent resource output even after other flexibility-enhancing additions including 8 to 13 GW of energy storage, relaxed transmission constraints and an increase in price-responsive demand. See https://www.nyiso.com/documents/20142/12899859/07_TPAS-ESPWG_Analysis%20Group%20Climate%20Change%20Phase%20II%202020.06.04.pdf/dbe8c45a-ede7-4801-1f43-adeb35c002af

For example, in a scenario that was seemingly devised to demonstrate the absurdity of assuming no fuel-switching, the Brattle study found extreme outcomes including incremental 'overbuild' of renewable and storage capacity by over 100 GW and massive (on the order of 50 percent) curtailment of renewable generation. While these studies do not purport to predict how the CLCPA will be achieved, the studies show that there is not a reasonable basis for assuming that all existing dispatchable resources will retire.

A full 20-year amortization period is compatible with the potential need to incur compliance costs in the future. The use of alternative fuels or other retrofits to comply with CLCPA requirements may require modest additional capital costs in the future. But a broadly applied prohibition on fossil fuel use would lead to higher future capacity, energy, and ancillary services prices to maintain an adequate supply of dispatchable generation and, therefore, need not be included in the Net CONE today. The peaking plant is newer and uses more advanced technology than other existing thermal generators in NYISO. Hence, it is not likely to be among the most expensive dispatchable generators to maintain in operation as environmental regulations grow stricter. As a result, a 20-year amortization period without adjustment for additional future capital costs is reasonable for such a unit.

CLCPA's Potential Effects on the Revenues of the Peaking Plant

Much of the discussion of this issue and potential impact of other future changes in environmental regulation have assumed that existing suppliers face only downside risks from regulatory changes. However, this ignores that stricter environmental standards and the large-scale entry of renewable resources could lead to two sources of much higher revenues:

- Fluctuations in intermittent output and forecasts errors of this output will rise as the reliance on renewable resources rise. This will likely increase the frequency of operating reserve shortages. Given the performance characteristics of the peaking plant, it will realize sizable increases in shortage revenues during these events.

- If all thermal units were to retire by 2040, investment in gas-fired units would not be viable and future demand curves would be set by more expensive technologies. In such a scenario, a peaking plant entering service in the next four years would benefit from higher capacity prices than are implied in the present DCR in the timeframe prior to 2040.

Attempting to quantify these and other market impacts of the CLCPA over the next two decades would necessarily be speculative and unreasonable for the DCR process. Hence, we recommend NYISO avoid selectively incorporating uncertain future impacts, and adopt a 20-year amortization period that remains a reasonable assumption that accounts for the market uncertainties on both the downside and upside. To account for the likelihood that alternative fuels will be more costly, the consultants could consider eliminating the energy revenues for the last three years of the project's life and retaining only reserve revenues during those years.

C. Cost of Fuel to Provide Operating Reserves

In their preliminary model of energy and ancillary services ("E&AS") revenues, the consultants assumed that the peaking plant incurs a fuel procurement cost when providing operating reserves. The unit is assumed to purchase gas to cover each hour of its reserve schedule in case it is called upon to provide energy in real time. If the unit does not provide energy in real time, the fuel is assumed to be sold back at an intraday discount of 10 percent in Load Zones C through G, 20 percent in Load Zone J, and 30 percent in Load Zone K. These assumed costs reduce net E&AS revenues and therefore increase the Net CONE. We recommended that the cost of reserves be reduced to a realistic level of $2.0/MWh or lower. This is especially reasonable for dual fuel units, which can be available to provide reserves without scheduling natural gas. As of the Interim Final Draft Report, the consultants have updated their Net E&AS model to use a $2.00/MWh cost of reserves for dual fuel units. The remainder of this section provides support for the consultants' assumption regarding the cost of reserves.

There are multiple ways that a generator can ensure it is able to convert its reserves to energy when needed without purchasing gas equivalent to its entire reserve schedule. Generators can typically acquire gas in the intraday market under most conditions. A generator with dual fuel capability can rely on its on-site oil for rare events when intraday gas is unavailable and offer energy at a correspondingly high bid price. It is unreasonable to assume that such a unit will regularly procure gas far in excess of what it expects to burn whenever it provides reserves. The preliminary model overstated the cost of reserves, especially in Load Zones J and K, by linking it to a fuel procurement strategy that is not representative of the actual behavior of reserve providers in New York.

For the previous methodology that was used in the Initial Draft Report, Table 4 shows the average annual number of hours in which the peaking plant (a) sells day-ahead reserves and (b) has no day-ahead or real-time market commitment. It also shows the average annual reserve net revenues.[6]

Table 4: Commitment Summary in Initial Draft Report

Zone	Intraday Gas Discount	Average Annual Value		
		Hours DA Reserve Commitment	Hours No DA or RT Commitment	Reserve Net Revenues ($/kW-year)
C	10%	7,154	393	$12.9
G (Rockland)	10%	5,948	559	$11.5
J	20%	1,085	5,489	$1.7
K	30%	111	5,418	$0.8

6 Data is from Appendix D of the Initial Draft Report. Day-ahead reserve hours include any hours in which the unit has a day-ahead reserve commitment, including if it buys out in real-time dispatch. "Reserve Net Revenues" includes net revenues in hours when the unit either provides reserves in the real-time market or provides reserves in the day-ahead market and subsequently buys out of its position in the real-time market.

Table 4 shows that the peaking plants sell day-ahead reserves in only 12 percent of hours in Load Zone J and 1 percent of hours in Load Zone K and earn minimal profit when doing so if the previous methodology is used. These units have no day-ahead market or real-time market energy or reserve commitment in over 60 percent of hours – hence, the lack of reserve hours cannot be explained by more profitable energy market opportunities. These results suggest that the units in Load Zones J and K are usually priced out of the reserve market because of the high assumed cost to provide reserves. This is not reasonable given that the peaking plant technology would be among the most flexible resources in NYISO and would likely be an active reserve market participant. As of the inclusion of a $2.00/MWh cost of reserves in the Interim Final Draft Report, this result has been made more realistic with the peaking plant in zones J and K providing reserves in over 6,000 hours per year.

Actual reserve offer data from suppliers in New York is instructive given that these offers should reflect the costs the consultants are attempting to quantify. This data supports a cost of reserves of approximately $2.0/MWh as shown in the following figure. Figure 2 compares actual historical day-ahead reserve offers for gas-only and dual fuel units in Load Zones J and K in 2019 to the implied cost of reserves in the draft net E&AS model.[7]

Figure 2: Cost of Reserves in Draft DCR Model vs. Historical Average DA Reserve Offers

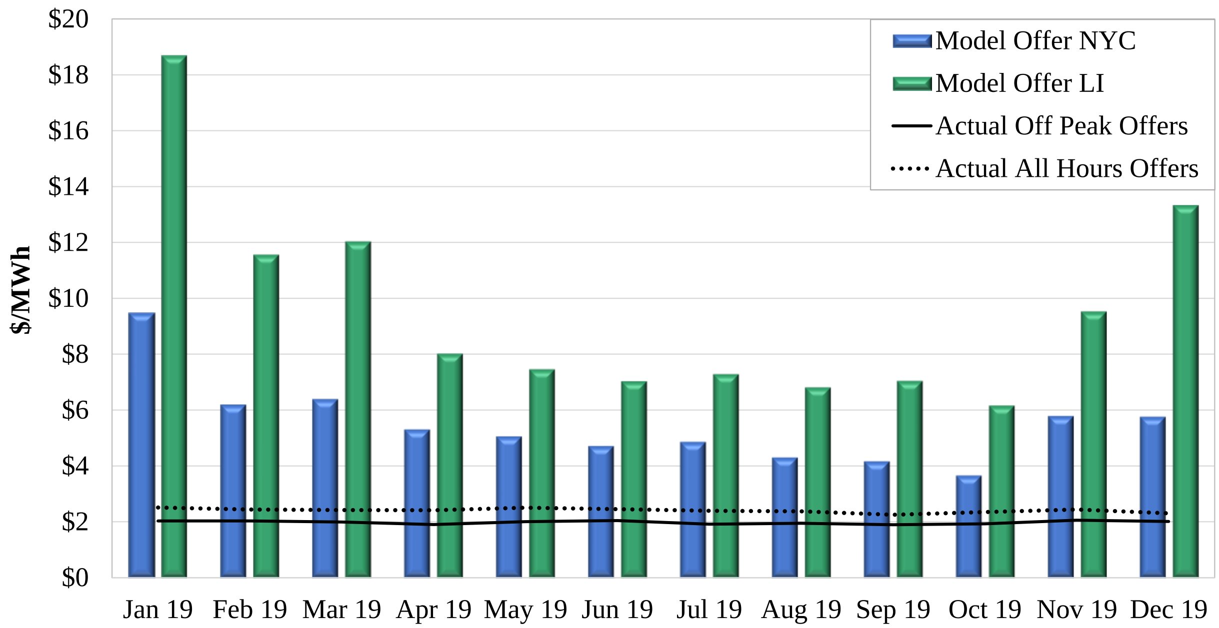


Figure 2 shows that the capacity-weighted average reserve offer was $2.0/MWh during off-peak hours, when offers are likely to be more competitive, and $2.4/MWh in all hours. Typical

7 We used hourly day-ahead offer data from units at five plants in zones J and K that offered 10-minute non-spin reserves in 2019. One additional plant that offered reserves was excluded as an outlier as it consistently offered reserves at prices much higher than other plants regardless of fuel prices.

reserve offers had little variation across months. By contrast, the draft model methodology implied an average cost of $6/MWh in Load Zone J and $9/MWh in Load Zone K in 2019, with monthly averages as high as $9 in Load Zone J and $18/MWh in Load Zone K.

Based on this data, we recommended that the consultants replace the fuel-based cost of selling reserves in the day-ahead market with a constant cost of $2.0/MWh. This will align the modeled cost with typical offer prices for similar existing units in New York. In the Interim Final Draft Report the consultants accounted for this recommendation and modified the cost of reserves for dual fuel units in their Net E&AS Model to $2.00/MWh.

D. Misalignment of Daily Gas Prices in E&AS Model

Stakeholders highlighted an error in the Energy and Ancillary Services Model, in which the natural gas price used during weekends and holidays is modeled using the price on the preceding business day. For example, the model treats the gas price on a Saturday and Sunday as identical to the gas price on the preceding Friday. In actuality, gas prices quoted by S&P Global for the next business day following a weekend or holiday reflect a strip price that includes the days during that weekend or holiday.[8]

This error results from a mismatch between how gas price data is read by the model and how it is published by S&P Global. The E&AS model interprets gas price input data as corresponding to the Trade Date in the same row, but gas prices obtained directly from S&P Global's SNL service correspond to the Flow Date in the same row. The Flow Date (when gas is actually delivered) is one business day after the Trade Date. As a result, when data from S&P Global is input directly into the E&AS Model's input files without adjusting it to align with the Trade Date in the same row, it is unnecessarily shifted forward by one business day by the model. The MMU replicated the E&AS results underlying the Interim Final Draft Report and determined that the gas price input data was not adjusted to align with the Trade Date in the same row. Hence, all gas prices are misaligned by one business day.

To analyze the impact of this issue, we reran the E&AS model with all inputs identical to the case underlying the Interim Final Draft recommendations except that gas prices input into the model were shifted backward by one business day (taking into account weekends and all federal holidays). This results in correct alignment of the gas price used to dispatch the plant on each date with the price quoted by S&P Global for the same Flow Date. After this adjustment, the gas price used for weekends and holidays in the Net E&AS model correctly corresponds to the S&P Global gas price for the next (as opposed to last) business day. Table 5 shows the results of this correction. Net E&AS revenues for the peaking plant declined by $2.7/kW-year to $3.2/kW-year in zones G through K and by a negligible amount in Zone C.

8 See quotation from correspondence with S&P Global in stakeholder comments submitted by TigerGenCo, LLC on August 24, 2020 at pp. 4-5.

Table 5: Impact of Gas Day Error on Net E&AS Results

Zone	Net E&AS Revenues ($/kW-year)	
	Interim Final Draft Report	Corrected Gas Dates
C	39.4	39.2
G (Dutchess)	33.4	30.6
G (Rockland)	45.6	42.7
J	39.8	37.1
K	58.8	55.6

The consultants can correct this issue in two ways. First, they can adjust the gas price data from S&P Global to align with Trade Date rather than Flow Date before entering it into the model, and clearly label that this adjustment must be made in the data input sheets. Second, they can alter the code of the model to interpret the gas data input as corresponding to the Flow Date in the same row, and to use the gas price on the following business day for weekends and holidays (rather than preceding one).

E. Level of Excess Adjustment Factors

We support the level-of-excess adjustment factors (LOE-AFs) adopted by the consultants in the Interim Final Draft Report. The LOE-AFs are a set of multipliers applied to historical LBMP data in order to simulate pricing conditions at the tariff-prescribed level of excess (LOE).[9] Section 5.14.1.2.2.2 of the MST defines the LOE-AFs as: "LOEz,t = the applicable adjustment factor for Load Zone z and hour t used to adjust for the prescribed level of excess. The adjustment factors shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review."

The LOE-AFs are calculated as the ratio of simulated NYISO market prices under LOE conditions to simulated prices under 'as-found' conditions. GE Energy Consulting was retained to run two cases in its GE-MAPS production cost modeling software: a 'base case' reflecting expected system conditions in the 2021-2025 period, and an 'LOE case' in which load was scaled up until the system reached the required level of excess. Adjustment factors were calculated using the GE-MAPS price outputs on a zonal, monthly, and peak period basis (including on-peak, peak load window and off-peak hour groups).

Assumptions regarding load and supply in the LOE-AF database were derived from the recently conducted 2019 CARIS Phase I study and from the preliminary 2020 Reliability Needs

9 The level of excess is defined by Section 5.14.1.2.2 of the MST as "conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues."

Assessment (RNA) model.[10] These assumptions reflect the latest information used in NYISO planning studies for the time period covered by the Demand Curve Reset. One notable exception is that simple cycle combustion turbines affected by the NYSDEC "Peaker Rule" were not modeled as retired in the LOE-AF database. Although these facilities have not filed with the NYISO for deactivation, their Peaker Rule compliance plans indicate that several facilities will retire or cease operation during the summer capacity period beginning in May 2023. Retirements of existing units are significant assumptions in the LOE-AF calculation because they reduce excess capacity in the base case 'as-found' model. Hence, if more capacity is modeled as retired in the base case, the system requires less adjustment to be at LOE conditions, and the calculated LOE-AFs will be smaller.

The exclusion of Peaker Rule retirements in the LOE-AF model by the NYISO and the consultants is reasonable and consistent with the tariff. Modeling the affected capacity as out-of-service during summer months would result in a reliability need in New York City that will be addressed by reliability solutions that have not yet been determined. Because the purpose of the RNA is to identify the need for such solutions, it would not be appropriate to model retirements precipitating a reliability need identified in the RNA without a corresponding solution.

Even if sufficient capacity were assumed to be retained (or generic replacement capacity added) to resolve the reliability issue in the LOE-AF database, inclusion of the Peaker Rule retirements would cause the LOE-AFs to be underestimated. This is because the historical LBMPs used to compute E&AS revenues will mostly not include the period after which the affected units plan to cease operation. Table 6 shows the degree of overlap between the historical LBMP data that will be used to determine each annual demand curve and the period when Peaker Rule requirements will be in effect (beginning May 2023). This overlap covers only four months (out of thirty-six total months) for only one out of four annual demand curve updates. However, if included in the LOE-AF database, the Peaker Rule retirements would impact the LOE-AFs applied to all historical LBMPs in all four annual demand curves. It would be inappropriate to adjust historical LBMP data based on an event that had not yet occurred and therefore could not have affected the value of that historical data.

Table 6: Overlap Between LBMP Data Used for Net E&AS Calculation and Peaker Rule Retirements

Annual Demand Curve	Historical LBMP Data	Portion of LBMP Data After May 2023
May 2021 - Apr 2022	Sep 2017 - Aug 2020	0.0%
May 2022 - Apr 2023	Sep 2018 - Aug 2021	0.0%
May 2023 - Apr 2024	Sep 2019 - Aug 2022	0.0%
May 2024 - Apr 2025	Sep 2020 - Aug 2023	11.1%
Average Overlap		**2.8%**

[10] See NYISO August 2020 DCR Draft Report at p. 39 and NYISO Installed Capacity Working Group presentation "Appendix: DCR Level of Excess – Adjustment Factors: Results of Additional MAPS Runs," July 22, 2020.

The MST requires that the adjustment factors "adjust for the prescribed level of excess" but does not require that all assumptions used in their determination be drawn from a single specific source such as the RNA. In this case, we support the decision by the NYISO and consultants to exclude the Peaker Rule retirements from the LOE-AF database. Modeling the affected units as in-service will result in a more accurate adjustment of historical LBMP data to reflect LOE conditions as required by the tariff.

While the recommended LOE-AFs are reasonable and consistent with the tariff, changes to the tariff and methodology could be made to better align the calculation of future LOE-AFs with the LBMP data used to estimate E&AS revenues. The current tariff requirement that LOE-AFs are determined as part of the periodic review and remain fixed for the entire review period restricts the NYISO's ability to develop adjustment factors that are specifically suited to the three-year period of historical LBMP data used in each annual update. If a single set of LOE-AFs was not fixed for the entire four-year period, then LOE-AFs could be calculated for each year based on the difference between as-found and LOE conditions during the actual time period from which historical LBMP data was obtained. We recommend that NYISO explore changes that would improve consistency of LOE-AFs with the associated LBMP data and reduce subjectivity in LOE-AF database assumptions for future demand curve resets.

F. Comments on Preliminary Recommendations for Load Zone C

Appropriateness of Use of Central Zone for NYCA Demand Curve

The consultants estimated a lower Net CONE value for the peaking plant located in Load Zone C than for the one in Load Zone F. Although Load Zone F was used as the location of the unit for the NYCA demand curve in the 2016 DCR, the consultants have recommended using the Load Zone C unit in this reset based on the preliminary results reflected in the Initial Draft Report.

We support the recommendation to use the Load Zone C unit because of its lower Net CONE and because it seems very unlikely that transmission constraints will lead capacity in Load Zone C to be less deliverable than capacity in Load Zone F for the foreseeable future. NYISO's most recent New Capacity Zone study issued in January 2020 found 858 MW of deliverability headroom between the Load Zone A-E and Load Zone F regions – an increase from 316 MW as of the last reset and more than enough to accommodate the peaking plant.[11]

The AC Transmission Projects approved by NYISO in 2019 and scheduled to enter service in December 2023 will further expand transfer capability on the Central East interface during the reset period. Hence, we consider that the unit located in the lower cost location – Load Zone C

11 See NYISO 2019/2020 New Capacity Zone Study, https://www.nyiso.com/documents/20142/6004104/2019-2020-NCZ-Study-Report.pdf/780f36e1-cee5-a174-5e7d-f5d2dbcaffd7

as of the Initial Draft Report – is very likely to be deliverable throughout the NYCA region. Therefore, this location should be used as the basis for the NYCA demand curve.[12]

Natural Gas Price for Load Zone C

The consultants propose to use a gas-only generator which purchases fuel at the TGP Zone 4 (200L) price plus a transport cost of 27 cents per MMbtu in the day-ahead market. In the real-time market, the consultants assume the unit would pay a 10 percent premium on gas to generate above the day-ahead schedule and receive a 10 percent discount on gas sold if it generates less than the day-ahead schedule.

To provide further analysis of the suitability of the consultants' recommendation, we considered historical benchmarking of gas-fired plants in Zone C, gas pipeline operational capacity and critical notice data, and the amount by which the recommendation might overstate E&AS revenues compared to another plausible alternative.

It is important to strike a reasonable balance that avoids significant over or under-estimation of net revenues for the demand curve unit. There may be circumstances when a specific set of assumptions over or under-estimate the fuel costs of a generator on specific days. However, it is also important to limit the complexity of the consultants' net E&AS revenue estimation model and the annual demand curve update process.

Analysis of Historical Plant Operations

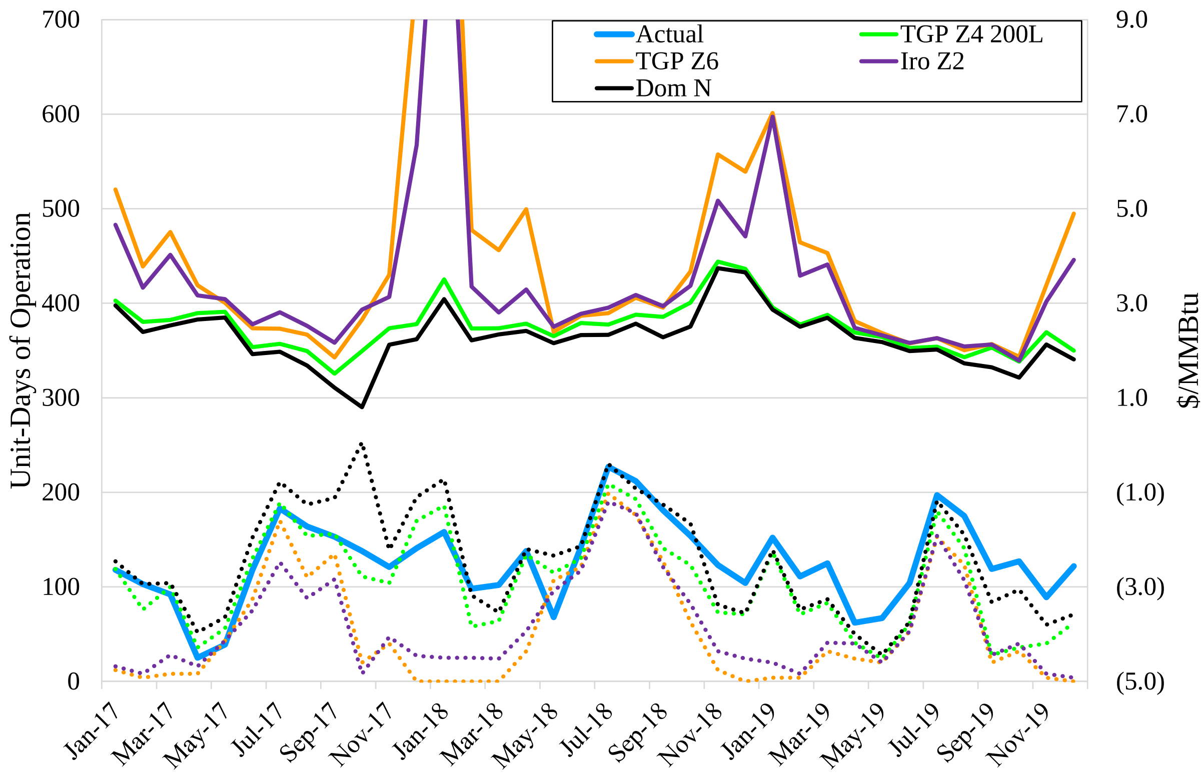
Figure 3 compares the actual number of days of historical operation for nine gas-fired units in Zone C to a backcast simulation for each unit under alternative fuel price assumptions. The simulation was performed using hourly day-ahead and real-time historical LBMPs at each plant node, daily gas indices for each hub from SNL, and plant parameters derived from unit-specific reference level data and plant-level EPA data. The lower portion of the chart (left axis) shows the actual combined days of operation compared to predicted days of operation using each gas hub price (dotted lines). The upper portion of the chart (right axis) shows average gas price for each index used in the analysis. Generator results are presented in aggregated form because confidential unit-level reference data was used for the simulation.

Of the four alternative gas hubs used, TGP Z4 200L and Dominion North were better predictors of actual Zone C plant operation than TGP Z6 and Iroquois Z2. Notably, this result holds in winter months, when prices at TGP Z6 and Iroquois Z2 often spike to high levels. During these periods, plants in Zone C operated much more often than would be expected if facing fuel costs at the TGP Z6 or Iroquois Z2 levels. Existing plants may have unique fuel supply arrangements

12 While present conditions support this conclusion, we continue to support efforts to develop more granular capacity zones which would improve price formation if deliverability constraints within present capacity regions become binding in the future.

that do not necessarily align with what the Demand Curve unit could expect to obtain.[13] However, this analysis indicates that gas priced at a discount to TGP Z6 and Iroquois Z2 hubs is available in central New York, including during winter months.

Figure 3: Historical vs. Backcast Operation for Zone C Gas-Fired Plants



Suitability of Gas Hub Alternatives

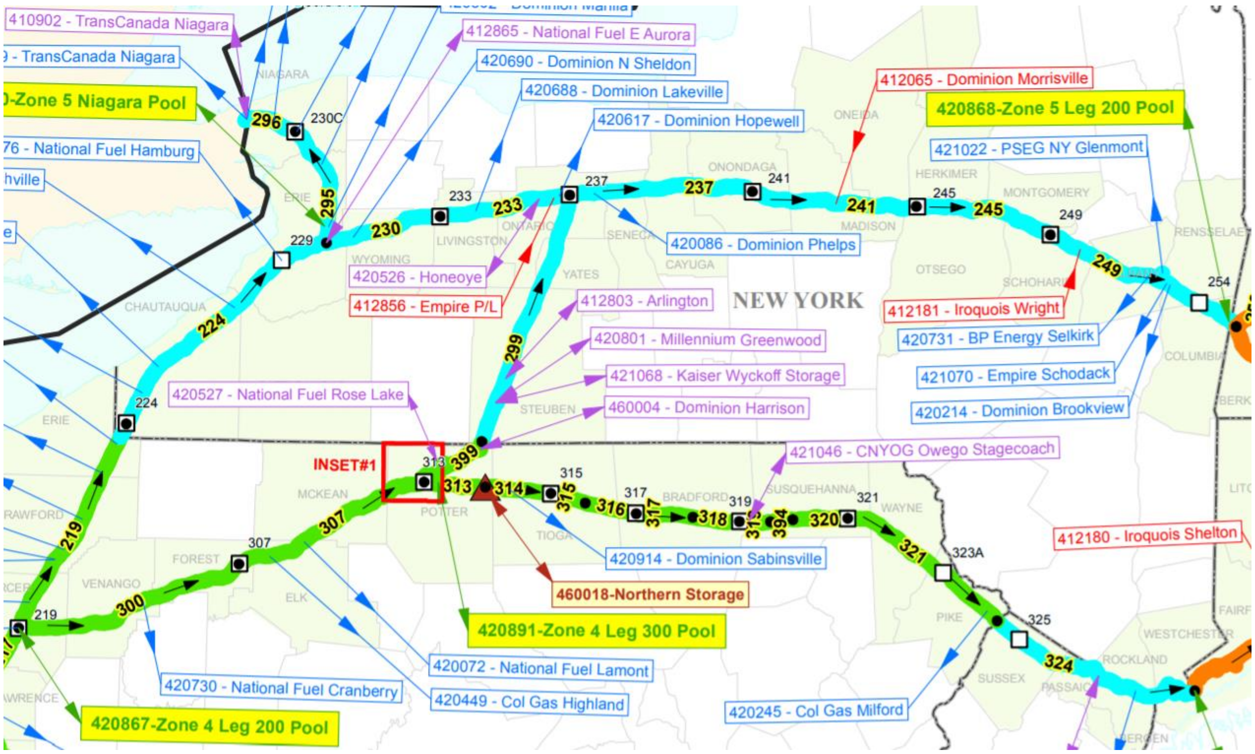
The choice of gas hub for the Zone C unit is complicated by the lack of a liquid trading hub located in Zone C. Figure 4 shows a map of the TGP pipeline system in New York. TGP Zone 4 extends through northern Pennsylvania. The pipeline enters New York from Zone 4 in two locations (segments 224 and 299 in western and central New York, respectively). Hence, TGP Z4 200L is geographically accessible during times when capacity is available for interruptible transport on TGP to Zone C. The TGP Zone 5 price refers to deliveries downstream of station 245, aligning more closely with NYISO Zone F than Zone C.[14] This index (along with others available in Zone F such as Iroquois Z2 and TGP Z6) is therefore geographically accessible but

13 Additionally, most existing units in Zone C are behind local distribution company (LDC) systems and likely face additional costs and flow constraints that the demand curve unit would not face.

14 S&P Global Platts defines Tennessee, Zone 5 (200 leg) as "Deliveries from Tennessee Gas Pipeline Zone 5, downstream of compressor station 245 extending to and including station 254."

not an appropriate pricing choice unless no other upstream alternatives are available. Finally, the Niagara hub located on the border with Ontario in western New York is geographically accessible via the TGP pipeline between zones A and C.

Figure 4: Map of TGP Pipeline in New York

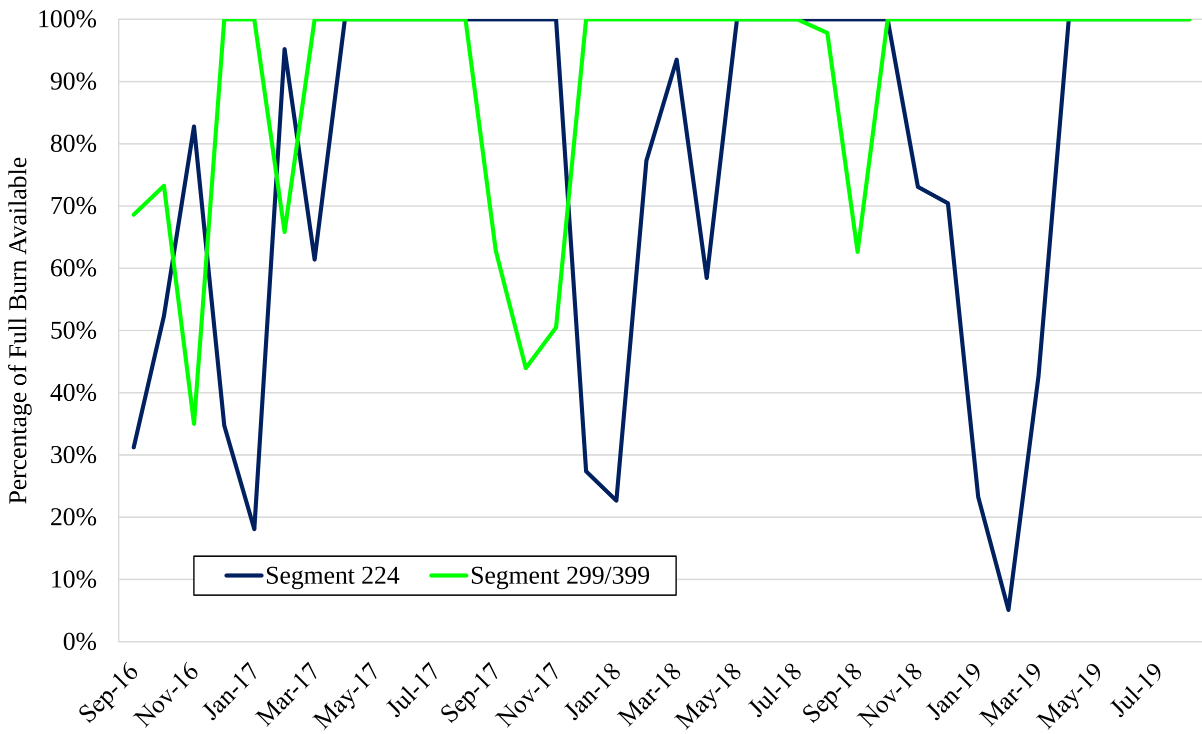


Operating Capacity Data

Figure 5 shows the historical average daily operational available capacity on TGP segments entering New York from Zone 4, as a percentage of the daily gas that would be required for the peaking plant to operate for 24 hours (approximately 75,000 Dth).[15] Capacity on Segment 224 connecting TGP Z4 200L to western New York was available in most months, but was frequently severely constrained in winter. Capacity on Segments 399 and 299 connecting TGP Z4 300L to central New York had greater availability. However, a review of daily critical notices issued by the TGP pipeline indicates that interruptible transport on both the 224 and 299 segments is frequently subject to restriction, particularly in winter. This data suggests that the purchase of gas at the TGP Z4 200L hub and transport to New York using interruptible service is often not possible during winter. In such months, the use of TGP Z4 200L as the gas hub may overstate net energy revenues of the peaking unit.

15 Available capacity data is obtained from SNL and reflects capacity in the Timely nomination window.

Figure 5: Operational Available Capacity on TGP Segments Entering New York



An alternative to offset the potential over-estimate of E&AS revenues is to use the Niagara hub in winter months. New York consistently exports gas to Canada via the Niagara interconnection between TGP and TransCanada. Hence, the price at Niagara can be seen as a proxy for the cost of acquiring gas at points in Zone A upstream of the Niagara spurline (segments 295 and 296). Data on operational available capacity indicates that segments in between zones A and C (segments 230 and 233) are rarely constrained, while segments further downstream in between zones C and F are frequently constrained in winter. Hence, the use of the Niagara price during winter months is reasonable for the region in between the bottleneck separating Zone 4 from New York and the bottleneck separating central from eastern New York.

The Niagara gas index is limited by its relative lack of liquidity. Niagara lacks significant trade volume on many days during the historical period used to estimate E&AS revenues. A potential solution is to consider the Dawn Ontario gas price, either for all days when Niagara would be used or on days when Niagara lacks trade volume. Dawn is connected to Niagara on the TransCanada system and historically exhibits very closely correlated prices with Niagara.

Potential Impact

Table 7 shows annual average net revenues of the peaking unit estimated using the Interim Final Net E&AS Model with alternative winter gas pricing assumptions. If Niagara is used in December through March instead of TGP Z4 200L, net E&AS revenues decline by $4.3/kW-year. This suggests that the impact of using TGP Z4 200L in months when it is restricted is relatively small compared to a reasonable alternative in upstate New York. If TGP Z6 is used in

December through March, net E&AS revenues decline by $15.2/kW-year, to a level even lower than the $26.7/kW-year Net E&AS revenue for the proxy unit in Zone F. Using a price that does not acknowledge any winter fuel price advantage for generators in western and central New York would result in net revenues that are likely significantly understated.

Table 7: Zone C Net E&AS Revenues[16]

Fuel Price Assumption	Average Annual E&AS Revenues
TGP Z4 200L + $0.27	$39.2/kW-year
TGP Z4 200L + $0.27 (Apr – Nov) Niagara + $0.27 (Dec – Mar)	$34.9/kW-year
TGP Z4 200L + $0.27 (Apr – Nov) TGP Z6 +$ 0.27 (Dec – Mar)	$24.0/kW-year

Although there are circumstances when the use of the TGP Z4 200L or Niagara indices could lead to an over-estimate of net revenue on individual days, we note that the resulting impact is offset by other conservative assumptions related to fuel costs. In particular, the assumed cost of securing gas to cover 100 percent of day-ahead reserve commitments results in a cost of providing reserves that is likely conservatively high, compared to the $2.0/MWh cost of reserves adopted by the consultants for generators in zones G-K. This results in net E&AS revenues in Zone C that are approximately $4.6/kW-year lower than if a $2.0/MWh cost of reserves were used, and this impact would larger and more problematic if a higher gas cost were adopted. The 10 percent premium or discount for intraday fuel purchases or sales is also likely to be excessive on most days. Finally, the annual run hour restriction of 1,060 hours for the peaking unit in Zone C to comply with NOx emission standards limits the extent to which net revenues increase if gas prices are under-estimated.

Significance of Market Correlation

Some stakeholders have highlighted concern about the lower correlation of TGP Z4 200L with Zone C energy market prices compared to alternative gas hubs. Although market price correlation is a useful criterion in general, it cannot be relied upon exclusively in locations where energy market prices are frequently not set by local gas-fired units. As shown in Figure A-8 of the MMU's 2019 NYISO State of the Market report, gas-fired units in central New York (zones B, C and E) were marginal in only about 20 to 35 percent of intervals in the real-time market during 2018 and 2019. At other times, prices in these zones were set primarily by generators in other zones. When prices are set by generators in other locations, local generator schedules may align with gas prices that are less highly correlated with local energy prices, as Figure 3 shows is the case for the majority of generation in Zone C.

16 Net E&AS revenues were calculated using the Interim Final Thermal Net E&AS Model published by the consultants on August 10, 2020 and do not include the VSS adder. Estimates shown in this table have corrected for the gas date misalignment in the Interim Final Draft results discussed in Section D.

Conclusions Regarding Gas Prices

The consultants' recommended gas cost of TGP Z4 200L + $0.27 is appropriate for Zone C during much of the year. It is important that the selection of gas hub recognize that there is a lower cost of fuel in western and central New York than in eastern New York, including in winter months. Gas hubs associated with eastern New York such as TGP Z6 and Iroquois Z2 are therefore not appropriate. Direct transport from the TGP Z4 200L region to Zone C is often not available in winter, which may result in overstated net E&AS revenues if this hub is used in all months. Therefore, we recommend that the consultants use the Niagara price hub plus $0.27 in winter months and TGP Z4 200L plus $0.27 in all other months.

Compliance with Environmental Regulations

The consultants have recommended the use of a peaking plant without selective catalytic reduction ("SCR") emissions controls and with a 17-year amortization period in Load Zone C. Counties in the Central Zone are not currently classified as being in Severe Nonattainment area with the National Ambient Air Quality Standard ("NAAQS"). The consultants' opinion is that the unit may accept limits on run hours instead of installing SCR emissions controls. This is appropriate and is consistent with assumptions for Load Zones C and F in prior DCRs.

G. Preliminary Recommendations for Load Zone G – Dutchess County

Compliance with Environmental Regulations

The consultants recommend using a unit with SCR emissions controls in Dutchess County locations of Load Zone G. This region falls outside of the Severe Nonattainment area for the eight-hour ozone NAAQS. The consultants initially considered that a unit in this location could comply with air quality regulations by limiting its run hours to meet applicable emissions limits, and that this would be the lower-cost option compared to installation of SCR emissions controls. They subsequently amended their recommendation for Dutchess County to include SCR emissions controls.

In general, the consultants have used a reasonable and principled approach to decide whether to include SCR emissions controls on units outside of Severe Nonattainment areas. However, there is legitimate concern about the ability to cite a unit without SCR emissions controls in Dutchess County. Recent Article 10 siting processes suggest that a new plant in this region can expect intense local opposition and may regard state of the art emissions controls as a necessity. Hence, it may be appropriate to consider factors beyond the emissions regulations in determining whether SCR emissions controls should be included for the peaking plant in Dutchess County.

Notwithstanding, based on the results reflected in the Interim Final Draft Report, the Rockland County unit is expected to be the basis for the demand curve covering the G-J Locality, so the SCR emissions controls assumption for the Dutchess County unit should not ultimately affect the capacity demand curves over the next four years.

H. Preliminary Recommendations for Load Zone G – Rockland County

Use of TETCO-M3 as Natural Gas Hub

We support the consultants' recommendation to use the TETCO M3 gas index price plus a transportation cost of $0.27/MMBtu for a plant in the Rockland County location in Load Zone G. The TETCO M3 market zone does not geographically include points in Rockland County, but it does include points of interconnection with the Algonquin pipeline at Lambertville, NJ and Hanover, NJ.[17] Although firm forward-haul transport capacity for this segment of the Algonquin pipeline is not currently available, gas purchased in the TETCO M3 market zone can be transported on an interruptible basis by paying Algonquin's AIT-1 tariff rate (currently $0.2421/MMBtu).[18] Such interruptible transport is generally available to points in Rockland County. Pipeline bottlenecks typically occur downstream of points in Rockland County and upstream of Algonquin Citygates delivery points and the pipeline's interconnection with Iroquois.[19] In rare situations when interruptible transport to Rockland County is not available, a plant equipped with dual fuel capability (as assumed by the consultants) can rely on oil to meet its capacity obligation.

Pipeline data supports the finding that gas transported from the TETCO M3 zone via Algonquin is available in Rockland County. Algonquin announces any restrictions on customers' gas transport nominations via daily critical notices when conditions warrant such restrictions. In 2019, Algonquin announced restrictions on interruptible nominations sourced from points west of its Stony Point Compressor Station 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. Stony Point is located on the west shore of the Hudson River at the eastern border of Rockland County (see Figure 6 below). Hence, while transport on Algonquin is frequently restricted, the main bottlenecks are located downstream. Transport to points in Rockland County such as the interconnect with Millennium Pipeline at Ramapo is generally available.

17 S&P Global Platts defines the Texas Eastern, M-3 index as applying to "Deliveries from Texas Eastern Transmission beginning at the outlet side of the Delmont compressor station in Westmoreland County, PA, easterly to all points in the M3 market zone, except for deliveries to Transcontinental Gas Pipe Line at Lower Chanceford".

18 The owner of Algonquin has recently filed rates with FERC which would increase the maximum interruptible transport (AIT-1) rate to $0.2867/DTh. These rates have not yet been approved at the time of writing.

19 S&P Global Platts defines the Algonquin Citygates trading location as "Deliveries from Algonquin Gas Transmission to all distributors and end-use facilities in Connecticut, Massachusetts and Rhode Island". The Iroquois pipeline interconnections with Algonquin in Connecticut.

Figure 6: Map of Algonquin Pipeline

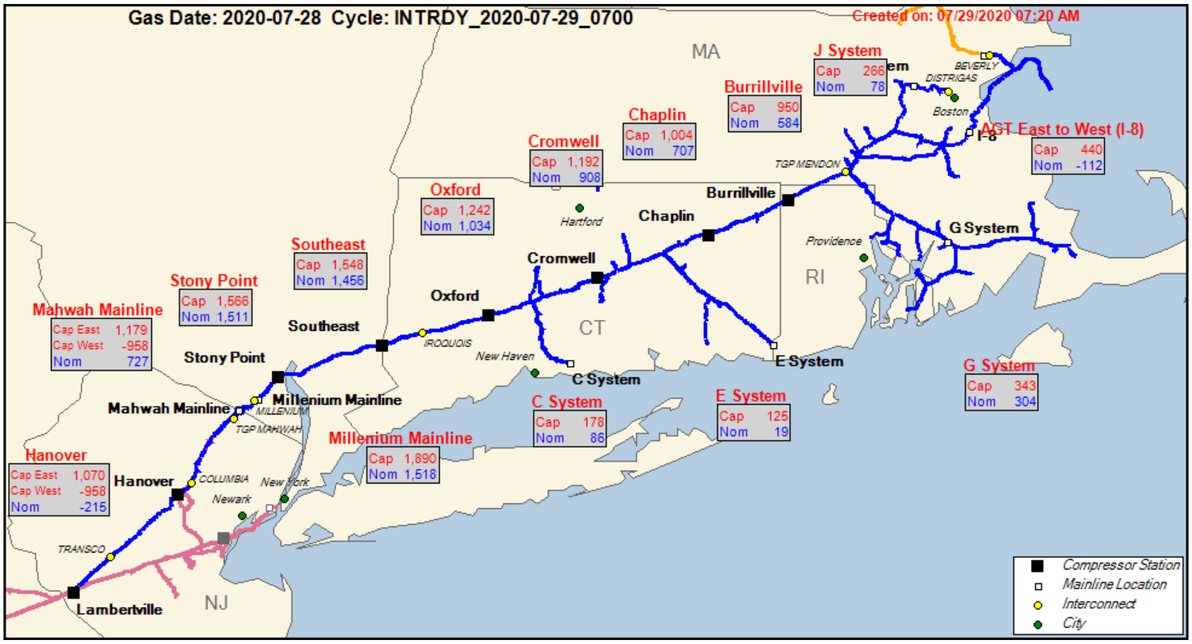
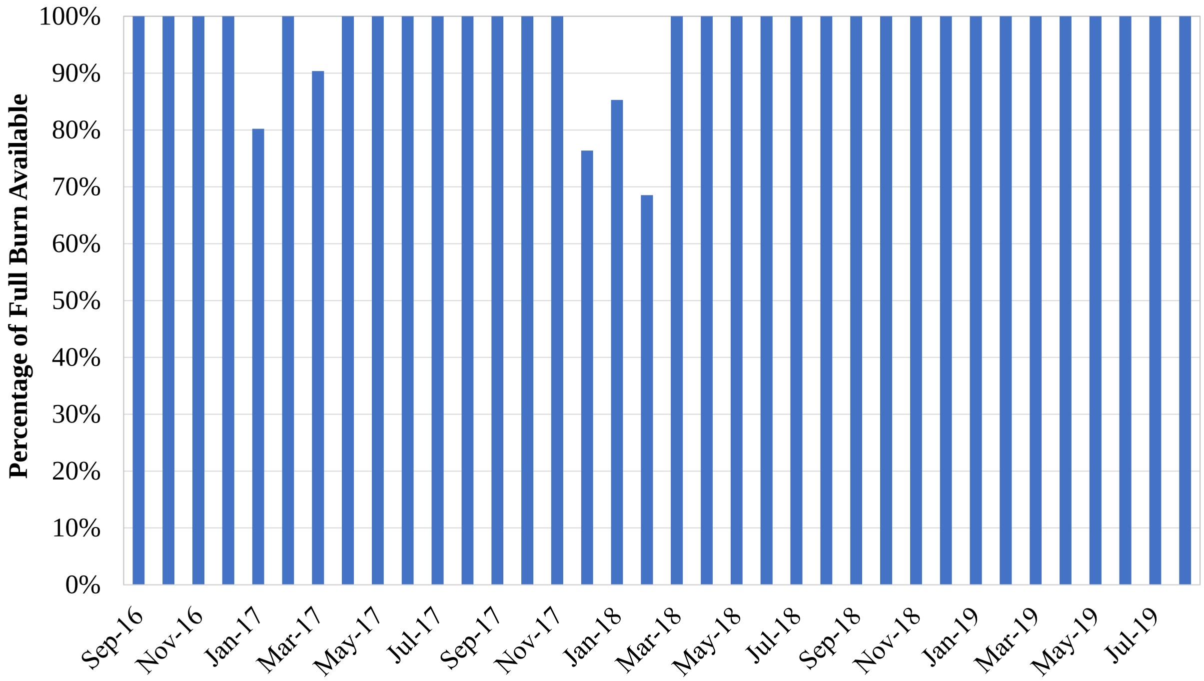


Figure 7 shows the average daily operational available capacity on the Algonquin pipeline segment passing through the Millennium Mainline station in Ramapo, NY as a percentage of the daily gas that would be required for the peaking plant to operate for 24 hours (approximately 75,000 Dth).[20] Average available capacity exceeded the maximum daily burn in most months, and covered a high percentage of maximum daily burn even in cold winter months. This is likely a conservative measure, as a peaking unit typically will not generate for all hours of a day. Furthermore, as noted above, the recommended peaking plant design for Rockland County is dual fuel and, therefore, also has the option to run on oil in the minority of days when gas may not be available.

20 Available capacity data is obtained from SNL and reflects capacity in the Timely nomination window.

Figure 7: Operational Available Capacity on Algonquin Millennium Mainline Segment



Although operational available capacity exceeded the maximum burn requirements of the peaking plant on average in most months, pipeline constraints limit the availability of gas on some days. To estimate the approximate magnitude of this impact, we recalculated the net E&AS revenues of the Rockland County peaking plant using a 'restricted TETCO M3' price plus $0.27 in Table 8. We calculated the restricted price as a weighted average of the TETCO M3 and Iroquois Z2 prices for each day, where the weight assigned to TETCO M3 is the ratio of operational available capacity on the Ramapo segment to the plant's gas consumption on that day in the Net E&AS model results plus a safety margin of 10 percent. After applying this restriction and running the E&AS Model, net E&AS revenues declined by $2.0/kW-year (2.0 percent of Net CONE). By contrast, if the Iroquois Z2 price is used on all days, Net E&AS revenues would decline by $12.1/kW-year (12.3 percent of Net CONE). The DCR should select the gas hub that most accurately reflects realistic prices for the peaking plant, without introducing excessive complexity into NYISO's annual update process.

Table 8: Zone G Net E&AS Revenues[21]

Gas Hub Assumption	Zone G (Rockland) Net E&AS Revenue ($/kW-year)
TETCO M3 + $0.27	42.7
TETCO M3 + $0.27, Restricted by Availability	40.7
Iroquois Z2 + $0.27	30.6

21 Net E&AS revenues were calculated using the Interim Final Thermal Net E&AS Model published by the consultants on August 10, 2020 and do not include the VSS adder. Estimates shown in this table have corrected for the gas date misalignment in the Interim Final Draft results discussed in Section D.

Hence, we consider the consultants' use of TETCO M3 plus $0.27/MMBtu (along with the assumed intraday premium or discount of 10 percent) to be appropriate for the Rockland County unit, while use of the Algonquin Citygate or Iroquois Zone 2 hubs would be inappropriate given the county's proximity to the TETCO M3 market zone.

I. Comments on Preliminary Recommendations for Load Zone J

Switchyard and Interconnection Costs

The consultants' recommendation to use gas-insulated switchgear (GIS) instead of air-insulated switchgear (AIS) in Load Zone J is conservative. Con Edison Transmission Planning Criteria do not mandate use of GIS for new facilities, but the consultants assume that GIS is used in dense urban areas due to space constraints and aesthetic considerations. The consultants indicated in the NYISO stakeholder process that the use of GIS instead of AIS results in a reduction of assumed land footprint for the Frame unit, from 15 acres to 12 acres, with a corresponding reduction of land lease costs (approximately ~$2/kW-year).[22] This 3-acre reduction of land footprint comes at significant expense, equivalent to an approximately $33 million difference (or ~$12/kW-year) in capital cost between GIS and AIS.

In general, it is appropriate to evaluate design choices on an economic basis when multiple choices are permissible. Such logic would favor use of the lower-cost AIS switchgear in Load Zone J with commensurately higher lease costs due to use of a 15 acre site instead of a 12 acre site. However, it is reasonable to consider that limited availability of land in practice could restrict developers' switchgear choices at some locations in Load Zone J. Evidence from other recent projects in New York suggests that developers have selected GIS in consideration of land footprint impact, even outside of New York City.[23]

Hence, we do not recommend that the consultants modify the assumption that GIS would be selected in Load Zone J, but it should be emphasized that this assumption is likely to err on the conservative (higher cost) side of available design choices. Conservativeness in this area should be taken into consideration when assessing the overall reasonableness of the New York City demand curve.

We note that some stakeholders have raised concerns that elements of the consultants' switchyard and interconnection costs do not align with their own experience. Projects each face unique risks and will have cost items that vary above and below what is assumed by the DCR. Individual assumptions that are conservative or optimistic within the range of reasonable costs do not necessarily imply that the gross CONE is biased upward or downward overall.

J. Conclusions

The consultants performed a comprehensive analysis of the costs of new entry in each capacity region in New York. This required an in-depth analysis and estimates of a comprehensive set of

[22] See presentation by Burns & McDonnell to the Installed Capacity Working Group on May 19, 2020.

[23] For example, the recent Cricket Valley Energy and CPV Valley projects both made use of GIS switchgear.

parameters. In these comments, we identify several areas where additional refinements or modifications are warranted. We also discuss certain assumptions or approaches proposed by the consultants that we find to be reasonable. In summary, we recommend:

- Assuming a cost of debt between 6.0 and 6.5 percent, based on typical borrowing costs over a reasonable historical period.
- Adopting a 20-year amortization period instead of 17 years for thermal units. If the 20-year assumption is adopted, it would be reasonable to attribute zero energy revenues to the peaking plant during the last three years of the 20-year period.
- Correcting the Net E&AS Model to correctly align gas price flow dates with model days.
- Using TGP Z4 (200L) gas hub plus $0.27/MMBtu in the months of April through November and the Niagara gas hub plus $0.27/MMBtu in the months of December through March for the Load Zone C unit.

In addition, we support the NYISO's use of the following assumptions:

- Modeling units affected by the NYSDEC "Peaker Rule" as in-service in the LOE-AF database.
- Basing the NYCA demand curve on the lower of the Load Zone C and Load Zone F Net CONE. Based on the Initial Draft Report, this would support the use of Load Zone C.
- Using the TETCO M3 gas hub plus $0.27/MMBtu transport cost and assuming 10 percent intraday premium or discount for the Load Zone G (Rockland County) unit.

We believe establishing reasonable and realistic assumptions to calculate the net CONE for the capacity demand curves is essential and we encourage NYISO to adopt these recommendations.

Appendix B: Gas Price Index Data Use in the Net EAS Revenues Model

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Addendum: Gas Price Index

This addendum describes a change in how gas prices are incorporated in the fossil net EAS revenues model. It outlines the previous method, the change in the model, and the impact on results.

The net EAS revenues model imports daily natural gas spot price index data from S&P Global Market Intelligence and applies the natural gas spot prices to hourly decision-making logic. The previous version of the model accompanying the Interim Final Report released on August 10, 2020, incorporated S&P's daily natural gas prices as prices on the "trading dates," when delivery contracts were agreed upon, and considered the subsequent date as the "flow date" upon which gas would be delivered. For this reason, in assessing potential dispatch decisions for a given operating day, we shifted S&P reported gas prices one day forward to ensure that the dates of the gas prices used in the model corresponded to the historical operating day LBMPs and reserve prices. The gas price assigned to weekends and holidays was the Friday reported price, or the last day before a weekend/holiday. Table 1 shows this method for a set of example dates.

Table 1: Interim Final Report Model Assumption (Example Dates)

Reporting Date in S&P Data	Trading Date	Flow Date	Date S&P Gas Prices applied in Model
Monday 2/1	Monday 2/1	Tuesday 2/2	Tuesday 2/2
…	…	…	…
Thursday 2/4	Thursday 2/4	Friday 2/5	Friday 2/5
Friday 2/5	Friday 2/5	Sat. 2/6 - Mon. 2/8	Sat. 2/6 - Mon. 2/8
Monday 2/8	Monday 2/8	Tuesday 2/9	Tuesday 2/9

Based on stakeholder input and follow-up conversations with S&P Global Market Intelligence, Analysis Group confirmed that the natural gas spot price index actually reflects the flow date. This required a change in the fossil logic of the net EAS revenues model to remove the one day forward shift. In addition, the gas price assigned to weekends and holidays was changed to the Monday price or the first day after the holiday. Table 2 shows this method for a set of example dates. This change has been made to the model and is reflected in the updated values set forth in the updated version of the Final Report published on September 9, 2020.

Table 2: Final Report Model Revised Assumption (Example Dates)

Reporting Date in S&P Data	Trading Date	Flow Date	Date S&P Gas Prices applied in Model
Monday 2/1	Friday 1/29	Monday 2/1	Monday 2/1
…	…	…	…
Thursday 2/4	Wednesday 2/3	Thursday 2/4	Thursday 2/4
Friday 2/5	Thursday 2/4	Friday 2/5	Friday 2/5
Monday 2/8	Friday 2/5	Sat. 2/6 - Mon. 2/8	Sat. 2/6 - Mon. 2/8

Holding all else the same, this change increases the ICAP monthly reference point prices by approximately: (i) 0.2 percent in Load Zone C; (ii) 3.0 percent in Load Zones F, K, and G (Rockland County); (iii) 2.5 percent in Load Zone G (Dutchess County); and (iv) 2.0 percent in Load Zone J.

Appendix C: NYC Land Lease Cost Assumption Data

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Memorandum

Date: September 2, 2020

To: NYISO

From: Burns & McDonnell

Subject: NYC Land Lease Cost Assumption Basis re: Demand Curve Parameters Review

As part of determining the annual land lease cost assumption, Burns & McDonnell reviewed over 15 different data points including property tax values, stakeholder-provided feedback and other market transaction data. Property tax values were identified for adjacent property to existing power plants within Load Zone J. Stakeholder-provided feedback included property appraisal reports for existing and/or industrial sites within Load Zone J. Other public and private market transaction data included the observation of a purchase of a waterfront parking lot in Astoria and values quoted through discussions with various property owners in the potential acquisition of land for similar use.

For data points where only property value was implied based on assessed value for property tax purposes or a market sales transaction, the value was converted to a $/Acre value and multiplied by 5.5% to determine the annual lease payment expressed as $/Acre-year. The range of values observed as part of this including the value used as part of the 2019-2020 Demand Curve Reset are shown in Table 1.

Table 1: Summary of Property Values

Description	Property Value ($/Acre)	Annual Lease ($/Acre-year)
Low end observed property value range	$ 182,752	$ 10,051
Average of Property Tax Values Evaluated by BMCD	$ 3,264,359	$ 160,712
2019-2020 Demand Curve parameter value	$ 4,909,091	$ 270,000
Average of Stakeholder Provided Property Values	$ 11,736,518	$ 645,509
High end observed property value range	$ 18,181,818	$ 1,000,000

Summary

Based on the information reviewed and discussed within this memorandum, Burns & McDonnell found that property values and associated leasing cost for property within New York City will have a wide range of potential values and is highly dependent on site specific factors and conditions. Using the value of land leasing cost from the 2016 DCR study, escalated to $2020 using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator (Q1 2015-Q1 2020) arrived at a value ($270,000/acre-year) that was within the observed range of annual leasing costs identified by Burns & McDonnell's review indicating that the use of an escalation approach resulted in reasonable values for purposes of this Demand Curve Review.

Appendix D: Total Owner's Cost Comparison

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Appendix D:
Comparison of this DCR's Owner's Costs to the prior DCR

The Consultant developed the following table as a comparison of the owner's costs for this DCR to the prior DCR, based on publically available data from the prior reset.

Zone G-Dutchess County	2016 Report	2016 Escalated	2020 Report	% Dif.
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	$16,430,000	
AFUDC - EPC Portion	$19,866,000	$21,657,990	$18,564,786	
AFUDC - Non EPC Portion	$1,920,000	$2,093,191	$6,318,222	
Working Capital and Non-Fuel Inventories (include	$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**	**$60,853,008**	**0.3%**
Total Capital Investment	**$341,901,000**	**$372,741,797**	**$369,524,946**	**0.9%**

Notes
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.