ANALYSIS GROUP

Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Initial Draft Report

Results and recommendations contained herein are preliminary and subject to change. The results herein use data for the period September 1, 2016 through August 31, 2019. The results will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

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This initial Draft Report provides preliminary values for the 2021/2022 Capability Year ICAP Demand Curves as well as methodologies and inputs to be used in determining the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Year. *All numerical results presented in this initial Draft Report include data as required for the estimation of net Energy and Ancillary Services (EAS) revenues. Net EAS revenues are estimated using data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 2017 through August 2020.*

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Acronyms and Glossary

Capitalized terms that are not specifically defined in this Report shall have the meaning set forth in the NYISO Market Administration and Control Area Services Tariff and Open Access Transmission Tariff.

Acronym or Abbreviation	Description
AF	Attachment Facilities
AP	Amortization Period
ARV	Annual Reference Value
ATWACC	After Tax Weighted Average Cost of Capital
BACT	Best Available Control Technology
BPCG	Bid Production Cost Guarantee
Btu	British Thermal Units
CAES	Compressed Air Energy Storage
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CSAPR	Cross State Air Pollution Rule
CSO	Capacity Supply Obligation
CSPP	Comprehensive System Planning Process
CT	Combustion Turbines
CTO	Connecting Transmission Owner
CY	Class Year
DAMAP	Day-Ahead Margin Assurance Payment
DCR	Quadrennial ICAP Demand Curve Reset Process
DMNC	Dependable Maximum Net Capability
DOL	NYS Department of Labor
EAS	Energy and Ancillary Services

Acronym or Abbreviation	Description
EFORd	Equivalent Demand Forced Outage Rate
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, Construction
ERC	Emission Reduction Credits
FERC	Federal Energy Regulatory Commission
FEMA	Federal Emergency Management Agency
FICA	Federal Insurance Contributions Act
FTE	Full Time Equivalent
GADS	Generating Availability Data System
GE	General Electric International, Inc.
GHG	Greenhouse Gases
HHV	Higher Heating Values
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
ICR	NYCA Minimum Installed Capacity Requirement (MW)
IRM	NYCA Installed Reserve Margin (%)
ISO	International Organization for Standardization
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
kW-mo.	Kilowatt-month
kW-year	Kilowatt-year
LAER	Lowest Achievable Emission Rate
LBMP	Locational Based Marginal Pricing
LCR	Locational Minimum Installed Capacity Requirement
LDC	Local Distribution Company
LFG	Landfill Gas

Acronym or Abbreviation	Description
LHV	Lower Heating Value
LI	Long Island (Load Zone K)
LOE	Level of excess
LOE-AF	Level of excess adjustment factor
LOLE	Loss of Load Expectation
MHPS	Mitsubishi Hitachi Power Systems
MIS	Minimum Interconnection Standard
MMBtu	Million Btu
MMU	Market Monitoring Unit (Potomac Economics)
MPs	Market Participants
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NNSR	Nonattainment New Source Reviews
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NYC	New York City (Load Zone J)
NYCA	New York Control Area
NYCRR	New York Codes, Rules and Regulations
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority
NYSDEC	New York State Department of Environmental Conservation

Acronym or Abbreviation	Description
O_2	Oxygen
O&M	Operations and Maintenance
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, L.L.C.
POI	Points of Interconnection
PPA	Power Purchase Agreement
ppb	Parts per billion
ppmvd	Parts per million by volume on a dry basis
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
PTE	Potential to Emit
PV	Photovoltaic
P&W	Pratt & Whitney Power Systems
REV	New York Reforming the Energy Vision proceeding
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
ROS	Rest of State (Load Zones A-F)
RP	Reference point price
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SDU	System Deliverability Upgrades
SER	Significant Emission Rates
Siemens	Siemens Energy Inc.
SiPEP	Siemens Performance Estimating Program
SO_2	Sulfur Dioxide
SUF	System Upgrade Facilities

Acronym or Abbreviation	Description
UARG	Utility Air Regulatory Group
UCAP	Unforced Capacity
ULSD	Ultra-low Sulfur Diesel
U.S.	United States
USEPA IPM	United States Environmental Protection Agency Integrated Planning Model
VOC	Volatile Organic Compounds
VSS	Voltage Support Service
WACC	Weighted Average Cost of Capital
WSR	Winter-to-summer ratio
ZCP	Zero Crossing Point
ZCPR	Zero Crossing Point Ratio

Figures and Tables

I. Introduction and Summary

A. Introduction

Section 5.14.1.2 of the New York Independent System Operator, Inc. (NYISO) Market Administration and Control Area Services Tariff (Services Tariff) requires that locational ICAP Demand Curves be established periodically through a review by an independent consultant, and be reviewed with stakeholders and the NYISO through a process that culminates in the filing with the Federal Energy Regulatory Commission (FERC) of ICAP Demand Curves approved by the NYISO Board of Directors.

On July 18, 2019, the NYISO contracted with Analysis Group Inc. (AGI) to conduct the independent review of ICAP Demand Curves, to be used starting in Capability Year 2021/2022. Analysis Group, Inc. (AGI) teamed with Burns & McDonnell (BMCD) to complete the development of ICAP Demand Curve parameters, described in this initial Draft Report (Report).

The results and recommendations provided in this Report are preliminary and subject to change. The values provided herein for estimating net EAS revenues are based on data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 2017 through August 2020.

B. Study Purpose and Scope

The purpose of this Report is to summarize the preliminary results of our study of the ICAP Demand Curve process and parameters. As required by the Services Tariff, the Report evaluates the net cost of a peaking plant, 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," with the scale (i.e., number and size of units) identified in the consultant's review.[1] The Services Tariff identifies multiple requirements for the development of ICAP Demand Curve parameters. Our review and analysis conforms to these various requirements. For example, the Services Tariff requires that the periodic review of ICAP Demand Curves:

> "…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, to meet minimum capacity requirements, and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[2]

The costs and revenues are to be determined under conditions that reflect specified excess supply conditions in NYCA and in each Locality. Specifically, the Services Tariff requires that:

[1] Services Tariff, Section 5.14.1.2.

[2] Services Tariff, Section 5.14.1.2.

> "…[t]he 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…"[3]

Several additional elements to be included in the quadrennial review are specified in the Services Tariff, including the following:

- The appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves declines to zero (the zero crossing point, or ZCP);
- The translation of the annual net revenue requirement of the peaking plant into monthly values that reflect differences in seasonal capability; and
- The escalation factor and inflation component of the escalation factor applied to the ICAP Demand Curves.[4]

The Services Tariff also specifies the process for selecting the independent consultant, and sets forth a schedule for the consultant's analysis and review of the consultant's findings and report by stakeholders, NYISO, the Market Monitoring Unit (MMU), and the NYISO Board of Directors. The entire process – herein referred to as the ICAP Demand Curve reset (DCR) process – is to be completed and filed with FERC no later than November 30 of the year prior to the first Capability Year in which the ICAP Demand Curves shall apply (in this case, the Capability Year beginning May 1, 2021).

C. Study Process

AGI and BMCD have conducted the ICAP Demand Curve review in an open and transparent process that involved the full vetting of issues raised by stakeholders. AGI and BMCD have worked with the NYISO throughout the process to conduct an orderly and transparent presentation of key issues for discussion with stakeholders, and to ensure that the ICAP Demand Curve review was consistent with the requirements under the Services Tariff and the structure and experience of New York's wholesale electricity markets. Table 1 contains a list of stakeholder meetings in which AGI or BMCD participated, and the issues discussed with stakeholders in each meeting.

AGI/BMCD's review of ICAP Demand Curve matters with stakeholders helped identify important scoping issues, evaluate concepts and metrics relevant to the DCR process, and provided guidance for AGI/BMCD's consideration of and recommendations on key DCR issues and outcomes. While the content of and findings in this Report rest solely with AGI and BMCD, it reflects the results of a productive and deliberative process involving full and substantive input throughout a comprehensive stakeholder process that unfolded of the course of approximately one year.

[3] Services Tariff, Section 5.14.1.2.

[4] Services Tariff, Section 5.14.1.2.

Table 1: Summary of AGI and BMCD Stakeholder Engagement

Date	Committee / Working Group	Topic
August 23, 2019	ICAPWG	Introduction to team and DCR
October 11, 2019	ICAPWG	DCR timeline Initial key DCR considerations
November 6, 2019	ICAPWG	Introduction to peaking plant technology evaluation Review of net Energy and Ancillary Services (EAS) revenue model for fossil generating resources (CT and CC) Process for selecting gas hubs for pricing
December 11, 2019	ICAPWG	Technology screening overview (CT, CC and battery storage) Proposed Net EAS revenues model modifications for CT and CC Potential approaches to model net EAS revenue for battery storage
January 30, 2020	ICAPWG	Technology screening and environmental review Preliminary unit performance, capital costs, and O&M estimates Level of excess adjustment factors Continued analysis of peaking pant amortization period and natural gas hubs Additional discussion of net EAS revenues battery storage modeling
February 25, 2020	ICAPWG	ICAP Demand Curve shape and slope Initial discussion of financial parameters Additional discussion of net EAS revenues battery storage modeling
March 26, 2020	ICAPWG	Technology selection review Updates to unit performance, capital costs, and O&M estimates Preliminary recommendations of financial parameters and gas hubs for pricing Overview of winter-summer ratio methodology Additional discussion of net EAS revenues battery storage modeling
April 22, 2020	ICAPWG	Capital cost and O&M updates Updates to recommendations for gas hubs for pricing and amortization period Preliminary recommendations regarding consideration of SCR emissions control and dual-fuel capability Discussion of COVID-19 related considerations on financial parameter recommendations

		Further enhancements to the net EAS revenues battery storage modeling
May 19, 2020	ICAPWG	Updates to financial parameter considerations Preliminary Level of Excess Adjustment Factor results PILOT payments and property taxes Preliminary reference point prices Additional details on net EAS model logic for fossil resources

Note: All materials are posted and available on the NYISO website, available here: https://www.nyiso.com/icapwg

D. Study Analytic Approach and Outline

The creation of ICAP Demand Curves for NYCA and each Locality includes four specific tasks, organized and described in this Report as follows:

- ***Assessment of the peaking plant technology (Section II).*** In this step, we evaluate and develop information on technologies with the goal of fulfilling the Services Tariff's requirement that the peaking plant be the technology with the lowest fixed and highest variable costs and be economically viable.[5] Specifically, we evaluate available technologies consistent with the Services Tariff's definition in NYCA and each Locality with respect to capital costs, operating costs, operating life and other operating parameters, degree of successful commercialization and operational history, and applicable siting and environmental permitting requirements.
  Based on these factors, we also consider whether and how the peaking plant could be practically constructed within each Locality and ROS, and how a potential developer would evaluate various design capabilities and environmental control technologies when making investment decisions in consideration of project development and operational risk, and opportunities for revenues over the economic life of the project.[6] The technology choice assessment, including the recommended technology, its installed capital cost, and operational costs and parameters, is presented in Section II.
- ***Estimation of the gross cost of new entry (gross CONE) (Section III).*** In this step, we estimate the fixed annual costs of the peaking plant options, including the recovery of and return on upfront capital costs, taxes, insurance and fixed operations and maintenance (O&M). A levelized fixed charge is calculated to ensure recovery of capital costs and taxes given financial parameters that reflect the specific risks associated with merchant plant development in the NYISO markets.
- ***Estimation of net EAS revenues for the peaking plant technology (Section IV).*** In this step, expected EAS revenues for the peaking plants in NYCA and each Locality, net of operating costs, are estimated using a model constructed by AGI for this purpose. The model includes a mechanism to adjust the location based marginal prices (LBMPs) and reserve prices used in the net EAS revenues model to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[7]
- ***Determination of reference point price and ICAP Demand Curve in NYCA and each Locality (Section V).*** In this step, gross CONE estimates (from Section III) with expected net EAS

[5] Services Tariff, Section 5.14.1.2.

[6] FERC has found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 37 (2011)). FERC has also held that "[a]n economically viable technology must be physically able to supply capacity to the market, but other than this requirement … economic viability determinations are a 'matter of judgment.'" (*See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 60 (2014)). FERC has further clarified that the "peaking plant represents the hypothetical marginal unit, and, therefore, must be able to be replicated." (*See New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 at P 65 (2017)). These considerations are discussed in greater detail in Section II.

[7] The Services Tariff requires that net EAS revenues be estimated for the peaking plant technology under system conditions that reflect the applicable minimum Installed Capacity Requirement (ICR) plus the capacity of the peaking plant, which AGI defines as the "level of excess" or LOE. The derivation of the LOE-AFs and how historical market prices are adjusted to reflect LOE conditions are described in detail in Section III. *See* Services Tariff, Section 5.14.1.2.

revenues (from Section IV) are combined to calculate the reference point price (RP) values for the ICAP Demand Curves for NYCA and each Locality. Other parameters that govern the shape and slope of the ICAP Demand Curves, including the ZCP and the winter-to-summer ratio (WSR), are also considered.

- ***Annual updating of NYISO ICAP Demand Curve reference point prices (Section VI).*** In this step, RPs and ICAP Demand Curves are updated annually based on escalation of installed capital costs, recalculation of net EAS revenues using updated electricity prices, fuel prices, emission cost data, and determination of the WSR.[8]

In this study, we analyze the currently prescribed Localities for the ICAP Market, which includes the G-J Locality, New York City or NYC (Load Zone J) and Long Island or LI (Load Zone K), as well as the state as a whole, or the NYCA.

Each of the steps described above involves a complex mix of historical data, forecasts, and modeling techniques geared towards developing an appropriate representation of New York electricity market structures and dynamics. It involves extensive review of relevant data and analytic methods, and requires a selection of methods, models and data from among a range of reasonable alternatives based on the application of decision criteria and professional judgment. It also involves a comprehensive review with stakeholders of the purpose, effectiveness, and appropriateness of selected assumptions, methods and data.

AGI and BMCD developed their recommendations for this DCR through the continuous interaction with stakeholders over a nearly year-long period. AGI and BMCD received feedback on proposals and analyses from NYISO and stakeholders in written and verbal form across numerous meetings of the ICAPWG.

The DCR requires not only analysis of a wide array of quantitative market, financial, and economic data and analytics, but also the application of reasoned judgment when the empirical evaluation is limited by sparse, uncertain, and variable historical data and forecast assumptions. Consequently, at the outset of the process AGI established a set of objectives and criteria against which it reviewed and considered DCR-related matters and methodological issues on both quantitative and qualitative bases. The objectives and criteria were developed to help guide the analysis and provide a framework for the evaluation of process and analytic alternatives. Specifically, AGI established that potential DCR issues should be evaluated against the following objectives and criteria:

- *Economic Principles* – Proposed changes to ICAP Demand Curve parameters and methods should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO electricity markets.
- *Accuracy* – ICAP Demand Curve parameters should reflect the actual cost of new entry in New York with as much certainty as is feasible.

[8] The NYISO operates its capacity market in two separate, six-month Capability Periods. This construct recognizes the differences in the amount of capacity available over the course of each year and the impact of these differences on revenues throughout the year. The WSR is used to account for the differences in capacity available. The WSR is discussed in greater detail in Section IV.

- *Transparency* – The DCR calculations and periodic updates to net CONE should be clear and transparent to Market Participants (MPs), and annual update methods and calculations should be understandable and allow MPs to develop market expectations.
- *Feasibility* – The DCR design and implementation should be practical and feasible from regulatory and administrative perspectives.
- *Historical Precedent and Performance* – DCR designs should be informed by quantitative analysis based on historical data (to the extent feasible), and should draw from lessons learned in the markets with experience in administration of capacity markets (NYISO, ISO New England Inc. (ISO-NE), and the PJM Interconnection, L.L.C. (PJM)). Consistency between DCRs also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

E. Summary of Recommendations and Overview of RP Results

AGI has applied the methods, models and equations described in this initial Draft Report to identify preliminary RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2021/2022. These values are presented in Table 2 through Table 5, below.

To arrive at these results, AGI and BMCD considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the preliminary RP values provided herein. [**All numerical results presented below will be updated in September 2020 to use the finalized data as required for the estimation of net EAS revenues and escalation of capital costs**.[9]] Specifically, AGI and BMCD preliminarily conclude the following:

- The GE 7HA.02 (H Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. 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, and Load Zone G (Rockland County), and without SCR emissions control technology in the other locations assessed (i.e., Load Zone C, Load Zone F, and Load Zone G (Dutchess County)).
- Based on market expectations for fuel availability and fuel assurance, changes in market structures, consideration of applicable reliability and LDC tariff requirements, and developer expectations, the H Class Frame machine should include dual fuel capability in Load Zone G (Rockland County), Load Zone G (Dutchess County), Load Zone J, and Load Zone K. AGI and BMCD recommend a gas-only (without dual fuel capability) design in ROS (i.e., Load Zone C and Load Zone F).
- The state of New York has begun a process to decarbonize the power sector over the next couple decades, including passage of the Climate Leadership and Community Protection Act (CLCPA). This does not eliminate consideration of a fossil-fueled plant as the reference case technology. It does, however, suggest review of the ways in which these legislative efforts affect the development and operation of such facilities, which could in turn affect the present-day financial analysis parameters (e.g., the appropriate amortization). We recommend a 17-year

[9] The composite escalation factor used to escalate gross costs in this Report is described in Section VI.

amortization period for fossil-fueled plants in consideration of the CLCPA's restrictions on fossil fuel operations for electric generation past 2039.

- Based on our review, battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time. We come to this conclusion based primarily on our estimates of the net CONE for a sample battery storage facility with 4-, 6-, and 8-hour duration of storage.
- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55% debt and 45% equity; a 7.7% cost of debt; and a 13.0% return on equity, for a WACC of 10.09%. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 8.92% and 8.55%, respectively.
- Net EAS revenues are estimated for the peaking plant technologies using gas hubs that reflect consideration of a number of factors, including consistency of gas prices with LBMPs within each Load Zone, liquidity of trading, geographic consistency with the locations evaluated, and precedence of use in other studies/analysis. To that end, net EAS revenues are estimated using the following gas hubs, which remain fixed for the four year duration of the reset period:

  - Load Zone C: TGP Zone 4 (200L)
  - Load Zone F: Iroquois Zone 2
  - Load Zone G (Dutchess County): Iroquois Zone 2
  - Load Zone G (Rockland County): TETCO M3
  - Load Zone J: Transco Zone 6 New York
  - Load Zone K: Iroquois Zone 2

- ICAP Demand Curves should maintain the current zero crossing point (ZCP) values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

Table 2 provides preliminary parameters for the 2021/2022 Capability Year ICAP Demand Curves for each location assessed consistent with the conclusions and technology findings described above. Table 3 through Table 5 provides additional information for the other technologies evaluated. For ICAP Demand Curves where more than one location is evaluated (i.e., NYCA and the G-J Locality), the appropriate locations and peaking plant technology and design selected as the basis for the 2021/2022 Capability Year ICAP Demand Curves remain fixed for the four year duration of the reset period.

Table 2: Preliminary ICAP Demand Curve Parameters ($2021)
GE 7HA.02

		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]	$122.30	$123.40	$139.82	$157.24	$201.26	$167.36
Net EAS Revenue ($/kW-Year)	[2]	$45.58	$36.46	$35.38	$55.96	$42.62	$59.87
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$76.72	$86.94	$104.44	$101.28	$158.64	$107.49
ICAP DMNC (MW)	[4]	326.7	328.5	329.9	347.0	348.8	348.8
Total Annual Reference Value	[5] = [3] * [4]	**$25,063,999**	**$28,559,527**	**$34,454,327**	**$35,145,132**	**$55,333,074**	**$37,490,768**
Level of Excess (%)	[6]	100.9%	100.9%	102.3%	102.5%	103.5%	106.5%
Ratio of Summer to Winter DMNCs	[7]	1.040	1.040	1.058	1.058	1.078	1.076
Summer DMNC (MW)	[8]	332.0	333.2	334.9	350.2	354.5	352.6
Winter DMNC (MW)	[9]	344.8	346.6	348.6	370.5	374.3	373.3
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.55	$8.57	$10.96	$10.66	$17.49	$13.01
Winter ($/kW-Month)	[11]	$4.84	$5.49	$5.94	$5.73	$8.07	$4.45
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,507,463	$2,855,624	$3,671,140	$3,733,832	$6,199,744	$4,588,208
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,669,866	$1,904,290	$2,071,242	$2,123,706	$3,022,435	$1,660,252
Seasonal Revenue (Summer)	[14] = 6 * [12]	$15,044,779	$17,133,744	$22,026,842	$22,402,994	$37,198,465	$27,529,245
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,019,198	$11,425,738	$12,427,451	$12,742,236	$18,134,610	$9,961,511
Total Annual Reference Value	[16] = [14]+[15]	**$25,063,978**	**$28,559,482**	**$34,454,292**	**$35,145,230**	**$55,333,075**	**$37,490,756**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$8.13	**$9.23**	**$12.98**	**$12.75**	**$21.72**	**$20.29**
ICAP Max Clearing Price ($/kW-Month)		$15.29	$15.43	$17.48	$19.66	$25.16	$20.92
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes:
[1] The peaking plant technology choice in Load Zones C and F is a 1x0 GE 7HA.02 operating in gas only mode without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[2] The peaking plant technology choice in Load Zone G (Dutchess County) is a 1x0 GE 7HA.02 that includes dual fuel capability without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[3] The peaking plant technology choice in Load Zones G (Rockland County), NYC, and LI is a 1x0 GE 7HA.02 (tuned to emit 25ppm NOx) that includes dual fuel capability and SCR emissions controls.
[4] The preliminary net EAS revenues are estimated using data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

Table 3: Comparison of Preliminary Reference Point Prices by Technology ($2021/kW-mo.)

Monthly Reference Point Price ($/kW-Month)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$28.04	$27.92	$39.88	$33.53
	Gas Only, with SCR	$22.52	$23.77	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$17.21	$28.23	$22.78
	Dual Fuel, without SCR	-	-	$16.36	-	-	-
	Gas Only, without SCR	$11.36	$12.91	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$12.75	$21.72	$20.29
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$12.98	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$8.13	$9.23	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$21.61	$18.64	$46.53	$38.60
	Gas Only, with SCR	$14.15	$15.63	-	-	-	-
4-hr BESS	Battery Storage	$18.89	$18.69	$20.46	$21.61	$30.92	$25.11
6-hr BESS	Battery Storage	$25.74	$25.84	$28.14	$29.74	$40.05	$35.18
8-hr BESS	Battery Storage	$34.71	$34.93	$38.28	$40.25	$52.49	$48.35

Table 4: Comparison of Preliminary Gross CONE by Technology ($2021/kW-year)

Gross CONE ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$302.41	$312.50	$394.23	$320.48
	Gas Only, with SCR	$279.83	$282.81	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$202.29	$271.33	$214.78
	Dual Fuel, without SCR	-	-	$179.37	-	-	-
	Gas Only, without SCR	$158.97	$160.84	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$157.24	$201.26	$167.36
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$139.82	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$122.30	$123.40	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$224.02	$238.02	$385.15	$263.89
	Gas Only, with SCR	$205.45	$208.74	-	-	-	-
4-hr BESS	Battery Storage	$212.30	$214.12	$215.84	$223.24	$283.27	$227.53
6-hr BESS	Battery Storage	$295.44	$298.07	$300.50	$311.18	$382.20	$320.22
8-hr BESS	Battery Storage	$378.60	$382.06	$385.19	$399.15	$481.12	$412.91

Table 5: Comparison of Preliminary Net EAS by Technology ($2021/kW-year)

Net EAS ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$34.67	$45.46	$33.04	$49.40
	Gas Only, with SCR	$43.90	$34.23	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$50.05	$35.73	$52.30
	Dual Fuel, without SCR	-	-	$34.11	-	-	-
	Gas Only, without SCR	$46.34	$33.02	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$55.96	$42.62	$59.87
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$35.38	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$45.58	$36.46	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$75.39	$109.80	$104.71	$136.81
	Gas Only, with SCR	$80.25	$70.89	-	-	-	-
4-hr BESS	Battery Storage	$51.18	$54.65	$58.47	$56.98	$59.03	$69.33
6-hr BESS	Battery Storage	$51.46	$53.14	$59.95	$57.03	$59.47	$73.96
8-hr BESS	Battery Storage	$49.62	$50.91	$58.02	$55.12	$58.16	$74.50

Note:
[1] Preliminary net EAS revenues are estimated using data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

II. Technology Options and Costs

A. Overview

The Services Tariff specifies that the ICAP Demand Curve review shall assess and consider the following:

> "… 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"[10]

The 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," and the peaking plant is defined as "the number of units (whether one or more) that constitute the scale identified in the periodic review."[11] The FERC precedent regarding peaking plant technology indicates that, "only reasonably large scale, standard generating facilities that could be practically constructed in a particular location should be considered."[12] In this section, we consider the following:

1. Simple Cycle Plant – Simple cycle plants consist of one or more combustion turbines fueled by natural gas and/or liquid fossil fuels. This study analyzes multiple types and generations of simple cycle technologies.

2. Energy Storage Plant - A battery storage plant is also included in the analysis. Battery storage options with duration capabilities of 4-hours, 6-hours, and 8-hours have been evaluated.

3. Combined Cycle Plant – A combined cycle plant is included in the analysis for informational purposes only. A combined cycle plant consists of a combination of simple cycle turbine(s) and steam turbine(s), which serve to recover waste heat to improve combined efficiency.

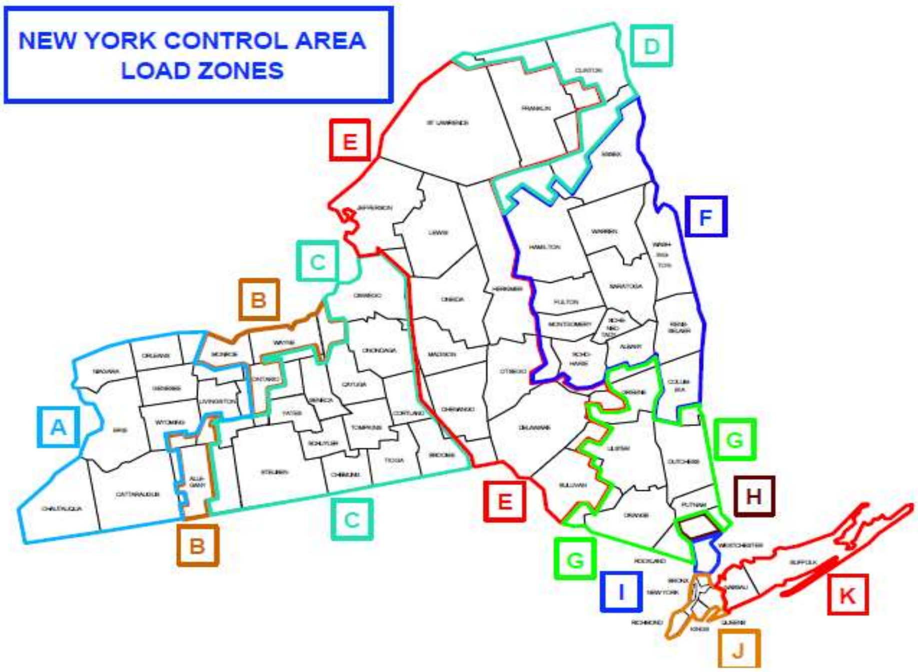
In Section II.B, we apply screening criteria to identify alternative simple cycle technologies that will be evaluated in the DCR study. Section II.C summarizes applicable environmental and siting requirements, which have implications for installed capital costs, and fixed and variable operations costs. Dual fuel capability, capital costs, fixed O&M costs, and variable O&M costs are evaluated in Sections II.D, II.E, and II.F, respectively. Section II.G describes technical and performance characteristics needed to evaluate net EAS revenues.

[10] Services Tariff, Section 5.14.1.2.

[11] Services Tariff, Section 5.14.1.2.

[12] See, e.g., New York Independent System Operator, Inc., 134 FERC ¶ 61,058, at P 37.

Figure 1: Load Zones and Localities



B. Technology Screening Criteria

BMCD was engaged to select simple cycle and energy storage technology option(s) to evaluate as the potential peaking plant for each ICAP Demand Curve. BMCD evaluated peaking plant technology options for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K (see Figure 1). In addition, a combined cycle option was evaluated for each location for informational purposes only.

To comply with the Service Tariff requirements, BMCD utilized the following screening criteria for peaking technology selection:

- Standard generating facility technology – available to most market participants;
- Proven technology – operating experience at a utility power plant;
- Unit characteristics that can be economically dispatched;
- Ability to cycle and provide peaking service;
- Can be practically constructed in a particular location; and
- Can meet environmental requirements and regulations.

The analysis of potential options identified both simple cycle technologies and energy storage technology as technical candidates for peaking operation. Simple cycle technologies are the current peaking plant technology underlying each of the ICAP Demand Curves. Energy storage technology is capable of peaking operation within discharge duration and state of charge limitations, which are constraints that do not apply to simple cycle technologies with reliable fuel supply. Energy storage technologies were included alongside simple cycle technologies for economic evaluation. Selected representative battery technologies are described in Section

II.B.6. While lithium ion battery energy storage systems (BESS) were evaluated, the results of the economic evaluation indicate that BESS is not the lowest cost technology option to be selected to serve as a peaking plant in any location for this reset.

1. Simple Cycle Technologies

Described below are the peaking plant technology options that satisfy the screening criteria and reflect the following key features for each technology option:

1. *Aeroderivative Combustion Turbines*

- Number of starts does not impact maintenance schedule
- Fast start up time (~10 minutes) and ramp rates
- Highest performing units generally require water injection for NO_x control in addition to a selective catalytic reduction (SCR) emissions control system
- Reasonably sized units (approximately 20 to 100 MW) available where multi-unit plants are advantageous
- Typically require higher fuel gas pressures than frame units
- Decades of utility scale operating experience

2. *Frame Combustion Turbines*

- Commercially available frame units range in size from approximately 50 to 400 MW
- F-class turbines exhibit nominal output in the 200-250 MW range
- Advanced class turbines, which may also be labeled G, H, or J-class, exhibit nominal output in the 275 – 400 MW range
- New frame peaking units in the United States will likely be F-class or advanced class
- Frame units typically include dry low emissions combustion systems for NO_x control on natural gas operation. Water injection is required for NO_x controls with liquid fuel operation
- F class units can provide significant capacity in 10 minutes and full output in 11 to 14 minutes; Maintenance impacts may apply to fast starts. Conventional start is approximately 30 minutes
- Advanced class units have similar startup capabilities, though fast start packages are available for full load in 10 minutes, assuming purge credit and start permissives are met. Maintenance impacts may apply with fast start capability.
- Major maintenance cost may be based on operating hours or start quantity, depending on operation. Generally, if there are more than 27 operating hours per start, maintenance will be hours-based. If there are less than 27 hours per start, maintenance will be starts-based.
- Depending on the application, frame turbine models may be available with different NO_x emissions rates. Performance impacts may apply for lower NO_x emissions rate controls
- Decades of utility scale operating experience

3. *Reciprocating Internal Combustion Engines (RICE)*

- Utility scale applications most commonly rely on heavy duty, medium speed engines in the 9-11MW and 18-20 MW classes

- Compression ignition models have gas and liquid fuel capability. Spark ignition models are only capable of gas operation
- Fast start up time as low as five minutes for natural gas engine and seven minutes for dual fuel engine. Engine jacket temperature must be kept warm to accommodate start times under 10 minutes
- Shutdown as quickly as one minute
- High efficiency, good part load performance
- With site conditions below 3,000 feet and 95°F, altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines
- Gas pressure requirements are lower than combustion turbines
- Installed costs are often similar to those of aeroderivative combustion turbine facilities of similar size
- Maintenance intervals are based on operating hours and are independent of number of starts
- Reciprocating engines are typically installed with SCR emissions controls to control NO_x emissions to approximately 5ppm on natural gas fuel

2. *Aeroderivative Combustion Turbine Peaking Options*

The aeroderivative combustion turbines that were considered as candidate peaking plant technologies are shown in Table 6. Output and heat rate information is based on manufacturer specifications and heat rates were converted to higher heating value (HHV). Many aeroderivative technologies are offered with model variants for water injection combustion, dry low emissions combustion, wet compression, intercooling, and other options that may impact performance. The GE LM9000 unit was not included because of lack of experience in North America in comparison to other GE aeroderivative models.

Table 6: Aeroderivative Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	LM6000	First introduced in 1997. Mature technology with multiple model variants.	45 - 58 depending on model	9,100 - 9,700 depending on model
General Electric	LMS100	First introduced in 2006. Mature technology with multiple model variants..	100 - 117 depending on model	8,600 - 8,800 depending on model
Siemens	SGT-A65 (former Rolls Royce Trent 60)	First introduced in 1996. Mature technology with multiple model variants.	60 - 71 depending on model	8,800 - 9,200 depending on model
Siemens	SGT-A45	Core technology based on Rolls Royce Trent turbines, similar to SCG-A65.	44	9,400
Mitsubishi Hitachi Power Systems	FT4000 (former Pratt & Whitney FT4000)	First introduced in 2012. Single and twin pack designs available.	71 single GT	9,200

Notes:

[1] Data from Original Equipment Manufacturer (OEM) literature. Based on nominal output at ISO conditions (59 deg F and 60% relative humidity)

[2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

Preliminary screening of the aeroderivative combustion turbine models indicated that the GE LMS100 and Siemens SGT-A65 units were the best representative candidates because of their higher capacity and efficiencies. Further refinement of the screening level analysis was performed to account for multiple units to achieve output in the 200 MW range. BMCD compared a 2x LMS100 plant (i.e. two LMS100 units in a single plant) to a 3x SGT-A65 plant with and without SCR emissions control technology for NO_x control. Screening costs normalized with and without SCR emissions controls favor the 3x Siemens SGT-A65 facility. It was noted that LMS100 units have a 25ppm NO_x emissions rate, so they are more likely to require SCR emissions controls because the heat input is above the 850 MMBtu/hr threshold in NSPS subpart KKKK, which requires them to meet a NO_x limit of 15ppm. Heat input for the SGT-A65 units is below the 850 MMBtu/hr threshold in Subpart KKKK, so they must meet a less restrictive NO_x limit of 25ppm. In addition, Siemens was recently awarded a project in New York City using the SGT-A65, so recent experience favors this unit as well. For these reasons, the 3x Siemens SGT-A65 option was selected as the representative aeroderivative technology.

3. Frame Combustion Turbine Peaking Option

The candidate peaking technologies included available advanced frame combustion turbines as shown in Table 7.

Table 7: Advanced Frame Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	7HA.02	First introduced in 2017, fleet operating hours of 205,000 EOH	384	8,890
Siemens	SGT6-9000HL	No units in commercial operation in North America (First delivery accepted in Nov 2019)	405	8,891
Mitsubishi Hitachi Power Systems	501JAC	No units in commercial operation in North America	425	9,082
Siemens	SGT6-8000H	Installed fleet has accumulated >1MM EOH	310	9,468
Mitsubishi Hitachi Power Systems	MHPS 501GAC	First commercial operation in 2014, mature technology	283	9,469
General Electric	GE 7FA.05	First FA.05 in operation in 2014 - F-Class is GE fleet leader	243	9,513
Siemens	Siemens SGT6-5000F	Installed fleet has accumulated >15MM EOH	260	9,588

Notes:
[1] Data from OEM literature. Based on nominal output at ISO conditions (59 deg F and 60% relative humidity)
[2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

The results of the screening of the candidate frame combustion turbine models are:

- The GE & Siemens F class combustion turbines are similar in output and performance;
- Three OEMs have G/H class turbines. The Siemens SGT6-8000H, Mitsubishi Hitachi Power Systems (MHPS) 501G, and GE 7HA.01; machines are similar in output and performance; the MHPS 501G and Siemens SGT6-8000H both have operational experience in combined cycle but no simple cycle experience
- F-class technology has proven simple cycle peaking application experience and hot SCR emissions controls operating experience

- There is commercial operating experience with the GE 7HA.02 unit in the United States. It has been installed for simple cycle operation with hot SCR emissions controls, so it is considered a viable option for peaking technology

Two peaking options for the DCR study were chosen from among the frame combustion turbines: the first was the GE 7F.05, an F class unit, a mature technology which has widespread operation experience across multiple markets in North America. An F class unit, the Siemens SGT6-5000F5, currently serves as the peaking plant technology underlying each of the ICAP Demand Curves. The second was the 7HA.02, an advanced class unit with commercial installations in North America, but fewer accumulated operating hours. The 7HA.02 has the most operating experience and best efficiency among similar advanced class units. The GE and Siemens F-class machines are similar in performance capabilities, but screening level cost analyses slightly favored the GE unit, so it was selected for this study.

4. Reciprocating Internal Combustion Turbine Peaking Option

Reciprocating engines are generally competitive with aeroderivative gas turbines, but the initial screening and the results of prior DCRs indicate that RICE technology is not likely to be the lowest cost alternative. Removing the RICE option also facilitated the assessment of more than one frame combustion turbine options and alternative storage durations of energy storage options. Therefore, RICE units were not considered for further study in the DCR.

5. Selected Simple Cycle Technology for Review

Based on the screening criteria and considerations presented above, costs were developed for the following peaking plants. Options were selected for the 200 MW size range for the aeroderivative and F class units, consistent with previous DCR studies. Given the larger capacity of advanced class units currently offered by manufacturers, the H class unit studied was sized around 350 MW.

- Three Siemens SGT-A65 units
- One GE 7F.05 unit
- One GE 7HA.02 unit

6. Energy Storage Power Plant

The lithium-ion battery storage market is growing, largely due to state level targets for storage and renewable energy, as well as declining costs for lithium-ion battery technology. In December 2018, the New York Public Service Commission issued an order establishing a target of 3,000 MW of energy storage by 2030.

The most likely candidates for new energy storage plants are battery energy storage systems (BESS) based on lithium-ion battery technology. Pumped hydro is the most mature storage technology, accounting for approximately 98% of worldwide electric power storage capacity, but this technology is limited in siting potential and requires longer permitting and implementation timelines than battery technologies. Flow battery technologies were considered in the initial screening process, but preliminary evaluations suggested that the capital costs were higher than similarly sized lithium-ion systems and the market is still nascent for the technology at utility scale.

The DCR study includes the following systems for comparison to traditional simple cycle technologies:[13]

- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

The market for lithium-ion batteries is dynamic, and while the stationary storage market is growing, most of the technology innovation and pricing is currently being driven by the electric vehicle market. Lithium-ion represents a broader technology class that includes dozens of battery chemistries, each with its own advantages and disadvantages. Three chemistries have emerged as the leaders in today's market:

- Lithium nickel manganese cobalt oxide (NMC)
- Lithium iron phosphate (LFP)
- Lithium nickel cobalt aluminum oxide (NCA)

Each technology has a different energy density and unique design considerations, and each may be more desirable for a specific site or application, but all three technologies may be suitable for the deep discharge peaking type application included in this DCR study. Since manufacturers of all three technologies are competing directly today for the same projects, the costs presented in this study are intended to represent a snapshot of the market pricing as it currently stands. These costs are not intended to be directly representative of one chemistry or one OEM.

A known limitation of lithium-ion technology is performance degradation. Over time, the energy capacity degrades due to age and cycling behavior. Therefore, a 200 MW battery with a 4-hour discharge duration today may have less than 4-hour discharge duration in the future after multiple years of operations (the power output remains constant). Longer project lifetimes will likely require capacity augmentation due to performance degradation throughout the life of the project, which means that additional batteries would be installed, or augmented to the existing batteries, during the operating life of the BESS. The original installation would typically be designed to account for future capacity augmentation, and the actual augmentation costs would be part of a long-term agreement that may also account for routine maintenance. The fixed O&M costs in this study are intended to account for routine system maintenance. The variable O&M costs in this study are intended to represent the costs for capacity augmentation, levelized annually over the life of the project. This is consistent with the current market as many lithium-ion manufacturers and/or integrators currently offer warranties or performance guarantees over extended timeframes.

BESS facility roundtrip efficiencies (the fraction of energy put into a battery that can be retrieved) are commonly 80 - 90% when measured on the alternating current (AC) side of the system. The BESS roundtrip efficiency assumed for this study is 85%.

[13] The installed battery cell capacity is sized to provide the stated gross MW for the design discharge duration.

7. *Combined Cycle Power Plant for Information Purposes*

A 1x1 combined cycle option was included in the study for informational purposes. The most likely candidates for new combined cycle plants are based on the F-class and advanced frame combustion turbines as shown in Table 8.

Table 8: Latest Advanced Combined Cycle Plant Options

GT Manufacturer	GT Base Model	1x1 Combined Cycle Nominal Capacity (MW)[1]	1x1 Combined Cycle HHV Heat Rate (Btu/kWh)[2]
General Electric	7HA.02	573	5,970
Siemens	SGT6-9000HL	595	6,010
Mitsubishi Hitachi Power Systems	501J	484	6,110
Siemens	SGT6-8000H	460	6,230
Mitsubishi Hitachi Power Systems	MHPS 501GAC	427	6,310
General Electric	GE 7FA.05	376	6,270
Siemens	Siemens SGT6-5000F	387	6,355

Notes:
[1] Data from OEM literature. Based on nominal output at ISO conditions (59 deg F and 60% relative humidity)
[2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

The 2x1 combined cycle power plant configuration is the most common design in the industry. However, since it is twice the capacity of the 1x1 combined cycle power plant configuration, it could require expensive system deliverability upgrades. To more closely provide peaker-type flexibility, the combined cycle plant would have to cycle frequently and start as quickly as possible. Fast start 1x1 combined cycle power plant configuration designs can hot start in about 35 minutes, per OEM data sheets. Therefore, without additional information to justify the additional capacity of a 2x1 combined cycle power plant; the 1x1 combined cycle configuration was selected for evaluation, with data presented for informational purposes only.

The combined cycle technology included for evaluation is the 1x1 GE 7HA.02. Advanced class machines exhibit better efficiencies than F-class units, and initial screening indicated that this unit may be the lowest cost alternative on a $/kW basis among 1x1 combined cycle options.

C. Plant Environmental and Siting Requirements

Environmental considerations, which can have significant impact on the design and permitting of simple cycle technology options and combined cycle power plant options, include air emissions, heat rejection, and water use. The conceptual designs and cost estimates developed for each fossil plant technology option include the necessary equipment and operating costs in order to meet the federal and New York State environmental requirements and regulations within each of the locations evaluated in this DCR.

1. Air Permitting Requirements and Impacts on Plant Design

Each of the candidate fossil peaking plant technologies and each of the combined cycle options would be required to obtain an air permit from the New York State Department of Environmental Conservation (NYSDEC). The air permit will require the new source to meet various Federal and New York State requirements. These requirements, among others, include New Source Performance Standards (NSPS), New Source Review (NSR), National Emission Standards for Hazardous Air Pollutants (NESHAP) and those specified in the New York State Codes, Rules, and Regulations (NYCRR). As discussed below, the fossil peaking plant technologies and combined cycle plants will also need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment.

a. New Source Performance Standards

The fossil peaking plant technologies and combined cycle options will be subject to NSPS, which are included in 40 CFR Part 60. The NSPS that are expected to apply to each of the generating options include:

- Subpart KKKK – Stationary Combustion Turbines (simple cycle and combined cycle plants)
- Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (simple cycle and combined cycle plants)

These two sections of the NSPS are technology specific and do not vary based on the installation location of the gas turbine. Subpart KKKK requires combustion turbines with heat inputs greater than 850 MMBtu/hour to limit NO_x emissions to less than 15 ppm while firing natural gas and to less than 42 ppm while firing liquid fuels (e.g., ULSD).[14] These standards apply to all the combustion turbine options with heat inputs greater than 850 MMBtu/hr, including the GE 7F.05 and GE 7HA.02 units. Based on the typical vendor data, the F-class machine used in this DCR has a NO_x emissions rate of 9 ppm, so it would not require a SCR emissions controls to satisfy Subpart KKKK.

The base model 7HA.02 emits 25ppm NO_x, which would require SCR emissions controls to comply with Subpart KKKK. However, GE also offers a version of the 7HA.02 unit tuned to emit 15 ppm NO_x, which would not require SCR emissions controls to satisfy Subpart KKKK. There are no hardware changes to the 7HA.02 turbine, but the unit is controlled for a lower combustion temperature to reduce NO_x production. Because firing temperature is also proportional to the turbine's output and efficiency, there is also a performance impact (approximately 5% reduction in output).

Similarly, for turbines with heat inputs between 50 and up to and including 850 MMBtu/hour, Subpart KKKK limits NO_x emissions to 25 ppm when operating on natural gas and 74 ppm when firing fuels besides natural gas (e.g., ULSD). The NO_x emissions rate for the Siemens SGT-A65 is 25 ppm, but since its heat input is less than 850 MMBtu/hour, it does not require SCR emissions controls to satisfy Subpart KKKK.

Subpart TTTT establishes CO_2 limits for "base-load" combustion turbines. Base-load combustion turbines must meet an emission limit of 1,000 lb CO_2/MWh or 1,030 lb CO_2/MWh and the limit applies to all sizes of affected

[14] All emissions rates are listed in parts per million by volume at 15% O_2 on a dry basis.

base-load units. The base-load unit requirements are applicable to the informational combined cycle plants evaluated. Non-base load units must meet an emission limit based on clean fuels and is an input based standard (e.g., lb CO_2/MMBtu basis). Non-base load status is based on a sliding scale for capacity factor based on a unit's net efficiency at International Organization for Standardization (ISO) conditions. BMCD estimated the net efficiency at 35% for simple cycle technologies. In order to avoid being subject to the "baseload" NSPS standard, which these turbines in simple-cycle mode cannot meet, the peaking plant needs to limit their capacity factors over a 12-operating month or a three-year rolling average basis to less than the net LHV efficiency at International Organization for Standardization (ISO) conditions. This limits each of the fossil peaking plant technology options to 3,066 hours of operation based on a 12-month rolling average.[15]

New York State also has performance standards for CO_2 emissions in the NYCRR. Table 9 compares Subpart TTTT requirement to the requirements of NYCRR Part 251 - CO_2 Performance Standards for Major Electric Generating Facilities. Each of the peaking plant technology options and combined cycle options must comply with both Subpart TTTT and NYCRR Part 251 requirements.

Table 9: Comparison of 40 CRF Part 60 Subpart TTTT to NYCRR Part 251 Requirements

Generating Facility Type	Subpart TTTT	NYCRR Part 251
Simple Cycle Combustion Turbine Gas-Fired	120 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g or 160 lb CO_2/MMBtu
Simple Cycle Combustion Turbine Multi-Fuel Fired[2]	120 to 160 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g or 160 lb CO_2/MMBtu
Combined Cycle Combustion Turbines (Informational)	1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n	925 lb CO_2/MWh-g or 120 lb/MMBtu

Notes:
[1] New York Codes, Rules and Regulations (NYCRR).
[2] For units determined to be non-base load units.
[3] MWH-g refers to gross generation output. MWH-n refers to net generation output, the energy generated minus the electricity used to operate the power plant.

b. New Source Review

The NSPS requirements discussed above are technology specific, not location specific. In addition to NSPS, new units will be subject to the EPA's New Source Review (NSR) program, which considers the impacts to the air quality in the vicinity of the emission source. If a project site is located in an area where a criteria pollutant's concentration is below its respective National Ambient Air Quality Standard (NAAQS), then the area is in

[15] For modeling purposes, we apply the runtime limitations for peaking plant operations by model year, instead of on a rolling average basis.

"attainment" for that pollutant. Areas where a criteria pollutant's ambient concentration is above its NAAQS is classified as a "nonattainment" area, and there are multiple levels of nonattainment (i.e. moderate vs. severe). The NSR program is split into two permitting pathways/regimes: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR). The preconstruction review process for new or modified major sources located in attainment and unclassifiable areas is performed under the PSD requirements. Preconstruction reviews for new or modified major sources located in nonattainment areas is performed under the NNSR program.

In order to improve a nonattainment area's air quality, the NNSR permitting pathway has more stringent permitting thresholds and requires stricter permitting analyses. In an attainment area, a source that would qualify for a PSD permit would need to perform a Best Available Control Technology (BACT) analysis, which reviews control technologies that have been installed on similar units for applicability to the new source. BACT analyses allow for the evaluation of cost feasibility when determining the control technology required. On the other hand, in a nonattainment area, a source applying for a permit under NNSR review is required to go through a Lowest Achievable Emission Rate (LAER) analysis, which does not take cost into consideration when determining applicable control technologies and thus typically has much more stringent control requirements. The NNSR only applies to the pollutants that are classified as nonattainment for a project area (meaning that one pollutant could undergo NNSR review if the site location is a nonattainment area for that pollutant, while the other pollutants could be subject to PSD review if the site location for such other pollutants is classified as attainment).

The PSD major source thresholds are listed in Table 10. The major source threshold for new combined cycle facilities is lower (100 tons/year) than the major source threshold for new simple combustion turbines (250 tons/year). The annual emissions are typically based on the potential to emit (PTE) at 8,760 hours/year of operation. If a new source is determined to be a major PSD source, then PSD review would be performed for any pollutant that exceeds the Significant Emission Rates (SER) listed in Table 10.

However, it is possible to "synthetically limit" a unit's operating profile to maintain emissions for applicable pollutants below the PSD thresholds (both the major source threshold and the SER threshold). By synthetically limiting the PTE, the facility will become a "synthetic minor source", requiring less strict permitting analyses. For example, a BACT analysis would not be required as a part of a federal synthetic minor permitting application.

On June 23, 2014, the Supreme Court issued a decision in Utility Air Regulatory Group (UARG) v Environmental Protection Agency (EPA), which challenged the EPA "Tailoring Rule".[16] As a result of this court decision, EPA may not treat greenhouse gases (GHGs) as an air pollutant to determine whether a source is a major source required to obtain a PSD permit. However, EPA can require PSD permits (which are otherwise required) to contain limitations on GHG emissions based on the application of BACT only if another pollutant is also subject to PSD.

For the current DCR, as shown in Table 10, the PSD major source thresholds are 100 tons/year for combined cycle facilities and 250 tons/year for the fossil peaking plant technologies.

[16] Utility Air Regulatory Group (UARG) v. Environmental Protection Agency, 134 S. Ct. 2427 (2014).

Table 10: PSD Major Facility Thresholds and Significant Emission Rates

Pollutant	NGCC Major Source Threshold (tons/year)	CT Major Source Threshold[1] (tons/year)	Significant Emissions Rate (tons/year)
Carbon monoxide (CO)	100	250	100
Nitrogen oxides (NO_X)	100	250	40
Sulfur dioxide (SO_2)	100	250	40
Coarse particulate matter (PM_{10})	100	250	15
Fine particulate matter ($PM_{2.5}$)	100	250	10
Volatile organic compounds	100	250	40
Greenhouse gases (GHG): as CO_2e	Note 2	Note 2	75,000
NGCC – natural gas combined cycle (informational); CT – combustion turbine			

Notes:
[1] CT major source thresholds are 250 tons/year since these sources are not one of the source categories listed in section 201-2.1(b)(21)(iii)(a) through (z) of 6 NYCRR.
[2] Per NYSDEC October 15, 2014 Enforcement Discretion for State GHG Tailoring Rule Provisions Memorandum, GHGs alone will not trigger Prevention of Significant Deterioration New Source Review (PSD NSR).

As mentioned above, any pollutant subject to PSD review (i.e. exceeds the PTE thresholds in Table 10) is required to perform a BACT analysis. Absent application of a synthetic operating limit, it is expected that in order for a new unit in New York State to meet the BACT standard, SCR emissions controls would be required for nitrogen oxide (NO_x) control and an oxidation catalyst would be required for carbon monoxide (CO) and/or volatile organic compounds (VOC) control. In addition to BACT requirements, an air quality impact analysis (air dispersion modeling), and an analysis of other impacts (e.g., soils, vegetation, and visibility) are required for all pollutants subject to PSD review.

NNSR only applies to the pollutants for which a given area is classified as in nonattainment. The current nonattainment areas in New York State are illustrated in Figure 2. These areas are nonattainment for the eight-hour ozone National Ambient Air Quality Standard (NAAQS). NNSR also applies throughout New York State for precursors of ozone (NO_X and VOC), since all of New York State is in the Ozone Transport Region (OTR). Since NO_X and VOC are treated as nonattainment pollutants statewide, proposed facilities may be required to comply with both the PSD requirements for attainment pollutants and NNSR requirements for nonattainment pollutants.

Figure 2: Current Nonattainment Areas in New York

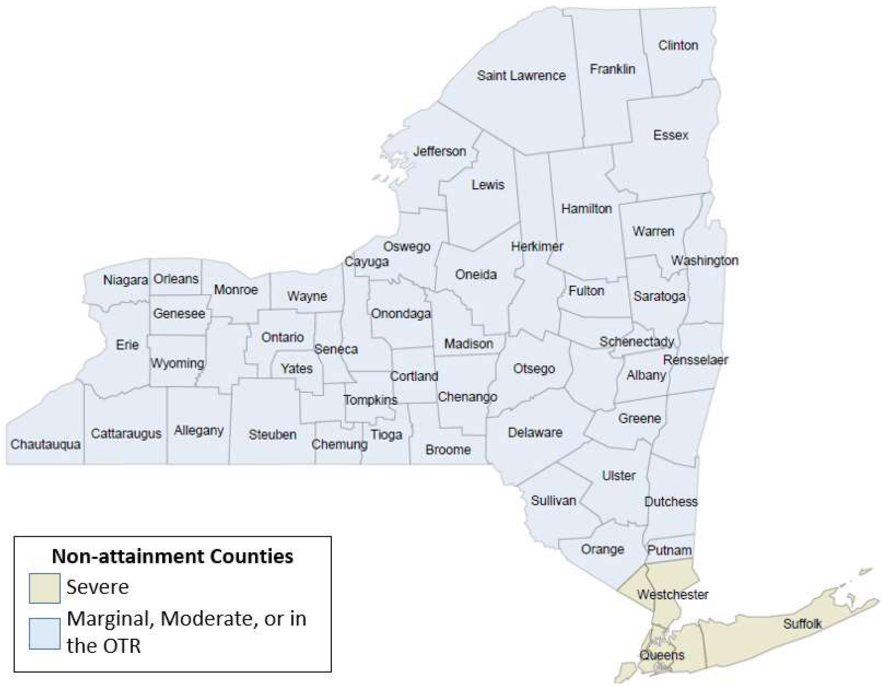


Table 11 presents the nonattainment major facility thresholds and emission offset ratios for each ozone nonattainment classification. Nonattainment areas classified as Severe include the New York City Metropolitan Area and the Lower Orange County Metropolitan Area. The New York City Metropolitan Area includes all of the New York City, as well as Nassau, Suffolk, Westchester and Rockland Counties. The Lower Orange County Metropolitan Area includes the Towns of Blooming Grove, Chester, Highlands, Monroe, Tuxedo, Warwick, and Woodbury. The remaining areas in the State are classified as either Marginal, Moderate or in the OTR.[17] Table 12 summarizes the ozone nonattainment classification and NNSR major source thresholds for NO_X and VOC for each of the locations evaluated as part of this DCR.

[17] Notably, Orange County includes areas that are both Severe and Marginal/Moderate nonattainment areas. Orange County is located within the G-J Locality, west of the Hudson River. Consistent with the past two DCRs, AGI and BMCD considered peaking plant technologies located in either Rockland County (west) or Dutchess County (east) in Load Zone G. The use of these two locations provides for a consideration of differences in attainment areas on peaking plant siting and permitting costs. AGI and BMCD did not consider specific locations within a county, which would be required to develop an accurate estimate for Orange County, given the differences in nonattainment designations throughout the region.

Table 11: NNSR Major Facility Thresholds and Offset Ratios

Contaminant	Major Facility Threshold (tons/year)	Emission Offset Ratios
Marginal, Moderate, or Ozone Transport Region (OTR):		
Volatile Organic Compounds (VOC)	50	At least 1.15:1
Nitrogen oxides (NO_x)	100	At least 1.15:1
Severe:		
Volatile Organic Compounds (VOC)	25	At least 1.3:1
Nitrogen oxides (NO_x)	25	At least 1.3:1

Table 12: Ozone Nonattainment Classification and Major Source Thresholds by Load Zone

	C – Central	F – Capital	G – Dutchess	G – Rockland	J – NYC	K – Long Island
Ozone nonattainment classification[1]	Moderate	Moderate	Moderate	Severe	Severe	Severe
NNSR NOx Major Source Threshold (tons/year)	100	100	100	25	25	25
NNSR VOC Major Source Threshold (tons/year)	50	50	50	25	25	25

Notes:
[1] Moderate nonattainment classification due to location in the Ozone Transport Region.

NNSR major sources located in nonattainment areas for ozone are required to install LAER technology. LAER is an emission rate that has been achieved or is achievable for a defined source and does not consider cost-effectiveness. SCR systems for NO_X control and an oxidation catalyst for VOC emissions are expected LAER technologies for combustion turbine facilities subject to NNSR.

Similar to the PSD permitting process, a synthetic limit (e.g., application of an annual operating hours cap/limit) could be applied to a new source or facility, which would bring the annual PTE below the thresholds listed above in Table 11 and Table 12. Since the facility would no longer be subject to NNSR, the LAER analysis would no longer be required.

The GE 7HA.02 peaking plant technology option with a 25 ppm NO_x emissions rate and the 1x1 7HA.02 informational combined cycle plant would already require the installation of SCR emissions controls per the NSPS Subpart KKKK limits discussed in the prior section. When using the *maximum* annual run hours limitation for simple cycle units for compliance with the NSPS TTTT regulation, the other technologies considered in this DCR would require SCR emissions controls as a part of NNSR analyses requiring LAER in all locations evaluated, regardless of nonattainment status of areas of each location. Based on the maximum hours per NSPS TTTT, the CO catalyst would be required for the Siemens SGT-A65 and the 1x1 7HA.02 in all locations evaluated. The control technology requirements (required to meet the NSPS or expected to meet LAER requirements as a part of NNSR absent any consideration of a synthetic limitation) are summarized in Table 13 below.

Table 13: Control Technology Requirements for Fossil Technologies Analyzed at Greenfield Sites at Maximum Annual Run Hours

	Load Zone C		Load Zone F		Zone G-Dutchess		Zone G-Rockland		Load Zone K	
	Moderate		Moderate		Moderate		Severe		Severe	
Technology	**SCR**	**CO Catalyst**	**SCR**	**CO Catalyst**	**SCR**	**CO Catalyst**	**SCR**	**CO Catalyst**	**SCR**	**CO Catalyst**
3x0 Siemens SGT-A65	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1x0 GE 7F.05	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x0 GE 7HA.02, 15 ppm NO_x	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x0 GE 7HA.02, 25 ppm NO_x	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x1 GE 7HA.02 (Informational)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Notes:
[1] Values shown are for maximum annual hours of operation (3,066 hours for SCGT technologies and 8,760 for CCGT technology).
[2] For dual fuel SCGT, the evaluation considers 720 hours operating on ultra-low sulfur fuel oil and the remaining 2,346 hours on gas.
[3] For dual fuel CCGT (informational), evaluation considers 720 hours operating on ultra-low sulfur fuel oil and the remaining 8,040 hours on gas.
[5] For gas only operation, the SCR and oxidation catalyst results above do not change.

In addition to the “maximum-hour” compliance analysis performed above, BMCD also analyzed other methodologies of compliance—specifically limiting the annual hours of operation of each technology in order to reduce emissions below the NNSR threshold to remove the requirement to perform a LAER analysis. The approximate hours per year restriction to eliminate the need to perform LAER for operating solely on natural gas or operating solely on ultra-low sulfur diesel (ULSD) fuel are shown in Table 14 and Table 15 below. The limits displayed in the tables are estimated based on lb/hr emissions rates at ISO conditions. The dispatch analyses take into account seasonal emissions differences due to different seasonal heat rates and capacities, so annual limits in the net EAS models may be different than those shown below.

NO_x emissions are higher for fuel oil operation than natural gas operation. In the case of a unit including dual fuel capability, the synthetic limit may be reached with fewer hours than a gas only unit, based on the quantity of each fuel used over the course of the year. Since the NOx emission rate of the 25 ppm base design of the 7HA.02 is above the NSPS KKKK, this unit will require SCR emissions controls to comply with the NSPS standard, which is not influenced by potential application of annual operating hours or project location. Therefore, it is included in the tables below, but not included in the synthetic minor analyses performed.

Table 14: Approximate Annual Operating Limits Needed to Not Require SCR Emission Controls Using Natural Gas Only at a Greenfield Site

Technology	C	F	G-Dutchess	G-Rockland	J	K
	Moderate	Moderate	Moderate	Severe	Severe	Severe
3x0 Siemens SGT-A65[1]	1,195	1,195	1,195	295	295	295
1x0 GE 7F.05	2,500	2,500	2,500	620	620	620
1x0 GE 7HA.02, 15 ppm NOx	1,060	1,060	1,060	260	260	260
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
1x1 GE 7HA.02 (Informational)	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]

Notes:
[1] These values are for the analyzed project (i.e., the SGT-A65 limit is for all three engines combined, per year).
[2] SCR emission controls are required for these units per the NSPS KKKK rule.
[3] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59 deg F and 60% relative humidity).

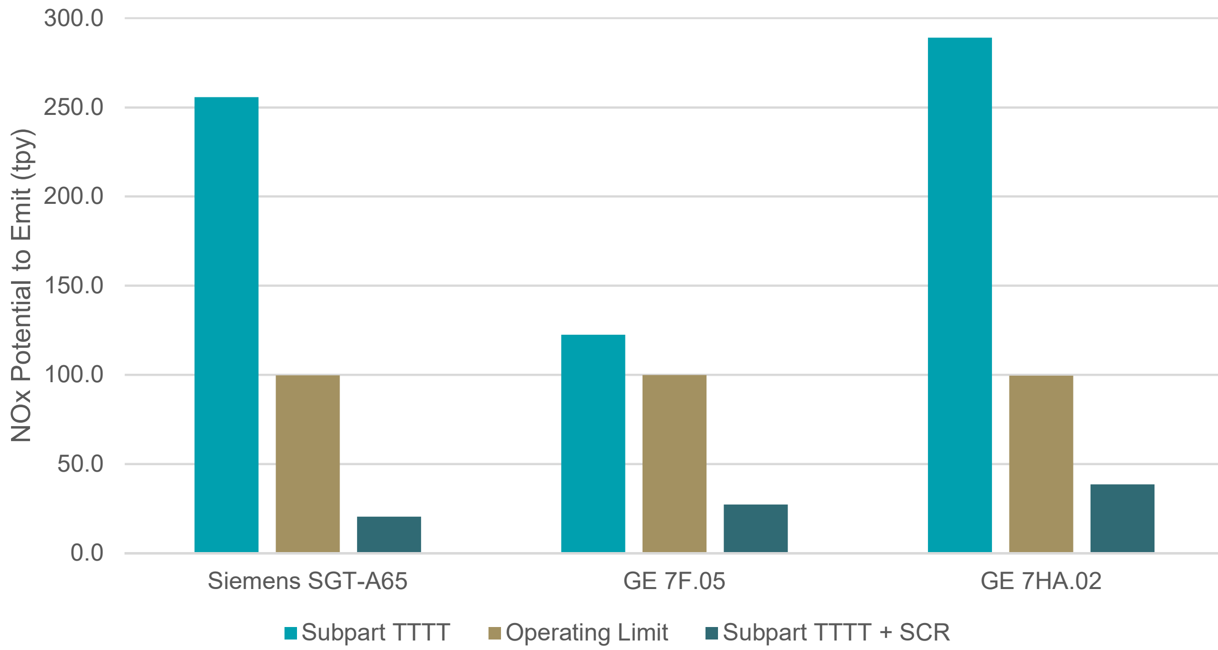
Table 15: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using ULSD Only at a Greenfield Site

Technology	C	F	G-Dutchess	G-Rockland	J	K
	Moderate	Moderate	Moderate	Severe	Severe	Severe
3x0 Siemens SGT-A65[1]	717	717	717	177	177	177
1x0 GE 7F.05	465	465	465	115	115	115
1x0 GE 7HA.02, 15 ppm NOx	312	312	312	78	78	78
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
1x1 GE 7HA.02 (Informational)	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]

Notes:
[1] These values are for the analyzed project (i.e., the SGT-A65 limit is for all three engines combined, per year).
[2] SCR emissions controls are required for these units per the NSPS KKKK rule.
[3] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59 deg F and 60% relative humidity).

Figure 3 shows the estimated NO_x emissions for the Siemens SGT-A65 unit, the GE 7F.05 unit, and the GE 7HA.02 15 ppm unit using the Subpart TTTT limit, the annual operating limits to become a synthetic minor source, and the Subpart TTTT hourly limits with SCR emissions controls. The GE 7HA.02 25 ppm unit (either in simple or combined configuration) will require SCR emissions controls in order to comply with NSPS KKKK, and thus are not included in this depiction. The emissions estimates shown are for natural gas operation only. The approximate hourly operating limit is used as the threshold to trigger NNSR permitting in a moderate county (limited to 100 tpy NO_x).

Figure 3: NOx Emissions Comparison



Including SCR emissions controls on a simple cycle gas only plant can serve to mitigate certain siting, permitting, and future market risks which are considered by power plant project developers. As discussed below, the fossil peaking plant technologies will need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment. In issuing a certificate, the Siting Board is required to determine the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[18] Based on the emissions estimates performed for the DCR, a GE 7HA.02 simple cycle plant with SCR emissions controls would have a lower PTE than a gas only plant with annual operating limits to bring it below the NNSR thresholds.

However, with a synthetic minor that may limit run hours, the installation of SCR emissions controls may ultimately be an economic decision by the plant developer, which trades off significant up-front capital costs and additional operating costs against loosened runtime restrictions. If the unit would not be expected to run for the number of hours that would require SCR emissions controls in many years, then it may not be economic for a new plant to install SCR emissions controls. Considering the balance of costs and risks discussed above, it is AGI's and BMCD's opinion that the developer of a new plant in Load Zones C, F, and G (Dutchess) in New York would not

[18] New York Public Service Law, Section 168(3)(c) requires that "the adverse environmental effects of the construction and operation of the facility will be minimized or avoided to the maximum extent practicable…"

seek to include SCR emissions control technology at the time of construction due to economic considerations. Instead, for these locations, it is assumed that the developer would accept and adhere to the applicable annual operating hours limit necessary to become a synthetic minor source.[19]

In addition to installing technologies to address LAER analysis, major sources in nonattainment areas are required to secure emission offsets, or emission reduction credits (ERCs), at the ratios of required ERCs to the facility's PTE presented in Table 11. The ERCs must be the same as for the regulated pollutant requiring the emission offset and obtained from within the nonattainment area in which the new source will locate. Under certain conditions the ERCs may be obtained from other nonattainment areas of equal or higher classification. NO_X and VOC ERCs for major sources locating in an attainment area of New York State may be obtained from any location within the OTR, including other states in the OTR, provided an interstate reciprocal trading agreement is in place.

The cost of securing emission offsets was included in the total capital investment estimates for each technology option. The estimated cost of the ERCs were based on the maximum NO_x emissions from natural gas operation. The ERCS were calculated with SCR emissions controls for Load Zone G (Rockland County), NYC, and LI. The annual hours were restricted to those needed to comply with NSPS Subpart TTTT. The annual emissions used in the ERC cost calculations were based on the controlled emission rate assumptions that are shown in Table 16.

[19] As described in Section IV.B.2.a, the operating hours limits are modeled in the Net EAS Revenue model as constraints on the total amount of combined NO_x emissions allowed each year from either natural gas or ULSD operations. Units without SCR in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions.

Table 16: Emissions Rate Assumptions for Fossil Plants

	NO_X (ppm) [1]	CO (ppm) [1]	VOC (ppm) [1]	CO_2 (lb/MWh) [2]
Natural Gas Firing without SCR/CO Catalyst				
1x0 GE 7F.05	9	9	1.3	1,230
1x0 GE 7HA.02, 15 ppm NO_x	15	9	2	1,120
Natural Gas Firing with SCR				
3x0 Siemens SGT-A65	2	2	5	1,130
1x0 GE 7F.05	2	2	1	1,230
1x0 GE 7HA.02, 25 ppm NO_x	2	2	1	1,130
1x1 GE 7HA.02 (Informational)	2	2	1	760
Ultra-Low Sulfur Diesel Firing without SCR				
1x0 GE 7F.05	42	14	2.4	1,650
1x0 GE 7HA.02, 15 ppm NO_x	42	12	2.4	1,490
Ultra-Low Sulfur Diesel Firing with SCR				
3x0 Siemens SGT-A65	5	2	2	1,510
1x0 GE 7F.05	5	2	2	1,650
1x0 GE 7HA.02, 25 ppm NO_x	5	2	2	1,510
1x1 GE 7HA.02 (Informational)	5	2	2	1,050

Notes:
[1] Parts per million on a dry basis, measured at 15% O_2.
[2] Based on full load, net plant heat rate at ISO conditions, higher heating value (HHV) basis, clean and new condition.

2. *Cap and Trade Program Requirements*

New stationary combustion sources in New York State are also subject to cap-and-trade program requirements including:

- CO_2 Budget Trading Program (6 NYCRR Part 242)
- Cross State Air Pollution Rule (CSAPR) Trading Program
- CSAPR NO_X Ozone Season Group 2 Trading Program (6 NYCRR Part 243)
- CSAPR NO_X Annual Trading Program (6 NYCRR Part 244)
- CSAPR SO_2 Trading Program (6 NYCRR Part 245)
- SO_2 Acid Rain Program (40 CFR Parts 72-78)
- Nonattainment and Ozone Transport Region (OTR) SIP Requirements (40 CFR 51.116 and 40 CFR 51.1316)

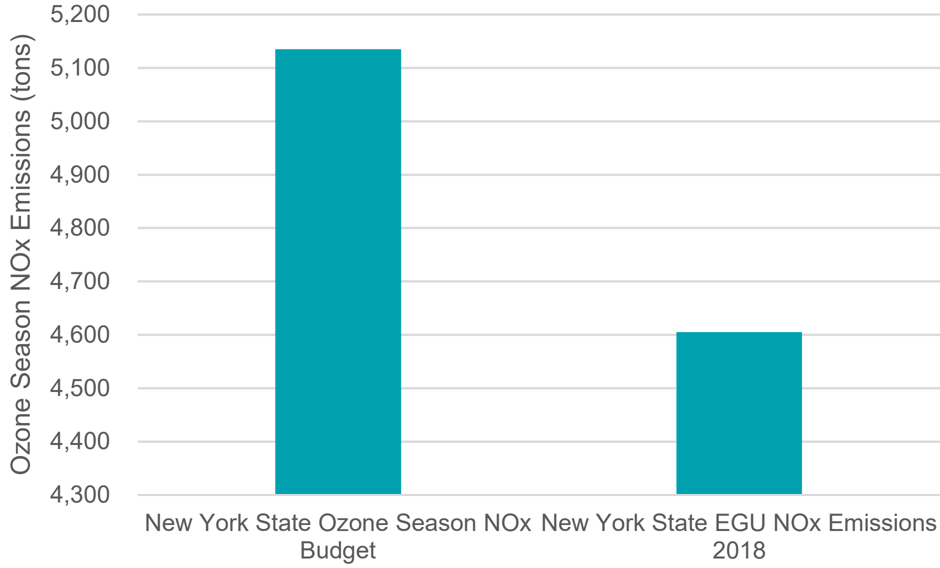
The CO_2 Budget Trading Program regulations would apply to all fossil peaking plant technologies assessed, as well as the informational combined cycle plants. Part 242 establishes the cap-and-trade provisions pursuant to the Regional Greenhouse Gas Initiative (RGGI), a nine-state cooperative effort to reduce greenhouse gas emissions from electrical generating facilities by means of a cap-and-trade program. Under RGGI, each participating state has committed to state regulations that will cap and then reduce the amount of the CO_2 that electrical generating facilities are allowed to emit in total across the RGGI region. CO_2 allowances are obtained by generators through a CO_2 allowance auction system and are traded using CO_2 Budget Trading Programs.

In general, Parts 243, 244, and 245 CSAPR regulations apply to any stationary fossil fuel-fired boiler or combustion turbine that serves a generator with a nameplate capacity equal to or greater than 25 MW producing electricity for sale.

The cost of CO_2, NO_X, and SO_2 allowances are included in the economic dispatch and accounted for in the net EAS revenue estimates for each technology option. In addition, the cost of ERCs is included in the capital cost estimates for each applicable location as required by NNSR air permitting requirements.

Starting in 2017, the CSAPR Update required New York electric generating units (EGUs) to participate in the new CSAPR NO_x Ozone Season Group 2 Trading Program instead of the original program (now named Group 1). The CSAPR update also lowered the ozone season budget for the State of New York by approximately 58% in order to address the revised and more stringent ozone NAAQS. Figure 4 demonstrates the new Group 2 ozone emissions budgeted for New York State, as well as the amount of NOx emissions emitted by EGUs in 2018 (the most recent year with data readily available).

Figure 4: New York State CSAPR Ozone Season NO_x Budgets and Electric Generating Units (EGUs) NO_x Emissions



The Clean Air Act sets out specific requirements for a grouping of northeastern states that make up the Ozone Transport Region. It was determined that the NOx, CO, and VOC emissions from these states impacted several other regions/states downwind. States in the OTR region must submit a State Implementation Plan (SIP) and install more stringent controls on equipment in order to control the production of ozone, even if a county or area meets the ozone standards. These requirements are discussed above and have been incorporated into the NYDEC New Source Review for New and Modified Facilities.

3. "Peaker Rule"

In 2020, New York State adopted 6 NYCRR Subpart 227-3, "Ozone Season Oxides of Nitrogen (NO_x) Emission Limits for Simple Cycle and Regenerative Combustion Turbines," ("NYDEC Peaker Rule"). This applies to owners and operators of simple cycle and regenerative combustion turbines that are electric generating units with a nameplate capacity of 15 MW or greater that inject power into the transmission or distribution systems, only during the ozone season (May 1 to September 30). By May 1, 2025, the NO_x emission limits will be 25 ppmvd for natural gas and 42 ppmvd for distillate or other liquid fuel oils. As shown in Table 13 above, the new fossil peaking plant technologies assessed comply with these thresholds. Therefore, this rule will not directly impact the new fossil peaking plants evaluated in this study.

4. Plant Cooling Requirements

The major source of heat rejection for combined cycle power plants is the steam turbine condenser. New combined cycle power plants typically use mechanical draft cooling towers or air-cooled condensers (ACCs). Both cooling methods can meet Clean Water Act Section 316(b) Rule requirements for new facilities. At some locations new combined cycle power plants are moving towards the use of ACCs driven by environmental and/or water scarcity concerns. The New York Department of Environmental Conservation issued NYSDEC Policy CP-#52, which seeks a performance goal of dry cooling for industrial facilities sited in coastal zones and the Hudson River up to Troy. For this study, it has been assumed that the informational combined cycle options would be designed with ACCs in all locations evaluated.

5. Other Permitting Requirements

Public Service Law Article 10 requires any proposed electric generating facilities with a nameplate generating capacity of 25 MW or more to obtain a Certificate of Environmental Compatibility and Public Need. The Article 10 process includes stakeholder intervention processes, including intervener funding provisions by the project developer. In its review, the New York State Board on Electric Generation Siting and the Environment (Siting Board) is required to find that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable. In doing so, the Siting Board must consider both the state of available technology and the nature and cost of reasonable alternatives.

6 NYCRR Part 487 establishes a regulatory framework for undertaking an analysis of environmental justice issues associated with the siting of an electric generating facility in New York State pursuant to Article 10. Part 487 is intended to enhance public participation and review of environmental impacts of proposed electric generating facilities in environmental justice communities and reduce disproportionate environmental impacts in overburdened communities. Specific analysis requirements are evaluated on a case-by-case basis. The estimates of total capital investment for each technology option include expenditures to conduct environmental justice analysis as part of the project development costs.

D. Dual Fuel Capability

The recommended technology choice also requires determining for each location whether the peaking plant should be a natural gas-only resource or have the capability to operate on both natural gas and ULSD (dual fuel). The current peaking plants include dual fuel capability for the NYC, LI, and G-J Locality ICAP Demand Curves. The current peaking plant for the NYCA ICAP Demand Curve is a gas-only design.

In this DCR, we have evaluated whether to recommend including dual fuel capability in each Load Zone. As with many of the technology choices considered, we evaluated potential recommendations against a review of relevant data and considerations tied to what developers are likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

The incremental costs for dual fuel capability (which would be deducted for a gas only unit) are shown in the capital cost estimates in Appendix B, and highlighted in Table 17 below. The capital costs includes gas turbine combustion system modifications provided by the OEM and field installed, a fuel oil storage tank with 96 hours of storage capacity, piping (fuel and water), and associated electrical and controls modifications. The owner's costs include the purchase of the fuel inventory and the additional fuel requirements for startup and commissioning.

Table 17: Incremental Dual Fuel Costs for Fossil Plants

	C	F	G-Dutchess	G-Rockland	J	K
3x0 Siemens SGT-A65						
Capital Costs, 2020 MM$	$11.3	$11.3	$11.3	$11.3	$12.3	$12.3
Owner's Costs, 2020 MM$	$7.0	$7.0	$7.0	$7.0	$7.1	$7.1
1x0 GE 7F.05						
Capital Costs, 2020 MM$	$16.9	$16.9	$16.9	$16.9	$20.1	$20.1
Owner's Costs, 2020 MM$	$8.5	$7.0	$7.0	$7.0	$8.6	$8.6
1x0 GE 7HA.02						
Capital Costs, 2020 MM$	$25.4	$25.4	$25.4	$25.4	$30.2	$30.2
Owner's Costs, 2020 MM$	$12.5	$7.0	$7.0	$7.0	$12.7	$12.7
1x1 GE 7HA.02 (Informational)						
Capital Costs, 2020 MM$	$25.4	$25.4	$25.4	$25.4	$30.2	$30.2
Owner's Costs, 2020 MM$	$13.5	$7.0	$7.0	$7.0	$13.8	$13.8

Based on our evaluation, AGI recommends that the peaking plant technology design should continue to include dual fuel capability in Load Zones G, J, and K. Consistent with the current design for the NYCA ICAP Demand Curve, AGI recommends continued use of a gas-only design for Load Zones C and F. This recommendation is based on the consideration of a number of tradeoffs a developer would consider when deciding whether or not to include dual fuel capability in a development project in New York state and whether, on balance, a developer would more likely than not decide to include dual fuel capability based on such considerations. Specifically, the following observations inform the conclusion that the answer to this question is yes in Load Zones G, J, and K, and no in the ROS:

- There are local electric reliability rules applicable to NYC and LI that require dual fuel capability. Additionally, nearly all gas fired generation in Load Zones J and K is connected to the LDC gas system, and several LDC gas tariffs require dual fuel capability for generators. Such LDC requirements are in place for National Grid in Load Zones C, F and K; Orange & Rockland and Central Hudson in Load Zone G; and Con Edison in Load Zone J.
- Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are increases in capital costs associated with the installation of dual fuel capability, and in annual costs tied to maintaining dual fuel systems, testing dual fuel capability, and carrying an on-site inventory of fuel for operations on the alternate stored fuel. On the other hand, these increases in cost could be outweighed by the value associated with potential increases in net EAS revenues from operating on the alternate fuel when the price for the alternate fuel is less than that of natural gas, and allowing production when gas supplies would otherwise be curtailed (such as during certain winter periods when gas supplies may be scarce due to higher demand for all end uses). Moreover, the value of dual fuel optionality may be greater under LOE market conditions, particularly to the extent that such conditions arise due to shifts in generation resources that increase reliance on gas-fired resources. These factors are particularly true in Load Zones G, J,

and K, where there are potentially more meaningful constraints on natural gas availability in winter months than in the rest of the state.

- Potential peaking plant developers would also consider various risks and benefits associated with project development and siting. Specifically, on the one hand adding dual fuel capability would expand the geographical flexibility for power plant siting, by supporting the siting of plants on (and obtaining gas supply from) the distribution systems of local gas distribution companies. Expanding such geographic flexibility increases the potential of finding sites that coincidentally minimize the costs to obtain both natural gas and electrical interconnections. On the other hand, the addition of oil-fired capability can complicate the process of successfully siting and permitting the facility.
- Finally, in the downstate regions a developer would likely view the addition of dual fuel capability favorably in light of New York State's reliance on natural gas for power generation which is expected to continue in the coming years, as well as in recognition of constraints on the use of natural gas that arise, particularly during winter months.

FERC's acceptance of the current peaking plant designs recognized that dual fuel capability is mandatory in NYC and LI, and, although not mandatory in Load Zone G, FERC agreed that "dual fuel capability comes with increased revenue potential, siting benefits, and reliability benefits, plus it can serve as a hedge to mitigate electricity price spikes during times of high natural gas prices." FERC also agreed that "the G-J Locality is a relatively geographically constrained region; therefore, the inclusion of dual fuel capability is important for providing increased siting flexibility," and that "current concerns regarding the ability to expand natural gas pipeline infrastructure and capacity in New York underscore the reliability benefits gained from dual fuel capability in the G-J Locality." FERC's acceptance of dual fuel capability for NYC, LI, and the G-J Locality as part of the 2013 DCR was based on similar reasons.[20]

In accepting a gas-only design for the NYCA ICAP Demand Curve as part of the 2016 DCR, FERC agreed that Load Zones C and F are "far less geographically constrained than the G-J Locality" and that "natural gas supply conditions in load zones C and F are more favorable than in the G-J Locality because this region is generally located upstream of interstate natural gas pipeline constraints and has connections to natural gas supplies from the nearby shale gas producing regions." As a result, the "potential incremental revenues associated with having dual fuel capability are not outweighed by the potentially significant capital investment."[21]

E. Capital Investment Costs

Capital cost estimates were prepared for the construction of the following simple cycle technologies in New York Load Zones, C, F, G (Dutchess County), G (Rockland County), J, and K:

- Three Siemens SGT-A65 units
- One GE 7F.05 unit
- One GE 7HA.02 unit

[20] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 (2017) at P 48-49.

[21] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 (2017) at P 50-51.

Capital cost estimates were also prepared for the following energy storage technologies.

- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

In addition, for informational purposes, capital cost estimates were prepared for the construction of a 1x1 7HA.02 combined cycle facility Load Zones, C, F, G, J, and K.

The capital investment costs include the installed cost of the plant, owner's costs, and financing costs during construction. The installed cost estimate is based on a developer entering into an engineer, procure, construct (EPC) contract for project execution. Owner's cost estimates include the electric and gas interconnection facilities, owner development and management activities, fuel inventory (applicable for fossil units with dual fuel capability), builder's risk insurance, and an additional contingency.

Table 18 provides the conceptual design features for the plants in each of the locations evaluated.

Table 18: Recommended Fossil Peaking Plant Design Capabilities and Emission Control Technology

	C-Central	F-Capital	G-Dutchess	G-Rockland	J-New York City	K-Long Island
Fuel Capability	Gas Only	Gas Only	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel
Siemens SGT-A65 Combustion System NO_x Control	Water Injection	Water Injection	Water Injection	Water Injection	Water Injection	Water Injection
Post Combustion Controls for: 3 x Siemens SGT-A65	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
GE 7HA.02 base model NO_x emissions tuning	15 ppm	15 ppm	15 ppm	25 ppm	25 ppm	25 ppm
GE 7F.05 and GE 7HA.02 Combustion System NO_x Control	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry
	Fuel Oil: N/A	Fuel Oil: N/A	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection
Post Combustion Controls for GE 7F.05 and GE 7HA.02 simple cycle	None	None	None	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
Informational Combined Cycle Plant Cooling	Dry	Dry	Dry	Dry	Dry	Dry
Post Combustion Controls for Informational Combined Cycle	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst

1. *Plant Design Basis*

The plant design basis is conceptual and consistent with new facility design features that would be constructed in the current market. Key design assumptions include:

1. Site Conditions – In all Load Zones except Load Zone J, the cost estimate is based on a generic, greenfield site. Assumed land requirements for greenfield conditions are summarized below. In New York City, it is assumed that a peaking plant would most likely be built on a brownfield site at low elevation. Therefore, the New York City capital cost estimate includes a nominal allowance for demolition of existing facilities.

2. Storm Hardening – Costs were included to raise the Load Zone J site 4 feet as an allowance to accommodate floodplain zoning requirements and New York City building codes to prevent damage to the facility from flooding analogous to those which occurred due to Hurricane Sandy in 2012. BMCD considered that peaking plant in Load Zone J would most likely be located on brownfield sites along the waterfront. The Federal Emergency Management Agency (FEMA) minimum site elevation requirement is 14 feet NAVD88. Site elevations along the waterfront may be as low as 10 feet NAVD88.

3. Fuel – The capital cost estimates were developed based on the fuel assumptions shown above in Table 18. The cost delta to add or remove dual fuel capability is also shown in the costs in Appendix B. Dual fuel units include a cost for fuel oil inventory, with storage levels based on the capability to provide 96 hours of operation (equivalent to one week of on-peak operations; 6 days at 16 hours per day). The delivered cost for the initial fuel oil inventory is assumed to be $3.00 per gallon. Initial commissioning for each peaking plant assumes 50 hours of full load oil use for guarantee and emissions performance testing.

4. Cooling Design – As summarized in Table 18, it was concluded that for the informational combined cycle plants, cooling for all locations would include air cooled condenser (ACC) technology.

5. Inlet Cooling – Inlet air evaporative coolers were included for the aeroderivative and frame combustion turbines (for simple cycle plant options and the informational combined cycle plant). The inlet air evaporative coolers are operated when the ambient temperature exceeds 59°F. The evaporative cooler increases the water content of the air, which reduces its temperature typically 85% to 90% of the difference between the dry bulb and wet bulb temperature. Consequently, the largest temperature reduction occurs when the relative humidity is low. Since the air to fuel ratio in combustion is very high and the density of air increases as the temperature is lowered, the mass flow through the turbine is higher at lower temperature, which increases the MW generated.

6. Gas Pressure – The natural gas pressure was assumed to be 250 psig in all locations evaluated. Natural gas compressors were included in the EPC estimates to increase the fuel gas pressure to that required by the combustion turbine options assessed.

7. Emission Control Equipment – In Load Zones C, F, and G (Dutchess County), the NO_x limit to trigger PSD is 100 tons per year (tpy). Frame combustion turbines with NOx emissions rates equal to or less than 15 ppm (such as the 7F.05 unit and the 15 ppm NO_x variant of the 7HA.02 unit) could potentially receive an air permit without SCR emissions controls by assuming a run-hour limitation to stay below 100 tpy. Analyses by AGI suggest that in these locations developers may pursue this approach as a more profitable option from a financial perspective given that it is

permissible under the currently applicable emission requirements. Therefore, BMCD recommends considering the 7F.05 and 15ppm version of the 7HA.02 without SCR emissions controls in Load Zones C, F, and G (Dutchess County). BMCD based its cost estimates for the 7F.05 and 25ppm version of the 7HA.02 on a design that includes SCR emissions controls in Load Zones G (Rockland), J, and K. The aeroderivative option and informational combined cycle plants in all locations are assumed to include SCR emissions controls.

8. Black Start Capability – Black start capability has not been included in the cost estimate for any of the fossil plants or batteries given that the compensation for this service is cost based. Accordingly, the costs of such capability would be recovered in the compensation for such service, and, thus have been excluded from both the cost and revenue estimates. This is consistent with the approach for black start capability from the 2016 DCR.

9. Noise Mitigation – Preliminary noise modeling was performed to determine mitigation system assumptions for all technologies. Software modeling was performed with the facility placed in the center of a parcel with the acreage defined in the assumptions for this study. New York State Department of Environmental Conservation provides a guidance for circumstances under which sound creates significant noise impacts within the Program Policy Memorandum titled Assessing and Mitigating Noise Impacts. Projects in New York City are anticipated to be subject to the New York City Environmental Quality Review (CEQR) requirements and the New York City Noise Control Code. Based on the modeling results and BMCD permitting experience, the design basis assumes that all simple cycle gas turbine options would be installed indoors, and that the informational combined cycle plant would include a power island building that houses the gas turbine, steam turbine, and heat recovery steam generator (HRSG). The informational combined cycle plant also assumes the use of low noise fans on the ACC. All simple cycle, combined cycle, and BESS technologies include an additional allowance for sound barrier walls (these are not the same as the walls of the building, but rather a separate, strategically located barrier to mitigate noise impacts for compliance with threshold described above). The location and dimensions of the sound walls will vary depending on a host of site specific conditions, but the preliminary model results suggest that an allowance for barriers is warranted to meet the threshold of a 6 dBA increase of the assumed ambient sound levels.

10. Energy Storage Sizing – It is important to note that costs and designs for lithium-ion battery projects are changing rapidly in the market. BMCD's recent project experience suggests that NMC, LFP, and NCA technologies are competing directly and often with different form factors. Batteries may be installed in large buildings, modified containers, or purpose-built enclosures.

    a. Building designs: For building designs, the batteries are field installed in large pre-engineered building(s).

    b. Container designs: Containers may be modified shipping containers or custom designed enclosures, but they are generally pre-engineered with lighting, communications/controls, fire suppression systems, and auxiliaries located inside. HVAC units are commonly mounted on the sides or tops of the containers. The batteries typically ship separately for field installation in containers.

c. Purpose built enclosures: this is a recent trend in which OEMs or integrators ship a pre-engineered enclosure where the batteries and inverters may ship already installed at the factory. This is intended to reduce field installation costs.

There are site specific, application specific, and market specific cost drivers that may impact the form factor for a particular project. BMCD is not selecting a unique design basis, but the sizing process and criteria would be similar among all three technologies and all three form factors. The project is sized to accommodate the power and energy requirements at the point of interconnection (POI), and to account for performance degradation and subsequent augmentation.

Table 19 below shows the assumed losses for system components. The gross power output is sized to accommodate for the system losses, to achieve an output capability of 200 MW at the POI.

Table 19: BESS System Losses and Assumptions

BESS System Losses and Assumptions	
POI Rating (MW)	200
Duration (Hours)	4
Line Loss GSU to POI (%)	0.05%
GSU Loss (%)	0.50%
Auxiliary Load (%)	3.0%
Line Loss PCS Transformer to GSU (%)	0.3%
PCS Transformer Loss (%)	0.73%
Total Losses for Sizing PCS Inverters	4.58%
Gross MW Required	209

The power requirements detailed above are used to determine the inverter sizing and quantities. Table 20 shows the assumptions for power output based on an assumed inverter size.

Table 20: BESS Inverter Sizing

BESS Sizing for Power	
Inverter Power (MW)	2.65
Inverter Quantity	79
Gross MW	209

The battery capacity is sized to provide the gross MW for the design discharge duration. In addition to accounting for the system losses above, additional capacity is added for the inverter losses and battery specific losses. Because energy capacity degrades due to time and cycling behavior, projects with performance guarantees must be designed to account for the degradation. This is done through overbuild and/or augmentation strategies. Overbuild means additional capacity is included in the initial installation and capital cost. Augmentation means that additional batteries are added at intervals during the project life. The initial installation would be designed to accommodate future augmentation.

Overbuild and augmentation strategies are project specific decisions based on a multitude of design and risk factors that essentially assign the costs of performance degradation between capital and operating cost categories. For this study, the initial system was sized for minimal overbuild. While this may not be typical for an actual project, it is done to simplify the variables for capital cost and O&M costs. This is in line with providing the lowest fixed cost, highest variable cost unit because the BESS augmentation is shown entirely as a variable O&M cost. Table 21 shows how the BESS 4-hour option was sized for initial energy capacity. The longer duration options have proportionally larger battery quantities. Augmentation costs are discussed further in the O&M section.

Table 21: BESS Energy Sizing

BESS Sizing for Energy	
Gross Power (MW)	209
Duration (hours)	4
Gross Energy to Cover Power Needs (MWh)	836
Inverter Loss (%)	1.60%
Minimum State of Charge (%)	5.0%
Battery Discharge Loss (%)	4.0%
Gross Energy Initial Installation (MWh)	932
Gross MWh Overbuild Percentage (%)	16.5%

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2. *EPC Cost Estimate*

EPC cost estimates were prepared for a generic site and do not include preliminary engineering or development activities. All information is preliminary and not intended for project budgeting, design, or construction purposes. The capital cost estimates are based on BMCD's experience as an EPC contractor, engineering design firm, and consultant in the power generation and energy storage industries. BMCD has recent project execution experience, consulting experience, and/or proposal experience on simple cycle, combined cycle, and energy storage projects in New York, including New York City. For example, BMCD was part of a joint venture that built a combined cycle plant in Orange County and an Owner's Engineer for a recent combined cycle facility installed in Dutchess County.

Direct costs include the labor, materials, engineered equipment, subcontracts, and construction equipment to construct the facility. This includes site preparation, foundations, structural steel, equipment installation, buildings, associated piping, electrical, and controls tasks. Indirect costs include the construction management, engineering, and startup activities, as well as warranty and general administrative costs. Contingency is included to account for uncertainties in the quantities and pricing, which may increase during detailed design and procurement. In this case, a contingency of 10% was applied to the total direct and indirect project costs, which is typical practice for construction estimates of this type. A 5% EPC contractor fee is also applied to all estimated EPC costs.

- Equipment and Material Costs - Gas turbine costs are based on budgetary estimates from the respective OEMs. Other equipment and material quantities and costs are based on recent BMCD project costs, designs, and proposals for simple cycle, combined cycle, and energy storage projects. For all technologies, the EPC electrical scope ends at the high side of the generator step up transformer (GSU). GSU cost and installation are included in the EPC cost. For BESS options, the battery pricing was based on recent BMCD EPC proposals for storage projects and Owner's Engineering experience on large utility scale storage projects.
- Labor - Labor costs are based on man-hour durations within each craft multiplied times the respective labor rates. Costs are based on the EPC contractor self-executing the steel, piping, and equipment scopes. All other craft scopes are assumed to be subcontracted. Construction craft base pay and supplemental (fringe) benefits were obtained from the RSMeans Labor Rates for the Construction Industry (RSMeans) for the nearest municipality to each Load Zone evaluated. RSMeans is an industry standard construction cost database that includes locational labor rates that are updated annually. Burdened labor rates were developed by adding Federal Insurance Contributions Act (FICA) tax, state and federal unemployment taxes, general liability insurance, and workmen's compensation insurance. All-in wage rates were developed by adding allowances for small tools, supervision, construction equipment, and subcontractor overhead and profit. Work is assumed to be performed on a 50-hour work week by qualified union craft labor available in the respective area.

  Direct installation labor man-hours for the base cost estimates are for an ideal location and must be adjusted for locations where productivity is reduced due to a variety of factors, including weather, union rules, construction parking and laydown space limitations, etc. Based on BMCD experience, man-hours were multiplied by a labor productivity factor for each Load Zone evaluated.
- Energy Storage –Estimates for the BESS options were developed through a similar process. Due to an increasingly dynamic storage market, BMCD intends for the BESS sizing, capital costs, and O&M

costs to be indicative of the competitive market, not a specific technology or form factor.

3. *Owner's Costs*

Owner's costs include allowances for items such as development activities, project management oversight, Owner's Engineer, legal fees, financing fees, ERCs, fuel inventories, builder's risk insurance, and additional contingency. In Appendix B, BMCD includes the interconnection costs under the Owner's cost umbrella, but those items are discussed in more detail in the following sections.

Owner's costs can vary greatly depending on the Owner and project opportunity. Key assumptions for Owner's costs are included below:

- Owner development, oversight, and management related activities are duration-based, with assumptions for personnel cost for the Owner and/or consultants, plus expenses. Temporary utilities are duration-based costs for power consumed during construction.
- Allowances are included for spare parts, legal fees, permitting fees, and area development concessions that often arise as part of project permitting/siting.
- Applicable ERC price assumptions for NO_x and VOCs in each location are based on discussions with emissions brokers familiar with the current ERC market in New York. The price assumptions are shown in Table 22.
- The Startup and Testing Consumables allowance accounts for fuel and consumables during startup. Initial fuel inventory accounts for 96 hours of fuel oil storage for fossil unit options that include dual fuel capability. The tank and related infrastructure for fossil unit options that include dual fuel capability are included in the EPC cost.
- The Builders risk insurance allowance is based on 0.45% of the EPC capital cost.
- Owner's contingency is based on 5% of the total installed cost including EPC and all Owner's costs.

Table 22: ERC Price Assumptions

	C-Central	F-Capital	G-Dutchess	G-Rockland	J-New York City	K-Long Island
NO_x ERCs ($/ton)	$1,000	$1,000	$1,000	$6,500	$6,500	$6,500
VOC ERCs ($/ton)	$3,000	$3,000	$3,000	$7,000	$7,000	$7,000

Construction financing costs, including Allowance for Funds used during Construction (AFUDC) and Interest during Construction (IDC) were estimated at 7% of total EPC and non-EPC costs.

4. *Electrical Interconnection Costs*

Interconnection costs include Minimum Interconnection Standard (MIS) costs and, if applicable, System Deliverability Upgrade (SDU) costs. The NYISO planning department conducted deliverability analysis to determine whether any of the simple cycle plant options or BESS options being evaluated may require SDUs to obtain Capacity Resource Interconnection Service (CRIS). This analysis determined that all peaking plant options in all locations (simple cycle fossil units and BESS options) could be developed without a requirement to incur any SDU costs. Therefore, no SDU costs are included for any of the simple cycle or BESS options evaluated in this study.

Given that the combined cycle plant options are presented for informational purposes only, no deliverability assessment was conducted for these plants. As a result, no SDU costs have been included in the estimates developed for this study for the informational combined cycle options.

MIS costs are comprised of Developer Attachment Facilities (DAF), System Upgrade Facilities (SUFs) at the POI, SUFs beyond the POI, and Connecting Transmission Owner (CTO) Attachment Facilities (AF). The DAF costs begin at the high side bushing of the GSU. The cost of the GSU is included in the EPC estimate. BMCD included separate estimates for the plant switchyard and the interconnecting transmission line in the Owner's costs.

The interconnecting transmission line between the plant switchyard and the POI is assumed to be one mile long in Load Zone J (New York City) and three miles long in all other locations. The transmission interconnection in Load Zone J is assumed to be installed underground,[22] while interconnecting transmission lines in all other locations are assumed to be installed overhead.

The cost of the plant switchyard was based on the assumptions below:

- Air insulated switchgear (AIS) for all Load Zones except Load Zone J, which would include gas insulated switchgear (GIS) technology.[23]
- 345 kV high side voltage for all Load Zones except Load Zone K, which is assumed at 138 kV
- 5-position ring bus for 3x SGT-A65 option
- 3-position ring bus for 1x 7F.05, 1x 7HA.02, and BESS options
- 4-position breaker and a half configuration for the informational combined cycle plants

The costs for the switchyard, interconnecting transmission line to POI and SUFs at POI were estimated by BMCD. Budget pricing was obtained for the major electrical components. Bulk materials costs, installation labor costs, construction indirect and other indirect costs such as design, engineering and procurement were factored into the estimates developed for this study.

[22] According to Con Edison Transmission Planning Criteria (TP-7100-18) and its fundamental design principles, underground transmission is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, nearly all existing transmission in New York City is already underground. As a result, BMCD assumed an underground interconnection for the plants evaluated in this study.

[23] According to Con Edison Transmission Planning Criteria (TP-7100-18) and its fundamental design principles, GIS switchyard is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, it is BMCD's experience that power generation facilities and switchyards in dense urban areas such as those in Load Zone J require GIS facilities due to space constraints and aesthetic considerations.

5. Gas Interconnection Cost

Based on BMCD's experience with gas laterals, an installed pipeline cost of $180,000 per inch diameter per mile was used as the base assumption for the gas interconnection in all Load Zones except Load Zone J. Recent projects in New York and Connecticut suggest that 5 miles is a reasonable assumption for gas pipeline lateral length.[24] BMCD developed costs reflecting an average gas lateral length of five miles, with a 12-inch diameter pipeline for the 3x SGT-A65 and 7F.05 options and 16-inch diameter pipeline for the 7HA.02 options (both for the simple cycle options and informational combined cycle plants). The average cost for a metering and regulation station was estimated at $3.5 million in all Load Zones except Load Zone J.

These costs represent a generalized estimate to interconnect with either an interstate natural gas pipeline or a gas local distribution company (LDC) distribution system. As described above, units with dual fuel capability are expected to have greater geographic siting flexibility, including the ability to interconnect with an LDC. Interconnection costs to an LDC may be higher or lower than comparable interconnection costs to an interstate pipeline, depending on a multitude of factors including distance, terrain, and existing right-of-way.

It is reasonable to expect that the interconnection for Load Zone J would be shorter than the five mile length estimated above for all other locations, but the difficulty of installing a pipeline in New York City would likely offset any savings from a shorter distance. This would result in an installed pipeline cost greater than the $180,000 per inch diameter per mile assumed for all other locations. BMCD believes that a non-site-specific allowance for Load Zone J of $20 million for a 1 mile 12-inch or 16-inch diameter interconnect to an LDC pipeline plus a metering station is reasonable to account for the increased costs expected for gas interconnection within New York City.

6. Summary of Capital Investment Costs

Capital investment costs for each location and technology option are summarized in the tables below. Fossil simple cycle options for Load Zones C and F assume natural gas only projects, while dual fuel projects are assumed in all other locations. SCR emissions control technology is included for all informational combined cycle plants and SGT-A65 options in all locations. For the 7F.05 and 7HA.02 simple cycle units, SCR emissions controls are included only for Load Zones G (Rockland County), J, and K. The 7F.05 and 7HA.02 simple cycle units for Load Zones C, F, and G (Dutchess County) assume that the units would elect to be subject to an annual operating hours limitation to allow for avoidance of the need to install SCR emissions controls. Add/deduct costs for these options are included in the cost buildups in Appendix B. Capital costs in $/kW units are based on the total capital cost divided by the ICAP performance of each plant option evaluated.

[24] For example, CPV Valley in Middletown, NY included a gas interconnect that was 7.8 miles long. The length of the gas interconnect for the proposed Killingly Energy Center in CT is anticipated to be 2.8 miles long.

Table 23: Capital Cost Estimates ($2020 million)

	C-Central	F-Capital	G-Dutchess	G-Rockland	J-New York City	K-Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	$304	$307	$327	$339	$405	$346
1x0 GE 7F.05 (with Dual Fuel and SCR)	$267	$270	$275	$287	$366	$306
1x0 GE 7F.05 (with Dual Fuel, without SCR)	-	-	$253	-	-	-
1x0 GE 7F.05 (Gas Only, without SCR)	$223	$226	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$354	$357	$362	$374	$460	$399
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	-	-	$313	-	-	-
1x0 GE 7HA.02 (Gas Only, without SCR)	$271	$274	-	-	-	-
Informational Combined Cycle Plants						
1x1 GE 7HA.02 (with SCR)	$674	$688	$737	$786	$934	$875
Energy Storage						
BESS 4-hour	$311	$313	$316	$327	$393	$333
BESS 6-hour	$433	$437	$441	$457	$531	$470
BESS 8-hour	$556	$561	$566	$587	$669	$607

Table 24: Capital Cost Estimates ($2020/kW)

	C-Central	F-Capital	G-Dutchess	G-Rockland	J-New York City	K-Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	$1,918	$1,935	$2,063	$2,136	$2,550	$2,178
1x0 GE 7F.05 (with Dual Fuel and SCR)	$1,290	$1,299	$1,313	$1,375	$1,743	$1,454
1x0 GE 7F.05 (with Dual Fuel, without SCR)	-	-	$1,210	-	-	-
1x0 GE 7F.05 (Gas Only, without SCR)	$1,075	$1,085	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$1,030	$1,034	$1,043	$1,077	$1,318	$1,144
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	-	-	$948	-	-	-
1x0 GE 7HA.02 (Gas Only, without SCR)	$829	$835	-	-	-	-
Informational Combined Cycle Plants						
1x1 GE 7HA.02 (with SCR)	$1,361	$1,380	$1,473	$1,571	$1,860	$1,742
Energy Storage						
BESS 4-hour	$1,554	$1,567	$1,580	$1,636	$1,968	$1,665
BESS 6-hour	$2,167	$2,186	$2,205	$2,285	$2,656	$2,349
BESS 8-hour	$2,779	$2,805	$2,829	$2,934	$3,343	$3,033

F. Fixed & Variable Operating and Maintenance Costs

In addition to the initial capital investment, there are other costs associated with the simple cycle, informational combined cycle, and energy storage options. These include fixed operating and maintenance (O&M) costs, variable O&M costs, and fuel costs. The following sections describe the components that are included in the fixed O&M and the variable O&M. Appendix B contains tables that provide a breakdown of the fixed and variable O&M cost estimates for each technology in each location evaluated.

1. Fixed O&M Costs

The fixed O&M includes two components, fixed plant expenses and fixed non-operating expenses. Fixed plant expenses are O&M expenses that are not affected by plant operation (i.e. not related to fuel consumption or annual electric generation).

a. Fixed Plant Expenses

Fixed O&M costs were developed using BMCD proprietary tools that generate cost estimates for plant staff labor, routine maintenance, training, laboratory expenses, safety equipment, building and grounds maintenance, and administrative and general costs.

The plant staff labor costs are based on the staffing levels in Table 25. The full time equivalent (FTE) employees are comprised of O&M staff, management and administrative staff. Energy storage facilities are assumed to be remotely monitored by existing Owner staff, and therefore the fixed O&M results do not include labor personnel costs.

Table 25: Staffing Levels and Salaries Used for O&M Estimates

	C - Central	F - Capital	G (Dutchess)	G (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	7	7	7	7	7	7
1x0 GE 7F.05	7	7	7	7	7	7
1x0 GE 7HA.02	7	7	7	7	7	7
Informational Combined Cycle Plants						
1x1 GE 7HA.02	22	22	22	22	22	22
Annual Salary (Wage plus Benefits)						
Full-Time Equivalent Personnel	$126,000	$136,000	$179,000	$188,000	$241,000	$209,000

BMCD escalated the labor rates from the 2016 DCR for this study using the cumulative change in the average wage rates for the respective Load Zone areas in the RSMeans Labor Rates for the Construction Industry since 2016. Note that the labor rates from the RSMeans source were not used for O&M personnel wage rates, but the average labor escalation is anticipated to be reflective of general labor trends. In assessing the plant staff average labor rate and benefits, BMCD examined the 2019 – 2020 prevailing wage rate information for Operating Engineer codes for representative labor districts in each Load Zone. For the districts in Load Zones C, F, G, and K, the

Operating Engineer Class A categories tracked within 0.5% - 8.5% of the escalated DCR assumptions when considering 2,000 hours at the prevailing wage plus supplemental benefits. For Load Zone J, the Operating Engineer Group 28 was used for a proxy for power plant operator. The annual salary using the prevailing wage was 15% lower than the escalated DCR value. Because the prevailing wage labor categories were broad and not necessarily specific to power generation equipment, BMCD used this information as proxies to evaluate the reasonableness of using escalated wage rates from the 2016 DCR. This evaluation indicated that the use of escalated wage rates from the 2016 DCR is a reasonable assumption for this study.

b. Site Leasing Costs

The site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. BMCD developed site leasing costs using values 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).

Table 26: Site Leasing Cost Assumptions ($2020)

	New York City	Long Island	Load Zones C, F, and G
Land Requirement - Simple Cycle Options (acres)	12	15	15
Land Requirement – Informational Combined Cycle (acres)	27	30	30
Land Requirement - BESS 4-hour (acres)	9	12	12
Land Requirement - BESS 6-hour (acres)	12	15	15
Land Requirement - BESS 8-hour (acres)	15	18	18
Lease Rate ($/acre-year)	$270,000	$26,000	$22,000

c. Total Fixed Operations and Maintenance

The total fixed O&M expenses including the fixed plant expenses and site leasing costs are shown in Table 27. As described below, property taxes and insurance are estimated separately as a percentage of total installed costs. Property taxes and insurance are not included in Table 27.

Table 27: Fixed O&M Estimates ($2020/kW-year)

	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies[1]						
3x0 Siemens SGT-A65	$14.69	$15.32	$17.20	$17.20	$38.06	$18.84
1x0 GE 7F.05	$11.25	$11.67	$13.06	$13.06	$28.73	$14.22
1x0 GE 7HA.02 (with SCR)	$7.94	$8.19	$9.02	$9.02	$18.46	$9.72
1x0 GE 7HA.02 (without SCR)	$8.36	$8.61	$9.49	-	-	-
Informational Combined Cycle Plant[2]						
1x1 GE 7HA.02 (with SCR)	$11.37	$11.92	$13.75	$13.75	$29.42	$15.19
Energy Storage[3]						
BESS 4-hour	$6.30	$6.30	$6.30	$6.30	$17.15	$6.55
BESS 6-hour	$7.85	$7.85	$7.85	$7.85	$22.40	$8.15
BESS 8-hour	$9.45	$9.45	$9.45	$9.45	$27.70	$9.80

Notes:
[1] Based on degraded performance at ICAP conditions
[2] Based on degraded, unfired performance at ICAP conditions
[3] Based on 200,000 kW net output at point of interconnection.

d. Taxes

Property taxes are equal to the product of (1) the unadjusted property tax rate for the given jurisdiction, (2) an assessment ratio, and (3) the market value of the plant, reflecting the installed capital cost exclusive of any SDU costs.

Outside of New York City, the effective property tax rate is assumed to be 0.9% for all fossil peaking plant technology options based on the assumption that the plant will enter into a Payment in Lieu of Taxes (PILOT) agreement, which will be effective for the full amortization period. PILOTs are typically developed based on project specific and regional economic conditions and are expected to vary based on the unique circumstances of each county and project at the time of negotiations. A 0.75% rate was used in the prior two resets. However, a review of

PILOT data available from the New York State Comptroller's Office indicated that 0.9% is a reasonable assumption for this study that is consistent with current PILOTs agreements for natural gas plants in New York.[25]

In New York City, the property tax rate equals 4.7%, which is equal to the product of (1) the Class 4 Property rate (10.5%) and (2) the 45% assessment ratio.[26]

However, the New York Real Property Tax Law Section 489-BBBBBB(3)(b-1) provides a 15-year tax abatement in New York City for the peaking plant underlying the NYC ICAP Demand Curve.[27] Accordingly, it is assumed that each simple cycle fossil peaking plant option receives this exemption and incurs taxes only for years 16 and beyond.

Energy storage plants are provided a 15-year tax abatement statewide pursuant to New York Real Property Tax Law Section 487.[28] A 15 year property tax exemption is assumed for all battery storage plants in all locations for this study.

The informational combined cycle plant is assumed to pay the same 0.9% effective property tax rate as simple cycle peaking plants for locations outside New York City. This plant is not assumed to be eligible for the New York City tax abatement applicable to the simple cycle plant options. As a result, the informational combined cycle plant is assumed to be subject to the 4.7% property tax rate in all years.

e. Insurance

Insurance costs are estimated as 0.6% of the EPC capital cost. This same assumption was used for the last two DCRs. This cost assumption is also consistent with values identified from prior BMCD consulting experience in New York.

2. Variable O&M Costs

For fossil plants, variable O&M costs are directly related to plant electrical generation. Where applicable, variable O&M costs include routine equipment maintenance, makeup water, water treatment, water disposal, ammonia (if SCR emissions controls are included in the design), SCR catalyst replacements (if applicable), CO catalyst replacements (if applicable), and other consumables not including fuel. In the tables in Appendix B, variable O&M for water and SCR emissions controls related items are shown separately.

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[25] The Office of the New York State Comptroller provides financial data for local governments, including Industrial Development Agencies (IDA). *See* http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm AGI identified PILOT agreements for 9 natural gas plants, with effective PILOT tax rates ranging from 0.25% to 2.14%, and the median value of these rates was 0.93%. These projects include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large combined cycle units. AGI did not review recent PILOT payments for nuclear units, which may have a different long-term outlook for energy revenues than gas plants.

[26] *See* http://www1.nyc.gov/site/finance/taxes/property-tax-rates.page and https://www1.nyc.gov/site/finance/taxes/property-determining-your-assessed-value.page.

[27] *See* New York Real Property Tax Law, Section 489-aaaaaa et seq.

[28] See https://www.tax.ny.gov/research/property/assess/manuals/vol4/pt1/sec4_01/sec487.htm

Simple cycle plants do not include demineralized water treatment systems in the EPC capital cost, so the O&M assumptions include temporary demineralized water trailers for treatment, as applicable. Demineralized water is assumed for water injection for NO_x control for fuel oil operation on all turbines options if dual fuel capability is included in the design and for gas operation on the SGT-A65 units. This is reflected in the higher cost for water related O&M for those cases. The 7F.05 and 7HA.02 units have dry combustion on gas operation. Water consumed for inlet evaporative cooling is not demineralized. The informational combined cycle option includes an onsite demineralized water treatment system. Raw water source is assumed to be wells or surface water for all Load Zones except Load Zone J. In Load Zone J, use of municipal water is assumed at $5 per 1,000 gallons.

Major maintenance, shown in Table 28, for combustion turbines is broken out separately from routine variable O&M for all fossil options. Combustion turbine major maintenance typically consists of combustion inspections, hot gas path inspections, and major inspections. Cost estimates account for a complete cycle through the first major inspection, based on manufacturer budgetary estimate information and BMCD's experience.

Major maintenance costs for the SGT-A65 are estimated on dollar per gas turbine hourly operation ($/GTG-hr) basis and are not affected by number of starts. Estimates are shown for one turbine and should be multiplied by three when all three turbines are in operation.

Major maintenance costs for the frame engine options (7F.05 and 7HA.02) are dependent on the operating profile, so they may be based on dollar per gas turbine start ($/GT-start) basis or dollar per gas turbine hour. In general, if there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27 hours per start, maintenance will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive. The operational profile determines whether the annual maintenance costs will be based on hours or starts.[29]

A summary of the non-major-maintenance variable O&M cost for each fossil technology option in each location is provided in Table 29 and Appendix B.

[29] As shown in Table 45, none of the studied units run for an average of more than 27 operating hours per start, so the major maintenance costs are all calculated as start-based.

Table 28: Major Maintenance ($2020 USD)

		C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies							
3x0 Siemens SGT-A65	$/GT-hour	$190	$190	$190	$190	$190	$190
	$/start	N/A	N/A	N/A	N/A	N/A	N/A
1x0 GE 7F.05	$/GT-hour	$350	$350	$350	$350	$350	$350
	$/start	$9,500	$9,500	$9,500	$9,500	$9,500	$9,500
1x0 GE 7HA.02 (with SCR)	$/GT-hour	$600	$600	$600	$600	$600	$600
	$/start	$16,200	$16,200	$16,200	$16,200	$16,200	$16,200
1x0 GE 7HA.02 (without SCR)	$/GT-hour	$600	$600	$600	$600	$600	$600
	$/start	$16,200	$16,200	$16,200	$16,200	$16,200	$16,200
Informational Combined Cycle Plant							
1x1 GE 7HA.02 (with SCR)	$/GT-hour	$600	$600	$600	$600	$600	$600
	$/start	$16,200	$16,200	$16,200	$16,200	$16,200	$16,200

Table 29: Natural Gas Variable O&M Costs ($2020/MWh)

Natural Gas Variable O&M		C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies							
3x0 Siemens SGT-A65	With SCR	$10.07	$9.95	$9.85	$9.85	$10.17	$9.72
1x0 GE 7F.05	With SCR	$1.48	$1.48	$1.48	$1.48	$1.50	$1.48
	No SCR	$0.90	$0.90	$0.90	N/A	N/A	N/A
1x0 GE 7HA.02 (25 ppm)	With SCR	$1.37	$1.37	$1.36	$1.36	$1.39	$1.36
1x0 GE 7HA.02 (15 ppm)	No SCR	$0.90	$0.90	$0.90	N/A	N/A	N/A
Informational Combined Cycle Plant							
1x1 GE 7HA.02 (25 ppm)	With SCR	$1.55	$1.55	$1.55	$1.55	$1.57	$1.54

Notes:
[1] Excludes fuel consumed and revenues from electricity produced during start.
[2] Based on natural gas operation at 59 deg / 60% RH. Informational combined cycle based on unfired baseload operation.

Variable O&M for BESS options is included to account for capacity augmentation over time. Per Section II.B.6, all lithium-ion batteries experience performance degradation based on age and cycling behavior. Capacity augmentation means that batteries are added to the system over its life to maintain the full discharge duration at rated capacity. Recent market trends indicate that battery integrators and OEMs are commonly offering fixed or annual pricing for performance and/or capacity guarantees rather than an explicit variable pricing model that would be more comparable to fossil technologies. While variable pricing structures may not represent the recent trend, BMCD has reviewed proposals and/or contracts with variable pricing structures on past projects. For modeling comparisons with fossil technologies, it was desirable to model the augmentation as a variable cost for purposes of this study.

Battery performance degradation differs depending on the battery chemistry, discharge duration, and cycling behavior. However, based on curves received from multiple vendors for recent projects with similar use cases (approximately 365 deep discharge cycles per year), it is reasonable to assume a 2% annual degradation rate for modeling purposes. BMCD modeled capacity augmentation as a levelized cost over the project life, shown in terms of dollars per MWh discharged.

When calculating the estimates for augmentation, BMCD considered two key pricing factors:

- It is widely assumed in the industry that lithium-ion battery pricing will continue to decline over the upcoming decade. Due to confidentiality, battery pricing for augmentation is not based on forward pricing information provided by battery OEMs. Instead, future battery pricing for the augmentation events considered publicly available battery pricing projections (developed by others).
- BMCD also considered a modest learning rate for battery installers.

The variable O&M cost estimate result is $12.00/MWh for all BESS options. The combined fixed plus variable O&M results in this DCR are consistent with recent proposals and estimates reviewed by BMCD for similar systems and use cases.

G. Operating Characteristics

The plant operating characteristics used to evaluate the fossil technology options in each Load Zone are:

- Summer and winter degraded capacity ratings, summer dependable maximum net capability (DMNC), winter DMNC and ICAP plant capacity (net output) and net heat rate (fuel efficiency);
- Average degradation of net capacity and net heat rate as plant ages;
- Equivalent demand forced outage rate (EFORd); and
- Plant startup time and fuel required for startup.

The net output and net heat rate for all the combustion turbine and combined cycle technology options are impacted by ambient conditions (temperature and relative humidity) and site elevations. The site elevations in each Load Zone are defined in Table 30.

Table 30 also provides the ambient temperatures and relative humidity for the summer, winter, summer DMNC, winter DMNC and ICAP. The summer and winter ambient conditions in each Load Zone are determined at the average winter and summer conditions. The summer and winter DMNC ambient conditions in each Load Zone are determined at the average of the ambient conditions recorded at the time of the applicable Transmission District's seasonal peak during the previous four like Capability Periods, as recorded at the nearest approved weather station. The ICAP ambient condition is defined as 90°F and 70% relative humidity. The ICAP DMNC value is used to express capital costs and fixed O&M on an equivalent $/kW and $/kW-year basis. Ambient conditions for summer average, winter average, summer DMNC, and winter DMNC are based on data from 17 New York airports provided by the NYISO. The temperature inputs from applicable airports were used to determine the ambient conditions based on the weighted inputs and methodology set forth in the NYISO Installed Capacity Manual. Net EAS revenues utilize performance values (e.g., heat rate) associated with average summer and winter conditions, respectively, since net EAS revenues are calculated throughout the full year.

Table 30: Ambient Conditions for Current DCR

Load Zone	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity (%)
C - Central	421	Summer	64.4	76.0
		Winter	32.0	74.4
		Spring-Fall	59.0	60.0
		Summer DMNC	88.9	57.7
		Winter DMNC	10.8	55.7
		ICAP	90.0	70.0
F - Capital	275	Summer	65.5	69.1
		Winter	33.1	65.6
		Spring-Fall	59.0	60.0
		Summer DMNC	89.4	54.7
		Winter DMNC	13.2	59.1
		ICAP	90.0	70.0
G - Dutchess County	165	Summer	67.1	77.2
		Winter	36.0	75.5
		Spring-Fall	59.0	60.0
		Summer DMNC	92.9	51.5
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
G - Rockland County	165	Summer	67.1	77.2
		Winter	36.0	75.5
		Spring-Fall	59.0	60.0
		Summer DMNC	92.9	51.5
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
J - New York City	20	Summer	70.7	66.4
		Winter	41.2	60.9
		Spring-Fall	59.0	60.0
		Summer DMNC	93.3	58.8
		Winter DMNC	21.1	46.4
		ICAP	90.0	70.0
K - Long Island	16	Summer	67.8	77.3
		Winter	39.5	69.2
		Spring-Fall	59.0	60.0
		Summer DMNC	88.8	59.0
		Winter DMNC	16.5	50.2
		ICAP	90.0	70.0

The detailed plant performance data for each technology option in each location is provided in Appendix B.

Gross performance results for SGT-A65 option are based on Siemens Performance Estimating Program (SiPEP). Gross performance ratings for 7F.05 and 7HA.02 options are based on data requested from GE at performance points across a range of ambient conditions and adjusted for differences between these conditions. All performance ratings shown are based on natural gas operation. Minimum load is defined as the minimum emissions compliant load (MECL), as reflected in the OEM ratings. Appendix B includes full load and minimum load performance estimates at the conditions identified in Table 30 above.

BMCD adjusted these performance results for auxiliary loads, system losses, and performance degradation. Heat rates are calculated for higher heating value (HHV). The power plant performance begins to degrade once the facility begins to operate. Some of the degradation is not recoverable, however, most of the performance loss is recovered after major equipment overhauls. The plant performance degradation percentages used to calculate degraded output and heat rate from new and clean percentages are shown in Table 31. These degradation adjustments are indicative of average degradation between overhauls, based on BMCD experience on past projects. The same adjustment values were also assumed for the 2016 DCR.

The degraded net plant capacity and degraded net plant heat rates at the ICAP ambient conditions (90°F and 70% relative humidity) for each Load Zone are shown in Table 32 and Table 33, respectively. Performance for all ambient conditions is provided in Appendix B. Average degraded net plant capacities are used throughout the economic analysis as described in Sections III and IV. The use of the average degraded net plant capacity is used to reflect expected operations over the life of the plant.

Table 31: Average Plant Performance Degradation over Economic Life

Plant	Average Degradation of Net Output	Average Degradation of Net Heat Rate
3x0 Siemens SGT-A65	2.5%	0.8%
1x0 GE 7F.05	3%	1.8%
1x0 GE 7HA.02	3%	1.8%
1x1 GE 7HA.02 Combined Cycle (Informational)	1.8%	1.1%

Table 32: Average Degraded Net Plant Capacity ICAP (MW)

Natural Gas (MW)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	159	159	159	159	159	159
1x0 GE 7F.05	207	208	209	209	210	210
1x0 GE 7HA.02 (with SCR)	344	346	347	347	349	349
1x0 GE 7HA.02 (without SCR)	327	329	330	N/A	N/A	N/A
Informational Combined Cycle Plant						
1x1 GE 7HA.02 (with SCR)	495	499	501	501	502	503

Note:
[1] Based on degraded ICAP performance. Informational combined cycle option is base load, unfired performance.

Table 33: Average Degraded Net Plant Heat Rate ICAP (Btu/kWh)

Natural Gas (Btu/kWh)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	9,730	9,730	9,730	9,730	9,720	9,720
1x0 GE 7F.05	10,360	10,360	10,360	10,360	10,360	10,360
1x0 GE 7HA.02 (with SCR)	9,460	9,460	9,460	9,460	9,460	9,460
1x0 GE 7HA.02 (without SCR)	9,490	9,380	9,490	N/A	N/A	N/A
Informational Combined Cycle Plant						
1x1 GE 7HA.02 (with SCR)	6,410	6,400	6,400	6,400	6,410	6,410

Note:
[1] Based on degraded ICAP performance. Informational combined cycle option is base load, unfired performance.

Table 34: BESS Net Power at POI

Net Power (MW)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Energy Storage						
BESS 4-hour	200	200	200	200	200	200
BESS 6-hour	200	200	200	200	200	200
BESS 8-hour	200	200	200	200	200	200

Note:
[1] BESS is sized for 200 MW net at the POI. Energy capacity is maintained through capacity augmentation throughout the project life.
[2] Heat rate is not applicable to BESS units because fuel is not directly consumed.

EFORd is defined as "A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate."[30] The North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS) continuously collects availability/reliability data from more than 7,700 power plants in the US and Canada. The data is organized by plant type, size ranges and plant age ranges. BMCD included EFORd data extracted from NERC GADS based on the performance since 2012 for units that are no more than 10 years old.

The original equipment manufacturers provided start-up times and start up curves that were used to calculate the start-up fuel consumption. The start-up data is included in Appendix B. For the simple cycle frame combustion turbines, both conventional start- up and fast start- up information is provided. The 7HA.02 unit can achieve full output in 10 minutes. The 7F.05 unit can achieve approximately 200 MW in 10 minutes, but full load takes another 1-4 minutes. For the informational combined cycle plants the start-up data is for hot, cold, and warm starts.

III.Gross Cost of New Entry

Gross CONE encompasses all costs associated with plant construction and operations aside from those arising from providing energy and ancillary services, which are addressed in Section IV. Gross CONE includes the recovery of capital costs, including a return on investment. The annualized cost associated with a capital investment reflects the financial parameters described in Section III.A that capture the investor's cost of capital and the period over which the return of and return on the upfront capital investment is assumed to be recovered. Section III.B describes the translation of these up-front capital costs, along with time-varying tax costs, into a levelized fixed charge (e.g., an annual carrying charge) that allows full recovery of the plant's capital costs over the course of the plant's assumed life. Finally, Section III.C provides estimates of the gross CONE, including the levelized fixed charge, fixed O&M expenses, and insurance.

A. Financial Parameters

[30] *See* IEEE-SA Standards Board, "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity" Sponsor Power System Analysis, Computing, and Economics Committee of the IEEE Power Engineering Society Approved December 29, 2006 American National Standards Institute.

The development of a new supply resource requires the upfront investment of new capital to construct the facility. The financial parameters translate these upfront technology and development costs into an annualized value that is an element of gross CONE for each location evaluated. Subtracting the estimated annual net EAS revenues from this annualized gross CONE values produces the annual reference value (ARV), which is often referred to as the net CONE value. That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technologies. This translation from up-front to annualized value is reflected in the so-called “levelization” factor. The parameters that affect the levelization factor (the “financial parameters”) include:

- The weighted average cost of capital required by the developer, based on the developer’s required return on equity (ROE), its cost of debt (COD), and the project’s capital structure, as reflected in the ratio of debt to equity (D/E ratio);

- The term, in years, over which the project is assumed to recover its upfront investment, referred to as the amortization period (AP); and

- Applicable tax rates, which affect the costs of different types of capital.

These elements are not determined in isolation. Appropriate values for these parameters need to reflect the interrelationships among them, and as a whole appropriately reflect the financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market and policy context. While we discuss each item separately below, ultimately our selection of the parameters making up the assumed WACC and the AP is based on an evaluation of how these parameters, in combination, reflect the financial risks of project development.

The selection of these financial assumptions should capture industry expectations of costs, and reflect project-specific risks, including development risks and risks to future cash flows for a merchant developer, based on investor expectations over the life of the project. Many factors can affect investor risks – such as uncertainty and variability in fuel prices and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; the development of energy and environmental policies with implications for industry demand, costs, revenues and the operability of the facility; and the pace and nature of technological change. Further, data that may be available on individual components of the WACC and the AP can vary with factors specific to circumstances, including location, corporate structure, prevailing economic/financial conditions, fuel and electricity market expectations, financial hedges (such as power purchase agreements), and the nature and impact of current and potential future market and regulatory factors.

Ultimately, the recommended WACC and the AP reflect our view of the risks associated with the merchant development of a peaking plant in the NYISO market context, and the return required by investors to compensate for those risks. AGI’s recommendations are based on our professional judgment, reflecting the particular circumstances of merchant development of a peaking plant in the NYISO market context; the sources of information identified and described below; past professional experience, including conversations with developers and people in the finance community; and AGI’s view of industry conditions, market factors, and relevant state policy at the time of this study, including past experience with merchant development in the NYISO markets.

AGI also presents its thoughts on some of the key perspectives with respect to development approaches, key existing and emerging development, market, and regulatory risks that are needed to interpret available data and information. Finally, AGI presents its recommended assumptions for WACC and AP based on our careful review of all of these factors from the perspective of potential resource developers in the New York electricity market.

1. Amortization Period

The AP is the term over which the project developer expects to recover upfront capital costs, including the return on investment. In the context of the DCR model, it is the period of time (in years) over which the discounted cash flow from net EAS revenue streams (net of annual fixed costs) are netted out against the upfront capital investment cost of the peaking plant. In this sense, what is often referred to as the "economic life" of the asset can, in principle, differ materially from the potential physical or operational life of the plant; while the physical life of the plant reflects the expected length of time the plant will remain in operation (usually before major overhauls would be required), the economic life reflects financial considerations, particularly risks associated with assuming future revenue streams in light of market and technological uncertainties.

The AP must balance risks over the full physical life of the plant. On the one hand, plant owners will earn net revenues over the full physical life of the plant (while incurring costs for component replacement and maintenance overhauls over time). Based on extensive operating experience, an expected physical life of at least thirty years is reasonable for a fossil-fueled peaking plant.[31] On the other hand, many factors create risks to future cash flows. These include changes in markets, technologies, regulations, policies, and underlying demand from consumers. To the extent that any of these changes lead to a long-term outlook for revenues that is less than assumed in the current analysis or captured in annual updates, investors would tend to under recover total costs. To account for these risks, investors may seek a shorter AP.

In light of these factors, the 2016 DCR recommended an AP of 20 years for a fossil peaking plant, reflecting the balance of risks and uncertainty faced by project developers.[32] However, we modify this recommendation for fossil peaking plants in light of recent policy development in the State of New York. Specifically, in 2019 the New York enacted the Climate Leadership and Community Protection Act (CLCPA), which requires that all load in New York be supplied by zero-emissions resources as of 2040.[33] In effect, the CLCPA prohibits the operation of a peaking plant in New York burning fossil fuels after 2039. In principle, the owner of a fossil generating facility constructed now could implement plant modifications that would allow the plant to continue to operate, for example, by using a zero-carbon fuel (e.g., hydrogen) or the acquisition of zero-carbon “drop in” fuels that could be used in place of the current fossil fuels. While we recognize this may be possible, the technology and/or markets to accomplish this and continue to operate in compliance with the CLCPA beyond 2039 cannot be assumed to exist at this time. Thus the developer of a fossil peaking plant would face substantial uncertainty about the financial returns of a fossil

[31] Units may require significant capital expenditures to retrofit or upgrade units to maintain in operation. The current analysis does not consider these incremental investments in the discounted cash flow analysis.

[32] Analysis Group, “Study to Establish New York Electricity Market ICAP Demand Curve Parameters,” September 13, 2016.

[33] Chapter 106 of the Law of the State of New York of 2019. Requirements established by the CLCPA include: (1) a goal to reduce GHG emissions 85% over 1990 levels by 2050, with an incremental target of at least a 40% reduction by 2030; (2) producing 70% of electricity from renewable resources by 2030 and 100% from zero-emissions resources by 2040; (3) increasing energy efficiency by 23% over 2012 levels; (4) building 6 GW of distributed solar by 2025, 3 GW of energy storage by 2035, and 9 GW of offshore wind by 2035; (5) electrification of the transportation sector, as well as water and space heating in buildings.

peaking plant under the CLCPA starting in 2040, given the uncertain availability and cost of zero-emission technologies, markets, and alternative fuels.

To evaluate amortization periods for fossil peaking plants under the CLCPA, we estimate the number of years a developer could reasonably assume it would be able to participate in the NYISO markets given the economically viable fossil peaking technologies considered absent upgrades, modifications or other future design changes that could potentially facilitate continued operation as a zero-emission resource beginning in 2040. This time period will vary depending on when the peaking plant commences operations. For example, the developer of a fossil-fueled peaking plant that begins operation at the start of the first Capability Year encompassed by this DCR (i.e., commencing operation on May 1, 2021) should not expect an operating life exceeding approximately 18.7 years (i.e., the time between May 1, 2021 and December 31, 2039) without plant retrofits to remain compliant with the CLCPA's zero-emission requirement beginning in 2040. Similarly, a new plant commencing operations at a later point in time would expect to operate for a shorter economic life. Table 35 shows the economic life a fossil peaking could reasonably assume depending on the Capability Year encompassed by this DCR in which the plant commences operations.

Given these factors, AGI recommends an AP of 17 years for fossil-fueled peaking plant options in all locations evaluated. This is an appropriate assumption given the balance of risks and uncertainty faced by project developers in New York markets. As shown in Table 35, 17 years represents the average economic operating life of a fossil peaking plant over the upcoming four-year period covered by this DCR.

An amortization period of 17 years strikes a reasonable balance between many considerations, including the general regulatory and technological risk faced by investors in fossil fuel resources within New York, the specific operational limits posed by the CLCPA regarding fossil fuel use for electricity generation beginning in 2040, and the uncertainty that exists at this time regarding the availability and cost of conversion technologies and/or fuels that may or may not be available to extend a plant's economic life beyond 2039.

Table 35: Potential Economic Operating Life of Fossil Plants

Capability Year	Potential Operating Life of Fossil Plant	Average Operating Life of Fossil Plant 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:
[1] The potential commercial operating life was calculated by counting the number of years between May 1st of the Capability Year and January 1st, 2040.

The amortization period for battery storage plants face a different set of considerations than fossil peaking plants. Unlike fossil plants, battery storage plants do not face the same regulatory constraint on future operations. On the other hand, there is simply no current experience with battery storage operating for more than 10 years. Thus, battery storage operation generally, and specifically in the New York context, faces a wide range of uncertainties related to the expected economic and physical lifetime of new battery units. These uncertainties include the potential for cell degradation, wear and tear on balance-of-system components, uncertain market dispatch outcomes, and potential variations in operational modes and uses in system operations. Further, because battery storage is still an early-stage technology likely to experience further improvements in operational performance, particularly cycling energy losses, the first wave of battery storage plants to operate in New York may be less competitive than battery units that enter the market at a later date with more advanced technologies. This reduced competitiveness may translate into lower net revenues, particularly toward the end of the amortization period. These technology effects are more significant for battery technologies, given their early state of technological development, compared to fossil peaking technologies.

As discussed in Section II, we partly address some of the uncertainties associated with future battery operations by analyzing battery storage plants in which the augmentation costs to counter battery cell degradation over an extended timeframe are captured in battery variable O&M costs, rather than in up-front capital costs. However, we recognize that given the relative newness of battery storage technologies in power system operations, and the uncertainty associated with both storage facility longevity and market revenues, lenders and investors would likely seek to recover costs on an expedited timeframe relative to existing power system technologies with long-standing operational experience. Considering these factors, we assume an AP for battery storage technologies of 15 years, slightly shorter than that assumed for fossil peaking plant technology options.

2. *Weighted Average Cost of Capital*

The cost of capital for a new peaking plant will reflect the proportion of each source of capital in the project's capital structure – that is, the ratio of debt to equity – and the “cost” of different sources of capital – that is, the required return on equity and the cost of debt. These costs, in turn, reflect the project’s capital structure, because this structure affects the likelihood that debt will be paid and equity will receive returns (in excess of project costs). Thus, the return on equity, cost of debt and capital structure are inter-related.

The appropriate WACC for use in the DCR needs to reflect the project-specific risks associated with the development of a new peaking plant by a merchant developer within the NYCA in the timeframe of interest in this DCR (i.e., 2021-2025). However, data are not available to directly observe the WACC for such a project. As a result, AGI developed its recommended WACC based on data from a number of different sources.

- **Metrics from publicly traded companies.** AGI considered financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets – that is, independent power producers (IPPs). Many IPPs are no longer publicly traded after a series of purchases by private firms.[34] Data on these companies before their purchase include various data

[34] Riverstone Holdings LLC acquired Talen Energy in December 2016, see, “Riverstone completes $5.2B acquisition of Talen Energy,” December 6, 2016, https://www.spglobal.com/marketintelligence/en/news-insights/trending/5183c2giwe8eid5el82qva2; Energy Capital Partners purchased Calpine in March 2018, see, “ Consortium Led by Energy Capital Partners Completes Acquisition of Calpine

or analytic measures of COD, ROE and D/E ratios based on publicly available report data. While such data is not current, it provides insight into the cost of capital in recent years. AGI's assessment considers this data, with an understanding that project-level and company-level WACC values will differ when specific projects are more or less risky than the company as a whole.[35]

- **Independent assessments.** AGI considered a variety of independent assessments, including: estimated WACC for publicly traded companies developed by financial analysts (e.g., in the context of so-called "fairness opinions"); and assessments of the costs of merchant plant development. These independent assessments include information on the WACC under different corporate structures, including so-called "project finance," in which the project is financed as a stand-alone entity without recourse to a company's balance sheet.

AGI's recommendations are based on its professional judgment, reflecting the information and data identified below; past professional experience, including conversations with developers and people in the finance community; and an appropriate balancing of these various sources of information and experiences considering the market risks faced by a new merchant peaking plant being developed within the NYISO markets.

In evaluating this data, AGI views the appropriate WACC for a new peaking plant as bounded from below by the WACCs typical of established IPPs, and from above by the WACCs that are more representative of stand-alone project-financed developments. As noted above, the appropriate cost of capital for a specific project should reflect the particular risks faced by that project, not the risks associated with the company or investors that are considering the development of that project.[36] The WACC for a new merchant project is generally greater than that for publicly-traded IPP companies because these companies tend to have portfolios of assets that balance and mitigate risks, and thus lower the overall WACC at the company level. These portfolios include various financial assets, including financial hedges and long-term contracts, as well as portfolios of physical assets spanning varied geographies (including regions with different load profiles), technologies, fuels and vintages.

On the other hand, AGI assumes that a peaking plant project would not likely be developed through a stand-alone project finance approach by a private entity. Development of the peaking plant through such financing within the NYISO market context could require a higher WACC than through a project developed using the balance sheet of a larger entity, such as a publicly traded IPP (balance sheet financing).[37]

Given these factors, in developing its recommendations, AGI assumes that the WACC appropriate for a new merchant peaking plant in the NYISO market would be greater than the WACC for IPPs, but less than that of a

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Corporation; Announces Management Roles and Board of Directors," March 8, 2018, https://www.ecpartners.com/news/consortium-led-by-energy-capital-partners-completes-acquisition-of-calpine-corporation-announces-management-roles-and-board-of-directors; and Vistra Energy acquired Dynegy in April 2018, see, "Vistra Energy Completes Merger with Dynegy," April 9, 2018, https://investor.vistraenergy.com/investor-relations/news/press-release-details/2018/Vistra-Energy-Completes-Merger-with-Dynegy/default.aspx.

[35] "The company cost of capital is *not* the correct discount rate if the new project is more or less risky than the firm's existing business. Each project should in principle be evaluated at its *own* opportunity cost of capital." Brealey, Richard, Steward Myers, and Franklin Allen, *Principles of Corporate Finance*, Ninth Edition, New York: McGraw-Hill/Irwin, 2008, p. 239.

[36] As noted in one text, "It is clearly silly to suggest that [a company] should demand the same rate of return from a very safe project as from a very risky one." Brealey, Myers and Allen, 2008, p. 240.

[37] Larger entities, including publicly traded IPPs, may use project finance to develop projects.

project-financed project. Below, AGI evaluates the individual financial parameters that bear on the recommended WACC, recognizing these bounds and the interrelationships among these parameters in determining the WACC.

[***Note: The COVID-19 pandemic has caused substantial turmoil in financial markets. Our preliminary recommendations account for these market changes as currently observed, but in light of the on-going changes in the financial markets we continue to monitor these conditions and anticipate revisiting our recommended WACC before the final report to determine whether new information gained about financial markets in the coming months merits additional adjustments.***]

Cost of Debt

The cost of debt reflects a project developer's ability to raise funds on debt markets.

Figure 5 reports the cost of debt issued from January 1, 2017 to present for four power companies with meaningful ownership of merchant units: Calpine Corporation, NRG Energy Inc., Talen Energy Supply LLC, and Vistra Energy Corp. Coupon rates since 2017 largely range from approximately 4% to 8% , although some issuances have required high rates, above 10% in one case.

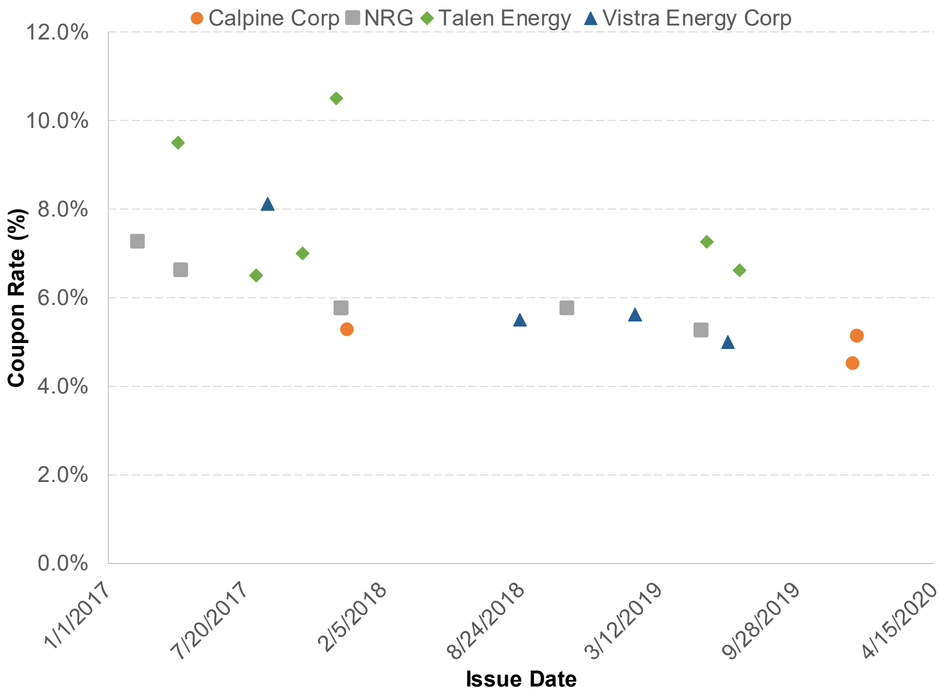
All four companies listed above have issued below-investment grade debt in 2019: Calpine issued debt rated B and BB, NRG and Vistra both issued debt rated BB and BBB-, and Talen's issuances are rated B+.

Figure 5 shows that the BB and B rated debt issued by IPPs has ranged from 4.5% to 7.3% in 2019. To our knowledge, these companies have not issued debt since the onset of COVID-19 pandemic, so this prior data do not help inform how the pandemic has affected debt costs.

AGI also considered data on the generic cost of corporate debt. Figure 6 provides the generic corporate COD for companies with BB and B credit ratings. The figure shows that COD for below-investment grade issues has generally decreased over the past year, with rates falling below 6% prior to the COVID-19 outbreak. Since the outbreak, COD for BB and B generic debt has risen significantly and been highly volatile.

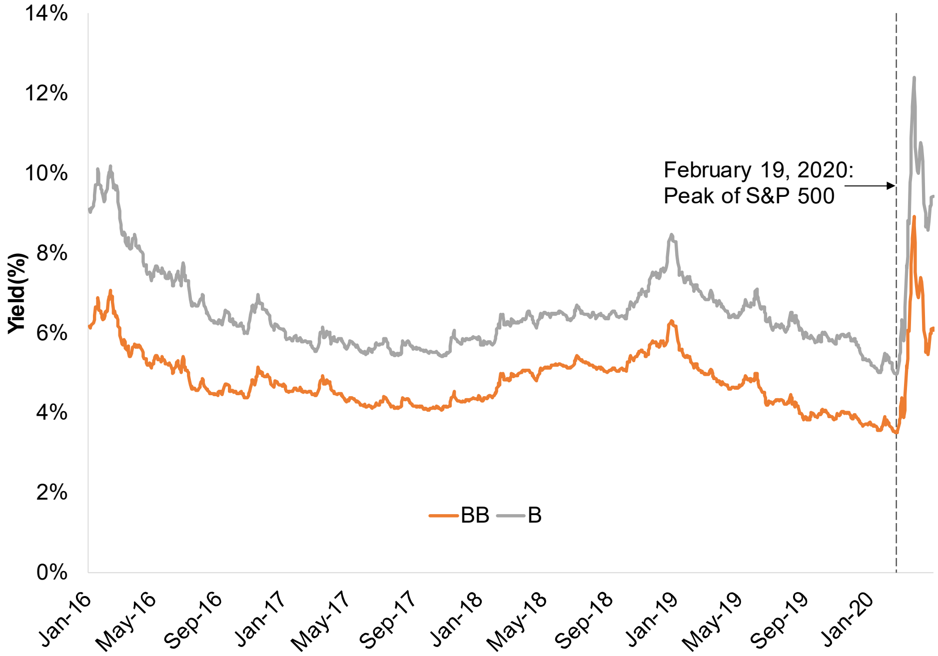
Based on these factors, AGI preliminarily recommends a COD of 7.7%. This recommendation reflects a number of factors, including post-COVID-19 rates for B rated debt, pre-COVID-19 debt rates, and general economic and market conditions, including some expectation of moderation in from levels current experienced in the markets. [***Note: As with other financial parameters, we will continue to monitor financial markets and may update this recommendation given additional information obtained prior to issuing our final report.***]

Figure 5: Cost of B and BB Rated Debt for Independent Power Producers, by Issuance, 2017-2020



Note:
[1] Accessed on March 2020 from Bloomberg, L.P. Additional detail is provided in Appendix C.

Figure 6: Generic Corporate Bond Yields, by Credit Grade



Source:
[1] St. Louis Federal Reserve Bank of St. Louis, FRED. Bank of America Merrill Lynch US and Corporate Index Effective Yields.

Return on Equity

The recommended ROE is developed using data from several sources. One source of data is the estimated return on equity for publicly traded IPPs. In the 2016 DCR, AGI evaluated the cost of equity for four companies, Calpine, NRG Energy, Dynegy and Talen Energy, finding the average cost of equity to be 10.47% and 11.05% based on Bloomberg and Value Line data, respectively. Since that time, Calpine, Dynegy and Talen were acquired by private corporations[38], which do not publicly report their finances. Table 36 reports the estimated ROE for NRG Energy and Vistra Energy based on the capital asset pricing model (CAPM).[39] [40] Appendix C provides further details on these calculations. Company betas are obtained from Value Line and Bloomberg. With Value Line betas, estimated ROEs are 7.75% for Vistra and 10.51% for NRG, with an average of 9.13%. With Bloomberg

[38] Vistra Energy, which acquired Dynegy in 2018, is publically traded. We reviewed Vistra's financial profile as part of our analysis.

[39] Other approaches not used include the Discounted Cash Flow (DCF) and historical risk premium. Similarly, AGI notes that utility regulators may consider a variety of information and models (including CAPM, DCF, or historical risk premiums) when setting the ROE for regulated utilities. Therefore, AGI did not consider a comparison of CAPM estimates of ROEs for regulated utilities when estimating the relevant ROE for a merchant power plant developer. This is consistent with the assumption that the rate of return for a safer project this regulated cost recovery is not the same as the return for a riskier project that does not benefit from guaranteed cost recovery.

[40] We evaluated publicly traded companies operating in electricity markets to identify companies with sufficient activity in merchant power supply to provide useful information on the return on equity for IPPs. Our assessment identified only two companies, NRG Energy and Vistra.

betas, estimated ROEs are 6.57% for Vistra to 9.01% for NRG, with an average of 7.79%. While both NRG and Vistra have substantial merchant generation holdings, they also have substantial holdings in other regulated and unregulated businesses in the electric power sector, including generation facilities operated under long-term contracts and competitive retail supply operations.[41] As these companies' business activities extend outside of merchant power generation and their generation asset holdings reflect a portfolio of assets with various vintages (and contract structures), their return on equity are not necessarily comparable to the required return on equity for a new peaking plant project in New York.

A second source of data is independent estimates of the ROE for new power plants developed in other, but related, contexts. Net CONE studies in neighboring markets provide a benchmark for comparison. PJM and ISO-NE have used ROEs ranging from 12.8% to 13.8% in recent net CONE studies.[42] These values reflect different methodologies and data sources.

A third source of data considered is estimates of the ROE for stand-alone project finance developments. Based on several independent sources, ROEs for stand-alone project finance developed have ranged from approximately the low teens to as high as 20%.[43]

Based on this information, AGI recommends a ROE of 13.0%, reflecting a balance between the lower IPP values (which range up to 10.51%) and higher project finance values. The recommended ROE is near the bottom of the range of WACC values from the previous net CONE studies in PJM and ISO-NE largely reflect the low value of the risk free rate at this time.

Table 36: Cost of Equity for Publically Traded IPPs

Corporation	Ticker	Value Line Beta	Value Line Cost of Equity	Bloomberg Beta	Bloomberg Cost of Equity
NRG Energy Inc	NRG	1.25	10.51%	1.03	9.01%
Vistra Energy	VST	0.85	7.75%	0.68	6.57%
Group Average		1.05	9.13%	0.86	7.79%

Notes:

[1] CAPM estimates are based on a 6.9% market risk premium from Duff and Phelps, SBBI 2019 Classic Yearbook, and a 1.88% risk free rate based on the Thirty-Year Treasury Constant Maturity Rate.
[2] Company beta values are from Value Line and Bloomberg.

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41 *See*, Freitas Jr, Gerson, "Virus May Show How Wall Street Misjudged Two Power Companies," Bloomberg, May 4, 2020.

42 See, The Brattle Group, "PJM Cost of New Entry," April 19, 2018; The Brattle Group, "PJM Cost of New Entry," May 15, 2014; and Newell, Samuel A. and Christopher D. Ungate, "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve," April 1, 2014.

43 *See*, for example, EPA Integrated Planning Model, Chapter 8 Financial Assumptions, which reports a 16.1% ROE at a 55% debt ratio and 3.8% risk free rate; DOE National Energy Technology Laboratory (NETL) (2008), which indicates that a 15% to 20% ROE is common for low and high risk power projects at debt ratios of 50% to 70% (DOE-NETL, "Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects", September 2008.); and Etsy (2003), which notes that Calpine typically sought an 18% to 22% as a project finance developer circa 2002, with a debt ratio of 65%. (Etsy, B. and Kane, M. "Calpine Corporate: The Evolution from Project to Corporate Finance." Harvard Business School, Case Study 9-201-098.) Chadbourne, "Merchant Gas Projects: How Many More?" Project Finance NewsWire, August 2016.

Debt to Equity Ratio

The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of the capital supporting the investment. Thus, a merchant peaking plant project could reasonably be developed through a range of capital structures.

AGI recommends a D/E ratio of 55% debt to 45% equity given a balance of tradeoffs involved with greater or lesser leverage. On the one hand, the capital structure of IPP companies (at the corporate, not the project level) currently reflect lower levels of debt than have been historically carried. Figure 7, which shows the debt share of capital for Calpine, Dynegy, NRG, and Vistra over the past 3 years, illustrates this effect.[44] While corporate level capital structure may not be particularly informative of the appropriate project-level capital structure, we consider the general trend toward lower leverage, given low debt costs (prior to the COVID-19 outbreak), in our assessment.[45]

On the other hand, many sources indicate that the limited fixed revenues streams for a merchant peaking plant in NYISO markets would limit debt level. For example, the California Energy Commission has previously assumed a D/E ratio of 40/60 for merchant fossil generation, while National Energy Technology Laboratory has previously assumed a D/E ratio of 30/70 for merchant combustion turbines.[46] Thus, from the standpoint of these structures, a 55/45 D/E equity ratio appears conservative (i.e., tending to a lower WACC). However, capital structures in other net CONE studies have assumed even higher levels of debt than we assume for this DCR.[47]

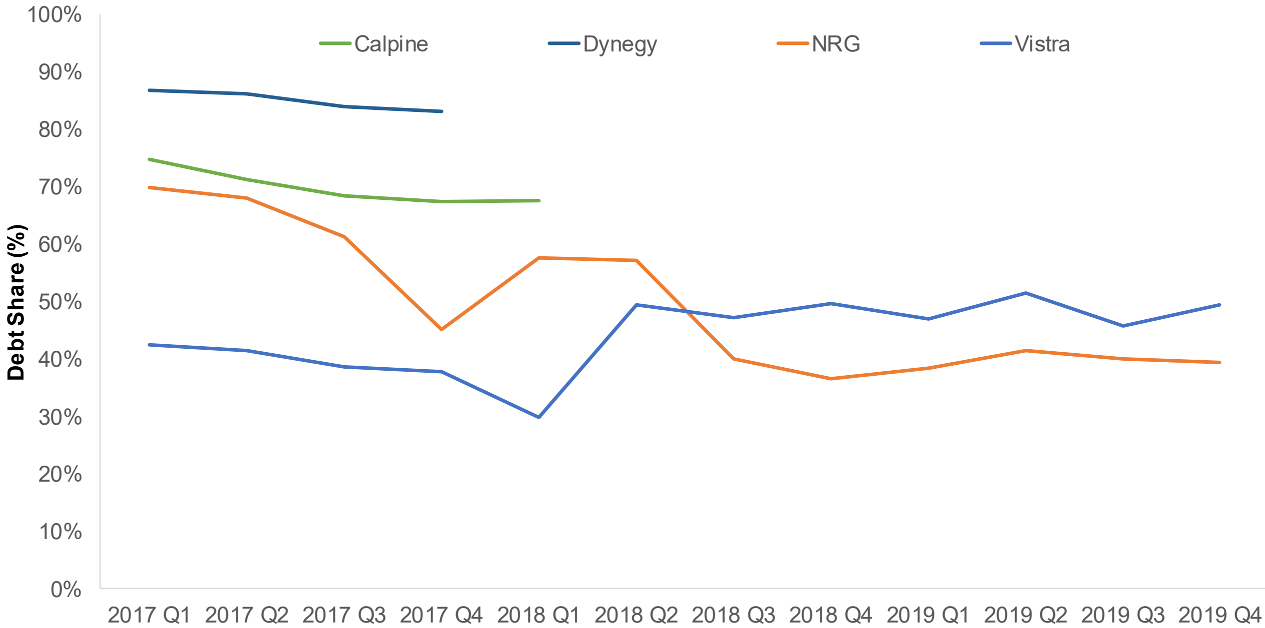
[44] The market value of equity is calculated as enterprise value minus cash and near-cash items; data for the calculations is from Bloomberg, L.P.

[45] Note that deleveraging of these companies (i.e., lower debt share), which was previously expected by the companies themselves and analysts, may place pressure to lower debt levels of individual projects. *See*, e.g., UBS Financial ("We believe all IPPs will accelerate their debt paydown efforts…") (How to Value Power? December 8, 2015.)

[46] California Energy Commission, 2010, p. 59, Table 18; National Energy Technology Laboratory, 2010, p III-18, Exhibit 3-2.

[47] Recent PJM and ISO-NE studies assume debt levels of 60% to 65%. See, The Brattle Group, "PJM Cost of New Entry," April 19, 2018; Concentric Energy Advisors, "ISO-NE CONE and ORTP Analysis," January 13, 2017; The Brattle Group, "PJM Cost of New Entry," May 15, 2014 ; and Newell, Samuel A. and Christopher D. Ungate, "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve," April 1, 2014.

Figure 7: Debt to Capital Share, Independent Power Producers, 2017-2019



Note:
[1] The market value of equity is calculated as the enterprise value minus cash and near cash items.
Source:
[1] Bloomberg L.P., accessed March 2020.

Calculation of the WACC

AGI's assessment of factors related to the calculation of the WACC has considered the data on the following: ROE, COD, and D/E ratios presented above; facts and circumstances unique to the NYISO markets, including the extent of past experience with merchant development; the rapidly-changing nature of federal and state energy and environmental policies, including passage of the CLCPA; and likely project/ownership structures for new peaking plant development in New York. The calculation of the before-tax WACC is shown in equation 1.

$$WACC = Debt\ Ratio * COD + (1 - Debt\ Ratio) * ROE \tag{1}$$

The ATWACC is calculated as shown below in equation 2:

$$ATWACC = Debt\ Ratio * COD * (1 - composite\ tax\ rate) + (1 - Debt\ Ratio) * ROE \tag{2}$$

This calculation reflects the common tax treatment of interest as a deductible expense for corporate income tax purposes. Income taxes reflect Federal tax rates (assumed to be 21%), corporate New York State tax rates (6.5%),[48] and, for Load Zone J, the New York City business corporation tax rate (8.85%).[49] These result in composite income tax rates of 36.35% (NYC) and 27.5% (all other locations).[50]

Using these equations and the considerations presented above, AGI recommends a WACC of 10.09%, based on a debt ratio of 55%, a COD of 7.70%, and a ROE of 13.00%. This results in a nominal ATWACC of 8.92% in NYCA, LI, and the G-J Locality and 8.55% in NYC.

The recommended ATWACC is consistent with previous and currently approved capital cost values in NYISO and other neighboring market (e.g., ISO-NE and PJM) for net CONE evaluations utilized for capacity market purposes. The current ATWACCs in ISO-NE and PJM are 8.1% and 7.5% (respectively), while the current ATWACC for the NYISO as approved during the 2016 DCR is 8.46%. The higher ATWACC proposed for this DCR (as compared to the 2016 DCR) reflects a combination of factors. Relative to the other RTOs, developers within New York may face greater project-specific risk that arises from the lack of long-term contracts, greater uncertainty over the mix of supply and demand resources that will result from changes in regional markets and energy policies over time, expectations for relatively flat load growth over the time period encompassed by this DCR (i.e., 2021-2025), potentially more challenging siting and development opportunities within New York, and potential operational and price impacts of the state’s move towards power sector decarbonization over the next two decades. Relative to the 2016 DCR, the higher ATWACC reflects the slightly lower cost of debt, the changes in tax law, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments.

B. Levelization Factor

To estimate the ARV, it is necessary to translate one time installed capital costs into an annualized cost over the assumed economic life of the plant. This annualized cost is fixed over the plant’s economic life, such that an owner receiving revenues equal to this cost would have enough funds to offset exactly the original upfront investment, including a return on capital. AGI refers to this amount as the levelized fixed charge (e.g., an “annual carrying charge”). This charge reflects both the recovery of and return on upfront capital costs and the tax payments associated with this investment that vary over time due to depreciation schedules and variation in certain tax levels over time (i.e., availability of a 15-year property tax abatement for fossil peaking plant technologies in NYC and for battery storage options in all locations).

The levelization factor is the ratio of the levelized fixed charge to total installed capital costs. This factor is developed in three steps. First, annual costs are calculated as the sum of principal debt payments, interest on debt, income tax requirements, property taxes, and the target cash flow to equity.[51] Second, the net present value

[48] *See* New York Department of Taxation and Finance, Form CT-3/4-I.

[49] *See* http://www1.nyc.gov/site/finance/taxes/business-business-corporation-tax.page.

[50] State and local taxes are no longer deductible from federal corporate taxes, so the composite rate now sums the applicable federal, state, and local tax rates.

[51] Similarly, using the required cash flow to equity, income taxes can be calculated as:

$$Income\ Tax = \frac{t}{(1-t)} * (Cash\ Flow\ to\ Equity + Principal\ Debt\ Payments - Depreciation)$$

of the total carrying costs is levelized over the assumed economic life of the plant using the real ATWACC. Third, the levelization factor is calculated as the ratio of the levelized fixed charge to the total installed capital cost.

Annualized costs, including the required ROE, are expressed in constant real dollars. The analysis assumes forward-looking inflation of 2.1% annually in both costs and revenues streams. This inflation rate reflects the combined effect of many factors likely to affect future operational costs and net EAS revenues. The recommended value is consistent with the current long-term inflation forecasts from the Survey of Professional Forecasters as reported by the Philadelphia Federal Reserve Bank in the Q1 2020,[52] as well as long-term inflation in electricity prices as reported by the EIA Annual Energy Outlook.[53]

Table 37 provides a summary of all financial parameters used in each location, including financing costs, tax rates, depreciation schedules, and the assumed amortization period. Property tax rates were discussed in Section II. Annual depreciation schedules are provided in Table 38. Depreciation schedules are based on the Federal Internal Revenue Service (IRS) Publication 946 and follow the half-year convention. Fossil peaking plant options are depreciated with a 15-year schedule; the informational combined cycle plants are depreciated with a 20-year schedule; and battery storage plants are depreciated with a 7-year schedule.[54]

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[52] The Survey of Professional Forecasters forecast headline CPI of 2.20% between 2020-2029 and headline PCE of 2.00% between 2020-2029. *See* https://www.phil.frb.org/research-and-data/real-time-center/survey-of-professional-forecasters/2020/survq120.

[53] *See* EIA AEO 2020, January 29, 2020, Table 3 Energy Prices by Sector and Source. The EIA forecasts real price growth for residential electricity of 0.0% for the period 2019 to 2050 and nominal price growth of 2.3% for the Nation as a whole. For the mid-Atlantic, which includes portions of the PJM footprint in addition to New York, the EIA AEO forecasts real growth of 0.6% and nominal growth of 3.0%.

[54] For discussion of the depreciation of battery units see, National Renewable Energy Laboratory, “Federal Tax Incentives for Energy Storage Systems,” January 2018, https://www.nrel.gov/docs/fy18osti/70384.pdf.

Table 37: Summary of Financial Parameters by Location

Finance Category	NYCA	G-J	NYC	LI
Inflation Factor (%)	2.10%	2.10%	2.10%	2.10%
Debt Fraction (%)	55.00%	55.00%	55.00%	55.00%
Debt Rate (%)				
Nominal	7.70%	7.70%	7.70%	7.70%
Real	5.48%	5.48%	5.48%	5.48%
Equity Rate (%)				
Nominal	13.00%	13.00%	13.00%	13.00%
Real	10.68%	10.68%	10.68%	10.68%
Composite Tax Rate (%)	27.50%	27.50%	36.35%	27.50%
Federal Tax Rate	21%	21%	21%	21%
State Tax Rate	6.50%	6.50%	6.50%	6.50%
City Tax Rate	0.00%	0.00%	8.85%	0.00%
WACC Nominal (%)	10.09%	10.09%	10.09%	10.09%
ATWACC Nominal (%)	8.92%	8.92%	8.55%	8.92%
ATWACC Real (%)	6.68%	6.68%	6.31%	6.68%
Amortization Period (Years)	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit
Tax Depreciation Schedule	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)
Fixed Property Tax Rate (%)	Abatement for Battery	Abatement for Battery	4.7% with 15-Year Abatement	Abatement for Battery
Insurance Rate (%)	0.60%	0.60%	0.60%	0.60%
Levelized Fixed Charge (%)	12.77% Fossil Unit; 12.00% Battery Unit	12.77% Fossil Unit; 12.00% Battery Unit	12.71% Fossil Unit; 12.26% Battery Unit	12.77% Fossil Unit; 12.00% Battery Unit

Notes:
[1] The levelized fixed charge (%) for NYC differs from NYCA, the G-J Locality, and LI based on the treatment of property taxes and capital costs. Levelized fixed charge also vary for battery plants due to the shorter amortization period and depreciation period.
[2] NYC reflects the 15-year property tax abatement for both fossil and battery storage peaking plant options. NYCA, the G-J Locality, and LI reflect a 15-year property tax abatement for the battery storage plants, and a 0.9% property tax rate for fossil plants.

Table 38: Modified Accelerated Cost Recovery Tax Depreciation Schedules

	Tax Depreciation		
Year	7 Year (Battery)	15 Year (Simple Cycle)	20 Year (Combined Cycle)
1	14.29%	5.00%	3.75%
2	24.49%	9.50%	7.22%
3	17.49%	8.55%	6.68%
4	12.49%	7.70%	6.18%
5	8.93%	6.93%	5.71%
6	8.92%	6.23%	5.29%
7	8.93%	5.90%	4.89%
8	4.46%	5.90%	4.52%
9	0.00%	5.91%	4.46%
10	0.00%	5.90%	4.46%
11	0.00%	5.91%	4.46%
12	0.00%	5.90%	4.46%
13	0.00%	5.91%	4.46%
14	0.00%	5.90%	4.46%
15	0.00%	5.91%	4.46%
16	0.00%	2.95%	4.46%
17	0.00%	0.00%	4.46%
18	0.00%	0.00%	4.46%
19	0.00%	0.00%	4.46%
20	0.00%	0.00%	4.46%
21	0.00%	0.00%	2.23%

Source:
[1] IRS Publication 946.

C. Annualized Gross Costs

Using the levelization factor developed above and the capital and fixed O&M costs presented in Section II, Table 39 and Table 40 provides annualized gross CONE values for each peaking plant within each location.

Table 39: Gross CONE by Peaking Plant Technology and Load Zone ($2021/kW-Year)

Peaking Plant Technology		C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
GE 7F.05	**Dual Fuel with SCR**						
	Fixed O&M	$11.71	$12.15	$13.59	$13.59	$33.93	$14.81
	Insurance	$5.46	$5.52	$5.61	$5.94	$6.73	$6.64
	Levelized Fixed Charge	$171.43	$172.64	$174.58	$182.75	$230.67	$193.32
	Gross CONE	$188.60	$190.31	$193.78	$202.29	$271.33	$214.78
	Gas only with SCR						
	Fixed O&M	$11.71	$12.15	$13.59	$13.59	-	-
	Insurance	$4.95	$5.01	$5.10	$5.44	-	-
	Levelized Fixed Charge	$156.86	$158.15	$160.15	$168.32	-	-
	Gross CONE	$173.52	$175.31	$178.85	$187.35	-	-
	Gas only without SCR						
	Fixed O&M	$11.71	$12.15	$13.59	-	-	-
	Insurance	$4.33	$4.39	$4.49	-	-	-
	Levelized Fixed Charge	$142.93	$144.29	$146.36	-	-	-
	Gross CONE	$158.97	$160.84	$164.44	-	-	-
1x0 GE 7HA.02 25ppm	**Dual Fuel with SCR**						
	Fixed O&M	$8.26	$8.52	$9.38	$9.38	$21.63	$10.11
	Insurance	$4.53	$4.56	$4.61	$4.80	$5.38	$5.33
	Levelized Fixed Charge	$136.78	$137.36	$138.47	$143.06	$174.26	$151.92
	Gross CONE	$149.58	$150.45	$152.47	$157.24	$201.26	$167.36
	Gas only with SCR						
	Fixed O&M	$8.26	$8.52	$9.38	$9.38	-	-
	Insurance	$4.07	$4.10	$4.16	$4.34	-	-
	Levelized Fixed Charge	$123.65	$124.30	$125.46	$130.04	-	-
	Gross CONE	$135.98	$136.92	$139.00	$143.77	-	-
1x0 GE 7HA.02 15ppm	**Dual Fuel without SCR**						
	Fixed O&M	$8.69	$8.96	$9.87	-	-	-
	Insurance	$3.94	$3.98	$4.03	-	-	-
	Levelized Fixed Charge	$123.97	$124.69	$125.91	-	-	-
	Gross CONE	$136.61	$137.63	$139.82	-	-	-
	Gas only without SCR						
	Fixed O&M	$8.69	$8.96	$9.87	-	-	-
	Insurance	$3.45	$3.49	$3.55	-	-	-
	Levelized Fixed Charge	$110.15	$110.95	$112.23	-	-	-
	Gross CONE	$122.30	$123.40	$125.65	-	-	-

Note:
[1] Property taxes are included in the levelized fixed charge.

Table 40: Gross CONE by Battery Storage Technology and Load Zone ($2021/kW-Year)

Peaking Plant Technology		C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
4-Hr BESS	**Battery**						
	Fixed O&M	$6.37	$6.37	$6.37	$6.37	$18.21	$6.53
	Insurance	$7.99	$8.07	$8.14	$8.46	$8.96	$8.90
	Levelized Fixed Charge	$197.94	$199.68	$201.32	$208.41	$256.10	$212.10
	Gross CONE	$212.30	$214.12	$215.84	$223.24	$283.27	$227.53
6-Hr BESS	**Battery**						
	Fixed O&M	$7.96	$7.96	$7.96	$7.96	$23.78	$8.23
	Insurance	$11.43	$11.54	$11.65	$12.10	$12.82	$12.74
	Levelized Fixed Charge	$276.04	$278.57	$280.89	$291.12	$345.60	$299.25
	Gross CONE	$295.44	$298.07	$300.50	$311.18	$382.20	$320.22
8-Hr BESS	**Battery**						
	Fixed O&M	$9.66	$9.66	$9.66	$9.66	$29.41	$9.98
	Insurance	$14.87	$15.02	$15.15	$15.74	$16.68	$16.58
	Levelized Fixed Charge	$354.07	$357.38	$360.38	$373.75	$435.03	$386.35
	Gross CONE	$378.60	$382.06	$385.19	$399.15	$481.12	$412.91

Note:
[1] Property taxes are included in the levelized fixed charge.

IV. Energy and Ancillary Services Revenues

A. Overview

The Services Tariff requires that the periodic review of ICAP Demand Curves be established considering, in part,

- "…the likely projected annual Energy and Ancillary Services revenues of the peaking plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[55]

The costs and revenues are to be determined under conditions that reflect specified capacity supply conditions. Specifically, the Services Tariff requires that:

- "…[t]he 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…"[56]

AGI refers to these tariff-specified conditions as the "LOE" conditions.

In this Section, we present the method used to estimate the net EAS revenues of the peaking plant for NYCA and each Locality. Consistent with the LOE requirement, net EAS revenues are calculated under conditions in which system resources equal either (1) NYCA Minimum Installed Capacity Requirement (ICR) plus the capacity of the peaking plant in NYCA, or (2) Locational Minimum Installed Capacity Requirement (LCR) plus the capacity of the peaking plant in individual Localities.[57]

First, AGI summarizes its approach for estimating net EAS, including a description of the net EAS model, the data inputs, and the approach to adjusting prices to be consistent with LOE market conditions. Second, AGI summarizes the process for annually updating estimated net EAS revenues over the reset period. Finally, AGI presents preliminary results of applying the net EAS revenues model for the 2021/2022 Capability Year.

B. Approach to Estimating Net EAS Revenues

1. Overview

For each Capability Year, RPs in NYCA and each Locality are based on estimated gross CONE (described in Section III, above) less the expected net revenues the peaking plant would earn in NYISO's energy and ancillary services markets. The net revenues earned from participating in these markets reflect the prices paid for supply of

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[55] Services Tariff, Section 5.14.1.2.

[56] Services Tariff, Section 5.14.1.2.

[57] Note that ICR is defined in terms of MW, equal to total capacity needs (i.e., peak demand plus reserve requirements, in MW). The ICR is based on the Installed Reserve Margin (IRM), which is the level of reserve capacity in excess of peak load required in the NYCA, denominated in percentage terms. Throughout this report, AGI uses both terms, when appropriate. For example, when describing system capacity need in MW, AGI uses ICR. When referencing the required level of reserves in percentage terms, AGI uses IRM.

Energy and Ancillary Services net of the fuel and variable costs of production. Because RPs are established to ensure sufficient revenues for new entry, estimates of net EAS revenues should reflect the forward-looking expectation of net revenues under LOE conditions consistent with the requirements of the Services Tariff.

Net EAS revenues are estimated based on the simulated dispatch of the peaking plant using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and data on the non-fuel variable costs and operational characteristics of the peaking plant technology. AGI's approach 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 RPs evolve (with a lag) consistent with actual EAS market outcomes (as adjusted for LOE conditions).

AGI's model estimates the net EAS revenues of the peaking plant on an hourly basis for the historical 3-year period assuming that the resource earns the maximum possible revenues by supplying energy or reserves in either the Day-Ahead Market (DAM) or Real-Time Market (RTM). Each year, as part of an annual updating of the ICAP Demand Curves, net EAS revenues will be recalculated using the same model, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges.

2. *Net EAS Model Construct*

a. Fossil Model Logic

The AGI simulated dispatch model uses a "dispatch logic" functionally consistent with NYISO energy and ancillary services markets.[58] Specifically, the AGI model estimates the net EAS revenues earned by the peaking plant on an hourly basis assuming dispatch of the plant and market offers set at the opportunity cost of producing energy or providing reserves.[59] In the model, the peaking plant can earn revenues through supplying in one of four markets: (1) DAM commitment for Energy, (2) DAM commitment for reserves, (3) RTM dispatch for Energy, or (4) RTM supply of reserves. In addition, a plant maintains the ability to buy out of either DAM Energy or reserves commitments, based on changes in RTM prices. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual-fuel capability (if applicable) is accounted for through the option to generate on natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

Figure 8 and Figure 9 contain schematics of the commitment/dispatch logic for the DAM and RTM, respectively. The model first determines whether to commit the plant to supply energy or reserves in the DAM based on the net revenues of each position. Similar to DAM commitment, RTM dispatch determines the operating state (supplying energy, supplying reserves, not supplying) contingent on the peaking plant's DAM commitment. Thus, the plant can change operating status from its DAM commitment if such a switch in operating status is sufficiently profitable

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[58] In practice, an individual plant's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical peaking plant considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to plant-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical peaking plant.

[59] AGI assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant, and thus do not account for the downward pressure that this additional supply may have on realized prices. In this regard, the estimates may tend to overstate revenues.

in real-time. Real-time fuel costs reflect a premium for purchases and discount for sales relative to day-ahead gas prices. The value of this premium varies by Load Zone. These intraday premiums/discounts reflect potential operating or other opportunity costs to securing (or not using) fuel in real-time, which may be incurred due to balancing charges with an LDC, illiquidity in the market during periods of tight gas supply, or imperfect information on the part of either the buyer or seller.[60] This additional cost is incorporated into RTM buy out decisions for all plants. As illustrated in Figure 9, peaking plants can exist in one of nine operating states in each hour, based on the DAM and RTM choices. These "operating" states include:

- DAM energy commitment, with RTM energy dispatch
- DAM energy commitment, with a buy out and a RTM reserves dispatch
- DAM energy commitment, with a buy out and no dispatch in the RTM
- DAM reserves commitment, with a RTM reserves dispatch
- DAM reserves commitment, with a buy out and a RTM energy dispatch
- DAM reserves commitment, with a buy out and no dispatch in the RTM
- No DAM commitment, with no dispatch in the RTM
- No DAM commitment, with an energy dispatch in the RTM
- No DAM commitment, with a reserves dispatch in the RTM

In contrast, the net EAS revenues model for the informational combined cycle plants only consider the energy commitment and dispatch of the plant in both DAM and RTM, including the ability to buy out of a DAM energy commitment in the RTM. The informational combined cycle plants are assigned a flat annual adder of $3.90/kW-year as an estimate of net ancillary services revenues, based on settlement data provided by the NYISO for comparable plants.

When evaluating an Energy commitment in either the DAM or RTM, the model ensures that all costs, including amortized start-up costs, can be recovered.[61] In the DAM, start-up costs for the Frame combustion turbine can be recovered over the full runtime block, which is determined dynamically based on profitable hours; within the RTM, Frame combustion turbine plants must recover their startup costs over two hours. In contrast, in both the DAM and RTM; aeroderivative plants recover start-up costs over the first hour of commitment. Plants are also constrained by applicable runtime limitations as described in Section II.C.

Plants are also constrained by applicable runtime limitations as described in Section II.C. For peaking plants modeled with SCR emissions control technology, the NSPS limitation for CO_2 is a limiting constraint on hours of operation. BMCD estimated the maximum annual runtimes for all combustion turbines with SCR emissions control

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[60] These costs are based on estimates reported by the NYISO Market Monitoring Unit (MMU) in their State of the Market Report based on their review of available data. The real time premium/discount is applied to all operating hours throughout the year. In practice, these annual average values may over-estimate net EAS revenues during some hours (e.g. winter months) if the DAM-RTM price difference is driven by changes in gas market conditions and under-estimate net EAS revenues during other hours (e.g., during periods of gas liquidity). During periods of gas liquidity, this could either overstate the true cost of selling out of a gas position in real-time or overstate the true cost of purchasing gas in real-time, thereby foregoing a potential RTM dispatch. On net, these effects would tend to both decrease and increase real time net EAS revenues in various hours throughout the year.

[61] The model does not allow a plant to be committed uneconomically. In actual operation of the markets, to the extent that a plant would be committed uneconomically, it would be eligible to receive either Day-Ahead Margin Assurance Payment (DAMAP) or a Bid Production Cost guarantee (BPCG) payment. These payments would compensate a plant for its costs, offsetting losses on a daily basis

technology to be 3,066 hours. BMCD deemed that the informational combined cycle plants, which are assumed to install SCR emissions control technology, would not face runtime limitations. For combustion turbines without SCR emissions control technology, the limiting constraint is the NSPS requirement for NO_x emissions. Plants without SCR emission controls in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions. Operating hours limits are modeled in the Net EAS Revenue model as constraints on the total amount of combined NO_x emissions allowed each year from either natural gas or ULSD operations. Due to differences in heat rate and capacity by season, the exact emissions per run hour also differs by season. The mass of NO_x emissions is calculated for each profitable run hour, and the total amount of emissions per year is limited to the NSPS maximum.[62]

Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-synchronized reserve markets at their opportunity cost of holding or obtaining adequate fuel supplies. Here, the opportunity cost reflects the real time intraday premium (discount) of buying (in real time) or selling (from a day-ahead procurement) natural gas. Dual fuel plants do not face an opportunity cost to provide reserves when ULSD prices (plus applicable transportation charges) are lower than natural gas prices (plus applicable charges).

[62] The model evaluates environmental runtime limits on a model-year basis, where model years cover a 12-month period from September 1 to August 31 (e.g. September 1, 2019 to August 31, 2020). If a plant is committed above its applicable environmental runtime limit during that period, the model removes the least profitable energy (either DAM or RTM) runtime blocks until the plant is in compliance. Plants are allowed to earn DAM reserve revenues at the prevailing DAM reserve price during runtime blocks removed in this fashion.

Figure 8: Net EAS Revenues Model Day-Ahead Commitment Logic

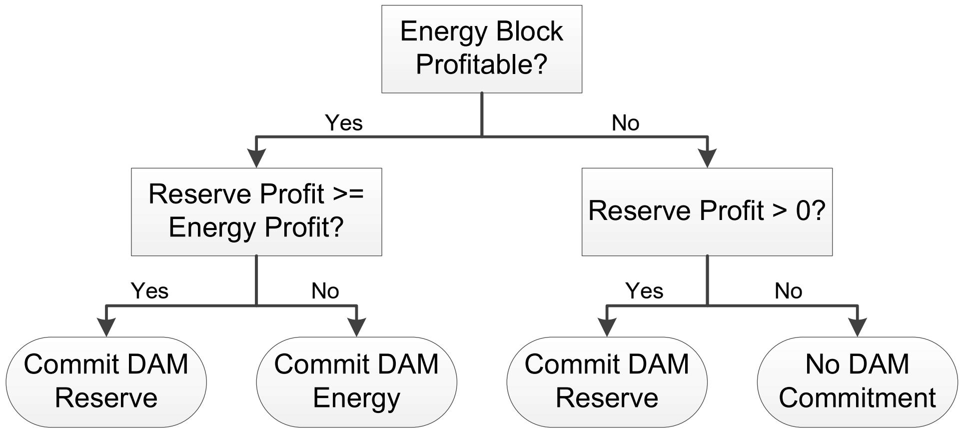
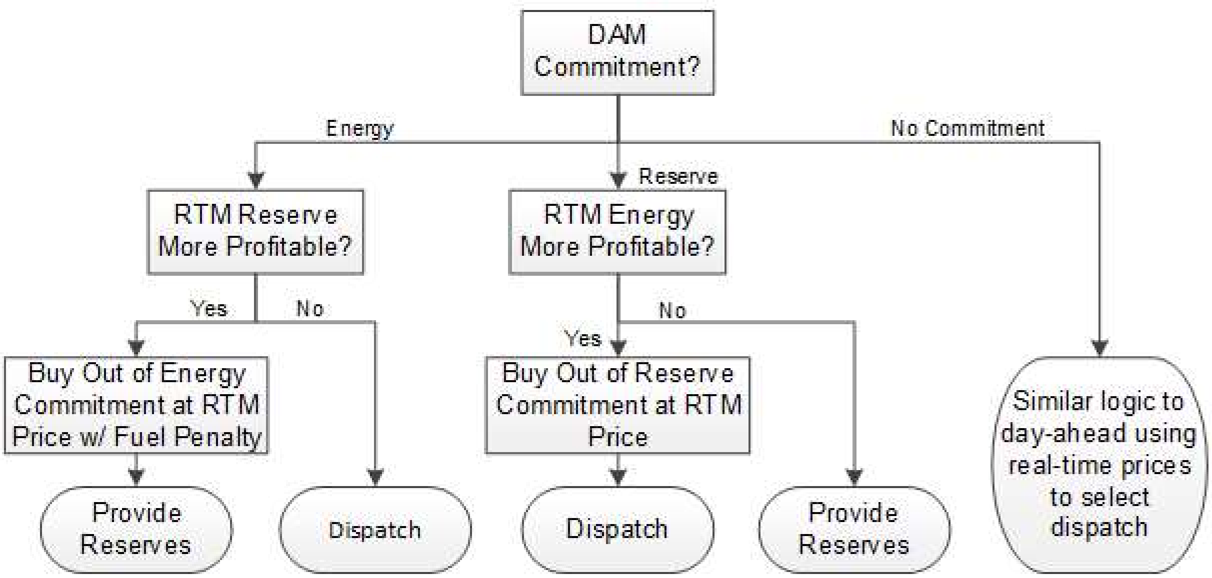


Figure 9: Net EAS Revenues Model Real-Time Supply Logic



The net EAS revenues model estimates hourly revenue streams for the peaking plants based on prices over the three-year historical period. Within this hourly model, peaking plants are assumed to be fully committed for the duration of the hour. That is, the net EAS revenues model for peaking plants does not allow for partial dispatch or minimum load operations. In contrast, the net EAS revenues estimates for the informational combined cycle plants assume the plant may be committed at minimum load between energy commitments, to the extent that this would be more profitable than incurring an additional startup cost.

Equation 3 provides a simplified representation of the net EAS revenues (NEAR) calculation used when considering energy dispatch in each hour, where profits are determined using parameters specific to each Load Zone and, when applicable, each peaking plant:[63]

$$NEAR = LOE\text{–}AF * LBMP - HR * P(fuel) - VOM - ASC - EC - RS1 \qquad (3)$$

Where:

$LOE - AF$ = LOE adjustment factors for each Load Zone and time period

$LBMP$ = Hourly LBMPs (either DAM or RTM) for each Load Zone

HR = Heat rate for the applicable peaking plant and Load Zone

$P(fuel)$ = Price of fuel (natural gas or, if applicable, oil), which varies by day and Load Zone, including relevant transportation costs and real time intraday premium/discount

VOM = Variable operations and maintenance costs

ASC = Amortized startup cost (dynamically determined)

RS1 = NYISO Rate Schedule 1 charge (varies annually, but is constant across Load Zone and technology)

EC = Emission costs, where costs are a function of both emission rates and allowance prices for CO_2, NO_X (annual and seasonal) and SO_2 (CSPAR and Acid Rain) that is:

$$EC = (CO2Rate * CO2\_Price) + (NOxRate * NOx\_Price) + (SO2Rate * SO2\_Price)$$

When estimating total annual net EAS revenues, the model separately considers relevant unit parameters for Summer and Winter Capability Period months, including each plant’s seasonal capacity and heat rate. Total annual revenues are the sum of revenues earned during each hour of the year reflecting seasonal ratings, with energy and reserves revenues derated by the peaking plant’s EFORd.

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[63] That is, equation 3 does not fully represent the tradeoffs between DAM and real-time Energy and reserve profits, or the ability of the plant to buy out of its commitment.

As a final step, the model calculates the annual average net EAS revenues as the simple average of all revenues over the three-year period, plus a flat adder for providing Voltage Support Service (VSS).[64]

An important component of the net EAS revenues model is the ability of the model to assess plants with either dual fuel capability (if applicable) or gas only operation. When evaluating fuel commitment decisions, the model compares the applicable fuel costs in each hour. For a dual fuel unit, the peaking plant is assumed to operate on the most economic fuel for a full runtime block. Plants are not allowed to fuel switch within an individual block.

Notably, the current model does not consider potential limitations in gas only operations; all gas plants are assumed to be able to procure fuel as needed, at historical prices.[65] As described in Section II, AGI considered potential limitations in fuel availability as part of its qualitative review. To the extent limitations in fuel availability are not captured in the current economic model, net EAS revenues for gas only plants may tend to be overstated.

b. Battery Model Logic

Like the fossil model, the AGI simulated dispatch model for battery storage uses a “dispatch logic” that is functionally consistent with NYISO energy and ancillary services markets.[66] Net EAS revenues are earned by the battery on an hourly basis in the RTM and DAM energy and reserve markets. The model’s “dispatch logic” maximizes net EAS revenues while accounting for the battery technology’s unique technical properties, including limited energy storage capacity, the need for a balancing of energy charges and discharges, energy losses during charging, and operational practices that can reduce battery degradation. We first describe how the model accounts for these technical characteristics, and then describe the model’s framework for determining participation in the NYISO markets, which follows three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch.

Due to the physical energy limitations of a battery, the model determines charge and discharge of the battery simultaneously in hour-pairs. Each hour-pair includes an hour in which the battery purchases energy (to charge the battery) and an hour in which it supplies energy (through discharge of the battery). This logic ensures there is always a balance between energy inflows and outflows. The model also limits the range of stored energy to between zero and the battery’s maximum storage capacity.

For each hour-pair, the model accounts for energy losses when charging and assumes the full charge or discharge of the battery’s capacity. However, because of charging losses, more time is required for a full charge of the

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[64] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Historical average annual net EAS revenues are escalated from the three-year midpoint (here, $2017) into real dollars (here, $2019) for the ICAP Demand Curves using the GDP implicit price deflator.

[65] Similarly, the model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AGI does not expect OFOs to meaningfully affect the net EAS revenues of dual fuel plants, particularly in Load Zone J and K, where OFOs are more common. To the extent that OFO days are correlated with periods of high natural gas prices, these plants would already be expected to run on oil.

[66] In practice, an individual plant’s historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical battery considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to plant-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical battery plants evaluated in this study.

battery than is required for a full discharge; thus, to maintain the energy balance of inflows and outflows of power, additional charging time is required for any given level of stored energy.

Along with consuming and supplying energy, the battery can supply reserves. The battery is assumed to be eligible to provide 10-minute spinning reserves when it has no DAM or RTM energy discharge position but has stored energy or is charging. The battery can supply reserves at either its full capacity or the amount of energy that remains stored, whichever is smaller. When the battery is charging, the model assumes it can supply reserves at either its full capacity or the amount of energy that remains stored plus the amount of power scheduled to be withdrawn from the grid for charging purposes.

When the battery is not charging or discharging, a target storage level of 50% of the battery's capacity is assumed. For example, a 4-hour battery would maintain a target level of 2 hours of charge between charge and discharge.

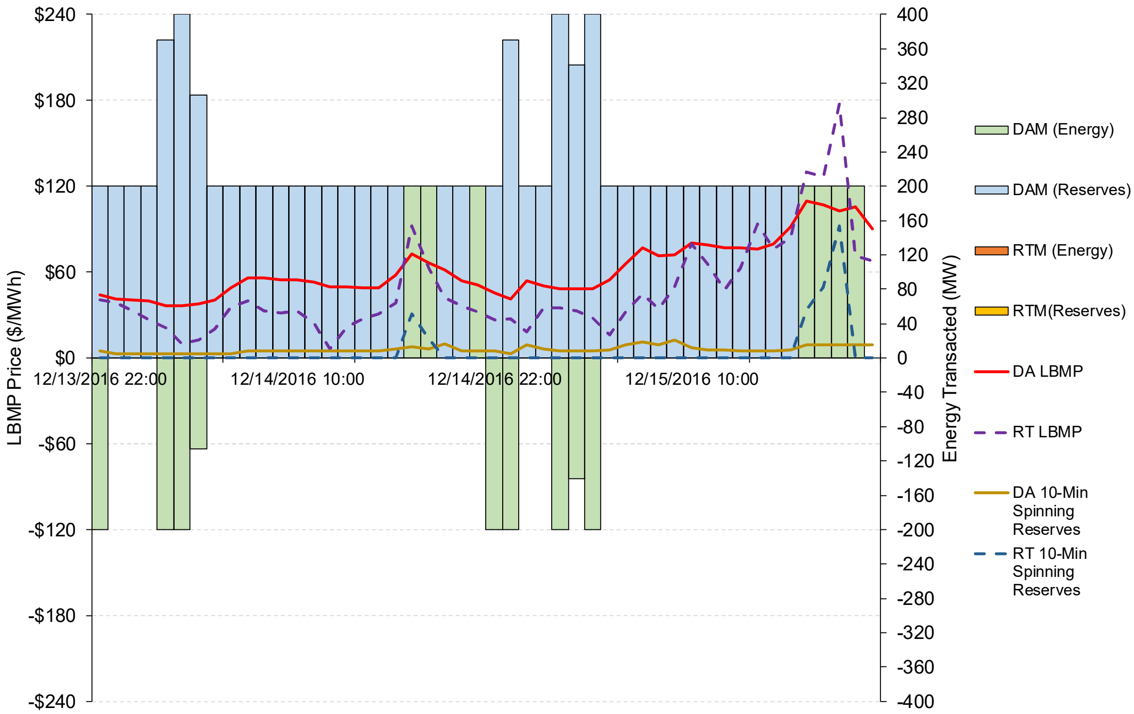
The dispatch logic for battery storage is split into three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch. Figure 10, Figure 11, and Figure 13 illustrate how the model is solved for two illustrative days in the three steps. The left axis (and lines) show the LBMPs and reserve prices determined by the NYISO markets in each hour. The right axis (and bars) shows the battery energy transactions determined by the model; positive values represent MW discharged onto the grid while negative values represent MW withdrawn from the grid for charging. Withdrawal MW should not be mistaken for actual inflows into the battery, as in these cases the battery only received 85% of the energy withdrawn because of charging inefficiencies.

The **first step** determines the daily DAM positions. The model determines whether to commit a set of hour-pairs to charge and discharge energy in the DAM based on maximizing net revenues in the energy and reserve markets for a cycle-day.[67] For each cycle-day, the model generates every feasible day-ahead position hour-pair given the current position of the battery storage resource. It then ranks the profitability of adding each set of hour-pair positions to the current position. If adding the hour-pair to the battery's position increases profitability relative to doing nothing, the model will do so and repeat this process. The model will also add hour-pairs to its position in order to hit the target level of energy for the battery (i.e., 50% of the battery's capacity), even when it does not increase revenues.

This step outputs a full cycle-day of DAM positions, an example of which can be seen for two days in Figure 10. Three hour-pairs are committed on the first DAM day and four hour-pairs are committed on second DAM market day, as depicted by the green energy discharge bars above the y-axis and corresponding charging hours below the y-axis. The battery resource provides reserves whenever it has energy stored or is charging. In each case, the model cannot feasibly position another hour-pair that would drive greater profits than the determined set of positions.

[67] A cycle-day is defined as a 24-hour period between 10:00 pm and 9:59 pm the following day.

Figure 10: AGI Battery Model Step 1 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery



The **second step** considers whether net revenues are maximized by emptying the battery each day or maintaining stored energy between cycle-days. The model determines the multi-day behavior of the battery by comparing net EAS revenues of these two different options.[68]

The outcomes of this second step can be seen in Figure 11. Here, the model determined it was more profitable to enter the day of 12/14 with energy stored, and thus it eliminated two discharge hours on 12/13 (not shown in Figure 11). It has also eliminated charging hours on 12/14 relative to what was shown in Figure 10. The model similarly compares 12/13 and 12/14, making no changes to the DAM position, and compares 12/14 to 12/15, determining it is more profitable to eliminate the final two discharge hours and instead to store energy for 12/16.

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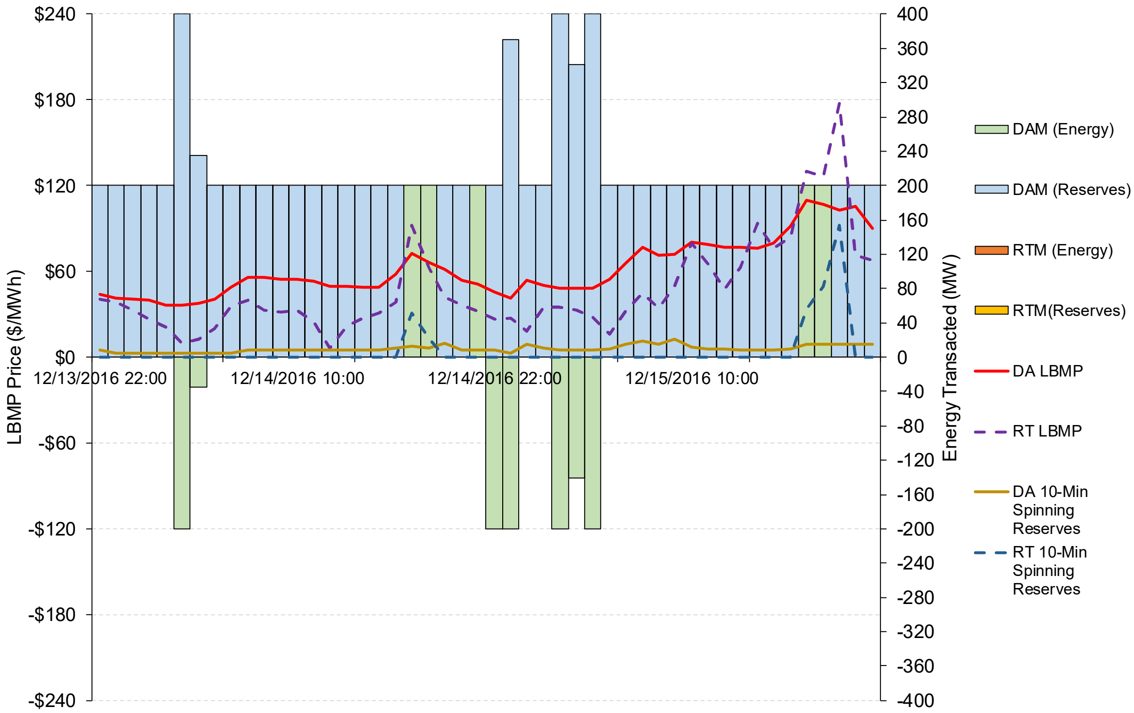
[68] The model calculates net EAS revenues of maintain energy levels across days by adjoining adjacent cycle-days. For each pair of days, the model creates a new set of DAM commitments by eliminating the appropriate number of discharge hours on day 1 and charge hours on day 2 in order to maintain the target energy level (i.e., 50% of the battery's capacity) between both days. Net EAS revenues are recalculated based off the new energy levels across both cycle-days. If net EAS revenues are higher with the new set of DAM commitments, then the revised commitments are implemented by the model. Otherwise, the initial DAM commitments are left unchanged. The model pairs adjacent cycle-days moving forward day-by-day considering any commitment changes made by the previous pair of cycle-days. This process concludes the DAM commitments made by the model.

Figure 11: AGI Battery Model Step 2 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery



The **third step** determines any incremental RTM positions using logic similar to the daily DAM position process. In the RTM, the battery plant supplies (and consumes) energy given arbitrage opportunities presented by RTM LBMPs. The plant's RTM operational decisions are contingent on the DAM positions established in steps 1 and 2. While we assume the battery does not buy out of a DAM energy position, the battery can buy out of DAM reserve position and take on a RTM energy position instead.

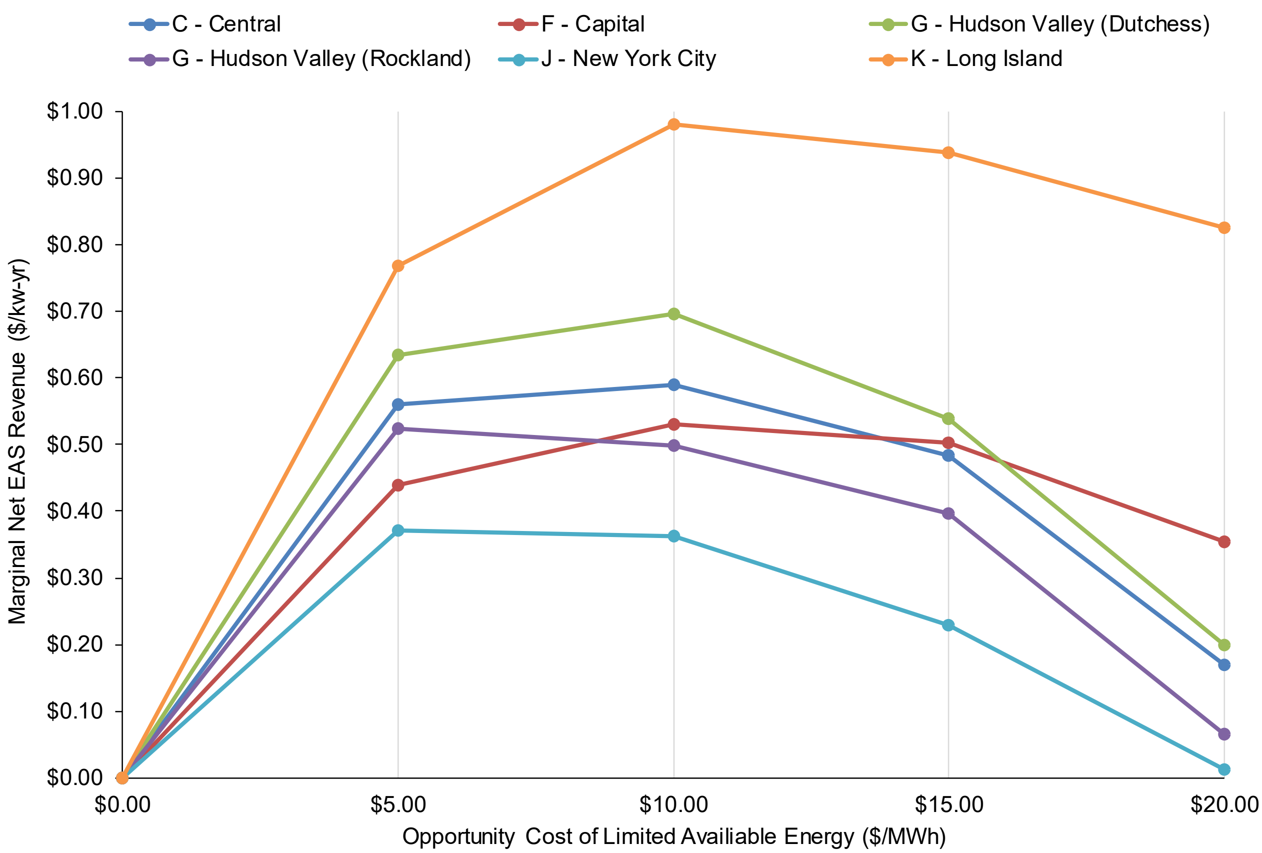
To evaluate such arbitrage opportunities, the model generates every feasible RTM hour-pair given the current hourly positions of the battery. When evaluating and ranking the profitability of adding hour-pairs in the RTM, the model calculates an 'estimated profit' using the RTM LBMP for the first hour and the DA LBMP for the second hour. This reflects the fact that, in real-time, a resource operator would not know a future RT LBMP and could use the DA LBMP as an approximation. However, once these RTM positions are entered into, the model will use RTM LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position.

Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for LBMP uncertainty in the real-time market. This hurdle rate reflects two components - an opportunity cost of limited available energy and a risk premium. The battery model must clear the hurdle rate (i.e., estimate its new position to be more profitable than the hurdle rate) in order to enter into a RTM position.

The opportunity cost of limited available energy reflects that, if the battery used its limited energy to earn revenues in low priced hours, it may not have sufficient stored energy be earn higher revenues in the future. The risk premium accounts for market participant's risk aversion when participating in the real-time market, given the potential for higher volatility of real-time prices and the potential for losses to result from deviations from its DAM positions. We assume the risk premium is $10/MWh, and calculate the opportunity cost of limited available energy empirically using the model, see Figure 12.

Figure 12 provides the marginal net EAS revenues evaluated for different assumed hurdle rates, compared to if no hurdle rate was used (i.e., a hurdle rate equal to $0/MWh). For each location evaluated in this study, a revenue maximizing opportunity cost value is chosen (i.e., the maximum point on the figure). To obtain the total hurdle rate, we add the $10/MWh risk premium to this opportunity cost value. This assessment resulted in a total hurdle rate assumption of $15 per MWh in Load Zone G (Rockland County) and Load Zone J, and $20 per MWh in Load Zone C, Load Zone F, Load Zone G (Dutchess County), and Load Zone K.

Figure 12: Change in RTM Net EAS Revenues for Alternative Bid Offer Hurdle Costs, 4-Hour Battery

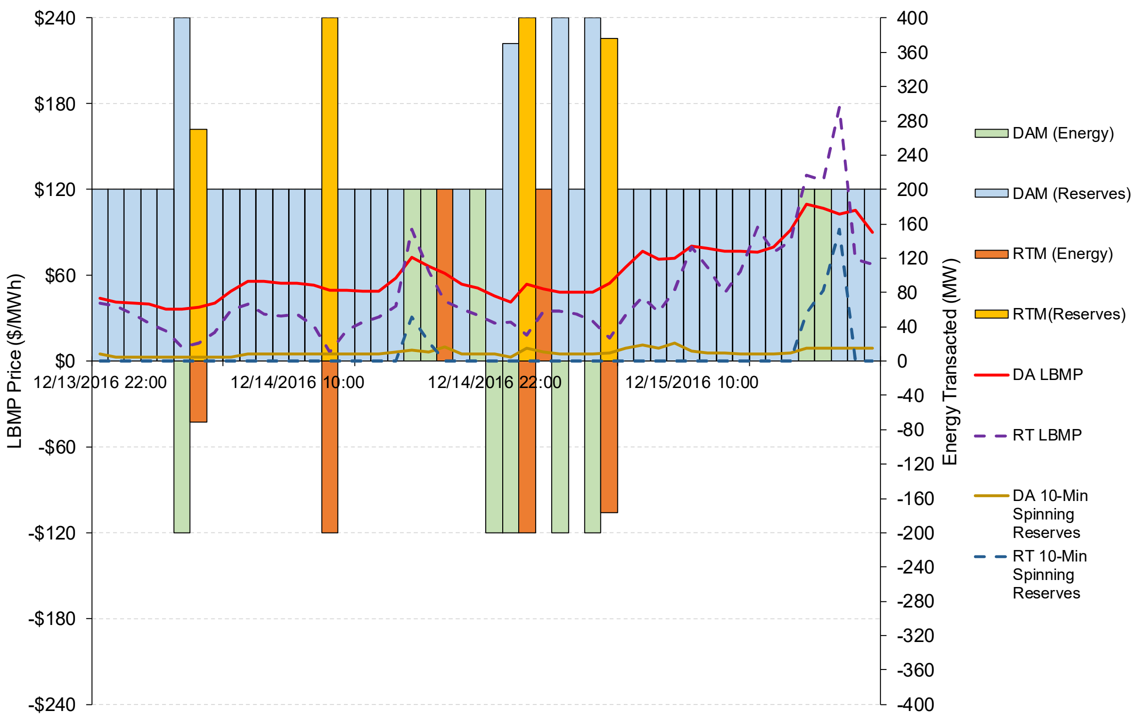


Note:
[1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh opportunity cost value.

For each RTM hour-pair, partial charging is updated accordingly to reflect the additional power needed for the extra hour pair. The partial charging hour is assigned to the hour with the lowest RTM LBMP that is feasible. This process concludes the RTM positions determined by the model. Unlike the previous two DAM steps, the realized profits may not reflect the maximum RTM energy and reserve revenues because of imperfect knowledge and risk aversion.

In Figure 13, the model commits one RT hour-pair on 12/14 and one RT hour-pair on 12/15. On both days, the battery capitalizes on low RTM LBMPs for charging and discharges based on higher expected real-time prices compared to DAM prices. This can be seen by the dark orange bars. In both hour-pairs, the estimated profits for discharge in the second hour use a DAM LBMP that is higher than the RTM LBMP. As a result, the realized profits will be lower than the estimated profits.

Figure 13: AGI Battery Model Step 3 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery



To summarize, batteries can exist in one of ten operating states in each hour, based on the combination of DAM and RTM positions. These "operating" states include:

- DAM energy position, with RTM energy dispatch
- DAM energy and reserve position, with RTM energy and reserve dispatch
- DAM reserves position, with a RTM reserves dispatch
- DAM reserves position, with a RTM energy dispatch
- DAM reserves position, with a RTM energy and reserve dispatch
- DAM reserves position, with no dispatch in the RTM
- No DAM position, with a RTM reserve dispatch
- No DAM position, with a RTM energy dispatch
- No DAM position, with a RTM energy and reserve dispatch

- No DAM position, with no dispatch in the RTM

The net EAS revenues model estimates hourly revenues streams for the battery plants based on prices over the three-year historical period. Equation 4 and 5 provide a simplified representation of the net EAS revenues (NEAR) calculation used in each hour when considering charging and reserves and discharging dispatch, respectively. Profits are determined using parameters specific to each Load Zone and, when applicable, each battery duration:

Charging and reserves:

$$CHARGE\ COST = P_{charg} * 1\ hr * \left(LOEAF * LBMP_{Energy} + RS1 + TRANS\right)$$

$$RESERVE\ REV = P_{charg} * 1\ hr * (LOEAF * LBMP_{Reserve}) + \min(E_{stored},\ CAP * 1\ hr) * (LOEAF * LBMP_{Reserve})$$

$$NEAR = RESERVE\ REV - CHARGE\ COST \quad (4)$$

Discharging:

$$NEAR = P_{discharge} * 1\ hr * \left(LOEAF * LBMP_{Energy} - VOM - RS1\right) \quad (5)$$

Where:

$LOEAF$ = LOE adjustment factors for each Load Zone and time period (%)

$LBMP_{energy}$ = Hourly Energy LBMPs (either DAM or RTM) for each Load Zone ($/MWh)

$LBMP_{reserve}$ = Hourly reserve prices (either DAM or RTM) for each Load Zone ($/MWh)

P_{charg} = Power withdrawn from grid (MW)

$P_{discharg}$ = Power injected into grid (MW)

CAP = Power capacity of battery (MW)

E_{stored} = Stored energy in battery (MWh)

VOM = Variable operations and maintenance costs ($/MWh)

RS1 = NYISO Rate Schedule 1 injection charge (varies over time, but is constant across Load Zones and technology) ($/MWh)

TRANS = Transmission Service Charge rates (varies over time and across Load Zones) ($/MWh)

Total annual revenues are the sum of revenues earned during each hour of the year with energy and reserves revenues derated by the plant's EFORd. As a final step, the model calculates the annual average net EAS revenues as the simple average of all revenues over the three-year period, plus a flat adder for providing VSS.[69] Unlike the fossil model, the batteries have no seasonal differences in unit parameters or ratings.

c. Model Data

The data used in the net EAS revenues model includes hourly locational energy and reserve prices, daily fuel prices and daily emission allowance prices (for CO_2, SO_2, and NO_x) for the three-year period (September through August) ending in the year prior to the beginning of the Capability Year to which the relevant ICAP Demand Curves will apply.[70] Other peaking plant costs and operational parameters (e.g., heat rate, VOM costs) needed to run the model are established at the time of the DCR, and described in Section II and Appendix A.

i. LBMPs and Reserve Prices

DAM and RTM LBMPs and reserve prices use zonal integrated hourly average values that are available through the NYISO market and operation data. Reserve prices are based on prices for 10-minute non-spinning reserves for the GE 7HA.02 and Siemens SGT-A65 units, as BMCD, in discussion with NYISO, has determined that all modeled types are capable of supplying 10-minute non-spinning reserves. Reserve prices are based on 30-minute operating reserves for the GE 7F.05 units.

In addition to energy reserve revenues, the peaking plants can also supply VSS. VSS revenues are determined on an annual basis, with supply determined outside the dispatch model. VSS payments are added to the final estimate of annual net EAS revenues and are based on actual settlement data analyzed by the NYISO. The annual average VSS revenue was found to be $2.04/kW-year for combustion turbines and battery storage options. A VSS adder of $1.63/kW-year is used for the informational combined cycle plants. (The fixed VSS adder is incremental to the $3.90/kW-year net ancillary services revenue adder used for the informational combined cycle plants.) These revenues are included as fixed adders for all peaking plant (combustion turbines and battery storage) and informational combined cycle plants in all locations evaluated in this study.

ii. Oil and Natural Gas Prices

Natural gas prices are based on price indices for natural gas market hubs selected by AGI for each location evaluated as reported by S&P Global Market Intelligence (SPGMI). SPGMI gas indices are developed using price and volume data submitted from market participants for actual next-day transactions at various points along identified sections of pipelines, and represent volume-weighted average prices for next day delivery, excluding outliers that are greater than two standard deviations from the mean.[71] AGI's net EAS revenues model aligns gas day delivery and DAM LBMPs, and applies a fixed intraday premium or discount for real time gas purchases, as discussed below.

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[69] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Historical average annual net EAS revenues are escalated from the three-year midpoint (here, $2019) into real dollars (here, $2021) for the ICAP Demand Curves using the GDP implicit price deflator.

[70] For the preliminary results presented in this Report for the 2021/2022 Capability Year ICAP Demand Curves, we use data for the three-year period through August 2019. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

[71] *See* S&P Global Market Intelligence Natural Gas and Power Index Methodology and Code of Conduct, 2018.

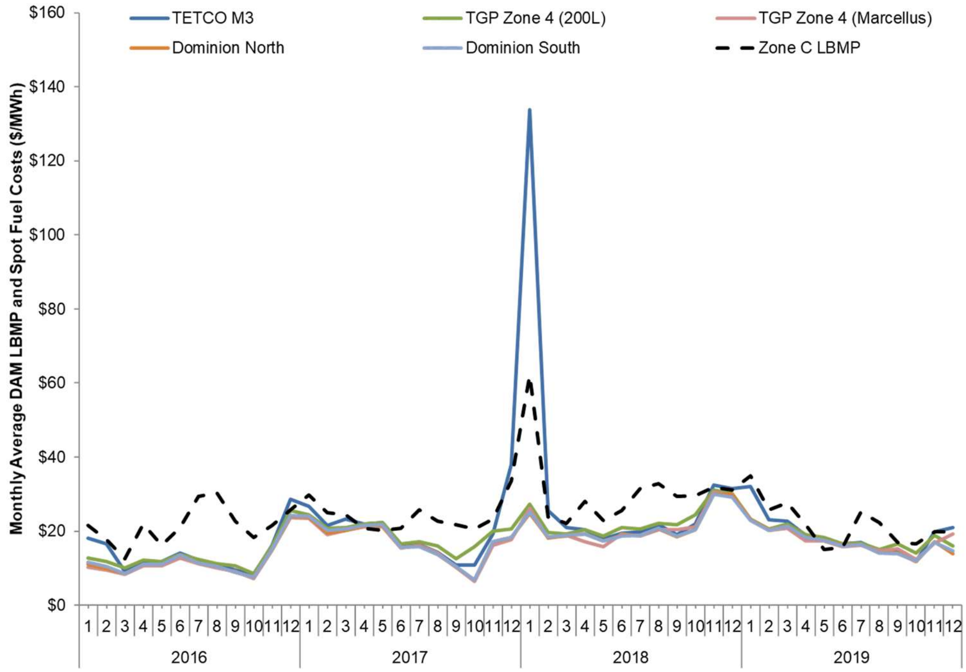
Despite the existence of numerous pricing hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a peaking plant in a given location. AGI considered numerous gas index options for the peaking plants in question, based on several selection considerations:

- *Market Dynamics.* The gas index should reflect gas prices consistent with LBMPs, recognizing that other factors such as transmission congestion also influence the frequency and level of spikes in LBMPs. Ideally, the gas index used in peaking plant net EAS revenues calculations would reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions.
- *Liquidity*. The natural gas index should have a reasonable depth of historical data available, representing trades occurring at sufficient volumes over a reasonable period of time.
- *Geography.* The natural gas index (which typically reflects average trading prices over a broad geographic area) should represent trades across pipelines that have an appropriate geographic relationship to potential peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points. While recognizing the relevance of geographic proximity, AGI also considered whether gas indices fully captured variation in pricing within a given Load Zone, particularly to the extent that such pricing variation is relevant to delivery to a peaking plant in NYCA.
- *Precedent/Continuity.* The natural gas index selected should reflect and be supported by information collected from multiple sources and should take into account what is used for other NYISO planning and market evaluation purposes. While the appropriate choice of gas index can vary in accordance with the purpose and objectives of the study, consistency and continuity should be considered when other factors do not clearly indicate an alternative.

An important factor in our identification of an appropriate gas index was the historical relationship between gas prices and LBMPs. In some cases, it is apparent from comparison of gas indices and zonal LBMPs, that during certain periods (particularly winter months) zonal LBMPs did not reflect marginal supply from facilities relying on fuel prices at certain gas price indices nearby to that Load Zone. LBMPs in a given Load Zone may demonstrate strong relationships with certain gas indices, suggesting that marginal plants may rely on fuel from these sources. However, other gas indices can show weaker price relationships during winter months. To the extent that a peaking plant could receive delivery of gas at these prices during these periods, these price differentials suggest a profitable opportunity for short-term arbitrage between natural gas and electricity markets. However, such arbitrage opportunities do not necessarily reflect a long-run equilibrium given the potential that new (peaking plant) entry increases congestion on these gas delivery lines and other factors that will tend to bring these markets into equilibrium.

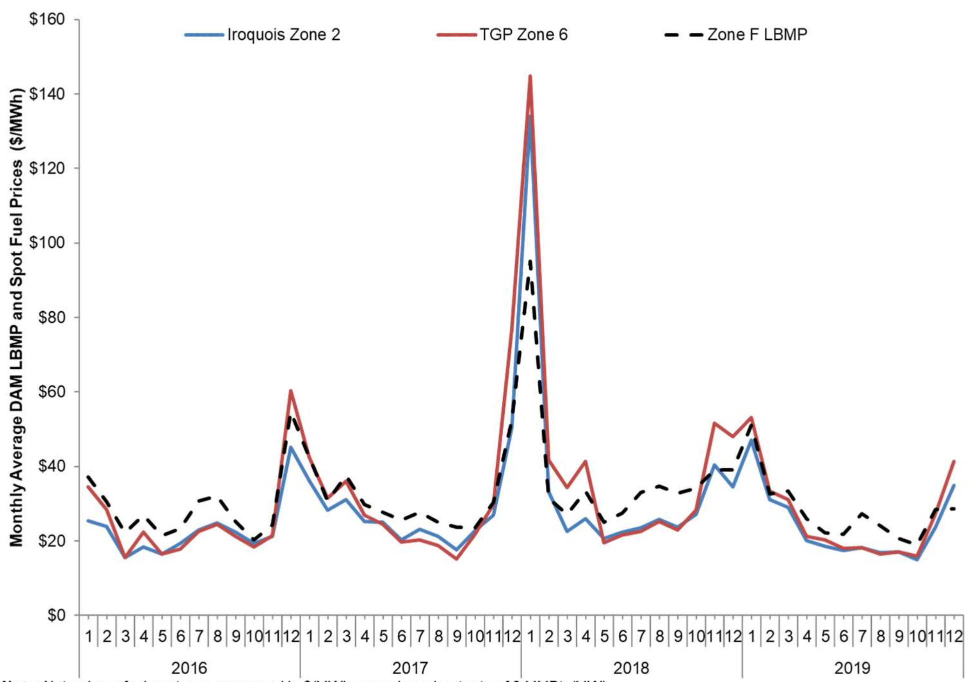
Figure 14 through Figure 18 provide comparisons of gas prices for various hubs and LBMPs for Load Zone C, Load Zone F, Load Zone G, Load Zones J, and Load Zone K, respectively. These figures compare the monthly average fuel costs for a hypothetical generation plant (with a heat rate of 8 MMBtu/MWh) and monthly average LBMPs for 2016 to 2019.

Figure 14: Natural Gas Price Indices and Load Zone C LBMPs



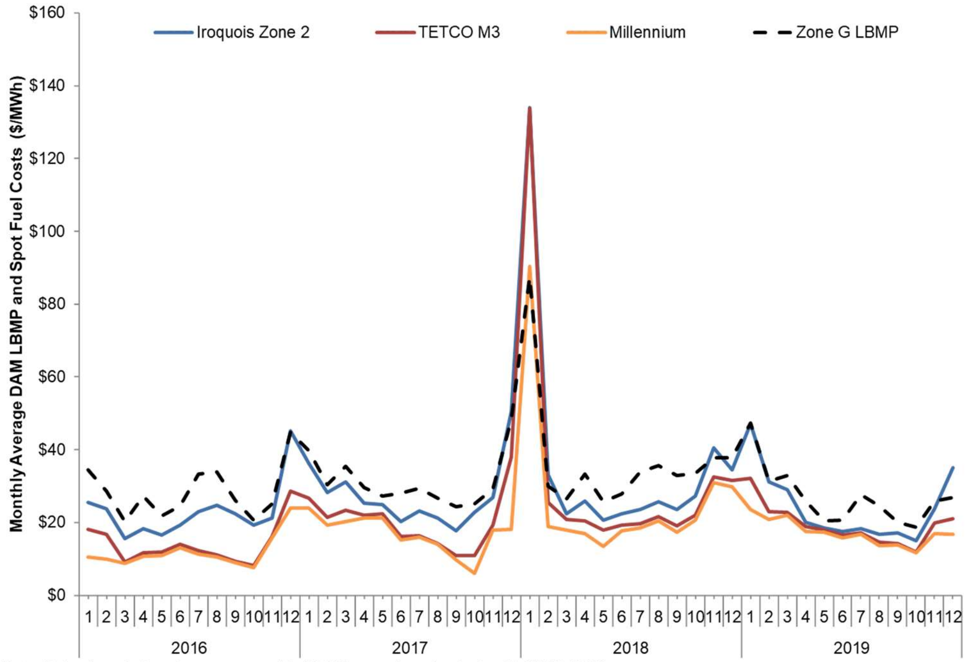
Note: Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources: SNL (Fuel Prices); NYISO (DAM LBMPs).

Figure 15: Natural Gas Price Indices and Load Zone F LBMPs



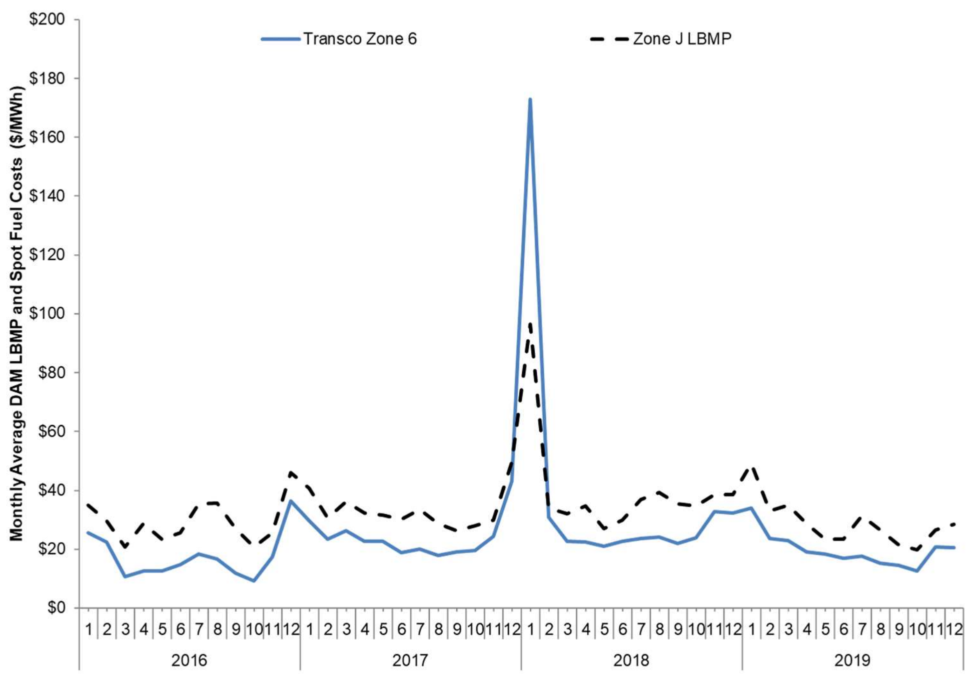
Note: Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources: SNL (Fuel Prices); NYISO (DAM LBMPs).

Figure 16: Natural Gas Price Indices and Load Zone G LBMPs



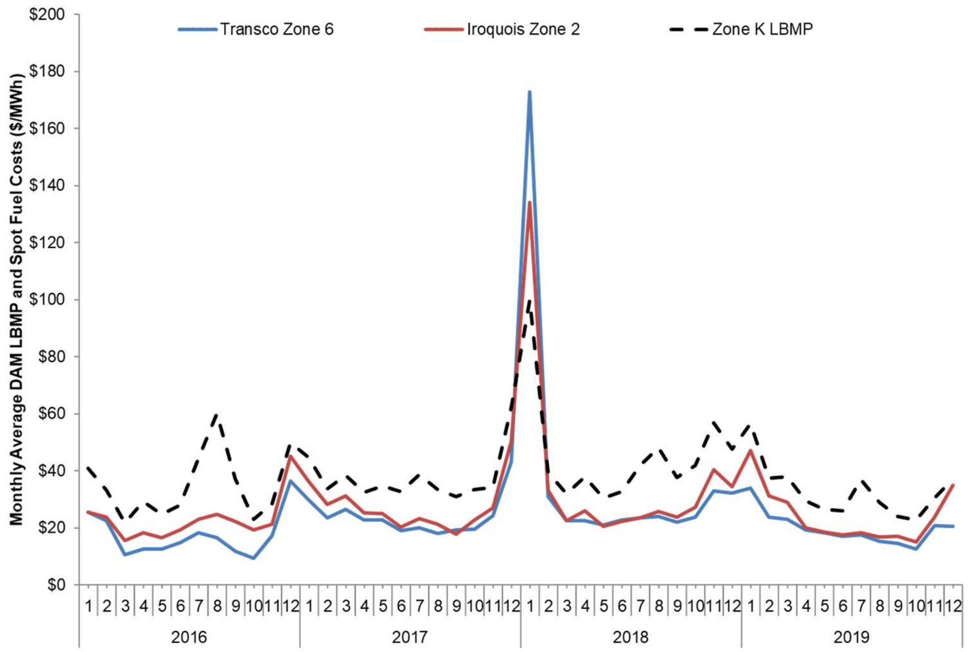
Note: Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources: SNL (Fuel Prices); NYISO (DAM LBMPs).

Figure 17: Natural Gas Price Indices and Load Zone J LBMPs



Note: Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources: SNL (Fuel Prices); NYISO (DAM LBMPs).

Figure 18: Natural Gas Price Indices and Load Zone K LBMPs



Note: CARIS Blend (Zone K) is comprised of a weighted average of spot prices at Iroquois Zone 2 (60%) and Transco Zone 6 NY (40%). Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources: SNL (Fuel Prices); NYISO (DAM LBMPs).

Table 41 identifies the gas hubs selected by AGI based on the considerations listed above, along with input and discussions with NYISO and stakeholders.

Table 42 summarizes AGI's assessment of potentially applicable natural gas indices for each location based on the criteria identified above.

For Load Zones J, Transco Zn 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to Load Zone J and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets.

For Load Zone F, Load Zone G (Dutchess County), and Load Zone K, AGI recommends the use of Iroquois Zone 2 as the natural gas index. These recommendations reflect a balance of considerations, particularly market dynamics and geography. For Load Zone K in particular, Iroquois Zone 2 reflected the best proxy for gas prices during constrained conditions.

For Load Zone G (Rockland County), AGI recommends the use of TETCO M3 as the natural gas index. Certain indices with geographic proximity did not provide a reasonable expectation of the long-run equilibrium between gas and electricity markets. In particular, the Millennium pipeline crosses the zone through Rockland County, but it may not have the required flexibility of supply for a peaking generator during all seasons, particularly after entry of a facility. The Millennium pipeline also has limited reported trading volume in years before 2019, which raise liquidity concerns for use as a proxy gas pricing hub. By contrast, TETCO M3 is a liquid trading hub which best reflects the fuel cost of a peaking generator running intermittently throughout the year.

In Load Zone C, a number of pipelines, including those owned by Tennessee Gas Pipeline (TGP), Dominion, and Millennium, cross the zone. Price analysis conducted by the Market Monitoring Unit found that historical energy price patterns best matched simulated operations based on the TGP Zone 4 (200L) gas hub. Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, AGI recommends the use of TGP Zone 4 (200L) as the natural gas index for Load Zone C.

Table 41: Recommended Gas Index by Load Zone

Load Zone	Natural Gas Index
Load Zone C	TGP Zone 4 (200L)
Load Zone F	Iroquois Zone 2
Load Zone G (Dutchess)	Iroquois Zone 2
Load Zone G (Rockland)	TETCO M3
Load Zone J	Transco Zn 6 NY
Load Zone K	Iroquois Zone 2

Table 42: Natural Gas Hub Selection Criteria, By Load Zone

Load Zone C						
Decision Criteria		**TETCO M3**	**TGP Zone 4 (200L)**	**TGP Zone 4 (Marcellus)**	**Dominion North**	**Dominion South**
	Market Dynamics	High LBMP Correlation	Medium LBMP correlation	Medium LBMP correlation	Medium LBMP correlation	Medium LBMP correlation
	Liquidity	High	High	Medium	Medium	High
	Geography	No	Yes	Yes	Yes	No
	Recommendation		✔			
Precedent	**2016 DCR**	Yes	No	No	No	No
	CARIS (2019) Phase I	No	No	No	No	Part of Zones A-E Blend
	SOM (2018)	No	No	No	Yes	No

Load Zone F			
Decision Criteria		**TGP Zone 6**	**Iroquois Zone 2**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation
	Liquidity	High	Medium
	Geography	No	Yes
	Recommendation		✔
Precedent	**2016 DCR**	No	Yes
	CARIS (2019) Phase I	Part of Zones F-I Blend	Part of Zones F-I Blend
	SOM (2018)	No	Yes

Load Zone G (Dutchess)			
Decision Criteria		**TETCO M3**	**Iroquois Zone 2**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation
	Liquidity	High	Medium
	Geography	No	Yes
	Recommendation		✔
Precedent	**2016 DCR**	No	Yes
	CARIS (2019) Phase I	No	Part of Zones F-I Blend
	SOM (2018)	No	Part of Zone G Blend

Load Zone G (Rockland)				
Decision Criteria		**TETCO M3**	**Iroquois Zone 2**	**Millennium**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation	Medium LBMP correlation
	Liquidity	High	Medium	Low
	Geography	Yes	No	Yes
	Recommendation	✔		
Precedent	**2016 DCR**	No	Yes	No
	CARIS (2019) Phase I	No	Part of Zones F-I Blend	No
	SOM (2018)	No	Part of Zone G Blend	Part of Zone G Blend

Load Zone J		
Decision Criteria		**Transco Zone 6 NY**
	Market Dynamics	High LBMP Correlation
	Liquidity	High
	Geography	Yes
	Recommendation	✔
Precedent	**2016 DCR**	Yes
	CARIS (2019) Phase I	Yes
	SOM (2018)	Yes

Load Zone K			
Decision Criteria		**Transco Zone 6 NY**	**Iroquois Zone 2**
	Market Dynamics	Medium LBMP correlation	Medium LBMP correlation
	Liquidity	High	Medium
	Geography	Yes	Yes
	Recommendation		✔
Precedent	**2016 DCR**	Yes	No
	CARIS (2019) Phase I	Part of Zone K Blend	Part of Zone K Blend
	SOM (2018)	No	Yes

For plants that include dual fuel capability, oil prices are based on the New York Harbor Ultra –Low Sulfur Number 2 Diesel spot price as reported by the Energy Information Administration (EIA).[72]

Table 43 identifies assumptions for various additional costs associated with the use of natural gas or ULSD (for plants assumed to include dual fuel capability). Both natural gas and oil incur transportation and tax costs. Natural gas transport costs range from $0.20 to $0.27 per MMBtu, while oil transport costs range from $1.50 to $2.00 per MMBtu.[73] Within the net EAS model, if the plant was not committed Day-Ahead, real-time net EAS revenues reflect

[72] Data is available from the EIA. *See* https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=eer_epd2dxl0_pf4_y35ny_dpg&f=d

[73] As discussed in Section II, dual fuel plants are assumed to maintain a 96 hour fuel oil inventory. Fuel burn above 96 hours is assumed to be replaced at the daily spot price plus the applicable oil transportation cost. The model does not include limitations to, or assumptions for, the time necessary to refuel each tank. This assumption is supported by estimated oil burn rates projected by the net EAS revenues model. Using data for the period September 2016 through August 2019 associated with the preliminary results provided in this Report, AGI found that for dual fuel peaking plants in Load Zones G, J, and K – assuming the GE HA.02 25ppm with dual fuel and SCR emissions controls -- the minimum number of days to burn 96 hours of fuel oil was 6 days (Load Zone K), 9.5 days (Load Zone J), and 10 days (for the Dutchess County locations in Load Zone G). The maximum total annual oil burn is 119 hours (Load Zone K) occurring during the 12-month period from September 2017 – August 2018. See Appendix E for additional details regarding operations on oil projected by the net EAS revenues model for the preliminary results presented in this Report.

natural gas fuel costs that include an additional intraday gas premium, which ranges from 10% to 30% depending on location. The use of these premiums (discounts) is described above.

Table 43: Fuel Cost Adders by Capacity Region

Capacity 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

Note:
[1] NYC ULSD tax is based on current sales tax rates.
Sources:
[1] Potomac Economics, 2019 State of the Market Report, Table A-16.
[2] New York State Department of Taxation and Finance, Publication 718-A Enactment and Effective Dates of Sales and Use Tax Rates, Effective August 1, 2019.

iii. Emission Allowance Prices:

Allowance prices for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are obtained from S&P Global Market Intelligence, and represent national annual prices for both pollutants, and seasonal prices for NO_x.[74] CO_2 allowance prices are obtained from the Regional Greenhouse Gas Initiative's (RGGI) auction results, representing RGGI-region clearing prices established on a quarterly basis.[75]

iv. Other Fossil Model Data

As noted earlier, the LBMPs, reserve prices, fuel prices, and emission allowance prices are all updated annually to recalculate the net EAS inputs to annual updates of the ICAP Demand Curves. The net EAS revenues model requires additional input data to carry out the calculations, which are not updated as part of the annual update process. This data falls into three main categories:

1. **Peaking plant operating characteristics**: this data includes heat rates, emissions rates, summer/winter capacity ratings, operating capabilities (e.g., start time), and locations (to identify the appropriate LBMPs and gas hubs).
2. **Peaking plant operating costs:** this data includes variable O&M costs, unit start-up costs, natural gas transportation cost adders and taxes, and RTM fuel premiums.
3. **Revenue and pricing data**: this data include voltage support services adders (for all plants) and ancillary service adders (for the informational combined-cycle plants). This category also includes level of excess adjustment factors (LOE-AFs), discussed below in Section IV.B.2.d and in Appendix D.

[74] Annual and seasonal allowance prices are reported on each weekday. Daily values are applied to all hours in the day. Allowance prices are carried forward from a Friday through the subsequent weekend when data is not reported.

[75] RGGI auction results are available here: https://www.rggi.org/market/co2_auctions/results. RGGI's quarterly auctions take place at the start of January, April, July, and October; daily costs are assigned based upon the most recent auction price.

Operating characteristics and costs are summarized further in Table 43 and Appendix B.

v. Battery Specific Data

The net EAS revenues model for battery storage uses the same data as the fossil model for a wide variety of parameters, including LBMPs, LOE-AFs, and Rate Schedule 1 charges. The battery model requires additional input data. This data falls into three main categories:

1. **Battery operating characteristics:** this data includes charging efficiency, storage duration, and the assumed target charge level (i.e., 50% of the battery's capacity), all provided by BMCD.
2. **Battery operating costs:** these data include variable O&M costs provided by BMCD.
3. **Revenue and pricing data:** these data include transmission service charge rates and prices for 10-minute spinning reserves, which are the basis for reserve prices in the battery model. These are both available on the NYISO website. For VSS revenues, the same $2.04/kW-year adder as applicable to combustion turbines peaking plant options is applied to the battery storage options.

d. Level of Excess Adjustment Factors

The net EAS revenues model incorporates adjustment factors to zonal LBMPs and reserve prices to account for the Services Tariff requirement that costs and revenue estimates used in determining the ICAP Demand Curves reflect system conditions with capacity equal to the applicable minimum Installed Capacity Requirement plus the capacity of the peaking plant in NYCA and each Locality (the LOE condition).[76] Consistent with the 2016 DCR, this Services Tariff requirement is addressed through the development of a set of LOE adjustment factors (LOE-AFs) that modify the historical LBMPs and reserve prices used in the net EAS revenue calculations to approximate prices under LOE conditions.

For example, if actual LBMPs are based on system conditions with resource margins well above the tariff-prescribed LOE conditions, net EAS revenues would likely be lower than the peaking plant would experience under LOE conditions. In this case, the adjustment factors should tend to increase net EAS revenue estimates (i.e., reflect a multiplier greater than one). Conversely, if actual LBMPs are at system conditions reflecting a shortage of resources relative to the tariff-prescribed LOE conditions, estimated net EAS revenues would likely exceed those that the peaking plant would experience at LOE conditions, leading to adjustment factors of less than one.[77]

AGI has developed a set of LOE-AFs based on production cost model simulations conducted by GE Energy Consulting (GE), using GE's Multi-Area Production System (MAPS, or GE-MAPS). GE-MAPS generates hourly, locational marginal prices based on a detailed production cost simulation system of NYISO and connected power regions, with system operations and dispatch based on forecasted load, generating asset operational and cost characteristics, and a representation of constraints on the transmission system. For the purposes of this Report,

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[76] Services Tariff, Section 5.14.1.2.

[77] If actual system conditions on which historical prices are based are exactly the same as the LOE conditions, then the adjustment factor (for that given time period and Load Zone) would be 1.0.

GE relied on supply and load assumptions within the 2019 Congestion Assessment Resource Integration Study (CARIS) Phase 1 Base Case data.[78]

LOE-AFs are developed through the comparison of two modeling cases. A base case represents current system conditions ("as found" conditions), while an "LOE" case represents system conditions at the tariff-prescribed LOE. LOE-AFs are developed as the ratio of average day-ahead LBMPs in the base case to average LBMPs in the LOE case for each Load Zone, where LBMPs are first averaged within each month and period across all of the modeled years 2021 to 2025. Three periods are evaluated: on-peak, peak load window, and off-peak, are defined as follows:

- *On-peak* hours are all hours between 7 am and 10:59pm, Monday through Friday except for NERC defined holidays and Peak Load Window hours (below).
- *Peak Load Window* hours are as follows: [79]
  - Summer (June-August): hours beginning 1 pm until 6:59 pm
  - Winter (December-February): hours beginning 4 pm until 9:59 pm
- *Off-peak* are all hours not defined as included within on-peak or peak load window hours

To model system conditions appropriate under the LOE case, system loads were adjusted in each Load Zone so that the resulting ratio of peak load to available resources equaled the applicable reserve margin consistent with LOE market conditions – i.e., ICR/LRC plus the capacity of the peaking plant for each capacity region.

For purposes of the preliminary data provided in this Report, AGI used an assumed value of 300 MW for the peaking plant in each capacity region. This approximately represents the average MW size of the various peaking plant options evaluated in this study. The LOE-AFs will be updated in September 2020 to reflect the appropriate values based on the actual MW size for the recommended peaking plants within each capacity region.

Within GE-MAPS, LBMPs are modeled in every hour of each year of the DCR period (2021 – 2025) under this base-case representation. Each LOE-AF (by Load Zone, month and period) reflects the average over the four-year DCR period. A single set of LOE-AFs was developed. This set of LOE-AFs, calculated at the time of the DCR, will remain set for the duration of the reset period, and will be applied to historical LBMPs and reserve prices used in each subsequent Capability Year's net EAS revenues calculation during the reset period.

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[78] A draft of the 2019 CARIS Phase 1 report was presented to the NYISO Electric System Planning Working Group on April 23, 2020. The 2019 CARIS Phase 1 database reflects current changes to system conditions and updated parameters, including updated generator additions and retirements, 2019 Gold Book peak load and energy forecasts, and updated fuel and emission price forecast. For additional details regarding the 2019 CARIS Phase 1 database, see NYISO, "2019 CARIS 1 Draft Report Review," Presentation to Electric System Planning Working Group, April 23, 2020, https://www.nyiso.com/documents/20142/12126107/03%202019CARIS1_DraftReport%20presentation.pdf/aec74470-f8e3-cea0-9e94-80f056472212.

[79] These definitions correspond to the peak load windows proposed by NYISO for wind and solar resources to determine relative capacity value weightings as part of the Market Design Concept Proposal. See, for instance, the November 21, 2019 presentation to the ICAPWG and Market Issues Working Group. AGI reviewed average annual LBMPs by Load Zone and month and confirmed that peak periods are consistent with this definition.

As described in Equation (1), LBMPs and reserve prices are multiplied by the LOE-AFs to approximate prices that would be faced by a peaking plant at LOE market conditions, consistent with the requirements of the Services Tariff. For example, if the three-year average LBMP during a given peak hour in a Load Zone in July is $50/MWh, and the LOE-AF for peak hours in July is 1.02 for such location, then the LBMP for that hour used in net EAS calculations would be $50 * 1.02 = $51/MWh.

Average preliminary LOE-AFs across all months and periods ranged from 1.03 in Load Zone F to 1.07 in Load Zone C. Appendix D contains the full set of preliminary LOE-AFs used in the preliminary net EAS revenues analysis by Load Zone, month and period based on the GE-MAPS analysis.

C. Preliminary Results

The preliminary values in this Report are for the 2021/2022 Capability Year. For subsequent Capability Years encompassed by this reset period, the net EAS revenues will be calculated using the same model, but with updated data as part of the annual update process described in Section VI below.

Preliminary net EAS results for the Capability Year 2021/2022, by location, are summarized in Table 44 through

Table 46. Included are the preliminary average annual net EAS revenues (in nominal $/kW-year) over the three-year historic period, summarized by peaking plant type and location, as well as preliminary average annual values for run hours, unit starts, and hours of operation per start. Appendix E includes detailed preliminary data for each peaking plant, with net EAS revenues reported by DAM position and RTM dispatch, fuel use, and year.

The results provided in this Report are preliminary and subject to change. The values provided herein for estimating net EAS revenues are based on data for the three-year period September 2016 through August 2019 and preliminary LOE-AFs using an assumed 300 MW value for the peaking plant underlying each ICAP Demand Curve. The values will be updated in September 2020 to reflect data for the period September 2017 through August 2020 and final LOE-AFs reflecting the actual MW size of the recommended peaking plants for each capacity region.

Table 44: Preliminary Net EAS Model Results for Fossil Peaking Plants by Load Zone, Dual Fuel Capability

		Annual Average Net EAS Revenues ($/kW-year)						Annual Average Run Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	$47.30	$44.47	$42.42	$44.04	$44.78	$77.54	1,893	1,442	976	1,063	1,533	5,992
F	Capital	$36.38	$32.93	$34.90	$36.24	$33.37	$72.17	1,067	796	751	878	852	5,694
G	Hudson Valley (Dutchess)	$35.79	$32.53	$33.50	$34.19	$32.96	$72.85	1,239	924	756	970	979	5,874
G	Hudson Valley (Rockland)	$54.07	$48.36	$43.93	-	-	$106.10	2,619	2,341	1,320	-	-	7,561
J	New York City	$41.19	$34.53	$31.92	-	-	$101.18	2,700	2,077	1,123	-	-	7,580
K	Long Island	$57.85	$50.54	$47.74	-	-	$132.20	2,922	2,560	1,520	-	-	7,932

		Annual Average Unit Starts						Annual Average Hours per Start					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	150	142	305	84	143	56	12.6	10.2	3.2	12.7	10.7	107.6
F	Capital	129	120	302	101	123	58	8.3	6.6	2.5	8.7	6.9	98.7
G	Hudson Valley (Dutchess)	139	128	289	108	131	56	8.9	7.2	2.6	9.0	7.5	105.5
G	Hudson Valley (Rockland)	154	173	357	-	-	26	17.0	13.5	3.7	-	-	290.8
J	New York City	205	184	330	-	-	41	13.2	11.3	3.4	-	-	183.4
K	Long Island	206	221	382	-	-	44	14.2	11.6	4.0	-	-	178.9

		Annual Average Reserve Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	14	10	19	14	9	-
F	Capital	93	22	103	98	22	-
G	Hudson Valley (Dutchess)	72	18	82	73	15	-
G	Hudson Valley (Rockland)	53	1	72	-	-	-
J	New York City	13	1	41	-	-	-
K	Long Island	15	1	16	-	-	-

Notes:
[1] Results reflect data for the period September 2016 through August 2019 and preliminary LOE-AFs using an assumed 300 MW value for the peaking plant underlying each ICAP Demand Curve. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020 and LOE-AFs reflecting the actual MW size of the applicable peaking plants.
[2] Assumes $2.04/kW-year VSS revenues for combustion turbine plants and $5.53/kW-year revenues for combined cycle plants from VSS and other ancillary service provision, based on settlement data analyzed by NYISO.
[3] Runtime limits were applied based on NSPS and annual operating hour limits for plants that do not include SCR emissions controls.
[4] Combined cycle plants are modeled for informational purposes only. Reserve dispatch is not modeled for combined cycle plants; reserve revenues are incorporated through the $5.53/kW-year adder described in note [2] above.

Table 45: Preliminary Net EAS Model Results for Fossil Plant by Load Zone, Natural Gas-Only

		Annual Average Net EAS Revenues ($/kW-year)						Annual Average Run Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65
C	Central	$47.30	$44.47	$42.42	$44.04	$44.78	$77.54	1,893	1,442	976	1,063	1,533	5,992
F	Capital	$34.77	$31.50	$33.08	$35.23	$31.91	$68.50	1,041	773	721	952	829	5,638
G	Hudson Valley (Dutchess)	$34.24	$31.09	$31.79	$33.41	$31.51	$69.81	1,219	905	734	1,022	960	5,829
G	Hudson Valley (Rockland)	$52.62	$46.87	$42.47	-	-	$102.89	2,620	2,319	1,295	-	-	7,518

		Annual Average Unit Starts						Annual Average Hours per Start					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65
C	Central	150	142	305	84	143	56	12.6	10.2	3.2	12.7	10.7	107.6
F	Capital	128	119	299	109	122	59	8.1	6.5	2.4	8.7	6.8	96.1
G	Hudson Valley (Dutchess)	138	127	286	112	129	57	8.9	7.1	2.6	9.1	7.4	102.9
G	Hudson Valley (Rockland)	152	172	355	-	-	27	17.2	13.5	3.6	-	-	281.9

		Annual Average Reserve Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	14	10	19	14	9	-
F	Capital	93	22	103	98	22	-
G	Hudson Valley (Dutchess)	72	18	82	73	15	-
G	Hudson Valley (Rockland)	55	1	73	-	-	-

Notes:

[1] Results reflect data for the period September 2016 through August 2019 and preliminary LOE-AFs using an assumed 300 MW value for the peaking plant underlying each ICAP Demand Curve. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020 and LOE-AFs reflecting the actual MW size of the applicable peaking plants.

[2] Assumes $2.04/kW-year VSS revenues for combustion turbine plants and $5.53/kW-year revenues for combined cycle plants from VSS and other ancillary service provision, based on settlement data analyzed by NYISO.

[3] Runtime limits were applied based on NSPS and annual operating hour limits for plants that do not include SCR emissions controls.

[4] Combined cycle plants are modeled for informational purposes only. Reserve dispatch is not modeled for combined cycle plants; reserve revenues are incorporated through the $5.53/kW-year adder described in note [2] above.

Table 46: Preliminary Net EAS Model Results by Load Zone, Batteries

		Annual Average Net EAS Revenues ($/kW-year)			Annual Average Run Hours		
		Battery Duration			Battery Duration		
Load Zone		4-Hour	6-Hour	8-Hour	4-Hour	6-Hour	8-Hour
C	Central	$49.45	$49.73	$47.95	645	812	966
F	Capital	$52.81	$51.35	$49.20	575	759	929
G	Hudson Valley (Dutchess)	$56.50	$57.93	$56.06	721	914	1,058
G	Hudson Valley (Rockland)	$55.06	$55.11	$53.27	638	832	998
J	New York City	$57.04	$57.46	$56.19	669	883	1,046
K	Long Island	$66.99	$71.47	$71.98	918	1,164	1,331

		Annual Average Unit Cycles			Average Daily Hours		
		Battery Duration			Battery Duration		
Load Zone		4-Hour	6-Hour	8-Hour	4-Hour	6-Hour	8-Hour
C	Central	161	135	121	1.8	2.2	2.6
F	Capital	144	127	116	1.6	2.1	2.5
G	Hudson Valley (Dutchess)	180	152	132	2.0	2.5	2.9
G	Hudson Valley (Rockland)	160	139	125	1.7	2.3	2.7
J	New York City	167	147	131	1.8	2.4	2.9
K	Long Island	230	194	166	2.5	3.2	3.6

Notes:
[1] Results reflect data for the period September 2016 through August 2019 and preliminary LOE-AFs using an assumed 300 MW value for the peaking plant underlying each ICAP Demand Curve. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020 and LOE-AFs reflecting the actual MW size of the applicable peaking plants.
[2] Assumes $2.04/kW-year VSS revenues for all plants, based on settlement data analyzed by NYISO.

V. ICAP Demand Curve Model and Reference Point Prices

A. Introduction

The ICAP Demand Curves are designed to ensure that the ICAP market provides sufficient revenues to support the development of new peaking plant resources to maintain resource adequacy. In Sections III and IV, AGI established the values for gross CONE and net EAS revenues for the peaking plant technologies in all locations evaluated in this study. The difference in annualized gross CONE and net EAS revenues is defined as the ARV. That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technologies. This section describes how the resulting ARVs are translated into RPs that form an anchor for the slope of the ICAP Demand Curve in each capacity region, thereby accounting for the tariff-prescribed LOE conditions and seasonal nature of the ICAP markets. With these conclusions in hand, AGI presents the resulting preliminary ICAP Demand Curve parameters for each capacity region for Capability Year 2021/2022. Section VI summarizes the procedures for annual updating of ICAP Demand Curve parameters through the formulaic approach established at the time of this DCR.

B. ICAP Demand Curve Shape and Slope

The ICAP Demand Curves are designed with three basic elements: a cap on the maximum allowable prices, a floor on prices (at zero), and a sloped demand curve that determines prices for varying levels of capacity between this cap and floor. In principle, the ICAP Demand Curve slope reflects the declining marginal value of additional capacity in terms of incremental improvements in reliability – that is, as the quantity of capacity increases. Incremental capacity provides diminishing value in terms of reductions in loss of load expectation (LOLE). The sloped portion of the demand curve, in principle, is intended to capture this declining value. However, at some point, this value becomes so small that incremental capacity provides no meaningful improvement in reliability. To capture this limit, the ICAP Demand Curves include a ZCP, which reflects the point at which incremental capacity provides no incremental value and the price declines to zero. Along with capturing the declining marginal value of capacity, a sloped demand curve also reduces the volatility of capacity market prices, which can reduce developer financial risk thereby providing a market environment more conducive to capital investment to support resource adequacy, and reduces incentives for the exercise of market power.

The ICAP Demand Curves are constructed such that the peaking plant would exactly recover its ARV when the system is at the LOE – that is, the applicable ICR/LCR plus the capacity of the peaking plant. Given differences in costs between Load Zones as well as transmission constraints that limit flows between Load Zones, separate ICAP Demand Curves are established for NYCA and each Locality. Each ICAP Demand Curve is comprised of three portions (each of which is a straight line) reflecting the three components discussed above:

1) Maximum allowable price: A horizontal line with the price equal to 1.5 times the monthly gross CONE value for each capacity region;
2) Sloped segment: A sloped straight-line segment that intersects with number (1) and passes through two points: (a) the point at which the capacity is equal to the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, and the price is equal to the NYCA/Locality RP, and (b) the zero crossing point at which the price is equal to zero; and

3) Price floor: A horizontal line with the price equal to zero and the quantity includes all quantities greater than the ZCP quantity.[80]

Ultimately, the slope of the sloped portion of the line is determined by the RP and ZCP. As described below, the RP is a function of the ARV, the ZCP ratios (ZCPR), the impact of additional capacity from the tariff prescribed LOE conditions, and seasonal factors. The following sections provide additional detail on the ZCPR, winter-to-summer ratio (WSR), and LOE factors. Following this discussion, the RP formula and ICAP Demand Curve geometry is presented in greater detail.

1. Zero crossing point

In the 2013 DCR, the ZCPs for NYCA and the Localities were set at 112% of IRM for NYCA, 118% of LCR for Long Island, 118% of LCR for New York City, and 115% of LCR for the G-J Locality. This decision retained the then-current ZCPs for NYCA, NYC, and LI, and set the ZCP for the G-J Locality midway between the values for NYC and NYCA. Prior to this decision, two separate analyses of the ZCP were performed to inform ZCP decisions. The first analysis was a study completed by FTI that evaluated the economics of setting the ZCPs based on GE-MARS analysis of loss of load expectations associated with varying levels of capacity in the market.[81] While FTI had recommended revising the ZCPs based on the results of its analysis, the independent consultant during the 2013 DCR ultimately recommended adjusting ZCPs to a point midway between then-current values and the values recommended by FTI. After the completion of the consultant's study report for the 2013 DCR, an analysis was performed by the Market Monitor Unit (Potomac Economics) that was also based on GE-MARS modeling completed by NYISO Planning staff.[82]

Both the FTI and MMU recommendations for potential changes to ZCPs were based on assessments of the point at which additional capacity beyond the applicable minimum requirement provided little or no marginal value in terms of improved reliability (as reflected in resulting changes LOLE). However, the analyses differed in two key respects. First, the underlying MARS modeling used in the FTI analysis was based on "shifts" in capacity from the Localities to the NYCA. In contrast, the modeling used by MMU relied on adding incremental capacity to each Locality and NYCA. Second, FTI relied on judgement to determine the ZCP – that is, relying on visual inspection to determine the point at which incremental value was near zero. The MMU quantitatively fit curves through scenarios outcomes to determine where the change in LOLE became zero.

Since the 2013 DCR, no additional studies have been conducted to specifically inform the determination of ZCPs for the ICAP Demand Curves. However, in the *Reliability and Market Considerations for a Grid in Transition* report, the NYISO recommended consideration of a separate initiative to assess the shape and slope of the ICAP Demand Curves.[83] NYISO has proposed for stakeholder review a 2021 project effort to conduct such an

[80] When referencing the ZCP in percentage terms relative to applicable IRM or LCR, AGI uses the term zero crossing point ratio (ZCPR).

[81] NERA Report, pp. 14-15.

[82] The MMU analysis was presented at the August 22, 2013 ICAPWG meeting.

[83] "Reliability and Market Considerations for a Grid in Transition," NYISO, December 20, 2019, at p. 54, available at: https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf.

assessment outside the context of the DCR. Considering these factors, AGI recommends that the current ZCPs remain unchanged for this DCR.

2. Winter-to-Summer Ratio

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. Figure 19 illustrates the differences in price during the winter season when there is a higher quantity of system 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.[84] 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.

The preliminary results presented in this Report reflect the applicable WSR values determined using data for the same three-year historic period as the preliminary net EAS revenues estimates (i.e., September 2016 through August 2019. The WSR values will be updated in September 2020 to reflect data for the period September 2017 through August 2020.

[84] 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 in 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.

Figure 19: Illustration of the Reference Point Price, Level of Excess, and Seasonal Capacity

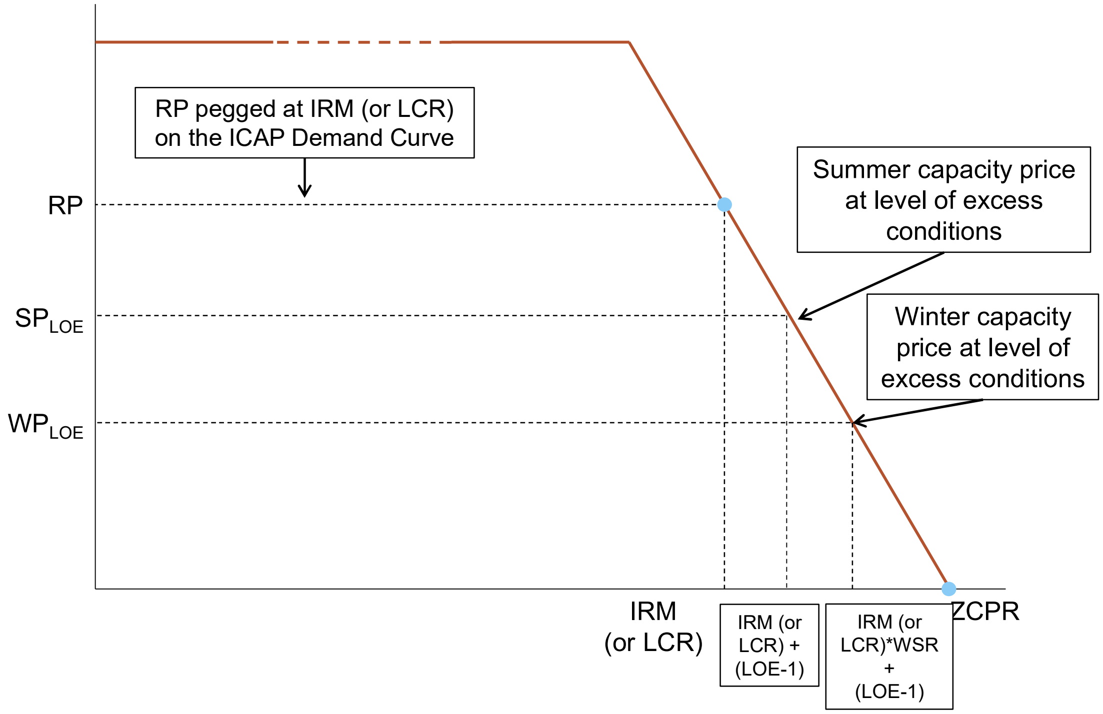


Table 47 provides the WSR values used in this Report and reflect data for the period September 2016 through August 2019.

Table 47: Winter-to-Summer Ratio by Location

Capacity Region	Capability Year	Winter-Summer Ratio
NYCA	2021-2022	*1.040*
G-J	2021-2022	*1.058*
New York City	2021-2022	*1.078*
Long Island	2021-2022	*1.076*

Note:
[1] The preliminary results have been calculated using the WSR from the 2019 Annual Update for Capability Year 2020-2021, which reflect data for the same three year period used to determine the preliminary net EAS revenues estimates provided in this Report (i.e., September 2016 through August 2019). The WSR values will be updated in September 2020 to reflect data for the period September 2017 through August 2020.

3. *Level of Excess Criterion*

The 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.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)} \quad (6)$$

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 ICR/LCR values are based on the peak load forecasts and the IRM/LCR values for the 2020/2021 Capability Year. Table 48 and Table 49 provides 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 48: Fossil Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2020)	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%	100.41%	100.54%	100.90%	100.85%	101.29%
G-J	15,695	90.0%	101.12%	101.48%	102.46%	-	103.54%
NYC	11,477	86.6%	101.60%	102.11%	103.51%	-	105.05%
LI	5,227	103.4%	102.94%	103.89%	106.45%	-	109.30%

Note:
[1] Average degraded net capacity by technology is provided in Table 32.

Table 49: Battery Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2020)	2020-2021 IRM/LCR	LOE (%) by Battery Duration		
			4-hr BESS	6-hr BESS	8-hr BESS
NYCA	32,296	118.9%	100.52%	100.52%	100.52%
G-J	15,695	90.0%	101.42%	101.42%	101.42%
NYC	11,477	86.6%	102.01%	102.01%	102.01%
LI	5,227	103.4%	103.70%	103.70%	103.70%

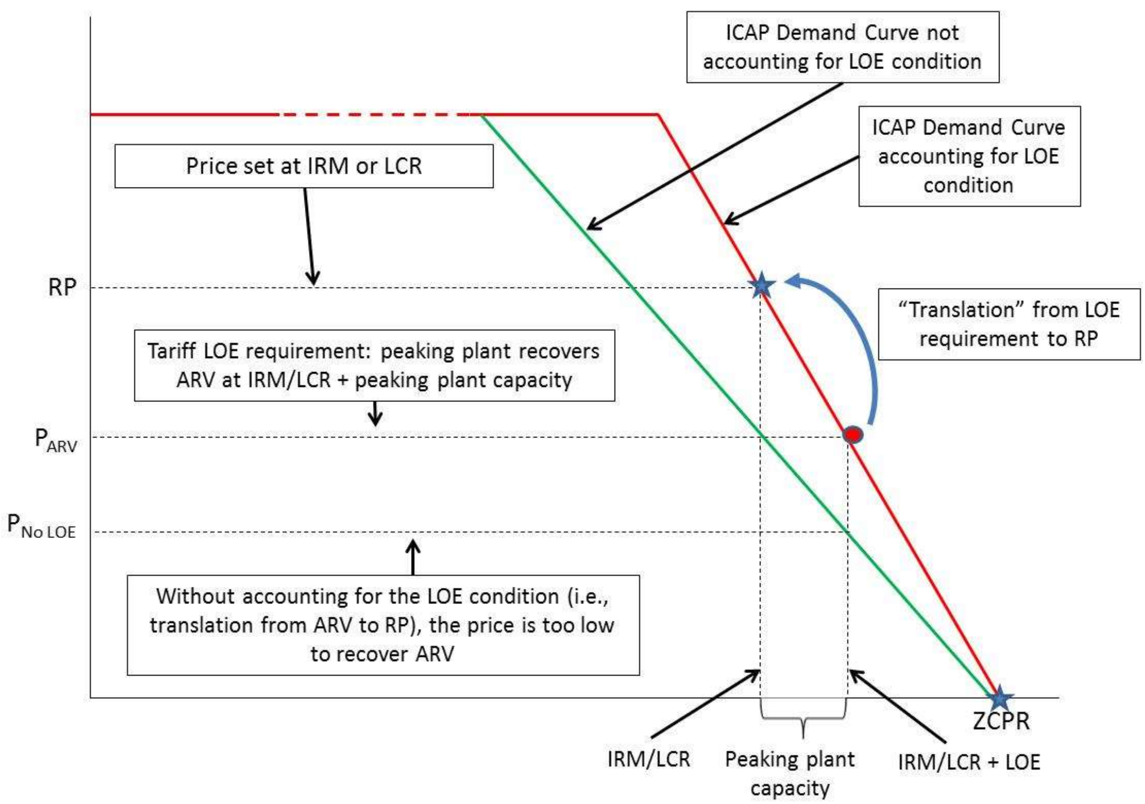
Note:
[1] Average degraded net capacity by technology is provided in Table 32.

C. Reference Point Price Calculations

Figure 20 illustrates the "geometry" of the ICAP Demand Curve and the LOE requirements, which in turn determine the RP. The ICAP Demand Curve slope is determined by two conditions: (1) the requirement that peaking plant earns its revenue requirement at the LOE, illustrated by the red dot in Figure 20, with the price P_{ARV} and the quantity "IRM/LCR + LOE"; and (2) the ZCPR. These two points define the red line in Figure 20, which is the ICAP Demand Curve slope. Having defined the ICAP Demand Curve slope, the RP can be calculated at the appropriate quantity for each capacity region – that is, the IRM for NYCA and the LCR for each Locality. This calculation requires a translation that is defined below.

Figure 20 also illustrates the ICAP Demand Curve slope absent the LOE requirement (the green line, set so that the peaking plant recovers its ARV at the IRM/LCR). When the RP is calculated *without* an adjustment to account for the tariff prescribed LOE condition, the price earned by the hypothetical peaking plant at the LOE (i.e., $P_{No\ LOE}$ in Figure 20) would be insufficient to recover ARV.

Figure 20: Illustration of the Reference Point Price and Level of Excess Requirement



Equation (7) defines the RP as a function of both the seasonal capacity adjustment (the WSR) and the LOE requirement:

$$RP = \frac{ARV * AssmdCap}{6 * \left[SDMNC * \left(1 - \frac{LOE-1}{ZCPR-1}\right) + WDMN \quad * \left(1 - \frac{(LOE-1)+(WSR- \quad)}{ZCPR-1}\right)\right]} \qquad (7)$$

Where:

ARV is the annual reference value for the relevant peaking plant ($/kW-year)

SDMNC is the summer dependable maximum net capability for the relevant peaking plant (MW)

WDMNC is the winter dependable maximum net capability for the relevant peaking plant (MW)

AssmdCap is the average degraded net plant capacity for the relevant peaking plant

LOE is the ratio of IRM/LCR plus the assumed capacity of the relevant peaking plant to IRM/LCR (%)

WSR is the ratio of total winter ICAP to total summer ICAP, as calculated by the NYISO for the relevant capacity region

ZCPR is the ZCP ratio of the ICAP Demand Curve for the relevant capacity region

RP is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region

Along with accounting for the LOE requirement, Equation (7) also accounts for differences in the capacity market revenue and peaking plant capacity between Summer and Winter Capability Periods. These differences in seasonal prices were illustrated in Figure 19. Thus, the plant's ARV (defined in $/kW-year) is met through different revenue streams in each season – that is:

$$ARV * AssmdCap = 6 * SP * SDMNC + 6 * WP * WDMNC \qquad (8)$$

Where:

SP and *WP* represent the assumed summer and winter capacity prices at the tariff prescribed LOE conditions as illustrated in Figure 19 and Figure 20.

Equation 7 reflects the solution to the revenue adequacy requirement in Equation 8, given the following equations for *SP* and *WP*:

$$SP = RP \times \left(1 - \frac{LOE-1}{ZCPR-1}\right)$$

$$WP = RP \times \left(1 - \frac{(LOE - 1) + (WSR - 1)}{ZCPR - 1}\right)$$

D. Preliminary ICAP Demand Curve Parameters

AGI has applied the methods, models and equations described in this Report to identify preliminary RPs and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2021/2022. These preliminary values are presented in Table 50 through Table 53, below. Figure 21 through Figure 24 provides a comparison of these preliminary ICAP Demand Curve parameters relative to ICAP Demand Curve parameters for the first Capability Year encompassed by prior DCRs.[85]

The results provided in this Report are preliminary and subject to change. The values provided herein for estimating net EAS revenues and WSR values are based on data for the three-year period September 2016 through August 2019. The preliminary LOE-AFs used assume a 300 MW value for the peaking plant underlying each ICAP Demand Curve. The values will be updated in September 2020 to reflect data for the period September 2017 through August 2020. Final LOE-AFs will reflecting the actual MW size of the recommended peaking plants for each capacity region.

To arrive at these results, AGI and BMCD considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of RP values. [**All numerical results presented below will be updated in September 2020 to use the finalized data as required for the estimation of net EAS revenues and escalation of capital costs**.] Specifically, AGI and BMCD preliminarily conclude the following:

- The GE 7HA.02 (H Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. 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, and Load Zone G (Rockland County), and without SCR emissions control technology in the other locations assessed (i.e., Load Zone C, Load Zone F, and Load Zone G (Dutchess County)).
- Based on market expectations for fuel availability and fuel assurance, changes in market structures, consideration of applicable reliability and LDC tariff requirements, and developer expectations, the H Class Frame machine should be built with dual fuel capability in Load Zone G (Dutchess County), Load Zone G (Rockland County), Load Zone J, and Load Zone K. AGI and BMCD recommend a gas-only (without dual fuel capability) design in ROS (i.e., Load Zone C and Load Zone F).
- The state of New York has begun a process to decarbonize the power sector over the next couple decades. This does not eliminate consideration of a fossil-fueled plant as the reference case technology. It does, however, suggest review of the ways in which these legislative efforts affect the development and operation of such facilities, which could in turn affect the present-day financial analysis parameters (e.g., the appropriate amortization). We recommend a 17-year amortization period for fossil-fueled plants in consideration of restrictions on fossil fuel operations past 2039 pursuant to the CLCPA.

[85] All values are expressed in nominal dollars.

- Based on our review, battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time. We come to this conclusion based primarily on our estimates of the net CONE for a sample battery storage facility with 4-, 6-, and 8-hour duration of storage.
- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55% debt and 45% equity; a 7.7% cost of debt; and a 13.0% return on equity, for a WACC of 10.09%. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 8.92% and 8.55%, respectively.
- Net EAS revenues are estimated for the peaking plant technologies using gas hubs that reflect consideration of a number of factors, including consistency of gas prices with LBMPs within each Load Zone, liquidity of trading, geographic consistency with the locations evaluated, and precedence of use in other studies/analysis. To that end, net EAS revenues are estimated using the following gas hubs, which are fixed for the four-year duration of the reset period:

  - Load Zone C: TGP Zone 4 (200L)
  - Load Zone F: Iroquois Zone 2
  - Load Zone G (Dutchess County): Iroquois Zone 2
  - Load Zone G (Rockland County): TETCO M3
  - Load Zone J: Transco Zone 6 New York
  - Load Zone K: Iroquois Zone 2

- ICAP Demand Curves should maintain the current ZCP values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves. ICAP Demand Curves should maintain the current zero crossing point (ZCP) values.

Table 50 provides the preliminary parameters of the ICAP Demand Curves for the 2021/2022 Capability Year consistent with the conclusions and technology findings described above. Table 51 through Table 53 provides additional information for the other technologies evaluated. For ICAP Demand Curves where more than one location is evaluated (i.e., NYCA and the G-J Locality), the appropriate location and peaking plant technology selected as the basis for the 2021/2022 Capability Year ICAP Demand Curves remain fixed for the four year duration of the reset period.

Table 50: Preliminary ICAP Demand Curve Parameters ($2021)

GE 7HA.02

Parameter	Source	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
		Current Year (2021-2022)					
Gross Cost of New Entry ($/kW-Year)	[1]	$122.30	$123.40	$139.82	$157.24	$201.26	$167.36
Net EAS Revenue ($/kW-Year)	[2]	$45.58	$36.46	$35.38	$55.96	$42.62	$59.87
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$76.72	$86.94	$104.44	$101.28	$158.64	$107.49
ICAP DMNC (MW)	[4]	326.7	328.5	329.9	347.0	348.8	348.8
Total Annual Reference Value	[5] = [3] * [4]	**$25,063,999**	**$28,559,527**	**$34,454,327**	**$35,145,132**	**$55,333,074**	**$37,490,768**
Level of Excess (%)	[6]	100.9%	100.9%	102.3%	102.5%	103.5%	106.5%
Ratio of Summer to Winter DMNCs	[7]	1.040	1.040	1.058	1.058	1.078	1.076
Summer DMNC (MW)	[8]	332.0	333.2	334.9	350.2	354.5	352.6
Winter DMNC (MW)	[9]	344.8	346.6	348.6	370.5	374.3	373.3
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.55	$8.57	$10.96	$10.66	$17.49	$13.01
Winter ($/kW-Month)	[11]	$4.84	$5.49	$5.94	$5.73	$8.07	$4.45
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,507,463	$2,855,624	$3,671,140	$3,733,832	$6,199,744	$4,588,208
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,669,866	$1,904,290	$2,071,242	$2,123,706	$3,022,435	$1,660,252
Seasonal Revenue (Summer)	[14] = 6 * [12]	$15,044,779	$17,133,744	$22,026,842	$22,402,994	$37,198,465	$27,529,245
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,019,198	$11,425,738	$12,427,451	$12,742,236	$18,134,610	$9,961,511
Total Annual Reference Value	[16] = [14]+[15]	**$25,063,978**	**$28,559,482**	**$34,454,292**	**$35,145,230**	**$55,333,075**	**$37,490,756**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$8.13	**$9.23**	**$12.98**	**$12.75**	**$21.72**	**$20.29**
ICAP Max Clearing Price ($/kW-Month)		$15.29	$15.43	$17.48	$19.66	$25.16	$20.92
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes:
[1] The peaking plant technology choice in Load Zones C and F is a 1x0 GE 7HA.02 operating in gas only mode without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[2] The peaking plant technology choice in Load Zone G (Dutchess County) is a 1x0 GE 7HA.02 that includes dual fuel capability without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[3] The peaking plant technology choice in Load Zones G (Rockland County), NYC, and LI is a 1x0 GE 7HA.02 (tuned to emit 25ppm NOx) that includes dual fuel capability and SCR emissions controls.
[4] The preliminary net EAS revenues are estimated using data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

Table 51: Comparison of Preliminary Reference Point Prices by Technology ($2021/kW-mo.)

Monthly Reference Point Price ($/kW-Month)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$28.04	$27.92	$39.88	$33.53
	Gas Only, with SCR	$22.52	$23.77	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$17.21	$28.23	$22.78
	Dual Fuel, without SCR	-	-	$16.36	-	-	-
	Gas Only, without SCR	$11.36	$12.91	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$12.75	$21.72	$20.29
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$12.98	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$8.13	$9.23	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$21.61	$18.64	$46.53	$38.60
	Gas Only, with SCR	$14.15	$15.63	-	-	-	-
4-hr BESS	Battery Storage	$18.89	$18.69	$20.46	$21.61	$30.92	$25.11
6-hr BESS	Battery Storage	$25.74	$25.84	$28.14	$29.74	$40.05	$35.18
8-hr BESS	Battery Storage	$34.71	$34.93	$38.28	$40.25	$52.49	$48.35

Table 52: Comparison of Preliminary Gross CONE by Technology ($2021/kW-year)

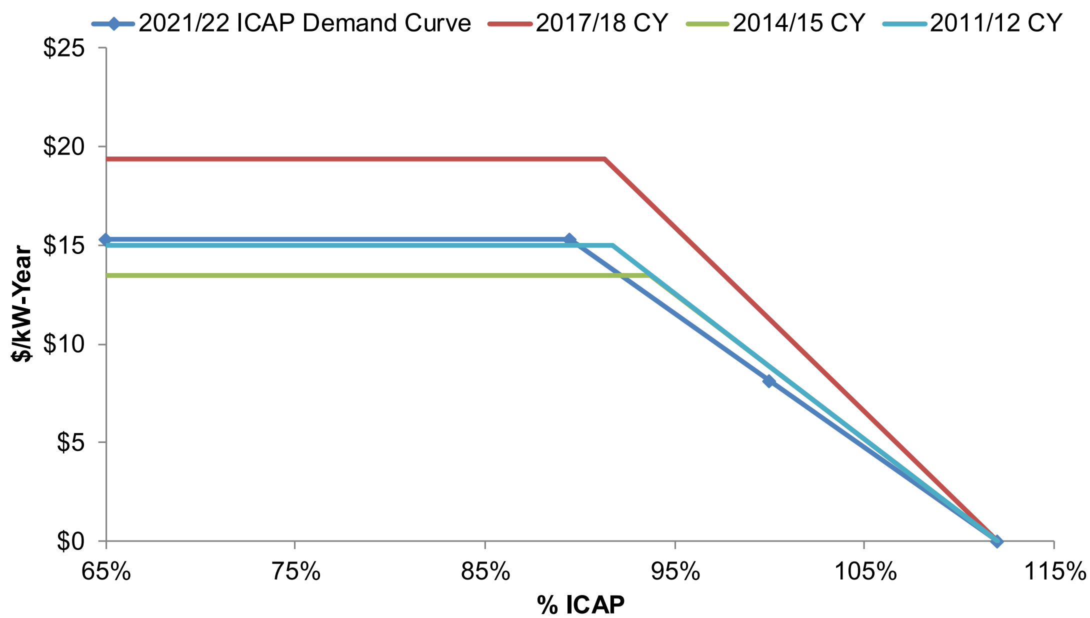
Gross CONE ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$302.41	$312.50	$394.23	$320.48
	Gas Only, with SCR	$279.83	$282.81	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$202.29	$271.33	$214.78
	Dual Fuel, without SCR	-	-	$179.37	-	-	-
	Gas Only, without SCR	$158.97	$160.84	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$157.24	$201.26	$167.36
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$139.82	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$122.30	$123.40	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$224.02	$238.02	$385.15	$263.89
	Gas Only, with SCR	$205.45	$208.74	-	-	-	-
4-hr BESS	Battery Storage	$212.30	$214.12	$215.84	$223.24	$283.27	$227.53
6-hr BESS	Battery Storage	$295.44	$298.07	$300.50	$311.18	$382.20	$320.22
8-hr BESS	Battery Storage	$378.60	$382.06	$385.19	$399.15	$481.12	$412.91

Table 53: Comparison of Preliminary Net EAS by Technology ($2021/kW-year)

Net EAS ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$34.67	$45.46	$33.04	$49.40
	Gas Only, with SCR	$43.90	$34.23	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	-	$50.05	$35.73	$52.30
	Dual Fuel, without SCR	-	-	$34.11	-	-	-
	Gas Only, without SCR	$46.34	$33.02	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	-	$55.96	$42.62	$59.87
	Dual Fuel, tuned to 15 ppm, without SCR	-	-	$35.38	-	-	-
	Gas Only, tuned to 15 ppm, without SCR	$45.58	$36.46	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$75.39	$109.80	$104.71	$136.81
	Gas Only, with SCR	$80.25	$70.89	-	-	-	-
4-hr BESS	Battery Storage	$51.18	$54.65	$58.47	$56.98	$59.03	$69.33
6-hr BESS	Battery Storage	$51.46	$53.14	$59.95	$57.03	$59.47	$73.96
8-hr BESS	Battery Storage	$49.62	$50.91	$58.02	$55.12	$58.16	$74.50

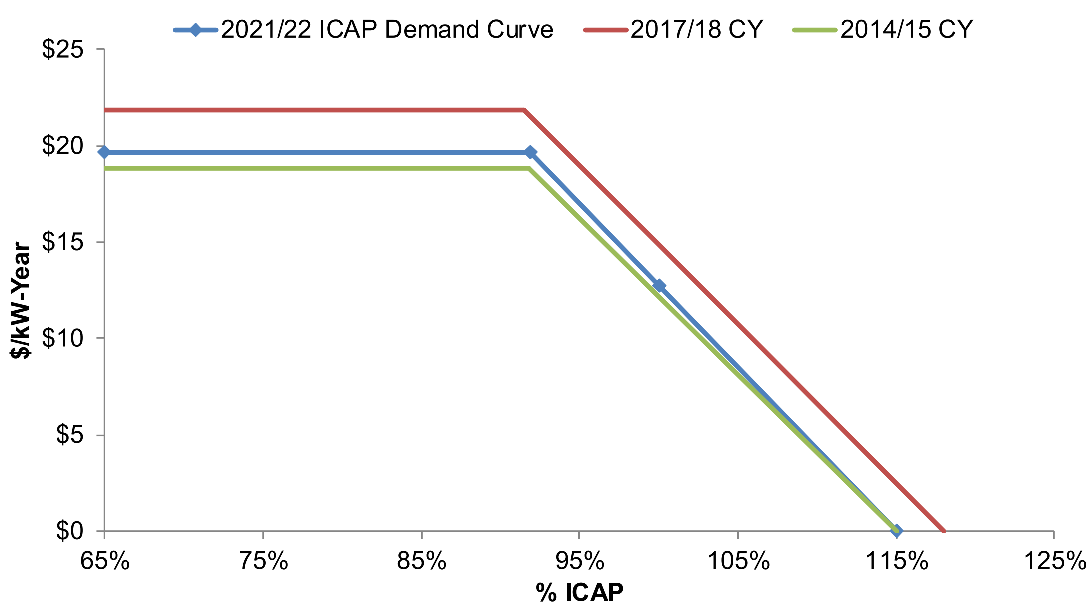
Note:
[1] The preliminary net EAS revenues are estimated using data for the three-year period September 2016 through August 2019. The values will be updated in September 2020 to reflect data for the period September 1, 2017 through August 31, 2020.

Figure 21: Comparison of Preliminary NYCA 2021/2022 ICAP Demand Curves to Prior ICAP Demand Curves



Note:
[1] 2021/2022 Preliminary NYCA ICAP Demand Curve is based on peaking plant located in Load Zone C.

Figure 22: Comparison of Preliminary G-J Locality 2021/2022 ICAP Demand Curve to Prior ICAP Demand Curves



Note:
[1] 2021/2022 Preliminary ICAP Demand Curves for the G-J Locality is based on a peaking plant located in Rockland County location within Load Zone G.

Figure 23: Comparison of Preliminary NYC 2021/22 ICAP Demand Curve to Prior ICAP Demand Curves

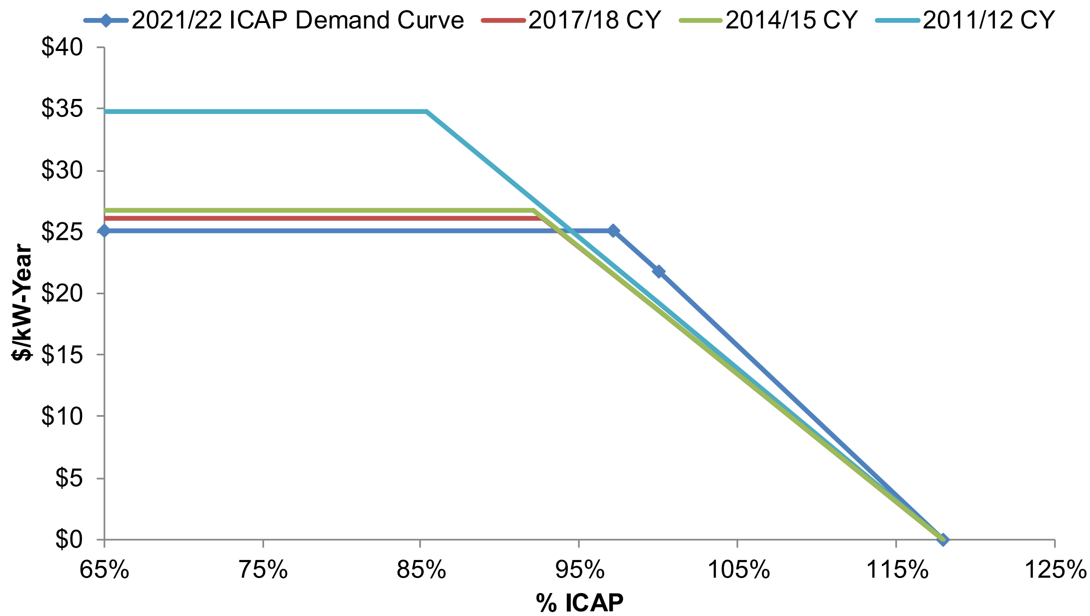
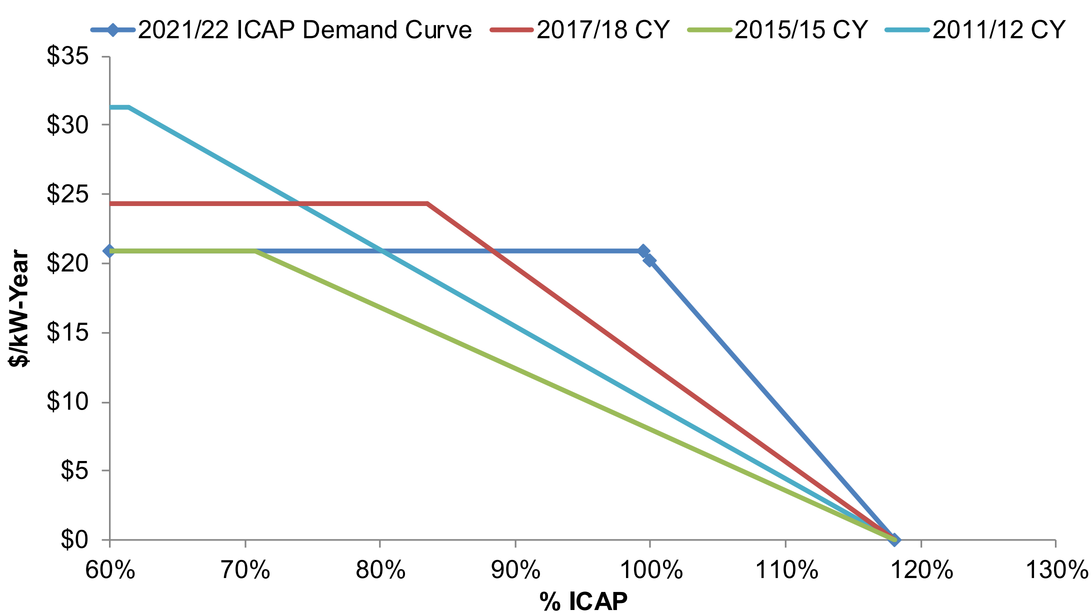


Figure 24: Comparison of Preliminary LI 2021/2022 ICAP Demand Curve to Prior ICAP Demand Curves



VI. Annual Updating of ICAP Demand Curve Parameters

As described above, AGI's demand curve model calculates the RPs for each Locality and NYCA based input values for revenue requirements (i.e., ARV), financial parameters, "shape" parameters and other parameters (WSR, and various capacity values). Outputs of the DCM provide the applicable ICAP Demand Curve parameters for the Capability Year in question and associated financial metrics. These outputs include the gross CONE ($/kW-year), net EAS revenues ($/kW-year), ARV ($/kW-year and total $/year), ICAP monthly RP ($/kW-Month), ICAP Demand Curve maximum clearing price ($/kW-Month), and ICAP Demand Curve length (%).

ICAP Demand Curves will be updated annually based the updating of (1) gross CONE, (2) net EAS revenues, and (3) the WSR. Updates to gross CONE and net EAS revenues will be based on the data and models discussed in Sections III and IV, and described in greater detail below. The WSR will be updated by NYISO and account for resource entry and exit decisions that would lead to changes in system resource conditions that are expected to persist over time.[86] However, changes in the WSR will occur gradually, because the WSR will be measured over a rolling 3-year period.

Table 54 contains a summary of the factors used in the ICAP Demand Curve calculations, with an indication of data source and whether or not they are updated annually (items in BOLD are updated annually).

Table 54: Overview of ICAP Demand Curve Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
ICAP Demand Curve Values	
Zero-crossing point	Fixed for Quadrennial Reset Period
Reference Point Price Calculation	
Peaking Plant Net Degraded Capacity	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Winter Capability Period DMNC	Fixed Value (Fixed for Quadrennial Reset Period)
Installed Capacity Requirements (IRM/LCR)	Fixed Value (Fixed for Quadrennial Reset Period)
Monthly Available Capacity Values for Use in Calculating WSR	**NYISO Published Values**

[86] Services Tariff, Section 5.14.1.2.2.3.

The NYISO will post updated ICAP Demand Curve values on or before November 30th of the calendar year immediately preceding the beginning of the Capability Year for which the updated ICAP Demand Curves will apply.

A. Annual Updates to Gross CONE

An element of annual updates is the update of gross CONE. 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.[87]

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

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

The cost-component weighting factors are calculated for each peaking plant technology reflecting each component's share of total peaking plant installed capital costs. Table 55 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 over the reset period, but the values resulting from the indices will be updated annually based on the indices and component weights described in Table 55.

The general component of the composite escalation factor between Q2 2019 and Q2 2020 was 1.73%. The composite escalation factor for the recommended peaking plant technology based on the data available as of this Report is 3.87%.

The composite escalation rate (and the rate associated with the general component thereof) will be updated annually using data published by indices as of October 1st of the year prior to the start of the Capability Year to which the relevant ICAP Demand Curves will apply. 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).

[87] Services Tariff, Section 5.14.1.2.2.1. This methodology represents a change since the 2016 DCR. *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 55: Composite Escalation Rate Indices and Component Weights, by Technology (2021-22 Capability Year)

Cost Component	Index	Interval	Calculation of Index Value	Growth Rate	Component Weight, by Technology							
					SGT-A65 WLE	GE 7F.05	1x0 GE 7HA.02 25ppm	1x0 GE 7HA.02 15ppm	8000J CC	BESS 4h	BESS 6h	BESS 8h
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	3.89%	20%	30%	25%	25%	37%	15%	15%	15%
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	3.24%	26%	18%	16%	16%	22%	16%	14%	13%
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	5.57%	31%	25%	35%	35%	18%			
Storage Battery Costs	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Storage Batteries (7901)	Monthly	Average of finalized February, March, April values	-0.34%						53%	56%	57%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	1.73%	23%	27%	23%	23%	23%	16%	15%	15%
Composite Escalation Rate					**3.75%**	**3.59%**	**3.87%**	**3.87%**	**3.54%**	**1.20%**	**1.11%**	**1.06%**

Note:
[1] Escalation rates in this Report reflect the most current data available for each index.[88]

[88] The recommended index for the “turbine component” of the composite escalation factor is different for battery storage plants than fossil peaking plant options. For fossil peaking plant options, the “turbine component” is labeled as “Gas and Steam Turbine Costs” in the table. For battery storage options, the “turbine component” is labeled as “Storage Battery Costs” in the table.

B. Annual Updating of Net EAS

1. Updating Approach and Timing

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, but model inputs would 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 and the LOE-AFs would not be updated for the purposes of annual recalculation of net EAS revenues.

Table 56 contains a summary of the factors used in the net EAS calculation, with an indication of data source and whether or not they are updated annually (items in **bold** are updated annually).

Table 56: Overview of Treatment of Net EAS Model Parameters for Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
Net EAS Revenue Model, including Commitment and Dispatch Logic	Fixed for Quadrennial Reset Period
Peaking plant Physical Operating Characteristics, including start time requirements, start-up cost minimum down time and runtime requirements, operating hours restrictions and/or limitations (if any), heat rate	Fixed for Quadrennial Reset Period
Energy Prices (day-ahead and real-time)	**NYISO Published Values**
Operating Reserves Prices (day-ahead and real-time)	**NYISO Published Values**
Level of Excess Adjustment Factors	Fixed for Quadrennial Reset Period
Annual Value of other ancillary services not determined by net EAS Model (*e.g.*, voltage support service)	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking plant primary and secondary (if any) Fuel Type	Fixed for Quadrennial Reset Period
Fuel tax and transportation cost adders	Fixed Value (Fixed for Quadrennial Reset Period)
Real-time intraday gas acquisition premium/purchase discount	Fixed Value (Fixed for Quadrennial Reset Period)
Fuel Pricing Points (*e.g.*, natural gas trading hub)	Fixed for Quadrennial Reset Period
Fuel Price	**Subscription Service Data Source or Publicly Available Data Source**
Peaking plant Variable Operating and Maintenance Cost	Fixed Value (Fixed for Quadrennial Reset Period)

Peaking plant CO_2 Emissions Rate	Fixed Value (Fixed for Quadrennial Reset Period)
CO_2 Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
Peaking plant NO_x Emissions Rate	Fixed Value (Fixed for Quadrennial Reset Period)
NO_x Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
Peaking plant SO_2 Emissions Rate	Fixed Value (Fixed for Quadrennial Reset Period)
SO_2 Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
NYISO Rate Schedule 1 Charges	**NYISO Published Values**

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

Updated net EAS revenues values would be combined with updated gross CONE values to establish the RPs and ICAP Demand Curve parameters for NYCA and each Locality by November 30th of the year preceding the beginning of the Capability Year to which the updated ICAP Demand Curves will apply.

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