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***Via E-Mail to** rpatterson@nyiso.com & ztsmith@nyiso.com*

To: Analysis Group Inc. ("AGI")
Burns & McDonnell ("BMCD")
New York Independent System Operator, Inc. ("NYISO")

From: Matthew Schwall, Director of Market Policy & Regulatory Affairs

Date: July 1, 2020

Re: **Comments on Proposed Installed Capacity Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Initial Draft Report**

Independent Power Producers of New York, Inc. ("IPPNY")[1] submits the following Comments on the June 4, 2020 *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Initial Draft Report* (the "Draft Report") prepared by AGI and BMCD (collectively, the "Consultants") for the instant Demand Curve Reset ("DCR") process. Importantly, updated analyses recently issued by both the NYISO and the affected Transmission Owner, Con Edison, demonstrate the State's public policy initiatives will drive significant reliability needs on the New York system by 2023, *i.e.*, during *this* DCR period. Reference point prices must be adequate to ensure the system maintains sufficient dispatchable resources to address these needs and provide for a reliable system over the long term. Indisputably, the need to do so has only

[1] IPPNY is a trade association representing companies involved in the development of electric generating facilities including renewable resources, the generation, sale, and marketing of electric power, and the development of natural gas and energy storage facilities in the State of New York. IPPNY member companies produce a majority of New York's electricity, utilizing almost every generation technology available today, such as wind, solar, natural gas, oil, hydro, biomass, energy storage, and nuclear.

become more immediate. Aspects of the Draft Report, however, are materially deficient and will not produce the price signals needed to support this investment. IPPNY thus urges the Consultants to revise the Draft Report as established herein.

Background

The fundamental purpose of capacity markets is to ensure resource adequacy. The Federal Energy Regulatory Commission ("FERC")-approved demand curve structure does so by establishing market price signals that provide a level of compensation that is adequate to attract new resources and retain needed existing resources to promote system reliability over the long term while neither under-compensating nor over-compensating generators.[2] The reference point price signals reflect the net cost of new entry ("CONE") of a proxy peaking plant, *i.e.*, the costs of developing and operating a flexible and dispatchable resource capable of meeting peak load requirements and associated long-term resource adequacy needs.[3] To date, the selected proxy peaking plant technology has been a gas turbine facility, in part, because of its flexibility and dispatchability.

Significant developments have occurred since the last DCR process that must be taken into account for the ICAP Demand Curves to continue to effectively ensure resource adequacy. Accelerating its focus on combatting climate change since the last DCR process concluded in 2016, New York State has taken a number of actions and correspondingly implemented incentive programs to support renewable and energy storage resources. Most significantly, the Climate Leadership and Community Protection Act ("CLCPA") enacted last summer mandates 70% of electricity consumed in New York State must be produced by renewable resources by 2030 and

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[2] See New York Independent System Operator, Inc., 103 FERC ¶61,201 (2003); New York Independent System Operator, Inc.,122 FERC ¶ 61,211 (2008) at P 103.
[3] See NYISO, Market Administration and Control Area Services Tariff ("MST"), Section 5.14.1.2.1

requires installation of 6,000 MW of solar by 2025, 3,000 MW of energy storage by 2030, and 9,000 MW of offshore wind by 2035.[4] In addition, the CLCPA requires that the power sector must be emissions free by 2040, thereby prohibiting the operation of fossil-fueled resources – the technology historically selected as the DCR proxy peaking unit. To date, the State has awarded out-of-market contracts to 5,721 MW of onshore and offshore renewable resources.[5]

Of equal importance to this DCR process, last December, the State also implemented new environmental regulations, known as the Peaker Rule, substantially restricting the permitted nitrogen oxides ("NOx") emission levels for peaking units by 2023 and lowering permitted emission levels even further by 2025 – the exact type of flexible units needed to meet reliability requirements on which the ICAP Demand Curves are based.[6] The Peaker Rule applies to a

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[4] New York State Climate Leadership and Community Protection Act, S.B. 6599, 2019 Leg., 242nd Sess. (N.Y. 2019) (codified as Ch. 106, L.2019) (the "CLCPA "). The CLCPA builds on the PSC's implementation of its Clean Energy Standard ("CES") program implemented on August 1, 2016. (*See* NYPSC Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard,* Order Implementing Clean Energy Standard (issued and effective August 1, 2016) (hereinafter, "CES Proceeding" and "CES Order," respectively.) Solicitations under the CES Program that have led to the award of far more State-backed incentive contracts began in 2017, have been held annually and are expected to announce even larger contract awards through at least 2027. For example, the CES 2.0 Whitepaper issued earlier this month proposed that NYSERDA will issue awards for 4,500 GWh/year of Tier 1 resources and 750 MW to 1,000 MW per year of OSW resources through 2027. (See NYPSC Case 15-E-0302, *supra*, "White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act" (issued June 18, 2020) (hereinafter, "CES 2.0 Whitepaper").)

[5] *See* New York State Energy Research and Development Authority ("NYSERDA") Renewable Energy Standard Tier 1 Solicitations for 2017, 2018, and 2019, available at https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts; *see also* NYSERDA Offshore Wind Solicitation for 2018, available at https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2018-Solicitation. Structured on competitive market economic principles, the NYISO's markets to date have not been designed to value the emissions free attributes of these resources, compensation which would facilitate investment in these resources. The NYISO's carbon pricing proposal would value the emissions free attributes of these resources, but the State has so far decided not to weigh in on the concept, instead choosing to rely on request for proposal processes to hand-select the individual resources used to meet CLCPA mandates. If the recommendations contained in the CES 2.0 Whitepaper are adopted, procurements by NYSERDA will continue under the various CES initiatives – and will include an entirely new initiative focused on New York City access to larger amounts of renewable resources – at an accelerated pace for the foreseeable future. (*See* CES 2.0 Whitepaper, *passim*.)

[6] *See* 6 NYCRR Subpart 227-3; *see also Adopted Subpart 227-3, Ozone Season Oxides of Nitrogen ("NOx") Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, Dep't of Envtl. Conserv., available at https://www.dec.ny.gov/regulations/116131.html.

substantial number of New York City and Long Island peaking plants. As evidenced in compliance plans filed in March, many of these units will retire – a result captured in the NYISO's Reliability Planning process underway contemporaneous with this DCR process.

As reflected in the analyses presented at the June 19, 2020, meeting of the Electric System Planning Working Group, while many of these resources will be permitted to retire – a fact, as noted below, that should be reflected in the DCR process modeling – both resource adequacy deficiencies and transmission security violations will result from the retirement of a subset of these units. Of the reliability needs identified, there are two resource adequacy deficiencies in Zone J load pockets – a 110 MW deficiency beginning in 2023 and growing to 180 MW by 2030, and a 360 MW deficiency beginning in 2025 and growing to 370 MW by 2030. Transmission security violations begin in 2025 and grow to 1,075 MW by 2030. It is thus more critical than ever that adequate price signals are provided in this DCR process to incentivize the investment necessary to ensure resource adequacy in New York going forward.[7]

At the same time that the grid is expected to become composed of a larger amount of intermittent resources in accordance with the CLCPA and the Peaker Rule, New York public policy is also expected to significantly increase energy consumption and, potentially, peak demand levels. New York City's adoption of Local Law 97 requires greater electrification of

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[7] *See* 2020 RNA Preliminary (1st Pass) Reliability Needs (hereinafter, "2020 RNA"), available at https://www.nyiso.com/documents/20142/13200831/02%202020RNA_1stPassRN.pdf/8a0de336-bd24-1260-dc4b-5df58cdb049f; *see also* 2020 RNA Con Edison Preliminary Findings, available at https://www.nyiso.com/documents/20142/13200831/03%202020%20RNAConEd%20Local%20System%20Base%20Case%20Assessments%20Results.pdf/17424cd7-3cef-3637-2388-5a27654af266. It bears note that the New York State Reliability Council has demonstrated that interconnecting more intermittent resources to the grid results in a lower reliability contribution of these resources and the need to significantly increase the Installed Reserve Margin ("IRM") for the New York Control Area ("NYCA") in both ICAP and Unforced Capacity ("UCAP") terms, particularly if accompanied by retirement of higher availability traditional dispatchable resources. (*See* The Impact of High Intermittent Renewable Resources on the [IRM] for New York at P 3, available at http://www.nysrc.org/PDF/Reports/HR%20White%20Paper%20-%20Final%204-9-20.pdf.)

buildings to offset on-site fuel oil or natural gas combustion for heating and cooling purposes, which increases system peak demand.[8] Likewise, the CLCPA mandates that 22 million tons of carbon dioxide be reduced from the economy through further enhanced energy efficiency and electrification measures.[9]

With reliability – and, concomitantly, resource adequacy remaining paramount – this is the investment environment upon which IPPNY has considered the Consultants' recommendations and provides these comments. Across the board, the Consultants' recommendations appear to include aggressively low cost assumptions for components of the gross CONE of the proxy peaking plant technology precisely at the very time when it is critical for the Demand Curves to provide adequate investment signals to new technologies and needed existing dispatchable resources to enable the State's goals to be manifested while meeting impending reliability needs (discussed further herein). In large part, the Consultants' assumptions omit important system composition changes that cannot reasonably be ignored, and the recommendations focus too heavily on theoretical models of how merchant investment should occur and not enough on how the New York system actually operates and how the existing laws, regulations, and New York's unique political and regulatory climate have impacted, and can be expected to continue to impact, New York-specific investments.

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[8] *See* Local Laws of the City of New York for the Year 2019 – No. 97. Available at, https://www1.nyc.gov/assets/buildings/local_laws/ll97of2019.pdf.
[9] *See* New York's Nation Leading Climate Targets, available at https://climate.ny.gov/.

A. **<u>The Consultants' Preliminary Level of Excess Adjustment Factors Must Reflect the Resources Expected to be on the NYISO System To Effectively Align with the Assumptions Used, and the Approach Taken, in the NYISO's Comprehensive Planning Processes and Meet the System's Resource Adequacy Needs.</u>**

The NYISO's MST requires that the costs and revenue estimates used in determining the ICAP Demand Curves reflect system conditions with capacity equal to the applicable minimum ICAP requirement adjusted to incorporate the size of the peaking plant in the NYCA and each Locality.[10] To do so, the Level of Excess Adjustment Factors ("LOE-AFs") modify the historical, three-year average of Locational Based Marginal Prices and reserve prices used in the net Energy and Ancillary Services ("EAS") revenue calculations to approximate prices under LOE conditions. The supply and load assumptions that are used to determine the LOE-AFs are critical inputs for just and reasonable ICAP Demand Curves to be set, and, therefore, must incorporate updates to the system composition to provide accurate information at the time the Demand Curve parameters are set.

All of the NYISO's planning studies rely on the same set of base case inclusion rules to define the resource assumptions used in their respective base case assessments.[11] In the Draft Report, the Consultants state that they relied on supply and load assumption data from the 2019 Congestion Assessment Resource Integration Study ("CARIS") Phase 1 Base Case – the study to conduct the NYISO's Economic Planning Process under the CSPP – to set the LOE-AFs using GE Energy Consulting's ("GE") Multi-Area Production System ("GE-MAPS").[12] Based on its

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[10] MST, Section 5.14.1.2

[11] The NYISO's the Comprehensive System Planning Process ("CSPP") consists of the Economic Planning Process, the Reliability Planning Process, and the Public Policy Planning Process.

[12] Draft Report at PP 102-103.

start date, the CARIS Phase 1 Base Case utilized supply and load information from the 2019 Gold Book plus known changes through the point the assumptions were finalized on July 31, 2019.[13] In contrast, while it began with the CARIS Phase I Base Case, the base case the NYISO more recently finalized for its 2020 Reliability Needs Assessment this spring incorporated system composition changes since last July ("2020 RNA").[14] To do so, the 2020 RNA utilized supply and load information from the 2020 Gold Book and from generators' compliance plans submitted in response to the Peaker Rule, consistent with the NYISO's base case inclusion rules.[15] Since the CARIS Phase I Base Case was finalized nearly a year ago, the changes to the system that have either already occurred or are now known will occur during this DCR period have been significant. The information relied upon to date to calculate the LOE-AFs on which resources are expected to be operating over the four-year DCR period is, therefore, unnecessarily stale given that more updated information on expected resources is readily available.

Incorporating these adjustments into the LOE-AF calculations is critical given the system impacts of these resources. On June 19, 2020, the NYISO presented the first pass results of its 2020 RNA. The 2020 RNA identifies both reliability and transmission security needs occurring over the study period.[16] Specifically, the NYISO has identified transmission security violations beginning in 2024 and a Loss of Load Expectation ("LOLE") resource adequacy violation beginning in 2026 and increasing in severity through 2030 due to retirements and projected load

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[13] *See* 2019 CARIS Base Case Results: Preliminary at P 4, available at https://www.nyiso.com/documents/20142/8193286/06%202019_CARIS_1_Base.pdf/035ba2a0-c022-8021-7111-ccc975a6bcd3. The CARIS Phase I report was approved by the BIC on June 24, 2020 and by the MC today, and is expected to be approved by the NYISO's Board in July. This action triggers the development of the CARIS Phase II base case in July, which was the basis for the assumptions used in the 2016 DCR process.
[14] The 2020 RNA is the study that informs the Reliability Planning Process.
[15] *Id*. at P 18.
[16] 2020 RNA at PP 28-34.

growth.[17] The RNA results make it clear that the stale assumptions concerning future operation of resources from the CARIS base case grossly overstate the resources operations that the NYISO expects to have on the system. Having an accurate representation of future resources is important to make sure that the LOE-AF values are not overstated.

AGI should thus be provided LOE-AFs that have been updated by inputting into GE-MAPS the changes to future resource entry and exit that are assumed as part of the 2020 RNA base case because, *inter alia,* that more recent base case reflects nearly an entire year's worth of new information regarding the current and future status of supply compared to the stale CARIS Phase 1 Base Case. Failure to do so would overstate the LOE-AFs and produce artificially inflated EAS revenues, resulting in unjust and unreasonable Demand Curves. Specifically, AGI should be provided LOE-AF calculations that assume known and expected generation additions and deactivations consistent with the base case inclusion rules while retaining sufficient generation to solve the reliability needs identified on the system consistent with the information presented at the June 19 ICAP Working Group meeting.[18]

B. Modifications to the Draft Report Are Required to Accurately Reflect the Gross CONE of the Fossil-Fueled Proxy Peaking Unit in All Zones.

The Consultants' proposed Demand Curve parameters significantly understate the gross CONE of the fossil-fueled proxy peaking technologies. The financial parameters do not adequately capture the risks associated with developing a fossil-fueled peaking unit in New York

[17] *Id.* at PP 28-29 and 43-44. The NYISO will next request, and consider, updates to Local Transmission Owner Plans to upgrade the local transmission and distribution systems.

[18] *Id.* at PP 12-16. Importantly, the assumed resource additions in the 2020 RNA includes several hundred MW of wind facilities. Adding resources with low UCAP ratings, such as wind facilities, results in an increase in the IRM. The NYISO LOE-AF estimates need to account for the reduced reliability value of these wind resources either by increasing the future assumed IRM when estimating how much load to add to estimate the LOE-AF values or by derating the added load related to Wind Facility additions to account for the IRM increase.

State. The proposed amortization period of 17-years does not align with the commercial operation dates ("COD") for any of the resources that may be built during this DCR period, and the Weighted Average Cost of Capital ("WACC") is unrealistic because it understates the cost of capital required in order to develop a fossil-fueled peaking plant in the high-risk New York market. Moreover, the Consultants' proposed natural gas hubs for Zone C and Zone G do not correlate with the actual cost of delivered gas in those zones, and a number of the capital cost recommendations are low-ball estimates in the face of New York-specific evidence that development capital costs are, in some cases, multiples higher.

Most misguided of all is the Consultant's recommendation that the Zone G – Dutchess County proxy peaking unit should be designed to *limit* its run hours in lieu of installing Selective Catalytic Reduction ("SCR") emissions control technology to comply with existing environmental regulations at the same time that NYISO studies recognize the heightened need for more flexible dispatchable resources to balance the higher penetration of intermittent resources on the system in the future. The NYISO is actively developing market products to value increased flexibility in operation of dispatchable resources to meet State public policy goals and there is every indication that additional emission restrictions may well be implemented before the State reaches its carbon-free end state in 2040. The Consultants have viewed the installation of SCR controls as purely an economic decision process where the developer only adds SCR if expected revenues are higher with SCR than without SCR. That analysis fails to capture that the Demand Curves model a unit that is required to ensure reliability of the NYISO system and that the New York siting process is arduous with a clear preference for cleaner resources.

i. Financial Parameters

Amortization

In the last DCR process, the amortization period of the proxy peaking unit was assumed to be 20 years. AGI has appropriately recognized that the CLCPA's 2040 carbon-free electric sector mandate reduces the assumed 20-year economic lifespan of a fossil-fueled peaking unit. AGI therefore recommends an amortization period of 17 years. AGI states that 17 years is reasonable because it is the average economic operating life of a fossil peaking plant over the upcoming four-year DCR period, and because it strikes a balance between general regulatory and technological uncertainty regarding the availability and cost of conversion technologies to comply with the CLCPA beyond 2040.[19]

First, AGI's proposed 17-year period wholly ignores the fact that no new fossil peaking plant similar to the proxy unit has been certificated or is under construction. A project responding to the signals being sent by the reference price points proposed in this DCR process by initiating a project would not be likely to be on line until the second half of this DCR period, at the earliest.

Indeed, review of the NYISO's interconnection queue confirms AGI's currently proposed amortization period is untenable. There are three fossil-fuel based projects in Class Year 2019 ("CY19") – the Danskammer project (#791), the Liberty Generating Alternative project (#668), and the Gowanus Gas Turbine Facility Repowering project (#778).[20] The projects have estimated CODs of October 2023; February 2024; and May 2024, respectively. Assuming,

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[19] Draft Report at P 63.

[20] *See* CY19 Status Update (January 7, 2020), available at https://www.nyiso.com/documents/20142/10150338/05_CY19%20Status%20Update_TPAS-Jan072020_Draft.pdf/acbc5e0d-c4b1-74f5-718e-5a3c755a8eb6

arguendo, that each of these facilities proceeds and achieves its intended COD, they would have economic operating lives of 16.3, 15.9, and 15.7 years, respectively, in compliance with the CLCPA's mandate.[21] Thus, under what are likely the best case scenarios, on average, and consistent with AGI's methodology for proposing that 17 years is the average operating life across the four-year DCR period, the average operating life of the three facilities in CY19 is only 16 years. And, any developer of a fossil-fueled project subsequently entering a future CY is likely to have a COD later than those of the three CY19 projects, making the Consultants' approach even more deficient.

Importantly, this 16-year period also presumes estimated CODs will hold in the face of permitting, construction and other delays that are common for electric generating projects in New York. Even under these best-case circumstances, the proposed 17-year amortization period is insufficient for project developers to recover the capital costs of their projects. Thus, considering probable construction timelines based on proposed projects that could actually be developed during this DCR period, and taking into account some potential for delays to be faced, a reasonable amortization period for the fossil-fueled peaking plant can be no longer than 15 years.

WACC

In light of the current market uncertainties engendered by COVID-related impacts, AGI has established it will not recommend final financial parameters until it issues its final report. However, at least as of the initial Draft Report, AGI has relied on the following inputs to calculate its proposed WACC of 10.1% for proxy units in this DCR: Return on Equity ("ROE")

[21] The commercial operating life was calculated by counting the number of years between May 1 of the Capability Year the unit reaches COD and January 1, 2040, consistent with Consultants calculations used to recommend a 17-year amortization period (see P 63 of Draft Report).

of 13%; Cost of Debt of 7.7%; and a Debt/Equity ratio of 55/45. These proposed inputs do not, however, accurately reflect the risk of investing in the New York market.

As reflected in the Initial Draft Report, AGI determined the WACC inputs, in part, based on publicly available information from publicly traded IPPs (Vistra Energy, NRG Energy, Calpine, and Talen Energy) and independent assessments.[22] Specifically, in an attempt to support its proposal, AGI first evaluates the estimated ROE for two of these publicly traded IPPs (NRG and Vistra) which has averaged between 7.79% and 9.13% -- while acknowledging that, because these companies' business activities and portfolios of assets extend outside of merchant power generation, their ROE is "not necessarily comparable to the required [ROE] for a new peaking plant project in New York."[23] AGI next relies on the previous two net CONE studies of PJM and ISO-NE, which had ROEs that ranged from 12.8% to 13.8%.[24] Lastly, AGI considers estimates of the ROE for stand-alone project finance developments from several independent sources, which ranged as high as 20%.[25] Based on all of this information, AGI recommends an ROE of 13%, which it claims is a balance between the lower IPP value and higher project finance values.

To further support its approach, AGI says it "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." That said, AGI also recognizes "the appropriate cost of capital for a specific

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[22] Draft Report at PP 64-65.
[23] *Id.* at pp. 70-71.
[24] *Id.*
[25] *Id.* Notably, each of the studies cited by AGI report ROEs for stand-alone project finance that ranges from 15% to 22%.

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."[26]

Importantly, notwithstanding the history of project development in New York to date, AGI expressly rejects basing the proposed WACC for NYISO on a peaking plant project developed through a stand-alone project finance approach by a private entity while also admitting that "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)."[27] AGI states that, "given these factors," it "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 project-financed project."[28]

By failing to adequately consider New York-specific evidence, however, AGI's analysis incorrectly concludes that a peaking plant project would not likely be developed by a private entity on a stand-alone basis. In addition, as NYISO is a single state market, it is unreasonable to determine the WACC based on evidence of IPP balance sheet project financings and stand-alone project financings occurring on a national or broader regional basis, such as in ISO-NE or PJM. In determining the WACC for a single-state ISO, AGI must instead more heavily weigh the financings for recent developments in the State, which have been made on a stand-alone project finance basis by private-equity backed entities, not through balance sheet financings.

Contrary to AGI's supposition, the specific information related to investments in New York confirms that future investments are likely to be made on a stand-alone project finance

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[26] *Id.* at 65.
[27] *Id.*
[28] *Id.* at P 65-66.

basis. The Bayonne Energy Center project, a series of peaking units, was private equity backed and project financed, and that approach has continued over time.[29] Likewise, the most recent fossil-fueled plants constructed in New York were financed by private-equity backed entities – Competitive Power Ventures ("CPV")[30] and Advanced Power.[31] IPPNY has been authorized by each of the companies to state that both the CPV Valley Energy Center and the Cricket Valley Energy Center ("CVEC") were financed through project-specific non-recourse debt. Moreover, IPPNY has spoken with its members and has conducted its own internal research and cannot find a single instance of a new gas-fired project securing primary financing on a balance sheet basis in New York in the past 20 years.[32]

Furthermore, each of the companies that is actively developing the three fossil-fueled projects as part of CY19 – Danskammer Energy LLC, Diamond Generating Corporation, and Eastern Generation – are private-equity backed, and each is pursuing stand-alone, non-recourse project financing.[33] AGI's proposed ROE of 13% is too low because it over weights the ROE of publicly-traded IPPs and of neighboring net CONE studies when the evidence clearly demonstrates that investment in New York has been, and very likely will continue to be, made on

[29] IPPNY utilized the IJGlobal Project Finance & Infrastructure Journal transactional database to research the financial records of the Bayonne Energy Center project.

[30] *See* CPV, *Overview*, available at https://www.cpv.com/our-company/.

[31] *See* Advanced Power, *About*, available at https://advancedpower.ch/about/ IPPNY recognizes that both of these projects involved construction of a combined cycle facility but there is no basis to presume financing for a peaking facility would proceed on a meaningfully different basis given the state of competitive markets, generally, and the regulatory climate in New York, in particular.

[32] IPPNY utilized the IJGlobal Project Finance & Infrastructure Journal transactional database. The following gas-fired generators have been project financed since January 1, 2000: CVEC; CPV Valley; Bayonne Peaker Energy Center; Astoria Energy Phase I & Phase II; Rensselaer Combined Cycle Power Plant; and Caithness Long Island Power Plant. Projects that were balance sheet financed were limited to acquisitions and additions to existing facilities.

[33] IPPNY also has been authorized by Danskammer Energy LLC, Diamond Generating Company, and Eastern Generation to state that the companies are each pursuing non-recourse project financing. Based on review of the NYISO Interconnection Queue Class Year 2017 and 2019 projects, NRG Energy Inc. is the only publicly-traded IPP with a fossil-fueled project under development in New York, and NRG has authorized IPPNY to state that the project is expected to pursue non-recourse project financing.

a project finance basis. Given that investment in fossil-fueled infrastructure in New York is being pursued by private-equity backed companies on a project-finance, non-recourse basis, stand-alone project financing should thus be utilized as the basis to calculate the ROE.

AGI's proposed ROE is also too low because it *underweights* the level of risk faced by developers of fossil generation in New York. As explained, *supra*, new legislation and regulations already enacted, such as the CLCPA, the Renewable Siting Act and the Peaker Rule, require a higher ROE to account for the additional risk faced by fossil investments. Moreover, initiatives under consideration will only serve to place further pressure on these investments. For example, the NYISO has submitted two sets of buyer-side market power mitigation tariff revisions to FERC that are expressly designed to enable out-of-market investments associated with State public policy to clear the capacity market spot auctions more expeditiously, thereby increasing the likelihood that merchant resources will face suppressed capacity prices at some point over their investment horizon.[34] Likewise, the CES 2.0 Whitepaper issued in the CES Proceeding proposes to make large-scale hydro impoundment projects providing renewable energy in New York City eligible to participate in the CES Program under certain conditions based on the broad definition of hydro facilities included in the CLCPA.[35] If adopted by the Commission, the Tier 4 approach will reverse the clear policy direction on this issue expressly

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[34] Docket No. ER20-1718-000, *New York Indep. Sys. Operator, Inc.*, Proposed Enhancements to the "Part A Exemption Test" Under the "Buyer-Side" Capacity Market Power Mitigation Measures (Apr. 30, 2020), stating "Currently, Examined Facilities are analyzed in sequential cost order, lowest to highest based, on their Unit Net [CONE], an estimate of their annual Net CONE, for both the Part A and Part B Exemption Tests… the NYISO would adjust this ranking to place "Public Policy Resources," ("PPRs") i.e., resources that are more likely to actually be constructed given New York State laws, regulations, and policies, ahead of non-PPRs in evaluations under the Part A Exemption Test; *see also* Docket No. ER16-1404-002, *New York Indep. Sys. Operator, Inc.*, Compliance Filing and Request for Commission Action No Later Than June 8, 2020 (Apr. 7, 2020). Of note, work on one of these efforts began in December with proposed tariff revisions filed in effectively six months, well after development commenced on the merchant fossil-fueled projects cited herein that are members of CY19.

[35] CES 2.0 Whitepaper at P 45-57.

barring such participation that has been in place for nearly 15 years – yet another example of shifts in public policy creating significant investor uncertainty.[36]

In light of the combination of the substantial increase in State-subsidized resource participation in the New York markets expected to accelerate in the near term, increasingly stringent environmental regulations, prohibitions on expanded natural gas infrastructure in New York City (which could very easily grow to include the entire State in the contest between elected officials over who is the most environmentally conscious), the uncertainty of the NYISO's carbon pricing program, the CLCPA requirement that the power sector be carbon-emissions free by 2040 as well as pending actions, an investor considering putting capital into a fossil-fueled peaking plant development project in New York is taking on far more risk now than in any previous DCR period. Indisputably, development of fossil-fuel generation projects in New York is burdened with greater risk than the same project in a neighboring market – neither PJM nor ISO-NE are single state markets where State policy has an immediate and direct effect on market outcomes. Furthermore, those markets provide longer-term price and revenue certainty to developers through their forward market structures. The seven-year lock-in of forward capacity revenue in ISO-NE significantly de-risks a project in that market; particularly when compared to the NYISO spot market. That alone supports making the 13.8% assumed in ISO-NE's gross CONE calculations the "lower bound" for New York's ROE. Recent events, such as the opposition faced by CPV Valley in its lateral permitting process, also explained *supra*, and the Chapter 11 bankruptcy of Empire Generating Company, whose asset is a 10-year

[36] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Adopting a Clean Energy Standard (Aug. 1, 2016) at P 105-106; *see also* Case 03-E-0188, *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard*, Order Regarding Renewable Portfolio Standard (Sept. 24, 2004).

old gas-fired facility, have only served to exacerbate the market risk investors face in New York.[37]

In any case, given the market and public policy developments since the last DCR process documented herein, it is most certainly unreasonable to conclude that the ROE required by investors in this DCR process has *decreased* from the 13.4% that was adopted for the current DCR period. Even a simple averaging of the lowest (6.57%) and highest (22%) ROEs identified in the Draft Report results in an ROE of 14.38%.[38] At the Aril 22 meeting of the ICAP Working Group, CVEC stated that the "return on equity for new build in New York should not be decreasing but moving higher as the investment communities' views of market and regulatory risks to New York gas fired generation resources have increased significantly over the last four years."[39] To that end, CVEC then recommended an ROE in the 15%-17% range based on current risk premium demanded by project company equity investors to compensate for State policies and market conditions that are generally unsupportive of steady, predictable returns of gas-fired generation in New York State. Taking a simple average of the highest range of publicly traded IPP values cited in the Draft Report (10.51%)[40] and the medium range proposed by CVEC (17%), the resulting ROE (13.75%) is still higher than AGI has proposed. Therefore, given the current environment, it is far more reasonable for AGI to be guided by the actual

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[37] Sweeny, D. (June 5, 2019). Bankrupt power plant owner seeks FERC approval on upstream ownership change. S&P Global. Available at https://www.spglobal.com/marketintelligence/en/news-insights/trending/ZwF6mmnE7PepqWPp412LKQ2

[38] Draft Report at P 71; *id*. at Footnote 43.

[39] *See* CVEC Comments on Analysis Group Financing Assumptions, presented at the April 22, 2020, ICAP Working Group meeting, available at https://www.nyiso.com/documents/20142/12067564/Cricket%20Valley%20Feedback%20on%20Proposed%20DCR%20Financial%20Parameters.pdf/1622859e-50ad-7b07-2aa1-27de12264810

[40] Draft Report at P 71.

experience of companies that have successfully financed New York projects and adequately account for the real risks faced by fossil-fuel projects moving forward in New York.

Beyond ROE, AGI's proposed D/E ratio is not achievable in today's market without a financial hedge. As explained in greater detail in the CVEC comments submitted contemporaneously with IPPNY's comments, the significant regulatory uncertainty that exists today and the lack of a forward market providing forward cash flow visibility, explained *supra*, is driving lenders to demand hedges (commonly, the length of construction +5 years) that provide some level of revenue certainty. Hedges either increase the net CONE of the proxy peaking unit (revenue put) or increase the need for credit support in the form of expensive heat rate call options. AGI should account for the existence of such hedging arrangements by incorporating the cost of hedging into its net CONE assumptions. If a hedging assumption is not incorporated into the net CONE assumptions, the debt leverages need to be decreased or interest rates significantly increased to account for the risk of debt unsecured by contracted revenues.

ii. **Zone G and Zone C Gas Hubs**

AGI recommends that the natural gas prices for Zone G-Rockland, Zone G-Dutchess, and Zone C be based on the price indices for the TETCO M3, Iroquois Zn 2, and TGP Zn 4 (200L) gas hubs, respectively, including a $0.27/MMBtu gas transportation adder.[41] IPPNY fully endorses the comments submitted by CPV which demonstrate that AGI's recommendations do not accurately reflect the cost of delivered gas to any of these Zones.[42] As CPV demonstrates, the TETCO M3 gas index with the $0.27/MMBtu adder understates the cost of delivered gas to Rockland County. The proposed use of the TGP Zn 4 (200L) price index for Zone C is

[41] *Id.* at PP 97-98.
[42] Supporting evidence for statements made herein on AGI's Zone G and Zone C gas hub recommendations can be found in either CPV's Comments.

inappropriate because the $0.27/MMBtu generic transportation adder understates the cost of delivery into New York, and the transportation that would be necessary to make TGP Zn 4 gas deliverable is fully subscribed. The proposed use of the Iroquois Zn 2 price index understates the delivery cost to Dutchess County because the Iroquois system is fully subscribed and expensive upgrades would be required to serve a 350 MW peaking unit that are not reflected in the 0.27/MMBtu generic transportation adder.

Zone G – Rockland County

AGI's recommendations do not fully account for the costs associated with actually transporting gas to a power plant, which include the costs of the commodity purchase, the transportation on the main pipeline, and the transportation on the lateral to the power plant. On certain pipelines, the commodity cost includes the cost of transportation on the main pipeline. The TETCO M3 price index includes the cost of transportation on the Texas Eastern Pipeline but does not include delivery into Rockland County or the surrounding counties, as evidenced in the Texas Eastern Pipeline tariff.[43]

For gas to be deliverable to Rockland County over the Texas Eastern Pipeline, an approximately 25-mile lateral, which is five times the length of the distance assumed by BMCD for purposes of assumed pipeline lateral costs, would be required to access the pipeline.[44] Using BMCD's own estimates, such a lateral would cost at least $72M.[45] As CPV indicates, a 25-mile pipeline is very likely to cost in excess of $100M.

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[43] *See* CPV Comments.
[44] Draft Report at P 46.
[45] *Id.* ($180,000 per inch)(16-inch diameter)(25 miles)

AGI recognized the geographic disconnect between Rockland County and TETCO M3 in the 2016 DCR process, and found that the gas hub did not meet the geography criterion for Zone G. That fundamental fact has not changed, and the generic transportation adder of $0.27/MMBtu proposed by AGI does not account for the substantial additional costs that would be borne by the developer of a peaking unit in Zone G connecting to the Texas Eastern Pipeline. Moreover, TETCO M3 has a weaker correlation with Zone G power prices than do the alternatives. The most accurate gas hub index for Zone G Rockland County continues to be Iroquois Z2 plus the $0.27/MMBtu adder.

Zone G – Dutchess County

Based on conversations between IPPNY members and Iroquois Zn 2 operators, it is IPPNY's understanding that the addition of a peaking unit in Zone G Dutchess County that takes gas delivery from Iroquois Zn 2 would require $75M in compression upgrades to the Iroquois system.[46] The upgrades would be necessary because Iroquois Zn 2 is constrained and fully subscribed. AGI's proposed generic adder of $0.27/MMBtu does not come close to covering the expense that would be incurred by a new peaking unit in Dutchess County seeking to interconnect to Iroquois Zn 2 and, therefore, AGI should increase the Dutchess County adder to reflect the costs of the compression upgrades.

Zone C

Like the TETCO M3 price index for Zone G Rockland County, the TGP Zn 4 price index does not cover deliveries into Zone C, and the generic $0.27/MMBtu adder does not account for

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[46] Iroquois Zn 2 operators have agreed to corroborate the statements herein with AGI, as requested.

the full costs that would be incurred by a peaking unit for delivery into Zone C. Transportation on TGP Zn 4 (200L) is fully subscribed, and, even if it were not, the transportation costs would be no less than the market-based price differential for delivery downstream of pipeline constraints into NY. For gas to be deliverable into Zone C, the shipper would have to buy transportation along alternative paths that are also fully subscribed. As explained in greater detail in the CPV Comments, in order for TGP Zn 4 (200L) to be an appropriate gas hub for Zone C, AGI would have to recommended an adder in the range of $1.00 to $1.60/MMBtu. Two viable alternative gas hub options that AGI should consider for recommendation include TGP Zn 6 or Iroquois Zn 2 because these pipelines provide for gas delivery into New York, embed the cost of pipeline congestion, and have a far closer correlation with Zone C power prices.

iii. **Capital Investment and O&M Costs**

The Consultants' cost assumptions do not account for the full cost of developing a peaking unit in New York State. Specifically, the assumed capital investment costs of developing a lateral pipeline do not reflect the real-world evidence that demonstrates costs have been, and will likely continue to be, significantly higher than the Consultants have proposed. The Consultants also do not consider evidence provided that demonstrates that the proposed land lease cost assumptions are below the actual assessed value of property in Zone J. In both cases, the Consultants should increase their cost assumptions. Lastly, there are a number of other areas where the Consultants have understated the cost of project development. IPPNY's comments do not address these areas but IPPNY supports the comments of NRG, CPV, and Eastern Generation.

Gas Interconnection Costs

Based on BMCD's experience with gas laterals, the Consultants recommend an installed pipeline cost of $180,000 per inch diameter per mile as the base assumption for gas interconnection in all Zones except Zone J.[47] BMCD then assumed that 16-inch diameter piping would be used for the 7HA.02 unit and that the average gas lateral length in New York is 5-miles, based in part on the CPV Valley Millennium lateral gas interconnection which was 7.8 miles in length. Under these assumptions, the costs of developing the gas lateral for CPV Valley would be assumed to have cost $22.5M.[48] However, as the Cost Completion Report for the Millennium lateral demonstrates, actual costs exceeded $70.07M, nearly triple the Consultants' recommendation due to the extraordinary costs of building a pipeline specific to New York.[49] The Cost Completion Report notes that overall costs were higher than expected due to a number of factors that are likely to be faced by projects in New York: State, local and federal preferences that led to the use of trenchless construction methods; construction challenges due to the potential presence of endangered species; noise limitation requirements; and increased legal costs from unanticipated litigation over State and federal permits.

As the evidence demonstrates, it is exceedingly difficult to build new pipeline infrastructure in New York State. CPV Valley faced significant opposition from the New York State Department of Environmental Conservation ("NYDEC") over permitting.[50] Ultimately, it was a FERC decision that allowed construction on the lateral to move forward.[51] The challenges

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[47] Draft Report at P 46.
[48] ($180,000 per inch per mile)(16 inches)(7.8 miles)
[49] FERC Docket No. CP16-17. Cost Completion Report of Millennium Pipeline Company, L.L.C. Available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15083695
[50] *See* NYDEC Valley Lateral Project. Available at https://www.dec.ny.gov/permits/110485.html
[51] Docket No. CP16-17. Declaratory Order Finding Waiver Under Section 401 of the Clean Water Act (September 15, 2017). Available at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14681426

that developers are likely to face in permitting pipelines have only increased since the 2016 DCR process. On February 6, 2020, Mayor Bill de Blasio signed Executive Order No. 52, memorializing NYC's policy against the use of expanded fossil fuel infrastructure, specifically including pipelines for the transfer of fossil fuels.[52] While specific to NYC, the order is indicative of the general public and political sentiment towards fossil fuel use in New York. Likewise, the Cuomo administration's opposition to new natural gas infrastructure has been unyielding, even in the face of significant issues with the ongoing ability of utilities to serve new customers. These factors indisputably increase the risk of doing business in New York and, thus, as explained *supra*, the cost of capital.

If BMCD has estimated the average length of a gas lateral developed in New York in part on the actual length of the CPV Valley lateral, it should base its proposed costs per inch of pipeline on the actual costs incurred by CPV Valley for its lateral, which is the most recent pipeline for which the costs actually demonstrate the financial risks of constructing fossil-fueled infrastructure in New York under circumstances that are likely to be replicated for future projects.

[52] Executive Order No. 51. Statement of Administration Policy Against Addition of Infrastructure that Expands the Supply of Fossil Fuels in New York City (February 6, 2020). Available at https://www1.nyc.gov/assets/home/downloads/pdf/executive-orders/2020/eo-52.pdf

Site Leasing Costs

The Consultants recommend site leasing costs for NYC of $270,000/acre-year, which grossly underestimates NYC site leasing costs. BMCD developed the site leasing costs using values from the 2016 DCR process study, escalated to $2020 using the cumulative change in the Gross Domestic Product implicit price deflator.[53] However, the proposed site leasing costs for both the 2016 DCR process study and the 2014 DCR process study simply escalated the site leasing costs from the previous study.[54] The last time actual NYC market data on land valuations was utilized was a decade ago during the 2010 DCR process.[55] Relying on ten-year old data when actual, independently derived data is available is patently unreasonable. As discussed during stakeholder meetings, to address site considerations, Eastern Generation was required to contract with three different, independent appraisers pre-selected by New York City to value two sites, one in Queens and one in Brooklyn, that either house power generating assets or will do so in the future. These appraisals issued as recently as last November demonstrate that the escalated for inflation approach used by the Consultants to define land lease valuations for the 2020 DCR process study is flawed and does not produce values that represent the value of NYC land. Using independent appraisals is the best source of information to inform land valuations, not simply escalating stale assumptions. The Consultants should utilize these independent appraisals to provide more accurate NYC land leasing assumption costs.[56]

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[53] Draft Report at P 50.
[54] 2016 DCR Draft Report at P 44. Available at https://www.nyiso.com/documents/20142/1391705/Analysis%20Group%20NYISO%20DCR%20Final%20Report%20-%209_13_2016%20-%20Clean.pdf/55a04f80-0a62-9006-78a0-9fdaa282cfc2
[55] NERA Economic Consulting Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator (September 3, 2010) at P 30.
[56] Eastern Generation has provided the Consultants with the appraisals.

iv. Selective Catalytic Reduction Emissions Control Technology

In the last DCR process, the consultants demonstrated that the Siemens SGT6-5000F5, the current peaking unit technology, without SCR would need a 2,500--hour annual operating limit on gas to meet the 100 tons/year annual NOx emissions threshold in moderate ozone nonattainment regions, *i.e.*, NYCA and the Zone G (Dutchess).[57] The operating limit on the GE Frame H Class unit without SCR that is being proposed by the Consultants as the proxy unit in this DCR process for the moderate ozone nonattainment regions is even tighter. The Consultants should thus continue to recommend that the proxy peaking plant for the Zone G-J Locality include SCR control.

This issue was thoroughly addressed in the last DCR process. In that process, the NYISO identified Zone G-Dutchess County as the proxy unit designation for the Zone G-J Locality.[58] While Zone G-Dutchess was identified as an attainment area, Zone G-Rockland was identified as a non-attainment area under the Nonattainment New Source Review program. Protestors argued to FERC that the proposed proxy peaking plant in the Zone G-J Locality (the Siemens unit) should not include SCR equipment because the 100 tons/year threshold could be met with an annual operating limit of 2,500 hours.[59] Rejecting this argument specific to the Zone G-J Locality in its 2017 DCR Order given the environmental composition of the areas in the sub-zone, FERC accepted the recommendation of the consultants, NYISO Staff, and the NYISO

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[57] Docket No. ER17-386, New York Independent System Operator, Inc., Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021 (Nov. 18, 2016), Exhibit D, Analysis Group, Inc. et al., Study to Establish New York Electricity Market ICAP Demand Curve Parameters at 27.
[58] 2017 DCR Order at P 30.
[59] Docket No. ER17-386, *supra*, Motion to Intervene, Comments and Protest of the City of New York and Multiple Intervenors (Dec. 9, 2016) at P 25.

Board of Directors that the proxy peaking plant in the Zone G-J Locality must include SCR equipment, ruling:

> With regard to protesters' arguments regarding NYISO's proposal to include SCR emissions controls in the peaking plant design for the G-J Locality ICAP Demand Curve, we note that the current ICAP Demand Curve for the G-J Locality is based on a peaking plant design with SCR emissions controls. We agree with NYISO and IPPNY that nothing has changed since the last ICAP Demand Curve reset that would reduce the need for SCR emissions controls in the G-J Locality. Rather, we agree with NYISO that, for the Rockland County portion of load zone G, a nonattainment area for purposes of New Source Review requirements with very restrictive [NOx] emissions thresholds, the peaking plant design must include SCR emissions controls. Furthermore, as NYISO explains, there are much higher [NOx] emissions rates that result from operating on a dual fuel peaking plant's alternative fuel source. *Because the G-J Locality includes a nonattainment area (the Rockland County portion of load zone G), NYISO appropriately concluded that the G-J Locality peaking plant design must include SCR emissions controls.* Moreover, as discussed further below, we accept NYISO's proposal to include dual fuel capability in the peaking plant design for the G-J Locality, which further supports the need for SCR emissions controls in the G-J Locality. Therefore, we find that there is sufficient evidence in the record to conclude that NYISO's proposal to include SCR emissions controls in the peaking plant design for the G-J Locality ICAP Demand Curve is just and reasonable.[60]

As was true in the last DCR process, Rockland County remains a non-attainment area and remains located within the Zone G-J Locality. Thus, that fact alone supports continuing to include SCR equipment on the proxy unit for the Zone G-J Locality.

Moreover, while the Consultants here have preliminarily recommended the GE H Class unit for the Zone G-J Locality, Tables 14 and 15 on page 28 demonstrate that the number of hours that the H Class unit operating on gas without SCR would be allowed to operate to meet the 100 tons/year threshold would be only 1,060 hours, 58% fewer hours than the Siemens SGT6-5000F5 unit without SCR would have been allowed to operate without SCR. Siting an H

[60] *Id*. at PP 30-31 (Emphasis added).

Class unit without SCR in the Zone G-J Locality thus provides too little operating flexibility to ensure NYISO reliability needs are met. As FERC rejected the Siemens unit without SCR for the Zone G-J Locality in the last DCR process that could have satisfied the 100 tons/year threshold with a 2,500-hour annual operating limit, proposing a technology that would require an even lower annual operating limit here lacks merit.

Important regulatory changes since the last DCR process also must be taken into account. First, with the enactment of the CLCPA, 70% of electricity consumed in New York State must be produced by renewable resources by 2030. Most of the new resources that will be needed to meet this requirement will be intermittent, which is expected to result in increased reliance upon quick start, highly flexible resources to respond to variations in intermittent generation. Specifically, as the NYISO established in Power Trends 2020, "[t]o balance lower capacity factor, intermittent resources, and shorter-duration resources like energy storage, bulk power system operators will require a full portfolio of resources that can be dispatched in response to any change in real-time operating conditions to maintain bulk power system reliability. The ability to dispatch resources to reliably meet ever-changing grid conditions and serve New York's electric consumers *will always be paramount.*"[61]

The current proxy peaking plant technology for the Zone G-J Locality – the Siemens SGT6-5000F5 unit with SCR – has an annual operating hour limit of 3,360 hours, meets the New Source Performance Standard for CO2 emissions, and therefore has much greater flexibility to meet the NYISO's growing requirement for highly flexible dispatchable resource production. It is important to recognize that the NYISO is working to enhance its market rules to incentivize

[61] *See* Power Trends 2020 at P 17, available at https://www.nyiso.com/documents/20142/2223020/2020-Power-Trends-Report.pdf/dd91ce25-11fe-a14f-52c8-f1a9bd9085c2 (emphasis added).

highly flexible dispatchable supply.[62] Indeed, it has made this effort a fundamental part of its Grid in Transition initiative.[63] This effort will be for naught, however, if this DCR process produces reference price points that effectively preclude those resources from being developed.[64]

Given the Commission's past determinations and in light of the intervening developments since the last DCR process, resource adequacy considerations must drive the determination concerning SCR controls for the Zone G-J Locality proxy unit. Proposing a unit that requires an annual operating limit that is less than half of the annual operating limit that was rejected by the consultants, NYISO Staff, NYISO Board, and FERC in the last DCR process makes no sense. Therefore, the Consultants should recommend that the Zone G-J Locality proxy unit continue to include SCR equipment.

C. <u>The Net EAS Revenue Model Developed by AGI Inappropriately Assumes Optimal Dispatch of the Peaking Plant Unit and Overstates Expected EAS Revenues.</u>

The Demand Curve reference point prices for the NYCA and each Locality are developed during the DCR process, and subsequent annual update process, by subtracting net EAS revenues from the proposed peaking plant's unit gross CONE. As demonstrated above, because changes in the system composition have not been taken into account, AGI has produced net EAS revenues that are artificially inflated. In addition to that fundamental flaw, the net EAS revenue model must accurately reflect the costs of operating the peaking plant when forecasting its

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[62] *See* Draft 2020 Master Plan at PP 6-7, 22, and 24-35, available at https://www.nyiso.com/documents/20142/12800807/2020_Master_Plan_DRAFT.pdf/99c93bb9-b26e-d470-ce04-79f7cd37e5ed.

[63] 2019 Reliability and Market Considerations for a Grid in Transition, available at https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50.

[64] *See* Potomac Economics 2019 State of the Market Report for the New York ISO Markets at P 1-2, available at https://www.nyiso.com/documents/20142/2223763/NYISO-2019-SOM-Report-Full-Report-5-19-2020-final.pdf/bbe0a779-a2a8-4bf6-37bc-6a748b2d148e?t=1589915508638 (emphasizing the need for competitive market signals to continue to be efficient as the system evolves in response to public policy initiatives).

dispatch and the associated revenues that will be available to it. However, the dispatch model developed by AGI overstates the EAS revenues that are assumed to be available to the proxy peaking plant because the model assumes optimal dispatch of the peaking plant.

Specifically, the "dispatch logic" used in the model presumes perfect foresight by first determining whether to commit the plant to supply energy or reserves in the day-ahead market ("DAM"), if it is profitable to do so, based on the assumed market offers.[65] In the real-time market ("RTM"), the model will use similar logic if there was no day-ahead commitment. If there was a day-ahead energy or reserve commitment, the model will allow the plant to buy out of the commitment if it is more profitable to do so. For example, if it is more profitable for the plant to buy out of a day-ahead reserve commitment to provide energy the model allows the plant to do so to further optimize revenues. Relying on this perfect foresight assumption, however, produces far higher revenues than a plant could reasonably expect to earn for several reasons.

To begin with, DAM offers are due before the gas prices are known, which causes significant risk to the peaking plant owner. For example, a plant could be scheduled on natural gas when it is uneconomic to run on gas, *i.e.,* if the price of gas in real-time is more than was anticipated when the DAM offer was submitted. To mitigate this risk, a competitive supplier will often include a risk adder (e.g., 5-10% of fuel price) into its DAM offer. This approach, and the associated cost, is consistent with the inclusion of risk and opportunity costs that are permitted in a generator's cost-based reference level.[66] However, this legitimate risk premium has not been accounted for in the net EAS revenue model developed by AGI which results in the

[65] Draft Report at P 81-82.
[66] *See* Section 9 of NYISO Reference Level Manual, available at https://www.nyiso.com/documents/20142/2923301/rl_mnl.pdf/ae26885c-9f44-b0bb-11ab-e09ac2431c69

model committing the peaking plant for more hours than would actually be expected. AGI should revise its model to include the risk adder to more accurately calculate the net EAS revenues available to a peaking unit.

Likewise, in the RTM, the net EAS model maintains a plant's ability to buy out of either DAM energy or reserve commitments, based on changes in RTM prices. The model assumes a flat real-time fuel premium for purchases in all operating hours throughout the year (i.e., 10% in Rest of State and Lower Hudson Valley, 20% in New York City, and 30% in Long Island) and the same percentage discount for sales, relative to day-ahead gas prices. These intraday premium/discounts are intended to reflect potential operating or other opportunity costs to securing (or not using) fuel in real-time and are incorporated into the RTM buy-out decisions for all plants. However, this simplified, flat percentage approach is likely to significantly overstate revenues in certain hours, especially during winter months when the gas market conditions cause far more substantial price difference in the DAM and RTM price. That is, when there is a substantial energy price spike in the RTM compared to the DAM it is often associated with a significant price spike in gas prices that the model is currently not designed to capture at all. These hours can significantly skew the model results thereby overstating annual revenues and, therefore, AGI must account for these gas price spikes in the net EAS revenue model.

Additionally, there are often operational flow order ("OFO") pipeline restrictions, especially in the winter months, that are also not accounted for in AGI's model. Because a plant can be penalized for being short of its day-ahead gas nomination when an OFO is in effect, plants often must manage their risk by over-procuring gas at high prices thereby resulting in an economic loss. Also, when a ratable OFO is in effect, gas flows are restricted to the same volume each hour, which could cause the plant to run at a loss in certain hours.

Taken together, the net effect of the issues discussed above cause a material overstatement of the peaking plant net revenues. In response to these concerns raised during stakeholder meetings, AGI summarily contended these impacts were adequately offset by hours that the model underestimates net EAS revenues.[67] Absent more support for this claim, IPPNY recommends that AGI enhance the "dispatch logic" in the net EAS model, as proposed herein, or develop a scaling factor that reflects more accurate revenue estimates.[68]

D. <u>Conclusion</u>

In its presentation concerning the NYISO's CARIS I report, and specifically, the 70 x 30 scenario set forth therein, the NYISO's Market Monitoring Unit, Potomac Economics, emphasized the importance of sending accurate price signals to support the State's public policy efforts effectively, including adequate capacity market signals.[69] As AGI and BMCD consider the matters raised herein, IPPNY remains available to provide further information or clarification and is committed to engage its members to support such efforts. Thank you for your ongoing consideration of these issues.

Respectfully submitted,

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[67] Draft Report at P 86.
[68] IPPNY supports the use of a scaling factor as explained in further detail in the CPV Comments.
[69] Market Monitoring Unit Comments on 2019 CARIS Phase I Report at P 5-6 (emphasizing renewable resources must still rely on market pricing in addition to environmental attribute payments and adequate signals must be sent to flexible resources to continue to balance the system), available at https://www.nyiso.com/documents/20142/13246341/2019%20CARIS%20Phase%20I%20MMU%20Assessment__6-20-2020.pdf/73f7f738-9525-0cc5-a29f-442ba2f12332; see also CES 2.0 Whitepaper at P 4 (asserting New York State should actively pursue policies that accelerate the development of advanced technologies).