Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2019 Projects

POTOMAC ECONOMICS

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EXECUTIVE SUMMARY

The NYISO administers buyer-side market power mitigation ("BSM") measures in New York City ("Zone J") and the G-J Locality to prevent capacity prices from being artificially suppressed below competitive levels by the subsidized entry of uneconomic resources.[1] The BSM measures address such entry by imposing an Offer Floor on resources that do not satisfy criteria that are described below. The Offer Floor deters uneconomic entry that would otherwise be intended to suppress capacity prices below competitive levels. To the extent that uneconomic resources are subsidized for other reasons, an Offer Floor may still be imposed to ensure that such entry does not suppress prices below competitive levels.

The NYISO evaluates each Examined Facility in the Class Year process to determine whether it should be subject to Offer Floor mitigation. The NYISO's Tariff requires the Market Monitoring Unit to prepare a report that must be posted concurrently with the results of any BSM determinations.[2]

NYISO's Process of Issuing BSM Determinations

The NYISO's BSM evaluation of the Class Year projects is coordinated with its Project Cost Allocation ("PCA") process. In each round of the process, the NYISO provides each project remaining in the Class Year with its estimated PCA and its BSM determination (if applicable), so each developer can consider this information before deciding whether to accept its PCA. To receive CRIS, the developers of the Class Year projects are required to accept their PCA, headroom payment, and Deliverable MW and post the required Security. If a CY Project developer does not satisfy one or more of these requirements, the project does not receive CRIS and a new PCA round begins.

When a project leaves the CY process, the PCA amount for other projects in the Class Year may change, and the ICAP, Energy, and Ancillary Services price forecasts (which are inputs to the BSM determinations for other Examined Facilities) may be updated. Thus, the NYISO provides an updated BSM determination in each round for each remaining Examined Facility until the completion of the Class Year.

In CY19, the NYISO conducted three rounds of the PCA process. In the third (and final) round, the NYISO issued final determinations for 11 projects for an exemption under the Part A and Part B tests, six projects under the REE provisions, and one project under the CEE provisions.

1 Terms with initial capitalization not defined in this report have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff ("MST" or "Tariff"), and if not defined therein, then in Open Access Transmission Tariff Attachment S.

2 See MST Sections 23.4.5.7.6.8, 30.4.6.2.13, and 30.10.4.

Examined Facilities Evaluated in Class Year 2019

Examined Facilities in CY19 in Zone J and the G-J Locality ("CY19 Projects") have been evaluated for a Competitive Entry Exemption ("CEE"), a Renewable Entry Exemption ("REE"), and under the Part A & B tests:

- Competitive Entry Exemption – This provision ensures that the BSM measures do not prevent a new unsubsidized resource from entering the market. An Examined Facility can request a CEE if it does not have a contract, agreement, arrangement, or other relationship with certain entities that could serve as a conduit for a subsidy.
- Renewable Entry Exemption – Examined Facilities that are exclusively powered by solar, wind, and Limited Control Run-of-River hydropower are eligible to request a REE. These are technologies that the NYISO determined to be weak instruments for the exercise of buyer-side market power because of their relatively low capacity value and high fixed costs.
- Part A Test exemption – This allows a new resource to sell capacity when its entry would not depress capacity prices below competitive levels. Thus, this allows a subsidized resource (that does not qualify for a Renewable Entry Exemption) to sell capacity as long as it does not raise the capacity surplus above moderate levels.
- Part B Test exemption – This allows a new economic resource to sell capacity even if it is subsidized or developed by a regulated utility or agency of New York State. A resource is deemed economic if the projected revenues it would receive from the wholesale market would exceed its levelized costs over its first three years of operation.

The following table provides a description of each CY19 Examined Facility and the status of its BSM evaluation.[3]

3 For the Gowanus Repowering Project, the capacity shown in the table represents the total CRIS requested for the new facility. The Danskammer Project (or the "Danskammer Repowering Project") is also a repowering project, and the capacity shown in the table represents the CRIS requested in addition to the CRIS of the existing facility.

Table 1 – Summary of CY19 Examined Facilities

Examined Facility	Zone	Summer ICAP MW	Unit Type	Status
King's Plaza	J	6	CT	Exempt under Part A and Part B
Spring Creek	J	8	CT	Exempt under Part A
Groundvault Energy Storage	J	12.5	ESR	Exempt under Part A
Stillwell Energy Storage	J	10	ESR	Exempt under Part A
Cleancar Energy Storage	J	15	ESR	Exempt under Part A
Flint Mine Solar	G	100	Solar	Exempt under REE
Danskammer	G	88.9	CC	Exempt under CEE
Greene County I	G	20	Solar	Exempt under REE
Greene County II	G	10	Solar	Exempt under REE
Little Pond Solar	G	20	Solar	Exempt under REE
Greene County 3	G	20	Solar	Exempt under REE
Hannacroix Solar	G	3.23	Solar	Exempt under REE
Monsey 44-6	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-2	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-3	G	5	ESR	Not exempt, Accepted PCA
Cuddebackville Battery	G	10	ESR	Not exempt, Accepted PCA
Yonkers Grid	I	20	ESR	Not exempt, Accepted PCA
Eagle Energy Storage	I	20	ESR	Not exempt, Accepted PCA
KCE NY 2	G	200	ESR	Initial determinations only
Gowanus Repowering	J	574	CT	
Rising Solar II	G	20	Solar	
KCE NY 8a	G	20	ESR	
Blue Stone Solar	G	20	Solar	
KCE NY 14	G	20	ESR	
KCE NY 18	G	20	ESR	

The remainder of this Executive Summary provides an overview of the BSM evaluations for the CY19.

Evaluation of Examined Facilities for Competitive Entry Exemption in CY17

In CY19, the NYISO evaluated the Danskammer Repowering Project for a CEE. The NYISO reviewed the project developer's certifications along with planned or existing contracts with non-qualifying entities. The NYISO evaluated the submission for any non-qualifying contractual relationships, and concluded that the Danskammer Repowering Project was eligible for the CEE. Accordingly, it was determined to be exempt from an Offer Floor.

Evaluation of Examined Facilities for Renewable Entry Exemption in CY19

In the Initial Decision Round of CY19, the NYISO evaluated eight solar projects in Zone G (107 MW UCAP) for a REE and confidentially provided initial determinations. Two of these Examined Facilities rejected their Project Cost Allocation.[4] Subsequently, the NYISO provided final determinations to six Examined Facilities (87 MW UCAP) under the REE provisions.

The NYISO calculates a Renewable Exemption Limit ("REL"), which limits the total capacity that may receive a REE in each Mitigated Capacity Zone in each Class Year. The purpose of the REL is to limit the exemptions to renewable resources such that their entry would not have a significant impact on the capacity prices. The REL, subject to a minimum value, is constructed as the sum of the following factors, each of which tend to offset the price suppressive effect of additional renewable entry:

- UCAP MW associated with the change in forecasted peak load over the Mitigation Study Period
- UCAP MW associated with Incremental Regulatory Retirements ("IRRs")[5]
- The Unforced Capacity Reserve Margin ("URM") Impact[6]
- The UCAP MW in the Renewable Exemption Bank at the beginning of the Class Year[7]

The NYISO determined the REL for the G-J Locality in CY19 to be 554 MW, which was higher than the total UCAP of Examined Facilities evaluated for a REE (87 MW UCAP). The following figure shows the various components of the REL in CY19.

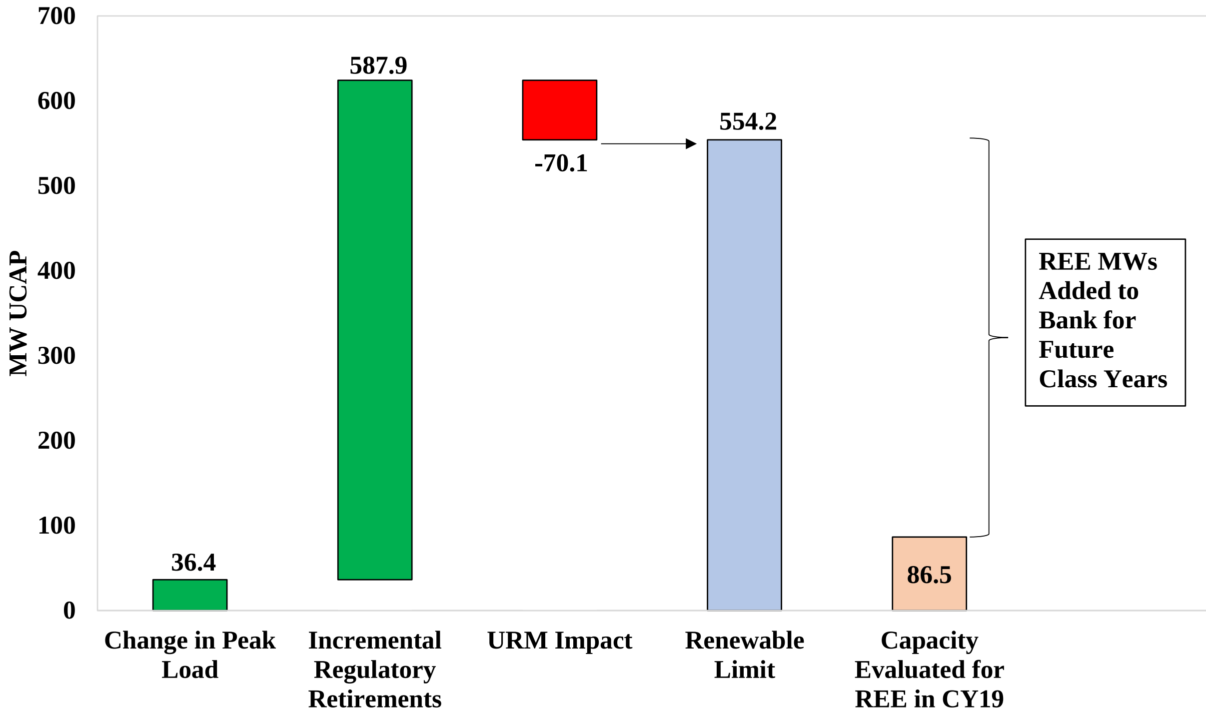
4 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

5 IRRs include the UCAP of generators forecasted to retire during the Mitigation Study Period that occur due, in significant part, to state regulations.

6 The URM Impact is the change in the UCAP requirement of the Locality as a result of the entry of intermittent renewable resources that are being evaluated for a REE in the Class Year.

7 The Renewable Exemption Bank represents the UCAP MW from the prior CY that was carried forward and be made available for granting REEs in the current CY. The bank for CY19 is zero.

Figure 1 - Renewable Entry Exemption Limit and Capacity Evaluated in G-J Locality[8]



As shown in Figure 1,Incremental Regulatory Retirements constitute the largest component of the REL in CY19. In CY19, the primary reason for identifying certain UCAP MW as IRRs was the NYSDEC's "Peaker Rule", which imposes limits on NOx emissions rates of simple cycle unit beginning in May 2023. Any affected units whose owners indicated that they intend to retire or permanently cease operation to comply with the May 2023 limits were considered to be Incremental Regulatory Retirements.

Evaluation of Examined Facilities under Part A and Part B Tests in CY19

In CY19, the NYISO provided initial BSM determinations for 16 Examined Facilities based on Part A and Part B tests. Of these, five projects rejected their Project Cost Allocation after the Initial Decision Period.[9] The NYISO subsequently issued final BSM determinations for 11 Examined Facilities based on Part A and Part B tests.

8 Since Zone J is nested within the G-J Locality, any positive UCAP MW in the Renewable Exemption Bank for Zone J are deducted from the bank for the G-J Locality. Hence, the final value for the Renewable Exemption Bank in the G-J Locality that will be available from CY19 is -203.1 MW. See section III.A.5.

9 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

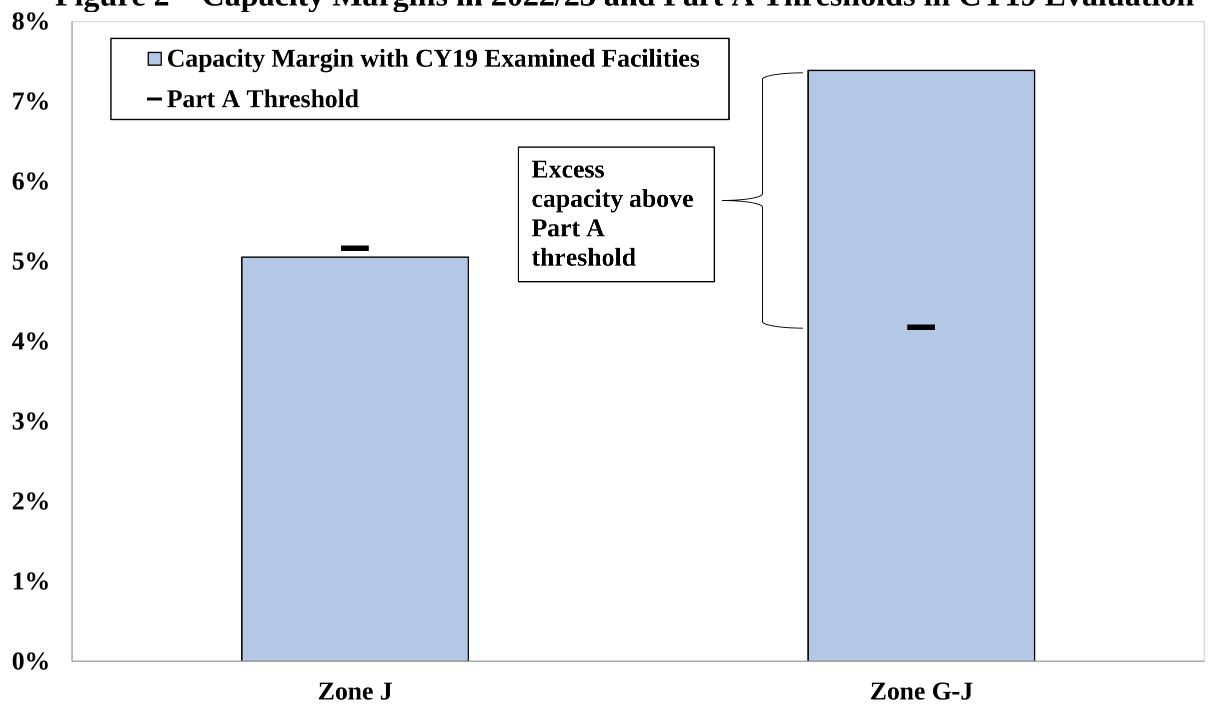
CY19 Part A Test Results

The purpose of the Part A test is to ensure that a resource will be determined to be exempt when its capacity will be needed to satisfy the capacity requirement for a particular Locality. An Examined Facility is determined to be exempt under the Part A test if the price forecast for the first year of its operation is higher than the "default net CONE" or "DNC".

The NYISO's forecasted UCAP prices for Zone J (including all the Examined Facilities) were higher than the DNC during the first year of the Mitigation Study Period (May 2022 to April 2023). Therefore, all four Examined Facilities that are located in Zone J were determined to be exempt under the Part A test in CY19. The continued low capacity margin and the relatively small amount of CRIS requested in Zone J resulted in exemptions to all Examined Facilities under the Part A test. The Summer capacity margin in Zone J (including all Examined Facilities) was 5.1 percent of the Summer UCAP requirements, while the Part A threshold (i.e. the surplus level below which Examined Facilities would be exempt from an Offer Floor) is 5.2 percent.[10]

The NYISO's forecasted UCAP prices for the G-J Locality were lower than the respective DNC values during the first year of the Mitigation Study Period. Accordingly, none of the Examined Facilities located in the G-J Locality were determined to be exempt under the Part A test.

Figure 2 – Capacity Margins in 2022/23 and Part A Thresholds in CY19 Evaluation



10 When the capacity margin is at the Part A threshold, the annual capacity price is equal to the Default Net CONE. When the capacity margin exceeds this threshold, the annual prices will fall below the Default Net CONE.

Overall, we find that the assumptions used in the Part A test were in accordance with the NYISO's Tariff.

CY19 Part B Test Results

In the final round of the CY19 BSM evaluations, the Unit Net CONE ("UNC") of the King's Plaza Project was lower than the forecasted capacity prices over the three-year Mitigation Study Period, which is from May 2022 to April 2025. Accordingly, it was determined to be exempt from the Offer Floor under the Part B test as well. The King's Plaza Project participates in the local utility's demand response programs. Inclusion of revenues from these led to a significant decrease in the Unit Net CONE of the King's Plaza.

The UNCs of all other Examined Facilities (largely solar PV and battery storage projects) were above the ICAP price forecast. Therefore, these facilities were not exempt under the Part B test. In general, high capital costs and/ or high fixed costs associated with these technologies resulted in relatively high UNCs for these facilities.

Overall, we find that the Part B tests in the final round of the CY19 evaluations were performed in accordance with the NYISO MST, and the results are consistent with the fundamental objective of the BSM measures.

Enhancements to the BSM Procedure

As a part of our review, we have identified a number of issues that, if addressed, would improve the accuracy of the BSM evaluations. These relate to the Part A and Part B testing procedures, REE calculations, test assumptions regarding forecasted in-service capacity supply, entry dates of the Examined Facilities, and estimation of revenue offsets and costs.[11]

None of the issues we identified, by itself or in combination, affected the final determinations in the CY19 BSM evaluations. However, it is important that the NYISO work with its stakeholders to address these issues in future evaluations because:

- Implementing the recommendations related to the REE could have resulted in a different value for the Renewable Exemption Bank, which will be used in BSM evaluations for future class years.
- Some of these issues could have affected the Unit Net CONE and the Offer Floor of a subset of CY19 Projects during the Initial Decision Round.
- These issues may have significant impacts on the results of future BSM evaluations.

11 See section IX.

I. Introduction and Summary

The NYISO's Market Administration and Control Area Services Tariff ("MST" or "Tariff") requires that the Market Monitoring Unit ("MMU") prepare a report to be posted concurrently with the results of buyer-side market power mitigation ("BSM") determinations.[12,13]

In Class Year 2019 ("CY19"), the NYISO conducted the Part A and Part B tests of the BSM evaluations for 25 Examined Facilities.[14,15] Of these, eight Examined Facilities were also evaluated for Renewable Entry Exemptions ("REE"), and one was evaluated for a Competitive Entry Exemption ("CEE").[16] The NYISO provided initial determinations to all 25 Examined Facilities prior to the Initial Decision Period of the Project Cost Allocation ("PCA") process. Seven Examined Facilities rejected their PCA at the end of the Initial Decision Round.[17] Therefore, 18 Examined Facilities received final determinations, of which 12 were exempted from an Offer Floor pursuant to the provisions of either the Part A and Part B tests, the CEE provisions or the REE provisions.

This report provides our review of the NYISO's BSM evaluations, and it has been posted concurrently with the final BSM determinations for the CY19 Examined Facilities.[18] We find that the NYISO's BSM determinations for CY19 were made in accordance with the Tariff and based on reasonable assumptions.

12 See Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc., 139 FERC ¶ 61,244 (2012) at PP 130. Also see MST §23.4.5.7.6.8.

13 Terms not defined herein have the meaning set forth in the MST, and if not defined there, then as defined in the Open Access Transmission Tariff ("OATT").

14 The following projects required Additional SDU Studies, and were not provided with BSM determinations as part of CY19: CH Interconnection, Liberty Generating Alternative, Ravenswood Energy Storage 1, Ravenswood Energy Storage 2, and EI Sunset Park (formerly Empire Wind).

15 See MST §23.4.5.7.2.

16 See MST §23.4.5.7.9 and §23.4.5.7.13 for Tariff provisions for CEE and REE, respectively.

17 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

18 The NYISO's final determinations in Class Year 2019 are available at: https://www.nyiso.com/market-monitoring.

Table 2 presents a brief overview of the Examined Facilities in Zone J and the G-J Locality in CY19 (or "CY19 Projects"), and their status at the end of CY19.[19]

Table 2 – Summary of CY19 Examined Facilities

Examined Facility	Zone	Summer ICAP MW	Unit Type	Status
King's Plaza	J	6	CT	Exempt under Part A and Part B
Spring Creek	J	8	CT	Exempt under Part A
Groundvault Energy Storage	J	12.5	ESR	Exempt under Part A
Stillwell Energy Storage	J	10	ESR	Exempt under Part A
Cleancar Energy Storage	J	15	ESR	Exempt under Part A
Flint Mine Solar	G	100	Solar	Exempt under REE
Danskammer	G	88.9	CC	Exempt under CEE
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Greene County II	G	10	Solar	Exempt under REE
Little Pond Solar	G	20	Solar	Exempt under REE
Greene County 3	G	20	Solar	Exempt under REE
Hannacroix Solar	G	3.23	Solar	Exempt under REE
Monsey 44-6	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-2	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-3	G	5	ESR	Not exempt, Accepted PCA
Cuddebackville Battery	G	10	ESR	Not exempt, Accepted PCA
Yonkers Grid	I	20	ESR	Not exempt, Accepted PCA
Eagle Energy Storage	I	20	ESR	Not exempt, Accepted PCA
KCE NY 2	G	200	ESR	Initial determinations only
Gowanus Repowering	J	574	CT	
Rising Solar II	G	20	Solar	
KCE NY 8a	G	20	ESR	
Blue Stone Solar	G	20	Solar	
KCE NY 14	G	20	ESR	
KCE NY 18	G	20	ESR	

This report discusses key results and assumptions in the BSM exemption tests in CY19. For each assumption, the report discusses how the outcome of the test was affected by the assumption, whether the assumption was in accordance with the MST, and whether the assumption was generally reasonable and consistent with the purposes of the BSM measures. In discussing the reasonableness of the particular assumptions, we identify potential concerns that

19 For the Gowanus Repowering Project, the capacity shown in the table represents the total CRIS requested for the new facility. The Danskammer Project (or the "Danskammer Repowering Project") is also a repowering project, and the capacity shows in the table represents the CRIS requested in addition to the CRIS of the existing facility.

may justify changes in NYISO procedures or in the BSM rules. A list of assumptions that may be improved for future BSM exemption tests is provided in Section IX of this report. The following sections review key elements of the NYISO's BSM determinations:

- Section II discusses the NYISO's review of the Danskammer Repowering Project for the Competitive Entry Exemption.
- Section III discusses the NYISO's evaluation of six solar PV projects in the G-J Locality for the Renewable Entry Exemption.
- Section IV discusses the Part A test in which the NYISO compares the forecasted ICAP price in the first year of the Mitigation Study Period ("MSP") to the Default Net CONE.
- Section I discusses the results of the Part B test in which the NYISO compares the forecasted ICAP price during the three-year MSP to the project's Unit Net CONE. Key inputs to the Part B test are discussed in sections VII and VII.
- Section VII evaluates the NYISO's estimates of the cost of new entry ("CONE") for each Examined Facility, which is used to calculate its Unit Net CONE.
- Section VIII evaluates the estimated net revenues for each project from the NYISO's Energy and Ancillary Services markets. The estimated net revenues are also used to calculate the project's Unit Net CONE.
- Section VIIII discusses assumptions that affect both the Part A and Part B tests.
- Section IX summarizes our overall conclusions and discusses issues that could be addressed in future BSM determinations.

II. Competitive Entry Exemption Evaluation

The Tariff provides for the NYISO to exempt from an Offer Floor Examined Facilities that meet certain Tariff criteria under the Competitive Entry Exemption ("CEE") provisions.[20] Generally, the CEE provisions were put in place to exempt merchant projects that do not receive payments from New York State governmental entities or a Transmission Owner from buyer-side mitigation because the developers of such projects should have market incentives to enter based on their own expectations of market conditions. MST §23.4.5.7.9 specifies the requirements that a project developer needs to fulfill in order to establish that the project is not supported by payments or other subsidies (either direct or indirect) through contracts with non-qualifying entities.

A. CY19 Evaluation of CEE Projects

In CY19, the Danskammer Repowering Project requested a CEE.[21] The project developers executed initial Certification and Acknowledgement forms and again as they recertified at different points during the evaluation. The developer also submitted a schedule listing planned or existing contracts with non-qualifying entities and a number of such documents, along with information necessary to calculate a Unit Net CONE ("UNC") for the project. The CEE Project developer's submission to the NYISO included non-disclosure agreements, interconnection studies, fuel service and transport agreements, among other documentation related to the development of the facility.

The NYISO reviewed the developer submissions and, where applicable, requested additional information to determine whether the developer had entered or planned to enter into non-qualifying contracts. The NYISO determined the Danskammer Repowering Project to be exempt from an Offer Floor under the CEE provisions. We find that the determination for the Danskammer Repowering Project was made in accordance with the MST.

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20 MST § 23.4.5.7.9.

21 See NYISO notice available at: https://www.nyiso.com/documents/20142/8363446/Class_Year_2019_Exemption_Requests.pdf/f3d2a7ac-2c44-6d1a-76f8-d202f8917a45

III. Renewable Entry Exemption Evaluation

The Tariff provides for the NYISO to exempt from an Offer Floor Examined Facilities that meet certain criteria under the Renewable Entry Exemption ("REE") provisions.[22] For CY19, Examined Facilities that are exclusively powered by solar, wind, and Limited Control Run-of-River hydropower are eligible to request a REE. These are technologies that the NYISO determined to be weak instruments for the exercise of buyer-side market power because of their relatively low capacity value and high fixed costs.

Under the Tariff, the NYISO calculates a Renewable Exemption Limit ("REL"), which limits the total capacity that may receive a REE in each Mitigated Capacity Zone ("MCZ").

- If the total UCAP of Examined Facilities that are eligible for a REE ("Qualified Renewable Entry Applicants" or QREAs) in a MCZ is lower than the REL, each QREA will receive a REE. The remaining MWs of the REL may be made available for granting REEs in following Class Years according to the calculation specified in MST 23.4.5.7.13.5.5.
- If the total UCAP of QREAs in a MCZ exceeds that zone's REL, exemptions in the amount of the REL are awarded on a pro rata basis (using UCAP MW) to each QREA.

In CY19, eleven projects provided written notice to the NYISO requesting a REE. All Examined Facilities that requested a REE were determined to be QREAs. These included 10 solar projects in Zone G and one offshore wind project in Zone J. Of these, eight solar projects in Zone G totaling 213 MW of summer CRIS were evaluated for a REE in CY19 in the Initial Decision Round.[23, 24] Subsequently, two projects withdrew from CY19 and six solar projects totaling 173 MW of summer CRIS (87 MW UCAP) were evaluated for a REE in the Final Decision Round.

The REL in CY19 was determined to be 671 MW UCAP for Zone J and 554 MW UCAP for the G-J Locality. As the REL exceeded the total UCAP of QREAs, all six projects received an exemption in the full amount of their requested CRIS. Figure 3 and Figure 4 show the total REL, the values of various factors used in estimating the REL, and the total UCAP of QREAs in CY19 for Zone J and the G-J Locality. We discuss the NYISO's methodology for calculating the REL in subsection A, and the process of awarding REEs in CY19 in subsection B.

The NYISO's REE determinations in CY19 were consistent with its Tariff.

22 See MST §23.4.5.7.13.

23 One project proceeded to an Additional System Deliverability Upgrade ("SDU") Study, one revised its technology to become a non-intermittent resource, one project that was an alternate version of another CY19 project withdrew from CY19

24 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

Figure 3 - Renewable Entry Exemption Limit and Capacity Evaluated in Zone J

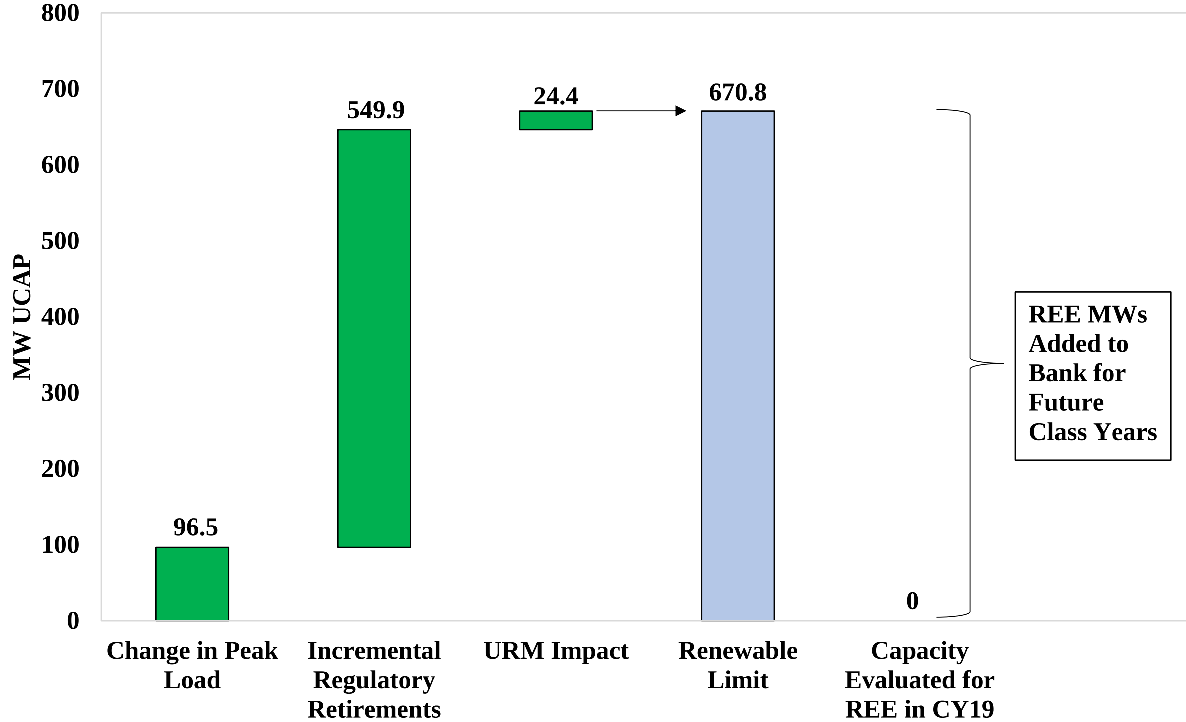
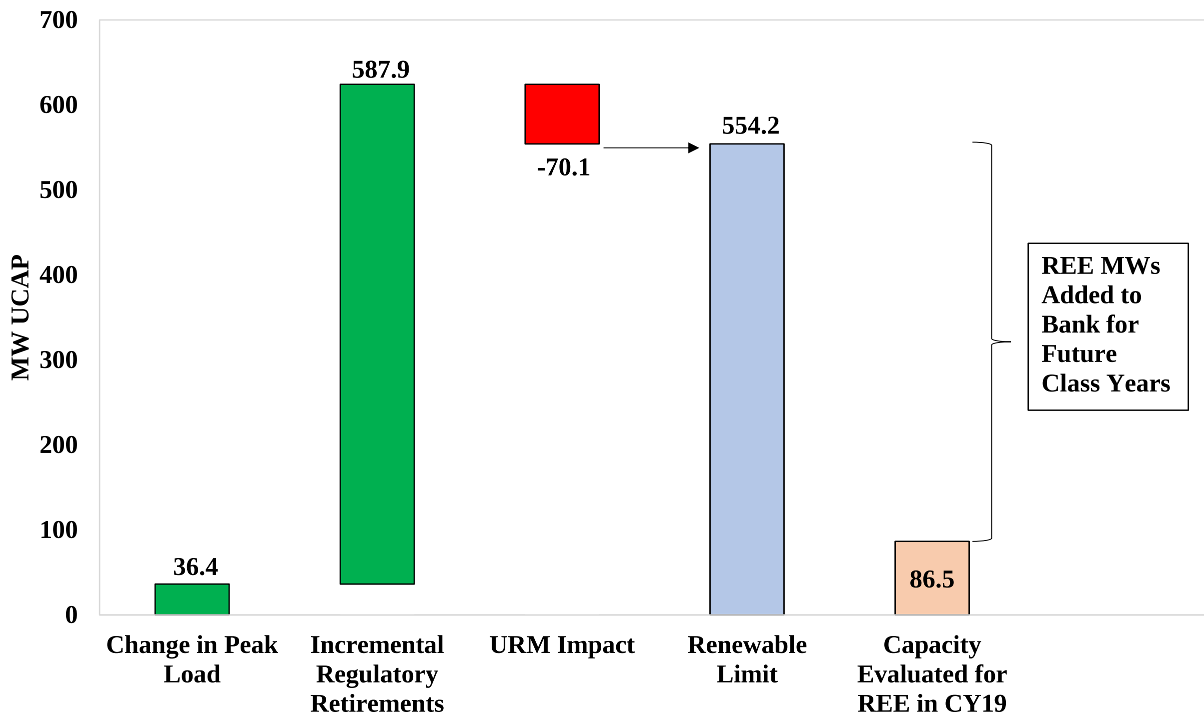


Figure 4 - Renewable Entry Exemption Limit and Capacity Evaluated in G-J Locality[25]



25 Since Zone J is nested within the G-J Locality, any positive UCAP MW in the Renewable Exemption Bank for Zone J are deducted from the bank for the G-J Locality. Hence, the final value for the Renewable Exemption Bank in the G-J Locality that will be available from CY19 is -203.1 MW. See section III.A.5.

A. Calculation of Renewable Exemption Limit

The purpose of the REL is to limit the exemptions to renewable resources such that their entry would not have a significant impact on the capacity prices. The REL, subject to a minimum value, is constructed as the sum of several factors each of which tend to offset the price suppressive effect of additional renewable entry. The REL is calculated as the higher of: (a) the Minimum Renewable Exemption Limit or (b) the sum of the following four items:

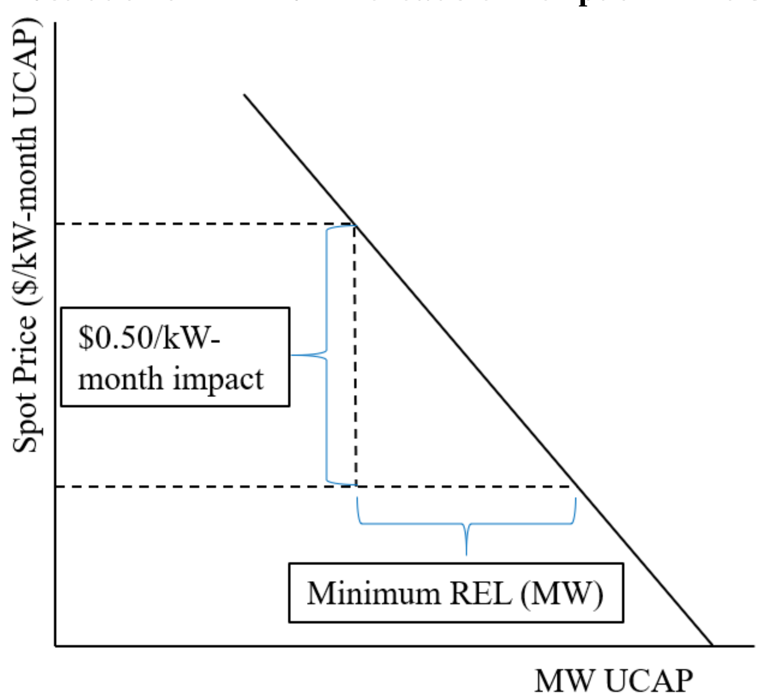
- UCAP MW associated with the change in forecasted peak load over the Mitigation Study Period
- UCAP MW associated with Incremental Regulatory Retirements ("IRRs")
- The Unforced Capacity Reserve Margin ("URM") Impact
- The UCAP MW in the Renewable Exemption Bank at the beginning of the Class Year.

We discuss the NYISO's calculation of the Minimum Renewable Exemption Limit, and each of the four terms in subpart (b) of the above formula in the remainder of this subsection.

1. Minimum Renewable Exemption Limit

The Minimum Renewable Exemption Limit is the amount of UCAP that would cause the forecasted ICAP price to decrease by $0.50/kW-month. Under the NYISO's Tariff, this would determine the minimum value the REL can assume for each MCZ. Figure 5 illustrates the calculation of the Minimum Renewable Exemption Limit for a zone.

Figure 5 - Illustration of Minimum Renewable Exemption Limit Calculation



The NYISO calculated the Minimum Renewable Exemption Limit for each zone as $0.50/kW-month divided by the three-year average of the ICAP demand curve slopes over the Mitigation Study Period. The Minimum Renewable Exemption Limit was determined to be 35.4 MW in the NYC Locality and 53.9 MW in the G-J Locality.[26] In CY19, the REL was not determined by the Minimum Renewable Exemption Limit in either Zone J or the G-J Locality.

2. Change in Forecasted Peak Load

An increase in peak load leads to an increase in the capacity requirement of a Locality, thus reducing the local capacity margin (and increasing the capacity price). Hence, including changes in peak load when determining the REL allows for entry of additional renewables without suppressing capacity prices.

In accordance with its Tariff, the NYISO calculated the change in peak load between 2020 and the last year of the Mitigation Study Period (2024/25) using the summer non-coincident peak load forecasts for Zone J and Zones G-J in the 2020 Gold Book. The resulting change was converted to UCAP MW using the ICAP/UCAP Derating Factor from the Summer 2020 ICAP Demand Curve for each zone.

The Tariff is not prescriptive about the appropriate factor to be used for converting the change in forecasted peak load to UCAP MW. Therefore, the NYISO's usage of the ICAP/ UCAP Derating Factor was consistent with its Tariff.

Some stakeholders have asserted that modifying the NYISO's calculation would better align it with the underlying intent of the REL. Specifically, they proposed including the applicable LCRs in the conversion of the Change in Forecasted Peak Load to UCAP MW to ensure the REL is consistent with the change in the capacity margin due to changes in peak load.[27] However, such a proposal would not be appropriate because it would go beyond the language of the tariff that requires the NYISO to consider load changes—not only those factors that may affect the requirement. Most factors that affect the LCRs are unrelated to changes in forecasted peak load.

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26 NYISO, "Class Year 2019 Renewable Exemption Limit Assumptions and Calculation," November 11, 2020, p. 4, https://www.nyiso.com/documents/20142/8363446/Renewable-Exemption-Limit-Assumptions-and-Calculations-Class-Year-2019-November-11,-2020.pdf/aea0004a-37b9-2475-57fd-70ed670c91d6

27 For instance, in the CY19 BSM evaluations, the LCR for Zone J decreased from 86.6 percent in 2020/ 21 to 83.4 percent in 2024/25. While the peak load changed by 96.5 MW in Zone J, considering the LCRs would have reduced the Renewable Exemption Bank by 315.4 MW.

3. Incremental Regulatory Retirements

IRRs include the UCAP of generators forecasted to retire during the Mitigation Study Period that occur due, in significant part, to state regulations.[28] State actions that cause resources to exit the market would reduce the capacity margin, thus enabling additional entry of renewable resources without suppressing prices.

In CY19, the primary reason for identifying certain UCAP MW as IRRs was the "Peaker Rule" issued by the New York State Department of Environmental Conservation ("NYSDEC") in 2019. The Peaker Rule imposes limits on NOx emissions rates of simple cycle combustion turbine plants beginning in May 2023 with stricter limits beginning in May 2025.[29] The CY19 Mitigation Study Period includes the introduction of the May 2023 emissions limits, but not the May 2025 limits. Owners of affected generation notified the NYISO of their intended compliance plans. Any affected units whose owners indicated that they intend to retire or permanently cease operation to comply with the May 2023 limits were considered to be Incremental Regulatory Retirements for the purpose of CY19 BSM evaluations.[30]

Compliance plans for some units affected by the Peaker Rule indicated that the units will cease operation in the ozone season (May 1 through September 30) but will continue to operate in other months. Such units were not identified as IRRs by the NYISO, as their compliance plans do not indicate intent to retire or permanently cease operation as required by the Tariff.

Overall, the NYISO determined the total quantity of IRRs to be 549.9 MW UCAP in Zone J and 587.9 MW in the G-J locality, including the Zone J units (see Table 3). The NYISO's determination of IRRs in its CY19 BSM evaluations is reasonable and consistent with the Tariff.

28 Pursuant to MST §23.4.5.7.15, the NYISO forecasts generator retirements for the purpose of its ICAP forecast based on a variety of factors. The resources identified by the NYISO as IRRs are a subset of the total forecasted retirements. As per the Tariff, IRRs include existing units forecasted to retire "that have retired, or are planning to permanently cease operation in order to comply with or in response to new or amended regulations or statutes, or other regulatory or related action, including but not limited to those that impact (i) Generator emissions, (ii) inability to renew or modify the necessary operating permits, (iii) availability of fuel supply, (iv) assessment of property taxes, and (v) compensation or other incentive outside of the ISO markets received by a Generator that is contingent upon its permanently ceasing operation."

29 Peaker Rule text available here: https://www.dec.ny.gov/regulations/116131.html

30 See the NYISO's 2020 Reliability Needs Assessment (RNA), figures 7-9 on pp. 17-18 (available here: https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf/64053a7b-194e-17b0-20fb-f2489dec330d) for a summary of the anticipated status of affected generators based on compliance plans provided to the NYISO.

Table 3 - Facilities Affected by DEC Peaker Rule and Incremental Regulatory Retirements

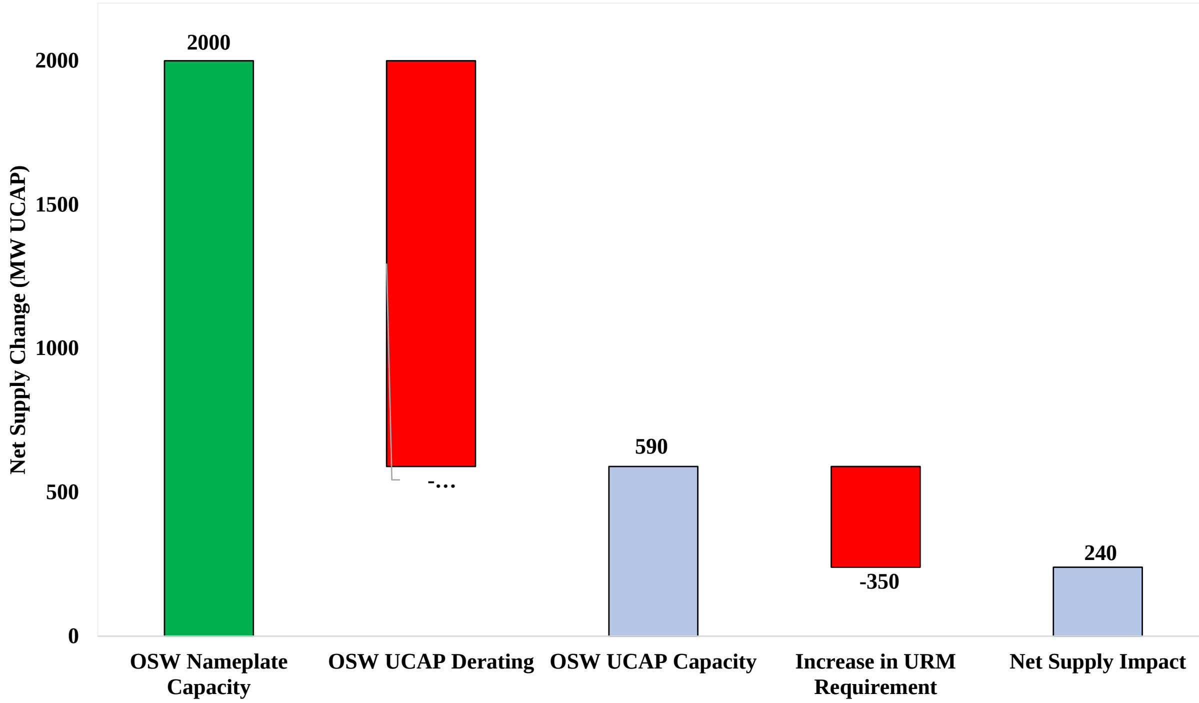
Units	CRIS MW		2023-2024 Compliance Plan Status	2025 Compliance Plan Status	Incremental Regulatory Retirement in CY19
	Summer	Winter			
Zone J					
Ravenswood GTs (01, 10, 11)	50	64	Out of Service	Out of Service	Yes
Astoria GTs (2-1 through 2-4, 3-1 through 3-4, 4-1 through 4-4)	504	621	Out of Service	Out of Service	Yes
Con Ed 74th St	39	49	Out of Service	Out of Service	Yes
Con Ed Hudson Ave 5	15	20	Out of Service	Out of Service	Yes
Astoria GT1	16	21	In Service	Winter Only	No
Gowanus 1&4 (1-1 through 1-8, and 4-1 through 4-4)	279	364	Winter Only	Winter Only	No
Gowanus 2&3 (2-1 through 2-8 and 3-1 through 3-8)	300	391	In Service	Winter Only	No
Narrows 1&2 (1-1 through 1-8, and 2-1 through 2-8)	309	404	In Service	Winter Only	No
Arthur Kill GT1	17	22	In Service	Out of Service	No
Con Ed 59th St	15	20	In Service	Out of Service	No
Zones G-I					
Coxsackie GT	20	26	Out of Service	Out of Service	Yes
South Cairo	20	26	Out of Service	Out of Service	Yes

4. URM Impact of Qualified Renewable Exemption Applicants

The URM Impact is the change in the UCAP requirement of a MCZ as a result of the entry of intermittent renewable resources that are being evaluated for a REE in the Class Year. While entry of intermittent renewable resource increases the capacity supply, it may also cause the UCAP requirement to increase due to the high unavailability of such resources. A higher requirement would reduce the capacity margin, and enable additional entry of renewables without lowering prices. Figure 6 illustrates the effect of the URM in reducing the net change in UCAP supply resulting from the entry of a renewable resource, using data from a NYSRC study of the potential impact of 2,000 MW of offshore wind in Zone J.[31]

[31] The NYISO’s April 7, 2020 Compliance Filing for the Renewable Entry Exemption cites a study by the New York State Reliability Council (“NYSRC”) that found a 350 MW increase in the New York City UCAP requirement after modeling an additional 2,000 MW of offshore wind resources in that zone. As a result, the net increase in supply is the UCAP MW of the offshore wind resources (590 MW) minus the URM increase (350 MW), for a net increase of only 240 resulting from the 2,000 MW offshore wind resource.

Figure 6 - URM Impact Example from NYSRC Study



The Tariff requires the NYISO to calculate URM Impact separately for each Mitigated Capacity Zone.[32] The NYISO calculated the URM Impact by forecasting the NYCA IRM and LCRs with and without the facilities evaluated for a REL in CY19 assumed to be in service. In-service capacity assumptions in the base case were consistent with the assumptions used for the ICAP Forecast discussed in Section VIII of this report. In each case, the NYISO forecasted the NYCA IRM using its Tan45 process and then forecasted LCRs using its alternative LCR methodology. The NYISO calculated a URM impact of 24.4 MW in Zone J and -70.1 MW in the G-J Locality. The NYISO indicated that the URM impact for the G-J locality is negative because capacity requirements selected by the LCR Optimizer shifted from the G-J locality to other zones when the facilities evaluated for a REL in CY19 were included. This was the result of an increase in the zonal derating factor for zones G, H, and I.

Potential Issue with Calculation of URM Impact

The Tariff requires the NYISO to estimate the URM Impact of all QREAs in a CY.[33] As such, the NYISO models all QREAs as in-service when estimating the URM Impact prior to issuing

32 It is defined as "the megawatt value calculated by the ISO when converting the (a) the Installed capacity Reserve Margin (IRM) for the NYCA or (b) the Locational Minimum Installed Capacity Requirement (LCR) for a given Locality within the NYCA into UCAP terms using ICAP to UCAP conversion factors consistent with the corresponding resource adequacy study".

33 MST §23.4.5.7.13.5.4.

the initial determinations, and incorporates the result into its calculation of the REL and the update to the Renewable Exemption Bank. However, if some of the QREAs were to drop out of the CY after the Initial Decision Periods, the URM Impact will not be adjusted. Therefore, to the extent that the QREAs that dropped out had a positive incremental URM Impact associated with them, the final URM Impact and the Renewable Exemption Bank for the CY would be overestimated.

The above situation illustrates a potential shortcoming of the current Tariff. Although this issue did not impact the CY19 determinations or the Renewable Exemption Bank, we recommend the NYISO modify its Tariff and develop procedures for estimating the incremental URM Impact associated with each QREA in its future BSM evaluations. This would allow the NYISO to utilize a more appropriate value for URM Impact in its REL and Renewable Exemption Bank calculations.

5. Renewable Exemption Bank

The Renewable Exemption Bank represents the UCAP MW from the prior CY that was carried forward and be made available for granting REEs in the current CY. The Renewable Exemption Bank will be updated every CY by the difference between (a) the sum of change in forecasted peak load, the URM impact, and the IRRs in the CY, and (b) the REEs that are granted in the CY. The Tariff provides that the starting value of the Renewable Exemption Bank shall be zero in CY19. Hence, no UCAP MWs associated with the Renewable Exemption Bank were included in the calculation of the REL for the CY19 BSM evaluations. In CY19:

- In Zone J, the NYISO calculated a REL of 670.8 MW and did not evaluate any resource in that zone for a REE. Hence, the value for the Renewable Exemption Bank in Zone J which will be carried over to the next CY is 670.8 MW.
- In the G-J Locality, the NYISO calculated a REL of 554.2 MW and awarded 86.5 MW of REE to Examined Facilities in that zone. Since Zone J is nested within the G-J Locality, any positive UCAP MW in the bank for Zone J are deducted from the bank for the G-J Locality.[34] Hence, the Renewable Exemption Bank for the G-J Locality that will be available from CY19 is -203.1 MW.

B. Awarding Renewable Entry Exemptions

Exemptions under the REE provisions are awarded based on each applicant's UCAP. The Tariff provides that applicants' requested CRIS will be converted to UCAP MW in accordance with the applicable UCAP Derating Factor ("UCDF") determined in the Class Year Deliverability Study.[35]

34 MST §23.4.5.7.13.5.5.2.

35 The UCDF is defined in OATT §25.7.8.2.1.1. The UCDF for Intermittent Power Resources is calculated based on their resource type.

In CY19, the UCDF used for the solar resources evaluated for a REE (approximately 50 percent) was consistent with the Class Year Facility Studies Preliminary Deliverability Analysis Draft Report. Accordingly, the 173.2 MW of requested CRIS of QREAs that were evaluated in CY19 were converted to 86.5 MW of UCAP. Since this value is lower than the REL for the G-J Locality (554.2 MW), all QREAs in CY19 received a REE.

The NYISO's methodology to convert requested CRIS of QREAs to UCAP is consistent with the Tariff. However, using the UCDF established in the Class Year Deliverability Study may lead to an outcome that is inconsistent with the intended price impact of REEs.

The UCDF is used in the Class Year Deliverability Study to model an intermittent resource's output during summer peak conditions. Hence, it represents a resource's performance only during the summer. In contrast, the ICAP price effects of a resource would depend on its derating factors during summer and winter. Intermittent renewable resources can have significantly different Summer and Winter UCAP values. In a situation where the average capacity value of QREAs in a CY is significantly lower than the average UCDF (e.g. if most of the capacity is from solar projects), the current Tariff would result in exempting fewer resources than intended. Conversely, if the average capacity value of QREAs in a CY is higher than the average UCDF (e.g. if most of the capacity is from wind projects), the current Tariff would result in exempting more resources than intended.

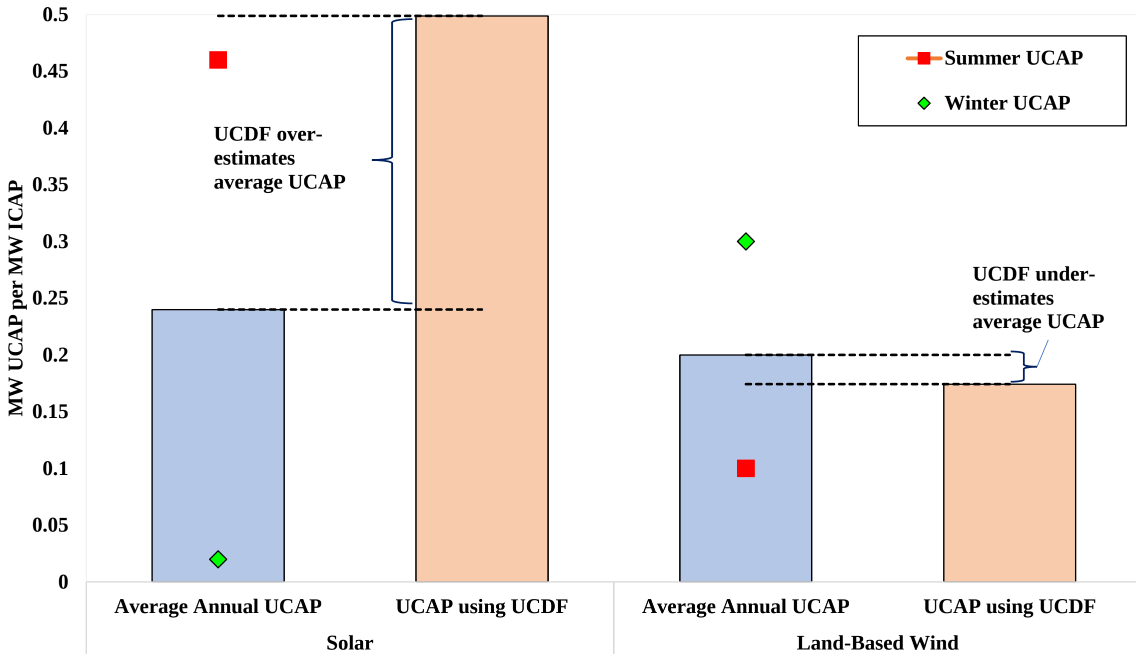
For instance, consider a situation where the REL is determined by the Minimum Renewable Entry Limit, and the $0.50/kW-month corresponds to 54 MW of REL in the G-J Zone.[36] Assume that a 150 MW solar project in Zone G is seeking a REE, and that the UCDF of solar projects is 50 percent. Therefore, the UCAP MW associated with the project is 75 MW, which is greater than the REL. Accordingly, under the current Tariff, the project will receive a REE for only 54 MW of UCAP (i.e. 108 MW of CRIS). However, the annual average capacity value for a new solar project is 24 percent.[37] Therefore, the price impact of this project's entry is $0.33/kW-month on an average, or 44 percent lower than the intended $0.50 impact. Therefore, the project would receive a REE for all of its requested CRIS MW if its UCAP was calculated based on its capacity value.

Figure 7 compares the UCAP of solar and land-based wind resources estimated using the (a) UCDF of the resource type, and (b) the average annual (summer and winter) derating factors of the resource type. The use of UCDF to allocate the REL to QREAs results in the capacity price impact of granting REEs to be over-estimated for some resource types (such as solar) and under-estimated for others (such as wind).

36 This calculation assumes a slope of approximately $0.93/kW-month per hundred MW of UCAP.

37 The NYISO's Installed Capacity Manual assumes a default unforced capacity rating of 46 percent summer and 2 percent winter for a new solar facility with 1 or 2 axis tracking arrays.

Figure 7 - Comparison of Solar and Wind UCAP and UCDF



The above examples illustrate the issue with using a UCDF to estimate the annual price impact of a resource. Accordingly, we recommend the NYISO consider amending its Tariff so that the derating factors used to award REEs are based on the capacity value of each QREA.

C. Conclusion

In CY19, six solar projects in Zone G (173 MW summer CRIS) sought a REE. The NYISO determined the REL to be 671 MW for Zone J and 554 MW for the G-J Locality. The total UCAP MW of the six QREAs was lower than the REL for the G-J Locality. Accordingly, all six QREAs were exempted from the Offer Floor under the REE provisions. The Renewable Exemption Bank values at the end of CY19 are 671 MW for Zone J and -203 MW for the G-J Locality. We find the NYISO's REE determinations for CY19 to be consistent with its Tariff.

We identified the following issues that we recommend the NYISO consider addressing in its future evaluations:

- Develop procedures for estimating the URM impact specific to each QREA in a CY
- Use an annual average capacity value of the resource instead of the UCDF to estimate the UCAP of a QREA.

None of the above issues affected the ultimate outcome of the CY19 BSM evaluations.

IV. Part A Test Results

The Part A test compares a forecast of capacity prices for the first year of the MSP to the Default Net CONE, which is 75 percent of Mitigation Net CONE. [38] The purpose of the Part A test is to ensure that a resource is not mitigated when its capacity will be needed to satisfy the capacity requirement for a particular Locality.[39]

In its CY19 BSM evaluation, the NYISO initially conducted the Part A test for 16 Examined Facilities.[40] The NYISO tested these projects sequentially according to their presumptive Offer Floors from lowest to highest. A unit is exempt in the Part A test if the price forecast for the first year of the MSP is higher than the Default Net CONE ("DNC"). If a project receives an exemption, it is included in the test for the subsequent project. Otherwise, it is excluded from the ICAP forecast for the subsequent project in the sequence.

Following the Initial Decision period, five Examined Facilities (including two that were initially determined to be eligible for a REE) rejected their Project Cost Allocations ("PCAs"). [41] In the final round, the NYISO conducted the Part A test for 11 Examined Facilities. In CY19:

- The total summer UCAP supply (including the CY19 Projects) was 105.1 percent of the capacity requirements in Zone J, where the Part A threshold (i.e. the surplus level below which Examined Facilities would be exempt from an Offer Floor) is 105.2 percent. Therefore, Part A ICAP price forecast for Zone J was higher than the DNC. Accordingly, the NYISO determined that all Zone J resources evaluated in the CY19 (a total of 39.6 MW) were determined to be exempt under the Part A test.
- The total summer UCAP supply (before including the CY19 Projects) in the G-J Locality was 106.4 percent, while the Part A threshold is 104.2 percent. Therefore, Part A ICAP price forecast for G-J Locality was lower than the DNC. Hence, none of the CY19 Projects located in the G-J locality were determined to be exempt under the Part A test.

We find that the Part A tests in the CY19 BSM evaluations were performed using reasonable assumptions that were in accordance with the NYISO MST. Sub-section IV.A evaluates the assumptions used to forecast capacity prices and to perform the BSM evaluation for each

38 See *BSM Narrative and Numerical Example*, Section 2.

39 For each Examined Facility, the Part A test is conducted after the Part B test.

40 In addition to the 16 Examined Facilities, the NYISO also evaluated CEE projects and QREAs under the part A test.

41 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

Examined Facility. The conclusion of this section summarizes our evaluations of the Part A test in CY19.

A. Implications of Factors Identified in Section VIII

This sub-section discusses how key factors identified in Section VIII affected the Part A test.

1. Starting Capability Period of Summer 2022

In accordance with the Tariff, the CY19 Projects were assumed to enter in Summer 2022. However, it is unrealistic to assume that all CY19 projects would begin operations on the same timeline.[42] The CY19 Projects included a diverse set of technologies and project circumstances. It is unrealistic to assume that currently operational projects, small battery storage resources which tend to have short development times, and large thermal repowering projects will all have the same in-service date.

The use of Summer 2022 as the SCP for all CY19 Projects affected the Part A test in the following manner:

- The assumed capacity margin during the years preceding the MSP was smaller in Zone J and larger in the G-J Locality, relative to the margins in the first year of the MSP. This is because:
  - The assumed in-service capacity in Zone J during the years preceding MSP did not differ significantly from the 2022/23 capability year, and the prevailing Zone J LCR is higher than the value assumed for 2022/23.
  - The assumed in-service capacity in the G-J Locality during the years preceding MSP was larger or similar to the 2022/23 supply, and the prevailing G-J Locality LCR is lower than the value assumed for 2022/23.

  Accordingly, assuming an earlier start date for Examined Facilities that are currently operational or have short lead times would not have altered the Part A test determinations in CY19.
- The forecasted ICAP prices in the G-J Locality (and Zone J) were significantly higher for 2023/24 than for 2022/23 (the first year of the MSP), due to the removal of capacity affected by the Peaker Rule in May 2023. Hence, the capacity surplus in the G-J locality was considerably smaller in 2023/24, but was still insufficient to exempt units under the Part A test. Therefore, assuming a later start date for Examined Facilities with longer lead times would not have altered the Part A test determinations in CY19.

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42 See subsection VIII.A for additional discussion of this issue.

2. Capacity Assumed to be In-Service During the Mitigation Study Period

As discussed in VIII.B, the NYISO made several assumptions regarding the set of resources that will be in-service before and during the MSP for the CY19 BSM evaluations.

Approximately 1000 MW of capacity (ICAP Summer) from Indian Point Unit 3 in the G-J Locality was assumed to retire prior to the Summer 2022 Starting Capability Period. The NYISO excluded this capacity based on public information that the unit will cease operations in 2021. Including Indian Point Unit 3 would have further lowered the Part A ICAP price in the G-J Locality by up to $63/kW-year. However, since none of the Examined Facilities in the G-J Locality were determined to be exempt under the Part A test provisions, including the Indian Point Unit 3 would not have affected the outcome of the Part A test.

3. Estimating Locational Capacity Requirements for the Mitigation Study Period

In its CY19 evaluations, the NYISO forecasted Locational Minimum Installed Capacity Requirements ("LCRs") for 2022/2023 for Zone J and the G-J Locality as 85.5 percent and 91.4 percent, respectively. The LCRs for the 2020/2021 Capability Year in Zone J and the G-J Locality were 86.6 percent and 90.0 percent, respectively. The NYISO determined its LCR forecast for the MSP using its Alternative LCR Methodology and the assumptions developed for the ICAP Forecast.[43]

The forecasted LCRs have a significant impact on the available headroom in the Part A test. For instance, a one percentage point decrease in Zone J LCR would have reduced the ICAP price forecast in the first year of MSP by up to $22/kW-year.

However, to the extent that the forecasted LCRs differed from the prevailing values, the use of the current (i.e. 2020/21 Capability Year) LCRs in the ICAP Forecast would not have changed the outcome of the Part A test. The use of the higher LCR of 86.6 percent would have still resulted in all Zone J Examined Facilities being exempt under the Part A test, and the use of a lower LCR of 90 percent would not have resulted in any Examined Facilities in the G-J Locality receiving an exemption.

4. Testing Multiple Examined Facilities

As described in subsection VIII.H, all Examined Facilities with a presumptive Offer Floor that equals the Default Net CONE ("DNC") are tested simultaneously, and would receive the same determination under the Part A test. This process has the potential to mitigate Examined Facilities even when a subset are required to satisfy the Locality's capacity requirements.

43 See subsection VIII.B.

In CY19, the forecasted Zone J ICAP price in the Part A test when all the Examined Facilities are included was still higher than the DNC. The forecasted ICAP price in the G-J Locality was lower than the DNC even when none of the Examined Facilities were included. Therefore, testing all Examined Facilities simultaneously did not affect the results of the Part A test of the CY19 BSM evaluation.

B. Potential Issue with the Part A Test Procedure

The Part A test is intended to exempt Examined Facilities whose capacity is needed to meet the requirement of a Mitigated Capacity Zone. In the Part A test, the NYISO compares the forecasted ICAP prices for the first year of the MSP to the DNC for the Locality in which the Examined Facility is located.

Consider a BSM evaluation in which the only Examined Facility is a unit located in Zone J. The current test procedure would only compare the Zone J DNC with the Zone J ICAP price forecast during the first year of the MSP. Therefore, the current test procedure does not directly consider the level of capacity supply in the G-J Locality. Consequently, if the Zone J price forecast is not affected by the G-J Locality forecast, the current procedure could result in mitigating an Examined Facility even if it is required for meeting the G-J capacity requirement.

Although this issue did not impact the CY19 BSM evaluations, it could impact future BSM evaluations. Hence, we recommend the NYISO consider modifying its Part A test procedure to allow for exempting Examined Facilities if they are needed to satisfy the capacity requirement in any of the Localities where they are located.

C. Conclusions

In CY19, the forecasted ICAP prices for the first year of the MSP were higher than the DNC in Zone J. Hence, all 39.6 MW of Examined Facilities in Zone J were determined to be exempt under the Part A test. The forecasted ICAP prices for the first year of the MSP were lower than the DNC in the G-J Locality. Hence, none of Examined Facilities in the G-J Locality were determined to be exempt under the Part A test. Overall, we find that the Part A tests in CY19 evaluations were performed in accordance with the NYISO MST.

We identified two issues that affected the Part A ICAP price forecast in CY19 that we recommend the NYISO address in its future evaluations:

- The Starting Capability Period is unrealistic for most Examined Facilities
- Current procedure for testing multiple Examined Facilities could result in mitigation even when some of the projects are needed to satisfy the capacity requirement

Neither of the above issues, by itself or in combination, affected the ultimate outcome of the Part A test in the CY19 BSM evaluations.

V. Part B Test Results

An exemption is granted in the Part B test if the average capacity price forecast over the three-year MSP is higher than the Unit Net CONE of the Examined Facility.[44] The Unit Net CONE is equal to the annualized levelized CONE of the project minus the net revenue earned from selling Energy and Ancillary Services.[45] The purpose of the Part B test is to ensure that a project is not mitigated when it would be economic for the project to move forward.

In the CY19 BSM evaluation, the NYISO conducted the Part B test for 16 Examined Facilities.[46] The NYISO's ordering of Examined Facilities for the Part B test included the nine facilities that were eligible for CEE or REE. Examined Facilities were ordered according to their presumptive Offer Floors and tested sequentially. If the presumptive Offer Floor of an Examined Facility was lower than the ICAP price forecast, it was included in the test for the subsequent project. Otherwise, the Examined Facility was excluded from the ICAP forecast for the subsequent project in the sequence.

In the Final Decision Round of the CY19 BSM evaluation, the NYISO conducted the Part B test for 12 Examined Facilities.[47] The ordering for the Part B test included 6 facilities that were eligible for REE. The UNC of the King's Plaza Project was lower than the corresponding capacity price forecast over the MSP in the final round of the CY19 BSM evaluation. Accordingly, it received an exemption under the Part B test.

We find that the Part B test in final round was performed using reasonable assumptions that were in accordance with the NYISO MST. Subsection V.A evaluates the assumptions used to forecast capacity prices and to perform the Part B test of the CY19 BSM evaluation.

A. Implications of Factors Discussed in Sections VI, VII and VIII

This sub-section discusses how several key factors identified in other sections of this report affected the outcome of the Part B test in the CY19 BSM evaluations. Sections VI, VII and VIII discuss in detail other assumptions that were used in the Part B test.

44 See BSM Numerical Example, Section 3.

45 The assumptions for the estimated annual levelized CONE calculations for the Examined Facilities are evaluated in Section V, while the reasonably anticipated net revenue assumptions are evaluated in Section VII. Other relevant forecasting assumptions are discussed in Section VII.

46 In addition to the 16 Examined Facilities, the NYISO also evaluated CEE Projects and QREAs under the Part B test.

47 At the end of the second decision round, one of the Examined Facilities located in a non-Mitigated Capacity Zone failed to post security for its PCA. Consequently, the NYISO provided the members of CY19 their final PCA and BSM determinations as part of the third round.

1. Starting Capability Period of Summer 2022

In accordance with the Tariff, the CY19 Projects were assumed to enter in Summer 2022.[48] However, it is unrealistic to assume that all CY19 projects would begin operations in the same timeframe. For instance, it is unrealistic to assume that currently operational projects, small battery storage resources which tend to have short development times, and large thermal repowering projects will all have the same in-service date.

In the CY19 evaluations, forecasted ICAP prices during the last two years of the MSP in Zone J and the second year of MSP in the G-J Locality were substantially higher than the first year forecast due to the removal of capacity affected by the Peaker Rule.[49] Hence, assuming a project will be in service earlier than its actual start date could lead to mitigation of an otherwise economic project. On the other hand, assuming an operational project to enter into service later than its likely operational date could lead an uneconomic project to be exempted. Nonetheless, given the presumptive Offer Floors of the CY19 Projects, the Starting Capability Period assumption by itself did not impact the outcome of the CY 19 evaluations.

In addition to the ICAP price forecast, the Starting Capability Period also affected the UNC of several CY19 Projects. As discussed in VI.A.1 and VII.A.1, misalignment of the SCP with the likely Commercial Operational Date ("COD") resulted in:

- An overestimate of the opportunity cost component of the Gross CONE of the Gowanus Repowering Project because of the foregone profit resulting from retiring the existing units earlier than necessary to comply with the DEC Peaker Rule,[50]
- A higher capital cost (by up to 10 percent) for battery storage project(s) that plan to enter the market later than Summer 2022 when battery costs are expected to be lower,[51] and
- A slightly higher EAS revenue offset for CY19 Projects that were already operational at the time of evaluation due to the assumed retirement of Indian Point Unit 3 prior to the MSP.[52]

Aligning the start dates for these projects with their likely CODs would not have affected the initial or final determinations in the Part B test of the CY19 BSM evaluations. However, for a subset of the battery storage project, the lower capital costs associated with a later entry date would have enabled a lower Offer Floor than the value determined by the NYISO.

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48 The assumption regarding the Starting Capability Period is discussed in further detail in subsection VIII.A.

49 See *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & Reference*, available at: https://www.nyiso.com/documents/20142/8363446/ICAP-Buyer-side-Mitigation-Test-Data-Assumptions-Document-Class-Year-2019-December-22-2020.pdf/32caa63f-72d8-0258-255d-de201947dca8.

50 See subsection VI.C.3.

51 See subsection VI.A.1.

52 See subsection VII.A.2.

2. Capacity Assumed to be In-service during the Mitigation Study Period

As discussed in VIII.B, the NYISO made several assumptions regarding the resources that will be in-service before and during the MSP for the CY19 BSM evaluations. In particular, the following assumptions had a significant impact on the forecasted ICAP prices in the CY19 Part B test:

- Approximately 1000 MW of capacity (ICAP Summer) from Indian Point Unit 3 in the G-J Locality was assumed to retire prior to the Summer 2022 Starting Capability Period. The NYISO excluded this capacity based on public information that the unit will cease operations in 2021. Including the Indian Point Unit 3 would have further lowered the Part B ICAP price in the G-J Locality by up to $64/kW-year, and would not have had a direct impact on the ICAP prices in Zone J. Therefore, including the Indian Point Unit 3 would not have affected the outcome of the Part B test.
- In the last two Capability Years of the MSP, based on the information from the compliance plans of generators affected by the Peaker Rule, the NYISO (a) excluded over 500 MW in Zone J (ICAP Summer) and over 540 MW in G-J Locality (ICAP Summer) for the last two years of the MSP, and (b) assumed that over 250 MW (ICAP Summer) of capacity would not be selling capacity during the ozone seasons (May through September) occurring after May 2023. Including all the capacity from units affected by the Peaker Rule would have reduced the average Zone J ICAP price forecast over the MSP by up to $72 per kW-year, and would have likely resulted in a different Part B determination for the King's Plaza Project.

We find the NYISO's assumptions to exclude these units from the capacity supply to be reasonable and compliant with its Tariff.

3. Estimating Locational Capacity Requirements for the Mitigation Study Period

In its CY19 evaluations, the NYISO forecasted Zone J LCRs for 2022/2023, 2023/24, 2024/25 as 85.5 percent, 83.5 percent and 83.5 percent, respectively. The forecasted G-J Locality LCRs for 2022/2023, 2023/24, 2024/25 were 91.4 percent, 89.5 percent and 83.5 percent, respectively. The LCRs for the 2020/2021 Capability Year in Zone J and the G-J Locality were 86.5 percent and 90.0 percent, respectively. The NYISO determined its LCR forecast for the MSP using its Alternative LCR Methodology and the assumptions developed for the ICAP Forecast.

The forecasted LCRs have a significant impact on the Part B ICAP price forecast. For instance, a one percentage point decrease in Zone J LCR would have reduce the average ICAP price forecast over the MSP by up to $22 per kW-year.

However, to the extent that the forecasted LCRs differed from the prevailing values, the use of the current 2020/2021 LCRs in the ICAP Forecast would not have changed the outcome of the Part B test for the CY19 Projects in Zone J or the G-J Locality.[53]

4. Issues Affecting CONE of Energy Storage Resources

As described in Section VI.C.2, the NYISO made several adjustments to the costs submitted by a number of ESRs. In particular, the following adjustments had a significant impact on the UNC of these projects:

- *Demand Charges* – All stand-alone battery storage projects that are sized 5MW or more and are interconnected to the distribution system incur demand charges for any energy they withdraw from the grid. Demand Charges constitute the single largest operating expense of battery storage projects in New York. However, a number of cost submissions either did not include any Demand Charges or included an unsubstantiated value. For such projects, the NYISO estimated the applicable Demand Charges that ranged from $50 per kW-year to $96 per kW-year, depending on a number of factors that include the rate schedule of the local utility, voltage level, and the withdrawal schedule.
- *Contingency* – The NYISO utilized estimates of contingency that were developed by its consultant, since most battery storage projects were in a very preliminary stage of development. The NYISO's consultant's estimates for cost contingency for storage projects ranged from 10 percent to 20 percent of the EPC costs, which are considerably higher than the value used in the Gross CONE of the demand curve peaking unit (5 percent). This adjustment resulted in an increase in the Gross CONE of battery storage projects by up to $21 per kW-year.
- *Sales Tax* - A number of project developers did not include any sales taxes on battery equipment costs or submitted an unsubstantiated value. The NYISO applied sales tax of 8.1 to 8.9 percent, depending on the county where the project is located.
- *Fixed O&M* – A subset of storage projects submitted Fixed O&M costs that were unsubstantiated. The NYISO utilized estimates from the 2020 ICAP Demand Curve Reset study in cases where the submitted values were unsubstantiated and lower. This adjustment resulted in an increase in the Gross CONE by $18 to $26 per kW-year

None of the above four cost adjustments, by themselves, affected the determinations under the Part B test. However, reversing any one of the above adjustments would have resulted in a lower Offer Floor for a subset of the battery storage projects. If all four adjustments are reversed, two of the battery storage projects could have received an exemption under the Part B test. We find the NYISO's approach to reviewing and adjusting the submitted costs to be reasonable.

53 The NYISO lowered the forecasted LCRs used in the Initial Decision Round to account for impacts of the AC Public Policy Transmission projects that are expected to be in-service during the last year of the MSP, as discussed in Section VIII.D. This resulted in a reduction of the Zone G-J LCR in the last year of the MSP. However, this assumption did not alter the final outcome of the Part B Test in CY19.

5. Issues Affecting Net Revenues of Energy Storage Resources

As described in subsection VII.D.1, the NYISO estimated the net revenues for the ESRs in its CY19 evaluations using an optimization model that included a characterization of various physical costs/ constraints related to the operation of the resource. [54] However, the dispatch model likely overestimated the net revenues of battery storage units for the following reasons:

- The dispatch model assumed perfect foresight of prices for the unit operator.
- The NYISO's model implicitly allowed for interval-level offers/ bids, whereas the unit operators can only submit hourly offers/ bids in accordance with current market rules.

Modifying the NYISO's model to address the above shortcomings would only reduce the net revenues, and increase the UNC of the Examined Facility. Ultimately, since none of the ESRs in the CY19 BSM evaluation were determined to be exempt under the Part B test, addressing the above issues would not have affected the initial or final determinations for ESRs.

6. Impact of Non-NYISO Revenues Included in Net CONE Estimates

The Tariff requires the NYISO to include in its net revenue calculations "revenues associated with other energy products (such as energy services and renewable energy credits".[55] Therefore, the NYISO considered revenues from the local utility's demand response programs and from the sale of Renewable Energy Credits ("RECs") in estimating the UNC of some the CY19 Projects. These non-NYISO market revenue streams, particularly from the demand response programs (where applicable), reduced the UNCs of the Examined Facilities significantly.[56]

7. Opportunity Costs of Repowering Projects

Repowering currently operating units could result in foregone profits from existing units. Hence, there is an opportunity cost that needs to be considered as part of Gross CONE of the Gowanus and Danskammer Repowering Projects in CY19. As discussed in VI.C.3, NYISO estimated the opportunity cost component of the Gross CONE as the NPV of the difference between capacity revenues and estimated operating costs over the expected life of the existing facility. However, since the Gowanus Repowering Project rejected its PCA after the Initial Decision Period and the Danskammer Repowering Project was determined to be exempt under the CEE provisions, the opportunity cost did not affect the final determinations.

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54 The constraints modeled included a limit on the total number of charge/ discharge cycles.

55 See MST §23.2.1. Also see subsection VII.C.

56 The King's Plaza project participates in local utility demand response programs. See https://microgridknowledge.com/new-microgrid-kings-plaza-coned/

8. Forecasting ICAP Reference Point

For the CY19 BSM evaluations, the NYISO forecasted the ICAP reference points for the MSP by inflating the Gross CONE associated with currently effective ICAP demand curves, updating net revenues of the demand curve unit, and updating the winter-to-summer ratio.[57]

However, the federal corporate tax rate has decreased from the value used in the 2016 ICAP Demand Curve Reset study. Similarly, the recently filed ICAP Demand Curve Reset study suggests that the WACC has decreased considerably from the 2016 study. Given its Tariff provisions, the NYISO did not consider any updates to these financial parameters when forecasting the ICAP reference point.[58] Incorporating changes to the tax rate and the cost of capital parameters would have lowered the average ICAP reference point (over the MSP) for Zone J by $18 per kW-year.

Although this issue may have affected the initial determination(s) under the Part B test for a subset of the CY19 Projects, all else being equal, it would not have impacted the final Part B test determinations.

5. Cost of Capital

The NYISO estimated the cost of capital for the solar PV projects in CY19 as a composite of Weighted Average Cost of Capital ("WACC") values that are representative for regulated and merchant entities in New York.[59] The NYISO's estimate of the WACC was approximately 50 basis points lower than the value developed as part of the 2020 ICAP Demand Curve Reset study. Utilizing the 2020 ICAP Demand Curve Reset study would have increased the UNC of these projects by up to 13 percent. However, the NYISO's assumptions regarding cost of capital did not affect the initial or final determinations for the solar PV project under the Part B test.

The NYISO utilized WACC from the 2020 ICAP Demand Curve Reset study for a number of ESRs whose developers submitted lower or unsubstantiated cost of capital values. Reversing this change would have lowered the UNC of ESRs by up to $130 per kW-year. Although, this issue, by itself, would not have affected the Part B test determination, it could have allowed for a lower Offer Floor for several resources.

We find the NYISO's assumptions regarding the WACC of CY19 Projects to be reasonable.

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57 See subsections VII.B, VIII.F, and section 2.4 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

58 See MST §23.4.5.7.15.3.4 and §23.2.1.

59 See subsection VI.B.2.

B. Conclusions

In the CY19 BSM evaluations, the UNCs of only the King's Plaza Project in Zone J was lower than the average capacity price forecast over the three-year MSP. Accordingly, only this facility was determined to be exempt from the Offer Floor under the Part B test. The inclusion of revenues from the utility's demand response program resulted in a significant reduction in the Unit Net CONE of the King's Plaza Project.

None of the UNCs of the other Examined Facilities were below the ICAP price forecast. Therefore, these facilities were not exempt under the Part B test. In general, the following factors resulted in relatively high UNC for these facilities:

- High capital costs, and high fixed costs (particularly demand charges) of the battery storage resources
- High capital costs of solar PV projects

Overall, we find that the Part B tests in the final round of the CY19 evaluations were performed using reasonable assumptions in accordance with the NYISO MST.

We recommend the NYISO address the following issues in its future evaluations:

- Starting Capability Period is unrealistic for most Examined Facilities
- Modify ESR dispatch model to: (a) reflect the ability of the ESR to submit only hourly offers, (b) account for the operator's limited foresight of future prices when offering the unit
- Develop a transparent procedure for estimating the REC value of various renewable resources
- Consider modifying the definition of Mitigation Net CONE to allow for using a reasonable forecast of the ICAP demand curves

None of the above issues affected the final determinations for the CY19 BSM evaluations. However, the Starting Capability Period issue likely affected the Offer Floor for some of the Examined Facilities in the Initial Decision Round.

VI. Part B Test Input – Cost of New Entry

The BSM exemption test requires the NYISO to estimate the annual levelized CONE of each Examined Facility for use as an input to the Part B test. The developers of the CY19 Projects provided cost information which was evaluated by the NYISO with the assistance of engineering consulting firms. In some cases, the NYISO substituted a developer's identified cost estimates with one that the NYISO determined was more reasonable. This section evaluates key assumptions used in the CONE estimates.

A. Implications of Factors Identified in Section VIII

This sub-section briefly discusses how factors identified in Section VIII affected the estimated CONE of the CY19 Projects.

1. Starting Capability Period of Summer 2022

The requirement to use the same Starting Capability Period of Summer 2022 for each project affected the determination of the Unit Net CONE for the Gowanus Repowering Project and a subset of the battery storage projects.

- The Gowanus Repowering Project is intended, in part, to comply with the DEC Peaker Rule beginning in May 2023.[60] The assumption of a Summer 2022 in-service date required the NYISO to include foregone profits from the capability periods prior to the Peaker Rule taking effect, whereas assuming an in-service date aligned with the regulations would not have incurred such an opportunity cost.
- For a subset of the battery storage projects, the developer(s) indicated that their project would commence operations in 2024. Consequently, they assumed considerable reduction in battery costs relative to a project with a start date of Summer 2022. However, consistent with its Tariff requirements, the NYISO aligned the in-service date with the SCP of Summer 2022, and adjusted the submittal to remove the impact of reduction in battery capital costs between 2022 and 2024.

B. Assumptions Affecting the CONE of Multiple Types of CY19 Projects

1. Treatment of Pre-Existing And/or Common Facilities

The Gowanus Repowering, Danskammer Repowering, King's Plaza and Spring Creek Projects will be located at existing generator sites. A new project located on a site with existing units might use preexisting equipment on the site, share pre-existing equipment with other generators at the site, and share new equipment with existing or future generators. The MST requires the

60 See Preliminary Scoping Statement filed by Astoria Generating Company, L.P, in its Certificate of Environmental Compatibility and Public Need Pursuant to Article 10, May 14, 2019.

NYISO to estimate the CONE of an Examined Facility based on its "embedded" cost. This sub-section discusses the criteria used by the NYISO to estimate the embedded costs allocated to the Examined Facilities, when the costs are related to pre-existing and/or common (i.e., shared) facilities.

Pre-Existing Non-Common Facilities

Pre-existing non-common facilities include equipment that was originally built for another generator that is no longer in use. The NYISO estimated the embedded cost of pre-existing noncommon facilities at the Examined Facility site(s) based on their book values. The use of book values was consistent with the requirement to use embedded costs.

Pre-Existing Common Facilities

As a general matter, when a project is located at an existing plant that is owned by an incumbent generator, the project may take advantage of the economies of scale that come from using facilities that were purchased or constructed well before the project was conceived and that are still being used for *other* generators at the same site. For example, the new project may share labor costs, control room functions, interconnection facilities, and inventory capacity with other generators at the site. Such facilities are known as pre-existing common facilities.

To the extent that the developers plan to use pre-existing common facilities, the NYISO allocated costs from such facilities to the Examined Facilities only if additional costs would be incurred to expand the capacity of the common facilities. Hypothetically, if an on-site storage facility costing $100,000 would be expanded 50 percent at a cost of $40,000 to accommodate the needs of an additional project, $100,000 would be included in the CONE estimate for first project, while $40,000 would be included in the CONE estimate for the second project.

Similarly, to the extent that the Examined Facility resulted in an increase in the costs of operating the site (e.g. labor, materials), the additional operating costs were included in the CONE of the Examined Facility. We believe the NYISO's assumptions regarding pre-existing common facilities were consistent with the Tariff and are likely to produce CONE estimates that are consistent with the true economic cost of the new entry.

2. Cost of Capital

The NYISO used the cost of capital estimates submitted by the CY19 Projects' developers when they were reasonably consistent with the risk profile of the project and/ or were well-substantiated. The documentation reviewed by the NYISO to evaluate the reasonableness of the submitted cost of capital estimates includes credit agreements for similarly-situated projects, communications with lenders, results of the CAPM model, and presentations from financial advisors. The NYISO determined that the submitted WACC values of five Examined Facilities were substantiated, and used the developer-submitted assumptions in estimating the Gross CONE. For the rest of the CY19 Projects:

- A considerable number of developers indicated that their WACC is consistent with the values developed as part of the 2020 ICAP Demand Curve Reset study.[61]
- For evaluating solar projects, the NYISO developed a representative WACC that is lower than the value developed in the 2020 ICAP Demand Curve Reset study. The NYISO's estimate reflects the lower risk associated with the REC revenues (relative to revenues from the NYISO's markets).[62] The NYISO estimated the WACC for solar projects as the weighted average of typical WACC for regulated and merchant entities in New York, with the contributions of REC revenues and NYISO-market revenues to the project's NPV as weights.[63]
- For all other Examined Facilities, to the extent that firm-specific or project-specific information was unavailable or unsuitable for calculating the WACC for that Examined Facility, the NYISO used values developed in the 2020 ICAP Demand Curve Reset study.

We find the cost of capital parameters used by the NYISO in the CY19 BSM evaluations to be reasonable.

3. Amortization period

The estimated CONE of each CY19 Project was amortized over the project's economic life, which is the period over which an owner seeks to recover the project costs along with a return on investment. The assumed economic life affects the Gross CONE in a significant manner.

Gas-fired Examined Facilities

For the CY19 evaluations, the NYISO assumed a 20-year amortization period for all gas-fired Examined Facilities. This is consistent with the currently effective assumptions underlying ICAP Demand Curves and past BSM evaluations. However, the assumed life of 20 years exceeds the value assumed in the 2020 ICAP Demand Curve Reset study, where the NYISO's consultants used a 17-year amortization period. This is because the Climate Leadership and Community Protection Act ("CLCPA") requires that the electric system be zero emissions by 2040, which creates uncertainty regarding the operating status of new fossil-fired projects after

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61 The cost of capital estimates developed as part of the 2020 ICAP Demand Curve reset study can be found at: https://www.nyiso.com/documents/20142/14526320/Analysis-Group-2019-2020-DCR-Final-Report.pdf/0dc75930-e651-2120-80de-234d98cd548b

62 See discussion of Non-NYISO Market Revenue Streams included in the NYISO's calculation of Net CONE in Section VII.C of this report.

63 The NYISO used merchant WACC inputs from the 2020 ICAP Demand Curve Reset study and regulated WACC inputs from the most recently approved rate cases of regulated electric utilities in the mitigated capacity zones (Con Edison, Central Hudson and Orange & Rockland).

2040. However, for CY19 Examined Facilities, there were a number of project-specific factors that justified using a longer project life than 17 years. The project-specific factors considered by the NYISO include, among others, a higher residual value attributable to the specific design of the projects and/or ability to burn zero-carbon fuels. Hence, we find the NYISO's use of a 20-year amortization period to be reasonable.

Energy Storage Resources

The NYISO assumed a 20-year amortization period for storage projects. This is consistent with the treatment of other technologies in the last approved ICAP Demand Curve Reset study. Furthermore, multiple project developers submitted documentation (for instance, capacity and performance guarantees) that substantiated this assumption.

A number of CY19 Projects submitted an amortization period of less than 20 years but indicated a much lower WACC that was not substantiated. As discussed in subsection B.2, the WACC used in the evaluation of these projects was based on inputs from the 2020 ICAP Demand Curve Reset study. However, the assumed cost of capital in that study is representative of what is encountered by merchant entrants whose economic life is longer than the submitted values.[64] Accordingly, the NYISO utilized an amortization period 20 years for projects whose submitted WACC was replaced with values from the 2020 ICAP Demand Curve Reset study.

The NYISO's approach for determining the amortization period for battery storage projects was reasonable.

Solar Projects

The NYISO assumed a 20-year amortization period for solar projects. This is consistent with the treatment of other technologies in the last approved ICAP Demand Curve Reset study and the NYISO's last completed study on exempt renewable technologies.[65]

4. Interconnection Costs

Consistent with Commission directives in previous BSM evaluations, the NYISO used the Project Cost Allocations ("PCAs") for System Upgrade Facilities ("SUFs") and System Deliverability Upgrades ("SDUs") and the headroom payments from the CY19 Facilities Studies

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64 See summary of cost of capital and economic life parameters in Analysis Group, *Independent Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*, p. 73.

65 See NYISO presentation to Installed Capacity Working Group on March 3, 2016, p. 8, https://www.nyiso.com/documents/20142/1399264/Renewables%20Exempt%20Technologies%20Numerical%20Analysis%20ICAPWG%2003032016-C.pdf/dc711d95-8481-1d12-57e3-5f447c9a954d

Reports to estimate the interconnection costs of the Examined Facilities.[66] The NYISO is responsible for developing the PCAs, so cost estimates were developed for each Examined Facility by the NYISO with input from the Connecting or Affected Transmission Owners ("TO") and the developer.

A developer must post financial security for the amount equal to its PCA in order to remain in the Class Year. If the actual cost of constructing the SUFs and/or SDUs is lower than the amount of Security, the developer is only responsible for the actual cost incurred.[67] The purpose of the PCA is to ensure that the developer is financially responsible for any interconnection costs, while the purpose of the BSM evaluation process is to estimate the expected cost of new entry of an Examined Facility. So, the differing purposes of the processes may justify the use of two estimates.

5. Interest During Construction

The NYISO estimated the Interest During Construction ("IDC") using the draw schedule and construction loan terms for CY19 Projects when the submitted information was well substantiated. In other situations, the NYISO used a technology-specific default construction draw schedule.

6. Contingency

The NYISO, in consultation with its engineering consultants, evaluated the validity of cost data submitted by the CY19 Projects' developers. In cases where there was significant around the submitted cost data, the NYISO utilized a contingency value that is higher than the input to the prevailing ICAP Demand Curves calculations. For CY19 evaluations, factors that contributed to greater uncertainty in costs are: a) the developers did not have a signed EPC contract for constructing the Examined Facility, and b) the Examined Facility is in a preliminary stage of development. The contingency values used by the NYISO in CY19 BSM evaluations ranged from 5 percent to 20 percent of EPC costs.

C. Assumptions Affecting the CONE of Individual CY19 Projects and Technologies

1. CONE of Renewable Projects

Eight solar projects located in Zone G were evaluated as part of CY19. The NYISO's consultants estimated benchmark values for capital and fixed operating costs for utility-scale solar projects in Zone G of various sizes based on experience with similarly-sized projects.

66 See MST §23.4.5.7.3.3.

67 See OATT §25.8.6.2.

The NYISO reviewed the cost documentation from the CY19 Projects' developers, and compared the submitted costs with its consultants' benchmark values. If the submitted costs were comparable to (or exceeded) the relevant benchmark, and/ or the submitted costs were well-substantiated, the NYISO utilized the capital and operating costs data from the CY19 Project developers.

Federal Tax Credits

Solar projects are eligible for an Investment Tax Credit ("ITC") or a Production Tax Credit ("PTC") (if the facility commenced construction prior to January 1, 2018) as part of a federal incentive for renewable generation. The ITC reduces the federal income tax of the investors by an amount equal to 10 to 30 percent (depending on the in-service date) of the project's eligible capital costs, and is realized in the first year of the project's commercial operation.[68] The PTC is a per-kWh tax credit for the electricity produced by the facility over a period of 10 years.

The NYISO solicited documentation from developers to support the level of federal incentives that they claimed for their projects. For developers who did not substantiate the level of federal incentive they claimed, the NYISO relied on the following assumptions in evaluating their Examined Facilities:

- Given the capital intensive nature of a solar facility, the PTC level for solar projects, and the restrictive timeline for PTC eligibility, the economics of the solar projects favor use of the ITC rather than the PTC. Accordingly, the NYISO performed its evaluations assuming that the CY19 Projects will benefit from the ITC.
- The NYISO assumed a default rate of 26 percent for the ITC, consistent with a project beginning construction in 2020 or being able to 'safe harbor' the system at the 2020 level of ITC.
- The NYISO applied the 26 percent ITC rate to a cost basis that included all capital cost items but excluding the interconnection costs.
- The NYISO reduced the depreciable cost for the project by 13 percent of the ITC cost basis, and applied a five-year MACRS schedule to depreciate the applicable costs.

2. CONE of Battery Storage Projects

Thirteen battery storage projects were evaluated as part of CY19 BSM evaluations. In this subsection, we discuss the NYISO's evaluation of the capital and fixed costs of these projects.

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68 See U.S. Department of Energy, "Guide to the Federal Investment Tax Credit for Commercial Solar Photovoltaics", January 2020, https://www.energy.gov/sites/prod/files/2020/01/f70/Guide%20to%20the%20Federal%20Investment%20Tax%20Credit%20for%20Commercial%20Solar%20PV.pdf

Capital Costs

The NYISO's engineering consultants developed detailed zone-specific capital cost benchmarks for battery storage projects in New York. The NYISO reviewed the cost documentation from the CY19 Projects' developers, and compared the submitted costs (total and individual cost elements) with its consultants' benchmark values. If a submitted value was comparable to (or exceeded) the relevant benchmark value, and/ or the submitted value was well-substantiated, the NYISO utilized the data from the CY19 Project developers. Otherwise, the NYISO relied on the data from the benchmarks provided by its consultant. The cost benchmarks were developed on the basis of costs the consultants have observed for actual projects in operation and under development, taking into consideration the project location, and installed capacity.

We summarize below key adjustments the NYISO made to various capital cost components of battery storage projects in its CY19 BSM evaluations:

- *Engineering, Procurement and Construction ("EPC") Costs* - Most project developers provided firm documentation in support of their submitted equipment costs. However, several other EPC cost elements, particularly the construction/installation labor and materials costs, were not well substantiated. Hence, the NYISO utilized the developer-submitted equipment costs, but relied on its consultant's benchmarks for other EPC costs for a subset of the CY19 Projects.
- *Non-EPC Costs* - Eight projects submitted Non-EPC costs that were well below the consultant's benchmark values. Since the submitted values were not well substantiated, the NYISO replaced them with its consultant's estimates.
- *Sales Tax* – A number of project developers did not incorporate any sales tax on the battery equipment (or submitted an unsubstantiated value) in their cost submissions. Sales tax on battery equipment typically ranges from 8.1 to 8.9 percent depending on the location. Although, there are a number of proposals to eliminate this tax for battery storage, the projects are currently not exempted in New York. Accordingly, the NYISO included the cost associated with applicable sales tax to all the submissions that did not include or underestimated this cost.[69]

Fixed Costs

The NYISO found that the fixed costs inputs for several battery storage projects were not well substantiated. We summarize the NYISO's evaluation of the key components of fixed costs for these projects:

- *Fixed O&M Costs* – Fixed O&M costs for ESRs include a number of components such as system maintenance and augmentation costs (typically part of the Long Term Service

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69 See summary of sales tax exemption provisions for New York in Joshua K. Lawrence, "A Sales Tax Boost for the Energy Storage Industry?", July 10, 2020, at https://www.hodgsonruss.com/blogs-All-About-Sales-Tax,a-sales-tax-boost-for-the-energy

Agreement or "LTSA"), property insurance allowance, and site leasing allowance.[70] The following are the key adjustments the NYISO made to fixed O&M costs of ESRs in its CY19 BSM evaluations:

- The NYISO compared the submitted fixed O&M costs to the estimates developed for ESRs by the engineering consultants as part of the 2020 ICAP Demand Curve Reset study. The NYISO substituted unsubstantiated submittals with estimates from the 2020 ICAP Demand Curve Reset study in cases where the former were lower than the latter.
- The developer(s) of some of the CY19 Projects indicated that they intend to increase the duration of their ESR(s) from two hours to four hours over the life of the project. Consequently, the submissions included LTSA costs that reflected this increases in duration. Since these resources were treated as two-hour ESRs for the BSM evaluation, the submitted LTSA costs were likely to be higher relative to how these resources were modeled. In estimating the Gross CONE of these projects, the NYISO utilized the LTSA cost estimates for a four-hour ESR from the 2020 ICAP Demand Curve Reset study. We recommend that the NYISO develop fixed costs benchmarks that are appropriate for the duration of the ESR for its future BSM evaluations. Nonetheless, using the appropriate cost estimate is unlikely not to have any impact on the outcome of CY19 evaluations.

- *Demand Charges* - Currently all stand-alone battery storage projects that are sized 5MW or more and are interconnected to the distribution system are expected to incur demand charges for any energy they withdraw from the grid, as per provisions described under the standby service rates for various utility companies.[71] Demand charges constitute the single largest operating expense of battery storage projects in New York, and are largely composed of two charges: (a) Contract Demand Delivery Charge, and (b) As-Used Daily Demand Delivery Charge.[72] A number of project developers did not include any demand charges or submitted an unsubstantiated value in their cost submissions. For such projects, the NYISO included the applicable demand charges based on the applicable utility tariff.
  - In its CY19 BSM evaluations, the NYISO treated the Daily As-Used Demand Delivery Charge as a fixed cost. However, since these charges vary based on the

70 The performance of batteries degrades with time. Hence, batteries need to be replaced or new batteries need to be added to the existing system periodically to maintain stable performance throughout the life of the project. The costs associated with replacing or augmenting the existing batteries are referred to as augmentation costs.

71 For instance, for details on the applicable demand charges for ConEd and O&R utlities, see "Grid-Connected Electric Storage System Charges", available at: https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/bulk-energy-storage/charges-applicable-to-grid-connected-electric-energy-storage-systems.pdf.

72 Contract Demand Delivery Charge is a fixed monthly charge and ranges from $2.55 to $7.57 per kW-month, depending on the utility network and the voltage level. As-Used Daily Demand Delivery Charge is a variable charge and ranges from $0.22 to $1.02 per kW of daily peak demand, depending on the utility network, voltage level, month, and time of the day. See, *Grid-Connected Electric Storage System Charges, available at:* https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/bulk-energy-storage/charges-applicable-to-grid-connected-electric-energy-storage-systems.pdf.

timing of the peak demand, including them as a fixed cost may result in an inaccurate estimate. Accordingly, although this issue did not impact CY19 BSM determinations, we recommend that the NYISO incorporate the Daily As-Used Demand Charges into its dispatch model for ESRs in future evaluations.

3. CONE of Repowering Projects

The Gowanus and Danskammer Repowering Projects involve removal of existing units that are currently operational and developing the Examined Facility at a nearby/ same site. Therefore, to the extent that it is profitable to continue operating the existing units, removing them from service prematurely result in foregone profits over the remaining expected life.

Hence, the NYISO estimated an opportunity cost for the Gowanus and Danskammer Repowering Projects and included it in the estimated Gross CONE of each of these Examined Facilities. The opportunity costs were calculated as the net present value of the forecasted capacity market revenues of the existing units less their estimated fixed costs and capital expenses.[73, 74]

The NYISO's inclusion of opportunity costs in the Gross CONE of repowering projects is reasonable.

4. CONE of Other Thermal Projects

The King's Plaza and Spring Creek Projects are seeking CRIS rights for new and/or existing behind-the-meter thermal generation that is located at retail customer demand sites.[75] The projects have historically acted as self-supply for retail load and have not sold installed ICAP. To estimate the Gross CONE of these projects, the NYISO considered the capital costs of (a) facilities required to interconnect these projects with the local transmission owner, and (b) any new generating equipment that was added to the existing site. A significant portion of the existing equipment was either not intended to be used for capacity market participation or was fully depreciated, and therefore was not included in the calculation of Gross CONE. For operating costs, the NYISO considered only incremental expenses above the pre-existing

73 In estimating the fixed costs and capital expenditures for existing units, the NYISO considered relevant information from the developers, costs of similar units, and publicly-available cost data for units located in New York.

74 For example, consider a hypothetical repowering project in Zone J where an existing facility that is likely to continue operations until May 2025 is replaced with the peaking unit studied in the 2020 ICAP Demand Curve reset. Assuming the Zone J ICAP price forecast to be $100/kW-year, fixed costs to be $50/kW-year, and a WACC of 8.2 percent, the NPV of foregone profits over a period of three years would be $128/kW. The opportunity cost component of the Gross CONE of the new project can be estimated by levelizing the NPV over 20 years as approximately $16/kW-year.

75 For example, the Kings Plaza project is a microgrid as described in the following article: https://microgridknowledge.com/new-microgrid-kings-plaza-coned/

operating budgets of the facilities.[76] We believe that the NYISO's approach to evaluating costs for these projects is reasonable.

D. Conclusion – Cost of New Entry

We reviewed detailed information on the NYISO's estimates of the annual levelized CONE values for the CY19 Project. We find that the NYISO's estimates were reasonable and made in accordance with the Tariff.

[76] Pre-existing budgets are related to the projects' self-supply functions and are not contingent on the projects' CRIS requests

VII. Part B Test Input – Net Revenue

The forecasted net Energy and Ancillary Services revenue is a key component of the Part B test, since a new project developer expects to recoup a large share of its investment from future energy and ancillary services revenues.[77] Estimating the net revenue of a new generator is a complex endeavor, requiring the use of models to estimate future LBMPs and reserve prices at which the new facility would sell its output, and forecast when the Examined Facility will be scheduled.

We reviewed the assumptions used by the NYISO to estimate the net revenues for the CY19 Projects to determine whether they were reasonable and consistent with the Tariff. We find that the NYISO used assumptions that were reasonable and tariff compliant. This section is divided into the following sub-sections:

- Implications of key assumptions described in Section VIII
- LBMP and Ancillary Services Price forecasts – This component of the net revenue model forecasts market clearing prices where the Examined Facility would sell electricity.
- Non-NYISO Market Revenue Streams – This sub-section describes the NYISO's treatment of non-NYISO market revenues for some of the CY19 Projects
- Scheduling models – This forecasts how the Examined Facility will be scheduled based on the LBMPs estimated by the NYISO, the operating parameters (e.g. variable costs, heat rate) of the Examined Facility, and other factors that affect scheduling.
- The conclusion discusses the overall results of the net revenue evaluation.

A. Implications of Assumptions Discussed in Section VIIII

This sub-section discusses how factors identified in Section VIIII affected the net revenue estimates for the CY19 Projects.

1. Starting Capability Period of Summer 2022

The Starting Capability Period is important because the assumed timing of entry affects the resource mix, gas futures prices and the load forecast, which are key drivers of the LBMP price forecast that is used to calculate net revenue.[78] Under the current Tariff, all CY19 Projects are assumed to enter in Summer 2022, although it would be more reasonable to assume that some existing and/ or short lead-time projects would enter much earlier (e.g. some of the ESRs, the King's Plaza and Spring Creek Projects). If a more realistic in-service date was assumed for the existing projects, their LBMP forecast is likely to have been lower due to the inclusion of the

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77 Net revenues are an input to the Unit Net CONE. See *BSM Numerical Example*, Section 3.2.

78 The assumption regarding the Starting Capability Period is discussed in further detail in Sub-section VIII.A.

Indian Point-3 unit until April 2021. Hence, all else being equal, using a later in-service likely resulted in higher forecasted net revenues and lower UNC values for projects that are already in-service.

2. Capacity Assumed to be In-service During the Mitigation Study Period

The NYISO forecasted LBMPs using the following assumptions for deactivated units and units under a deactivation notice:[79][80]

- For the CY19 BSM evaluation, over 129 MW (ICAP Summer) from units that are currently in a Mothball Outage ("MO") or an ICAP Ineligible Forced Outage ("IIFO") would not offer capacity during the MSP if they had a negative NPV from returning to service;
- Over 1000 MW of capacity (ICAP Summer) from Indian Point-3 unit would be retired by April 2021. The NYISO excluded this capacity based on publicly available information that the units would cease operations.

The exclusion of Indian Point likely had a significant impact on the LBMPs, and resulted in lower UNCs for the Examined Facilities. Including the other deactivated units would have raised net revenues by a relatively small amount, since units in this category are likely to have low capacity factors and correspondingly low impacts on forecasted LBMPs.

B. LBMP and Ancillary Services Price Forecasts

The subsection discusses the NYISO's methodology and its assumptions for projecting the energy and ancillary services prices that were used to estimate the net revenues for the CY19 Projects.

1. LBMP Forecast

Consistent with the CY17 BSM evaluations, the NYISO utilized a two-step procedure for forecasting the LBMPs for the MSP and the Capability Years 2020/21 and 2021/22.[81] The

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79 These assumptions are discussed in further detail in Sub-section VIII.B.1.

80 As described in section V.A.2 , over 750 MW (ICAP Summer) of peaker units are expected to retire by the end of 2022/23. The NYISO did not model exclusion of these units for forecasting the LBMPs. However, since the peaker units have low capacity factors they are expected to have low impacts on the forecasted LBMPs.

81 The NYISO used the forecasted or historical (as available at the time of analysis) LBMPs to determine the net energy and ancillary services revenue for the demand curve unit at the tariff defined Level of Excess conditions, in a manner consistent with the DCR rules. The projected net revenues were then used to forecast the ICAP reference points for the years before and during the MSP, as described in section 2.4.2 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References* document.

NYISO's approach entailed using the outputs of a neural network model and the GE-MAPS model in a sequential manner to forecast the LBMPs.[82]

The NYISO utilized updated the neural network model that it developed and used in its CY17 BSM evaluations, to predict hourly zonal LBMPs for Capability Years 2020/21 – 2024/25.[83]

The NYISO utilized results from the GE-MAPS simulations to adjust the output of the neural network model (hourly zonal LBMPs) for changes in resource mix during the future years, and for the differences in zonal and nodal pricing.[84] Specifically, the NYISO used LBMPs from GE-MAPS simulations to estimate a matrix of scalars (at a month-hour level) for adjusting the output of the neural network model to forecast LBMPs for use in the scheduling models.

The rest of this subsection describes other assumptions that the NYISO made in forecasting the LBMPs for the CY19 BSM evaluations.

Gas Futures Prices

For the CY19 BSM evaluations, the NYISO used gas futures prices to forecast the gas prices, LBMPs and the net revenues for the Examined Facilities and the Demand Curve unit. This is consistent with the approach the NYISO utilized in the Part B tests in previous Class Years.[85] The forecasted LBMPs for projects in Zone G were primarily based on gas prices at Iroquois Zone 2, forecasted LBMPs for projects in Zone J were primarily based on gas prices at Transco Zone 6 (NY).

RGGI Futures Prices

Operating costs for power plants in the Regional Greenhouse Gas Initiative ("RGGI") member states include the costs associated with obtaining carbon allowances to cover their CO2 emissions. LBMPs generally reflect the marginal costs of gas-fired generation, including the cost of RGGI allowances. RGGI allowance futures prices do not indicate considerable

82 NYISO's approach for forecasting the LBMPs for the MSP is further described in section 3.2 of the BSM Narrative and Numerical Example.

83 See Section VI.C in *Assessment Of The Buyer-Side Mitigation Exemption Tests For The Class Year 2017 Projects* report.

84 In addition to modeling the entry of CY19 Projects, the MAPS simulations also modeled changes to the capacity of a number of existing units, as described in subsection VII.A.2.

85 In CY19 evaluations, however, the NYISO corrected inputs into the model for the gas "flow date" issue and how the gas prices are assigned for weekends and holidays, to align with the methodology utilized in the most recent DCR Study. See, section "Addendum: Gas Price Index" of the *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years –Final Report*

differences between the historic prices and prices during the MSP. Therefore, unlike previous BSM evaluations, no adjustment was made to the net revenues of the CY19 gas-fired projects to account for changes in the RGGI allowance prices.

2. Ancillary Services Prices Forecast

The forecasted prices of all reserve products for the MSP and the Capability Years 2020/21 and 2021/22 were based on the historical prices from the analogous period, consistent with the approach the NYISO used in its prior evaluations.[86]

- To forecast reserve prices for future years, historical prices were adjusted to account for the impact of changes in the resource mix using an array of scalars (at a month-hour level). These scalars were derived from the LBMP results of GE-MAPS simulations of scenarios with and without the Examined Facilities.[87]
- The NYISO began to model Zone J reserve requirements starting June 26, 2019. Hence, data on any increase in the Zone J reserve prices relative to the SENY reserve prices were not available for the entire historical period that was considered for forecasting prices for the MSP. Therefore, the NYISO projected the reserve prices for the Zone J resources by assuming a similar average differential between Zone J and SENY reserve prices, as was observed during the Capability Year 2019/20.

C. Non-NYISO Market Revenue Streams

A number of CY19 Projects indicated that their projects would receive revenues in addition to what they would receive from the NYISO-operated markets. The Tariff requires the NYISO to include in its net revenue calculations "revenues associated with other energy products (such as energy services and renewable energy credits".[88]

Revenues from Sale of Renewable Energy Credits ("RECs") - All solar facilities in CY19 were determined to be eligible for Tier 1 RECs.[89] The NYISO assumed that all solar Examined Facilities in CY19 will receive payments for the RECs they generate. Such projects are generally compensated for RECs through long-term bilateral contracts rather than a procurement mechanism that sets transparent uniform prices for all renewable resources. When revenues are received by an Examined Facility from the sale of energy, capacity, ancillary services, or other

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86 The reserve prices for 2020/21 were kept the same as prices in 2015/16, prices for 2021/22 were kept same as prices in 2016/17, and so on.

87 See section IV.B.1 on p. 68 of the 2016 ICAP Demand Curve Reset study, 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.

88 See MST §23.2.1

89 Details of eligibility to produce Tier 1 RECs can be found here: https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Eligibility

services such as RECs to an agency of the State or a regulated utility, the NYISO replaces the revenue from the contract with a competitive proxy value that one would expect comparable units would to receive.[90] The NYISO assumed a value of $22.09/MWh, equal to the most recently posted Tier 1 REC sale price posted by NYSERDA.[91] At this price, a renewable resource with a capacity factor of 16 percent would be attributed REC revenues of approximately $31/kW-year in the BSM evaluation.

The NYISO's inclusion of REC revenues was compliant with its Tariff, and the methodology to estimate REC revenues of solar resources was consistent with its previous BSM evaluations and a related Order from the Commission. However, we recommend in future evaluations that the NYISO estimate competitive proxy values for REC revenues that are more representative of payments to all renewable resources, not only those that qualify for the Tier 1 REC program. This approach should consider that the effectiveness of a resource in satisfying environmental goals could vary significantly depending on the technology and location of the resource. For instance, energy from a new renewable unit in downstate zones is more likely to displace fossil-fuel generation than energy from a similar type of resource located in an upstate zone. However, an improved approach for estimating the competitive proxy values would not have affected the determinations for the CY19 facilities.

Revenues from Utility Demand Response Programs – A subset of CY19 Projects indicated that they are eligible for and/or have entered into contracts with their local utility to provide demand response. In estimating the revenue offset to Gross CONE, the NYISO considered revenues from demand response programs that are designed to solely address distribution-level reliability needs. The NYISO's classification of demand response revenues was consistent with a recent FERC Order that addressed inclusion of utility demand response programs in the offer floors of Special Case Resources ("SCRs"). For example, the Commissioned deemed the Distribution Load Relief ("DLRP") program to be designed to address solely distribution-level reliability needs and not transmission system reliability.[92] The NYISO's treatment of the demand response revenues was compliant with its Tariff and with a related Order from the Commission. In future class years, it will be important to evaluate the distribution-level and transmission-level

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90 See Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc., 140 FERC ¶ 61,189 (2012) at PP 134, 135 and 137.

91 This reflects the sale price of Tier 1 RECs offered by NYSERDA for the 2020 compliance year. See https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/REC-and-ZEC-Purchasers/2020-Compliance-Year

92 See New York State Public Service Commission, et al. v. New York Independent System Operator, Inc., 173 FERC ¶ 61,022 (2020) at PP 32-33. For example, the standard reservation rate paid by Con Edison's DLRP program is $18/kW-month during the May through September capability period, in addition to a $1.00/kWh performance payment rate. Assuming six hours of event hours per year, the resource could earn up to $114/kW-year from DLRP.

reliability benefits provided by Examined Facilities as these distribution-level reliability programs evolve.

D. Scheduling Models

The following subsections discuss the scheduling models the NYISO used for estimating the net revenues of the CY19 Examined Facilities.

1. Energy Storage Resources

The NYISO modeled the operation of a ESR as an optimization problem with the objective of maximizing profit from the sale of energy and reserves over all the intervals in the MSP. The key assumptions underlying the NYISO's ESR dispatch model are as following:

- The ESR will be committed in the day-ahead market for selling 10-minute spinning reserves in all hours. The resource can buy-out of its day-ahead commitment, and discharge/ charge in each interval in real-time.
- The resource will be able to modify its offer for every interval in the NYISO's real-time market.
- The number of charge/ discharge cycles a resource can go through is limited to an average (over the MSP) of one cycle per day.
- The charging cost in the model includes a cost adder, calculated as the product of the unit's State of Charge ("SOC") and a constant value, to prevent the SOC from deviating significantly from a preestablished target (50 percent). The NYISO estimated this adder as the value that produced an average SOC of 50% over the MSP.
- The unit-specific round-trip efficiency of the ESR is applied when the unit is charging.
- The ESR incurs costs associated with auxiliary station load (unit-specific) and rate schedule 1 costs for injections (0.30 $/MWh) and withdrawals (0.78 $/MWh).

We identify two factors that are likely to result in the ESR dispatch model overestimating the unit's net revenues:

- Under the current rules, all resources can only submit hourly offers. Therefore, allowing the unit operator to place interval-level offers/bids would enable unrealistically high net revenues for the unit.
- The model assumes perfect foresight of future prices for the unit operator. Hence, the resulting net revenues are likely to be overestimated.[93]

As discussed in section I, neither of the above issues would have affected the CY19 determinations. Nonetheless, they could result in an unreasonably low UNC estimates in future

93 The cost adder that is applied to the SOC could partially limit the increase in net revenues due to the perfect foresight assumption. However, the extent to which the assumed cost adder offsets the increase in net revenues due to perfect foresight is unclear.

evaluations. Accordingly, we recommend the NYISO modify its ESR dispatch model to address these issues.

2. Solar PV Resources

The NYISO estimated real time schedules for solar resources based on hourly output profile data that was substantiated by project developers. The NYISO estimated each solar project's net revenues from the sale of (a) energy in the NYISO's real-time market, and (b) Renewable Energy Credits ("RECs").

For each year of the Mitigation Study Period, the NYISO estimated each resource's net revenue as the product of the assumed output and the sum of the real-time energy price at its location in that hour and the REC price. For hours when the hourly energy price was negative and greater in magnitude than the REC price, revenue was assumed to be zero.

3. Thermal Repowering Projects

The CY19 Danskammer Project is a combined cycle facility and the Gowanus Repowering Project is combustion turbine facility. The NYISO estimated the net revenues for these units using the scheduling models its consultants developed as part of the 2016 ICAP Demand Curve Reset study.[94] The scheduling models for these units determine the optimal set of hours for running the unit each day based on DAM and RT LBMPs and Ancillary Services prices, considering various categories of costs (including fuel costs based on gas and oil prices, start-up costs, balancing charges, emissions allowance costs) and constraints on operation of the unit (e.g. start time, run hour limits).

4. Other Thermal Projects

The King's Plaza and Spring Creek Projects involved behind-the-meter generation projects that were originally intended to serve only the host load. A new interconnection to the distribution network enabled export of energy from existing or additional onsite generation, and import of energy to meet demand in the microgrid system.[95] As a general matter, net revenues for such projects could include one or more of the following components in addition to any applicable non-NYISO revenues:

- NYISO-market revenues from sale of energy and ancillary services from the generation onsite
- Energy supply cost savings due to imports from the NYISO market

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94 The assumptions and methodology for the Demand Curve scheduling models are described in *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, dated June 23, 2016.

95 For example, the Kings Plaza project is a microgrid that converted from a standalone power system to a grid-connected model. See https://microgridknowledge.com/new-microgrid-kings-plaza-coned/

The NYISO determined the net revenues for the onsite generators using the scheduling models its consultants developed as part of the 2016 ICAP Demand Curve Reset study.

Interconnection to the NYISO's system could provide these resources an additional energy source to meet their local microgrid demand, and hence, could lower their energy supply costs. The NYISO estimated the energy supply cost savings from interconnection by determining the hours during which it would be less expensive to import power than to rely on self-supply to meet the local demand, subject to the constraints of the interconnection agreement. The hourly profile of the local microgrid demand was based on historical data for a full year.

E. Conclusion

Overall, we find that the NYISO's methodologies for estimating the net revenues were reasonable and compliance with its Tariff. We recommend the NYISO consider the following methodological changes for its future evaluations:

- Develop a transparent procedure for estimating the REC value of various renewable resources
- Modify its ESR dispatch model to account for the following:
  - Reflect the ability of the ESR to submit only hourly offers
  - Develop a reasonable methodology that accounts for the operator's limited foresight of future prices when offering the unit

None of the above issues affected the ultimate outcome of the CY19 BSM evaluations.

VIII. Assumptions Affecting Part A and Part B Tests

A. Starting Capability Period of Summer 2022

The Starting Capability Period ("SCP") is the Capability Period in which the Examined Facilities are assumed to begin operating and offering capacity for the purposes of the BSM evaluations. The Tariff requires the NYISO to assume that all Examined Facilities will be in service three years after the start of the Class Year, so the NYISO assumed that CY19 Projects will be in service beginning in May 2022.[96]

The three-year rule was implemented to increase transparency and the certainty for developers and market participants regarding the assumptions used in the BSM evaluations and to avoid gaming of the timing of a project's identification of its commercial operation date ("COD"). However, this approach often results in a misalignment of the SCP with the likely CODs of Examined Facilities in two ways:

- First, the COD of an Examined Facility depends on, among other factors, the underlying technology and its timeline for securing the required permits. As a result, assuming that all Examined Facilities will begin operations three years from the calendar year of the Class Year is likely to be incorrect for a number of Examined Facilities.
- Second, the tariff provision for determining the Starting Capability Period is tied to the start of the Class Year and does not account for the time required to perform CY studies. Therefore, in cases where the developer's decision to move forward with the project is contingent on the PCA and/or the determination, the SCP is much earlier than the likely commercial operation date.

The SCP is important because the timing of entry affects a number of inputs to the Part A and Part B tests, including the load forecasts, LCRs, units assumed to be in service for the BSM evaluations, capital costs, energy revenues and any applicable opportunity costs.[97] Furthermore, if the SCP is not aligned with the CODs of Examined Facilities, it might disadvantage Examined Facilities that are likely to be operational earlier than other projects.[98] Consequently, a fixed SCP could produce unreasonable determinations when actual CODs are misaligned with the assumed COD.

96 See MST §23.4.5.7.2.

97 We discuss the effects of each of these inputs on the Part A and Part B tests in CY19 in sub-sections IV.A.1, V.A.1, and VI.A.1. Previous MMU BSM Reports have identified additional problems with the Starting Capability Period assumption.

98 For instance, assuming that a new project with a long lead-time will begin operating at the same time as existing and/ or short lead-time projects may result in an unrealistically low capacity price forecast if it includes the new long lead-time project.

Hence, we recommend the NYISO modify its Tariff provisions related to the SCP to improve alignment with the likely CODs of the Examined Facilities. A potential alternative to the three-year rule could be to assume a COD that is based on the underlying technology of the Examined Facility.[99] Such a technology-specific start date rule could provide that that date be adjusted as needed to reflect an Examined Facility's progress in meeting its permitting milestones and the timing of conducting the CY studies.[100]

B. Capacity Assumed to be In-service During the Mitigation Study Period

The BSM exemption test requires the NYISO to project capacity prices as much as six years into the future. The resources that are assumed to be in service during the MSP are an important driver of the projected capacity prices. Over-estimating the amount of in-service capacity increases the likelihood of mitigating an economic project, while under-estimating the amount of in-service capacity may lead to under-mitigation. The capacity price forecast is very sensitive to the amount of capacity that is assumed to be in service. For instance, a 100 MW increase in UCAP could increase the Zone J prices by up to $18 per kW-year UCAP in the CY19 Part A test.

The LBMP forecasts are also affected by both the quantity of in-service resources and the anticipated capacity factor of the resources. High-capacity factor resources (e.g., current or prior CY Projects) have more impact on LBMPs than low-capacity factor resources (e.g., units in a Mothball Outage). The LBMP forecasts are a key input to the energy and ancillary services net revenues, which are used to calculate Unit Net CONE of the Examined Facilities.

In this sub-section, we discuss the treatment of several categories of resources in the NYISO's ICAP price and LBMP forecasts for CY19 Examined Facilities. We also identify areas where the Tariff or the current procedures for determining the in-service capacity should be modified.

99 For instance, the Energy Information Administration in its NEMS model assumes a lead time that varies as follows: less than a year (for ESRs), two years (for Combustion Turbine and Solar PV facilities), and four years (for Biomass, Coal and Offshore wind facilities) for most of the generation technologies.

100 The NYISO had recently proposed Tariff revisions for the Part A test that would have, in part, addressed the misalignment of the SCP with the likely COD. See NYISO's April 30, 2020 filing in ER20-1718-001. However, the Commission rejected the NYISO's filing. The NYISO filed a Petition for Review of the Commission's order in the United States Court of Appeals for the District of Columbia Circuit on December 31, 2020.

1. Additional Units, Excluded Units and Units Transferring CRIS Rights

The NYISO included most facilities classified as Existing Units in the 2020 Gold Book.[101] This sub-section discusses the assumptions regarding inclusion of other categories of generation ("Additional Units"), exclusion of certain existing facilities ("Excluded Units"), and CY19 Examined Facilities that replace the existing facilities ("Units Transferring CRIS Rights") in the NYISO's capacity price and LBMP forecasts for the CY19 BSM evaluations.[102]

Additional Units – These comprise resources that are in a Mothball Outage or an ICAP Ineligible Forced Outage ("IIFO") or resources that have recently retired. These resources currently possess CRIS rights, but are not operating and retain the ability to return to service during the MSP. The NYISO considered over 125 MW (Summer ICAP) in CY19 BSM evaluation of such resources. In accordance with its Tariff, the NYISO excluded resources that were in an IIFO as a result of Catastrophic Failure, and resources whose CRIS expired at the time of Initial Determinations. Furthermore, the NYISO included any resources that were determined to have a positive net present value in case they returned to service.

Excluded Units – In the CY19 BSM evaluations, the NYISO reviewed publicly available information demonstrating with reasonable certainty that some of the units currently operating are likely to retire before or during the MSP.

- The NYISO excluded the capacity from the Indian Point units 2 and 3 for all the years of the MSP. [103]
- The NYISO also considered information from the compliance plans of generators affected by the Peaker Rule The Peaker Rule limits NOx emissions rates of simple cycle units beginning in May 2023, with stricter limits beginning in May 2025. Units whose owners indicated that they intend to retire or permanently cease operation to comply with the May 2023 limits were excluded from the second year of the MSP. A subset of the affected unit owners indicated that some of the resources will not operate during the ozone season (May through September), but will continue operating during the other months of the year. Accordingly, the NYISO excluded these units from the ICAP supply for the months May through September.[104]

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101 See Table III-2 of the 2020 Gold Book for CY19 evaluation. These resources possess CRIS rights, and are currently operating or may be in a Forced Outage or Inactive Reserve status, and are referred to as "Existing Units" (see MST §23.4.5.7.15.4).

102 See Section 3.2.1.2 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References* document.

103 Indian Point unit 2 had retired in April, 2020, but was included as an existing facility in the 2020 Gold Book.

104 The NYISO identified units that ceased operations permanently due to the Peaker Rule as Incremental Regulatory Retirements for the purpose of its evaluations for REE. See subsection III..A.3.

Units Transferring CRIS Rights – The Gowanus Repowering and the Danskammer Repowering Projects involve transferring CRIS rights from existing units to the Examined Facilities. Hence, the NYISO excluded CRIS-adjusted DMNC of the existing units from its forecasts.

We find that the NYISO's treatment of Additional Units, Excluded Units, and Units Transferring CRIS Rights to be compliant with its Tariff.

2. Existing Units at Risk of Retiring or Mothballing

The NYISO, in accordance with its Tariff, included all Existing Units in its price forecasts.[105] However, several capacity suppliers that are currently operating may choose to mothball or retire if capacity prices drop to levels that are insufficient to cover their fixed operating costs. Therefore, it is unrealistic to assume that all Existing Units will continue to operate during the MSP regardless of how low the forecasted prices are. However, the NYISO's current Tariff does not allow it to consider the economic circumstances of the resources while developing the price forecasts. Although this issue did not affect the ultimate outcome of the CY19 BSM evaluations, unrealistically low price forecasts could act as a barrier to new entry in future Class Years. Therefore, we recommend the NYISO work with its stakeholders to develop reasonable criteria for treatment of Existing Units that are at risk of retiring or mothballing.

3. Prior Class Year Projects in the Interconnection Queue

The BSM exemption test requires the NYISO to estimate the effects on capacity and energy prices of prior CY projects in the Interconnection Queue ("Prior-CY Projects") that accepted their PCA in a previous Class Year but have not begun construction. The developer of a new project must post security for the amount of the PCA, but there is no guarantee that such a project will eventually be built.[106] The assumptions regarding such projects are important because over-estimating the amount of in-service capacity tends to depress the capacity price and the LBMP forecasts. Since new projects could have high capacity factors, over-estimating the amount of new in-service capacity will tend to have large effects on the LBMP price forecast, which will also tend to inflate the UNC of the Examined Facilities.

The NYISO's tariff does not prescribe any specific assumptions for the treatment of Prior-CY Projects in the BSM exemption tests. Hence, it is important to use a reasonable approach for treatment of these projects in both the ICAP forecast as well as the net revenue calculations. The NYISO's treatment of these projects is described below.

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105 See MST §23.4.5.7.15.4.

106 In some cases, the PCA may be very small relative to the overall investment, so there is little cost to the developer of remaining in the queue. In other cases, a project may remain in the interconnection queue for more than a year with little risk to the developer that it might lose a portion of its deposit if the project does not ultimately move forward.

The NYISO included a Prior-CY Project in the price forecasts based on whether it was reasonably likely that the project would be built under the circumstances modeled in the CY19 BSM evaluation. In particular, the NYISO assumed the project will be built if it has made progress in meeting its regulatory milestones, and if the project satisfied one of the following two criteria:

- the developer has made some other significant irrevocable financial commitment towards the project, or
- the project would earn sufficient forecasted revenues from the NYISO markets for it to be profitable for the developer to move forward.

The NYISO applied the above criteria to determine whether a particular Prior-CY Project will be built, and included it in the ICAP supply as a price-taker or at the project's Offer Floor, if applicable. The NYISO's treatment is reasonable given the uncertainty about whether the Prior-CY Projects will ever enter service.

4. Examined Facilities Seeking Competitive Entry Exemption

As discussed in Section II, the NYISO considered request for a CEE from the Danskammer Repowering Project in its CY19 BSM evaluation. The NYISO's Tariff requires it to conduct the Part A and Part B tests modeling the potential entry of CEE Projects like other Examined Facilities. Accordingly, the NYISO estimated the UNC of the CY19 Danskammer Repowering Project based on the information provided by project developers. The NYISO subsequently incorporated the UNC of the CEE Project into its ICAP price forecast in a manner that is consistent with the test procedure described in Section VIII.H. However, the Tariff-prescribed treatment for the CEE Projects could produce unreasonable outcomes for the BSM evaluations.

A developer's choice to move forward with a CEE Project will be driven by its own expectations, but the same information is not incorporated into the NYISO's estimated UNC. For instance, the developer of a CEE Project that would qualify for an exemption from the Offer Floor may commence construction, and expend a significant costs by the time the NYISO issues initial determinations. Similarly, it is possible for the developers of CEE Projects to have a view of the future market conditions that is significantly different from the NYISO's assumptions, particularly in areas where the NYISO's methodology could be enhanced.[107] In such situations, the UNC calculated in compliance with the tariff may not provide a reasonable representation of whether a CEE project would be in service during the MSP. Therefore, the NYISO's approach could result in unreasonably excluding CEE Projects in some situations.

[107] See Table 4 for a summary of recommended enhancements to BSM evaluations.

Therefore, we recommend the NYISO develop Tariff provisions that would allow it to estimate the UNC based on a) any significant expenditures that the developer may have incurred by the Initial Decision Period, and b) well-substantiated developer forecasts.

5. Examined Facilities Seeking Renewable Entry Exemption

As discussed in Section III, the NYISO considered requests for REE from eight Examined Facilities in its CY19 BSM evaluation. The NYISO's Tariff requires it to evaluate Examined Facilities for a REE after it has conducted its Part A and Part B evaluations. Accordingly, the NYISO estimated the UNC of the CY19 REE projects based on the information provided by project developers. The NYISO subsequently incorporated the UNC of these projects into its ICAP price forecast in a manner that is consistent with the test procedure described in Section VIII.H.

6. Class Year 2019 Projects Located Outside the Mitigated Capacity Zones

CY19 includes over 3GW (ICAP Summer) of projects that are located in Zones A-F and Zone K (Non-Mitigated Capacity Zones or "Non-MCZs"). The Tariff does not prescribe a specific treatment of the Non-MCZ Projects in its ICAP price forecast. Therefore, consistent with their treatment in for determining LCRs for the MSP, the NYISO assumed that all Non-MCZ Projects will be in-service as price takers in the ICAP spot auctions for determining the (a) total UCAP, (b) the ICAP/UCAP translating factor, and (c) the winter-to-summer ratio.

While it would be reasonable to include all Non-MCZ Projects that are currently operational, it may not be reasonable to assume all Non-MCZ Projects will be in-service as a project's decision to enter may depend on the capacity and energy revenues. Therefore, we recommend that the NYISO utilize the treatment that it followed in its CY17 evaluation for all the future CY evaluations.[108]

In CY19 BSM evaluations, the forecasted ICAP price for the G-J Locality for Winter 2024/25 was determined by the NYCA ICAP demand curve. Hence, assuming that a subset of the Non-MCZ Projects will not be in-service during the MSP could have raised the forecasted ICAP price. Ultimately, this assumption did not affect any of the CY19 BSM determinations.

C. Impact of Imports on Capacity Price Forecast

The NYISO's assumptions regarding capacity imports from neighboring control areas are important since they impact the ICAP price forecast used in the BSM evaluations. This sub-

108 See Section VII.D.6 of the CY17 BSM report that discusses the treatment of Class Year 2017 Projects Located Outside the Mitigated Capacity Zones.

section discusses the underlying assumptions for imports into the NYCA from PJM, ISO-NE, HQ and IESO across various transmission lines.

1. Imports from PJM to New York City

The BSM exemption tests require the NYISO to estimate the effects on capacity prices of controllable transmission lines that possess Unforced Capacity Deliverability Rights ("UDRs"). The assumptions regarding such facilities possessing UDRs are important, since there is currently over 300 MW of potential capacity associated with UDRs between the PJM Interconnection ("PJM") and New York City.[109] The evaluation of potential UDR capacity is complicated by two factors:

- Holders of rights to use UDRs must obtain capacity from the neighboring market in order to sell capacity into New York. They will not generally do this unless the New York City price is expected to be greater than the price in the neighboring market.
- If the holder of rights to use the UDRs elects by the annual deadline not to use its UDRs to import capacity to New York, the New York State Reliability Council's annual IRM technical study and Study Report will assume the line can provide emergency assistance. Consequently, the existence of the transmission line will tend to reduce the LCR for Zone J and the G-J Locality.

When conducting the MET for the CY19 Projects, the NYISO assumed that transmission lines possessing UDRs would import capacity to New York City when capacity could be sold at a price that would compensate the UDR rights holder for the cost of obtaining capacity and transmission service in the neighboring market.[110] This criterion was applied by Capability Year for the MSP since the PJM market runs annual rather than monthly auctions to satisfy installed capacity requirements. Overall, we find that the assumptions related to capacity imports that sink in New York City are reasonable and compliant with the NYISO Tariff.

2. Imports to Zones A-F and Zone K

The amount of net imports to and generation in NYCA Load Zones external to the G-J Locality can have a significant impact on the BSM exemption test for projects in the G-J Locality and New York City. This is because capacity prices in the G-J Locality and New York City are sometimes determined by the NYCA ICAP Demand Curve when there is substantial surplus capacity in either of those Localities. In general, capacity surpluses are forecasted to occur most during the Winter Capability Periods when the seasonal capability of most generators is highest. This subsection discusses assumptions made by the NYISO that affect the NYCA capacity price forecast.

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109 660MW CRIS for the HTP Scheduled Line expired in April, 2020.

110 The NYISO assumes that the cost of capacity in PJM's PSEG-North Local Delivery Area is equal to the clearing price in the Base Residual Auction in the closest year for which data is available.

Imports to Zone K

In recent years, there has not been a strong relationship between the capacity price spread between Long Island and neighboring ISOs, and the levels of capacity imports to Long Island across the Cross Sound Cable and the Neptune line (both of which have associated UDRs). Hence, the NYISO assumed that imports across the Cross Sound Cable and the Neptune line would remain at recently observed levels throughout the MSP.

Imports to Zones A-F

The NYCA's interfaces with neighboring Control Areas allow external resources from PJM, Hydro Quebec, ISO-NE and IESO to offer capacity into the NYCA region (*i.e.*, only the region outside of the G-J Locality, NYC, and Long Island).

PJM Interface – Net imports from PJM in recent Capability Year were not found to be price responsive. However, given the significant price differential in the forecasted NYCA prices for the MSP and PJM Base Residual Auction prices for 2021/22, the NYISO assumed that the imports from PJM would equal the Grandfathered import rights.[111] Other imports from PJM are likely to incur substantial firm transmission service charges, and were assumed to be zero for the CY19 BSM evaluation.

ISO-NE Interface – Net imports from ISO-NE in recent Capability Year were found to be price responsive. Therefore, the NYISO followed a price differential-based approach as described in the context of UDRs (see Section VIII.C.1) for determining the direction of capacity imports.[112] The capacity price differential was adjusted for the cost of Pay for Performance ("PFP") obligations of capacity suppliers in ISO-NE. The limits on the magnitude of net imports (or exports) from ISO-NE were based on the NYISO-determined import rights limits (or results of the most recent ISO-NE capacity auctions).

HQ Interfaces – Net imports from HQ in recent Capability Year were not found to be price responsive. The NYISO estimated the net imports from HQ to be at a level that was observed over the three most recent Capability Years from 2017/18 to 2019/20, limited by the import rights limits.[113]

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111 See section 3.2.3 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

112 The cost of ISO-NE capacity is based on average clearing prices for ISO-NE Rest of System. The NYISO assumed $3.80/kW-month for 2022/23, $2.00/kW-month for 2023/24, and since the clearing price for 2024/25 wasn't available, the NYISO assumed $2.04/kW-month by inflating the 2023/24 price. See section 3.2.3 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

113 See section 3.2.3 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

<u>IESO Interfaces</u> – Net imports from IESO in recent Capability Year were not found to be price responsive. The NYISO estimated the net imports from Ontario to be at a level that was observed over the most recent Capability Year of 2019/20, limited by the import rights limits.[114]

Overall, we find that the assumptions related to imports sinking in Zones A – F and Zone K were reasonable and compliant with the NYISO Tariff.

D. Estimating Locational Capacity Requirements for the Mitigation Study Period

The NYISO determines the Locational Minimum Installed Capacity Requirements ("LCRs") every year for New York City, Long Island and the G-J Locality, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirements. The capacity price forecast used in the NYISO's BSM evaluation is significantly dependent on the LCRs assumed for the duration of the MSP. Hence, the assumed LCRs are important assumptions in the BSM evaluation.

The LCRs during the MSP will be significantly influenced by the distribution of in-service capacity and by other system conditions which may differ from the current conditions. However, the NYISO's current Tariff does not provide any guidance regarding the LCRs to be used in the BSM evaluations. The NYISO estimated the LCRs for the MSP using the *Alternative Method for Determining LCRs* that the Commission approved in 2018. As discussed in VIII.B, the NYISO's assumptions underlying its capacity and energy price forecasts included several changes to its resource mix. For its CY19 BSM evaluation, the NYISO estimated LCRs during the MSP by modeling the following changes to the MARS topology that was used for determining the 2020/21 LCRs:

- Retirement or limited operation of units subject to the Peaker Rule in the last two years of the MSP
- Increase in the UPNY-ConEd interface transfer limit from 6000 MW to 7000 MW
- Entry or exit of resources based on criteria described in subsection VIII.B.1
- Addition of all CY19 Examined Facilities (including the Non-MCZ Projects)
- Inclusion of the Public Policy Western NY Transmission project in the last two years of the MSP
- Updated load forecast for the MSP based on the 2020 Gold Book data

For its initial determinations, the NYISO assumed that the Public Policy AC Transmission projects will not be in service during the MSP. The NYISO modified this assumption for its final determinations, and modeled Public Policy AC Transmission projects as in-service for the last year of the MSP. In the absence of modeling results that considered the entry of Public Policy AC Transmission projects, the NYISO estimated the effect on LCRs by considering

114 See section 3.2.3 of the Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References.

related studies which modeled these projects as in-service.[115] These indicated a decrease of at least 6 percentage points in the LCR for the G-J Locality, based on which the NYISO assumed a 6 percentage point reduction in the G-J Locality's LCR for the last year of the MSP.[116]

We find the NYISO's approach for estimating the LCRs in the CY19 BSM evaluation to be reasonable.[117]

E. Estimating Locality ICAP/UCAP Translation Factor

The ICAP/UCAP Translation Factor ("Translation Factor") is used to translate the ICAP requirement, ICAP demand curves and the total supply into UCAP terms. The NYISO calculated the Translation Factor by taking the ratio of the summation of UCAP to ICAP of the resources that were assumed to be in-service for the purpose of ICAP price forecast.[118]

The Translation Factor of the NYCA region increased significantly from 8.3 percent in summer season of 2020/ 21 to an average of 13.2 percent in the summer seasons during the MSP because of the inclusion of over 3 GW of intermittent CY19 Projects. The inclusion of these projects also resulted in a significant increase in the IRM from 118.9 percent in 2020/ 21 to an average of 127.3 percent over the MSP. Hence, although the NYCA Translation Factor increased substantially (relative to 2020/ 21), this change in conjunction with the increase in IRM resulted in only a modest impact on the UCAP requirement.

We find the NYISO's approach of estimating the Locality ICAP/UCAP Translation Factor to be reasonable.

F. Forecasted ICAP Reference Points

The NYISO's Tariff requires it to forecast the ICAP Reference Points for the MSP to develop each MCZ's ICAP Demand Curves for its BSM evaluations.[119] For the CY19 evaluation, the NYISO updated the Gross CONE, net energy and ancillary services revenue offset, and the

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115 See results for 1000 MW change in transfer capability on UPNY-SENY under the Optimization Methodology in "Alternative Methods for Determining LCRs" (presentation to Installed Capacity Working Group on June 1, 2017, and Results for Optimization Runs for T19 Project in "AC Public Policy Transmission Planning Report Addendum" (presented to Electric System Planning Working Group on February 11, 2019 at).

116 We discuss the impact of changes to the LCR on the Part A and Part B evaluations in subsections IV.A.3 and , I.A.3 respectively.

117 For the LCR values used in the CY19 BSM evaluation, see section 2.2 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

118 See subsection B. Forecasted ICAP/UCAP Translation Factors for different Localities are available in Table 4 of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & Reference*.

119 MST Section 23.4.5.7.15.3.

winter-to-summer ratio of the demand curve unit based on the methodology used in the Annual Update process. [120]

Gross CONE – The Tariff requires the NYISO to identify the projected ICAP demand curves for its BSM evaluations "by applying the "inflation index"". Furthermore, the Tariff defines Mitigation Net CONE ("MNC") as "the capacity price on the currently effective ICAP Demand Curve for the Mitigated Capacity Zone" at the prescribed Level of Excess. Therefore, the NYISO forecasted the Gross CONE of the demand curve unit by inflating the value underlying the currently effective ICAP Demand Curves using the applicable Inflation Index.[121]

However, the Tax Cuts and Jobs Act ("TCJA") came into effect in 2017, and resulted in a reduced marginal tax rate. Similarly, the recently filed ICAP Demand Curve Reset study suggests that the WACC has decreased considerably from the 2016 study due to changes in investment outlook.[122] While the Examined Facilities were able to reflect the more beneficial financial parameters, the forecasted ICAP demand curves used in the CY19 BSM evaluation do not reflect these changes. Incorporating the lower marginal tax rate and WACC updates from the most recent ICAP Demand Curve Reset study would result in a decrease in Zone J ICAP Reference Point by an average of $18 per kW-year for the MSP. Therefore, the lack of flexibility to update the Gross CONE of the demand curve unit for changes in financial parameters accorded the CY19 Projects a systematic advantage in the BSM evaluation. Although this issue did not affect the outcome of the CY19 evaluation, we recommend the NYISO consider modifying its Tariff definition of MNC in a manner that would allow it to utilize a reasonable forecast of the ICAP demand curves instead of the currently effective demand curves.

Energy and Ancillary Services Revenue Offset - The NYISO forecasted the LBMPs for the years 2020/21 through 2024/25 using the neural network model and GE MAPS.[123] The NYISO adjusted the forecasted LBMPs using with the prescribed Level of Excess factors, and applied the dispatch model that were developed as part of the 2016 ICAP Demand Curve Reset study to estimate the yearly EAS offset of the reference unit.

Winter-to-Summer Ratio - The NYISO updated the WSR for each capability period of the MSP using the total assumed summer and winter ICAP supply of capacity resources (see subsection

120 For updates regarding the Gross CONE, net EAS revenues, and WSR, see sections 2.4.1, 2.4.2, and 2.4.3, respectively of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*.

121 Section 23.4.5.7.15.

122 For instance, for NYC, the 2016 DCR assumed 8.36 percent WACC, whereas the 2020 DCR Study assumes 8.20 percent WACC.

123 See subsection VII.B.

B), translated into UCAP terms based on the associated ICAP/UCAP Translation Factors (see subsection E).[124]

Overall, we find the NYISO's approach to forecasting the ICAP Reference Points for the MSP to be compliant with its Tariff.

G. Treatment of Mitigated Projects in Capacity Forecast

The BSM exemption test requires the NYISO to estimate the effects on capacity prices of resources that are subject to an Offer Floor. An Offer Floor is imposed on such resources until the resource clears for 12 months, which do not have to be consecutive.[125] The treatment described below was applied to all MW of capacity that are subject to an Offer Floor and, including the mitigated units from Prior-CY Projects in accordance with subsection B.3.

The NYISO forecasted capacity prices not only during the MSP, but also for the months leading up to the MSP. If MW of capacity subject to an Offer Floor was expected to clear in a month prior to the MSP or during the initial portion of the MSP, those sales would be considered in the NYISO's assumptions regarding how much of the unit's capacity would be subject to the Offer Floor in subsequent months of the MSP. The price level of each Offer Floor was adjusted annually for inflation, using the 1.78 percent inflation rate underlying the currently-effective ICAP Demand Curves. We find that NYISO's methodology in this regard was reasonable and compliant with the NYISO Tariff.

H. Testing Multiple Examined Facilities

MST §23.4.5.7.3.2 states that "when the ISO is evaluating more than one Examined Facility concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR facilities will clear from lowest to highest, using for each Examined Facility the lower of (i) its Unit Net CONE or (ii) the numerical value equal to 75% of the Mitigation Net CONE". This provision is designed to ensure that the test identifies the most economic Examined Facility when some but not all of the Examined Facilities in the Class Year are economic.

124 Estimated values for WSR and ICAP/UCAP Translation Factors over the MSP are available in tables 3 and 4, respectively of the *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References* document.

125 The 12-month criterion is applied by the level of UCAP that cleared in the ICAP Spot Market Auction. Thus if a 100 MW resources clears 60 MW for six months and 100 MW for six months, 60 MW of the resource's cleared UCAP would not be mitigated and 40 MW would still be subject to the Offer Floor. See *BSM Numerical Example,* Section 8.4.

In its CY19 BSM evaluation, the NYISO continued to apply MST §23.4.5.7.3.2 to the Part A and Part B tests using a modified procedure that it used in CY15 and CY17 evaluations.[126] Specifically, the NYISO first tested the Examined Facility with the lowest presumptive Offer Floor by itself in the Part A and Part B tests assuming it offers as a price taker. If the first Examined Facility received an exemption, it was included in the test for subsequent Examined Facilities. If the first Examined Facility did not receive an exemption, then it was excluded from the ICAP forecast for the subsequent Examined Facilities in the sequence. We find NYISO's test procedure to be compliant with the Tariff, and support its continued use for future BSM evaluations with a modification that is described below.

Under the NYISO's current procedure, if the presumptive Offer Floors of multiple Examined Facilities were determined to be equal to the Default Net CONE, then all such projects are tested simultaneously in the Part A and Part B tests. This could result in mitigating all Examined Facilities even when a subset of the projects could have been exempt if they were tested sequentially. For instance, consider a BSM evaluation where two Examined Facilities, Project X of 200 MW and Project Y of 300 MW, are being evaluated for a Part A exemption. Assume that each Examined Facility's UNC is greater than the DNC, and that the in-service capacity is 350 MW below the Part A threshold. In this situation, if the Part A test is conducted simultaneously, neither of the two Examined Facilities would be exempt from an Offer Floor. However, if the Examined Facilities are tested one at a time, the first project to be tested would be exempt from an Offer Floor under the Part A test.[127] Figure 8 illustrates this example.

The purpose of the Part A test is to ensure that resource are exempted if their capacity is needed to satisfy reliability needs in their Capacity Zone. As illustrated above, testing Examined Facilities in order of their presumptive Offer Floors could result in all resources being tested simultaneously, which could lead to mitigating all resources even when a subset are required to satisfy local reliability needs. Hence, we recommend that the NYISO modify its Tariff to allow for testing Examined Facilities sequentially in the order of their Unit Net CONE rather than the presumptive Offer Floor.[128]

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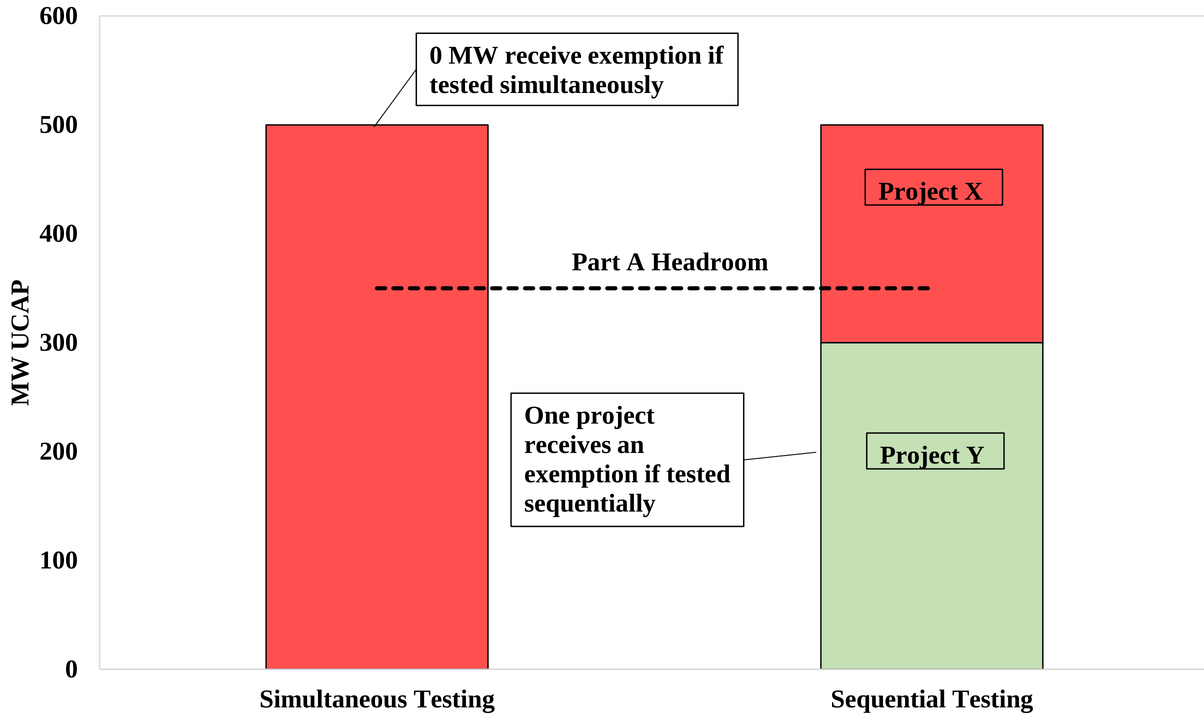
126 See *BSM Numerical Example*, Section 8.1 and Section 8.2.

127 We discuss the effect of the NYISO's testing order on the Part A test in CY19 in Section IV.A.4.

128 The NYISO had recently proposed Tariff revisions to the Part A test that would have addressed this issue for the Part A test. See NYISO's April 30, 2020 filing in ER20-1718-001. However, the Commission rejected the NYISO's filing. The NYISO filed a Petition for Review of the Commission's order in the United States Court of Appeals for the District of Columbia Circuit on December 31, 2020.

Figure 8 – Example Impact of Simultaneous Part A Testing



IX. Conclusions and Recommendations

In CY19 BSM evaluation, the NYISO issued final determinations for 11 projects for an exemption under the Part A and Part B tests, six projects under the REE provisions and one project under the CEE provisions.[129]

- All four Examined Facilities in Zone J were determined to be exempt under the Part A test, with the King's Plaza Project being exempt from an Offer Floor under the Part B test as well.
- Six solar PV projects in the G-J Locality were determined to be exempt under the REE provisions.
- The Danskammer Repowering Project were deemed to be exempt under the CEE provisions.

We reviewed materials documenting the NYISO's evaluation of investment and operating costs, the reasonably anticipated LBMPs and net revenues, and capacity price forecasts for all the CY19 Examined Facilities. In addition, we reviewed the materials regarding the request for a CEE. Lastly, we also reviewed the NYISO's assumptions and calculations for the Examined Facilities' requests for a REE.

Ultimately, the results of the determinations were driven by several key factors:

- Continued low capacity margins (i.e. supply in excess of the requirement) in Zone J and the relatively small amount of CRIS requested in Zone J resulted in exemptions to all Examined Facilities under the Part A test.
- Inclusion of distribution-level reliability program revenues led to a significant decrease in the Unit Net CONE of the King's Plaza Project.
- Incremental Regulatory Retirements resulting from the DEC Peaker Rule led to Renewable Entry Exemptions for the solar PV facilities located in the G-J Locality.

We conclude that the NYISO's BSM determinations in CY19 were made in accordance with the requirements of the Tariff and based on reasonable assumptions. We identify seven issues with the Tariff that, if addressed, could improve the accuracy of the capacity price forecasts and the Unit Net CONE, and/ or would strengthen the provisions of the REE or CEE. We also identify two improvements to the BSM evaluation assumptions that do not require tariff modifications. None of these issues, by itself or in combination, affected the final determinations in the CY19 BSM evaluations. Nonetheless, these issues may have significant impacts on the results of future BSM evaluations. Accordingly, we recommend that the NYISO address these issues in future evaluations.

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[129] During the Initial Decision Round 7 projects dropped out, of which 2 were seeking exemptions under REE.

The issues we identified are summarized in Table 4 below. The Table also shows the portion of BSM evaluations that is affected by the issue, whether addressing this issue requires a Tariff change (T) or can be addressed by improving existing procedures (I), and the subsection in the report where we discuss the specific issue in further detail.

Table 4 - Summary of Recommended Enhancements to BSM Evaluation

No	Issue	Evaluation/ Rec	Section
1	Interconnection costs may be inflated for some Examined Facilities	Part B/ T	VII.B.4
2	Starting Capability Period is unrealistic for most Examined Facilities	Part A & B/ T	VIII.A
3	Treatment of some Existing Units at risk of retiring or mothballing is unrealistic for some units	Part A & B/ T	VIII.B.2
4	Treatment of Examined Facilities seeking Competitive Entry Exemption may be inconsistent with developers' expectations	Part A & B/ T	VIII.B.4
5	Test Examined Facilities sequentially in the order of their Unit Net CONE rather than the presumptive Offer Floor	Part A & B/ T	VIII.H
6	Modify Part A test procedure to exempt Zone J projects if they are needed to satisfy the G-J Locality's capacity requirement	Part A/ T	IV.B
7	Modify following aspects of REE calculations: (a) Develop procedures for estimating the URM impact specific to each QREA in a CY (b) Use an annual average capacity value of the resource instead of the UCDF to estimate the UCAP of a QREA when awarding REE	REE/ T	III.A.3, III.B
8	Develop a transparent procedure for estimating the REC value of various renewable resources	Part B/ I	VII.C
9	Modify ESR dispatch model to: (a) Reflect the ability of the ESR to submit only hourly offers, (b) Develop a reasonable methodology that accounts for the operator's limited foresight of future prices when offering the unit	Part B/ I	VII.D.1
10	Consider modifying definition of Mitigation Net CONE to allow for using a reasonable forecast of the ICAP demand curves	Part A & B/ T	VIII.F

