**STATE OF NEW YORK**
**PUBLIC SERVICE COMMISSION**

**CASE 19-E-0530 - Proceeding on Motion of the Commission to Consider Resource Adequacy Matters**

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# COMMENTS OF POTOMAC ECONOMICS, LTD. ON MATERIALS IN THE JULY 10 TECHNICAL CONFERENCE

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Potomac Economics, Ltd. ("Potomac Economics") respectfully submits these comments in response to the New York State Public Service Commission's ("PSC" or "Commission") *Notice Soliciting Comments* issued on July 20, 2020. Potomac Economics Ltd. serves as the market monitoring unit for the New York Independent System Operator, Inc. ("NYISO").

The Commission requested comments on the results of the analyses of the resource adequacy alternatives in the materials prepared by the Brattle Group ("Brattle") for the July 10 technical conference. The Brattle materials include the qualitative and quantitative analyses ("Brattle Analyses") filed on May 19, 2020 and July 1, 2020, respectively.

## I. INTRODUCTION AND SUMMARY

The Brattle Analyses focus primarily on costs associated with NYISO's "buyer-side" market power mitigation measures (the "BSM Rules") in the capacity market. The BSM rules are intended to support the competitive performance of the capacity market be deterring uneconomic entry designed to suppress capacity prices and reduce the adverse short-term price effects of subsidized uneconomic entry. The latter has been of particular concern given the State's ambitions goals to expand renewable resource output in New York over the next decade. The BSM rules address this concern by applying a minimum offer price on subsidized new resources that do not qualify for an exemption. These rules apply to State-sponsored resources that are procured to satisfy New York State's environmental goals. We have worked with the NYISO to develop improvements in the BSM rules and other aspects of the NYISO's markets to limit the adverse effects of the BSM rules on sponsored resources.

The Brattle Group was retained to analyze the costs and benefits of the current capacity market design with the BSM rules versus several alternative resource adequacy market structures. Its quantitative analysis includes three scenarios and discusses the cost differences between the scenarios:

1. Current market with BSM ("Status Quo scenario")
2. Current market with expanded BSM ("Expanded BSM scenario")
3. Resource Adequacy Credits (RACs) without BSM ("No BSM scenario")

Brattle's qualitative analysis also discusses two additional alternative structures:

4. LSE Contracting for RACs and
5. Joint Procurement for Resource Adequacy and Clean Energy.

Brattle acknowledges that the final market structure (#5) would require extensive work to define the products and market rules, so no credible analysis of this alternative is possible. Likewise, Brattle does not quantify costs or benefits of market structure #4. However, experience in other markets is instructive, indicating that this option is likely the least preferred of the five alternatives. We discuss in Section II.C. of these comments why the LSE Contracting (#4) alternative would increase costs and undermine reliability over the long-run.

Other than our discussion of alternative #4, our comments primarily address the Brattle Group's quantitative analyses of alternatives #1 and #3 that seek to evaluate the cost of the current BSM rules and the corresponding benefits of eliminating them. Although Brattle does not specify how its RAC market would be implemented and how it differs from the current market, which is critically important in any comparative analysis, it finds that alternative #3 is the lowest-cost alternative. Therefore, its quantitative analysis compares the Status Quo (#1) to the RAC market with no BSM (#3), reporting that the status quo will generate annual costs that are $458 million higher than in the no BSM case. Likewise, Brattle compares cases #2 to #3, reporting that expanded BSM would produce annual costs exceeding $1.6 billion (excluding make-whole payments to nuclear units). We do not evaluate the Expanded BSM scenario (#2) because we are not aware of any FERC docket where this alternative is being considered.

These results along with Brattle's qualitative discussion of the alternatives seem to support a fundamental departure from NYISO's current capacity market construct. However, the assumptions and approach employed by the Brattle Group appear to have been selected to support such a recommendation. We find that the analyses do not adequately represent the recently filed improvements in the BSM rules, the planned energy and ancillary services market design enhancements, or the true effects of the market alternatives on market participants' long-term decisions. In particular, Brattle does not properly account for:

- The quantity of state-sponsored resources that would be exempted under the Part A, Part B, renewable entry exemption tests;
- The incentives the new entrants would have to contract with retiring resources to acquire their Capacity Resource Injection Service ("CRIS") rights, which would allow them to avoid mitigation; and
- The substantially increased market risk facing new entrants in the No BSM alternative, which Brattle ignores entirely. This is particularly problematic because it represents the primary benefit of BSM and a substantial cost of the removing BSM.

These analytic shortcomings render the results of the Brattle Analyses unreliable and an unreasonable basis for any determination by the Commission. To address these analytic concerns, we provide a comparative analysis of the current capacity market with the BSM rules and an assumed case without the BSM rules. This analysis corrects the flaws in the Brattle Analyses and its results stand in stark contrast to the Brattle results. While Brattle asserts that the consumer costs of BSM exceeds $400 million in 2030, our analysis that corrects the analytic flaws described above shows that elimination of BSM would actually *increase* consumer costs by roughly $24 million. This reduction is the result of accurately modeling the various paths available for sponsored projects to receive exemptions and enter the market, as well as recognizing the effects of higher capacity price volatility and risk to developers under the no BSM scenario.

Based on the flaws we identify in the Brattle Analyses and the alternative results we present that correct these flaws, we respectfully recommend that the Commission place little weight on the results of the Brattle Analyses in making its determinations in this proceeding. Instead we recommend that the Commission build a more complete record regarding the current NYISO market and the short-term improvements that are being made that will reduce the effects of the BSM rules on state-sponsored resources. We believe a more accurate assessment of these issues will support retention of the current capacity market and continued collaboration with NYISO to improve the performance of the BSM framework.

## II. COMMENTS ON BRATTLE ANALYSES AND RECOMMENDATIONS

In its qualitative analysis, the Brattle Group asserts that there is no economic rationale for applying the BSM rules to state-sponsored resources and proceeds to discuss its views on five potential resource adequacy alternatives. Three of the five do not include BSM rules that would apply to state-sponsored resources. In its quantitative analysis, it attempted quantify the cost implications of three of the scenarios: the Status Quo scenario that assumes the current market and BSM rules, an Expanded BSM scenario, and a No BSM scenario that involves a vaguely described reconstitution of the capacity market under State jurisdiction.  The direct and indirect costs of the restructuring the market in the last scenario are not quantified as Brattle seems to assume that the current market continues to operate without the BSM rules.  The comparison of most importance is the estimated differences between the Status Quo scenario (#1) and the No BSM scenario (#3), which quantifies the estimated cost of the BSM rules (or alternatively the benefits of repealing the BSM rules).

This section provides a critical evaluation discussion of the Brattle Analyses, raising a variety of concerns regarding Brattle's assumptions and methodology.  Some of these concerns pertain to errors in the Brattle Group's assumptions regarding the exemptions that would likely be available to the state-sponsored resources, while others relate to the simplifications in Brattle Group's model that cause it to fail to capture how the performance of the market would be affected by the removal of BSM in reality.

Section A provides a conceptual overview of the comparison of the Status Quo scenario (#1) and the No BSM scenario (#3).  To address the concerns described in Section A, Section B provides a more detailed analysis that estimates the incremental costs of the BSM rules in a manner that corrects the flaws in the Brattle Group's analysis.  Section C discusses several problems that would arise in the LSE Bilateral Contracting scenario (#4) that were not considered in the Brattle Analyses.

### A. Elimination of BSM Would Raise Costs to Consumers

Brattle's analysis comparing the Status Quo scenario (#1) to the No BSM scenario (#3) finds that the status quo is far more expensive for consumers in the reference year of 2030, indicating additional consumer costs of $458 million.  We have critically reviewed the Brattle Analyses and find a number of oversights or simplifications that substantially affect the results.

The Brattle Analyses ignore:

i. Key provisions of the BSM rules that would allow for many public policy resources to obtain exemptions under the Status Quo scenario;

ii. Anticipated changes in the E&AS market design that would lead many flexible zero-emitting resources to be economic and thus exempted from any mitigation; and

iii. How a market with no BSM to moderate the effects of out-of-market investment would create additional risks for participants that will ultimately increase costs for consumers.

These comments discuss our analysis, which corrects for these deficiencies, and finds that eliminating the BSM provisions would actually *raise* costs to consumers by $24 million relative to the Status Quo scenario in 2030. While this section provides an overview of our key concerns with the Brattle Analyses and our analysis to address them, Section B provides a more detailed description of the methodology.

***The Renewable Entry Exemption***

Brattle did not precisely consider how recently approved changes in the Renewable Entry Exemption would lead to additional exemptions for public policy resources. Of the 4.6 GW of intermittent renewable generation assumed to enter the market from 2020 to 2030 in Zones G to J, Brattle assumed that 550 MW of UCAP would receive exemptions under the Renewable Entry Exemption provisions. However, we performed a careful assessment of the expected retirements compared with the amount of eligible entering resources in the Status Quo scenario and estimated fewer renewable entry exemptions (379 MW of UCAP or 1.9 GW of nameplate capacity). Our estimated quantity is conservative because it does not include any new "Incremental Regulatory Retirements" beyond the retirements related to the DEC Peaker rule.

Any additional such retirements would increase the exemption quantities.[1] Our analysis also recognizes that any intermittent resources not receiving a renewable exemption would be eligible for one of the other exemptions discussed below, allowing some renewable resources to receive Part A exemptions. Section B.1 provides a detailed explanation of how we estimated the quantity of resources receiving Renewable Entry Exemptions.

***Energy and Ancillary Services Markets and the Part B Test***

The growth in intermittent renewable generation that is anticipated over the coming decade will substantially affect the outcomes of the energy and ancillary services markets in New York. Large increases in intermittent resources and retirements of conventional resources will lead to increased price volatility caused by the fluctuation in intermittent output. These fluctuations benefit energy storage resources that can charge when prices are low and discharge or sell reserves when prices are high. This dynamic would cause some of the ESRs to be economic and, therefore, to receive Part B exemptions, which if forecasted are granted to resources that are forecasted to be economic based on wholesale prices in their first three years of operation.

Further, in order to integrate the large influx of renewable resources, NYISO has laid out a plan for significant enhancements its energy and ancillary services ("E&AS") market design.[2] Brattle assumed that none of the 6.1 GW of capacity evaluated for a Part B test exemption would actually receive one. This is likely because Brattle did not consider how changes in the performance of the current markets or the forthcoming changes in the E&AS market design

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1 The amount of available renewable entry exemptions depends, in part, on the amount of Regulatory Retirements—that is, retirements that are driven by a change in laws or regulations. Our analysis assumed that some Regulatory Retirements would occur as a result of DEC Peaker Rule, but it did not consider future changes in New York State laws or regulations that could lead to additional retirements and a corresponding amount of additional renewable entry exemptions.

2 See *Power Trends 2020: The Vision for a Greener Grid*, pages 30-37 and *2020 Master Plan*.

would lead flexible policy resources, such as energy storage resources, to be economic and receive exemptions under the Part B test.

We estimate that with these anticipated market design changes, 1,281 MW would receive Part B exemptions or a reduced offer floor that would subsequently enable the resource to sell capacity.  This assumed quantity is conservative because the Part B test also recognizes revenue offsets from renewable energy credits and distribution-level reliability services.  We did not consider these revenue sources in estimating the Part B exemption quantities.  Hence, additional exemptions would likely be given to renewable generators and battery storage projects that provide such services.  Moreover, increased intermittency will likely increase E&AS revenues to flexible resources as we get closer to 2030, but the effects on energy and ancillary services prices were not fully reflected in our analysis, so reflecting these changes would also likely increase the number of Part B exemptions.  Section B.3 provides a detailed explanation of how we estimated the quantity of resources receiving Part B exemptions.

***Capacity Accreditation Improvements***

We have called for improvements in NYISO's capacity accreditation rules that would lead to additional exemptions.  However, we did not quantify these improvements in our analysis.  First, we have recommended reducing the capacity value of long-lead time units with low capacity factors because units with limited availability provide less reliability value than other capacity resources.

Second, we have recommended reducing the capacity value of large supply contingency resources because such units provide less reliability than smaller resources.  NYISO is expected to address these concerns, since they will become more impactful as the resource mix shifts to include higher levels of intermittent renewable generation.  Such changes would increase the availability of exemptions by raising the cost of supply from some existing resources and reducing the amount of existing supply that is recognized in the capacity market. Since these were not quantified in our analysis, our estimates of the costs and benefits of the BSM rules are conservative. In other words, these changes would likely cause the BSM rules to reduce consumer costs by more than the $24 million that we have estimated.

***The Part A Test and CRIS Transfers***

NYISO recently filed enhancements to the Part A test which will increase opportunities for public policy resources to receive exemptions when it would not lead capacity prices to be depressed below competitive levels. In addition, these enhancements will facilitate bilateral agreements whereby an existing generator can retire and transfer its CRIS to a new state-sponsored resource, allowing the resource to obtain a Part A exemption.

Brattle failed to consider how these changes would affect the number of Part A exemptions granted. Of the 6.1 GW of public policy resources entering between 2020 and 2030 that would be eligible for a Part A exemption, 0 MW were assumed to receive a Part A exemption in the Brattle study. Our analysis estimated that 4.0 GW of nameplate resources would receive a Part A exemption. The majority of this amount, 3.7 GW, would receive an exemption resulting from a CRIS transfer. Sections B.2 and B.4 provide detailed explanations of how we estimated the quantity of resources receiving Part A exemptions.

***Price Volatility and Market Risk***

One of the most serious deficiencies of the Brattle Analyses is that it fails to recognize the role of the BSM in supporting the integrity of the market and its performance in facilitating efficient investment and retirement decisions by market participants. Given Brattle’s willingness to ignore the primary purpose and benefits of the BSM rules, one can scarcely imagine that

Brattle would come to any other conclusion than that BSM is costly and unnecessary. However, considering BSMs role in supporting the performance of the market leads to precisely the opposite conclusion.

First and foremost, Brattle has assumed that the elimination of BSM would *not* increase risk to investors and other market participants. This assumption is at odds with reality and appears to partly be due to Brattle's overly simplified market model. Brattle assumes that older steam units would retire based on an average long-term going forward cost ("GFC"). This causes this assumed GFC to act essentially as a capacity price floor that mitigates the capacity price reductions that will occur as renewable resources enter. One could argue that this may be reasonable in the long-term when supply shocks work themselves out, it is demonstrably not true in the short term based on decades of empirical data regarding how generators make the decision to retire. In reality, generators will continue to operate at prices well below their long-run GFC for at least two reasons:

1. Generators will go into "harvest" mode where typical expenditures to extend the life of a resource are discontinued and it will continue to operate until it suffers major equipment failure. This allows the resource to operate at a much lower short-term GFC than assumed by Brattle.
2. To the extent that uncertainty regarding future market conditions, including the retirement decisions of other participants that own similar units, generators may not immediately retire when prices drop below their GFC level. In fact, they may not be able to forecast accurately when prices will decrease to these levels. This can cause transitory surpluses that would not be predicted in the Brattle model.

Because generators would not likely immediately retire when prices decrease to the long-term GFC level, capacity price volatility and price suppression without the BSM rules could be much larger on a year-to-year basis than Brattle has conceded. Therefore, the elimination of

BSM would expose generators to substantial additional market risk associated with out-of-market state-sponsored investment. This increase in market risk would lead to an increased cost of capital, slow the response of competitive suppliers to fluctuations in prices, and ultimately raise costs to consumers.

We estimate how the market risk associated with the increased price volatility would increase the weighted-average cost of capital ("WACC") of wholesale generators in two ways. First, we estimate the increase in the cost of debt and additional capital requirements for merchant generators based on standard criteria that credit rating agencies would use to assess risk in a market with increased price volatility. Second, we estimate how the cost of equity would increase to reflect the higher market risk of investment using the capital asset pricing model. Overall, we find that these additional risks would raise the after-tax WACC from 8.4 percent by 1.0 percent to 9.4 percent for all generators relying on capacity market revenues. This widespread increase in market risk would increase the net cost of new entry, as well as the going forward costs for existing generators. Section B.5 provides a detailed explanation of how we estimated the increase in capital costs and the resulting increase in consumer costs under the No BSM scenario.

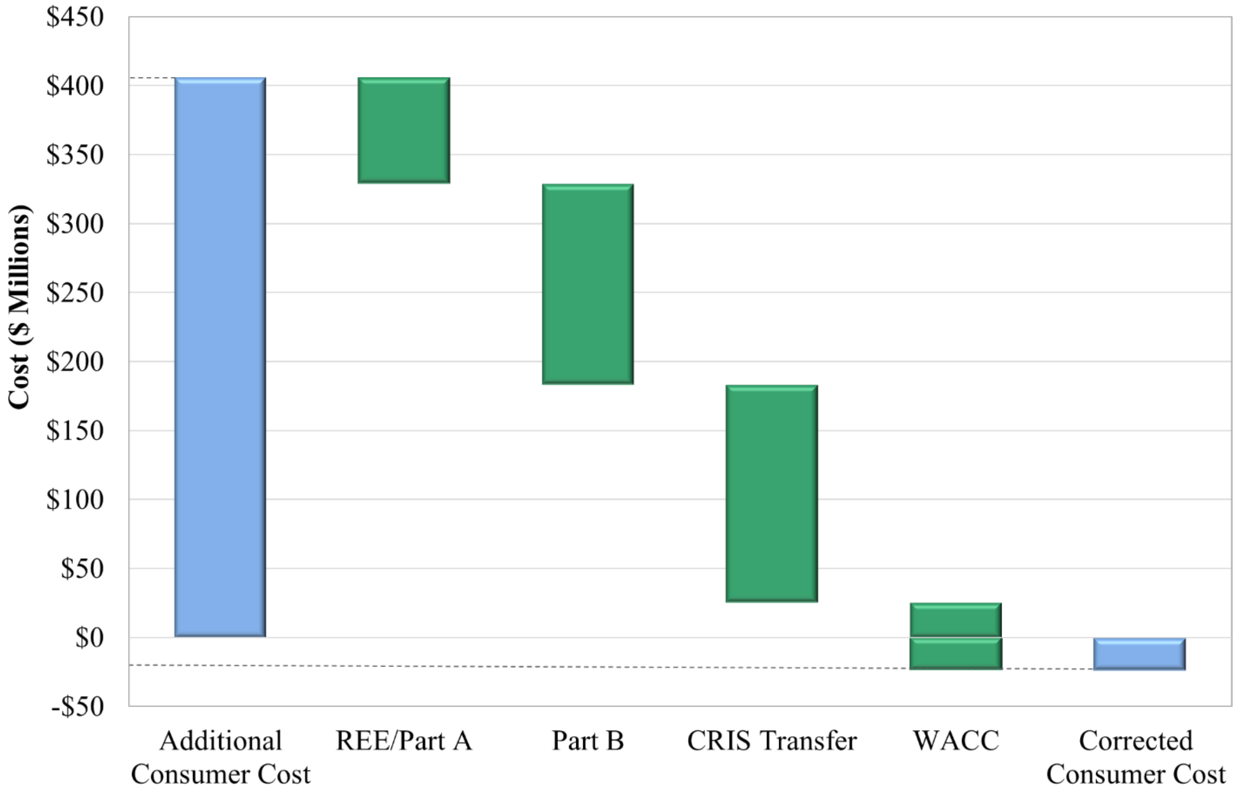
***Summary of the Corrected Effects of Eliminating BSM***

Our comments raise concerns regarding the Brattle Analyses in a number of areas. Taken together, our corrections addressing these concerns cause the estimated cost effects of the BSM rules to change from an *increase* of more than $400 million in 2030 to a *decrease* of $24 million.

The following figure summarizes the overall effects of the individual methodological changes on the comparison of the Status Quo scenario (#1) and the No BSM scenario (#3). The left-most bar shows the consumer cost savings for 2030 if New York shifted from the Status Quo to a No BSM scenario as estimated by Brattle estimated.  The green bars show how much the estimated consumer cost savings falls as we apply each methodological correction by area.

**Effects of Correcting the Brattle Assumptions on Estimated Contract Costs**

Base Case




The initial Additional Consumer Cost shown in the figure ($406 million) is slightly lower than the value reported in the Brattle Analysis ($458 million) primarily because it reflects the impact of the E&AS enhancements (discussed above) in both the Status Quo and No BSM scenarios.  Since these enhancements would generally lower the capacity demand curves and GFCs of steam turbines, they would slightly reduce the additional capacity contracting costs identified in the Brattle Analysis.

**B. Detailed Reworking of Brattle's Quantitative Analysis**

Brattle's analysis compared the consumer costs across three resource adequacy structures.  However, as explained in Section A, Brattle did not give adequate consideration to a number of factors that would affect the buyer-side mitigation evaluations and overall market performance under the Status Quo and No BSM scenarios (#1 and #3). We have attempted to replicate Brattle's analysis, capturing as many of their assumptions as could be gleaned from their public reports, and based on these assumptions, we have generated similar estimates of consumer costs under the Status Quo and No BSM scenarios. Using this as a base model, we then examined how the estimated consumer cost savings would change if these additional factors were considered appropriately. In this section, we describe the changes we made to address specific deficiencies in Brattle's analysis and the resulting changes in the estimated consumer cost savings.

While Brattle assumed that 550 MW (UCAP) of renewable generation would receive renewable entry exemptions and 0 MW of exemptions would be granted under the Part A and Part B tests through 2030 in the Status Quo scenario, we performed a more detailed unit-level assessment. Our approaches to the Renewable Entry Exemption, Part A, and Part B tests are described in Part 1, 2, and 3 or this section. Since some resources would not be exempt from mitigation, Part 4 of this section analyzes the extent to which additional projects would have an incentive to purchase CRIS rights from an existing generator (which would then retire) in order to get a more favorable Part A test outcome. Based on the resulting changes in the mitigation exemption test outcomes and the additional costs to procure CRIS rights, we re-estimated consumer costs in the Status Quo scenario (#1).

We also modified the cost of capital assumptions under the No BSM scenario (#3) to account for the increased risk from higher expected price volatility as compared with the Status Quo. Considering the effects of these revised capital cost assumptions on the capacity demand curve and the cost of supply for new and existing resources, we re-estimated consumer costs as described in Part 5 of this section.

The overall impact of these changes of consumer costs is provided in Part 6 of this section. To the extent possible, we performed our estimates using assumptions from Brattle's Analysis except where we have specifically chosen to use an alternative assumption discussed in this section. The remainder of this section provides the methodological details and assumptions underlying our analysis.

### 1. **Renewable Entry** Exemptions

Under recently approved rules, the NYISO would grant BSM exemptions to qualified renewable entrants subject to a cap that changes every Class Year depending on several factors. The REE cap is determined as the sum of changes to UCAP requirement due to peak load growth, regulatory retirements and the Unforced Capacity Reserve Margin ("URM") impact, subject to a minimum quantity that corresponds to a 50 cents/kW-month price impact.

In our analysis, after considering the change in peak load from 2020 to 2030 and assuming that peaking unit capacity affected by the DEC rule would qualify as Incremental Regulatory Retirements, we determined that 337 MW (UCAP) of Zone J units of offshore wind resources could be exempt under the REE provisions. In Zone G, all (41 MW) of the total UCAP of solar PV projects was determined to be under the minimum REE cap in 2030, and accordingly, these projects were not subject to mitigation.[3]

We utilized Brattle's Effective Load Carrying Capability ("ELCC") estimates as the basis for estimating the impact of the URM on the exemption test and the amount of ICAP that would be exempt as a result. This resulted in 1.6 GW (ICAP) of exemptions for offshore wind

[3] Modeling all Class Year BSM evaluations through 2030 could result in more renewables being exempt under the REE criteria, relative to our 2030-specific analysis. This is because the Class Year-to-Class Year peak load change may not be as large as the drop from 2020 to 2030, and peaking unit retirements in specific years could lead to more unit being exempt under the REE criteria. However, to the extent that units receive more exemptions under REE criteria, the amount of PPRs exempted under Part A could be reduced.

generation and 0.3 GW (ICAP) of exemptions for solar PV generation.

### 2. Part A Evaluations

NYISO recently filed enhancements to the Part A test which would allow new entrants to be exempted from Buyer-Side Mitigation if the capacity surplus is lower than a certain threshold ("Part A threshold"). The enhancements would allow Public Policy Resources ("PPRs") to be tested ahead of non-PPR entrants. Hence, the NYISO's proposed rules would enable PPRs to avoid mitigation when the capacity surplus is below the Part A threshold due to retirement of existing capacity and/or growth in demand.

We estimate that 339 MW of energy storage resources ("ESRs") entering Zone J before 2025 would be exempt from mitigation. The estimated capacity surplus in the G-J Locality is expected to be larger than the Part A threshold, so no PPRs were determined to be exempt under the Part A test criteria outside of Zone J.[4]

### 3. Energy and Ancillary Services Market Enhancements and Part B Evaluation

The NYISO is pursuing several E&AS market design enhancements that will promote integration of intermittent renewables by increasing the compensation to flexible resources and reducing revenue for inflexible resources. Modeling these market enhancements would reduce the project-specific net cost of new entry for projects evaluated in the Part B test (which known as "Unit Net CONE") of ESRs and increase their likelihood of securing Part B exemptions. Under the Part B test criteria, resources that are economic based on the energy and capacity

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4 Modeling individual Class Year BSM evaluations through 2030 could result in more PPRs being exempt under the Part A criteria, relative to our analysis. This is because the market could be significantly tighter in some of the intervening years between 2020 and 2030 due to the timing of unit retirements and variations in LCRs and loads. Therefore, the amount of PPR capacity exempted under Part A criteria in our analysis is likely to under-estimate the actual amount of available exemptions. However, to the extent that more PPRs receive exemptions under the Part A test criteria, the amount of renewables that receive an exemption under REE could be reduced in subsequent years.

prices during the first three years of operation are granted an exemption.

In our analysis, we considered the impacts of the following E&AS market design enhancements on the investment signals for the demand curve unit, steam turbines, and PPRs including ESRs:

- Modeling local reserve requirements in New York City load pockets,[5] [6] and
- Modifying operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.[7]

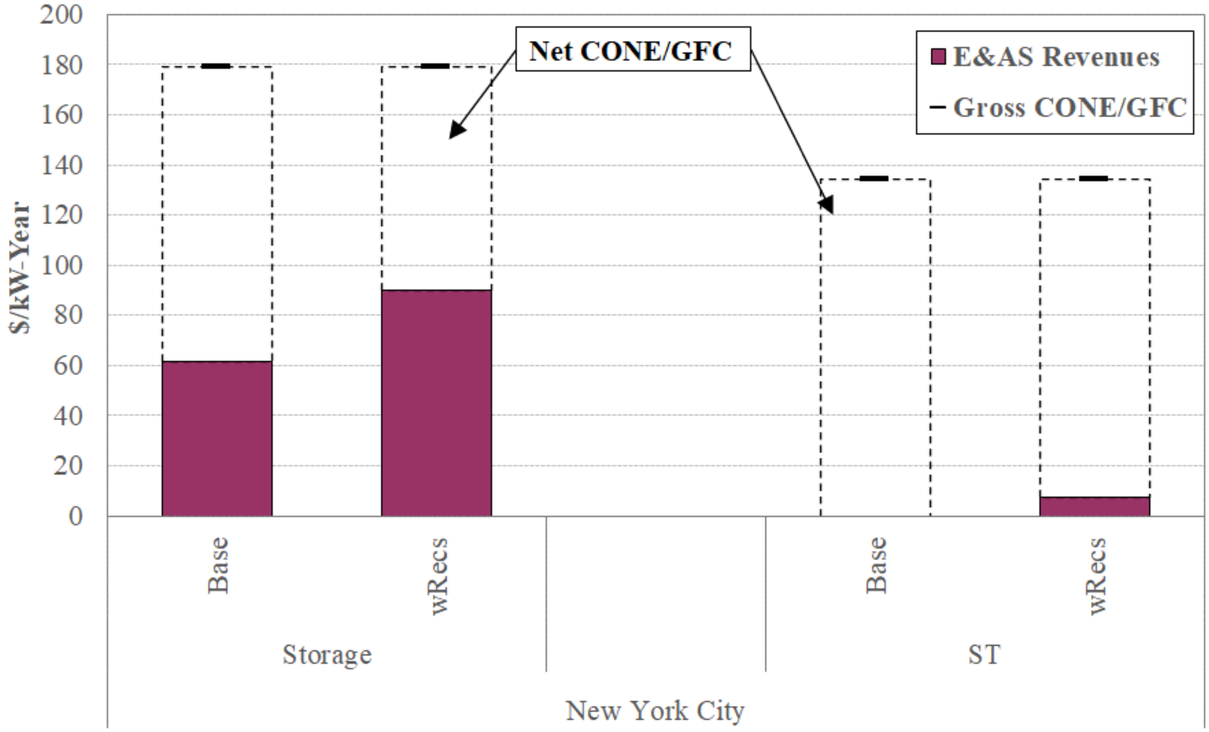
The following figure shows the estimated impact of these enhancements on the E&AS revenues, Unit Net CONE values, and GFCs in 2030 for ESRs and steam turbine units in Zone J.

[5] We estimated the impact of this recommendation by increasing the energy and reserve prices by an amount equal to the BPCG per MW-day of the UOL for the LRR committed units in the CARIS 70x30 scenario, allocated to hours in proportion to the reliability needs. We also assume market-based incentive payments to the units having the capability to switch over from gas to oil in less than one minute based on the estimated incremental marginal cost of steam turbines burning a blend of oil and gas for reliability.

[6] Although our estimates of local reserve revenues were derived from the CARIS 2030 Scenario Load HRM Method case, it is important to note that the case did not fully consider the effects of local reserve requirements. This is because the requirements for local reserves modeled in the case did not consider how peaking generation retirements (resulting from the DEC Peaker Rule) would increase requirements for spinning reserves. Considering the additional reserve requirements would increase the effects of the E&AS enhancements that we modeled.

[7] We estimate that this enhancement would result in up to $10/kW-yr increase in net E&AS revenues. This corresponds to 1.25 hours of shortage per year times the ISO-NE PFP rate of $7,000/MWh plus its $1,000/MWh reserve demand curve for 30-minute operating reserves. However, the actual level of additional shortage pricing would likely include more hours at lower average price levels.

**Impact of Pricing Enhancements on Net Revenues for ESRs and Steam Turbine Units**




As shown in the figure, the modeled market enhancements resulted in: (a) significantly higher E&AS revenues (and lower Unit Net CONE values) for ESRs, and (b) the 2030 Unit Net CONE of the ESRs to be much lower than the GFCs of steam turbine units in Zone J.

In our analysis, the steam turbine units continue to be on the margin in both Zone J and G-J Locality after accounting for resources exempt under REE and Part A criteria.[8] Consequently, ESRs entering in 2030 encounter a capacity price that is above their Unit Net CONE values and secure Part B exemptions. Furthermore, we note that some ESRs entering before 2030 that would not be able to secure exemptions at the time of their entry would be able to secure exemptions in a subsequent year. This is because such units could initially enter as ERIS-only resources and then obtain lower Unit Net CONE values if they requested CRIS at a

[8] This finding is consistent with Brattle's Analysis. See slide 15 of Brattle's July 1 presentation.

later date.[9] ESRs opting to receive CRIS rights in a later year would have reduced embedded costs as a result of the effects of depreciation.[10]

This approach is relatively conservative because it does not consider the additional exemptions that would result from opportunities for ESRs to interconnect where they earn additional E&AS revenues from relieving intrazonal transmission bottlenecks. Brattle's GridSim model does not consider the effects of intrazonal congestion or even most interzonal transmission constraints. However, NYISO's recent CARIS 70x30 case found widespread transmission constraints at the 115kV levels that would provide additional opportunities for ESRs to pass the Part B test.[11]

#### 4. CRIS Transfers

NYISO's recently filed enhancements to the Part A test of its BSM evaluations could facilitate bilateral agreements between existing generators and PPRs. These agreements would transfer CRIS rights from an existing resource to a PPR, enabling the PPR to enter without being subject to mitigation if the retirement of the existing resource would raise forecasted price levels enough for the PPR to pass the exemption test. To the extent that PPRs can secure CRIS rights through one-time payments to existing units, it would reduce the consumer costs through avoided contract costs.

Before considering the potential for CRIS transfers in our analysis of the renewable entry,

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9 In our analysis, we assume that 300 MW of ESRs enter Zone J by 2023, an additional 375 MW by 2025, and an additional 675 MW by 2030.

10 For instance, a 2025 ERIS-only resource would have depreciated (assuming straight-line depreciation over 20 year project life) by about 23% of its initial capital investment by 2030, and thus the embedded cost of the resource in 2030 is about 77% of its initial capital cost. However, the benefits from lower embedded cost is partially offset by the shortened MACRS schedule (able to utilize only the last 3 years of the 7 years MACRS schedule) and shorter amortization period (15 years) over which the CONE for the resource is estimated for the BSM evaluations in 2030.

11 See NYISO 2019 Congestion Assessment and Resource Integration Study Report (July 2019), pp. 84-101, link. See also MMU Review of 2019 CARIS Phase 1 Study, June 2020, link.

Part A, and Part B exemption test processes, we estimated that approximately 1.3 GW (UCAP) of the total capacity of PPRs seeking entry would be mitigated. The scenarios modeled by Brattle included over 3.5 GW of existing steam turbine capacity with relatively high GFCs that set clearing prices in Zone J. Hence, there is sufficient existing steam turbine capacity in Zone J for the mitigated PPRs to acquire CRIS through such transfers, thereby avoiding higher contract costs.

In addition to PPRs that would otherwise be mitigated, some merchant facilities would also be interested in acquiring CRIS through a bilateral transfer. These include: (a) merchant entrants that would realize cost savings by repowering an existing facility, and/or (b) merchant entrants that lack access to suitable land for developing their projects in New York City. For the purposes of this analysis, we consider potential merchant entry by four-hour battery storage resources.

We estimated the bilateral CRIS transfer prices for each zone based on the following potential buyers and sellers:

- PPRs that would otherwise be mitigated – The maximum price they would be willing to pay for CRIS rights is the net present value of the total capacity payments that these resources will not receive if subject to mitigation.
- Merchant entrants – The maximum price they would be willing to pay for CRIS rights of an existing generator will be the cost savings associated with usage of existing infrastructure. Merchant storage units will be willing to pay up to the difference between their Unit Net CONE values and the forecasted capacity clearing prices.
- Existing steam turbine – These units are likely to be the least expensive sellers of CRIS rights. The price level associated with this supply curve will be driven by the owners' willingness to accept the corresponding payment price to retire, which is

derived from future expected profits, which are zero for all steam turbine units in the Status Quo scenario.

Given these observations regarding the supply and demand for CRIS rights, the maximum clearing price in this market would be the willingness to pay of merchant storage units. Accordingly, we conservatively estimate the bilateral price to be 50 percent of the difference between the ICAP market clearing price (i.e. the steam unit's GFC) and the Unit Net CONE of the merchant battery storage unit in 2030. Applying this framework to our analysis of Zone J results in a CRIS transfer price of $19/kW-year.

### 5. Weighted Average Cost of Capital

The risk associated with cash flows is a key driver of the cost of capital used to evaluate an investment. Accordingly, an increase in volatility of prices under the No BSM scenario will lead to a commensurate increase in the return required by investors as compensation for the additional risk. Brattle's analysis suggested that capacity prices would be similar on an expected basis in both the Status Quo and No BSM scenarios. However, the downside risk and the volatility of cash flows would materially increase under the No BSM scenario. The higher downside risk would adversely affect the cost of debt, while the overall volatility of cash flows would particularly impact the cost of equity.

The NYISO's consultants periodically estimate the financing parameters for a merchant entrant in New York as part of the ICAP Demand Curve Reset process. These parameters represent the consultants' assessment of (and stakeholders' inputs regarding) risks faced by a new entrant under the Status Quo scenario. We made adjustments to the consultant-estimated Cost of Debt ("COD") and Cost of Equity ("COE") values to reflect the increased risk that an asset entering (or operating in) the NYISO footprint is likely to encounter under the No BSM scenario and the resulting effects on consumer costs.

a. Cost of Debt

As discussed in Section B, the wholesale market would experience larger supply and demand shocks in the No BSM scenario, which would increase the downside risk of having periods of severely depressed prices. For instance, in the NYCA zone where there is no mitigation and several large units have been retained via contracts with New York State agencies, the prices were eight percent of the Net CONE in the 2019/20 Capability Year. Many wholesale generators depend on capacity revenues for a vast majority of their cash available for debt service, and low capacity prices will significantly affect the ability of a project to cover its debt service requirements.

The ability of a project to satisfy its debt service obligations as measured by the Debt-Service Coverage Ratio ("DSCR") under a range of conditions is a key consideration of credit agencies when assigning a rating. A strong DSCR would generally lead to a better credit rating, while a low DSCR under normal and stressed conditions would lead to (a) a lower credit rating and/ or (b) an increase in liquidity requirements for the project. For instance, S&P's guidelines indicate that it expects a BBB-rated asset to have a DSCR that exceeds one under stressed conditions for at least a five-year period, while it expects a B-rated asset to have sufficient reserves for only three years in the downside case.[12, 13] Even if two projects get an identical rating based on an initial assessment, consideration of performance in a downside case would result in potential adjustments (up or down) to the debt rating.

The table below shows the DSCRs (along with the underlying energy and capacity

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12 See Table 16 - Downside-Case Expectations, Standard & Poor's *Project Finance Operations Methodology* published on September 16, 2014.

13 *Id.* at paragraph 79, "Debt service reserve accounts are generally sized to meet the next debt service payment (generally scheduled every six months)".

revenues, and fixed costs) for a Zone J peaking unit under a base case, and under the downside case for the Status Quo and No BSM scenarios. The guidance from S&P states that the downside case for capacity markets is assumed to be "a capacity price generally reflecting two factors: about one-third of the capital cost required to attract investment in new power plants and the reserve margin the market administrators usually establish."[14] Incidentally, the short-term GFC of a steam unit in Zone J is likely to be close to one-third of the Net CONE of the peaking unit. Accordingly, we assume the capacity prices to be $65/kW-year in the downside case under Status Quo. We assume the downside capacity prices in the No BSM scenario to be at 50 percent of the downside case price in Status Quo, given recent outcomes from the ROS capacity zone.

**Debt Service Coverage Ratios in Base and Downside Cases**

Zone J Demand Curve Unit, 2019/20 Capability Year

| | | | Downside Case | |
|---|---|---|---|---|
| | **Notes** | **Base Case** | **Status Quo** | **No BSM** |
| E&AS Revenues | [1] | $ 37 | $ 33 | $ 33 |
| Capacity Revenues | [2] | $ 178 | $ 65 | $ 33 |
| Fixed Costs | [3] | $ 38 | $ 42 | $ 42 |
| Net Cash Flow | [4] = [1] + [2] - [3] | $ 177 | $ 57 | $ 24 |
| Debt Service | [5] | $ 63 | $ 63 | $ 63 |
| **DSCR** | [6] = [5] / [4] | **2.8** | **0.9** | **0.4** |

The above table shows that, in the downside case, the cash flows under the No BSM scenario will be well below the amounts required to cover the Zone J unit's debt service without a significant liquidity reserve in excess of typical levels.[15] In contrast, the cash flows under the

14 See Table 4 - Market Exposure: Market Downside Case Guidance For Power Projects and Table 8 - Power Projects: Standard & Poor's Downside Case Assumptions Guidance, Standard &Poor's *Project Finance: Key Credit Factors For Power Project Financings* published on September 16, 2014. We reduced the E&AS revenues and increased the fixed costs in the downside case in accordance with criteria in Table 4 and Table 8.

15 "Debt service reserve accounts are generally sized to meet the next debt service payment (generally scheduled

Status Quo scenario in the downside case are likely to be sufficient to cover their debt service for over several years.  Furthermore, the potential for unpredictable and artificial excess supply increases this tail risk (of stressed conditions) under the No BSM scenario relative to the Status Quo scenario.

As per criteria outlined by S&P, the poor performance in the downside case coupled with the increased likelihood of high-risk conditions provides a basis for adjusting the debt rating under the No BSM scenario down (relative to the Status Quo scenario) by *at least* one notch to B-.[16, 17]  The average spread between B and B- rated corporate bonds in recent years has been approximately 100  bps.[18]  Accordingly, we adjusted Brattle's assumed COD in No BSM scenario from 7.75 to 8.75 percent.

b. Cost of Equity

Although the expected prices may be similar across the Status Quo and No BSM scenarios, the volatility of prices under the No BSM scenario will be higher relative to the Status Quo scenario.  Consequently, investors will require a higher return on equity for assets relying on NYISO capacity markets under the No BSM scenario.

The Capital Asset Pricing Model ("CAPM") indicates that, all else being equal, the return on equity required by investors is directly proportional to the volatility of returns on the asset (as

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every six months)".  See paragraph 79, Standard & Poor's *Project Finance Operations Methodology* published on September 16, 2014.

16 See paragraphs 72, 79 and 99, Standard & Poor's *Project Finance Operations Methodology* published on September 16, 2014.

17 Under the No BSM scenario, increasing liquidity reserves to a level that would meet the criteria for a B rating is likely to lead to higher financing costs relative to downgrading the rating by one notch.

18 See (a) pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ratings.htm and (b) http://people.stern.nyu.edu/adamodar/podcasts/valUGspr19/session7slides.pdf.

measured by the standard deviation of returns).[19] Therefore, the COE under the No BSM scenario can be estimated by scaling up the market risk component of the COE under the Status Quo scenario by the ratio of standard deviations of the expected capacity prices under the No BSM and Status Quo scenarios.[20]

We impute the market risk component under the Status Quo scenario as the difference between the COE of a merchant entity and a regulated entity in New York. Based on our review of recent rate cases, and the COE estimated by the NYISO's consultants, we assume the market risk component of the COE to be 400 bps under the Status Quo scenario.[21] To estimate the increase in standard deviation of capacity prices under the No BSM case, we developed price distributions with the following characteristics for the Status Quo and No BSM scenarios:

- Both scenarios – Assume that: (a) the mean capacity clearing price would be equal to the long-term GFC of the steam turbine units, (b) the maximum clearing price would be Reference Point of the capacity demand curve, and (c) that the functional

[19] Under the CAPM formulation,

Expected return of equity for an asset $a$ = Risk-free Rate + $\beta_a$ x Market Risk Premium

The CAPM $\beta_a$ estimated as: $\beta_a = \sigma_a/\sigma_m \times \rho_{a,m}$

where,

$\beta_a$ is the asset beta,

$\sigma_a$ is the standard deviation of the asset's returns,

$\sigma_m$ is the standard deviation of the market's returns,

$\rho_{a,m}$ is the correlation coefficient of market returns and the asset returns.

[20] For the purpose of this analysis, we assume that the asset's returns for a given period are proportional to the asset's capacity revenues.

[21] For example, the Public Service Commission has recently approved an ROE of 8.8 percent for Con Ed (2020) and Central Hudson (2018). By contrast, the most recent ROE recommended by NYISO in its ongoing Demand Curve Reset process is 13.0 percent. The difference in ROE of over 4 percent is indicate of the higher cost of capital associated with merchant as opposed to regulated returns in New York.

form of the price distribution would be characterized by a modified-PERT or Gamma distribution.

- Status Quo scenario – Assume that: (a) the short-term GFC of the steam turbines represents the lower bound on capacity prices and (b) the mode of the capacity price distribution is within 10 percent of the mean.

- No BSM scenario – Assume that: (a) the short-term GFC of the steam turbines represents the lower bound on capacity prices and (b) the likelihood of prices being at any value between upper and lower bounds is similar with a higher likelihood of prices clearing near the upper and lower bounds.

Our analysis of distributions that fit the above characteristics suggested that the volatility of capacity prices (i.e. standard deviation) in the No BSM scenario is 50 percent to 150 percent higher than in the Status Quo scenario. This implies an increase in required COE to be in the range of 200 bps to 600 bps. For our analysis, we assumed an increase in COE of 200 bps (i.e. 50 percent of the market risk component) in the No BSM scenario.

c. After-Tax Weighted Average Cost of Capital

Overall, we estimate an increase of approximately 100 bps in the total ATWACC for the demand curve unit.[22] The resulting ATWACC (of 9.43 percent) is reasonable and consistent with discount rates we have observed in confidential reviews of resources that face repair or retirement decisions under challenging regulatory environments.

The increase in WACC would increase consumer costs in the No BSM scenario in three ways:

- First, it would raise the ICAP Reference Point, which will lead to increase in capacity procurement costs (by raising the quantity procured).

22 We increased the WACC for specific resources is proportion to the share its revenues from the capacity market,

- Second, it would increase the Gross CONE of PPRs that do not enter into Index RECs contracts to the extent they rely on capacity revenues. This will increase the contract costs for these resources.
- Lastly, to the extent that the GFC of steam turbines includes capital expenses, the financing cost associated with those would increase, thus increasing the overall GFC of the steam turbine.[23]

We estimated the consumer cost increases due to each of the above three categories and applied it to offset any increase in capacity procurement costs under the Status Quo scenario.

### 6. Conclusions Regarding the Comparison of Status Quo and No BSM Scenarios

After applying the adjustments described in this section to Brattle's analysis, we estimate that the elimination of BSM would lead to a $24 million increase in consumer costs in 2030. The following table summarizes the quantities of PPRs that we estimate would receive exemptions from mitigation by technology type, location and the type of exemption received as applicable.

**Summary of Mitigation Status of PPRs**

| Zone | PPR Type | Total Capacity (UCAP MW) | Exemption (UCAP MW) REE | Exemption (UCAP MW) Part A | Exemption (UCAP MW) Part B | Mitigated (UCAP MW) |
|---|---|---|---|---|---|---|
| NYC | ESR | 1350 | 0 | 339 | 1011 | 0 |
| NYC | Offshore Wind | 562 | 337 | 0 | 0 | 353 |
| NYC | Other | 1000 | 0 | 0 | 0 | 1000 |
| LHV | ESR | 270 | 0 | 0 | 270 | 0 |
| LHV | Solar | 41 | 41 | 0 | 0 | 0 |
| **Total** | | **3223** | **378** | **339** | **1281** | **1353** |

23 To estimate this cost increase, we assumed that the refurbishment cost component of the steam turbine GFC used in Brattle's analysis corresponds to annualized payment of a single upfront capital project over six years using a merchant cost of capital, then re-calculated this annual payment with a higher cost of capital.

### C. Transition to a Bilateral Market for Capacity Would Raise Costs to Consumers and Undermine Reliability

One of the scenarios addressed in Brattle's qualitative analysis is to transition to a structure where LSE's are required to contract for "Resource Adequacy Credits". Brattle notes a number of disadvantages to this approach, but does not fully consider the implication of this proposal on New York's consumers.

Based on our review of this alternative, transitioning to a bilateral LSE Contracting market would raise costs to consumers because it would undermine the price formation and transparency that occurs in a competitive market with uniform non-discriminatory pricing. Moving away from the current competitive market design would increase risk to investors and diminish incentives for new entry. Ultimately, weak investment incentives would tend to undermine reliability by making it difficult for the state to attract new generation investment without signing expensive above-market contracts.

One feature of a bilateral LSE contract market is that it would not use a sloped demand curve, so it has many of the features of a capacity market with a vertical demand curve at the level of the installed capacity requirement for each LSE. A vertical capacity demand curve leads to inefficient price formation, increased price volatility, poor price transparency, and increased investor risk. Ultimately, these problems stem from the fact that the value a vertical demand curve does not reflect the value of capacity. The value is derived from the reliability capacity provides to electricity consumers. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases.

The contribution of surplus capacity to reliability can only be captured by a sloped demand curve.

In a bilateral market that essentially reflects a vertical demand curve, prices will generally set inefficiently low and fail to provide proper incentives to new and existing resources. However, prices could be set inefficiently high as margins tighten, particularly if the market is illiquid and market power is difficult to mitigate. Brattle identifies these concerns in its qualitative analysis of this alternative.

These concerns have been manifest in other RTOs that operate under vertical demand curves or bilateral contracting structures. In the Midcontinent ISO, an RTO we have monitored since its inception, capacity prices have cleared at inefficiently low levels for years, leading to premature retirements and inefficient capacity exports to PJM.

Likewise, ISO New England's forward capacity market used a vertical capacity demand curve for the first eight years. In the first six years, the capacity market always "cleared" at the auction floor price, which was typically less than half of the estimated net cost of new entry. In the last two years before the Federal Energy Regulatory Commission required ISO New England to implement a sloped demand curve, the auction "cleared" at the auction starting price in some locations, which was a level far above the net cost of new entry. The ISO New England experience demonstrates how the vertical demand curve inherent in a bilateral contract market for capacity will tend to increase price volatility, clearing at inefficiently low or high levels.

Bilateral LSE contracting for resource adequacy would increase financial risks to most suppliers. While bilateral contracts with developers of public policy resources are often touted as providing revenue certainty that would reduce the cost of capital to those developers, this ignores that a bilateral contract regime increases risks to all other generators and even increases risks to generators under bilateral contracts in the medium to long-term. For example, suppose a generator sells capacity through a long-term contract with a state agency at a price equal to its revenue requirement minus the energy and ancillary services revenues it expects to receive. If the state agency enters into subsequent contracts that reduce energy and ancillary services revenues below the first developer's expectations, the total revenues to the first developer could below its annual revenue requirement, rendering its project unprofitable.

Long-term bilateral contracts are often touted as reducing investment risk by providing revenue certainty that is a hedge against the large upfront investment cost. While this is true, it comes at a significant cost because it shifts these financial risks on to consumers. Advocates of long-term contracting may assert that this is a benefit to consumers because it allows them to "lock-in" a price for years to come. However, this misunderstands the nature of financial risk. This lock-in does not provide a long-term hedge since consumers buying electricity far in the future rarely have offsetting sales or other exposure in a comparable time frame to be hedged. In fact, most non-residential consumers would face *increased* risk from locking-in future electricity costs because few businesses normally enter in to fixed-price contracts with their customers 20+ years in the future. Long-term contracts expose consumers to the risk of bearing future energy costs at a particular level even if energy prices are lower in the future.

In their November 8, 2019 comments in this Case 19-E-0530, the Joint Utilities provided salient examples of the risk of signing expensive long-term contracts. They report that "the Commission had noted that long-term contracts had become as much as 40 percent more expensive than market levels and estimated overpayments by utility customers in the amount of $2.7 billion between the beginning of 1995 and the end of 1999."[24]

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[24] See pages 34-35.

The use of long-term contracts led to large rate increases beginning in the 1990s, and consumers were not totally free of these contracts until the last decade. Ultimately, the recognition of this helped push New York State towards deregulation of the power market at the end of the 1990s, and deregulation has provided significant benefits to consumers over the last two decades. We recommend this Commission avoid repeating the mistake of increasing reliance on long-term contracting for resource adequacy.

## III. CONCLUSIONS AND RECOMMENDATIONS

Brattle's estimates the consumer costs of the BSM rules in 2030 to exceed $450 million. We have critically reviewed the Brattle Analyses and found a number of oversights, simplifications, and other flaws that substantially affect the results. Specifically, Brattle under-estimated the likely number of mitigation exemptions and failed to consider that the elimination of BSM rules would significantly increase investment risk. Ultimately, we estimate that the elimination of the BSM rules would actually *increase* consumer costs by an estimated $24 million in 2030.

Based on the flaws we identify in the Brattle Analyses and the alternative results we present to correct these flaws, we respectfully recommend that the Commission place little weight on the results of the Brattle Analyses in making its determinations in this proceeding. Instead, we recommend that the Commission build a more complete record regarding the current NYISO market and the short-term improvements that are being made that will reduce the effects of the BSM rules on state-sponsored resources. We believe a more accurate assessment of these issues will support retention of the current capacity market and continued collaboration with NYISO to improve the performance of the BSM framework.

Respectfully submitted,

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