Impact of Carbon Pricing on Potential Expanded Buyer-Side Mitigation in the NYISO Markets

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About the Author

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Background

New York State has recently enacted some of the most comprehensive and aggressive goals for reductions in greenhouse gas emissions and expansion of renewable generation and other low-emitting generation technologies anywhere in the country through the New York State Climate Leadership and Community Protection Act ("CLCPA").[1] CLCPA will lead to the addition of substantial new state-supported renewable capacity to the New York Independent System Operator's ("NYISO") Installed Capacity ("ICAP") market, which already currently exhibits an excess of supply and little or no growth in demand. This expansion of clean generation is complicated by the fact that there are a number of proceedings currently before the Federal Energy Regulatory Commission ("FERC") that challenge whether such state-supported supply can continue to be largely exempt from Buyer-Side Mitigation ("BSM") in the NYISO ICAP market and elsewhere.[2] Most pertinently, FERC has ruled that current BSM practices in PJM Interconnection ("PJM") are no longer just and reasonable due to the impact of state-supported capacity.[3] PJM has responded to FERC's ruling with a proposal that would expand PJM's Minimum Offer Price Rule ("MOPR," PJM's analogue to BSM in NYISO) to cover all types of resources, including existing resources, and eliminate many of the exemptions currently offered to state-supported resources that allow them to avoid MOPR treatment (while also allowing state-sponsored resources to exit the centralized capacity market via a Resource-Specific Fixed Resource Requirement option).[4] While FERC has not yet issued a final decision in the PJM proceeding, FERC's actions to date in that region are consistent with its actions in New England, where FERC has stated its intent "to use the MOPR to address the impacts of state policies on the wholesale capacity markets."[5] These developments, along with the significant expansion of state-supported resources under the CLCPA, raise the question of the

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[1] Senate Bill S. 6599 and Assembly Bill A. 8429, 2019-20 Session.

[2] *See*, generally, *Independent Power Producers of New York v. New York Independent System Operator*, FERC Docket No. EL13-62-000 (ongoing proceeding challenging participation of state-supported resources in the NYISO capacity market) and *Calpine Corp. et. al. v. PJM Interconnection LLC,* FERC Dockets EL16-49-000, ER18-1314-000, and EL18-178-000 (consolidated) (ongoing proceeding requiring PJM to adopt changes to its capacity market to mitigate and accommodate state supported resources).

[3] *Calpine Corp. et. al. v. PJM Interconnection LLC,* 163 FERC ¶ 61,236 (2018).

[4] *Calpine Corp. et. al. v. PJM Interconnection LLC,* FERC Dockets EL16-49-000, ER18-1314-000, and EL18-178-000 (consolidated), "Initial Submission of PJM Interconnection, L.L.C.," (filed Oct 2, 2018) ("PJM MOPR Comments").

[5] *ISO New England Inc.,* 162 FERC ¶ 61,205 at P 22 (2018).

impact on markets, consumers, and New York's clean energy goals if FERC were to impose an expansion of BSM in NYISO that caused all new and existing clean generation to be subject to mitigation.

In parallel with these developments, NYISO has over the past two years been developing a proposal to add to its wholesale market a carbon charge set by the state at the Social Cost of Carbon.[6] As has been documented in several studies,[7] such a carbon charge would internalize the cost of carbon emissions into market prices in the NYISO energy market, and would thus increase the revenue received by zero and low-carbon generation resources, which in turn would make such resources more competitive on a purely market basis and thus decrease or possibly eliminate their need for state support. By bringing state-supported resources "in-market," a carbon charge could thus eliminate or greatly reduce the potential impact of a potential FERC-imposed expansion of BSM by causing resources that would otherwise be subject to BSM to no longer be subject to mitigation, and/or by reducing the mitigated offer floor to which affected resource offers are re-set via the operation of BSM.

This paper seeks to answer two linked questions related to the intersection of New York's clean generation goals with a potentially expanded BSM and a NYISO-administered carbon price. First, if FERC were to impose an expansion of BSM, what would the impact be on markets and consumer costs? And second, how would the impacts of FERC-imposed mitigation change if NYISO were to proceed with implementing its proposed carbon price?

It is important to note that this paper offers neither a prediction of whether FERC will act to impose expanded BSM in the NYISO ICAP market, nor a prediction of the specifics of how such expanded mitigation would be implemented if it were imposed by FERC. While we have assumed a particular representative set of expanded BSM rules to proceed with this analysis, these assumptions are not predictions and there are a range of approaches that could be taken in implementing a set of expanded BSM rules, all of which would have somewhat different ultimate impacts. Rather, this analysis is meant to provide policymakers and stakeholders an illustrative quantification of the potential impact of hypothetical FERC-imposed expanded BSM with and without a NYISO-administered carbon price to assist in future decision-making around both future ICAP market structures and whether to proceed with NYISO's carbon price proposal.

Current NYISO BSM Rules and Potential Changes to Expand Them

NYISO currently applies BSM to a specified set of new resources that do not otherwise qualify for an economic or a competitive entry exemption by showing that they are being built by an entity with no incentive or capability to

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[6] New York ISO, "Carbon Pricing Draft Recommendations," Aug 2, 2018 available at https://www.nyiso.com/documents/20142/2179214/Carbon%20Pricing%20Draft%20Recommendations%2020180802.pdf/575a6d2b-ad09-d8f8-e566-39a0c04f9a43.

[7] See Sam Newell et. al., The Brattle Group, "Analysis of a New York Carbon Charge (Updated," presented to the New York Integrating Public Policy Task Force, Dec 21, 2018 ("Brattle Report"), available at https://www.nyiso.com/documents/20142/2244202/Brattle-Study-Analysis-of-a-New-York-Carbon-Charge.pdf/0930b5ec-aa1b-b837-4cd8-cd8f8768d57d, Pallas LeeVanSchaick, Potomac Economics, "MMU Evaluation of Impacts of Carbon Pricing," presentation to the NYISO Market Issues/ICAP Working Group, May 9, 2019, available at https://www.nyiso.com/documents/20142/6474763/MMU+Study+re+Carbon+Pricing__5092019.pdf/40b832a6-b1f7-f973-9f60-4aaf4e9ab22f?version=1.0&t=1557161407651&download=true, and Susan F. Tierney and Paul J. Hibbard, Analysis Group, "Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets," Oct 3, 2019 ("Analysis Group Report"), available at https://www.nyiso.com/documents/20142/2244202/Analysis-Group-NYISO-Carbon-Pricing-Report.pdf/81ba0cb4-fb8e-ec86-9590-cd8894815231?t=1570098686835.

exercise buyer market power.[8] NYISO's current BSM rules either explicitly or effectively exempt from BSM most, but not necessarily all, of the clean resources covered by the CLCPA and similar clean energy programs, despite these resources generally receiving state-mandated support payments that would otherwise cause them to be subject to BSM. First, BSM is currently only applicable to new resources, so existing state-supported renewables and existing nuclear resources receiving Zero Emission Credits ("ZECs") are not covered. Second, the current rules only apply to "Mitigated Capacity Zones" which currently is defined solely as New York City (Zone J) and the Lower Hudson Valley (Zones G-J). Resources located in regions upstate from Zones G-J, as well as Long Island (Zone K) are not currently subject to BSM. Finally, in determining the mitigated offer floor price at which resources subject to BSM must offer, current rules allow for the value of state-supported attribute payments (such as RECs) that are procured through a competitive process, such as NYSERDA's annual long-term renewable procurements, to be netted against the resources' going-forward costs in determining the mitigated floor price. This rule in practice would likely cause most upstate renewables procured through NYSERDA auctions to be assigned a mitigated floor price close to zero even if the rules were otherwise expanded to cover them, effectively exempting them.

Under current rules, all existing state-supported resources, such as existing renewables and upstate nuclear resources receiving ZECs, would not be covered by BSM, nor would most future new onshore, grid-scale renewables procured through NYSERDA's ongoing long-term renewable procurements. The only resources subject to mitigation under current rules are likely to be new offshore wind, storage, and potentially other high-cost grid-scale renewables located in Zones G through J. While this is a limited subset of resources, as is discussed in following sections, it is still likely to be a material amount of capacity given the CLCPA mandates, and thus even NYISO's current relatively limited BSM rules likely will have a material impact going forward, just much less of an impact than they would if the rules were expanded. Importantly though, there are proposals before FERC from NYISO to add an exemption for renewables and from the NYPSC and NYSERDA to add an exemption for storage, which would effectively exempt both downstate offshore wind and storage and effectively avoid all BSM for clean energy resources RTO-wide.[9]

Potential changes to the current BSM rules could take a variety of forms. One illustrative scenario would involve a series of related rule changes that would effectively expand BSM to all clean energy resources in New York that receive state-supported attribute or other contractual payments. The rule changes that would accomplish this include:

- Expansion of BSM to cover all regions of NYISO, not just Zones G-J
- Expansion of BSM to cover existing resources, as well as new resources
- Removal of consideration of revenue streams other than energy and ancillary services revenues when determining both whether a resource is subject to BSM and the resource's mitigated offer floor price.

It is notable that these illustrative rule changes are consistent with the MOPR changes proposed by FERC for PJM in the proceeding that is currently pending.

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[8] *See* New York ISO Market Services Tariff Attachment H, Section 23.4.5 for current BSM rules.

[9] *See New York Independent System Operator, Inc.*, FERC Docket No. ER16-1404-000, "Compliance Filing and Request for Commission Action Within Sixty Days" (filed Apr 13, 2016) (NYISO requesting a renewable exemption of 1000 MW of ICAP per year) and *New York Independent System Operator, Inc.*, FERC Docket No. ER16-1404-000, "Compliance Filing and Request for Commission Action Within Sixty Days" (filed Apr 13, 2016) (NYISO requesting a renewable exemption of 1000 MW of ICAP per year) and *New York Public Service Commission v. FERC*, FERC Docket No. EL19-86-000, "Complaint on Behalf of the New York State Public Service Commission and the New York State Energy Research and Development Authority and Request for Fast Track Processing" (July 29. 2019) (NYPSC and NYSERDA requesting a storage exemption).

Impact of BSM in NYISO, both currently and under an illustrative expansion scenario

The renewable and zero-carbon goals enacted in the CLCPA, in conjunction with prior NYPSC rulemakings, result in a significant share of capacity in the NYISO market being potentially subject to expanded BSM if it were imposed by FERC. Under current BSM rules, with mitigation restricted to Zones G-J, minimal capacity is subject to mitigation. Over the coming years some storage and offshore wind will enter Zones G-J, likely amounting to around 0.9 GW of potentially mitigated capacity by 2025 in Unforced Capacity terms.[10] As Figure 1 below shows, if an expansion of BSM along the lines discussed above were imposed in 2021, the capacity immediately potentially subject to mitigation would be comprised of upstate nuclear capacity and new upstate onshore grid-scale wind and solar procured by NYSERDA.[11] This capacity could total as much as 3.8 GW of Unforced Capacity, or close to 10% of the market, in 2021 but would likely only be subject to expanded BSM if a carbon price were not implemented by NYISO.[12] Over 2022 through 2025, the amount of potentially-mitigated clean energy resources will expand as New York fulfills the goals of the CLCPA, and, importantly, resources such as offshore wind and storage which would likely be affected by expanded BSM even with a NYISO-administered carbon price enter the mix over these years.[13] The result of this ongoing entry of new clean capacity is that by 2025, as much as 7.8 GW of Unforced Capacity, or 20% of the market, would potentially be subject to BSM, with as much as 2 GW of that comprised of offshore wind and storage.

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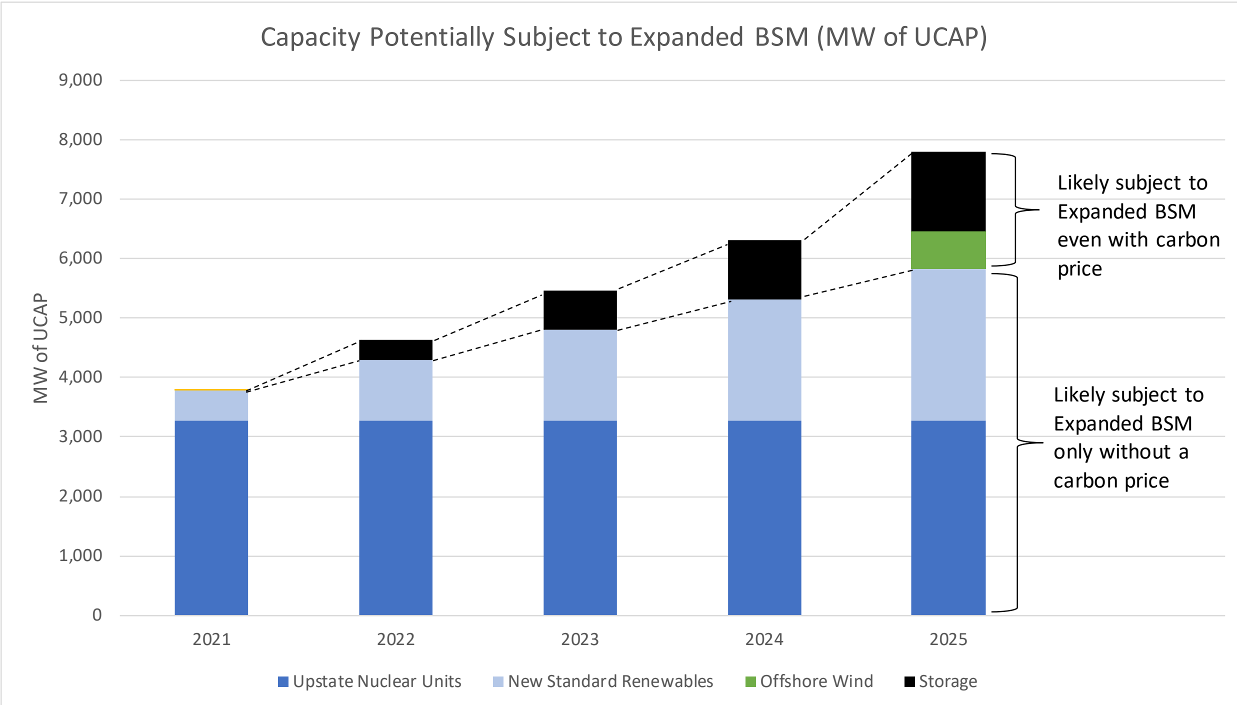
[10] This includes the Empire offshore wind project (310 MW of UCAP at a 38% UCAP crediting rate) connected into Zone J as well as an assumed 586 MW of storage resources located in Zones G-J by 2025, based on the CLCPA's 2030 storage goal.

[11] Existing upstate renewables procured by NYSERDA in past renewable auctions may also technically be subject to mitigation under an expansion of BSM, but would typically receive a mitigated offer floor of zero because once the construction capital costs for renewables are sunk and no longer part of going-forward costs they are typically economic due to their low ongoing operating costs. In other words, while these existing upstate renewable resources may be subjected to the expanded mitigation, such mitigation will likely have little impact. Thus, existing renewables (as of 2020) are not included as potentially mitigated resources for the purposes of this analysis, even if they may be technically subject to mitigation under expanded BSM. Upstate renewables entering the market from 2021 onward are assumed to be subject to mitigation under an expansion of BSM at mitigated offer floor prices that include construction capital costs and are thus well in excess of zero.

[12] With respect to onshore, grid-scale renewables, the most recent NYSERDA Large-Scale Renewable Auction produced an average REC price of $18.52 per MWh while The Brattle Group has estimated that a carbon charge set at the level in the NYISO proposal would produce an increase in energy revenues for new renewable resources of approximately $18 to 20 per MWh, indicating that a carbon price is likely to drive the mitigated offer floor price for upstate conventional renewables to zero (Brattle Report at 30). Using the methodology proposed by PJM for determination of mitigated offer prices for nuclear units (see PJM MOPR Comments at 46), a carbon price would similarly likely drive the mitigated offer floor price for the upstate nuclear units to zero.

[13] For example, the recent offshore wind solicitation resulted in two projects being selected with a weighted average all-in price of $83.36 per MWh in 2018$, or roughly $95 per MWh in nominal terms in 2025, the first full year in which the projects are online (New York State Energy Research and Development Authority, "Launching New York's Offshore Wind Industry: Phase 1 Report," October 2019, at 22). All-in energy and capacity prices for Zones J and Zones K have averaged $45 and $43 respectively over the past three trailing years suggesting that if recent past prices are a reasonable predictor of near-term future 2025 the two projects will require approximately $50 per MWh in state support payments, thus triggering buyer-side mitigation. If future prices are higher than past prices then the required state support will be less, but is unlikely to fall all the way to zero even with a carbon price, given the projected energy price impact of approximately $18 to 20 per MWh for a carbon price as proposed by NYISO (see footnote 9).

FIGURE 1

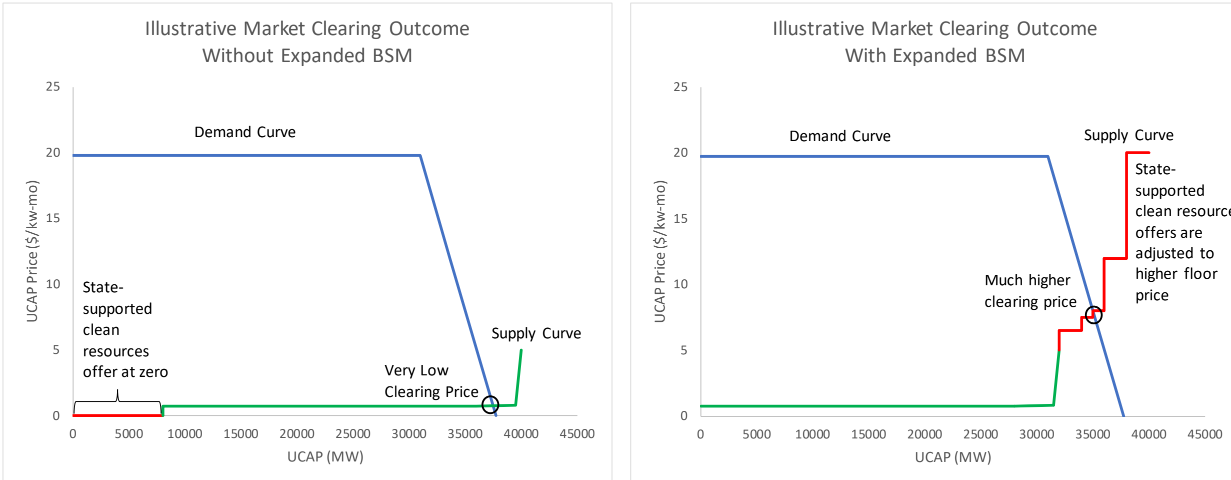


Absent any application of BSM, this expansion of capacity will likely result in ICAP market prices declining and approaching the minimum level needed to retain existing gas/oil resources as these state-supported resources will offer into the ICAP market at or near zero.[14] As discussed above, under current BSM rules the only capacity subject to BSM would be storage and renewables located within Zones G-J, with all upstate and Long Island resources exempt. The result is that under current rules, BSM will eventually have a moderate impact as the CLCPA goals ramp up but will have little impact in the near term.

If FERC were to impose an expansion of BSM as reflected in the illustrative scenario, capacity prices would increase greatly immediately upon implementation because upstate renewables and nuclear would be subject to mitigation. This expansion of BSM would significantly increase capacity clearing prices by replacing the actual capacity market offers of clean generation with mitigated floor prices or "competitive proxy" offers intended to approximate the level at which these resources would offer in the absence of any state support payment such as a REC or ZEC. Figure 2 below illustrates how the application of expanded BSM would increase capacity prices:

[14] For the purposes of this analysis we assume that ICAP clearing prices do not under any circumstances fall below an annualized value of $0.75 per kw-month. This level is the most recent summer and winter capability period auctions (2019/20) and is the lowest annualized capability period auction price experienced in NYISO to date.

FIGURE 2

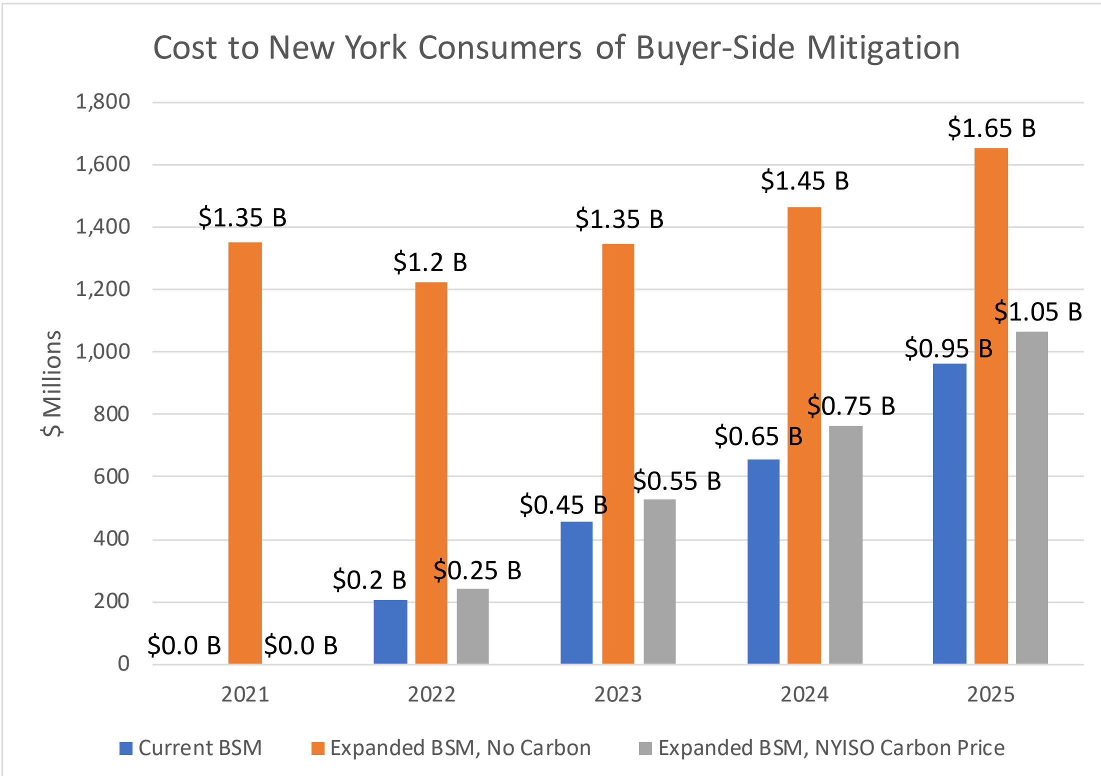


As Figure 2 illustrates, an expansion of BSM to cover all state-supported resources would create two significant inefficiencies, the costs of which would ultimately be borne by New York consumers. First, the ICAP clearing price would be significantly, and inappropriately, inflated. This is so because the state-supported clean resources affected by an expansion of BSM receive attribute payments (such as RECs and ZECs) that in part compensate them for their greenhouse gas emission displacement benefits, which are not currently valued in NYISO wholesale markets. The current zero- or near-zero offers from these resources thus reflect their emission abatement value in an analogous (if less efficient and precise) manner as internalizing the value through application of a carbon price in the wholesale market. Current NYISO BSM rules allow consideration of at least REC revenue in determining the offer floor price for mitigated resources but, as discussed above, we assume that a hypothetical expansion removes this consideration. Inflating the offers of these resources through application of BSM in the absence of a carbon price thus fails to recognize that their existing offers effectively already incorporate the value of their emission reduction attributes and results in an inappropriately and inefficiently elevated market clearing price. Second, as is apparent from Figure 2, expansion of BSM to state-supported clean resources will likely result in some or potentially all those resources failing to clear the ICAP market. Thus, in order for these resources to nonetheless enter or remain on the grid, as they must in order to achieve the goals set forth by the CLCPA, the state payments to these resources will likely need to be increased to offset the lost capacity revenue relative to the status quo, effectively resulting in consumers paying twice for this capacity – a inefficiency that is commonly referred to as the "double procurement" problem resulting from mitigation.

Without a carbon price in place in NYISO markets the cost to consumers of a hypothetical FERC-imposed expansion of BSM would be both immediate and significant. If expanded BSM were imposed in 2021, the cost to consumers of elevated capacity prices and increased state support payments to offset lost capacity revenues would be approximately $1.35 billion in the first year of implementation, an increase of over 60% compared to the cost of capacity under current BSM rules. This cost would rise over time as additional clean resources enter the market, reaching over $1.6 billion by 2025. By comparison, the cost to consumers of the existing BSM rules is much lower – likely zero in 2021 rising to about $0.95 billion in 2025 as storage and offshore wind resources enter the constrained downstate zones.

As discussed above, implementation of a carbon price as proposed by NYISO would greatly reduce the impact of FERC-imposed expanded BSM by internalizing the emission attribute value into energy revenues for many state-supported resources. In the case of upstate nuclear and upstate grid-scale renewables this would likely cause their mitigated offer prices to be reduced all the way to zero due to their relatively low costs, effectively causing mitigation of them to have no impact, while the mitigated offer floor prices for other higher-cost CLCPA-mandated resources such as offshore wind and storage would also fall, if not all the way to zero. If expanded BSM were imposed by FERC in the presence of a carbon price as proposed by NYISO, the costs of BSM would be similar to the present status quo -- zero in the first year of implementation and reaching just over $1 billion by 2025. Figure 3 below summarizes these costs over the 2021 to 2025 period.

FIGURE 3



Thus, while a carbon price does not over the longer-term fully avoid potential costs associated with BSM, it avoids the immediate large increase in customer costs that would occur if expanded BSM were imposed without a carbon price, and thus provides time for stakeholders to consider additional measures to respond to the challenges BSM poses for the implementation of the CLCPA goals. Further, over the long-run, and even potentially by 2025, the cost of mitigation to consumers with a carbon price in place may approach zero if costs for storage and offshore wind drop to the point where they are economic with a carbon price at the Social Cost of Carbon, which would drive their mitigated offer prices to zero and cause mitigation of them to have no material effect. Thus, a carbon price likely provides benefits from the perspective of limiting BSM-related costs even if FERC does not impose an expansion of BSM on NYISO.

Appendix: Analytic Approach and Detailed Results

As a baseline for comparison to both current BSM rules and a hypothetical FERC-imposed expanded BSM scenario, we developed a fundamental projection of the NYISO ICAP market from 2021 to 2025 without any BSM provisions. Key assumptions for this projection include:

- Current ICAP market rules remain in place, with the exception that BSM is not applied to any resources
- Market-wide demand based on the peak load forecast presented in the NYISO 2019 Gold Book,[15] with demand for constrained zones based on the peak load ratios utilized for developing the ICAP demand curves for the most current ICAP capability periods
- Demand curve parameters based on the most recent winter and summer capability periods, scaled for projected load and adjusted for inflation at 2% per annum[16]
- Existing capacity based on cleared capacity totals for the most recent winter/summer capability periods. Going forward we assume the following specific permanent retirements for existing resources:
    - Indian Point 2 in 2020 and Indian Point 3 in 2021
    - Cayuga 1 in 2019
    - Somerset in 2021
- Cricket Valley gas combined-cycle plant is assumed to enter in 2020. No additional non-renewable, non-storage resources are assumed to enter over the 2021-25 period
- Clean resources are assumed to enter the market as follows:
    - Resources procured through the NYSERDA 2017 and 2018 large-scale renewable solicitations are assumed to enter in 2020 and 2021 respectively[17]
    - Annual NYSERDA solicitations of conventional renewables with the same quantity and mix of procured resources as the 2018 solicitation are assumed to continue annually for the remainder of the period with the resources entering the market three years following the solicitation
    - Storage resources mandated by the CLCPA are assumed to enter the market at a rate of 300 MW per year RTO-wide starting in 2022. Storage resources are distributed by zone based on peak load
    - Offshore wind resource procured through the recent NYSERDA solicitation (Empire and Sunrise) are assumed to enter in 2025. No other offshore wind resources are assumed to enter over the 2021 to 2025 period
    - Distributed solar resources mandated by the CLCPA are not represented because they are behind the meter and not likely to directly participate in the ICAP market
- Clean energy resources are assigned default UCAP values as per the NYISO ICAP manuals (30% winter / 10% summer for onshore wind, 2% winter / 46% summer for utility-scale solar, 38% winter and summer for offshore wind)[18]

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[15] New York ISO, "2019 Load and Capacity Data (Gold Book)," April 2019.

[16] New York ISO, "Demand Curve 2019-20," available at https://www.nyiso.com/documents/20142/2953344/Demand-Curve-2019-2020.pdf/fbe06a61-0578-d056-5c78-dfab5b9ae74b.

[17] New York State Energy Research and Development Authority summaries of 2017 and 2018 Large-Scale Renewables Solicitation Results, available at https://www.nyserda.ny.gov/-/media/Files/Programs/LSR/RES-Solicitation-Fact-Sheet.pdf (2018) and https://www.nyserda.ny.gov/-/media/Files/Programs/Clean-Energy-Standard/2017-RES-RFP-Results-Factsheet.pdf (2017).

[18] New York ISO, Manual 4: Installed Capacity Manual (Ver 6.44), Effective Date 9/26/2019, pp. 52-54.

- All state-supported resources are assumed to offer into the ICAP market at zero, while existing gas/oil resources are assumed to offer at an annualized level of $0.75 per kw-year, based the most recent capability period auction (2019/20) results

This baseline fundamental price projection produces the following projected zonal ICAP annual average market clearing prices for 2021 to 2025.

($/kw-mo)	2021	2022	2023	2024	2025
G-J Locality	$9.33	$7.81	$5.42	$3.72	$1.46
Zone K	$2.99	$2.40	$1.46	$0.75	$0.75
Rest of State	$1.55	$0.75	$0.75	$0.75	$0.75

This baseline is then first compared to a scenario representing the current status quo BSM rules:

- BSM applied to state-supported new renewables in zones G-J
- BSM not applied to state-supported resources elsewhere in the RTO
- BSM not applied to any existing resources
- Clean resources that do not clear the market due to application of BSM nonetheless enter in the market and are compensated by the state for lost capacity revenues relative to the no-BSM baseline scenario
- BSM rules follow current tariff and manuals
- State support payments to offshore wind and storage are not incorporated into the determination of mitigated floor prices for these resources
- All other assumptions identical to the baseline "no BSM" scenario.

This "status quo BSM" scenario produces the following projected zonal ICAP annual average market clearing prices, and uncleared state supported clean capacity for 2021 to 2025:

($/kw-mo)	2021	2022	2023	2024	2025
G-J Locality	$9.33	$8.96	$7.97	$7.48	$6.87
Zone K	$2.99	$2.40	$1.46	$0.75	$0.75
Rest of State	$1.55	$0.75	$0.75	$0.75	$0.75
Uncleared Clean Capacity (UCAP MW)	0	147	294	440	897

Next the baseline scenario is compared to a hypothetical FERC-imposed expansion of BSM without a carbon price. Key assumptions for this hypothetical "Expanded BSM, no Carbon" scenario include:

- BSM is applied to the entire RTO, rather than just Mitigated Capacity Zones (G-J)
- Existing resources receiving state-mandated attribute payments are subject to BSM. While this in theory covers all NYSERDA-contracted existing renewables and upstate nuclear receiving RECs/ZECs, because the going-forward costs for existing renewables are typically very low this provision would only in practice affect the upstate nuclear fleet
- For the purposes of calculating their mitigated offer floor prices, upstate nuclear units utilize going-forward costs consistent with the default values for existing nuclear proposed by PJM in their FERC

proceeding ($631 and $593 per Megawatt-Day for single and dual unit plants respectively), escalated for inflation at 2% per year

- All revenues other than energy and ancillary services revenues are not incorporated into the determination of mitigated resource floor prices
- Clean resources that do not clear the market due to application BSM nonetheless enter or remain in the market and are compensated by the state for lost capacity revenues relative to the baseline scenario
- BSM rules otherwise follow current tariff and manuals
- All other assumptions identical to the baseline "no BSM" scenario

The "Expanded BSM, No Carbon" scenario produces the following projected zonal ICAP annual average market clearing prices, and uncleared state supported clean capacity for 2021 to 2025:

($/kw-mo)	2021	2022	2023	2024	2025
G-J Locality	$9.71	$8.96	$7.97	$7.48	$6.87
Zone K	$6.98	$5.09	$4.31	$3.75	$3.25
Rest of State	$6.98	$5.09	$4.31	$3.75	$3.25
Uncleared Clean Capacity (MW)	2,364	1,979	2,785	3,539	4,989

Finally, we compare the baseline to a second hypothetical FERC-imposed expansion of BSM, but this time with a carbon price implemented as proposed by NYISO. This "Expanded BSM, NYISO Carbon" scenario utilizes the same assumptions with regards to the implementation of the BSM expansion except as follows:

- While NYSERDA-procured onshore grid-scale renewables would still be technically subject to BSM, the implementation of a carbon price would be sufficient to drive the mitigated floor price for these resources to zero, based on the observation that recent NYSERDA renewable procurements have yielded REC prices at approximately the same level as the projected impact of NYISO's proposed carbon price on energy prices
- Similarly, based on the projected impact of the carbon price on energy prices we assume that the mitigated floor price for the upstate nuclear units will be driven to zero
- However, we assume that offshore wind resources and storage resources will continue to be subject to BSM at floor prices sufficiently high to preclude those resources from clearing.

The "Expanded BSM, NYISO Carbon" scenario produces the following projected zonal ICAP market annual average clearing prices, and uncleared state-supported clean capacity for 2021 to 2025:

($/kw-mo)	2021	2022	2023	2024	2025
G-J Locality	$9.33	$8.96	$7.97	$7.48	$6.87
Zone K	$2.99	$2.89	$2.45	$2.22	$2.06
Rest of State	$1.55	$0.75	$0.75	$0.75	$0.75
Uncleared Clean Capacity (MW)	0	300	600	900	1,963

When compared to the baseline “No BSM” scenario, the three BSM scenarios produce the following incremental impact on consumer costs:

($ Millions)	2021	2022	2023	2024	2025
Current BSM Rules, No Carbon					
Higher Capacity Prices	$0	$190	$435	$647	$949
Double Procurement	$0	$14	$19	$20	$16
Total	$0	$204	$454	$667	$965
% Total Capacity Cost Increase vs. No BSM	0%	12%	37%	74%	206%
Expanded BSM, No Carbon					
Higher Capacity Prices	$1,306	$1,1192	$1,304	$1,425	$1,599
Double Procurement	$44	$31	$42	$48	$52
Total	$1,351	$1,224	$1,346	$1,472	$1,651
% Total Cost Increase vs. No BSM	62%	71%	109%	164%	352%
Expanded BSM, NYISO Carbon					
Higher Capacity Prices	$0	$224	$504	$749	$1,041
Double Procurement	$0	$16	$23	$24	$25
Total	$0	$240	$526	$773	$1,066
% Total Cost Increase vs. No BSM	0%	14%	43%	86%	227%