New York Battery and Energy Storage Technology Consortium, Inc.

VIA ELECTRONIC FILING

April 12, 2021

Hon. Michelle L. Phillips
Secretary
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: CASE 15-E-0751 – REPLY COMMENTS - In the Matter of the Value of Distributed Energy Resources – Comments on ACOS Methodology to Develop Standby and Buyback Rates

Dear Secretary Phillips:

The New York Battery and Energy Storage Technology Consortium ("NY-BEST") submits these reply comments in relation to the *Staff Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates* jointly developed by the NYS Department of Public Service (DPS) and the New York State Energy Research and Development Authority (NYSERDA) that was filed on November 25, 2020, and comments filed in the proceeding on March 8, 2021.

We appreciate the opportunity to share these comments. We can be reached at info@ny-best.org or by phone at 518-694-8474. Thank you.

Sincerely,

Dr. William Acker
Executive Director

NY-BEST Reply Comments

CASE 15-E-0751

In the Matter of the Value of Distributed Energy Resources – Comments on ACOS Methodology to Develop Standby and Buyback Rates

I. Introduction

Over the last two years, the Public Service Commission (Commission) has amassed a substantial case record in this proceeding to give it enough evidence to proceed with reform of Standby and Buyback rate design in New York. The Department of Public Service (DPS) Staff's consultant has proposed a framework Decision Tree methodology that provides a transparent, uniform, and cost-based approach to the cost allocations used to design standby rates. Just as importantly, the Decision Tree is relatively straightforward and can be adopted into practice. While NY-BEST outlined a handful of limited but necessary modifications to the methodology in our comments filed on March 8, 2021, the methodology largely accomplishes the objectives that this proceeding set out to achieve.[1] Therefore, the crux of the methodology should be left intact. NY-BEST is grateful to DPS Staff for the time and effort that they have put into reaching this point.

In the following reply comments, NY-BEST respectfully requests that the Commission:

- Promote Uniformity and Simplicity
    - The Commission should reject proposals from the Joint Utilities (JU) that add unnecessary complexity and jeopardize the ability to implement the Decision Tree in a practical manner. Instead, the Commission should largely adopt the approach outlined in the Staff Whitepaper from November 25, 2020 to arrive at Standby and Buyback rates that are consistent and uniform, cost-based, and fairly allocated.
- Accept the Coincident Peak/Non-Coincident Peak allocator as proposed in the DPS Staff Whitepaper.
- Ensure Compliant ACOS submissions from the downstate utilities.
    - While the Commission may decide to accept ACOS submissions that deviate somewhat from the level of granularity proposed in the Decision Tree

[1] In the comment letter submitted 3/8/2021, NY-BEST recommended the following modifications to the Question #s indicated below
3) Replace the word "Could" with "Would" and strike "small group of customers" from the guidance regarding how to answer the question. During the Technical Session, Guidehouse was clear that "small group of customers" would not apply to C&I. If the Commission decides to apply it to residential (NY-BEST agrees with AEE that it should not), they should provide clear guardrails for when "small group of customers" is a suitable criterion for analysis.
4) Add the phrase "or regional peak" to recognize that infrastructure higher in the system such as substations should still be classified as shared even if its peak loading hours diverge from the coincident peak of the system as a whole.
2.5 – Proposed) New Question Between #2 and #3, "Does a power injection have the potential to reduce the cost of the asset?" If "Yes" then Shared, otherwise proceed to Question 3.

whitepapers, submissions, at a minimum, must include the ability to answer Question 6. To promote uniformity, the Commission should issue guidance regarding the logic to answer each question and retain the authority to order revisions to compliance filings if they deviate significantly from Commission guidance.

- Reject JU arguments that Buyback rates are an accurate price signal as currently implemented.
    - Buyback rates are not a cost-based price signal and are unique to New York State.
    - The high level of Standby and Buyback charges challenges the economics of Energy Storage Resources (ESRs) putting them over the threshold that would subject them to BSM rules.
- Adopt an exemption from Buyback Demand charges for stand- alone storage assets interconnected prior to December 31, 2030, five years longer than what is proposed by DPS staff, to support the pathway to the State's energy storage goal of 3 GW by 2030 and to allow the storage market to mature.

In developing a final Order, the Commission must consider the broader policy context surrounding this proceeding, such as the State's aggressive energy storage and decarbonization goals, market animation for merchant energy storage, and the participation of energy storage in wholesale markets.

II. Promote Uniformity and Simplicity: The Commission Should Reject Proposals from the Joint Utilities that Add Unnecessary Complexity and Jeopardize the Ability to Implement the Decision Tree

The November 2020 Staff whitepaper correctly observes that "*there is a need for a standard, transparent, and repeatable methodology at a comparable level of granularity*" to perform the ACOS studies used to design Standby rates. (Whitepaper p. 9) Success in this process will be the achievement of a standard and uniform approach to ACOS studies at a sufficient level of granularity to implement the Decision Tree.

The Commission must reject the Joint Utilities (JU) proposal to apply the Decision Tree separately for the various customer classes and voltage levels. The JU note that this would require separate spreadsheets by voltage level or class. This approach would preclude uniformity as each utility has significant differences in terms of customer eligibility, primary voltage criteria, and size thresholds in their rate designs. The table below illustrates the significant diversity in commercial rate size and voltage thresholds throughout the NY utilities. Shaded areas indicate rate applicability by customer size (kW).

				Rate Size Breakpoints (kW)							
Utility	Rate	Voltage	Primary Definition	< 5	< 10	> 10	25	100	300	500	1,000
ConEd	SC 2										
	SC 8	LT									
	SC 8	HT	> 600 V								
	SC 9	LT									
	SC 9	HT	> 600 V								
CenHud	SC 2ND										
	SC 2	Sec									
	SC 2	Pri	> 600 V								
NYSEG	SC 2										
	SC 3	Pri	> 2,400 V								
	SC 7	Sec									
	SC 7	Pri	> 2,400 V								
RGE	SC 2										
	SC 3	Either	> 600								
	SC 7										
	SC 8	Either	> 600								
O&R	SC 2ND										
	SC 2 D	Sec									
	SC 2 D	Pri	> 2400								
	SC 3	Pri	> 2400								
	SC 9	Pri	> 2400								
NIMO	SC 2 ND										
	SC 2 D										
	SC 3	Sec									
	SC 3	Pri	> 2200								

In addition to the great heterogeneity in commercial rates, this approach would introduce an overwhelming amount of complexity to the process. Instead of a single spreadsheet to implement the Decision Tree by asset type and voltage level as contemplated in the Whitepaper, utilities would produce dozens of spreadsheets supported by a labyrinth of workpapers.

Another complication to this approach would be that the Decision Tree questions could be answered differently for each rate class despite having the same voltage levels. As an example, Question 3 asks if an asset would become stranded due to a decrease in demand. It is conceivable that a utility may provide a speculative "Yes" response to Question 3 for substation assets for a large primary rate class and a "No" response for a medium primary rate class. In this hypothetical, a utility could make an unsupported assertion that an asset would become stranded due to a decrease in demand despite it being utilized by many other customers on other rate classes at the same voltage level. If the Decision Tree is to be implemented in a simple and uniform manner, it cannot be implemented as a "Choose your own adventure" on a rate class by rate class basis.

A bespoke application of the Decision Tree to each rate class (and voltage level iterations within rate classes) provides greater opportunity for utilities to interpret the Decision Tree in manner that skews the results to achieve their desired rate outcomes and conflicts with the proceeding objectives of uniformity, simplicity, and transparency. Lastly, designs in New York must be revenue neutral to the otherwise applicable rate class. The added complexity

that would result from applying the Decision Tree by rate class and voltage would also complicate the revenue neutral construction of the actual rates.

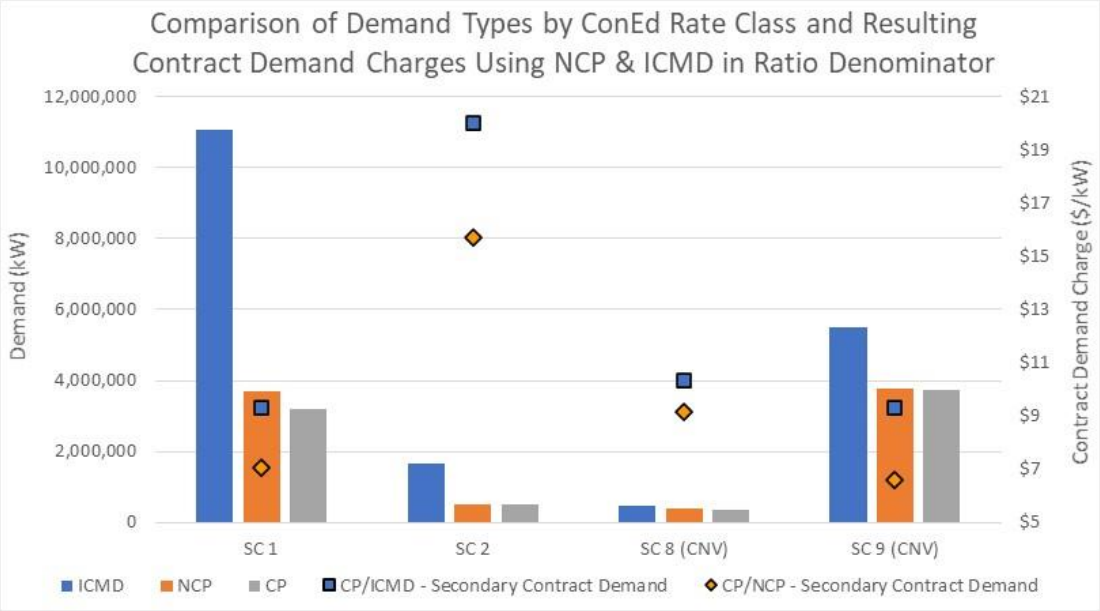
III. Accept the CP/NCP Allocator

The Decision Tree Whitepaper proposes to allocate costs by using a Coincident Peak/Non-Coincident Peak allocator (CP/NCP). The Commission should adopt the CP/NCP allocator because the construction of standby rates is a ratemaking exercise. Ratemaking must reflect cost causation and the primary cost causing activity in the lower voltage portions of the electric distribution system is NCP demand. At higher voltages where infrastructure is shared among more customer groups, CP demand emerges as the primary driver of costs. The Decision Tree method aims for simplicity through the use of this ratio to apportion costs between local and shared. This ratio is simple, transparent, and reflects the degree to which different customers utilize infrastructure at different levels of the system.

The JU propose the use of Individual Customer Maximum Demand (ICMD) as the denominator in the ratios as they claim that it is a more realistic indicator of load diversity. To the contrary, using ICMD makes the assumption that there is no load diversity and the distribution infrastructure is built to handle all customers consuming their maximum demands at the same time. While infrastructure immediately proximate to the customer must be sized to meet ICMD, the Decision Tree asset groupings are too broad to isolate facilities that are specifically installed to serve the maximum demand of a specific customer. The Decision Tree uses asset categories that match the FERC Form 1 groupings which are more expansive in scope than assets that can be clearly linked to specific customer maximum demand. As a result, NCP is the correct allocator as this is the primary cost causing activity at lower levels of the distribution system and the FERC Form 1 categories are broad categories used for ratemaking and regulatory accounting.

While the JU allege that "*NY BEST would advance its interests by reducing the allocation of costs to Local to the bare minimum*" (JU Comment Letter pp. 11-12), the same could be said for the JU in advocating for the use of ICMD as the denominator in the allocator. The use of ICMD has the sole effect of increasing the local allocation of costs and the Commission should view the JU argument on ICMD for what it is; an extreme position aimed at maximizing the revenue obtained through contract demand charges. The graphic below illustrates the wide disparity in ICMD and NCP by rate class for ConEdison, as well as the resulting impacts of Contract Demands.[2]

[2] ConEd workpapers, submitted 3/9/2021



It is important that the Commission remain mindful of the potential for residential customers and Secondary voltage customers to be placed on Standby rates due to adoption of energy storage or opt into standby rates. The choice of allocator has stark impacts on the ultimate rate design and the use of CP and NCP comports with existing rate making practice.

Rate classes with higher levels of utilization are more likely to deliver the expected revenue requirements from As-used demand charges based on their higher load factors. Revenue neutrality is a core principle of Standby rate design in New York and the CP/NCP allocator reflects this by apportioning the revenue requirement by asset and rate class based on the degree to which assets are utilized.

The Commission must also reject the proposed use of the Average On-peak demand to Contract Demand. There is scant evidence in the record to support the use of this allocator, no known precedents in New York for its use as an allocator in tariff construction, or evidence that Contract Demand values on file at each utility reflect present grid conditions.

While the JU would clearly prefer the predictability of contract demand charges, As-used demand charges are a more granular price signal that allow batteries to make daily decisions regarding their operations. As-used demand charges may actually deliver greater revenues to the JU if energy storage deployments proliferate once the barrier of inefficient standby rate designs are rectified.

IV. Ensure Compliant ACOS Studies from the Downstate Utilities

To increase transparency and to maintain proper oversight, the Commission should:

1. **Direct the utilities to include a rationale for their answers to the Decision Tree questions by voltage class**. This will ensure that the Commission, and stakeholders,

fully understand how and why the utilities are implementing the Decision Tree. Already, the JU have proposed to allocate certain costs in a surprising manner.

2. **Retain the right to order utilities to revise their compliance filings subsequent to a Commission Order in this proceeding if their logic significantly diverges from the Decision Tree and from other utilities.** While it is likely that some utilities may answer some of the Decision Tree questions differently, a uniform approach requires a consistent set of logic to answer the questions.

   The JU logic regarding the answer to Question 5 at the primary demand level illustrates a tradeoff in the granularity of ECOS data and the ability to answer Decision Tree questions[3]. There may be an argument that an increase in NCP demand at the primary voltage level could increase the costs for conductors, but this question cannot be answered definitively for the utilities that comingle multiple asset types into the same category. When this is the case, a "Yes" answer to Question 5 at the primary voltage level would result in assets such as conduits and poles receiving a local allocation as well, due to being comingled with conductors. This challenge illustrates the need for Commission guidance regarding answers to questions and to provide guardrails around how questions should be answered when there is extensive comingling of different asset types in the same category.

3. **Ensure that utilities continue to apply the Commission's long-standing definition of "local"[4] and "shared" as they implement the Decision Tree.** For instance, the following footnote in the JU comments states "*An exception would be classes of customers that take service directly at the substation or transmission levels. For such classes it would be reasonable for a portion of transmission costs to be considered local.*" (JU p. 7) In the overwhelming majority of circumstances, transmission facilities are shared amongst a multitude of customers and, therefore, it would be inappropriate to allocate any transmission costs as local. The Commission should establish guardrails on question responses to ensure that hypothetical edge cases do not drive the logic behind question responses.

4. **Direct the utilities to provide granularity of cost data by asset type.** ConEdison, O&R, and Central Hudson state they are unable to produce detailed ECOS data at the level of granularity envisioned in the Decision Tree. The Joint Utilities assertion that "*requiring the utilities that use the revenue requirement approach to alter their underlying ECOS studies to the FERC accounts approach would be a major undertaking only to achieve the same results*" (JU p. 4) is speculative based on the materials in the record. Each of these utilities have produced a result, but they have not demonstrated that the results are the same as if they had faithfully followed the Decision Tree

[3] JU Comments, p. 7

[4] (Dec 2018 Whitepaper p. 3, May 2019 Order pp. 5, 28)

Methodology using the FERC Form 1 categories. They have not done this and the only way to demonstrate that this assertion is true would be to perform a side-by-side comparison of methods. The ECOS groupings by functional revenue requirement preclude the ability to answer Question 6 in the Decision Tree either at all or with sufficient granularity. Question 6 is a core feature of the Decision Tree and is discussed in greater detail in the Buyback rates section of our comments. While the Commission may ultimately accept ECOS data groupings that diverge from those proposed in the Decision Tree and it is possible that alternate groupings may provide similar results, they will not be exactly the same as if the Decision Tree method was followed as intended and the Commission must consider how much accuracy it is willing to sacrifice in rate design to accommodate ConEdison, O&R, and Central Hudson's ECOS groupings by functional revenue requirements.

IV. Reject the argument that current Buyback Demand rate designs are an accurate price signal and recognize their impact on energy storage in the NYISO capacity market

Buyback Rates are not currently a Cost-Based Price Signal

The JU introduce a hypothetical circumstance where there is a battery and intermittent renewables on the same circuit where the battery seeks to "*maximize wholesale revenues by discharging at high levels*" during periods of low load on the circuit resulting in curtailment of other renewables and necessitating further infrastructure investment. They then state that "*the Buyback Contract Demand Charge provides both an appropriate price signal to size maximum injections and help the electric distribution utility anticipate power flows."* (p. 17)

The Buyback demand charge, as currently constructed, is not an appropriate price signal but, instead, serves as a crude barrier to prevent storage assets from exporting more than their standby demand. Cost causative storage exports are identified in the interconnection study and are either precluded as a condition of interconnection or remedied through circuit upgrades paid for by the interconnection applicant. Buyback demand charges should be recognized for what they are: non-seasonal and non-time differentiated demand charges applied to exports based on speculative assumptions regarding cost causation. They also include financially devasting penalties for exceeding buyback demand limits: 12x the Buyback demand charge for overages < 10% of the Buyback demand limit; and 24x the Buyback demand charge for overages > 10% of the Buyback demand limit.[5]

The JU subsequently assert that "*In the case of stand-alone energy storage systems that are not utility-controlled, the Joint Utilities recommend continuing to apply Contract Demand Charges in buyback rates and if necessary, enhance utility and/or NYSERDA programs to the extent additional incentives are required."* In essence, the JU position is that the utilities can maintain unsupported Buyback charges that would otherwise thwart storage asset participation in NYISO markets and NYSERDA can provide increased incentives to pay for

[5] ConEd Tariff SC 11, Leaf 472

these Buyback charges to overcome this market barrier. While it appears that the JU are showing their preference for energy storage that is under utility control and dispatch, third party owned storage resources that are dispatched by the utilities pay Buyback charges too.[6] This fact seems to undercut the JU argument regarding utility control as some sort of arbiter as to whether Buyback charges should apply. Furthermore, the JU preference for energy storage assets under their control is in conflict with the development of a merchant energy storage sector and dual participation of energy storage in retail and NYISO market applications.

Construction of Buyback Rates using the Decision Tree requires the ability to answer Question 6

Future Buyback demand charges in New York will be determined based on the ability to answer Question 6 in the Decision Tree. Question 6 was added to the Decision Tree to provide a mechanism to remove costs that are unaffected by reverse power flows. The differentiation in Standby versus Buyback charges from Question 6 is critical to devising Buyback charges that only reflect costs for items that are clearly impacted by reverse power flows.

The table below provides an assessment as to whether the filings for each utility provide sufficient granularity to answer Question 6 for each asset type.

Utility	Sufficient Granularity to Answer Question 6	Notes
NYSEG	Yes	
RGE	Yes	
National Grid	Yes	
ConEd	No	Question 6 not answered, but could be if Poles, Towers, Fixtures (364) and UG Conduits (366) could be identified and removed
O&R	No	See ConEd Notes
Central Hudson	Yes	Based on Spreadsheet 2 from 3/8/2021 filing

The Commission should not accept any utility ACOS that does not answer Question 6 for the relevant asset types.[7]

[6] NY-BEST is not taking a position against utility dispatch of DERs in response to distribution system conditions, but design and implementation of such programs are beyond the Scope of this proceeding.

[7] NY-BEST is concerned that a "Yes" answer to Question 5 could result in an allocation of local costs to Buyback rates that should be excluded. NY-BEST urges the Commission to consider adding Question 6 again subsequent to

Impact of Standby/Buyback Charges on NYISO Buyer Side Mitigation Rules for Storage

The Commission must be mindful of the interactions between Standby and Buyback demand charges and the ability to participate in NYISO capacity markets. Under the Buyer-Side Mitigation (BSM) rules, Energy Storage Resources (ESRs) must be evaluated against the Cost of New Entry (CONE). A recent report from the Market Monitoring Unit of NYISO identified Standby and Buyback demand charges as a significant component of the cost structure for ESRs in their BSM evaluation in the most recent class year.[8] The high operating expenses of ESRs, due to standby and buyback rates, have the potential to cause them to fail BSM tests and preclude them from unmitigated participation in the capacity market. In this circumstance, the result is higher capacity prices for consumers. The NYISO BSM rules for DERs have been controversial, but Commission action to devise cost-based Standby and Buyback rate designs would ameliorate a barrier to ESRs in the BSM evaluations.[9]

The JU assert that "*The impact of Contract Demand Charges on broader clearing prices in the market, which include the effect of the capacity demand curve and the volume in the capacity market, is likely to be negligible.*" (JU p. 19). This assertion contradicts the findings of the NYISO MMU's recent report on the 2019 Capacity Class year. The NYISO market monitoring unit (MMU) presented at the March 29th 2021 NYISO ICAP working group meeting on the NYISO 2019 Class Year BSM evaluation. Only 3 projects (representing 37.5 MW) of 13 total energy storage projects representing 362.5 MW, passed mitigation to be able to participate in the market without offer floors. In their assessment of major factors affecting the BSM evaluation the MMU listed distribution utility demand charges first.[10] In constrained areas of the NYISO grid such as Zone J, 100 MW of capacity in either direction can have significant impact on the clearing prices in the auction and the resulting charges to consumers. For instance, consider a situation where a distribution-connected storage asset clears the NYISO market and is the price setting unit for the ICAP market in Zone J. All costs in its capacity offer that are attributable to non-cost-based Standby and Buyback charges are magnified through raising the capacity clearing price charged to all customers.

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the allocation step after Question 5 between shared and local to differentiate the local costs that go into Standby vs. Buyback charges.

[8] Potomac Economics, Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2019 Projects, February 2021, pp. 24, 27, 36-37 https://www.potomaceconomics.com/wp-content/uploads/2021/02/MMU-Report-re-CY19-BSM-Evaluation-020821.pdf

[9] S&P Global Market Intelligence "Split FERC directs NYISO to expand scope of buyer-side mitigation rules" https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/split-ferc-directs-nyiso-to-expand-scope-of-buyer-side-mitigation-rules-57193877

[10] "Highlights from the MMU Review of Class Year 2019 BSM Evaluation" NYISO ICAP WG March 29,2021 https://www.nyiso.com/documents/20142/20226859/MMU Presentation re CY19 BSM Evaluation.pdf/c95e35f1-5b54-9eb3-5310-0cb2957934d1

V. Adopt an exemption from Buyback demand charges for stand-alone storage for assets operational by December 2030

New York's ambitious energy storage and decarbonization goals require bold action to by all agencies of government to ensure that energy storage is developed quickly and efficiently. This entire proceeding has occurred because a plurality of market stakeholders acknowledged that existing Standby and Buyback rates had no basis in reality and needed to be reformed. The existing rate designs have restricted the growth in New York of a rapidly growing global industry that New York State's leadership has recognized is essential to its decarbonization and economic growth. An exemption from buyback charges for energy storage through 2030 will support the State's 3 GW by 2030 storage goal, as well as its efforts to grow the industry in New York State, by removing a major barrier to energy storage deployment. An exemption will also allow the Commission and industry stakeholders to develop an operating track record to determine if reformed Standby and Buyback rate designs emanating from this proceeding accurately capture cost causation and benefits from stand-alone storage assets. Furthermore, it will give projects in the development stage time to refine business models to accommodate the new Standby and Buyback rates that will emerge from a Commission Order. The JU propose that any exemption for stand-alone storage be limited to 5 years (JU p. 18), but the Commission must recognize that abrupt changes in cost structure while a facility is still servicing debt could pose a significant hurdle to obtaining financing.

The JU makes the assumption that 50% of the energy storage interconnection queue will be operational prior to 2025 in an effort to support its claims of foregone revenues resulting from this exemption (JU p. 14). This is an optimistic assumption in light of straoge deployment experience to date, especially given the complexities of permitting, financing, building, and interconnecting stand-alone storage. The JU claim a presumed cost shift of $7.2M/yr is based on current Standby and Buyback rates (which nearly all stakeholders have acknowledged are not cost-based) and presume that a stand-alone storage asset is connected at secondary voltage. There is simply no evidence to support the JU's highly speculative cost-shift claim. The ACOS studies were designed to study load, not the costs of injected power and cannot be relied upon to make cost-shift claims. The JU claim that the impacts of the time limited exemption from buyback rates for stand-alone storage will be material, while the impacts on the NYISO market from Standby/Buyback demand charges are negligible, when in fact the opposite is true.

Lastly, the JU cite the experience with solar as a cautionary corollary, but the energy storage industry must be viewed differently. Storage market participants have accepted that reasonable Standby rates will be applied to the charging power of stand-alone assets and have participated in this proceeding to help shape these rates. An exemption for storage from buyback charges through 2030 would support the State's mandated storage goals, as well as the core principles of REV as established by the Commission, and will allow the storage market to mature and grow in New York.

Conclusion

A core principle of the entire VDER proceeding has been to animate markets. The Commission must demonstrate its commitment to market animation by addressing the barriers to storage development posed by current Standby and Buyback rate designs. The Commission now has a robust Decision Tree methodology developed by Guidehouse, as well as an extensive case record to developed by participants in this proceeding to realize the long sought-after goal of devising cost based Standby and Buyback rates. In making its decision, the Commission must ensure that the goals of uniformity, simplicity, and transparency are realized. This will require each utility to provide logical and supported answers to Decision Tree questions by voltage level with sufficient granularity to answer Question 6. In addition, by providing energy storage an exemption from buyback charges through 2030, the Commission will remove a significant barrier to storage deployment and support the State's 's mandated energy storage deployment goals.

NY-BEST appreciates the Commission's consideration of these comments.