Honorable Kathleen H. Burgess, Secretary  
New York State Department of Public Service  
Three Empire State Plaza  
Albany, NY 12223-1350

October 9, 2018

Subject: Case 18-E-0018 – In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators

Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Burgess:

On June 19, 2018, the Joint Utilities\(^1\) (“JU”) filed a proposed model tariff\(^2\) for compensation of a hybrid energy storage system (“ESS”) and distributed generation system interconnected with the three-meter configuration approved in the New York Public Service Commission’s (“Commission”) April 19, 2018 Order.\(^3\) Our understanding based on email communications with the Department of Public Service Staff is that comments on the JU’s model tariff would be accepted on or before October 9, 2018.\(^4\) Although we largely agree with the structure proposed in the model tariff, we have significant concerns related to the proposed treatment of hybrid systems that are capable of grid charging.

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\(^4\) Email from Sandra Hart, Department of Public Service, to Peter S. Ross & Ilan Gutherz, Borrego Solar Systems, Inc. (Sept. 19, 2018).
I. The Uncertainty and Promise of Energy Storage Calls for Flexible Policymaking.

Energy storage is a unique and versatile grid resource that can provide a wide range of benefits, including demand charge management, load following, reserve capacity, frequency regulation, and reduce the need for both polluting generation resources and investment in transmission and distribution infrastructure. Described as a “key component of our energy future,” the Commission observed that “the integration of storage into DER deployments . . . has the potential to substantially enhance DER’s capability to lower system costs and provide a variety of energy services.”\(^5\) However, for all its promise, the energy storage industry is still in its infancy in New York, and its full potential has yet to be realized. It is thus imperative that the rules for compensating hybrid storage systems under VDER are flexible enough to accommodate a diversity of technologies and use cases. Locking the industry into one particular use case or business strategy risks foreclosing a whole host of unforeseen applications and hampering the market’s ability to develop and demonstrate the myriad potential use cases for emerging ESS technologies. Instead, the Commission should allow the private sector to innovate, take on risk, and devote capital to figuring out the most optimal way to develop energy storage in New York. This will not only increase ESS deployment in line with the State’s Energy Storage Roadmap\(^6\) and the goals of REV, but will also ultimately drive down costs and maximize benefits for ratepayers. Simply put, allowing for flexibility at the outset will result in more ESS at lower cost in the long term.

Moreover, it is essential that the Commission ensure that hybrid ESS systems receive appropriate compensation for the benefits they provide. As we explain below, we recommend several improvements to the JU proposed tariff language that would ensure that hybrid ESS systems are able to operationalize a wide range of use cases and that these systems receive credit for the wide array of benefits they are able to provide. Specifically, we recommend the following:

- The Commission should clarify that hybrid ESS systems, \textit{i.e.} those paired with technologies eligible for Tier 1 RECs,\(^7\) are eligible for all capacity alternatives under the VDER value stack.
- The Commission should direct the utilities to implement an “electron tagging” accounting approach for hybrid systems capable of grid charging that accurately values energy generated from the paired distributed generating facility.
- In the event that “electron tagging” is deemed too administratively burdensome, the Commission should adopt, on an interim basis, a \textit{de minimus} accounting scheme under

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\(^6\) \textit{New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations} (June 21, 2018).

\(^7\) The Commission expanded VDER-eligibility to any clean generation technology that satisfies the requirements described for Tier 1 resources under the Clean Energy Standard. \textit{See PSC, Order on Value Stack Expansion and Other Matters}, at 14 (Sept. 12, 2018).
which a hybrid system capable of grid charging is eligible for the full Value Stack for all exports so long as the paired generating facility charges the ESS at least 75% of the time, the same percentage required for solar ITC eligibility.

II. Hybrid ESS Projects Should be Eligible for All Capacity Alternatives in the VDER Value Stack, Not Just Alternative 3.

Our first recommendation is that the revised tariff clarify that hybrid ESS projects may opt in to all capacity alternatives in the VDER Value Stack -- not just Alternative 3 (“Alt. 3”). Although the tariff states that hybrid systems will receive credit for “Value Stack Capacity Component Credit,” the tariff does not specify which of the three capacity alternatives hybrid systems could receive.

In its Order adopting the Phase One VDER tariff, the Commission adopted Staff’s recommendation to allow intermittent generation paired with ESS to receive compensation under VDER. One of Staff’s key recommendations was that “the presence of energy storage should not result in any change in compensation except that compensation for environmental value and the MTC should only be provided for net monthly exports.” In our view, this passage clearly indicates that the Commission intended for hybrid ESS systems to be eligible for all components of the value stack, including the three capacity alternatives. However, based on subsequent conversations that Borrego Solar has had with the utilities, it has become clear that they may not fully agree with this interpretation of the March 9 Order.

In addition, we note that in its September 12 Order, the Commission determined that standalone storage would be eligible only for Alt. 3. That decision applies only to standalone ESS, and we submit that the logic underlying that decision should not be extended to storage paired with clean generation resources, even those projects that are capable of grid-charging. Nevertheless, we believe it is important that the Commission provide the market with clarity regarding its intent with respect to eligibility for Capacity Alternatives 1 and 2 (“Alt. 1” and “Alt. 2”). In our view, hybrid ESS, particularly when deployed at the distribution scale and paired with a solar photovoltaic (PV) facility or other intermittent generation, modifies the generation profile of the project, but does not replace it completely. That is, the solar PV or other generation typically dominates the energy production, and the project as a whole remains largely non-dispatchable, though somewhat more operationally flexible than a true intermittent resource. One reason for this is explained by the Commission itself in the March 9 Order: “Because of current federal tax credit rules, most energy storage systems are only charged with renewable power, and therefore the net monthly injection restriction may be unnecessary.” Indeed, it is reasonable to expect that the vast majority of hybrid ESS systems will take advantage of the federal investment tax credit for solar generating equipment. In order to claim the tax credit, ESS must charge at least 75% of the time from the associated solar facility.

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8 Phase One VDER Order (Mar. 9, 2017) at 46.
9 PSC, Order on Value Stack Expansion and Other Matters, at 14 (Sept. 12, 2018).
10 Phase One VDER Order (Mar. 9, 2017) at 48.
11 See 26 CFR 1.48-9(d)(6).
12 Id. (indicating that dual-use equipment is solar energy property if other non-solar sources of energy do not exceed 25% of total annual input).
addition, the cost of ESS systems rises significantly as the duration of the ESS increases. This means that most ESS deployed in the near term will be short-duration systems that are not capable of sustaining the kind of output usually associated with dispatchable resources.

Accordingly, the Commission should clarify that hybrid systems, even those configured such that they can draw energy from the grid, are allowed to receive Alt. 1 or Alt. 2 compensation. Confirming this interpretation of the March 9 Order would recognize the unique constraints that face hybrid systems while still encouraging them to provide significant relief during expected peak hours, thus reducing capacity, distribution, and energy costs for other ratepayers.

Moreover, giving projects a choice of Alt. 1 or Alt. 2 compensation would not dampen the incentive to develop projects that are capable of reliably meeting the stringent demands of Alt. 3. One reason for this is that most batteries have a limited number operating cycles before they begin to degrade significantly. Although the single-hour requirement of Capacity Alternative 3 may complicate financing, systems that can reliably hit the Alternative 3 peak hour may well be able to operate with less degradation than those that opt in to Alt. 1 or Alt. 2, for which the kW-year capacity value is diluted over a larger share of hours. Allowing optionality, therefore, is a win-win from a policy standpoint. Systems that can satisfy the more targeted, hard-to-predict dispatch signals will likely opt for Alt. 3 compensation, while smaller systems that are unable to ensure they are discharging during the single-hour ISO system peak will nonetheless be encouraged to discharge to relieve capacity at other peak hours.

III. Borrego Supports Options 2a and 2b in the JU Model Tariff.

Borrego Solar supports the utilities’ proposed Options 2a and 2b, with the caveat that the Commission should direct the JU to clarify that all systems receiving Capacity Credit may opt into any of the three capacity alternatives available under the Phase One Tariff.

Option 2a appropriately allows paired systems that exclusively charge the ESS with clean energy from a distributed generation facility (and thus do not import electricity from the grid) to receive full Value Stack compensation, including all applicable credits for energy, capacity, environmental, DRV/LSRV, and MTC, based on hourly net injections measured at the customer meter. We note that this option may not require the three-meter configuration that the model tariff proposes. Because there is no possibility of grid charging, a single meter at the point of common coupling should be sufficient to obtain all the data required to credit the paired system.

Option 2b properly gives full Value Stack compensation to paired systems with appropriate customer controls that are designed so that injections are only made with the ESS not in a charging or discharging mode. Under Option 2b, the battery is prevented from injecting power to the grid. Thus, the only electricity that would receive VDER credit would be electricity from the paired intermittent generator.

It is appropriate to compensate these systems with full Value Stack compensation based on net hourly injections measured at the point of common coupling, because in both options, all injections to the grid would be generated by VDER-eligible intermittent resources. However, as
noted above, the Commission should clarify what is meant by the statement in Options 2a and 2b that such systems may receive the “Value Stack Capacity Component Credit.” For the reasons provided in Section II, we recommend that the Commission require amendments to the tariff to clarify that systems charged exclusively with VDER-eligible intermittent resources and those where the ESS does not inject energy into the grid should be eligible for all components of the Value Stack, including all three Capacity value stack alternatives.

IV. Option 2c Should be Modified to Accurately Compensate Clean Distributed Energy that has been used to Charge the ESS and then Subsequently Discharged into the Grid.

Option 2c specifies compensation for hybrid ESS systems that are capable of charging from the grid. Importantly, the Commission has already spoken to this issue in the March 9 Order. Specifically, the Commission there adopted Staff’s proposal, which was that for hybrid systems, “compensation for environmental value and the MTC should . . . be provided for net monthly exports.”\(^1\) Staff’s proposal—which was adopted in whole by the Commission—also explained that “while the use of system power to charge storage should be permitted, and even encouraged to the extent that it can support the system by reducing peak demand and variability, environmental and MTC compensation should not be provided for the export of stored system power.”\(^2\)

In contrast to this approach, the JU’s Option 2c proposes that separately metered hybrid PV plus ESS systems that are capable of grid charging would be eligible only to receive full Value Stack credit — Energy, Capacity, Environmental, DRV and/or MTC — for instantaneous injections, net of any discharge recorded on the ESS meter in the applicable interval. Hourly exports attributed to the ESS discharge only would be eligible for Energy, Alt. 3, and DRV compensation.\(^3\)

Option 2c appears to be focused on a legitimate challenge associated with hybrid renewable plus storage resources: ensuring that energy that was generated elsewhere on the electrical grid (“brown power”) is not credited with components of the VDER Value Stack that are intended for attributes associated with intermittent renewable resources (e.g., E-value and the MTC). Though we agree in principle that customers should not receive E or MTC credit for importing and then later exporting “brown power,”\(^4\) we strongly disagree with the accounting approach proposed on Option 2c.

\(^{13}\) Phase One VDER Order (Mar. 9, 2017) at 46.

\(^{14}\) Id.

\(^{15}\) Though not explicitly stated, it is assumed that LMBP would be credited for all net injections to the grid. The JU Model Tariff only sets rules for calculating Value Stack Capacity Component Credit, Environmental Component Credit, and MTC. See JU Model Tariff, Attachment A, Section 1.

\(^{16}\) At present, we do not contend that grid-charged ESS paired with community distributed generation should receive MTC for electricity that originated from the grid and not from the community distributed generation. Similarly, because the Phase One E value in its current form is a fixed $/kWh rate that is not shaped to account for differing marginal emission rates, we agree that ESS should not receive E value compensation for any grid-charged “brown power.” Should the Commission, as part of VDER Phase 2, endeavor to “shape” the E-value to take into account different marginal emissions rates on the grid, “brown power” imports should then be able to receive E credit. An ESS could charge at a time when pollution is low and discharge at a time when pollution is high, providing environmental benefits to the grid and decreasing total pollution associated with New York’s power sector.
Specifically, the JU proposal would not ensure that green and brown power are credited differently, as required by the March 9 Order. Rather, the JU proposal would treat any power discharged from an ESS as “brown power” -- even if the source of the power was a co-located renewable energy system. In other words, the JU proposal is significantly broader than the Commission’s approach. This approach, if adopted, would result in significant undercompensation of hybrid systems, because any power that passes through a co-located ESS would be unfairly “brown-washed” and deemed ineligible for the full Value Stack. In other words, Option 2c treats all energy discharged from the ESS as if it were grid-charged “brown power,” regardless of the actual source of that power. This method not only undervalues clean energy, but also is inconsistent with the logic of the JU’s Options 2a and 2b, which recognize that clean generation that is time-shifted through the use of a paired battery system should still be eligible for the full Value Stack. Discounting such time-shifted clean energy runs directly counter to the directives of New York’s REV and the Commission’s VDER Order, both of which aim to promote the deployment of distributed energy resources that address system peaks by compensating them for the value they provide during the highest-cost hours.

Rather than brown-washing green electrons, the correct approach would be to measure the amount of brown power imported and to ensure that the hybrid system’s monthly credits do not include E and MTC credit for that brown power. This is important because although non-grid-charged systems can certainly provide value to ratepayers and the grid, grid-charged hybrid systems can provide additional benefits that non-grid-charged systems cannot. Such systems can be utilized to reduce onsite load to manage a customer’s demand charges. Grid-charged hybrid systems also can charge at low demand hours — even when the sun is not shining — and discharge at peak hours when the grid needs the electricity the most. Because they are more flexible than systems that rely exclusively on energy from intermittent resources, they can participate more actively in the wholesale ancillary services market, offering frequency regulation and other ancillary benefits to the bulk power system, while also reducing emissions and distribution and transmission system peaks.

VI. Borrego’s Proposed Modification to Option 2c.

To ensure that hybrid systems that are capable of grid-charging are not disadvantaged relative to non-grid-charging systems, several modifications to Option 2c are required. Below, we recommend two alternatives that would improve upon the JU proposal and ensure that systems that charge from the grid receive appropriate credit under VDER.

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17 For example, consider an MTC-eligible PV system that is paired with a lithium ion battery and is compensated under Alt. 2. The battery in this example is capable of charging from the grid and otherwise qualifies for the JU’s Option 2c. On summer days, the PV system charges the battery during early off-peak hours, and discharges it during peak hours to increase production during the 2pm to 7pm Alt. 2 window. However, the battery also is capable of charging from the grid during cloudy weather to meet the project’s capacity obligations and participate in the NYISO wholesale market. In this example, even if the battery charges 90 percent of its energy from the PV system, Option 2c treats all of the discharged energy as if it were fossil-fueled, grid-charged electricity. Any solar energy that passes through the battery receives no Alt. 2, no MTC, and no E-value.
A. **Preferred Solution: Electron Tagging Accounting**

Under VDER, exports of energy from renewable resources are credited with the full Value Stack, whereas exports of grid-charged energy are, at a minimum, not eligible for the E and MTC components of the Value Stack. (As explained above, we recommend that the Commission clarify that discharges of energy from hybrid renewable + storage systems be eligible for all capacity alternatives, regardless of whether they are capable of grid-charging).

The key accounting challenge that arises with grid-charged-capable systems is how to distinguish time-shifted renewable generation from exports of energy that was produced elsewhere on the grid (and is potentially more carbon-intensive). Though complicated, it is technically feasible to keep track of green exports vs. brown imports by post-processing the metered data from a two or three meter scheme.

As prescribed in the Commission’s April 19 Order and reflected in the JU Model Tariff, grid-charged-capable hybrid systems where the ESS and the generator each have a separate inverter typically will have three utility meters — one meter at the ESS, one at the generator, and one at the Point of Common Coupling.\(^\text{18}\) By post-processing meter data, it is possible to determine the state of charge of the battery at all times, which would allow the utility to determine what proportion of monthly exports were grid-charged versus renewable-charged. Unlike the JU’s proposed Option 2c, this post-processing would allow the utility to provide E and MTC credit for the portion of ESS discharges that could be attributable to renewable generation. Such an approach would eliminate any risk of over or under-compensation of battery-discharged energy, because energy drawn from the grid would receive DRV and Alt. 3, while energy drawn from the PV would receive the full Value Stack compensation. Neither would receive compensation intended for the other.

Exhibit A details how such an “electron tagging” scheme could work for one summer day of production from a community distributed generation solar PV plus ESS system that has elected to receive capacity value Alt. 2. In this example, hourly interval data is collected from meters at both the PV and ESS terminals. The PV output meter is compared with the ESS input meter, and timestamped kWh values that match renewable generation to charging are tagged as green electrons. ESS imports that do not match a PV export are tagged as brown electrons. The kWh exported between 2-7pm receives Alt. 2 treatment except for that portion attributable to brown electrons. If, in this example, the system happened to be exporting during the ISO system peak hour, the system would also receive compensation under Alt. 3 for that portion of the charge attributable to grid-charging. This electron tagging post process approach would also allow the utilities to determine what proportion of a system’s monthly exports should receive E and MTC credit, and what proportion should receive only the DRV. The JU’s Option 2c correctly assumes that hybrid systems can receive non-Alt. 3 capacity alternatives as under that

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\(^\text{18}\) See New York Public Service Commission, *Order Modifying Standardized Interconnection Requirements*, Case No. 18-E-0081 *et al.*, at 17 (Apr. 19, 2018) (“A three-meter configuration was presented that would accommodate the many potential combinations of hybrid ESS and DG projects proposed by developers. The Commission agrees that the three-meter configuration presented at the ITWG, comprised of a utility meter at both the ESS and the DG, as well as at the Point of Common Coupling, will provide the necessary data for compensation purposes and therefore approves that configuration.”).
Option, certain injections receive the “Capacity Component Credit” while other injections attributable to ESS discharge only receive Alt. 3.

To implement this change, the proposed tariff language of 2c should be revised to read:

Storage Export Netting Configuration - For Customers with ESS paired with electric generating equipment with a separate Company revenue grade interval meter and appropriate telemetry on the AC side of the inverter of the ESS and whose storage configuration does not meet the requirements of 2.a or 2.b above, the Value Stack Capacity Component Credit, Environmental Component Credit, and MTC will be determined by reducing the net hourly injections, as measured at the Company’s meter located at the Customer’s PCC with the Company’s system, by any net hourly imports during the applicable period. The amount of hourly exports attributed to the import of grid power (i.e., the hourly injection not eligible for the Value Stack Capacity Component Credit, Environmental Component Credit, and MTC) will be eligible for DRV and Value Stack Capacity Component Alternative 3 compensation.

B. Alternative Interim Solution: The 75% Threshold-Based Accounting Method

Borrego has engaged in preliminary discussions with utility representatives concerning the above electron tagging solution. Our understanding is that the utilities’ principal objection to the approach above is that the administrative cost of deploying such an accounting scheme would outweigh any perceived benefit in accounting precision. For this reason, we propose a simpler, alternative approach that would avoid significantly undervaluing time-shifted renewable generation but would address the utilities’ concerns about administrative complexity. This approach could serve as an interim solution until the utilities are able to adopt a more cost-effective, administrable method.

Specifically, we propose that grid-charged systems could be eligible for full Value Stack compensation — including, as applicable, Capacity Value Alternative 1, 2 or 3, E-value, DRV and MTC value — as long as the system engages in no more than a de minimis amount of grid charging. We recommend that if a battery is charged at least 75% by the clean intermittent generation a project would be eligible for the full Value Stack without the need for more precise accounting. The 75% threshold is the same percentage the Internal Revenue Service requires for PV systems to receive the federal commercial energy Investment Tax Credit (“ITC”). Given the importance of the ITC to deployment of paired PV and storage systems, and the likelihood that that the vast majority of hybrid systems deployed in New York will be paired with PV, it is highly unlikely that most hybrid ESS systems would charge less than 75% from the PV. Moreover, the value of the ITC for ESS rises proportionally with the amount charged from the renewable energy system. To claim the full value, the “dual use” ESS would have to be charged by renewable energy 100 percent of the time. Otherwise, the credit is based on the prorata portion of renewable energy the ESS receives. Accordingly, this 75% threshold is a

19 See 26 CFR 1.48-9(d)(6) (indicating that dual-use equipment is solar energy property if other non-solar sources of energy do not exceed 25% of total annual input).
reasonable cutoff to use if the goal is administrative simplicity, and will cover the vast majority of assets, thus reducing or eliminating the need for more precise accounting. Documentation proving that a project’s ESS qualifies for the ITC would create a presumption that it meets the 75% threshold.

We fully recognize that this is an imprecise method, as there is a possibility that a small amount of exported grid-charged energy would receive MTC and E value compensation as if it were PV-generated. Nevertheless, this accounting formula is likely to be significantly more accurate than the JU proposal, which would treat all electrons that enter the co-located ESS system as if they came from the grid, thus totally discounting the value of time-shifted renewable generation and discouraging beneficial uses of the ESS. We submit that New York should not penalize VDER-eligible hybrid systems simply because the utilities’ have unilaterally determined that employing a more accurate accounting methodology is too administratively burdensome. Rather, if the Commission favors a less-than-perfect but more administrable accounting method, it should err on the side of fully compensating clean energy, in line with the State’s laudable clean energy goals.

To implement this de minimis alternative, the JU proposed tariff could be amended to include the following language:

*De minimis import configuration - For Customers with ESS paired with electric generating equipment eligible to receive Tier 1 RECs (i) with net hourly imports less than or equal to 25% of net hourly exports during a billing period, or (ii) who are able to demonstrate that the ESS’s use of energy from sources other than the paired electric generating equipment does not exceed 25 percent of the ESS total energy input, the Value Stack Capacity Component Credit, Environmental Component Credit, and MTC will be based on net injections to the Company’s electric system as measured at the Company’s meter located at the point of common coupling (“PCC”) and calculated as described in [insert each utility’s reference to normal Value Stack calculations].*

Systems that fail to meet this 75 percent threshold would be compensated with the JU proposed Option 2c. This “rough justice” solution would recognize that when a system disproportionately charges the ESS with grid-imported energy, the risk of overcompensating brown electrons outweighs the risk of undercompensating green electrons.

Again, our preferred “electron tagging” solution would be the most accurate, would avoid any such discrepancies, and would be more in keeping with REV’s vision of spurring the development of DERs by fairly compensating such resources for the actual value they provide the grid. However, given the utilities’ misgivings about implementing this more accurate approach, we strongly recommend that the Commission adopt the *de minimis* approach as described above, rather than the highly inaccurate methodology proposed in the JU filing—at least until the utilities are able to implement a more accurate, administratively feasible solution.

Finally, it is important to note that although the ITC requires 75 percent solar PV charging (and incentivizes 100 percent solar PV charging), some projects could provide greater
value by retaining the ability to at least minimally charge the ESS from the grid. For instance, a hybrid system could rely on grid-charged power to provide behind-the-meter services, such as managing a customer’s monthly demand charges. Grid-charging capability also would allow the system to participate more fully in the wholesale ancillary services market, especially down regulation. The opportunity to charge from the grid when energy prices are low and discharge when prices are high also could prove to be a valuable revenue stream. Such charging behavior would benefit the system as a whole by increasing energy availability during all peak intervals, including those that occur outside of the NYISO peak hour or in the 2-7pm summertime window. Over time, system peaks may shift dynamically to different times of the year and hours of the day, and grid-charged ESS could play a key role in shaving those peaks as they emerge. Finally, for systems serving onsite load, the ability to charge from the grid could provide resiliency and reliability benefits to customers should the co-located generator fail or require externally-supplied station power.

Conclusion

We thank the Commission for its attention to this important issue, and look forward to the speedy adoption of this important tariff, along with the modifications described herein.

Sincerely,

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