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REVITY ENERGY

December 23, 2024

VIA EMAIL (stephanie.delarosa@puc.ri.gov)

Stephanie De La Rosa
Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

Re: **In re:** ***Development of Storage Tariff Frameworks; Docket No. 24-34-EL***

Dear Ms. De La Rosa:

I write on behalf of Revity Energy LLC and its affiliates ("Revity") to provide public comment in response to the Rhode Island Public Utilities Commission's ("RIPUC") December 4, 2024 Notice of Staff-Led Workshop, Request for Public Comments, and Deadline to Identify Designated Stakeholders in the above-referenced docket proceeding (the "Notice"). As a preliminary matter, Revity's comments are principally focused on energy storage co-located with existing and/or future distributed energy resources. The reasons for that are twofold: First, Revity lacks a thorough understanding of the stand-alone battery storage regulatory regimes across the country and—with only 19 days to respond to the Notice—has not had sufficient time to edify itself to provide meaningful guidance to the RIPUC. Second, while Revity understands that the RIPUC has been charged with developing comprehensive tariff regulations to govern the entire energy storage market within the State, Revity strongly believes that the co-location market is the most efficient avenue through which the State can meet the aggressive storage targets imposed by S2499/H7811.

Co-located energy storage can, assuming proper discharge constraints, serve to increase the daily output of a distributed energy resource facility without significant upgrades or costs. The National Renewable Energy Laboratory ("NREL") estimates that the cost of co-locating storage with photovoltaic solar energy systems ("PSES") facilities is seven percent (7%) lower than standalone storage facilities.[1] "Co-locating the PSES and storage subsystems produces cost

[1] National Renewable Energy Laboratory, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, September 2022, p. 50 (via chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.nrel.gov/docs/fy22osti/83586.pdf).

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savings by reducing costs related to site preparation, permitting and interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit."[2] Co-located, DC-coupled (or restricted AC-coupled) energy storage also avoids the difficult economic question of balancing the retail rate for which a storage facility will pay to charge versus the rate at which a storage facility will be compensated to discharge. Moreover, the developers/owners/operators of distributed energy resource facilities have experience with local land control, municipal permitting and the existing regulatory scheme that has governed the State's renewable energy industry for the last 7 years. Co-located energy storage will not only advance the energy storage targets set by S2499/H7811 but also advance the aggressive distributed energy targets set by the 2021 Act of Climate insofar as co-located energy storage may allay interconnection constraints on future distributed generation projects. In sum, Revity is focused on prioritizing co-located storage solutions and Revity respectfully suggests that the RIPUC, through this docket, should be as well.

STAKEHOLDER PROMPTS FOR AN INTERCONNECTION TARIFF FRAMEWORK (24-34-I)

1. Applicability

a. What constitutes the distribution system? Some existing generation facilities have purpose-built interconnection that serve no other distribution customers and may never serve additional customers. Are these distribution facilities? Does it matter if those facilities are built to connect directly to the transmission system?

The distribution system generally refers to the infrastructure responsible for transferring energy from generation sources to end users, ensuring a balanced supply and demand. As to the question of whether "existing generation facilities [which] have purpose-built interconnection that serve no other distribution customers and may never serve additional customers," Revity would challenge the premise of the question. Revity has interconnected 26 PSES facilities with nameplate capacity of 97.3 MWAC in Rhode Island and there have been very few instances where the interconnection work ordered by the Company did not include work to address future needs of distribution customers. Indeed, the Company has often stated that it is their engineering standard to require interconnecting DG customers to build or pay to build for future distribution needs. While there may be *some* existing generation facilities with "purpose-built" interconnection that do not serve and may never serve additional customers, that result (as the RIPUC knows) is not the Company's standard operating procedure.

b. For storage facilities co-located with facilities subject to existing interconnection tariffs and process, should the existing tariffs control?

For storage facilities co-located with *prospective* DG facilities, the existing interconnection tariff should control the entire system proposal. A developer with a combined generation/storage project should proceed through the "Standard Process" (with its innumerable flaws) articulated by Section 3.4 of the existing interconnection tariff. However, for storage facilities co-located with *existing* distributed generation facilities, there should be an expedited process for examining the

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[2] *Id*.

extent to which the co-located energy storage system may increase (or decrease) the burden on the EDS modifications originally installed by the developer of the existing system. The majority of these co-located storage projects will be located at sites which have undergone substantial interconnection studies by the Company within the past five (5) years. While Revity understands that the Company will need to engage in some level of verification that the co-located storage facility will not overburden existing EDS infrastructure, the State will never be able to achieve the General Assembly's aggressive storage targets if each such project is required to go through the "Standard Process" applied to new DG projects. In Massachusetts, for example, storage is often treated as an extension of the existing generation asset. Rhode Island should follow this model to avoid duplicative or conflicting requirements, with adjustments for specific operational roles (e.g., charge/discharge cycles, non-export requirements).

The existing interconnection tariff (R.I.P.U.C. No. 2258) already has provisions for the "Simplified Process" (Section 3.1) and the "Expedited Process" (Section 3.3) for projects with "minimal apparent grid impact." Certainly, there are questions that will arise with co-located storage projects that are not currently contemplated by the existing interconnection tariff such as whether the co-located storage project is DC-coupled or AC-coupled and whether the project utilizes acceptable export-control methods (such as a dispatch limiting schedule or operating envelope agreements). Addressing these issues may require disclosure/study provisions to be added to Section 3.3; however, to the extent that a developer can show the Company that its proposed storage system co-located with an existing DG facility will not exceed the original nameplate capacity approved when the DG facility was interconnected, the co-located storage facility should not be required to proceed through the "Standard Process" which requires a pre-application, preliminary review, application, feasibility study and/or impact study and, often, an affected systems operator study. The "Standard Process" is broken and a developer should not be required to endure it twice for one integrated facility.

Lastly, proposed storage facilities co-located with an existing PSES site should have interconnection queue priority over standalone storage facilities proposed in the same area. The Company requires DG developers to pay for all system modifications ordered by the Company regardless of whether the DG developer needs those modifications to interconnect its facilities. The RIPUC has found that there exists no guarantee in the standard form Interconnection Service Agreement or the interconnection tariff for reimbursement of those modifications. And so, if the DG developers are going to be required to build (and often over-build) whatever interconnection modifications are ordered by the Company and the DG developers are required to hand those assets over to the Company at ATI and the RIPUC is not going to require the Company to reimburse the DG developers for the economic value forfeited to the Company, *at the very least*, the DG developers should have priority in the interconnection queue to connect co-located storage facilities to the EDS modifications that that developer built in the first place.

c. **Should a single interconnection tariff for all export facilities not subject to an existing interconnection tariff be developed, or should the current focus be on storage facilities? For example, examining a tariff for additional facilities, such as microgrids, could be useful, but could be more time consuming and delay the outcome on storage interconnection.**

Given the aggressive targets dictated by S2499/H7811, the RIPUC should initially focus on storage-specific interconnection tariffs to expedite deployment and address immediate market needs as dictated by the General Assembly. Rhode Island could develop broader tariffs later to encompass microgrids or other export facilities.

2. **Study Process**

a. **What interconnection studies should be required for energy storage resources?**

i. **Should the process allow for the applicant to seek alternative interconnection studies, for example one study without restrictions and one study subject to operational guidelines?**

Yes, Rhode Island should allow for alternative interconnection studies. For example, Massachusetts permits "dispatch-limited studies," which simulate operations under specific constraints to minimize grid upgrades. Alternative interconnection studies could also consider "dynamic operating envelopes", used in other countries, which allow the EDC to study the amount of capacity that is available on a distribution network at the feeder or substation level, and then define the range of power transfer capacity (both generation and load) that can be allowed at each DER connection point without violating distribution system thermal and voltage limits.[3] The energy tariff should contemplate Operating Envelope Agreements ("OEA") defined as "[a] contractual agreement between the utility and the system owner that defines a mutually acceptable set of time-based technical operating requirements (an 'Operating Envelope') for a PV and storage system that limits risk to neighboring customers and the utility's infrastructure and provides certainty to both the utility and the PV system owner."[4] "The conceptual framework for an OEA is one integrated technical and process concept designed to manage interconnection costs and streamline interconnection timelines to support near-term renewable energy deployment in furtherance of long-term climate mitigation solutions."[5]

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[3] Baringa, THE VALUE OF DISTRIBUTED ENERGY RESOURCES FOR DISTRIBUTION SYSTEM GRID SERVICES FOR MASSACHUSETTS CLEAN ENERGY CENTER at p. 3 (March 13, 2024) (via chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf).

[4] National Renewable Energy Laboratory, USE OF OPERATING AGREEMENTS AND ENERGY STORAGE TO REDUCE PHOTOVOLTAIC INTERCONNECTION COSTS: CONCEPTUAL FRAMEWORK at p. 3 (March 2022) (via chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.nrel.gov/docs/fy22osti/81960.pdf).

[5] *Id*. at 20.

Lastly, hosting capacity maps should be updated to include additional information such as "size or impact of group studies and queue, system constraints/thresholds before applying to interconnect, location and nature of constraint (import/export), if seasonal, windows, real-time and forecast constraints, and advanced notice of curtailment."[6] Alternative interconnection studies should provide flexibility which can reduce costs and accelerate approvals.

ii. If alternatives are allowed, how should alternatives be initiated and sequenced?

For storage facilities co-located with existing PSES facilities, the interconnection review should follow the review process under Section 3.3 of the existing interconnection tariff for "Expedited Process." As discussed in Revity's response to Question 1(b), this process permits the Company to conduct internal reviews including, but not limited to, protection review, aggregate harmonics analysis review, aggregate power factor review and voltage regulation review. Co-location storage developers should be able to request alternatives in their interconnection application. The sequence could involve: (1) a baseline study for unrestricted operations and (2) alternative studies under proposed operational limits (e.g., export control settings). Alternatives should follow a clear timeline to prevent delays and delays at any review level should have consequences.

With respect to storage facilities proposed to be co-located with future PSES facilities, the National Renewable Energy Laboratory identified the alternative paths as follows:

> Building out a process to consider the value of energy storage in managing PV interconnection costs may also necessitate changes to process sections of an interconnection tariff. Paired energy storage as an alternative solution to interconnect is likely only to be preferred by system owners if it does not add time, cost, or uncertainty to project development. Therefore, utilities may consider providing three options for each interconnection study: option 1 is the cost and timeline of interconnecting the full PV system size with necessary grid upgrades, option 2 is the cost and timeline of interconnecting a downsized PC system, perhaps with limited or no grid upgrades, and option 3 is the cost, timeline, and operating parameters for interconnecting the proposed PV system size with limited or no system upgrades. Note that option 3 could be realized through paired energy storage or curtailment of excess solar via advanced inverter controls. Providing all three options upfront will reduce the number of iterations on system characteristics, reduce the number of studies required, and speed up timelines for the utility, the system owner, and all other subsequent system owners in the interconnection queue.[7]

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[6] Baringa, THE VALUE OF DISTRIBUTED ENERGY RESOURCES FOR DISTRIBUTION SYSTEM GRID SERVICES FOR MASSACHUSETTS CLEAN ENERGY CENTER at p. 21 (March 13, 2024).
[7] National Renewable Energy Laboratory, USE OF OPERATING AGREEMENTS AND ENERGY STORAGE TO REDUCE PHOTOVOLTAIC INTERCONNECTION COSTS: CONCEPTUAL FRAMEWORK at p. 18 (March 2022).

Co-located energy storage systems must have a stream-lined interconnection process.

b. What characteristics of the facilities, such as size, location, and/or configuration, should determine the study requirements?

As always, facility size, location, and configuration will impact the study process. As previously discussed, if a storage facility is co-located with an existing PSES site with acceptable export-control settings, these facilities should receive priority, expedited interconnection review compared to a standalone storage facility which proposes to both charge from and discharge to the EDS.

3. <u>Costs</u>

a. What interconnection studies should be required for energy storage resources?

i. What fees can be assessed fairly via a schedule?

Application and standard study fees should be pre-defined based on project size, as seen in Massachusetts' cost allocation for demand response programs. For example, smaller storage projects could have fixed fees, while larger ones pay based on complexity. For storage facilities co-located with existing distributed generation facilities, the fee schedule should align with the fee schedule for Expedited Review under Table 2 of the interconnection tariff. Facilities greater than 500 kW pay a $750 pre-application report fee and a $3/kW application fee (minimum of $300 and maximum of $2,500) and actual costs for other necessary studies. While co-located facilities may present study challenges requiring additional fees, all fees for such facilities should be assessed pursuant to a schedule.

ii. Which fees, if any, should depend on project scope and size?

Costs for grid upgrades, advanced studies, or additional equipment (e.g., non-export relays) should scale with project size and impact. Larger or import/export-capable systems might incur higher fees. The pre-application fee should not depend on project scope or size. The application fee could depend on project scope or size and, obviously, the actual study costs will depend on scope and size.

iii. Which other interconnection costs should be collected from applicants and how?

Currently, Rhode Island law states that the Company "may only charge an interconnecting renewable-energy customer for any system modifications to its electric power system specifically necessary for and directly related to the interconnection."[8] While that law has not been uniformly applied to DG developers, Revity would strongly encourage the adoption of storage tariff provisions that strictly enforce both the spirit and the letter of that law. Customers have little (if any) leverage to negotiate interconnection service agreements with the Company and, as the RIPUC has found, the existing interconnection tariff does not always guarantee developers cost reimbursement for system modifications required by the Company even when those modifications

[8] R.I. Gen. Laws § 39-26.4-3(a).

are not necessary or directly related to the DG interconnection. As the RIPUC has found, the Company has and will threaten to cancel DG projects unless developers agree to construct (or pay for the construction of) system modifications despite those modifications having no relationship with the proposed facility. The provisions of the storage tariff (be they incorporated into the existing interconnection tariff or as part of a new storage interconnection tariff) should restrict the Company from being able to order system upgrades that cannot be identified as strictly necessary to accommodate the storage facility. Storage developers should only be responsible for costs for grid modifications necessary to accommodate the facility.

iv. What is reasonable timing for assessment and payment of study costs and construction costs?

The total maximum days from application to interconnection service agreement under the Simplified Review Process is 20/50 days, the Expedited process is 45/65 days, and the renewable DG Standard process is 175/200 days. The timing for assessment and payment of study costs and construction costs for co-located storage projects should hue more closely to the Expediated process. Initial study fees should be paid upon application submission. Construction costs could follow a phased schedule, with final payment upon project completion.

b. Under what conditions, if any, should a storage facility be eligible for a reduction/credit to the interconnection construction costs? (See e.g., Tariff RIPUC No. 2243 Appendix A, Policy 3).

Revity has nothing to add in response to this question.

4. <u>Other</u>. What other main elements can stakeholders identify that do not fall within the basis tariff structure provided above?

Revity has nothing to add in response to this question.

<u>STAKEHOLDER PROMPTS FOR A TERMS AND CONDITIONS TARIFF FRAMEWORK (24-34-TC)</u>

1. <u>Availability</u>

a. What types of energy storage resources should be eligible for service under a WDS?

To develop a cost-effective market for DERs to provide grid services, the tariff must both ensure that DER are available to provide critical grid services and can be relied upon with confidence and also allow for maximum revenues to be stacked when grid services are not required thereby reducing the cost of providing grid services.[9] At times of high load and high market prices, dispatchable, AC-coupled DER will want to generate and discharge power onto the EDS thereby unloading heavily loaded distribution facilities.[10] At times of low load and low market prices,

[9] Baringa, THE VALUE OF DISTRIBUTED ENERGY RESOURCES FOR DISTRIBUTION SYSTEM GRID SERVICES FOR MASSACHUSETTS CLEAN ENERGY CENTER at p. 36 (March 13, 2024).
[10] *Id*.

dispatchable, AC-coupled DER will want to absorb power thereby loading more lightly loaded, or reverse flow, distribution facilities.[11] Eligibility must reflect these market conditions.

b. What types of energy resources should be eligible for service under a retail service tariff?

Revity has nothing to add in response to this question.

c. Should storage facilities be considered a distinct class of customers because they have unique characteristics, warranting separate cost allocation and rates?

Yes.

i. Are these characteristics different for similarly designed wholesale and retail storage systems?

Revity has nothing to add in response to this question.

ii. If storage facilities should be considered a distinct class of customers, should that apply to standalone, generation-sited, or other configurations?

Co-located ("generation-sited") storage facilities should be considered distinctly from standalone storage facilities. DC-coupled facilities should be considered distinctly from AC-coupled facilities. Export-controlled facilities should be considered distinctly from facilities without export controls.

d. Should the tariff availability depend on concurrent enrollment in net metering, Renewable Energy Growth, or other programs or tariffs?

Tariff availability should not depend on concurrent enrollment in net metering, Renewable Energy Growth Program, or other programs or tariffs. Storage facilities co-located with existing PSES facilities should be permitted to participate in the same programs as the co-located PSES facilities and storage facilities should be entitled to an adder on the credit (in the case of the net metering program) or the rate (in the case of the REG program) to properly incentivize the rapid increase of storage development as targeted by the General Assembly in S2499/H7811. Storage adders are a useful feature of Massachusetts' SMART program.

i. Should availability allow a wholesale storage facility to be paired with generation participating in the retail market?

As definitions of distribution level products and services evolve, it is critical that tariff design allows for co-participation in existing markets. The tariff should permit both DC-coupled (co-located) storage facilities as well as AC-coupled storage facilities; however, provisions of the tariff should recognize the disparate costs and benefits of each of these designs.

[11] *Id*.

e. Should other facility types, like microgrids, be considered at this time or should a storage tariff be the priority?

Given the aggressive targets dictated by S2499/H7811, the RIPUC should initially focus on storage-specific tariffs to expedite deployment and address immediate market needs. Rhode Island could develop broader tariffs later to encompass microgrids or other export facilities.

2. <u>Study Process</u>

a. Once the interconnection costs for a storage facility have been incurred, do storage facilities generally create ongoing costs to the distribution system?

Revity challenges the premise of this question insofar as the question only assumes that storage facilities *create* costs and have no potential to *save* costs to the EDS. Strategically sited storage facilities can obviate (or, at the very least, delay) the need for more expensive (ratepayer-funded) upgrades to the EDS. The State's November 2017 Power Section Transformer Phase One Report found that "storage systems help shave peak load, provide ancillary services to the grid such as voltage control, and enable more variable renewable energy to the system by backing them up when the sun and wind are not available."[12] The storage tariff design must account for the EDS savings offered by a proposed storage facility as an offset to the costs.

i. Operations costs?

Storage facilities will change the EDS operational costs. Certainly, there will be operational costs associated with integrating storage facilities; however, strategically integrated storage facilities should reduce operation costs in other areas. For example, dispatchable distributed energy systems can support the EDC in managing the voltage levels on its network.[13] Voltage on a long feeder will tend to drop, requiring additional transformers or voltage regulating devices; however, injecting current along such a feeder, AC-coupled storage facilities can mitigate this voltage drop and reduce the need for more costly network interventions.[14]

ii. Maintenance costs?

Storage facilities should obviate or delay the need for certain maintenance costs. AC-coupled dispatchable distributed energy resources have the potential to reduce peak load and thereby alleviating an existing, emerging or future network constraint.[15] These solutions can be used to

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[12] RHODE ISLAND POWER SECTION TRANSFORMER PHASE ONE REPORT at p. 36 (November 2017) (via chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://ripuc.ri.gov/sites/g/files/xkgbur841/files/utilityinfo/electric/PST-Report_Nov_8.pdf).
[13] Baringa, THE VALUE OF DISTRIBUTED ENERGY RESOURCES FOR DISTRIBUTION SYSTEM GRID SERVICES FOR MASSACHUSETTS CLEAN ENERGY CENTER at p. 15 (March 13, 2024).
[14] *Id*.
[15] *Id*. at p. 17.

defer or avoid network reinforcement investments and can create headroom to enable other customers to interconnect.

iii. Ongoing capital investment? If so, related to what (growth, modernization, asset condition, etc.)?

Revity has nothing to add in response to this question.

b. Do responses to part a on cost causation depend materially on any of the following:

i. Wholesale versus retail participation,

Revity has nothing to add in response to this question.

ii. Metering/wiring configuration,

AC-coupled storage facilities will have a greater cost-causation impact than DC-coupled storage facilities.

iii. Whether the interconnection relies on existing distribution system capacity,

The question of cost causation impact for a storage facility's interconnection relying on existing distribution system capacity depends on the identity of the storage facility developer. If that developer previously paid for additional system modifications to the EDS in order to interconnect a renewable-energy system, that same developer connecting a co-located storage facility to excess EDS capacity (which the developer originally paid for) should have little to no cost causation impact. That developer has an equitable right to utilize the EDS infrastructure for which it originally paid.

iv. Timing of charging and discharging,

Revity has nothing to add in response to this question.

v. Electrical location of the facility, or

The location of the storage facility certainly impacts the cost causation analysis. For example, if a dispatchable distributed energy system is going to effectively manage the thermal constraints on the Company's EDS, the facility must be connected downstream of the constraint.[16] Distributed energy system facilities are more valuable to the EDC and future customers if they are connected where there is—or is likely to be—an import constraint.[17] Properly siting the storage facility, considering the individual feeder, phase and network segment, is important to engage dispatchable distributed energy to provide maximum distribution network value.[18]

[16] Baringa, THE VALUE OF DISTRIBUTED ENERGY RESOURCES FOR DISTRIBUTION SYSTEM GRID SERVICES FOR MASSACHUSETTS CLEAN ENERGY CENTER at p. 3 (March 13, 2024).
[17] *Id*.
[18] *Id*.

vi. Something else?

Revity has nothing to add in response to this question.

c. All retail customers are assessed certain mandatory charges per various laws. Are there any configurations under which storage connected to the distribution system would or should be able to avoid those charges?

Revity has nothing to add in response to this question.

3. <u>Other</u>: What other main elements can stakeholders identify that do not fall within the basic tariff structure provided above?

Revity has nothing to add in response to this question.

Regards.

Nicholas L. Nybo
Senior Legal Counsel
REVITY ENERGY LLC AND AFFILIATES

Docket No. 24-34-EL-TC & I – Public Utilities Commission - Development of Tariffs Applicable to Energy Storage Systems Connected to the Electrical Distribution Systems
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