October 2, 2026

Mr. Jeffrey Gaudiosi
Executive Secretary
Public EDCs Regulatory PURA
Ten Franklin Square
New Britain, Connecticut 06051

Re: DOCKET NO. 26-06-04 IMPLEMENTATION OF CLEAN ENERGY SUCCESSOR PROGRAMS; SECOND NOTICE OF REQUEST FOR WRITTEN COMMENTS

Dear Mr. Gaudiosi:

The Connecticut Solar & Storage Association ("CONNSSA") submits the following in response to the Public Utility Regulatory Authority's (PURA) September 9, 2026 Notice of Request for Written Comments 2 in the above referenced docket.

1. Multipart Payment Framework (MPF) for NRES Buy-All and SCEF Successor Programs; The Authority requests stakeholder feedback on the proposal to offer an MPF compensation structure for FTM projects enrolled in the NRES and SCEF successor programs, including the following topics:

a. How the per-kW payment level should be determined and updated;

Developers reserve a definitive recommendation on how to calculate or update the per-kW rate until after the October, 22, 2026 Technical Meeting. Proceeding with establishing pricing mechanisms at this juncture is structurally backwards. CONNSSA members require a granular walkthrough of the proposed data models and calculator mechanics before responding with specific quantitative formulas.

At the October 22 Technical Meeting, developers ask Eversource to produce and verify the grid load data used to conclude that mid-day solar generation has plateaued to a point of zero marginal value. Stakeholders challenge this baseline assumption and require empirical validation.

If PURA moves forward with designing a rate-setting mechanism, the following criteria must be structurally enforced. History shows a lack of clarity in calculating demand response and front-of-the-meter payouts, frequently leaving developers without line-item supporting evidence. The per-kW calculation methodology must be universally modellable and transparent. If it is overly complex, it will introduce market friction and destroy project financeability.

The framework should not utilize the standard retail kilowatt-hour rate as a financial ceiling if that is the intention. If the grid experiences critical strain during the 4:00pm to 8:00 p.m. window, the rate must operate as a true, premium incentive adder to account for the added technological costs of flexible dispatch (i.e. establish a premium adder with no retail rate cap).

The $85 million annual programmatic cap (cross-inclusive of RRES, NRES, ESS, and SCEF) beginning in 2028 mean high per-kW performance payouts will drain the budget rapidly. The updating mechanism must balance these payments so they do not throttle the deployment of standard, solar-only projects, which remain the most viable to get deployed.

b. How the targeted period should be determined and updated, and whether the timing should vary seasonally;

Developers note that the targeted period and its seasonal variations are directly linked to the core rate-determination mechanics and cannot be evaluated in isolation.

Stakeholders agreed that seasonality and targeted window updates are completely tied to how the per-kW payment levels are determined. Developers also note that solar production naturally peaks during specific months of the year, creating a distinctive "head and shoulder curve." They stress that any seasonal variation or targeting mechanism must explicitly account for this natural generation curve rather than assuming flat grid performance year-round.

Mentioning historical precedents like California's clean energy grid evolution, developers pointed out that as more solar enters the grid, it naturally "tamps down" mid-day demand peaks. This shifts the true grid pain point heavily to late afternoon and evening.

Stakeholders analyzed a parallel program—the New York VDER framework (Value of Distributed Energy Resources)—and its associated NYSERDA calculator tool. They feel that under that seasonal/hourly tracking model, developers are heavily penalized during peak sun hours (e.g., getting paid only 5 cents/kWh at 1:00 p.m. on a sunny June day) while receiving massive premiums (e.g., 29 cents/kWh) at 7:30 p.m. when solar assets are no longer naturally producing.

There is another difference if the EDC's compare their MPF to something like the NY VDER program. NYSERDA pays an upfront cash grant which is based on the DC system size of the project utilizing the NY-Sun MW Block program. So, the Connecticut EDC's cannot expect that they will now simply pay a "VDER" like rate, which for comparison, in Con Edison Westchester territory, on average is about .14 cents kWh over a 12-month period. The economics for solar will not work at .14 cents kWh by itself. A better, fairer state framework is in Rhode Island where the REG program has proposed new Feed-In-Tariff (FIT) rates = .31 cents for ITC eligible projects and .37 cents for non-ITC eligible projects.

Because determining seasonal time slots requires complex interval modeling, developers maintain that it is impossible to give a definitive answer on seasonality without a technical meeting. They ask Eversource to present granular data first so developers can evaluate exactly how these proposed seasonal shifts will affect system modeling and revenue predictability.

c. Whether kW performance payments should be based on the minimum one hour average discharge over the designated period, or another method;

Developers have concerns with the Eversource proposed "minimum" hourly metric, arguing it creates a worst-case penalty system. Instead, they indicated a strong preference for an averaging metric to protect project viability.

Developers analyzed Eversource's proposed calculator model using a scenario (a hypothetical 1.5 to 2 MW system with a 50-cent per kW performance rate). Under Eversource's framework, if a system produces exceptionally well for three hours of the 4:00 to 8:00 p.m. window but drops significantly during the final hour (e.g., falling to 200 kW between 7:00 and 8:00 p.m. as the sun sets), the developer is only compensated based on that single lowest hourly number (200 kW) across the entire block.

Developers noted that this "minimum" rule severely drives down incentive levels for systems with any natural or operational inconsistency, erasing the financial credit for the hours the system actually performed at a high clip. Utilizing an average of the four hours within the targeted window would be a far more productive and fair option for the market.

Eversource is explicit about the consequences for projects without storage: "PV-only resources that do not sustain output through the final hour of a period (e.g., 7-8 PM), would have a performance value of effectively zero kW and would not be provided additional compensation."[1]

CONNSSA recognizes that additional solar generation in the late afternoon and early evening has real value to the electric system, and that pairing storage with solar can extend that value further into the evening peak. CONNSSA's concern is with how the MPF measures that value. By setting compensation to the lowest one-hour output within the window, the MPF credits a system only for its weakest hour and gives no recognition to the energy the same array delivers during the other hours of the peak period. A solar array producing strongly from 4:00 to 6:00 p.m. contributes to meeting peak load in those hours, yet under a minimum-hour metric that contribution is worth nothing if output falls off by 7:00 or 8:00 p.m.

The existing behind-the-meter Energy Storage Solutions (ESS) program already operates effectively using an average based on total kilowatt-hours delivered over the dispatch period. CONNSSA members questioned why a front-of-the-meter program should deviate from this established norm. There were questions about going to a highly granular, hour-by-hour "minimum" tracking framework requires advanced metering infrastructure and whether the EDCs existing meters even possess the hyper-specific interval tracking capabilities required to administer such a metric.

CONNSSA asks why Eversource would disregard a system's contribution across the rest of the peak window and compensate only its lowest hour. The EDCs' own dispatch practice under the ESS Program addresses compensation in a meaningfully different way. Of the 128 Active Dispatch events Eversource called between summer 2024 and summer 2026, events averaged approximately 2.4 hours, and nearly all were concentrated in the 5:00 to 8:00 p.m. period.

[1] Eversource Comments, p. 7.

The 6:00 to 7:00 p.m. hour was included in 127 events, and the 5:00 to 6:00 p.m. hour in 105 events (see Figure 1). ESS also compensates Active Dispatch performance on an average basis: "performance per event is equal to the average discharge rate of the BESS in kW-AC over the length of the event,"[2] and the seasonal incentive is based on the average across all events. The EDCs have thus recognized the value of shorter-duration resources that deliver during the heart of the evening peak and have measured that value by average performance. It is not clear why the MPF would instead assign value to a four-hour window only to the extent that a resource can sustain output through its final hour.

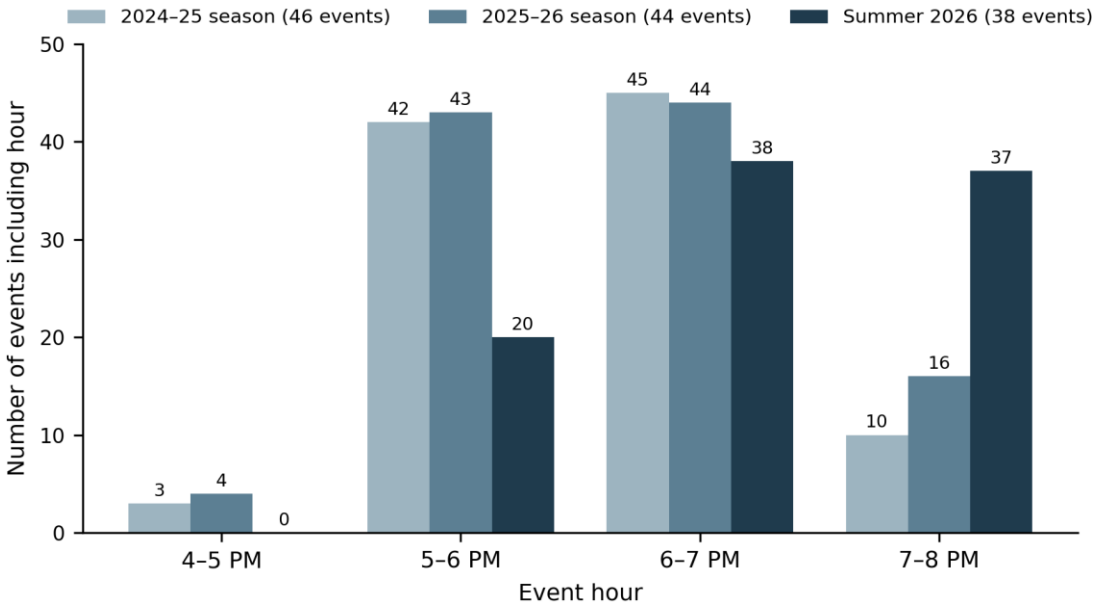

Figure 1. Eversource ESS Active Dispatch Events Including Each Hour, Summer 2024-Summer 2026

A "minimum" metric forces developers into tight battery programming strategies. To avoid being penalized by the 7:00 to 8:00 p.m. drop-off, developers would be forced to artificially limit or hold back exports in the earlier hours just to ensure they have enough capacity to artificially inflate that final hour's "minimum" baseline.

The minimum-hour metric also creates a risk that a single point of failure can remove an entire day's payment.

While CONNSSA would conceptually be open to a performance payment strategy that acknowledges the average performance of the system during the target hours as a blended average, CONNSSA is not formally proposing a different interval-based metric at this time. Every such metric shares the same underlying problem: its value depends on hourly data that participants cannot currently see and a calculation they cannot currently verify.

[2] ESS Program Manual, § 6.6, p. 62.

CONNSSA asks for greater detail from the EDCs before proposing an alternative interval-based performance metric. Any performance payment measured hourly across a peak window, whether tied to the minimum hour, as Eversource proposes, or to average output, would require a level of data granularity and complexity that CONNSSA does not believe the EDCs are currently able to account for transparently to customers and developers. As described in Section 1(i), commercial customers today cannot verify simpler, quarterly-reconciled generation payments.

If PURA adopts a kW performance payment two guardrails are necessary. First, hours in which output is limited by EDC-directed curtailment or flexible interconnection export limits must be excluded from the performance calculation or deemed performed. Eversource itself anticipates that FTM projects will "increasingly manage their output to minimize grid impacts" under flexible interconnection.[3] Second, the formula, inputs, and exclusions must be published and replicable by the participant.

d. Whether MPF participation should require co-located storage to charge exclusively from PV to maintain statutory eligibility for the renewable energy tariff program, and how exclusive PV charging should be verified and enforced;

Developers view topic (d) through the lens of statutory PURA, market flexibility, and economic choices for project development.

The breakdown of developers' feedback on whether participation should require exclusive PV charging or allow grid charging. Developers noted that the regulatory landscape regarding front-of-the-meter (FTM) storage has been highly unstable. Prior to 2025, the PURA had claimed the jurisdictional power to run an FTM storage program, but that PURA was subsequently altered by a 2025 Public Act.

Developers highlighted a condition in the proposed policy stating the MPF is only viable *provided that* the paired battery system is charged exclusively from the co-located front-of-the-meter solar asset.

Developers emphasized that because these proposed projects are front-of-the-meter assets, they are entirely unable to participate in the Green Bank's Energy Storage Solutions (ESS) program, which is structurally restricted to behind-the-meter configurations. Because of this exclusion, developers see this exclusive solar-charging framework as a way for the PURA to regain management over an FTM-specific storage program that operates separate and distinct from traditional netting tariff systems. Developers opposed mandatory coupling stating that pairing a battery with a solar array should remain entirely optional, not a strict requirement for program enrollment.

[3] Eversource Comments, pp. 5-6.

In addition, CONNSSA believes developers should be allowed to build solar-only projects if they choose (such as utilizing west-facing arrays to naturally capture late-afternoon value). If the PURA "dangles a carrot" by offering a premium performance adder for storage, developers will naturally choose to add paired batteries only where it makes financial sense and where grid hosting capacity allows. **Mandatory pairing would create a severe barrier to entry for participants who lack the upfront capital or the specific grid interconnection capacity required for both assets.**

(e) The implications of an MPF compensation structure for solar-only and paired solar and storage project economics

Developers expressed critical concerns regarding how the MPF would distort the economics of both solar-only and paired solar-and-storage projects, warning that it could inadvertently restrict market growth.

Developers detailed the economic implications beginning with market attrition and "budget drain" for solar-only projects. As previously described, the state's successor programs operate under a strict, legally mandated $85 million programmatic cap that is collectively shared across multiple buckets, including RRES, NRES, ESS, and SCEF. Because pairing energy storage with solar requires a significantly higher dollar-value incentive to be economically viable, each paired project will drain a much larger portion of the fixed $85 million budget. Developers explicitly warned that this will result in a smaller absolute number of projects being selected during competitive solicitations.

Because Public Act 26-127 caps aggregate program spending at $85 million per year across the successor programs and ESS,[4] every MPF dollar allocated to a paired project is a dollar unavailable to other projects. The implication for solar-only projects is therefore not merely the absence of an adder. It is a shrinking share of a fixed budget.

Standard solar-only projects are historically the easiest, fastest, and most cost-effective assets to get deployed. Developers fear that by diverting heavy financial incentives toward complex storage projects, the framework will stifle the deployment of standard solar-only arrays that the market is ready to build right now.

The MPF creates a financial barrier to entry. Requiring or heavily favoring a multi-part framework tied to storage introduces an economic barrier for developers and customer hosts who lack the substantial upfront capital or funding resources required to finance both solar and storage equipment simultaneously.

Beyond capital, developers flagged that many geographic locations simply do not have the physical grid hosting capacity required to interconnect both a large solar array and a high-capacity battery system. Forcing an MPF structure on these areas would destroy the economic viability of development in constrained grid zones.

[4] Public Act No. 26-127 § 4(a).

Project financeability relies entirely on predictable revenue modeling. Several developers pointed out Eversource's shortcomings at explaining or providing supporting evidence for how its current performance payouts are derived. Right now, developers receive demand-response checks with zero line-item documentation and have to repeatedly email the utility to understand the math. Introducing an even more convoluted per-kW framework will make project revenues completely unpredictable, making banks highly hesitant to finance them.

Historically, Connecticut's clean energy programs were designed to incentivize *renewable generation* (creating clean energy). Under the MPF, developers note that the programs are being unfairly tasked with dual mandates: clean energy generation *plus* flexible grid dispatch and peak shaving, without any expansion of the underlying budget.

One developer pointed out that "power is what the utility needs, and solar is creating energy." To make paired project economics work, the per-kW payment cannot be capped by standard retail rates. It must be modeled as a clear, premium "carrot" that outpaces the added operational costs and efficiency losses of charging and discharging a battery asset.

Lastly, the commercial paired solar-and-storage market in Connecticut remains nascent. According to the Green Bank's ESS Performance Report, only seven commercial solar-plus-storage projects have been successfully deployed since the start of the ESS Program.[5] **Any framework that assumes paired FTM projects can be financed and built at scale should be tested against that deployment record.**

(f) How bid preferences should be administered within an MPF framework?

Developers did not lay out a mechanical framework for bid preferences. Instead, they issued a strong caution against allowing the EDCs to control selection criteria, flagging it as an anti-competitive risk and raising several points regarding how bid preferences and selection should be managed under the proposed framework.

Developers raised additional concerns regarding competitive solicitation under an MPF structure saying without strict regulatory guardrails, Eversource and UI could use bid preferences to selectively lock out specific projects, choosing *only* front-of-the-meter projects that feature paired solar and storage.

Developers have views on mandatory carve-outs for solar-only project. To combat this utility bias, developers argued that the PURA must step in to administer explicit, protected percentage carve-outs or guardrails. These preferences must guarantee that a fixed portion of the accepted bids are preserved strictly for solar-only installations. The economic reality is that solar-only projects remain the most likely to get successfully deployed by the market. Developers say that if bid preferences are heavily tilted toward expensive paired-storage setups, the selection pool will shrink dramatically, stalling overall clean energy deployment under the program's hard statutory limits.

[5] Connecticut Green Bank, Energy Storage Solutions Performance Report, https://energystoragect.com/ess-performance-report

Ultimately, developers view the administration of bid preferences as another reason why the overall process feels rushed. They maintain that the PURA cannot safely set bid preferences or scoring criteria until a formal technical meeting takes place. Eversource must first present its fully mapped-out calculator and data models so stakeholders can ensure the solicitation rules remain genuinely competitive and do not create artificial market barriers.

g. Whether the EDCs should have discretion to adjust the targeted period for individual projects to align with specific system demands;

CONNSSA withholds comment until after the Technical Meeting.

h. Relevant operational aspects and lessons learned from similar programs in other jurisdictions, such as Hawaii and Nevada;

Again, developers expressed that it seems that these out-of-state frameworks are being used to devalue solar power and that Connecticut's market is not yet mature enough to handle them.

A member pointed out that Eversource is using data from these jurisdictions to argue that adding midday solar no longer adds value because it has already successfully "tamped down peaks."

Another CONNSSA member notes that the EDCs have previously compared their goals to the New York Value of Distributed Energy Resources (VDER) framework explaining that under the NYSERDA calculator, a sunny day at 1:00 p.m. only pays 5 cents a kilowatt-hour because the grid doesn't need the power then. However, feeding the grid at 7:30 p.m. pays 29 cents. Since solar doesn't naturally produce at 7:30 p.m., the member too felt that this framework is designed to "devalue solar here."

i. Any additional considerations for the implementation of an MPF for successor programs in Connecticut.

Members discussed additional implementation barriers that PURA must consider before moving forward with a Multipart Payment Framework (MPF) in Connecticut.

There was emphasis that the $85 million programmatic cap across the RRES, NRES, ESIS, and SCEF programs is now signed into law. And that because paired solar-and-storage systems carry a much higher dollar value than solar-only installations, baking a large per-kW incentive (like the 50-cent example discussed) into the framework means a smaller overall number of projects will be selected before the state's budget cap is completely exhausted.

The argument was made that Connecticut's clean energy programs have historically been tasked with growing clean energy generation and reducing Greenhouse Gas emissions. Forcing them to absorb "peak shaving" and "flexible dispatch" duties under the same rigid budget means new clean energy generation deployment will slow. Funds originally intended for new generation will be diluted to encourage (or require) non-generating technology designed to offset periods of high grid operating costs. If the goal is targeted power delivery to control grid operating costs, perhaps funds in other budgets intended for peak power generation could be diverted to support the integration of BESS into new solar installations.

A member noted that under Eversource's framework, a front-of-the-meter (FTM) storage asset would be forced to charge *exclusively* from its co-located solar array to maintain statutory eligibility. Because it is an FTM asset, it would be entirely blocked from participating in the Green Bank's existing behind-the-meter Energy Storage Solutions (ESS) Program.

An additional warning was raised over what was termed the EDCs lack of transparency in processing payouts. Battery developers currently have no idea how their demand-response payouts are calculated because "these checks arrive with no statements" it was stated. And that if Connecticut implements an MPF, it must be easy to understand and easy to model. Otherwise, piling additional time-differentiated variables onto EDCs that already struggle with basic payout transparency will break developer trust.

CONNSSA notes that Eversource anticipates MPF performance "would be measured by a single utility-owned meter with interval capability."[6] The EDC would thus own the meter, hold the data, perform the calculation, and make the payment. For these incentives to be bankable, developers and business owners will need access to the same granular data set, and the ability to confirm that the calculation is correct.

That access does not exist today, even for far simpler compensation. Current NRES compensation does not depend on hourly interval data; it is based on generation reconciled on a quarterly basis. Yet CONNSSA members' review of their commercial customers' NRES projects indicates that neither customers nor developers are able to properly assess whether their compensation aligns with actual system production. In some cases, commercial customers are not receiving notifications that payments have been made at all. CONNSSA members have encountered similar problems with ESS performance incentive payments, which are calculated and paid by the Program Administrators; customers have been asked to accept those payments on good faith, and in a number of cases discrepancies were identified only through independent review of inverter-level data. In its first-round comments, CONNSSA also asked the EDCs to clarify whether their existing billing systems can accommodate interval data at all.[7]

If customers and developers cannot verify a quarterly generation payment today, they will not be able to verify a payment that depends on a greater level of granularity (i.e., the lowest hour of output on each day of the year for a combined solar-and-storage system). Pairing solar with storage and grading the combined system by a calculation that neither the customer nor the developer can see would create an unacceptable framework. Before any interval-based incentive is adopted, CONNSSA recommends that PURA require three things.

[6] Eversource Comments, p. 7.
[7] CONNSSA Comments, p. 2.

First, data access: participants should receive the interval data used for settlement, at the same granularity used in the calculation, through an automated, no-cost channel within a defined period after each settlement cycle. Second, payment notification and settlement statements: every payment should be accompanied by notice to the customer and a statement showing the measured output, any excluded hours and the reason for exclusion, the rate applied, and the resulting amount. Third, dispute resolution: a defined dispute process with deadlines, in which revenue-grade inverter or participant metering data is accepted as evidence.

CONNSSA respectfully suggests that the EDCs demonstrate this level of transparency for existing NRES compensation before PURA considers a more complex, interval-dependent compensation stream.

2. NRES Successor Program Netting Tariff; The PURA seeks comments on mechanisms to incentivize the paired deployment of solar and storage resources for customers enrolling under a Netting tariff in the non-residential successor program. Specifically, the PURA requests stakeholder comments on whether a non-residential Netting tariff should offer netting on an instantaneous basis with exports compensated at a rate less than the full kWh retail rate, mirroring the approach that has been considered for residential behind-the-meter projects. See Eversource Comments, Aug. 26, 2026, p. 5. In their responses, stakeholders should describe how an instantaneous Netting tariff with reduced export compensation can be implemented within a continued competitive solicitation process, pursuant to Public Act No. 26-127.

CONNSSA offers two preliminary observations. First, a reduced export rate is not needed to create a storage signal for commercial netting customers. As CONNSSA explained in the first round, commercial projects already "calibrate energy storage to deliver additional power to a facility at specific times of day in order to lower demand-facing charges."[8] Netting customers have additional opportunity to mitigate demand charges through on-site generation. Demand-charge mitigation is a meaningful price signal that need not be duplicated through a reduced export rate.

Second, Public Act 26-127 § 2(a) provides that "[t]he rate for such tariffs shall be established by the solicitation."[9] An administratively set, below-retail export rate appears to be in tension with that directive, and PURA has already concluded that the Act does not authorize a standard-offer framework for NRES. CONNSSA does not see how an administratively set export discount can be reconciled with a rate "established by the solicitation" without requiring bidders to price the discount into their bids, which would add the complexity and financing risk discussed above. CONNSSA requests that this question also be addressed at the Technical Meeting.

[8] CONNSSA Comments, p. 2.
[9] Public Act No. 26-127 § 2(a).

Residential Incentive Adder Implementation; In response to PURA's request for stakeholder comments regarding whether residential incentive adders should continue to be administered as volumetric adder based on total production or an alternative method, stakeholders suggested that, to reduce the need for dedicated production meters, adders could be administered as (1) fixed per-kW incentives, or (2) per-kWh incentives based on energy exports recorded at the revenue meter. Eversource Comments, Aug. 26, 2026, p. 13; SEIA, ACT, and United Comments, Aug. 26, 2026, p. 15. The PURA seeks further stakeholder comments on the benefits and drawbacks of these alternative adder administration approaches, including whether any fixed per-kW incentive should be administered monthly or as a one-time upfront incentive.

CONNSSA does not intend to restate at length the preferences it set out in its prior filings.[10] In brief, CONNSSA recommends that the adder approach follow the tariff structure. For systems enrolled in the Netting tariff, incentive adders could be administered as export-based per-kWh adders measured at the customer's revenue meter, consistent with the shift to instantaneous netting. For systems enrolled in the Buy-All tariff, adders should continue to be based on system performance as recorded by the production meter.

Thank you.

Michael Trahan

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[10] CONNSSA Comments, p. 4.