STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
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DOCKET NO. 26-06-04 IMPLEMENTATION OF CLEAN ENERGY SUCCESSOR PROGRAMS

November 18, 2026

PROPOSED INTERIM DECISION

This proposed decision is being distributed to the participants in this proceeding for comment. The proposed decision is not final. The Authority will consider the participants' arguments and exceptions before reaching a final decision, which may differ from the proposed decision. Therefore, this proposed decision does not establish any precedent and does not necessarily represent the Authority's final conclusion.

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PROPOSED INTERIM DECISION

I. INTRODUCTION

A. SUMMARY

In this Interim Decision, the Public Utilities Regulatory Authority (Authority or PURA) establishes the general framework for renewable energy tariffs for residential customers, non-residential customers, and community solar projects for The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI; collectively, with Eversource, the electric distribution companies or EDCs) effective January 1, 2028 through December 31, 2035, pursuant to sections 1, 2, and 3 of Public Act No. 26-127, An Act Concerning Renewable Power Generation. The Authority also directs the EDCs to develop and submit additional information for consideration in the remainder of this proceeding.

B. BACKGROUND OF THE PROCEEDING

On June 5, 2026, the Authority initiated the above-captioned proceeding to implement successor programs to the Residential Renewable Energy Solutions (RRES), Non-Residential Renewable Energy Solutions (NRES), and Shared Clean Energy Facility (SCEF) Programs, pursuant to Public Act No. 26-127, An Act Concerning Renewable Power Generation, §§ 1, 2, and 3.

The Authority indicated its intent to issue an interim decision in this docket to provide direction regarding the overall structure of successor programs, recognizing that significant changes from the current programs may require time to implement before successor programs take effect in January 2028. See Notice, Sept. 21, 2026, p. 1. Additional aspects of successor clean energy program implementation will be considered throughout the remainder of this proceeding. Pursuant to Public Act No. 26-127, §§ 1(b), 2(a), and 3(a), a final decision will be issued no later than December 1, 2027.

C. CONDUCT OF THE PROCEEDING

On June 26, 2026, the Authority issued a Notice of Proceeding. On July 28, 2026, the Authority issued a Notice of Request for Written Comments on the following topics: (1) Time-differentiated compensation, (2) Residential metering requirements, (3) Residential incentive adder implementation, and (4) Additional topics. On or before August 31, 2026, the Authority received 17 sets of written comments from interested stakeholders.

On September 9, 2026, the Authority issued a second Notice of Request for Written Comments on the following topics: (1) Multipart Payment Framework for NRES Buy-All and SCEF successor programs, (2) NRES successor program netting tariff, and (3) Residential incentive adder implementation. On October 2, 2026, the Authority received 11 sets of written comments from Program stakeholders.

On October 22, 2026, the Authority held a Technical Meeting to discuss the topics outlined in the prior Notices of Request for Written Comments.

D. PARTICIPANTS

A listing of all Participants to this proceeding is appended hereto as Appendix A.

II. STATUTORY AUTHORITY AND OBJECTIVES

A. PUBLIC ACT NO. 26-127

Public Act No. 26-127, § 1(b) directs the Authority to initiate a proceeding to establish a successor program to the RRES Program, and to establish (1) tariffs for each EDC, (2) a rate for such tariffs, and (3) tariff terms and conditions consistent with the requirements of this section.

Public Act No. 26-127, § 2(a) directs the Authority to initiate a proceeding to establish a successor to the NRES Program, and to establish (1) a procurement plan for the EDCs and resulting tariffs for selected projects, (2) a price cap on a cents-per-kilowatt-hour basis concerning any distributed energy resource selected, and (3) tariff terms and conditions.

Public Act No. 26-127, § 3(a) directs the Authority to initiate a proceeding to establish the Community Solar Program as the successor to the SCEF Program, and to establish (1) a procurement plan for the EDCs and resulting tariffs for selected projects (2) a price cap on a cents-per-kilowatt-hour basis concerning any shared clean energy facility selected, and (3) tariff terms and conditions.

Public Act No. 26-127, § 4(a) specifies that, for tariff years commencing on and after January 1, 2028, the target for the total aggregate procurement of energy products by the EDCs shall be (1) 180 megawatts (MW) per year for the programs established pursuant to Public Act No. 26-127, §§ 1, 2, and 3; and (2) an aggregated total of $85 million per year for programs established pursuant to Public Act No. 26-127, §§ 1, 2, and 3 and General Statutes § 16-243ee.[1]

B. OBJECTIVES FOR CLEAN ENERGY SUCCESSOR PROGRAMS

When establishing the current renewable energy tariff programs, the Authority established objectives to guide the development and successful implementation of the programs to ensure that the tariffs, and the associated programs, were designed to achieve the state's policy goals. Here, the Authority proposes a set of common objectives to guide the design and implementation of all three successor clean energy programs, based on the goals set forth in Public Act No. 26-127.

The current RRES program objectives are as follows:

1. To support the sustained, orderly development of the state's solar industry, ensuring at a minimum that Connecticut's annual historical

[1] General Statutes § 16-243ee refers to the Energy Storage Solutions (ESS) Program, which is active until December 31, 2035. Public Act 26-127, § 6(a). The ESS Program, although subject to the aggregate program budget cap beginning in 2028, is not directly modified by this decision.

deployment of residential solar is maintained (i.e., approximately 50–60 MW per year);
2. To achieve a 100% zero carbon electric grid by 2040, including by promoting additional annual deployment of residential renewable energy as needed;
3. To balance participant costs and benefits with non-participant costs and benefits and electric system costs and benefits;
4. To ensure program accessibility for customers, by providing customer protections both explicitly through resources and disclosure forms, and through simplified program and tariff designs;
5. To encourage increased inclusivity overall, as well as program participation by low and moderate-income (LMI) customers and customers in environmental justice communities.

Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, PURA Implementation of Section 3 of P.A. 19-35, Renewable Energy Tariffs and Procurement Plans (RRES Decision), p. 7.

The current NRES program objectives are as follows:

1. To foster the sustained, orderly development of the state's Class I renewable energy industry;
2. To deploy the full megawatt capacity allowable under statute, to the extent possible (see General Statutes § 16-244z(c)(1)(A));
3. To ensure least-cost program outcomes through the annual solicitation process;
4. To enable program accessibility for customers through simplified program and tariff designs; and
5. To encourage increased inclusivity overall, as well as program participation by customers in vulnerable and environmental justice communities.

Decision, June 30, 2021, Docket No. 20-07-01, PURA Implementation of Section 3 of P.A. 19-35, Renewable Energy Tariffs and Procurement Plans (NRES Decision), p. 7.

The current SCEF program objectives are as follows:

1. To annually and cost-effectively procure up to 50 MW of SCEFs, as defined in General Statutes § 16-244z;
2. To provide savings to specific categories of customers, particularly customers with LMI, low-income service organizations, and customers who reside in environmental justice communities; and
3. To lower or eliminate barriers to entry for Subscriber Organizations.

Decision, Dec. 7, 2022, Docket No. 22-08-04, Annual Shared Clean Energy Facility Program Review – Year 4, p. 7.

The Authority proposes updated program objectives for the successor clean energy programs. These objectives build on those of the current programs, while incorporating the policy objectives that the legislature set forth in Public Act No. 26-127. Additionally, the Authority finds that successor programs would benefit from a consolidated set of objectives to improve program simplicity for participants, as well as to recognize common aims for renewable energy deployment across different market segments.

The proposed objectives establish a common policy framework for the successor clean energy programs while preserving the flexibility necessary to account for differences in program structure, statutory requirements, and market segments served. The objectives are intended to guide program design, implementation, and evaluation, including considerations of the tradeoffs among renewable energy deployment, ratepayer impacts, system benefits, accessibility, and equity. These objectives may involve competing considerations, and no objective should be evaluated in isolation. Accordingly, the Authority will consider the objectives collectively when evaluating program requirements and potential modifications, consistent with applicable statutory mandates. Where appropriate, the Authority may establish program-specific metrics to evaluate progress toward these objectives.

The Authority proposes the following objectives for the clean energy successor programs:

1. To advance Connecticut's carbon reduction targets, specified in General Statutes § 22a-200a(a), through the orderly deployment of Class I renewable energy resources;
2. To provide positive net benefits to all ratepayers, including enhanced distribution system efficiency and utilization;
3. Maximize clean energy deployment within the MW capacity and budget allowable under Public Act No. 26-127, § 4(a), to the extent feasible;
4. To promote program accessibility through straightforward program and tariff designs and appropriate participant protections;
5. To advance inclusive and equitable access to clean energy resources and their benefits.

III. RESIDENTIAL CLEAN ENERGY PROGRAM DESIGN

In its February 27, 2026 report to the legislature in Docket No. 25-02-14, Renewable Energy Tariff Program Successor Study, the Authority offered several recommendations for successor program design based on its evaluation of the current RRES Program and stakeholder positions. See PURA Corresp., Feb. 27, 2026 (Successor Study Report). Here, the Authority builds on that extensive stakeholder process, within the specifications of Public Act No. 26-127 and with the goal of advancing the proposed objectives of the successor clean energy programs.

This section addresses the general tariff framework and does not yet make a final determination on all aspects of residential program design, which will continue to be evaluated over the course of this proceeding. Where possible, the Authority aims to

preserve the current RRES Program rules to promote continuity, minimize administrative burden, and avoid participant confusion during the transition to the successor program.

A. TARIFF STRUCTURES

Public Act No. 26-127, § 1(d) requires that the successor to the RRES Program continue to offer residential customers[2] two tariff options, each for a term not to exceed 20 years, specifically stating:

> (1) On and after January 1, 2028, in compliance with the program established under this section, each electric distribution company shall offer tariffs with terms not to exceed twenty years, to any residential customer for the purchase of energy products and renewable energy certificates generated from a distributed energy resource that (A) emits no pollutants, (B) is located on a customer's premises, and (C) has a nameplate capacity rating of twenty-five kilowatts or less per dwelling unit located on such premises.
>
> (2) Tariffs offered pursuant to this section shall be: (A) For the purchase of any energy at the rate established by the authority pursuant to subsection (c) of this section, and any renewable energy certificates generated by such energy resource, on a cents-per-kilowatt-hour basis, and (B) for the purchase of any energy produced and not consumed in a period of time established by the authority, and any renewable energy certificates generated by such renewable energy resource, on a cents-per-kilowatt-hour basis. A residential customer may not select more than one tariff offered pursuant to this section for the same premises.

Public Act No. 26-127, § 1(i) requires that the EDCs offer the residential tariffs for eight years, or until December 31, 2035.

As in the RRES Program, the Authority uses the term "'buy-all tariff" to mean "[a tariff for] the purchase of any energy at the rate established by the Authority pursuant to subsection (c) of this section, and any renewable energy certificates generated by such energy resource, on a cents-per-kilowatt-hour basis," and the term "netting tariff" to mean "[a tariff] for the purchase of any energy produced and not consumed in a period of time established by the authority, and any renewable energy certificates generated by such

[2] "Residential customer" is defined as "a customer that resides in a single-family home, a multifamily development consisting of two to four dwelling units or a multifamily development consisting of five or more dwelling units, provided in the case of a multifamily development consisting of five or more such units, (A) not less than sixty per cent of the units of the multifamily development are occupied by persons and families with income that is not more than sixty per cent of the area median income for the municipality in which it is located, as determined by the United States Department of Housing and Urban Development, or (B) such multifamily development is determined to be affordable housing by the Public Utilities Regulatory Authority according to any alternative metrics designated by the authority." Public Act No. 26-127, § 1(a)(8).

renewable energy resource, on a cents-per-kilowatt-hour basis." Public Act No. 26-127, § 1(d)(2); see RRES Decision, p. 8.

Based on the analysis of tariff structures presented below, the Authority directs the EDCs to implement the necessary billing and IT modifications to establish, no later than January 1, 2028, two tariff options for the RRES successor program: (1) \an instantaneous netting tariff and (2) a flat buy-all tariff. Both tariffs shall have terms of up to 20 years.

1. Netting Tariff

Under a netting tariff, a customer's renewable energy production and electricity consumption are metered together using a bidirectional meter. RRES Decision, p. 9. All renewable energy production consumed within the established netting interval is netted against the appropriate rate components under a customer's applicable tariff, and all renewable energy production not consumed within the established netting interval is compensated at an established rate. Id., pp. 9–10. Public Act No. 26-127, § 1(d)(2) directs the Authority to establish the period of time, or interval, for the netting tariff under the RRES successor program.

Currently, the RRES Program uses a monthly netting interval, under which a participant's electricity imports and exports to the grid are netted over the course of each monthly billing period to determine the customer's net electricity consumption or production for billing purposes. RRES Decision, p. 8. In developing successor program recommendations, the Authority evaluated various netting intervals and considered alternatives to the RRES Program's monthly netting interval in Docket No. 25-02-14. In its final report to the legislature, the Authority recommended that a successor residential solar program utilize instantaneous netting, under which electricity imports and exports are netted at the time they occur. Successor Study Report, pp. 1, 35, 40.

The Authority found that instantaneous netting would better reflect the real-time value of energy to the grid. Id., p. 1. The current monthly netting interval effectively serves as a form of "virtual" or "free" energy storage provided by the grid, as customers may apply credits from excess production to offset consumption regardless of the time that energy is produced or consumed. Id., p. 39. In contrast, instantaneous netting would better reflect the variable value of clean energy generation to the grid and strengthen incentives for customers to invest in storage, particularly when paired with reduced compensation for energy exported to the grid. Id. Offering compensation at less than the full retail rate for real-time exports to the grid would incentivize customers to maximize self-consumption of renewable energy at the time of generation through load management or deployment and operation of behind-the-meter (BTM) energy storage, thus aligning demand with times of energy generation and shifting load away from peak demand periods. Successor Study Report, pp. 39–40.

The Authority conducted a benefit-cost analysis (BCA) of instantaneous netting with reduced export compensation and found that it would significantly improve the program-wide ratepayer impact measure (RIM) compared to a program with monthly netting at the full retail rate. Id., pp. 42–44. These results support the choice of

instantaneous netting paired with reduced export compensation to advance the objective of providing positive net system benefits to all ratepayers.

Importantly, instantaneous netting is feasible using the EDCs' existing metering equipment, although billing updates will be required. Id., p. 35; Interrog. Resps. OCC-7, CAE-43.[3] Existing meters record energy imports and exports on separate channels, enabling the EDCs to bill customers for energy purchased from the grid and separately credit customers for exports to the grid at a different compensation rate. Id., p. 35; Interrog. Resps. OCC-7, CAE-43. In contrast, alternative daily, sub-daily, or hourly netting intervals would require AMI, which is not yet widely deployed in Eversource service territory. Eversource Interrog. Resp. CAE-1, Docket No. 25-02-14.

a. Stakeholder Comments

i. Netting Interval

Several stakeholders expressed support for instantaneous netting paired with reduced export compensation. The Connecticut Green Bank (CGB) points to language in Public Act No. 26-127 that prioritizes the pairing of solar and storage systems that provide system benefits for all ratepayers by reducing peak demand. CGB Comments, Aug. 26, 2026, pp. 1–2. Accordingly, CGB recommends that the successor framework establish lower export compensation to encourage paired solar and storage systems to "retain and shift solar production that would otherwise be exported to the grid during periods of low onsite load, and instead utilize that energy to reduce customer and system demand during peak periods," reducing costs passed on to all ratepayers through the non-bypassable federally mandated congestion charge. Id., p. 4. The Office of Consumer Counsel (OCC) recommends that instantaneous netting with energy exports be compensated at a flat rate that is less than the retail rate with current metering capabilities, and states that the flat rates should be equal to or less than the weighted average hourly value provided by solar generation. OCC Comments, Aug. 26, 2026, p. 12. Eversource states that adjusting netting intervals and compensation for excess generation would incentivize customers to optimize the use of onsite generation through paired energy storage. Eversource Comments, Aug. 26, 2026, pp. 9–10.

The Solar Energy Industries Association (SEIA), the Alliance for Climate Transition (ACT), and Advanced Energy United (United; collectively, the Clean Energy Parties) note that instantaneous netting will involve estimating the percentage of a solar system's production that will be exported in real-time each month using customer energy consumption and solar production data; these estimates will necessarily be uncertain and widen the range of customer outcomes, particularly if customers do not have access to

[3] UI suggests that its advanced metering infrastructure (AMI) meters cannot perform instantaneous netting without manually reprogramming each meter. See UI Corresp., Oct. 16, 2026, p. 8; UI Comments, Oct. 2, 2026, pp. 9–10. At the same time, UI confirms that its existing meters record energy imports and exports on separate channels, on a real-time basis. Id. These separate measurements of energy sent to the grid and received from the grid are the only additional information required to adopt an instantaneous netting compensation structure. The Authority also notes that, when the RRES Program was established, UI indicated that "instantaneous netting has the lowest administrative costs and offers the least complex billing relative to the other netting options." RRES Decision, p. 11.

granular energy usage data. Clean Energy Party Comments, Aug. 26, 2026, pp. 7–8. Nevertheless, the Clean Energy Parties recognize that instantaneous netting will "provide an economic signal to the market to move toward solar and energy storage because of the relative benefit of storing solar energy for self-consumption outside of daylight hours." Id., p. 8.

ii. Time-Differentiated Export Compensation

Additionally, the Authority considered whether the successor residential tariffs should adopt time-differentiated export compensation rates, noting that the Successor Study Report recommendations indicated that export compensation could shift from a fixed rate to a time-varying rate in the future. Notice, July 28, 2026, pp. 1–2. The Authority requested stakeholder feedback on the optimal timing of such a shift. Id.

Most stakeholders oppose near-term time-differentiation in residential compensation rates. CGB recommends that such a transition should occur gradually for residential customers, stating that the initial tariff could use a fixed reduced export compensation rate while stakeholders collaborate on developing the technical and programmatic requirements necessary for a future transition to time-differentiated export rates. CGB Comments, Aug. 26, 2026, p. 6. The Clean Energy Parties and the Connecticut Solar and Storage Association (ConnSSA) caution against overly complex compensation structures for participants and installers. Clean Energy Party Comments, Aug. 26, 2026, pp. 7–9; ConnSSA Comments, Aug. 26, 2026, p. 3. The Clean Energy Parties state that any consideration of time-differentiated export compensation should be determined after AMI is deployed, more granular energy usage data is available, and updated time-of-use (TOU) rates are established. Clean Energy Party Comments, Aug. 26, 2026, p. 9. Similarly, the Acadia Center, the Conservation Law Foundation (CLF), People's Action for Clean Energy (PACE), Portland Clean Energy Task Force, Sierra Club, and Vote Solar (collectively, the Clean Energy Advocates) recommend postponing time-differentiated export compensation until updated residential TOU rates and periods are available to avoid creating two different "peak" definitions for residential customers. Clean Energy Advocates Comments, Aug. 26, 2026, p. 4.

UI also recommends postponing time-differentiated export compensation until updated TOU rates and periods are available. UI Comments, Aug. 26, 2026, p. 4. Eversource recommends that more complex compensation structures be prioritized for large resources because for residential customers, the benefits of time-differentiated compensation would be less significant, while adjusting netting intervals and compensation for excess generation would be sufficient to optimize generation without more complex time-differentiated frameworks. Eversource Comments, Aug. 26, 2026, pp. 9–10. Conversely, DEEP supports time-differentiated compensation for the RRES successor program, stating that it is "the only way to have the benefits to all ratepayers be greater than the costs" and should not be postponed for any reason. DEEP Comments, Aug. 26, 2026, pp. 4–5.

b. Authority Analysis

The Authority concludes that the RRES successor program shall adopt instantaneous netting with exported energy compensated at a rate less than the full retail rate. Public Act No. 26-127 indicates a clear goal for successor programs to prioritize delivering benefits to all ratepayers. Instantaneous netting paired with reduced export compensation can advance this objective. By incentivizing customers to consume solar onsite, through battery storage or demand flexibility, clean energy generation is effectively shifted away from hours of high solar production and low load, and toward hours when energy is more expensive to procure and deliver. See Successor Study Report, pp. 33–34. Reduced export compensation for real-time exports thus serves as a proxy for time-differentiated compensation in the absence of interval metering or AMI.

Further, additional time-differentiation of export compensation is unnecessary at this time. As noted in the Successor Study Report, a fixed export compensation rate provides an effective proxy for time-differentiation, while recognizing current limitations of available metering equipment. Additionally, instantaneous netting presents a more complex program structure for residential customers to understand when compared to the current RRES Program. Avoiding additional complexity via time-differentiated exports while participants adapt to the new program framework will further the fourth program objective of promoting program accessibility through simplified program and tariff designs. Pursuant to General Statutes § 16-243n(a), the EDCs should propose time-varying rates for residential customers by October 1, 2027. The Authority agrees with stakeholders that solar programs should avoid implementing time-differentiated frameworks that duplicate or conflict with the anticipated TOU proposals. Once updated TOU rates are available, this may present an opportunity to further align solar compensation with established TOU periods and rate structures.

Eversource estimates that it could implement billing upgrades for residential instantaneous netting at a cost of approximately $1 million and timeline of 12 months. Eversource Interrog. Resp. CAE-01. Eversource recommends that compensation for exported energy should remain tied to prevailing retail rate components, stating that using existing rate values within EDC billing systems would streamline tariff administration and be easier for customers to understand. Eversource Comments, July 31, 2026, Docket No. 25-02-14, pp. 3–4; Tech Mt'g Tr., Oct. 22, 2026, 93:1–94:5. However, Eversource stated that implementing a separate export compensation rate not tied to existing bill components would also be feasible. Tr., 94:7–17.

In Docket No. 25-02-14, UI estimated that it could adapt current methods used for the RRES Buy-All tariff and Rate SG2 for a real-time netting option for less than $100,000 with an implementation timeline of between six to eight months. UI Interrog. Resp. CAE-01, Docket No. 25-02-14. UI did not subsequently provide an updated estimate of the cost and timeline in this docket, noting that the previous response was "a high-level, preliminary estimate" based on limited information and citing the need to engage outside vendors after an Authority final decision. UI Interrog. Resp. CAE-01. However, UI's previous estimates in Docket Nos. 25-02-14 and 20-07-01 suggest that an instantaneous netting option could be implemented without excessive cost, building on existing tariff

designs. Additionally, UI notes that Rate SG2 currently prices imports and exports separately using the two meter channels, and anticipates that implementing a similar approach used for an instantaneous netting tariff could be straightforward. Tr., 47:1–21; 39:9–12. The Authority also issued a procedural order directing the EDCs to conduct a request for proposals (RFP) to evaluate billing upgrade requirements. Notice of Procedural Order, Oct. 9, 2026, pp. 1–2. Thus, the Authority expects that UI, to the extent it has not already done so, will soon complete a more thorough evaluation of the implementation requirements.

The EDCs shall implement billing updates to enable a netting tariff with an instantaneous netting interval. As initial estimates indicated that billing updates to accommodate instantaneous netting could be completed within 12 months or less, the Authority directs the EDCs to complete implementation of billing updates such that customers can apply to the program and begin receiving compensation under the RRES successor netting tariff beginning on January 1, 2028.[4]

For clarity, instantaneous netting should solely require changes to the billing system to utilize the import and export channels of both EDCs' existing metering equipment, such that exports to the grid can be compensated at a different value from prevailing retail rates. As discussed above, the Authority is not authorizing time-varying export compensation at this time, and no manual adjustments to meters should be required. As the values of the import and export meter channels are already measured and reported monthly on RRES customers' bills, implementing instantaneous netting should require only simple changes to EDC billing systems. The Authority will evaluate the prudence of all implementation costs after they have been incurred. The EDCs will be responsible for demonstrating the reasonableness and prudence of expenditures and taking all reasonable measures to contain costs.

A specific compensation rate for exported energy has not yet been determined. In establishing tariff rates, the Authority must take into account:

> the electric system benefits received by all ratepayers from the distributed energy resource based on time of production, equitable distribution of participant benefits, the Comprehensive Energy Strategy adopted pursuant to section 16a-3d of the general statutes, the Integrated Resources Plan developed pursuant to section 16a-3a of the general statutes, the system efficiency and utilization goal established pursuant to section 16a-3v of the

[4] Eversource suggests that, if its AMI plan proceeds as proposed in Docket No. 26-05-10, Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules, it may "recommend instantaneous netting be implemented in parallel with deployment of a new [customer information system (CIS)] instead of making changes to existing IT infrastructure that would be promptly replaced." Eversource Interrog. Resp. CAE-1. However, Eversource is unable to estimate when instantaneous netting could be implemented in conjunction with the new CIS. Interrog. Resp. CAE-30. Deferring implementation of instantaneous netting based on the as-yet uncertain outcome of Eversource's AMI plan would delay the authorized program framework by at least several years, which is not an acceptable timeline for successor programs that are statutorily required to begin in 2028.

> general statutes and the value or benefits of distributed energy resources to the reliability of the electric grid in the state.

Public Act No. 26-127, § 1(c). In the remainder of this proceeding, the Authority will analyze and determine an export compensation methodology and rate that satisfies these statutory requirements. To preserve flexibility in the ultimate export rate determination, the EDCs shall implement billing system updates such that the export compensation rate may be either linked to existing bill components or programmed as an independent value that can be updated over time.

Finally, in its report to the legislature, the Authority did not recommend the continued assessment of a production-based non-bypassable charge (also referred to on customer bill as the solar energy adjustment or solar production charge).[5] Successor Study Report, pp. 16, 36. The Authority maintains this determination. Non-bypassable charges are utilized in the RRES program to avoid overcompensating netting customers when excess generation is credited at the full retail rate. Under an RRES successor program with reduced export rates, non-bypassable charges are no longer required, as the export rate may be directly adjusted to ensure appropriate customer compensation.

2. Buy-All Tariff

In the Successor Study Report, the Authority recommended that, for most participants, the successor residential program offer a single netting tariff option, as over 99% of RRES customers have chosen the netting option to date. Successor Study Report, p. 40. However, the Authority determined that the RRES successor program should retain a buy-all option for low-income customers and multifamily affordable housing (MFAH) projects. Id., pp. 40–42. The buy-all tariff offers a predictable revenue stream independent from a customer's retail rate, protecting customers enrolled in low-income discount rates (LIDR) from eroded value under the netting tariff. Id. Additionally, the buy-all tariff is required for MFAH properties under the RRES Program and allows for simpler benefit allocation among tenants, building owners, and project owners. Id., p. 41. Stakeholders continue to affirm the importance of a buy-all tariff option for MFAH and low-income customers. CGB Comments, Aug. 26, 2026, p. 7; Clean Energy Party Comments, Aug. 26, 2026, p. 15.

Consistent with these recommendations, the Authority authorizes a buy-all tariff for the RRES successor program, with energy and renewable energy certificates (RECs) purchased at a fixed per-kWh compensation rate over the 20-year tariff term. Eligibility for the buy-all tariff shall be limited to income-eligible customers (as defined by Public Act

[5] In the RRES Program, "non-bypassable charge" means a charge that cannot be netted against behind-the-meter renewable energy production for the purposes of a customer's electric utility bill. RRES Decision, p. 39. The Authority authorizes a non-bypassable charge for RRES systems installed in a given calendar year if it calculates that full retail net metering will provide system owners with a rate of return higher than the target (e.g., 11%). Id. The non-bypassable charge is assessed per kWh of solar energy produced for RRES netting customers. Motion No. 7 Ruling, Feb. 24, 2022, Docket No. 20-07-01RE01, p. 2. The non-bypassable charge in the RRES Program is distinct from the Non-Bypassable Federally Mandated Congestion Charge (NBFMCC), which is the electric rate component where program costs are recovered from all ratepayers.

No. 26-127, § 1(a)(9), customers whose income does not exceed sixty percent of the state median income (SMI); or who resides in an affordable housing development) and properties classified as MFAH. To maintain continuity with the current program rules, the Authority intends to preserve the same MFAH eligibility classifications as currently used in the RRES Program.[6]

The RRES Program currently utilizes a buy-all tariff with the same structure as the successor tariff authorized herein. Under a buy-all tariff, the EDC separately records a participant's electricity consumption from the grid and the participant's renewable energy production, compensating the participant for all eligible production at the applicable tariff rate while billing the participant for all electricity consumed at the applicable retail rate. Compliance, Jan. 22, 2026, Docket No. 25-08-02, Att. 01B (RRES Year 5 Program Manual), p. 11. Because the existing RRES buy-all tariff already employs this structure, the EDCs should be able to administer the successor buy-all tariff using their existing billing systems, without requiring additional billing system upgrades. Accordingly, the Authority expects that the EDCs can implement the successor buy-all tariff by updating the applicable tariff compensation rate and any other necessary program parameters, rather than undertaking the more extensive billing system modifications that may be required to implement a new netting methodology.

A specific buy-all compensation rate that appropriately reflects electric system benefits to ratepayers, an equitable distribution of participant benefits, and Connecticut's policy goals, as required by Public Act No. 26-127, § 1(c), will be determined in the remainder of this proceeding.

Additionally, the Authority will investigate whether separate buy-all compensation rates for income-eligible customers and MFAH properties would more appropriately reflect the distinct characteristics of the two customer segments and advance state policy goals. Stakeholders in the most recent RRES Program annual review proceeding, Docket No. 26-08-02, Annual Residential Renewable Energy Solutions Program Review and Rate Setting – Year 6, suggested that larger 5+ unit MFAH projects have lower upfront costs than the 1–4 unit residential segment, due to economies of scale; conversely, other stakeholder noted that MFAH projects have similar costs due to more complicated

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[6] For the purposes of the RRES Program, a three-tier methodology is used for determining when multi-family housing is "affordable housing," and, therefore, is considered a residential customer pursuant to General Statutes § 16-244z(b)(2):

Tier I: Multi-family properties with 5 or more units that participate in the Low-Income Housing Tax Credit Program (LIHTC) or that contain a majority of households earning 80% or less of Area Median Income (AMI) as set by the U.S. Department of Housing and Urban Development (HUD).

Tier II: Multi-family properties with 5 or more units where more than 66% of the residents have a household income at or below 60% of SMI. Naturally Occurring Affordable Housing (NOAH) properties, defined as multi-family properties with 5 or more units with rent levels affordable to persons or families earning less than 80% AMI, based on CT Department of Housing rental calculations.

Tier III: Multi-family properties with 5 or more units that apply for review by the Agencies, are determined to meet the eligibility requirements of an affordable multi-family dwelling by the Agencies, and are approved as an affordable housing facility by PURA.

RRES Year 5 Program Manual, p. 51 (footnotes omitted).

building and ownership arrangements and tenant benefit sharing requirements. See Eversource Comments, May 28, 2026, Docket No. 26-08-02, pp. 7–8; OCC Comments, Aug. 19, 2026, Docket No. 26-08-02, p. 4; CGB Comments, Aug. 19, 2026, Docket No. 26-08-02, pp. 1–3. More analysis is needed to determine whether buy-all compensation rates should be differentiated between low-income and MFAH projects. To the extent that EDC systems cannot currently accommodate different buy-all rates by customer class,[7] the Authority directs the EDCs to implement changes to allow separate low-income and MFAH buy-all compensation rates no later than January 1, 2028.

B. ADDERS

Public Act No. 26-127, § 1(c) specifies that:

> [i]n addition to a tariff rate applicable to any residential customer, the authority shall authorize a separate tariff rate for (1) low-income customers and residential customers in a multifamily development as described in subparagraph (A) or (B) of subdivision (8) of subsection (a) of this section, and (2) residential customers that reside in a distressed municipality, as defined in section 32-9p of the general statutes.

The RRES Program includes incentive adders for low-income customers and customers who reside in distressed municipalities.[8] See, e.g., RRES Year 5 Program Manual, p. 16. For both the netting and buy-all tariffs, incentive adders are assessed based on total PV production as measured by a utility-owned production meter.

1. Stakeholder Comments

Solar contractors participating in the RRES Program recommended that the successor residential program be designed to minimize reliance on utility-owned production meters. Specifically, solar contractors argue the production meter requirement adds equipment and installation costs, requires additional physical space, can lead to delays associated with scheduling utility work, and caused disagreements and challenges throughout the RRES Program. Clean Energy Party Comments, Aug. 26, 2026, pp. 11–13; Clean Energy Advocates Comments, Aug. 26, 2026, pp. 6–7. Instead of adders based on total system production, stakeholders suggested basing them on energy exports as measured by the revenue meter. Id.; Clean Energy Party Comments, Aug. 26, 2026, p. 15. Alternatively, Eversource suggested basing adders on a fixed value, such as system

[7] Eversource suggested that its billing system can accommodate different buy-all rates, and the change could be implemented at no cost and a minimal timeline. Eversource Interrog. Resp. CAE-26, Docket No. 26-08-02. UI was unable to provide information regarding implementation cost or timeline. UI Interrog. Resp. CAE-26, Docket No. 26-08-02. The Authority anticipates that this should be a straightforward change with zero or minimal implementation cost, but nevertheless directs the EDCs to pursue implementation to allow various options for the successor program design.

[8] Customers are eligible for the RRES income-eligible adder if they have verified incomes at or below 60% of SMI. Customers are eligible for the RRES distressed municipality adder if they reside in Economically Distressed Communities, as defined by the Connecticut Department of Economic and Community Development (DECD).

capacity, if the production meter requirement is removed. Eversource Comments, Aug. 26, 2026, pp. 11–12.

The Clean Energy Parties[9] state that either method (fixed capacity-based incentives or volumetric incentives based on exports) offers the benefit of not relying on a production meter and provide an incentive to drive deployment among certain customers; however, a capacity-based approach would be preferable as it provides a clear and reliable incentive amount. Clean Energy Party Comments, Oct. 2, 2026, p. 12. Save the Sound similarly argues that a fixed capacity-based incentive would likely incur lower administrative costs and simplify project financing. Save the Sound Comments, Oct. 2, 2026, p. 1. Conversely, OCC prefers adders administered based on volumetric energy exports, but expresses concern that export-based adders would discourage onsite consumption of produced energy. OCC Comments, Oct. 2, 2026, p. 14. OCC and Eversource also recommend against upfront incentives, as they could expose ratepayers to risk by funding incentives for facilities that may not remain in service for their full useful lives. Id.; Eversource Comments, Oct. 2, 2026, p. 10.

Eversource states that it would be feasible to administer fixed per-kW residential incentives within existing processes and systems, and expects that the current quarterly frequency of incentive payments of the RRES program will remain adequate for any successor program. Eversource Interrog. Resp. CAE-6; Eversource Comments, Oct. 2, 2026, p. 9. UI states that, if the Authority adopted a fixed per-kW incentive structure and retained a quarterly or annual payment cadence, UI could likely administer the incentive through a modified semi-automated process similar to the current approach, where incentive calculations are done within the billing system based on production data but payments are issued outside of the billing system. UI Interrog. Resp. CAE-6, p. 1.

2. Authority Analysis

The Authority adopts a fixed capacity-based adder structure, which eliminates one use of production meters for netting customers under the RRES successor program. Incentive adders can readily achieve their intended objective—advancing inclusive and equitable access to clean energy resources and their benefits, and authorizing a separate tariff rate for low-income customers, MFAH residents, and residents of distressed municipalities pursuant to Public Act No. 26-127, § 1(c)—without being tied to total system production. An incentive adder assessed based on installed kW capacity reduces reliance on production meters, which can increase project development costs, with minimal changes to EDC processes while continuing to enable equitable access by reducing the higher upfront costs of such projects. The Authority finds capacity-based adders preferable to adders based on exports measured at the revenue meter. A capacity-based adder offers predictable value for participants and facilitates more accurate estimates of total program costs. By contrast, adders based on energy exports are inherently more uncertain under a netting tariff design that incentivizes self-

[9] Along with SEIA, ACT, and United, Vote Solar is also included in the Clean Energy Parties' October 2, 2026 Comments.

consumption over exports and could create competing financial incentives for participants.

Accordingly, the Authority authorizes incentive adders as a fixed value per kW AC of installed system capacity for the RRES successor program. Incentive adders shall continue to be provided on a quarterly basis, maintaining the cadence used in the RRES Program to minimize administrative changes and implementation costs. As incentive adders are currently issued outside of the EDCs' billing systems, minimal updates to EDC systems and processes should be required to facilitate a capacity-based method of incentive administration. Specific incentive values will be determined in the remainder of this docket.

C. METERING REQUIREMENTS AND REC TREATMENT

Utility-owned production meters are revenue-grade meters that enable the EDCs to measure a project's total renewable electricity production. EDC Compliance, Jan. 22, 2026, Docket No. 25-08-02, Annual Residential Renewable Energy Solutions Program Review and Rate Setting – Year 5, Att. 1b, p. 9. Under the current RRES Program, these meters are required to calculate production-based customer adders and assess non-bypassable charges. As discussed in Section III.B above, however, the RRES successor program's framework no longer requires a utility-owned production meter for incentive adders. Additionally, production meters will no longer be required for the assessment of non-bypassable charges under the netting tariff. See Section III.A.1, Netting Tariff. For customers participating under the buy-all tariff, production meters will still be necessary to measure total production and determine customer compensation.

Utility-owned production meters also serve a separate function under the RRES Program: measuring renewable energy production for purposes of accounting for RECs, which the EDCs sell into the New England Power Pool Generation information system (NEPOOL GIS) REC market on behalf of all ratepayers. See, e.g., RRES Decision, p. 19. As in the RRES Program, successor residential tariffs are for the purchase of energy and RECs. Public Act No. 26-127, § 1(d)(1). Thus, REC production from renewable resources installed under the RRES successor program must continue to be measured and accounted for, whether through existing utility-owned production meters or an alternative mechanism.

1. Stakeholder Comments

The Authority solicited comments on potential approaches to measure REC generation without the need for a production meter, including the accuracy, cost, administrative feasibility, and legal permissibility of alternatives. Notice of Request for Written Comments, July 28, 2026, pp. 2–3.

Several stakeholders suggest that RECs could be recorded based on exports measured at the revenue meter, rather than total system production. Clean Energy Party Comments, Aug. 26, 2026, p. 13; Clean Energy Advocates Comments, Aug. 26, 2026, p. 7; ConnSSA Comments, Aug. 26, 2026, p. 4. The Clean Energy Parties state that utility revenue meters meet the NEPOOL GIS meter accuracy requirements. Clean Energy

Party Comments, Aug. 26, 2026, p. 13. The EDCs oppose the proposal to measure RECs at the revenue meter, stating that this would significantly undercount the volume of RECs produced and reduce revenue from REC sales that are passed through to ratepayers. Eversource Interrog. Resp. CAE-8; UI Interrog. Resp. CAE-8. Based on the average customer profile, Eversource estimates a potential 40% reduction in REC revenues if only RECs associated with exports are recorded, because this approach would not capture solar energy generated and consumed onsite. Eversource Interrog. Resp. CAE-8.

Alternatively, solar industry stakeholders suggest that RECs can be measured with inverter data. The Clean Energy Parties emphasize that revenue-grade inverter data is "available through virtually all commercially available solar inverters." Clean Energy Party Comments, Aug. 26, 2026, p. 13. The Clean Energy Parties also state that either the EDCs or another state-designated entity would be required to serve as the independent verifier for generation reporting to NEPOOL, and system owners would report production data to the designated independent verifier on a regular basis. Id., pp. 13–14. ConnSSA and the Clean Energy Advocates similarly support the use of inverter data for REC measurement. Clean Energy Advocates Comments, Aug. 26, 2026, p. 7; ConnSSA Comments, Aug. 26, 2026, p. 4.

In contrast, the EDCs oppose the use of inverter data. Eversource asserts that, when the use of inverter data was previously examined for REC reporting under the RRES Program, the EDCs found that it "would require approval of alternative reporting methodologies to be utilized when customer data was unavailable, and that significant software and license costs would be incurred to support the automated collection and management of customer inverter data." Eversource Comments, Aug. 26, 2026, p. 12. UI states that using inverter data instead of production meters is not feasible, raising concerns related to the cost of establishing and maintaining interfaces for transmitting inverter data, potential disruptions to data availability if vendors go out of business, and EDC inability to verify or test the accuracy inverter production data. UI Comments, Aug. 26, 2026, pp. 7–8.

Additionally, the Clean Energy Advocates suggest that an estimation-based production methodology could be used to report RECs to NEPOOL GIS; however, compared to the use of inverter data, the estimation method is less preferred as it involves greater verification complexity and less reliable data than direct inverter or production-meter measurement and would require NEPOOL approval. Clean Energy Advocates Comments, Aug. 26, 2026, p. 7.

Finally, Eversource suggests that the costs and contingencies of inverter data could be avoided by implementing an alternative approach that would invoke General Statutes § 16-245a(g)[10], which authorizes the Authority to reduce the minimum Class I resource requirement for electric suppliers and EDCs based on a forecast of production from resources enrolled in clean energy programs. Eversource Comments, Aug. 26, 2026, p. 12. Eversource states that this approach would likely reduce the administrative

[10] Eversource cites General Statutes 16-245a(h); however, the Authority notes that after recent amendments to the statutes, the relevant section is 16-245a(g).

requirements of EDC reporting, reduce the Authority's obligations to review and approve Class I resource applications, and secure the benefits of clean energy programs for all Connecticut customers. Id. In general, Eversource recognizes that production metering requirements create costs and would support eliminating the requirement in the residential successor program, provided that the program is designed to efficiently operate without consistent production data. Id., p. 11.

2. Authority Analysis

Moving away from production meters in favor of an alternative approach would offer several benefits for the RRES successor program. Production meters add project costs and complexity, and related implementation and measurement issues have recurred in multiple RRES annual review dockets. Most recently, the Authority examined issues affecting DC-coupled solar-plus-storage projects that use a shared inverter. Decision, Oct. 28, 2026, Docket No. 26-08-02, Annual Residential Renewable Energy Solutions Program Review and Rate Setting – Year 6, p. 24–30. These challenges illustrate the limitations of relying on production meters and are likely to persist under the successor program.

The first alternative, measurement of RECs based on exports at the revenue meter is likely to significantly undercount REC generation, with corresponding reductions to the revenue from REC sales. Under a successor program design that aims to incentivize self-consumption to shift load away from peak periods, the problem of REC undercounting is likely to be exacerbated. Accordingly, this approach is not an acceptable alternative to the use of production meters.

Inverter data, however, may provide a viable option for REC measurement. Under the Energy Storage Solutions (ESS) Program, active dispatch data is typically transmitted from the battery operator directly to the EDCs' distributed energy resource management system (DERMS) provider. See ESS Program Administrator Compliance, Jan. 27, 2026, Docket No. 25-08-05, Annual Energy Storage Solutions Program Review – Year 5, ESS Program Manual Clean, pp. 98–101. A similar approach could potentially be adapted for the RRES successor program.

However, additional consideration is needed due to potential concerns around cost and data access, particularly in the case of disruption to contractor or original equipment manufacturer (OEM) operations. For example, following SunPower's bankruptcy, its battery systems became unavailable through the EDCs' DERMS platform because the application programming interface (API) connection between SunPower and the DERMS platform was lost. Decision, Dec. 17, 2025, Docket No. 25-08-05, Annual Energy Storage Solutions Program Review - Year 5, p. 36. That issue remains unresolved more than a year later. This experience illustrates the potential risk of relying on third-party data connections without a reliable means of maintaining REC measurement and reporting when those connections fail.

The use of inverter data for REC measurement was previously considered in Docket No. 22-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 2, where the EDC submitted a proposal for the use of customer inverter data.

Compliance, Aug. 18, 2022, Docket No. 22-08-02, Att. 1. In their proposal, the EDCs concluded that it could be feasible to effectively use customer inverter data to report RECs to NEPOOL GIS, if certain criteria were met to address long-term risks to the availability and consistency of inverter data and anticipated costs of integrating data with EDC systems. Id., pp. 1–2. The EDCs' inverter data proposal is now several years old, and may not reflect up-to-date information as inverter technology has evolved.

Accordingly, to evaluate options for REC treatment under the RRES successor program with complete and current information, the Authority directs the EDCs to jointly submit, as compliance by March 1, 2027, an updated inverter data proposal. The proposal shall include, at a minimum: (1) a discussion of methods to continue REC reporting using inverter data when such data becomes unavailable, including when an API connection is lost because a company ceases operations; and (2) options for establishing automated data collection and management procedures, with associated cost and implementation timeline estimates. Following receipt of the filing, the Authority intends to address the use of inverter data in the final decision in this proceeding. For clarity, the filing shall address only the use of inverter data for REC measurement; it is not required to consider potential inverter data use for production-based incentive adders or non-bypassable charges, as these are no longer applicable under the successor program framework.

Finally, as stated above, Eversource suggests that the costs and contingencies of inverter data could be avoided by using the procedure contained in General Statutes § 16-245a(g)[11] to reduce the minimum Class I resource requirement for electric suppliers and EDCs based on a forecast of production from resources enrolled in clean energy programs. Eversource Comments, Aug. 26, 2026, p. 12. However, this alternative procedure in General Statutes § 16-245a(g) does not appear to be available to the RRES and SCEF successors. Public Act No. 26-127, § 2(e) states: "The [A]uthority shall follow the procedures established pursuant to subsection (g) of section 16-245a of the general statutes for certificates issued by the New England Power Pool Generation Information System for any Class I renewable energy source purchased by an electric distribution company pursuant to this section" (emphasis added). This language appears only in the section authorizing the NRES successor program (§2), and is absent in the RRES and SCEF successor program sections of Public Act No. 26-127 (§1 and § 3). Therefore, for RRES successor REC measurement, there is no current statutory option to use estimate

[11] "The authority, in consultation with the Commissioner of Energy and Environmental Protection and the Office of Consumer Counsel, shall initiate a proceeding to establish procedures for the disposition of renewable energy certificates purchased pursuant to section 16-244z, sections 16a-3f to 16a-3j, inclusive, and sections 16a-3m, 16a-3n and 16a-3p which may include procedures for selling renewable energy certificates or to retire such certificates on behalf of all ratepayers and reduce the percentage of the total output or services of an electric supplier or an electric distribution company generated from Class I renewable energy sources required pursuant to subsection (a) of this section. Any such reduction shall be based on the energy production that the authority forecasts will be procured. The authority shall determine any such reduction of an annual renewable portfolio standard not later than one year prior to the effective date of such annual renewable portfolio standard. An electric distribution company shall not be responsible for any administrative or other costs or expenses associated with any difference between the number of renewable energy certificates planned to be retired pursuant to the authority's reduction and the actual number of renewable energy certificates retired." General Statutes § 16-245a(g).

or forecast production to retire RECs on behalf of all ratepayers and reduce the percentage of the total output or services of an electric supplier or an electric distribution company generated from Class I renewable energy sources required pursuant to subsection (a) of General Statutes § 16-245a. Public Act No. 26-127, §1(f) for RRES, and §3(e) for SCEF, allow the EDCs to sell the RECs they purchase and credit the REC sale revenue to all ratepayers.

IV. NON-RESIDENTIAL AND COMMUNITY SOLAR PROGRAM DESIGN

In its Successor Study Report, the Authority offered several recommendations for successor program design based on its evaluation of the current NRES and SCEF Programs and stakeholder positions. The Authority builds on that extensive stakeholder process here, with modifications to the recommended program structure pursuant to the specifications of Public Act No. 26-127 and with the goal of advancing the proposed objectives of the successor clean energy programs.

This section addresses the general tariff framework and does not yet make a final determination on all aspects of non-residential and community solar program design, which will continue to be evaluated over the course of this proceeding. Where possible, the Authority aims to preserve the current program rules to promote continuity, minimize administrative burden, and avoid participant confusion during the transition to the successor program.

A. SOLICITATION RULES AND PROCESS

In the Successor Study Report, the Authority recommended replacing current competitive solicitations with a "walk-up" approach where projects are awarded standard-offer tariffs upon meeting maturity requirements, which could offer greater certainty to project participants and ensure that only viable projects will be awarded a tariff agreement and reserve capacity in the program. Successor Program Report, pp. 63–64.

In establishing a successor to the RRES Program, the Authority must establish "(1) tariffs for each electric distribution company, (2) a rate for such tariffs, and (3) tariff terms and conditions consistent with the requirements of this section." Public Act No. 26-127, § 1(b) (emphasis added).

In establishing a successor to the NRES Program, the Authority must establish:

> (1) a procurement plan for the electric distribution companies and resulting tariffs for selected projects pursuant to subsection (b) of this section, (2) a price cap on a cents-per-kilowatt-hour basis concerning any distributed energy resource selected pursuant to this section, and (3) tariff terms and conditions consistent with the requirements of this section . . . . The rate for such tariffs shall be established by the solicitation pursuant to subsection (b) of this section.

Public Act No. 26-127, § 2(a) (emphasis added). After the commencement of the NRES successor program:

> On and after January 1, 2028, not less than annually, each electric distribution company shall jointly or individually solicit and file with the Public Utilities Regulatory Authority for its approval one or more projects selected resulting from any procurement issued pursuant to this section that are consistent with the tariffs approved by the authority pursuant to subsection (a) of this section.

Public Act No. 26-127, § 2(b)(1). Public Act No. 26-127, §§ 3(a) and 3(c) contain provisions for the Community Solar Program established as the SCEF successor program, which are similar to the NRES successor provisions provided above.

> The meaning of a statute shall, in the first instance, be ascertained from the text of the statute itself and its relationship to other statutes. If, after examining such text and considering such relationship, the meaning of such text is plain and unambiguous and does not yield absurd or unworkable results, extratextual evidence of the meaning of the statute shall not be considered.

General Statutes § 1-2z.

The Authority invited participants to file briefs providing legal analysis regarding the project selection methods for the NRES and SCEF successor programs allowable under Public Act No. 26-127, recognizing that the legislation may contain some ambiguity as to whether successor programs are required to competitively solicit projects or may use a standard-offer compensation framework. Notice of Briefs, July 20, 2026, p. 2. Specifically, General Statutes § 16-244z referenced the "competitiveness" of the procurements authorized for the NRES and SCEF Programs, while Public Act No. 26-127 does not. In establishing the NRES Program selection methodology, the Authority determined that "the references [to "competitiveness"] in subsections (b) and (c) clearly direct a competitive component in the § 16-244z(a) solicitations." NRES Decision, pp. 16–17.

OCC, DEEP, and the EDCs argue that the plain language of Public Act No. 26-127 is clear and unambiguous, and indicates the legislature's desire for a continued competitive process by specifying that the rate for tariffs for NRES and SCEF successors be established by the solicitation. OCC Brief, pp. 5–6; EDC Joint Brief, pp. 1–2; DEEP Brief, pp. 4–6. Further, DEEP argues that "[g]iven Sections 2 and 3 of the Act require the Authority to establish a price cap, the Act clearly assumes the NRES and SCEF successor programs will be competitive procurements that necessitate a price cap." DEEP Brief, pp. 4–5.

Additionally, OCC, DEEP, and the EDCs each identify that an earlier draft of Raised Bill 5340 directed the Authority to set the rate for the NRES successor program, but the language was amended in the version ultimately adopted. OCC Brief, p. 3; DEEP Brief,

pp. 6–7; EDC Joint Brief, p. 3. OCC acknowledged that the legislation may leave some ambiguity, as the absence of the requirement to "monitor the competitiveness of procurements and adjust procurement parameters to maintain competitiveness" is a consequential textual difference; however, OCC noted that the Act establishes a new and separate framework rather than amending General Statutes § 16-244z, so "the lack of explicit reference to a 'competitive' bidding process can be instructive, but not dispositive." OCC Brief, p. 6.

Conversely, SEIA and ACT, CLF and Vote Solar, Verogy, and Allco argue that Public Act No. 26-127 does allow the Authority to utilize a standard-offer framework. SEIA and ACT state that the omission of the term "competitive" must indicate a different legislative intent for solicitations than the currently existing process, and assert that the word "solicitation" does not necessarily imply a competitive process. SEIA Brief, pp. 2–3. Allco similarly notes the absence of references to "competitiveness," stating that the legislature knows how to require price competition when it wishes to do so. Allco Brief, pp. 3–5. CLF and Vote Solar assert that the legislation does not dictate competitive bidding at the solicitation stage, and the Authority can instead ensure procured energy is competitive through post-award cost-containment measures and regulatory tools. CLF Brief, pp. 2–3.

Based on stakeholder briefs and its own legal analysis of Public Act No. 26-127, the Authority determined that the legislation does not authorize a standard-offer compensation framework for the NRES and SCEF successor programs. See Notice, Sept. 9, 2026, p. 1. The absence of references to "competitiveness" alone cannot be taken as evidence that the legislature intended to allow a standard-offer framework. General Statutes § 16-244z(b) refers to a competitive solicitation but also cross-references subsection (a), which omits the "competitive" phrase; this could indicate that a "solicitation" as used by the legislature could be understood as competitive even without explicit references to "competitiveness." In contrast, Public Act No. 26-127, § 1(b), which directs the Authority to establish "a rate for such tariffs" for the RRES successor program, clearly authorizes administratively set tariff rates and is notably different than the NRES and SCEF successor program sections.

Finally, the legislative history of amendments to H.B. 5340 shows that the original draft legislation allowed for a standard-offer model, but the replacement of that language in the final legislation indicates that the legislature intended for the NRES and SCEF successor programs to be competitive. Accordingly, the NRES and SCEF successor programs shall continue to utilize competitive solicitations for project selection.

Notwithstanding the above determination, legislative intent supports the conclusion that small non-residential projects may continue to be selected and compensated on a standard-offer basis.

In the NRES Decision, the Authority found that:

> allowing the compensation rate to be administratively determined for small projects eligible to participate in the Program *is* consistent with the

> legislative intent to create a successor to the current LREC/ZREC program as the compensation rate for the existing small ZREC program is administratively set. Further, the Authority concurs with stakeholders' comments that smaller projects may be unduly affected by the administrative burden of the competitive solicitation process. Coupled with the current undersubscription in the small ZREC program, the Authority finds any additional burden on potential bidders could further diminish market activity. Therefore, interpreting the statute to require a competitive solicitation (and thus foreclose an administratively determined rate) for the projects intended to be a successor to the small ZREC program would yield an absurd or unworkable result. Accordingly, the Authority authorizes the Small Zero Emission category . . . to be administratively set, providing all eligible projects the administratively set rate on a first-come, first-serve basis.

NRES Decision, pp. 17–18.

Public Act No. 26-127 reflects legislative intent to create a successor to the current NRES Program, retaining the project selection and compensation methodology of NRES. The NRES program awards tariff agreements to small projects less than 200 kW on first-come, first-served and lottery basis with administratively set tariff pricing, despite the language regarding competitive solicitations in General Statues § 16-244z. The NRES Program, in turn, continued the standard-offer selection approach used for small projects under the legacy Low and Zero Emissions Renewable Energy Credit (LREC/ZREC) Program. See NRES Decision, pp. 17–18. Accordingly, the NRES and LREC/ZREC Programs provide a well-established precedent that small projects are not subject to the requirement for competitive solicitations. Therefore, in the NRES successor program, small non-residential projects less than 200 kW may be awarded tariff agreements on first-come, first-served and lottery basis with administratively set tariff pricing.

The Authority notes that there may be merits to a standard-offer approach, which offers greater revenue certainty for participants and could address the speculative bidding and high project attrition observed under competitive procurements. Ultimately, project development risk is priced into project bids, with ratepayers bearing the cost of higher-priced selected projects. A more complete analysis of the relative ratepayer benefits of a standard-offer and competitive procurement program could better inform solar program design choices. However, the Authority will not conduct further evaluation at this time as current successor program legislation does not authorize a standard-offer program.

B. TARIFF STRUCTURES

Public Act No. 26-127, § 2(b)(1) requires that eligible non-residential customers be offered two tariff options, specifically stating:

> For any such selected project that is a distributed energy resource that emits no pollutants that (A) is located on a customer's premises, (B) is not more than five megawatts in size, and (C) serves the distribution system of an electric distribution company, each electric distribution company shall

> offer a tariff (i) for the purchase of all energy and renewable energy certificates generated at a rate consistent with the procurement plan approved by the authority, and (ii) for the purchase of any energy produced and not consumed in a period of time established by the authority, and any renewable energy certificates generated by such renewable energy resource, on a cents-per-kilowatt-hour basis, subject to any tariff terms, conditions or other stipulations of the authority, including, but not limited to, the capacity rights of such source.

Public Act No. 26-127, § 2(a) requires that "[a]ny such tariff shall be for a term not to exceed twenty years." Section 2(h) requires that the EDCs offer the non-residential tariffs for eight years, or until December 31, 2035.

The Authority uses the term "buy-all tariff" to mean a tariff "for the purchase of all energy and renewable energy certificates generated at a rate consistent with the procurement plan approved by the authority," and the term "netting tariff" to mean a tariff "for the purchase of any energy produced and not consumed in a period of time established by the authority, and any renewable energy certificates generated by such renewable energy resource, on a cents-per-kilowatt-hour basis." Public Act No. 26-127, § 2(b)(1). Based on the analysis of tariff structures presented below, the Authority directs the EDCs to establish a netting tariff with instantaneous netting and a flat buy-all tariff, both with terms of 20 years, for the NRES successor program. As discussed further below, in establishing a flat buy-all tariff, the EDCs shall allow for the potential incorporation of a multipart payment framework (MPF), subject to further consideration in the remainder of this proceeding.

1. Buy-All Tariff

Under the NRES Program, projects that choose the buy-all tariff option are compensated at a fixed per kWh volumetric rate for all energy, RECs, and any environmental attributes produced by the project. NRES Decision, p. 11. The same per-kWh compensation structure is used for all projects selected in the SCEF Program. Decision, Dec. 18, 2019, Docket No. 19-07-01, Review of Statewide Shared Clean Energy Facility Program Requirements (SCEF Decision), Ex. B, pp. 5, 9. Buy-all NRES projects and all SCEF projects are front-of-the-meter (FTM) and interconnect directly to the distribution grid, selling all output directly to the applicable EDC at the fixed volumetric rate and paying the EDC for their full metered usage, if applicable, at the applicable retail rate. Compliance, Jan. 28, 2026, Docket No. 25-08-03, Annual Non-Residential Renewable Energy Solutions Program Review - Year 5, Att. 2a (NRES Year 5 Program Manual), p. 19; Compliance, Jan. 15, 2026, Docket No. 25-08-04, Annual Shared Clean Energy Facility Program Review – Year 7, Att. 1 (SCEF Year 7 Program Manual), p. 9.

In accordance with the Authority's recommendation in the Successor Study Report that programs be designed to reflect the time-varying value of solar generation and to incentivize projects to include collocated energy storage, the Authority requested comments on whether and how to incorporate time-differentiated compensation into the non-residential buy-all tariff and Community Solar Program. Successor Study Report, pp. 63, 66; Notice, July 28, 2026, pp. 1–2.

a. Multipart Payment Framework (MPF) Proposal

Eversource proposes a MPF that would compensate projects for both overall delivery of energy to the electric power system and the sustained delivery of clean energy during periods of high load requirements. Eversource Comments, August 26, 2026, p. 6. Eversource cautions that competitively soliciting projects could become more complicated with time-differentiated compensation rates and could bias selection toward projects that generate more output during off-peak periods. Id., p. 2. Instead, Eversource suggests the MPF model as a method to incorporate performance-based compensation rates to encourage the collocation and management of battery energy storage systems (BESS) and to enhance the value that clean energy resources provide to the electrical power system. Id., pp. 2–3.

Under Eversource's proposal, projects would continue to be selected and compensated based on their fixed bid price per kWh, as in the current NRES Program, but would also be eligible to receive an additional incentive for the minimum amount of power delivered during a designated period that coincides with both high load and reduced PV output. Id., p. 6. Eversource proposes that these additional payments be provided on a dollar-per-kW basis with performance calculated daily and equal to the minimum one-hour average output during the designated period. Eversource Comments, August 26, 2026, p. 7.

Under the MPF model, solar PV-only projects that do not maintain output throughout the final hour of the period would not receive any additional compensation for that day. Id. In contrast, projects that pair solar PV with energy storage could manage storage discharge to sustain output from the combined system through the end of the period and be compensated based on the minimum hourly average output (kW) over the designated period. Id. Eversource recommends that incentives be based on the minimum hourly dispatch to maximize the benefit of extending delivery of solar energy through the full evening peak period.[12] Eversource Comments, Oct. 2, 2026, p. 3.

Eversource recommends that, for administrative efficiency, the Authority approve a uniform dollar-per-kW payment rate in advance of solicitations that would be available to all projects selected within a program year. Eversource Comments, Aug. 26, 2026, p. 8. The per-kW payments would "provide a predictable price signal to which successor program participants can respond by building and managing collocated storage resources that better align the delivery of additional clean energy with system requirements." Id., p. 7.

Eversource suggests the hours of 4:00 to 8:00 p.m. as a reasonable default for the designated period of high load and reduced PV output. Id., p. 6. However, Eversource recommends that the EDCs have discretion to adjust the targeted period for individual projects, provided that program rules give participants sufficient opportunity to adjust their operations and maintain expected revenues. Id., pp. 6–7; Eversource Comments, Oct.

[12] For comparison, ESS performance incentives are based on the average kW dispatched across all active dispatch event hours in each season. See ESS Program Administrator Compliance, Jan. 27, 2026, Docket No. 25-08-05, ESS Program Manual Clean, p. 8.

2, 2026, p. 3. Under this model, the targeted period would be included within project-specific tariff agreements and be subject to revision by the EDC "within certain limitations and with sufficient notice to the customer."[13] Eversource Comments, Oct. 2, 2026, p. 3. Eversource states that this flexibility would allow the EDCs to optimize the operation of resources to align with locational requirements, including those that may vary by season. Eversource Comments, Aug. 26, 2026, p. 6; Eversource Comments, Oct. 2, 2026, p. 3.

Eversource notes that the per-kW payment rate for sustained output will be "[o]ne of the most critical parameters" for the program. Eversource Comments, Aug. 26, 2026, p. 8. As an illustrative example, Eversource provided an attachment to its comments modeling the potential operation and revenue of a MPF payment structure with a $0.50 per kW-day incentive, but notes that actual revenue would be influenced by numerous program design features. Id.; Eversource Comments, Aug. 26, 2026, Att. 1. Public Act No. 26-127, § 2(d) requires that incentives for energy storage systems incorporated into clean energy tariff rates provide aggregate system benefits to all ratepayers. Eversource suggests that the methods used to evaluate the cost-effectiveness of the ESS Program could be an appropriate initial basis for setting per-kW payment levels.[14] Eversource Comments, Oct. 2, 2026, p. 2. Eversource, UI, and CGB, as co-administrators of the ESS Program, are "of the cautious opinion" that a per-kW payment for FTM storage paired with a buy-all solar tariff could support recovery of the cost of storage resource's development costs while maintaining a RIM score of 1.4, as FTM storage development costs are generally lower than those of BTM storage; however, whether the framework could achieve a participant cost test (PCT) of at least 1.0 would depend on the specific project costs, incentive levels, and benefits considered. Interrog. Resp. CAE-42.

Eversource anticipates that the performance of paired solar and storage resources would be measured with a single utility-owned meter with interval capability, and states that existing NRES and SCEF metering configurations would largely be sufficient to manage additional per-kW compensation. Eversource Comments, Aug. 26, 2026, p. 7. Additionally, Eversource suggests that eligibility for the MPF be limited to projects where the battery storage exclusively charges from the paired solar PV system, as energy output must be from a Connecticut Class I renewable energy source to be eligible for incentive payments under programs authorized pursuant to Public Act No. 26-127. Id. Adherence to such requirements could be verified through periodic reporting or audits of storage

[13] Eversource recognizes that policies and procedures for target period revisions require additional discussion, and "would welcome the opportunity to collaborate with prospective program participants to develop processes by which operational requirements could be identified, updated, and effectively communicated to both optimize operations and reasonably sustain revenue on which project financing will rely." Eversource Comments, Oct. 2, 2026, p. 3.

[14] Performance-based incentives for large commercial and industrial ESS customers are currently $275 per kW for years 1–5 of enrollment and $175 per kW for years 6–10, and are paid out based on the average kW discharge from all events called during each dispatch season (i.e., summer or winter). Eversource Comments, Oct. 2, 2026, p. 2; ESS Program Administrator Compliance, Jan. 27, 2026, Docket No. 25-08-05, ESS Program Manual Clean, p. 45. The corresponding ESS C&I Program BCA reports a Connecticut Ratepayer Impact Measure (RIM) of 1.23, indicating that the modeled incentive levels provide net benefits to Connecticut ratepayers. ESS Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Docket No. 26-08-05, Annual Energy Storage Solutions Program Review – Year 6, Att. 2, p. 74.

operations, although reporting requirements could potentially be mitigated through appropriate sizing requirements for paired storage resources relative to generation. Eversource Comments, Oct. 2, 2026, pp. 4–5.

Under this proposed compensation structure, Eversource suggests that the Authority adopt appropriate sizing and operational requirements, such as limiting performance payments to a maximum percentage of the nameplate capacity of a paired PV system, to encourage sizing that can meet program requirements and to distribute the available budget among more projects. Eversource Comments, Aug. 26, 2026, p. 8; Interrog. Resp. CAE-26. Additionally, Eversource recommends that the MPF structure be available only to FTM resources with paired storage, as solar-only projects would be unlikely to sustain significant output over the full evening period and calculating small or zero-value payments for solar-only resources would likely add administrative complexity without corresponding benefits. Eversource Comments, Oct. 2, 2026, p. 5.

Eversource asserts that the proposed MPF framework would support the deployment of FTM paired solar and storage resources, enhance the value of clean energy programs, and minimize the cost of sustaining clean energy deployment. Id., pp. 5–6. The majority of NRES projects have enrolled under the buy-all tariff, and SCEF projects are exclusively FTM; Eversource states that FTM resources have historically been more likely to require distribution system upgrades to interconnect, and minimizing the cost of continued clean energy deployment "will require FTM projects to increasingly manage their output to minimize grid impacts." Eversource Comments, Aug. 26, 2026, p. 5. Eversource recommends that the Authority focus on developing new compensation models for FTM resources that can complement other measures, such as flexible interconnection, to maximize the value of clean energy resources. Id., pp. 5–6.

Finally, Eversource does not expect that the proposed MPF would require changes to the EDCs' billing systems or other system modifications. Eversource Interrog. Resp. CAE-3. Per-kW performance payments could be calculated based on performance data and administered outside of the billing system, following a similar approach to participant compensation in the NRES and SCEF Programs. Id.; Interrog. Resp. CAE-29. The process could initially be administered manually, with opportunities for automation considered as participation increases. Id.

b. Stakeholder Comments

The Authority solicited stakeholder comments on Eversource's MPF proposal, inviting stakeholders to provide specific recommendations on the methodology for setting per-kW payment levels, how to determine the targeted period, and other elements of the proposed framework. Notice, Sept. 9, 2026, p. 2.

UI does not oppose further evaluation of the MPF concept, recognizing that it reflects a broader policy objective of encouraging FTM solar and storage resources capable of delivering energy during periods of system needs. UI Comments, Oct. 2, 2026, p. 2. However, UI notes that the successor program proceeding "is fundamentally focused on renewable energy tariff design rather than the development of a comprehensive FTM storage framework," and suggests that the Authority preserve

flexibility to reevaluate broader FTM storage policy through a separate proceeding if additional review is warranted in the future. Id., pp. 2–3. UI acknowledges that programs in other jurisdictions, including Hawaii and Nevada, have shown that compensation mechanisms can encourage delivery of renewable energy during targeted periods of system need; nevertheless, UI urges caution when evaluating MPF implementation due to potential implementation requirements and costs, interactions with REC administration, and overlaps with wholesale market participation. Id., p. 7.

UI recommends that any per-kW payment level be tied to clearly defined and measurable system benefits (e.g., peak load reduction, reliability support, operational flexibility); established on a program-wide basis rather than adjusted for individual projects; and examined to ensure that MPF payments are necessary to encourage the desired behavior and avoid duplicating ratepayer-funded incentives. Id., p. 3. Additionally, UI asserts that the targeted period should be supported by objective system data regarding periods when customer demand remains elevated after solar production declines, and should include seasonal differentiation on a program-wide basis. UI Comments, Oct. 2, 2026, p. 4. Unlike Eversource, UI does not support allowing the EDCs to establish project-specific targeted periods, arguing that such adjustments would increase program administration, settlement complexity, metering requirements, and implementation costs. Id., p. 7. Regarding performance measurement, UI states that the proposed minimum one-hour average output methodology "provides a straightforward and administratively practical approach that encourages sustained performance throughout the entire designated period rather than short-duration output spikes." Id., pp. 4–5.

The Clean Energy Parties state that the proposed MPF "is a reasonable starting point and deserves serious evaluation." Clean Energy Party Comments, Oct. 2, 2026, pp. 4–5. The Clean Energy Parties previously "cautioned that time-differentiated compensation fits poorly within a competitive solicitation, because bidders would have to price on-peak and off-peak rates themselves, and the resulting rates would reflect project economics rather than value to the grid," and note that the MPF structure avoids this problem by preserving a flat $/MWh bid price with an additional time-based component set in advance of each solicitation. Id., p. 4. Accordingly, the Clean Energy Parties state that they may be able to support a MPF program design but require greater clarity on several aspects that were not fully described in Eversource's initial proposal. Id., p. 5. These include the level and basis of the per-kW payment, including whether it will be sufficient to support the cost of storage; the contract term and durability of the rate; and the charging source and winter performance. Id., pp. 7–9.

The Clean Energy Parties emphasize that the per-kW payment rate is the means for a paired project to recover the cost of storage, so a rate set too low would fail to incentivize paired solar and storage systems. Clean Energy Party Comments, Oct. 2, 2026, pp. 7–8. The Clean Energy Parties argue that the rate should be set using a transparent avoided cost framework and reflect the identified value that sustained output in the designated period provides to ratepayers. Id., p. 8. Additionally, the per-kW rate and core program terms should be fixed for the contract term for selected projects, and any updates to the per-kW rate should apply solely to future solicitations. Id. Relatedly,

the Clean Energy Parties submit that any EDC revisions to the targeted period after project selection should specify that the period should never be longer than it was at the time of bid, and there should be no more than one designated period per day. Id., pp. 8–9. The tariff should also specify at the time of bid the hours within which the targeted period may move and the notice that would be provided prior to any changes, as the timing of the designated period affects project operations. Id. Finally, the Clean Energy Parties support a program designed to encourage systems paired with storage, but caution that incentives to support the cost of storage would likely allow paired projects to bid below comparable solar-only projects, making it difficult for solar-only projects to be selected. Id., p. 10.

OCC suggests that per-kW compensation be aligned with the hourly marginal system value at the time of delivery, rather than a single payment level applied to the entire designated period. OCC Comments, Oct. 2, 2026, pp. 1–2. Accordingly, OCC proposes hourly performance payments calculated based on the hourly per-kW rate and actual performance in each hour, and recommends kWh-based payments. Id., p. 3. OCC also recommends that the Authority maintain flexibility in defining the targeted period to reflect evolving system peaks, supported by data on seasonal variance in system peak characteristics. Id. OCC does not support limiting collocated batteries to charging exclusively from solar, in the absence of a strong system value justification for such a limit. Id., p. 4. Finally, OCC does not oppose giving the EDCs some discretion to adjust the targeted period for individual projects to reflect location-specific constraints, noting that utilities in Massachusetts have sought to increase load between 11:00 a.m. and 3:00 p.m. to absorb excess solar generation near certain substations; however, any adjustments must be subject to published and standardized criteria. OCC Comments, Oct. 2, 2026, p. 6.

OCC also proposes an alternative method to incorporate time-differentiated compensation into competitive procurements for the non-residential successor program, under which the EDCs would prepare common time-differentiated per-MWh price caps based on hourly avoided cost values and competitive bids would be structured as an overall single-value percentage discount from the EDC-established price caps. OCC Comments, Oct. 2, 2026, pp. 12–13; OCC Corresp., Oct. 16, 2026. OCC recommends that avoided costs be determined based on grid value and utilize a level of granularity that balances precision with simplicity. Id. OCC suggests that the cost curves could be based on the Avoided Energy Supply Costs in New England (AESC) study, but otherwise does not propose a specific method for calculating avoided costs. Tr., 134:12–18. OCC argues that bids submitted as a single-value percentage discount would "enable a straightforward bid evaluation process where the bids with the largest discount values are awarded." OCC Comments, Oct. 2, 2026, p. 13. OCC acknowledges that this approach has not been used in other states. OCC Corresp., Oct. 16, 2026, p. 10.

DEEP does not support the creation of a MPF for the NRES buy-all and SCEF successor programs, asserting that the compensation levels should be consistent with the value the projects provide to ratepayers. DEEP Comments, Oct. 2, 2026, pp. 1–2. DEEP recommends that the EDCs be required to develop a Connecticut-specific tool to evaluate the value of energy in a time-differentiated manner. Id.

CLF, in principle, supports performance-based payments that provide compensation for paired generation and storage for shifting solar output into the hours when it is worth more, citing the declining marginal system value of additional PV in ISO-NE as BTM PV has flattened midday load. CLF Comments, Oct. 2, 2026, pp. 1–2. However, CLF expresses concern that the record regarding the MPF proposal is inadequate to take a position on specific elements of the potential program design. Id., p. 2. In particular, CLF asserts that additional analysis is needed to set MPF parameters, including a BCA of FTM paired resources, valuation of distribution benefits, and value-segmentation analysis. Id. CLF also emphasizes that the compensation structure must reflect the locational value of DERs on the distribution system, rather than leaving location-specific value unpriced or subject to case-by-case EDC discretion. Id., pp. 2, 9–13.

ConnSSA argues that the per-kW calculation method must be transparent and modellable, stating that an overly complex approach will introduce market friction and reduce project financeability. ConnSSA Comments, Oct. 2, 2026, p. 1. ConnSSA developers also express concern regarding the proposed payment based on the minimum hourly dispatch, arguing that it "severely drives down incentive levels for systems with any natural or operational inconsistency," requires tight battery programming strategies, and creates risk that a single point of failure can eliminate an entire day's payment. Id., pp. 3–4. ConnSSA instead suggests that compensation could be based on average kW discharge over the duration of the period, as in the ESS Program, and requests greater detail from the EDCs regarding an alternative interval-based performance metric. Id., pp. 3–5. If a per-kW performance payment is adopted, ConnSSA emphasizes that projects should not be penalized for any hours in which output is limited by EDC-directed curtailment or flexible interconnection export limits, and that any program parameters must be published and replicable by participants. Id., p. 5. ConnSSA recommends that participants receive the granular data used for performance incentive settlement within a defined period, and a dispute resolution process be established. ConnSSA Comments, Oct. 2, 2026, p. 10. Finally, ConnSSA cautions that high per-kW payments will rapidly drain the $85 million aggregate program budget cap and could restrict deployment of solar-only projects, which remain the most viable to reach deployment. Id., pp. 2, 6. To address this, ConnSSA suggests that the Authority establish a percentage carve-out for solar-only installations. Id., p. 7.

Verogy supports the proposed MPF, although it would prefer an energy storage adder similar to that used in Massachusetts' SMART Program to encourage paired solar and storage deployment. Verogy Comments, Oct. 2, 2026, p. 1. Verogy is "generally agnostic to MPF performance requirements," as long as they are achievable with currently-available technology and sufficient to finance FTM storge, and does not oppose allowing the EDCs to shift targeted performance periods based on seasonal or project-specific grid needs. Id. However, Verogy objects to the proposed requirement that storage charge exclusively from the paired PV, stating that during winter, storage could take several days to recharge from solar generation and would not be able to reduce peak load at its full capacity. Id., p. 2. Verogy also asserts that the MPF should be available both to generation-only assets that perform during targeted MPF performance periods and to standalone grid-tied storage assets. Id.

Eversource suggests that a working group process be used to develop consensus proposals could expedite development of successful program designs. Eversource Corresp., Oct. 16, 2026, p. 8. Eversource notes that stakeholder collaboration would help define performance criteria, metering configurations and charging restrictions, interaction with flexible interconnection and real-time automation controller (RTAC) capabilities, rate setting and project economics, and boundaries of project-specific peak periods. Id. UI and industry stakeholders express support for participating in a working group process. Tr., 24:12–19; 129:12–20; 198:3–11.

c. Authority Analysis

The Authority finds that a MPF model to facilitate FTM paired solar and storage deployment within a buy-all tariff is a promising conceptual proposal that warrants further consideration. However, a more complete proposal and analysis is required before authorizing a final program design. Accordingly, the Authority directs the EDCs to further develop the MPF proposal, in collaboration with stakeholders, for consideration in the remainder of this docket.

A MPF that compensates clean energy resources for both overall energy production and sustained output over a designated period can improve the ratepayer value of successor clean energy programs, incentivizing the delivery of clean energy output over the hours when it provides the greatest system value. Due to the extensive deployment of solar PV in New England to date, bulk system and distribution peaks now typically occur outside solar generation hours. Incorporating compensation for the sustained delivery of renewable energy during periods where peaks are likely to occur, if valued appropriately, can thus improve the value of renewable energy to the system and benefit all ratepayers.

A MPF design can be readily incorporated into the existing solicitation process, building on the current program design and aligning with the statutory requirement for continued competitive solicitations. As in the current NRES and SCEF Programs, projects would continue to submit per-MWh bids, with the lowest-cost evaluated bids selected for enrollment. Maintaining the competitive solicitation process will facilitate the selection of least-cost resources, whether standalone solar projects or paired with storage. The Authority previously indicated its intent to incorporate time-differentiated compensation into a potential standard-offer program. Successor Study Report, p. 66; Notice, July 28, 2026, pp. 1–2. However, the Authority recognizes stakeholders' concerns that time-differentiated compensation would be needlessly complex to implement within a competitive solicitation model. Additionally, time-differentiated bids would likely reflect underlying project economics rather than optimizing operation to provide system value. In contrast, a MPF offers an alternative model that maintains existing solicitation processes for energy procured by the EDCs, while incorporating an additional capacity-based incentive for projects to sustain renewable output during hours when PV output declines and system load remains high. This program framework furthers the objective of program accessibility through simplified tariff structures, while creating a clear incentive for FTM projects to deploy paired storage and operate it in a way that provides benefits to all ratepayers.

Additionally, a MPF program design is consistent with the statutory direction for PURA to examine and incorporate incentives for energy storage systems that provide electric distribution benefits, provided that the incentives in the aggregate provide benefits to all ratepayers. Public Act No. 26-127, § 2(d). A capacity-based performance incentive would compensate paired solar and storage resources for the additional benefits that storage provides to the electric distribution grid. Additionally, allowing the designated period for kW-based incentives to vary on a project-by-project basis can address the statutory directive to examine "incentives concerning the location of a distributed energy source on the electric distribution system in a manner that improves the reliability of such system." Public Act No. 26-127, §§ 2(d), 3(d). Any incentives incorporated into the tariffs authorized under Public Act No. 26-127 must be for clean energy resources eligible for the programs; specifically, an eligible project must be a distributed energy resource that "emits no pollutants." Public Act No. 26-127, §§ 1(a)(7), 2(b)(1). Accordingly, any storage output compensated under the program must be verifiably charged from the collocated solar PV system to ensure that discharged energy qualifies as renewable and may be compensated under the successor program tariffs.

Nevertheless, a more comprehensive MPF proposal is required before determining whether and how to incorporate capacity-based payments for sustained peak period output into the final program design. As discussed above, stakeholders raised questions regarding important aspects of the MPF that are not yet fully detailed in Eversource's conceptual proposal. For example, the proposed per-kW payment is a key parameter that will impact program outcomes. The record requires further analysis regarding a per-kW payment level that would provide net benefits to all ratepayers, as required by law. Adoption of the MPF also requires evaluation of whether such a payment level can also offer a sufficient incentive for project owners to finance the cost of storage deployment, including a more detailed analysis of revenue potential that considers daily energy production and weather patterns. Additionally, while adjustments to the designated period for individual projects have the potential to provide location-specific value, procedures must be developed to ensure that such benefits are valued appropriately without unduly increasing risk to developers, which would hinder deployment and potentially increase ratepayer costs. The record would benefit from a more complete description of how project-specific periods would be determined and the conditions under which these periods may be adjusted after a project is selected.

A working group is an appropriate avenue for stakeholders to develop a common understanding of a potential MPF program design, refine program design elements and contractual terms, and identify areas of consensus. Working group processes have been successfully utilized across several programs and proceedings to develop proposals with input from involved parties.

Accordingly, no later than January 1, 2027, the EDCs shall initiate and lead a working group (MPF Working Group) to further develop a MPF Report, which shall be filed for further stakeholder feedback and Authority consideration in the remainder of this docket. A designated working group to develop the MPF Report, rather than utilizing the existing Interconnection Working Group, is preferable to maintain a clear delineation of tasks and to account for the Interconnection Working Group's already full agenda. The

EDCs shall invite, at a minimum, the Clean Energy Parties, ConnSSA, OCC, DEEP, and CGB.

No later than April 1, 2027, the EDCs shall jointly file, for review and approval, a comprehensive MPF Report based on the results of the working group process. The MPF Report shall include the following, at a minimum:

(1) proposed performance criteria and settlement procedures, including the methodology for calculating per-kW payments;

(2) a proposed per-kW payment rate based on a Connecticut-specific BCA, including the assumptions, methodology, and system benefits used to derive the rate, and a proposed methodology for updating the payment level over time;

(3) a methodology for establishing the designated performance period, including consideration of seasonal and locational needs, and the extent to which project-specific periods are appropriate;

(4) proposed conditions, limitations, and notice requirements governing any changes to project-specific peak periods after project selection;

(5) proposed metering and data requirements, storage charging restrictions, and verification requirements for ensuring that compensated energy is eligible for Class I renewable energy certification;

(6) sizing requirements for paired PV and energy storage resources to ensure that projects meet the program's proposed operational objectives;

(7) a project revenue and operating model that includes historical weather and daily solar production data, battery charging and discharging behavior, and adjustable per-kW and per-kWh compensation inputs, to evaluate project performance and economics used under alternative program parameters;

(8) an assessment of EDC implementation requirements for the recommended proposal;

(9) an evaluation of interactions with potential storage participation in wholesale markets, flexible interconnection, and other relevant programs or rates, including potential duplication of ratepayer-funded benefits; and

(10) a proposed program manual establishing the applicable program requirements and administrative procedures.

The filing shall identify areas of consensus and non-consensus among working group participants and shall include any comments or alternative proposals submitted by participants. The EDCs shall also describe the working group's process, the issues considered, and the rationale for any recommendations on which consensus was not achieved.

Finally, while the MPF proposal will continue to be evaluated in the remainder of this docket, the Authority authorizes the continued use of a flat buy-all tariff on a per-kWh basis. Project compensation rates will be determined based on the results of prior solicitations for competitively-selected project categories, and any other factors determined by the Authority, and administratively set for small projects not selected competitively. As this framework is currently used for the NRES buy-all tariff, the Authority presumes that no EDC billing or system updates will be required. Any additional incentives on a kW basis under a MPF, if ultimately authorized, could likely be administered outside of the EDC billing systems; for example, using a similar process to the current quarterly administration of REC payments or the administration of ESS performance incentives and minimizing the need for significant system updates.

2. Netting Tariff

Under the netting tariff structure in the current NRES Program, customers are compensated based on a two-part rate that consists of an energy export rate as well as a REC and Environmental Attribute rate.[15] NRES Decision, p. 11–13; NRES Year 5 Program Manual, p. 12. The NRES Program utilizes a monthly netting interval. Id. Public Act No. 26-127 directs the Authority to establish the interval for a netting tariff for the successor to the NRES Program.[16] Public Act No. 26-127, § 2(b)(1)(ii).

The Authority solicited stakeholder comments regarding the adoption of instantaneous netting for the NRES successor program. Notice, Sept. 9, 2026, p. 3. The Authority noted that instantaneous netting with exports compensated at a rate less than the full retail rate has been considered for the residential successor program and requested stakeholder comments on whether the NRES successor program should utilize the same approach. Id. Additionally, the Notice asked stakeholders to comment on how instantaneous netting with reduced export compensation could be implemented within a competitive solicitation process, as required by Public Act No. 26-127. Id.

a. Stakeholder Comments

Eversource supports consideration of an instantaneous non-residential netting interval with exported energy compensated at a value below the full retail rate and does not anticipate that such a structure would require fundamental changes to the existing solicitation process, provided that the applicable compensation methodology is established through the successor tariff. Eversource Comments, Oct. 2, 2026, p. 8. Eversource notes that this would provide an incentive for netting tariff customers to optimize generation by TOU period. Eversource Comments, Aug. 26, 2026, p. 5. For

[15] This section applies only to the successor to the NRES program, which is required to offer a netting tariff option to participants. Projects participating under the SCEF program and its successor are sell all energy to the EDCs with a buy-all-type compensation rate, as there is no onsite customer load against which to net energy production.

[16] In the Successor Study Report, the Authority recommended that the non-residential successor program offer only a buy-all tariff for program simplicity, recognizing that a majority of NRES participants have opted for the buy-all tariff. Successor Study Report, p. 63. As a result, prior consideration of the netting interval and tariff was limited. However, the Authority builds on the analysis of the residential netting tariff and compensation approach, as BTM residential and non-residential renewable energy systems offer similar value to participants and the electric distribution system.

competitively selected projects, Eversource recommends that the $/MWh bid continue to be used to evaluate proposals, with the compensation applicable to instantaneous netting established through a uniform methodology. Eversource Comments, Oct. 2, 2026, p. 8. Eversource suggests that the methodology could distinguish between the components of the retail rate and the value each component provides to the electric system, and proposes that the approach used in Massachusetts' SMART program be used as an example. Id., pp. 8–9.

UI states that NRES netting with an export compensation rate below the full retail rate "is conceptually feasible and could be implemented within a successor NRES framework," but recommends that existing NRES Program tariff structures and administrative process be preserved to the greatest extent possible. UI Comments, Oct. 2, 2026, pp. 9–10. UI notes that implementation for small projects, which are currently selected on a non-competitive basis, could be accomplished through an administratively established export compensation rate applicable to all eligible projects within that category. Id., p. 11. For competitively selected medium and large projects, the existing competitive procurement could largely be maintained; developers would continue to submit bids while the export-compensation methodology for excess generation would apply consistently to all selected projects within a given program year. Id.

The Clean Energy Parties oppose a reduced export compensation rate for non-residential netting projects, stating that the approach creates a tension between incentivizing solar and storage deployment and reducing incentives to invest in those projects. Clean Energy Party Comments, Oct. 2, 2026, p. 11. The Clean Energy Parties argue that a reduced export rate may fail to fully capture locational and distribution-system value provided by BTM resources, which can reduce customer demand from the distribution system, reduce power flows from the upstream grid, and do not incur regional transmission costs. Id. Additionally, the Clean Energy Parties assert that the transition to instantaneous netting would alter project economics and could adversely affect project revenue predictability and debt service coverage for project hosts. Id., p. 12. Therefore, the Clean Energy Parties recommend that netting export compensation be maintained at the full retail rate. Id., pp. 11–12.

OCC supports netting on an instantaneous basis. OCC Comments, Oct. 2, 2026, p. 12. OCC asserts that instantaneous netting allows for payments that more accurately reflect the value of the generation provided, and recommends that export rates be based on avoided costs. Id. OCC supports "the same transition in the residential context for the same reasons: monthly kWh-based netting lets consumers offset high-cost peak consumption with low-value midday exports." Id. However, OCC suggests using an hourly avoided cost-based compensation approach for the export compensation rate, similar to their recommendation for buy-all projects, where the EDCs would determine time-differentiated per-MWh price caps based on hourly avoided costs and participants would bid an overall single-value percentage difference from the EDC-established price caps. Id., pp. 12–13.

DEEP maintains its position that programs should be designed to value energy at the time of production, not consumption, as the value to non-participants depends on

when it is delivered; therefore, instantaneous netting with reduced export compensation is not the optimal program design. DEEP Comments, Oct. 2, 2026, p. 3.

Eversource estimates that implementation of instantaneous netting for the NRES successor program would cost about $1.5 million and take 12 months to complete. Eversource Interrog. Resp. CAE-2. These costs would be additional to the estimated cost of implementation for the RRES successor program, but assume a coordinated implementation for the residential and non-residential successor programs. Id.; Eversource Interrog. Resp. CAE-31. UI asserts that instantaneous netting is feasible and could potentially leverage billing and system enhancements developed for the residential successor program; however, UI states that it cannot provide a reliable estimate of the additional costs or implementation timeline. UI Interrog. Resp. CAE-2. Both EDCs anticipate providing additional implementation cost information in response to the Authority's procedural order no later than December 30, 2026. Eversource Interrog. Resp. CAE-31; UI Corresp., Oct. 16, 2026, p. 9.

b. Authority Analysis

The NRES successor program shall adopt instantaneous netting for the netting tariff. The Authority makes this determination for the same reason as for the residential program: instantaneous netting paired with reduced export compensation can advance the objective of providing positive net benefits to all ratepayers, by serving as a proxy for time-differentiated compensation. Reduced compensation for energy exported to the grid on a real-time basis will create an intrinsic incentive for customers to charge storage from solar and self-consume energy stored behind the meter. Additionally, a consistent framework for both the residential and non-residential netting tariffs will simplify program administration and enhance clarity for participants.

An instantaneous netting tariff can be implemented within competitive solicitations with minimal changes to existing NRES procurement processes. The export rate can be determined using a consistent methodology across rate classes, allowing project bidders to estimate revenue potential and the EDCs to evaluate bids on a consistent basis. Participants can continue to bid a REC rate that reflects project economics. For small projects that are not competitively selected, the same export rate methodology can be used as the administratively-set export rate.

Instantaneous netting and reduced export compensation is also compatible with customer enrollment in TOU rates. Export rates govern only compensation for energy sent to the grid; customer enrollment in TOU rates would apply to the timing of energy consumption and can deepen the incentive for BTM load shifting without creating a duplicative or conflicting TOU structure for solar compensation. Additionally, BTM commercial storage is eligible to receive incentives under the ESS Program, which can enhance both participant and system value through active dispatch compensation for EDC-called events.

Notably, the EDCs initially recommended an instantaneous netting interval for the NRES Program when it was established. NRES Decision, pp. 11–12. At that time, PURA authorized a monthly netting interval, finding that instantaneous netting could create price

uncertainty for participants and present a barrier to the sustained, orderly development of the state's renewable energy industry. Id. However, the solar market has advanced significantly compared to when the NRES Program began, and the Authority finds the adoption of instantaneous netting to be a reasonable program modification that will advance the proposed program objectives.

Accordingly, the EDCs shall implement billing updates to enable a netting tariff with instantaneous netting. Wherever possible, the EDCs shall strive to combine implementation of instantaneous netting across the residential and non-residential tariffs to minimize the administrative cost and timeline of such updates. The Authority directs the EDCs to complete implementation of billing updates such that the application and interconnection portals for the NRES successor tariffs may open beginning on January 1, 2028. As with the residential netting tariff, to preserve flexibility in the ultimate export rate determination, the EDCs shall implement billing system updates such that the export compensation rate may be either linked to existing bill components or programmed as an independent value that can be updated over time. The Authority will establish a standardized methodology for export compensation rates that fulfills statutory directives in the subsequent portion of this proceeding.

V. COST RECOVERY

Public Act No. 26-127, §§ 1(f), 2(f), and 3(e), provides that:

> The costs prudently and reasonably incurred by an electric distribution company pursuant to this section shall be recovered on a timely basis through a nonbypassable fully reconciling component of electric rates for all customers of the electric distribution company. Any net revenues from the sale of products purchased in accordance with any tariff offered pursuant to this section shall be credited to customers through the same fully reconciling rate component for all customers of such electric distribution company.

This statutory language is identical to the cost-recovery language in General Statutes § 16-244z(e), which governs the RRES, NRES, and SCEF Programs. In implementing these existing programs, the Authority established a consistent framework for recovering prudently incurred program costs, crediting program revenues to ratepayers, and requiring detailed cost accounting and full prudence review. This framework remains appropriate for the successor residential, non-residential, and community solar programs, subject to the modifications described below.

For the SCEF Program, the Authority authorized the EDCs to:

> seek recovery of all payments made to Subscribers and Subscriber Organizations under the SCEF Program through the NBFMCC charge . . . To offset the program costs, the EDCs shall credit any revenues from the sale of energy and RECs associated with the delivered output from a SCEF for the full term of Subscriber Organization's enrollment under the Tariff. Furthermore, the Authority authorizes each EDC to seek recovery all of prudently-incurred costs related to the implementation and administration

> of the Modified SCEF Program Requirements. Final cost recovery will be contingent upon demonstration by the EDC that it has taken all reasonable measures to contain the costs of implementation and administration of the program . . . [C]ost recovery of implementation and administration costs is contingent upon the EDCs demonstrating that the costs were prudently-incurred and that all reasonable measures to contain costs were taken. Lastly, The Authority directs the EDCs to submit a detailed report on the revenues generated from the sale of energy and RECs associated with the delivered output from SCEF's in their applicable annual Revenue Adjustment Mechanism (RAM) filings.

SCEF Decision, p. 19. Similarly, when establishing the RRES Program, the Authority directed the EDCs to:

> to maintain detailed, itemized records of all cost incurred in the establishment and implementation of the Residential Tariff program. The EDCs shall seek recovery of all reasonable and prudently incurred expenses in the applicable [RAM] proceeding (e.g., 21-01-03 or 21-01-04). All such expenses will be subject to a full prudence review. The EDCs bear the burden of proof of the reasonableness and prudence of all costs incurred. The EDCs shall provide a summary of each of the following categories of costs and revenues for the Residential Tariff program in each applicable RAM proceeding, with data for the previous calendar year: (1) REC incentive payments; (2) REC revenue; (3) EDC administrative costs; (4) fees collected; and (5) net Residential Tariff program costs or revenues based on (1) through (4).

RRES Decision**,** p. 34. The Authority adopted a comparable approach for the NRES Program, directing the EDCs to:

> maintain detailed, itemized records of all cost incurred in the establishment and implementation of the Program authorized herein. The EDCs shall seek recovery of all reasonable and prudently incurred expenses in the applicable [RAM] proceeding (e.g., 21-01-03 or 21-01-04). All such expenses will be subject to a full prudence review. The EDCs bear the burden of proof of the reasonableness and prudence of all costs incurred. Additionally, until such a time as the Authority determines otherwise, the EDCs shall sell the RECs into the New England Power Pool Generation Information System renewable energy credit market and pass the revenues to ratepayers through the same RAM component through which it seeks cost recovery. The EDCs shall provide a summary of each of the following categories of costs and revenues for the Program in each applicable RAM proceeding, with data for the previous calendar year: (1) REC incentive payments; (2) REC revenue; (3) the energy costs associated with both the buy-all and netting tariffs; (4) EDC administrative costs; (5) fees collected; and (6) net Program costs or revenues based on (1) through (6).

NRES Decision, pp. 47–48.

Consistent with these precedents, all prudently incurred, uncapitalized costs associated with the implementation and administration of the successor residential, non-residential, and community solar programs shall be eligible for recovery through the RAM, specifically the NBFMCC rate mechanism, in the proceeding associated with the year in which the costs were incurred (i.e., for 2028 costs, Docket No. 28-01-03 for Eversource and Docket No. 28-01-04 for UI). Any fees collected in connection with the programs shall offset program costs.

The EDCs bear the burden of proving that all costs for which they seek recovery are reasonable and were prudently incurred. Recovery is not automatic merely because a cost relates to a program authorized by the Authority or required by statute. Rather, the EDCs must demonstrate that the costs were prudently incurred and that they took all reasonable measures to contain implementation and administration costs. The submission of cost estimates for program administration or IT billing system changes does not satisfy or otherwise relieve the EDCs of this burden. The prudence of such expenditures will be evaluated by the Authority after the costs have been incurred. These requirements ensure that ratepayers bear only those costs that are reasonably necessary to implement the programs, to the exclusion of inappropriate or excessive costs resulting from inefficient management, poor program implementation, or inadequate cost controls.

To facilitate meaningful review and ensure transparency, each EDC shall separately identify the costs and revenues associated with each individual program – residential, non-residential, and community solar – in its applicable RAM filing. For each program, the EDC shall provide data for the previous calendar year and itemize, at a minimum: (1) REC revenues, if applicable, which shall be used to offset program administration costs; (2) cash compensation and billing credit compensation costs associated with each tariff under each program; (3) EDC administrative costs, broken out to the greatest practicable level of detail, including IT and billing costs, incremental staffing costs, marketing costs, and other administrative expenses; (4) any fees collected, which shall be used to offset program administration costs; and (5) net program costs or revenues based on the foregoing categories. This level of detail will enable the Authority to evaluate program costs individually, assess whether administrative expenditures are reasonable, and determine the net impact on ratepayers.

Further, two clarifications to the cost-recovery practices used for the existing programs are warranted for the successor solar programs. These clarifications are intended to preserve appropriate cost recovery while preventing the RAM from becoming a mechanism for recovering capital investments outside the base distribution rate case process or recovering labor costs that do not constitute incremental program expenses.

First, all capitalized project costs associated with the successor solar programs, including capital investments for billing system and IT modifications, shall not be eligible for recovery through the RAM. This limitation does not categorically preclude recovery of otherwise reasonable and prudent capital investments; rather, it preserves the distinction between recovery of operating expenses through an annual reconciling mechanism and

recovery of capital investments through base distribution rates. The EDCs may seek recovery of eligible capital investments through a base distribution rate case, subject to the applicable review of the investments, including their prudence and appropriate treatment in rate base.

The RAM is intended to provide timely recovery of eligible program expenses that the EDCs incur in implementing programs required by statute or Authority order. It is not intended to provide an alternative pathway for recovering capital investments outside the more comprehensive review conducted in a base distribution rate case. Unlike ordinary operating expenses, capital investments generally provide benefits over multiple years and may be reflected in rate base, with associated depreciation expense and a return on investment. Allowing the EDCs to recover such investments through the RAM could accelerate recovery relative to the ordinary base-rate process and diminish the opportunity for a comprehensive review of the investments and their associated costs. Accordingly, excluding capitalized project costs from RAM recovery maintains appropriate regulatory oversight, preserves the distinction between operating and capital expenditures, and reduces the risk that ratepayers will bear costs through a RAM mechanism not designed for review of capital additions.

The EDCs' positions in the recent RAM proceedings further support establishing a clear distinction between RAM and base-rate recovery for capital investments. In response to discovery, Eversource stated that pre-existing capital projects included in the RAM should be transferred into rate base and recovered through base distribution rates beginning with the implementation of new distribution rates, while emphasizing the importance of gradualism to avoid rate shock. Eversource Interrog. Resp. CAE-71, Docket No. 26-01-03, Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company, p. 1. Similarly, although UI supported continued recovery of capital projects through the RAM, UI also supported transferring such projects from the RAM to base distribution rates in rate cases. UI Interrog. Resp. CAE-72, Docket No. 26-01-04, Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company, p. 1.

In light of these considerations, the Authority will not extend RAM eligibility to capitalized project costs for the successor solar programs.

Second, internal labor costs eligible for recovery through the RAM shall be limited to incremental labor costs directly attributable to the implementation and administration of the successor solar programs. The EDCs shall not recover through the RAM the costs of existing personnel whose labor would otherwise be incurred in the absence of the successor programs, nor may they recover the same labor costs twice through both the existing and successor programs by allocating the same staffing hours to both the predecessor and successor solar programs.

As the RRES, NRES, and SCEF Programs are phased out and the successor programs are implemented, the Authority expects the EDCs to transition personnel and associated responsibilities from the existing programs to the successor programs, as appropriate. To the extent that personnel currently administering the existing programs

can perform work associated with the successor programs as their prior responsibilities diminish, the associated labor costs shall not be treated as incremental merely because the work is performed under a new program. The EDCs must demonstrate that any labor costs claimed for recovery reflect additional staffing or additional labor expenses attributable to the successor programs, rather than the reassignment of existing resources or the continuation of costs already recovered through another cost mechanism.

This requirement is necessary to prevent double recovery of costs and ensure that ratepayers are not charged additional amounts for work that existing personnel can perform within their current staffing resources. In their RAM filings, the EDCs shall separately identify incremental labor costs by program, describe the activities performed, identify the basis for determining the incremental costs, and explain how they accounted for the transition of responsibilities from the existing programs. The Authority will review these costs under the same standards of reasonableness and prudence applicable to all other program expenditures.

VI. CONCLUSION AND ORDERS

A. CONCLUSION

In this Interim Decision, the Authority establishes the general framework for renewable energy tariffs for residential customers, non-residential customers, and community solar projects for the EDCs to ensure that such programs can take effect on January 1, 2028, pursuant to sections 1, 2, and 3 of Public Act No. 26-127. The Authority also directs the EDCs to develop and submit additional information for consideration in the remainder of this proceeding.

B. ORDERS

For orders requiring a filing, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's orders must be identified by: Docket Number, Title, and Order Number. Compliance with orders shall commence and continue as indicated in each specific order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date. Unless otherwise provided or determined by the Authority, filings submitted in compliance with an order shall constitute satisfaction of the order. Filings requiring Authority approval must be filed as a motion.

1. No later than January 1, 2027, the EDCs shall initiate and lead a working group (MPF Working Group) to further develop a MPF Report, which shall be filed for further stakeholder feedback and Authority consideration in the remainder of this docket. The EDCs shall invite, at a minimum, the Clean Energy Parties, ConnSSA, OCC, DEEP, and CGB to participate in the MPF Working Group.

2. No later than March 1, 2027, the EDCs shall jointly file, as compliance, an updated inverter data proposal. The proposal shall include, at a minimum: (1) a discussion of methods to continue REC reporting when inverter data becomes unavailable,

including when an API connection is lost because a company ceases operations; and (2) options for establishing automated data collection and management procedures, with associated cost and implementation timeline estimates.

3. No later than April 1, 2027, the EDCs shall jointly file, for review and approval, a comprehensive MPF Report based on the results of the working group process. The MPF Report shall include the following, at a minimum:
(1) proposed performance criteria and settlement procedures, including the methodology for calculating per-kW payments;
(2) a proposed per-kW payment rate based on a Connecticut-specific BCA, including the assumptions, methodology, and system benefits used to derive the rate, and a proposed methodology for updating the payment level over time;
(3) a methodology for establishing the designated performance period, including consideration of seasonal and locational needs, and the extent to which project-specific periods are appropriate;
(4) proposed conditions, limitations, and notice requirements governing any changes to project-specific peak periods after project selection;
(5) proposed metering and data requirements, storage charging restrictions, and verification requirements for ensuring that compensated energy is eligible for Class I renewable energy certification;
(6) sizing requirements for paired PV and energy storage resources to ensure that projects meet the program's proposed operational objectives;
(7) a project revenue and operating model that includes historical weather and daily solar production data, battery charging and discharging behavior, and adjustable per-kW and per-kWh compensation inputs, to evaluate project performance and economics used under alternative program parameters;
(8) an assessment of EDC implementation requirements for the recommended proposal;
(9) an evaluation of interactions with potential storage participation in wholesale markets, flexible interconnection, and other relevant programs or rates, including potential duplication of ratepayer-funded benefits; and
(10) a proposed program manual establishing the applicable program requirements and administrative procedures.
The filing shall identify areas of consensus and non-consensus among working group participants and shall include any comments or alternative proposals submitted by participants. The EDCs shall also describe the working group's process, the issues considered, and the rationale for any recommendations on which consensus was not achieved.

4. No later than January 1, 2028, the EDCs shall implement the necessary billing and IT modifications to establish two tariff options for the RRES successor program: (1) a netting tariff with instantaneous netting and (2) a flat buy-all tariff. Both tariffs shall have terms of up to 20 years. To preserve flexibility in the ultimate export rate determination, the EDCs shall implement billing system updates such that the export compensation rate may be either linked to existing bill components or programmed as an independent value that can be updated over time. The EDCs

shall complete implementation of billing updates such that customers can apply to the program and begin receiving compensation under the residential successor netting tariff beginning on January 1, 2028.

5. No later than January 1, 2028, the EDCs shall implement the necessary billing and IT modifications to establish two tariff options for the successor NRES Program: (1) a netting tariff with instantaneous netting and (2) a flat buy-all tariff. Both tariffs shall have terms of up to 20 years. In establishing a flat buy-all tariff, the EDCs shall allow for the potential incorporation of a multipart payment framework for the successors to the NRES and SCEF Programs. To preserve flexibility in the ultimate netting export rate determination, the EDCs shall implement billing system updates such that the export compensation rate may be either linked to existing bill components or programmed as an independent value that can be updated over time. The EDCs shall complete implementation of updates such that the application and interconnection portals for the non-residential successor tariffs may open beginning on January 1, 2028.

6. No later than January 1, 2028, the EDCs shall implement billing system changes, if necessary, to allow for separate low-income and MFAH buy-all compensation rates.

7. All prudently incurred, uncapitalized costs associated with the implementation and administration of the successor residential, non-residential, and community solar programs shall be eligible for recovery through the RAM, specifically the NBFMCC rate mechanism, in the proceeding associated with the year in which the costs were incurred (i.e., for 2028 costs, Docket No. 28-01-03 for Eversource and Docket No. 28-01-04 for UI).
    a. Any fees collected in connection with the programs shall offset program costs.
    b. Each EDC shall separately identify the costs and revenues associated with each individual program – residential, non-residential, and community solar – in its applicable RAM filing.
    c. For each program, the EDC shall provide data for the previous calendar year and itemize, at a minimum: (1) REC revenues, if applicable, which shall be used to offset program administration costs; (2) cash compensation and billing credit compensation costs associated with each tariff under each program; (3) EDC administrative costs, broken out to the greatest practicable level of detail, including IT and billing costs, incremental staffing costs, marketing costs, and other administrative expenses; (4) any fees collected, which shall be used to offset program administration costs; and (5) net program costs or revenues based on the foregoing categories.
    d. Further, in their RAM filings, the EDCs shall separately identify incremental labor costs by program, describe the activities performed, identify the basis for determining the incremental costs, and explain how they accounted for the transition of responsibilities from the existing programs.

e. All incurred costs will be subject to a full prudence review. The EDCs bear the burden of proof of the reasonableness and prudence of all program expenditures.

8. All prudently incurred, capitalized costs associated with the implementation and administration of the successor residential, non-residential, and community solar programs shall be eligible for recovery through a future EDC base distribution rate case. All costs will be subject to a full prudence review. The EDCs bear the burden of proof of the reasonableness and prudence of all costs incurred.

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