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Public Utilities Regulatory Authority
Ten Franklin Square
New Britain, Connecticut 06051

RE: DOCKET NO. 26-06-04: IMPLEMENTATION OF CLEAN ENERGY SUCCESSOR PROGRAMS

Dear Commissioners,

The Office of Consumer Counsel ("OCC") submits these comments[1] in response to the Authority's Notice of Request for Written Comments, as issued in the above-captioned docket on September 9, 2026.[2] OCC appreciates the opportunity to comment on the development of successor programs to the Residential Renewable Energy Solutions ("RRES"), Non-Residential Renewable Energy Solutions ("NRES"), and Shared Clean Energy Facility ("SCEF") programs. OCC continues to gather data and information to better understand the issues and develop recommendations for PURA. OCC looks forward to offering further recommendations and analysis as the record in this docket develops.

I. MULTIPART PAYMENT FRAMEWORK FOR NRES BUY-ALL AND SCEF SUCCESSOR PROGRAMS

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

OCC recommends that compensation be aligned with the marginal system value of the resource at the time of delivery, based on predetermined hourly per-kW payments rather than a

[1] These comments were prepared with substantial assistance from Synapse, OCC's consultant in this proceeding
[2] Notice of Request for Written Comments (Second Notice), Docket No. 26-06-04, *Implementation of Clean Energy Successor Programs*, Sept. 9, 2026.

single payment applied to the whole designated period. Capacity value is not constant within the designated period; discharge between 6:00 PM and 7:00 PM may offer considerably more value to the electricity system than discharge between 4:00 PM and 5:00 PM. A battery is dispatchable, so compensation levels should signal when the resource could optimally discharge; solar is passive and cannot shift its production in response to an hourly price signal.[3]

OCC further recommends that hourly payments be set using avoided costs as the price cap, accounting for the extent to which generation transmission and capacity costs are avoided in each hourly period.[4] Those values should be informed by an updated value of distributed energy resources study, guided by the National Standard Practice Model, which OCC has recommended in previous rounds of comments.[5] The Authority may want to consider adjusting incentives to recognize the distribution peaks and locations subject to grid constraints. In this regard, it may be helpful for the Authority to review how incentive levels are set under ConnectedSolutions+ in Massachusetts.[6]

The Authority should review incentive levels periodically rather than keep them fixed for the life of the program. Annual review would allow the Authority to adjust compensation as system conditions and avoided costs change and is consistent with what OCC has previously recommended.[7]

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

[3] OCC Written Comments, Docket No. 25-02-14, p. 2, Dec. 12, 2025, (time-differentiated compensation "reflects the marginal system value of solar at different times/periods and aligns with ratemaking principles").
[4] OCC Written Comments, Docket No. 25-02-14, p. 8, Feb. 4, 2026, (recommending that interim compensation rates "reflect the avoided costs associated with solar energy relative to prevailing retail rates").
[5] OCC Letter in Lieu of Written Comments, Docket No. 25-02-14, pp. 1–2, Sept. 10, 2025, (a value of solar study "that quantifies avoided energy, capacity, transmission, distribution, and integration costs would provide the most efficient reference for determining compensation rates and adders"); OCC Written Comments, Docket No. 25-02-14, p. 8, Feb. 4, 2026, (recommending that the National Standard Practice Manual "be used as a guide for conducting the study"). See also National Standard Practice Manual, National Association of State Energy Officials, https://www.naseo.org/Data/Sites/1/media/tknaseo/nspm-main-2026-final.pdf.
[6] See https://www.eversource.com/business/save-money-energy/energy-efficiency-programs/demand-response/connectedsolutionsplus
[7] OCC Written Comments, *id*, p. 9, Feb. 4, 2026 (supporting a common program duration "provided that the Authority retains the ability to review and adjust program parameters annually"); OCC Written Comments, *id*, p. 2, May 9, 2025, (supporting "the continuation of an annual review process" that would "allow for adjustments to the tariffs where closer alignment with program goals and cost containment is necessary or achievable")

The Authority should maintain flexibility in defining the targeted period instead of establishing a permanent one. The period should respond to evolving system peaks and account for realistic battery discharge duration alongside demonstrated system need. The same flexibility holds for seasonal variation, which OCC supports where system data reflects and supports such an approach.

OCC, accordingly, recommends that the Authority direct the electric distribution companies ("EDCs") to provide data and metrics to indicate the seasonal variance in timing, duration, magnitude, and pricing of system peaks. This data could inform the initial definition of the designated period and, if the EDCs provide updated data annually, indicate when the period should be updated.

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

Payment based on the minimum one-hour average discharge over the designated period oversimplifies the compensation structure and potentially omits information about when resources contribute within the period. Eversource notes that a resource failing to sustain output through the final hour would register a performance value of effectively zero kW, receiving no additional compensation.[8] If the dispatch period is extended to include more hours, batteries bear the risk of providing minimal output by the final hour and receiving a disproportionately penalized level of compensation.

OCC recommends hourly performance payments instead: actual performance in each hour, multiplied by that hour's applicable rate. This would reflect the time-differentiated performance of the resources providing capacity throughout the designated period. Depending on how the hourly rates are set, this structure would also encourage batteries to optimize their performance throughout the period rather than curtailing exports to maintain a leveled output. While consistent output contributes to efficient peak reduction, it is OCC's understanding that storage discharge under hourly pricing would generally align with the multi-hour discharging capacity of modern batteries in a grid-beneficial manner. OCC also recommends that the designated period duration be determined such that the intervals within the period do not significantly vary in price.

[8] Eversource Written Comments, Docket No. 26-06-04, p. 7, August 26, 2026.

The Authority may alternatively consider kWh-based performance payments to reflect the value of the energy exported during the peak period. Under the Energy Storage Solutions ("ESS") program, capacity-based compensation is associated with EDC-announced active dispatch events, not fixed periods.[9] When the period is fixed and recurring and no system need threshold governs the measurement of peak production benefits, resource contributions are reflected by the actual volume of energy they export. Resources that dispatch on this schedule operate more as energy resources than demand resources. A kWh-based payment would also align with the fixed period structure of time-varying rates and how customers realize benefits from onsite consumption of solar during on-peak periods.

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

OCC recommends that the Authority does not limit co-located batteries to charging from paired photovoltaic ("PV") facilities, so long as the arrangement otherwise satisfies Public Act 26-127 and applicable program requirements.[10] OCC is not aware of a strong system value justification for exclusively requiring PV charging. The economic benefit a paired resource delivers depends on when the battery charges and when it discharges, not on where the stored energy originated. A customer on a time-varying rate who charges off-peak from the grid and discharges during the system peak still provides peak load shifting, which is the benefit the program is designed to procure. Where a battery is sited with solar, the pairing itself satisfies the statutory purpose of encouraging renewable technologies, regardless of the source of each kWh stored.

An exclusive charging requirement could potentially result in inefficient battery charging and discharging. It could also act as a barrier to storage deployment without any associated cost savings for ratepayers.

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[9] General. Statute. § 16-243ee; Energy Storage Solutions Program, Docket No. 17-12-03RE03. Performance-based compensation under that program is associated with EDC-announced dispatch events rather than with fixed, recurring periods.

[10] Public Act No. 26-127; see also § 16-243ee (limiting Energy Storage Solutions eligibility to behind-the-meter systems paired with end-use customers).

E. The implications of an MPF compensation structure for solar-only and paired solar and storage project economics

The economics for solar-only and paired solar and storage projects depend on the compensation rates and actual project performance. The Authority's question is, therefore, best answered through a benefit-cost analysis and a rate and bill impact analysis, as OCC has previously stated.[11]

OCC has observed that the costs of storage projects are high and the subsidy gap is potentially substantial. Storage incentives warrant further analysis to confirm that programs are designed in a manner to deliver commensurate benefits for all contributing customers.[12] With this pending analysis, OCC recommends that storage projects be funded within existing annual program budgets rather than increasing the program budgets to fund storage.[13]

F. How bid preferences should be administered within an MPF framework

OCC continues to support bid preferences that advance policy objectives, including preferences for distressed municipalities, landfills and brownfields, and projects sited to relieve localized congestion.[14]

The more challenging issue that the MPF raises is the difference in underlying bid factors between solar-only and paired solar and storage projects, which complicates comparative bid evaluation. Paired solar and storage projects have higher costs to recover but may reduce their bid prices due to anticipated compensation from peak period storage discharge.

Given that difference, OCC recommends that the Authority consider adopting auction tranches to separately evaluate the two resource types: solar-only in one tranche and paired solar

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[11] OCC Written Comments, Docket No. 25-02-14, p. 2, May 9, 2025 (recommending "a thorough benefit costs analysis and cost-effectiveness test, as designed through the National Standard Practice Manual"); OCC Written Comments, Docket No. 25-02-14, p. 1, July 31, 2025 ("conducting a full-benefit cost-analysis as well as a corresponding bill impact analysis would allow participants and stakeholders a more granular understanding of these benefits and costs").

[12] Id, "the costs of storage projects are high, and the necessary subsidy gap is substantial. Any storage incentives considered in the successor programs should be seriously analyzed to ensure that they provide commensurate benefits for all contributing consumers"

[13] OCC Written Comments, Docket No. 25-02-14, p. 4, Dec. 12, 2025 (budget-based caps "provide clearer and more predictable cost controls than fixed megawatt limits"); see also OCC Written Comments, Docket No. 25-02-14, p. 4, Feb. 4, 2026; § 16-244z(c)(1).

[14] OCC Written Comments, Docket No. 25-02-14, p. 2, 4, May 9, 2025, see also OCC Written Comments, Id, p. 4, Feb. 4, 2026 (noting "the demonstrated effectiveness of bid preferences under NRES").

and storage in another. A bidder could still submit a single bid, which the Authority would evaluate and procure within separate categories. Tranches would permit a more equitable comparison across consistent technologies and help ratepayers pay the lowest reasonable price for the relevant resource. This approach could allow developers to prepare complete bids rather than modifying their prices to account for the per-kW compensation or in an attempt to underbid solar-only projects.

Adoption of tranches would raise the question of how much capacity to procure for each. The Authority could set aside a fixed amount to procure from each tranche, procuring all projects priced below avoided costs, whether solar-only or paired solar and storage, until the budget caps are reached. Alternatively, the Authority could first procure paired solar and storage projects, then accept solar-only projects until the budget caps thresholds are met. OCC recommends against fixing allocations for any tranches at this time. Once actual bids are available, the Authority could then compare pricing across categories and decide whether the differences warrant different treatments.

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

OCC does not oppose giving the EDCs some discretion to adjust the targeted period for individual projects, particularly where an EDC is targeting specific constrained locations. Massachusetts offers such an example, where utilities have sought to increase load between 11:00 AM and 3:00 PM to absorb excess solar generation near certain substations.[15] Similar discretion could be exercised in Connecticut, pursuant to published and standardized criteria. Without that structure, project-specific adjustments risk inconsistent treatment across the EDCs and potentially complicate the bid comparison upon which competitive solicitation relies. Any adjustments should, therefore, be disclosed in the annual program review.[16]

[15] Massachusetts Energy Efficiency Advisory Council, ConnectedSolutions Update, slide 11, https://ma-eeac.org/wp-content/uploads/Connected-Solutions-Update-For-Posting-v25523139.pdf
[16] OCC Comments, Feb. 4, 2026

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

OCC is not aware of any state that requires a competitive bidding process for both solar and storage. There are examples of solar-only competition, but the battery programs known to OCC use a standard offer approach. OCC recommends that the Authority treat the experience of standard offer storage programs elsewhere as informative on potential program mechanics, including how designated periods are defined, how performance is measured, and how compliance is verified. Those programs may help inform compensation levels, which should be capped using Connecticut-specific avoided costs.[17]

In this section, OCC offers some preliminary findings from other jurisdictions but notes that none of these programs serve as a true analogue to Connecticut's NRES or SCEF programs. The salient difference is that most of the customer-facing DER programs described use tariffs or administratively determined incentive structures rather than selecting each participating project through a competitive solicitation.

i. Summary of Lessons Learned from Jurisdictional Practices

- All three states in this section value energy exports at less than retail rates.
- The export rates in other states generally provide incentives to optimize storage charge and discharge through shorter netting intervals and distinct compensation structures for self-consumption and export.
- Compensation rates based on $/kWh can appropriately incent storage without $/kW compensation.
- Administratively-set, regularly updated adjustment factors can be used to approximate export forecasts, simplifying developer bids made under netting programs.

ii. Hawaii

Hawaii has adopted a multi-part payment framework by recognizing the value of energy exports and battery performance individually. The Hawaii Public Utilities Commission launched

[17] *Id*

its Smart DER and Bring Your Own Device ("BYOD") tariffs in April 2024.[18] Under Smart DER, exported energy receives time-varying compensation, with higher rates during the evening peak and lower rates during solar-heavy daytime hours. BYOD provides participating battery customers with additional compensation for providing grid services.

The structure is conceptually similar to the proposed MPF for Connecticut, even though the programs are not direct procurement analogues. Smart DER puts the time signal in the $/kWh export rate, while BYOD separately recognizes the ability of a battery to provide dependable power when needed. Under the initial BYOD Level 1 design, participants committed a specified amount of battery capacity for a two-hour daily period.[19] For example, a customer could receive Smart DER compensation for energy exported during the evening peak while separately receiving BYOD compensation for committing a specified amount of battery capacity during a two-hour period. This provides one instance of treating the value of delivered energy and the value of dependable battery capability as separate products rather than trying to capture both in one single payment.

Hawaii's implementation also highlights several operational issues that can affect whether compensated battery capacity delivers the intended system value. Hawaiian Electric found that some batteries participating in the predecessor Battery Bonus or Scheduled Dispatch Program did not always operate as expected. Certain systems shifted into manufacturer-controlled "Storm Watch" charging during severe weather, while some could only begin scheduled discharge at 15-minute increments. Hawaiian Electric also used AMI data to identify non-performing systems, directed 50 customers[20] to correct performance, and applied monthly penalties where continued noncompliance warranted them. All identified customers had returned to compliance by the end of 2024. Hawaii supports separating energy value from battery-performance value but highlights that payment design is only one part of ensuring batteries perform as intended. Dispatch precision, metering, device controls, verification, and treatment of

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[18] Public Utilities Commission of The State Of Hawaii, Docket No. 2019-0323, Summary of Instituting a Proceeding to Investigate Distributed Energy Resource Policies Pertaining to the Hawaiian Electric Companies https://puc.hawaii.gov/wp-content/uploads/2023/12/DPS-Phase-3-Decision-and-Order-Summary.pdf ,p. 1-2, April 1, 2024

[19] Id, p. 2-3

[20] Hawai'i Public Utilities Commission, Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies Annual CER Program Review Report, https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/customer_energy_resource_equipment/2024_annual_cer_report.pdf , March 31, 2025

non-performance determine whether promised capacity actually provides system value. Those lessons are particularly relevant to the discussions in Connecticut regarding compensation of storage as a capacity resource.

One important distinction is that, while Hawaii's Smart DER and BYOD programs are tariff-based, Hawaii does use competitive procurement for renewable generation, storage, and aggregated DER grid services.[21] However, those procurements do not provide a direct example of comparing individual solar-only and solar-plus-storage projects under a tariff program like Connecticut's proposed NRES and SCEF successors.

iii. Nevada

Nevada's practices regarding export rate compensation and netting intervals provide useful information for Connecticut's NRES Netting discussion.

Under NRS § 704.7732, qualifying customer-generators receive a credit for excess electricity, with the credit based on a percentage of the retail rate that would otherwise apply when the electricity is exported. The credit decreases as capacity thresholds are reached. The statutory tiers stepped down the credit from 95% to 88%, then to 81%, and ultimately to 75%[22] of the applicable retail rate. Tier 4, at 75% of the retail rate, is now the open tier with no capacity limit.[23] Nevada's approach to compensation creates a distinction between self-consumption and exports.[24] Solar used onsite avoids a retail-priced purchase, while excess generation sent to the grid receives the discounted export credit. Storage can therefore have value even without a separate battery incentive by allowing customers to retain solar generation for later use rather than exporting it below the retail rate.

Nevada also illustrates why the netting interval matters separately from the export rate. Beginning October 1, 2025, new net-metering customers in northern Nevada are billed using 15-

[21]State of Hawaii Public Commission, RFP DOCKET NO. 2017-0352, Renewable Energy Procurement https://puc.hawaii.gov/energy/renewable-energy-procurement/

[22] NRS 704.7732, Utility required to provide customer-generator with credit for excess electricity; amount of credit; monthly report of cumulative installed capacity of certain net metering systems https://www.leg.state.nv.us/nrs/nrs-

[23] Public Utilities Commission of Neveda, Net Metering in Nevada https://www.puc.nv.gov/renewables/net-metering-in-nevada/

[24]NRS 704.7732, https://www.leg.state.nv.us/nrs/nrs-704.html#NRS704Sec7732

minute netting.[25] Within each interval, NV Energy compares generation and consumption, and any remaining export is credited at 75% of the applicable retail rate. The distinction matters even though the nominal export rate remains 75%. Under broader netting (e.g., monthly netting), generation produced earlier may offset consumption occurring later. Shorter-interval netting reduces that opportunity, meaning more generation can be treated as an export while later consumption is purchased at retail rates. For example, if a customer exports 10 kWh of solar generation in the afternoon and later consumes 10 kWh in the evening, monthly netting may allow those amounts to offset. Under 15-minute netting, the afternoon generation may instead receive the 75% export credit while the evening consumption is purchased at the full retail rate. A battery could reduce that difference by storing the afternoon generation for later use. Nevada law also recognizes the connection between time-varying rates and storage. NRS § 704.7725[26] supports greater use of energy storage by providing time-variant rate structures with rates that vary based on when electricity is consumed from or supplied to the grid.

Nevada shows that below-retail rate compensation and shorter-interval netting can and likely should be considered together. The export rate determines the value of an exported kWh, while the netting interval determines whether that kWh is treated as an export.

iv. California

California provides a different model for recognizing the time-dependent value of solar and storage. Under the Net Billing Tariff ("NBT"), adopted by the California Public Utilities Commission ("CPUC") in Decision 22-12-056,[27] exported electricity is no longer compensated at the full retail rate. Instead, export credits are based on values derived from the CPUC Avoided Cost Calculator ("ACC"), which reflects costs such as energy, generation capacity, transmission

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[25] NVEnergy, Net Metering and Energy Storage Interconnection Handbook https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/cleanenergy/handbooks/SolarGenerations-Handbook.pdf ,p. 21.

[26]NRS 704.7725, Utility required to submit request to Commission to establish time-variant rate schedule designed to expand use of energy storage systems; review and approval or denial of request by Commission https://www.leg.state.nv.us/nrs/nrs-704.html#NRS704Sec7725

[27] PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF , December 15, 2022, p. 59-60

and distribution capacity, and other system benefits. The resulting export values vary by month and hour.[28]

This approach places much of the storage incentive directly into the energy price. Solar exports during the middle of the day generally receive lower compensation, while exports during evening periods may receive significantly more compensation. For example, a customer may receive relatively little for exporting excess solar generation during the middle of the day, but a battery allows that same energy to be stored and exported later in the evening when the applicable export value is higher. The price signal therefore rewards not just the amount of energy exported, but the time it is delivered to the grid. CPUC's 2025 Grid Modernization Report[29] states that the share of new behind-the-meter solar installations paired with storage increased from roughly 13% to 69%[30] following implementation of the NBT. CPUC attributes the new framework to creating more granular price signals for shifting solar production into higher-value hours.

California also provides useful considerations for the NRES Netting discussion. The NBT uses no temporal netting; imports are charged at retail rates while exports are separately credited at the applicable export rate.[31] CPUC recognized that this makes prospective project savings harder to estimate because the result depends on the timing of customer load and solar production. Rather than requiring perfect forecasts, CPUC adopted standardized netting adjustment factors that developers can use as a proxy when estimating customer exports under no-netting treatment. Those factors are updated annually.[32]

California offers two potential takeaways. First, time-dependent system value can be reflected directly through granular $/kWh compensation rather than through a separate $/kW payment. Second, its adjustment-factor methodology provides a useful precedent for the forecasting problem created by instantaneous netting. Connecticut could similarly consider standardized assumptions or profiles when evaluating NRES Netting bids.

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[28] *Id*, December 15, 2022, pp. 141-142

[29] California Public Utilities Commission, California's Grid Modernization Report To The Governor and Legislature, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/californias-grid-modernization-report-2025--volume-i.pdf , December 2025, pp. 10

[30] *Id*, p. 10

[31] Public Utilities Commission of The State Of California, Item# 23 (Rev. 1) Agenda Id# 22685, Energy Division Resolution E 5324 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M535/K542/535542694.PDF ,p. 2-4

[32] Public Utilities Commission of The State Of California, Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF ,p. 3-4

II. NRES SUCCESSOR PROGRAM NETTING TARIFF

I. Instantaneous netting and export compensation below the retail rate

OCC supports netting on an instantaneous basis.[33] Instantaneous netting allows for payments that more accurately reflect the value of the generation provided, which matters especially when solar is paired with storage. OCC supported 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.[34] Instantaneous netting also depends on interval metering. OCC continues to recommend that the Authority confirm AMI readiness by service territory and customer class and consider transitional or hybrid approaches where the enabling infrastructure is not yet uniformly available.[35]

OCC supports an export rate set below the full retail rate. The full retail rate is likely well above the value of the generation provided, and reducing compensation below this value appropriately recognizes cost causation principles.[36] Export rates should be set using avoided costs as a price cap, and the EDCs should be required to estimate and provide the average hourly avoided costs used to determine that cap.

J. Implementation of instantaneous netting within a continued competitive solicitation process

Under an instantaneous netting program, procuring solar and storage generation within a competitive solicitation process is challenging. The EDCs may need to compare proposals that contain a variety of different hourly prices and different hourly generation profiles. The export generation profiles could vary significantly across bidders based on (1) the customer's PV and storage system sizing relative to onsite loads, (2) incentives provided by the export tariff, (3) onsite consumption, and (4) demand response participation impacting onsite consumption. The

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[33] 15-Minute increments may be considered as acceptable for instantaneous netting, if meter capabilities and utility billing infrastructure precludes measuring in shorter intervals.

[34] *Id* p.2, (OCC "supports the transition from monthly to instantaneous netting, which better reflects real-time system conditions and reduces peak cost shifting," whereas monthly netting "allowed customers to offset high-cost peak consumption with low-value midday exports, increasing cost for non-participants and decreasing grid benefits").

[35] OCC Written Comments, p. 2–3, Feb. 4, 2026 (noting concern regarding "Advanced Metering Infrastructure (AMI) readiness and uneven deployment across service territories" and recommending that the Authority "consider transitional or hybrid approaches until enabling infrastructure is uniformly available", citing Docket No. 24-10-04; Docket No. 17-10-46RE04; Docket No. 11-02-03.

[36] OCC Written Comments, Docket No. 25-02-14, p. 1, July 31, 2025

customer export profiles might change not only daily, but also weekly or monthly. The export profile of a school with multiple vacations including summer vacations, for example, differs from that of a business with a consistent consumption pattern seven days a week, 365 days a year.

OCC recommends the Authority adopt a simplified bidding strategy as follows. First, the EDCs prepare common time-differentiated per-MWh price caps based on hourly avoided costs. Then, competitive bids are structured as an overall single-value percentage discount from the EDC-established price caps. This would eliminate the need to forecast bidders' export and onsite-consumption behavior. OCC believes that bidding projects are best equipped to anticipate their own export and onsite consumption behaviors and account for them in their bid formulations.

The Authority could choose a level of granularity for the time-differentiated price caps that balances precision with simplicity. For example, price caps could vary by season or by month, and within each period they could be set hourly or on a coarser on-peak and off-peak basis. However, the more that the price caps are aggregated, the greater the chance that they deviate from avoided costs. There is also a question of whether the price caps, and therefore any associated bids, should change each year of the program term to reflect changes in future avoided costs. Price caps that are set for the full program term are more likely to deviate from actual avoided costs.

Under OCC's proposed approach, all bids would retain the same relative hourly price curve since they would be proportional to the EDC's hourly avoided cost values. As NRES is designed to provide a net benefit to the grid and to ratepayers, the relative hourly value of exports should be derived from grid value rather than supply-side costs. Ratepayers are agnostic about export and onsite consumption profiles under a net-billing tariff as both behaviors provide cost-effective value to the grid.

Single-value percentage discount bids from the set price caps enable a straightforward bid evaluation process where the bids with the largest discount values are awarded. One project may bid a 5% discount off established price caps, for example, while a more competitive project may bid a 10% discount. Thus, the projects that export energy at the most cost-effective rate at any hour will be selected.

III. RESIDENTIAL INCENTIVE ADDER IMPLEMENTATION

OCC believes that further analysis is needed to determine the most cost-effective approach to administer residential incentive adders, as previous increases in residential incentive adders have not clearly demonstrated a corresponding increase in residential solar deployment rates. The design and magnitude of the adder should be informed by a benefit-cost analysis and rate and bill impact analysis to mitigate the risk of overcompensating participating customers. Such analysis should also consider the effectiveness of economically distressed municipality adders in reaching the intended customers in those municipalities.[37]

To eliminate the need for dedicated production meters, the Authority proposes two alternative methods of administering residential incentive adders: (1) a fixed per-kW incentive and (2) a per-kWh incentive based on energy exports recorded at the revenue meter. OCC does not support the fixed per-kW incentive because it would not accurately reflect the system's performance and benefits contributed to the grid, unless payouts are predicated on the system having non-zero export generation. Between the two options, OCC prefers administering the residential incentive adders using a per-kWh incentive based on energy exports. This approach would provide compensation that is more aligned with the value of the grid benefits. OCC is concerned, however, that this method would discourage onsite consumption of produced energy. If PURA could tie the per-kWh export incentive to a peak window, that may mitigate some of this concern. Otherwise, OCC generally continues to favor residential incentive adders based on total production, with transparent customer pricing and strict disclosure requirements so that participants know the incentives.[38]

OCC also cautions against the use of one-time upfront incentives as they expose ratepayers to unnecessary risk. An upfront incentive was administered in the ESS program until 2025 and has since been significantly reduced due to the unrecoverable cost of recipient nonperformance.[39]

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[37] Eversource Written Comments, Docket No. 26-06-04, p. 10, August 26, 2026.
[38] OCC Written Comments, Docket No. 25-02-14, p. 3, May 9, 2025 (emphasizing "the importance of transparent customer pricing and a simple and accessible application process," together with "stringent customer disclosure requirements that ensure customers are receiving accurate information and are made aware of available adders and federal incentives")
[39] Final Decision, Docket No. 25-08-05, p. 9, December 16, 2025.

IV. CONCLUSION

OCC appreciates the opportunity to submit these comments and thanks the Authority and stakeholders for their continued work on this docket.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that on this day the foregoing document was filed with the Public Utilities Regulatory Authority, and copies thereof were served upon each person designated on the official service list in this proceeding in accordance with R.C.S.A. § 16-1-15.

Dated at New Britain, Connecticut this 2nd day of October 2026.

/s/ *Paschaline Poku*
Paschaline Poku, Esq.
Commissioner of the Superior Court