JOINT REBUTTAL TESTIMONY OF JIM KENNERLY AND TOBIN ARMSTRONG, SUSTAINABLE ENERGY ADVANTAGE, LLC

MARCH 29, 2024

I. INTRODUCTION

Q: Mr. Armstrong, please state your name, employer, and title.

A: My name is Tobin Armstrong. I am a Principal Analyst at Sustainable Energy Advantage, LLC ("SEA").

Q: Mr. Kennerly, please state your name, employer and title.

A: My name is Jim Kennerly. I am a Director at Sustainable Energy Advantage, LLC ("SEA").

Q: Have you submitted other testimony in Docket 23-44-REG?

A: Yes, we submitted joint Direct Testimony in support of the Distributed-Generation Board and Office of Energy Resources' Recommendations for the 2024-2026 Renewable Energy Growth Program Year filing dated December 20, 2023.

Q: What is the purpose of your Rebuttal Testimony?

A: The purpose of our Rebuttal Testimony is to answer:

- The Joint Reply Testimony of the Narragansett Electric Company (d/b/a) Rhode Island Energy Witnesses, Dr. Carrie Gill, Ms. Erica Russell Salk, and Mr. Kenneth Campbell.
- The Direct Testimony of the Division of Public Utilities and Carriers' Witness, Mr. Michael Brennan (hereafter "DPUC" and "Mr. Brennan", respectively).

Q: Mr. Armstrong, please indicate which aspects of the instant rebuttal testimony you are sponsoring.

A: I am sponsoring the testimony and Schedules contained or referred to in Section II (Post-Tariff Revenue Assumptions), Section III (Interconnection Cost Assumptions) and Section IV (Small Solar Cost Data).

Q: Mr. Kennerly, please indicate which aspects of the instant rebuttal testimony you are sponsoring.

A: I am sponsoring the testimony and Schedules contained or referred to in Section V (Small Solar Assumptions/Prices), Section VI (Program Term and Ceiling Price Adjustment Mechanism), and Section VII (Incentive-Payment Adders).

II. POST-TARIFF REVENUE ASSUMPTIONS

Q: In their testimony, did Mr. Brennan and the DPUC make any recommendations with regard to post-tariff revenue assumptions in ceiling price calculations?

A: Yes. Mr. Brennan and the DPUC argue that the assumed post-tariff revenue utilized by SEA should not be discounted by 20% to reflect the new requirements of Chapter 300, which states in part, that after April 15, 2023, all new virtual net metering (VNM) systems subject to the 275 MW cap established by Chapter 300 must have their compensation reduced by 20%. Mr. Brennan and the DPUC reason that, because SEA already applies a 40% reduction to assumed post-tariff revenue (as discussed on page 47 of SEA's Direct Testimony), the 20% reduction in compensation required by law should be subsumed by the 40% reduction already applied.

Q: Would it be appropriate for the PUC to adopt the DPUC's approach to post-tariff revenue calculation in which a 20% reduction reflecting the change in law is not applied?

A: No, we do not believe so. SEA believes that failing to de-rate the post-tariff revenue by a further 20% would not appropriately reflect the uncertainty regarding program availability and the applicable rate at the end of the tariff term relative to current law. This is because projects in the 2024 through 2026 REG Program year are likely to have such a 20% reduction apply to their post-tariff revenue, barring any further change in policy.

Q: Why is it reasonable to assume that the 20% reduction in VNM revenue will apply to projects in the 2024 through 2026 REG Program?

A: As Mr. Brennan has acknowledged in his testimony, Chapter 300 states that, after April 15, 2023, all new VNM systems subject to the 275 MW cap must have their compensation reduced by 20%. The PUC has already indicated, through its action in Docket 22-39-REG, that REG projects should not be expected to take on the cost of reconfiguring front-of-meter projects to behind-the-meter projects at the end of their tariff life. Therefore, as the PUC indicated in its ruling in Docket 22-39-REG, all future REG projects can reasonably be expected to operate as virtual net metering projects following the conclusion of the REG tariff term and thus would have the 20% reduction to compensation apply to their post-tariff revenue. Additionally, given the pace of virtual net metering installations in recent years, as well as the hundreds of MW of potential VNM projects in the interconnection queue, it is difficult to assume the 275 MW VNM cap would not be reached over the next 20-24 years. As such, it is possible that by the time REG projects in the 2024 through 2026 program year conclude their tariff, VNM revenue will not be available, or will be available at an even steeper reduction to compensation than 20%.

Q: Why does the 40% discount to post-tariff revenue applied by SEA in prior program years not subsume the 20% reduction in VNM recently enacted?

A: We believe this issue is a matter of perspective. From the perspective of the 2023 Ceiling Price development process, prior to the enactment of the 20% reduction in VNM revenue per Chapter 300, Mr. Brennan would be correct that the 40% discount to post-tariff revenue applied was intended to capture these types of changes in law. However, because the 40% discount is intended to capture uncertainty relative to current law, it is necessary to fold the 20% discount now required by statute into the calculation of post-tariff revenue in addition to the 40% uncertainty discount, as the un-discounted baseline from which financiers and project developers will evaluate project revenue has shifted.

If adopted, Mr. Brennan's suggested approach is, in effect, reducing the post-tariff discount applied by 50%. However, Mr. Brennan offers no reasoning as to why project developers or financiers should be expected to view post-tariff revenue with more certainty relative to the 2023 Program Year.

The unstated assumption in Mr. Brennan's suggested approach is that there will be no additional cuts to net metering compensation in the future that are larger than 20% over the next 20-24 years (when the tariff term of most projects in this plan will end). Take, for instance, a scenario in which Chapter 300 discounted VNM rates by 40%. Under such a scenario, Mr. Brennan's suggested approach would result in a post-tariff revenue stream with no further discounts beyond those applied by statute. Given this, SEA argues that holding the post-tariff discount utilized in the 2023 Program Year constant, regardless of future changes in statute.

Lastly, Mr. Brennan's suggested approach does not recognize the multiple dimensions of risk reflected in the 40% discount applied. Not only is there uncertainty relating to future policy (e.g., availability of policy providing post tariff revenue, and the applicable formula in statute used to derive the applicable rate), but there is also uncertainty regarding the values of retail rates on which VNM rates are calculated that will be in effect during the post-tariff period. As such, even if policy risk were theoretically eliminated, the construct of the VNM program (e.g., variable retail-rate derivative revenue) produces inherent risk which is reflected in the 40% discount. Given that Mr. Brennan's suggested approach, in effect, reduces the post-tariff discount applied by 50%, it suggests a reduction in this dimension of risk – which we do not believe is applicable.

III. INTERCONNECTION COST ASSUMPTIONS

Q: In their testimony, did Rhode Island Energy object to language in SEA's direct testimony regarding interconnection cost sharing?

A: Yes. Rhode Island Energy (RIE) objects to SEA's statement made in our Direct Testimony (see Bates Page 22, Lines 2-4) that "broad-scale cost sharing between developers and ratepayers for such common upgrades is not currently authorized in Rhode Island, and the results of the currently ongoing group studies are not publicly known." RIE clarifies in reply testimony that R.I. Gen. Laws § 39-26.3-4.1 provides that the PUC may determine that costs relating to a "specific system modification benefiting other customers" is eligible for cost sharing. RIE further notes that it has filed two Petitions with the PUC in Dockets 23-37-EL and 23-38-EL seeking approval for such cost-sharing treatment.

Q: Does SEA believe that this clarification should justify any revisions to the interconnection costs assumed in ceiling price calculations for the 2024 through 2026 REG program years?

A: No. When designing inputs for use in the calculation of ceiling prices, it is important to assume costs that are representative of the typical project in order to provide appropriate headroom under the ceiling price under which healthy competition may emerge. SEA's statement made in direct testimony was intended to note that Rhode Island currently lacks a broad-scale cost sharing program such as the provisional cost allocation program approved by the Massachusetts Department of Public Utilities. Approval of such a program would create a reasonable degree of certainty that interconnection costs state-wide would have some degree of policy relief and would need to be considered when setting ceiling prices. If ultimately granted by the PUC, the potential authorization to approve cost sharing for certain specific system modifications that deliver shared benefits, on the other hand, does not provide such certainty. This is because, unless and until there is a broad-scale cost sharing program applicable to "typical" projects in Rhode Island, it is unclear if:

- REG-eligible projects will be located in areas of RIE's distribution system with eligible system modifications;
- RIE will petition for cost sharing for such upgrades;
- The PUC will approve such cost sharing; and
- The timing of such approval (if granted).

Furthermore, as the PUC has yet to rule on any of the petitions noted by RIE (and is not anticipated to until the summer of 2024, at the earliest) it is not appropriate for SEA to assume what standard of review will be applied to such petitions. Therefore, SEA believes that it is not reasonable to assume that such (notional) cost relief will be available to a typical REG-eligible project.

Finally, and even if REG-eligible projects are able to benefit from interconnection cost sharing, it is SEA's expectation that such cost savings would allow them to bid more competitively under the ceiling price, thereby delivering ratepayer savings through the dynamics of healthy competition and obviating the need for such changes to the ceiling prices.

Q: **In their testimony, did Rhode Island Energy also object to SEA's use of regional interconnection cost data when forming interconnection cost assumptions used in ceiling price calculations?**

A: Yes. RIE recommends that SEA use Rhode Island specific interconnection cost data to assess trends in interconnection costs for future years. In doing so, RIE argues that "Utilizing data from states other than Rhode Island does not consider the differences in the electric distribution system topology, engineering design standards, geographical differences in labor wages, how pricing and procurement varies between Companies, and how regulatory constructs vary between states."

Q: **In asserting these "differences…between states," does RIE provide any tangible evidence or specific examples of how these claimed differences should be used to derive any alternative estimates for interconnection costs in the state?**

A: No, they do not.

Q: **Does SEA have concerns with RIE's proposed approach of relying on strictly historical Rhode Island interconnection data when forming interconnection cost assumptions used in ceiling price calculations?**

A: Yes. SEA is concerned that failing to consider regional trends in interconnection costs may dramatically understate the potential interconnection costs faced by future REG-eligible projects. In SEA's experience, as states experience increasing levels of DG penetration, interconnection costs, absent any broad cost-sharing mechanism, tend to rise in a non-linear fashion. This is because once grids experience higher levels of saturation, the scope (and resulting cost) of upgrades required to facilitate the interconnection DG can increase dramatically for both distribution- and transmission-side investments. As such, a simple linear trending analysis utilizing historic costs is unlikely to reflect the costs associated with such inflection points.

For several reasons, SEA believes that this dynamic is likely to play out in Rhode Island. First, given delays in the interconnection process stemming from increased review complexity and Affected System Operator (ASO) studies, historic interconnection cost data for projects greater than 1 MW is significantly lagged, and thus at substantial risk of being unrepresentative of projects currently under study. Based on SEA's market knowledge and public interconnection data from neighboring states, it is our assumption that projects over 1 MW are likely to take at least 2-3 years (if not longer) from entering the interconnection queue to commercial operation. As such, SEA is confident that relying upon historic data from Rhode Island alone is unlikely to produce an accurate outlook of expected costs for either projects currently in the interconnection queue or projects entering the interconnection queue in 2024 and is thus likely to unnecessarily accentuate dynamics of unhealthy competition after two years of poor procurement results.

Second, large volumes of DG in Rhode Island are being included in ASO studies, with future studies expected. Specifically, the ongoing Western Rhode Island (WRI) Area ASO Study #3 implicates over 100 MW of solar projects and has been in process since August 2021. RI Energy's March Paragraph 9 report notes that initial study results have identified voltage issues, which could necessitate system upgrades including a synchronous condenser solution. Given that SEA has no additional information regarding expected study outcomes and resulting costs, the presence of an ASO study implicating large volumes of DG that has already identified issues requiring system upgrades in initial findings creates significant uncertainty and potential for upward deviation in future interconnection costs relative to historic costs. Even if the instant ASO study does not produce costly interconnection fees, additional ASO studies are expected to be launched following the conclusion of the instant study, indicating that most future large DG facilities will be subject to such study, and potential resulting system upgrade costs, going forward. Specifically, based on RI Energy's March Paragraph 4 reporting, 33 substations with a combined 260 MW of pending solar interconnections may need ASO studies in the next 6 months.

Q: In its own testimony, does the DPUC share Rhode Island Energy's concerns regarding the inclusion of regional costs into the calculation of ceiling prices for Large Solar projects?

A: No, they do not. In fact, on Page 14 of his testimony, Mr. Brennan notes that he is confident that at the proposed ceiling price values(which include an averaging of Rhode Island and regional values) RIE will still be able to select "only the most competitive eligible projects in the open enrollments," given that "the competitive classes will reflect the changing dynamics of interest rates, project costs and other factors in the prices that they bid."

Q: Given your firm's competition-related concerns with using exclusively Rhode Island interconnection data that is at risk of being substantially out of date in ceiling price calculations, why is it reasonable for SEA to utilize regional interconnection cost data?

A: R.I. Gen. Laws § 39-26.6-5(d)(1) provides that ceiling prices may consider "Transactions for newly developed renewable energy resources, by technology and size, in the ISO-NE control area and the northeast corridor." As such, in order to provide a robust and representative sampling of cost data, it has been standard practice for SEA to utilize regional data to inform inputs used in ceiling price calculations. As described in SEA's direct testimony, SEA applied this same regional approach to its interconnection costs assumption, and specifically aimed to sample states (like Rhode Island) with both relatively high levels of DG penetration and (where possible) known and measurable interconnection costs that reflect the results of completed transmission and distribution studies. It is important to note that, although SEA utilized interconnection data from Massachusetts and Maine, SEA included historic interconnection costs from Rhode Island in its analysis.

IV. SMALL SOLAR COST DATA

Q: **In their reply testimony, did RI Energy object to the collection of certain data regarding the installed costs for Small-Scale Solar projects?**

A: Yes, RIE expressed hesitation regarding the collection of actual installed cost data from customers, arguing that RI Energy does not currently collect such information.

Q: Does SEA propose to collect actual installed cost data from RIE?

A: No. SEA and OER’s intent is to collect the same installer/developer self-reported estimates for Small-Scale Solar installed cost as opposed to information that would serve as proof of actual costs. This request would be consistent with the request that has been made by SEA and OER, and fulfilled by RIE (and prior to that, National Grid), in many prior program year ceiling price development processes.

Q: Was SEA able to clarify this matter with RIE?

A: Yes. Following the receipt of their testimony, SEA reached out to RIE to clarify the intent of its request to RIE via email. RIE concurred that, provided that the request being made is consistent with the information provided in prior program years, RIE has no issue continuing to meet the need in the future, and suggested to our team that they consider the matter resolved.

V. SMALL SOLAR ASSUMPTIONS/PRICES

Q: In their reply testimony, did Mr. Brennan and the DPUC make any recommendations with regard to the financing assumptions for Small Solar projects?

A: Yes, Mr. Brennan and the DPUC request recalculation of ceiling prices in this category in light of the "significant change in interest rates" since the end of the stakeholder process and the Board's vote to recommend the prices on November 14, 2023.

Q: What values are the Small Solar interest rate on term debt inputs based upon?

A: The values for interest rate on term debt for Small Solar projects are from UMass Five Credit Union's MySolar Loan public website[1], which Small Solar market participants indicated to SEA is a frequent solar loan originator in that market segment, and thus representative of typical solar loan financing terms.

Q: Have these rates changed since October 2023, and if so, how have they changed?

A: Yes, they have. Rather than decreasing, as Mr. Brennan suggests, the current loan offers from UMass Five have increased by 100 basis points, as shown in SEA Table 1 below.

SEA Table 1 – Comparison of 10-Year and 15-Year UMass Five Solar Loan Offers (October 2023 vs. March 2024)

Date	UMass Five Solar Loan Offer		Difference
	October 2023	March 2024	
120 Month (10-Year)	7.88%	8.88%	+1.00%
180 Month (15-Year)	8.13%	9.13%	+1.00%

[1] https://umassfive.coop/personal/loans/sustainability/mysolar

Q: Do Mr. Brennan and the DPUC state other objections to the inputs utilized to set the Small Solar ceiling prices?

A: Yes. In light of the increased cost of debt, Mr. Brennan and the DPUC appear to suggest that the cost of debt be excluded completely from the calculation of the Small Solar prices, reasoning that the high cost of debt would cause host owners of Small Solar projects to finance their projects entirely with their own equity.

Q: Is an all-equity capital structure a reasonable or equitable assumption for the ceiling prices?

A: We do not believe so. While it is possible that more residential and business customers may choose to respond to the high cost of debt by using more cash equity to finance a Small Solar project, it is unclear what percentage of said customers would finance the entire cost via cash equity, versus a reduced share of such equity. However, to SEA's knowledge, no entity presently has access to such data on the whole, nor is such data easily collected on a large scale from anyone in Rhode Island. However, we note that, according to the Lawrence Berkeley National Laboratory, the median income of residential customers installing solar has declined over time[2], and with it, the remaining pool of residential customers that can finance a solar PV project entirely from their own cash equity. Furthermore, and in SEA's experience, customers that can finance the upfront cost of a project entirely from cash equity tend to have much higher incomes than those who cannot. Thus, adopting Mr. Brennan and the DPUC's request is likely to

[2] See Forrester, et al. *Residential Solar-Adopter Income and Demographic Trends: 2023 Update*. December 2023. Available at: https://emp.lbl.gov/publications/residential-solar-adopter-income-2

disproportionately favor customers of Rhode Island Energy with higher incomes, and thus inhibit low- and moderate-income ratepayers in their efforts to access the REG program.

Q: Does Mr. Brennan, in his reply testimony, suggest any other alterations to the Small Solar prices?

A: Yes, he does. Mr. Brennan suggests that "Based on the evidence from 2022, the Division believes that the Small Solar class ceiling prices should be set at a level that is more in line with the 2022 prices" on account of their being a stronger degree of demand for projects in that program year relative to the 2023 Program Year. Furthermore, Mr. Brennan also suggested that the Small Solar prices be recalculated to account for the assumptions he and the DPUC suggest are correct with regard to post-tariff "merchant" revenue.

Q: Did SEA's analysis suggest that the capital and operating costs of Small Solar projects should be set at 2022 program year levels?

A: No, it did not. As described in our Direct Testimony and in a variety of Schedules filed with it, our assumption of capital, operating and financing costs for Small Solar either increased, or remained level, relative to the 2023 Program Year. Furthermore, we note that there is solid evidence (as Mr. Brennan himself acknowledged in his testimony) that the 2023 prices led to severe under-subscription in the Small Solar categories, which suggests that increasing prices only to levels that partially cover costs does not have merit.

Q: Is it reasonable to recalculate the Small Solar ceiling price to account for a different post-tariff revenue assumption?

A: We would not recommend that the Commission consider adopting this approach, given that the changes made in Chapter 300 to virtual net metering compensation by the General Assembly strongly suggest that a 40% compensation derate is not a sufficiently conservative assumption over such a 20-year life.

VI. PROGRAM TERM AND CEILING PRICE ADJUSTMENT MECHANISM

Q: In their reply testimony, do Mr. Brennan and the DPUC address the three-year term of ceiling prices, or the recommended Ceiling Price Adjustment Mechanism?

A: Yes. In his testimony, Mr. Brennan explains that the DPUC only supports establishing ceiling prices for the 2024 Program Year. Mr. Brennan states that the DPUC arrived at this conclusion because the DPUC views market conditions as being "too volatile and uncertain to support a multi-year recommendation of prices." To this end, the DPUC cites the volatility in interest rates alone over the three-month period since SEA calculated the recommended ceiling prices," and further cites anticipated changes in capital costs from year to year.

Q: Does SEA concur in Mr. Brennan's assessment of the volatility of interest rates over the proposed duration of the program plan?

A: No, we do not. Though Mr. Brennan is correct that there have been short-term swings in U.S. 10- and 20-year Treasury prices, the premise of his argument that short-term volatility is indicative of the Treasury market's expectation of longer-term volatility is unfounded.

Q: Even as values for 10- and 20-year Treasury securities have been somewhat volatile in the last several months, has the outlook for 10- and 20-year Treasury values over the 2025 and 2026 program year changed materially since October?

A. No. In fact, as shown in **SEA Rebuttal Schedule 1**, it appears that the Treasury markets' collective longer-term expectations (which are reflected in the 2025 and 2026 Program Year prices) are generally the same as in October 2023, when said outlook was generated for the purpose of calculating the proposed prices in those years.

Q: Can you please explain how SEA developed the anticipated interest rate on term debt inputs for the prices proposed in the recommended program plan shown in SEA Rebuttal Schedule 1?

A: Yes. SEA utilized the interest rates on 10- and 20-year Treasury securities from October 11, 2023, and utilized the Market Consensus Forecast developed by econforecasting.com (described in our response to PUC 1-20), an open-source provider of forecasted market prices of a number of types, to forecast average 10- and 20-year rates from monthly values generated by the Forecast over the duration of the 2024, 2025 and 2026 Program Years. Using these 10- and 20-year average values over each program year during the three-program year period, SEA also calculated appropriate proxies for 13- and 15-year "risk-free" rates by weighting the 10- and 20-year values to produce expected "risk-free" rates over those periods. Once these average rates are generated, SEA layers on a 3.25% risk premium for Solar and Anaerobic Digestion projects, and a 3.5% risk premium for

Wind and Hydro projects.[3] The general approach described here is also described in our Direct Testimony and **SEA Schedule 3**.

Q: Was the revised outlook for the 2025 and 2026 Program Year as of March 28, 2024 shown in SEA Rebuttal Schedule 1 calculated in the same manner?

A: Yes, it was.

Q: Is the approach taken in SEA Rebuttal Schedule 1 the same approach as is proposed to be used by SEA on behalf of OER and the Board to effectuate the Ceiling Price Adjustment Mechanism with regard to interest rates on term debt?

A: Yes, it is.

Q: Do the results in SEA Rebuttal Schedule 1 substantiate the DPUC's concerns regarding volatility in a multi-year program plan?

A: No, they do not. As shown in SEA Table 2 and SEA Table 3 below, the interest rate outlook for the period of the 2025 and 2026 Program Years appears largely unchanged since October. In fact, the outlook for Large Solar projects is precisely the same as it was back in October, and thus precisely the same as was proposed for the 2025 Program Year, and only six basis points (0.06%) less than expected for the 2026 Program Year. As such, and even given the substantial changes in the prices of 10- and 20-year Treasuries, the changes are not substantial enough for the long-term outlook for any category to trigger the applicability of the Mechanism.

[3] As was the case for the 2023 prices approved in Docket 22-39-REG, the difference in risk premium is intended to account for relative fuel availability and assurance.

SEA Table 2 – Difference Between Recommended Interest Rates on Term Debt and Market Expectations for the 2025 Program Year

Renewable Energy Class	**Small Solar I**	**Small Solar II**	**Medium Solar**	**Comm'l Solar/CRDG**	**Large Solar/ CRDG**	**Wind/Wind CRDG**	**Small-Scale Hydro**	**Anaerobic Digestion**
Debt Term (Years)	13	10	13	13	15	15	20	15
Interest Rates Included in Ceiling Prices for 2025 PY (Extracted 10/2023)	6.91%	6.78%	6.88%	6.88%	6.96%	7.18%	7.32%	6.96%
Expected Average Over 2025 PY (Extracted 3/28/2024)	7.04%	7.04%	7.04%	7.04%	6.96%	6.96%	7.29%	6.96%
Difference in Proposed vs. Currently Expected 2025 PY Interest Rate (10/2023-3/28/2024)	**+0.13%**	**+0.26%**	**+0.16%**	**+0.16%**	**0.00%**	**-0.22%**	**-0.03%**	**0.00%**
Interest Rate Threshold Triggered in Mechanism?	No	No	No	No	No	No	No	No

SEA Table 3 - Difference Between Recommended Interest Rates on Term Debt and Market Expectations for the 2026 Program Year

Renewable Energy Class	**Small Solar I**	**Small Solar II**	**Medium Solar**	**Comm'l Solar/ CRDG**	**Large Solar/ CRDG**	**Wind/Wind CRDG**	**Small-Scale Hydro**	**Anaerobic Digestion**
Debt Term (Years)	13	10	13	13	15	15	20	15
Interest Rates Included in Ceiling Prices for 2026 PY (Extracted 10/2023)	6.97%	6.84%	6.95%	6.95%	7.03%	7.25%	7.40%	7.03%
Expected Average Over 2026 PY (Extracted 3/28/2024)	7.07%	7.07%	7.07%	7.07%	6.98%	6.98%	7.32%	6.98%
Difference in Proposed vs. Currently Expected 2026 PY Interest Rate (10/2023-3/28/2024)	**+0.10%**	**+0.23%**	**+0.12%**	**+0.12%**	**-0.06%**	**-0.27%**	**-0.08%**	**-0.06%**
Interest Rate Threshold Triggered in Mechanism?	No	No	No	No	No	No	No	No

Q: Given the findings shown in SEA Rebuttal Schedule 1, which reflect market expectations for the future, does the recent volatility in interest rates provide any evidentiary basis for a decision to approve only a single year of ceiling prices?

A: No, it does not.

Q: In his testimony, Mr. Brennan also cites changes in module prices on a quarter-on-quarter and year-on-year basis. Do these changes justify approving only one year of prices?

A: No, we do not believe so. Overall, the reduction in prices of 11% quarter-on-quarter and 23% year-on-year for modules in the United States represents a four (4) cent per Watt ($0.04/W) and eight (8) cent per Watt ($0.08/W) difference, respectively.

Q: Relative to the typical prices of REG-eligible projects, is this a significant difference from expectations?

A: No. All other factors held equal; the impact of this change is approximately 1% to 2% of total capital cost for any eligible Solar project. Furthermore, price increases of this magnitude are not uncommon from year to year on multiple other potential components of the total capital cost of a given project, including for inverters, installation labor, balance of system, or others. Thus, we believe that the level of change Mr. Brennan observes in module pricing is effectively captured in the change in the recommended prices from year to year.

Q: Even if such cost and interest rate volatility were significant enough to justify a change to the prices, did SEA develop a market adjustment mechanism for the 2025 and 2026 REG Program Years intended to facilitate such adjustments while limiting market participant and ratepayer risk?

A: Yes. SEA proposed the Ceiling Price Adjustment Mechanism, which is described in detail in Section V of our Direct Testimony (contained on Bates Pages 29- 35), as well as in RIE's Revised Schedules RIE-1 and RIE-2.

Q: Was this pricing adjustment mechanism discussed prior to filing with the DPUC?

A: Yes. In their comments submitted September 18, 2023 to OER and the Board (as shown in SEA Schedule 8), the DPUC suggested that any three-year plan for prices should allow for a "mechanism" that allowed for the re-opening of prices "in the event that the results of open enrollments and/or changes in key drivers suggest that the ceiling prices may need to be adjusted". In response to these comments, and others filed by RIE, the DPUC stated in their comments dated October 31, 2023 the DPUC stated that they were "supportive of the potential triggers". Except for the portion that pertains to the measurement period for the interest rate trigger (which was extended to the length of the third quarter of the calendar year prior to the start of the next program year), the potential thresholds that the DPUC suggested they approved of are the same.

Q: Was this pricing adjustment mechanism discussed with Rhode Island Energy?

A: Yes, SEA made several minor technical changes to the initially proposed Mechanism in response to both the DPUC and RIE comments, which are described in SEA's final presentation of the prices to the DG Board in SEA Schedule 5. As shown in their revised tariff filing, the company has proposed adopting the Mechanism as proposed.

Q: Please restate the precise language of the mechanism included in Rhode Island Energy's revised solicitation and program rules.

A: We restate the Mechanism verbatim from Revised Schedules RIE-1 and RIE-2 below:

These (prices/ceiling prices) will remain the same, unless one of the following three conditions occur. If one or more of the following three conditions occur, the Board may update the ceiling prices with regards to the specific condition that was met for future Program Years, subject to Commission approval. The Board and/or its consultant will review the below three conditions in the third quarter prior to each Program Year. The three conditions are:

- *Major deviations (± 50 basis points (bps)) in interest rate on term debt inputs from the Board's forecasted values, or*
- *Major deviations (±10%) from the Board's forecasted installed capital cost inputs, or*
- *Any changes in state or federal law, regulation or policy that have a direct, material, and mandatory impact on program design, cost, performance, and financing inputs for eligible RE Growth projects, or upon any other factor that would change the expected rate of return for such projects, as determined by the Board.*

Q: Would the Mechanism as restated herein limit the risk of the volatility cited in Mr. Brennan's testimony, both for ratepayers and market participants?

A: Yes. The Mechanism mitigates said risk for the two main categories cited by Mr. Brennan on behalf of the DPUC, and respectfully should be approved as proposed in Revised RIE-1 and RIE-2.

Q: Has either Mr. Brennan or the DPUC provided any substantive evidence suggesting the mechanism would be unable to address these sources of volatility?

A: No, they have not.

VII. INCENTIVE-PAYMENT ADDERS

Q: Do SEA, OER and the Board believe that the DPUC's suggestion to scale the adders to their incremental benefits has merit?

A: No.

Q: On the other hand, if the Commission were to agree with the DPUC and require that adders be scaled to their incremental benefits, what approach does SEA believe should be taken to ensure the adders are fully and properly valued?

A: If the Commission agrees with Mr. Brennan and the DPUC that only incremental benefits should be assessed in developing an adder, we believe said adders must, at minimum, reflect the full value of said incremental (and quantified) benefits conferred by Landfill and Brownfield projects.

Q: Please describe the incremental benefits of Solar projects sited on Landfill and Brownfield parcels relative to a baseline of greenfield, ground-mounted Solar projects of the same size.

A: Relative to a baseline of a greenfield, ground-mounted project of a similar size that is not located on a "core forest" parcel, there are two incremental conservation benefits of landfill and brownfield-sited solar projects:

- Avoided Property Value Losses; and
- Ecosystem Services/Value of Open Space

Q: When accounting for these benefits, can SEA compare the incremental costs of the adder for each type of Solar project greater than 1 MW with the incremental quantifiable benefits described herein?

A: Yes, please see SEA Table 4 and SEA Table 5 below (which are based on calculations found in SEA Rebuttal Schedule 1), which contains the comparison of incremental costs to incremental benefits for Large Solar I-IV projects selected in each of the 2024-2026 program years, and reaching commercial operation four years thereafter, both with and without Docket 4600 economic development benefits.

SEA Table 4 - Comparison of Incremental Landfill and Brownfield Adder Costs and Quantifiable Benefits (2024-2026 PY – With Docket 4600 Economic Development Benefits)

Eligible Project	**Program Year**	**COD Year**	**Incremental Total Docket 4600 Benefits**	**Incremental Total Project Cost**	**Adder Value (as Proposed)**	**Ratio of Incr. Benefits/Costs**	**Adder Value (Scaled to Incr. Benefits)**
Unit	**Year**	**Year**	**NPV $/MW**	**NPV $/MW**	**¢/kWh**	**Ratio**	**¢/kWh**
Large Solar I + Brownfield Adder	2024	2028	$705,000	$502,495	3.6	1.40	5.1
Large Solar II + Brownfield Adder	2024	2028	$380,913	$393,646	2.9	0.97	2.8
Large Solar III + Brownfield Adder	2024	2028	$288,013	$376,308	2.8	0.77	2.1
Large Solar IV + Brownfield Adder	2024	2028	$240,701	$361,547	2.7	0.67	1.8
Large Solar I + Brownfield Adder	2025	2029	$705,368	$490,004	3.6	1.44	5.2
Large Solar II + Brownfield Adder	2025	2029	$379,679	$384,325	2.9	0.99	2.9
Large Solar III + Brownfield Adder	2025	2029	$285,805	$367,492	2.8	0.78	2.2
Large Solar IV + Brownfield Adder	2025	2029	$238,030	$353,161	2.7	0.67	1.8
Large Solar I + Brownfield Adder	2026	2030	$705,983	$476,426	3.6	1.48	5.3
Large Solar II + Brownfield Adder	2026	2030	$378,615	$373,825	2.9	1.01	2.9
Large Solar III + Brownfield Adder	2026	2030	$283,753	$357,135	2.8	0.79	2.2
Large Solar IV + Brownfield Adder	2026	2030	$235,509	$343,222	2.7	0.69	1.9
Large Solar I + Landfill Adder	2024	2028	$648,451	$527,399	4.3	1.23	5.3
Large Solar II + Landfill Adder	2024	2028	$323,078	$423,606	3.6	0.76	2.7
Large Solar III + Landfill Adder	2024	2028	$229,950	$389,744	3.4	0.59	2.0
Large Solar IV + Landfill Adder	2024	2028	$182,410	$376,494	3.3	0.48	1.6
Large Solar I + Landfill Adder	2025	2029	$649,581	$516,327	4.3	1.26	5.4
Large Solar II + Landfill Adder	2025	2029	$322,644	$415,557	3.6	0.78	2.8
Large Solar III + Landfill Adder	2025	2029	$228,548	$382,681	3.4	0.60	2.0
Large Solar IV + Landfill Adder	2025	2029	$180,552	$369,817	3.3	0.49	1.6
Large Solar I + Landfill Adder	2026	2030	$650,942	$502,676	4.3	1.29	5.6
Large Solar II + Landfill Adder	2026	2030	$322,362	$404,842	3.6	0.80	2.9
Large Solar III + Landfill Adder	2026	2030	$227,286	$372,229	3.4	0.61	2.1
Large Solar IV + Landfill Adder	2026	2030	$178,827	$359,740	3.3	0.50	1.6

SEA Table 5 - Comparison of Incremental Landfill and Brownfield Adder Costs and Quantifiable Benefits (2024-2026 PY – No Docket 4600 Economic Development Benefits)

Eligible Project	Program Year	COD Year	Incremental Total Docket 4600 Benefits	Incremental Total Project Cost	Adder Value (as Proposed)	Ratio of Incr. Benefits/Costs	Adder Value (Scaled to Incr. Benefits)
Unit	**Year**	**Year**	**NPV $/MW**	**NPV $/MW**	**¢/kWh**	**Ratio**	**¢/kWh**
Large Solar I + Brownfield Adder	2024	2028	$492,366	$502,495	3.6	0.98	3.5
Large Solar II + Brownfield Adder	2024	2028	$218,840	$393,646	2.9	0.56	1.6
Large Solar III + Brownfield Adder	2024	2028	$127,665	$376,308	2.8	0.34	0.9
Large Solar IV + Brownfield Adder	2024	2028	$82,077	$361,547	2.7	0.23	0.6
Large Solar I + Brownfield Adder	2025	2029	$498,927	$490,004	3.6	1.02	3.7
Large Solar II + Brownfield Adder	2025	2029	$222,327	$384,325	2.9	0.58	1.7
Large Solar III + Brownfield Adder	2025	2029	$130,127	$367,492	2.8	0.35	1.0
Large Solar IV + Brownfield Adder	2025	2029	$84,027	$353,161	2.7	0.24	0.6
Large Solar I + Brownfield Adder	2026	2030	$505,554	$476,426	3.6	1.06	3.8
Large Solar II + Brownfield Adder	2026	2030	$225,846	$373,825	2.9	0.60	1.8
Large Solar III + Brownfield Adder	2026	2030	$132,609	$357,135	2.8	0.37	1.0
Large Solar IV + Brownfield Adder	2026	2030	$85,991	$343,222	2.7	0.25	0.7
Large Solar I + Landfill Adder	2024	2028	$426,751	$527,399	4.3	0.81	3.5
Large Solar II + Landfill Adder	2024	2028	$153,226	$423,606	3.6	0.36	1.3
Large Solar III + Landfill Adder	2024	2028	$62,050	$389,744	3.4	0.16	0.5
Large Solar IV + Landfill Adder	2024	2028	$16,463	$376,494	3.3	0.04	0.1
Large Solar I + Landfill Adder	2025	2029	$434,339	$516,327	4.3	0.84	3.6
Large Solar II + Landfill Adder	2025	2029	$157,739	$415,557	3.6	0.38	1.4
Large Solar III + Landfill Adder	2025	2029	$65,539	$382,681	3.4	0.17	0.6
Large Solar IV + Landfill Adder	2025	2029	$19,439	$369,817	3.3	0.05	0.2
Large Solar I + Landfill Adder	2026	2030	$441,969	$502,676	4.3	0.88	3.8
Large Solar II + Landfill Adder	2026	2030	$162,260	$404,842	3.6	0.40	1.4
Large Solar III + Landfill Adder	2026	2030	$69,024	$372,229	3.4	0.19	0.6
Large Solar IV + Landfill Adder	2026	2030	$22,406	$359,740	3.3	0.06	0.2

Q: If the Commission adopts the reasoning of the DPUC with regard to scaling the adders, what minimum values are appropriate for such adders?

A: As noted above, SEA concurs with, and supports, OER and the Board's recommendation that the PUC approve the cost-based adders as proposed. However, if the Commission determines that there is merit in the DPUC's suggestion to scale the adders to the level of their incremental benefits, the recommended adders should, at minimum, be scaled based on the values provided below in SEA Table 4 (consistent with the values derived in SEA Table 4 and SEA Table 5).

SEA Table 6 - Scaled Adder Values by Program Year and Economic Development Benefit Inclusion (cents/kWh)

Economic Development Benefit Inclusion	With Econ Dev. Benefits	Without Econ Dev. Benefits	With Econ Dev. Benefits	Without Econ Dev. Benefits	With Econ Dev. Benefits	Without Econ Dev. Benefits
Program Year	**2024**	**2024**	**2025**	**2025**	**2026**	**2026**
Large Solar I + Brownfield Adder	5.1	3.5	5.2	3.7	5.3	3.8
Large Solar II + Brownfield Adder	2.8	1.6	2.9	1.7	2.9	1.8
Large Solar III + Brownfield Adder	2.1	0.9	2.2	1.0	2.2	1.0
Large Solar IV + Brownfield Adder	1.8	0.6	1.8	0.6	1.9	0.7
Large Solar I + Landfill Adder	5.3	3.5	5.4	3.6	5.6	3.8
Large Solar II + Landfill Adder	2.7	1.3	2.8	1.4	2.9	1.4
Large Solar III + Landfill Adder	2.0	0.5	2.0	0.6	2.1	0.6
Large Solar IV + Landfill Adder	1.6	0.1	1.6	0.2	1.6	0.2

VIII. CONCLUSION

Q: Does this conclude your rebuttal testimony?

A: Yes.

SEA Rebuttal Schedule 1 – Comparison of Interest Rates on Term Debt in Recommended Prices with Current Outlook

See File Named '23-44-REG_SEA Rebuttal Schedule 1 - Comparison of Interest Rates on Term Debt in Recommended Prices with Current Outlook_FINAL'

SEA Rebuttal Schedule 2 – Comparison of Incremental Incentive-Payment Adder Benefits and Costs With and Without Docket 4600 Benefits and Costs

See File Named '23-44-REG_SEA Rebuttal Schedule 2 – Comparison of Incremental Incentive-Payment Adder Benefits and Costs With and Without Docket 4600 Economic Development Benefits'