RESPONSE TO SEA REC PRICING REVIEW REQUEST FOR COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, COALITION FOR COMMUNITY SOLAR ACCESS, AND ILLINOIS SOLAR ENERGY ASSOCIATION

March 28, 2023

The Solar Energy Industries Association, Coalition for Community Solar Access, and Illinois Solar Energy Association (collectively the "Joint Solar Parties" or "JSP") appreciate the opportunity to respond to the IPA's consultant Sustainable Energy Advantage's ("SEA") considered and proposed changes to REC pricing for the Adjustable Block Program ("ABP") and Solar for All ("SFA") starting with 2024-2025 program year.

JSP RESPONSES:

1. Questions Regarding "Near-Term Pricing Options"
    a. The Joint Solar Parties continue to support the CREST model approach. While the Joint Solar Parties continue to offer proposals where they disagree with inputs or correct errors—some of which raise prices and some of which reduce prices—in order to provide what they believe is more accurate pricing, the Joint Solar Parties do not suggest changes to the fundamental approach.
    b. The Joint Solar Parties have an open mind with regard to forecasting of individual price components of the net metering credit. The IPA and its consultants have experience procuring in or observing the wholesale markets in which energy, capacity, and transmission set values of net metering credits (at least for utility-served customers). The Joint Solar Parties note that with Small DG and perhaps smaller Large DG—specifically for categories where customers are likely to be Subtype (d) or (e) net metering customers—the bundled rate is perhaps more logically approached with a bundled percentage increase.
    c. Historically, the IPA has assumed for Large DG that customers receive an energy, capacity, and transmission credit. This is not accurate, because there is not a per kWh capacity charge under the hourly pricing rates for ComEd or Ameren. However, the IPA can estimate hourly prices against a typical generation profile for rooftop solar and can estimate transmission prices (which for at least one utility is provided as a per kWh charge rather than a demand-based charge).
    d. No, there should not be adjustments based solely on uptake. Uptake is determined by factors surrounding then-current market conditions. Uptake in a previous year is not necessarily indicative of interest in a future year. The IPA should continue to strive for accuracy in CREST model inputs.
    e. No. For blocks with long sales cycles—particularly Large DG, the Public Schools block, and behind-the-meter systems in the EEC Block—the potential for a changed price midway through the block puts additional risk on developers and customers.
    f. In no event should *current year* uptake be used to modify pricing during that year, for the same reasons as identified in (e) above. Artificially reducing prices due to popularity in previous years risks a gold rush/doldrums cycle if pricing is good one year leading to high uptake, a price overcorrection based on a synthetically-produced reduction, followed by high uptake the following year if prices are

overcorrected the other direction. The best approach continues to be striving for accurate pricing in the CREST model.

2. The "strike price" model is likely to introduce substantial uncertainty into the RPS budget and introduce a greater potential for budget shortfalls toward later years of the current ramp through the 2030-31 delivery year in the event that in one year energy prices plummet (especially related to contracts entered into today with high energy prices). A strike price is highly challenging for Large DG, because many systems are served by ARES which will provide net metering value based on the retail supply product. The difference between the then-current wholesale energy prices under the competitive customer provider of last resort (POLR) hourly energy and capacity/transmission passthrough rate and a fixed (or similar) ARES product could be substantial, leading to an enhanced version of the "basis risk" utility-scale projects take when selling at node prices but being settled against zonal prices. For community solar projects (and to some extent Small DG) where the bill credit rate is known for all (community solar) or much more common (Small DG) it may be feasible, but the Joint Solar Parties oppose an indexed approach to ABP pricing. The same factors that are present under the ABP are similarly present for SFA.
3. It is unclear what SEA means when it concludes "Therefore, adders intended to drive participation based on customer savings are appropriately based on policymaker discretion, rather than cost based modeling" on Slide 34. Fifty percent customer savings (65% for public sector/NFP with third party ownership) is a program requirement, not a marketing tool. Failure to provide such savings leads to discipline for the Approved Vendor. These savings can and should be modeled on a cost basis. *Additional* savings could be modeled based on policymaker discretion, but the minimum savings is exactly that—a mandatory program minimum.
4. To the knowledge of the Joint Solar Parties, project installed costs is already a required disclosure in the Part II application. (*See* Program Guidebook dated October 18, 2022 at 98 (paragraph 21). If SEA envisioned additional or different information than is already collected, it is not apparent to the Joint Solar Parties. The Joint Solar Parties strongly oppose compelled disclosure of risk-adjusted equity return target, because (i) such information is subjective and subject to constant change (even by project within the same block), (ii) is highly confidential and proprietary, (iii) is impossible to verify, and (iv) to the extent additional data is sought for each smaller project, an additional administrative burden on top of an already extensive reporting regimen. The Joint Solar Parties do not oppose allowing Approved Vendors to voluntarily provide it, although the Joint Solar Parties note that the IPA has previously rejected even formal third-party studies that include industry input (for instance in ICC Docket No. 22-0231). The Joint Solar Parties are unsure how operating expenses could or should be reported, particularly with many shared costs across systems (such as monitoring or control systems, sales and marketing for community solar, etc.) Once again, the Joint Solar Parties are not opposed to voluntary disclosure in the context of stakeholder feedback processes.
5. The Joint Solar Parties do not at this time have specific comments on the high-level categorizations but note the bigger question is implementation of these changes in the model that remains accurate to the structure and actual value under the IRA. Those items cannot be discussed in the abstract. Also, the Joint Solar Parties note that the costs of an apprenticeship program being unclear is far different than it being zero.

6. Until Direct Pay is more fully fleshed out by federal authorities (including qualifications), it is not possible to accurately model the implications of Direct Pay.
7. The Joint Solar Parties do not oppose adders to meet public policy goals that may add to costs (such as developing on impacted land in "energy communities") but prefer to respond on a case-by-case basis depending on the adder and the cost.
8. Adjustment downward of REC Prices for projects that *may* qualify for IRA adders pushes developers closer to neutrality between projects that do not meet a broader range of public policy goals and those projects that do. Respectfully, the absurdity of penalizing a project with a lower REC price that receives *federal* money to benefit low-income or disadvantaged communities demonstrates why these adjustments should be avoided. The Joint Solar Parties also note that adder qualification is complex and guidance remains constantly evolving. The Joint Solar Parties strongly discourage modifying REC prices based on whether a project actually claims an adder.
9. The Joint Solar Parties—led by the trade associations—are still evaluating this issue and do not have a response at this time.
10. The Joint Solar Parties—led by the trade associations—are still evaluating this issue and do not have a response at this time.
11. Not at this time.
12. Not at this time. The Joint Solar Parties strongly opposed different savings obligations depending on ownership structure (customer-owned vs. third party-owned) that the IPA is currently implementing and opposes this change as well.
13. The Joint Solar Parties—led by the trade associations—are still evaluating this issue and do not have a response at this time.