RESPONSE TO WORKSHOP #3 REQUEST FOR COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE COALITION FOR COMMUNITY SOLAR ACCESS, AND THE ILLINOIS SOLAR ENERGY ASSOCIATION

The Solar Energy Industries Association, the Coalition for Community Solar Access, and the Illinois Solar Energy Association (collectively the Joint Solar Parties) appreciate the opportunity to respond to the Illinois Power Agency's most recent solicitation for comments for the next LTRRPP revision.

As an initial matter, the Joint Solar Parties appreciate that the IPA is soliciting comments by necessity during a period of uncertainty as to when (or if) omnibus or narrower energy legislation will pass. Many of the issues raised—particularly selection of new projects and new future pricing—are addressed in great detail in potential legislation. These and other aspects of potential legislation either directly or indirectly impact the issues discussed below. The Joint Solar Parties, like the IPA, are addressing these comments to the state of the law as it exists today. The positions taken by the Joint Solar Parties may change with legislation, depending on its content, and Joint Solar Parties would request the opportunity to comment on these issues again if/when legislation passes.

In addition, the Joint Solar Parties appreciate that the IPA (and, at the IPA's suggestion, the Commission) made clear that the current RPS funding issues are a crisis for industry. The Joint Solar Parties wish to reiterate that the funding crisis not only prevents new project selection but also imperils both Energized projects and projects that are working toward Energization. While some of the questions below impact operating projects, many relate to new project application and selection. Unless or until funding is addressed legislatively, selection of projects from waitlists will remain largely a theoretical exercise.

Slide 10: Selection of Projects to Increase Project Variety

> 1. Absent legislative changes that create a new community-driven community solar category and specify selection criteria, what additional refinements or considerations should the Agency include in the next Revised Long-Term Plan for the selection of projects in future blocks that are "intended to increase the variety of community solar locations, models, and options in Illinois"? Why are those refinements appropriate?

JSP RESPONSE: The Joint Solar parties believe there is currently a good variety of different community solar options in Illinois. The marketplace contains a number of competing products, many of which meet or exceed the customer retaining 20% of the community solar bill credit as input into the CREST model. In the experience of the Joint Solar Parties, consumers tend most to care about the retail product and adjacent issues (such as customer care) more than other factors regarding the community solar project.

The Joint Solar Parties have addressed issues of location in other contexts, but generally support modifications to the CREST model for systems in more urban areas that have additional costs associated with development, such as land and labor costs, among others. The Joint Solar Parties note that California has had a carveout in the Green Tariff Shared Renewable program intended to spur development in environmental justice communities, which tend to be more urban. This carveout has existed since 2013 but no projects have yet been built. The Joint Solar Parties attribute this in part to the challenges of land cost/availability/quality (i.e. whether the roof stock can handle systems), development and EPC costs, shading, and other factors that are also present in Illinois. The Joint Solar Parties primarily attribute the lack of development in this carveout to the fact that the compensation is not differentiated from more typical projects, so systems that are comparably more difficult and expensive to develop receive no additional revenue or other favorable terms.

With regard to "models," it is not clear to the Joint Solar Parties the advantage to consumers or the program to encourage—or select projects based on—diversity of business models. Without examples of the types of business models that the IPA seeks to encourage (aside from "community-driven"), the threshold question of whether there *should* be business model diversity is impossible to answer, as is the best method to incentivize business model diversity.

> 2. Besides defining a selection process, are there other considerations related to project applications, or subscriber requirements that the Agency should consider for these types of projects? If so, what considerations and why?

JSP RESPONSE: To the extent that the IPA wishes to encourage something other than the "typical" community solar project, the Joint Solar Parties strongly encourage the IPA to explain the types of projects it would like to see. While the Joint Solar Parties are aware that the IPA would prefer to see fewer agrarian projects and more projects with a smaller nameplate capacity, any changes would have to be in the context of the modifications suggested.

Put another way, it is neither possible nor wise to look at a typical project today and attempt to incentivize "not that." Incentives—and selection processes/project requirements—require specific focus on what is being incentivized, how it is achieved, and what the barriers are to achievement. For instance, supporting more urban rooftop community solar will likely require the CREST model to take into account (for those projects) the additional costs and potentially lower efficiency from agrarian ground mount community solar. Incentivizing smaller projects may require subscription flexibility to deal with the risk to REC Contract revenue of churn on many smaller projects (where each lost subscriber is a higher percentage of nameplate capacity) rather than fewer, larger projects.

Slide 11: Waitlist Management

> 3. Are land use permits and site control the correct items for verification to maintain community solar waitlist position, or should the process used in 2020 be modified? If so, what modifications should be offered?

JSP RESPONSE: The Joint Solar Parties support a per kW deposit to stay on the waitlist, payable every two years. The Joint Solar Parties have supported project readiness criteria in the past, and support developer "readiness" criteria as well to confirm that developers still believe in their projects' ability to pencil.

The Joint Solar Parties is not aware of how community solar projects will be selected off the waitlist without legislation. The Joint Solar Parties support the approach to the waitlist in pending legislation and generally speaking support all projects that maintained their position on the waitlist under the process in 2020 should have an opportunity to go forward. Other than the per kW deposit and maintaining site control as demonstrated by an original or amended agreement (or evidence of valid assignment from the original parties to the current parties), the Joint Solar Parties do not recommend additional criteria for remaining on the waitlist.

That said, the ordinal waitlist is challenging because of the ongoing disconnect between interconnection queues and the waitlist order. Even if some projects were to reapply, they may be stuck behind other applicants still working their way through the restudy process. This is especially challenging now that the waiver in ICC Docket No. 18-1853 has expired and community solar will have to make a go/no go decision potentially before projects ahead in queue make their own decisions. Circumstances can shift underneath a developer as ABP timelines frequently do not match with the deadlines in Part 466.

4. What allowances, if any, should be considered for restoring lapsed verification items?

JSP RESPONSE: The IPA should consider requests for restoration on a case-by-case basis, determining in large part based on whether the Approved Vendor made a good-faith effort to restore the lapsed verification item during the window for doing so. For instance, genuine efforts to secure an extension to a special use permit or documented attempts to negotiate an amended option should in most cases lead to a project receiving additional leeway. The IPA could publish its decisions anonymizing (or redacting) developer-specific information to provide transparency and a degree of predictability to the process.

Slide 12: Small Subscriber Requirements

5. Should the small subscriber approach for projects in future blocks be updated? For example:

JSP RESPONSE: As an initial matter, the Joint Solar Parties are concerned that the IPA believes that small subscriber retention is not sufficiently difficult to justify the adder. As an initial matter, the Joint Solar Parties reject the notion that the incentive should be lowered because some market participants have found efficiencies. More to the point, the Joint Solar Parties understand that it is in fact challenging and expensive to identify, market, and successfully enroll small subscribers. Given the amount of money riding on ensuring the system is 100% subscribed and 75% or more small subscribers at Energization and the last day of the following four full Quarterly Periods—because failure to do so forfeits substantial REC revenue, especially for the fourth full Quarterly Period—the current burdens and barriers to enrolling small subscribers cause owner/operators substantial concern under the *status quo*.

a. Should the IPA decrease the size cut-off from 25 kW? If so, what is an appropriate alternative, and why?

JSP RESPONSE: No; proposals in other states have a cutoff of 40 kW. Also, 25 kW provides a subscription large enough so it is worth the while of a small commercial customer for the transactional hassle and "small commercial" customers are specifically identified along with residential customers in Section 1-75(c)(1)(N).

> b. Should the IPA create different small subscriber requirements or thresholds for residential and small commercial subscribers? If so, what modifications and why?

JSP RESPONSE: No. Unless or until statute separates the two, they are all small subscribers that Section 1-75(c)(1)(N) requires be given opportunities.

Responding further, the appeal of commercial customers in many contexts is the ability to be an anchor tenant on a community solar system (Section 1-10 of the IPA Act allows 40% of a project to be subscribed by a single or affiliated customers). Due to their size, a single small commercial account on a single project cannot be an anchor tenant.

The Joint Solar Parties further note it is not clear what problem or issue this question is attempting to solve. The Joint Solar Parties are not aware of any specific issue or concern related to small subscribers other than the outstanding success of community solar projects in Illinois serving small subscribers.

> c. Should the IPA consider limitations on multiple subscriptions from one business entity (e.g., multiple branches of a bank or retail chain)?

JSP RESPONSE: No. Subscription placement is largely an issue of transaction costs. Allowing a single entity or affiliated entities—such as local government buildings, bank branches, or gas stations—reduces the transaction costs because the effort to educate the customer about the program, the product, and the required disclosure forms is focused on a single entity. Also, commercial customers (unlike residential customers) tend to negotiate contracts, leading to additional costs. The program gets no benefit from making it harder for a bank, a local government (including a school district), or another non-residential customer to take advantage of community solar at a larger scale—but not so large as to overwhelm the program or even a single facility, because each separate facility must have a subscription of less than 25 kW and the group of affiliated entities cannot subscriber more than 40% of a single facility.

Slide 13: Coordination with Utility Subscription Management

> 6. What adjustments could allow for better coordination between subscription management process for utility net metering enrollment (and bill crediting) and the ABP program requirements to verify subscription levels for REC payments?

JSP RESPONSE: The Illinois Shines program and brochure in general should provide more information to the consumer about the roles of the various parties. For instance, while it is not the owner/operator's fault if a major utility is not able to correctly apply bill credits, customers will blame their community solar provider for failure to receive their savings.

The issues encountered by members of the three trade associations that make up the Joint Solar Parties have included the following:

- Enrollments incorrectly rejected, at times due to misapplication of the 110% of 12-month historic usage screen;
- Enrollments that have been approved have been later removed, for example ComEd's portal will remove previously validated subscribers from projects because of a 0.1 – 0.3 kW discrepancy in load size, due to rounding errors;
- After energization (for the purposes of interconnection, not Energization under the REC Contract), credits to customers are either incorrect or not placed on the customer's bill for several cycles.

Additional utility IT investments are likely necessary to permanently fix these problems.

The Joint Solar Parties note that these issues are largely with the Commission's jurisdiction, although the IPA can provide information about common issues to subscribers under the Illinois Shines materials, so that customers better understand who is/are causing the delays and why. For instance, while Illinois Shines Brochure does suggest speaking to the Approved Vendor and has information about contacting the Program Administrator and the AG, it would be helpful to explain for certain critical aspects of system development and value (interconnection, net metering credit placement on bills, etc.) to say who is responsible. Illinois Shines should also encourage customers to contact their Approved Vendors about billing questions, including net metering credits. In addition, the IPA should consider including additional flexibility for counting subscriptions when the subscription is improperly rejected by the utility. The IPA can also facilitate discussions with the utilities to the extent that utility systems or processes are getting in way of subscribing Adjustable Block Program systems.

Slide 19: Comparison to REC Prices (& Other Incentives) in Other States

> 1. How do ABP REC prices compare to incentives offered in other states, and how do those differences impact market activity and consumer interest in solar? Are there states which Illinois should look to as a model? Are there states whose examples Illinois should avoid?

JSP RESPONSE: As an initial matter, the Joint Solar Parties advise against a comparison of REC pricing across markets. Generally speaking, both project costs and REC prices vary widely based on program rules and unique costs and/or revenue streams across states. For example, community solar project development is largely relegated to rooftops in New Jersey, so construction costs are higher than a comparably sized ground-mount system on farmland. States also have varying clean energy goals, net metering credit rates, land lease opportunities, taxes, REC contract terms, and Low-to-Moderate Income (LMI) requirements, which all significantly impact costs. Moreover, states have taken very different approaches to incentivizing project development. These structural differences are baked into REC pricing, making comparison of REC pricing between any two states generally impractical because the cost and revenue assumptions going into pricing vary so wildly. The following examples may be able to better highlight some of these differences:

- New York uses a value stack approach in which the state has determined values for each component of every project, including: Energy Value (LBMP), Capacity Value (ICAP), Environmental Value (E), Demand Reduction Value (DRV) and Locational System Relief Value (LSRV). The main value of these is based on a fluctuating NYISO LMP pricing so it is impossible to understand the long-term value that will flow to these projects. Moreover, each value stack has a different locational and temporal value, based on the project characteristics. When a project is energized, it can lock in the E, DRV and LSRV components at a fixed rate.

- In Massachusetts, Class 1 REC prices have varied widely in the past few years but it typically hovers around the $30-40 range. MA's SMART program allows a project to lock in a rate for energy plus RECs that varies, depending on the project's attributes, vintage and NEM status. The energy credit value that a project receives will fluctuate monthly so the REC value floats on top of that energy value to reach the fixed value. For example, if the fixed SMART value is $0.20/kWh (which is around where the program started), and the energy credit was $0.11/kWh in a particular month, the REC value would be $0.09/kWh that month. The base rate for the SMART value varies by system size and location, but is currently around $0.11/kWh for most projects 1-5MW, and projects can receive additional adders based on project attributes.
- New Jersey is in the middle of a transition from their previous SREC program to a more permanent REC program that can help the state meet its long-term clean energy goals. Community solar was enabled during the transition phase, so these projects received Transition RECs (TRECs) of $129/MWh, on top of a full retail rate credit for subscribers. The permanent REC program will be at lower value, probably between $80-90/MWh, however program rules are not final. This program requires projects to be on rooftop, landfill or brownfield and incentivizes providers to meet a high LMI component (51% LMI).
- Maryland provides a full retail rate credit for subscribers and a fluctuating, market-based REC that is currently around $50/MWh.

The Joint Solar Parties provided the REC and other revenue stream values to illustrate the differences between states that underlie the different REC pricing.

Slides 22-24: Model Inputs

2. Should REC prices continue to be set using a REC Pricing model based on the CREST model which is a cost-based approach, or should a different approach to REC pricing be considered? If a different approach is recommended, please explain how the approach in detail, and if available provide examples of its use from other jurisdictions. Note that the Agency does not believe that it has the statutory authority to conduct competitive procurements as part of the Adjustable Block Program.

JSP RESPONSE: Generally speaking the Joint Solar Parties support using the CREST model, updated to address changes in circumstance. The only exception to the Joint Solar Parties is situations in which legislation requires different pricing.

Changes to the CREST model may cause the REC Price to go up or go down. For instance, estimates of interconnection of under $300,000 is highly inaccurate for community solar projects in the Commonwealth Edison service territory. The IPA should request actual anonymized interconnection information from ABP projects interconnections from ComEd and Ameren. In the same vein, anonymized data from developers and owner/operators could provide better information about lease rates, although the Joint Solar Parties suspect that geography may also be a driving factor as well.

Also, the IPA should consider changes to the estimate of the value of energy (and thus net metering credit value). While avoided distribution costs may tend to rise at a compound rate, wholesale and retail energy prices do not smoothly increase over the years—or even necessarily increase over the short- to medium-term. Assuming a 2% annual increase in retail supply (as opposed to delivery) rate greatly overestimates the total energy price, and thus the percentage of the net metering credit retained by a system owner/operator.

To the extent that legislation imposes new costs and there is no explicit prohibition in statute of modifying pricing, the Joint Solar Parties recommend that the CREST model should be updated upon passage of legislation to take into account new costs of program participation such as prevailing wage.

> 3. If the CREST tool continues to be used as the basis for the REC Pricing model updated, what assumptions and inputs should be updated? How can market-based signals be better incorporated into these assumptions? Please see Tables on pages 4 to 7 for a list of the inputs and Appendix D to the Long-Term Plan for a detailed description of the REC Pricing model.

JSP RESPONSE: Please see above. In addition, the ITC is now 26%, not 30%. The Agency should also continuously review the projected value of offset energy and net metering (for behind-the-meter systems), community solar bill credits (community solar), and the DG Rebate (currently for all non-residential behind-the-meter systems and community solar) as the basis for CREST calculations. None of these values increase or decrease predictably—or even stay the same over time.

Slide 25: Small Subscriber Adder

> 4. How have subscriber acquisition models evolved over the past five years and how do those changes impact small subscriber acquisition and management costs? What modifications to small subscriber adders should be considered in light of these changes?

JSP RESPONSE: No changes at this time, at least without industry-wide data. Because a limited number of projects are Energized and very few have passed the fourth full Quarterly Period after Energization (i.e. the last of the quarterly subscription level reconciliations under the REC Contract), the industry is still in its very early stages of learning what works, what does not, and the costs associated with winning strategies.

In addition, trends in other states may not match trends in Illinois. Illinois remains unique in requiring a customer-signed disclosure form to be uploaded for each subscription. The administrative and timing impact of this additional consumer protection is not reflected in data from other states that supports far more automated customer acquisition. While the Joint Solar Parties stress they are not seeking to change that aspect of the Adjustable Block Program at this time, that distinction must be considered in comparing Illinois customer acquisition data to national trends.

Slides 26-29: Solar for All REC Pricing

> 5. Should Illinois Solar for All REC prices continue to be set based on ABP REC prices with adjustments to assumptions, or set using a different approach? If a different approach, what would you propose, and why?

JSP RESPONSE: Yes, they can continue to be based on the ABP REC prices but with adjustments to assumptions to reflect the differences between ABP and SfA projects. Specifically, there needs to be considerations for the significant costs and challenges that exist in the SfA program that do not exist in the ABP such as pricing terms, increased soft costs with low-income customer identification and verification. The Joint Solar Parties recommend that the Program Administrator work with stakeholders and the IPA to assess how current processes may be contributing to soft costs and identify where there is potential for cost-effective process improvement.

The Joint Solar Parties do encourage the IPA to reconsider its approach to REC prices for 5 or more unit (multi-family) Distributed Generation Pricing Model. Multi-family cannot benefit from true net metering, and the only tariffed solution provided by utilities is to take service under community solar, including under Section 16-107.5(*l*)(1)(B). Of course, community solar means that the customers' bill credit is only on part of the supply component of the bill (for instance, neither ComEd nor Ameren default supply bill credits include transmission) and delivery-side net metering/offsetting is replaced by the Smart Inverter Rebate. The Joint Solar Parties encourage the IPA to create REC prices under multi-family that will incentivize these projects, which are currently not financeable given the relatively lower energy revenue streams.

> 6. If Illinois Solar for All REC Prices continue to be based on ABP REC Prices what changes, if any, to the assumptions used for the adjustments between ABP and Illinois Solar for All should be made for each ILSFA sub-program? Please see page 9 for a list of these assumptions.

JSP RESPONSE: In the Distributed Generation subcategories, the Joint Solar Parties would suggest increasing in capital and O&M costs, given the significant time and effort required to identify, verify, and work with each low-income customer, as well as provide the significant on-going interactions to ensure effective customer protections and positive customer experiences.

In addition, as the Joint Solar Parties noted in response to the second question 3 in the IPA's Request for Comments #2, the IPA currently prohibits not-for-profit and public sector distributed generation projects monetizing the ITC, even when a third-party ownership structure would otherwise allow it. The Joint Solar Parties recommended replacing that approach with a two-tiered system, one for when the ITC cannot be monetized (such as customer-owned) and one where the ITC can be monetized (such as a PPA or lease structure). The CREST model should be adapted to address this two-tiered structure, including the Joint Solar Parties' proposal that the pricing difference is not 100% of the ITC value, given the costs of monetization.

7. ABP REC Prices change as blocks of capacity are filled. Should Illinois Solar REC Prices change in step with changes to ABP REC Prices, or should scheduled changes only be through the biennial Long-Term Plan revision process? (Note, that the Agency has the discretion to modify prices up to 25% between Plan revisions).

JSP RESPONSE: While the Joint Solar Parties expressed above no objection to using ABP pricing as a starting point (before accounting for program differences), the Joint Solar Parties' proposal should be read as a starting point rather than a recommendation to have SfA pricing change in lockstep with ABP pricing. SfA prices should not change frequently. REC prices are designed to have systems that result in no upfront cost and tangible savings for customers. Unlike a mass market program without subscriber restrictions, challenges such as identifying low-income residents, navigating income approval, significant administrative time will not disappear as we see more participants in SfA program.[1]

Slide 30: Making REC Prices More Dynamic

8. For the Adjustable Block Program and/or the Illinois Solar for All Program, should the Agency consider specific mechanisms or triggers for REC Price changes, in particular, if there are market indicators that REC prices are higher than needed to encourage consumer uptake of solar? Or lower than needed? How should the Agency determine whether those triggers have been hit, and how should the Agency balance the need for transparency and stability with efforts at reflecting a more precise REC price?

JSP RESPONSE: The Joint Solar Parties strongly oppose changes to make REC prices less predictable within a block or between blocks. While the IPA does have discretion to make changes to block pricing by statute, sudden changes are very harmful to the marketplace and can frustrate customers whose projects that looked beneficial suddenly are not due to unplanned changes to REC pricing. Section 1-75(c)(1)(K) requires that the Adjustable Block Program pricing "for renewable energy credit[s] to adjust at a predictable rate over time."

In addition, the Joint Solar Parties note that in addition for changing at a predictable rate over time, Section 1-75(c)(1)(K) also requires that "[t]he Adjustable Block program shall be designed to provide a transparent schedule of prices and quantities to **enable the photovoltaic market to scale up** . . ." Enabling the photovoltaic market to "scale up" is inconsistent with attempting to price RECs such that demand for a block exactly matches its capacity. A healthy market has some over-commitment as some projects—no matter the readiness criteria—fall through for whatever reason. Conversely, the Joint Solar Parties do not recommend pricing such that each project is on knife's edge for penciling out, making the unexpected costs and roadblocks that are almost always found in development and that would otherwise be routine potentially fatal to the project.

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[1] While process improvements in the Solar for All program would substantially mitigate these costs, they would still not be eliminated even with perfect and instantaneous responses from the program.