RESPONSE TO MARCH 14 DRAFT PROGRAM GUIDEBOOK REQUEST FOR COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, COALITION FOR COMMUNITY SOLAR ACCESS, AND ILLINOIS SOLAR ENERGY ASSOCIATION

April 3, 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 draft Program Guidebook dated March 14, 2023. All citations herein to the "Draft Guidebook" are to the clean (as opposed to the redline) PDF of the draft updated Program Guidebook.

Public School Block Subscription Flexibility

The Draft Guidebook proposes to remove the ability for an Approved Vendor with a community solar project in the Public School block to switch an anchor tenant from accounts in the host school district to another school district. (*See* Draft Guidebook at 14.) The Joint Solar Parties note that as long as an "anchor" must be a single account, larger systems (for instance, a 5 MWac system) require an anchor with a minimum size (500 kW in this hypothetical) that may not work for many districts. While school buildings and district buildings may have substantial usage, if they are served by ARES and not served on purchase of receivables then 500 kW is a substantial subscription—especially while the Carbon Free Resource Adjustment remains on the ComEd bill—to only offset delivery charges. Yet that is exactly what the community solar bill credit will offset (utility charges) in ComEd today and Ameren starting around November 1, 2023 (pursuant to ICC Docket No. 22-0208). ARES charges will only be part of "utility charges" if the ARES sells its receivable to the utility, which in turn is only available in ComEd and Ameren and then only as an optional service for non-residential customers with peak demand up to 400 kW.

Allowing buildings in another school district to become the anchor ensures that public schools remain the beneficiaries while also making sure that school districts aren't forced into limited or potentially undesirable (hourly utility rates) options. The Public School Block has had enough trouble getting off the ground, and another barrier should not be imposed while the block continues to struggle to get traction.

Ambiguity in the EEC Block Discussion

The Joint Solar Parties recommend a change to the EEC Block discussion that did not change in the Draft Guidebook but is related to a relatively new and evolving program and thus merits revision. The LTRRPP and subsequent clarification made clear that in order to participate in the EEC Block, the Approved Vendor must be an EEC and only an EEC may hold the REC Contract through the sixth anniversary of Energization. The Joint Solar Parties commented on these terms, but agree this is the current state of the LTRRPP. However, both the LTRRPP and Statute further make clear that there are no specific obligations related to an EEC developing or owning the system itself—only that an EEC must be the Approved Vendor.

In contrast, the Program Guidebook uses language that at least implies some sort of ownership requirement due to discussion of assigning "projects" as opposed to the REC Contract or Product Orders to the REC Contract:

> If an EEC project is assigned under the 2021 or 2022 REC Delivery Contracts to a non-EEC Approved Vendor before Part II verification, it will have failed to meet EEC requirements, will not be Part II verified, and will be removed from REC contract with forfeiture of collateral. The project may be reapplied to another category for which it is eligible. If there is a waitlist for the new category to which it is applied, the project will be added to the waitlist as of the date of this reapplication to the new category. Projects that are developed by Approved Vendors certified as EEC and receive a REC contract through the EEC block of capacity may not assign those projects to an Approved Vendor that is not also a certified Equity Eligible Contractor for six years after the Part II verification date of the project. After six years from the Part II verification date has passed, this moratorium on assigning EEC projects to Approved Vendors that are not certified as an EEC is lifted.

(Draft Program Guidebook at 14.) The IPA should clarify that the prohibited assignment is of the REC Contract or Product Orders thereto that include EEC Block systems unless the assignee is an EEC:

> If ~~an~~ **Product Order containing an** EEC project is assigned under the 2021 or 2022 REC Delivery Contracts to a non-EEC Approved Vendor before Part II verification, it will have failed to meet EEC requirements, will not be Part II verified, and will be removed from REC contract with forfeiture of collateral. The project may be reapplied to another category for which it is eligible. If there is a waitlist for the new category to which it is applied, the project will be added to the waitlist as of the date of this reapplication to the new category. Projects that are ~~developed~~**applied to the EEC Block** by Approved Vendors certified as EEC and receive a REC contract through the EEC block of capacity may not assign **Product Orders containing** those projects to an Approved Vendor that is not also a certified Equity Eligible Contractor for six years after the Part II verification date of the project. After six years from the Part II verification date has passed, this moratorium on assigning **Product Orders containing** EEC projects to Approved Vendors that are not certified as an EEC is lifted.

The Joint Solar Parties note this language if left uncorrected causes issues for tax equity financing of EEC Block systems in sales contracts (*i.e.*, where the customer buys the system but the Approved Vendor administers the REC Contract) or third-party financing of EEC-owned systems. That is because the current guidebook language gives the incorrect impression that only EECs can own the system itself, prohibiting sales contracts (i.e. requiring a lease or PPA for Small DG and Large DG systems) or third-party financing. The Joint Solar Parties recommend that the IPA make the clarification in order to lower soft costs imposed on EECs and avoid unnecessary restrictions on EECs.

Waitlist Procedures

The Joint Solar Parties generally support a first come/first served approach for all blocks to the extent another selection criteria is not imposed or if there is a tie that has a defined tiebreaker (such as points for traditional community solar or community-driven community solar). (*See* Draft Guidebook at 17-18.)

For traditional community solar specifically, the Joint Solar Parties recommend that the IPA clarify an ambiguity in the Program Guidebook regarding systems that receive points for interconnection. Specifically, it is not clear whether the following applies to a traditional community solar system that generally speaking is not required to have a valid interconnection agreement to apply but might rely on an interconnection agreement for points that place it on the waitlist (or above the five point minimum threshold):

> Any project that is required to have a valid interconnection agreement as part of its Part I application that has exited the interconnection queue must provide proof that it has reapplied for interconnection as a condition of its selection off of the waitlist.

(Draft Guidebook at 18.)

The IPA should require an interconnection agreement to be continuously in place as a prerequisite of being taken off the waitlist if the system received interconnection points. If a system was advantaged due to its project readiness, it should not be able to shed that readiness. There is no guarantee that the project will have a viable path to interconnection in the event it drops from the queue.

Site Control

The Draft Guidebook contains a new requirement that the Approved Vendor or installer must sign the site control agreement. (*See* Draft Guidebook at 41.) However, for many developers, the Approved Vendor (which is often on the corporate level) is an affiliate of the entity that owns the system-in-development or unaffiliated. For example, for larger systems it is frequently the case that the developer has a subsidiary that owns all of the assets (site control, interconnection, permit(s), and the like) for a project but the parent company is the Approved Vendor. The Approved Vendor may change and the project ownership may change hands. Similarly for developers of smaller systems, the Approved Vendor and installer entities do not actually own project assets.

The Joint Solar Parties recommend that the requirement that the Approved Vendor or installer countersign the site control agreement be eliminated. This prevents needlessly complicates the process of the Part I application for the customer (for behind-the-meter systems) or for financing (for front-of-meter systems and behind-the-meter systems).

The Joint Solar Parties also note that in order to finance projects—even as transferability of tax credits may be possible and utilized in some cases—the primary method is for the entity monetizing the credits to own the system and its assets (including the site control). For the many Approved Vendors associated with owner/operators that use third-party tax equity financing, any restrictions on assigning site control will make unlocking federal tax benefits under the Inflation Reduction Act far more difficult.

Storage ("Battery Backup") Systems

When paired with solar, storage is critical to bringing reliability benefits to both individual customers and the grid generally. The Adjustable Block Program and Solar for All should support deployment of storage paired with storage in Illinois. The Joint Solar Parties urge in the strongest terms that the IPA generally allow for program rules that remove barriers to pairing storage with applying systems.

As an initial matter, while battery storage is the most common, the Joint Solar Parties suggest references to storage generally rather than "backup batteries". (*See* Draft Guidebook at 43-44.)

Any implementation of storage is going to be inherently limited unless the IPA removes the 155% DC to AC ratio. (*See* Draft Guidebook at 43.) The Joint Solar Parties suggest that either the limit be 255% DC to AC ratio for systems with storage (subject to further exemption requests) and a clear procedure for requesting clearance for a higher ratio concurrent with or prior to the Part I application.

Prevailing Wage

The Program Guidebook includes new guidelines for the prevailing wage rates paid to workers installing solar. (*See* Draft Guidebook at 48-49.) Specifically, the Program Guidebook includes requirements not imposed by the Illinois Department of Labor for paying (potentially) the same employee or contractor different rates for different work on the same project. While the Joint Solar Parties appreciate that the IPA appears to be attempting to provide guidance, the Joint Solar Parties fear that adding these guidelines have the potential to conflict with current or future Illinois Department of Labor requirements for wages to the same employee or contractor performing multiple tasks.

Program Timing

The Program Guidebook contains new schedules for the application process for different system types. The Joint Solar Parties do not object to any of the content of these schedules but strongly recommends guidelines (if not deadlines) for review of Part I and Part II applications. (*See also* Draft Guidebook at 57-58.) Expectations for Part I and Part II application review is critically important to manage expectations of customers and third parties (like financing) that tend to blame Approved Vendors for delays in application processing. In some cases—such as third-party financing—delays in Part II application processing can lead to liquidated damages or other financial penalties because the original payment schedule (usually tied to when the system is placed in service) is highly contingent on the time value of money and thus delays on REC Contract payment irrevocably destroy value.

In addition, the Joint Solar Parties understand that Energy Solutions' current approach is to review applications in the order that they are received but to relegate applications that require follow-up information to the bottom of their queue. If the Joint Solar Parties' understanding is accurate, this creates a massive inefficiency for partially reviewed applications—especially where the follow-up is minor—especially given that Energy Solutions has estimated to certain members of the trade associations that comprise the Joint Solar Parties that 30% of applications require follow-up.

Disclosure Forms

The section on Disclosure Forms suggests that an API is available to generate disclosures. (*See* Draft Guidebook at 54 n.24.) To the understanding of the Joint Solar Parties, there is not currently a functioning API and there is not currently a timeline in place for such functionality to be in place. Furthermore, the Joint Solar Parties understand that there are several lingering bugs with the CSV upload function.

In addition, the Joint Solar Parties appreciate that a third-party subscription service soliciting TBA Disclosure Forms for multiple different community-driven community solar systems owned by unaffiliated entities would be inconsistent with the spirit of community-driven community solar. (*See* Draft Guidebook at 55.) However, if a single Approved Vendor or affiliated Approved Vendors have multiple projects within the same "local subscriber" territory (county, adjacent counties, or townships as the case may be), the Approved Vendor or their third-party subscription manager should be allowed to issue TBA Disclosure Forms specific to that local subscriber territory and Approved Vendor or affiliated Approved Vendors. This is especially the case if the community outreach for the systems was undertaken jointly. The Joint Solar Parties recommend allowing this type of community-driven community solar-specific version of a TBA Disclosure Form.

Change of Approved Vendors

The Joint Solar Parties recommend that in addition to waitlisted projects, the IPA allow change of Approved Vendors (with consent of the customer signing the Disclosure Form, if applicable) between the Part I application and submission of the applicable batch to the Commission for approval. (*See* Draft Guidebook at 60-61.)

In addition, the Program Guidebook should make clear that ownership of the system can change at any time as long as the Approved Vendor remains unchanged and the Approved Vendor retains rights to the RECs generated by the system. (*See id.* at 61.) Restrictions on ownership transfer of the system assets (as opposed to the REC Contract or pre-REC Contract application between Approved Vendors) is not consistent with the LTRRPP ("The Agency does not require a specific delegation of duties between the Approved Vendor, sales generating firms, installer/developer, and system owner" (Final LTRRPP dated August 23, 2023 at 187)). There is nothing materially different about the time period before approval of the Part I application as opposed to a later date.

Part I Application Requirements

The Part I application requirements now include a requirement that if the site map changes from the site control document to the Part I application—even including the number of modules or wattage of modules—the "customer" must sign an updated site map. (*See* Draft Guidebook at 71.)

As an initial matter, it is unclear whether this applies to community solar, where the "customers" are the subscribers. The site host is frequently not a customer of the system.

Setting that issue aside, the Joint Solar Parties strongly oppose this requirement. The site control document will inherently be a rough draft and the system design will inevitably change—including after the Part I application through when EPC actually takes place and the system owner makes a final selection of modules and other equipment. Many site control documents will have a layout but the area potentially under control is explicitly allowed to be greater or lesser within pre-defined ranges (whether a portion or all of a roof or a portion or all of a parcel for ground mount).

The signed site map changes are particularly confusing in light of the general ability of an Approved Vendor to change site layout between Part I and Part II anywhere within a roof or parcel if the system is the only system on the site, among several other bases for changes. (*See* Draft Guidebook at 74.) Most if not virtually all site control documents will provide terms and conditions for how the actual layout may change and the boundaries of such changes. It makes little sense to require a customer signature at that interim step (the Part I application) when further changes are allowed to happen prior to Part II.

Small Subscribers

The IPA proposes to allow less than 25 kW of subscriptions per small subscriber, even if the subscriptions come from multiple different systems. (*See* Draft Guidebook at 82.) The Joint Solar Parties strongly oppose this recommendation.

The genesis for the small subscriber requirement is currently in Section 1-75(c)(1)(N) of the IPA Act, which states in relevant part:

> The Agency shall establish the terms, conditions, and program requirements for photovoltaic community renewable generation projects with a goal to expand access to a broader group of energy consumers, **to ensure robust participation opportunities for residential and small commercial customers** and those who cannot install renewable energy on their own properties.

(20 ILCS 3855/1-75(c)(1)(N) (emphasis added).) The concept of a "small subscriber" defined as certain rate classes and a subscription to a specific system as strictly less than 25 kW was implemented in the initial LTRRPP and carried forward through the current LTRRPP. (*See, e.g.*, Final LTRRPP dated August 23, 2022 at 200.)

Public Act 102-0662 included a new minimum small subscriber requirement: "**projects** shall have **subscriptions of 25 kW or less** for at least 50% of the facility's nameplate capacity and the Agency shall price the renewable energy credits with that as a factor" (20 ILCS 3855/1-75(c)(1)(K)(iii)(2) (emphasis added).)

The consistent theme of the statutory language and the LTRRPP is that the concept of a small subscriber is based on a specific project and a subscription *from that project* of under 25 kW. In other words, a small subscriber is defined from the perspective of a subscription between one system and one customer. Nothing in Section 1-75(c)(1)(K)(iii)(2) limits the number of small subscriptions with different facilities a single customer may have. The LTRRPP similarly does not contain approval for limits on the number of subscriptions a single customer may hold with multiple projects that would qualify for each separate project as a small subscription.

The IPA's proposal creates problematic statutory and implementation consequences as well. By limiting the number of small subscriptions a single customer may have, the "robust participation" of that residential or small commercial customer is being limited in a way not otherwise contemplated by statute. The term "robust participation opportunities" does not suggest limits or restrictions on the *customer's* opportunities, even as the IPA (and later statute) imposed restrictions on the opportunities of a single community solar project with that customer.

In addition, this restriction will cause an implementation nightmare for Energy Solutions to cross-check every small subscription against every other small subscription to ensure that a single utility account does not have more than 25 kW, and then a secondary review to determine which subscription was first in time (which may stretch back over several disclosure forms if the original subscription was renewed in a way that required a new disclosure) and layered tiebreakers. The Joint Solar Parties fear that screening questions will lock in larger residential and small commercial customers to only 25 kW of subscriptions rather than (as smaller residential customers and larger customers can do) a fuller offset of their bill, limiting their benefits.

The Joint Solar Partis further note that the term "small subscriber" (which is not a statutory term or a term in the LTRRPP) should be stricken from the glossary. (*See* Draft Guidebook at 99.) Instead, the small subscriber defined in Section 1-75(c)(1)(K)(iii)(2) should be implemented defining small subscription relative to subscription size in a particular project and not aggregate subscription size for a customer.