To: Illinois Power Agency
From: The Joint Non-Governmental Organizations (ELPC, NRDC, Vote Solar)
Date: December 3, 2021
Subject: Joint NGOs - Response to ABP Comment Request.

The Environmental Law and Policy Center, the Natural Resources Defense Council and Vote Solar (VS), commenting together as the Joint Non-Governmental Organizations or Joint NGOs (JNGOs), appreciate the opportunity to comment ahead of the Illinois Power Agency's (IPA or Agency) development of its 2022 revision to the Long-Term Renewable Resources Procurement Plan (Plan or LTRRPP).

The passage of the Climate and Equitable Jobs Act (Public Act 102-0662) this fall requires significant expansion and reimagination across the renewables programs and procurements outlined in the IPA's Plan. It is an exciting and busy time and the IPA has a lot on its plate. With this in mind, the Joint NGOs urge the Agency to anticipate the need for continued growth and evolution even after the final Plan has been approved by the Illinois Commerce Commission. This need for ongoing evolution will be particularly true for:

- The new community-driven community solar program, where the state still has much to learn about what a successful community-driven project looks like (and potentially for other new programs where there is still much to learn).
- REC prices, where Illinois needs to set prices to drive significantly expanded renewables goals, but does not want to repeat past mistakes of failing to adjust those prices if market response is out of line with statutory goals.
- And the low-income distributed generation subprogram of the Illinois Solar for All Program, which has seen far lower uptake than similar programs in other states and therefore requires ongoing and detailed attention to get it on track.

The Joint NGOs comments in response to the various requests for feedback published in early November touch on each of these topics and respond to multiple of the specific requests for comments the IPA makes. The Joint NGOs look forward to working constructively with the Agency and other stakeholders through the Plan's update process and beyond to make Illinois' renewables programs and procurements a success and achieve the goals of the Climate and Equitable Jobs Act.

Annual Block Capacity

1. With the updated Long-Term Plan scheduled to be approved in July 2022, initial blocks of annual capacity opening in December of 2021, and 1-75(c)(1)(K) referencing annual blocks of capacity by delivery year, how should the timing of block opening be reconciled?
    a. Should the Agency utilize an approach to backdate the opening of annual blocks to the start of the 2022-2023 delivery year (June 1, 2022), which would result in the initial annual blocks opened on December 14, 2021 be open for less than a year? Or is there some other way of prorating the timing of annual blocks?
    b. Are there considerations that would necessitate taking a different approach for reconciling the timing of block opening by category?
    c. For categories with an initial allocation period of two years, is the initial period the 2021- 2022 and 2022-2023 delivery years, resulting in the next block opening June 1, 2023?

The Joint NGOs have no strong position on how the agency should reconcile the directive for annual blocks with the timing of the Plan. Ultimately, the Agency should prioritize keeping things simple and keeping the market moving. With this in mind, it would be appropriate for initial blocks coming out of this Plan to *not* be allocated for a term that perfectly aligns with a year so long as the Agency plans to comply with the directive for annual blocks over the long-term. The IPA is in the best place to judge (1) how important it is to sync annual blocks with budget years, particularly in light of new budgetary flexibility and (2) how long it will take to open new blocks after the Plan is approved.

The JNGOs do urge that the IPA plan for the blocks opened in December 2021 to remain open until shortly before the next set of blocks open. If the Plan is approved in July but new blocks will not be open until October, for instance, there is no reason to close (and reallocate capacity from) the December 2021 blocks until roughly September. The IPA need not set a hard timeline for either block opening in 2022 or the closure of the blocks opened in December 2021. Rather, it would be appropriate to plan for the closure of the December 2021 blocks a certain number or range of weeks prior to the opening of new blocks in 2022.

Finally, it is worth noting that, for the community-driven community solar (CDCS) category, the language of statute mentions the "equivalent" of two years of capacity, not the first two annual blocks. This means the quantity opened immediately should be equivalent to two blocks, not that there should be a delay in the opening of future CDCS blocks until 2023.

3. What considerations should be made when redistributing uncontracted capacity at the end of a delivery year? Should waitlists be pure first-come first-served or some other process?

There are two pieces of this question: first, if multiple categories have waitlists how to distribute between categories and, next, how to distribute capacity within a category.

With regard to how to distribute capacity between categories, the JNGOs believe it is appropriate to prioritize waitlists for some categories over others. In particular, if there are waitlists for the EEC category within the ABP, that category should be prioritized first, at least until the EEC category ramps up to the 40% portion of the ABP intended under the law. Additionally, the JNGOs continue to see reason in the IPA's original prioritization of projects with customers in-hand over projects without for their initial allocation of discretionary capacity following the first plan. In the context of the new ABP categories created by PA 102-0662, the JNGOs believe this should be expanded to the prioritization of projects with customers or communities (in the case of Community-Driven Community Solar) in-hand, versus those without. In this case, that would mean prioritizing the general market community solar block of the ABP last.

With regard to how to distribute capacity within a category, the JNGOs recommend that, for community-driven community solar, higher scoring projects receive capacity first.

Open Questions from the withdrawn draft Second Revised Long-Term Plan

6. Community Solar (Section 6.5.3, pg. 150-151) *For this draft Second Revised Plan, the Agency seeks stakeholder feedback on if small subscriber adders should be reduced. The shift to online marketing and enrollment is likely an additional cost savings for community solar providers that may not be reflected in the current adder. To elicit feedback on this topic, and in lieu of additional data or cost modeling, the Agency suggests starting with the midpoint of the range of costs reported by GTM Research, or $14.82/REC for 50% or over small subscriber levels. This approach produces adders very similar to the current Minnesota adder.*[1]

The small subscriber adder likely needs to be reexamined in light of new requirements from PA 102-0662 that projects have subscriptions of 25 kW or less for at least 50% of the facility's nameplate capacity and that the Agency shall price the renewable energy credits with that as a factor. In light of this requirement, the major question now seems to be whether or not the IPA should incent projects for going above and beyond the 50% requirement with a small subscriber adder - presumably the adder would either not be available for the first 50% of small subscribers or everyone would get it. It is unclear to the Joint NGOs whether or not such an adder will be necessary to ensure adequate access to community solar for small customers. Regardless of which approach the Agency takes in this first Plan, the Agency should monitor the outcome to discern whether both small subscribers and large subscribers have adequate access to the community solar market in order to reassess that decision in the next Plan. To the extent the Agency does opt for a small subscriber adder, the JNGOs support revisiting the adder amount in light of new data, including the GTM report referenced, as well as after a review of community

[1] Note that the separate Request for Stakeholder Feedback on the REC Pricing Model contains additional questions related to subscriber management costs.

solar REC price modeling in light of new provisions around community solar bill crediting under PA 102-0662.

8. Technical System Requirements (Section 6.12.1, pg. 168): *As discussed in Section 6.3.3.1.2, for this Second Revised Plan, the Agency is interested in feedback on specific alternatives to signed interconnection agreements for new community solar applications where there may be a long lead time between project application and selection. The Agency understands that certain stakeholders, particularly the utilities, are interested in alternative indicators of project maturity for community solar projects that may also alleviate pressure on interconnection processes. In Docket No. 19-0995, some stakeholders argued against the inclusion of the interconnection agreement requirement, but suggested no workable alternative indicator of project maturity to replace this requirement. The Agency continues to believe that signed interconnection agreements are an appropriate indicator of project maturity for distributed generation projects above 25 kW.*

Requiring executed interconnection agreements for projects as a condition for entering a process in which there is some uncertainty about whether a project will receive RECs (such as with the lottery process in the initial blocks of the CS projects) does not provide useful information to either developers or the Agency about project maturity or viability. In the lottery for the initial blocks of CS, there were many feeders and substations that had multiple projects in queues. In nearly all of those cases, there were many more projects on the queues than were awarded RECs in the lottery. Although the utilities have not made data available about the interconnection cost estimates of different projects in the queues, anecdotal evidence suggests that projects that were further down interconnection queues had significantly higher interconnection cost estimates than projects that were higher up the queues. So, for example, if there were twelve projects on a substation queue (which we know was the case on some substations or feeders), the first project on a substation queue would be expected to have significantly lower cost estimates than the twelfth project. Nevertheless, the likelihood that a project would be the only project selected on that queue in the initial blocks lottery would mean that project would move to the first position on the queue after the lottery and would have the upgrade costs of the first position instead of the twelfth. In this hypothetical example, while the twelfth project would initially believe that the project was not viable, it would be viable if it were the only one selected. This example shows that the interconnection agreement could provide little or no information about project viability.

Given the challenges Illinois has already seen with the requirement for interconnection agreements for community solar, the JNGOs support the IPA's efforts to identify alternative project maturity thresholds. Possibly, a reasonable, viable alternative could be completion of the Interconnection System Impact Study in the Part 466 interconnection process for projects in categories that have long lead times between application and award of RECs. The JNGOs recommend the IPA seek feedback in their draft Plan release on the extent to which the Interconnection System Impact Study could serve as a reasonable alternative.

With regard to community-driven community solar, in particular, the JNGOs have already commented in support of piloting an alternative to an interconnection agreement for certain projects as a project maturity requirement in the ABP block opening in mid-December. These comments were made in part due to concerns over the desirability of having community groups go through the expense of finalizing an interconnection agreement when their chances of winning a REC contract are uncertain. The JNGOs continue to support the proposal from earlier comments and, if the IPA adopts it, recommend that in the draft Plan, the IPA refrain from proposing a final project maturity approach for this ABP category. Rather, the IPA should plan to carry out a stakeholder feedback process after the initial scoring of project applications for community-driven community solar and finalize project maturity requirements for this category in light of stakeholder feedback and lessons learned from that experience.

11. Batch Contract Approval (Section 6.14.6, pg. 180): *In stakeholder comment processes conducted by the Agency, parties have repeatedly requested allowing the rollover of collateral from projects withdrawn from the program to newly applied projects. The argument offered has been that, especially in the residential sector, the collateral requirement has created risks and costs for Approved Vendors who cannot control for decisions homeowners might make to cancel an installation. The Agency continues to believe that the collateral requirement is an important component of ensuring that only projects with a high degree of likely completion are submitted to the program. However, the Agency recognizes the concerns that have been raised repeatedly and is open to considering a narrow set of circumstances for allowing collateral from cancelled projects to be reallocated, such as if a homeowner sells the property prior to installation. The Agency welcomes stakeholder comments on what might be an acceptable list of such circumstances, and on the mechanics of how those exceptions could be applied (such as what level of proof would be appropriate).*

Collateral requirements impose significant risks on Approved Vendors. The Joint NGOs appreciate the need for the Agency to impose collateral requirements to protect the State's interest in receiving contractually obligated RECs. However, the current system transfers the risk of individual residential customers' delivery of RECs to the Approved Vendors. Some of that risk should rest with the state and the contract holders and that where possible, the Agency should provide flexibility for the Approved Vendors to manage that risk.