Please find below the comments on the IPA's draft Guidebook released on November 28, 2018 by the Solar Energy Industries Association, the Coalition for Community Solar Access, and the Illinois Solar Energy Association (collectively "Joint Solar Parties").

<u>Discretionary capacity (page 5):</u>

> These totals leave the Agency with 166.5 MW of discretionary capacity to allocate across the various Group/category combinations for completing the program's first phase (i.e., to meet the initial 2020-2021 goals of 1,000,000 RECs delivered annually through the Adjustable Block Program).

The Joint Solar Parties note that the LTRRPP itself makes clear that of the available capacity for the Adjustable Block program, 30% is allocated to Group A and the remaining 70% is allocated to Group B. (*See* Final Approved LTRRPP at 100 n.303.) While the Joint Solar Parties do not believe the IPA has any intention other than to allocate the "discretionary capacity" 30-70 between Group A and Group B respectively, the Joint Solar Parties recommend clarifying this matter in the Guidebook.

<u>DG Site Control (page 14 and lottery guidelines):</u>

> "The Approved Vendor must provide a written binding contract, option, or other demonstration of site control acceptable to the Program Administrator for all projects where the Approved Vendor is not also the project owner and the host." In the lottery guidelines this is expanded to include " copy of a binding lease, option, or PPA contract between the Approved Vendor or project developer and the site owner as proof of site control "

The Joint Solar Parties support this requirement for Community Solar projects. However, the IPA should allow other alternatives to a PPA for behind-the-meter contracts (which frequently do not have a lease or option). For instance, a host agreement should be accepted. The Joint Solar Parties are uncomfortably with the seeming requirement that developers submit PPAs when other documents establish site control. Thus, instead of naming specific documents, the IPA should accept any binding agreement to allow the developer to occupy the site.

<u>REC Quantity Calculation (page 15)</u>:

> 1. The application portal will automatically calculate the PVWatts estimated production and the standard capacity factors of 16.42% for fixed mount or single axis trackers and 19.32% for dual axis tracking systems. Applicants will be allowed to choose either of these numbers, rounded to the nearest whole REC for their 15-year contract REC delivery amount, or can choose a lower number if their alternative capacity factor determines that a lower number is appropriate. Any arrays with an azimuth greater than 270 or less than 090, a tilt of greater than 80 degrees, or that do not meet the Minimal Shading Criteria may not use the standard capacity factors and must either use the PVWatts estimate or approved alternative capacity factor.
> 2. Any proposed alternate capacity factor that is calculated using a proprietary third-party software tool will require the Approved Vendor to provide a copy of the third-party software tool with appropriate licenses to the Program Administrator as well as providing all inputs to the tool in a manner which will allow the Program Administrator to replicate the generation claimed. The Program Administrator will accept alternate

capacity factors on a case by case basis after reviewing the methodology used to determine such alternate capacity factor.

The Joint Solar Parties have three concerns with the above-quoted section. First—and of the utmost importance—the IPA does not allow an alternative capacity factor to be higher than the higher of PV Watts or the standard capacity factor. Second, and also highly important, is the requirement that the Approved Vendor provide the IPA (with a license) the third-party tool used to develop the REC forecast. Both of those proposals are unnecessary and harmful for the following reasons:

- **Burden is on the Approved Vendor.** The Approved Vendor bears the risk of an inaccurate REC forecast. If the Approved Vendor overestimates, they are likely to under-deliver and be forced to replenish collateral. (*See* Final Approved LTRRPP at 136 ("On an annual basis, failure to deliver RECs for the previous year will result in the utility drawing on the collateral to be compensated for the undelivered RECs from that year that already received payment.").) If an Approved Vendor believes its assets will generate more, it should not be forced to transfer uncompensated RECs under a standing order to the utility when a higher capacity factor would have allowed the Approved Vendor to receive fuller compensation for the RECs actually delivered.[1] If the Approved Vendor is overly optimistic, it will face the collateral drawdown. That is a risk the Approved Vendor should be able to take on—without the IPA recreating the calculation.

  Separate and apart from this issue, the collateral drawdown is unnecessarily harsh in early years. The Joint Solar Parties recommend the following language to be added to restrict collateral drawdown:

  a. *FIRST YEAR: The Delivery Year Requirement is equal to the annual quantity derived from the approved project capacity factor, and is prorated for the first delivery year and the last delivery year if the delivery term does not start on June 1 of a year. In addition, for the first 365 days of the delivery term, the quantity of RECs that the Seller has to deliver can be reduced by 50%.*
  b. *COLLATERAL: The IPA should not draw on collateral for the first 3 years or productions, although the developer should still be responsible for fulfilling those RECs in subsequent years. Beginning year 4 the IPA should draw on collateral in the event of a shortfall, in the event the Project underproduces AND does not unexpired banked RECs.*

[1] The Joint Solar Parties recognize that there is some value in banking of RECs to avoid collateral drawdown in future years under the Final Approved LTRRPP and the Commission's Final Order in ICC Docket No. 17-0838. However, if a system is *consistently* overgenerating because the capacity factor is too low, the additional RECs left over in the bank will be uncompensated. The Approved Vendor should have within its Il how conservatively or aggressively to estimate production.

- **No Impact on IPA Planning.** The Joint Solar Parties understand that the initial 666 MW of capacity available under this Final Approved LTRRPP will not be raised or lowered based on the number of RECs that systems with REC contracts are expected to deliver. In other words, the IPA will not be procuring more or less solar capacity based on the estimated or actual capacity factor of the systems. While the Joint Solar Parties understand the IPA using information about actual REC deliveries for estimation purposes, there is no need to be so restrictive in how an Approved Vendor develops their own REC production estimate. Forcing Approved Vendors to underestimate because PV Watts and the standard capacity factors underestimate would deprive Approved Vendors of revenue from RECs generated and transferred irrevocably to the utility for no additional compensation.
- **Not covered in the LTRRPP.** The LTRRPP explicitly allows for alternative capacity factor calculations, but does not require that they be lower than the PV Watts or standard capacity factor.

  > Approved Vendors will have the option of using a standard capacity factor, or proposing an alternative capacity factor based upon an analysis conducted using PV Watts or an equivalent tool. Alternative capacity factors may be proposed as part of each system's application and will be subject to review and approval by the Program Administrator.

  (*See* Final Approved LTRRPP at 130.) This is a substantial change from the LTRRPP that substantially alters the available revenue to Approved Vendors. In addition, the LTRRPP did not require that the Program Administrator be able to recreate calculations with any third-party tools.
- **Additional Expense and Logistical Issue.** The Joint Solar Parties note that the requirement that the Program Administrator would have to have a license to a third-party tool and be able to recreate all calculations was not part of the Final Approved LTRRPP. This requirement was raised for the first time in the Guidebook, which came out less than two months before Block 1 open. The Joint Solar Parties believe the IPA should generally abstain from introducing new barriers—especially those that bring limited value to the IPA—this late in the process.
- **PV Watts Used Inconsistently with Purpose.** The Joint Solar Parties note that PV Watts, by its own terms, is not intended to be the basis for binding estimates of output. For instance, the Joint Solar Parties noted the following language on PV Watts' website:[2]

  Important Note. PVWatts® is suitable for very preliminary studies of a photovoltaic system that uses modules (panels) with crystalline silicon or thin film photovoltaic cells. PVWatts® production estimates do not account for many factors that are important in the design of a photovoltaic system. If you are using PVWatts® to help design a system, you should work with a qualified professional to make final design decisions based on an assessment of the system location and using more detailed engineering design and financial analysis tools.

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[2] https://pvwatts.nrel.gov/, available under pop-up window linked to "Help" category, under subcategory "Getting Started." The Joint Solar Parties were unable to generate a direct link to this language.

> If the IPA's concern is overestimation without basis, the IPA could adopt NREL's suggestion to require a "qualified professional" (such a licensed engineer) to provide a stamped estimate if the increase is greater than 20%. This would also eliminate the need for the Program Administrator to recreate every calculation, because a licensed professional engineer is stamping.
>
> The Guidebook should make clear that the default capacity factors will not be applied if an alternative capacity factor from a pre-approved third-party production estimate tool is utilized. In addition, the Guidebook should establish a process by which third-party production estimate tools can be approved within ten calendar days of the ABP program start date (i.e. January 15, 2019) so submissions can be fully made.

The Joint Solar Parties' third issue with the above-quoted section from the Guidebook is that the single-dual axis split is inconsistent with the Final Approved LTRRPP. The Final Approved LTRRPP states:

> The calculation for the standard capacity factor will be based on the following average capacity factors which, as discussed below, are based upon the capacity factor used in the Fall 2017 Utility DG procurement and adjusted for an expected degradation rate over 15 years.
>
> - Fixed - mount system 16.42%
> - Tracking system 19.32%

(Final Approved LTRRPP at 130-31 (footnotes omitted).) The plain language makes clear that a tracking system—without distinction within that category—has a standard 19.32% capacity factor. The default calculation should be rewritten to conform to the plain language of the Final Approved LTRRPP.

5% for Already Energized Systems

Systems that are installed at the time of initial application to the ABP do not have the same construction risk as systems not yet energized. Also, because of the timing of contracting and payment there is a very short period that the bonding would need be put up by the Approved Vendor on energized systems. Because of this, we would like to ask that systems that are energized at the time of application to the ABP are allowed to use a 5% holdback from their REC payment as the sole initial collateral required.

<u>Required Items (page 23 and again on page 25)</u>

> • Project Cost (inclusive of material cost, labor cost, permitting cost, other costs)

The Joint Solar Parties strongly oppose including this information in Part I or Part II of the application.

With regard to disclosure in Part I: First, at the time of Part I application, most (but not all) systems will not be built; thus, the project cost is simply an estimate. Second, it is unclear why the IPA is interested in an estimate (which is likely to be an internal estimate) of total costs. Third, even if the IPA had a legitimate interest in a project estimate such an interest would be outweighed by the developer's interest in keeping its proprietary estimates confidential. In addition, coupled with the IPA's intrusive requests for information about customer-specific any individual that has or obtains access to this information could easily determine a developer's highly proprietary customer pricing model. Simply designating the information "Confidential" and/or shielding it from FOIA disclosure is insufficient protection—a developer's pricing model is highly sensitive and most if not all developers strongly oppose releasing that information in any context.

With regard to disclosure in Part II: First, similar to the estimate in Part I, there does not appear to be a legitimate interest for the IPA in obtaining individual, specific project-development costs. Second, actual development costs are proprietary information—again, simply designating the information as "Confidential" or shielding it from FOIA disclosure is insufficient.

While the IPA provides no justification for this request, the Joint Solar Parties speculate that one reason may be to assess the accuracy of the Adjustable Block pricing model. If that is the case, obtaining portfolio-level or average information would be a far superior alternative.

> • Required Uploads:
> 1. For all projects:
> - Signed Disclosure Form
>
> . . .
>
> - Proof that the brochure was provided to the customer

The Joint Solar Parties understand that if there is already a contract in place for the system (or a subscription if community solar) at the time of the Part I application, the signed disclosure form and the proof that the brochure was provided to the customer (assuming the IPA persists in requiring these documents to be uploaded rather than maintained by the Approved Vendor and audited) is not necessarily unreasonable. However, many community solar systems will have no subscribers at the time the project is submitted to the Adjustable Block program (i.e the Part I application). In fact, unless the IPA allows much more flexibility in the Disclosure itself, it may be difficult to impossible to provide an accurate Disclosure form given that:

- The IPA reserves the right to reject a proposed capacity factor, and currently requires an estimated production total on the Disclosure form;
- Detailed engineering and final design may not have taken place by the time of the Part I application, meaning system characteristics impacting total production (for a specified nameplate capacity) could change;

- Owner/operators may not be able to offer firm pricing before determining pursuant to which Block (if any) the system will be compensated.

The Joint Solar Parties propose one of two solutions to this issue. The preferred solution is to require these documents be submitted in the Part II application, with the caveat that a community solar facility may not be fully subscribed at energization (in fact, the IPA explicitly allows for a six-month extension to more fully subscribe the facility). In the alternative, the less preferable solution—which is still far superior to the draft—is to make clear that the signed Disclosure and proof that the Brochure was provided is only required at the Part I application to the extent it exists at the time of Part I application.

Moving a system more than 5% (page 25 and lottery guidelines):

> Note that variations of less than 5% (or less than 1 kW, if 1 kW exceeds 5%) in size or capacity and variations in plot placement that impact less than 5% of the total surface area covered by the solar array(s) will not require project reapproval.

Requiring projects to have less than 5% variation in plot placement between program application and construction is unnecessarily restrictive and does not reflect the realities of the development process. This approach should be rejected.

As an initial matter, the Joint Solar Parties note that the IPA stated earlier in the draft Guidebook:

> A project's REC payment is based on the quantity of RECs estimated to be produced by the system, and this amount will be considered the lesser of the estimated production in Part I and Part II of the application. In this way, a system that is built smaller than planned will not benefit from excess REC payments that the final system cannot support as a result of its decreased production estimate. On the opposite side, if a project's final size is larger than the planned size, an increase in the REC payment could present unexpected budget management challenges. An Approved Vendor has the option of canceling and resubmitting a system if the final size is larger than the proposed system or if it desires to have the system change from a distributed generation project to a community solar project, or vice versa. However, the REC price will be that of the Block open at the time of resubmission, not of the original submittal. A new application fee will be required because the Agency will need to review the system design, which would be different from what was originally submitted (e.g., because of the change in system size). If a project is resubmitted and approved, the collateral associated with the original system would be applied to the resubmitted system.

(Draft Guidebook at 21.) This appears to be a direct quote from page 133 of the Final Approved LTRRPP. The LTRRPP—and, earlier, the draft Guidebook—addressed how a developer whose system size changes from Part I to Part II would be handled. Notably, it is silent about any percentage cap (such as 5%) or any requirement about the location of the system on the identified parcel. As developers have undertaken the development process, there was no reasonable expectation based on the Final Approved LTRRPP (or the Commission's Final Order in ICC Docket No. 17-0838) that such restrictions would be imposed.

Setting aside consistency with the Final Approved LTRRPP, the IPA's proposed approach—particularly with regard to system location—is inconsistent with the normal development process. Generally speaking, developers submit development site plans to obtain Special Use and Conditional Use permits, among other things. Development sets are the design of the system using the basic due diligence information available to the developer without having to do invasive site investigation. Examples of this due diligence include topographical information, wetland delineations, etc. Site plans submitted for non-ministerial permit applications generally contain some wiggle room for the project to move to accommodate information gathered through more invasive due diligence measures. Invasive due diligence is generally not conducted until a project has secured a contract/incentive and is ready to move forward with construction. Detailed geotechnical engineering data and detailed drain tile investigation, among others, are examples of more invasive due diligence. Geotechnical engineering shows the developer the exact make-up of the soil and rock under the system, and the developer (or EPC) uses this information to conduct structural engineering sets. It is often the case that projects are moved to accommodate the results of this work, often more than 5% beyond the layout of the original development site plan.

Conversely, it is not clear why the IPA has an interest in the facility being located no more than 5% beyond the layout of the original development site plan. If the IPA is concerned about changes that may impact the projected REC output, the IPA could simply require confirmation from the developer that the shading study and other relevant technical details have not materially changed. The Joint Solar Parties are unable to identify any other reason for the 5% locational requirement.

In a similar vein, the Joint Solar Parties cannot understand why—given the protections independently in place from the quoted language on page 21—the IPA has an interest in system capacity remaining within the greater of 1 kW or 5% of the Phase I application. To the extent that the IPA is concerned a system will default on or otherwise lose its Interconnection Agreement, the IPA should simply require that the system maintain its signed Interconnection Agreement.

Proposed alternative language should be consistent with the proposal for changes to Section E.2 for the lottery comments below.

RECS Created Prior to Contract Signing Should be Deliverable (page 27)

Systems that are eligible (energized after June 1, 2017) should be able to deliver all RECs generated since energization.

1. This is not how the IPA has treated previous REC contracts for DG, so it is unclear what the change is. (The 15 and 16 DG procurements bought RECS for specific energy years, but the ABP is not tied to specific energy years)

2. With the elimination of spot procurements there is no market for these RECS. If this was to be a provision it should have been stated earlier in this process. Because it was not clear it will harm primarily small residential early adopters.

3. The IPA is entering into contracts with already degraded systems, and the system owners will not get full value for their RECS.

4. This actually derisks the REC procurement for the utilities because they are getting some history of REC production from that system at contract signing.

Comments Related To The Final Lottery Document

At the afternoon stakeholder session on November 30, 2018, the Joint Solar Parties understood the IPA to invite limited comment on the lottery document released on November 28, 2018. To that end, the Joint Solar Parties wish to raise three issues.

- **Conforming Changes to Guidebook Comments.** The following items were not subject to previous comment and the Joint Solar Parties commented for the first time on these issues in the Guidebook comments above. The IPA should accept the Joint Solar Parties' comments above, and make the following conforming changes to the final lottery document:
    - With regard to Section E.2, The Joint Solar Parties commented extensively on the requirements for no more than a 5% change in both capacity *and* location on the parallel section in the Guidebook. The Joint Solar Parties recommend deleting the entirety of Section E.2 and replacing it with the following: "All projects must be built on the parcel identified on the Part I application. In addition, the project must maintain its signed Interconnection Agreement after any changes are made prior to energization."
    - With regard to Section F.2, the Joint Solar Parties recommend that the IPA make clear that the proportion of the held-back capacity will remain 30% Group A and 70% Group B.
    - With regard to Section G.2, the Joint Solar Parties commented on alternatives to the three documents listed as potential proof of site control in the case of a behind-the-meter project. To effectuate these comments, the Joint Solar Parties recommend revising Section G.2 as follows: "Projects must submit a copy of a binding lease, option, ~~or~~ PPA contract**<u>, or other fully executed document (such as a hosting agreement) granting the right to construct the system on the host's land</u>** between the Approved Vendor or project developer and the site owner as proof of site control for any project where the project owner is not also the Approved Vendor and the host."
- **Last Project In.** In Section B.3, the final lottery document explains what happens when the final project selected is greater than the remaining capacity in the Block—specifically, the whole project gets into that Block. However, this section is only

explicitly applicable in the event of a lottery and for 200% of Block 1 (or 100% of Block 1 for both community solar lotteries). The Joint Solar Parties recommend that the IPA clarify that this standard applies to other Blocks—including explicitly Blocks 3 and 4—and also to the developer cap if the last project selected would exceed the 20% cap.

Language recommendation (Section B.6):

> Following the Block 1 lottery, if the capacity of the remaining unselected projects in a Group/category exceed the capacity of the applicable Block 3, then projects will be automatically selected for Block 3 using the ranking from the original Block 1 lottery. Selection of projects will be made by taking remaining projects in order starting from the lowest remaining number until Block 3 is filled to 100%. These projects would all receive Block 3 pricing. Block 3 would then be considered closed. In the event that the last project selected in a Group/category would exceed the capacity allocated to any particular Block, that project would be approved in its entirety. Under no circumstance will there be a separate or additional lottery for Blocks 3 and 4, and no developer cap for Block 3 or Block 4 to the extent that the lottery did not fill Blocks 3 or 4, respectively.

Additionally, the IPA should clarify that if the developer cap is triggered, the final project selected should be included in its entirety under that party's cap. If the final project were not included under the cap, a party will almost certainly receive less than 20% of the capacity of a Block, yet still have the cap applied.

Language recommendation (End of Section D.1):

> In the event that the last project selected for any affiliated family of project developers in a Group/category would exceed the 20% capacity cap, that project would be approved in its entirety.

- **Definitions of Developer and Control.** Because "affiliated family of developers" is a wholly new concept that is not mentioned in FEJA, the IPA's Long-Term Plan, Final ICC order or subsequent filings, these terms must be clearly defined. Ambiguity about the terms "developer" and "control" especially could restrict commercial activity in ways beyond the goals of the developer cap. For instance, the Lottery procedure states that "this capacity cap will not be applied at any point after the initial lottery," but it is not explicitly clear whether the entity with ownership of a project selected in the lottery can sell that project to another entity at some point in the future without triggering the cap for the buying entity. Similarly, it is not explicitly clear if an entity that sells a project *before* the lottery will have that project counted toward its cap if the project (now under new ownership) is the selected in the lottery.

  To effectuate this change, the footnote to Section D.1 should read: "'Developer' means the entity that, at the time of the Part I application, holds financial control of a project that is entered into the Adjustable Block program. To be clear, the 20% cap applies to an affiliated family of developers, not installers or Approved Vendors."

In addition, the definition of “control” could cause unintended consequences that exceed the goals of the cap. Most notably, two completely unrelated developers that share a common equity investor could be caught up in a single developer cap. Lenders often provide financing to multiple developers, and under the IPA’s definition of “control” the unrelated clients of that lender would potentially share “common debt and equity financing arrangements.” Further, a developer’s arrangement with a particular lender may give the lender some contractual ability to “direct the management [or] policies” of that developer. Under the IPA’s definition of “control” two unrelated developers that have similar contractual arrangements with the same lender would be subject to a single cap.

These concerns are especially acute because there are a relatively small number of lenders active in community solar finance, and multiple lenders are involved in project finance in general. If every bank were unintentionally limited to 20% of any particular block, this could create enormous instability in the market and risk achieving program goals.

However, concern about this term is not limited solely to financing parties. Many companies interested in the Illinois ABP have a national or global focus. As such, it is very likely that two unrelated developers, installers or contractors could have any variety of contractual arrangements to buy, sell or construct projects in other markets. Any contract language that provides one party any recourse over the other could be perceived as “power to direct the management and policies” of the counterparty. Under the IPA’s definition of “control” those two unrelated developers would be subject to a single cap even though the contract that makes them “affiliated” relates to a completely separate transaction in another state.

The Joint Solar Parties do not believe this cap was intended to be applied so broadly, and IPA can eliminate this uncertainty by deleting this footnote entirely.