RESPONSE TO ILLINOIS POWER AGENCY REQUEST FOR COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE COALITION FOR COMMUNITY SOLAR ACCESS, AND THE ILLINOIS SOLAR ENERGY ASSOCIATION

February 28, 2022

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 related to the Draft 2022 Long-Term Renewable Resources Procurement Plan (the "LTRRPP" or "draft LTRRPP").

Section 2 (and Addendum)

The LTRRPP interprets the portfolio allocation of RECs to apply specifically to the *quantitative target amounts listed in law* (up to 45 million RECs), and not to any procurements in excess of these amounts. While the Joint Solar Parties agree that meeting the target of 45 million RECs from new solar and wind is a statutory obligation, the language is equally clear that the 45 million RECs are a floor and not a ceiling:

> In any given delivery year, if forecasted expenses are less than the maximum budget available under subparagraph (E) of this paragraph (1), the Agency shall continue to procure new renewable energy credits until that budget is exhausted in the manner outlined in item (i) of this subparagraph (C).

(20 ILCS 3855/1-75(c)(1)(C).) While the Joint Solar Parties do not object to—and in fact supported—a 5% budget cushion (at least in early years) for the IPA to gather data about the impact of indexed RECs and other new procurements on the budget, the Joint Solar Parties urge the IPA to regularly review whether additional budget is available to procure more RECs to meet and exceed the statutory floors sooner.

The Joint Solar Parties provide this response in the context of the Addendum to the draft LTRRPP for public comment released on February 18, 2022. The Joint Solar Parties believe based on preliminary analyses that there may be errors in the calculation of future obligations, but are not able to provide in-depth analysis at this time. The Joint Solar Parties request that the IPA make their model of future costs and budget calculations available in an unlocked spreadsheet to allow for further analysis and constructive criticism. The Joint Solar Parties reserve the right to submit an addendum to these comments addressing the February 18 addendum.

Section 5 – Competitive Procurements

Project Labor Agreements: The Joint Solar Parties note that the general contractor—which is frequently not the bidder—is responsible for entering into a Project Labor Agreement Section 1-75(c)(1)(Q)(2). In fact, a bidder that is not itself a general contractor may not have even selected a general contractor at the time of bidding. If the Project Labor Agreement is required as a prerequisite to bidding, it will force needless negotiation between organized labor, contractors, and developers on projects that are not selected (and thus perhaps less likely to be built). A better approach is to require a Project Labor Agreement to be submitted a certain amount of time before construction begins on the project.

The Joint Solar Parties do agree, however, that a winning bidder that fails to secure a Project Labor Agreement on the requisite timeline should lose its collateral. Each Project Labor Agreement will be the result of negotiation and thus each one will be different, but each Project Labor Agreement should be reviewed for the statutory requirements in Section 1-10 of the IPA Act.

Collared Pricing: On page 118, the LTRRPP poses the following question prompt:

> A price collar would reduce both upside and downside exposure to bidders, and the Agency is interested in stakeholder feedback on the price collar concept and if an introduction of a price collar could reduce risks for bidder and therefore result in lower expected bid prices.

The Joint Solar Parties wish to stress that for an indexed product, a collar *increases*, not decreases, the risk to bidders.[1] This is because projects are not financed to average or optimistic scenarios but to worst-case scenarios because debt and tax equity expect and demand minimal risk. In this way, financing parties are different than one might imagine an investor in other contexts that more heavily considers best-case scenarios. Put another way, the more stable the revenue stream the more attractive to financing parties because the floor is raised—even if it is at the expense of potential upside.

Because an indexed product with a collared REC would likely see less debt and tax equity financing (or financing of the same amount on worse terms), the Joint Solar Parties would expect as a general trend for bids to increase, not decrease, if a collar was put into place.

Equity Standards: The Joint Solar Parties recommend that plans related to inclusion of Equity Eligible Contractors include: (1) use of Equity Eligible Contractors to date through submission of the bid (if any), (2) a demonstration of how the minimum goals of Equity Eligible Contractor involvement will be met that have not already been met before the bid, and (3) how much of any expanded goals are from construction activities subject to a Project Labor Agreement, because the Project Labor Agreement requirement may impose some restrictions on which vendors may be used for construction.

The Joint Solar Parties noted that the IPA is still considering how to evaluate "comprehensive" compliance with Equity Eligible Contractor procurement goals. The Joint Solar Parties recommend the IPA first define what "comprehensive" is and how specifically it is measured. For instance, bidders that are Equity Eligible Contractors themselves might meet the definition, while another definition would include beating then-applicable goals by a pre-defined threshold (for instance, 150% of the minimum threshold). Whatever standard applies, it should be quantitatively measurable and well defined rather than based on a scoring system or qualitative analysis.

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[1] The Joint Solar Parties note that each collar would have to be evaluated on its own terms and in the context of energy market projections. Factors that determine reception of a particular collar by a particular financing party includes the floor and how it is set/calculated, the ceiling and how it is set/calculated, and wholesale energy market projections.

The Joint Solar Parties note that the statutory language in Section 1-75(c-10)(3) refers to giving preference where "a higher portion of contract value flows to equity eligible contractors." Because this is pre-construction (and frequently early stage development) bidding, flow of funds to Equity Eligible Contractors—or any vendor—is largely prospective. However, as a way to quantitatively measure the commitment to "a higher portion of contract value" flowing to Equity Eligible Contractors, the Joint Solar Parties recommend allowing bidders to commit to spend (measured in dollars) on Equity Eligible Contractors as a percentage of the strike price multiplied by the bid annual quantity. This allows a demonstration that a "higher portion of contract value" is going to Equity Eligible Contractors and encourages wider scopes of work going to Equity Eligible Contractors.

The Joint Solar Parties further note that deeming bids to be reduced by a fixed percentage (for instance 10% as floated in the draft LTRRPP) to benefit certain bidders can have a substantial impact for products like brownfield solar, where 10% of the average winning bid for the 2019 procurement would have been over $5.80/REC. The Joint Solar Parties suspect that in moving from a fixed REC model of bidding and toward a strike price model, the impact could be even more stark in certain procurements and is likely going to be substantial for all bidders.

The Joint Solar Parties' primary recommendation is to both create a tiebreaker for equal bids in favor of bidders with "comprehensive" (however defined) Equity Eligible Contractor goals and also increasing the benchmark for those systems. At minimum, if the IPA takes the Joint Solar Parties' recommendation that "a higher portion of contract value" flowing to Equity Eligible Contractors can be demonstrated by pledging a certain amount of spend to Equity Eligible Contractors, the benchmark should be increased such that 50% of the net present value of that additional commitment is added to the confidential maximum strike price.[2] The Joint Solar Parties would support a minimum and maximum amount of this benefit.

In the alternative, if the IPA does not accept the Joint Solar Parties' primary recommendation of tiebreaker and special benchmark considerations, the IPA should set a fixed dollar per MWh of strike price (for instance, $2/MWh) as the deemed lower amount. A fixed amount allows for greater transparency and ability to plan bidding strategy.

Non-Solar Community Renewable Generation: The Joint Solar Parties support investigation of non-solar photovoltaic community renewable generation project procurements. The Joint Solar Parties suggest that the IPA release an RFI on issues related to market demand for different technologies, potential resolutions to legal issues (for instance, the floating energy value to strike against, which may be different depending on the utility service territory), and other feedback on potential differences in terms and conditions from utility-scale REC Contracts and Adjustable Block Program REC Contracts.

[2] For example, if a bidder committed to $1,500,000 spent on Equity Eligible Contractors, the benchmark would increase by an amount such that the net present value of that increase to the strike price would be $750,000 (50% of 1,500,000). The Joint Solar Parties note that there would have to be a minimum commitment to demonstrate "a higher portion of contract value" is flowing to be defined by the IPA, and perhaps a maximum benefit so there is not an opportunity for gaming the benchmark.

Section 7 – Adjustable Block Program

- *REC Pricing (Section 7.5.2 and Appendixes)*

The Joint Solar Parties recommend several changes to the REC pricing models used to generate REC prices. In some cases—in particular for behind-the-meter systems in the schools program—price changes are necessary to generate substantial market interest (as seen by the performance of the schools program to date). In those cases, the Joint Solar Parties recommend changes to REC pricing to stimulate program interest.

In other cases, the CREST model has inputs that do not accurately reflect real-world conditions. The Joint Solar Parties wish to emphasize in these cases that the CREST model should provide an accurate baseline but that the IPA may decide for other reasons to reduce REC prices (the Joint Solar Parties note that no statute or Commission order requires usage of CREST model results with no modification) to an amount necessary to stimulate but not overstimulate a project category. The Joint Solar Parties believe the value in correcting the CREST model and then modifying the results is that the CREST model should provide as accurate an accounting of costs and benefits as possible; further modification (especially to lower REC prices) should come with recognition of the efficiencies provided by the Illinois market.

Below, the Joint Solar Parties provide comments generally applicable to all of the pricing models, followed by comments related to specific programs. The Joint Solar Parties note that the Equity Block does not currently have separate pricing, so comments are equally applicable to the Equity Block when there is an equivalent Equity Block program.

<u>Generally Applicable Comments</u>

- **Investment Tax Credit (ITC)**
  - The CREST model assumes 100% utilization of the ITC. In other words, the CREST model assumes that every dollar in ITC that a system could earn is converted to a cash value. While perhaps this is true in certain cases where the system owner monetizes the tax credits by applying them to their own tax liability, 100% utilization is not accurate for any individual or entity using third-party tax equity financing. While values widely vary, a more reasonable estimate of ITC utilization is 80% NPV for sophisticated third-party financing and likely less for simpler or smaller third-party financing (such as with a syndicator).
  - The ITC is scheduled to step down to 22% in 2023. While the Joint Solar Parties certainly hope the ITC at least maintains its current levels and are involved in federal-level advocacy on this issue, the CREST model should recognize the stepdown for any system that is selected in the block currently scheduled to open on June 1, 2023. The Joint Solar Parties would not object to an earlier date for the Equity Block, where some newer entrants may not have had time or resources to develop an Investment Tax Credit safe-harbor strategy.
- **System costs:**
  - The NREL data related to system costs is expressed in terms of DC system size—a logical approach, given that panels are measured in DC and everything from Racking/balance of system to installation labor adjusts primarily based on DC

capacity. However, the CREST model appears to tie nominal installation costs to *AC* capacity, which is problematic for two scenarios. First, when the DC system size used in the CREST model is considerably larger or smaller than the DC capacity used to generate the proxy cost numbers (detailed in Appendix D). Second, when there is a large DC system size delta (in some categories as much as 15%) between Group A and Group B, but the same nominal system cost is used due to the AC size being the same. Either the IPA should modify the CREST model to take a DC-based input or the IPA should translate the system's costs from DC to AC using conversion factors appropriate for the particular Group and system classification.

    - The Joint Solar Parties continue to see higher equipment prices as identified in previous comments. While the Joint Solar Parties hope the prices come down in the future (allowing modification of REC prices downward if/when that occurs), for now a developer taking on certain project types is essentially making a bet in applying a system that equipment prices will come down in time for engineering, procurement, and construction ("EPC") on the system. This approach, if taken by particular market participants, may lead to program-wide delays and higher than average attrition rates. Specific examples of higher component costs include:
        - According to NASDAQ indexes, key components of pipes/trays/wires and racking—specifically aluminum, copper, and steel—have increased about 142%, 178%, and 380% respectively. Copper is also prevalent in inverters.
        - According to new research published by Wood Mackenzie, average solar module prices increased in Q2 2021 by 15% from Q1 as a result of increased polysilicon, aluminum, glass, and freight costs for shipments to the US. Freight costs have also heavily impacted tracker prices, as have ongoing tariffs
        - It is *not currently accurate* to estimate a consistent decline in component prices due to tariffs and current trends in raw material prices. While the Joint Solar Parties hope the current trends reverse soon, hope for the future does not reflect current costs.
- **Net Present Value**: In looking at the revenues of the system relative to the expenses, a large portion of expenses (especially for behind-the-meter systems) come prior to the first dollar of revenue while REC and energy revenue streams last (depending on the program) 15 years to all 25 years modeled. The revenues in later years have diminished value to the system owner due to needing to wait and the requirement of covering many—though not all—costs related to the system upfront. The "net present value" approach examines the current value of revenue in later years by assuming returns on an investment of the same amount that are foregone by waiting for that revenue and thus being unable to invest it today. While there is no single right answer for what that return rate should be, sometimes referred to as the "discount rate," it is to a certainty greater than zero. The Joint Solar Parties reviewed the REC pricing models in depth, and were not able to identify whether a discount rate or assessment of the net present value of the RECs themselves. Specifically, even in the unlocked version of the spreadsheet, the Joint Solar Parties' attempts to test by modifying the REC value did not lead to changes in the cash flow model and thus could not determine whether there was a discount for REC value based on the timing of REC of the REC payment itself. The REC pricing model should integrate a discount rate related

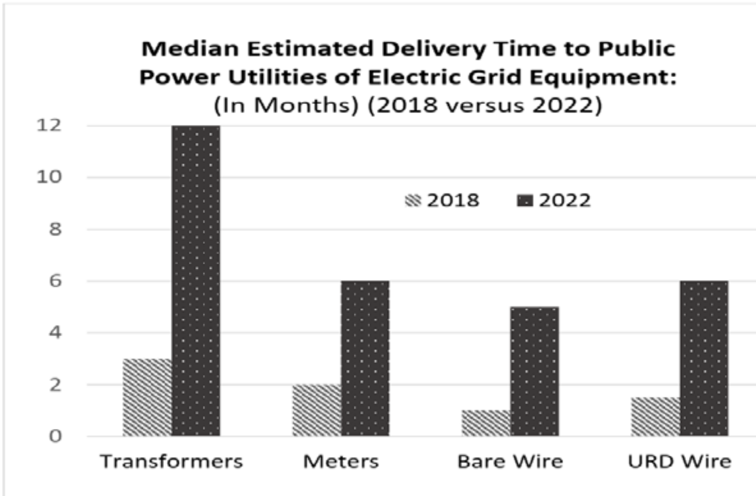
to the REC payment itself, particularly for revenue streams that last longer (for instance, RECs paid over 20 years rather than upfront or over about 6.5 years).

  - As an example, using industry standard discount rates, 20 years of RECs from the public school program would have the same approximate NPV as 15 years of RECs from the Large DG program that are paid over about 6.5 years. The Joint Solar Parties note that despite having the same pricing as the Large DG block, it appears that not a single schools project has been submitted despite many schools-based projects taking part in the first iteration of the Adjustable Block Program.
  - If the CREST model does account for the timing of REC payments, the Joint Solar Parties recommend that the IPA provide an explanation of where that is reflected in the model, or a summary of the discount assumptions specifically related to timing of REC revenue itself.

- The assumed increased annual value of the net metering credit should be 1%, not 2%. Even if the IPA believes that 2% is appropriate for the distribution portion of the bill (small DG systems are in many cases hosted by customers eligible for full retail net metering instead of solely having the DG Rebate as an option), 1% is a closer proxy for the supply side that does regularly increase year to year and in fact has decreased year over year more than once in the last ten years.
- The developer fee in the CREST model is reasonable for systems up to 2 MW. However, above that level, the implied development fee is cut by a third for 5 MW systems—to the point where the anticipated development fee is approximately $50,000 *less* for a 5 MW system than a 2 MW system.[3] The Joint Solar Parties appreciate the dearth of data available on 2-5 MW systems but note the IPA appears to have used utility-scale system data, which is not analogous to large DG in terms of costs/economies of scale, system design (for instance, utility-scale uses trackers but rooftop does not) or margins. Instead, of using NREL data for utility-scale systems, the IPA should model the development fee for 2-5 MW systems by extrapolating from the data points used for the smaller categories. The Joint Solar Parties further note that NREL's U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 estimated development fees at $0.30-0.32/W (DC) for a 2 MW (DC) system.
  - In the alternative, the Joint Solar Parties note that a somewhat more realistic developer fee of approximately $1 million for a 5 MW (AC) system can be calculated using the same NREL report to apply a fee of 12% of EPC costs (for which a reasonable proxy is Generation Equipment plus Balance of Plant plus Interconnection).
- The American Public Power Association ("APPA") recently released talking points regarding the current equipment supply chain constraints that its members are experiencing. Currently, the median estimated delivery time to public power utilities of electric grid equipment is significantly delayed. For example, a transformer that took three months to deliver in 2018, is now expected to a take a year. These delays are expected to continue to worsen. Below is a chart the illustrates the delays described by APPA, which

[3] The Joint Solar Parties, using the "Development Cost & Assumptions" Tab, calculated the development fees to be $699,669 for a 5 MW (AC) (6.094 MW (DC)) project and $750,653 for a 2 MW (AC) (2.438 MW (DC)). These values translate to approximately $0.33/W DC for 500 kW-2 MW (AC)—which the Joint Solar Parties believe is a reasonable amount—but only $0.11/W DC for 2-5 MW (AC) systems, which is too low even for a full 5 MW (AC) system, to say nothing of a smaller system like a 2.5 MW (AC) system.

would impact both systems themselves and interconnection (including the projected six-month construction timeline assumed in the CREST model for larger systems).



<u>Comments Applicable to Small DG (Including Equity Block)</u>

- Section 16-107.5(h-5)(3) of the Public Utilities Act provides that interconnection costs assessed to Level 1 systems may not exceed $200. While this phrase is currently subject to litigation in ICC Docket No. 20-0700, the interconnection cost estimate should be a uniform $200 (plus an additional $50 for the application fee if that is approved as a separate cost by the Commission).

<u>Comments Applicable to Schools Program</u>

- Due in part to the lack of an apparent discount rate, the JSP believes that the REC and values for the school program will not result in many, if any, successful projects. At minimum, due to the time value of money and the even (rather than accelerated) payments over 20 years, REC pricing should at least have parity with Large DG to encourage significant participation in the Schools Block. If there is not at least parity with the Large DG blocks, schools projects will likely apply to that category first, negating the justification for a stand alone schools category. The likely result of this disparity will be to push otherwise potential Public Schools projects into the Large DG category, negating the carveout to help Tier 1 and Tier 2 schools.
- Based on the experience of member companies of the trade associations that comprise the Joint Solar Parties, many Tier 1 and Tier 2 schools are anticipated to need a roof replacement as part of a rooftop solar system. The Joint Solar Parties were unable to locate where in the model the potential cost of a new roof to support solar is accounted for as a cost. Even if the eventual REC pricing is modified so that the REC price does not include the full cost of roof replacement, the price of roof replacement should be recognized at minimum as part of rooftop developments on many Tier 1 and Tier 2 schools.

Comments Applicable to Traditional Community Solar

- Bill credits
    - The IPA currently assumes that all customers are C&I customers in the REC pricing model. For ComEd projects, once ComEd's systems are upgraded and it takes on providing full credits for all customers, ComEd will provide a Price-to-Compare credit for all customers that is very similar (though not identical) for all customers from the smallest residential subscriber to a large steel mill. This will remain the case unless or until ComEd no longer provides the non-residential price to compare as the crediting rate for all non-small subscriber classes. Thus, assuming all customers are at the Price-to-Compare and modeling the PEA as neutral to a small credit (as it has been in the past), ComEd REC prices may decrease.
    - In contrast, Ameren non-residential customer credits are likely to prove very difficult to model. Ameren proposes to provide the LMP at the time the related energy was generated, and to calculate a capacity and transmission credit calculated as follows each month: Cap/Trans Credit = Cap/Trans bill charge (in $) x (kWh associated with the subscription)/(the customer's total kWh consumed for the same time period). The value will vary widely based on multiple factors including market conditions (primarily related to LMPs and cap/trans $/MW-day), customer usage, customer capacity/transmission allocations, and the system's generation profile. There will not be a one-size fits all approach; the IPA should instead choose a "typical" larger subscriber and use assumptions about their usage patterns and projections about LMPs, capacity, and transmission to come up with large subscriber modeling.
- Disparity between Group A and Group B pricing: The Joint Solar Parties believe the disparity between Group A and Group B pricing is indicative of underlying problems in the model, especially given the reduced bill credit revenue in Ameren based on historic prices to compare. The Joint Solar Parties are continuing their review of relative costs but note the difference has historically been much less between Group A and Group B.
- Small Subscriber Administration (Section 7.5.6): The LTRRPP correctly anticipates that ComEd and Ameren will provide consolidated billing to system owners on an optional basis for a fee, but it is important to note that the utilities will not be purchasing the receivables and will instead require that all utility charges be paid first in the event of arrearages or partial payments before the first dollar goes to the system owner. In other words: the consolidated bill may save on the costs of issuing the bill (although the system owner may still have to calculate key values) but will not provide additional or enhanced remittance services (and in fact may be less protective because the utilities will not take additional steps to collect nor will they charge early termination fees).

- *Timing Of REC Pricing (Section 7.5.7)*

The Joint Solar Parties note that the statutory language in Section 1-75(c)(1)(K) requires that "the Adjustable Block program shall provide a transparent annual schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." In the draft LTRRPP, the IPA proposes to only set prices for the 2022-2023 delivery year blocks and withhold release of pricing for the 2023-2024 delivery year blocks until a later date. While the Joint Solar Parties appreciate the IPA giving itself the opportunity to listen to market signals such as drops in the current high commodity and shipping prices that are outlined above and justify higher REC values immediately, the Joint Solar Parties strongly prefer that the IPA commit to REC prices through at least 2023-24, and subsequently at least two years out going forward. This transparency and predictability, as intended in the legislation, allows developers to make a better-informed decision about investing substantial resources into preparing a project for submission in 2022-23 with a project that may end up on a waitlist until the 2023-24 block opens. If prices are known, the developer will know whether it makes sense to continue to move the project forward. Without that insight, such a developer is essentially gambling their project on the eventual REC pricing is at or above the minimal REC price that allows the project to pencil.

- *Adjustments (Section 7.5.3)*

The Joint Solar Parties recommend that the IPA consider two adjustments for REC pricing: if the system is in a "built environment" (defined further below) and if the system is constructed using contractors with a Department of Labor-certified apprenticeship program.

To foster a significant number of projects in urban and suburban areas and reclaim already-developed lands, the Joint Solar Parties recommend the Agency offer a single, modest adder for community solar projects constructed on the "built environment." The built environment adder should encompass a variety of land uses, including projects in Equity Eligible Communities, rooftops, parking lots, carports, canopies, dual-use land, abandoned lands that were previously developed, brownfields, water bodies (floating solar) and other similar uses as defined by the IPA. The Joint Solar Parties believe this step will place systems in a built environment into closer parity with projects sited on prime farmland and thus advantage built environment projects. The Joint Solar Parties note that the adder value could be set through a stakeholder process related to additional costs of the built environment.[4]

The Joint Solar Parties acknowledge the constraints of the Agency's REC budget and the state's ambitious REC procurement goals. To increase cost certainty for IPA budgeting purposes and manage the impact on the budget overall, the Joint Solar Parties suggest that the adder should be implemented on a pilot basis, perhaps 50 megawatts per year for the first three years of traditional community solar. The IPA and other interested stakeholders can then study the effects of that pricing on project applications, accepted projects, and successfully completed projects.

An adder related to use of contractors with a Department of Labor-certified apprenticeship programs recognizes the long-term value to the state meeting its clean energy generation goals through longer-lasting and better-performing systems built with well-trained personnel.

- *CS Project Selection (Section 7.4.3)*

The Joint Solar Parties strongly urge the IPA to modify selection of Traditional Community Solar to reflect statutory language, address the lessons learned from the 2019 lottery and other states.

[4] Examples of such costs include potentially higher taxes, higher labor costs, impact on system value of onsite contamination or potential onsite contamination, and limitations on system size/orientation.

The Joint Solar Parties propose that the IPA open waitlists for Traditional Community Solar on August 1, 2022 that operate on a first-come/first-served basis based on the day the project was submitted to the waitlist. To the extent that on a particular day there are applications that exceed remaining capacity, the IPA should use the last date of the site control document, the effective date of the interconnection agreement,[5] and the land-use permit (if required). To the extent that a tie remains, the Joint Solar Parties recommend using the effective date of the interconnection agreement (as a proxy for queue position), followed by a random selection between any remaining ties.

The Joint Solar Parties' proposal effectuates the text and intent of Section 1-75(c)(1)(K)(iii)(1) of the IPA Act: "the Agency shall select projects on a first-come, first-serve basis, however the Agency may suggest additional methods to prioritize projects that are submitted at the same time." First come/first served is the primary statutory obligation, and project maturity to break ties is a logical continuation of this policy.

While the phrase "at the same time" in Section 75(c)(1)(K)(iii)(1) is not defined, that phrase should be read in a way that avoids amassing of a large pool of projects that are selected not by first-come/first-served but by lottery (or points or any other criteria). By opening a waitlist on August 1st i.e. when the 2022-23 blocks for non-Traditional Community Solar categories open) and using a first-come/first-served approach based on application date, there is a much lower chance of a 2019 lottery-style pileup of projects. Developer caps can prevent the best-capitalized or largest developers from crowding out competitors by flooding the program with early and numerous applications.

The phrase "at the same time" should not be read as the date of a block opening—whether a waitlist is in place at the time or not. Reading "at the same time" in this way not only undermines the first-come/first-served statutory obligation but also greatly increases the chance of a repeat of the overcapacity and interconnection problems that impacted the initial lottery (described in further detail below). The mass lottery created winners and losers based on random chance; due to interconnection issues even "winners" frequently had to abandon otherwise valuable projects and a portion of their collateral with it.

The first-come/first-served approach based on the time of the application also supports the policy goal of avoiding the pitfalls of the original lottery. First, a developer will have immediate clarity into whether a project will receive an award based on available capacity and thus will be able to make an informed decision about the future of the project. Under the New First Notice Rule for Part 466 published on January 3, 2022 in the Illinois Register, a 100% deposit on interconnection costs will be due 15 business days after signature of the interconnection agreement. (*See* Proposed § 466.Appendix D, Section 5.2 (46 Ill. Reg. 1, 97 (January 3, 2022)).) If a project is forced to wait months to see its score or lottery results, it will have to provide its interconnection deposit soon after signing (a program prerequisite that the Joint Solar Parties strongly support) and risk utility

[5] Specifically, the Joint Solar Parties mean by "effective date" the date entered on the first page of the standard interconnection agreement reflected in 83 Ill. Admin. Code § 466.Appendix D. The Joint Solar Parties understand this date is the day that the EDC offers the partially executed interconnection agreement for interconnection customer countersignature.

drawdown of those funds in the interim. If developers are forced to wait a long time between submission and selection, better-capitalized and risk-tolerant developers will be strongly favored.

The Joint Solar Parties realize that ties that exceed program capacity within the same day of application are likely to be smaller than the original lottery but will still be possible. As a result, the Joint Solar Parties suggest project maturity, as measured by the last date of the site control documentation, the effective date of the interconnection agreement, and the land-use permit (if required), as a secondary screen. This allows projects that have been waiting longer to go forward more quickly. Again, if the IPA is concerned about a small handful of developers flooding the waitlist, developer caps are an effective tool to prevent a single entity from having too significant of a first-mover advantage.

To the extent that ties still remain after ordering projects by maturity, the Joint Solar Parties recommend the effective date of the interconnection agreement as a proxy for queue position to maintain the integrity of the queue as much as possible. To the extent ties remain, (an exceedingly rare possibility) the Joint Solar Parties propose a random selection.

The Joint Solar Parties strongly oppose point systems. In large part, the opposition is due to the typical window required to collect all applications (such as the six-month window for the currently open block of Community-Driven Community Solar; *see* Program Guidebook dated December 10, 2021 at 17.) While appropriate in some contexts—particularly smaller blocks like CDCS or low-income community solar in the Solar for All program—the concerns with delay and the demonstrated ability of developers to submit projects well beyond available capacity in a given window shows that the long window is inappropriate for Traditional Community Solar. Recent experience in Colorado and New Jersey indicates that points-based systems can lead to long delays and uncertain outcomes that raise costs and uncertainty for all program participants. Lenders and equity partners look at first-come, first-serve with comfort when doing due diligence on projects. Random selection or points-based systems cause risk, which raises the costs of capital and equity. This risk is not accurately represented in the current hurdles rates in the REC model.

The Joint Solar Parties note that their proposed approach is designed to address lessons of the initial lottery. After the initial LTRRPP included a lottery for oversubscribed categories, the Joint Solar Parties requested post-Final Order relief for the IPA to open the program over the summer of 2018. The Joint Solar Parties made this request for two interrelated reasons. First, we believed that opening the program application window early would reduce the likelihood of a lottery. Second, opening the program early would give participants a clearer picture of the market potential and competitive landscape. A clearer view of the market potential and the competitive landscape incentivize rational behavior and lower risk. The IPA and Commission balanced obligations related to standing up a new program and the issues raised by the Joint Solar Parties, ultimately leading to the Commission denying the Joint Solar Parties' proposed relief. The program application window opened in January 2019, over 9 months after the initial LTRRPP was approved. The likely lottery and the long lead time before program opening incentivized behavior that exacerbated or created new problems, including a joint effort by ComEd and the industry to waive or adjust certain obligations under Part 466 of the Commission's rules.

As a result, 486 projects in Group A totaling over 920 MW (AC) and 433 projects totaling over 840 MW (AC) in Group B were submitted against (after allocation of discretionary capacity) 61.5 MW in Group A and 145 MW in Group B. In other words, over 93% of Group A and 82% of Group B projects were sent to the waitlist.

The Joint Solar Parties appreciate the steps the IPA and the utilities took to mitigate some of the effects of the initial lottery, but unfortunately those mitigations both had limited effect and caused issues of their own. The Joint Solar Parties can both appreciate efforts to mitigate a bad situation in the past and advocate in the strongest terms that such a situation not be repeated again.

- *CS First Block Opening (Sections 7.4.3)*

The Joint Solar Parties can see both sides on the IPA's determination that no capacity should be allocated to Traditional Community Solar during the 2022-2023 Delivery year, pursuant to the amendments in Public Act 102-0662. The Joint Solar Parties note that, despite the lack of the "at least" language, Section 1-75(c)(1) generally speaking provides minimum levels or target procurement levels and not caps and thus opening a Traditional Community Solar block on August 1, 2022 is both permitted under the IPA Act and advisable.

- *Scoring Criteria Comments (Section 7.4.5)*

The Joint Solar Parties recommend changes to the IPA's proposed scoring rubric for CDCS.

First, the IPA should provide a minimal point bonus for systems under 500 kW; while the Joint Solar Parties recognize this is a statutory criteria, there is still no explanation for why smaller community-driven community solar systems provide more benefit to subscribers, the community, or ratepayers.

In addition, while the Joint Solar Parties support points for placing solar on previously-developed land (or any "built environment" as defined above), for community-driven community solar there should be more autonomy for the local community to determine the best location. The Joint Solar Parties further note that having a site-specific RFP process is one of the primary scoring criteria.

Second, the IPA should fully define "local" requirements for the local subscriber requirements. In the experience of the Joint Solar Parties—data that the IPA also tracks through the annual report—a certain amount of churn is common as subscribers move or terminate for other reasons. There are particular issues that must be addressed related to the statutory requirement that subscriptions be portable and a commitment that subscribers remain local. Given the types of response rates the Joint Solar Parties members see in Illinois and nationwide, depending on how restrictively "local" is defined, systems that commit to local subscribers may encounter real challenges subscribing in the first instance much less meeting churn.

Third, the IPA should make the scores and narratives for submitted and selected projects available, with redactions as necessary to protect personal information. Such information will give successful and unsuccessful participants an opportunity to learn from previous submissions.

- *Unused Capacity Allocation (Section 7.3.5)*

Although the Joint Solar Parties are well aware of the solar industry's appetite for new development in Illinois with the passage of Public Act 102-0662, barriers in particular blocks—from prices far too low in the Schools Block to ramp-up time required to register Equity Eligible Contractors (much less allow EECs to begin development to the point where an EEC has projects to submit)—are likely to prevent them from being fully utilized in the 2021-22 delivery year or even the 2022-23 delivery year. The existence of barriers in individual programs, however, is not reflective of the solar industry's development appetite or the ability of the solar industry to provide cost-effective solar development as directed by statute.

In addition, the Joint Solar Parties note that the General Assembly in its wisdom decided to reconcile the competing interests of top-line Adjustable Block Program procurement goals (1-75(c)(1)(C)) and carve-outs of capacity within the Adjustable Block Program (1-75(c)(1)(K)) with a mechanism to reallocate unused capacity at the end of a delivery year. The mechanism has very few requirements other than allowing reallocation such that the statutory program minimums are not implicated.[6]

As the Adjustable Block Program both restarts incumbent programs and creates new programs such as the Equity Block and the Schools Block, the Joint Solar Parties believe there should be a balance between reallocating capacity to blocks with higher demand (reflected by a waitlist) and preserving the legislatively-directed division of Adjustable Block Program capacity. In addition, the Equity Block in particular reflects not only an allocation of resources but an overall policy goal that should not be impaired simply because the Equity Eligible Contractor program is anticipated to take longer to stand up.

To that end, the Joint Solar Parties propose the following:

- For any unused capacity in the blocks that opened on December 14, 2021 (other than Traditional Community Solar):
    - All unused capacity should remain in the Equity Block
    - For all other blocks with unused capacity, 50% of that unused capacity should remain in its original block. The remaining 50% should be:
        - First allocated to any block (other than Traditional Community Solar) that has a waitlist. If waitlist capacity exceeds this unallocated capacity, the unused capacity should be allocated in proportion to waitlist size (in kW)
        - If there is any remaining capacity, it should be allocated to all blocks (other than Traditional Community Solar) in proportion to the minimum values required pursuant to Section 1-75(c)(1)(K)

[6] The Joint Solar Parties note that the statute does not specifically require redistribution of unallocated capacity in proportion to initial allocations or preservation of those proportions: "To the extent there is uncontracted capacity from any block in any of categories (i) through (vi) at the end of a delivery year, the Agency shall redistribute that capacity to one or more other categories giving priority to categories with projects on a waitlist. The redistributed capacity shall be added to the annual capacity in the subsequent delivery year, and the price for renewable energy credits shall be the price for the new delivery year. **Redistributed capacity shall not be considered redistributed when determining whether the goals in this subsection (K) have been met.**" (20 ILCS 3855/1-75(c)(1)(K) (emphasis added).)

    - Traditional Community Solar should not receive any of that initial reallocation.
- For any unused capacity in blocks that open on or after June 1, 2022 but on or before May 31, 2023 (other than Traditional Community Solar):
    - All unused capacity should remain in the Equity Block—if substantial unused capacity remains, the Joint Solar Parties urge the IPA work with stakeholders to identify barriers and a plan to mitigate those barriers.
    - For all other blocks with unused capacity (other than Traditional Community Solar), 25% should remain in the original block and the remaining 75% should be:
        - First allocated to any block with a waitlist. If waitlist capacity exceeds this unallocated capacity, the unused capacity should be allocated in proportion to waitlist size (in kW)
        - If there is any remaining unused capacity, it should be allocated to all blocs in proportion to the minimum values required pursuant to Section 1-75(c)(1)(K)

The Joint Solar Parties emphasize that this is intended as an interim approach while certain new programs ramp up and blocks with system types that have a longer sales cycle ramp up. Although only noted specifically with respect to the Equity Block, the Joint Solar Parties recommend that the IPA seek stakeholder feedback on barriers for any program that fails to fill blocks in both 2021-22 and 2022-23. The Joint Solar Parties understand there is a substantial appetite for new development and acquisition and many developers are active in or looking at Illinois, so continually underfilled blocks may be an indication of one or more barriers to success.

For an abundance of clarity, the Joint Solar Parties intend the proposal above to be an interim approach only. The Joint Solar Parties reserve their right to advocate for a different reallocation structure for blocks opening on or after June 1, 2024.

- *Equity Block (Section 7.4.6.2)*

The Joint Solar Parties are strongly committed to the growth of a thriving Equity Eligible Contractor community in Illinois. The member companies of the trade associations that comprise the Joint Solar Parties include the developers, general contractors, and long-term owner/operators that will be hiring, partnering with, and investing in Equity Eligible Contractors.

However, while the Joint Solar Parties represent a broad range of companies that will work closely with EECs, the Joint Solar Parties do not speak for the broader EEC community. As new and emerging businesses in a highly-regulated area, EECs will also have a critical viewpoint that should be gathered, heard, and responded to.

In that context, the Joint Solar Parties have noted several components of the Equity Block that threaten to impose burdens on Equity Eligible Contractors that make it *harder* to build wealth than for other direct and indirect participants in the Adjustable Block Program. In contrast, Section 1-75(c)(1)(P) requires that "All programs and procurements under this subsection (c) shall be designed to encourage participating projects to use a diverse and equitable workforce and a diverse set of contractors, including minority-owned businesses, disadvantaged businesses, trade unions, graduates of any workforce training programs administered under this Act, and small businesses."

First, the IPA has interpreted the Equity Block as requiring the Approved Vendor submitting the project to be an EEC. The Joint Solar Parties fully support EECs taking on the role of submitting projects and administering the REC Contract *if they wish to do so*, but note that there are different and additive capital and expertise requirements to submit a project and administer the REC Contract (not to mention finance the project, whether for construction debt before selling to an end-use customer or engaging in tax equity financing). The Joint Solar Parties acknowledge that the statutory language contemplates having each Approved Vendor applying to the Equity Block be an EEC. While legislative clarification would be the most helpful step, the Joint Solar Parties recommend the IPA consider whether—at least as a temporary matter—whether the definition of "applicant" could be broader as EECs as a group build up the capacity necessary to become Approved Vendors to address this initial barrier.

Second, the Joint Solar Parties recommend that Approved Vendors that are EECs should be allowed to submit a system for a Part 1 application but sell that system to a non-EECs prior to the Part 2 application and still have that system qualify for the Equity Block. At its essence, between the Part 1 and Part 2 applications—for the most part after the award of the REC Contract but before construction commences—almost all early-stage developers sell their projects to long-term owner/operators. Non-EECs use this method to build wealth through sales without taking on the risk of securing financing or long-term operation—much less program compliance or administration of the REC Contract. Current market trends are for many solar companies to start in early stage development and grow (in both experience and capital resources, through accumulation or through being purchased) to the point of being able to take on long-term ownership and operation.

By foreclosing this pathway to systems participating in the Equity Block, EECs that wish to be developers (as opposed to solely contractors, sub-contractors, or other service providers) cannot take the wealth-building pathway of their peers through selling the system[7] between signing the REC Contract and proceeding with construction. Further, EECs due to the statutory definition (specifically majority ownership by Eligible Persons) will have certain pathways to wealth—such as purchase by a competitor or private equity—unavailable if they wish to maintain EEC status. While the Joint Solar Parties do support restrictions to ensure Eligible Persons and both gaining experience and generating wealth from the Equity Block, those restrictions should not place barriers to Equity Eligible Contractors that other Approved Vendors do not experience.

Third, the Joint Solar Parties oppose the requirement considered by the IPA that all Approved Vendors (presumably EECs) applying projects to the Equity Block would only be able to use EECs as designees. The Joint Solar Parties are concerned that developer or general contractor Equity Eligible Contractors lose most of their ability to work with experienced contractors and subcontractors that do not qualify.[8] The Joint Solar Parties fully expect the EEC community to be

[7] The Joint Solar Parties are aware that an Approved Vendor need not own the system. However, there are two key concerns. First, for Equity Eligible Contractors selling to the end-use customer, the Equity Eligible Contractor is forced to take on an Approved-Vendor-as-a-Service role that is capital intensive (due to collateral obligations) prior to selling. Second, for Equity Eligible Contractors that seek to sell the system to a third party owner of the system, it will be very difficult to meet financing expectations with the REC Contract held by an unaffiliated Approved Vendor (the Equity Eligible Contractor) at closing of tax equity and debt financing prior to the Part 2 application.

[8] The Joint Solar Parties note that many MBEs and WBEs certified by the State of Illinois' Business Enterprise Program, which have substantial contractor or developer experience outside of solar, may not be eligible as an EEC.

competitive on price and quality with other contractors and subcontractors, but the Joint Solar Parties note that any new entrant to an industry is likely to have at least some learning curve and that attracting new entrants is a goal of the broader EEC programs.

Fourth, the Equity Block does not have a blanket cure provision that allows EECs a broader ability to cure deficiencies. As many EECs will be newer entrants and/or relying on newer entrants, that cure ability will both lower the stakes of on-the-job learning as well lower the stakes with a purchaser (whether a long-term owner/operator or an end-use customer) that relies on receiving the full REC value. Similarly The Joint Solar Parties fear that EECs may face demands for more stringent warranties and more intensive diligence because of their status as new entrants, which creates a needless drag on wealth creation.

As noted above, these four issues are from the perspective of the member companies of the trade associations that comprise the Joint Solar Parties. The Joint Solar Parties urge the IPA to consider the issues above and reach out to other entities that will participate in the Equity Block, primarily the EECs. Through that outreach the IPA can design an Equity Block program that meets the statutory goal of wealth creation for Eligible Persons and the growth of a vibrant EEC community throughout all aspects of the solar industry.

Section 8 – Solar For All

- *Multifamily Building Benefits for Master Metered Buildings (Section 8.5.4.3)*

The Joint Solar Parties appreciate the exploration in this section into allowing master-metered buildings to participate. The Joint Solar Parties agree with the approach of allowing landlords to commit to passing along savings of 50% of the savings from net metering to tenants in a variety of ways.

The Joint Solar Parties note that because 50% of savings can be a moving target over the course of a year, there should be some flexibility to match the actual savings over the course of a year with associated projects. As a result, the Joint Solar Parties recommend that if the IPA believes the landlord should identify the direct benefits in correspondence to their tenants, compliance could be measured by requiring upload of annual correspondence from the landlord disclosing the value of 50% of the net metering credits, the identity and quantity spent on tenant benefits during that same timeframe, and that dollar-for-dollar any shortfall in spending during the past year would be made up in the current year. The Joint Solar Parties suggest that the IPA develop a more comprehensive list of examples of tenant benefits that would qualify by soliciting stakeholder feedback from both Solar for All Approved Vendors and customers.

- *Job Training (Section 8.8.1)*

The Joint Solar Parties note that as the various programs increase in size after Public Act 102-0662, there may be a disconnect between the number of available trainees (because job training programs take time to complete) and Approved Vendors developing and building projects. As a result, the Joint Solar Parties recommend that the IPA during the first few years after passage of Public Act 102-0662 review the hiring of job trainees of Solar for All Approved Vendors in light of the number of available qualified graduates of training programs.

- *Coordination with LIHEAP/PIPP Community Action Agencies (Section 8.8.3)*

The Joint Solar Parties further believe that allowing Community Action Agencies to work with Solar for All Approved Vendors to identify potential customers would be encouraged if Community Action Agencies were exempted from registering as designees provided that the Community Action Agencies do not generate disclosure forms on behalf of an Approved Vendor. Community Action Agencies are specifically in place as trusted resources to assistance-eligible customers and do not need to be held to the same standards as other designees, especially because customer participation is a benefit to the Community Action Agency as the administrator of programs that will allow scarce dollars to stretch further with successful installations and subscriptions.

- *Income Qualification Process (Section 8.10.4.1)*

One of the biggest barriers to fully-scaled customer participation in the Solar for All program, based on feedback from Joint Solar Parties member companies, is the burden placed on customers to prove their income.

To address this issue of Low-Income Distributed Generation incentive, the Joint Solar Parties recommends the Solar for All Program Administrator take on the responsibility of income verifying participants. Solar for All Approved Vendors spend on average 3 hours on income verification per customers, because Approved Vendors are private companies it can be a struggle to build and gain trust to get accurate information, documenting every adult in the household, can be the blocker to a successful project. By having the Solar for All Program Administrator handle the income verification, trust can be built, an efficiency in project approval can be seen, and it will result in more completed low-income projects.

With regard to low-income community solar, the current income qualification functions make it far more difficult and administratively demanding for a low-income resident to benefit from a solar program than it is for a wealthy resident. Based on the experience of a member company of one of the trade associations that takes part in the Joint Solar Parties that has enrolled over 400 low-income residents in Low Income Community Solar, nearly 20% of customers that self-identify as low-income have difficulty finding the necessary paperwork to prove their income, and some decided against completing the enrollment process due to the administrative hassle. Furthermore, this same company found that, of the customers who ultimately complete the income verification process through a tax transcript, less than 1% do not meet the 80% AMI threshold and only by a few hundred to a thousand dollars in annual income. This data suggests that low-income customers are not prone to lie about their income, and that the benefits of proving each individual person's income does not outweigh the loss in participation due to the administrative burden imposed on low-income customers. Therefore, the Joint Solar Parties urge the IPA to remove barriers to participation in Solar For All stemming from the current income verification process, such as allowing verification of other low-income assistance programs (outside of LIHEAP and PIPP) through self-attestation rather than from the program itself.

With regard to LIHEAP and PIPP, the Joint Solar Parties recommend allowing utilities to confirm LIHEAP or PIPP status. Utilities have customer flags for current PIPP participation and LIHEAP participation that is current or during the previous 12 months in order to administer Section 16-

115E of the Public Utilities Act (requiring utilities to reject enrollment of current PIPP customers or customers on or having taken LIHEAP in the last 12 months). Much like utilities confirm customer subscription information, the utilities could also confirm on a rolling basis PIPP/LIHEAP status.

In addition, under the current Approved Vendors Manual, the Low Income Community Solar (LICS) sub-program includes the additional eligibility verification method of using HUD Qualified Census Tracts (QCTs), representing areas with households earning less than 60% of AMI. However, the Joint Solar Parties recommend that this verification method be expanded to include Census Blocks that represent areas with households earning less than 80% of AMI. This expanded eligibility is made available in the Approved Vendors Manual for other sub-programs and should be included in LICS eligibility as well to further promote access to the benefits of community solar.

Without regard to those changes, the Joint Solar Parties recommend that income qualification metrics for LICS be based on the household, not individuals. The Joint Solar Parties expect this to streamline the application and verification process, in part by reducing paperwork. The Joint Solar Parties also expects that verification at the household level, rather than individual level, will increase participation since several potential customers, Approved Vendors, Grassroots Educators, and Community Action Agencies have deemed the individual-level verification as overly intrusive.

- *Consumer Protections (Section 8.11)*
    - *Elimination of post-Disclosure Cooling Off Period (so Contract and Disclosure Can Be Signed Simultaneously) Plus 14 Day Cancellation*

The Joint Solar Parties strongly support elimination of the seven-day cooling off period after the disclosure is provided because it is consumer unfriendly and unnecessarily complicates the transaction. Some member companies of the trade associations that comprise the Joint Solar Parties that participate in Solar for All have observed the required two visits within a week in between has led to confusion and distrust of the program, which is the opposite of what the IPA seeks to build with the program and its brand. Combined with the proposal to substantially shorten the disclosure form, the Joint Solar Parties believe that the required forms will be much easier for customers to engage and digest.

In the alternative, the Joint Solar Parties support an extended cancellation period for Solar for All DG projects. However, the Joint Solar Parties note that the longer the cancellation period for Community Solar subscriptions, the longer the delay between when the customer can be enrolled with the utility and begin receiving benefits. The Joint Solar Parties would recommend -ten days as a compromise between giving customers time to review materials and creating customer- and developer-unfriendly delays.

The Joint Solar Parties also note that customers should not be allowed to request contracts in any language. The Joint Solar Parties note that the Disclosure Form is currently only available in two languages (English and Spanish) and the Joint Solar Parties have concerns about providing the disclosure form for signature in one language but being required to translate the contract into another language. In the experience of the Joint Solar Parties, obtaining translations of specialized documents with industry-specific terms (some of which are required by the Marketing Guidelines or other program requirements) is expensive and time-consuming.

- *Energy Sovereignty (see also Section 8.2.4)*

The Joint Solar Parties recommend that low-income ownership (including by not-for-profits or limited liability companies serving low-income customers) should not be restricted to just direct panel ownership. Specifically, ownership for the purposes of the Energy Sovereignty programs should include ownership of a special purpose entity (SPE) that owns the system—whether by an individual customer for a behind-the-meter system or all subscribers for a low income community solar system—or through a fund holding one or more systems (with direct ownership or ownership in trust by a third party). Further, unless the limited liability company itself is the Approved Vendor, the entity providing Approved Vendor services should be allowed to bill the SPE or fund for its services provided those charges are disclosed at the time the low income customer takes ownership.

Section 9 – Consumer Protections

- *Potential Approved Vendor Management Policies/Training of Designee Requirements (Section 9.3.1)*

The Joint Solar Parties recommend that the respective Program Administrators register Designees but provide streamlined requirements to address concerns about undue burden on Designees including small and emerging businesses. The proposal in the draft LTRRPP for Designee training and management plans works best for Approved Vendors with fewer designees touching more customers and not Approved Vendors using more designees that each touch fewer customers. Such an approach—which again may work in some instances—may discourage Approved Vendors from working with small or emerging businesses that would touch fewer customers because of training and management requirements.

The Joint Solar Parties recommend that to the extent Community Action Agencies (as administrators of PIPP/LIHEAP) or units of government are used to identify potential customers or subscribers, those entities should not be required to become designees unless they also generate disclosure forms on behalf of an Approved Vendor. These entities are in a unique place of trust with residents and in particular vulnerable populations.

- *Prohibition on Balloon Loan Payments (Section 9.4.1.2)*

The Joint Solar Parties support the proposed prohibition on balloon loan payments. The Joint Solar Parties do not recommend that balloon payments be conditioned on passing through incentive payments.

- *ABP CS Minimum Contract Terms (Section 9.4.1.4)*

The minimum contract terms require "a good faith estimate of the subscription price expressed as a monthly rate or on a per kilowatt-hour basis." Many (if not most) community solar offers in Illinois allow a customer to retain a percentage of their community solar bill credit with the remainder charged as a subscription fee. While an Approved Vendor could calculate a good-faith estimate of the applicable subscription price for a given month for certain customers (i.e. those whose community solar credit is based on the Price to Compare), a better approach would be to allow such products to provide "a description of the formula used to calculate the subscription price and a statement describing whether (or in what circumstances) the customer is guaranteed to have a subscription price below their bill credit." This allows the most prevalent structure to not be forced into a "good faith estimate" of a meaningless value because it garbles the savings guarantee.

- *"Suboptimal" Design (Section 9.5.1)*

The Joint Solar Parties noted that for residential systems in particular—in addition to some smaller non-residential systems—rooftop constraints can mean that a system is far from ideally (in terms of maximum insolation) designed but still generate savings and other value for the customer. For a residential customer that is for all intents and purposes stuck with their roof design and orientation, a design may optimize available resources and provide benefits like savings—what a customer cares about—even though in an academic/theoretical sense a system oriented in a different way would produce more. For a customer that benefits from their location-optimized system, it is completely irrelevant that if they had a different house or different roof their system could have produced more.

As a result, any disclosure should note that the system is designed to the limitations of available rooftop and that the customer should confirm that the overall deal is beneficial. The disclosure should avoid any suggestion that there is a more optimal system *that the customer could have installed at their current premises.* This avoids having the customer hold an Approved Vendor to an abstract (and irrelevant) ideal design standard that would not work at the particular customer's location.

- *Disclosure – Move to Disclosure Based on MA SMART (Sections 9.5.1 and 9.5.2)*

The Joint Solar Parties strongly support moving to a disclosure based on the Massachusetts SMART program (at least in terms of length and information covered). The Joint Solar Parties have long believed that simplifying and shortening the disclosure would help potential customers better engage and digest the material.

The Joint Solar Parties further note that the SMART program allows for more flexibility in subscription sizing. Maintaining that concept but adjusting it for Illinois, the Joint Solar Parties recommend that the disclosure include an ability for the customer to authorize a subscription up to their maximum size allowed pursuant to utility tariff. This will eliminate guesswork related to subscription sizing that resulted from, for instance, ComEd's use of rolling 12-month historic usage to determine maximum sizing.

Furthermore, the Joint Solar Parties suggest further streamlining the customer's enrollment in the Solar For All program by including the customer's disclosure of their household income on the Disclosure Form itself, rather than having a separate Basic Information Form (BIF). Reducing the paperwork for Solar For All customers would help encourage potential customers to read and fully digest the information rather than skim over it.

- *Consumer Protection Working Group (Section 9.8)*

The Joint Solar Parties support implementation of a consumer protection working group and allowing that working group to be open to all entities expressing an interest in representing consumer interests. However, by not specifically mentioning the solar industry (while allowing for a catch-all "interested parties"), the Joint Solar Parties hope the IPA was not suggesting that industry would be discouraged or excluded. To the contrary: the Joint Solar Parties believe that industry will greatly benefit from hearing from the IPA and other stakeholders about the issues they are seeing in the market, the enforcement decisions/points of emphasis, and other take-homes that allow industry participants to review their own practices and better inform future decisions.

Section 10 – Diversity, Equity, and Inclusion

The Joint Solar Parties strongly support continuous improvement to the diversity of the solar energy workforce and understands that for a variety of reasons plans and measurements are a component of making that improvement. However, the number of reports proposed in the LTRRPP distracts efforts from compliance—especially for smaller and newer entities (including EECs themselves who are not exempt from reporting requirements)—and can be streamlined while remaining consistent with the statute.

The Joint Solar Parties thus propose the following approach to Equity Eligible Contractor goals and monitoring consistent with Section 1-75(c-10) of the IPA Act:

- Maintain the proposed education and initial submission of a compliance plan in late 2022 to early 2023.
- Around the end of 2023/beginning of 2024 and each year thereafter, in the applicable Approved Vendor portal provide a short-form update that allows an Approved Vendor to state whether it is on target to meet the goals in its plan and if not, which ones does it expect to fall short on and what corrective actions will it take. If the IPA determines that more action must be taken, it could require a Corrective Action Plan as contemplated in Section 1-75(c-10)(1)(B).
- Combine the backwards-looking annual report in 1-75(c-10)(1)(C) and any changes to the compliance plan required in Section 1-75(c-10)(1)(A) into a single report provided concurrently with the annual report.

The Joint Solar Parties are aware the IPA provided guidance on reporting on February 16, 2022 for Part II verification of projects. The Joint Solar Parties are highly concerned with this approach to demographic reporting, especially for Small DG projects as it relates to "per project" issues, as it creates two concerns. First, the request to report the number of hours of each project for installation and construction. While many contractors or employees do track time, it does not reflect the benefits to employees who are primarily compensated through salary and not simply hours spent installing projects. Furthermore, the proposed approach does not take into consideration the number of hours by other full time employees or contractors to bring about these projects including permitting, warehouse coordinators, and sales employees. All Approved Vendors have employees, contractors, or third-party vendors that fulfill these roles and all are vital to the success of the Illinois solar industry.

Even if sales employees, contractors or vendors were included in the per-project count, Approved Vendor employees responsible for sales, permitting, or design would not be counted as well in some cases. For example, if a full time sales employee pitches 10 projects to 10 different families, but only one moves forward (which is often the case), that employee would not be counted for the full time work they completed and for which they are compensated. Similarly, sales employees or agents may spend significant time interacting with customers interested in Large DG (including schools) or subscriptions that end up not going forward for whatever reason (including using a competitor). Not counting these employees', contractors' and vendors' time would not give the IPA a full picture in the required ethnicity and diversity reporting and the benefits of solar programs to solar workers. Second, the reporting of hours and demographics on a per-project basis for Small DG is too cumbersome, given how schedules and assignments can change daily depending on sick leave, weather, or other considerations. This can also be problematic for small companies that do not have staff capacity to track this efficiently, adding to increased costs.

In the alternative, the Joint Solar Parties would suggest quarterly overall employee demographic reporting (at least for employees whose work involves Illinois Adjustable Block Program and Solar for All systems), which can also include position titles. The Joint Solar Parties are confident this alternative proposal would give more accurate information on the employment demographics in the industry while minimizing increased costs for administration. The Joint Solar Parties also support the IPA revisiting this process in future plans to ensure it is getting the data accurately that it needs to meet state legislative requirements.

The Joint Solar Parties note that an Approved Vendor should have the option—but not requirement—to submit any of the plans or reports identified above on behalf of a group of affiliated Approved Vendors. In addition, Approved Vendors that do not have any projects selected after the LTRRPP is approved should not be required to submit any of these reports unless or until they participate in a competitive or Adjustable Block Program procurement subsequent to the approval of this LTRRPP.[9] This also avoids retroactive application of a requirement that does not commence until June 1, 2023.

[9] The Joint Solar Parties note that if an Approved Vendor has completed construction of all of its projects, the "project workforce" is likely to be zero prime contractor or subcontractor jobs. (*See* Section 1-75(c-10)(1).)