Illinois Solar Energy Association

June 27, 2017

SENT VIA EMAIL

Anthony Star
Illinois Power Agency
160 N. LaSalle Street, Suite C-504
Chicago, IL 60601

RE: ILLINOIS SOLAR ENERGY ASSOCIATION RESPONSE TO ILLINOIS POWER AGENCY'S LONG-TERM RENEWABLE RESOURCES PROCUREMENT PLAN REQUEST FOR COMMENTS

Dear Mr. Star,

The Illinois Solar Energy Association ("ISEA") appreciates the opportunity to respond to the Illinois Power Agency's ("IPA") Long-Term Renewable Resources Procurement Plan ("LTRRPP") Request for Comments. ISEA represents a diverse membership of over 100 businesses and individual advocates that promote the widespread adoption of solar throughout Illinois. Because of its diverse membership, ISEA submits the following recommendations on behalf of its residential solar working group, which is comprised of local and national installation firms focused on accelerating residential solar installations. Where in full agreement with other industry working groups, ISEA has included language and best practices that should also be observed for those specified market segments.

A. **GEOGRAPHIC ELIGIBILITY OF RENEWABLE ENERGY RESOURCES**

1. **What level of documentation and analysis should be required from an adjacent state project as part of a request that the IPA consider determining that the project is eligible to provide RECs for the Illinois RPS?**

2. **What would be an appropriate methodology for the IPA to use to determine that a project located in a state adjacent to Illinois meets the public interest criteria enumerated in Section 1-75(c)(1)(I)? For example, should it be a weighted scoring system based upon each of the criteria outlined in the law contributing towards meeting a minimum aggregate score, or does a threshold level of compliance with each criterion have to be fully demonstrated?**

   The IPA has authority to ensure procurements of renewable energy credits further the state's interest in health, safety, and welfare of its residents.[1] ISEA suggests that IPA couples this authority with the legislative findings of the Future Energy Jobs Act to ensure most effective plan implementation. General guidance provided by IPA will offer adequate information while allowing for flexibility in business models from renewable energy companies.

[1] Section 1-75(c)(1)(I) of the IPA Act.

B. **MEETING PERCENTAGE-BASED RPS TARGETS**

1. **To incent the development of new resources outside the Initial Forward Procurement requirements and the Adjustable Block Program, how should the IPA consider balancing short-term REC procurements for meeting annual RPS percentage goals with procurements of multi-year commitments for RECs? In responding to this question, please consider that the eligibility requirements under the revised RPS may reduce the availability of eligible RECs from existing projects, potentially necessitating the development of new generation.**

   ISEA recommends that the IPA prioritize long-term new build requirements in the Long-Term Renewable Resources Procurement Plan ("LTRRPP"). While the IPA may fall short of an overall RPS percentage goal in the first few years, the statutory priority and legislative findings prioritize new build over meeting short term RPS goals. The IPA will have an opportunity to adjust balance between short-term and long-term REC commitments in future long-term planning sessions. However, to meet the spirit of the legislation that calls for development of distributed resources, and allow a sustainable solar market to get established, the IPA should prioritize the long-term, new build goals over any short-term, 1-year commitment REC options.

2. **Should the IPA develop distinct procurements that target specific renewable generating technologies beyond wind and solar? And if so, what technologies?**

   ISEA recommends that the IPA focus on the renewable technologies referenced in statutory language. However, IPA could review potential adjustments in future long-term planning events as technologies change or become more viable; such as solar storage.

C. **ADJUSTABLE BLOCK PROGRAM**

<u>Blocks</u>

1. **What approaches should the IPA consider for determining the size of blocks? What are the advantages/disadvantages of having a larger block size as opposed to a smaller block size?**

   ISEA believes that whether blocks are small or large is less important than (1) ensuring that there is no lag time between blocks and (2) minimizing the drop-down in price between blocks. Blocks should be predictable and transparent as individual blocks close and subsequent blocks open. This applies to blocks for both residential and commercial solar sizes. ISEA addresses these issues in subsequent responses.

   In particular, the first block should be sized to account for the backlog of projects completed and energized between the effective date of the law and the program start date. There is significant interest in solar and potential pent up demand for DG which necessitates the first block should be larger in size than subsequent blocks.

- For subsequent block size determination, the IPA must balance its annual goals with its annual budget to ensure that there is no lag time between blocks due to budget issues. Reductions between blocks should be calibrated on future expectations of changes in costs, rather than historical figures. Such declines should be small to discourage a “rush to the door” effect from developers and ensure a smooth market.

2. **Should the category for systems between 10 kW and 2 MW be subdivided into distinct blocks? And if so, what are the appropriate break-points (e.g., 100 kW, 200 kW, 500 kW) between categories, and why?**

ISEA members agree that different sized systems should receive different REC values. Typically, smaller systems do benefit from the economies of scale larger systems do not and require larger REC values to be built. This additional REC value for smaller systems could be distributed as an adder on top of a set price for a typical 2 MW system.

ISEA recommends values for REC prices be divided into a total of six (6) subcategories differing by system size to address differing project economics and to ensure diversity in solar adoption across the residential, commercial, and industrial categories. Each category below would receive a different monetary value in exchange for a system’s RECs:

(1) 0 kW to less than 10 kW
(2) 10 kW to less than 25 kW
(3) 25 kW to less than 250 kW
(4) 250 kW to less than 500 kW
(5) 500 kW to 1 MW
(6) 1 MW to less than or equal to 2 MW

However, ISEA members disagree about whether adders are enough. Some installers think a carve-out for larger residential and smaller commercial systems is necessary in addition to differing REC values to ensure project diversity.

Smaller installers advocate for a minimum build requirement for system sized 10 kW to 500 kW of 25% of MWs dedicated to 10 kW and 2 MW sized systems. This minimum capacity requirement for 10-500 kW sized systems will encourage project size and customer diversity. Systems sized 10-500 kW are commonly less likely to get built due to their increased costs and challenges to secure financing.

As mentioned above, this carve-out for systems sized 10-500 kW is not universally supported by ISEA members. Some members felt that a carve-out for 10-500 kW systems is warranted, because it would ensure diversity in system size and in customers. They argue this will help guarantee that some of the objectives of the Future Energy Jobs Act, for example the goal “to encourage: the adoption of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can … enhance the continued diversification of Illinois’ energy resource mix…”[2] Other members argue adders alone will create the same diversity without further segmenting the market place.

[2] FEJA, Section 1 Findings (a)(1).

3. **Should the initial block or blocks have a different structure than subsequent blocks to account for expected pent up demand?**

   Yes, the initial block for each sub-block, regardless of category should be large enough to account for expected pent up demand as well as other factors such as the start-up costs for a company to participate in this program and come to scale. The initial block should also have the flexibility to "adjust" its pricing upwards if necessary depending on project uptake. An example trigger for adjusting the price could be that if the block is not filled to 50% capacity within six (6) months, then the IPA should increase the block price. The trigger-rate would depend on the size of the block. Or conversely, the IPA could utilize a release valve, so if the first block pricing over-incentivizes the market by the first block filling up within one (1) month of program launch date, the IPA could adjust the pricing downward accordingly. Any modifications to the block price or size should be communicated to participants in a timely manner to avoid market confusion. ISEA encourages the IPA to ensure a pricing in the first block that will ensure market up-take. Because it has authority to increase or decrease the block pricing, the IPA should be wary of underpricing the block. To undervalue the first block price could create confusion and delay in program uptake or solar investment.

4. **What criteria should be used to prioritize projects within a block when applications exceed the remaining available capacity in a block? Should the projects be prioritized on a first-come first–served basis or by other criteria?**

   All projects regardless of system size should be queued in the order the Program Administrator receives them. In order to facilitate this queuing, all applications should be submitted through a single application portal and should be time stamped once submitted. However, if an application is incomplete (please see our later comments regarding application qualification), then the application will be returned to the applicant to provide additional information for resubmission. So long as the requested information and/or missing documentation is received within a given time period (for example, within 5 – 10 business days from the date of the request), then the applicant will not lose his or her place in line. IPA staff and the Program Administrator should play close attention to project attrition and establish a transparent process for removing projects from the ABP that do not meet completion deadlines.

   By following this queuing process, the Program Administrator will easily be able to monitor the available capacity in each block and to properly queue systems for subsequent blocks. In the event that a project will roll-over into a subsequent block, the applicant should be notified at the time of application submission.

5. **How should the Agency handle the transition between blocks? Should a block close automatically upon being filled? Or should a block remain open until a predetermined date? Upon a block being closed, should the next block open immediately, or should there be some delay?**

   All blocks should automatically close, and the next block should open when one closes. In determining how to handle the transition between blocks, the IPA should focus on ensuring that the transition between blocks does not result in a boom/bust cycle for the industry. Specifically, there should be no lag time or delay between blocks. Whether blocks are closed automatically upon being filled or closed on a predetermined date, the subsequent block should open immediately following the prior block's closure, allowing for previously submitted and queued systems to flow into the subsequent blocks automatically.

Additionally, the statutory language of FEJA directs the IPA keep blocks open in the event funds may run out. This would allow projects to reserve future uncommitted funds and keeps the program running smoothly.[3]

Prices

At the May 17 afternoon workshop, the IPA outlined two potential approaches for setting ABP REC prices: a cost-based model, and a market observation approach.

6. **Should the ABP REC prices be based on a cost-based model which takes into account the revenue requirements for new projects in Illinois, or should it be based on market observations of pricing data as well as developments in other jurisdictions?**
   a. **For the cost-based approach please provide recommendations for data inputs that should considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.**

   b. **For the market observations approach, please identify the jurisdictions that could be considered, and any significant differentiators between those jurisdictions and Illinois that should be used to adjust results.**

   c. **Does the methodology for determining REC pricing have to be either cost-based or market observation based, or can it be a combination of both? Are there any other approaches that should be considered?**

7. **How should the approach for determining REC prices take into account geographic differences in price or cost factors, e.g. local labor/land costs etc.? How narrowly or broadly should geographic factors be considered?**

8. **Besides geography and system size, are there other factors that should be considered to create differentiated pricing?**

In response to questions 6-8, ISEA recommends that the IPA should look to the following

[3] (vi) If, at any time, approved applications for the Adjustable Block program exceed funds collected by the electric utility or would cause the Agency to exceed the limitation described in subparagraph (E) of this paragraph (1) on the amount of renewable energy resources that may be procured, then the Agency shall consider future uncommitted funds to be reserved for these contracts on a first-come, first-served basis, with the delivery of renewable energy credits required beginning at the time that the reserved funds become available. (1-75(c)(1)(L)).

indicators to help determine the initial block price for all market segments:

- **Past Procurements.** While past procurements should help inform the block prices, they should not be the only data point used to determine bock prices for several reasons, including that:
    - Not all past procurements distinguished between solar and other forms of renewable energy. The Solar Photovoltaic ("SPV") Procurement would be the most appropriate procurement for consideration by the IPA, as it was limited to distributed generation solar.
    - Certain procurement programs allowed older projects that were already built to participate, driving down bid prices. Again, the SPV Procurement would be a more appropriate procurement for consideration here, because there was a new build requirement for that program.
    - Not all past procurements distinguished between sizes effectively. With respect to the SPV Procurement, there was a price differential between 0-25 kW and 25 kW – 2 MW, but these categories should be further divided into sub-blocks as proposed above.
    - The amount of attrition and failure to fulfill speculative contracts across procurements indicates that the price may be insufficient to finance certain projects. Accordingly, the IPA should not rely too heavily on the prices in any procurement, including the SPV, solely based on the average price, but taking into consideration the full range of prices and which contracts failed to be fulfilled.

- **Other SREC Markets.** The IPA could look to other SREC markets such as Massachusetts, D.C., New Jersey to see solar installation and SREC price trends. However, the IPA should also be cautious in considering SREC markets facing a current state of oversupply, such as Maryland, Ohio, or Pennsylvania. In addition, the IPA should recognize that the Illinois solar market is unique compared to these other solar markets, where development has been incentivized for years due to robust SREC programs. Specifically, the IPA should recognize that the ABP is different from the liquid SREC markets in these states due to the fact that the ABP provides an upfront and fixed payment for a 15-year REC contract. Other states have compliance markets with different regulatory structures, different costs of living and labor costs, different power prices, and different SREC supply/demand dynamics.

- **System Components.** ISEA encourages the IPA to utilize a stakeholder process to capture the following differences for all size categories in price or cost factors, including but not limited to:
    - Equipment costs (modules, inverters, meters, etc.);
    - Labor costs (including organized labor and labor increases);
    - Interconnection costs (including increases);
    - Permitting costs (will vary based on jurisdictions);
    - Soft cost proxy or buffers to account for overhead and cost to entry, such as customer acquisition costs that may be higher at beginning of ABP;
    - Operation and maintenance;
    - Changes in other national incentives or impacts of tariffs (e.g., Investment Tax Credit

step down or elimination, or solar trade case impacts);
  - Rising interest rates on financing costs;
  - Lease rates, electricity prices and real estate costs across the state (including expected inflation in such costs);
  - Marketing and ongoing customer management costs – particularly for community solar projects;
  - Potential impact of revisions to the DG Rebate;
  - Electricity prices (accounting for variability in territory); and
  - Considerations regarding hitting the Net Energy Metering cap and how any new tariff structures, including smart meter tariff, impact the cost-benefit of solar.

- **Cost of Renewable Spreadsheet Tool.** NREL in partnership with the Sustainable Energy Advantage, LLC has developed a Cost of Renewable Spreadsheet Tool[4] ("CREST") to utilize a series of inputs as described above to determine the various costs that a solar system will entail. If this model were to be considered as a mechanism to develop appropriate REC prices (in addition to historic data from solar procurements and market data), then ISEA highly recommends the tool should be completed with stakeholder input.

- **Other Incentive Programs.** Additionally, the IPA can reference other solar incentive programs that may not traditionally operate like the Illinois' REC market, but utilize an RPS targets as a means to deploy various renewables through more fixed incentives. ISEA cautions that there are limitations to these programs, and as such, while ISEA recommends taking best practices from these programs, it does not recommend IPA approach review looking for a carbon copy example.

- **Solar Massachusetts Renewable Target ("SMART") Program[5]** utilizes a competitive procurement for large systems 1 MW-5 MW in addition to a set of indexes determined by a cost based methodology to start the program. The competitive procurement under this program should determine the correct incentive level for various system sizes. The IPA can utilize a similar approach by using its more recent procurements in tandem with certain cost analysis from stakeholder input to set appropriate rates. Additionally, the SMART program offers higher incentives for certain project types such as low-income. Utilizing a tiered incentive structure that enables certain incentives to be paired with one another may yield a useful pathway for the IPA to consider when determining how to incentivize certain project types. However, ISEA cautions the IPA in duplicating the Massachusetts' Department of Energy Resources' ("DOER") approach with respect to the design of this program, as it is currently still in its implementation phase. Accordingly, the success of the model and its underlying assumptions are yet to be proven as a functioning and proper method for incentivizing continued development of distributed generation solar.

- **NYSERDA NY-Sun Program[6]** offers a declining block incentive program structured similarly to the program that will be developed in Illinois. This program's incentive levels

[4] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/development-of-the-next-solar-incentive.html.
[5] *www.mass.gov/eea/docs/doer/rps-aps/final-program-design-1-31-17.pdf*
[6] https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sunf

were set based on set MW targets and budget allocation. The NY-Sun Program is a good example on how to run transparent public-facing incentive program, track system costs, and analyze project economics on an ongoing basis. The IPA may also want to reference the "balance of system costs" structure that NYSERDA uses to track system costs. As NYSERDA has done, it is necessary to regularly improve project timeline requirements, budgets, and administration along with changes in other policies. Interconnection standards, NEM rules, and other policies will continuously evolve, potentially rendering the program structure incompatible with policy changes. However, ISEA would urge IPA to not adopt the NY-Sun process for registering and approving projects. Requiring forms such as one-line drawings and shading percentages is duplicative, administratively burdensome, and will increase the cost and time of solar installations. As discussed in these comments, ISEA proposes a more simplified process for registration and approving projects in an effort to minimize the administrative burden and cost imposed on all participating stakeholders.

- **California Solar Initiative**[7] determined incentive levels by total budget and MW goals with the objective of insuring that various system types received reasonable paybacks. The Initiative also helped develop the Expected Performance Based Buy-Down (EPBB) system size method, which would be an essential sizing methodology that the IPA should utilize when allocating upfront incentives for smaller systems. The EPBB methodology would enable the IPA to determine the expected output of the system to forecast the level of RECs it will gather on a per system basis over the 15-year contract window. The Energize Connecticut Residential Solar PV Incentive[8] also uses the EPBB methodology when allocating its incentive to residential solar systems.

In addition to the factors listed above, the IPA should also address price variability in different electric territories and within those territories. Options for variability should be considered between territories (Ameren, ComEd, municipal, and cooperative utilities) and variability within a territory.[9]

Additionally, ISEA offers the following recommendations regarding changes to blocks and the transition between blocks:

- It is critical to the industry that there is no lag time between blocks. Whether the blocks increase or decrease in value, the industry should have continued access to RECs or be allowed to reserve their REC value, depending on system size.

- It is also critical that the values for each block do not have dramatic declines. ISEA recommends a drop down of no greater than ten percent (10%) between blocks. This will enable market stability and allow the industry to provide accurate price quotes to

[7] http://www.gosolarcalifornia.ca.gov/csi/rebates.php.
[8] https://www.energizect.com/your-home/solutions-list/residential-solar-investment-program.
[9] NYSERDA can be instructive as an example for how to calculate variability between utilities. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Megawatt-Block-Dashboards/Residential-Small-Commercial-MW-Block.

customers (modeling based on two or three block prices).

- ISEA also recommends establishing a process to create an open, transparent system to changing any block prices. The IPA can look to the ABP adoption rate in each block at a set time to determine if any given block is priced too high or too low. After first quarter of opening of the program or new block, the IPA can look to see how many RECs have been distributed or reserved in each block (10kW and under, 10kW to 25 kW, etc.). If REC distribution seems high or low, the IPA can seek to determine the cause, such as REC price, slow interconnection lines, or simply pent up demand. The IPA can then determine what action to take, including potential raising or lowing REC value. The entire process should be transparent to stakeholders to install market confidence, stability and overall program and development sustainability.

Project Development Process

9. **How much time should be allowed between system application/contract approval and when a system must be energized? The time allowed could take into account issues like (i) the seasonality of applications, (ii) delays in permitting, interconnection, (iii) equipment availability and etc. Should this time vary by size of system, geographic location, or interconnecting utility?**

10. **What type of extensions to a guaranteed in-service date should be allowed, and what additional requirements should there be for extensions?**

11. **What information about a system should be required for a system to be qualified to participate in the program (e.g. site control, local permitting, interconnection status, etc.)? Should the requirements be different for smaller systems (e.g., under 10 kW) than larger systems? Should the requirements be different depending on whether the system is being interconnected with an investor-owned utility, a municipal utility, or a rural electric co-op?**

For systems 0 – 25 kW, ISEA recommends that a project not be able to submit its application for qualification in the ABP until the system has been interconnected. Upon application submission, the applicant will be able to provide full and final information regarding system specifications and will be able to provide Proof of Interconnection to substantiate the system's mechanical completion and energization. This qualification will (1) minimize project attrition; (2) ensure equitable access to eligible projects; (3) minimize the administrative burden on all parties, including the IPA, the Program Administrator, Aggregators, installers, and clients.

For systems 25kW – 2,000 kW, applicants should be required to have reached a sufficiently advanced stage in the development process to have good insight into whether a project is likely to be viable before reserving capacity in the ABP. In Massachusetts, for example, projects proponents must demonstrate the following criteria before reserving capacity in the ABP:

- General project information (Address, owner, contact information)
- Site Control - project sponsor has an executed lease, ownership document, or exclusive option for site control

- Permits - project sponsor demonstrates that all non-ministerial permits have been secured
- Interconnection - project sponsor has a signed, executed interconnection agreement for the proposed project

12. **What development deposit/credit requirements should there be in addition to any program fees? And for how long should such requirements run?**

    The IPA should impose neither credit requirements nor program fees on program participants for systems 25 kW and smaller. Collateral requirements for smaller systems are burdensome, difficult to administer, and unnecessary if program qualification is that a system be energized and/or interconnected in order to apply.

13. **Should there be intermediate project milestones to help ensure that projects that have reserved RECs out of a block are successfully developed, and that closure of blocks due to all RECs being allocated is effectively managed? If so, how should milestones and performance standards vary between smaller and larger projects?**

    Such project milestones will only be necessary for ensuring that reserved systems (over 25 kW) meet their energization/interconnection deadline (by the end of their reservation period). By restricting participation until energization/interconnection for systems 25 kW and smaller, the parties will not need to monitor project development milestones, and will instead only need to monitor the commencement and ongoing delivery of RECs.

    Larger projects should be able to reserve a guaranteed position in the ABP for 9-12 months from the date their application is approved.

    Extensions:

    - Projects should be granted free extensions to the 9-month reservation period for the following circumstances:
        - Litigation related to project siting;
        - Indefinite extension due to delays in interconnection (only for projects that are mechanically complete); and
        - Good cause, at the discretion of the IPA.
    - Projects should be granted a single 6-month extension for any reason in exchange for an additional deposit of $25/kW (refundable upon completion).

    No site substitutions should be allowed; projects on different sites should be treated as different projects, and must separately apply for space in the ABP.

14. **For the Supplemental Photovoltaic Procurement, inverter readings were allowed for systems below 10 kW, and revenue grade meters were required for larger systems. How should these standards be updated for the ABP?**

    In the interest of minimizing the burden on all stakeholders and in maximizing the amount of RECs produced and delivered (that is, not requiring frequent manual reporting from all systems), ISEA recommends the following reporting requirements:

    The IPA should consider allowing for systems 25 kW and smaller to report via estimates and only requiring that a reading be submitted once per year to ensure the actual production is in line with the estimates. Other states allow for small projects to produce SRECs based on estimates, and the IPA could ensure actual production by requiring an annual reading. For their SREC programs, both D.C. and Maryland allow for systems smaller than 10 kW to report via estimates.

    For systems over 10 kW, the IPA could consider requiring systems to have an online system monitoring ease automatic reporting. Massachusetts imposes this requirement on systems over 10 kW in its SREC programs.

<u>Clawback Provisions</u>

15. **What claw back provisions would be appropriate for ensuring that RECs are delivered while not creating potentially prohibitive additional costs or burdens?**
16. **What would be reasonable circumstances to allow for the waiving of clawback provisions? (e.g., fires, severe weather, etc.)**

17. **Should clawback provisions vary based on system size? If so how should these provisions vary?**

18. **How should clawback provisions carry over when a system and/or system location is sold?**

    ISEA recommends Illinois follow other state programs, and should not require excessive clawback provisions for systems less than 25 kW. Clawback provisions for small-scale systems have been determined to be administratively burdensome and unnecessary. For systems less than 25 kW, there are an abundant amount of scenarios and variables that will prohibit the IPA to putting forward a standardized process for enforcing clawback provisions on these customers. For example, a residential homeowner may choose varying financing mechanisms to install and obtain a solar system such as a power purchase agreement, lease, loan, or outright buy the system with cash on hand.

    When it comes to determining whom may be responsible for this clawback provision and when it can lead over a dozen to thousands of entities that the IPA would need to track to insure that this clawback provision is enforced. This could lead to a point where the administrative burden to follow the various entities liable for the clawback penalty may outweigh the revenue the IPA may be able to recover through this provision. With this in mind, it may be more imperative for the IPA to accurately track or correctly forecast the number of RECs that IPA can count on when procuring its incentive to enable less than 25 kW systems. A program that has reliably achieved this methodology, one may look at the first program that enabled the proliferation of small-scale distributed generation, the California Solar Initiative, as discussed above which developed the Expected Performance-Based Buy Down methodology that is also used in Connecticut as discussed earlier.

However, it is understandable that the IPA needs assurances that the solar system's enrolling in the ABP will meet the criteria of the program and the many obligations the IPA must meet in order to administer it. Therefore instead of developing unique or burdensome clawback provisions, the IPA should develop requirements for solar systems participating in the program that they must prove and agree to upfront to be able to obtain their incentive such as a permanency provision. The California Solar Initiative Program Handbook on pages 33 and 34[10] go over requirements that the IPA should consider adopting to insure that the solar assets providing RECs to the IPA's program from small systems throughout the program.

ISEA also recommends waiving the clawback provisions for the Solar for All DG incentives. However, clawback provisions would remain in place for community solar or larger non-profit installations.

Regarding clawback provisions on systems above 25kW, the solar industry would recommend a technical conference to discuss details and learn from best practices in other states.

Additional Feedback on ABP:

In addition to questions above, ISEA also recommends the IPA manage the flexible 25% of funds in line with goals of the statute. The FEJA allows IPA to determine what to do with 25% of the MWs dedicated to the photovoltaics. ISEA recommends that the IPA give itself flexibility in the long-term plan to determine what to do with that 25% after the roll out of the ABP. This would allow time to see how the different markets are developing or responding, which can provide insight into how to best manage goals of improving public health and environment and diversifying energy supply. Without some time and experience, it is hard to advise on what the priorities should be.

Consumer Protections

19. What consumer protection elements should the IPA consider adopting as part of the ABP program? How should those elements differ between distributed generation and Community Solar?

ISEA acknowledges the IPA has an important role in ensuring the implementation of the ABP program is done responsibly, however, ISEA encourages adoption of consumer protection

[10] California Public Utilities Commission (February 2016). California Solar Initiative Program Handbook http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10415

elements that are mindful of existing law and do not create potentially duplicative or conflicting requirements for solar companies. There is an extensive body of local, state and federal law that already regulates solar providers. Federal and Illinois law governs virtually all aspects of a solar transaction, including any business practices associated with the sale of any system that would be a part of the ABP program. Specifically, up to fourteen (14) federal laws[11], eight (8) Illinois consumer protection laws[12], and state licensing laws regulating installers, contractors, and lenders already regulate solar companies that would participate in the ABP program, install distributed generation.[13]

ISEA recommends that IPA focus its consumer protection efforts on ensuring standardized disclosures to consumers. This approach addresses the sources of consumer risk in a manner that still allows smaller solar companies to comply with the law while being able to provide a competitively priced product to Illinois consumers. ISEA recommends standardized, concise, consumer-friendly disclosure forms for ABP program-supported solar transactions. These disclosure forms would summarize key terms of conditions of a solar transaction in easy-to-understand, consumer friendly language. We encourage the IPA to adopt Solar Energy Industry Association's ("SEIA") model disclosure forms for solar purchases, leases, and power purchase agreements.[14] The SEIA model disclosure forms would address consumer confusion and provide an opportunity outside of a solar contract or a sales presentation for a consumer to review key terms and obligations of a solar transaction. Doing so would align Illinois with existing industry best practices and other states that have adopted consumer protection proposals based on the SEIA model disclosure forms.

ISEA also recommends the IPA could ensure adherence to consumer protection rules by requiring registration and providing compliance guides for participating companies. Registration requirements are common regulatory requirements, and solar companies are already required to be licensed with Illinois local licensing. IPA could maintain registration to increase ease of

[11] CAN-SPAM Act (regulating email solicitations); Consumer Leasing Act (regulating solar lease disclosures); Electronic Funds Transfer Act (regulating electronic payments made pursuant to any solar agreements); Electronic Signatures Act (regulating the use of electronic signatures on any solar agreements); Equal Credit Opportunity Act (safeguarding against anti-discriminatory lending practices); Fair Credit Reporting Act (regulating the use of credit scores in solar transactions and any credit reporting in connection with making payments on solar loans or leases); Magnuson-Moss Warranty Act (regulating solar warranties); Federal Trade Commission Act (prohibiting unfair and deceptive marketing and sales practices); Gramm–Leach–Bliley Act (safeguarding any personal information submitted to solar energy companies); Service members Civil Relief Act (protecting Service members from adverse action in connection with financing extended for solar financing); Telemarketing Rules (federal rules governing telemarketing activity); Telephone Consumer Protection Act (federal law governing telemarketing activity); Dodd-Frank Wall Street Reform and Consumer Protection Act (regulating unfair, deceptive or abusive trade practices in connection with any solar financing); Truth in Lending Act (requiring key disclosures in connection with loans for solar energy systems).

[12] Illinois Consumer Fraud and Deceptive Business Practices Act (815 ILCS 505/1 et seq.), right of cancellation for home solicitation sales (815 ILCS 505/2B), a requirement that home improvement contractors complete work or return money upon demand (815 ILCS 505/2Q), the Illinois Consumer Installment Loan Act (205 ILCS 670/1 et seq.), the Illinois Interest Act (815 ILCS 205/0.01 et seq.), the Home Repair and Remodeling Act ("HRRA") (815 ILCS 513/1 et seq.), the Electronic Mail Act ("EMA") (815 ILCS 511/1 et seq.), and the Illinois Personal Information Protection Act (815 ILCS 530/1 et seq.).

[13] Illinois establishes minimum qualifications and standards for all installers (83 Ill. Adm. Code 468 et seq.), contractors (225 ILCS 335 et seq.) and lenders (205 ILCS 670/1 et seq.) that interface with Illinois consumers.

[14] A copy of the Solar Energy Industry Association's model disclosure forms are available at http://www.seia.org/research-resources/solar-transaction-disclosures.

communication with participating companies, however ISEA recommends that any DER registration requirements be limited to essential organizational information needed to identify and correspond with ABP providers. Further, the IPA could consider developing compliance guides for solar companies seeking to operate in Illinois such that they are aware of relevant existing Illinois and federal law that would apply to their business practices. These compliance guides could also inform participating ABP providers with information on what the industry is already doing to ensure quality consumer experience in Illinois.

Most importantly, the industry is leading in safeguarding consumer rights in the solar industry. ISEA is working to ensure that consumer protection is at the forefront of our growing state solar industry. As an affiliate of the Solar Energy Industry Association (SEIA), ISEA has adopted professional codes of conduct and complaint resolution process to ensure that consumers can be confident that ISEA business members and the Illinois solar industry work is of the utmost quality. For example, ISEA has adopted the following national standards and processes:

- **Solar Energy Marketplace Standards:** ISEA has adopted SEIA's Solar Business Code, the national standard of conduct that provides guiding principles for the U.S. solar industry market space.[15] The Code is a comprehensive rulebook covering a broad range of state and federal law and regulations on advertising, marketing & consumer interactions, and contracts. The Code includes language related to unfair, deceptive, or abusive acts or practices; accuracy and clarity in advertising; sales and marketing interactions; and contracts including information on Renewable Energy Certificates. All ISEA and SEIA members agree explicitly to follow and be bound by the Code.

- **Solar Business Code of Ethics:** ISEA has adopted SEIA's Code of Ethics, which ensures our members are committed to conducting business in an ethical manner and upholding the integrity of the solar industry.[16]

- **Complaint Resolution Process:** ISEA has adopted SEIA's Complaint Resolution Process, which is a tool to resolve complaints regarding violations of the Solar Business Code.[17] Process reviews are controlled by SEIA and independent resolution panels. The process allows any consumer to submit a complaint to SEIA for review and action. If a complaint raises criminal conduct or an issue better handled by a government regulator, SEIA will pass the complaint onto the appropriate state or federal government entity. The SEIA Code and complaint process is meant to supplement government regulation, not supplant it. We continue to work with state and federal offices to make sure consumers experience solar as a success story.

[15] SEIA Solar Business Code can be found here: http://www.seia.org/policy/consumer-protection/seia-solar-business-code.
[16] SEIA Code of Ethics can be found here: http://www.seia.org/policy/consumer-protection/code-ethics.
[17] SEIA Complaint Resolution Process can be found here: www.seia.org/sites/default/files/SEIA%20SBC%20Complaint%20Resolution%20Process%20v%201.1%20-%20Jan%202016.pdf.

- **Telemarketing Rules**: ISEA adopts SEIA's Telemarketing Rules, which include clarifications and definitions on 'Spoofing,' Telemarketing/Unwanted Calls, and Lead Generation.[18]

The solar industry prides itself on its record of consumer protection and believes that success requires informed consumers who fully understand transactions before entering them. From our small installers to our board of directors, ISEA is fully committed to consumer protection. Our industry is booming, creating new choices for Illinois residents and businesses. To ensure a quality, sustainable market we are committed to protecting the consumer while ensuring solar can remain affordable and viable.

20. Should the ABP require the use of a standard disclosure form? If so, what elements should that form include?

ISEA would support a standardized disclosure form for ABP participants that is concise and consumer-friendly. The form should only require the most important information a consumer would need to know before entering into a solar transaction. The form should simplify the underlying agreement – not require disclosures of volumes of information that provides limited value to consumers that could potentially confuse them. SEIA's Consumer Protection Committee developed a series of model disclosure forms that we would recommend form the basis for any standard disclosure form for systems participating in the ABP program.

Borrowing from the SEIA disclosure form, the elements of the form should include:

- The name, state license number and contact information for the solar installer;
- The name, state license number and contact information for the warranty and maintenance provider if different from the solar installer;
- Key price terms, the system payment schedule, and any fees the consumer would be responsible for;
- A clear disclosure of any payment escalators;
- System design assumptions (e.g. system size, estimated annual production, estimated annual degradation, connectivity to the grid, eligibility for any state incentive or net metering programs);
- A disclosure of any UCC filings made in connection with the system;
- A summary of responsibilities for system repairs;
- A description of any roof warranties;
- A summary of any system transfer provisions in connection with a sale;
- A description of any system guarantees;
- A description any utility price assumptions and savings assumptions used in the sales presentation (not a required, predetermined price, but a way to allow for transparent understanding of calculations that vary by company);

[18] SEIA Telemarketing Rules can be found here: http://www.seia.org/sites/default/files/SEIA%20Industry%20Alert%20-%20Telemarketing%20Rules%20-%20Jan%202016_0.pdf.

- A disclosure concerning the ownership of any renewable energy credits; and,
- A description of the consumer's rescission rights;

These disclosure forms however should not include a mandated, one-size-fits-all formula or savings calculator. Because business models and financing solutions differ widely, ISEA recommends following the method laid out in the SEIA model disclosure form that provides for a clear transparent explanation in how a business developed the savings assumptions.

21. Are there examples from other states of model approaches to consumer protection, and/or lessons learned regarding insufficient consumer protections?

ISEA remains confident that consumer protection will be a priority as the Illinois market expands because of the industry-led leadership coupled with existing, sufficient consumer protections under local, state, and federal law. Depending on a solar company's business model, a solar company operating in Illinois would potentially be subject to at least fourteen (14) federal laws, eight (8) state consumer protection laws, and state licensing laws regulating installers, contractors and lenders that would interface with consumers.

From the solar industry's experience in other states, the lesson learned is that state regulators can sometimes fail to enforce existing laws that regulate solar transactions, or could improve coordination across regulators in a way that reflects the overlapping regulatory framework that solar companies navigate. The most common consumer risk associated with solar transactions is consumer confusion concerning key terms and conditions of their solar agreement. Thus, any steps that can be taken to ensure that consumers understand a solar transaction are important.

The SEIA Consumer Protection Committee has developed model disclosure forms that have recently been adopted by a number of states' solar consumer protection proposals. The experience of other states' attempts to enact new laws to regulate the solar industry are instructive here as states like New Mexico[19] and Florida[20], for example, adopted solar consumer protection laws that only required disclosure forms based on the Solar Energy SEIA model disclosure forms. New Jersey's Bureau of Public Utilities is also considering adoption of the SEIA forms.[21] States are adopting these concise policies to compliment, not duplicate, federal and state law that covers virtually every aspect of a solar transaction. Thus, the solar industry recommends that Illinois consider a similar approach by encouraging standardized disclosures of key contract terms and conditions based on the SEIA model disclosure forms.

Further, ISEA recommends that solar contractors who offer distributed generation services

[19] A final version of H.B. 199 is available at https://nmlegis.gov/Sessions/17%20Regular/final/HB0199.pdf.
[20] A final version of S.B. 90 is available at https://www.flsenate.gov/Session/Bill/2017/90/BillText/er/PDF.
[21] The forms under consideration before the New Jersey Bureau of Public Utilities is available at http://njcleanenergy.com/files/file/Appeals/1f%20-%20NJCEP%20Solar%20Lease%20Disclosure%20Form%20v5.pdf.

behind the meter (just as energy efficiency contractors work behind the meter) be treated equitably under the consumer protection rules and regulations. Marketing materials should not be individually screened or collected for approval by IPA because solar contractors are already subject to Illinois marketing laws. To do so would be administratively burdensome and set confusing, and potential incongruous business standards and rules.

Finally, ISEA recognizes there will be different and unique consumer protection considerations for community solar offerings and especially within the Solar for All low-income program.

In addition to the responses to the IPA's questions, ISEA offers the following comments for Program Administrator, Administrator, and on the role of aggregators.

Program Administration and Program Administrator

With respect to the Program Administration the Administrative model, and the Program Administrator, ISEA offers the following recommendations:

- **The IPA follows its Model #2 as proposed in the Adjustable Block Programs workshop for systems under 25kW.** That is, Aggregators will submit batches of systems to the Program Administrator for approval under the Program, and Aggregators will contract with the utility for batches of individual systems. This model will minimize the administrative burden on all market participants and eliminate the need for the utility to contract with individual systems/individual system owners. Moreover, this will separate the contracting component from the Program Administrator's role. The Program Administrator's sole responsibility should be to process applications and to manage the overall administration of the program from an application standpoint. The contracting should occur separately and between the utility and Aggregators.

- **The Program Administrator meet the following qualifications:**
  - Experience with Distributed Generation system qualification and certification, such as the Program Administrator for PennAEPS.
  - Experience with issuing incentives and working with Aggregators.
  - Ability to build/modify existing an online application that can provide status reports to applicants and manage blocks and system queuing.
  - Require Program Administrator to solicit and accept feedback from applicants on initial application process (through beta testing) and for continued/ongoing improvements to program design and application process throughout life of ABP.
  - Online Application & Certification Goal: To create an online application to streamline process and save cost and time, ensuring that the application:
    - Minimizes supporting paperwork requirements - allow applicant to make certifications on application to eliminate need for documentation.
    - Maximizes the amount of the process to be completed and managed online in simplified and standardized format.
    - The IPA could establish a pre-application before final rules are set, so systems can submit this year or early next year so that there is not lag and a subsequent rush at program opening.

- **Administration/Tracking Progress**
  - Block Closures and Queuing – The IPA and Program Administrator must provide the market with adequate transparency and notice into status of blocks filling, including queuing for subsequent blocks.

<u>Role of Aggregator</u>

With respect to Aggregators in the program, ISEA offers the following recommendations:

1. Under its Administrative Model #2, the IPA should require all program applications to be submitted either through an *X number of system* batch minimum or through a third party aggregator. Primarily, third party Aggregators will participate as the applicant and manager on behalf of aggregated DG resources, both with the Program Administrator in the application process and with the utility in the contracting process and ongoing contract management. As Aggregators have facilitated bidding and ongoing contract delivery and settlement under both Illinois' SPV and DG procurements, Aggregators can serve a similar function in the ABP by:
   a. Submitting ABP applications to the Program Administrator on behalf of the client to streamline the application, certification and contracting process, which will alleviate the burden on the Program Administrator and on the contracting utilities (which, in turn, helps to control program costs);
   b. Facilitating payment to distributed system owners (a lump sum is paid to the Aggregator, which can be distributed to owners by the Aggregator);
   c. Facilitating ongoing management and delivery of RECs, including operational support for meter reading submissions where applicable.

2. Follow similar but more stringent Aggregator Qualification requirements from SPV Procurement Plan to impose parameters on Aggregator participation and address Consumer Protection issues (as there are Qualified Installer parameters, there should be Qualified Aggregator Parameters). Some recommendations are as follows:
   a. In relevant part, the SPV Procurement Plan defines an Aggregator as a "third-party (i.e., non-system owner) that (i) owns or plans to acquire either unconditional title to or rights to legally transfer renewable energy credits from distributed renewable energy devices through contracts with multiple system owners, and (ii) is willing to contract with the [*utility (for purposes of the ABP)]* and accepts [*its*] standard [] terms as well as procedures for contract administration." Notwithstanding the foregoing, the IPA should allow for certain system owners possessing a minimum number of systems (i.e., 1 MW minimum) to apply directly as their own Aggregator, so long as they (1) satisfy other Aggregator pre-qualification requirements as provided below and (2) are able to contract in batches with the utilities.
   b. Aggregators (whether third party or submitting batch systems on their own behalf) must pre-qualify with the IPA by meeting several provisions. At a minimum, an Aggregator must demonstrate to the IPA that the Aggregator is:
      i. Registered to do business in the State of Illinois;

ii. Able to ensure meter data is collected from aggregated systems;
iii. Is or will be registered with GATS and/or M-RETS upon contract award; and
iv. Satisfies a minimum financial requirement.

c. The Procurement Administrator will maintain a website where a list of pre-qualified Aggregators will be available to interested parties (i.e., installers and homeowners who will need to use a pre-qualified Aggregator in order to participate in the ABP).

D. COMMUNITY SOLAR

__Geographic Considerations__

1. **Should the IPA consider taking steps to encourage projects to be located geographically closer to subscribers? If so, what steps should be considered?**

2. **How can geographic diversity be ensured?**

IPA should not encourage projects to be located geographically close to subscribers. A subscriber proximity mandate (or even incentives) will warp the market, raise costs for subscribers and the program overall, and work against statutory goals for geographic diversity.

A proximity mandate would encourage developers to only build projects in densely populated areas where there are likely to be sufficient subscribers. This would create a land "rush" in a few key municipalities and neighborhoods, raising land acquisition costs significantly. A similar subscriber "rush" would inundate customers, creating consumer protection issues.

While urban areas are being inundated with marketing materials, people in rural areas would see far fewer opportunities to subscribe to a project because densities are too low to foster development. The lack of geographic restrictions in the statute makes community solar very attractive to Southern Illinois, as communities with sparse population are not dependent upon a small population of neighbors to make community solar a reality. Proximity mandates would prohibit rural communities from participating in community solar, working against the Act's geographic diversity clause.

As such, IPA shouldn't have any rigid proximity requirements in the first LT Plan. The only restriction should be that the project be located in the same utility service territory as the subscriber. Interconnection/congestion hurdles and land costs will naturally distribute project locations statewide. If the Agency observes that projects are not geographically distributed, the IPA could revisit this in the 2nd long-term plan.

As mentioned above, geographic diversity will happen due to a variety of factors, and IPA should not be overly prescriptive in this area. The requirement that projects be located in the same utility service territory as subscribers will ensure general distribution across the state. Further, interconnection costs will naturally distribution also; as upgrade costs for any particular substation are triggered, projects will be sited in other, more cost-effective areas. The DG rebate will also transition to an incentive based on locational value once the 5% NEM cap is reached.

As such, IPA shouldn't have any rigid geographic requirements in the first LT Plan. The only restriction should be that the project be located in the same utility service territory. If the Agency observes that projects are not geographically distributed, the IPA could revisit this in the 2nd long-term plan.

Project Application Requirements

3. **Should Community Solar projects have different application requirements than a comparably sized distributed generation project? What level of demonstration of subscriber interest should be required prior to approving an application from a Community Solar project?**

4. **How should co-location of Community Solar projects be addressed in light of the definition of community renewable generation projects that is capped at 2 MW?**

Community Solar projects should not be required to demonstrate subscriber interest at the time of the project's application to the program. A minimum subscription requirement at the time of application would likely have unintended consequences.

- Subscriber minimums present a significant risk to consumers. Consumers should not be required to subscribe to a project whose economics are unknown and subject to change based on future REC prices that are available when a developer has reached an arbitrary subscriber threshold. Developers should be able to market subscriptions to consumers with a full understanding of the project economics.
- Customer acquisition is a significant expense, particularly for projects with significant residential customers. A requirement to make this investment for a project that has neither been approved nor awarded capacity represents a risk that most experienced and responsible developers and/or their financial investment partners will be unwilling to shoulder.
- It is problematic to require tens of thousands of customers to enroll in projects that may or may not come to fruition, or which may not come online for years. Such an outcome will undoubtedly result in public frustration and dissatisfaction with the program.

Co-location can lower costs for consumers through reduced zoning, permitting and other development costs. These savings are passed on to consumers and ratepayers, resulting in more solar at lower cost. However, ISEA is cognizant that unlimited co-location could undermine the notion of Community Solar, so we propose that co-location be limited to 4-5 projects.

Community Solar Blocks

5. **Should the design approach for blocks for Community Solar vary from that used for Distributed Generation (e.g., size of blocks, criteria for prioritizing applications)?**

ISEA recommends against creating separate block criteria or prioritization measures for community solar applicants. Fewer sub-divisions make the development process more predictable and cost-effective for developers and subscribers. Blocks should also account for the full development, customer acquisition, permitting, zoning and finance timelines for CS projects.

6. **What would be reasonable assumptions to make for the cost of acquiring and maintaining subscribers? How will these costs be expected to vary over time (e.g., the difference between initial subscriber recruitment and managing churn rates)? How will these costs differ between managing residential and commercial subscribers?**

   ISEA has no comment on this topic.

7. **Should the value proposition to the customer for a subscription to a Community Solar project be more, or less, attractive than for a comparable sized DG system at the customer's location?**

   ISEA has no comment on this topic.

<u>Development Milestones</u>

8. **Should the time allowed for Community Solar project development be different than for comparably sized Distributed Generation systems?**

   Community solar projects face longer project development timelines than other similarly sized projects, particularly if those other projects are customer-sited facilities. Behind-the-meter projects face many fewer hurdles in terms of siting, permitting and zoning, since they already have site control and they will likely have lower interconnection costs since they are making use of some or all of the generation on site. ISEA recommends allowing 12-18 months for project development.

9. **What project development milestones should be required to demonstrate sufficient levels of subscriber interest before a contract may be terminated?**

   ISEA has no comment on this topic.

<u>Residential versus Commercial Interest</u>

10. **What, if anything, should the IPA consider to ensure robust residential participation in Community Solar?**

    ISEA has no comment on this topic.

11. **Should REC pricing vary based on the portion of the project that is residential? How can this be verified, and what would be required over time to ensure ongoing residential**

participation?

ISEA has no comment on this topic.

12. **Should project application/viability requirements be different based on the mix of residential and commercial customers?**

    ISEA has no comment on this topic.

13. **Are there additional considerations that should be made for projects that are entirely subscribed with commercial customers, or entirely subscribed with residential customers?**

    ISEA has no comment on this topic.

We thank the IPA for its efforts on the LTRRPP and look forward to the continued development of renewable resources in the State of Illinois.

Best Regards,

Illinois Solar Energy Association