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Illinois Power Agency
Attention: Anthony Star
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Re: Request for Comments to Long-Term Resources Procurement Plan

Mr. Anthony Star:

On behalf of United States Solar Corporation ("**US Solar**") and Acciona Energy USA Global LLC ("**Acciona**"), Chapman and Cutler LLP hereby submits the following comments in response to the Illinois Power Agency's ("**IPA**") Request for Comments issued on June 6, 2017. As active developers of solar facilities in various jurisdictions throughout the United States, US Solar and Acciona welcome the opportunity to provide their collective perspective and experience with respect to the matters currently before the IPA.

Background

The Future Energy Jobs Bill (SB 2814) (the "**Act**") was enacted into law on December 7, 2016, as Public Act 99-0906, with an effective date of June 1, 2017. Among other things, the Act calls for updates to Illinois' renewable portfolio standards ("**RPS**"), net metering, and energy efficiency standards, as well as a new zero emissions credits plan. Under the Act, the IPA is charged with developing various plans and Illinois' investor owned utilities are charged with collecting and distributing funds and entering into contracts for the procurement of emissions credits.

As a key component of the Act, the IPA is required to conduct a long term renewable resources procurement plan (the "**LTRRPP**"), which will set forth the rules for procuring renewable energy credits ("**RECs**") from renewable energy sources, such as distributed generation and community solar. In order to assist the IPA with the development of the Long Term Procurement Plan, the IPA elected to hold a series of workshops to discuss with interested stakeholders its proposed revisions to Illinois' RPS on May 17, 18 and 24, 2017 (the "**Workshops**"). Following the Workshops, the IPA issued a request for comments to interested stakeholders on the topics discussed at the Workshops. US Solar and Acciona's joint comments are provided below.

Comments

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 Agency consider determining that the project is eligible to provide RECs for Illinois RPS?

Whatever requirements the IPA seeks to impose, it should be mindful that the purpose of the Act is to incent solar development in Illinois. Therefore, to the extent it allows projects located in other states to be eligible to provide RECs for the Illinois RPS, it should take care that it does not inadvertently diminish the incentive for developers to build in Illinois.

With respect to Community Solar projects, we believe the eligibility requirement should be that the project must interconnect directly to the distribution system that serves customer load in Illinois. For example, if a project is connected to a distribution feeder line in an adjacent state to Illinois, the interconnecting substation should be located in the state of Illinois. We believe this requirement is consistent with the intent of the Act, and will help to promote the goals of increasing fuel and resource diversity in the State of Illinois, even for projects that are physically located in adjacent states.

B. MEETING PERCENTAGE-BASED RPS TARGETS

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

The IPA should not develop procurements that target any specific renewable generating technology that is not expressly provided for under the Act.

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?

We believe that smaller block sizes may incent high-risk, low-probability projects to apply for earlier blocks to capture higher REC pricing before the projects have conducted adequate due diligence or received appropriate levels of commitment related to financing. This behavior may result in many of those projects never coming to fruition – see New York as an example. In contrast, we believe that larger block sizes will create a level playing field for developers and will provide developers with the time necessary to perform adequate due diligence prior to application.

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?

The Act provides for distinct blocks for RECs procured pursuant to the "Solar for All Program," community solar and distributed generation; we do not believe further distinct blocks are necessary or contemplated by the Act. Since the primary goal of the procurements is to procure RECs to satisfy the RPS requirements, we believe that creating distinct categories (with differences in pricing among the categories) is inconsistent with the Act's stated goals, and an inefficient use of ratepayer funds. We believe that creating two categories (one for <10kW (which is generally residential distributed generation) and one for >10kW) may be appropriate if there are no differences in REC pricing among the categories.

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

We believe that pent up demand can be accounted for by creating larger, equal-sized blocks.

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?

While we believe that a first-come first-serve approach is appropriate, the IPA should establish clear criteria for bidder qualification and application completeness. We believe such criteria should include experience and prior development success, demonstrated site control, interconnection application or initial assessment, and sufficient creditworthiness. We believe that using such criteria will help avoid pitfalls faced by states such as New York where inexperienced and unqualified bidders have clogged the development pipeline, which has resulted in very limited renewables development.

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?

Similar to the approach taken by other states, we believe that upon being filled, a block should immediately close and the next block should immediately open.

<u>Prices</u>

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?

The IPA should price-check the REC prices with developers and/or financiers to ensure viability prior to the program launch. Establishing some criteria that the program must be financially viable is important. This can be accomplished by a either cost-based or market-based approach.

i. **For the cost-based approach please provide recommendations for data inputs that should be considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.**

Capacity factor would be an appropriate input. However, we note this is a difficult factor to consider since it is highly customized per project and fluctuates across design standards as well as geographic locations. Bill credit / net metering revenue would also be an appropriate input. However, this will be very difficult considering the deregulated market nature of Illinois.

ii. **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.**

Minnesota would be a good jurisdiction to consider for community solar. The community solar program in Minnesota has been successful in deploying a large amount of new solar generation capacity. The combination of bill credit value and REC value resulted in projected initial developer revenue between $100 - $140 per MWh, a rate that is financially viable, and still provided an attractive option to ratepayers.[1]

iii. **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?**

It can and should be both. The IPA should work with developers and/or financiers to ensure viability prior to the launch of the program. If this is not possible, then the IPA should work with an impartial third party (for example, Marathon Capital) to estimate required REC rates for project viability, considering cost-based concepts and market-specific concepts that include projected bill credit / net metering revenue.

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?

For community solar, not at all. This can be effectively captured in a project size classification approach.

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

We strongly oppose a "residential" adder. We believe a residential adder would create undue complexity into the REC pricing. Moreover, any pricing difference for residential can be addressed through a bill

[1] Enhanced applicable retail rate bill credit, which is inclusive of REC value, is equal to approximately $12 cents for commercial and approximately 15 cents per kwh for residential in 2017, subject to future changes of retail rate. We believe this rate is financeable and has led to the significant deployment of new solar in Minnesota.

credit. We would support a construct that would allow projects that produce more kWh/kWp to receive that value. In other words, a single-axis tracker project that is expected to generate 10,000 RECs should receive more total value in RECs than a fixed tilt project of the same nameplate capacity that is expected to generate 8,000 RECs.

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?

We believe that 12 months (for Distributed Generation) and 24 months (for Community Solar) are reasonable times for each project type, given the differences in interconnection for each project type. Extensions should be permitted for force majeure events, which should include delays in permitting or interconnection that are outside of the developer's control.

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

Extensions should be permitted for force majeure events, which should include delays in permitting or interconnection that are outside of the developer's control.

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?

Requirements should include:

a. Binding site control (proof of lease, not a non-binding LOI)
b. Proof of a submitted interconnection application
c. Fees paid

We do not believe the requirements should differ depending on whether the system is being interconnected with an investor-owned utility, a municipal utility, or a rural electric co-op.

For projects under 10 kW, which are generally distributed generation, the requirements should include:

a. Host customer signature on application
b. Fees paid

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

Similar to the Initial Procurement, we believe that the deposit/credit requirements should be $15,000/MW for solar. The full deposit/credit requirement should either be refunded upon project completion or re-financed into performance assurance for the REC contract. We note that in some jurisdictions, the utility's deposit requirements allow developers to fund the deposits directly into an escrow arrangement between the developer, utility and the developer's financiers. This structure has allowed developers to obtain financing with respect to such deposits, and has greatly facilitated the development process. We would highly recommend that the Illinois utilities incorporate this type of mechanism.

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?

We believe that intermediate project milestones are not necessary. To help ensure that projects with a high likelihood of success remain in queue, consider decreasing the refundable portion of the deposit over time. For example:

a. Refund 80% of deposit/credit requirement if developer cancels project within the initial 6 months;
b. Refund 50% of deposit/credit requirement if developer cancels project between 6-18 months; and
c. Refund 100% of deposit/credit requirement if developer completes project within the permitted time.

<u>Clawback Provisions</u>

14. What clawback provisions would be appropriate for ensuring that RECs are delivered while not creating potentially prohibitive additional costs or burdens?

IPA should establish a reasonable performance guarantee that contains clawback provisions on a per MWh basis, such that the initial program deposit amount could roll over into the security amount. For example, a $15,000/MW deposit should also be sufficient security amount for a clawback provision.

15. What would be reasonable circumstances to allow for the waiving of clawback provisions? (e.g., fires, severe weather, etc.)?

Only force majeure events that result in project termination and shutdowns.

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

These should only vary between large and very small projects. For instance:

>10 kW should all have the same provisions.

<10 kW should be an estimated production basis without clawback (too hard to enforce).

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

Clawback provisions should be transferable upon project sale. Any security or clawback provision should remain with project owner.

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?

No. The purpose of community solar is to allow utility customers to participate in solar by subscribing to a portion of a solar facility's capacity. The level of benefit that customers will receive will depend, in part, on the economics of the project. Therefore, developers should be incentivized to locate projects in areas that maximize savings. By requiring projects to be located geographically closer to subscribers, the IPA would only be artificially increasing costs for developers and hindering solar development in Illinois. Ultimately, subscribers should be indifferent as to the physical location of the solar projects in which they subscribed as they will share the same connection to the facility regardless of location. Moreover, subscribers can choose projects that are located closer to them if they so desire. All parties, however, will benefit from lower cost projects.

2. How can geographic diversity be ensured?

Geographic diversity will occur naturally as a result of the interconnection process. In short, there are only a limited number of projects that can be interconnected to the system in a single location before costs at that location become prohibitive. Therefore, developers will naturally seek to diversify locations so as to reduces interconnection costs.

Moreover, in our experience, local zoning processes and laws will play a large role in siting decisions. Simply put, certain municipalities and counties will seek to attract solar development by implementing solar friendly rules - while others may be less solar friendly. Again, developers will make siting decisions that maximize the economics of the projects and will look to as many solar friendly areas as they are able.

The IPA should not take any measures to artificially ensure geographic diversity, as doing so could adversely impact the overall costs of projects and, therefore, impede solar development in Illinois.

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?

We do not believe different application requirements are necessary. In fact, having too many standards can be burdensome for both developers and utilities. Instead, utilities should develop requirements that are workable for all developer types.

Community Solar projects should not have to demonstrate any level of subscriber interest in order to apply for interconnection. Because interconnection application typically occurs very early in the development process, developers simply may not yet be at the stage of signing up subscribers. The IPA should not require developers to artificially accelerate the development process. Developers will already be sufficiently motivated by the deposit/credit requirements that could be forfeited.

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?

The goal of the Act is to incent solar development in Illinois. Therefore, the IPA should take care to avoid recommending any program requirements that are counter to that purpose. Specifically, the IPA should take care not to implement requirements that cause projects to be uneconomic and, therefore, unfinanceable.

To that end, locating projects in close proximity to other projects should be permitted so long at the interconnecting utility allows.

That said, there are certain restrictions the IPA can place on all projects to ensure that developers are not simply building large-scale utility projects. For instance, the IPA can require that each project have its own project company, site control, and interconnection.

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)?

No. As further explained above, we do not believe this is necessary.

6. 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?

This determination should be made at the customer level, and may vary based on the customer's motivation for selecting the particular project type. The IPA should not be involved in making this decision for customers.

Development Milestones

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

We believe that 12 months (for Distributed Generation) and 24 months (for Community Solar) are reasonable times for each project type, given the differences in interconnection for each project type.

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

None. Some developers may wait until construction has commenced to begin contracting subscribers, whereas, others may require the project to be fully subscribed before construction. This is a risk that developers will need to manage with their subscribers and their financiers, and should not be dictated by the IPA.

Residential versus Commercial Interest

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

The best assistance that the IPA can provide is to help ensure that potential subscribers have access to relevant information so that they can make informed decisions. We would recommend that the IPA create and maintain a customer analysis tool on its website to serve as an un-biased, third party source of information for interested parties. This will help potential subscribers understand the program and compare different opportunities.

10. 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?

We believe this is unnecessary and would be impractical and onerous to administer.

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

No. Based on our experience, this is not necessary.

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

No. Based on our experience, this is not necessary.

Conclusion

We want to thank you again for this opportunity to provide comments in response to the items discussed at the Workshops. US Solar and Acciona are excited about the opportunity to expand their renewable energy development activities in the State of Illinois and look forward to working with the IPA to develop a program that promotes renewable energy in and renewable energy-related job growth Illinois. Should you have any questions or wish to discuss our experience in other States further, we are happy to meet at your convenience.

Respectfully submitted,

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