



November 13, 2017

Mario Bohorquez
Illinois Power Agency
Planning and Procurement Bureau Chief
160 North LaSalle Street
Chicago, Illinois 60601

RE: Comments for the Draft Long-Term Renewable Resources Procurement Plan

Mr. Bohorquez:

We are pleased to contribute our comments on the Draft Long-Term Renewable Resources Procurement Plan (“LTRRPP”) published by the Illinois Power Agency (“IPA”) on September 29, 2017. In short, we express our appreciation to the IPA for allowing us this opportunity. Our comments are based on many years of developing, financing, constructing, and operating over 100 MW of ground-mounted photovoltaic energy projects throughout the United States. Specific sections from the regulation text are first quoted below in italics and then reviewed with our comments. The comments are organized in the order in which they appear in the LTRRPP.

6.4. REC Pricing Model: The REC Pricing Model is based on the CREST model developed by the National Renewable Energy Laboratory (“NREL”). In developing the REC Pricing Model, the default inputs in the CREST model were updated to use publicly available data from the most recent NREL solar photovoltaic system cost study and certain information received by the Agency in the responses to the Request for Comments the Agency issued in June 2017.

Proposed Replacement Language: *We propose a thorough review of modeling assumptions.*

We commend the IPA for taking such an analytical and objective approach to calculating the associated REC prices for various system sizes. While we do not have specific replacement language, we do have significant concerns as it relates to the inputs used in the CREST model and their subsequent impact on the REC Pricing Model - as well as directional suggestions for updates to these assumptions..

As background, we compared the inputs in the CREST model against our own economic model, using inputs and assumptions based on years of successfully financing, constructing, and operating 100 MW of distributed solar (and specifically 10+ MW of community solar). Having financed over \$250 million of solar projects throughout the United States, with a range of sophisticated financing and accounting firms who have reviewed our model, assumptions, and structure in granular detail, we urge the IPA to further evaluate and re-consider the following assumption sets:

(For reference, we are using the currently available version of the Excel file named “LTRRPP-Appendix-E-2-Adjustable-BPCSP.xls.”)

- **Yield / Production:** the initial assumptions in the model suggest a year-one yield of 1,489 kWh / kW-dc; this is significantly outside the typical range we have seen and modeled ourselves. By way of example, our engineering team ran a PVSYST analysis for a 2.8 MW-dc / 2.0 MW-ac fixed-tilt solar system in McHenry County. Using the appropriate weather file and associated soiling assumptions, our analysis gave a yield of 1,308 kWh / kW-dc. Using that same property, our engineering team completed a PVSYST analysis for a tracker system; that analysis gave a yield of 1,451 kWh / kW-dc. While it is not evident in the CREST model whether the project is a fixed-tilt or tracker system, the yield would suggest a tracker system. If that is the case, then nearly all of the upfront and operating cost assumptions are incorrect. Moreover, with only an additional 145 kWh / kW-dc garnered from a tracker system, there is little to no incentive to build the more expensive tracker system in Illinois.

Impact: *This higher-than-standard assumption overstates product revenues and decreases the Levelized Cost of Energy; thereby decreasing the Base REC Price versus what would actually be required at lower yields.*

Proposal: *We propose assuming a fixed-tilt system (to be consistent with the cost assumptions in the model) and using a more typical Illinois yield of ~1,300 kWh / kW-dc.*

- **Operations & Maintenance:** as developers and long-term owners / asset managers of a portfolio of distributed solar projects, we are intimately familiar with the costs associated with these projects. While this model includes an amount for O&M, it omits the following very significant costs:
 - Insurance: \$3,000 to \$4,000 per MW
 - Rent / Property Purchase / Site Control: leases are typically \$1,000 - \$1,500 per acre or \$5,000 - \$7,500 per MW
 - Property Taxes: PILOTs are still being negotiated by local assessors, but a conservative assumption is \$7,500 per MW
 - Residential Community Solar Administration Costs (e.g., Collections, Customer Service, etc.): \$15,000 - \$25,000 per MW
 - Asset Management Costs: \$5,000 - \$10,000 per MW

Impact: *Omitting these costs overstates the profitability of a project and decreases the Levelized Cost of Energy; thereby decreasing the Base REC Price relative to the REC price levels that would actually be required given the full range of project costs.*

Proposal: *We propose including these costs in the CREST model.*

- **Revenues:** the CREST model delivers a “Levelized Cost of Energy” that is required to deliver a certain user-provided return; it should be noted that this revenue is effectively the “net” revenue realized by the project *after applying discounts-to-market* (e.g., we currently market Massachusetts community solar at a 10% discount) as well as factoring in community solar customer defaults.

Impact: *The rates modeled represent the “net” revenues after discounts / defaults and should be grossed up to reflect the starting utility tariff rates and to incorporate defaults before calculating the Base REC Price.*

Proposal: *We propose “grossing up” required revenues to reflect a “10% discount to market” offering to customers and a 2-3% lost revenue rate per annum (to incorporate customer moves and defaults for community solar with a majority of residential customers).*

- **Financing Assumptions - Debt:** in our experience developing and financing community solar, “standard” project finance assumptions do not always apply. In particular, lenders do not price community solar risk – especially residential community solar – at “par” to other projects, requiring higher interest rates, higher transaction costs, a greater DSCR, and shorter tenors.

In addition, given the front-loaded nature of the Illinois REC program’s cash flows, with fifteen years of revenues being paid in the front five years, and only ~\$0.06 / kWh remaining thereafter, lenders to projects in Illinois will need to creatively structure their offerings. As a result, using a “standard” model like the CREST model is not appropriate, as it assumes steady amounts of cash flow are able to service the debt over time.

Impact: *In our view, the CREST model overstates the amount of leverage that would be available, understates the cost of the leverage, and is aggressive with regard to the ability to reduce the overall investor equity check required; as a result, this smaller initial equity investment understates the Levelized Cost of Energy required and thereby decreases the Base REC Price versus what would actually be required.*

Financing Assumptions - Target Return: taking the overall debt concerns under consideration, and given the variety of financing structures (along with the challenges of structuring debt for a front-loaded series of cash flows), our experience has shown that the key initial metric for financing distributed solar projects is typically the **cash-on-cash, unlevered return**. This metric avoids much of the “noise” that can be created due to differing financing costs, debt sizing, etc.

Impact: *Using an unlevered model would provide a more accurate and less “noisy” view of target revenues.*

Proposal: *We propose targeting unlevered returns. Alternatively, if the IPA wants / needs to view these projects on a levered basis, we recommended speaking with several local financing firms to appropriate size the debt, financing costs, DSCR, etc.*

- **Tax Equity/Depreciation:** the CREST model is currently structured to evaluate a “tax-efficient” investor case, which is the “best case” scenario and not the “mean case.” Additionally, the modelled “tax-efficient” investor appears to understate the investment tax credit (“ITC”) and overstate the depreciation; both of these assumptions need to be checked. Also, using a levered after-tax return as specified in the model is well below market. It would be appropriate to use an unlevered after-tax return in the 8-9% range as good approximation of market returns.

Impact: The combined effects of these changes would require higher REC prices.

Proposal: Model an unlevered after-tax return in the 8-9% range.

Finally, it is worth noting that the initial community solar model used to estimate the costs associated with community solar understates the costs of acquiring and serving these customers. Examples include:

- **Customer Acquisition Costs:** while ~\$0.09 / Watt-dc seems to be a reasonable **target** for overall customer acquisition costs based on the realities of the Illinois market (tighter margins from lower overall revenues will mean that community solar acquisition costs will almost certainly have to come down from the \$0.15 - 0.20 / Watt-dc level that we have seen in other markets), it should be noted that the smaller size of customers (~5,000 kWh per customer) will require more customers / project than those in other states.

(By way of comparison, our customers in Massachusetts have been allocated more than twice as much: more than ~10,000 kWh per customer).

It remains to be seen whether the companies who specialize in acquiring and serving community solar customers will be able to efficiently acquire more customers for the same amount of MW to the degree that these costs can come down on a per-Watt-dc basis.

Proposal: We would propose at least \$0.15 / watt-dc, with the caution that this is likely the low end of the range, given smaller customer sizes.

- **Customer Service Costs:** as noted above, there are significant direct costs associated with servicing community solar customers (e.g., customer service, credit card / payment processing, etc.), but there are also other costs from lost revenues due to moves, delinquencies, etc. In our experience these costs tend to run higher than those in the baseline model, and we would encourage the IPA to spend more time refining these assumptions.

Proposed “Top-Line” Levelized Revenue Requirement: Based on our experience and our own internal modeling, we strongly believe that the “all-in” \$ / kWh realized by a 2 MW community solar projects needs to be slightly above \$0.20 / kWh.

This amount assumes less than \$0.06 / kWh from net metered residential customers; the remainder would from the REC price, inclusive of the community solar adder. Specifically, we assume 50% residential off-takers and 50% from a larger commercial off-taker. By way of comparison, this \$0.20 / kWh is in line with similarly targeted rates contemplated for community solar projects under Massachusetts’ newly adopted Solar Massachusetts Renewable Target Program (“SMART”).

Note: Our comments do NOT factor in additional negative impacts on project economics that could result from the current Suniva trade case in front of the International Trade Commission or changes to the tax law that would lower the 35% corporate rate or in any way impact the ITC. Should this case result in higher prices for panels or new tax law result in lower value for tax benefits, RECs would need to be re-priced appropriately.

6.9. Approved Vendors: Participation in the Adjustable Block Program will take place through, and conditional upon, an Approved Vendor process proposed by the Agency.

Proposed Replacement Language: *Participation in the Adjustable Block Program will take place through, and conditional upon, an Approved Vendor process proposed by the Agency. Approved Vendors are mandated to require compliance from their subcontractors..*

We are pleased to see this emphasis on consumer protection. Over the last two years, we have successfully financed, constructed, and currently operate four (4) community solar projects totaling 10+ MW and serving approximately 300 residential customers. As such, much like the IPA, it is of the utmost important to us that the proper consumer protection measures are in place for Illinois' community solar program. It is our intention to make Illinois the beacon of community solar programs, and we will only be able to do that if community solar projects are trusted by the residential customers it intends to serve.

While we understand the IPA's desire to streamline the reporting and contracting associated with community solar, we do note that some of these provisions could create unexpected issues / complications. For example, building and marketing community solar often requires contracting with one or more third-parties to acquire customers, and these parties often outsource this activity further to other local marketing teams. As a result, even with the best intentions, Approved Vendors will often have limited visibility into the granular activity of these salespeople. While we certainly require our vendors to certify that they will require their own teams to comply with applicable local, state, and federal laws, this is difficult to document directly.

6.13 Customer Information Requirements / Consumer Protections: Approved Vendors will be required to submit information to the Agency regarding the customer hosting the system, or the host of the community solar project, and the information that was provided to that customer. The purpose of requiring this information is to ensure consumer protections. The information that must be provided to all customers (and such provision documented to the Agency) includes: a copy of the contract for the power purchase agreement, lease, or sale. Vendors may use model leases and model power purchase agreements ("PPAs") provided by the Solar Energy Industries Association ("SEIA") or other standard contracts that have been approved by the Agency.

Recommendation: We applaud the level of detail and consumer-focused terms provided in this section. From our first community solar project, we have taken steps to be in compliance – and make sure that our contractors are in compliance – with all of the relevant federal, state, and local laws. At the same time, while we certainly understand the desire to provide transparency to consumers, we strongly caution against any push towards “standardized” contracts across projects / developers. Competition with regard to contract terms is essential for a robust marketplace, as we have been pleased to see our offering resonate with residential customers across other states in a way our competitors have not.

In addition to the aforementioned recommendation, please see specific comments below related to the *Contracts* and *Disclosure Form* requirements:

- **Contracts:** we propose noting that Approved Vendors may also use their own forms if they meet the overall program requirements.
- **Disclosure Form:** this form requires a significant amount of proprietary and potentially confidential information; moreover, this is information that is often subject to significant change over the development timeline. We support consumer disclosure; however, we want to make sure

that the standard is appropriate to the commercial realities of project development and propose acknowledging these uncertainties and providing a way to update these disclosures across the process.

7.3.1. Co-location Standard: If there are multiple projects owned by a single entity (or, non-separate entities) located on one parcel of land, or on contiguous parcels of land, any size-based adders will be based on the total size of the projects. For projects located on contiguous parcels, if the total combined size of the projects is greater than 2 MW, then the projects must be owned by separate entities.

Proposed Replacement Language: *If there are multiple projects owned by a single entity (or, non-separate entities) located on contiguous parcels of land, any size-based adders will be based on the size of the individual project. For projects located on contiguous parcels owned by a single entity (or, non-separate entities), the total combined size of the projects cannot exceed 6 MW.*

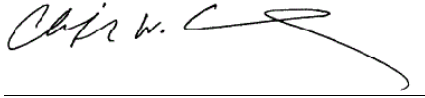
Like others in the market, we are concerned that limiting a developer's ability to co-locate projects will prevent the robust installation of community solar projects. Given the current supply rates in ComEd and Ameren, as well as the currently proposed REC prices and Community Solar Adders (as well as other proposed incentives), 2 MW community solar projects *are not economically viable*. Allowing developers to build a *maximum* of 6 MW on contiguous parcels helps achieve economies of scale and *makes projects economically viable*—even if each individual project has its own interconnection point. The LTRRPP even concedes this fact, stating that “while co-location can undermine the concept of distributed small projects, it can also capture economies of scale from larger projects: large, available parcels with good interconnection points can be low-cost and efficient ways to develop large amounts of renewables quickly.”

Over the last several months, we have had conversations with dozens of landowners throughout Illinois about leasing land for the development of community solar projects. During these conversations, nearly every landowner has expressed an interest in developing multiple community solar projects on their properties—many of which are contiguous parcels. Limiting a landowner's ability to contract with the same developer on multiple projects on his/her land creates unnecessary inefficiencies—for the landowner, developers, and the utilities. As the LTRRPP is currently written, the only way for a landowner to construct multiple community solar projects on contiguous parcels is to contract with separate and distinct solar developers—which creates excessive financial and time burdens for the landowner.

When developing the current language surrounding co-location, we applaud the IPA for analyzing the market manipulation experienced in Minnesota where developers would submit multiple interconnection applications for 1 MW projects on the same or contiguous parcels. Like the IPA, we would like to avoid / eliminate this potential issue in Illinois. However, due to the rural landscape of Illinois, the electrical grid is structured in such a way to make such manipulation impossible. Aside from the major metropolitan areas, the vast majority of the utility distribution substations are 10 MVA or less (ComEd and Ameren). Given the low minimum daytime load in these rural areas, and thus the associated risk of back-feeding, most of these substations will only be able to interconnect a maximum of 6-8 MW—unless a developer is willing to pay for substantial system upgrades, which would likely make projects cost and time prohibitive. As such, we do not expect to see the co-location issues in Illinois as experienced in Minnesota—especially if the 6 MW aggregate limit is enforced on contiguous parcels.

Thank you again for the opportunity to share our comments and perspective on the LTRRPP. We have been impressed by the IPA's overall approach, and we look forward to continuing to participate in this process going forward. Please do not hesitate to reach out to us if you have any questions about this response. You may contact either Keith Akers (keith.akers@syncarpha.com; 212-419-4840, ext 200) or Matt Preskenis (matt.preskenis@syncarpha.com; 212-419-4840, ext 100).

Syncarpha Capital, LLC

A handwritten signature in black ink, appearing to read "Clifford W. Chapman", with a long, sweeping underline that extends to the right.

By: Clifford Chapman,
Title: Managing Member