COMMENTS ON THE DRAFT LTRRPP FOR PUBLIC COMMENT
<u>ON BEHALF OF THE JOINT SOLAR PARTIES</u>

The Joint Solar Parties greatly appreciates the opportunity to provide feedback on the Illinois Power Agency's ("IPA") draft Long-Term Renewable Energy Resources Procurement Plan ("LTRRPP") for public comment. The Joint Solar Parties comprise of the Solar Energy Industries Association ("SEIA"), the Illinois Solar Energy Association ("ISEA"), and the Coalition for Community Solar Access ("CCSA").

The Joint Solar Parties will divide their comments into separate documents. This joint document will address the Adjustable Block models (collectively "model" or "models") identified as Appendixes E-1 and E-2 to the LTRRPP. Some of these comments are specific to one project type, and some are inclusive of all. Unless specifically stated, the IPA should assume that the comment is relevant to all project types. The individual associations within the Joint Solar Parties will submit their own, separate document to address all other feedback from their respective Associations on the draft LTRRPP for public comment.

I.

INTRODUCTION AND BACKGROUND

A. About the Joint Solar Parties

As the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans, SEIA represents all organizations that promote, manufacture, install and support the development of solar energy. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy. SEIA has worked to promote, develop and implement the use of solar energy in the United States since 1974.

ISEA is a non-profit organization that promotes the widespread application of solar and other forms of renewable energy through our mission of education and advocacy. ISEA represents a diverse membership of over 125 businesses and 400 individual advocates who promote the widespread adoption of solar throughout Illinois. ISEA business members widely represent solar industry market segments, including residential, commercial, community, utility scale solar, module and inverter manufacturers and solar supply chain retailers.

CCSA is a business-led trade organization, comprised of over 40 member companies, that works to expand access to clean, local, affordable energy nationwide through community solar. Our mission is to empower energy consumers, including renters, homeowners, businesses and households of all socio-economic levels, by increasing their access to reliable clean energy. CCSA, in partnership with a thriving network of non-profits, affiliate trade associations, and allied stakeholders, serves as the central voice for the community solar industry in developing vibrant and sustainable markets for community solar. CCSA members are active nationwide and we have been actively engaged in the informal Illinois stakeholder process to date, having submitted initial written input on June 27, 2017.

B. Joint Solar Parties Recommended Guiding Principles

Before delving into specific comments and recommendations on the models, the Joint Solar Parties wishes to establish an overarching principle for the IPA—and ultimately, the Illinois Commerce Commission ("Commission")—to evaluate the models. The Joint Solar Parties believe the primary concerns for the models should be accuracy and objectivity in identifying and quantifying costs and revenue streams.

To be clear: the Joint Solar Parties do not believe that the goal should be to *maximize* (or, conversely, to minimize) the Adjustable Block pricing. Our members have experienced fallout in other states where over-priced incentives have over-heated markets leading to unhealthy boom-and-bust cycles, just as often as under-priced incentives have failed to stimulate market development. It is our objective to help the IPA avoid both of these negative outcomes. The Joint Solar Parties believes the goal should be to make the model as realistic about expected costs, revenues, and incentives as possible. An accurate and objective model will allow the solar industry (including Joint Solar Parties members) to compete based on its ability to offer customers value by continuing to drive down costs.

The Joint Solar Parties' proposed guiding principle best carries out the mandates of the Future Energy Jobs Act ("FEJA"). For instance, the Illinois Power Agency Act contains the following mandate:

> The Adjustable Block program shall be designed to provide a transparent schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time.

(20 ILCS 3855/1-75(c)(1)(K).) A realistic and accurate set of assumptions is the best way to ensure the Adjustable Block REC price both "enable[s] the photovoltaic market to scale up" and "adjust[s] at a predictable rate over time" in two ways. First, accurate and realistic pricing in the initial block pricing reduces the potential for a boom – or bust – cycle followed by an overcorrection. Second, realistic initial block pricing will increase the likelihood of controlled ("predictable") adjustments between blocks. Taken together these steps will help the solar industry grow and deepen its footprint in Illinois, as opposed to sudden and unpredictable scaling up and down as REC pricing alternates between under- and overvaluation.

In addition to avoiding under- and over-valuation, the Joint Solar Parties also wish to emphasize the importance of maintaining neutrality between on-site project economics and community solar economics. We have seen incentive programs in other states inadvertently tip the scales toward one project type or another, resulting in market distortion.

The Joint Solar Parties believe that generally speaking, the IPA made appropriate and defensible choices in designing the Adjustable Block program, balancing the need to segment Adjustable Block pricing with simplicity and ease of administration. These comments address the elements of the model for which we believe there are ways to improve accuracy, transparency and balance, relying on publicly available data sources and industry-accepted standards and assumptions.

[*Please see table on the following page*]

The below chart summarizes which categories in these comments apply to which market segments.

	Large DG	Small DG	Community Solar
Physical O&M	Yes	Yes	Yes
Insurance	Yes	Yes	Yes
Property Taxes	N/A	N/A	Yes
Land Lease Payments	N/A	N/A	Yes
Asset Management Fees	Yes	Yes	Yes
Community Solar Administration	N/A	N/A	Yes
Collateral	Yes	Yes	Yes
Interconnection Upgrades	Yes	N/A	Yes
Net Metering Credit	Yes	Yes	Yes
Customer Savings	Yes	Yes	Yes
Step-Down in MACRS	Yes	Yes	Yes
Tax Treatment of Smart Inverter Rebate	Yes	N/A	Yes
Timing of Incentive Payments	Yes	Yes	Yes
Post Tariff Market Value of Production	Yes	Yes	Yes
Unleveraged Return	Yes	Yes	Yes
Capacity Factor adjustment	Yes	Yes	N/A
Units and Measurements	Yes	Yes	Yes

II.

PROPOSED ADJUSTMENTS TO COSTS

A. The Model Should Align Project Cost Assumptions With Publicly Available Data Or Joint Solar Parties Estimates

A wide range of cost components go into developing a distributed or community generation facility. In keeping consistent with the Joint Solar Parties' goal of having the model be as realistic as possible), it is critically important that the IPA recognize significant cost categories and provide realistic estimated values.

As an initial matter, according to the Joint Solar Parties' review of the model, the only cost category included was "Operations and Maintenance," ("O&M") or the cost to physically maintain the distributed or community generation system's operations. However, there are many other project cost categories associated not captured in O&M. The model itself acknowledges this issue on the CREST tab, where a pulldown menu is offered in cell G30 with an explanation available in cell I31:

> If "Simple" is selected in the cell above, then this input should reflect the total expected fixed cost of project operations and maintenance, in $/kW-yr. This includes the insurance, project management, property tax (or payment in lieu thereof), land lease, and royalty expenses which would have been broken out separately in the "Intermediate" case. Other labor and spare parts should also be included in this estimate.
>
> * * *
>
> If "Intermediate" is selected, then this input should reflect the expected annual fixed O&M costs before taking into account the additional listed expenses, which are entered below.

According to the Joint Solar Parties' review, by toggling the "simple" input assumption to "intermediate" in cell G30, the model identifies and thus aims to account for many, but not all, of the appropriate cost categories. However, the Joint Solar Parties are concerned that if model toggle is changed from simple to intermediate, the $16/kW-yr dc value in cell G31 does not change—even though according to the comment in cell I31, the value should vary depending on whether "simple" or "intermediate" is selected because some costs are separate line items in the "intermediate" model. The Joint Solar Parties noted that by changing the toggle in G30, the REC price for a 2MW community solar project in ComEd's territory increase by almost 60%, from $43.09 to $68.09. This change in REC value stems from a more than 20% increase in Levelized Cost of Energy, from $117.5/MWh to $142.5/MWh. Clearly, the REC model is very sensitive to adjustments in cost categories.

This leads to two recommendations. First, the IPA should be clear as to whether the $16/kW-yr dc value in cell G31 is intended to apply to "simple" or "intermediate" selection in G30. While the Joint Solar Parties suspect the default is intended to be "simple," the Joint Solar Parties strongly recommend that the IPA spell it out. Second, the Joint Solar Parties recommend that instead of utilizing the "simple" model, the IPA utilize the intermediate model and add additional line items to reflect additional costs. If IPA chooses to use the "simple" model, then IPA should detail out and make sure these additional costs are rolled into the value in cell G31.

B. The IPA Should Update Values For Three Categories of Costs in the CREST O&M Model

The Joint Solar Parties have reviewed the broken-out cost components in the model if "intermediate" is chosen in cell G30. Based on its review, the Joint Solar Parties recommend changes in the model to three cost categories.

1. Insurance

General solar industry practice ensures that all PV systems have some level of insurance. Typically, coverages include property insurance, general liability, umbrella coverage, and other relevant lines (including insurance related to construction/O&M, vehicle policies, etc.). As recognized by the model, insurance is a real cost.

The Joint Solar Parties acknowledge that there is no single ideal source of data on what insurance costs, because insurance costs are based on several factors including location of assets, scale, credit, etc. However, based on the experience of the Joint Solar Parties member companies, the Joint Solar Parties believe that a good proxy for total insurance costs is about $0.20 per $100 of assessed project value. The Joint Solar Parties note that other inputs, including tax benefits, are also calculated on an assessed project value basis, so calculating insurance costs on that basis should not be infeasible or unfamiliar for the model.

2. Property Taxes

As an initial matter, the Joint Solar Parties acknowledge that property tax treatment of solar generation facilities—particularly community solar—is a fluid and evolving issue. At this point in time, the Joint Solar Parties recommend that the IPA assume that off-site solar facilities, i.e. community solar facilities that do not serve on-site load, will be taxed in a similar manner to wind generation facilities (which are much more established across Illinois). The Joint Solar Parties understand that wind has a standard assessed value of $120K/MW and the average tax rate in Illinois is between 7.5% and 10%. The Joint Solar Parties estimate that solar will be about $70K/MW assessed value, so property taxes will be within $5-$7K per MWac per year.

The Joint Solar Parties note that under the 'Intermediate' scenario, the model assumes an Annual Property Tax Adjustment Factor of 10% decline each year. The Joint Solar Parties estimate that the depreciation schedule is likely to be about 3.5% per year. However, the IPA's use of 4% year-over-year decline in the cost to install new projects is a reasonable proxy, and the IPA should update the model accordingly.

Because the tax treatment of solar remains fluid and evolving, the Joint Solar Parties recommend that the IPA assume that counties will analogize to wind in the model. We are aware of draft legislation intended for the 2018 session that will attempt to establish solar-specific metrics for property tax assessment. Should that legislation pass, we would encourage the IPA to update the model accordingly – and if needed, request explicit permission from the Commission to do so.

3. Land Lease Payments (Applies to Community Solar Projects)

Land leases are an unavoidable component of community solar projects, but often excluded from behind the meter projects (where the sole customer and host are the same entity). Thus, while it may be appropriate to have no land lease payment for Large DG and Small DG projects, the IPA must assume some cost for this in their model for Community Solar projects.

Like insurance, actual project costs for land lease payments will vary by several factors (including location) but will ultimately depend on a price generated by an arms-length transaction between two parties. Thus, there cannot be a unified estimate what the lease payment should be for modeling purposes, but we believe that prices currently range from about $800/acre/year to $1200/acre/year, with and without escalation factors.

However, as pointed out by the Joint Solar Parties elsewhere in these comments, diversity in actual payments does not preclude the IPA from making a realistic and accurate estimate.

Assuming 5 acres per MWdc installed, the Joint Solar Parties believe that $13,000/year is a middle-ground assumption for a 2MWac community solar facility, and the costs can be scaled by facility size as appropriate.

4. Royalties

It is unclear to the Joint Solar Parties what is meant by or included in 'Royalties' in the 'intermediate' model – this is not a cost-category that Joint Solar Parties companies are used to seeing. The IPA should clarify what costs it is attempting to capture in the "royalties" category and confirm that, after addressing the Joint Solar Parties comments, this section does not double count any costs that were recognized elsewhere. The Joint Solar Parties notes that the royalties section is a significant cost—equal to the CREST model value for insurance for a 2,000 kW (DC) community solar facility.

C. Three Categories of Costs Should Be Added to the CREST O&M Model

The Joint Solar Parties note at least three categories of costs that do not appear to be accounted for in the CREST model. The Joint Solar Parties recommend that the IPA either add these as line items as a supplement to the CREST model, or (without regard to whether the IPA uses the "simple" or "intermediate" approach) add them into the calculation in cell G31 (which is designed to accommodate all CREST-classified O&M costs that are not separately broken out in the "intermediate").

1. Asset Management Fees Should Be Included in the Model

As the Joint Solar Parties defined O&M above, the term covers physical maintenance of assets. However, on top of physical maintenance of the system, the operator of the solar generation facility will incur asset management costs that cover non-physical maintenance items such as:

- Monitoring system performance—especially given REC delivery performance targets with harsh penalties for falling short;

- Billing customers/subscribers—especially because bills may be based on either the net metering credit identified on individual customers' utility bills or the value of the kWh generated by the solar generation facility;

- Accounting and reporting—in addition to internal or customer-related reporting, Approved Vendors (who may or may not be the system operator) must collect certain information for the annual report identified in the draft LTRRPP for public comment (*see* LTRRPP at 121-22).

While the categories above are applicable to all Adjustable Block-eligible solar generation projects, additional administrative costs are frequently incurred in community solar projects due to the increased number of customers and subscription management associated with each system.

Instead of one offtaker in a traditional behind the meter system, a community solar system will have 3 or more customers, and potentially many more. Because subscriptions are also transferrable and assignable, contract administration is potentially more complex than for a behind the meter project. Additional costs related to administration of community solar projects are discussed in Section II.D.2.

The cost for a developer of both physical O&M and asset management is determined by the market and developer-specific confidential information; insufficient publicly available data is available for the Joint Solar Parties to provide insight into this otherwise proprietary information. The Joint Solar Parties recommend the IPA consider an O&M cost in the range of $10 per kW (DC) per year and an asset management fee of $5/kW (DC) per year.

2. The Cost of Collateral Should Be Included in the Model

IPA proposes requiring collateral for REC delivery equal to 10% of the contract value. With contract values potentially approaching and exceeding several million dollars for some larger facilities (particularly those with residential adders or serving low income/environmental justice area customers), tying up a couple to several hundred thousand dollars of cash or in a letter of credit is a significant cost. While the Joint Solar Parties will address collateral in other contexts, for the purposes of the model the IPA should recognize the real cost to the developer to provide such collateral.

The Joint Solar Parties do not currently have a projection for this value[1], but depending on the ultimate options available for providing collateral, the IPA should include an estimate of the cost to provide collateral in its model.

3. Some Measure of Customer Savings Should Be Included in the Model

As the Joint Solar Parties understand the model, it essentially seeks to balance costs and revenues/incentives, solving for the REC incentive. In other words, the model currently assumes that all revenue, including net metering credit value, will be revenue into the project.

In the Joint Solar Parties' experience in Illinois and other states, only a limited number of customers (if any) are interested in a solar array that does not provide an added value to the customer. This customer value is income from the customer perspective, but it is a reduction in revenue from the perspective of the project. If the model seeks to evenly balance costs and revenues/incentives, then there is either no room for customer value or the model needs to be updated to reflect customer savings.

While the Joint Solar Parties believe diversity of products in the marketplace will be one of the strengths of the Illinois solar market—and each product may have a different way of generating and demonstrating value to customers—each product must provide and demonstrate *some* value. Consistent with the Joint Solar Parties' recommendation that the IPA avoid basing incentives on subjective project-specific costs, the Joint Solar Parties propose the IPA consider a standard customer value as a proxy. The Joint Solar Parties suggest that a reasonable assumption is 20%

[1] In its comments on the Long Term Plan, the Joint Solar Parties may make suggestions for alternate forms of collateral intended to have a lower developer cost than posting cash or a Letter of Credit.

of the estimated annual net metering credit value and suggests an appropriate way to capture this cost in the model is by reducing the net metering credit value by 20%. While the Joint Solar Parties are looking forward to IPA and other stakeholder feedback on its particular valuation approach, it is imperative that the IPA provide *some* estimate of customer savings.

D. The IPA Should Update CREST Capital Costs

1. The CREST Interconnection Upgrade Cost Estimates are too Low

The Joint Solar Parties has identified two primary issues with the CREST model interconnection costs, both of which cause the model to underestimate interconnection costs. First, the NREL benchmarking study assumption of $46,158 per 2MWdc project, which in the Joint Solar Parties' experience is too low by a factor of two or more. For example, according to the Joint Solar Parties' research, average interconnection costs in Minnesota were closer to $100k or above per MWac community solar project.

Large customer-sited solar projects, because they are by definition located close to load, have interconnection upgrade costs that are generally significantly less than community solar projects located away from load. Residential systems (under 10kW) do not generally have interconnection upgrade costs.

The Joint Solar Parties stresses that national or regional state interconnection costs are only the roughest proxy, and average interconnection costs tend to vary utility-by-utility by the system assets themselves and custom and practice. The distribution system assets themselves frequently dictate the range of feasible (from an engineering perspective) upgrades that may be necessary. Custom and practice addresses how utilities approach interconnection. For instance, under the Illinois Commerce Commission's Part 466 Rule regarding interconnection, a utility may generally allow expedited screening or may push more projects to Level 4 review. The IPA should consider seeking information from the utilities, both before the Commission approves the LTRRPP and during the subsequent 60-day window for modifications to the Adjustable Block program.

Second, the model incorrectly uses a formula to reduce the assumed interconnection costs in cell G22:

> =('NREL Benchmarking Study'!B5-('NREL Benchmarking Study'!$B$8*'NREL Benchmarking Study'!B12))*(1-('NREL Benchmarking Study'!$B$15*('NREL Benchmarking Study'!$B$17-'NREL Benchmarking Study'!$B$16)))

Multiplying cell B8 by cell B12 in the NREL Benchmarking Study sheet incorrectly assumes that the $250/kW smart inverter rebate reduces project interconnection costs. The Joint Solar Parties are unsure of the basis for the IPA's belief that interconnection costs will go down due to the smart inverter rebate. The Joint Solar Parties are not aware of any reason actual interconnection costs would be impacted by the presence or absence of the smart inverter rebate.

The second highlighted part of this formula incorrectly assumes that interconnection costs will decline by 4% per year. We recommend that IPA zero this out in the model. Interconnection costs are not something that is controlled by developers or improving equipment; rather, it is a cost number given by utilities for the construction and supporting work that needs to be done to interconnect the system with the distribution grid. Some of those costs are labor costs, and the Joint Solar Parties are unaware of any evidence for 4% annual reductions in labor rates paid by the utilities. To the contrary, in the Joint Solar Parties' experience as the number of projects seeking and obtaining interconnection in a utility service territory increases, the cost of interconnection will increase because number of feeders that do not require significant upgrades in order to handle solar will decrease.

2. The IPA Should Better Align Community Solar Administrative Costs With Subscribers

Consistent with the Joint Solar Parties' goals of realistic and accurate assumptions, the IPA should adjust community solar administrative cost assumptions to better align with the small[2] subscriber percentage. Briefly, community solar administrative cost is the cost needed to fill and maintain a book of community solar customers, above and beyond the costs to manage solar assets of all types. The proposed $4.98/MWh cost adder for a basic large C&I offtake project (as few as three larger C&I customers) is likely too high, because generally speaking managing relationships with fewer and sophisticated customers takes less effort. However, to the extent more smaller customers are added, the project operator's costs increase due to contract volume and the potential for more frequent customer turnover. The proposed $7.89/MWh cost adder for 50% small customer participation is may be too low for management of this customer group.

Beyond the need to more accurately reflect administrative costs for community solar projects, there are a number of reasons that a higher small participation adder would further statutory goals of encouraging robust participation and customer opportunity in the residential sector. The Joint Solar Parties do not currently have a specific estimate to suggest regarding community solar administrative costs for projects with large C&I off-takers versus small offtakers. We encourage the IPA to address this differentiation through a transparent accounting of the adder values established in Section II.D.2.

III.

PROPOSED ADJUSTMENTS TO REVENUES

A. The Net Metering Credit Assumptions Are Incorrect For Most Customers

The model contains several errors and inaccuracies related to the potential net metering credit. While the Joint Solar Parties and its members appreciate the complexity and fluidity of Illinois net metering (including virtual net metering for community solar projects), the model has several assumptions and values that are easily correctable.

As a starting point, it is important that the model accurately reflects the fact that Illinois differentiates the formula for the metering credit value based on the customer's utility delivery class and tariff structure. Generally speaking, tariff components that are billed in energy units of $/kWh are offset by the net metering credit value. Tariff components that are fixed charges, and those components billed in demand units of $/kW are not offset by the net metering credit value.

[2] SEIA explains 'small subscriber' language in a separate set of comments.

As a general rule, the net metering credit rate for residential customers will include most billing components – energy supply, distribution charges, and other ancillary components (apart from fixed charge components). For medium and large non-residential customers (defined as those customers having >100kW peak demand in ComEd and >150 kW peak demand in Ameren), distribution charges are billed in demand ($/kW) units, and are not offset by on-site generation or net metering credits. Small commercial customer class billing is a bit of a mixed bag, with Ameren billing for delivery in $/kWh and ComEd billing for delivery in $/kW.

This distinction is very significant, because it points to a real discrepancy between the portion of a typical residential bill versus a typical commercial bill that can be offset with coincident on-site generation or net metering via an on-site project or community solar subscription. This discrepancy is not currently reflected in the IPA's model.

The Joint Solar Parties recommend that IPA make additional corrections as follows:

- **Modify Competitive Class C&I NEM Credit Value**. Competitive default C&I customers receive net metering credits equivalent to LMP (i.e. "offset-able" prices do not include delivery charges or other ancillaries). These medium and large non-residential customers represent by far the largest portion of non-residential electricity sales among both utilities (approximately 80% in ComEd and 80-85% in Ameren, depending on load zone).[3]

  The Joint Solar Parties examined the average on-peak LMPs in ComEd and Ameren over the last five years, and the annual average values were 3.515 cents (2012), 3.687 cents (2013), 4.758 cents (2014), 3.333 cents (2015), and 3.515 cents (2016) per kWh on peak in ComEd and 2.836 cents (2012), 3.013 cents (2013), 4.064 cents (2014), 2.811 cents (2015), and 2.606 cents (2016) per kWh on peak in Ameren.[4] The Joint Solar Parties note not only that these values are significantly lower than 5.798 c/kWh and 5.140 c/kWh, but the Joint Solar Parties do not believe that these values support a 2% annual escalator. The Joint Solar Parties also note that the polar vortex appeared to skew the LMPs in 2014—it appears, for instance, that the January and February average on-peak LMPs in 2014 were in some instances almost triple the values in other January and February LMPs in the date range..

  The Joint Solar Parties recommend that the IPA assume for each utility the respective average on-peak LMP of the last five years (either as the Joint Solar Parties have calculated above or weighted for expected production), or alternatively, the average on-peak LMP for calendar year 2016. While the Joint Solar Parties do not recommend an escalator because an escalator is not borne out by the last five years of data, the Joint Solar Parties do not necessarily object to a 1% annual escalator.

[3] For more information, see https://www.icc.illinois.gov/electricity/switchingstatistics.aspx
[4] These values were obtained by taking the average on-peak energy price for each month, then averaging those values across a calendar year. These calculations do not take into account that solar facilities are expected to produce more in summer months, or that production on at minimum weekends would be considered off peak.

Further, the Joint Solar Parties recommend the IPA assume a bundled rate NEM credit for small customers that have load to build smaller system size projects (0-100 kW) and a LMP based NEM credit for large commercial customers that have enough load (and available space) to build larger system size projects (100kW – 2 MW in) to calculate REC rates for each customer class and system size.

- **Eligible Retail Customer Capacity Cost Double Counting**. As the IPA is aware, both ComEd and Ameren roll in the cost of capacity in the Electricity Supply Charge (ComEd) and Purchased Electricity (Ameren) charges for eligible retail customers (as the term "eligible retail customer" is used in 220 ILCS 5/16-111.5(b).) However, in the "Net Metering Value" tab, it appears that lines 21 and 29 include capacity as a separate line item. Thus, Lines 21 and 29 should be eliminated.

- **Competitive[5] C&I Customers As Community Solar Subscribers.** FEJA states that no one customer can take more than 40% of a single community solar project. For projects that do not receive the 50% or 75% residential/small commercial adder, IPA should assume that the NEM credit value is that of competitive C&I customers.

- **Incorrect Community Solar Tariff.** The Joint Solar Parties recognize that the IPA had a deadline of two days after the Illinois Commerce Commission approved community solar tariffs for Ameren, ComEd, and MidAm to publish the draft LTRRPP for public comment. That short timeframe may have contributed to several errors in addressing community solar net metering credits, which include: (1) customers who are not in an eligible retail customer class do not receive net metering credits for capacity or transmission, and (2) customers who are eligible retail customers only receive net metering credits for capacity, not transmission.

- **Unrealistic Demand Reduction Assumptions.** Under the 'rates' tabs, the model calculates a capacity credit by translating a kW capacity charge into a kWh charge. As an initial matter, the Joint Solar Parties note that community solar does not reduce a customer's actual demand (although the Joint Solar Parties acknowledge that the community solar credit for utility bundled supply customers includes capacity). For distributed solar, it is true that behind the meter assets might, in certain circumstances, reduce a portion of a retail customer's demand during the system peak hour(s) used by RTOs to calculate capacity and transmission charges in the subsequent pricing period. However, as this is highly variable and not 'bankable,' (without batteries, that is), it is standard practice to not include any demand reduction savings in the financing of systems. As a result, the Joint Solar Parties recommend that the IPA not include demand charge savings in the model.

The Joint Solar Parties supports the IPA's choice to not differentiate between utility supply and ARES customers for the purposes of the model. While the Joint Solar Parties acknowledge that the net metering (and virtual net metering) value can differ between utility supply and RES supply, the IPA, the Joint Solar Parties, and stakeholders lack sufficient public information to account for

[5] For the purposes of these comments, the Joint Solar Parties use the term "competitive class" to refer to customer classes that are not eligible for a bundled supply rate from the utility.

RES pricing. As a result, the Joint Solar Parties believe that the IPA correctly based the model on utility supply customers.

The Joint Solar Parties also note that there seem to be a number of discrepancies between the credit values in the DG vs Community Solar model but assumes that these should be cleared up when the models are adjusted to appropriately capture net metering credit values for different project and customer types.

B. The Model Should Account for Existing Federal Tax Law

The models have significant but technical and easily correctible inaccuracies in assessing the maximum federal tax benefits solar developers will be able to capture. The Joint Solar Parties encourage the IPA to make these technical and easily correctable changes to better reflect existing federal tax law. The Joint Solar Parties note that these changes do not require policy decisions or forward-looking assessment of potential changes in law, because the Joint Solar Parties' proposed changes are intended to harmonize the models with federal tax law as it exists today.

1. The Model Should Account For 2018 Step-Down In Bonus Depreciation (MACRS)

The IPA's model should set bonus depreciation at 30%, or allow adjustments based on actual project bonus depreciation eligibility. The model currently assumes that equipment in a PV system is eligible for 50% bonus depreciation. While that is true for systems placed into service in 2017, the schedule declines to 40% for systems placed in service in 2018, 30% for systems placed in service in 2019, and 0% for systems placed in service beyond 2019. For the reasons below, the Joint Solar Parties believe that the bonus depreciation value should be set at 30% given requirements in the draft LTRRPP for public comment and the potential timing of the Adjustable Block program opening.

First, although there is still technically time left in 2017, the Joint Solar Parties recommend against assuming the full 50% bonus depreciation for 2017. Technically, projects "placed in service" in 2017 would qualify for the full 50% bonus depreciation, and FEJA does not prohibit participation of projects "energized" on or after June 1, 2017. (*See* https://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs (MARCS eligibility); 20 ILCS 3855/1-75(c)(1)(K) (Adjustable Block eligibility).) However, given the draft nature of the LTRRPP—including the Approved Vendor and consumer protection prerequisites to participation, much less the terms of Adjustable Block contracts, co-location restrictions, etc.—it is unrealistic to expect many developers to begin construction *prospectively* in 2017 in hopes that their project will comply with to-be-determined aspects of the LTRRPP.

Second, the IPA has not yet made a firm commitment to when the Adjustable Block program will open. The Joint Solar Parties emphasize it is not criticizing the IPA for the lack of a firm commitment, but it is possible that the Adjustable Block program will not open the first block until late 2018 or early 2019. In that case, it is unrealistic to expect many developers to begin construction prospectively based on an assumption of when the Adjustable Block will open.

The simplest way to approach this issue would be to assign 30% bonus depreciation to all projects in the model, and update the model at the end of 2019 (assuming no additional changes in law). However, if the IPA wishes to not make a policy decision or guess about "placed in service" date of solar facilities participating in the Adjustable Block program, the IPA could simply take into account the individual project's actual "placed in service" date. A reasonable proxy would be the year in which the first payment under the Adjustable Block program at energization is invoiced.

Additionally, IPA should review the model to ensure that only MACRS depreciable assets are being allocated to bonus depreciation.

2. The IPA Should Update Tax Treatment of the Smart Inverter Rebate

Based on the Joint Solar Parties' review of the model, it appears that treatment of the smart inverter rebate might be artificially increasing REC prices. (*See* 220 ILCS 5/16-107.6(c)(1) (explaining initial $250/kW smart inverter rebate for non-residential customers).) As the Joint Solar Parties understand application of federal tax law, the Investment Tax Credit and bonus depreciation (MARCS) are applied to the project value *before* applying the $250/kW rebate. The effect of the IPA's decision to reduce the project value by $250/kW *before* applying the tax benefits is to reduce the perceived value of the tax benefits, and thus artificially increase the REC price coming out of the model. The IPA should realize the full value of the tax benefits and apply the $250/kW after tax benefits.[6]

The Joint Solar Parties note that, by its own terms, the initial $250/kW rebate only applies to non-residential customers, and eventually residential customers will have an option to take full net metering or supply-only net metering with a to-be-announced per kW rebate. (*See* 220 ILCS 5/16-107.6(c)-(d).) The Joint Solar Parties understand that the IPA may have to make assumptions about the incentive selected by the customer in order to properly price the model.

C. The Model Should Align REC Revenue Estimates With Statutorily-Required Payment Terms

FEJA is extremely prescriptive in terms of REC payments: while most Adjustable Block-eligible systems have 20% of REC payments paid on energization and the subsequent four anniversaries of energization, the smallest (under 10 kW) projects must be paid for the full value of all RECs upon energization. (*See* 20 ILCS 3855/1-75(c)(1)(L)(ii) and (iii).) The model does not appear to take this accelerated payment into account in the annual revenues. This has the affect of overestimating how much operating revenue is coming into the project after year 4. The IPA should adjust the model to show the REC payments as revenue in the appropriate timeframes.

D. The Model Should Align its 'Post Tariff Market Value of Production' with Net Metering Credit Minus Customer Savings Assumptions

Starting in Year 16 the models assume project revenue to include a 'Post Tariff Market Value of Production' (cell V16). This is 4.67c/kWh and 7.47c/kWh in the Community Solar and DG models respectively. These revenue assumptions have a material impact on project economics. It is challenging to figure out exactly where these numbers are coming from, but in reality they should be the assumed net metering credit value minus customer savings. If they are intended to reflect the value of future REC sales, the Joint Solar Parties urge the IPA to provide a basis for the estimated REC value, including who the IPA believes are the likely purchasers. Furthermore, the

[6] Indeed, the smart inverter rebate is not revenue in to the project until after the system is operational.

Joint Solar Parties point out the disparity in the treatment of this revenue assumption for a 2MW DG systems vis-à-vis a community solar system. As discussed above, a 2MW system will most certainly be associated with a competitive class commercial customer, and the credit value would be the same as received by a similar community solar offtaker. The IPA should adjust this revenue assumption to both align with the customer and project appropriate net metering credit as discussed in Section III.A. and account for customer savings as discussed in Section II.D.2.

IV.

OTHER ADJUSTMENTS

A. The Model Should Be Based on an Unleveraged Rate of Return

Similar to many other costs and revenues, interest rates, and financing terms including debt-equity ratio and debt structure will greatly vary between Adjustable Block participants. Because these characteristics are all subjective and project-specific, the Joint Solar Parties do not recommend that the IPA allow the model to adapt to a particular project's debt and equity characteristics. Instead, the Joint Solar Parties recommend that the IPA consider an unleveraged rate of return for several reasons.

First, because RECs are paid on an accelerated basis, the Joint Solar Parties anticipate that financing will not uniformly consist of long-term debt. Second, because the model does not (and in the opinion of the Joint Solar Parties should not) include a cash hold-back or reserve for accelerated REC payments, the model essentially anticipates (but cannot address) the potential for negative after-tax cash flow in later years and a corresponding inability to cover debt payments if such debt is used. Third, it will be far simpler to model an unleveraged rate of return, because the IPA does not have to guess at a realistic or accurate financing rate.

That said, the Joint Solar Parties fully support IPA's use of a 12% levered internal rate of return assumption for behind the meter solar. The Joint Solar Parties suggest that IPA translate this into an unlevered assumption and remove all interest/principle payments. The Joint Solar Parties believe this value appropriately balances the favorable nature of certain benefits while recognizing the investment is riskier than a regulated monopoly utility investment. However, the Joint Solar Parties recommend that the IPA consider a higher internal rate of return for community solar projects, where the necessity of obtaining and maintaining subscriptions (or be subjected to the non-zero but less lucrative QF rate the utilities must pay for unsubscribed shares) introduces significant additional risk—especially if residential and small commercial customers are involved. However, this must be balanced with the principle of keeping onsite and offsite projects on equal footing. The Joint Solar Parties do not have an estimate of the proper internal rate of return for a community solar project at this time.

B. The Model Should Assume a Different Capacity Factor for DG Systems vs Community Solar Systems

The IPA proposes to use the same capacity factor for all systems, based on the capacity factor it has observed from its distributed generation procurements pursuant to Section 1-56(i) of the Illinois Power Agency Act. However, capacity factors are determined not only by the solar irradiation at a specific geographic location, but also by the tilt of the panels towards the sun. For ground mount projects, of which utility scale projects are almost without exception, system design allows for optimal tilt towards the sun. However, for rooftop solar, the tilt is by necessity at a lower angle if the system is flush to the roof, generally 10% on a flat roof vs 25 to 30% for ground mount in Illinois. This difference in tilt, holding panel azimuth constant, leads to a significantly different capacity factor.

While the Joint Solar Parties support this assumption for community solar systems – which will likely be predominantly ground mounted systems, the Joint Solar Parties urge the IPA to use a lower capacity factor in its model to calculate REC values for DG systems[7].

Through analysis run by Joint Solar Parties member companies, PVWatts produces the following capacity factors for rooftop C&I vs ground mount:

Region	PVWatts											
	Rooftop C&I				Ground Mount (fixed tilt)				Ground Mount (tracker)			
	Capacity Factor (DC)	Capacity Factor (AC)	Production for 1 MWdc System	Yield (kWh/kW)	Capacity Factor (DC)	Capacity Factor (AC)	Production for 1 MW System	Yield (kWh/kW)	Capacity Factor (DC)	Capacity Factor (AC)	Production for 1 MW System	Yield (kWh/kW)
Northern IL (Rockford)	13.6%	16.3%	1,191,360	1,191	15.1%	18.1%	1,322,760	1,323	18.0%	21.6%	1,576,800	1,577
Central IL (Springfield)	14.4%	17.3%	1,261,440	1,261	16.1%	19.3%	1,410,360	1,410	19.4%	23.3%	1,699,440	1,699
Southern IL (Evansville)	14.0%	16.8%	1,226,400	1,226	15.4%	18.5%	1,349,040	1,349	18.4%	22.1%	1,611,840	1,612
Average	**14.0%**	**16.8%**	**1,226,400**	**1,226**	**15.5%**	**18.6%**	**1,360,720**	**1,361**	**18.6%**	**22.3%**	**1,629,360**	**1,629**

This overestimation of capacity factor for rooftop systems has the effect of overestimating the revenue coming into a DG project vis-à-vis a community solar project, introducing a competitive disadvantage for rooftop solar. Therefore, the Joint Solar Parties urge the IPA to use a 14% capacity factor in Appendix E-1 for calculating REC values for DG systems.

C. The Model Should Be Harmonized With Statutory Units and Measures

Unlike previous statutory requirements, which were either silent on units or required measurement in direct current (DC), some of the statutory requirements for Adjustable Block facilities are in alternating current (AC). For instance, the statutory maximum unit size for eligibility in the Adjustable Block program is expressed in AC, not DC:

> "Community renewable generation project" means an electric generating facility that: . . .
> (4) is limited in nameplate capacity to less than or equal to 2,000 kilowatts.
> * * *

[7] Note that in its comments on the Long Term Plan, the Joint Solar Parties support IPA's use of average capacity factors for the calculation of REC values but urges the IPA to allow projects to submit their own estimate of production based on PVWatts for the purposes of REC delivery obligations.

> "Distributed renewable energy generation device" means a device that is: . . . (4) limited in nameplate capacity to less than or equal to 2,000 kilowatts.
> * * *
> "Nameplate capacity" means the aggregate inverter nameplate capacity in kilowatts AC.

(20 ILCS 3855/1-10.) However, the nameplate capacity is expressed in the model in terms of DC. The IPA should update the model to harmonize the model with the statutory definition.

On the other hand, the $250/Watt smart inverter rebate is expressed in terms of DC: "The value of the rebate shall be $250 per kilowatt of nameplate generating capacity, measured as nominal DC power output, of a non-residential customer's distributed generation." (220 ILCS 5/16-107.6(c)(1).) This should be expressed in DC units.

V.

CONCLUSION

The Joint Solar Parties greatly appreciate the opportunity to provide feedback on the model presented with the draft LTRRPP for public comment. Although these comments focused mostly on changes to improve the model, the Joint Solar Parties wish to emphasize that the model itself is generally well constructed, but simply will benefit from improved values and assumptions. If the IPA makes the changes proposed above, the Joint Solar Parties believe that the Adjustable Block program will better meet the statutory goal of a transparent model that adjusts predictably over time and allows the Illinois solar industry to scale up. The Joint Solar Parties look forward to addressing other issues with the Adjustable Block program (including the International Trade Commission case that could result in a tariff on imported solar panels) in separate comments.

Respectfully submitted,

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