

**STATE OF ILLINOIS**  
**ILLINOIS COMMERCE COMMISSION**

<b>Illinois Power Agency</b>	:	
	:	
<b>Petition for Approval of the IPA's Revised</b>	:	<b>19-0995</b>
<b>Long-Term Renewable Resources</b>	:	
<b>Procurement Plan Pursuant to Section</b>	:	
<b>16-111.5(b)(5)(ii) of the Public Utilities Act.</b>	:	

**ORDER**

February 18, 2020



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ORDER

By the Commission:

**I. PROCEDURAL HISTORY**

This matter concerns a verified Petition filed with the Illinois Commerce Commission (“Commission”) by the Illinois Power Agency (“IPA” or “Agency”) for approval of the first Revised Long-Term Renewable Resources Procurement Plan (“Revised Plan” or “Revised LTRRPP”) on October 21, 2019 (“IPA Petition”).

The Initial Long-Term Renewable Resources Procurement Plan (“Initial Plan” or “Initial LTRRPP”) was developed by the IPA pursuant to the provisions of Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act (“IPA Act”) and Section 16-111.5 of the Public Utilities Act (“PUA”). The Initial Plan was developed under authority established through Public Act 99-0906 (“PA 99-0906”), enacted December 7, 2016 (effective June 1, 2017), which substantially revised the Illinois Renewable Portfolio Standard (“Illinois RPS” or “RPS”). The Initial Plan covered the IPA’s renewable energy resources procurement and programmatic activities for 2018 and 2019 and was approved by the Commission in Docket No. 17-0838. *Ill. Power Agency*, Docket No. 17-0838, Order (Apr. 3, 2018).

Section 16-111.5(b)(5)(ii)(B) of the PUA provides that the IPA “shall review, and may revise, the plan at least every 2 years thereafter.” 220 ILCS 5/16-111.5(b)(5)(ii)(B). The Revised Plan constitutes the IPA’s first such update. This subparagraph further provides that “[t]o the extent practicable, the [IPA] shall review and propose any revisions to the long-term renewable energy resources procurement plan in conjunction with the [IPA]’s other planning and approval processes conducted under this Section.” On August 15, 2019 a draft Revised Plan was released for public comment concurrently with the IPA’s release of its draft 2020 Electricity Procurement Plan. The Revised Plan filed for Commission approval reflects the IPA’s consideration of comments received on the draft Revised Plan.

The Administrative Law Judge (“ALJ”) granted the following Petitions to Intervene: Ameren Illinois Company d/b/a Ameren Illinois (“Ameren”); the Solar Energy Industries Association, the Coalition for Community Solar Access, and the Illinois Solar Energy

Association (together “Joint Solar Parties” or “JSP”); Carbon Solutions Group (“CSG”); Cypress Creek Renewables, LLC; Environmental Law & Policy Center and Vote Solar (together, “ELPC/VS”) and Natural Resources Defense Council (jointly, “ELPC/NRDC/VS”); Commonwealth Edison Company (“ComEd”); Summit Ridge Energy, LLC (“Summit”); the Illinois Chamber of Commerce (the “Chamber”); and the Citizens Utility Board (“CUB”). Staff of the Commission (“Staff”) and the Illinois Attorney General’s Office (“AG”) also participated in this proceeding.

On November 8, 2019, an ALJ Ruling was issued that stated that no hearing would be held in this matter and that instead verified comments would be required.

Objections to the Revised Plan (“Objections” or “Obj.”) were filed on November 4, 2019 by the following parties: Staff, ComEd, Ameren, the Joint Solar Parties, ELPC/VS, and Summit. Responses to Objections to the Revised Plan (“Responses” or “Resp.”) were filed on December 2, 2019 by the Chamber and on December 3, 2019 by the following parties: Staff, the Joint Solar Parties, the AG, Ameren, ComEd, the IPA, and ELPC/NRDC/VS. Replies to Responses (“Replies” or “Rep.”) were filed December 17, 2019 by the following parties: CSG, ComEd, Staff, the Joint Solar Parties, Ameren, Summit, the IPA, ELPC/NRDC/VS, and CUB.

The ALJ served the Proposed Order on January 15, 2020. Briefs on Exceptions were filed on January 24, 2020 by the following parties: CSG, ELPC/NRDC/VS, Staff, ComEd, the Joint Solar Parties, the IPA, Ameren, and the AG. Reply Briefs on Exceptions were filed on January 31, 2020 by the following parties: Staff, the Joint Solar Parties, Summit, Ameren, ELPC/NRDC/VS, ComEd, and the IPA.

The Initial Plan addressed the IPA’s proposed set of programs and competitive procurements to acquire renewable energy credits (“RECs”) for RPS compliance obligations applicable to three Illinois electric utilities: Ameren, ComEd, and MidAmerican. The Initial Plan also described how the IPA would develop and implement the Illinois Solar for All (“ILSFA”) Program, which utilizes a combination of funds held by the IPA in the Renewable Energy Resources Fund (“RERF”) and funds supplied by the utilities from ratepayer collections, to support the development of photovoltaic resources, along with job training opportunities (supported separately) to benefit low-income households and environmental justice communities.

The Revised Plan covers the IPA’s proposals for procurements and programs that could be conducted during calendar years 2020 and 2021. However, as discussed throughout the Plan, absent legislative changes, RPS budget limitations will constrain the ability of the IPA to conduct additional procurements or expand program capacity for its Adjustable Block Program. Therefore, the Revised Plan provides a general framework for changes to procurements and programs should additional funding become available.

The IPA expects that as part of its annual procurement planning process conducted in calendar year 2021 (for implementation in 2022), it will again update and revise this Plan.

## II. CHAPTER 2: LEGISLATIVE/REGULATORY REQUIREMENTS OF THE PLAN

### A. Section 2.5.2.2 Opt-out Municipal Aggregation

#### 1. Joint Solar Parties

The Joint Solar Parties note that the IPA invited stakeholders to request an explicit ruling from the Commission that an opt-out aggregation may include community solar. See IPA Petition at 27. The Joint Solar Parties agree with ELPC/VS that community solar subscriptions could legally be included as an opt-out aggregation product under Section 1-92 of the IPA Act. Section 1-92 explicitly allows municipalities, counties, and townships to “solicit bids and enter into service agreements to facilitate for those loads the sale and purchase of electricity *and related services and equipment.*” 20 ILCS 3855/1-92(a) (emphasis added). The Joint Solar Parties note that the phrase “and related services” recurs throughout Section 1-92. Because subscriptions impact the sale and purchase of electricity (specifically through the bill credit), Section 1-92 must be interpreted as allowing subscriptions to be a part of opt-out aggregation. The Joint Solar Parties urge the Commission to specifically hold that “the municipal aggregation approach is legally permissible,” as the IPA requested as a prerequisite to convening a stakeholder process. Consistent with the IPA’s stated reluctance to enable opt-out municipal aggregation, the Commission should also require the IPA to conduct a process that results in integration of subscriptions and behind-the-meter systems with the Adjustable Block Program and ILSFA systems into opt-out municipal aggregation. JSP Obj. at 12-13.

ComEd—and to some extent the IPA—argue that the issue is out of scope for the docket. ComEd’s argument that the request is out of scope is belied by the IPA itself raising the issue in Section 2.5.2.2 of the LTRRPP. The IPA argues that not all stakeholders are in this docket but does not explain why stakeholders who are interested were unable to intervene after reviewing Section 2.5.2.2 of the draft or filed Revised LTRRPP or the Joint Solar Parties’ Objections. Also, the IPA does not identify the stakeholders that might object to the Joint Solar Parties’ request who might be prejudiced by not participating in the present docket. JSP Rep. at 7.

The IPA’s argument that the IPA Act does not mention “subscriptions” and referenda under Section 1-92(a) is a red herring. See IPA Resp. at 4. As an initial matter, the fact that “subscription” is not mentioned in Section 1-92 is irrelevant. Nowhere in Section 1-92 are RECs mentioned, yet RECs are frequently part of opt-out aggregation programs and the Joint Solar Parties are unaware of IPA objections to including RECs as part of opt-out aggregations. RECs are no less related to energy supply than a subscription. Furthermore, even if the Commission agreed (which it does not) with the IPA that referenda passed before the effective date of PA 99-0906 could not have contemplated subscriptions, a municipality, county, or township could simply issue another referendum with the statutorily required language. The Joint Solar Parties further note that, contrary to the IPA’s concerns, Part 470 neither “implements Section 1-92” (it simply governs alternative retail electric supplier (“ARES”) behavior) nor prohibits inclusion of subscriptions. See IPA Resp. at 4; JSP Rep. at 7-8.

With regard to the IPA’s concerns about signing the disclosure form, the purpose of Section 1-92 is to allow elected officials—supported by consultants and village counsel—to negotiate on behalf of their residents for a standard opt-out offer that each

resident may reject for any or no reason. By requiring a customer-signed disclosure form, the IPA is inserting itself between elected officials—who obtained the power to negotiate an opt-out product on behalf of their residents by referendum—and the residents that voted for that power. JSP Rep. at 8.

Ameren does not take a position on the Joint Solar Parties' request but recommends that the Commission consider the potential effects of allowing subscriptions of LTRRPP-procured systems in opt-out aggregation. The Joint Solar Parties appreciate that if the Commission makes their requested rulings it would likely be the beginning—rather than the end—of working through implementation issues. The Joint Solar Parties anticipate that such issues would come up at minimum in the IPA's next energy procurement plan, and likely in stakeholder meetings beforehand. JSP Rep. at 9.

## **2. ELPC/NRDC/VS**

ELPC/NRDC/VS acknowledge the concerns raised by the IPA about opt-out municipal aggregation and agree that more discussion would be needed to have confidence in an opt-out municipal aggregation that includes community solar. However, ELPC/NRDC/VS also agree with the Joint Solar Parties that the plain reading of the statute does not appear to foreclose the possibility that community solar could be included as one of the “related services and equipment” referred to in the municipal aggregation statute at Section 1-92 of the IPA Act. Thus, ELPC/NRDC/VS agree that the Commission should not interpret the statute to definitively prohibit community solar. Instead, ELPC/NRDC/VS join the Joint Solar Parties in requesting that the Commission convene a stakeholder process in which the intersection of municipal aggregation and community solar can be further discussed. ELPC/NRDC/VS Resp. at 37.

## **3. Ameren**

Ameren does not take a specific position on this request; however, Ameren does have some concerns related to the impact this request may have when coupled with the Joint Solar Parties' other request regarding the applicability of Section 1-75(c)(1)(N). Ameren Resp. at 5. The Joint Solar Parties' request, that the Commission find “that for [Adjustable Block Program] and other LTRRPP-procured community renewable generation projects the utility is the sole source of monetary net metering credits for subscribers,” JSP Obj. at 11-12, is magnified when combined with the inclusion of community solar subscriptions as an opt-out aggregation product. Currently, approximately 60% of Ameren's residential customers are served by an ARES, with virtually all receiving service through an aggregation program. When aggregation was implemented, the number of customers switching, and the abrupt migration of their load, introduced significant uncertainty into Ameren's ability to forecast load and the IPA's ability to effectively hedge its supply agreements. This uncertainty led to the adoption of the current biannual procurement process by the IPA, and history suggests that forecasting uncertainty and hedging uncertainty typically translates into higher customer supply costs. Ameren would request that the Commission consider the impact the Joint Solar Parties' request would have on not only the utility's ability to properly plan its procurement needs but the potential financial impact on Ameren's supply service customers. Ameren Resp. at 5-6.

#### **4. ComEd**

In response to the Joint Solar Parties' request, ComEd states that the request is simply not germane to this docket. The Revised LTRRPP was submitted for Commission consideration and approval under Section 1-56(b) and 1-75(c) of the IPA Act and Section 16-111.5(b)(5) of the PUA. See IPA Petition 1. Municipal aggregation is authorized under Section 1-92 of the IPA Act. 20 ILCS 3855/1-92; ComEd Resp. at 7.

Second, the IPA did not invite requests for a determination on this issue. The IPA was merely responding to the ELPC/VS comments regarding its draft plan. IPA Petition at 27. ComEd states this is not the time or the place to raise this unrelated issue of statutory interpretation. ComEd Resp. at 7.

#### **5. Staff**

Staff believes that the parties' arguments should give the Commission pause. However, should the Commission agree with the parties that support the legality of opt-out municipal aggregation, Staff agrees with ELPC/NRDC/VS that a stakeholder process is an important safeguard to prevent any unintended effects on customers or the Adjustable Block Program. Staff Rep. at 6.

#### **6. IPA**

The Revised Plan at Section 2.5.2.2 states that, first, the IPA is highly skeptical that municipal aggregation of community solar subscriptions could be construed as a permitted "related service" to electricity under Section 1-92 of the IPA Act, and second, even if opt-out municipal aggregation of community solar subscriptions were legally authorized, subscribers must still individually review and execute individual subscription disclosures if their community renewable generation project is participating in the Adjustable Block Program, ILSFA, or the Agency's Non-Solar Community Renewable Generation Procurement. IPA Resp. at 3.

Also, the IPA also believes that the municipal aggregation concept is not authorized for community project subscriptions because: (i) any authorizing referendum that a municipality's voters previously passed under Section 1-92(a) for opt-out electric supply enrollment did not mention community solar subscriptions, since the standard referendum language in Section 1-92(a) refers only to "supply of electricity" and the community solar concept has been legally permissible for less than three years, post-dating the most recent opt-out aggregation referendum in the state (thus raising due process concerns around what authorization could have been offered by voters); (ii) PA 99-0906, which legally created the concept of community renewable generation projects in Illinois, did not mention municipal aggregation; (iii) Part 470 of the Commission's Rules, implementing Section 1-92, considers only municipal aggregation of electric supply rather than community project subscriptions (83 Ill. Adm. Code 470); and (iv) opt-out enrollment in a community project subscription would likely also entail a customer's enrolling in virtual net metering under a utility's tariff, again without the customer's actual affirmative consent. IPA Resp. at 3-4.

In addition, the IPA asserts that this proceeding is not the forum for the Commission to decide the legality of opt-out municipal aggregation for community solar subscriptions, as numerous interested stakeholders (the many municipalities that might

be interested and the private brokers that might assist them in soliciting bids) would not be on notice that the issue is being decided. In the IPA's view, the Commission should not attempt to rule on the question in this docket. IPA Resp. at 4.

If municipal aggregation of community solar subscriptions were found to be legally authorized by the Commission or some other authoritative adjudicatory body, the IPA would continue to strongly oppose any attempt, as suggested by the Joint Solar Parties, to relax the requirements of Section 6.13 of the Revised Plan regarding receipt of a standard brochure and receipt and execution of a standard disclosure form. The IPA's brochure and disclosure form requirements are fundamental to subscribers receiving standardized information and constitute the backbone of the IPA's efforts to deliver uniform content and education about the rights and obligations under a ratepayer-funded program to everyday citizens. IPA Resp. at 5. IPA Rep. at 4.

A 2 megawatt ("MW") community solar project participating in the Adjustable Block Program could receive up to \$4 million in incentive funding through its REC delivery contract alone. Those generous incentives, administered by the State of Illinois through the IPA, are premised in part on the expected costs of subscriber acquisition and management. Necessitating that a participating project must agree to meet certain standards is a relatively small requirement for the State of Illinois to make in light of offering such generous incentive funding. Besides, assuming opt-out aggregation for community solar subscriptions was legally authorized, a community solar developer seeking to acquire subscribers via opt-out municipal aggregation could simply choose to forego the Adjustable Block Program or ILSFA Program should it find individual subscriber acquiescence to be too burdensome. Given that option, relaxing consumer protection requirements for projects participating in IPA-administered programs would make little sense. IPA Rep. at 4-5.

Lastly, Ameren's Response mentions potential load migration concerns related to utilizing municipal aggregation for community solar subscriptions. While not entirely responsive to Ameren's point, the IPA wishes to highlight an aspect of subscriber acquisition via aggregation that may be likewise troubling. A standard 2 MW community solar project may support the energy consumption levels of perhaps 400 average residential customers (i.e., through assuming a 5 kilowatt ("kW") standard subscription size). Thus, 10 such projects would support 4,000 residents, and so on. Through the Adjustable Block Program, the IPA has only approved 112 community solar projects totaling over 214 MW. The IPA questions whether a mid-sized municipality could even utilize community solar subscriptions through municipal aggregation. IPA Rep. at 5-6.

The State's choice to allow for and support community solar is presumably premised on its ability to present a different renewable energy product than was already available through the market. Reducing subscribers down to tens of thousands of passive participants who may have no knowledge of their fractional individual participation—and never having offered direct acquiescence to that participation—begins to mirror renewable energy participation through existing passive means, such as the broader decarbonization of energy supply through much less expensive utility-scale projects. From a policy standpoint, this is problematic; the significant premiums for REC prices from community solar projects versus utility-scale projects can only be justified if high value is attributed to direct customer participation in a project. IPA Rep. at 6-7

The IPA thus asks to clarify Section 6.13 of the Revised Plan to provide that any community solar subscription aggregation program (if legally possible) for a project participating in the Adjustable Block Program or ILSFA would still need to ensure that every individual subscriber receives and executes an individualized standard disclosure form. The IPA believes that Section 1-75(c)(1)(N) of the IPA Act, which empowers the Agency to “establish the terms, conditions, and program requirements” for community solar projects participating in the Adjustable Block Program, gives ample authority for this requirement, just as it does for any other non-aggregated community solar subscription. IPA Resp. at 5.

## **7. Commission Analysis and Conclusion**

The Commission notes that Section 1-92 of the IPA Act states that:

The corporate authorities of a municipality, township board, or county board of a county may adopt an ordinance under which it may aggregate in accordance with this Section residential and small commercial retail electrical loads located, respectively, within the municipality, the township, or the unincorporated areas of the county and, for that purpose, may solicit bids and enter into service agreements to facilitate for those loads the sale and purchase of electricity and related services and equipment.

20 ILCS 3855/1-92(a). Pursuant to this language, the Commission finds that even if community solar is not specifically prohibited, it is also not specifically allowed. This is not surprising as the IPA points out that community solar subscriptions were not contemplated anywhere in Illinois law when Section 1-92 was enacted via Public Act 96-0176 in 2009. Even more important for purposes of this docket, community solar as envisioned in the Adjustable Block Program was not contemplated when the municipal aggregation provisions were enacted.

The Commission agrees with the IPA that this proceeding is not the forum for the Commission to decide the legality of opt-out municipal aggregation for community solar subscriptions, as numerous interested stakeholders - such as the many municipalities that might be interested and the private brokers that might assist them in soliciting bids - would not be on notice that the issue is being decided. IPA Resp. at 4.

Practically speaking, this will not impact current municipal aggregations because no referendum asked whether the municipal aggregation should also include community solar subscriptions. Also, the IPA identifies lots of problems if it were found to be permitted by the IPA Act – problems which should not be addressed without all necessary parties being notified.

Although the possibility of a municipal aggregation program providing community solar is fairly unlikely, the IPA nevertheless asks to clarify Section 6.13 of the Revised Plan to provide that any community solar subscription aggregation program (if legally possible) for a project participating in the Adjustable Block Program or ILSFA would still need to ensure that every individual subscriber receives and executes an individualized standard disclosure form. The Commission agrees that the IPA can do this, although at

this point it seems unnecessary and would only apply to Adjustable Block Programs which receive IPA funding, not other community solar programs.

### **III. CHAPTER 3: RPS GOALS, TARGETS, AND BUDGETS**

#### **A. Section 3.22 Impact of RPS Budget on Procurement and Program Activities**

##### **1. Ameren**

Ameren notes that Section 1.1 in the Revised Plan identifies a Second Subsequent Forward Procurement with the goal of procuring 1,000,000 RECs annually from new utility-scale wind projects as a remaining activity that was approved in the Initial Plan. This procurement was originally scheduled to occur in Fall 2019 and the results of the procurement event were sent to the Commission for approval at its October 30, 2019 meeting. At the meeting, however, the Commission rejected the results of the utility scale wind procurement event based on the recommendation of the procurement administrator. In light of this rejection, Ameren recommends that the Revised Plan specifically state the funds that were allocated for this procurement event in the Initial Plan be used for additional utility-scale wind RECs in the Revised Plan. Ameren Obj. at 1-2.

In its Response, the IPA agrees and proposes to conduct a utility-scale wind procurement in 2020 or 2021 for the 1,000,000 RECs which were previously sought in the recently rejected procurement event. Additionally, the IPA states the procurement should first include stakeholder feedback similar to the first brownfield solar REC procurement which was not successful. *Id.* at 9; Ameren Rep. at 6-7. Ameren does not object to either of these proposals.

Ameren notes that the IPA makes an additional proposal that the procurement not be conducted until after a single REC Contract is developed through the stakeholder process referenced in the Revised Plan. While Ameren has not objected to the concept of pursuing a single REC Contract, Ameren suspects this will take considerable effort with the potential for a robust stakeholder debate and the potential for gridlock. Therefore, rather than the utility-scale wind REC procurement be contingent on the completion of a single REC Contract stemming from the stakeholder process as proposed by the IPA, Ameren recommends that the Plan be amended to state that the next utility scale wind REC procurement will occur no later than May 31, 2021, even in the event the stakeholder process fails to result in a single REC Contract. Further, if a single REC Contract is not developed, the latest version of the utility-scale REC Contract would form the basis for the 2021 contract, subject to minor modification where warranted. Ameren Rep. at 7.

In addition to this utility-scale wind procurement, the Revised Plan indicates that projected budgets will likely not be enough to cover forward looking expenses associated with the Initial LTRRPP. The Revised LTRRPP acknowledges that multiple factors could ultimately result in changes to this projection, including higher than forecasted retail sales of electricity, lower than expected small subscribers for community solar projects, less than complete subscription levels for community solar projects, failure of projects currently under contract to be developed and the potential for legislative changes which could increase future renewable budgets. Finally, the Revised Plan indicates that the expense projections are intentionally on the higher side of expectations and Ameren

states that this is appropriate, given the uncertainty in future renewable budgets. Ameren Obj. at 3.

As a result of this uncertainty, the Revised Plan recommends no further REC procurements or awards. However, should budget funds become available, the Revised Plan proposes a contingency approach which would prioritize budgets in the following order: 1) awards of up to 500,000 RECs per year under the Adjustable Block Program; 2) target of 50,000 RECs per year from a competitive brownfield solar procurement; 3) a competitive procurement of utility-scale solar; and 4) a competitive procurement of utility-scale wind. Additionally, the Revised Plan recommends the alternative compliance funds be allocated towards the Adjustable Block Program. These funds were previously collected from utility real time pricing customers and retail electricity suppliers and are currently held by the utilities in liability accounts. Ameren Obj. at 3-4.

Ameren recommends modifying the Revised Plan's contingency approach as follows: 1) a 50/50 split among competitive REC procurements for utility-scale solar and wind, with alternative compliance funds being used for these procurements; 2) target of 50,000 RECs per year from a competitive brownfield solar procurement; and 3) incremental awards under the Adjustable Block Program only to the extent that it can be demonstrated that the cost of RECs awarded are expected to be lower cost than the options above.

Ameren believes utility-scale REC procurements are likely to yield the highest quantity of RECs under contract at the lowest cost to customers. Data from existing contracts stemming from the Initial Plan indicates that utility-scale RECs have averaged a little over \$4 per REC, whereas Adjustable Block Program RECs have averaged about \$61 per REC, more than 14 times higher than utility scale RECs. The primary reason for the projected REC budget constraints is the significantly higher price of the Adjustable Block Program REC purchases, with these RECs accounting for only about 13% of total RECs under contract from the Initial Plan, while they account for more than 90% of total payments that will be made to suppliers over the next few years. Although the Revised Plan states that utility-scale REC targets have already been achieved, Ameren notes that the utility scale REC targets are identified as minimums under the statute. In other words, the Revised Plan has the authority to seek additional utility scale RECs beyond the minimum targets. Ameren Obj. at 4-5.

In hindsight, Ameren believes the administratively-set prices for the Adjustable Block Program RECs under the Initial LTRRPP were set too high and this led to oversubscription of blocks in community solar and large distributed generation. These high REC prices have been the primary driver of the current REC budget constraints and the result is that approximately 90% of RPS budget dollars over the next several years will be spent on Adjustable Block Program RECs. Ameren states that it has executed about \$237 million in Adjustable Block Program contracts with an expectation that once systems are energized, it should receive about 261,000 RECs per year. In contrast, Ameren has about \$110 million in executed utility scale REC contracts with an expectation that once systems are energized, it should receive about 1,700,000 RECs per year. The price gap between Adjustable Block Program RECs and utility-scale RECs has been approximately 1400%. Ameren Rep. at 5-6.

Although ELPC/NRDC/VS argue that the low utility-scale REC prices may not be sustainable going forward based upon the IPA's statement, Ameren notes that utility-scale REC prices could increase in excess of 1400% before they would equal those incurred under the Adjustable Block Program. Further, all the concerns raised by ELPC/NRDC/VS can be addressed through the IPA and Staff process associated with the confidential price caps (benchmarks) in future utility-scale REC procurements. These price caps form the maximum price under which the IPA and Commission will award REC contracts for which the utility executes. This process affords the IPA and Staff the ability to increase the price cap as necessary to reflect current market conditions. Ameren Rep. at 19.

In their Response, ELPC/NRDC/VS point out that the Investment Tax Credits will ramp down for both commercial and residential renewable systems. ELPC/NRDC/VS Resp. at 21. They argue this should be a justification to pursue Adjustable Block Program RECs now as opposed to later. However, ELPC/NRDC/VS fully acknowledge that costs to install these systems are likely to decline over time. *Id.* The implication is that ELPC/NRDC/VS are speculating that the negative impact of tax credit phase outs will exceed the benefit of declining solar installation costs. However, Ameren opines that the relationship between future tax credit impacts and declining solar installation costs is not known. More importantly, assuming for the sake of argument that ELPC/NRDC/VS's argument has merit, it would advocate for maximizing utility-scale RECs (and not Adjustable Block Program RECs) as soon as possible to increase the amount of installed renewable MWs in advance of the tax credit phase out. Ameren Rep. at 19-20.

Considering the cost efficiencies of utility scale REC procurements, Ameren concludes that the installed MW capacity of newly developed renewable generation within Illinois should be substantially higher when compared to the MWs associated with Adjustable Block Program REC awards. This takes on a higher level of importance when considering that about 2,000 MW of Illinois fossil fuel generation retirements are proposed by the end of 2019. Ameren Obj. at 4-5.

In addition, implementing Ameren's recommendations would improve the IPA's progress towards the REC annual percentage goals. The RPS also has a target to achieve 25% RECs by 2025/2026, whereas the current status is that the 2019/2020 actual is approximately 7% compared to a 2019/2020 target of 17.5%. The key takeaway is that the majority of renewable dollars under contract have been committed to Adjustable Block Program RECs (using best available information, about \$800,000,000) and yet, the quantity of RECs under those contracts are not having an impact to move the State closer to its total REC targets. Ameren believes its proposal to prioritize utility scale RECs over Adjustable Block Program RECs in the IPA's contingency plan is the best course of action. Doing so would make the most efficient use of customer paid funds by maximizing RECs for the least cost and the result would be a lessening of the gap in total REC targets. Ameren Rep. at 18.

Ameren understands the statutory intent to pursue a balance between utility-scale solar and wind and the Adjustable Block Program. However, Ameren emphasizes the 2020/2021 statutory target of 1,000,000 RECs per year for the Adjustable Block Program has already been exceeded and further, the 2025/2026 target of 1,500,000 RECs (less than 500,000 RECs remaining) is approximately 6 years and 5 months in the future. As

stated previously, this allows the IPA two more Plans (2021 and 2023) and about \$1.5 billion in incremental customer collections in order to satisfy the 2025/2026 target for the Adjustable Block Program. Ameren Rep. at 17-18. This can be achieved during the implementation of the next two LTRRPP's which are expected to be filed in 2021 and 2023. In the interim, the IPA should focus on maximizing RECs at the lowest possible cost so as to close the significant gap in the RPS percentage target (the "REC Gap"). The RPS target is calculated as a percentage of total retail load and it increases 1.5% per annum until 2025-2026 when it reaches a maximum of 25% of total retail load. Ameren Rep. at 2-3

In addition, Distributed Generation solar costs may decline as the market matures and since Illinois has time to reach the remainder of the Adjustable Block Program target, delaying incremental awards may result in lower DG REC prices, thus providing benefit to customers and resulting in the development of additional renewable generation in the state. Delaying the award of additional Adjustable Block Program RECs will also allow time to formulate appropriate changes to the current program design.

The administration of the utility scale REC contracts is substantially simpler when compared to the Adjustable Block Program REC contracts and this translates into additional cost savings for Illinois customers. Using the alternative compliance funds for utility-scale RECs would make the most efficient use of these funds and is consistent with the Commission's Order in the Initial Plan. Ameren Obj. at 6. Although the IPA asserts that contract administration should not be a criteria in determining funding prioritization (IPA Resp. at 8), Ameren states that given that the high block prices for the Adjustable Block Program are the cause of the current budget constraints, it would seem important and consistent with the statutory goals that the IPA would entertain all means to efficiently utilize the customer funded RPS, including a desire to minimize administrative costs. Another factor is that any incremental Ameren staffing additions and related utility costs associated with the Adjustable Block Program will be recovered via tariffs from Ameren customers. Ameren Rep. at 4-5.

Ameren notes that the IPA opines that stopping the Adjustable Block Program for a few years would negatively impact solar installer jobs in Illinois, which in turn would negatively impact the Illinois economy. IPA Resp. at 7. In response, Ameren states that not only do the utilities already have a significant amount of contracts for distributed generation and community solar RECs stemming from the Initial LRTTPP, but that the vast majority of these contracts represent solar projects that are yet to be developed and additional distributed generation REC Contracts stemming from the Initial LRTTPP are expected to be executed in 2020 which represent projects that are yet to be developed. These undeveloped projects, and their associated backlog of work, should keep solar installers and associated jobs with a considerable amount of work into the foreseeable future. Furthermore, utility scale projects would also add jobs and help to provide assurances that wholesale power prices continue to remain affordable for customers. Ameren Rep. at 3-4.

## 2. AG

The AG agrees that funds already budgeted for utility-scale wind procurements should be explicitly retained in the Revised Plan for future utility-scale wind procurements. AG Resp. at 4.

In response to Ameren's suggested revisions to the contingency plan, the AG shares Ameren's interest in the procurement of statutorily-mandated REC quantities at the lowest possible cost to consumers. The AG points to the large disparity in price between utility-scale RECs and all others. The AG suggests that, where permissible under the law, the IPA should apply procurement prioritization guidelines to achieve the most cost-effective results possible. The relatively low utility-scale REC prices, at less than \$5.00 per REC, can help the State progress towards its carbon reduction goals efficiently and at a lower cost to the public. AG Resp. at 5-6.

Considering together (1) the statutory cost cap, (2) the limited amount of time to reach the statutory goal of statewide RECs equaling 25% of retail customer load in 2025 and current progress towards that goal, (3) the IPA's projected budget shortfall, and (4) the resultant recommendation in the Revised Plan to not conduct any further procurements, the AG urges the Commission to direct the IPA to modify the Revised Plan to prioritize utility-scale procurements before any other new procurements are considered to address the REC Gap. The Revised Plan considers the possibility that alternative compliance funds may be used to ensure contract obligations are met. Revised Plan at 28. The AG does not argue that the IPA should violate or risk violation of any existing contract terms and makes this recommendation subject to availability of alternative compliance funds outside of satisfying existing contractual obligations. AG Resp. at 6.

The IPA Act establishes lower and upper limits for the number of RECs to be procured from utility-scale wind per year. The IPA must procure at least 1,000,000 RECs per year from utility-scale wind, but the cumulative amount of new RECs delivered from new wind projects cannot exceed the number of RECs the IPA projects will be delivered from new photovoltaic solar projects in the same delivery year. 20 ILCS 3855/1-75(c)(1)(G)(iii). Accordingly, if the Commission orders the IPA to prioritize procurement of utility-scale RECs, to the extent that the IPA must procure solar RECs to comply with Section 1-75(c)(1)(G), the AG urges the Commission to direct the IPA to specify in the Revised Plan that utility-scale solar RECs will be procured as long as they cost less on a dollar-per-REC basis than other types of solar RECs available. AG Resp. at 6.

The AG also agrees with Ameren that in light of already reaching the 2020 program target for the Adjustable Block Program and the quantity of RECs still needed to reach the 2025 goal, time remains to address the 2025 program target for the Adjustable Block Program via the 2021 and 2023 Long Term Renewable Resource Procurement Plans. Ameren Obj. at 5. The AG therefore urges the Commission to focus on near-term compliance challenges identified by the IPA in the Revised Plan and to address those challenges with the least-cost options available. Based upon available information, it appears to the AG that utility-scale procurements are the best and least-cost solution to the challenges at hand. AG Resp. at 7.

### 3. ELPC/NRDC/VS

While ELPC/NRDC/VS agree that overall costs are an important factor for the Commission to consider, Ameren's argument that the lowest cost should dictate the Revised Plan is misplaced. PA 99-0906 looks to increase not only the quantity, but also the quality and diversity of the renewable build. The IPA's proposed approach to prioritize any available funding first on the Adjustable Block Program is reasonable and consistent with the statute, and the Revised Plan should not be modified. ELPC/NRDC/VS Resp. at 19.

The IPA Act and the Initial Plan set out several requirements. First, the Revised Plan must include a way to meet the goals to procure a percentage of renewable energy credits tied to eligible retail sales; this percentage increases over time. Revised Plan at 49. Second, the Revised Plan must achieve certain new build targets for wind and solar through purchasing RECs. *Id.* (noting the Revised Plan distinguishes between the terms "goal" and "target" to help delineate the difference between overall percentage goal(s) and specific numeric REC mandates). These goals for new wind and solar RECs are 2,000,000 by 2020, 3,000,000 by 2025, and 4,000,000 by 2030 for each type of renewable energy. Revised Plan at 49-50. While the REC totals for new wind and solar build are equal, half of the solar RECs must be procured through the Adjustable Block Program. Revised Plan at 15. The Adjustable Block Program is designed to develop solar projects that are different than utility scale solar projects, e.g. on rooftops of homes and businesses and community solar projects, through set prices versus a competitive market. The solar projects in the Adjustable Block Program range from 1 kW to 2000 kW and typically are likely smaller in size than utility scale projects. ELPC/NRDC/VS Resp. at 19-20. The requirement that half of the new solar RECs be procured from the Adjustable Block Program and the emphasis on new build reflects a significant shift in how the Illinois General Assembly intended the program to work since the passage of PA 99-0906. ELPC/NRDC/VS Resp. at 20.

The legislative findings of PA 99-0906 give a broad overview of the changes and goals of the revisions to renewable procurement since 2016. The intent of PA 99-0906 is not simply to ensure compliance at the lowest cost, meaning purchasing RECs at the lowest price. Instead, the outcomes of PA 99-0906 are focused on increasing equity, including ensuring benefits and opportunities are felt by all Illinois citizens, maximizing adoption of distributed resources, and encouraging private investment and economic growth. Plan at 10. As the IPA has stated in its Plan, this was a meaningful shift away from lowest cost being the sole factor in determining what to procure. Plan at 10-11. ELPC/NRDC/VS Resp. at 20.

Ameren argues that utility scale renewables are the cheapest RECs, but ELPC/NRDC/VS opine that there is at least one indication that the current prices may not continue to be so low in the future. The Revised Plan states "the IPA has become aware of concerns held by developers of utility-scale renewable energy projects that there may be a shallow market for long-term bilateral energy off-take agreements for geographically qualifying projects which developers believe are necessary for providing the revenue certainty required for financing new facility construction." Revised Plan at 28. In other words, the IPA is indicating that current REC prices may not be enough to incite new projects if project developers do not have a contract to sell the associated electricity from

the project. The utility-scale REC prices experienced to date, alone, may be too low to actually bring about new build in the future. ELPC/NRDC/VS Resp. at 21.

Further, Ameren argues that all solar prices will continue to drop and this somehow warrants delaying more investment into the Adjustable Block Program. While costs for renewable energy systems will likely continue to decline over time, solar, especially residential systems, are facing a ramp down of the Investment Tax Credit that has spurred significant development of solar and corresponding economies of scale. Over the next three years, the Investment Tax Credit will decrease, starting at 30% in 2019; to 26% in 2020; to 22% in 2021; to 10% for commercial and 0% for residential in 2022. The Plan should take advantage of this tax incentive now to the maximum extent possible, as any reduction in cost of systems in equipment or installation unlikely will match the benefits of the Investment Tax Credit. ELPC/NRDC/VS Resp. at 21.

ELPC/NRDC/VS share the AG's interest in ensuring that the Plan procures the statutorily required proportion of RECs at the lowest possible cost to consumers. However, the IPA must implement this goal in light of the explicit statutory requirement that the IPA procure at least 50% of its quantitative new solar REC targets from Adjustable Block Projects. 20 ILCS 3855/1-75(c)(1)(C). ELPC/NRDC/VS also agree with the IPA that there are other positive attributes of a balanced distributed generation solar market that go "beyond a simple analysis of REC prices." IPA Resp. at 7. PA 99-0906 very deliberately created separate markets for utility scale renewables that compete in wholesale markets and distributed generation (behind the meter and community solar) in recognition of the fact that these two types of projects provide different and distinct benefits to the grid. These include the impact on Illinois workers and businesses and the desire (as demonstrated by thousands of applications to date) of Illinois homeowners and businesses to install solar. These and other characteristics of a healthy distributed generation market motivated the Illinois General Assembly to explicitly require the IPA to procure "at least" 50% of the new solar RECs from Adjustable Block Program projects. 20 ILCS 3855/1-75(c)(1)(C). ELPC/NRDC/VS Rep. at 3-4.

Thus, while ELPC/NRDC/VS share Ameren and the AG's overall interest in cost-effective procurement within the context of the statutorily prescribed balance between utility-scale and distributed generation, ELPC/NRDC/VS cannot support the specific recommendation to prioritize utility-scale procurements before any other new procurements are considered. Instead, ELPC/NRDC/VS believe that the IPA and Commission should consider new methods to set REC prices that could result in a more cost-effective Adjustable Block Program, especially for community solar RECs. In light of the numerous concerns that community solar REC prices may currently be higher than necessary, ELPC/NRDC/VS respectfully request that the Commission order the IPA to alter the Plan to include a workshop to solicit comments to inform a new methodology for setting Adjustable Block Program prices for community solar projects for the next filed Plan Update. ELPC/NRDC/VS Rep. at 4.

#### **4. Joint Solar Parties**

As an initial matter, under the IPA Act, up to 75% of all RECs can be sourced from new utility scale wind and solar. See 20 ILCS 3855/1-75(c)(1)(C). However, the procurement targets for wind and solar are independent in the statute, and the IPA Act

provides specific direction for the source of RECs from solar facilities. Specifically, pursuant to Section 1-75(c)(1)(C)(i)-(iii) of the IPA Act, 40% of RECs from new solar facilities must come from utility scale systems, 2% from brownfield solar, and at least 50% from the Adjustable Block Program. The Joint Solar Parties stress that this is a statutorily-sourced REC purchase obligation, and not an allocation of funds; the Illinois General Assembly decided that (despite common knowledge that the Adjustable Block Program would likely include more expensive RECs) the Adjustable Block Program should produce at least 50% of RECs annually. JSP Rep. at 34.

Further, not only is it statutorily required, the findings in the PUA make it clear the Adjustable Block Program is necessary to meet the goals and findings of the General Assembly. See PA 99-0906, § 1(a)-(b) (legislative findings). Meeting these goals will not be possible if the Adjustable Block Program is abandoned in favor of utility-scale development that is separately authorized (and required) by statute. JSP Rep. at 35.

In the one year the Adjustable Block Program has been active, thousands of Illinois residents and businesses have been able to invest in solar providing real power and control over energy bills, and solar jobs in Illinois increased 37% between 2017 and 2018. With nearly 5,000 solar employees, Illinois has the 13th largest solar workforce in the US. JSP Rep. at 35.

The appropriate venue for discussion of the legislatively-directed minimum procurement targets in Section 1-75(c)(1)(C) is with the General Assembly. The General Assembly allowed up to 75% of RECs from utility scale wind and solar. However, the General Assembly did not provide the Commission or IPA an alternative for procuring distributed resources simply due to budget constraints or to meet REC percentage procurement targets. See 20 ILCS 3855/175(c)(1)(F). In fact, the General Assembly made clear that the procurement targets in Section 175(c)(1)(C)(i)-(iii) must be prioritized over other procurement goals such as a certain percentage of overall RECs—not just from new wind or solar—each year. Compare 20 ILCS 3855/1 75(c)(1)(F)(iii) with 20 ILCS 3855/1-75(c)(1)(F)(iv); JSP Rep. at 36.

For these reasons, the Joint Solar Parties recommend that Ameren’s proposal (as supported by the AG) should be rejected to the extent it conflicts with the statute and delayed for the 8% of RECs subject to discretion. JSP Rep. at 36.

## 5. IPA

Ameren notes that the results of the Fall 2019 utility-scale wind procurement were rejected by the Commission on October 30, 2019 and requests that “the Plan specifically state the funds that were allocated for this procurement event in the Initial Plan be used for additional utility scale wind RECs in this Plan.” Ameren Obj. at 2. As of the Plan’s filing on October 21, 2019, the Fall 2019 wind procurement event was not complete. In light of this result, the IPA agrees with Ameren’s recommendation to hold another utility-scale wind procurement. The IPA proposes that it conduct a utility-scale wind procurement in 2020 or 2021 to complete procurement of the 1,000,000 RECs that had been expected from the Fall 2019 utility-scale wind procurement. This procurement need not be dependent on the identification of additional funds; the IPA previously factored in the assumption that 1,000,00 RECs annually would have been procured. IPA Resp. at 8.

However, before conducting another utility-scale wind procurement, the IPA strongly recommends that it first follow a process similar to what was conducted after the first brownfield site photovoltaic procurement was not successful: before conducting a second procurement event, the IPA took feedback from stakeholders to identify any barriers resulting in a prior, unsuccessful procurement and on how to improve its process for a future procurement. In addition, as discussed in Section 5.3.1 of the Revised Plan, this next utility-scale wind procurement should not be conducted until a new REC Contract is developed through the stakeholder process referenced therein. Thus, while the IPA would seek to conduct the procurement in 2020, successful completion of the stakeholder feedback process and new contract development could result in this next utility-scale wind procurement not occurring until 2021. IPA Resp. at 9.

With respect to its contingency plan, while the IPA appreciates Ameren's points regarding the relative prices of RECs from different categories of resources, Section 1-75(c)(1)(C) of the IPA Act requires that the IPA meet its solar quantitative procurement targets through at least 50% from projects using the Adjustable Block Program, at least 40% from utility-scale solar projects, and at least 2% from brownfield site photovoltaic projects. The IPA presently has approximately 3,000,000 annual REC deliveries under contract from new utility-scale solar projects (and a similar number from new utility-scale wind projects), but projects to have just over 1,000,000 RECs under contract from the Adjustable Block Program—and will thus require hundreds of thousands of additional annual REC deliveries through the Adjustable Block Program to ensure that its 2025 procurement target is met. IPA Resp. at 7.

Further, the IPA explains that focusing only on REC prices ignores the rhythm of small-scale solar development. While utility-scale projects have demonstrated an ability to ramp up to scale quickly, if the Adjustable Block Program simply stops for a few years, solar installers in Illinois will need to lay off workers or close operations. This negative impact on the Illinois economy may be hard to overcome, and when the time is needed for more RECs from the Adjustable Block Program to meet the 2025 target, the existing infrastructure necessary for DG projects (including sales/marketing functions and installers) may be lacking and would take time to redevelop. This is the type of start/stop cycle that the solar industry desperately seeks to avoid. Thinking about the Adjustable Block Program purely through the lens of relative REC prices ignores the impact on Illinois workers and businesses and the desire (as demonstrated by thousands of applications to date) of Illinois homeowners and businesses to install solar. The benefits to customers across the state who are able to install solar onsite, or subscribe to a community solar project, must be considered above and beyond a simple analysis of REC prices. IPA Resp. at 7.

Ameren also states that administration of utility-scale REC contracts is simpler than Adjustable Block Program contracts. But the IPA asserts simplicity of contract administration should not be a relevant criterion in determining funding prioritization. Section 1-75(c)(1)(K)-(N) of the IPA Act sets forth program administration and contracting requirements for the Adjustable Block Program that are undeniably more complex than those used for utility-scale projects. At the same time, the General Assembly adopted Section 1-75(c)(1)(C) targets for REC procurement through the Adjustable Block Program that are higher than the targets applicable to utility-scale solar projects. While this added

complexity for the Adjustable Block Program was a known feature of the revised Illinois RPS, it did not prevent the drafters of the revised RPS from treating the Adjustable Block Program with priority. IPA Resp.at 8.

The IPA notes that the AG's reliance on prices from prior utility-scale procurements overlooks the IPA's most recent wind procurement, as no bids were approved from that procurement and thus no prices were released. While the IPA is not at liberty to discuss participation levels or bids received through that process, an unsuccessful procurement could indicate that low prices from prior utility-scale procurements may not carry permanence (and possibly cannot carry permanence due to market structure challenges that limit the number of viable long-term energy off-takers in Illinois), so the AG may not be entirely warranted in expecting similarly low winning bid prices from future utility-scale wind and solar procurements. IPA Rep. at 8-9.

Lastly, comparing utility-scale procurement prices to Adjustable Block Program prices is an apples-to-oranges comparison. While both involve procuring RECs, each is done under an entirely different statutory scheme with the involvement of different sets of parties and different payment schedules and obligations. Distributed generation and community solar projects feature Illinois residents and businesses making an active decision to source electricity from solar generation. This process necessitates educating and marketing to these parties; siting, financing, and constructing numerous diffuse individual photovoltaic installations; and providing ongoing support to hosts and subscribers. Those requirements are either not present or scaled back considerably for utility-scale projects. It should be no surprise that significantly more incentive capital is required to successfully develop Adjustable Block Program-incented solar installations. IPA Rep. at 9.

Despite this known difference between Adjustable Block Program and utility-scale solar products and costs, the General Assembly still set procurement targets for RECs from the Adjustable Block Program at higher levels than those from utility-scale solar projects. Specifically, Section 1-75(c)(1)(C)(i)-(iii) of the IPA Act calls for the IPA to procure at least 50% of new photovoltaic project REC procurement targets from Adjustable Block Program projects, but only at least 40% from new utility-scale solar projects. And, while at present, the IPA has procured enough RECs under contract to meet the 2020, 2025, and 2030 targets for utility-scale solar RECs, it cannot meet the 2025 targets from the Adjustable Block Program without additional project participation. If focusing only on REC price was warranted, this prioritization would be reflected in the drafters' intent as demonstrated through applicable targets in the Illinois RPS. As it is not, the IPA continues to support opening additional blocks from the Adjustable Block Program to meet its 2025 Adjustable Block Program procurement targets should funding become available. IPA Rep. at 9.

## **6. Commission Analysis and Conclusion**

The Commission approves the IPA and Ameren agreement that the Revised Plan should specifically state that funds associated with the recently rejected utility-scale wind REC procurement should be allocated towards a future utility-scale wind REC procurement. IPA Resp. at 8. The IPA proposes that it conduct a utility-scale wind procurement for the 1,000,000 RECs which were previously sought in the recently

rejected procurement event. The Commission notes favorably that this procurement is not dependent on the identification of additional funds. Additionally, the IPA states the procurement should first include stakeholder feedback similar to the process in the unsuccessful first brownfield solar REC procurement. The Commission agrees that stakeholder feedback is an important part of the process and the IPA should seek this feedback before initiating another utility-scale wind procurement. If the new utility-scale wind REC procurement fails to procure any or all of the 1,000,000 RECs sought, the Commission directs the IPA to allocate the remaining funds in accordance with the Revised Plan's contingency plan as outlined below.

The Commission notes, however, that the IPA does not want to conduct the make-up utility-scale wind procurement until a new REC Contract is developed. The Commission does not agree. A new REC Contract was not required for the failed Fall 2019 procurement and the IPA does not adequately explain why it should be required now. Rather, the Commission adopts Ameren's recommendation that the Plan be amended to state that the next utility-scale wind REC procurement will occur no later than May 31, 2021, even in the event the stakeholder process fails to result in a new REC Contract. Further, the Commission adopts Ameren's proposal that if a new REC Contract is not developed, the latest version of the utility-scale REC contract would form the basis for the 2021 contract, subject to minor modification where warranted. Ameren Rep. at 7.

With respect to the IPA's contingency plan, the relevant statutory Section states the following:

Subject to subparagraph (F) of this paragraph (1), the long-term renewable resources procurement plan shall include the goals for procurement of renewable energy credits to meet at least the following overall percentages: 13% by the 2017 delivery year; increasing by at least 1.5% each delivery year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter. In the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1), the long-term plan shall prioritize compliance with the new wind and new photovoltaic procurement requirements described in items (i) through (iii) of subparagraph (C) of this paragraph (1) over the annual percentage targets described in this subparagraph (B).

20 ILCS 3855(c)(1)(B). No party disputes Ameren's statement that the current status is that the 2019/2020 actual percentage is approximately 7% compared to a 2019/2020 target of 17.5%. This falls well short of the desired goal of 25% by 2025. The statute further states that:

Of the renewable energy credits procured under this subsection (c), at least 75% shall come from wind and photovoltaic projects. The long-term renewable resources procurement plan described in subparagraph (A) of this

paragraph (1) shall include the procurement of renewable energy credits in amounts equal to at least the following:

(i) By the end of the 2020 delivery year:

At least 2,000,000 renewable energy credits for each delivery year shall come from new wind projects; and

At least 2,000,000 renewable energy credits for each delivery year shall come from new photovoltaic projects; of that amount, to the extent possible, the Agency shall procure: at least 50% from solar photovoltaic projects using the program outlined in subparagraph (K) of this paragraph (1) from distributed renewable energy generation devices or community renewable generation projects; at least 40% from utility-scale solar projects; at least 2% from brownfield site photovoltaic projects that are not community renewable generation projects; and the remainder shall be determined through the long-term planning process described in subparagraph (A) of this paragraph (1).

20 ILCS 3855/1-75(c)(1)(C). It is also clear from the record that the IPA has met the 2,000,000 REC requirement for both new utility-scale wind and new utility-scale solar and, in fact, has procured 3,000,000 each of utility-scale RECs (or will once the Fall 2019 utility-scale wind procurement is re-run). Also, the IPA projects to have just over 1,000,000 RECs under contract from the Adjustable Block Program. IPA Resp. at 7.

Ameren and the AG argue that the required number of RECs from the Adjustable Block Program have been procured. As required by the statute, 50% of the required 2,000,000 minimum RECs for photovoltaic have been procured for the Adjustable Block Program. The Commission agrees that this is a correct reading of the plain language of the statute.

Other parties, such as ELPC/NRDC/VS, opine that 50% of all new photovoltaic must be in the Adjustable Block Program, not just 50% of the required minimum. This reading conflicts with the plain language and the statement that the Adjustable Block Program procurement percentage should happen “to the extent possible.” 20 ILCS 3855/1-75(c)(1)(C)(i).

With this reading of the statute, it is clear that the IPA has met the 2020/2021 statutory target of 1,000,000 RECs per year for the Adjustable Block Program. Moreover, the 2025/2026 target for the Adjustable Block Program is 1,500,000 RECs, of which the IPA has less than 500,000 RECs remaining to procure. The Commission notes that this allows the IPA over six years, two more Plans (2021 and 2023), and about \$1.5 billion in incremental customer collections in order to satisfy the 2025/2026 target for the Adjustable Block Program. See Ameren Rep. at 17-18. The Commission finds that the IPA’s proposal would serve to reduce the Revised Plan’s compliance with the statute’s overall RPS goals.

With this in mind, the Commission does not see the merit in the IPA’s contingency plan and adopts Ameren’s proposal with some slight revisions. While the availability of

additional funds is unknown, the Commission agrees with Ameren that prioritizing utility scale RECs over Adjustable Block Program RECs in the IPA's contingency plan will be more likely to move the State closer to its total REC targets and, therefore, should be given priority. To this end, should funds become available, the Revised Plan's contingency approach should be modified as follows:

First, the IPA shall conduct a competitive procurement for up to 500,000 annual RECs from utility-scale solar and/or wind projects.

Second, should additional funding exist or become available after a utility-scale procurement event noted above, the IPA should conduct an additional brownfield solar procurement with a target quantity of 50,000 RECs delivered annually. The Commission agrees with the IPA that "providing ongoing support for [this] market segment that was offered robust narrative support in the declaratory passages of Public Act 99-0906", Revised Plan at 79, is prudent.

Third, should funding be available after the above-mentioned procurement events, the IPA should open additional blocks of capacity for the Adjustable Block Program to accommodate whatever funds are available, up to the number of RECs needed to reach a total of 1,500,000 annually delivered RECs from the Adjustable Block Program. The Commission agrees with the IPA's proposal in the Revised Plan that smaller block sizes than those specified in Section 6.3.1 might be advisable, but the Commission defers to the IPA's determination at the time this opportunity presents itself. While it is unlikely that sufficient funding will become available to procure even more RECs, the Commission wants to clarify that the IPA should not procure more than the 2025/2026 statutory target of 1.5 million Adjustable Block Program RECs. Revised Plan at 79.

However, notwithstanding the revised contingency plan described above, the Commission directs the IPA to ensure that a minimum of 1 million annual RECs from the Adjustable Block Program be maintained at all times.

#### **IV. CHAPTER 6: ADJUSTABLE BLOCK PROGRAM**

##### **A. Section 6.3.3 Managing Waitlists, 6.3.3.1 Community Solar, Section 6.3.3.1.2 Approach to Opening New Community Solar Blocks, and 6.4 REC Pricing Model**

###### **1. Staff**

Staff states that in Section 6.3.3.1, the IPA notes that the community solar blocks in the Adjustable Block Program are several times oversubscribed. The IPA compensated for this excess supply by entering all proposed projects into a lottery with equal chances for each project. Approved Vendors were thus motivated to complete interconnection agreements for as many projects as possible to increase the odds that one of their projects would get selected. Staff Obj. at 4.

Staff notes that three consequences resulted from the disconnect between Illinois' interconnection rules and project selection. One is that Approved Vendors of selected projects will not know their projects' costs until the utility completes all the re-studies on a given circuit for projects higher up in the queue. A second consequence of the disconnect is that, when a lottery assigns equal probability of winning to each and every project, the IPA cannot be sure that the set of selected projects have the lowest cost to

Approved Vendors. A third consequence that can happen when the lottery assigns equal probability to each project is that one Approved Vendor can be awarded several more contracts than other Approved Vendors. While this result may not increase costs, it is arguably unfair. Staff Obj. at 4-5.

Staff explains that the Commission's interconnection rules, Parts 466 and 467, assign 100% of interconnection costs to each individual project. If there is more than one project in the queue on a given circuit, the utility will estimate the costs for each project in order of their queue position. 83 Ill. Adm. Code 466.120(c); 83 Ill. Adm. Code 467.70(c). For example, if the first project requires some upgrade to the distribution system, but the second project does not, because the first project's upgrade obviated the need for more investment to accommodate it, those costs are not shared between the two projects. The first project pays the entire cost, while the second project pays none. It can work the other way as well: the first project may have relatively low interconnection costs, while the second project may have to pay substantial sums, even though the need to do so is at least partially due to the first project's presence. As the number of projects on a given circuit increase, the pattern of cost assessments becomes more complex. The upshot of this method is that interconnection costs on circuits with a queue larger than one are opaque and unpredictable. Staff Obj. at 5.

It appears that there are proposed projects that would theoretically proceed if offered a REC Contract. Staff Resp. at 3. The Revised LTRRPP allocate 50% of capacity to the waitlist and it allows new community solar projects to apply for REC Contracts outside of the existing waitlist. In part, the IPA recommended this action because it indicated that it found that the vast majority of projects selected were located in rural areas. Revised LTRRPP at 116. The IPA's Revised Plan sets aside 50% of the capacity for any new community solar blocks withdrawn from the waitlist and used to develop projects in more urban areas. Revised LTRRPP at 117-118. Staff Resp. at 3.

In Staff's view, there is very little reason to adhere to the existing waitlist in any form as the basis for allocation of REC Contracts for community solar projects. The ratio between the number of community solar projects that can be funded, given the resources available, and the volume of applications indicates that many of these projects were speculative. It appears that most or all community solar projects that do not receive a REC Contract are not likely to be constructed. Given the existing interconnection rules, the vast majority of these community solar projects are likely to be abandoned in the absence of funding. Approved Vendors are then required to re-apply their projects for interconnection to become eligible for the Adjustable Block Program. This does not seem to be an efficient use of resources. Staff Resp. at 4.

Rather than a lottery that assigns equal probability to each project, Staff recommends that the IPA narrow the set of projects eligible for selection. One method to do this is to require each Approved Vendor and its affiliates to order its projects from most preferred to least preferred. Tier 1 of a lottery would then be the five or so top projects as selected by each Approved Vendor and its affiliates. The IPA would then run a lottery on Tier 1 projects only. If there is sufficient funding for all Tier 1 projects, then the lottery is run on Tier 2: the second five or so best projects as selected by Approved Vendors and their affiliates. Staff Obj. at 6.

Staff accepts that this procedure would not entirely eliminate cost unpredictability. The requirement in Part 466, Electric Interconnection of Distributed Generation Facilities (83 Ill. Adm. Code 466), and Part 467, Electric Interconnection of Large Distributed Generation Facilities (83 Ill. Adm. Code 467), that each interconnection must pay all incremental costs with no sharing with other, lower queued projects on a given circuit means the utility must re-estimate all lower-queued projects when one higher up in the queue withdraws. One method to mitigate this unpredictability is that the lottery could further require that an Approved Vendor must place any project that is in the first queue position in its Tier 1. If an Approved Vendor and its affiliates have more than five or so projects with the first queue position, then its Tier 1 projects must be the ones with the lowest interconnection cost per kW installed capacity. Staff Obj. at 6.

Staff asserts that such a process will tend to reduce total interconnection costs, since Approved Vendors are likely to rank their projects by cost. Approved Vendors have an incentive to pick the lowest cost projects for Tier 1, since the revenues are largely consistent across community solar projects. While it is probable that some interconnection cost re-estimation is going to be required, a process where Approved Vendors are self-selecting their best projects should reduce the need for it. And a requirement to place projects that are first in queue to be put forward first would certainly reduce the need for re-estimation. Staff Obj. at 7.

Staff also believes that this will make the lottery process fairer. That is, projects are more likely to be spread around more evenly between Approved Vendors. As was seen in the previous lottery, the results, even when randomly generated, can result in some firms being selected a disproportionate number of times while others have few or no selections. Staff Obj. at 7.

With respect to geographic diversity, Staff argues that the best definition of geographic diversity is that projects should be placed across the entire State and not concentrated in one region. In Staff's view, projects are broadly disseminated across the State. In addition, there are legitimate reasons for not requiring some portion of REC contracts to be in non-rural locations. First, it seems to be the consensus that rural locations have generally lower land and interconnection costs. Second, it is not clear to Staff what purpose is served by requiring some percentage of projects to be in an urban location. Staff Resp. at 5-6.

While Staff does not oppose increasing community solar presence in more urban areas, it does not agree with the IPA and ELPC/NRDC/VS's view that geographic diversity necessarily refers to the urban rural split. Therefore, it seems to Staff that a better use of the program's resources is to concentrate them on the most solar capacity for the lowest price. Staff Rep. at 4.

Staff does not disagree that Adjustable Block Program prices, especially for community solar, could be reduced without inflicting serious harm on the Adjustable Block Program. It appears that there is more than enough interest in acquiring community solar REC Contracts such that a lower price will not cause all projects to be withdrawn. Staff is not proposing a specific approach to using market prices to develop Adjustable Block Program prices in these comments. However, Staff believes that the IPA should consider investigating such a method. The IPA Act grants the IPA the ability to make these

amendments to price: “[t]he Agency may periodically review its prior decisions establishing...the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values[.]” 20 ILCS 3855/1-75 (c)(1)(K). It seems likely that closer adherence to market prices might also limit excess demand for CS projects and reduce the need for waitlists. Staff Resp. at 6-7.

Finally, the level of resources that might be available beginning in 2020 could mean that very few new projects can be funded. It may be unlikely that more community solar projects are going to be funded in the coming year. If there are more funds forthcoming, the institutional arrangements are likely to change as well. Staff believes that this is another reason that the community solar waitlist can be ended, so that the projects that are more likely to be efficiently and expeditiously constructed can be selected for REC contracts. Staff Rep. at 5.

## **2. Joint Solar Parties**

The Joint Solar Parties advocate for selecting projects based on project readiness criteria and have advocated against keeping the waitlist order for community solar. Phase I of the community solar program featured a disconnect between the interconnection process and the Adjustable Block Program process that led to chaos and uncertainty for project developers and utilities alike, not to mention landowners and local zoning officials. The Joint Solar Parties believe the most reasonable approach to bring stability to the program and reduce speculation is to link the interconnection process with the project selection process with increased criteria related to project readiness. JSP Obj. at 13.

The Joint Solar Parties strongly recommend the Commission reject the LTRRPP approach to use the ordinal waitlist for community solar and instead use first-come, first-served. Using the current waitlist order will only exacerbate the misalignment between the REC awards and the interconnection queue, require a new utility waiver, and create more market instability. JSP Obj. at 15.

Instead of the LTRRPP proposal, the Joint Solar Parties suggest an alternate approach that will ultimately get the two tracks in better alignment. This would involve clearing out the waitlist entirely and reopening the program on a first-come, first-served basis with increased application criteria related to project readiness and including an up-front deposit that would be applied to the project’s collateral. The IPA would have to provide a date certain far enough in advance to allow planning, and finalize procurement rules several months in advance to allow developers to plan and apply the most meritorious (under the program’s new selection criteria) projects. JSP Obj. at 17.

All projects on the waitlist that already faced a pay-or-get-out decision and elected “get out” would simply begin the interconnection process anew. Once a project receives its upgraded cost estimate, pays the initial deposit and signs the interconnection agreement, it will be eligible to reapply to the Adjustable Block Program (once it is open). Once the capacity of all available blocks is filled, the IPA will close that market segment until the following year. This approach will allow predictability and known targets so the market is responding to a single application window each year. JSP Obj. at 17.

In their first-come, first-served proposal, the Joint Solar Parties argue that a developer with a signed interconnection agreement can make educated decisions

whether the REC prices for the particular open block(s) will bear the interconnection costs projected by the utility. The developer can choose not to sign the interconnection agreement, withdraw from the interconnection queue and not apply to the Adjustable Block Program (especially if fees or deposits increase). The utility will then restart and refresh studies for projects behind in queue, giving those projects an accurate view of their projected upgrade costs once they reach the point of receiving an interconnection agreement for signature under Part 466 of the Commission's rules. Ultimately, this process will help winnow down the existing waitlist because existing utility grids simply cannot handle the number of projects on the list. JSP Obj. at 18.

For projects that do choose to apply to the Adjustable Block Program, the Joint Solar Parties state that the IPA should require an up-front, meaningful collateral payment as a requirement of the application. To be clear, adding additional collateral under the current system with a disconnect between project selection and the interconnection queue would be very harmful. However, if the Commission—through modifying the project selection process and interconnection rules in Part 466—successfully aligns interconnection and project selection, additional collateral helps further ensure that mature, realistic projects are submitted to the Adjustable Block Program. Under the Joint Solar Parties' preferred approach, if selected for RECs, the Approved Vendor would have 18 months plus extensions and other delays currently available under the REC Contract to reach Energization (as defined in the REC Contract). If the developer builds the project within the allotted timeframe, it would receive 100% of the collateral back (or could elect to roll the funds into performance collateral). If the developer fails to meet those deadlines, it could pay for an additional fee for a one-time extension. If the developer fails to meet that final deadline, it would lose the collateral. This requirement ensures that speculative projects with questionable economics do not apply to the Adjustable Block Program because vendors will not risk capital on risky projects. JSP Obj. at 19.

Additionally, the Joint Solar Parties say the IPA should recognize that the fastest way to clear the existing waitlist of projects would be to preference projects that participated in Phase I of the ABP over new projects. A preference would recognize the significant capital and effort that developers put into these projects, while also preventing communities and landowners across the state from a needless round of project development and permitting. The waitlist preference would be executed with a preapplication window, with IPA opening Block 1 for a certain term, solely for projects that were on the Phase I waitlist. The Joint Solar Parties explain that a project's numerical place on the ordinal waitlist would be immaterial this would only look at whether the project was on the waitlist. After the initial term, any eligible project could apply. This approach would help clear the backlog of projects without preventing new market entrants from participating. JSP Obj. at 20.

While the IPA and stakeholders will need to work out some of the details, the Joint Solar Parties state that, taken as a whole, a first-come, first-served system based on project readiness criteria would be a fair, transparent and implementable approach to project selection that would bring stability to the market. JSP Obj. at 20.

The Joint Solar Parties further propose that the Commission should reject the IPA's proposal on time. They state that 120 days - 60 days of notice plus a 60-day application window - is far too short to develop a community solar project. Achieving interconnection

or zoning permits independently can frequently require more than 120 days; both are required for most systems and at minimum a signed Interconnection Agreement is required. There is little incentive for developers to begin a pipeline of community solar projects in advance because it is not worth the development costs—as much as \$50,000-\$100,000 per project—to sit and wait for a hypothetical future block to open that may be so small the IPA may only consider small systems. See Revised LTRRPP at 118; JSP Obj. at 20-21.

While the Joint Solar Parties understand the policy goals that the IPA is seeking to achieve through the Revised LTRRPP, none are supported by statute. Nowhere in Section 1-75(c) of the IPA Act is there a goal or preference for municipal or community group driven projects, nor is there a goal or preference for subscriber proximity to a project. Similarly, nowhere in Section 1-75(c) of the IPA Act is there a size preference or goal for community solar—in contrast with behind-the-meter systems, where the statute provides explicit resource allocation between under 10 kW and over 10 kW systems. *Compare* 20 ILCS 3855/1-75(c)(1)(K)(i) and (ii) (behind-the-meter) with 20 ILCS 3855/1-75(c)(1)(K)(iii) (community solar, no size-based goals). While the IPA Act does contain a geographic diversity goal, it is purely geo-spatial:

The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation projects in diverse locations and are not concentrated in a few geographic areas.

20 ILCS 3855/1-75(c)(1)(K). The mandate is to avoid concentration “in a few geographic areas” and ensure projects are “in diverse locations.” While community solar projects may be located largely (though certainly not exclusively) in rural areas, there are hundreds of Large distributed generation and Small distributed generation projects located in urban areas. The Joint Solar Parties believe that the existing mix successfully achieves the statutory mandate for geographic diversity. Even if the Commission does determine that each market segment should also be sufficiently diverse, the Commission and the IPA should instead focus on whether community solar adders for urban areas generally or specific urban areas (such as Cook County) are necessary to align the incentive with local costs. JSP Obj. at 23-24.

While all stakeholders strive for more solar and community solar development in Cook County and other urban areas, development in rural areas is a foreseeable result of a one-size-fits-all REC payment without noting the different land costs and availability, tax burdens, interconnection costs, permitting costs, and other factors that make urban development more expensive. The Joint Solar Parties argue that better aligning REC payments to projects in urban areas with actual costs to develop in urban areas will greatly increase the number of projects in those areas. JSP Obj. at 24-25.

Setting aside the statutory issue, the Joint Solar Parties further note the inconsistency between the Revised LTRRPP’s scoring system and the IPA’s other stated goals. The IPA has repeatedly emphasized two issues with regard to community solar:

controlling price and ensuring projects that are selected are actually developed. The scoring system proposed by the LTRRPP is at odds with both. JSP Obj. at 25.

The Joint Solar Parties argue that the IPA's proposed scoring model incentivizes more expensive community solar systems. The base per-REC prices (without community solar adders) are 35%-91% higher for under 100 kW systems (depending on size and Group) than an over 500 kW system. Even the price per-REC for an under 500 kW but over 100 kW system is 6%-17% higher (depending again on size and Group) than an over 500 kW system. Also, depending on the township, there may be limited entities available to subscribe that are not potential "small subscriber" qualifiers—in fact, for an under 100 kW system, the statutory requirement that no subscriber exceed 40% of a system leaves few subscribers that are not small subscribers eligible to participate. As a result, the IPA should anticipate a maximum small subscriber adder. In the absence of statutory restrictions (such as minimum allocations to certain project classes), providing solar at a higher cost to fewer customers does not seem to be consistent with the directives of the IPA Act. JSP Obj. at 25-26.

In addition, the IPA has strongly emphasized that all selected projects must be built. The IPA clarified in January and February 2019 through edits to the Program Guidebook and online FAQs that Approved Vendors were expected to sign all REC Contracts/Product Orders presented and that failure to do so would subject the Approved Vendor to discipline. JSP Obj. at 26. The Joint Solar Parties state, however, that for systems tied to a specific site by a municipal (or community group) RFP would be captive to the eventual interconnection costs quoted by a utility. Unless the municipality or community group specifically screened the location for affordability of interconnection costs, there is little guarantee that interconnection costs will make the system viable. If there is any interconnection queue on the same substation or feeder, the costs quoted in the signed Interconnection Agreement will be subject to change and thus will entail risk. JSP Obj. at 26.

Setting that issue aside, the Joint Solar Parties have several additional concerns with the selection process itself. First, the LTRRPP adopts ELPC's use of townships for defining at least two scoring opportunities: township population density and subscriber location. LTRRPP at 117, *id* at n.330. Using township as a scoring metric is problematic for multiple reasons. Townships are arbitrary designations that bear little connection to any notion of "community" in the colloquial sense or from an electricity perspective. It is likely that few customers can even name their own township, much less feel a strong connection to their township. It is also unclear whether (or if so at what level of effort) utilities, Approved Vendors, designees, or others can effectively determine in which township a customer is located. Limiting the location of a project or its subscribers based on this arbitrary designation will result in enormous development difficulties, new risks, gaming, and significant project failure. JSP Obj. at 21.

Further to this first point, the Joint Solar Parties note that the LTRRPP does not provide a public dataset for township population density nor any description for how the township density classes will be determined, just a footnoted reference to comments by ELPC/VS. The lack of this information makes project development incredibly difficult. If project selection is to be based on a township density ranking that is not publicly available and has not been approved by the Commission, project developers, community groups

and even municipalities would face enormous ambiguity about their project's chances of success (including if population density changes over time). JSP Obj. at 21-22.

Second, the scoring system appears to contemplate each system receiving its own score and being selected independently. However, this raises several concerns: first, the Joint Solar Parties note that a system under 100 kW (AC)—which receives a substantial score boost under the IPA's proposal—is too small to be in a batch by itself. In other words, if that same Approved Vendor does not obtain another awarded system in the same Block, it is not clear how a Product Order would be created. In a nightmare scenario, a large number of Approved Vendors submit under 100 kW systems but each only receives one award each—and thus nobody can actually develop. JSP Obj. at 22-23.

Joint Solar Parties note that the statutory language has two requirements: (1) the Adjustable Block Program procure RECs from systems in diverse locations; and (2) the systems not be concentrated in a few areas. 20 ILCS 3855/1-75(c)(1)(K). The conjunctive “and” between “photovoltaic distributed renewable energy generation devices” and “new photovoltaic community renewable energy generation projects” demonstrates that the General Assembly is directing the Commission and IPA to view the Adjustable Block Program as a whole. The General Assembly could have required that each component—behind-the-meter and community solar—individually achieve geographic diversity but did not. JSP Resp. at 11.

Even if the Commission interpreted Section 1-75(c)(1)(K) as requiring an independent demonstration of geographic diversity, it is not clear that ELPC's measure of 90% of projects in the two least dense zip codes shows a failure of geographic diversity. ELPC/VS did not demonstrate, for instance, that northern, central, western, or southern Illinois received insufficient projects. ELPC/VS also did not demonstrate that 10% of projects in the five densest categories of zip codes is disproportionate on a land availability basis or what parity would look like. It appears that ELPC/VS have simply decided that remedial action is necessary “until a minimum level of diversity was met,” without defining how that would be measured. See ELPC/VS Obj. at 3; JSP Resp. at 12.

The Joint Solar Parties explain that the best way to incentivize community solar development in urban areas is an adder that at least levels the playing field. Any adder applied to urban areas would have to take into account transactional barriers and costs. An adder would have to be sufficient for a developer to take on not only the additional land costs and (potentially) tax and permitting burdens but also the financing risk. To the extent that additional criteria are imposed, the additional risk must be offset by additional funding. JSP Resp. at 17-18.

Because there is some diversity in preferred developer approaches, the Joint Solar Parties believe the details would have been best for a stakeholder process. However, given that the IPA (in contrast to its approach with its own consumer protection proposals) asserts that vagueness is grounds for rejection, the Joint Solar Parties have developed the following detailed approach:

STEP 1: The LTRRPP will set the following program terms and conditions:

- Eliminate the Group A and Group B waitlists for community solar, as supported by the Joint Solar Parties and Staff (among other parties).
- In the LTRRPP, the IPA will outline a strictly applied developer “hard cap” (i.e. a cap that is treated as a not-to-exceed).
- Require, in addition to an application fee, a \$50/kW deposit due on the date of the selection that is refundable only if a project is not selected or a force majeure event.
- Applicants must show that they have either paid the deposit on their waiver (i.e. paid to stay after the lottery) or have gone back through the interconnection process, signed a new interconnection agreement and in doing so have accepted that the utility will move forward with interconnecting the project.
- The LTRRPP will require notice be provided not less than six months before new capacity is opened, to allow informed planning of reentry into the interconnection queue. Each developer will balance the costs of earlier application with the risk of falling back in queue.
- Other than as reflected in the bullet points above, application prerequisites are the same as under the existing program.

STEP 2: All projects that meet the minimum qualifications for program participation are accepted in the order of their respective applications to the Adjustable Block Program except that no project that would exceed the developer cap shall be selected.

STEP 3: Winning projects are submitted to the Commission for approval and the REC Contracting process continues as set out in the initial LTRRPP.

JSP Rep. at 19-20.

The Joint Solar Parties note a few features of the detailed proposal above. First, the developer cap—and strict enforcement thereof—is a critical component of this proposal. With a properly designed and strictly enforced developer cap, the advantage of a developer that is able to send in interconnection applications quickly is limited. The earlier a cap is known, the better developers can allocate development resources efficiently and avoid the problem of the initial program where developers applied as many projects as possible to increase lottery odds. JSP Rep. at 20.

Second, the first-come, first-served approach raises barriers to entry while lowering risks post-selection. The Joint Solar Parties note that small developers would be better protected by the Joint Solar Parties’ proposed approach than either a lottery (or other random selection event) or using the waitlist. All developers will face the same program rules, but larger developers will be disincentivized from flooding the program with projects because they may be unable to win more than a small handful. The Joint Solar Parties do not change the set of prerequisites (non-ministerial permits, site control, and signed interconnection agreement) that are frequently \$50,000-100,000 or more in pre-application costs. JSP Rep. at 20.

Finally, while seemingly very different on the surface, depending on where the developer cap is set (and the volumes to be procured) the Joint Solar Parties' proposal shares several aspects with Staff's project selection proposal. First, both focus on getting the most likely to succeed projects to the forefront; Staff focuses on developer preference while the proposal above focuses on interconnection cost risk. While developer preference is an appealing criterion for the Joint Solar Parties, as explained in detail above developers are unlikely to have actionable information to make informed decisions if their projects are further back in queue. Second, both use caps to prevent a single or small group of developers from cornering the market. Third, both focus on a selection event rather than rolling selection (as a waitlist approach might take). JSP Rep. at 21.

### **3. ComEd**

ComEd explains that the ability of a distributed energy resource to interconnect to the distribution system is limited by available hosting capacity at the location of the proposed interconnection at the time of the interconnection. The current interconnection rules require assigning 100% of the interconnection costs to each individual project. 83 Ill. Adm. Code 466, 467. This means that costs will be assigned based on the queue position of the project and not shared. A project with the first queue position may require some upgrades to the distribution system, but the second project may not. The reverse can also be true: projects earlier in the queue may not require upgrades but a later project may be required to pay substantial interconnection costs. Every time the projects in the queue change, the utility must perform re-studies to re-estimate interconnection costs. All agree this leads to unpredictability. Interconnection costs depend on the time of the associated interconnection and the project's queue position at that particular point in time. ComEd Resp. at 3.

ComEd notes that in deciding whether to proceed with a project, Approved Vendors may consider various factors – only one of which is interconnection. Other costs such as project profitability, land acquisition, local regulations, etc. all could factor into the decision whether to proceed. The revenues Approved Vendors get from REC contracts are fixed, so ensuring that least cost projects are selected may only serve to increase returns for developers. ComEd Resp. at 3-4.

ComEd states – that through no fault of the utilities – interconnection costs are uncertain. That is the nature of the queue. In determining whether a customer is eligible to interconnect to an Illinois public utility, utilities must comply with the Commission's interconnection rules and any applicable tariffs. Both sources of authority require the utilities to allow any customer or project to interconnect, so long as they agree to pay for any costs for facility upgrades necessary to ensure that the interconnection does not compromise the "safety and reliability of the units and the electric utility system." 220 ILCS 5/16-107.5(h). The interconnection rules (see 83 Ill. Adm. Codes 466 and 467) were established pursuant to Section 16-107.5(h) of the PUA, which requires, among other things, "nondiscriminatory terms of agreement." 220 ILCS 5/16-107.5(h). Additionally, the PUA prohibits utilities from making or granting "any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage." 220 ILCS 5/9-241. Use of a readiness criterion should be an IPA process under the Revised LTRRPP for REC awards. It cannot and should not be a part of the utility process to determine prerequisites for interconnection. ComEd Resp. at 5.

Staff and the Joint Solar Parties both present objections associated with the overlap between the interconnection process and the processes described in the Revised LTRRPP for determining Adjustable Block Program eligibility. ComEd opines that this overlap can be eliminated by removing the requirement to have a signed interconnection agreement upon application within Section 6.12.1 of the Revised LTRRPP. ComEd notes that a signed interconnection agreement is not required for projects under 25kW or utility-scale projects that are competitively bid. Eliminating this requirement has the potential to significantly reduce the number of utility interconnection studies by reducing the number of interconnection requests from projects that would not be viable without Adjustable Block Program REC revenue. As a result, technical studies for projects that do decide to submit interconnection requests would likely yield more realistic scopes of distribution system upgrades and interconnection cost estimates. Prior to such applications, customers may request pre-application reports under the Commission's interconnection rules. A pre-application report does not provide cost information but will provide information to determine whether there may be system constraints at the contemplated point of interconnection that could increase a project's interconnection costs. ComEd Resp. at 6.

By way of example, ComEd executed interconnection agreements with 482 eligible community solar projects prior to the deadline for projects to apply for the IPA's Adjustable Block Program for community solar. Subsequent to the IPA lottery, and as of December 11, 2019, 371 of those 482 projects have withdrawn. Thus, while obtaining an interconnection agreement is certainly a step toward constructing a community solar facility, ComEd asserts it does not necessarily provide a strong indication of project maturity. ComEd Rep. at 2.

#### **4. Ameren**

The Revised Plan proposes to keep existing REC prices unchanged for open distributed generation blocks and any distributed generation blocks that may open under the Plan's contingency proposal. The same is true of community solar REC prices with the exception of minor changes associated with the small subscriber price adjustment. During implementation of the Initial Plan, the community solar and large distributed generation allocations under the Adjustable Block Program encountered significant oversubscription. The IPA subsequently implemented a lottery process as a means to select and award contracts. Ameren believes this oversubscription is a clear indicator that REC prices are higher than needed to entice participation. Moreover, these high prices have been the largest driver behind the Plan's projected budget constraints. Ameren Obj. at 6.

Although Ameren recommends that utility scale RECs take priority over Adjustable Block Program RECs in the contingency proposal, Ameren also recommends changes to the Adjustable Block Program REC pricing, as follows:

- The Plan should lower REC prices for community solar and large DG. Ameren believes this would help to eliminate the oversubscription issue in the future and help ensure that budgets are less constrained.

- In the event oversubscription were to occur again, Ameren recommends the lottery process be eliminated and replaced with a process where the price is lowered until the quantity of vendor MWs interested in executing contracts equals the MWs available in the block offering. This design is favorable because it is market based, it eliminates the random lottery and it makes efficient use of customer paid funds.

Ameren Obj. at 7.

Ameren notes that the IPA suggests that Ameren's proposal cannot be adopted because the process must include "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." IPA Resp. at 26. Ameren disagrees with the IPA's position. Under Ameren's recommendation, the IPA would continue to make public a transparent block of prices, but at lower prices when compared to current levels.

Ameren states that its alternative to the lottery would only be implemented in the event of another oversubscription. While the detailed process for implementation has yet to be formalized, one suggestion is to transparently lower the REC price in small increments. As prices are transparently lowered and some bidders lose interest in continuing with their proposed project at the lower price, the oversubscription gap would narrow. This process of lowering the price would continue until a point where the quantity of MWs available in the block equals (or is close to) the bidder quantity. Using this process, the initial block prices remain fully transparent and predictable, just as they are currently. Even in the event of oversubscription, the block prices would remain transparent as they are lowered. The only unpredictable variable is the actual price that will be awarded in an oversubscription scenario. That might be a concern absent the realization that the bidders themselves have free will to decide what price under which they are willing to proceed with their project (i.e., as the price is lowered, bidders have sole discretion to decide whether to continue or not). Ameren believes this process, if implemented, would be consistent with the statute. Moreover, the benefits are substantial and include more efficient use of customer paid renewable funds and the elimination of the controversial lottery process which contains random winners and losers. Ameren Rep. at 8.

Ameren asserts that deferring these issues until the next Plan would ignore the lessons learned during the implementation of the Initial LTRRPP and result in inefficient use of customer paid renewable funds. For these reasons, Ameren recommends the Commission reject ELPC/NRDC/VS's recommendation and urges the Commission to take action now and implement the Ameren recommendation that prices should be reduced sooner rather than later. Ameren Rep. at 20.

## **5. Summit**

While Summit acknowledges that the waitlist has a place among a new set of selection criteria, the rankings set forth during the lottery that took place in April 2018 should be eliminated completely. Summit Obj. at 2.

In the Plan, the IPA addresses the fact that projects lack geographic diversity and their relative location to the subscribers served. Specifically, the IPA acknowledges this matter as a community solar issue only. The IPA should leverage precedent from other markets where system type is either considered as a selection criteria and is thereby granted separate program incentive capacity or given financial incentive adders. The purpose in both instances is to prevent rooftop or canopy installations from having to compete with “greenfield” development, which benefits from both cost and energy production advantages. Summit notes that thus far the IPA has not provided any specific capacity allocation for rooftop or canopy systems, or other similarly situated large scale systems, that can be constructed in areas that have higher population densities. Summit Obj. at 2-3.

Further, following the methods that have been set out in other programs, non-greenfield projects, which will more often than not be better suited for more densely populated areas in the State of Illinois, should have the capability to secure capacity from multiple categories. A project that can be constructed on an industrial or urban facility, which may not have enough load to serve as a behind-the-meter project, or a parking lot canopy with inherent additional costs should not be limited to the specific allocation of capacity for community solar. Additionally, those projects should not be forced to compete with the large-scale greenfield projects that are cheaper to build, situated on land that costs less to rent and generate more electricity as they can be mounted on trackers. Summit Obj. at 3.

In considering the overall location of most of the community solar projects that have been previously awarded, the IPA acknowledges that while the projects are geographically diverse in terms of location throughout the State, the projects are primarily located in rural areas on farmland. In order to address the lack of project diversity, the IPA has proposed new means for awarding community solar Projects in future blocks. However, the Plan set forth by the IPA seeks to treat diversity of projects as wholly a community solar issue. The IPA provides a very narrow reading of what is community, by indicating through their selection criteria that community should apply to subscribers in the same township or general location of the State. Summit opines that this is not the intent or purpose of community solar. While the IPA is seeking to grow the proliferation of solar installations throughout the State, their narrow reading of “community” seeks to compartmentalize the generation of consumption of solar energy in direct contrast with the purpose of community solar. Summit states that the purpose is to enable the Illinois ratepayer to participate in the benefits offered through solar power, including those who cannot afford to purchase or lease their own photovoltaic system. Summit Obj. at 4-5.

Summit avers that, when considering the rationale of community solar, the purpose is for multiple subscribers to have access to solar energy without having to incur the substantial financial burden of placing direct generation panels on site at their residence. By allowing subscribers to commit to solar energy without these costs, the IPA increases the access to solar energy for the people of Illinois while simultaneously decreasing their reliance on traditional forms of electricity generation. Summit Obj. at 5.

When considering the proposal of the IPA, there is neither the ability for rooftop or canopy community solar projects to receive capacity from multiple program categories, nor is there a specific carve out within a particular category. Based on the nature of a

rooftop or parking lot canopy project, which would advance the IPA's initiative of providing for diversity of solar projects, and also developing certain solar projects closer to their subscribers, the Commission should consider the following specific rulings:

1. Rooftop projects and/or other non-greenfield developments that may sell on-bill credits to residential or small business subscribers should have access to multiple program categories and should qualify for the small subscriber adder within each. Specifically, these projects should be able to receive capacity from the Large DG category, the community solar category and/or the IPA's discretionary capacity. This flexibility would allow non-greenfield projects to contribute towards the renewable energy initiative of the IPA without limiting these projects to the community solar category and enable more Illinois ratepayers to participate thereby increasing capacity within the ABP category that saw the highest demand. In the event that a rooftop or other non-greenfield project is selected under the Large DG category, the project should be afforded the same residential REC adder as offered in the community solar category.
2. In addition to allowing for flexibility in awarding capacity to rooftop projects, and other non-greenfield projects from various program categories, the Commission should recognize that these projects are a wholly unique system type, and sector of the solar energy market, and thus warrant their own capacity allocation. Accordingly, the Commission should direct the IPA to allocate at least 20% of the overall capacity in all future program categories to rooftop and other non-greenfield systems. This reserve of capacity allocation is permissible under the IPA Act, and could be achieved as follows:
  - a. Direct the IPA to allocate a minimum of forty percent (40%) of the Discretionary category to rooftop and other non-greenfield projects. This would be ten percent (10%) of the overall program capacity reserved; plus
  - b. Direct the IPA to reserve twenty percent (20%) of the capacity in the category allocated for Large DG to award to rooftop and other non-greenfield projects. This would be five percent (5%) of the overall program capacity reserved; plus
  - c. Direct the IPA to reserve twenty percent (20%) of the capacity in the category allocated for community solar to award to rooftop and other non-greenfield projects. This would be five percent (5%) of the overall program capacity reserved.

Summit argues that this would allow for rooftop and other non-greenfield projects to help diversify the solar projects in the State, addressing the concern of the IPA in the LTRRPP, while also expanding to the vastly oversubscribed community solar category. Furthermore, this Order would allow the Commission to advance the growth of solar energy availability for the tax paying residents of Illinois by providing sufficient subscriber options to meet the demand of the State. Summit Obj.at 5-7.

To date, Summit states that it has been documented that flaws existed in the algorithm utilized by the IPA in conducting the April 2019 Adjustable Block Program lottery. While projects on the current waitlist should be afforded some acknowledgment in future selection criteria over entirely new developments, the projects should not be selected by their placement within a flawed result order. As such, Summit objects to the maintenance of the current ordinal waitlist as a means for awarding future development projects. Consistent with the proposal of the IPA, Summit requests that this Commission issue an order directing that all future community solar projects be awarded points based on the following criteria: 1) waitlist presence; 2) projects with committed subscribership from low and medium income subscribers; 3) system type – rooftop system, parking lot canopy and any other large scale non-greenfield system; 4) development density; and 5) job training commitment. Summit recommends that projects be selected based on the aggregate number of points received. In the event that projects receive the same number of points, all ties should be determined based on the date of the original interconnection agreement. Summit Obj. at 8-10.

## **6. Chamber**

The Chamber notes that PA 99-0906 was passed to accelerate the growth of solar development in Illinois, which is realized with ratepayer monies. The Commission should ensure appropriate program parameters as stewards of that funding. The Chamber agrees with the Joint Solar Parties that the Revised Plan incentivizes more expensive community solar systems, which makes little economic sense. The project selection process should be based on project readiness. Chamber Resp. at 2.

The Chamber notes that the upfront costs associated with getting ready to apply for the Adjustable Block Program grant are immense. Developers must consider numerous cost factors when deciding on a project, such as land costs, interconnection costs, labor, taxes, and permitting. The focus should be on the economic merits of the project to encourage continued growth in the solar industry. Keeping costs as low as possible and developing an efficient LTRRPP is key to development. The Chamber asserts that projects will not be built if the economics do not support development and adding on additional geographic diversity requirements, that are not mandated by statute, will slow project development. Chamber Resp. at 2.

Further, the Chamber argues that the proposal to not reallocate unused funds back to remaining capacity on the waitlist will further hamper solar growth. With scarce resources for solar development, holding back funding at this stage because the project is not in a preferred location rather than seeking continued project development overall is misguided. Chamber Resp. at 2.

Finally, and most importantly to the Chamber, these projects are being developed with funding provided by Illinois residential and business ratepayers. The priority should be continued development at reasonable costs, which will ultimately result in more solar on the grid. The Commission should reject ELPC/VS's scoring criteria recommendation as it does not control project costs nor encourage robust solar development expansion. Chamber Resp. at 3.

## 7. AG

The AG points out that Illinois is far from achieving the annual RPS targets prescribed by the IPA Act. These targets will increase each year from now to 2025. To achieve these targets within the IPA Act's compliance budget, the Revised Plan must emphasize the procurement of renewable resources at the lowest price wherever possible. See 20 ILCS 3855/1-75(c)(D)–(E) (establishing the RPS compliance budget and providing for curtailment of procurement contracts if the budget is exceeded). Accordingly, the Commission should reject parties' requests to make REC procurements more time- and cost-intensive than necessary to comply with the Act. By introducing additional factors other than price into the procurement determination, these proposals can be expected to reduce the price competition necessary to control the cost of Adjustable Block Program procurements and thus should be rejected. AG Resp. at 7.

The AG supports the adoption of cost-control measures (and opposes new procedures that could drive up costs) in IPA procurements conducted pursuant to statute and the IPA's Plans. Like Ameren, the AG observes that the Adjustable Block Program is oversubscribed and that the lottery process must therefore be put into use. Turning again to the significant premium in the price for RECs procured via the Adjustable Block Program over utility-scale REC procurements, to the extent that the IPA relies upon the Adjustable Block Program to procure RECs, the AG also urges the Commission to consider ordering modifications to the Plan to help control the cost of RECs procured via the Adjustable Block Program. AG Resp. at 8.

The AG agrees with Ameren that a market-based mechanism such as the one described by Ameren could function to push the Adjustable Block Program's REC costs downward. As currently structured, REC prices within a block are static, necessitating focus on other criteria and a lottery in the event of oversubscription. Oversubscription suggests that REC prices are more than sufficient to attract developers, and the AG urges the Commission to view this scenario as an opportunity to reduce the cost of the Adjustable Block Program. Accordingly, the AG urges the Commission to order the IPA to modify the Revised Plan to include a mechanism to select vendors for award of a contract from oversubscribed blocks with a cost-based mechanism. AG Resp. at 8.

ELPC/VS's recommendations relate to the Plan's approaches to opening new community solar blocks and to managing the waitlist for replacing lottery-selected projects that withdraw from oversubscribed blocks in the Adjustable Block Program. ELPC/VS Obj. at 1-5; see Revised Plan at 117-118. The IPA Act calls for the Plan to account for geographic diversity in procuring RECs through the Adjustable Block Program. 20 ILCS 3855/1-75(c)(1)(M). However, RPS compliance is the ultimate goal of REC procurements, including procurements of community solar projects through the Adjustable Block Program. See 20 ILCS 3855/1-75(c). The Revised Plan correctly treats geographic diversity as an interest to be promoted, but not at the cost of hindering RPS compliance efforts. ELPC/VS's proposal could upset this careful balance by overemphasizing geography and further increasing REC prices in community solar procurement. AG Resp. at 9.

ELPC/VS's first recommendation is to impose a minimum geographic diversity score for community solar projects to be eligible for the Adjustable Block waitlist in the

event the block is oversubscribed. The Commission should reject this recommendation. The Revised Plan already promotes geographic diversity by reserving half of waitlist slots for projects from currently underrepresented regions of the State. There is no need to reserve all waitlist slots for projects from these regions. Further, excluding community solar projects in the regions of the State that contribute the most RECs to the program could have a chilling effect on development in the State's most productive areas, reducing the number of RECs per project and procurement of solar RECs necessary to meet the statewide RPS targets at a reasonable cost. AG Resp. at 10.

## **8. ELPC/NRDC/VS**

ELPC/NRDC/VS recommend that the Commission direct the IPA to make several refinements to their proposed approach for opening new community solar blocks to ensure compliance with statutory goals around geographic diversity.

One of the major issues addressed by the IPA in its Revised Plan is how to move forward with its community solar program in light of an initial round of that program that failed to deliver on the diversity requirements of the law yet resulted in a waitlist many times the program's capacity. When the legislature created its new community solar program, a subset of a larger distributed solar program called the Adjustable Block Program, it mandated that the program drive community solar development in diverse locations across the State:

The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation projects in diverse locations and are not concentrated in a few geographic areas.

20 ILCS 3855/1-75(c)(1)(M). Yet, as ELPC/VS note, the community solar projects developed in response to the initial Plan were almost universally located in more rural areas, leaving urban and highly developed areas behind. ELPC/VS argue that this required the IPA to revise the program to satisfy statutory requirements around geographic diversity. However, the IPA also had to contend with a very long waitlist for the community solar program consisting of projects that largely reflected the lack of diversity seen amongst selected projects. The IPA balanced these competing interests of diversity and waitlisted projects in the Revised Plan filed with the Commission by dedicating 50% of any new community solar capacity to the waitlist and 50% to projects that "increase the variety of community solar locations, options, and models in Illinois." Revised Plan at 117; ELPC/VS Obj. at 2-3.

Under the currently proposed implementation of the approach to open new community solar blocks, any new project may enter, and the IPA's new diversity criteria only come into play in the event the block is oversubscribed. While oversubscription is entirely possible, it should not be counted upon. Nor should projects scoring zero be allowed to maintain a place on the waitlist, ahead of projects that apply late but actually achieve even one of the diverse criteria. Finally, allowing new projects that are not taking steps to advance the variety of community solar in Illinois to advance separately from, and likely ahead of, waitlist projects does nothing to advance any diversity goals while

giving new projects a leg up (versus waitlist projects) just because they are new. ELPC/VS Obj. at 3.

The IPA's proposal limits the application window for diverse projects to 60 days and then immediately reallocates any remaining capacity back to the waitlist. ELPC/VS understand from interactions with the solar industry as well as with urban communities that urban community solar projects take more time and effort than do comparatively simple rural projects. Thus, limiting the time window during which urban projects have to apply to 60 days may not be sufficient time to enable the community solar program to deliver project diversity. ELPC/VS Obj. at 3-4.

While the 60-day application window for diverse projects exceeds the 14-day application window for the original program, ELPC/NRDC/VS note that it still may not be sufficient because applicants to the original program had more time to prepare to apply prior to the program opening. In the case of the first round of the program, applicants were effectively alerted that there would be funding available for a community solar program when PA 99-0906 passed in December 2017, more than a year ahead of the program finally opening in January 2019. Under the Revised Plan, diverse applicants would be notified of available funding 180 days before applications are due - receiving less than half the time waitlist projects received to gear up to apply. ELPC/VS Obj. at 4.

ELPC/VS/NRDC believe the approach in the Revised Plan filed by the IPA, with some minor modifications, has merit and is a reasonable approach to increasing community solar project diversity in the short-term. ELPC/NRDC/VS Resp. at 28. The IPA's scoring approach assigns points to submitted projects based on four criteria. The first criteria, "development density," measures how developed land is by township and is intended to be a direct measure of how urban or rural an area is. ELPC/VS developed the methodology for calculating development densities in the public comments on the draft Revised Plan and that methodology was adopted by the IPA in the Revised Plan. The next three criteria: "development in response to a site-specific RFP from a municipality or community group," "commitment to serve subscribers in the same or adjacent townships," and "project size" are intended to help pull community solar projects into truly dense areas, not just push them to the edge of urban areas. Thus, ELPC/NRDC/VS opine that the criteria work together to incent projects to locate not just in non-rural areas, but in the heart of urban areas, by rewarding the very limited amount of capacity expected to be available for community solar through this Plan to projects that score higher across these criteria. ELPC/NRDC/VS Resp. at 28-29.

ELPC/NRDC/VS state that a few modifications suggested by various parties in their objections would further improve this scoring approach. Those include:

- Providing diverse projects more than 60-days to apply to the program - feedback from both the Joint Solar Parties and ELPC/VS indicate that the IPA's proposed 60-day time window will not work.
- Ensure township boundary and development density information is readily accessible. While this information is already publicly available, the Commission should require additional steps to address the Joint Solar Parties' concerns about the clarity of township boundaries and development density scores. For instance, the IPA could publish

- definitive versions of this information on the Adjustable Block Program website and provide simple tools to ensure this information is clear and readily available (e.g. zoomable township map).
- Eliminate complications with batching. The IPA should ensure that batching requirements do not hobble the development of smaller community solar projects selected through the IPA's project scoring process, as outlined in the concern raised by Joint Solar Parties in their objections.
  - Take steps to discourage gaming of site-specific RFPs.
  - Maintain some flexibility to improve scoring criteria. Maintaining some flexibility around scoring criteria could allow the IPA to react to changing circumstances or incorporate good new ideas. For instance, this flexibility could allow the IPA to integrate the ELPC/VS suggestion to not advance projects that score zero points; add criteria that would help draw projects into urban areas, such as Summit's suggestion to award additional points to projects not located on a greenfield; and consider future proposals for improved subscriber proximity requirements.

ELPC/NRDC/VS Resp. at 29-30.

ELPC/NRDC/VS opine that while some improvements could be made to the IPA's project scoring approach, the general approach is reasonable under the current circumstances. The Commission should feel confident that adopting this approach is a sound short-term method for encouraging more community solar project diversity if additional resources become available in this Plan. ELPC/NRDC/VS intend to continue discussing long-term solutions with the Joint Solar Parties and other stakeholders and will inform the Commission in an appropriate filing if an agreement is reached. ELPC/NRDC/VS Resp. at 30.

In order to provide full approval of Revised Plan elements and, in particular, decisive action on contested issues, ELPC/NRDC/VS assert that the Commission should explicitly approve: (1) the use of a scoring approach in the Revised Plan for community solar project selection, (2) the purpose of the scoring being to improve community solar project diversity, and (3) the specific attributes that could be scored. ELPC/NRDC/VS Rep. at 15-16.

In order to clarify the purpose of the scoring to promote project diversity in the Plan, ELPC/NRDC/VS recommend the following minor edit to the Revised Plan on page 117 discussing why scoring would be used: "projects whose selection would be in part intended to increase the variety of community solar locations, models, and options in Illinois." ELPC/NRDC/VS Rep. at 16.

ELPC/NRDC/VS propose that the Commission should add a stakeholder feedback process to the Revised Plan to gather feedback with which to refine the scoring approach in order to best achieve the goals of increasing the variety of community solar locations, models, and options in Illinois. Stakeholder feedback should be gathered on: (1) the timeline for project application to and any potential reallocation of funds from community solar projects selected through scoring, (2) whether minimum scores should be required

for any individual or subset of attribute(s) for all scoring pathway applicants, (3) automatic triggers to lower attribute scores, (4) qualification requirements for individual attributes (e.g., should site-specific RFPs be required to have been issued prior to the announcement of the opening of the block), (5) number of points awarded, and (6) other attributes that should be considered in order to increase the variety of community solar locations, models, and options in Illinois - such as the proposal from Summit to award points to non-greenfield projects. ELPC/NRDC/VS Rep. at 16-17.

In preparing the Initial LTRRPP, ELPC/NRDC/VS note that the IPA administratively set prices for RECs at a level that would incentivize projects to achieve the goals of PA 99-0906 “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); ELPC/VS Obj. at 6.

ELPC/VS have advocated adjusting prices in subsequent blocks based on price signals since the program’s inception. Administratively setting prices always presents risks of either overpricing for RECs (which would result in a surplus of interest in the program and effectively overpaying for the capacity targets set by policy) or underpricing the RECs (which would result in program utilization that would not achieve the State’s policy targets). ELPC/VS reiterate that the IPA should consider reducing REC prices to reflect the overwhelming volume of applications for community solar projects. Clearly, the market sent a signal that the prices were overly generous. ELPC/VS Obj. at 8-9.

For the purposes of this issue, ELPC/NRDC/VS suggest that the Commission distinguish between short- and long-term solutions. In the short term (for purposes of the small number of projects expected to receive allocations under this Plan update), ELPC/NRDC/VS support using the REC pricing proposed in the IPA’s Plan. This would provide predictability for these projects that are able to move forward. In addition, by the time new capacity is available, ELPC/NRDC/VS anticipate further cost reductions that should be reflected in future REC pricing. While ELPC/NRDC/VS do not propose a specific market pricing approach here, they believe it should be left to the IPA to conduct such an investigation in the context of the development of its next Plan update. ELPC/NRDC/VS Resp. at 23.

The Joint Solar Parties contest two aspects of the IPA’s proposal. First, JSP argues that the IPA Act’s diversity requirement applies only to the Adjustable Block Program “as a whole” and not to the community solar and distributed generation sub-programs individually. Second, JSP argues that “it is not clear” that the general lack of community solar projects in urban areas “shows a failure of geographic diversity.” ELPC/NRDC/VS maintain that the Joint Solar Parties are wrong on both counts. The best evidence of the legislature’s intent is the language of the statute itself. *Bruso v. Alexian Bros. Hosp.*, 178 Ill. 2d 445, 451-52 (1997). In this case, the statute plainly requires the IPA to design the Adjustable Block Program so that RECs are procured “from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation projects in diverse locations and are not concentrated in a few geographic areas.” 20 ILCS 3855/1-75(c)(1)(K). If the General Assembly cared only about the diversity of the Adjustable Block Program as a whole it would not have independently listed the distributed generation program and the community renewable program. The use of the word “and” means that the General Assembly wanted both the

DG program and the community solar program to result in a diverse mix of projects. ELPC/NRDC/VS Rep. at 5-6.

The Joint Solar Parties and Staff also appear to argue that the IPA Act applies only to geographic diversity at a superficial level (i.e. in northern, central, western, or southern Illinois) but not to the geographic differences between rural and urban areas of Illinois. According to ELPC/NRDC/VS, however, the IPA Act requires that projects be located “in diverse locations and are not concentrated in a few geographic areas.” 20 ILCS 3855/1-75(c)(1)(K). The IPA reasonably interpreted this statutory language to require broad geographic diversity of projects located throughout the State, including in both rural and urban areas. To the extent the statute is ambiguous, the IPA’s interpretation is supported by the broader expressions of legislative intent, including the IPA Act’s specific goal for the IPA to “[i]mplement renewable energy procurement and training programs throughout the State to diversify Illinois electricity supply, improve reliability, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents, including low-income residents.” 20 ILCS 3855/1-5(H) (legislative findings and declarations); ELPC/NRDC/VS Rep. at 6.

Several parties suggested changes to the IPA’s project selection approach be used when substantial new funding becomes available either through legislative action or adoption of subsequent Plan updates (new funding may become available under existing programs in the 2024 timeframe). ELPC/NRDC/VS suggest that the Commission need not act at this time regarding these various proposals. ELPC/NRDC/VS expect that the IPA’s current budget gap for the Adjustable Block Program will need to be resolved in the context of new legislation and, at that time, the IPA will need to propose significant revisions to the LTRRPP. ELPC/NRDC/VS Resp. at 35.

ELPC/NRDC/VS believe that further discussion is needed to examine how the IPA’s project selection process can be decoupled from the utilities’ interconnection process to the maximum extent possible. The rules governing the interconnection of distributed generation, 83 Ill. Adm. Code 466, are intended to provide a transparent, predictable and well-defined process for distributed generation to interconnect with utility systems. ELPC/NRDC/VS advocate for sound interconnection policy and believe that an investigation by the Commission into current interconnection practices of utilities should be undertaken as a separate matter. However, ELPC/NRDC/VS also believe that the process adopted by the IPA and the Commission in the initial allocation of Adjustable Block Program capacity created an undesirable link between the Adjustable Block Program and the interconnection process that should be avoided in the future. The fundamental problems with the link between the interconnection process and the Adjustable Block Program project selection process are that they are: (1) governed by separate statutes and rules with different policy objectives, and (2) administered by different entities (the IPA for the Adjustable Block Program and the utilities for the interconnection processes). ELPC/NRDC/VS Resp. at 36-37.

ELPC/NRDC/VS argue that the IPA may not disregard one set of statutory mandates (geographic diversity) in favor of another (cost-effectiveness). The IPA and Commission must balance and pursue these two statutory goals together. At the end of the day, the IPA Act provides the IPA with discretion and flexibility to pursue the multiple and overlapping requirements of the law in the most cost-effective way possible. The

Commission shall approve the Plan if it “reasonably and prudently” accomplishes the requirements of the law. See 220 ILCS 5/16-111.5(b)(5)(ii)(D). The IPA’s proposed scoring approach is reasonable and the Commission should approve it. ELPC/NRDC/VS Rep. at 12.

## 9. IPA

In Docket No. 17-0838, the IPA proposed, and the Commission adopted, a random selection process (i.e., a lottery) to choose selected projects in the case of oversubscription of available program capacity. However, the prospect of a lottery likely spurred community solar project developers, which do not first need to identify customers or subscribers before proposing projects into the program, to secure additional physical sites for proposing additional projects. Despite the IPA’s project maturity standard requiring a signed interconnection agreement, proof of site control, and obtaining all non-ministerial permits (requirements proposed by industry parties during the development of the Initial Plan), the initial application period featured 5-10 times more community solar projects than capacity available. IPA Resp. at 10.

Despite the IPA’s REC pricing model offering additional incentive for smaller projects, the vast majority of proposed projects were at or near the maximum allowable size of 2 MW and located in less populated, often agrarian areas as a means to control land acquisition costs. The IPA’s initial observations into subscriber acquisition found that most acquisition is being conducted through direct mail and/or online portals. Also, the IPA notes that project developers have repeatedly requested flexibility to switch subscribers across projects. IPA Resp. at 10.

The end result is a community solar marketplace that arguably bears more resemblance to “green” or “renewable” retail electric supply offers than a regime under which subscribers feature a direct “community” connection to or investment in a given physical project. In an effort to reduce project development and subscriber acquisition costs, community solar projects approved through the program’s first phase generally reflect a transactional, developer-driven model of remote projects and disconnected subscribers. IPA Resp. at 11.

The IPA recognizes that those developers having submitted projects into the program have interests worth respecting. At the same time, having now completed the program’s first phase for community solar, the IPA believes this Revised Plan allows an opportunity for the identification of any gaps that resulted from its prior approach to project application and selection. While available budgets may be tight for the foreseeable future, remedying such gaps should be a high priority for any new funding or program capacity that becomes available. IPA Resp. at 11.

The IPA thus arrived at the following proposal included in the Revised Plan. For any new community solar block, 50% of that block’s capacity would be taken from the existing ordinal waitlist under that order. This way, and as distinguished from any new lottery or other selection process, project developers would have clear visibility into the likelihood of their project’s selection prospects. And as opposed to holding all capacity for new projects intended to address gaps, existing project developers who do not meet or score favorably under newly developed criteria would still have a pathway to development. IPA Resp. at 11.

Use of the existing ordinal waitlist would offer no incentive for projects faring poorly on that ordinal list to maintain a spot in the interconnection queue. Developers for projects ranked, for example, #200-#500 in that rank order would know the very low likelihood of obtaining a REC delivery contract and could make an informed choice to cease development. IPA Rep. at 13.

As outlined in Section 6.3.3.1.2 of the Revised Plan, for the remaining 50% of that new block's capacity, projects would be scored on the basis of four criteria: development density, community involvement, subscriber proximity, and project size. To accommodate new projects potentially needing to be pulled together to meet these criteria, the Revised Plan offers a minimum 60-day period between notification of a pending block opening and that block actually opening and a 60-day project application period. IPA Resp. at 12.

The IPA is concerned that any new community solar project selections will occur against the backdrop of approximately 110 similarly-looking community solar projects having already been selected, and a waitlist of hundreds more projects featuring largely the same characteristics. While cost and certainty were incredibly important to allocating discretionary capacity in ensuring that Section 1-75(c)(1)(C)(i)'s 2020 delivery year annual REC delivery target could be met without exceeding available funding (and even still, the Adjustable Block Program faces a major budget crunch outlined extensively in Chapter 3 of the Revised Plan), the relevant question for this Revised Plan is how best to prioritize community solar project selection for this next phase of the ABP. The IPA believes that doing so involves the identification of gaps in project diversity from prior project selection processes and proposing a solution for remedying those gaps; this is a distinct concern produced by a fundamentally different analysis than determining how to prioritize discretionary capacity eight months ago. IPA Resp. at 17-18.

Further, ELPC/VS and Joint Solar Parties request that any capacity allocated to community solar projects enhancing portfolio diversity not be "reallocated" after 60 days. As the IPA states in response to the Joint Solar Parties' arguments, a longer application window may be advisable. The IPA notes that an extended application window would likely lead to a more diverse pool of project applications, while a 60-day application window without redistribution of capacity (as ELPC/VS suggests) would likely lead to supporting only those existing proposals who could presently apply and score favorably in the diversity-enhancing category. While the IPA prefers the approach of a longer application window, the IPA would also support extending the application window without then reallocating project diversity capacity. IPA Resp. at 24-25.

ELPC/VS offer a general objection to the Revised Plan's community solar REC prices, stating that community solar block prices should be "repriced[d] . . . based on the strong market demand for that category." ELPC/VS Obj. at 9. No methodology or order of magnitude is offered for this requested "repricing." Ameren raises a similar concern, stating that "oversubscription is a clear indicator that REC prices are higher than needed to entice participation," and seeks that such prices be "lowered." Ameren Obj. at 6-7; IPA Resp. at 26.

As described in Section 6.4 of the Plan, the IPA adopted and modified the National Renewable Energy Laboratory's Cost of Renewable Energy Spreadsheet Tool ("CREST")

to develop a model for calculating REC prices. CREST is an economic cash flow model that estimates the cost of energy in terms of cents per kW hour associated with specific input assumptions regarding technology type, location, system capital and operating costs, expected production, project useful life, and various project financing variables. Given this methodological rigor, the IPA is generally reluctant to depart from prices established through the CREST model but recognizes that market feedback can serve as an important check on the reasonableness of prices. IPA Resp. at 26-27.

While the Agency's initial Adjustable Block Program application period featured undeniably strong market demand from community solar project developers—the current 800+ community solar project waitlists were established almost exclusively through projects applying in the program's first two weeks—it is uncertain whether that demand was driven by the incentive structure posed by a lottery in the case of oversubscription, overly generous REC prices, or some combination of these and other factors. In any event, the next block which opens (Block 5) will feature prices approximately 15% lower than the Block 1 prices which were potentially available for that initial application rush. Additionally, the Revised Plan no longer offers the Initial Plan's highest possible adder for small subscriber participation, thus further reducing possible REC prices by approximately an additional \$11. Under the Initial Plan, a 2 MW Group A community solar project with a Block 1 award and full small subscriber participation could have achieved a REC price of \$85.79; under the Revised Plan, for Block 5, that maximum price is now \$66.74, a 22% decrease. IPA Resp. at 27.

For now, the IPA believes that these price changes, which do not depart from its CREST model methodology, constitute appropriate adjustments in response to market demand. However, should circumstances warrant, the IPA reserves its right under Section 1-75(c)(1)(M) of the IPA Act to alter REC prices by amounts “that do not deviate from the Commission's approved value by more than 25%” outside of its process for formally revising the Plan. IPA Resp. at 27.

With respect to Large Distributed Generation prices, which are cited as a concern by Ameren but not by ELPC/VS, the IPA notes that the pace of Large Distributed Generation program submissions has leveled off considerable as block prices have been reduced from Block 1 to Block 4. At the time of this filing, capacity still remains within Block 4 for Large DG projects in both Group A and B—providing actual market feedback that even if Block 1 prices may have been too generous, present prices may be reasonably set. IPA Resp. at 27-28.

## **10. Commission Analysis and Conclusion**

First and foremost, it is clear to the Commission that much of the problem with the waitlist and price uncertainty stems from Parts 466 and 467 of the Commission's rules. Obviously, these rules cannot be changed in this docket. The Commission, however, cannot ignore the issues raised by parties, such as the uncertainty in price that results from changes in queue position. Accordingly, Staff is directed to initiate workshops to explore amending Part 466 and Part 467 to alleviate some of the issues raised. The Commission recognizes the urgency of the rulemaking but also understands the technical and operational complexities that go along with amending the interconnection rules. The Commission directs Staff to begin the workshop process within 30 days of the issuance

of this Order and, within six months of the issuance of this Order, to submit to the Commission a Staff Report, including suggested rule changes, and a draft Initiating Order for a rulemaking proceeding. The Commission also directs Staff to include a provision in the draft Initiating Order that requires the assigned Administrative Law Judge to set a schedule that allows the Commission to enter a Second Notice Order before the IPA files its next proposed update to the LTRRPP. Moreover, the Commission notes that ComEd's proposal to remove the requirement that applicants have a signed interconnection agreement is supported by Ameren in its Reply Brief on Exceptions. The Commission finds that, because of the costs involved in preparing cost studies and the interaction of the waitlist with the queue, this proposal should be addressed in the rulemaking workshops. Another issue the workshops should consider is whether removing this project readiness criteria will alleviate the need to amend the rules.

Next, this issue must be considered from both a near and long-term perspective. In the near-term, it appears that this issue will have little impact. The Commission notes that there is essentially no money for the Adjustable Block Program unless a new law is passed and any new law may change any of the decisions reached herein.

Nevertheless, the Commission has considered the many proposals and the lengthy critiques parties have offered on these proposals. The Commission notes that support for the waitlist is almost non-existent, but the parties are unable to agree on any of the other proposals. In fact, Ameren's proposal to hold a reverse auction (which was supported by the AG) is the only proposal to receive another party's support, however, the Commission agrees with the other parties that it violates the statute's requirement that the LTRRPP must include a schedule of standard block purchase prices. 20 ILCS 3855/1-75(K).

For the very limited money that is available, the IPA suggests maintaining the Commission-approved waitlist, and the Commission agrees. The IPA points out that by maintaining the existing ordinal waitlist, project developers with unfavorable positions know that those projects have no immediate prospect for development and can abandon development efforts (including the interconnection application) until such time as significant new funding becomes available. The Commission finds that by maintaining the waitlist, developers have a clear idea of the likelihood of their project being developed in the next two years.

The IPA proposes 50% of capacity be procured through projects on the waitlist and 50% of capacity be selected based on diversity criteria. The Commission notes that the IPA has agreed to several proposals from parties, such as timing, maps, and batches, and the Commission agrees that these suggestions improve the IPA's proposal. First, however, the Commission must consider whether 50% of capacity should be reserved to correct the IPA's perceived lack of geographic diversity that resulted from the initial rounds of Adjustable Block Program community solar procurements. The Commission notes that the IPA Act states that:

The Adjustable Block program shall be designed to ensure that renewable energy credits are procured from photovoltaic distributed renewable energy generation devices and new photovoltaic community renewable energy generation

projects in diverse locations and are not concentrated in a few geographic areas.

20 ILCS 3855/1-75(c)(1)(K). The pressing question regarding this sentence is whether it is enough for the Adjustable Block Program as a whole to be diverse or whether the individual distributed generation and community solar programs need to be diverse themselves. The Commission reads the first part of this sentence to clearly require that the Adjustable Block Program should be designed so that RECs are procured from diverse locations for both solar distributed generation and new community solar projects. In other words, “diverse locations” are required for both solar distributed generation and community solar, not just the Adjustable Block Program as a whole.

The second part of the sentence could mean either that the Adjustable Block Program should ensure that RECs for the Adjustable Block Program as a whole are “not concentrated in a few geographic areas” or it could equally be that “not concentrated in a few geographic areas” is an expansion of what is meant by “diverse locations.” To make matters even more unclear, it is not evident what the difference is between “diverse locations” and “not concentrated in a few geographic locations.”

The IPA reasonably interpreted this statutory language to require broad geographic diversity of projects located throughout the State, including in both rural and urban areas. To the extent the statute is ambiguous, the IPA’s interpretation is supported by the broader expressions of legislative intent, including the IPA Act’s specific goal for the IPA to “[i]mplement renewable energy procurement and training programs throughout the State to diversify Illinois electricity supply, improve reliability, avoid and reduce pollution, reduce peak demand, and enhance public health and well-being of Illinois residents, including low-income residents.” 20 ILCS 3855/1-5(H) (legislative findings and declarations).

The Commission finds that the IPA has articulated a reasonable interpretation of Section 1-75(c)(1)(K)’s diversity requirement that is consistent with the broader intent of PA 99-0906. In instances where the statute is unclear, the agency’s interpretation of its own enabling statute is given substantial weight and deference. *See Commonwealth Edison Co. v. Ill. Commerce Comm’n*, 2019 IL App (2d) 180504, ¶ 56, appeal denied (upholding the IPA and Commission’s statutory interpretation to enable Adjustable Block Program project development in municipal and co-op territory as “more consistent with the stated legislative intent”).

Although, the Commission finds that the geographic diversity requirement applies to both distributed generation and community solar, the IPA’s proposal only addresses community solar. The Commission accepts the Revised Plan’s explanation that the IPA introduces geographic diversity factors specifically for community solar because it has observed a geographic diversity problem only with community solar.

Moreover, by limiting the diversity requirement to only half the capacity to be procured, the IPA has proposed a more limited, targeted, and balanced approach to addressing the challenge of community solar project diversity. Also, because the IPA’s proposal retains the Commission-approved waitlist, which provides developers with information, and reacts in a reasonable manner to the results of the previous rounds of the Adjustable Block Program, the Commission finds that the IPA’s proposal strikes a

balance between the dual goals of accommodating existing proposals developed in reliance on non-qualitative ranking and attempting to achieve a more diverse project mix.

Although the Commission approves the IPA's proposal, the Commission agrees with ELPC/NRDC/VS that stakeholder feedback is a valuable tool to refine the scoring approach in order to best achieve the goals of increasing the variety of community solar locations, models, and options in Illinois. Thus, the Commission directs that stakeholder feedback be gathered on: (1) the timeline for project application to, and any potential reallocation of funds from, community solar projects selected through scoring; (2) whether minimum scores should be required for any individual or subset of attribute(s) for all scoring pathway applicants; (3) automatic triggers to lower attribute scores; (4) qualification requirements for individual attributes (e.g., should site-specific RFPs be required to have been issued prior to the announcement of the opening of the block); (5) number of points awarded; and (6) other attributes that should be considered in order to increase the variety of community solar locations, models, and options in Illinois - such as the compelling proposal from Summit to award points to non-greenfield projects.

The Commission next turns to REC pricing in the Adjustable Block Program. The IPA states that the next block which opens (Block 5) will feature prices approximately 15% lower than the Block 1 prices. Additionally, the Revised Plan no longer offers the Initial Plan's highest possible adder for small subscriber participation, thus further reducing possible REC prices by approximately an additional \$11. In other words, under the Initial Plan, a 2 MW Group A community solar project with a Block 1 award and full small subscriber participation could have achieved a REC price of \$85.79; under the Revised Plan, for Block 5, that maximum price is now \$66.74, a 22% decrease. IPA Resp. at 27. The Commission agrees that it is clear that the prices available in the Initial Plan were too high, which is evident from the oversubscription to community solar and the over 800 projects on the waitlist. It is not clear that the prices for Block 5 are too high or what an appropriate price would be and, notably, no party made a suggestion. The Commission directs the IPA to consider lowering the Block 5 price any amount up to its discretionary power to reduce prices 25% without Commission approval. The IPA should look not only to diversifying projects but also to procuring the most RECs possible with the intent to efficiently invest ratepayer money.

As far as long-term issues and decisions, the Commission agrees that further workshops should be held and stakeholder input considered bearing in mind the discussion herein and specifically the following conclusions: 1) the waitlist must be cleared - the Commission believes that four years on a waitlist is more than any developer can expect; and 2) REC prices must be lower to both efficiently invest ratepayer money and limit oversubscription resulting in a lottery process. Notably, the Initial Plan's approach was a first-come, first-served approach, unless there was oversubscription which then switched the process to a lottery. In other words, the Commission agrees that a first-come, first-served approach can work if there is significantly more capacity and the RECs are priced appropriately. For prices, the IPA must recognize market signals rather than solely relying on its cost modeling approach. The Commission looks favorably upon Ameren's proposal for a reverse auction but notes that this would require legislative action. Other various proposals that deserve exploration are: a developer cap; collateral; and methods to reduce gaming. Prior to the next plan update filing, the IPA must meet

with parties in an attempt to narrow the issues presented consistent with the findings the Commission has made herein.

## **B. Section 6.6 Adjustable Block Payment Terms quarterly payments**

### **1. Ameren**

Section 6.6 of the Revised Plan recommends that as part of the contract update process, new contracts allow for three separate quarterly delivery schedules to reduce the lag time between payments. Ameren is concerned that this change will add unnecessary administration to an already complex process, thus increasing the possibility of accounting and settlement errors. Ameren Obj. at 7.

Ameren points out that the entire the Adjustable Block Program settlement process is still in the early stages of implementation. In fact, at the time of this filing, Ameren's accounting and settlement personnel have only participated in two quarterly settlements, both of which have proven to be very challenging. These two quarterly settlements have represented only about 3% of the total amount of Adjustable Block Program dollars still to be paid. Ameren Obj. at 7-8.

With the uncertainty of future workflow, Ameren believes the best course of action is to continue with the already established quarterly cycle of March, June, September and December. Given that the implementation of invoice processes for existing contracts are in their infancy, incremental changes as proposed by the IPA are premature, create risk, and should be rejected by the Commission. Ameren Obj. at 8.

Although Ameren remains concerned about the possibility of administrative burden and its associated costs, Ameren is willing to concede this issue should the Commission direct the IPA and their Program Administrator to commit to reviewing the process in the next LTRRPP and then recommending appropriate corrective modifications, as necessary. Ameren Rep. at 8-9.

### **2. Joint Solar Parties**

While the Joint Solar Parties are sympathetic to the administrative burdens of starting up a new program, a better approach would be to have monthly billing windows. This would allow energization payments under the REC Contract to be processed faster and under a regular schedule but simplify administration of compliance periods. It will also blunt the impact of missing the billing window—particularly if it was missed due to no fault of the Approved Vendor. JSP Resp. at 21-22.

### **3. IPA**

The IPA appreciates that payment processes are complex and is committed to help support Ameren's payment processes in any way possible, though the IPA would be curious to know more specifically what aspects of the payment process have proven difficult. The IPA notes that new REC contracts and product orders are approved by the Commission approximately every two weeks, and payment for an energized project often occurs many months after a project comes under contract, so there is generally not a rush to accomplish all these tasks at once for a single vendor or project in the weeks after a defined quarter ends. As the IPA's Revised Plan proposal contemplates the IPA and the respective Program Administrator continuing to maintain control over the issuance of

invoices for payment, the IPA remains confident that it can appropriately manage the invoicing process even with three quarterly payment schedules running in parallel. IPA Resp. at 29.

In Response, the Joint Solar Parties reiterate their desire for monthly billing windows. The IPA continues to believe that for first (or only) payments, there is no practical difference between the IPA's proposal and that of the Joint Solar Parties. That first payment will be made in the quarterly cycle in which the Approved Vendor submits an invoice to the utility containing the project. Where the IPA and the Joint Solar Parties appear to differ is the treatment of subsequent payments for distributed generation systems over 10 kW and community solar projects. After the initial 20% of REC value payment for these systems, the balance of the system's REC value is presently made over 16 subsequent quarterly payments over 4 years. The IPA remains confused as to whether the Joint Solar Parties now seek monthly billing (48 monthly payments over 4 years) rather than quarterly billing. IPA Rep. at 24.

To the extent the Joint Solar Parties now seek monthly billing, the IPA is opposed to this request. Monthly billing would feature a three-fold increase in the number of transactions to be processed, offering a significant increase in administrative burden without having demonstrated a corresponding justification. Insofar as the Joint Solar Parties rely on negative consequences of missing a quarterly invoice as the justification for monthly invoicing and payments, the IPA believes that missing an invoice window should be consequential, and payment terms which require prompt and timely attention to paperwork before payment are an important safeguard against fraud and abuse. Likewise, to the extent that the Joint Solar Parties merely seek flexibility such that if an Approved Vendor fails to timely submit an invoice, that Approved Vendor could just submit this invoice the following month rather than waiting until the next quarter, the IPA opposes that proposal. With over ten thousand photovoltaic systems participating in the Adjustable Block Program, keeping payments on defined schedules provides important administrative efficiency and predictability. Allowing projects to move from one payment cycle to another at the Approved Vendor's whim would increase the likelihood of billing errors. IPA Rep. at 24-25.

#### **4. Commission Analysis and Conclusion**

It appears to the Commission that Ameren has agreed to wait to see how implementation of the Revised Plan proceeds. The IPA indicates it is willing to listen and work with Ameren on issues that arise. The Commission believes this is the best approach and, as suggested by Ameren, can consider any changes to the process in the next review proceeding.

The Commission agrees with the IPA that the proposal of the Joint Solar Parties is unclear. Either they are proposing exactly what the Revised Plan says or they are proposing monthly invoices, which is a dramatic increase in work. The Joint Solar Parties have not demonstrated that their proposal is reasonable or necessary, and it is rejected.

## **C. Section 6.7 Program Guidebook**

### **1. Joint Solar Parties**

The Joint Solar Parties request that the Commission direct that the REC Contract should include either dispute resolution before the IPA as an initial step or at minimum a term that makes IPA interpretations of the REC Contract binding on both parties. The Joint Solar Parties note that the IPA's own rules allow for it to serve as a mediator (for a fee set out in the rule). See 83 Ill. Adm. Code 1200.420; JSP Obj. at 29-30.

The Joint Solar Parties appreciate the IPA's openness to taking on a role as a mediator of disputes under the REC Contract, despite raising implementation concerns. See IPA Resp. at 31. While the Joint Solar Parties were specifically intending for the mediator role to take place in a dispute between the Buyer (utility) and Seller (Approved Vendor) involving contract interpretation, the Joint Solar Parties do not oppose a broader mediation option. To the extent the REC Contract includes a relatively broader mediation option for either Buyer or Seller, the Joint Solar Parties imagine there would have to be a mechanism for the IPA to decline to mediate when the IPA believes its own contractual rights or obligations are implicated by the dispute. JSP Rep. at 29.

### **2. IPA**

The Joint Solar Parties offer a novel proposal requesting that the REC Contract "include either dispute resolution before the IPA as an initial step or at minimum a term that makes IPA interpretations of the REC Contract binding on both parties." JSP Obj. at 43. While the IPA is not an adjudicative body and none of its staff is trained as mediators (the reference to mediation contained in the JSP Objections concerns the activities of the IPA's defunct Resource Development Bureau, which concern clean coal procurements and assistance with evaluation of bids or development of facilities), IPA staff is intimately familiar with the REC delivery contract, already provides informal feedback to questions about contract terms, and attempts to take a neutral, unbiased role in disputes between Buyers and Sellers. IPA Resp. at 31.

The IPA notes that to the extent the IPA were to serve as a formal mediator of REC Contract disputes, that role should be limited to matters for which the IPA exercises no formal role requiring its judgment under the contract (such as the recognition of a force majeure event or granting an extension for project energization). IPA Resp. at 31.

### **3. Commission Analysis and Conclusion**

The Commission notes that the IPA seems to have agreed to the Joint Solar Parties' proposal that the IPA act as mediator between utilities and Approved Vendors in some REC Contract disputes. Because of the familiarity of the IPA with the REC Contract and processes, this seems reasonable, with the understanding that in areas where the IPA would be an interested party, this would be obviously inappropriate. The Commission agrees that the REC Contract being discussed in workshops should adopt a measure that incorporates this proposal.

**D. Section 6.9.1 Approved Vendor Designees, Section 6.13.4 Disciplinary Determinations**

**1. Joint Solar Parties**

The Joint Solar Parties object to the new regulatory requirements on non-Approved Vendors (labeled “designees” by the LTRRPP), the inadequate procedural protections for Approved Vendors subject to discipline, failure to address the overly burdensome disclosure form, and the obligation to resign the disclosure form for a customer to move to a different community solar project. JSP Obj. at 35.

First, the Joint Solar Parties object to the Revised LTRRPP’s proposed registration of Approved Vendor “designees” without limiting clarifications. See LTRRPP at 135-136. The Revised LTRRPP identifies designees as: “third-party (i.e., non-Approved Vendor) entities that have direct interaction with end-use customers. This includes installers, marketing firms, lead generators, and sales organizations. The Agency reserves the right to add additional categories as needed.” *Id.* at 135. The Joint Solar Parties’ primary objection is the vagueness of what it means for a designee to register. The Joint Solar Parties may have limited to no objection if registration is a simple matter of identifying the existence of a relationship with an Approved Vendor. JSP Obj. at 35.

The Joint Solar Parties are concerned, however, that given the IPA’s approach to implementing consumer protections, “registration” is more likely to be implemented as regulation. The Joint Solar Parties urge the Commission to explicitly state that “registration” is limited to providing contact information, acknowledging the existence of the business relationship with the Approved Vendor, and identifying basic categories of the consumer-facing services provided. The Joint Solar Parties note that the IPA proposes to maintain—and the Joint Solar Parties support—Approved Vendor responsibility for the actions of their designees and other agents, so it is unclear what new responsibilities will or should be required of “designees” because no responsibilities are removed from Approved Vendors. See, e.g., LTRRPP at 136, 144; JSP Obj. at 35-36.

Second, the Joint Solar Parties object to the minimal procedural safeguards for Approved Vendors subject to potential discipline. At minimum, the IPA must implement a process for an Approved Vendor to request rehearing to allow for review under the Illinois Administrative Review Law. See 735 ILCS 5/3-101 (defining “administrative decision”). A better approach would be to add the procedural protections outlined by the Joint Solar Parties in public comments, including: 1) commit to a system with formalized requirements—perhaps even IPA-promulgated rules—setting procedures, obligations, and rights during complaint and Approved Vendor status investigations; 2) formalized requirements for IPA review of Program Administrator decisions should have a formalized process for rehearing so that an Approved Vendor may avail themselves of the Administrative Review Law (735 ILCS 5/3-101 *et seq.*); 3) formalized requirements for Program Administrator Decisions and IPA review that set out clear standards for decisions and the right to, at minimum, a telephonic hearing; and 4) if the Program Administrator or IPA identifies a global objection to, for instance, marketing materials or customer interaction materials, there should be a defined procedure for remedying the objection by the Approved Vendor rather than disciplining the Approved Vendor in the

broadest range of scenarios where there is a good-faith difference of opinion on the requirements of marketing guidelines. While not addressing these requirements individually, the LTRRPP offers blanket opposition to such procedural protections that it is merely restricting access to incentive money, not the solar market generally. See LTRRPP at 147-148; JSP Obj. at 36.

While the Joint Solar Parties understand that solar development outside the LTRRPP may take place, the reality is that the Adjustable Block Program and ILSFA were put in place because the Illinois General Assembly determined the previous approaches were insufficient to meet their renewable development goals. Additionally, given the IPA's pending decision to publicly release complaints and discipline on Approved Vendors, it is even more important to allow for administrative review, because IPA decisions or discipline without due process could have a chilling effect on specific companies, impacting the marketplace. The Adjustable Block Program and ISFA are state programs administered by a state agency; whether or not full Illinois Administrative Procedures Act due process protections are required, the IPA should provide procedural protections. JSP Obj. at 36-37.

Third, the Commission should direct simplification of the IPA-mandated disclosure form. In addition to the procedural burdens identified in its Objection, the disclosure forms are extremely long and cumbersome and make incorrect assumptions about many products and services. In the experience of Joint Solar Parties' member companies, the customer experience deteriorates as an Approved Vendor (or equivalent in other states) representative spends more and more time with a customer as part of sales process. In a typical in-person or telephonic sales scenario, the representative and customer will input solar system data for the Approved Vendor contract, but then will need to re-enter the same data and upload the information to the official program website. After it is uploaded, they wait to then download an "official" version of the form. After it is downloaded, it is signed and then uploaded again. This entire process can be delayed depending on website loading times and internet connections and adds 30-45 minutes to the process. The JSP would welcome a Commission-facilitated forum or working group to improve the disclosure form and process to ensure a quality customer experience while also meeting Commission's requirements. JSP Obj. at 37-38.

Several other aspects of the disclosure—from its length to overly binary forced responses to including information that does not help customers make informed decisions—make the disclosure less helpful to the very customers the LTRRPP seeks to educate. While the length of disclosures is not determinative of quality, the Joint Solar Parties note that the Adjustable Block Program and ILSFA disclosure forms are multiple times longer than any other state. In addition, no other state requires disclosures to be generated exclusively through an official program website. As noted above, a Commission-facilitated forum or working group may work well to improve the disclosure form, in part because it will free the IPA from playing triple roles as proponent (of its form), facilitator, and ultimate decision-maker. JSP Obj. at 38.

Fourth, the Commission should modify the Revised Plan to allow for changes in the community solar system in which a customer is subscribed on a shorter form. In these scenarios, an Approved Vendor would offer customers the same exact contractual terms and conditions—the essence of the disclosure—but for another community solar project.

The Joint Solar Parties do not object to providing customers the new system-specific information (for example anticipated production and degradation), thus providing the customer with the same information as would have been in the initial disclosure. However, in certain situations, such as if development for one system is delayed and an Approved Vendor wishes to accommodate valued customers by subscribing them to a system that is developed or closer to development, the Approved Vendor should be able to do so without subjecting the customer to the more burdensome disclosure form process. JSP Obj. at 39.

The IPA does not address any of the specifics of the Joint Solar Parties' proposals, but instead argues that it has exercised its review powers judiciously thus concluding that the existing safeguards are sufficient. See IPA Resp. at 47-48. While the current IPA administration appears to focus on its own actions and intentions, the members of the Joint Solar Parties over a series of 15-year contracts may operate under several different IPA administrations. JSP Rep. at 32-33.

The IPA and the AG make related arguments that procedural protections are not necessary because the only potential discipline is barring an Approved Vendor from future participation in the Adjustable Block Program. See, e.g., IPA Resp. at 45-46; AG Resp. at 12-13. The Adjustable Block Program is currently the exclusive incentive for under 2 MW solar facilities. If other revenue streams were sufficient to incentivize development of under 2 MW solar facilities, the Adjustable Block Program may be less important. However, without the Adjustable Block Program, there is no other avenue to sell RECs under financeable long-term contracts and Illinois' low energy prices make surviving based on net metering and federal tax incentives alone impossible. JSP Rep. at 33.

## **2. AG**

The Commission should reject the Joint Solar Parties' request that the Revised Plan incorporate its proposed procedures for reviewing complaints against, and potential discipline of, Approved Vendors. The Joint Solar Parties' proposed procedures are overly burdensome, and the IPA has acted within its discretion in determining and reviewing eligibility for the programs it administers. The IPA Act provides that the IPA "establish[es] the terms, conditions, and program requirements for community renewable generation projects." 20 ILCS 3855/1-75(c)(1)(N). Pursuant to this authority, the IPA conditions eligibility for Adjustable Block and ILSFA incentives on Approved Vendors' compliance with consumer protections codified in the Revised Plan. Revised Plan at 147; AG Resp. at 12.

The only potential discipline an Approved Vendor faces under the Revised Plan is the suspension of its eligibility for program incentives. The Revised Plan details the IPA's procedures for determining whether to revoke incentive eligibility from an Approved Vendor, including detailed notice of the investigation and alleged infraction, opportunity for the Approved Vendor to refute the allegation with a written or oral explanation, notice of all Program Administrator determinations, and the opportunity to appeal. Revised Plan at 147-148. The procedures outlined in the Revised Plan are sufficient to ensure a fair and timely review of an Approved Vendor's eligibility for these incentives. Accordingly, the AG requests that the Commission approve Section 6.13.4 (Disciplinary Determinations) of the Plan as proposed by the IPA. AG Resp. at 12-13.

### **3. CSG**

While generally supportive of the IPA's efforts to ensure the probity of Approved Vendor designees, CSG urges the Commission to be cognizant of what type of designee roles should be covered as well as the time necessary to implement any new designee registration or vetting process. Depending on the scope of designees falling under any new registration requirements and the actual criteria to be met for registration, significant time may be necessary for Approved Vendors and designees to adjust to any new requirements. Informing designees of new requirements, possibly needing to collect documents from designees or training designees and providing information to the IPA could take considerable time. To avoid situations where Approved Vendors risk disciplinary action by the IPA despite making good faith efforts to comply with new requirements for designees, CSG urges the Commission to specify that any new requirements be rolled out over a period of 90 days before the IPA may take disciplinary action. A 90-day roll out period should apply to any future changes in designee registration requirements as well. CSG Rep. at 2.

To help prevent applying any new designee requirements too broadly, CSG also recommends that the Commission find that such new requirements at least only initially apply to solar installers and developers. These roles arguably warrant imposition of registration requirements due to their greater degree of contact with consumers. Application of registration requirements beyond these roles could easily become unwieldy as it would be difficult to differentiate those roles with less consumer contact. CSG Rep. at 2-3.

### **4. CUB**

The Joint Solar Parties liken a simple registration process for third-party designees (installers, marketing firms, lead generators and sales organization) which directly interact with the end-use customer to regulation of those parties. Far from it, the IPA developed these processes to ensure customer-facing vendors and their designees provide consistent messaging and to "prevent fraud and gaming opportunities, concerns which the IPA's Program Administrator identified from its experience in other jurisdictions." IPA Resp. at 37. These requirements to vet vendors and their designees and ensure compliance with program rules are rationally tied to providing customers with complete and accurate information about the LTRPP Programs. CUB Rep. at 2-3.

The potential for abuse by Approved Vendors and their designees is something CUB has seen materialize in the competitive energy supply market in Illinois, where rampant, aggressive, and at times misleading and fraudulent sales techniques are used to coerce customers to sign up. It is rational, reasonable, and entirely appropriate for the IPA to design processes to avoid this same type of marketing activity in the solar arena. In the Revised Plan, the IPA attempts to clarify and strengthen existing processes to achieve that end. Furthermore, the funds to support the Adjustable Block Program and ILSFA come from ratepayers and the programs are completely optional. If companies choose to opt in, there are substantial potential awards in the form of huge REC values. In order to take advantage of these incentives, vendors must play by the rules. CUB Rep. at 3-4.

The Joint Solar Parties exaggerate the impact of these consumer protections, which require a customer disclosure form to actually be signed by the customer. The protections also control the format in which that disclosure form is presented, executed, and uploaded. IPA Resp. at 38. This is not an expansion of IPA authority but rather modification of the implementation procedures already established and approved by the Commission with the goal to strengthen development of renewables. As the IPA rightly stated, “there is little evidence that the IPA’s common sense and judiciously applied consumer protection requirements have inhibited participation levels.” *Id.* Unless and until there is evidence of these processes being overly burdensome and problematic, the Commission should retain the customer disclosure requirements as written in the Plan. CUB Rep. at 4.

CUB agrees with the AG that the Joint Solar Parties’ proposed procedures for reviewing complaints against and potential discipline of Approved Vendors should likewise be rejected. The Joint Solar Parties suggest that the Plan should include various procedures akin to “due process” to provide a higher level of administrative review than already contained in the Plan. These additional procedural protections are not necessary. Section 6.13.4 of the Revised Plan details the IPA’s procedures for determining whether to revoke incentive eligibility from an Approved Vendor, including detailed notice of the investigation and alleged infraction, opportunity for the Approved Vendor to refute the allegation with a written or oral explanation, notice of all Program Administrator determinations, and the opportunity to appeal. CUB agrees with the AG that the procedures outlined in the Plan are sufficient to ensure a fair and timely review of an Approved Vendor’s eligibility for these incentives. AG Resp. at 12-13.

## 5. IPA

Sections 6.9 and 8.11 of the Initial Plan authorized the IPA to develop a process for considering applications from solar companies (including developers, installers, and REC aggregators) to become “Approved Vendors” within the Adjustable Block Program and ILSFA Program. Only Approved Vendors would be allowed to serve as counterparties (Sellers) under REC contracts; as such, the registration process would consider a company’s reliability and fitness to market responsibly to consumers, to manage a Seller’s reporting and collateral responsibilities under a REC contract, and to comply with all Program requirements. The IPA notes that as of December 2, 2019, there were 332 registered Approved Vendors in the Adjustable Block Program and 28 in ILSFA. IPA Resp. at 32.

The Initial Plan at Section 6.9 provided that Approved Vendors must document that all installers and other subcontractors that they work with comply with applicable local, state, and federal laws and regulations. However, as described in Section 6.9 of the Revised Plan, the IPA now proposes that designees – that is, non-Approved Vendor entities that “have direct interaction with end-use customers [including] installers, marketing firms, lead generators, and sales organizations” – must register with the ABP, with the revocable assent of the Approved Vendor(s) with whom the designee is working. As stated in the Revised Plan, this requirement would help to improve consumer confidence by verifying which entities are recognized by the Program; it will also better allow the Program to monitor designees’ actions. A designee may already be disciplined under the Program (that is, its ability to operate in connection with Program-related

transactions could be suspended or terminated), but ultimate responsibility for designee action may lie with Approved Vendors: an Approved Vendor could be suspended or terminated from Program participation (that is, submitting project applications and receiving REC contract awards) if its designee violates Program requirements. IPA Resp. at 32-33.

The Joint Solar Parties are concerned that registration of designees could be implemented as “regulation” rather than mere registration. The Joint Solar Parties misunderstand the intent of the IPA with this new requirement. It is intended to provide more transparent information about entities participating (or not participating) in the programs. This will aid both potential system hosts as well as Approved Vendors. IPA Resp. at 33.

To squarely address this confusion, the IPA offers the following clarification to the filed Revised Plan, for the Commission’s consideration: in addition to the basic information provision described by the Joint Solar Parties, a designee is additionally responsible for acknowledging that they will comply with all requirements for installers or marketing agents, as applicable. Failure by a designee to comply with applicable requirements could subject the designee to suspension or termination from registration. If the designee ignores a suspension (or termination) decision made by the Program Administrator and continues its market activity nonetheless, any Approved Vendor that works with the designee during that period will be subject to discipline. Likewise, Approved Vendors found to be working with entities engaged in the proscribed activities that fail to register may be also be subject to discipline. IPA Resp. at 33-34.

Raising an argument previously proposed and rejected in Docket No. 17-0838, the Joint Solar Parties once again argue that the IPA would be unjustified in revoking an Approved Vendor’s ability to participate in a program absent adoption of the Joint Solar Parties’ preferred set of procedural safeguards generally applicable to administrative decisions of an entirely different character. IPA Resp. at 45.

As the Commission found in Docket No. 17-0838, “it is clear to the Commission that the IPA does not have regulatory authority over this industry. The IPA is administering a program for which interested parties must comply with the rules if they wish to receive the benefits of the program.” Docket No. 17-0838, Order at 108. As with its competitive procurements, the IPA, through registering entities as an Approved Vendor, is determining whether an entity meets participation requirements for a state-administered incentive program. Denial does not bar that entity from engaging in any specific form of commercial conduct; it merely bars that entity from participating in transactions supported by a state-administered program. Indeed, the IPA, in conjunction with or through its Procurement Administrator, has for years routinely determined that certain bidders to or projects submitted into its competitive procurements are not qualified. Because that entity is always free to sell the product at issue through other transactions - just as Approved Vendors are free to sell their RECs to other buyers through transactions occurring outside of the Adjustable Block or ILSFA - the right at issue is merely the privilege of entering into that bilateral transaction, and such decisions have never necessitated formal hearings or procedures of the type requested by the Joint Solar Parties. IPA Resp. at 45-46.

Nevertheless, the IPA has significant and meaningful procedural safeguards in place to ensure that any suspension of an Approved Vendor or designee is justified by evidence, and with that entity having a right to rebuttal. These safeguards are outlined in the Revised Plan, and largely mirror a process already established in the IPA's Guidebook. In practice, these powers have been judiciously exercised. The IPA has only suspended three entities under the Program. Each was a clear violation requiring corrective action. In one case, appeal to the IPA indeed resulted in a reduction of the suspension period, thus demonstrating the power of the IPA's existing safeguards. IPA Resp. at 46-48.

Further, in instances featuring any vagary in the application of program requirements (such as aggressive marketing about guaranteed savings, which the Agency concedes offers some grey area), the IPA has never suspended an Approved Vendor. This is not to say that the IPA will never suspend entities for such violations; it is merely to say that the Joint Solar Parties' ongoing concerns about process are not borne from any actual abuses in practice. IPA Resp. at 48.

## **6. Commission Analysis and Conclusion**

The Commission notes that this issue is similar to that addressed in the Initial Plan docket. The Commission stated:

The Commission does not find designating an entity with the Approved Vendor status to be the legal equivalent of a license grant. There is no indication in the statute that the legislature intended for the IPA to grant a license in this circumstance. Also, it is clear to the Commission that the IPA does not have regulatory authority over this industry. The IPA is administering a program for which interested parties must comply with the rules if they wish to receive the benefits of the program. This argument of the Joint Solar Parties is rejected.

Docket No. 17-0838, Order at 108. The Joint Solar Parties have not provided an argument that would make the Commission change its decision. Whether the Revised Plan is discussing Approved Vendors or Approved Vendor Designees, the same logic applies.

CSG raises a valid concern about the implementation of requirements on Approved Vendor Designees. CSG suggests that Approved Vendors should be given a reasonable amount of time to learn of, seek clarity if necessary, and implement with designees any new requirements imposed by the IPA on Approved Vendor Designees before either the Approved Vendor or Designees are subject to penalties. Although CSG proposes a 90-day timeframe, the Commission finds the IPA's approach outlined in its Brief on Exceptions and Reply Brief on Exceptions to be reasonable. The IPA suggests that a 45-day lead time should apply to general changes, but that the IPA should still maintain an emergency pathway for immediate implementation of new or modified consumer protection requirements when warranted. Additionally, the IPA commits to enforcing program requirements in the case of immediate implementation by taking into account any practical challenges. The Commission finds these modifications to CSG's suggestion to be appropriate and they are adopted.

With respect to the process for reviewing the complaints, the IPA has a clear process. If, after complying with this process, the IPA finds that an Approved Vendor or Approved Vendor Designee is not adhering to the IPA's terms and conditions, the result is that the Approved Vendor or Approved Vendor Designee will not receive ratepayer funds for these programs. The Commission finds it appropriate and reasonable that the IPA only provide this incentive funding to Approved Vendors or Approved Vendor Designees that comply with the programs' rules.

## **E. Section 6.13 Consumer Protections**

### **1. Joint Solar Parties**

The Joint Solar Parties believe that strong consumer protections are important to a well-functioning program. However, the IPA has so far departed from its statutory authority that the Commission should not endorse continued expansions. The Commission should also take into account that the IPA's implementation of the consumer protection guidelines in the Initial LTRRPP at minimum took aggressive interpretations of Commission directives. JSP Obj. at 30-31.

The Joint Solar Parties explain that, typically, the Commission provides the IPA with high-level directives in procurement plans (such as the LTRRPP) for the IPA to implement. However, in the specific case of consumer protections, the implementation of Commission directives from Docket No. 17-0838 demonstrate that on this issue much more explicit instruction is necessary. The IPA took an aggressive interpretation of the Commission's Order in Docket No. 17-0838 and the Initial LTRRPP in formulating consumer protections to date. JSP Obj. at 31.

For example, the Commission decided in Docket No 17-0838, "to limit the application of the consumer protections to customers with subscriptions under 25 kW." Docket No. 17-0838, Order at 108. In the IPA's final marketing guidelines for both behind-the-meter systems and community solar systems, the overwhelming majority of requirements—including those inspired by Part 412—apply to not just under 25 (or 100) kW subscriptions but all systems and subscriptions. For both behind-the-meter and community solar, the only requirements that appear to only apply to under 25 kW systems or subscriptions are certain agent training requirements and badging requirements for in-person solicitation. JSP Obj. at 31-32.

The Joint Solar Parties note that the IPA argues that "[u]ltimately, the IPA settled on developing a streamlined version of a disclosure form for larger customers," IPA Resp. at 40, but the Joint Solar Parties are not aware of separate disclosure forms or brochures for over 25 kW systems or subscriptions. At minimum, no such streamlined version is apparent on the Adjustable Block Program website ([illinoisabp.com](http://illinoisabp.com)) on the face of available documents. In addition, the requirements for automatic renewal under the Community Solar Marketing Guidelines appear to be nearly identical to Part 412 for all customers. JSP Rep. at 31.

In another example, the Initial LTRRPP which was filed as a compliance filing in Docket No. 17-0838 contained a description of the disclosure form; it did not contain a description of the major features of the disclosure form that the IPA implemented. Because no other state had similar requirements prior to the IPA adopting these

requirements in Illinois, the Joint Solar Parties were unable to object during the Commission process. While there is overlap, the actual disclosure form process was so dramatically expanded from the LTRRPP discussion that it is in practical terms a completely new proposal that the Joint Solar Parties and other stakeholders could not vet in the Initial LTRRPP litigation. For instance, the Joint Solar Parties would have noted that requiring upload, download, and re-upload of the disclosure form adds substantial time to the sales pitch and has the strong potential to frustrate customers. JSP Obj. at 32-33.

At minimum, the IPA's implementation of the Commission's directives and its own LTRRPP on consumer protection issues was inconsistent with the spirit of the Commission's Order on Part 412 protections and the IPA's own proposal in the LTRRPP on the disclosure forms. The Joint Solar Parties urge the Commission to consider this history and provide clear, explicit direction (and narrower discretion) in revising the LTRRPP on consumer protection issues. Additionally, the Commission could facilitate an additional forum or working group to improve the disclosure form and specific interplays between the consumer experience and consumer protections to ensure a quality customer experience while also meeting the Commission's requirements. The Joint Solar Parties hope that moving these discussions to a Commission-facilitated informal process will reduce the burden on the IPA from triple roles of being both a proponent of their initial proposal, the facilitator, and the decision-maker. JSP Obj. at 34.

As a practical matter, to the extent that the IPA plans to modify the Marketing Guidelines or other documents in response to PA 101-0590, the Commission should modify the LTRRPP to only allow such modifications to the extent that the IPA presents (and justifies) an outline of the material details of the changes to be made. In the draft LTRRPP for approval, the Joint Solar Parties note that the IPA only identified "require[ing] community solar subscription agreements to clearly disclose any terms of automatic contract renewal" as a topic. LTRRPP at 144. JSP Rep. at 32.

## **2. CSG**

CSG acknowledges the larger discussion concerning changes to consumer protections under the Plan, but wishes to comment on another aspect of the consumer protection requirements not expressly raised but implicitly present. Specifically, when any change concerning consumer protections is made, Approved Vendors must engage in significant work to implement those changes. Such efforts entail revisions to internal databases, changes to websites, edits to and/or creation of new documents, and training, among other activities. The opportunity for stakeholders to provide feedback to the IPA and Program Administrator before new consumer protections are implemented and any lead time provided to prepare for changes in consumer protection requirements are very beneficial to Approved Vendors and designees. CSG appreciates such efforts by the IPA and encourages the Commission to also recognize the benefits of allowing for stakeholder input and providing for implementation lead time. CSG urges the Commission to formalize the practice of seeking stakeholder input by requiring such before adoption of any new consumer protections. The Commission should also establish a minimum lead time of 45 days before any new consumer protection requirements become effective. Longer periods should be permitted as necessary. CSG Rep. at 3.

### 3. IPA

The IPA notes that many requirements to which the Joint Solar Parties object are intended to prevent fraud and gaming opportunities, concerns which the IPA's Program Administrator identified from its experience in other jurisdictions. The Commission, in Docket No. 17-0838, expressly cited in its Order that relying on the Program Administrator's experience and insights was a consideration. Docket No. 17-0838, Order at 107. The notion that these implementation details constitute an expansion of the IPA's authority determined through the Commission's prior Order, let alone an unsupported one, is misleading. Contrary to the Joint Solar Parties' complaints, the Commission has recognized that developing specific program forms, processes, and requirements was statutorily ceded to the IPA and its Program Administrator—as it should be, given the IPA's day-to-day observation of behavior under the programs it administers. IPA Resp. at 37.

Ultimately, the Joint Solar Parties seek to reduce costs applicable to transactions conducted through the program. But the IPA's focus is not purely on the “commercial transactions” which make up the program; the IPA must also be concerned with customer experience, education, and positive outcomes for Illinois ratepayers from a ratepayer-funded program. The IPA does seek to reduce transaction costs but has insights into (and a responsibility to prevent) potential gaming or fraud vulnerabilities that require the use of processes which may seem burdensome or unnecessary to those unaware of their potential for abuse. The IPA and its Program Administrator work diligently to balance these competing factors, but as the Commission previously recognized, how best to negotiate that balance must be left up to the IPA and its Program Administrator to determine. IPA Resp. at 37-38.

For project developers, the trade-off is simple: as the Commission previously held, a solar project developer may choose not to avail itself of state-administered incentive funding, in which case it need not present customers with a standardized program brochure; need not require that customers read, review, and execute a standard disclosure form through a form and process dictated by the Program Administrator; and may market to customers in any manner otherwise consistent with local, state, and federal law. But once an entity chooses to avail itself of state-administered incentive funding, its marketing and conduct in connection with that project must meet a baseline standard established by the IPA stemming from its responsibility in setting the terms, conditions, and requirements applicable to program participation. IPA Resp. at 38.

Also, regarding the Joint Solar Parties suggestion of “Commission-facilitated informal process” on program participation requirements, the IPA is not opposed to further discussion around program requirements. However, as the Commission has recognized, under State law, the IPA and its Program Administrator are responsible for determining the “terms, conditions, and program requirements” applicable to participation in the programs which the Agency administers. As only the IPA and its Program Administrator are in position to spot ongoing vulnerabilities to gaming, abuse, and fraud, final decisions about program participation requirements—including and especially consumer protection requirements—must be left to the IPA. IPA Resp. at 39.

As the Joint Solar Parties highlight, the Commission's Order in Docket No. 17-0838 allowed for more stringent treatment of systems and subscriptions below 25 kW in size. In developing program requirements (including its Marketing Guidelines and Disclosure Forms), the IPA was faced with the question of which requirements were general program requirements applicable to all projects' program participation, and which other were consumer protection requirements which should be specifically applied only to under 25 kW systems and subscriptions. IPA Resp. at 39-40.

The IPA states that plainly misleading marketing, for instance, should be impermissible in any context; for any well-functioning program, it should subject any offending entity to potential discipline. Similarly, no Approved Vendor's representatives should be allowed to imply that it represents the State of Illinois or a public utility, regardless of the size or sophistication of the customer, as concerns beyond customer sophistication are placed at issue and the failure to prohibit such conduct generally could place the program's legitimacy at risk. Ultimately, the IPA settled on developing a streamlined version of a disclosure form for larger customers, exempting salespeople working with larger customers from training requirements, and exempting salespeople working with larger customer from certain identification requirements as a way to narrow requirements applicable to systems and subscriptions above 25 kW. IPA Resp. at 40. In its Brief on Exceptions, the IPA notes that 157 distributed generation project applications for systems above 25kW in size are for residential projects. IPA Brief on Exceptions at 13-14.

In Objections, the Joint Solar Parties propose no alternative and instead seek to highlight these choices as some "abuse" necessitating "prescription." Thus, the Joint Solar Parties have no alternative proposal to adopt; through this explanation, the IPA simply seeks to highlight its efforts to fairly and reasonably balance multiple considerations. IPA Resp. at 40.

The Joint Solar Parties argue in several places that successfully generating a disclosure form requires a sequence of "upload[ing], download[ing], and then re-upload[ing]." JSP Obj. at 33, 38. However, within the Adjustable Block Program, the purported upload-download-upload maneuver is required only if an Approved Vendor chooses not to avail itself of several process-simplifying steps. For the Adjustable Block Program, the Program Administrator has enabled a facility whereby a vendor may create a spreadsheet with a standardized set of data fields for a distributed generation project (including multiple rows within a single spreadsheet for multiple projects) and upload this spreadsheet into the respective program portal to generate disclosure forms, thus allowing the vendor to work within a familiar software environment (Microsoft Excel), saving the time and effort that would be required to manually type the information into the program portal. There is no need for a customer and sales agent working together to type out data to populate a customer contract and then manually type out the same data again for the disclosure form. IPA Resp. at 40-41.

Within the Adjustable Block Program, the Program Administrator has also enabled an interface for an Approved Vendor to link its internal database and software to the Adjustable Block Program portal in order to directly generate disclosure forms without going through the intermediate step of uploading spreadsheets. Either the spreadsheet

or interface method can generate dozens or even hundreds of disclosure forms at once with a single press of a button. IPA Resp. at 42.

Following creation of a disclosure form, an Approved Vendor need only click a button or two to forward the disclosure form to the customer's stored e-mail address. The customer will then have the opportunity to review and electronically sign the disclosure form within the Adjustable Block Program online portal or within an e-signature platform enabled by the ILSFA portal – and the disclosure form process will then be complete without any additional uploading or downloading required. IPA Resp. at 42.

While the Initial Plan did not expressly require execution of the disclosure form by the customer, this requirement is of utmost importance to ensure consumer protection: if the disclosure form is to have meaning, the customer should be given ample time to review and understand it – and then given an opportunity to affirm that understanding. The Approved Vendor or installer designee should not expect a customer to always receive, review and approve the disclosure form within a span of minutes. In the context of a financial decision that is potentially tens of thousands of dollars (either through the purchase of a system, or through the commitment to future payments through a lease or PPA) the amount of time spent to review and consider the disclosure form is entirely appropriate. IPA Resp. at 42.

The Joint Solar Parties also request a Commission directive to “simplif[y]” the disclosure forms (presumably for both the Adjustable Block Program and ILSFA). Unfortunately, the JSP do not identify any specific element in need of simplification. JSP gesture to the purported challenges of the disclosure forms’ “length to overly binary forced responses to including information that does not help customers make informed decisions” but do not call out any specific element that is improper, unnecessary, or confusing. The Joint Solar Parties’ lack of specificity suggests that they cannot identify particular elements that should not be on the disclosure forms. Without specific suggestions, the IPA is uncertain how to respond to the call for simplification. IPA Resp. at 43.

Finally, the Joint Solar Parties ask that the Commission direct a process whereby an Approved Vendor could substitute a new community solar project for the originally identified community solar project after a prospective subscriber receives and executes a disclosure form for the first project. This approach disregards the concept that a community solar project grants a subscriber a relationship with a specific solar array and that disclosure of its attributes is important. If subscribers were presumed to be indifferent to the particular solar project in their supply portfolio, there would be no need for the community solar model at all – utility-scale solar generation in the overall supply mix could accomplish the goal of connecting ratepayers with solar-powered electricity at a lower cost, while “green” retail supply offers could provide a customer with RECs to match their consumption without required disclosure of project attributes. The IPA takes seriously the Illinois General Assembly’s endorsement of the community solar model – finding that community solar can grant Illinois residents “expand[ed] access to renewable energy resources” (PA 99-0906 at § 5, creating new 20 ILCS 3855/1-5(7)) – and believes that a subscriber should be made aware of the community solar resource being accessed. IPA Resp. at 43-44.

The IPA's disclosure form, completion process, and communication process are all designed to ensure that the customer indeed reads and executes a form containing vital program information. Based on feedback from the IPA's Program Administrator its third-party consultant (the Clean Energy States Alliance, which has authored numerous papers on state solar disclosure form requirements), the process for completion is conducted through controlled, authenticated channels. Absent actual customer execution through a controlled environment, participating entities may find workarounds, leaving a disclosure form as merely a paper requirement ineffective at achieving its overarching purpose: providing the customer with important, standardized information read and understood before entering into a significant and complex transaction. Even with these safeguards in place, the IPA has ongoing concerns about Approved Vendors or Designees completing disclosure forms on behalf of customers; one of three program suspensions issued to date by the IPA was for this very offense. IPA Resp. at 44-45.

#### **4. Commission Analysis and Conclusion**

Based on the arguments presented, the Commission does not modify its conclusions from those reached in Docket No. 17-0838. In particular, the Commission continues to agree with the IPA that specific implementation issues should largely be left to the IPA. The Commission notes that the Joint Solar Parties do not seem to have specific proposals regarding the wording of disclosure forms and the Commission is not going to examine the forms or processes to identify problems. Also, the IPA was able to provide reasonable responses to the few specific complaints that were raised by the Joint Solar Parties.

CSG makes a reasonable suggestion regarding the time it takes to implement consumer protection changes - that a 45-day lead time for the implementation of changes be adopted. In its Brief on Exceptions, the IPA suggests that this lead time should apply to general changes, but that the IPA should still maintain an emergency pathway for immediate implementation of new or modified consumer protection requirements when warranted. The Commission notes that the IPA also commits to enforcing program requirements in the case of immediate implementation by considering practical challenges. The Commission finds that these proposed modifications to CSG's suggestion are appropriate and the approach outlined in the IPA's Brief on Exceptions is adopted.

#### **F. Section 6.13 Model Contract Documents**

##### **1. Ameren**

Section 6.13 of the Revised Plan proposes to continue to have the ability to use model documents from the Solar Energy Industries Association ("SEIA") as templates for distributed generation vendors. While Ameren believes that the ability to offer model documents for use by vendors and customers is important to achieving the legislature's goals, the use of model documents should be monitored to ensure that documents imported from other regulatory jurisdictions are consistent with Illinois law and Commission tariffs. Ameren Obj. at 8.

With this concern in mind, Ameren notes the IPA's Illinois Shines webpage currently features a model Power Purchase Agreement ("PPA") from SEIA as a model

document for Illinois distributed generation vendors. Ameren states that, as noted and agreed to by the Commission in its Order in Docket No. 17-0838, PPAs are not appropriate for use by distributed generation developers with retail customers in Illinois. Docket No. 17-0838, Order at 109. Ameren argues that only Illinois utilities, cooperatives, municipal electric systems, and certified alternative retail electric suppliers can enter into agreements with retail customers for the purchase of electric supply, which is the sole purpose of a PPA. Ameren further argues that the model PPA agreements on the Illinois Shines pages are inconsistent with the provisions of both the Illinois Electric Suppliers Act and the PUA. Accordingly, Ameren recommends the following addition to Section 6.16:

At a minimum, Approved Vendors may also use model leases and model financing instruments provided by the Solar Energy Industries Association (“SEIA”), or other contracts that meet requirements provided by the Agency so long as those documents are consistent with Illinois law.

Ameren Obj. at 8-9.

In Docket No. 17-0838, AIC states that it expressed its opposition to the inclusion of PPAs as part of the IPA's outward facing consumer resource materials. In its Objections in that proceeding, the Company based its opposition on Illinois law that limits the ability to conduct the retail sale of electric service to customers in investor-owned utilities' service territories to either the host utility or ARES. Docket No. 17-0838, AIC Obj. and Comments at 2; Ameren Rep. at 9.

The IPA's Response to Objections in Docket No. 17-0838, stated "Ameren thus seeks that the Plan clarify that any underlying retail energy sale would require valid certification as a retail electric supplier. The Agency is supportive of this change but suggests that instead of using the term "registered," the term "certified" be used instead. (See, e.g., 220 ILCS 5/16-115; 83 Ill. Adm. Code Part 451)." Docket No. 17-0838, IPA Resp. to Obj. at 69-70; Ameren Rep. at 10.

While ELPC disputed the basis of Ameren's reasoning in Docket No. 17-0838, it offered language that accomplished Ameren's goal of having the Initial Plan comply with Illinois law regarding retail electric service in investor owned utility service territories. Ameren accepted the language proposed by ELPC that implemented its position on this issue. Docket No. 17-0838, AIC Verified Reply to Comments and Obj. at 3-4. Ameren states that because there was no further discussion of this issue in that proceeding, and the Proposed Order supported Ameren's position, Ameren offered no further comment on this issue in Docket No. 17-0838. Ameren Rep. at 10.

Despite the Commission's Order in Docket No. 17-0838 and the IPA's stated agreement with AIC's position in that docket, Ameren notes that the IPA currently features PPAs on its Illinois Shines website as resource materials for consumers' use when contracting for the lease of generating equipment. The IPA Petition invited stakeholders to review the specific documents used for consumer education purposes. IPA Petition at 24. Ameren elected not to provide comments based on the Commission's Order in Docket No. 17-0838, specifically regarding the impermissibility of PPAs to finance distributed generation development in Illinois, and the IPA's need to exclude these

arrangements from the consumer education information on that IPA's website, because it believes the language in the Commission's Order in 17-0838 was unambiguous. Ameren Rep. at 10-11.

Ameren notes that the IPA attempts to justify its inclusion of PPAs on its website by employing a theoretical scenario that Ameren explains is inconsistent with both practical experience of distributed generation deployment in Illinois and the business models used by distributed generation installers. The IPA asserts that a distributed generation developer could also be an ARES, and therefore could legally enter into a PPA with a customer to whom it was leasing generating facilities. IPA Resp. at 52. However, Ameren notes that in the 11 years since the adoption of net metering and distributed generation interconnection rules in Illinois, it is aware of no distributed generation developer who has registered as an ARES with the Commission. Ameren further notes that the business model successfully deployed by distributed generation developers in Illinois is inconsistent with the substantial ongoing financial and legal commitments required of ARES. Ameren Rep. at 14.

The IPA's hypothetical scenario of a distributed generation developer becoming a ARES is an unlikely scenario that while technically possible would be unlikely to occur. Yet Ameren states it is being offered to justify the IPA's backpedaling from its previous support of Ameren's position regarding the impermissibility of the use of PPAs to finance distributed generation developments in Docket No. 17-0838. If the IPA insists on including PPAs in their consumer education materials, it should put the appropriate qualifier on every mention of a PPA, such as: in Illinois, a distributed generation developer must be a certified ARES in order to offer a PPA, and consumers should ask for the developer's certification before entering such an agreement. Ameren Rep. at 14-15.

While the IPA bases its argument on a theoretical concept, the damage from the IPA's position on this issue is very real. A cursory review of its Illinois Shines website shows four different documents identifying PPAs as acceptable financing tools for DG developers. In one of these documents, Ameren states that the IPA authorizes the sale of electricity to customers within the certificated service area of a utility by an entity other than a utility or an ARES, even though it lacks legislative authority to do so. The IPA further claims the authority to regulate the terms and conditions of an agreement to sell electricity, even though the legislature has not granted it that authority, either. Using the Plan as its pretext, the IPA effectively claims for itself the responsibilities and authority the legislature assigns to the Commission, even though the IPA utterly lacks the ability to enforce any aspect of a PPA, which increases the potential harm to the Illinois consumers it seeks to protect. Ameren Rep. at 15-16.

Ameren argues that ELPC/NRDC/VS mischaracterize the facts and the precedential value of a declaratory judgement issued in Docket No. 98-0630, in which, ELPC/NRDC/VS would have the Commission believe PPAs are found to be allowed for use by distributed generation developers. However, the Order in Docket No. 98-0630 specifically "cautions that its reliance upon the facts presented in this particular case does not constitute a determination of those facts or conditions that must be present to justify exclusion of the definition of an ARES under Sections 16-102 (iv) and (v) in every situation" and that its order "is without prejudice to any positions, arguments, or evidence,

that may be advanced in Docket 98-0607, or any other proceeding." Docket No. 98-0630, Order Granting Request for Declaratory Ruling at 4; Ameren Rep. at 20-21.

ELPC/NRDC/VS propose the use of PPAs to finance development of distributed generation installations in Illinois. ELPC/NRDC/VS Resp. at 3-9. While Ameren supports the use of third-party financing mechanisms used by its customers and distributed generation developers to enable the deployment of renewable generation, Ameren will only support financing mechanisms consistent with the Electric Supplier Act and the PUA. Since the inception of net metering and the distributed generation interconnection rules in 2008, Ameren has recognized that generating equipment can be either owned or leased by its customers without affecting its customers' rights to monetize the output of that generation through tariff mechanisms such as qualified facilities or net metering. Ameren Rep. at 21-22.

Ameren's position is based in Illinois law dating back to the 1965 Electric Suppliers Act, in which the legislature identified responsibilities and sole rights to provide electric service within certificated service territories. See 220 ILCS 30/5, *et seq.* In 1997, the legislature created an exception to those sole rights and responsibilities for ARES (specifically Sections 220 ILCS 5/16-102; 5/16-103; 5/16-115; 5/16-115A-E; 5/16-118; and 5/16-119), while taking care to ensure that developers of distributed generation facilities were not assigned either the responsibilities nor the rights of ARES (Section 16-102 (iv) and (v)). In both instances, the legislature assigned the responsibility to administer the provisions of those acts to the Commission. See 220 ILCS 30/8; 220 ILCS 30/10; 220 ILCS 5/16-115 (a)-(d). All the Commission rulings cited by ELPC/NRDC/VS to support their position only further enforce these two provisions of Illinois law – they do not create new legal standards. Ameren Rep. at 22.

Ameren argues that it is irrefutable that a third party who sells the electricity from a generator to a retail customer is engaging in a sale of electricity. The PPA documents placed by the IPA on its website confirm that this transaction is at the core of a PPA. The legislation cited in the previous paragraph makes plain that this type of sale, in an investor-owned utility's service territory, can be conducted only by the host utility or, to use the IPA's own language from Docket No. 17-0838, by a "certified" ARES. Docket 17-0838, IPA Resp. to Obj. at 69-70; Ameren Rep. at 22-23.

Ameren claims that ELPC/NRDC/VS's position undermines the utilities' ability to enforce other aspects of Illinois' interconnection rules since the IPA invites developers and customers to rely on it to address concerns with any aspect of the interconnection process and contracts, and the legislature has assigned no parameters to the IPA in exercising that authority. Essentially, utilities would be operating interconnection programs under two sets of rules – those contained in the Administrative Code and administered by the Commission, and those claimed by the IPA in its consumer education materials that have no boundaries or parameters. Therefore, Ameren believes that the Commission should reject ELPC/NRDC/VS's recommendation regarding the use of PPAs by DG developers. Ameren Rep. at 23.

In response to whether Ameren's recommendation is outside the scope of this proceeding, Ameren explains that the IPA requested parties comment on its Revised Plan and every aspect of the Revised Plan is subject to comments, edits and recommendations

in this proceeding, including the IPA's consumer education materials. Ameren Rep. at 24-25.

## 2. Joint Solar Parties

As an initial matter, the Joint Solar Parties aver that Ameren's argument fails as a matter of statutory construction. Ameren's core argument is that, "[o]nly Illinois utilities, cooperatives, municipal electric systems and certified alternative retail electric suppliers can enter into agreements with retail customers for the purchase of electric supply, which is the sole purpose of a PPA." Ameren Obj. at 9. The Joint Solar Parties note that Ameren provides no citation for this premise, relying completely on the bare assertion. However, Ameren's formulation is inconsistent with the plain language of the PUA. In other words, Ameren incorrectly characterizes the types of entities that may sell energy to a customer. While it correctly identified alternative retail electric suppliers, public utilities, cooperatives and municipal utilities, Ameren did not include "an entity that owns, operates, sells, or arranges for the installation of a customer's own cogeneration or self-generation facilities." That type of entity is identified independently of utilities (public, municipal, or cooperative) and alternative retail electric suppliers. The Joint Solar Parties note that the statutory language of "a customer's own cogeneration or self-generation facility" in subsection (iv) and (v) of the exclusions to "alternative retail electric supplier" does not require the retail customer to own or operate the facility to fall under either exception. 220 ILCS 5/16-102; JSP Resp. at 6-7.

Ameren does not point to a prohibition on "an entity that owns, operates, sells, or arranges for the installation of a customer's own cogeneration or self-generation facilities" selling products or services to a retail customer because no such prohibition exists in the PUA. Thus, Ameren's suggested language "so long as those documents are consistent with Illinois law" adds nothing because third-party ownership and operation of a behind-the-meter facility is specifically contemplated by Section 16-102 of the PUA and is not prohibited. JSP Resp. at 7.

While this statutory language is sufficient to definitively rebut Ameren's argument, the Joint Solar Parties further note that Ameren appears to be taking an overly simplistic approach to ownership and operation. In many areas of law, from environmental to tax, the question of what entity is an "operator" is a complex, fact-based inquiry. This is especially true given that under Part 466 of the Commission's Rules, an entity—in many cases, the retail customer—is the "Interconnection Customer" with rights and obligations under the standard interconnection contract. In the event that the retail customer (i.e. the electricity user in the shoes of a "buyer" under a PPA) is the Interconnection Customer, it is not clear how any factual inquiry into who "operates" the behind-the-meter generation facility would not at minimum include the retail customer. JSP Resp. at 7.

The Joint Solar Parties state that to the extent that an electric utility at any point denies a customer net metering solely based on ComEd's determination that the customer has a PPA financing arrangement with a third-party system owner, the Joint Solar Parties believe such an action would violate Section 16-107.5 of the PUA. The Joint Solar Parties trust that such an electric utility would be disciplined accordingly for its failure to meet its obligations under the PUA. Because a definitive announcement by the Commission will have a deterrent and market-calming effect, the Joint Solar Parties

recommend that the Commission make clear that merely using a PPA financing structure does not render an otherwise eligible retail customer ineligible for net metering. JSP Rep. at 9-10.

The Joint Solar Parties state that it is important that the Commission in the final Order make a clear statement that PPA financing structures are both allowable under Illinois law and are fully consistent with the requirements for net metering pursuant to Section 16-107.5 of the PUA. PPAs are the only way many entities can monetize tax incentives, especially tax-exempt entities such as governments or not-for-profits. In addition, PPAs are popular even with for-profit entities that do not want a solar asset on their books (as would be the case for ownership and certain leases) and/or would like a turnkey approach to solar. JSP Rep. at 10.

### 3. ComEd

ComEd opines that ELPC/NRDC/VS's comments are not well-founded. In 2007, the Illinois General Assembly amended the PUA to include, among other things, Section 16-107.5, the net metering provisions of the PUA; and effective June 1, 2017, Section 16-107.5 was amended by PA 99-0906. 220 ILCS 5/16-107.5. Section 16-107.5, as originally enacted and as amended by PA 99-0906, defines an "eligible customer" for purposes of the Net Metering Statute as "a retail customer *that owns or operates* a solar, wind, or other eligible renewable electrical generating facility with a rated capacity of not more than 2,000 kW that is located on the customer's premises and is intended primarily to offset the customer's own electrical requirements." 220 ILCS 5/16-107.5(b) (emphasis added); ComEd Rep. at 3-4.

While PA 99-0906 added an exception to this requirement for what is commonly referred to as "community solar" projects (220 ILCS 5/16-107.5(l)), that exception does not apply to individual customers that allow the placement of a photovoltaic system on his or her premises under a photovoltaic PPA. Consequently, ComEd maintains that a retail customer entering into a photovoltaic PPA will not be eligible to receive energy credits under the law. ComEd Rep. at 4.

ComEd states that its Commission-approved tariffs incorporate these same requirements. See Rider POGNM - Parallel Operation of Retail Customer Generating Facilities with Net Metering, ILL. C.C. No. 10, 3rd Revised Sheet No. 294 (Canceling 2nd Revised Sheet No. 294). Indeed, ComEd also notes that Page 2 of the photovoltaic PPA Disclosure Form mentions tax consequences of not owning a photovoltaic system. See October 2018 Comments at 2-3 (citing photovoltaic PPA Disclosure Form at 2); ComEd Rep. at 4-5.

In short, the PUA states "owns or operates" and ComEd avers that this does not allow for PPAs broadly. 220 ILCS 5/16-107.5(b). ComEd recognizes, however, that as ELPC/NRDC/VS indicate, in the past, customers have chosen to finance their projects using a third-party PPA, and this may cause confusion going forward. See ELPC/NRDC/VS Resp. at 9. Nonetheless, the IPA, Commission, and the parties are bound by the PUA. ComEd is open to discussion and guidance from the Commission – in a more appropriate forum – on what specifically is or is not allowed pursuant to the PUA and the Commission's regulations. But ELPC/NRDC/VS's discussion of this issue is not well-founded or appropriate. ComEd Rep. at 5.

#### 4. ELPC/NRDC/VS

ELPC/NRDC/VS state that Ameren's and ComEd's arguments regarding PPAs disrupt settled law and expectations in the Illinois solar market and threaten the IPA's goal to provide a "transparent, positive experience" for participants in the Adjustable Block Program. See Plan at 142. The utilities incorrectly argue the law makes a distinction between PPAs and leases. The Commission should reject Ameren and ComEd's arguments and clarify that a customer's choice to finance their on-site renewable energy project using a third-party PPA (1) does not require registration as an ARES, and (2) does not disqualify the customer from the Illinois net metering or smart inverter rebate programs under Sections 16-107.5 and 16-107.6 of the PUA. ELPC/NRDC/VS Resp. at 3.

ELPC/NRDC/VS explain that third-party financing helps customers finance distributed generation projects without up-front costs. Under a third-party PPA, the renewable energy provider installs and owns the system on the customer's property and the customer pays an agreed-upon rate for the electricity generated by the system over a long-term contract, typically 15 or 20 years. Third-party leases are another variety of third-party financing. Under a third-party lease, the customer makes monthly payments to the solar provider. ELPC/NRDC/VS Resp. at 3.

Third-party financing is particularly important for non-taxable entities like schools, universities, churches, non-profits, and municipalities, as well as low-income customers, because those customers and entities generally cannot take advantage of federal tax incentives for renewable energy. Under a third-party financing arrangement, the third-party can take the tax credits and accelerated depreciation and pass those savings along to customers through lower lease payments or PPA rates. Third-party financing also helps expand customer access to renewable energy, as the up-front costs of renewable energy can be a barrier to entry, especially for lower-income families. ELPC/NRDC/VS Resp. at 3-4.

Third-party financing is common in Illinois, and there are many Illinois municipal agencies, school districts, churches, and non-profits that are currently using, or are interested in pursuing, a third-party lease or PPA to help meet their clean energy goals. Also, while the low-income ILSFA Program is only recently getting off the ground in this State, third-party PPAs are commonly utilized in established low-income solar programs in other states. ELPC/NRDC/VS Resp. at 4-5.

Ameren's argument that third-party PPA financing for distributed generation is "not appropriate" in Illinois is incorrect on the merits and directly conflicts with Illinois law and prior Commission precedent. Ameren ignores clear Commission precedent and legislation that explicitly authorize third-party financing arrangements without the need to register as an ARES. ELPC/NRDC/VS Resp. at 5-6. In 1998, the Commission issued a declaratory ruling confirming that third-party sales of power pursuant to a third-party financing arrangement do not trigger ARES requirements under Section 16-102 of the PUA. In *CogenAmerica (Morris) LLC*, 1998 WL 34302949 (Docket No. 98-0630), the Commission granted a cogeneration developer's request for a declaratory ruling that it was not subject to regulation as an ARES where the company developed and provided electricity to an industrial customer from an on-site cogeneration facility. In granting the

declaratory order, the Commission recognized that the third-party development of the project was “essentially a financing mechanism” and did not change the essential character of the project in a way that would require regulating the provider as an ARES. ELPC/NRDC/VS Resp. at 6.

In 1999, the legislature amended Section 16-102 of the PUA to clarify and confirm that any third-party entity that “owns, operates, sells, or arranges for the installation” of a customer’s self-generation facility on behalf of that customer is not an ARES. 220 ILCS 5/16-102 (excluding from the definition of an ARES “an entity that owns, operates, sells, or arranges for the installation of a customer’s own cogeneration or self-generation facilities ...”). Legislative history confirms that this language “explicitly provides expanded cogeneration and self-generation options to electric consumers with opportunity for third-party financing and operating arrangements.” See Floor Debate of SB 24, May 27, 1999, Comments of Senator Mahar at 46, 58. As explained by the lead sponsor of the bill, these arrangements could include either a “third party or lease option.” *Id.*; ELPC/NRDC/VS Resp. at 6-7.

ELPC/NRDC/VS note that Ameren argues that the Commission “agreed to” Ameren’s interpretation of Illinois law regarding PPAs in Docket No. 17-0838. Ameren Obj. at 8. In response, ELPC/NRDC/VS state that the Commission did not “agree to” Ameren’s position in Docket No. 17-0838. Instead, the Commission adopted “clarifying language,” supported by ELPC, that did not take a position on the legality of PPA financing in Illinois. See Docket No. 17-0838, Order at 109; ELPC/NRDC/VS Resp. at 7.

In Docket No. 17-0838, ELPC provided a detailed legal argument supporting the legality of third-party PPAs. Ameren did not respond to the legal merits of ELPC’s argument in that docket. Instead, Ameren proposed alternative language to avoid confusion regarding the “different meanings” of the term “power purchase agreement” without taking a position either way on the merits of the issue. The Commission adopted this compromise in its Final Order, specifically noting that the Order “incorporates ELPC’s language.” Thus, Ameren’s statement that the Commission “agreed to” Ameren’s position that PPAs are not appropriate in Illinois is a mischaracterization of that Order. ELPC/NRDC/VS Resp. at 7.

The fact that Ameren is raising this issue in 2019 is confusing because this issue has been settled in Illinois since at least 2012. In the IPA’s 2012 renewable resources procurement case (Docket No. 12-0544), the IPA and Exelon raised the question of whether or not PPA financing for distributed generation would require the provider to register as an ARES. ELPC responded by citing *CogenAmerica* and the statutory amendments to Section 16-102 of the PUA. In their Replies, Exelon and the IPA conceded that third-party PPA financing of distributed generation does not require registration as an ARES. It is unfortunate that now—seven years later—Ameren has chosen to reopen this issue. The Commission should reject Ameren’s position and send a clear message that third-party PPAs remain a viable financing option for DG customers in Illinois. ELPC/NRDC/VS Resp. at 8-9.

ELPC/NRDC/VS opine that for more than eleven years, it was generally understood that the statutory term “own or operate” as used in Section 16-107.5 included customers that chose to finance their project using a third-party PPA. And many current

net metering customers have, in fact, used third-party PPAs to finance their systems and many Illinois solar providers offer PPAs as an option for new customers. ELPC/NRDC/VS Resp. at 9-10. Yet, on October 26, 2018, ComEd filed comments with the IPA announcing a new legal opinion that distributed generation customers that choose PPAs to finance their systems do not “own or operate” a PV system within the meaning of Section 16-107.5 and therefore will not be eligible to net meter in ComEd’s service territory. Since then, ComEd has advised its customers to shift from PPAs to third-party leases if they intend to apply for net metering under Section 16-107.5 or the related smart inverter rebates under Section 16-107.6. ELPC/NRDC/VS Resp. at 10.

ELPC/NRDC/VS explain that ComEd’s position on net metering affects the IPA’s LTRRPP in several direct and indirect ways. The IPA’s Revised Plan expresses the IPA’s view that “it is essential to ensure that [the Adjustable Block Program] produces not only project development, but also a transparent, positive experience for system hosts and subscribers.” Revised Plan at 142. The Revised Plan identifies model contracts and disclosure forms, including information about PPAs, that customers can use to navigate the contracting process with Approved Vendors. *Id.* ComEd’s new legal position is causing confusion and ambiguity that undermines the transparent customer experience the IPA is trying to provide through its Plan. Participants in the Adjustable Block Program deserve to know whether they will be eligible for net metering if they elect to finance their system using a PPA. The current situation puts Illinois customers in the legal limbo of either accepting ComEd’s position or risking the loss of their net metering status. ELPC/NRDC/VS Resp. at 11.

The Commission, not ComEd, is responsible for authoritatively interpreting and implementing the PUA. For the following reasons, the Commission should clarify that the term “eligible customer” in Section 16-107.5 of the PUA includes customers that choose to finance their on-site distributed generation facility using a third-party PPA or lease. By doing so, the Commission can resolve the uncertainty created by ComEd’s new legal opinion and help promote the IPA’s goal of clarity and transparency for Adjustable Block Program participants. ELPC/NRDC/VS Resp. at 11-12.

ELPC/NRDC/VS notes that Section 16-107.5(b) of the PUA defines “eligible customer” for the purposes of net metering to mean a “retail customer that owns or operates a solar, wind, or other eligible renewable electrical generating facility with a rated capacity of not more than 2,000 kW that is located on the customer’s premises and is intended primarily to offset the customer’s own electrical requirements.” The key issue is whether the words “own or operate” as used in this definition include customers that choose to finance their DG systems using PPAs. ELPC/NRDC/VS Resp. at 12.

The statutory phrase “own or operate” in Section 16-107.5(b) of the PUA, when read in context with the rest of the PUA, supports an interpretation of “eligible customer” to include systems that are financed using PPAs. The statute’s use of the word “or” in the phrase “own or operate” means that the legislature did not intend to require customers to “own” their system in order to net meter. Third-party ownership is explicitly allowed. The key question is whether the legislature intended the word “operate” to distinguish between the two most common third-party ownership models—leasing and PPAs—for the purpose of net metering. ComEd argues that it did. ELPC/NRDC/VS opine that the better reading of the statute is that it did not. ELPC/NRDC/VS Resp. at 12-13.

ELPC/NRDC/VS explain that there is no functional difference between a project financed using a third-party lease and a project financed by a third-party PPA. The project operates in the exact same way. In the *CogenAmerica* case, the Commission looked to the characteristics of the project itself, not the specifics of the customer's selected financing arrangement, to determine whether the project at issue was the customer's "own project" for the purposes of ARES regulation under Section 16-102 of the PUA. The Commission recognized that the third-party arrangement was merely a "financing mechanism." 1998 WL 34302949 at \*4. It did not change the fundamental characteristics of the project, or "fruits of ownership," in any material way. See *id.* at \*3. Thus, the customer's choice of a third-party financing arrangement was immaterial to the project developer's potential status as an ARES under Illinois law. The Commission determined that the customer possessed "sufficient indicia of control" to be considered the "owner" of the project for the purposes of Section 16-102 of the Act. ELPC/NRDC/VS Resp. at 13.

Even if the Commission finds the statutory phrase "own or operate" to be ambiguous, it should reconcile the meaning of the words in light of the clear legislative intent of the law to encourage and streamline the development of distributed resources in Illinois. See *Commonwealth Edison Co.*, 128 N.E. 3d at 1177 (finding the Commission's statutory interpretation "more consistent with the stated legislative intent" of the Act). The legislature created a net metering program in 2007 in order to "encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment." 220 ILCS 5/16-107.5(a). ComEd's new interpretation of Section 16-107.5 conflicts with these legislative goals and makes it more difficult for customers to finance solar projects in Illinois. PA 99-0906 contains similar expressions of legislative intent. ComEd's interpretation of "own or operate" to rule out third-party PPA financing makes it more difficult for customers to finance distributed solar projects in Illinois. The Illinois courts have said statutes must not be read in isolation, but as a whole. *People v. NL Industries*, 152 Ill. 2d 82, 98 (1992); *People v. Jordan*, 103 Ill. 2d 192, 206 (1984). To the extent the Commission finds the phrase "own or operate" to be ambiguous, it should interpret the law "in favor of the stated legislative intent of promoting the programs." *Commonwealth Edison Co.*, 128 N.E.3d 1165 at 1167. ELPC/NRDC/VS Resp. at 15.

ComEd's interpretation of the word "operate" to exclude PPA customers from net metering appears to be unprecedented, and it would isolate Illinois in comparison to states like Pennsylvania and New York. The Illinois General Assembly intended the net metering program to "encourage private investment in renewable energy resources." 220 ILCS 5/16-107.5(a). The Commission should reject ComEd's interpretation that conflicts with this intent. ELPC/NRDC/VS Resp. at 17.

ELPC/NRDC/VS further explain that net metering applications are governed by Part 465 of the Commission's rules. The rules require Illinois utilities to establish and publish a net metering application form that meets the requirements of Illinois law. 83 Ill. Adm. Code 465.35. The Part 465 rules do not distinguish between third-party leasing and third-party PPAs, and ComEd has not proposed to initiate a rulemaking process to distinguish leases from PPAs for the purposes of net metering. Even though the Part 465 rules do not distinguish between leases and PPAs, ComEd has chosen to distinguish them on the Company's net metering application form. The Commission should not allow

ComEd to make its own unilateral policy decisions regarding net metering without Commission review or oversight, especially where ComEd's position is violating the law and frustrating the IPA's intent to provide a "transparent, positive experience" for participants in the Adjustable Block Program filed for Commission review and approval in this docket. Plan at 142; ELPC/NRDC/VS Resp. at 17-18.

For all of these reasons, ELPC/NRDC/VS respectfully request that the Commission explicitly reject Ameren's and ComEd's arguments regarding PPA financing and clarify that a customer's choice to finance their on-site renewable energy project using a third-party PPA (1) does not require registration as an ARES, and (2) does not disqualify the customer from the Illinois net metering or smart inverter rebate programs under Sections 16-107.5 and 16-107.6 of the PUA. ELPC/NRDC/VS Resp. at 18. There is an urgent need for the Commission to clarify the legality of third-party PPAs in this docket. This issue has been litigated in prior IPA procurement plan dockets (including Docket Nos. 12-0544 and 17-0838), involves the IPA's marketing guidelines and disclosure forms described in the current IPA Plan (Plan at 142), and is materially affecting participants in the IPA's programs. ELPC/NRDC/VS Resp., Attach. A & B. The Commission should exercise its authority to clarify that third-party PPA financing is legal in Illinois and does not disqualify a customer from net metering under Section 16-107.5 of the PUA. Further delay is not reasonable and will conflict with the successful implementation of the IPA's Long-Term Plan and growth of the distributed solar market in Illinois. ELPC/NRDC/VS Rep. at 22-23.

## **5. IPA**

As the IPA outlined in its Petition, this objection relates to prior correspondence in which Ameren advised the IPA that it should not produce a customer disclosure form specific to PPA transactions because of a belief that PPA financing arrangements are prohibited in Illinois absent the developer being certified as an alternative retail electric supplier. In so doing, Ameren continues its ongoing mischaracterization of the Commission's conclusion in Docket No. 17-0838. Ameren Obj. at 8-9; IPA Resp. at 49. The IPA notes that the Commission's Order in Docket No. 17-0838 merely states that "the Commission adopts Ameren's clarifying language regarding power purchase agreements that incorporates ELPC's language. AIC Rep. at 3-4." Docket No. 17-0838, Order at 109. At no point in Ameren's Reply in Docket No. 17-0838 does Ameren contest ELPC's legal argument or seek a contrary ruling to ELPC's conclusions from the Commission. Instead, the Commission merely adopted the neutral, uncontested phrase "financing arrangement" as a way to negotiate disagreement between the parties. IPA Resp. at 49-51.

But even if Ameren's position on the legality of PPAs was correct, the IPA states that Ameren's request that the Plan be revised is misguided. Even under Ameren's reading, PPAs are permissible financing instruments for solar project developers; the entity would simply have to be registered as an alternative retail electric supplier first. Regardless, even if PPAs are simply being used as a financing instrument for solar development under the Adjustable Block Program or ILSFA program, then sharing model agreements for that form of transaction, or producing a standardized customer disclosure form providing valuable information to customers engaging in that type of transaction, is entirely consistent with the IPA's responsibilities for ensuring that parties to these

transactions have clear, transparent, and standardized understanding of risks and benefits. IPA Resp. at 52.

The IPA generally agrees with the Joint Solar Parties' and ELPC/NRDC/VS's analyses and wishes to offer context on select points raised by ELPC/NRDC/VS. ELPC/NRDC/VS is correct that ComEd submitted comments to the IPA on its draft PPA-specific disclosure form on October 26, 2018 stating ComEd's belief that a customer financing its system through a PPA would then be legally ineligible for net metering. The receipt of these comments was the IPA's first exposure to ComEd's interpretation. Despite the IPA's REC pricing model assuming net metering revenues for system hosts, and at no prior point (including approval of that REC pricing model through Docket No. 17-0838) did ComEd express its view of the inapplicability of that net metering revenue assumption for a PPA-financed system. Had the IPA been aware that ComEd held such an interpretation prior to the development and submission of its Initial LTRRPP, it would have sought clarity from the Commission through that proceeding to ensure that its system revenue assumptions were appropriate. IPA Rep. at 29.

ELPC/NRDC/VS are likewise correct that the IPA then adjusted its Adjustable Block Program distributed generation disclosure form for PPA financing in light of ComEd's comments. The purpose of the IPA's standard customer disclosure forms is to ensure that customers receive relevant, standardized information about the decision to host and finance a photovoltaic project. This includes providing information about benefits, financial costs, and risks. While the IPA does not seek to discourage customers from going solar, the IPA believes that ComEd's interpretation constitutes a risk to expected revenues important enough to require express disclosure through that form—especially when that interpretation poses a direct risk to the customer, rather than the project developer. IPA Rep. at 30.

The IPA notes ComEd's legal argument, that a distinction can be drawn between a lease and a PPA insofar as a lease is effectively "ownership" (and thus permissible under Section 16-107.5's "owns or operates" language), while a PPA is not. The IPA asserts, however, that a lease is, by definition, not ownership. Further, the IPA is unaware of any reason to believe that a customer leasing a system is any less the system's operator than a customer financing a system through a PPA. In either case, the system is sited at the customer's premises and used to offset that customer's electricity usage. Thus, the IPA sees no merit in ComEd's strained interpretation of Section 16-107.5's net metering eligibility requirements. IPA Rep. at 30.

The IPA supports ELPC/NRDC/VS's request for clarity on the viability of PPA financing through this proceeding. Additionally, the IPA believes that offering PPA financing should not require certification as an ARES, nor should it render a customer's system ineligible for net metering. IPA Rep. at 31.

## **6. Commission Analysis and Conclusion**

In Docket No. 17-0838, the Commission adopted "clarifying language," supported by ELPC, that did not take a position on the legality of PPA financing in Illinois. See Docket No. 17-0838, Order at 109. Although the Commission adopted agreed language that removed any mention of model PPAs, the Commission merely adopted the neutral, uncontested phrase "financing arrangement" as a way to negotiate disagreement

between the parties. The Commission's Order in Docket No. 17-0838 does not support the utilities' position.

Ameren's suggested language in this proceeding also does not accomplish its underlying goal of requiring that third-parties in a PPA be certified ARES. Indeed, the Joint Solar Parties state "Ameren's suggested language 'so long as those documents are consistent with Illinois law' adds nothing because third-party ownership and operation of a behind-the-meter facility is specifically contemplated by Section 16-102 of the PUA and is not prohibited." JSP Resp. at 7. Regardless, the Commission does not adopt Ameren's language because it is unnecessary.

In Article XVI of the PUA, an "alternative retail electric supplier" is defined as essentially any entity selling power and energy to a retail customer. However, the definition specifically excludes:

*an entity that owns, operates, sells, or arranges for the installation of a customer's own cogeneration or self-generation facilities, but only to the extent the entity is engaged in owning, selling or arranging for the installation of such facility, or operating the facility on behalf of such customer, provided however that any such third party owner or operator of a facility built after January 1, 1999, complies with the labor provisions of Section 16-128(a) as though such third party were an alternative retail electric supplier.*

220 ILCS 5/16-102 (emphasis added). Also, Section 16-107.5, as originally enacted and as amended by PA 99-0906, defines an "eligible customer" for purposes of net metering as "a retail customer *that owns or operates* a solar, wind, or other eligible renewable electrical generating facility with a rated capacity of not more than 2,000 kW that is located on the customer's premises and is intended primarily to offset the customer's own electrical requirements." 220 ILCS 5/16-107.5(b) (emphasis added). The Commission sees no ambiguity or basis for the utilities' position in this language. It is clear that the third-party in a PPA arrangement is excluded from the definition of ARES and that an end-use customer that has financed a distributed generation installation through a PPA is an eligible customer. It is also clear that the definition of "eligible customer" includes no limitations regarding the financing arrangements of installed generation. How a customer finances installed generation is immaterial to whether the customer "owns or operates" the generating facility for the purpose of offsetting the customer's electrical requirements.

Moreover, Ameren and ComEd have not provided a compelling distinction between a lease and a PPA. ComEd also acknowledged that its position may cause confusion going forward (ComEd Rep. at 5), which is a result the Commission wants to avoid since it would be contrary to the statutory goal of promoting renewable resources. To the Commission, these two arrangements appear to be functionally equivalent. ELPC/NRDC/VS agree and state that there "is no functional difference between a project financed using a third-party lease and a project financed by a third-party PPA." ELPC/NRDC/VS Resp. at 13.

Apparently PPAs have been used for many years and, importantly for purposes of this docket, the IPA assumed the use of PPAs in creating its REC pricing model. Based on the clear statutory language and the history of PPA usage in these circumstances, the Commission finds that it is appropriate to maintain the status quo and allow PPAs.

## **G. Section 6.14.1 Batches**

### **1. Joint Solar Parties**

Currently, in order to have a completed application, a system must be part of a batch that is 100 kW-2,000 kW in size. A larger system may be a batch by itself, but smaller systems—including, by definition, all under 10 kW systems—must be batched with others. This current approach creates a bottleneck for smaller systems that cannot be reviewed until a full batch is assembled. JSP Obj. at 39.

The Revised LTRRPP would allow the Approved Vendor to submit systems on a rolling basis but allows the Program Administrator to select which projects go in which batch. See LTRRPP at 148; JSP Obj. at 39-40. The Joint Solar Parties opine that a better approach would allow Approved Vendors to select which systems to put in which batches once a system is approved. This will allow Approved Vendors to better manage their own financing portfolios. JSP Obj. at 40.

The IPA in its Response made a proposal consistent with the Joint Solar Parties' request. The Joint Solar Parties urge the Commission to adopt the IPA's proposed approach to project batching as stated in the IPA's Response. JSP Rep. at 36.

### **2. CSG**

CSG appreciates the IPA's reconsideration on the issue of batches under Section 6.14.1 of the Plan. The IPA's current position as reflected in its Response will better facilitate the application process. CSG Rep. at 4.

### **3. IPA**

The IPA appreciates the insights of the Joint Solar Parties on this issue and agrees with this Objection. The IPA believes accommodating the Joint Solar Parties' request should be implemented by continuing the approach that the IPA laid out in the Revised Plan with the caveat that once systems' Part I applications are verified, and before they are sent to the Commission for approval, an Approved Vendor will be consulted and given the opportunity to specify how its verified systems are batched so long as those batches of verified systems are at least 100 kW in size. For Approved Vendors who do not desire to assemble batches into portfolios in this way, the IPA's proposed rolling batch approach would be used. IPA Resp. at 53.

### **4. Commission Analysis and Conclusion**

The Commission adopts the proposal outlined in the IPA's Response which is supported by the Joint Solar Parties and CSG. The Commission agrees with the Joint Solar Parties that the proposal is an improvement because it allows Approved Vendors to select which systems to put in which batches once a system is approved. This will allow Approved Vendors to better manage their own financing portfolios.

## **H. Section 6.14.6 Batch Contract Approval Collateral Withholding Process**

### **1. Ameren**

In Section 6.14.6, the Revised Plan recommends a clarification to the collateral withholding process that would allow an Approved Vendor an option, if it posts a letter of credit as collateral, to have the utility withhold the collateral amount from the final REC payment (or from the only REC payment if a distributed generation system is 10kW or smaller) in exchange for a release or reduction of the letter of credit. Ameren Obj. at 9.

Consistent with typical contract provisions within energy commodity contracts, Approved Vendors should have an option to post cash or a letter of credit in order to meet their collateral obligations. Any Approved Vendor providing a letter of credit should possess an option at any time during the contract term to post cash collateral directly to the utilities in order to the immediately release or reduce the letter of credit. If an Approved Vendor is short of cash but wishes to have cash collateral in place instead of a letter of credit, the Approved Vendor could post the cash directly upon receipt of a payment from the utility; effectively, this would lead to the same outcome as if the new withholding language were in place. Ameren Obj. at 10. Ameren believes any collateral withholding option adds administrative complexity to agreements without appreciable benefits. Ameren disagrees with this proposal and recommends that it be rejected by the Commission. Ameren Obj. at 10.

Ameren agrees with the IPA that the Joint Solar Parties' position should be rejected by the Commission. Ameren Rep. at 9.

### **2. Joint Solar Parties**

Joint Solar Parties state that in the Initial LTRRPP approved by the Commission, "The Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last REC payment for the system (or only REC payment for small systems) in exchange for not needing to maintain the ongoing collateral requirement." Initial LTRRPP at 136. However, the REC Contract requires withholding from the first payment. See REC Contract, Cover Sheet, Modification to Section 4.3(b) of Exhibit J ("Seller may request for Buyer to withhold, and if so requested, Buyer shall withhold, a portion of the first REC payment in the amount of the Collateral Requirement of such Designated System as Seller's Performance Assurance in respect of such Designated System in lieu of the timing required by the first paragraph of this Section.") The Joint Solar Parties recommend that the Commission require changes to the REC Contract to be consistent with the initial LTRRPP. JSP Obj. at 30.

### **3. IPA**

The Joint Solar Parties note that the Initial Plan gave the Approved Vendor the option to choose to have the required 5% collateral amount (as a percent of total contract value) withheld from the last REC payment for the system (or only REC payment for a Small DG project) in exchange for not needing to maintain the ongoing collateral requirement. The Joint Solar Parties further state that the Adjustable Block Program and ILSFA REC Contracts "require" a Seller to only have collateral withheld from the first REC

payment. This statement is simply incorrect, the IPA explains, because no project is required to have collateral withheld from its first payment. IPA Resp. at 54.

Regarding the Initial Plan's Section 6.16.1 provision about withholding monies from the last REC payment in exchange for not needing to maintain collateral, under the existing Adjustable Block Program and ILSFA REC Contracts, it is always the case that a project with a letter of credit posted as collateral may elect to replace the letter of credit with a withheld REC payment. Further, a project with cash collateral posted may elect to replace the cash collateral with withholding of a REC payment, although such a transaction would essentially net to zero. The contractual language authorizing this swap is as follows:

Should payment be due to Seller, Seller may request for a portion or all of the payments to be withheld, and if so requested, Buyer shall withhold such payments, to maintain such Performance Assurance Amount.

For this reason, no amendment to the existing Standard REC Contracts is necessary. IPA Resp. at 55.

#### **4. Commission Analysis and Conclusion**

The Commission notes that Joint Solar Parties do not appear to have filed any reply to Ameren or the IPA. Having considered the IPA's argument and reviewed the relevant language, the Commission cannot adopt the Joint Solar Parties' position. The Commission finds that the Joint Solar Parties' proposal appears to be based on an incorrect reading of the REC Contract, which does not require any project to have collateral withheld from its first payment.

Also, Ameren's proposal appears to propose a change that has already been addressed in the REC Contract and Revised Plan and that was also included in the Initial Plan. Ameren did not file a Reply, perhaps in recognition of this.

#### **I. Section 6.15.1 Adjustable Block Program Development Time Allowed, Section 5.3.1 Competitive Procurement Schedule**

##### **1. ComEd**

ComEd notes that Section 5.3.1 of the Revised Plan remains largely the same as the Initial LTRRPP. The Revised Plan adds only the following language:

Additionally, the Revised Plan seeks Commission permission, similar to the discussion in Section 6.15.1, to allow the Buyer and Seller to execute an amendment to the contract, through mutual assent, allowing for a system's removal from the contract, with forfeiture of associated Performance Assurance, should the Approved Vendor no longer wish to develop that system. This approach would allow both parties to step away from unwanted contractual obligations and ease the Agency's RPS planning process.

RLTRRPP at 99 (emphasis added). This addition, allowing for "a system's removal from the contract ... should the Approved Vendor no longer wish to develop that system" is

appropriate in its purpose, and providing for “forfeiture of associated Performance Assurance” is an adequate remedy for removal. The inclusion of the phrase allowing “the Buyer and Seller to execute an amendment to the contract, through mutual assent,” however, is problematic. ComEd Obj. at 2.

The Commission should tighten this language to reflect the fact that the utility Buyers are not involved in selecting the Approved Vendor sellers, the products, or the contracts. The IPA does all of that, subject to Commission review and approval. Indeed, this is the IPA’s Plan, as reviewed and approved by the Commission. The utility Buyers do not have discretion in deciding whether to enter into the contracts, or with whom to execute those contracts. Therefore, it is unclear why the Plan appears to assume that it is within the utility Buyers’ discretion whether or not to amend those contracts. Furthermore, the Plan should not leave open the possibility that those contracts could be unevenly administered, with the utility Buyer granting assent in some circumstances and not in others. ComEd Obj. at 2.

A better way to accomplish the goals of this proposed revision without any unintended consequences would be to state the following:

Additionally, the Revised Plan seeks Commission permission, similar to the discussion in Section 6.15.1, to allow the ~~Buyer and Seller~~ to provide notification to the Buyer, the Agency, and the Commission that it is exercising its option to allow execute an amendment to the contract, through mutual assent, ~~allowing~~ for a system’s removal from the contract, with forfeiture of associated Performance Assurance, ~~should~~ because the Approved Vendor no longer wishes to develop that system. This approach would allow both parties to step away from unwanted contractual obligations and ease the Agency’s RPS planning process.

Upon receipt of this notification, the utility Buyer would then send a standardized form amendment to the Approved Vendor Seller to be duly executed to effectuate this removal option. As revised, this section still accomplishes the goal of allowing “both parties to step away from unwanted contractual obligations and ease the IPA’s RPS planning process,” in a timelier fashion than previously allowed, but without the incorrect implication that a utility Buyer can exercise discretion in this procurement process. ComEd Obj. at 3.

The Plan also uses the “mutual assent” language that ComEd objects to in Section 6.15.1. The only suggestion ComEd makes is to clarify that the Approved Vendor Seller would exercise an option and provide notification to the IPA and Commission, as opposed to the utility Buyer and Approved Vendor Seller executing an amendment. ComEd Obj. at 4-5.

## **2. Joint Solar Parties**

The Joint Solar Parties support ComEd’s proposal. Also, the Joint Solar Parties note that as the standard REC Contract exists today, it is structured as a master contract between a utility counterparty and an Approved Vendor with one or more attached

“Product Orders.” A Product Order is the reflection of a batch of systems (or, for a system over 100 kW, as few as one) that are approved as a unit by the IPA and Commission. Currently, there is no mechanism within the master REC Contract for an Approved Vendor to remove a Product Order voluntarily and forfeit the related collateral. Especially when a system encounters an impediment to energizing, it makes little sense to wait for the system (or multiple systems) to fail to energize on time to remove the Product Order. Instead, to more efficiently approve replacement projects, the Product Order should be removable immediately upon notice by the Approved Vendor. JSP Resp. at 19-20.

### 3. IPA

The IPA is somewhat puzzled at ComEd’s claim that a utility as Buyer under a REC contract does not truly have “the ability to assent or decline” to an amendment. Even if ComEd believes that its contractual administration actions are inherently guided by Commission directive, the Revised Plan would specifically grant Commission approval for ComEd’s discretion, making ComEd’s concerns unwarranted. Regardless, the IPA appreciates that ComEd may harbor its own reasons for avoiding the weight of discretion. Thus, the IPA does not oppose ComEd’s proposal to give Approved Vendor Sellers under REC contracts an automatic removal option that utilities would be required to grant if the Seller exercises it. Additionally, the IPA does not oppose the edited Revised Plan language proposed by ComEd for each of Sections 5.3.1 and 6.15.1, believing it to be a sensible implementation of ComEd’s proposed approach. The IPA would like to add the additional clarification that the IPA will have responsibility for developing the specific forms and procedures to effectuate this removal option for Sellers. IPA Resp. at 57.

On Response, the Joint Solar Parties note their agreement to ComEd’s Objection clarifying the mechanisms used for the removal of systems which an Approved Vendor no longer plans to develop from an Adjustable Block Program or ILSFA REC delivery contract. JSP Resp. at 19-20. The Joint Solar Parties, however, address only the removal of a Product Order (i.e., a batch which may be one or more systems), and offers a broad statement on Response that a Product Order “should be removable immediately upon notice by the Approved Vendor.” *Id.*; IPA Rep. at 32.

The IPA responds that the challenge identified in ComEd’s Objection and the Joint Solar Parties’ Response includes the removal of a system from a contract in addition to the removal of a Product Order, as one system among many within a given Product Order may no longer be sought to be developed by an Approved Vendor. Second, to the extent that the Joint Solar Parties’ intent regarding immediate removal of a Product Order does not involve the forfeiture of collateral associated with that system, or to the extent that Joint Solar Parties seek to allow for removal of a Product Order before collateral is posted, the IPA disagrees with the Joint Solar Parties’ request. As collateral is due within 30 business days after the Trade Date (i.e., the date of Commission contract approval), the IPA believes that an Approved Vendor should not have an open-ended option to withdraw a system or Product Order without having posted collateral, nor should the Approved Vendor be able to remove a system or Product Order without acknowledging the forfeiture of collateral associated with that system. IPA Rep. at 32.

#### **4. Commission Analysis and Conclusion**

ComEd proposes that the IPA's language in Sections 6.15.1 and 5.3.1 of the Revised Plan be modified. The Joint Solar Parties and the IPA agree to ComEd's proposal. The Commission finds ComEd's language to be reasonable and agrees that it should be reflected in the Revised LTRRPP.

##### **J. Section 6.15.3 Deadline for issue of REC Payment checks**

###### **1. Joint Solar Parties**

The Joint Solar Parties stress the importance of financing and commercial transactions to make projects become a reality, but also maintaining a quality customer experience. The launch of the Adjustable Block Program has resulted in substantial delays in getting the actual REC payment checks from the utilities to Approved Vendors. In fact, at the time of submission of these comments, there are Approved Vendors who submitted batches for completed solar projects in January 2019 that have yet to receive any payments. In some instances, these are residents who are forced to finance individual systems much longer than anticipated. JSP Obj. at 43.

There are several causes for the delay, but two areas in particular where delays seem to be the most significant: 1) review by the Program Administrator of the batches before being sent to the Commission for approval (currently taking 2-3 months); and 2) Program Administrator Part II verification, which occurs after a contract is signed by the utility and Approved Vendor. As a customer protection measure, the Joint Solar Parties recommend a required turnaround time of no more than one month after Energization for review of the Part II verification (with exceptions for Approved Vendor delay) and monthly windows to invoice utilities under the REC Contract. At that point in the process (Part II verification), systems have been installed and energized, the contract has been approved by the Commission and signed by the Approved Vendor and utility, and there should be little delay in Part II approval and ultimately payment by the utility. JSP Obj. at 43-44.

###### **2. IPA**

The Joint Solar Parties express concern with the pace of Adjustable Block Program project applications, particularly for those applications already energized – complaining that “there are Approved Vendors who submitted batches for completed solar projects in January 2019 that have yet to receive any payments.” JSP Obj. at 43. To the extent that, as of early November, this was true of any batch, it would not be true of a batch that entirely contained fully installed projects in January 2019 where the Approved Vendor has subsequently satisfactorily responded to all follow-up requests for information from the Program Administrator; any such batch would have been approved in full, or some of its projects deemed ineligible, well before November. IPA Resp. at 58.

As background, a project application begins with Part I submission, even for already-built (and energized) projects, which the Program Administrator then reviews. Under Section 6.14.4 of the Initial Plan, which is reiterated (and modified) in the Revised Plan, a batch of projects will be reviewed at the Part I stage and then, upon review of all project applications, the batch (less any projects found ineligible or withdrawn by the Approved Vendor) will be forwarded to the Commission for review and approval if at least 75% of the batch's kW volume is deemed eligible. Part II applications for already-

energized projects can be begun before the Administrator's approval of the Part I application and before the Commission's approval for contracting, although the Part II application cannot be completed until after Commission approval. For projects not yet built at the time of Part I application, the Part II application is initiated upon energization, which is usually well after Commission approval and contracting. IPA Resp. at 58.

Delays in approval commonly arise with Part I applications for prospective projects, where there is some inherent degree of speculation over the viability of the project and issues of site control or technical specifications (among others) sometimes give rise to additional information requests from the Program Administrator. Thus, the problem identified by the Joint Solar Parties could be that prospective projects with problematic Part I applications were included in the same batch as already-energized projects, and an entire batch cannot be forwarded to the Commission for approval until all projects in the batch are reviewed with finality (either approved or deemed ineligible) by the Program Administrator. IPA Resp. at 59.

In light of concerns around the pace of project application review, the Joint Solar Parties demand "a required turnaround time of no more than one month after Energization for review of the Part II verification (with exceptions for Approved Vendor delay)." The IPA is committed to reducing review times and notes that the average wait time for a Part II review time has been significantly reduced for projects that submitted their Part II applications during the recently completed September-November contractual quarterly period. However, the IPA opines that a prescribed maximum turnaround time is poor policy. IPA Resp. at 59-60.

### **3. Commission Analysis and Conclusion**

The Commission notes that the IPA is committed to reducing review times and that the average wait time for a Part II review has been significantly reduced for projects that submitted their Part II applications during the recently completed September-November contractual quarterly period. In addition, the Commission agrees that a prescribed maximum turnaround time could have unintended consequences and should not be adopted at this time. The Commission encourages the IPA to adhere to its commitment to reduce review times.

#### **K. Section 6.16.2 Options to Reduce REC Delivery Obligations**

##### **1. Joint Solar Parties**

The Joint Solar Parties state that one of the more substantial risks to project economics for all system types is REC delivery due to the clawback term in the REC Contract. No matter how many or how few RECs a system delivers, pursuant to a standing order all RECs must be delivered to the utility. If the Approved Vendor under-delivers on a three-year rolling average basis, the IPA will either require a cash payment or draw upon the Approved Vendor's collateral (with a requirement that the collateral be promptly replenished). If the Approved Vendor over-delivers, the surplus RECs will be carried forward against future under-deliveries. JSP Obj. at 26-27.

A better approach, the Joint Solar Parties opine, would be to allow the Approved Vendor to defer REC delivery clawbacks—so long as delivery was within a reasonable band, for instance 15% of anticipated delivery—until the end of the 15-year Product

Order. Once expiration of the Product Order is imminent, the Approved Vendor should have the ability to elect to pay any (net after carryforwards) shortfall as a clawback or extend the contract obligations up to 24 additional months. This approach would allow a system to continue delivering RECs to utilities for retirement and address the intermittent nature of solar, while still ensuring that RECs are generated and delivered during the term of the Product Order. It would also avoid ad hoc payments into the renewable resources budget as collateral drawdowns take place each year that the IPA cannot plan for or effectively use. JSP Obj. at 27-28.

The Commission held in Docket No. 17-0838 that there is a statutory obligation that the Approved Vendor transfer all RECs generated by a participating system and that such contract must last at least 15 years. See Docket No. 17-0838, Order at 128-129. Allowing an Approved Vendor the right (but not requirement) to extend the term of a Product Order and keep a system delivering would be consistent with that statutory framework as long as the system continued to provide all RECs to the utility during the extended term. JSP Obj. at 28.

Also, if a system does underproduce, the clawback is a cash payment, not a replacement REC. To the Joint Solar Parties' reading, there is currently no request in the LTRRPP to use those funds to procure replacement RECs or requirements for such replacement RECs. JSP Rep. at 27. Most important to the Joint Solar Parties, the IPA and utilities will be receiving all RECs produced by the system except to the extent that a system is allowed to modify the applicable irrevocable standing order pursuant to the REC Contract. JSP Rep. at 27.

The real issue here is allowing REC Contract counterparties reliant on an intermittent resource to mitigate intermittency. At its essence, the Joint Solar Parties' proposal is to recognize that no developer or owner/operator controls the weather. While developer and owner/operator skill and decisions do impact output, one of the primary factors, weather, is completely out of developer control. Based on how owner/operators obtain revenue, all incentives are to maximize production—which is inherently limited and under risk from the weather. Because each facility must initiate an irrevocable standing order as a prerequisite to Energization (i.e. the REC Contract event that qualifies a facility for its first payment), there is not a question about a system holding back RECs from the utility. Instead, it is a matter of how many RECs will weather patterns allow developers to generate. The Joint Solar Parties thus recommended a change to the REC Contract to allow the State (via utilities) to receive their full contracted-for number of RECs. JSP Rep. at 28.

Given that there is no incentive for developers to underproduce in early years and no ability to alter the weather, the Joint Solar Parties recommend deferring a limited portion of REC production goals to a two-year extension. This allows the developer to provide additional RECs that would not otherwise be obtained and retired by the IPA or utilities in years 16 and 17 (as applicable) at no marginal cost to the utilities or IPA. JSP Rep. at 29.

With regard to financing, the IPA states that: “[t]housands of applicant systems have already been developed and financed based on under-delivery risks in the present REC Contract; those risks have been known since before the Program began accepting

project applications.” IPA Resp. at 61. The IPA provides no basis for its conclusion that thousands of systems have already been financed—it is not clear how the IPA knows the financing status. More to the point, the IPA’s dismissal does not take into account whether already closed or ongoing financings were on worse terms than otherwise possible. JSP Rep. at 28-29.

In addition, the Joint Solar Parties appreciate that the IPA proposed workshops to address certain issues regarding the REC Contract. While the Joint Solar Parties recommended workshops, the Joint Solar Parties recommended workshops before this docket rather than afterward, so the issues not subject to consensus could be litigated. The Joint Solar Parties believe that due to the contract development process—where the IPA takes comments from industry and then proceeds to enter negotiations that include utilities, the IPA, its Procurement Administrator, and Staff (without the solar industry)—having a Commission Order is more effective than a workshop process to bring about change. JSP Obj. at 29.

## **2. CSG**

CSG supports the Joint Solar Parties’ position on the need for greater flexibility in complying with REC delivery obligations. Under the current terms, risk related to REC delivery (particularly the risk of collateral drawdown) is nearly all on the shoulders of the Approved Vendor, developer, and system owner (which includes homeowners). The IPA and utilities, on the other hand, experience little to no risk. The largest factor behind the risk faced by the former group is outside of their control—the weather. Although the rolling three-year average and banking provisions under the Initial Plan are meant to mitigate that risk, such provisions do not protect against poor weather conditions at the outset of the 15-year contract term or successive years of poor insolation. Under such scenarios, Approved Vendors, developers, and system owners could collectively owe hundreds of thousands of dollars due to the weather—which is undeniably beyond their control. In contrast, the counterparties to the REC contracts face no repercussions for falling short on their REC targets. For instance, the current funding issues ensure that there will be major REC shortfalls well beyond under delivery of Adjustable Block Program systems, yet the utilities will experience no penalty. CSG Rep. at 4.

CSG states that even a system that delivers 93 RECs more than the contracted quantity can still owe \$3,284.91 in collateral drawdowns over the life of the contract. CSG notes that there is the opportunity to recover some of this collateral that has been drawn down at the end of 15 years; however, this is still a significant cost to have to carry over time for the system owner or Approved Vendor. Also, more importantly, this full value is not likely to be recovered given the contract’s method of allocating surplus RECs from the highest value to the lowest value. Also worth noting, is that the three-year rolling average does not fully alleviate these instances of collateral drawdown. CSG Rep. at 6-7.

Instead of creating a complicated system with multiple blocks of surplus RECs, CSG supports the Joint Solar Parties’ recommendation to allow systems to continue delivering RECs for an additional two years to earn back or negate collateral drawdowns. While CSG does not disagree with the IPA that many systems have been developed and financed based on under-delivery risks in the present REC Contract, CSG replies that is because there was no other option. CSG also points out that many of the systems

participating in the Adjustable Block Program were built before the terms of the REC Contract were even known. CSG Rep. at 9.

As for the IPA's concern that a "utility could be left without enough RECs to meet annual statutory commitments but with no compensation for the loss," this will happen anyway, if the 15-year term remains inflexible. Moreover, CSG states that the utilities are not using the money collected in situations of under delivery to purchase more RECs. Adoption of the Joint Solar Parties' proposal to extend the REC delivery term by an additional two years at least lets the utilities eventually receive the contracted for RECs. The IPA also expressed a question as to whether the Joint Solar Parties were suggesting that payments for RECs are expected during the additional two years. CSG states that it does not understand additional payments to be part of the proposal. With an additional two years of collecting RECs, the odds also increase that the utility may actually receive more RECs than expected initially under the contract, at no additional cost. CSG Rep. at 9.

With regard to the IPA's concern that allowing for a two-year extension could result in Approved Vendors overestimating capacity factors to produce effectively a 17-year delivery term (IPA Resp. at 62-63), all capacity factors are reviewed and approved by the Program Administrator based on modeled system output. In other words, Approved Vendors cannot submit exaggerated capacity factors because of the safeguards already in place. CSG Rep. at 10.

Nor does CSG believe that allowing for a two-year extension will make compliance planning difficult, as the IPA suggests in its Response. IPA Resp. at 63. CSG explains that the RECs expected to be generated in the additional two years will have already been planned for and paid for—they would simply have not been delivered yet. Such RECs could easily be applied to previous years' obligations that were not met. Given that payment and generation are totally decoupled and existing provisions for banking surplus RECs, which are common in the industry, applying RECs to a different compliance year in this limited situation should not be difficult or complicated. CSG respectfully urges the Commission to adopt the Joint Solar Parties' position on this issue. CSG Rep. at 10.

### **3. IPA**

The Initial Plan at Section 6.16.2 provided for annual evaluation of REC delivery performance using a three-year rolling average approach, with the additional provision that any annual overproduction relative to the annual contractual commitment could be "banked" into future contract years without expiration and used to offset annual shortfalls, potentially reducing or eliminating collateral drawdowns in particular delivery years. The Adjustable Block Program and ILSFA Standard Delivery Contracts provide that any such banked RECs (called "Surplus RECs" in the contracts) still remaining and unused after the final annual review under the Approved Vendor's REC Contract can be used to obtain refunds for prior collateral drawdowns due to REC underperformance. Additionally, an Approved Vendor has a portfolio-wide "bank" of these over-delivered RECs, so banked RECs from one project can later be used to offset under-performance from another project. IPA Resp. at 60.

The Joint Solar Parties complain that this allowance is not sufficient to compensate them for the risk of underperformance. The IPA opposes the Joint Solar Parties' proposal.

Thousands of applicant systems have already been developed and financed based on under-delivery risks in the present REC Contract; those risks have been known since before the Program began accepting project applications. The Program has received well over 10,000 project applications under this known and understood balancing of non-performance risk, and to now shift obligations further in favor of Approved Vendors ignores that underperformance risk has not been a meaningful barrier to project development. IPA Resp. at 61.

Furthermore, the existing Standard REC Contracts already provide cushion for Approved Vendors to balance lean years with fat years within the 15-year contractual delivery term. Additionally, Approved Vendors are able to, and have been able to, choose a custom capacity factor at the time of project application (and update it downward if necessary when the project is built) to minimize the risk of REC under-delivery. While solar developers are substantially able to mitigate risk under the existing programmatic and contractual terms, the Joint Solar Parties' proposal to defer responsibility for any annual under-deliveries until the end of the contract essentially places all risk on the contractual counterparty (either a utility or the IPA) for year-by-year shortfalls – while the law provides specific annual goals and targets for REC procurement in the State and by utility. See, e.g., 20 ILCS 3855/1-75(c)(1)(B), (C). Utilities already face some risk under the Adjustable Block Program and ILSFA Standard REC Contracts, since the three-year average concept and the use of prior-delivered banked RECs, which are elaborations not found in the law's simple year-by-year RPS obligations, still leave open the possibility that the utility could be left without enough RECs to meet annual statutory commitments but with no compensation for the loss. The IPA therefore opposes the Joint Solar Parties' specific proposal to defer year-by-year clawbacks in the event of under-deliveries. IPA Resp. at 61-62.

#### **4. Commission Analysis and Conclusion**

The Commission notes that many contracts have already been approved that contain the provisions opposed by the Joint Solar Parties and CSG. The Commission is reluctant to approve a new REC Contract with such a dramatic change in terms. Also, as approved in Docket No. 17-0838, the current REC Contracts have provisions for three-year rolling averages of REC deliveries and the ability to bank RECs. The Commission finds that these provisions provide sufficient risk management protection for Approved Vendors. Thus, the Commission does not adopt the Joint Solar Parties' proposal as supported by CSG.

##### **L. Section 6.17 Annual Report**

###### **1. Joint Solar Parties**

The Joint Solar Parties note that one of the ways for an Approved Vendor to both lose their Approved Vendor status and default on their REC Contract is to fail to submit an annual report. The Revised LTRRPP addresses new additions to the annual reports, such as "Other information related to ongoing program participation, including use of graduates of job training programs and other information related to increasing the diversity of the solar workforce," but the Joint Solar Parties note that the IPA has not released a draft. Revised LTRRPP at 159; JSP Obj. at 40.

The Joint Solar Parties have two concerns with this language. First, each trade association member of the Joint Solar Parties strongly supports increasing the diversity of the solar workforce and have put (and will continue to put) in substantial work to achieve that goal. However, it appears the IPA is looking for both (1) information on Approved Vendor utilization of the existing ILSFA job training programs, and also (2) undefined diversity in general. To the first request, the ILSFA program administrator, Elevate Energy, is already charged with providing reports on the success and placement of these workforce programs, so this requirement would be duplicative at best, but creates additional unknowns for Approved Vendors when determining how to report sub-contractor hiring, etc. However, and more importantly, it is not clear to the Joint Solar Parties what additional diversity employment information the IPA is seeking and for what purposes when the Commission is already statutorily overseeing solar—including but not limited to installers, many of which are not Approved Vendors—diversity achievement. JSP Obj. at 40-41.

Second, many solar companies active in Illinois not only have Illinois employees and subcontractors, but also have workforce out of state. The Joint Solar Parties are concerned about IPA overreach not only in Illinois reporting, but also into national information. JSP Obj. at 41.

In addition to these concerns, the Joint Solar Parties urge the Commission to direct the IPA to allow Approved Vendors in financing vehicles to limit disclosures about ultimate stockholders/parents and affiliates. The Joint Solar Parties believe that the current disclosures would make equity financing much more challenging and tax equity financing nearly impossible; to the extent that such financing has already been set up, the Joint Solar Parties are concerned that existing deals could be put into crisis. Typically, such Approved Vendors would not be expected to develop new projects and instead exist to service existing REC Contracts. JSP Obj. at 41.

## **2. ELPC/NRDC/VS**

ELPC/NRDC/VS agree with the IPA that the reporting requirement is not duplicative and serves a clear and valid purpose. On the second point, the Joint Solar Parties raise some potential concerns about this requirement that can and should be avoided in its implementation. The clarifications about this reporting requirement made by the IPA in their response may have already assuaged these concerns. If not, ELPC/NRDC/VS urge the IPA and the Commission to recognize that this reporting requirement is targeted at Illinois workforces and that every precaution should be taken to avoid burdensome requirements that would complicate project financing. ELPC/NRDC/VS Rep. at 23-24.

## **3. IPA**

The Initial Plan included a requirement that Adjustable Block Program Approved Vendors submit an Annual Report. The Initial Plan further described that the Annual Report would include specific items and other information related to ongoing program participation. In the Revised Plan, the IPA merely changed this requirement to: other information related to ongoing program participation, including use of graduates of job training programs and other information related to increasing the diversity of the solar workforce.

The IPA states that it added this requirement in an open-ended manner because there are different ways in which this information could be reported, and the IPA wants to learn from those on the ground what accomplishments they have achieved. That was the goal of adding this reporting element: to celebrate how the increase in solar development in Illinois is improving diversity in the state’s renewable energy workforce. Further, this reporting would not be duplicative of the workforce development work conducted by the ILSFA Program Administrator; those programs focus on ILSFA-specific training and hiring requirements, and any work done directly with ILSFA Approved Vendors—of which there are 28—would not be duplicative of efforts for the remaining 304 Adjustable Block Program Approved Vendors. IPA Resp. at 64.

Nonetheless, the IPA commits to seeking stakeholder feedback after approval on how this information should be reported. Furthermore, the IPA commits to gathering this information for informational purposes only; failure of an Approved Vendor to hire trainees or diversify their workforce, while disappointing and contrary to the Joint Solar Parties’ own stated goals, would not be considered as criteria for continuation of their Approved Vendor status. IPA Resp. at 65.

The Joint Solar Parties also request that “the Commission direct the IPA to allow Approved Vendors in financing vehicles to limit disclosures about ultimate stockholders/parents and affiliates.” JSP Obj. at 41. The IPA notes that the items listed in the Revised LTRRPP for the Annual Report do not require such disclosures; rather, this information must be provided when an entity registers to become an Approved Vendor—and it may be designated confidential and commercially sensitive, and thus exempt from further disclosure. The IPA thus sees no basis for this objection from the Joint Solar Parties. IPA Resp. at 65.

#### **4. Commission Analysis and Conclusion**

The Commission agrees with the IPA and holds the IPA to its commitment to seek stakeholder feedback on how this information should be reported. Further, the Commission agrees with the IPA that this information should be gathered for informational purposes only and failure of an Approved Vendor to hire trainees or diversify their workforce, while disappointing, would not be considered as criteria for continuation of their Approved Vendor status. IPA Resp. at 65.

Also, the Commission does not see any requirement in the Annual Report that affiliate or stockholder information must be reported. To the extent the Joint Solar Parties are discussing different requirements, the IPA appears to address their concerns by noting that such information would be treated confidentially.

### **V. CHAPTER 7: COMMUNITY RENEWABLE GENERATION PROJECTS**

#### **A. Section 7.1 Statutory Overview**

##### **1. Joint Solar Parties**

The Joint Solar Parties respectfully request that the Commission address the applicability of the first two paragraphs of Section 1-75(c)(1)(N) of the IPA Act. See 20 ILCS 3855/1-75(c)(1)(N). The Joint Solar Parties suggest that the Commission has interpreted that the first paragraph authorizes the IPA to create terms and conditions for the entire Adjustable Block Program—not just the community renewable generation

program identified in Section 5.8.4 in the Initial LTRRPP, which is separate and distinct from the Adjustable Block Program. See Docket No. 17-0838, Order at 106-107; JSP Obj. at 11.

The Joint Solar Parties claim that as a result of their interpretation that the first paragraph applies to all Adjustable Block Program projects, it follows that the second paragraph must as well. The Joint Solar Parties believe there is no reading of the second paragraph other than requiring utilities to provide the community renewable generation credit to all LTRRPP-procured projects—including Adjustable Block Program projects. While non-LTRRPP community renewable generation projects may fall to the default under Section 16-107.5 of the PUA that places the burden on the electricity provider (which may not be the utility), Section 1-75(c)(1)(N) appears to make clear that for Adjustable Block Program and other LTRRPP-procured community renewable generation projects the utility is the sole source of monetary net metering credits for subscribers. The Joint Solar Parties urge the Commission to explicitly endorse this interpretation and direct Ameren and ComEd to make conforming changes to Rider NM and Rider POGCS, respectively. Obj. at 11-12.

In response to ComEd, the Joint Solar Parties state that the issue of whether utilities must provide a monetary value for all subscriptions in LTRRPP-procured projects is not out of the scope of this docket. The issue of utility obligations—which include obligations to provide net metering credits to customers—is raised in Section 7.7 of the LTRRPP. See Revised Plan at 176-177. In addition, the utility net metering credit rate is relevant for REC pricing so long as the IPA uses it as its starting point for the cost-based model approved in Docket No. 17-0838. JSP Rep. at 3.

The Commission should reject Ameren’s argument that the Joint Solar Parties’ proposed ruling would prevent subscribers in LTRRPP-procured community renewable generation projects from selecting an ARES. The Joint Solar Parties state that utilities in Massachusetts, New York, Maryland (including affiliates of ComEd), and New Jersey are able to provide credits to retail customers taking supply service from those states’ equivalents to ARES. Pursuant to statute and utility tariffs, virtual net metering for community renewable generation projects is a purely virtual transaction. The entity required to provide the customer credit retains the energy value of the community renewable generation project’s output. In other words, it is irrelevant whether the electric utility keeps the value of the subscriber’s share of generated energy and credits the subscriber or an ARES is assigned both the energy value and crediting responsibility. JSP Rep. at 3.

The Joint Solar Parties state that the IPA, Ameren, and ComEd all address a related issue by arguing that Section 16-107.5(l)(2) of the PUA forecloses the Joint Solar Parties’ interpretation of Section 1-75(c)(1)(N). First, the IPA argues that “the reference to electric utilities does not exclude the possibility that an ARES may also have responsibility to provide bill crediting to its customers that subscribe to community renewable generation projects.” IPA Resp. at 67. The IPA’s logic could equally be applied to Section 16-107.5(l)(2)—relied upon by Ameren and ComEd—that the obligation on the “electricity provider” does not exclude the possibility that the utility may also have the responsibility to provide bill crediting. JSP Rep. at 4.

While at first blush the IPA's interpretation would seem to create an endless loop of interpreting "shall" as permissive in both statutes, the canons of statutory construction dictate that the more specific section take precedence over the more general section. The Joint Solar Parties note that "[i]t is also a fundamental rule of statutory construction that where there exists a general statutory provision and a specific statutory provision, either in the same or in another act, both relating to the same subject, the specific provision controls and should be applied." *Mattis v. State Univ. Retirement Sys.*, 212 Ill. 2d 58, 77, 816 N.E.2d 303, 287 Ill. Dec. 541 (Ill. 2004) (quoting *Knolls Condominium Ass'n v. Harms*, 202 Ill.2d 450, 459, 781 N.E.2d 261, 269 Ill. Dec. 464 (Ill. 2002)). Here, Section 1-75(c)(1)(N)—which is specific to a subset of community renewable generation projects procured pursuant to the LTRRPP—is the more specific section and thus must govern notwithstanding broad language in Section 16-107.5(l) of the PUA. JSP Rep. at 4-5.

The Joint Solar Parties note that Ameren and ComEd make arguments that Section 16-107.5(l) clearly directs the electricity provider—not the utility—to provide net metering credits to customers. The Joint Solar Parties note that the clarity of Section 16-107.5(l) is irrelevant. Unlike other canons of statutory construction, conflict between sections—rather than ambiguity—is the prerequisite for applying the rule of the more specific controlling over the general. The Joint Solar Parties aver that the more specific requirements of Section 1-75(c)(1)(N) must take precedence over the more general provisions in Section 16-107.5(l). JSP Rep. at 5.

The Joint Solar Parties note that ComEd's own marketing materials stated—and were later revised to merely suggest—that ComEd provides net metering credits for subscribers of community solar facilities. See JSP Rep., Attach. A at 1. This material explicitly states that ComEd itself provides "bill credits." The revised version, provided by ComEd in discovery and now available at the same website, implies that ComEd provides the bill credit. See JSP Rep., Attach. B at 2; JSP Rep. at 5-6.

The IPA argues that granting the Joint Solar Parties' request "would at minimum create a troubling inconsistency between community solar projects participating in the Adjustable Block Program." IPA Resp. at 67-68. The IPA did not fully explain the reason that a difference would be "troubling" other than the Adjustable Block Program may be relatively more attractive for investment. While the Joint Solar Parties are not privy to the investment decisions of their membership or the market at large, anecdotally the Joint Solar Parties understand that the Adjustable Block Program and ILSFA are seen as sufficiently different that developers commit to program participation strategies rather than making project-by-project decisions. However, if the IPA finds that granting the Joint Solar Parties' request leads to additional resources going toward the Adjustable Block Program and interest in ILSFA diminishing, the IPA has the power to request Commission reconsideration (or itself review) the ILSFA program pricing, terms, and obligations to account for any imbalance. JSP Rep. at 6.

The Joint Solar Parties note that in other states, a single utility-offered community solar credit improves the customer and system owner experience by having a single crediting point of contact and more rate transparency. In other words, if the Commission correctly reads the statute as explained above, the results will be a positive for consumers and developers. JSP Rep. at 6.

For the foregoing reasons, the Commission should adopt the Joint Solar Parties' proposal to issue an explicit ruling that Section 1-75(c)(1)(N) requires Ameren and ComEd to provide monetary net metering credits to subscribers in LTRRPP-procured community renewable generation projects. JSP Rep. at 6.

## 2. Ameren

Regardless of whether this is their intent, Ameren states, the practical impact of the Joint Solar Parties' position that for Adjustable Block Program and other LTRRPP-procured community renewable generation projects the utility is the sole source of monetary net metering credits for subscribers is subscribers will no longer have choice for their electric supply service. For community solar subscribers, only the supply service portion of their bill is netted. Ameren explains that if subscribers/customers want to receive any netting benefits under the Joint Solar Parties' proposal, they would be restricted to using Ameren electric supply services to receive any monetary benefit from their subscription. Ameren Resp. at 3.

For behind the meter generator installations, both the delivery and supply portions of the bill are netted for residential and small non-residential customers. To the best of Ameren's knowledge, every renewable-fueled generator interconnected or planned for interconnection under Part 466 since the launch of the IPA's Adjustable Block Program has received or anticipates receiving REC monies from an Adjustable Block Program. Again, if these customers want to receive the netting of the supply portion of their bills, the Joint Solar Parties' proposal will restrict them to using only Ameren's electric supply services, effectively negating supply choice for these customers simply because they want to use renewably-fueled generation funded through an Adjustable Block Program. Ameren Resp. at 3.

Ameren disagrees with the Joint Solar Parties' interpretation and application of Section 1-75(c)(1)(N). Additionally, Ameren believes that the Joint Solar Parties misapply the language directing utilities' compliance with Section 16-107.5 of the PUA. Section 16-107.5 identifies responsibilities and limitations for utilities in implementing the net metering process, which includes providing netting for electric delivery and, in cases where the customer has chosen a utility supply option, electric supply. In reading Section 16-107.5, several instances where the legislature specifically prohibits an interpretation like that advanced by the Joint Solar Parties can be identified. Ameren Resp. at 4.

Section 16-107.5(l)(1) states that "each electricity provider shall allow net metering as set forth in this subsection (l) and for the following projects...(C) *subscriptions to community renewable generation projects.*" 220 ILCS 5/16-107.5(l)(1)(C)(emphasis added). Section 16-107.5(l)(2) of the PUA explicitly recognizes that the Illinois General Assembly identified that "[n]otwithstanding anything to the contrary, an electricity provider shall provide credits for the electricity produced by the projects described in paragraph (1) of this subsection (l). The electricity provider shall provide credits at the subscriber's energy supply rate on the subscriber's monthly bill equal to the subscriber's share of the production of electricity from the project, as determined by paragraph (3) of this subsection (l)." 220 ILCS 5/16-107.5(l)(2); Ameren Resp. at 4.

Additionally, Section 16-107.5(m) clearly states that "[n]othing in this Section shall affect the right of an electricity provider to continue to provide, or the right of a retail

customer to continue to receive service." 220 ILCS 5/16-107.5(m). Finally, Section 16-107.5(n)(3) undercuts the Joint Solar Parties' argument that utilities are the only parties that are allowed to sell power in specific instances related to Adjustable Block Programs: "[n]othing in this paragraph (3) shall be interpreted to mandate that a utility that is only required to provide delivery services to a given customer must also sell electricity to such customer." 220 ILCS 5/16-107.5(n)(3); Ameren Resp. at 4-5.

Ameren would also note that while the legislature made several modifications to Section 16-107.5 as part of the same legislative process that produced Section 1-75(c)(1)(N), it did not in any way indicate that customers who are beneficiaries of Adjustable Block Program projects should have their rights to supply choice curtailed. Instead, it added language that expressed the contrary position, as illustrated above, and it stands to reason that if it intended to impose an obligation on customers to choose between supply choice and the receipt of monies through the Adjustable Block Program, it would have stated so. Ameren believes the Joint Solar Parties' proposal would violate the statutes governing retail electric choice and the Company's Commission-approved tariffs. Therefore, the argument put forth by the Joint Solar Parties should be rejected by the Commission. Ameren Resp. at 5.

### **3. ComEd**

The Joint Solar Parties request that the Commission make an affirmative finding that the utility is the sole source of monetary net metering credits for subscribers. The Joint Solar Parties further request that the Commission direct utilities to make conforming changes to Rider NM and Rider POGCS. These requests are outside the scope of this proceeding and unlawful. ComEd Resp. at 6-7.

First, ComEd asserts that the Joint Solar Parties cannot cite to a portion of the Revised LTRRPP to which this applies. Second, and perhaps more importantly, ComEd argues that this position is unlawful. Section 16-107.5(l)(3)(B) clearly states that the utility is not the sole source of monetary net metering credits for subscribers as ARES are responsible for their customers. 220 ILCS 5/16-107.5(l)(3)(B). Contrary to the Joint Solar Parties' argument, the PUA clearly recognizes that ComEd and Ameren customers should not be paying for supply credits when the customer is with an ARES. *Id.*; ComEd Resp. at 7.

### **4. IPA**

The PUA provides that subscribers to community renewable energy generation projects, including the community solar projects that participate in the Adjustable Block Program and ILSFA, shall receive bill credits for their subscription shares of a project's generation at each subscriber's "energy supply rate." 220 ILCS 5/16-107.5(l)(1)(c), (l)(2). Moreover, the PUA provides that it is "electricity providers," including ARES if applicable, that shall provide the bill credits. 220 ILCS 5/16-107.5(b)(iii), (l)(1), (l)(2). This creates uncertainty for both prospective subscribers and community solar providers around the value of a community solar subscription, since supply pricing from a single ARES can be more volatile and less transparent than utility default supply rates. It also necessitates a complex system for wholesale settlements between the utility and ARES – which could in turn give the ARES an incentive to drop the community project subscriber as a supply customer, since the ARES generally receives compensation from the utility at the

Locational Marginal Pricing rate, far below the supply rate at which it credits the customer. IPA Resp. at 65-66.

With this backdrop, the Joint Solar Parties present a statutory construction argument around community renewable generation bill crediting parsing the language of the IPA Act to purportedly show that the following statement in the law's section about the Community Renewable Generation Program. See 20 ILCS 3855/1-75(c)(1)(N). This is apparently meant to imply that only electric utilities shall provide bill credits to subscribers to Adjustable Block Program community solar projects – even where the subscriber is enrolled with an ARES. IPA Resp. at 66.

The IPA is sympathetic to the policy basis for this point of view: the community solar market would indeed be simplified if only electric utilities had the responsibility to provide bill credits to subscribers (presumably at the utility default supply rate, though this is left unstated by JSP). Nevertheless, the IPA opposes the Joint Solar Parties' proposal for both legal and practical reasons. First, it is clear that the second paragraph of Section 1-75(c)(1)(N) (in context with the first paragraph of that subsection) is not stating a requirement applicable to only plan-participating community renewable generation projects; it is simply restating the general requirement of Section 16-107.5 (and expressly referencing the more detailed requirements therein) for "a community renewable generation project" – that is, any community project without qualification. The reference to electric utilities does not exclude the possibility that an ARES may also have responsibility to provide bill crediting to its customers that subscribe to community renewable generation projects. The Joint Solar Parties have ignored the plain text of the net metering statute (Section 16-107.5), which, as noted above, provides that any electricity provider (expressly defined to include an ARES) shall provide bill credits to a community solar (or non-solar community project) subscriber "at the subscriber's energy supply rate on the subscriber's monthly bill." 220 ILCS 5/16-107.5(l)(2); IPA Resp. at 66-67.

Also, the Joint Solar Parties' interpretation would at minimum create a troubling inconsistency between community solar projects participating in the Adjustable Block Program, which apparently would have bill credits provided to subscribers solely by electric utilities, versus community solar projects participating in ILSFA, which would not have utility-only crediting as there is no statutory hook regarding ILSFA projects that could overcome Section 16-107.5(l)(2)'s clear language about "electricity providers" providing bill credits. This lack of parity could discourage solar developers from applying to the Low-Income Community Solar Project Initiative or Low-Income Community Solar Pilot Projects procurement. IPA Resp. at 67-68.

Finally, utilities and ARES alike would likely find it difficult to write and implement their net metering policies to treat a community renewable generation project differently depending on whether it had a REC Contract under a Plan procurement program. Under Joint Solar Parties' approach, whenever a plan-participating project is removed from its REC Contract, either due to an early removal/termination or at the scheduled end of a 15-year delivery term, bill crediting responsibility would shift from the electric utility to the ARES (for subscribers with alternative retail supply service). It would be difficult for utilities and ARES to track these contractual statuses that often exist outside of the utility's or ARES' formal monitoring authority. IPA Resp. at 68.

The IPA notes that Ameren states that to the best of its knowledge, “every renewable-fueled generator interconnected or planned for interconnection under Part 466 since the launch of the IPA’s ABPs has received or anticipates receiving REC monies from an ABP.” AIC Resp. at 3. In response, the IPA is aware of foundations that require that RECs cannot be sold as a condition of offering grant funding for new renewable energy projects. In addition, some corporate projects may not involve the sale of RECs so that those environmental attributes can be used to meet sustainability goals or to advertise that products and services are powered by renewable energy. Lastly, the IPA has also administered and executed contracts for distributed generation projects under the ILSFA (which is a meaningful distinction given that the Joint Solar Parties’ proposal relies on language specific to the Adjustable Block Program). Thus, while the IPA agrees with Ameren that the Joint Solar Parties’ net metering provider requirement cannot be adopted, it believes Ameren’s statement that all projects interconnected or planned for interconnection under Part 466 “received or anticipate receiving REC monies from an Adjustable Block Program” also cannot be correct. IPA Rep. at 33.

For these reasons, the IPA respectfully opposes any Commission order adopting the Joint Solar Parties’ interpretation of the bill crediting discussion in Section 1-75(c)(1)(N) of the IPA Act. IPA Resp. at 68.

## **5. Commission Analysis and Conclusion**

The Joint Solar Parties rely on a portion of the Commission’s decision in Docket No. 17-0838 where the Commission is considering whether the IPA must have all details of the Adjustable Block Program included in the LTRRPP or whether it can rely on its Program Administrator to expand upon the details. Docket No. 17-0838, Order at 106-107. The Joint Solar Parties’ reliance on this portion of the Commission’s decision in Docket No. 17-08383 does not provide support for its proposal. Due to this erroneous interpretation of the Commission’s Order, the Joint Solar Parties’ request lacks clarity. Although it seems that the Joint Solar Parties want utilities to provide bill credits, it is not clear which specific programs their interpretation applies to and whether it would apply to a customer’s total bill or just a portion.

The IPA reads the Joint Solar Parties’ argument to request that only electric utilities shall provide bill credits to subscribers in Adjustable Block Program projects, even where the subscriber is enrolled with an ARES. The Commission agrees with the IPA, ComEd, and Ameren that Section 1-75(c)(1)(N) refers to Section 16-107.5 of the PUA, which provides no support for the Joint Solar Parties’ position. Section 1-75(c)(1)(N) states:

Electric utilities shall provide a monetary credit to a subscriber's subsequent bill for service for the proportional output of a community renewable generation project attributable to that subscriber as specified in Section 16-107.5 of the Public Utilities Act.

20 ILCS 3855/1-75(c)(1)(N). Moreover, as specified in Section 16-107.5 of the PUA, “an electricity provider shall provide credits for the electricity produced by the projects described in (1) of this subsection (l),” which itself describes electricity provider responsibilities for net metering. 220 ILCS 5/16-107.5(l)(2). Section 16-107.5 also states that:

For those participating customers and subscribers who receive their energy supply from an alternative retail electric supplier, the electric utility shall remit to the applicable alternative retail electric supplier the information provided under subparagraph (A) of this paragraph (3) for such customers and subscribers in a manner set forth in such alternative retail electric supplier's net metering program, or as otherwise agreed between the utility and the alternative retail electric supplier. The alternative retail electric supplier shall then submit to the utility the amount of the charges for power and energy to be applied to such customers and subscribers, including the amount of the credit associated with net metering.

220 ILCS 16-107.5(i)(3)(B). The Commission finds Joint Solar Parties' position is not consistent with the law and it is denied. The Joint Solar Parties also urge the Commission to direct Ameren and ComEd to make conforming changes to Rider NM and Rider POGCS. Consistent with this interpretation of the IPA Act and PUA, this request is also denied.

## **B. Section 7.3.1 Co-location Standard**

### **1. Joint Solar Parties**

The Joint Solar Parties explain that the Revised LTRRPP addresses for the first time a proposal for how a system will be priced if it is co-located, as defined in Section 7.3.1 of the Revised LTRRPP, with a system that has already been selected in the Adjustable Block Program. The Revised LTRRPP proposes to impose not only a 10% penalty on the base REC (i.e. before small subscriber adders) for the second system, but also the value that the 10% penalty would have been on the co-located system. See Revised LTRRPP at 167. This penalty will apply if the second system was selected within a year of the first system, or the first system has yet to commence construction. The penalty would apply even if one or both systems had been previously sold to a different Approved Vendor. See *id.*; JSP Obj. at 41-42

The Joint Solar Parties recommend that the Commission reject this approach. The likely result is that the second system—especially if the construction cycles are different—will have little to no economies of scale or cost savings but will have a 20% or more reduction in base REC value—a devastating reduction for a Block 4 or 5 project, especially if small subscriber bonuses are removed. The Joint Solar Parties expect that while decisions to commence construction are site-specific and depend on factors including interconnection costs, more co-located projects will not accept their award under the IPA's proposal. JSP Obj. at 42

### **2. IPA**

Recognizing the efficiencies and likely costs savings of co-locating two community solar projects—efficiencies that would not otherwise be reflected in the IPA's REC pricing model—the Commission's Amendatory Order in Docket No. 17-0838 authorized the IPA to set a schedule of REC prices applicable to co-located community solar projects. Docket

No. 17-0838, Amendatory Order at 1-2 (May 2, 2018). This still leaves open the question of under exactly what circumstances a system should be considered co-located. While a second co-located system developed five years later would not benefit from the same efficiencies as two projects applying simultaneously, there must be some limitations to avoid leaving open the opportunity for gaming through, for example, project assignment to a different Approved Vendor. Thus, Section 7.3.1 of the Revised Plan attempts to better define under what circumstances community solar projects would be considered “co-located” such that co-located REC pricing applies. IPA Resp. at 68.

The Joint Solar Parties make no argument as to why the IPA or Commission should be particularly alarmed about these projects’ level of participation in the program, as the existing community solar waitlists include hundreds of proposed projects presumably ready to accept a far more limited number of REC Contract awards and choosing a non-co-located project would enhance geographic diversity. Since the co-location concept is a concession to the developer community to begin with – an exception from the IPA Act’s basic definition (20 ILCS 3855/1-10) of community renewable generation projects as up to 2,000 kW – it is unclear why the Revised LTRRPP is inconsistent with the law’s goals. IPA Resp. at 68-69.

### **3. Commission Analysis and Conclusion**

The Commission notes the definition of community solar in the IPA Act limits nameplate capacity to less than or equal to 2,000 kW. 20 ILCS 3855/1-10. It appears to the Commission that allowing projects to co-locate exceeds these limits and that the IPA has imposed reasonable terms to balance both the statutory definition, yet still allow developers to capture economies of scale. The Commission declines to adopt the Joint Solar Parties’ proposal.

## **VI. CHAPTER 8: ILLINOIS SOLAR FOR ALL PROGRAM**

### **A. Section 8.6.1.1 Low-Income Distributed Generation Project Eligibility**

#### **1. ELPC/NRDC/VS**

ELPC/VS state that the Commission should require the IPA to take steps to identify and correct problems with the Low-Income Distributed Generation Sub-Program, in the event uptake does not materialize, before reallocating funds to other sub-programs. ELPC/NRDC/VS note that the goal of the ILSFA Program is to bring solar to low-income and environmental justice customers. The IPA Act states:

The objectives of the Illinois Solar for All Program are to bring photovoltaics to low-income communities in this State in a manner that maximizes the development of new photovoltaic generating facilities, to create a long-term, low-income solar marketplace throughout this State, to integrate, through interaction with stakeholders, with existing energy efficiency initiatives, and to minimize administrative costs.

20 ILCS 3855/1-56(b)(2). As such, the Low-Income Distributed Generation sub-program is a cornerstone of the larger ILSFA Program as the only part of the program to install solar directly on low-income and environmental justice customers’ homes and apartments. Furthermore, the sub-program is the most critical to the success of the Utility

Job Training Program (see 220 ILCS 5/16-108.12), as it is the only sub-program in the ILSFA Program to have direct requirements for hiring trainees: “Companies participating in this [Low-Income Distributed Generation Sub-] program that install solar panels shall commit to hiring job trainees for a portion of their low-income installations...” 20 ILCS 3855/1-56(b)(2)(A); ELPC/VS Obj. at 9.

Thus far, uptake for this important sub-program has mostly stalled. As of the beginning of November 2019, the dashboard illustrating applications for the ILSFA Program to-date showed a single application of a very large (2 MW - the maximum allowed) project into the program. While the lack of many applicants, and small applicants, in particular, is discomfiting to ELPC/VS, it is too early to say whether it is a definite cause for concern. Unlike for the Low-Income Community Solar and Non-Profit and Public Facility sub-programs, solar providers cannot easily begin lining up potential applications prior to the finalization of program requirements, at least for smaller systems. Therefore, it is expected that the Low-Income Distributed Generation sub-program will lag the other sub-programs—a pattern common to the rollout of other sub-programs, including the Adjustable Block Program here in Illinois, where residential solar installations have been growing exponentially, but program uptake into the Small Distributed Generation category is still much weaker than other categories. ELPC/VS Obj. at 10.

At the same time, ELPC/VS are familiar with some anecdotal reports of challenges from solar providers interested in or actively trying to work in the Low-Income Distributed Generation space. For one thing, ELPC/VS understand that the REC Aggregators that typically partner with and serve as Approved Vendors for small residential solar installers are not able to carry out some of the more bureaucratic requirements of the program and are generally unwilling to participate in the ILSFA Program because of the allocation of responsibility and risk in the program. Additionally, ELPC/VS state that it is a fairly narrow window of eligibility for the ILSFA Distributed Generation sub-program, particularly in the 1-4 Unit category. In addition to the typical considerations for customer eligibility in the Adjustable Block Program (e.g. homeownership, insulation, electric infrastructure up to code, sufficient space on roof), Approved Vendors looking to do rooftop installations for ILSFA also consider income eligibility, deferred maintenance issues, and lower electric bills that make it more difficult to justify the fixed costs of solar installations, thereby impacting both financial prospects for the Approved Vendor and cost savings potential for program participants. ELPC/VS Obj. at 10-11.

ELPC/VS agree and urge the Commission, in light of the critical importance of the Low-Income Distributed Generation sub-program and particularly its smallest projects to the goals and objectives of the ILSFA and Utility Workforce Training programs, to direct the IPA to identify and seek to correct any challenges potentially facing the Low-Income Distributed Generation sub-program before reallocating its funds to other programs. ELPC/VS Obj. at 11.

The ELPC/NRDC/VS support the IPA’s decision in the Revised Plan to set aside 25% of the ILSFA Distributed Generation sub-program for projects on 1-4 Unit buildings. This sub-category of projects is critical for achieving the job training goals of the statute and provides the most significant financial benefits to program participants. As seen in

the 2019-2020 program year, a single large (2 MW) ground-mounted project can claim \$4 million in REC value - over half of the annual budget. ELPC/NRDC/VS Rep. at 24.

ELPC/NRDC/VS recognize that the 1-4 Unit projects already receive preferential treatment in the Project Selection process but echo the IPA's sentiment that this only applies to those submitted during the Project Submission window. This window was approximately one month in the 2018-2019 program year and approximately two weeks in the 2019-2020 program year. ELPC/NRDC/VS believe that most Approved Vendors in the Distributed Generation sub-program will submit batches periodically as they bundle enough customers to cross the 50 kW threshold. If they hit that 50 kW number two weeks after the Project Selection window has closed, and if the Distributed Generation sub-program budget has been fully claimed by large, REC-intensive projects, then those customers will have to wait an entire year before finding out if ILSFA is a viable option. ELPC/NRDC/VS Rep. at 24.

The IPA's proposal - creating a carveout of 25% of the sub-program budget for 1-4 Unit projects - provides an elegant but incomplete solution to this problem. ELPC/NRDC/VS believe this carveout should extend to a full year of protected sub-category funding. A full year provides additional clarity and certainty to Approved Vendors in the 1-4 Unit sub-market and developers on the sidelines thinking about participating in the program. As such, ELPC/NRDC/VS recommend the following revisions to the Revised Plan:

To further ensure that diversity of projects, 25% of each program year budget will be reserved for 1-4 unit building projects for the first nine months of the program year. At the end of each program year, unused funds in this reserved sub-category will rollover to unreserved funds for the following program year of Distributed Generation sub-program. If at that time there are applications from five-unit and larger buildings that have not been approved and there is remaining funding from the 1-4 unit building set aside, the funds would be released for any 5+ unit building size projects (Revised Plan at Page 192).

ELPC/NRDC/VS Rep. at 25.

The Commission should take additional steps to ensure that the ILSFA Distributed Generation sub-program is protected from premature reallocation of funding. The IPA opposes the proposal on the grounds "that improving the Distributed Generation sub-program will be an iterative process spanning multiple years and multiple Plans as the Agency receives new information about project development and other programmatic issues and adjusts sub-program terms and conditions accordingly." IPA Resp. at 75. In its argument, the IPA points out that withholding funding for future Distributed Generation sub-program customers could be inhibiting other customers from accessing ILSFA benefits through budgetary expansion of other sub-programs. ELPC/NRDC/VS Rep. at 25-26.

ELPC/NRDC/VS believe that it is too soon to resort to reallocation, and urge the Commission order the IPA to alter the Plan to limit their ability to reallocate funds from the

RPS budget. While ELPC/NRDC/VS appreciate the steps taken by the IPA to boost participation within the Distributed Generation sub-program, ELPC/NRDC/VS maintain that funds should not be redirected to other sub-programs until there has been sufficient opportunity to make adjustments to the Distributed Generation sub-program and sufficient time to watch these adjustments change the market. Avoiding reallocation is particularly important as assurance that funds will be available in the sub-program (and not be reallocated to other sub-programs) is important to motivate developers to enter this market and enable them to secure financing. The specter of reallocation can have a chilling impact on market development. ELPC/NRDC/VS Rep. at 26.

While the IPA's responses discuss two-years of the program having moved forward, in reality the program was only open for one month of the first program year - a time period widely acknowledged to be too short to enable projects in the Distributed Generation sub-program to participate - and then reopened for the current program year in early September 2019. Furthermore, the IPA's assertion that a commitment to not reallocate funds from this sub-program in the current Plan would be a restriction with no stopping point, is not true - the IPA would be able to change this policy decision in its next Plan update. And given the extremely short 3-month runway the sub-program has had to date, ELPC/NRDC/VS believe waiting until the next Plan update to reallocate capacity would be prudent, that would give a year for the sub-program to run (September 2019-September 2020) and then another year for the program (September 2020 to September 2021) to continue running while and after the IPA seeks to correct any deficiencies that arise in the first year, before considering the reallocation of funds in the Plan update process that will begin in summer 2021. The Commission should therefore alter the Revised Plan to ensure that the Distributed Generation sub-program funding is not reallocated until the next Plan update at the earliest, and after significant steps - such as increasing the REC value - are taken to boost participation. ELPC/NRDC/VS Rep. at 26-27.

ELPC/NRDC/VS respectfully ask that the IPA begin a process of reassessing the REC value for the ILSFA Distributed Generation sub-program and formally explore other potential barriers to sub-program success, if the sub-program does not see a significant uptick in small project deployment by March 2020 (six months from the opening of the current program year). Initial market indicators (i.e. project submission levels and Approved Vendor applications) suggest that the Distributed Generation sub-program is having difficulty recruiting project developers from the Adjustable Block Program. This is in stark contrast to the other sub-programs, which have seen healthy growth and a dynamic community of Approved Vendors. Given that the program largely depends on Approved Vendors for generating public interest and submitting projects, in ELPC/NRDC/VS's view, this could be a critical step to boosting participation in the Distributed Generation sub-program, and ELPC/NRDC/VS believe that the REC value may need to be revisited in order to catalyze project development. ELPC/NRDC/VS have reason to believe that the typical ILSFA residential project is smaller than the typical Adjustable Block Program residential project. This leads to disproportionately high fixed costs, both those related to customer acquisition and with the installation itself. These fixed costs make a portfolio of ILSFA residential projects less palatable to a developer or investor than the REC formula - which focuses on "comparably-sized project[s]" - suggests. ELPC/NRDC/VS Rep. at 27-28.

It could also be the case that it is insufficient for the REC value to just be comparable to similar projects in the Adjustable Block Program. There is an opportunity cost to developers in creating a new sales process, learning the nuances of the Approved Vendor process, and diverting resources away from the plentiful Adjustable Block Program budget. This might suggest that the payoff from ILSFA Distributed Generation needs to accommodate higher returns. ELPC/NRDC/VS Rep. at 28.

## 2. IPA

The IPA appreciates that many stakeholders have expressed concern around the slow progress thus far of the Low-Income Distributed Generation sub-program and wishes to quickly review the budgetary structure of ILSFA. The law provides that funds from the RERF shall be used in specified percentages (see 20 ILCS 3855/1-56(b)(2)) for the four sub-programs of ILSFA, but does not provide any such percentages for the approximately \$11 million dollars of utility RPS collections that the law allocates to ILSFA each year (20 ILCS 3855/1-75(c)(1)(O)). The Initial Plan provided that utility funds shall be used for the three non-competitive sub-programs (but not for Low-Income Community Solar Pilot Projects) according to the same relative percentages as the law specifies for those sub-programs from the RERF, but also provided that the IPA may monitor activity and exercise its discretion to re-allocate utility funds from one sub-program to another as needed. For the 2018-2019 program year, one multi-family project application with a 15-year REC value of around \$4.0 million was received in the Low-Income Distributed Generation sub-program but the project was withdrawn by the Approved Vendor during the project review process. IPA Resp. at 71.

The Low-Income Distributed Generation sub-program thus had substantial unused total funds (over \$6.8 million) after the 2018-2019 program year project application period; the IPA exercised its budget re-allocation authority to a limited degree to accommodate heavy interest in the Low-Income Community Solar Project Initiative sub-program, moving \$355,723.97 of unused utility funds from the Low-Income Distributed Generation and Non-profit/Public Facilities sub-programs (60% from the former and 40% from the latter, mirroring their relative shares of total utility funds). Approximately \$6.7 million of remaining 2018-2019 budget for Low-Income Distributed Generation was rolled over to the next program year, making around \$14.0 million available for Low-Income Distributed Generation in 2019-2020. During the 14-day initial project application period for 2019-2020, one eligible project was received (the same project that had applied in 2018-2019, with previously open issues resolved) and ultimately recommended by the Program Administrator for a REC Contract. Another batch of ten single-family projects was not verified but many of those projects may be resubmitted by the Approved Vendor in the future once errors in their applications are resolved. IPA Resp. at 72.

With this background, the IPA is aware that project applications have not flowed in the Low-Income Distributed Generation sub-program as rapidly as many stakeholders had hoped for. Challenges to developing a project on a single-family home or multi-family residential building with low-income residents can include the structural integrity of the property, the creditworthiness of the building owner, and general lower awareness of solar power (or distrust of energy marketers) among low-income communities. The IPA believes that its REC pricing model, which offers a substantially higher REC price for this sub-program than for a comparably-sized project participating in the Adjustable Block

Program, adequately captures the risks and costs that a solar developer faces in the low-income market; that its Site Suitability Guidelines help developers to identify and remedy any structural problems before installation; and that its Grassroots Education program and ILSFA Distributed Generation Marketing Guidelines will together help to inform and build trust with low-income individuals potentially interested in solar. The IPA recognizes that building this sub-program to a sustainable, robust level of activity may be a long-term challenge that cannot be solved in a year (as of this filing, just over six months have passed since project applications first opened in the sub-program) and is committed to getting it right. The IPA welcomes proposals, either within this Revised Plan proceeding or through less formal feedback, for how to improve performance in the sub-program. IPA Resp. at 72-73.

The IPA opposes the restriction on its authority suggested by ELPC/VS for the following reasons. First, the IPA has already sought to mitigate the Low-Income Distributed Generation sub-program's challenges through changes made in the Revised Plan, including the following: 1) 25% of each program year budget will be reserved for 1-4 unit projects for the first nine months of the program year; 2) master-metered multi-family building owners will face a requirement to pass on benefits to all tenants in the building rather than attempting to limit the benefits to just low-income residents; and 3) the Agency has suggested an additional option for income verification that may also help overcome barriers faced by the sub-program. Second, the IPA is fully committed to making policy adjustments in between plan approvals, to the extent the plan permits, to seek to address challenges in the low-income residential sub-program. For example, the Project Selection Protocol developed and published in May 2019 sought to achieve diversity between 1-4 unit projects and 5+ unit projects. The IPA also understands that there are a number of ILSFA Approved Vendors who have stated their intent to begin to participate in this sub-program. IPA Resp. at 73-74.

But most importantly, the IPA expects that improving the performance of the Low-Income Distributed Generation sub-program will be an iterative process spanning multiple years and multiple plans as the IPA receives new information about project development and other programmatic issues and adjusts sub-program terms and conditions accordingly. While the IPA is mindful of the need to be responsible stewards of the Low-Income Distributed Generation sub-program's potential for bringing onsite solar to Illinoisans of limited means, the Revised Plan should not hinder the IPA from accommodating other demonstrated ILSFA program interest as needed. The IPA concludes by stating that it will exercise great caution before re-allocating funding from the Distributed Generation sub-program. IPA Resp. at 74-75.

### **3. Commission Analysis and Conclusion**

First, the Commission addresses ELPC/NRDC/VS's request that the IPA be prohibited from reallocating funds away from this sub-program. While the IPA discusses two-years of the program having moved forward, the Commission notes that ELPC/NRDC/VS clarify that the program was only open for one month of the first program year - a time period they assert to be too short to enable projects in the Distributed Generation sub-program to participate - and then reopened for the current program year in early September 2019. The Commission agrees that this is a short timeframe for a program with the many identified issues to have been open. The Commission adopts

ELPC/NRDC/VS's proposal to not reallocate funds at this time but, the Commission notes that this can be addressed again in the next review.

It is clear to the Commission that the Distributed Generation sub-program has experienced implementation challenges. It has not attracted Approved Vendors, perhaps because, as ELPC/NRDC/VS note, those Approved Vendors looking to do rooftop installations for ILSFA must also consider income eligibility, deferred maintenance issues, and lower electric bills that make it more difficult to justify the fixed costs of solar installations, thereby impacting both financial prospects for the Approved Vendor and potential cost savings for program participants. ELPC/VS Obj. at 10-11. Interestingly, the IPA provides its own list of challenges to developing a project on a single-family home or multi-family residential building with low-income residents, which it asserts can include the structural integrity of the property, the creditworthiness of the building owner, and general reduced awareness of solar power (or distrust of energy marketers) among low-income communities. IPA Resp. at 72-73. Of note to the Commission, most of these items are arguably out of the IPA's control.

ELPC/VS also complain that "the REC Aggregators that typically partner with and serve as Approved Vendors for small residential solar installers are not able to carry out some of the more bureaucratic requirements of the program and are generally unwilling to participate in the ILSFA Program because of the allocation of responsibility and risk in the program." ELPC/VS Obj. at 10-11. The Commission agrees that this is a problem, but ELPC/VS do not indicate what bureaucratic requirements are causing problems. Without specific proposals, a directive from the Commission to the IPA to fix problems with this sub-program will not be helpful. The problems are multi-faceted, and the IPA must work with ELPC/NRDC/VS and other interested parties to improve the sub-program.

ELPC/NRDC/VS also request that the REC price for this sub-program be raised. The Commission notes that the REC prices are already high compared to other LTRRPP programs. Although the Commission does not find that re-allocating money at this time is appropriate, it also is not clear that increasing the REC price will improve response to this program. The Commission sees the other issues identified as being more problematic than price. For that reason, the Commission declines to raise the REC price for this sub-program.

## **B. Section 8.6.1.2 Demonstrative Tangible Economic Benefits for Residents of Multifamily Buildings**

### **1. Ameren**

In Section 8.6.1.2, the Revised Plan discusses implementing aggregated net metering in multifamily buildings that are not master metered. The IPA appears to be concerned about how to ensure the equitable allocation of roof-mounted generation to the tenants of a multi-family building if the generator is interconnected to the utility's distribution system through the meter for the owner's main building account. Ameren Obj. at 10.

Ameren anticipated this concern during the revision of its Rider NM-Net Metering tariff. Under the Rider NM-Net Metering tariff, if the owners of multi-family buildings want to make the full capacity of their generator available to provide aggregated net metering

to their tenants, then they are required to have the generator interconnected to Ameren's electric distribution system. Alternatively, Ameren notes that the arrangement described above will also provide aggregated net metering, with the electricity exported to the grid and available to offset the tenants' usage being reduced by the usage associated with the main building account. Ameren Obj. at 10-11.

## **2. IPA**

The IPA appreciates that Ameren believes it has been proactive on this matter, but the IPA states that the purpose of the Revised Plan's language in Section 8.6.1.2 is to clarify the obligations of a landlord of a non-master metered multi-family building for purposes of providing tangible economic benefits to the building's residents. Therefore, the IPA believes no change to the Revised Plan is warranted on this issue. IPA Resp. at 75.

## **3. Commission Analysis and Conclusion**

The parties do not appear to have identified an issue for Commission resolution. Therefore, no revision to the Revised Plan on this issue is necessary.

### **C. Section 8.6.3 Incentives for Non-Profits and Public Facilities**

#### **1. Joint Solar Parties**

Consistent with the Joint Solar Parties' recommendations in public comment, the IPA no longer prohibits Approved Vendors from monetizing federal tax incentives as a precondition of participating in the non-profit and public sector behind-the-meter ILSFA incentive. See LTRRPP at 198. Prohibiting an Approved Vendor from monetizing the federal tax credit was forcing the Approved Vendor to leave a generally available revenue stream on the table with no benefit to the State of Illinois or the customer. However, the LTRRPP would require a higher customer savings value for systems where federal tax incentives were captured. See *id.* The Joint Solar Parties do not understand why the LTRRPP punishes an Approved Vendor for securing non-state and non-ratepayer revenue streams. JSP Obj. at 42-43.

#### **2. IPA**

For background, the IPA explains that the draft Revised Plan included a proposal to exclude any Non-profit/Public Facilities project receiving the Investment Tax Credit ("ITC"), which was intended to align this sub-program with the REC pricing model. As noted in Section 8.2.2 of the Revised Plan (footnote 470), the REC pricing model assumes that a Non-Profit/Public Facilities project owner is a non-taxable entity and thus does not utilize the ITC. However, after reviewing stakeholder comments on the draft Revised Plan, including from the Joint Solar Parties, which emphasized the importance and commonality of the ITC to financing these types of projects, the Agency elected in the filed Revised Plan to align the sub-program with the REC pricing model in a different way from the draft Revised Plan. This approach provides additional flexibility to ILSFA Approved Vendors. IPA Resp. at 76.

The baseline REC pricing incentive available in this sub-program, intended to provide a healthy 12% return on equity to developers, remains unchanged from the Initial Plan and presumes that the project owner does not use the ITC. To properly align

available incentives, receipt of the ITC will be permitted when an Approved Vendor representing a project in this sub-program either (i) certifies that the project's owner will not apply for the ITC in relation to the project installation, or (ii) agrees to provide 65% net savings (as a percentage of net metering value generated), elevated from the usual 50% net savings requirement, to the participating host of the project. This requirement recognizes that the ITC provides significantly more revenue to a project developer than that assumed in the REC prices paid to these projects. IPA Resp. at 76-77.

While the Joint Solar Parties allege that the Revised Plan would "punish" a project owner for securing the ITC revenue stream, the IPA states that it simply wishes to avoid granting an unnecessary and unjustified windfall to Non-profit/Public Facilities developers above that envisioned by the REC pricing model. JSP Obj. at 42-43. Existing uptake in this program has been healthy, with approximately \$7 million worth of project applications (before eligibility determinations) received in each of the 2018-2019 and 2019-2020 program years, in both cases exceeding the original annual program year budgets. The IPA explains that changes made to this and other aspects of the Non-profit/Public Facilities sub-program in the Revised Plan are intended to ensure the greatest amount of program value flows to those non-profit and public entities that produce the greatest public value and thus enjoy the most benefit from the new solar economy. IPA Resp. at 77.

### **3. Commission Analysis and Conclusion**

The IPA has explained the basis for REC prices in this category. The IPA's proposed requirement recognizes that the ITC provides significantly more revenue to a project developer than that assumed in the REC prices paid to these projects. The Commission sees no reason to direct revisions to the Revised Plan based on the Joint Solar Parties' Objections.

#### **D. Section 8.12.2 Project Selection for Sub-programs with High Demand**

##### **1. ELPC/NRDC/VS**

ELPC/NRDC/VS recommend that the Commission direct the IPA to retain discretion around how to use the ILSFA program's project selection process to incentivize work with minority- and woman-owned businesses. When applications to ILSFA sub-programs with administratively-set prices exceed the space available, the Program Administrator utilizes a project selection process to advance those projects that most closely align with the goals and priorities identified in law and detailed through the Revised Plan. In order to do this, the Program Administrator scores projects on a number of criteria related to those goals and priorities and selects those projects with the highest scores. ELPC/VS Obj. at 12.

One of the criteria on which projects are scored is their utilization of minority- and woman-owned businesses, which is consistent with statutory goals around a diverse workforce. See 20 ILCS 3855/1-75(c)(7). ELPC/VS agree with the IPA that including criteria related to project utilization of minority- and woman-owned businesses in the scoring for ILSFA project selection makes sense and aligns with the goals and priorities of the law. ELPC/VS Obj. at 12.

However, ELPC/NRDC/VS note that the Revised Plan actually gets more specific about exactly what the Program Administrator will score to determine whether projects

are utilizing minority- and woman-owned businesses: “Attributes that will receive higher scores include: ... Projects developed by Approved Vendors that are women- or minority-owned businesses...” (Plan at 207). While ELPC/VS agree that this specific approach is one way to incentivize working with minority- and woman-owned businesses, it is not the only way and they worry that approving this specific approach in the Plan could inadvertently block more effective approaches to incentivizing this work. ELPC/VS Obj. at 12.

Through both organizations’ work with the ILSFA Working Group, ELPC/VS are aware of concerns that placing incentives around minority- or woman-owned business status on the Approved Vendors, alone, limits the effectiveness of the intended incentive. This limitation would occur because contractors and subcontractors are extremely common in the solar business and, in theory, expanding the reach of this criteria beyond just Approved Vendors and into the entire solar supply chain would be positive. At the same time, ELPC/NRDC/VS are aware of concerns from the ILSFA Program Administrator about the feasibility of expanding the reach of this criteria, particularly if contracted work has not yet occurred. ELPC/VS Obj. at 13.

Therefore, ELPC/VS do not ask the Commission to change how the criteria around incentivizing work with minority- and woman-owned businesses functions today. ELPC/NRDC/VS do not ask the Commission to direct the IPA to move away from a focus on the Approved Vendor. Rather, ELPC/NRDC/VS urge the Commission to direct the IPA to be more general when it talks about what the criteria focused on incentivizing minority- and woman-owned business participation will encompass in the Plan that will be approved by this Commission. ELPC/VS Obj. at 13.

In its Response, the IPA indicates that it “is open to considering ELPC/VS’s suggestion,” but first “recommends a workshop or public comment process to flesh out this requirement including how to ensure that a commitment to work with those businesses can have upfront verification and also be reduced to contractually-enforceable provisions.” IPA Resp. at 79. ELPC/NRDC/VS believe such an approach to any change to this attribute - or any attribute - makes sense. The IPA further points out that ELPC/VS’s original language suggestion was inaccurate inasmuch as it is the Approved Vendors, not the projects that must work with specific businesses. Accordingly, ELPC/NRDC/VS recommend the Commission order the following language edit for page 208 of the Plan:

- ~~Projects developed by~~ for which Approved Vendors ~~that are~~ work with women- or minority-owned businesses, or

ELPC/NRDC/VS further recommend that the Commission alter the Plan to ensure that, prior to adopting an additional scoring consideration for projects for which Approved Vendors work with minority- or woman-owned businesses, the IPA hold a workshop or public comment process to flesh out this requirement, including how to ensure that a commitment to work with those businesses can have upfront verification and also be reduced to enforceable provisions. ELPC/NRDC/VS Resp. 29-30.

## 2. IPA

In the ILSFA Program, when a program year opens and applications in a sub-program are received that, once reviewed and verified, exceed the value of annual budgetary funds available for that sub-program, a project selection protocol is used to select projects to be submitted to the Commission for approval. This approach was not described in the Initial Plan but was developed (including through taking stakeholder input) by the ILSFA Program Administrator during the implementation and launch of the program. For both the 2018-2019 and the 2019-2020 program years, the project selection protocol was used for the Low-income Community Solar sub-program. IPA Resp. at 77-78.

Given the need for this process, in the Revised Plan the IPA included new Section 8.12.2 to describe the selection process for ILSFA Program. That section includes a description of the criteria to be used, such that attributes that will receive higher scores include: 1) Location with an Environmental Justice Community, 2) Location within a low-income community (as defined in Section 8.6.3 of the Revised Plan), 3) Projects developed by Approved Vendors that are women- or minority-owned businesses, 4) Preferences for types of subscribers in Low-Income Community Solar projects, as outlined in Section 8.6.2; and 5) Other attributes that align with Plan priorities. IPA Resp. at 78-79.

In response to ELPC/VS, the IPA states that a reason why it phrased the attribute to be “developed by Approved Vendors” is that this would be a measurable attribute because the Approved Vendor would have to demonstrate that it is woman- or minority-owned. This attribute is verifiable – which is a key consideration when selecting some projects but not others due to funding limitations. The IPA is open to considering ELPC/VS’s suggestion but prior to adopting an additional scoring consideration for projects (or more accurately the Approved Vendor) that work with minority- or woman-owned businesses, the IPA recommends a workshop or public comment process to flesh out this requirement including how to ensure that a commitment to work with those businesses can have upfront verification and also be reduced to contractually-enforceable provisions. In other words, these protocols would clearly establish how an Approved Vendor would provide robust documentation of the planned work and how, because its project could be selected ahead of other projects that do not make this commitment, it would be at risk of contract termination if it subsequently did not work with the committed woman- or minority-owned businesses in actually developing the project. IPA Resp. at 79.

## 3. Commission Analysis and Conclusion

The Commission notes that the IPA is open to considering ELPC/VS’s suggestion but recommends a workshop or public comment process first to flesh out this requirement, including how to ensure that a commitment to work with those businesses can have upfront verification and also be reduced to contractually-enforceable provisions. The Commission agrees that this appropriate.

The Commission notes that the Revised Plan already includes an open-ended general requirement that states: “other attributes that align with Plan priorities.” The Commission finds this to be broad enough to allow the replacement of listed attributes

with other attributes that further the same Plan priorities so that no change in language in the Revised Plan is necessary to allow the IPA to adopt any changes that result from the discussions.

## **E. Section 8.13.2 Determining Income Eligibility**

### **1. ELPC/NRDC/VS**

ELPC/NRDC/VS recommend that the Commission direct the IPA to improve consumer protections by shifting the responsibility of verifying household income eligibility for ILSFA from the Approved Vendor to the Program Administrator and maintaining flexibility for future changes to the income verification process. ELPC/NRDC/VS explain that Approved Vendors of the ILSFA program currently have three options for verifying income eligibility: 1) by demonstrating enrollment in third-party programs with similar income thresholds, 2) by providing Form W-2 tax documents for every member of the household over 18 years of age, or 3) by collecting Form 4506-T paperwork to pull Form 1099 tax transcripts. ELPC/VS take no issue with the first two options but worry that the third (and, admittedly, least preferable) option puts consumers' sensitive information at risk and might be inhibiting participation by Approved Vendors. ELPC/VS Obj. at 14.

ELPC/NRDC/VS recommend that all income eligibility that is not determined through a qualified third-party program be decided by the Program Administrator. This role for the Program Administrator appears to be evident in the Plan: "The Illinois Solar for All Program Administrator will...Act as the centralized source for income verification and maintain database of program participants." Revised Plan at 201. It will be significantly easier for the Program Administrator to develop the expertise and protocols to request, process, handle, and destroy sensitive information than for individual Approved Vendors to do so. The Approved Vendor would still collect the Basic Information Form that requires the participant to list income levels for all adult members of the household and to declare whether they own or rent. This form also has a page that invites participants to choose how they would like to verify their income eligibility. If they choose an option that requires sensitive information, such as Option 2 (W-2) or Option 3 (4506-T) then the official income verification process would be done after the project is submitted for the Program Administrator's review. This process could lead to an increased number of projects that are disqualified after batch submission, so the current rule requiring 75% of submitted projects to be eligible might need to be altered. ELPC/VS Obj. at 15.

ELPC/VS are open to alternative solutions and would like to maintain flexibility in the Revised Plan that allows changes to the income verification process as we learn more about obstacles to implementing ILSFA. In their comments on the draft Revised Plan, the ILSFA Working Group suggested an alternative process that would mirror the existing income verification methods for community solar projects in the Distributed Generation sub-program. The IPA determined that this was insufficient verification for the relatively high value of Distributed Generation projects. While ELPC/VS understand the concern about the misallocation of funds based on unverified reports, they are also mindful that some version of this recommendation might eventually become the best course for protecting consumers and improving participation by Approved Vendors. As such,

ELPC/VS encourage the Commission to leave room for flexibility and adaptation for income verification methods between this Plan and the next. ELPC/VS Obj. at 15-16.

In Reply, ELPC/NRDC/VS support the IPA's suggestion that provides prospective Low-Income Distributed Generation customers with an option to verify their income through the Program Administrator. This approach was included in the Initial Plan for customers interested in community solar subscriptions but not for Distributed Generation customers. ELPC/NRDC/VS support the IPA's recommendation that the Commission approved Section 8.13.2 of the Revised Plan with this additional approach for Low-Income Distributed Generation. IPA Resp. at 82. Given the turbulent history of energy suppliers in Illinois using predatory or misleading tactics, ELPC/NRDC/VS expect that this change will provide customers with additional comfort in going through the ILSFA qualification process. While ELPC/NRDC/VS agree that most income verification will take place using other means - and maintain that there should be easier and more dignified options for potential customers to verify their income - ELPC/NRDC/VS believe this recommendation from the IPA will boost participation in the ILSFA Distributed Generation sub-program. ELPC/NRDC/VS Rep. at 30.

ELPC/NRDC/VS also recommend that the Program Administrator play a larger role in connecting interested customers with applicable Approved Vendors. ELPC/NRDC/VS are mindful that it is not the job of the Program Administrator - or the Grassroots Education organizations they fund - to do customer acquisition or lead generation for Approved Vendors. ELPC/NRDC/VS are also mindful, however, of the concerns from potential ILSFA customers regarding how difficult it is to connect with the program and find Approved Vendors that have specific offers for their specific circumstances. The current system requires potential customers to go through a long list of Approved Vendors that may or may not serve their needs. If the Program Administrator is able to perform income verification for interested customers, ELPC/NRDC/VS suggest that the Program Administrator also provide a landing page that invites customers to input relevant pre-screening information. This information could then help direct them to the specific vendor(s) that work in their area on their type of project. ELPC/NRDC/VS urge the Commission to alter the Revised Plan to state that the IPA or its Program Administrator will explore options for channeling interest in the program towards the Approved Vendor community. ELPC/NRDC/VS Rep. at 30-31.

## **2. IPA**

The IPA does not agree with ELPC/VS's proposal. Submitting a project application to the ILSFA Program requires substantial information about the proposed project to be developed and submitted by the Approved Vendor at its own cost (as the program prohibits upfront payments from participants). If participants' income eligibility was an unknown prior to project submittal, the risk to the Approved Vendor would be disproportionately high as its time and effort in developing the project could be wasted. IPA Resp. at 81.

ELPC/VS do state that they are "open to alternative solutions and would like to maintain flexibility in the Plan that allows changes to the income verification process as we learn more about the obstacles to implementing ILSFA." ELPC/VS Obj. at 15. The IPA notes that for low-income community solar, the IPA proposes the following:

While generally the Agency would expect the Approved Vendor to verify a potential low-income community solar subscriber's income through one of the methods described in this Revised Plan, the Agency recognizes that some potential subscribers would prefer to have their income verified independently of their community solar subscription. In such cases, a potential subscriber may request income verification directly through the Program Administrator, and if approved, that verification would remain valid for six months. The Program Administrator would provide the potential subscriber with a verification letter that could be provided to the Approved Vendor.

A similar approach could be considered for the Low-Income Distributed Generation sub-program. Under this approach, a homeowner interested in participating could request income verification directly through the Program Administrator and be issued an eligibility letter that an Approved Vendor could then use as part of the project application. This approach would have the secondary benefit that an interested homeowner would be able to use the eligibility letter with multiple Approved Vendors if he or she desired to solicit multiple proposals for a solar project. The IPA respectfully asks that the Commission approved Section 8.13.2 of the Revised Plan with this additional approach for Low-Income Distributed Generation. IPA Resp. at 81-82.

### **3. Commission Analysis and Conclusion**

ELPC/NRDC/VS accepted the IPA's proposal presented in its Response. This seems reasonable to the Commission as well and it is approved. ELPC/NRDC/VS made an additional proposal in their Reply that the IPA's Program Administrator should steer parties in the ILSFA to Approved Vendors. The Commission agrees that this could provide reassurance that the vendors are part of the program. The Commission determines that the IPA and the ILSFA Program Administrator should explore implementing a process to connect interested income-qualified customers with ILSFA Approved Vendors, but agrees with the IPA that any such process must be implemented in a competitively neutral fashion and strive to provide equal information and opportunities to all applicable ILSFA Approved Vendors. Further, the IPA will conduct a stakeholder feedback process to work through key implementation details prior to implementation.

## **VII. FINDINGS AND ORDERING PARAGRAPHS**

The Commission, having reviewed the entire record, is of the opinion and finds that:

- (1) Commonwealth Edison Company, Ameren Illinois Company d/b/a Ameren Illinois and MidAmerican Energy Company are corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;
- (2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;

- (3) the recitals of fact and conclusions of law in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law;
- (4) the Revised Long-term Renewable Resources Procurement Plan, as modified herein, will reasonably and prudently accomplish the requirements of Section 1-56 and subsection (c) of Section 1-75 of the Illinois Power Agency Act;
- (5) the Revised Long-term Renewable Resources Procurement Plan, as modified herein, should be approved by the Commission; and
- (6) the Illinois Power Agency should file a compliance filing within 60 days of this Order consistent with the findings herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications adopted in the prefatory portion of this Order, the Revised Long-term Renewable Resources Procurement Plan, is hereby approved.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 18<sup>th</sup> day of February, 2020.

(SIGNED) CARRIE ZALEWSKI

Chairman